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Steam Coal for Power and Industry Issues and Scenarios

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Steam Coal for Power and Industry

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Abstract

This working paper provides a comprehensive overview of the status of world steam coal production and use. It reviews current reserves and forecasts, production, consumption and pricing. The main issues facing the industry, especially in light of environmental challenges, the future outlook for coal as an important energy source for power and industry are discussed. The implications for developing countries production and use of coal are considered and the need for stronger emphasis on the reform of the regulatory framework and encouraging private investment in coal mining especially for export.

Further work is planned to review the World Bank's experience in lending for coal mining projects with a view to developing a policy paper addressing issues and problems encountered in past lending experiences.

STEAM COAL FOR POWER AND INDUSTRY

WEIGHTS, MEASURES AND CONVERSION FACTORS

Btu	=	0.252 kilocalories = 1.055.1 kilojoules
kcal	=	4.1868 kilojoules = 3.968 Btu
km	=	0.621 miles
kWh	=	3412 Btu
kg	=	2.21 pounds
mt	=	1,000 kg
tce	=	1,000 kg with 6,680 kcal per kg or 6.7 million kcal
toe	=	10.2 million kcal
1,000 cubic meters of natural gas	=	9.31 million kcal

PRINCIPAL ACRONYMS AND ABBREVIATIONS

AIC	-	Average encrimental cost, a proxy for LRMC
AFBC	-	Atmospheric fluidized bed combustion
bbl	-	barrel
Btu	-	British thermal unit
CC	-	Combined Cycle
CHP	-	Combined heat and power
CO2	-	Carbon dioxide
CPE	-	Centrally planned economies
dB	-	Decibel
dwt	-	dead-weight ton
ESP	-	Electrostatic precipitator
FBC	-	Fluidized bed combustion
FGD	-	Flue gas desulfurization
GDP	-	Gross domestic product
GW	-	Gigawatt
GWh	-	Gigawatt hours
Hz	-	Hertz
IGCC	-	Integrated coal gasification and combined cycle
IGHAT	-	Integrated gasification and humid air turbine cycle
kg	-	Kilogram
km	-	Kilometer
kW	-	Kilowatt
KWh	-	Kilowatt hours
LIMB	-	Limestone Injection Multistage Burner
LNG	-	Liquified Natural gas
LRMC	-	Long-Run Marginal Cost
M	-	Million
m	-	meter
mm	-	milimeter
m3	-	cubic meter
mmBtu	-	Million British thermal units
mt	-	metric ton (tonne)
Mmt	-	Million metric tons
Mtce	-	Million tons of coal equivalent

Mtpy	-	Million tons per year
MW	-	Megawatt
NOx	-	Nitrogen oxide
PCF	-	Pulverized coal-fired (boilers)
PFBC	-	Pressurized fluidized bed combustion
ppm	-	parts per million
PSIG	-	Pounds per square inch guage
PSE	-	Producer subsidy equivalent
ROM	-	Run-of-mine
SO2	-	Sulfur dioxide
spm	-	Suspended particulate matter
SCR	-	Selective catalytic reduction
tce	-	ton of coal equivalent
toe	-	ton of oil equivalent
TWh	-	Terawatt hours

STEAM COAL FOR POWER AND INDUSTRY

ISSUES AND SCENARIOS

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The report has been prepared by the authors on the basis of information and literature available in 1991/92. The authors have benefited from recent work by Shigeru Kataoka and B. Guerami, and from valuable comments by the reviewers, Messrs. Cordukes, Pollak, Fritz and Choe.

EXECUTIVE SUMMARY

Main Issues and Findings

1. A review of current and future world coal production and utilization yields a picture of a stable and sustainable energy sub-sector, which, however, is vulnerable to increasing external influences, mainly of an environmental nature. These externalities will require a rethinking of strategies in a traditionally conservative and complacent sector: a failure to do so by continuing business as usual may result in a significant loss of the fuel market share for coal in the medium term. The long-run strength of the role of coal as economically attractive fuel for power and industry may be compromised if the coal producers and users neglect to respond to the short-run comparative disadvantages they are facing in environmental and cost terms. Indeed, rather than merely reacting to negative developments, the coal industry's chance lies in taking the initiative and in developing creative new strategies for survival.

2. The main issues that are evident in the coal chain from production to utilization are the following:

(i) Coal mining productivity and production costs show a wide disparity worldwide, not only because of local geological circumstances but also due to markedly differing efficiencies of individual enterprises. Many old underground mines in Eastern Europe, China and India are commercially marginal or non-viable, while other mines suffer from institutional and technical inefficiencies. Streamlining and rehabilitation of the coal mining industry is urgent in several major coal-producing countries, including the financial and institutional restructuring of coal mining in the CIS, Poland, and Czechoslovakia. High West European production costs will lead to an inevitable continuing shrinkage of the subsidized coal industry in the UK and Germany.

(ii) Coal preparation (washing, other beneficiation) is likely to become more important as the environmental impact of coal mining and transport is examined more closely, and as the efficiency benefits of higher-quality coal in power station and industrial use are defined more clearly. Similarly, the mitigation of the environmental damage from mining, such as the reclamation of open-pit land, and the protection of groundwater, will be an essential requirement even outside the OECD. The costs of mitigation and coal preparation (e.g US$4-8/ton for coal washing) will have to be borne by producers and consumers: where market mechanisms do not determine the sharing of such costs, least-cost economic solutions will have to be found by optimization.

(iii) International coal trade is encouraged by the worldwide spread of coal resources, and by the relative ease of bulk transport that facilitates a competitive international market. The current 10% share of traded coal in total world coal consumption is likely to

increase significantly over the next 10-20 years, in the wake of the reduction of European coal production and the subsequent influx of imported seaborne steam coal from lower-cost producers. Emerging coal exporters with low cost structures and high-quality steam coal, such as Indonesia and Colombia, will make strenuous efforts to gain a larger share of a growing international steam coal market. However, the risks of new mining ventures in emerging or established coal exporting countries, in a market characterized by buyers' choice and bargaining power, are high.

(iv) International coal prices have a stable record over time, following the more violent fluctuations of the oil market only slowly, if the latter prove to be sustained. The competitive nature of the traded coal market, with unconstrained entry of new participants, limits the rise of coal prices. Similarly, the competition from other fuels such as natural gas and heavy fuel oil creates a price cap in areas where such alternative fuels are readily available. The sea freight component of the delivered coal price, typically 15-25% of the total, is also limited by the free market in bulk freight, and by the long-term prospect of sufficient shipping and port capacity in exporting and importing countries. Only low-cost producers will be able to make substantial new investments in mining and exporting capacity in the future.

(v) Domestic coal prices, in contrast to those for internationally traded coal, are heavily controlled in most countries that produce and consume coal. Among the world's major coal consumers, the USA is the only country where the coal market is efficient, although its major customer, the power industry, is heavily regulated. In other major consuming countries, such as the CIS, Germany, the UK, China, and India, direct and hidden subsidies abound, the pricing structure often is distorted, and the government intervenes directly in the controlling of coal prices. The efficiency loss of these distortions is heavy: subsidized consumer prices lead to waste or wrong investment decisions; artificially low producer prices discourage the development of new coal resources; producer subsidies maintain commercially non-viable mines; and the lack of price discrimination by coal quality or transport distance distorts the fuel choice. Domestic coal price reform is urgent.

(vi) Environmentally benign coal utilization is becoming a key element of strategic planning in the power generating and industrial sectors. Increasing local and global concerns about the effects of atmospheric emissions from coal burning, such as ambient air quality, acid rain or global warming, are dominating the decisions about fuel choice and appropriate technologies. In a departure from the earlier practice of merely minimizing the cost of supply, power utilities now face an expanded menu of investment choices, including demand-side efficiency improvements, new generating technologies, and environmentally-driven retrofitting, which need to be optimized under regulatory constraints. The choice of coal as boiler fuel now has to be embedded in the framework of environmental mitigation and

energy conservation that satisfies the new requirements.

(vii) Emerging "clean coal technologies" for power generation and industrial steam raising are being developed rapidly to commercial scale. These new or adapted technologies range from advanced coal preparation, coal refining and gasification, through combustion and generation processes such as fluidized-bed combustion (FBC), integrated gasification/combined cycle (IGCC), and pollutant-minimizing burner technology, to more efficient flue gas scrubbing and filtering methods. These developments are responding to the environmental restrictions increasingly being placed on conventional coal-burning facilities. Although carbon emissions can be affected only marginally by these technologies through higher efficiency of fuel use, other atmospheric emissions such as SO2, Nox, and particulates can be controlled effectively. While some of the more advanced processes are still in the pilot stage, the FBC technology has already proven to be popular in industrial and cogeneration applications, and IGCC technology is approaching maturity.

(viii) Fuel choice for power and industry differs by region, depending on the relative prices of available fuels. Nevertheless, the efficiency, cost, and environmental advantages of natural gas-fired power generation (particularly in its combined cycle configuration) are making gas the preferred fuel in most parts of the world where it is available at not more than US$ 2-4/mmbtu. Coal technology with environmental safeguards is competitive only in areas with simultaneously low coal cost and high gas cost (China, India, parts of Eastern Europe), or where gas is not readily available. Everywhere else, the attractiveness of gas is limited only by the volumes that can be supplied before the price rises significantly. In the long run, coal gasification technology may take over from natural gas facilities, as depletion raises the relative price of gas.

(ix) Coal consumption projections until 2015 indicate that the imposition of significantly tightened environmental requirements (carbon taxes, stricter emission restrictions) during this decade would result in a temporary decline in coal use until after the turn of the century, followed by a renewed growth of coal consumption as the relative price gap to gas widens again. Under a business-as-usual scenario (including current environmental limitations), or under the assumption of a sustained jump in oil and gas prices, world coal consumption grows at about 2-3% per year for the next 20 years. Under all scenarios, global consumption in 2015 is significantly above that in 1990, even in the case of a strong dip in the late 1990s. This is particularly pronounced in the case of Asia, which shows the biggest absolute increment in coal use among all regions, regardless of the underlying assumptions. In fact, Asian coal demand drives the revival of coal use in the next century in the strict-control scenario, while the OECD demand stagnates. China and India, and at a later stage the revitalizing Eastern European and CIS countries, will be the driving forces of incremental coal demand.

(x) The role of the developing countries in the global coal picture in the coming decade will have to be characterized by innovative and creative approaches to producing and using coal. This would include a greater concentration on improvement of mine productivity, mitigation of environmental damage, combination of power efficiency and coal preparation investments, transfer of emerging clean coal technology, and the promotion of a broad spectrum of options for utility planning. A stronger emphasis on the reform of the regulatory framework affecting the coal sector (including power industry regulation and coal pricing), and on encouraging the opening up of the coal and power sectors to private investment will be necessary. Private or joint ventures in export-oriented coal mining, or in combined power/coal development, will need to be encouraged by carefully targeted assistance. The Bank's growing involvement in Eastern Europe, and its continuing activity in China and India, will focus these efforts naturally on the major future coal users where problems exist.

The Environmental Challenge for Coal

3. Prima facie, the future of coal in a world concerned about global warming and acid rain looks bleak. Its advantage as a stable, long-term fuel source with a 300-year availability at current production rates (as compared to reserve/production ratios of 40-60 for oil and gas) is rapidly being eroded by the perception that carbon, sulfur, nitrogen, and dust emissions from coal burning are far worse than those from other fuels. In addition, coal is burdened by the land deterioration caused by mining, and by the need to dispose of ash and other waste.

4. Notwithstanding the environmental handicaps, the underlying strength and momentum of the role of coal as fuel for power and industry should not be underestimated. The world consumption of steam coal is approaching 3 billion metric tons per year, of which close to 2 billion tons are used by the power sector. In the long run, this represents about 25-30% of total primary energy consumption in calorific terms. Despite fluctuations in this share, caused by periods of sustained high or low oil prices, the core demand for coal has remained relatively stable. These volumes, and the fact that coal-fired equipment in the power and industrial sectors has high capital costs and long life, guarantee that changes in the relative importance of the coal sector are slow and happen in small increments.

5. Even with the help of this feature, the coal industry would face a steady decline, as other, cleaner fuels increase their market share in power generation and industrial cogeneration. This "do-nothing" scenario is unlikely to materialize, as efforts to improve the environmental attractiveness of coal have been underway for some time. Even the "business-as-usual" reference case employed for projections in this report takes into account that large strides have already been made in the OECD countries to put in place emission limits, and encourage environmentally more benign technologies for coal use. The base case for future coal utilization, therefore, shows a continuing increase of coal demand on the back of the spread of mitigation technologies. Not even the

imposition of radical new greenhouse-gas-limiting measures such as a substantial carbon tax would break the back of the coal industry in the long run, although they would lead to a temporary decline, followed by a revival driven by a resumption of cost competitiveness.

6. This is where the challenge lies. The lean times during the late 1990s and early 2000s under the "carbon-tax" scenario have to be weathered by strong efforts by the coal and equipment industries to develop and implement highly productive coal mining, transportation and utilization processes, and to streamline their institutions. Failing that, the loss of market share may have been so large that a possibly re-opening relative price gap between coal and gas may not find the coal and power industries in a position to respond quickly enough. The best course of action for the 1990s under severe environmental constraints will be institutional, regulatory, and pricing reform, and the improvement of efficiency in coal production and utilization. The Bank should assist its borrowers in this effort.

Comparative Costs and Prices

7. The long-term stability of international coal prices masks a wide range of local and regional differences that determine the relative attractiveness of coal as fuel. On a common heat value basis, steam coal (ranging from lignite to bituminous) has a typical current range of costs between US$0.60 and US$2/mmBtu, with international CIF prices closer to the upper end of the range. Coal availability at an economic cost close to the lower end of the range (pithead delivery of low-quality coal to power stations in India, China, or Eastern Europe) provides a competitive edge vis-a-vis natural gas even with substantial environmental mitigation investment. In all other cases, coal is only attractive if gas is unavailable or very costly. In economic terms, therefore, it is only the slowly increasing price differential between coal and gas over the next 20 years, as forecast by most analysts, that moves coal-fired generation back into a competitive position.

8. This generally valid economic picture is undermined by the distortions existing in domestic energy pricing in many coal-consuming countries. For reasons of residential consumer protection, mine employment maintenance, or energy self-sufficiency, governments are controlling coal prices and the fuel choice of major consumers. This is the case in Europe, where mines producing internationally uncompetitive coal are kept operating, and power utilities are obliged to buy domestic coal in violation of least-cost principles. It is also the case in China and India, where coal from specific mines is allocated to power stations, and prices often do not reflect quality differentials and transport costs correctly. The distortions lead to coal use beyond economically justified levels, or to the use of high-cost domestic coal instead of low-cost imports.

9. Price distortions and the lack of price reform often is the result of an inflexible institutional and regulatory framework in the coal sector. The lack of market mechanisms in the domestic pricing and market clearing process hampers the efficient production and use of coal. A liberalization of coal prices, and a general deregulation of the coal sector in the direction of creating an arms-length regulatory process are desirable targets for the heavily-controlled coal industry in Europe and Asia. A leaner, more flexible coal sector will have a

better chance of survival than one subject to traditional interventionist government rules. Similarly, an increased readiness on the part of hitherto reluctant governments to allow more private investment in profitable coal mining ventures would attract capital and efficient management to the sector: Indonesia and China have demonstrated that private coal mining franchises and joint ventures can be introduced successfully in a mostly state-controlled sector.

10. The Bank can play a useful role in the encouragement of regulatory reform, price liberalization, and the opening of the sector to private investment. An increasing involvement in more complex lending operations will allow issues in both coal and power sector regulation to be addressed simultaneously, as the efficiency and environmental requirements will imply combined operations that encompass mining rehabilitation, coal preparation, coal transport, combustion technology, and power station efficiency. The vulnerability of the global coal sector in the 1990s should be a powerful incentive to streamline the industry, and prepare the sector for renewed growth in the next century.

I. OVERVIEW

Background and Status

1.1 The nature of coal. Coal is a family name for a wide variety of solid fuel minerals. These range from low-heat, high-moisture content peat to the high-heat, high-carbon content anthracite.[1] The basic differences in characteristics are the result of variations in the nature of the initial material, the environment in which it is deposited, and the complex physical and chemical reactions that transform waste vegetation into solid fuels. The degree of 'coalification' determines the rank or geological classification of these minerals as anthracite, bituminous, sub-bituminous or brown coal, or lignite. Generally, the extent to which waste is displaced by useable fuel depends on the time elapsed - the older the coal, the more complete is the coalification process. The oldest coal field dates back to about 300 million years (Table 1.1).

Table 1.1: CHRONOLOGY OF COAL RESOURCES BY TYPE

Era	Period	Age (million years)	Rank of Coal
Quaternary	Pleistocene	Up to 1	Peat
Tertiary	Miocene	1 - 20	Lignites
	Oligocene	20 - 40	Lignites
	Eocene	40 - 60	Lignites and sub-bituminous
Mesozoic	Cretaceous	60 - 100	Sub-bituminous and bituminous
	Jurassic	100 - 150	Bituminous
	Triassic	150 - 180	Bituminous
Upper Paleozoic	Permian	180 - 210	Bituminous and Anthracitic
	Carboniferous	210 - 300	Bituminous and Anthracitic

1.2 Coal Classification. Coal is classified according to its content and properties on the basis of chemical analysis and a number of empirical tests. Two types of chemical analyses are generally used - ultimate analysis which determines coal constituents like percentage of carbon, hydrogen, oxygen and sulfur without mineral matters or ash, and proximate analysis which determines moisture, volatile matter and ash, all adding up to 100%. Coking coals are additionally analyzed for caking and coke-making properties. The results are expressed in qualifying terms denoting the method of analysis such as "as-received basis", "moisture-free basis", "dry-mineral-free basis" etc., and form the basis of classification of coal by rank. However, there is no

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[1] Peat is generally ignored in discussions of coal.

internationally accepted system of demarcation among coal of different rank. Table 1.2 shows the US classification of coal by rank.

Table 1.2: CLASSIFICATION OF COAL BY RANK IN USA

Fixed carbon %	Volatile Matter %	C.V. limits (dry, mmf basis) Equal or Greater	Less	Limits (moist, mmf basis) Equal or Greater	Less	BTU/lb /a moist /b, mmf basis) Equal or Greater	Less
Class	Group	than	than	than	than	than	than
I. Anthracitic	Meta-anthracitic	98	-	-	2	-	-
	Anthracitic	92	98	2	8	-	-
	Semi-anthracitic	86	92	8	14	-	-
II. Bituminous	Low-volatile	78	86	14	22	-	-
	Med.-volatile	69	78	22	31	-	-
	High-volatile A	-	69	31	-	14,000 /c	-
	B	-	-	-	-	13,000 /c	14,300
	C	-	-	-	-	11,500	13,300
III. Sub-bituminous	A	-	-	-	-	10,000	11,500
	B	-	-	-	-	9,500	10,500
IV. Lignitic	Lignite A	-	-	-	-	6,300	9,500
	Lignite B	-	-	-	-	-	6,300

Note: mmf - mineral matter free
/a 1,000 BTU/lb = 556 kcal/kg = 2,326 kj/kg;
/b moist refers to inherent moisture in coal and not moisture adhering to the surface of coal particles;
/c coals having 69% or more fixed carbon on the dry, mineral matter free basis shall be classified according to fixed carbon, regardless of calorific value.

Source: Annual Book of ASTM Standards, pp. 36 & American Society of Testing and Materials, 1979.

1.3 The Economic Commission for Europe (UN-ECE), however, recognizes only two broad categories of coal: (a) hard coal with a gross calorific value in excess of 5,700 kcal/kg on moisture and ash free basis (23.84 mj/kg), listed according to calorific value, volatile matter content and coking properties; and (b) brown coal with a gross calorific value not exceeding 5,700 kcal/kg on moisture and ash free basis. The International Energy Agency (OECD/IEA) also uses these two categories for its statistics on production, trade and consumption. Hard coal is further disaggregated into coking and other bituminous coal and anthracite, and brown coal into sub-bituminous coal and lignite.

1.4 Coking or metallurgical coal has the quality that when it is heated in a closed vessel in the absence of air it produces a hard porous mass (coke) that is used in industry for the manufacture of iron and steel. All other bituminous coal and anthracite, defined as hard coal used for steam and power generation, are known as steam or thermal coal. Sub-bituminous coal (also classified as thermal coal) has a calorific value ranging between 4,165 to 5,700 kcal/kg and lignite lower than 4,165 kcal/kg. Since lignite also has high moisture content, it is mostly used for on-site use (in power plants) and is not an internationally traded fuel.

Coal Resources and Reserves

1.5 In contrast to oil and natural gas, coal resources and reserves are extensive and widely endowed over the world, and this dispersion enhances its attractiveness as a long-term source of energy supply. Coal occurs as thick beds of black mineral and is easily identifiable by its outcrops (i.e. portions that are visible on the surface) and easy combustibility. The occurrence of coal in large continuous seams, some of which outcrops, makes it easier to find than oil or gas. The large physical or geological endowments of coal resources make it the most abundant fossil fuel resource worldwide.

Conservative estimates place worldwide geological resources at over 10,000 billion metric tons of coal equivalent. Significant geological coal resources are available in about 50 developing countries, a similar number to the countries with significant gas availability.

1.6 While the physical occurrence of coal is readily noted, estimates of economically recoverable reserves are more difficult to secure and are mostly confined to major or established producers. Few national governments collect reliable information about what can be called real mineable reserves. Conversely, national data on coal resources do not serve any commercial purpose. Government authorities are generally interested in the broad assessment of deposits in order to develop national energy policy. The information is often compiled from data of different vintages, seldom accounting for resources already exhausted or lost, and based on arbitrarily fixed parameters. In most of the OECD countries, producers are required to provide annual reports on proven reserves of oil and gas, but not coal. Only in the USA, the coal mining companies are required to report the balance of minable reserves to the government at the end of each year.

1.7 The assessment of economic attractiveness of coal resources is a time-consuming and expensive process, requiring the combined expertise of geology, mining, transport and marketing. This is usually undertaken directly by the mining enterprise to establish a viable mining operation and does not extend beyond a property life of 30-40 years.[2] The process of evaluation commences with exploration which includes drilling into coal beds (seams), physical and chemical analysis of coal samples and determination of the appropriate technology for extraction of coal. Basic geological information is obtained from the general geology of the area, surface prospecting and mapping and bore hole drilling. These data are assembled to determine the size of the mining block, nature of rock strata above and below the coal beds, attitude and continuity of the strata. Other information required include the presence of methane gas, unusual properties of water etc., which could have effect on the choice of mining technique and cost of production. Explored reserves are categorized as proven, probable or possible (measured, indicated or inferred) to indicate the decreasing degree of confidence on the estimates of quantity and quality of deposits.

1.8 Currently almost all major coal producing countries assess and update their coal resource and reserve on a regular basis. These informations are compiled by the IEA, ECE and other international energy agencies. The data currently available is presented in Annex 1.1. The estimates of recoverable reserves should be treated with some caution. These do not always include the most economically exploitable reserves at the current state of knowledge of mining technology. They are basically estimates of the total amount of coal in specified coal seams in a few selected coal fields. The amount of saleable coal that can be recovered from this reserve after accounting for losses sustained during mining and beneficiation process may not exceed two-thirds of the original amount. On the other hand, only a fraction of the known reserves

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2/ Normally, the recoverable reserves in existing mines are 20-30 times the current level of annual production. There is no incentive to extend the knowledge beyond their own leasehold. However, mining enterprises continue to build up new inventory as old reserves are exhausted, in order to assure consumers about the prospects of long-term supply.

have been sufficiently explored for mining purposes. Vast reserves in Australia, Botswana, China, South Africa and the former USSR still await further exploration and development of transport infrastructure to facilitate their exploitation.

1.9 The world has abundant reserves of bituminous coal which is sufficient to last more than two hundred years at the current level of production. Proven recoverable reserves of hard coal at 1,075 billion metric tons have increased by more than 80% and brown coal (including lignite) at 521 billion metric tons by nearly 30% when compared to the information available in 1983. The recoverable reserves are sufficient to meet world demand at the current consumption level for about 280 years. With reserve to production ratios of 40 years for oil and 60 years for natural gas, coal appears to be the largest potential source of energy for current and future use (Table 1.3).

Table 1.3: RESERVE/PRODUCTION RATIOS OF FOSSIL FUELS IN 1988 (years)

	Natural Gas	Crude Oil	Coal
Asia/Pacific	70	18	160
Middle East	360	112	
W. Europe	33	13	300
Africa	115	31	360
S. America	90	51	285
N. America	17	19	260
Other	55	15	295
Total World	60	40	280

1.10 With 610 billion mt of hard coal reserves, China has by far the largest endowment followed by the USA and the CIS (former USSR). These three countries together account for more than 75% of global hard coal reserves. Though Germany, Poland and the UK have significant reserves of coal and are still major producers, their shares are expected to continue a gradually decline. This is due to greater depth and difficult geology of the reserves, and the concomitant high cost of mining. Some of the countries faced with near exhaustion of reserves at shallow to moderate depth have stretched the parameters of reserve calculation to the technologically feasible limits. They include Belgium, France, Germany, Netherlands, Poland and the UK where the pithead cost of production already exceed the border price of similar products from abroad, but mining continues for social or political reasons.

1.11 On the other hand, a large number of countries with significant reserves have emerged as important producers due to easier mining conditions and low cost of production. These include Australia, China, Colombia, India, Indonesia and South Africa. In all, about 50 developing countries are assessed to hold geological coal resources, of which 19 have economically recoverable reserves.

Coal Production

1.12 Most hard coal and almost all lignite is consumed in the country of production. China, USA and the former USSR produce and consume most of the coal in the world. They alone account for about 64% of world hard coal and 55% of total coal production. The top ten countries account for 94% of all hard coal and 87% of total coal production in the world.[2] Of the countries with the largest endowments, China, India, former USSR and USA essentially produce coal for large domestic markets, while others (Australia, South Africa, Colombia) rely heavily on export markets in Europe and East Asia.

1.13 History of Coal Production. The start of significant coal production can be traced back to the early seventeenth century in England. The use of coal as an energy source to drive steam engines and in the form of coke, to produce iron and steel, propelled the first Industrial Revolution. It was coal that fueled industrial development in the nineteenth and early twentieth century. England dominated coal production in the early nineteenth century, producing 70 million metric tons (Mmt) annually by the middle of the century and up to 250 Mmt per year on the eve of the First World War. English predominance sharply declined towards the end of the nineteenth century as smaller coal industries in other countries (notably Germany and USA) expanded. The USA emerged as the world's largest producer by the end of the nineteenth century - a position it regularly maintained until recently. In 1913, France, UK, Germany and USA contributed nearly 90% of world coal production, practically all the commercial energy supply of the world during that period.

1.14 Twentieth century developments in the coal industry have been more complex and variable. Two world wars, the Great Depression of the thirties, followed by sustained recovery and growth in the fifties and sixties, independence in the former colonial territories, urban and industrial growth in the developing countries, shifts in the structure of production and consumption, and the emergence of rival fuels have all variously affected the worldwide pattern and trends of coal production and consumption. However, the primary development affecting coal use has been the emergence of oil as the leading energy source in the post second World War period. This resulted in a rapid shift from coal to oil, with the share of coal declining from 61% of commercial energy supply in 1950 to 35% in 1973. In 1967 coal was displaced by oil as the leading source of energy in the world market, although the countries of Eastern Europe and the former USSR, as well as China, continued to rely heavily on coal. While the world energy requirements increased with rapid economic growth at rate of 4% per annum during the 1950s and 1960s, coal production could grow only at about 2% per annum during the same period.

1.15 With the oil price shocks in the 1970s, coal, as well as other alternative sources of energy, received renewed attention from energy planners. The large diversified resource base of coal and relatively cheaper cost of development and exploitation (outside of Western Europe) makes it an attractive energy source for the long-term. However, the predicted rapid growth in coal demand has not materialized as yet due to the recession in the 1980s, oil price decreases during the 1980s, environmental concerns with

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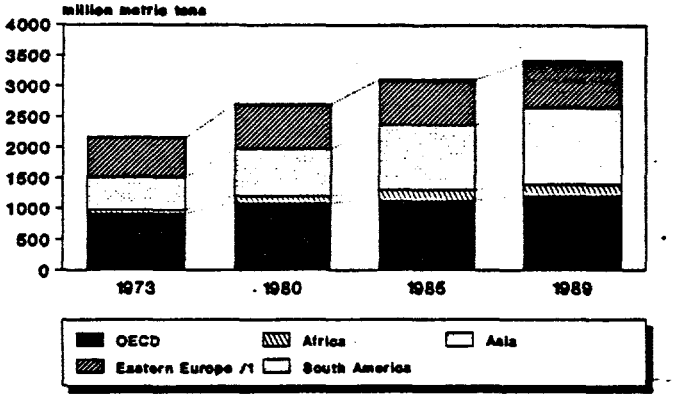
[2] The countries are China, USA, former USSR, India, Poland, Australia, South Africa, Germany, UK and North Korea in the descending order of volumes produced in 1989.

pollutant emissions, industrial restructuring as well as efficiency and conservation measures in the OECD, (Figure 1.1 and Annex 1.2).

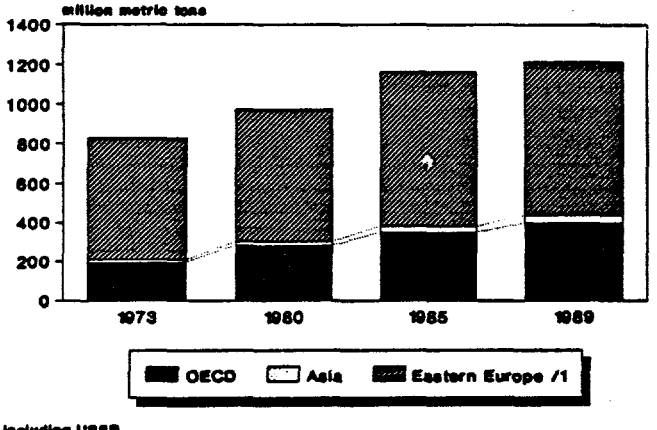
Figure 1.1: HARD COAL PRODUCTION BY REGIONS



/1 Including USSR
Source: IEA: Coal Information 1990.

1.16 During 1980-1989, world production of hard coal increased at a rate of 2.7% p.a, compared to 2.1% between 1971-1981. The worldwide hard coal production in 1990 was estimated to be around 3,575 Mmt, roughly around the same level as in the previous year. Brown coal/lignite production increased at an average rate of about 2% p.a. between 1980 and 1990. Total production of brown coal was estimated to be around 1,165 Mmt in 1990, compared to 980.1 Mmt in 1980 (Figure 1.2 and Annex 1.2).

Figure 1.2: BROWN COAL/LIGNITE PRODUCTION BY REGIONS



/1 Including USSR
Source: IEA: Coal Information 1990.

1.17 Underlying the gradually increasing trend in worldwide production of hard coal is a wide variation in the growth and pattern of production among the major coal producing countries. About 85% of the net increase in hard coal production in the 1980s took place in the developing countries, with the balance coming from OECD and East European countries. Among the OECD countries, production increases in Australia and USA were offset by decline in Western Europe and Japan. Overall, hard coal production in the OECD grew at an average rate of around 2% p.a. between 1980 and 1990. With the exception of 1985-86, production in Western Europe fell each year during the 1980s.

This decline accelerated towards the end of the decade with coal production declining by nearly 5% p.a. between 1987 and 1990. The drop in North American coal production in 1985-1986 was reversed for the remainder of the decade as production increased at an average rate of 4% p.a. in 1987-1990. Australian coal production grew at a rapid rate of around 9% p.a. in the 1980s as the country emerged as a major coal producer and trading partner. On the other hand, coal production in Eastern Europe was fairly constant in the 1980s but fell sharply (by almost 8%) in 1989 and 1990.

1.18 The rapid increase in hard coal production in developing countries is mostly accounted for by a few countries - China and India increased production to match domestic demand, while South Africa has expanded production to serve both domestic and export markets. Increased production in Australia and new producers such as Colombia, Venezuela and Indonesia is mainly directed towards export markets in Western Europe and Asia. Coal production grew at an average rate of 5.5% p.a. among the producers in Asia, with China and India accounting for the bulk of this increment. Coal production in Africa mostly takes place in South Africa where production levels increased rapidly in the early 1980s. Finally, starting from a much smaller base, coal production grew most rapidly in Latin America (over 11% p.a.). Most of this increase took place in Colombia.

1.19 By 1990, the pattern among coal producers was radically different from that in the 1980s, as the leading producers in the world switched places during the intervening decade. China has emerged as the largest coal producing country, accounting for nearly 30% (1,066 Mmt) of world hard coal production in 1990. The USA occupies the second place, producing around a fifth of the world's output. The CIS remains the third largest producer with another 15% of the total. Poland and UK, which were among the leading producers a decade ago, fell behind India, Australia and South Africa. Western European countries continued their planned reduction of coal output with the closure of unprofitable mines and other rationalization measures. Production from all East European countries including the former USSR declined by almost 8.5%. In Poland and Romania, the decline in production was as much as 15% and 50% respectively due to financial and labor problems. Overall, the share of the ECE region has gone down from 64% to 52% in a decade. Once a coal-surplus area, the region as a whole is on the verge of becoming a coal-deficit area. The expanding coal producers from other parts of the world where coal can be mined by the open-pit method at much lower costs, are now looking forward to profitable opportunities in both domestic and export markets. Aside from China, India, Australia and South Africa, other emerging coal producers of significance are Colombia, Venezuela and Indonesia.

1.20 The growth in the production of lignite is largely influenced by the same trends. The pattern of distribution, however, differs considerably from that of hard coal. East Germany, the CIS and West Germany have long been the leading lignite producers. With unification, Germany has emerged as the world's largest lignite producing country. Although their share of world output has steadily declined over the years, unified Germany and the former USSR still produced nearly 45% of the world's lignite output in 1990. The Czech and Slovak Federal Republic (CSFR) was the only other country producing over 100 Mmt of lignite in the 1980s, although production has fallen below that mark since 1987.

1.21 The inclusion of lignite merely adds a few more countries to the existing list of middle-rank producers - the dominance of China, USA and CIS in worldwide coal production is maintained even when lignite output is added. Germany emerges as a more important solid fuels producer when lignite is considered. Inclusion of lignite also increases the importance of Poland and Czechoslovakia, albeit on a much smaller scale.

1.22 In summary, world coal resources are adequate to meet all projected solid fuels needs in the foreseeable future. Production levels in the major coal producing countries are high enough to sustain all perceived national demand, with some countries utilizing the surplus production to meet international demand. On the other hand, Western Europe, Japan, South Korea and some East European countries will continue to face declining national production partly due to adverse geology and depletion of reserves, and partly due to the high exploitation costs for working at a greater depth. A few new entrants such as Indonesia and Venezuela are likely to become important coal producers and exporters. Zambia, Zimbabwe, Botswana, Mozambique and Swaziland all have sizeable coal resources but so far have had only limited success in developing them due to low levels of domestic demand and lack of transport infrastructure for exports.

International Coal Trade

1.23 Close proximity to coal resources is an important, but no longer decisive, factor influencing coal utilization. Most hard coal and almost all lignite is consumed in the country of production. Only Australia has emerged as a major coal-producing country where exports exceed domestic consumption. Other significant exporters, such as USA and South Africa, produce the bulk of their coal for domestic markets and trade internationally mostly at the margin. On the other hand, a growing number of countries secure most of their coal supplies from imports. Japan is by far the largest coal importing country, whereas Western Europe has emerged as the largest coal importing region.

1.24 World coal trade has undergone significant changes in this century. Prior to World War I, the major components of international trade were intra-European flows principally involving British and German exports and US exports to Canada. The major import markets were in France, Netherlands, Belgium and Italy. The Netherlands and Belgium imported most of their coal from Germany while the other European importers relied mostly on Britain. British and German exports declined sharply after World War I and thereafter continued to decline rapidly.

1.25 The USA gradually established itself as an important coal exporter in international markets - first in Western Europe and then in Japan. The USA has long been a major supplier of coking coal to Western Europe and Japan and sells significant amounts of steam coal in Western Europe. As the former USSR emerged as a major producer, it too developed a substantial export trade - predominantly to the other communist countries. With markets in Germany and elsewhere in Europe, Poland also emerged as a major exporter after World War II. Subsequently, Canada, Australia and South Africa also developed their coal export capabilities. In the first two cases, the impetus to export trade came from the rapidly increasing demand for coking coal in the growing Japanese steel industry. Australia also subsequently developed its steam coal exports and markets in Western Europe. South Africa's exports have mostly

consisted of steam coal to Western European markets, although some coking coal has also been exported to Japan in the past (Table 1.4 and Annex 1.3).

Table 1.4: WORLD STEAM COAL TRADE
(Mmt)

	1973	1978	1983	1988	1989 \1
Western Europe	19.0	44.0	62.5	74.6	75.8
North America	8.3	11.5	10.1	13.1	11.0
Japan	1.0	2.1	15.5	30.1	31.6
Total World	64.5	83.8	126.8	188.9	191.2

\1 Estimates.
Source: Drewry Shipping Associates Limited.

1.26 Currently, international trade in steam coal is small compared to the global consumption levels. Imports account for around 6-7% of steam coal demand, although traded volumes are large enough to rank steam coal as a leading internationally traded commodity. Past developments have given rise to the competitive structure that currently prevails in the international coal markets. Coal export trade is dominated by United States, Australia and South Africa which together account for over 60% of coal trade. Competitive pressures have intensified as they, along with other newcomers, direct their exports to the same primary markets in Western Europe and Asia. In 1984, Australia overtook the lead in coal exports from the USA, which for many years had been the primary coal exporter. The United States and South Africa are the leading suppliers of metallurgical coal and steam coal, respectively, to Western Europe - together, they supply over 50% of the regions total coal imports. Other significant exporters include Australia (12%) and former USSR (8%). Although South American exports to Western Europe are expected to grow quickly and will account for 15% of Europe's imports by 2000, they will be close to export capacity by then. Coal exports to Asia are dominated by Australia which was the source of 46% of Asia's import demand (over 70% of Japan's) in 1989. Other exporters to the Asian market are Canada (16%), South Africa (13%), USA (12%) and USSR (6%).

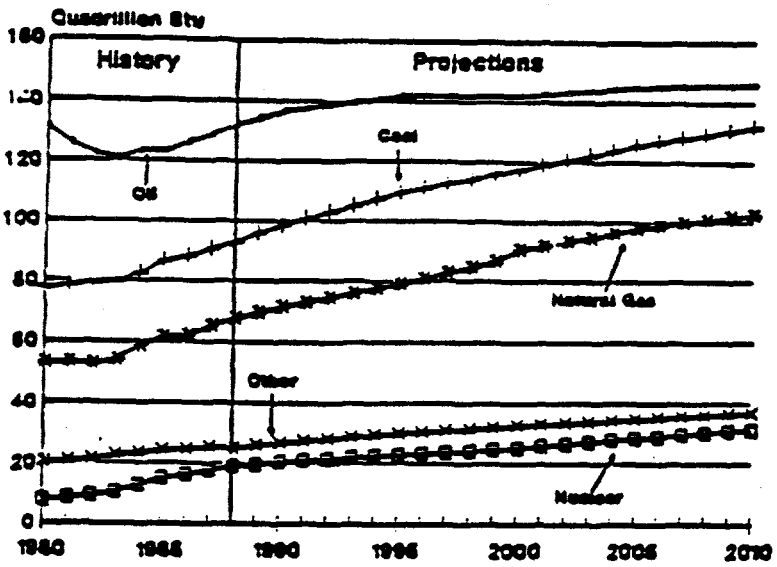
1.27 The major markets for imported coal are in Western Europe and Asia which together accounted for 78% of the 399.4 Mmt of total coal imported in 1990 - they accounted for nearly 80% of steam coal imports (216.4 Mmt in 1990). Of the latter, Western Europe imported 45% and Asia 38%. The Asia region was the largest market for imported metallurgical coal (47% of total) followed by Western Europe (28%). In terms of coal type, metallurgical coal was the principal type of coal traded before 1980 - little steam coal entered the world market. In 1990, however, metallurgical coal trade volume (183 Mmt) was slightly lower than that of steam coal. Moreover, trends in the 1980s indicate that steam coal flows will predominate in the 1990s.

1.28 Global steam coal imports virtually doubled during the 1980s, surpassing metallurgical coal import levels by the end of the decade. Shipping volumes also doubled in the 1980s and since 1973 - when some 21 million tons were shipped - there has been a seven-fold increase in seaborne steam coal trade. While Western Europe constitutes the main market for traded steam coal, it is the Asian market that exhibited the fastest growth in the 1980s. Led by Japan, Asian importers increased their purchases from 13 Mmt in 1980 to 75 Mmt by 1990. Japan's imports jumped from 6 Mmt to nearly 36 Mmt during this period. Similarly, Asian imports of metallurgical coal increased to 91.6 Mmt in 1989, with two-thirds of the imports directed towards Japan. Import demand in Western Europe has been less rapid, but growth resumed in the late 1980s, raising steam coal imports to 96 Mmt and coking coal to 50 Mmt in 1990. Outside of Western Europe and Asia-Pacific area, there are few countries that need to import coal. Israel emerged in the 1980s to become a 4 Mmt per year market, and there are several smaller importers which are expected to buy more from international markets in the future.

Coal Consumption

1.29 Primary Energy Consumption. Spurred primarily by sustained economic growth in the industrialized countries, world commercial energy consumption grew fairly rapidly in the fifties and sixties, with average rates of growth exceeding 5.0% per annum. For over two decades, oil literally fuelled this economic growth, but the subsequent sharp rise in oil prices precipitated a worldwide recession and permanently altered the linkage between economic growth and primary energy demand. The fivefold increase in international oil prices, in real terms, between 1970 and 1980, however, had profound effects on the subsequent growth and pattern of commercial primary energy consumption in the world. In the aftermath of the oil price shocks, the rate of growth of world energy consumption slowed to 2.9% p.a. between 1970-1979 and 2.2% p.a between 1980-1989. In 1990, total commercial primary energy consumption in the world amounted to 8,030 million tons of oil equivalent (toe), with oil accounting for nearly 40% of total consumption , followed by coal(27%) and natural gas (22%). Although oil remains the single most important source of energy, its relative importance has steadily diminished in recent years. All other fuels have increased their relative shares in world energy consumption during the past decade, with natural gas emerging as the fastest growing fossil fuel. Together oil and gas still account for about 60% of world's total primary energy demand, whereas the share of solid fuels is around 30% (Figure 1.3 and Annex 1.2).

Figure 1.3: PRIMARY ENERGY CONSUMPTION



Source: Energy Information Administration/International Energy Outlook 1990

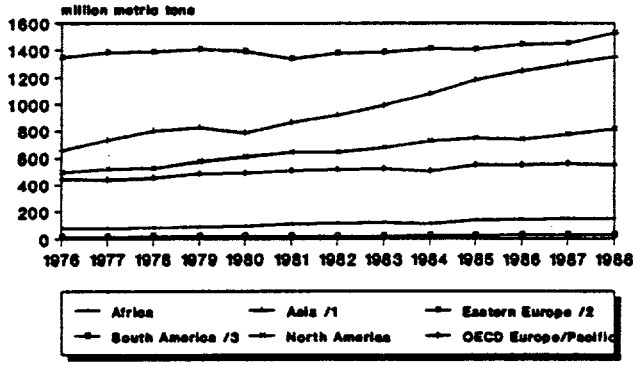
1.30 From the mid-1970s onwards sustained efforts have contributed to a rapid decline in energy intensity (i.e. amount of energy required to produce a given unit of economic output) in industrialized countries. The restructuring of the industrial economies, combined with energy efficiency and conservation measures, has resulted in a decline in energy intensity indicators in the industrialized countries so that 20% less energy is consumed per unit of GDP today than it was in 1973. Between 1973 and the present, energy demand growth in the OECD countries has averaged less than 1% p.a. whereas GDP growth rate has been close to 2.5% p.a.. In the 1980s, energy demand growth has averaged 0.6%-0.7% p.a. in the OECD countries.

1.31 A striking feature of the world energy markets is the growing divergence of energy consumption trends between the industrialized countries and the rest of the world. In contrast to the slow growth in the OECD countries, energy consumption has rapidly increased elsewhere during the past two decades. One exception to this is the recent downturn in energy consumption in Eastern Europe as a result of economic restructuring currently underway in the countries of the region. Energy consumption in developing countries has increased at a rapid pace, averaging 4-5% p.a. in the 1980s. Their share in world primary energy consumption has increased from around 20% in 1980 to nearly 30% in 1990. Over 60% of the net increase in energy requirements has taken place in Asia where energy demand growth has averaged 5% p.a. Energy demand growth has been fairly rapid in Africa and Latin America in the 1980s, albeit starting from a smaller base.

1.32 Coal Consumption Trends. Coal's share of the total energy market had been on a steady decline until the 1970 oil crises once again raised expectations of a large expansion in the use of coal. Numerous forecasts were made on the basis of the abundance and low cost of world coal reserves to project optimistic medium and long-term trends of coal use in the industrial and electricity sectors. However, the predicted strong upswing in the coal

industry did not materialize as the recession in the 1980s led to slower-than-expected growth in the electricity sector and a temporary curtailment of investments in the electricity supply industry in the early 1980s. Other adverse factors dampening coal demand in the 1980s included the weakening of oil prices in mid-1980s, the increased availability of gas and nuclear capacity, and the environmental concerns associated with the burning of fossil fuels, specially coal (Figure 1.4 and Annex 1.4).

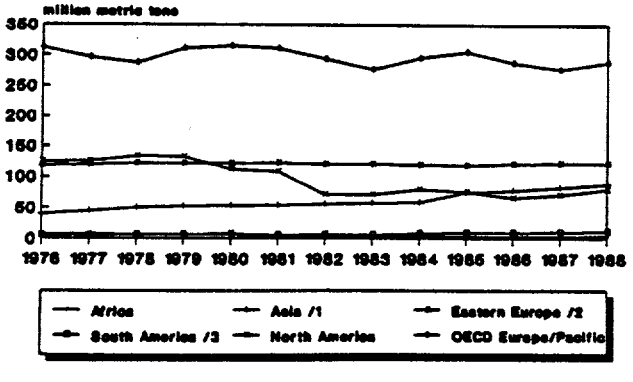
Figure 1.4: STEAM COAL CONSUMPTION, 1980-1989



/1 excluding Japan
/2 including USSR
/3 including Mexico

1.33 Nevertheless, coal demand recovered strongly in the late 1980s compared to the modest increases in the first half of the decade. Overall, worldwide coal consumption grew at an average annual rate of 3.0% p.a. during the 1980s, largely due to increased activities in the industry after 1987. The consumption of thermal coal has increased at an average annual rate of 3.2% p.a. between 1980 and 1989, while the consumption of coking coal in iron and steel production has declined by 0.6% p.a. during this period (Figure 1.5). The primary impetus to the recent growth in steam coal demand has come from the sharp rise in electricity demand and the large-scale expansion of coal-fired electricity generating in many countries of the world. Underpinned by their power systems' requirements, coal consumption increased at an average annual rate of 5% p.a. in the developing countries. The growth in OECD countries has been more modest (averaging 1.2% p.a. in the 1980s), again mostly to meet additional requirements in the electricity supply industry. On the other hand, coal consumption in Eastern Europe has dropped off sharply in the past three years, after remaining fairly stable for most of the decade.

Figure 1.5: COKING COAL CONSUMPTION, 1976-1988



/1 excluding Japan
/2 including USSR
/3 including Mexico

1.34 The dominant presence of China, combined with the large coal program in India, has enabled Asia to emerge as the world's largest coal producing and consuming region. The growth in coal consumption has been particularly rapid in the 1980s during which time, in addition to the growth in China and India's massive coal-based power systems, a large number of other countries in the region have also shifted to substantial coal-based power generation programs. After growing at an average rate of over 6.5% p.a. in the 1980s, coal consumption in Asia accounted for slightly over 40% of total consumption in 1990 (compared to 31% in 1980). In North America, which accounts for another 21% of total consumption, growth in domestic demand (mostly in the USA) averaged 2.2% p.a. in the 1980s and the surplus was exported. Production difficulties in Poland and former USSR are resulting in declining consumption in Eastern Europe which nonetheless accounts for around 22% of coal consumption. Coal demand has been particularly sluggish, and declining, in Western Europe due to overall improvements in power generation efficiency - the region's share in world coal consumption was slightly under 10% in 1990 as opposed to 12.5% in 1980. Coal consumption has been declining in both UK and Germany, slightly offset by small growth in other countries in the region.

1.35 In other parts of the world, coal consumption has grown rapidly in South Africa where production capacity was expanded in the early 1980s to serve both domestic and export markets. Domestic coal consumption in Australia (primarily in the Eastern States) is at a low level relative to production as most of the coal is exported. Other significant coal-consuming countries include Japan, North and South Korea, Brazil, Mexico and Indonesia. With the exception of Western Europe and Japan, the rising coal requirements of the consumers will be largely met through increased domestic production.

Consumer Categories.

1.36 A direct or indirect method is available for coal to compete in all fuel combustion applications. Coal is burned in boilers, and boilers are available in many different sizes to serve every combustion need.[4] Coal has the potential to compete directly in its solid form, or converted to gases, or mixed with oil or water. Conversion of coal into electricity can also serve to meet most energy needs. In stationary combustion, coal competes with oil, natural gas, nuclear power, as well as other primary and even non-commercial energy sources. The fuel choice decision in a particular end-use may be entirely determined by the production technology (e.g., iron & steel making), or, at the other extreme, may involve no additional expenditures (e.g. dual-fired or multi-fuel burners). In general, however, substitution between different energy sources requires some additional investments either in the supply infrastructure or in the end-use equipment, or both. Coal will be used as a solid fuel, or converted to some other form, so long as the incremental costs of burning coal can be justified by the added value in the end-use.

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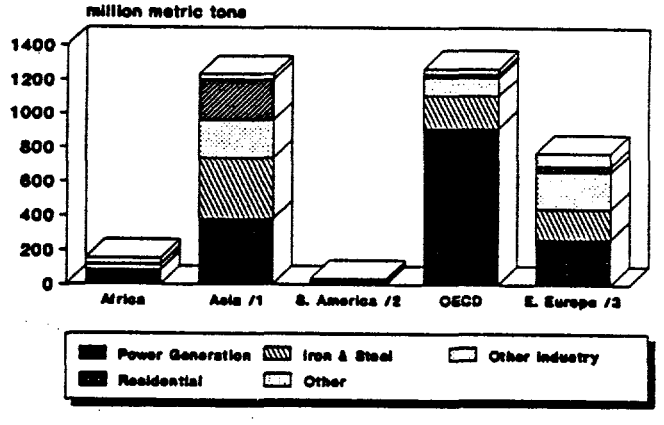
[4] This precludes the use of boiler in road transportation where it is such an uncompetitive alternative that it is rarely used. Similarly, coal use in railway transportation has also become increasingly uneconomic. The focus here is solely on fuel use and competition in stationary combustion applications.

1.37 Not all energy fuels are perfect substitutes for each other, and considerable rigidities in the existing pattern of energy consumption (and in the stock of equipment) limit rapid or widespread inter-fuel substitution, particularly in the short-term. Coal, in particular, is expensive to transport and distribute, and the need to invest in associated handling, disposal and storage facilities, and burn coal in an environmentally acceptable manner makes coal inconvenient and costly for all but the largest users. Hence, the greatest potential for fuel substitution by coal lies with the electricity supply industry and the largest industrial users. In general, the economics of coal use vis-a-vis alternative sources of energy will determine both the short-term fuel substitution possibilities as well as the longer-term expansion of coal-based power generation and large industrial coal use. The most apparent near-term opportunities for increased coal use are in coal-fired thermal power plants. Substitution possibilities also exist for coal burning to generate process heat for industry, or to substitute oil or natural gas in under-boilers in the industrial and residential sectors. The long-term potential for coal substitution will be greater during periods of sustained economic growth, replacement of existing capital stock, and general or localized shortages of alternative commercial energy sources. This does not take into account possible future shifts of coal use to new applications such as increased coal refining, production of synthetic fuels, or other new technologies that may become attractive with technical innovation and fuel cost shifts. Historically, coal started out as primary fuel for transport, households, and steel production, only to be replaced in many of the transport and household applications and to move into power generation: similar developments in the future cannot be excluded.

Figure 1.6: COAL CONSUMPTION BY SECTOR, 1988



\1 Excluding Japan.
\2 Including CIS.
\3 Including Mexico.

1.38 The electricity supply industry has always dominated steam coal demand, particularly in the OECD countries. More recently, rapid expansion of coal-fired electricity generating capacity in the developing countries has enabled the power sector to increase its share of worldwide steam coal consumption from 55% in 1980 to close to 70% in 1990. In OECD countries, electricity generation accounts for as much as 80-90% of steam coal consumption. The iron and steel industry accounts for all metallurgical coal consumption and about 8-10% of steam coal consumption. Steam coal consumption in general industry (i.e., other than iron and steel), has witnessed rapid growth in the 1980s and accounts for another 10%. This figure is much lower in North America and

Western Europe where much of the existing stock of equipment is based on oil or natural gas. In recent years, residential use of coal has increased in China, North and South Korea and South Africa, but declined in all OECD regions and Eastern Europe. Residential consumers account for 7-8% of global coal consumption (Figure 1.6 and Annex 1.2).

1.39 Electricity Generation. The power sector in most countries generally consists of a few large generating and distribution entities who maintain a continuous program of capacity additions and replacement. This is particularly true since the growth of electricity demand has been and is expected to remain high relative to both economic and overall energy demand growth. In addition, since electricity can be generated using a wide variety of energy sources, the sector is likely to respond more readily to the fuel substitution possibilities that arise as a result of changes in relative prices and supplies of different fuels. For coal, the power sector represents the primary market where it maintains a degree of economic competitiveness that it finds difficult to attain in other sectors. Because of its inconvenience and other undesirable attributes, coal would likely provide a much smaller role in fuel substitution without power generation.

1.40 World electricity output, nearly two-thirds of which is in conventional thermal stations, is currently approaching 10,000 TWh, with the OECD countries contributing about 60% of the total. Electricity output in the world has increased at average rate of 5% p.a. or more during the 1980s. Even higher growth (up to 10% p.a.) in electricity generation took place in the industrialized Asian economies - South Korea, Taiwan, Hong Kong - and China and India. With the Asian economies leading the way, growth in electricity output in the developing countries is expected to remain at or exceed this pace in the 1990s: World Bank projections indicate a growth rate of about 7% for electricity demand in developing countries.

1.41 Steam coal requirements for power generation will continue to determine the pace of global consumption and trade in the 1990s and beyond. According to IEA estimates, thermal power plants account for four out of every five tons of steam coal consumed, the global consumption in 1990 amounting to about 1.7 billion tons. This is only an estimate but more reliable figures indicate that over 1.1 billion tons of coal were consumed in OECD countries alone, and global power sector requirements have increased steadily over the past decade, averaging a growth of 3.4% p.a..

1.42 OECD Countries. Electricity generation accounts for over 80% of OECD coal requirements and coal, at 40%, is the largest source of energy for power generation. Electricity output in the OECD countries has steadily increased at 4% p.a. in the 1980s, with rises as high as 6% p.a. in Japan. The production of electricity in the OECD is further projected to grow 2.3% p.a. during the 1990s with Western Europe in the 1.5-2% range and Japan 3-3.5%. About 40% of the total electricity produced in OECD countries comes from power stations burning coal, compared to 35% in 1973 (see Table 1.5). In the OECD as a whole, power sector's consumption of coal has grown steadily since the 1970s as a result of about 4% p.a. increase in power demand and the expanded use of coal-fired plants. In Western Europe, total coal consumption by electric utilities increased more or less in line with electricity output, rising by 2% p.a. Approximately one-third of the power supply in 1988 was generated from coal-fired plants, about the same proportion as in 1973 and 1980. In North America, the increase in coal use - which averaged over 4%

p.a. over the same period - has again been well in advance of the growth of electricity production. The share of coal is much higher, with over half of the electricity output in 1988 generated by coal. The share of coal in Japan's power generation has also increased rapidly from under 10% in the 1970s to 15% in 1988.

Table 1.5: SHARE OF OECD ELECTRICITY OUTPUT GENERATED FROM COAL (%)

	1973	1978	1983	1988
Western Europe	33	34	33	32
North America	42	41	50	51
Japan	8	7	12	15
Total OECD	35	36	38	40

Source: IEA/OECD Energy Balances

1.43 Developing Countries. The high priority placed on adequate electricity output for economic development has led most developing countries to undertake rapid expansion of their power supply systems. Yet, many electric utilities have been hard pressed to match the rapid growth in demand for electricity that has averaged around 7% during the 1980s and 10% in the 1970s. The demand for electricity in developing countries is projected to grow at an average rate of 6.6% p.a. in the 1990s.

Table 1.6: INSTALLED CAPACITIES IN DEVELOPING COUNTRIES

Type	1989		1999	
	GW	%	GW	%
Hydro	185	39.3	322	37.7
Geothermal	2	0.4	5	0.6
Nuclear	14	3.0	38	4.4
Oil Thermal	70	14.8	84	9.7
Gas Thermal	13	6.7	65	7.8
Coal Thermal	169	35.8	341	39.8
Total	471	35.8	855	100.0

Source: World Bank, Energy Series Paper No. 21, Capital Expenditures for Electric Power in the Developing Countries in the 1990s, February 1990.

1.44 According to World Bank estimates, the total installed generating capacity in developing countries was about 471 GW at the end of 1989. The capacity breakdown by type of plant is summarized in Table 1.6. The breakdown of generating capacity is roughly in the order of 39% hydro, 36% coal, 20% oil and gas, and balance from other sources. Coal consumption for power generation has increased most rapidly in Asia (10% p.a.) during the 1980s and presently accounts for over one-third of steam coal consumption. Despite

rapid growth in the 1980s, coal use in Latin American utilities is still quite limited. In Southern Africa (South Africa, Zambia, Zimbabwe), which presently has the only significant coal market in the region, consumption in the power sector has increased 5% p.a. in the 1980s and accounts for over half of the steam coal consumption. Based on current power development programs in developing countries, World Bank estimates point to an 80% expansion in their installed capacity in the 1990s to reach 855 GW by the end of 1999, with coal share in electricity generation rising to about 40%.

1.45 Industrial Users. Coal, like oil and gas, can be used to generate steam, direct heat and power in a wide variety of industrial applications. However, because of the large capital cost differentials between coal burning and supply facilities compared to those for oil and gas, coal use in industry is mostly limited to those users that can either take advantage of its specific characteristics (e.g., iron and steel industry) or enjoy sufficient economies of scale in production. The largest industrial consumers of coal are in the iron and steel industry where metallurgical coal is a primary raw material input in the production of iron. The largest steam coal use in industry takes place in cement production where it used to generate process heat in ovens and kilns. The use of coal as an industrial boiler fuel is closely linked to relative fuel costs and availability, and also depends on the size of production and proximity to coal supplies.

1.46 The iron and steel industry represents the second largest market for coal, after electricity generation. The bulk of the coal consumed in the iron and steel industry is metallurgical coal although some steam coal is also used for thermal applications and power generation. Demand for metallurgical coal is closely related to developments in the market for crude steel and the technology employed it its manufacture. These affect the type and amount of coal needed and the intensity with which they are used in the manufacturing process.

1.47 In the steel market, worldwide output has long grown slowly and declined in the 1970s. Growth in the demand for finished steel was about 0.8% p.a. in the 1980s. Finished steel output markets have been particularly buoyant since 1987 and world output reached an all-time high of 782 Mmt in 1989. With the exception of the recent upswing in the late 1980s, steel output in OECD countries have been on a steady decline since the early 1970s. On the other hand, steel production has progressed rapidly in the developing countries, in particular Asia where output has increased 10% p.a. in the 1980s. The largest growth has taken place in China, India, North and South Korea. Growth in steel output in South Korea has averaged over 20% p.a. Growth in steel production in Latin America, mainly in Brazil and Mexico, has slowed in the 1980s compared to growth in the previous decade, but still averaged over 5% p.a. Production levels in Eastern Europe and former USSR fell in the 1980s, with the decline accelerating after 1987.

1.48 The consumption of coking coal has been affected by technological improvements in iron and steel making that have reduced its relative importance. Firstly, the increased use of continuous casting has reduced the amount of raw steel required to produce a given volume of finished steel products. Crude steel production has trailed demand for finished steel, expanding at a rate of 0.6% p.a. in the 1980s. With the growing use of mini-mills, electric arc furnaces (EAF) are also producing a greater share of crude steel. The amount of pig iron produced per ton of finished steel has

decreased. Unit use of coke per ton of pig iron has also fallen. Use of other fuels and greater processing of ores before their injection into the blast furnace helped lower coke use. In addition, modification of coking practices has reduced the use of high-quality, most expensive coking coke. For example, the pulverized coal injection (PCI) process allows the direct injection of limited amounts of coal into the blast furnace in conjunction with coke and sintered iron ore. Direct injection of coal is more economical as one ton of PCI replaces about 1.5 tons of coking coal, and inferior coking coals can be used in PCI. The result has been stagnation or worse in the only market in which coal has a technical advantage.

1.49 The slowing of growth in steel demand, the increased use of EAF and competition from lower-quality coal is likely to cause a further decline in consumption of coking coal in the OECD countries. Coke consumption by the iron and steel industry can be expected to trend towards the use of lower quality coking coal (soft and semi-soft) in blends with high-quality coking coal, as well as the introduction of new technologies. Nevertheless, higher growth in worldwide steel demand and coke consumption can be expected.[2] Most of the future growth in coke consumption is expected to take place in the developing countries.

1.50 The use of steam coal as an <u>industrial fuel</u> is technically feasible in all steam generation and process heating methods used in industry. However, steam coal consumption in the OECD countries (except Japan) has been on a steady decline since the early 1960s. Between 1960 and 1975 a large portion of coal-burning industrial facilities were converted to oil or gas. In many instances, the coal burning and handling facilities were dismantled or completely replaced, and environmental regulations and space requirements have limited reconversions back to coal.

1.51 Industrial boilers make up the largest share of fuel-using equipment in general industry, and represent the markets with the highest potential for coal substitution. However, the ready availability and flexibility of oil supplies at comparatively low prices in the two decades prior to the 1970s had the effect of making most industrial energy equipment heavily dependent on oil products. Despite the sharp rise in oil prices since, the long life-expectancy of boiler equipment has led to a continued preponderance of heavy fuel oil in the industrial mix of industrialized and developing countries. In the absence of the flexibility of an industrial grid, the possibilities of fuel substitution to coal has been limited to dual or multi-fuel burners.

1.52 General industrial use accounts for around 10% of steam coal consumption. Industrial consumption of thermal coal is strongly influenced by the general economic conditions and the perceptions of relative fuel costs and availability. This is particularly true in Western Europe and North America where large-scale expansion of coal use has been increasingly limited to the electric utilities. On the other hand, general industrial demand for coal has risen sharply in Japan and other Asian countries.

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[2] Despite the implementation of newer methods, use of high-quality coking coal is still prevalent. In Japan, for example, despite the rapid introduction of PCI technology, soft or semi-soft coke for PCI use still makes up only 5% of total coke use.

1.53 While the industrial sector consumes a small share of the coal for thermal applications, worldwide growth in industrial consumption has been rapid in the 1980s (over 12% p.a.). The largest industrial demand growth has taken place in the Pacific region (over 20% p.a.), Asia (11% p.a.) and Latin America (10% p.a.). Insufficient data prevent further disaggregation of industrial steam coal consumption into industrial sub-sectors. In addition to cement, the main industrial consumers of steam coal are pulp and paper, chemicals, textiles and refractors. In aggregate, these already consume significant amounts of thermal coal, mainly for self-generation of power. Although cement manufacture is presently the most important industrial market, it is the under-boiler use which seems to offer the greatest potential with many manufacturers in the process of installing new coal-fired plants or converting existing ones from oil-burning. Recently, for example, general industrial demand in Japan has begun to overtake the requirement of the cement industry, rising to 7-8 Mmt in 1989 and further growth is promised by the replacement of old boiler plants (Table 1.7).

