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Section 1

"Environmental Trends in Asia Are Accelerating the Introduction of Clean Coal Technologies and Natural Gas,"

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ENVIRONMENTAL TRENDS IN ASIA ARE ACCELERATING THE INTRODUCTION OF CLEAN COAL TECHNOLOGIES AND NATURAL GAS

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This paper examines the changing energy mix for Asia to 2020, and impacts of increased coal consumption on Asia's share of world SO_2 and CO_2 emissions. Stricter SO_2 emissions laws are summarized for eight Asian economies along with implications for fuel and technology choices. The paper compares the economics of different technologies for coal and natural gas in 1997 and in 2007. Trends toward introducing clean coal technologies and the use of natural gas will accelerate in response to tighter environmental standards by 2000. The most important coal conversion technology for Asia, particularly China, in the long term is likely to be integrated gasification combined-cycle (IGCC), but only under the assumption of multiple products.

I. INTRODUCTION[2]

Historically, the goal of most Asian economies to sustain rapid economic growth has had priority over environmental concerns. But, this goal is increasingly being modified across Asia to include serious efforts to reduce coal-related emissions. A recent research study by the APEC Expert's Group on Clean Fossil Energy indicates that most APEC economies are introducing strict emission limits for SO_2.[3]

This paper: (1) compares the energy mix in Asia with the rest of the world in 1996 and 2020, (2) the growth in coal consumption to 2020, (3) trends in environmental legislation, and (4) compares the economics of clean coal and natural gas combined-cycle technologies. The economic assumptions used in the analysis are believed to be representative of the relative costs of different technology options.[4] Comparisons are made to show relative electricity costs under different technology and fuel cost assumptions in 1997 and 2007.

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[2] The three main sources of data for this paper are Charles Johnson and Xiaodong Wang, 1997, "Overview of Coal Consumption and Related Environmental Trends, Implications for Greenhouse Gas Emissions", Charles Johnson, 1996, "Environmental Trends in Asia Accelerating the Introduction of Clean Coal Technologies and Natural Gas", and APEC Clean Fossil Energy Experts' Group, 1997, Study on Atmospheric Emissions Regulations in APEC Economies and Their Compliance at Coal-fired Plants.

[3] APEC Clean Fossil Energy Experts' Group, 1997, Study on Atmospheric Emissions Regulations in APEC Economies and Their Compliance at Coal-fired Plants

[4] A detailed comparison of power plant costs in various Asian locations is beyond the scope of the present study.

II. ENERGY MIX IN ASIA

Asia's energy mix is quite different from the rest of the world in the use of two fuels: coal and natural gas. As shown in Figure 1, coal accounts for 45 percent of the total primary energy consumption in Asia—more than double the share of the rest of the world (20 percent).[5]

The second anomalous energy source is natural gas, which accounts for 29 percent of the primary energy mix outside of Asia, but only 9 percent of the energy mix in Asia. There are a number of reasons for the heavy reliance on coal and low dependence on natural gas in Asia. First, natural gas reserves in Asia are equal to less than 10 percent of the energy content of coal reserves. Second, most natural gas reserves are located far from the main markets, and the transport of natural gas over long distances requires major investments in infrastructure. Third, coal is well established in most Asian markets, with substantial coal-related infrastructure already in place. In contrast, there is limited natural gas infrastructure in most Asian economies, with no regional natural gas pipeline system such as found in North America and Western Europe. These factors suggest a *gradual shift* in the energy mix between coal and natural gas in Asia.

The largest factor explaining the high share of coal in Asia is China, which relies on coal for about 76 percent of its commercial primary energy needs as shown in Figure 2.[6] Figure 2 shows that that when China is excluded, the rest of Asia relies on coal for only 26 percent of its energy needs, and has a very high 50 percent dependence on oil.

III. THERMAL COAL OUTLOOK IN ASIA[7]

The growth rate of coal consumption in Asia averaged 4.5 percent per year from 1980 to 1995, but the rate is projected to slow to about 3.1 percent between 1995 and 2020. This slowdown is due to the following combination of factors: (1) greater efficiency in coal use, (2) slower growth in energy consumption as Asian economies graduate to higher income levels, and (3) substitution of other energy options in response to tighter environmental legislation and increased competition from natural gas. As shown in Figure 3, coal consumption in Asia almost doubled between 1980 and 1995, and is projected to double again by 2020. As shown in Figure 3, Asia's share of world coal consumption increased from 28 percent in 1980 to 45 percent in 1995, and is projected to reach 57 percent by 2020.

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[5] Note: Biomass energy is excluded from the analysis, as most biomass is not traded commercially. However, in China, biomass consumption equals about 240 million metric tons of coal equivalent.

[6] Official Chinese estimates of the primary energy mix are slightly different, mostly due to different assumptions in converting hydroelectric generation back to fossil-fuel equivalents. China's primary energy mix in 1994 was given as 75% coal, 17.4 percent crude oil, 1.9 percent natural gas, and 5.7 percent hydropower.

[7] In this paper Asia includes Australia and New Zealand.

The projected growth rate of coal assumes moderate economic growth rates, rapid expansion of natural gas consumption, and major increases in coal conversion efficiency in Asia. Coal consumption in Asia could double as early as 2015 if natural gas developments are slower than expected, and China's economy grows at more than 6.5 percent per year over the 2000-2015 period. A doubling of coal consumption in Asia by either projection (2015 or 2020) will result in serious environmental consequences for more than half of Asia unless there is widespread use of clean coal technologies.

IV. ASIA'S ENERGY MIX IN 2020

Moderately accurate projections of future coal consumption can be made for the next few years in Asia based on current trends, and the lack of infrastructure to support a rapid switch to alternative fuel options. However, longer term projections are quite speculative, and are complicated by some government projections that are based on policy objectives, but are not sufficiently supported by solid analysis, policy initiatives or a strong legislative framework. The author recently made projections to 2020 based on "optimistic" assumptions about rapid growth rates in natural gas consumption in Asia. The optimistic projections for natural gas use are based on estimates of the competitive position of natural gas with coal in Asia as more stringent SO_2 emissions limits are enforced, and the assumption that regional natural gas pipeline networks will be established by 2010.

Figure 4 shows the projected primary energy shares of Asia and the rest of the world in 2020. Even with the projected rapid increase in natural gas consumption in Asia (5.8 percent/year), increasing its share of the energy mix from 9 percent in 1995 to 16 percent in 2020, coal is expected to account for about 41 percent of the energy mix in 2020. The share of new renewable energy (excluding biomass, hydro, and geothermal) is projected to account for 1.5-2.5 percent of the energy mix in Asia and the world by 2020.[8]

Figure 5 shows that almost two-thirds of the growth in coal consumption in Asia over the 1980-94 period was in the electricity sector. The electricity sector is projected to account for at least two-thirds of the growth in coal consumption in Asia to 2020. The increase in coal consumption in electricity generation is projected to be at least a billion tons of coal per year over the 1995-2020 period.

