# MARKET SURVEY
# FOR
# NUCLEAR POWER
# IN
# DEVELOPING COUNTRIES

# GENERAL REPORT

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DEPARTMENT OF STATE
AGENCY FOR INTERNATIONAL DEVELOPMENT
WASHINGTON, D.C. 20523

cc memo: SA, NE, EA, CA

MEMORANDUM

January 10, 1974

TO : AA/ASIA, Mr. Donald MacDonald
AA/AFR, Mr. Samuel Adams
AA/LA, Mr. Herman Kleine
AA/SA, Mr. Robert Nooter

FROM : SER/ENGR, Mr. M. M. Vogel

SUBJECT: International Atomic Energy Agency Survey

AID participated in the recently completed "Market Survey for Nuclear Power in Developing Countries" which was undertaken by the International Atomic Energy Agency (IAEA). The countries studied were Yugoslavia, Egypt, Greece, Turkey, Pakistan, Bangladesh, Singapore, Philippines, Korea - Thailand - Argentina, Mexico, Jamaica, Chile. The survey considered plants that might be commissioned during the period 1980 - 1989.

The results of the survey, which was completed in June 1973, have been published by the IAEA in a set of reports. A "General Report" summarizes the purpose, nature, methodology, data and analytic results - individual and aggregate - for the countries studied. For each of the fourteen (14) countries studied there is an individual "Country Report", which was submitted to the country itself for clearance for printing. (Bangladesh and Pakistan have restricted distribution of their "country reports" to participants only - Yugoslavia has not yet cleared its "country report" for printing).

AID contributed a lump sum of $25,000, assistance of various Mission and AID/W personnel, information that was available to AID on electric power in the countries studied, and the services of Mr. John H. Rixse, Jr., Office of Engineering, who coordinated AID's contribution and worked on the "Survey Steering Committee".

Similar contributions were made by the AEC, the Export-Import Bank, the Inter-American Development Bank and the International Bank for Reconstruction and Development as well as by agencies, manufacturers and utilities in Canada, Japan, England, Germany, Sweden and India. The countries studied contributed substantially in services, local costs and all the basic data on their own situation.

AID's participation in this study was not to encourage consideration of AID financing nuclear power plants. Rather, the study assures that in the countries studied there is a much better understanding of their current and future energy situation and some of the approaches that might be utilized in meeting those needs.

Attached is a copy of the General Report dated September 1973. Copies of the general and detailed country reports are being provided to key members of your staff by our Regional Engineering Coordinators, who also have available a copy for the AID Missions in each of the countries which participated in this survey.

It is our understanding that additional copies of the report, if required, can be obtained from the IAEA by purchase. We have a very limited number of copies available in AID for the basic distribution to our working offices and to the Missions. Copies of the reports are also available for reference in the Power and Telecommunications Branch (SER/ENGR), AID's Document Reference Center and in STATE/SCI (Dr. Justin Bloom's Office).

Attachment a/s

cc: (w/o Attachment)
Ambassador Glennan
Ambassador Tape
STATE/SCI, Dr. Bloom
SER/CM, Mr. Owens
GC, Mr. Gair
CM/COD/CTR, Mr. Stanfield
TA/OST, Mr. Arnold
SER/ENGR, Mr. Dangler
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SER/ENGR, Mr. Stevens
SER/ENGR, Mr. Sloan

Alex
Sam

p. I-5 Cost Structure
petroleum industry

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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 56 000 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.

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[1] As classified under the United Nations Development Program.
[2] See General Conference Resolution GC(XV)/RES/285.

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 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.

[3] For convenience this will be called "study period" throughout the report.

## FINANCIAL AND MANPOWER SUPPORT OF SURVEY ACTIVITIES[a]

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.


[a] Estimates as of April 1973.

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.

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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.

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# 1. INTRODUCTION

## 1.1. Summary of report

The International Atomic Energy Agency, in response to the recommendations of its Working Group on Power Reactors of Interest to Developing Countries, undertook a Market Survey of the nuclear power plants that might be commissioned during the period 1980-1989. Fourteen reports, one for each of the developing countries that took part in the Survey, will describe the study results. A summary of these studies is presented in Appendix N to this report.