Table 1.7: INDUSTRIAL CONSUMPTION OF STEAM COAL IN JAPAN
(Mmt)

	1985	1986	1987	1988	1989
Cement	8.1	7.2	7.5	8.0	8.3
Pulp & Paper	1.2	1.4	2.1	2.3	2.6
Chemical, Others	3.3	3.4	3.6	3.7	4.0
Total	12.6	12.0	13.2	14.0	14.9

Source: Tex Report and Coal Manual

1.54 Outside the electricity sector, the largest single market for steam coal is in cement manufacture. The type of rotary kiln generally used to produce cement 'clinker' can burn with liquid or solid fuels with ease. Moreover, fuel costs are an important consideration in cement production, accounting for 25-40% of total production costs. Thus, the industry responded to the steep rise in fuel oil prices in late 1970s by rapidly shifting its production to coal. In Japan, for example, coal utilization in the cement industry increased from less than 0.5 Mmt in 1978 to over 10 Mmt in 1981, and the decline in fuel oil use was equally spectacular. Many manufacturers in Western Europe also converted their kilns to burn coal when it became the cheapest fuel.

1.55 While the cement industry offers considerable opportunities for increased coal utilization, actual consumption levels have fallen far short of the levels predicted in the early 1980s. This was largely due to the stagnation and decline in cement production in the early 1980s, followed by the fall in fuel oil prices in 1986 and 1988 which encouraged reconversions to fuel oil at plants not easily supplied by solid fuels. Japan's cement industry is currently using less coal than it did in 1978. The impact of falling oil prices on coal consumption was minimized by the strong growth in cement production since 1987 due to growing demand in the construction industry. This trend is likely to be sustained in the developing countries in the 1990s, but not so in the OECD countries with the exception of Japan.

1.56 Residential Sector. Residential and commercial use of coal is limited to a few countries. These include China, North and South Korea, UK, Germany and a number of East European countries. Traditionally in the large coal-producing countries, the residential and commercial sectors represent a captive outlet for domestic mines. The availability of competitively priced oil products and oil and gas has eroded the contribution of coal in this market. For example, in UK, natural gas has rapidly replaced coal as the primary residential fuel. Residential use has increased rapidly in Asia (mostly China and South Korea) and South Africa, but stagnated or declined elsewhere in the 1980s.

International Coal Prices

1.57 International steam coal prices in the 1980s have generally followed developments in the supply and demand conditions in the world coal markets. At the start of the decade, surging demand placed considerable pressure on international coal supplies, causing the average prices to the major importing countries to spiral upwards. Coal supply problems were aggravated by strikes and delays in Australia, strikes in Poland, and transport bottlenecks in the USA. Spot prices as high as $70/mt were paid for small tonnages in early 1982 when the market peaked. Average import values for steam coal in 1981 reached $62.21/mt for all imports to Western Europe and $65.22 to Japan, the highest mark in the 1980s. Between 1983 and 1988, however, steam coal trade was characterized by lower sales and steady decline in FOB prices that pushed the netback to as little as $20/mt in some cases. By the late 1980s, average values of steam coal imports to Western Europe and Japan had fallen to $41-42/mt. Several developments contributed to this weakening of coal prices, including: (a) a slowdown of demand growth resulting from a slowdown in electricity generation, (b) an intensification of market competition with the entry of new exporters such as China and Colombia, (c) large-scale investments in export capacity expansion among existing and new exporters, and (d) the fall in oil prices in 1986. [£]

Table 1.8: STEAM COAL IMPORT VALUES
(Average Unit Value CIF - $/mt)

Imported to:	Japan	EEC
1980	54.60	51.51
1982	64.92	61.72
1984	49.67	45.57
1986	44.86	45.53
1988	42.63	44.94
1990	50.98	51.28

Source: IEA, Coal Information 1991.

[£] While the period of low oil prices was of short duration and did not endanger coal markets in electricity generation and, to some degree, in industry, it exerted downward pressure on an already weak steam coal market, driving down prices to their lowest levels in the following year.

1.58 Between 1988 and 1991, international steam coal prices have been on an upward trend, partly due to the strength of the U.S. Dollar and the rise in shipping rates. However, the main reason has been the renewed strengthening of demand coinciding with increasing losses on the supply side due to strikes, shipping delays, political turmoil, and even weather damage. Tight supply conditions in the Japanese steam coal market caused average import prices to increase 14.4% over the previous year's level in 1989, followed by a further 5% increase in 1990 when average steam coal import prices to Japan reached their highest level since 1983 at $50.98/mt (see Table 1.8). Similarly, import prices in Western Europe has also increased each year since 1987, with the average import prices reaching $51.20/mt in 1990. 1991 and 1992 are showing a reversal of the rising price trend with both long-term contract prices and spot prices falling to late 1980's levels.

Table 1.9: STEAM COAL EXPORT VALUES
(Average Unit Value, FOB, $/mt)

Exported from:	Australia	USA
1980	33.34	44.50
1982	46.61	53.96
1984	36.97	51.10
1986	31.87	46.83
1988	30.56	42.06
1990	38.27	40.16

Source: IEA, Coal Information 1991.

1.59 For U.S. coal producers, average export values continued the decline started in 1983, falling to about $40/mt in 1990/91. U.S. exporters took advantage of the narrowing gap between Australian and U.S. coal prices in the European market and significantly increased their exports to some buyers such as Electricite de France. As in Europe, the price differential between Australian and U.S. steam coal exports to Japan narrowed significantly, from $16.57/mt in 1980 to $1.73/mt in 1990. [1]

Existing Coal Forecasts

1.60 Forecasts of future trends in domestic and international coal markets are regularly made by industry experts, government agencies and international energy agencies. In the aftermath of the oil shocks, the general consensus was one of large expansion in coal consumption and trade. Coal forecasts made during this period tended to be overly optimistic, particularly in the case of steam coal. IEA/OECD estimates in 1978, for example projected that steam consumption in its member countries would increase between 2.7-3.0% p.a. between 1976 and 2000 - actual growth has been closer to 1% p.a. so far and according to more recent estimates, consumption during the remaining years is unlikely to be sufficiently high to achieve these targets. In addition to

[1] In Western Europe, the price differential fell from $12.62/ton in 1980 to 7.30/ton in 1990.

growing environmental awareness of the problems with fossil fuel use, several factors have dampened the demand for coal. These include slower worldwide economic growth, a fall in oil prices, preponderance of oil-fired boiler stock and the high costs of conversion, and technological or efficiency improvements that have reduced the unit consumption of coal in key industries. More recent models of coal consumption and trade have attempted to take into account some of these diverse influences, and current projections point to lower rates of growth in key coal indicators between now and the year 2000.

1.61 Coal Demand. The International Energy Agency (IEA) at the OECD prepares country forecasts on the basis of annual submissions by member countries, supplemented by the IEA's own estimates. IEA forecasts show coal demand in the OECD growing 1.6% p.a. from 1,201 million mt of coal equivalent (Mtce) in 1988 to 1,459 Mtce in 2000. Total primary energy requirements are projected to grow 1.4% p.a. during the same period. Coal is likely, therefore, to slightly increase its share of OECD energy requirements - from 21% in 1988 to 22% in 2000. While electricity production in the OECD is expected to grow 2.4% p.a., the share of coal will fall from 40.5% in 1988 to 38.8% in 2000 - mostly due to further expansion in gas-fired capacity. Coal requirements in North America are expected to grow 1.3% p.a. with almost all of this growth taking place in the electricity sector. Coal requirements in the Pacific are expected to grow at 2.1% p.a., led by 4% p.a. growth in coal use in electricity generation. Coal requirements for electricity in Western Europe are forecast to grow 2.2% p.a., although concern over global warming is already leading to lower forecasts. Growth in steel production in the OECD can be expected only in the short-term. Most of the future growth steel demand and coke consumption is expected to come from producers in non-OECD countries.

1.62 In the developing countries, demand for coal is expected to grow rapidly during the 1990s, following economic growth rates of 3-4% per year. The industrialized economies of Asia, along with China and India, are again expected to account for much of the overall growth in coal consumption. The growing gap between demand and supply in the region is likely to stimulate further trade and demand for both steam and coking coal increases. In Eastern Europe and former USSR, demand for coal will continue to be dominated by the electricity sector and is expected to grow at over 2% p.a. until 2000. Ongoing economic restructuring in the region is likely to reduce industrial and residential coal consumption in the short-term before it starts to rise again.

1.63 According to the U.S. Energy Information Administration (EIA), worldwide coal consumption is expected to grow 2.3% p.a. until 2000 in the base case, primarily to help meet increasing worldwide demand for electricity. The growth in coal consumption is expected to be slower thereafter (average growth of 1.2% p.a. between 2000-2010). Coal demand in the 1990s is expected to grow 1.6% p.a. in the OECD and 2.7% p.a. in the developing countries. Coal consumption in Asia is expected to grow nearly 3.0% p.a. in the major Asian countries. Increased demand and limited supplies in Western Europe and Asia, excluding China and India, is also expected to contribute to growth in the international coal trade.

1.64 According to forecasts prepared by the Institute of Energy Economics (IEE) in Japan, total energy requirements are expected to increase at 7% per year in Indonesia, Malaysia and Thailand. Coal requirements are estimated to grow from 2.9 Mtce in 1987 to 17.3 Mtce in 2000 in Thailand, increasing coal's

share of primary energy requirements from 10% to 25% in 2000. South Korean energy demand is projected to grow 5.6% p.a. between 1987 and 2000, with coal demand growing at a slower rate of 4.1% p.a.. Coal consumption in Taiwan and Hong Kong is projected to grow faster at 5.5% and 5.8% per year respectively. Chinese coal requirements are forecast increase to 4.1% p.a. until 2000, according to the same source, dropping coal's share of total energy requirements from 75.5% in 1987 to 70.2% in 2000.

1.65 Coal Production. Current IEA projections point to 1.6% annual growth in total coal production in the OECD until year 2000. The fall in the projected levels is mostly due to revised estimates of US coal production by 2000, which is 10% lower than earlier forecasts. Total coal production in North America is currently projected to grow 1.8% p.a. between 1988 and 2000. Coking coal production is expected to decline between 1989 and 1995 and remain fairly constant thereafter. In Europe, coal production is expected to continue to decline in all the major coal-producing countries, including UK (1.1% p.a.) and France (9% p.a.) and Germany (2.6% p.a.). Australian coal production, however, is forecast to grow 4% p.a. between 1988 and 2000. Most of this growth will take place in steam coal production which is projected to grow 5.1% p.a.. Australian coking coal production will grow more slowly at 2.5% p.a. during the same period.

1.66 Production increases in the developing countries are likely to be substantial although the amount available in the international market will depend on the expansion of export capabilities among existing and new producers. Coal production in China will continue to increase but, at least in the medium-term, will be primarily used to meet domestic demand. According to forecasts prepared by Japan's IEE, coal production in China will grow 3.4% p.a. until 2000. In Indonesia, the forecasts point to a rapid increase in production from 2.4 Mtce in 1987 to 43 Mtce in 2000. The Indonesian government's own estimates show that production will reach 15 Mmt by 1994 of which 7-9 Mmt will be available for export.

1.67 International Coal Trade. IEA projections of steam coal imports have been substantially revised downwards in its recent publications. According to current estimates, OECD steam coal imports are expected to increase from around 110 Mtce in 1989 to 179 Mtce in 2000, while coking coal imports will rise from 133 Mtce to 175 Mtce in 2000. Forecasts of OECD exports have been recently revised upwards by the IEA to take account of higher Australian export projections. Australian steam coal exports in 2000 are projected to reach 74 Mtce in by 2000, as opposed to 41 Mtce in 1988. In contrast, US steam coal exports are expected to rise form 29 Mtce in 1989 to 41 Mtce in 2000. In the coking coal market, Japan's imports are expected to rise to 92 Mtce (from 73 Mtce in 1980) by 2000 due to improved prospects in the steel industry (Table 1.10).

Table 1.10: COMPARATIVE FORECASTS OF WORLD COAL EXPORTS IN 2000
(Million metric tons)

	Steam Coal	Coking Coal
1989 Actual	197	184
IEA	347	158
ABARE	278.5	167.0
Lee	190-305	-
NCA	324	164

Source: IEA Coal Information 1990.

1.68 In the IEA projections, a major expansion in coal trade is expected between now and year 2000, from 373 Mmt in 1988 to 505 Mmt in 2000. Growth in world coal trade is again expected to primarily occur in the steam coal sector, in response to increased demand for power plants and industrial users. Total steam coal trade is expected to 347 Mmt in 2000, compared to 178 Mmt in 1988. Australia is projected to remain the largest steam coal exporter, with 93 Mmt in exports by 2000. The USA is also forecasted to increase its share of the trade market, from 17% to 22%. South Africa's total market share is expected remain fairly constant at 21% but it is expected to make substantial gains in steam coal exports to Western Europe after the relaxing of sanctions. Poland's level of steam coal exports and, hence, its market share is expected to decline. China is expected to export 25 Mmt by 2000 (11 Mmt in 1989). Colombia and Venezuela are seen as rapidly growing low-cost producers, with joint exports of 40 Mmt by 2000. The IEA's forecasts for growth in coking coal trade point to a decline in world trade from 195 Mmt in 1988 to 158 Mmt in 2000. The USA is projected to reduce its coking exports to Western Europe and Asia.

1.69 The US National Coal Association (NCA) forecasts that international trade will increase at an average annual rate of 2.8% p.a. until 2000, reaching 488 Mmt by that year. The Australian Bureau of Agricultural and Resource Economics (ABARE) expects world trade in steam coal to increase at a faster rate than total demand. Seaborne imports of steam coal are expected grow to 278.5 Mtce in 2000. Strong market growth is expected take place in Asia due to strong electricity demand growth and an increasing share of coal in total generating capacity. Other industry estimates project world seaborne steam coal imports to grow to between 190-305 Mtce by 2000.

1.70 The range of projected trade volumes is large, indicating significant uncertainty. However, this reflects the fact that less than 10% of total global steam coal production is traded internationally; small changes in local demand or production capacity can lead to wide swings in traded volumes.

II. COAL MINING AND PREPARATION ISSUES

2.1 Every coal seam was originally deposited as vegetable matter in near level terrain which has subsequently undergone metamorphism due to tectonic pressure and temperature. In the process, the coal seams lie in any disposition from horizontal to vertical. The method of mining coal depends upon the thickness of the seam, strata cover above the seam and its inclination from the surface.

2.2 There are basically two types of coaàl surface mines, open pit or surface mines and underground or deep mines, depending upon the relationship of the coal seam with respect to the surface configuration. Surface mining is adopted where the coal is close to the surface, and the volume of overburden to be removed to mine the coal is within economic limits. When the coal seams lie relatively deeper beneath the surface or when they run deep inside the earth from an outcrop region, underground mining results.

Open Pit Mining

2.3 Where the coal seam is close to the surface, it is possible to use modern earth moving equipment to remove or strip the cover and expose the coal. Bulldozers and scrapers can be used to scrape and remove the cover if the material is soft. Otherwise, shovels or excavators, draglines, or wheel excavators are used in conjunction with a wide variety of transport and ancillary equipment which facilitate the removal of considerable volume of overburden and the subsequent removal of coal.

2.4 The basic deciding factor for the economic limits of open pit mining is the ratio of depth of overburden to thickness of coal. It is usually expressed in terms of cubic meter of solid overburden to be removed to extract one tonne of coal. This can vary from less than 1:1 to 1:30 depending upon the quality of coal, hardness of the strata and the type of equipment used for removing the overburden. Even high overburden ratios can be economically attractive, if the coal and overburden quality are appropriate. The depth of an open pit mine can vary from as little as few meters to over 250 meters.

2.5 The stripping of overburden usually starts at the place where the coal seam outcrops at the surface, or lies under the shallowest cover. Depending upon the hardness of the overburden strata, it is drilled and blasted so that rocks can be broken into smaller fragments suitable for the loading bucket. Usually a narrow steep bench 18 - 30 meters wide and 12 - 18 meters high is formed to facilitate deployment of earth moving equipment. Such benches are formed in steps until the top of the coal seam is reached. The operating cycle consists of drilling and blasting of rock, excavation of blasted rock and extraction of coal.

2.6 For stripping extra thick overburden, very large-scale equipment has to be deployed to make the mining process economically feasible. Electric and diesel engine equipped shovels are available in all sizes with bucket capacity ranging from 2 to over 100 cubic meters. They operate with matching trucks to carry at least 3 - 4 bucket fills at a time.

2.7 Draglines are specially designed excavating equipment which can operate from the top of much higher benches and are equipped with very large buckets (100 m^3) that swings on a boom to dump or side-cast its load at a distance up to 180 m away from a height of 15 - 20 storied building. Smaller draglines are also in use for limited activities. The choice of large equipment rests on its productivity and economy. An all purpose dragline is more versatile than a shovel; on the other hand, a shovel for the comparable reach (and matching transport units) works faster.

2.8 Yet another large capacity loader in use for removing large volume of material is the bucket-wheel excavators. These are large mobile, continuous excavating equipment that operate on level benches. They remove the material (usually unconsolidated to moderately hard or pre-blasted) from bench faces with a large, toothed bucket mounted on a wheel. A bucket-wheel excavator can cut 20 - 30 m above and 7 - 10 m below the bench floor.

2.9 In open-pit mining, the slope of bench faces and of the high wall must be carefully planned and executed. The slopes at the bottom of a deep pit cannot be as steep as those near the surface. Any side collapse can lead to loss of human life and equipment deployed below. The lateral forces working on the wall strata and ground vibrations caused due to heavy blasting tend to induce rock slides. It is important that mined out pit areas are back-filled as soon as possible to stabilize the quarry faces.

2.10 After the open-pit mining is completed, the ground presents a devastated look with long furrows and mounds of rock. The area is devoid of vegetation and often contains pools of rust-colored acidic water which may drain off into nearby water channels. With careful planning and much expenditure after mining operations cease, it is possible to restore the land to its former use. When the operation first starts, the valuable top soil is carefully removed and preserved. After mining and backfilling, it is again spread over the surface to restore vegetation. Most of the coal mining countries have already enacted laws to prevent any misuse of land in the future. Environmental degradation caused by open pit mining is dealt with in more detail in the environment section below.

Underground Mining

2.11 Depending upon how coal seams are found to occur inside the earth, underground mines are either developed by level tunnels (adits) starting from a hillside or by inclined tunnels (drifts/slopes) from the outcrop region or by shafts (also called pits). Shafts are vertical openings reaching the coal seam from the surface above. Usually coal seams not economically mineable by open pit method or lying at depths exceeding 30 m or so are developed by shaft. Depths of underground mining range from 30/40 meters to about 1500 meters. Coal seams being softer compared to the host sedimentary strata consisting of harder sandstone, shale etc. cannot withstand the rock pressure and become unsuitable for mining operation at greater depth. Ventilation problems associated with high rock temperature and humidity add to the problems leading to higher cost.

2.12 All coal mines must have two access roads, one for the supply of fresh air and the other for exhaust. They also serve for transport of coal and men, and for supply material. Coal seams can be approached more expeditiously by shafts,

but the initial investment in ventilation and hoist systems and the day to day operating costs are higher. On the other hand, drifts can also be very expensive if they are to traverse through unstable or water bearing strata. Many such issues have to be carefully analyzed before a decision can be taken about the mode of access to a mine.

2.13 There are many ways of mining coal but principally, they fall into two broad categories namely, room-and-pillar (also known as bord-and-pillar) and longwall. The former, which is older of the two methods, consists of developing a checker board of roadways (rooms) around large square or rectangular blocks (pillars) of coal and later extracting the pillars. In the latter system two parallel roads (gates) are driven for a certain distance into a coal block, and then are connected by a third straight road driven at right angle to the other two roads. The connecting road is called the longwall, which is allowed to advance or retreat, winning all the coal lying between the two gate roads.

Room-and-Pillar

2.14 The room-and-pillar method of mining with high degree of mechanization has been widely practiced in Australia, South Africa and the U.S.A. Some variation of the above, with lower level of mechanization but more manual-intensive is the principal method of mining in India and many other developing countries. The method is applicable in level to moderately inclined thick seams at shallow depth, up to 200 - 250 meters from the surface and under strong roof and floor strata conditions. The rooms are 3 to 5 meters wide with pillar size ranging from 18 to 40 meters square or somewhat rectangular but bigger in area. The greater the depth, the larger is the size of the coal pillar to support the strata above. However, the method is not feasible beyond a certain depth. Initial development consists of forming rooms and pillars in a predetermined block of coal called panel. This operation yields 5 - 15% of the *in situ* reserves. The next operation, called depillaring, consists of reducing the pillar size, leaving sufficient stumps of coal to support the roof before completely withdrawing from the area. This operation yields 40 - 50% of the reserves, overall recovery being of the order of 50 - 70% of the *in situ* reserves, depending upon the thickness of the coal seam and its depth from the surface.

2.15 During the development stage, the rooms are supported wherever necessary with wooden props and bars set in goal post style or with roof bolts. During the pillar extraction stage, support of the void created is provided by a combination of wooden props set in rows, roof bolting, and wooden cogs(cribs). However, large sections of pillars also have to be left behind for safe withdrawal of men and material before roof collapse takes place. It is obvious that the method is wasteful and sometime hazardous.

2.16 The conventional method of actual extraction involves cutting a slot at the coal face, followed by drilling, blasting, loading and transporting the broken coal out of the mine. With the development of safe explosives, the cutting process is now virtually eliminated. In the less mechanized system, coal is hand or machine loaded into small mine cars riding on tram lines or in small scraper chain conveyors. Each face produces only 15 - 20 mt of coal at a time. The operation is cyclic in nature, as coal winning and evacuation and ventilation of a large number of such production faces are labor intensive. Productivity of

both men and machines is low.

2.17 Continuous mining machines have replaced many stages of cyclic operation above. These rugged machines shear, claw, or rip away the coal from the face and load them on a piggy-back conveyor, or on tire-mounted shuttle cars which operate between the continuous miner and belt conveyor system. Freshly exposed roof is systematically supported by roof bolts. Although the method still remains poor in terms of the degree of extraction of in situ reserves it is highly productive with very low cost of production. Despite serious inroads made by longwall mining in many countries, continuous miners still remain very popular and contribute to the major share of underground production in Australia, South Africa and the U.S.A.

Longwall Mining

2.18 Longwall mining was first introduced in the U.K. in the early part of this century. Its adaptability to diverse geological conditions, varying degrees of mechanization, and the high productivity and rate of recovery of in situ reserves has made it the most popular method of mining in the world. It contributes most of the underground hard coal production in China, and in all countries of Europe, Japan, and a substantial portion in Australia, South Africa and the U.S.A. The method is becoming more popular in other countries as well. It is very capital intensive, but highly productive.

2.19 A normal longwall panel is developed by driving a pair of gate roads supported by steel arches or props and bars, 100 - 200 meters apart into a panel for a distance of 600 - 2,000 meters. At the end of the drivage, the two gate roads are connected by a straight road called the longwall face. From here the longwall face retreats towards the starting point of the drivage. In the advancing longwall system, the gate roads are connected after 15 - 20 meters from the starting point and then the extraction proceeds toward the panel boundary.

2.20 The face is equipped with coal winning, transportation and roof support equipment. A steel plated conveyor is laid along the full length of the face, the coal winning machine(shearer) rides on this conveyor. The shearer travels back and forth along the face and working like a milling machine claws out about 600 mm width of coal at a time. A mechanism at the base guides the ripped coal on to the conveyor. The shearer may be replaced in softer coal by a plough which planes thin slices of coal and loads it on to the conveyor. A series of articulated steel canopies or beams held up by steel uprights provide support at the work place. Steel uprights may consist of simple friction props to very complicated self advancing hydraulic powered-supports.

2.21 As the extraction proceeds, the conveyor and supports are moved forward close to the face, and the void behind is filled in by caving of roof stone. Most of the coal (90 - 95%) between two roadways are extracted. If the coal seam is more than 3 meters thick, the extraction is carried out in two or more descending slices. A continuous stream of fresh air is coursed through the mine to dilute the gases and ventilate the machinery.

2.22 The system is very capital intensive. At the fully mechanized longwall faces, the steel supports that hold up the roof immediately over the coal face

and conveyor are automatically moved forward as coal is mined in front of the conveyor. The only human operators needed in this system are the men who travel between the hydraulic props manipulating the levers and valves that control the movement of supports and an operator for the shearer.

Mining Costs and Constraints

2.23 Underground coal mining is inherently hazardous. One has to be constantly aware of the dangers from highly combustible methane gas and coal dust, of falling roof and sides, unexpected inrush of water, etc. Automatic monitoring and alarm systems indicating presence of dangerous concentration of gas, dust and other hazards have improved the working conditions in recent times. Fall of roof at longwall faces which was one of the major causes of accidents, has been substantially reduced with the introduction of hydraulic powered support. Underground mining is becoming safer day by day due to constant improvement of technology, yet the unexpected does happen and hundreds of lives are lost every year, and many times that number are seriously injured and permanently disabled (Annex 2.1).

2.24 More than half of 1990 hard coal production in Australia (162 mt), Canada (38), Colombia (21), India (225), Russia (542) and the U.S.A. (895) comes from surface mining. Even in the U.K., traditionally an underground mining country, 20 - 25% of the production (93) comes from open pit mines working on the outcrops of coal seams previously worked out from underground. The leading producer of underground coal is China, where more than 95% of the 1000 mt annual production comes from below-surface mines.

2.25 Most of the lignite or brown coal is however, mined by open pit method, very often with highly productive bucket-wheel excavators. This highly productive and economic method of mining suits the low calorific value of such fuel. Leading producers are Australia (48 mt), Canada (31), all East European countries (234), Germany (359), Greece (54), Spain (21), and the U.S.A (81). (Annex 1.2).

2.26 Open pit production is generally cheaper, and the operations much safer. The very nature of underground mining leads to higher cost. With reserves at shallow depth exhausting with years of mining operation, most of the European countries along with Japan and South Korea, are finding underground coal mining very uneconomical. Old mines are closing down and very few new mines are opened. These countries are becoming increasingly dependent on imported coal from Australia, Canada, China, Colombia, Poland, Russia, South Africa, the USA and Venezuela. Costs of production in market-oriented exporting countries (USA, Australia, South Africa, Colombia) are close to the ex-mine price that can be achieved in the market, including an appropriate profit margin. As individual mines' extraction costs increase (e.g. with increasing depth or decreasing thickness of the seam, ash content increase, etc.), the operations at the mine are terminated if the achievable market price does not allow a satisfactory profit. Such mining operations tend to be efficient, as they are forced to respond to market signals. In coal producing countries that consume most steam coal domestically, trade only at the margin, and are not subject to an open steam coal market (China, India, Eastern Europe, Germany), the efficiency of mining operations is lower, and costs are not closely related to prices (see Chapter 4).

Production Costs

2.27 Reliable data on production costs in major coal producing countries, especially those engaged in export of coal, are not easily obtained for commercial reasons. Cost data of selected countries are given in Annex 2.2. Coal mines in the European countries are very deep and old. High wage cost, coupled with high material and energy cost of mining at great depth have made coal mining there very unremunerative. Decisions have already been taken to phase out coal production over the next one or two decades. Current efforts are directed to concentrate mining activities in the profitable collieries and in the increase of the average output per colliery and per longwall face. Reconstruction and modernization of coal industries in Western Europe and Poland changed significantly the structure of coal production costs. In the period 1976-86, the share of manpower cost was reduced to a great extent but the introduction of a higher degree of mechanization increased the share of material costs and depreciation charges. Only in the former USSR, the proportion of manpower cost seems to have remained high and material cost low, indicating a lower degree of mechanization. This does not reflect true input costs, but shows a high level of subsidization in the economy.

2.28 During the last 25 years, the number of collieries in France declined from 70 to 9, in Germany 101 to 30, in the UK 481 to only 86. The same happened in Eastern Europe, but at a reduced pace: in Czechoslovakia, the reduction was from 24 to 14 and in Poland from 81 to 70. No major changes were noticed in the former USSR (Annex 2.3). This reduction in the total number of collieries had a profound effect on hard coal production level in Europe. In Western Europe, hard coal production in 1990 was only 207 Mmt against 336 Mmt in 1970, a reduction of 62% in 20 years. In east-European countries, hard coal production marginally increased from 655 Mmt in 1970 to 716 Mmt in 1990 despite some major reduction in Poland which was more than made up by the USSR.

2.29 The decline of coal production in Europe and Japan stimulated the growth of low-cost steam coal production in Australia, Canada, Colombia, South Africa and the USA. Lower costs of production in these countries can be attributed to favorable geology and large scale open pit mining (Annex 2.2). This fostered the large growth in international trade of steam coal since the early 1970's. The landed price of steam coal from Australia, Canada, South Africa and the USA is lower than the domestic production cost of such coal in all west European countries and Japan. At present, the west European and Japanese coal production is subsidized to a large extent to preserve some production base in the home country and to provide employment to local communities (see Chapter 4). Even in Poland, where the production cost is comparatively lower, the current figures do not indicate the true cost due to a high degree of subsidy for many items of input.

Productivity

2.30 Productivity in coal mining industry often means the labor productivity and is used as the efficiency index. It is expressed in terms of coal output(ton) per man per shift or simply OMS. Since the duration of a working shift varies from country to country, sometimes it is also expressed in terms of output per man per

hour. It is derived by dividing the total saleable production of the year by the total manshifts worked during the year. The methods of computation of manshifts vary widely from country to country. Some take into consideration all persons working at surface and underground, while others compute only the production related workers. Statistical information about labor productivity and the method of computation are regularly published only in a few countries (Annex 2.4). Other major coal producing countries like China and the former USSR never publish any information on the subject.

2.31 Labor employment in underground mines is necessarily higher, accounting for 35-60% of the total cost. The productivity in underground mines depends on many factors, including intensity of operations, production technology and mechanization, organization of production and management of labor, all of which are controllable items. The uncontrollable factors which substantially determine underground mine productivity are the natural conditions like depth of mining, thickness and inclination of coal seams, their gassiness, competence of roof and floor strata, rock temperature of host strata and many other geological features. Moderately thick coal seams (2-3m) lying at a shallow depth (100-250m) and within competent strata are the ideal conditions for high productivity. The examples are Australia, South Africa and the USA. Open pit mines employ fewer labor but more expensive equipment. The labor cost constitutes less than 15% of the total compared to 50-60% in equipment and material charges. Within limits, the larger the equipment size the higher is the productivity. Therefore, the correct choice of optimum-size equipment has an important bearing on the productivity. Thick flat seams lying at shallow depth at low stripping ratios lead to higher levels of productivity. Examples are Australia, Canada, India, South Africa, the USA and the former USSR.

2.32 In many developing countries and former centrally planned economies, the mining companies are required to run social infrastructure like housing facilities, schools, hospitals, clinics, etc., which are usually provided by local governments elsewhere. In some countries, there is a need to develop many in-house capabilities which can be easily procured from outside in developed countries. These include equipment repair and maintenance facilities. All these activities require additional non-productive manpower which tend to lower the overall OMS. Therefore, it is not always meaningful to compare the productivity of one country with that of the other and assess the relative efficiency of mining operations. Nor does the labor productivity in isolation indicate the economic efficiency of the industry.

Coal Preparation

2.33 Run-of-mine coal frequently contains varying proportions of non-coal substance; for example sandstone and shale from roof and floor, and dirt bands embedded within the coal seam. Besides the above, modern day conveyor transport often carries a large volume of rocks from mine development workings. In many countries, combustible materials in coal seams are intimately mixed with sand and clay at their depositional stage. Run-of-mine coal materials vary in size from 300 mm or more to fine dust. The modern mechanized system of mining also produces a high proportion of fine coal (below 3 mm) during mining and transport operations. Coal from many seams worked in the mine come together at the surface. Water used for dust suppression in the mine makes the coal dust very wet and

sticky. All these require to be processed, and coal of uniform size and quality has to be marketed.

2.34 The function of coal preparation is to sort out the run-of-mine coal, improve its quality by separating the dirt from the coal, and sizing the products according to customer demand. Separation of marketable products and unwanted waste must be done with great care not only to obtain clean products, but also to avoid undue loss of carbon in the waste. At the same time, the operation must be carried out economically to avoid raising the cost of the coal unduly. Run-of-mine coal is first screened, oversize rocks removed, and the lump coal crushed. The whole product is then screened into different size fractions according to the market demand. Alternatively, coal is separated from other materials in a washer bath by taking advantage of the differences in density between coal (specific gravity 1.3 - 1.6) and other mineral matter (specific gravity 1.8 - 2.4). The water in the bath is constantly pulsated, and the upward movement of the water lifts the lighter coal to the top and at the same time allowing the heavy material to settle at the bottom. Alternatively, the specific gravity of the liquid in the bath is increased by mixing finely ground magnetite with water so that the coal floats on the top and the heavy material sinks to the bottom. There are many other processes for the separation of coal and dirt. Finally, water is removed from the washed products by natural drainage, filtration, centrifuging or heat drying.

2.35 The process may yield two (clean and waste) or three (clean, middling and waste) products. The ash content of "clean" steam coal may vary from 10 - 20%, "middling" 20 - 35%, and "waste" above 60%. The ash content of clean coal is dependent on market considerations. Export coal is required to have an ash content so that the calorific value of coal reaches at least 6,000 kcal\kg, (10,800 Btu/lb) depending upon the basic rank and quality of the coal. The middling is used for local steam raising for power generation and district heating. Reject material is also finding some use in fluid bed boilers for district heating. Other rejects go for road construction, or for the manufacture of lightweight aggregates for building construction.

2.36 Coal is a high-bulk low-value mineral at the pit head, but its delivered cost is substantially influenced by the distance of the consumer from the mine, transport mode and unit cost of transportation (per mt kilometer) and intermediate handling charges. The delivered cost of coal (even clean export coal) at the consumer's plant may be several times the pit head price. Therefore, all efforts are made to reduce the non-combustible matter in the coal before it is dispatched from the mine, to reduce the cost of transport per unit of calorific value.

2.37 In China and India, two of the largest producers and consumers of steam coal, the need for preparation and cleaning of steam coal is still in doubt. Potential coal demand in these countries far exceeds the production. Investment capital being scarce, there is a continuing debate on whether coal preparation plants should be set up to improve the quality and in the process lose a part of the production, or new coal production capacity should be built to narrow the gap between supply and potential demand. The main issue is not one of economic justification. In China, for example, the incremental cost of coal washing amounts to about US$3/mt, while the transport, plant maintenance and other

savings are estimated to exceed this figure. The debate focuses on the question whether the users (power utilities) or the coal mines should invest in the beneficiation facilities. In a non-market context, where coal allocation to power plants has been the rule, this is not an issue that can be solved easily, as the parties do not have a clear incentive to come to an agreement.

2.38 In Europe and other countries where thin seams are worked, and where coal is always contaminated with a large proportion of rock and shale, beneficiation is an integral part of coal mining activity. Since coal preparation also involves loss of combustible matter in the waste, it may not be always economic to clean coal for local consumers and central power stations, unless the economic benefit clearly exceeds the higher cost of beneficiated coal. It should be noted that sulfur, one of most offending polluters, is not fully removed by washing alone.

2.39 The beneficiation cost depends upon the quality and size distribution of run-of-mine raw coal. It also depends upon the character of inherent and extraneous dirt. The plant and process costs increase with the complexity of design objectives and process flow-sheet. A fine coal recovery circuit may cost 50% more both in terms of plant investment and operating costs. In the USA, operating cost for thermal coal beneficiation, without a froth flotation circuit to recover fine coal, ranges from US$1.65 to 2.20/mt of clean coal. The depreciation charge amounts to another US$2.00 per ton. There are not many thermal coal washing plants in China, but the few plants that are operating have operating costs comparable to those of the USA. In Europe, where run-of-mine coal is more dirty, and all efforts are made to recover all fractions of coal, the beneficiation cost are twice as high, US$7-8/mt.

Environmental Impact of Coal Mining

2.40 The concern about the environmental impact of coal mining initially arose from a coal conservation movement which soon started drawing attention to the environmental consequences of mining of coal and its use. It did not receive much attention even in the developed world, where coal mining has been in progress for more than a century and half, prior to the 1950s. In the developing countries, this awareness came in the 1970s. This can be partly attributed to lower intensity of coal mining and partly to the fact that since most of the operations were limited to underground mining, the damage to surface land could be localized. This is not to minimize the effects of waste piles in mining areas where they always remained an eye-sore to the rural landscape and not infrequently contributed to the air pollution and constituted a safety hazard.

2.41 When the emphasis shifted to large-scale opencast mining with the attendant ugly piles of overburden and waste dumps causing serious degradation to the local ecology, attention got focussed to visible impact of mining. Large-scale deforestation of mining areas to accommodate mines and their infrastructure, including the townships, became another major issue. The awareness of the public to these consequences during the last two decades or so put the coal industry under pressure to mitigate the damaged environment and to develop a strategy, which from the beginning of the coal mining project cycle takes into account all aspects of environmental problems.

2.42 Environment impacts need assessment at each stage of mining activities. Major problems are:

1.	Immediate	- agricultural land degradation/subsidence - forest land denudation - resettlement of population
2.	Medium term	- disturbance to water regime - air pollution - noise abatement; ground vibration - occupational health of mine workers
3.	Longer term	- waste disposal - disturbance to ecology, flora and fauna

Land Degradation

2.43 While the impact of underground mining is predominantly in the form of ground subsidence and cracks in the surface which are localized, opencast mining affects a much larger area of land, firstly by the mine proper and next by the large network of haul roads around the mine site. Thus opencast mine causes a more significant change in land use compared to underground mining, as it renders the surface area derelict with thorough deprivation of top soil, and interferes with surface drainage and morphology of rivers. Opencast mining also increases the run off of rain water, leads to lowering of the ground water table and depletes the subsurface aquifers. The net effect is the disruption of the hydrological cycle which ultimately affects the habitat. In addition to the above, a large proportion of the coal reserves amenable to opencast mining is found underneath forest land, giving rise to conflicts between coal mining and conservation of forests.

2.44 Underground Mining. Subsidence to surface due to underground mining is influenced by the method of mining. With the exception of a few countries, longwall is the predominant method of mining today. In this technology large blocks of coal are systematically extracted which allow very even and gentle lowering of the ground causing minimum damage to the surface. The alternative technology of room and pillar (with its variants) prevents surface subsidence by partial extraction or by leaving behind suitably dimensioned pillars of coal to support the roof and strata above. However, in earlier times when underground mining started and the dynamics of superincumbent roof pressure was not properly understood, the design of such coal pillars was deficient, and the surface over mined areas suffered from uncontrolled and unpredictable subsidence. To avoid subsidence under built-up areas or to protect sensitive structures and surface features like rivers, lakes, forest, etc., it is now very common either to leave behind a solid bloc of coal or to undertake longwall mining under very controlled conditions, and/or to fill up the post mining void with sand or mine waste.

2.45 Subsided land is not deprived of its top soil. There may be cracks in the ground, smaller ones get naturally filled up with surface water run off. When the cracks are large and have disturbed the water table, it may be necessary to

fill up the entire subsided trough to its original contour, before the land can be put back to its original use. Generally speaking, in case of underground mining, the land can be restored to its pre-mining use in a short time. The extent of land degradation by such subsidence and the efforts required for its reclamation are relatively small compared to those attributed to opencast mining.

2.46 Opencast (Surface) Mining. In the case of opencast mining, the land use is lost both due to quarrying as well as by dumping of overburden, waste material and removal of top soil. It has been estimated by the coal industry in India that annually abut 50 square kilometers of land use is lost due to production of only 150 million tonnes of coal by opencast mining from very shallow depth. This will go up substantially as the depth of mining and volume of production goes up. In addition, significant quantities of waste are generated by coal preparation plants, which also require dumping areas.

2.47 It is now widely recognized that mining is an interim land use and therefore, the industry ought to make all efforts to remedy damages to the extent possible. Environmental protection agencies in most countries now insist the mining industry take the following steps:

(a) Reclaim the mined land concurrently with extraction of coal, or with a minimum of time lag;

(b) Dump overburden and waste material, to the extent possible, within the mined out areas (Forest land not to be ordinarily used for external dumps);

(c) Restore, to the extent possible, post-mining land use to pre-mining land use. However, where water is a scarce resource, the worked out pits should be used as storage reservoirs to meet local water needs; and

(d) Re-vegetation of waste dumps and plantation of trees over such land.

Land Reclamation Laws

2.48 Reclamation of land or re-vegetation of dumps cannot be left to the natural processes. In this respect, the management of top soil which is the key to successful reclamation requires greater attention to ensure economic success. The study of the top soil alone can determine the most suitable species of plants that could render the biological reclamation process a success or not. With the help of proper technology, even the most degraded soil can be salvaged and put to productive use.

2.49 Many countries have already enacted laws, developed national programs and specific policies for environmental protection and against land degradation. Some of them are particularly addressed to the mining industry. The cost of such environmental protection may be initially borne by the mining industry, but ultimately legal provisions of this kind raise the overall level of the cost of production.

2.50 In the CIS, where the land and natural resources belong to the state, the constitution emphasizes the importance of protection of natural resources. It is mandatory to reclaim the land allocated to surface and underground mining. There is a separate land reclamation division in each mining enterprise to oversee the implementation. In Germany, a law enacted in 1920 established an association to deal with the regional planning of the Ruhr coal mining area. By another act in 1962, this body was made responsible for a development plan which includes refuse disposal, land utilization, and restoration of derelict mining areas. In Eastern Germany (former GDR), mining licenses stipulated the rights and obligations of the mining companies to reclaim the land affected by mining to its former use and in the interim period, pay adequate compensation to the land losers. Similar, if not more stringent laws exist in Czechoslovakia. Poland introduced strict land reclamation laws in 1961. Similar laws and oversight bodies exist in France and Great Britain. The first environmental protection law in China was enacted in 1979. A separate ministry was created in 1982 which is responsible for both oversight and implementation.

2.51 In the USA, the National Environmental Policy Act of 1969 covers a wide area of natural policy in relation to environmental problems. It requires an environmental impact assessment plan before the mining operations can start. The Surface Mining Control and Reclamation Act of 1977 requires the federal government to regulate coal mine reclamation, and to establish the minimum reclamation performance standards. The rules are being streamlined to reduce the federal involvement and to increase the discretion of the state authorities.

Technology and Cost of Land Reclamation

2.52 During the last two decades, great progress has been achieved in land reclamation technology based on biological treatment of the mined debris and waste. It involves:

(a) separate storage of different categories of mine waste;

(b) careful analysis and research of waste to establish the most appropriate plant species for vegetation;

(c) attention to surface drainage and hydrological factors; and

(d) regarding, terracing and landscaping of the land to suit the ultimate use.

2.53 Experience shows that the site engineering stage of reclamation is the most expensive part of the operation. If this is properly planned ahead of time and is integrated with the mining operation, it could be more efficient and cost effective. The degree of site engineering work required is largely determined by planned end use of land. Restoration of the land to agricultural use requires the highest degree of site engineering. The requirement of site engineering can be met with advance planning of waste transport and storage systems. Overburden disposal that creates "hills and dales" requires a lot of material handling at the subsequent stages to create a reasonable level for agricultural purposes. Waste disposal in fan shape reduces the levelling work. In the USA, normally inpit crest-shaped disposal dumps are common, perhaps due to the favorable

geological feature of flat coal seams in the country. Dragline seems to be the most efficient mode of overburden removal and waste disposal with subsequent levelling of crests. Wheel and crawler-mounted dozers have become an integral part of the process.

2.54 The most common technique of reclamation and surface levelling is to leave the ground with incomplete levelling or in terraced form. This is reported to be less costly but the land becomes easily amenable to grazing and forestry. The main precondition for a successful biological reclamation is to create a substrate for plant growth that is physically, chemically and biologically fertile. In many places, the top soil is first removed and stored separately. After the general reclamation process, the top soil is replaced and ploughed in to restructure the soil. Often the nitrogen losses during the storage process have to be compensated with high nitrogen dressings. Many other chemicals may have to be added to restore the natural fertility of the soil. The various techniques for soil reclamation, planting and seeding in different parts of the world have become the subject matter of much research.

2.55 Earth moving accounts for about 80% of the reclamation costs. However, it is a high-cost/low-risk activity, whereas re-vegetation, planting of trees and cultivation of land is a low-cost/high-risk activity. It is difficult to estimate average costs of these two activities, as they are site-specific.

Mine Fire

2.56 Mine fires are a peculiar environmental hazard to be found in some areas where two special conditions are present: (a) natural occurrence of those coal seams in which the chemical composition of the coal mass is liable to spontaneous combustion; (b) exposure of these seams to air to permit ready access to oxygen to initiate the combustion and later for sustaining an open fire. Such exposure occurred frequently in former times when these coal seams were inefficiently mined from the outcrops, leaving behind small sizes of coal pillars. In the course of time, these undersize pillars got crushed by the roof weight and became the main sources of fire at multiple points.

2.57 Surface dumps of overburden containing carbonaceous shale, and other dumps made of rejects from coal preparation plants containing rocks with both thin bands of coal and pyritic sulphur which are very susceptible to spontaneous combustion. If these fires remain unattended, they burn slowly unimpeded for decades until all the carbonaceous and sulphurous material are consumed. Surface fires are also known to occur in opencast thick coal benches, specially in those belonging to lower rank sub-bituminous quality.

2.58 The measures to control the mine fires is to smother or blanket the fire area with sand, earth and clay which are compacted to prevent any ingress of air. If the fire area is small, it can be drowned with water. Under suitable conditions, the spread of fire can be contained by trenching, similar to the method practiced to contain forest fires. Fire in surface dumps can be contained in the early stages of quenching it with water followed by dozing, levelling and compacting with heavy earth moving machinery.

Water Resources Damage

2.59 Underground and surface mining adversely affect ground and surface water quantity and quality. Underground mining operations have in many cases affected the natural ground water table in the vicinity. Because of the recession, the yield of wells and boreholes in the neighborhood is reduced or even stopped. Large opencast mines which are planned to go 100 to 400 meters below the surface, will have a much more serious impact on the ground water tables and also in the drainage pattern of the area concerned. In many coalfields of China and India, there is chronic shortage of water, which is so acute during the dry season that even the drinking water requirement is met with great difficulty. Water conservation, therefore, becomes essential. The mine operator has to ensure optimal use of surface and ground water. Hydro-geological exploration investigations are necessary to provide a better understanding of geo-mining conditions. Water balance and water management become part of the environment plan of the proposed mine.

2.60 Water pumped out from many mines also poses problems of low $_{ph}$ value (indication of high acidity), especially encountered in mines containing high inorganic sulphur (pyrites) in coal. Even otherwise, due to physical and chemical contaminations, mine water is known to contain excessive quantities of bacteria, chlorides, fluorides, iron, nitrates, sulphate, trace elements, etc. Changes in physical and chemical properties of surface water are caused due to discharge of raw mine water in the local drainage system without treatment. Mine water which even after treatment cannot comply with the drinking water standard can be used for industrial purposes and also be used for local agricultural purposes rather than be discharged into rivers and streams.

2.61 Liquid effluent from coal beneficiation plants also contains most of the dissolved chemicals mentioned above, beside the suspended coal and clay particles that accumulate during the washing process. Cleaning operations include settling in large ponds, and water clarification by chemical additives. The clarified water is recirculated in the process plant. Untreated water is no longer to be drained in the rivers and streams. Rain water seeping through overburden and reject dumps may leach the toxic heavy metal compounds to the subsurface water table. It is necessary to regularly monitor the dumps and underground water for the presence of toxic substances.

Dust and Air Quality

2.62 Underground and opencast mines vary a great deal with regard to damage to air quality (excluding occupational hazards to health). Coal handling and washing plants are common to both types of operations. But air pollution created during overburden and coal excavation processes in opencast mining is far more serious. Suspended particulate matter (SPM) and respirable dust are predominant impacts, representing nuisance and health hazards to the area and to a lesser extent, to the ecological balance.

2.63 Like all other components of the coal cycle, coal transport has also an environmental impact. Coal is transported over short distance by trucks and conveyors and over longer distances by rail, barges, ships and slurry pipelines. Coal dust occurs during loading and unloading, and during transportation en

route. Its impact is felt by all natural systems (including agriculture, forestry, horticulture, aquaculture), buildings, and installations and human beings. But so far, environmental impacts on human beings only have received the most serious attention.

2.64 The transport of coal in all of its forms necessarily involves fugitive dust, even though precautionary measures are increasingly taken to minimize its occurrence. It is generally estimated that at every stage of loading and unloading about 0.02% of coal handled is lost due to fugitive dust. It is further estimated that about 50% of coal dust losses occur during the journey time and 25% each at loading and unloading time, total amounting to about 0.8 to 1.0 kg per ton of coal throughput. There is little information available about the overall effect of fugitive dust emissions (apart from loss of coal) from coal handling and transport en route, although estimates have been made that 16% and 23% of mean particulate loading of the air in the Atlantic and Mountain regions of the USA, respectively, are due to this.

2.65 Table 2.1 shows an estimate for atmospheric emissions from an unit train carrying 11,430 tons of coal making a round trip of about 1,000 km: a total of about 20 tons of pollutants. In order to minimize the losses, water spray and dust extractors are used at loading and unloading points beside using wind guards, polymer sprays, etc. Some rail cars in the USA use flip top lids.

Table 2.1: ATMOSPHERIC EMISSION FROM A UNIT COAL TRAIN

Emissions	Kilogram per trip
Particulate	345
Hydrocarbon	2,075
Carbon monoxide	935
Sulphur dioxide	780
Nitrous oxides	4,855
Particulate during loading	2,285
Particulate during unloading	2,285
Fugitive emissions	5,700
Total	19,270

Source: Environmental Impacts of Coal Mining and Utilization--Chadwick, Highton and Lindman, pp. 76.

Noise

2.66 Problems of noise are pronounced in surface mining since operations are more extensive than underground mining. The introduction of high capacity heavy

earth moving equipment, the construction of large coal handling plant and coal washeries create the problems of high noise, often exceeding 100 decibels (dB). Ambient noise level in a busy mining area is of the order of 55-80 dB during the day time and 55-67 at night time. Mining in forest areas could lower the noise level to 40-45 dB at night. The usual maximum acceptable noise level threshold is 85-90 dB during the day. In general, noise abatement in surface mining is difficult. It requires joint efforts of several parties, including equipment manufacturers, mine operators and research organizations to minimize the pollution effects of noise. However, the following steps can mitigate some noise:

(a) installation of efficient silencers in the exhaust system of internal combustion engines;

(b) lining of coal chutes with noise absorbent material;

(c) proper maintenance of all plant and equipment;

(d) separating the mine area from all residential areas; and

(e) planting wide belts of thick-foliage trees in the intervening areas.

Vibration

2.67 Ground vibration caused by heavy blasting in opencast mines is a nuisance to the public and a hazard to the buildings and structures. The vibration is caused by the detonation of high explosives, often exceeding 600-700 tons at a time, at quarry benches. It has been observed that with the help of sequential blasting, up to 700 tons of explosives could be detonated in one blast and still keep the vibration within an acceptable limit of 70 mm/sec in the soil and soft rock and 120 mm/sec in hard rock, which is not likely to cause any damage to property.

III. COAL TRANSPORT AND TRADE ISSUES

3.1 Although less than 10% of current total world steam coal production is traded internationally, this share is likely to grow. The main reason for this will be the gradual decline of high-cost coal mining in Europe (UK, Germany, Poland, Russia, Czechoslovakia), and the partial replacement of this capacity by lower-cost seaborne imports into Europe. This development will be accommodated by increasing U.S. exports, more aggressive marketing of South African coal after the lifting of sanctions, and the rapid development of new exporters such as Indonesia and Colombia. This rising importance of coal trade warrants a close review of the trading, freight, and infrastructure issues.

A. INLAND TRANSPORTATION AND PORTS

3.2 If world coal trade and consumption is going to expand at the substantial rate being predicted by many forecasters (para 1.60-1.70), this expansion must be supported by adequate transportation infrastructure within the exporting and importing countries and by the port facilities of those countries. For both inland transportation and ports, the capabilities of the exporting countries tend to be the most critical. This was certainly true during the seaborne coal trade boom of the late 1970's and the early 1980's; the bottlenecks and long queues of ships waiting for port space were on the export side, not with the importers. However, at least one of the countries (United Kingdom) expecting major increases in coal imports during the next decade does not currently have the capacity needed to handle all of the expected imports; and several central European countries might change from their normal pattern of rail receipts from eastern bloc sources to water-borne coal provided by overseas suppliers. Because of the increases expected in demand and the shifts expected in supply sources during the next decade, the following section of the report discusses the inland transportation and port situation for both exporters and importers. Only the major shippers and receivers of coal are discussed in detail. Domestic transport issues in major producing and consuming countries such as India and China are dealt with in a separate section.

Overview of Exporter Infrastructure

3.3 Exporter infrastructure is not a problem at present and is unlikely to constrain the total volume of world coal trade in the future. Decisions on when and where to build the new capacity needed to support future growth will affect the market shares of the individual countries; but it appears likely that the projects will be constructed in time to support the expected market growth. In every country with a potential for significant increases in coal exports over the next ten years, well-capitalized private firms or governmental agencies are moving forward with project evaluation and planning. Some of the potentially significant issues relevant to all countries are discussed in the following sections under the headings of: (i) Port Facilities, (ii) Inland Transportation Facilities, (iii) Charges for Inland Transportation, and (iv) Risks for New Exporting Countries.

3.4 Port Facilities. Many of the largest exporters of coal currently have an excess of port capacity; Australia, the United States, South Africa, Canada and Poland all have the ability to increase shipments significantly without expanding facilities. In some of these countries, new capacity will be needed if shipments expand according to commonly accepted projections, but there should be little difficulty in developing the new capacity if the demand does materialize, and if it does so in a reasonably orderly fashion. In the countries that are just beginning to develop coal export industries the story is different. For example, in Colombia, Venezuela and Indonesia, huge expenditures are needed for port facilities. Table 3.1 compares present export levels with existing and planned port capacity. The table indicates clearly that for the world as a total there is plenty of capacity, and there will continue to be if the planned projects are developed.

Table 3.1: SEABORNE EXPORTS AND CAPACITY FOR MAJOR EXPORTERS (Mmt)

		Port Capacity		
		Present		
Exporter	1990 Actual	Low Cost	High Cost	Planned
Australia	106.1	146	-	17
Canada	31.0	40	-	-
China	17.0	28	-	25
Colombia	13.5	15	7	20
Indonesia	6.0	7	5	47
Poland	14.6	26	-	-
Russia	22.0	26	-	-
South Africa	49.4	58	-	10
United States	96.0	163	10	4
Venezuela	3.0	-	5	20
	358.6	509	27	143

3.5 Inland Transportation Facilities. The situation for inland transportation is generally similar to that for ports: the established exporters have adequate facilities, but the newly developing exporters need major investments. The rail system in South Africa is already capable of supporting 80 Mmt per year, far above present port capacity. While it is difficult to determine precise capacity figures for the United States and Australia, it is generally accepted that the rail systems in those countries can handle any foreseen increases in coal exports. In addition, the United States has a greatly expandable barge network that can be used as needed for export traffic. Poland has adequate rail capacity, by virtue of the fact that exports have dropped sharply while the rail system has remained in place. Canada probably has limited potential for rail service expansion, but Canadian exports are not expected to grow significantly. Among the newly emerging exporters, Colombia, Venezuela and China all need major investments in railroads in order to support more exports. All of the export-oriented mines in Indonesia are located near the coast and either have direct access to deep

water or to rivers over which they can barge to the coast. Inland transportation is not a problem for any of these operations.

3.6 Charges for Inland Transportation. There is no reason to expect that charges for inland transportation will have to increase significantly in order to support increased exports. Existing rail rate structures for the major exporters all include reasonable profits and some include major economic rents. For the newly emerging exporters, modern rail systems will probably reduce overall costs of moving coal to the ports because long and uneconomical truck hauls are now being used.

3.7 Risks for New Exporting Countries. The question of whether or not the potential new coal exporters will proceed with the transportation infrastructure needed to support higher levels of exports seems to be the single most important issue in the area of coal trade and transportation. If these countries all hold back, the growing import coal market could be supplied by existing producers (notably the United States, Australia and South Africa). However, coal prices to importers would then be higher than they otherwise might; and the developing countries will have missed an opportunity to build a base for long term economic development. On the other hand, if all of the potential projects proceed and are built before the demand materializes, the result could be a return to the over-capacity and depressed prices of the early and middle 1980s, and potentially severe strains on the economies of the developing coal export countries.

3.8 These expenditures involve much more risk than the expenditures needed by the established exporters, because:

(i) The new exporters are primarily developing countries with inherently higher investment risks;

(ii) There is little established market for the coals to be produced in these countries; investors bear the risk that demand will expand as predicted and that both costs and quality from these new exporter countries will be competitive.

(iii) Financing is needed for development of both the mines and the infrastructure; and

(iv) For most of the developing countries, it is difficult to configure the infrastructure expenditures in such a way as to make incremental investments; investments and risks must be on a large scale.

3.9 Australia is well-fixed with modern, efficient ports to handle its present level of exports and more. Annex 3.1 shows that total capacity of the existing ports now exceeds the current export level of about 106 Mmt by some 40 Mmt.

3.10 The projections for increases in Australian exports generally call for tonnages substantially greater than the excess capacity at existing terminal facilities. However, potential port expansions of 12 Mmt at Dalrymple Bay and

5 million at Newcastle can go forward when the volume of business justifies expansion. Other expansions should also be possible if required.

3.11 Almost all of the coal exported by Australia is moved to the ports by rail. Distances from mine to port are short, ranging from only 80 kilometers up to about 300. Rail service is adequate, but costs are very high as compared to rates in other countries. The IEA estimates that Australian rail charges are about three times as high as rates in Canada, South Africa or the United States, when measured on a ton-kilometer basis (Annex 3.2). The high level of the Australian rates does not reflect high underlying costs, but rather a monopoly pricing policy by the government agencies owning the railroads. Recent changes in the taxation regime and the railways' move to more commercial operations will reduce this distortion.

3.12 Canada. Eastern Canada has only one exporter, Devco, which ships from its own terminal in Nova Scotia. Three ports serve the western Canadian coal industry. Southern British Columbian and Alberta mines ship through either Westshore Terminals at Roberts Bank or Neptune Terminals just north of Vancouver; and the northern B.C. mines (Quintette and Buillmoose) ship via Ridley Terminal near Prince Rupert, B.C. The Westshore Terminal handles about eighty percent of western Canadian exports and has an annual throughput capacity of about 20.0 Mmt. Actual shipments reached the capacity level in 1989, but an expansion of 3.0 Mmt per year is scheduled for completion at the end of 1991.

3.13 Although there is considerable excess capacity on the west coast in total, much of the excess is in the north and will not be usable by exporters in the southern region. Because the Canadian coals have such long rail hauls, they are generally high in cost (loaded on the vessel) compared to the coals from other countries. [2] The cost disadvantage has discouraged new development plans in western Canada. Therefore, it seems likely that the 6.5 Mmt of excess capacity at the two southern terminals will be adequate to handle any foreseeable Canadian exports. It is possible that the market for coals exported out of the Power River Basin in the United States will expand and bring new business to the terminals in the Vancouver region. These coals can be shipped out of U.S. ports, but the lowest cost route is through Vancouver. These coals are low in Btu and have not yet been widely accepted in the Pacific Rim market; but their low costs might attract more customers as time goes by, increasing the demand for more capacity in Vancouver.

3.14 China. It is difficult to assess the adequacy of China's coal transportation infrastructure because the volumes of exports, imports and internal movements are likely to change significantly over the next decade or

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[2] Rail movements to Canadian terminals on the west coast average about 1100 kilometers. Canadian coals moving to utilities in eastern Canada or to U.S. and Canadian steel mills on the Great Lakes must travel about 2,000 kilometers. The long distance and the fact that the westbound movements must pass through the Canadian Rockies result in high rates to any of Canada's customers that are not located in the coal fields.

two and are also likely to be significantly different than official projections. [9] However, the Chinese have put into place numerous improvements in rail and port facilities and have upgraded the country's ability to move coal internally and to export it. The three northern ports of Qinhuangdao, Shijiu and Lianungang with 99 million tpy capacity are now and will continue to be the main outlets for waterborne coal. Annex 3.3 summarizes their capabilities. Rail facilities to each of these three ports have been improved; and work is continuing on some lines. Other, smaller, ports that also export coals are: Dalian Port in Shandong Province, Xingang port in Tianjin, Zhangjiagang port in Jiangsu, Xiamen port in Fujian and both the Zhanjiang and Huangpu ports in Guangdong. These other ports shipped about 2.8 Mmt in 1989.

3.15 The major improvement in rail facilities has been upgrading of the line from the Datong coal-producing region to the port of Qinhuangdao. This double-tracked and computer-controlled line can now handle 10,000 ton unit trains. The lines to Lianyungang are being double-tracked as well. According to recent estimates, China has plans to export 25 Mmt per year by 1995, compared to less than 16 million in 1989. The port and rail capacity should be adequate to support the 25 million tonne level.

3.16 Colombia. At the present time, Colombia has only one port (Puerto Bolivar) capable of loading large bulk carriers; and the railroad serving that port is the only rail line capable of moving large volumes of coal for export shipment. The lack of rail and port facilities in other parts of the country is probably the major factor holding back exports. Puerto Bolivar is a dedicated facility built by the developers of the El Cerrejon mine. The port, which can load Cape size [10] vessels, is presently shipping at a rate of about 15 Mmt per year. All of this coal is delivered by rail on a line that runs directly from El Cerrejon to the port. Proposals are being considered to expand the capacity to more than 20 Mmt, possibly as high as 25 million. Expansion would require a new shiploader, more passing track, at least one additional train set and new equipment at the mine itself. Smaller vessels can be accommodated at other ports, including Santa Marta, Cartegena and Barranquilla. These ports have deep water offshore and can take Panamax or even Cape size vessels, but the long loading times generally make use of the larger vessels unattractive. All of these ports are served by truck at the present time, at a cost of about $8-12 per tonne, but there will soon be rail service to Santa Marta if Drummond Coal proceeds with its planned new project to develop a mine at La Loma and ship the coal through Santa marta.

3.17 Indonesia. All of the export-oriented mines now being planned in Kalimantan have access to water without the need to construct rail facilities. Some can move the coal directly to deep water loading terminals by belt; most will truck the coal to inland rivers, barge it to the coast and load it into ocean-going vessels. The transloading operations will be performed by

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[9] McCloskey, Gerard, "China's Coal: Plans in Perspective", paper presented to the 4th Pacific Rim Coal Conference, June 1989.

[10] See Table 3.2.

permanent facilities, floating cranes, or ships' gear. Kalimantan will have the capability to ship at least 21.5 Mmt per year, and possibly as much as 40 million, in Panamax vessels or larger by the end of 1994. This capacity is well above the present export levels of about 10 Mmt. Annex 3.4 lists the status of the various terminal projects.

3.18 Because it is commonly recognized that the Indonesian projects are relatively low in cost and close to the coast, it seems likely that inland transport and ports will not pose any major constraints on future Indonesian production. Indonesian production should be competitive in Asian markets even if not all of the planned terminals are built. However, the terminals are probably necessary if Indonesian coals are going to compete in Europe. It would seem that rapid loading of Cape size vessels would be a requirement to obtain the most attractive freight rates on long hauls.

3.19 Poland. Because of the decline in its coal exports in recent years, Poland now has considerable excess capacity at its ports, and probably in its rail systems. The country exported about 36 million in 1985, but only 28 million in 1990; for 1991 the volume is estimated in the 18 to 20 million tonne range. [11] Seaborne movements traditionally account for just over one half of all exports, but the percentage of shipments by sea is likely to increase. This increase should follow from the expected heavy cuts in rail shipments to the former USSR and eastern European customers whose economies are shrinking and who have difficulty finding the hard currency to pay for coal imports. There were at least 12 Mmt of excess capacity in 1989. With exports running at lower levels in 1991, current excess capacity must be in the order of 14 to 17 Mmt (Annex 3.5).

3.20 Swinoujscie and the North Port of Gdansk are the main export ports, with modern terminals operating 24 hours per day year round. They can receive and load vessels up to 65,000 dwt and 100,000 dwt respectively. The smaller ports are not so well equipped, and their role is diminishing. Nonetheless, 25% of seaborne exports was handled via these small ports in 1989. All of the shipments to these export ports move by rail, and about 95% of the tonnage moves in unit trains. The distance from mines to ports ranges from 500 to 650 km. Despite the significant distance, the use of dedicated equipment in unit train movements allows a turnaround time for the trip of only 24 hours from the mines near Katowice to the Baltic ports. The rates for moves to the ports have risen dramatically over the past few years and are now reported at an average of about (US)$11.00 per tonne. [12] Shipments to many eastern and western European customers move entirely by rail. The distances to these customers are moderate and the rail system appears capable of handling the traffic.