V. ENVIRONMENTAL PROBLEMS

The environmental problems related to coal use are widely recognized by Asian governments. However, most state utilities are facing difficulties in meeting the growth in demand for new electricity generation capacity, and are cautious about major investments in expensive SO_2 control technologies. The rapid growth of independent power producers is making it easier for governments to enforce strict environmental limits on new power plants. Independent power producers rely heavily on international bank loans to finance

[8] Recent plans for a serious of large hydroelectric projects in China and a number of other Asian countries, suggest that hydro's share of the total energy mix could be as high as 3 percent in 2020.

power plants, and no major international bank will consider loans to power plant projects that fail to meet the environmental standards of the country, and increasingly, also the emission standards established by the World Bank.

In 1992, the APEC Experts' Group on Clean Fossil Energy undertook a survey of coal-using APEC member economies to determine their priorities on coal-related emissions. In order of importance, the APEC economies placed SO_2 first, particulates second, NO_x third, and CO_2 fourth. SO_2 and particulates are still the highest-priority coal-related pollutants for most Asian member economies, however over the 2000-2020 period greater attention is also likely for CO_2 emissions.

The reason for the greater concern over SO_2, particulates, and NO_x is that these emissions have immediate impacts on the local and regional populations and on the environment. The issue of controlling CO_2 emissions to reduce possible global warming is important in most economies, but presently does not take priority over reducing SO_2 emissions that have more immediate health and environmental impacts.

There are substantial differences in estimates of SO_2 emissions in Asia, particularly for China. Figure 6 shows China's and India's shares of estimated total SO_2 emissions in Asia in 1997. The estimates are not exact, but show that China accounts for roughly 63 percent of Asia's SO_2 emissions followed by India with about 14 percent of the total.[9] The high percentage of SO_2 emissions from China is largely a reflection of their dominant share of Asia's coal consumption. Reduction of Asia's SO_2 emissions over the long term depends heavily on the environmental policies and technology choices of China.

VI. ENVIRONMENTAL REGULATIONS

In 1997 the APEC Experts' Group on Clean Fossil Energy published a study on emissions regulations among APEC members. This discussion is heavily based on the basic data contained in this APEC study. The present and planned emissions limits for the coal-burning Asian APEC members are summarized below. SO_2 emission limits are stated in different units among Asian economies, including mg/m^3, parts per million (ppm), and in Japan, the K-value method. In addition, there are local standards that often exceed national standards, plus ambient concentration standards, and other site specific restrictions. The following summaries of SO_2 emission limits are intended only as a general guide to SO_2 legislation among APEC members.

(1) The <u>People's Republic of China</u> issued national emission standards in March 1996. The new standards are divided into three stages, depending on when the plant was approved for construction. The most stringent stage III standard applies to plants approved after 1996. The stage III standard allows the burning of coal with up to 1.0 percent sulfur content (SO_2 emissions up to 2,100 mg/m^3) without the use of SO_2 control technology. However, plants burning coal with a sulfur content greater than 1.0 percent must add SO_2 control technology and meet an emissions limit of 1,200 mg/m^3 (or ~0.6 percent sulfur coal). The apparent contradiction in standards will need to be clarified. In addition to the national standards, local

[9] Estimates for China's share of Asia's SO_2 emissions range up to as high as 70 percent.

province and city regulations are more stringent in some areas of China, and already require SO_2 technology. Although these standards are less strict than those of the other Asian APEC member economies, they reflect an important step toward controlling SO_2 emissions, where in some southern provinces (Sichuan and Guizhou) the average sulfur content of coal is at least 3 percent.

(2) Chinese Taipei's limit of 500 ppm SO_2 can be met by importing low-sulfur coal. However, all power plants with capacities above 200 MW have been retrofitted with flue gas desulfurization (FGD) units, and SO_2 technology will be included in all new power plants.

(3) Indonesia's present SO_2 emission limit of 1,500 mg/m^3 will be reduced to 750 mg/m^3 from 2000 onward. Although some of Indonesia's low sulfur coals can meet these emission standards, most locations on Java have air quality problems that are likely to result in a requirement for SO_2 control technologies at large coal-fired plants. Although the state utility has not installed SO_2 control technologies on its coal-fired plants, most independent power producers planning to add SO_2 control technologies to their new coal-fired plants.

(4) Hong Kong's existing PC Castle Peak plant can meet the limit of 2,100 mg/m^3 with low sulfur coal, but new plants will need SO_2 control technologies to meet the limit of 200 mg/m^3. Significant new coal-fired capacity is unlikely in Hong Kong.

(5) Japan uses the K-value method, which is based on the stack height, plus the plume rise height, and a constant based on air quality. Much stricter local standards exist, with emission limits of 50-80 ppm for some plants (equal to about 0.1% sulfur compliance coal). All new coal-fired power plants include SO_2 control technologies.

(6) The Republic of Korea's present limit on plants using imported coal of 500 ppm will be reduced to 250 ppm in January 1999. The state utility, KEPCO, has embarked on a major program to install SO_2 control technologies on its coal-fired plants.

(7) The Philippines will reduce its present limit of 1,000 mg/m^3 of SO_2 emissions from power plants to 700 mg/m^3 in January 1998. The 1,000 MW Sual coal-fired IPP presently under construction in the Philippines includes SO_2 control technology.

(8) Thailand's new emissions standards limit SO_2 emissions for power plants above 500 MW to 320 ppm. Domestic high sulfur lignite cannot meet these limits without SO_2 control technology, but imported coal can meet the present standards.

Because of environmental problems related to high sulfur lignite burning in Thailand, local resistance to coal-fired power plants may lead to the installation of FGDs on future coal-fired plants. Two of the three planned coal-fired plants, based on imported coal, are expected to include FGD technologies.

In Figure 7, the emission limits for each of the above economies have been converted to the equivalent sulfur content of coal (compliance coal) that could be burned in coal-fired plants without exceeding the respective emissions limits. The estimates of the sulfur content of compliance coal are *approximate*, and vary slightly owing to power plant performance characteristics.[10]

The main observation is that six of the eight economies surveyed now have, or will have by 2000, emission standards that limit the sulfur content in coals burned to less than 0.5 percent. In the two economies that have less stringent emission standards, Chinese Taipei already requires SO_2 control technologies on all plants, and some provinces and cities in the People's Republic of China have much stricter emission limits than the national standard.

Presently, most traded coal in Asia is in the 0.5-0.7 percent sulfur range and cannot meet the limits that are becoming the norm. Therefore, suppliers of very low sulfur compliance coal may obtain price premiums in the future. Utilities are accelerating efforts to meet tighter emissions standards by switching fuel (substituting low sulfur compliance coal and natural gas) and installing SO_2 control technology.

