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INDONESIA

Asia-Pacific Energy Series

Country Report

by

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DISCLAIMER

EXECUTIVE SUMMARY

GEOGRAPHY AND ECONOMY

- Indonesia is a tropical archipelago 3,400 miles long. It has more than 13,000 islands, which straddle the equator and extend from the mainland of Asia to Australia. Its population of more than 180 million people makes it the fifth most populous nation in the world. About 3,000 islands are inhabited in significant numbers, but the vast majority of the people live in the four large islands of the western half of the country. More than 60% of the people live on the densely populated island Java, which is the nation's political, commercial, and industrial center.

- Indonesia's overall economic performance in recent years has exceeded expectations. Between 1983 and 1989, growth in GDP averaged 5.9% per year. In 1989 Indonesia had an estimated GDP of US$82.7 billion and per-capita income of US$471.

- Development and diversification of the Indonesian economy are the government's long-term goals. Despite a long history as an oil exporter, Indonesia still has a low per-capita income, and oil revenues play a major role in financing national development. The nation is nonetheless prepared for declines in oil production during the coming decade, and the government is fully aware of the need to move away from over-reliance on the oil sector.

- The government's successive five-year development plans, launched in 1969, have placed emphasis on industrial expansion and the promotion of exports. As a result of sustained industrial growth during the 1970s and 1980s, the industrial sector has begun to overtake agriculture's traditionally dominant contribution to GDP. The current five-year plan (known as "Repelita V," 1989-93) is seen as the stage in which the national economy will approach the "take-off" phase.

- Deregulation policies have been implemented to stimulate private sector productivity and competitiveness, particularly in export commodities. To this end, liberalization measures have been applied to the banking and financial sectors to improve internal efficiency and the capability of mobilizing private savings so as to increase investment capital to productive sectors.

- The collapse in oil prices during the mid 1980s caused major economic dislocations in many oil-exporting countries. Indonesia's revenues from oil and LNG exports plummeted from approximately US$18.8 billion in 1981 to less than US$7 billion in 1986. This decline in revenues provided the impetus for the government to strengthen its economic diversification policies, which have enhanced nonoil sector revenues. Export earnings from nonoil commodities expanded rapidly during the 1980s, growing from US$4.2 billion in 1981 to approximately US$12.2 billion in 1988. Oil and LNG export revenues were surpassed by revenues from other export commodities for the first time during 1987.

INDIGENOUS ENERGY RESOURCES

- Indonesia is blessed with an abundance of energy resources. Its oil reserves, estimated at 11 billion barrels, represent 22% of Asia-Pacific oil reserves (including China) and 1.4% of total OPEC oil reserves. Natural gas reserves are currently estimated at 91.5 trillion standard cubic feet. Total coal reserves are estimated at more than 31 billion tons, with proven reserves at 3.5 billion tons.

- Indonesia also has vast hydropower resources, which could contribute significantly to the rapidly growing demand for electricity. The nation's theoretical hydropower resources total nearly 76,000 MW. Although hydropower potential exists on all major islands, much of Indonesia's remaining potential is in thinly populated areas, such as Irian Jaya and Kalimantan. At the end of the fourth five-year development plan in early 1989, less than 5% of the theoretical resource had been developed.

- Indonesia has more than 70 active volcanoes and the potential to be one of the world's biggest producers of geothermal energy. Geothermal resources are estimated to exceed 10,000 MW. More than half of this potential (5,500 MW) is on Java, and this island is the site of all of the 290 MW of geothermal capacity additions during the current five-year development plan, 1989-93.

ENERGY IN THE ECONOMY

- Many of the areas with the greatest energy resource potential in Indonesia are located far from population centers. The mismatch between the location of nonoil energy resources and population centers, compounded by the transport difficulties inherent in an island nation make the economy highly dependent on its oil and gas reserves and consumption of petroleum fuels.

- After the first oil price shock in 1973, the government began to rationalize the utilization of energy-sector resources, which are entirely state owned. Diversification in domestic consumption was encouraged to maximize the quantity of oil available for export. New domestic uses for natural gas were promoted, and LNG exports began in 1977. Indonesia is now the world's biggest exporter of LNG (estimated at 19.5 million tons in 1990). The discovery of new gas fields near densely populated areas has given gas-fired power generation a position of priority in electric power planning.

The coal industry was revived after a long period of decline, coal-fired electric power generation has been greatly expanded, and export markets have been sought for coal.

- Petroleum has been and will remain the dominant fuel in Indonesia's primary energy mix, although the government's policy to diversify energy sources has already resulted in a substantial amount of fuel substitution. In 1971 oil represented nearly 94% of commercial primary energy; this share declined to 84% in 1980, 74% in 1985, and 68% in 1988. Oil's share is expected to remain in the 58-60% range during the early 1990s.

- Oil and gas are the largest earners of foreign exchange. Coal is potentially an important exporter earner. The share of oil and gas in total export revenues reached a peak of 82% in 1982. It has steadily declined since then and was only 39% in 1989.

- Although the percentage contribution of oil and gas to the economy is likely to diminish even further as the nonoil share of GDP increases, the petroleum sector will still play a crucial role for a variety of reasons. A significant proportion of oil and gas export revenues goes directly to the government, and development plans will continue to rely heavily on anticipated oil revenues. Petroleum exports will remain a major earner of valuable foreign exchange. Oil will continue to serve as "the" fuel for development, as an input factor for production of other goods.

- Electricity generation is the main vehicle through which the government has been able to implement its energy diversification policies. Oil still plays a major role as an electricity generation fuel, but its role has been greatly reduced through the promotion of natural gas, coal, hydropower, and geothermal energy. Natural gas was the first fuel to gain a significant share in the primary energy supply. From a mere 1.5% in 1971, it increased to nearly 15% in 1980 and reached 21% in 1988. Coal's share rose from 1.3% in 1971 to almost 7% in 1988. Expansion of geothermal and hydropower has been limited; their combined share of the primary energy mix in 1988 was 4.7%, as opposed to 3.6% in 1971. By the end of the current five-year development plan (1989-93), the government forecasts that the energy mix will be 58% oil, 25% gas, 9% coal, and 8% hydro/geothermal.

- The industrial sector is the largest consumer of energy, accounting for over 47% of final energy consumption. The transport sector, which is the most heavily reliant on petroleum fuels, represents around 30% of final energy use, while the household, commercial, and public sector makes up the remainder. The government anticipates that final energy use will grow at rates averaging around 4.7% per year during the current five-year economic development plan (1989-93). This growth will raise final energy use from 231 million barrels of oil equivalent in 1989 to 290 million barrels of oil equivalent in 1993.

- It should be noted that the number of *potential* domestic energy consumers in Indonesia is extremely large. Three-quarters of the nation's villages, for example, do not yet have electricity and are therefore dependent on wood, charcoal, peat, and biomass for their energy needs.

- Despite the abundance and variety of energy resources in Indonesia, projected rapid economic growth in the next two decades will outstrip the nation's capacity to meet energy demand solely from indigenous sources. Expansion of coal and natural gas production are already expected to be inadequate to meet demand from the electric power sector, and an 800-MW nuclear power plant has therefore been included in the plan for added generation capacity. Unless major new reserves of oil are discovered, the projected demand pattern suggests that Indonesia may become a net importer of oil early in the twenty-first century.

GOVERNMENT AGENCIES AND INSTITUTIONAL ARRANGEMENTS

- Overall energy policy and planning is set forth in the national five-year plans. Guidance on policy issues related to energy is provided by the National Energy Coordinating Board (BAKOREN), a cabinet level policy board chaired by the Minister of Mines and Energy.

- The Ministry of Mines and Energy controls and supervises the four state-owned energy enterprises and their respective areas of responsibility: Pertamina (oil, gas, and geothermal energy), the State Gas Corporation (city gas), the State Electric Power Corporation (electricity), and Perum Tambang Batubara (the state coal company).

- Indonesia is a member of the Organization of the Petroleum Exporting Countries (OPEC) and a member of the six-country Association of South East Asian Nations (ASEAN). Within OPEC, Indonesia is generally regarded as a neutral party that can play a role in moderating disputes among member countries. The current Secretary General of OPEC, Dr. Subroto, is an Indonesian and a former Minister of Mines and Energy. Within the Asia-Pacific region, Indonesia is the leading oil exporter and has a key role in maintaining regional oil supplies and moderating prices.

OIL INDUSTRY

- Indonesia has a long history of oil use and has been a commercial producer for more than a century. Indonesia was a pioneer in the production sharing contract (PSC) system, which was developed to formalize cooperation between the government and foreign oil companies. The first PSC was signed in 1964, and by 1989, 18 production-sharing contractors were operating in Indonesia.

- Indonesia may undergo the transition from net oil exporter to net oil importer by the early twenty-first century, as a result of even modest increases in consumption plus impending declines in production. Domestic oil demand is expected to grow at 2.3 percent per year during 1990-95, slowing to 2.0 percent per year during 1995-2000. These growth rates are moderate in comparison to many other Asian countries, which are forecasting oil demand growth of 7-8% per year.

- Indonesian petroleum product prices have been among the lowest in the region. Indonesia is now in the process of market deregulation and decentralization. Fuel pricing is being brought into line with market prices, which is expected to have a dampening effect on demand growth.

- Indonesia currently produces about 1.4 million barrels per day (b/d) of crude oil and condensate, about 0.8 million b/d of which is exported. In the near term, production of heavy sweet crudes—chiefly from the enhanced oil recovery project in the Duri field and from the new finds in the Intan and Widuri fields—is expected to increase by around 100,000 b/d. However, the additional production from these and other fields is not expected to fully offset the forecast production declines. Production is expected to peak at around 1.5 million b/d in 1993 and then enter a period of decline, falling below 1.0 million b/d by the year 2000.

- Crude export availability is expected to decline more sharply than production, partly because of internal oil product requirements and partly because of the country's ambitious plans to move into export refining.

- Indonesia has the region's most sophisticated refining system. Effective crude distillation capacity is 735,000 b/d. Ideally, the system should be fully able to meet domestic demand as well as produce significant quantities of exportable gasoline and kerosene. Minor technical problems have prevented the hydrocracker trains from running at fully capacity, and the nation finds itself year after year importing costly middle distillates while exporting lower-valued low-sulfur waxy residual fuel and naphtha. The refineries produced 654,000 b/d of refined products in 1989 and imported 58,000 b/d of product, primarily middle distillates.

- Indonesia is currently expanding its refining industry and has plans for up to four export-oriented refineries. Depending on the completion of these projects, crude exports may fall to somewhere in the range of 150,000-300,000 b/d by the turn of the century. Additionally, crude imports, which currently average 80,000-90,000 b/d may rise to 200,000-250,000 b/d by the year 2000.

NATURAL GAS INDUSTRY

- Of the currently estimated 91.5 trillion standard cubic feet of natural gas reserves, 38 trillion standard cubic feet are located in the Natuna Sea area. The Natuna Sea fields are among the most promising gas fields, but their distance from the major population centers has limited commercial domestic use of natural gas in the past. The first major gas deposits to be developed were in East Kalimantan and Aceh Provinces, which are far from the major population and industrial centers on the island of Java.

- Most natural gas is liquefied and exported as LNG. Gas production in 1989 was almost 2 trillion standard cubic feet. Two-thirds of this production was liquefied and exported as LNG. Indonesia is the world's largest LNG producer and exported an estimated 19.5 million tons in 1990. The bulk of these exports have gone to Japan, although South Korea and Taiwan are emerging as important importers. Completion of gas processing plants at Arun and Badak in 1988 greatly increased Indonesia's production and export of liquified petroleum gas (LPG). Japan is also the principal market for Indonesian LPG exports.

- Feedstock uses (chiefly fertilizer) constitute the second-largest market for Indonesia's natural gas, followed by other industrial uses, electricity generation, and city gas operations.

- The government is actively encouraging the substitution of natural gas for oil, and funding has been sought from international agencies for the expansion of city gas operations. Presently, efforts are now under way to develop gas fields near big population centers for local use. The offshore Poleng and Kangean fields, for example, are being connected by submarine pipeline to East Java, where the gas will be used by the state electric utility, the city gas network, the petrochemical industry, and other local industries. The ultimate goal is to build a trans-Java pipeline to create an integrated gas supply network.

PETROCHEMICAL INDUSTRY

- A significant increase in petrochemical capacity is expected during the current and upcoming five-year development plans (1989-93 and 1994-98), mostly for basic petrochemicals.

- In 1989 imports of basic petrochemicals exceeded US$700 million. The government hopes to replace these imports by domestic production. However, planned developments will require substantial new investment. This will also mean an increase in domestic use of condensate and naphtha as feedstock, thereby reducing their export availability.

- Current firm plans for major projects include major olefins and aromatic centers as well as other plants to produce styrene monomer, polypropylene, carbon black, polyethylene, and methanol.

ELECTRICITY

- From the period 1968 to 1988, the electric power sector grew much more rapidly than the economy as a whole. The average annual growth in electricity generation was 15.1% in the second five-year development plan (1974-78), 21.3% in the third plan (1979-83), and 16.1% in the most recently completed plan (1984-88). By contrast, the average annual GDP growth rates in the respective five-year plans were 7.2%, 5.7%, and 3.5%.

- At the end of 1989 the state-owned power system, Perusahaan umum Listrik Negara (PLN), had an installed capacity of 8,452 MW. Outside the PLN system, installed capacity (mostly operated by industrial concerns) was 10,3323 MW. Power generation by the PLN system accounted for 54% of Indonesia's total electricity production.

- In 1971 the oil share of total power sector fuel was 77%. As electricity demand burgeoned, the share of oil rose to 89% in 1982. The government, through the state electric utility, phased in a number of alternatives to oil, and by 1988 oil's share fell to around 59% of the total electric power fuel mix. Hydro and geothermal generation together accounted for 21.6% of total generation, followed by coal at approximately 20% and natural gas at 1.2%.

- Within the state-owned power system (PLN), dependence on oil was substantially lower than the national average, particularly after the completion of the Suralaya coal-fired power plant in West Java. In 1989 oil accounted for only 39% of the state utility's fuel mix. Privately owned and operated plants, which account for roughly half of total electricity generation, are still largely reliant on oil.

- One option for maximizing future development of hydropower resources is to link the islands of Sumatera and Kalimantan—which have large hydropower potential—with the Java grid via submarine transmission cables. The main obstacles to this option are high costs and technical difficulties.

- Indonesia's geothermal plant (140 MW installed capacity) is one of the largest commercial geothermal facilities in the world. This facility is in Kamojang, West Java, and is operated by Pertamina, the state oil company.

COAL INDUSTRY

- Coal has a long history of use in Indonesia, but the success of the oil industry after World War II forced the coal industry into a long period of stagnation. After the first round of world oil price increases in 1973-74, coal was given a prominent place in the government's energy diversification policy. Production rebounded from a low of around 150,000 tons in 1973 to nearly 2 million tons in 1985 and around 8.7 million tons in 1989. Production is forecast to reach nearly 21 million tons by 1993.

- Because of unexpectedly high levels of production in 1989, coal exports that year exceeded 2.5 million tons—about ten times the amount that the government had initially projected. The expansion of export markets is expected to continue, since coal production levels will far surpass domestic demand.

- Coal-fired power plants and the cement industry account for almost all of domestic coal consumption.

- Most of the export coal is produced under the government's system of production sharing contracts. Nine production sharing contractors are expected to be operating by 1993. The state-owned coal company (Perum Tambang Batubara) produces coal chiefly for domestic use.

IMPACT OF THE 1990-91 MIDDLE EAST CRISIS

- Turmoil in the Middle East beginning in August 1990 reduced world oil supplies by about 4.5 million barrels a day and drove prices up. Clearly, with an export volume the size of Indonesia's, even a modest increase in selling price can add up to a massive amount of additional revenue. But the increased prices are not an unqualified boon to Indonesia and will be accompanied by disadvantages such as those outlined below.

- The key lesson learned after the second oil price shock in 1979-80 was that an excessively high price will dampen world economic growth, will encourage conservation and fuel switching, and will ultimately reduce demand for oil. Both producers *and* consumers can be hurt by oil price volatility. Indonesia's Minister of Energy and Mines, Ginandjar Kartasasmita, has on numerous occasions pointed out that, from the Indonesian perspective, a relatively stable real price of oil is desirable. Serious economic pressures have resulted from oil price instability, and the Indonesian government has worked hard to ensure that severe swings in oil revenues will not destabilize the economy.

- Increased government spending causes an increase in economic aggregate demand, which in turn may be inflationary. Since Indonesia balances the budget each fiscal year (with a prediction of the year's oil price used to determine income from oil), unexpected income from the oil price hike *must* result in increases in government spending in the fiscal year in which it is received. For the 1990 fiscal year, the government's goal was to keep inflation at 5-6%; yet inflation reached 7% by August 1990 and 9% by October 1990. The crisis in the Middle East made it increasingly difficult for the Indonesian government to keep inflation rates within single digits.

- Higher oil prices exacerbate the government subsidy to the domestic petroleum product market. Domestic product prices are fixed, whereas the value of raw crude has risen.

- Indonesia has placed considerable emphasis on the development of nonoil export commodities, and maintaining too high an oil price may cut into these exports by reducing the buying power of the country's export markets.

- A little-known factor in the Indonesian oil trade pattern is that Indonesia *imports* about 80,000 b/d of Middle Eastern crude, chiefly because the waxy Indonesian crudes are unsuited for production of asphalt and lubes. Historically, the bulk of this supply came from Saudi Arabia. More recently, however, Indonesia concluded a barter trade agreement with Iraq, in which Iraq provided the required crude and Indonesia provided a variety of nonoil commodities. The loss of Iraqi supplies not only forced Indonesia to seek alternate supplies at higher prices, but also eliminated a market for Indonesia's nonoil exports.

- Indonesia, along with other moderate OPEC countries, announced its intention to help compensate for the loss of Iraqi and Kuwaiti production by relaxing the current OPEC production ceiling. Although its official OPEC quota has never been a limiting factor, Indonesia asked for a 100,000 b/d quota increase by December 1990, and production has been modestly expanded. This announcement provoked a great domestic controversy, given recent oil production policy.

- On several occasions, Minister Ginandjar has noted that Indonesia's oil reserves are sufficient—but relatively modest—and that it is more prudent to avoid production in excess of the country's economic requirements. This policy takes on an added significance when considering that Indonesia's transition to the status of a net oil importer is looming on the horizon. Buying oil in the future may be a much more costly venture than it is currently—even taking into consideration the recent price increases.

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Preface

As part of our continuing assessment of Asia-Pacific energy markets, the Energy Program has embarked on a series of country studies that discuss in detail the structure of the energy sector in each major country in the region. To date, our reports to the U.S. Department of Energy, Assistant Secretary for International Affairs and Energy Emergencies, have covered Australia, China, Indonesia, Japan, Malaysia, the Philippines, Singapore, South Korea, Taiwan, and Thailand. The country studies also provide the reader with an overview of the economic and political situation in the various countries. We have particularly highlighted petroleum and gas issues in the country studies and have attempted to show the foreign trade implications of oil and gas trade. Finally, to the greatest extent possible, we have provided the latest available statistics—often from unpublished and disparate sources that are unavailable to most readers. Staff members have traveled extensively in—and at times have lived in—the countries under review and have held discussions with senior policymakers in government and industry. Thus, these reports provide not only information but also the latest thinking on energy issues in the various countries.

It is our hope that over the next few years these country studies can be updated and will provide a continuous, long-term source of energy sector analysis for the Asia-Pacific region.

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LIST OF ABBREVIATIONS

ADB	Asian Development Bank
ADO	automotive diesel oil
ASEAN	Association of South-East Asian Nations
BAKOREN	National Energy Coordinating Board (abbreviated from Badan Koordinasi Energi)
BAPPENAS	National Development Planning Agency
BATAN	National Atomic Energy Agency (abbreviated from Badan Tenaga Atom Nasional)
BBM	five petroleum fuels (abbreviated from *bahan bakar minyak*)
BKKA	Foreign Contractors Coordinating Board of Pertamina (abbreviated from Badan Koordinasi Kontraktor Asing); name changed to BPPKA in 1990
BKPM	Investment Coordinating Board (abbreviated from Badan Koordinasi Penanaman Modal)
BPPKA	Foreign Contractors Guiding Board of Pertamina (abbreviated from Badan Pembinaan Pengusahaan Kontraktor Asing)
BPPT	Agency for the Assessment and Application of Technology (abbreviated from Badan Pengkajian dan Penerapan Teknologi)
BOT	build, operate, and transfer
CIF	cost, insurance and freight
CNG	compressed natural gas
COW	contract of work
EOR	enhanced oil recovery
EXOR	export-oriented refinery

FOB	free on board
GDP	gross domestic product
GSP	government selling price (abolished April 1989)
ICP	Indonesian crude price (introduced April 1989)
IDO	industrial diesel oil
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LSWR	low-sulfur waxy residual fuel oil
MIGAS	Directorate General of Oil and Gas (abbreviated from Minyak dan Gas Bumi)
MTBE	methyl tertiary butyl ether
OPEC	Organization of Petroleum Exporting Countries
Pertamina	State Oil Corporation (abbreviated from Perusahaan Tambang Minyak Negara)
PGN	State Gas Company (abbreviated from Perusahaan Gas Negara)
PLN	State Electric Power Corporation (abbreviated from Perusahaan umum Listrik Negara)
PPTMGB	Oil and Gas Manpower Development Center (abbreviated from Pusat Pengembangan Tenaga Minyak dan Gas Bumi), which operates the Oil and Gas Academy
PSC	production sharing contract
PT	*perusahaan terbatas*, meaning "Limited Company." Unlike "Ltd." in English, the Indonesian abbreviation PT *precedes* the company name.
PTB	Perum Tambang Batubara, the state coal company
PTBA	PT Tambang Batubara Bukit Asam (a state coal company, merged in 1990 into PTB)

Repelita	Indonesian abbreviation for five-year development plan (fifth plan, Repelita V, encompasses fiscal years 1989-93)
RON	research octane number
Rp.	rupiah
SLC	Sumateran light crude

LIST OF MEASUREMENTS

b	barrel
b/d	barrel per day (calendar days)
b/doe	barrel per day of oil equivalent
b/sd	barrel per stream day
boe	barrel of oil equivalent
BTU	British thermal unit
cal	calorie
GW	gigawatt (1,000,000 kilowatts)
GWh	gigawatt-hour
kcal	kilocalorie
kg	kilogram
km	kilometer
km^2	square kilometer
kVA	kilovolt ampere
kW	kilowatt
kWh	kilowatt-hour
m^3	cubic meter
mb/d	thousand barrels per day
MW	megawatt (1,000 kilowatts)
MWh	megawatt-hour
NGL	natural gas liquids
scf	standard cubic foot
scf/d	standard cubic foot per day
toe	ton of oil equivalent
ton	metric ton (1,000 kg)

One

NATIONAL OVERVIEW

GEOGRAPHY

In terms of both population and territory, Indonesia ranks among the largest countries of the world. Its estimated population in 1990 was 180 million, placing it immediately after the United States as the fifth most populous country in the world. Indonesia is an archipelago of more than 13,000 islands stretching from the Asian mainland to Australia and ranging from the world's largest island land masses to mere coral atolls. The total land area is more than 1.9 million square kilometers (km^2) or 0.74 million square miles—which is more than five times the size of Japan. Since Indonesia claims an additional 3.3 million km^2 of sea area, the land forms just over one-third of the nation's total economic territory.

Indonesia shares the islands of Irian (New Guinea) and Kalimantan (Borneo)—respectively, the second and third largest islands in the world (after Greenland)—with its neighbors. Irian is divided between Papua New Guinea on the east and the Indonesian province of Irian Jaya on the west. Kalimantan is divided between East Malaysia and Brunei in the north and the Indonesian provinces known collectively as Kalimantan in the south. The major islands are illustrated in Figure 1.1.

Indonesia is divided administratively into 27 provinces (Figure 1.2), which are grouped into six regions. Three large island groups with the majority of Indonesia's populace—Sumatera, Java, and Kalimantan—constitute the western part of the country. The eastern part consists of the Nusa Tenggara island group, which stretches from Java southeastward nearly to Australia, and the Sulawesi and Maluku-Irian Jaya island groups farther north.

Volcanic activity is a prominent feature of the agriculturally rich islands. There are 70 active volcanoes in the country, and 17 of them are on Java alone. Two-thirds of Java's land surface is volcanic deposits. Because of the seemingly inexhaustible fertility of the soil, renewed by matter thrown out by volcanoes and carried down by rivers, Java became known in Indonesian legend as the "rice island," hence its capacity to support more than half the nation's population.

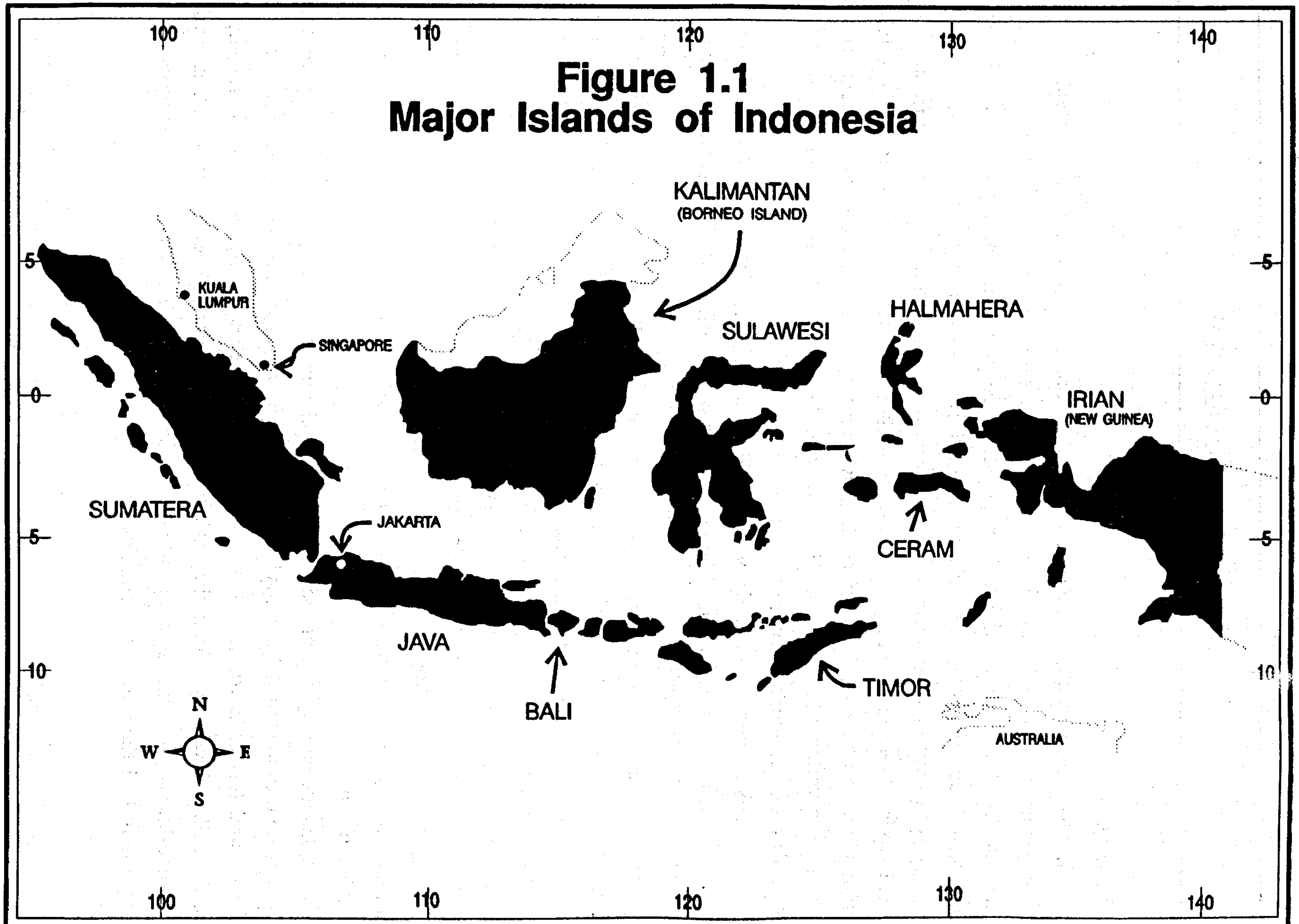
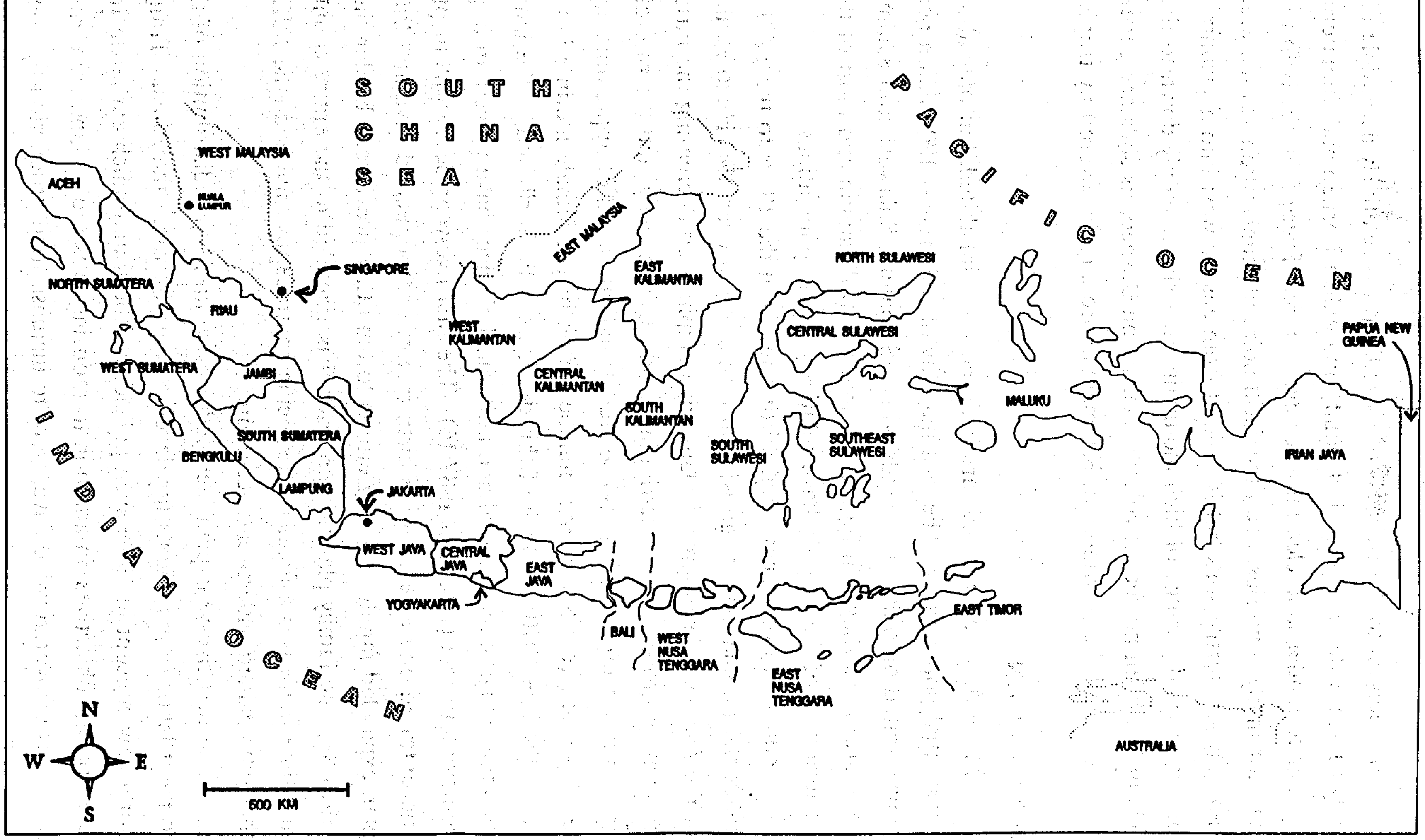


Figure 1.1
Major Islands of Indonesia

Figure 1.2
Provincial Boundaries



In addition to the richness of its soil, Java is relatively accessible (1,000 km long but only 81 km wide at its broadest point) and unlike Borneo and Sumatera has no dense jungles to hinder land clearance for agriculture. These features help to explain why Java has, for many centuries, been the focal point of immigration. Sumatera, by contrast, has not only less fertile soils but is divided from east to west into a swampy coastal zone, a hilly zone, and a range of high mountains that slope steeply down to the Indian Ocean. There has been no recent volcanic activity on Borneo, its soils are generally poor in nutrients, and the provinces of Kalimantan are largely covered by tropical rainforest.

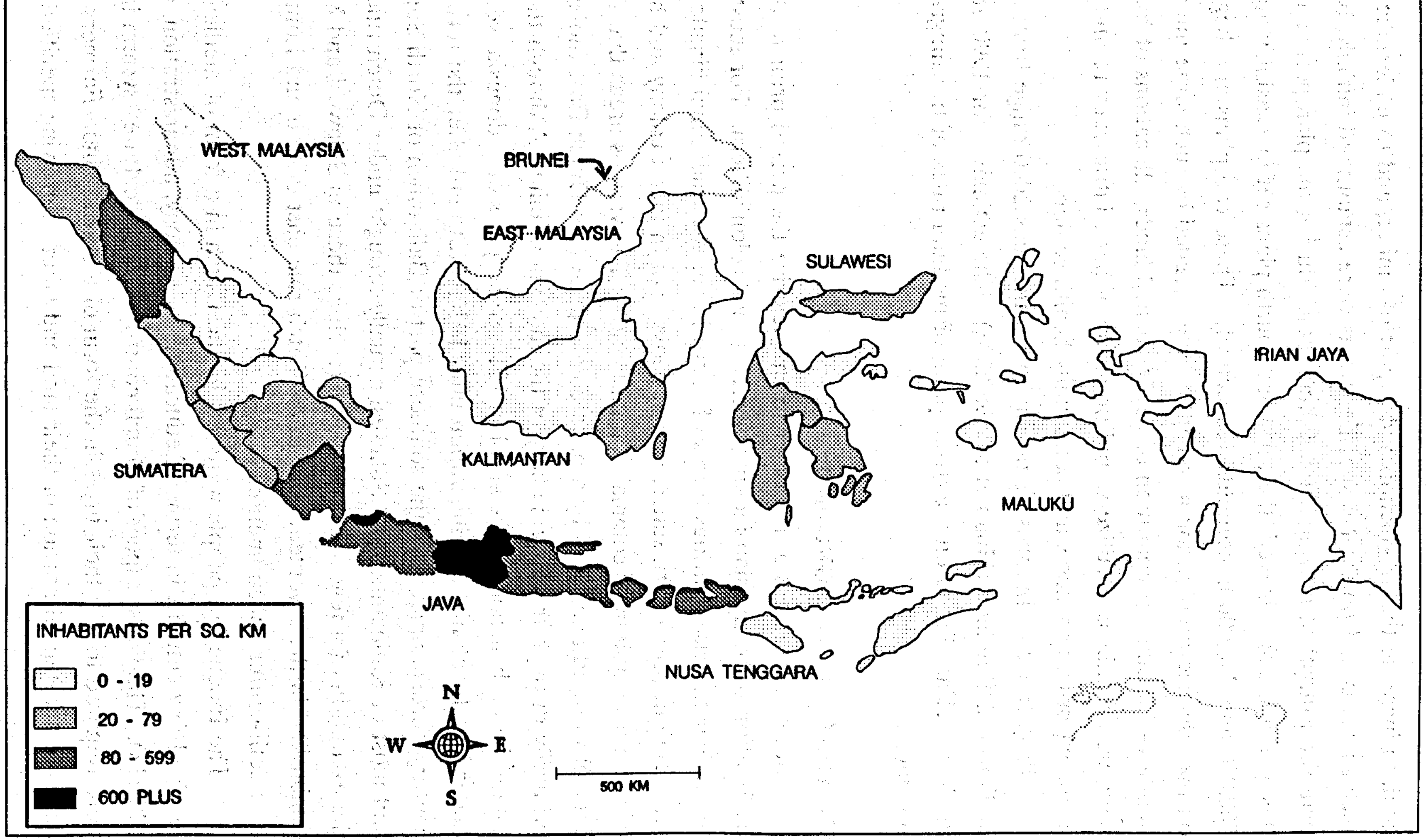
POPULATION

More than 6,000 islands are believed to be inhabited, but only about 3,000 have substantial populations. The vast majority of Indonesia's 180 million people are concentrated on only four islands—Java, Sumatera, Sulawesi, and Kalimantan. By comparison, as shown in Figure 1.3, much of Kalimantan and most of the islands in the eastern part of the country have relatively sparse populations.

Indonesia experienced high birth rates from the 1950s to the 1970s, and in the mid-1980s the population was growing at a rate of just over 2% (Hugo et al. 1987:321). All of the five-year development plans have emphasized decreasing the birth rate to prevent population growth from outstripping productive capacity, and the rate of population growth has been declining. Some studies indicate a fall of approximately 25% in the fertility rate (from 5.6 average number of births per female lifetime in the late 1960s to 4.3 in the late 1970s). Much of this decline can be attributed to the national family planning program, and social and attitudinal changes have played an important contributory role (Hobohm 1987:16). The first five-year development plan (1969-73) concentrated on decreasing the birth rate of overpopulated Java and Bali, and the second plan expanded family planning efforts to ten other provinces. Under the third plan (1979-83), the family planning program was extended to the entire country, and for the first time there was a focus on a specific contraceptive method (the IUD), which had by that time gained widespread acceptance.

The first five-year plan included a program for a redistribution of the populace and to meet labor requirements for development elsewhere than Java. Transmigration was not a new concept in 1969; such policies can be found much earlier in Indonesian history. The specific objectives, in addition to reducing pressure by landless farmers on the resources of overcrowded Java, were to increase food production by opening up new

Figure 1.3
Population Density by Province



land, to increase the production and export of timber, and to undertake public works such as roads and ports. No specific targets were established initially, but the second plan set a target of moving 250,000 households during the plan period 1974-78. Although this goal was not achieved, the third and fourth plans set increasingly ambitious targets of 500,000 and 750,000 households, respectively. These two plans also began concentrating on the advance preparation at reception sites needed by such large numbers of migrating families—including preparation of newly opened lands, allocations of food provisions, rice seed, tree seedlings, fertilizers, and provision of basic infrastructure and services, including primary schools and community health centers.

Projections of Indonesia's population in the year 2000 range from a low of 196 million to 239 million (Hugo et al. 1987:328). The estimates for 1990 and 2000 provided in Table 1.1 are based on the assumption of medium rates of transmigration between provinces.

HISTORICAL BACKGROUND

In one sense, it is a misnomer to characterize the period prior to the 1945 declaration of Indonesian independence as the "colonial" era. For most of the time that the Dutch exercised various forms of control over the traditional kingdoms and other independent premodern states, Indonesia was not in fact a colony and had no experience of a uniform system of colonial administration. The various areas that fell under Dutch control were administered by a private enterprise (the Dutch East Indies Company), primarily through the intermediary of the indigenous elite. Although the Dutch first established a beachhead of control in 1619, some parts of Indonesia were not brought under Dutch colonial administration until 1936. Not until after the turn of the twentieth century, for example, were the southern part of Bali, much of North Sumatera, Aceh, and most of Kalimantan and Sulawesi actually brought under Dutch rule. Indeed, with the exception of a few coastal enclaves (such as those in Sulawesi and Maluku) established in the seventeenth century, Dutch rule east of Bali and Lombok was largely a twentieth-century phenomenon.

The Indonesian people were left by the Dutch in a form of medieval servitude and received few benefits in terms of education, technology, administration, and law (Bunton 1983:18). The worst aspect of Dutch control was the "culture" system in which peasants were required to pay their taxes in the form of a levy in kind. Farmers were forced to devote a substantial portion of their land and labor to growing specified cash crops such

Table 1.1
Population Estimates by Region, 1990 and 2000
(million persons)

Region	1990	2000
Java	102.4	108.6
Sumatera	39.4	51.4
Sulawesi	13.2	15.7
Kalimantan	10.8	16.6
Nusa Tenggara	10.0	11.3
Maluku and Irian Jaya	4.4	7.1
Entire country	180.1	210.7

Source: Hugo et al. 1987.

as coffee and spices for fixed prices, that ensured profits to the company and the indigenous elites that supervised the system at the grassroots. The last traces of this oppressive system were abolished only in 1916. Between the two world wars, much land in Indonesia was transferred from corporate to private Dutch ownership, exacerbating the plight of the masses.

The archipelago was occupied and administered by Japanese forces from 1942 to 1945. The Indonesian Nationalist Party led by Sukarno, which had worked with the Japanese wartime administration, stepped into the power vacuum at the moment of the Japanese surrender and proclaimed Indonesian independence in August, 1945. When the militarily superior Dutch returned and attempted to restore colonial rule, fighting broke out and continued through 1946. By 1948 the nationalists, with their capital at

Yogyakarta, retained control only of Central Java and Aceh, while rival groups (including the communists) retained control in various other parts of the country.

Under a postwar truce between the nationalists and colonial authorities, an attempt was made to create a federation linked in a special relationship to the Netherlands. The various opposing sides could not collaborate, and the islands were the scene of intermittent fighting until 1949. The Netherlands, faced with international condemnation as the result of brutal "police actions," finally relinquished all powers in December 1949. Shortly thereafter, the federation concept of government for the archipelago was discarded, and in August 1950 Indonesia was proclaimed a unitary republic, with the center of power in Jakarta.

Two subsequent additions were made to Indonesian territory. The oil-rich western part of the island of New Guinea, now known as Irian Jaya, was ceded by the Netherlands in 1963. In 1976 the eastern part of Timor became a province of Indonesia, following the unilateral withdrawal of Portuguese colonial authorities.

Indonesian history since independence has been characterized as a continuing attempt to create a unified nation out of the multifarious social organizations, religions, customs, languages, and outlooks of the population (Missen 1972:85). The need to create or cultivate cohesive forces is especially important in Indonesia because of its size, the relative isolation of many of its islands, and the extraordinary ethnic and linguistic diversity of its people.

The Indonesian nationalist leaders recognized early in the twentieth century that national symbols, common values, and a common language would be essential for achieving national unity. Since nearly 90% of the population is classified as Muslim, it is not surprising that one of the largest nationalist movements with the widest appeal under Dutch rule was an Islamic organization devoted to education and social work. At national youth conferences in the 1920s, Indonesia was proclaimed to be "one nation, one language, one motherland." The basic ideology of the future state was first proposed by Sukarno in 1945. It is known as *Panca Sila* or the "Five Principles of State": belief in one Supreme Being, nationalism, humanitarianism, social justice, and popular sovereignty. This ideology was designed to appeal to Indonesians of all persuasions, religions, and ethnic groups, and it remains the basic philosophy of state today.

A common national language was seen as an essential integrating force to unite a population with more than 250 mutually incomprehensible languages. The 1928 youth conference adopted market Malay—the lingua franca of traders for centuries—as the national language and renamed it "Indonesian" (*Bahasa Indonesia*). This language is the first language of only about 12% of the population (originally mostly in parts of Sumatera and Kalimantan), and as a minority language it was a judicious choice. It was already in use in a much wider area at the time than any other language, and its adoption avoided resentment against domination by speakers of Javanese, which is the first language of about 40% of the population. Over the decades since independence, the proportion of the population who can speak Indonesian has gradually risen (from about 40% in 1971 to about 60% in 1980) and will continue to rise as successive cohorts pass through the national primary education system.

Despite the efforts of Indonesian nationalists during the first half of this century, the independent republic received little from Dutch rule in terms of a legacy of nation building. Moreover, because of the prominence of Java in government, commerce, and urban areas—all 5 cities with a population of more than 1 million in 1980 (Drake 1989:101) were on Java—to many "outer" islanders it seemed after independence that Dutch overlords had merely been replaced by Javanese. Regional discontent in the late 1950s (based partly on the belief that economic policymaking was overly centralized and the distribution of benefits was weighted heavily in favor of Java) resulted in a series of rebellions and threatened to undermine the stability of the new nation.

Under the form of "guided democracy" pursued during the Sukarno era, political life deteriorated into polarized confrontation between the communist party and all other political forces, creating a deadlock that was broken only by a coup attempt in 1965. The coup attempt, led by communist army officers with the aid of the Indonesian Communist Party, lasted only a few days but resulted in the slaughter of perhaps several hundred thousand people. The Communist Party was crushed during the coup and was officially banned by Major General Suharto, who assumed full powers to restore law and order. In spite of Sukarno's involvement with the communists, he was not immediately removed from office and remained as president with minimal powers. After Suharto was appointed acting president by the People's Consultative Assembly in 1966, Sukarno was placed under house arrest, where he remained until his death in 1970. Suharto was elected president in 1968 and has subsequently been re-elected at five-year intervals.

In contrast to the stormy mobilizations of the masses for patriotic causes during the Sukarno years, under President Suharto's "New Order" government the opposition parties have been relatively inactive. The prevailing philosophy is that economic development produces demands that are difficult to contain within the framework of representative democracy, hence stability and overall economic growth must have priority over political participation. The president has given some indications, however, that his present term (1988-93) might be his last (although no official announcement has been made) and that the next candidate of the government-sponsored political party (Golkar) should expect to face competitive election campaign challenges.

When Suharto came to power in 1965, the economy was nearly in ruins. Sukarno's anti-foreign campaign (including his "confrontation" policy toward newly independent Malaysia) caused foreign enterprises and potential investors to shun Indonesia. The abrupt change of leadership therefore provides a clear starting point for examining modern economic development in Indonesia. It also marks the reversal of policies that led to political instability, low economic growth, high inflation, stagnant exports, and the virtual absence of foreign enterprise for an entire decade.

NATIONAL ECONOMY AND FIVE-YEAR DEVELOPMENT PLANS

The developmental successes of the New Order government during the 1970s and 1980s can be attributed to the support that the president enjoys from the armed forces (the most important political organization in Indonesia) and to the policies of the president's professional economic advisers, which have been supported by the bureaucracy, the business community, and Golkar. The president's technocrats designed and implemented a series of five-year development plans.

The successive five-year plans are often cited by the acronym for the official Indonesian term, followed by a roman numeral. For example, the current (fifth) plan is known as Repelita V. The plans conform to Indonesia's fiscal year, which begins in April. The current plan began in April 1989 and continues through March 1994. For simplicity, this report refers to the successive plans as follows, although it should be understood that the years are all fiscal years:

Repelita I, first plan, 1969-73
Repelita II, second plan, 1974-78
Repelita III, third plan, 1979-83
Repelita IV, fourth plan, 1984-88
Repelita V, fifth plan, 1989-93
Repelita VI, sixth plan, 1994-98

The first plan aimed at economic and political stabilization, modernization of the agricultural sector, and striving for greater national unity. About 70% of the targets were met, and the remaining 30% of projects were carried over into the next plan. The second plan concentrated on developing essential infrastructure, on expanding industry (including import substitutes and exports such as textiles), with emphasis on developing industries processing raw materials. Despite the impacts on the economy caused by the bankruptcy of the state oil and gas enterprise in 1976, about 75-80% of the overall targets were still met (Bunton 1983:43-44). The third plan emphasized industries producing manufactured goods and focused on important problems such as regional development, transmigration, bolstering economically weak groups, and social welfare projects. The fourth plan continued to give priority to economic development, but placed more emphasis than before on the development of human resources (including education, health, nutrition, and housing).

The fifth development plan has been described as the stage in which the national economy is approaching the "take-off" phase. The goal is to achieve economic take-off by the end of the next plan period, around the turn of the century. The prospects for achieving this goal are reflected in the recent major economic indicators shown in Table 1.2. GDP growth rates have been sustained at about 5%, whereas inflation has remained in single digits. External debt and the debt-service ratio, however, remain high. The economy has performed better than many analysts expected, so the government's goal of achieving "take-off" by the end of the decade may not be unrealistic, particularly since the composition of Indonesia's exports has undergone a significant shift away from nearly total reliance on oil and gas. Throughout Asia, a key component in economic takeoff has been the growth in exports of manufactured goods, rather than primary commodities.

MAJOR ECONOMIC INDICATORS AND CURRENT ISSUES

As a net oil-exporting country, Indonesia has previously been highly dependent on oil and gas export earnings. The fall in the oil price during the 1980s significantly reduced Indonesia's foreign exchange earnings. During the years 1970 to 1981, export revenues from oil and gas increased at an annual rate of 45.5%, while the economy as a whole was enjoying more than 7% growth annually. Table 1.3 provides data on oil and gas versus other export revenues from 1970 to 1989. The share of oil and gas in total export revenues was 40% in 1970, reached a peak of 82% in 1982, and constantly declined thereafter, resulting in a short-term crisis in the balance of payments. Figure 1.4

Table 1.2
Major Economic Indicators, 1986-90

Indicator	1986	1987	1988	1989	1990
Population (millions)	168.1	171.6	175.2	178.9	182.7
Labor force (millions)	70.2	72.3	74.5	76.8	—
GDP (Rp. trillions)[a]	90.0	94.3	99.7	105.6	—
Growth in GDP (%)	5.6	4.8	5.7	5.4	—
Debt service ratio (%)	36.8	34.7	40.0	38.3	—
Balance of payments (US$ billions)[b]	-4.1	-1.7	-1.9	-1.4	-0.7[c]
Bank of Indonesia foreign exchange reserves (US$ billions)	5.3	6.5	6.2	6.5	6.4[d]
Money supply (Rp. trillions)	11.7	12.7	14.4	20.1	22.6[d]
Inflation rate (%)[e]	8.8	8.9	5.5	6.0	9.1[f]
Oil and gas exports (US$ billions)	8.3	8.6	7.7	8.6	5.1[d]
Exports other than oil and gas (US$ billions)	6.5	8.6	11.5	13.5	7.9[d]
Total imports (US$ billions)	10.7	12.4	13.2	16.4	10.8[d]

Notes: — Not yet available.
a. Based on 1983 constant prices.
b. Current account.
c. Through first quarter of 1990.
d. To July 1990.
e. Based on consumer price index in 17 cities.
f. To October 1990.

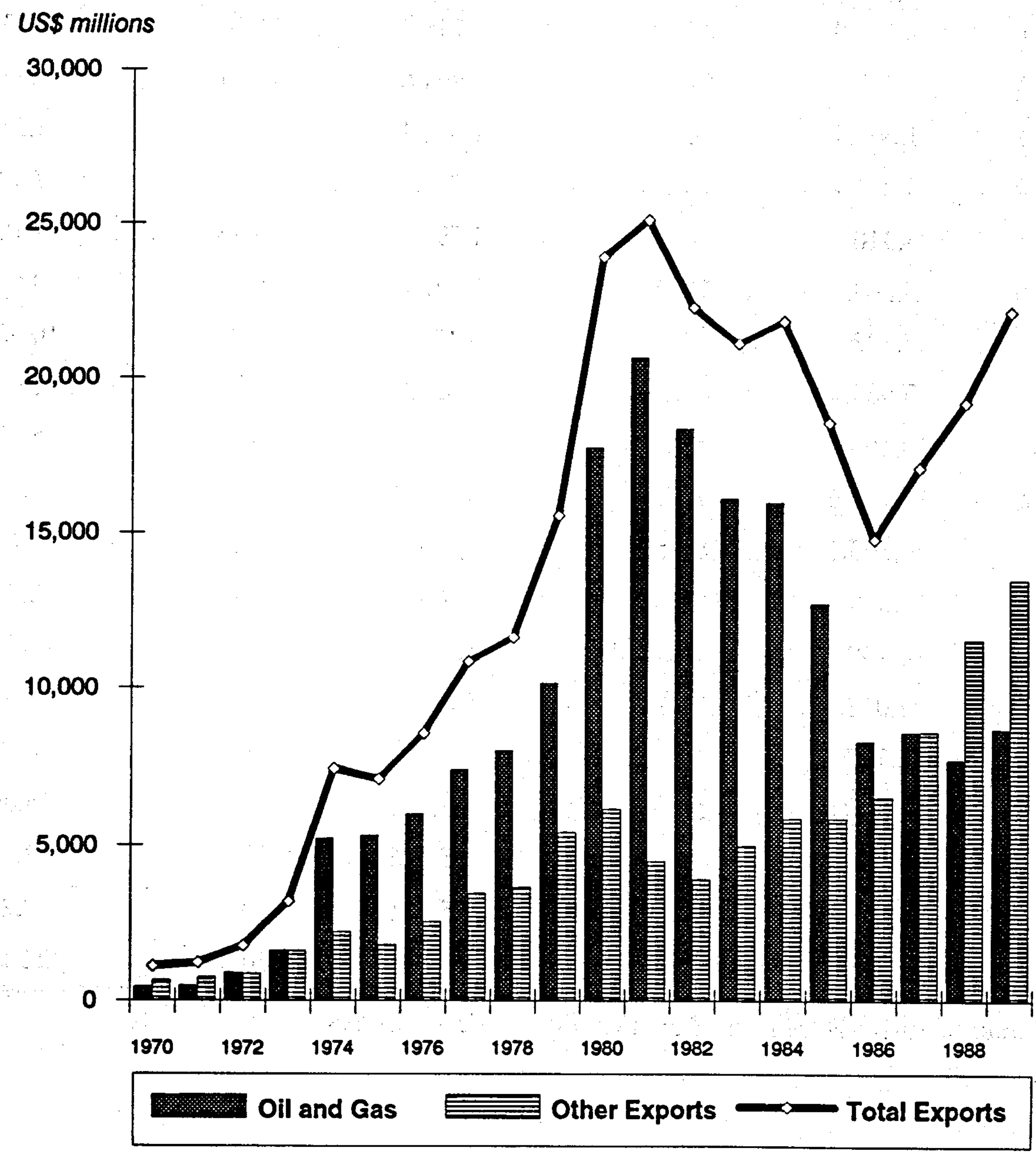
Sources: *The Indonesian Economy*, October 1989; Central Bureau of Statistics 1989 and *Economic Indicators*, October 1990.