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[11] Ciszak, Eugeniusz, "Poland: Changing Domestic Demand - Opportunities for Coal Export" paper presented to the Coal Trans 91 Conference, October 1991.

[12] Jerzy Wronka & Natalia Cizek, "Poland and USSR: the Changing Costs of Transporting Coal by Rail and the Effects on Export", paper presented to the CoalTrans 91 Conference, October 1991.

3.21 Because of the high cost of mining in Poland and the difficulties expected in converting Poland's economy from Communist to free market, it would be unrealistic to expect a significant increase in Polish coal exports at any point in the future. In fact, in December 1988 the government announced a plan to end all exports by the year 2000; while it is no longer clear that the plan will be carried out, the prospects for increased exports certainly seems dim. Recently, there has been speculation that power plants in the northern part of the country might begin to import coal. If Poland develops any transportation constraints on coal movements, those constraints might be due to the lack of capability for handling imports rather than any problem with exports.

3.22 CIS. The former Soviet Union is not well-suited to export coal. Rail distances to export points are great and most ports have neither deep water nor modern ship-loading equipment. Despite these obstacles, the USSR was exporting about 39 Mmt per year as late as 1989. Because of the changes and disruptions in the eastern European economies and within the USSR, total exports dropped to about 25 Mmt in 1990 and appear to be headed even lower in 1991. [13] Various sources indicate that in 1990, about 7 Mmt went to eastern Europe (about 5 million of which went through Black Sea ports), about 7 million went out of Pacific ports and the remaining 11 million moved by Baltic or Black Sea ports to western customers.

3.23 Rail distances from some of the major production regions to the export ports and to border crossing points in eastern Europe are long, and range from 500 to 4,000 km (Annex 3.6).

3.24 Rail movements are reportedly inefficient, but the level of exports is so small compared to total coal output that it seems unlikely that the capabilities of the rail system in the successor countries will pose any serious constraint to exports.

3.25 According to recent estimates, [14] the Black Sea and Baltic ports were strained to move 15 Mmt per year of exports. On the Pacific coast, Nakhodka is already shipping near its full capacity handing the tonnage from the Neryungri mine to its Japanese customers. This contract for 5.5 Mmt per year of coking coal reportedly will last until 2001. In sum, there appears to be little room for expansion of exports above past levels unless: (i) new port facilities are constructed, or (ii) the eastern European nations recover and then find it economical to pay for the extremely long rail hauls from the Russian coal fields that can provide export-quality coals.

3.26 South Africa. Because of the country's remote location, all exports must move by sea. More than 90% of the current 48 Mmt move through the modern terminal at Richards Bay. This terminal, which can handle Cape size vessels is currently shipping about 44 Mmt, which is now full capacity. However, in

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[13] Adamovsky, E., panel discussion at CoalTrans91 Conference, October 1991.

[14] Doyle, Guy, "Prospects for Polish and Soviet Coal Exports", IEA Coal Research, June, 1989

1992 an expansion project will be completed and Richards Bay will be able to ship 53 million. Two other small ports, Durban and Maputo, can ship about 2.8 and 0.6 Mmt, respectively. The South African government controls exports through allocations of shipment authorizations to coal producers. The government has authorized a level of 80 Mmt, but economics will determine whether this level is ever reached. The railroad system already has the track capacity to handle 80 Mmt; only more rolling stock and crews would be needed to reach that volume.

3.27 Preliminary estimates have been made for a further expansion of Richards Bay to the range of 60-64 Mmt. This would be the limit of the port in its present configuration. This upgrade phase would involve the installation of a fourth shiploader, the full integration of original and subsequent stockyards, and associated equipment. Capital costs are estimated at R273 million (R39 per annual mt). At a 15% capital recovery factor, this capital cost would be equivalent to about R5.85/mt moved, or US$2.23 at an exchange rate of 2.62 rand per dollar. [15] Expansion up to the 80 Mmt level would require completely new greenfields construction. This new construction might take place at Richards Bay, but also might be done elsewhere (at Maputo, for instance). No matter which site would be chosen, the project would require new dredging, quays, storage pads, stacker/reclaimers, shiploaders, etc. Costs for that construction are estimated to be in the range of R70 per annual mt, or about (US) $4.00/mt moved. The relatively high cost of the final expansion phase of Richards Bay, coupled with the fact that the new mines needed to support more exports would also be greenfields projects, make it questionable whether or not the expansion to the 80 Mmt level will occur.

3.28 United States. Although there have been occasions during recent months when some of the East Coast ports in the United States have been working at capacity, the country's overall ability to export coal far exceeds present shipment levels. This excess capacity is a carryover from the construction undertaken in response to the shortages of port capacity in the early 1980's. Seaborne exports from the United States totalled about 82 Mmt in 1990. Port capacity is estimated at about 163 Mmt, not including the potential for shipments through the Great Lakes (Annex 3.7). Thus, total shipments could expand sharply without causing major delays at ports. There would be cost increases to the shippers if such an expansion occurred, but these would be relatively minor.

3.29 If all of this capacity were to be pressed into service, the marginal rates would increase, probably by something like $2.00/mt. Such an increase would reflect the higher costs at some of the smaller ports and/or the additional costs associated with midstream loading operations in the Mississippi River. Also, there would be some additional costs to shippers if they were forced to ship out the of the lower Mississippi instead of the ports along the East Coast that are closer to Europe.

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[15] Hawardan, Mike, "South Africa: 80 MTPA of Coal Exports - When and How?", paper presented to CoalTrans 90 Conference, October, 1990.

3.30 The inland transportation systems supporting these ports do not appear likely to be constrained for significant periods by any potential increase in export volumes. Baltimore, the Newport News terminals, Lamberts Point, Charleston and Mobile are all served by different railroad systems. Mobile is also served by barges, as are all of the terminals along the lower Mississippi River. The Mississippi does not have any locks in its lower reaches, and accordingly has tremendous capacity. Shipments on this river can come from Central Appalachia, the Midwest and the Rocky Mountains. The western railroads appear capable of supporting the port activity planned along the West Coast. From time to time, lack of barge availability can constrain shipments on the Mississippi. These shortages are normally due to swings in the grain trade that also moves down the river. If coal exports were to grow in a reasonably steady manner, it seems safe to assume that barge construction could keep pace with the need.

3.31 Venezuela. The growth of Venezuelan coal exports is now severely constrained by lack of efficient rail and port capacity. Whether or not the several major export-oriented mines now being planned do indeed proceed with development is closely tied to the decision on construction of a new railroad and a port that would serve all these projects. Venezuela has one reasonably large export mine at Paso Diablo. This mine will be producing about 3 million tonnes per year and shipping it via a 76 km truck haul to Santa Cruz de Marta (just north of Maracaibo), a move offshore into the Gulf of Venezuela on 2500 tonne barges, and finally onto vessels up to 60,000 dwt. The developers of Paso Diablo and two other mines are considering a joint effort to build a railroad of about 70 km and a port at Paraguaipoa. This port on the Gulf of Venezuela would be limited to Panamax vessels. [16]

3.32 If the decision is made to proceed with the transportation infrastructure and the development of the three mines, total Venezuelan exports could then increase to about 20 Mmt per year. If the transportation system is not upgraded, exports will continue to move by truck to small ports in Lake Maracaibo or the Gulf of Venezuela, and will probably be limited to no more than a few Mmt per year.

Domestic Transport in China and India

3.33 India. India's coal fields are mainly confined to the south-eastern quadrant of the country, whereas the major consumers of coal are spread throughout the country, thereby causing transport logistics problems. Out of 240 Mmt of raw and clean coal requiring transport in 1991, 35 Mmt were moved by captive rail, 18 Mmt by captive belt conveyor, and 4 Mmt by captive rope way systems of the power stations. Another 23 Mmt were moved by road to power stations, coal washeries and other industrial customers. The rest were moved by rail, with rail cum sea route contributing less than 4 mt. Coal contributes about 45% of total freight traffic of the Indian Railways, amounting to about 160 mt in 1991. Some coal is handled more than once, such as transporting raw coal to washery, and washed products to consumers. Although the Indian Railways will remain the main carrier of coal, their

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[16] Vining, Paul, talk presented to the Virginia Coal Council, October, 1991.

share of coal transport will go down from the current 67% to 63% within the next five years and to 57% by the end of the decade. The total volume of coal traffic will, however, grow. The average distance of coal haul is about 1,200 km in northern India, 950 km in the West, and 600 km in the South. The landed cost of coal in some important industrial centers on the western and south-western coasts is several times higher than the pithead price of coal. The principal routes of coal movement from the coal fields are to Delhi and further north-west; to Bombay, Ahmedabad and further west; and to Madras and further south. These routes, which carry 80% of India's freight traffic and 3.8 billion passengers, are already under strain are operating at capacity saturation levels, and require large capital inputs to meet the challenges of the next decade. Indian Railways have an ambitious program to rehabilitate nearly 20,000 km of track, add 200,000 rail cars to its fleet and acquire 1,000 new electric locomotives and 2,950 diesel electric locomotives to replace the current averaged units.

3.34 China. Coal mining in China is spread widely; there is some coal production in 29 of 32 provinces and autonomous regions, and at least in half of the counties in every region. Therefore, in many cases coal is produced and consumed locally: no long distance transport is involved. The national production in 1990 was about 1,100 Mmt of which 45% came from central government mines, 7% from provincial mines and the rest from local governments and others. The production from central and provincial government mines are allocated at the national level to priority industries and transported by railways. All other consumers have to arrange their own modes of transport, be it rail (if any spare capacity is left), road, waterways, or rail-cum-coastal shipping. The surplus coal provinces are Shanxi, Shaanxi, Ningxia and Inner Mongolia in the north, Guizhou in the south-west and Henan in the center. The deficit areas are the industrial center in the north-east, and the east-central and south-east regions, which are dependent on rail movement of coal. The average haul distance of coal is only 550 km, but some of the rail-cum-sea routes are more than 2,000 km long.

Importer Capabilities to Receive and Handle Coal

3.35 The capabilities of coal importers to receive and handle all of their coal needs has not been a significant constraint on coal trade in the past, and does not seem likely to become a problem in the future. The primary reason for the typical balance between import needs and capabilities is probably the fact that importers tend to build coal receiving and storage capabilities at the same time that new power plants or steel mills are built. This pattern can be seen in the plans for the new facilities now being planned. For example, Mexico hopes to build seven new power plants during the next decade (in addition to those already under construction). Six of the seven will be on the coast; the planning for each includes new coal receiving and storage facilities.

3.36 There are some changes to coal transportation infrastructure taking place in Europe that will affect coal trade. The first of these is the construction of new ports in the United Kingdom to accommodate the expected sharp increase in imports to replace domestic coal production that will be

closed down. The second is the changes to the barge system on the continent. Each is discussed in more detail below.

3.37 New Ports in the United Kingdom. The newly privatized electrical utilities in the United Kingdom have announced plans to increase their use of imported coal as a means of lowering costs and sulfur emissions. This policy will force British Coal to shut down a significant number of mines and curtail production. According to the IEA, the level of imports into the UK is now about 14.6 Mmt per year and is likely to increase to about 30 million by the year 2000. [17] The increase in imports will all come from new steam coal tonnage, which in 1990 was only about 6 Mmt.

3.38 Although there are numerous deep draft ports for receiving coking coals, there are now no ports convenient to the existing power plants that can receive large vessels. However, new port facilities are being considered at several different sites and plans are firm for at least one port (Gladstone) that will handle large vessels. The utilities expect to have ports in place to handle 20 Mmt of imports by 1995. [18] The main possibilities for port construction or expansion are listed in Annex 3.8. The table indicates that more than 40 Mmt of new capacity would be added if all the projects under consideration were built. While it seems unlikely that all will proceed, the probability is high that imports into the U.K. will not be seriously constrained by port capacity.

3.39 Barge Systems in Continental Europe. One major project is already underway that will improve barge movements across Europe, and other plans are being discussed to upgrade sections of other systems in the eastern countries. These changes will open up possibilities for seaborne coal to move to central European customers that had relied on rail deliveries in the past or that were considering other fuels for new plants. The largest project now underway is the construction of the Rhine-Main-Danube connection in Germany. This project, which will be completed in October, 1992, will allow 3500 mt "Europa" class barges to cross Europe from the Rotterdam area to Constanta on the Black Sea. This route would potentially let coal customers in Central Europe take advantage of the lower ocean freight rates into Rotterdam. There are also tentative plans being considered to upgrade canal systems along the Elbe and the Oder to improve coal and other trade into the former East Germany and into Czechoslovakia. Figure 3.1 shows the affected canal routes.

3.40 However, it is not yet clear that the barge rates across the new canals will be low enough to achieve a net savings for the entire movement, as compared to the present route through the Black Sea ports and up the Danube. Because of the low water on the Rhine, barge rates from Rotterdam across the new canal connection have recently been quoted at $25/tonne. This is $15 above the typical $10 rate up the Danube from the port of Constanta to Hungary, and would more than offset the ocean freight likely to be saved by

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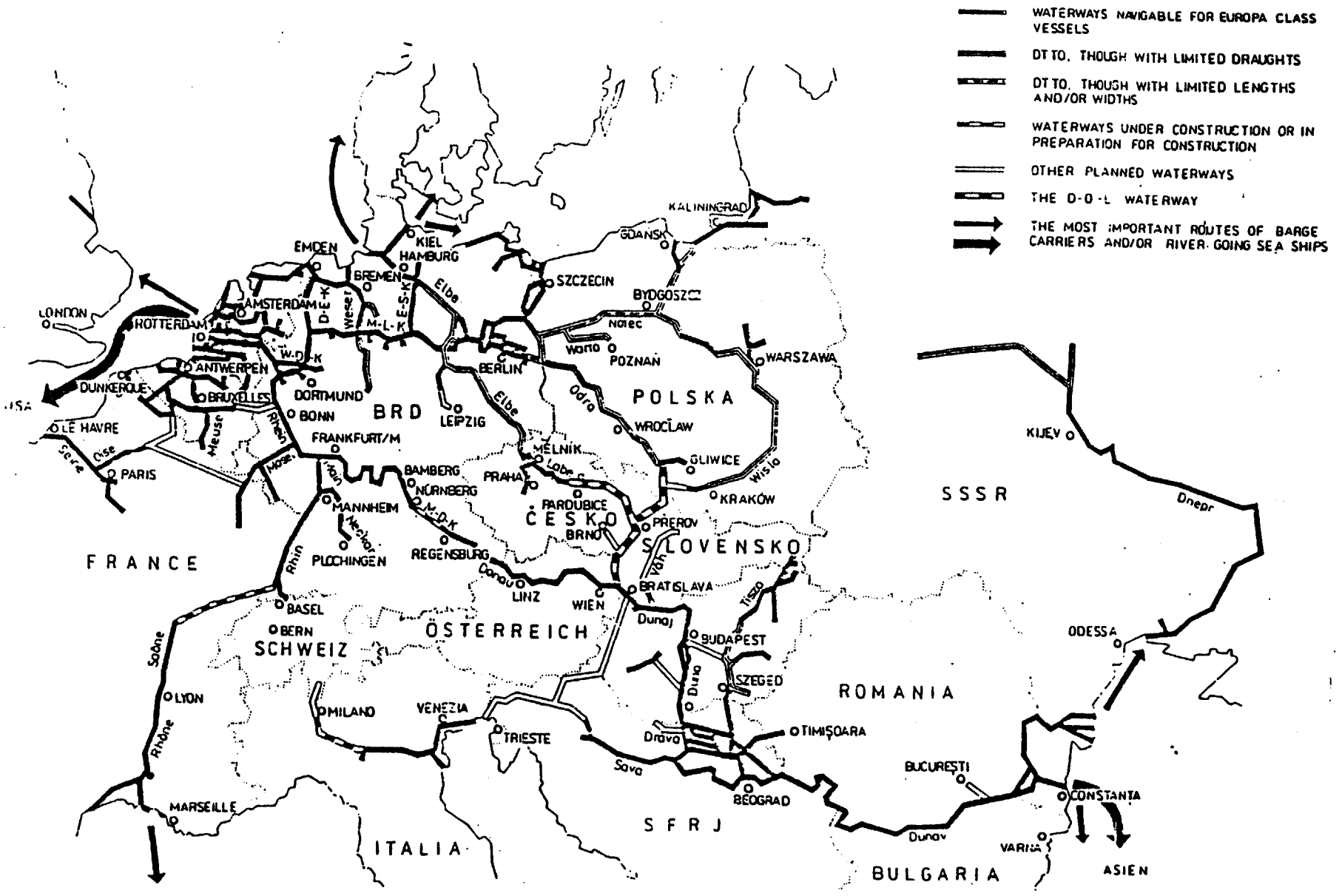
[17] "Coal Information 1991", International Energy Agency, 1991.

[18] McNair, Keith, a talk presented to the CoalTrans 91 Conference, October, 1991

Figure 3.1

EUROPEAN CANAL ROUTES



Source: Kubec, Jaroslav, "Inland Barge Transportation: Opportunities for Expansion through the Rhine-Danube-Oder

using Rotterdam rather than Constanta as the port of entry into Europe. For Hungary, the Rhine-Main-Danube rate would have to be below $17 mt to become competitive for this business (Annex 3.9). Rates may drop this low once the Rhine returns to higher water levels.

3.41 Existing Total Import Port Capabilities. The total worldwide capacity of all ports currently importing coal is over one billion (10^9) mt per year. While this total does not reflect individual bottlenecks that might occur at specific sites, the huge difference between capacity and current coal trade levels (about 400 Mmt per year) indicates that few constraints on trade are likely to be seen because of limited import infrastructure.

B. THE OUTLOOK FOR OCEAN FREIGHT OF COAL

Freight Rates

3.42 As the great majority of international coal trade outside the former centrally planned economies is transported from exporting country to importing country by ocean vessel, the importance of ocean freight rates to the delivered price of coal is widely recognized. Table 3.2 quantifies that importance. The table shows the freight percentage of delivered price (FAS importer's port) for several heavily used trade routes and common coal types. In the examples in the table, freight ranges as high as 26% of delivered price, depending on the type of coal and distance transported. Considering that freight rates historically have swung up and down by factors of four to five in periods as short as one to two years, it is clear that any outlook on future coal trade needs to address ocean freight rates as part of the assessment.

Table 3.2: TYPICAL FREIGHT COMPONENTS IN COAL PRICE (1991 US$)

Voyage	Vessel Size [12]	Coal Type	Export Port Coal Price	Freight Rate	Freight % of Deliv'd Price
HR/Japan via Richards Bay	Cape	High Vol. Met	49.93	15.50	24
HR/ARA	Cape	High Vol. Met	49.93	6.25	11
		Steam	39.41	6.25	14

[12] Cape size refers to vessels greater than 80,000 dwt; Panamax to vessels in the 40,000 to 80,000 range. Vessels smaller than 40,000 dwt are called Handy size.

Queensland/ Rotterdam	Cape	Low Vol Met	52.38	12.75	20
		Steam	38.69	12.75	25
U.S. Gulf/ ARA	Panamax	Mid Vol Met	51.28	8.75	15
		Steam	35.11	8.75	20
Richards Bay/ Spain	Panamax	Steam	33.17	11.50	26

3.43 When looking at ocean freight rates it is important to keep in mind the basic mechanisms and characteristic behavior of the ocean freight rate market. The common assumption is that the ocean freight market is a true free market; that is, the supply of ships and demand for their services, real and anticipated, determines freight rates. Accepting that premise, the following characteristics of the market are understandable:

- Shortages of capacity always will be shorter than periods of excess capacity. (New ships can be built in much less time than it takes to scrap old ones out of the fleet.)
- In an improving market, suppliers will add to capacity to meet the incremental demand and will usually over-invest.
- When demand weakens, rates will fall freely until a level is reached at which the least efficient ships are forced out of the market.
- The market usually rises higher during upturns than is commonly expected, and sinks lower during downturns than is broadly anticipated.
- Over the long term, the supply of vessels tends to be more important than demand in determining the market's direction.

3.44 The salient characteristic of ocean freight rates historically has been their volatility. A look at the history of rates over several major trade routes says it best (Annex 3.10): Spot (voyage charter) rates from 1977 to 1991 in U.S. dollars per metric ton for the Hampton Roads/Japan via Richards Bay voyage in cape size vessels and Hampton Roads/ARA (e.g. Rotterdam) voyage in Panamax size vessels show swings within a range of US$6-22 mt. Short term swings in rates were even greater. Rates as high as $25.50 mt for the Hampton Roads/ARA route were recorded.

Ship Sizes Used in Moving Coal

3.45 Vessels of all sizes are used in moving coal, but most tonnage is transported in Panamax size or larger. The larger sizes are preferred because they are more economical. The vessels most commonly used on some of the primary coal routes are:

Australia - Japan	Cape and Panamax
Australia - Europe	Cape
U.S. East - Japan	Cape and Panamax
U.S. East - Europe	Small Cape
U.S. Gulf - Europe	Panamax
South Africa - Japan	Cape
South Africa - Europe	Cape
Canada - Japan	Cape
Colombia - Europe	Cape, Panamax and Handy

3.46 All significant exporters can ship in large vessels; the smaller vessels are used when: (i) the customer does not have a deep draft port or (ii) the size of the order does not justify the use of a large vessel. It seems likely that future movements of coal will continue to use approximately the same mix of vessel sizes as today's movements.

Size, Distance and Rates

3.47 Within the basic mechanisms of vessel supply and demand balance, ocean freight rates for coal vary as non-linear functions of vessel size and voyage distance. Table 3.3 illustrates these phenomena. On a ton-mile basis, the Cape size vessels have lower rates than the Panamax, and the longer voyages have lower rates than the shorter. The basic explanations of these phenomena are what one might expect:

- There is economy of scale in vessel size; for a larger vessel many things, from construction cost to fuel consumption, are cheaper than for a smaller vessel - again on a ton-mile basis.

- The ton-mile rate for a longer voyage is less than for a shorter voyage because the costs comprise a mix of fixed costs plus variable costs which are nearly proportional to length of a voyage. The fixed costs - fixed in the sense they are independent of voyage length - include loading and discharge times plus port charges for tugs, pilot services, etc. The most obvious variable cost is for propulsion fuel.

Table 3.3: DISTANCES AND RATES FOR FIVE BENCHMARK VOYAGES

Voyage	Vessel Size	Distance (NM)	Freight US$/Tonne	Freight US$/1000 Ton-Miles
HR/Yokohama via Richards Bay	Cape	15,465	15.50	1.00
HR/Rotterdam	Cape	3,485	6.25	1.79
Hay Point/ Rotterdam	Cape	11,555	12.75	1.10
New Orleans/ Rotterdam	Panamax	4,790	8.75	1.83
Richards Bay/ Tarragona via Gibraltar	Panamax	6,460	11.50	1.78

Capital, Operating and Voyage Costs

3.48 Although, as noted above, ocean freight rates are determined by the supply and demand balance/imbalance of available tonnage and not by costs per se, rates are nonetheless constrained on the low side by costs. Hence, it is useful to look at the categories of cost with which ship owners and operators are concerned and note how each category affects the lower bound of rates. Conventionally, costs to the vessel owner/operator are categorized as "capital," "operating" and "voyage." Capital costs, loosely termed "capital recovery," are cost of construction or purchase, whether financed or paid out of equity. Operating costs are those semi-fixed expenses such as crew wages, maintenance and insurance which are incurred so long as a vessel is in an operational status, regardless of whether it is generating revenue at any given time. Voyage costs are primarily those expenses incurred in carrying out a particular transport of coal from one port to another; e.g., fuel, port charges and canal fees. Annex 3.11 shows annualized costs for average operations of two typical sizes of vessel.

Fleet Profile

3.49 It is estimated that less than 10% of the current dry bulk fleet was built before 1971. An age profile of those built since then and in service as of January 1, 1991 is shown in Annex 3.12.

3.50 The total tonnage now in service is 207 million dwt. Of this total, 19% is five years old or less, 50% is ten years old or less, and only 8% is 15 to 20 years old. This is a fairly young fleet, a consequence no doubt of the building boom in the mid 1980's. Although the supply of shipyards and trained

shipbuilding personnel has been dramatically reduced since the building boom, the youth of the fleet should tend to forestall any sharp rise in building costs for the next two to four years.

Supply, Demand and Outlook

3.51 A look at the history, current state, and near term expectations of supply, demand and their balance is preliminary to describing the outlook for freight rates (Annex 3.13). Historical evidence shows that a balance "rate" (supply minus demand over supply) of around 10% is the optimum for general economic health and stability in the industry. The projection of balance in the optimum range through the mid-90s leads to the conclusion that ocean freight rates will grow gradually with the general growth in the world economy through that period. One must note, however, that the optimum balance rate is narrow; swings in the balance rate of 1 to 2 points in the past have resulted in wide swings in freight rates. [20]

Current market expectations are outlined below:

(i) In response to growing world economies and a rational balance of tonnage supply/demand, rates will rise gradually for the foreseeable future (excepting seasonal cycling due to grain demand, strongly influenced by purchases by the USSR successor states). A small surplus of tonnage supply (balance rate) plus expected growth in trade will produce an upward trend in freight rates in the range of 4.5-5.5% (in current U.S. dollars) annually through the 1990's. Sometime after 1994 this overall average rate is likely to include another cycle of over building, over supply and resultant large, short term swings in freight rates. [21]

(ii) There will be considerable volatility in rates, though not nearly to the extent of the mid 80's. By 1992/93 aging of the fleet and limited yard capacity will place considerable upward pressure on rates. [22]

3.52 The comparison of the current relationship of freight rates to costs and a review of market expectations lead to the following conclusions:

(i) There are not currently any imbalances between costs and rates or between vessel supply and demand that are creating pressures for significant swings in ocean freight rates.

(ii) It seems likely that the expected growth in world trade and the sharp increase (that has already occurred) in ship construction

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[20] Mitsui O.S.K. Lines; Lloyds Shipping Economist; Farhley's Drewry Shipping Consultants Ltd.

[21] Hill & Associates, P. Rogers of SS&Y

[22] N. Collins, H. Clarkson & Co Ltd.

costs will result in an upward trend in ocean freight rates during the 1990's.

(iii) The potential for wide swings around the trend line in freight rates still exists.

(iv) None of the foreseeable scenarios for ocean shipping capacity and rates appears likely to place any sustained constraint on the volume of world coal trade.

IV. COAL PRICING ISSUES [23]

4.1 Most steam coal consumption takes place in the country of production. An international market for steam coal emerged on a significant scale only after the first oil crisis and currently about ten percent of total production enters the world market. The price of internationally traded coal is determined under competitive market conditions, while domestic steam coal pricing in individual countries is subject to varying degrees of government control.

4.2 The delivered prices of steam coal, imported or locally produced, vary widely depending on a number of physical, marketing, socio-economic and financial factors that can at any given time encourage or inhibit the sale of coal by producers. [24] Prices vary according to the geographical location of the consumer relative to the coal producer, as well as the category of end-use consumption (e.g., industry or power generation). Quality characteristics of the coal are an important source of price differences, and these include heat content, sulfur content, moisture and ash content, as well as other qualities. Market considerations such as the structure of the coal industry and markets in each country also influence the level of delivered prices, as does the coal supply and demand balances at the time. Contract terms such as (i) whether the prices are for spot, short-term, or long-term, (ii) escalation factors, and others can lead to substantial variations in retail steam coal prices. Delivered prices are also typically subject to considerable influence, and often direct control, by national governments. Finally, transport costs constitute a significant part of the CIF price.

International Steam Coal Prices

4.3 With the exception of the limitations on the use of imported coal that currently exists in some countries, steam coal trade is conducted in a competitive world market - a market in which coal is bought and sold under short-, medium- or long-term contracts, generally on a FOB basis and expressed in US Dollars. Competitive forces in the international coal markets are enhanced by the widespread nature of the reserve base and the large number of producers, few institutional barriers to entry (with the possible exception of access to capital) for new producers, and competition from other sources of energy. Hence, the supply function in the international market can be expected to closely correspond to the long-run marginal cost curve for the exported supply. The demand for imported coal, on the other hand, is strongly influenced by (i) the domestic coal policies and production levels maintained in the major importing countries; and (ii) the prices and availability of alternative fuels.

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[23] This discussion is limited to steam coal prices.

[24] This lack of uniformity is further complicated by the less than complete transparency and inadequate documentation of prices in coal markets when compared to oil and other primary commodity prices.

4.4 Import Demand for Steam Coal. Issues related to government intervention in domestic coal markets are discussed in the following section. However, national government policies regarding indigenous coal production in the major important countries are an important determinant of the overall level of coal imports and international prices. Over three-fifths of all traded coal are directed towards Western Europe and Japan, where governments continue to effectively regulate domestic coal markets to protect the indigenous coal industries from import competition. For example, UK and West Germany together produced 178 Mmt in 1989, while importing less than 15 Mmt. The average price of domestic coal in the two countries, however, has consistently been substantially above the import prices. The high level of domestic production, compared to imports, is artificially maintained by trade barriers, subsidies and other government support to the respective coal industries. The growing trend towards the lessening of government involvement in coal markets in Western Europe will strongly influence the future development of the international market, particularly given the importance of the region's demand for traded coal. Most forecasts of long-term trade volumes point to a sharp rise in coal imports by 2005, brought on primarily by large substitution of imported coal for the coal currently produced in UK and Germany.

4.5 Export Supply. The coal industry, due to its relatively large untapped resource base, is typically characterized as a constant cost industry, and coal supply curves are generally expected to remain relatively flat in real terms over the foreseeable range of coal demands likely to persist for the rest of this century. The emergence of new low-cost producers also means that worldwide coal mining costs should not come under pressure from gradual depletion of low cost coal reserves and a shift to less productive marginal mines for some time. In the long-run, however, coal production costs will rise as less productive marginal mines are developed, deeper and thinner seams are exploited, and as over-burden ratios rise in strip-mining areas. On the other hand, price effects of the depletion of the cheapest mines will be partly offset by technological innovations in mining, preparation and transport methods - the scope for such cost-cutting technical progress is considerable, particularly for producers in the developing countries and Eastern Europe. Further, higher cost marginal mines will only be developed if coal is a competitive source of energy and there is sufficient demand at costs that justify their development.

4.6 At present, the supply of traded coal is dominated by the three largest exporters (Australia, USA and South Africa). Together these countries account for nearly 70% of total steam coal trade. In future, the dominance of this group is likely to lessen, but they will continue to supply around 60% of trade coal in 2000. Other coal suppliers include East European countries (mainly Poland and the CIS), and new producers in the developing countries. The newcomers to the international coal market (notably, Colombia, China, Indonesia and Venezuela) are typically low-cost producers exporting high-quality thermal coal from open-pit developments. A common feature in all these countries, excepting China, is that their coal mining is mostly based on export-oriented private commercial ventures. Table 4.1 shows recent estimates of the representative costs to produce and deliver steam coal from selected exporting countries to the major importing areas. The typical range of total production costs is around $ 22-55/mt, with operating costs in the range of $17-51/mt. Transport costs are an additional $ 10-13/mt to Western Europe and $ 8-15/mt to the Far East. The ranking of producers according to their

production costs is not likely to change significantly in the near future. South Africa is expected to maintain its position as the lowest cost major supplier. Colombian costs are expected to fall to approach those in South Africa while production costs in Venezuela and Indonesia are expected to be even lower than Colombia. Australia is likely to maintain its middle position, while USA and Canada will remain the highest cost suppliers of traded coal, making them "swing" suppliers to the market.

Table 4.1: REPRESENTATIVE EXPORT COSTS OF STEAM COAL (1988 US$/mt)

	Variable Cost,FOB	Total Cost,FOB	Europe		Japan	
			Transp. Costs	Total Cost, CIF	Transp. Costs	Total Cost, CIF
Australia	24-36	33-45	13	46-58	9	42-54
USA	29-51	32-55	10	42-55	15	47-60
Canada	32-41	37-55	13	50-58	9	46-54
South Africa	17-23	22-31	10	32-41	11	33-42
Colombia	25-31	40-50	-	-	8	58

Source: IEA Coal Information, 1990.

4.7 The comparison of the productions costs in Table 4.1 with the import price levels in also provides a perspective on market conditions in the recent past, as well as on the short- and medium-run market prospects for traded coal. Assuming no significant changes in the real costs of production during the 1980s, one study found that steam coal prices between 1980 and 1984 (average $74/mt in constant 1988 dollars) were substantially higher than the corresponding export costs and provided high profit margins to all exporters. In contrast, the average steam coal price between 1987 and 1989 ($48/mt) was inadequate to cover the full cost of supply for all the exporting countries shown except South Africa.[25] The severe problems experienced by coal producers in the late 1980s demonstrates the rigidities in coal mining in terms of responding readily to sharp reductions in coal demand and prices.[26] The price assumptions on the basis of which mine developments were committed in the early 1980s became less viable with the drop in coal demand during the subsequent recession, and almost totally untenable with the collapse of the oil prices in 1986. Most producers have sought to remain in business by streamlining operations and raising productivity levels, and by resorting to extreme financial restructuring measures such major cost cutting, foregoing

[25] M. Radetzki, Long-run Price Prospects for Coal, Oil and Gas in International Trade, SNS Occasional Paper No. 22, 1990.

[26] In this respect, surface mining is less vulnerable than underground mining since operations can be shut down and restarted with relative ease and little deterioration in mining conditions. In contrast, it is generally more difficult, costly and time-consuming to bring an underground mine back into production.

returns on investment and renegotiating loan repayment schedules with lending agencies. For many investors, coal has emerged as at best a long-term investment prospect with low rates of return subject to market fluctuations that may wipe out returns for prolonged periods. Real steam coal prices have once again been rising gently since 1989 and this trend is expected to continue for the rest of this decade as the market regains its balance (Annex 4.1).

4.8 The relative competitive position of the exporters in the short-term is also significantly affected by fluctuations in their exchange rates. In the context of steam coal, the relationship of the US Dollar to the Australian Dollar and the South African Rand is particularly important. For example, until 1986 the exchange rate of the Australian Dollar vis-a-vis the US Dollar remained low, offsetting the lower coal export prices after 1983-84. In the first half of 1987 the Australian Dollar appreciated substantially, making it more difficult for Australian producers to follow declining world market prices. The appreciation of the Australian Dollar (it moved from US$0.63 in 1986 to US$0.89 at the beginning of 1989) in turn put pressure on these exporters to raise their prices. Similarly, after strengthening in 1986 (to US$ 0.50), the South African Rand has since fallen (to around US$ 0.35 in 1990) and this has enabled the industry to price its exports competitively. The East Asian market is dominated by Japanese buyers (steel and power companies), who have sufficient clout to influence coal prices CIF Japan, causing Australian and other suppliers to act as price takers. A similar buyer's market exists in Japan for LNG from South-East Asian suppliers. The fuel mix strategy in Japan, therefore, exerts a strong influence on East Asian fuel markets.

4.9 In the long-run, the availability of traded coal will closely correspond to the trends in long run marginal costs of potential export supply among existing and new producers. A recent study by IEA Coal Research estimated the amount of world thermal coal supplies that would be available in year 2000 at different prices. The conventional assumption is that producers will be willing to produce coal from existing mines and those where investment is already committed so long as the price covers the unavoidable variable costs. Producers will invest in new projects only if the price covers the total costs of production, including a normal return on capital. The FOB price range for export coal available under these circumstances would be around $46-48/mt in 2000 in constant US$. This compares with average FOB export prices in 1990 of $38-41/Mt for the major OECD exporters, and even lower prices for such producers as South Africa. Thus, the FOB price of steam coal could rise by $7-10/mt by 2000 if a substantial rise in import demand would take place. Transport costs would add about $10-13/mt to the total FOB costs, bringing the range of delivered CIF costs to Europe in the year 2000 to about $56-61/mt. FOB coal prices would remain in the $38-40/mt range if import demand in year 2000 does not rise significantly above the current traded volume of around 200 million tons. [27]

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[27] Given the abundance of coal reserves, the size of the future market is not expected to have such a large impact on equilibrium coal prices. One reason for this high sensitivity may be that the timeframe considered in the IEA study (until year 2000) is too short to permit an optimal expansion of supply in the event the market grows at this rapid rate.

4.10 The IEA Coal Research study concludes that CIF import prices of $56-60/mt in year 2000 would induce a sufficiently large-scale substitution of imports for indigenously produced coal in the UK and Germany and expand the global volume of exported supply to around 300-350 Mmt per year. Other available forecasts also project CIF coal prices of between $40 and $60 per metric ton in the year 2000. World Bank estimates project FOB export prices in constant 1985 US$ in 2000 at $30/mt from South Africa, $36/mt from Australia, and $38/mt from USA. [28] The corresponding CIF prices in Western Europe would fall between $40-55/ton. The US EIA estimates total trade volume to reach around 350 million tons by 2000, with total CIF prices in Western Europe in the late 1990s at $50/ton for exports from South Africa and South America, and about $10 more for supply from Australia and South Africa.[29] A common feature in all these forecasts is the assumption that oil prices will not remain below $18/bbl for significant periods of time in the 1990s.

4.11 While these forecasts have generated a wide range of plausible scenarios of price outcomes and traded volumes in 2000, there remains considerable uncertainty regarding both the level of demand and the position of the cost curves in the future. Since the resource base is not likely to cause an upward push in the price levels, and monopolistic price increases are unlikely, technological innovations are likely to be an important determinant of changes in the equilibrium price for traded steam coal in the long run. The changes in labor and capital costs per unit of output are generally accepted as a proxy for real production cost trends. Labor and capital costs in US mineral production fell at a rate of 3.2% p.a. between 1919 and 1957 - the scope for raising productivity and reducing real production costs through similar technical progress is considerable for a large number of current producers. For example, under the assumption that technical change will reduce the cost of production (and transport) by 0.7% p.a., one study concluded that the long-run equilibrium price for traded steam coal could decline from $57-59/mt CIF in 2000 to $53-55/mt CIF in 2010.[30] Another complication in international coal pricing emerges from the fact that most forecasts represent the "sustainable" price that is required to ensure the long run survival of the industry. In practice, actual prices are likely to fluctuate within a broad band - the approximate limits of which are set by the variable cost curve and the fuel oil price. Where the price will be in this range will depend on the level of excess capacity in the export supply. If excess capacity is present then prices are likely to move towards the bottom of the band, while tighter supply conditions will push prices up towards the higher range of the fuel oil price equivalence band.

4.12 Role of Oil Prices. An important consideration in the determination of international coal prices is the role of oil prices. The recent developments on a relative prices of the two fuels seems to indicate that the price of oil, in heat equivalence basis, seems to act as an upper bound to the price of coal in world markets, beyond which the import demand for coal is

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[28] World Bank, Price Prospects for Major Primary Commodities, Report No. 814/90, November 1990.

[29] Energy Information Administration, Annual Prospects for World Coal Trade 1989, Washington DC 1989.

[30] M. Radetzki, op. cit.

highly sensitive to changes in relative fuel prices. International steam coal prices rose steadily following the oil price increases in the 1970s, but with somewhat of a lag and at a slower rate. Prices increased in 1974-75, following the first oil price hike, and then again in 1979-81 after the second one to exceed $61/mt in 1981. Coal prices rose in response to oil price increases largely due to two reasons: (1) the much higher prices of fuel oil, vis-a-vis coal, caused some users to switch to coal, and (2) rising crude prices pushed up bunker oil prices and hence freight rates. However, the 1980-81 price acceleration was also strongly influenced by a combination of supply side problems in coal markets that were unrelated to developments in the oil markets. In 1981-84, as these supply constraints eased, and as import demand stagnated in the wake of worldwide economic recession, coal prices started to decline as rapidly as they had risen in the 1979-81 period. On the other hand, the fall in coal prices in 1986-87 can be seen as a direct market adjustment to the collapse of oil prices in 1986. Thus, as the price of coal approaches the upper range of the price equivalence band, the demand for coal becomes very price elastic, since heavy fuel oil can then substitute coal on a large scale. Beyond this threshold, any further increase in coal prices would likely result in large market losses. The maximum price for steam coal may be just below two-thirds of the oil price, both expressed in per barrel or ton of oil equivalent. This in turn implies that the CIF price for coal cannot durably exceed 50, 65 and 80 dollars per metric ton, when the oil price is 15, 20 and 25 dollars per barrel respectively (Annex 4.2).

4.13 So long as coal prices remain below the upper range of the oil price equivalence band, its level is more likely to be determined by the demand and supply conditions in the international coal market itself. Further, coal prices in real terms are likely to rise less rapidly than oil in the long run. While coal prices did rise substantially after the oil price hikes in the 1970s, the difference between the coal and oil prices on a heat content basis actually widened until the mid-1980s, reflecting partly the impact of other underlying forces in the different energy markets. Secondly, although coal and oil (and natural gas) compete directly in the under-boiler fuel markets in industry and power generation, the use of coal in industry has steadily declined and the same is true for fuel oil in electricity generation - these trends are particularly pronounced in the industrialized countries. In the longer-term, therefore, as oil supplies become increasingly more expensive, coal and oil may be consumed in entirely different markets which will tend to weaken any direct link between coal and oil prices that may currently exist. Hence, coal prices in the future are likely to be determined less by competition between coal and oil directly, and more by intra-fuel competition among coal suppliers and by competition between coal, natural gas, and nuclear power in electricity generation. Rising oil prices may affect the price of coal by increasing the demand for coal, and by increasing coal transportation costs, but oil prices are unlikely to be the main determinants of coal prices.

4.14 Environmental considerations will influence the coal market significantly. Externalities are likely to be imposed either as emission constraints, or as environmental taxes on fuels. The imposition of site-specific or regional atmospheric emission limits will result in a combination of higher demand for high-quality (i.e. low-sulfur) coal, and the introduction of environmentally more benign coal-using technologies. If the emphasis is more on switching to high-quality coal, its price will rise while the price of low-grade, high sulfur coal will decrease. This change in relative prices, in turn, may induce the accelerated introduction of "cleaner" combustion or

scrubbing technologies that utilize low-quality coal while still meeting emission limits economically. On the other hand, the introduction of price penalties such as a carbon tax would accelerate the switching from coal to natural gas, and the implementation of end-use efficiency measures. In early 1992, proposals for future carbon taxation in the European Community indicated possible price increases of 50% for coal and one third for natural gas.

Domestic Pricing Policies

4.15 Since less than 10% of all coal produced is traded in international markets, delivered prices to consumers in most countries are determined by the local production conditions and government policies in the individual country. The extent of government intervention in domestic coal markets can range from direct ownership of mines and production facilities to any or all of the following: (a) regulation of prices and/or output; (b) subsidies to coal producers and/or consumers; (c) trade barriers and other support; and (d) environmental regulations for both producers and consumers.[31] Domestic pricing policies are motivated by a host of policy considerations or objectives, such as the need to improve the financial performance of the state enterprises in the sector or increase government budgetary revenues, the desire to promote the development or sustenance of coal producing and certain coal using industries, a concern for energy security and self-sufficiency, a concern for affordability of energy to targeted consumers, a desire to minimize the political and social implications of severe restructuring or dislocations in the coal industry, as well as other economic and non-economic considerations.

4.15 In countries where domestic production competes with imported coal, governments generally intervene in coal markets to protect domestic producers or consumers from international competition. The most prominent examples of regulatory attempts to segment domestic coal markets are in Western Europe where traditionally dominant coal producers have come under increasing competitive pressure from low-cost foreign imports. Government assistance has been provided in the form of subsidies and grants to both coal producers and consumers. In addition, government policies have also been directed towards restricting the flow of imported coal to large coal users, and thereby weakening the price link between domestic and traded coal. With a few exceptions, steam coal prices in the developing countries, and in Eastern Europe, are also subject to substantial government control or regulation. Domestic coal markets in many developing countries, and the former centrally planned economies, are dominated by state-owned companies which buy and sell coal on the basis of directives and prices set by the government agencies.

4.16 Despite significant progress in rationalizing coal mining decisions and improving productivity, indigenous coal production in Western Europe and Japan are unable to compete in the primary coal markets without substantial

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31/ Some of the common approaches to domestic coal pricing include (i) hands-off pricing; (ii) average cost pricing; (iii) border pricing; (iv) two-tier pricing; and (v) long-run marginal cost pricing. These approaches are discussed in detail in an earlier Bank report (Energy Department Paper No. 23, Domestic Coal Pricing: Suggested Principles and Present Policies in Selected Countries, September 1985).

assistance from the government.[22] The near exhaustion of low-cost reserves at shallow to moderate depth in Western Europe and Japan have driven up local mining costs, so that domestic steam coal has consistently been priced higher than its border equivalents. Government support has been necessary to maintain or enhance the ability of domestic producers to compete with imported coal and other fuels. Financial support to domestic coal production is provided in the following ways: (a) by direct state grants or subsidies to coal producers; (b) by discriminatory pricing policies; and, (c) by trade barriers, such as import quotas, or long-term agreements between coal producers and large coal consumers arranged through government oversight. (see Annex 4.3 for a review of coal support programs in the OECD).

4.17 In Germany, for example, demand for domestically-mined coal is secured at a minimum rate of 40 Mmt per year by the so-called "Jahrhundertvertrag" (literally 'Contract for the Century') agreement negotiated between domestic producers and electric utilities. Similarly, the state-run British Coal (until 1987 the National Coal Board) has always provided most of the coal requirements of the electric utilities. According to a series of agreements the main public utility, Central Electricity Generating Board (CEGB), was obliged to take not less than 95% of their annual coal requirements from British Coal. The recent privatization of the British electricity industry has reduced direct government intervention, making it likely that imported coal will play an increasing role in power generation in the future. In addition to providing direct grants, the Japanese government also operates a system of import quotas to protect domestic coal producers. These quotas are allocated to final consumers, and are set equal to their expected requirements net of deliveries from domestic suppliers. According to the government, this system has been instituted in order to secure a smooth and gradual reduction of domestic coal supply.

4.18 Subsidized domestic coal production, combined with import restrictions, have given rise to segmented domestic markets for coal in which prices have deviated from their border equivalents. Government price support to domestic producers is provided through the use of dual-pricing mechanisms whereby some domestic coal (and all imported coal) is sold to industrial consumers and partially to electric utilities at border prices, while the bulk of domestic production is sold to electric utilities at higher (non-competitive) prices approaching production costs. In all cases, the margin between the two is usually quite large, with domestic coal priced at 50-100% above import levels. In West Germany, for example, domestic coal to German utilities has been priced over two times the level of import prices in recent years (see Table 4.2).

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[22] There are also a few high-cost coal producing countries in the developing world, such as Brazil, Argentina and Morocco, where domestic producers are unable to compete with imports. As in Europe and Japan, coal production has also been subsidized in these countries.

Table 4.2: PRICES FOR DOMESTIC AND IMPORTED STEAM COAL TO UTILITIES IN GERMANY (in DM/tce)

Year	Domestic Coal	Imported Coal
1978	179.00	106.25
1980	209.88	134.25
1982	255.50	193.75
1986	275.00	148.25
1988	282.23	109.00
1990	290.10	122.69

Source: OECD/IEA, Energy Prices and Taxes, Third Quarter 1990.

4.19 The future of coal production in Western Europe and Japan is therefore linked to social and political considerations than it is to the cost of producing coal. The extent of future decline in production will depend on the maintenance of government support, whether the electric utilities continue to guarantee purchases of locally-mined coals, and on the long-term plans for restructuring the coal industries in these countries. As government support diminishes, coal imports are likely to play an important role in meeting future requirements in these countries. Hence, deciding on a pricing policy is less important than deciding on policies which affect the supply and demand conditions, and therefore the price of coal. The major policy decision affecting the pricing of coal will be whether coal users, particularly electric utilities, are free to purchase their coal from the cheapest sources of supply, domestic or imported.

4.20 In the past, coal production and utilization decisions in the centrally planned economies of Eastern Europe and the CIS, as well as China, have been determined by government policy. Government-controlled production, allocation and distribution of coal has substituted for the market. The prices of domestic coal are administered by government agencies. Coal pricing policy involves setting prices at the producer, wholesale (industrial users), and retail (domestic and small commercial) levels. Between each level is usually a system of taxes and subsidies. Producer prices are generally set on a cost-plus basis for the sector as a whole. Thus, coal prices to producers have been generally set in relation to average production costs, without reference to marginal costs of new production or international energy prices. Within this average, however, there are substantial variations in the performance of the various mines, with producer prices often insufficient to finance operations in a large number of them.

4.21 Wholesale prices to large industrial customers and electric utilities are developed from producer prices through the application of levies and subsidies. In general, coal prices to these customers are characterized by high level of subsidies for steam coal in order to promote substitution away from oil products. Most of these subsidies are provided to "protected" consumers who purchase all or most of their coal needs under state plans. The share of subsidized coal varies widely across uses, but is generally close to 100% for railways and electric utilities, and much less for industries.

4.22 Low-quality coal is a major source of energy in Eastern Europe. These countries have the world's largest reserves of lignite and the highest level of lignite production. It is now a major fuel for electricity generation in this region. Despite the fact that the manpower productivity of mines, particularly underground mines, is low when compared to international levels, production costs are also generally lower. This and subsidies have led in many cases to coal prices that are lower than international prices. In Czechoslovakia, for example, the current price of hard coal is K 610/mt (US$25/mt), representing (on a heat basis) about 75% of the price of coal imported from Poland and 57% of coal imported from overseas. Coal quality differentials are also not adequately accounted for. The price of lignite to large customers in Czechoslovakia is about the same as that of hard coal (around US$25/mt), although production costs are lower and consumers incur additional costs through lower combustion efficiency and capacity utilization.

4.23 Issues related to coal pricing in China are discussed in detail in a recent Coal Pricing Study[33] and other Bank documents[34]. As in the other planned economies, state control over coal production, distribution and utilization decisions has been pervasive. Since the economic reforms in the early and mid-1980s, the coal sector, like many other parts of the economy, has been characterized by the coexistence of government-controlled coal supply and allocation with coal that is bought and sold in the free market. About 65% of the total output comes from mines owned by state, provincial and county governments. Most of this coal is sold at set prices under the state allocation plan, although coal from provincial and county mines are sold at more flexible 'guidance' prices. Collectively and individually owned mines at the local level sell their coal in the free market at negotiated prices, so long as they can secure access to transport.

Table 4.3: PLAN AND MARKET PRICES FOR STEAM COAL IN CHINA \a
1989 (Yuan/mt)

	Plan	Free Market
Beijing	55-70	140-150
Shanjang	45-70	80-180
Jiangsu	65-80	220-280
Shanxi	34-50	110-140

\a These are indicative prices gathered during Bank visits to the cities cited and discussions with coal-purchasing companies and users.

Source: Coal Pricing in China, World Bank Discussion Paper No. 138, 1991.

4.24 State allocated coal is sold to "protected" customers at subsidized plan prices that do not cover the economic costs of supply. Taking the LRMC for mining Shanxi coal (Y 107/mt), a recent Bank study estimated the delivered LRMC for China as a whole to be around Y 130/mt. Against this, the delivered

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[33] Coal Pricing Study, Report No. 7377-CHA, World Bank, February 1989.

[34] See, for example, Coal Pricing in China, World Bank Discussion Paper No. 138, 1991.

price to large power plants is around Y 80/mt, corresponding to minehead price of Y 65/mt. With respect to the marginal production costs, therefore, the subsidy amounted to Y 50/mt delivered and Y 35/mt at minehead.

4.25 Steam coal prices in India are administered by the government, which controls virtually all coal output. The largest government-owned coal company, Coal India Limited (CIL) accounts for 90% of production, and other state-owned companies for much of the remainder. The government sets coal prices at the minehead, while consumers pay the transportation cost. The government's energy policy since the oil price shocks has centered on efforts to reduce the country's oil import burden. Coal prices to consumers have been kept at low levels in order to promote substitution away from oil products, and to keep the general price level down (coal is one of the country's primary commodities).

4.26 The government's policy of lowering costs to coal users resulted in domestic prices that did not allow producers to cover the costs of production. CIL, for example, experienced losses equivalent to over 40% of sales revenue in the early 1980s. The government established a new coal pricing policy in the early 1980s based on the principle of CIL recovering the full cost of production, subject to satisfactory operating performance, and also allowing for a return on assets. This is again a case of "average-cost pricing", and is in line with the government's pricing policies for other commodities. A series of price increases in the 1980s has enabled the real price of domestic coal to reach levels approaching production costs. The increases in prices have also improved considerably the resource mobilization in the coal sector. International trade in coal is limited, with India exporting or importing less than a million tons annually. Although steam coal mining costs are among the lowest in the world, the quality of the output is also low, so that it is not directly tradeable (the bulk of the coal deposits are in the 6,000-8,000 Btu/lb range and ash content is in the 26-32% range). A linkage with international coal prices, therefore, appears unrealistic.

Effects of Coal Price Distortions

4.27 In countries where coal production, transport, and/or consumption is subsidized, the delivered price of coal will tend to deviate from its efficiency level, as reflected by international prices or by the marginal cost of indigenous supply. When coal prices are regulated by the government, the basis for setting or approving the prices is likely to be the average cost of production for the sector as a whole. Prices determined in this way (i.e. based on average costs) are often substantially different from the market clearing price in a free-market economy, where supply decisions are based on the marginal cost of production (i.e. the cost to open and operate a new mine or expand an existing operation). The difference between the two can be significant, especially when coal reserves have been depleted to the point where future mines are faced with rapidly rising costs of mining the remaining reserves. This is the case in both European and Japanese coal mining industries and results in marginal mining costs that are substantially higher than average costs.

4.28 Marginal-cost-driven indigenous supply implies that the coal supply price will vary, often significantly, from mine to mine, although the variation will be limited by import prices. Imposing price uniformity under these circumstances will have the adverse effects of concealing the extent to

which particular mines or pits are economic, altering the merit order of mines in terms of their economic viability, and raising the average costs of production. Coal prices on the basis of average costs for the industry as a whole are likely to be lower than the prices needed to recover the full costs associated with any new mine opened to satisfy coal demand. A further problem with average cost pricing is that it provides an inadequate basis for incorporating coal quality differentials since they have no necessary relationship to production costs.

4.29 In the absence of clear market-dictated guidelines for coal pricing, the domestic prices of coal distort the economically efficient or least-cost pattern of domestic energy consumption, and hamper the development of international trade in coal. They also affect the prices of energy-intensive manufactured products, and lead to additional distortions in consumption and trade. High domestic coal-price levels distort fuel competition, particularly for electric utilities, and limit the role imported coal can play in reducing energy costs. For example, since important buyers in UK or Germany cannot discriminate among sellers, the subsidy has encouraged the extensive use of expensive domestic coal in power generation where more economical alternatives (oil, gas or imported coal) can be substituted. On the production side, distortions in coal prices have hampered the ability of producers to make economically optimal investment decisions.

4.30 The economic losses resulting from the subsidization of high-cost production in the OECD are manifested in the costs borne by consumers in terms of higher prices and tariffs, and in the financial costs of government support. The high costs of domestic coal to electric utilities are in turn passed on to customers in the form of higher electricity tariffs. For example, to partially compensate the utilities for the much higher cost of using domestic coal, electricity consumers in West Germany are charged a "coal levy" (Kohlepfennig) which are transferred to a "power production fund", out of which the claims of the electric utilities are paid. In general, the electricity tariffs in West European countries are among the highest in the world.

4.31 Figure 4.1 traces the growth in government transfers to coal producers, as measured in producer subsidy equivalents (PSE), in selected coal-importing countries in the OECD between 1982 and 1987. A PSE defines the monetary payment to domestic producers equivalent to the total value of existing support provided at current levels of production, consumption and trade, and world prices. The PSEs include not only grants and other state direct payments but also the value of protection provided by price supports, import constraints and the practical effects of special sales arrangements.[35] Total direct and indirect subsidies to coal producers in selected OECD countries, as measured in producer subsidy equivalents (PSE), increased rapidly between 1982

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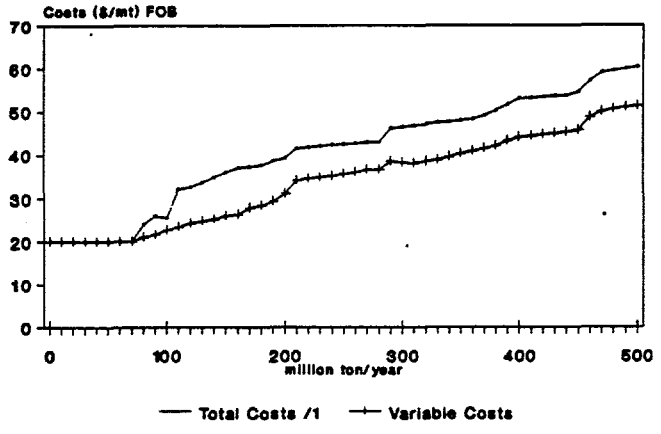
[35] There has been considerable debate as to whether specific long-term agreements between coal producers and major consumers constitute support when they are not underpinned by government measures such as restrictions on coal imports. Whatever the answer to this question is in a specific case, the practical effect of these arrangements on coal imports and prices is the same as if there were protection for domestic production. Therefore, the PSE calculations also include an evaluation of the effects of these arrangements.

and 1987, but has declined somewhat since then. The broad pattern of growth was particularly marked in the 1985-87 period, mainly in the price support components, as world coal prices dropped in relation to domestic production costs and as the exchange rates of the currencies of the major coal-exporting countries (particularly USA) fell relative to those of the high-cost coal-producing countries. Price support to the coal industry, measured as the sum of excess payments on purchases of steam coal by public electricity producers, account for over 60% of total financial support in both UK and Germany, and over 85% of total assistance in Japan.

Figure 4.1: TOTAL PRODUCER SUBSIDY EQUIVALENTS (PSE) FOR COAL PRODUCTION IN SELECTED OECD COUNTRIES (1982-1987)



/1 Including normal capital returns
Source: IEA Coal Research

4.32 Government support in the former planned economies, as well as in a number of developing countries, has typically been directed towards subsidizing coal costs to consumers to induce fuel substitution away from oil products. When average prices are below the marginal cost of supply, demand will be above the economically optimal level. leading to shortages. The direct economic impact of subsidized consumer prices has been to generate high intensity of energy use, and suboptimal demand patterns for end-use energy. Low coal prices in China, CIS and other East European countries have encouraged a high degree of substitution of heat for other inputs, and slowed the development of both factor and fuel substitution possibilities particularly in the industrial sectors. The final use of coal itself has been characterized by low boiler efficiencies, poor building insulation and insufficient amounts of cogeneration of process heat and power. In addition, with consumer prices uniform across the country, or across large regions, there is no incentive to establish coal-using industries in locations that minimize transport costs. Inadequate accounting of the differences in transport costs, as well as quality differentials, has also been common in these countries. This has resulted in the underpricing and undersupply of high quality coal, as well as pollution by consumers deprived of better, cleaner fuels.

V. COAL UTILIZATION ISSUES

5.1 Of the approximately 4 billion tons of non-coking coal (both hard coal and brown coal/lignite) consumed annually worldwide, about 80% are used for power generation. The remainder is accounted for mainly by industrial boiler use, and by burning in households for heating and cooking. This predominance of power sector use of coal has a bearing on the type of issues that arise in the context of coal utilization. Seen from the power generation side, about 40% of total electricity production in the OECD countries is fuelled by coal (about 60% by fossil fuels in general), and the shares in the developing world are likely to be similar. The link between coal and power worldwide is a dominant feature in both energy subsectors.

5.2 Similarly, the geographical distribution of consumption determines the issues: China, the USA and the CIS (former USSR) account for about 60% of total global coal consumption. Six countries together (the above three plus India, Germany and Japan) consume 75% of world coal. The consumption pattern in these main consumer countries implies a heavy concentration of coal use in power generation, and significant environmental issues arising from atmospheric emissions.

5.3 The consumption pattern implies that the major issues are:

(i) the efficiency of transformation of the fuel heat content to electric power and the resulting power sector technology choices;

(ii) the comparative cost of utilizing different fuels and technologies for power generation;

(iii) the environmental impact of coal use in power stations, and the options available for mitigation;

(iv) the optimal role of coal in the future operation of power supply systems; and

(v) the role of emerging coal-use technologies for power generation.

5.4 Other coal-use-related issues include (i) the environmental and health impact of the burning of low-quality coal by households, particularly in urban areas of China and Eastern Europe, and (ii) the technological choice of fuel and boilers by small and medium industrial consumers (an efficiency issue particularly in China). Although these considerations are important locally, they need to be addressed on a case-by-case basis, and therefore are not subjects of this report. The following discussion focuses on the fuel and technology choice in the power sector, given the system optimization and environmental constraints that the sector faces in its decisions concerning coal use.

Power Generation Efficiency

5.5 Power utilities throughout the OECD have been pursuing an active search for generating technologies that would yield a higher transformation efficiency from

fuel to electricity output. This strategy has resulted in the widespread use of combined-cycle technology, the introduction of higher-efficiency steam thermal plant, and an intensive research and development effort to commercialize new combustion technologies. Developing countries have joined this trend with a time lag and on a selected basis, as the higher efficiency achieved by new technologies usually brings with it more sophisticated maintenance requirements, larger and more expensive stocks of spare parts, and a higher foreign exchange component of investments. In particular, it is the need for a disciplined and thorough operation and maintenance regime that has deterred many less efficient developing utilities from installing even mature new technologies such as combined cycle plant.

5.6 Traditional coal-fired steam plant has a net plant efficiency of about 35%, i.e only just over one third of the energy content of the fuel is converted to electricity for grid supply. For the same kind of plant, a higher steam pressure increases the efficiency, while the installation of flue gas scrubbing decreases it, both by small margins. In contrast, different generating technologies such as combined cycle or fluidized-bed combustion (FBC) increase the efficiency significantly. For combined cycle plant, the fuel choice again influences efficiency: the use of natural gas as fuel brings highest plant efficiency, while the gasification of coal adds a process that decreases the eficiency gains of combined cycle operation. Table 5.1 and Annex 5.1 illustrate the range of generation efficiencies.

Table 5.1: GENERATING PLANT EFFICIENCIES

Plant Type	Net Plant Efficiency (%)
Traditional steam thermal	
- natural gas	36
- coal with FGD	34-37
- coal without FGD	35-38
Combined cycle	
- natural gas	40-50
- with coal gasification	39-46
Fluidized bed combustion	35-36
Combustion turbine	25-30
Steam-injected gas turbine	
- natural gas	40
- with coal gasification	36
Slow-speed diesel	40
Waste-to-energy systems	20
Nuclear	30-35
Fuel cells	36-56

5.7 Among the mature technologies suitable for large-scale power plants, the gas-fired combined cycle (CC) technology clearly is the most attractive from the point of view of net plant efficiency alone. As compared to coal-fired plant, this gives the CC facility the posibility to use gas that is more expensive per BTU than coal, and still retain a competitive edge. The lower capital cost per KW of generating capacity is an additional bonus for CC (see below).

5.8 The higher efficiency, and now also high reliability of CC technology make it the preferred choice for power utilities where natural gas is plentiful and available at comparatively low cost (Europe where served by regional gas pipelines, regions of the USA with adequate gas supply, South-East Asia). Where this is not the case, the significant initial infrastructure costs for pipelines, gas liquefaction, loading terminals, and LNG vessels quickly raise the cost of gas delivered to the power plant, and use up the efficiency margin. In the long run, the emerging technology of Integrated Coal Gasification/Combined Cycle (IGCC) will be able to provide the high efficiency of CC operation in areas of low-cost coal: although the gasification process uses up some of the enhanced efficiency, the technology is likely to be competitive.

5.9 Apart from plant efficiency, power utilities tailor their fuel and technology choice to the load-following needs of their systems. For base load purposes, large coal-fired traditional steam plant or nuclear plant is suitable, as not much flexibility is needed to serve a constant 24-hour load. For shoulder and peaking periods of the daily load curve, however, utilities require plant higher in the merit order that can follow the swings in capacity demand elastically. This need is filled by CC technology much better than by traditional coal-fired facilities. With IGCC technology maturing within this decade, even coal-based utilities that rely on distillate-fired turbines or hydro storage for their peaking needs, will be able to utilize CC facilities to obtain more flexibility.