The major objective of the Market Survey was to determine the size and timing of nuclear power plants that could, on economic grounds, justifiably be built in the countries studied and commissioned during the period 1980 - 1989. These results are summarized in Section 2, which also includes a summary of data with respect to the power systems of the fourteen countries studied, the market for nuclear power under the reference case conditions, the sensitivity of this market to variations in such parameters as discount (interest) rates, fuel escalation rates, and capital costs, and the financial requirements of the power system expansion plans under reference case conditions.

Many social and economic factors have a bearing on the growth of the power system of a country. Factors such as present and projected population, Gross National Product, energy resources and consumption are summarized in Section 3.

In Section 4, the economic and technical methodologies and parameters are described as well as the range of values assumed for each parameter. The various computer programs used in the studies are also described.

Each country provided forecasts of the energy requirements that must be met by the electrical system. These forecasts were reviewed based on an analysis of economic and social factors, and compared with other forecasts. The basis for the forecasts used in the study, the forecasts themselves, including the country forecasts, are summarized in Section 5.

Section 6 includes a discussion of the factors considered in developing the system expansion plans, the most important being parameter constraints, reserve margins, transmission limitations and limits to the size of generating units.

The evaluations utilized data describing the units in the existing systems, generating unit additions planned by the country, and other units considered in the expansion plan. These data, which included both technical and operating characteristics, are summarized in Section 7.

In Section 8, the nuclear market expected in each of the fourteen countries and for all countries as a whole is summarized for the reference conditions. The sensitivity of this market to selected economic parameters and the distribution of this market by unit sizes is also reported.

Finally, the financing requirements of the expansion plans, the bases for estimating cash flows, the resulting domestic and foreign cash flows and the nuclear fuel working capital requirements are summarized in Section 9.

Further information on methodology, computer programs, and various key parameters are included in the Appendixes.

## 1.2. Approach and bases of analyses

As a starting point for the analysis, energy/demand forecasts were made for each participating country. Details of how these forecasts were developed are given in Appendix F. For several countries both a low and a high forecast were studied. The characteristics of each country's electric power system assumed to be in existence at the start of the study period were then defined, along with the technical and economic data for the nuclear and thermal plants considered in the expansion programs.

Alternative generating system expansion configurations, involving nuclear and conventional units, were developed to meet the required thermal capacity additions (see Table II-2) and the present worth of costs associated with each configuration determined using a computer program. This program, called the Wien Automatic System Planning Package (WASP), estimated the capital and operating costs of each expansion alternative plan for the period 1980 - 2000. The two-decade period was used in the evaluation to minimize the effect of not operating plants built during the study period to the end of their economic life time, even

though the study was specifically interested only in the first decade of this period. Each plant was credited with a salvage value at the end of the year 2000. All costs were discounted to 1 January 1973, to determine the present worth of these costs. The method of treating escalation of capital costs and fuel costs is given in Appendix D. By varying the mixture of nuclear and conventional plants added during the study period, it was possible to find in each case which combination of plants resulted in the minimum present worth. This minimum present-worth combination of plants will be referred to as the "near-optimum" expansion plan. See Section 4.2(e) for further discussion of the term "near-optimum".

A description of the WASP computer program and other computer programs used in the analyses is given in Section 4 together with a summary of the types of data required for the evaluations.

## 2. SUMMARY OF RESULTS

### 2.1. Characteristics of power systems evaluated

The characteristics of the power systems in each of the participating countries in 1979 (the year prior to the study period) are summarized in Table II-1. The data given represent existing systems and committed power system expansion plans of each country including the conventional plant additions necessary to provide an adequate reserve margin above the forecast peak demand. The peak demand figures were obtained by a forecasting method developed for the Survey (see Appendix F). In cases where the country's own forecasts (designated by H in Table II-1) were appreciably higher than the Market Survey forecasts, these were also analysed.