Table 1.3
Oil and Gas Exports versus Other Exports, 1970-89

	Oil and Gas Exports		Other Exports		Total Exports
Year	(US$ millions)	(% of total exports)	(US$ millions)	(% of total exports)	(US$ millions)
1970	446.3	40.28	661.8	59.72	1,108.1
1971	477.9	38.74	755.7	61.26	1,233.6
1972	913.1	51.36	864.6	48.64	1,777.7
1973	1,608.7	50.10	1,602.1	49.90	3,210.8
1974	5,211.4	70.17	2,214.9	29.83	7,426.3
1975	5,310.6	74.77	1,791.9	25.23	7,102.5
1976	6,004.1	70.25	2,542.4	29.75	8,546.5
1977	7,378.1	67.98	3,474.5	32.02	10,852.6
1978	7,985.4	68.58	3,657.8	31.42	11,643.2
1979	10,163.7	65.19	5,426.4	34.81	15,590.1
1980	17,781.6	74.24	6,168.8	25.76	23,950.4
1981	20,663.2	82.11	4,501.3	17.89	25,164.5
1982	18,399.1	82.4	3,929.0	17.60	22,328.1
1983	16,140.7	76.33	5,005.2	23.67	21,145.9
1984	16,018.1	73.18	5,869.7	26.82	21,887.8
1985	12,717.9	68.40	5,868.8	31.58	18,586.7
1986	8,276.6	55.90	6,528.4	44.10	14,805.0
1987	8,556.0	49.93	8,579.6	50.07	17,135.6
1988	7,681.4	39.97	11,537.1	60.03	19,218.5
1989	8,680.2	39.17	13,479.5	60.83	22,159.7

Source: Central Bureau of Statistics, *Economic Indicators*, October 1990.

Figure 1.4
Changing Role of Oil and Gas in Total Export Revenues, 1970-89



compares oil and gas export revenues with export revenues from other commodities, and plots the long-term trend in total export revenues from 1970 to 1989. Following the oil price shock of 1979-80, Indonesia's oil and gas export revenues climbed steeply, peaking at nearly US$20.7 billion in 1981. Revenues declined noticeably in 1986 when world oil prices collapsed and hovered in the US$8 billion range from 1986 to 1989. Meanwhile, nonoil and nongas export revenues have expanded impressively, and 1987 marked the first time since the early 1970s that they exceeded revenues from oil and gas exports.

Figure 1.5 displays the changing percentage share of oil and gas in total export revenues during 1970-89. The greatly increased role of oil and gas revenues following the oil price shocks of 1973-74 and 1979-80 is sharply visible, as is the greatly expanded role of other export commodities from 1986 onward. After the oil price shocks, the government adopted policies directed toward broadening and further diversifying the productive base of the economy over the medium and long term, by moving away from over-dependence not only on oil but also on exports of other raw materials such as rubber, coffee, and timber. The emphasis has been on enhancing the production of competitive industrial and manufactured goods in order to maximize the value added. At the same time, high priority was given to increasing government revenues by the means of (1) intensified taxation through simplifying tax procedures and improving the efficiency in the government's tax institution, (2) increasing private savings through the improvement of the banking system, and (3) establishing money and capital markets.

One of the efforts by the government in boosting nonoil exports has been to keep the exchange rate of the rupiah, the Indonesian currency, at a level that will enable domestic producers to compete in the world market. This was accomplished by two substantial devaluations of the currency, in 1983 and in 1986, after the sharp drops in oil prices, and by gradually depreciating the currency in line with the differentials in inflation rates. This action was strengthened by several government deregulation policies designed to stimulate the private sector to increase productivity in producing competitive export commodities. Selected foreign exchange rates at the end of each year 1984-90 are provided in Table 1.4.

Deregulation has also been extensively applied in banking and other financial institutions to improve their internal efficiency and their ability to mobilize private savings and to encourage more investment in productive sectors. The two aforementioned programs—the nonoil exports and the mobilization of domestic savings—will determine the future success of the Indonesian economy.

Table 1.4
Exchange Rates, 1984-90
(Indonesian rupiah per unit of selected currencies)

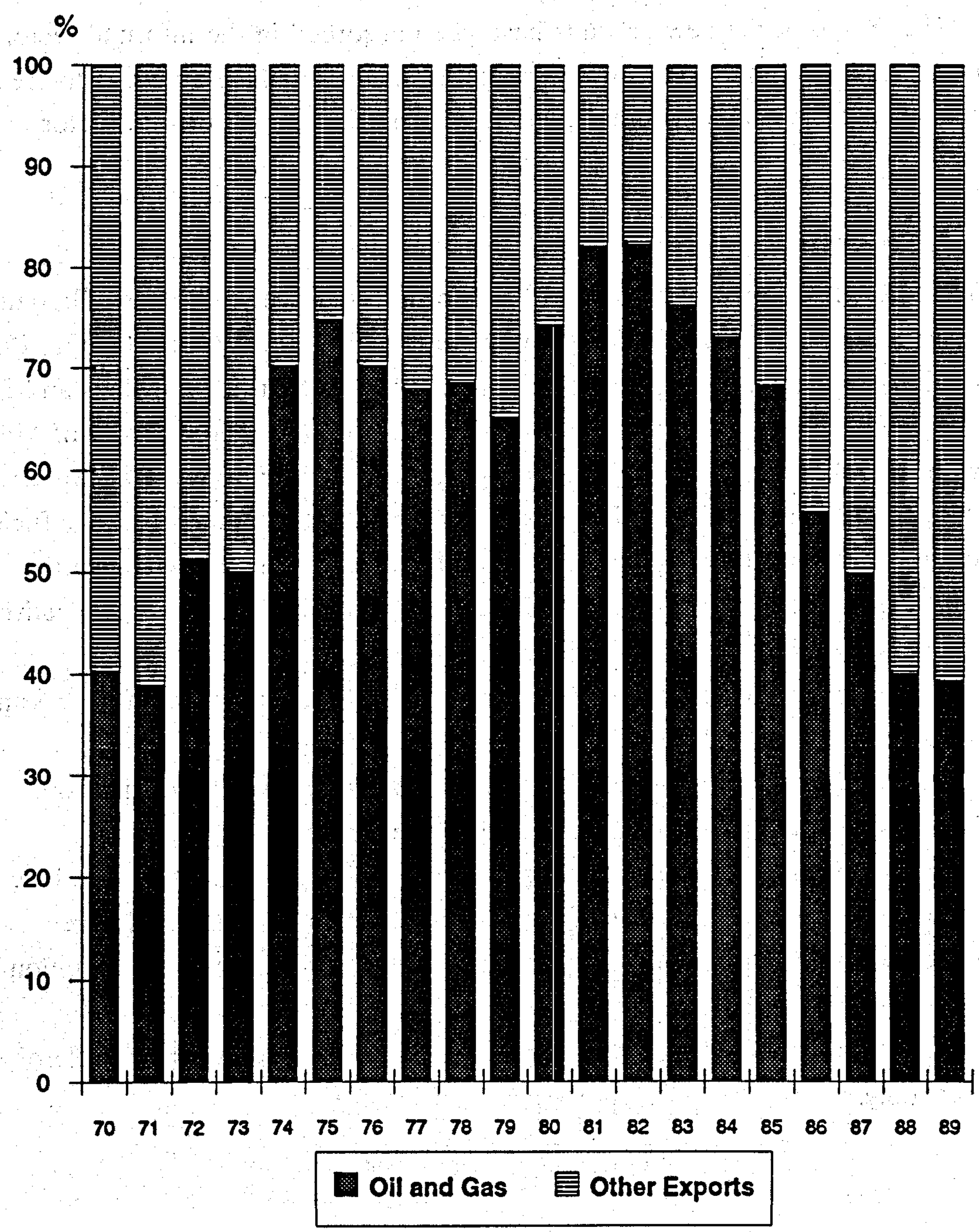
Currency	1984	1985	1986	1987	1988	1989	1990
U.S. dollar	1,075	1,130	1,649	1,655	1,737	1,805	1,878
Australian dollar	900	777	1,100	1,200	1,488	1,432	1,476
British pound	1,280	1,643	2,420	3,090	3,120	2,935	3,670
French franc	113	148	256	306	285	311	370
German mark	344	453	834	1,041	974	1063	1,235
Hong Kong dollar	140	148	217	217	226	234	370
Japanese yen	4.35	5.65	10.23	13.50	13.84	12.66	14.55
Malaysian dollar	444	464	634	665	642	668	695
Singapore dollar	497	536	761	833	896	955	1,100
Swiss franc	420	537	1,005	1,285	1,155	1,173	1,455

Note: Data apply to December of each year 1984-89 and to October of 1990.

Source: Central Bureau of Statistics, *Economic Indicators*, October 1990.

To achieve significant growth Indonesia still needs foreign aid support. Indonesia is now facing a heavy external debt burden, and the current debt-service ratio is almost 40% (Table 1.2). Although Indonesia has gained an international reputation as a reliable borrower and has never rescheduled repayments of debt, the country is now facing rapidly rising debt-service payment obligations. The burden has been worsened by the appreciation, relative to the rupiah, of certain currencies such as the Japanese yen and German mark. A reduction of this ratio is an important factor in economic policy during the fifth five-year development plan.

Figure 1.5
Changing Percentage Share of Oil and Gas in Export Revenues, 1970-89



Another major problem now faced by Indonesia is labor. Although the government's family planning program has achieved some success in lowering the birth rate, the number of new entrants (young men and women) into the labor force has continued to increase. The average annual labor force growth in the 1960s was 2.2% and rose to 2.3% in the 1970s and 2.7% in the 1980s. It is projected to decline, however, to 2.3% in the 1990s and to 1.7% in the first decade of the next century (*Asia-Pacific Briefing Paper*, April 1991). Some of the new entrants have been absorbed in the informal sector, where productivity and income are very low. The government is making an effort to create new employment, especially by encouraging greater investment by the private sector in labor-intensive production.

NATIONAL ENERGY POLICY

Overall energy policy and planning is set forth in the five-year plans. Guidance on policy issues related to energy is provided by the National Energy Coordinating Board (BAKOREN), a cabinet level policy board chaired by the Minister of Mines and Energy. (For a detailed explanation of this institution, see Part Four). The Ministry of Mines and Energy then establishes an energy implementation plan to carry out the policy directives.

The goal of energy policy in Indonesia is to provide the country with a sufficient and reliable energy supply at the right time and at affordable prices that will give the optimum benefit to the wealth of the nation. To achieve the basic policy objectives, the government is focussing on the following four areas:

- Intensification of energy resource development and expansion of processing facilities.
- Diversification of energy sources, which is meant to gradually shift from predominantly oil-based fuel to multiple fuel sources.
- Indexation of every kind of energy to identify the most effective uses by energy source, whether as a domestic fuel or for generating foreign exchange.
- Conservation efforts aimed at more efficient production and consumption of all forms of energy.

These policy objectives are further elaborated in Part Three below on the role of energy in the economy.

Two

INDIGENOUS ENERGY RESOURCES

OVERVIEW

Indonesia is endowed with an abundance of commercial and noncommercial energy resources. The noncommercial types of energy are those traditionally used by rural society and include animal power, wood, charcoal, small-scale hydropower, and biomass. Since data on noncommercial energy resources are imprecise and often unavailable, this report deals only with the commercial energy resources available in Indonesia: oil, natural gas, coal, large-scale hydropower, geothermal energy, and nuclear power.

Commercial energy resources supply the domestic market and also generate foreign exchange, which is earned principally from the export of oil and liquefied natural gas (LNG). Much of Indonesia's economic development during the 1970s was financed by oil revenues. The nation is now also developing other energy resources such as peat, is debating a nuclear power plant for Java, and is investigating renewable energy sources such as solar, wind, and ocean thermal energy conversion. Most of Indonesia's primary energy resources, however, are in places that are distant from centers of population and economic activity. Java, in particular, accounts for more than 60% of the country's total population and an even larger percentage of nonenergy economic activity, but this island has only a small fraction of the country's primary energy resources. The allocation of energy resources is therefore a key issue in energy policy. Since some of the resources are readily exportable, there is an even more complicated system of trade-offs between domestic fuel-mix choices and exports. Transport and logistic difficulties are compounded further by the archipelagic nature of Indonesian territory. In the national energy policy, priority is given to the diversification of energy sources so that local demand can be met efficiently and export marketing can continue.

Energy resources, particularly oil and natural gas, play a major role in the Indonesian economy. Parts Three, Five, and Six below deal respectively with energy and the economy, oil, and natural gas. The discussion of oil and gas in this part is limited to details of reserves and exploration. Production and other "upstream" operations and the "downstream" operations such as processing, transport, and marketing, are discussed in Parts Five and Six.

OIL RESOURCES

In 1985 Indonesia celebrated the centenary of the country's commercial oil production, which began in 1885. The first oil fields to be developed were in the central part of Sumatera. Shell and Standard Oil were the first oil companies to operate in Indonesia. Prior to World War I, production was only 25,000 barrels per day (b/d), but by the outbreak of World War II, output had expanded to 160,000 b/d. In the early 1950s production surpassed the prewar levels and then began to accelerate.

Oil exploration received a major boost in 1964 when the government introduced production sharing contracts (PSCs). The PSC system gave foreign companies the opportunity to explore and develop prospective oil-bearing areas. After a company's initial investment costs were recouped, the remaining oil production was to be divided between the company and the government. By 1977 a total of 59 PSCs were signed, and oil production peaked at over 1.7 million b/d that year. The PSC system has thus far evolved successfully, and PSCs are now in their fourth generation, but there are doubts (discussed further in Part Five) as to whether the PSC structure will be suitable for Indonesia's future exploration requirements.

The Indonesian government does not publish official oil reserve figures. Government estimates have been stated in ministerial speeches, however, and are cited in various unofficial reports. The U.S. Embassy in Jakarta compiles an annual "Petroleum Report," and its 1989 comparisons of recent reserve estimates are summarized in Table 2.1.

Indonesia accounts for approximately 18% of oil reserves and 31% of gas reserves in the Asia-Pacific region (including China). In the global market, naturally, Indonesian reserves constitute a far smaller proportion. As shown in Table 2.2 and Figure 2.1, Indonesia accounts for less than 1% of world oil reserves and slightly more than 2% of global gas reserves. Indonesian reserves represent only 1.4% of total OPEC oil reserves and 5.2% of OPEC gas reserves.

With the exceptions of Indonesia, China, Burma, and Brunei, the nations of the Asia-Pacific region are already highly dependent on oil imports from outside the region, and this dependency is expected to rise during the coming decade. At present, Indonesia is an important net exporter of energy. Once the country enters the stage of a newly

Table 2.1
Comparison of Oil Resources Estimates
(billion barrels of oil or oil equivalent)

Source	USDOE	MME	PI	OGJ	WM
Known oil resources					
Original oil in place	72.1	84.5	—	—	—
Proved ultimate recovery	20.1	—	20.2	—	—
Cumulative production	10.6	15.5	—	—	—
Remaining recoverable oil	10.1	11.0	7.8	8.3	4.9
Remaining recoverable gas	—	16.6	—	14.3	18.3
Undiscovered resources					
Original oil in place	53.9	48.8	—	—	—
Gas	—	37.0	—	—	—
Ultimate recovery	15.5	—	—	—	—

Notes: — no estimate given. USDOE: U.S. Department of Energy, Energy Information Administration. MME: Speeches by Ginanjar Kartasasmita, Minister of Mines and Energy, August 1989. PI: Petroconsultant, Inc. OGJ: *Oil and Gas Journal*, December 1988. WM: Woods and McKenzie.

Source: U.S. Embassy, Jakarta 1989.

industrializing economy, however, the nation's reserves of all forms of energy may be needed to supply the rapid increase in energy consumption that is projected for the 1990s and beyond. Furthermore, the general feeling in the oil industry is that Indonesia at best will be able to hold oil production level in the 1990s, and some are less optimistic. Oil is

Table 2.2
Indonesian Oil and Gas Reserves in the Global Context, 1990

Area	Oil (million barrels)	Gas (trillion scf)	Indonesian Share (% of oil)	(% of gas)
Indonesia	11,050	91.5	100.0	100.0
Asia-Pacific region				
Excluding China	26,242	263.3	42.1	34.7
Including China	50,242	298.6	22.0	30.6
OPEC	773,819	1745.1	1.4	5.2
Noncommunist world	916,258	2554.0	1.2	3.6
Total world	999,113	4208.3	1.1	2.2

Source: Oil and Gas Journal, December 1990.

the most thoroughly exploited of Indonesia's resources, and as oil product consumption rises, it appears likely that demand will exceed domestic production. It is generally accepted that Indonesia will most likely become a net importer of oil within the coming decade.

The move from net exporter to net importer does not mean that Indonesian crudes will disappear from the regional market, although it implies that supplies will tighten. Indonesian crudes, as noted below, are low in sulfur—lower than Indonesian environmental regulations require. Since demand for low-sulfur feedstocks will remain high in Japan and is likely to increase in Taiwan, South Korea, and a number of other areas, the optimum course for Indonesia may be to import cheaper, high-sulfur crudes

Figure 2.1
Indonesian Oil and Gas Reserves in the Global Context, 1990

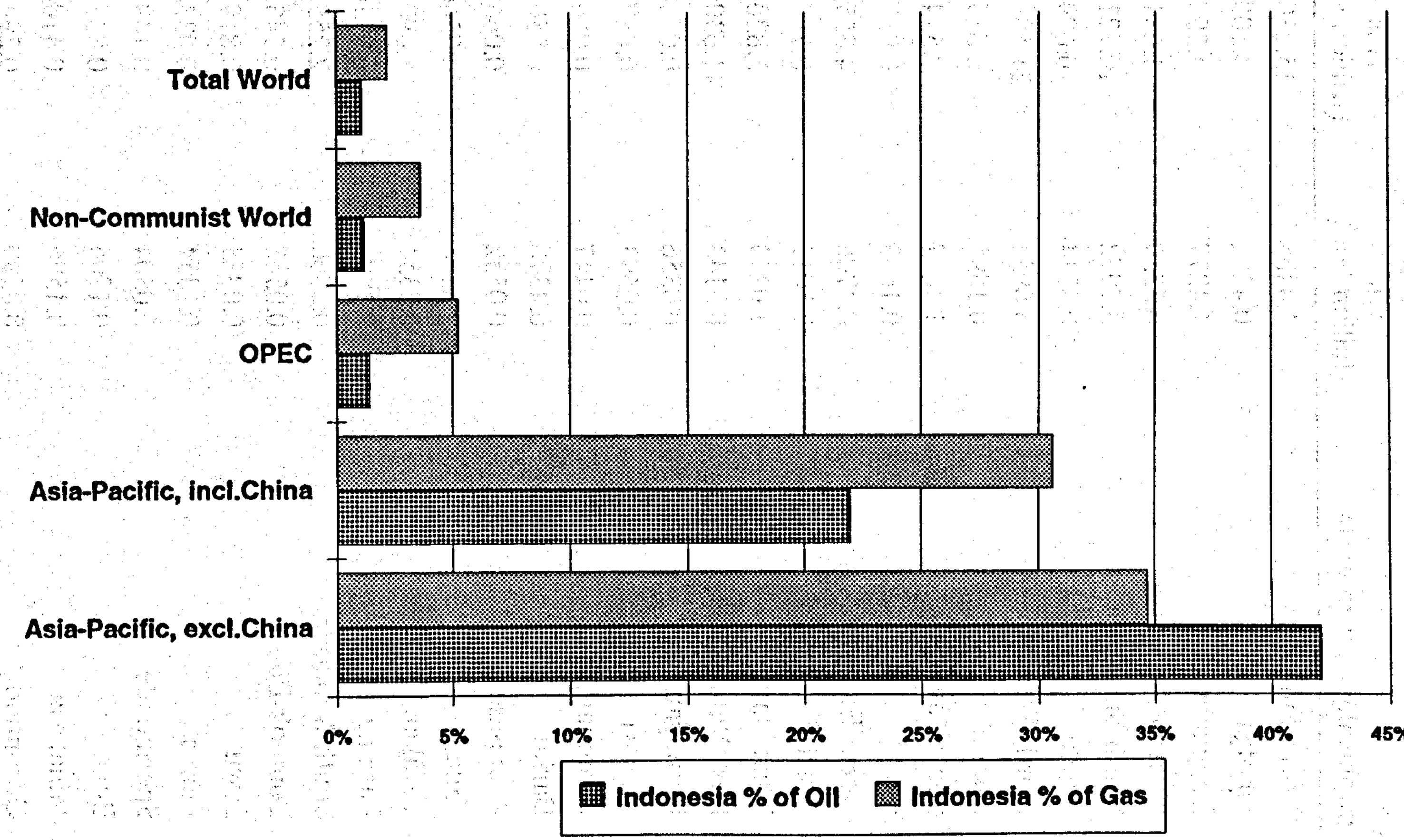


Table 2.3
Theoretical Hydrocarbon Reserves

	Basins (geographically west to east)	Oil (billion boe)	Gas (trillion scf)	Current Status
1	North Sumatera	1.4485	15.2300	producing
2	Sibolga	0.4281	4.5000	
3	Bengkulu	1.4277	4.2900	
4	Central Sumatera	6.5259	1.6314	producing
5	South Sumatera	3.7972	10.7216	producing
6	Sunda	0.4214	0.6994	producing
7	North West Java	3.6954	21.5891	producing
8	Biliton	0.1895	0.8150	
9	South Java	1.4677	8.5744	
10	Pati	0.1605	0.9379	
11	North East Java	0.4706	4.8554	producing
12	North East Java Sea	2.8012	8.7875	producing
13	West Natuna	1.0243	3.8205	producing
14	East Natuna	0.3143	41.6306	
15	Ketungau	0.0356	0.0448	
16	Melawi	0.0693	0.0872	
17	Pembuang	0.0447	0.0562	new
18	Barito	0.4378	0.5507	producing
19	Asem-asem	0.0532	0.0669	
20	Kutai	14.8238	74.7560	producing
21	Tarakan	0.7351	1.8902	producing
22	Lariang	0.1806	0.9110	
23	South Makasar	0.3860	2.2553	
24	Lombok-Bali	0.0588	0.5438	
25	Sawu	0.0885	0.8192	
26	Flores	0.1354	0.0338	
27	Spermonde	0.0304	0.1493	new
28	Bone	0.1706	0.8377	
29	Minahasa	0.1596	0.4104	
30	Gorontalo	0.0599	0.2942	
31	Banggai	0.1877	1.0963	

Table 2.3. Continued.

Basins (geographically west to east)		Oil (billion boe)	Gas (trillion scf)	Current Status
32	Salabangka	0.0786	0.4594	new
33	Manhoi	0.0017	0.0083	new
34	Buton	0.0132	0.0647	
35	Tukang Besi	0.0519	0.2546	new
36	Timor	0.5766	0.1442	
37	Sulawesi	0.0042	0.0200	new
38	South Sulawesi	0.0077	0.0390	new
39	West Buru	0.0129	0.0649	new
40	Buru	0.0944	0.0236	new
41	North Halmahera	0.0072	0.0018	new
42	East Halmahera	0.0430	0.0108	new
43	North Obi	0.0135	0.0680	
44	South Halmahera	0.0950	0.0238	
45	South Obi	0.0193	0.0972	new
46	Seram	0.6861	0.1715	new
47	South Seram	0.0687	0.0172	new
48	West Weber	0.0505	0.0126	new
49	Weber	0.3326	0.0832	new
50	Tanimbar	0.1571	0.0393	
51	Salawati	1.4368	0.3392	producing
52	Bintuni	0.4369	0.1092	producing
53	Misool and Kepala Burung	0.0391	0.0098	new
54	Aru Through	0.5061	0.1265	
55	Waipoga	0.5781	0.1445	new
56	Biak	0.1140	0.0285	new
57	Waropen	0.0622	0.0155	
58	Akimengah	0.3833	0.0958	
59	Sahuk	0.2396	0.0599	
60	Jayapura	0.0246	0.0062	new
Total estimated reserves		48.4110	216.7980	

Source: Atik Suardy and J. Taruno P.H., cited in U.S. Embassy, Jakarta 1990.

from abroad and reserve some volume of domestic crudes for export. Importing crude is a political impossibility for many OPEC countries, but Indonesia has shown itself to be pragmatic on this issue and has openly discussed expanding imports of Middle Eastern crudes (in addition to current imports required for lube and asphalt production at the Cilacap refinery.)

A total of 60 hydrocarbon sedimentary basins have been identified in Indonesia. The most recent analysis of these basins was conducted in 1985 by Atik Suardy and J. Taruno P.H., geologists employed by Pertamina, the state oil company. They estimate that the basins have a combined reserve of 84.5 billion barrels of oil equivalent (boe), consisting of 48.4 billion barrels oil plus 36.1 billion boe (216.8 trillion standard cubic feet) of natural gas.

Of the 60 basins, 73% are located offshore, and nearly a third of the offshore basins are located in deep waters that are difficult to explore. Moreover, 17% of the onshore basins are situated in difficult terrain. Thirty-four of the basins have been explored, and 14 have been assessed as producing basins. Table 2.3 delineates theoretical hydrocarbon reserves in place by basin, including associated and nonassociated natural gas reserves.

CRUDE OIL QUALITIES

Indonesia produces a wide array of crude qualities, as outlined in Table 2.4. Crude characteristics vary depending in part on the type and location of the sedimentary basin. Approximately two-thirds of Indonesian crudes can be classified as paraffinic, about 22% are aromatic, and 11% are naphthenic. Although API gravities vary from 18 to 54, the majority of crudes fall within the range of 31 to 39. However, one characteristic of paraffinic crudes is that the yields of fuel oil from crude distillation are much higher than might be inferred from the API gravities. For example, the yield of fuel oil from distillation of Arab light (API = 33.4) is about 45%, whereas the fuel oil yield from the supposedly "lighter" (API = 34.5) Minas crude is about 57%.

Indonesian crudes are generally "sweet" (low in sulfur), and most of the country's crude streams contain less than 0.3% sulfur by weight. Because of the high quality of Indonesia's light, sweet crudes, they are expected to command premium prices in the oil market during the 1990s. The majority of new production in recent years, however, has been heavier crudes such as Duri. While these are still low in sulfur, and therefore attractive on environmental grounds, their high wax content and extremely high fuel oil yields make them relatively unattractive to many foreign refiners.

Table 2.4
Characteristics of Indonesian Crudes and January 1988 Production

Crude Type	° API (60° F.)	Sulfur (% weight)	Specification	Production (b/d)
Sumeratan light crudes/Minas	34.1	0.090	paraffinic	399,843
Arun Condensate	54.0	0.002	paraffinic	170,304
Arjuna	36.7	0.090	naphthenic	112,995
Handil	32.2	0.100	aromatic	98,267
Duri	19.8	0.200	aromatic	77,305
Cinta	27.8	0.150	paraffinic	59,238
Attaka	42.3	0.090	paraffinic	47,139
Lalang	39.9	0.060	paraffinic	40,422
Badak	38.6	0.080	paraffinic	40,384
Southern Palembang	27.6	0.110	aromatic	35,951
Ramba	37.0	—	—	34,869
Walio/Kasim	34.1	0.720	paraffinic	25,398
Lirik	34.2	0.070	aromatic	20,335
Katapa/north Sumateran crudes	50.8	0.060	paraffinic	16,668
Sepinggan	31.7	0.110	aromatic	15,461
Bima	34.0	—	—	15,057
Bekapai	41.2	0.080	naphthenic	14,936
Kakap	46.5	—	—	13,781
Jatibarang	29.0	0.070	paraffinic	11,510
Udang	39.1	0.050	paraffinic	9,451
Arimbi	33.0	0.140	paraffinic	7,879
Talang Akar Pendopo	35.5	0.060	aromatic	6,420
Sanga-sanga/Juata island	29.6	0.000	aromatic	4,842
Sembakung	37.0	0.090	aromatic	3,127
Tanjung	39.7	0.100	aromatic	3,036
Sangatta	35.1	0.060	aromatic	2,583
Bunyu	31.7	0.090	aromatic	2,224
Salawati	38.0	0.490	paraffinic	1,658
Madura	46.4	—	—	1,597
Bula	21.6	2.490	naphthenic	1,244
Klamono	18.8	0.800	—	980
Total				1,294,904

Note: — Not available.

Sources: BPPKA (Pertamina) data; "Guide to Export Crudes for the 80s," *Oil and Gas Journal*, various issues 1983.

NATURAL GAS RESOURCES

Confirmed natural gas reserves in Indonesia are currently estimated to be 91.45 trillion standard cubic feet (scf), as shown in Table 2.5. The estimated reserves in place by hydrocarbon basin of 216.8 trillion scf, prepared by Pertamina's geologists, is provided in Table 2.3. Current production includes associated and nonassociated gas both from onshore and offshore fields. Cumulative gas production through the end of the fourth five-year development plan (March 1989) totalled only 1.7 trillion scf, representing less than 2% of proven reserves. The huge potential for gas production and utilization in Indonesia therefore remains largely untapped.

Until recently, hydrocarbon exploration activities in Indonesia were not concerned with finding natural gas. In the course of oil exploration activities, however, significant quantities of natural gas were discovered, and the challenge has been to find ways to use the gas or convert it into forms less difficult to transport and sell. Natural gas was originally used only as a fuel in the oil fields themselves. Beginning in the 1930s, oil field operators in Sumatera began to reinject gas into oil wells to enhance oil recovery and as a pressure-maintenance technique. Because of the lack of markets for gas, however, most oil producers simply flared most of the associated gas. Only during the past two or three decades have producers established markets that warrant the investment in infrastructure required for gas production, transportation, and utilization.

In 1958 the government launched an important nonfuel use for natural gas, when the Pupuk Sriwijaya (PUSRI) company's fertilizer plant in South Sumatera began to use gas as a feedstock to produce urea. This fertilizer complex has been expanded and now consists of four plants that consume around 50 billion scf of natural gas annually. Subsequent to this innovation, planning for associated gas utilization has become an integral factor in oil field development. Additional uses have been developed for gas both as a domestic fuel (such as for heating and electric energy generation) and as a feedstock for the petrochemical industry and export-oriented plants.

Indonesia's first liquefied petroleum gas (LPG) plant was constructed in Aceh in 1971. In 1977 the first natural gas liquids (NGL) plant was built in West Java. Finally, large gas reserves that were discovered in Aceh in 1971 and in East Kalimantan in 1972 led to the initiation of Indonesia's first liquefied natural gas (LNG) projects. In 1977 Indonesia's first cargo of LNG was shipped from Aceh, North Sumatera, and in the following year LNG exports commenced from East Kalimantan. Indonesia is now the

Table 2.5
Proven Gas Reserves

Area	Proven Reserves (trillion scf)	(% of total)
Natuna Island group	37.81	41.34
East Kalimantan	23.17	25.34
North Sumatera	14.56	15.92
South Sumatera	4.62	5.05
West Java	6.69	7.32
East Java	2.37	2.59
Central Sumatera	0.96	1.05
Sulawesi	0.82	0.90
Irian Jaya	0.45	0.49
Total	91.45	100.00

Source: Said 1989.

world's largest LNG producer and exporter. Total production in 1989 was approximately 18.6 million tons.

Despite the progress made in natural gas development, natural gas utilization is still clearly in its early stages in Indonesia. Two-thirds of the country's gas production is converted to LNG, and only 15% is sold for use by industrial and city consumers. City gas represents less than 2% of total gas use. Further discussion of recent discoveries of gas reserves and the potential markets for their production is provided in Part Six.

To date, the biggest hurdle confronting the Indonesian gas sector has been transport infrastructure. The main gas consumers—LNG plants, fertilizer complexes, and steel mills—have been large users that can be located close to the resources. There are other potential large-scale users (notably the power sector) and a huge untapped market in the commercial and residential sectors, but constructing the pipeline network needed to reach these markets will be a daunting task. All of the largest concentrated markets are in Java and are separated by water from the largest untapped reserves. Even if trunklines were laid to Java, reticulating the urban areas would involve massive expense and dislocation.

There are many potential markets outside Java as well, such as the large amount of diesel power generation on Sumatera. While these demands are much closer to the resources, however, they are so widely scattered that the costs of serving individual customers appears prohibitive.

Foreign oil companies in Indonesia have been largely unenthusiastic about developing gas reserves for purposes other than LNG. The government has kept domestic gas prices low to help domestic industries, and the companies argue that the price has always been so low as to make development for the domestic market uneconomic. Since gas represents one of Indonesia's least-utilized resources, the government is reassessing its current policies in this sector.

PROPERTIES OF TYPICAL GASES

Indonesia's three largest-producing gas fields account for nearly three-fourths of current gas production. Arun in North Sumatera is operated by Mobil Oil and accounted for about 47% of total production in 1989. Badak field in East Kalimantan is operated by Huffco and accounted for 23% of the total. Arjuna in West Java is operated by ARCO and produced about 3% of the total. In all three operations, the fields of associated gas are located mostly offshore. A comparison of the composition of gases produced by these three fields is provided in Table 2.6. The properties of LNG from the Badak and Arun fields are given Table 2.7. The properties of butane and propane (the main constituents of LPG) from Arjuna gas are given in Table 2.8.

The fields on and around Natuna Island are notable for their extremely high (40-80%) concentrations of carbon dioxide (CO_2), which poses problems for their development. Natuna Sea reserves are estimated to account for 41% of Indonesia's total gas reserves, however, so the motivation to develop the resource is very strong. The CO_2 must be stripped and reinjected, thus adding considerably to the capital costs of any project implemented in this area.

Table 2.6
Compositions of Badak, Arun, and Arjuna Gases

Component	Badak	Arun	Arjuna
N_2	0.6	0.3	1.4
CO_2	0.0	15.0	1.0
C_1	29.4	72.0	52.3
C_2	49.4	6.0	11.0
C_3	29.2	2.6	19.8
iC_4	6.0	0.6	4.1
nC_4	6.9	0.6	5.2
iC_5	2.6	0.4	2.0
nC_5	1.7	3.3	1.2
C_6	1.7	0.0	1.0
C_7+	3.2	0.0	1.1

Source: BPPT 1988.

Table 2.7
Properties of Indonesian LNG

Properties	Arun LNG	Badak LNG
Components (molecular %)		
N_2	0.06	0.01
CO_2	0.00	0.00
C_1	87.29	90.75
C_2	7.86	4.94
C_3	3.64	2.92
iC_4	0.53	0.62
nC_4	0.55	0.69
iC_5	0.05	0.06
nC_5	0.02	0.01
Liquid density (kg/liter)	0.471	0.449
Gas density (kg/cubic meter)	0.789	0.767
Gross calorific value		
Gas (megajoules/cubic meter)	43.1	42.1
Liquid (megajoules/kg)	54.6	54.8
Net calorific value		
Gas (megajoules/cubic meter)	38.9	38.0
Liquid (megajoules/kg)	49.3	49.5

Source: BPPT 1988.

Table 2.8
Properties of Commercial Butane and Propane from Arjuna Gas

Properties	Butane	Propane
Components (molecular %)		
C_2	0.00	1.83
C_3	0.13	96.97
iC_4	40.00	1.17
nC_4	42.89	0.03
iC_5	9.17	0.00
nC_5	4.50	0.00
C_{6+}	3.31	0.00
Liquid density (kg/liter)	0.588	0.508
Gas density (kg/cubic meter)	2.580	1.970
Calorific value (megajoules/kg)		
Gross	50.5	51.0
Net	46.6	46.9

Source: BPPT 1988.

COAL RESOURCES

Indonesia's theoretical coal reserves are estimated at over 31 billion tons, although *proven* reserves are only 3.5 billion tons. Coal deposits in Indonesia are found mainly in Sumatera and Kalimantan, as shown in the estimated reserves summarized in Table 2.9. Approximately 58% of the proven reserves are in Sumatera and the remainder are in Kalimantan. Smaller reserves are inferred on the islands of Java, Sulawesi, and Irian Jaya. Hypothetically, Sumatera's coal reserves may exceed 22 billion tons, accounting for 71% of the nation's total hypothetical reserves.

Coal has been mined in Indonesia for centuries, but commercial coal production did not begin until around 1850 in East Kalimantan. Mining has been carried out on an industrial scale in Indonesia for more than a century. The first large-scale mining began in 1892 in Ombilin, Central Sumatra, and a railway line was built through the mountains to transport the coal to the seaport in Padang.

In the age of coal-powered steamships, locomotives, and factory boilers, coal was a key energy source in the Indonesian economy, and Indonesian coal was also exported to neighboring countries. After reaching a peak of more than 2 million tons in 1941, production was disrupted during the world war, and the mines recovered only partially in the postwar period. Coal production in the early 1950s stagnated in the range of 0.80-0.97 million tons per year and then entered a long period of decline, reaching a low of less than 150,000 tons in 1973. During this period, coal could not compete with oil, which was cheaper and more convenient to use.

Following the first round of world oil price increases in 1973, coal was given a prominent place in the government's energy diversification policy. Coal has become a preferred substitute for oil, especially for electricity generation. It is also used by the cement plants that are scattered across the more populous islands. Thus, although Indonesia is the only Southeast Asian country that has coal export capability at present, most of Indonesia's coal is consumed domestically. The share of coal in domestic commercial energy consumption is currently less than 7%, but this share is expected to increase significantly during the 1990s, particularly during the latter half of the decade when domestic oil fields begin to play out. Details of the rapid recovery of the coal industry since 1974 and projected future growth are provided in Part Nine.

Table 2.9
Estimated Coal Reserves
(million tons)

Island	Proven	Indicated or Inferred	Hypothetical	Total
Sumatera	1,534	4,991	15,728	22,253
Kalimantan	1,992	7,787	103	8,882
Java	4	23	20	47
Sulawesi	0	89	0	89
Irian Jaya	0	4	0	4
Total	3,530	11,895	15,851	31,276

Source: Perum Tambang Batubara data, cited in U.S. Embassy, Jakarta 1990.

COAL QUALITY

More than 65% of Indonesian coal is lignite, most of which is found in South Sumatera. The rest is primarily classified as subbituminous and bituminous, although a small amount of anthracite is found in Sumatera. Lignites have lower calorific value and higher moisture content than subbituminous, bituminous, and anthracite coals. Most of Indonesia's coals have quality deficiencies, including one or more of the following: low energy content, high moisture, unacceptable grindability, and low fusion temperature. A comparison of the quality of Indonesian coals by operating company is provided in Table 2.10.

Table 2.10
Indonesian Coal Quality

Island, Mine, and Contractor	Moisture: Total (%)	Moisture: Inherent (%)	Ash (%)	Volatile Matter (%)	Fixed Carbon (%)	Sulfur (%)	Calorific Value (kcal/kg)	Hardgrove Index	Coal Type
Sumatera									
Ombilin	11	6.00	5.50	38.00	50.00	0.50	6,975	40	B
Parambahan (PT Allied Indo Coal)	-	4.00	7.10	37.30	51.60	0.51	7,217	40	B
Sinamar (JAMBI)	-	11.50	4.00	31.00	45.00	1.75	5,700	-	SB
Bukit Asam/Air Laya	25	8.00	7.00	42.50	51.00	0.50	6,800	62	SB
Suban	6	2.00	9.00	15.80	78.00	< 1	8,000	-	A
Muara Tiga Kecil	23.9	12.70	3.76	40.04	44.35	0.50	6,377	-	SB
Muara Tiga Besar	27	13.45	4.20	40.47	42.05	0.36	5,905	-	L
Banko	28-39	-	4.1-12	42.6-47.9	43.9-49.4	0.2-1.5	6,200-6,900	-	L
Kalimantan									
Senakin (PT Arutmin Indonesia)	-	4.00	17.30	40.00	38.70	0.70	6,200	37	B
Sarongga (PT Arutmin Indonesia)	-	29.40	2.30	37.00	30.90	0.10	4,344	-	L
Bindu (PT Utah Indonesia)	7	-	17.90	35.90	39.20	2.40	6,090	47	B
Petanggis (PT Utah Indonesia)	8	-	11.60	39.10	41.30	0.70	6,420	38	B
Pinang (PT Kaltim Prima Coal)	-	5.00	5.00	38.60	50.90	0.50	7,150	-	B
Samaranggau (PT Kedeco Jaya Agung)	-	22.10	2.10	41.10	34.70	0.10	4,910	-	SB
Roto (PT Kedeco Jaya Agung)	-	14.40	1.20	42.10	42.30	0.10	5,830	-	SB
Wara (PT Adaro Indonesia)	-	28.38	2.49	36.24	32.71	0.18	4,844	38-70	SB
Tutupan (PT Adaro Indonesia)	-	19.74	1.50	40.03	39.63	0.10	5,584	31-45	SB
Paringin (PT Adaro Indonesia)	-	16.64	1.05	41.05	41.25	0.09	5,903	44	SB
Lati, Binungan (PT Berau Coal)	-	15.70	1.90	38.60	43.90	1.06	5,800	56	SB
Lati, Binungan (PT Tanito Harum)	-	7.50	7.50	40.00	45.00	0.55	6,600	47	B
Lati, Binungan (PT Muluti Harapan	-	11.00	6.00	37.00	41.00	1.50	6,300	45	B
Lati, Binungan (PT Chung Hua OMS)	-	9.50	12.40	45.00	-	1.25	6,395	27-45	B
Balikpapan (Badak Syncline)	-	22.30	4.70	-	-	0.15	4,797	-	SB

Notes: - Data not available. Data are on an air-dried basis for all coals except Bindu and Petanggis, for which the as-received basis applies.
A: anthracite. B: bituminous. SB: subbituminous. L: lignite.

Source: Perum Tambang Batubara 1987.

HYDROPOWER RESOURCES

Indonesia's vast hydropower resources could contribute significantly to the rapidly growing demand for electricity. The nation's theoretical hydropower resources are 75,624 MW. All of the large islands have important hydropower potential (Table 2.11). Early in 1988 total installed hydropower capacity amounted to 2,980 MW, and during fiscal year 1988 (the final year of the fourth five-year development plant), the State Electric Power Corporation added 713.5 MW of hydropower capacity. Thus, at the end of the fourth plan period, total hydropower capacity represented only 4.9% of theoretical resources. During the fifth plan period (1989-93), a total of 368.5 MW will be added to existing hydropower capacity. Details of the planned additions are outlined in Table 2.12. Five projects totalling 183 MW are planned for Java, and four units totalling 145 MW are planned for Sulawesi. A small project is scheduled for Bengkulu in Sumatera, and other minihydro projects are planned at various locations.

Hydroelectric potential has not yet been tapped more extensively because of technical constraints, economic limitations, the isolation of the best dam sites, and types

Table 2.11
Potential Hydropower Resources

Region	Estimated Potential (GW)
Irian Jaya	22.4
Kalimantan	21.6
Sumatera	15.8
Sulawesi	10.2
Java	4.5
Bali and Nusa Tenggara	0.7
Maluku	0.4
Total	75.6

Source: BAKOREN 1990.

Table 2.12
Hydroelectric Plant Construction Plan, 1989-93

Site	Generating Units	Installed Capacity (MW)
Bakaru, South Sulawesi	2 x 63 MW	126.0
Mrica (units 2 and 3), Central Java	2 x 60 MW	120.0
Tulung Agung, East Java	1 x 30 MW	30.0
Kedung Ombo, Central Java	1 x 23 MW	23.0
Tenggari, North Sulawesi	2 x 9.5 MW	19.0
Bengkulu, Sumatera	4 x 4 MW	16.0
Ciliman, Central Java	1 x 10 MW	10.0
Minihydropower units at various sites	various	24.5
Total		368.5

Source: BAKOREN 1990.

of water stream. Most of the potential is in thinly populated places, such as Irian Jaya, (3 people per km^2 in 1980) and Kalimantan (12 people per km^2), where demand is too low to justify large-scale hydropower investment. By contrast, more than half of the theoretical potential in heavily populated Java (690 people per km^2) has already been tapped. The mismatch between population distribution and the sites where hydropower, coal, and other energy resources are found is thus a basic problem for Indonesian development planners. Proposals for the construction of undersea cables to transport electricity between islands have been under study for a number of years. Ideally, electric power planners would like to link Kalimantan, which has the highest potential in the western half of the country, with the Java grid. But because of the distance and technical difficulties involved, the first undersea link to Java is likely to be a cable from Sumatera, across the relatively narrow strait that separates the two islands.

GEOTHERMAL ENERGY

As a volcanic archipelago with 70 active volcanoes, Indonesia has the potential to become one of the world's biggest producers of geothermal energy. The country's total geothermal resources have been estimated by the World Bank at more than 10,000 MW electricity generation equivalent. More than half of total potential capacity (5,500 MW) is located in Java, the most populous island with by far the highest growth rate of electricity demand in the near future. Since a recurring problem has been that energy resources are located too far away from population centers, geothermal's proximity should bode well for its development. It is ironic, however, that in certain instances, geothermal potential may exist *too* close to populated areas, and development may dislocate many people. Among the other populous islands, Sulawesi has a potential capacity of 1,400 MW and Sumatera 1,100 MW. The remaining potential capacity is scattered among other islands of the archipelago.

At the present time, Indonesia has only one geothermal plant, operated by Pertamina, the state oil company, and located in Kamojang, West Java. The 30-MW facility started up in 1983, and two 55-MW units added in 1988 brought installed capacity to 140 MW—one of the largest commercial geothermal facilities in the world. The government plans to increase geothermal capacity by 290 MW during Repelita V (1989-93). There are proven fields in Salak and Drajat, also in West Java, and their combined ultimate potential exceeds 600 MW. The Salak installation is scheduled for completion in 1991. A 110-MW project is under development at Drajat and is expected to come on-line in 1993. In 1972 the U.S. government provided assistance for the exploration of geothermal potential in the Dieng field, Central Java, where a 55-MW unit is scheduled for completion in 1994. Other exploration is also being carried out in the Lahendong field in Sulawesi.

Most of the emphasis on geothermal energy development has been concentrated in Java, where the demand is greatest. The exploitation of geothermal potential on other islands could be more economical than alternative fuel sources for electric power generation. In Java there are several options for producing baseload power. These include hydro, gas-fired steam, gas-fired combined cycle, and coal-fired steam. On the other islands, however, choices are more restricted. Most generation outside Java makes use of diesel generator sets, which generate power at a much higher unit cost than in Java. Moreover, the diesel fuel presently used for electricity generation could be better used for domestic transport or as an export commodity.

NUCLEAR POWER

Although Indonesia has managed to diversify electric power generation during the past two decades by utilizing its large reserves of domestic fuels, electric power planners estimate that the planned additions of oil-, gas-, and coal-fired capacity plus added hydropower capacity during the 1990s will be insufficient to meet Java's projected electricity demand at the turn of the century. To prepare for the possibility of introducing nuclear generation into the national electric power system, a feasibility study was carried out early in the 1980s with Italian assistance. In the meantime, experience in nuclear power generation has been gained through the operation of a small, experimental research reactor in Serpong, West Java, which has an installed capacity of 30 MW.

Although reservations and objections to the introduction of nuclear generation have been raised by various environmental groups, a decision has been taken on the timing for bringing nuclear-powered generation on line. The government has announced that an 800-MW nuclear power plant will be built in Gunung Muria, Central Java, and that construction should begin around the turn of the century. Dissension exists within the government over this plan, so the timing is subject to change. Changes in the availability of other energy sources, such as gas and coal, may also influence the plans for nuclear development.

Three

ENERGY IN THE ECONOMY

OVERVIEW

Energy has been the main contributor to modern economic growth in Indonesia in several ways. First, as marketable commodities, energy resources such as oil and gas generate revenues directly for the government. Indonesia is a net oil and gas exporting country, and oil in particular has played a leading role in national development, both as the major domestic energy resource and as an important source of foreign exchange. Second, resource development has an indirect impact on regional economic development and employment generation. Third, domestic energy resources are relatively inexpensive inputs to other economic sectors, and they have therefore promoted the rapid growth of the manufacturing and transportation sectors and the establishment of energy-intensive industries such as steel and fertilizer. Indonesia's success in expanding nonoil exports during the 1980s can be attributed in large part to such inexpensive energy inputs; critics might add, however, that such pricing policies have not contributed to efficiency of use, expansion of supply, or proper resource allocation.

Energy as an economic input is measured in terms of both final energy consumption and primary energy consumption. "Final energy" is consumed by end users in its final form (such as petroleum products, city gas, coal, and electricity), whereas "primary energy" is measured in terms of the primary form (oil, natural gas, coal, hydropower, and geothermal energy). Data for the consumption of final energy, which is generated from commercial primary energy, include losses from conversion, transformation, transmission, and distribution of the primary energy before it is consumed in final form.

The National Energy Coordinating Board of Indonesia divides consumption into three sectors: (1) industrial, (2) transportation, and (3) commercial and residential. The industrial sector includes manufacturing, mining, and other industries. Public sector consumption is included in the commercial and residential sector. The National Energy Coördinating Board prepares its projections of future energy consumption based on current patterns in these sectors and on assumptions about future performance of the Indonesian economy.

Consumption for agricultural uses is included in the industrial consumption data, but it accounts for only a tiny fraction of the total. The energy consumed by the farmers—who constitute the great majority of the population—is largely noncommercial, and accurate data for the consumption of noncommercial forms of energy are unavailable. Thus, despite the size of the agricultural sector and its importance to the Indonesian economy, it is not fully addressed in this discussion.

RECENT CONSUMPTION PATTERNS

Commercial Primary Energy Mix

Table 3.1 displays Indonesia's primary energy consumption by fuel type, 1971-88, while Table 3.2 provides the government's forecast of consumption during the current five-year development plan, 1989-93. Figure 3.1 charts the trend from 1971 to 1993, and the percentage shares of primary energy by fuel are plotted in Figure 3.2.

While it is obvious that oil has been and will remain the dominant fuel, its share in the overall energy mix has declined dramatically since the early 1970s. In 1971 oil represented 93.6% of the energy mix; this share declined to 83.6% by 1980 and continued its drop to around 74% in 1985 and 68% in 1988. Forecasts indicate that the share of oil will fall to under 60% during the early 1990s, but will linger in the 58%-60% range as it becomes more difficult to make rapid gains in fuel substitution. As discussed more fully in the following chapters of this report, further expansion of nonoil energy, such as natural gas and coal, will require massive capital expenditure and significant lead times; oil is expected to retain its dominance in the near term as the government works to phase in alternatives.