Environmental Constraints

5.10 The use of coal as fuel for power and industrial boilers imposes pollution burdens on the environment, both locally and globally. The main environmental costs arising from coal burning are (Table 5.2):

(i) SO2 emissions;

(ii) NOx emissions;

(iii) CO2 emissions;

(iv) Dust and particulate emissions;

(v) Ground and water pollution from ash disposal.

Table 5.2: POLLUTION FROM FOSSIL FUEL BURNING

	Coal	Oil	Natural Gas
Pounds per million Btu:			
SO2 emissions	3-8	1-3	0
NOx emissions	0.9	0.4	0.2
Particulates emissions	2.5	0.2	0
CO2 emissions	202-215	167-170	115
Solid waste	10-30	0	0

	Pulv.coal with FGD	Coal FBC	Coal IGCC	Gas CC
Pounds per MWh:				
SO2 emissions	4-6	3.5-6.0	0.5	-
NOx emissions	3.5	1.5-2.0	0.5	0.8
CO2 emissions	1,800-2,000	1,900-2,100	1,700-1,800	800-850
Solid waste	400	300- 500	110-150	-

5.11 Of the total annual global carbon emissions of about 7 billion tons, less than a quarter is accounted for by tropical deforestation: the remainder is caused by the burning of fossil fuels. Coal burning in China, the CIS and the USA alone accounts for about 1.3 billion tons of carbon emitted (Annex 5.2). Worldwide, coal burning represents about 43% of total carbon emissions from fossil fuel use, and about one third of total global carbon emissions. Per million BTU, coal is the least attractive of the fossil fuels in terms of carbon emissions: its contribution to the production of greenhouse gases with potential global warming effects is significant. Although new coal-combustion technologies such as atmospheric or pressurized fluidized-bed (AFBC or PFBC), or IGCC can reduce the carbon output somewhat through higher efficiency of combustion and power generation, the environmental attractiveness does not increase much: natural gas shows much lower CO2 emissions, and even petroleum products remain superior to coal.

5.12 Emissions of sulfur (SO2) and nitrogen oxides (NOx) create notorious local and regional problems in areas that use coal with a high content of these elements. In particular, the acid rain effects of the burning of high-sulfur, high-nitrogen coal lead to dying forests, water quality deterioration, and soil damage. In addition, severe health effects on local populations are evident through high-sulfur urban smog and acidic air pollution in general. Such acid rain phenomena are widespread in Eastern Europe and southwestern China, and have been identified and addressed in North America and Northwestern Europe. While SO2 emissions are projected to decline in Europe and North America as result of strong mitigation measures, the sulfur output in Asia (particularly China) is likely to grow rapidly with the increased coal use anticipated (Annex 5.3). The impact is regional rather than only local, and calls for broad-based strategies and regional cooperation. Again, coal is the worst offender per BTU among fossil fuels, and easily emits twice the SO2/NOx amount of oil products. Natural gas

emissions of these pollutants are negligible compared to both coal and oil, a feature that contributes significantly to the image of gas as a "clean fuel".

5.13 In contrast to CO_2, the sulfur and nitrogen emissions from coal burning can be reduced significantly by generating power using appropriate technologies. Apart from measures on either side of the combustion process, such as coal blending, coal beneficiation, and flue gas scrubbing, the choice of combustion process itself lends itself to SO_2/NO_x reduction. This is particularly true for the emerging IGCC process, which may be able to reduce emissions to about 15-30% of the level of traditional boilers or FBC boilers (Annex 5.4).

5.14 Particulates emissions and solid waste disposal are perennial problems of coal-fired boilers in power and industry. The burning of oil and natural gas generates a negligible fraction of the ash and dust output of coal plant. Respiratory problems in the local population, and pollution of the soil and groundwater in the vicinity of the ash dumps are common problems encountered near coal-fired power facilities. In addition, the space for ash disposal often is limited, leading to dislocation of populations and deterioration of the landscape: European power utilities in densely populated and cultivated areas are experiencing this problem. Again, short of switching to gas or oil, the IGCC process appears to offer the most attractive reduction in ash output.

5.15 Paradoxically, the efforts to capture sulfur by flue gas desulfurization or lime injection create an increased solid waste disposal problem. Many of the sulfur-absorbing technologies generate viscous or solid acidic waste that is difficult to dispose of. This feature may increase the waste that needs to be disposed of by up to 200% (Annex 5.4), as the sorbent that is injected into the flue gas stream or the boiler creates more waste volume. Increased emphasis is now being placed on the improvement of FGD and other sulfur-capturing technologies, in order to achieve a by-product that has a market. Although the recovered sulfur can be marketed profitably to the chemical industry, the recovery process is costlier than the traditional and advanced FGD processes that produce waste (or a wallboard-quality gypsum product): wet FGD process retrofits on power plant average a capital cost of US$180-260/KW (or US$460-620/ton SO_2 removed), while the retrofit of FGD with sulfur recovery costs about US$250-380/KW (or US$640-820/ton of SO_2) (Annex 5.5).

5.16 Environmental mitigation costs of coal-fired power generation have been rising in general: the addition of FGD, selective catalytic reduction (SCR), and mechanical and electrostatic particulate filters can easily increase the KW cost of thermal plant by about US$300-400, or about one third of the base cost. In addition, the cost of ash dumps and safeguarding of soil and water quality increases. Much of the increases have happened in recent years, as environmental standards and regulations have been introduced in response to air quality and other environmental concerns (Annex 5.6). These regulations are either standards of ambient air quality, specifying allowable maxima for milligrams of pollutants per cubic meter of ambient air, or specific standards limiting the emissions from individual power plants, using a wide variety of unit measurements such as weight of pollutant per cubic meter of exhaust, pounds per million Btu, etc. The standards vary widely by country (Annex 5.7). Compliance with the standards has to be tailored to the type of regulation employed by the host country of the utility: a command-and-control approach requires design of each power plant to

specifications, while a more flexible, market-oriented regulatory approach such as that represented by the U.S. Clean Air Act, allows a number of options such as emissions trading and banking of excess compliance for the future (Annex 5.7).

Choice of Technologies

5.17 The increasing demands on both coal use efficiency and abatement of detrimental environmental effects has triggered an acceleration of the development of appropriate technologies to serve both objectives. One track of development focuses on the replacement of coal by other, environmentally more benign fuels such as natural gas, while raising the efficiency of power generation and industrial steam production. This direction of research and development is producing higher-efficiency gas turbines, more efficient combined-cycle plants, and advanced gas-based fuel cell generating plant. Simple-cycle gas turbines are expected to reach efficiencies of up to 35% by the mid-1990s, and fuel cell development could result in an average efficiency of up to 45% by the same time. Although fuel cell technology, at its early stage of serious development, still carries a high cost per KW (upwards of US$2,500), its advantages are extremely low NOx emissions (5 ppm compared to 120 ppm and 45 ppm for uncontrolled and steam-injection gas turbines, respectively), low maintenance, and only water as waste product. Similarly, nuclear technology is progressing, and advanced reactor designs with passive safety features are under development. The issue of final nuclear waste disposal, of course, has not yet been resolved satisfactorily.

5.18 The second track of technology development involves the improvement of coal utilization to accommodate the efficiency and environmental requirements, and remain competitive with alternative fuels. The range of technological choice covers the utilization spectrum from coal preparation, coal refining, and coal quality blending, through gasification and various combustion processes and boiler types, to flue gas scrubbing and waste disposal (Annex 5.8). The following paragraphs summarize the major conventional or emerging coal use technologies and their predominant features (Sources: Kataoka, 1992, Guerami 1992, Power Technologies Inc. 1991, Argonne National Laboratory 1990, Clean Coal Technology Economics Conference 1990, EPRI SO2 Control Symposium 1991, PowerGen Conference 1991, Industrial literature 1990-1992).

5.19 Coal Cleaning. Ash and pyritic sulfur can be removed by physical cleaning of coal delivered at the users' facilities before it enters the boiler. Chemical or biological cleaning of coal adds the capability to remove some of the organic sulfur as well. Cleaning is done by centrifugal or electrostatic separators, through washing and flotation, or through hydrogenation. This cleaning process, of course, does not have to be conducted at the user facility, but can take place at the mine, to save transport costs (para 2.33-2.39). In any case, it raises the cost of the delivered weight unit of coal, in the case of conventional physical cleaning by about US$5-7/mt [26]. With the removal of the ash, the calorific value of the ton of coal increases: together with the transport cost

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[26] Research on "ultra-clean coal" technologies, primarily in Australia, U.S. and Japan, has not yielded cost-effective solutions yet, but holds some promise for the future, if energy prices increase.

saving, the cost per Btu in the coal fuel as delivered after washing may not change much. Initial pilot projects for drying and processing Western U.S. low-sulfur, high-moisture coal to raise calorific value from about 8,000 Btu/lb to 11,000-12,000 Btu/lb indicate that processed coal can be delivered to Pacific destinations at about US$1.80-2.00/Btu, i.e. competitive with Australian supplies. As boilers are designed for a certain coal quality input, coal cleaning may require boiler adaptation investments.

5.22 Coal/Water Mixtures. A coal slurry, consisting of pulverized coal and water, can be transported by pipeline, and fired in boilers designed for heavy fuel oil-firing. Competing fuels for this kind of application exist, such as the increasingly marketed "orimulsion", a product of Venezuelan Orinoco Basin heavy bitumen emulsified with water and additives. Boilers designed for oil firing need to be adapted and derated to accept these slurry fuels: fuel pumping capacity has to be increased, heating systems for maintaining fuel temperature have to be installed, special burners have to be installed, and electrostatic precipitators have to be retrofitted to capture fly ash. As the emulsions emit more SO2 and NOx than fuel oil, flue gas cleaning equipment has to be installed. Estimates for the cost of conversion of oil-fired plant to coal/water mixtures or similar emulsions have been estimated as at least US$150/KW, and probably significantly more if the FGD equipment has to be substantial. However, spare fuel-oil-based generating capacity exists (e.g. about 70 GW in the EEC), and the comparative economics may be attractive with a low-cost coal/water mix.

5.23 Coal Blending and Switching. Moving to lower-sulfur coal with higher calorific value, either by changing fuel suppliers or by blending higher-quality coal with local low-quality fuel, also requires boiler adjustment investments. Recent U.S. case studies examining the investment needs for a switch to coal with a lower ash content and a sulfur content of about 0.5% (compared to the design coal with 2.5-3.5% sulfur) indicate a range of conversion cost of US$30-100/KW for dust control, venting, unloading and conveyor modifications, steam generator adaptation, fans, precipitators, and coal handling. Nevertheless, this investment cost may well be more attractive than improvements in the capacity of the FGD system to reduce emissions from burning high-sulfur coal.

5.24 Coal Conversion and Refining. Raw coal can be turned into a series of derived fuels such as refined coal (char), low-sulfur fuel oil, methanol, naphtha, low-BTU fuel gas, and high-Btu pipeline gas. These synthetic fuels are refined from coal by processes such as hydrogen restructuring, pyrolysis, oxygen-based gasification, or hydrogen-based liquefaction (Annex 5.9). The nature of this process is more akin to oil refinery operations and petrochemical industries than to conventional power generation, as it produces a range of fuels for different applications apart from power station fuel. The gasification process, however, can be integrated with a combined cycle power generation facility (IGCC), to serve this purpose only (see below). A combination of solid and liquid coal-derived fuels could, according to initial industry estimates, be delivered at about US$3-4/mmBtu, depending on the cost of the input coal.

5.25 Integrated Coal Gasification and Combined Cycle (IGCC). The emerging technology of gasification coupled with combined-cycle power generation is one of the most promising coal use developments. Pilot projects in the U.S. and Europe (Texaco, Dow/Destec, Shell, Lurgi, Demkolec) are demonstrating the

technical feasibility and efficiency of the process at increasing plant sizes (Annex 5.10). The costs of the combined plants are still on the high side, but their investment costs are becoming comparable to the full capital cost of a conventional pulverized-coal plant with all environmental mitigation equipment. On that basis, the environmental performance of IGCC exceeds that of the conventional plant. Where natural gas is available in relative abundance, the natural gas-using combined cycle is superior to IGCC on efficiency, emissions, and cost grounds, as the fuel is cleaner-burning, and no investment cost for a gasifier is required. However, where fuel for existing natural gas combined cycle plants may become expensive, or where old thermal plants are to be repowered, IGCC may be a future attractive option. In areas without access to low-cost natural gas, and with abundant local coal supplies, IGCC could be the choice for environmentally more benign use of coal. Further development of an integrated gasification/humid air turbine cycle (IGHAT) may hold out further promise of increased power generation efficiency, and lower NOx emissions, perhaps at somewhat lower cost per kWh.

5.26 Natural Gas Cofiring and Reburning. The injection of natural gas into the boiler, either to replace part of the coal fuel, or to create an oxygen-deficient zone, reduces the harmful emissions from coal burning proportionately to the gas share in the process. Although incremental capacity costs are relatively modest (estimated to be about US$3-30/KW), much depends on the relative prices of gas and coal. Recent U.S. estimates, using cases with 3% sulfur coal, and current U.S. utility costs of gas and coal, arrive at the conclusions that using lower-sulfur coal or installing FGD equipment, and installing low-NOx burners, can be less costly per ton of SO2/NOx removed than 15% natural gas reburning or cofiring (Power Engineering, February 1991). Again, easy access to low-cost gas is a key feature.

5.27 Slagging Combustor. The process to burn coal in stages to maximize combustion efficiency, and to keep combustion temperatures high to concentrate impurities in removable slag has been developed to help both the efficiency and environmental objectives. Oxygen input minimization, and injection of lime sorbent control the NOx and SO2 emissions. Recent studies have indicated that this technology could be competitive with other retrofit or repowering options. Current development focuses on direct coal firing of gas turbines, where slagging combustors would prepare the fuel adequately for direct use in a gas turbine.

5.28 Limestone Injection Multistage Burner (LIMB). The technology of injecting dry limestone into the boiler is suitable for the absorption of sulfur in a wide range of sulfur content in coals, but may create other problems such as increased particulate control needs. The capital cost of the retrofit on existing coal-fired plant is attractively low, but the total levelized cost of SO2 removal does not appear to be significantly lower than the range of other available technologies for this purpose.

5.29 Low-NOx Burners. A range of burners for coal combustion has been developed that avoids the creation of excessive nitrogen oxides during the combustion process from nitrogen in the fuel and the combustion air. Burners control the fuel and air staging to create a fuel-rich combustion zone. Although high NOx control levels can be achieved, the process contributes to increased particulate and CO emissions, which have to be controlled in turn by additional investments.

5.30 Supercritical Boilers. Higher power generation efficiencies can be achieved by burning coal in recent designs of supercritical and ultra-supercritical boilers, where main steam pressure is about double that in conventional coal-fired plant (Annex 5.1). Net plant efficiency in such plant can be raised from 35% to about 37%. Apart from the efficiency improvement, however, no other beneficial environmental effects can be gained by the use of the technology.

5.31 Fluidized Bed Combustion. A major development in combustion technology has been the fluidized bed concept, now spreading widely in OECD countries for power generation applications (Annex 5.11), and in China for small industrial use. The main applications have been in the area of atmospheric fluidized bed combustion (AFBC), either in its bubbling or circulating modes (A detailed review of the AFBC technology is available as World Bank Technical Paper No.107, 1989). The AFBC process has proved to be particularly attractive for industrial steam and cogeneration applications. The more recent pressurized fluidized bed combustion process (PFBC) is also commercially available, but has not yet gained wide application. Its operation under high pressure in a contained environment makes it technically somewhat more demanding, both in terms of maintenance and spares/repairs. All FBC technologies have in common the principle of an air-blown moving bed of crushed coal and limestone in the boiler, which allows sulfur absorption, NOx control through higher combustion efficiency, and better net plant efficiency. The PFBC process allows the use of high-pressure exhaust gases for a combined-cycle operation, which raises the plant efficiency further. The capacity limit of FBC processes is being tested now at about 300 MW, which appears to be the optimal size for efficiency. Current research and pilot projects in the U.S., UK, and Japan concentrate on (i) the combination of coal gasification, PFBC, and a topping combustor to achieve a combined-cycle efficiency of about 45%, and (ii) the combination of AFBC and an air heater to be able to add a (non-combustion) gas turbine to the cycle. The former process may be suitable for power utility applications, while the latter may be attractive for industrial cogeneration.

5.32 Flue Gas Desulfurization. The environmental objective is met by the removal of pollutants from the stack exhaust gas, mainly by adding scrubber facilities to the post-combustion ductwork. Lower-cost options utilize in-duct sorbent injection with waste collection facilities downstream, while the more advanced options for scrubbing use more elaborate additional facilities, and a variety of sorbents (Annex 5.5). Ongoing improvements of scrubber technology are focusing on the enhanced ability of the process to remove sulfur, on reducing the cost per ton of SO2 removed, and on the production of marketable by-products (driven by the U.S. Clean Air Act requirements and other countries' environmental regulations), rather than on net plant efficiency: as a result, the already negative impact of simple FGD on generating efficiency often is increased as the processes become more elaborate. Conventional FGD processes use up more of station generation, as they improve their sulfur removal ability. Economically, the saving grace may be the compensating benefits accruing from the sale of recovered sulfur and other by-products. In addition, the development of more reliable and larger scrubbers with economies of scale, will enable utilities to eliminate spare absorbers and reduce the unit cost of the FGD facilities by about one quarter (Power Engineering, February 1991).

5.33 Selective Catalytic Reduction. This post-combustion NOx removal process relies on the injection of ammonia and catalysts into the flue gas stream, removing 70-80% of the NOx. As in the FGD case, the process uses up some power generating efficiency by adding downstream energy-consuming facilities. The technology is being widely applied, particularly in Europe and Japan, often in conjunction with FGD.

5.34 Particulate Removal Systems. Technologies to remove dust and particulates from the flue gas range from mechanical collectors with low efficiency, to filters and scrubbers, and electrostatic precipitators (ESP) that can remove even fine particulates with high efficiency (Annex 5.8). Local dust emissions controls require the installation of such equipment in many coal-fired plants worldwide.

5.35 The wide choice of available and emerging technologies for the cleaner and more efficient use of coal in power generation and industrial processes requires clear optimization on the part of the users, in order to achieve the lowest-cost system operation while fulfilling all environmental requirements. Some technologies fulfill both the efficiency and environmental dictates simultaneously, while others have to be combined to compensate for opposing effects (Annex 5.8). The spectrum of choice is further expanded by (i) non-coal alternatives of supply, (ii) end-use efficiency and conservation options such as demand-side management conducted by power utilities, (iii) market mechanisms such as emissions trading and "banking" of emission allowances, and (iv) electricity sales and exchanges between utility grids. Least cost optimization by utilities increasingly is applying a broader range of options.

Comparative Cost of Options

5.36 Power systems that consider the continuing use of coal as one of their generating possibilities, are faced with a widening array of options that can be used as components of a least-cost development scenario. In power sector applications, the choices between options are not simply dependent on the relative costs of each technology, but are determined by long-term system scenarios. While the prospective industrial user of coal chooses between fuels and technologies suitable for an individual industrial process, the power utility has to consider the appropriate mix of technologies and policies that will allow it to cover both base load and the system peaks. While the peak demand of the system can be satisfied by optimizing the mix between gas turbines, peaking hydro plant, power purchases, or demand management, the base load demand needs to be accommodated by the optimal mix of coal thermal, gas combined cycle, nuclear, and run-of river generating plant. Coal use normally is restricted to base load utilization, as the high capital cost and relatively low fuel cost of coal-fired generation makes it attractive to operate the plant at a high plant load factor. The comparison with alternatives, therefore, is restricted to those that can serve the same purpose, namely supplying system base load.

5.37 The comparative costs of the major competing base load generation technologies, levelized to yield a comparison per kWh generated over the equipment's lifetime, are summarized in Table 5.3 and Annex 5.12. Much of the choice concerning the technology mix depends on the plant factor (i.e. whether the generating plant is used as base load for 70-90% of the yearly hours, or for

a smaller share of the time), and on the relative costs of fuels. With the capital costs of the individual technologies roughly given (or changing only slowly over time with the development of each process), plant factors and fuel costs are the main variables that are subject to change and assumption.

Table 5.3: LEVELIZED COST OF POWER GENERATION AT 70% PLANT FACTOR (US¢/KWh)

	Coal $2/mmBtu Gas $3/mmBtu	Coal $1/mmBtu Gas $4/mmBtu
Conventional pulverized coal	5.2	4.3
Pulverized coal with FGD/SCR/ESP	6.2	5.2
Coal fluidized bed combustion	5.7	4.9
Coal gasification/combined cycle	5.7	4.8
Natural gas combined cycle	4.0	4.8
Nuclear	6.5	6.5

5.38 Nevertheless, it is clear from the comparative analysis based on current average fuel costs (say, about $2/mmBtu for coal and $3/mmBtu for gas), and a plant utilization factor of 70%, that natural gas-fired combined cycle technology is economically more attractive than any other options including coal, where both fuels are available at these average prices. The superiority of gas CC is quite robust, as the gas cost would have to rise to at least $5/mmBtu before any of the coal-based technologies would be competitive at the current coal cost of about $2/mmBtu. This is the situation in many utilities in the U.S. and Europe, in Japan at a higher imported fuel cost level, and in other areas with available gas supply.

5.39 There are, of course, many instances where cheap coal is abundant, and natural gas is not easily available without major infrastructure investments. Pithead power stations in India and China have coal available at about $0.5-0.75/mmBtu, which translates into coal-fired plant levelized cost of about US¢ 4.3-4.7/kWh (with all environmental safeguards); at the same time, these utilities have access to only limited amounts of gas, and demand for higher gas volumes would raise the delivered gas price to a point where the levelized cost of gas CC plant would no longer be preferable to coal-based generation. An additional advantage for coal use in such situations is the fact that the full panoply of environmental safeguards (FGD, SCR, ESP, FBC, IGCC) may not have to be employed in remote mining/generation areas: conventional pulverized coal generating plant with only limited environmental equipment, at about US¢ 4/kWh with cheap pithead coal, is competitive with gas CC plant even at a gas price of $3/mmBtu. Similarly competitive situations for coal exist where the coal is low-sulfur, and gas has a high opportunity cost of foregone LNG exports, such as in Indonesia: the comparison is between a conventional coal plant with limited scrubbing, and a gas CC plant with relatively expensive fuel, both falling within a narrow range of levelized costs.

5.40 A niche for advanced coal-using technologies ("clean coal technologies") such as FBC and IGCC exists for the future in situations where the full impact

of SO2/NOx control and particulate control of low-grade coals has to be borne by the utility, and natural gas is either unavailable or excessively expensive. In comparison to full flue gas cleanup downstream, these gasification/combustion technologies appear clearly competitive. Even in areas where natural gas currently is abundant and low-cost, realistic projections over 10-20 years may indicate that gas-fired combined cycle plant installed now may need to switch to gasified coal fuel in the future, if the gas/coal cost differential widens sufficiently. In such cases, it may be wise to design the CC plant in a way that allows the later retrofitting of a coal gasifier to replace piped natural gas or LNG.

5.41 Power utilities are increasingly likely to exercise the options ranging from fuel selection, coal switching, and power purchase, to advanced coal-burning technologies and flue gas cleanup, and demand-side management, in order to meet both efficiency (least-cost) and environmental constraints. This approach is particularly advanced in OECD countries, driven by strict environmental standards, competition, and increasingly sophisticated compliance options. Annex 5.13 illustrates the anticipated least-cost fuel and technology mix development of a generic U.S. power utility and of 10 selected U.S. power pools, under different relative fuel cost scenarios. Apart from the peaking use of simple-cycle gas turbines, the base load plant mix responds elastically to a widening of the gas/coal price gap: especially over longer-term (30-year) planning periods, advanced coal technology such as IGCC that complies with environmental standards takes over from natural gas plant as the preferred base load technology choice, as the gas price escalation is increased. While natural gas CC is the clearly more attractive investment for a 10-year horizon, the 30-year horizon shows a shift of natural gas plant to intermediate and peaking use, being replaced at base load by suitable coal technology. Similarly, the introduction of the emissions allowances trading option may show that both limited intra-utility trading and perfect large-scale trading could lower the cost of SO2 control significantly as compared to only adapting existing plant or constructing new advanced plant. Annex 5.14 summarizes the expectations for the impact of the U.S. Clean Air Act on the utility choice.

5.42 Although the spectrum of options for developing country utilities is narrower, the core decisions about the pattern of base load capacity mix are similar. The key choice in the area of thermal generation remains that between natural gas and coal technologies (with heavy fuel oil playing a major role), and is determined by the relative prices of the fuels available locally. Utilities in India and China will be depending on domestic cheap coal as the basic fuel for the foreseeable future, and advanced coal technologies will penetrate these markets as environmental considerations will weigh more heavily, while the limited natural gas will be used at the margin to round out the plant mix. On the other hand, utilities in fuel-importing countries like Korea and the Philippines, or in countries like Thailand that have committed their indigenous clean fuel reserves already, are in a position to exploit cost differentials between internationally traded fuels. Their technology choice for base load generation will be dictated by the anticipated relative prices of traded steam coal, LNG, and piped gas. Fuel-exporters such as Indonesia, who have both abundant coal and natural gas, have to trade off the opportunity cost of exports of coal and gas against each other in their domestic use. Of the 4,500 MW of additional generating plant to be installed in the next 5 years in Indonesia,

about 2,500 MW will be natural gas-fired combined cycle, exploiting small gas fields unsuitable for export of LNG. However, about 1,200 MW of coal-fired capacity are also to be installed, and in the longer run the cost of LNG exports foregone may swing the base load pattern back to cheaper indigenous coal.

5.43 The above choices and options are based on today's relative fuel prices, and assumptions that gradual changes in the price differential will take place (Table 5.4). In general, steam coal of a tradeable quality (i.e. about 10,500-13,000 Btu/lb, 0.5-1.5 % sulfur, 7-15% ash) is available to CIF consumers worldwide at about US$1.50-2.00/mmBtu, implying a power generating cost of about US¢ 4.7-6.2/kWh with conventional or advanced coal technologies. Extremely low-cost coal production, or distorted domestic prices, such as in India or China, can depress the cost of pithead generation substantially below this range. In comparison, natural gas, either delivered by pipeline or as LNG, is available to consumers at prices of about US$2-4/mmBtu, resulting in a combined cycle generating cost of about US¢ 3.2-4.8/kWh in similar base load conditions. Heavy fuel oil often is available at relatively low prices close to US$2/mmBtu, but generation efficiency makes oil-fired plant inferior to gas combined cycle at about US¢ 5/kWh. Nevertheless, for smaller plant applications in areas where the choice is only between coal and fuel oil, the oil-fired option may prove attractive if the sulfur emission problem can be addressed. Emerging fuels such as orimulsion are competing mainly with oil in existing plant, and are priced accordingly. Petroleum coke, a residual from refinery operations, is available locally in selected locations, and does not have a global impact.

Table 5.4: AVERAGE PRICES OF FUELS END-1991

	US$/mmBtu	US$/unit
Coal (tons)		
Spot CIF NW Europe, 10,800 Btu/lb	1.77	42
FOB US East Coast, 12,000 Btu/lb	1.33-1.52	35-40
FOB South Africa, 11,000 Btu/lb	1.28	31
FOB Australia, 12,000 Btu/lb	1.33-1.52	35-40
FOB Colombia, 12,000 Btu/lb	1.44	38
CIF Taiwan, 11,700 Btu/lb	1.63	42
CIF Japan, 12,000 Btu/lb	1.55-2.00	41-52
CIF Rotterdam, 12,000 Btu/lb	1.50-2.00	40-52
East German brown coal	1.50	
CSFR lignite	1.00-1.50	
China local load center, 9,000 Btu/lb	1.50	30
China pithead, 9,000 Btu/lb	0.75	15
India pithead, 9,500 Btu/lb	0.55	11
Natural gas (MCF)		
USA domestic	2.00-2.50	
Europe delivered (pipe or LNG)	2.00-3.00	
CIF Japan LNG	3.00-4.00	
Europe new development	4.00-5.00	
Petroleum coke (tons)	0.85-1.20	30-40
Heavy fuel oil, high sulfur (tons)	2.00-2.50	80-100

5.44 Current World Bank forecasts of commodity price movements call for gradual increases over time in both petroleum and coal prices, after a temporary dip in 1992. For coal, the assumption of a temporary decline is justified by recent international coal price developments, which have shown a downward trend during 1991 and early 1992 (Annex 4.2). Natural gas prices can be expected to follow oil prices with reasonable regularity, although a few recent contractual developments are pointing in the direction of a possible closer linkage to coal prices, at least as partial weighting. The Bank's as well as other international projections indicate an increasing differential between coal and gas/petroleum prices: in terms of current dollars, petroleum prices are expected to increase from US$17/bbl in 1991 to about US$31/bbl in 2000, while coal prices are projected to rise from US$42/mt to US$62/mt in the same period. The increases in real terms of 26% for petroleum and 7% for steam coal would imply a constant-dollar unit cost in the year 2000 of about US$1.60-2.15/mmBtu for coal, and about US$2.50-5.00/mmBtu for gas. At these fuel prices, coal-fired generation cost would change only marginally in real terms, while gas-fired generation cost would shift to about US¢ 3.6-5.6/kWh. In high-gas-price/low-coal-price areas, this change in comparative costs could reduce the attractiveness of natural gas significantly.

5.45 The projections, of course, are based on relatively unchanging estimates of coal and gas reserves worldwide, and on constant capital costs of technology. Changes in assumptions in these parameters may result in a quite different scenario of future fuel mix in power generation. For example, it could be expected that gas reserves increase significantly as higher prices encourage further exploration and field interpretation, thus keeping gas prices from rising as fast as anticipated now. Similarly, increasingly strict environmental requirements, particularly those affecting carbon emissions, would raise the cost of coal-fired generation further, thus compensating for any gas price increases over time. For example, a decision by the international community to impose a "carbon tax" of, say, US$20 on each ton of coal could raise the coal cost to US$2.25-3.00/mmBtu, and place the levelized cost of coal-based generation in the range of US¢ 5.5-7.2/kWh, well out of competitive range of gas, and subject to competition from nuclear power. On the other hand, continuing technological advance in coal technology could lower the capital cost and raise the plant efficiency of coal-burning plant, as already witnessed in the early stages of the development of fluidized bed and gasification technology. Chapter VI explores the impact of such changes in assumptions on global and regional coal demand.

Industrial Cogeneration

5.46 Recent years have shown a trend towards the blurring of the line between utility and industrial users of fossil fuels for power generation and process steam. In particular, cooperative approaches between utilities and industrial cogenerators have been developing in order to (i) satisfy local requirements for environmental protection and emission mitigation, and (ii) optimize the possibilities of selling independent surplus power to the grid or varying purchases from the grid. Specialized intermediaries, generating power and steam for sale to both industrial and utility clients, are emerging as key players in this field. The increasing trend towards an opening up of the upstream (generating) part of the power sector to independent investors makes this narrower linkage between industry and utilities possible.

5.47 Apart from bituminous coal, the fuels used in this environmental and efficiency cooperation often are waste or residual products that would have to be disposed of otherwise. They include such products as petroleum coke, anthracite waste ("culm") (2,500-3,500 Btu/lb), coal washing rejects, waste sludge, wood chips, discarded tires, agricultural waste, and low-grade coals with low Btu and high ash content. The advantages of the system are the usual cogeneration ones of utilizing both the electricity and the steam produced, plus the ability to dispose of otherwise harmful waste. The steam is utilized in chemical production processes and other industrial use such as injection for enhanced oil recovery (Power Engineering, August 1990). The electricity generation capability contributes to the dispatch optimization of the power utility, and to the power cost minimization of the industrial facility. The U.S. utility Tennessee Valley Authority has introduced a "real-time pricing" system for large industrial consumers, providing computerized hourly electricity price quotes to the consumers, who then can decide whether to buy from the utility or use own generation.

5.48 The technology that has made the flexible use of different and low-grade fuels possible while maintaining environmental standards, is the fluidized-bed combustion process. Its attractiveness for industrial and cogeneration applications has been demonstrated in diverse circumstances such as in the USA and China. Increasingly, utilities and cogeneration investors are considering this process to utilize local low-cost but low-grade coal or lignite, where the high sulfur and NOx emissions can be mitigated at reasonable cost, and under restricted site circumstances (where the "footprint" of the plant matters because of resistance from local populations). Eastern European power generation, either by utilities or in cooperation with cogenerators, can use lignite or brown coal at about US$1.50/mmBtu, yielding a levelized generation cost with FBC of about US¢ 5.3/kWh. Even more attractive costs in the range of US¢ 4.5-5.0/kWh could be achieved with Indian or Chinese pithead coal.

Outlook

5.49 Increasingly strong demands for higher power generating efficiency and environmental impact abatement will force power sector utilities, cogenerating enterprises, and industrial fossil fuel users to expand the spectrum of options from which to chose the mix of energy sources. On the system development side, the options will range from fuel preparation and blending, through switching to natural gas, introduction of advanced coal combustion processes, and downstream flue gas cleanup, to demand management incentives, electricity and emission allowance trading. In institutional terms, the differences between industrial and utility generation will diminish through the emergence of intermediaries and cogeneration arrangements with both efficiency and environmental objectives. In the short and medium term, perhaps into the first decade of the next century, natural gas-fired combined cycle plant is likely to be the technology of choice for base load power generation, where gas is available and coal is not unusually cheap. In the long run, the increasing price differential between gas and coal and the maturing of advanced coal technologies are likely to bring a return to reliance on coal-fired base load plant, pushing natural gas into intermediate and peaking service in the merit order of plant.

VI. STEAM COAL CONSUMPTION SCENARIOS

6.1 The recent history and future possibilities of disequilibrium in energy markets produce many uncertainties about the future course of development of coal and other energy sources. Energy needs for the remainder of this decade will continue to rely heavily on oil, although its relative importance will continue to decline. In the event of oil shortages, the future energy markets will only clear by some combination of sharply higher prices, slower growth, and a costly restructuring of economic and industrial activity. While higher prices induce the development of natural gas, higher-cost oil deposits and synthetic fuels, these energy sources are not nearly as abundant, dispersed nor, in the case of synthetic fuels, technologically or commercially developed as coal. This abundance and geographical dispersion of coal reserves, combined with its strong penetration in power supply industries, point to a steady expansion of coal use during the next twenty years and possibly beyond. However, a massive shift from oil to coal is unlikely to materialize, in large part due to the environmental concerns associated with the burning of fossil fuels, particularly coal. The extent of future coal use will greatly depend on technological advances that enable the mining, shipping and burning of coal in an environmentally acceptable manner while maintaining its cost competitiveness.

6.2 This report develops thermal coal utilization scenarios using a methodology which forecasts mix choice and coal requirements on the basis of (a) assumptions of economic and industrial growth, energy demand, and electricity supply, and (b) a disaggregated comparison of equipment and fuel costs of alternative energy technologies in primary end-uses. The structure of the model can be divided into four discrete, yet interconnected, blocks: (i) choice of energy technology, or investment decisions, in the major end-use categories; (ii) boiler fuel mix in power and industry; (iii) medium- and long-term coal requirements in coal-consuming countries; and (iv) linkages with the above which forecast coal prices, production and imports. Seven regions [37] were identified for purposes of model simulation. Coking (metallurgical) coal is excluded from the analysis.

6.3 A number of scenarios have been developed to forecast coal use under different circumstances. The reference case is intended to capture the present conditions in the international and regional coal markets, and assumes the continuation of current trends in steam coal markets, government coal and energy policies, and environmental protection. Additional scenarios or cases are developed to investigate the effects of modifications in the reference case assumptions regarding (a) the rate of capacity utilization in coal-fired boilers or plants, (b) the penetration of new coal technologies, (c) costs of meeting environmental standards enacted at the international, regional or national level, and (d) relative fuel prices. All cases are based on identical assumptions about economic growth, aggregate energy demand, future energy prices (with the exception of the fuel price scenarios), and electricity demand growth. The main impact of changing scenario assumptions

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[37] North America, Western Europe, Pacific (Japan/Australia (NZ), Other Asia, Africa/Middle East, South America and Eastern Europe/CIS.

is on the balance between coal-fired and gas-fired base-load power plant, and thus an overall steam coal consumption.

Economic Growth and Energy Demand Assumptions

6.4 Estimates prepared by OECD/IEA, DOE/EIA and the Bank form the basis for the assumptions about economic growth and energy demand trends in the medium- and long-term. For all cases, world GDP is assumed to grow at 3.0% per annum between 1995 and 2005, while total world energy requirements will grow at an average annual rate of about 2.5% until 2005 and 2.2% for the remaining years ending in 2015.

6.5 Economic activity in the OECD countries is assumed to expand at an average rate of 2.7% p.a. from 1995 to 2005, and 2.4% p.a. from 2005 to 2015. In the OECD countries, economic growth is projected to be slightly higher in the North American and Pacific member countries than in the individual European countries. For OECD as a whole, energy demand is expected to grow about 1.3% per year, implying a further decline in energy intensity of about 1.3% annually until 2005. The growth in real GDP in the developing countries as a group is assumed to average 3.8% annually for the period upto 2005, and 3.0% p.a. from 2005 to 2015. The former centrally planned economies of the CIS and other East European countries are assumed to expand (after an initial contraction) at an average annual rate of 2.4% until 2005, and 2.8% for the period 2005-2015. Total energy demand is assumed to grow by 4.5% p.a. in the developing countries and by 2.9% p.a. in countries that have had centrally planned economies. These categories have been developed to simplify the analysis, although there are clearly wide differences within each category.

Relative Fuel Price Assumptions - Reference Case

6.6 International oil prices (in 1985 constant dollars) are assumed to decline from US$ 14.5/bbl in 1990 to US$11.7/bbl (in 1985 constant dollars), thereafter remaining constant in real terms until 1995 at the 1991 level. Oil prices are projected to again rise to around US$14.5-15.0/bbl after 1995, remaining at that level in real terms until 2005. Natural gas prices are assumed to follow oil prices closely. However, coal prices are assumed to increase less rapidly since supply curves are relatively flat in those countries which have the most potential for expanded production, and competition is expected to keep prices approximately in line with production and transport costs. International steam coal prices (in constant 1985 dollars). (FOB, East Coast USA) are assumed to decline slightly from US$29/mt on 1990 top US$27/mt in 1995, remaining at that level in real terms until 2000 when it is projected to increase to US$30/mt.

Results of the Reference Case

6.7 In addition to the above considerations, the reference case projections are using (a) existing energy and electricity balances in individual countries aggregated to regional totals, and (b) current plans for further capacity expansion and replacement in the primary coal end-use categories, as reported by individual countries to international organizations. Further, the reference case assumes (i) a plant factor of 70% in base-load thermal power plants; (ii) relative gas and coal price differential of US$1.0-1.5/mmbtu; (iii) the continuation of existing government coal and environment policies, as well as current investment plans for the development of coal resources and

the expansion and replacement of coal-using stock of equipment. In the absence of unforeseen events, continuation of current environment policies does not have a major impact on availability and use of coal, at least not at the level of aggregation treated in this study. However, if environmental concerns lead to major technological breakthroughs or if government policies result in aggressive promotion of emissions controls, the future of coal development could be markedly different from the reference case projections (paras 6.17-6.24).

6.8 The demand for coal is separated into four end-use categories: thermal power station consumption, demand for steam coal in industry, residential/commercial demand, and other small uses including energy sector consumption. These are discussed in succession below.

6.9 Electricity Generation. The regional use of coal in electric utilities was determined using a three-step approach. First, the existing stock of coal-fired powerplants, as well as future investments, was identified from national government plans submitted to the IEA (in the case of OECD countries) and the World Bank. Table 6.1 shows the large projected increase in coal-fired capacity in the developing countries, primarily in Asia where it more than doubles between 1990 and 2000. The share of coal in OECD power generation remains around 40% of total generating capacity with a slight increase in coal-fired capacity. Beyond 2000, electricity demand growth is assumed to average 2.2% p.a. in the OECD, 3.0% p.a. in Eastern Europe, and over 5.5% p.a. in the developing countries until 2015.

Table 6.1: COAL-FIRED ELECTRICITY GENERATING CAPACITY (GW)

	1990	2000
OECD		
N. America	314.2	339.0
Pacific	42.1	63.6
W. Europe	151.4	172.5
	507.7	575.1
Developing Countries		
Asia	118.0	257.8
Africa	43.3	60.5
S. America	4.2	10.6
	165.5	328.9

Source: IEA, Coal Information 1991, and Bank estimates.

6.10 Secondly, coal consumption by powerplants was estimated using the following simplified assumptions:

Coal Plant	Capacity Factor	Average Heat Rate for Power	Coal Typical Heat Value
Bituminous	70%	8,600-9,900 Btu/Kwh \1	12,000 Btu/lb
Lignite	70%	11,000 Btu/Kwh	3,000 Btu/lb

\1 Conventional pulverized coal - 9,600 Btu/Kwh; Pulverized coal with FGD, and ESP - 9,900 Btu/Kwh; Coal-fired fluidized bed combustion - 8,600-9,600 Btu/lb; and integrated coal gasification/combined cycle - 8,900 Btu/lb.

6.11 In the final stage, utility coal consumption was broken down by regional usage, as shown in Annex 6.1 and summarized in Table 6.2. The reference case projections anticipate that, over the long-term, coal will become more important in electricity generation, providing most of the increased thermal power generation not met by natural gas. Growth in coal use for power generation is expected to be slower in the 1990s than in the 1980s and slower still in the years after 2000 (with the possible exception of Eastern Europe). For OECD countries, this is attributed to improved efficiency in generation and coal use; for developing countries, to the gradual completion of electrification.

6.12 Industrial Sector. Whereas it is possible to identify specific coal-fired power expansion plans, such information is generally not available for the smaller, more widely dispersed industrial and retail consumers. For these sectors, specific countries or regions were identified where industrial, residential and commercial customers have traditionally used coal as an energy source.[*] The aggregate coal consumption for each potential demand region was forecast according to projected growth of industrial activity, relative proximity to a coal-producing region or port of import of coal, and fuel substitution possibilities within each region.

6.13 Residential and Other Users. The use of coal in the residential and commercial, transportation and energy sectors comprised only 6-7% of total worldwide coal consumption in 1990 and will probably continue to shrink (except for large commercial establishments and where district heating is feasible) due to its inconvenience for small consumers, and its disadvantages to locomotives relative to diesel fuel or electricity. Large-scale use of

[*] Coal use in the iron and steel industries, including some thermal coal consumption but consisting mostly of coking coal, is not included in these projections. The analysis is restricted to the major steam coal users.

coal for residential heating is limited to China and Eastern Europe. Coal may also be use in limited quantities for the production of chemicals, for production of carbon dioxide for enhanced recovery of oil, and for production of heat and hydrogen to produce tar sand oil.

6.14 Total Coal Demand, Supply and Trade. The overall results of the reference case projections are presented in Table 6.2 which indicates projections of coal demand in 2005, 2010 and 2015. In the reference case, between 1995 and 2005, world coal utilization increases at an average rate of 2.7% p.a., rising from 2,970 Mtce in 1995 to 3,689 Mtce in 2005. Worldwide coal consumption rises further to over 4,600 Mtce by 2015. Substantial growth in coal consumption is projected to take place in all the major coal-consuming regions. In OECD, coal consumption will increase at or slightly below the current rates in North America and Western Europe, while rising sharply (5% p.a.) in the OECD Pacific region (mainly Japan). In Asia, coal consumption will increase from just under 900 Mtce in 1990 to 1,200 Mtce in 2005 and nearly 1,600 Mtce by 2015. Starting from a much smaller base, coal utilization in South America will increase rapidly from around 20 Mtce in 1990 to over 70 Mtce in 2015. Economic restructuring will lead to a slowdown in short-term coal consumption trends in Eastern Europe, although coal use is projected to grow rapidly after the year 2000 (averaging 3.0% p.a. between 2000-2010).

Table 6.2: REFERENCE CASE COAL CONSUMPTION SCENARIOS
(Mtce)

	1980	1990	1995	2000	2005	2010	2015
Total Steam Coal Consumption							
North America	501.4	659.5	719.8	777.9	856.1	928.9	997.6
Pacific	53.7	115.0	158.4	200.2	250.9	308.1	358.2
W. Europe	299.1	300.9	320.7	353.9	377.4	404.2	426.9
Asia	519.6	874.1	982.9	1073.1	1208.3	1361.9	1543.0
South America	11.2	20.9	32.7	40.9	50.9	62.2	72.5
Africa	79.1	145.1	161.2	178.2	199.9	230.7	257.0
E. Europe	541.6	594.7	595.0	652.7	745.2	855.2	975.6
Total World	2005.7	2710.1	2970.8	3276.9	3688.6	4151.2	4630.7
Steam Coal Consumption in Power Sector							
North America	442.9	594.0	651.5	706.8	779.7	846.6	910.1
Pacific	40.9	82.5	112.2	138.4	174.7	214.1	246.2
W. Europe	224.0	246.4	258.9	293.3	314.3	337.2	357.4
Asia	162.4	377.7	484.1	567.3	663.9	778.0	918.0
South America	4.1	8.1	16.8	22.7	30.5	39.7	48.9
Africa	53.8	81.3	91.1	101.7	117.0	139.5	160.4
E. Europe	265.8	265.8	293.8	335.0	396.6	468.9	551.0
Total World	1194.0	1655.8	1908.4	2165.0	2476.7	2824.1	3192.1

6.15 These estimates are in turn compared to future trends in coal production in order to assess the supply-demand balance and ,market-clearing conditions during the projection period. Coal production in North America is assumed to grow 1.1% p.a. between 1990 and 2000 to 891 Mtce, and slightly under 1.0% p.a. from 2000 to 2010. The existing forecast for Australian hard coal production point to a growth of 3.0% p.a. between 1990 and 2000. Most of this growth will be in steam coal production with a forecast growth of 4.4% p.a. for 1990-2000, and 3.5% p.a. thereafter until 2010. In Western Europe, coal production is expected to continue to decline, with total coal production forecast at around 200 Mtce by 2000. Outside the OECD, production increases could be substantial. The coal production in China is expected to continue to grow rapidly at an average rate of 3.0% p.a. between 1990 and 2010. Economic restructuring, combined with increasing unrest among mining communities in the CIS are likely to result in some decline in coal production in Eastern Europe as a whole until 2000. In the medium to long-term, coal production in Eastern Europe is projected to increase at an average rate of 2.3% p.a. between 2000 and 2010.

6.16 When demand and supply balances are estimated for each region, deficits in any region are assumed to be met by imports from coal-surplus regions with export capabilities. The primary importing regions will remain in Western Europe and East Asia, while Japan will continue to be the single largest coal-importing country during the projection period. The level of future coal trade will greatly depend on government coal policies in these countries. Since the reference case assumes the continuation of existing government policies, the displacement of domestic production by imports is assumed to take place more rapidly in Japan and United Kingdom than in Germany. Japan, for example, is assumed to meet all its thermal coal requirements from imports after the year 2000. Similarly, about 30-35% of current domestic production in U.K. will be displaced by imports after 2000 in the reference case. Significant entry of imported coal into German coal markets is postulated only for the period after 2005. Under these assumptions, coal imports are projected to increase sharply from around 360 Mtce in 2000 to nearly 650 Mtce by 2010. At that point, international steam coal trade is likely to amount to about 16% of total steam coal consumption, up from about 7% in 1990.

Table 6.3: STEAM COAL IMPORTS BY REGION
(Mtce)

Region	1990	1995	2000	2010
North America	9.7	4.6	6.7	2.4
Pacific	32.8	50.7	89.1	194.2
Western Europe	84.8	119.7	176.8	302.6
Asia	39.4	44.0	60.9	90.8
South America	1.4	2.0	3.4	6.5
Eastern Europe	15.9	18.0	26.9	42.4
World	184.0	238.9	363.8	644.9

Results of Alternative Scenarios

6.17 A wide array of technological options for coal combustion have emerged in recent years in response to the growing demand for higher combustion efficiency and environmental pollution abatement. A discussion of the comparative costs of the major competing technologies is provided in para 5.36-5.48. With a given set of capital costs for individual technologies, the choice of technology mix, and hence coal requirements will be sensitive to the plant factor of large combustion facilities such as base load power plants, and to the relative cost of fuels. Whereas the reference case was developed using the approximate cost structure presented in Table 5.3, additional scenarios have been generated to assess the impact of changing these cost assumptions.

6.18 Plant Factors. Since capital costs constitute a major portion of the total unit costs of coal-fired power generation, these costs are extremely sensitive to the rate of capacity utilization, or plant factors, in the power plant. The projections in Table 6.4 highlight the sharp drop in coal consumption when the coal-fired generation plants operate at 50% plant factor in the future, as opposed to base load generation for 70-90% of the yearly hours. A lower plant factor for coal-fired facilities could result from a rapid increase of lower-cost nuclear or hydro plant (pushing the coal plant higher in the merit order) or from accelerated conservation.

Table 6.4: STEAM COAL CONSUMPTION BY PLANT FACTORS
CONVENTIONAL PULVERIZED COAL TECHNOLOGY
(Mtce)

Plant Factor	1990	1995	2005	2015
50%	2710.1	2683.9	3084.2	3763.9
70%	2710.1	2970.8	3688.6	4630.7
90%	2710.1	3469.1	4327.0	5438.1

6.19 Environmental Considerations. The important link between energy and environment, including both the conventional pollutants from fossil fuel combustion and the growing concern regarding the possible climatic effects of "greenhouse gases" is receiving increasing attention at the national and international levels. Most OECD countries have introduced or are planning stricter emission standards for SO2, Nox and particulate matters for new and, in some cases, existing combustion facilities. While some countries, notably Sweden, Canada, Denmark, Germany, Japan, the Netherlands, and U.S.A. have already adopted or proposed legislation for emission standards, the question of whether or not to apply strict standards for power plant and large industrial facilities is still being debated in most other countries. Most OECD governments have also expressed their willingness to reduce carbon dioxide emissions as part of policies to reduce the threat of global warming. It would make little sense for countries to introduce large carbon emission taxes unilaterally since the policies of a single country would not affect global warming. Therefore, negotiations on an international agreement to

curb CO2 emissions are underway under the auspices of the United Nations, and any agreement would then require all governments to implement stricter CO2 emission standards. A few countries, such as Sweden, Finland, the Netherlands and Norway, have already adopted carbon taxes designed to encourage the development of market instruments that enable the user to seek the most economic means to achieve reduction rates.

6.20 The level of carbon taxes required to achieve certain emission targets has been analyzed in several studies.[32] The studies show that the tax has to be sizeable and to increase over time, just to stabilize emissions at current levels. The tax rates estimated to be necessary for the stabilization of emissions at the 1990 level by the end of 2020, range from US$30 to US$150 per ton of carbon. According to IEA estimates, a tax of US$100/mt of carbon would more than double the steam coal price from US$44/mt of coal in 1988 to US$104/ton, while adding US$12 to the price of a barrel of oil. The gas price would increase by about 60% from its value in 1988 (see Table 6.5). Proposals by the European Commission in early 1992 would imply a tax of US$10 per barrel of oil equivalent on an energy basis. This would mean fuel price increases that are somewhat lower than those of Table 6.5, and penalize coal less relative to other fuels.

Table 6.5: THE EFFECT OF A US$100 TAX PER TON OF CARBON ON ENERGY PRICES (US$, 1988)

	Crude Oil	Coal	Natural Gas
Unit of Measure	Barrel	Metric ton	Ton of oil Equivalent
Tons of carbon/ unit of fuel	0.12	0.61	0.60
World Market Price ($)	14.9 \1	44.0 \2	95.0 (3)
Carbon Tax ($)	12.0	60.5	60.0
Price Increase (%)	81	138	63

\1 IEA average import price.
\2 OECD average CIF steam coal import price.
\3 EEC average import price of pipeline.

Source: IEA, Energy Prices and Taxes, First Quarter 1990.

[32] See P. Hoeler, A. Dean and J. Nocholson, "Macroeconomic implications of reducing greenhouse gas emissions: a survey of empirical studies", OECD Economic Studies, No. 16, 1991, and OECD/IEA, Greenhouse Gas Emissions: The Energy Dimension, 1991.

6.21 Bringing the structure of fossil fuel pricing and taxation more in line with environmental considerations would lead to changes in relative fuel prices. The taxation of coal would increase in relative terms, while there would be some price increases for gas and oil. Fuel switching induced by such a tax change would then be expected to result in a sizeable reduction in carbon emissions from fossil fuels. For this study, the price effect of an incremental carbon tax on steam coal, equivalent to US$20 per metric ton of steam coal,[40] is analyzed. On a heat-content basis, this would raise the cost of coal by US$0.75/mmbtu. The results of these simulations are presented in Annex 6.1 and summarized in Table 6.6. With a sharp rise in fossil fuel, particularly coal, prices due to carbon taxes, there is likelihood of major expansion of non-fossil fuel (at present mainly hydro and nuclear power) use for power generation. Within the fossil fuel options, natural gas would become more prominent where available. Total steam coal consumption by 2015 would reach only about 70% of the reference case. A carbon tax of US$20/ton of coal would raise the levelized cost of coal-fired power generation units to the range of Usc 5.5-7.2/Kwh, placing it in the range of competition from nuclear power sources.

Table 6.6: THE EFFECTS OF CARBON TAX ON COAL CONSUMPTION (Mtce)

	1980	1990	1995	2000	2005	2010	2015
Carbon Tax (US$20/ton of steam coal)							
North America	501.4	659.5	719.8	672.2	580.1	629.8	676.7
Pacific	53.7	115.0	158.4	151.9	147.3	180.3	196.6
W. Europe	299.1	300.9	320.7	275.2	197.8	211.9	224.0
Asia	519.6	874.1	982.9	913.6	920.9	1023.9	1170.2
South America	11.2	20.9	32.7	25.8	33.5	38.4	46.1
Africa	79.1	145.1	161.2	146.2	135.7	158.0	177.5
Eastern Europe	541.6	594.7	595.0	520.3	428.6	533.0	681.4
Total World	2005.7	2710.1	2970.8	2705.2	2443.8	2775.3	3172.4

6.22 The above scenario does not assume a general decrease in fuel demand because of higher prices across the board, but merely illustrates the impact of a shift between fuels because of changing relative prices. As a carbon tax would raise all fossil fuel prices (although not at the same rate), it would be reasonable to also assume that demand for fossil fuels in general would decline or grow more slowly. Similarly, growth rates of the demand for coal and gas would deviate more, as gas would become relatively cheaper: such a boost in gas demand may exert upward pressure on the gas price, perhaps compensating for some of the incremental comparative advantage gained by gas through the carbon tax. As the dynamics of the fuel market are difficult to project (including interference by oil price fluctuations), the above exercise assumes no change in the electricity demand growth rate. In the initial years

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[40] This refers to a net increase in the relative price of coal vis-a-vis other fuels, the prices of which would increase also, but by a lesser extent than coal.

of a carbon tax introduction (1995-2000), existing coal-fired capacity is used less, while plant factors of other generating plant increase. In the following 5-year increments, retired coal capacity is replaced by other generating capacity. Coal-fired capacity only starts to increase again around 2010, as the one-shot carbon tax imposition is being eroded by the faster pace of gas price increases.

6.23 Stricter Local Emission Standards. Future use of coal in areas currently setting stricter environmental standards will depend, in large part, on the continued commercialization of more efficient and less polluting coal-based combustion technologies. The wide choice of available and emerging technologies for cleaner and more efficient use, their cost structure, and their effectiveness in meeting environmental requirements are discussed in Chapter 5. Coal utilization projections have been made using the cost structures developed in Annex 5.8 for the major technological options, assuming that relative fuel prices remain as in the reference case, but that stronger local emission restrictions will force a combination of fuel switching and the introduction of new coal utilization technologies.

6.24 In this scenario, the first 5-year period after 1995 shows a milder decline in coal use than in the carbon tax scenario, as the gas/coal price differential does not shrink: rather than expanding non-coal generation from existing facilities, utilities have an incentive to switch to low-sulfur coal. While the carbon tax scenario does not leave much choice other than a move out of coal, the scenario base don tougher local emission regulation allows the continued use of coal in an environmentally more benign manner. The following 5-year periods are characterized by utilities first retrofitting existing coal plant with scrubbers, and later moving into emerging combustion technologies such as IGCC and FBC that enable them to use low-cost coal while reducing SO2 and NOx emissions. The increasing cost gap between gas and coal after the year 2000 is likely to make these technologies competitive with gas-fired combined cycle for new plant.

Table 6.7: THE EFFECTS OF STRICTER EMISSION STANDARDS ON STEAM COAL CONSUMPTION
(Mtce)

	1980	1990	1995	2000	2005	2010	2015
Stricter Emission Standards and Clean Coal Combustion Technologies \1							
North America	501.4	659.5	719.8	691.2	708.9	793.0	851.5
Pacific	53.7	115.0	158.4	167.6	192.0	242.2	273.6
W. Europe	299.1	300.9	320.7	296.7	298.3	329.6	330.9
Asia 519.6	874.1	982.9	931.2	972.3	1094.8	1239.0	
South America	11.2	20.9	32.7	34.1	41.0	48.7	56.8
Africa	79.1	145.1	161.2	146.4	159.7	178.5	198.3
Eastern Europe	541.6	594.7	595.0	542.0	566.9	661.6	784.1
Total World	2005.7	2710.1	2970.8	2809.2	2939.1	3348.5	3734.4

\1 At 70% plant factor.

6.25 Coal use again is lower than in the reference case in all regions with the large-scale introduction of new higher-efficiency and higher-cost technological options, although not as dramatically as in the case of carbon taxes (80% of the reference case). There are some variations within the overall decline in the projections. In areas where cheap coal is available, and natural gas is not, coal remains the fuel of choice for power and industrial sectors. In India and China, for example, delivered price of US$0.5-0.75/mmbtu to pithead power plants translates into coal-fired levelized cost of electricity of US¢4.3-4.7/Kwh (with all the environmental safeguards). Conventional pulverized coal plants with only limited environmental equipment, at about Usc 4/Kwh with cheap pithead coal, can compete with natural gas CC plant even at a gas price of US$3.0/mmbtu.

6.26 Accelerated Oil/Gas Price Rise. The reference case and the stricter emissions case assume a gradually widening gap between oil/gas prices and coal prices, as coal prices increase more slowly in real terms. The carbon tax scenario assumes a dramatic one-time reduction in the differential. A major disruption in oil markets, if sustained, could accelerate the widening of this gap, pushing the cost of gas-fired generation into a less competitive band faster. Table 6.8 illustrates this scenario, assuming a departure from the reference case in the form of an earlier widening of the relative price gap between coal and gas to 1:4 per mmbtu by the year 2000. This increase in the cost competitiveness of coal vis-a-vis other generating options would lead to an early acceleration of the growth of coal use, pushing the volume of coal utilization well beyond the reference case after the year 2000. The incentive for new plant will be effective an earlier date than in the reference case.

Table 6.8: THE EFFECTS OF RISING RELATIVE OIL/GAS PRICES ON COAL CONSUMPTION \1
(Mtce)

	1980	1990	1995	2000	2005	2010	2015
America	501.4	659.5	719.8	777.9	942.7	1033.5	1121.4
Pacific	53.7	115.0	158.4	211.0	267.2	335.3	419.2
W. Europe	299.1	300.9	320.7	396.7	434.0	475.5	515.9
Asia	519.6	874.1	986.4	1095.8	1254.9	1433.5	1576.9
S. America	11.2	20.9	32.7	40.9	52.4	63.3	72.8
Africa	79.1	145.1	163.5	182.2	206.8	247.3	290.6
E.Europe	541.6	594.7	595.0	716.5	936.1	1183.8	1420.5
Total World	2005.7	2710.1	2976.6	3420.9	4094.2	4772.3	5417.2

\1 At 70% plant factor.

Regional Differences

6.27 After growing at an average rate of over 6.5% p.a. in the 1980s, steam coal consumption in Asia accounted for around 30% of worldwide consumption in 1990. In the reference case, steam coal consumption in Asia will grow at an average annual rate of 2.5-3.0% until 2015, so that the region will account for close to 40% of worldwide steam coal consumption by 2015. The share of

OECD coal consumption is projected to decline from around 40% in 1990 to under 38% in 2015. Within the OECD, aggregate coal consumption (and imports) will grow rapidly in the Pacific region (Japan/Australia/NZ, averaging 5% p.a. until 2005) but at a slower rate in North America and Western Europe. The share of worldwide consumption drops in both North America (21% in 2015 compared to over 24% in 1990) and Western Europe (9% in 2015), while growing in Pacific (8% in 2015, up from 4% in 1990). Fairly rapid growth of steam coal consumption in South America will double that region's share from 0.8% in 1990 to 1.6% in 2015. Steam coal consumption in Africa (mainly South Africa) is projected to grow at the same rate as worldwide consumption so that the region's share will remain around 5% of the total. With slow growth rates in the short to medium-term, the share of Eastern Europe is projected to drop slightly from over 21% in 1990 to 20% in 2005, rising again to around 21-22% by 2015.

6.28 In the alternative scenarios, the pattern of coal consumption in the individual regions will be affected differently due to the varying impact of the alternative policies in each region. Thus, for example, the adverse effects of a carbon tax or other environmental standards are most prominent in the OECD where steam coal consumption reaches only 62% (in the case of the carbon tax scenario) and 75% (clean coal technology scenario) of the reference case in 2015. In the low-cost coal producing countries (India, China, South Africa), the decline in steam coal consumption from the reference case levels is not as dramatic since coal remains the least-cost alternative because of (i) low coal supply costs, and/or (ii) the lack of availability or high cost of alternative energy sources, such as natural gas.

6.29 Implications for coal development and trade. Forecasting beyond 2005 is highly speculative, given the many uncertainties surrounding the main variables influencing coal demand and supply. However, it is clear that future trends in capacity utilization, relative fuel prices and environmental protection will have a strong impact on coal demand. Although not modelled explicitly, coal production levels will have to adjust to balance the changing demand scenarios under the different assumptions. An important policy area will be the future regulation of coal prices, and the government subsidies provided to important producers and/or consumers in the major coal-consuming areas. The accelerated removal of these subsidies would stimulate coal production outside the high-cost areas, and trade beyond current levels, offsetting some of the decline brought about by stricter emission standards. In the long run (i.e. 2015), even the scenarios assuming severe externally imposed cost penalties on coal indicate an increase in steam coal consumption: the importance of coal as fuel is unlikely to diminish.

VII. THE ROLE OF DEVELOPING COUNTRIES

7.1 The global coal sector appears to be dominated by consumption and production in the more developed countries, either in the OECD, or in Eastern Europe and South Africa. International coal trade flows, in particular, are characterized by the predominance of economically advanced suppliers (USA, Australia, and South Africa) and buyers (Western Europe, Japan). A closer look, however, indicates that developing countries are playing a significant role in coal production and consumption, and are likely to assume a much greater importance in the global coal picture. The developing world (outside the OECD and Eastern Europe) produces more than 30% of all coal. China and India alone account for 28%, China being the largest coal producer worldwide. These two countries are, however, largely self-contained, producing coal almost exclusively for their own consumption. Both China's and India's power sectors are heavily based on coal, with China also relying on coal for industrial boilers and residential use. These coal-based economies have little choice in their fuel mix, as their coal reserves (much of them low-grade) are cheap to extract and to deliver to pit-head power plants, and gas reserves are limited.

7.2 The outlook for the developing countries' role in coal matters is impressive: coal consumption by the year 2015 under the reference case is expected to almost double in Asia, Africa, and Latin America, while it is not projected to rise by more than 50% in the OECD and Eastern Europe. The main driving force behind the expansion of coal consumption in the developing world will be China and India, who have outlined ambitious expansion plans in coal mining and coal-fired power generation. Other developing countries, however, will participate increasingly in the expansion: Indonesia's power investment program includes a large component using indigenous coal reserves, and Thailand and the Philippines are contemplating the investment in generating plant based on imported coal. The need to ensure cost minimization in countries with rapidly rising electricity demand but limited investment resources will require the reliance on a low-cost fuel resource with reasonable price stability such as coal.