Table II-2 summarizes the capacity additions made to each system during the study period. As seen in this table, the hydro and pumped storage additions played an important

TABLE II-1. CHARACTERISTICS OF POWER SYSTEMS IN 1979, THE YEAR PRIOR TO THE FIRST STUDY YEAR

| Country [a] | Energy generation (GWh × $10^3$) | System load factor (%) | Peak demand (MW) | Installed capacity (MW) | | | Reserve margin [b] (%) |
|---|---|---|---|---|---|---|---|
| | | | | Hydro | Thermal [c] | Total | |
| Argentina | 38.2 | 58.3 | 7500 | 3026 | 6916 | 9942 | 18.8 |
| Bangladesh-L | 2.7 | 55.0 | 560 | 130 | 654 | 784 | 33.0 |
| Bangladesh-H | 3.9 | 55.0 | 800 | 130 | 904 | 1034 | 24.0 |
| Chile | 10.6 | 60.5 | 1995 | 1612 | 934 | 2546 | 27.6 |
| Egypt | 19.5 | 71.9 | 3097 | 1310 [c] | 2149 | 3459 [d] | 11.7 |
| Greece | 23.8 | 65.0 | 4175 | 1560 | 4061 | 5621 | 35.0 |
| Jamaica-L | 3.5 | 68.0 | 585 | 15 | 787 | 802 | 37.0 |
| Jamaica-H | 4.3 | 68.0 | 715 | 15 | 937 | 952 | 33.0 |
| Korea | 28.2 | 66.3 | 4857 | 710 | 5900 | 6610 | 30.1 |
| Mexico | 65.4 | 61.2 | 12200 | 6200 | 9011 | 15211 | 24.7 |
| Pakistan | 17.0 | 58.2 | 3325 | 925 | 2553 | 3392 | 19.6 |
| Philippines [e] | 13.7 | 65.0 | 2391 | 569 | 2799 | 3368 | 57.0 |
| Singapore-L | 7.8 | 65.0 | 1365 | 0 | 1819 | 1819 | 33.0 |
| Singapore-H | 8.0 | 68.0 | 1345 | 0 | 1841 | 1841 | 37.0 |
| Thailand | 14.2 | 66.0 | 2450 | 1341 | 2348 | 3689 | 50.5 |
| Turkey-L | 21.2 | 63.0 | 3850 | 2490 | 2200 | 4690 | 20.7 |
| Turkey-H | 25.7 | 63.0 | 4650 | 3228 | 2950 | 6178 | 31.0 |
| Yugoslavia-L | 59.4 | 67.5 | 10050 | 5860 | 6703 | 12563 | 21.3 |
| Yugoslavia-H | 80.4 | 67.5 | 13600 | 8360 | 7678 | 16038 | 15.6 |

[a] L = Market Survey low load forecast.
H = Country high load forecast.
[b] In critical quarter.
[c] Including nuclear which is identified separately in later tables.
[d] Excluding emergency hydro.
[e] Luzon grid.

role in many of the countries studied. However, for the purpose of the analyses, these additions, which generally followed the country's own expansion plans, were assumed to be fixed during the study period because of the complexity of carrying out a meaningful comparison of hydro and thermal alternatives and also because of the lack of reliable economic data on the given hydro projects. In the view of the Market Survey staff, most of the countries' plans for hydro and pumped storage developments seemed reasonable, generally, in the light of all of the relevant circumstances including social factors, availability of indigenous fossil fuels, foreign exchange constraints etc.

TABLE II-2. CAPACITY ADDITIONS DURING STUDY PERIOD (MW)