In absolute terms, consumption of oil will continue to rise, although the annual average growth rate of oil use during the 1980-88 period was the lowest of all primary energy sources. This reflects the success of the government's energy diversification policy. As illustrated in Figure 3.3, the shares of nonoil energy resources have been increasing rapidly since the late 1970s. In 1971 coal's share was 1.3%, the share of natural gas was 1.5%, and hydro/geothermal accounted for 3.6%. Natural gas was the first fuel to gain a significant share of the energy mix, reaching nearly 15% by 1980, while the shares of coal and hydro/geothermal fell. By 1988, however, expansions in coal and hydro/geothermal caused their percentage shares to rise to 6.6% and 4.7%, respectively, while the natural gas share continued to rise to around 21%. Abundant proven reserves of coal and gas, together with the potential hydropower and geothermal resources, will

Table 3.1
GDP and Primary Energy Consumption By Fuel, 1971-88

	Primary Energy Consumption (thousand toe)					Gross Domestic Product		
Year	Coal	Oil	Gas	Hydro-power and Other	Total	Current billion rupiah	Real 1980 billion rupiah	Real 1980 US$ million
1971	118	8,335	135	318	8,906	3,672	22,539	14,132
1972	116	9,572	135	338	10,161	4,564	24,663	15,464
1973	79	10,809	198	358	11,444	6,753	27,453	17,213
1974	92	11,799	476	387	12,754	10,708	29,580	18,547
1975	117	12,790	506	417	13,830	12,642	31,061	19,476
1976	97	14,268	528	411	15,304	15,467	33,191	20,810
1977	109	15,747	1,954	406	18,216	19,033	36,116	22,645
1978	116	17,340	2,813	364	20,633	23,814	40,778	25,568
1979	137	18,933	3,411	322	22,803	34,052	43,995	27,585
1980	146	21,046	3,701	292	25,185	48,914	48,914	30,669
1981	168	22,298	4,089	305	26,859	58,240	52,849	33,136
1982	176	23,549	3,840	318	27,883	62,737	52,764	33,083
1983	165	22,819	4,759	478	28,221	77,676	55,090	34,541
1984	199	22,702	5,991	521	29,413	89,750	57,021	35,752
1985	353	23,486	6,527	1,421	31,787	96,997	57,395	35,986
1986	1,597	23,150	7,410	1,620	33,776	102,683	60,939	38,209
1987	2,091	24,550	7,386	1,767	35,794	124,817	64,638	40,528
1988	2,497	25,902	7,906	1,787	38,092	142,020	69,733	43,723
Annual average growth rate (%)								
1971-79	1.9	10.8	49.7	0.1	12.5	32.1	8.7	8.7
1980-88	42.6	2.6	10.0	25.4	5.3	14.3	4.5	4.5
1971-88	19.7	6.9	27.1	10.7	8.9	24.0	6.9	6.9

Sources: Primary energy consumption figures from International Energy Agency 1989 and 1990; economic figures from Asian Development Bank 1989 and Central Bureau of Statistics, *Economic Indicators*, October 1990.

Table 3.2
Forecast of Primary Energy Consumption, 1989-93
(million boe)

Year	Coal	Hydro-power	Geo-thermal	Natural Gas	Nonoil Subtotal	Oil	Total	Oil as % of Total
1989	21.2	23.2	2.0	72.6	119.0	190.5	309.5	61.6
1990	25.9	23.3	2.0	79.4	130.5	194.7	325.2	59.9
1991	26.1	23.9	3.5	83.2	136.6	204.4	341.0	59.9
1992	27.7	24.5	5.1	89.3	146.5	212.4	358.9	59.2
1993	33.1	25.0	5.1	94.8	158.1	218.0	376.1	58.0
Average annual growth rate (%)								
1989-93	11.9	1.9	26.6	6.9	7.4	3.4	5.0	

Source: Ministry of Mines and Energy 1989.

make possible the further reduction of oil's share in the energy mix. When economically sound, and correctly priced, other energy resources will continue to be substituted for oil. The 1993 shares forecast by the government are 58.2% oil, 25.1% gas, 8.8% coal, and 8.0% hydro/geothermal.

Figure 3.4 shows Indonesia's commercial-energy intensity and oil intensity relative to real GDP (in 1980 US$) from 1971 to 1988. Overall energy intensity is quite high, and it is clear that oil played a decisive role in economic performance in the 1970s. The energy diversification policy that was launched in the mid-1970s made an impact on oil intensity, which began to decline in the 1980s, but total energy intensity continued to rise as

Figure 3.1
Total Primary Energy Consumption by Fuel Type, 1971-93

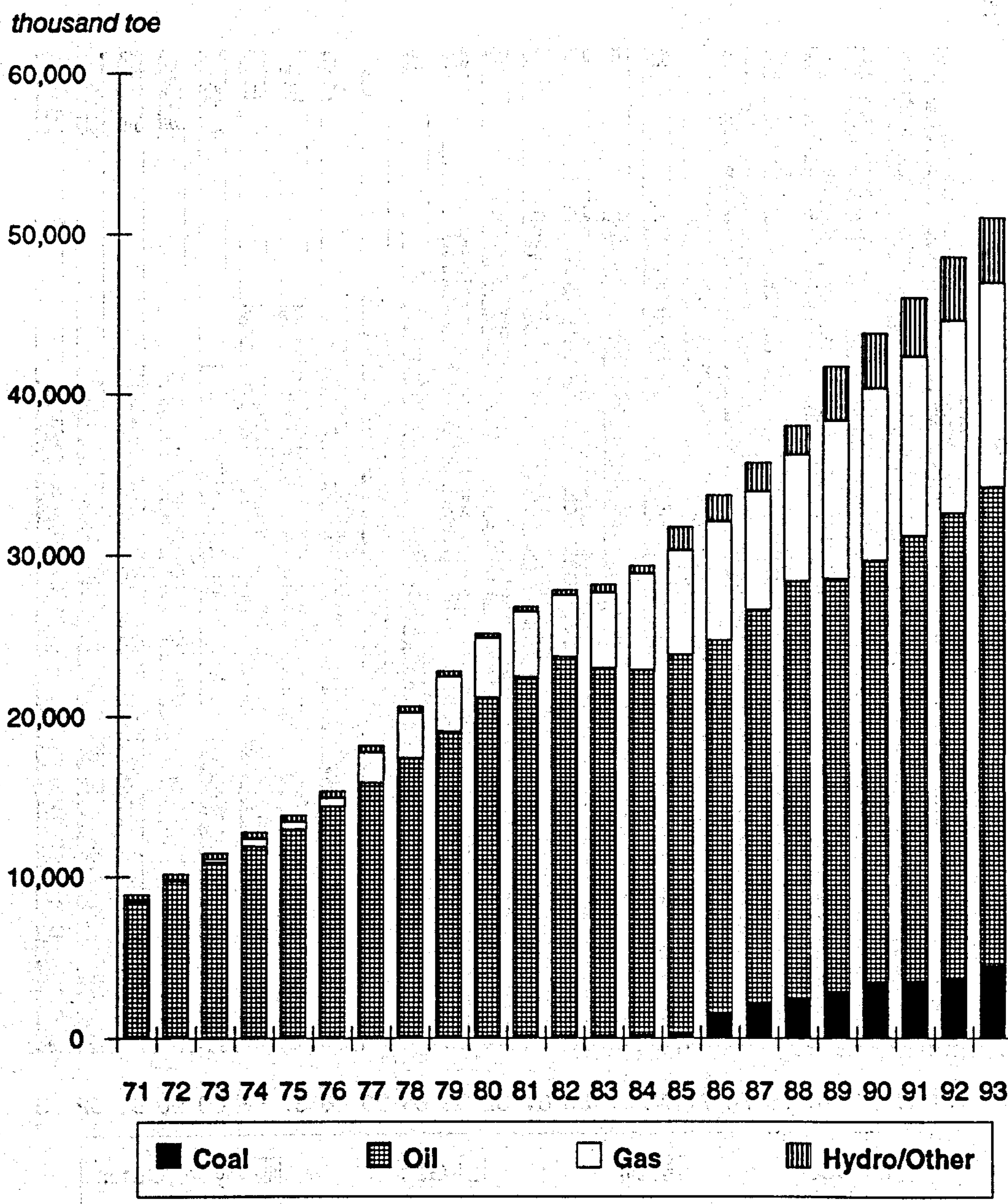


Figure 3.2
Primary Energy Consumption by Fuel Type, 1971-93

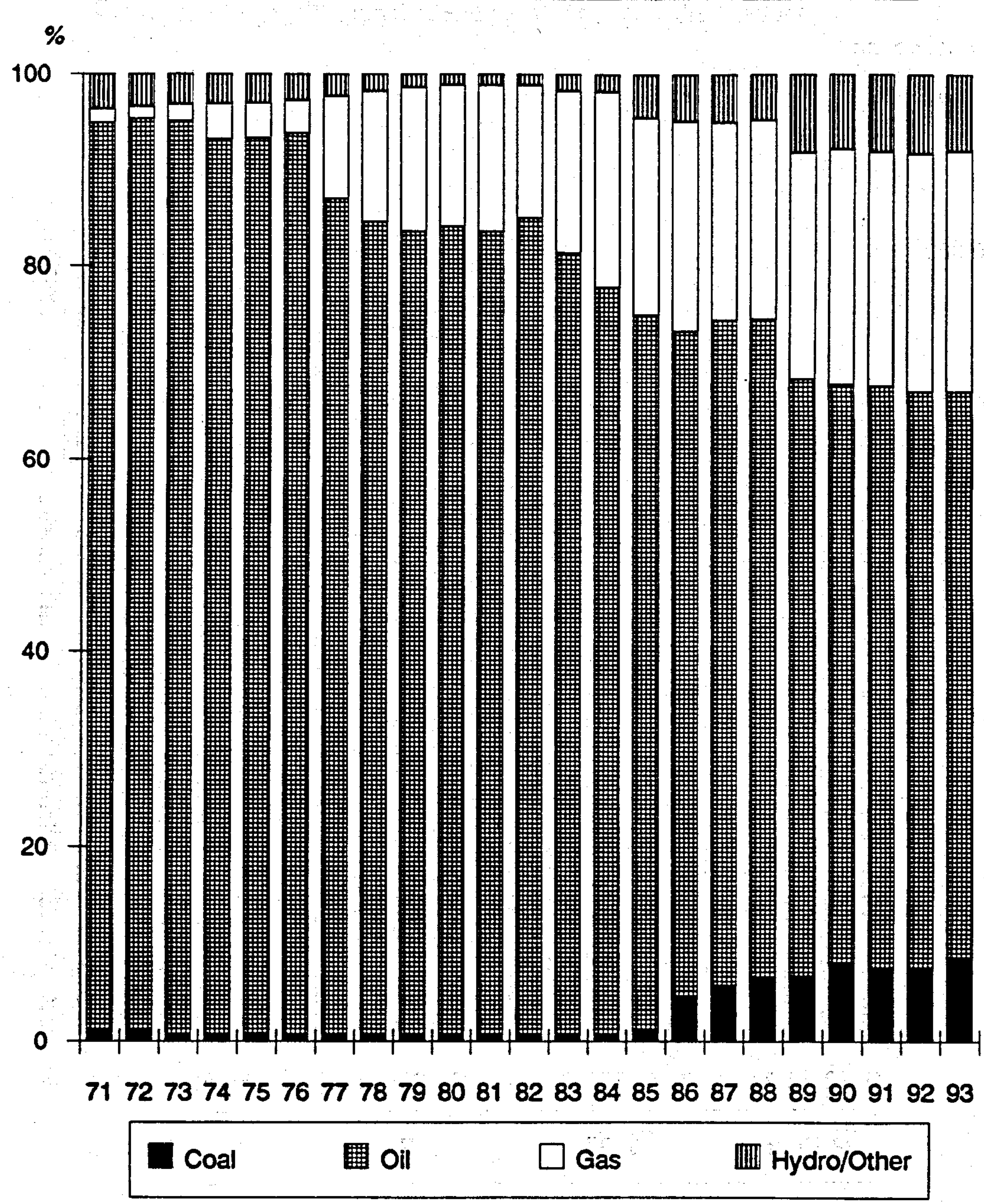


Figure 3.3
Changing Role of Fuel Types in Primary Energy Consumption, 1971-93

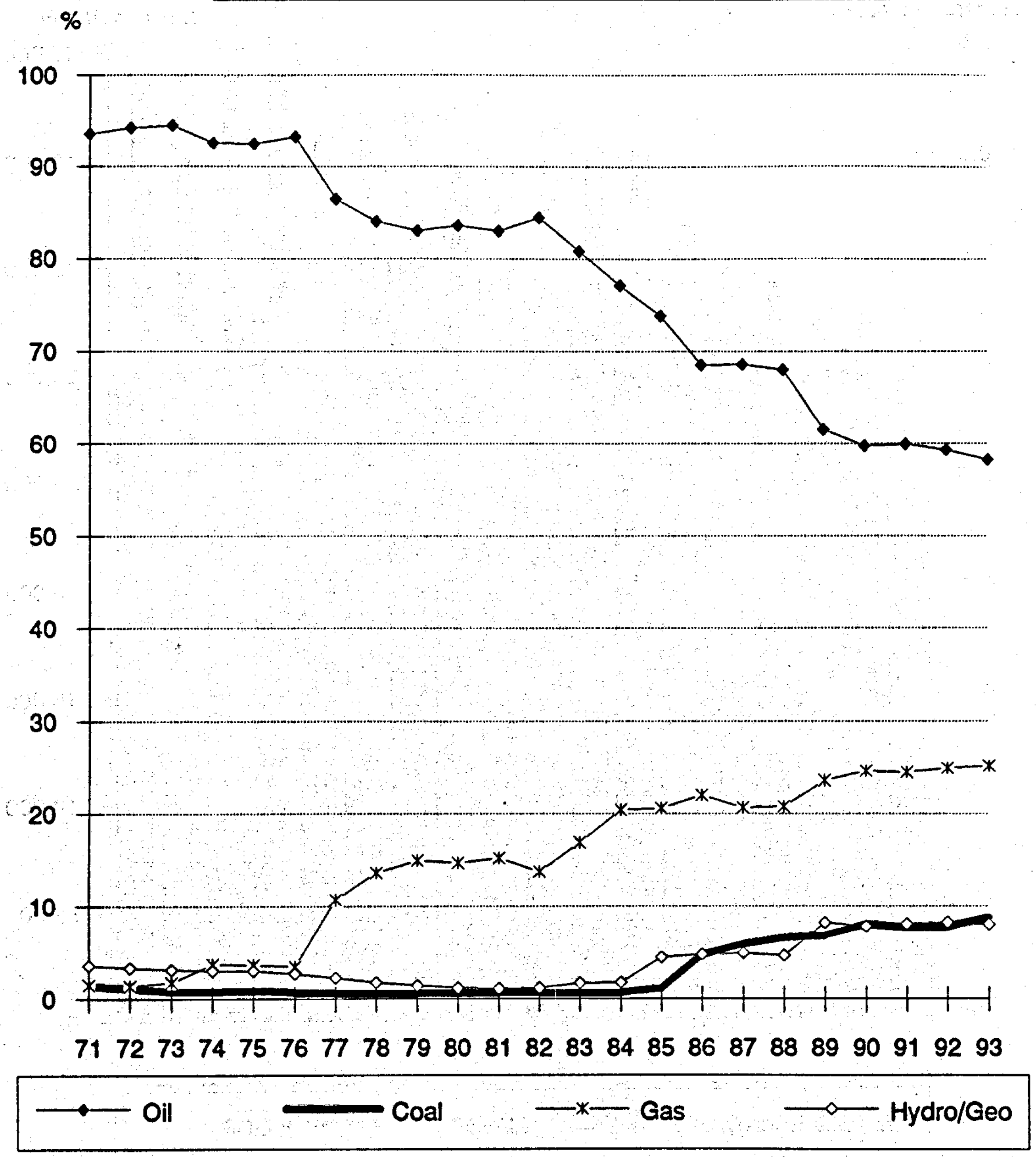
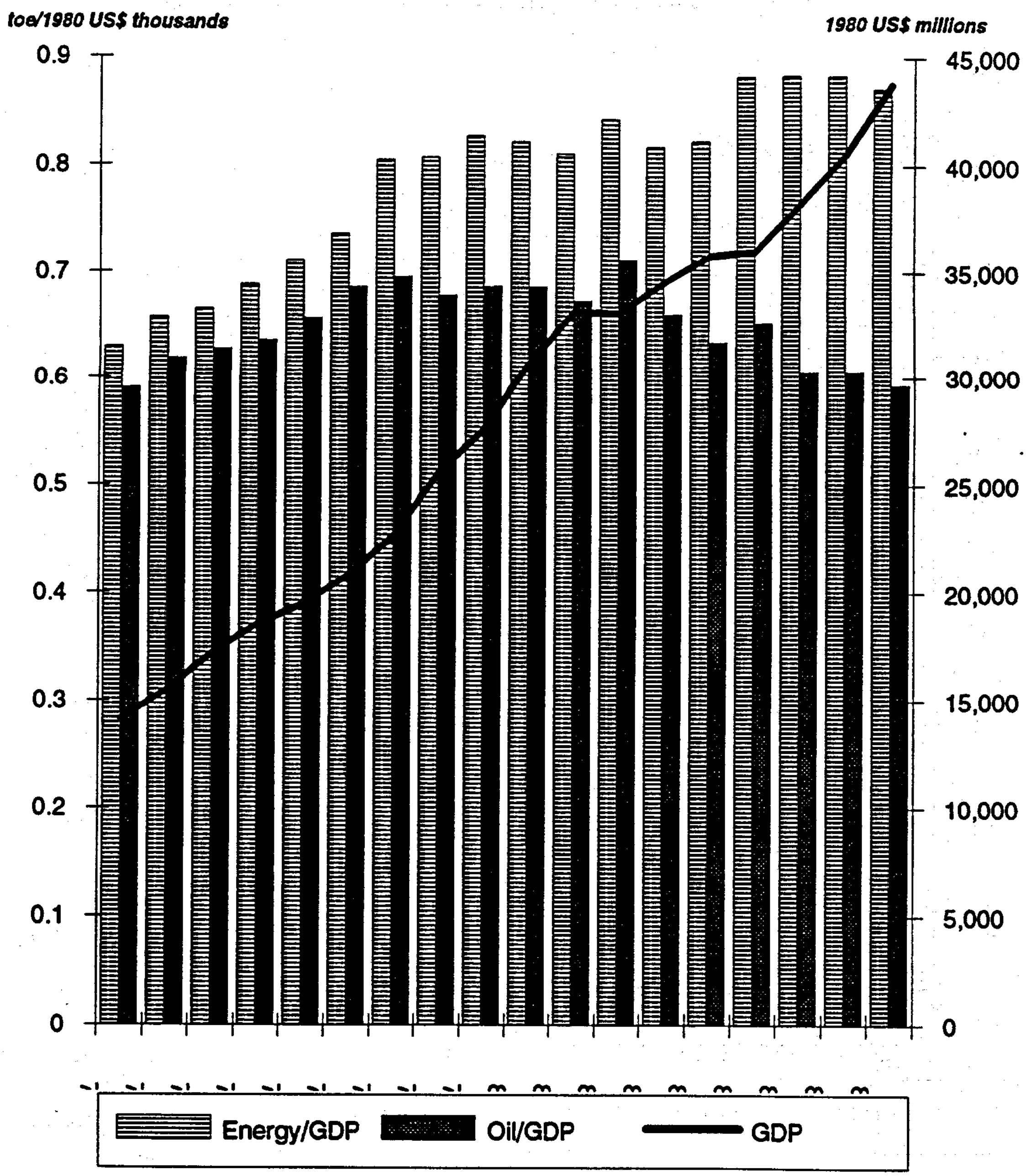


Figure 3.4
Energy and Oil Intensity of GDP, 1971-88



economic development progressed. While this is not unusual for a country at Indonesia's level of economic development, there is considerable room for improvement in the efficiency of energy use.

Final Energy Consumption

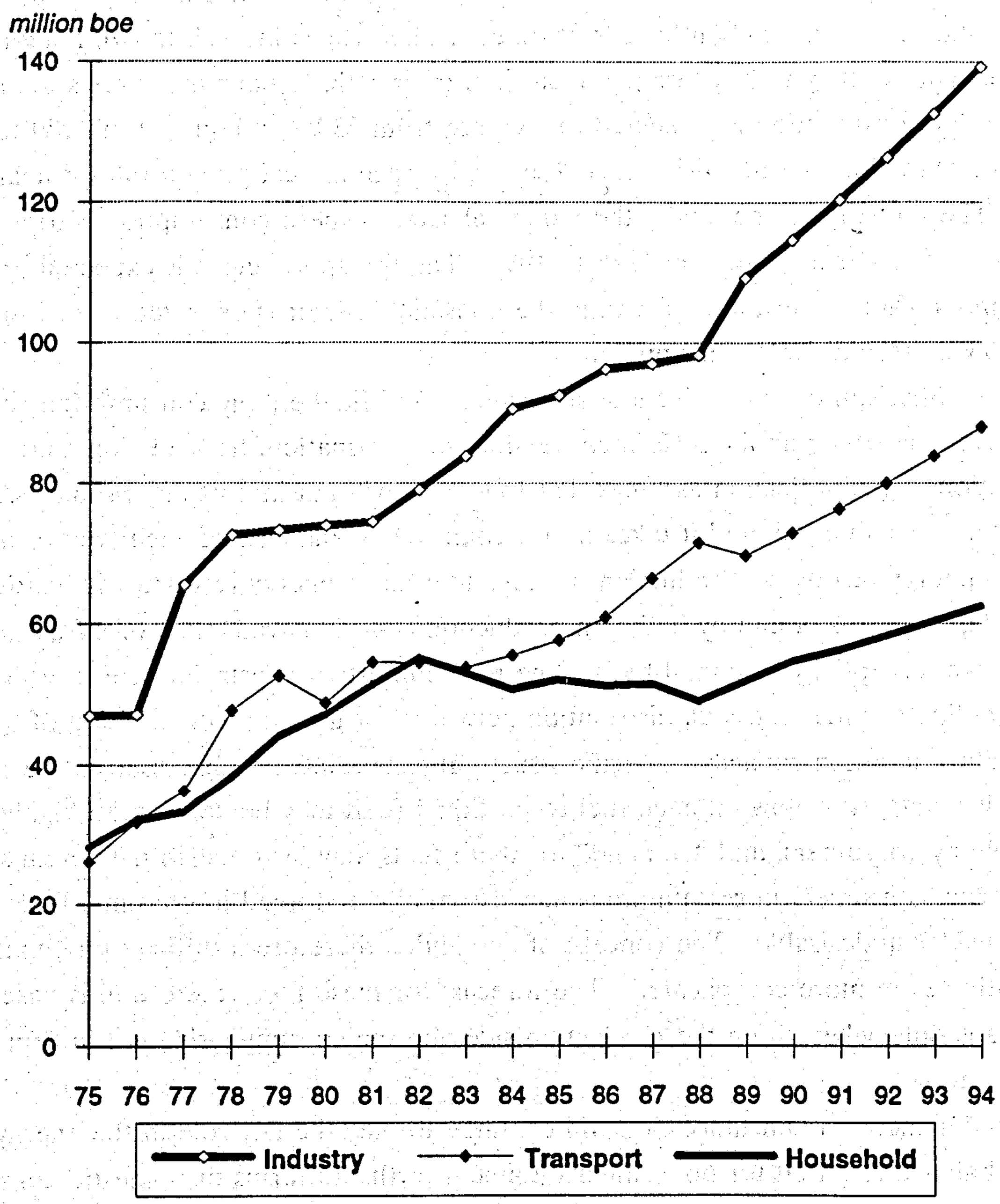
Table 3.3 and Figure 3.5 trace final energy consumption by sector from 1975 to 1994. During the five-year period of fiscal years 1975 to 1980, final energy consumption grew at nearly 11% per annum. Final energy use from 1981 to 1988 is estimated to have grown at around 2.8% annually. Of the three major sectors, the industrial sector accounts for the majority of final energy use (around 45%), and this sector has also displayed the steadiest pattern of growth—around 9.6% per annum from 1975 to 1980 and 4% annually from 1981 to 1988. In contrast, during the same two periods, energy use by the transportation sector grew at average annual rates of 13.4% and 4%, respectively, while the household, commercial, and public sector grew at 10.9% in the first period and then posted declines of around -0.7% annually during the 1981-88 period. The inconsistent growth registered by the transportation sector can be explained by noting that petroleum fuel use dominates this sector, and there were several oil product price adjustments by the government which caused fluctuations in the use of transport fuels. Figure 3.5 clearly shows the drop in transport sector energy use in response to the 1979-80 price increase and the somewhat slow recovery pattern that followed.

Pricing policy had a significant impact also on commercial and residential energy consumption. During the 1975-80 period, commercial and residential energy use grew at rates of nearly 11% per year. The rapid growth in this sector, however, occurred only in the 1975-82 period (Figure 3.5). A large increase in the price of kerosene, which is the dominant fuel in the commercial and residential sector, caused a decline and then a levelling off in consumption from 1983 onward, so that the overall growth rate for the 1981-88 period averaged -0.7%. During the fourth development plan (1984-88), the government's rationalization of the price of kerosene resulted in a price rise of approximately 50%, which in turn encouraged conservation and fuel switching. At the same time, the government adopted conservation measures for government offices and public utilities. Partly for these reasons, the percentage share of the commercial and residential sector in final energy consumption declined from around 28% in 1975 to 22% in 1988. During the same period, the transportation sector's share rose from 26% to 33%. Industry's share remained roughly constant at 45-46%.

Table 3.3
Final Energy Consumption by Sector, 1975-94

Year	Industry		Transport		Household		Total
	million boe	% of total	million boe	% of total	million boe	% of total	million boe
1975	46.9	46.4	26.0	25.8	28.0	27.8	100.9
1976	47.0	42.5	31.6	28.6	31.9	28.9	110.5
1977	65.5	48.6	36.2	26.9	33.1	24.6	134.8
1978	72.6	45.8	47.7	30.1	38.2	24.1	158.5
1979	73.3	43.2	52.5	30.9	43.9	25.9	169.7
1980	74.0	43.6	48.7	28.7	47.1	27.7	169.7
1981	74.5	41.3	54.4	30.2	51.2	28.4	180.1
1982	79.1	41.9	54.4	28.9	55.1	29.2	188.5
1983	83.9	44.0	53.7	28.2	52.9	27.8	190.4
1984	90.6	46.1	55.5	28.2	50.6	25.7	196.6
1985	92.4	45.8	57.6	28.5	52.0	25.7	202.1
1986	96.2	46.2	60.9	29.2	51.1	24.6	208.3
1987	97.0	45.2	66.5	30.9	51.4	23.9	214.9
1988	98.2	44.9	71.5	32.7	48.9	22.4	218.6
1989	109.2	47.4	69.7	30.2	51.7	22.4	230.6
1990	114.6	47.3	72.9	30.1	54.6	22.5	242.1
1991	120.3	47.6	76.4	30.2	56.2	22.2	252.9
1992	126.4	47.8	80.0	30.2	58.2	22.0	264.6
1993	132.7	47.9	83.8	30.3	60.3	21.8	276.8
1994	139.3	48.1	87.9	30.3	62.4	21.6	289.7
Average annual growth rate (%)							
1975-80	9.56		13.36		10.93		10.96
1981-86	5.26		2.27		-0.03		2.95
1981-88	4.02		3.98		-0.66		2.80
1975-88	5.85		8.10		4.37		6.13
1989-94	4.99		4.75		3.84		4.66

Figure 3.5
Final Energy Use By Sector, 1975-94



PROJECTION OF ENERGY CONSUMPTION

The government's projections for final energy consumption and commercial primary energy consumption during the current five-year plan (1989-93) are based on the assumption of an annual 3.5% GDP growth rate during the plan period.

The forecast scenario (included in Table 3.2) projects an increase in primary energy consumption from 309 million barrels of oil equivalent (boe) in 1989 to 376 million boe in 1993, representing a 5% average annual rate of growth. Under the same scenario, final energy consumption is projected to increase from 230.6 million boe in 1989 to around 290 million boe in 1994, anticipating an average annual growth rate of nearly 4.7%. The growth is to be led by the industrial sector, where consumption is forecast to increase at 5% per annum from 1989 to 1994. The transport sector is expected to grow at around 4.8% annually, and growth in the household sector is expected to pick up again and grow at around 3.8% per annum.

A comparison of the projections for primary and final energy consumption shows that there is a loss of about 24% in conversion, transformation, transmission, and distribution. This projection assumes that Indonesia will not import any primary energy resources other than oil, and it takes into account the availability of each type of nonoil primary energy resource. Production of most alternative energy resources is relatively inflexible, since it is bound by limits on production capacity, availability of infrastructure, and market receptivity to nonoil fuels. The most important constraints are transportation and handling facilities for coal, distribution networks for gas, and construction of new electricity generation capacity. Specific structural constraints are discussed in the respective chapters below on each fuel type. Some fuels may be considered highly desirable by consumers, and "demand" for these fuels may far outstrip the actual supply. Conversely, consumers in certain areas may essentially be forced to consume fuels that they consider undesirable. The concept of demand is therefore a difficult one, making forecasting even more complicated. The forecast for these fuels, therefore, is based on firm plans only, where both the production side and the consumer side are in firm agreement.

Under these circumstances, oil will continue to play the key role in the energy supply balance required for domestic economic growth. In terms of domestic utilization and production and refining capacities, oil is the most flexible fuel source. The trade-off, however, is the opportunity cost lost when oil is used domestically rather than exported.

FORECAST ENERGY USE BY SECTOR AND FUEL

The government provides its forecast energy balance by sector and fuel as shown in Tables 3.4 through 3.8, which display, respectively, the current five-year plan (1989-93) forecast balances for oil products, natural gas, coal, geothermal energy, and hydropower.

Oil product output is projected to grow at rates averaging 2.8% per annum during the period, from 208.4 million barrels in 1989 to 233.0 million barrels in 1993. Transport sector oil use is forecast to increase at nearly 4.8% per year, which will result in the transport sector increasing its share of total consumption from around 37% in 1989 to 39% by 1993. Industrial use of oil will increase at around 2.2% per annum, and household use will remain flat. Despite the goal of reducing oil use for electricity generation, use is forecast to grow at around 2% annually. Significant increases (11.6% per annum) are forecast for bunkers, losses, and other uses.

Natural gas production is forecast by the Ministry of Mines and Energy to increase from 5,249 million standard cubic feet per day (scf/d) in 1989 to 6,947 million scf/d by 1993 (Table 3.5), representing an average annual growth rate of 7.3%. The MIGAS forecast (Table 3.6) for the same period is slightly more optimistic. Feedstock uses account for over 78% of gas consumption throughout the period. The most rapid increases in gas use are seen in electricity generation and the household sector, which are forecast to experience growth rates of nearly 48% and 24% per annum, respectively. Still, their percentage shares of total consumption remain quite low; the power sector share will increase from 1.3% in 1989 to 4.5% by 1993, and the household sector's share will grow from a mere 0.1% to 0.3% during the same period.

Among the fossil fuels, coal production and use is expected to grow most rapidly during Repelita V—perhaps even more rapidly than government official forecasts would indicate. Repelita V's forecast of 1989 coal production was originally set at 6 million tons, but actual production of 8.7 million tons far surpassed this. This allowed for exports of over 2.5 million tons in 1989—ten times as much as was originally expected in the forecast (Table 3.6). The official forecast for 1993 indicates a production level of 15 million tons. Further detail on coal production and trade is provided in Part Nine of this report, including historical data through 1989. The largest coal user is the power sector, which accounted for an estimated 63% of total coal use in 1989 and is expected to account for 68% by 1993. The next-largest user is industry, which accounted for 36% of 1989 consumption and is expected to represent around 31% of consumption in 1993. In absolute terms, coal use by industry is expected to increase from 1.9 million tons in 1989

Table 3.4
Forecast Oil Product Balance, 1989-93
(thousand barrels)

Item	1989	1990	1991	1992	1993	Average Annual Growth Rate (%)
Production	208,401	208,401	207,737	205,967	233,032	2.8
Consumption						
Final						
Industry	39,627	40,548	42,542	43,216	43,141	2.15
Transportation	70,159	73,438	76,913	80,597	84,502	4.76
Household	44,709	44,709	44,710	44,710	44,710	0.00
Intermediate[a]	21,644	22,214	24,655	24,708	23,382	1.95
Other[b]	14,365	13,817	15,604	19,147	22,305	11.63
Total consumption	190,504	194,727	204,424	212,377	218,040	3.43

Notes: a. Electricity generation.
b. Includes bunkers and losses.

Source: Ministry of Mines and Energy 1989.

Table 3.5
Forecast Natural Gas Balance, 1989-93
(million scf/d)

Item	1989	1990	1991	1992	1993[a]	Average Annual Growth Rate 1989-93 (%)
Production	5,249.0	6,148.4	6,428.0	6,509.7	6,947.0	7.3
Consumption						
Final energy						
Industry	881.4	925.5	960.9	1,018.8	1,079.5	5.2
Household	7.3	11.1	14.0	15.6	17.1	23.7
Intermediate energy[b]	64.9	127.4	140.4	220.0	307.4	47.5
Other consumption						
Feedstock	3,974.4	4,500.1	4,736.2	4,705.9	5,335.6	7.6
Field use	155.4	145.8	150.5	111.4	38.4	-29.5
Total consumption	5,083.4	5,709.9	6,002.0	6,063.7	6,778.0	7.5
Natural gas use for primary energy[c]						
LNG, city gas, and other	1,109.0	1,209.8	1,265.8	1,357.8	1,442.4	6.8
LPG	42.9	49.0	53.4	58.6	62.0	9.7
Total primary energy use in million scf/d	1,151.9	1,258.8	1,319.2	1,416.4	1,504.4	6.9
Total primary energy use in thousand boe	72,610.2	79,351.7	83,171.4	89,289.3	94,839.0	6.9

Notes: a. Not including Natuna gas for planned LNG plants.
b. Electricity generation.
c. Primarily in feedstock use above.

Source: Ministry of Mines and Energy 1989.

Table 3.6
Coal Balance, 1989-93
(thousand tons)

Item	1989	1990	1991	1992	1993	Average Annual Growth Rate 1989-93[a] (%)
Coal production	6,000	8,000	11,000	13,000	15,000	25.7
Coal consumption						
Final energy						
Industry	1,905	2,013	2,015	2,147	2,179	3.4
Tranportation	85	85	85	85	85	0.0
Intermediate energy[b]	3,367	4,481	4,587	4,587	5,978	15.4
Total consumption	5,357	6,578	6,687	6,819	8,242	11.4
Coal exports	250	1,305	4,255	5,925	6,315	124.2
Total production in thousand boe	23,707	31,439	42,893	52,766	60,302	26.3
Total consumption in thousand boe	21,167	25,852	26,075	27,676	33,133	11.9

Notes: a. The discrepancy between the average annual growth rates in tons and in boe is attributable to the differences in BTU content of coals.
b. Electricity generation.

Source: Ministry of Mines and Energy 1989.

Table 3.7
Projected Geothermal Energy Utilization, 1989-93

Item	1989	1990	1991	1992	1993
Installed capacity (WM)					
Kamojang	140	140	140	140	140
Salak	—	—	110	110	110
Darajat	—	—	—	—	110
Dieng	2	2	2	2	57
Lahendong	—	—	—	—	15
Total	142	142	252	252	432
Electricity production capacity (GWh)					
Kamojang	1,210	1,210	1,210	1,210	1,210
Salak	—	—	950	950	950
Darajat	—	—	—	—	950
Dieng	17	17	17	17	493
Lahendong	—	—	—	—	130
Total electricity production capacity					
in GWh	1,227	1,227	2,177	2,177	3,733
in thousand boe	2,448	2,448	4,345	4,345	7,449
Total electricity generated					
in GWh	986	986	1,761	2,535	2,753
in thousand boe	1,968	1,968	3,514	5,059	5,494

Note: — Nil.

Source: Ministry of Mines and Energy 1989.

Table 3.8

Projected Hydropower Installed Capacity and Generation, 1989-93

Item	1989	1990	1991	1992	1993
Installed capacity (MW)					
Existing PLN[a]	2,668	2,788	2,827	2,953	2,953
Existing non-PLN	918	918	918	918	918
PLN additions[b]	120	39	126	0	59
Total installed capacity	3,706	3,745	3,871	3,871	3,930
Electricity generation					
in GWh	11,629	11,696	11,953	12,275	12,548
in thousand boe	23,206	23,340	23,853	24,496	25,041

Notes: a. Installed capacity at the beginning of the fiscal year.
b. Not including minihydro units.

Source: Ministry of Mines and Energy 1989.

to 2.2 million tons in 1993. A small amount of coal is also used by the transport sector (less than 2% of total consumption), but this amount is expected to remain flat. As coal production expands, the bulk of the new production is targeted for export. Coal export availability is expected to jump to over 6.3 million tons by 1993, as opposed to 1989 actual exports of 2.546 million tons.

As mentioned in Part Two, Indonesia possesses great potential for geothermal energy development. During Repelita V, installed capacity should triple, from 142 MW currently to 432 MW by 1993. The large facility at Kamojang (140 MW) will be joined by new installations at Lahendong (15 MW), Salak and Darajat (110 MW each). The

2-MW Dieng facility will be expanded to 57 MW. The Ministry of Mines and Energy estimates that geothermal electricity generation will rise from 986 GWh to 2,753 GWh during the period.

Modest increases in hydropower capacity are also planned. At the beginning of the current five-year plan in 1989, the state power utility (PLN) was operating 2,668 MW of hydro capacity, while other entities operated 918 MW. PLN plans additions totalling 344 MW (not including minihydro units) during the current five-year plan, which will bring total hydropower capacity to 3,930 MW by 1993. Hydropower generation by PLN is forecast to increase from 6,946 GWh in 1989 to 7,927 GWh by 1993. Further details on the electric power sector are provided in Part Eight of this report.

Four

GOVERNMENT AGENCIES AND INSTITUTIONAL ARRANGEMENTS

OVERVIEW

Within the Indonesian government, the departmental institution in charge of the energy sector is the Ministry of Mines and Energy. There are also nondepartmental government agencies involved in energy policy, namely, the National Energy Coordinating Board (BAKOREN, abbreviated from Badan Koordinasi Energi), the Electrical Power Generation Development Team, the Agency for the Assessment and Application of Technology (BPPT, abbreviated from Badan Pengkajian dan Penerapan Teknologi), and the National Atomic Energy Agency (BATAN, abbreviated from Badan Tenaga Atom Nasional). Several state-owned companies are in charge of implementing the policies set out by the Ministry of Mines and Energy. In the parliament, one commission, Commission VI, is in charge of the industry, mining and energy, and investment sectors. These institutions' roles in the Indonesian energy sector are described below.

MINISTRY OF MINES AND ENERGY

The Ministry of Mines and Energy has a broad range of responsibilities in energy policy and planning and in resource delineation and development, including overall responsibility for geological activities, exploration, mining and processing of coal, geothermal resources, petroleum (oil and gas) and other minerals, and the development, generation, and distribution of electricity. The minister serves as Chairman of the Board of Commissioners of Pertamina, the state-owned oil company, and is Chairman of BAKOREN, a cabinet-level policy board consisting of several ministers (see below). The minister is also the head of the Indonesian delegation to meetings of the Organization of Petroleum Exporting Countries (OPEC). Indonesia is the only Asian member of OPEC, having joined in 1962, and a former Minister of Mines and Energy, Dr. Subroto, was elected OPEC Secretary General in 1988. Indonesia's role in OPEC is described more fully in Part Five of this report. The ministry has four directorates general: the Directorate General of Mining, the Directorate General of Geology and Mineral

Resources, the Directorate General of Oil and Gas (MIGAS, abbreviated from Minyak dan Gas Bumi), and the Directorate General of Electric Power and New Energy.

The ministry controls and supervises the state energy and mining enterprises. These enterprises, and the respective energy and mining subsectors in which they are responsible for executing government policy, are as follows:

State Enterprise	Subsector
Pertamina	oil, gas, and geothermal energy
State Gas Corporation (Perusahaan Gas Negara, PGN)	utility gas
State Electric Power Corporation (Perusahaan umum Listrik Negara, PLN)	electricity
Perum Tambang Batubara (PTB)	coal
PT Tambang Timah	tin mining
PT Aneka Tambang	miscellaneous mining

Although these companies have direct access to the minister, in practice, they receive direction on technical matters from the respective directors general related to the subsector. The organizational structure of the ministry is outlined in Figure 4.1.

National Energy Coordinating Board (BAKOREN)

This institution, which was established in August 1980 by presidential decree, is in charge of (1) formulating the national energy policy, (2) providing the overall program direction for the development and utilization of national energy resources, and (3) coordinating the program's execution and policy development by the institutions in charge of implementing the overall program goals. The agency is chaired by the Minister of Mines and Energy. Other members include: the Minister of Public Works, Minister of Industry, Minister of Defense and Security, Minister of Communications, State Minister for Research and Technology, State Minister for Population and the Environment, State Minister for National Development and Planning, Head of the National Atomic Energy Agency, President Director of Pertamina, Director General of Oil and

Gas (who also serves as the first secretary to the agency), and the Director General of Electric Power and New Energy (who also serves as the second secretary).In carrying out its task, the agency receives support from the Energy Resource Technical Committee, consisting of members from all energy-related institutions, and a Permanent Team in Forecasting Energy and Petroleum Fuel Demand.

Electric Power Generation Development Team

Established in October 1987 by presidential decree, this team coordinates and supervises the implementation of electric power generation projects and issues guidelines regarding policies in the electricity sector. The team is chaired by the State Minister for Research and Technology, concurrently Chairman of the Agency for the Assessment and Application of Technology (BPPT). Members include the Minister of Mines and Energy, Minister of Finance, State Minister for National Development Planning, Minister/State Secretary, and the chairman of the Investment Coordinating Board.

Agency for the Assessment and Application of Technology (BPPT)

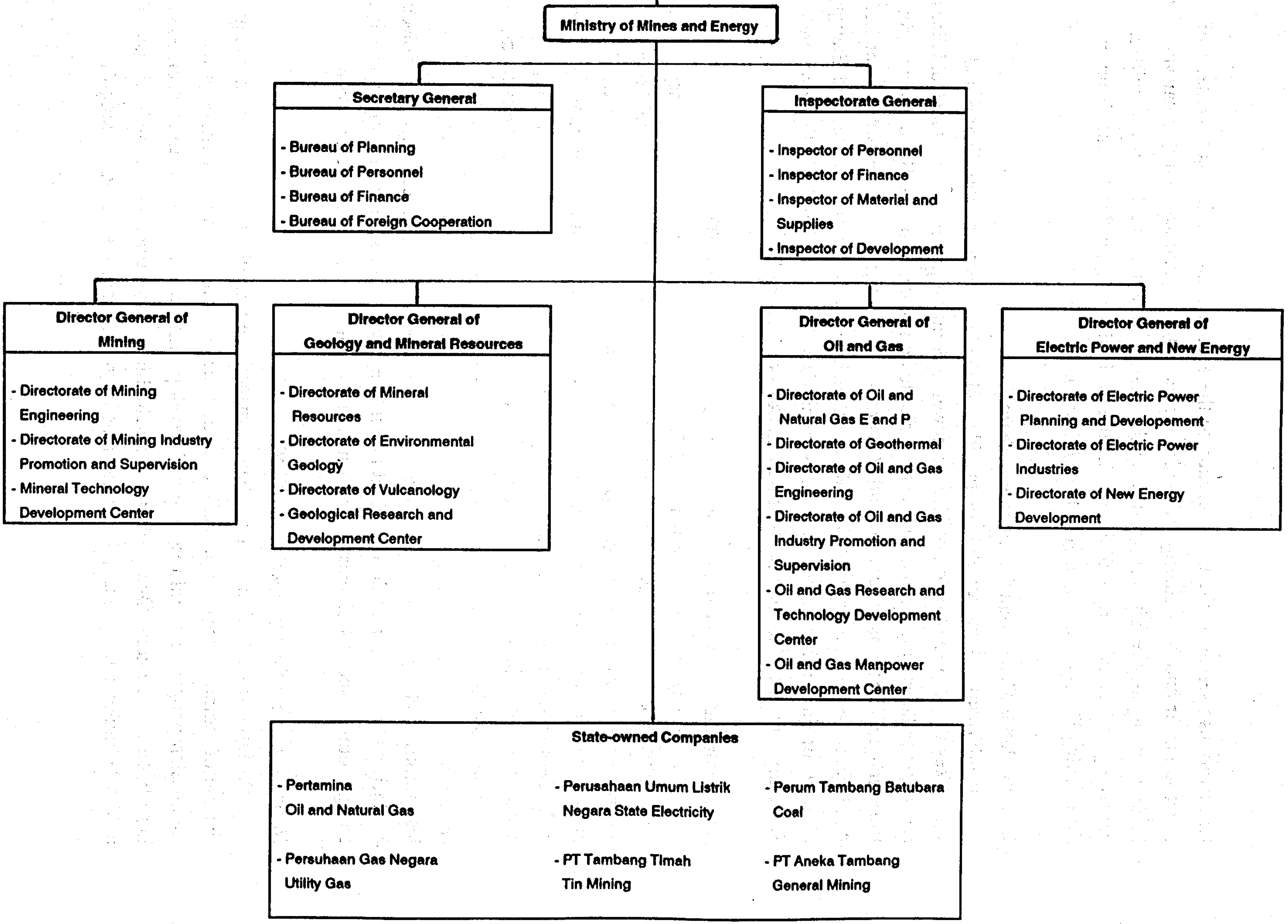
The Agency for the Assessment and Application of Technology is an agency responsible for planning development on a micro-economic level. It was established in August 1978 by the president and placed directly under the president's authority. This agency is concurrently chaired by the State Minister for Research and Technology. One of BPPT's many areas of responsibility is natural resources and energy, in which it assesses the development and utilization of energy—such activities as cost assessment, technology availability and adaptability, environmental impacts and other social considerations. In performing its task, the agency works closely with the related institutions in charge of specific energy sources. Currently, the agency is deeply involved in electricity research and development and in the new energy sources, mostly renewable energy sources such as biomass, solar, wind, and ocean thermal energy conversion.

National Atomic Energy Agency (BATAN)

BATAN was established in 1968 and assigned the task of studying and controlling the use of atomic energy for peaceful ends and the general health and welfare of the Indonesian people. Several research and development activities related to nuclear power have been undertaken. One project has resulted in the construction and maintenance of a 30-MW multipurpose research nuclear reactor in Serpong, West Java. Along with

Figure 4.1

Organization of the Ministry of Mines and Energy



BPPT and the Directorate General of Electric Power and New Energy, BATAN is responsible for conducting feasibility studies for nuclear facilities and also for developing technical expertise in nuclear technology.

MIGAS

The Directorate General of Oil and Natural Gas is in charge of regulating every facet of the oil and gas industry. It is usually known as MIGAS, from the abbreviation of its official Indonesian name, Minyak dan Gas Bumi. MIGAS advises Pertamina and, through Pertamina, indirectly oversees the production sharing contractors. It licenses service companies to do business in the petroleum sector, enforces safety and environmental regulations, and supervises training programs for Indonesian workers. It is also responsible for regulating geothermal energy. The organizational structure of MIGAS is included in Figure 4.1.

PERTAMINA

Overview and Activities

Pertamina, the state oil and gas company, is the focus of the Indonesian petroleum sector. According to the U.S. Embassy in Jakarta, Pertamina's gross profits for the 1988 fiscal year were rupiah (Rp.) 1.59 trillion (US$920 million), an increase of 14.2% from the previous year. Net profits for the same fiscal year were Rp. 747 billion (US$430 million), an increase over the previous fiscal year. At the end of 1989 *Petroleum Intelligence Weekly* ranked Pertamina thirteenth among the world's oil companies and sixth among those that are national oil companies, based on criteria that include oil and gas reserves, output, refining capacity, and product sales.

Pertamina was created in 1968 through the merger of two smaller national companies, Pertamin and Permina. National Law Number 8/1971 assigned responsibility to the company for all petroleum activities in Indonesia, including exploration, exploitation, refining and processing, transportation, and marketing. Pertamina is vested with responsibility to supply and serve the domestic demand for oil and natural gas. The law provides for cooperation between Pertamina and other parties in the form of production sharing contracts (PSCs), which enable foreign oil companies in Indonesia to operate under contract to Pertamina and enables Pertamina to retain management control over all contractors' activities. In addition, Pertamina is in charge of developing geothermal energy resources and operates the geothermal power plant in Java.

Pertamina has faced many challenges since its inception. In the early years of its existence, Pertamina had many responsibilities in addition to oil and gas. The government's intention at the time was to use Indonesia's oil revenues to hasten economic modernization and develop high-technology industries, but few institutions were capable of handling such a far-reaching and large-scale task. Pertamina was the most advanced in dealing with large-scale projects and was thus given the responsibility to develop projects outside the oil and gas business. Among the projects that it subsequently controlled were the PUSRI fertilizer plants in South Sumatera, the Krakatau Steel Plant in West Java, rice estates in Sumatera, and the industrial estates on Batam Island near Singapore (which were developed mainly as a logistical and operational base for oil- and gas-related business). Through the expansion of its scope of operations and control over these large enterprises, Pertamina came to dominate the Indonesian economy and to be regarded as the nation's main revenue generator.

Pertamina's vision was to ensure that the money used for the development of oil resources was spent mainly within Indonesia. Pertamina then launched an ambitious plan to become self-sufficient in oil-related services, such as exploration facilities, marine transport (tanker and nontanker) facilities, air transport services, refineries, and petrochemical plants. To finance such projects, Pertamina secured commercial loans without first conducting adequate feasibility studies, and these loans eventually became a heavy burden not only for Pertamina but for the government as a whole. Its borrowing practices and operational practices were criticized both domestically and abroad. Pertamina came to be regarded as virtually a state within a state, since many of the loans were committed without proper consultation with the government. Pertamina had difficulties in repaying the loans as a result of bad financial management and lack of consideration for the actual cash-flow projections. In 1975 it was officially announced that Pertamina had debts of US$3.1 billion in foreign loans and owed an additional US$113 million to domestic contractors. At the same time, Pertamina also owed unpaid taxes to the government. To be fair, it was not merely poor management that pushed Pertamina to the edge of bankruptcy; Pertamina had been saddled with more enterprises (some of them destined to be money-losers) and more diverse responsibilities than a corporation of its size could responsibly handle. Pertamina's management of its affairs was deplorable, but the government's management of Pertamina must share some of the blame.

In view of the difficulties faced by Pertamina, the government took control of Pertamina's financial management and prohibited further borrowing. Projects that were unrelated to oil and gas—the fertilizer plant, the steel plant, and the Batam island project among others—were transferred to other government institutions. Oil- and gas-related projects were reviewed and given priority ranking. The timing of some of them was slowed, and others were postponed or cancelled. Pertamina underwent a complete management reorganization, its operations were brought under control, and it subsequently became a healthy corporation.