There are no commercial options available for controlling greenhouse gas emissions related to coal-burning. The only method for reducing emissions of the primary coal-related greenhouse gas, CO_2, is to increase conversion efficiencies, therefore reducing CO_2 emissions per unit of electricity. Figure 8 shows carbon emissions from coal in Asia and the world for 1980 and 1995, with projections to 2020. As shown in Figure 8, Asia's share of total world carbon emissions from coal increased from 28 percent in 1980 to 45 percent in 1995, and is projected to increase to 57 percent in 2020.

Therefore, possible international agreements to significantly reduce coal-related CO_2 emissions are likely to place emphasis on Asia (particularly China) where most of the growth in coal-based CO_2 emissions is projected to occur over the 1995-2020 period.[11]

VII. POWER PLANT ECONOMICS

The power plant costs discussed here reflect my views on the relative costs of these technologies in the late 1990s. In most cases, current costs are lower than they were in the early 1990s, and efficiencies are slightly to substantially higher. Over the past 5 years, capital costs for coal-fired plants have decreased by 15-25 percent, and by 25-40

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[10] Assumes power plants burn coal with 27.4 GJ/t (26 million Btu coal), with 93 percent of the contained sulfur emitted as plant stack gases.

[11] It should be noted in discussions about China's large total SO_2 and CO_2 that Chinese officials will emphasize the need to also consider per capita emissions.

percent for natural-gas-fired combined-cycle plants. Cost estimates from different sources vary widely, and site-specific factors can add costs that change the economic ranking of technologies discussed here. The present generation of proven subcritical, pulverized coal combustion technologies for electricity generation typically have conversion efficiencies of 35-38 percent (HHV) for plants burning bituminous coals (1-3 percent less with wet FGD), and 15+ percent less for plants burning lignite. Supercritical plants can increase efficiencies by about 4-10 percent, and ultra supercritical plants can increase efficiencies by slightly more. Denmark has a supercritical coal-fired plant that reportedly has an efficiency of about 43 percent (HHV). At present, subcritical plants dominate in Asia, however, increased use of supercritical plants can be expected in some countries, particularly those dependent on higher cost imported coal.

Circulating fluidized bed combustion (CFBC) technology is not discussed, but is recognized as an excellent technology for smaller sized plants (usually less than 200 MW), and is quite suitable for variable and/or poor quality coal. The costs of CFBCs are in the same range as similar sized PC plants.

Under development are pressurized technologies and integrated gasification combined cycle technologies with conversion efficiencies of 40-45 percent in the first generation of plants, and potentially 45-50 percent when the technologies are fully developed.

In order to simplify the analysis in this paper, four technology options were compared, three of which, are widely used around the world. Table 1 shows the cost and operating assumptions for the coal and natural gas technologies evaluated. It is recognized that there are numerous competitive variations to the technologies discussed here. Not included in the analysis are site-specific land costs or taxes. For consistency, the plants were assumed to be large (a minimum of 500 MW), operated at a load factor of 75 percent, have a 15 percent interest rate on capital, and are constructed in developing Asian economies.

The costs and operating assumptions in Table 1 are intended for general comparisons between technologies and fuel costs, to assist energy policy makers in understanding their relative economics. The technologies compared include three fully proven technologies: (1) pulverized coal-fired plants without FGD (PC), (2) pulverized coal-fired plants with FGD (PC+FGD), and (3) natural gas-fired combined-cycle plants (Gas-CC). With respect to emerging clean coal technologies, the most promising emerging technology for the twenty-first century are technologies that gasify coal. Examined here is IGCC technology that combines coal gasification technology with a combined-cycle power plant. IGCC technology has very low emissions of SO_2 and particulates, and lower NO_x and CO_2 emissions than PC technologies. Recent advances in efficiencies of gas turbine technologies also improve the efficiencies of IGCC plants.

The costs of the PC technology are given for plants with and without flue gas desulfurization (FGD) technology. It is assumed that the SO_2 control technology for PC plants is an FGD unit capable of capturing at least 90 percent of SO_2 emissions. However, less costly SO_2 control technologies are available that recover a smaller percentage of SO_2 emissions, and they could become important in selected Asian economies, such as China.

The PC option is the most widely used coal-fired technology in the world, and it is unlikely to be rapidly displaced by any known coal-fired technology.

The IGCC technology has been demonstrated at commercial scales, but has yet to meet the commercial power plant operating standards needed to gain acceptance by private power companies for electricity generation. However, this is the technology that can deliver the best environmental performance of any known commercial-sized, coal-fired technology, and is evolving rapidly.

To simplify the analysis, two natural gas prices were assumed:[12] \$3.50/1,000 ft^3 for pipeline natural gas and \$4.30/1,000 ft^3 for liquefied natural gas (LNG). Long distance natural gas pipelines are common in North America and Western Europe but not in Asia. Natural gas production costs vary widely, but typically range from about \$1.00 to \$2.00 per 1,000 ft^3. Pipeline transport costs over long distances range from about \$0.06 to \$0.12 per 1,000 ft^3 per 100 km, depending on distance and pipeline size (capacity). Assuming a representative natural gas production cost of \$1.50/1,000 ft^3, and adding \$0.08/100 km transport costs for a pipeline distance of 2,500 km gives a natural gas delivery cost of \$3.50/1,000 ft^3. Actual pipeline prices can vary substantially from these estimates, due to market conditions, the availability of competing fuels and taxes.

Typical c.i.f. LNG prices in Asia in 1997 are about \$3.50/1,000 ft^3 of natural gas, plus the cost of storage facilities and regasification at the power plant (assume \$0.80/1,000 ft^3), giving a price of \$4.30/1,000 ft^3 at the power plant.[13]

With respect to coal, for minemouth power a typical (constant 1997 dollar) price of \$15.00 per ton is assumed for a typical 5500/kcal/kg Chinese coal. Finally, Asian economies are increasingly importing thermal coal at \$38-43/t c.i.f., and a representative (constant 1997 dollar) import price of \$40/t in southeastern coastal China is assumed for a 6700 kcal/kg thermal coal.

VIII. ELECTRICITY COSTS FOR COAL AND NATURAL GAS-CC OPTIONS

The levelized costs of electricity from the assumptions in Table 1, excluding land costs and taxes, range from \$0.0319/kWh to \$0.0547/kWh. Electricity costs from different technologies are site specific, and can vary considerably between locations. The goal of the analysis was not to show the exact costs/kWh, but to show *relative costs* which provide more useful information on the relative competitive positions of different options. Second, the costs of technologies are decreasing, and efficiencies are improving. Therefore, comparisons were made for plants ordered in 1997 and plants ordered a decade later in 2007. The estimates for costs a decade from now reflect plausible trends in costs and plant efficiencies.

Table 2 shows relative costs for the different technology and fuel options for plants ordered in 1997 in constant 1997 dollars. The comparisons are for natural gas by pipeline (\$3.50/1,000 ft^3), LNG (\$4.30/1,000 ft^3), minemouth coal (\$15.00/t @ 5500 kcal/kg) and imported coal (\$40/t @ 6700 kcal/kg). Levelized electricity cost comparisons are with a pulverized coal-fired plant including FGD (PC+FGD) as 100 percent.