7.3 Apart from the established but traditionally domestically-oriented coal producers such as China, India, and Indonesia, new developing-country production facilities are emerging and marketing their output in the world coal market. Indonesia itself has opened its reserves to private mining, and has licensed private operators to export high-quality steam coal. Similarly, Colombia is expanding its mining capacity with the help of private investment, again mainly for export. Countries of Southern Africa with significant coal reserves such as Zimbabwe, Zambia, and Botswana may emerge as higher-profile coal producers than in the past, benefitting from the improvements in the political environment of southern Africa, and perhaps participating in exports through South Africa. Most of the financial assistance to the coal sector in developing countries has been provided by multilateral sources to public-sector coal mining enterprises, primarily the World Bank. Recent years have shown that private financing can be mobilized for export-oriented new coal mining ventures such as in Indonesia, China and Colombia.

Bank Assistance

7.4 The Bank's first coal project, in a developing country undertaken shortly after the institution's establishment, involved financing an underground manual longwall operation at the Lota Schwager mine in Chile. However, the Bank's continuous involvement in the coal sector and coal project lending worldwide was initiated in the mid and late 1970's. Throughout the 1980's, the Bank maintained an active involvement in financing coal exploration and coal mine (including infrastructure) development projects. The Bank's participation in coal projects has covered all regions of the world, with the most substantial operations being in the East Asia and Pacific, and South Asia areas, where coal reserves in developing countries are particularly abundant. With the economic difficulties faced in Eastern Europe, and the creation of the successor states of the former Soviet Union, these countries and particularly those with traditional coal mining industries, are receiving increasing attention from the Bank. In the majority of cases worldwide, Bank lending has been preceded by extensive sector and economic investigations. Apart from upstream coal projects, the Bank traditionally has maintained a significant lending program for coal-fired power generation, often including coal mine development.

7.5 Asia. The first coal project undertaken by the Bank's Industry Department, and still one the largest Bank lending operations for a specific project in the coal sector (US$185 million) was at Bukit Asam in South Sumatra, Indonesia where the Bank, with co-financiers, assisted with the development of the 3 million tonnes per year openpit coal mine operation. This project was an integrated mine-rail-port-ship operation with the project encompassing 400 km. of railway rehabilitation and renewal; development of a port; and procurement of a ship to transport coal to a new power plant at Suralaya in West Java. Following this project, the Bank initiated a US$25 million Coal Exploration Project to assist the government to identify future coal mine potential to feed subsequent thermal power developments. In China, the Bank is financing the Changcun underground longwall coal mine and preparation plant development. In addition, the Bank has pre-appraised or appraised a number of other coal projects for discussion with central government, and has undertaken Coal Sector, Coal Pricing and Coal Utilization Studies and is undertaking a Coal Transport Study. The Bank has participated in the first two phases of expansion of the Mae Moh Lignite openpit mine in Thailand, and is continuing to finance mine equipment requirements under ongoing Power System Development projects. In India, following a major sector review and report, the Bank has participated in three coal projects: (i) the 5 mtpy Dudhichua mine (US$109 million); (ii) the Jharia Project encompassing a 3 mtpy underground coking coal mine (Pootkee Bulliary) and preparation plant, and a 2.5 mtpy openpit (US$58 million); and (iii) the Coal Mine Quality and Improvement Project encompassing development of the 5 mtpy Gevra openpit mine expansion, the 5 mtpy Sonepur Bazari openpit and a component to finance the importation of coking coal (combined US$340 million). Bank staff are preparing a project to assist to investigate options to extinguish the Jharia coalfield fires, the largest area of sustained underground post-mining combustion in the world. Technical assistance and project preparation has been provided in Burma, South Korea, Vietnam, Lao PDR, Pakistan and Bangladesh.

7.6 Europe, Middle East and Central Asia. The Bank financed (US$27 million) the Jerada Coal Mine Modernization and Expansion Project in Morocco, providing subsequent advice regarding mine closure. As a component of the Elbistan Thermal Power Project in Turkey, the Bank, together with co-lenders, provided technical assistance for the associated captive lignite mine development. Coal Sector and Coal Pricing Studies were undertaken by the Bank. Under a subsequent Energy Sector Loan, financing (US$100 million) was provided for equipment and spare parts for the lignite and hard coal sectors. In Yugoslavia, the Bank advised on the development of lignite mines and, subsequently, on the restructuring/closure of certain underground coal mines. The Bank financed the Kolubara (Tamnara West) lignite openpit (US$134 million) as a component of the Kolubara B Power project. Technical assistance for coal sector analysis, restructuring, and investment preparation has been provided in Poland, CSFR, Hungary, Romania, Bulgaria, Ukraine, Kazakhstan, Iran, and Afghanistan.

7.7 Latin America and Africa. An Engineering Loan/Technical Assistance was provided in Argentina for exploration at the Rio Turbio mine. In Colombia (as executing agency for UNDP) the Bank provided technical assistance to Comibol in the development of the El Cerrejon coal mine. In addition, the Bank provided an Engineering/Technical Assistance Loan for exploration and pre-feasibility studies of several coal prospects. In Mexico, the Bank-financed rehabilitation of the steel sector included a component on captive coking coal mine rehabilitation. Further technical assistance to evaluate potential coal development was provided to Brazil, Peru, Bolivia, and Venezuela. In Zambia, the Bank financed an Engineering Project to study the rehabilitation of the Mamba colliery, including a component to finance spare parts for the mine operation. A Coal Engineering Loan was provided to Tanzania to undertake coalfield exploration and to finance equipment for the Kiwira underground coal mine. In Madagascar, the Bank reviewed UNDP-financed consultant coal sector studies. In Nigeria, the Bank financed a coal sector study as a component of a broader Energy Sector Review.

7.8 Coal-Fired Power Generation. Within the Bank's overall lending program, thermal power generation occupies a prominent position. Most of the financial assistance for the construction of thermal generating plant to date has been focused on coal and lignite-fired facilities, reflecting the resource availability and comparative cost structure in the major borrower countries. Of the approximately US$ 25 billion committed by the Bank for power sector assistance in the period 1980-1991, about 20% or US$ 5 billion was allocated to the financing of coal-fired thermal power plant. The vast bulk of these generating facilities supported by the Bank are located in the major coal-using Asian developing economies, primarily India, Indonesia, and China. Loans for coal and lignite-based power generation were also extended to Thailand, Hungary, Yugoslavia, and Turkey. Least-cost power system optimization in the three dominant countries consistently has yielded an important role for coal as preferred fuel, although natural gas is attractive to supplement the coal-based systems where it is available at reasonable cost. Traditionally, environmental standards in these countries did not call for the installation of efficient emission mitigation equipment on coal-fired power plant. In recent years, attention has been focused on ensuring that the investments are as environmentally benign as possible: higher-quality coal is

specified (Indonesia), or flue gas scrubbing equipment is included (Thailand). Recent power sector assistance in Eastern Europe focuses exclusively on FGD retrofitting (CSFR) or coal-to-gas conversions (Poland).

Outlook

7.9 The momentum of the 1980s in multilateral financing of upstream coal sector investments has slowed down considerably. Over the years, the focus has shifted from coal mining to downstream coal utilization in the power sector. This trend is likely to continue as increasing awareness of environmental impact of coal use, and of energy use efficiency will direct the attention of donors further towards utilization issues and investments. Future global warming conventions and concerns will encourage fuel switching and conservation strategies in energy, at the expense of coal development. Similarly, the coal-based economies of Eastern Europe, now emerging as major recipients of assistance, are more in need of retrofitting and rehabilitation of their shrinking energy supply systems, than of new mine development.

7.10 However, a longer-term and broader perspective may change the perception. First, gas reserves do not seem to have the same depth as known coal reserves. Although new exploration constantly expands the proven gas reserves, depletion of economically usable gas is likely to come much earlier than that of coal. Future oil and gas price fluctuations are likely to be more violent than coal price changes, and the long-term increase in gas prices may be faster than that of coal. Secondly, the large stock of existing coal mining facilities coal-based power generation, and industrial steam raising plant makes it necessary to consider the rehabilitation and retrofitting of the complete coal chain (mines, transport, power plants, and industrial boilers) for environmental reasons. Thirdly, the rapidly growing Asian coal economies, and the restructuring (and later revitalizing?) Eastern European economies will be dependent on coal as basic fuel for a long time to come.

7.11 This prospect may open new directions for the financing of the coal sector in its broad definition from exploration to utilization in developing countries. Rather than focus narrowly on coal mine expansion and coal-fired generating plant construction, sector development increasingly will need to consist of more complex interventions in the mitigation of environmental impact, and the promotion of efficiency. The expansion of coal production and utilization will have to be supported within a framework of a least-cost strategy that is clearly limited by the twin constraints of environmental and conservation parameters. The main future areas of activity in the coal sectors of developing countries are likely to be:

(i) mine rehabilitation operations, including safety improvements, land reclamation, other environmental mitigation, and productivity improvement;

(ii) coal preparation and washing, including transfer of advanced beneficiation technology if economically justified, perhaps combined with power sector efficiency improvement operations;

(iii) combined mine and power plant investments, such as captive mines to supply pithead power plants, where this forms part of a least-cost power sector strategy;

(iv) transfer of emerging coal utilization technologies (such as IGCC, FBC, etc.) that have been proved to be commercially and economically feasible on a large scale, and where reliability is robust; and encouragement for the improvement of conventional technologies to achieve greater efficiency, such as supercritical boilers;

(v) efficiency and conservation investments throughout the coal chain as additional options of least-cost strategy; this would include a range of options from mining efficiency investments through coal transport optimization, power system loss reduction, to demand-side management by power utilities, and incentives for industrial coal users;

(vi) sector policy reform, such as coal and power pricing reforms, coal market deregulation, institutional and regulatory reform in the coal and power sectors, the opening of the coal and power investment opportunities to private investors, and the provision of a framework for the establishment of cogeneration arrangements, independent power generating intermediaries, and the use of previously neglected coal waste materials.

RESOURCES AND RESERVES OF WORLD COAL (1987)
(million metric tons)

Country 1	Coal rank 2	Proved amount in place 3	Proved recoverable reserves 4	Estimated additional amount in place 5	Estimated additional reserves recoverable 6
Afghanistan	BT	112	66	400	-
Argentina	SB	195	130	385	-
	LN	-	-	7,350	-
Australia	BT	66,220	45,340	500,000	250,000
	SB	4,100	3,700	-	-
	LN	46,500	41,900	204,000	183,000
Austria	LN	350	65	80	65
Bangladesh	BT	1,054	-	-	-
Belgium	BT	715	410	1,400	900
Botsowana	BT	7,000	3,500	100,000	-
Brazil	SB	3,276	1,245	15,207	6,980

Remarks 7

Definition:

(a) Proved amount in place- Tonnage that has been both carefully measured and has also been assessed as exploitable under present and expected local economic conditions with existing available technology

(b) Proved recoverable reserves- Tonnage that can be recovered under present and expected local economic conditions with existing available technology

Country 1	Coal rank 2	Proved amount in place 3	Proved recoverable reserves 4	Estimated additional amount in place 5	Estimated additional reserves recoverable 6	Remarks 7
Bulgaria	BT	36	30	1,200	-	It includes estimates of amounts which could exist in unexploited extensions of known deposits or in undiscovered deposits in know coal-bearing areas as well as amounts inferred through knowledge of favorable geological conditions
	LN	4,418	3,700	700	-	
Canada	BT	5,585	3,831	24,125	-	
	SB	13,150	1,135	14,990	-	
	LN	2,055	2,000	8,970	-	
Chile	BT	79	31	125	75	
	SB	4,500	1,150	-	-	

Country 1	Coal rank 2	Proved amount in place 3	Proved recoverable reserves 4	Estimated additional amount in place 5	Estimated additional reserves recoverable 6	Remarks 7
China	BT	650,000	610,000	17,981	-	(d) Estimated Additional Reserves Recoverable - It is the quantity of (c) above which might become recoverable within foreseeable economic and technological limits
Columbia	BT	16,524	9,666	-	-	
Czechoslovakia	BT	5,400	1,870	3,600	-	
Egypt	BT	25	13	-	-	
	SB	-	40	-	-	
France	BT	790	213	200	50	BT - Bituminous including anthracite; SB - Sub-bituminous and LN - Lignite
	SB	151	45	-	-	
	LN	30	-	-	-	
Germany	BT	44,000	23,919	186,300	-	
	LN	92,000	56,150	-	-	
Greece	LN	5,312	3,000	-	-	
Hungary	BT	1,407	596	702	77	
	SB	2,841	982	1,952	369	
	LN	5,465	2,883	3,337	1,124	
India	BT	129,154	60,648	110,177	47,177	
	LN	2,100	1,900	3,932	3,932	

Country 1	Coal rank 2	Proved amount in place 3	Proved recoverable reserves 4	Estimated additional amount in place 5	Estimated additional reserves recoverable 6	Remarks 7
Indonesia	BT	-	1,000	-	-	
	SB	-	400	-	-	
	LN	-	1,600	-	-	
Iran	BT	3,754	193	-	-	
	LN	2,295	-	-	-	
Japan	BT	8,348	856	-	-	
	LN	175	17	-	-	
Korea (North)	BT	2,000	300	2,700	-	
	SB	300	300	2,200	-	
Korea (south)	BT	238	158	1,377	593	
Madagascar	BT	1,000	-	-	-	
	LN	75	-	-	-	
Malaysia	BT	15	4	78	-	
	SB	-	-	305	26	
	LN	-	-	270	-	
Mexico	BT	1,569	1,252	1,960	1,168	
	SB	793	634	792	586	

Country 1	Coal rank 2	Proved amount in place 3	Proved recoverable reserves 4	Estimated additional amount in place 5	Estimated additional reserves recoverable 6	Remarks 7
Mongolia	BT	12,000	-	-	-	
	LN	12,000	-	-	-	
Morocco	BT	134	45	-	-	
	LN	44	-	-	-	
Netherlands	BT	1,406	497	-	-	
New Zealand	BT	49	27	267	15	
	SB	277	81	953	9	
	LN	1,556	9	5,500	28	
Nigeria	BT	-	21	21	-	
	SB	338	169	1,000	-	
Pakistan	SB	145	102	310	217	
Peru	BT	-	960	-	-	
	LN	-	100	-	-	
Philippines	SB	170	82	-	-	
				-	-	

Country 1	Coal rank 2	Proved amount in place 3	Proved recoverable reserves 4	Estimated additional amount in place 5	Estimated additional reserves recoverable 6	Remarks 7
Poland	BT	63,800	28,700	100,500	30,000	
	LN	13,000	11,700	20,400	10,200	
Portugal	BT	7	3	-	-	
	LN	38	33	-	-	
Romania	BT	70	-	-	-	
	SB	2,800	-	-	-	
	LN	1,100	-	-	-	
South Africa	BT	121,218	55,333	5,000	-	
Spain	BT	532	379	2,188	379	
	SB	292	155	738	158	
	LN	408	236	199	189	
Swaziland	BT	2,020	1,820	3,000	-	
Taiwan	BT	220	100	-	-	
	SB	220	100	-	-	

Country 1	Coal rank 2	Proved amount in place 3	Proved recoverable reserves 4	Estimated additional amount in place 5	Estimated additional reserves recoverable 6	Remarks 7
Tanzania	BT	304	200	1,500	-	
Thailand	SB	15	14	-	-	
Turkey	BT	593	175	-	756	
	LN	7,847	5,929	-	382	
United Kingdom	BT	190,000	3,300	186,700	-	
	LN	1,000	500	-	-	
USA	BT	225,943	112,972	69,885	-	
	SB	163,516	81,758	276,934	-	
	LN	41,023	20,511	392,733	-	
USSR	BT	130,000	104,000	2,100,000	-	
	SB	47,000	37,000	1,900,000	-	
	LN	110,000	100,0090	1,200,000	-	
Venezuela	BT	642	417	2,117	918	
Vietnam	BT	300	150	700	-	
	LN	12	-	-	-	
Yugoslavia	BT	80	70	22	-	
	SB	1,760	1,500	275	-	
	LN	16,000	15,000	3,500	-	

Country 1	Coal rank 2	Proved amount in place 3	Proved recoverable reserves 4	Estimated additional amount in place 5	Estimated additional reserves recoverable 6	Remarks 7
Zaire	BT	600	600	-	-	
Zambia	BT	69	55	18	-	
Zimbabwe	BT	1,535	734	5,820	-	
Total	BT	1,696,478	1,074,399	3,830,045	332,118	
	SB	246,876	130,777	2,216,059	8,359	
	LN	492,551	391,633	2,157,601	199,920	

STEAM COAL FOR POWER AND INDUSTRY

COAL PRODUCTION AND CONSUMPTION

Hard Coal Production by Regions/Countries [1]
(million metric tons)

	1973	1980	1984	1985	1986	1987	1988	1989	1990[2]
TOTAL WORLD	2247.1	2813.3	3073.5	3237.7	3320.0	3404.9	3486.1	3557.2	3575.0
OECD [3]	915.6	1092.5	1093.1	1137.5	1159.1	1183.2	1189.5	1222.2	1269.6
Australia	55.5	72.4	104.6	117.5	133.4	147.7	134.8	147.8	161.8
Canada	12.3	20.2	32.1	34.3	30.5	32.7	38.6	38.8	37.8
Germany	104.5	94.5	84.9	88.8	87.1	82.4	79.3	77.5	76.5
United Kingdom	132.0	130.1	51.2	94.0	108.1	104.4	104.1	101.1	92.9
United States	530.1	710.2	755.6	738.8	738.4	762.3	784.9	810.0	858.7
Other OECD	81.2	65.1	64.7	64.1	61.6	53.7	47.8	47.0	41.9
NON-OECD [4]	1331.5	1720.8	1980.4	2100.2	2160.9	2221.7	2296.6	2335.0	2305.4
AFRICA + MIDDLE EAST	68.8	121.1	165.5	176.4	180.2	181.1	187.1	176.8	182.5
South Africa	62.4	115.1	159.5	169.8	172.4	172.8	178.2	168.8	174.5
Zimbabwe	2.8	2.8	2.6	3.0	4.0	4.8	5.1	5.1	5.1
Other Africa	3.6	3.2	3.4	3.6	3.8	3.5	3.8	2.9	2.9
CHINA	417.0	620.2	789.2	872.3	894.0	928.0	979.9	1054.0	1066.3
ASIA	129.6	179.2	218.9	229.0	243.5	258.2	269.0	279.8	302.9
India	78.2	114.0	147.4	154.2	166.0	179.7	188.3	198.7	225.1
North Korea	30.0	36.0	38.0	39.0	39.5	39.5	40.0	40.5	40.5
South Korea	13.6	18.6	21.4	22.5	24.3	24.3	24.3	20.8	17.3
Other Asia	7.8	10.6	12.1	13.3	13.7	14.7	16.4	19.8	20.0
USSR	510.6	553.0	556.0	569.0	588.0	595.0	599.0	577.0	542.3
NON-OECD EUROPE	195.9	233.2	229.7	229.8	229.2	230.7	230.1	213.3	176.0
Czechoslovakia	27.8	28.3	26.4	26.2	25.4	25.6	25.5	25.1	23.9
Poland	156.6	193.1	191.6	191.6	192.1	193.0	192.7	177.4	145.3
Romania	7.2	8.1	8.5	8.7	8.7	9.1	9.1	8.3	4.5
Other Non-OECD Europe [5]	4.3	3.7	3.2	3.3	3.0	3.0	2.8	2.5	2.3
LATIN AMERICA	9.6	14.1	21.1	23.7	26.0	28.7	31.5	34.1	35.4
Brazil	2.3	5.2	7.5	7.7	7.4	6.9	7.3	6.5	6.2
Colombia	2.8	4.1	6.6	9.0	10.7	13.5	15.3	18.9	20.5
Mexico	2.5	3.1	5.1	5.2	5.6	6.2	5.6	6.0	6.0
Other C + S America	2.0	1.7	1.9	1.8	2.3	2.1	3.3	2.7	2.7

(1) Hard coal includes anthracite and bituminous coal, and for the United States, Australia, and New Zealand, sub-bituminous coal. For further information, see Principles and Definitions in Part II.
(2) Where data for individual countries are not available, estimates have been included in totals.
(3) Source: IEA/OECD Coal Statistics.
(4) Source: IEA/OECD *World Energy Statistics and Balances* and Secretariat estimates.
(5) Includes Bulgaria, Hungary and Yugoslavia.

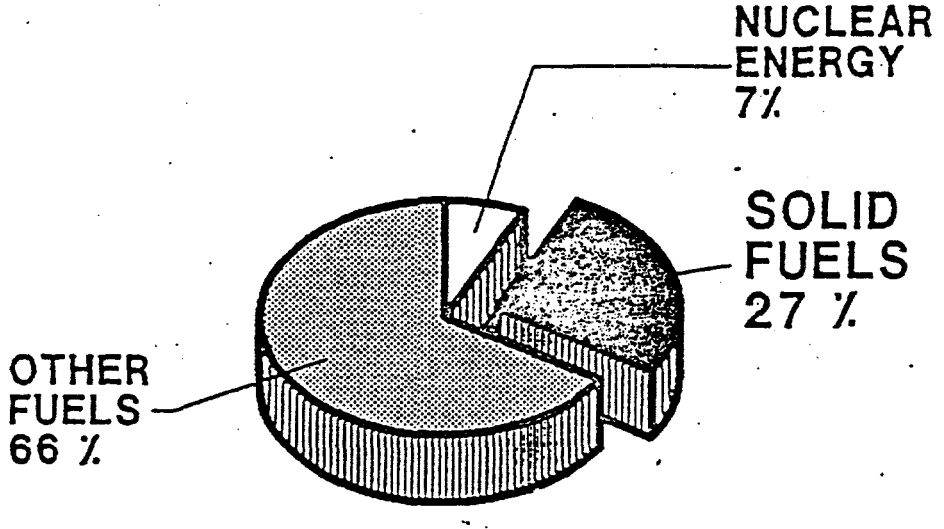
Brown Coal/Lignite Production by Regions/Countries [1]
(million metric tons)

	1973	1980	1984	1985	1986	1987	1988	1989	1990e [2]
TOTAL WORLD	832.7	980.1	1122.3	1172.3	1197.4	1221.2	1235.7	1246.3	1165.0
OECD [3]	442.0	543.0	629.0	665.9	670.6	674.7	681.7	700.9	643.6
Australia	24.1	32.9	33.2	38.4	36.1	41.8	43.4	48.3	47.7
Canada	8.1	16.5	25.3	26.5	26.5	28.6	32.1	31.7	30.7
Germany, western	118.7	129.9	126.7	120.7	114.4	108.9	108.6	109.9	107.6
Germany, eastern	246.2	260.9	296.3	315.5	314.7	309.8	313.5	304.2	251.4
Greece	13.3	23.2	32.5	35.9	38.1	44.6	48.3	51.9	54.0
Spain	3.0	15.5	24.3	23.6	22.4	20.5	17.6	21.9	21.1
United States	12.9	42.8	57.2	62.8	69.3	71.1	77.2	78.6	81.0
Other OECD	15.7	21.3	33.5	42.5	49.1	49.4	41.0	54.4	50.1
NON-OECD [4]	390.7	437.1	493.3	506.4	526.8	546.5	554.0	545.4	521.4
AFRICA	-	-	-	-	-	-	-	-	-
CHINA	-	-	-	-	-	-	-	-	-
ASIA	12.9	20.3	25.6	31.1	30.6	34.9	35.6	39.1	46.6
India	3.3	4.8	7.1	7.8	7.1	8.4	8.7	9.9	12.9
North Korea	7.0	10.0	11.0	12.0	12.5	12.5	12.5	13.0	13.0
Other Asia	2.6	5.5	7.5	11.3	11.0	14.0	14.4	16.2	20.7
USSR	157.0	163.0	156.0	157.0	163.0	165.0	172.0	164.0	159.1
NON-OECD EUROPE	220.7	253.8	311.7	318.3	333.2	346.6	346.4	342.3	315.7
Bulgaria	26.5	29.9	33.4	30.7	35.0	36.6	34.0	34.1	32.6
Czechoslovakia	81.2	94.9	102.9	100.4	100.8	101.0	98.0	92.3	82.8
Hungary	23.4	22.6	22.5	21.4	20.8	20.5	18.6	17.9	16.6
Poland	39.2	36.9	50.4	57.7	67.3	73.2	73.5	71.8	66.3
Romania	17.7	27.1	35.8	37.9	38.8	42.4	49.6	53.0	35.2
Other Non-OECD Europe [5]	32.7	42.4	66.7	70.2	70.5	72.9	72.7	73.2	82.2
LATIN AMERICA	0.1	-	-	-	-	-	-	-	-

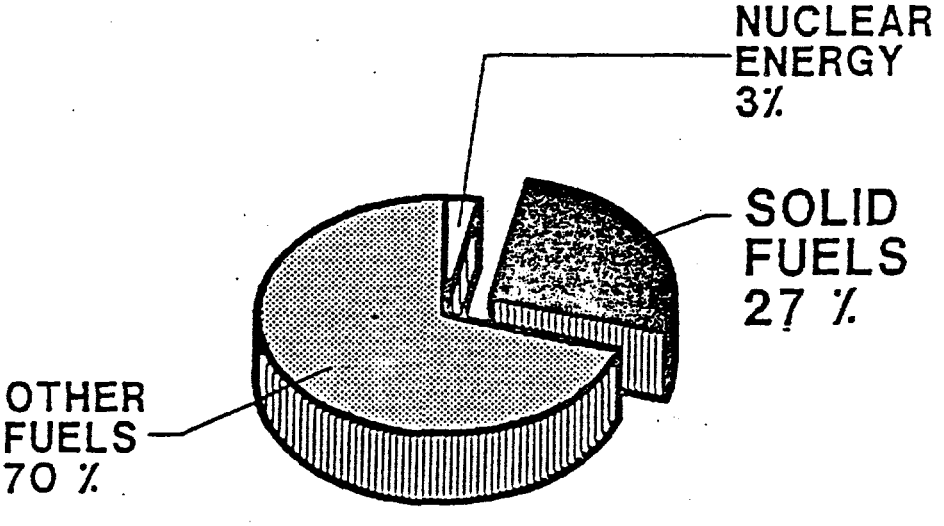
(1) Brown coal represents lower grade coal and includes lignite. For further information, see Principles and Definitions in Part II.
(2) Where data for individual countries are not available, estimates have been included in totals.
(3) Source: IEA/OECD Coal Statistics.
(4) Source: IEA/OECD *World Energy Statistics and Balances* and Secretariat estimates.
(5) Includes Albania and Yugoslavia.

PRIMARY ENERGY CONSUMPTION
SHARE OF COAL

ECE REGION

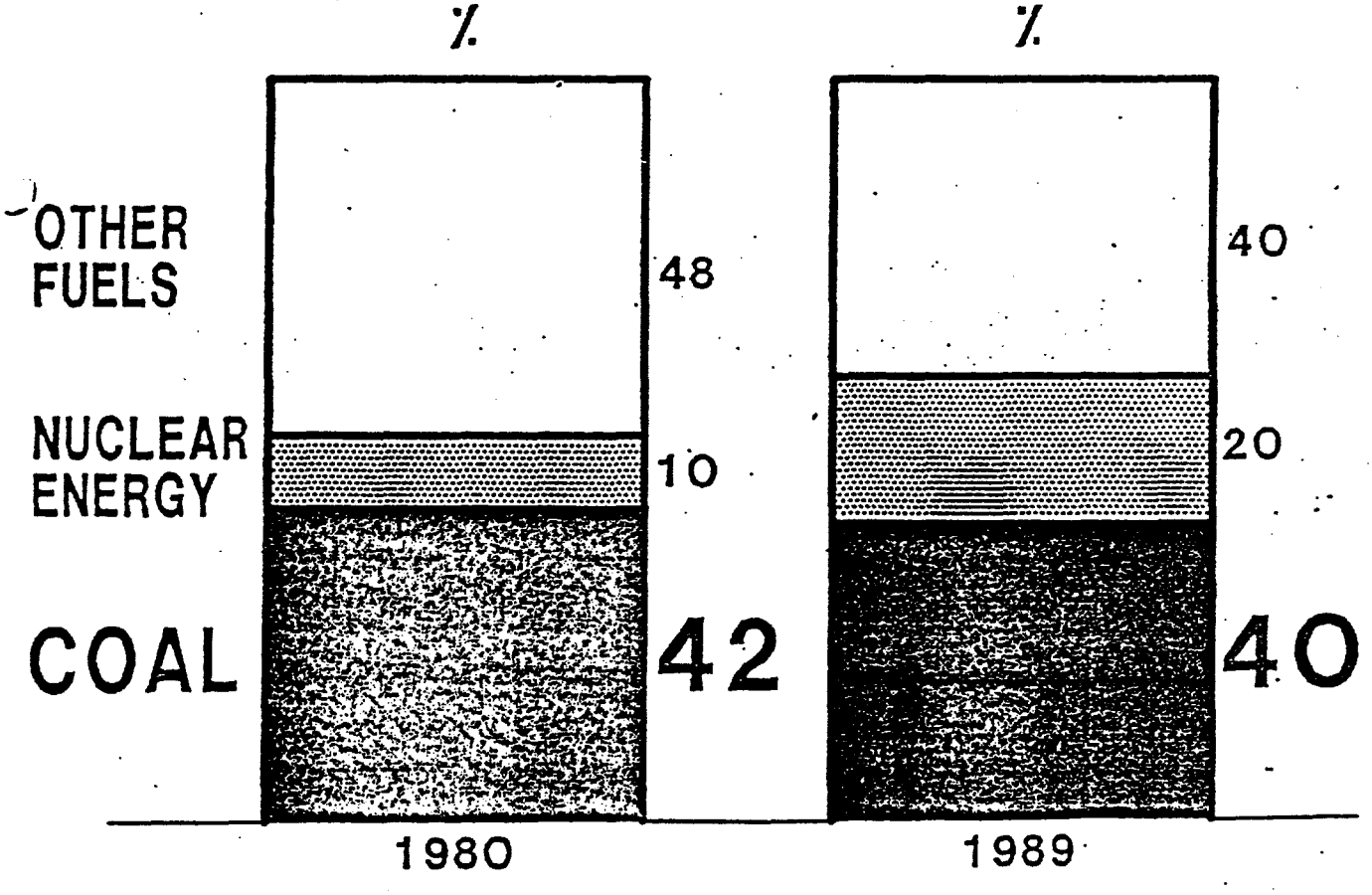


1988



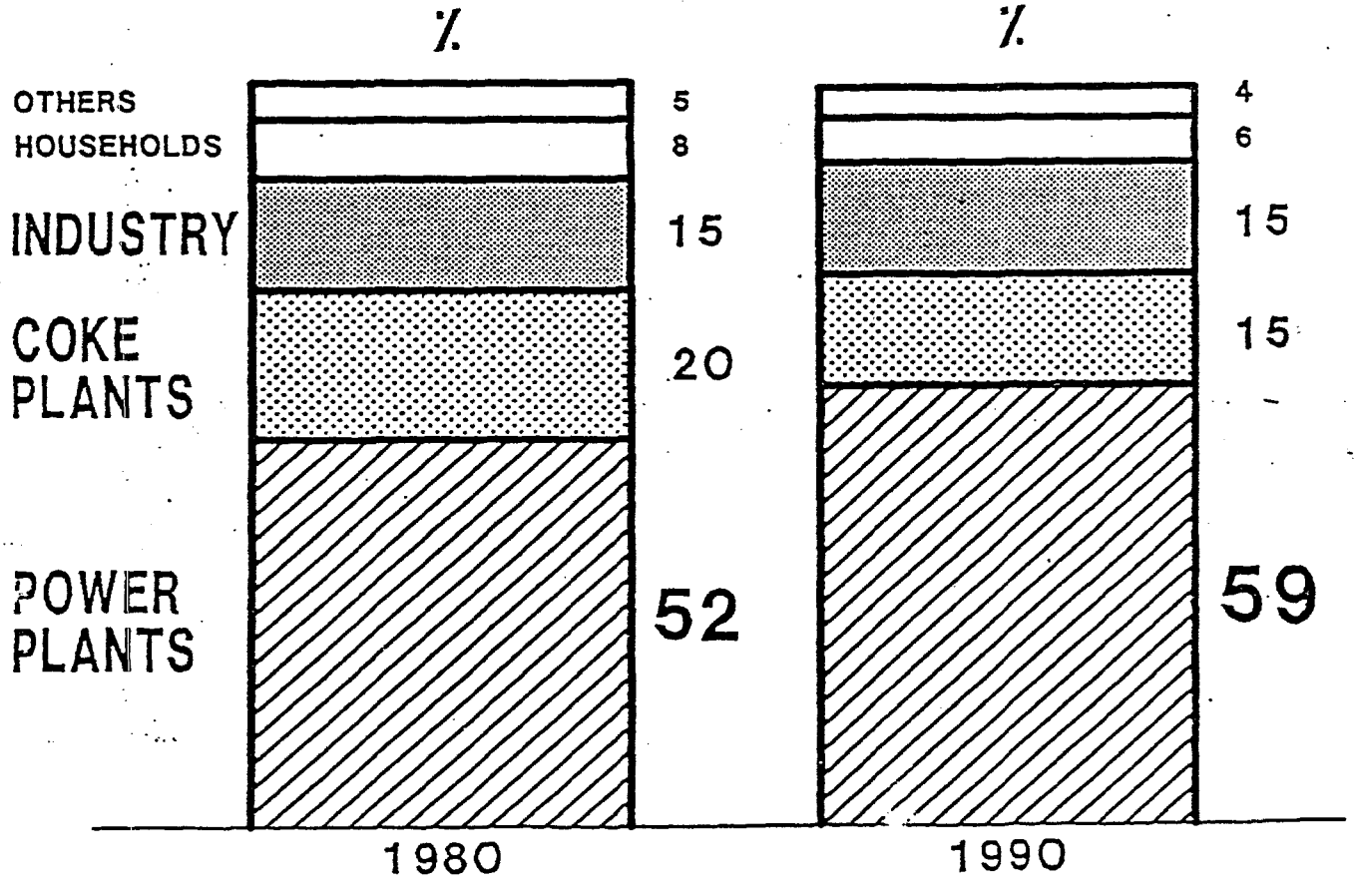
ELECTRICITY PRODUCTION
SHARE OF COAL

ECE REGION



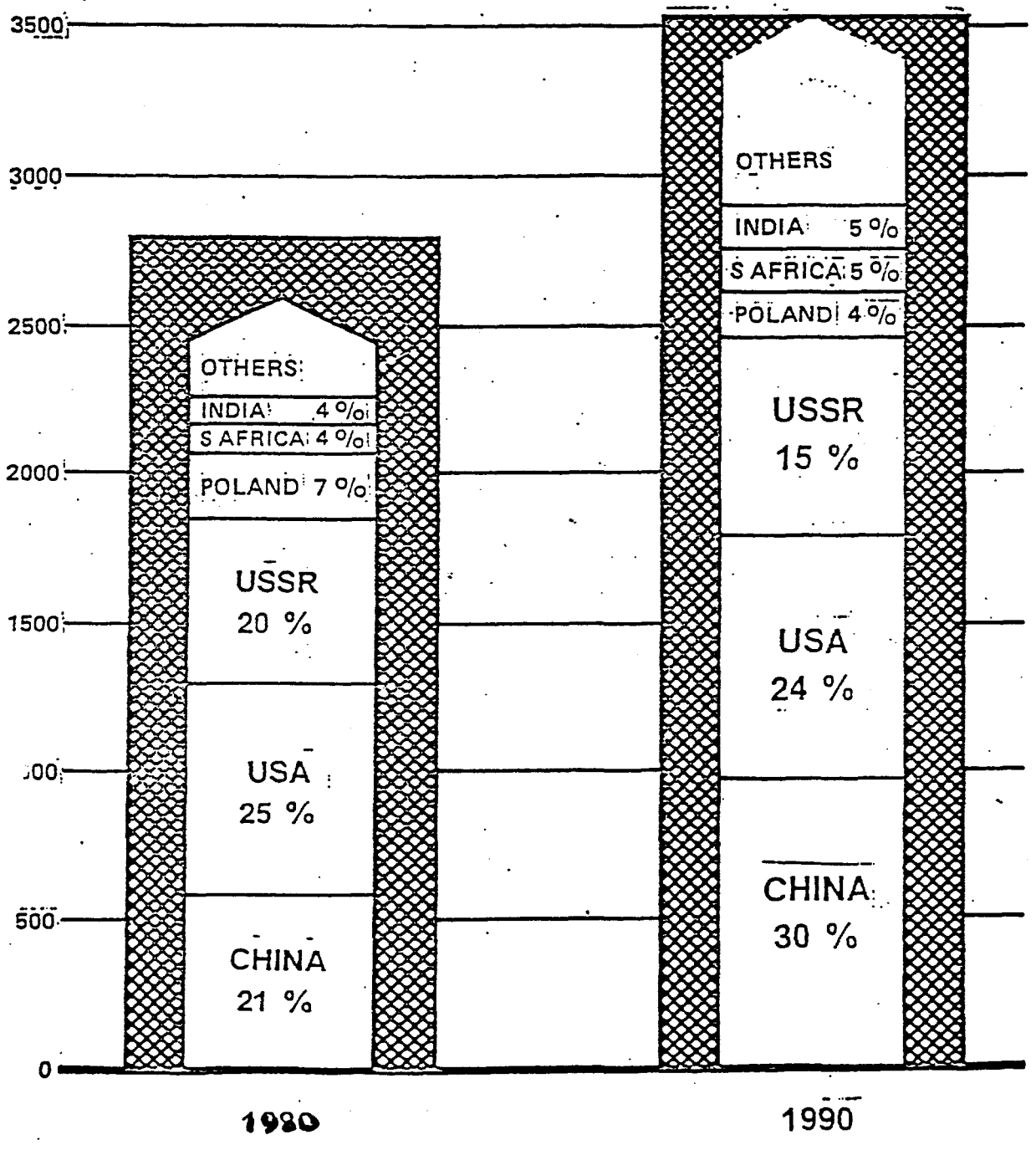
HARD COAL CONSUMPTION
SHARES OF END-USERS

ECE REGION

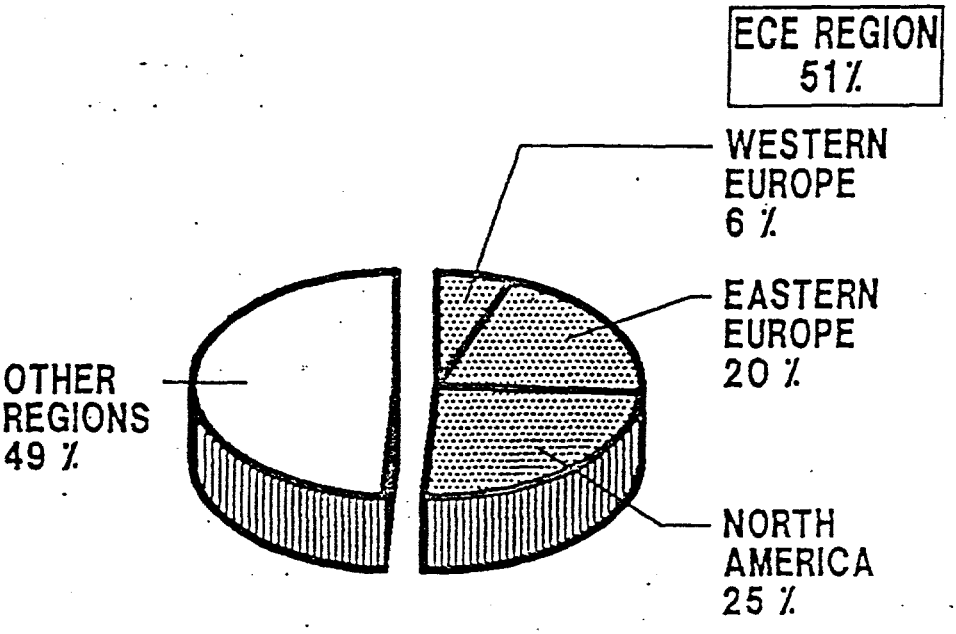


HARD COAL PRODUCTION
MAJOR PRODUCERS

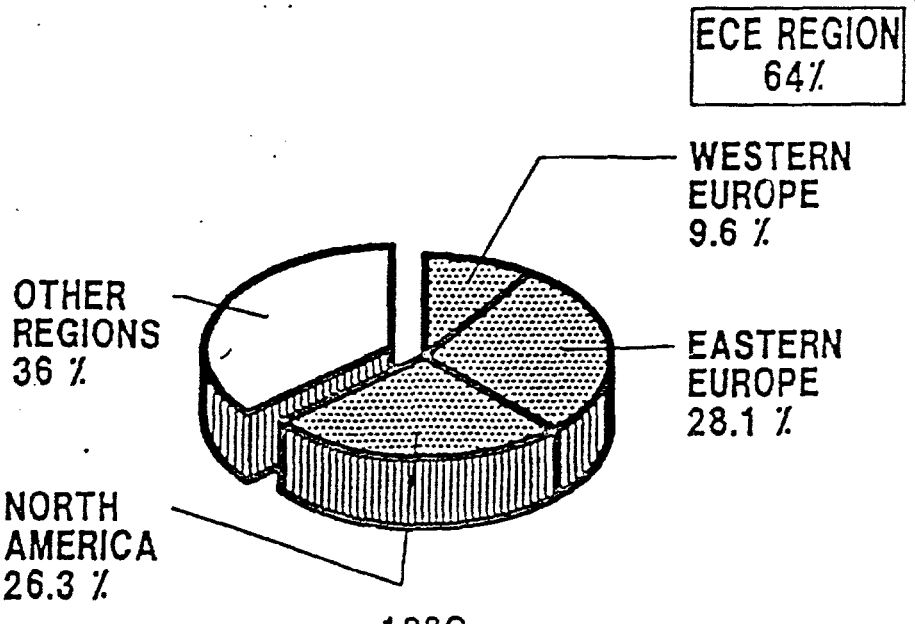
(MILLION METRIC TONS)



ECE AND WORLD HARD COAL PRODUCTION



1990



1980

Table 4.1 **World Total Hard Coal Trade**
(Mmt)

	North America		OECD Europe		Japan		Latin America		Asia (1)		Africa + Mid.East		Former C.P.E's		Balancing Item		World	
Exporters	1989	1990	1989	1990	1989	1990	1989	1990	1989	1990	1989	1990	1989	1990	1989	1990	1989	1990
Canada	0.9	0.9	2.9	3.6	19.0	18.8	1.7	1.5	6.0	6.7	-	0.3	-	-	2.3	-0.8	32.8	31.0
USA	14.5	14.2	44.8	48.3	11.8	10.9	5.1	6.6	10.8	8.0	1.0	2.3	3.0	2.6	0.5	3.1	91.5	96.0
Australia	-	0.0	15.1	19.6	52.1	54.1	1.5	1.8	25.3	26.8	0.8	1.4	1.9	1.6	2.0	0.8	98.7	106.1
Other OECD	-	-	9.9	11.4	0.3	0.2	-	-	0.1	0.2	0.3	0.3	0.1	0.3	0.8	-0.4	11.5	12.0
OECD	15.4	15.1	72.7	83.1	83.4	84.0	8.2	9.9	42.3	41.6	2.0	4.5	5.1	4.6	5.3	2.2	234.4	245.0
Poland	-	-	11.8	13.4	-	-	2.1	2.2	0.4	0.4	0.3	-	13.7	12.0	-	-	28.3	28.0
USSR	-	-	7.0	8.3	8.0	8.4	-	-	-	-	0.2	-	24.6	21.8	-	-	39.8	38.5
China	-	-	3.1	2.8	4.0	4.5	-	-	3.1	4.0	-	-	4.5	5.7	-	-	14.7	17.0
Colombia	1.2	1.3	8.1	8.3	0.2	-	1.4	1.5	1.1	1.2	1.0	1.2	-	-	-	-	13.0	13.5
South Africa	-	-	21.7	26.3	4.9	4.8	0.8	0.9	17.0	15.2	2.3	2.2	-	-	-	-	46.7	49.4
Oth. non-OECD	0.4	0.2	3.9	3.7	1.0	1.6	-	-	0.3	0.9	-	-	0.9	1.6	-	-	6.5	8.0
TOTAL	17.1	16.7	128.4	145.7	101.5	103.3	12.5	14.5	64.2	63.3	5.8	7.9	48.8	45.7	5.1	2.3	383.4	399.4

Table 4.2 **World Steam Coal Trade**
(Mmt)

	North America		OECD Europe		Japan		Latin America		Asia (1)		Africa + Mid.East		Former C.P.E.'s		Balancing Item		World	
Exporters	1989	1990	1989	1990	1989	1990	1989	1990	1989	1990	1989	1990	1989	1990	1989	1990	1989	1990
Canada	0.9	0.9	0.8	0.9	1.3	1.3	0.1	0.2	1.5	1.2	-	-	-	-	-0.5	-0.4	4.1	4.1
USA	8.6	9.7	18.2	21.0	1.7	1.3	-	0.7	5.7	4.7	0.3	1.2	0.1	-	-2.2	-0.2	32.4	38.4
Australia	-	-	6.7	9.8	22.1	24.5	0.2	0.2	11.6	12.7	0.4	0.5	-	-	2.1	1.5	43.1	49.2
Other OECD	-	-	5.8	8.1	-	-	-	-	-	0.1	0.3	0.3	-	0.2	0.4	-1.1	6.5	7.6
OECD	9.5	10.6	31.5	39.9	25.2	27.1	0.2	1.1	18.9	18.6	1.0	2.1	0.1	0.3	-0.3	-0.4	86.1	99.3
Poland	-	-	9.0	9.6	-	-	-	-	-	-	-	-	12.3	11.0	-	-	21.3	20.6
USSR	-	-	5.5	6.5	2.5	2.9	-	-	-	-	-	-	13.2	9.7	-	-	21.2	19.1
China	-	-	3.1	2.8	2.8	3.2	-	-	3.1	4.0	-	-	2.2	3.0	-	-	11.2	13.0
Colombia	1.2	1.3	8.0	8.3	-	-	1.4	1.5	1.1	1.2	1.0	1.2	-	-	-	-	12.7	13.5
South Africa	-	-	21.7	26.1	1.4	1.4	0.8	0.9	16.4	14.3	2.3	2.2	-	-	-	-	42.6	44.9
Oth. non-OECD	0.4	0.2	3.0	2.9	0.9	1.3	-	-	0.3	0.9	-	-	0.2	0.7	-	-	4.8	6.0
TOTAL	11.2	12.2	81.8	96.0	32.8	36.0	2.4	3.5	39.8	39.0	4.3	5.5	28.0	24.7	-0.4	-0.5	199.9	216.4

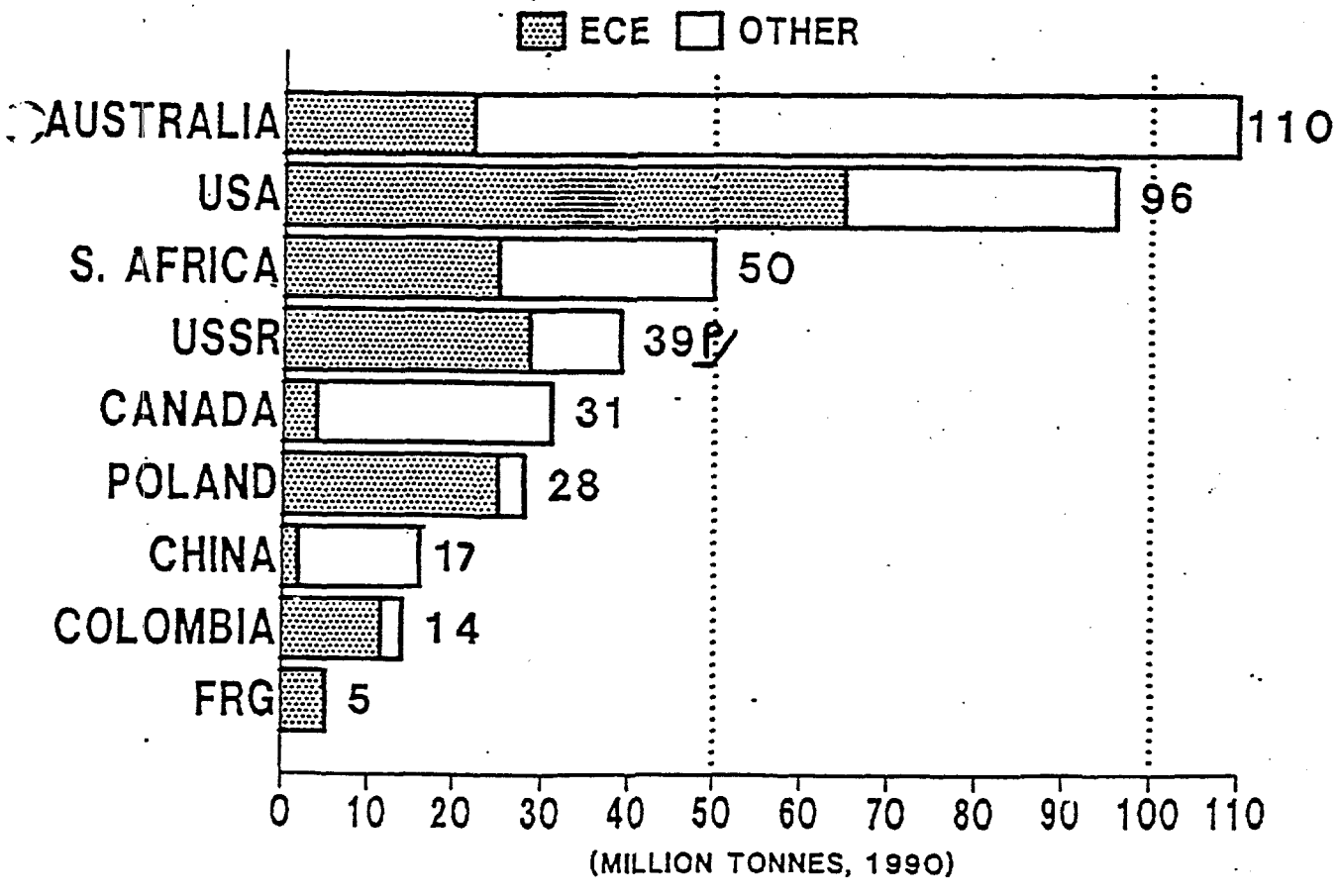
Sources: IEA/OECD Coal Statistics and other Secretariat sources, including international sources.

(1) Excludes Asian CPE's and Japan.

Note: Data in the columns North America to Japan are import statistics. The rows Canada to OECD (except for above mentioned columns) are export statistics. All other data are based on national and international sources and estimates. The sum of coking coal and steam coal may not add up to total hard coal due to rounding, which may also cause discrepancies among tables 4.1 to 4.3 and other trade data in this publication.

MAIN COAL EXPORTING COUNTRIES

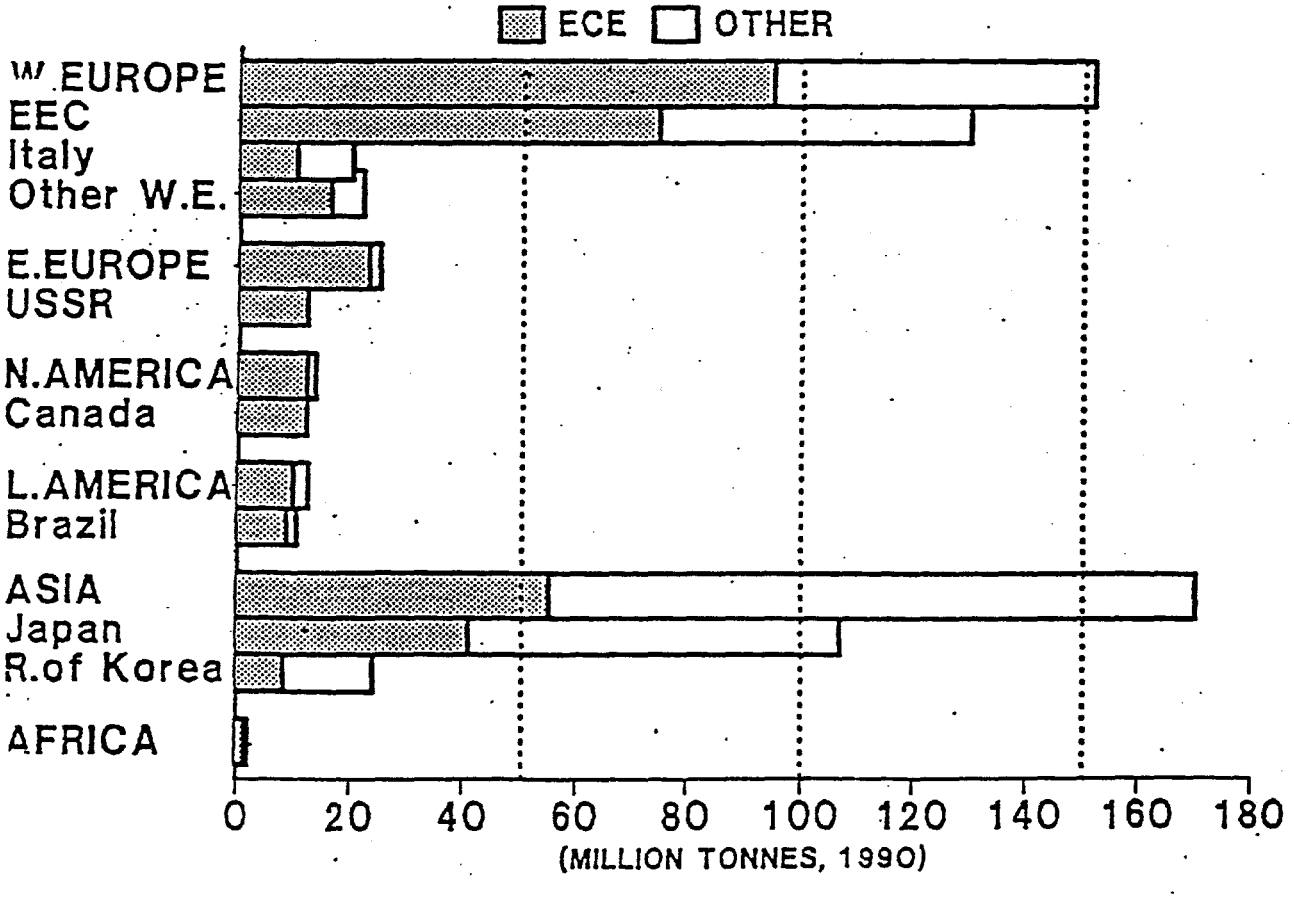
DESTINATION OF EXPORT



P : PROVISIONAL

MAIN
COAL IMPORTING REGIONS

ORIGIN OF IMPORTS:



STEAM COAL FOR POWER AND INDUSTRY

COAL PROSPECTS UP TO THE YEAR 2000

6 March 1990

	Consumption (Mt)			Production (Mt)			Imports (Mt)			Exports (Mt)		
	1980	1990	2000	1980	1990	2000	1980	1990	2000	1980	1990	2000
WESTERN EUROPE	350.6	337.6	361.7	268.9	209.2	193.5	114.8	137.8	178.9	19.0	9.6	6.0
EUROPEAN ECONOMIC COMMUNITY	330.1	310.4	322.2	264.5	204.7	186.2	99.2	114.5	143.6	18.9	9.4	5.8
Belgium	16.0	12.1	10.4	6.3	1.9	0.0	10.1	10.7	10.9	0.4	0.5	0.5
Denmark	10.0	12.2	13.9	0.0	0.0	0.0	10.0	12.2	13.9	0.0	0.0	0.0
France	48.2	24.1	18.0	20.2	11.0	8.0	29.5	13.9	10.5	0.4	0.8	0.5
Germany, Fed. Rep. of	89.5	81.6	84.0	94.5	75.0	70.0	9.6	8.0	15.0	12.4	4.5	1.0
Greece	0.5	1.4	2.0	0.0	0.0	0.0	0.5	1.7	2.3	0.0	0.3	0.3
Ireland	1.2	3.0	3.0	0.1	0.0	0.0	1.3	3.0	3.0	0.0	0.0	0.0
Italy	17.0	20.4	23.6	0.0	0.0	0.0	17.2	20.4	23.6	0.0	0.0	0.0
Luxembourg	0.3	0.2	0.2	0.0	0.0	0.0	0.4	0.2	0.2	0.0	0.0	0.0
Netherlands	6.2	12.4	14.0	0.0	0.0	0.0	7.2	14.6	16.0	1.5	1.8	2.0
Portugal	0.6	3.4	4.9	0.2	0.2	0.2	0.4	3.2	4.9	0.0	0.0	0.0
Spain	16.8	27.1	39.3	13.1	19.5	20.0	5.7	9.6	19.3	0.0	0.0	0.0
United Kingdom	123.6	112.7	109.0	130.1	97.0	88.0	7.3	17.0	24.0	4.0	1.5	1.5
OTHER WESTERN EUROPE	20.5	27.2	39.5	4.4	4.5	7.2	15.6	23.3	35.3	0.1	0.2	0.2
Austria	2.9	3.6	3.3	0.0	0.0	0.0	2.9	3.6	3.3	0.0	0.0	0.0
Finland	5.7	5.6	6.8	0.0	0.0	0.0	4.7	5.6	6.8	0.0	0.0	0.0
Norway	0.9	0.9	0.8	0.3	0.3	0.3	0.8	0.6	0.5	0.1	0.2	0.2
Sweden	2.1	4.0	3.6	0.0	0.0	0.0	2.2	4.0	3.6	0.0	0.0	0.0
Switzerland	0.3	0.5	0.0	0.0	0.0	0.0	0.6	0.5	0.0	0.0	0.0	0.0
Turkey	4.5	8.3	15.5	3.6	3.8	6.5	0.8	5.0	12.0	0.0	0.0	0.0
Yugoslavia	4.1	4.4	9.5	0.5	0.4	0.4	3.7	4.0	9.1	0.0	0.0	0.0
EASTERN EUROPE (incl. USSR)	751.1	792.9	800.5	785.7	828.9	830.4	31.2	35.2	34.8	61.9	70.2	57.5
USSR	532.5	574.0	600.0	553.0	606.0	630.0	6.2	8.0	8.0	26.6	40.0	35.0
EASTERN EUROPE (excl. USSR)	218.6	218.9	200.5	232.8	222.9	200.4	25.0	27.2	26.8	35.3	30.2	22.5
Bulgaria	6.9	6.6	6.6	0.3	0.2	0.2	6.7	6.4	6.4	0.0	0.0	0.0
Czechoslovakia	29.5	27.7	23.3	28.3	24.9	20.7	5.1	4.5	4.5	3.7	1.8	0.2
German Democratic Republic	6.9	4.1	4.1	0.0	0.0	0.0	6.8	4.5	4.5	0.3	0.3	0.2
Hungary	4.5	4.6	4.3	3.1	2.0	1.5	1.6	2.6	1.9	0.3	0.1	0.1
Poland	159.1	158.7	146.0	193.1	187.0	170.0	1.0	1.2	1.5	31.1	28.0	22.0
Romania	11.8	17.3	16.3	8.1	8.8	8.0	3.7	8.0	8.0	0.0	0.0	0.0
EUROPE	1 101.7	1 130.5	1 162.2	1 054.6	1 038.1	1 023.9	146.0	173.0	213.7	80.9	79.7	63.4

Coal Prospects up to the Year 2000

	Consumption (Mt)			Production (Mt)			Imports (Mt)			Exports (Mt)		
	1980	1990	2000	1980	1990	2000	1980	1990	2000	1980	1990	2000
NORTH AMERICA	629.4	771.9	879.0	730.4	881.5	1 022.8	16.7	16.5	19.3	98.4	126.0	163.0
Canada	21.4	22.4	29.0	20.2	39.5	58.8	15.6	14.0	12.0	15.3	31.0	42.0
United States	608.0	749.5	850.0	710.2	842.0	964.0	1.1	2.5	7.3	83.2	95.0	121.0
ECE REGION	1 731.1	1 902.4	2 041.1	1 784.9	1 919.6	2 046.7	162.7	189.5	233.0	179.3	205.7	226.4
LATIN AMERICA	22.6	32.8	44.6	17.8	39.8	63.2	7.1	12.9	27.5	0.1	16.1	42.1
Argentina	1.4	1.6	1.7	0.4	0.4	0.5	0.9	1.2	1.3	0.0	0.1	0.1
Brazil	9.2	13.6	15.5	5.2	5.0	2.0	4.6	11.0	15.0	0.0	0.0	0.0
Chile	1.7	1.7	1.3	1.0	2.1	2.1	0.8	0.6	1.2	0.0	0.0	0.0
Colombia	4.2	3.8	3.9	4.1	18.0	34.0	0.0	0.0	0.0	0.1	14.0	30.0
Mexico	5.5	11.9	22.0	7.0	12.0	12.0	0.6	0.1	10.0	0.0	0.0	0.0
Peru	0.2	0.1	0.1	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Venezuela	0.4	0.2	0.2	0.0	2.2	12.5	0.2	0.0	0.0	0.0	2.0	12.0
ASIA	870.7	1 469.6	1 822.8	796.5	1 313.0	1 629.6	84.0	184.1	237.8	4.7	16.0	41.4
Afghanistan	0.1	0.1	0.1	0.1	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0
Bangladesh	0.2	0.6	0.6	0.0	0.0	0.0	0.2	0.6	0.6	0.0	0.0	0.0
Burma	0.2	0.2	0.2	0.0	0.1	0.1	0.2	0.1	0.1	0.0	0.0	0.0
China	589.5	980.0	1 180.0	595.8	995.0	1 200.0	2.0	2.5	2.5	3.8	14.5	22.0
Hong Kong	0.0	12.0	14.0	0.0	0.0	0.0	0.0	12.0	14.0	0.0	0.0	0.0
India	108.0	218.0	300.0	109.2	215.0	290.0	0.6	7.0	10.0	0.5	0.0	0.0
Indonesia	0.2	6.2	28.0	0.3	6.0	45.0	0.0	0.0	0.0	0.0	0.6	17.0
Iran	1.0	1.2	1.3	0.9	1.3	1.5	0.1	0.0	0.0	0.0	0.0	0.0
Israel	0.0	4.7	6.8	0.0	0.0	0.0	0.0	4.7	6.8	0.0	0.0	0.0
Japan	87.7	114.5	133.0	18.0	9.5	5.0	69.1	105.0	128.0	0.0	0.0	0.0
Korea, Dem. Rep. of	43.0	52.0	52.0	43.2	50.0	50.0	0.5	4.0	4.0	0.1	0.5	0.5
Korea, Rep. of	25.9	52.4	74.0	18.6	23.5	25.0	7.3	28.9	49.0	0.0	0.0	0.0
Malaysia	0.0	1.4	1.9	0.2	0.2	0.6	0.0	1.2	1.3	0.0	0.0	0.0
Mongolia	0.4	0.7	0.7	0.4	0.7	0.7	0.0	0.0	0.0	0.0	0.0	0.0
Pakistan	1.9	2.9	2.8	1.6	2.7	2.7	0.1	0.5	0.5	0.0	0.0	0.0
Philippines	0.3	0.6	0.0	0.3	1.3	1.3	0.0	0.5	0.5	0.0	0.3	1.8
Singapore	0.0	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0
Thailand	1.5	1.1	3.0	0.0	0.0	0.0	0.0	1.1	3.0	0.0	0.0	0.0
Viet Nam	4.7	5.1	5.0	5.3	5.6	5.6	0.0	0.0	0.0	0.3	0.1	0.1
Other Asia	6.0	16.0	19.0	2.6	2.0	2.0	4.1	16.0	17.0	0.0	0.0	0.0

Source: UN estimates.

