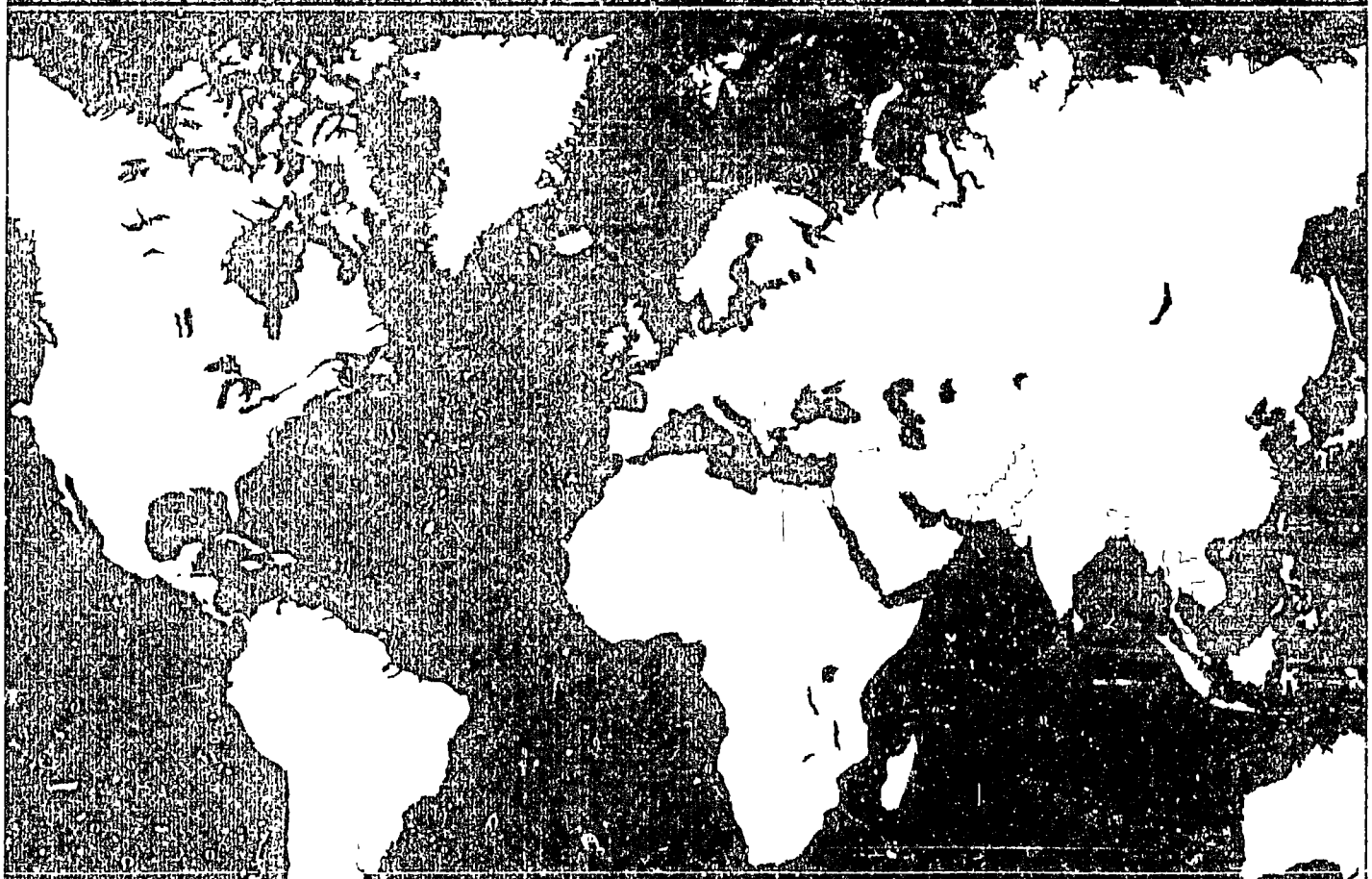
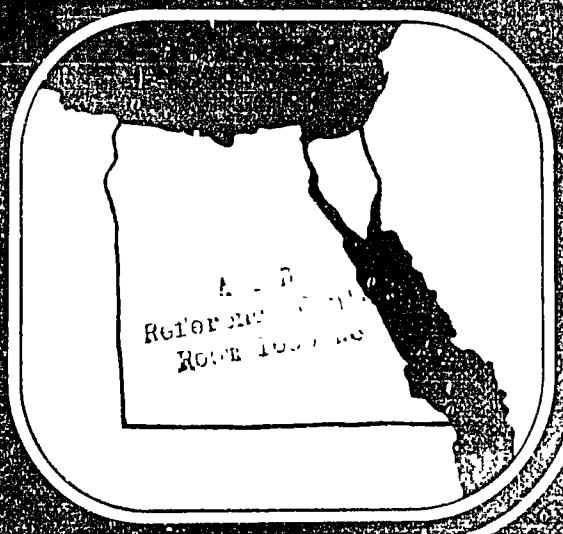
MARKET SURVEY FOR NUCLEAR POWER IN DEVELOPING COUNTRIES





EGYPT

ARAB REPUBLIC OF

MARKET SURVEY
FOR
NUCLEAR POWER
IN
DEVELOPING COUNTRIES

EGYPT,
ARAB REPUBLIC OF

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FOREWORD

It is generally recognized that within the coming decades nuclear power is likely to play an important role in many developing countries because many such countries have limited indigenous energy resources and in recent years have been adversely affected by increases in world oil prices. The International Atomic Energy Agency has been fully aware of this potential need for nuclear power and has actively pursued a program of assisting such countries with the development of their nuclear power programs. So far, inter alia, the Agency has:

(a) Sponsored power reactor survey and siting missions;
(b) Conducted feasibility studies;
(c) Organized technical meetings;
(d) Published reports on small and medium power reactors; and
(e) Awarded fellowships for training in nuclear power and technology.

At present only eight developing countries[1] have nuclear power plants in operation or under construction - Argentina, Brazil, Bulgaria, the Czechoslovak Socialist Republic, India, the Republic of Korea, Mexico and Pakistan. The total of their nuclear power commitments to date amounts to about 5200 MW as compared to an estimated installed electric generation capacity of about 50 000 MW. It is estimated that by 1980 only 8% of the installed electrical capacity of all developing countries of the world will be nuclear. In contrast, in the industrialized countries more than 16% of total electrical capacity will be nuclear by 1980.

In view of the possible greater need for nuclear power in developing countries it was recommended at the Fourth International Conference on the Peaceful Uses of Atomic Energy, held in Geneva in 1971, and at the fifteenth regular session of the General Conference[2], that efforts should be intensified to assist these countries in planning their nuclear power program. In response to these recommendations the Agency convened a Working Group on Nuclear Power Plants of Interest to Developing Countries on 11 - 15 October 1971 to review the then current status of the potential for nuclear power plants in these countries and advise on the desirability of carrying out a detailed market survey for such plants.

As a result of its deliberations, the Working Group recommended that a Market Survey be carried out to determine in a more definitive way the size and timing of demand for nuclear power plants in selected developing countries where they might play an economic role in complementing conventional energy sources. The Working Group also pointed out that, although the Survey would be performed in the interests of the countries concerned, the results should be directed toward the nuclear industry, including manufacturing, engineering, construction and financial institutions, who would be looked to ultimately for meeting the requirements for equipment, facilities and financing as identified in the Survey.

In response to these recommendations, the Director General decided that the Survey should be undertaken and steps were initiated in November 1971.

The objectives of the Survey as finally undertaken were as follows:

(a) Examine the potential role of nuclear power in interested developing countries over the next five to fifteen years as a means of defining the size and timing of the installation of nuclear plants in this period.
(b) Identify the specific market for small and medium power reactors in the countries participating in the Survey.
(c) Estimate the financial requirements for the selected power system expansion programs in each of the participating countries.

Thus, this Survey will define the size and timing of the likely market for nuclear plants to be commissioned in the participating developing countries and the domestic and foreign financial requirements for that market in the 1980-1989 period[3].

It should be emphasized that this report provides only an indication of the need for nuclear power and associated financial considerations for the countries involved. The

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[1] As classified under the United Nations Development Program.
[2] See General Conference Resolution GC(XV)/RES/285.
[3] For convenience this will be called "study period" throughout the report.

scope of the data and information surveyed are not in such great detail as to allow the findings to be considered the equivalent of a rigorously determined feasibility study of any specific installation. The results, however, are as accurate as they could be made within the limits of data, time and manpower available. The methodology and analytical procedures used are believed to be accurate.

In case the countries may need more detailed plans, an in-depth analysis will be required. It is suggested that the matter of defining the steps which would be needed to implement the suggested nuclear power programs, by all parties concerned, be the subject of further study after the participating countries have had an opportunity to thoroughly analyse the results of the Survey.

In order to avoid biasing the results in favour of nuclear power, the approach and bases for analysis, including the technical and economic parameters, were subject to careful review by independent observers at the start of the study and prior to its completion. Comments by these observers were taken into consideration wherever possible. It is hoped that as a result of these reviews any bias however unintentional has been removed from the study.

SCOPE AND IMPLEMENTATION

In November 1971 letters were sent to 23 developing countries considered to be the most promising candidates for introduction of nuclear power in the time period of interest. Fourteen of these countries expressed an interest in participating and agreed to provide relevant basic data and counterpart staff to work with the visiting teams of experts. Seven Survey missions were undertaken as follows:

Turkey-Greece	3-21 July 1972
Argentina-Mexico	7 August - 1 September 1972
Jamaica-Chile	4-15 September 1972
Republic of Korea-Singapore-Philippines	23 October - 17 November 1972
Pakistan-Arab Republic of Egypt	13 November - 1 December 1972
Thailand-Bangladesh	20 November - 8 December 1972
Yugoslavia	4-5 and 15-17 January 1973

The team selected for each mission was assigned the responsibility of collecting the necessary information on the characteristics of the power supply system(s) concerned, the projected power demand, current plans for expansion of the system(s), the availability of indigenous energy resources, and related economic and technical factors. This information was subsequently analysed by each mission team, reviewed by the country involved and used as a basis for the final report.

Data gathered by the missions were also evaluated by the engineering staff of the Agency and by the experts assigned to the Survey. This evaluation included consideration of power flows in the basic interconnected system under normal operating conditions, the possible differences in transmission system requirements under varying generating capacity plans, an analysis of the transient stability and frequency stability of each system following an unplanned outage of one or more generating units, an analysis of alternative power system expansion plans involving nuclear and conventional plants and an estimation of the present worth of all costs for each plan. The results served as a basis for the selection of near-optimum power system expansion programs for each of the fourteen countries involved.

FINANCIAL AND MANPOWER SUPPORT OF SURVEY ACTIVITIES

Since the Market Survey was not foreseen at the time the Agency's 1972 budget was prepared, financial support was obtained from various countries and financial institutions. Furthermore, the work of the Market Survey could not have been completed within the time and manpower constraints but for the great efforts of the personnel in each country who participated in the preparation and review of data, the Agency professional and supporting staff, and the contributions of many other experts and organizations.

Support in cash funds was made available from:

Federal Republic of Germany	US $ 25 000
Inter-American Development Bank	25 000
International Bank for Reconstruction and Development	50 000
United States – Export-Import Bank	75 000
Agency for International Development	25 000
Atomic Energy Commission	9 950
Total	US $ 209 950

In addition, several countries provided experts on either a cost-free or partially cost-free basis:

	Approximate man-weeks
Canada	22
Federal Republic of Germany	48
France	4
India	3
Japan	17
Sweden	9
United Kingdom	14
United States of America	19
Total	136

The fourteen participating countries contributed counterpart personnel and bore part or all of the expenses of each Survey mission during the time spent in the country in addition to the cost of preparing the responses and data required for the analyses.

The Agency's contribution to the Survey included US $20 000 in cash plus approximately 260 man-weeks of professional staff, secretarial and administrative support, equivalent to about US $176 000. In addition, special consultants to the Agency provided about 170 man-weeks of support equivalent to about US $112 000.

Based on the above, the total cost of the Survey is estimated to amount to US $555 000, including more than US $100 000 for cost-free services provided by its sponsors.

ACKNOWLEDGEMENTS

Mr. O. B. Falls, Jr., USA, consultant to the Agency, was Project Manager for the Market Survey.

To list all of those who contributed in one way or another, even for one country, would be lengthy. Hence, specific recognition is limited to:

Associated Nuclear Services Ltd (ANS), London, England – who furnished, under a special contract, an electric utility system planning expert for each mission and co-ordinated the technical systems analysis work for the participating countries.

Bechtel Corporation, San Francisco, California, USA – who furnished complete heat rate data for the many sizes and types of fossil and nuclear power plants used in the Survey analyses.

Lahmeyer International GmbH, Frankfurt, FRG – who also furnished heat rate data, consulting service on costs and availability of smaller nuclear reactors, and an expert in mining of coal and lignite.

Tennessee Valley Authority, Chattanooga, Tennessee, and the Atomic Energy Commission, USA – who made available TVA's basic power system planning computer program, Mr. Taber Jenkins of TVA's staff and Dr. David Joy of Oak Ridge National Laboratory (USAEC) to develop the changes required to provide the computer program capabilities especially needed for the Market Survey.

Others who contributed materially to the work of the Survey were the many organizations and the liaison officers from each country as listed in the Appendixes and the outstanding staff of consultants and Agency personnel who participated in the several missions and in the work at headquarters.

It is hoped that the information contained in this report will be of value to each country in formulating appropriate plans in regard to the potential use of nuclear energy for electric power generation in the years ahead.

INTRODUCTION

Fourteen Country Reports, one for each of the developing countries that took part in the Survey, have been prepared. These fourteen Country Reports are summarized in the General Report.

Sections 1-8 of each Report contain data gathered during the visit of the team of experts and other data gathered for general accuracy. Sections 9-17 present the method of approach, the data used in the analyses, the analyses made and the results of the studies. General data and methodology common to the studies for all countries are given in the Appendixes.

Section 1 concerns general economics and contains data on population, gross national product, mineral resources and energy consumption.

Data on the national energy resources such as hydro potential, fossil fuel reserves, refinery capacity and production, and nuclear materials resources are given in Section 2.

The electricity supply system, its development, generating and transmission facilities, costs of existing plants and plants under construction, various system operating and economic criteria, and technical data on existing generating units are given in Section 3.

The historical growth of the electrical demand is described in Section 4, together with historical data on per-capita consumption, installed capacity, energy generated, load factor, and system load characteristics. Data are also given on system reliability, reliability criteria, and outage experience.

The future system requirements are described in Section 5 including projections of maximum demand, generated energy, load factor and future reserve capacity. Also included are data on generating units and transmission facilities planned, under construction or projected, and on future sites.

Section 6 contains data on local material and labour costs, labour practices, and the participation of local industry in the manufacture of power system components.

Economic and financial aspects such as the method of evaluating the economic merit of projects, sources of funds, import duties and restrictions are described in Section 7.

Section 8 contains a description of the administration and regulation practices of the Agencies responsible for nuclear power and information on nuclear legislation, licensing and safety.

Section 9 describes the analytical approach used in the study; the bases of analysis, the computer programs, and the economic and technical methodology and parameters. The approach taken to determine the sensitivity of the results to certain parametric changes is also described.

In Section 10 are described the bases of the load forecasts used in the study, the future load characteristics such as seasonal peak demand, the load duration data, and the load factor.

The results of the analysis of the factors limiting system development, made by Associated Nuclear Services, are given in Section 11, including data on system reliability, response of the system to loss-of-load, and recommendations on limits of generating unit sizes.

The existing and committed electrical power system technical data, such as unit capacity, heat rates, fuel costs, forced and scheduled outage rates, seasonal and energy factors relating to hydro, and data on emergency hydro and pumped storage are given in Section 12.

Capital cost data and the bases for their calculation are given in Section 13.

The technical characteristics of the alternative generating units considered for the expansion of the power system are given in Section 14.

The analyses of the alternative expansion programs are described in Section 15, including a discussion of the alternative plans considered, the method of determining the "optimum" expansion program and the consideration given to system reliability.

The results of the study for the reference conditions and the sensitivity of these results to various parameters are given in Section 16. These results include the overall thermal plant additions required during the study period, the nuclear units required, and the financial requirements of the reference case expansion plan.

The summary and conclusions of the study are presented in Section 17.

A number of Appendixes have been included to provide additional information on the computer programs, methods of forecasting load, methodology and parameters used, fossil and nuclear fuel costs, general technical and economic data on thermal and nuclear plants, and other appropriate data.

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1. ECONOMIC BACKGROUND

1.1. Geographic features

The Arab Republic of Egypt occupies the north-eastern corner of the African continent, extending across the Gulf of Suez into the Sinai region, as shown in Fig. 1-1. It has roughly a square shape, stretching 1024 km from the Mediterranean in the north to Sudan in the south, and 1240 km from Libya to its eastern borders. Of its total area of 1 002 000 km^2, only 34 500 km^2 (3.4%) is agricultural land.

Summer temperatures are very high, reaching 32°C on the Mediterranean coast and 40°C or more in the south and in the desert. The winters are relatively warm. Along the Mediterranean coast there is occasional rain, totalling a few centimeters per year, mainly in the winter. Inland there is less rain and a few hundred kilometers south of the Mediterranean there is essentially no rainfall. Cultivation depends almost entirely on irrigation and is possible only in the Nile basin and the oases. North of Aswan the land irrigable by the Nile is an extended narrow strip of 2 to 15 km width. About 25 km north of Cairo the Nile

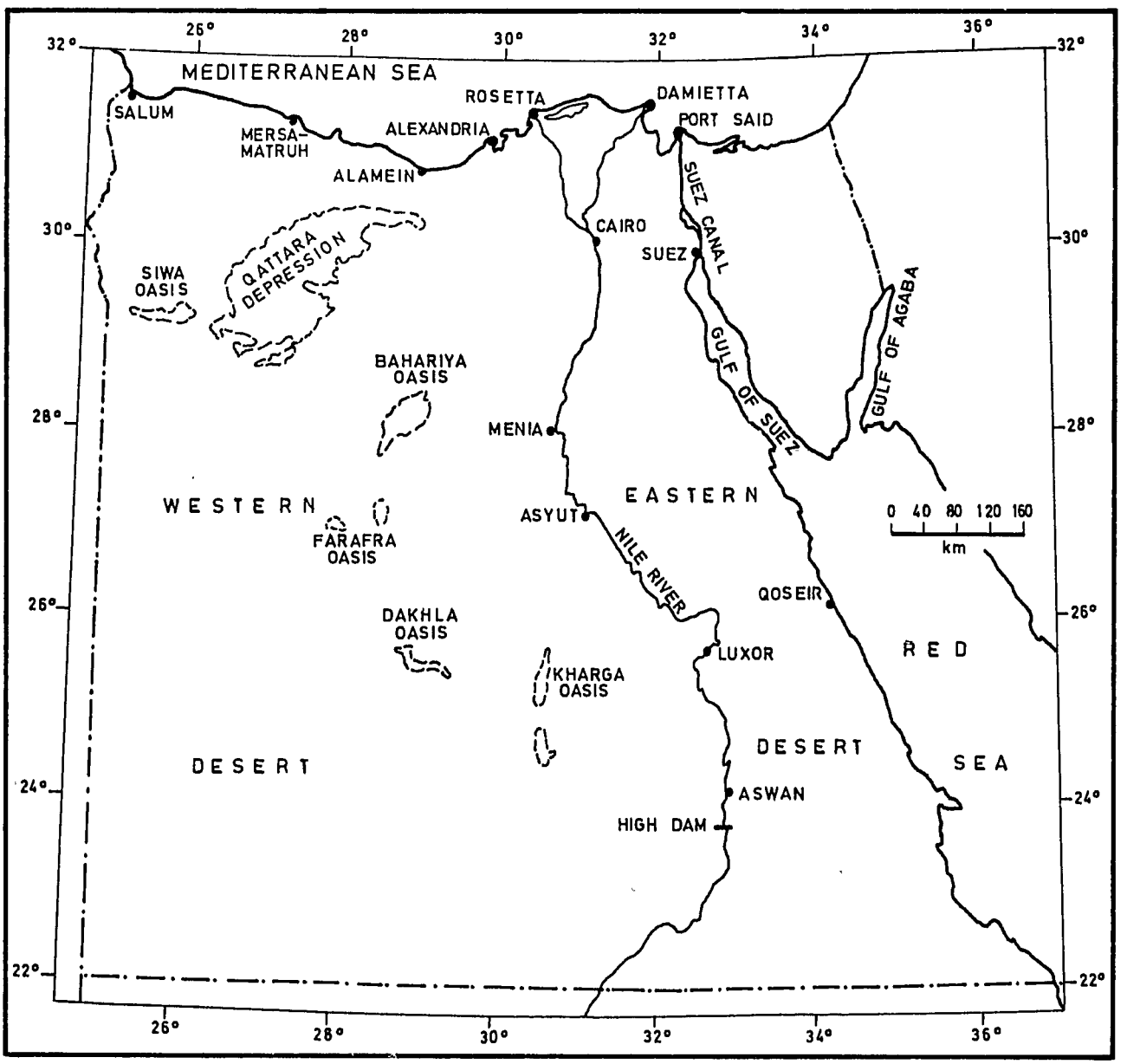

FIG. 1-1. MAP OF EGYPT.

branches into two main streams between which lies the fertile Delta. This limited but very fertile arable land is hemmed in by the Western or Libyan Desert and by the mountainous Eastern or Arabian Desert.

Historically the salient feature of the Nile has been its annual flood, reaching Egypt in the period August to November. Today the flood is a feature of the past. The construction of the High Dam near Aswan, started in 1960 and essentially completed in 1968, has made it possible to completely control the river flow and release water as it is needed for irrigation.

1.2. Population

The total population is estimated to have been 34.8 million in 1972 and is projected to be 37.2 million in 1975 and 41.6 million in 1980 (see Table I-1). The annual growth rate was 2.54% between the 1960 and the 1966 censuses. However, a family planning program was started in 1965 and from 1966 to 1970 there was a decrease in the birth rate from 41.0 to 35.6 per thousand. If this lower rate continues, the above projections are too high.

TABLE I-1. POPULATION DATA AND PROJECTIONS IN SELECTED YEARS

Year	Total population (10^3)	Birth rates (per 10^3)	Death rates (per 10^3)	Rates of natural increase (per 10^3)	Population per km^2 of inhabited area
1937 [a]	15921				466.1
1947 [a]	18967				546.4
1960 [a]	25832	43.1	16.9	26.2	733.2
1966 [a]	30139	41.0	15.8	25.2	845.5
1967	30907	39.2	14.2	25.0	
1968	31693	38.1	16.1	22.0	
1969	32501	36.8	14.4	22.4	
1970	33329	35.6	15.0	20.6	
1971	34076				
1972	34839				
1975	37233				
1980	41594				

[a] Census year. Apart from census years population is estimated at mid-year by the Central Agency for Public Mobilization and Statistics. Substantially higher estimates have been made by the National Planning Centre.

The population is concentrated in the Nile Valley and the oases, while the deserts are practically unpopulated. This has resulted in a rapidly increasing population density which has reached 980 per km^2 of populated area, one of the highest in the world.

The 1960 and 1966 censuses showed that only 51.5% of the population was in the labour force age range (15-64 years of age) whilst about 45% was younger than 15 years and 3.5% older than 64 years. Thus the dependent part of the population is unusually high with, as a result, relatively high requirements for expenditure on education, health and social services. As a result of the increasing industrialization and internal migration, the urban population is growing at a much faster rate than the total population. The population living in towns as a percentage of the total population increased from 33% in 1947 to 37% in 1960 and 40% in 1966.

1.3. National economics[1]

(a) Gross National Product

Economic growth in Egypt over the last decade has been accompanied by substantial structural changes of the economy. Banks, insurance companies, wholesale trade, transport and virtually the whole of the mining and manufacturing sectors became state-owned and managed. Economic development during 1960-70 was guided by two Five-Year Plans. Over this ten-year period, in spite of the disruptions due to war, the Gross National Product (GNP) has grown in real terms at about 5%/yr. Because of the disruptions the growth has been erratic and the last Five-Year Plan was not accomplished. According to a draft of the Ten-Year Plan for 1973-82 the GNP should reach 5700×10^6 £E in 1982, which would mean that a 7.2% average annual increase in the GNP is being planned.

The development of the GNP since 1959-60 in constant 1964-65 prices is given in Table I-2.

TABLE I-2. GROSS NATIONAL PRODUCT AT CONSTANT 1964-65 PRICES

Fiscal[a] year	GNP (10^6 £E)	GNP per capita (US $)
1959-60	1 489	168
1960-61	1 570	172
1961-62	1 620	174
1962-63	1 817	151
1963-64	1 998	162
1964-65	2 192	174
1965-66	2 311	179
1966-67	2 298	173
1967-68	2 277	167
1968-69	2 389	171
1969-70	2 584	181

[a] Fiscal years begin 1 July.
In May 1962 the exchange rate was changed from 0.3482 £E = 1 US $ to 0.4348 £E = 1 US $.

(b) Indigenous minerals

The extent of Egypt's mineral wealth is relatively unknown although the Government, through the General Organization for Research and Mining, has for the past several years intensified its programs for the exploration of new, and for the exploitation of existing, mineral deposits. The contribution of mining and quarrying to the industrial output in 1969 is estimated at 11 million £E.

The most important minerals presently being exploited are shown in Table I-3.

[1] The Egyptian national currency is the Egyptian pound £E. The rate of exchange relative to the US dollar prior to 1962 was 0.3482 £E = 1 US $. Since that date it has been 0.4348 £E = 1 US $.

TABLE I-3. MINING PRODUCTION (10^3 t)

Mineral	1952	1965	1966	1967	1968	1969	1970
Phosphate rock	478	594	661	683	1441	660	716
Manganese [a]	209	46	47	19	1	1	2
Iron ore [b]	-	254	220	211	224	230	227
Salt (common)	498	494	627	584	622	385	376
Sulphur	-	4	12	9	3	1	-
Asbestos	0.6	3.5	1.9	1.9	2.6	-	0.2

[a] Mn content.
[b] Fe content.

(c) Industrial production capabilities and growth

Primarily, Egypt has an agricultural economy. While its industries produce many items for the residential, and commercial markets, essentially all heavy industrial products and major components for power plants and transmission lines are imported.

The basic industries in Egypt include mining and a basic metals industry, chemicals, food products and textiles. The rate of industrial expansion of these industries is indicated by the Industrial Production Index Numbers shown in Table I-4.

TABLE I-4. INDUSTRIAL PRODUCTION INDEX NUMBERS (Index number in 1963 equals 100)

Branch of Industry	1964	1965	1966	1967	1968	1969	1970
Mining	159	124	137	139	211	290	n.a.
Manufacturing	114	121	116	112	124	123	n.a.
Food	96	102	89	89	97	122	141
Textiles	105	114	112	117	123	124	130
Chemicals	129	145	158	138	154	156	164
Basic metals	100	99	133	107	132	136	121
General	116	121	117	115	131	136	n.a.

1.4. Total energy consumption

(a) Distribution of energy consumption by source

Table I-5 shows the growth in energy consumption from 1960 to 1969 in terms of thousands of metric tons of equivalent coal (TEC). During the years 1960 to 1969, the average annual rate of growth of energy consumption was only 2.7% and was very irregular, largely due to the disruptions previously mentioned. During this time, however, hydro power increased from a very low value to a point where by 1969 it was more than 25% of the total. The consumption of gas in Egypt is very low in relation to the total, being less than 1%, and has therefore been omitted from the table.

TABLE I-5. ENERGY CONSUMPTION, 1960-69.

Year	Liquid fuels	Solid fuels	Hydroelectric [a]	Total	Energy consumption per capita (kg coal equiv.)
	10^3 TEC [b]				
1960	7 340	160	150	7 650	296
1961	6 972	301	630	7 903	298
1962	7 396	273	730	8 399	309
1963	7 912	271	800	8 983	322
1964	8 668	495	1 045	10 208	357
1965	8 339	459	1 110	9 908	337
1966	9 011	312	1 150	10 473	347
1967	7 486	480	1 195	9 161	296
1968	8 672	500	1 845	11 017	348
1969	6 149	539	2 500	9 188	283

[a] Hydroelectric energy converted to TEC at a rate of 1 000 kWh = 0.6 TEC.
[b] 1000 TEC = 28.5×10^9 Btu = 7.25×10^9 kcal.

(b) Electrical energy as a share of total energy

Table I-6 shows the relative importance of thermo and hydro generated electricity, liquid and solid fuels in the total energy consumed in Egypt during the years 1964-69. As can be seen, electricity is becoming increasingly important.

TABLE I-6. DISTRIBUTION OF TOTAL ENERGY CONSUMPTION, 1964-1969 (%)

Year	Thermal power stations	Hydro power stations	Total electricity	Liquid fuels [a]	Solid fuels
1964	14.1	10.1	24.2	70.9	4.9
1965	15.5	11.4	26.9	68.5	4.6
1966	15.9	10.8	26.7	68.8	4.5
1967	18.6	13.0	31.6	63.2	5.2
1968	14.3	16.9	31.2	64.4	4.4
1969	14.1	27.3	41.4	52.7	5.9

[a] Excluding that used for electricity generation.

1.5. Interest in nuclear power

By the late 1970's the capacity of the existing and planned stations will fall short of that required by some 600 to 800 MW. This deficit will have to be met either by additional fossil-fuelled stations or by nuclear power. In discussion, staff of the Atomic Energy Establishment (AEE) and the Ministry of Electricity stated that two 400 MW nuclear units were being

studied for starting operation in the period 1979 to 1981, and that thereafter they expected that an increasing proportion of power generation would be nuclear.

The AEE has studied the use of nuclear plants for desalination and believe that, because of the increasing demand for water for agriculture, nuclear desalination will become very important in the future. In that event dual purpose (power/water) plants would be appropriate and would have an important bearing on Egypt's future power program. In the present study, however, this possibility has been ignored and the forecast of the market for nuclear power plant is consequently a conservative one.

2. NATIONAL ENERGY RESOURCES

2.1. Hydroelectric potential

(a) Existing hydroelectric power stations

There are at present two principal hydroelectric power stations in Egypt.

The first is the Aswan Dam which was originally built for irrigation purposes. Later a hydroelectric power station was added which has been in operation since 1960. It consists of nine units, seven with a capacity of 46 MW each, and two with a capacity of 11.5 MW each. The total capacity is 345 MW.

The second is at the Aswan High Dam 7 km upstream. Construction of the dam took place in the 1960's and was completed in 1968. It is now being filled and is expected to reach its normal level in 1980. The hydroelectric station contains twelve units each of 175 MW capacity.

The operation of both dams is based on the following requirements:

(i) Sufficient water is released from the dams to keep the river Nile navigable,
(ii) No more water – apart from that required for (i) – is released than is needed for irrigation purposes,
(iii) The level of the pool between the Aswan Dam and the High Dam should not change more than ±3 m.

These regulations will be followed strictly up to the year 1980 when the High Dam is expected to be filled. Afterwards these requirements will be followed strictly in years of low water conditions, whilst in years of high water conditions more water than needed for irrigation might be available and be used for the production of additional electric power.

(b) Additional potential hydroelectric power resources – Nile barrages

Downstream of the Aswan Dam the river Nile has a length of 940 km with a difference in height of 75 m. Barrages exist at Esna, Nag-Hammadi, and Asyut. Construction of seven additional barrages is being considered. The three existing barrages were built only for irrigation and have no installations for the production of hydroelectric power. The additional ones were foreseen mainly to prevent the erosion of the Nile Valley which is expected to result from the construction of the High Dam.

The barrages will be comparatively low, between 4 and 8.5 m high. Even so, it could be worthwhile to make use of them for the production of electric power. If one were to use all ten barrages, the maximum average power produced could be about 600 MW, and the minimum average (in January) would be about 300 MW. Table II-1 gives some details of the barrages, and in each case, the maximum average power. Whether such power stations should be built or not is under investigation. The results of the investigations are not expected to be available until 1976. The construction of the barrages would not start before the end of the 70's and the first could come into operation about 1985. These barrages could contribute to the overall power production during the study period.

(c) Additional potential hydroelectric power resources – The Qattara Project

The Qattara Project, named after a deep depression in the western desert south of El Alamein, was first proposed in 1925. Since that time a number of studies have been made and are still going on. The basic idea is to dig a canal from the Mediterranean Sea to this depression and let the water of the Mediterranean flow into the depression and evaporate. Professor Bassler of the University of Darmstadt is guiding a study of this project for the Egyptian Government. According to the AEE, Professor Bassler's preliminary figure (1971) for the overall cost of the first step of the project was US$468 × 10^6, of which 60% was for the canal, 30% for civil works, and 10% for equipment including a 600 MW power station. He assumed that the canal would be constructed by using nuclear

TABLE II-1. ESTIMATED CHARACTERISTICS OF THE NILE BARRAGES HYDROELECTRIC PROJECTS

Power station	Distance from Aswan (km)	Head	Utilized flow (m^3/sec)	Maximum average power (MW)	Annual energy (10^6 kWh)
Silsila	74	7.50	1800	86	725
Esna	167	5.90	1600	66.4	490
Quift	266	6.10	1600	66.4	490
Nag-Hammadi	360	4.00	1300	45	330
Sohag	445	8.50	1600	86	709
Asyut	544	5.00	1000	41.5	324
Deirut	608	7.70	1000	57	471
Samalut	692	7.10	1200	57	436
Beba	775	6.10	1000	47.5	350
El-Ayat	857	6.10	1000	47.5	352
Total		64.00		600.3	4 677

explosions. If the canal were to be excavated by conventional methods, its cost alone was estimated to be about US $624 × 10^6. Professor Bassler's study is expected to be ready at the beginning of 1973.

2.2. Coal and lignite

There are small coal deposits in the Sinai but they are of no significance for the production of power.

2.3. Oil and natural gas

(a) Production

The petroleum industry has had an increasing importance in Egypt's economy during the past decade. From an annual output of 3.3 million tons in 1960, production of crude oil has expanded to 14.8 million tons in 1971 despite the loss of the Sinai oil fields. Before 1967 the latter accounted for almost 80% of total production and would now add about 6 million tons. In addition natural gas resources have also been found and are being developed. Further development of crude oil and natural gas production is planned as shown in Table II-2. The biggest producing oil fields are the Morgan fields in the Gulf of Suez, the associated onshore fields, and El Alamein on the coast west of Alexandria.

TABLE II-2. PRESENT AND PLANNED PRODUCTION OF CRUDE OIL AND NATURAL GAS (10^6 t)

Year	Crude oil	Natural gas [a]
1971 actual	14.8	-
1976 estimated	20.4	3.1
1982 estimated	45.0	5 [b]

[a] 1 lb = 21 000 Btu.
[b] If export contracts are obtained, this would be raised to 10 × 10^6 t.

(b) Amount and location of reserves

Egypt's present reserves of oil and natural gas and her plans for the future development of reserves are shown in Table II-3.

Natural gas is found principally in the Nile Delta at Abu Madi and off-shore at Abu Qir, and at Abu Gharadig in the Western Desert. It is planned to use the Abu Madi gas as a fuel for power stations and for industry, and as raw material for fertilizer manufacture at Talkha. LPG in the Abu Gharadig gas will be split off in a plant near Cairo and will be bottled for household use. The remaining gas will be transferred to Helwan, south of Cairo, for use in various industries and power stations, and also as a reducing agent in new blast furnaces. The Abu Qir gas will be used by industry in Cairo.

TABLE II-3. PRESENT AND ESTIMATED FUTURE RESERVES OF CRUDE OIL AND NATURAL GAS (10^6 t)

Year	Oil	Natural gas [a]
1971 actual	145 [b]	75
1976 estimated	355	400
1982 estimated	285	365

[a] 1 lb = 2100 Btu.
[b] Excluding Sinai.

Oil is produced mainly in the Gulf of Suez and on its western shore. However, the Western Desert is now considered to be the most promising area, and as shown in Fig. 2-1, three basins are indicated. One is north of the Qattara Depression embracing the finds at El Alamein, Yidma, Razzak, Umbarka and Meleiha. The second is south of the Depression and includes the find at Abu Gharadig. The third is west of Qattara where exploration is taking place but where no find has yet been made. The oil so far found has been located in relatively small lenses and no big find has been made. However, exploration by several foreign companies and the Egyptian General Petroleum Company is continuing with the active encouragement of the Government.

(c) Pipelines

The contract for a 340 km, 42-inch, pipeline (SUMED) from Suez to Alexandria was awarded in October 1969. Difficulties in arranging financing have delayed the start of construction. It is also planned to connect the Abu Gharadig field to the export facilities at El Alamein on the Mediterranean coast through a 12-inch line, and later to construct a gas pipeline to the Cairo area.

(d) Consumption of crude and fuel oil

Before the effect of the 1967 war, Egypt had a net import of crude oil and a net export of fuel oil (see Table II-4). The increasing domestic crude oil production since 1968 has made a net export of crude oil possible. The effect of the 1967 war on the refinery capacity has been overcome and in 1972 net export of fuel oil was resumed.

(e) Refinery capacity

The operating capacity of the three refineries increased from 5 million metric tons in 1971 to 6.5 million in 1972. It is planned to increase it to 9.5 million metric tons in 1976 and 13 million in 1982. The capacity is now more than required for domestic consumption.

Information on distribution of refinery production as fuel oil and lighter products was not available.

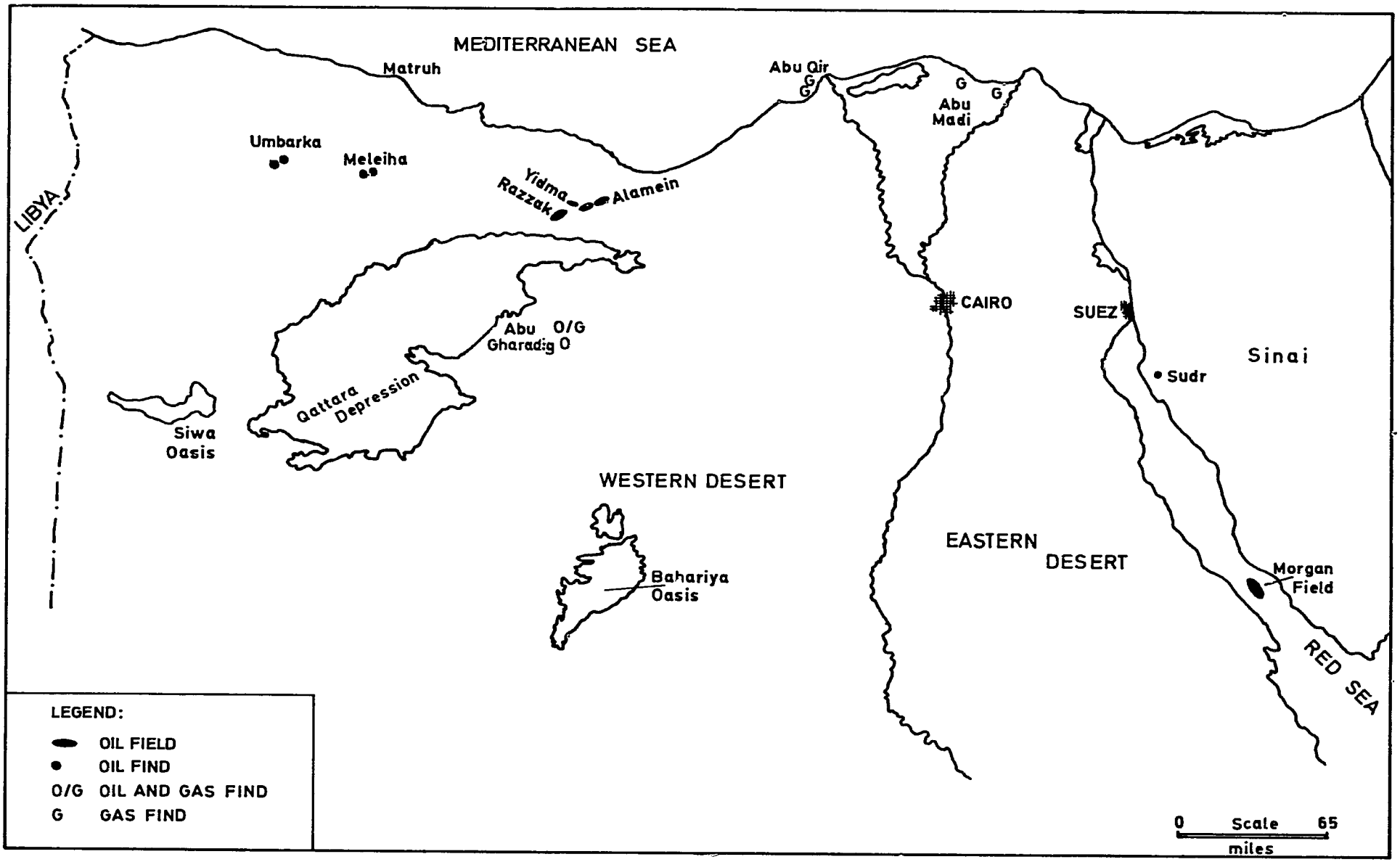

FIG. 2-1. OIL AND GAS: CONCESSIONS, FIELDS AND WELLS DRILLED.

TABLE II-4. CONSUMPTION OF CRUDE OIL AND FUEL OIL (10^6 t)

Year	Crude oil			Fuel oil		
	Domestic production	Net imports	Domestic supply	Domestic production	Net imports	Domestic supply
1960	3.33	1.14	4.47	2.73	-	2.73
1961	3.83	0.88	4.71	2.65	-0.21	2.44
1962	4.74	0.67	5.41	2.82	-0.43	2.39
1963	5.65	0.19	6.56	3.39	-0.94	2.45
1964	6.36	1.55	7.91	4.24	-1.45	2.79
1965	6.48	1.97	8.45	4.68	-1.71	2.97
1966	6.26	2.33	8.59	4.20	-0.94	3.26
1967	5.58	1.20	6.78	3.33	-0.11	3.22
1968	8.58	-2.55	6.03	3.05	0.02	3.07
1969	12.30	-9.22	3.08	1.48	1.61	3.09

(f) Projected import of crude oil and fuel oil

It is planned to continue to cover domestic requirement for crude and fuel oil by domestic production and to maintain a net export surplus.

(g) Current and projected cost of oil and gas

The present price of £E 7.5/t for fuel oil applies uniformly all over Egypt and has been maintained over the last five years. Fuel oil is used by power stations, large industries and bakeries. A rebate is given to large consumers.

The price has been fixed by the Government and is expected to remain unchanged for a considerable time. It includes a Government tax of £E 0.5/t and is said to cover costs while profits come from the lighter products. Export prices of fuel oil correspond to £E 7.5/t and the posted prices in Italy. Crude oil is exported at international prices.

(h) Exploration activities

The approach to exploration for oil and gas has placed primary emphasis on commercial considerations. In the main, exploration for oil and gas has been undertaken in co-operation with foreign enterprises, usually through partnership agreements with the Egyptian General Petroleum Company (EGPC). Most concession agreements provide for equal sharing of production between partners; usually the foreign partner is responsible for investment in exploration which, in the event of a commercial discovery, is shared by EGPC. Each partner is responsible for marketing its share of output. Terms are, however, flexible. EGPC has at present several foreign operating partners. In addition to the operations which it undertakes in partnership, the EGPC is prospecting on its own account in certain areas of the Western Desert and in the Nile Delta through the General Petroleum Company which it wholly owns. Egypt has recently issued invitations for foreign exploration in the Mediterranean offshore, most of which is open. In addition large areas of the Western Desert are uncommitted or will become free shortly.

2.4. Uranium ores

Following early prospecting work of a reconnaissance nature in the period 1956 to 60, systematic prospecting has been done since 1961.

There are three possible sources of uranium:

(a) Conventional type uranium deposits;
(b) Uranium contained in the monazite mineral found in the heavy mineral beach sands; and
(c) Uranium contained in phosphate rock.

(a) Conventional type uranium deposits

No economic or near economic uranium ore reserves have as yet been proved in conventional type deposits. A considerable number of occurrences have been discovered, especially in the Central Eastern Desert, but the amount of sub-surface exploration is too small to allow ore reserves to be estimated.

Favourable geological indications in both the Eastern Desert and Western Desert make it possible that intensified prospecting may prove low cost uranium ore in conventional type deposits.

(b) Heavy mineral beach sands of the Nile delta and Mediterrean coast

The potential reserves of nuclear raw materials (both U_3O_8 and ThO_2) in the heavy mineral beach sands are very high. An approximate reserve estimate to a depth of 20 m is as follows:

Heavy minerals	Monzite	ThO_2	U_3O_8
600 000 000 t	6 000 000 t	370 000 t	28 000 t

While production of uranium from this source is possible, it would be a by-product operation, whose economics would depend on the successful development of the whole beach sands industry and the marketing of the various principal products. If, for example, an industry with an annual throughput of one million tons of heavy minerals were developed, it could theoretically provide between 40 to 50 t U_3O_8 annually. Even assuming the most favourable sales conditions for the principal products, it is probable that the U_3O_8 cost would be high. At the same rate of production about 600 t ThO_2 could also be recovered annually at an estimated cost of 5 to 10 US $/lb ThO_2.

(c) Phosphate rock

It is estimated that about 100 000 t U_3O_8 may exist in phosphate rock in the country, but with present technology and availability of deposits only about one half of this would be theoretically recoverable. Any recovery of U_3O_8 would be a by-product operation completely dependant on the installation of triple-superphosphate plants. No such plants exist at present. A triple-superphosphate plant handling half a million tons of raw phosphate rock per year could theoretically produce 25 t U_3O_8 a year at a cost in the range of 15 to 30 US $/lb U_3O_8.

3. ELECTRICITY SUPPLY SYSTEM

3.1. Past history and development of industry up to the present

Before 1964 the generation, transmission and distribution of electricity was in the hands of a large number of Government, municipal and private organizations. The placing of the entire electricity supply under unified national control was made possible by the formation in 1964 of the Ministry of Electric Power and its subsidiary organization, the Egyptian General Electricity Corporation. GEC is responsible for the generation, transmission and distribution of power in Egypt and accounts for about 80% of the total generation capacity of Egypt, the remaining 20% being plants that supply process steam and electric power to various industries. These are being connected to the GEC unified grid, but since new industrial power plants are not being built, their relative importance will diminish over this decade and be unimportant by the 1980's.

3.2. Present organization structure

The General Electricity Corporation reports to the Ministry of Electricity. The structure of the Corporation is shown in Fig. 3-1, and the overall structure of the Ministry of Electricity is shown in Fig. 3-2. It should be noted that the Authority for Rural Electrification also reports to the Ministry of Electricity, and is responsible for extending electrical service to the many unelectrified villages.

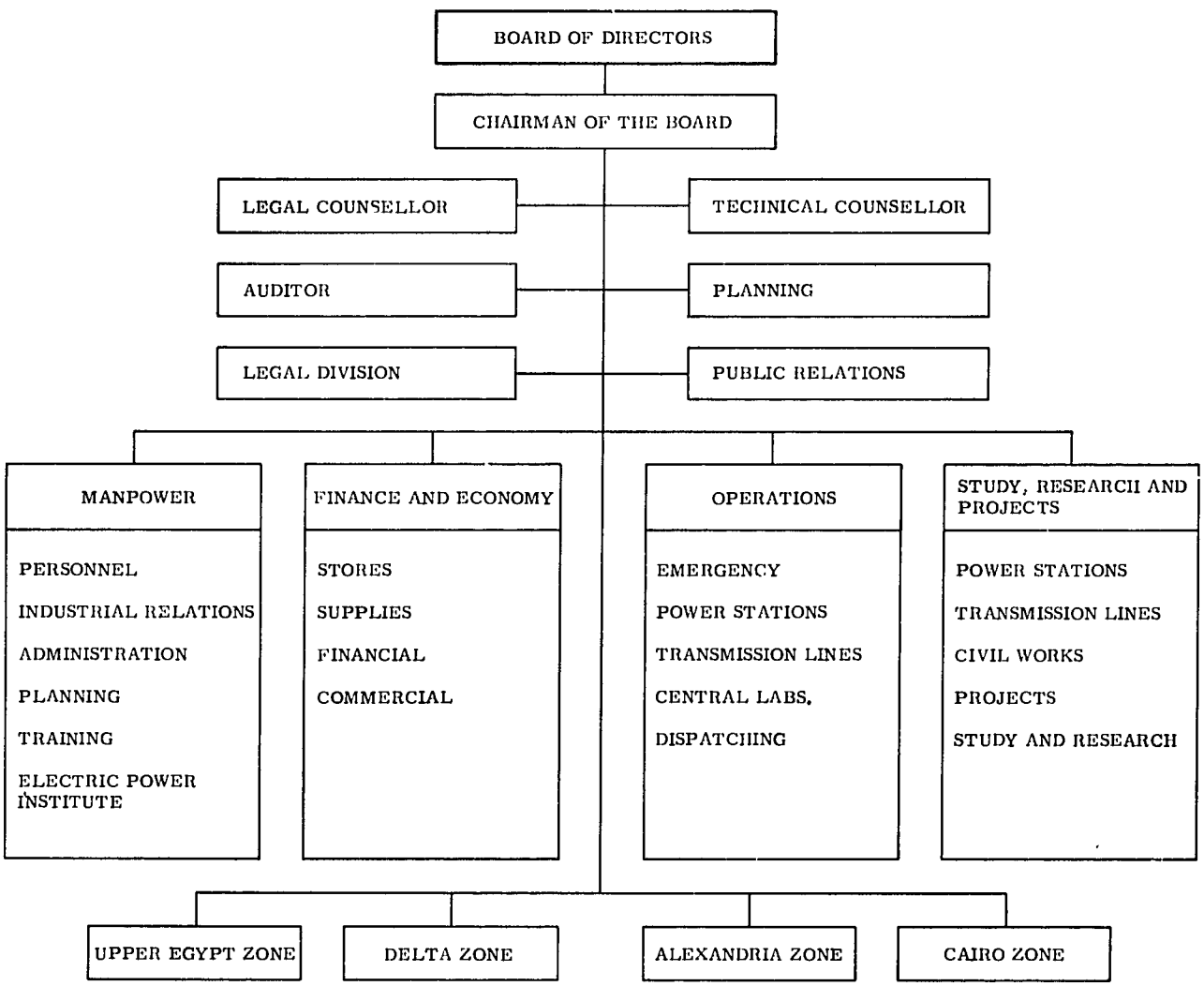

FIG. 3-1. ORGANIZATION CHART OF THE GENERAL ELECTRICITY CORPORATION.

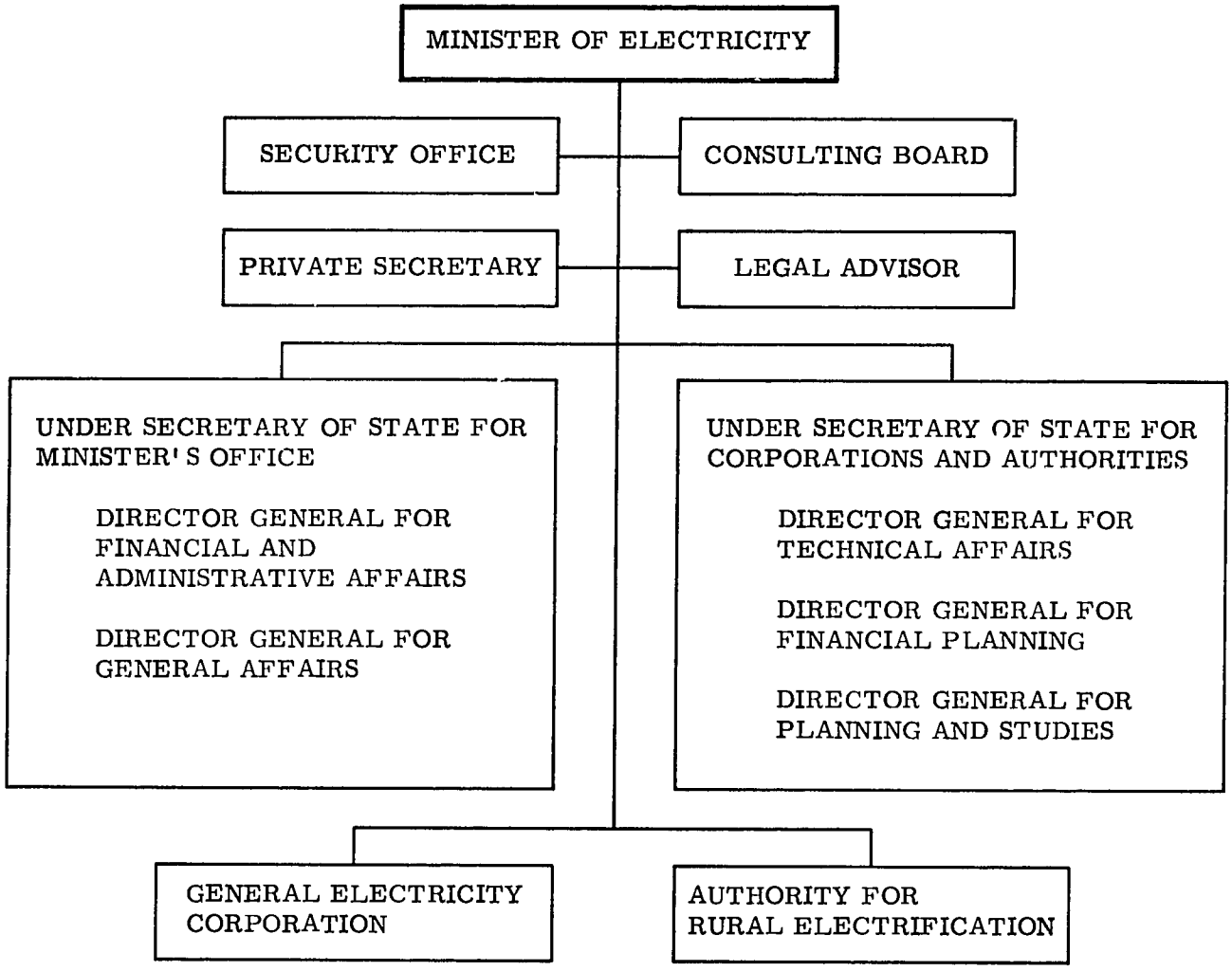

FIG. 3-2. ORGANIZATION CHART OF THE MINISTRY OF ELECTRICITY.

3.3. Geographic areas of responsibility

GEC's area of responsibility includes all of Egypt, though the responsibility for the electrification of rural areas has been assigned to the Authority for Rural Electrification.

3.4. Generation and transmission facilities

(a) Generation

Before 1960 a major portion of the power was generated by oilfired units located at Cairo, Alexandria and in the Delta. In 1960 to 1961 the 345 MW hydro station at the Aswan Dam became operational and in 1968 the Aswan High Dam (potential capacity 2100 MW) became operational. In addition, three 87 MW units were installed in Cairo West Station in 1966-68 and a station with two 110 MW units is in the early stages of construction at Kafr El Dawar in the Delta. The Aswan units are connected with the major load centres in the Cairo region by two 500 kV single circuit transmission lines. A network of 220 kV and 132 kV lines interconnect the various load centres in the Delta and Upper Egypt and distribution is by 66 and 33 kV feeders.

Table III-1 shows that the generating plant installed in the GEC system in November 1972 had a total capacity of 3774 MW, made up of 1329 MW of thermal capacity and 2445 MW of hydro capacity at Aswan. At present only one third of the Aswan capacity can be utilized for

TABLE III-1. LIST OF GENERATING PLANT[a]

Zone and station	Type[b]	Year(s) commissioned	Unit No. and capacity (MW)	Total installed capacity (MW)	Energy production in 1971 (GWh)
Upper Egypt					
High Dam	H	1967 - 70	12 x 175	2 100	3 181
Aswan Dam	H	1960 - 61	7 x 46, 2 x 11.5	345	1 682
Asyut	T	1966 - 67	3 x 30	90	135
Subtotal				2 535	
Cairo					
Cairo North	T	1952 - 53 1954 - 55	2 x 10, 1 x 20 2 x 30	100	206
Cairo South	T	1957 - 65	4 x 60	240	443
Cairo West	T	1966 - 68	3 x 87	261	405
Tebbin	T	1958 - 59	3 x 15	45	152
Subtotal				646	
Delta					
Suez	T[c]	1964	4 x 25	100	-
Talkha	T	1955 - 56 1966 - 67	3 x 12.5 3 x 30	127	234
Damanhour	T	1960 1968	2 x 15 3 x 65	225	269
Subtotal				452	
Alexandria					
Siouf	T	1961 1969	2 x 26.5 2 x 30	113	314
Max	GT	1966	2 x 14	28	119
Subtotal				141	
Total				3774	

[a] Excludes a number of outdated stations.
[b] H = Hydro
T = Thermal, oil-fired
GT = Gas turbine (gas-fired)
[c] Also burns coal

winter peak load (see below). The generating stations are grouped in four interconnected zones; namely, Upper Egypt, Cairo, Delta and Alexandria. Additional units of unspecified capacity were installed by autoproducers, their generation of energy in 1971 amounting to approximately 20% of that of the GEC. A map showing power station locations was not available.