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[12] \$ = US\$, and tons are metric tons.

[13] 1,000 cubic feet (28.32 m^3) of natural gas is approximately equal to 1.0 million Btu.

For example in quadrant I in Table 2, relative electricity costs are shown assuming fuels are minemouth coal and pipeline natural gas. As shown, a PC plant (without FGD) generates electricity at 88 percent of a PC plant with FGD (PC+FGD). Electricity from a Gas-CC plant is only 7 percent more expensive than a PC+FGD, and IGCC is 23 percent more expensive. The main observations from Table 2 are as follows:

(1) Gas-CC plants fueled by pipeline natural gas are likely to displace PC+FGD plants using imported coal.

(2) Gas-CC plants fueled with LNG are competitive with PC+FGD plants using imported coal, and both coal and LNG will be used in these markets.

(3) PC plants that are not required to install FGD can compete with either pipeline or LNG options in all markets.

(4) IGCC technologies are not competitive under any of the fuel option scenarios, therefore will need substantial added benefits from the production of other products, (chemicals and heat) to become competitive.

Table 3 shows the same comparisons for more advanced plants ordered in 2007, assuming constant dollar costs. The main observations from Table 3 are as follows:

(1) IGCC becomes more competitive, and is only about 7 percent more expensive than PC+FGD plants when imported coals are used. However, to compete with natural gas or LNG, IGCC will need added income the from production of other products.[14]

(2) Gas-CC plants using pipeline natural gas will be highly competitive in markets using PC+FGD plants and imported coal. The majority of power plants in these markets are likely to switch to natural gas.

(3) There is a decrease in the percentage differences in electricity costs among the technology and fuel options over the next decade. Consequently, increasing numbers of multiple fuel and technology markets are likely, and increased competition.

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[14] Under a possible severe greenhouse gas reduction scenario, where CO_2 must be collected and sequestered, coal gasification has an added advantage over traditional coal-fired technologies, because it is less costly to recover CO_2 in the gasification process than from convention coal-fired plants.

CONCLUSIONS

Coal is expected to remain the dominant fuel in Asia over the 1995-2020 period. However, tighter emissions regulations by 2000 in the major coal consuming economies will accelerate the introduction of SO_2 control technologies, plus fuel switching to very low sulfur coals and natural gas (also coalbed methane in selected locations). A premium for very low sulfur compliance coals may develop over the next decade. The improved economics of natural gas combined-cycle plants, in combination with stricter SO_2 emission regulations, will greatly accelerate the introduction of natural gas into the power generation sector in Asia. Pipeline natural gas, where available at \$3.50/1,000 ft^3, is highly competitive with coal in all coal importing economies in Asia, and is expected to increase its market share over the next 15 years.

In the long term, IGCC technology is the most promising technology for coal-based economies, such as China. It has the highest environmental benefits of any coal technology plus is capable of producing multiple products. The key to the commercial success of coal gasification and electricity generation will be the ability to produce and sell multiple products, electricity, chemicals and heat.

The trends toward introducing clean coal technologies, and expanding the use of cleaner fuels in Asia's electricity sector will accelerate in response to tighter environmental standards by 2000. After 2000, the majority of large coal-fired plants in Asia are expected to install SO_2 control technologies or use low sulfur fuels.