Coal Prospects up to the Year 2000

	Consumption (Mt)			Production (Mt)			Imports (Mt)			Exports (Mt)		
	1980	1990	2000	1980	1990	2000	1980	1990	2000	1980	1990	2000
AFRICA	90.8	152.8	158.4	122.1	197.8	212.9	1.8	3.8	6.3	29.1	47.6	56.0
Algeria	0.5	1.5	1.5	0.0	0.0	0.0	0.5	1.5	1.5	0.0	0.0	0.0
Botswana	0.4	0.4	0.5	0.4	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0
Burundi	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Egypt	0.9	1.2	2.7	0.0	0.0	0.0	0.9	1.2	2.7	0.0	0.0	0.0
Morocco	0.6	1.6	2.5	0.7	0.8	0.8	0.0	0.8	1.8	0.0	0.0	0.0
Mozambique	0.3	0.3	0.3	0.2	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1
Nigeria	0.1	0.1	0.1	0.2	1.5	1.5	0.2	0.0	0.0	0.0	0.2	0.6
South Africa	84.5	145.5	148.5	116.6	190.0	205.0	0.0	0.0	0.0	28.7	47.0	55.0
Swaziland	0.0	0.0	0.0	0.2	0.2	0.2	0.0	0.0	0.0	0.2	0.2	0.2
Tanzania	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Zaire	0.3	0.3	0.3	0.1	0.1	0.1	0.0	0.2	0.2	0.0	0.0	0.0
Zambia	0.6	0.1	0.1	0.6	0.5	0.5	0.0	0.0	0.0	0.0	0.0	0.0
Zimbabwe	2.5	1.8	1.9	3.1	4.1	4.2	0.1	0.0	0.0	0.1	0.1	0.1
OCEANIA	36.2	42.2	65.3	74.4	150.5	207.5	0.0	0.0	0.0	42.5	104.5	140.8
Australia	34.4	41.8	64.8	72.5	148.0	205.0	0.0	0.0	0.0	42.4	104.0	140.0
New Zealand	1.8	0.4	0.5	1.9	2.5	2.5	0.0	0.0	0.0	0.1	0.5	0.8
WORLD	2 751.5	3 599.9	4 132.2	2 795.8	3 620.7	4 159.9	255.6	390.3	504.6	255.7	389.8	506.6

Source: UN Estimates.

STEAM COAL FOR POWER AND INDUSTRY

Accident Statistics of Selected Countries

Country	Year	Production (mt)	Fatal accident	Frequency (per mt)	Nonfatal accidents/a	Frequency
Australia /b						
(NSW)	1985	117.5	9	0.28	9,070	265
	1986	126.9	7	0.20	8,751	244
FRG	1984	84.9	68	0.27	18,864	72.2
	1985	88.8	57	0.22	18,909	73.0
India /c	1984	149.3	176	0.10	1,201	0.71
	1985	159.1	204	0.12	1,029	0.63
Turkey	1984	36	279	10.6	14,996	567
	1985	35	271	8.1	15,832	533
UK /c	1984/85	94.0	22	0.09	378	1.43
	1985/86	108.0	28	0.06	731	1.94
USA /c	1984	752	118	0.35	10,022	29.1
	1985	741	63	0.20	8,755	26.9
China /d	1984	789	-	-	-	-
	1987	928	[5,500]	[5.9]	-	-

/a Lost time accidents, at least one day off.
/b Rate per million work-hours.
/c Rate per 100,000 work-shifts.
/d Accident statistics not published.

STEAM COAL FOR POWER AND INDUSTRY

PRODUCTION COST
(Current US dollar per metric ton)

Europe

Country	U.K.		France		Germany		Poland		Czech * Slovak.	USSR*	
Year	1976	1984	1976	1986	1976	1986	1976	1986	1986	1976	1986
Cost Items											
Manpower	17.8	28.8	35.6	-	32.3	53.9	9.9	10.1	67.7	48.7	48.6
Material	8.8	20.3	15.1	-	23.4	47.8	9.5	9.5	12.8	18.7	21.4
Overhead	5.2	12.4	3.6	-	3.0	7.0	5.6	8.6	8.5	11.9	9.0
Depreciation	1.3	4.0	2.0	-	2.2	4.6	1.2	0.9	11.0	20.7	21.0
Total	33.1	65.5	56.3	125.8	60.9	114.2	26.2	29.0	100.0	100.0	100.0
Index	241	918	293	853	305	572	204	326	-	-	-

Others

Country	India		China		South** Africa	Austral. Q'lnd**	Colom-bia**	USA - East Appalach.**
Year	1980	1989	1978	1986	1990	1990	1990	1990
Cost Items								
Manpower	8.6	7.6	2.8	3.0	-	-	-	-
Material	3.3	5.1	4.4	3.1	-	-	-	-
Overhead	1.2	2.0	1.2	1.9	-	-	-	-
Depreciation	0.9	1.6	1.2	2.1	-	-	-	-
Total	14.0	16.3	9.6	10.1	10.8	21.2	34.0	29.9
Index	100	212	100	564	-	-	-	-

Notes: * Actual cost not available, percentage only.
** Open pit production cost only.

Sources: Report of Committee on Energy, ECE, August, 1991.
China Coal Pricing Study, World Bank, February, 1989.
Operational Statistics, Coal India, 1991.

PRODUCTION AND EXPORT COST OF COAL
(1990 US Dollar/Metric ton)

		Cal value Kcal/kg	Average: Mine operating cost	Capital recovery charges	Inland trans & loading	Total FOB	CIF cost (Japan)	CIF cost (Europe)
1. Australia	- Queensland							
	Open pit	6,800	12.2	9.9	13.5	35.6	42.8	47.2
	- New South Wales							
	- Underground	6,760	27.5	9.5	9.7	46.7	55.2	59.2
	- Open pit	6,740	21.4	11.9	10.9	44.2	52.7	56.7
2. Canada	- Western							
	Open pit	6,810	21.4	1.5	20.4	43.3	52.0	55.4
3. Colombia	- Cerrajon area							
	Open pit	6,910	25.0	19.0	7.0	51.0	-	57.7
4. South Africa	- Transvaal							
	Open pit	6,410	9.3	1.5	12.3	23.1	32.8	31.8
5. United States	- Northern Central Appalachia							
	Open pit	6,930	28.1	1.8	13.9	43.8	56.6	52.3
	Underground	7,390	22.0	1.5	22.5	46.0	60.8	52.7
	- Southern Appalachia							
	Open pit	7,170	33.4	1.1	4.7	39.2	52.0	47.7
	- Utah underground	6,740	23.1	3.5	22.3	48.9	57.7	-

Source: IEA Report, 1991.

STEAM COAL FOR POWER AND INDUSTRY

TREND OF RECONSTRUCTION AND MODERNIZATION IN EUROPEAN MINES

	No of mines		Average Daily Production (Metric Ton) (Saleable)		Production Per Face (Saleable)	
	1965	1989	1965*	1989	1965	1989
Belgium	58	2	1,966	4,200	352	934
Czechoslovakia	24	14	4,050	5,950	242	452
France	70	9	2,720	5,524	325	2,567
Germany	101	30	4,959	9,972	600	1,739
Poland	81	70	4,798	8,844	4878	1,014
UK	481	86	1,520	4,223	430	1,477
USSR	449*	443	2,693*	2,410	497*	544

* 1975.

Source: ECE Paper - Working Party on Coal, August 1991.

STEAM COAL FOR POWER AND INDUSTRY

PRODUCTIVITY OF COAL MINES

Country/Year	1985	1986	1987	1988	1989
				(Metric ton (per manshift)	
Australia					
Underground	1.64	1.70	1.87	1.92	2.05
Open pit	4.15	4.31	4.57	4.80	4.83
France					
Underground	4.14	4.20	3.90	n.a.	n.a.
Germany					
Underground	4.52	4.58	4.69	4.80	n.a.
India					
Underground	0.54	0.53	0.54	0.57	0.55
Open pit	2.24	2.44	2.65	2.91	3.08
Poland					
Underground	4.00	3.90	3.80	3.80	n.a.
Spain					
Underground	2.50	3.10	2.80	n.a.	n.a.
UK					
Underground	3.10	3.90	4.40	n.a.	n.a.
USA					
Underground	12.92	16.43	18.18	19.67	n.a.
Open pit	19.88	26.27	27.95	30.30	n.a.
Czechoslovakia					
Underground					1.0-4.0
Open pit					4.0-5.0
China (est.)					
Average					1.5-2.0

STEAM COAL FOR POWER AND INDUSTRY

Australian Port Capacity [1]

Port Name	Capacity
Abbot Point	6.5 mmtpy
Dalrymple Bay	18.0
Hay Point	25.0
Gladstone	29.0
Brisbane	3.0
Subtotal Queensland	81.5
Newcastle	46.0
Port Kembla	14.0
Balmain	4.5
Subtotal New South Wales	64.5
TOTAL AUSTRALIA	146.0

[1] Hill & Associates, Inc. estimates.

Indicative Inland Transportation Charges in Major Coal Exporting Countries (1990)

Country, Region, Carrier, Route	Distance (km)	Freight Charge (/mt) Local Currency	US$	Unit Charge (US cents/ mt/km)	Port Charges (US$/mt)
Australia					
N.S.W., rail					
Singleton - Newcastle	80	9.00	7.02	8.78	3.85
West - Newcastle	280	16.10	12.56	4.49	
South - Port Kembla	170	11.00	8.58	5.05	3.82
Sydney					4.27
Queensland, rail					
North Bowen Basin - Abbott Pt.	160	12.50	9.75	6.09	
North Cent. Bowen Basin - Hay Pt.	210	12.70	9.91	4.72	
Cent. Bowen Basin - Dalrymple Bay	270	12.80	9.98	3.70	
S.W. Bowen Basin - Gladstone	320	13.10	10.22	3.19	
Canada					
British Columbia, rail	1100	23.25	20.00	1.82	
United States (all rates courtesy of Fieldston Coal Transportation Manual)					
Central Appalachia (E. Kentucky, Southern W. Virginia, Western Virginia)					
Rail to Baltimore (CSX)	950-1300		18.50-22.50	1.5-1.6	
Rail to Hampton Roads (CSX)	650-1100		15.50-19.00	1.5-2.1	
Rail " " " (NS)	600-750		18.50-20.50	2.2-2.6	
Rail to Charleston (CSX)	850-1500		18.50-20.50	1.2-1.9	
Rail " " (NS)	950-1050		21.50-25.00	2.1-2.5	
Rail (NS or CSX) & Barge to New Orleans/Baton Rouge	2350-2900		14.00-19.00	0.5-0.6	
Barge only to N.O./Baton Rouge	2250-2750		7.00-10.00	0.2-0.3	
Northern Appalachia (Northern W. Virginia, Pennsylvania, Ohio)					
Rail to Baltimore (CSX)	350-700		15.50-19.50	2.2-3.6	
Rail to Philadelphia (CR)	500-750		13.50-17.50	2.0-2.4	
Alabama					
Barge to Mobile	600-700		6.50-9.00	0.7-0.9	
Rail (CSX) to Mobile	450-500		12.50-14.50	2.0-2.1	
Illinois Basin (Illinois, Indiana, Western Kentucky)					
Barge to New Orleans/Baton Rouge	1500-1700		6.00-8.00	0.3-0.4	
Rail (IC) to Mobile	1050-1150		12.50-14.50	1.0-1.1	
Uinta Basin (Utah)					
Rail (UP & SP) to Los Angeles/Long Beach	1300-1550		14.50-18.00	1.0-1.1	
Powder River Basin (Wyoming, Montana)					
Rail (BN & MRL) to Vancouver	2250-2600		16.50-18.00	0.6-0.7	
Rail (BN or CNW) & barge to Gulf Coast	3400-2850		20.00-23.50	0.5-0.6	
South Africa					
Transvaal, rail					
Witbank - Richards Bay	580	27.00	10.40	1.80	3-6

Source: Compiled by the CIAB Standing Committee on Coal Information.

Note: U.S. rail rates shown are published tariff charges. Most of the export coal moves under contract rates below published charges. U.S. rail and barge rates in $/mt include port transloading costs while unit charges do not include barge or vessel transloading costs.

Source: Coal Information 1991, International Energy Agency.

STEAM COAL FOR POWER AND INDUSTRY

Main Chinese Coal Ports [1]

Port Name	Capacity (MM Tpy)	1989 Shipments (MM tons)	1989 Exports (MM Tons)	Vessel Capacity (DWT)
Qinhuangdao	75	47	10.5	70,000 (will be Capesize)
Shijiu	15	N/A	0.8	Cape and Handy Berths
Lianyungang	9	N/A	1.8	Handy Size
Totals	99	N/A	13.1	

[1] Wei Guofu, "China's Coal Industry and Export", paper presented to the 5th Pacific Rim Coal Conference, July 1990.

STEAM COAL FOR POWER AND INDUSTRY

New Coal Terminals on Kalimantan [1]

Name	Due Date	Max Size (DWT)	Capacity (MM Tpy)	Mines Served
Tanjung Bara	07/91	180,000	7.0*	Kaltim Prima
Tanah Merah 1	12/92	60,000	2.0*	Kideco
IBT Palau Laut 1	04/93	200,000	10.0*	Adaro, Arutmin, etc.
IBT Palau Laut 2	12/94	200,000	20.0	Same
Balikpapan 1	03/93	50,000	2.5	Multi Harapan Utama, Tanito Harum & other Mahakan River
Balikpapan 2	-	80,000	5.0	Same
Kota Baru 1	-	70,000	3.0	Arutmin
Kota Baru 2	-	100,000	5.0	Same
TOTAL TPY			54.5	

* Under construction

[1] International Coal Report, June 14, 1991.

STEAM COAL FOR POWER AND INDUSTRY

Polish Port Capacity and Shipments [1/]
(Million Tonnes Per Year)

Port Name	Capacity	1984	1986	1988	1989
Gdynia	4.0	3.9	2.2	1.7	1.4
Gdansk (Old)	2.0	1.7	1.1	1.1	0.8
Gdansk (North)	9.0	8.8	7.0	6.5	6.4
Szczecin	4.5	5.3	3.3	2.0	1.6
Swinoujscie	6.5	5.2	3.8	4.3	4.4
TOTAL	26.0	24.9	17.5	15.6	14.6

1/ Kuiper, Henk, "Infrastructure: To What Extent Will it determine the Quality of Coal Traded?" paper presented to CoalTrans 90 Conference, October 1990.

STEAM COAL FOR POWER AND INDUSTRY

Typical Rail Distances for USSR Exports
(Kilometers)

Basin	Black Sea	Baltic	Pacific	Hungarian Border
Donetsk	500	1,750	-	2,000
Pechora	4,000	2,500	-	-
Kuznetsk	4,000	4,000	-	-
South Yakutia	-	-	2,500	-

STEAM COAL FOR POWER AND INDUSTRY

Estimated Capacity of U.S. Ports [1]
(Million Tonnes Per Year)

Port Name	Total Cap.	Domestic	Export Cap.
Baltimore - Bayside	6.3	0	6.3
Baltimore - Curtis Bay	5.4	3.0	2.4
Baltimore - Consol	9.1	2.7	6.4
H. Roads - Dom. Term.	15.9	2.3	13.6
H. Roads - Pier IX	10.9	0.2	10.7
H. Roads - Lamberts Pt.	40.8	3.7	37.1
Charleston - Shipyard	1.8	0	1.8
Mobile - McDuffie	17.2	0	17.2
Lwr Miss - N.O. Bulk	4.5	1.8	2.7
Lwr Miss - Electro Coal	22.7	*	*
Lwr Miss - Burnside	1.8	*	*
Lwr Miss - IMT	10.9	*	*
Lwr Miss - Midstream	22.7	*	*
Los Angeles	2.7	0	2.7
Long Beach	8.2	0	8.2
Stockton	3.0	0	3.0
TOTALS	183.9	20.9*	163.0*

* 7.2 million tonnes of domestic shipments moved through these ports, and have been added into the domestic movement totals and subtracted from the net totals to arrive at correct net available export capacity.

The figures in this table reflect only those ports where export shipments are now made on a frequent basis. The table excludes the Great Lakes ports that are occasionally used, and excludes Pier 124 in

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[1] Based on a 1990 survey of the ports by Hill & Associates, Inc.

Great Lakes ports that are occasionally used, and excludes Pier 124 in Philadelphia, which has recently been closed but could be reopened. The table also does not reflect the additional 4 million tonnes capacity expected at Lamberts Point following the installation of surge storage silos and the construction of the new ground storage facility planned by the Norfolk Southern Railroad.

STEAM COAL FOR POWER AND INDUSTRY

Potential New/Expanded U.K. Ports [1]

Site	Sponsor	Approx. Cost (Million £)	Plan Capacity (MMTPY)	Max Ship Size (DWT)
Bristol (Royal Portbury)	National Power	15-30	6	80,000
Hull	National Power	5	3	30,000
Redcar	National Power	N/A	6-8	170,000
Port Talbot	National Power	50	12	150,000
Humber	Nat. Power/ Power Gen	100	10+	Cape
Isle of Grain	Nat. Power/ Power Gen	N/A	Trans-Ship	115,000
Liverpool (Gladstone)	Power Gen	30	6	75,000

[1] Source: International Coal Report (January-September, 1991).

STEAM COAL FOR POWER AND INDUSTRY

Estimated Coal Import Transportation Costs by Alternate Routes into Hungary Colombian Coal [1]

Via Rotterdam:

Ocean Freight - Puerto Bolivar to Rotterdam Capesize Vessel, 4600 Miles	$7.00
Vessel Unloading to Barge	2.50
Barge Via Rhine-Main-Danube	25.00
Total Freight:	$34.50

Via Black Sea:

Ocean Freight - Puerto Bolivar to Constanta Handysize Vessel, 6000 Miles	$14.00
Vessel Unloading to Barges	2.50
Barge Via Danube	10.00
Total Freight:	$26.50

Existing Import Port Capabilities Annex B shows a listing of all port facilities currently in use for importing coal. The Annex shows estimates of capacity for each terminal and port charges for those that are not private operations.

The total capacity of all these ports is over one billion (10^9) tonnes per year. While this total does not reflect individual bottlenecks that might occur at specific sites, the huge difference between capacity and current coal trade levels (about 400 million tonnes per year) indicates that few constraints on trade are likely to be seen because of limited import infrastructure.

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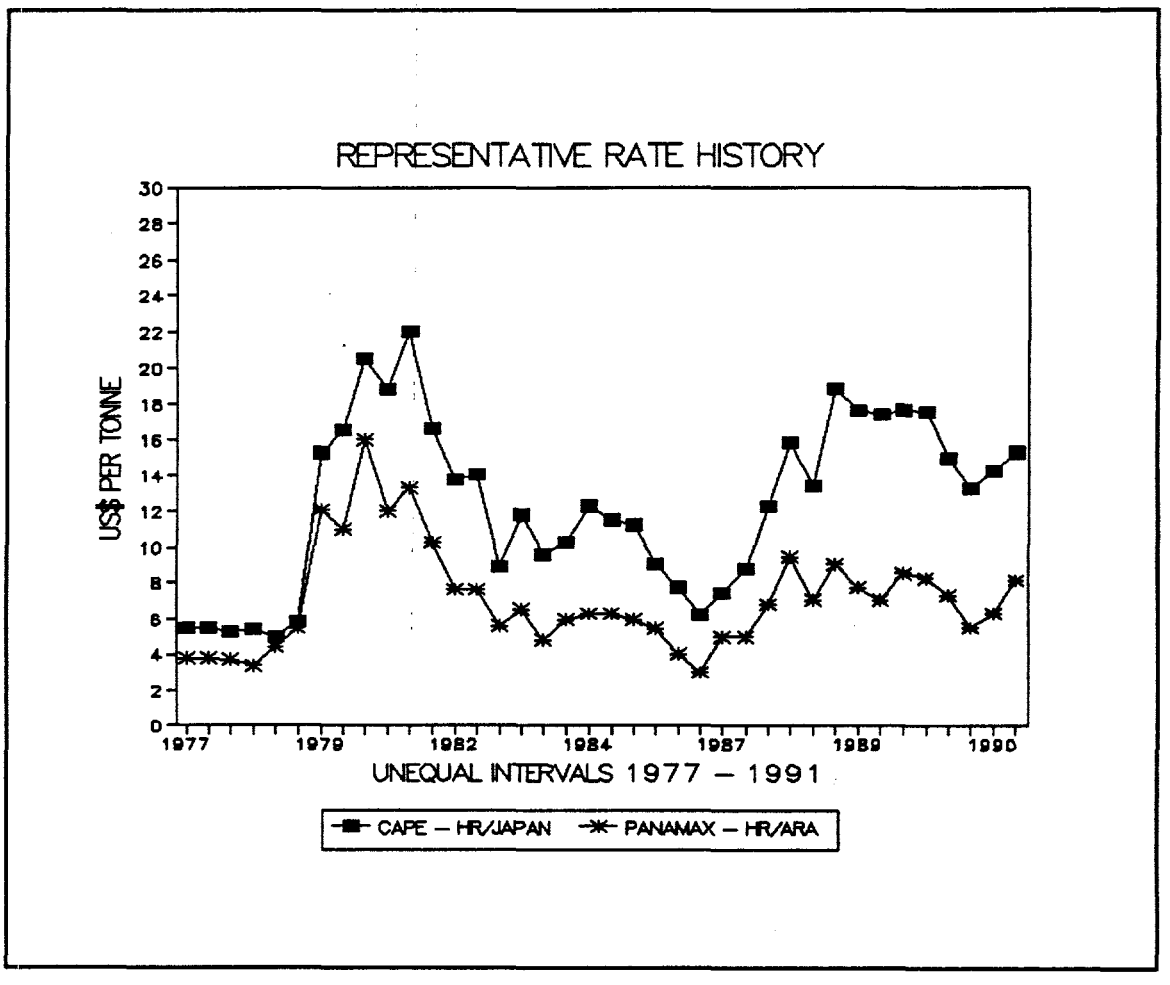
[1] **Source: Hill & Associates, Inc. estimates.**

STEAM COAL FOR POWER AND INDUSTRY

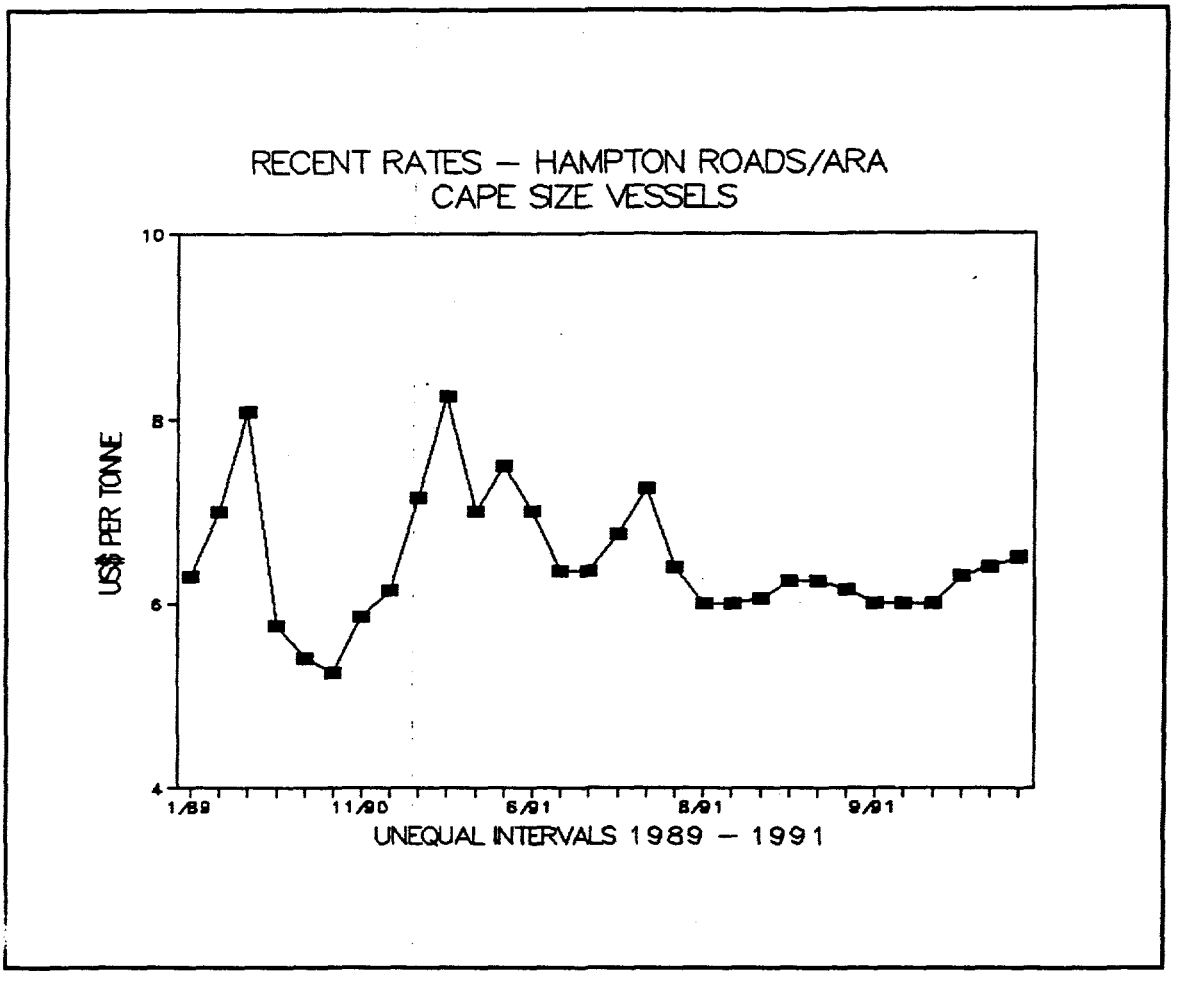
COAL FREIGHT RATE DEVELOPMENT

Figure 3.1



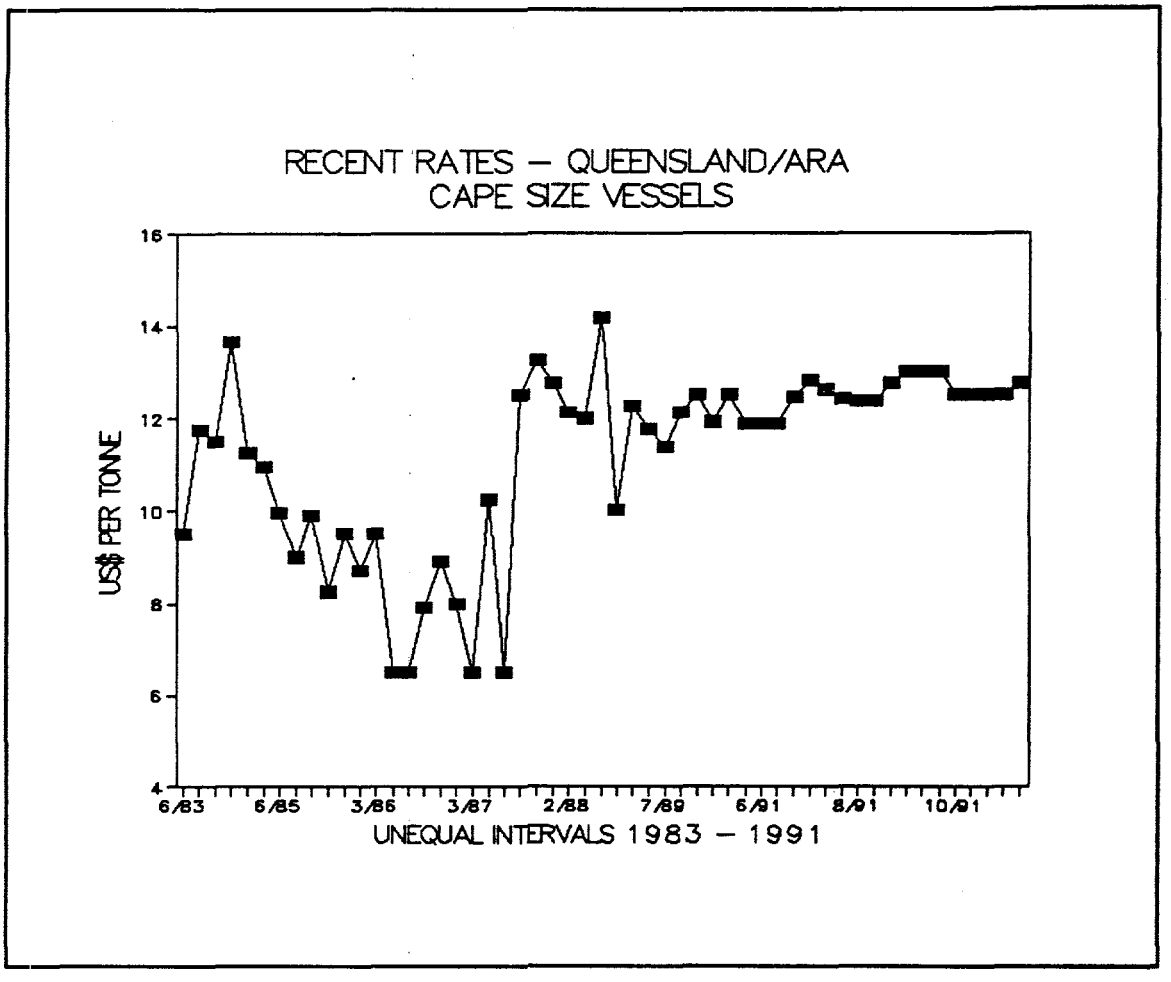
Source: Simpson, Spence & Young; Marsoft.

Figure 3.2



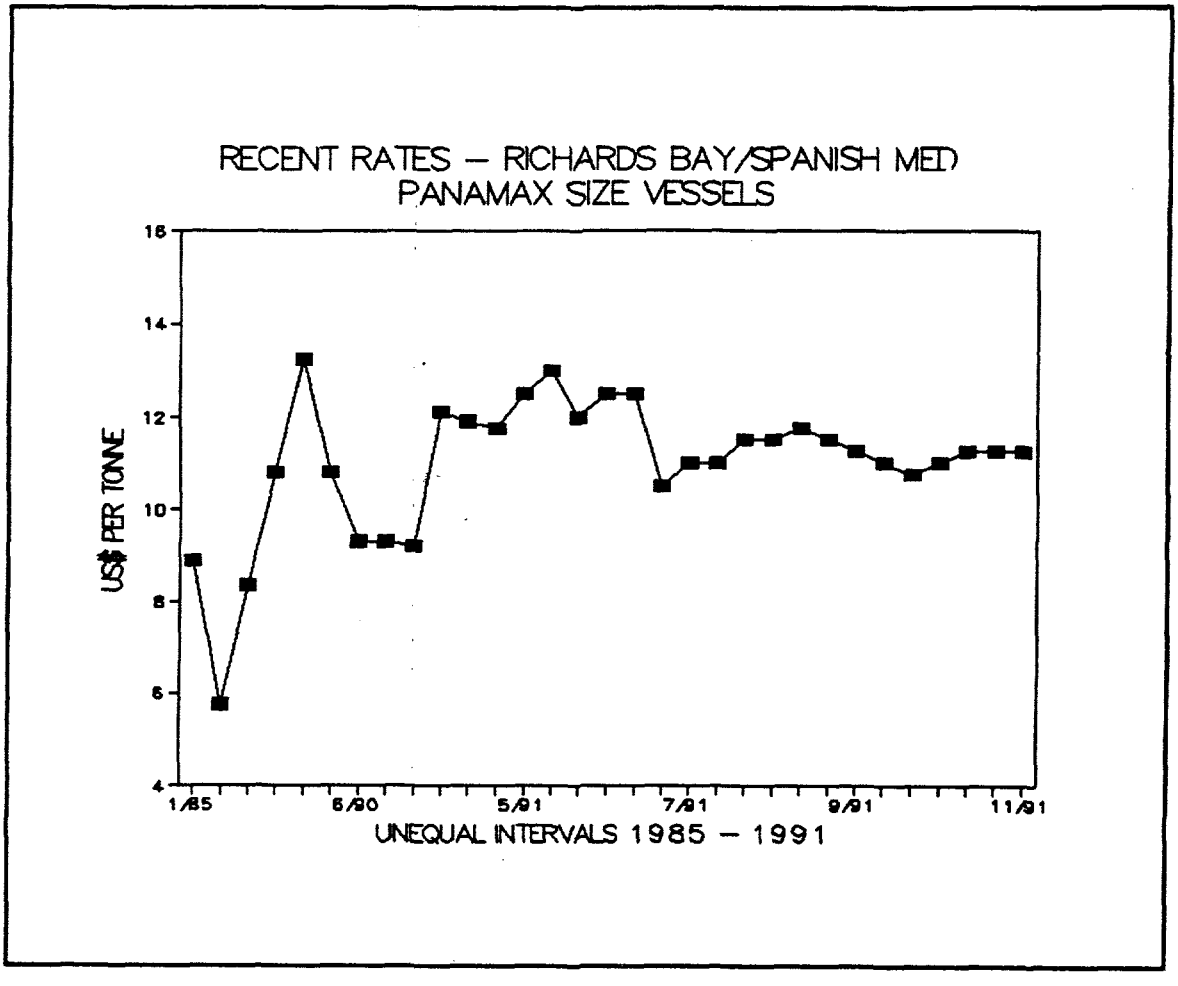
Source: Simpson, Spence & Young.

Figure 3.3



Source: H. Clarkson & Company, Ltd; Simpson, Spence & Young.

Figure 3.4



Source: H. Clarkson & Company, Ltd; Simpson, Spence & Young.

STEAM COAL FOR POWER AND INDUSTRY

Shipping Cost

The principal characteristics of capital costs in regard to their effect on freight rates are:

- Capital costs are essentially fixed for the life of the vessel. (An exception is the two-step financing often being used today: financing is for seven years only with a large balloon to be refinanced at the end of the seven-year term.)

- Over the long term the capital cost must be recovered of course for vessel operation to be a viable business.

- However, a positive ROI can be foregone for extended periods when the freight market is poor. This apparently has in fact been a common practice at times during the last ten years.

Operating costs characteristics are:

- They are semivariable, mostly fixed for up to a year, but variable from one year to the next; e.g., insurance, crew wage scales, etc.

- Some operating costs, such as maintenance, can be postponed when freight rates are low.

The primary voyage cost characteristics are:

- They are fully variable for each voyage a vessel undertakes.

- The category includes fuel costs, port costs such as pilotage and tug services, and canal charges.

  Fuel comprises IFO (Intermediate Fuel Oil), used by the propulsion diesel engines, and marine diesel, used by the various auxiliary engines on a vessel. IFO is a residual oil and although cheaper follows the price of crude. Marine diesel is highly refined; its price fluctuates with the price of crude plus other factors such as refinery capacity.

  Port costs are usually levied in local currency and thus vary with exchange rates relative to the U.S. dollar. Primarily due to recent depreciation of the U.S dollar, ports costs have become a distinctly significant component of freight rates - which are customarily measured in U.S dollars.

  Both the major canals, Suez and Panama, are effectively in competition with ocean routes which are longer but have no canal fees to pay. For example, our cost models shown the cash cost per ton from Hay Point, Queensland, Australia to Rotterdam via the Suez and via the Cape of Good Hope to be virtually the same. The competition of routes appears to have a strong dampening effect on canal fees.

- Voyage costs plus most elements of operating cost set the lower bound for freight rates. Except for the most extraordinary circumstances, the operator will lay up or scrap his vessel before undertaking voyages at a cash loss.

Rates at cost, with and without capital recovery (cost of 80% financing) plus rates for equity financing at a target ROI of 12% for 15 years are shown in Table 3.13 in comparison to current actual market rates. The capital costs are for 1991 new building. (Construction of many vessels now in the fleet was much cheaper than the current cost).

With the cautions that the market rates are actual but only samples in a volatile market, and the cost figures are just estimates, Table 3.11 indicates the following:

- On the Hampton Roads to Rotterdam voyage, a new Panamax vessel can recover its cash costs and make a substantial but incomplete contribution to capital recovery/ROI.

- On the same voyage, a small cape size vessel can achieve a clear profit and easily meet a modest ROI target.

- On the longer voyage to Japan, with topping off in Richards Bay, a somewhat larger cape size (120,000 dwt) can clear its cash cost and recover most of the capital cost, but doesn't nearly meet the assumed ROI target. In practice it is probable that this voyage is made profitably with older and/or much larger vessels. (Although a fully laden 120,000-dwt vessel is near the current draft limitations at Hampton Roads, it has been a common practice for some years to partially load much larger vessels there and top them off at Richards Bay.)

Table 1: COST PRICE COMPARISONS FOR TYPICAL FREIGHT RATES COST/PRICE (US$/TONNE) - 1991 BUILD

Voyage	Cost Only (80% Loan) Cash Cost	Cost Only (80% Loan) W/Capital Recovery	12% ROI (100% Equity)	Market Price
Hampton Roads/Rotterdam:				
Panamax (60k dwt)	4.78	6.84	7.50	n/a
Cape Size (100k dwt)	3.85	5.50	6.03	6.30
Hampton Roads/Japan via Richards Bay:				
Cape Size (120k dwt)	9.34	16.20	18.40	15.50

Source: Hill & Associates, Inc., Ocean Freight Model.

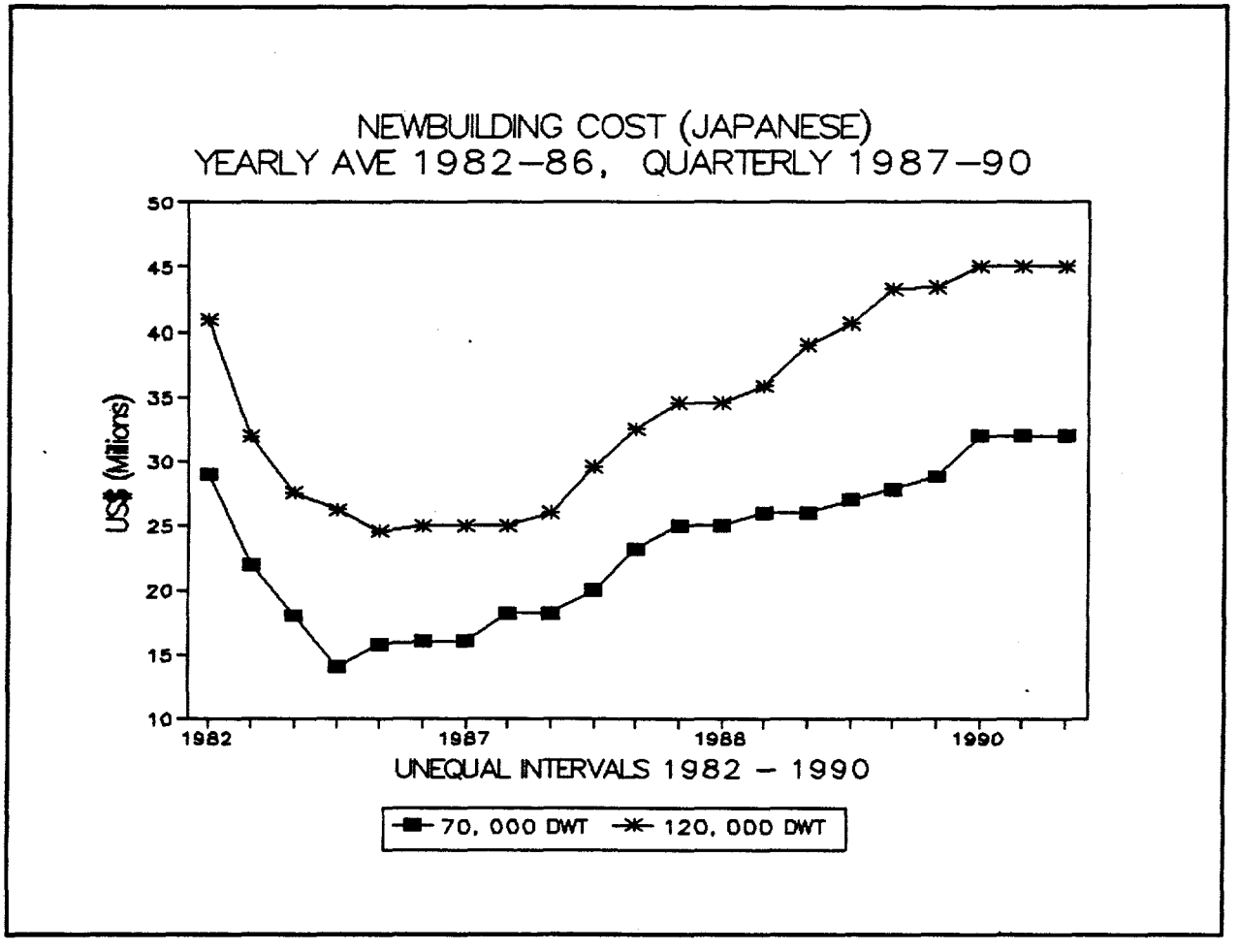
Construction Cost

In large part due to appreciation of the Yen vis-a-vis the U.S. dollar, new construction cost of dry bulk cargo vessels increased sharply form 1986 into 1990. Figure 1 shows newbuilding cost at Japanese shipyards from 1982 through early 1991. For example, a 120,000-dwt vessel built in 1991 typically costs around $45 million. The same vessel built in 1986 cost only $24.6 million.

From this illustration it is apparent that vessels built in the mid 1980's, which are still considered nearly new, have a significant advantage over 1991 new construction in regard to the capital component of the rates they can accept. Table 2 makes this point clear. It is the same as Table 1 except that the cost estimates are based on 1986 construction versus 1991.

For 5-year old vessels the freight rates needed not only to recover capital costs but also to exceed the assumed ROI target are well under current market rates for all three sizes of vessel and voyage shown.

Figure 1



Source: Lloyd's Shipping Economist.

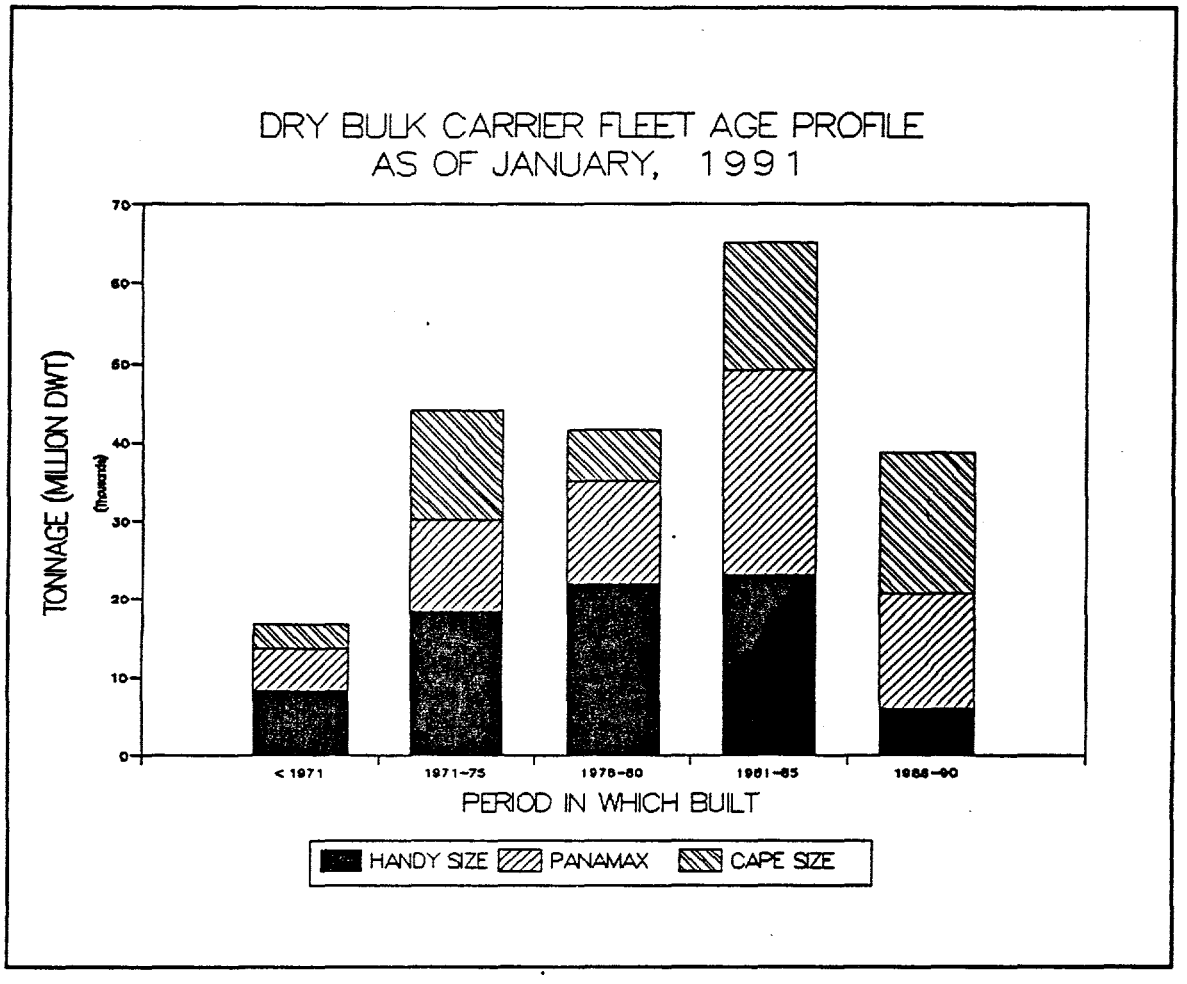
Table 2: COST PRICE COMPARISONS FOR TYPICAL FREIGHT RATES COST/PRICE (US$/TONNE) - 1986 BUILD

Voyage	Cost Only (80% Loan) Cash Cost	Cost Only (80% Loan) w/Capital Recovery	12% ROI (100% Equity)	Market Price
Hampton Roads/Rotterdam:				
Panamax (60k dwt)	4.78	5.81	6.14	n/a
Cape Size (100k dwt)	3.85	4.68	4.94	6.30
Hampton Roads/Japan via Richards Bay:				
Cape Size (120k dwt)	9.34	13.09	14.29	15.50

Source: Hill & Associates, Inc., Ocean Freight Model.

STEAM COAL FOR POWER AND INDUSTRY

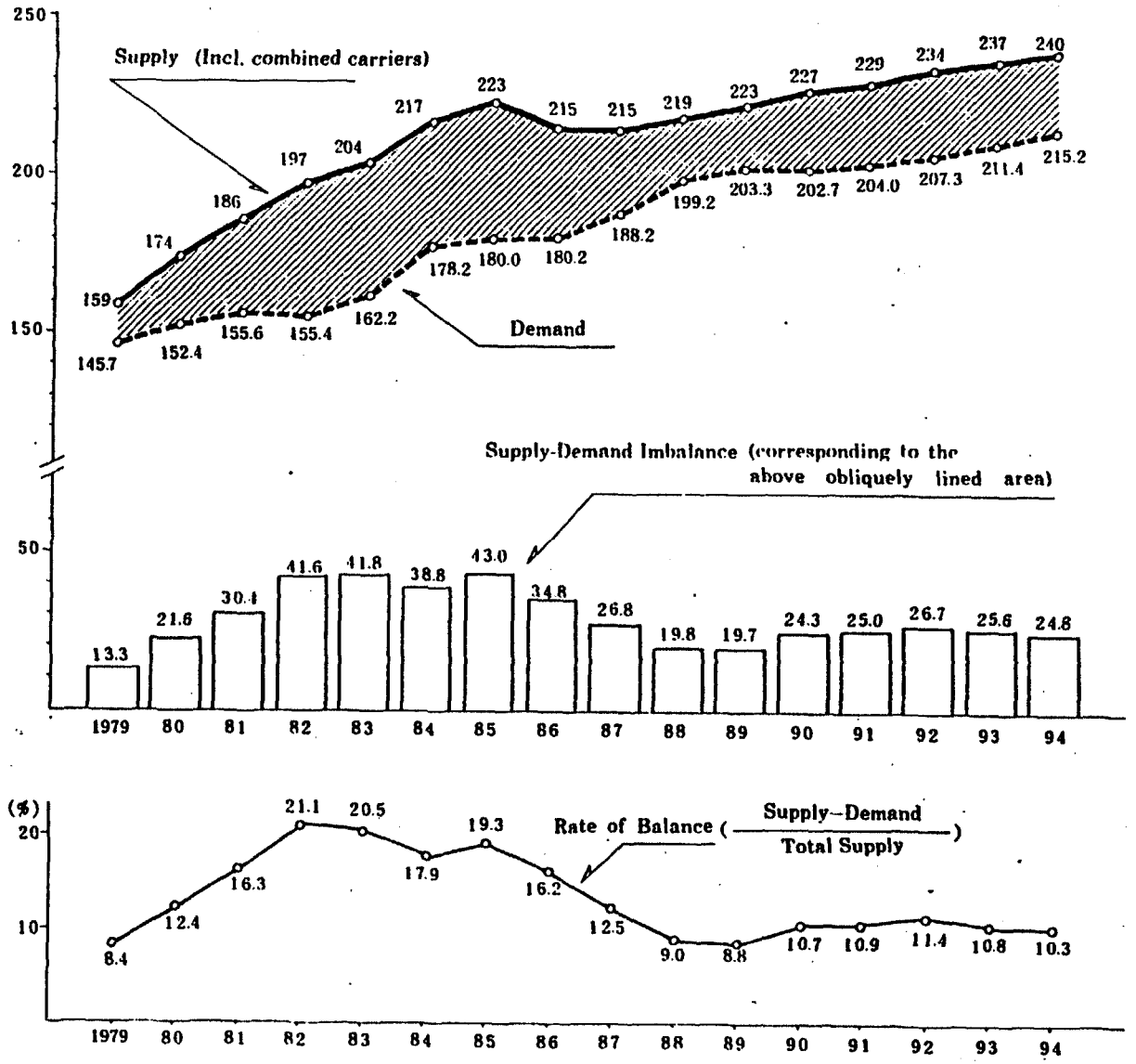
COAL FLEET AGE PROFILE



Source: Simpson, Spence & Young, "Annual Shipping Review 1990"

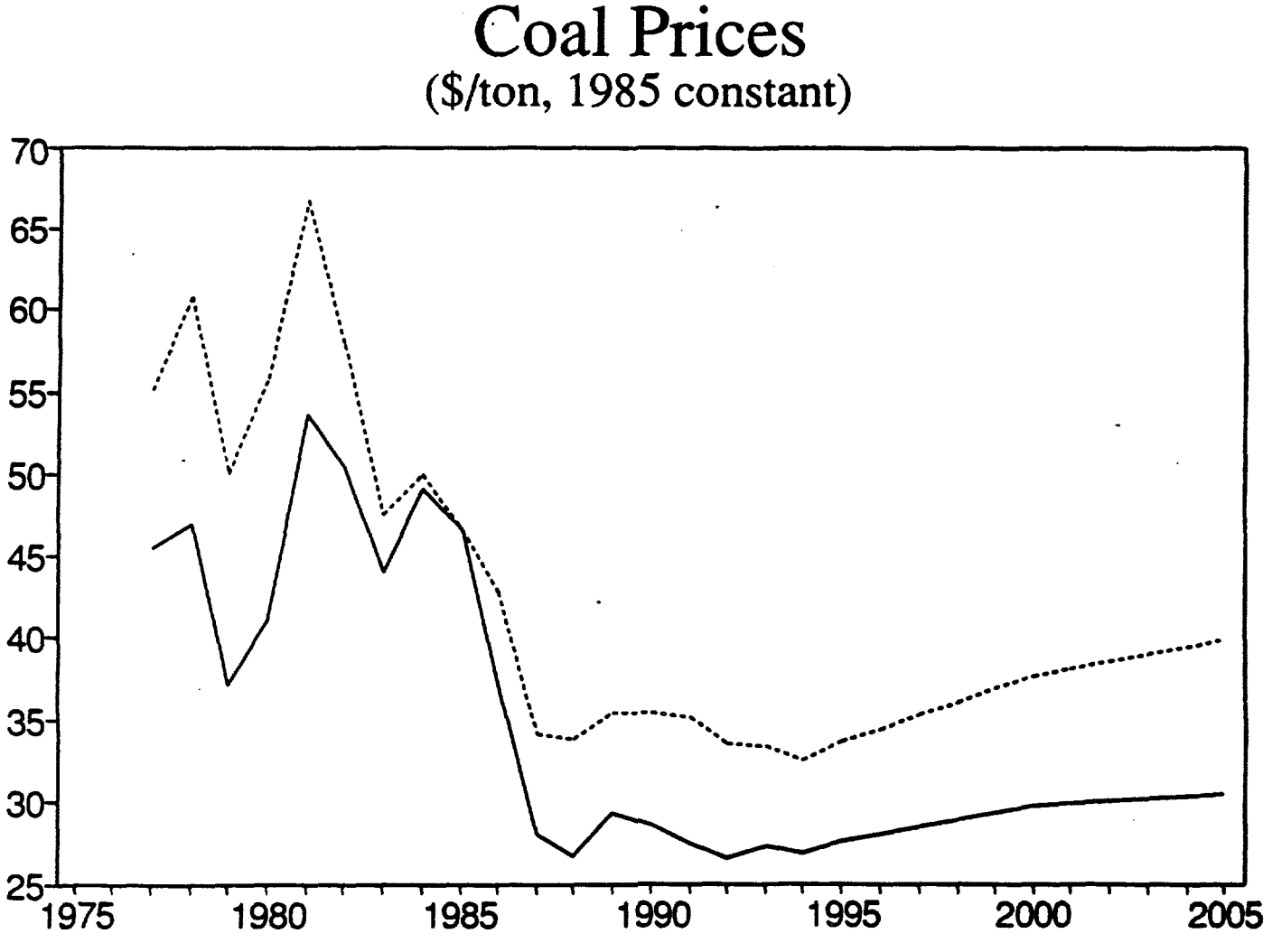
STEAM COAL FOR POWER AND INDUSTRY

Supply-Demand Balance of Bulk Carriers



Source: Lloyd's Shipping Economist; Farhley's Drewery Shipping Consultants, Ltd.

International Steam Coal Prices



Note: 12,000 btu/lb, 1% sulfur, 12% ash, f.o.b. piers Hampton Roads, Norfolk, United States

—— Deflated by Manufacturing Unit Value (MUV) Index
- - - - Deflated by US GNP deflator

Source: World Bank, International Economics Department.

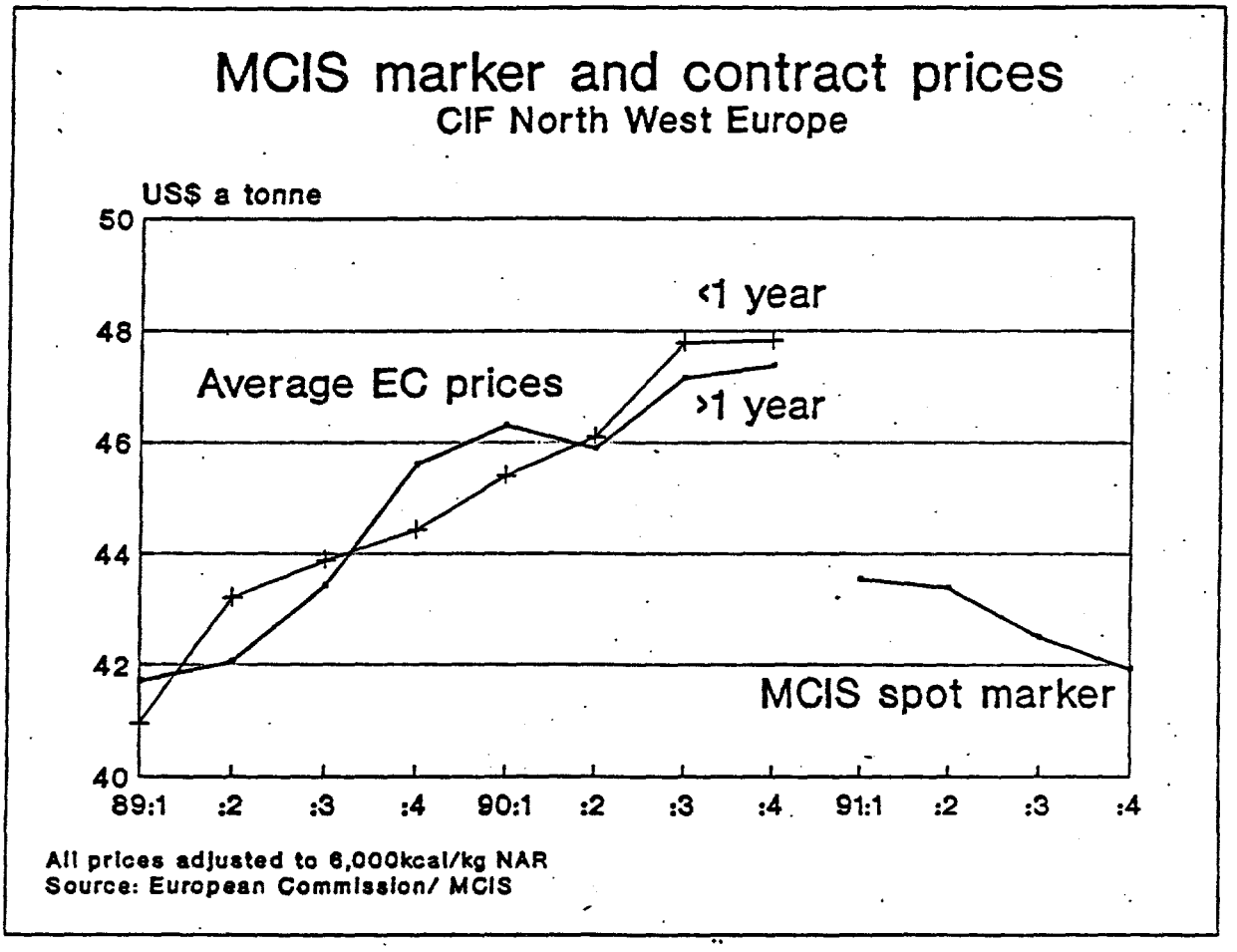
Thermal Coal - Prices, 1977-89 (Actual) and 1990-2005 (Projected)

	($/ton)								
	United States /a			South Africa /b			Australia /c		
	Current $	1985 Constant $ MUV /d	1985 Constant $ US GNP /e	Current $	1985 Constant $ MUV /d	1985 Constant $ US GNP /e	Current $	1985 Constant $ MUV /d	1985 Constant $ US GNP /e
Actual									
1977 /f	33	46	55	20	27	32	29	40	49
1978	40	47	61	20	24	31	29	34	44
1979	35	37	50	21	22	30	30	31	42
1980	43	41	56	31	29	40	39	38	51
1981	57	54	67	41	39	48	53	50	62
1982	52	50	58	43	41	47	55	53	61
1983	45	44	48	32	31	34	38	38	41
1984	49	49	50	32	32	33	31	31	32
1985	47	47	47	34	34	34	34	34	34
1986	44	37	43	27	23	26	31	26	30
1987	36	28	34	24	19	23	28	21	26
1988	37	27	34	28	20	25	35	25	32
1989	41	29	35	31	22	27	38	27	33
Projected									
1990	42	29	35	32	22	27	40	27	33
1991	44	27	35	34	21	27	43	27	34
1992	43	27	34	33	20	26	42	26	33
1993	44	27	34	34	21	26	43	27	33
1994	44	27	33	34	21	25	43	26	32
1995	47	28	34	36	21	26	46	27	33
2000	61	30	38	48	23	30	58	28	36
2005	75	31	40	58	24	31	71	29	38

/a 12,000 btu/lb, <1% sulfur, 12% ash, f.o.b. piers, Hampton Roads, Norfolk, United States.
/b 11,300 btu/lb, <1% sulfur, 15% ash, f.o.b. piers, Richards Bay, South Africa.
/c 12,000 btu/lb, <1% sulfur, 14% ash, f.o.b. piers, Newcastle/Port Kembla, Australia.
/d Deflated by Manufacturing Unit Value (MUV) Index.
/e Deflated by US GNP deflator.
/f May-December 1977.

Sources: Coal Week, and Coal Week International, various issues (actual); World Bank, International Economics Department (projected).

Recent Coal Price Developments

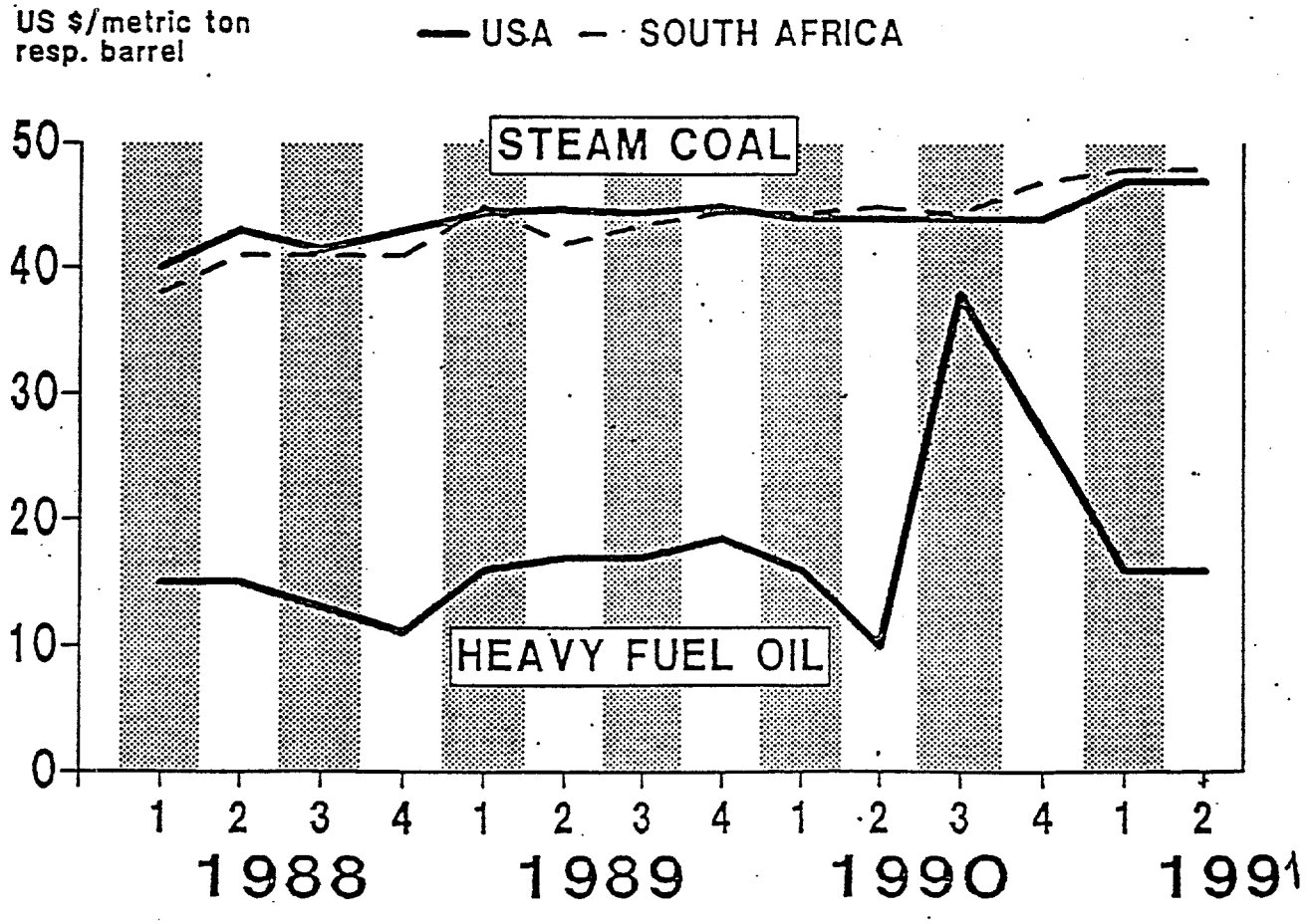


STEAM COAL FOR POWER AND INDUSTRY

STEAM COAL PRICES

VS. HFO PRICES

SPOT MARKET (ROTTERDAM)



STEAM COAL FOR POWER AND INDUSTRY

COAL POLICIES IN WESTERN EUROPE AND JAPAN

1. Over three-fifths of all traded coal are directed towards Western Europe and Japan, where governments continue to effectively regulate domestic coal markets to protect the indigenous coal industries from import competition. For example, UK and West Germany together produced 178 million tons in 1989, while importing less than 15 million tons. The average price of domestic coal in the two countries, however, has consistently been substantially above the import prices. The high level of domestic production, compared to imports, is artificially maintained by trade barriers, subsidies and other government support to the respective coal industries. The growing trend towards the lessening of government involvement in coal markets in Western Europe will strongly influence the future development of the international market, particularly given the importance of the region's demand for traded coal.

2. Despite significant progress in rationaling coal mining decisions and improving productivity, indigenous coal production in Western Europe and Japan are unable to compete in the primary coal markets without substantial assistance from the government. The near exhaustion of low-cost reserves at shallow to moderate depth in Western Europe and Japan have driven up local mining costs, so that domestic steam coal has consistently been priced higher than its border equivalents. Government support has been necessary to maintain or enhance the ability of domestic producers to comptete with imported coal and other fuels. Financial support to domestic coal production is provided in the following ways:

- by direct state grants or subsidies to coal producers;
- by discriminatory pricing policies that have emerged as a result of efforts to segment domestic coal markets from international competition; and,
- by trade barriers, such as import quotas, or long-term agreements between coal producers and large coal consumers arranged through government oversight.