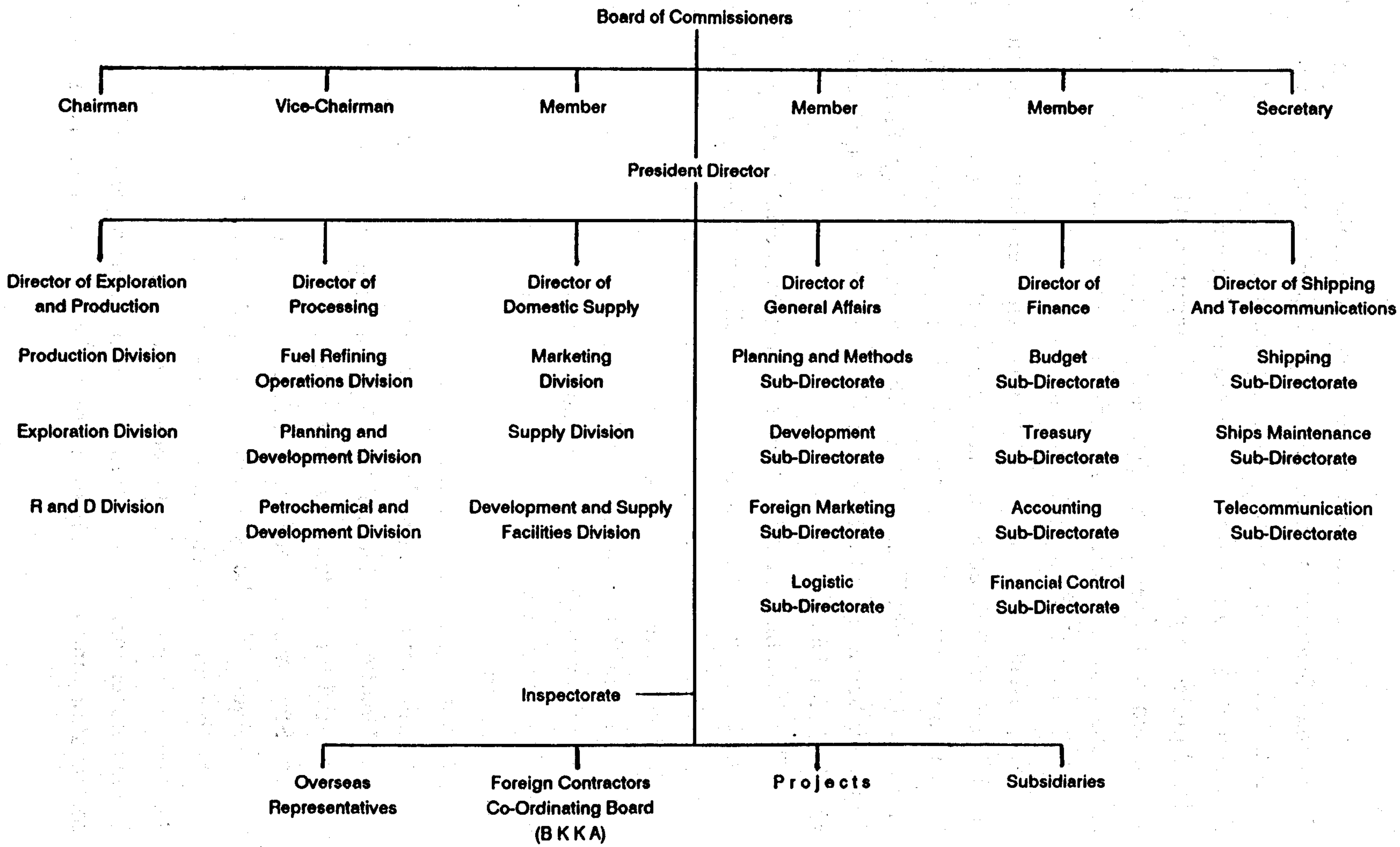
At present, aside from managing its own operations, Pertamina still has several subsidiaries or affiliated companies. Among them are contractors and consultants (PT Elnusa), hotel chains (Patra Jasa), nontanker marine transport (PT Patra Tongkang), insurance (PT Patra Tani, PT Tugu Mandiri, and PT Tugu Pratama), air services (PT Pelita Air Service), and others, including various types of agribusiness (PT Perta Insana and PT Patra Tani).

The Pertamina Board of Commissioners was established by National Law 8/1971 to represent the government in formulating policy guidelines, providing supervisory control over Pertamina's activities, and recommending to the government the necessary steps to be taken within the framework of improving the management of Pertamina, including the composition of Pertamina's Board Directors. Its supervision over management includes overseeing the budget, project execution, creation of subsidiaries and joint ventures, and major sales contracts. The board is responsible to the president of Indonesia and has the following members:

- Minister of Mines and Energy, Chairman and concurrently member
- Minister of Finance, Vice Chairman and concurrently member
- Head of the National Development Planning Agency (BAPPENAS), member
- Minister or State Secretary, member
- State Minister of Research and Technology, concurrently Chairman of the Agency for the Assessment and Application of Technology, member
- Executive Secretary to the Board, member

As shown in Figure 4.2, the President Director of Pertamina reports to the Board of Commissioners and has responsibility for overseas representatives, foreign contracts coordination, and subsidiary enterprises. Within Pertamina he is responsible for the

Figure 4.2
Organization of Pertamina



Source: Pertamina, Public Relations office.

following six directorates:

- The Exploration and Production Directorate is in charge of all activities within Pertamina related to exploration and production. It supervises the exploration and production activities that are carried out by contractors and is responsible for putting new areas out to bid for PSCs. On its own behalf, Pertamina is the operator of several fields throughout the country, which produced around 70 thousand b/d of oil and condensate in 1989
- The Processing Directorate is in charge of all refinery operations in Indonesia, including Pertamina's petrochemical operations. It is responsible for ensuring that the country has an adequate supply of the major petroleum products (based on requests by the Domestic Supply Directorate), through the output of the refineries and, if necessary, through product imports.
- The Domestic Supply Directorate is responsible for forecasts of product demand and coordinating delivery of needed products throughout the country through its domestic marketing division. Its product terminals are located across the archipelago, and it is in charge of expanding or upgrading existing facilities and building new facilities to meet demand.
- The Shipping and Telecommunications Directorate oversees both the domestic and foreign distribution of Pertamina's crude and petroleum products. It operates its own fleet and charters other vessels according to need. The vessels that it operates and charters are oil tankers and lighters—both used to transfer product to satisfy domestic requirements—and smaller inter-island boats for servicing offshore facilities and satisfying regional distribution requirements.
- The General Affairs Directorate is in charge of all administrative processes within Pertamina. Under this Directorate, the Foreign Marketing Sub-Directorate is in charge of all foreign sales of Pertamina's own crude production, of the government's share of crude produced under PSCs, and of liquefied natural gas.
- The Finance Directorate is in charge of all financial administration processes within the corporation.

In addition, there is an agency in Pertamina that coordinates the operating companies in Indonesia:

- The Foreign Contractors Coordinating Board represents Pertamina in PSC management control. It is the foreign oil companies' contact within Pertamina.

It reviews the budgets and annual work programs of PSCs and also reviews the contractor recommendations for awarding contracts on projects. It plays the determining role in establishing the commercial viability of any discovery and oversees all phases of contract activities. It was formerly known as BKKA (abbreviated from Badan Koordinasi Kontraktor Asing), but in 1990 its name was changed to Badan Pembinaan Pengusahaan Kontraktor Asing (BPPKA).

FOREIGN COMPANIES AND PRODUCTION SHARING CONTRACTS

Foreign oil companies have played a key role in the development of Indonesia's petroleum resources for more than a century. Prior to Indonesian independence, the terms of agreement offered by the Dutch colonial government gave the concession holders absolute rights to explore for and exploit oil and gas resources in their respective concession areas for specific periods of time. The colonial government in return received a royalty based on production. In the postwar period, during the first years of independence, the Indonesian government offered similar terms of agreement to the concessionaires.

The contract of work (COW) approach to foreign involvement was introduced in 1963. Three COWs were awarded to PT Caltex Pacific Indonesia and Calasiatic/Topco, PT Stanvac Indonesia, and PT Shell Indonesia. The terms of the COWs differed from earlier agreements by replacing fixed royalties with a system of profit sharing between the contractor and the government and transferring title to the oil from the contractor to the state.

The production sharing contract (PSC) approach was likewise introduced in the mid-1960s, and it has subsequently become the most common type of agreement for cooperation between Pertamina and investors in the upstream petroleum sector. The first PSC was signed in 1964 between Pertamina and Refican. By 1969, 30 PSCs were in force, and by 1982 the number had risen to 75. At the end of 1989, a total of 84 contracts were in force: 2 COWs, 2 technical assistance contracts, and 80 PSCs. Of the 84 contracts, 25 are producing. The major contract fields in operation are discussed in Part Five below.

The terms and conditions of cooperation are subject to government regulation, and Pertamina is required by law to seek terms that are most favorable for the state. The government approves such cooperation only after the Board of Commissioners has permitted Pertamina to enter into a cooperative agreement. Parliament is given notice of every PSC that has been approved by the president.

The PSC terms have undergone several modifications since they were first announced, mostly to adapt to changing situations such as world oil prices and related issues. The salient features of most recent terms, announced in February 1989, are as follows (U.S. Embassy, Jakarta 1990):

- Management responsibility rests with Pertamina.
- The contractor pays a bonus at the time the contract is signed. The bonus is not cost recoverable for a six- to ten-year period. The contractor may withdraw after completion of the minimum expenditure commitment to the first two to four years, depending on the specific contract, or after any succeeding year.
- Exploration expenses are recoverable only from commercial production. The contractor assumes all risks of exploration; that is, if there is no commercial discovery, the contractor cannot recover exploration costs.
- Although one international oil company may operate several separate blocks within Indonesia, costs incurred in one contract area are not chargeable to the operations of a different block.
- A bonus is paid by the contractor to Pertamina when production reaches a level specified in the contract.
- The contractor is reimbursed in crude oil for all allowable current costs of production and amortized exploration and capital expenditures. The oil allocated for this purpose is termed "cost oil," and the quantity is determined by dividing allowable costs during the production period by the export price. The remainder of the crude produced during the production period is termed "profit oil," which is divided between the government and the contractor. The government's share (after taxes) is usually 85% for oil and 70% for gas. The proportions specified in the contract vary, however, between 75:25 and 90:10, depending on the characteristics of the field and production volume.
- Production sharing contractors must supply to Pertamina from their share of profit oil approximately 8.5% of all production as a domestic market obligation. The producer is paid the export price for this oil during the first five years of production from a field, and after five years the contractor is paid 10% of the export price. (Previous to these last terms and conditions, the contractor was paid US$0.20/barrel).

- During the course of the exploration period, the contracted area is gradually reduced by specified percentages within fixed periods of time. If the remaining area is not declared commercial by the end of the exploration period, the entire contract area must be relinquished, unless an extension is granted.
- If the area is declared commercial, the contract usually runs for 30 years from the date it is signed. Under unusual circumstances, either the exploration phase of the contract or the total length of the contract can be extended by mutual agreement between Pertamina and the contractor.
- All production, including crude stored at export terminals, is the property of the government with Pertamina as its agent. Contractors do not receive title to their shares until the oil is lifted, and Pertamina controls the disposition of the crude. A contractor nominates a schedule of tanker liftings on a monthly basis to Pertamina. If Pertamina needs the contractor's crude oil entitlement for other purposes, the contractor's nomination may be deferred by mutual agreement. If, during the course of a year, a contractor cannot lift his share or if he lifts too much, a cash settlement must be made at the end of the calendar year. The price used for establishing a value for the overlifted or underlifted imbalance is calculated on an annual weighted average based on the export price.

Future of the Production Sharing Contracts

Indonesia was the pioneer of the PSC type of arrangement, and its success, and the improvement of its terms in dealing with foreign companies, has been a source of considerable pride for the government. Although Indonesia deserves admiration for its innovative work in this area of petroleum contracts, there are increasing signals that this form of arrangement, which served Indonesia so well in the past, may not be the optimal contract and taxation regime for the coming decades. Unfortunately, Indonesia's past success with PSCs, and an almost paternal affection for the very concept of the PSC, makes it difficult for the government and Pertamina to evaluate the potential of other forms of contracts.

Foreign companies have a number of complaints about the PSC system (which in itself, some argue, shows that the system must have some merit). Complaints include the way that export prices are determined, the domestic market obligation, and the fact that exploration losses cannot be spread between blocks. The issues of spreading exploration expenses between blocks may be important for full development of Indonesian oil;

Australia recently relaxed its rigid "ring-fencing" requirements, and the result was a major turnaround in the country's production outlook.

Whatever complaints the companies have (there is some validity to most of them) and from a national perspective as well, the PSC may be outdated. The PSC is a good system for developing large fields in highly prospected areas, and discourages or prohibits the development of marginal fields. As politically distasteful as it may seem, there are strong arguments for the use of a progressive taxation system, such as the resource rent tax system used in Australia and Papua New Guinea. The latter would ensure that the Indonesian government extracted high taxes from the most profitable deposits, while also allowing deposits that are uneconomic under PSC terms to come into production. The large fields in Indonesia may already have been found. So the future level of production may depend on new approaches to attract foreign participation in exploration and development.

STATE GAS COMPANY (PGN)

Utility (or city) gas has been available in Indonesia since 1859. At that time, a Dutch private company was granted sole operating rights for city gas in Jakarta (then called Batavia). The company extended its operation to cover other cities. Surabaya's branch was opened in 1879, Semarang in 1898, Bogor in 1901, Medan in 1919, Bandung in 1921, Cirebon in 1925, and Ujung Pandang (then called Makasar) in 1937. In 1958 the government nationalized the company and made it part of and under the responsibility of the state electricity company. In 1965 the gas operations were removed from the latter's control and established as a separate, state-owned company. At that time it became known as Perusahaan Gas Negara (PGN), or State Gas Company. PGN is headed by a president director, who is assisted by three directors.

From the outset in 1859, city gas was manufactured from coal. In 1956 some of the gas was manufactured from oil—kerosene was actually used for this purpose. In 1976, however, use of manufactured gas from coal was eliminated. Natural gas began to come into play and was used in the first time in Cirebon in 1974, supplied by Pertamina from the Cilamaya gas field. Jakarta, Bogor, Medan, and Surabaya followed in the use of natural gas in 1979, 1980, 1986, and 1987, respectively.

In 1990 PGN decided to close its branches in Bandung, Semarang, and Ujung Pandang. These were the cities that still used gas manufactured from oil. PGN had experienced losses in these cities due to high operating costs, and there were inadequate customers, particularly industrial users, to justify the operations. After these closures, only five cities are still served by PGN. The remaining cities have an advantage in that their locations are relatively close to natural gas fields, and they also have potential demand which can justify the economics of a city gas operation.

COAL SECTOR

Directorate General of Mining and the Directorate of Coal

Coal is one of the important natural resources reserved under the constitution for state management, to ensure maximum financial benefits for the nation. All aspects of the coal industry are therefore coordinated by the government. Within the Ministry of Mines and Energy, the Directorate General of Mining has responsibility for promoting and supervising the mining industry. Coal is included in its mandate, although oil and natural gas are not. The organizational structures of the Directorate General and its Directorate of Coal are shown in Figure 4.1. The Directorate of Coal is responsible for all coal-related affairs in Indonesia, including the formulation of policies, planning, coordination, establishing necessary regulations, and granting coal mining concessions. All formal decisions are announced in the name of the director general. The directorate has three subdirectorates with responsibilities respectively for (1) promoting mining enterprises, (2) coal development, and (3) coal distribution and environment.

Coal Operating Companies

Indonesia has a single state-owned coal mining company: Perum Tambang Batubara (PTB). Although the company reports directly to the Minister of Mines and Energy, it also consults the Director General of General Mining and the Director of Coal on policy and technical matters.

PTB was established in 1968. It is responsible for general surveys, exploration, exploitation, purchase, processing, transportation, and sale of coal throughout Indonesia. With regard to coal production, PTB operates an underground mine in Ombilin, West Sumatera, and recently assumed operation of the Bukit Asam coal mine, formerly operated by PT Tambang Batubara Bukit Asam (PTBA). PTB also serves as the coordinator for all coal concessions operated under production sharing contracts. In this respect, the role of PTB in the coal sector is similar to that of Pertamina in the oil and gas sector. The terms and conditions of agreement for coal concession contracts are formulated and negotiated by PTB, although the contracts are formally approved and signed by the Director General of Mining on the recommendation of PTB and the Directorate of Coal.

PTBA was established in 1980 as a separate state-owned company for the exploration and production of coal in the Bukit Asam area, South Sumatera. Its mandate included the implementation and operation of the Bukit Asam integrated project, which was created to supply the Suralaya power plant in West Java. This coal-fired plant was built to use coal of Bukit Asam quality, and the integrated coal mining and transportation development project was financed in part by more than US$1 billion in funding from the World Bank. The project was originally envisaged as a component of the government's energy diversification policy, based on long-term assumptions about petroleum prices and the increasing export value of Indonesia's oil. Although such forecasts were proven wrong during the 1980s, the project has been implemented nonetheless. In 1990 PTBA was absorbed into PTB, leaving PTB as the sole state-owned operating company.

Coal is mined also by domestic and foreign private companies. A number of concession areas in West Sumatera, South Sumatera, South Kalimantan, and East Kalimantan have been granted to production sharing contractors. Several private companies and some cooperative companies operate mining areas in the southern part of Sumatera and West Java, but to date production has been very small.

Coal Production Sharing Contracts

After production sharing contracts proved successful in the oil and gas sector, a comparable system was created by the Ministry of Mines and Energy to enable foreign companies to explore for and produce coal. East Kalimantan was designated as the area to be developed initially under such arrangements, since the mining areas in Sumatera were already operated by the two state-owned coal companies and domestically owned private companies. The rights and obligations of contractors can be summarized as follows (Asian Development Bank 1985):

Contractor's Obligations

- An Indonesian-based limited company (PT) must be formed by the contractor.
- The initial area contracted at the time the agreement is signed will be reduced in size to 60% at the end of the general survey and to 40% at the end of a three-year exploration period.

- The contractor will expend a minimum of US$120 per square kilometer during the general survey period and a minimum of US$500 per square kilometer during the exploration period.
- Once production begins, the contractor submits 13.5% of the annual production to PTB.
- The contractor also pays corporation tax on the taxable income at a rate of 35% for the first 10 years of operation and 45% from the eleventh year onward.
- Regional taxes are to be paid in an agreed lump sum, as specified in individual contracts.
- A dead-rent payment is made to PTB, proportional to the size of the contracted working area.
- After ten years of operation, 51% of shares in the company must be offered for sale to Indonesian citizens, enterprises, or institutions.
- If a requirement for large quantities of coal develops in Indonesia, the contractor will sell all or part of its coal to PTB. The selling price for deliveries in this case will be equal to current average prices in the southwest Pacific region, including Australia.

Contractor's Rights and Responsibility

- The contractor is given sole rights to mine the area, subject to environmental and other regulations, for a period of thirty years, starting at the time of initial production.
- The contractor is exempted from exploration and production royalties and from import and export tax duties.
- Losses incurred during the first five years of operation may be carried over into the following years.
- The contractor may apply accelerated depreciation on invested capital.
- An investment allowance amounting to 20% of the total investment is apportioned over a period of four operating years.
- The contractor is allowed to transfer the following funds in any currency without limitations: (1) net operation profits in proportion to the shareholdings held by foreigners; (2) foreign loans and interest incurred on those loans; (3) funds generated through depreciation of imported capital assets; (4) proceeds from

sales of shares by foreign shareholders to Indonesian nationals; and (5) any compensation received in the event of nationalization of the coal industry.

- Contractors are allowed to export their production, to their own countries or elsewhere, provided due consideration is given to Indonesia's needs for coal in any year.

ELECTRICITY SECTOR

The Ministry of Mines and Energy has overall responsible for electricity in Indonesia, and the ministry's Directorate General of Electric Power and New Energy formulates government policy in the electric power sector. The organizational structure of the Directorate General is shown in Figure 4.1.

The State Electric Power Corporation was established in 1961. It is commonly known by the acronym for its official Indonesian name, Perusahaan umum Listrik Negara (PLN). The work of PLN is coordinated by the Ministry of Mines and Energy. The corporation is headed by a president-director, who is appointed by the president of the country and is accountable to the Minister of Mines and Energy. PLN is responsible for the planning and implementation of electric power generation, transmission, distribution and sales of electricity.

STATE-OWNED ENERGY COMPANIES

Table 4.1 provides a listing of Indonesia's state-owned energy companies in terms of total revenues, operating costs, profits, amount of taxes paid, and assets in 1988 and 1989. Details are given for five companies, although the merging of PTBA into PTB in 1990 now leaves only four state-owned energy companies. The sheer size of Pertamina relative to the other companies, particularly PGN and PTB, stands out clearly. In 1989 Pertamina's revenues of around US$6.5 billion were over 145 times as large as PGN's revenues, while Pertamina's profits of US$276.5 million were 92 times as large. As the state electric utility, PLN's assets are assessed at a high value—given that their operations and facilities extend across the most far-reaching area—but PLN's profits are subject to significant fluctuations; note the major disparity between profits recorded in 1988 and 1989. It may even be that PLN will post a net loss in 1991 if the current tariff is not increased. The current tariff structure is presented in Table 8.7.

The four state-owned companies in the energy sector dominate the energy business in Indonesia. Their role is crucial not merely in economic terms but also in a political

Table 4.1
Performance Comparison among State-owned Companies in the Energy Sector, 1988-89
(US$ millions)[a]

	Revenues		Operating Costs		Profits		Tax Paid		Assets	
Company	1988	1989	1988	1989	1988	1989	1988	1989	1988	1989
Pertamina	5,910.652	6,516.343	5,130.556	5,825.485	374.685	276.454	405.412	414.404	7,641.815	7,922.992
PLN	1,093.307	1,491.134	1,088.637	1,235.732	4.670	255.402	70.774	23.904	6,340.359	7,812.742
PTBA[b]	69.395	132.551	83.246	127.565	3.420	4.986	6.482	10.077	606.843	646.126
PGN	26.504	44.768	25.018	41.756	1.485	3.012	0.236	0.710	70.384	89.341
PTB	19.853	13.088	18.101	12.581	1.751	0.168	0.000	0.339	55.119	54.071

Notes: a. The original ministry data are in rupiah. Data above have been calculated based on rupiah/US$ exchange rates of 1,737 for 1988 and 1,805 for 1989.
b. In 1990 PTBA was merged into PTB.

Source: *Pertambangan dan Energi*, No. 4, 1989.

sense. These companies are the government's arm for its involvement in the energy sector. As stated in the constitution regarding exploitation of natural resources, Indonesia's resources are a primary constituent of the national wealth, and they are under the jurisdiction of the state. They should be developed and utilized to maximize benefits and promote the greater welfare of all Indonesian citizens. Some degree of privatization and linking of the domestic energy market with international energy markets is seen as desirable, and private participation has been encouraged insofar as it promotes the best development of the resource. For example, the build-operate-transfer system pertaining to electric power capacity (discussed in Part Eight) is one means by which the government has encouraged the private sector to take some of the burden for supplying the country's burgeoning demand for electricity. Additionally, the government is now allowing private companies to purchase motor gasoline, reblend standard grades up to premium grades (using MTBE, a high-octane oxygenate that simultaneously reduces the need for gasoline leading), and resell the product at competitive market prices. In general, when private sector involvement can improve efficiency, the government has increasingly encouraged its expansion. This policy extends only to a certain point, however. Given the long-standing importance of energy resources as strategic commodities, the government will always be the key player in the Indonesian energy market.

Five

OIL INDUSTRY

OPEC MEMBERSHIP

Indonesia joined the Organization of Petroleum Exporting Countries (OPEC) in 1962 and is the only member nation in the entire Asia-Pacific region. The country has recently played a major role in OPEC, especially as a mediator in disputes among members, usually concerning the allocation of production quotas. Other member countries regard Indonesia as neutral in such disputes, and the election in 1988 of Dr. Subroto (a former Indonesian Minister of Mines and Energy) as Secretary General of OPEC was supported by all members, since candidates from other member countries were considered "not neutral." During the 1980s, it became commonplace for certain OPEC members to produce above their official quotas, and the lack of OPEC unity severely eroded its ability to control market prices. Since Indonesia never exceeded its quota, it avoided many of the disputes that arose between other members.

Indonesia's production is neither large nor small relative to other OPEC producers, although its reserves are small in comparison to those of the Persian Gulf countries. As of November 1989 Indonesia's OPEC production quota was 1.307 million b/d. When the production ceiling was raised at the December 1989 OPEC ministers' meeting, Indonesia's quota increased slightly, but its share of the total quota fell from 6.7% to 6.22%.

The Indonesian government's decision not to exercise its right to maintain parity based on its recent share was apparently an effort by Indonesia to resolve a dispute among the Gulf countries over quota shares. At the meeting, Kuwait argued that its percentage share of the total quota should be increased because of its production capacity. The decrease in Indonesia's percentage share enabled OPEC to increase the Kuwaiti share from 5.6% to 6.8% of total OPEC production for the first half of 1990, thereby resolving the dispute.

Indonesia's OPEC quotas since 1986 are shown in Table 5.1. At the December 1989 OPEC ministers' meeting, the OPEC production ceiling was raised from 20.501 million b/d in the fourth quarter of 1989 to 22.086 million b/d for the first half of 1990.

Table 5.1

OPEC Quotas for Indonesia, 1986-90

Year	Quota for First Half (million b/d)	Quota for First Half (% share of total OPEC)	Quota for Second Half (million b/d)	Quota for Second Half (% share of total OPEC)
1986			1.193	7.09
1987	1.133	7.17	1.190	7.17
1988	1.190	7.17	1.240	6.70
1989	1.240	6.70	1.307	6.70
1990	1.374	6.22	—[a]	—[a]

Notes: a. Quotas were suspended following the Iraqi invasion of Kuwait in August 1990, and were raised to 1.44 million b/d for the second quarter of 1991. Quotas will be reviewed at the June 1991 OPEC meeting.

Sources: *Oil and Gas Journal* and *Weekly Petroleum Argus: Oil Price Reporting and Analysis*, various issues, 1989-90.

Indonesia was allocated 1.374 million b/d of the newly established quota, representing a 6.22% share of total OPEC production for the first half of 1990. Production quotas were suspended during the second half of the year as members scrambled to make up for supplies lost after the Iraqi invasion of Kuwait. The bulk of the shortfall was made up for by large production increases in Saudi Arabia, Venezuela, Libya, Nigeria, and Iran. Indonesia managed to expand production only modestly, and even this increase was primarily a function of ongoing development activities. Indonesia is not a country where nominal production capacity is [illegible] above actual production, and hence it does not have the capability to massively boos[illegible] roduction to take advantage of short-term oil price increases. Additionally, there are many voices within Indonesia that oppose excessive production levels, preferring instead a conservative approach that avoids the possibility of over-rapid resource depletion.

EXPLORATION ACTIVITIES

Exploration activities have varied widely each year since the first production sharing contracts (PSCs) were signed in 1964. Table 5.2 shows exploration expenditures, seismic activities, total exploration wells drilled, total drilling depth, and average Indonesian crude oil export price from 1967 to 1989. The strong correlation between exploration expenditure and oil price is shown in Figure 5.1. The correlation between number of wells drilled and oil price is shown in Figure 5.2. The relationship, though clear, is not quite as distinct as seen in the previous figure, the reason being that in the early 1970s, per-well drilling costs were lower.

The rapid increase in contractors, which numbered 52 by 1973, is reflected in the exceptionally high level of seismic work during the years 1968-74 (Table 5.2). On the eve of the first oil crisis in 1973, exploration costs were still relatively low. The subsequent rapid increase in costs was caused by the oil boom, particularly because of the scarcity of equipment and services that resulted from the big increases in oil prices. The long decline in exploration expenditures after 1982 reflects the decreasing seismic activity in Indonesia during this period. This trend was then worsened by the sharp decline in the oil price in 1986; operators' margins were reduced, which in turn discouraged them from making further investments in search of new fields. The lowest point was reached in 1987, when exploration expenditures in current dollar terms were less than the 1980 level and fewer exploration wells were drilled than at any time since the 1960s.

This pattern illustrates how volatile the oil business is to changes in oil prices. In fact, during the fourth five-year plan, 1984-89, seismic activity was far below Pertamina's projections (Figure 5.3). Because of these conditions in the industry, the government has recently introduced several strategies—such as tax incentives and PSC terms and conditions that are more favorable to the contractor—to encourage more investment in oil exploration. Following the upturn of oil prices in 1987 and subsequent price stabilization, exploration expenditures increased in 1988 and 1989, and although 1990 data are not yet published, expenditures appear to have increased once again.

Table 5.2
Petroleum Exploration Activities and Average Oil Export Prices, 1967-89

Year	Expenditure (US$ millions)	Seismic Activity (thousand km)	Number of Wells Drilled	Drilling Depth (thousand feet)	Export Price (US$/b)
1967	6	8,060	17	26	1.59
1968	16	39,899	37	175	1.61
1969	27	121,543	46	244	1.61
1970	66	80,853	94	604	1.64
1971	123	81,551	155	871	2.16
1972	152	63,626	154	952	2.82
1973	210	67,520	192	1,230	4.00
1974	349	59,802	212	1,365	11.89
1975	458	41,179	183	1,084	12.57
1976	315	22,510	141	755	12.67
1977	273	14,360	122	735	13.51
1978	346	16,659	140	752	13.53
1979	477	32,441	152	1,121	18.76
1980	909	49,977	185	1,033	31.79
1981	1,456	64,077	244	1,577	35.51
1982	1,723	57,430	238	1,721	35.24
1983	1,481	65,260	264	1,638	30.08
1984	1,286	28,750	218	1,418	29.31
1985	1,177	34,030	217	1,115	27.72
1986	966	29,276	157	790	13.80
1987	583	27,730	82	592	17.30
1988	728	32,713	135	910	15.50
1989	831	47,913	108	627	17.50

Note: Prices are average Indonesian oil export prices, calculated by dividing total export revenue by total export volume.

Source: MIGAS data, cited in U.S. Embassy, Jakarta 1990.

Figure 5.1
Oil Exploration Expenditures versus Oil Price, 1967-89

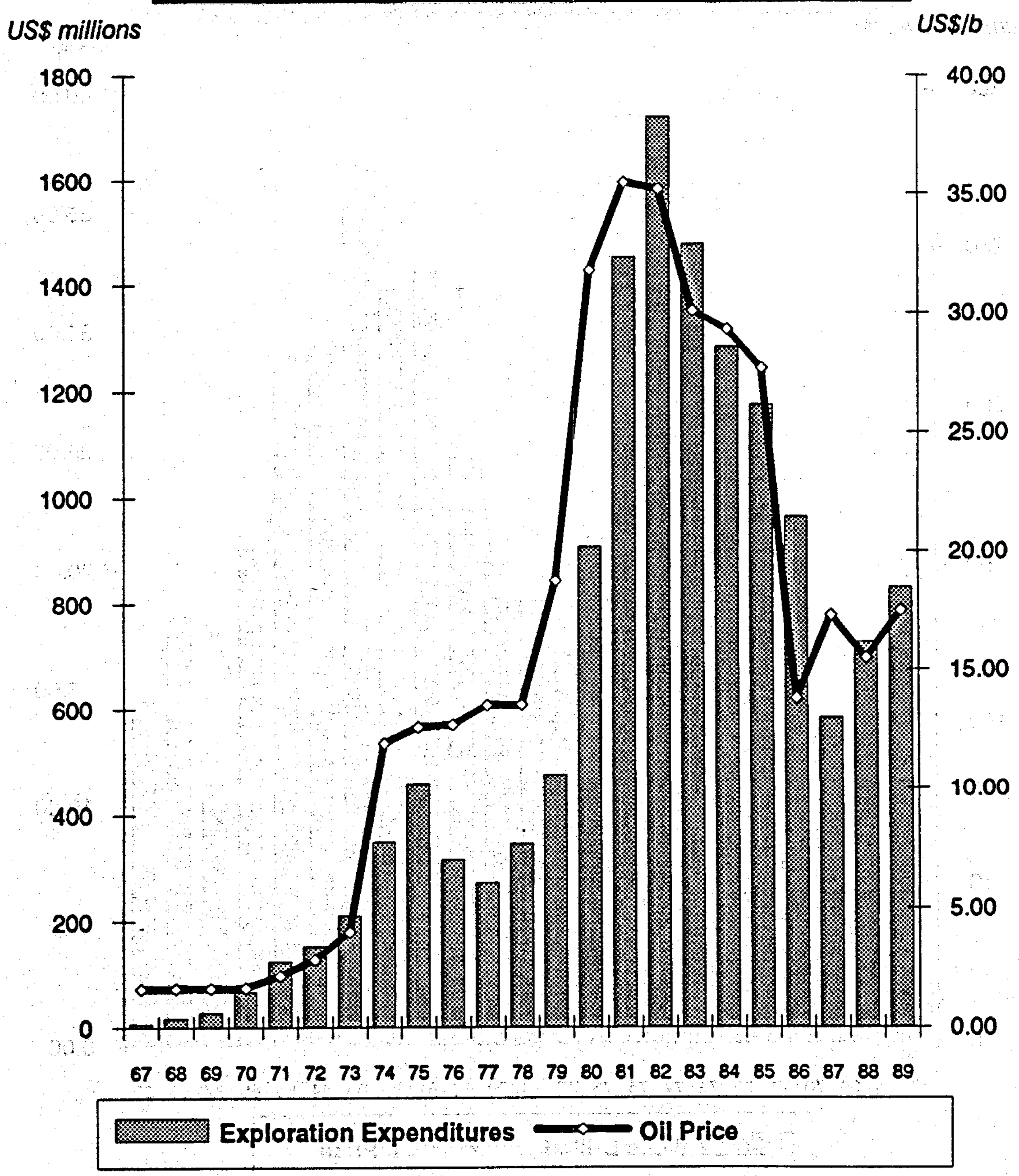


Figure 5.2
Oil Price versus Exploratory Drilling, 1967-89

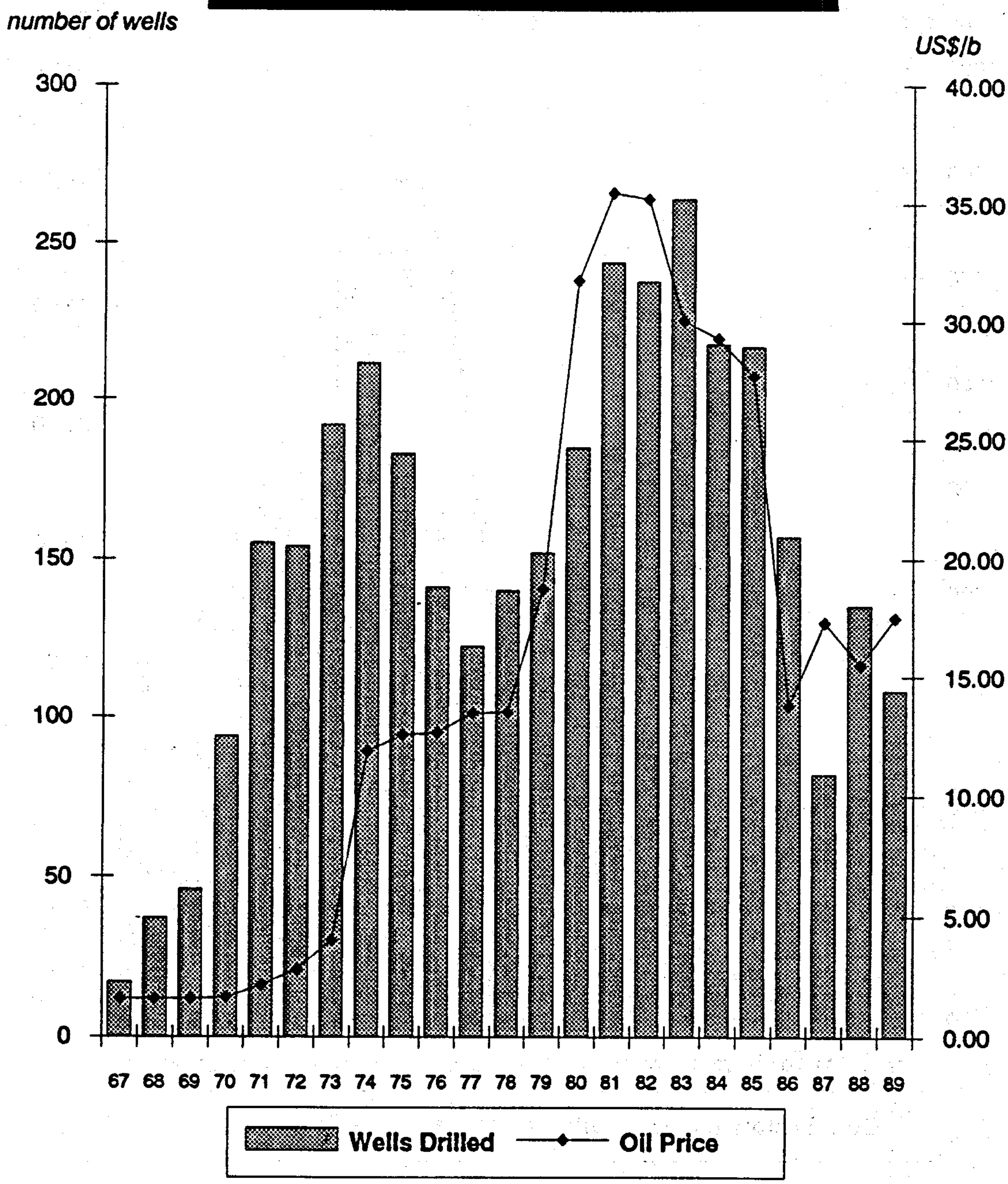
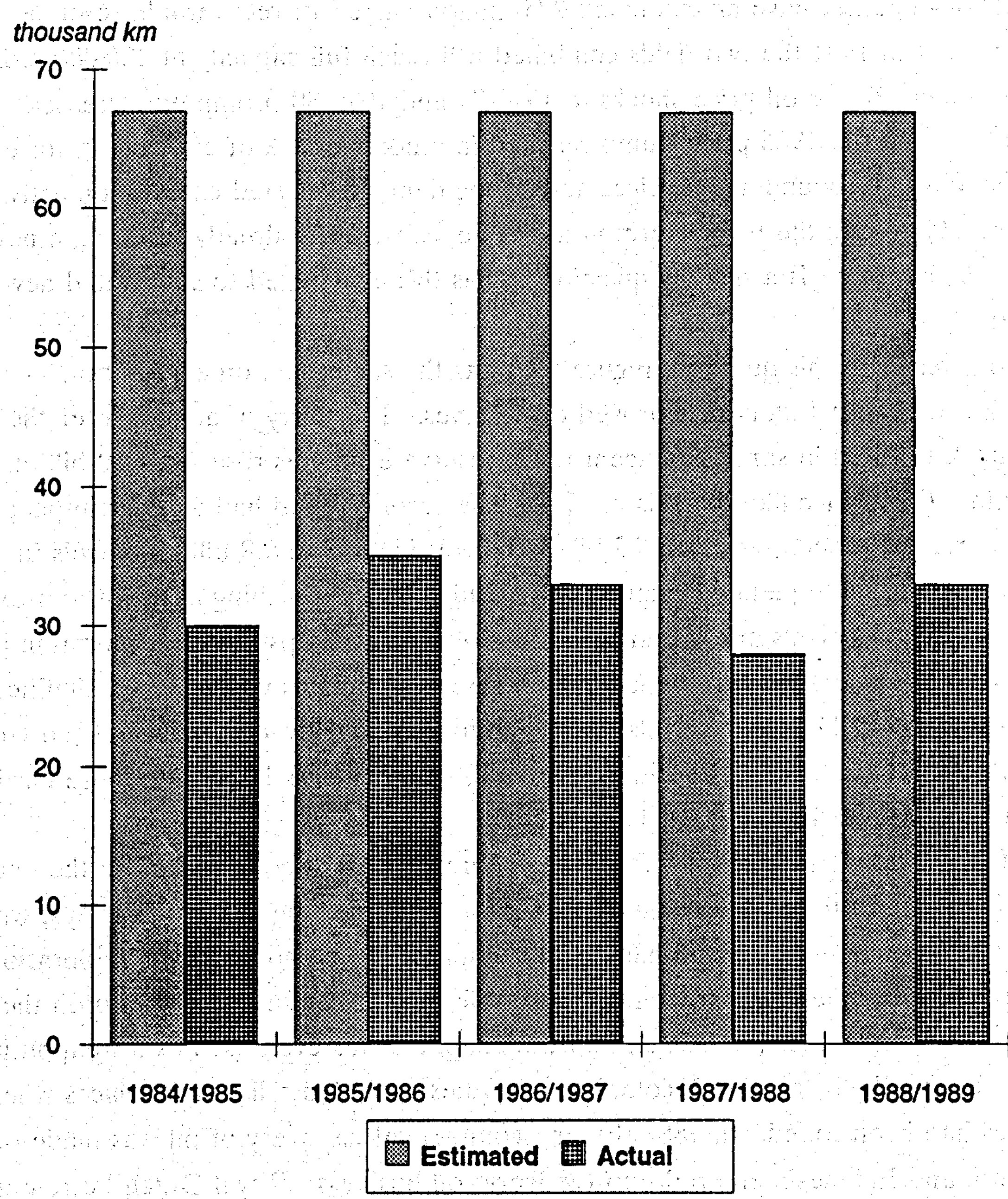


Figure 5.3
Estimated versus Actual Seismic Activities, 1984-88



Exploratory drilling results are summarized in Table 5.3. Of the 72 wildcat wells drilled in 1989, oil and gas shows were reported at 25, a success ratio of 35%. From a commercial standpoint, the most significant recent discoveries are in an offshore area southeast of Sumatera, operated by Maxus Indonesia (formerly known as IIAPCO). Two large oil fields in this area—Intan, discovered in late 1987, and Widuri, discovered in early 1988—together have an estimated 275 million barrels of recoverable reserves. It is expected that in 1991 the two fields combined will reach full capacity at 220,000 b/d.

As expected, the oil price shocks in 1973-74 and 1979-80 prompted increased exploration, and the 1986 price slump resulted in a notable lack of enthusiasm for exploration in 1987. Rebounding oil prices and strong demand boosted exploration activity in 1988 and 1989—and the recent turmoil in the Persian Gulf is already fostering a new wave of exploration. But the key question is: has this activity led to substantial new discoveries?

To investigate this question, Figure 5.4 plots the same data on exploration expenditures against Indonesia's proved oil reserves. The flurry of activity after the first price shock resulted in some significant finds; reserve estimates rose from 10 billion barrels in 1973 to 11 billion barrels in 1974. The second round had a lesser impact in which oil reserves increased from 9.5 billion barrels in 1980 to 9.8 billion barrels in 1981. Proven reserves subsequently began a fairly steady decline, reaching a low of approximately 8.2 billion barrels at the end of 1989. Following the upswing in exploration and the stronger oil prices seen in the late 1980s, reserve estimates were given a significant boost—back up to 11 billion barrels, according to the "Worldwide Survey" of the *Oil and Gas Journal* in December 1990. Still, in general, the prognosis is that the more easily identifiable oil fields have already been found.

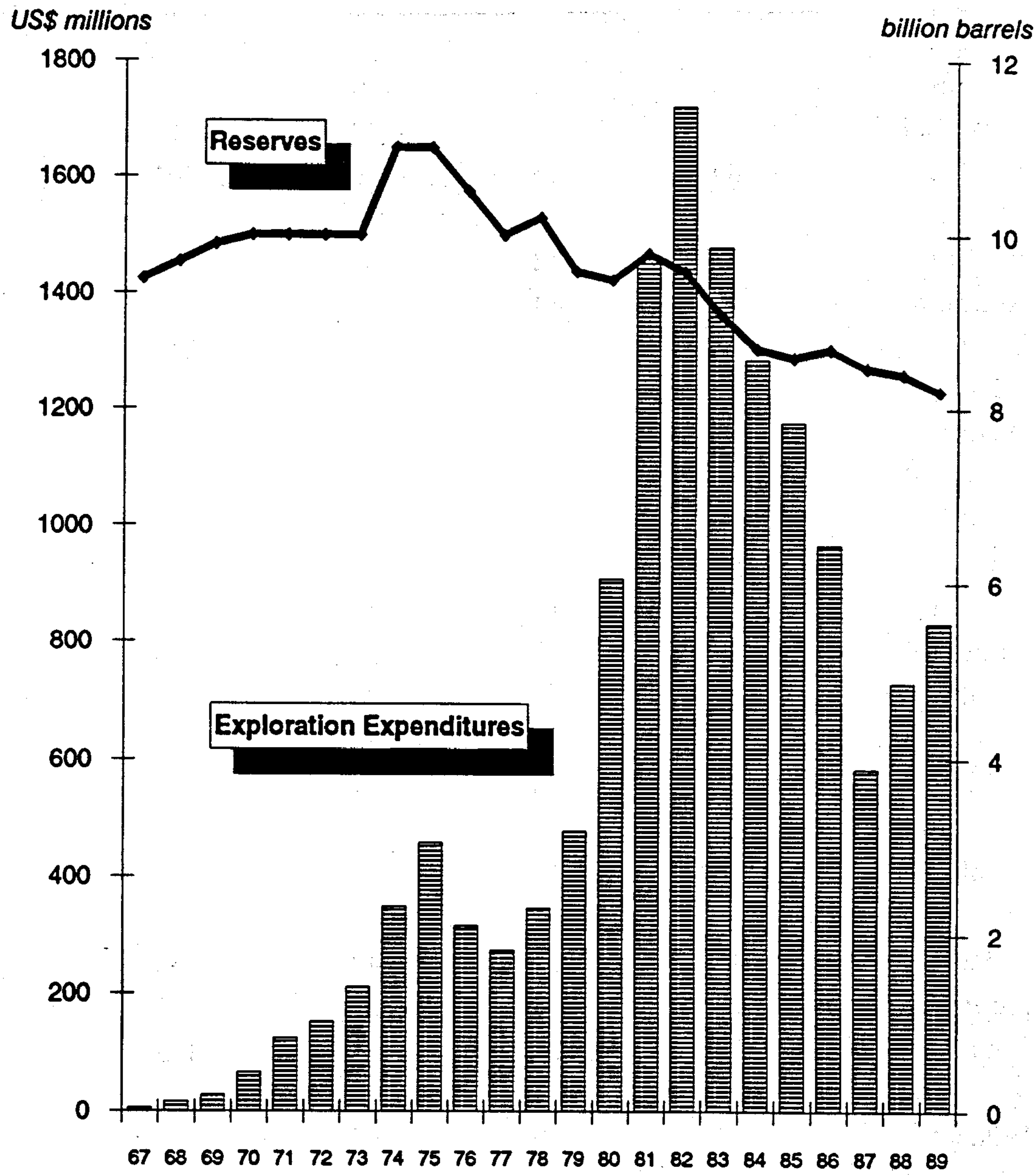
Most of Indonesia's significant oil fields were, in fact, discovered before the end of World War II, and the only onshore greenfield areas remaining are in Irian Jaya, where the remote, mountainous terrain has a major impact on the economics of exploration and development. Indonesia has a long history of oil use; for centuries, oil found on the surface was used to coat torches, and burning naphtha was even used as a weapon in sea battles. In the 1860s the Dutch colonial authorities compiled a list of 52 places where oil seepages had been found. In 1885 the first commercial discovery of oil was made on Sumatera, and Indonesia entered into the world oil business. Royal Dutch Petroleum Company was formed in 1890 to continue developments on Sumatera, and in 1907 it merged with Britain's Shell Transport and Trading Company to form Royal Dutch Shell.

Table 5.3
Exploratory Drilling Results, 1983-89

Year and Type	Number of Exploratory Wells Drilled: Oil	Gas	Dry	Total	Success Ratio (%)
1983					
Wildcat	26	13	100	139	26
Appraisal	63	13	49	125	61
Total	89	26	149	264	44
1984					
Wildcat	25	12	67	104	36
Appraisal	68	14	32	114	72
Total	93	26	99	218	55
1985					
Wildcat	27	8	77	112	31
Appraisal	49	18	38	105	64
Total	76	26	115	217	47
1986					
Wildcat	18	12	47	77	45
Appraisal	49	8	33	90	65
Total	67	20	80	167	55
1987					
Wildcat	15	8	24	47	49
Appraisal	13	3	19	35	46
Total	28	11	43	82	48
1988					
Wildcat	15	19	49	83	41
Appraisal	24	6	22	52	58
Total	39	25	71	135	47
1989					
Wildcat	16	9	47	72	35
Appraisal	17	5	14	36	61
Total	33	14	61	108	47

Source: MIGAS data, cited in U.S. Embassy, Jakarta 1990.

Figure 5.4
Oil Reserves and Exploration Expenditures, 1967-89



Over 40 foreign firms have participated in the Indonesian oil industry. Currently, 18 international oil companies are producing oil under PSCs, and two firms are operating under COWs.

OIL PRODUCTION

The locations of major oil fields currently producing in Indonesia are shown in Figure 5.5, which also maps the locations of major gas fields, LNG plants, and refineries. Because of the vast size and complexity of the sea area included in the country's economic territory, it is impossible to illustrate all the offshore concession areas on a small-scale map. For technical specialists requiring such detailed information, large-scale maps of concession areas throughout the archipelago have been published by Petroleum News in Singapore, and general maps may be found in the annual *International Petroleum Encyclopedia*.

In 1989 crude production averaged 1,231 thousand barrels per day (mb/d), and condensate production averaged 178 mb/d, for a total of 1,409 mb/d. This figure was an increase over 1987 and 1988 levels, but was substantially less than the 1.6 million b/d produced in 1980 and the all-time high of 1.7 million b/d produced in 1979. Condensate production is dominated by Mobil's Arun field in Aceh, where condensate production averaged 120 mb/d in 1989. The long-term trend in crude and condensate production and exports during the 1970s and 1980s is shown in Table 5.4 and Figure 5.6. Total production expanded rapidly during the 1970s, peaking at 1,685 mb/d in 1977. During the 1970-79 period, production grew at average annual rates of 6.4%, and exports kept pace at 6% per annum. During the 1980s, however, production declined at -1.1% per annum, and exports fell by an even more rapid -3.3% annually, as more crude was devoted to domestic refining.

The total crude and condensate produced by each operating company is shown in Table 5.5 for the years 1974, 1980, and 1989. During that period, Caltex's share fell from nearly two-thirds of total production in 1974 to around 46% in 1989. Caltex remains the dominant producer, followed by ARCO (8.9%), Mobil (8.8%), Total (6.3%), and Maxus and Unocal (around 5% each). Sumateran light crude (SLC, from the Minas field) accounted for around 500 mb/d of Caltex's total 642 mb/d production in 1989, and the Duri field accounted for the remainder.