| Country | Total added capacity | Hydro and pumped storage additions | Net thermal capacity additions | Thermal capacity retired | Total thermal capacity required |
|---|---|---|---|---|---|
| Argentina | 9 944 | 4 160 | 5 784 | 1 016 | 6 800 |
| Bangladesh-L | 1 300 | 0 | 1 300 | 0 | 1 300 |
| Bangladesh-H | 3 801 | 0 | 3 801 | 49 | 3 850 |
| Chile | 2 470 | 720 | 1 750 | 0 | 1 750 |
| Egypt | 5 039 | 420 | 4 619 | 181 | 4 800 |
| Greece | 6 769 | 2 565 | 4 204 | 296 | 4 500 |
| Jamaica-L | 1 000 | 0 | 1 000 | 0 | 1 000 |
| Jamaica-H | 1 550 | 0 | 1 550 | 0 | 1 550 |
| Korea | 9 100 | 0 | 9 100 | 0 | 9 100 |
| Mexico | 21 380 | 2 200 | 19 180 | 490 | 19 670 [a] |
| Pakistan | 3 471 | 1 471 | 2 000 | 0 | 2 000 |
| Philippines | 5 235 | 0 | 5 235 | 165 | 5 400 |
| Singapore-L | 1 950 | 0 | 1 950 | 150 | 2 100 |
| Singapore-H | 4 525 | 0 | 4 525 | 175 | 4 700 |
| Thailand | 4 750 | 900 | 3 850 | 0 | 3 850 |
| Turkey-L | 6 959 | 4 019 | 2 940 | 60 | 3 000 |
| Turkey-H | 10 771 | 5 981 | 4 790 | 60 | 4 850 |
| Yugoslavia-L | 10 750 | 4 750 | 6 000 | 0 | 6 000 |
| Yugoslavia-H | 14 875 | 4 275 | 10 600 | 0 | 10 600 |

[a] See footnote [d] Table II-3.

## 2.2. Market for nuclear plants under reference conditions[1]

The projected markets for nuclear plants which will be commissioned in each participating country during the study period are shown in Table II-3 based on the reference economic parameters. Also shown in the table is the percentage of each country's total thermal market which might be met by nuclear plants over the study period.

[1] Reference conditions are those expected most likely to be in effect during the study period. They include a general cost inflation factor of 4%/yr (equivalent to computing all costs in terms of constant 1 January 1973 US dollars) and, relative to that level, an 8% discount rate, 2% oil, natural gas and coal price escalation rate, zero capital cost and nuclear fuel price escalation rates, 1.0 ratio of the assumed foreign exchange rate to the official foreign exchange rate.

TABLE II-3. PROJECTED ANNUAL NUCLEAR PLANT ADDITIONS BY COUNTRY [a,b] (MW)

| Country | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | Total nuclear additions | Total thermal market | Nuclear % of total market |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Argentina [c] | 600 | | | 600 | 2 x 600 | | 800 | 800 | 1 000 | 1 000 | 6 000 | 6 800 | 88.2 |
| Bangladesh-L | | | | | | | | | | | | 1 300 | 0 |
| Bangladesh-H | | | | | | | | | | 600 | 600 | 3 850 | 15.6 |
| Chile | | | | | 300 | 300 | 300 | | | 300 | 1 200 | 1 750 | 68.6 |
| Egypt | | | | 600 | | 600 | 600 | 600 | 2 x 600 | 600 | 4 200 | 4 800 | 87.5 |
| Greece | | | 400 | 400 | 400 | 600 | 600 | 600 | 600 | 600 | 4 200 | 4 500 | 93.3 |
| Jamaica-L | | | | | | | | | | | | 1 000 | 0 |
| Jamaica-H | | | | | | | | | | 300 | 300 | 1 550 | 19.3 |
| Republic of Korea | | 600 | 600 | 600 | 2 x 600 | 600 | 2 x 600 | 2 x 600 | 600+ 800 | 600+ 800 | 8 800 | 9 100 | 96.7 |
| Mexico | | 600 | 600 [d] | 600+ 800 | 800 | 3 x 800 | 3 x 800 | 1 000 | 2 x 800 1 000 | 3 x 1 000 | 14 800 | 19 600 | 75.6 |
| Pakistan | | | | | | | 600 | | | | 600 | 2 000 | 30.0 |
| Philippines | | | 600 | | 600 | | 800 | 800 | | 1 000 | 3 800 | 5 400 | 70.3 |
| Singapore-L | | | | | | | | | | | | 2 100 | 0 |
| Singapore-H | | | | | | | 600 | 600 | 600 | 800 | 2 600 | 4 700 | 55.3 |
| Thailand | | | | | 400 | 400 | 600 | | 600 | 600 | 2 600 | 3 850 | 67.5 |
| Turkey-L | | | | | | | | | 600 | 600 | 1 200 | 3 000 | 40.0 |
| Turkey-H | | | | | | | 600 | 600 | 600+ 800 | 600 | 3 200 | 4 850 | 66.0 |
| Yugoslavia-L | | | | 600 | 600 | 800 | | 800 | 1 000 | 1 000 | 4 800 | 6 000 | 80.0 |
| Yugoslavia-H | | | 600 | 800 | 800 | 800 | 2 x 800 | 2 x 800 | 1 000 | 2 x 1 000 | 9 200 | 10 600 | 86.8 |
| Total nuclear (L) | 600 | 1 200 | 2 200 | 4 200 | 5 500 | 5 700 | 7 900 | 5 800 | 9 000 | 10 100 | 52 200 | 71 200 | 73.3 |
| Total nuclear (H) | 600 | 1 200 | 2 800 | 4 400 | 5 700 | 5 700 | 10 700 | 7 800 | 10 400 | 12 800 | 62 100 | 83 350 | 74.5 |
| Nuclear % of total thermal (L) | 13.5 | 26.4 | 44.0 | 73.7 | 75.3 | 86.4 | 86.3 | 78.4 | 87.3 | 94.8 | | | |
| Nuclear % of total thermal (H) | 12.5 | 24.0 | 51.9 | 70.4 | 68.3 | 83.2 | 89.9 | 83.0 | 88.9 | 98.5 | | | |