The maximum effective generating capacity of the GEC is limited by the power that can safely be imported by the Cairo, Delta and Alexandria zones from Upper Egypt, which in turn is limited by the capability of the Lower Egypt zone to pick up the load in the event of

failure of the 500 kV lines from Upper Egypt. At present this limit is 500 MW[2]. The peak demand in the Upper Egypt zone is at present 300 MW so that the effective capacity of the zone is 800 MW. The installed capacity of the other three zones is 1239 MW so that the effective generating capacity of the whole system is 2039 MW with all thermal plant in service.

The water in the reservoir of the High Dam has not yet reached its final level and the turbines are operating at reduced head. With minimum water flow, which usually occurs in the month of January, the base load of the two stations is reduced to a total of 475 MW (Aswan 175 MW, High Dam 300 MW). Some additional energy is available for peak load generation and the present reliable contribution towards meeting the peak demand of the system is 600 MW.[2] Adding the total thermal capacity of 1329 MW gives 1929 MW as the highest winter peak load which could be met at present with all thermal plants in service.

The 500 MW safe limit for transfer from Upper Egypt will gradually increase with growth of spinning reserve in the system. In addition, as the water rises at the High Dam, the capacity of Aswan will rise to 1335 MW in 1980 and to still higher values in subsequent years.

(b) Transmission

The present transmission system comprises:

(i) Two 500 kV single-circuit lines from Aswan to Cairo, each 790 km long, with two intermediate switching and transforming stations.
(ii) A 220 kV grid network of double-circuit lines, together with a 66 kV distribution network, covering the Cairo, Delta and Alexandria zones. There is also a 33 kV distribution network stretching eastwards from Alexandria.
(iii) A 132 kV double-circuit network, extending from Aswan to near Cairo and supplied intermediately from the 500 kV transforming stations, together with a 33 kV distribution network.

The 500 kV lines transmit the output of the Aswan hydro stations, less local load and loads tapped en route, to Cairo whence the power is distributed by the 220 kV system which also interconnects the nine thermal stations in the Cairo, Delta and Alexandria zones. No map or diagram of the transmission system was made available.

Characteristics of the transmission lines are given in Table III-2.

TABLE III-2. CHARACTERISTICS OF 500 kV, 220 kV AND 132 kV LINES

Conductors			Impedance (Ω/km per circuit)	
Voltage (kV)	No./phase	Type	Series	Shunt
500	3	ACO 500	0.0217 + j0.302	$-j3.96 \times 10^{-6}$
220	1	ACSR 400	0.0835 + j0.412	$-j2.71 \times 10^{-6}$
132	1	ACSR 323	0.10 + j0.388	$-j2.85 \times 10^{-6}$

Compensation equipment for the 500 kV lines comprises 6 × 165 MVA of shunt reactors, two banks being at Aswan and two at each of the intermediate substations, and 3 × 80 MVA synchronous compensators at the Cairo end. Single-phase auto-reclosing is employed with a fault clearance time of 0.12 sec and 0.16 sec to clear and reclose.

[2] The Egyptian Atomic Energy Establishment has subsequently revised the safe transfer limit to 560 MW and the peak capacity of Aswan to 675 MW. For conservatism the figures quoted in the text have been used in subsequent analysis.

Switchgear fault ratings are as follows:

500 kV	15 000 MVA
220 kV	10 000 MVA
132 kV	5 000 MVA
66 kV	1 500 - 3 000 MVA (according to location)

(c) Generating plant construction costs

Table III-3 shows the cost breakdown of the Cairo West Power Station, the most recently constructed thermal power station in Egypt.

(d) Transmission line construction costs

Table III-4 gives approximate construction costs for 500 kV, 220 kV and 66 kV overhead lines.

TABLE III-3. BREAKDOWN OF CONSTRUCTION COSTS OF THE CAIRO WEST POWER STATION BUILT IN 1966-68.

Item	Cost[a]	
	£E	US $
Mechanical and electrical equipment, c.i.f.	-	30 600 000
Civil work	1 910 984	4 395 100
Inland transportation of equipment	250 000	575 000
Erection	1 525 000	3 507 500
Fuel tanks	280 000	644 000
Civil work for the planned 4th unit	150 000	345 000
Land, roads, railway siding, fuel, pipe lines, taxes and housing, etc.	4 047 000	9 307 800
Total		49 374 400
US $/kW		189

[a] Official exchange rate: 0.4348 £E = 1 US $.

TABLE III-4. TRANSMISSION LINE CONSTRUCTION COSTS[a]

Voltage (kV)	Type	Cost[b]	
		£E/km	US $/km[c]
66	Double-circuit	15 000	34 500
220	Double-circuit	20 000 - 25 000	46 500 - 57 500
500	Two single circuits (per circuit)	23 000	53 000

[a] The above are approximate construction costs of overhead lines. Those for the 66 kV and 220 kV lines are understood to be at 1972 price levels, but the cost for the 500 kV line represents the contract price negotiated in 1960-63.

[b] Approximately 30% is local expenditure and 70% foreign expenditure.

[c] 0.4348 £E = 1 US $.

3.5. System reserve capacities

As shown in Section 3.4 (a), the present effective generating capacity provides ample reserve to meet the estimated maximum demand of 1440 MW in 1972.

Operating conditions are governed, however, by the objective of obtaining the maximum hydro energy consistent with limiting to an acceptable extent the interruptions of supply to consumers caused by simultaneous outages of the two 500 kV Aswan-Cairo line circuits. A comprehensive study of this problem has led to the following thermal plant operation, spinning-reserve and automatic load-shedding procedure.

With a present daily peak demand of 800-850 MW in the Cairo, Delta and Alexandria zones, 460 MW of thermal plant is kept in operation continuously. For most of the 24 hours this plant carries minimum load, which is 220 MW, but output is increased to limit the 500 kV import to 500 MW (see footnote 2) during the evening peak.

When a double-circuit outage occurs load is shed automatically at the 66 kV substations in up to ten 50 MW stages at 0.2 Hz intervals from 48.8 Hz to 47.0 Hz. This arrests the fall of frequency after two seconds at a minimum of 46.5 Hz. There is then a temporary recovery to 48.5 Hz, followed by a further fall, with final recovery starting after 8 seconds. If, for any reason, final recovery is delayed, three further 50 MW stages of sequential automatic load shedding with time lag take place. Arrangements for three stages of limited automatic load restoration are being developed. Provided that one 500 kV line can be immediately restored to service, it is usually possible to resume full supplies within about 15 minutes of the initial failure.

TABLE III-5. DATA ON EXISTING THERMAL POWER PLANTS

Station[a]	Number of identical units	Operating power of unit (MW)		Heat rate (Btu/kWh)	
		Minimum	Maximum	At min. power	At max. power
Cairo North	2	4	10	15 848	12 953
	1	8	20	15 848	12 953
	2	12	30	15 848	11 429
Cairo West	3	35	87	10 095	9 524
Cairo South	4	24	60	13 410	10 857
Talkha	3	12	30	14 476	11 429
	3	5	12.5	14 476	12 457
Tebbin	3	6	15	16 114	12 953
Damanhour	3	26	65	12 267	
	2	6	15	12 267	
Siouf	2	12	30	13 334	11 429
	2	11	26.5	13 334	11 429
Suez	4	10	25	15 695	
Max	2	6	14	19 962	14 857
Asiyut	3	4	30	13 905	

[a] All stations are oil-fired except Max which is a gas turbine.

3.6. Operating and maintenance costs of a recent thermal station

The Cairo West Station is the most recent addition to the General Electricity Corporation's thermal plants. It has 420 workers. Their annual wages are 138 732 £E (US $315 800), and the annual cost of maintenance, materials and supplies for 1971 was about £E 56 524 (US $130 000). These result in a unit cost of 0.80 mill/kWh for salaries and 0.32 mill/kWh for materials and supplies.

3.7. Technical data on existing thermal and hydro units

Table III-5 gives the operating ranges and heat rates for existing thermal plants, and Table III-6 gives the range of operation for the hydro plants.

TABLE III-6. DATA ON EXISTING HYDRO POWER PLANTS

Station	Number of identical units	Operating power of unit (MW)	
		Minimum	Maximum
Aswan Dam	7	12.6	37[a]
	2	2.4	7.8[b]
Aswan High Dam	12	80	175

[a] 46 MW installed.
[b] 11.5 MW installed.

4. HISTORICAL SYSTEM DATA

4.1. Historical load growth

(a) Maximum demand, energy generated, installed capacity and load factor

Table IV-1 and Fig. 4-1 show the growth of installed capacity, maximum demand and generated energy during the period 1960-1971. The table also shows the annual load factors. The equivalent annual compound growth rates from 1960-1970 are:

Maximum demand 7.5%
Generated energy 8.6%

It should be noted that about 260 MW of installed capacity, mostly out of date steam stations and small diesels, were removed from the generating plant list during 1972. It should also be noted that the annual load factor of the system is unusually high, largely because of the high percentage of industrial load in the system (see Table IV-2).

(b) Distribution of electricity supply and demand

In 1971 the GEC generated 7400 GWh (see Table IV-1). During this period an additional 1500 GWh was generated by power plants associated with industrial plants. The consumption of the energy generated by GEC by various sectors of the economy for the fiscal years 1966-67 to 1971-72 is shown in Table IV-2.

(c) Per-capita consumption

Table IV-3 shows the per-capita usage of electricity for the period 1960-1972. These figures are based on the energy generated by GEC and thus include system losses but exclude the electrical energy generated by the industrial plants. Had the industrial plant energy generation been included, the per-capita values would have been about 17% higher.

TABLE IV-1. GROWTH OF INSTALLED CAPACITY MAXIMUM DEMAND AND GENERATED ENERGY 1960-1971

Year	Installed capacity (MW)	Maximum demand		Generated energy		Annual load factor (%)
		MW	Annual increase (%)	GWh	Annual increase (%)	
1960	1219	533		3079		66.0
1961	1308	592	11.0	3461	12.4	66.6
1962	1303	625	5.6	3804	9.9	69.5
1963	1308	665	6.4	4374	15.0	75.1
1964	1488	710	6.8	4597	5.1	74.0
1965	1728	750	5.6	5000	8.8	76.2
1966	1968	824	9.9	5138	2.8	71.2
1967	2808	872	5.8	5632	9.6	73.8
1968	3317	930	6.6	6114	8.6	75.0
1969	3920	987	6.1	6500	6.3	75.1
1970	4032	1100	11.5	7000	7.7	72.7
1971	4032	1160	5.5	7400	5.7	72.9
1972	3774[a]					

[a] Excludes outdated stations.

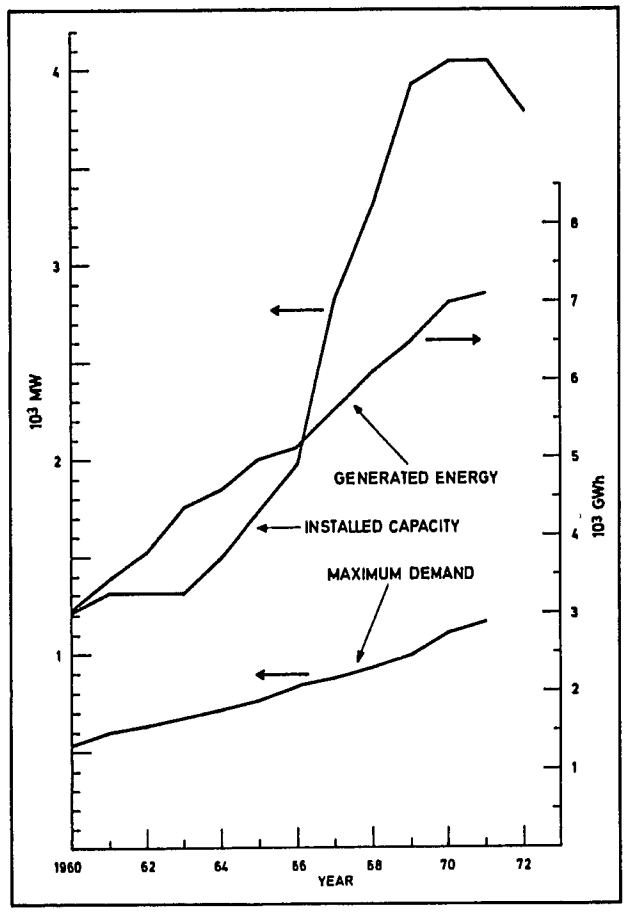

FIG. 4-1. GROWTH OF INSTALLED CAPACITY, MAXIMUM DEMAND AND ENERGY GENERATED.

TABLE IV-2. CONSUMPTION OF ELECTRICAL ENERGY BY DIFFERENT SECTORS OF THE ECONOMY (GWh)[a]

Year (fiscal)	Industry	Agriculture	Municipal	Total
1966 - 67	3 173	256	1 200	4 629
1967 - 68	3 278	335	1 329	4 942
1968 - 69	3 469	426	1 527	5 422
1969 - 70	3 685	497	1 611	5 793
1970 - 71	3 734	552	1 755[b]	6 041
1971 - 72	3 875	594	1 856[b]	6 325

[a] Excluding the electrical energy generated by industry in its own plants.
[b] Including rural electrification.

(d) Distribution of electrical supply

Prior to 1960 all power in Egypt was generated in thermal plants. Since the completion of the hydro power station at Aswan in 1960, hydro power has become increasingly important, and with the completion of the Aswan High Dam in 1968, further hydro capacity became available. Figure 4-2 shows the contribution of thermal and hydro stations to the total energy generated during the period 1952-1971.

TABLE IV-3. PER-CAPITA ENERGY USAGE (1960 - 72)

Year	Per-capita usage[a] (kWh/yr)
1960	119.2
1961	130.2
1962	139.5
1963	156.5
1964	160.4
1965	170.1
1966	170.4
1967	182.2
1968	192.9
1969	200.0
1970	210.0
1971	216.7
1972	220.0

[a] Based on energy generated by the GEC.

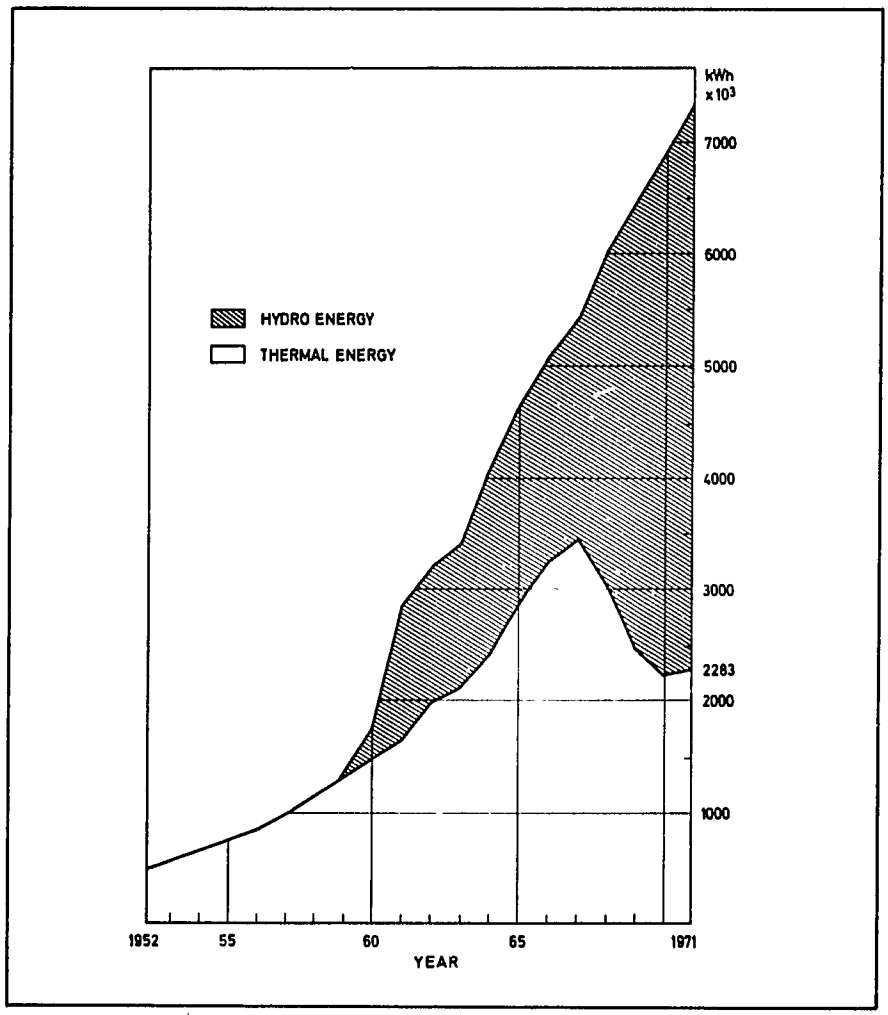

FIG. 4-2. GENERATION BY THERMAL AND HYDRO STATIONS.

(e) System load characteristics

A load curve for a typical December day in 1971 is shown in Fig. 4-3. It is seen from this load curve that the Middle and Upper Egyptian loads, which are primarily industrial loads, are nearly constant – accounting for the high load factor maintained by the system.

An annual load duration curve for 1971 is shown in Fig. 4-4.

(f) Transmission interconnection capacity

The interconnection capacity provided by the existing transmission system appears to be adequate.

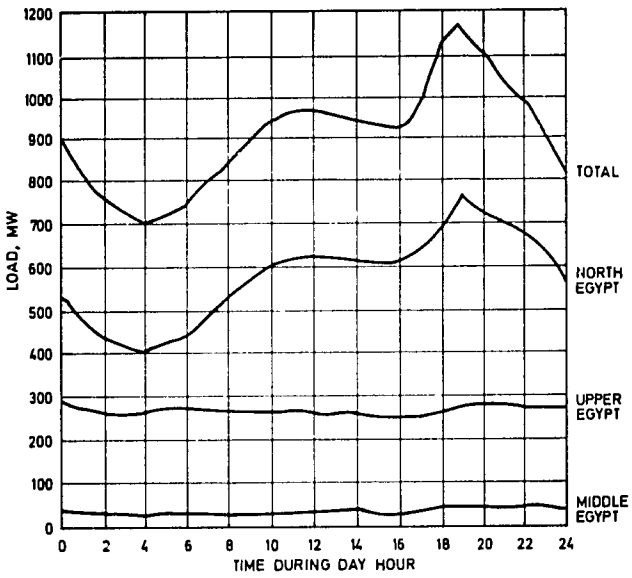

FIG. 4-3. TYPICAL DAILY LOAD CURVE (FOR DECEMBER 1971)

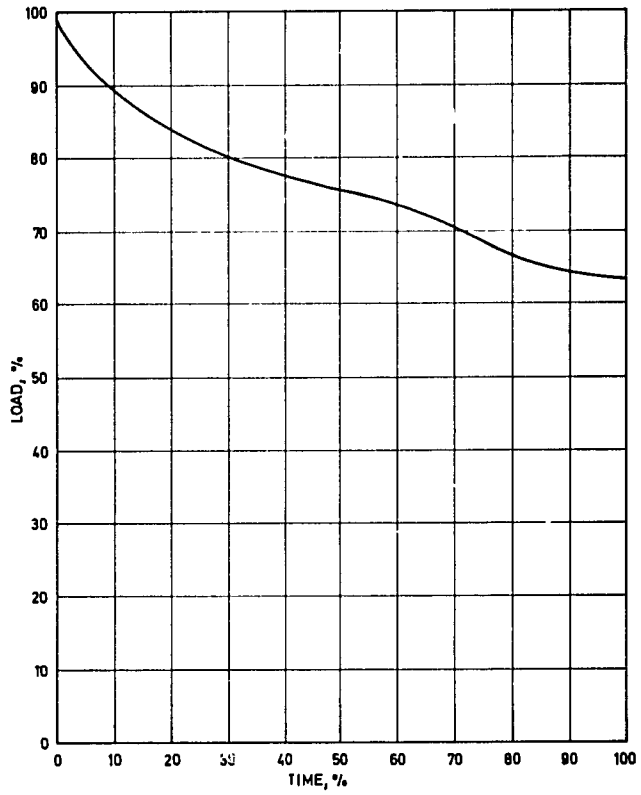

FIG. 4-4. ANNUAL LOAD DURATION CURVE FOR 1971.

4.2. System reliability

(a) Reliability criteria

As stated in Section 3.5, the present system is operated so as to utilize maximum hydro energy consistent with the requirements of system reliability. These requirements provide for automatic load shedding so as to maintain the system if both circuits of the 500 kV line trip.

(b) Outage records – Transmission lines

In practice reliability has been seriously impaired by double-circuit outages of the 500 kV lines, due mainly to insulator flash-overs, but also to clashing of conductors. (In an effort to reduce flash-overs, longer insulator strings were installed, resulting in clashing during strong winds.) Performance has been improved since the introduction of live-line insulator washing, both circuits being completely covered every 6-12 months.

(c) Outage records – Generating plants

Table IV-4 gives rates of both forced and scheduled outages of the thermal plants. Though not exact records, these rates are understood to be representative of recent experience.

TABLE IV-4. GENERATING PLANT OUTAGE RATES

Station	Unit No. and MW	Forced outage (% time)	Scheduled outage (% time)
Asyut	3 x 30	4.5	8
Cairo Nortn	2 x 10	2.5	8
	1 x 20	3.0	8
	2 x 30	2.7	8
Cairo South	4 x 60	3.5	8
Cairo West	3 x 87	2.0	8
Tebbin	3 x 15	2.0	8
Suez	4 x 25	n.a.	8
Talkha	3 x 12.5	0.5	8
	3 x 30	1.0	8
Damanhour	2 x 15	5.0	8
	3 x 65	2.0	8
Siouf	2 x 26.5	3.0	8
	2 x 30	6.0	8
Max	2 x 14	5.0	8

5. PROJECTED SYSTEM DATA

5.1. Projection of maximum demand, generated energy and load factor

Table V-1 gives projections to the year 2000 of maximum demand, generated energy and annual load factor. Projections of maximum demand and generated energy are shown graphically in Fig. 5-1.

The projections up to and including 1985 were provided by the Egyptian General Electricity Corporation and are based on the estimated requirements of various sectors shown in Table V-2. The very high growth between 1971 and 1975, which is in marked contrast both to the historical growth up to 1971 and to the modest growth forecast between 1975 and 1982, is based on specific new loads such as a ferro-silicon plant, a 40 000 t/yr aluminium plant and an expansion of the existing iron and steel complex at Helwan, which are expected to arise in this period. The high annual load factor for 1974 through 1982 results from the fact that during this period the industrial load will be a large percentage of the total. The rather erratic growth beyond 1975 is based on analysis of the prospective growth in various consumer classes provided by the Atomic Energy Establishment (AEE), but no details were provided.

The estimated zonal breakdown of the projected maximum demands for the study period is given in Table V-3.

TABLE V-1. PROJECTED GROWTH OF EFFECTIVE GENERATING CAPACITY, MAXIMUM DEMAND AND GENERATED ENERGY[a]

Year	Effective generating capacity at peak[b]	Maximum demand		Generated energy		Annual load factor (%)
		MW	Annual increase (%)	GWh	Annual increase (%)	
1971		1 160		7 400		72.9
1972	1 929	1 440	24.2	7 700	4.1	61.0
1973	2 029	1 750	21.5	9 570	24.3	62.5
1974	2 239	2 060	17.7	13 250	38.4	73.5
1975	2 450	2 450	18.9	15 500	17.0	72.2
1976	2 850	2 610	6.5	16 400	5.8	71.8
1977	3 250	2 780	6.5	17 400	6.1	71.5
1978	3 350	2 950	6.1	18 500	6.3	71.6
1979	3 450	3 075	4.2	19 600	6.0	72.8
1980	3 900	3 250	5.7	20 700	5.6	72.8
1981	3 950	3 450	6.2	21 800	5.3	72.2
1982	4 400	3 600	4.3	23 000	5.5	73.0
1985	5 500	4 850	10.5	29 200	8.2	68.8
1990	9 700	8 400	11.6	47 000	10.0	64.0
1995	15 000	12 900	8.9	72 000	8.9	63.8
2000	23 000	19 700	8.8	110 000	8.8	63.8

[a] Projections beyond 1985 are tentative.

[b] Effective generating capacity at peak = (combined contributions of Aswan Dam and High Dam towards meeting annual maximum demand) + (installed capacity of all other plant).

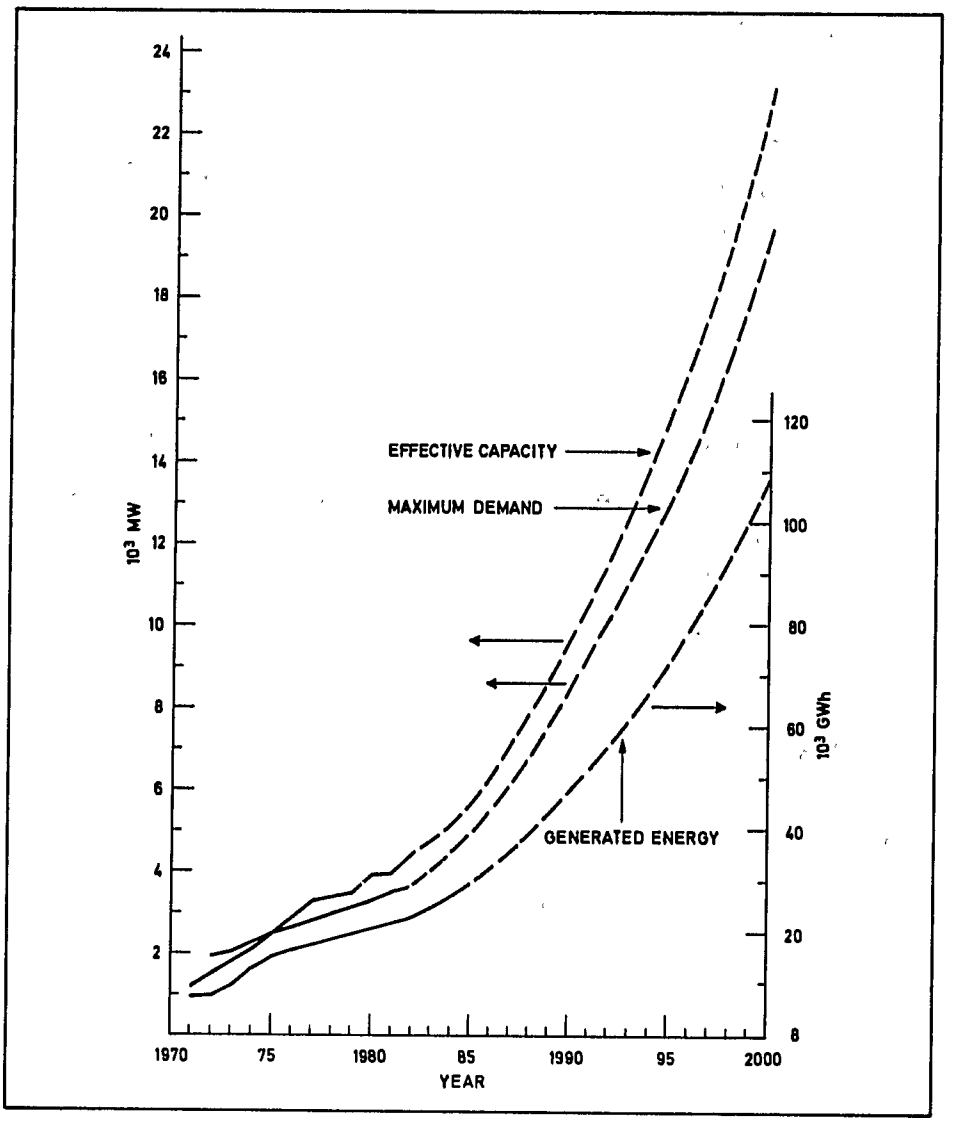

FIG. 5-1. FORECAST GROWTH OF EFFECTIVE GENERATING CAPACITY, MAXIMUM DEMAND AND ENERGY GENERATED.

TABLE V-2. PROJECTIONS OF ELECTRICAL ENERGY CONSUMPTION FOR FISCAL YEARS 1972-73 TO 1981-82 (10^6 kWh)

Years	Industry	Agriculture	Public utilities	Rural electrification	Total
1972-73	5111	790	1655	108	7664
1973-74	6734	929	1708	199	9570
1974-75	9938	1188	1803	315	13244
1975-76	11816	1275	1910	458	15459
1976-77	12328	1364	2080	616	16387
1977-78	12944	1431	2250	780	17405
1978-79	13562	1516	2433	948	18459
1979-80	14200	1790	2510	1071	19571
1980-81	14880	1871	2640	1274	20665
1981-82	15600	1887	2890	1456	21843

TABLE V-3. ZONAL BREAKDOWN OF FORECAST MAXIMUM DEMAND (MW)

Zone	1980	1985	1990
Upper Egypt	1 050	1 500	2 400
Cairo	965	1 500	2 700
Delta	770	1 100	2 000
Alexandria	465	750	1 300

5.2. Projection of generating capacity

The projections of generating capacity are shown in Table V-1 and Fig. 5-1; the figures being effective generating capacity at peak, i.e. reliable hydro capacity plus installed thermal (including nuclear) capacity.

The basis for the figures up to 1982 is given in Table V-4. From 1985 onwards the projected effective capacity figures include a reserve plant margin equal to approximately 20% of the part of the demand which remains to be met after deducting the contribution of the Aswan hydro stations.

TABLE V-4. PROGRAM OF PLANT INSTALLATION AND EXPANSION OF EFFECTIVE GENERATING CAPACITY (1972-82)

Year	Station	Type	Capacity (MW)	Cumulative effective generating capacity at peak (MW)			
				Thermal	Hydro	Nuclear	Total
1972	Existing capacity at November 1972			1 329	600	-	1 929
1973	Aswan	H	100	1 329	700	-	2 029
1974	Aswan	H	100	1 329	800	-	2 129
1975	Aswan	H	100				
	Kafr El-Dawar 1	T	110			-	
	Rounding adjustment	T	1	1 440	900		2 340
1976	Aswan	H	100				
	Kafr El-Dawar 2	T	110				
	Cairo South 1	T	150				
	Abu Qir 1	T	150	1 850	1 000	-	2 850
1977	Aswan	H	100				
	Cairo South 2	T	150				
	Abu Qir 2	T	150	2 150	1 100	-	3 250
1978	Aswan	H	100	2 150	1 200	-	3 350
1979	Aswan	H	100	2 150	1 300	-	3 450
1980	Aswan	H	50				
	Nuclear 1	N	400	2 150	1 350	400	3 900
1981	Aswan	H	50	2 150	1 400	400	3 950
1982	Aswan	H	50				
	Nuclear 2	N	400	2 150	1 450	800	4 400

TABLE V-5. APPROXIMATE ANNUAL OPERATING CONDITIONS OF HYDRO STATIONS IN 1978 (MW)

Items	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Unified power system peak load	2 850	2 847	2 840	2 835	2 830	2 825	2 740	2 763	2 784	2 810	2 830	2 850
A. Low-water conditions												
Average daily power of the Aswan and High Dam hydro stations	625	910	940	927	1 006	1 376	1 414	1 170	960	920	940	1 020
Contribution of the hydro stations in meeting the peak load	1 100	1 270	1 310	1 272	1 346	1 700	1 715	1 475	[illegible]58	1 258	1 300	1 390
B. High-water conditions												
Average daily power of the Aswan and High Dam hydro stations	723	1 120	1 202	1 182	1 644	1 852	1 827	1 741	1 276	1 120	1 173	1 320
Contribution of the hydro stations in meeting the peak load	1 600	1 476	1 552	1 527	1 900	1 900	1 900	1 900	1 590	1 450	1 450	1 523

Considering the Aswan stations, the need for irrigation water is lowest in the month of January (926 m^3/sec). It is highest in the month of July (2777 m^3/sec). The consequence is that the power available from the High Dam varies substantially over the year. Table V-5 shows the expected annual operating conditions of the Aswan Dam and Aswan High Dam in the year 1978 at a peak load of 2850 MW. With the completion of the High Dam the water conditions at the Aswan Dam will allow it to be operated at constant load throughout the year.

The monthly energy available from the Aswan Dam and the High Dam stations after 1980 can be seen in Table V-6.

The average power available from the Aswan High Dam is well below the maximum power of the hydroelectric station because of the limited availability of water, especially in January when irrigation requirements are low. However, the regulating basin between the Aswan Dam and the High Dam permits the use of the High Dam for peaking. In the years after 1980 (when the High Dam's Lake Nasser is filled), the minimum peak power load (January) will increase steadily as the daily time interval of a given block of peak power decreases. Table V-7 shows the expected peak loads in January from 1980 to 1990, calculated on the average power consistent with January water flow requirements in any average flow year.

Referring again to Table V-1 it will be noted that a 5800 MW increase in capacity is required between 1980 and 1990. This becomes 6000 MW if allowance is made for the retirement of 200 MW of existing capacity. Of this requirement 400 MW will be obtainable as additional peak output from Aswan.

5.3. Generation planning

The plants under construction or projected are listed in Table V-8.

5.4. Transmission planning

The program for the 220 and 132 kV line and substation reinforcements to meet load growth during the next five years is being implemented.

It is intended to extend the 500 kV lines from Cairo to the Mediterranean coast west of Alexandria, a direct distance of some 180 km, to connect the 2 × 400 MW nuclear units proposed for 1980/82. A 500 kV transformer station at Cairo South is also planned for 1982.

TABLE V-6. MONTHLY ENERGY AVAILABLE FROM ASWAN DAM AND HIGH DAM HYDRO STATIONS AFTER 1980 (10^3 kWh)

Month	Aswan Dam	High Dam	
	Energy during average year	Energy during low flow year	Energy during high flow year
Jan.	146 069	395 555	493 275
Feb.	163 296	470 843	588 000
Mar.	186 446	541 632	672 077
Apr.	179 712	532 800	666 000
May	184 732	669 600	849 395
June	172 512	864 000	1 104 235
July	177 295	908 170	1 210 973
Aug.	205 567	807 240	1 030 685
Sept.	179 120	526 075	626 875
Oct.	179 527	543 610	632 400
Nov.	175 896	550 400	638 395
Dec.	167 846	555 515	629 424

TABLE V-7. EXPECTED PEAK LOADS OF THE ASWAN DAM AND HIGH DAM HYDRO STATIONS IN JANUARY OF EACH YEAR, 1980-1990

Year	Peak load (MW)
1980	1335
1981	1390
1982	1420
1983	1460
1984	1510
1985	1540
1986	1565
1987	1630
1988	1650
1989	1680
1990	1775

TABLE V-8. PLANTS UNDER CONSTRUCTION OR PLANNED

Station	Plant capacity and type	Commissioning year
Under construction		
Kafr El Dawar	2 x 110 MW oil/gas-fired	1975-76
Definitely planned		
Cairo South	2 x 150 MW gas-fired	1976-77
Abu Qir	2 x 150 MW gas-fired	1976-77
Under study		
Nuclear	2 x 400 MW	About 1980
Future possibilities		
Qattara Depression	600-4000 MW hydro	Not before 1983
Nile barrages	600 MW hydro	Not before 1983

Ultimately there may be a further extension of the 500 kV system north of Cairo to form a ring to reinforce the Cairo-Alexandria-Delta 220 kV system.

Interconnection between Egypt and Libya is under study. This would be via the proposed 500 kV point, west of Alexandria.

5.5. Planned future reserve capacity

Reserve requirements are calculated by probability methods, allowing a probability of insufficient thermal capacity of between 0.001 and 0.0001 coincident with minimum (low flow) output from Aswan. A forced outage probability of 0.02 is assumed for the new 110 MW and

150 MW thermal units and the resulting reserve requirement when these have been installed is 340 MW or 16% of the total thermal capacity.

On the installation of the first 400 MW nuclear unit, for which a forced outage probability of 0.06 is assumed, the reserve requirement increases to over 20%, but this proportion will fall as further units are installed.

Future reserve requirements will depend on the sizes of the new units introduced but, for the purpose of estimating approximate total capacities, the GEC suggested that a margin of 20% be added to the demand to be met by thermal (including nuclear) plant.

5.6. Siting data

The major considerations for the siting of power plants in Egypt are the adequacy of cooling water and the proximity of load centres. Several sites are being considered for future fossil-fuelled plants, including the industrial centre of Helwan, the Abu Qir area in the Northern Delta and the expansion of the Kafr El Dawar plant (see Fig. 5-2). (See Section 6.4 for information on nuclear sites.)

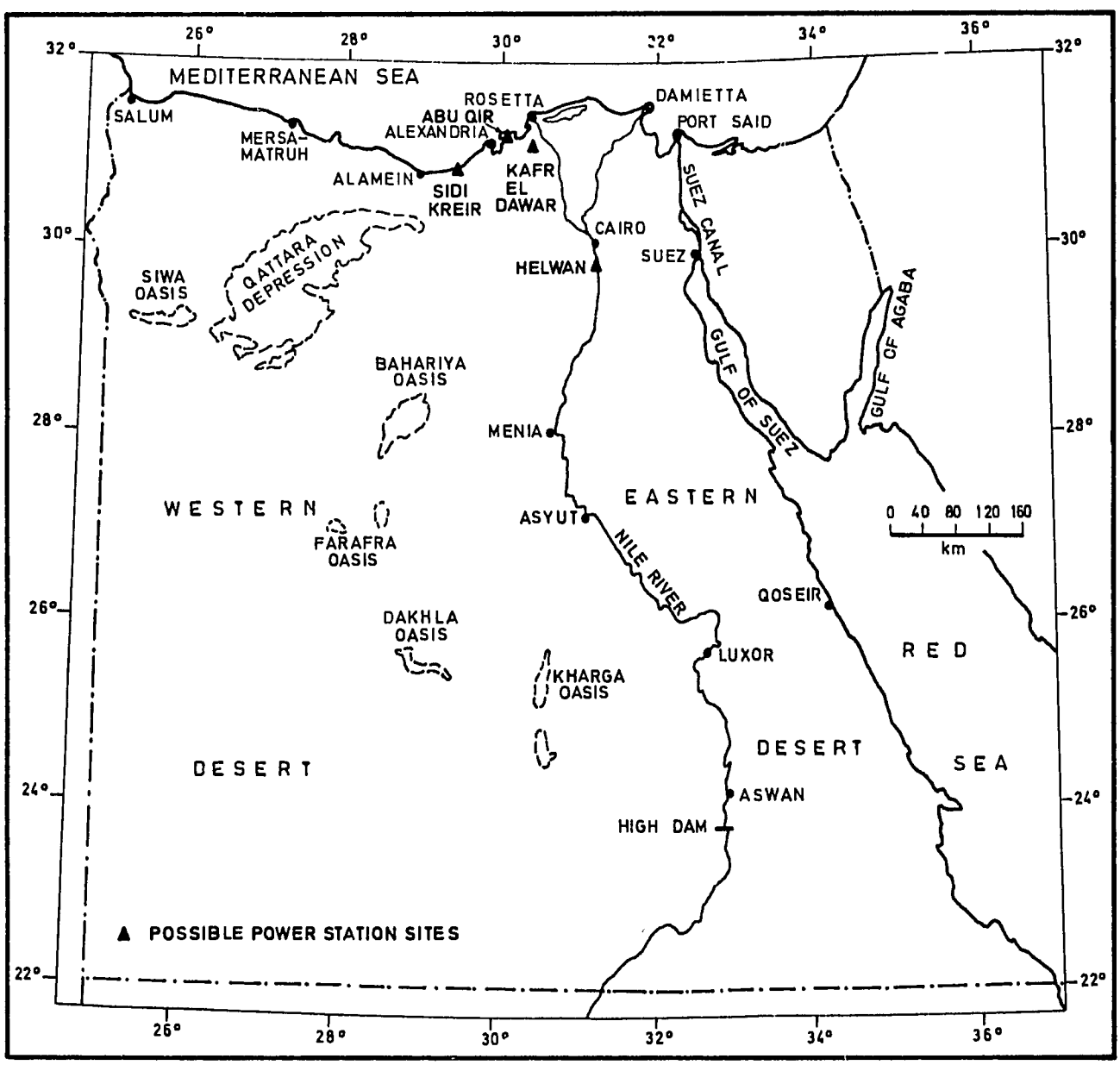

FIG. 5-2. POSSIBLE SITES FOR FOSSIL-FUELLED OR NUCLEAR POWER STATIONS.

6. NATIONAL CAPABILITIES AND LOCAL COSTS

6.1. Contribution of Egyptian industry to power projects recently completed or now under construction

All civil engineering works associated with the construction of electrial power stations can now be carried out by Egyptian contractors using local construction materials and labour. Also, erection of mechanical and electrical equipment can be undertaken by Egyptian companies, three of which belong to the Egyptian General Electric Corporation. A list of construction contractors is given in Table VI-1. The equipment itself is, however, imported and supplied by the main contractor.

Equipment related to power plants and produced by Egyptian industry includes small boilers, electric motors, insulated and non-insulated cables, and lead batteries. Consequently, the contribution of Egyptian industry to power projects would consist of the civil work and the small components associated with the mechanical and electrical work.

6.2. Targets for future local industrial participation in power projects

As a result of the industrialization process now under way in Egypt, it is likely that the capability of Egyptian industry for participating in power projects will increase progressively.

6.3. Local construction costs and practices

(a) Labour costs

Labour rates for various types of crafts at the Kafr El Dawar Power Plant, at present under construction, are shown in Table VI-2. They are low compared with Western European or North American rates, but are comparable with labour rates in other countries at similar levels of development.

(b) Construction materials costs

Costs of some local construction materials are shown in Table VI-3.

(c) Construction practices

Modern construction equipment is available in Egypt but, of course, not to the same extent as in North America and Western Europe. The lower wages in Egypt reinforce the tendency to employ somewhat more labour for construction than would be used for comparable work in North America or Western Europe.

(d) Labour productivity

Productivity in the construction of power plants in Egypt cannot easily be judged since the site of the latest thermal plant being erected has been changed and its construction time-table delayed by the effects of the 1967 war. Productivity depends particularly on the productivity of the individual worker, on the quantity and quality of the equipment being used, and on the organization and planning of the work. While the productivity of the individual worker seems to be in the same range as in comparable countries, the change of site and disruption of the construction time-table appears to have affected the overall productivity. Disregarding these factors, it seems likely that the productivity in Egypt will increase relative to Western Europe and North America before the first nuclear plant is constructed.

6.4. Problems and costs associated with possible nuclear power plant sites

Studies and reports on site selection for the first nuclear power plant were carried out in 1963 and 1964. Several sites were found to be both available and suitable and, among them, one on the Mediterranean coast, approximately 35 km south-west of the city of

TABLE VI-1. SOME OF THE MAJOR CONSTRUCTION CONTRACTORS

Engineering General Company, Cairo
Tractor and Engineering Company, Cairo
Misr Company for Electrical and Mechanical Equipment, Cairo (owned by the GEC)
General Company for Electrical Projects (Elegr Co.) (owned by the GEC)
High Dam Company for Mechanical and Electrical Projects (Hidelco Co.) (owned by the GEC)
Misr Concrete Company
Arab Contracting Company (Osman Ahmed Osman)
Egyptian Contracting Company (Ex Moktar Ibrahim)
El Nasr General Contracting Company (Hassan Allam)

TABLE VI-2. LABOUR COSTS [a]

Category	Rate	
	£E/day	US$/h [b]
Welders, top quality	2.0	0.76
Fitters, millwrights and steelworkers	1.5	0.57
Electrical technicians	2.5-3	0.95-1.13
Electrical workers	1.5	0.58
Carpenters	1.0	0.38
Concrete workers	1.0	0.38
Masons	1.0	0.38
Unskilled workers	0.5	0.19

[a] Costs at Kafr El Dawar (Nile Delta).
[b] 7 h/day including 15% fringe benefits.
0.4348 £E = 1 US$.

TABLE VI-3. COST OF CONSTRUCTION MATERIAL

Type of material	Unit cost [a]	
	£E	US$
Profile steel	180/t	18/cwt
Reinforcing bars	100/t	10/cwt
Reinforced concrete	50-80/m^3	88-141/yd^3

[a] 0.4348 £E = 1 US$.

Alexandria along the Alexandria-Mersa Matruh coastal road, was recommended for the first plant.

The main factors taken into account in selecting a site are:

(a) Existing and planned electric power generation and transmission;
(b) Population density;
(c) Meteorology;
(d) Geology and soil formation;
(e) Hydrology;
(f) Seismic conditions;
(g) Water requirements;
(h) Transportation requirements; and
(i) Civil construction requirements.

The site provisionally selected and several other sites along the Mediterranean coast have low population density and access to cooling water. They are also connected to Alexandria, the Delta and Cairo by good roads. Good facilities are available at the nearby port of Alexandria. The maximum width and weight on the road and the maximum capacity of the cranes available in Alexandria harbour would have to be investigated in the light of the largest components of the size and type of power reactor selected. Further details of the site are available in reports by the consulting engineers Kennedy and Donkin.

6.5. Plans for staffing of future conventional and nuclear power plants

A UNDP (ILO sponsored) Electric Power Training Institute was established in 1967 at the Cairo South Power Station. Its stated objectives are: to conduct instructor training courses, conduct refresher courses for graduate engineers and technical personnel, upgrading courses for skilled workers and technicians, technical training courses, and, as a pilot training project, undertake the electrification of a village.

A Project Manager and seven United Nations experts have been conducting an extensive program for the past four years. The facilities include a 4200 m^2 block of floor space on three floors, over 6000 m^2 of outdoor area for training in transmission and rural electrification, over US $200 000 worth of equipment and a test transmission line consisting of four steel towers supporting 250 m of double-circuit line for three-phase operation.

This Institute has had an important role in the past four years in the implementation of the 500 kV system, and in the expansion of the GEC. It seems likely that the Institute could be expanded to provide a major training unit for future nuclear plants.

7. ECONOMIC AND FINANCIAL ASPECTS

7.1. Economic ground rules

The economic ground rules used by the Egyptian General Electricity Corporation in economic analysis are as follows:

Interest rate: The Corporation's capital is provided through the Government (Ministry of Finance), and for bookkeeping purposes an interest rate of 4.5% is used. The funds for recent power stations have been obtained on favourable terms ranging from a loan for the Cairo West power station at 3/4% over 40 years from the United States of America to the loan for the High Dam hydroelectric station at $2\frac{1}{2}$% over 12 years after commissioning from the USSR. In an economic analysis of the break-even size between nuclear and oil-fired stations presented to the 1971 Geneva Conference the sensitivity of the break-even size to different fixed charge rates (5%, 7%, 10%, 14%) was investigated.

Interest during construction: Included in capital costs at the rate of interest used for the economic analysis.

Construction period: The estimated actual construction period. For fossil fuel and hydro power stations no definite period has been established, but the circumstances of each project have been taken into account in economic evaluation. For nuclear stations, five years has provisionally been assumed.

Plant life: For nuclear stations a 25-year plant life has been assumed. Actual amortization periods used are:

	Years
Hydro stations	40
Fossil fuel stations	30
Transmission lines	30
Substations	25
Overhead networks	30
Underground networks	25

Escalation: Estimated for each project on the basis of the applicable contracts and the project's special circumstances. No definite rule is applied generally.

Plant factor: It is assumed that nuclear stations will be operated on base load for 6000 h/yr (i.e. plant factor 76%).

Capital cost adjustments: It is assumed that the capital costs of a power reactor in developing countries will vary according to their level of development between 30 and 40% above the costs in the country of origin.

Fuel oil price: It has been established by the Government at a uniform price of £E 7.5/t, for oil of calorific value 9600 kcal/kg, corresponding to about US $ 0.43/10^6 Btu.

Customs duties and taxes: Included in cost estimates. Customs duties are 2% on all power station equipment (except 5% for switchgear and their accessories for 500 kV or more). The fuel oil price of £E 7.5/t quoted above includes a Government tax of £E 0.5/t.

7.2. Current methods and sources of financing

The General Electricity Corporation is a Government agency and obtains its capital, both local currency and foreign exchange, through the Government. Its budget and accounts, both for capital and operating expenditures, are part of the Government's (Ministry of Electricity) budget and accounts. Its net profits or losses revert to the Government.

7.3. Foreign exchange considerations in evaluating capital and fuel costs

Foreign exchange and capital investments are controlled by the Government. In economic calculations the official exchange rate and, either an interest rate of 5% or the interest rate offered by foreign financial institutions, are used.

7.4. Import duties and taxes applicable to utilities

Import duties and taxes apply to the General Electricity Corporation (see Section 7.1).

8. ADMINISTRATIVE AND REGULATORY

8.1. Organization of the Atomic Energy Establishment

The Egyptian Atomic Energy Establishment (AEE) is a governmental organization constituted by Presidential Decree number 288 of 1957. It took over the functions of the preceding Atomic Energy Commission which was constituted on 19 February 1955 by the Prime Minister's order and received legal status by act number 509 of 19 October 1955.

The functions of the AEE are, in summary:

(a) Training of specialists and conducting research in the various scientific fields related to atomic energy;

(b) Establishing the necessary laboratories and institutions for training and research as well as for peaceful uses and applications of atomic energy;

(c) Exploration, extraction, import, export, exchange and utilization of raw materials of interest for nuclear energy;

(d) Production of materials, apparatus and equipment necessary for atomic energy and its applications;

(e) Taking measures for public security and protection against radiation hazards, and proposing necessary legislation;

(f) Following international progress in the field of atomic energy and representing Egypt in international atomic energy organizations and conferences;

(g) Suggesting plans and projects that the State should undertake in order to derive the maximum benefit from the applications of atomic energy.

The AEE is governed by a Board with twelve members. The members are drawn from amongst scientists and engineers working in the nuclear energy field, from universities and research institutions and from Ministries directly interested in the applications of nuclear energy such as the Ministry of Electricity and the Ministry of Industry. The Chairman of the Board is the President or a Minister acting for him. At present the President of the Academy of Scientific Research and Technology, who holds ministerial rank, occupies the post. Members of the Board are appointed by Presidential decree for a term of three years which is renewable.

Decisions of the Board are sent to the Presidency of the Republic and to the Prime Minister. If objections are not made by them within one week, the decisions are considered as agreed. The decisions of the Board are executed through the Director of AEE.

The budget and program of the AEE is proposed by the Board. The part containing personnel and running costs is sent directly to the Ministry of Finance for approval. The investment program is submitted to the Ministry of Planning, which has to approve the yearly investments and also AEE's contributions to Egypt's Five and Ten-Year Plans. When the Ministry of Planning has agreed to the investment program, it is submitted to the Ministry of Finance for approval and for the appropriation of the necessary funds.

The AEE operates the Nuclear Research Centre at Inchas, near Cairo, which has twelve scientific divisions including the reactor division. The Director of AEE is advised by a Board of Heads of Scientific Divisions. He is assisted in his work by a Deputy Director for International and External Relations and Nuclear Power Projects, a Deputy Director for Scientific Planning and Nuclear Materials, and a Secretary General for Administrative and Financial Services (see Fig. 8-1).

8.2. Relationship of the Atomic Energy Establishment to other interested organizations

The AEE collaborates with all Ministries and governmental organizations concerned with nuclear matters and national planning, such as the Ministry of Electricity and the Electricity Corporation, the Ministry of Health, the Ministry of Planning, and the Ministry of Industry

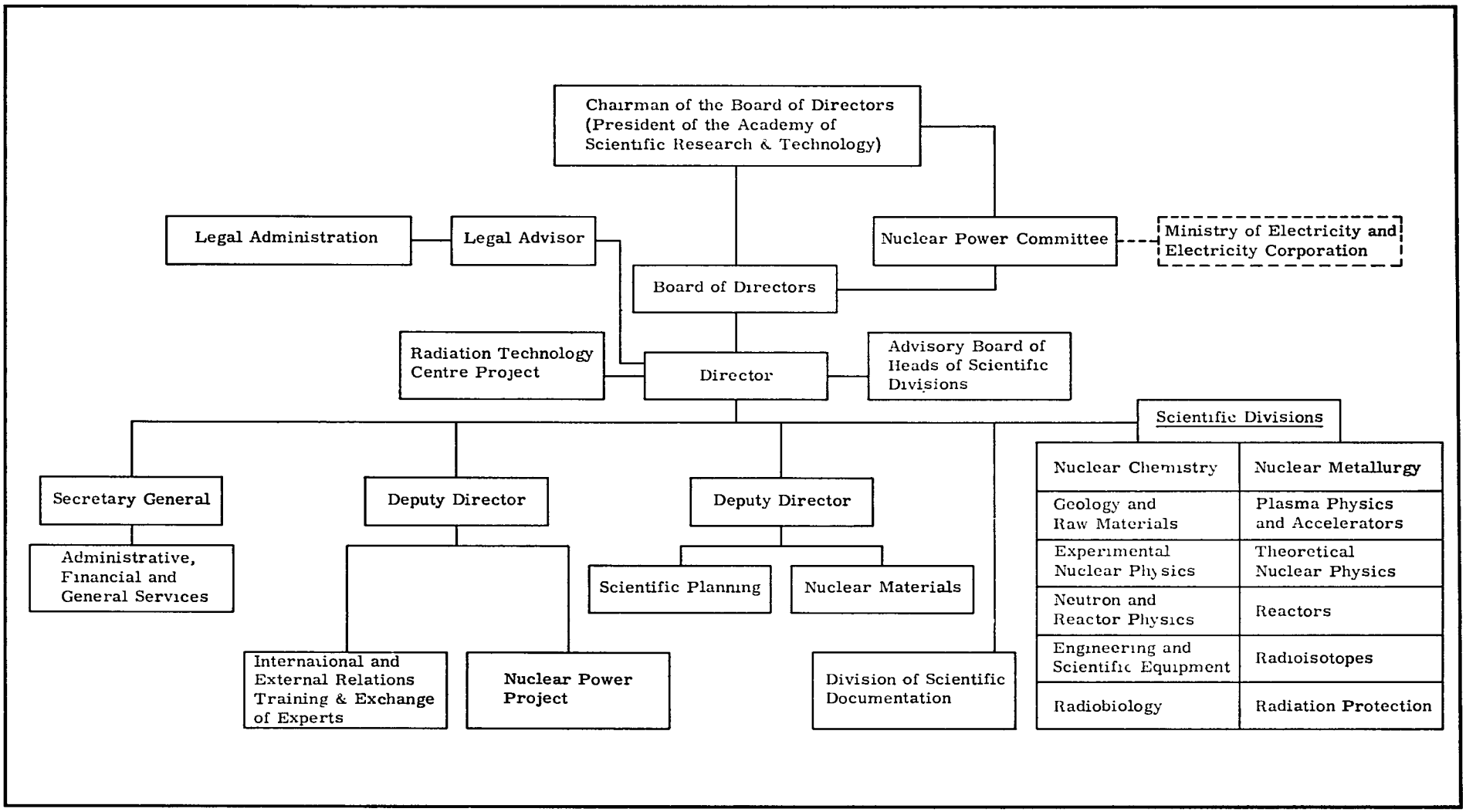

FIG. 8-1. ORGANIZATION OF THE ATOMIC ENERGY ESTABLISHMENT.

as well as with scientific research centres and universities. Matters relating to nuclear power are considered in a Nuclear Power Committee which includes representatives of AEE, of the Ministry of Electricity and of the Electricity Corporation. A similar committee is being established which will deal with the setting up of a centre for radiation technology, and with all applications of radiation sterilization and food preservation and with research and development in the fields of medicine, biology, and agriculture.

8.3. Safety, licensing and nuclear legislation

The AEE is the regulatory and licensing body for nuclear power plants and responsible for safety assessments.

The use of, and protection against, ionizing radiation is covered by law number 59 of 1 March 1960. Article 3 provides that the Ministry of Health shall issue licences for the installation and use of X-ray equipment, accelerators and sealed radioisotopes, and supervise all matters relating to protection against radiation hazards. The AEE supervises the use of unsealed radioisotopes and reactors and issues the required licenses.

Egypt has ratified the IAEA Convention on Third Party Liability in the Field of Nuclear Energy.

9. ANALYTICAL APPROACH

9.1. Approach and bases of analyses

The major objective of this study is to determine the size and timing of nuclear power plants that could, on economic grounds, justifiably be built in Egypt during the period 1980 to 1989, and to determine the sensitivity of the results to certain of the key parameters. The economic criterion, which is explained fully in Appendix D, is that the total operating and capital costs of the expansion plan for the generating system should be near to the minimum when calculated in terms of present worth at 1 January 1973 and in terms of constant US dollars at that date. That is, normal price escalation is not treated explicitly. The implicit treatment of escalation is discussed in Appendix D. Any expansion plan must clearly be consistent with the forecast of load growth during the period of the study, and with other technical constraints of the system.