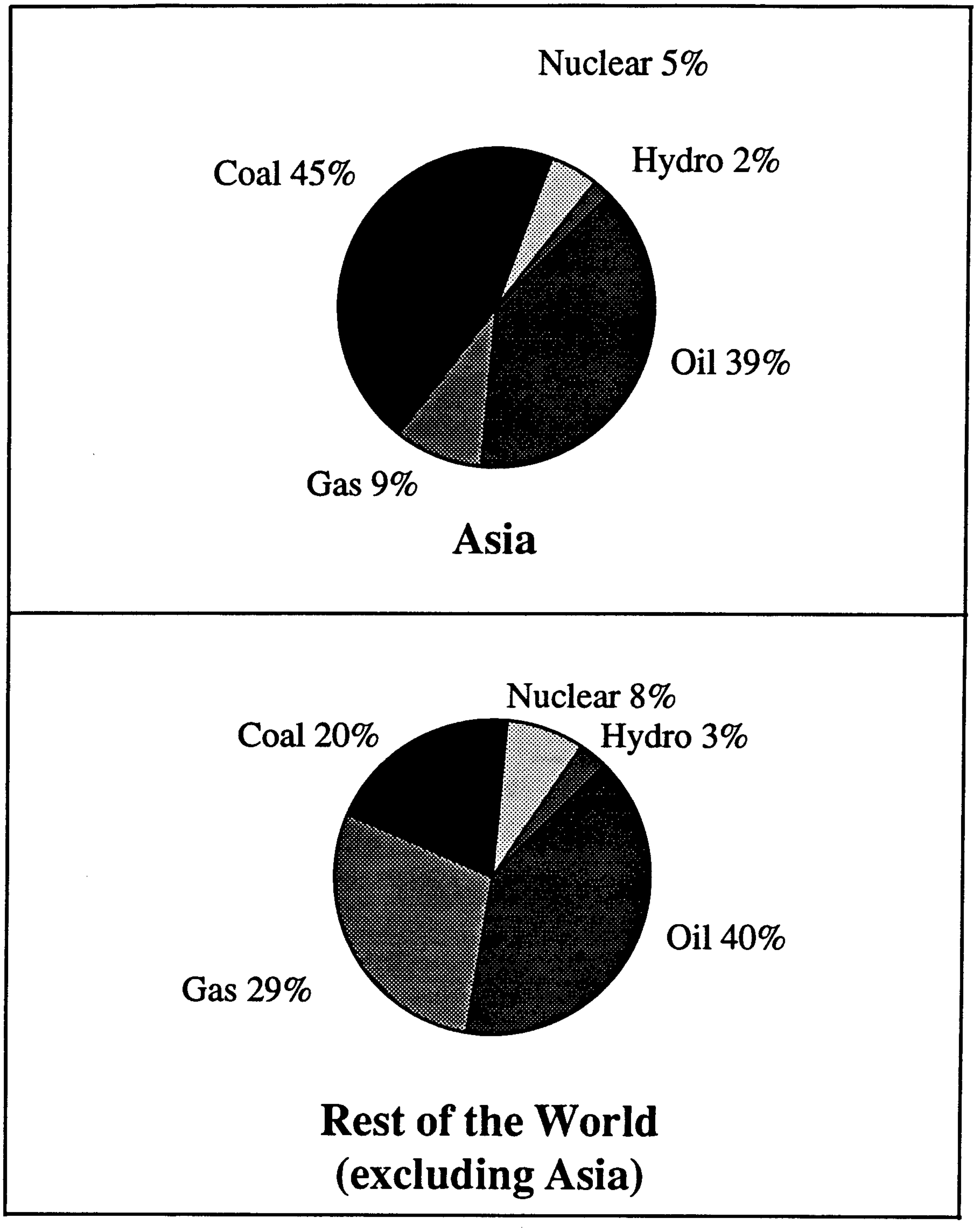


Figure 1. Primary Energy Shares in Asia and the Rest of the World in 1996

Source: BP, 1997

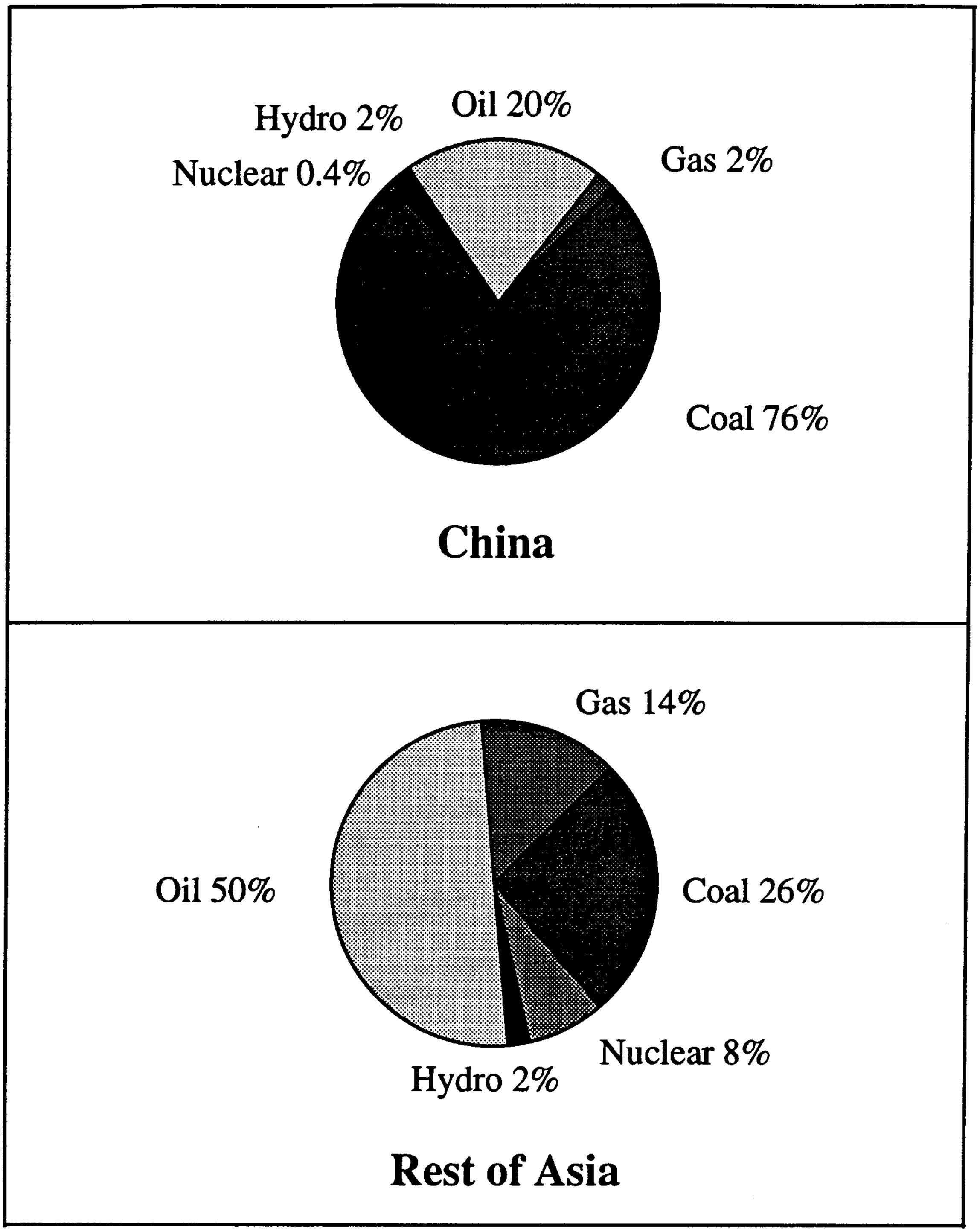
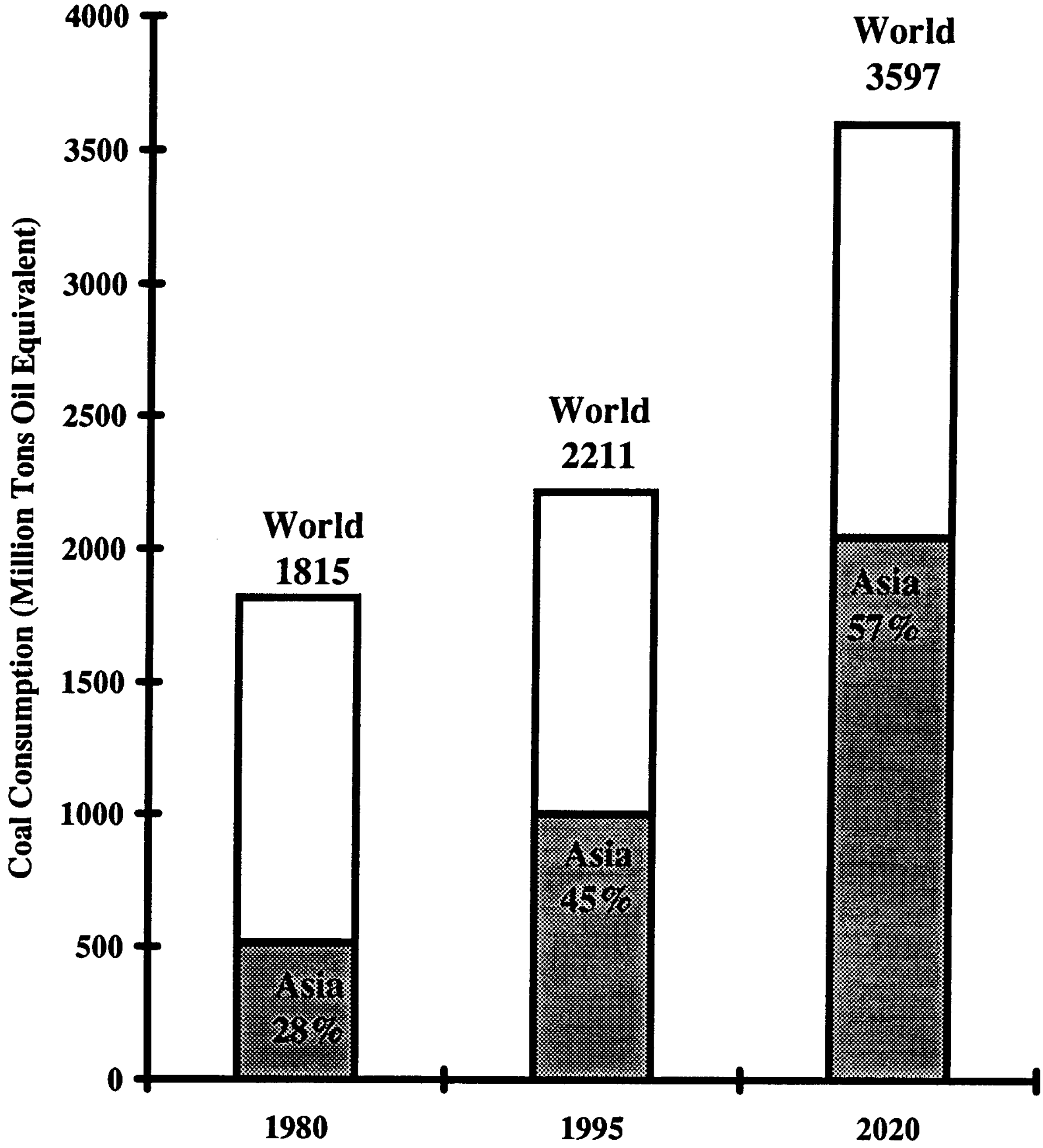