An increasing amount of Indonesia's oil is produced via the enhanced oil recovery (EOR) technique known as steamflooding. Incremental production from steamflooding

Figure 5.5
Refineries, LNG Plants, and Major Oil and Gas Fields

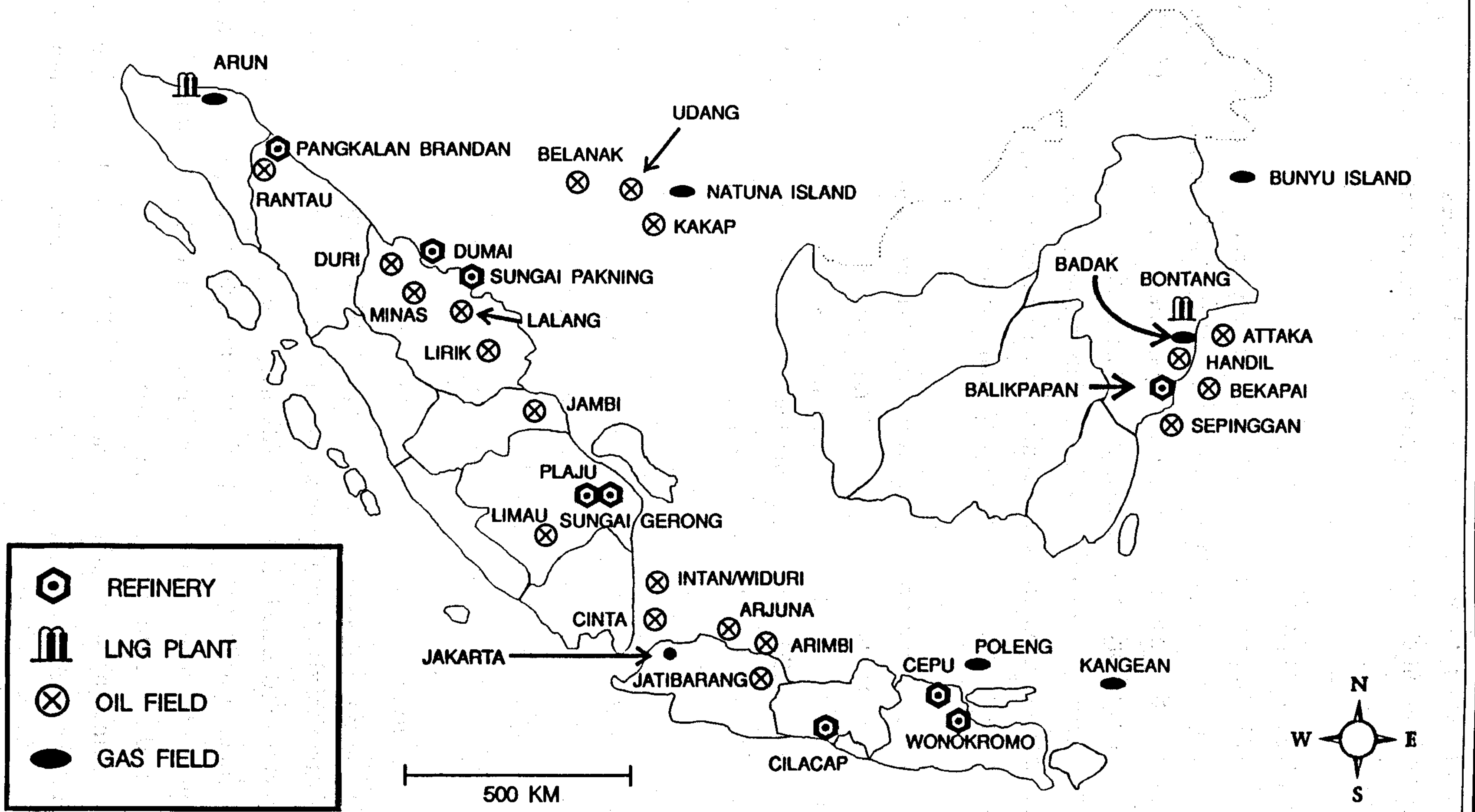


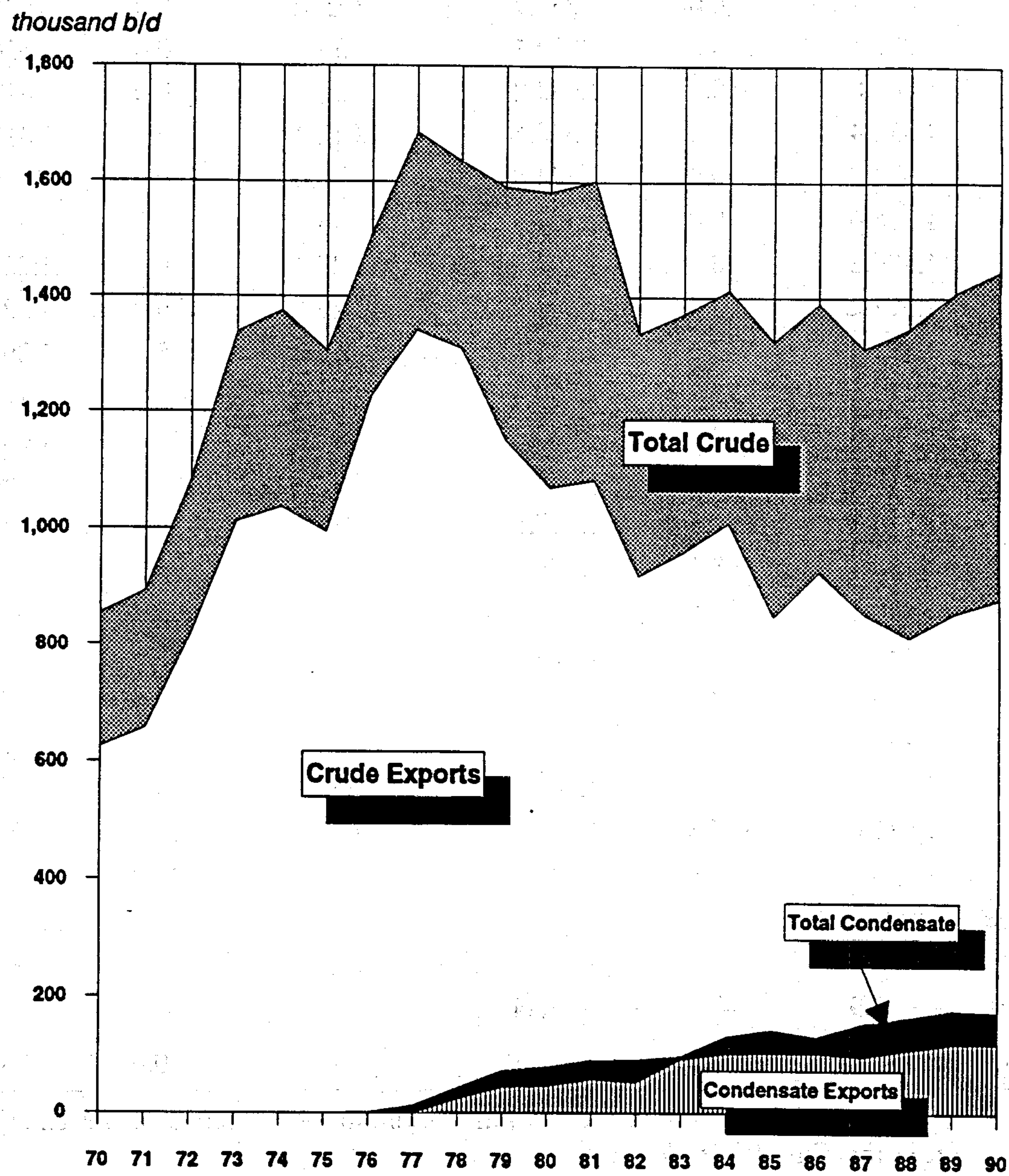
Table 5.4
Production and Export of Crude and Condensate, 1970-90
(thousand b/d)

	Production			Export		
Year	Crude	Conden-sate	Total	Crude	Conden-sate	Total
1970	853.7	0.0	853.7	625.4	0.0	625.4
1971	892.1	0.0	892.1	656.4	0.0	656.4
1972	1,083.8	0.0	1,083.8	817.2	0.0	817.2
1973	1,338.4	0.0	1,338.6	1,012.4	0.0	1,012.4
1974	1,374.8	0.0	1,374.8	1,036.6	0.0	1,036.6
1975	1,306.6	0.0	1,306.6	994.7	0.0	994.7
1976	1,506.8	0.8	1,507.7	1,227.4	0.0	1,227.4
1977	1,671.2	13.4	1,684.7	1,329.6	0.0	1,329.6
1978	1,591.5	43.6	1,635.1	1,268.2	25.1	1,293.3
1979	1,517.5	72.9	1,590.4	1,080.5	44.9	1,125.5
1980	1,500.8	80.0	1,580.8	991.0	46.6	1,037.5
1981	1,510.6	91.7	1,602.3	992.3	58.1	1,050.4
1982	1,245.1	92.5	1,337.5	826.6	52.9	879.5
1983	1,272.7	98.5	1,371.9	862.7	93.2	955.9
1984	1,280.1	132.5	1,412.5	878.6	102.7	981.4
1985	1,181.5	143.9	1,325.4	705.8	103.6	809.3
1986	1,256.8	132.6	1,389.7	793.5	103.6	897.0
1987	1,158.5	154.4	1,312.5	700.8	98.9	799.7
1988	1,181.3	165.4	1,346.7	648.4	109.5	757.9
1989	1,231.0	177.8	1,408.8	678.4	120.3	798.6
1990	1,270.0	175.0	1,445.0	705.0	120.0	825.0
Average annual growth rate (%)						
1970-79	5.9	—	6.4	5.6	—	6.1
1980-89	-2.0	8.3	-1.1	-3.7	10.0	-2.6

Notes: — Not applicable. Data for 1990 are preliminary estimates of the Energy Program, East-West Center.

Sources: MIGAS data and *OPEC Annual Statistical Bulletin*, various issues.

Figure 5.6
Crude and Condensate Production and Exports, 1970-90



Note: 1990 figures are East-West Center preliminary estimates.

Table 5.5
Crude and Condensate Production by Operating Company, Selected Years, 1974-89
(thousand b/d)

Company	1974	1980	1989
ARCO	89.5	133.8	125.2
Asamera	19.3	7.0	33.2
Caltex	903.8	754.9	641.8
Calasiastic and Topco	5.4	5.6	5.6
Conoco	0.0	18.5	8.8
CSR	1.4	0.9	1.3
Hudbay	0.0	0.0	58.6
Huffco	2.5	23.3	40.7
Kodeco	0.0	0.0	0.9
Marathon	0.0	0.0	7.1
Maxus	54.2	82.2	69.8
Mobil Oil	0.0	61.3	124.3
Petromer Trend	30.4	54.3	20.4
Phillips	0.0	6.0	0.0
Stanvac	46.7	31.6	39.5
Tesoro	7.0	7.3	4.9
Total Indonesia	2.3	198.8	88.4
Unocal	101.4	108.8	68.2
Lemigas	1.0	0.6	0.0
Pertamina	110.0	8.7	70.0
Total	1,374.9	1,576.6	1,408.7

Source: U.S. Embassy, Jakarta 1990.

is currently higher in Indonesia than in any other country employing the technique. Steamflooding was first introduced in Indonesia in the Duri field, where production started in 1958, peaked at about 65,000 b/d in 1964 and declined to a plateau of about 40,000 b/d during the 1967-84 period. The steamflood pilot project began in 1975, and a design plan for steamflooding the entire Duri area began in 1981. Production was still about 40,000 b/d when the steamflood injection started in mid-1985; it was boosted to about 90,000 b/d in 1989 and is expected to reach a peak of 330,000 b/d in 1993. Steamflooding has increased the Duri recovery rate from the previous 15% of oil-in-place to an average of 55%, thus justifying the massive investment of US$2 billion required for the first phase of the project from 1984 to 2001.

Recent developments such as the Intan and Widuri oil fields, and the more recent Duri EOR project, will boost oil production in the early 1990s. But even in the most optimistic scenarios, oil production is expected to level off and remain, at best, flat for the remainder of the decade. Most analysts believe that Indonesian oil production has reached maturity and is now entering a period of decline.

CRUDE SELLING PRICES

Until 1989, sales of Indonesian crudes followed the government selling price (GSP) system, which was based on OPEC's official GSP for member crudes. Changes in the price of selected Indonesian crudes between 1980 and 1990 are shown in Table 5.6. The production sharing contractors in Indonesia used an "export price" figure for cost recovery and tax computations. After oil prices fell in 1986, the GSP often differed significantly from true market prices. The operating companies were extremely dissatisfied, since the difference in this calculation had a major impact on their profits and the competitiveness of the oil in international markets. According to the "Petroleum Report" compiled annually by the U.S. Embassy in Jakarta, the GSP was the most serious problem facing the operators in Indonesia, especially during the year 1988. Although the government attempted to resolve the problem through tax incentives, the operating companies still complained that the incentives did not fully compensate for the revenue losses resulting from the continued use of the GSP system.

Consequently, the GSP was replaced on 1 April 1989 by the Indonesian crude price (ICP) formula. The ICP provides for Indonesian crude sales at prices calculated on the basis of monthly average spot prices for a basket of five internationally traded crudes: Indonesian Minas, Malaysian Tapis, Australian Gippsland, the UAE's Dubai, and Omani

Table 5.6
Selected Indonesian Crude Oil Prices, 1980-90
(US$/barrel)

	Minas/SLC	Duri	Cinta	Arjuna	Handil	Badak
January 1980	27.50	27.50	27.00	28.95	27.55	30.25
May 1980	31.50	31.50	31.00	32.95	31.55	34.25
January 1981	35.00	35.00	34.50	36.45	35.30	37.75
November 1982	34.53	33.10	33.30	35.20	34.80	36.25
February 1983	29.53	27.85	28.25	30.20	29.50	30.95
April 1984	29.53	25.95	28.25	30.20	29.50	30.95
February 1985	28.53	25.95	27.25	28.65	28.00	28.65
August 1985	28.53	24.00	27.05	28.65	27.80	28.65
February 1987	17.56	15.60	17.10	18.09	18.61	18.79
August 1987	17.15	16.10	17.20	18.09	17.61	18.79
August 1989	17.49	15.41	16.87	17.39	17.17	17.77
April 1990	n.a.	15.75	17.04	17.63	17.41	18.31

Source: MIGAS data.

crudes. Linking the ICP to spot market prices is a more rational system and has remedied most of the dissatisfaction among producers.

CRUDE EXPORTS, IMPORTS, AND THE REFINING SLATE

Exports of crude and condensate by country of destination during 1985-89 are shown in Table 5.7, while Table 5.8 provides a breakdown of condensate exports, 1984-88. The trends in crude and condensate exports from 1984 to 1989 to Japan, the United States and other world regions are shown in Figure 5.7, with additional detail on condensate exports in Figure 5.8. Virtually all of the exports are absorbed within the Pacific market. In 1989 Japan purchased 56% and the United States purchased 25% of Indonesia's crude and condensate exports. U.S. imports averaged 157 mb/d, which amounted to less than 3% of total U.S. imports. However, around 108 mb/d of this went

Table 5.7
Export of Crude Oil and Condensate
by Destination, 1985-89
(thousand b/d)

Destination	1985	1986	1987	1988	1989
Japan	373.3	383.5	406.7	427.8	444.3
United States	259.4	252.4	216.8	217.5	197.0
China	—	8.7	—	4.5	32.6
Taiwan	23.0	19.8	26.1	26.3	31.1
South Korea	55.6	49.1	44.2	39.7	30.1
Singapore	23.0	75.4	46.0	7.9	26.8
Australia	9.8	21.6	32.5	27.1	24.1
New Zealand	6.8	11.6	—	—	8.7
Italy	0.4	—	—	1.7	1.8
Other Europe	3.8	0.5	1.2	5.1	1.7
Trinidad	28.8	19.9	—	—	—
Bahamas	3.9	25.3	3.4	—	—
Other Caribbean	6.1	13.8	16.9	—	—
Philippines	13.4	11.5	4.8	—	—
Malaysia	—	3.1	1.0	—	—
Gulf Sea	0.7	—	—	—	—
Total exports	808.0	896.2	799.6	757.6	798.2

Note: — Nil or negligible.

Source: MIGAS data.

Table 5.8
Export of Condensate by Destination, 1984-88
(thousand b/d)

Destination	1984	1985	1986	1987	1988
United States	35.03	31.47	30.86	45.16	48.86
Korea	8.31	31.42	23.37	17.19	23.17
Japan	19.60	16.95	10.07	15.08	12.34
Taiwan	0.00	4.37	3.39	12.23	10.82
Australia	5.53	5.12	8.91	6.21	5.49
Singapore	4.97	6.16	11.57	2.01	3.69
Netherland	0.00	0.00	0.00	0.00	1.76
Italy	1.23	0.00	0.00	0.00	1.75
Other Europe	0.55	0.00	0.00	0.00	1.60
Philippines	0.00	0.00	0.68	0.00	0.00
New Zealand	16.02	6.87	11.58	0.00	0.00
Malaysia	1.84	0.00	3.15	1.00	0.00
Total	93.09	102.36	103.58	98.88	109.48

Notes: Condensate exports in 1989 totalled 120.3 thousand b/d. Export data by destination for 1989 are not yet available.

Source: MIGAS data.

Figure 5.7
Crude and Condensate Exports by Destination, 1984-89

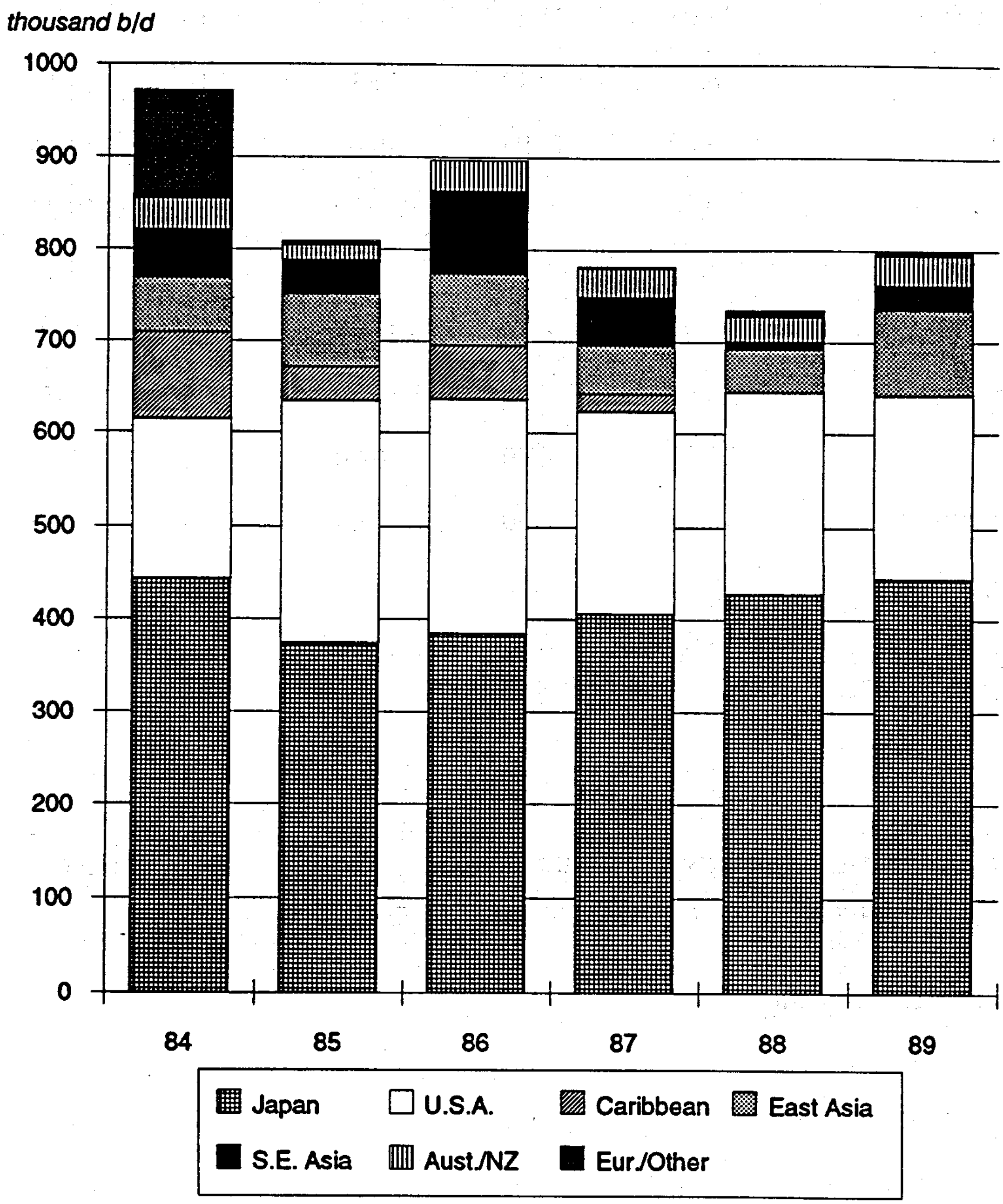
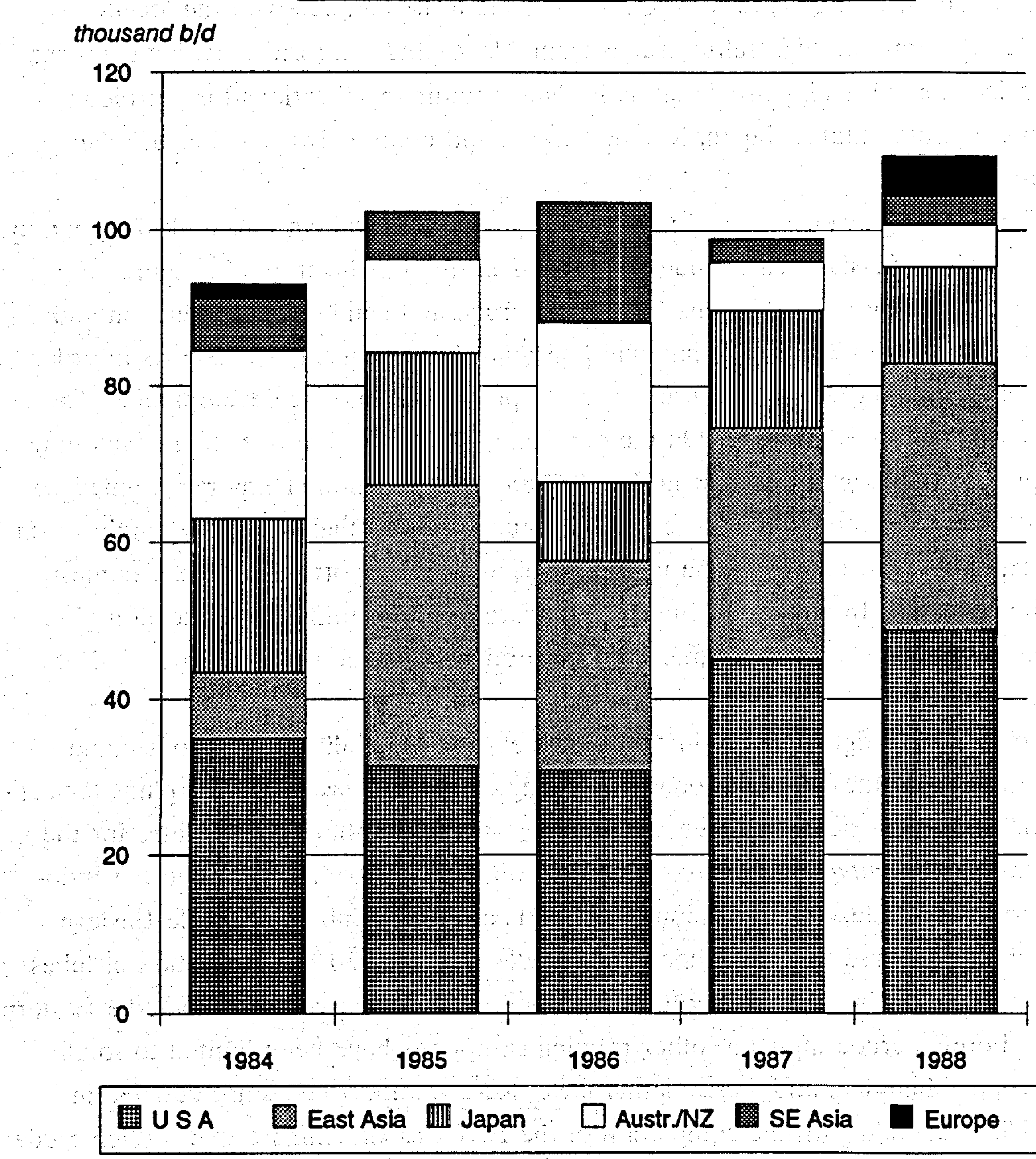


Figure 5.8
Condensate Exports by Destination, 1984-88

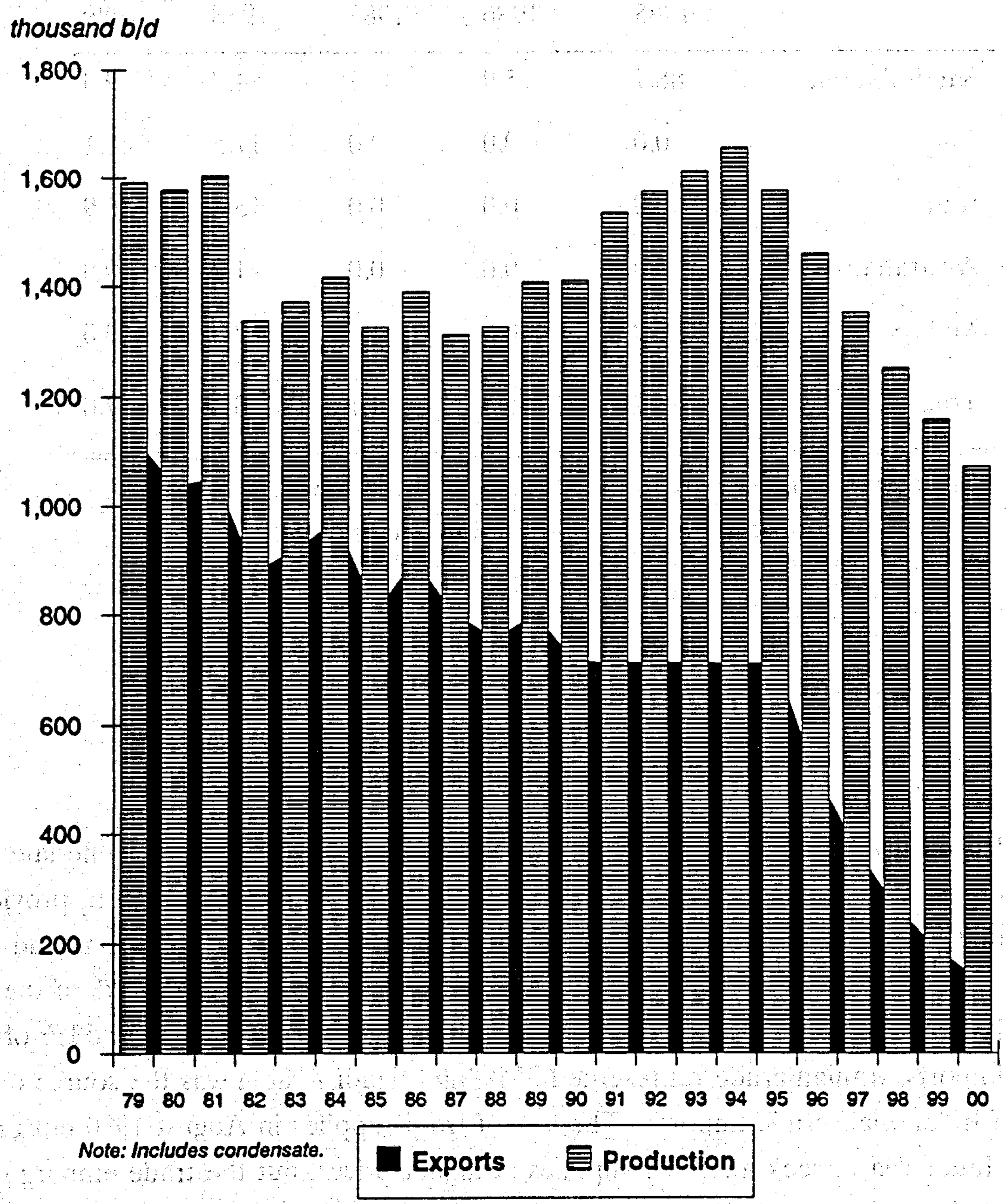


to the U.S. West Coast region, and on the U.S. West Coast, Indonesian crudes accounted for 40% of total imports. Although foreign crudes in general represent a small percentage of the West Coast crude supply, they play a larger role in the local crude slate than the numbers would indicate, because they are generally light and low in sulfur. Some of the smaller refiners on the U.S. West Coast would be unable to meet product specifications if low-sulfur foreign crudes were not available to be blended with the locally available medium- and high-sulfur crudes from Alaska and California. Rising concerns over environmental quality are resulting in tighter sulfur specifications for petroleum fuels in the United States, Japan, Korea, Taiwan, and potentially a number of other Pacific-rim nations.

The declining availability of Indonesian export crudes will cut into both the quantity *and* the quality of Asia-Pacific crude supplies. The trend is illustrated in Figure 5.9, which tracks historical and forecast Indonesian crude and condensate production and exports from 1979 to 2000. The national policy has been to maximize exports in order to earn foreign exchange, which in turn is used to promote economic development. The strategy has had mixed success. On the one hand, oil revenues have fueled development of other economic sectors, so that in the 1987-88 fiscal year nonoil export revenues for the first time exceeded oil and gas export revenues; on the other hand, the emphasis on crude exports has resulted in some inefficiencies and lost opportunities in the domestic oil refining sector. In any event, Indonesia's energy and economic diversification plans may be moving forward just in time, since oil production is soon to enter a period of decline.

Note that the figure on production versus export availability takes into account refinery runs of domestic crudes only; depending on the success of current plans for construction of export-oriented refineries (EXORs)—and the optimal crude slates for the new units—crude *imports* will increase substantially. A little-known factor in the Indonesian oil trade pattern is that Indonesia imports around 80 mb/d of Middle Eastern crude, chiefly because the waxy Indonesian crudes are unsuited for production of lubes and asphalt. The Cilacap refinery therefore requires a certain volume of Middle Eastern crudes. Foreign crude inputs to other refining complexes have been limited to small quantities of Malaysian and Australian crudes. Recent import levels are detailed in Table 5.9. Depending on the completion of the EXORs, we estimate that foreign crude imports will be somewhere in the range of 200-250 mb/d by the turn of the century.

Figure 5.9
Oil Production versus Export Availability, 1979-2000



Note: Includes condensate.

Table 5.9
Crude Oil Imports, 1985-89
(thousand b/d)

	1985	1986	1987	1988	1989
Saudi Arabia	88.7	75.9	82.7	54.8	9.0
Iraq	0.0	0.0	0.0	17.5	41.1
Iran	0.0	0.0	0.0	13.2	26.9
Australia	0.0	0.0	0.0	1.7	0.0
Malaysia	0.0	0.0	1.4	2.8	0.0
Total	88.7	75.9	84.1	90.0	77.0

Sources: Central Bureau of Statistics data for 1987-88; U.S. Embassy, Jakarta 1990 for 1985-86 and 1989.

Historically, Saudi Arabia was the sole source of Mideast supplies; in the late 1980s, however, Indonesia entered a barter trade agreement with Iraq whereby Iraq provided crude and Indonesia provided a variety of nonoil commodities. Imports from Iraq (and Iran also) commenced in 1988, but Saudi light crude still accounted for 64% of the total crude imports. By the following year, imports from Iraq amounted to over 53% of total crude imports, Iranian crude represented 35%, and Saudi Arabia was the source of just 12% of Indonesia's crude imports. The loss of Iraqi supplies in August 1990 not only forced Indonesia to seek alternate supplies at higher prices, but the trade embargo also eliminated a market for Indonesia's nonoil exports.

DOWNSTREAM ACTIVITIES: DOMESTIC REFINERIES

Prior to the 1980s, Indonesia had only limited oil refining capabilities. In response to rising demands for kerosene and diesel oil, the country launched an ambitious refinery expansion program that has given Indonesia the most sophisticated refinery system in Asia. Indonesia's refinery configuration is provided in Table 5.10. Four major refining complexes, totalling around 830 mb/d of crude capacity, are currently in operation: (1) Dumai and Sungai Pakning in Sumatera, (2) the Musi River refineries (Plaju and Sungai Gerong) in Sumatera, (3) Balikpapan in East Kalimantan, and (4) Cilacap in Central Java. The key process in the expansion plan has been hydrocracking, one of the most advanced—and expensive—oil cracking technologies. The Balikpapan and Dumai refineries both have hydrocrackers, while the Musi complex has a catalytic cracking unit. In addition, the local industry has catalytic reforming capacity for producing high-octane reformate for gasoline blending. The four major complexes account for almost all of the installed capacity; the three smallest refineries (Pangkalan Brandan in North Sumatera, Cepu in Central Java, and Wonokromo in East Java) together have a total crude capacity of only 11 mb/d.

Crude inputs planned for 1990 to the four key complexes are estimated as follows: Balikpapan's input of 210.7 mb/d includes mainly domestic crudes such as Handil, Bekapai, Minas, Duri, Lalang, Badak, and Sepinggan, plus significant quantities (around 32 mb/d) of Australian Jabiru crude. Cilacap's 1990 inputs are estimated at 289 mb/d, composed of Rantau, Minas, Arjuna, Arimbi, and Attaka crudes, Arun condensate, plus around 95 mb/d of Middle Eastern crude and around 20 mb/d of Tapis from Malaysia. Dumai complex's 1990 inputs are estimated at 151 mb/d, made up of around two-thirds Minas plus one-third Duri and other central Sumateran crudes such as Pedada and Lirik. Musi's inputs are estimated at 101 mb/d, around three-fourths of which are South Sumateran crudes such as Jambi, Ramba, Limau, Talang Akar Pendopo, Palembang Selatan, Jene, Tabuhan, Corridor, and Rawa. The remainder is chiefly Minas and Duri crudes from central Sumatera.

Pertamina's Directorate of Processing is making efforts to improve refinery efficiency and productivity. It plans to increase the service factor—the ratio between operational days and calendar days in a year—from 92% to 95% and to reduce refinery losses (currently 7.2% of total volume) to 6%. In addition, efforts will be made to optimize the crude slates for each complex.

Table 5.10
Configuration of Pertamina Refineries, 1990
(thousand b/d)

Units	Balik-papan	Cilacap	Dumai and Sungai Pakning	Pang-kalan Bran-dan	Musi[a]	Cepu	Wono-kromo	Total
Crude	231.5	300.4	162.4	5.0	114.3	4.0	2.0	819.6
Vacuum	84.8	30.7	83.5	—	30.0	—	—	229.0
Vis	—	49.9	—	—	10.0	—	—	59.9
Coking	—	—	31.8	—	—	—	—	31.8
Catalytic	—	—	—	—	12.6	—	—	12.6
Hydro—	49.7	—	50.4	—	—	—	—	100.1
Catalytic	18.0	30.0	13.5	—	—	—	—	61.5
Hydro	—	18.0	—	—	—	—	—	18.0
Hydro	18.0	18.1	15.4	—	—	—	—	51.5
Alkylation	—	—	—	—	0.6	—	—	0.6
Lubes	—	5.0	—	—	—	—	—	5.0
Asphalt	—	7.5	—	—	—	—	—	7.5
H_2 (thousand scf/d)	60.0	—	78.8	—	—	—	—	138.8

Notes: — No capacity.
a. The Musi River facilities comprise the Plaju and Sungai Gerong refineries (see Figure 5.1).

Sources: Pertamina data and *Oil and Gas Journal*, December 1990.

CURRENT PRODUCT BALANCE

Indonesia's sophisticated refinery configuration and the large amounts of processing involved should have allowed Indonesia to meet all domestic product needs and have a surplus of valuable light products for export. In practice, unfortunately, minor technical hitches have prevented the hydrocrackers from running at full throughput. Figure 5.10 compares the design output of the Indonesian refining sector with 1989 actual output and domestic demand. As the figure shows, Indonesia's refineries should be able to produce a substantial surplus of exportable gasoline and kerosene. Although current output comes relatively close to meeting domestic demand, the technical problems have left Indonesia as an exporter of low-value fuel oil and naphtha rather than higher-valued products and as an *importer* of small quantities of kerosene and diesel.

Table 5.11 provides Indonesia's petroleum product balance, 1986-89. In 1989 around 38 mb/d of diesel, 19 mb/d of kerosene, and 2 mb/d of fuel oil were imported, versus exports of 111 mb/d of low-sulfur waxy residual fuel oil (LSWR), 30 mb/d of naphtha, 8 mb/d of jet fuel, and a small amount of high octane motor gasoline components and other products. It is worth noting that the two chief exports, LSWR and naphtha (for which Japan is the main customer), are relatively low in value. Ideally, some of the LSWR now being exported could be used as feed for the hydrocrackers. This would increase production of gasoline, kerosene, and diesel, obviating the need for product imports and possibly setting Indonesia on the road to becoming an export refining center, which is the government's stated goal.

Moreover, Indonesia exports small quantities of high-octane motor components. If the production of high-octane blendstocks were increased—such as reformates and methyl tertiary butyl ether (MTBE)—some of the naphtha now exported could be uplifted to motor gasoline. Naphtha exports may also be reduced as new petrochemical facilities begin to come onstream within the next few years.

Pertamina has already achieved some success in its downstream refining diversification. In December 1988 Pertamina signed an agreement with the U.S. Defense Supply Center to supply the U.S. naval base in Subic Bay, the Philippines, with jet fuels: 360,000 barrels of JP-4 and 300,000 barrels of JP-5 type. The first shipment of these jet fuels was made in April 1989 from the Dumai refinery. To increase refinery utilization, Pertamina has also invited foreign oil producers to refine their crude in Indonesia. In 1988 Pertamina signed a contract to refine 10,000 to 20,000 b/d of Malaysian crudes with an Indonesian private company which purchases Malaysian crudes and exports the

Table 5.11
Petroleum Product Balance, 1986-89
(thousand b/d)

Year and Product	Production	Import	Export	Consumption
1986				
Refinery LPG	13.3	—	7.3	6.0
Naphtha	47.1	0.2	42.2	7.9
Avgas	0.1	0.2	0.1	0.2
Gasoline	77.0	—	1.1	77.0
Kerosene	118.1	0.5	—	118.6
Jet fuel	4.4	8.4	—	12.8
High-speed diesel	128.5	3.5	—	132.0
Low-speed diesel	24.4	—	—	27.0
Fuel oil	131.0	4.7	101.3	34.4
Asphalt, lubes, and other	12.5	—	3.0	11.5
Total	556.2	15.3	147.6	445.1
1987				
Refinery LPG	13.5	—	6.6	6.9
Naphtha	62.8	—	54.8	8.2
Avgas	0.3	—	0.1	0.2
Gasoline	81.9	1.7	—	83.6
Kerosene	115.6	3.2	—	118.8
Jet fuel	10.4	6.5	—	16.9
High-speed diesel	134.8	13.3	—	148.1
Low-speed diesel	23.8	2.2	0.0	26.0
Fuel oil	168.8	10.7	121.4	56.0
Asphalt, lubes, and other	12.5	—	—	12.5
Total	624.37	37.6	179.3	479.3

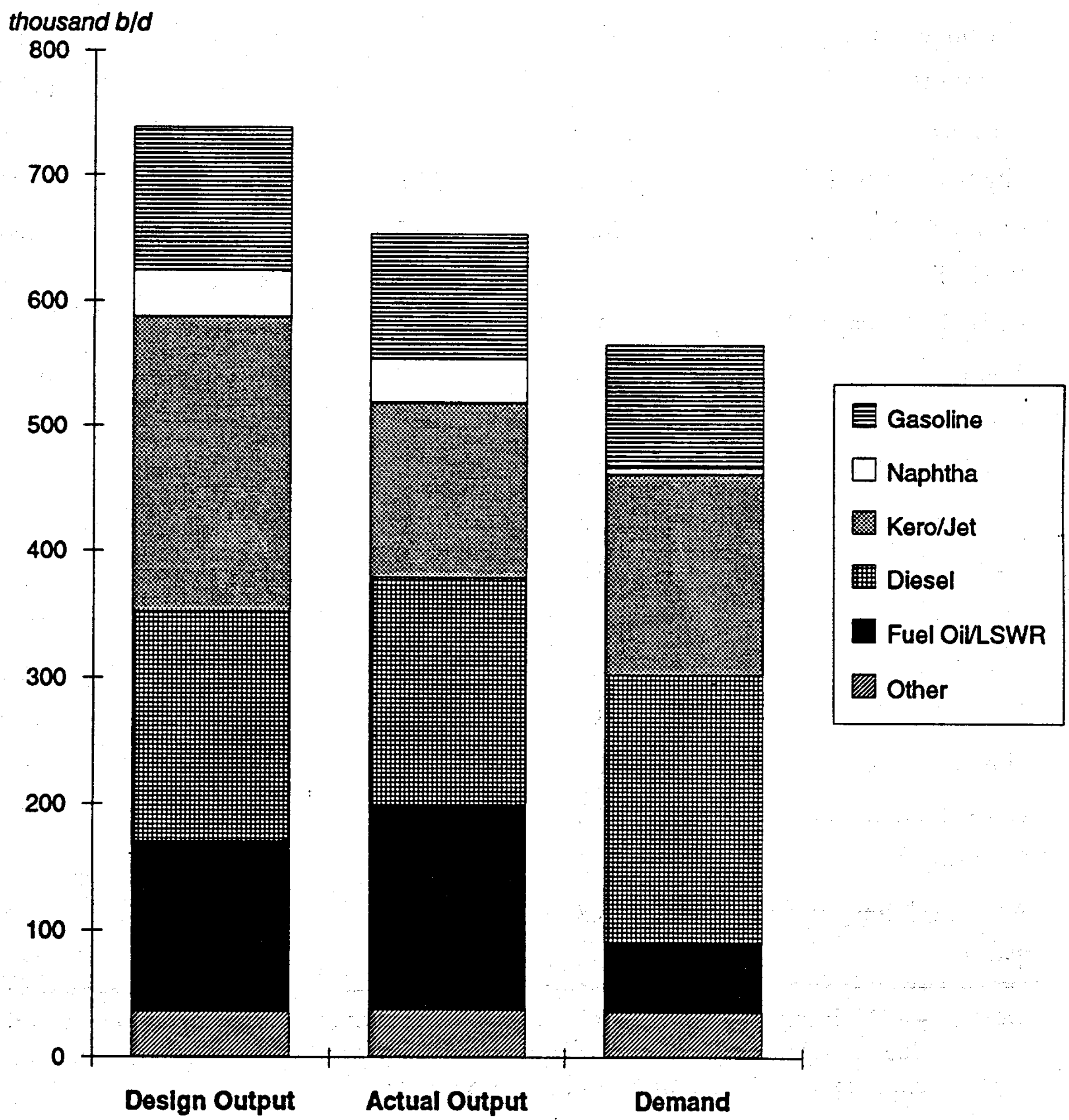
Table 5.11. Continued.

Year and Product	Production	Import	Export	Consumption
1988				
Refinery LPG	8.6	—	1.1	7.5
Naphtha	47.9	—	44.0	3.9
Avgas	0.3	—	—	0.3
Gasoline	87.7	—	2.8	84.9
Kerosene	113.4	—	—	117.4
Jet fuel	15.9	4.0	—	15.9
High-speed diesel	141.1	23.6	—	164.7
Low-speed diesel	26.8	0.3	—	27.1
Fuel oil	179.7	8.5	125.8	54.8
Asphalt, lubes, and other	24.4	—	1.8	22.6
Total	645.8	36.4	175.5	499.1
1989				
Refinery LPG	8.9	—	—	8.9
Naphtha	35.3	—	29.6	5.8
Avgas	0.3	—	—	0.2
Gasoline	100.0	—	0.3	98.0
Kerosene	119.2	—	—	128.0
Jet fuel	20.5	18.6	8.2	16.6
High-speed diesel	151.0	32.6	—	179.0
Low-speed diesel	28.2	5.2	—	32.6
Fuel oil	161.6	1.9	111.2	55.0
Asphalt, lubes, and other	28.8	—	1.9	26.8
Total	653.9	58.4	151.2	556.5

Notes: — Volume negligible or nil. Individual products may not balance exactly due to stock changes and transfers between product categories. Gasoline exports are high-octane motor components.

Sources: MIGAS and Pertamina data.

Figure 5.10
Refinery Design Output versus Actual Output and Demand in 1989



products back to Malaysia. The export-oriented refineries should add to Indonesian export capability in the mid-1990s and onward.

DOMESTIC CONSUMPTION OF PETROLEUM PRODUCTS

Pricing of Five BBM Fuels

For the average citizen, concerns about oil center on petroleum products—specifically on product pricing. The five main products (aviation fuels, gasoline, kerosene, diesel fuel, and fuel oil) are collectively known as BBM (abbreviated from *bahan bakar minyak*, the Indonesian term for "petroleum fuels"). BBM prices are regulated by the government and, with the exception of kerosene prices, are uniform throughout the nation. Kerosene prices are fixed jointly by the central and local governments. Pricing policy is formulated within the context of government revenues from the industry, the distribution of income, the purchasing power of the majority of the population, and overall planned economic growth. Since petroleum products are a major input to other sectors of the economy, product prices are believed to have a multiplier effect on the growth of these sectors. Product prices have a direct impact on the competitive strength of industries (notably in terms of cost of production for manufactured export goods) and also indirect impacts, such as employment generation and the promotion of regional development.

The evolution of BBM prices from May 1979 to May 1990 is presented in Table 5.12. The government launched five rounds of price increases during the first half of the decade. Prices were raised in May 1980, January 1982, January 1983, January 1984, and April 1985. One of the chief impacts was on the heavily subsidized kerosene, which rose in price from 38 rupiah per liter in 1980 to 165 rupiah per liter in 1985—which at the prevailing exchange rates was the equivalent of raising the price from US 6 cents per liter to US 15 cents per liter. Prices were reduced slightly in 1986, chiefly in response to the collapse of world oil prices, but were raised again in May 1990. The price of kerosene was raised to 190 rupiah per liter, but with the change in exchange rates, the equivalent price was only US 10 cents per liter. Gasoline prices, on the other hand, were raised to 450 rupiah per liter, equivalent to US 91 cents per gallon—a price comparable to many international markets.

It is perhaps somewhat misleading to characterize Indonesia's BBM prices as low in comparison to those of other countries in the region. In setting prices, the Indonesian government considers the levels that are affordable to most Indonesians, taking into

Table 5.12
Domestic Fuel Prices, Selected Years, 1979-90
(rupiah/liter)

Date	Avgas	Avtur	Super Gasoline	Premium Gasoline	Kero-sene	ADO	IDO	Fuel Oil
3 May 1979	100	100	140	100	18	35	30	30
1 May 1980	150	150	220	150	38	53	45	45
4 January 1982	240	240	360	240	60	85	75	75
7 January 1983	300	300	400	320	100	145	125	125
12 January 1984	300	300	400	350	150	220	200	200
1 April 1985	330	330	450	385	165	242	220	220
10 July 1986	250	250	450	385	165	200	200	200
25 May 1990	330	330	570	450	190	245	235	220

Note: Super gasoline (98 RON) was replaced by a lower-lead, premix (92 RON) in May 1990, blended by private firms and sold at market prices.

account the relatively greater buying power of the Japanese, Singaporeans, and others. However, the disparities in price between the various products and the system of cross-subsidization have contributed to a skewed demand barrel and a number of market inefficiencies. In the current system, Pertamina calculates its total operational cost, including feedstock acquisition, transport, refining, and marketing, and then computes the average fuel cost that would cover its costs. If actual revenues from oil product sales do not add up to the costs, the government susidizes the loss. The Indonesian domestic market is only distantly related to international markets, and as discussed further in the section on refining below, this has given little incentive to Pertamina to become more market-oriented and outward-looking.

Historical and Forecast Demand

display Indonesia's petroleum product consumption from 1971 to the year 2000 is shown in Table 5.13 and Figures 5.11 and 5.12. Figure 5.11 plots the products as individual lines so that the impact of the BBM price increases during the early 1980s and the price reduction of 1986 can be seen clearly for each product. We foresee the May 1990 price increase as having a further dampening effect on demand for kerosene in particular, although as noted above the kerosene price is still low by international standards. Figure 5.12's stacked-bar format gives a better picture of the total demand figure.

Like many Asia-Pacific nations, the Indonesian demand barrel is heavily weighted toward middle distillates. Although we forecast overall growth averaging 2.3% annually during the 1990-95 period, diesel demand is forecast to grow at nearly 3.9% per year. Still, Indonesia's oil demand growth rates are not nearly as staggering as some of the rates witnessed in other Asian nations. As a major oil exporter with limited reserves, Indonesia is acutely conscious of the need to restrain domestic demand growth. Already, a significant amount of fuel substitution (such as coal for fuel oil and LPG for kerosene) has occurred

The impact of the higher price regime in the early 1980s is clearly displayed in Figure 5.11; demand for all major fuels levelled off or dropped, though gasoline and diesel demand growth recovered quickly. In 1986 prices were reduced in response to weak market prices for oil. Demand consequently jumped from 445 mb/d in 1986 to an estimated 573 mb/d in 1990, prompting the government to raise prices once again in May 1990. Even though kerosene remains the cheapest of the BBM fuels, kerosene demand has fallen and is expected to decline further in the coming decade. From a 1989 consumption level of about 150 mb/d, kerosene demand should fall to approximately 121 mb/d in 1995, before turning upwards again and reaching 140 mb/d in the year 2000.

Percentage compositions of demand, 1971-2000, are presented in Figure 5.13. The most visible shifts in the demand barrel are the constriction of fuel oil and kerosene use, the expansion of demand for diesel, gasoline, and LPG, and the phase-in of naphtha as feedstock for petrochemical facilities scheduled for startup in the mid-1990s. By the end of the decade, 5% of the demand barrel is expected to be naphtha. In 1971 fuel oil represented 14% of petroleum fuels demand (excluding "other" products such as asphalt and lubes), yet this percentage is expected to fall to 10% by the year 2000. Kerosene's

Table 5.13
Oil Product Demand, 1971-2000
(thousand b/d)

Year	Other	Fuel Oil	Diesel	Kero/jet	Gasoline	Naphtha	LPG	Total
1971	8.4	22.2	49.7	54.7	28.9	0.0	0.1	164.1
1972	12.5	24.5	58.0	60.1	30.2	0.0	0.2	185.5
1973	23.6	28.0	60.7	66.8	33.3	0.0	0.4	213.0
1974	23.9	25.6	69.5	77.3	36.5	0.0	0.7	233.5
1975	12.5	28.4	79.6	89.1	41.1	0.0	1.0	251.8
1976	3.0	30.1	86.5	96.2	44.8	0.0	1.1	261.7
1977	13.6	38.6	95.9	109.0	49.4	0.0	1.2	307.6
1978	9.3	42.9	108.4	125.8	55.9	0.0	1.5	343.8
1979	9.3	45.6	118.4	134.4	60.2	0.0	1.7	369.6
1980	9.9	50.3	134.7	146.0	65.4	0.0	1.9	408.1
1981	8.2	57.9	152.4	154.8	71.6	0.0	2.2	447.1
1982	8.4	59.4	163.8	152.3	71.3	0.0	2.4	457.6
1983	6.9	48.6	167.6	141.9	67.5	0.0	2.7	435.3
1984	6.2	59.2	166.0	134.6	69.3	0.0	3.5	438.8
1985	12.6	62.4	163.8	131.1	70.8	7.8	4.6	453.0
1986	11.5	52.0	159.0	131.7	77.0	7.9	6.0	445.1
1987	12.5	56.0	174.1	135.9	83.6	8.2	6.9	477.1
1988	22.6	54.8	191.8	133.6	84.9	3.9	7.5	499.1
1989	26.8	55.0	211.6	150.4	98.0	5.8	8.9	556.4
1990	31.0	64.0	211.0	149.0	102.0	5.0	10.5	572.5
1991	32.1	64.6	219.1	142.9	103.7	5.0	11.4	578.9
1992	33.3	65.2	227.6	137.1	105.5	5.0	12.3	586.0
1993	34.5	65.8	236.4	131.5	107.3	5.0	13.3	593.8
1994	35.7	66.4	245.5	126.1	109.1	15.0	14.4	612.3
1995	37.0	67.0	255.0	121.0	111.0	35.0	15.6	641.6
1996	38.6	66.8	260.2	124.6	112.0	35.0	16.7	653.9
1997	40.4	66.6	265.5	128.3	113.0	35.0	17.9	666.6
1998	42.2	66.4	270.9	132.1	114.0	35.0	19.2	679.6
1999	44.0	66.2	276.4	136.0	115.0	35.0	20.5	693.1
2000	46.0	66.0	282.0	140.0	116.0	35.0	22.0	707.0
Average annual growth rate (%)								
1971-79	1.2	9.4	11.5	11.9	9.6	—	43.2	10.69
1980-89	11.7	1.0	5.1	0.3	4.6	—	18.9	3.50
1990-95	3.6	0.9	3.9	-4.1	1.7	47.6	8.2	2.31
1990-2000	4.0	0.3	2.9	-0.6	1.3	21.5	7.7	2.13
1995-2000	4.5	-0.3	2.0	3.0	0.9	0.0	7.1	1.96

Note: — Not applicable.

Sources: International Energy Agency 1989 and 1990 for 1971-88 data; MIGAS and Pertamina data for 1986-89; Energy Program, East-West Center, for forecast 1990-2000.