One forecast of the growth in system demand has been used and the method of deriving it is given in Section 10. A number of alternative expansion plans that were consistent with the forecast were examined and the near-optimum plan determined by the use of a series of computer programs, the principal one being the Wien Automatic System Planning Package (WASP). This program evaluated the capital and operating costs of each alternative expansion plan over the period 1980 to 2000. The reason for extending the evaluation for a decade beyond the study period proper is to take account of at least ten years of operation of all plants introduced during the study period.

The analysis was based partly upon data obtained during the visit of the Market Survey Mission to Egypt in November 1972 and partly on data developed to permit a consistent approach to the fourteen-country survey.

A summary of the computer programs used in the analysis is given below together with a summary of the data required for the evaluation. These data and the results obtained in the analysis are discussed in more detail in the sections that follow.

9.2. Description of computer programs

The basic tool used in the analysis of the alternative system expansion plans was the WASP program. Two subsidiary programs were used to provide specific data for the WASP program - the ORCOST program for calculating the capital costs of various fossil and nuclear units and the polynomial regression analysis program used to fit a polynomial equation to the load duration data.

(a) Wien Automatic System Planning Package (WASP)

The WASP program utilizes six blocks of input data as the basis for simulating the operation of the power stations on a seasonal (quarter-by-quarter) basis, evaluating the operating costs of each plant, present-worth discounting these operating costs and the capital costs associated with all additions beyond the start of the study and determining the total system costs to the year 2000.

The data required for this analysis are as follows:

(i) System load description - consisting of the year-by-year peak demands for the power system during the study period, quarterly load duration data expressed as the coefficients of a polynomial equation, and factors relating the quarterly peak loads to the annual peak loads.

(ii) Fixed system description - consisting of a list of the generating units that will be in operation at the start of the study year (1978), their maximum and minimum operating levels, their minimum load and incremental heat rates, 1 January 1973 fuel costs, and expected operating and maintenance costs. The description also includes data on the retirement of existing plants, on specific firmly planned additions and on seasonal factors affecting the operation of the hydro units in the system.

(iii) Alternative generating units - consisting of the technical data on the various sizes and types of generating units that may be considered for an alternative expansion plan during the study period. The data required are the same as those required for the fixed system.

(iv) A series of alternative expansion plans - each consisting of a year-by-year definition of the generating units to be added during the study period.

(v) Loading order - for both of the plants in the fixed system and those considered as expansion alternatives.

(vi) Capital costs of the alternative generating units - broken down into foreign and domestic costs; and the expected economic life of the units.

The output from the WASP program consists of a quarter-by-quarter, plant-by-plant tabulation of the energy generation and associated costs for the study period. The total of these costs, plus the capital costs of the additions minus their salvage value at the study horizon, all present-worthed to 1973, is the "objective function" used to measure the economic merit of the system being analysed. That is, the expansion plan with the smallest value for the objective function was considered to be the "best" or "near-optimum".

A detailed description of the data input to the WASP program is included in the following sections and the results of the analysis are described in Section 16. For further information on the WASP program, see Appendix A.

(b) Capital cost program

The capital cost data required by the WASP program were determined by utilizing the ORCOST computer program. This program, which was obtained from Oak Ridge National Laboratory of the US Atomic Energy Commission, had been prepared by them to provide estimates of power plant capital costs in the USA for PWR, BWR, HTGR, coal, oil and gas-fired plants. Provision had been made in the program to adjust equipment, material and labour costs from region to region. This made it possible to adjust the costs to conditions prevailing in Egypt by utilizing local labour, materials and equipment cost information. Section 13 describes how these cost data were developed. For a more detailed description of the ORCOST program, see Appendix B.

(c) Polynomial regression program

Load duration curves were obtained from the Egyptian General Electricity Corporation. The WASP program required quarterly load duration curves expressed as the coefficients of a fourth order polynomial. The coefficients were calculated by a least-squares curve-fitting program that is described in more detail in Appendix C. The coefficients and the actual shapes of the quarterly load duration curves defined by the polynomial expressions are shown and discussed in Section 10.

9.3. Economic methodology and parameters

The economic merit of the various alternative expansion plans was determined and used as a basis for selecting the near-optimum case. External or social costs were disregarded, as were taxes and restraints on foreign capital. Definitions of the costs and other economic parameters are given in Appendix D.

The parameters for the reference case were assumed to be as follows:

	Study values	Equivalent real values (at 4% inflation)
Discount rate	8%	12%
Capital cost escalation rate	0	4%
Oil and gas price escalation rate	2%	6%
Nuclear fuel escalation rate	0%	4%
Loss-of-load probability (fraction)	Maximum - 0.01 Average - less than 0.005	

The cost of gas was taken as the fuel oil cost prevailing in the Persian Gulf at 1 January 1973, plus ocean and inland transport costs, on a cost/kcal basis.

9.4. Technical methodology and parameters

In order to facilitate preparation of data for the WASP program, the characteristics of the alternative generating units which might be installed on the system were standardized as described in Appendix E. The range of plant types and sizes considered are shown in Table IX-1. Oil plants were not considered in the expansion plan, in view of the statement by the Egyptian Petroleum Company that future plants would be gas-fired. In this regard, however, it should be noted that the fuel cost for gas is the same, on a cost/kcal basis, as for oil.

TABLE IX-1. PLANT SIZES AND TYPES CONSIDERED AS POSSIBLE SYSTEM ADDITIONS

Type of plant	Rated capacities (MW)
Gas-fired	300, 400, 600, 800, 1000
Nuclear	300, 400, 600, 800, 1000
Gas turbine	50

Two possible hydro projects were considered for the expansion alternatives - the Qattara Project and the Nile barrages. While either or both projects could develop, it was felt that the Qattara Project is not likely to become operative during the study period and it was thus omitted. The ten Nile barrage hydro units with a total capacity of 600 MW could become operative during the study period, but their construction will depend upon irrigation rather than power criteria. In view of this uncertainty, these were also omitted from the expansion plans that were analysed.

Coal plants were not included in the study in view of the limited quantities of coal in Egypt.

Characteristics of the alternative generating units are described in more detail in Section 14, and the supporting data on operating and maintenance costs, expected outage rates and plant life are described in Appendix E.

9.5. Sensitivity studies

In order to evaluate the sensitivity of the results obtained for the reference case to the various economic parameters used, studies were carried out for other values of these parameters. These are summarized as follows:

	Study values	Equivalent real values (at 4% inflation)
Discount rate	6%, 10%, 16%	10%, 14%, 20%
Oil price escalation rate	0%, 4%	4%, 8%
Nuclear fuel price escalation rate	2%	6%

Evaluations were carried out using a load forecast developed by the Egyptian General Electricity Corporation for the period 1980-89 with adjustments in the 1990s based on a forecast prepared by the Market Survey as described in Appendix F.

Two sets of capital cost data were used. These were ORCOST-1 (lower differential capital costs between nuclear and conventional plants) and ORCOST-3 (reference capital costs as of 1 January 1973). For details of these costs see Appendix B.

In the sensitivity studies, all parameters listed above were kept constant except for the parameter being studied. The results of these studies are discussed in Section 16.

10. FORECASTS OF SYSTEM LOADS AND LOAD DURATION CURVES

10.1. Review of load forecasts used in the study

Projections of the generated energy requirements and system load factors were obtained by the Mission and have been reported in Section 5. It was noticed that the growth rate projected for 1971-1975 is very high and is in marked contrast to the historical growth up to 1971 and the projected growth after 1975. The reason for the high growth of maximum demand in the early 1970s is that specific new loads will materialize from several projects now under construction including a ferro-silicon plant, a 40 000 t/yr aluminium plant and an expansion of the existing iron and steel complex at Helwan. This rapid expansion will probably be followed by a period of less than normal growth – about 7% from 1976 through 1985, returning to a growth rate of 10% for the last five years of the study period. It was also noted that the present annual load factor is 72%. However, during the 1978-1990 period the annual load factor is expected to change from 72% to 64% due to the lower load factor associated with the more rapidly growing commercial-residential loads and the rural electrification program. Thus the maximum demand during the same period is expected to increase at an average rate of up to 11.6%.

Forecasts were made for all countries of the study by H. Aoki. The method he used is described in detail in Appendix F. He based his forecasts on population projections, the per-capita energy requirements and on the per-capita GNP. The forecasts made by Aoki do not take into account such anomalies as the bringing into operation of several major industrial plants in the short period described above. However, his energy forecasts for the period 1975-1990 have an annual rate of growth of 8% which was consistent with the forecasts made by Egypt for that period. Aoki adjusted his forecast to take into account the short range anomaly and these adjusted forecasts (Table X-1) were used for the study and are in agreement with the forecasts made by Egypt for the study period. Beyond 1990 there is an increasing deviation between the forecasts of Egypt and those of Aoki. Aoki's forecasts were used for the period 1990-2000, but it should be recognized that this had only minimal effect upon the additions that would be required during the study period. These forecasts are shown in Figure 10-1. It should be noted that Aoki forecast the energy requirements and that the maximum demand was calculated utilizing a load factor of 72% in 1980, decreasing to 69% in 1985 and to 64% in 1990 as shown in Table X-2.

10.2. Derivation of load description data required for WASP program (Module 1)

(a) Annual peak load demand

The year-by-year maximum demand as described above is stated in Table X-2 for the period 1978-2000.

(b) Quarterly peak loads

The month-by-month peak load forecast for 1978 as provided to the Mission was given in Table V-5. The WASP program required quarterly peak load data. The factors relating the quarterly peak demand to the annual peak demand were based on the data in Table V-5, and are:

Quarter	Ratio of quarterly peak to annual peak
1	0.926
2	0.921
3	0.977
4	1.000

TABLE X-1. FORECAST OF GROSS ELECTRIC GENERATION AND PEAK DEMAND BY THE MARKET SURVEY [a]

	1961	1965	1968	1970	1971	1975	1980	1985	1990	1995	2000
Population (10^6)	26.52	29.29	31.70	33.33	34.00	36.80	40.63	44.86	49.53	54.69	60.38
Gross National Product											
GNP/capita (1964 US$)	130	147	140		150	176	214	261	317	377	447
Annual growth rate (%)	3.1	-1.6	2.3	4.0	4.0	4.0	4.0	4.0	3.5	3.5	
Gross electric generation											
kWh/capita	140	190	210	222	252	470	510	650	949	1170	1430
GWh				7400	8580	15500	20700	29200	47000	63900	85300
Load factor (%)				72	72	72	72	69	64	64	64
Peak electric demand (MW)				1170	1360	2450	3280	4830	8380	11400	15390

[a] Forecast prepared by H. Aoki, January 1973.

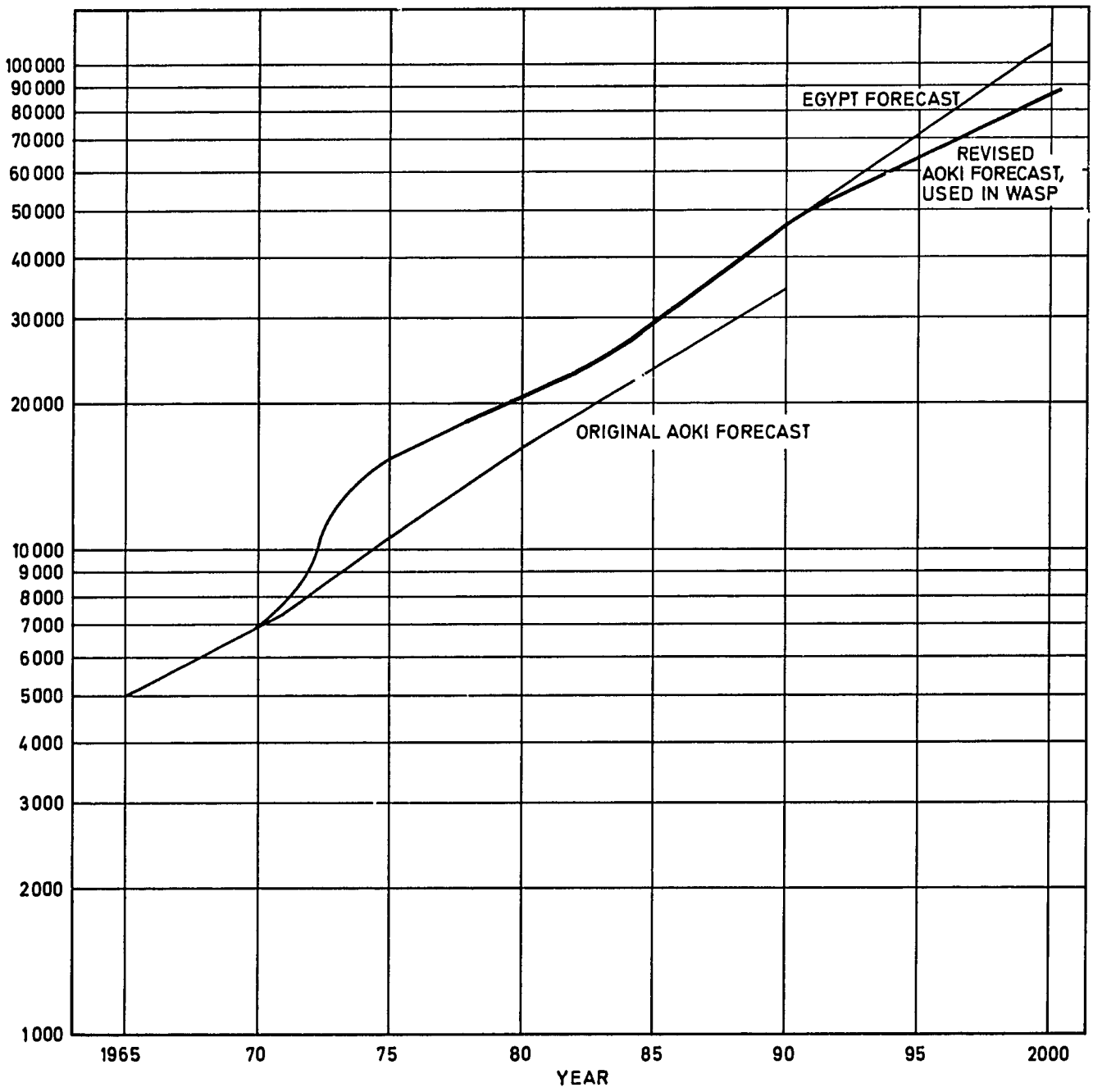

FIG. 10-1. ENERGY FORECAST.

TABLE X-2. COMPARISON OF FORECASTS OF ENERGY AND MAXIMUM DEMAND

Year	Egypt forecast			Aoki forecast	Base data used for WASP Program		
	Energy (GWh)	Load factor (%)	Max. demand (MW)	Energy (GWh)	Energy (GWh)	Load factor (%)	Max. demand (MW)
1978	18500	71.6	2950		18408.2	71.9	2923
1979	19600	72.8	3073		19504.0	71.9	3097
1980	20700	72.8	3246	20700	20669.0	71.9	3282
1981	21800	72.2	3447		22136.4	71.9	3516
1982	23000	73.0	3597		23717.1	70.9	3766
1983	24905	71.6	3972		25426.7	69.7	4091
1984	26966	70.2	4387		27156.5	68.8	4445
1985	29200	68.8	4845	29200	29124.8	67.9	4831
1986	32116	67.8	5407		32053.1	66.9	5392
1987	35324	66.8	6034		35263.0	65.9	6019
1988	38851	65.9	6732		38819.0	65.0	6720
1989	42732	64.9	7513		42710.8	64.0	7505
1990	47000	64.0	8383	47000	47001.9	64.0	8383
1991	51185	63.8	9158		49984.8	64.0	8914
1992	55743	63.8	9974		53141.4	64.0	9479
1993	60707	63.8	10862		56516.7	64.0	10080
1994	66113	63.8	11829		60093.9	64.0	10719
1995	72000	63.8	12883	63900	63906.5	64.0	11398
1996	78369	63.8	14022		67864.8	64.0	12104
1997	85301	63.8	15263		72064.4	64.0	12853
1998	92847	63.8	16613		76533.0	64.0	13650
1999	101060	63.8	18082		81276.3	64.0	14495
2000	110000	63.8	19682	85300	86305.7	64.0	15393

Study period

(c) Study increment

As seen from Table X-2, the maximum demand at the beginning of the study was approximately 3000 MW and increased to just over 15000 MW by the year 2000. The WASP program carried out its computations by considering the system demand requirements in discreet blocks of capacity. This block is called the study increment, and was selected in accordance with the rules described in Appendix A. The study increment used in the load description was 50 MW.

(d) Quarterly load duration curves

Monthly load duration data for January and July 1972 were obtained by the Mission. It was assumed that the shape of the quarterly load duration curves would be the same as these two curves. These data were reduced to a fourth order polynomial by use of the polynomial regression program described in Appendix C. In view of the fact that the load factor changed a number of times during the study period, a new set of coefficients was required from time to time. The quarterly load factors ranged from 66-78% as shown in Table X-3. Quarterly load duration curves were developed for each required quarter load factor (by adjusting the curves as shown in Fig. 10-2).

TABLE X-3. LOAD DESCRIPTION – WASP PROGRAM DATA

Year	Max. demand (MW)	Quarterly load factors (%)					Energy (GWh)
		1st	2nd	3rd	4th	Annual	
1978	2 923	76.01	77.99	74.04	73.01	71.89	18 408.2
1979	3 097	76.01	77.99	74.04	73.01	71.89	19 504.0
1980	3 282	76.01	77.99	74.04	73.01	71.89	20 669.0
1981	3 516	76.01	77.99	74.04	73.01	71.89	22 136.4
1982	3 766	76.01	77.99	74.04	73.01	71.89	23 717.1
1983	4 091	75.00	76.01	73.01	73.01	70.95	25 426.7
1984	4 445	73.01	75.00	71.92	71.97	69.74	27 156.5
1985	4 831	71.97	74.04	71.04	71.04	68.82	29 124.8
1986	5 392	71.04	73.01	71.01	70.01	67.86	32 053.1
1987	6 019	70.01	71.97	68.99	68.99	66.88	35 263.0
1988	6 720	68.99	71.04	68.01	68.01	65.94	38 819.0
1989	7 505	68.01	70.01	66.97	66.92	64.97	42 710.8
1990	8 383	66.92	68.99	65.99	65.99	64.00	47 001.9
1991	8 914	66.92	68.99	65.99	65.99	64.00	49 984.8
1992	9 479	66.92	68.99	65.99	65.99	64.00	53 141.4
1993	10 080	66.92	68.99	65.99	65.99	64.00	56 516.7
1994	10 719	66.92	68.99	65.99	65.99	64.00	60 093.9
1995	11 398	66.92	68.99	65.99	65.99	64.00	63 906.5
1996	12 104	66.92	68.99	65.99	65.99	64.00	67 864.8
1997	12 853	66.92	68.99	65.99	65.99	64.00	72 064.4
1998	13 650	66.92	68.99	65.99	65.99	64.00	76 533.0
1999	14 495	66.92	68.99	65.99	65.99	64.00	81 276.3
2000	15 393	66.97	68.99	65.99	65.99	64.00	86 335.7

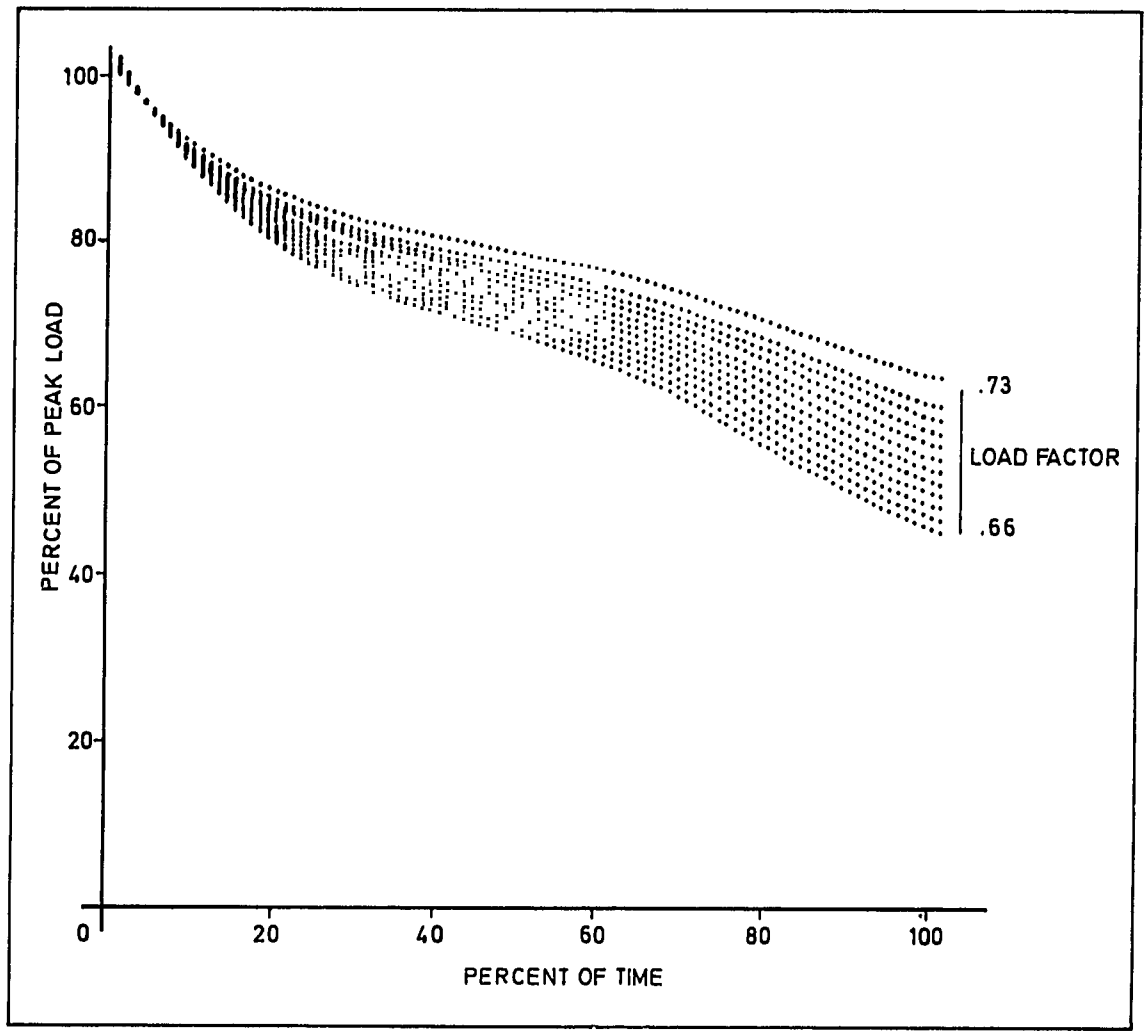

FIG. 10-2. QUARTERLY LOAD DURATION CURVES.

(e) Coefficients oi polynomial describing load duration curve shapes

The fourth order polynomial is given below and the table of the coefficients for each load factor used in the study is given in Table X-4.

$$\text{Fraction of quarterly peak demand} = b_0+b_1t+b_2t^2+b_3t^3+b_4t^4$$

where t = hours during the quarter at that demand or less.

(f) Annual load factors

As stated above the annual load factor at the beginning of the study is 72% – approximately the value of the load factor in Egypt in 1971, and reflects the importance of the industrial sector as an energy consumer. In view of the plans for rural electrification and of the growing importance of the commercial and residential electrical loads, Egypt has forecast that the annual load factor will diminish gradually during the 1980s to a value of 64%. This was shown in Table X-2. As stated above, polynomial expressions describing the load duration curves were derived for each load factor used in the study.

TABLE X-4. POLYNOMIAL COEFFICIENTS FOR LOAD DURATION CURVE SHAPE

Quarterly load factor [a] (%)	Coefficients [b]				
	b_0	b_1	b_2	b_3	b_4
77.99	1.000	-1.185	2.786	-3.246	1.276
76.01	1.000	-1.292	3.039	-3.541	1.392
75.00	1.000	-1.346	3.165	-3.688	1.450
74.04	1.000	-1.399	3.292	-3.836	1.508
73.01	1.000	-1.454	3.419	-3.983	1.566
71.97	1.000	-1.508	3.545	-4.131	1.624
71.04	1.000	-1.561	3.672	-4.278	1.682
70.01	1.000	-1.615	3.799	-4.426	1.739
68.99	1.000	-1.669	3.925	-4.574	1.798
68.01	1.000	-1.723	4.052	-4.721	1.856
66.97	1.000	-1.777	4.178	-4.869	1.914
65.99	1.000	-1.831	4.305	-5.016	1.972

[a] See Table X-3.
[b] See Appendix C for definition of coefficients.

11. LIMITING FACTORS IN SYSTEM DEVELOPMENT

11.1. General philosophy

The major load centres in Egypt are at Cairo, Alexandria and the Delta in Lower Egypt and near Aswan in Upper Egypt. These are the zones considered in this study.

Figure 11-1 shows the arrangement of the four zones of the supply system (Upper Egypt, Cairo, Delta and Alexandria) and the approximate distances involved. It also shows schematically the existing 500 kV lines from Aswan to Cairo and the proposed extension to a point slightly to the west of Alexandria, where it is expected that the first two or three nuclear reactors would be sited. The existing main transmission in the Cairo, Delta and Alexandria zones is at 220 kV; reinforcement at 500 kV is envisaged but its extent and timing are uncertain.

The following studies are based on the load projections of the General Electricity Corporation, in agreement with the Agency, and on a plant expansion program developed by the Agency in which all new generating capacity required during the period of the study is conventional thermal or nuclear plant installed in the Cairo, Delta and Alexandria zones.

The years 1980, 1985 and 1989 have been chosen for the load flow/transient stability analysis and 1983 and 1989 for the frequency stability studies, 1983 being the programmed year of installation of the first nuclear reactor.

11.2. Load flow/transient stability

Table XI-1 shows plant/load balances for minimum and maximum hydro conditions at times of peak load in 1980, 1985 and 1989.

The breakdown of load between zones is based on the detailed estimates of the General Electricity Corporation for 1980 and rough estimates for 1985 and 1990.

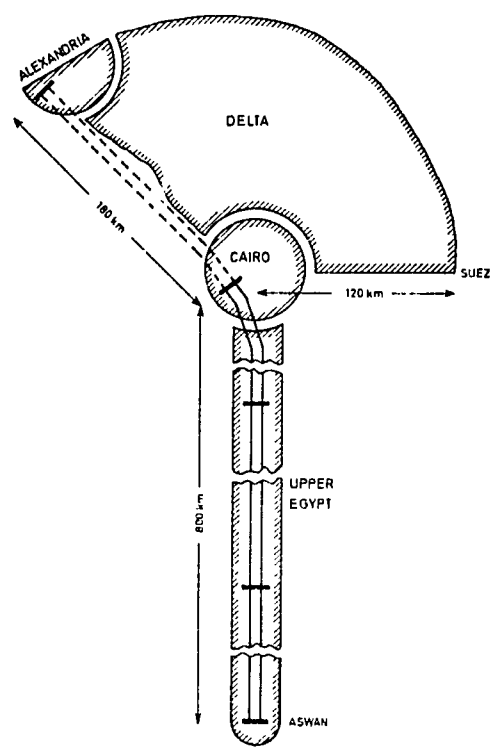

FIG. 11-1. ARRANGEMENT OF ZONES AND 500 kV TRANSMISSION LINES.

TABLE XI-1. PLANT LOAD BALANCES FOR 1980, 1985 AND 1989 PEAK LOADS (MW)

Zone	Installed capacity			Generation		Demand [c]	Export (+) or import (-)	
	1979 [a]	Additions [b]	Total	Min. hydro	Max. hydro		Min. hydro	Max. hydro
1980								
Upper Egypt [d]	2535	-	2535	1410	2040	1050	+360	+990
Cairo	946	-	946	655	430	965	-310	-535
Delta	452	600	1052	730	480	770	- 40	-290
Alexandria	661	-	661	455	300	465	- 10	-165
Total	4594	600	5194	3250	3250	3250	-	-
1985								
Upper Egypt [d]	2535	-	2535	1620	2260	1500	+120	+760
Cairo	846	-	846	730	560	1500	-770	-940
Delta	452	600	1052	900	690	1100	-200	-410
Alexandria	661	1200	1861	1600	1340	750	+850	+590
Total	4494	1800	6294	4850	4850	4850	-	-
1989								
Upper Egypt [d]	2535	-	2535	1800	2260	2200	-400	+ 60
Cairo	801	1800	2601	2220	2040	2400	-180	-360
Delta	415	1200	1615	1380	1270	1750	-370	-480
Alexandria	661	1800	2461	2100	1930	1150	+950	+780
Total	4412	4800	9212	7500	7500	7500	-	-

[a] Derived from Tables III-1 and V-2 with deduction of assumed retirements in Cairo and Delta after 1980.
[b] Cumulative additions after 1979 (all nuclear and conventional thermal).
[c] Due to rounding, these values are at slight variance with values in other chapters of the report.
[d] All hydro except for 90 MW of thermal capacity at Asyut, generating 40 - 70 MW according to conditions.

It has been assumed that the 600 MW of new gas-fired plant programmed for 1980 would be located in the Delta, and the 600 MW nuclear plants for 1983 and 1985 near Alexandria. Of the remaining 3000 MW of nuclear plant to be installed by 1989, 1800 MW has been assumed to be in the Cairo zone, 600 MW in the Delta and 600 MW near Alexandria, bringing the total for the latter zones to 1800 MW.

1980 - 3250 MW peak load

There will be large exports of hydro power from Upper Egypt. With maximum hydro capability 500 kV line loading, allowing for the two intermediate tapping points, will approach the limit with one of the two circuits nearest Aswan out of service.

1985 - 4850 MW peak load

Owing to growth of load, export from Upper Egypt will be somewhat lower than in 1980 but still substantial. With 1200 MW of nuclear capacity the Alexandria zone will provide exports of the same order, thus sharing with Upper Egypt the support of the heavily importing Cairo and Delta zones.

1989 - 7500 MW peak load

With further growth of load, Upper Egypt will now import substantially under the minimum hydro condition but will be self-supporting, or slightly exporting, with maximum hydro. With 1800 MW of nuclear capacity (out of a total of 4200 MW) and a comparatively small local load, the Alexandria zone now takes over from Upper Egypt the role of heavy exporter.

General

The gradual change during the study period of the role of the Upper Egypt zone, as described above, can be regarded as inevitable; but the power transfers between the other three zones will be governed by the disposition of new plant, of which the above pattern is one of several different possibilities. It is clear, however, that with the use of 500 kV connections as necessary, there should be no load flow/transient stability difficulties in introducing substantial nuclear capacity during the study period or in accommodating generator sizes up to the limits of 600-700 MW shown in Table XI-2.

TABLE XI-2. RECOMMENDED LIMITS OF GENERATOR SIZE

Year	Maximum demand [a] (MW)	Unit size (MW)
1980	3300	600
1985	4900	600
1990	8400	700
1995	11400	800
2000	15400	1000

[a] Rounded figures.

11.3. Frequency stability

The rate of fall of system frequency due to the loss of a large generator is limited initially by the quick response of the thermal plant and later by load shedding resulting from the operation of underfrequency relays. Recovery tends to be delayed until the slow response of the hydro generation becomes effective. In general, therefore, the amount of effective thermal reserve capacity is more important than the amount of hydro reserve.

Effective thermal reserve, i.e. the increase in output which is immediately available, is limited to a small proportion of the spinning capacity. Thus peak-load periods are found to be less critical than light-load periods when, despite the larger apparent total reserve, the effective thermal reserve is smaller. This is also usually the case under maximum, compared with minimum, hydro conditions, and the former have accordingly been selected for study since they are likely to be the more severe.

Load shedding as a function of underfrequency is an established practice which has been assumed to be retained for the future. The operation of underfrequency relays was assumed to be in three stages at 48.8 Hz, 48.6 Hz and 48.4 Hz and, for the purpose of the study, each stage was assumed to have no time delay.

1983

The three stages of load shedding were assumed to be in 100 MW blocks and the studies were based on the loss of 600 MW of generation.

Figure 11-2 is the frequency/time characteristic corresponding to the loss of 600 MW of generation during the light-load period with 2650 MW system load and spinning reserve capacity divided in the proportions of 880 MW hydro and 630 MW thermal generation. Three stages of load shedding operate before the recovery of system frequency.

Figure 11-3 shows for comparison the improved conditions which apply during a peak-load period with 4100 MW of system load. The spinning reserve capacity is 320 MW hydro and 480 MW thermal. The reduced frequency dip results in only one stage of load shedding.

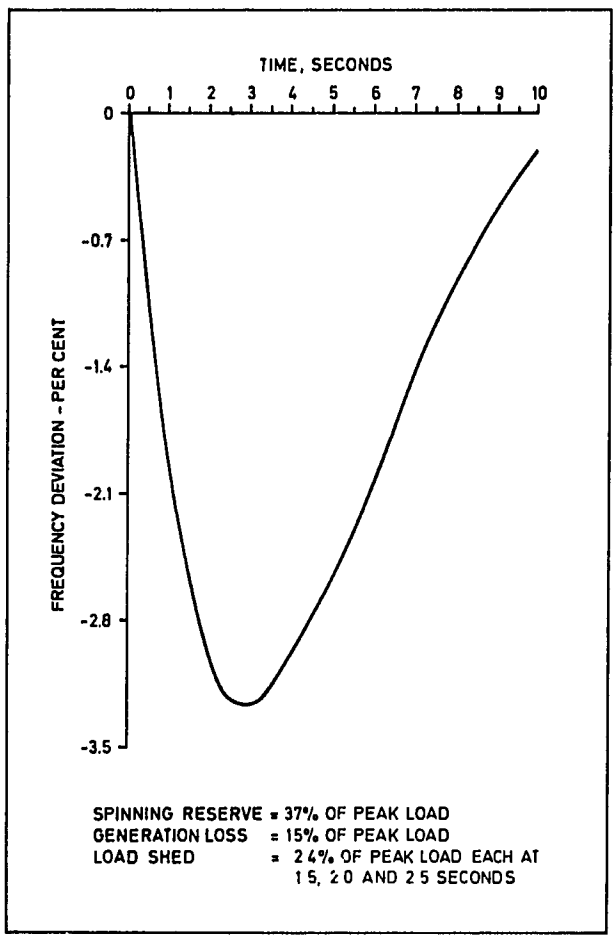

FIG. 11-2 SYSTEM FREQUENCY VARIATION (1983 LIGHT LOAD).

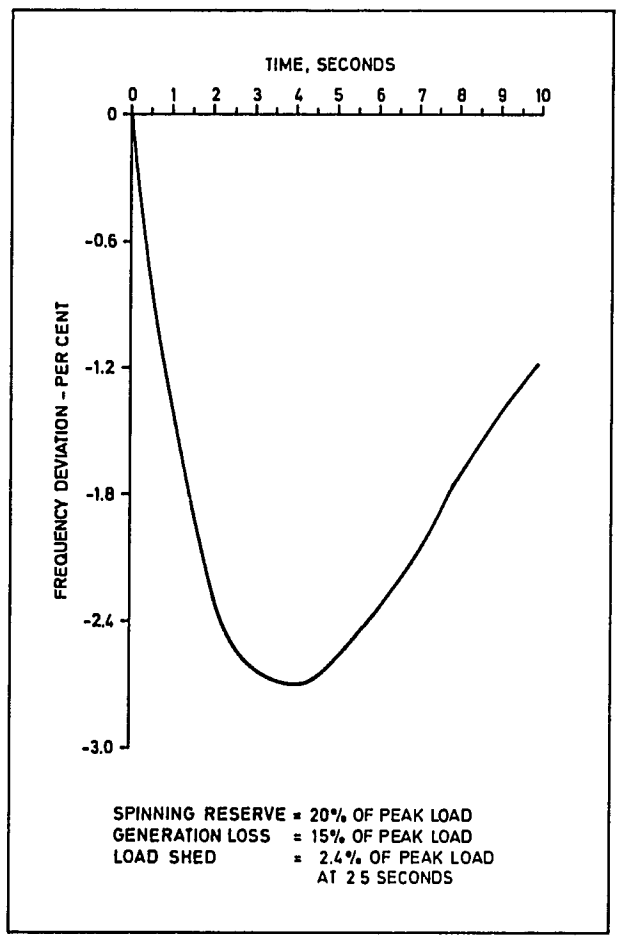

FIG. 11-3. SYSTEM FREQUENCY VARIATION (1983 PEAK LOAD).

1989

Load shedding was assumed to be in blocks of 170 MW. Studies were based on the loss of 600 MW of generation depicting either the loss of a fully loaded 600 MW unit or a larger unit loaded to 600 MW.

The frequency characteristic corresponding to the loss of generation during the light-load period with 4900 MW system load and spinning reserve capacity in the proportion of 875 MW hydro to 600 MW thermal generation is shown in Figure 11-4. A single stage of load shedding operates before the recovery of system frequency.

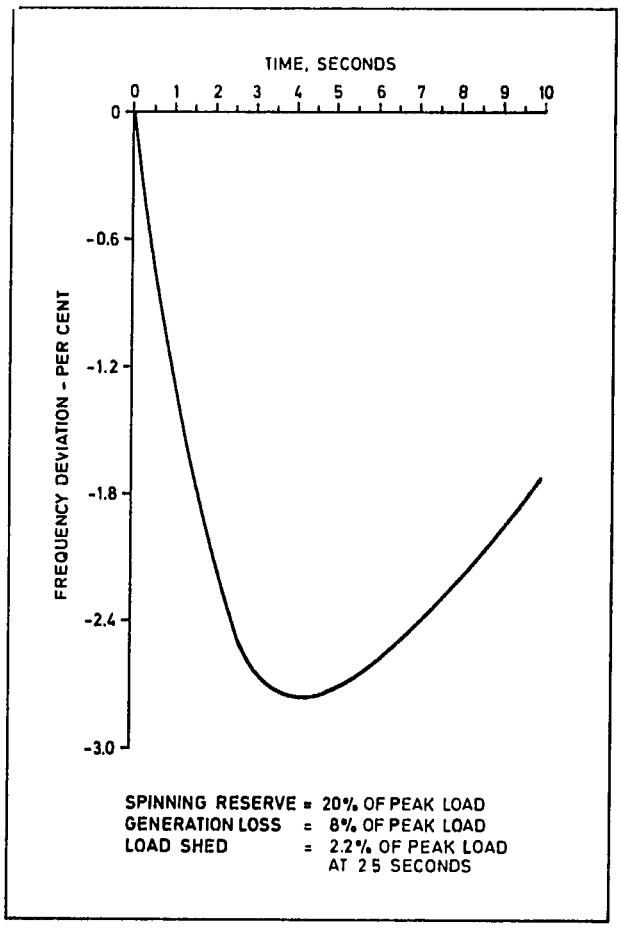

FIG. 11-4. SYSTEM FREQUENCY VARIATION (1989 LIGHT LOAD).

Conclusions

The scale of load shedding to be expected on loss of 600 MW of generation in 1983, though not inconsiderable, is very much smaller than would occur on double-circuit outage of the Aswan-Cairo 500 kV lines (see Table XI-1) and is regarded as acceptable.

In 1989 the scale of shedding is much reduced but so will be the corresponding effect of double-circuit line failure. On the principle that the proportions of load shedding which are acceptable diminish as the systems grow in size, no more than a marginal increase in unit size (to 700 MW) is considered advisable for 1990.

The recommended limits of 800 MW and 1000 MW for 1995 and 2000, arrived at by deduction, are intended to eliminate all load shedding on failure of a single generator.

11.4. Limits to introduction of large units

Table XI-2 shows the proposed limits of generator rated capacity at five-year intervals from 1980 to 2000, based on the considerations in Sections 11.2 and 11.3.

Note: The WASP computer work was completed based on preliminary recommendations regarding maximum size of units. For the study period the maximum size units of the

selected expansion plan are 600 MW which is consistent with the above. For the extended study period, however, the selected expansion plan utilizes 800 and 1000 MW units which are somewhat larger than the final ANS recommendations. This, however, does not affect the conclusions of the study.

11.5. System reliability

The loss-of-load probability calculations referred to in Section 15 are on the assumption of complete pooling of generating capacity, which implies transmission interconnections of 100% reliability.

Losses of load due to local sub-transmission failures are a normal risk in every system but the reliability of the main interconnecting circuits, in this case the 500 kV lines, is a factor requiring particular consideration.

In normal conditions a modern 500 kV line equipped with single-phase auto-reclosing can be expected to have an average outage rate not exceeding 1 in 3 years per 100 km, and a typical line section will therefore be at least as reliable as a large generator unit. With duplicate line circuits, as they exist between Aswan and Cairo and as proposed between Cairo and Alexandria, the risk of supply failure should be negligible except during a scheduled outage of individual line sections.

As stated in Section 4.2, however, due to unfavourable atmospheric conditions the performance of the Aswan-Cairo lines has been exceptionally bad and, though considerably improved by live-line insulator washing, double-circuit outages are still liable to occur. As can be seen from Figs 11-2 and 11-4, load shedding caused by such outages will gradually decrease between 1983 and 1989.

For the proposed new 500 kV lines between Cairo and Alexandria and for such 500 kV reinforcements as may be needed within the Delta and Cairo zones, it would be reasonable to expect the normal high standard of reliability partly because of improved design and partly because the atmospheric conditions are considerably less severe in Lower Egypt than in Upper Egypt.

12. CHARACTERISTICS OF THE EXISTING AND COMMITTED ELECTRIC POWER SYSTEM

12.1. Discussion of the existing power system and committed plans for expansion

The existing system has 3774 MW of installed capacity; 2445 MW of hydro and 1329 MW of fossil fuel plants as shown in Table III-1. During the 1973-1977 period 2 × 110 MW units at Kafr el Dawar, 2 × 150 MW units at Cairo South and 2 × 150 MW units at Abu Qir are scheduled to become operative. No retirements are expected in this period. Thus the total fossil fuel capacity at the beginning of the study period is 2149 MW as shown in Table XII-1. The hydro capacity will be unchanged at 2445 MW giving a total installed capacity of 4594 MW in 1978.

TABLE XII-1. DATA ON EXISTING THERMAL PLANTS (AT 1978)

Plant	WASP code	Fuel	Units No. x MW	Total installed capacity (MW)	Fuel cost (US$/$10^6$ kcal)
Cairo North	CAN1	Oil	2 x 10	20	151
Cairo North	CAN2	Oil	1 x 20	20	151
Cairo North	CAN3	Oil	2 x 30	60	151
Cairo West	CAW1	Oil	3 x 87	261	151
Cairo South	CAS1	Oil	4 x 60	240	151
Talkha	TAL1	Oil	3 x 30	90	151
Talkha	TAL2	Oil	3 x 12.5 [a]	36	151
Tebbin	TEB1	Oil	3 x 15	45	151
Damanhour	DAH1	Oil	3 x 65	195	151
Damanhour	DAH2	Oil	2 x 15	30	151
Siouf	SIO1	Oil	2 x 30	60	151
Siouf	SIO2	Oil	2 x 26.5 [b]	54	151
Suez	SUZ1	Oil	4 x 25	100	151
Max (gas turbine)	MAX1	Oil	2 x 14	28	151
Asyut	AST1	Oil	3 x 30	90	151
Kafr El-Dawar	KAFD	Gas	2 x 100 [c]	220	151
Cairo South	CAS2	Gas	2 x 150 [d]	300	151
Abu Qir	ABUA	Gas	2 x 150 [d]	300	151
				2 149	

[a] Listed as 3 x 12.
[b] Listed as 2 x 27.
[c] Added in 1974-75.
[d] Added in 1976-77.

12.2. Derivation of thermal plant data required for fixed system (WASP Module 2)

(a) Grouping of plants by size, type of fuel and fuel cost

The plants of the existing system, at the beginning of 1978, were grouped as shown in Table XII-1. Sizes generally are the nominal, or nameplate rating of the units. The existing (1972) plants are oilfired. In view of the policy of using natural gas for plants to be built beyond 1972 and of the policy of pricing gas and oil on the same cost-per-unit-of-heating-value (see para. (d)), no differentiation was made between gas and oil-fired plant fuel costs.

(b) Minimum and maximum unit operating capacity

The value of the minimum capacity and maximum capacity of each unit of the existing system was based on data obtained from the General Electricity Corporation, the maximum capacity being the nominal unit rating and the minimum capacity varying for each unit according to experience. For the six units to be added between 1972 and 1978 the minimum was taken as 25% of the nominal rating. (It should be noted that for the larger units added after 1978, 50% of the nominal rating was taken as the minimum, as described later.)

(c) Base load and incremental heat rates

Heat rates were obtained for all existing units from the General Electricity Corporation. These data were provided to the WASP program as follows:

(i) the heat rate at a minimum load, in kcal/kWh, and
(ii) the average heat rate, in kcal/kWh, for energy generated above the minimum.

These data are shown on the computer printout sheet, Table XII-2.

(d) Fuel costs (nuclear, oil, gas) broken down into domestic and foreign components

At present all plants in the system, except some retired units, burn oil. However, in view of recent discoveries of oil and natural gas south of El Alamein, the Egyptian Petroleum Corporation has decided, as a matter of policy, to encourage the use of gas. They plan to bring gas by pipeline to the major cities, and to set the cost of gas at the same value, on a cost-per-unit-heating-value, as oil. The current cost of oil is £E 7.5/t. Since the oil has a heating value of 96 000 kcal/kg, this is a cost of 166 US¢/10^6 kcal. Noting, however, that a rebate is given to the larger consumers and that the price has been maintained for five years (see Section 2.6(g)), it was decided to use as an oil price the cost of oil in the Persian Gulf plus ocean transport charges, which is 150¢/10^6 kcal (see Appendix I).

In view of the policy to price gas on an equivalent-heating-value basis, this value was used also for the cost of natural gas. No allowance was made for inland transportation of oil or gas.

(e) Forced outage rates

Data on forced outage rates for existing plants were obtained by the Mission as reported in Table IV-4. These values were used for the existing plants. For the three plants becoming operational between now and 1978, values based on experience in the USA, as described in Appendix E, were used.

(f) Days per year of scheduled maintenance

Scheduled maintenance data also were obtained by the Mission, as reported in Table IV-4. These data were used for all existing units. For the three new plants to be added, a period of 21 days was used, based on the experience described in Appendix E.

(g) Fixed and variable operating and maintenance costs

Data obtained on operating and maintenance costs were incomplete. Thus, for reasons of uniformity, in treating these costs the standards derived from experience, as reported in Appendix E, were used. It should be noted that the station capacity, rather than the unit capacity, was used to select the appropriate cost values.

12.3. Derivation of hydro plant data required

The importance of hydro generation in the power system is apparent when one considers that the installed hydro capacity of the Aswan and High Dams is 2445 MW whereas the capacity of all thermal plants including the plants to become operational by 1978 is 2149 MW.

TABLE XI-2(a). PRINTOUT OF FIXED SYSTEM GENERATING UNIT DATA

	NAME	NO. OF SETS	MIN. LOAD MW	CAP-CITY MW	BASE LOAD HEAT RATE	AVGE INCR HEAT RATE	FUEL COSTS CENTS/MILLION DMSTC	FORGN	TYPE	LCTN	FRCD OUT-AGE RATE	DAYS SCHL MAIN	MAIN CLAS	ENRGY GWH	O&M (FIX)	O&M (VAR)	FULL LOAD HEAT RATE
1	CAN1	2	4	10	3994.	2778.	151.00	0.0	1	1	2.50	30	20	0.	0.600	0.0	3264.
2	CAN2	1	8	20	3994.	2778.	151.00	0.0	1	1	3.00	30	40	0.	0.600	0.0	3264.
3	CAN3	2	12	30	3994.	2138.	151.00	0.0	1	1	2.70	30	40	0.	0.600	0.0	2880.
4	CAW1	3	35	87	2544.	2548.	151.00	0.0	1	1	2.00	30	100	0.	0.300	0.0	2546.
5	CAS1	4	24	60	3379.	2307.	151.00	0.0	1	1	3.50	30	80	0.	0.300	0.0	2736.
6	TAL1	3	12	30	3648.	2368.	151.00	0.0	1	1	4.00	30	40	0.	0.500	0.0	2880.
7	TAL2	3	5	12	3648.	2800.	151.00	0.0	1	1	4.00	30	20	0.	0.500	0.0	3153.
8	TEB1	3	6	15	4061.	2732.	151.00	0.0	1	1	2.00	30	20	0.	0.900	0.0	3264.
9	DAH1	3	26	65	3091.	2349.	151.00	0.0	1	1	2.00	30	80	0.	0.300	0.0	2646.
10	DAH2	2	6	15	3091.	2559.	151.00	0.0	1	1	5.00	30	20	0.	0.300	0.0	2772.
11	SIO1	2	12	30	3360.	2560.	151.00	0.0	1	1	6.00	30	40	0.	0.500	0.0	2880.
12	SIO2	2	11	27	3360.	2539.	151.00	0.0	1	1	3.00	30	40	0.	0.500	0.0	2873.
13	SUZ1	4	10	25	3955.	2403.	151.00	0.0	1	1	4.00	30	40	0.	0.600	0.0	3024.
14	MAX1	2	6	14	5030.	2779.	151.00	0.0	2	1	5.00	30	20	0.	0.900	0.0	3744.
15	AST1	3	4	30	3504.	2805.	151.00	0.0	1	1	4.50	30	40	0.	0.600	0.0	2898.
16	KAFD	2	27	110	3171.	2378.	151.00	0.0	1	1	6.50	21	150	0.	0.300	0.0	2573.
17	CAS2	2	37	150	3119.	2341.	151.00	0.0	1	1	5.30	21	150	0.	0.280	0.0	2533.
18	ABUA	2	37	150	3119.	2341.	151.00	0.0	1	1	5.30	21	150	0.	0.280	0.0	2533.
19	HYDE	1	345	1280	0.	0.	0.0	0.0	5	1	0.0	0	0	8912.	0.600	0.0	0.
20	EHYD	1	1165	1165	3119.	2341.	400.00	0.0	-1	1	0.0	0	0	0.	0.0	0.0	3119.
21		0	0	0	0.	0.	0.0	0.0	0	0	0.0	0	0	0.	0.0	0.0	3119.

TABLE XII-2(b). LEGEND FOR TABLE XII-2(a)

NAME	WASP code for existing plants (see Table XII-1 for fossil plants), HYDE = hydro and EHYD = emergency hydro.
NO. OF SETS	Number of units of a given size located at a given plant.
MIN. LOAD, MW	Minimum load at which units will be operated (see 12.2 (b)).
CAP-CITY, MW	Maximum load at which units will be operated (see 12.2 (b)).
BASE LOAD HEAT RATE	Unit heat rate at base load, kcal/kWh (see 12.2 (c)).
AVGE INCR HEAT RATE	Unit heat rate for each kW above base load, in kcal/kWh (see 12.2 (c)).
FUEL COSTS, DOMESTIC	Fuel costs in US$/kcal × 10^6 (see 12.2 (d)).
FUEL COSTS, FOREIGN	Same as above, except for imported fuel (used for nuclear fuel only).
TYPE	A code where -1 = emergency hydro 1 = gas fired 2 = gas turbine 5 = hydro
LCTN	Not used. Defaulted to 1 in all cases.
FRCD OUTAGE RATE	Days lost due to forced outage (see 12.2 (e)).
DAYS SCHL MAIN	Days lost due to scheduled outage (see 12.2 (f)).
MAIN CLAS	An arbitrary assignment of unit size, for maintenance calculations.
ENRGY, GWh	Used only for hydro (see 12.3 (b)).
O & M (FIX)	Average O & M costs, in US$/kWh-month (see 12.2 (g)).
O & M (VAR)	Not used.
FULL LOAD HEAT RATE	Full load heat rate, as calculated by WASP based on the base load heat rate and average incremental heat rate data above.

(a) Distribution of hydro capacity into base and peak load components

The hydro generation consists of two installations, the Aswan Dam and the High Dam. The Aswan Dam operates on a run-of-river basis and was thus treated as base load. The High Dam, which is upstream from the Aswan Dam, has a regulating basin downstream and can be used for peaking. However, this peaking capability is limited by the amount of power that can be safely transmitted to Lower Egypt over the double circuit 500 kV line, which in turn is limited by the spinning reserve required to maintain the system load in the event of a failure of the 500 kV line.

The General Electricity Corporation has made a forecast of the development of the loads of Lower and Upper Egypt and on this basis has predicted that the maximum load (including base and peak load) that could be utilized in 1980 is 1335 MW and that this would increase gradually to 1775 MW in 1990 as shown in Table V-7. These values, adjusted to give approximately equal annual increases, as shown in Table XII-3, were used for the maximum capacity of the hydro system in the WASP program.

(b) Energy generation

The energy that can be generated by the hydro system is a function of the water flow, and varies year to year. Table V-5 and V-6 show the average daily power, average Aswan Dam energy and the energy capability of the High Dam for low-flow and high-flow years.

The average daily power over the year for both dams at low-water conditions as shown in Table V-5 is 1017 MW, amounting to 8912 GWh. This is somewhat below the sum of 2118 GWh for the Aswan Dam and 7365 to 9142 GWh for the High Dam as shown in Table V-6.

TABLE XII-3. FORECAST PEAK LOADS ON EXISTING HYDRO SYSTEM

Year	Maximum hydro load that can be utilized [a]	Existing emergency hydro [b]	Year	Maximum hydro load that can be utilized [a]	Existing emergency hydro [b]
1978	1 280	1 165	1990	1 780	665
1979	1 310	1 135	1991	1 830	615
1980	1 350	1 095	1992	1 880	565
1981	1 390	1 055	1993	1 930	515
1982	1 430	1 015	1994	1 980	465
1983	4 170	975	1995	2 040	405
1984	1 510	935	1996	2 090	355
1985	1 550	895	1997	2 150	295
1986	1 590	855	1998	2 210	235
1987	1 640	805	1999	2 270	175
1988	1 680	765	2000	2 330	115
1989	1 730	715			

[a] Reference Table V-7, smoothed to give approximately equal annual increases.
[b] 2445 MW less maximum hydro load that can be utilized.

Though recognizing that this may understate the actual energy available by about 15%, the lower figure of 8912 GWh was used in the WASP program. (Had the higher figures been used, the fossil plants would have operated at a lower capacity factor, but the expansion plan, including the number and capacity of nuclear units required, was fixed by the system maximum demand rather than by the energy, and would not have changed.)

(c) Seasonal capacity and energy factors

The monthly variations of flow, and hence of energy, are rather large as shown in Tables V-5 and V-6. However, as it was not reasonable, because of the computer running time required, to use a month-by-month analysis in the WASP program (even though the program has that capability), quarterly values based on averaging the monthly values were used. Quarterly factors to apply to the base capacity, peak capacity and energy are shown in Table XII-4. The energy factors were derived from the average daily power (low-water conditions) stated in Table V-5, and were maintained throughout the study. The resulting hydro capacity factors are also shown in Table XII-4.

TABLE XII-4. QUARTERLY FACTORS FOR HYDRO SYSTEM

Factors	1st	2nd	3rd	4th
Base load	1.00	1.00	1.00	1.00
Peak load	1.00	1.00	1.00	1.00
Energy	0.203	0.271	0.290	0.236
Resulting hydro capacity factors	0.645	0.862	0.992	0.750

(d) Allocation of total capacity to emergency hydro

As noted above, only a portion of the full 2445 MW capacity of the Aswan Dam is utilized as base load and peaking capacity. However, it was felt that the system should be given some credit for the potential emergency use of the Aswan units not included in the above. Thus, the total capacity (2245 MW) less the hydro capacity listed in Table XII-3 was treated as emergency hydro. By placing this emergency hydro last in the loading order, the computer was instructed to use this hydro only when the rest of the system could not meet the energy demand. As will be seen, this represented only a small amount of energy. The energy associated with this emergency hydro was not included in the energy discussed in (b) above but, as already explained, the energy was somewhat understated, and thus an allowance was made for the emergency hydro in this understatement.

(e) Pumped storage plants

No pumped storage plants are in operation and none were considered in the expansion alternatives. Should the Qattara Project materialize, pumped storage may have a place in Egypt.

(f) Operating and maintenance costs

Operating and maintenance costs for the hydro system were not included as an item of input cost.

12.4. Computer printout showing characteristics of system at start of study period

The data described above were utilized to describe the fixed system (WASP Module 2). The computer printout of these data is shown in Table XII-2.

13. CAPITAL COST DATA

13.1. Basis for thermal plant cost estimates developed by ORCOST computer code

Appendix B describes in detail how capital cost estimates were developed using the ORCOST computer program. The required input data for this program are shown in Table 5 of Appendix B. Except for the equipment, materials and labour cost indices, which varied for each of the countries covered by the Survey, these input data were kept constant to provide consistency among results. The following paragraphs describe how the input data were established.