Figure 2. Primary Energy Shares in China and the Rest of Asia in 1996

Source: BP, 1997

Figure 3
Coal Consumption in Asia and the World in 1980 and 1995, and Projections to 2020



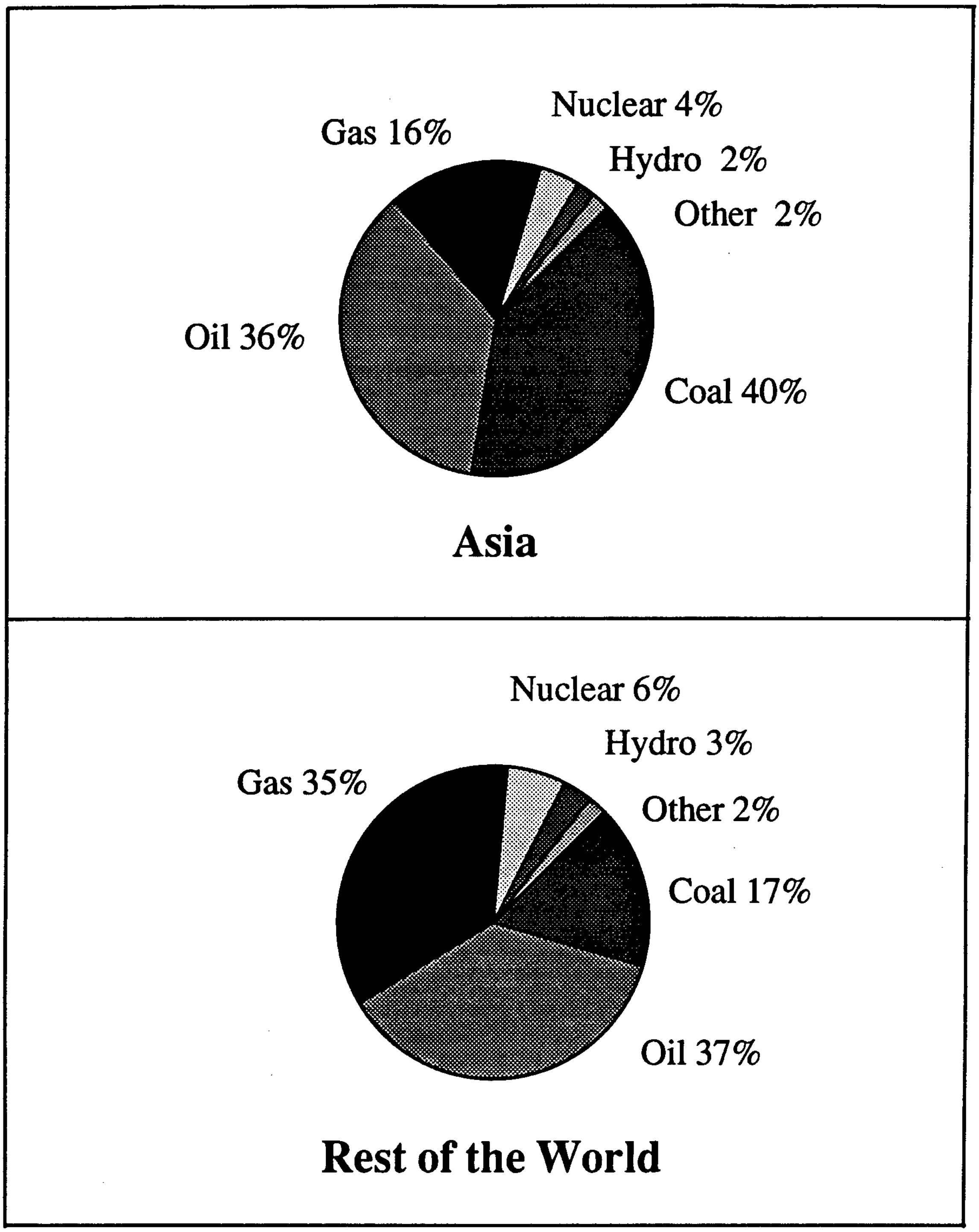


Figure 4. Primary Energy Shares in Asia and the Rest of the World in 2020

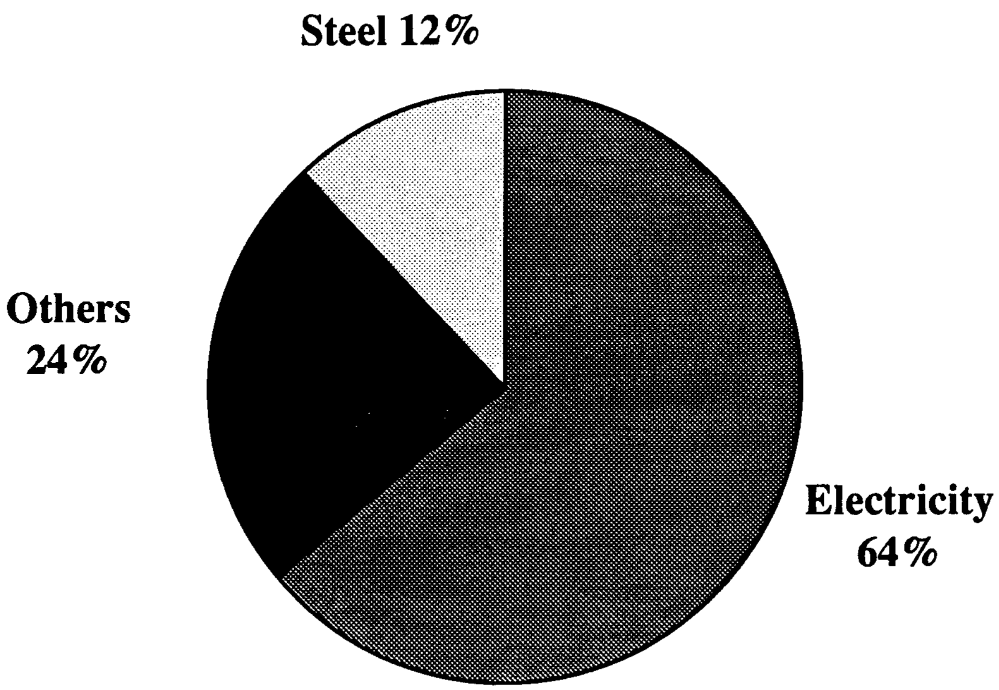