[a] Under reference conditions.
[b] L = Market Survey low load forecast; H = country high load forecast.
[c] Markets for countries with one load forecast are included in both low and high load totals.
[d] Actual capacity = 670 MW in country studies.

It is seen that during the early years of the study period, the percentage of the total thermal capacity additions served by nuclear plants is relatively small; however, from 1983 onwards the nuclear portion is more than 70%.

One of the specific objectives for the Market Survey was to investigate the potential usage of small reactor power plants. Initial search through the reactor manufacturing industry indicated substantially no interest in sizes below 400 - 600 MW and no acceptable price data on sizes below these levels. Nevertheless, a decision was taken to establish the minimum size nuclear plant to be used in the evaluation studies at 100 MW. Costs were then established for sizes of 100, 200, 300 and 400 MW in the small size range. However, the studies indicated that the 100 MW size was not economically justifiable in any of the countries, under the conditions assumed. The smallest size was 200 MW and only a very few units in this size were indicated. The first size showing any appreciable market was 300 MW.

Table II-4 shows the potential market for nuclear plants by size of plants for each year of the study period. Although the Survey included nuclear alternatives from 100 MW to 1000 MW, the potential market for plants in the size range of 200 - 400 MW is relatively small in comparison to the total nuclear market. This table shows that the market for small reactors (up to 400 MW) amounts to only about 6% of the total nuclear market for both the low and high load forecasts.

TABLE II-4. DISTRIBUTION OF POTENTIAL MARKET FOR NUCLEAR PLANTS BY SIZES OF PLANTS[a,b]

| Year | Low load forecast | | | High load forecast | | |
|---|---|---|---|---|---|---|
| | Small 200-400 MW | Medium 600 MW | Large 800-1 000 MW | Small 200-400 MW | Medium 600 MW | Large 800-1 000 MW |
| 1980 | - | 600 | - | - | 600 | - |
| 1981 | - | 1 200 | - | - | 1 200 | - |
| 1982 | 400 | 1 800 | - | 400 | 2 400 | - |
| 1983 | 400 | 3 000 | 800 | 400 | 2 400 | 1 600 |
| 1984 | 1 100 | 3 600 | 800 | 1 100 | 3 000 | 1 600 |
| 1985 | 700 | 1 800 | 3 200 | 700 | 1 800 | 3 200 |
| 1986 | 300 | 3 600 | 4 000 | 300 | 4 800 | 5 600 |
| 1987 | - | 2 400 | 3 400 | - | 3 600 | 4 200 |
| 1988 | - | 3 600 | 5 400 | - | 4 200 | 6 200 |
| 1989 | 300 | 3 000 | 6 800 | 600 | 3 600 | 8 600 |
| Total | 3 200 | 24 600 | 24 400 | 3 500 | 27 600 | 31 000 |
| % of total | 6.1 | 47.1 | 46.8 | 5.6 | 44.4 | 50.0 |

[a] Under reference conditions.
[b] See Tables II-3 and VIII-8 to VIII-10 for more details.