(a) Interest rate

ORCOST-1 and ORCOST-3 capital cost estimates were based on an assumed 8% interest rate during construction. This was assumed to be constant for all cases considered even though the present-worth discount rate was varied from 6% to 16%. The effect of this assumption on the results of the survey was not considered significant.

(b) Construction schedules

The construction schedule for each size and type of plant was based on current US construction experience. Extrapolations were made for the smaller plant sizes. The results are shown in Table XIII-1.

TABLE XIII-1. CONSTRUCTION SCHEDULES ASSUMED IN CAPITAL COST ESTIMATES (yr)

Plant size (MW)	Oil or gas-fired	Coal-fired	Nuclear
100	2.5	3.0	4.5
300	3.0	3.5	5.0
600	3.5	4.0	5.5
1000	4.0	4.5	6.0

(c) Contingency and spare parts factors

As seen in Table 5 of Appendix B, contingency factors were taken to be 5% on equipment and materials and 10% on construction labour. The spare parts factor was assumed to be 1% of equipment and materials costs corresponding to US practice.

(d) Other considerations

The ORCOST program allows for the inclusion of unusual costs such as costs of special materials, the use of cooling towers instead of river or ocean water, the inclusion of SO_2 removal equipment, and overtime pay; however, none of these costs was included in the capital costs estimates. The capital costs do include electrostatic precipitators for stack gas clean-up for all fossil-fuelled plants.

13.2. Derivation of equipment, materials and labour cost indices

(a) Equipment cost index

A review of recent world market prices of conventional plant equipment indicated that on a competitive bid basis these should be about 85% of the prices used in ORCOST. Allowing 5% additional for transportation costs of such equipment gave an equipment index for con-

ventional thermal plants of 0.9. In the case of nuclear plant equipment, however, it was decided that world market prices should be only about 95% of the prices used in ORCOST. After allowing for transportation costs, this gave an equipment index of 1.0 for PWR plants.

(b) Materials cost index

A comparison of costs of construction materials in Egypt (see Table VI-1) with costs used in ORCOST is given in Table XIII-2. The ratio of such costs gave a materials cost index of 0.95.

TABLE XIII-2. COMPARISON OF MATERIAL COSTS IN EGYPT AND THE USA

Item	Amount[a]	Costs in Egypt (10^6 US $)	Costs in USA[b] (10^6 US $)
Structural steel	5×10^3 t	2.0	2.2
Reinforcing bars	10×10^3 t	2.2	2.2
Concrete	115×10^3 yd^3	2.3	2.5
Plyform	2.5×10^6 ft^2	1.2	1.3
Other lumber	6.5×10^6 bd.ft.	1.1	1.1
		8.8	9.3
Material cost index = 8.8/9.3 = 0.95			

[a] For a 1000 MW PWR.
[b] ORCOST base location (Middletown, USA).

(c) Labour cost index

A comparison was made of labour costs in Egypt and in the USA in order to develop a labour cost index. Table XIII-3 indicates labour costs of selected crafts and skills, the man hours required of each craft to construct a 1000 MW PWR, and the resulting total labour costs. In order to account for the higher degree of mechanization in the USA, the above total labour cost was divided by 0.25. The labour cost index was the ratio of this value to comparable labour cost totals in the USA and was 0.21.

TABLE XIII-3. LABOUR COST INDEX DATA

Type of craft	Wage (US $/h)	Man-hours[a] (10^3)	Costs[a] (10^6 US $)	US costs (10^6 US $)
Common labour	0.19	1250	0.24	8.71
Bricklayer	0.38	66	0.025	0.72
Carpenter	0.38	600	0.23	6.14
Iron worker	0.57	530	0.30	5.27
Electrician	1.09	860	0.775	9.64
Steam fitter	0.57	2250	1.285	25.32
Operating engineer	0.58	600	0.35	5.66
Other	0.35	600	0.21	3.83
Total			3.415	65.3
Labour effectiveness (largely related to degree of mechanization)		0.25		
Resulting labour cost index = $\frac{3.415}{0.25 \times 65.3} = 0.21$				

[a] Amounts, man-hours and costs refer to a 1000 MW PWR.

(d) Indirect cost indices

These were taken to be the same as used in ORCOST (see Appendix B for details).

13.3. Summary of ORCOST capital cost data for generating units considered as expansion alternatives

ORCOST-3 printouts of capital costs of 600 MW gas-fired and PWR plants are shown in Tables XIII-4 and XIII-5. Costs calculated by ORCOST-3 of other plant sizes considered as possible additions to the assumed fixed electric power system are given in Tables XIII-6 and XIII-7 and summarized in Table XIII-8. Similar summaries of costs calculated by ORCOST-1 (used in sensitivity studies) are given in Table XIII-9.

TABLE XIII-4. ORCOST-3, CAPITAL COST ESTIMATES FOR A 600 MW GAS-FIRED PLANT (10^6 US $)[a]

		EQU.	MAT.	LABOUR	TOTAL
	DIRECT COSTS				
20	LAND AND LAND RIGHTS				0.1
	PHYSICAL PLANT	EQU.	MAT.	LABOUR	TOTAL
21	STRUCTURES AND SITE FACILITIES	0.7	6.7	2.2	9.6
22	REACTOR/BOILER PLANT EQUIPMENT	11.4	2.2	1.7	15.3
23	TURBINE PLANT EQUIPMENT	17.1	5.7	2.1	25.0
24	ELECTRIC PLANT EQUIPMENT	4.1	1.0	1.1	6.2
25	MISCELLANEOUS PLANT EQUIPMENT	0.9	0.7	0.4	2.0
26	SPECIAL MATERIALS	0.0	0.0	0.0	0.0
	INCREMENTAL ALLOWANCE FOR ENVIRONMENTAL ASSURANCE				
	SO-2 REMOVAL SYSTEM	0.0	0.0	0.0	0.0
	COOLING TOWERS	0.0	0.0	0.0	0.0
	SUBTOTAL (PHYSICAL PLANT)	34.2	16.4	7.4	58.0
	CONTINGENCY ALLOWANCE				3.3
	SPARE PARTS ALLOWANCE				0.5
	SUBTOTAL (PHYSICAL PLANT)				61.7
	OVERTIME ALLOWANCE (40.0 HR WORKWEEK)				0.0
	SUBTOTAL (TOTAL PHYSICAL PLANT)				61.7
	INDIRECT COSTS				
91	CONSTRUCTION FACILITIES, EQUIPMENT, AND SERVICES				6.1
92	ENGINEERING AND CONSTRUCTION MANAGEMENT SERVICES				10.0
93	OTHER COSTS				3.0
94	INTEREST DURING CONSTRUCTION (8.0 PCT- 3.50 YRS)				10.2
	SUBTOTAL (TOTAL INDIRECT COSTS)				29.3
	SUBTOTAL (TOTAL PLANT COST)				91.1
	CAPABILITY PENALTY (0.0 PCT- 0.0 MW(E))				0.0
	TOTAL PLANT CAPITAL COST (AT START OF PROJECT)				91.1
	$ / KW(E)				152.
	ESCALATION DURING CONSTRUCTION (0.0 PCT)				0.0
	TOTAL PLANT CAPITAL COST (AT COMMERCIAL OPERATION)				91.1
	$ / KW(E)				152.

[a] Costs are in 1972 constant dollars

13.4. Treatment of transmission costs

The Egyptian General Electricity Corporation plans to construct future gas-fired plants near to the major load centres, on the Nile or its canals. In view of the population density

TABLE XIII-5. ORCOST-3, CAPITAL COST ESTIMATES FOR A 600 MW NUCLEAR PLANT (10^6 US $)[a]

		EQU.	MAT.	LABOUR	TOTAL
	DIRECT COSTS				
20	LAND AND LAND RIGHTS				0.1
	PHYSICAL PLANT	EQU.	MAT.	LABOUR	TOTAL
21	STRUCTURES AND SITE FACILITIES	1.2	12.9	5.1	19.2
22	REACTOR/BOILER PLANT EQUIPMENT	29.5	11.3	3.2	44.1
23	TURBINE PLANT EQUIPMENT	26.9	8.0	3.0	38.0
24	ELECTRIC PLANT EQUIPMENT	4.7	6.6	1.9	13.2
25	MISCELLANEOUS PLANT EQUIPMENT	1.8	0.2	0.6	2.5
26	SPECIAL MATERIALS	0.0	0.0	0.0	0.0
	INCREMENTAL ALLOWANCE FOR ENVIRONMENTAL ASSURANCE				
	UPGRADED RADWASTE SYSTEM	0.0	0.0	0.0	0.0
	COOLING TOWERS	0.0	0.0	0.0	0.0
	SUBTOTAL (PHYSICAL PLANT)	64.1	39.1	13.7	117.0
	CONTINGENCY ALLOWANCE				6.5
	SPARE PARTS ALLOWANCE				1.0
	SUBTOTAL (PHYSICAL PLANT)				124.5
	OVERTIME ALLOWANCE (40.0 HR WORKWEEK)				0.0
	SUBTOTAL (TOTAL PHYSICAL PLANT)				124.5
	INDIRECT COSTS				
91	CONSTRUCTION FACILITIES, EQUIPMENT, AND SERVICES				8.9
92	ENGINEERING AND CONSTRUCTION MANAGEMENT SERVICES				22.9
93	OTHER COSTS				5.0
94	INTEREST DURING CONSTRUCTION (8.0 PCT- 5.50 YRS)				33.4
	SUBTOTAL (TOTAL INDIRECT COSTS)				70.2
	SUBTOTAL (TOTAL PLANT COST)				194.9
	CAPABILITY PENALTY (0.0 PCT- 0.0 MW(E))				0.0
	TOTAL PLANT CAPITAL COST (AT START OF PROJECT)				194.9
	$ / KW(E)				325.
	ESCALATION DURING CONSTRUCTION (0.0 PCT)				0.0
	TOTAL PLANT CAPITAL COST (AT COMMERCIAL OPERATION)				194.9
	$ / KW(E)				325.

[a] Costs are in 1972 constant dollars

along the inland waterways, nuclear plants will be built on the coast 20-40 km west of Alexandria. A value of US $13/kW was added to the capital costs of nuclear plants to account for the additional transmission costs associated with these coastal locations.

13.5. Costs of hydro and pumped storage plants added during study period

No pumped storage plants or additional hydro plants were considered for the alternative expansions.

13.6. Cost of gas turbines

Costs of 50 MW gas turbines were assumed to be US $125/kW. Since gas turbines were loaded above the thermal steam plants, neither their capital nor their operating costs influenced the comparison of other thermal plant additions.

TABLE XIII-6. SUMMARY OF NUCLEAR PLANT CAPITAL COSTS CALCULATED BY ORCOST-3 (10^6 US $)

Account No.	Plant size				
	300 MW	400 MW	600 MW	800 MW	1 000 MW
Direct costs					
20	0.1	0.1	0.1	0.1	0.1
21	14.5	16.3	19.2	21.5	25.6
22	29.0	34.6	44.2	52.4	59.9
23	21.8	27.5	38.0	47.8	57.1
24	8.7	10.3	13.2	15.7	17.9
25	2.1	2.2	2.5	2.8	3.0
Subtotal	76.2	91.0	117.2	140.3	163.6
Contigencies	4.3	5.1	6.5	7.8	9.1
Spare parts	0.7	0.8	1.0	1.2	1.4
Indirect costs					
Accts 91-93	31.4	33.2	36.7	40.3	43.8
Interest during construction	20.9	25.3	33.4	41.2	49.7
Total costs	133.5	155.4	194.8	230.8	267.6
Unit costs (US $/kW)	445	389	325	288	268

TABLE XIII-7. SUMMARY OF GAS-FIRED PLANT CAPITAL COSTS CALCULATED BY ORCOST-3 (10^6 US $)

Account No.	Plant size				
	300 MW	400 MW	600 MW	800 MW	1 000 MW
Direct costs					
20	0.1	0.1	0.1	0.1	0.1
21	5.7	7.1	9.6	11.9	14.0
22	8.2	10.6	15.2	19.8	24.2
23	14.3	18.0	24.9	31.4	37.5
24	4.5	5.2	6.2	7.0	7.8
25	1.6	1.7	2.0	2.1	2.3
Subtotal	34.4	42.7	58.0	72.3	85.9
Contigencies	1.9	2.4	3.3	4.1	4.8
Spare parts	0.3	0.4	0.5	0.6	0.7
Indirect costs					
Accts 91-93	13.5	15.8	19.1	21.0	21.4
Interest during construction	5.4	7.0	10.2	13.3	16.5
Total costs	55.5	68.3	91.1	111.3	129.3
Unit costs (US $/kW)	185	171	152	139	129

TABLE XIII-8. CAPITAL COSTS OF EXPANSION ALTERNATIVE GENERATING UNITS - ORCOST-3

N300 LOCAL	114.0	$/KW	FOREIGN	378.0	$/KW	PLANT LIFE =	32. YRS
N400 LOCAL	100.0	$/KW	FOREIGN	334.0	$/KW	PLANT LIFE =	32. YRS
N600 LOCAL	84.0	$/KW	FOREIGN	282.0	$/KW	PLANT LIFE =	32. YRS
N800 LOCAL	75.0	$/KW	FOREIGN	250.0	$/KW	PLANT LIFE =	32. YRS
N1TO LOCAL	70.0	$/KW	FOREIGN	231.0	$/KW	PLANT LIFE =	32. YRS
G100 LOCAL	64.0	$/KW	FOREIGN	190.0	$/KW	PLANT LIFE =	30. YRS
G150 LOCAL	56.0	$/KW	FOREIGN	169.0	$/KW	PLANT LIFE =	30. YRS
G200 LOCAL	52.0	$/KW	FOREIGN	155.0	$/KW	PLANT LIFE =	30. YRS
G300 LOCAL	46.0	$/KW	FOREIGN	139.0	$/KW	PLANT LIFE =	30. YRS
G400 LOCAL	43.0	$/KW	FOREIGN	128.0	$/KW	PLANT LIFE =	30. YRS
G600 LOCAL	38.0	$/KW	FOREIGN	114.0	$/KW	PLANT LIFE =	30. YRS
G800 LOCAL	35.0	$/KW	FOREIGN	104.0	$/KW	PLANT LIFE =	30. YRS
G1TO LOCAL	32.0	$/KW	FOREIGN	97.0	$/KW	PLANT LIFE =	30. YRS
GT50 LOCAL	0.0	$/KW	FOREIGN	125.0	$/KW	PLANT LIFE =	20. YRS

TABLE XIII-9. CAPITAL COSTS OF EXPANSION ALTERNATIVE GENERATING UNITS - ORCOST-1

N300 LOCAL	98.0	$/KW	FOREIGN	330.0	$/KW	PLANT LIFE =	32. YRS
N400 LOCAL	87.0	$/KW	FOREIGN	292.0	$/KW	PLANT LIFE =	32. YRS
N600 LOCAL	72.0	$/KW	FOREIGN	246.0	$/KW	PLANT LIFE =	32. YRS
N800 LOCAL	64.0	$/KW	FOREIGN	218.0	$/KW	PLANT LIFE =	32. YRS
N1TO LOCAL	60.0	$/KW	FOREIGN	200.0	$/KW	PLANT LIFE =	32. YRS
G100 LOCAL	67.0	$/KW	FOREIGN	200.0	$/KW	PLANT LIFE =	30. YRS
G150 LOCAL	59.0	$/KW	FOREIGN	175.0	$/KW	PLANT LIFE =	30. YRS
G200 LOCAL	54.0	$/KW	FOREIGN	160.0	$/KW	PLANT LIFE =	30. YRS
G300 LOCAL	47.0	$/KW	FOREIGN	142.0	$/KW	PLANT LIFE =	30. YRS
G400 LOCAL	44.0	$/KW	FOREIGN	130.0	$/KW	PLANT LIFE =	30. YRS
G600 LOCAL	39.0	$/KW	FOREIGN	115.0	$/KW	PLANT LIFE =	30. YRS
G800 LOCAL	35.0	$/KW	FOREIGN	105.0	$/KW	PLANT LIFE =	30. YRS
G1TO LOCAL	35.0	$/KW	FOREIGN	97.0	$/KW	PLANT LIFE =	30. YRS
GT50 LOCAL	0.0	$/KW	FOREIGN	125.0	$/KW	PLANT LIFE =	20. YRS

14. CHARACTERISTICS OF ALTERNATIVE GENERATING UNITS CONSIDERED FOR EXPANSION DURING STUDY PERIOD

14.1. Review of plan for system expansion

As stated in Section 12.2, three thermal plants (six units) with a total capacity of 820 MW are to become operational by 1978, at which time the installed capacity of the fossil-fuelled stations will be 2149 MW. The Mission visited the site of the Kafr El-Dawar plant in the Delta where the foundations are in place. Though the Cairo South and the Abu Qir plants are not yet under construction, it seems likely that they will become operational as planned. Beyond the 1978 date, however, there exist no firm plans although the addition of 2 X 400 MW nuclear units in 1980 is considered.

In view of the uncertainty beyond 1978 the selection of plant beyond that data was left open. Data were provided for 300, 400, 600, 800, and 1000 MW gas-fired and nuclear plants and a 50 MW gas turbine as alternatives when future plants are selected.

14.2. Characteristics of hydro and pumped storage projects which might be added

The possible hydro alternatives consist of two projects, the Nile Barrages and the Qattara Project, as described in Section 2.1. As stated in that Section, the cost of the Qattara Project is very high and its feasibility depends partly upon the use of nuclear explosives. This project was not considered for the study period. It should be noted, however, that the capacity of the Qattara Project is 600 MW and could replace one 600 MW unit in the expansion program

The ten Nile Barrage hydro stations described in Section 2.1 have a total capacity of 600 MW. The question of their feasibility is under study, but the earliest date at which the first unit could become operational is 1985. They were not included in the study.

14.3. Minimum and maximum thermal capacity additions required

As seen from the data of Section 10.2, the maximum demand increases from 2923 MW in 1978 to over 15 000 MW by the year 2000. This peak demand is reached in the 4th quarter, which is the critical quarter. The reserve margin (not including emergency hydro) in the 4th quarter of 1978 is 17.3%. It was found that the loss-of-load probability at that time was less than 0.0001, even if the emergency hydro is excluded from consideration. (For the definition of loss-of-load probability, see Appendix A.)

As larger units are added to the system (the largest unit in the system in 1978 is 150 MW), the reserve required to keep the loss-of-load probability to a reasonable value increases. Even so, in the early 1980s a critical quarter reserve of 10% is sufficient for reasonable loss-of-load probability values when credit is given for the emergency hydro. The critical quarter reserve requirement increases, however, to about 14% by the late 1980s and assuming that large units only are added to the system, an even higher reserve would be required during the 1990s.

The critical quarter reserve margins and loss-of-load probability for each year during the study period are discussed in more detail in the next Section.

14.4. Characteristics of thermal units for alternative generator system (WASP Module 3)

(a) Choice of unit sizes and types of plants

The sizes and code names of the 14 plants used in the WASP program for evaluating alternative generating units being considered as possible additions to the electric power system are listed in Table XIV-1.

TABLE XIV-1. STANDARD SIZES AND TYPES OF PLANTS USED IN THE STUDY

Size (MW)	Type of plant and code name		
	Nuclear	Gas	Gas turbine
50			GT50
100		G100	
150		G150	
200		G200	
300	N300	G300	
400	N400	G400	
600	N600	G600	
800	N800	G800	
1 000	N1T0	G1T0	

(b) Minimum operating capacities

Minimum operating capacities were assumed to be 50% of the name plate rating as discussed in Appendix E.

(c) Heat rates

Half load and incremental heat rates were taken from data given in Appendix G.

(d) Other data

Operating and maintenance costs, forced outage rates and scheduled maintenance days were taken from data given in Appendix E. Natural gas costs were 150 US $¢/10^6$ kcal, the same as the cost of fuel oil on an equivalent heating value basis, see Appendix I. Nuclear fuel cycle costs were taken from data given in Appendix J.

14.5. Computer printout of characteristics of selected alternative generating units

The characteristics of the units listed in Table XIV-1 are summarized in Table XIV-2. This is a computer printout of WASP Module 3.

TABLE XIV-2. PRINTOUT OF EXPANSION ALTERNATIVE GENERATING UNIT DATA[a]

	NAME	NO. OF SETS	MIN. LOAD MW	CAP-CITY MW	BASE LOAD HEAT RATE	AVGE INCR HEAT RATE	FUEL COSTS CENTS/MILLION DMSTC	FORGN	TYPE	LCTN	FRCD OUT-AGE RATE	DAYS SCHL MAIN	MAIN CLAS	ENRGY GWH	O&M (FIX)	O&M (VAR)	FULL LOAD HEAT RATE
1	N300	0	150	300	2645.	2360.	0.0	57.90	0	1	6.50	28	300	0.	0.0	0.0	2503.
2	N400	0	200	400	2643.	2362.	0.0	57.00	0	1	9.80	28	400	0.	0.420	0.0	2502.
3	N600	0	300	600	2638.	2365.	0.0	55.10	0	1	12.00	28	600	0.	0.320	0.0	2501.
4	N800	0	400	800	2632.	2369.	0.0	53.20	0	1	12.20	35	800	0.	0.270	0.0	2500.
5	N1T0	0	500	1000	2627.	2372.	0.0	51.30	0	1	12.20	35	1000	0.	0.230	0.0	2499.
6	G100	0	50	100	2526.	2314.	151.00	0.0	1	1	6.50	21	100	0.	0.610	0.0	2420.
7	G150	0	75	150	2486.	2322.	151.00	0.0	1	1	5.30	21	150	0.	0.450	0.0	2404.
8	G200	0	100	200	2415.	2273.	151.00	0.0	1	1	5.40	21	200	0.	0.360	0.0	2344.
9	G300	0	150	300	2473.	2313.	151.00	0.0	1	1	6.50	28	300	0.	0.280	0.0	2393.
10	G400	0	200	400	2461.	2227.	151.00	0.0	1	1	9.80	28	400	0.	0.240	0.0	2344.
11	G600	0	300	600	2465.	2301.	151.00	0.0	1	1	12.00	28	600	0.	0.190	0.0	2383.
12	G800	0	400	800	2471.	2299.	151.00	0.0	1	1	12.20	35	800	0.	0.170	0.0	2385.
13	G1T0	0	500	1000	2482.	2280.	151.00	0.0	1	1	12.20	35	1000	0.	0.160	0.0	2381.
14	GT50	0	50	50	4000.	4000.	151.00	0.0	2	1	2.00	4	75	0.	0.750	0.0	4000.

[a] For legend see Table XII-2(b).

15. ANALYSIS OF ALTERNATIVE EXPANSION PROGRAMS

15.1. Method of analysis

(a) Description of method used to determine the optimum expansion program

In 1980 the maximum demand of the power system will be approximately 3300 MW, more than one-third of which is supplied by the hydro units at Aswan. These hydro units could supply more, except that the power transmitted over the 500 kV lines to Lower Egypt is restricted to the spinning reserve capacity in Lower Egypt in order to have good system security, this amount being at present 500 MW. As discussed in Section 11.3, the largest unit size acceptable for satisfactory system operation during the study period is 600 MW.

The year-to-year increase in peak demand during the early part of the study period is about 200 MW, increasing to nearly 500 MW in 1989-90. In the early 1980s, possible additions include 200 MW units annually, 300-400 MW units every other year, 600 MW units every third year, or some similar combination.

Since the loss-of-load probability in 1978-80 is very good (even if the large amount of emergency hydro is neglected), the system is not limited by this consideration from accepting 600 MW units. Further, since the operating costs of units in the 200-600 MW range (of the same type) are very similar, the principal concern becomes minimum capital investment. By a comparison of the capital costs of the above alternatives (on a present-worth basis), it was clear that the addition of 600 MW units was substantially less expensive than the alternatives. Thus an alternative expansion plan consisting of 600 MW units was selected for trial.

This trial alternative expansion was evaluated to determine the loss-of-load probability during the study period, both with and without consideration of the emergency hydro, and found to be suitable. It was then adopted as the basic expansion plan for the study. (The loss-of-load probability associated with this expansion plan is discussed in Section 15.2 (c).)

(b) Summary of cases considered

The alternative types to be considered were gas and nuclear plants. The method of approach was to evaluate the total costs (capital and operating costs) on a present-worth basis for the system where the year of introduction of nuclear power was progressively advanced from 1980 to 1990. This method assumed that once nuclear power was economical, it would remain so, providing that all nuclear plants in the system would operate with a high capacity factor. This proved to be the case.

15.2. Derivation of input data required for WASP Module 4-6

(a) Schedules of plant additions during study period

Additions were made to the existing system when, after considering retirements and the changes in the use of the hydro and emergency hydro as described in Section 12, the existing system without the additions could not meet the maximum demand with at least a small reserve margin. The retirements, changes in hydro, the thermal plant additions of the alternative expansion plan and the total installed capacity (excluding emergency hydro) for each year of the study are shown in Table XV-1. As stated above, the addition types during the study period were varied during the analysis.

(b) Expansion configurations from end of study period to the year 2000

An expansion plan consisting of 400, 600, 800 and 1000 MW gas and nuclear plants was selected for the period 1991-2000. This selection was made without regard to the economic merit of various types as, aside from a generally reasonable reserve margin, no consideration was given to system reliability during this period.

TABLE XV-1. SELECTED EXPANSION PLAN (MW)

Year	Retirements	Hydro		Thermal	Total excl. emergency hydro
		Hydro additions	Emergency hydro deletions		
1978					3 429
1979		+ 30	- 30		3 459
1980		+ 40	- 40	600	4 099
1981		+ 40	- 40		4 139
1982		+ 40	- 40		4 179
1983	40	+ 40	- 40	600	4 779
1984		+ 40	- 40		4 819
1985	60	+ 40	- 40	600	5 399
1986	36	+ 40	- 40	600	6 003
1987		+ 50	- 50	600	6 653
1988		+ 40	- 40	2 x 600	7 893
1989	45	+ 50	- 50	600	8 498
1990	30	+ 50	- 50	800	9 318
1991	54	+ 50	- 50	G600	9 914
1992		+ 50	- 50	N600	10 564
1993		+ 50	- 50	G600	11 214
1994	100	+ 50	- 50	N800	11 964
1995	240	+ 60	- 60	G1T0	12 784
1996	28	+ 60	- 60	N800	13 606
1997	180	+ 60	- 60	G1T0	14 486
1998	456	+ 60	- 60	N1T0 G400	15 490
1999	60	+ 60	- 60	G1T0	16 490
2000		+ 60	- 60	N1T0	17 550

Study period

In order to make sure that nuclear plants added in the study period were operated at a high capacity throughout the expanded study period, about half of the additions made in the 1991-2000 years were gas units, which were above the nuclear plants in loading order.

Table XV-1 shows the retirements, changes in hydro and emergency hydro, the alternative expansion plan additions and the total installed capacity (excluding emergency hydro) for the year 1991-2000 as well as the years of the study period.

Figure 15-1 shows the maximum demand in the critical (fourth) quarter of the installed capacity (with and without emergency hydro) for the expected study range.

(c) Minimum and maximum reserve ranges during critical period

The selected alternative expansion plan described above was analysed to determine the system reliability (neglecting the transmission system). The results of the analysis are shown in Table XV-2. In this table the year-by-year reserve margin during the critical

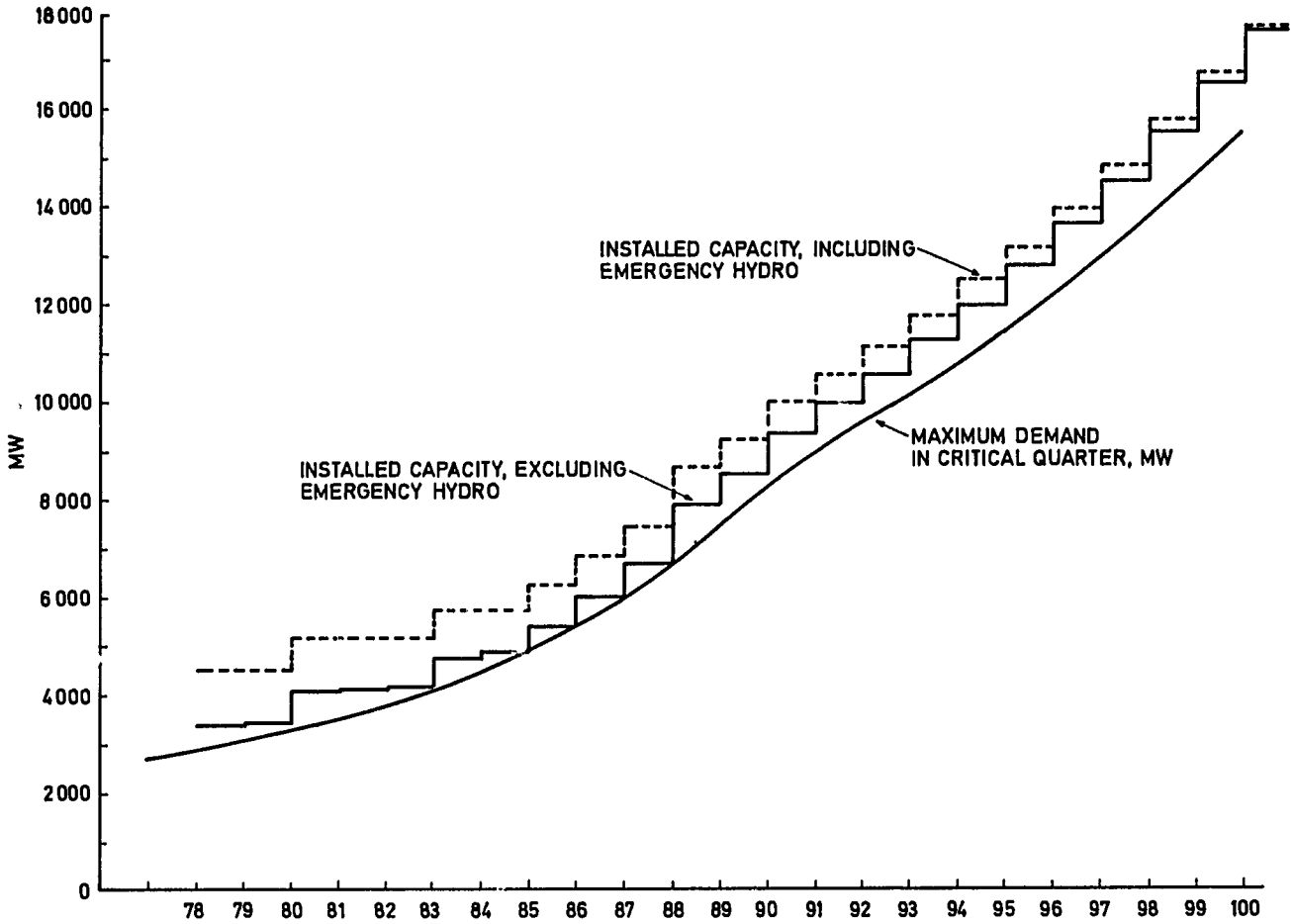

FIG. 15-1. COMPARISON OF INSTALLED CAPACITY AND MAXIMUM DEMAND FOR SELECTED EXPANSION ALTERNATIVE.

quarter is shown, together with the loss-of-load probability with and without credit for emergency hydro. Obviosuly the loss-of-load probability with credit for the emergency hydro is satisfactory, with a maximum value of 0.0088 and an average during the study range of 0.0017. The loss-of-load probability without credit for the emergency hydro is unacceptable for nearly all of the years – showing the importance of the emergency hydro.

However, as seen from Table XV-3 the average amount of emergency hydro used during a quarter ranges from 0 to 26.8 MW. Considering that the maximum is only 1% of the installed capacity of hydro, it seems likely that the emergency hydro could be accommodated within the water flow criteria.

It was decided, based on the above, that the trial alternative expansion program was acceptable.

(d) Loading order

The loading order of the plants in the system was established using the incremental fuel costs of each plant as a guide. The resulting loading order is shown in Table XV-4, using the same code names as used in Sections 12 and 14.

(e) Other input data

The economic parameters used in the analysis (WASP Module 6) are discussed in Appendixes B, D and K.

TABLE XV-2. RELIABILITY OF THE SELECTED EXPANSION PLAN DURING THE CRITICAL QUARTER

Year	Max. demand (MW)	Capacity (MW)	Reserve margin (%)	Loss-of-load probability	
				No credit for emerg. hydro	Credit for emerg. hydro
1978	2 923	3 429	17.3	0.0000	0.0000
1979	3 097	3 459	11.7	0.0064	0.0000
1980	3 282	4 099	24.9	0.0041	0.0000
1981	3 515	4 139	17.8	0.0127	0.0000
1982	3 766	4 179	11.0	0.0331	0.0000
1983	4 091	4 779	16.8	0.0208	0.0000
1984	4 445	4 819	8.4	0.0529	0.0003
1985	4 831	5 399	11.8	0.0417	0.0006
1986	5 392	6 003	11.3	0.0416	0.0018
1987	6 019	6 653	10.6	0.0440	0.0038
1988	6 720	7 893	17.4	0.0190	0.0021
1989	7 505	8 498	13.2	0.0281	0.0049
1990	8 383	9 318	11.1	0.0343	0.0088

TABLE XV-3. AVERAGE EMERGENCY HYDRO QUARTERLY LOADS REQUIRED

Year	1st	2nd	3rd	4th
1978	0.6	0.2	0.0	0.0
1979	2.4	0.9	0.0	0.0
1980	2.2	0.1	0.1	0.0
1981	7.3	0.9	0.3	0.2
1982	18.5	4.4	1.3	1.2
1983	10.9	3.3	1.1	1.1
1984	24.4	13.0	4.2	5.1
1985	26.7	16.7	3.4	3.3
1986	22.4	17.3	4.7	4.5
1987	26.8	19.3	6.0	6.1
1988	10.6	8.4	3.1	2.4
1989	15.7	13.2	6.1	4.9
1990	19.2	16.4	8.8	7.6
1991	18.1	15.7	10.0	7.4
1992	15.9	13.7	11.5	6.4
1993	22.1	13.4	7.4	6.9
1994	17.5	14.2	7.6	6.9
1995	15.6	14.0	8.1	7.1
1996	15.3	12.0	7.1	6.9
1997	12.7	11.2	6.6	6.3
1998	10.3	9.1	5.2	5.7
1999	7.4	7.0	3.2	4.7
2000	5.1	5.1	2.6	2.9

TABLE XV-4. LOADING ORDER

Loading order	Plant and mode of operation	Loading order	Plant and mode of operation	Loading order	Plant and mode of operation
1	Hyde	23	DAH1 – Base load	45	CAS1 – Peak load
2	N1T0 – Base load	24	DAH2 – Base load	46	SIO1 – Peak load
3	N800 – Base load	25	KAFD – Base load	47	SIO2 – Peak load
4	N600 – Base load	26	G1T0 – Peak load	48	TAL1 – Base load
5	N400 – Base load	27	G800 – Peak load	49	TAL2 – Base load
6	N300 – Base load	28	G600 – Peak load	50	SUZ1 – Base load
7	N1T0 – Peak load	29	G400 – Peak load	51	CAN2 – Base load
8	N800 – Peak load	30	G300 – Peak load	52	CAN3 – Base load
9	N600 – Peak load	31	G200 – Peak load	53	CAN1 – Base load
10	N400 – Peak load	32	G150 – Peak load	54	TEB1 – Base load
11	N300 – Peak load	33	G100 – Peak load	55	TAL1 – Peak load
12	G1T0 – Base load	34	ABUA – Peak load	56	CAN3 – Peak load
13	G800 – Base load	35	CAS2 – Peak load	57	AST1 – Peak load
14	G600 – Base load	36	KAFD – Peak load	58	SUZ1 – Peak load
15	G400 – Base load	37	CAW1 – Peak load	59	TAL2 – Peak load
16	G300 – Base load	38	DAH1 – Peak load	60	TEB1 – Peak load
17	G200 – Base load	39	DAH1 – Peak load	61	CAN1 – Peak load
18	G150 – Base load	40	DAH2 – Peak load	62	CAN2 – Peak load
19	G100 – Base load	41	CAS1 – Base load	63	GT50 – Base & Peak
20	ABUA – Base load	42	SIO1 – Base load	64	MAX1 – Base load
21	CAS2 – Base load	43	SIO2 – Base load	65	MAX1 – Peak load
22	CAW1 – Base load	44	AST1 – Base load	66	EHYD

16. RESULTS

Having selected an alternative expansion plan, as discussed in Section 15.2, a series of computer runs were made to determine the optimum year of introduction of nuclear power for the reference conditions and for variations of selected reference condition parameters. The optimum year of introduction of nuclear power was the year giving the minimum objective function value.

16.1. Variation of objective function for reference conditions and selected alternative configuration

Values of the objective function for each of the cases run at reference conditions (i.e. 8% discount rate, 0% escalation rate on capital and nuclear fuel, 2% escalation rate on gas, ORCOST-3 capital costs) are shown in Table XVI-1 and these data are plotted in Fig. 16-1. It is seen that the optimum year of introduction of nuclear power is 1983 for the reference case (underlined value of objective function).

16.2. Market for nuclear plants during study period

(a) Size of plants

As discussed in Section 15-1, the additions during the study period consisted of a series of 600 MW plants, either gas-fired or nuclear, depending on the study.

(b) Dates of introduction

The optimum date of introduction of nuclear plants as described above is 1983. Referring to the program of plant additions shown in Table XV-1 one notes that there is only one addition prior to 1983, a 600 MW unit in 1980, and that during the 1983-89 period there are seven 600 MW additions. It follows that with 1983 being the optimum year of introduction of nuclear power, the optimum expansion would have 1 × 600 MW of gas and 7 × 600 MW of nuclear power plants during the study period. The system data for this expansion plan are shown in Table XVI-2.

16.3. Sensitivity analysis

(a) Influence of discount rate

The optimum year of introduction of nuclear power was markedly influenced by changes in the discount rate. Sensitivity runs were made at 6%, 10% and 16% discount rate to show this effect. The resulting objective functions are shown in Table XVI-1, and plotted in Fig. 16-2. As seen, for 6% the optimum year of introduction of nuclear plants (value underlined) is 1980 or earlier, for 10% it is 1985, and for 16% it is beyond the study period.

(b) Influence of capital costs

The use of capital cost data generated by ORCOST-1 (see Appendix B), which have lower nuclear-fossil differential costs, has essentially the same influence on the competition between nuclear and gas plants as the use of a 6% discount rate. Under such conditions the optimum year of introduction of nuclear power is 1980 or earlier, as shown in Fig. 16-2, so that the nuclear market would be increased to 8 × 600 MW.

TABLE XVI-1. COMPARISON OF OBJECTIVE FUNCTION FOR VARIOUS PARAMETER VALUES

Case No.	Year of introduction of nuclear power	Reference case	Discount rate			ORCOST-1	Gas price escalation rate		Nuclear fuel price escalation rate
			6%	10%	16%		0%	4%	2%
1	1980	1 489.02	1 901.53		601.[illegible]8	1 396.02	1 418.60	1 581.46	1 604.66
	1981[a]								
	1982[a]								
2	1983	1 487.72	1 916.04	1 162.73	582.05	1 411.04	1 392.74	1 612.50	1 589.80
	1984[a]								
3	1985	1 493.77	1 937.53	1 160.14	571.88	1 429.46	1 375.20	1 650.53	1 583.11
4	1986	1 503.69		1 161.60	565.83	1 449.57			1 581.10
5	1987			1 164.54	561.29	1 470.01	1 352.12		1 580.86
6	1988			1 171.08	554.83	1 507.09	1 334.14		1 581.50
7	1989			1 174.11	551.87	1 524.53	1 325.34		
8	1990				549.47	1 540.26	1 317.26	1 880.95	
9	1992				548.44	1 562.41	1 312.32	1 925.54	

[a] No plants installed.

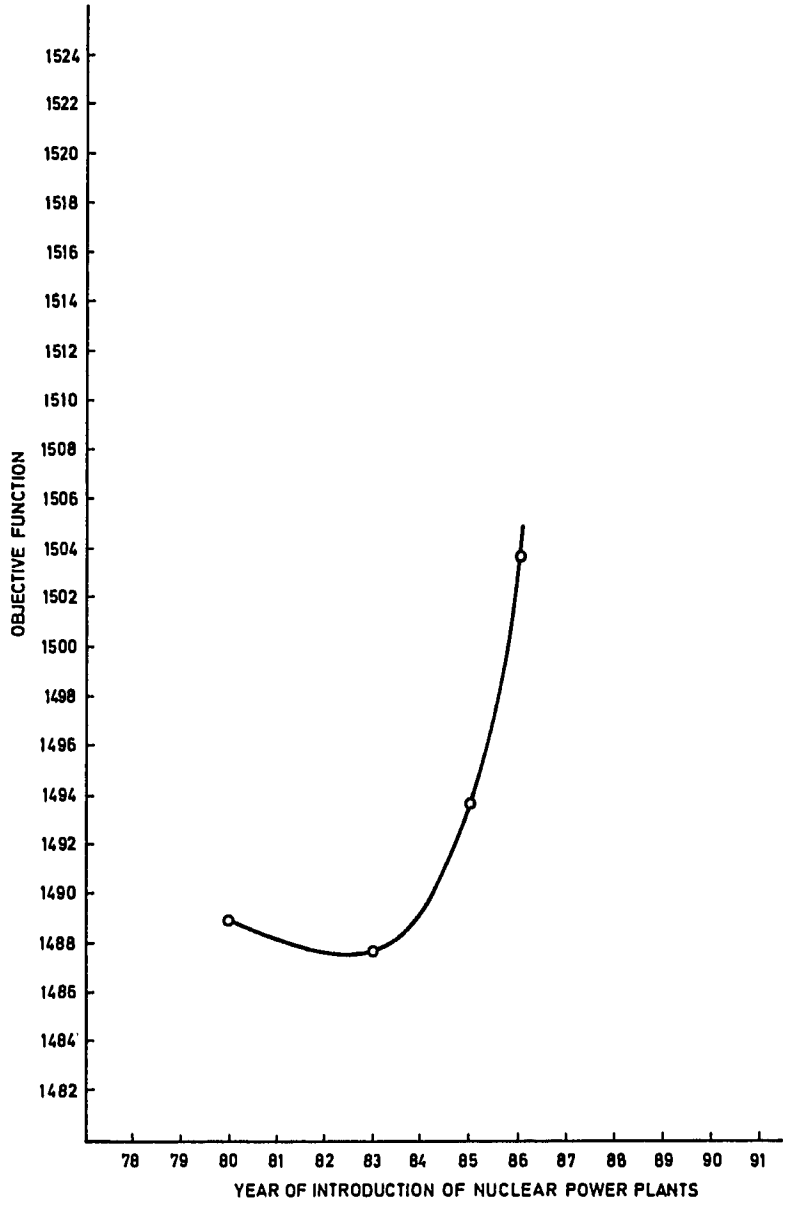

FIG. 16-1. OBJECTIVE FUNCTION – REFERENCE CONDITIONS.

(c) Influence of fuel escalation rates

In the reference case, nuclear fuel was assumed to escalate at an annual rate of 0% relative to the general inflation rate while the net escalation rate of gas was taken to be 2%/yr. To evaluate the effect of these assumed escalation rates, separate runs were made using a 2% relative escalation rate on nuclear fuel and 0% and 4% relative escalation rate on gas; in each case all other parameters were kept the same as in the reference case. Table XVI-1 and Figs 16-2 and 16-3 show the effect on the date of introduction of nuclear power of varying these fuel escalation rates.

16.4. Financial considerations associated with the reference case expansion program

Capital costs of alternative generating units considered in the expansion plans were calculated by the ORCOST program described in Section 13 and in Appendix B. These capital costs were used by the WASP program in determining the objective functions of each expansion alternative.

TABLE XVI-2. SYSTEM CAPACITY EXPANSION SCHEDULE

Reference case: 8% discount rate
ORCOST-3
2% escalation of gas

Year	Installed capacity (MW)							% Reserve [d]	Annual loss-of-load probability [e]
	Retirements	Nuclear	Conventional steam	Hydro [a]	Emergency hydro [b]	Gas turbines	Total [c]		
Total system 1972	-	-	1301 [f]	600	1845	28	1929		0.00001
Additions 1973-1979	-	-	820 [g]	+710	-710	-			0.00001
Total system Jan. 1979	-	-	2121	1310	1135	28	3459		0.00001
Additions 1980	-	-	600 (gas)	+40	-40	-	4099	24.9	0.00005
1981	-	-	-	+40	-40	-	4139	17.8	0.00005
1982	-	-	-	+40	-40	-	4179	11.0	0.00005
1983	40 [h]	600	-	+40	-40	-	4779	16.8	0.00005
1984	-	-	-	+40	-40	-	4819	8.4	0.0003
1985	60 [i]	600	-	+40	-40	-	5399	11.8	0.0006
1986	36 [j]	600	-	+40	-40	-	6003	11.3	0.0018
1987	-	600	-	+50	-50	-	6653	10.6	0.0038
1988	-	1200	-	+40	-40	-	7893	17.4	0.0021
1989	45 [k]	600	-	+50	-50	-	8498	13.2	0.0049
Total additions 1980-1989	181	4200	600 (gas)	+420	-420	-	5039	-	-
Total system 1989	181	4200	2540	1730	715	28	3498	13.[illegible]	
Additions 1990-2000	1036	5000	4600	+600	-600	-28	8536		
Total system 2000	1217	9200	7140	2330	115	-	17550	14	

[a] Aswan and High Dam.
[b] Aswan High Dam.
[c] Excluding emergency hydro.
[d] Critical quarter (4th).
[e] During critical quarter.
[f] Plants 1-15 fixed system list.
[g] Plants 16, 17, 18, of fixed system list.
[h] Cairo North 2 x 10, 1 x 20.
[i] Cairo North 2 x 30.
[j] Talkha 3 x 12.
[k] Tebbin 3 x 15.

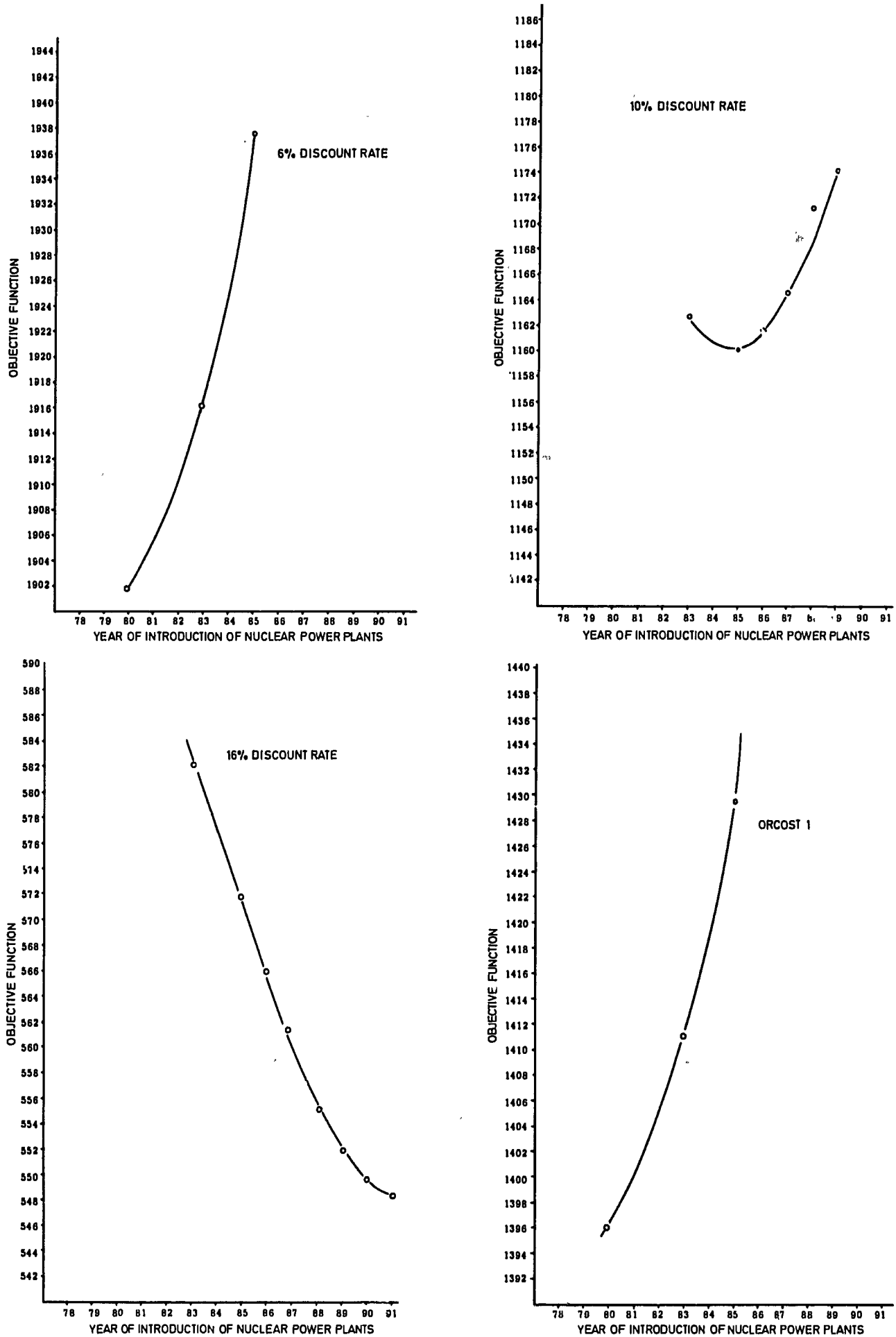

FIG. 16-2. OBJECTIVE FUNCTION – SENSITIVITY CASES.

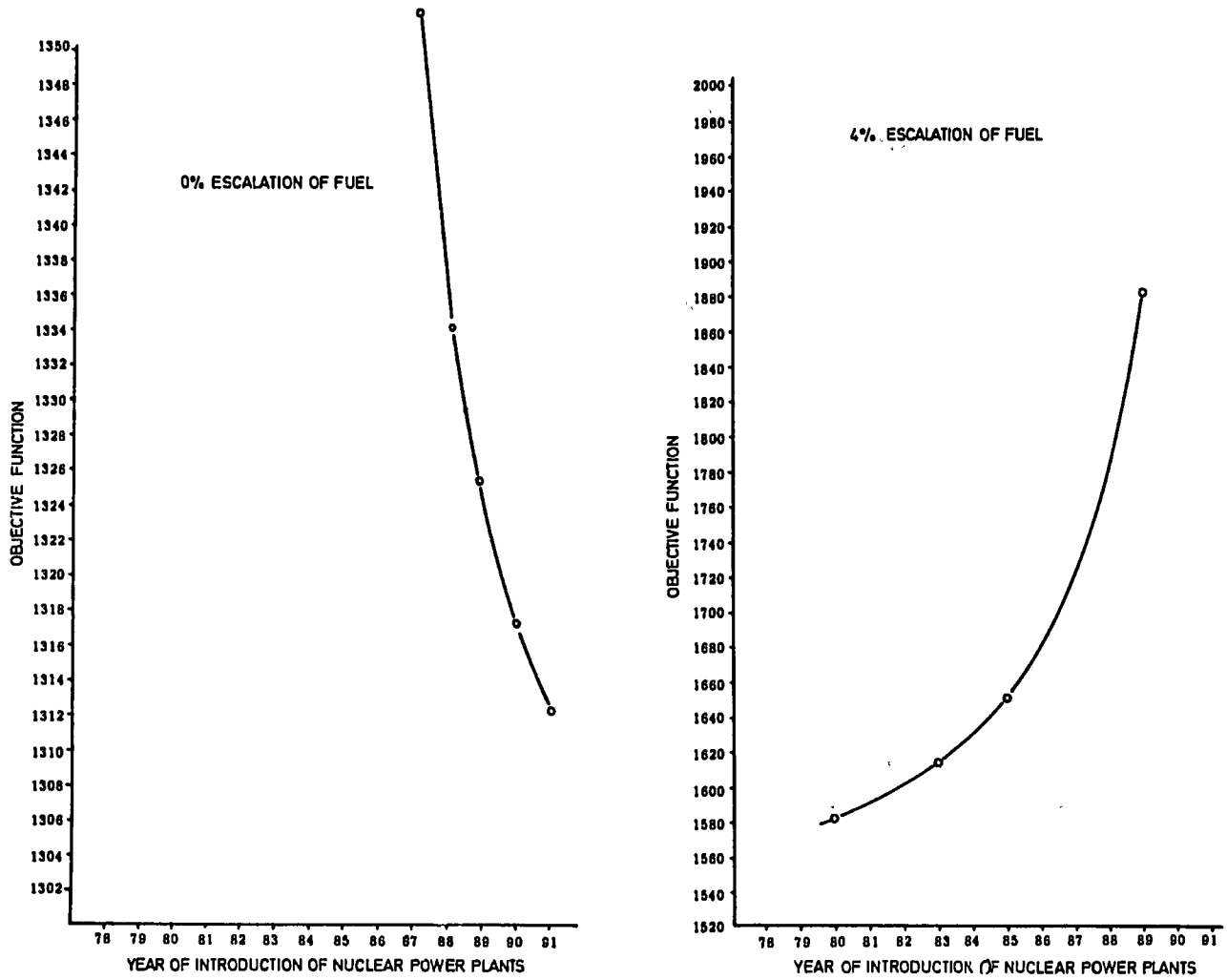

FIG. 16-2. (cont.)

As a supplement to the basic analyses described above, it was decided to determine the year-by-year domestic and foreign cash requirements of the reference case expansion plan, as a guide to planners and financial institutions. In order to accomplish this, a computer program was written (cash-flow program).

The input data required for the cash-flow program for each year of the study period and for each plant that becomes operational during that year are as follows. Plants were assumed to become operational on 1 January and capital costs were assumed to have been fully expended by the end of the preceding year. These assumptions are consistent with the WASP program.

(a) Plant construction schedule (the same schedule, in years, that was used in the ORCOST calculations). The ORCOST-3 total plant capital costs (including interest during construction) are distributed over the construction period according to the expenditure-time schedules assumed in ORCOST.
(b) Per cent of expenditure that was domestic (the foreign being 100 minus this value).
(c) Capital cost, in US $/kW (same value as used in the WASP program; this value includes interest during construction).
(d) Unit capacity, in MW.

The cash-flow program, using a 4th order polynomial approximation of the S-curve used in the ORCOST program, developed the year-by-year domestic and foreign expenditures associated with each plant. These values were printed in tabular form, together with the annual totals.

It should be noted that nuclear plants were entered in two parts – (a) the cash requirements of the plant excluding the first (fuel) core, and (b) the cash requirements of the first

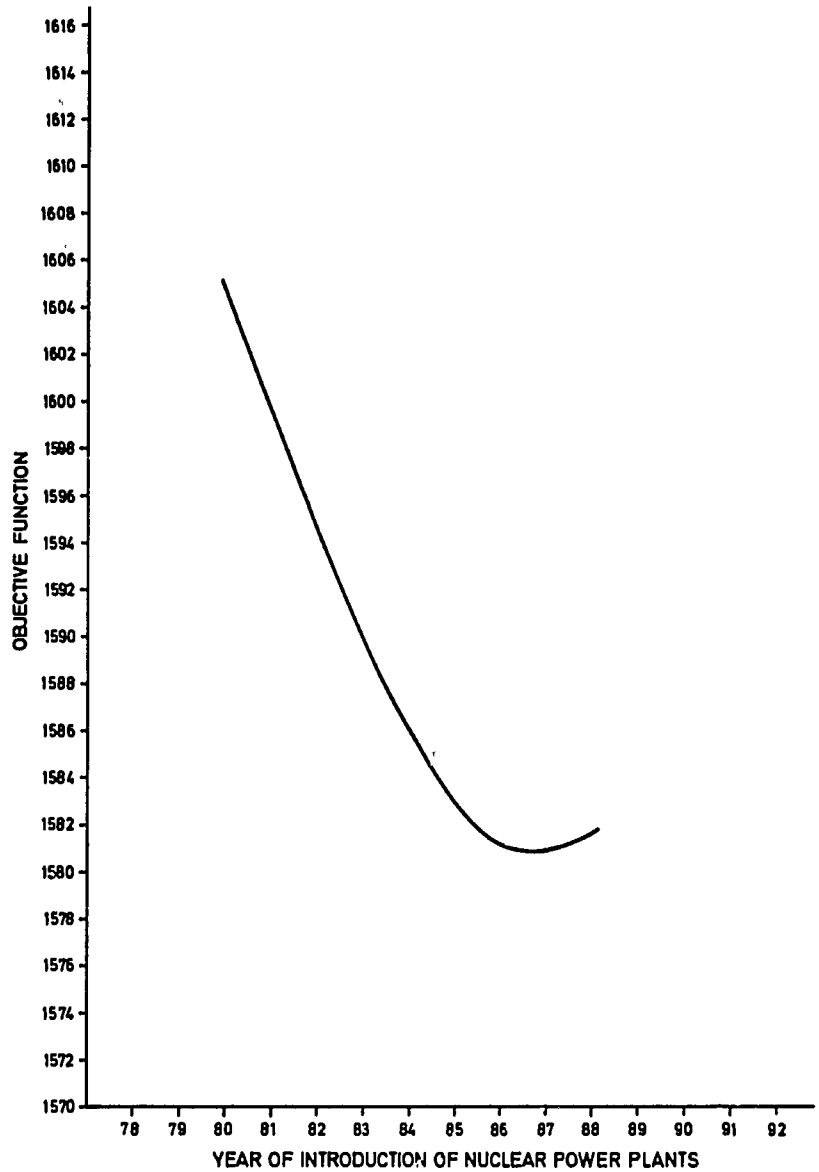

FIG. 16-3. OBJECTIVE FUNCTION - 2% NUCLEAR FUEL ESCALATION RATE.

core. These first core requirements were calculated on the basis of 90% cash required during the year preceding operation, and 10% being required one year earlier.