Figure 5. Percent of growth in coal consumption in Asia: 1980-1994

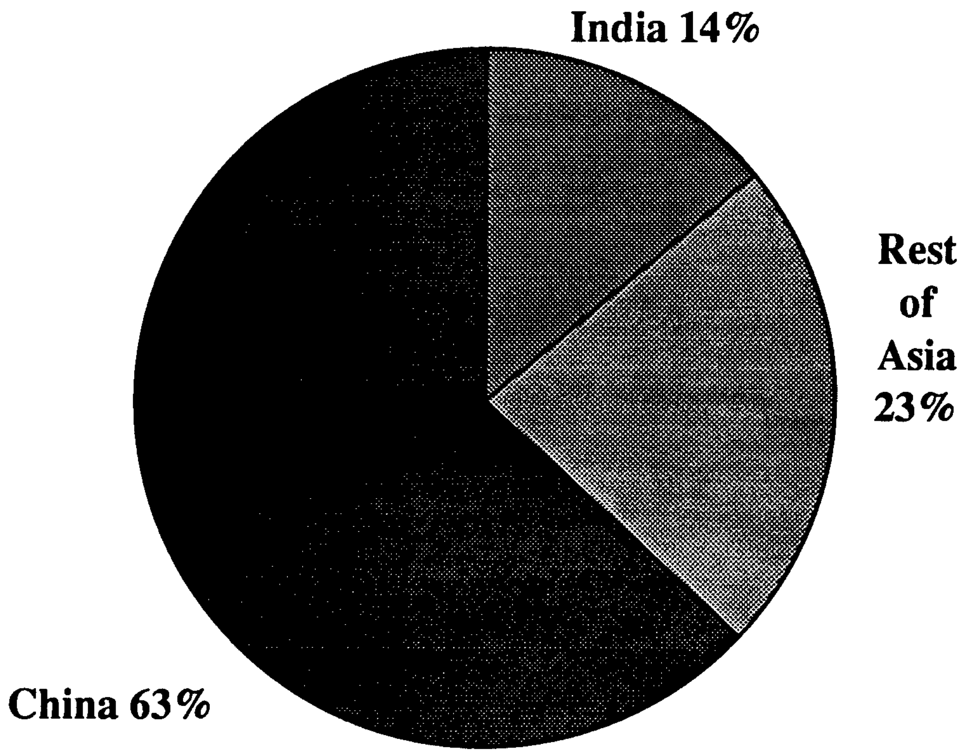


Figure 6. Estimated Shares of Asia's SO_2 Emissions from China and India in 1997. Asia Total Emissions Estimated at 47 Million Tons SO_2.

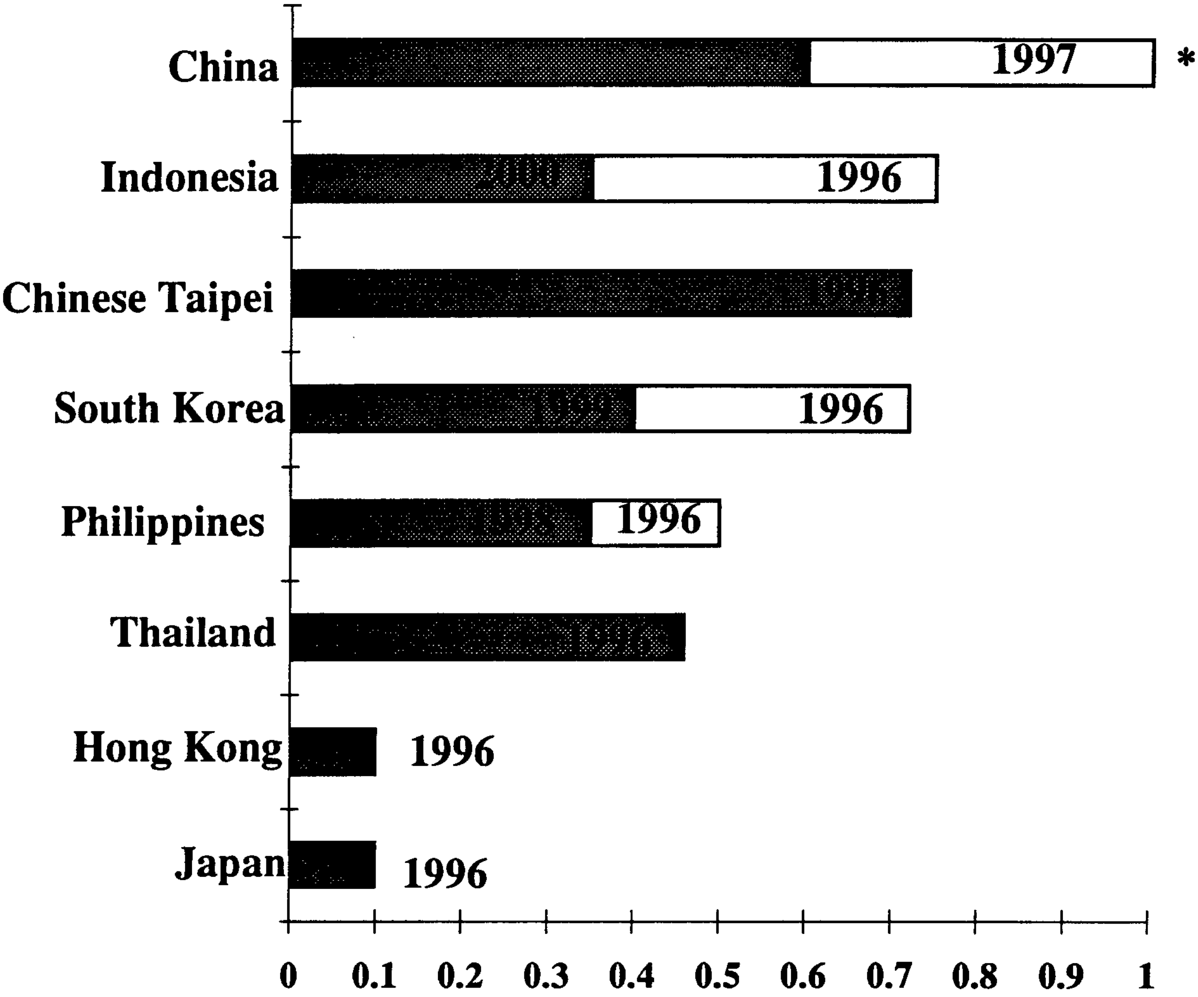


Figure 7. Estimated maximum percent sulfur in coal that will meet emissions standards in eight Asian economies.