3. Subsidies by the national governments of OECD coal-importing countries have a major impact on the price of coal. Direct subsidies are given for offsetting operating losses or labor costs, investments, interest payments, maintaining stockpiles, and assisting in research and development. Indirect subsidies include supporting pension and welfare programs, development grants to promote alternative employment in coal-mining areas, and payments to cover inherited liabilities in the coal mining industry. In addition to these cash or operating subsidies, there are significant sub*sidies implicit in the capital and tax requirements for the coal industry. In West Germany, France and UK, government ownership and control of the coal

industries have resulted in greatly reduced capital costs (profit requirements, interest on debt) and commensurate reductions in income taxes paid by these industries. The largest subsidies tend to be related to capital-cost subsidies, although direct operating subsidy for offsetting losses have been large in France and Spain.

4. Direct cash subsidies in the OECD countries range from US$ 4.40/mt to US$ 26.40/mt, and total cash subsidies ranged from US$ 179 million to US$ 2,500 million in 1987.[1] Most West German hard coal production is currently subsidized at levels exceeding triple the world price. Total subsidies have increased from DM 4.1 billion (US$ 1.7 billion) in 1982 to DM 10.9 billion (US$ 5.9 billion) in 1988. Similarly, a large portion of UK's coal production is also subsidized. Direct subsidy is provided by the electric power industry on the basis of a purchase agreement between British Coal and the electric utilities. Subsidies to the Spanish coal industry amounted to 60 billion pesatas (US$ 517 million) in 1989.

5. Governments have also employed additional non-price incentives and quotas to expand or maintain consumption of domestic coal. These include import quotas, long-term contracts and other administrative arrangements to protect domestic coal producers and the employment they provide. In Germany, for example, demand for domestically-mined coal is secured at a minimum rate of 40 million tons per year by the so-called "Jahrhundertvertrag" (literally 'Contract for the Century') agreement negotiated between domestic producers and electric utilities. The electric utilities are bound by these long-term contracts to purchase domestic coal to meet a certain percentage of their requirements, currently around 87%, while the balance is met by imported coal. The price paid by the German utilities for domestic coal is intended to cover the producers' break-even costs (net of direct subsidies). The contracts are further linked to a system of subsidies and rebates to the utilities, as well as a ceiling on imported coals.

6. Unlike Germany, however, no import quotas apply in United Kingdom, with most consumers in the private sector using to imported coal while domestic coal is consumed largely by the public sector for power generation. Since the British coal industry enjoys a larger natural protection than Germany or France due to more favorable location of consumers vis-a-vis domestic mines than ports, no significant trade protection has been necessary, despite the fact that minehead prices are higher than CIF import prices. Nontheless, the state-run British Coal (until 1987 the National Coal Board) has always provided most of the coal requirements of the electric utilities. According to a series of agreements the main public utility, Central Electricity Generating Board (CEGB), is obliged to take not less than 95% of their annual coal requirements from British Coal. Further, a base tonnage is supplied at a price based on formula reflecting the average costs of domestic production and world market prices for fuels, while the balance of CEGB's requirements are supplied at prices aligned to those of imported coal. However, there have been recent changes in the relationship between domestic coal industry and the soon-to-be-privatized electricity supply industry in UK. In 1988 the government announced plans to privatize the electric power

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[1] International Energy Agency, Coal Prospects and Policies in IEA Countries, 1987 Review, Paris 1988.

industry and form four succesor companies: National Power and PowerGen, the National Grid, and the state-owned Nuclear Electric Company. National Power, which will consist of the two generating co*mpanies, National Power and PowerGen, have already indicated that they will reduce their domestic consumption to 65 million tons by 1992. Although they will be freer to import coal after privatization, however, their transitional contracts with British Coal will limit to under 10 million tons through 1993. The government is also considering privatizing British Coal; this could significantly change the cost and availability of domestic coal supplies. Since more than half of British Coal's collieries are currently operating under a loss, they would be unlikely to survive unless they are protected under privatization.

7. Government support to the indigenous coal industry in Japan has been provided under a series of official coal policy plans developed by the Coal Mining Council and submitted to MITI. In addition to providing direct grants, the government operates a system of import quotas to protect domestic coal producers. These quotas are allocated to final consumers, and are set equal to their expected requirements net of deliveries from domestic suppliers. According to the government, this system has been instituted in order to secure a smooth and gradual reduction of domestic coal supply. The *price for domestic coal is set in accordance with the "coal index prices" which are based on the cost of domestic coal production and the prices of imported coal and other competing fuels.

8. Subsidized domestic coal production, combined with import restrictions, have given rise to segmented domestic markets for coal in which prices have deviated from their border equivalents. Government price support to domestic producers is provided through the use of dual-pricing mechanisms whereby some domestic coal (and all imported coal) is sold to industrial consumers and partially to electric utilities at border prices, while the bulk of domestic production is sold to electric utilities at higher (non-competitive) prices approaching production costs. In all cases, the margin between the two is usually quite large, with domestic coal priced 50-100% above import levels. In West Germany, for example, domestic coal to German utilities has been priced over two times the level of import prices in recent years. Similarly, domestic mine-head prices are significantly higher then CIF import prices in other OECD coal-importing countries. Despite British Coal's 75% productivity gain between 1985 and 1988, high quality steam coal can still be imported more cheaply than subsidized local coal supplies. In Japan, the prices of domestic steam coal has been almost three times the price of imported coal of equivalent quality since 1986.

9. The economic losses resulting from these government support systems are manifested in the costs borne by consumers in terms of higher prices and tariffs, and in the financial costs of government support. The high costs of domestic coal to electric utilities are in turn passed on to customers in the form of excessive electricity tariffs. For example, to partially compensate the utilities for the much higher cost of using domestic coal, electricity consumers in West Germany are charged a "coal levy" (Kohlepfennig) which are transferred to a "power production fund", out of which the claims of the electric utilities are paid. In general, the electricity tariffs in West European countries are among the highest in the world.

10. The International Energy Agency estimates the extent of government transfers to coal producers, as measured in producer subsidy equivalents (PSE), in OECD coal-importing countries on a regular basis. A PSE defines the monetary payment to domestic producers equivalent to the total value of existing support provided at current levels of production, consumption and trade, and world prices. It is thus a measure of the support systems necessary to keep domestic production competitive with imports at current levels of output, producer incomes and import prices. The PSE includes all items of support provided to the current level of domestic production of coal that the industry would normally be expected to cover in a competitive situation. These include not only grants and other state direct payments but also the value of protection provided by price supports, import constraints and the practical effects of special sales arrangements.[2/]

11. As can be seen from Figure 4.2 in the main text, the PSEs for coal production increased rapidly between 1982 and 1987, but has declined somewhat in 1988 and 1989. The broad pattern of growth was particularly marked in 1985-87 period, mainly in the price support components, as world coal prices dropped in relation to domestic production costs and as the exchange rates of the currencies of the major coal-exporting countries (particularly USA) fell relative to those of the high-cost coal-producing countries. Price support to the coal industry, measured as the sum of excess payments on purchases of steam coal by public electricity producers, account for over 60% of total financial support in both UK and Germany, and over 85% of total assistance in Japan. According to IEA estimates, price support to the coal industry amounted to US$ 1,180 million in UK, US$ 1,151 million in Japan, and US$ 3,600 million in West Germany during 1987.

12. Although much of the high-cost production remains in place, some progress has been made in rationalizing coal production in both Western Europe and Japan. The closure of mines with no long-term prospects of economic viability and the reduction of the mining workforce has recently been accelerated in many of the high-cost producing countries. During 1988 and 1989, transfers to coal producers declined in two countries and showed signs of levelling off in the others. Most progress has been made in Belgium, where the closure of the last mines is in progress and scheduled to be completed in 1992. The sharp cuts in capacity and output have been accompanied by proportional cuts in assistance benefitting coal production (see Table 4.3). Under Japan's Eighth Coal Policy Plan, indigenous supply of domestic steam coal is to be reduced to 10 Mmt p.a., while metallurgical coal production will be completely phased out in the early 1990s. The effects of the new policy are already evident in 1988-89 as the total PSEs were accordingly lower for those years. Assistance to domestic producers in Germany, however, continued to rise slightly, but at a slower rate than in previous years.

2/ There has been considerable debate as to whether specific long-term agreements between coal producers and major consumers constitute support when they are not underpinned by government measures such as restrictions on coal imports. Whatever the answer to this question is in a specific case, the practical effect of these arrangements on coal imports and prices is the same as if there were protection for domestic production. Therefore, the PSE calculations also include an evaluation of the effects of these arrangements.

13. The restructuring of the coal industry in UK continued with the closure of a further four million tons of high-cost capacity in 1988-89 and the expansion of low-cost production. Both direct grants to the coal industry, and price support, have been declining since 1987; starting in 1988 the government aslso ceased paying deficit grants to British Coal. While fundamental restructuring and privatization of the coal industry may occur by the mid-1990s, it appears that British Coal will face intensifying pressures from imports and other fuels with the privatization of the electric supply industry. The government also expects that British Coal will cover all its costs, including interest payments, in the future.

14. The future of coal production in Western Europe and Japan is therefore linked to social and political considerations than it is to the cost of producing coal. The extent of future decline in production will depend on the maintenance of government support, whether the electric utilities continue to gurantee purchases of locally-mined coals, and on the long-term plans for restructuring the coal industries in these countries. In all cases, coal import costs are significantly lower than the full unsubsidized marginal costs of domestic production from new coal mines or expansions of existing mines. Domestic coal production in Western Europe and Japan is therefore projected to continue to decline through the 1990s.

15. In the absence of government support, coal imports are likely to play an important role in meeting future requirements in these countries. Hence, deciding on a pricing policy is less important than deciding on policies which affect the supply and demand conditions, and therefore the price of coal. Coal trade to Western Europe has grown significantly, and even more dramatically in Japan, with all the major exporters able to supply at closely competitive rates. Japan has already emerged as largest coal importer. UK and West Germany are likely to be marginal coal importers through the 1990s, but possibly significant coal importers after 2000. The major policy decision affecting the pricing of coal will be whether coal users, particularly electric utilities, are free to purchase their coal from the cheapest sources of supply, domestic or imported. production costs.

STEAM COAL FOR POWER AND INDUSTRY

Power Generating Plant Efficiency

1. Coal Steam Plant Net Heat Rates

(700-1000 MW class Conventional PC type Coal-fired plant)

Auxiliary power Without FGD - 7%
With FGD - 8%

Steam Condition (PSIG/F/F)	FGD [1]	Relative Net Efficiency (%)	Net Plant Efficiency (%)	NHR (BTU/kWh)
2400/1000/1000	WO	100	35	9751
2400/1000/1000	W	99	34.7	9836
3500/1000/1000	W	101	35.3	9669
4500/1050/1050/ 1050	W	107	37.1	9199

1/ WO: Without
W: With

2. Typical Combined Cycle Unit Arrangements Available from Manufacturers:

No. of G. T.	Model G. T.	Frequency (Hz)	Gas Turbine MW	Steam Turbine MW	Total Capacity MW	Net Efficiency (%)
Partial List of Area Brown Boveri Combined-Cycle Blocks						
1	13E	50	142.1	71.7	213.8	49.9
2	13E	50	284.2	145.1	429.3	50.1
1	13	50	94.0	50.2	144.2	47.4
2	13	50	188.0	101.9	289.9	47.6
3	13	50	282.0	152.9	434.9	47.6
4	13	50	376.0	205.1	581.1	47.7
1	11N	60	78.1	43.0	121.1	47.8
2	11N	60	156.2	88.3	244.5	48.2
3	11N	60	234.3	133.5	367.8	48.4
4	11N	60	312.4	179.0	491.4	48.5
Partial List of General Electric Combined-Cycle Blocks						
1	6541B	50	37.7	18.8	56.5	44.3
2	6541B	50	75.4	40.5	115.9	47.5
4	6541B	50	150.8	82.7	233.5	47.9
1	9161E	50	116.9	55.5	172.4	48.8
2	9161F	50	233.8	113.4	347.2	49.2
1	9281F	50	212.2	106.4	318.6	51.2
1	6541B	60	37.7	18.8	56.5	46.3
2	6541B	60	75.4	40.5	115.9	47.5
4	6541B	60	150.8	82.7	233.5	47.9
1	7111EA	60	83.5	40.0	123.5	48.1
2	7111EA	60	167.0	82.0	249.0	48.5
1	7191F	60	150.0	72.0	222.0	51.2
2	7191F	60	300.0	145.7	445.7	51.3
Partial List of Siemens Combined-Cycle Blocks						
2	V64	50/60	117	63	180	51.8
3	V64	50/60	175.5	96	271.5	52.1
4	V64	50/60	234	130	364	52.4
1	V94	50	144	87	231	51.1
2	V94	50	288	177	465	51.4
3	V94	50	432	269	701	51.7
1	V84	60	99	59	158	50.9
2	V84	60	198	120	318	51.2
3	V84	60	297	183	480	51.5

Source: Manufacturers' Literature.

STEAM COAL FOR POWER AND INDUSTRY

Atmospheric Emissions from Coal Burning

1. SO2 and CO2 Emissions of Three Countries:

	China \1	India \2	USA \3
Coal (mt/y)	1065	200	840
Coal fired generation (GW)	99	44	300
Coal for power use (mt/y)	267	150	710
SO2 (mt/y)	20 \4		16 \5
CO2 (million tons carbon) \6	532.3	139.9	1191.7
CO2 (mt carbon) % of world	(9.9%)	(2.6%)	(22.2%)

\1 1990
\2 1987
\3 1987
\4 Total for fossil fuel by a paper presented to EPA/EPRI FGD Symposium in 1988.
\5 Total for fossil fuel by a paper presented to Clean Coal Technologies Conference in 1990.
\6 Total for fossil fuel (CDIAC Numeric Data collection 1988).

2. CO2 Emissions from Fossil Fuel Combustion in Major Countries (million tons Carbon in 1986):

Country	Natural Gas	Oil	Coal	Total	Percentage
USA	222.9	531.1	437.7	1191.7	22.2
USSR	285.6	335.0	371.9	992.5	18.5
China	7.3	77.7	447.3	532.3	9.9
Japan	22.2	147.8	76.3	246.3	4.6
W.Germany	23.1	77.1	82.4	182.6	3.4
U.K.	29.6	53.0	81.7	164.3	3.1
India	2.8	32.7	104.4	139.9	2.6
Poland	5.3	11.8	105.3	122.4	2.3
Canada	28.7	50.3	24.8	103.8	1.9
France	15.2	56.9	23.1	95.2	1.8
World Total	827	2297	2250	5374	

(Source: Marlanf G., et.al; CDIAC Numeric Data Collection 1988).

3. CO2 Reduction in Various Types of Power Generation:

Type of Plant	Fuel	Conditions	CO2 Reduction \2	
Conventional	Coal	246K/538/538C	0 (base)	(41%)
USC \1	Coal	316K/595/595/595C	- 6%	(43%)
USC \1	Coal	350K/650/595/595C	- 8%	(45%)
High Efficiency Gas Turbine CC	NG	1350C Gas Turbine	-18%	(50%)
" "	NG	1500C Gas Turbine	-25%	(54%)
IGCC	Coal	1350C Gas Turbine	- 9%	(46%)
IGCC	Coal	1500C Gas Turbine	-14%	(48%)
PFBC	Coal	169K/538/538C	- 7%	(44%)

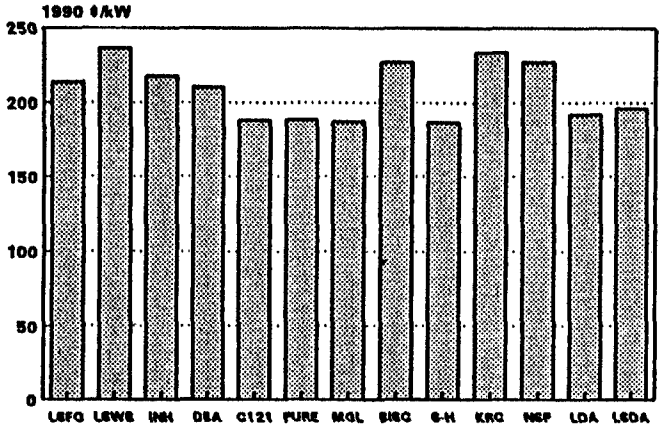
\1 Ultra Supercritical Plant.
\2 Figures in parenthesis are net plant efficiency based on low heating value.

Source: S. Kataoka, Coal Burning Plant and Emission Control Technologies; Technical Note, World Bank, January 1992.

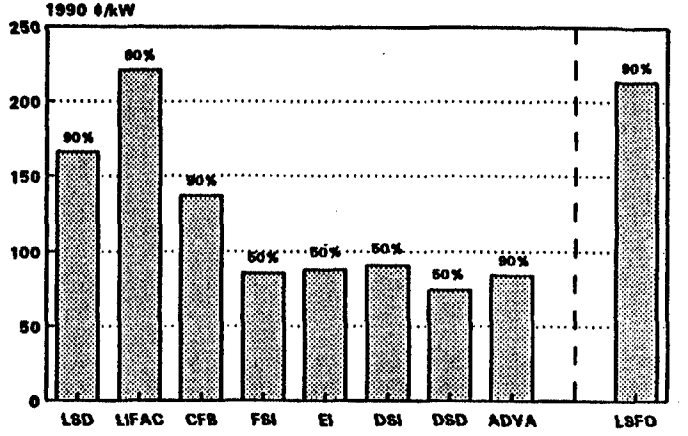
STEAM COAL FOR POWER AND INDUSTRY

Cost of FGD Processes

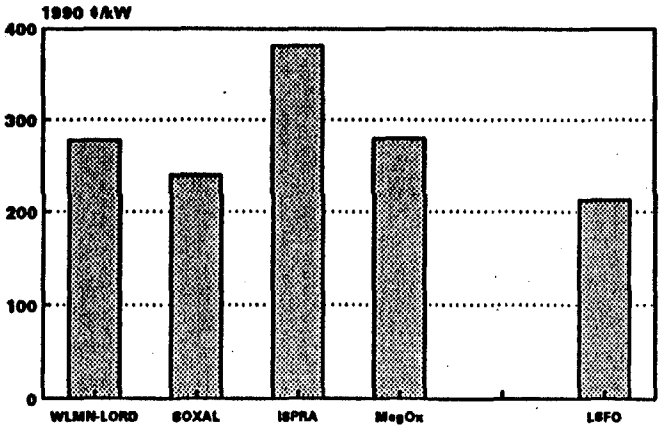
WET THROWAWAY CAPITAL COSTS
(RETROFIT, 300 MW, 2.6% S)



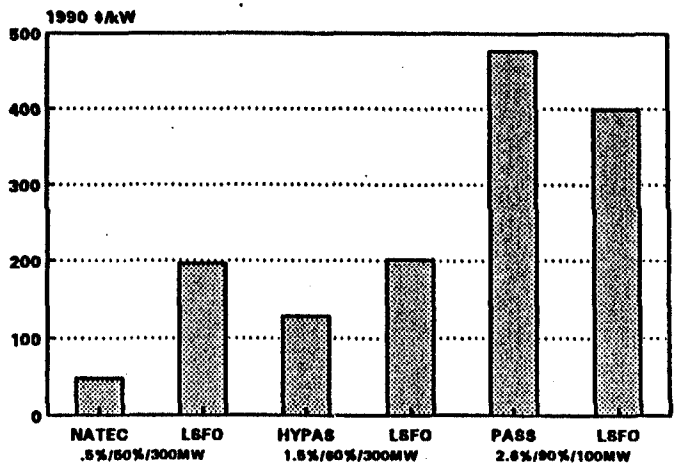
DRY THROWAWAY CAPITAL COSTS
(RETROFIT, 300 MW, 2.6% S)



RECOVERY PROCESS CAPITAL COSTS
(RETROFIT, 300 MW, 2.6% S)

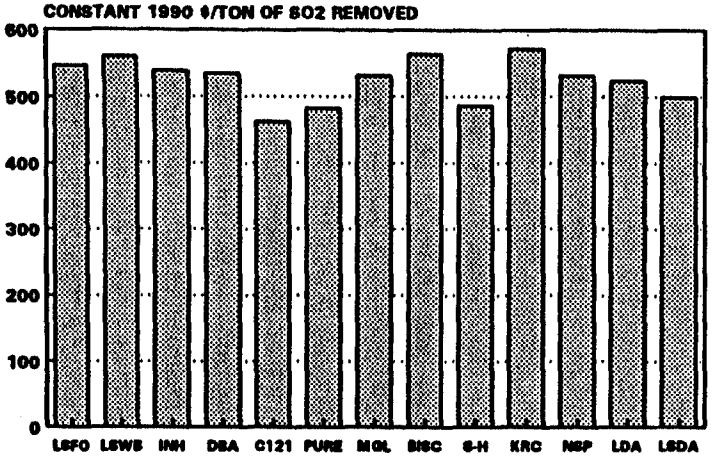


ALTERNATE THROWAWAY CAPITAL COSTS
(RETROFIT, VARIOUS S%, REMOVAL & MW)

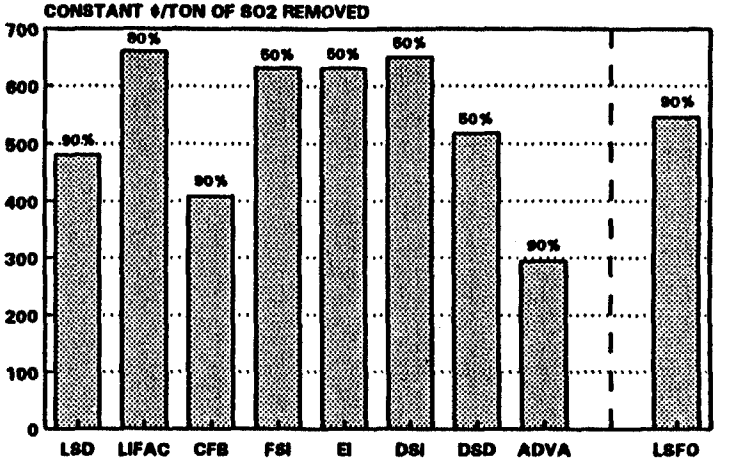


Source: R.J. Keeth, P.A. Ireland, P.T. Radcliffe: Economic Evaluations of 28 FGD Processes; EPRI SO_2 Control Symposium 1991.

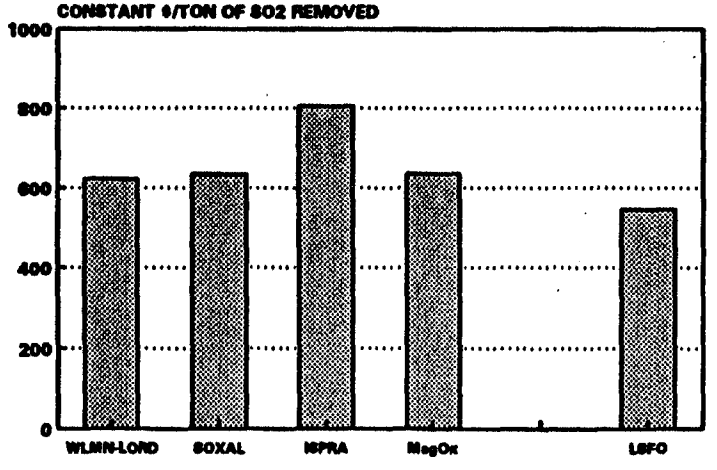
WET THROWAWAY LEVELIZED COSTS
(RETROFIT, 300 MW, 2.6% S)



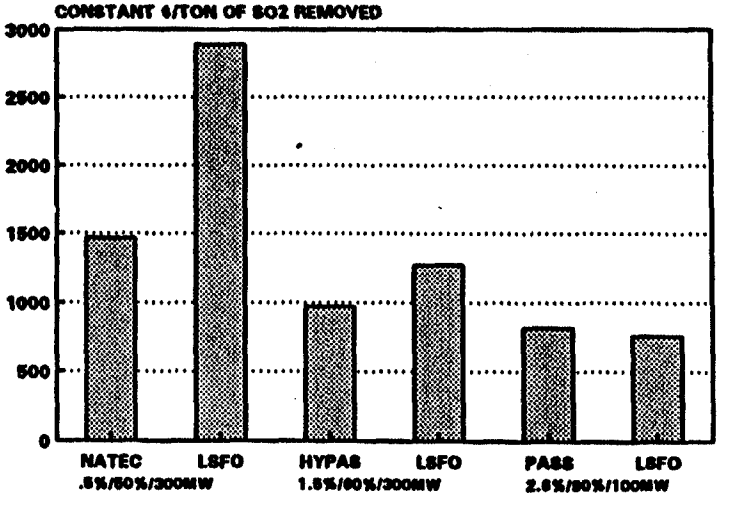
DRY THROWAWAY LEVELIZED COSTS
(RETROFIT, 300 MW, 2.6% S)



RECOVERY PROCESS LEVELIZED COSTS
(RETROFIT, 300 MW, 2.6% S)



ALTERNATE THROWAWAY LEVELIZED COSTS
(RETROFIT, VARIOUS S%, REMOVAL & MW)



STEAM COAL FOR POWER AND INDUSTRY

Current and Projected SO_2 emissions by region (millions tons per year).

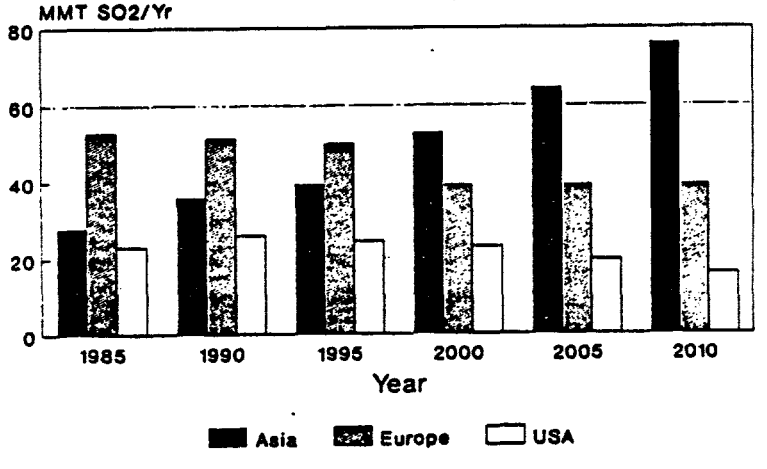
Region/ Country	Emissions of SO_2 in millions tons/year Year 1985	1990	2000	2010
Europe	53	50	39	39
U.S.A.	23	26	23	16
Asia	26	35	53	76
China	17	23	34	49
India	3	4	5.4	6.7
Other	6	8	13.6	20.3

Europe: Emissions estimates based on the RAINS-EUROPE current reduction plan scenario, August 1991.

U.S.A: Estimates obtained from National Acid Precipitation Assessment Program (NAPAP) Integrated Assessment. Draft Sept. 1990.

Asia: Base case scenario, Foell and Green, 1990.

Current and Projected SO2 Emissions by Region



Source: Proposal for an International Collaborative Project on Acid Rain and Emission Reduction in Asia; World Bank September 1991.

STEAM COAL FOR POWER AND INDUSTRY

Pollutant Removal Efficiency

Pollutant Removed (% of Untreated)
(In Brackets: Pollutant Added)

Technology	SO2	NOx	Solid Waste (Ash)	Solid Waste (Other)	Suspended Particulates
Coal benefication					
- Float/sink superaction	65-80	0	60		
- Dry Separation	55-60	0	60		
- Chemical Cleaning	90	0	34-42		
- Coal/Water Mixtures	49-77	0	90		90
Pulverized Coal with FGD					
- Average Without SCR	90	0	0	(50-200)	0
- Average with SCR	90	80-90	0	(50-200)	0
- Advanced with sale of by-product	90-99	0	0		65
Fluidized bed Combustion					
- Atmospheric (AFBC)	90-95	60	0	(40-130)	0
- Prescribed (PFBC)	90-95	70	0	(40-130)	0
Slagging Combustor	60-90	50	0	(50-190)	(100)
Limestone Injection Burner	50-60	50-60	0	(40-130)	0
Gas Reburning	10-20	60	20		
IGCC	92-99	92	0-60		65

Source: B. Guerami: Prospects for Coal and Clean Coal Technology; WDR 1992 Background Paper No. 20.

FGD PROCESSES EVALUATED IN EPRI STUDY

Wet Throwaway

Limestone with Forced Oxidation (LSFO)
Limestone with Wallboard Gypsum (LSWB)
Magnesium Enhanced Lime (MGLM)
Limestone/Inhibited Oxidation (LSINH)
Limestone with Dibasic Acid (LSDBA)
Pure Air/Mitsubishi (PURE)
CT121/Bechtel (CT121)
NSP Bubbler (NSP)
Passamaquoddy Recovery Scrubber (PSMQY)
Saarberg Holter (S-H)
BISCHOFF (BSHF)
Noell/KRC (KRC)

Regenerable Throwaway

Lime Dual Alkali (LDA)
Limestone Dual Alkali (LSDA)

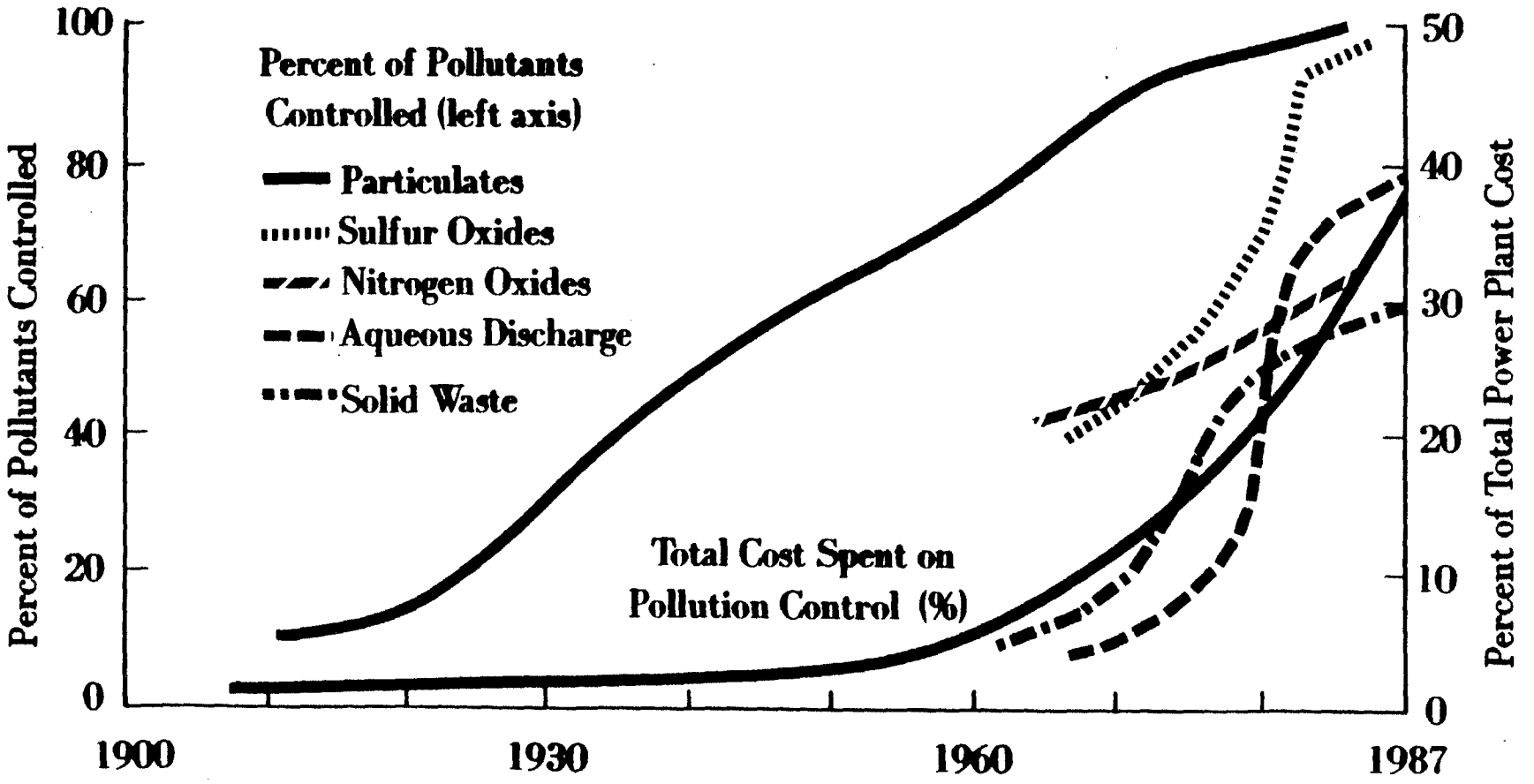
Dry Throwaway

Lime Spray Dryer (LSD)
Furnace Sorbent Injection (FSI)
Economizer Injection (EI)
Duct Sorbent Injection (DSI)
Duct Spray Drying (DSD)
Tampella LIFAC (LIFAC)
Lurgi Circulating Fluid Bed (CFB)
HYPAS (HYPAS)
ADVACATE/Moist Dust Injection (ADV)
NaTec Dry Sodium Injection (NATEC)

Sulfur Recovery

SOXAL (SOXAL)
Wellman-Lord (WM-LD)
Magnesium Oxide (MgO)
ISPRA Bromine (ISPRA)

PERCENTAGE OF POWER PLANT COST SPENT ON POLLUTION CONTROL AS PERCENTAGE OF POLLUTANTS CONTROLLED INCREASES



Source: "Coal-fired Power Plants of the Future," Scientific American, Sept., 1987

STEAM COAL FOR POWER AND INDUSTRY

Standards of Ambient Air Quality and Emissions

A. Standards of Ambient Air Quality
(Unit: mg/m3, unless otherwise indicated)

	Annual Average	Daily Maximum	Once Maximum
1. SO2			
China \h Class I	0.02	0.05	0.15
II	0.06	0.15	0.50
III	0.10	0.25	0.70
India		0.12	
Indonesia		0.26 (0.10 ppm)	
Philippines		0.369 (0.14 ppm)	0.85 \e (0.3 ppm)
Thailand	0.10	0.30	
World Bank Guidelines	0.10	0.50	
USA Primary \a	0.08 (0.03 ppm)	0.365 (0.14 ppm)	
Secondary \b	0.06 (0.02 ppm)	0.26 (0.1 ppm)	1.30 \c(0.5 ppm)
FRG			
Japan		0.04 ppm	0.1ppm\e
2. NOX			
China Class I	0.12	0.05	0.10
II	-	0.10	0.15
III	-	0.15	0.30
India			
Indonesia		0.0925 (0.05ppm)	
Philippines			0.19\e (0.10ppm)
Thailand			0.32\e
World Bank	0.1 (0.05ppm)	-	-
USA Primary	0.1 (0.05ppm)	-	-
Secondary	0.1 (0.05ppm)	-	-
Japan	0.02 - 0.03ppm	0.04 to 0.06ppm	-

3. Dust

China			
a) Total suspend			
Class I	-	0.15	0.30
\f II	-	0.30	1.00
III	-	0.50	1.50
b) Fly dust			
Class I	-	0.05	0.15
\g II	-	0.15	0.50
III	-	0.25	0.70
India		0.50	
Indonesia	-	0.26	-
Philippines	-	0.15	0.25\e
Thailand	0.1	0.33	-
World Bank	0.1	0.50	-
USA\d Primary	0.075	0.26	-
Secondary	0.06	0.15	-
FRG			
Japan		0.1\g	0.2\e \g

Note:
\a Primary based on health effects on humans.
\b Secondary based on environmental effects.
\c Max 3 hour concentration.
\d In 1990, EPA revised the standards for total suspended particulate matter. It has been observed that the particles that are most closely correlated with adverse health effects are those having a diameter of 10 micron or less. The revision of the NAAQS (National Ambient Air Quality Standards) provides that:
--Primary standards are set only for particles 10 micron or less in diameter. (This is called the PM10 standard).
--The primary annual average PM10 standard is 0.065 mg/m3.
--The primary 24 hour PM10 standard is 0.15 mg/m3.
It has been proposed that the secondary 24 hour standard be changed to a value between 0.07 and 0.09 mg/m3.
\e One hour average.
\f Suspended particles of 100 microns or less in diameter.
\g Suspended particles of 10 microns or less in diameter.
\h Class I standards are the ideal. They are intended to apply to nature conservation areas, resorts and historical areas.

Class II standards establish threshold concentrations beyond which chronic effects on humans and adverse effects on plants are likely to occur. They are intended to apply to urban residential, commercial, cultural or rural areas.

Class III standards represent interim targets in areas already subject to heavy pollution. A number of cities exceed these targets.

B. Standards for Emissions from Coal Fired Power Generating Plants
(Units as Indicated)

1. SO2

China	17.557 tph	(31.1 tph)
Indonesia	0.30 g/m3 (SO3)	
Philippines	1500mg/scm (573ppm)	
Thailand		
World Bank	4.2-21.0 t/h \a	
	0.01-0.05 mg/m3 \b	
USA \c	2.5 lb/million Btu heat input (1073ppm) (by 1/1/95)	
	1.2 lb/million Btu heat input (515 ppm) (by 1/1/2000)	

2. NOx

China		
India		
Indonesia	0.17 - 0.46 g NOX/m3	
Philippines	2g/scm	
Thailand		
World Bank	Coal: 300 nanogram/J	(417ppm)
	Lignite: 260	(361ppm)
USA \c	0.45 lb/million Btu (269ppm) for tangentially fired boilers; 0.50 lb/million Btu (300 ppm) for dry bottom, wall-fired boilers (both of the above two items by 1/1/95); Not decided for other type of boilers.	
Japan	>700 MW	200ppm
	< 40 to 500 MW<	250ppm
	< 5 to 40 MW<	300ppm

3. Dust

China I	200 mg/m3
II	400
III	600
India	350 mg/m3 (<210 MW); 150 mg/m3 (<210 MW)
Indonesia	
Philippines	300mg/scm (new boilers); 500mg/scm (existing boilers)
Thailand	
World Bank	100 mg/m3 (urban), 150 mg/m3 (rural)
USA \c	50 mg/m3

Japan	(ordinary)	(special) \e
(a) For Coal of 5,000kcal/kg and more:		
Gas volume: <200,000 m3/h	0.10g/m3	0.05
< 40,000 - 200,000<	0.20	0.10
40,000<	0.30	0.15
(b) For coal of 5,000 kcal/kg and less:		
	0.80	0.40

\a Criterion I: Maximum SO2 emission (tph), dependent on background levels: Lower value in moderately polluted environment; higher value in unpolluted environment.

\b Criterion II: Maximum allowable ground level increment to ambient (mg/m3 one year average).

\c Clean Air Act Amendments (CAAA) of 1990: See Para C.

\d Japanese criteria for emissions: q = Kx10^(-3) x He^(2)
where q is the hourly volume of sulphur oxides emitted (Nm3/h) and He, effective height of stack, is the sum of actual height of stack and smoke ascent height. The size of K, which varies according to the region, inversely determines the degree of regulation, for the effect of a reduction in K is a much stiffer control standard. The standard for sulphur oxide has hence been labelled the "K-value regulation." All of Japan is controlled under sixteen K ranks ranging 3.00 to 17.5. Example: Tokyo, Osaka, Nagoya, etc.:
K = 3.0.

\e Special emission standards are applied to Tokyo, Yokohama, Nagoya, Osaka, etc.

C. USA Clean Air Act Amendments (CAAA) 1990 (USEPA)

A summary of effects on power generation industry is as follows:

Title I:	Non-Attainment Provisions
III:	Air Toxic Provisions
IV:	Acid Rain Provisions
V:	Permit Provisions

SO2 Emissions (Title IV): The present level of SO2 emission in USA total is 16 million tons per year. The approximately 8 mtpy reduction in SO2 emissions are to take place in two phases, with the Phase I goal about half by 1/1/95, and the remainder in Phase II by 1/1/2000. SO2 reductions will be achieved through the use of a new emission "allowance" program and a nationwide utility average emission rate limit. An allowance is the authority to emit one ton of SO2 in a year. The SO2 emission rate limit in each phase will be enforced by allocating the total number of allowances based on an average utility system-wise emission rate limit. A Phase I emission rate limit of 2.5 lb of SO2 per million Btu of energy input (equivalent to 1075 ppm) is imposed by controlling emissions on 261 specifically listed electric utility boilers at 110 utility power plants. The allowance system will carry over into Phase II which is applied to all utility units and limits emissions at 1.2 lb of SO2 per million Btu of energy input (equivalent to 516 ppm). There will also be an overall Phase II cap of

8.9 mt of SO2 per year for the total nationwide emissions of SO2 after 1/1/2000. This overall cap will be enforced by limiting the number SO2 allowances to 8.9 million. After 1/1/2000 (1995 for Phase I affected units) a utility plant owner must have 1 allowance for each ton of SO2 emissions. A utility unit is defined as one 25 mW and larger that sells more than 1/3 of the power output.

NOX Emissions (Title IV): The acid rain control requirements target a 2 million ton per year NOX reduction which is to be achieved by 1/1/95 by installing low nox burners on the same 261 Phase I "affected units" (existing utility boilers) that must reduce their SO2 emissions. Allowance NOX emission levels for Phase II affected units are to be established by EPA in regulations to be issued by 1/1/97 and must be met on Phase II units by 1/1/2000. The requirements are specified in terms of an emission limit in pounds per million Btu heat input to be achieved on an annual basis. The value of emission limits cannot be higher than the following: emission limit at 0.45 lb of NOX/million Btu for tangentially fired boilers and 0.50 lb of NOX/million Btu for dry bottom, wall-fired boilers. However, EPA can set higher limits if these rates cannot be achieved using low NOX burners. Affected units will not be required to install additional emission controls beyond low NOX burners. Time constraints are tight, with compliance required by 1/1/95.

Particulates (Title I): PM 10, Non attainment. The PM-10 NAAQS is 50 micrograms per cubic meter (annual average). All PM-10 non-attainment areas are assumed to be "moderate" with an end of 1994 attainment deadline. EPA has the authority to reclassify an area to "serious" at its discretion with a 2001 attainment deadline. In moderate areas, a new source review will be required and "reasonably available control measures", RACM, will be required by 1993. Use of "best available control measures", BACM, is required by the end of 1994, and a new source review will be required for all sources emitting 70 TPY or more of PM-10.

Source: S. Kataoka: Technical Note on Coal Burning Plant and Emission Control Technologies, World Bank, January 1992.

STEAM COAL FOR POWER AND INDUSTRY

Emission Control Technologies

1. Various type of emission control technologies have been developed by power utility companies and plant equipment manufacturers. There are three categories in environmental emission control technologies: (i) Precombustion control; (ii) In-situ control; and (iii) Postcombustion control. These technologies can be applied for both of new plant and retrofit.

2. Number and installed capacity (in MW) of coal-fired units with Flue Gas Desulfurization (FGD) in use as of December 1989 is shown in the following table: (Source: IEA Coal Research, April 1990.

Country	Retrofit		New		Not Known		Total	
	No.	MWe	No.	MWe	No.	MWe	No.	MWe
Austria	5	672	4	1117	1	100	10	1889
Czechoslovakia	4	400	-	-	-	-	4	400
Denmark	1	350	1	250	-	-	2	600
FRG	140	33579	20	3967	18	2721	178	40263
Finland	3	540	-	-	-	-	3	540
France	-	-	1	600	-	-	1	600
GDR	1	250	-	-	-	-	1	250
Japan	21	4040	8	4050	14	2764	43	10854
Netherlands	7	2750	-	-	-	-	7	2750
Sweden	12	683	9	403	-	-	21	1086
Turkey	-	-	3	36	-	-	3	36
USA	50	13572	119	5707	60	1972	229	72615

Types of coal fired units with FGD in use as of December 1989 are as follows: (Source: IEA Coal Research, April 1990).

Country	Limestone/ Gypsum FGD		Other wet Scrubbers		Spray dry Scrubbers		Sorbent Injection		Others	
	No.	MWe	No.	MWe	No.	MWe	No.	MWe	No.	Mwe
Austria	3	690	1	100	3	397	3	312	-	
Cz,slovak	1	200	-	-	-	-	2	*	1	200
Denmark	1	250	-	-	1	350	-	-	-	-
FRG	124	34782	1	64	32	2870	1	770	11	1787
Finland	-	-	-	-	1	260	2	280	-	-
France	-	-	-	-	-	-	1	600	-	-
GDR	-	-	-	-	-	-	-	-	1	250
Japan	39	10652	2	202	-	-	-	-	2	*
Netherlds	7	2750	-	-	-	-	-	-	-	-
Sweden	-	-	1	7	8	547	12	532	-	-
Turkey	3	36	-	-	-	-	-	-	-	-
USA	11	5985	162	55991	43	7228	1	350	12	3061
Totals	189	55345	167	56364	88	12042	31	2834	27	5298

Note: * Capacity not known.

3. Wet limestone-gypsum in which gypsum, biproduct of the system, is utilized is mainly used in Japan and Germany. Other wet scrubbers, so-called "throwaway" FGD system in which the absorber product is disposed of is mainly used in USA. Those two wet systems have SO2 removal efficiencies of 90%. Dry scrubbing with spray dryer involves the injection of a lime slurry into the flue gas stream ahead of the particulate collection device. SO2 removal efficiencies range from 70 to 90%. Sorbent injection system involves the injection of dry calcium sorbents into either the furnace or ductwork where the sorbent reacts with the SO2. This system is a low-capital-cost retrofit technology suitable for applications where low (less than 50%) SO2 removal is required.

4. Major means of NOX removal technology are as follows:

(1) Low NOX designs applied to boiler:

Fuel:	Gas	Oil	Coal
(a) Sulfur in fuel (%)	0	0.1-0.3	1-3
(b) Gas Recirculation (F)	250-350	350-500	500-800
(c) Two stage combustion (T)	150-200	200-300	400-600
(d) Low NOX Burners (L)	100-200	150-250	250-400
(e) F+T+L	40-80	80-150	150-250

(2) DeNOX System: Selective Catalytic Reduction (SCR)

5. Alternative types of dust collectors are:

(a) Electrostatic Precipitator (ESP)
(b) Pulse jet fabric filter (PJFF)
(c) Reverse air fabric filter (RAFF)
(d) Cyclose separator
(e) Wet Scrubber
(f) Wet Collector

6. In the category of precombustion control, the following three methods are currently used:

(a) Coal cleaning
(b) Coal switching
(c) Coal blending

7. Cost comparisons and economic evaluations relating to mitigation of environmental emissions of various types of fossil fuel thermal power plants are presented in various publications. Some examples are summarized in the following tables:

(A) Table 1.

Serial No.	Type of Plant	Cost ($/Kw)
(1)	Wet FGD	180-260
	Sulfur recovery FGD	250-380
	Dry FGD	50-220
(2)	Wet FGD (Emission reduction percentage: 90%)	150-280
	Spray Dryer (70-90%)	140-210
	Dry injection (50%)	70-120
(3)	Wet FGD (400 MW)	175
	Spray Dryers and Dry FGD	75
	SCR (NOX reduction: 80%)	100
(4)	Wet FGD	133-150
	SCR (NOX reduction: 80%)	40-53
(5)	LNB+OFA	20-25
	LNB+OFA+Return or SNCR	25-50
	LNB+OFA+SCR	100-150

(6)	LS-FGD (475 MW)	140
	L-FGD (770 MW)	130
	LS-FGD (2700 MW)	240
	LSD-FGD (256 MW)	170
(7)	New 300 MW PC plant w/LNBs (Emission control SOX/NOX 0/50%)	1150
	Additional costs for:	
	(a) PC plant w/scrubber (90/50%)	70
	(b) PC plant w/scrubber SCR (90/80%)	320
	(c) Low NOX/SOX Burner (90/80%)	5
	(d) FBC Boiler w/SCR (90/80%)	175
	(e) IGCC (90/80%)	350
(8)	500 MW Conventional PC	1300-1600
	500 MW FBC	1100-1500
	500 MW IGCC	1100-1900
(9)	80 MW PFBC	2000

(B) Table 2

(700 MW Class Coal Fired)

Type	PC*1	PC*2	PC*3	AFBC	PFBC	IGCC
W/FGD	No	Yes	Yes	Yes	Yes	No
W/SCR	No	Yes	Yes	Yes	Yes	No
W/ESP	No	Yes	Yes	Yes	Yes	No
Emissions:						
SO2 (ppm)	1000	100	100	30		
NOX (ppm)	300	60	60	40	30	30
Dust (mg/m3)	20000	30	30	10	5	5
Gross output (MW)	700	700	700	700	700	700
Aux Power (%)	7	8	9	8	3	12.7
Net output (MW)	651	644	637	644	679	611
Plant net eff (%)	35.0	35.3	37.1	36.0	39.5	40.5
Plant net H/R (BTU/KWH)	9751	9669	9199	9481	8641	8427
Investment ($/KW)	1300	1670	1735	1500	1500	1800

Source: S. Kataoka, 1992

Table 3:
High-Temperature Particulate-Removal Systems

Type of System	Manufacturer	Capacity, ACFM	Collection Efficiency, %	Minimum Part. Size with Efficiency >50%, μ	Maximum Operating Temp, °F	Maximum Operating Pres, atm	Maximum Collection Efficiency, %	Applicable Dust Loading Range, gr/SCF	Pressure Drop, in. W. G.	Status
Mechanical Collectors										
Cyclones	Buell	50,000	80-90	5-10	1400	2	90-95	--	4-40	Commerc.
	Ducon	58,000	80-90	5-10	1500	10	90-95	--	4-40	Commerc.
Tornadoes	Aerodyne	30,000	93-97	0.5	1500	10	98	<30	30	Commerc.
Bed Filters										
Granular	Combust'n Pwr.	--	>90	2	1400	--	>90	--	10-15	Under Dev.
	Ducon	--	--	--	--	--	--	--	--	Under Dev.
	C.U.N.Y.	--	--	--	--	--	--	--	--	Under Dev.
Panel Rex	Rexnord	20,000	95-99	--	>900	1	>99	<40	4-15	Commerc.
Sonic-Agglomeration Collection Systems										
Alternating Veloc. Precip.	Braxton	--	--	--	--	--	--	--	--	Under Dev.
Scrubbers										
Fused Salts	Battelle	--	--	--	--	--	--	--	--	Under Dev.
Filters										
Metal & Ceramic	Michigan Dynamics	--	>99	<0.5	2000	1	>99	--	--	Commerc.
Electrostatic Precip.	--	--	>99	<0.5	800	1	>99	--	<1	Commerc.

Source: Power Technologies, Inc., 1991

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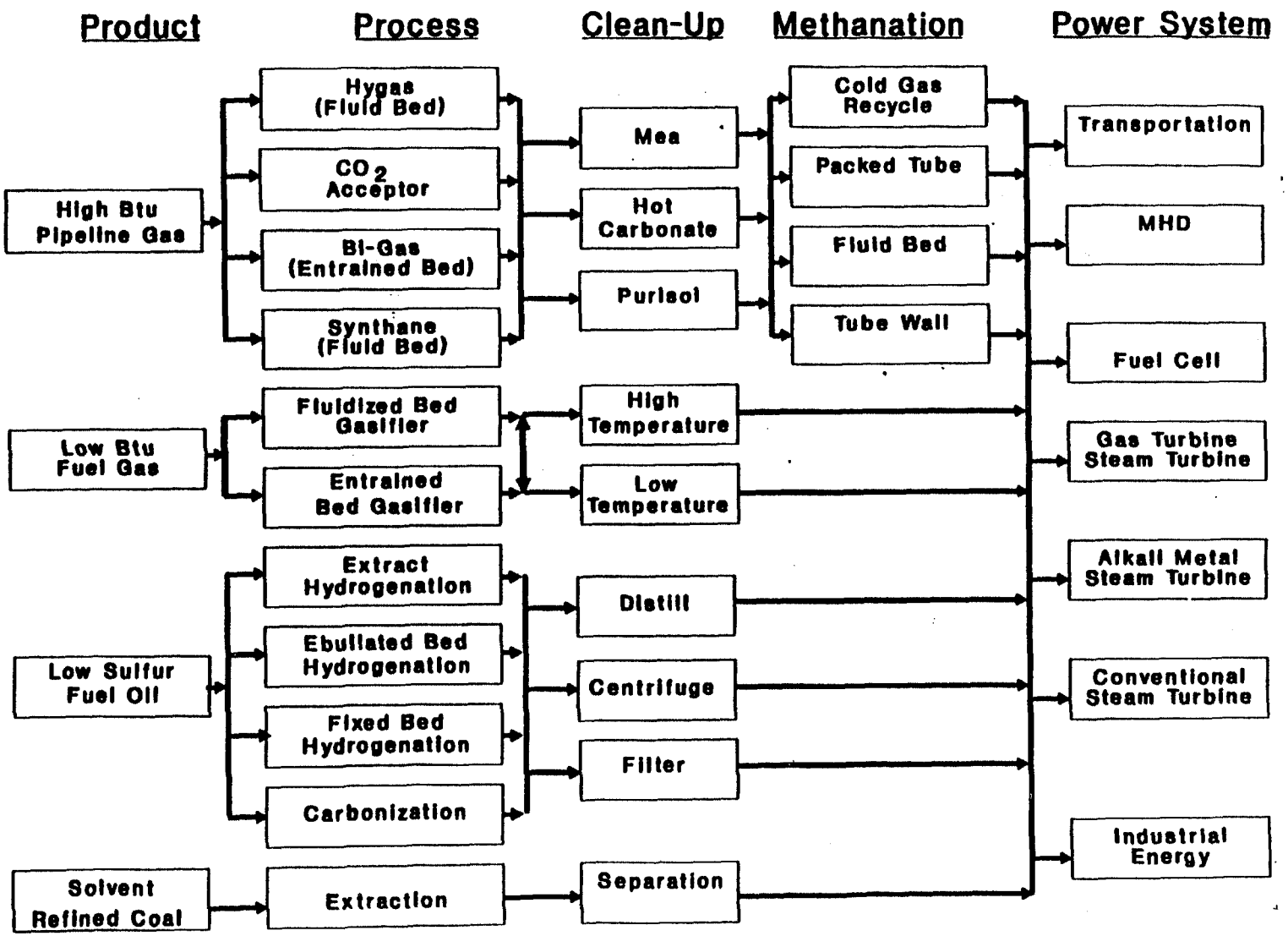
Coal Conversion and Refining Processes

1. Clean Energy From Coal Program



Source: Power Technologies Inc., 1991.

2. TYPICAL FUEL SPECIFICATIONS

FUEL ANALYSIS	Petroleum No. 2 Fuel Oil	Coal-Derived Fuels: Solid Boiler Fuel SRC-I	Liquid Boiler Fuel Heavy[a]	Liquid Boiler Fuel Distillate[b]	Turbine Fuel Distillate[c]	Intermediate-Btu Gas[d]
Nominal boiling range, °F	300 to 700	-	400+	350 to 700	325 to 700	-
Gravity, °API	32	-	-7.5	10.7	25.7	-
Viscosity, cSt, 100°F	2.6	-	500	3	2	-
Flash point, °F	150	-	150+	150+	150+	-
Proximate analysis, %						
Moisture (as-received)	-	2.21	-	-	-	-
Volatile matter	-	66.49	-	-	-	-
Fixed carbon	-	31.20	-	-	-	-
Ash	-	0.10	-	-	-	-
Total		100.00				
Ultimate Analysis, wt%						
Ash	-	0.10	200 ppm	0.03	-	-
Sulfur	0.1	0.68	0.48	0.23	0.01	-
Hydrogen	12.50	5.77	7.37	8.96	11.40	-
Carbon	87.38	84.29	88.15	86.26	88.46	-
Nitrogen	0.02	2.06	1.30	0.91	0.04	-
Oxygen	-	4.89	2.70	3.61	0.09	-
Moisture	-	2.21	-	-	-	
Total	100.00	100.00	100.00	100.00	100.00	
Heating Value, Btu/lb (as-received)	19,400	15,240	16,700	17,200	18,970	-
Ash Softening Temperature °F	-	1,990	-	-	-	-
Mole %						
CH_4	-	-	-		-	0.40
H_2	-	-	-	-	-	36.50
CO	-	-	-	-	-	50.90
CO_2	-	-	-	-	-	11.00
H_2S	-	-	-	-	-	0.15
COS	-	-	-	-	-	0.07
N_2	-	-	-	-	-	0.80
Ar	-	-	-	-	-	0.15
						100.00
Mole wt (Average)	-	-	-	-	-	20.3
Higher Heating Value Btu/SCF	-	-	-	-	-	287

[a]H-Coal® fuel oil, Ref: EPRI AF 710

[b]SRC-II distillate blend, Ref: R. Moshitto (P&M Co.), 13th Inter. Soc. Energy Conv. Conf., August 1978.

[c]Upgraded H-Coal® distillate (by hydrotreating), Ref: EPRI AF 710.

[d]Economics of Texaco gasification process for fuel gas production, FP-239, Task 18, Sept. 1980.

Source: Power Technologies, Inc., 1991

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COAL GASIFICATION

Table 1: **IMPORTANT COAL GASIFICATION PROCESSES FOR POWER GENERATION**

Process	Texaco	Dow	Shell	British Gas/Lurgi	High Temperature Winkler
Developmental Status	Commercial	Commercial	Building first commercial unit	Near commercial (operating demonstration unit)	Near commercial (operating demonstration unit)
Current Gasifier Capacity:					
Coal input - MW_t	300	460	650	170	160
Fuel gas - MW_t	228	359	520	153	132
Heat recovery - MW_t	60	83	104	7	16
Net CGCC - MW	95	161	250	--	--
Type of Process	slurry feed entrained flow slagging	slurry feed two-stage entrained flow slagging	dry feed entrained flow slagging	dry feed moving bed slagging	dry feed fluidized bed dry ash
Feed Coal Characteristics:					
Size	-100 mesh	-100 mesh	-100 mesh	-2 inch	-1/4 inch
Accept fines	unlimited	unlimited	unlimited	some	better
Preferred coal	bituminous	subbituminous or bituminous	any	highly caking bituminous	lignite
Operating Characteristics:					
Exit gas temp. °F (°C)	2,400°F(1,316°C)	1,900°F(1,038°C)	2,600°F (1,427°C)	1,000°F (538°C)	1,800°F (982°C)
Steam requirements	none	none	small	small	moderate
Oxygen requirements	highest	high	high	lowest	moderate
Key Distinguishing Characteristics	large heat recovery	two-stage operation and heat recovery	dry feeding and heat recovery	liquid hydrocarbons in raw gas	large char recycle and non-slagging operation
Key Technical/Economic Issue	large oxygen and heat recovery duty	two-stage operation with bituminous coal	dry feeding and highly integrated operability	coal fines and coal type limitations plus liquid by-product utilization	carbon conversion and non-slagged ash

Source: EFA Pacific, Inc., 1991.

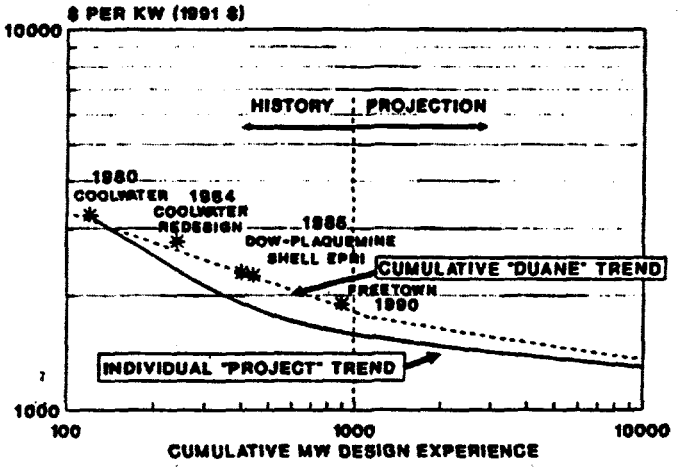

Figure 1 – IGCC Capital Cost Learning Curve

Source: MacGregor, Maslak, Stoll: Market Outlook for IGCC, Power Gen 1991.

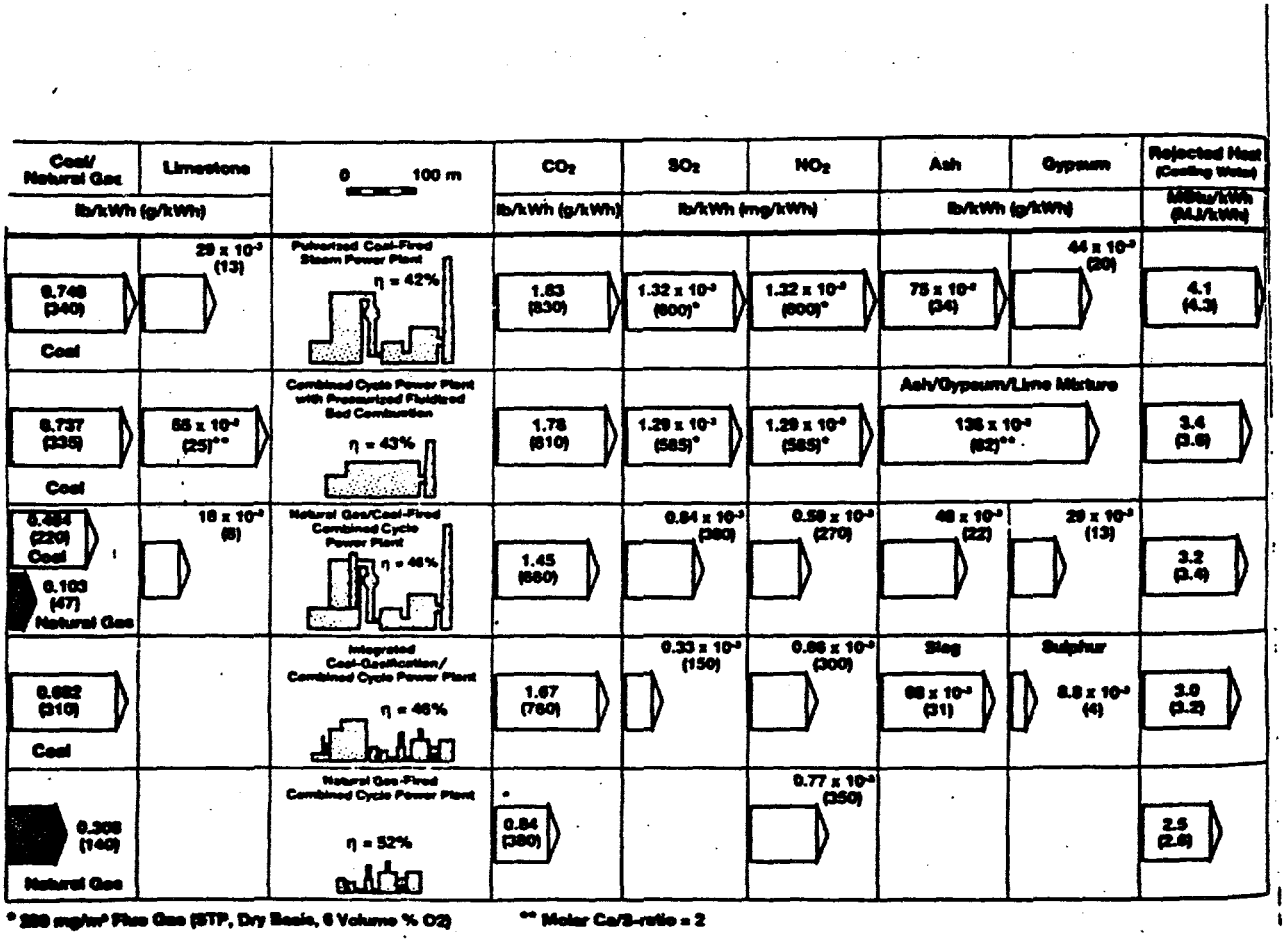

Figure 2: Comparison of Supply Flows, Emissions and By-Products of Different 600MW Class Power Plants

Source: Mueller, Termuchlen: The Future of IGCC Power Plants, Power Gen 1991.