Tables XVI-3(a) and (b) display the domestic and foreign cash flows associated with capital investments for the near-optimum solution, based on reference conditions, i.e. that of Table XVI-2. The cash-flows are given for each plant and for the total program. Only plants commissioned during the 1980s are included, so the cash flows begin in 1976 and peak in 1985 though in fact they will continue to increase after then because of expenditures on plants to be commissioned during the 1990s.

For the nuclear plants the fuel cycle working capital requirements are also shown. Although individual fuel purchases are normally financed over short terms, e.g. three to five years, there is in fact a substantial investment outstanding in fuel over the life of the plant. Also, the fuel capital investments used in the WASP economic evaluation are the present-worth levelized average investment over plant life, thus they may be used as an approximation to the cost of the first core and in Table XVI-3(b) they have been distributed over the two years preceding commissioning more or less according to the payment schedule for the first core (Appendix J). The total requirements are about US $1628 million, about US $1251 million in foreign currency. (These are 1973 costs with no allowance for escalation.) The nuclear fuel costs are shown separately by years and in total, at the lower part of Table XVI-3(b). The total is about US $118 million, all of which requires foreign exchange.

TABLE XVI-3(a). DOMESTIC CASH FLOW FOR THERMAL UNITS COMMISSIONED IN 1980-1989

YEAR	PLANT	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	TOTAL
1980	G600	.0	.0	.2	4.4	11.4	6.6	.0	.0	.0	.0	.0	.0	.0	.0	.0	22.7
1981	No Plants Added																
1982	No Plants Added																
1983	N600	.0	.0	.0	.3	2.5	9.4	16.0	16.6	5.7	.0	.0	.0	.0	.0	.0	50.7
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
1984	No Plants Added																
1985	N600	.0	.0	.0	.0	.0	.3	2.5	9.4	16.0	16.6	5.7	.0	.0	.0	.0	50.7
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
1986	N600	.0	.0	.0	.0	.0	.0	.3	2.5	9.4	16.0	16.6	5.7	.0	.0	.0	50.7
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
1987	N600	.0	.0	.0	.0	.0	.0	.0	.3	2.5	9.4	16.0	16.6	5.7	.0	.0	50.7
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
1988	2xN600	.0	.0	.0	.0	.0	.0	.0	.0	.6	5.0	18.8	32.1	33.2	11.4	.0	101.4
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
1989	N600	.0	.0	.0	.0	.0	.0	.0	.0	.0	.3	2.5	9.4	16.0	16.6	5.7	50.7
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Domestic total		.0	.0	.2	4.7	14.0	16.3	18.9	28.9	34.3	47.5	59.8	63.8	55.0	28.0	5.7	377.6

TABLE XVI-3(b). FOREIGN CASH FLOW FOR THERMAL UNITS COMMISSIONED IN 1980-1989

YEAR	PLANT	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	TOTAL
1980	G600	.0	.0	.7	1[illegible]	34.3	19.8	.0	.0	.0	.0	.0	.0	.0	.0	.0	68.3
1981	No Plants Added																
1982	No Plants Added																
1983	N600	.0	.0	.0	.9	7.6	28.3	48.1	49.8	17.2	.0	.0	.0	.0	.0	.0	152.1
	Fuel	.0	.0	.0	.0	.0	.0	.0	1.7	15.0	.0	.0	.0	.0	.0	.0	16.8
1984	No Plants Added																
1985	N600	.0	.0	.0	.0	.0	.9	7.6	28.3	48.1	49.8	17.2	.0	.0	.0	.0	152.1
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	1.7	15.0	.0	.0	.0	.0	16.8
1986	N600	.0	.0	.0	.0	.0	.0	.9	7.6	28.3	48.1	49.8	17.2	.0	.0	.0	152.1
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	1.7	15.0	.0	.0	.0	16.8
1987	N600	.0	.0	.0	.0	.0	.0	.0	.9	7.6	28.3	48.1	49.8	17.2	.0	.0	152.1
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	1.7	15.0	.0	.0	16.8
1988	2xN600	.0	.0	.0	.0	.0	.0	.0	.0	1.8	15.2	56.6	96.3	99.6	34.4	.0	304.2
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	3.4	30.1	.0	33.6
1989	N600	.0	.0	.0	.0	.0	.0	.0	.0	.0	.9	7.6	28.3	48.1	49.8	17.2	152.1
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	1.7	15.0	16.8
Foreign total		.0	.0	.7	14.3	42.0	49.1	56.7	88.4	118.2	144.2	196.2	208.4	183.5	116.1	32.3	1250.6
Total - nuclear fuel only		.0	.0	.0	.0	.0	.0	.0	1.7	15.0	1.7	16.7	16.7	18.4	[illegible].8	15.0	117.0

17. SUMMARY AND CONCLUSIONS

17.1. Basic conditions

Table XVII-1 summarizes the conditions assumed in the analysis of various alternative expansion plans in Egypt during the period 1980-1989. In carrying out the analysis it was assumed that no hydro additions would be made during the study period. Additions now planned or under construction will result in a system capacity in 1979 of 3459 MW (excluding emergency hydro). The alternative expansion plan selected requires a 600 MW unit be added in 1980. (The AEE and GEC are considering 2 × 400 MW nuclear units for that year.)

The selected expansion plan conditions were held constant for all study runs except for the year of introduction of nuclear power, which varied with the run. (Of course during sensitivity studies, one condition at a time was varied to determine the effect on the year of introduction of nuclear power.)

TABLE XVII-1. SUMMARY OF CONDITIONS ASSUMED IN THE ANALYSIS

	1979	1989
Population (10^6)	39.83	48.56
GNP/capita (US $/yr)	205.8	304.9
Energy consumption utility (GWh/yr)	19 500	42 730
Peak demand (MW)	3 097	7 505
Total installed capacity (MW)[a]	3 459	8 498
Installed capacity, critical period (MW)[a,b]	3 459	8 498
Thermal capacity (MW)	2 149	6 768
Reserve margins (%)[b]	11.7	13.2
Annual loss-of-load probability[c]	0.00005	0.0076

[a] Excluding emergency hydro.
[b] In fourth quarter of year.
[c] Including emergency hydro.

17.2. Economic basis

The economic merit of the various alternatives was determined from an objective function representing the present worth of all costs associated with the construction and operation of the generating units being considered. External or social costs were disregarded, as were taxes and restraints on foreign capital. Although the study period was extended to a horizon ending in the year 2000, the capacity additions during the 1990-2000 period were held constant and assumed to contribute a constant amount to the objective function. Thus, changes in the objective function are essentially caused by changes in the types of units added during the study period.

The economic data used as a basis for present-worth calculations are summarized in Table XVII-2. The capital costs were derived for construction conditions in Egypt as described in Section 13. The heat rates given are based on data in Appendix G and the unit fuel costs are as given in Table XIV-2.

17.3. Summary of cases considered

In developing the near-optimum expansion plan, consideration was given to: (a) the reserve margin required to maintain a reasonable loss-of-load probability[3], (b) the unit size

[3] Reasonable loss-of-load probability was considered to be a 10-year average of 0.005 or less for the study period, and a maximum annual value of 0.01.

TABLE XVII-2. ECONOMIC DATA ASSUMED IN THE ANALYSIS[a]

Plant type (MW)	Capital cost (US $/kWh)	Full load heat rates (kcal/kWh)	Fuel cost (US ¢/10^6 kcal)	Operating and maintenance cost (US $/kW-month)
Gas-fired				
100	254	2420	151.0	0.610
150	225	2404	151.0	0.450
200	207	2344	151.0	0.360
300	185	2393	151.0	0.280
400	171	2344	151.0	0.240
600	152	2383	151.0	0.190
800	139	2385	151.0	0.170
1000	129	2381	151.0	0.160
Nuclear				
300	492	2503	57.90	0.520
400	434	2502	57.00	0.420
600	366	2501	55.10	0.320
800	325	2500	53.20	0.270
1000	301	2499	51.30	0.230
Gas turbine				
50	125	4000	151.0	0.750

[a] In constant 1 January 1973 US dollars.

permitted, consistent with system stability (600 MW during the study period), (c) the maximum demand and the annual growth of maximum demand, and (d) the relative costs of various size units. The resulting alternative system expansion plan consisted of the addition of a series of 600 MW units on the schedule shown in Table XVII-3.

17.4. Summary of sensitivity studies

Seven sensitivity studies were made, in each case holding all reference case conditions constant except the condition under study. The year of introduction of nuclear plants and the number required during the study period for each of the seven sensitivity studies is shown in Table XVII-4.

17.5. Potential 1980-1989 nuclear power market

The most likely market for nuclear plants in Egypt under varying economic conditions is also shown in Table XVII-4. It is seen that the nuclear market varies from 0 to 4800 MW.

Numerous sensitivity studies were carried out varying fuel escalation rates and capital costs. It was found that the schedule of nuclear plant additions shown in Table XVII-4 (Schedules A to E) covered all of the variations in economic parameters.

TABLE XVII-3. UNIT ADDITIONS IN SELECTED EXPANSION PLAN

Year	Addition
1980	600 MW
1981	
1982	
1983	600 MW
1984	
1985	600 MW
1986	600 MW
1987	600 MW
1988	2 x 600 MW
1989	600 MW

TABLE XVII-4. POTENTIAL MARKET FOR NUCLEAR POWER PLANTS IN EGYPT (plants commissioned 1980 - 1989) (MW)

Year	Reference case 8%/yr discount rate	Sensitivity cases			
		6% discount rate ORCOST-1 4%/yr fuel (gas) escalation rate	10% discount rate	16% discount rate 0%/yr fuel (gas) escalation rate	2% nuclear fuel escalation rate
Schedule	A	B	C	D	E
1980		600			
1981					
1982					
1983	600	600			
1984					
1985	600	600	600		
1986	600	600	600		
1987	600	600	600		600
1988	2 x 600	2 x 600	2 x 600		2 x 600
1989	600	600	600		600
Total	7 x 600 = 4200	8 x 600 = 4800	6 x 600 = 3600	0	4 x 600 = 2400

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APPENDIXES

A. WIEN AUTOMATIC SYSTEM PLANNING PACKAGE (WASP)

B. GENERATING PLANT CAPITAL COSTS (ORCOST)

C. LOAD DESCRIPTION DATA FOR WASP PROGRAM

D. ECONOMIC METHODOLOGY AND PARAMETERS

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APPENDIX A

WIEN AUTOMATIC SYSTEM PLANNING PACKAGE (WASP)

R. Taber Jenkins*

INTRODUCTION

The WASP package is a series of six computer codes which include capabilities especially developed for the needs of the IAEA Market Survey. At the same time, it is a second generation of an earlier power system planning program developed by and for the Tennessee Valley Authority in the United States of America. The package is designed to find the "optimum" power system expansion plan within established constraints. By optimum is meant that the discounted cash flow (capital and operating expense) is minimized over the study period with provision made to reduce effects of uncertainties beyond that period.

Until recent years the choice of generating equipment available to an electric utility was fairly limited. In many cases only one fuel could be considered and it was only necessary to determine the appropriate unit size. The major questions to be resolved were, firstly, the extent to which it was sensible to increase the unit size in order to benefit from the economy of scale at the expense of early investment and of possible system operating problems and, secondly, how much should be spent to reduce heat rates. The traditional method of solution was for the system planner to assume two or three possible expansion plans and to determine their present-worth values either by hand calculations, or, more recently, with computer assistance, but with the planner intervening at various stages of the calculation. Such solutions required many hours of engineer's time in spite of the fact that the range of cases studied was extremely limited.

The choice of generating equipment is now much wider and includes nuclear units, gas turbines, combined cycle, quick start intermediate fossil fuel units and pumped storage stations. Dynamic programming, in its most general sense, is an ideal method for solving the system planning problem. However, even with a limited range of possible expansion plans this method of solution was impractical without the aid of a computer. With the additional range of units now available the number of possible expansion plans is so large that even with the aid of computers general linear programming is impractical.

The WASP package attempts to tread the ground between the two extremes. The system planner is given the facility to direct the area of study to configurations which he believes most economic, but the program will tell him if his restrictions were a constraint on the solution. The WASP program then permits him to modify his constraints and, without repeating all the previous computational effort, to determine the effect of the modification. This process can be repeated until an optimum path conforming with the user-imposed constraints is determined.

The WASP package consists of six modular programs which may be operated sequentially in a single run, or may be operated individually. The six modules are:

(1) a program to describe the forecast peak loads and load duration curves for the system;
(2) a program to describe the existing power system and all future additions which are firmly scheduled;
(3) a program to describe the alternative plants which could be used to expand the power system;
(4) a program to generate alternative expansion configurations;
(5) a program to determine if a particular configuration has been simulated and, if not, to simulate operation with that configuration; and
(6) a program to determine the optimum schedule for adding new units to the system over the time period of interest.

* Tennessee Valley Authority, United States of America.

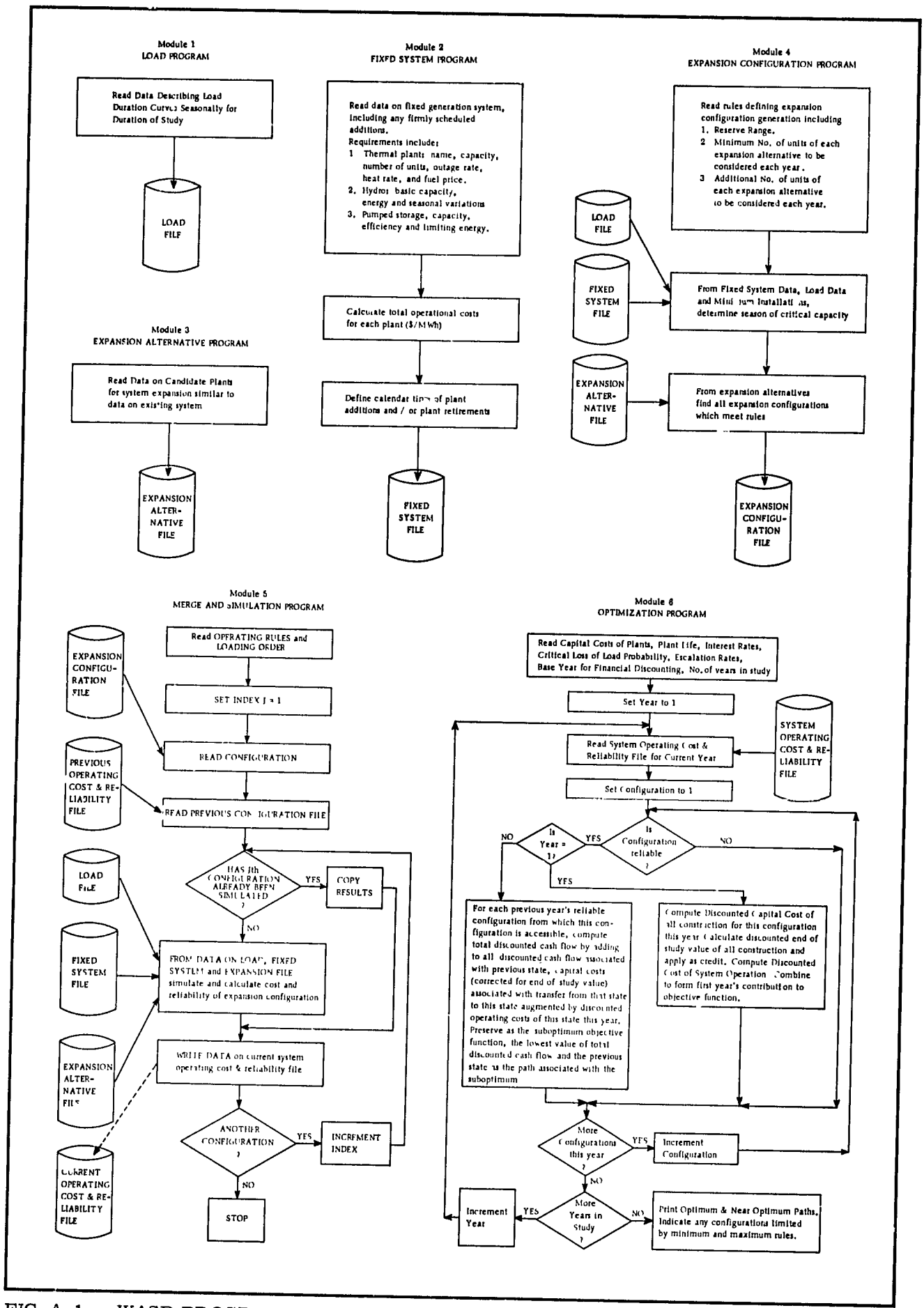

FIG. A-1. WASP PROGRAM FLOW SHEET.

Each of the first three programs creates data files which are used in the remaining programs. Additional files are created by the fourth and fifth program and are used in the sixth. Each program produces a printed summary. Figure A-1 shows a flow chart of this program.

An immediate advantage of the modular program approach is that the first three programs (loads, existing system, expansion alternatives) can be run separately and in parallel to eliminate the bulk of the data errors. These programs are very fast to run, thus avoiding extensive long runs with incorrect data. The separation of the expansion configuration generator from the simulation produces further savings in computer time by permitting elimination of a large number of expansion configurations from being simulated when data errors are made in defining configurations to be considered. The ability to save simulation results on a data file is the major time-saving feature of the program. While searching through successive re-runs of the last three programs for the unconstrained optimum, only those simulations which have not been performed are executed. Since simulation is the most time-consuming part of examining an expansion configuration, the computation time saved can be very large.

The program permits consideration of up to 20 alternative generating units (size, fuel, heat rate etc.). In addition to thermal units, hydro and pumped-storage units can be included in the list of alternatives. If a series of hydro or pumped-storage projects are to be considered by the program, projects of each type must be identified in the chronological order in which they would be installed in the system. Up to 20 such projects may be included in the list. When hydro or pumped-storage units are added to the system, they are merged with existing hydro or pumped-storage units. Therefore, all of the hydro projects count as only one alternative and all of the pumped-storage projects count as an additional alternative.

The expansion configurations to be chosen for simulation in any year are controlled by three factors:

(i) The configuration must satisfy the specified minimum and maximum reserve margin.
(ii) The choices must lie within minimum and maximum constraints (tunnels) specified by the user.
(iii) They must be accessible from at least one of the previous years' alternatives.

The logic of modules 5 and 6 is broken into three general areas: firstly, the simulation of the power system operation which makes use of a probabilistic simulation method which has generated much interest in recent years; secondly, the handling of financial cash flows and their effects on the function to be minimized; thirdly, the actual optimization procedure utilizing a dynamic programming algorithm. These three aspects and their handling in the program are described briefly below. More complete information is available from the references and textbooks.

Simulation

The purpose of the simulation is to provide an estimate of production costs associated with a given system configuration. This is the most time-consuming part of the program.

The program permits the years to be broken into as many as 12 periods each of which may have its own peak load, load shape, hydro operating characteristics and maintenance schedule. The running time of the simulation is directly proportional to the number of periods chosen. Consequently, for the purposes of the Survey, the year was divided into four periods or seasons. On the basis of seasonal peak loads and seasonal capacity variations caused by hydro conditions, a heuristic method is used to develop a "reasonable" distribution of maintenance among the seasons. By 'reasonable' is meant that maintenance on the largest units will be in that season which has the greatest difference between installed capacity and peak load, while maintenance on smaller units is distributed in those seasons having less excess capacity. Having decided in which season maintenance on a particular unit will occur, the actual maintenance within the season is randomly distributed.

The heart of the simulation is the algorithm which distributes the energy among the units on the system. It is an extension of the old load duration curve method which rigorously accounts for random outages of thermal units and has the effect of causing units higher on the loading order to supply more energy at a higher unit price than would otherwise be

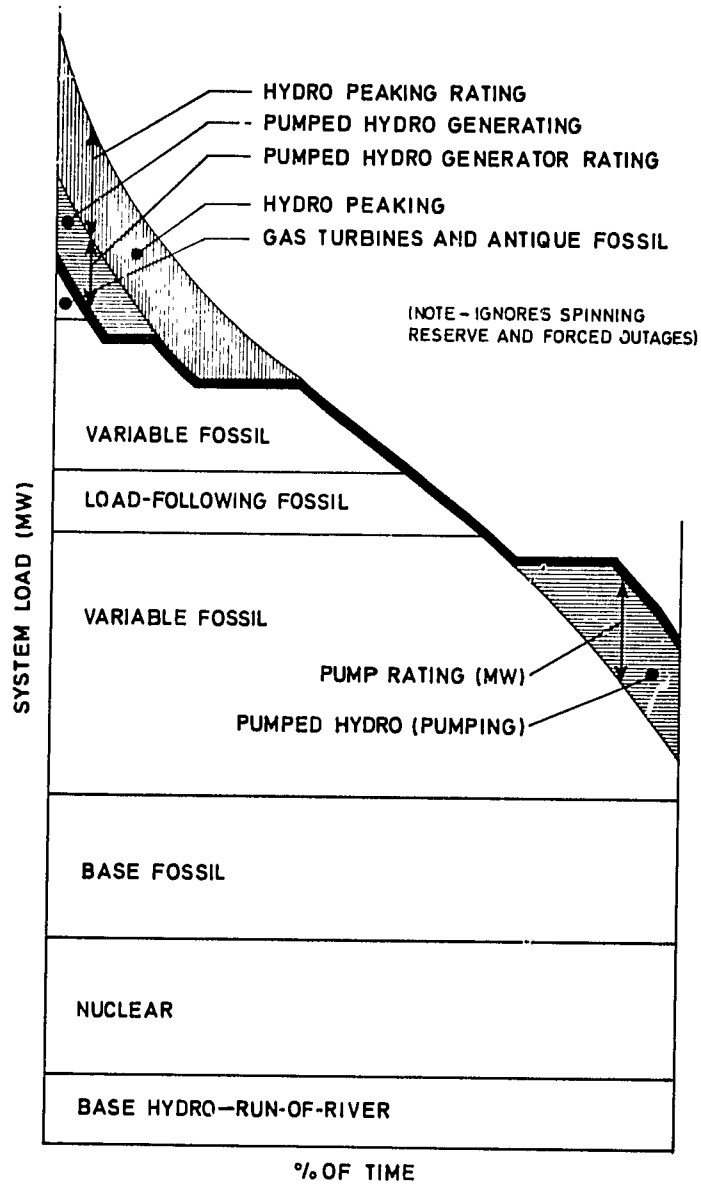

FIG. A-2. IDEALIZED PLACING OF VARIOUS TYPES OF STATION UNDER THE LOAD DURATION CURVE.

experienced. Figure A-2 illustrates the idealized placement of various capacity types under a typical load duration curve. The above procedure is illustrated by the simple diagrams shown in Fig. A-3.

Figure A-3(a) shows a load duration curve with ten thermal units "stacked" under the load curve. As long as all units are running, units 1-4 run 100% of the time; units 5-9 run part of the time; and unit 10 does not run at all. However, if a unit fails, for example unit 1, unit 2 assumes the position of unit 1; 3 the position of 2; and so on. The same effect can be achieved by raising the load curve by the capacity of unit 1, as shown in Fig. A-3(b), in which case units 5 to 9 inclusive have their energy requirements increased and unit 10, which formerly did not generate at all, is carrying significant load. If it is assumed that outages of unit 1 are random, and occur x% of the time, then (100 - x)% of the time the system operates like Fig. A-3(a) and x% of the time like Fig. A-3(b). Therefore, a resultant "expected" load curve (called the equivalent load) which is shown as the solid line in Fig. A-3(c) can be computed. An algorithm computes the resultant equivalent load curve recursively as one considers all of the units in the merit order of their loading. Figure A-4 shows the resultant equivalent load curve after all the plants have been considered. If the total system generating capacity is plotted on the ordinate, the corresponding value on the abscissa, p^*, represents the per cent of time the equivalent load exceeds the system generating capacity. In other words, the value p^* represents the per cent of time that the system cannot meet the expected load. The probability of not meeting the load is simply p^* 100.

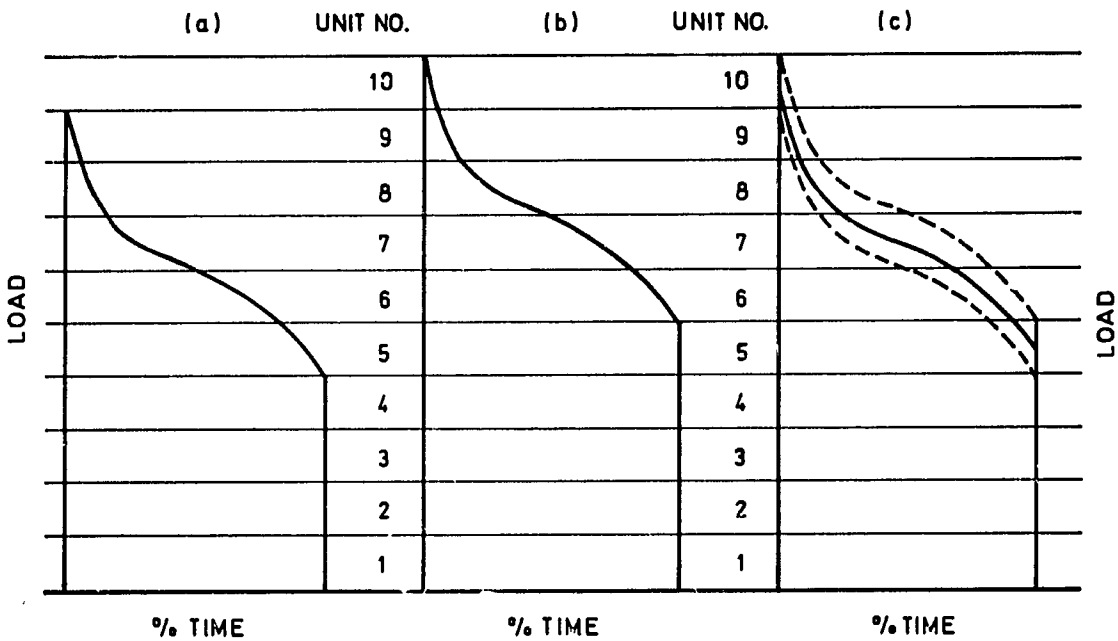

FIG. A-3. ILLUSTRATION OF THE METHOD OF STACKING THERMAL UNITS UNDER THE LOAD CURVE

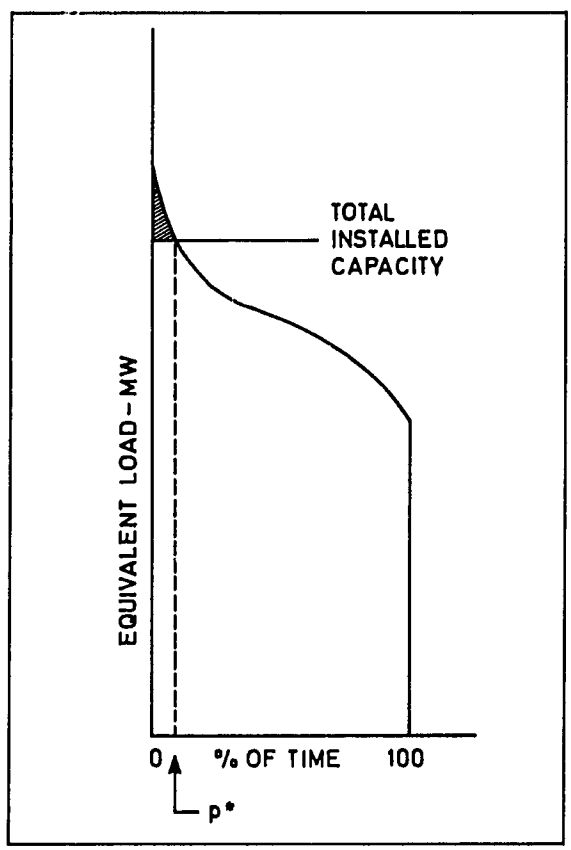

FIG. A-4. EQUIVALENT LOAD CURVE FOR AN ENTIRE SYSTEM.

The loss-of-load probability calculated in this model only considers the generating system. To get a true measure of system reliability, the transmission and distribution systems must also be considered, but consideration of the system aspects is beyond the scope of the model. The true system loss-of-load probability can never be less than the loss-of-load probability calculated by the model since the model assumes a perfect transmission system. The area

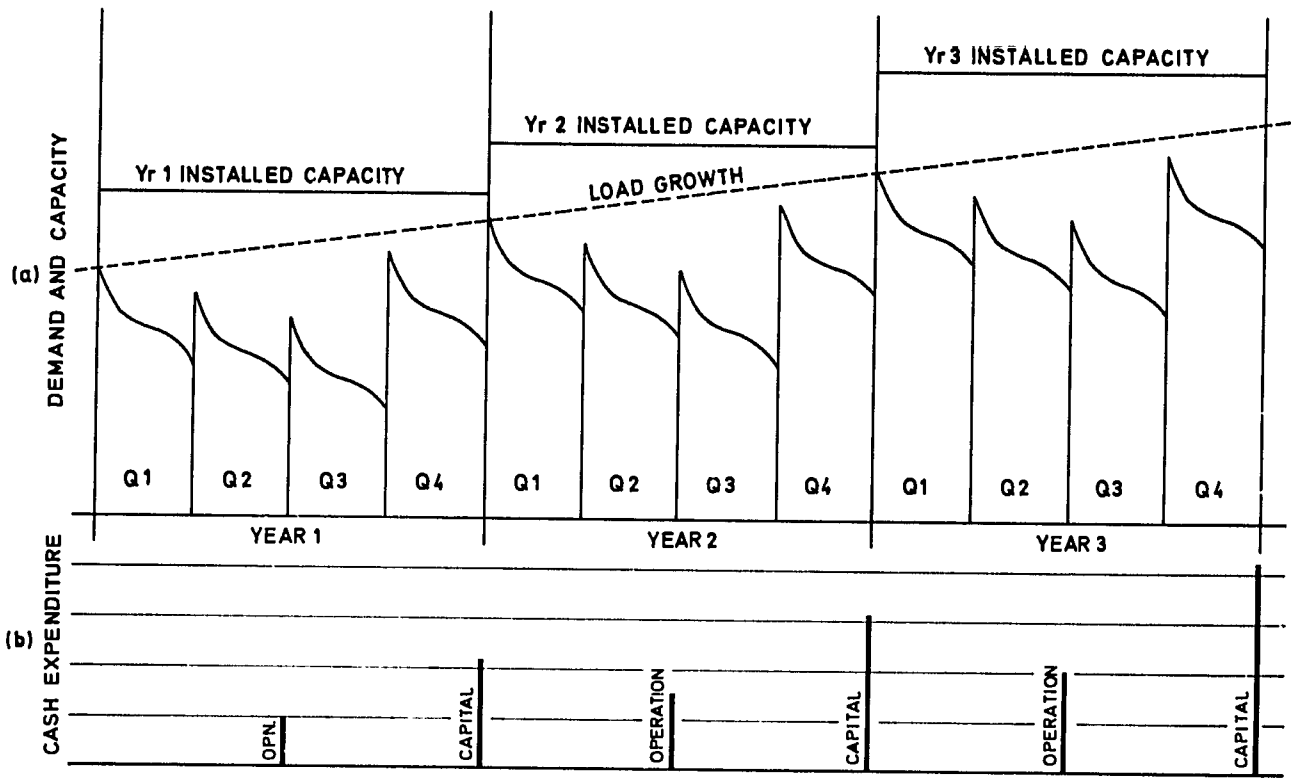

FIG. A-5. SCHEMATIC DIAGRAM OF LOAD GROWTH AND CORRESPONDING CASH FLOWS.

between the equivalent load curve and the ordinate above the total installed capacity is a measure of the probable value of energy demand not served. The simulation code calculates loss-of-load probability and the amount of energy not served for each time period of the study (usually quarterly).

The more complicated aspects of the probabilistic simulation are beyond the scope of this simplified description. These aspects include the simulation of pumped storage and hydro units and the use of multiple capacity blocks for thermal units to better represent actual unit loading.

Treatment of economics

Consider the situation illustrated in Fig. A-5(a). This shows, in diagrammatic form, three years in the history of a power system experiencing load growth. It is seen that at the beginning of year 2 and year 3 an increase in system capacity is required by the growth in load. The capital expenditure which is equivalent to all of the construction costs of these plants is considered to be concentrated at a single point in time when the plant becomes operative. The operating expense to serve the given load duration curves is assumed for simplicity to be concentrated at the middle of each year. The corresponding cash flow diagram is shown in Fig. A-5(b). The present worth, to some reference year, of such a cash flow (ignoring the effects of the study horizon) is a measure of the cost of that particular expansion scheme.

The method chosen to deal with the end effects caused by a finite study horizon is to assume that the salvage value of any piece of equipment installed during the study is proportional to the unused portion of its plant life. Therefore, the present worth of the cash flow calculated in the previous paragraph should be reduced by the present worth, measured from the horizon, of a credit for each plant's salvage value. The function (present worth) to be minimized then may be stated symbolically as

$$F = \sum_{k=0}^{NYRS-1} \left[\sum_{\ell=1}^{NINST_k} \left[P_{k,\ell}\left(C_\ell\right) - P_{NYRS,\ell}\left(C_\ell \cdot \frac{L_\ell - NYRS + k}{L_\ell}\right)\right] + \sum_{m=1}^{NFUELS} P_{(k+\frac{1}{2}),m}\left(PC\emptyset ST_{(k+1)}\right)\right]$$

where F — objective function
NYRS — number of years in the study
$NINST_k$ — number of installations in the kth year
$P_{k,\ell}$ — present-worth factor for the kth year and ℓth plant
C_ℓ — capital cost of the ℓth plant
$P_{NYRS,\ell}$ — present-worth factor for the horizon and the ℓth plant
$P_{(k+\frac{1}{2}),m}$ — present-worth factor for the mth fuel in the kth year
L_ℓ — plant life of the ℓth plant
$PC\emptyset ST_{(k+1)}$ — operating cost of the mth fuel system for the (k+1) year
NFUELS — number of different fuel types considered

Dynamic programming

In optimization terminology, the above function is known as an objective function or performance criterion. The value of the objective function denotes the relative benefit of a particular expansion schedule. The purpose of the optimization package is to determine which one of the selected alternative expansion schedules minimizes the value of the objective function. Dynamic programming is a powerful optimization tool and requires the definition of three types of variables: the stage variable, the state variable, and the control variable. The stage variable defines the sequence of events and, in the WASP program, is defined as the year being considered. The state variable describes the state of the system under study and is defined as the configuration of installed units in any given year. Once the values of the state variable are defined for all stages, any question concerning the system can be answered. The change between the states that might occur from stage to stage is determined by the value of the control variable between stages. Hence the control variable determines the capital investment and operating costs from year to year. In simple terminology, the control variable is the independent variable and the state variable is the dependent variable.

In operation a number of configurations are generated for each stage (year) of the study. These configurations must satisfy the constraints of reserve margin and capacity-mix specified by the user. The production cost and reliability of each of these configurations is determined in the simulations for the appropriate year (stage). All of these calculations are performed before going to the dynamic program. In Fig. A-6 a number of states are represented, by dots, for two successive stages, k and (k+1).

It should be kept in mind that the value of the objective function associated with each state in the kth stage is the minimum cost path from the beginning of the study to that state. In calculating the cost of the paths from state B to state A, the capital cost corresponding to the transfer from state B to A and the operating costs for state A are added to the value of the objective function of state B. This represents the present-worth cost of expanding the system to state A and passing through state B. The costs for the other paths from states C, D, E and F converging at state A are calculated in a similar manner. The path which yields the lowest value of the objective function at state A is retained by storing the objective

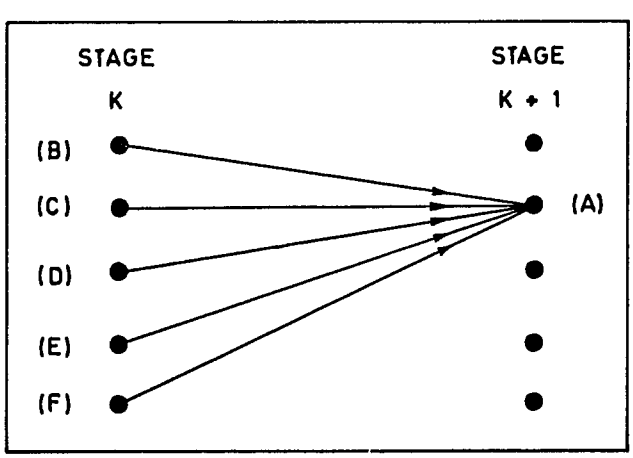

FIG. A-6. ILLUSTRATION OF A DYNAMIC PROGRAM STEP.

function and sufficient information for determining the state in the previous stage. The other paths are discarded as they cannot possibly be part of the optimal trajectory. This procedure is repeated for all of the states in stage (k+1). Then the next stage (k+2) is considered, with the calculations proceeding until the study horizon is reached. Then the lowest value of the accumulated objective function in the final stage is traced back from that state through the various stages to determine the optimal expansion strategy.

In order to provide flexibility in representing real system situations, many features have been included in the WASP package. All cash flow is separated into domestic and foreign exchange in computing total expenditure. Total operating costs and cost of the fuel used in the plant are separately stated. Thus discounting and escalation may be applied separately to the domestic and foreign costs of operating plants consuming different fuels. In the same manner, the capital cost of each expansion alternative is separated into foreign and domestic components. Different discount rates and escalation rates on capital costs (foreign and domestic) are permitted on each alternative. Consequently, many sensitivity studies can be carried out with a minimum of computational effort after a basic optimum has been reached. Studies of the effects of plant capital cost, capital cost interest rates and escalation, exchange ratio (foreign/domestic), plant life, interest rate on operating cost, and critical loss-of-load probability require only reruns of the sixth (dynamic programming) step. If the operating policy does not change and if there are no pumped-storage installations, the escalation of operating costs may also be included in sensitivity studies.

LIMITATIONS OF THE PACKAGE

The program suffers mainly from approximations in the simulation. When the year is divided into large time blocks, the maintenance schedule is only approximate. Since the simulation uses a load duration curve technique, the chronological sequence of events during the individual periods is lost. The hydro representation includes two approximations. All hydro is lumped into a single pseudo-plant with an "always-run" and a "peak-shaving" component. The peak-shaving component is removed from the load duration curve prior to thermal plant simulation. This is not rigorous since hydro is also normally used to cover forced outages of thermal units. All pumped-storage units are also lumped into a single pseudo unit and will not exactly simulate multiple plants with widely varying weekly capacity factors.

ACKNOWLEDGEMENTS

Dr. R.R. Booth of the State Electricity Commission of Victoria (Australia) introduced the probabilistic simulation method and provided the Tennessee Valley Authority with early versions of his simulation and dynamic programming system expansion model. Dr. David Joy of Oak Ridge National Laboratories (USA) provided extensive consultation and development work on the simulation and generous advice and instruction on the dynamic programming method. At TVA Mr. Roger Babb (formerly with TVA) did extensive work to speed the simulation, Miss Katherine McQueen of the Power Research Staff coded and debugged and extensively modified the first generation TVA program and T.R. Jackson of TVA's Power Supply Planning Branch struggled with the difficulties of TVA's first generation program to produce useful results. The improvements in this program are largely a result of his experience. Finally, Mr. Peter Heinrich of IAEA's Computing Centre Staff has carried much of the burden of debugging and implementation on the IAEA computer.

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APPENDIX B

GENERATING PLANT CAPITAL COSTS (ORCOST)

STEAM-ELECTRIC POWER PLANTS

In order to carry out the very large number of capital cost estimates for the thermal generating units being considered as expansion alternatives, it was necessary to make use of a digital computer program, ORCOST. This program was prepared specifically to provide estimates of the capital costs of steam-electric power plant in the United States of America for use in studies conducted by the Oak Ridge National Laboratory for the USAEC Division of Reactor Development and Technology. The code includes cost models for PWR, BWR, HTGR nuclear plants and coal, oil, and gas-fired plants which were developed from ORCOST's "big brother" CONCEPT II [1-7]. In developing both CONCEPT II and ORCOST the assumption was made that, for a given type and size of power plant and irrespective of its geographical location, the sizes of individual items of equipment, the amounts of construction materials, and the number of man-hours of construction labour remain the same for each of the nine major direct plant cost accounts shown in Table B-1. (Accounts 21-26/91-93 of the USAEC uniform system of accounting.) Such an assumption permits one to start with a base model in which costs for each of the major direct plant cost accounts are identified and to adjust these costs to conditions prevailing at different site locations by applying appropriate indices for equipment, material and labour cost. These indices reflect the unit costs of these items relative to the unit costs used in the base model. In the case of plant equipment costs the index to be used includes both cost escalation factors and cost factors specific to the site.

In CONCEPT II these indices are calculated within the program from input data on the actual unit costs of equipment, materials and labour, whereas in ORCOST the indices are calculated separately.

After applying the specific indices, the computer program sums up the adjusted total direct cost of the physical plant.

In order to estimate these direct plant costs as a function of plant size, a second assumption is made, namely that the exponential scaling laws developed for the base model (to reflect the variation in costs of each of the major accounts with plant size) are independent of the indices used for equipment, materials, and labour costs.

TABLE B-1. 2-DIGIT ACCOUNTS USED IN THE USAEC SYSTEM OF ACCOUNTING

Account No.	Item
Direct costs	
21	Structures and site facilities
22	Reactor/boiler plant equipment
23	Turbine plant equipment
24	Electric plant equipment
25	Miscellaneous plant equipment
26	Special materials
Indirect costs	
91	Construction facilities, equipment and services
92	Engineering and construction management services
93	Other costs

Having found the direct physical cost of the plant for a given size and site location, the program adds allowances for contingencies and spare parts and then computes the indirect costs by applying appropriate percentages to the physical plant costs.

The technique of separating the plant cost into individual components, applying appropriate cost indices, and summing the adjusted components is the basic tool used in ORCOST. The procedure is illustrated schematically in Fig. B-1.

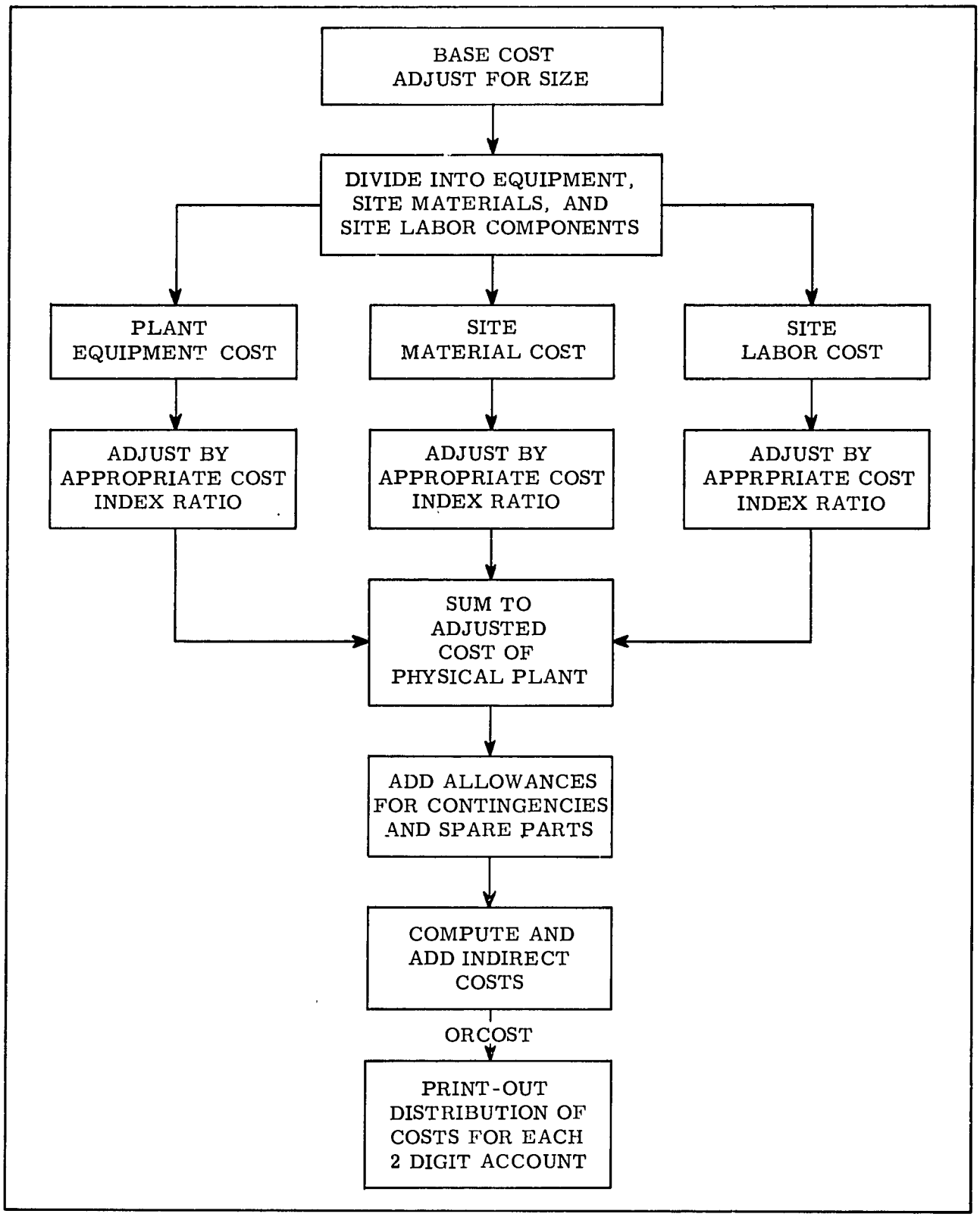

FIG. B-1. SCHEMATIC ILLUSTRATION OF ORCOST (AND CONCEPT II) PROCEDURE.

Selection of nuclear reactor type

It should be noted here that in view of the diversity of reactor types now available commercially and because of the limited scope of the Survey, it was decided to base the evaluation of nuclear versus conventional power plants on a single reactor type, the PWR. Such a selection is not intended to imply a preference for this particular type of nuclear plant, but merely to provide an illustration which is believed to be representative of nuclear power in general.

Other types of power reactors which have already been constructed and could be considered for developing countries in their future plans include AGR, BWR, HTGR, PHWR, and SGHWR.

It is believed that breeder reactors will not be developed to the point of being useful in planning systems in developing countries within the study decade.

To date, the following reactor types have been purchased or committed by the countries listed:

	Type	Gross electricity output (MW)
Argentina	PHWR	340
	CANDU-PHWR	600
Brazil	PWR	657
Bulgaria	PWR	2 x 440
Czechoslovakia	HWGCR	144
	PWR	2 x 440
India	BWR	2 x 210
	CANDU-PHWR	1 x 220
	CANDU-PHWR	3 x 220
Korea	PWR	595
Pakistan	CANDU-PHWR	137

The base cost model

The base cost model for each type of plant was established from a detailed cost estimate for a reference 1000 MW plant assumed to be located at "Middletown", USA, the standard hypothetical site described in Ref. [3].

Since the base cost models in the original ORCOST program were developed in 1971, these were updated to the end of 1972 by applying appropriate escalation rates on equipment, materials and labour. These costs are referred to in the Survey as ORCOST-1. However, recent construction experience in the USA indicated that some adjustments should be made in the scope of work, particularly as it affects the construction costs of nuclear power plants. These adjustments were made and the resulting costs are referred to in the Survey work as ORCOST-3.[1] The ORCOST-3 data are used as the reference case data in the Survey analyses. Table B-2 shows the ORCOST-3 total plant base cost models used for the Survey. Table B-3 shows a comparison of ORCOST-1 and ORCOST-3 total plant costs for 300, 600 and 1000 MW PWR and oil-fired plants. It also shows the modified costs (see below for discussion of country cost indices) for the participating country having the maximum cost levels and the one having the minimum cost levels. It is to be noted here that the adjustments made to obtain ORCOST-3 costs (from the ORCOST-1 values) resulted in essentially no change in the oil-fired (or other fossil-fired) plants, but there were substantial increases in the costs of nuclear plants of the order of 21-22% on all sizes. This resulted in the ratio of nuclear to oil-fired plant costs increasing from values of about 1.5 - 1.8 for ORCOST-1 to about 1.9 - 2.2 for ORCOST-3. ORCOST-1 costs were used to make a few sensitivity studies in selected countries in order to indicate the possible effect on Survey results if the ratio of nuclear to fossil-plant costs reverted to their pre-1972 levels.

[1] ORCOST-2 referred to data not used for Survey analyses.

TABLE B-2. ORCOST-3 BASE COST MODELS USED IN THE MARKET SURVEY (all 1000 MW capacity)

Account No.	PWR		Coal-fired		Oil-fired		Gas-fired	
	10^6 US $	Scaling exponent	10^6 US $	Scaling exponent	10^6 US $	Scaling exponent	10^6 US $	Scaling exponent
21	52.03[a]	0.80[a]	29.18	0.75	26.67	0.75	26.67	0.75
22	77.20	0.60	67.91	0.90	56.00	0.90	36.50	0.90
23	74.95	0.80	53.21	0.80	53.00	0.80	53.00	0.80
24	27.84	0.60	18.52	0.45	14.15	0.45	13.40	0.45
25	5.39	0.30	4.35	0.30	4.08	0.30	4.08	0.30
26	0	0	0	0	0	0	0	0
Total	237.41		173.17		153.9		133.65	

[a] For plant sizes below 800 MW, these figures become US $ 47.75 x 10^6 and 0.40 respectively.

TABLE B-3. COMPARISON OF CAPITAL COSTS FOR NUCLEAR AND OIL-FIRED PLANTS

Size (MW)	Type		ORCOST-1			ORCOST-3		
			Maximum country	Minimum country	USA	Maximum country	Minimum country	USA
300	PWR	Capital costs (US $/kW)	490	378	517	593	442	624
	Oil		272	210	316	268	206	315
		Cost difference (US $/kW)	218	168	201	325	236	309
		Cost ratio PWR/Oil	1.8	1.8	1.63	2.21	2.15	1.98
600	PWR	Capital costs (US $/kW)	358	275	377	439	322	460
	Oil		216	171	249	216	170	253
		Cost difference (US $/kW)	142	104	128	223	152	207
		Cost ratio PWR/Oil	1.64	1.61	1.51	2.03	1.89	1.82
1000	PWR	Capital costs (US $/kW)	296	225	312	365	266	382
	Oil		187	145	218	189	146	223
		Cost difference (US $/kW)	109	80	94	176	120	159
		Cost ratio PWR/Oil	1.58	1.55	1.43	1.93	1.82	1.71

The base model plant costs include, in all oil and coal-fired plants, electrostatic precipitators. However, these costs do not include any of the other so-called environmental control equipment such as SO_2 removal systems, cooling towers/lakes or near-zero radiation release systems. It was felt that environmental considerations which have caused designs of almost all future plants in industrialized countries to include such equipment, or provision to add it at later dates, would not generally apply during the study period in the developing countries included in the Survey. It is recognized, however, that in certain countries these considerations might possibly have to be faced and coped with during the study decade. Therefore, the following should be noted when considering the capital costs of future plants.

(a) High-efficiency (99.5 + %) electrostatic precipitators to remove particulate matter from stacks of oil or coal/lignite-fired plants cost of the order of US $8-10/kW of installed capacity. Thus, if precipitators are not required in any given instance, this amount may be omitted from the appropriate costs in Tables B-2 and B-3.

(b) Although there is no known proven process for the effective economic removal of SO_2 from the stack gases of fossil-fired plants, it is at present estimated that such equipment, when commercially applicable, could involve an additional equivalent investment cost of the order of US $50/kW for a 1000 MW plant burning coal containing 3.0% sulphur. This would include both the initial investment (about US $35-40/kW) and the capitalized operating cost and capacity penalty (about US $10-15/kW). The actual final costs would, of course, depend on the original sulphur content of the fuel being used, the size of plant, the ability to dispose of the recovered sulphur etc.

(c) Cooling towers, of various designs, are presently in use in many power plants and they can be considered fully developed technically. Their costs are reasonably well known for installations under a wide variety of conditions. The initial investment for a 1000 MW plant would be of the order of US $5-10/kW for fossil-fired plants depending on whether a mechanical draft or natural draft design is used. For nuclear plants, these values should be increased by about 50%. The costs of cooling lakes, ponds or equivalent methods of disposing of thermal discharges will vary quite widely, but they can be generally considered as less expensive overall than cooling towers if the amount of land required is available at a reasonable price. An upper limit of their cost can be considered as the cost of equivalent cooling towers.

(d) The addition of equipment to light-water nuclear plants to accomplish near-zero radiation release will be likely to cost about US $5-10/kW for larger sizes of plants, depending on the type of reactor plant involved.

It is quite possible, therefore, that costs for future fossil-fired plants could increase substantially more than for nuclear plants if precipitators, SO_2 removal systems and cooling towers or the equivalent were required for the fossil-fired plants and cooling towers or the equivalent and near-zero radiation release systems were required for nuclear plants. On a comparable basis, therefore, for large plants of the order of 1000 MW, the possible future incremental penalty against fossil-fired plants would appear to be of the order of US $40/kW when precipitators are not required and US $50/kW if precipitators are required for the coal-fired plants. These US $/kW values could increase by as much as 50% for the smaller sizes of units considered in the study.

It should be noted that, in addition to the increases in capital cost for environmental control equipment, the operating and maintenance costs of the plants, as discussed in Appendix E, will be increased.

Modifications of indirect costs

Indirect costs in the base model (construction facilities, equipment and services, engineering and construction management services, taxes, insurance and owner's general and administrative expenses) are estimated as percentages of the direct physical plant cost based on experience in the USA. It was recognized that this experience would not be directly

applicable to conditions prevailing in the countries being studied; therefore, the indirect cost percentages in the base model were adjusted to reflect such conditions. Such adjustments to the base model are easily made by changing the indirect cost indices applicable to Accounts No. 91, 92 and 93. The indices actually used are shown in Table B-4. These indirect cost indices were derived for the Survey as follows:

Firstly, it was assumed that the plants being considered would be two-unit plants; therefore, the costs of temporary facilities which would be common to both units were divided by two. Secondly, it was assumed that the costs of local labour and materials associated with account 91 would be about 75% of the costs used in the base model. These assumptions decreased account 91 from 6.6% of the physical plant costs to 5.3%, resulting in an index of 0.8 for account 91.

For account 92, engineering services were taken to be the same as for the USA based on the assumption that all design and engineering for the nuclear plant would be done by an architect-engineering firm from outside the country being studied. Costs of construction management services, moreover, were increased by US $ 5 million in the base model for overseas support of personnel supervising the construction. This increased the percentage of physical plant costs from 11.6% in the base model to 13.6% resulting in an index of 1.17 for account 92.

Account 93 was adjusted to remove the local taxes assumed for the base model resulting in an index of 0.71 for account 93.

Indirect cost indices for conventional plants were derived in a similar manner, to give the values: account 91 = 0.72, account 92 = 1.06, account 93 = 0.65.

In the cost model, indirect costs are calculated using a hyperbolic function. This results in abnormally high indirect costs for unit sizes below 300 MW both in terms of total dollar costs and the ratio of the indirect costs to total plant costs. Therefore, the calcula-

TABLE B-4. ADJUSTMENT OF THE INDIRECT COSTS OF THE BASE MODEL (1000 MW PWR) TO MARKET SURVEY CONDITIONS

Account No.		Percentage of physical plant cost		
		Base model		Market survey
91	Construction facilities, equipment and services			
	911 Temporary facilities	2.0		1.5
	912 Construction equipment	3.3		3.0
	913 Construction services	1.3		0.8
	Total for account 91	6.6		5.3
	Ratio – Market survey/base model		0.80	
92	Engineering and construction management services			
	921 Engineering services	5.8		5.8
	922 Construction management services	5.8		7.8
	Total for account 92	11.6		13.6
	Ratio – Market survey/base model		1.17	
93	Other costs			
	931 Taxes and insurance	2.7		1.5
	932 Staff training and plant start-up	0.3		0.3
	933 Owner's general and administrative expenses	1.2		1.2
	Total for account 93	4.2		3.0
	Ratio – Market survey/base model		0.71	

tion of indirect costs for the smaller sizes of plants was made by taking a linear approximation.