***China has effectively two standards for new plans: up to 1.0 percent coal can be burned in new plants, but above 1.0 percent coal requires SO_2 control to reduce emissions to the equivalent of 0.6 percent sulfur coal.**

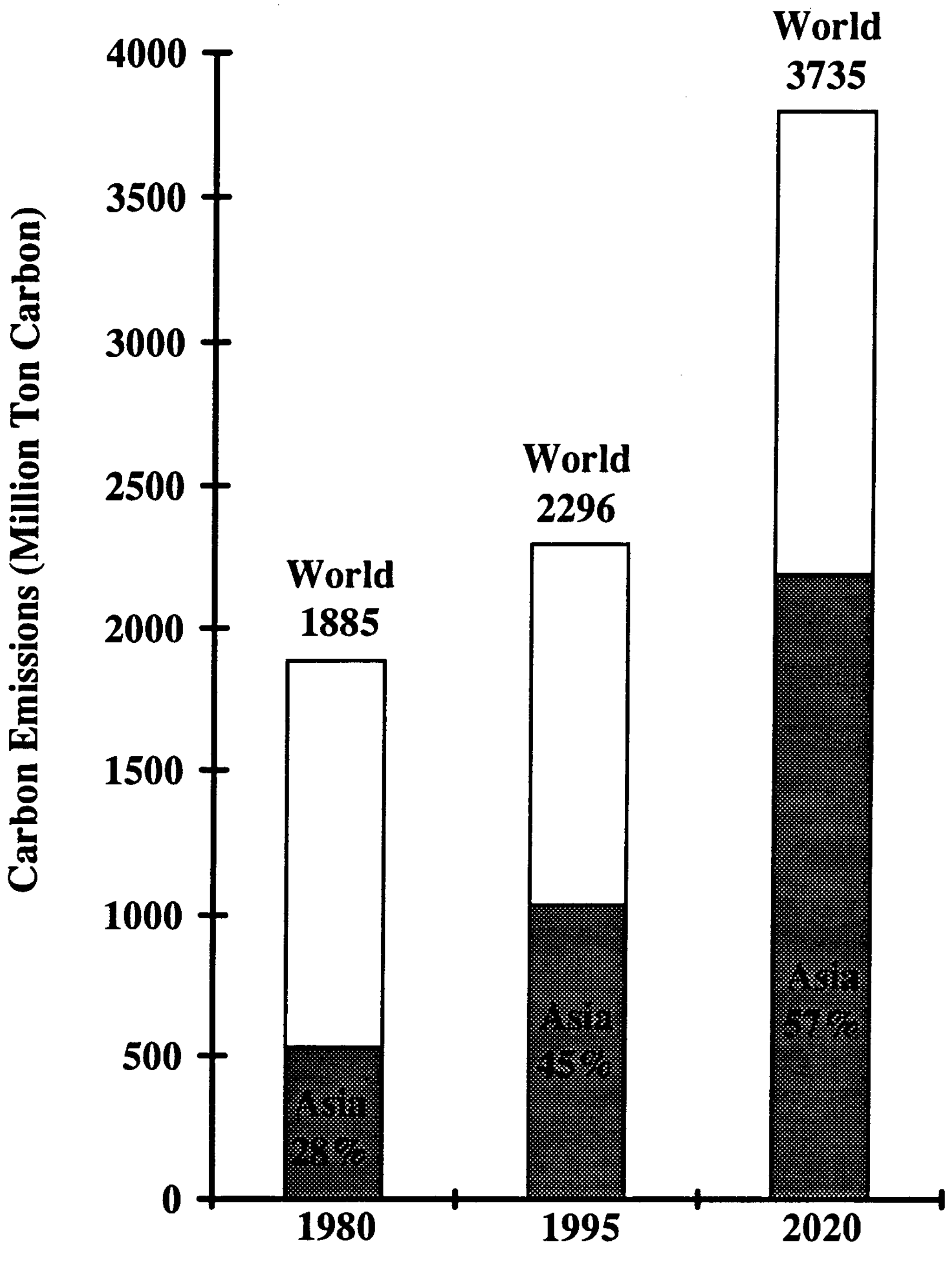


Figure 8. Carbon Emissions from Coal in Asia and the World in 1980 and 1995, and Projections to 2020

Table 1 Assumptions for Coal-Fired and Natural Gas Combined-Cycle Power Plant Comparisons (1997 US$)

Assumptions Year 1997	Units	Natural Gas-CC	Coal PC	Coal PC+FGD	IGCC
Capital cost	$/kW	500	950	1,075	1,375
Discount rate	%	15	15	15	15
Plant life	Years	20	30	30	20
O&M (excl. fuel)	cents/kWh	0.45	0.6	0.75	0.9
Conversion efficiency	%	47.5	36.7	35.8	42
Load factor	%	75	75	75	75
Assumptions Year: 2007	**Units**	**Natural Gas-CC**	**Coal PC**	**Coal PC+FGD**	**IGCC**
Capital cost	$/kW	400	850	950	1,075
Discount rate	%	15	15	15	15
Plant life	Years	20	30	30	20
O&M (excl. fuel)	cents/kWh	0.45	0.6	0.75	0.9
Conversion efficiency	%	51.5	38	37.2	46.5
Load factor	%	75	75	75	75
Fuel Price Assumptions					
Domestic (Local) Coal	$15/t (5,500/kcal/kg)				
Imported Coal	$40/t (6,700/kcal/kg)				
Pipeline Natural Gas	$3.50/1,000 ft^3				
LNG (include. regassification)	$4.30/2,000 ft^3				

1997 (TODAY)

Pipeline Gas	**I** IGCC 123% Gas-CC 107% PC+FGD 100% PC 88%	**II** IGCC 117% PC+FGD 100% PC 90% Gas-CC 89%
LNG	**III** IGCC 123% Gas-CC 122% PC+FGD 100% PC 88%	**IV** IGCC 117% Gas-CC 101% PC+FGD 100% PC 90%
1997	**Minemouth Coal**	**Imported Coal**

Table 2 Comparison of technology and fuel options for hypothetical plants ordered in 1997 in Asia. Shown are relative electricity costs of alternative technology and fuel options compared to the base case cost of 100% for a PC+FGD plant.

2007 (?)

Pipeline Gas	I IGCC 112% Gas-CC 104% PC+FGD 100% PC 89%	II IGCC 107% PC+FGD 100% PC 91% Gas-CC 86%
LNG	III Gas-CC 119% IGCC 112% PC+FGD 100% PC 89%	IV IGCC 107% PC+FGD 100% Gas-CC 99% PC 91%
2007	Minemouth Coal	Imported Coal

Table 3 Comparison of technology and fuel options for hypothetical plants ordered in 2007 in Asia. Shown are relative electricity costs of alternative technology and fuel options compared to the base case cost of 100% for a PC+FGD plant.

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no 1332.15 in folder