Figure 5.11
Demand by Petroleum Product, 1971-2000

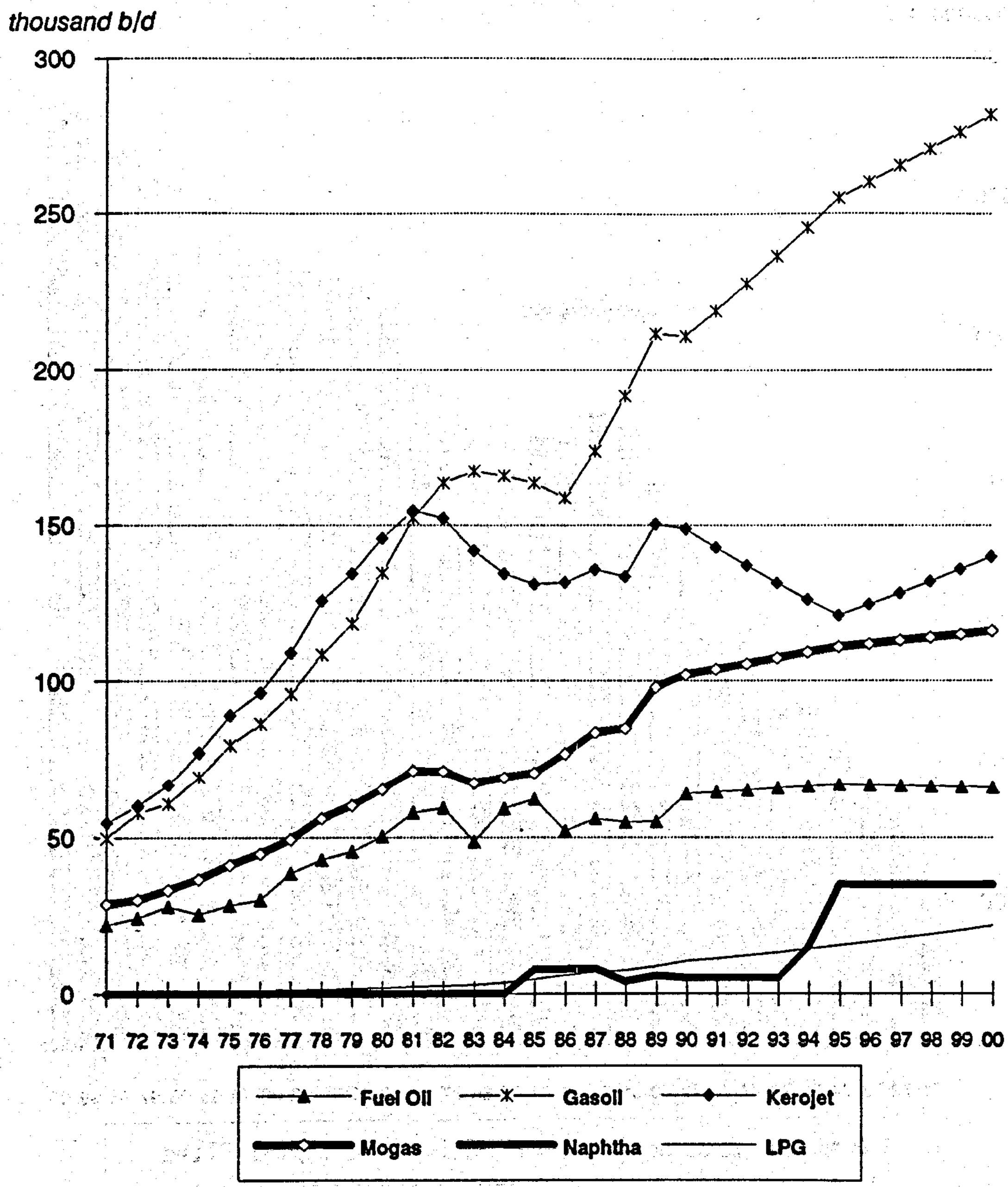


Figure 5.12
Total Petroleum Product Demand, 1971-2000

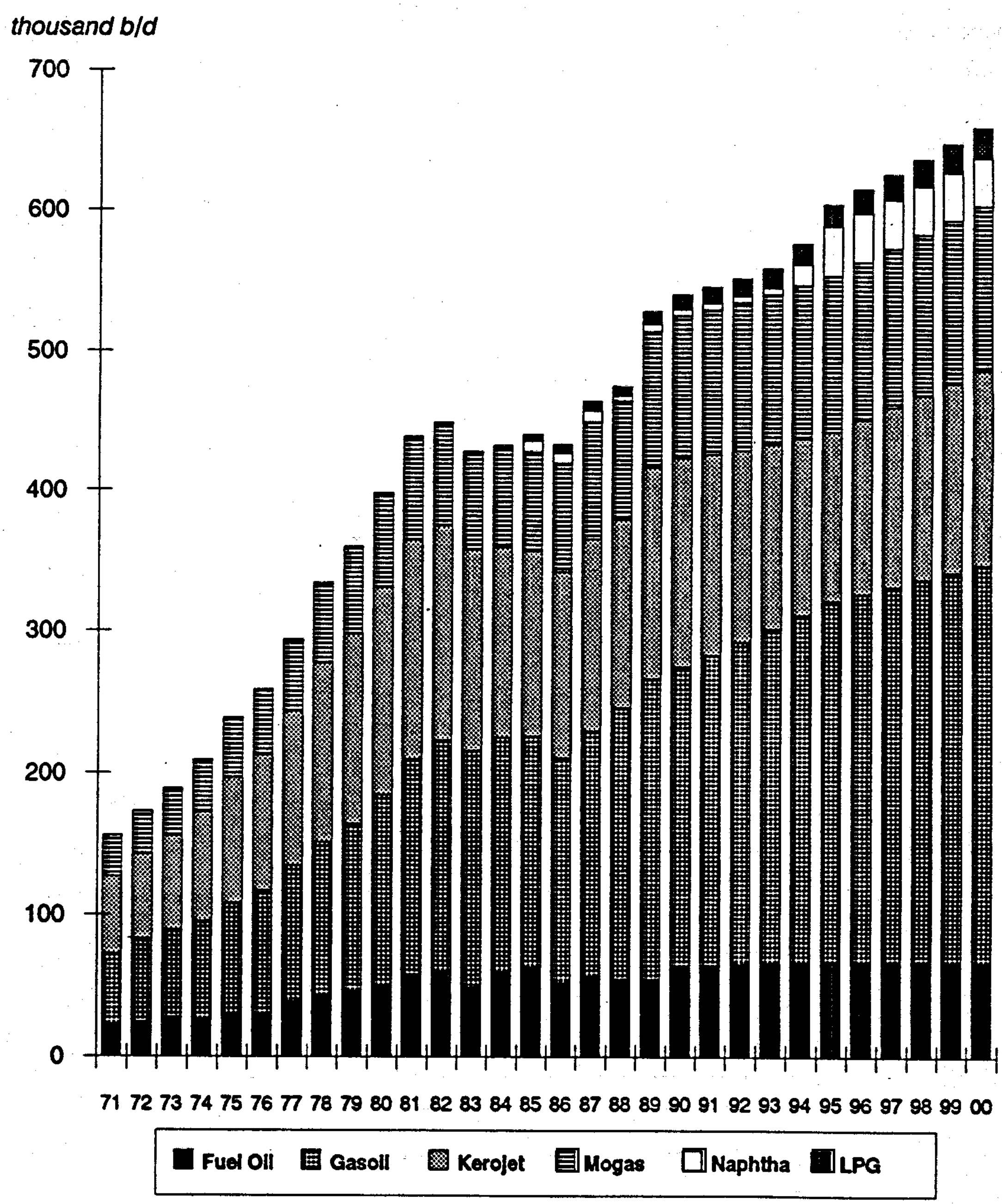
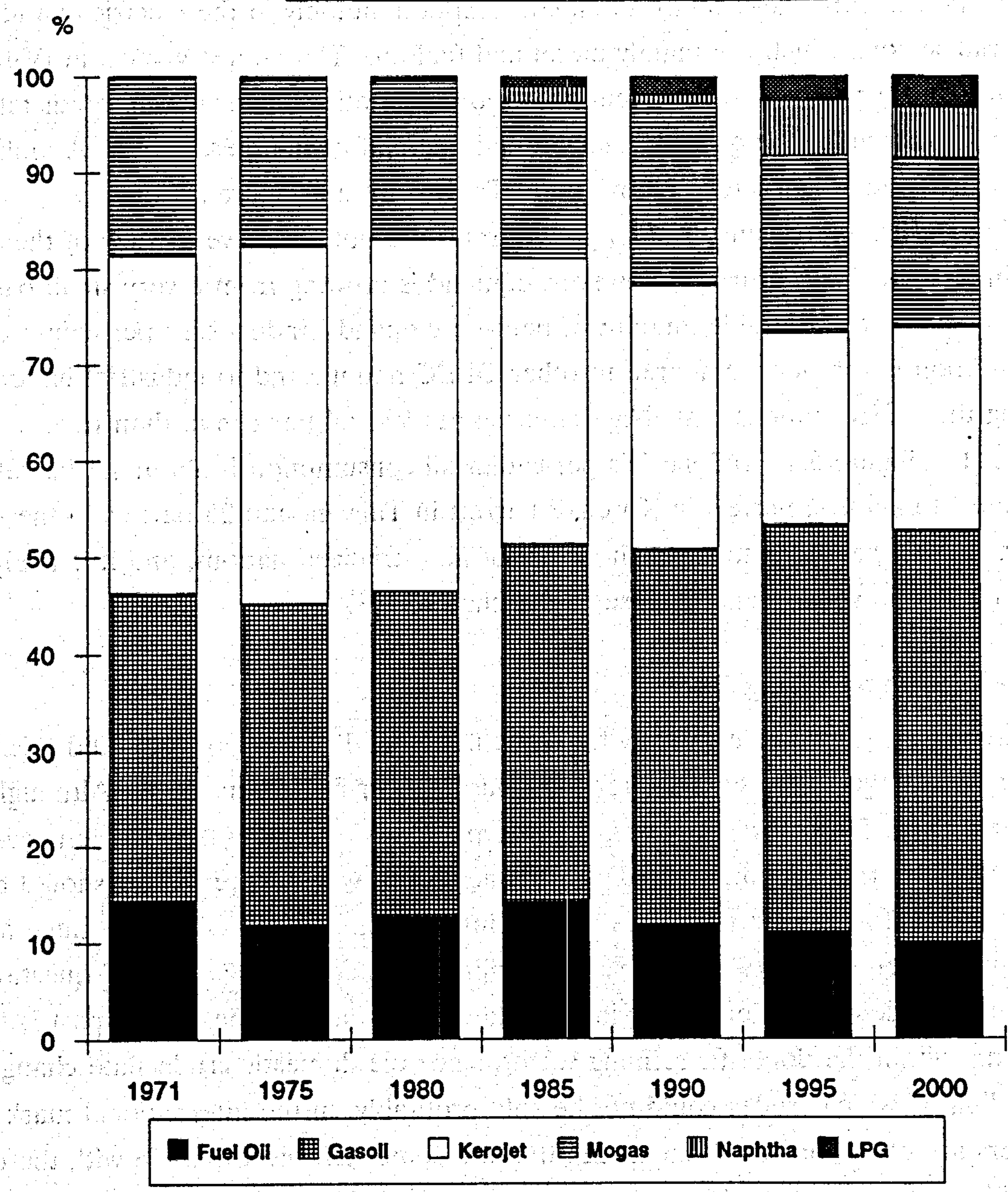


Figure 5.13
Composition of Oil Product Demand, Selected Years, 1971-2000



share drops even more sharply, from 35% in 1971 to just 21% by 2000. Motor gasoline's share fell from 19% in 1971 to 16% in 1980, but recovered to 19% in 1990 and is expected to remain roughly stable through the end of the decade. Diesel captures most of the share lost by other fuels, with percentage share growing from 32% in 1971 to 43% by the year 2000.

The energy diversification policies initiated in the fourth five-year development plan have helped to curb the increase in oil consumption, notably in the electricity and industrial sectors, which use mainly diesel and fuel oil. The largest growth in BBM consumption in recent years has been in the transportation sector which, predictably, absorbs almost all of the gasoline plus around one-half of the diesel used. A look at BBM consumption by sector is provided in Table 5.14 and Figure 5.14.

Indonesia's petroleum demand growth rates are not excessive in view of the rates seen in neighboring countries. However, demand is growing from a very small base, and there may be a considerable amount of pent-up demand. Indonesia's per capita oil consumption is very low compared to other OPEC nations and to industrial nations. Among the OPEC nations, only Nigeria consumes less oil per capita than Indonesia. As indicated in Figure 5.15, Indonesia's per-capita oil consumption is about 1.1 barrels, compared to about 6 barrels in Korea, 8 barrels in Taiwan, and 25 barrels in the United States. Indonesia hopes to enter the ranks of industrialized nations, and it is likely that oil consumption will continue to rise during the process.

REFINERY EXPANSION PLANS

Currently, plans are underway for construction of 1 to 4 export-oriented ("EXOR") refineries, largely geared toward producing gasoline for foreign markets. Although the market outlook for export refineries of this type seems bright for the next ten years, many critics, both inside and outside of Indonesia, ask why new refineries should be constructed before the existing ones are put into full operation. Given the huge investments of foreign exchange in the existing facilities, this seems to be a valid question. The government's determination to maximize crude export earnings has in the past led to problems within the domestic refining sector, since the domestic crude slate changed depending on which crudes could not be sold profitably on the international market. Refiners are often forced to run crudes that are somewhat incompatible with the design capabilities, and they have been either reluctant or unable to make the technical and procedural changes required to handle the conversion of surplus fuel oils into higher-

Table 5.14
Consumption of Fuel Products (BBM) by Sector, 1989
(barrels/day)

Sector	Avgas	Avtur	Mogas	Kerosene	Diesel	Fuel Oil	Total
Residential	0	0	0	123,976	0	0	123,976
Industry	4	244	582	1,383	48,182	38,910	89,306
Agriculture	1	1	5	0	16,522	2,755	19,284
Power	0	0	21	121	22,154	33,717	56,013
Transport	136	15,030	94,521	0	89,397	5,215	204,298
Armed forces	25	1,274	2,542	2,194	2,166	91	8,292
Pertamina own use	0	4	96	78	1,152	670	2,000
Total	166	16,553	97,767	127,753	179,572	81,358	503,169

Note: Fuel oil includes industrial diesel oil.

Source: Pertamina ADP 7 data base.

valued light products. For example, handling large quantities of LSWR requires heated storage tanks and pipelines to prevent the fuel oil from solidifying. Yet it appears that the incentives have not been sufficient for construction of new facilities of this type.

At present, only one of the proposed EXOR refineries is under construction. The chosen site of this 125 mb/d refinery is Balongan, on the northern coast of West Java. The planned crude slate is 100 mb/d of Duri plus 25 mb/d Minas. Financing for the US$1.8-billion project is being arranged by Mitsui, which reportedly has procured a loan from a group of 21 Japanese banks led by the Industrial Bank of Japan. Foster Wheeler

Figure 5.14
Petroleum Fuel Use by Sector, 1989

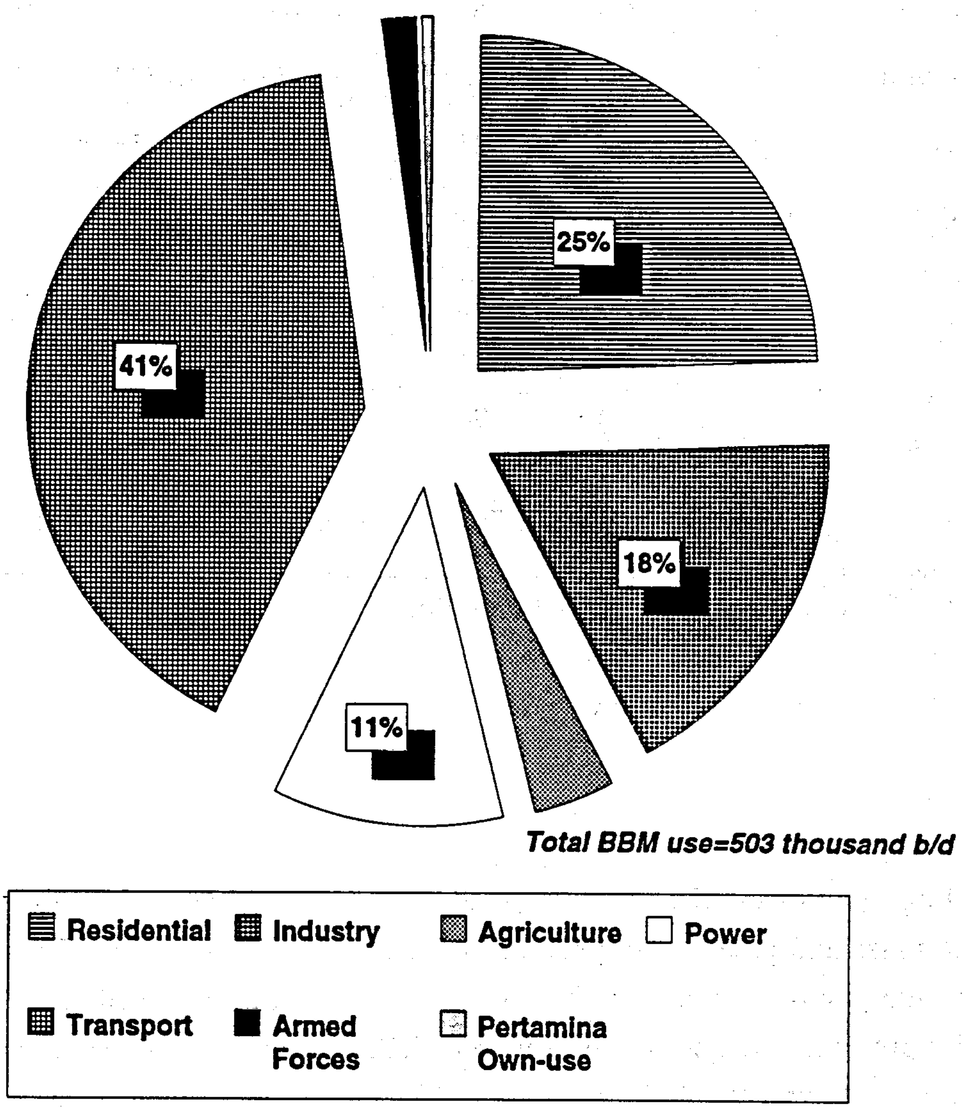
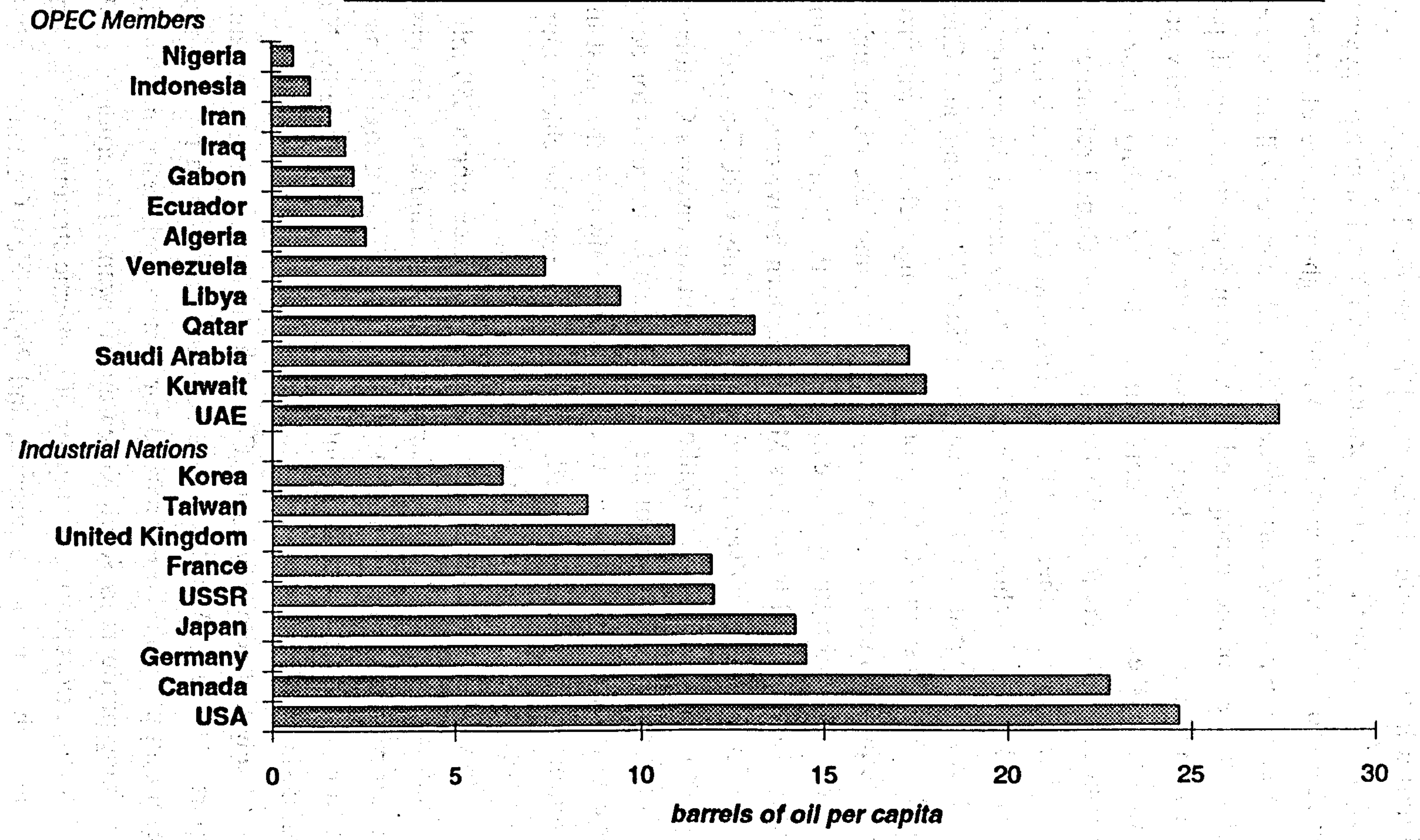


Figure 5.15
Per Capita Oil Consumption of OPEC and Selected Industrial Nations



(UK) and JGC (Japan) will be responsible for engineering and construction, and product output will be marketed by BP and Far East Oil Trading. The central technology will be a 62 mb/d integrated resid cat cracker (RCC) with a polypropylene unit. Output is expected to be 53 mb/d gasoline, 24 mb/d high-speed diesel, 14 mb/d industrial diesel, 10 mb/d kerosene, 5 mb/d propylene, 3.5 mb/d each fuel oil and cycle oil, and 2-3 mb/d of LPG. In view of the anticipated increases in domestic demand, part of the output will likely find its way into the local market. EXOR 1 may actually provide more for the Javanese market than the export market, thereby freeing up for export the traditionally Java-bound products from the Balikpapan and Dumai refineries.

Plans for the other EXORs are less firm, although it is likely that EXOR 4 will go ahead. EXOR 4's chosen site is next to the Dumai refinery complex. The joint venture involves Kanematsu-Gosho, Mitsui, Far East Oil Trading, and Chevron, with Chevron and Far East responsible for product marketing. Chevron will provide technology, which reportedly will include coking, hydrocracking, and lube oil manufacture. The US$1.5-1.8 billion, 140-mb/d refinery will capitalize upon the high levels of Duri EOR production and is also expected to process Middle Eastern heavy crudes.

EXOR 3 is tentatively planned as a 120-mb/d, RCC-based facility at Tanjung Uban, Riau Province. The US$1.5-billion joint venture involves C. Itoh and an as-yet unnamed U.S. company. One-third of the output would be targeted for domestic use, with the rest for export by C. Itoh and the other partner. Taiwan is the most likely market at this point, and if Taiwan is targeted, the crude slate will be chiefly Duri and Arun to produce large volumes of naphtha and low-sulfur fuel oil.

Previously, Mitsubishi and Aramco were discussing a 250 mb/d refinery to be located at Lombok. This plan has been shelved, and attention has shifted to plans for a smaller refinery to be located in Irian Jaya. This is referred to as the new EXOR 2, which is being discussed as a joint venture involving, reportedly, Nichimen and Total Indonesia. This $1.8-billion, 120-mb/d refinery would be built at Sorong, Irian Jaya; the most likely technology will be RCC, with the intent being to maximize gasoline output for export. The U.S. West Coast has been mentioned as a possible market. Kerosene and diesel output would be earmarked for eastern Indonesia, and Nichimen would export the remaining products to South Korea and Taiwan. The crude slate should be fairly light and sweet, incorporating a number of domestic streams as w[illegible] as other Asian crudes. Crudes such as Jabiru, Gippsland, and Papua New Guinea's [illegible]fu are likely candidates.

The new cat crackers will be a significant source of isobutylene, one of the feeds for MTBE production—which clearly offers an advantage if gasoline reformulations in export markets require oxygenate blending. However, Pertamina has not yet announced any plans for the refinery isobutylenes, and instead has announced its intention to build a 7-mb/d MTBE facility (300 billion tons/year) using butane and methanol as feedstocks. The process steps will involve isomerization, deisobutanization, dehydrogenation, and etherification. The feedstocks will be methanol from the Bunyu plant and LPG butane from the LPG plants at Bontang and Cilacap. The facility will be sited in East Kalimantan at Bunyu Island, with construction to begin in 1990 and product to be onstream in 1993. Investment costs are estimated at $139.6 million.

The current plan is to use the MTBE for domestic gasoline blending, since the government hopes to move to unleaded fuel by 1995. Indonesia has been producing two grades of leaded gasoline: 88 and 98 RON. The new gasoline standard would be a single grade: 92 RON clear. If the octane pool is sufficient, some of the domestically produced MTBE could be used for blending export-grade gasoline. If the export refinery ventures go forward, Indonesia's gasoline production capability will grow significantly, as will its potential demand for MTBE. At the present time, there are no plans to enter the merchant MTBE market. Still, if additional MTBE capacity is built at the new refineries, MTBE exports may become possible. The government recently stopped blending leaded premium gasoline, citing high costs and limited demand. Private companies, however, still have the option to buy 88 RON leaded and upgrade it to premium, provided that the additional octane is not the result of additional leading.

GOVERNMENT POLICIES IN REFINING

As mentioned, Pertamina is responsible for meeting domestic demand for petroleum products, and technically speaking, the country's domestic refining sector should be fully capable of meeting demand. Historically, however, supply imbalances have necessitated imports. If the income from BBM sales does not meet costs—including crude intake to domestic refineries, refinery operation, BBM import costs, storage, transportation, and marketing—the government makes a direct payment to Pertamina to cover the difference. In its subsidized status, there has been little incentive for Pertamina to become more outward looking; refined product output is nearly sufficient for domestic needs, and minor amounts of product trading are sufficient to balance the demand barrel. Potential opportunities for export marketing have been neglected.

Historically, Indonesia has not been a canny product trader, despite its sophisticated refinery configuration and its relatively favorable location. In part, suboptimal product exports have been the result of suboptimal refinery utilization. The government's top priority has been to maximize crude exports, and this has led to inefficiencies in the domestic refining sector, since actual crude slates vary so widely from design slates. Refinery effective capacity is currently estimated at 88% of nameplate, and the down-stream units are often underutilized.

The new direction is to capture the value-added of export refining and to become an active player in the regional product trade market. The government's chief impact on refining will be the extent of its commitment to EXORs 1-4. The presence of a number of foreign joint venture partners should provide a number of advantages besides capital. First, these partners are by their very nature outward looking, and they already appear to have a number of overseas markets in mind for the new output. Second, a number of the partners have considerable expertise in product blending, which may result in a wider array of products and more creative uses of intermediate blendstocks.

Other government policies affecting refining include the desire to supplant oil use in the power sector by increasing use of coal, natural gas, hydro, geothermal, and perhaps even nuclear power. Continuing price rationalization will most likely prevent runaway demand growth for other petroleum products as well. For example, reducing the kerosene price subsidy may increase LPG substitution, and natural gas development plans may provide ample supplies of LPG for this purpose.

The government also plans a substantial increase in petrochemical production, which will require additional supplies of naphtha and condensate as feedstock. Options exist for more complex feedstock trade between refineries and petrochemical facilities, though as yet there are no definite plans to integrate the two sectors.

Six

NATURAL GAS INDUSTRY

OVERVIEW

Indonesia is fortunate to have very large reserves of natural gas. As mentioned in Part Two above, Indonesia's gas reserves are currently estimated at about 91 trillion standard cubic feet (scf), which includes about 38 trillion scf in the Natuna Sea fields alone. Reserve estimates are expected to expand, since more gas fields are likely to be found. The abundance of this resource has stirred much excitement in Indonesia, since it is hoped that increases in natural gas production and utilization will play a major role in offsetting the decline in oil production that is expected to begin by the middle of the decade. Increased emphasis on gas in national energy policy, new discoveries, and growing interest among foreign oil companies all combine to provide the impetus for a new era in gas utilization.

The natural gas industry is relatively new in comparison to the oil industry. Natural gas was first used in 1958 by the fertilizer industry in South Sumatera, as a means of using the associated gas from oil wells in that region, which previously had been flared. Flaring has been further reduced by expanding the use of associated gas in other industries. Such uses are site-specific, however, and have been limited to cases where demand exists for the gas at the production sites. The government intends to further promote the use of associated gas and eliminate wasteful flaring practices wherever possible.

Throughout the Asia-Pacific region, natural gas use has been hindered by lack of infrastructure. Indonesia's situation is a case in point. Prior to the 1980s, most of the nonassociated gas deposits that had been identified were in remote areas. Plans to exploit these reserves focused on export opportunities, since the sites were too distant from population centers to make domestic uses of the gas practical. Recently, however, significant reserves of gas have been found nearer to populous areas; for example, the Poleng, Kangean, and Madura Strait fields are close to Java, and the Japex fields in North Sumatera are near to Medan.

Not until the liquefied natural gas (LNG) era began in the 1970s were plans made to develop Indonesia's abundant natural gas reserves. Fortuitously, two large fields were found in the early 1970s in Aceh Province in Sumatera and in East Kalimantan, at a time when Japan's gas demand was rapidly increasing because of its policy to utilize cleaner-burning fuels. Since the necessary LNG technology was already available, Indonesia seized the opportunity created by this demand and was among the first countries in the world to develop a significant LNG industry. Long-term contracts were established, and Indonesia has come to be regarded as a reliable supplier, both in term of deliveries and its willingness to cooperate in seeking improved agreements, such as price adjustments when market conditions warrant. This reputation has enabled Indonesia to continue the expansion of its LNG production. Indonesia is currently the biggest LNG producer in the world (an estimated 20 million tons in 1990) and accounts for more than 50% of the Japanese LNG market. Exports of LNG in 1989 were valued at US$2.95 billion.

Exports of liquefied petroleum gas (LPG) declined steadily from 1984 to 1988, but took a huge leap (an increase of 265%) in 1989 as two new LPG facilities came fully onstream. Singapore, Thailand, Hong Kong, and Australia are important customers, but by far the largest share of LPG exports is destined for the Japanese market. The first shipment under a long-term contract with Japan for 1.95 million tons per year was delivered in mid-1988, when Arun LPG production commenced. Japanese imports of Indonesian LPG in 1988 totalled over 682 thousand tons, around 2.3 times as much as 1987's figure of 296 thousand tons. By 1989 both the Arun and Badak LPG facilities were fully onstream, and total LPG exports to Japan jumped to nearly 2,105 thousand tons—three times the previous year's exports. LPG export revenues climbed from $48 million in 1987, to $85 million in 1988, and then to nearly $238 million in 1989.

As a means of promoting increased domestic uses of natural gas, government-related institutions have encouraged Pertamina and foreign operating companies to identify potential uses and attract more customers in the domestic market. The industrial sector is targeted as a potentially large consumer of gas, for both fuel and feedstock. When the proposed integrated gas grid is built in Java, it will provide an island-wide supply for the entire area where industrial concentration is greatest.

The electric power sector is seen as the biggest potential consumer of natural gas, since the fuel required by a single power plant could provide a steady, uninterruptable base demand which would support an entire gas project, thereby making it possible for smaller customers in the area to also switch over to gas. According to the national energy policy, there will be no further expansion of oil-fired power plants in Java. Since most of Java's hydropower potential has already been tapped, gas and coal are currently the only alternative domestic fuel sources for large-scale plants. The choice between these two fuels depends on the delivery price at the power plant, which is determined mainly by the location of the gas or coal field in relation to the power plant and by the economic criteria for developing the field. However, natural gas may the favored fuel in many cases, since environmental concerns will eventually place an upper limit on the amount of coal used in Java.

EXPLORATION AND FIELD DEVELOPMENT

Although the Indonesian LNG industry has been very successful, no exploration has been undertaken specifically to find natural gas. The discovery of gas fields has been only a by-product of oil exploration. The reasons are understandable: gas field development is technically more difficult, and the lack of ready markets has been a major disincentive for potential developers. As a contractor once remarked: "The problem in Indonesia is not finding gas but finding a market for it." Any future exploration, like the development of already-proved reserves, depends on the expansion of the gas market, which is likely to be slow. Lack of infrastructure has been a key constraint in the utilization of natural gas, especially for domestic uses.

Given these circumstances, most of the natural gas used domestically is associated gas that is a by-product of crude. Since the production costs had, for the most part, already been incurred in the development of the oil field, the government initially set the price of associated gas very low, with the intention of providing cheap fuel and feedstock to strategic industries such as fertilizer and steel. When it became clear that this policy further discouraged the development of natural gas fields, the government began to alter its natural gas pricing policies. The current pricing system is based on the economics of gas-field development, and an effort is made to determine a price acceptable to both seller and buyer. Domestic pricing is discussed in greater detail below.

Several nonassociated natural gas fields have been found recently. The potential for developing two of them is high because of size and location. One offshore field operated by Japex is near Medan, the biggest city in Sumatera. This field could supply gas-turbine and combined-cycle power plants and meet the local industry's increasing demand for city gas. Another field in Madura Strait, offshore East Java, is operated by Mobil Oil, and proven reserves are estimated at 17 trillion scf. The location is advantageous in that the gas can be used for power-plant expansion and to meet increasing industrial demand in East Java. It is also possible that an LNG plant will be built in this area.

The most recent development of nonassociated natural gas is an offshore field in East Java. Pertamina has concluded an agreement to sell PLN up to 150 million scf/d to supply PLN's gas-turbine and combined-cycle power plants in Gresik, East Java. PLN will be the biggest buyer. Other buyers, which together will account for additional demand of around 100 million scf/d, will be the petrochemical complex, other local industries, and city gas. The gas will be supplied from the Kodeco-operated Poleng fields, located northeast of Java, and the ARCO-operated Kangean fields, east of Madura (Figure 6.1). The gas will be transported by undersea pipeline to Gresik and will be distributed to the buyers through a local pipeline network.

Indonesia's biggest gas reserves are in the Natuna Sea. The problem with these reserves is the huge concentration of carbon dioxide gas—around 70% of the gas deposit is CO_2, which would have to be separated from the methane, ethane, and other hydrocarbons. In this era of rising concern over greenhouse gases, venting such an enormous amount of CO_2 into the atmosphere is strongly opposed. The contractor (Exxon) is planning to separate the CO_2 and inject it back into the ground, which will avoid excessive CO_2 emissions.

PRODUCTION

Indonesia's current gas companies and the types and locations of their fields are listed in Table 6.1. Table 6.2 shows production by operating company, 1986-89. The locations of major gas fields and LNG facilities are shown in Figure 5.5, which also detailed the locations of major oil fields.

The share of natural gas in domestic energy consumption increased during the 1980s (as discussed in Part Three above), and natural gas production grew steadily during the same period. Natural gas production grew at rates averaging approximately 7.3% per annum during the 1980s (Table 6.3 and Figure 6.2). Production is expected to continue its upward trend at similar growth rates; MIGAS forecasts that production will rise to 2,777 billion scf in 1993 from its 1989 level of around 1,975 billion scf. The increases in total production have not, however, been the sum total of uniform increases among all fields. Since the bulk of the gas is associated with crude oil production, field operators showing declines in crude production often show decreases in gas production as well. For example, ARCO's crude production fell from around 135 mb/d in 1988 to 125 mb/d in

Figure 6.1
Undersea Natural Gas Pipeline to East Java

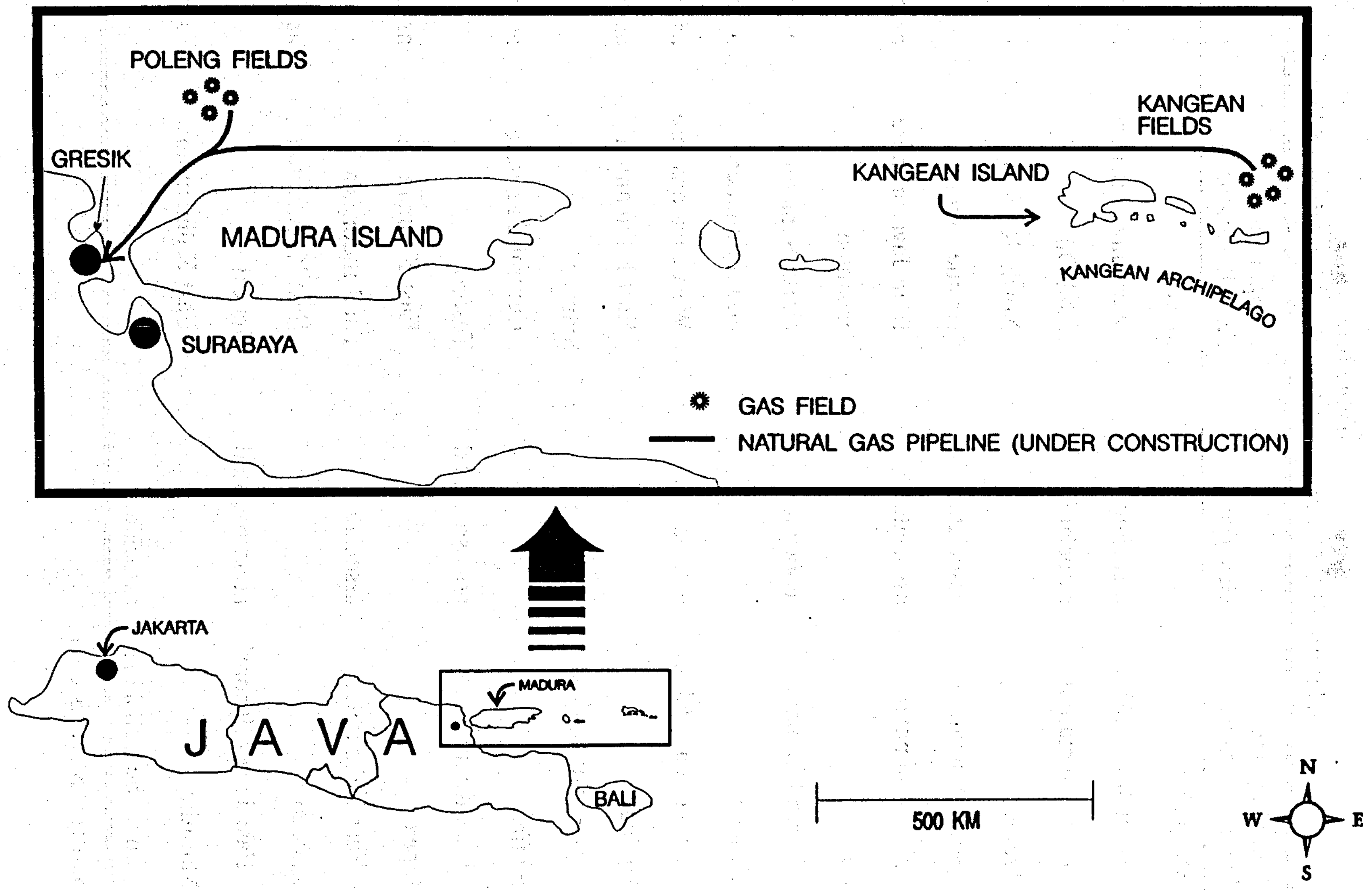


Table 6.1
Natural Gas Companies: Types and Locations of Fields

Company and Field Locations	Gas Type	Company and Field Locations	Gas Type
ARCO		Maxus	
West Java offshore	associated	West Java offshore	associated
East Kalimantan	associated	Mobil Oil	
Asamera		North Sumatera	nonassociated
South Sumatera	associated	Petromer Trend	
North Sumatera	associated	Irian Jaya onshore	associated
Caltex		Pertamina	
Central Sumatera	associated	North Sumatera	associated
Conoco		South Sumatera	associated
China Sea offshore	associated	West Java onshore	associated
Hudbay		East Kalimantan	associated
East Kalimantan	associated	Stanvac	
Huffco		Central Sumatera	associated
East Kalimantan	nonassociated	Tesoro	
Inpex		East Kalimantan	associated
East Kalimantan	associated	Total Indonesia	
Kodeco		East Kalimantan	associated
East Java offshore	nonassociated	Unocal	
Marathon		East Kalimantan	associated
China Sea offshore	associated		

Source: MIGAS data.

Table 6.2
Natural Gas Production by Operating Company, 1986-89
(million scf)

Company	1986	1987	1988	1989	1989 Share (%)
ARCO	68,403	64,345	59,000	55,777	2.82
Asamera	5,836	11,140	14,186	22,531	1.14
Caltex	31,081	32,304	28,615	30,512	1.54
Conoco	2,934	3,122	2,564	2,699	0.14
Hudbay	1,599	1,757	1,615	2,243	0.12
Huffco	381,530	379,472	436,925	453,147	22.93
Maxus	1,4274	11,996	11,177	13,658	0.69
Inpex	67,584	68,369	65,912	72,340	3.66
Kodeco	2,312	1,300	1,130	789	0.03
Lemigas	158	222	0	0	0.00
Marathon	6,715	11,450	9,116	11,363	0.58
Mobil	704,119	795,417	858,591	935,590	47.36
Pertamina	229,110	240,336	248,375	253,224	12.81
Petromer Trend	5,240	5,392	5,155	5,168	0.26
Stanvac	21,863	20,726	22,205	25,060	1.26
Tesoro	1,798	1,213	1,075	1,317	0.06
Total Indonesia	41,117	40,017	34,982	37,219	1.88
Unocal	43,247	43,472	46,238	52,784	2.67
Total	1,628,920	1,732,050	1,846,861	1,975,421	100.00

Note: Production volumes include gas stripped of liquids and reinjected.

Source: MIGAS data.

Figure 6.2
Natural Gas Production, 1980-93

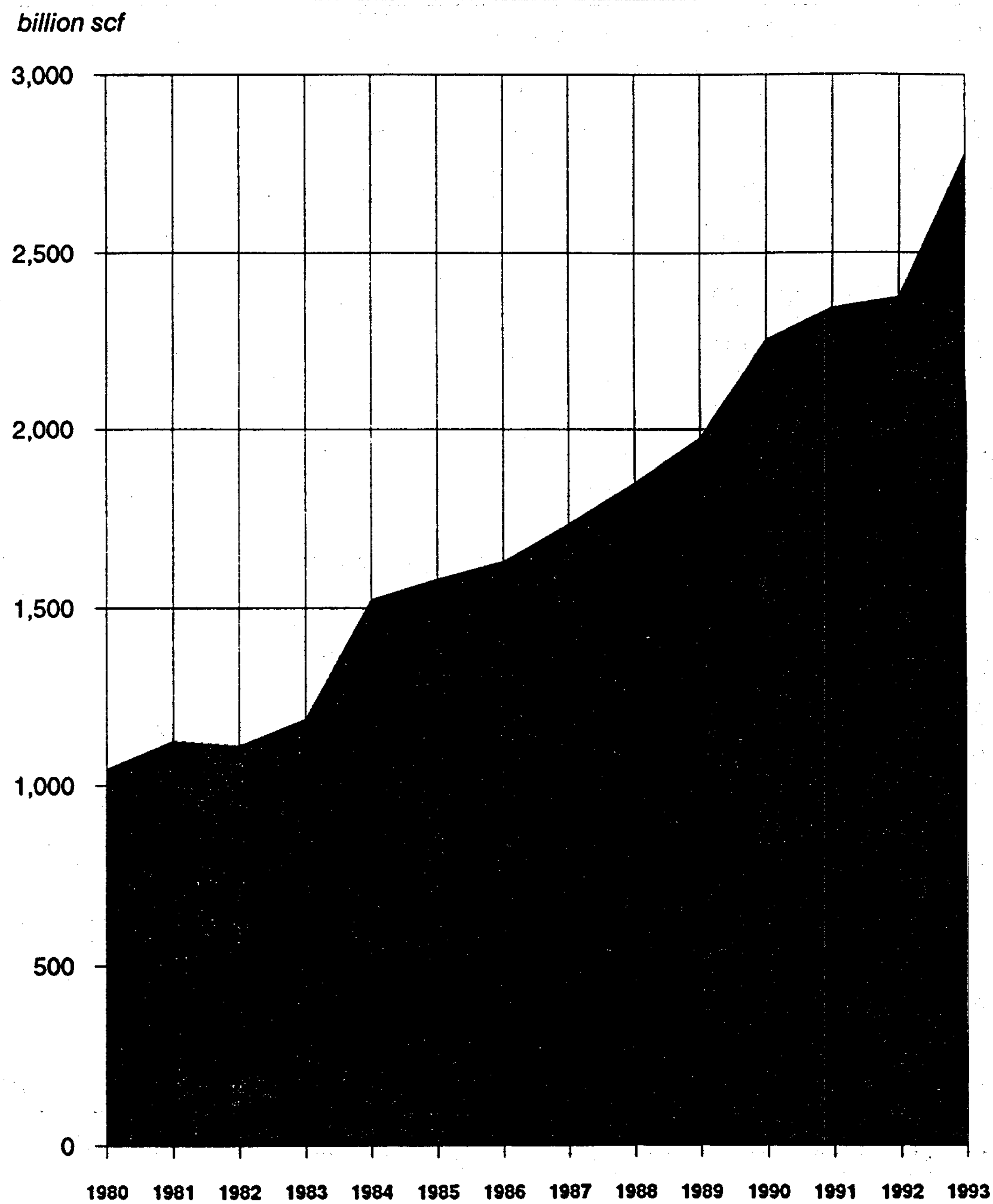


Table 6.3
Natural Gas Production, 1980-93
(billion scf)

Year	Production
1980	1,046
1981	1,124
1982	1,112
1983	1,186
1984	1,521
1985	1,580
1986	1,629
1987	1,732
1988	1,847
1989	1,915
1990	2,257
1991	2,346
1992	2,376
1993	2,776

Note: Data for 1989-93 are projections.

Source: MIGAS data.

1989, and its natural gas production fell from 59 billion scf to 55.8 billion scf concurrently.

Although seventeen companies were operating in 1989, over 80% of natural gas production was accounted for by just three operators: Mobil Oil alone accounted for over 47% of the total; Huffco's share was around 23%; and Pertamina's share was 13%. Most of the gas produced by the two biggest companies is destined for LNG production in their Arun (Mobil Oil) and Badak (Huffco) plants.

UTILIZATION

Table 6.4 details Indonesia's pattern of natural gas utilization, 1986-89. Two-thirds of net gas production in Indonesia in 1989 was liquefied and exported. The remainder was used chiefly as feedstock for fertilizer plants: 11% of *net marketed* production, plus a portion of the 4% share accounted for by the Cilamaya complex (which includes the Kujang Fertilizer Plant). The combined share of city gas and gas-fired electric power generation was only around 1.4%, although this marked a significant increase over the previous year (state electricity use grew by nearly 42% while city gas use increased by 478%). An effort has been made to introduce the use of gas in the transportation sector. Tests have been made with compressed natural gas (CNG) as a fuel for taxis in Jakarta, and the use of natural gas for buses and private cars is also under consideration.

Most of the remainder of net production is accounted for by flaring. Flaring in the oil fields is considered an undesirable waste of a valuable resource, and it runs contrary to the government's desire for maximum utilization of associated gas. In the early 1970s around two-thirds of total gas production was flared or lost. By 1980 this figure had been cut to around 20%. By working together to find potential uses, MIGAS, Pertamina, and the contractors have managed to significantly increase utilization rates, but as Table 6.4 establishes, flaring and losses still amounted to around 9.5% of net production in 1989. It will be difficult to reduce flaring much beyond this level in the near term, since most of the flaring occurs at offshore oil rigs, where there is a lack of infrastructure to gather and use the gas.

FUTURE GAS DEVELOPMENTS

The current five-year development plan forecasts steady increases in natural gas production and utilization during the plan period 1989-93 (Table 6.4). This forecast takes into account the following plans:

- Expansion of the Arun and Bontang LNG plants
- New LPG plants at Arun and the Musi complex (Plaju and Sungai Gerong)
- Expansion of fertilizer plants in East Kalimantan
- Gas-fired generation in the Gresik power plant
- Increased sales of city gas
- Use of gas as feedstock for new petrochemical products
- Increased CNG use for public transport in large cities

Table 6.4
Natural Gas Production, Utilization, and Losses, 1986-89
(million scf)

Item	1986	%	1987	%	1988	%	1989	%
Production								
Gross production	1,628,919		1,732,052		1,848,801		1,975,421	
Gas injection	245,686		249,668		251,824		262,062	
Gas lift	52,879		58,699		62,239		70,356	
Net production	1,330,354		1,423,685		1,534,738		1,643,003	
Utilization								
Own-use fuel	83,087	6.2	88,032	6.2	88,876	5.8	97,366	5.9
Sales								
State electricity	2,780	0.2	5,191	0.4	7,450	0.5	10,489	0.6
Fertilizer	136,074	10.2	138,681	9.7	142,260	9.3	153,201	9.3
City gas	1,295	0.1	1,674	0.1	1,511	0.1	8,740	0.5
Cilamaya[a]	76,504	5.8	77,792	5.5	76,812	5.0	55,108	3.4
Other industries	2,297	0.2	3,054	0.2	3,605	0.2	7,368	0.4
Subtotal sales	218,950	16.5	226,392	15.9	231,588	15.1	234,906	14.2
Sent								
To refineries	18,956	1.4	20,860	1.5	26,335	1.7	29,268	1.8
To LNG plants	834,411	62.7	917,032	64.4	1,025,002	66.8	1,089,763	66.3
To LPG/Lex plants[b]	40,980	3.1	24,453	1.7	29,164	1.9	36,339	2.1
Subtotal sent	894,347	67.2	962,345	67.6	1,080,501	70.4	1,155,370	70.3
Total utilization	1,196,384	89.9	1,276,769	89.7	1,400,965	91.3	1,487,642	90.5
Losses (flaring and other)[c]	133,970	10.1	146,916	10.3	133,773	8.7	155,361	9.5

Notes: a. Includes gas supplied to the Kujang Fertilizer Plant (Cikampek, West Java), the Krakatau Steel Plant (Cilegon, West Java), the Kujang Cement Plant (Cibinong, West Java), the Indocement Plant (Cibinong, West Java), and PGN (city gas in Jakarta and Bogor, West Java).
b. Includes condensate.
c. Includes shrinkage.

Source: MIGAS, *Data Pendukung*, 1989.

In addition, the Natuna field will be developed, and production is expected to begin toward the end of the current five-year plan in 1993. Natuna gas will initially be used for the Duri Steam Flood Project, and will also be sold to Singapore, but in the longer term it may also be exported as LNG. To hasten the expansion and diversification of domestic demand for natural gas, the government plans to construct an integrated pipeline and related infrastructure in Java. The Java pipeline will tap the recently discovered offshore fields and should greatly increase domestic consumption of natural gas.

DOMESTIC PRICES

Historically, the domestic price of natural gas has been set lower than its economic value. Pricing policy has thus provided no financial incentive for contractors to increase gas production and has discouraged development of nonassociated reserves in particular. The low domestic oil price, moreover, provided no incentive for fuel switching and thus prevented gas producers from diversifying their customers. Indonesia's energy pricing policies have, over the years, introduced serious distortions into the domestic market. In Bandung and Semarang, Central Java, for example, the city gas was manufactured from kerosene. The price of kerosene was so heavily subsidized that kerosene gasification—which is unheard of in most economically rational markets—emerged as a standard practice, and only recently were city gas operations shut down in these cities. PGN, the state gas company, has now fully replaced manufactured gas with natural gas and LPG.

The fixed pricing system was established in a June 1984 decree issued by the Minister of Mines and Energy. It imposed ceiling prices on natural gas consumed by domestic industries. The basic price categories in the decree, which contains no provision for price escalators or transportation charges, are as follows:

- PT Krakatau Steel (steel industry) is charged US$2.00 per million BTU for gas used as fuel for electricity generation and US$0.65 per million BTU for gas used as a raw material in the production process.
- Fertilizer plants are charged US$1.00 per million BTU.
- Other industries are charged US$3.00 per million BTU.