It should be noted that although the percentages applied to the physical plant costs to obtain the indirect costs vary with size of plant, the indirect cost indices remain constant for all sizes of plants.

Derivation of country cost indices

Specific cost indices for equipment, materials and labour were used for each participating country. These cost indices are stated as a ratio of the effective foreign costs to the US-based costs and thus allow the determination of total construction costs of the various types and sizes of plants in each country based on equipment, materials and labour cost indices and interest rates unique to each country. The following paragraphs explain how the cost indices were obtained and used to modify the US-based costs:

(a) Equipment cost index

The equipment cost indices were determined after giving consideration to international sources for the items of equipment, the location of the country relative to those sources, the transport costs from likely sources to the country, the competitive nature of the international market, known country preferences for equipment types and sources and the likely location of the power plants within the country, i.e. inland or on the seashore. On balance, the equipment cost index, for an "ideal" plant site in an "average" country, was established as 1.0 for nuclear plants and 0.9 for fossil plants relative to the US values in the ORCOST models. A specific index was then established for each country relative to these values, considering the above factors as they were known to apply or as best they could be approximated.

(b) Materials cost index

The materials cost indices were determined either from detailed costs of completed power plants provided by the countries or from specific prices in the country for construction materials such as structural steel, re-inforcing steel, concrete (ready-mix), ply-form and lumber.

In some cases where such data were not available the indices were estimated based on a comparison with known data for a neighbouring country or for the general area.

(c) Labour cost index

The labour cost indices were calculated from the wages for different types of craft usually available in the country, such as common labour, bricklayer, carpenter, iron worker, electrician, steam-fitter, operating engineer, and other classifications as available.

These wages were weighted by the amount of man-hours to be spent in the construction of a power plant. For this purpose a labour efficiency was estimated. Where no detailed information about wages was available, the labour cost indices were calculated from detailed costs of constructed power plants, or it was estimated by comparison with other countries.

ORCOST input and output

With the above modifications to the basic ORCOST program the actual input data required for each country include plant size and type, labour cost index, materials cost index, equipment cost index, cost escalation rates (if any), interest rates, construction period, length of working week (if different from 40 hours).

From these input data total capital costs are obtained as the output, with the cost adjusted to the specific country's cost levels. Table B-5 shows a printout sheet from the ORCOST-3 program summarizing input data for a 600 MW PWR with equipment, materials and cost indices set at 1.0. Tables B-6 to B-9 show output data from ORCOST-3 for various fossil-fuelled 600 MW plants, again with the cost indices set at 1.0. It should be pointed out

TABLE B-5. ORCOST-3 PRINTOUT OF INPUT DATA FOR 600 MW PWR

```
PLANT SIZE, MW(E).                                  S   =  600.0
PLANT TYPE.                                         T   = PWR
YEAR CONSTRUCTION STARTED.                          YS  = 1973.00
YEAR OF COMMERCIAL OPERATION.                       YO  = 1978.50
BASE YEAR FOR ESCALATION                            YBX = 1971.50
LENGTH OF WORKWEEK, HRS.                            HW  =   40.0
ANNUAL INTEREST RATE, PERCENT.                      XIR =    8.0
INITIAL EQUIP. ESCAL. RATE, ANNUAL PERCENT          EREB=    0.0
INITIAL MATLS. ESCAL. RATE, ANNUAL PERCENT          ERMB=    0.0
INITIAL LABOR ESCAL. RATE, ANNUAL PERCENT           ERLB=    0.0
EQUIPMENT ESCALATION RATE, ANNUAL PERCENT.          ERE =    0.0
MATERIALS ESCALATION RATE, ANNUAL PERCENT.          ERM =    0.0
LABOR ESCALATION RATE, ANNUAL PERCENT.              ERL =    0.0
PROVEN DESIGN                                         IFLAG =  0
SUBROUTINE NAMELIST OPTION NOT SELECTED               JFLAG =  0
HEAT REMOVAL - RUN OF RIVER                             ICT =  0
UPGRADED RADWASTE SYSTEM NOT SPECIFIED                  IEC =  0

CONTINGENCY AND SPARE PARTS FACTORS, PERCENT DIVIDED BY 100
            CONTINGENCY FACTORS                 SPARE PARTS FACTORS
     ---------------------------------  ---------------------
     EQUIPMENT & MATERIALS      LABOR     EQUIPMENT & MATERIALS
        F21CEM= 0.050       F21CL= 0.100       F21SEM= 0.010
        F22CEM= 0.050       F22CL= 0.100       F22SEM= 0.010
        F23CEM= 0.050       F23CL= 0.100       F23SEM= 0.010
        F24CEM= 0.050       F24CL= 0.100       F24SEM= 0.010
        F25CEM= 0.050       F25CL= 0.100       F25SEM= 0.010
        F26CEM= 0.050       F26CL= 0.100       F26SEM= 0.010
        FSOCEM= 0.050       FSOCL= 0.100       FSOSEM= 0.010
        FHRCEM= 0.050       FHRCL= 0.100       FHRSEM= 0.010

EQUIPMENT COST INDEX.                           A(IN,1) =  1.000
MATERIALS COST INDEX.                           A(IN,2) =  1.000
LABOR COST INDEX.                               A(IN,3) =  1.000

BASE COST MODEL
            COST                        COST BREAKDOWN FACTORS
          $MILLION   EXPONENT    EQUIPMENT MATERIALS LABOR
ACCT 21 C(1)= 47.75 N(1)=0.40 EF(1)=0.03 MF(1)=0.35 LF(1)=0.62
ACCT 22 C(2)= 77.20 N(2)=0.60 EF(2)=0.52 MF(2)=0.21 LF(2)=0.27
ACCT 23 C(3)= 74.95 N(3)=0.80 EF(3)=0.54 MF(3)=0.17 LF(3)=0.29
ACCT 24 C(4)= 27.84 N(4)=0.60 EF(4)=0.23 MF(4)=0.34 LF(4)=0.43
ACCT 25 C(5)=  5.39 N(5)=0.30 EF(5)=0.39 MF(5)=0.04 LF(5)=0.57
ACCT 26 C(6)=  0.0  N(6)=0.0  EF(6)=0.0  MF(6)=0.0  LF(6)=0.0
RAD. W. C(7)=  0.0  N(7)=0.60 EF(7)=0.69 MF(7)=0.13 LF(7)=0.18
C. TOW. C(8)=  0.0  N(8)=0.80 EF(8)=0.47 MF(8)=0.04 LF(8)=0.49
INDIRECT COSTS  F91= 0.80 F92= 1.17 F93= 0.71
```

TABLE B-6. ORCOST-3 PRINTOUT OF OUTPUT DATA ON THE CAPITAL COST OF A 600 MW PWR

PLANT CAPITAL INVESTMENT SUMMARY ($MILLION)
MIDD
600.0 Mw(E) PWR
1973.00 - 1978.50

	DIRECT COSTS				
20	LAND AND LAND RIGHTS				0.1
	PHYSICAL PLANT	EQU.	MAT.	LABOUR	TOTAL
21	STRUCTURES AND SITE FACILITIES	1.2	13.6	24.1	38.9
22	REACTOR/BOILER PLANT EQUIPMENT	29.5	11.9	15.3	56.8
23	TURBINE PLANT EQUIPMENT	26.9	8.5	14.4	49.8
24	ELECTRIC PLANT EQUIPMENT	4.7	7.0	8.8	20.5
25	MISCELLANEOUS PLANT EQUIPMENT	1.8	0.2	2.6	4.6
26	SPECIAL MATERIALS	0.0	0.0	0.0	0.0
	INCREMENTAL ALLOWANCE FOR ENVIRONMENTAL ASSURANCE				
	UPGRADED RADWASTE SYSTEM	0.0	0.0	0.0	0.0
	COOLING TOWERS	0.0	0.0	0.0	0.0
	SUBTOTAL (PHYSICAL PLANT)	64.1	41.2	65.4	170.7
	CONTINGENCY ALLOWANCE				11.8
	SPARE PARTS ALLOWANCE				1.1
	SUBTOTAL (PHYSICAL PLANT)				183.5
	OVERTIME ALLOWANCE (40.0 HR WORKWEEK)				0.0
	SUBTOTAL (TOTAL PHYSICAL PLANT)				183.5
	INDIRECT COSTS				
91	CONSTRUCTION FACILITIES, EQUIPMENT, AND SERVICES -				10.9
92	ENGINEERING AND CONSTRUCTION MANAGEMENT SERVICES -				28.1
93	OTHER COSTS				6.1
94	INTEREST DURING CONSTRUCTION (8.0 PCT- 5.50 YRS)				47.3
	SUBTOTAL (TOTAL INDIRECT COSTS)				92.5
	SUBTOTAL (TOTAL PLANT COST)				276.1
	CAPABILITY PENALTY (0.0 PCT- 0.0 MW(E))				0.0
	TOTAL PLANT CAPITAL COST (AT START OF PROJECT)				276.1
	$ / KW(E)				460.
	ESCALATION DURING CONSTRUCTION (0.0 PCT)				0.0
	TOTAL PLANT CAPITAL COST (AT COMMERCIAL OPERATION)				276.1
	$ / KW(E)				460.

TABLE B-7. ORCOST-3 PRINTOUT OF OUTPUT DATA ON A 600 MW COAL-FIRED PLANT

PLANT CAPITAL INVESTMENT SUMMARY ($MILLION)
MIDD
600.0 MW(E) COAL
1973.00 - 1977.00

	DIRECT COSTS				
20	LAND AND LAND RIGHTS				0.1
	PHYSICAL PLANT	EQU.	MAT.	LABOUR	TOTAL
21	STRUCTURES AND SITE FACILITIES	0.6	7.8	11.5	19.9
22	REACTOR/BOILER PLANT EQUIPMENT	22.7	5.1	15.0	42.9
23	TURBINE PLANT EQUIPMENT	19.1	6.0	10.3	35.4
24	ELECTRIC PLANT EQUIPMENT	4.9	2.4	7.5	14.7
25	MISCELLANEOUS PLANT EQUIPMENT	1.0	0.7	2.0	3.7
26	SPECIAL MATERIALS	0.0	0.0	0.0	0.0
	INCREMENTAL ALLOWANCE FOR ENVIRONMENTAL ASSURANCE				
	SO-2 REMOVAL SYSTEM	0.0	0.0	0.0	0.0
	COOLING TOWERS	0.0	0.0	0.0	0.0
	SUBTOTAL (PHYSICAL PLANT)	48.3	22.0	46.3	116.6
	CONTINGENCY ALLOWANCE				8.1
	SPARE PARTS ALLOWANCE				0.7
	SUBTOTAL (PHYSICAL PLANT)				125.4
	OVERTIME ALLOWANCE (40.0 HR WORKWEEK)				0.0
	SUBTOTAL (TOTAL PHYSICAL PLANT)				125.4
	INDIRECT COSTS				
91	CONSTRUCTION FACILITIES, EQUIPMENT, AND SERVICES -				8.0
92	ENGINEERING AND CONSTRUCTION MANAGEMENT SERVICES -				13.1
93	OTHER COSTS				3.6
94	INTEREST DURING CONSTRUCTION (8.0 PCT- 4.00 YRS)				21.9
	SUBTOTAL (TOTAL INDIRECT COSTS)				46.6
	SUBTOTAL (TOTAL PLANT COST)				172.1
	CAPABILITY PENALTY (0.0 PCT- 0.0 MW(E))				0.0
	TOTAL PLANT CAPITAL COST (AT START OF PROJECT)				172.1
	$ / KW(E)				287.
	ESCALATION DURING CONSTRUCTION (0.0 PCT)				0.0
	TOTAL PLANT CAPITAL COST (AT COMMERCIAL OPERATION)				172.1
	$ / KW(E)				287.

TABLE B-8. ORCOST-3 PRINTOUT OF OUTPUT DATA ON A 600 MW OIL-FIRED PLANT

PLANT CAPITAL INVESTMENT SUMMARY ($MILLION)
MIDD
600.0 MW(E) OIL
1973.00 - 1976.50

	DIRECT COSTS				
20	LAND AND LAND RIGHTS				0.1
	PHYSICAL PLANT	EQU.	MAT.	LABOUR	TOTAL
21	STRUCTURES AND SITE FACILITIES	0.5	6.9	10.7	18.2
22	REACTOR/BOILER PLANT EQUIPMENT	18.0	4.6	12.7	35.4
23	TURBINE PLANT EQUIPMENT	19.0	6.0	10.2	35.2
24	ELECTRIC PLANT EQUIPMENT	4.4	1.7	5.2	11.2
25	MISCELLANEOUS PLANT EQUIPMENT	1.0	0.7	1.8	3.5
26	SPECIAL MATERIALS	0.0	0.0	0.0	0.0
	INCREMENTAL ALLOWANCE FOR ENVIRONMENTAL ASSURANCE				
	SO-2 REMOVAL SYSTEM	0.0	0.0	0.0	0.0
	COOLING TOWERS	0.0	0.0	0.0	0.0
	SUBTOTAL (PHYSICAL PLANT)	43.0	19.9	40.6	103.5
	CONTINGENCY ALLOWANCE				7.2
	SPARE PARTS ALLOWANCE				0.6
	SUBTOTAL (PHYSICAL PLANT)				111.3
	OVERTIME ALLOWANCE (40.0 HR WORKWEEK)				0.0
	SUBTOTAL (TOTAL PHYSICAL PLANT)				111.3
	INDIRECT COSTS				
91	CONSTRUCTION FACILITIES, EQUIPMENT, AND SERVICES -				7.6
92	ENGINEERING AND CONSTRUCTION MANAGEMENT SERVICES -				12.3
93	OTHER COSTS				3.4
94	INTEREST DURING CONSTRUCTION (8.0 PCT- 3.50 YRS)				17.0
	SUBTOTAL (TOTAL INDIRECT COSTS)				40.3
	SUBTOTAL (TOTAL PLANT COST)				151.8
	CAPABILITY PENALTY (0.0 PCT- 0.0 MW(E))				0.0
	TOTAL PLANT CAPITAL COST (AT START OF PROJECT)				151.8
	$ / KW(E)				253.
	ESCALATION DURING CONSTRUCTION (0.0 PCT)				0.0
	TOTAL PLANT CAPITAL COST (AT COMMERCIAL OPERATION)				151.8
	$ / KW(E)				253.

TABLE B-9. ORCOST-3 PRINTOUT OF OUTPUT DATA ON A 600 MW GAS-FIRED PLANT

PLANT CAPITAL INVESTMENT SUMMARY ($MILLION)
MIDD
600.0 MW(E) GAS
1973.00 - 1976.50

	DIRECT COSTS				
20	LAND AND LAND RIGHTS				0.1
	PHYSICAL PLANT	EQU.	MAT.	LABOUR	TOTAL
21	STRUCTURES AND SITE FACILITIES	0.7	7.1	10.4	18.2
22	REACTOR/BOILER PLANT EQUIPMENT	12.7	2.3	8.1	23.0
23	TURBINE PLANT EQUIPMENT	19.0	6.0	10.2	35.2
24	ELECTRIC PLANT EQUIPMENT	4.6	1.1	5.0	10.6
25	MISCELLANEOUS PLANT EQUIPMENT	0.9	0.8	1.8	3.5
26	SPECIAL MATERIALS	0.0	0.0	0.0	0.0
	INCREMENTAL ALLOWANCE FOR ENVIRONMENTAL ASSURANCE				
	SO-2 REMOVAL SYSTEM	0.0	0.0	0.0	0.0
	COOLING TOWERS	0.0	0.0	0.0	0.0
	SUBTOTAL (PHYSICAL PLANT)	37.9	17.2	35.4	90.6
	CONTINGENCY ALLOWANCE				6.3
	SPARE PARTS ALLOWANCE				0.6
	SUBTOTAL (PHYSICAL PLANT)				97.5
	OVERTIME ALLOWANCE (40.0 HR WORKWEEK)				0.0
	SUBTOTAL (TOTAL PHYSICAL PLANT)				97.5
	INDIRECT COSTS				
91	CONSTRUCTION FACILITIES, EQUIPMENT, AND SERVICES -				7.2
92	ENGINEERING AND CONSTRUCTION MANAGEMENT SERVICES -				11.6
93	OTHER COSTS				3.2
94	INTEREST DURING CONSTRUCTION (8.0 PCT- 3.50 YRS)				15.1
	SUBTOTAL (TOTAL INDIRECT COSTS)				37.1
	SUBTOTAL (TOTAL PLANT COST)				134.6
	CAPABILITY PENALTY (0.0 PCT- 0.0 MW(E))				0.0
	TOTAL PLANT CAPITAL COST (AT START OF PROJECT)				134.6
	$ / KW(E)				224.
	ESCALATION DURING CONSTRUCTION (0.0 PCT)				0.0
	TOTAL PLANT CAPITAL COST (AT COMMERCIAL OPERATION)				134.6
	$ / KW(E)				224.

that these costs do not represent costs of plants built in the USA, but costs of plants in a hypothetical developing country with equipment costs, materials costs and labour rates equal to those in the north-east of the USA.

Land costs

Land costs are treated as a separate item in both ORCOST programs. To reflect the lower cost of land in the Survey countries relative to the USA, land costs were assumed to amount to US $100 000 instead of US $1 million assumed in the original program.

GAS TURBINE PLANTS

Only 50 MW gas turbine plants were considered in the studies. Their installed cost was assumed to be US $125/kW at 1 January 1973 price levels. The costs were assumed to escalate at the same general inflation rate used for the other types of plants and equipment. Where more than 50 MW of capacity of this type was required, multiples of this 50 MW unit size were assumed with installed costs constant at US $125/kW.

HYDROELECTRIC PLANTS

As explained in Appendix A, all hydro or pumped-storage capacity, at any point in time, is merged in the WASP program with the then existing hydro or pumped storage into one equivalent hydro or pumped-storage plant. The costs of each hydro or pumped storage plant added to the system during the study period was taken as given by the country. In a few cases where costs of individual hydro projects were given, but no schedule was provided as to the order in which the projects would be constructed, average costs in US $/kW were determined for all projects in the group for which costs were given, and these average costs then used to obtain the installed costs of the required hydro capacity. Where known hydro potential was identified, but no costs were available, estimates were made of the installed costs based on known costs of existing projects in the same area or based on average conditions.

REFERENCES

[1] De LOZIER, R.C., REYNOLDS, L.D., BOWERS, H.I., CONCEPT – Computerized Conceptual Cost Estimates for Steam-Electric Power Plants – Phase 1 User's Manual, ORNL-TM-3276 (1971).

[2] De LOZIER, R.C., SRITE, B.E., REYNOLDS, L.D., BOWERS, H.I., CONCEPT II – Computerized Conceptual Cost Estimates for Steam-Electric Power Plants – Phase II User's Manual, ORNL-4809 (1972).

[3] USAEC Guide for Economic Evaluation of Nuclear Reactor Plant Designs, NUS-531 (1969).

[4] United Engineers and Constructors Inc., 1000 MW Central Station Power Plants Investment Cost Study, UEC-AEC-720630 (1972).

[5] BOWERS, N.I., MYERS, M.L., Estimated Capital Costs of Nuclear and Fossil Power Plants, ORNL-TM-3243 (1971).

[6] United Engineers and Constructors Inc. (Jackson and Moreland Division), Cost of Large Fossil Fuel-Fired Power Plants, J+M No.636 (1966).

[7] USAEC, CONCEPT – A Computer Code for Conceptual Cost Estimates of Steam-Electric Power Plants, WASH-1180 (1971).

APPENDIX C

LOAD DESCRIPTION DATA FOR WASP PROGRAM

REQUIRED DATA

The load description data required for the WASP program are as follows:

(1) Study increment, in MW.
(2) Peak load demand for each year of study period, in MW.
(3) Seasonal (quarterly) peak load demands expressed as a percentage of the annual peak load.
(4) Coefficients of a polynomial describing the shape of the load duration curves for each of the four seasons of the year.

The program will thus calculate the corresponding annual load factor for each year of the study.

The following describes how these data were obtained.

Study increment

In carrying out the computations associated with the load duration curves, these are divided into blocks of capacity (MW) equal to a selected study increment. To avoid on the one hand a too rough approximation of the load curve and on the other hand a waste of computer time, the study increment was selected in accordance with the following rules:

(a) It must be greater than the largest value of system installed capacity, during the entire study period, divided by 590.
(b) It should be less than 2% of the smallest value of system installed capacity during the entire study period.
(c) It should be less than approximately three times the capacity of the smallest generating unit in the system.

Peak load demands for each year of study

Peak load demands for each year of the study were derived from data provided by the country or by mathematical or graphical interpolation of the five-year interval forecasts developed by the method described in Appendix F.

Seasonal peak load demands

The seasonal variation of peak load demand in each case was obtained from historical data for representative years provided by the country. To simplify preparation of input data, the seasonal peak loads measured as a percentage of the annual peak load were assumed to remain constant throughout the study period.

Coefficients of a polynomial describing shape of load duration curves

Coefficients of a fifth order polynomial were used to represent the shape of the load duration curves. This fifth order polynomial gave a satisfactory fit in virtually all cases. The curve fitting was done by a standard polynomial regression program (No. 1001G/ST3 in the WANG 700 series program library) on a WANG Model 700 computer with plotter.

This program calculates the coefficients b_i in the expression

$$L = b_0 + b_1X + b_2X^2 + \ldots\ldots\ldots\ldots + b_5X^5$$

where L = fraction of peak load,
X = fraction of total time.

The computer then plots the fitting curve as shown in Fig. C-1. Examples of the coefficients b_0 to b_5 are shown in Table C-1 under the heading "Load coefficients in force this year".

In addition, a special program calculates both the slope of the curve at the point X=1 and also the load factor which is given by

$$LF = \int_0^1 L \, dX = b_0 + \frac{b_1}{2} + \frac{b_2}{3} + \ldots\ldots\ldots + \frac{b_5}{6}$$

It is important that the polynomial should not have a negative slope at any point. It follows therefore that

$$L = b_1 + 2b_2 + 3b_3 + \ldots\ldots\ldots + 5b_5$$

has to be less than 0 for $0 \leq X \leq 1$.

The value of b_0 is forced near to unity by entering the point (0, 1) a number of times. An additional program on the WANG forces it exactly to 1.

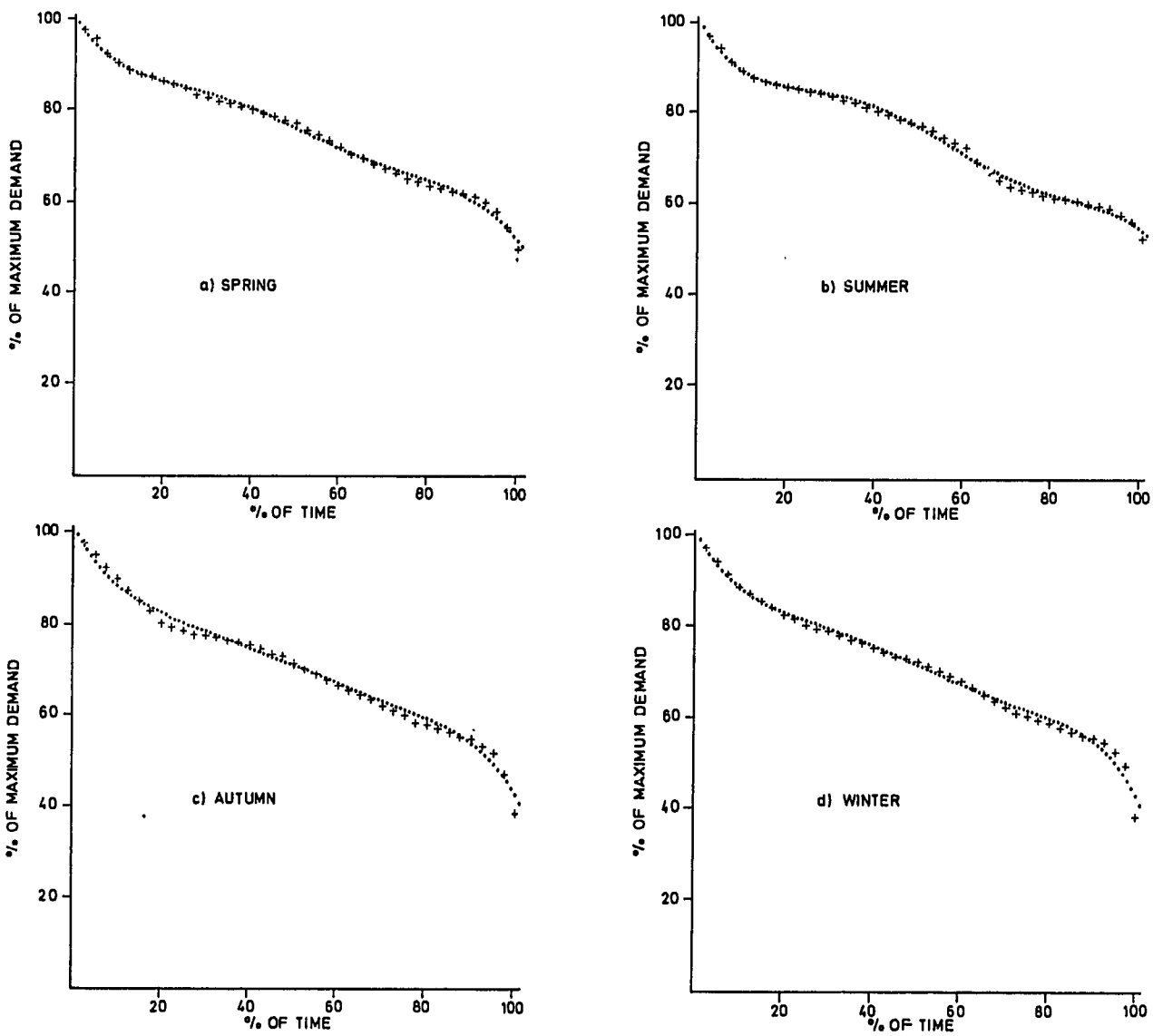

FIG. C-1. EXAMPLES OF THE FITTING OF A FIFTH ORDER POLYNOMIAL TO LOAD DURATION CURVES.

TABLE C-1. SAMPLE OUTPUT OF COMPUTER CALCULATIONS OF LOAD DURATION DATA.

```
PERIOD PEAK LOADS IN PU OF ANNUAL PEAK
  0.867000  0.989000  1.000000  0.971000

PERIOD PEAK LOADS IN MW
   25143.0   28681.0   29000.0   28159.0

LOAD COEFFICINTS IN FORCE THIS YEAR ARE
  1.000000 -2.958504 11.891810-23.599838 20.824448 -6.759686
  1.000000 -3.193929 12.838108-25.477798 22.481552 -7.297591
  1.000000 -3.131148 12.585763-24.977005 22.039658 -7.154149
  1.000000 -2.974198 11.954898-23.725037 20.934921 -6.795546

PERIOD   1 PEAK LOAD 25143.0 MW MIN LOAD   10012 MW
ENERGY UNDER LOAD DURATION CURVE     34304.1 GWH
PERIOD LOAD FACTOR(%) 62.30

PERIOD   2 PEAK LOAD 28681.0 MW MIN LOAD   10048 MW
ENERGY UNDER LOAD DURATION CURVE     37246.9 GWH
PERIOD LOAD FACTOR(%) 59.30

PERIOD   3 PEAK LOAD 29000.0 MW MIN LOAD   10530 MW
ENERGY UNDER LOAD DURATION CURVE     38169.4 GWH
PERIOD LOAD FACTOR(%) 60.10

PERIOD   4 PEAK LOAD 28159.0 MW MIN LOAD   11123 MW
ENERGY UNDER LOAD DURATION CURVE     38295.7 GWH
PERIOD LOAD FACTOR(%) 62.10
ANNUAL LOAD FACTOR(%) 58.26 ENERGY    148016.1 GWH

END OF DATA FOR YEAR 2000 * * * * * * * * * * * *
```

ANNUAL LOAD FACTORS

The following equations must hold:

$$AE = \sum_{1}^{4} PE_n = 2190 \sum_{1}^{4} (PLF_n)\,(PP_n)$$

$$AE = 8760\,(AP)\,(ALF) = 2190\,AP \sum_{1}^{4} (PPF_n)\,(PLF_n)$$

where AE = annual energy forecast,
AP = annual peak load,
ALF = annual load factor,
PLF = period load factor,
PP = period peak load,
PPF = period peak as a fraction of annual peak,
PE = period energy forecast.

From PLF, AP and PPF the WASP program will calculate an annual load factor (see Table C-1). If this calculated annual load factor (ALF_{ca}) is not equal to the projected annual load factor (ALF_{pr}) the values of PLF are modified by the quotient ALF_{pr}/ALF_{ca}. A code is available for the WANG 700 calculator which modifies the coefficients corresponding to a given PLF to give new coefficients corresponding to the projected PLF. This is done by calculating and applying a factor, a, as follows:

$$L = b_0 + a\,(b_1X + b_2X^2 \ldots\ldots b_5X^5) = 1 + \ldots\ldots \;.$$

Thus the shape of the curve is conserved.

This program was also used when the load factor varied during the time of the study. Figure C-2 shows an example of varying the load factor while conserving the shape of the load duration curve.

In some cases, seasonal load curves and load factors were not available but only one annual load curve and the seasonal minima and maxima. In these cases the following approximation for the load curve was used:

$$L = 1 - (1-LF^2)\, X^{LF}$$

From this expression the load factor LF can be shown to be

$$LF = \sqrt{L_{X=1}} = \sqrt{\frac{\text{minimum load}}{\text{maximum load}}}$$

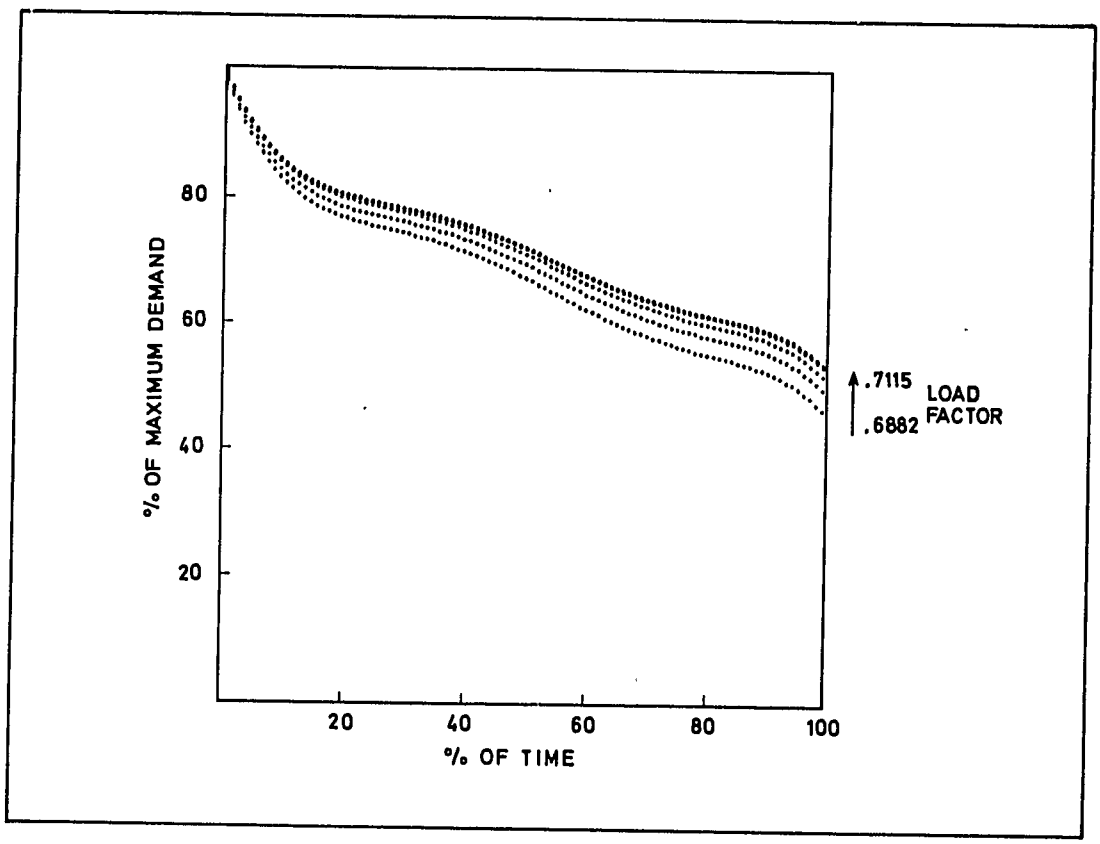

FIG. C-2. ILLUSTRATION OF THE EFFECT OF LOAD FACTOR ON A LOAD DURATION CURVE.

APPENDIX D

ECONOMIC METHODOLOGY AND PARAMETERS

The purpose of the Survey was to estimate the possible role of nuclear power in meeting the electric energy requirements of the countries over ten years from 1980 to 1989. Ideally the performance of this task would require estimating and comparing benefits and costs, both direct and indirect, arising from alternative development patterns, in order to determine in each case the power expansion plan yielding maximum total net benefits.

The above requirement has seldom been met in full even in analyses of a single project in one country. To fulfil it for the comparison of chains of projects extending over ten years and covering 14 countries would have been theoretically questionable and practically impossible.

A series of simplifying assumptions affecting both input data and the procedures for their aggregation, treatment and comparison was therefore unavoidable. The methodology described in the following sections represents an attempt at achieving a compromise between practical constraints and theoretical consistency.

The main components of this methodology involved:

(1) A definition of costs and benefits to be considered and the development of methods for estimating their quantitative values.

(2) A selection of criteria for comparing benefits and cost streams extending over time and containing domestic and foreign currency components in variable proportions.

(3) A choice of an optimization procedure and of a time horizon.

These three major components are reviewed in the following paragraphs.

DEFINITION AND ESTIMATES OF COSTS AND BENEFITS

It was assumed that costs rather than net benefits would be the only yardstick. This is tantamount to assuming that all programs of electric power expansion meeting projected demand with the imposed constraints on reliability offer the same total benefits and that the least cost program consequently yields maximum benefits to the ultimate consumers. In the case of comparing alternative ways of producing the same commodity, in this case electric power, this is a less questionable alternative than it would be in the general case of comparing alternative projects with different outputs. It does, however, ignore such indirect effects as, for instance, different employment levels arising from different power programs and their consequent effects on savings and investment or the future value of acquiring a pool of labour skilled in constructing and operating nuclear stations. Furthermore, it can lead to serious distortions where multi-purpose hydro plants are involved in the comparisons. Consequently in the latter case the share of costs assignable to power production was estimated.

Only costs directly connected with electricity production through a particular type of plant were taken into account. In particular such external or social costs as those arising from increasing environmental pollution in the case of fossil-fuelled stations or from the relatively larger thermal pollution by nuclear stations were disregarded in the basic analysis. The imposition of strict environmental controls by industrial countries leading to higher capital and fuel costs for thermal power stations shows that "external" costs may easily become "internal" over time. For the purpose of a basic analysis, however, and in spite of the recognition that the major industrial urban areas of some developing countries may well enact quantitative pollution controls, the effect of this assumption for the period under review does not appear to be decisive.

In all basic cases costs were defined as costs to the economy rather than costs to the electricity producers. A major consequence of this criterion was to eliminate taxes on all types of fuel and equipment from all cost inputs. This was a particularly critical assumption in the case of countries imposing a heavy fiscal burden on some types of fuel and in particular on fuel oil. It was felt, however, that the basic purpose of the Market Survey was

to advise countries on the total costs of alternative power programs estimated at the national level and that in this approach taxes represented internal transfers whose impact might distort the selection of power equipment which is most economic for the country as a whole. However, since the countries concerned are best judges of their tax policies which may involve items of social benefits disregarded by the Survey, since the electric utilities certainly view taxes on fuel and equipment as elements of costs, and since the Market Survey is addressed not only to the countries, but also to the potential equipment suppliers, alternative computations treating taxes as elements of costs were carried out for the cases which were expected to show critical differences in the results.

Finally, the actual data used as bases for capital and fuel costs of power stations and their extrapolation to varying local conditions are discussed in the relevant sections of the report.

SELECTION OF CRITERIA

The aggregation of domestic and foreign currency costs was carried out on the basis of the official rates of exchange prevailing on 1 January 1973. It is recognized that in many of the countries surveyed, the official rates do not reflect the relative values of foreign and domestic capital resources to the economy. Nor do they always represent values which achieve equilibrium between the supply of and the demand for foreign capital as evidenced by foreign exchange rationing and control, as well as by the existence of parallel markets.

The only defence of this approach which may substantially underestimate the true value of the ratio of foreign to domestic costs rests on its comparison with possible alternatives. The procedure of estimating "shadow" foreign exchange rates from 1980 till 1990 is dependent on political and economic forecasting and involves such a degree of uncertainty as to make its use unrealistic and its results highly doubtful. An estimate based on prevailing parallel rates would on the other hand rely on figures based on transitory trends and subject to large and rapid fluctuations.

The theoretical inaccuracies of using official rates of foreign exchange were somewhat reduced by the practices followed by some of the countries where the problem of instability was most acute. In some of these all domestic cost items of future projects were converted into hard currency equivalents on the basis of experience on past similar projects completed during periods when foreign exchange rates were more stable and more representative of the relative values of domestic and foreign capital resources.

As to the selection of the hard currency serving as common denominator, the US dollar was chosen for purposes of convenience and not because of any expectations of particular stability.

Increases of costs over time were assumed to take place at a rate identical for all countries and remaining constant over time. This rule involves three assumptions:

(a) The recognition of inflation as a permanent feature of the future economic development of both industrial and developing countries, an assumption which can hardly be questioned in the light of past experience.
(b) The assumption of an identical rate of inflation for all countries, which is admittedly wrong both on theoretical and empirical grounds but practically justifiable in view of the impossibility of realistic individual forecasts. The difficulty was, however, partially met by the combination of a single inflation rate with a series of alternative present-worth discount rates, a procedure more fully explained in the next section, thus giving each country the opportunity of basing its decisions on the values which it considers most relevant to its own case.
(c) The assumption of a rate constant over time is also based on considerations of practical expediency.

Finally the selection of 4% as the numerical value of expected annual price growth is a compromise between the much higher values recorded by most countries in the past and the somewhat lower targets set by their governments for the future.[1]

[1] The major exception was the rate of escalation for fuel oil which was taken at 6% for reasons explained at length in Appendix I.

The aggregation and comparison of time flows of costs was done through a discounting of their present-worth values and in all basic cases at a rate identical for all countries and assumed to remain constant in time. As in the previous case, this principle implies three decisions:

(a) The selection of present worth as a criterion. This decision must again be assessed against its possible alternative, which would have been to rank different patterns by their internal rate of return. The latter was, however, clearly ruled out since, apart from its theoretical flaws in the comparison of mutually exclusive projects, it requires estimates of benefits which the Survey deliberately refrained from making.
(b) The choice of an identical rate for all countries although the time value of money and resources is likely to be different for each of them. An objection to this choice is entirely valid and it was therefore decided to use a range of discount rates, computing for each country the corresponding present-worth values and consequent rankings of alternative expansion patterns and leaving to its discretion the decision which rate appears most suitable to its own conditions.
(c) The decision to assume that the rate of discount would remain constant in time may be open to theoretical objections since its value should in principle slowly decrease with higher levels of economic development and larger stocks of capital equipment. It was felt, however, that in the countries surveyed the practical difficulties involved in estimating, and in using, variable rates of discount far outweighed the possible advantages.

Finally the rates of discount and of inflation were combined into a single rate of discount equal to their difference. This considerably simplified the computational work since it was then possible to proceed on the basis of constant prices.[2]

For the basic case the rate of present-worth discount was chosen as 12% annual compound which was felt to be a representative average of the cost of money in most countries surveyed. Since, as was noted above, the rate of inflation was chosen as 4% annual compound, the corresponding constant price discount rate was 8%. For sensitivity studies constant price discount rates of 6% and 10% were used. The time origin for discounting was taken to be 1 January 1973.

METHODS OF OPTIMIZATION AND TIME HORIZON

In theory the selection of a lowest costs pattern of development for an electric power system requires:

(a) The choice of a method for a simultaneous optimization of the construction and operation of power plants expected to be available.
(b) The choice of a time horizon or cut-off date beyond which the differences of future costs arising from alternative decisions taken during the period under review may be considered negligible when reduced to their present-worth values at the date of origin for discounting.

Among the several methods of optimization, linear, non-linear and dynamic programming, the last was originally selected as offering the best combination of theoretical consistency and realistic system description. It became apparent, however, that the amount of computer time and man-power which the systematic application of this method would require were exceeding the limited resources of the IAEA computer made available for the Market Survey. Furthermore, the margins of uncertainty affecting some of the major input data did not always warrant the costs of applying a procedure based on such a comprehensive, detailed and exhaustive approach.

It was therefore decided, except for a few cases, to proceed along more empirical lines, thus achieving a substantial saving in time and man-power without an undue sacrifice

[2] This procedure of using a rate of constant costs discount $r' = r - i$, where r is the real rate and i the rate of inflation, is strictly valid only in continuous discounting, but the errors involved in discreet discounting are negligible.

of accuracy. For each country numerous plausible patterns of power system expansion of generating capacity for the 1980 to 1989 period were developed, their operation simulated under imposed constraints and the corresponding values of total present-worth costs computed for each pattern to find the minimum cost configuration. In each system, special attention was paid to determine in advance the system configurations which past trends and future constraints made particularly plausible. The theoretical flaws inherent in this empirical search were felt to be of relatively minor importance provided sound judgement was exercised in the selection of the alternative patterns used for simulation.

The selection of a time horizon was also based on compromise between theoretical accuracy and practical possibilities with the final decision substantially constrained by the latter factor. Consequently, while recognizing that a full analysis of the costs of power expansion patterns during the 1980 - 1989 period should theoretically extend up to a point in time when the economic consequences of alternative decisions lead to insignificant differences in present-worth values, it was also felt that detailed forecasts of development beyond the year 2000, and even beyond 1990, would not in most cases be realistic. Consequently, it was decided to take some, but not full account of future consequences by establishing for each system a single expansion plan for the 1990 - 2000 period which was then attached to each alternative plan for the 1980 - 1989 decade in the simulation and present-worth computation procedures. Furthermore, salvage values based on linear depreciation were factored in for all plants at the end of the Survey period.

The use of salvage values based on straight line depreciation, a practice current in most electric utilities accounting, involves a slight departure from strict economic accounting which should be based on sinking fund depreciation. It should be noted, however, that this procedure errs on the conservative side with regard to nuclear power stations since it leads to the use of higher present-worth coefficients than those of the sinking fund method.

As an example, for a power plant with a capital cost C commissioned j years before the cut-off date of the study and which is expected to have a useful life of ℓ years, the present-worth values of the capital cost of the plant net of salvage value discounted at the interest rate i would be given by

$$V_1 = C\left[1 - (1 - \frac{j}{\ell})(1+i)^{-j}\right]$$

according to the straight line method used in the survey, and

$$V_2 = C\,\frac{1 - (1+i)^{-j}}{1 - (1+i)^{-\ell}}$$

according to strict sinking fund depreciation.

For a plant built in 1985 or 15 years before the cut-off date set at year 2000, these formulae would yield the following capital cost charges to the objective function:

$$V_1 = 0.84\ C \text{ and } V_2 = 0.76\ C$$

Appendix A gives a comprehensive presentation of the WASP program used for simulating system operation and, in some selected cases, for dynamic optimization.

APPENDIX E

STANDARDIZED DATA FOR GENERATING UNITS CONSIDERED AS EXPANSION ALTERNATIVES

In order to facilitate preparation of input data for the WASP program, it was decided to standardize the characteristics of the various alternative types of thermal plants which might be used to expand the power system of each of the countries being studied. It was recognized that in some countries these standardized data might not be representative of units which would actually be considered as expansion alternatives and in such cases provision was made for modifying the data as necessary.

The following paragraphs describe the methodology used to develop the characteristics of the standardized alternative generating plants and the actual data used in the studies.

CHOICE OF UNIT SIZES, TYPES OF PLANTS AND NOMENCLATURE

Table E-1 shows the unit sizes, types of plants and standard nomenclature used for expansion alternatives. These choices were fixed in order to achieve comparable computer outputs.

TABLE E-1. SIZES, TYPES AND STANDARD NOMENCLATURE FOR EXPANSION ALTERNATIVES

Size (MW)	Type of plant					
	Nuclear	Lignite	Oil	Coal	Gas	Gas turbine
50						GT50
100	N100	L100	O100	C100	G100	
150		L150	O150	C150	G150	
200	N200	L200	O200	C200	G200	
300	N300	L300	O300	C300	G300	
400	N400	L400	O400	C400	G400	
600	N600	L600	O600	C600	G600	
800	N800	L800	O800	C800	G800	
1000	N1T0	L1T0	O1T0	C1T0	G1T0	

MINIMUM OPERATING CAPACITIES

It was recognized that thermal power plants can be designed to operate at as low as 25% of their rated capacity; for the purpose of the Survey, however, the minimum operating capacity of the standard plants was set at 50% of full load. Gas turbines were assumed to be operated at full load or not at all. Units in the fixed system (i. e. plants in the system at the start of the study period) with capacities below 50 MW were also assumed to operate only at full load and, for units of 50 MW and larger, the minimum operating capacity was taken to be that stated by the country.

HEAT RATES

Full load and half load heat rates for the standard alternative generating plants were derived from data provided by Bechtel Corporation and Lahmeyer International GmbH (see Appendix G for details of these).

OPERATING AND MAINTENANCE COSTS

Operating and maintenance costs of PWR and oil-fired plants were taken from data in the open literature [1, 2] adjusted to "end of 1972 dollars" by escalating at 4%/yr. Assuming that power stations would on an average have two units per station, operating costs for single unit plants were reduced by 15% to allow for the second unit. Property damage insurance was added to these costs. In the case of nuclear plants, this was assumed to amount to 0.25% of the capital cost and in the case of oil-fired plants to 0.1% of the capital cost. Tables E-2 and E-3 show the breakdown of operating and maintenance costs for PWRs and oil-fired plants. Gas-fired plants were assumed to have the same operating and maintenance costs as oil-fired plants, coal-fired plants were assumed to be 7% higher and lignite-fired plants 10% higher. These costs were adjusted to local conditions (i.e. lower staffing costs etc.) when warranted.

TABLE E-2. BREAKDOWN OF UNADJUSTED OPERATING AND MAINTENANCE COSTS FOR PWRs (10^3 US $/yr)[a]

Item	Capacity (MW)						
	100	200	300	400	600	800	1 000
Staffing	750	800	850	860	910	960	970
Maintenance supplies and services	260	330	410	465	580	680	760
Insurance[b]	500	570	610	690	810	940	1 070
Total	1 510	1 700	1 870	2 015	2 300	2 580	2 800
US $/kW per month	1.26	0.71	0.52	0.42	0.32	0.27	0.23

[a] Based on US conditions.
[b] Includes property damage and third party liability insurance.

TABLE E-3. BREAKDOWN OF UNADJUSTED OPERATING AND MAINTENANCE COSTS FOR OIL-FIRED PLANTS (10^3 US $/yr)[a]

Item	Capacity (MW)							
	100	150	200	300	400	600	800	1 000
Staffing	500	520	540	580	630	700	780	870
Maintenance supplies and services	170	200	240	300	360	500	620	760
Insurance	60	80	95	120	150	180	240	290
Total	730	800	875	1 000	1 140	1 380	1 640	1 920
US $/kW per month	0.61	0.45	0.36	0.28	0.24	0.19	0.17	0.16

[a] Based on US conditions.

SCHEDULED MAINTENANCE TIMES AND FORCED OUTAGE RATES

The scheduled maintenance times and forced outage rates assumed for the alternative generating plants are shown in Table E-4. These data result in the unavailability percentages given in Table E-5. They are essentially the same as the unavailabilities experienced on plants in the USA. These figures were also used for existing plants when actual data were unavailable. It is recognized that at the present time plant availabilities in some of the developing countries are substantially lower than these values. In addition, as nuclear units and much larger sizes of conventional plant are introduced, it is likely that total (forced and

TABLE E-4. SCHEDULED MAINTENANCE TIMES AND FORCED OUTAGE RATES OF ALTERNATIVE GENERATING PLANTS

Unit size (MW)	Scheduled maintenance (days/yr)		Forced outage rate (%)	
	Conventional	Nuclear	Oil/Gas, Nuclear	Coal, Lignite
50	21	-	7.5	9.6
100	21	28	6.5	8.6
150	21	-	5.3	7.5
200	21	28	5.4	7.5
300	28	28	6.5	8.7
400	28	28	9.8	12.0
600	28	28	12.0	14.1
800	35	35	12.2	14.5
1 000	35	35	12.2	14.5

TABLE E-5. PERCENTAGE UNAVAILABILITY OF ALTERNATIVE GENERATING PLANTS

Unit size (MW)	Unavailability (%)			
	Nuclear	Oil/Gas	Coal/Lignite	Electrical World[a]
50	-	13	15	13+
100	14	12	14	10 - 13
150	-	11	13	10 - 11
200	13	11	13	11
300	14	14	16	11 - 17
400	17	17	19	17
600	19	19	21	21
800	21	21	23	21
1 000	21	21	23	21

[a] Average for US plants as reported in Ref [3].

maintenance) outage times will be greater. This, however, is considered to be a transitory situation and it is expected that plant availabilities in the developing countries will improve with time as experience is gained with more sophisticated units until they approach those of the industrialized countries. This improvement is expected to occur within the study period of the Survey.

PLANT LIFETIME

Plant lifetimes were assumed to be 30 years for both nuclear and conventional plants. Linear depreciation of the plant investment cost was taken over this period. Since the levelized working capital component of the nuclear fuel cycle cost is treated as an addition to the plant investment cost, two years were added to the nuclear plant lifetime to correct for the fact that this working capital does not depreciate.

STUDY HORIZON

Although the time period of interest to the Survey is 1980 to 1989, the study horizon was extended to the year 2000 to allow for the influence of plants built in the second decade on the load factor of those introduced up to the end of 1989. Extension of the study horizon also results in a better approximation of the effect of escalation on the generating costs of oil-fired plants introduced in the 1980-1989 period (see also Appendix D).

TRANSMISSION COSTS

Transmission costs were not treated explicitly in the study, based on the assumption that they would be essentially the same for the alternative generating units being considered. In cases where extra transmission costs were required for the installation of a specific plant, such as a remote hydro plant, these were added to the capital costs of the plant and the available energy of the hydro plants was discounted by appropriate amounts to correct for transmission line losses.

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[1] KHAN, M.A., ROBERTS, J.T., "Small and medium power reactors – technical and economic status", 4th Int. Conf. peaceful Uses atom. Energy (Proc. Conf. Geneva, 1971) 6, IAEA, Vienna (1971) 57.

[2] NUS Corporation, Guide for Economic Evaluation of Nuclear Reactor Plant Designs, USAEC Rep. NUS-531 (1969).

[3] Electrical World (1 Nov. 1971) 47.

APPENDIX F

LONG RANGE FORECASTING OF THE DEMAND FOR ELECTRICAL ENERGY

H. Aoki

The basic objective of an electric power program is to provide sufficient power to meet the demand and to do so as economically as possible. In view of the time required for planning and constructing power plants, a plan for installing new power generation, transmission and distribution facilities should be established at least ten years in advance of the actual required date. The formulation of a reasonably reliable method for long range forecasting of the likely demand for electrical energy is therefore of vital importance.

A number of methods have been used and these are briefly reviewed below. The particular method used for providing forecasts for the countries covered by the Market Survey is described in detail.

VARIOUS METHODS

The methods used fall into two groups. In the first the country is considered in isolation, and the forecast is based upon past trends in that country.

(a) Simple extrapolation

The average growth rate of the demand for electrical energy over the past years is determined.

A factor, usually less than or equal to 1, is applied to the historical growth rate, and this modified growth rate is assumed for the future. Clearly the difficulty with this method lies in the determination of the modifying factor to be used for a particular country, particularly if it is a developing country.

(b) Correlation between the national economy and the energy demand

This involves taking some measure of the national economy, such as GNP or GDP, and comparing its historical growth with that for the demand for electrical energy. The past relationship between the two is then extrapolated into the future. Again this method is not particularly useful in the case of developing countries which are usually in a transitional stage of development in respect of their national economies and of their electrical energy demand.

Both methods can be useful for comparatively short range forecasts.

(c) Accumulative method

In this method various sectors of the country's economy and specific industries in the country are studied and estimates made of the likely individual future demands for electrical energy. These separate estimates are then added in order to give a complete forecast for the country. Again, this method is useful for short range forecasting but for long range it involves the making of sweeping assumptions about the long term development of particular industries and, whilst giving the appearance of accuracy, is in the end no more reliable than the first two methods.

The next three methods depend upon comparisons with one or more other countries.

(d) Sentiment method

This involves basing the forecast for a particular country upon either the forecast for what is believed to be a closely comparable country, or upon the recent experience of a country believed to be similar but rather more developed. Clearly the accuracy of this

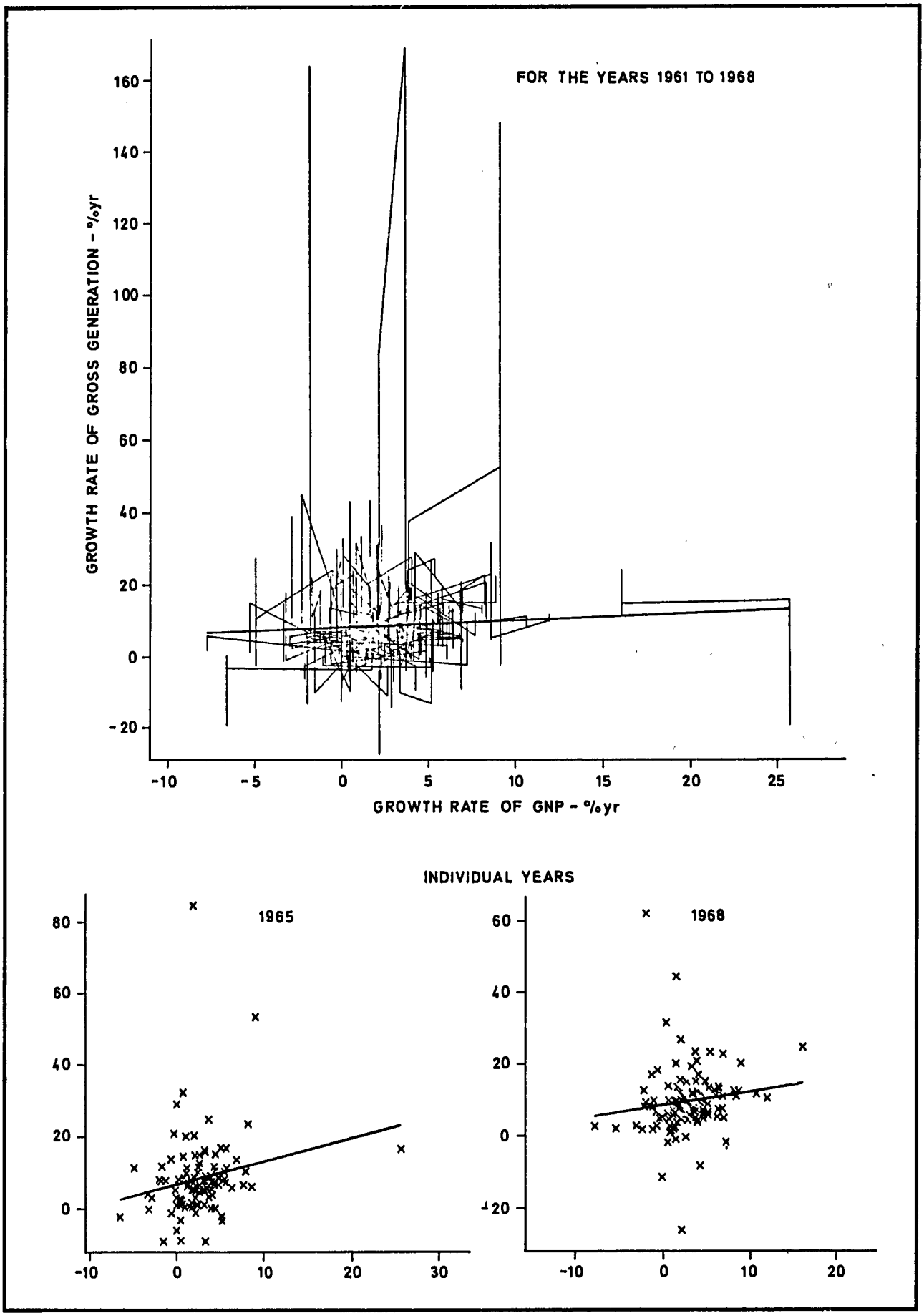

FIG. F-1. CORRELATION BETWEEN GROWTH RATE OF GROSS GENERATION AND OF GNP.