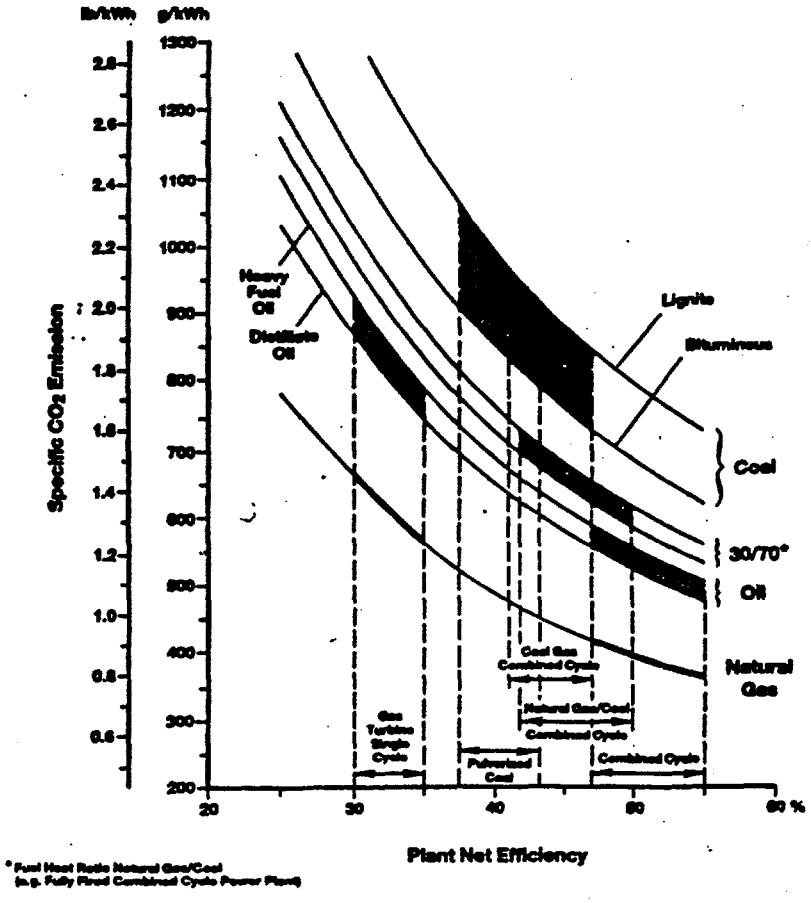

Figure 3: Specific CO_2 Emission from Different Power Plants as a Function of Net Station Efficiency

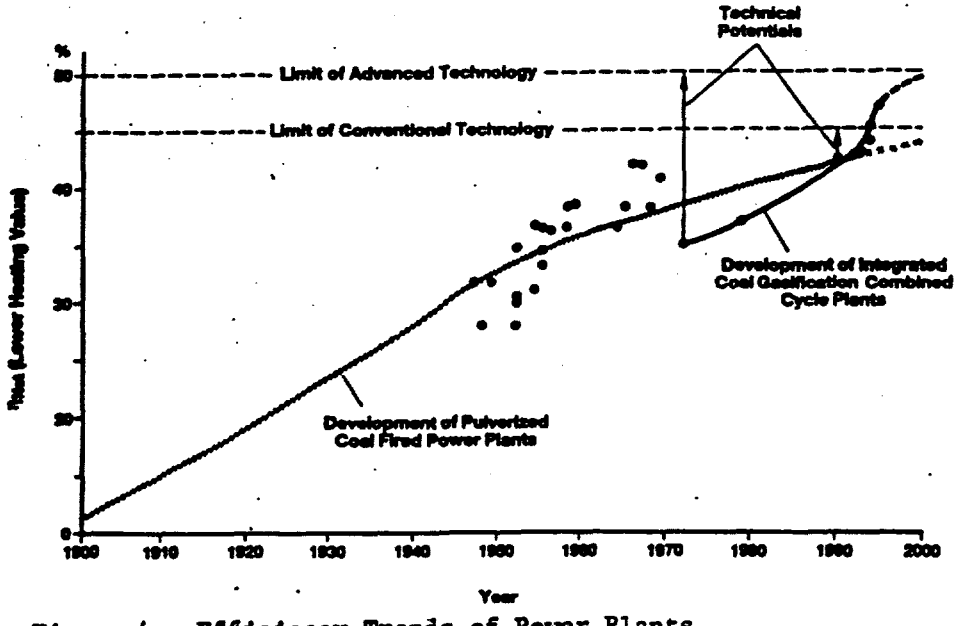

Figure 4: Efficiency Trends of Power Plants.

Source: Mueller, Termuchlen: The Future of IGCC Power Plants, Power Gen 1991.

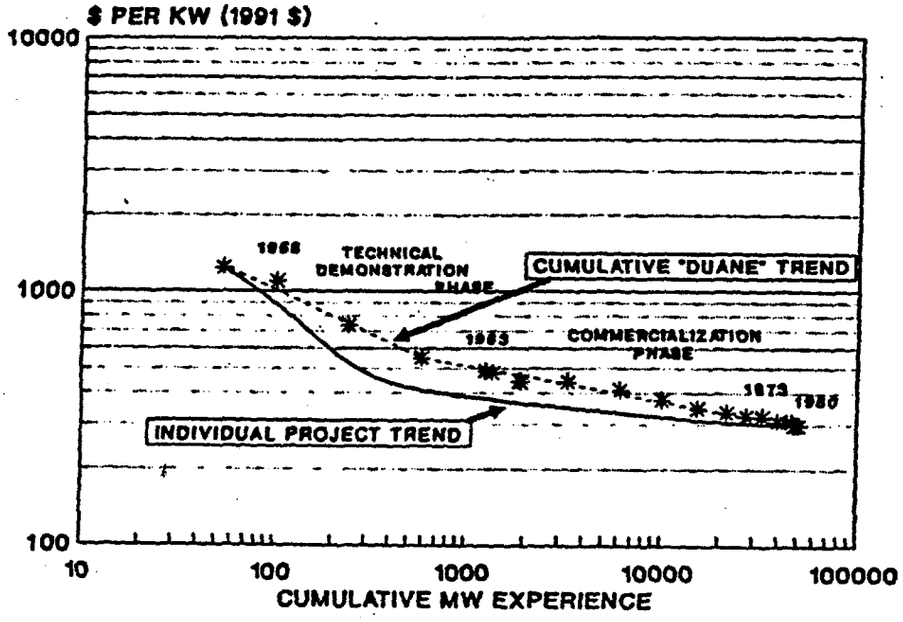

Figure 5 -- Simple Cycle Gas Turbine Capital Cost Learning Curve With Individual Project Cost Trend

Source: MacGregor, Maslak, Stoll: Market Outlook for IGCC, Power Gen 1991.

TABLE 2:
Summary of Major IGCC Projects

Project	Operation Year	MW Size	Status *
British Gas -Lurgi	1975	35	
British Gas -Lurgi	1981	50	
Texaco-Coolwater	1984	120	
Dow-Plaquemine	1987	160	
Shell Oil-Houston	1987	40	
Shell-Netherlands	1993	250	C
Penuelas, P.R.	1995	260	P
HTW/Lurgi-Germany	1995	300	C
Dow-PS Indiana	1995	230	P
C.E.-Springfld, Ill	1995	60	C
Texaco-Freetown,Mass	1996	520	P
Texaco-Delaware	1996	250	P
TECO	1996	250	P
CAC, Canada-Shell	1996	250	P
TAMCO	1996	120	P
Sierra Pacific	1996	90	P
Prenflow-Germany	1997	160	P

* C denotes committed, P denotes planned

Source: Power Technologies, Inc., 1991.

Table 3:

COMPARISON OF SULFUR EMISSIONS (lb/10^6 Btu)			
Gasifier	Coal	Resulitng SO_2 Emissions	EPA Standards
Lurgi	Illinois No. 6	0.10	1.2
Lurgi	Rosebud	0.05	1.2
IGT	Illinois No. 6	0.18	1.2
IGT	Rosebud	0.07	1.2
Foster Wheeler	Illinois No. 6	0.37	1.2
Texaco	Illinois No. 6	0.33	1.2
COMPARISON OF NITROGEN - OXIDE EMISSIONS (lb/10^6 Btu)			
Gasifier	Coal	Resulting NO_x Emissions	EPA Standards
Lurgi	Illinois No. 6	.051	0.7
Lurgi	Rosebud	.064	0.7
IGT	Illinois No. 6	.03	0.7
IGT	Rosebud	0.12	0.7
Foster Wheeler	Illinois No. 6	0.3	0.7
Texaco	Illinois No. 6	0.029	0.7
COMPARISON OF ~~NITROGEN OXIDE~~ PARTICULATE EMISSIONS (lb/10^6 Btu)			
Gasifier	Coal	Resulting Particulate Emissions	EPA Standards
Lurgi	Illinois No. 6	<0.01	0.1
Lurgi	Rosebud	<0.01	0.1
IGT	Illinois No. 6	<0.01	0.1
IGT	Rosebud	<0.01	0.1
Foster Wheeler	Illinois No. 6	<0.01	0.1
Texaco	Ilinois No. 6	<0.01	0.1

Source: Power Technologies, INc., 1991.

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Large Scale AFBC Power Plants

Plant Owner	Country	Comm. Oper. Mo/Yr	No. of Units	Type	Fuel	STEAM lb/hr x 1000	STEAM Pressure psig	Steam Temp	Cycle
Texas-New Mexico Power Company	USA	01/90	2	CFBC	Lignite	1,100	1,990	1,005	Reheat
Compagnie Parisienne de Chauffage	France	10/89	2	CFBC	Bit.coal	840	338	460	Reheat
Compagnie Parisienne de Chauffage	France	/87	2	CFBC	Bit.coal	840	338	460	Reheat
Schuylkill Energy	USA	01/89	1	CFBC	Culm	825	1,500	955	Reheat
Idemitsu Kosan Co. Ltd.	Japan	09/87	1	CFBC	Bit.coal	660	1,849	1,004	Reheat
Stadtwerke Duisburg	FRG	09/85	1	CFBC	Bit.coal	595	2,100	995	Reheat

Source: Power Magazine.

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Comparative Costs of Power Generation

I. Conventional Pulverized Coal Without Environmental Safeguards

1. Average cost of capacity: US$ 1,250/kW
   Annualized at 20 years, 10%: US$145/kW/year

Capacity Cost	US¢/kWh	at	Load Factor (%)
	3.3		50
	2.3		70
	1.8		90

2. Operation and Maintenance: US¢ 1.0/kWh

3. Heat Rate: 9,600 Btu/kWh

4. Coal Cost:

US$/million Btu	US¢/kWh
0.50	0.5
1.00	1.0
1.50	1.4
2.00	1.9
2.50	2.4
3.00	2.9
3.50	3.4

II. Pulverized Coal With FGD, De-NOx and ESP

1. Average cost of capacity: US$1,600/kW
   Annualized at 20 years, 10%: US$ 180/kW/year

Capacity cost:	US¢/kWh	at	Load Factor (%)
	4.1		50
	2.9		70
	2.3		90

2. Operation and Maintenance: US¢ 1.3/kWh

3. Heat rate: 9,900 BTu/kWh

4. Coal cost:

US$/million Btu	US¢/kWh
0.50	0.5
1.00	1.0
1.50	1.5
2.00	2.0
2.50	2.5
3.00	3.0
3.50	3.4

III. Coal-Fired Fluidized Bed Combustion

1. Average cost of capacity: US$1,600/kW
   Annualized at 20 years, 10%: US$ 180/kW/year

Capacity cost US¢/kWh	at Load Factor (%)
4.1	50
2.9	70
2.3	90

2. Operation and Maintenance: US¢ 1.0/kWh

3. Heat Rate:

   Atmospheric FBC: 9,600 Btu/kWh
   Pressurized FBC: 8,600 Btu/kWh

4. Coal cost:

US$/million Btu	US¢/kWh AFBC	US¢/kWh PFBC
0.50	0.5	0.4
1.00	1.0	0.9
1.50	1.4	1.3
2.00	1.9	1.7
2.50	2.4	2.2
3.00	2.9	2.6
3.50	3.4	3.0

IV. Integrated Coal Gasification/Combined Cycle

1. Average cost of capacity: US$1,600/kW
   Annualized at 20 years, 10%: US$ 180/kW/yr

Capacity cost US¢/kWh	at Load Factor (%)
4.1	50
2.9	70
2.3	90

2. Operation and Maintenance: US¢ 1.0/kWh

3. Heat Rate: 8,900 Btu/kWh

4. Coal Cost:

US$/million Btu	US¢/kWh
0.50	0.4
1.00	0.9
1.50	1.3
2.00	1.8
2.50	2.2
3.00	2.7
3.50	3.1

IV. Natural Gas-Fired Combined Cycle

1. Average cost of capacity: US$ 650/kW
   Annualized at 20 years, 10%: US$ 76/kW/yr

Capacity cost	US¢/kWh	at	Load Factor (%)
	1.7		50
	1.2		70
	1.0		90

2. Operation and Maintenance: US¢ 0.5/kWh

3. Heat rate: 7,700 Btu/kWh

4. Natural gas cost:

US$/million Btu	US¢/kWh
1.00	0.8
2.00	1.5
2.50	1.9
3.00	2.3
3.50	2.7
4.00	3.1
5.00	3.9
6.00	4.6

VI. Nuclear

1. Average capacity cost: US$2,500/kW
   Annualized at 30 years, 10%: US$ 265/kW/yr

Capacity cost	US¢/kWh Average Cap. Cost	at + 50%	Load Factor (%)
	6.1	9.2	50
	4.3	6.5	70
	3.4	5.1	90

2. Operation and Maintenance: US¢ 1.0/kWh

3. Heat rate: 10,000 Btu/kWh

4. Fuel cost:

US$/million Btu	US¢/kWh
0.50	0.5
1.00	1.0
1.50	1.5
2.00	2.0

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VII. Total Power Generating Cost (USc/kWh)

PLANT TYPE	Plant Factor (%)	Fuel Cost ($/million Btu) 0.5	1.0	1.5	2.0	2.5	3.0	3.5	4.0	5.0	6.0
Conventional Pulverized Coal	50.0	4.8	5.3	5.7	6.2	6.7	7.2	7.7			
	70.0	3.8	4.3	4.7	5.2	5.7	6.2	6.7			
	90.0	3.3	3.8	4.2	4.7	5.2	5.7	6.2			
Pulverized Coal with FGD, DeNOx and ESP	50.0	5.9	6.4	6.9	7.4	7.9	8.4	8.8			
	70.0	4.7	5.2	5.7	6.2	6.7	7.2	7.6			
	90.0	4.1	4.6	5.1	5.6	6.1	6.6	7.0			
Atmospheric Fluidized Bed	50.0	5.6	6.1	6.5	7.0	7.5	8.0	8.5			
	70.0	4.4	4.9	5.3	5.8	6.3	6.8	7.3			
	90.0	3.7	4.2	4.6	5.0	5.5	5.9	6.3			
Pressurized Fluidized Bed	50.0	5.5	6.0	6.4	6.8	7.3	7.7	8.1			
	70.0	4.3	4.8	5.2	5.6	6.1	6.5	6.9			
	90.0	3.7	4.2	4.6	5.0	5.5	5.9	6.3			
Integrated Coal Gasification/ Combined Cycle	50.0	5.5	6.0	6.4	6.9	7.3	7.8	8.2			
	70.0	4.3	4.8	5.2	5.7	6.1	6.6	7.0			
	90.0	3.7	4.2	4.6	5.1	5.5	6.0	6.4			
Natural Gas Combined Cycle	50.0		3.0		3.7	4.1	4.5	4.9	5.3	6.1	6.8
	70.0		2.5		3.2	3.6	4.0	4.4	4.8	5.6	6.3
	90.0		2.3		3.0	3.4	3.8	4.2	4.6	5.4	6.1
Nuclear - average capital cost	50.0	7.6	8.1	8.6	9.1						
	70.0	5.8	6.3	6.8	7.3						
	90.0	4.9	5.4	5.9	6.4						
- average cost + 50%	50.0	10.6	11.1	11.6	12.1						
	70.0	8.0	8.5	9.0	9.5						
	90.0	6.6	7.1	7.6	8.1						

VIII. Average Cost of Power Sector Options, 1992

	Capacity Cost ($/kW)	Fuel Cost ($/mm Btu)	Total Levelized Cost (¢/kWh) [1]
Conventional pulverized coal	1,250	2.0	5.2
PC with FGD/SCR/ESP	1,600	2.0	6.2
Fluidized bed combustion	1,600	2.0	5.7
IGCC	1,600	2.0	5.7
Natural Gas CC	650	3.0	4.0
Simple Cycle gas turbine	450	3.0	5.0
Oil fired steam	850	3.0	5.0
Fuel Cells	2,500	3.0	7.0
Nuclear	2,500	1.5	6.8
FGD retrofit	180-260		
FGD retrofit with sulfur recovery	250-380		
SCR retrofit	100		
Low-NOx burners retrofit	20-25		
Boiler retrofit for diff.coal	150-300		
Slagging combustor retrofit	400		
LIMB retrofit	150		
IGCC retrofit	350		
AFBC retrofit	300		
Gas cofiring retrofit	3		
Gas reburning retrofit	5-30		
Coal/water mixtures		3-5	
Synfuel from coal refining		3-4	

Sources: S. Kataoka, 1992; B. Guerami, 1992; Conference papers; Industry literature.

1/ At 70% plant factor.

STEAM COAL FOR POWER AND INDUSTRY

POWER SYSTEM IMPACT OF COAL TECHNOLOGIES

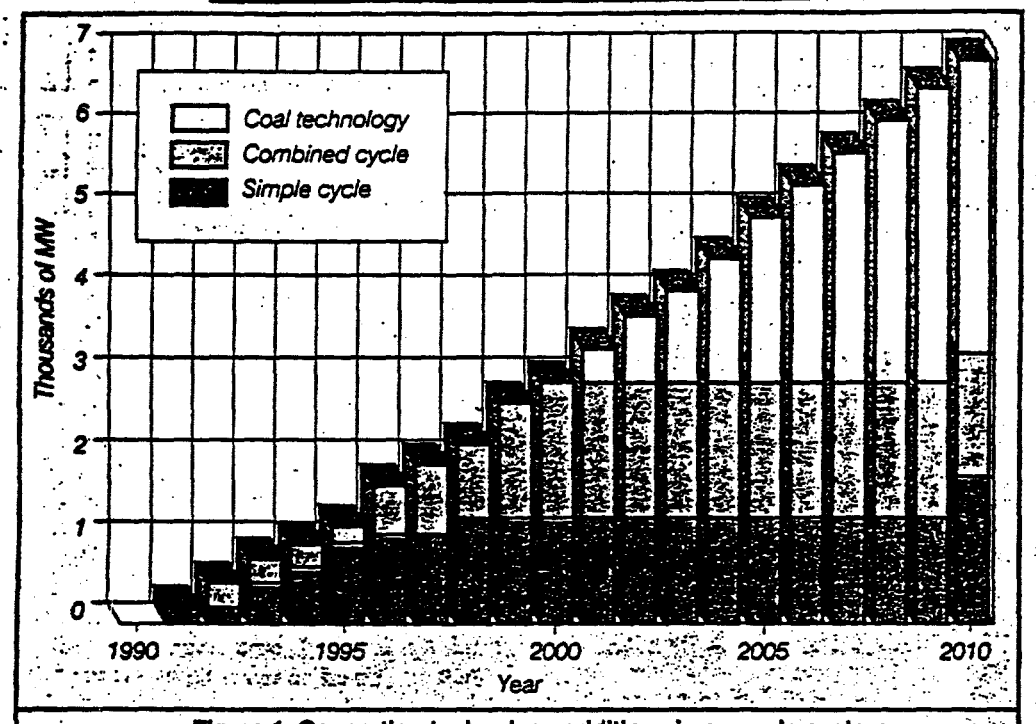


Figure 1. Generation technology additions in example system (DRI fuel cost projection).

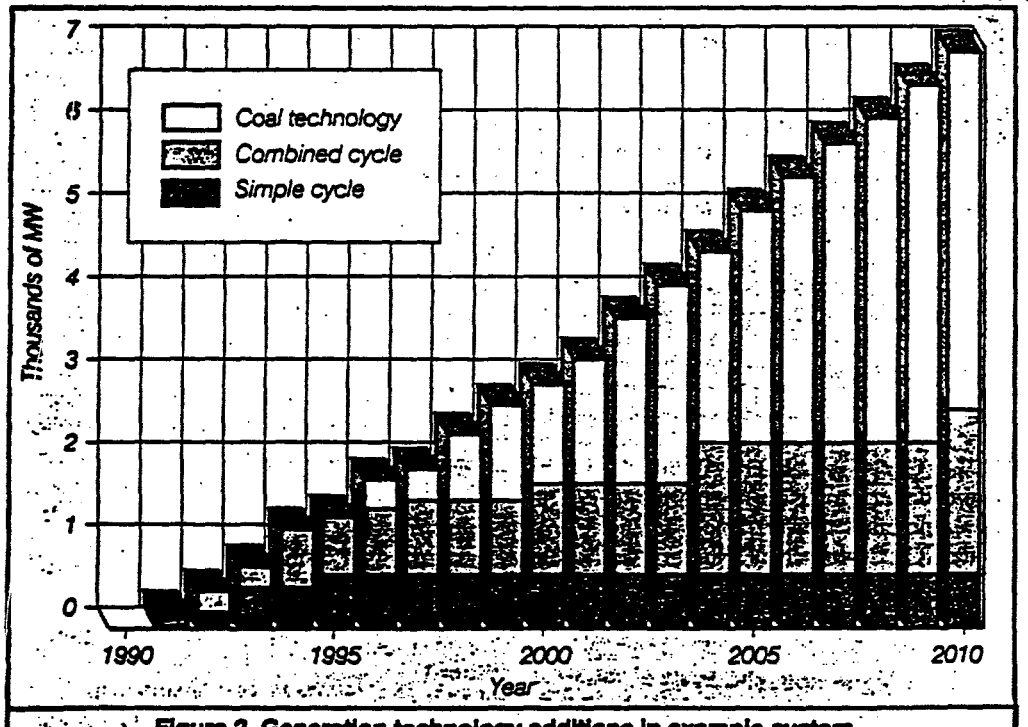
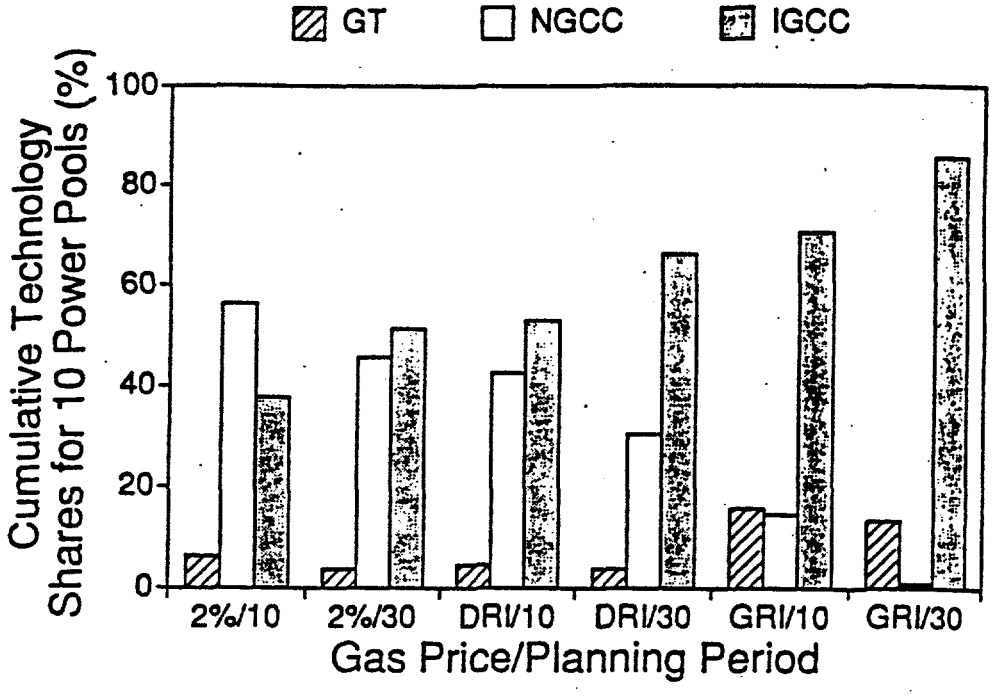


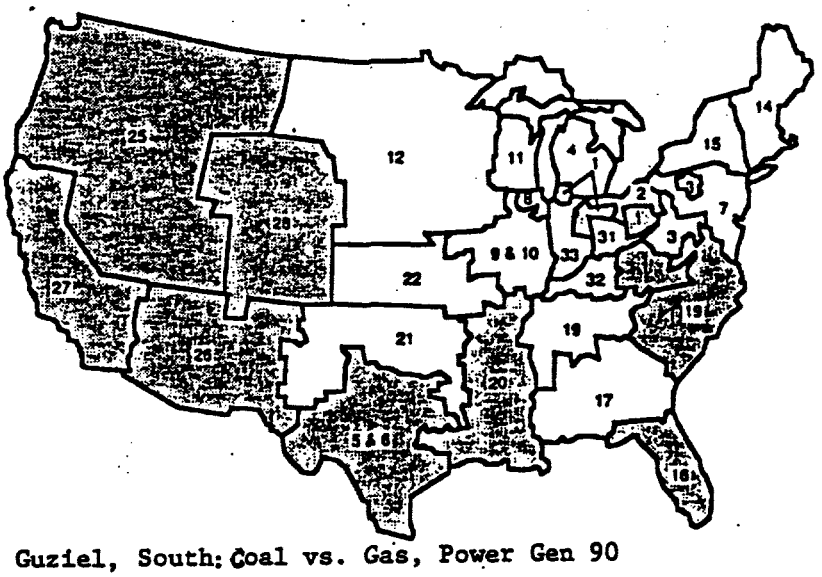
Figure 2. Generation technology additions in example system 50% higher than DRI fuel cost projection.

Source: Power Engineering, August 1991.

BETWEEN 1995-2004, IGCC CAPTURES 38-85% OF MARKETS ANALYZED REGARDLESS OF GAS PRICE OR PLANNING HORIZON, NGCC SHARE DECLINES

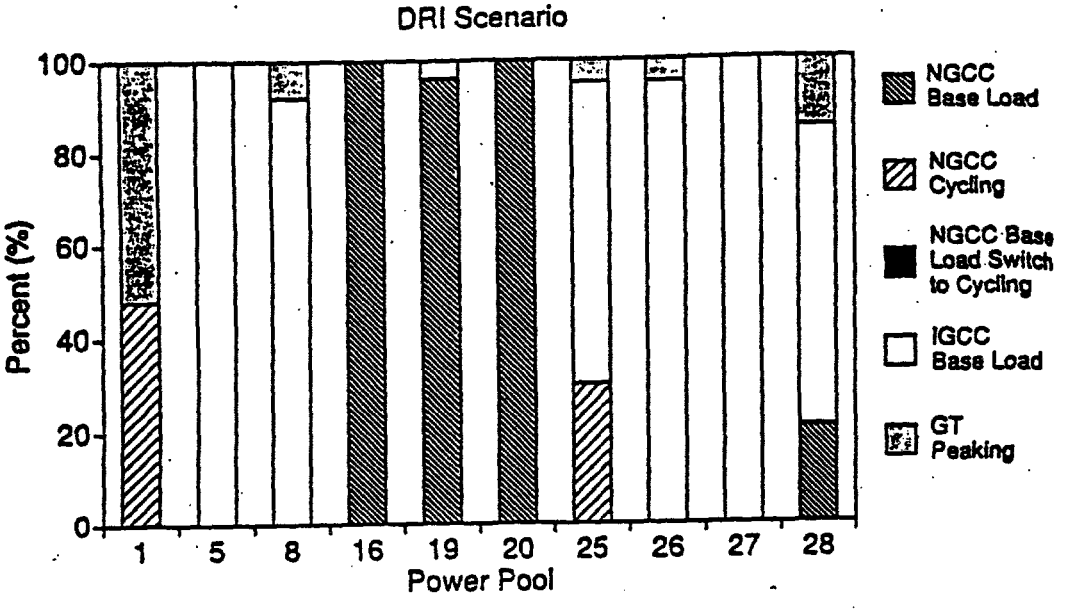


10 POWER POOLS EXAMINED REPRESENTED CHARACTERISTICS OF ALL POOLS IN U.S.

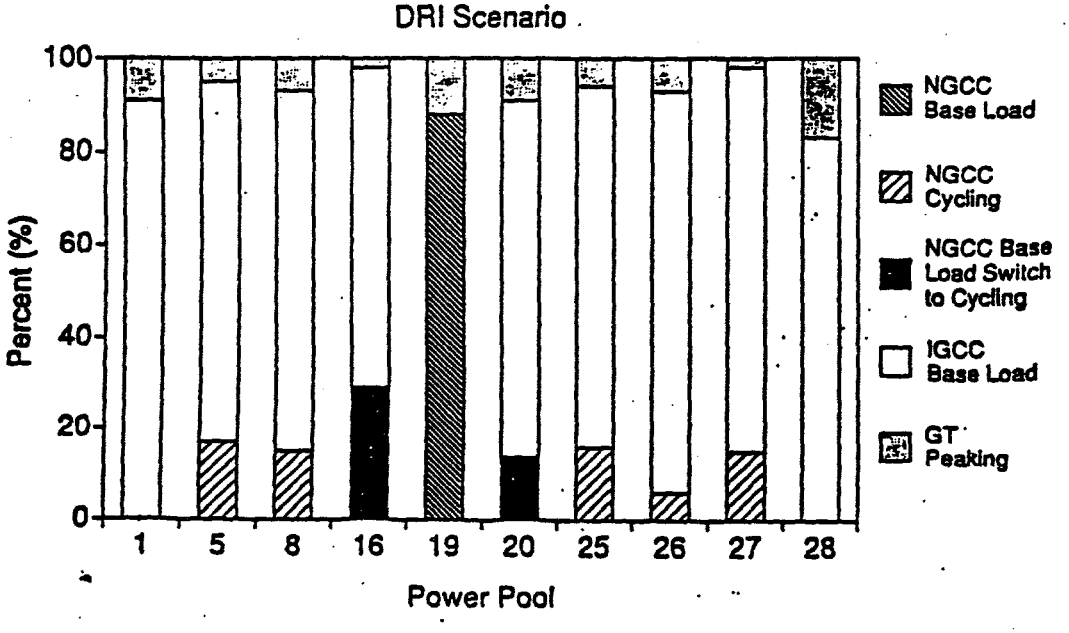


Source: Guziel, South: Coal vs. Gas, Power Gen 90

CUMULATIVE TECHNOLOGY MIX: 1995-2004

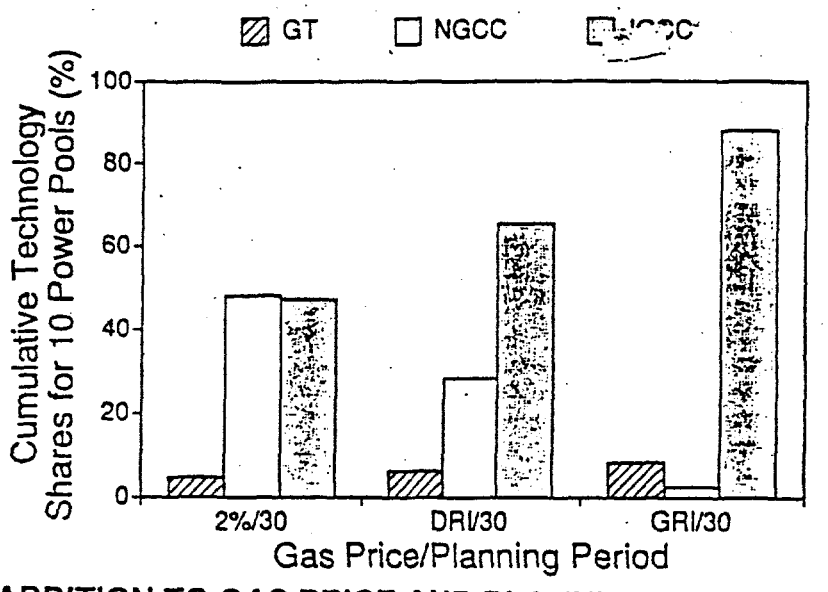


CUMULATIVE TECHNOLOGY MIX: 1995-2024



Source: Guziel, South: Coal vs. Gas, Power Gen 90

OVER LONGER-TERM (1995-2024), THE IMPACT OF GAS PRICES AND PLANNING HORIZON HAVE A MORE SUBSTANTIAL IMPACT ON TECHNOLOGY CHOICE



IN ADDITION TO GAS PRICE AND PLANNING HORIZONS, SYSTEM CHARACTERISTICS HAVE A SUBSTANTIAL IMPACT ON TECHNOLOGY CHOICE

Power Pool	1995-2004			1995-2024		
	2%	DRI	GRI	2%	DRI	GRI
1	●	●	◆	■	◆	◆
5/6	○	◆		■	■	
8	■	◆		■	■	
16	○	○	□	○	▲	▲
19	○	○	◆	○	○	◆

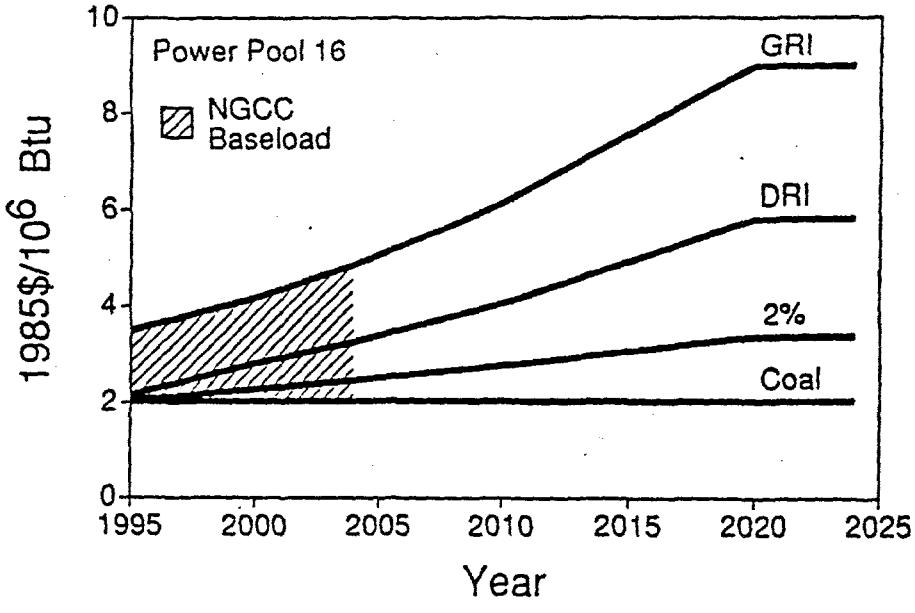
● NGCC units operate strictly as intermediate/cycling capacity. ○ NGCC units operate strictly as base-load capacity.

■ NGCC units operate strictly as intermediate/cycling capacity and IGCC units operate as baseload. □ NGCC and IGCC operate strictly as base-load capacity.

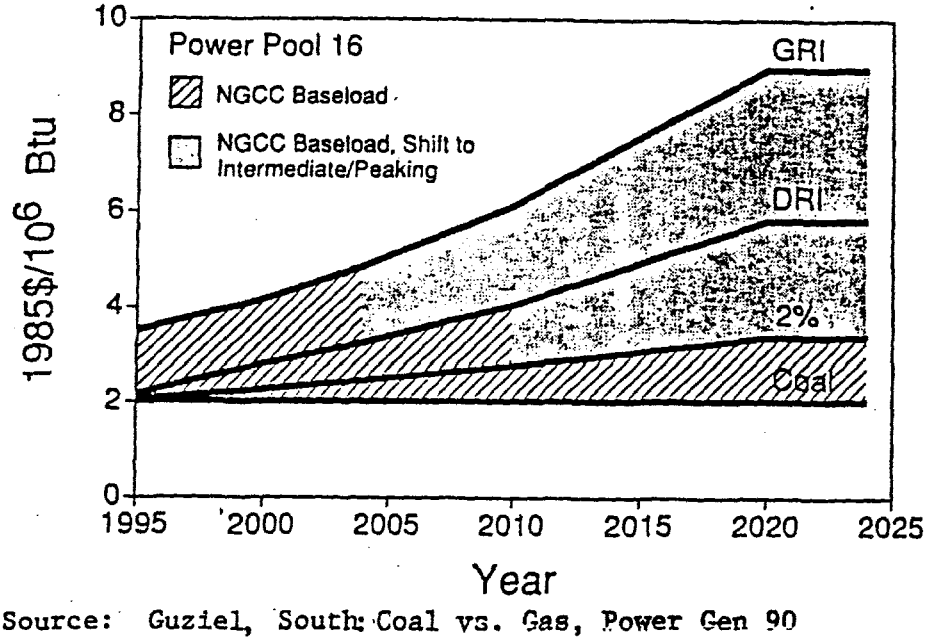
▲ NGCC units operate as base-load capacity in the near term and then shift to intermediate/cycling capacity when IGCC units are added during the later years of the study. ◆ IGCC units operate as baseload.

Source: Guziel, South Coal vs. Gas, Power Gen 90

NGCC OPERATED AS BASELOAD UNDER ALL GAS PRICES, 10 YEAR OPTIMIZATION



UNDER 30 YEAR OPTIMIZATION, DISPATCH OF NGCC UNITS IMPACTED BY GAS PRICE TRACK



Source: Guziel, South: Coal vs. Gas, Power Gen 90

STEAM COAL FOR POWER AND INDUSTRY

Benefits of Emission Trading

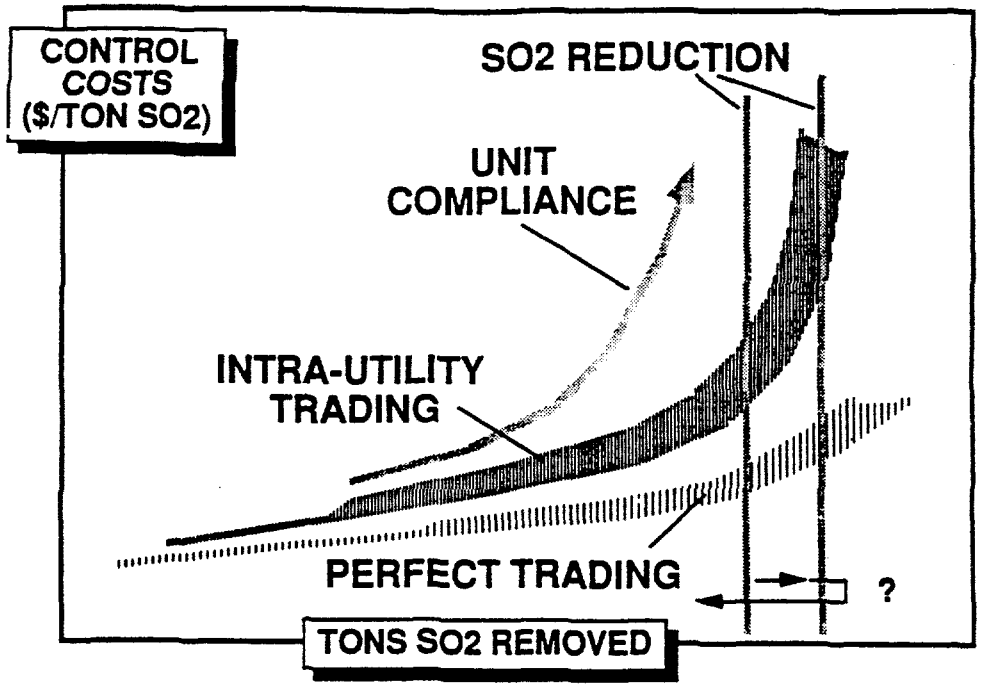


Figure 1. PLOTTING THE ALLOWANCE MARKET BALANCE

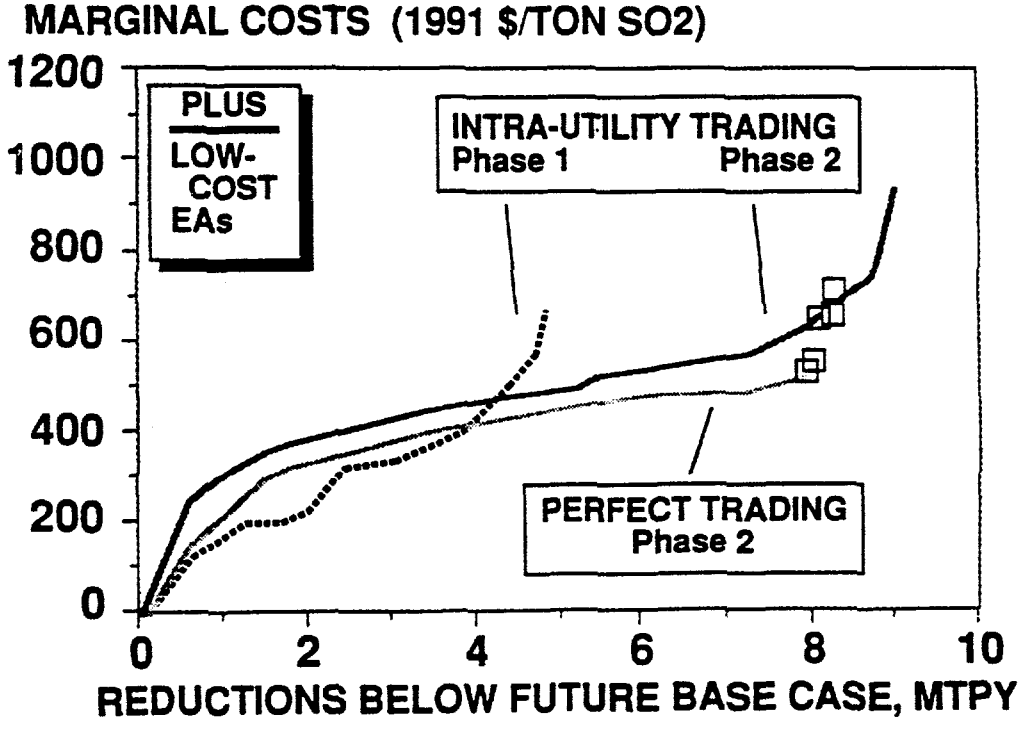


Figure 2. EFFECTS OF PERFECT TRADING

Source: Platt:Scrub vs. Trade, EPRI SO_2 Control Symposium,1991

STEAM COAL FOR POWER AND INDUSTRY

Table 1: Steam Coal Consumption Scenarios
Reference Case
(Mtce)

	1980	1990	1995	2000	2005	2010	2015
NORTH AMERICA							
Power Generation	442.9	594.0	651.5	706.8	779.7	846.6	910.1
Industry	39.3	41.2	43.3	45.4	49.7	54.7	58.8
Residential	3.8	3.8	3.5	3.1	2.9	2.6	2.5
Other	15.4	20.5	21.5	22.6	23.7	24.9	26.2
Subtotal (1)	501.4	659.5	719.8	777.9	856.1	928.9	997.6
PACIFIC							
Power Generation	40.9	82.5	112.2	138.4	174.7	214.1	246.2
Industry	10.4	27.6	41.4	56.9	71.2	88.9	106.7
Residential	0.9	0.4	0.1	0.0	0.0	0.0	0.0
Other	1.5	4.5	4.7	4.8	5.0	5.1	5.2
Subtotal (2)	53.7	115.0	158.4	200.2	250.9	308.1	358.2
WESTERN EUROPE							
Power Generation	224.0	237.4	258.9	293.3	314.3	337.2	357.4
Industry	52.9	42.9	43.1	44.2	46.4	49.9	52.4
Residential	19.2	14.5	12.5	10.0	10.1	10.4	10.2
Other	3.0	6.1	6.3	6.4	6.6	6.7	6.9
Subtotal (3)	299.1	300.9	320.7	353.9	377.4	404.2	426.9
ASIA							
Power Generation	162.4	377.7	484.1	567.3	663.9	778.0	918.0
Industry	160.8	221.3	247.9	272.6	286.3	300.6	315.6
Residential	155.7	244.7	219.8	201.2	225.4	249.8	274.8
Other	40.7	30.4	31.2	31.9	32.7	33.6	34.6
Subtotal (4)	519.6	874.1	982.9	1073.1	1208.3	1361.9	1543.0
LATIN AMERICA							
Power Generation	4.1	8.1	16.8	22.7	30.5	39.7	48.9
Industry	6.7	12.4	15.5	17.8	20.1	22.1	23.2
Residential	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal (5)	11.2	20.9	32.7	40.9	50.9	62.2	72.5
AFRICA							
Power Generation	53.8	81.3	91.1	101.7	117.0	139.5	160.4
Industry	14.3	26.9	31.0	35.3	39.3	45.2	48.9
Residential	2.0	3.1	3.6	4.0	4.5	4.9	5.4
Other	9.0	33.8	35.5	37.3	39.1	41.1	42.3
Subtotal (6)	79.1	145.1	161.2	178.2	199.9	230.7	257.0
EASTERN EUROPE							
Power Generation	265.8	265.8	293.8	335.0	396.6	468.9	551.0
Industry	183.8	213.9	197.9	212.7	239.3	273.2	307.3
Residential	31.9	34.0	30.2	35.5	38.0	40.0	42.0
Other	60.1	80.9	73.2	69.6	71.3	73.1	75.3
Subtotal (7)	541.6	594.7	595.0	652.7	745.2	855.2	975.6
WORLD							
Power Generation	1194.0	1646.8	1908.4	2165.0	2476.7	2824.1	3192.1
Industry	468.2	586.2	620.0	685.0	752.3	834.6	912.9
Residential	213.9	300.9	270.1	254.2	281.3	308.1	335.3
Other	129.7	176.2	172.4	172.6	178.4	184.5	190.5
Total	2005.7	2710.1	2970.8	3276.9	3688.6	4151.2	4630.7

/1 Assumptions:

(1) 70% Plant Factor

(2) Existing capital stock and environmental protection policies.

(3) Price of coal = US$ 2.0/mmbtu; price of gas US$ 3.0/mmbtu.

Table 2: Coal Consumption at 50% Plant Factor
(Mtce)

	1980	1990	1995	2000	2005	2010	2015
NORTH AMERICA							
Power Generation	442.9	594.0	483.7	504.8	542.1	595.2	639.9
Industry	39.3	41.2	43.3	45.4	49.7	54.7	58.8
Residential	3.8	3.8	3.5	3.1	2.9	2.6	2.5
Other	15.4	20.5	21.5	22.6	23.7	24.9	26.2
Subtotal (1)	501.4	659.5	552.0	576.0	618.4	677.5	727.3
PACIFIC							
Power Generation	40.9	82.5	80.1	94.7	119.6	148.8	171.2
Industry	10.4	27.6	41.4	56.9	71.2	88.9	106.7
Residential	0.9	0.4	0.1	0.0	0.0	0.0	0.0
Other	1.5	4.5	4.7	4.8	5.0	5.1	5.2
Subtotal (2)	53.7	115.0	126.3	156.5	195.7	242.9	283.2
WESTERN EUROPE							
Power Generation	224.0	237.4	231.4	256.9	275.4	284.0	301.0
Industry	52.9	42.9	43.1	44.2	46.4	49.9	52.4
Residential	19.2	14.5	12.5	10.0	10.1	10.4	10.2
Other	3.0	6.1	6.3	6.4	6.6	6.7	6.9
Subtotal (3)	299.1	300.9	293.2	317.5	338.4	351.0	370.5
ASIA							
Power Generation	162.4	377.7	452.4	510.6	504.1	568.9	671.3
Industry	160.8	221.3	247.9	272.6	286.3	300.6	315.6
Residential	155.7	244.7	219.8	201.2	225.4	249.8	274.8
Other	40.7	30.4	31.2	31.9	32.7	33.6	34.6
Subtotal (4)	519.6	874.1	951.2	1016.3	1048.5	1152.8	1296.3
LATIN AMERICA							
Power Generation	4.1	8.1	12.9	17.3	18.1	24.2	29.7
Industry	6.7	12.4	15.5	17.8	20.1	22.1	23.2
Residential	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal (5)	11.2	20.9	28.8	35.5	38.6	46.6	53.3
AFRICA							
Power Generation	53.8	81.3	81.9	81.3	89.2	98.7	113.5
Industry	14.3	26.9	31.0	35.3	39.3	45.2	48.9
Residential	2.0	3.1	3.6	4.0	4.5	4.9	5.4
Other	9.0	33.8	35.5	37.3	39.1	41.1	42.3
Subtotal (6)	79.1	145.1	151.9	157.9	172.1	190.0	210.1
EASTERN EUROPE							
Power Generation	265.8	265.8	279.1	292.4	323.8	339.2	398.6
Industry	183.8	213.9	197.9	212.7	239.3	273.2	307.3
Residential	31.9	34.0	30.2	35.5	38.0	40.0	42.0
Other	60.1	80.9	73.2	69.6	71.3	73.1	75.3
Subtotal (7)	541.6	594.7	580.4	610.2	672.4	725.4	823.1
WORLD							
Power Generation	1194.0	1646.8	1621.5	1758.0	1872.2	2059.1	2325.2
Industry	468.2	586.2	620.0	685.0	752.3	834.6	912.9
Residential	213.9	300.9	270.1	254.2	281.3	308.1	335.3
Other	129.7	176.2	172.4	172.6	178.4	184.5	190.5
Total	2005.7	2710.1	2683.9	2869.8	3084.2	3386.2	3763.9

/1 Assumptions:

(1) 50% Plant Factor

(2) Existing capital stock and environmental protection policies

(3) Price of coal = US$ 2.0/mmbtu; price of gas = US$ 3.0/mmbtu.

Table 3: Coal Consumption at 90% Plant Factor
(Mtce)

	1980	1990	1995	2000	2005	2010	2015
NORTH AMERICA							
Power Generation	442.9	594.0	870.6	908.7	975.7	1071.4	1151.8
Industry	39.3	41.2	43.3	45.4	49.7	54.7	58.8
Residential	3.8	3.8	3.5	3.1	2.9	2.6	2.5
Other	15.4	20.5	21.5	22.6	23.7	24.9	26.2
Subtotal (1)	501.4	659.5	938.9	979.8	1052.1	1153.6	1239.2
PACIFIC							
Power Generation	40.9	82.5	144.2	170.5	215.2	267.9	308.1
Industry	10.4	27.6	41.4	56.9	71.2	88.9	106.7
Residential	0.9	0.4	0.1	0.0	0.0	0.0	0.0
Other	1.5	4.5	4.7	4.8	5.0	5.1	5.2
Subtotal (2)	53.7	115.0	190.4	232.3	291.4	362.0	420.1
WESTERN EUROPE							
Power Generation	224.0	237.4	416.6	462.4	495.6	511.2	541.9
Industry	52.9	42.9	43.1	44.2	46.4	49.9	52.4
Residential	19.2	14.5	12.5	10.0	10.1	10.4	10.2
Other	3.0	6.1	6.3	6.4	6.6	6.7	6.9
Subtotal (3)	299.1	300.9	478.4	523.0	558.7	578.2	611.4
ASIA							
Power Generation	162.4	377.7	540.5	624.0	787.6	909.3	1072.9
Industry	160.8	221.3	247.9	272.6	286.3	300.6	315.6
Residential	155.7	244.7	219.8	201.2	225.4	249.8	274.8
Other	40.7	30.4	31.2	31.9	32.7	33.6	34.6
Subtotal (4)	519.6	874.1	1039.3	1129.8	1332.0	1493.2	1697.9
LATIN AMERICA							
Power Generation	4.1	8.1	15.4	25.0	29.2	45.0	55.3
Industry	6.7	12.4	15.5	17.8	20.1	22.1	23.2
Residential	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal (5)	11.2	20.9	31.3	43.2	49.7	67.4	78.9
AFRICA							
Power Generation	53.8	81.3	100.4	111.8	133.2	165.3	190.1
Industry	14.3	26.9	31.0	35.3	39.3	45.2	48.9
Residential	2.0	3.1	3.6	4.0	4.5	4.9	5.4
Other	9.0	33.8	35.5	37.3	39.1	41.1	42.3
Subtotal (6)	79.1	145.1	170.4	188.4	216.1	256.5	286.6
EASTERN EUROPE							
Power Generation	265.8	265.8	319.0	385.5	478.5	578.2	679.4
Industry	183.8	213.9	197.9	212.7	239.3	273.2	307.3
Residential	31.9	34.0	30.2	35.5	38.0	40.0	42.0
Other	60.1	80.9	73.2	69.6	71.3	73.1	75.3
Subtotal (7)	541.6	594.7	620.3	703.2	827.1	964.4	1104.0
WORLD							
Power Generation	1194.0	1646.8	2406.7	2687.9	3115.1	3548.2	3999.4
Industry	468.2	586.2	620.0	685.0	752.3	834.6	912.9
Residential	213.9	300.9	270.1	254.2	281.3	308.1	335.3
Other	129.7	176.2	172.4	172.6	178.4	184.5	190.5
Total	2005.7	2710.1	3469.1	3799.7	4327.0	4875.4	5438.1

/1 Assumptions:

(1) 90% Plant Factor

(2) Existing capital stock and environmental protection policies

(3) Price of coal = US$ 2.0/mmbtu; price of gas = US$ 3.0/mmbtu.

Table 4: The Effects of Carbon Tax on Coal Consumption (Mtce)

	1980	1990	1995	2000	2005	2010	2015
NORTH AMERICA							
Power Generation	442.9	594.0	651.5	622.0	545.8	592.7	637.1
Industry	39.3	41.2	43.3	34.1	24.9	27.4	29.4
Residential	3.8	3.8	3.5	2.6	1.2	1.0	1.0
Other	15.4	20.5	21.5	13.6	8.3	8.7	9.2
Subtotal (1)	501.4	659.5	719.8	672.2	580.1	629.8	676.7
PACIFIC							
Power Generation	40.9	82.5	112.2	110.7	117.1	143.4	160.0
Industry	10.4	27.6	41.4	37.6	28.5	35.6	35.2
Residential	0.9	0.4	0.1	0.0	0.0	0.0	0.0
Other	1.5	4.5	4.7	3.6	1.7	1.3	1.3
Subtotal (2)	53.7	115.0	158.4	151.9	147.3	180.3	196.6
WESTERN EUROPE							
Power Generation	224.0	237.4	258.9	234.6	172.9	185.4	196.6
Industry	52.9	42.9	43.1	28.3	18.6	20.0	21.0
Residential	19.2	14.5	12.5	7.5	4.0	4.2	4.1
Other	3.0	6.1	6.3	4.8	2.3	2.4	2.4
Subtotal (3)	299.1	300.9	320.7	275.2	197.8	211.9	224.0
ASIA							
Power Generation	162.4	377.7	484.1	510.6	597.5	676.9	798.7
Industry	160.8	221.3	247.9	218.1	171.8	180.4	189.4
Residential	155.7	244.7	219.8	161.0	135.2	149.9	164.9
Other	40.7	30.4	31.2	24.0	16.4	16.8	17.3
Subtotal (4)	519.6	874.1	982.9	913.6	920.9	1023.9	1170.2
LATIN AMERICA							
Power Generation	4.1	8.1	16.8	20.4	27.4	31.8	39.1
Industry	6.7	12.4	15.5	5.3	6.0	6.6	6.9
Residential	0.4	0.4	0.4	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal (5)	11.2	20.9	32.7	25.8	33.5	38.4	46.1
AFRICA							
Power Generation	53.8	81.3	91.1	91.5	93.6	111.6	128.4
Industry	14.3	26.9	31.0	24.7	21.6	24.9	26.9
Residential	2.0	3.1	3.6	2.0	0.9	1.0	1.1
Other	9.0	33.8	35.5	27.9	19.6	20.5	21.2
Subtotal (6)	79.1	145.1	161.2	146.2	135.7	158.0	177.5
EASTERN EUROPE							
Power Generation	265.8	265.8	293.8	301.5	237.9	328.3	440.8
Industry	183.8	213.9	197.9	148.9	143.6	163.9	201.3
Residential	31.9	34.0	30.2	17.8	11.4	8.0	8.4
Other	60.1	80.9	73.2	52.2	35.6	32.9	30.9
Subtotal (7)	541.6	594.7	595.0	520.3	428.6	533.0	681.4
WORLD							
Power Generation	1194.0	1646.8	1908.4	1891.2	1792.2	2070.0	2400.6
Industry	468.2	586.2	620.0	497.0	414.9	458.6	510.1
Residential	213.9	300.9	270.1	190.9	152.8	164.1	179.5
Other	129.7	176.2	172.4	126.1	83.9	82.6	82.2
Total	2005.7	2710.1	2970.8	2705.2	2443.8	2775.3	3172.4

/1 Assumptions:

(1) 70% Plant Factor

(2) Introduction of carbon tax of US$ 20/ton of coal after 1995

(3) Price of coal = US$ 2.0/mmbtu; price of gas US$ 3.0/mmbtu.

Table 5: The Effects of Stricter Emission Limits on Coal Consumption (Mtce)

	1980	1990	1995	2000	2005	2010	2015
NORTH AMERICA							
Power Generation	442.9	594.0	651.5	650.2	662.7	745.0	800.9
Industry	39.3	41.2	43.3	23.6	28.8	30.1	32.3
Residential	3.8	3.8	3.5	2.6	1.9	1.7	1.2
Other	15.4	20.5	21.5	14.7	15.4	16.2	17.0
Subtotal (1)	501.4	659.5	719.8	691.2	708.9	793.0	851.5
PACIFIC							
Power Generation	40.9	82.5	112.2	123.4	143.3	182.0	201.9
Industry	10.4	27.6	41.4	41.0	45.5	56.9	68.3
Residential	0.9	0.4	0.1	0.0	0.0	0.0	0.0
Other	1.5	4.5	4.7	3.1	3.2	3.3	3.4
Subtotal (2)	53.7	115.0	158.4	167.6	192.0	242.2	273.6
WESTERN EUROPE							
Power Generation	224.0	237.4	258.9	252.2	257.8	286.6	293.1
Industry	52.9	42.9	43.1	31.8	29.7	31.9	28.3
Residential	19.2	14.5	12.5	8.5	6.6	6.8	5.1
Other	3.0	6.1	6.3	4.2	4.3	4.4	4.5
Subtotal (3)	299.1	300.9	320.7	296.7	298.3	329.6	330.9
ASIA							
Power Generation	162.4	377.7	484.1	521.9	604.2	700.2	817.0
Industry	160.8	221.3	247.9	223.6	200.4	210.4	220.9
Residential	155.7	244.7	219.8	165.0	146.5	162.4	178.6
Other	40.7	30.4	31.2	20.8	21.3	21.8	22.5
Subtotal (4)	519.6	874.1	982.9	931.2	972.3	1094.8	1239.0
LATIN AMERICA							
Power Generation	4.1	8.1	16.8	20.9	27.7	34.2	41.5
Industry	6.7	12.4	15.5	12.8	13.0	14.3	15.1
Residential	0.4	0.4	0.4	0.3	0.2	0.2	0.2
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal (5)	11.2	20.9	32.7	34.1	41.0	48.7	56.8
AFRICA							
Power Generation	53.8	81.3	91.1	93.5	106.4	120.0	136.4
Industry	14.3	26.9	31.0	25.4	25.6	29.4	31.8
Residential	2.0	3.1	3.6	3.3	2.3	2.5	2.7
Other	9.0	33.8	35.5	24.2	25.4	26.7	27.5
Subtotal (6)	79.1	145.1	161.2	146.4	159.7	178.5	198.3
EASTERN EUROPE							
Power Generation	265.8	265.8	293.8	308.2	317.3	389.2	468.4
Industry	183.8	213.9	197.9	159.5	184.3	204.9	245.8
Residential	31.9	34.0	30.2	29.1	19.0	20.0	21.0
Other	60.1	80.9	73.2	45.2	46.3	47.5	48.9
Subtotal (7)	541.6	594.7	595.0	542.0	566.9	661.6	784.1
WORLD							
Power Generation	1194.0	1646.8	1908.4	1970.4	2119.3	2457.2	2759.2
Industry	468.2	586.2	620.0	517.8	527.3	578.0	642.5
Residential	213.9	300.9	270.1	208.8	176.4	193.5	208.9
Other	129.7	176.2	172.4	112.2	116.0	119.9	123.8
Total	2005.7	2710.1	2970.8	2809.2	2939.1	3348.5	3734.4

/1 Assumptions:

(1) 70% Plant Factor

(2) Accelerated introduction of new clean coal technologies

(3) Price of coal = US$ 2.0/mmbtu; price of gas US$ 3.0/mmbtu.

Table 6: The Effects of Rising Relative Oil/Gas Prices on Coal Consumption (Mtce)

	1980	1990	1995	2000	2005	2010	2015
NORTH AMERICA							
Power Generation	442.9	594.0	651.5	706.8	866.3	951.3	1033.1
Industry	39.3	41.2	43.3	45.4	49.7	54.7	59.4
Residential	3.8	3.8	3.5	3.1	2.9	2.6	2.8
Other	15.4	20.5	21.5	22.6	23.7	24.9	26.2
Subtotal (1)	501.4	659.5	719.8	777.9	942.7	1033.5	1121.4
PACIFIC							
Power Generation	40.9	82.5	112.2	149.2	191.1	241.3	302.8
Industry	10.4	27.6	41.4	56.9	71.2	88.9	111.2
Residential	0.9	0.4	0.1	0.0	0.0	0.0	0.0
Other	1.5	4.5	4.7	4.8	5.0	5.1	5.3
Subtotal (2)	53.7	115.0	158.4	211.0	267.2	335.3	419.3
WESTERN EUROPE							
Power Generation	224.0	237.4	258.9	336.1	370.9	408.5	443.8
Industry	52.9	42.9	43.1	44.2	46.4	49.9	54.1
Residential	19.2	14.5	12.5	10.0	10.1	10.4	10.9
Other	3.0	6.1	6.3	6.4	6.6	6.7	7.0
Subtotal (3)	299.1	300.9	320.7	396.7	434.0	475.5	515.9
ASIA							
Power Generation	162.4	377.7	487.6	590.0	710.5	849.6	936.2
Industry	160.8	221.3	247.9	272.6	286.3	300.6	330.6
Residential	155.7	244.7	219.8	201.2	225.4	249.8	274.8
Other	40.7	30.4	31.2	31.9	32.7	33.6	35.1
Subtotal (4)	519.6	874.1	986.4	1095.8	1254.9	1433.5	1576.7
LATIN AMERICA							
Power Generation	4.1	8.1	16.8	22.7	32.0	40.9	47.0
Industry	6.7	12.4	15.5	17.8	20.1	22.1	25.4
Residential	0.4	0.4	0.4	0.4	0.4	0.4	0.5
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal (5)	11.2	20.9	32.7	40.9	52.4	63.3	72.8
AFRICA							
Power Generation	53.8	81.3	93.4	105.6	123.8	156.1	189.7
Industry	14.3	26.9	31.0	35.3	39.3	45.2	53.2
Residential	2.0	3.1	3.6	4.0	4.5	4.9	5.8
Other	9.0	33.8	35.5	37.3	39.1	41.1	42.1
Subtotal (6)	79.1	145.1	163.5	182.2	206.8	247.3	290.7
EASTERN EUROPE							
Power Generation	265.8	265.8	293.8	398.8	587.5	797.5	968.6
Industry	183.8	213.9	197.9	212.7	239.3	273.2	327.8
Residential	31.9	34.0	30.2	35.5	38.0	40.0	48.0
Other	60.1	80.9	73.2	69.6	71.3	73.1	76.4
Subtotal (7)	541.6	594.7	595.0	716.5	936.1	1183.8	1420.7
WORLD							
Power Generation	1194.0	1646.8	1914.3	2309.1	2882.2	3445.1	3921.2
Industry	468.2	586.2	620.0	685.0	752.3	834.6	961.6
Residential	213.9	300.9	270.1	254.2	281.3	308.1	342.7
Other	129.7	176.2	172.4	172.6	178.4	184.5	192.1
Total	2005.7	2710.1	2976.6	3420.9	4094.2	4772.3	5417.3

/1 Assumptions:

(1) 70% Plant Factor

(2) Existing capital stock and environmental protection policies

(3) Increase in coal/gas price differential from $1-1.50/mmbtu to $3.0/mmbtu after 2005.