The decree makes no provision for the government's city gas distribution company (PGN), which is charged Rp. 3,500 per million BTU (slightly less than US$2 per million BTU at the present exchange rate). Most producers feel that natural gas sold at these rates is generally underpriced, and they are understandably reluctant to invest in gas development if sales revenues are so low.

The government has recognized the incompatibility between gas pricing policy and the goal of promoting gas development and use, and steps are being taken toward price reform. To encourage further development of natural gas for domestic uses, the government has recently announced that future determinations of natural gas price will be made on a case-by-case basis, taking into consideration the economics of field development and working to establish a price acceptable to both seller and buyer. In response to this announcement, several contractors have submitted proposals for supplying natural gas to the domestic market. Recently, an agreement was concluded by Pertamina for sales to the State Electric Power Corporation (PLN) at a price of US$2.53 per million BTU, to fuel PLN's Gresik power plant in East Java. The gas will be supplied by a pipeline from the Poleng and Kangean fields.

LIQUEFIED NATURAL GAS (LNG)

Liquefying natural gas is a capital-intensive process, since methane (C_1), a chief constituent of natural gas, has a boiling point of around -260° F. Natural gas must therefore be chilled and subjected to considerable pressure before it will liquefy. The liquefaction facilities, LNG tankers, and regasification facilities that make up an "LNG train" are specialized and expensive. Still, liquefaction has been the chief process by which Indonesia has been able to develop remote natural gas deposits for export.

When Indonesian LNG exports commenced in 1977, the United States was a significant market, but U.S. imports have fallen off sharply, and the U.S. West Coast market—which had been considered very promising—never opened to LNG imports at all. Japan is by far the major customer for Indonesia's LNG; for nearly a decade, Japan was the only customer. More recently, additional buyers have been found in South Korea (since 1986) and Taiwan (beginning in 1990). Taiwan is emerging as a major market; 27 cargoes totalling 1.5 million tons were scheduled for Taiwan in 1990, and a 20-year supply commitment has been made. Because of the increasing concern in these countries about the environmental impacts of coal and oil use, East Asian demand for LNG is expected to increase steadily.

Indonesia is the world's leading exporter of LNG and exported 342 cargoes totalling 18.7 million tons in 1989. With the startup of Taiwanese trade, preliminary figures for 1990 show that exports reached 366 cargoes totalling approximately 19.5 million tons—Japan contracted for 16 million tons, Korea for 2 million tons, and Taiwan for 1.5 million tons. Details on LNG exports, 1977 to 1990, are provided in Table 6.5 and Figure 6.3.

Indonesia has two LNG plants, both of which produce solely for export. There is no domestic market for LNG in Indonesia. PT Badak in Bontang, East Kalimantan, came onstream in August 1977, and PT Arun in Aceh Province, Sumatera, began production one year later. The steady increase in LNG exports since 1977 is entirely due to the continuing expansion of these two plants. They began operations with 5 trains (3 in Arun and 2 in Bontang) and currently have 11 (6 in Arun and 5 in Bontang). Existing and planned LNG facilities are detailed in Table 6.6. The capacity expansion plans at Arun and Bontang are being scheduled to coincide as closely as possible with demand expansion in Japan, Taiwan, and Korea.

Development of a grassroots LNG facility at the Natuna Island gas field is highly tentative at this point; it appears more likely that any development of the field will involve a pipeline strategy rather than an LNG plant. The estimated gas reserves are huge—estimated at 38 trillion scf, amounting to 41% of proven reserves—but the gas is around 70% carbon dioxide. Esso, the operating company, has informed the government that they will be able to handle the CO_2 volumes by reinjection, and the two parties have agreed to develop an integrated pipeline system from the field to Batam Island, which is an Indonesian industrial development site near Singapore, and from there on to Singapore itself. The pipeline will also provide gas to the Duri oil field in Sumatera for use in the steamflood project. In 1989 Caltex, operator of the Duri enhanced oil recovery (EOR) project, used 18% of the produced crude as fuel for the EOR project—amounting to around 25 mb/d. As Duri production approaches its peak of 300 mb/d within the next few years, 50 mb/d would theoretically be required on-site. Connecting a gas pipeline to the oilfield will free this oil for export. The gas may also be piped to the existing Mobil Arun LNG facility, although Esso would prefer to have its own LNG facility at Natuna rather than piping the gas to Arun. The government appears to favor the option of piping the gas to Arun, however, partly because recent exploration efforts in the Arun area have had only limited success. Massive investments already have been made in the Arun facility, and the motivation is naturally very strong to maintain supplies of gas for liquefaction and export.

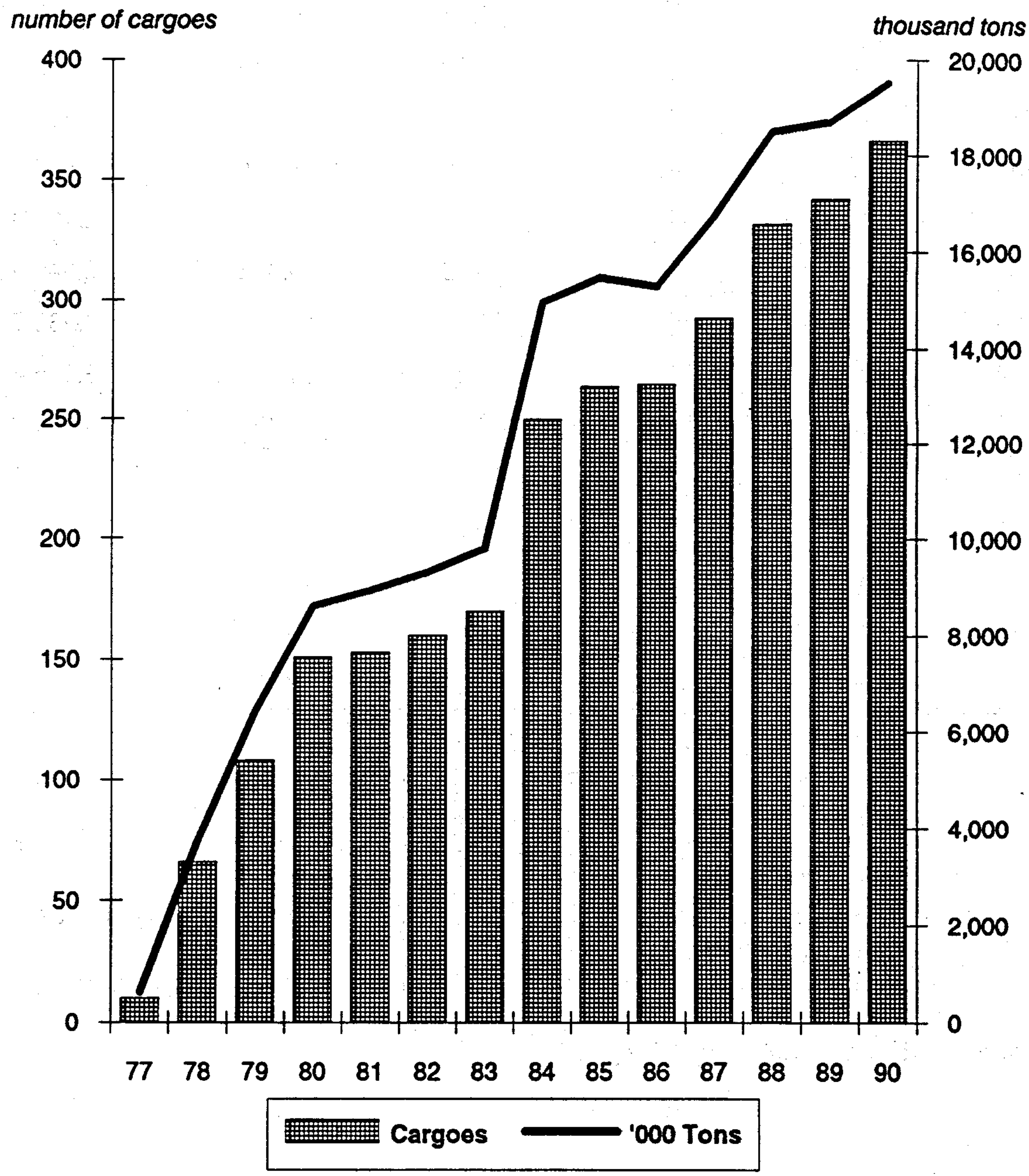
Table 6.5
LNG Exports, 1977-90

Year	Number of Cargoes	Trillion BTUs[a]	Volume[b] (million cubic meters)	Volume[b] (million tons)	Value[c] (US$ millions)
1977	10	28	1.34	0.623	72.3
1978	66	192	8.10	3.763	542.2
1979	108	323	13.85	6.435	1,123.4
1980	151	441	18.50	8.596	2,327.2
1981	153	446	19.21	8.926	2,496.9
1982	160	468	20.02	9.302	2,640.9
1983	170	499	21.10	9.804	2,532.7
1984	250	738	32.20	14.961	3,396.4
1985	264	779	33.30	15.472	3,801.0
1986	265	783	32.52	15.300	2,847.3[d]
1987	293	865	36.00	16.770	2,709.0
1988	332	955	39.69	18.508	2,923.7
1989	342	965	38.60	18.634	2,951.5
1990[e]	366	1,006	41.97	19.500	

Notes:
a. Indonesia is paid for BTU's delivered.
b. Volume in cubic meters represents LNG delivered to the purchaser. The equivalent in tons is based on 464.63 kilograms per cubic meter.
c. Contracted cargoes CIF for 1977-80 and contracted cargoes FOB for 1981-90.
d. Adjusted for overinvoiced receipts of $568 million and repayment of $591 million in overcharges.
e. Preliminary estimates of the Energy Program, East-West Center.

Source: MIGAS, *Data Pendukung*, 1989.

Figure 6.3
LNG Exports, 1977-90



Note: 1990 figures are East-West Center preliminary estimates.

Table 6.6
Existing and Planned LNG Facilities

Facility	Completion Date
Existing facilities	
PT Arun	
Trains I-III	1978
Train IV	1983
Train V	1984
Train VI	1986
Total capacity: 9.8 million tonnes	
PT Badak (Bontang)	
Trains A-B	1977
Trains C-D	1983
Train E (2.3 million tonnes)	1989
Total capacity: 11.5 million tonnes	
Planned expansions	
PT Arun	
Train VII (22.0 million tonnes)	1995
PT Badak	
Train F (2.3 million tonnes)	1994
Train G (2.3 million tonnes)	1996
Under consideration	
Natuna Island	
Trains 1-3 (total 6.9 million tonnes)	under consideration

LIQUEFIED PETROLEUM GAS (LPG)

Liquefied petroleum gas (LPG) is produced by both refineries and dedicated LPG plants, which are usually linked with gas fields. The chief constituents of LPG are propane (C_3) and butane (C_4), which have substantially higher boiling points than the methane (C_1) and ethane (C_2) fractions of natural gas and are therefore much easier to liquefy. Unlike LNG, LPG has both export and domestic markets. Domestically, it is used for heating in the industrial and household sectors, and domestic sales have increased steadily during the 1980s. As Table 6.7 notes, LPG domestic sales rose from around 86.5 thousand tons in 1983 to around 265.2 thousand tons in 1989. Some middle- and high-income households in the big cities have already begun using LPG instead of kerosene.

During the 1984-87 period, LPG production was dominated by the Arjuna gas plant and the Cilacap refinery. But after reaching a peak in 1984, production from the Arjuna plant declined steadily and was not counterbalanced by increased production at other facilities until 1988, when the Arun gas plant (now the biggest producer) and the Badak plant came onstream in June 1988 and November 1988, respectively. Production from these two new facilities climbed to nearly 1.9 million tons in 1989, thereby more than doubling the previous year's total LPG production from all facilities combined. Production capacity expansions are planned for several other existing facilities, and a new LPG plant is planned for the Musi refinery complex. The construction of the new export-oriented refineries in the mid- to late-1990s will also boost LPG production capacity.

Although the government has encouraged substitution of LPG for kerosene in the domestic market, the first priority for further expansion of LPG production is given to export sales, which declined between 1984 and 1986. LPG exports by destination are shown in Table 6.8. The Japanese market accounts for 85% of LPG exports, and Singapore historically has accounted for most of the remainder, although Korea emerged in 1989 as the second largest importer. After a decline of several years, the volume of exports to Japan more than doubled in 1988, and then more than tripled in 1989. As the volume of LPG exports declined in the mid-1980s, the total value of LPG exports declined even more sharply, since LPG prices—and oil prices in general—were falling. In volume terms, Indonesia's LPG exports to Japan in 1988 were more than 1.5 times the amount exported in 1984, but in current dollar terms, the value of the exports was barely two-thirds as much as the 1984 level. The most recent commitment for large-scale export

Table 6.7
LPG Production, Domestic Sales, and Exports, 1983-89
(tons)

Item	1983	1984	1985	1986	1987	1988	1989
Production by refineries							
Cilacap	10,222	103,848	105,837	125,743	135,297	127,190	138,130
Balikpapan	-	52,531	87,036	76,682	80,302	87,318	78,811
Dumai	-	8,506	24,159	46,329	23,767	22,302	36,954
Musi River[a]	36,986	21,496	3,522	9,439	33,140	56,487	47,513
Production by gas plants							
Arjuna	331,835	579,650	466,623	438,317	379,231	353,696	254,719
Arun	-	-	-	-	-	445,627	1,526,584
Badak	-	-	-	-	-	32,952	352,142
Mundu	24,333	24,915	28,014	29,187	22,075	22,632	24,199
Rantau	16,421	16,036	16,210	17,497	16,136	14,002	13,612
Tanjung Santan	94,401	84,731	87,680	87,255	90,354	90,927	99,523
Total production	514,198	891,713	819,081	830,449	780,302	1,253,133	2,572,687
Domestic sales	86,522	110,578	145,617	180,268	216,161	235,099	265,195
Exports	364,689	725,148	635,438	524,443	525,915	972,320	2,481,409

Notes: - Nil.
a. Plaju and Sungai Gerong refineries.

Source: MIGAS, *Data Pendukung*, 1989.

Table 6.8
LPG Exports by Destination, 1984-89

Destination, Volume, and Value	1984	1985	1986	1987	1988	1989
Japan						
Tons	447,180	368,062	349,533	295,949	682,083	2,104,926
US$ millions	99.018	77.810	46.302	34.000	69.678	209.060
Singapore						
Tons	118,398	210,799	152,576	193,665	179,184	103,136
US$ millions	15.761	26.373	8.673	10.696	9.145	4.721
Hong Kong						
Tons	26,238	16,107	7,211	9,321	19,679	32,835
US$ millions	4.722	2.899	787	678	1.156	2.157
Thailand						
Tons	81,022	3,0641	13,802	16,604	40,573	39,773
US$ millions	15.609	5.524	1.092	1.566	3.389	2.526
Australia						
Tons	—	—	—	6,640	14,806	2,629
US$ millions	—	—	—	632	1.357	0.159
Korea						
Tons	1,597	—	—	—	—	153,918
US$ millions	266	—	—	—	—	15.329
Malaysia						
Tons	—	614	—	—	—	—
US$ millions	—	111	—	—	—	—
Philippines						
Tons	6,324	6,030	—	—	—	33,978
US$ millions	1.205	2.899	—	—	—	3.126
USA						
Tons	44,388	—	—	—	—	1,547
US$ millions	8.017	—	—	—	—	.102
Other countries						
Tons	—	3,185	1,321	3,736	7,490	8,667
US$ millions	—	605	224	318	607	.587
Total						
Tons	725,147	632,253	523,122	522,179	936,325	2,481,409
US$ millions	144.598	116.221	57.078	47.890	85.332	237.766

Note: — No exports.

Source: U.S. Embassy, Jakarta 1990.

is an agreement to supply 1.95 million tons per year to Japan beginning in 1989. Actual Japanese imports of Indonesian LPG in 1989 exceeded 2.1 million tons.

Under the fifth five-year development plan, LPG production is projected to increase from 2.56 million tons in 1990 to 3.37 million tons in 1993, with a corresponding increase in exports from 2.23 million tons to 2.91 million tons.

CITY GAS

The city gas networks that supply the industrial, commercial, and household sectors are operated by Perusahaan Gas Negara (PGN), a state-owned company under the control of the Minister of Mines and Energy. PGN currently provides gas for heating in major cities in three provinces: (1) Jakarta, Bogor, and Cirebon in West Java, (2) Surabaya in East Java, and (3) Medan in North Sumatera. Given the comparative advantages of city gas over other heating fuels, these networks have great potential for expansion, which will boost domestic natural gas consumption. The three city-gas networks in West Java were the first to move completely away from manufactured gas. Medan and Surabaya were still supplied, until 1986 and 1987, respectively, by gas manufactured from either oil products or coal, which entailed higher operating costs. Manufactured gas has now been fully phased out in all cities. When the integrated gas network is constructed across Java, all of the cities connected to the network plus potential other cities will be supplied by natural gas.

During the fourth five-year development plan, gas sales increased from 2,712 million scf (76.8 million cubic meters) in 1984 to 7,813 million scf (221.2 million cubic meters) in 1988, representing an average annual increase of about 30% (Table 6.9). The biggest gas consumers are in the industrial sector, most of which is concentrated in the cities with gas networks. In 1987, 87% of PGN's sales were to industry, 10% to the household sector, and 3% to the commercial sector and other uses. PGN regards industrial users as its first-priority customers, not only because of their predominance in PGN sales but also because the industrial demand in these cities creates an overall base demand which in turn makes it economical to supply other gas users within the network.

Because of the rapid growth of the industrial sector in Indonesia, PGN is facing continued rapid increases in gas demand. According to the current five-year development plan, PGN gas sales are projected to increase from around 17,138 million scf (485 million cubic meters) in 1989 to 36,900 million scf (1,045 million cubic meters) in 1993 (Table 6.9). The expansion of supply to existing and potential customers is limited

Table 6.9
PGN Gas Sales, 1984-93

Year	Gas Sales (million scf)	Increase over Previous Year (%)
1984	2,712.2	—
1985	3,717.9	37
1986	5,032.3	35
1987	6,408.9	27
1988	7,812.7	22
1989	17,138.2	119
1990	17,205.3	0
1991	25,055.8	46
1992	29,212.3	17
1993	36,900.3	26

Notes: — Not available. Data for 1989-93 are forecasts.

Source: MIGAS 1989.

structurally by the geographical coverage and capacity of the existing network. During the current development plan period, PGN's primary objective is to increase supply capacity, especially in areas such as Jakarta, Bogor, Cirebon, Medan, and Surabaya, where demand is growing fastest. World Bank funding was received in 1986 for rehabilitation and expansion of the Jakarta, Bogor, and Cirebon networks, and further funding has been granted for expansion of PGN's gas systems in Surabaya and Medan, including the expansion of transmission pipelines (for high-pressure gas) and distribution pipelines (for low-pressure gas). Funding is also being sought from the Asian Development Bank for expansion of PGN activities in other cities.

Seven

PETROCHEMICAL INDUSTRY

OVERVIEW

Policies relating to the petrochemical industry in Indonesia are formulated by the Ministry of Industry, and the manufacture and sale of petrochemicals are regulated like those of other industrial products. The ministry subdivides chemicals into four industrial categories: (1) the cellulose and rubber industry, which includes pulp, paper, and motor vehicle tires; (2) the agricultural chemical industry, which includes fertilizers and pesticides; (3) the organic chemical industry, which includes petrochemicals and fine chemicals; and (4) the inorganic chemical industry, which includes cement, glass, and basic inorganic chemical products.

The Ministry of Mines and Energy also is involved in petrochemical development plans, because Pertamina is the sole source of feedstocks. Pertamina therefore plays a direct role in planning and also produces some petrochemical products, mainly as by-products from its refinery facilities. In contrast to Pertamina's nationwide responsibilities for oil and gas operations, however, there is no comparable state-owned company in charge of the petrochemical industry. Private companies are allowed to invest in the industry and manufacture their own products. Among the projects approved by the government for the current five-year plan, Pertamina has one project at the site of the Cilacap refinery, and fifteen other projects are being implemented by private companies.

The government of Indonesia has supported the development of the petrochemical industry for three key reasons: (1) the availability of adequate reserves of oil and natural gas as feedstock; (2) the domestic market potential and foreign market opportunities; and (3) the benefits to the domestic economy from investment by multinational and other foreign corporations. The development of the domestic industry in Indonesia was geared initially to meet domestic demand for products such as plastics, textiles, medicines, and fertilizers. The industry is now far more sophisticated and provides a wide range of products, including ammonia, urea, methanol, formic acid, polyvinyl chloride (PVC), purified terephthalic acid (PTA), polystyrene, polypropylene, staple fiber and yarn, polyethylene terepthalate (PET), nylon yarn, nylon tire cord (NTC), phthalic anhydride, maleic anhydride, dioctyl phthalate (DOP), formaldehyde resin, synthetic resin, alkylbenzene, and alkyl benzene sulfonate. As shown in Table 7.1, new products were added each year during the fourth five-year plan, and also in 1989, the first year of the fifth five-year development plan. During the fourth plan period, the capacity increase from 942 thousand tons (7 key products) in 1984 to 2,095.3 thousand tons (16 key products) in 1988 represented an average annual growth rate of 22%. Actual production achieved during this period is shown in Table 7.2. During the fourth five-year plan, the value of petrochemical product output grew in rupiah terms at a remarkably high average annual rate of 92%, and the value of output in 1988 was nearly fourteen times that of 1984.

The initial goal in developing the petrochemical industry was to meet domestic demand. The industry has also capitalized on the opportunity to export certain products, with encouragement from the government to develop export options as a means of increasing the national share of nonoil and nongas exports (although oil and gas are of course feedstocks). A national economic goal is to diversify exports so that the value-added from industrial processes can be captured, thus generating multiplier effects, such as increased employment and regional economic development. In recent years some products have been exported, including alkyd resin, nylon tire cord, surfactants, ammonia, urea, and formic acid.

Indonesia is somewhat unusual among OPEC chemical producers in that its production of derivative products is diversified, but its production of the "building block" olefins (ethylene, propylene, and butadiene) is negligible. Most of the OPEC nations that expanded, or attempted to expand, into petrochemicals in the 1980s did so on the basis of plentiful feedstocks for olefin manufacture. Indonesia has built from the market "backwards," whereas countries such as Saudi Arabia are attempting to branch into secondary chemicals to utilize their primary output, Indonesia already has secondary chemicals, but none of the primary inputs. In many ways the Indonesian approach is much more stable, since outlets for any future primary production are already established. Major investments in olefins capacity are already underway.

Since the rapid spurt of growth in downstream petrochemical production capacity was not balanced by commensurate development in the upstream sector, the result was a shortage of feedstock for the petrochemical industries, which could only be met through imports. The value of imports of petrochemical raw materials jumped from US$415 million in 1987 to US$700 million in 1988 (*Asian Oil and Gas*, November 1989).

Table 7.1
Petrochemical Industry Installed Capacity by Product, 1984-88
(tons)

Product	1984	1985	1986	1987	1988
Adhesive resin	577,100	659,100	832,600	840,100	880,100
Alkyl benzene	-	60,000	60,000	60,000	60,000
Alkyl benzene sulfonate	71,600	86,600	86,600	98,600	109,400
Dioctyl phthalate	-	30,000	30,000	30,000	33,000
Formic acid	-	-	-	-	10,000
Maleic anhydride	-	-	-	-	1,200
Methanol	-	-	330,000	330,000	330,000
Nylon tire cord	-	12,000	12,000	16,000	16,000
Phthalic anhydride	-	-	-	-	30,000
Polyester staple fiber	83,050	83,050	88,050	119,600	119,600
Polyester filament yarn	80,868	80,868	90,868	102,868	137,618
Polypropylene	-	-	-	10,000	10,000
Polystyrene	-	14,000	14,000	14,000	27,600
Polyvinyl chloride	84,000	84,000	84,000	94,000	94,000
Pure terephthalic acid	-	150,000	150,000	150,000	150,000
Resin synthetic	41,200	41,200	57,700	79,270	82,270
Urea	4,530	4,530	4,530	4,530	4,530
Total	942,348	1,305,348	1,840,348	1,948,968	2,095,318

Note: - No installed capacity.

Source: Ministry of Industry data.

Table 7.2
Petrochemical Production by Volume and Value, 1984-88

	1984		1985		1986	
Product	(tons)	(million rupiah)	(tons)	(million rupiah)	(tons)	(million rupiah)
Adhesive resin	269,310	73,760	289,290	123,770	313,752	68,628
Alkyl benzene	—	—	9,411	9,411	50,187	52,134
Alkyl benzene sulfonate	52,427	42,684	59,657	51,733	61,910	65,335
Dioctyl phthalate	—	—	10,093	8,223	24,125	24,031
Formic acid	—	—	—	—	—	—
Methanol	—	—	—	—	100,000	13,200
Nylon tyre cord	—	—	—	—	—	—
Phthalic anhydride	—	—	—	—	—	—
Polyester filament yarn	49,300	168,256	63,200	231,121	83,962	334,713
Polyester staple fiber	73,335	102,669	74,950	112,425	79,620	136,182
Polypropylene	—	—	—	—	—	—
Polystyrene	—	—	7,944	9,858	14,055	16,945
Polyvinyl chloride	68,704	59,021	72,705	60,010	88,000	71,891
Pure terephthalic acid	—	—	—	—	56,000	41,650
Resin synthetic	38,169	30,161	45,480	50,579	46,242	49,291
Urea	3,044	736,822	3,690	887,924	3,958	912,939
Total	554,289	1,213,373	636,420	1,545,054	921,811	1,786,939

Table 7.2. Continued.

	1987		1988	
Product	(tons)	(million rupiah)	(tons)	(million rupiah)
Adhesive resin	543,541	154,610	631,872	271,731
Alkyl benzene	55,300	70,362	66,000	99,777
Alkyl benzene sulfonate	52,654	69,243	59,270	79,085
Dioctyl phthalate	22,456	36,644	22,600	42,978
Formic acid	—	—	2,210	2,630
Methanol	183,724	19,398	270,000	46,428
Nylon tyre cord	10,521	94,575	13,400	151,146
Phthalic anhydride	—	—	9,000	11,183
Polyester filament yarn	88,153	369,982	115,352	430,500
Polyester staple fiber	93,267	195,861	100,297	225,000
Polypropylene	1,737	3,275	6,000	11,430
Polystyrene	11,855	26,981	16,893	51,833
Polyvinyl chloride	83,131	133,502	80,828	197,763
Pure terephthalic acid	122,245	101,635	130,000	132,314
Resin synthetic	51,926	83,549	65,232	122,893
Urea	4,154	1,038,156	4,178	1,012,327
Total	1,324,664	2,397,773	1,593,132	2,889,018

Note: — No production. For rupiah/US$ exchange rates, see Table 1.4.

Source: Ministry of Industry data.

Moreover, despite the massive growth in petrochemical production capacity, the Indonesian domestic market was far from saturated, and imports of chemical products (mostly consisting of petrochemical products) continued to increase during the mid-1980s (Table 7.3). Prominent among the petrochemical imports necessitated by domestic demand during the fourth five-year plan were (1) olefin derivatives (particularly feedstock for plastics, such as polyethylene, polypropylene, vinyl chloride monomer or VCM, ethylene glycol, and polyol); (2) aromatics derivatives (such as para-xylene, ortho-xylene, benzene, caprolactam, and phenol; (3) gas synthetics and C_1 derivatives (such as melamine, nitric acid, ammonium nitrate, penta-erythritol, methylamines, and 2-ethylhexanol; and (4) fine chemicals (such as rubber chemicals, plastic additives, dyestuff, pharmaceuticals, and pesticides). Overall, the value of chemical imports rose from around US$1.5 billion in 1986 to nearly US$2 billion in 1988.

Continuing strong domestic demand, coupled with the availability of oil and gas feedstocks, imply that ample opportunities still exist for future development of the nation's petrochemical industry. In addition, if internal distribution of feedstocks is improved, Indonesia may gain a comparative advantage in the petrochemical export market.

Table 7.3
Imports of Chemical Products by Value, 1987-88
(US$ millions)

Product	1986	1987	1988
Organic chemicals	597.3	608.2	777.4
Plastic materials	539.2	641.2	707.4
Inorganic chemicals	362.7	471.0	511.8

Note: Plastic materials include cellulose and resin-based plastic materials.

Source: Central Bureau of Statistics data.

CURRENT POLICY AND PLANS

The government's policies for the petrochemical industry during the fifth five-year plan (1989-93) and the sixth plan (1994-98) focus on the following broad objectives.

- Import substitution to reduce the need for imports of both upstream (i.e., feedstock) and downstream petrochemical products. This plan will be implemented by (1) the construction of the Olefin Center to expand production of derivatives such as ethylene, propylene, butadiene, isobutylene, polyethylene, polypropylene, ethylene oxide, and ethylene glycol; (2) the construction of the Aromatic Center to expand production of derivatives such as benzene, toluene, xylene, cyclohexane, caprolactam, styrene monomer, cumene/phenol, and bisphenol A; and (3) the construction of other petrochemical plants, including capacity to produce fine chemicals.
- Stabilization of the petrochemical industrial structure, which entails balancing and integrating the upstream, intermediate, and downstream petrochemical industries. This objective will be implemented by developing other petrochemical product industries that can utilize surplus (or easily available) products and create products required by other industries.
- Promotion of private-sector participation in the petrochemical industry, both by encouraging local investment and by attracting foreign investment. The government's Investment Coordinating Board (BKPM) is currently undertaking deregulation measures and simplifying bureaucratic procedures to provide further support for the government's strategy to promote investment in petrochemicals.
- Generation of export opportunities for petrochemical products by anticipating regional market demand and ensuring that production costs remain competitive within the market. (Though it should be noted that, in light of planned expansions throughout the region, the export opportunities may be less attractive than the domestic market.)

A total of 16 petrochemical projects were approved by the Investment Coordinating Board (BKPM) for implementation during the fifth plan period 1989-93 (Table 7.4). These projects included three major upstream facilities, which together accounted for more than three-quarters of the planned investment. Since the beginning of the plan period, at least two additional major upstream (olefins) projects have been approved, which are included in Table 7.4. The largest investments will be made in olefins.

Table 7.4
Petrochemical Industry Projects, 1989-93

Company, Location, and Major Products	Production Capacity (thousand tons/year)	Planned Investment (US$ millions)
Pertamina, Cilacap, West Java		450
Paraxylene	270	
Benzene	128	
PT AAI (Arun Aceh Industri)		1,275
Benzene	321	
Toluene	23	
Mixed xylenes	217	
Ortho xylene	40	
Cyclohexane	180	
PT Arseto Intertura Polystyrene, Serang, West Java		14
Polystyrene	18	
PT Asahimas Indonesia, Merak, West Java		197
Vinyl chloride monomer	150	
Polyvinyl chloride	70	
Ethylene dichloride	30	
PT Asean Polymer, Merak and Serang, West Java		100
Polypropylene	100	
PT Continental Carbon Restu Pertiwi, Serang, West Java		49
Carbon black	70	
PT Gema Polytama Kimia, Merak, West Java		27
Polyol	20	
PT Indofirst Nusantara Synthetic Rubber, Cilegon, West Java		45
Styrene butadiene rubber	25	
PT Mega Polymer Industri, Tangerang, West Java		159
Polypropylene	126	
PT Petrokimia Nusantara Interindo, Cilegon, West Java		375
High-density polyethylene	100	
Linear low-density polyethylene	100	

Table 7.4. Continued.

Company, Location, and Major Products	Production Capacity (thousand tons/year)	Planned Investment (US$ millions)
PT Pusat Olefin, Cilacap, Central Java		1,500
Ethylene	375	
Propylene	225	
Polyethylene	300	
Polypropylene	160	
Ethylene glycol	100	
PT Styrene Monomer Indonesia, Merak, West Java		120
Styrene monomer	100	
Toluene	5	
PT Sukses Bina Selaras, Bekasi, West Java		42
Styrene butadiene rubber	33	
PT Sulfindo Adi Usaha, Serang, West Java		69
Vinyl chloride monomer	100	
Ethylene dichloride	20	
PT Tripolyta Indonesia, Serang, West Java		220
Polypropylene	200	
PT Yasa Ganesha Pura, Serang, West Java		70
Ethylene glycol	80	
PT Chandra Asri, Serang, West Java		1,840
Ethylene	495	
Propylene	245	
Polyethylene	200	
Polypropylene	80	
Butylene	24	
MTBE	52	
Benzene	77	
Joint venture by Indonesian, Singaporean and Taiwanese companies on Bintan Island, Riau		
Aromatics	not available	1,500
Total planned		8,052

Sources: Ministry of Industry data; *Hydrocarbon Processing* and *Oil and Gas Journal*, various issues, 1990.

Initially, the largest (US$1.5 billion) project was planned to be the PT Pusat Olefin complex in Cilacap, Central Java, adjacent to the Pertamina refinery. This project is being promoted by a consortium of Dutch, Japanese, and Indonesian companies, led by Shell Overseas Investment (57% of equity). The complex is expected to save Indonesia US$665 million annually in foreign exchange, and the consortium will also engage in export marketing. Technology is to be provided by M.W. Kellogg. The complex was originally to come onstream by 1993, but the details of feedstock acquisition have not been fully settled. It now appears likely that a second, even larger (US$1.8-2.4 billion), olefins project will go ahead before the original Olefins Center. The new project is planned by PT Chandra Asri and is to be located at Serang, West Java. Pertamina reportedly has already committed to provide approximately 1.8 million tons per year of naphtha feedstock, and the plant is scheduled for completion in 1993. The outputs, which are geared for the domestic market, will include 495,000 tons/year of ethylene, 245,000 tons/year of propylene, 200,000 tons/year of polyethylene, 80,000 tons/year of polypropylene, 24,000 tons/year of butylene, and 52,000 tons/year of MTBE. As of the end of 1990, a third olefins plant had also been approved by the government. This US$1.5 billion facility is to be located at Bintan Island in Sumatera's Riau Province. Production is to begin by 1993, and the participants (a joint venture of Indonesian, Singaporean, and Taiwanese companies) plan to export the entire output. The planned output slate has not yet been announced for this project.

The second-largest push is in aromatics capacity. The largest (US$1.275 billion) project planned is the PT AAI (Arun Aceh Industri) aromatics complex in Aceh, Sumatera, which is expected to be onstream in 1992. The feedstock will be condensate from Mobil's Arun field, where production currently averages 120 mb/d. Output will include around 321,000 tons/year of benzene, 217,000 tons/year of mixed xylenes, 40,000 tons/year of orthoxylene, and 23,000 tons/year of toluene. Another large aromatics project (US$450 million) will be constructed at Cilacap by Pertamina. Output will include 270,000 tons/year of paraxylene and 128,000 tons/year of benzene.

The remaining petrochemical projects that have been approved are all sited in West Java. Among them are three polypropylene facilities, high-density and linear low-density polyethylene (HDPE and LLDPE) units, two styrene butadiene rubber (SBR) facilities, two vinyl chloride monomer (VCM) plants, two ethylene dichloride units, plus units for ethylene glycol, polystyrene, styrene monomer, polyol, and polyvinyl chloride.

PROJECTED INSTALLED CAPACITY AND PRODUCT DEMAND

The government's projections of installed capacity versus demand for each of 22 key petrochemical products are shown in Table 7.5. The projections are given for the first and last year of the fifth five-year plan and the last year of the sixth plan. Where possible, the supply capacity figures have been updated to account for the inclusion of the PT Chandra Asri olefins complex and a delay the completion of the original Olefins Center until the sixth plan period. Owing to major efforts made in the construction of aromatic and olefin facilities, surpluses are expected for several of these products and also for cyclohexane, VCM, styrene monomer, and NTC. Deficits may persist for products such as polyethylene, PVC, methanol, maleic anhydride, and dioctyl phthalate.

In rapidly developing economies, however, it is easy to underestimate the demand for petrochemicals, particularly for the bulk plastics. In many cases, demand is merely equal to domestic availability. Thus, while official projections show exportable surpluses for a number of products, a healthy Indonesian economy might well absorb all of planned production. Since petrochemical demand in domestic economies tends to feed into various exportable manufactures as well as resulting in substantial export substitution, the net benefits of domestic use may well exceed the value of any export revenues.

Table 7.5
Production Capacity and Domestic Demand Projections
for Major Petrochemical Products, Selected Years, 1989-98
(thousand tons/year)

Product	1989		1993		1998	
	Capacity	Demand	Capacity	Demand	Capacity	Demand
Alkyl benzene	60	69	180	84	180	101
Benzene	0	65	444	78	444	103
Cyclohexane	0	13	180	16	180	20
Dioctyl phthalate	36	24	69	29	69	37
Ethylene	0	427	495	625	495	832
Ethylene glycol	0	74	100	101	160	1,333
Maleic anhydride	1	2	1	3	1	4
Methanol	330	274	330	359	660	503
Nylon tire cord	16	9	28	11	28	14
Phenol	0	11	40	15	40	21
Phthalic anhydride	30	24	45	29	45	37
Polyethylene	0	281	400	328	700	561
Polypropylene	10	228	280	322	305	443
Polystyrene	29	27	34	35	48	46
Polyvinyl chloride	164	101	164	123	178	156
Propylene	10	237	285	335	285	442
Pure terephthalic acid	150	185	225	252	225	341
Styrene monomer	0	32	100	37	100	54
Toluene	0	31	25	38	25	49
o-Xylene	0	22	40	27	40	34
p-Xylene	0	129	487	176	487	239
Vinyl chloride monomer	150	104	250	126	250	161

Sources: Ministry of Industry data; *Hydrocarbon Processing* and *Oil and Gas Journal*, various issues, 1990.

Eight

ELECTRICITY

PROVISION OF ELECTRIC POWER AND GENERAL POLICY

The State Electric Power Corporation, which is known by the acronym for its official name, Perusahaan umum Listrik Negara (PLN), began from a relatively small base of installed capacity when it was established in 1961, and significant improvements in installed capacity and operation began only around 1968. Electric power is a capital-intensive industry, and PLN has limited investment resources for expanding installed capacity and network coverage. Hence, PLN has never been able to fully meet Indonesia's overall demand for electricity. Indonesia therefore relies on two additional sources of electricity: "captive" power plants built and operated by industries for their own power requirements, and local cooperative companies, which provide a small amount of electricity in some rural areas.

Captive power plants are an extremely important source of electricity. They originated because many large-scale enterprises, which could not be supplied with electricity in the quantity or of the quality that they require, installed their own generating plants and began to operate them to satisfy their own power requirements. Permission to install such plants is given by the Directorate General of Electric Power and New Energy in consultation with the Ministry of Industry. Total electric energy generated by these enterprises is almost as large as total PLN production, and in a few cases PLN purchases their excess electricity.

Electric power is also generated by local cooperative companies to supply some of the areas, usually rural, where the PLN grid does not extend. Production and consumption within the cooperatives are on a small scale in comparison to PLN's production.

With support from government funding in addition to its own revenues, PLN has steadily increased its capacity and enhanced the reliability of supply during the past three decades. PLN's ultimate goals are to extend the coverage of its service to the large-scale enterprises that have not yet been connected to the PLN grid and to provide electricity to the rural areas, most of which do not yet have access to electric power. About four-fifths of Indonesia's population live in the country's more than 60,000 villages. Rural electrification is one of the government's targets for regional development of Indonesia.

Under each of the successive five-year development plans, increasing numbers of villages have been supplied with electricity by PLN. At the end of the third five-year plan in 1983, about 13% of all villages had access to electric power. The total number of villages supplied by PLN with electricity under the rural electrification program rose from 7,636 at the beginning of the fourth plan to 17,978 by the end of the plan period in early 1989, thus giving coverage to about 30% of all villages. PLN's rural electrification scheme gives priority to villages that are reasonably accessible to the existing grid, provided that electrification of those villages is economically feasible. As alternatives to grid connections, PLN and other institutions are also studying and developing small-scale hydroelectric generation for isolated villages and nonconventional energy sources, such as wood gasification, biomass, wind energy, photovoltaic energy, and ocean wave energy.

In keeping with the government's policy to increase private participation in the economy—combined with the acknowledgement that PLN is not yet capable of providing for the entire national electric demand—the most recent major policy change affecting electric power development allows private companies to distribute and sell electricity, under the build, operate, and transfer (BOT) system. This system was originally proposed for the planning of the nuclear power plant but was later applied to other type of power plants. The system works as follows: private firms are invited to build a facility and operate it for a fixed number of years, during which time it is assumed that the firm's investment has been recouped and agreed profits have been made. At that stage, the facility is transferred to the government of Indonesia, specifically PLN. The duration of a BOT contract is calculated so that the investor can make a profit on the investment. In the case of a nuclear power plant, which has 30 to 40 years life duration, the firm will operate the plant for the first 15 years of operation. For other types of conventional power plants, which have 20 to 30 years lifetime, the firm will operate the plant for the first 10 years. The project for constructing the Gresik combined-cycle plant (see Figure 6.1) was initially opened to international bidders under this system, but the government subsequently decided to fund the project directly.

The general policy in electricity development must be carefully aligned with overall national energy policy, since electricity plays such a major role in the overall energy diversification policy. Current policy goals in the electric sector include the reduction of oil-fired generation and the substitution of less-tradeable energy sources for oil. Progress toward this goal has been successful only in PLN, however, since the captive power plants are still mainly oil-fired.

EVOLUTION OF THE ELECTRICITY SECTOR

The largest share of generating capacity has always been located on Java, the island that has by far the largest population and the most extensive commercial and industrial activities. In the early 1960s, electric power was supplied only in the large cities of Indonesia, and the total generating capacity was very limited. The most important source of Java's electric power at that time was hydropower, which was supplemented by diesel and steam generation. Outside Java, most plants were diesel-fired. Up to the mid-1960s the slow development of the electricity sector was mainly attributed to low GDP growth, which was about 2% per year. Beginning in 1967, however, economic growth, fueled by oil and gas export revenues, began to rise significantly under the New Order government and its introduction of the successive five-year development plans.

From 1968 to 1988, the period encompassing the first four plans, the electric power sector grew much more rapidly than the economy as a whole. The economic development of the country during this period was accompanied by huge increases in electricity demand, particularly for industrial, commercial and household use. Data on total generation in the final year of each successive five-year plan shows that PLN's generation more than doubled during each plan period and that non-PLN generation increased almost as rapidly (Table 8.1). A comparison of these final-year data shows that the average annual growth in electricity generation of both PLN and non-PLN combined was 15.1% in the second plan, 21.3% in the third plan, and 16.1% in the most recently completed plan. Demand for electric power is forecast to grow at 6.5% per year during the 1990-94 period. By contrast, the average annual GDP growth rates in the first four plans, respectively, were 6.7%, 7.2%, 5.7%, and (according to preliminary estimates) 3.5%. This, of course, is typical of increases in electricity demand as modernization takes place.

Table 8.2 shows PLN's installed capacity, production, and sales of electricity from 1969 to 1989. During that period, the average annual growth rates were 14.9% in installed capacity, 14.3% in energy production, and 15.1% in sales.

At the end of the fourth development plan in early 1989, PLN had an installed capacity of 8,452 MW. In addition, it is estimated that installed capacity outside PLN was 10,323 MW at that time. At the end of that period, PLN produced 25,439 GWh of the total 46,809 GWh of electric energy production in Indonesia, or 54%. At the beginning of the fourth plan, 4,406,077 customers were connected to the PLN system, and at the end of the plan period early in 1989 the total had risen to 9,657,349. Among

Table 8.1
PLN and Non-PLN Electric Energy Generation, Selected Years, 1973-88

	PLN		Non-PLN				
Year	(GWh)	(% of total)	(GWh)	(% of total)	Total Generation (GWh)	Population of Indonesia (million)	Generation per Capita (kWh)
1973	2,288	48	2,504	52	4,792	125	38
1978	4,910	51	4,792	49	9,702	141	69
1983	12,111	48	13,379	52	25,490	158	161
1988	25,439	54	21,370	46	46,809	175	267

Note: The data provide a comparison of electric power generation in the final years of the first through fourth five-year development plans.

Sources: Repelita IV 1984; Repelita V 1989; Central Bureau of Statistics, *Statistical Year Book of Indonesia* 1989.

the customers, 8,996,866 (93.2%) were from the household sector, 29,074 (0.3%) from industry, 401,988 (4.2%) from the commercial sector, and the remaining 229,421 (2.3%) in other categories (Repelita V 1989). As indicated above, the electrification of villages is an important objective for PLN, and in terms of sheer numbers the household sector has a vast number of potential customers. By comparison to PLN's approximately 9 million household customers at present, the total number of households in Indonesia is projected to rise from 40.6 million in 1990, to 46.7 million in 1995, and to 53.2 million in the year 2000 (*Asia-Pacific Briefing Paper*, April 1991).

Since Indonesia is an archipelago of thousands of islands, it has many isolated power systems. The largest is the Java interconnected system. The backbone for the

Table 8.2
PLN Installed Capacity, Electric Energy Generation, and Sales, 1969-89

Year	Installed Capacity (MW)	Electricity Generation (GWh)	Electricity Sales (GWh)
1969	527	1,756	1,204
1970	541	1,872	1,454
1971	527	2,084	1,589
1972	557	2,354	1,786
1973	664	2,499	1,893
1974	776	2,933	2,175
1975	922	3,345	2,444
1976	1,129	3,770	2,804
1977	1,377	4,127	3,082
1978	1,863	4,740	3,527
1979	2,288	5,723	4,287
1980	2,536	7,004	5,343
1981	2,555	8,420	6,523
1982	3,033	10,138	7,846
1983	3,406	11,846	9,101
1984	3,935	13,392	10,002
1985	4,515	14,777	11,041
1986	5,635	16,837	12,706
1987	6,200	19,253	14,786
1988	7,235	22,306	17,077
1989	8,452	25,623	19,993
Average annual growth rate (%)			
1969-73	5.2	8.5	11.4
1974-78	28.0	12.3	12.4
1979-83	9.8	21.4	22.5
1984-89	16.8	13.3	14.1

Source: PLN data.

power plants in this grid is the 500-kV cross-Java transmission line, which runs from the coal-fired Suralaya plant (West Java) by way of Jakarta and extends eastward nearly the entire length of the island to Surabaya. This high-voltage line will be further extended to Gresik, when the new gas-fired capacity comes on line.

During the fourth development plan, PLN constructed an additional 4,875.3 circuit-kilometers (c-km) of transmission lines, with an aggregate substation installed capacity of 8,021.9 megavolt-amperes (MVA). PLN has also constructed 36,887 c-km of medium-voltage lines and 47,365.5 c-km of low-voltage lines, with an aggregate distribution transformer station installed capacity of 4,039.7 MVA (Repelita V 1989).

Achievement in electric power development has been absorbed by the continuous increase of consumption. The past consumption of PLN electric power rose in average annual growth rates of about 15% during the first four five-year plans. The rapid growth in electricity consumption during these periods was brought about by the impressive growth of the economy, mainly derived from oil export revenues, which created a multiplier effect both by increasing demand in all consuming sectors and by providing government revenues for expanding electricity supply infrastructure. In addition, the suppressed demand for electricity in rural areas has been met by the expansion of the transmission network and the rural electrification program.

ELECTRICITY SECTOR FUEL MIX

Total electric power generation by fuel type from 1971 to 1989 is shown in Table 8.3 and Figure 8.1. The data include production by both PLN and non-PLN power plants. This series of data is drawn from the International Energy Agency's world energy statistics and balances, which are not in complete agreement with data compiled by PLN. The steep increase in generation as well as the changing fuel mix are sharply displayed. Figure 8.2 displays the percentage shares by fuel type. The importance of oil in electricity generation is dramatically illustrated, particularly during the 1970s and early 1980s. To meet briskly growing electricity demand, oil use in the power sector increased rapidly. In the PLN system, the share of oil in electricity generation increased from approximately 40% in 1970 to 61% in 1985. Dependence on oil outside the PLN system was (and continues to be) even higher. As shown in Table 8.3, the dependence on oil of total PLN and non-PLN generation was 77% in 1971, reached 89% in 1982, and then declined to 79% in 1985.

Table 8.3
Total Electricity Generation by Fuel Type, 1971-88

Year	Coal	Oil	Gas	Other	Total
In thousand toe					
1971	—	1,085	—	318	1,403
1973	—	1,258	—	358	1,616
1975	—	1,304	—	417	1,720
1977	—	2,095	—	406	2,502
1979	—	1,997	—	322	2,319
1980	—	2,132	—	292	2,424
1982	—	2,683	—	318	3,000
1983	—	2,723	—	478	3,201
1984	—	2,914	—	521	3,435
1985	100	5,742	1	1,421	7,264
1986	1,387	5,298	60	1,620	8,365
1987	1,876	5,731	97	1,767	9,471
1988	2,030	5,746	135	1,787	9,697
Average annual growth rate (%)					
1971-79	na	7.9	na	0.1	6.5
1980-88	na	13.2	na	25.4	18.9
1971-88	na	10.3	na	10.7	12.0
1985-88	173	0.0	382.7	7.9	10.1
In Gwh					
1971	—	3,724	—	1,425	5,149
1973	—	4,532	—	1,603	6,135
1975	—	6,559	—	1,865	8,424
1977	—	8,308	—	1,819	10,127
1979	—	11,305	—	1,442	12,747
1980	—	12,925	—	1,309	14,234
1982	—	15,162	—	1,422	16,584
1983	—	17,874	—	2,138	20,012
1984	—	26,818	—	2,334	29,152
1985	373	23,825	4	6,362	30,564
1986	5,163	21,930	198	7,250	34,541
1987	6,980	19,602	318	7,910	34,810
1988	7,552	21,014	444	8,000	37,010
Average annual growth rate (%)					
1971-79	na	14.9	na	0.1	12.0
1980-88	na	6.3	na	25.4	12.7
1971-88	na	10.7	na	10.7	12.3
1985-88	172.6	-4.1	380.6	7.9	6.6

Notes: — Nil.
na Not applicable.

Source: International Energy Agency 1989 and 1990.