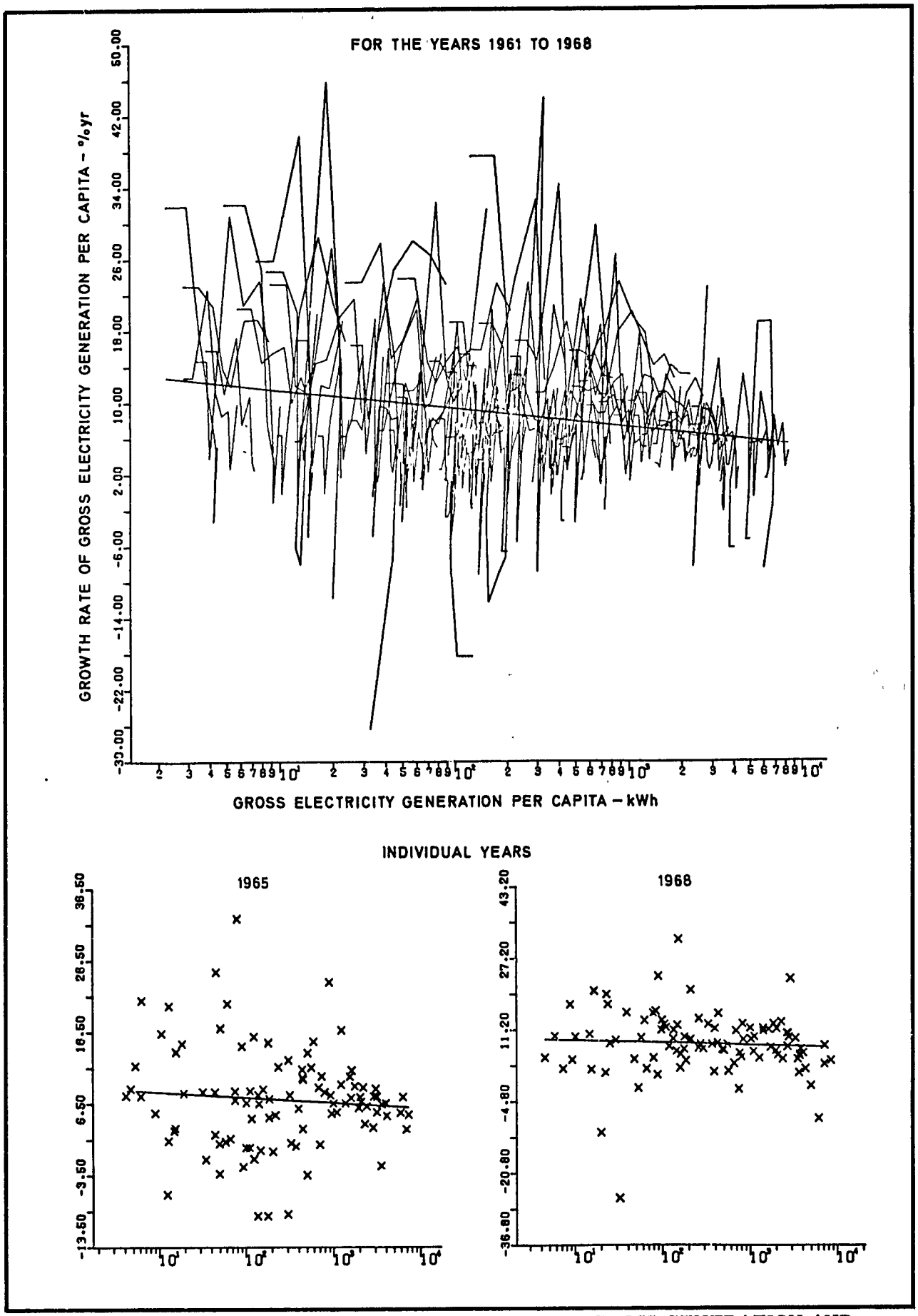

FIG. F-2. CORRELATION BETWEEN GROWTH RATE OF GROSS GENERATION AND OF GROSS GENERATION PER CAPITA.

method is completely dependent upon how comparable the reference country (or countries) really is. In this comparison it is necessary to take into account, for instance, the kind of energy resources available in the two countries since they might be similar in all respects except that one has a great deal of potential hydroelectric power which can be developed cheaply and the other has little potential or potential that would be costly to develop. The method is superficially attractive, but for the reasons stated cannot be recommended.

(e) World-wide correlation between growth rate of GNP and of energy generation

In this method the growth rate of GNP is plotted against the growth rate of electrical energy generation for as many countries as possible. If a correlation is seen to exist, and given that a reliable forecast of the future GNP can be made for the country being studied, this correlation can be used to forecast the future energy demand. Such data are plotted in Fig. F-1 for 111 countries, for the years 1961 to 1968 and for the two individual years 1965 and 1968. It will be seen from this figure that the correlation is very poor and this fact is confirmed by statistical analysis of the data. As a result this method cannot give reliable forecasts of electrical energy demand.

(f) World-wide correlation between the per-capita generation of electrical energy and the rate of growth of per-capita generation

This method would be used in a similar fashion to (e). The data for 111 countries are plotted in Fig. F-2. Clearly the correlation is a little better than that obtained for (e), but it is still inadequate for obtaining accurate forecasts of electricity demand.

THE AOKI METHOD USED FOR THE MARKET SURVEY

This method is similar to the last two described in that it is based upon data from a large number of countries. It is similar to method (e) in that it assumes that there must be a connection between generation of electrical energy and the state of the national economy. But it introduces the concept that the per-capita values of these variables, rather than the absolute values should be correlated. Figure F-3 shows a plot of electricity generation per capita against GNP per capita for 111 countries. The historical GNP data used in this plot were obtained from the IBRD World Table, January 1971, and are expressed in terms of constant prices (1964 US $).

The correlation between these two quantities is clearly much better than the one achieved in either method (e) or (f) and the correlation coefficient of the straight line fit shown in Fig. F-3 is remarkably high. Since the data at the upper and lower end of the figure tend to fall below this line, it is obvious that a better fit could be obtained by using a polynomial. This has been done in effect by determining the best straight line fit over a series of intervals of per-capita GNP as shown by Fig. F-4 for the 1968 data. It is important to note that both the single correlation lines and the curves obtained from the series of straight lines are virtually the same whether determined for any single year in the period 1961 to 1968 or determined from the data for all eight years grouped together (see Fig. F-5). Thus there is evidence that the relationship is stable and can be accepted as "universal".

The consequent recommended relationship is plotted in Fig. F-6. Close examination of the individual country lines in Fig. F-3 shows that, in general, if the initial point representing a particular country falls above or below the line, subsequent points at higher values of GNP per capita approach more closely to the trend line.

It is therefore possible to draw a number of "indicative" lines on each side of the main trend line which will indicate the likely path that will be followed by countries whose present state does not lie exactly on the line. Such indicative lines are drawn in Fig. F-6.

The use of the Aoki method has essentially been indicated above. A copy of the master trend curve is taken. The available historical data for the country being studied are plotted

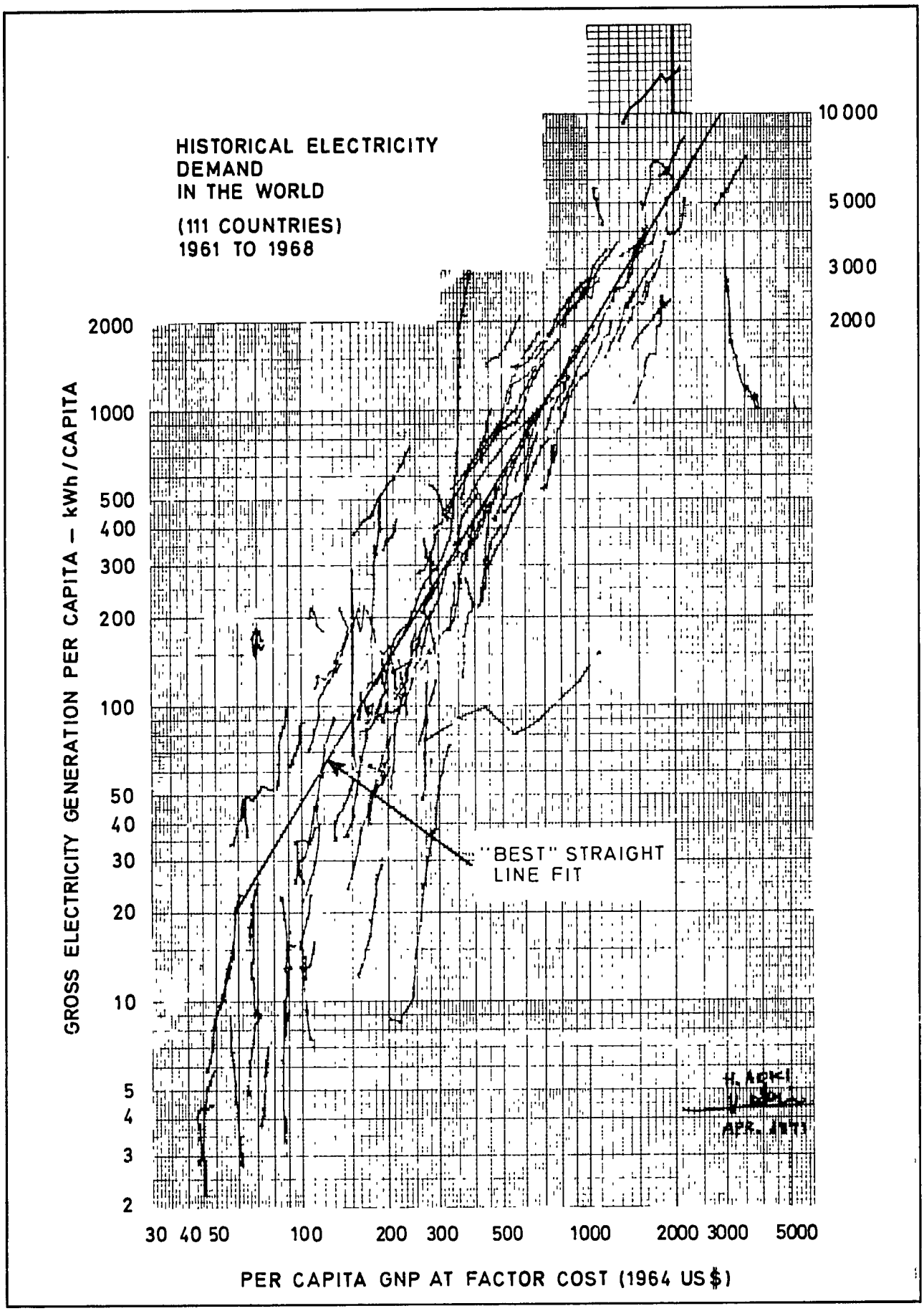

FIG. F-3. CORRELATION BETWEEN GROSS GENERATION PER CAPITA AND GNP PER CAPITA FOR 111 COUNTRIES FOR 1961 - 1968.

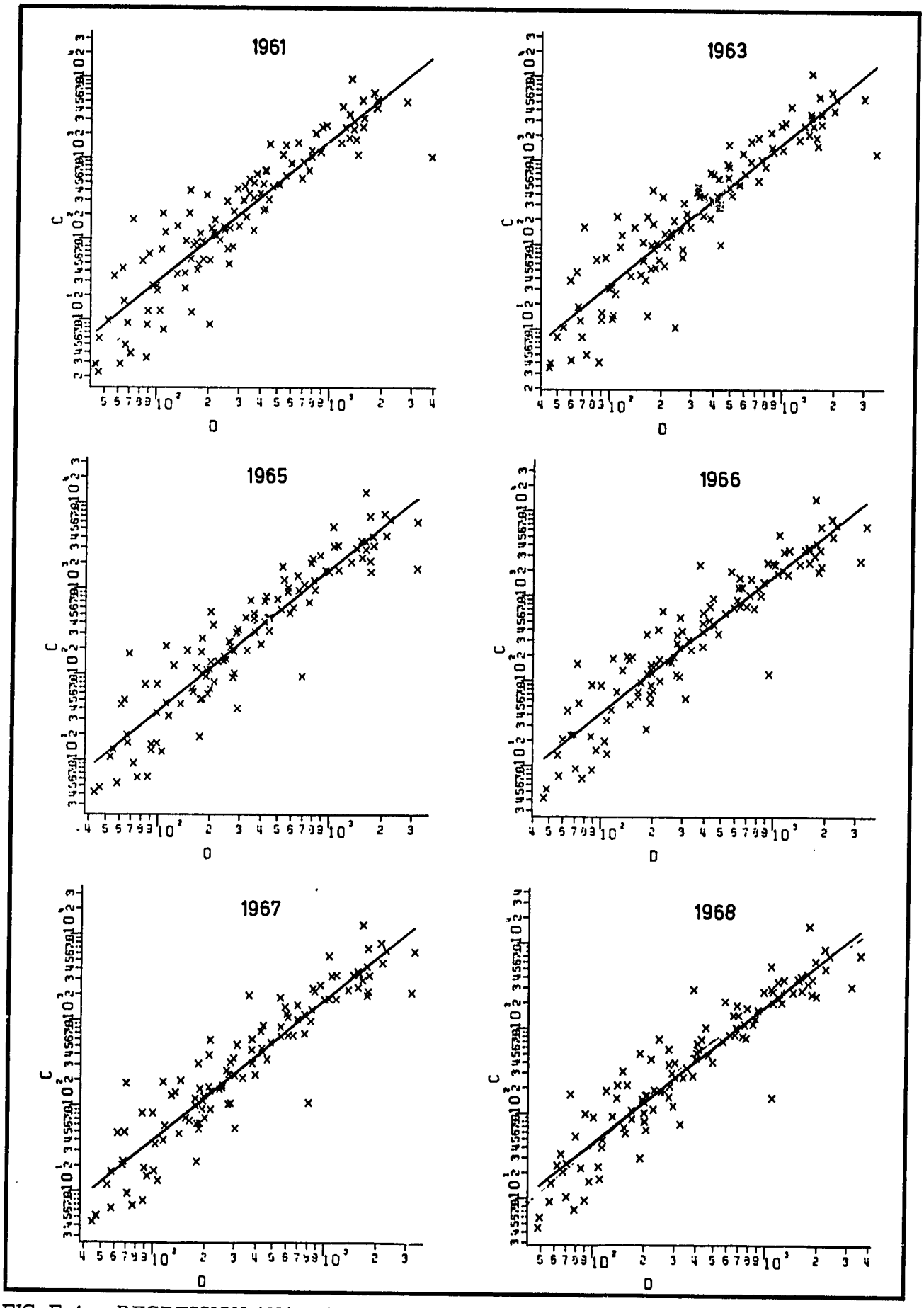

FIG. F-4. REGRESSION ANALYSIS OF THE PLOT OF GROSS GENERATION PER CAPITA VERSUS GNP PER CAPITA FOR 1968.

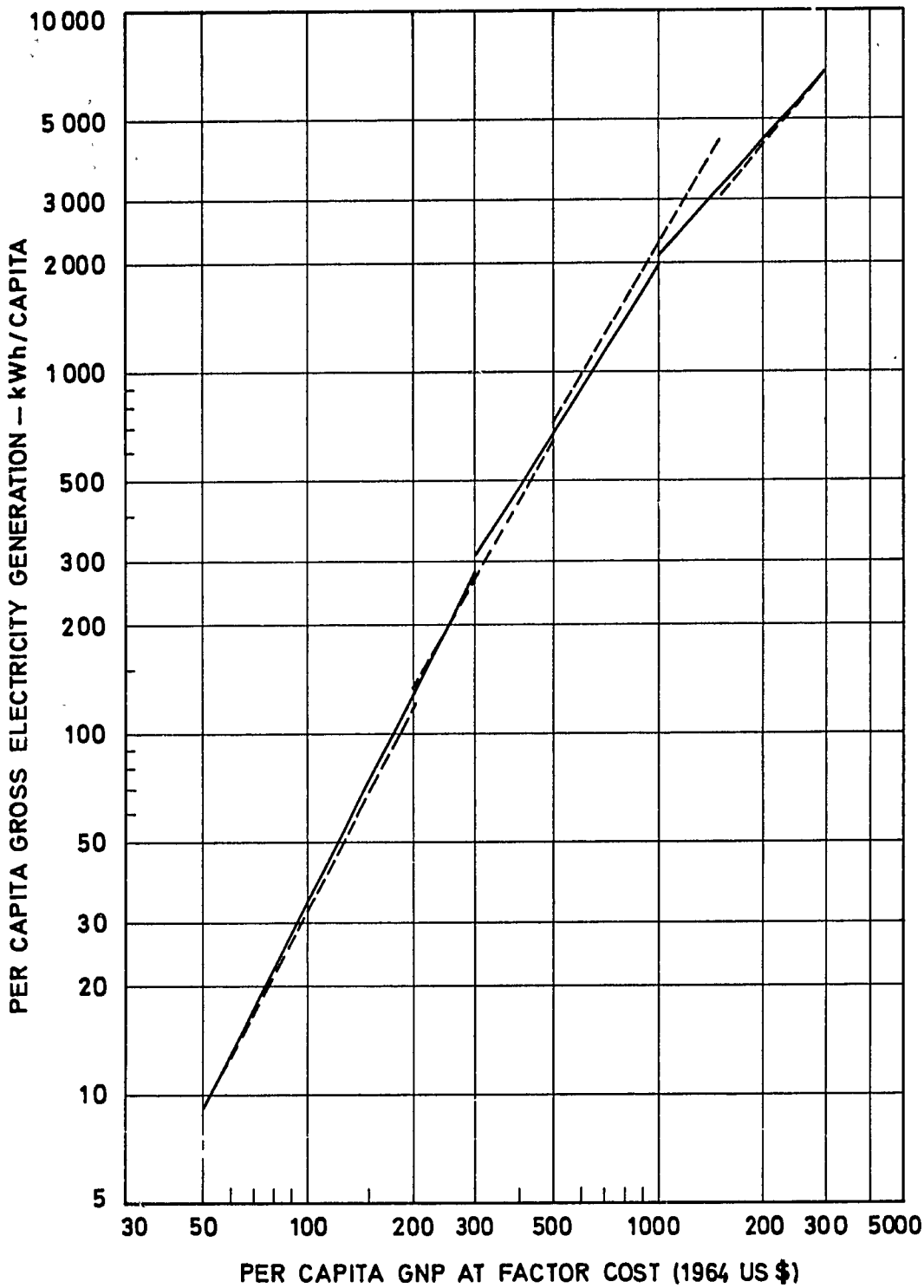

FIG. F-5. CORRELATION FOR INDIVIDUAL YEARS.

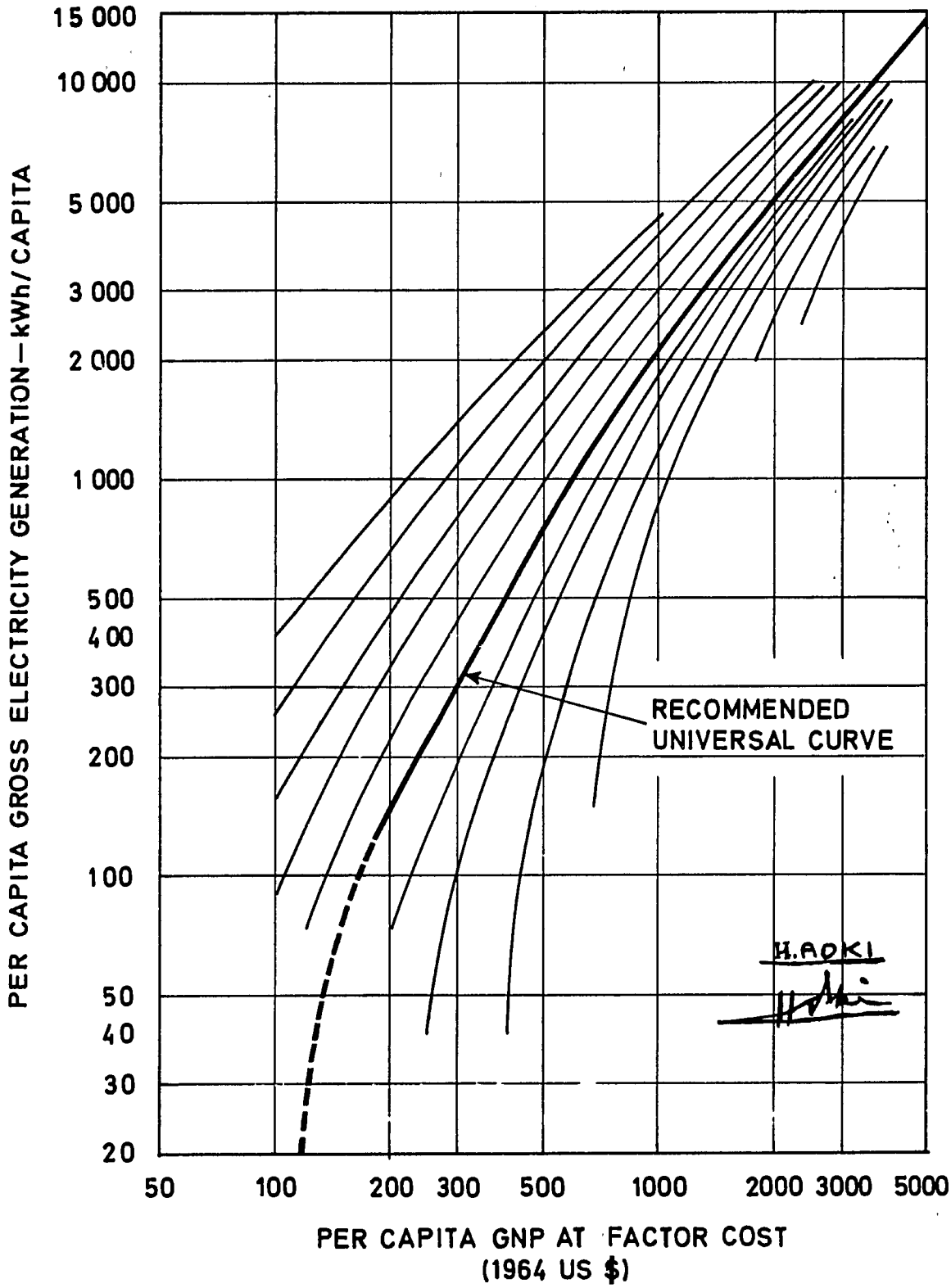

FIG. F-6. RECOMMENDED RELATION BETWEEN GROSS GENERATION PER CAPITA AND GNP PER CAPITA.

on the diagram. The future is then forecast by extrapolating this line following the main trend line or one of the indicative lines as appropriate. Given that a forecast of the future growth of GNP per capita is available, the future demand for electrical energy is then calculated from this extrapolation. This is done for the Survey countries in Figs F-7 and F-8.

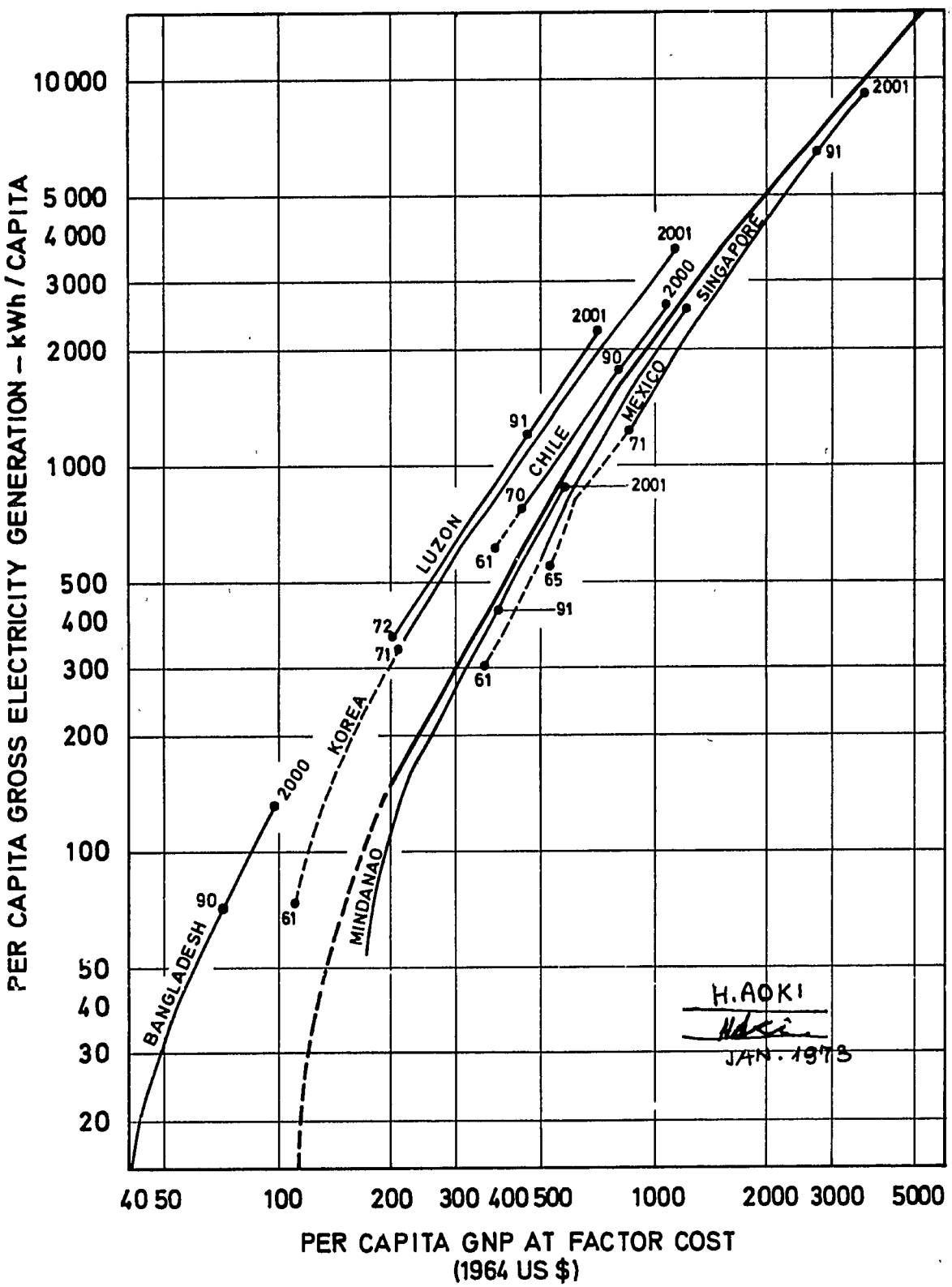

FIG. F-7. SURVEY COUNTRIES PLOTTED ON RECOMMENDED CURVE.

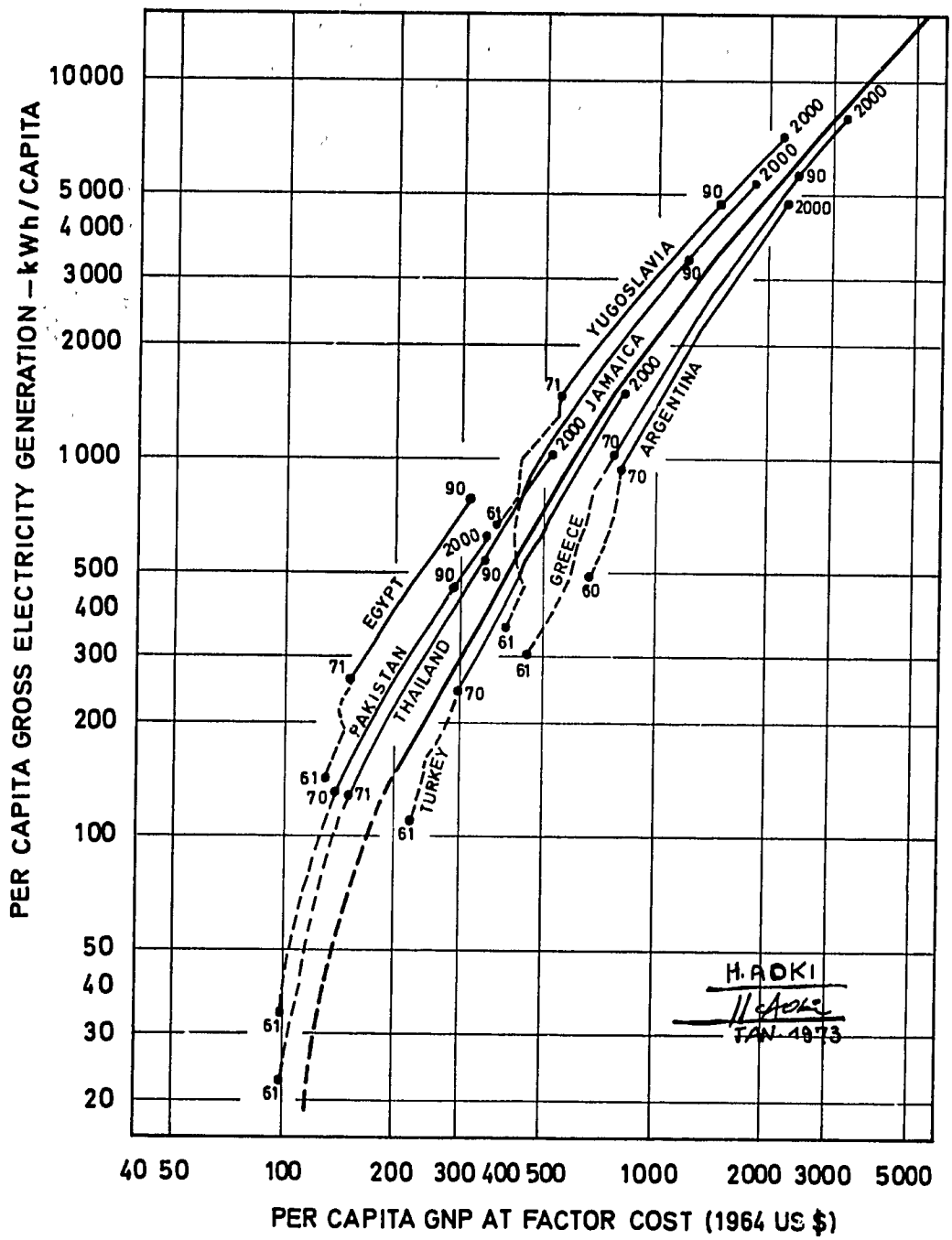

FIG. F-8. SURVEY COUNTRIES PLOTTED ON RECOMMENDED CURVE.

APPENDIX G

BASIS FOR HEAT RATE DETERMINATION

To permit an evaluation of the performance of various types of thermal power plants, the heat rates for energy conversion are required. Experienced power plant designers were requested to supply heat rates for modern plants of the type and size used in the expansion program for the various systems studied. The most detailed response was received from the Bechtel Corporation and the heat rates used in the study are based on the Bechtel data. These data were confirmed by information received from Lahmeyer International and also by data on existing plants collected in the participating countries.

The net and gross heat rates for pressurized water reactors (PWR) of capacity from 100 to 1500 MW and for coal, lignite, gas and oil stations from 100 to 1000 MW are listed in Tables G-1 to G-4. To be consistent with the country data on the fixed systems and on load forecasts, the gross heat rates were used in the study. The net heat rates are given to permit people familiar with design data to appreciate to more easily the values used.

The net heat rates for light water PWRs are calculated on the following bases:

(1) The use of a seven-heater cycle utilizing a two-reheat turbine is assumed. There are two high pressure heaters whose cascaded drains, combined with those of the third heater, are pumped into the reactor feed pump suction. Reactor feed pumps are driven in all cases by auxiliary turbines. All data on nuclear steam supply systems (NSSS) are based on information obtained from the Combustion Engineering Company (CE). This NSSS generates saturated steam at 70 kg/cm^2 (a 1.5 kg/cm^2 pressure drop to the turbine stop valve was assumed in all cases). Final feed-water temperature is 230°C.

(2) Auxiliary power requirements for reactor sizes of 800 MW and above are based on information obtained from CE. Auxiliary power requirements for reactor sizes below 800 MW are assumed to be 1.75% of output at the generator terminals at rated power and condenser pressure of 3.0 in Hg abs. In all cases, auxiliary power for the balance of plant is broken down in the following fashion:

	Rated load	50% load
Main transformer losses	0.40%	0.70%
Circulating water system (once through) auxiliary power	0.30%	0.60%
Balance of plant exclusive of main transformer & circulating pumps	0.95%	1.65%
Total balance of plant auxiliary power	1.65%	2.95%

(3) It should be noted that all heat rates assume that steam is generated at 70 kg/cm^2. Historically, the smaller units in the range 400 to 800 MW generated steam at 55 kg/cm^2 (770 lb/in^2 abs.); later steam pressures for larger units were increased to 58 kg/cm^2 (815 lb/in^2 abs.), and then to 63 kg/cm^2 (900 lb/in^2 abs.). Thus the heat rates in this study would appear better in comparison. However, CE states that were they to offer any of these smaller units today, they would quote them all on the basis of steam generated at 70 kg/cm^2 (1000 lb/in^2 abs.).

Heat rates were computed on the basis of using in all cases the smallest turbine exhaust consistent with turbine exhaust loading limits as specified by the two US turbine manufacturers.

TABLE G-1. NET HEAT RATES FOR FOSSIL-FUELLED PLANT[a]

Type	Full load		Half load		Incremental energy rate[b] (kcal/kWh)
	Power (MW)	Heat rate (kcal/kWh)	Power (MW)	Heat rate (kcal/kWh)	
Coal	100	2 443	50	2 592	2 294
	150	2 421	75	2 551	2 291
	200	2 378	100	2 501	2 255
	300	2 360	150	2 474	2 246
	400	2 358	200	2 463	2 253
	600	2 350	300	2 467	2 233
	800	2 352	400	2 472	2 232
	1 000	2 348	500	2 483	2 213
Lignite	100	2 666	50	2 832	2 590
	150	2 642	75	2 787	2 497
	200	2 595	100	2 732	2 458
	300	2 574	150	2 702	2 446
	400	2 573	200	2 690	2 456
	600	2 565	300	2 694	2 436
	800	2 567	400	2 701	2 433
	1 000	2 561	500	2 712	2 410
Gas	100	2 529	50	2 671	2 388
	150	2 506	75	2 629	2 383
	200	2 461	100	2 5[illegible]	2 345
	300	2 443	150	2 551	2 335
	400	2 441	200	2 539	2 343
	600	2 433	300	2 593	2 323
	800	2 435	400	2 549	2 321
	1 000	2 431	500	2 560	2 342
Oil	100	2 390	50	2 528	2 252
	150	2 368	75	2 487	2 249
	200	2 327	100	2 438	2 216
	300	2 309	150	2 413	2 205
	400	2 307	200	2 403	2 211
	600	2 300	300	2 406	2 194
	800	2 302	400	2 412	2 192
	1 000	2 297	500	2 422	2 172

[a] Based on information received from Bechtel Corporation.

[b] Incremental energy rate = $\frac{\text{(Full load heat rate) (Full load power) - (Half load heat rate) (Half load power)}}{\text{(Full load power - Half load power)}}$

TABLE G-2. GROSS HEAT RATES FOR FOSSIL-FUELLED PLANTS[a]

Type	Size (MW)	Full load heat rate (kcal/kWh)	Half load heat rate (kcal/kWh)	Incremental energy rate (kcal/kWh)
Coal	100	2 311	2 411	2 211
	150	2 290	2 374	2 206
	200	2 233	2 306	2 160
	300	2 280	2 361	2 199
	400	2 233	2 351	2 115
	600	2 270	2 354	2 186
	800	2 272	2 360	2 184
	1 000	2 268	2 370	2 166
Lignite	100	2 512	2 615	2 409
	150	2 490	2 574	2 406
	200	2 427	2 500	2 354
	300	2 478	2 560	2 396
	400	2 427	2 549	2 305
	600	2 468	2 553	2 383
	800	2 470	2 559	2 381
	1 000	2 465	2 570	2 360
Gas	100	2 420	2 526	2 314
	150	2 404	2 486	2 322
	200	2 344	2 415	2 273
	300	2 393	2 473	2 213
	400	2 344	2 461	2 227
	600	2 383	2 465	2 301
	800	2 385	2 471	2 299
	1 000	2 381	2 482	2 280
Oil	100	2 290	2 388	2 192
	150	2 270	2 347	2 193
	200	2 213	2 280	2 146
	300	2 259	2 335	2 183
	400	2 213	2 324	2 098
	600	2 250	2 328	2 172
	800	2 252	2 334	2 170
	1 000	2 248	2 344	2 152

[a] Based on information received from Bechtel Corporation.

The net station heat rates for fossil-fired units are based on the following assumptions:

(1) Steam generator efficiencies are based on 144°C exit gas temperature at full load, and on the following fuels:
   (a) bituminous coal at 5544 kcal/kg (10 000 Btu/lb),
   (b) lignite at 3465 kcal/kg (6250 Btu/lb),
   (c) low sulphur or "bunker C" fuel oil,
   (d) natural gas.

TABLE G-3. PWR NET HEAT RATES[a]

Full load		Half load		
Net generator output (MW)	Heat rate (kcal/kWh)	Net generator output (MW)	Heat rate (kcal/kWh)	Incremental energy rate (kcal/kWh)
100	2 591	50	2 840	2 342
200	2 590	100	2 834	2 346
300	2 589	150	2 828	2 350
400	2 589	200	2 822	2 355
600	2 587	300	2 811	2 363
800	2 585	400	2 799	2 371
1 000	2 583	500	2 786	2 380

[a] Based on information received from Bechtel Corporation.

TABLE G-4. PWR GROSS HEAT RATES[a]

Size (MW)	Full load heat rate (kcal/kWh)	Size (MW)	Half load heat rate (kcal/kWh)	Incremental energy rate (kcal/kWh)
100	2 504	50	2 651	2 357
200	2 503	100	2 648	2 359
300	2 502	150	2 645	2 361
400	2 502	200	2 643	2 362
600	2 501	300	2 637	2 365
800	2 500	400	2 632	2 368
1 000	2 499	500	2 627	2 372

[a] Based on information received from Bechtel Corporation.

(2) All steam generators are balanced draft, with both forced and induced draft fans.
(3) Flue gas electrostatic precipitators are included for coal and lignite steam generators only. Precipitator power requirements are assumed to be 0.20% of rated generator load at full load, and 0.40% of generator load at half load. Flue gas SO_2 scrubbers and associated auxiliary power have not been included.
(4) Turbine throttle conditions are assumed to be 125 kg/cm^2 and 537°C with reheat to 537°C for the 100 and 150 MW units; and 168 kg/cm^2 and 537°C with reheat to 537°C for the 200 MW to 1000 MW units.
(5) All turbines are tandem compound, with the low-pressure turbine frame-size chosen for the closest possible approach to maximum allowable exhaust-steam flow loading, to obtain the required unit generator load rating.
(6) Boiler feed pumps are motor driven for the 100 to 200 MW units and steam turbine driven for the 300 to 1000 MW units.
(7) A once-through condenser cooling water system has been assumed (no cooling towers), with the circulating water pumping power assumed to be 0.25% of the rated generator load at full load, and 0.50% of the generator load at half load.
(8) The main transformer loss has been assumed to be 0.40% of rated generator load at full load, and 0.70% of generator load at half load. The net station heat rates are at the high voltage side of the main transformer.
(9) All full load heat rates are 3.0 in Hg abs. condenser pressure and all half load heat rates are at 2.0 in Hg abs. condenser pressure.

Note: Assumptions 8 and 9 apply also to the PWR units.

APPENDIX H

GENERALIZED POWER SYSTEM ANALYSIS APPROACH TO DETERMINE SYSTEM LIMITATIONS

Associated Nuclear Services Ltd (ANS)*

Power system anaysis plays an important role in determining the technical constraints to be taken into account in system design and planning studies and powerful and sophisticated techniques are available for evaluating such aspects as power flows, short-circuit levels, transient stability and frequency stability. However, the limited extent and wide tolerances associated with system data normally available for long-term planning studies of the present nature often contrast considerably with the sophistication and accuracy of these analysis techniques. Fortunately, in a study involving the comparison of a number of expansion plans, the optimization process is relatively insensitive to system data over the typical range encountered on present-day networks.

A simplified approach to system analysis is thus sufficient for the Market Survey purposes, provided this is applied consistently. The technical constraints of major interest to the Survey are transmission limitations and limits to generator unit size. This appendix describes the generalized methods adopted for the assessment of these constraints in the majority of countries. In one or two countries either or both aspects had been studied in sufficient depth by the supply authority or their consultants over the study period (1980 to 1989) and only a comparative check is necessary. Details of the application of the methods (where necessary) and results are given in Section 11 of the Country Reports.

TRANSMISSION LIMITATIONS

The main functions of transmission may be categorized as follows:

(i) Bulk distribution/collection within a load/generation region.
(ii) Point-to-point bulk transmission from a 'remote' power station to a load centre (may be long or short distance).
(iii) Inter-regional bulk transmission (i.e. an extension of (ii) to a group of remote power stations).
(iv) Inter-regional interconnection.
(v) International interconnection.

The normal transmission limitations encountered are excessive short-circuit levels, thermal ratings and transient stability limits. The varying importance and generalized approach to the assessment of these limits with reference to the above categories is discussed below.

Short-circuit levels

Where possible the short-cricuit rating(s) of grid switchgear for the various categories above are generally chosen with sufficient margin to cover system development into the foreseeable future taking into account average transmission distances, load density and the relative expected proportion of local and remote power generation. Excessive short-circuit levels are most commonly encountered in very high load density areas (category (i)) particularly where the grid system is predominantly cabled (small transmission impedances) and it has been found necessary to employ switchgear of the maximum commercially available short-circuit rating. Also, increasing the proportion of load fed from generation connected at local grid voltage level will aggravate the grid short-circuit problem.

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The normal eventuality of excessive short-circuit levels is the introduction of a higher voltage grid, other measures such as system segregation merely introducing a time delay which will be approximately equal for all plans. Hence the timing of a higher grid voltage in a particular system as dictated by short-circuit ratings will tend to be a common factor in all practical plant programs and will generally have little influence on the economic comparison of programs. Thus it was only necessary to check grid switchgear ratings against normal practice and where applicable to identify any special limitations or requirements.

Load flow transient stability

To achieve a reasonable standard of supply security the transmission grid should be capable of meeting the normal and 1st contingency power flow requirements throughout each plan without exceeding cricuit thermal ratings, loss of system stability (system splitting) or recourse to load shedding.

Information on standard grid circuit thermal ratings was generally available from each country. Transient stability limits were estimated using the 30° transmission angle criterion. This is a guiding criterion which, for the typical fault types and fault clearance times encountered on present-day systems, will ensure the retention of transient stability in the majority of cases. In the few cases where unforeseen difficulties arise, it is usually possible to retrieve the situation by introducing or increasing shunt and/or series compensation. With transmission costs of typically 15% to 20% of total plant costs and compensation costs at 10% to 15% maximum of transmission costs, the rare maximum error thus involved in this approach is of the order of 2% of total plant costs. This is regarded as being well within the accuracy of the capital cost data available to the Survey and there is no justification for a more elaborate approach to transient stability assessment, barring perhaps some well recognized exceptions.

The most common restriction to power flows in category (i) transmission are the thermal capabilities of circuits. However, this will tend to be a common factor in all generating plant programs considered for a particular country and detailed load flow studies within major load or generation regions were not necessary for the Market Survey.

For category (ii) transmission, the power flow requirement was simply estimated from the capacity of the power station less any local load to be supplied. Inter-regional power flow requirements (categories (ii) and (iii)) were determined by a simple regional plant/load balance tabulation taking into account generating set size and outage criteria and varying hydrological conditions. The number of transmission circuits at grid voltage to meet the power flow requirements so determined for categories (ii), (iii) or (iv) was then estimated to sufficient accuracy, taking into account thermal ratings, transient stability limits and transmission security criteria. If the number of circuits was excessive, then a higher voltage was considered and first establishment costs and also step-down transformer capacity were taken into account.

A further consideration in determining the capacity of category (iv) transmission is the integrity of the interconnected system following faults or a sudden loss of load or generation. Experience of interconnected systems in particular in the USA and the Scandinavian countries [1, 2] indicates that for a reasonable stability performance the capacity of system interconnectors should be at least 10% of the installed generating capacity of the smallest of the two systems interconnected. This was used as a guiding criterion for analysis purposes.

Details of any existing or proposed international interconnections (category (v)) were obtained from the Survey countries. In all cases these were found to be of insufficient capacity to have any noticeable influence on the Survey results.

LIMITS TO SET SIZE

The economics of scale play a major role in reducing the specific cost of installed generation and this is particularly so for nuclear power generation. On the other hand, increased unit size has associated penalties in system requirements such as generation and transmission reserve capacity. Thus there exists an optimum size for overall minimum cost of power delivered to the consumer [1].

The effects of increased unit size on the transmission system are taken into account in the network analysis described in this appendix. Any special transmission requirements can be allowed for by adjusting plant input data to the WASP computer program as described in Appendix E. The effect of increased unit size on non-availability rates and generation reserves can be directly allowed for in the corresponding input data items of the WASP computer program as required by the loss-of-load probability routine described in Appendix A. In this manner the 'economic optimum' set size can be determined. However, in addition to the economic optimum set size there is what may be termed a 'technical limit' set size (or reactor size in the case of nuclear stations) dictated by the permissible disturbance effects following the sudden loss of the largest generating unit. In cases where this technical limit is less than the economic optimum (which is highly probable in smaller systems) this can have a dominant influence on the economics of introducing large units into such systems.

The system frequency transient following sudden loss of a large generation unit has been found of prime interest in the assessment of this technical limit. The complete representation of this transient, termed 'frequency stability', is very complex, but a simplified analysis method and computer program was developed by ANS for the sudy of typical system response to sudden loss of generation. Although approximate, the analysis technique is regarded as adequate for the Market Survey purposes, bearing in mind the relatively large tolerances in data inherent in a forecasting exercise. The technique and computer program are described in the following paragraphs.

The average system frequency model

The dynamic response of a power system to a sudden loss of generation is generally characterized by two distinct components of power variation in the period of 10 to 20 seconds immediately following the disturbance. These are the faster transient oscillations in synchronizing power (time period typically 1 - 2 s) which arise due to angular disturbances from the steady state and the slower variation in prime mover power (time period typically 10 - 20 s) due to the primary regulation effects of the governor/turbine response to frequency change. The ability of a system to remain in synchronism following a given angular disturbance is mainly dependent on the transfer impedances between sources, i.e. on the transmission network. System faults will usually give rise to much larger angular deviations than loss of generation and will thus dictate the requirements of the transmission network for retention of transient stability. Thus, provided the transmission network has been designed with due regard to transient fault studies and the emergency redistribution of power flow resulting from plant outages, it is reasonable to assume that synchronous stability will be retained following a sudden loss of generation. (A possible exception to this premise is the case of a sudden loss of generation immediately following a severe system fault. However, such second contingency events are not considered here.)

Assuming that the system remains in synchronism then, neglecting losses (which may be assumed constant throughout the disturbance), the rate of change of stored kinetic energy (i.e. frequency) at any instant is equal to the difference between power input to the system (i.e. prime mover power) and power output (i.e. load),

$$(2H_T)(f_a)\left[\frac{df_a}{dt}\right] = \Sigma P_{mk} - P_L \qquad (1)$$

where H_T is the total inertia constant of connected machines including rotating loads (typically 3.0 to 5.0),

ΣP_{mk} is the sum of prime mover input power of connected generators,

P_L is the total connected load,

f_a is the average system frequency.

All quantities are in p.u. on the base of nominal system frequency and total nominal power of connected generation.

Since the system is assumed to remain in synchronism the transmission network may be neglected and Eq. (1) may be modelled by a number of prime movers and their generating units feeding a single block load as indicated in Fig. 1 and referred to as 'the average system frequency model' [3]. Simplified equations modelling the variation of prime mover power and load are described in the next section.

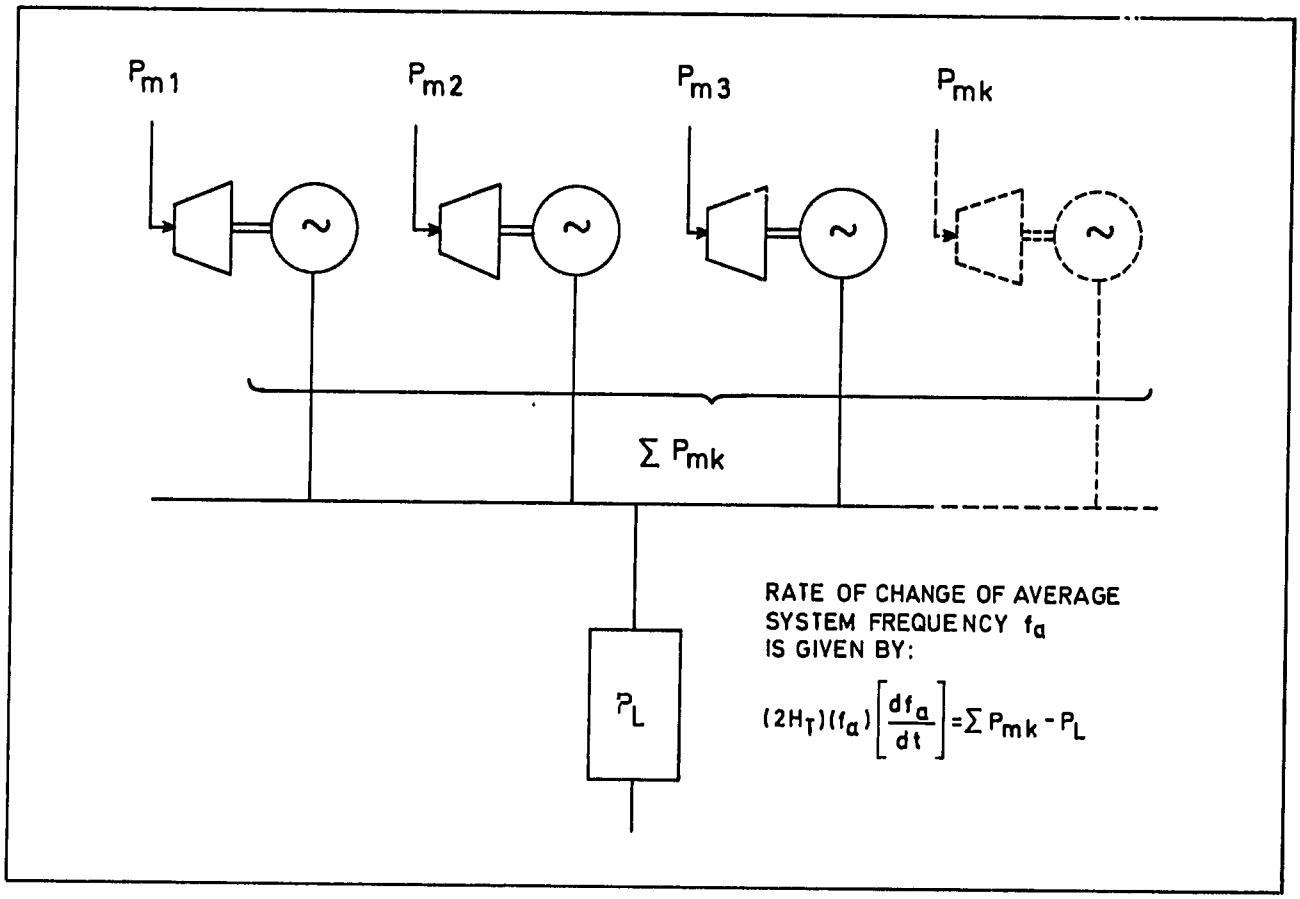

FIG. H-1. AVERAGE SYSTEM FREQUENCY MODEL.

Prime mover and load regulation

Maximum frequency dip before recovery (if it occurs), the time of maximum dip and the amount of load shed (if load shedding is permitted) are the main items of interest and thus the following assumptions can be made:

(i) Non-regulating base load units are assumed to have constant power output.
(ii) Only the governor/turbine response of regulating units is considered. Boiler response is neglected in thermal plants.
(iii) Secondary regulation is neglected.
(iv) Governor response is based on average system frequency. (The oscillating component due to synchronizing swings is generally at a much shorter time period than the governor/turbine response time and does not appreciably affect the prime mover output.)
(v) The total load P_L is assumed to depend only on average system frequency. Variations due to the oscillating component arising from synchronizing swings are neglected. Load variation with voltage, if desired, can be sufficiently represented by conversion to an equivalent variation with frequency.

Three types of regulating units are modelled:

(a) Thermal – non-reheat
(b) Thermal – reheat
(c) Hydro including pumped storage

For the time period of interest (about 10 s) thermal units will generally permit faster power change rates than hydro units, but with a limit on sustained change (typically up to 15%

of nominal power). Hydro units on the other hand can give much larger sustained variations in output approaching their nominal rating with total response times of typically 10 to 20 seconds.

(a) Thermal – Non-reheat model

It is assumed that the disturbance is of sufficient magnitude to drive the steam valve to its limiting position at constant rate. The time constant of a non-reheat turbine may be neglected and thus the change in power output of this type of unit may be represented to a first approximation by the equation

$$P_1 = \left[\frac{P_{1c}}{T_1}\right] (t) \text{ with limit of } P_{1c} \tag{2}$$

where P_{1c} is the maximum permissible power change,
T_1 is the time for the valve to move to its limiting position,
t is the time from loss of generator

(b) Thermal – Reheat model

As for the previous type the movement of the steam valve may be approximated by the equation

$$V_2 = \left[\frac{P_{2c}}{T_2}\right] (t) \text{ with limit of } P_{2c} \tag{3}$$

where P_{2c} is the maximum permissible power change,
T_2 is the time for the valve to move to its limiting position.

The change in power output of this type of regulating unit may thus be represented by

$$P_2 = \frac{1 + (m)(T_h)(p)}{1 + (T_h)(p)} (V_2) \tag{4}$$

where m is the proportion of power developed by the high pressure turbine
T_h is the reheat time constant
p is the Laplace operator

The maximum permissible power change for both reheat and non-reheat type generation will depend on the allocation of spinning reserve but will be typically about 10% of the nominal power of the generation block and may lie in the range 5% to 20%. The valve motion time is typically one second and may vary between 0.5 and 1.5 seconds. The factor m is typically 0.3 and the reheat time constant T_h may lie in the range 5 to 12 seconds.

(c) Hydro model

In Ref. [4] a simplified transfer function is derived which gives a very good approximation to the response of a hydro governor with dashpot. From this the change in gate opening may be represented by the equation

$$G = \frac{1 + (T_d\ p)}{1 + (T_3\ p)} \left[\frac{\sigma_a}{\delta}\right] (P_{n3}) \text{ with limit } P_{3c} \tag{5}$$

where $T_3 = \frac{T_g + T_d\ (\delta + \delta_t)}{\delta}$

T_d is the dashpot time constant (typically 5 s, range 2.5 - 25 s),
T_g is the governor response time or the inverse of governor open loop gain (typically 0.2 s, range 0.2 - 0.4 s),
δ is the permanent droop (typically 0.04 p.u., range 0.03 - 0.06 p.u.),
δ_t is the temporary droop (typically 0.31 p.u., range 0.2 - 1.0 p.u.),
σ_a is the average frequency deviation (= $f_a - f_0$),
P_{n3} is the nominal rated power output of regulating hydro generation,
P_{3c} is the maximum available change in power output (hydro spinning reserve).

Thus the change in power output for this type of regulating unit is given by

$$P_3 = \frac{1 - (T_w)(p)}{1 + 0.5(T_w)(p)} (G) \tag{6}$$

where T_w is water starting time and is inversely proportional to water head and directly proportional to penstock length. Typical values of T_w lie in the range 0.5 to 5.0 seconds.

The above model was also used to represent pumped storage plant operating in the generating mode.

Load regulation model

The variation of load with frequency may be represented by an equation of the type

$$P_L = (1 + (\alpha)(\sigma_a))\ (P_{L0} - P_s) \tag{7}$$

where P_{L0} is the total connected load at t = 0 and $f_a = f_0$,
P_s is the load shed as function of frequency and time,,
α is the load frequency regulation coefficient.

In those countries where load shed schemes are in existence, frequency settings and the amount of load shed for each stage were based accordingly. In other cases typical values were assumed. The determination of whether or not load shedding occurs is generally the prime factor of interest and thus the first stage frequency setting is the major item of load shed data. This is typically 48.5 to 49.0 Hz for 50 Hz systems and 58.5 to 59.0 Hz for 60 Hz systems.

The special case of pumping load being shed by under-frequency detection can be included in the load shedding scheme.

In Ref. [5] a range of values for the load/frequency regulation coefficient from 0 to 2.5 is given. The effects of load/voltage regulation can generally be adequately represented by increasing α. Thus a typical value for α of 2.0 was used except where more accurate information was available from the country studied.

Total regulation

The total prime mover power of connected units at instant t is given by

$$\Sigma P_{mk} = \Sigma P_{mk0} + P_m \tag{8}$$

where ΣP_{mk0} is the pre-disturbance power output of connected generating units excluding the lost generator, and

$P_m = P_1 + P_2 + P_3$ is the total change in prime mover outputs of connected regulating units.

Let the loss of generation be ΔP $(= P_{L0} - \Sigma P_{mk0})$ and since $\frac{d\sigma_a}{dt} = \frac{df_a}{dt}$, Eq. (1) becomes

$$(2H_T)(f_a)\ \frac{d\sigma_a}{dt} = P_m - \Delta P - (\alpha)(\sigma_a)(P_{L0} - P_s) + P_s \tag{9}$$

The effect of variations in f_a on the solution of Eq. (9) is small and may be neglected, hence

$$\sigma_a = \frac{1}{\alpha(P_{L0} - P_s) + (2H_T)(p)}\ (P_m - \Delta P + P_s) \tag{10}$$

The computer program

The computer program AVSYF (Average system frequency) for the step-by-step solution of Eq. (10) has been obtained by appropriately "patching" an existing digital program representation of an analogue simulator. Transfer functions of the type of Eqs (4-6), integral functions and limit functions exist as standard routines. Integration is performed by a simple three-step method, but provided a small enough time step is used, accuracy is sufficient. The program also includes a plot routine which permits an immediate plot of the frequency variation to be obtained as output.

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APPENDIX I

FUTURE FOSSIL FUEL PRICES

R. Krymm

INTRODUCTION

Although practically all countries covered by the Market Survey possess and exploit domestic fossil fuel resources, fuel oil either imported or derived from imported crude remains in most cases the main competitor of nuclear fuels for future electric power production.

This fact alone suggests the use of fuel oil as the "reference fuel" and the validity of this assumption is further strengthened by the tight supply and demand relationship which is expected to prevail for oil products in the foreseeable future. The latter consideration suggests that the few Market Survey countries which are domestic producers of oil and gas in substantial quantities would be perfectly justified in pricing these resources on the basis of opportunity uses; that is, on the basis of thermal costs parity with imported fuel oil with due correction for transportation expenses.

Also, prices of coal and lignite are dependent on local conditions and must be considered separately in each specific case.

It is, therefore, not surprising that the bulk of this section is devoted to the problem of costs and prices of crude and fuel oils entering international trade.

It was, however, clear from the beginning that the fuel oil picture in developing countries could not be seriously studied without reviewing the world-wide structure of the oil industry and its rapidly changing trends.

It was, therefore, decided to consider in turn:

(1) The present and expected demand and supply structure of crude oil and the major producing and consuming areas.
(2) The changing cost and price structure of crude oil and its future trends.
(3) The cost of transport of oil by tanker and pipelines.
(4) The relationship between crude and oil product prices.
(5) The treatment of domestically produced fossil fuels.

DEMAND AND SUPPLY OF CRUDE OIL

Table I-1 shows the actual 1970 and estimated 1980 demands for oil in major areas of the world. The forecast is based on conservative rates of growth and the average annual rate of 5.4% for the world should be viewed against the 7.8% rate which prevailed during the 1950-1970 period.

TABLE I-1. PAST AND ESTIMATED DEMAND FOR CRUDE OIL (10^6 t)

	1970 (10^6 t)	1980 (10^6 t)	Rate of growth of demand (%)
USA	750	1 160	4.5
Western Europe	600	980	5
USSR and Eastern Europe	390	700	6
Japan	200	400	7
China	20	80	15
Rest of world	300	500	5
Total world	2 260	3 820	5.4

TABLE I-2. WORLD ESTIMATED CRUDE OIL PRODUCTION[a]

Countries	1970	1971	1972	% Change 1971/72	1972: % of Total
		10^3 t			
NORTH AMERICA[b]					
USA	533 677	530 385	532 000	+12.3	
Canada	69 954	75 025	87 500	+16.6	
	603 631	603 410	619 500	+2.7	23.9
CARIBBEAN AREA					
Venezuela	193 209	184 921	167 400	-9.5	
Colombia	11 071	11 127	10 400		
Trinidad	7 225	6 690	7 400		
	211 505	202 738	185 200	-8.7	7.9
OTHER LATIN AMERICA					
Mexico	21 877	21 920	22 600	+3.0	
Argentina	19 969	21 494	22 150	+3.0	
Brazil	8 009	8 376	8 400		
Ecuador	191	174	3 500		
Peru	3 450	3 048	3 300		
Bolivia	1 124	1 714	1 900		
Chile	1 620	1 652	1 700		
	56 240	58 378	63 550	+8.9	2.4
MIDDLE EAST					
Saudi Arabia	176 851	223 515	285 500	+27.7	
Iran	191 663	227 346	254 000	+11.7	
Kuwait	137 398	146 787	152 000	+3.6	
Iraq	76 550	84 000	67 000	-20.2	
Abu Dhabi	33 288	44 797	50 000	+11.6	
Kuwait/SA "Neutral Zone" ..	26 724	29 118	30 300	+3.9	
Qatar	17 257	20 201	23 300	+15.3	
Oman	17 169	14 106	13 600	-3.6	
Egypt	16 404	14 706	11 000		
Dubai	4 306	6 252	7 500		
Sinai[c]	4 500	6 000	6 000		
Syria	4 353	5 254	5 300		
Bahrain	3 834	3 728	3 500		
Turkey	3 461	3 253	3 350		
Israel	77	62	50		
	713 835	829 125	912 400	+10.0	35.0
AFRICA (excluding Egypt)					
Libya	159 201	132 250	105 000	-20.5	
Nigeria	53 420	75 306	89 500	+18.8	
Algeria	47 253	36 346	52 000	+42.1	
Angola	5 065	5 830	7 200		
Gabon/Congo	5 442	5 794	6 600		
Tunisia	4 151	4 097	4 100		
Morocco	46	22	30		
	274 578	259 645	264 430	+1.8	10.2

TABLE I-2. (cont.)

Countries	1970	1971	1972	% Change 1971/72	1972: % of Total
		10^3 t			
WESTERN EUROPE					
West Germany	7 535	7 420	7 100		
Austria	2 798	2 516	2 500		
Norway	-	301	1 700		
Netherlands	1 919	1 715	1 630		
France	2 309	1 858	1 500		
Italy	1 408	1 294	1 200		
Spain	156	120	250		
Denmark	-	-	100		
UK	83	84	84		
	16 208	15 308	16 064	+4.9	0.6
FAR EAST					
Indonesia	42 102	44 521	54 000	+21.3	
Australia	8 292	14 373	15 150		
Brunei	6 916	6 528	9 200		
India	6 809	7 191	7 500		
Malaysia	859	3 275	4 450		
Burma	750	840	900		
Japan	750	751	730		
Pakistan	486	487	450		
Taiwan	90	112	100		
	67 054	78 078	92 480	+18.4	3.6
Western Hemisphere.. ..	871 376	866 526	868 250	+0.2	33.4
Eastern Hemisphere	1 071 675	1 182 156	1 285 374	+8.8	49.4
	1 943 051	2 048 682	2 153 624	+5.0	82.8
EASTERN EUROPE AND CHINA					
USSR	352 574	376 992	394 000	+4.5	
Romania	13 377	13 794	14 000		
Yugoslavia	2 854	2 953	3 100		
Hungary	1 937	1 955	1 950		
Albania	1 199	1 350	1 575		
Poland	424	395	370		
Bulgaria	334	304	250		
East Germany	200	200	250		
Czechoslovakia	203	193	195		
China[d]	20 000	25 500	29 600	+16.0	
	393 102	423 636	445 300	+5.1	17.2
World totals	2 336 153	2 472 319	2 598 924	+5.1	100.0

[a] Excluding small-scale production in Cuba, Thailand, New Zealand, Mongolia and Afghanistan.
[b] Including natural gas liquids, in Canada also synthetic oils.
[c] Under Israeli occupation.
[d] Including oil from shale and coal.

Even under these modest assumptions, Tables I-1, I-2, I-3 and I-4 demonstrate some striking developments, the most important being:

(a) A growing dependence of the USA on imported oil and, in particular, on Middle Eastern oil even though allowance has been made for Alaskan production at the end of the decade.

(b) A growing Western European dependence on imported and Middle Eastern oil even though allowance has been made for maximum North Sea production and the percentage share of imports is expected to decrease.

(c) A continuation of Japan's total dependence on oil imports.

(d) A sharp rise in Middle Eastern production which is expected to double over the 1970-80 decade from 700 to 1500 million tons per year when it will represent close to 40% of total world production and more than 50% of that of the non-socialist countries while bringing to the countries of the region annual revenues of the order of 30×10^9 US $/yr.

TABLE I-3. NATIONAL PRODUCTION AND IMPORTS IN THREE MAIN CONSUMING AREAS (10^6 t)

	National production		Total imports		Imports from Middle East	
	1970	1980	1970	1980	1970	1980
USA	534	660	214	500	30	300
(% of consumption)	(71)	(57)	(29)	(43)	(6)	(26)
Western Europe	16	160	584	820	300	600
(% of consumption)	(2.6)	(24)	(97.4)	(76)	(50)	(61)
Japan	1	2	199	398	170	300
(% of consumption)	(0.5)	(0.5)	(99.5)	(99.5)	(85)	(75)
Total	551	822	987	1 718	500	1 200

TABLE I-4. PAST AND ESTIMATED PRODUCTION IN MAJOR EXPORTING AREAS[a] (10^6 t)

	1970	Share of world consumption (%)	1980	Share of world consumption (%)
Middle East	714	31.6	1 500	39.3
Africa	274	12	330	8.6
Caribbean	212	9.3	220	6
Total	1 190	52.6	2 050	54

[a] For exact definition of the geographical areas, see Table I-2.

No mention is made at this stage of estimated world oil reserves, not because the subject is not important, but because the figures usually advanced are highly questionable and cover an extremely wide range. Thus, for instance, figures of the order of 60×10^9 tons are often advanced for proven oil reserves while ultimate potential reserves which were estimated at around 90×10^9 as late as 1960 are now quoted as exceeding 900×10^9 tons if account is taken of probable off-shore oil fields, secondary recovery methods, oil-bearing shales and tar sands. It thus appears that the question for the next few decades is not one of exhaustion, but of costs.

It should, however, be noted that if demand continues to expand indefinitely at the 5.4% rate forecast for the next seven years, even the 900×10^9 tons of presently estimated ultimate reserves would only last 55 years instead of the 15 years assured by 50×10^9 of proven fields. Consequently, the 15 to 1 ratio between the two reserve figures should not be construed too optimistically.

COST AND PRICE STRUCTURE OF OIL AND ITS FUTURE TRENDS

The question of cost and prices of oil is fraught with difficulties unparallelled in any other industry:

(a) Technical difficulties in accurately defining a particular type of crude. Oils of different characteristics have, of course, historically sold at different prices, but the problem has become particularly acute recently because of environmental consideration which could restrict drastically the sulphur emissions from oil-fired stations in most industrial countries. Without going into the intricate problem of costs of desulphurization it should be noted that differentials of 50% and more can exist between prices of crudes in the same producing area depending on their sulphur content.

(b) Accounting difficulties in ascertaining the real price of crude rooted in the structure of the international oil industry which has, up to now, controlled the production, distribution and marketing of petroleum through vertically integrated operations. As a result, most of the oil entering international trade was moved from producing to refining and marketing subsidiaries at accounting prices fixed internally by the integrated companies essentially in the light of fiscal considerations, while only small amounts of crude were sold to outsiders at what might have been considered market prices.

(c) Political difficulties arising from the relatively small share of production costs in the total selling price. As Table I-5 shows, the cost of production represents less than 10% of the price of crude in the Middle East, the remaining 90% being divided between revenues to host countries and profits to producing companies. Historically, the split between two groups has been the result of a constant power struggle which has recently turned in favour of the countries which now collect more than three-fourths of the f.o.b. price of crude. The latest steps of the struggle were marked by the Teheran Agreement which sharply increased the share of the host nations and provided for automatic increases every year until January 1975. A no less important step was taken at the beginning of 1973 with the Participation Agreement entered into by several of the Arab countries and, in particular, by Saudi-Arabia and Kuwait, providing for a 25% ownership of production by the countries with a final objective of 51% participation by 1981. While Iran and Libya may follow different approaches, there is an unmistakable trend towards control of production by the countries of origin. For the time being, the participating countries plan to re-sell their share of production to the international oil companies which control the necessary distribution and marketing channels, but the situation may well change over the present decade.

(d) Economic difficulties arising from the theoretical impossibility of allocating costs of crude oil to the variety of oil products obtained as a result of refining. Gasoline, kerosene, naphtha, light fuel oil, and heavy fuel oil obtained from a single input of crude are priced separately by private companies according to market conditions in order to maximize total profits. There is no way in which the cost of producing, transporting and refining one ton of crude oil can actually be allocated to the different products derived from it.

TABLE I-5. ILLUSTRATIVE BREAKDOWN OF PRICE OF HEAVY KUWAIT CRUDE IN PERSIAN GULF AND WESTERN EUROPEAN HARBOURS[a] (US $/t)

Production cost	1
Producing country royalties and taxes	10
Company profit	2
Total	13
Transport cost to Rotterdam by 130 000 t tanker	6
Delivered cost at harbour refinery	19

[a] Needless to say, this table and Table I-6 are presented as illustrations rather than precise cost breakdowns which would require an analysis of the refining, distribution, marketing and fiscal situation in a specific country.

To this should be added another important consideration affecting the whole price structure of oil products. Table I-6 illustrates two important and connected points: the heavy impact of indirect and direct taxes levied by oil importing countries on the total costs of oil products to the ultimate consumers and the wide gap between these total final costs paid by the users and the "technical production costs", however widely these may be defined. Although the values given in this table are approximate averages and although Western Europe is one of the areas with the heaviest burden of taxation on oil products, the conclusions are nevertheless generally valid.

TABLE I-6. ILLUSTRATIVE AVERAGE COST STRUCTURE OF OIL PRODUCTS OBTAINED FROM ONE TON OF CRUDE IN WESTERN EUROPEAN COUNTRIES (US $/t)

Cost of crude at harbour	19
Cost of refining	3.50
Storage, inland transit, distribution and marketing	20
Profits of distributing companies	2.50
Taxes levied by consuming countries (excise taxes on products and corporate income taxes)	40
Total	85

With regard to the incidence of taxation by industrial countries, it will be seen that it represents close to 50% of the costs of the ultimate products, and about 4 times the amount of taxes levied by producing countries. True, these taxes fall mainly on gasoline (although several Western European and some developing countries also tax heavy fuel oil) and the fiscal revenues are used for highway maintenance, traffic control etc.; in other words, for tasks which actually make the use of oil products possible. Nevertheless, the fact remains that the impact on final costs is extremely heavy.

This leads to the second point, i.e. the almost total divorce of costs of production from ultimate revenues derived from a given quantity of crude oil, a situation radically different from that of for instance coal for which the relationship is much more rigid.

Production costs in the Middle East are less than 2% of the ultimate total (1.2% of US $85/t in the example given). If company profits, transportation and refining costs are added, the combined cost would still remain less than 20%. Finally, even if distributing and marketing costs are counted, the percentage would only increase to 41%, so that close to 60% of final outlay go to taxes levied by governments of either the producing or consuming countries. This cost structure has several consequences, one of the most important being the relative insensitivity of final product costs to variations in the costs of production at the oil field. In the example given, an increase of the cost of production of crude oil in the Middle East by a factor of 10, from US $1 to 10 per ton, would only lead to a 12% rise in the ultimate product costs to the consumers. This goes a long way towards explaining the wide disparity of actual oil production costs throughout the world. It also points to the probability that higher costs connected with off-shore production, shale oil recovery and other potential reserves will prove no serious obstacle to their future exploitation.

Finally, it should be pointed out that taxes on heavy fuel oil may seriously affect its competitive position and lead to major distortions in the selection of power plants with a resultant economic loss for the country concerned.

Taking these difficulties in turn, the following assumptions are made for the purpose of estimating prices of fuel oil for the Market Survey:

(a) Since none of the Survey countries had expressed special reservations on environmental constraints, one of the cheaper types of crude oil with no limitation on sulphur content was selected as the basis. This was Kuwait crude of 31° API.

(b) Its price was based on data available for transactions between producing companies and independent third parties to which this type of crude was sold in the Persian Gulf in 1972 and escalated to 1 January 1973[1]. Transport costs to the major harbours of the countries concerned were estimated on the basis of data summarized in Table VII.

(c) It was assumed that the strong position of the producing countries will permit them to maintain and probably increase the growing revenues already provided for by the Teheran and Participation Agreements. Consequently, an annual rate of growth of oil prices of 5% was considered minimal while 6% was viewed as probable.

(d) The relationship between the prices of crude and heavy fuel oil was assumed on a basis explained at greater length in Section 4 of this Appendix.

COST OF TRANSPORT OF OIL BY TANKER AND BY PIPELINES

These costs are given in detail in Tables I-7 and I-8. The sensitivity of unit transport cost to size of tanker and pipeline must be stressed. Consequently, future transport costs will depend critically on the existence of harbour facilities capable of handling the largest type of tanker size compatible with the demand of the country.

RELATIONSHIP BETWEEN CRUDE AND OIL PRODUCT PRICES

As has already been pointed out, there is no generally valid relationship between the two products and the price of fuel oil is entirely dependent on supply and demand. There are, however, lower and upper limits imposed by the availability of substitutes.

Regarding fuel oil for power plants, an immediate substitute is available in the form of crude oil itself which, subject to certain precautions, can and has been used as a fuel. Consequently, and except for short-lived special cases, the price of a given quality of crude in a specific location sets an upper limit to the price of heavy fuel oil of comparative sulphur content.

With regard to a lower limit, the situation is much more complex since it depends on the availability of alternative fuels as well as on the possibility of altering the proportion of different refinery products, both in the short and long term. A historical study of the relationship between long term prices of fuel and crude oils of similar characteristics shows that the differential between them has seldom exceeded 10% (except in the special case of the US Eastern Seaboard and the Caribbean area).

It was, therefore, decided to use as reference prices for heavy fuel oil landed in the major harbours of the countries covered by the Survey the price of landed crude as a maximum and 90% of the price of crude as a minimum. In fact, 95% of the price of crude was chosen as a representative single value.

CONCLUSIONS

The procedure finally selected for estimating fuel oil prices for the countries of the Market Survey was based on four main assumptions each one being open to some objections:

(a) The price of crude in the Persian Gulf was used as the basis even though some of the countries covered, particularly in Latin America, are not importing crude from this

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[1] At the time these estimates were made, the impact of the 1973 devaluation of the US $ on the amount of taxes paid to the producing countries was still not officially agreed. It seems, however, that an increase of 10% in the payments to the countries would be a minimum expectation. Such an increase would result in the assumed price of Kuwait crude being more than US $14 per ton rather than the value of US $13 per ton f.o.b. Persian Gulf used in the Survey analyses. While further discontinuous increases of this nature are obviously difficult to forecast, their possibility emphasizes the advisability of assuming for oil prices a rate of escalation substantially exceeding that of general inflation.

TABLE I-7. COMPARATIVE TRANSPORTATION COSTS FROM PERSIAN GULF TO ROTTERDAM[a] IN VARIOUS SIZES OF TANKERS

Year of delivery	Size of tanker (dwt)	50 000	70 000	90 000	130 000	250 000	500 000
	Days at sea	58.2	58.2	56.4	58.2	58.2	58.2
	Days in port	3.2	3.2	3.3	3.3	3.5	3.5
	Trips per annum[b]	5.7	5.7	5.9	5.7	5.7	5.7
	Cargo (tons per trip)	47 200	66 300	85 000	123 400	240 000	480 700
	Voyage costs (US $ × 10^3)						
1971	Fixed direct costs	132.8	150.0	164.2	204.9	317.0	-
	Capital costs	121.0	154.7	175.0	246.7	396.7	-
	Bunkers[c]	50.5	70.7	98.2	126.6	163.1	-
	Port charges	13.0	17.2	19.5	24.8	43.6	-
	Total	317.3	392.6	456.9	603.0	920.4	-
1973	Fixed direct costs	171.4	192.1	209.8	260.9	405.6	18.2
	Capital costs	142.1	184.2	211.9	301.5	476.0	914.0
	Bunkers[c]	45.5	63.7	88.4	114.0	146.8	276.8
	Port charges	18.6	23.7	29.4	35.2	66.3	136.5
	Total	377.6	463.7	539.5	711.6	1 094.7	2 045.5
1975	Fixed direct costs	195.1	218.0	237.4	294.3	441.1	748.5
	Capital costs	173.7	228.4	276.3	397.5	740.4	1 269.2
	Bunkers[c]	51.4	71.9	99.9	128.8	165.9	312.7
	Port charges	20.5	26.1	32.4	38.8	73.0	150.7
	Total	440.7	544.4	646.0	859.4	1 420.4	2 481.1
	Costs (US $/t of cargo)						
1971	Direct costs	4.16	3.59	3.32	2.89	2.18	-
	Capital costs	2.56	2.33	2.06	2.00	1.65	-
	Total costs	6.72	5.92	5.38	4.89	3.83	-
1973	Direct costs	4.99	4.22	3.85	3.32	2.58	2.35
	Capital costs	3.01	2.78	2.49	2.44	1.98	1.90
	Total costs	8.00	7.00	6.34	5.76	4.56	4.25
1975	Direct costs	5.66	4.77	4.35	3.74	2.83	2.52
	Capital costs	3.68	3.44	3.25	3.22	3.09	2.64
	Total costs	9.34	8.21	7.60	6.96	5.92	5.16
	Costs (1972 world-scale equivalent)						
1971		68	60	55	50	39	-
1973		81	71	64	59	46	43
1975		95	83	77	71	60	53

[a] Distance for round trip 22 338 miles.

[b] All vessels in operation for 350 days each year.

[c] Bunker prices (US $/t) 1971 Persian Gulf 13.50, North Europe 21.00
1973 Persian Gulf 13.00, North Europe 18.00
1975 Persian Gulf 15.00, North Europe 20.00

TABLE I-8. ILLUSTRATIVE COSTS OF INLAND TRANSPORT BY PIPELINE

	Throughput	
	2×10^6 t/yr (10-in diam. pipeline)	5×10^6 t/yr (16-in diam. pipeline)
Costs (US cents/t per 100 miles)		
Capital	60	39
Other fixed	18	10
Variable	4	8
Total	82	57
Total cost (US cents/10^6 kcal per 100 mile)	8.1	5.6

Note: The table is restricted to pipeline sizes most likely to be encountered in oil-importing developing countries. The cost per ton of oil transported is, however, quite sensitive to size up to very large throughputs. Thus, for a pipeline with a transport capacity of 50×10^6 t/yr it would drop to less than 20 US cents/t per 100 miles, or to about 1/3 of the 5×10^6 t/yr figure.

[a] Assumes: flat country, no major river crossing; capital cost of pipeline US $9000/in diameter per mile; fixed charge rate 13.38%/yr based on an interest rate of 12% yr and on 20-yr sinking fund depreciation.
[b] Sufficient for supplying 1200 MW of oil-fired plants at 80% load factor.
[c] Sufficient for supplying 3000 MW of oil-fired plants at 80% load factor.

source. This is not as serious a flaw as it may seem since the policy of pricing oil from various sources on the basis of equality of delivered cost, with the main producing region serving as a reference point, has been a recurring feature of past price policies.

(b) An annual escalation rate of 6% was proposed for the 1973-1980 period, which is higher than the approximately 4% which the Teheran Agreement alone would imply, but takes into account the progressive impact of participation of the Arab countries in production and the sharp rise in oil demand.

(c) A fixed relationship was assumed between the prices of crude and of heavy fuel oil while the actual connection is flexible and complex. As has been explained this is a simplification but its impact on actual results is unlikely to involve errors of more than 5%.

(d) Taxes levied on fuel oil by consuming countries were ignored since they are internal revenues to the governments and should not affect the economic selection of power plants. There is no question that even though from the standpoint of the electric utilities taxes levied by their own country on a particular type of fuel are an element of total costs, the same taxes appear as a revenue item in national accounting. Since the purpose of the Market Survey is to estimate national costs of alternative power programs, domestic taxes on fuel should be excluded, at least in the basic reference cases.

(e) Estimated base prices, resulting from the above, for crude and heavy fuel oil in major harbours of the countries participating in the Market Survey are given in Table I-9.

(f) Gas turbine fuels were arbitrarily priced at 175% of fuel oil on the basis of an averaging of existing data.

(g) Domestically produced oil and gas was priced on the basis of parity of thermal costs with imported fuel oil or fuel oil refined from imported crude.

(h) Prices of domestically produced lignite and coal were estimated independently on the basis of the data supplied by the countries and escalated at the general rate of 4%/yr except in cases where there were convincing arguments to depart from this general procedure.

TABLE I-9. ESTIMATED BASE PRICES FOR CRUDE AND HEAVY FUEL OIL IN MAJOR HARBOURS OF MARKET SURVEY COUNTRIES[a], 1 January 1973

Harbour	Sea transport cost[b] (US $/t)	CIF Price of crude in harbour (US $/t)	Corresponding prices of fuel oil (US $/t)	US cents/10^6 kcal
Egypt				
Alexandria	3	16	15.2	150
Greece				
Piraeus	5	18	17.1	168
Turkey				
Izmet	5	18	17.1	168
Yugoslavia				
Trieste	6	19	18	177
Argentina				
Buenos Aires	6.5	19.5	18.5	182
La Plata				
Chile				
Valparaiso	7	20	19	187
Quintero				
Jamaica				
Kingston	6	19	18	177
Mexico				
Tampico	7	20	19	187
Vera Cruz				
Pakistan				
Karachi	1	14	13.3	131
Bangladesh				
Chittagong	2.5	15.5	14.7	145
Singapore	2	15	14.3	140
Thailand				
Bangkok	3	16	15.2	150
Philippines				
Bantangas	3	16	15.2	150
Korea				
Pusan-Ulsan	4	17	16.1	159

[a] Kuwait heavy crude 31° API with no sulphur restriction estimated at US $1.80/bbl or US $13/t f.o.b. in the Persian Gulf.
1 t crude = 7.2 bbl
1 t heavy fuel oil = 6.8 bbl
1 t heavy fuel oil = 40.3 × 10^6 Btu.
= 10.15 × 10^6 kcal.

[b] Transport costs by sea estimated on the basis of journey by tankers of size suitable for country harbours except for Mediterranean countries where special allowances were made for possible transport by pipeline or canal through Suez in the future.

APPENDIX J

NUCLEAR FUEL CYCLE COST TREATMENT

James A. Lane

INTRODUCTION

Fuel cycle costs in a nuclear power plant depend on a wide variety of economic parameters, such as the costs of uranium, of separative work and of industrial operations which vary with time. It is likely that some of these costs, such as those for natural U_3O_8 and separative work will increase with time, while other cost components such as fuel fabrication and fuel recovery will decrease. To complicate the situation even more, the value of fissile plutonium recovered from spent fuel can go up or down depending on its marketability as recycle fuel.

In addition to dependence on the above economic factors nuclear fuel costs also depend on engineering parameters such as the fuel burn-up per cycle, the fuel management scheme employed etc., which the reactor designer or plant operator can vary to optimize overall generating costs. Because of this balancing of economic and engineering factors, total nuclear fuel cycle costs tend to remain relatively constant with time. In the case of light-water reactors, fuel costs lie within the rather narrow range 20 ± 5 US cents/10^6 Btu (80 ± 20 US cents/10^6 kcal) regardless of size or plant design. Unlike oil costs, moreover, nuclear fuel costs are not sensitive to where the plant is located in the world. In view of this situation, it was decided that it would be sufficient for the purpose of the Market Survey to base the economic evaluation on current nuclear fuel costs taken from studies published in the open literature. For the reference case, these fuel costs were assumed to follow the general inflation rate of 4%/yr, the same as all other capital costs (see Appendix D). Sensitivity studies were also carried out using a 6% escalation rate, the same as that used in the reference case for oil and gas.

FUEL CYCLE COSTS FOR A 400 MW PWR

In a paper by J. T. Roberts and R. Krymm [1], a variety of numerical examples of nuclear fuel cost calculations for a hypothetical 400 MW pressurized water reactor are presented and discussed in detail. Figure J-I shows a generalized schematic diagram of the LWR fuel cycle used as a basis for the calculations and Table J-1 shows the assumed economic and engineering parameters. The data in Table J-1 were used in a present-worth calculation to determine the levelized fuel cycle cost under steady state (equilibrium) conditions with one-third of the core being replaced each year. For this simplified equilibrium case, total fuel cycle costs and corresponding direct and indirect components are calculated by following a single batch of fuel throughout its three-year lifetime. Table J-2 shows the results of this calculation.

Since the cost calculation for the equilibrium fuel does not take into consideration the higher unit costs associated with the first core, calculations were also carried out to find the first core cost and also the levelized 30-year average fuel cost for the first core plus the 29 equilibrium refuelling batches. Table J-3 compares the costs for the three cases considered. The levelized 30-year average fuel costs shown in the last column were taken as the reference case for the Survey; however, two adjustments were made for this purpose. Firstly costs were adjusted to reflect the increase in separative work costs to the US $36/kg announced by the USAEC on 14 February 1973, and secondly, indirect costs were based on the 8% interest rate taken as the reference case in the Survey. These two changes tended to balance one another with the result that levelized 30-year average fuel cycle costs amount to 1.78 US mill/kWh for a 400 MW PWR.

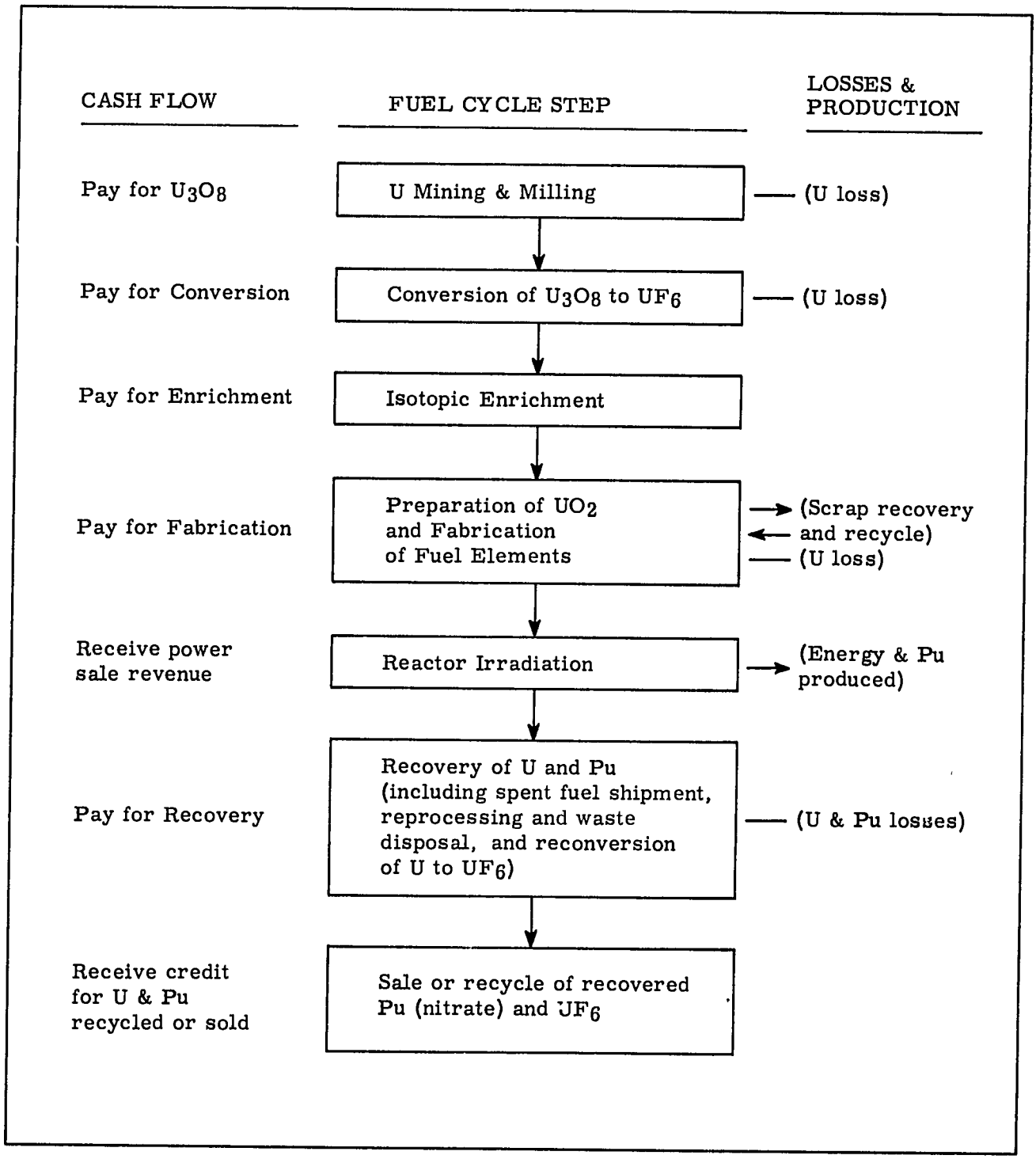

FIG. J-1. GENERALIZED SCHEMATIC DIAGRAM OF LWR FUEL CYCLE.

TABLE J-1. BASIS FOR FUEL CYCLE COST CALCULATIONS CARRIED OUT IN REF. [1]

1. Cost of natural uranium ore concentrate: US $7.00/lb U_3O_8

2. Losses (not economically recoverable) in processing:

Conversion	- 0.5%
Enrichment	- 0.0%
Fabrication	- 1.0%
Reprocessing (U and Pu)	- 1.0%
Reconversion, U nitrate to UF_6	- 0.3%

3. Uranium enrichment: Tails assay: 0.25% U-235
   Cost of separative work: US $32.00/SWU (kg)

4. Cost of converting U_3O_8 to UF_6: US $2.60/kg U (product)

5. Fabrication cost (including cost of scrap recovery):

First core	- US $110/kg U (product)
Equilibrium core	- US $ 80/kg U (product)

6. Recovery cost (including spent fuel shipment, reprocessing, reconversion of recovered uranium to UF_6):

First core	- US $44/kg U (feed)
Equilibrium core	- US $40/kg U (feed)

7. Plutonium credit: US $10.00/g (fissile)

8. Times at which pre-irradiation payments are made:

	First core	Equilibrium core
U_3O_8	15 months	12 months
Conversion	12 months	9 months
Enrichment	9 months	6 months
Fabrication	6 months	3 months

   Times at which post-irradiation payments or credits are made:

   Recovery + 6 months U and Pu credits + 9 months

9. Reactor power: 1222.5 MW(th) gross
   400 MW(e) net
   Plant capacity factor: 80%

10. Irradiation history:

First core	Batch "A"	Batch "B"	Batch "C"
Burn-up (MWd/t)	13 176	23 912	31 531
Initial enrichment (% U-235)	2.41	3.04	3.48
Final enrichment	1.24	1.17	1.08
Final fissile Pu (%) (based on U)	0.46	0.61	0.72
kg U charged to reactor	11 321	11 321	11 321
kg U discharged from reactor	11 100	10 949	10 846
In-core life at 80% load factor (yr)	1.00	2.00	3.00

   Equilibrium Batch: Same as Batch "C" above.

Power production (% of total):	Outer region	24.16
	Intermediate region	34.05
	Inner region	41.79
		100.00

TABLE J-2. FUEL COST ESTIMATE FOR THE EQUILIBRIUM CORE LIGHT WATER REACTORS [1]

Cost category and components	Unit fuel cost (US mill/kWh)		
	Direct	Indirect	Total
I. Fertile and fissile materials			
(a) U_3O_8 purchase, gross	0.523	0.158	0.681
(b) Credit for equivalent U_3O_8 in recovered U	-0.126	0.022	-0.104
(c) Credit for recovered plutonium	-0.276	0.048	-0.228
Subtotal I	0.121	0.228	0.349
II. Industrial operations			
(a) Conversion, gross	0.074	0.020	0.094
(b) Credit for conversion equivalent in recovered U	-0.018	0.003	-0.015
(c) Enrichment, gross	0.623	0.150	0.773
(d) Credit for enrichment equivalent in recovered U	-0.052	0.009	-0.043
(e) Fabrication	0.323	0.069	0.392
(f) Recovery	0.155	-0.024	0.131
Subtotal II	1.105	0.227	1.332
Total	1.226	0.455	1.681

TABLE J-3. LEVELIZED FUEL CYCLE COSTS FOR 400 MW PWR (US mill/kWh) [1]

	First core	Equilibrium core	30-year average
Direct	1.59	1.23	1.32
Indirect	0.51	0.45	0.46
Total	2.10	1.68	1.78

FUEL COSTS FOR SMALL AND MEDIUM POWER REACTORS

A paper by M. A. Khan and J. T. Roberts [2] presents information on fuel cycle costs for light water nuclear plants in the size range 100 to 600 MW. These costs adjusted to the conditions described above (8% interest rate, US $36/kg separative work) are summarized in Table J-4. Note that, due to different assumptions which are explained in the references, the fuel cycle costs for the two 400 MW cases (Tables J-3 and J-4) are slightly different.

TABLE J-4. FUEL COSTS IN SMALL AND MEDIUM POWER REACTORS [2]

Reactor size (MW)	Levelized total fuel cycle costs (US mill/kWh)
100	2.10
200	1.85
300	1.75
400	1.65
500	1.60
600	1.60

FUEL COSTS FOR OTHER PWR SIZES

Total fuel cycle costs for other sizes of PWRs taken from Refs [3-5] are plotted in Fig. J-2 along with the costs from the IAEA studies previously described. All costs were adjusted to an 8% interest rate, 80% plant factor and US $36/kg separative work. A linear relationship between nuclear plant capacity and total fuel cycle costs was adopted for the Survey as shown in Fig. J-2.

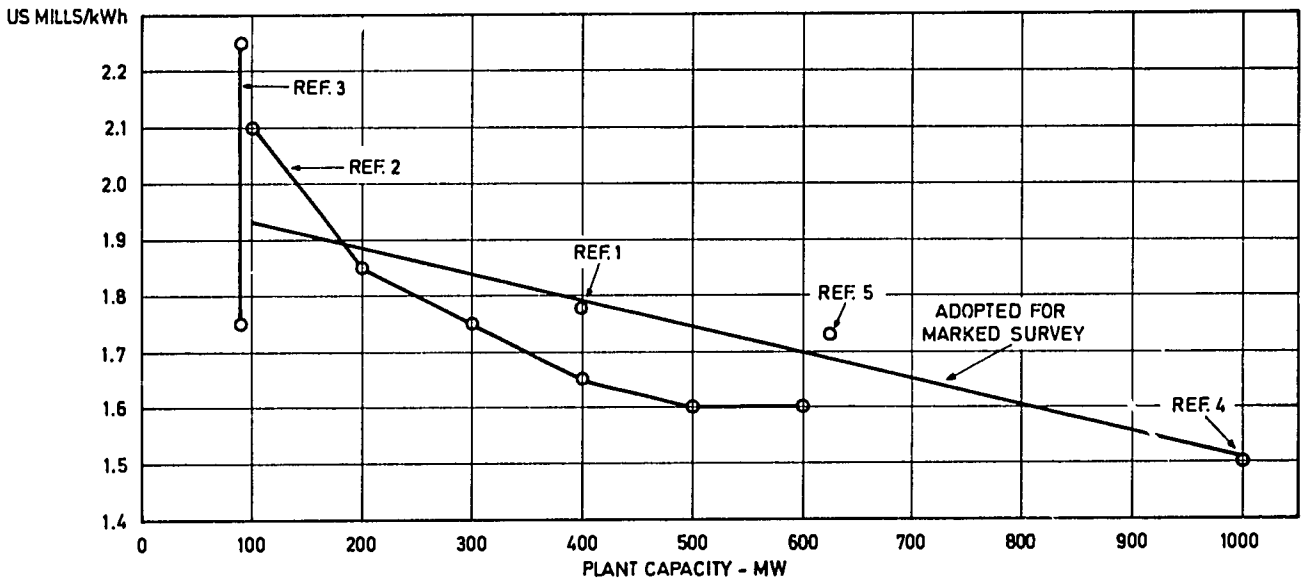

FIG. J-2. TOTAL FUEL CYCLE COSTS.

FUEL CYCLE WORKING CAPITAL COSTS

For the purpose of the WAST computer program, it was necessary to separate total fuel cycle costs into a "fixed" component which varies with the assumed interest rate and a "variable" component which varies with the amount of energy generated. The "fixed" component of nuclear fuel costs represents the levelized value of all outstanding investments associated with the fuel cycle over the life of the plant. Figure J-3 shows values of this fixed component taken from the previously mentioned references. As in the case of the total fuel cycle costs, a linear relationship between fixed costs and plant capacity was assumed as shown in Fig. J-3. It should be noted that the fixed component of nuclear fuel costs varies by only US $18/kW over the entire range of plant capacities, which is equivalent to about 2 US cents/10^6 Btu.

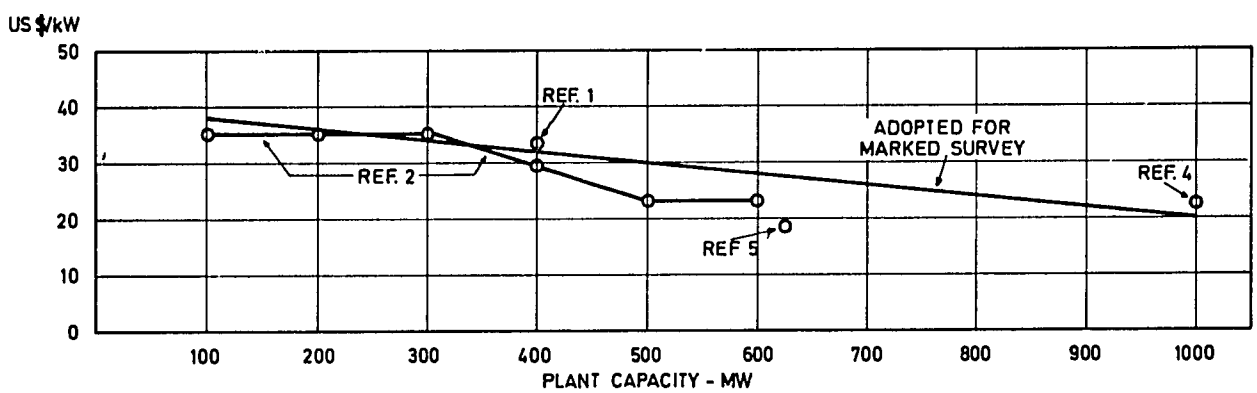

FIG. J-3. LEVELIZED FUEL CYCLE CAPITAL COSTS.

VARIABLE FUEL CYCLE COSTS

The difference between the total fuel cycle costs and the fixed component gives the variable fuel cycle costs. For the purpose of the WASP program, it was necessary to express the variable component in terms of US cents/10^6 kcal. For this purpose the full load gross heat rates estimated by the Bechtel Corporation (see Appendix E) were used. The resulting variable nuclear fuel costs are shown in Table J-5 along with total fuel cycle costs and the fixed component (calculated at 80% plant factor and 8% interest).

TABLE J-5. FUEL CYCLE COSTS ADOPTED FOR MARKET SURVEY

Plant capacity	Levelized fuel cycle costs (US mill/kWh)			Fuel load gross heat rate[a]	Variable fuel cycle costs
(MW)	Total	Fixed	Variable	(kcal/kWh)	(US cents/10^6 kcal)
100	1.93	0.43	1.50	2 504	59.8
200	1.89	0.41	1.48	2 503	58.9
300	1.84	0.39	1.45	2 503	57.9
400	1.79	0.37	1.43	2 502	57.0
600	1.70	0.32	1.38	2 501	55.1
800	1.60	0.27	1.33	2 500	53.2
1 000	1.51	0.23	1.28	2 499	51.3

[a] Gross heat rates were used to be consistent with the use of such heat rates in calculating conventional fuel costs.

REFERENCES

[1] ROBERTS, J.T., KRYMM, R., IAEA, "Fuel cost evaluation for light water reactors", Regional Training Course on Bid Evaluation and Implementation of Nuclear Power Projects, Tokyo, 29 November - 10 December 1971, IAEA-151, unpublished document, p.191.

[2] KHAN, M.A., ROBERTS, J.T., "Small and medium power reactors: Technical and economic status, potential demand and financing requirements", 4th Int. Conf. peaceful Uses atom. Energy (Proc. Conf. Geneva, 1971) 6, IAEA, Vienna (1972) 57.

[3] STORRER, J., GALLOIS, G., KAFKA, P., "Belgonucléaire and Siemens PWRs for small and medium power reactors", Small and Medium Power Reactors 1970 (Proc. Symp. Oslo, 1970), IAEA, Vienna (1971) 131.

[4] USAEC, Current Status and Future Technical and Economic Potential of Light Water Reactors, WASH 1082, March 1968.

[5] Electrowatt Engineering Services and Sargent and Lundy, Feasibility Study for a Nuclear Power Plant in Luzon, Philippines, February 1973.

SENSITIVITY STUDIES

In order that the results of the analyses of the participating countries could be compared and summarized, it was deemed desirable to analyse each country using the same basic values of the parameters and then to perform other analyses using different values of these parameters in order to determine the sensitivity of the results of the base case to such variations. This was done so that each country would have results available using parameter values which might more nearly represent its unique values. Also, since the base values are forecasts determined from historical information and a consideration of present and future trends, it was considered important to check the sensitivity of the selected system expansion plans to possible variations in these parameters.

The technique of using the WASP program to analyse predetermined system expansion plans allowed the addition of a number of sensitivity alternatives to each analysis at the expense of very little additional computer time.

The parameters selected for sensitivity studies and the values used are:

(a) Economic parameters

	Base case		Other cases	
	Study values[a]	Approximate equivalent "real" values	Study values[a]	Approximate equivalent "real" values
Discount rate (%)	8	12	6 & 10	10 & 14
Oil & gas price escalation (%)	2	6	0 & 2	4 & 8
Nuclear fuel price escalation (%)	0	4	2[b]	6
Capital cost of plants [c]	ORCOST-3		ORCOST-1	

[a] General inflation rate was assumed constant at 4%/yr.
[b] This value was used for sensitivity studies in only a few selected cases.
[c] ORCOST-3 values are as of 1 January 1973 and show a ratio of PWR to oil-fired plant costs ranging from about 1.8 to 2.2 (depending on MW rating) whereas ORCOST-1 values show a corresponding range from about 1.6 to 1.8. For a complete discussion of these costs refer to Appendix B.

(b) Load forecasts

The basic load forecast for each country was prepared on a common basis by Aoki as described in Appendix F. For several countries his forecast compared closely with that provided by the country itself; in those cases only one forecast was used. For most countries, however, the country forecast was appreciably higher than the Aoki forecast and in these cases both were used as the basis for analysis.

(c) Loss-of-load probability

An additional sensitivity study was carried out, in effect, on the variation in the loss-of-load probability. For a definition and further discussion of loss-of-load probability refer to Appendix A. The value of the loss-of-load probability for any given system is related to the amount of system reserve generating capacity and to the number, sizes and types of plants and this is also related to the degree of load shedding to be permitted at times of forced outage of generating capacity. Obviously, reducing the loss-of-load probability will increase the system cost to supply a given load and increasing it decreases system costs. Thus specific values, or a range of acceptable values, needed to be established for purposes of the

studies, since any specific system expansion plan is optimum only for a specific loss-of-load probability. Therefore, it was decided to use an average of the yearly values over the study period, as close as possible to 0.005 with a maximum of 0.010. It is considered that these values are representative of the values acceptable to developing countries, although they are substantially higher than the acceptable values for the industrialized countries. The actual loss-of-load probability value can be expected to vary from year to year depending on the amount and timing of generating capacity additions.

In a number of cases the loss-of-load probability value for a country's existing system was substantially higher than the maximum quoted above. The technique used in these cases was to bring the loss-of-load probability gradually down to the levels indicated above by adding more generating capacity. To achieve this generally required a number of attempts to determine the exact size of unit and the point in time when it should be added. A study of the results of these numerous analyses, involving varying values of loss-of-load probability, shows that although the value of the objective function (present worth) could vary considerably, the size and number of nuclear power units called for in the optimum (lowest present-worth value) case would vary only slightly. In this connection it should be pointed out that the probabilistic model used in deriving the loss-of-load probability values is limited in its handling of hydro power plants and, for systems with large proportions of hydro power, it tends to show unrealistically low loss-of-load probability values.

(d) Foreign exchange rates (shadow exchange)

In a few instances, studies were carried out to determine the sensitivity of the optimum case to variations in the rates of exchange between local and foreign currencies. This is intended to show the effect on capital-intensive projects of scarcity of foreign capital to finance such projects.

(e) Salvage values based on sinking fund depreciation

In the reference case, salvage values based on linear depreciation were factored in for all plants at the end of the study period (i.e. 2000). Although this practice is current in most electric utilities accounting, it involves a slight departure from strict economic accounting which should be based on sinking fund depreciation. Since the use of straight line depreciation gives a higher value of the objective function than sinking fund depreciation, its use tends to penalize capital intensive projects, i.e. nuclear plants. For this reason, the effect of using salvage values based on sinking fund depreciation was considered in some instances.

(f) Duties and taxes

Duties and taxes were not considered in the reference case; however, in some countries they might have an important influence on the market for nuclear power by increasing oil prices, on the one hand, and nuclear plant capital costs on the other. Sensitivity studies to evaluate the influence of duties and taxes were carried out for countries where their effect might be important.

(g) Environmental effects

It is not clear whether environmental considerations will play an important role in the participating countries; therefore, no allowance was made for these in the reference cases. If future environmental considerations require the use of fuels of low sulphur content or equipment to alleviate deleterious effects, capital and/or operating costs would increase and thereby influence the competition between fossil and nuclear plants. This factor was not treated in a finite quantitative manner in these studies; however, a qualitative and approximate quantitative discussion can be found in Appendix B.

APPENDIX L

IAEA SERVICES AND ASSISTANCE IN CONNECTION WITH NUCLEAR POWER

The International Atomic Energy Agency provides services and assistance to its Member States and to non-Member States under the United Nations Development Program (UNDP) in any technical field involving the peaceful application of nuclear energy permitted by its Statute. Information about the services and assistance available from and through the Agency is given in the publication "IAEA Services and Assistance"[1]. This booklet also explains who is eligible to receive services and assistance from the Agency and how these may be obtained.

In general, four stages can be identified in the initial introduction of nuclear power in a given country:

Stage 1. Preliminary survey
Stage 2. Preliminary study
Stage 3. Feasibility study
Stage 4. Construction and commissioning of power reactors.

Stages 1 and 2 are the most likely suitable subjects for technical assistance and during Stage 3 assistance could be requested from UNDP.

The activities in respect of which the Agency can assist or provide services related to nuclear power and the kinds of assistance possible are briefly summarized below. Neither this summary nor the "IAEA Services and Assistance" booklet can be exhaustive in coverage; therefore, if further information is required, it should be sought directly from the Agency's headquarters.

FIELDS OF ACTIVITY

(a) Activities connected with the development of nuclear power

Applications: Use of nuclear energy for the generation of electricity and possible other associated processes.

Economics of nuclear power: Comparison with other sources of power; economics of various fuel cycles; feasibility studies.

Nuclear power program: Planning of a nuclear power program; integration into a system; choice of reactor type; siting of reactors; training of staff; auxiliary services.

Fuels and fuel cycles: Fabrication, testing and inspection of reactor fuel elements and related processes; technical problems of fuel cycles.

Nuclear materials management: Establishment of methods.

Raw materials: Prospecting, mining, processing.

(b) Activities related to safety in atomic energy

Safety standards, regulations and procedures: Standards, regulations, codes of practice and recommendations and their application to specific operations and related procedures.

Radiological protection: Design of installations and laboratories; shielding; protective devices; personnel, area and environmental monitoring; instrumentation; decontamination; medical examinations; diagnosis and treatment of radiation injury and internal contamination.

[1] This publication is presently being revised.

Safety of reactors and nuclear materials: Safety aspects in the siting, design, construction and operation of power reactors and related facilities; management of radioactive wastes.

Safety evaluations: Safety evaluations of nuclear installations in respect of their design and siting, operational procedures, associated environmental monitoring and emergency planning.

(c) Activities related to legal aspects of atomic energy

Framing legislation in establishing national atomic energy authorities; legislation on third-party liability and on the licensing of nuclear facilities; provisions for insurance and other adequate financial protection of nuclear installations; legal problems in connection with the production, transport, use and storage of radioactive materials.

KINDS OF SERVICES AND ASSISTANCE

(a) Technical cooperation programs

Resources made available so that the Agency can provide technical and pre-investment assistance are used to implement projects under the Agency's regular program of technical assistance and under UNDP. Under these programs assistance may include one or more of the following elements:

Expert services: Experts can be sent individually or in teams to advise on or assist in general or specific fields of activity within the Agency's competence.

Equipment and supplies: These are usually provided in association with an internationally recruited expert.

Fellowships: Fellowships can be awarded as part of a comprehensive project or on an individual basis as a direct contribution to projects in the country's atomic energy program. These fellowships are available to qualified applicants at all educational levels and are not restricted to university graduates.

Intercountry projects: The Agency organizes a number of regional and interregional training courses and study tours every year in cooperation with its Member States and other United Nations organizations. Some of them deal with nuclear power. Large-scale projects of significant economic importance to countries in a region can be accommodated under the UNDP.

(b) Advisory and field services

The Agency provides, on request, information and advice on a number of subjects relating, among others, to nuclear power, as outlined above. If requested, missions may also be organized.

(c) Information services

The Agency also assists its Member States by means of a program of information services, including the International Nuclear Information System (INIS). Many of these activities relate to nuclear power.

(d) Supply of nuclear materials

Nuclear materials, such as uranium enriched in uranium-235 and plutonium, may be supplied to Member States by or through the Agency in accordance with Article XI of the Agency's Statute. The materials can also be supplied as fuel for power reactors.

ABBREVATIONS USED IN THE MARKET SURVEY REPORTS

ampere	A
approximately	approx.
barrels	bbl
billion	10^9
board feet	bd. ft.
British thermal unit	Btu
calorie	cal
centimetre	cm
cubic foot	ft^3
cubic metre	m^3
cubic yard	yd^3
cycles per second	Hz
degree centigrade	°C
degree Fahrenheit	°F
direct current	DC
feet	ft
figure(s)	Fig., Figs.
foot	ft
Gigawatt	GW
Gigawatt-hour	GWh
Hertz (cycles per second)	Hz
horse-power	hp
hour	h
hundredweight	cwt
kilocalorie	kcal
kilogram	kg
kilometre	km
kilovolt	kV
kilovolt-ampere	kVA
kilowatt	kW
kilowatt-hour	kWh
litre	l
maximum	max.
megawatt	MW
megawatt-hour	MWh
metre	m
normal cubic metre	Nm^3
million	10^6
number	No.
per annum	p.a.
per cent	%
pound (weight)	lb
pounds per square inch	lb/in^2
square foot/feet	ft^2
square metre	m^2
thousand	10^3
ton	t (always metric, unless specified otherwise as ton (UK) – long ton or ton (USA) – short ton.
tons of coal equivalent	TEC
volt	V
volt-ampere	VA
watt	W
yard	yd

APPENDIX N

COOPERATING ORGANIZATIONS AND PARTICIPANTS IN THE MARKET SURVEY MISSION

22 November - 1 December 1972

Atomic Energy Establishment
Atomic Energy Establishment Laboratories
President – Academy of Science
Ministry of Electricity
General Electricity Corporation
Rakte Paper Factory
Kafr El-Dawar Textile Factory
General Petroleum Corporation

Liaison officer: Dr. Kamal Effat, Atomic Energy Establishment

	Country	Status[a]
A. Böttcher, Nuclear expert, Nuclear Research Centre, Jülich	FRG	1
P.W. Cash, Electric Utility Systems Planning expert, Associated Nuclear Services, London	UK	2
Y. Fujiwara, Load Forecast expert, Tokyo Engineering Corporation	Japan	1
B. Kolbasov, Engineer, IAEA	USSR	3
O. Pedersen, Economist, IAEA	Denmark	3
A. Polliart, Nuclear expert, CEA, Paris	France	1
J. Wilson, Engineer, IAEA	USA	3

[a] Status 1 = Cost-free expert with salary, travel and per diem paid by the sponsoring country

Status 2 = Expert provided by contract with Engineering Consulting firm, the firm having the status of an independent contractor

Status 3 = IAEA staff member