Figure 8.1
Total Electricity Generation by Fuel Type, 1971-88

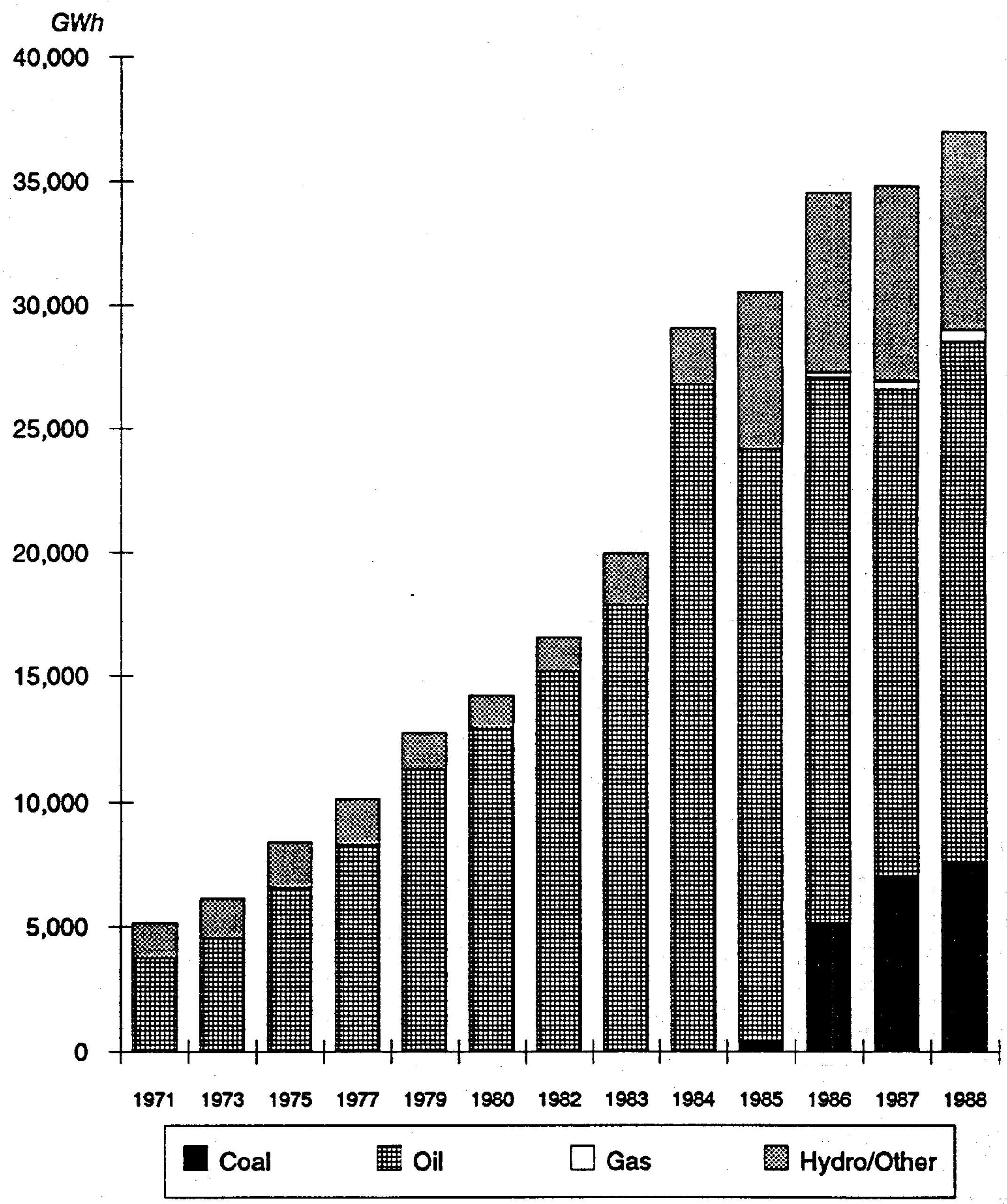
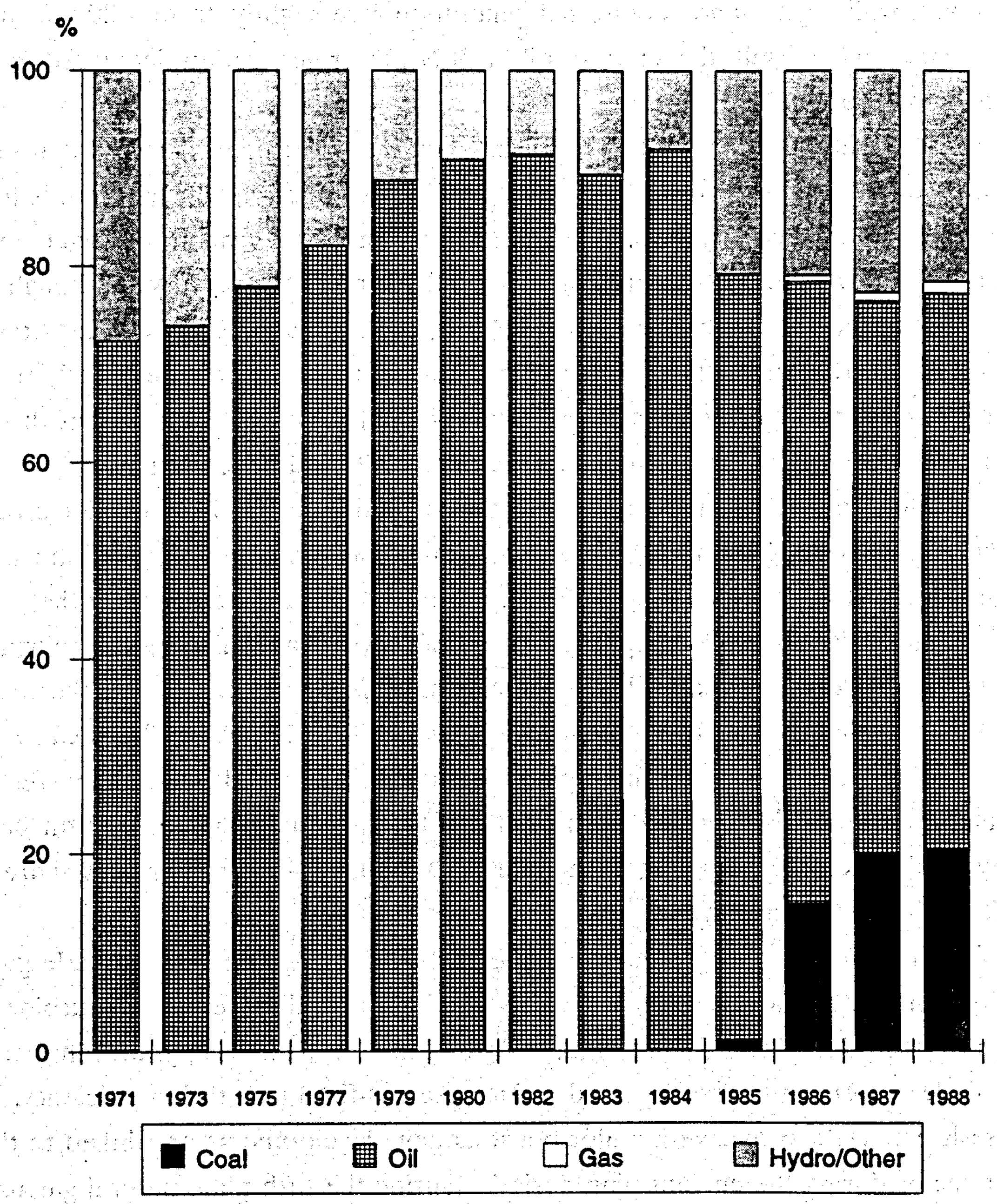


Figure 8.2
Electricity Generation by Fuel, 1971-88



Although dependence on oil-fired generation remains high, it should be noted that oil consumption in the power sector would have been far higher without the government's fuel diversification policy. Coal use in the electricity sector commenced in 1985 and grew rapidly during the period 1985-88; by 1988 more than 20% of Indonesia's electric power was generated from coal. During the same period, natural gas achieved a 1.2% share, while hydro and geothermal generation rose slightly, from a 20.8% share to a 21.6% share. As a result, the share of oil in PLN power generation decreased to 57% in 1986 and to 39% in 1989.

At the beginning of the fourth five-year plan, the government decided that no additional oil-fired power plants were to be constructed in Java, which accounts for more than 60% of total electricity demand. The government's hope was to massively reduce oil use in the power sector—to around 10% by the turn of the century—although the delays in construction of new power plants (coal, geothermal, and natural gas-fired), particularly in Java, have already forced a reassessment. It now appears likely that power shortages will be a serious problem in Java in 1991 and 1992, and that the government response will be a short-term return to oil-fired generation.

To help carry out the national energy diversification policy, PLN further diversified its power plants during the fourth development plan, with the intention of reducing the oil-fired share of electric power generation. Table 8.4 and Figure 8.3 show the development of PLN installed capacity by type of power plant. During the fourth plan period, coal made its entry into PLN's power-plant mix, and by the end of the plan period its share jumped to 16% of installed capacity. Geothermal facilities came on stream during the third development plan. Geothermal installed capacity in West Java was increased to 140 MW near the end of the fourth five-year plan, adding further to the variety of electricity sources, but by the end of the fourth plan geothermal's share was only 2% of installed capacity.

The discovery of new gas reserves near certain demand centers has made gas an attractive option for power generation. To tap these new discoveries, gas turbines have been constructed in North Sumatera and East Java, and planned upgrades into combined-cycle power plants are expected to increase gas-fired generation efficiency. Natural gas use is expected to receive a major boost as new developments are linked to the local power sector during the current plan period. During the fifth plan, natural gas use for electricity generation is forecast to grow from 65 million scf/d in 1989 to over 307 million scf/d in 1993, an almost fivefold increase in just five years.

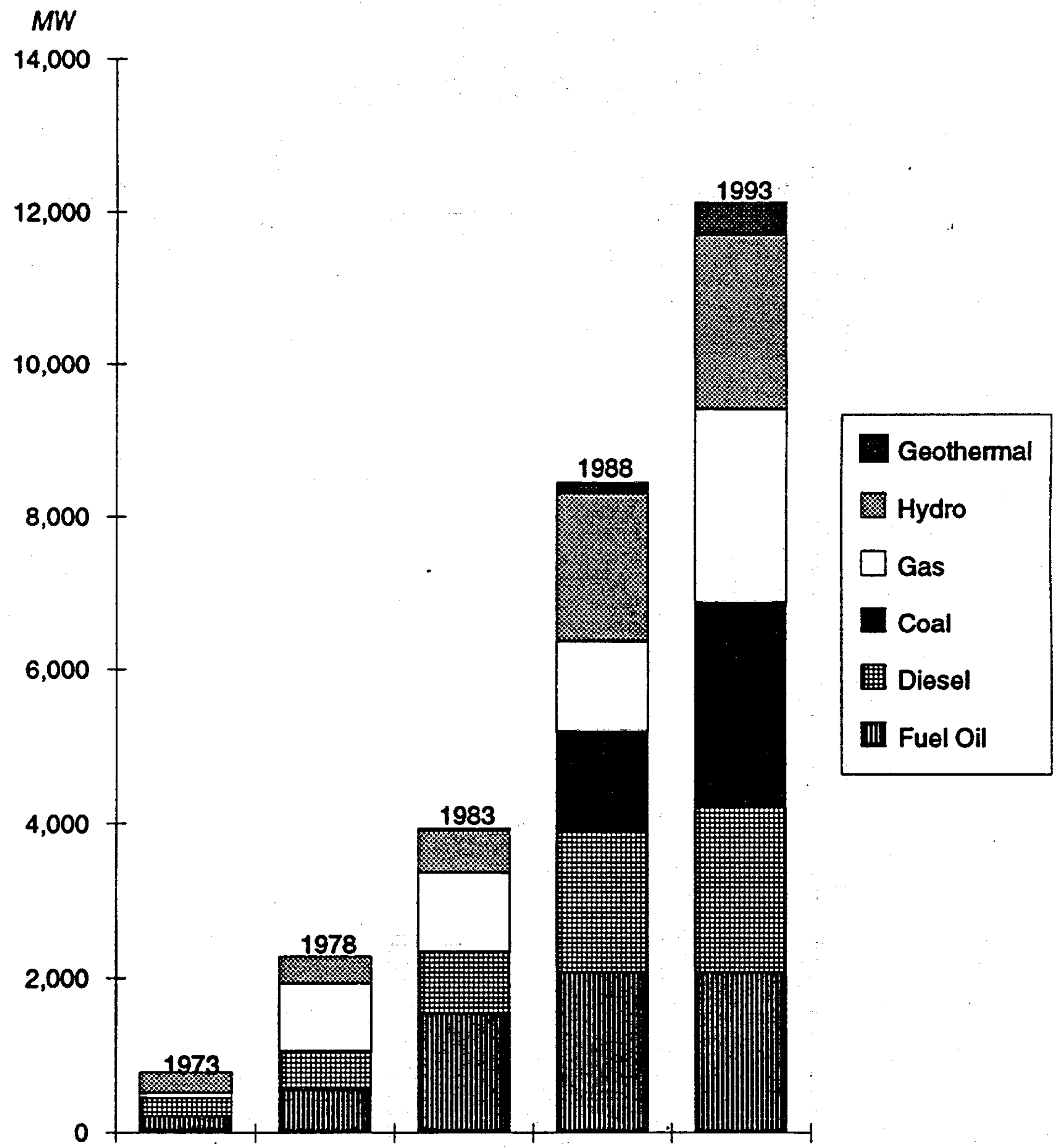
Table 8.4
PLN Installed Capacity by Fuel Type, Selected Years 1973-88

	1973		1978		1983		1988	
Plant Type	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)
Hydropower	278.7	35	350.7	15	536.4	14	1,927.5	23
Diesel	230.3	29	499.5	22	784.4	20	1,790.9	21
Oil-fired	225.0	28	556.3	24	1,556.3	40	2,086.9	25
Gas turbine	620.0	8	882.0	39	1,027.9	26	1,176.7	14
Coal-fired	0.0	0	0.0	0	0.0	0	1,330.0	16
Geothermal	0.0	0	0.0	0	30.0	1	140.0	2
Total	796.0	100	2,288.5	100	3,935.0	100	8,452.0	100

Note: The data represent installed capacity at the beginning (1 April) of the respective final fiscal years of the first through fourth five-year development plans.

Source: Repelita V 1989.

Figure 8.3
PLN Installed Capacity by Fuel Type, Selected Years, 1973-93



Note: 1993 projection assumes no scrapping of oil-fired capacity.

The chief substitute for oil-fired generation is coal, which came to the forefront as a major fuel in power plants built during the 1980s. The extensive improvement in coal production in Bukit Asam, Southern Sumatera, together with improvements in the coal transportation network (which includes railway and sea transportation), from the mine to the Suralaya power plant in West Java, has resulted in an increase in coal consumption from about 1.4 million tons at the beginning of the fourth plan to 4.5 million tons at the end. Growing concerns about environmental quality may limit coal use to a certain level (currently thought to be 30 million tons per year, an amount several times present consumption levels), although in the near term, tradeoffs between environmental protection and economic development are likely to favor economic development. Coal's share of electricity generation is forecast to grow dramatically during the 1990s. The current development plan calls for coal use of around 8.2 million tons in 1993, of which approximately 6 million tons is slated for electricity generation.

As noted, PLN, the state electric utility, accounts for only a fraction of Indonesia's power generation and is not considered able to fully keep pace with Java's growing demand for electricity. Many private companies, notably in the cement and steel industry, have installed their own, chiefly diesel-fired, capacity to ensure uninterrupted power supplies. For a time, PLN tried to encourage these operators to connect with the state power grid, and worked to improve reliability and customer satisfaction. Recent forecasts of electricity demand, however, indicate that Java will be faced with serious power shortages by 1991-92. Under the BOT system, the government has invited private companies to build additional generating capacity to serve the Javanese market, under the condition that the facilities revert to the state after 25 years. These private generators are encouraged to use coal and natural gas, and they must consult with the government on their fuel mix.

Most of the electric energy produced outside the PLN system comes from the captive power plants operated by large industrial concerns. A small proportion of non-PLN production also comes from cooperative companies in rural areas. At the end of the fourth development plan in 1989, total non-PLN electric energy production was 21,370 GWh, of which captive power accounted for 21,227 GWh, and cooperative companies the remaining 143 GWh (Table 8.1). In the 1988 PLN bought about 681 GWh from non-PLN generation power plants.

While the primary energy sources for PLN-generated power have been diversified significantly and now include oil, coal, hydropower, geothermal power, and natural gas, most of the captive power plants still use oil—either diesel or fuel oil. Natural gas is used by only a few of the captive plants, primarily in the industries that use natural gas as their feedstock. Natural gas is used by the steel company, PT Krakatau Steel, in West Java, and fertilizer companies such as PT Pupuk Sriwijaya (PUSRI) in South Sumatera and PT Pupuk Kujang in West Java. Most of the cooperatives rely on diesel fuel or minihydro generation. In the industrial sector, gas and coal have been substituted to some extent for oil—mainly for heating purposes. Most producers in the cement industry have converted their oil-fired plants and are now burning coal instead. In the larger urban areas, where city gas distribution networks are already in place, the use of natural gas is being intensified to supply heat to small and medium-scale companies. World Bank funding has been received for the continued expansion of these city gas networks.

The replacement of oil by other energy sources is not expected to be achieved rapidly by the large-scale industrial enterprises that have invested in private electricity generation systems. Rather than connecting to the PLN electric power grids, many companies prefer to generate their own power. For their marginal electricity demand, however, many of these large industrial concerns are now beginning to rely on the PLN grid. The state utility is trying to increase its efficiency and improve the reliability and quality of its power supply. As it gradually achieves these goals and expands its installed capacity, the larger industrial enterprises are expected to connect to the PLN grid in increasing numbers. Until this occurs, significant quantities of oil will continue to be used for power generation.

Even with the foreseen increases in generating capacity made possible by promotion of gas, coal, and geothermal, and the continuing use of oil-fired generation, the government feels that nuclear power may become necessary by the end of the decade, and plans are underway for the construction of an 800-MW nuclear power plant at Gunung Muria. There is understandable opposition to this idea. What remains clear is that fossil fuels will remain the dominant primary energy sources for domestic use, as well as playing the lead role in energy exports.

DEMAND PROJECTIONS AND FUTURE EXPANSION

The rapid growth of electric power demand is expected to continue during the current five-year development plan. Table 8.5 shows projected electric power demand and PLN production during the fifth five-year plan. Under the current expansion plan, PLN generation will provide for most of the increase in demand for electric power,

Table 8.5
Estimated Electric Power Sectoral Demand versus PLN Production, 1989-93
(GWh)

Sector	1989	1990	1991	1992	1993
National consumption					
Industry	31,081	32,862	34,764	36,192	37,698
Commercial	4,570	4,970	5,432	5,939	6,484
Household	8,492	9,465	10,468	11,504	12,575
Total Consumption	44,143	47,296	50,665	53,635	56,756
PLN production	28,890[a]	33,044	37,644	42,709	48,271

Note: a. Initial five-year plan forecast. See Table 8.2 for actual 1989 data.

Source: Repelita V 1989.

thereby greatly increasing PLN's share of total generation. According to the projection, consumption of PLN electricity generation will increase from 22,697 GWh (51.4% of total consumption) at the beginning of the plan period in 1989 to 38,851 GWh (68.4% of total generation) when the plan ends early in 1994. During the same period, it is projected that electric power provided by non-PLN power plants will decrease from 21,446 GWh (48.6% of total generation) to 17,905 GWh (31.6% of total generation). Most of the decrease in the share of non-PLN generation will result from the move away from captive power plants, as industries gradually connect to the PLN grid.

During the fifth plan period, a total of 6,302 c-km of transmission lines will be added to the existing PLN grid, together with an additional aggregate of 8,507 MVA installed capacity in substations. PLN will also construct an additional 62,938 c-km of medium-voltage lines, 90,549 c-km of low-voltage lines, and an aggregate of 12,424 MVA of distribution transformer stations. During the same period, PLN expects to gain an

7.34 million new customers. PLN also hopes to reduce its network losses from 16.7% at the beginning of the fifth plan to 14.8% by the end of the plan period.

To increase production in anticipation of the demand increases, PLN has adopted a long-term plan to increase its future capacity (Table 8.6). The expansion plan also calls for the retirement of some of the older, oil-fired power plants, but the current pressure on the supply system makes it unlikely that any significant amount of installed capacity, oil-fired or otherwise, will be retired during the fifth plan period. In Figure 8.3, the projection of 1993 installed capacity assumes that all of PLN's construction plans go forward and that no scrapping of capacity occurs. PLN will continue to restrain oil-fired generation whenever possible. No additional diesel power plants will be built in Java, although diesel plants are still necessary on the other islands, especially in remote areas. Combined-cycle power plants, which are among the most efficient types of power plants, will be introduced in the system, both in and outside of Java, as a result of commitment to increase gas utilization. Coal-fired power plants are expected to dominate the Java grid beginning in 1994. Hydropower supplying the Java grid will, on the other hand, reach a peak in 1996, beyond which it cannot be expanded because of resource limitations. Outside Java, peat will become a new fuel source for mine-mouth power plants in peat-rich areas of Sumatera and Kalimantan.

ELECTRICITY TARIFF

Electricity tariffs, like petroleum fuel prices, are considered politically sensitive, and they are controlled by the government. Despite the chronic need to increase revenue for reinvestment, PLN has been unable to raise the tariff to a level it considers sufficient. Hence, Indonesia's tariffs are among the lowest in ASEAN—although such comparisons are not entirely compelling, since Indonesia's GDP per capita is significantly lower than that of other ASEAN members. Inexpensive electricity has lent a comparative advantage to Indonesian manufacturers of export goods, and it has therefore been argued that low tariffs are beneficial for the economy as a whole. The government has adjusted the tariffs several times, usually in response to higher domestic fuel prices, but each increase has been strongly opposed by consumers. The last tariff increase was in 1989, but the state utility still feels that the tariff is too low and that projected revenues will be insufficient to fund necessary power sector expansions. Pressure to raise the tariff is also being exerted at the international level; for example, the World Bank has suggested that the tariff is too low, and is reluctant to provide further loans for electricity expansions.

Table 8.6
PLN Planned Capacity Additions, 1989-93
(MW)

Plant Type	1989	1990	1991	1992	1993
Hydropower[a]	136	23	126	—	59
Diesel	24	110.7	99	12	27.5
Gas turbines	100	20	—	—	—
Geothermal	—	—	110	110	70
Combined cycle	—	100	—	600	400
Coal (steam)	400	—	—	165	800
Natural gas (steam)	—	130	—	—	—
Minihydro	—	—	0.6	11.2	12.7
Diesel for rural areas	9	9.5	10	10.5	11
Total	669	393.2	345.6	908.7	1,380.2

Notes: — No plannned additions.
a. Not including minihydro units. The sequencing shown here is based on the initial five-year development plan. See Table 3.8 for the revised sequencing of hydropower capacity additions.

Source: Repelita V 1989.

Another tariff increase should be expected in 1991, although the government and parliament are still trying to reach accord on the appropriate level of the increase.

Table 8.7 shows the present electricity tariff in Indonesia. There is tariff discrimination depending on the category of user, the size of contracted power supply, utilization hours, and time. In the residential sector, the tariff discourages intensive use, because the tariff increases in proportion to the size of contracted power and the amount of energy consumed. The tariff for the industrial sector is relatively low, in keeping with government policy to support the nation's industrialization program. Like many tariffs, it discourages consumption during peak hours as a load-management strategy.

Table 8.7
PLN Electricity Tariff, January 1990

Customer Category and Contracted Power	Demand Charge (rupiah/kVA)	Energy Charge (rupiah/kWh)	Notes
Social			
< 200 VA	—	—	5,450 rupiah/month
250 VA — 200 kVA	2,700	45.0	
> 200 kVA	3,160	136.5	peak time
> 200 kVa	3,160	68.0	off-peak time
Residential			
250—500 VA	3,160	63.5	for first 60 hours
250—500	3,160	86.0	for hours exceeding 60
501—2,200 VA	3,160	76.0	for first 60 hours
501—2,200 VA	3,160	115.5	for hours exceeding 60
2,201—6,600 VA	5,520	155.5	
> 6,600 VA	5,520	196.5	
Commercial			
250—2,200 VA	5,520	166.0	for first 150 hours
250—2,200 VA	5,520	133.0	for hours exceeding 150
2,201 VA —200 kVA	5,520	186.5	for first 150 hours
2,201 VA —200 kVA	5,520	149.5	for hours exceeding 150
> 201 kVA	3,460	219.5	peak time
> 201 kVA	3,460	109.5	off-peak time
Hotels			
250 VA — 99 kVA	3,460	87.0	
100—200 kVA	3,460	95.0	
> 200 kVA	3,160	94.0	
Industry			
450 VA — 139 kVA	3,460	68.0	
140—200 kVA	3,460	138.5	peak time
140—200 kVA	3,460	70.0	off-peak time
201—9,999 kVA	3,160	134.0	peak time
201—9,999 kVA	3,160	68.0	off-peak time
> 9,999 kVA	2,960	119.5	peak time
> 9,999 kVA	2,960	60.0	off-peak time
Government			
250 VA — 200 kVA	5,520	122.5	
> 200 kVA	2,960	159.5	peak time
> 200 kVA	2,960	79.5	off-peak time
Street lighting	—	98.0	

Note: — Not applicable

Source: PLN data.

Nine

COAL

OVERVIEW

Indonesia is one of the few countries in Asia that has significant coal export capability, and it is the only country among the Association of Southeast Asian Nations (ASEAN) that has large enough coal reserves (estimated by the state-owned mining company at over 31 billion tons) to play a role in the export market. Indonesia's coal production grew from around 338 thousand tons in 1980 to over 3 million tons in 1987, and production amounted to nearly 8.7 million tons in 1989. Forecasts of coal production over the coming decade vary widely, depending on assumptions about the size of the domestic market and export opportunities, but all forecasts point to substantial growth. Total production in the year 2000 is expected to be somewhere between 40 and 50 million tons which, when compared to anticipated domestic consumption of 20-30 million tons, leaves 10-30 million tons available for export.

The national energy policy emphasizes the optimal domestic use of less-tradeable energy sources. Oil is the most easily tradeable, followed by natural gas (in the form of LNG and LPG), and then followed by certain types of coal. Some Kalimantan coals are among the lowest-cost in the world for the Asian market. The sulfur content of some of the coal is as low as 0.1%, which could meet most countries' sulfur emission standards without requiring the addition of flue gas desulfurization units. As discussed in Part Two above, however, most of the coals have quality deficiencies. The disadvantage in exporting lesser-quality coal is that the transportation cost remains constant whereas the price of the coal at the point of delivery is lower than that of high-quality coal. Since the proportion of total cost represented by coal handling is much higher in the case of lesser-quality coal, the Indonesian government plans to export higher quality coal, mostly to the Asia-Pacific market, and to retain coal of lesser quality for domestic uses, mostly in electricity generation and the cement industry. Wide acceptance in the electric utility market, however, will require considerable testing among utilities and careful quality control by producers.

TRANSPORTATION

As in the case of natural gas, the potential for coal use may depend largely on the proximity of coal mines to potential consumers. The long distances between Indonesian coal deposits and major population centers create complex problems for utilization. The ideal arrangement would be to build a power plant at the mine mouth. In such a case, the only transportation infrastructure required would be the electric power transmission lines. Since Indonesia's coal is not close to potential consumers, however, there is insufficient electricity demand near the coal resources to justify the base load of mine-mouth power plants.

For these reasons, the expansion of domestic utilization and of exports will require massive investment in transportation infrastructure over a period of time. Land transportation, loading ports, and receiving ports will have to be built, and transportation equipment for land, river, and sea transport will have to be purchased or leased. Marine and river transportation is used for the delivery of most of the coal currently mined, and the necessary barges and ships are generally rented by the coal companies. The massive investment in transportation infrastructure required by the coal industry makes government involvement essential, particularly in providing rail lines, ports, and handling facilities. The development of the coal sector is thus further complicated, since several government agencies are simultaneously involved. The essential transportation infrastructure is under the purview of the Ministry of Communications, but must be planned and constructed by the Ministry of Communication in coordination with the work of the Ministry of Mines and Energy and the operating companies.

A special transportation system was required in the Bukit Asam integrated project to accommodate the large volume of coal destined for the Suralaya power plant. The two main transportation entities involved in this system are PJKA (the state railway company under the Ministry of Communication), which is responsible for building, maintaining and operating the rail transportation network that carries coal from Bukit Asam to the port of Tarahan at the southern tip of Sumatera; and PT PANN (the national fleet development corporation), which is responsible for the shipment of coal from Tarahan to the receiving port in Suralaya.

Current major coal flows in Indonesia are illustrated in Figure 9.1, which shows major mining sites and the electric power and cement plants that are the principal consumers. The major flows originate in South Sumatera, West Sumatera, East Kalimantan, and South Kalimantan. Java is the chief domestic destination, and coal is also exported to Asian markets. In addition to the mines marked on the map, coal basins have been identified in West Kalimantan, Central Kalimantan, South Sulawesi and Irian Jaya, though these areas are not yet being developed commercially. Table 9.1 lists the major coal producers in Indonesia and the locations of their fields.

PRODUCTION AND TRADE

As described in Part Four, Indonesia's state-owned coal company is Perum Tambang Batubara (PTB). Until 1990 a separate state-owned company, PT Tambang Batubara Bukit Asam (PTBA), operated the Bukit Asam mine in South Sumatera, but PTB has absorbed PTBA and is now responsible for operating the Bukit Asam mine and for coordinating all coal production by production sharing contractors. At present all coal mining in Indonesia is opencast or openpit mining, with the exceptions of Ombilin in West Sumatera and the Kitadin mines in East Kalimantan, which use underground mining techniques. The "shovel and truck" mining method is used everywhere except in Bukit Asam (Air Laya), which employs the bucket wheel excavator method.

Coal production has been expanded as one means of reducing the growth rate of domestic oil consumption, in accordance with the national policy for diversification of energy use and maximization of oil export earnings. Recently, however, the impetus to expand coal mining has been dampened by the discovery of natural gas reserves, particularly at sites near population centers. This has brought the two energy resources into competition with each other in the domestic market, which is somewhat ironic considering that the national goal is to promote both fuels as substitutes for oil. For the most part, this competition is considered beneficial for the country, since it helps to determine the most appropriate energy sources and provide cheaper energy through least-cost optimization, which takes into consideration relative locational advantages and the economics of gas field versus coal mine development. As a result, earlier coal development plans geared toward domestic uses were modified. The original rationale behind East Kalimantan coal development, for example, was to supply coal-fired power plants in East Java, but this plan has been overtaken by subsequent discoveries of offshore natural gas fields close to Java. Developing these gas resources will meet part of the fuel demand for electricity generation in East Java at a significantly lower cost than could have been achieved using coal from East Kalimantan.

Since some of the future generation capacity in East Java will now be gas-fired, coal power plant development plans have been rescheduled or superseded. The preference

Figure 9.1
Major Coal Flows: Deposits, Mines, Cement Plants, and Power Plants

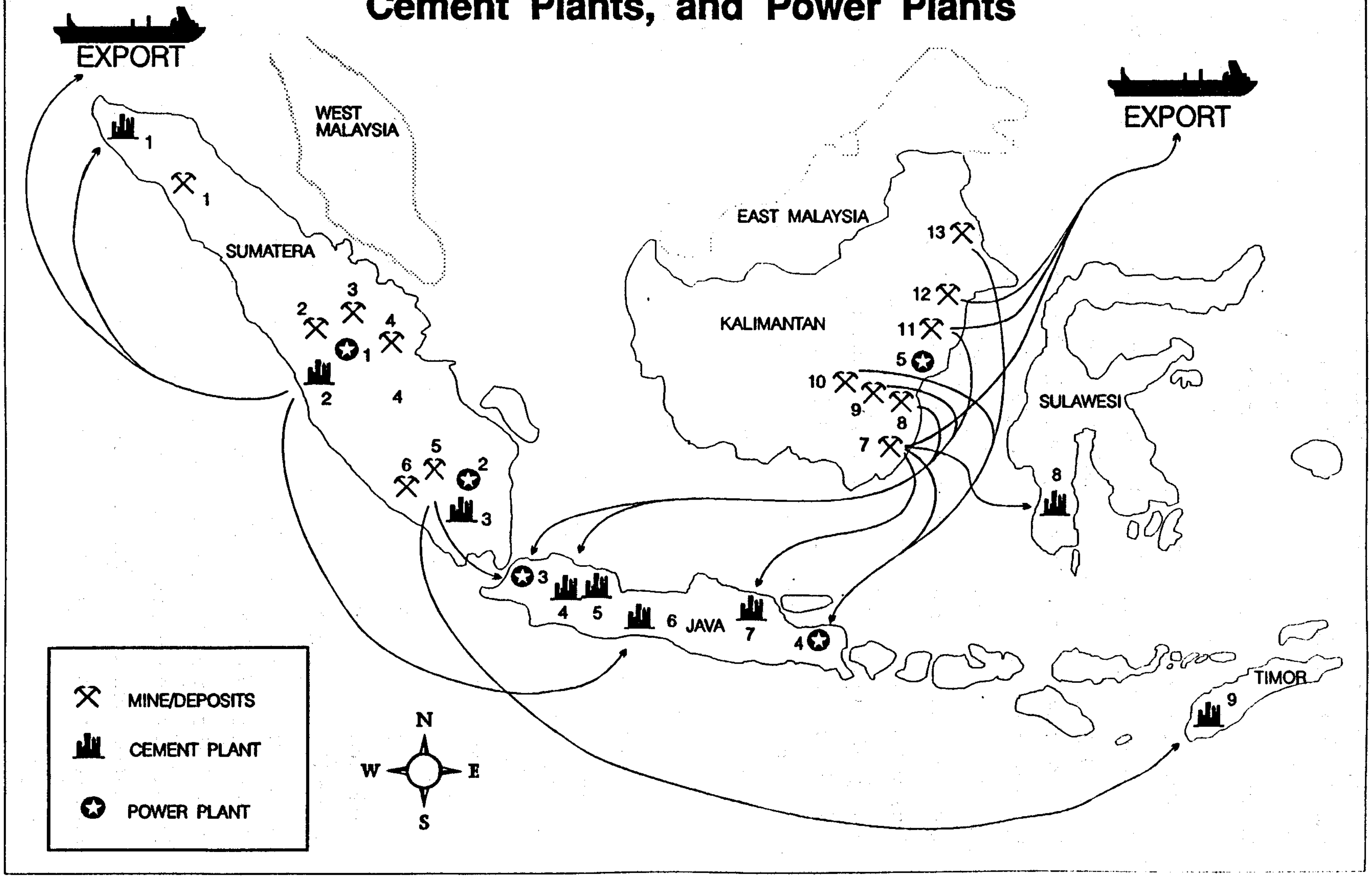


Figure 9.1. Continued.

MINE OR DEPOSIT COMPANIES

1 Meulaboh
2 Ombilin, Waringin, Parambahan (Perum Tambang Batubara: PT Allied Indo Coal)
3 Logas
4 Cerenti
5 Bukit Asam, Air Laya, Muara Tiga, Banko Barat, Banjarsari, Suban Jeriji, Arahan Selatan, Muara Tiga Selatan
6 Bengkulu (PT Bukit Sunur; PT Danau Mas Hitam)
7 Senakin (PT Arutmin Indonesia)
8 Bindu, Pentanggis (PT Utah Indonesia)
9 Samaranggau, Roto (PT Kideco Jaya Agung)
10 Tanjung (PT Adaro Indonesia)
11 Mahakam (PT Multi Harapan Utama; PT Tanito Harun; PT Kitadin Corp; PT Fajar Bumi Sakti; PT Bukit Baiduri Enterprise)
12 Pinang (PT Kaltim Prima Coal)
13 Lati (PT Berau Coal)

CEMENT PLANTS

1 Andalas
2 Pandang
3 Baturaja
4 Cibinong Indocement
5 Cirebon
6 Nusantara
7 Gresik
8 Tonasa
9 Kupang

COAL-FIRED POWER PLANTS

1 Salak, Ombilin
2 Bukit Asam
3 Suralaya
4 Paiton
5 Balikpapan

Source: Johannas 1989.

Table 9.1
Major Coal Companies and Fields

Company	Mining Field and Location	Capacity[a]	Status
State-owned companies			
Perum Tambang Batubara	Ombilin, W. Sumatera	850	operation
PT Tambang Bukit Asam	Bukit Asam, S. Sumatera	5,700	operation
Production sharing contractors			
PT Arutmin Indonesia	Senakin, S. Kalimantan	5,000	construction/ operation
PT Utah Indonesia	Petanggis, E. Kalimantan	2,000	construction
PT Kaltim Prima Coal	Pinang, E. Kalimantan	6,000	construction/ operation
PT Kideco Jaya Agung	Samaranggau, Roto, E. Kalimantan	2,000	construction/ operation
PT Adaro Indonesia	Wara, Tutpan, S. Kalimantan	4,000	feasibility study
PT Berau Coal	Parambahan, W. Sumatera	1,600	exploration
PT Allied Indo Coal	Parambahan, W. Sumatera	500	operation
PT Chung Hua OMD	S. Kalimantan	—	exploration
PT Multi Harapan Utama	Busang, Kalimantan	1,000	exploration/ operation
PT Tanito Harum	Sukodadi, P. Labu, E. Kalimantan	800	exploration/ operation
Private companies or cooperatives			
PT Kitadin	E. Kalimantan	320	operation
PT Fajar Bumi Sakti	E. Kalimantan	150	operation
PT Bukit Baiduri	E. Kalimantan	220	operation
PT Bukit Sunur	Bengkulu, S. Sumatera	150	operation
PT Danau Mas Hitam	Bengkulu, S. Sumatera	150	operation
Other companies			
CV Panca Bakti	W. Java	—	operation
CV Sejati Agung	W. Java	—	operation
Usaha Karya Cempaka, KUD	W. Java	—	operation
Penggarangan I, KUD	W. Java	—	operation
Total other companies		100	

Notes: — Not available.
a. 1993 thousand tons/year, based on optiministic production plans.

Sources: Perum Tambang Batubara data, cited in U.S. Embassy, Jakarta 1990; Johannas 1989.

for gas will cut into the market that East Kalimantan coal producers hoped to gain. Moreover, no new domestic coal customers have been identified to offset the loss. Fortunately for the production sharing contractors, most East Kalimantan coals are of higher quality than Sumateran coal, and the coal industry in East Kalimantan mines can therefore rely more on export markets.

The world oil price increases that began in 1973 ushered in a period of rapidly growing foreign exchange earnings for Indonesia. This provided a major incentive for rapid diversification of fuel sources, so that oil exports could be maximized. Coal was a key element in this effort. The government launched a program to increase domestic use of coal and reverse the long decline in coal production that began during World War II (see Part Two above). There were few signs of a coal production recovery until the mid-1980s, however, because of the long lead times necessary for mine development, the construction of the required coal transportation infrastructure, and the construction of the coal-fired power, cement, and other plants that were expected to absorb new production. Not until 1986 (when production reached 2.6 million tons) did the industry surpass its prewar peak. Detailed historical data for annual production since 1936 in each of Indonesia's three mines—Ombilin (Central Sumatera), Bukit Asam (South Sumatera), and Mahakam (East Kalimantan)—can be found in Johannas (1989).

The rapid development of coal production in the 1980s is shown in Table 9.2 and Figure 9.2. In 1971 coal production totalled 198,000 tons. By 1985 production had increased by nearly tenfold. During the 1971-79 period, coal production grew at rates averaging 4.4% per annum. In contrast, growth in output during the 1980s averaged over 43% per year, and growth is expected to continue at around 31% annually from 1990 to 1993. Production in 1989 totalled around 8.7 million tons, a figure well above government expectations, which anticipated production of 6 million tons. Production is expected to reach nearly 21 million tons in 1993.

The increases in production have enabled Indonesia to export substantial quantities of coal. Exports reached a record-high 2.55 million tons in 1989, and export capability by 1993 is estimated at over 12.5 million tons. The increases in production have also eliminated the need for coal imports. Table 9.2 provides historical data on coal imports, which prior to 1986 had been minimal. In 1986 and 1987, however, Indonesia was a net importer of coal; imports in 1986 and 1987 were 1.3 and 1.6 million tons, respectively, as opposed to exports of around 0.9 million tons each year. The reason for this unusual pattern was that the Suralaya coal-fired power plant came onstream, and Bukit Asam

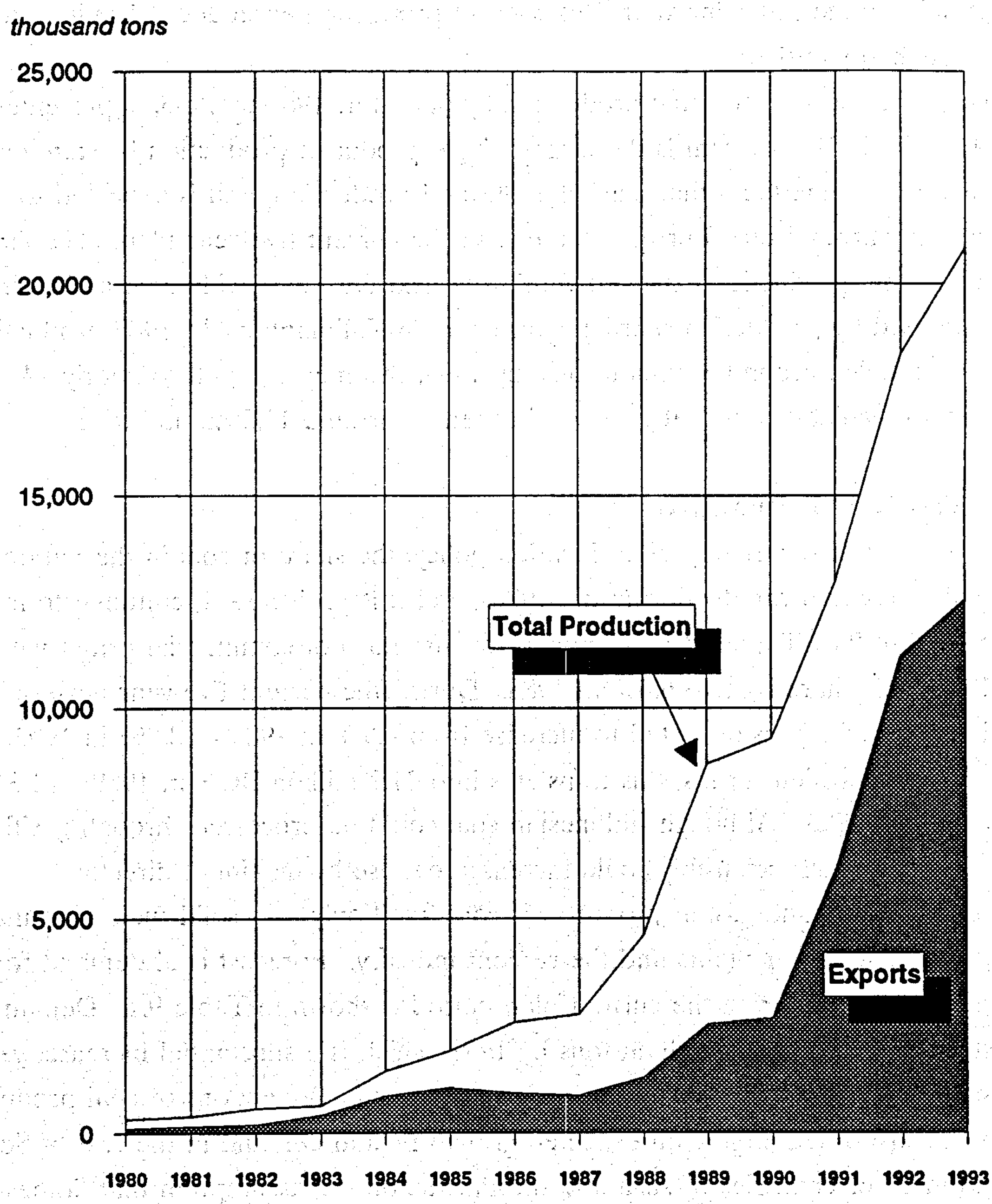
Table 9.2
Coal Production and Trade, 1971-93
(thousand tons)

Year	Production	Exports	Imports
1971	198	0	35
1972	179	0	0
1973	148	0	5
1974	156	0	0
1975	206	0	35
1976	183	0	0
1977	231	16	17
1978	264	38	24
1979	279	60	30
1980	338	112	40
1981	399	162	36
1982	588	211	33
1983	648	424	26
1984	1,468	882	29
1985	1,943	1,081	47
1986	2,601	942	1,303
1987	2,781	892	1,632
1988	4,613	1,307	935
1989	8,693	2,546	0
1990	9,290	2,683	0
1991	12,970	6,205	0
1992	18,335	11,222	0
1993	20,850	12,533	0
Average annual growth rate (%)			
1971-79	4.36	—	—
1980-89	43.45	41.49	—
1990-93	30.93	67.16	—

Note: — Not applicable.

Sources: Johannas 1989 for production data 1971-84; Indonesian Directorate of Coal, cited in U.S. Embassy 1990 for production data 1985-89; International Energy Agency 1989 for trade data 1971-85; PTB data for 1990-93 forecast.

Figure 9.2
Coal Production and Exports, 1980-93



coal production was initially insufficient to meet the new demand. Since the Suralaya facility was designed to accommodate Bukit Asam quality coal, Kalimantan coals were not brought in to make up for the shortfall. Instead, Australian coal and a small amount of Chinese coal were imported, and the Kalimantan coals continued to be exported. In 1989 Bukit Asam coal production had risen to nearly 1.9 million tons, and imports began to taper off. By the following year, Bukit Asam production exceeded 3.4 million tons, and imports had vanished.

Historical and forecast coal production by operator, 1985 to 1993, is presented in Table 9.3. While Bukit Asam is the largest single producer, production by state-owned companies represented less than half of 1989 total production, and is expected to represent only around one-fourth by the end of the current five-year plan. The large increases in coal production expected within the next few years will come chiefly from mines operated by production sharing contractors in Kalimantan. In 1989 production from PSCs totalled around 3 million tons; by 1993, this may catapult to nearly 14 million tons. Export availability at that time would then be around 12.5 million tons.

UTILIZATION AND DEMAND

As a result of the energy diversification policy, the share of coal in the national energy mix increased rapidly during the 1980s, and it is projected to continue to increase. As discussed in Part Three, coal accounted for just 1.3% of commercial primary energy in 1971, but this share rose to 6.6% in 1988. During the current five-year development plan, the share of coal is expected to increase from 6.9% in 1989 to 8.8% in 1993. In barrels of oil equivalent terms, this translates into 21.2 million BOE in 1989 and 33.1 million BOE in 1993. Although Indonesian coal could be processed through gasification or liquefaction, which ostensibly could increase coal use by making it directly substitutable for oil and gas, at present it is consumed only as a solid fuel. The major users are electric power plants and the cement industry. Forecast coal demand for these and other industries during the current plan period is shown in Table 9.4. Demand is forecast to reach nearly 8.7 million tons by 1993, which is a substantial increase, yet forecasts of production far surpass forecasts of demand. Projections of coal production and exports are based largely on expected growth in coal demand in the rest of Southeast Asia and in other countries of Asia and the Pacific, on the assumption that domestic Indonesian demand growth in the short term cannot absorb the projected rapid expansion of coal production capacity.

Table 9.3
Coal Production by Operator, 1985-93
(thousand tons)

Company	1985	1986	1987	1988	1989	1990	1991	1992	1993
State-Owned									
Perum Tambang Batubara	771	710	539	559	610	650	700	750	860
PT Tambang Bukit Asam	720	1,015	1,248	1,858	3,405	3,000	3,500	4,000	4,600
Production sharing contractors									
PT Arutmin Indonesia	0	0	0	121	686	1,000	1,500	1,750	2,000
PT Kaltim Prima Coal	0	0	0	0	344	500	1,680	4,765	5,520
PT Kideco Jaya Agung	0	0	0	0	0	0	100	500	1,000
PT Allied Indo Coal	0	0	53	444	513	500	500	500	500
PT Multi Harapan Utama	0	0	0	271	761	1,500	2,000	2,000	2,000
PT Tanito Harum	52	45	27	221	667	720	720	840	840
PT Utah Indonesia	0	0	0	0	0	0	250	500	700
PT Berau Coal	0	0	0	0	0	0	500	1,150	1,150
PT Adaro Indonesia	0	0	0	0	0	0	0	0	100
Private company or cooperative									
PT Bukit Baiduri	116	184	216	94	235	220	220	220	220
PT Bukit Sunur	24	133	115	186	430	150	150	150	150
PT Danau Mas Hitam	0	0	168	308	290	150	150	150	150
PT Fajar Bumi Sakti	116	133	142	141	156	150	150	150	150
PT Kitadin	201	330	433	366	449	650	750	810	810
Other operators	1	9	19	45	146	100	100	100	100
Total production	2,000	2,559	2,959	4,613	8,693	9,290	12,970	18,335	20,850
Exports and future export availability	1,081	942	892	1,307	2,546	2,683	6,205	11,222	12,533

Sources: Ministry of Mines and Energy 1989 for 1985-89 production data; PTB data for 1990-93 forecast.

Table 9.4
Coal Demand Projection, 1989-93
(thousand tons)

Users	1989	1990	1991	1992	1993
Power plants	3,623	4,553	4,613	4,820	6,338
Cement industry	1,977	1,992	1,992	2,105	2,197
Other	150	150	150	150	150
Total	5,750	6,695	6,755	7,075	8,685

Source: Ministry of Mines and Energy 1989.

With the exception of Bukit Asam, Indonesia's coal mines are not user-specific. Each company develops its own domestic or international market, or both, and their production is expected to expand in accord with market conditions. For example, in East Kalimantan, coal production still greatly outstrips current and anticipated demand, yet it is one of the areas most sought-after by production sharing contractors, since coal export avenues from East Kalimantan have already been established.

PTB has a specific market to supply from its production at the Bukit Asam mine. The state-owned company is responsible for meeting the coal demand of the Suralaya power plant, and some of its coal is also shipped to the cement plant in Kupang, at the western end of Timor. Bukit Asam coal production is therefore expected to increase at least in proportion to the expansion of the power plant's capacity. Up to 1989, the two coal-fired units (each of 400 MW) consumed 2.2 million tons of coal annually. During 1989-90, when two additional coal-fired units (each of 400 MW) came on line, this demand doubled to 4.4 million tons annually. As noted, it was initially difficult for PTB to meet this increase in demand.

In 1984, when the first unit of the Suralaya power plant came on line, the electric power authorities were aware that the ability of Indonesia's coal mining industry to fully supply the plant might lag several years behind actual power plant completion. When supply shortages occurred, usually as the result of transportation difficulties or production problems at the Bukit Asam mine, coal was purchased for the plant from private domestic companies, on condition that the delivered price of domestic coal at Suralaya was less than the CIF price of imported coal. Otherwise, coal was imported from Australia or China. In 1988 domestic production improved to the point that imported coal was phased out. Present plans call for the construction of three additional units at Suralaya, each of 400 or 600 MW. Bukit Asam coal should be sufficient to meet the projected demand; production is forecast to reach 4.6 million tons by 1994 (Table 9.3), 7.7 million tons in 1998, and 10.0 million tons in the year 2000.

In the mid-1980s, the electric power authorities planned to build a second coal-fired power plant complex of the same capacity as Suralaya at Paiton, East Java, and the first four units were expected to come on line during the current five-year plan period, 1988-93. The construction schedule has now been set back and only one unit is scheduled to come on line in 1993-94. It will be supplied by companies operating in East Kalimantan. The construction of the remaining units may be taken up again during the next five-year plan.

FUTURE DEVELOPMENT

In its attempt to maximize coal utilization, the government introduced a broad policy for future coal production and consumption in the mid-1970s, and a Presidential Instruction was issued in 1976 to the responsible ministries, directing them that coal should be used to the greatest extent possible in cement manufacture and electric power generation. The government's coal strategy included plans for overall coal flow, a coal demand projection, pricing policies, and mine-by-mine production plans. Five years after this "loose" policy was made, production, consumption, and coal flow all had failed to conform to the specifications of the policy. The government then relaxed its stance and decided to rely more on market economics to guide the development of the industry. This path appears to have been a prudent one; as indicated in Table 9.3, domestic coal production is forecast to exceed domestic coal demand from 1989 onward, and coal is expected to gain importance as both a domestic fuel and as an export commodity.

ENVIRONMENTAL ISSUES

Coal is by no means an environmentally benign fuel. The environmental impact assessment required for any coal project development in Indonesia must therefore apply to all stages of coal exploitation: exploration, production, transportation, and combustion. The rapid increase in coal consumption during the 1980s has raised the issue of emission standards, and plans for coal utilization now have a level of complexity beyond the traditional problems associated with mining and transport infrastructure. Current plans, which rely on existing power-plant technology, place an upper limit on the amount of coal which can be used in Java. The limit is thought to be around 30 million tons/year for Javanese power plants, with the currently required emissions technology. Since Indonesian coal is fairly low in sulfur, the focus of capital expenditure in the future is likely to be on building new coal-fired electric capacity with ash control but little or no sulfur emission control.

Concern also exists in Indonesia with reference to the impacts of increased coal combustion on greenhouse gas emissions and global warming. Given the dramatic increases in coal production described in this report, these concerns may be valid. However, to gain the proper perspective on Indonesian coal use, it is important to keep in mind the fact that fossil fuel combustion has been underway on a much grander scale for decades in the developed world, and problems associated with global warming cannot truly be attributed to countries like Indonesia, where on a per-capita basis—and on an absolute basis as well—fossil fuel use is quite low. Indonesian coal use amounted to around 5-6 million tons in 1989, and even assuming a very high market-penetration rate, coal use in Indonesia is not expected to top 30 million tons by the end of the decade. In comparison, China used over *one billion* tons of coal in 1989, and exploitation of the Chinese coal resource is expected to continue. Given the foregoing, it seems unlikely that Indonesian policies encouraging coal development and utilization will be abandoned merely for purposes of lessening Indonesia's contribution to global warming. There are more pressing environmental and economic problems to which the government must attend.

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