## 2.3. Sensitivity of market to other conditions

The influence of changes in the basic parameters such as discount rate and oil price escalation rate on the potential market for nuclear plants is shown in Table II-5. As seen in this table, the market for small nuclear plants is quite sensitive to changes in the economic parameters. Under minimum market conditions, the potential market drops from the range of 3200 - 3500 MW to zero, while under maximum conditions it increases to the range of 6500 - 7800 MW. In the case of medium size plants, the reference market ranging from 24 600 - 27 600 MW drops to the range of 10 200 - 10 800 MW under minimum conditions and increases to the range of 26 400 - 31 800 MW under conditions favouring nuclear plants. In

TABLE II-5. SENSITIVITY OF THE NUCLEAR POWER MARKET TO CHANGES IN ECONOMIC PARAMETERS (MW)

| Plant size | Market under reference conditions [a] | | Minimum nuclear market conditions [b] | | Maximum nuclear market conditions [c] | |
|---|---|---|---|---|---|---|
| | Low forecast | High forecast | Low forecast | High forecast | Low forecast | High forecast |
| Small (200-400 MW) | 3 200 | 3 500 | 0 | 0 | 6 500 | 7 800 |
| Medium (600 MW) | 24 600 | 27 600 | 10 800 | 10 200 | 26 400 | 31 200 |
| Large (800-1 000 MW) | 24 400 | 31 000 | 23 600 | 29 400 | 24 400 | 31 000 |
| Total | 52 200 | 62 100 | 34 400 | 39 600 | 57 300 | 70 000 |

[a] 8% discount rate, 2% oil price escalation rate.
[b] 8% discount rate, 0% oil price escalation rate.
[c] 8% discount rate, 4% oil price escalation rate (essentially the same market was obtained with 6% discount rate or ORCOST-1 capital costs).
Note: all parameter values are in addition to the assumed 4% general inflation rate.

TABLE II-6. FINANCING REQUIREMENTS BY COUNTRY FOR ALL THERMAL PLANTS TO BE COMMISSIONED DURING 1980 - 1989 [a] (US $ × $10^6$) [b]

| Country | Plant investment | | Nuclear fuel cycle investment | Total |
|---|---|---|---|---|
| | Domestic | Foreign | | |
| Argentina | 1 068 | 1 047 | 144 | 2 259 |
| Bangladesh-L | 76 | 320 | 0 | 396 |
| Bangladesh-H | 187 | 919 | 17 | 1 123 |
| Chile | 191 | 548 | 41 | 780 |
| Egypt | 378 | 1 133 | 117 | 1 628 |
| Greece | 501 | 1 141 | 122 | 1 764 |
| Jamaica-L | 44 | 262 | 0 | 306 |
| Jamaica-H | 77 | 443 | 10 | 530 |
| Korea | 1 222 | 1 818 | 239 | 3 279 |
| Mexico | 2 859 | 2 642 | 348 | 5 849 |
| Pakistan | 125 | 421 | 17 | 563 |
| Philippines | 370 | 1 032 | 92 | 1 494 |
| Singapore-L | 121 | 295 | 0 | 416 |
| Singapore-H | 289 | 946 | 69 | 1 304 |
| Thailand | 341 | 802 | 76 | 1 219 |
| Turkey-L | 302 | 762 | 34 | 1 098 |
| Turkey-H | 394 | 1 289 | 86 | 1 769 |
| Yugoslavia-L | 860 | 805 | 111 | 1 776 |
| Yugoslavia-H | 1 466 | 1 440 | 211 | 3 117 |
| Total low forecast (L) | 8 458 | 13 028 | 1 341 | 22 827 |
| Total high forecast (H) | 9 468 | 15 621 | 1 589 | 26 678 |

[a] Under reference case conditions (see Section 2.2 for definition).
[b] 1 January 1973 US dollars.

contrast to the situation pertaining to small nuclear plants, the market for large plants is relatively insensitive to changes in the economic parameters considered. The reason for this is that when power systems become large enough to accept units in the larger size range, nuclear plants capture essentially all of the market even under conditions which tend to favour conventional plants. Thus, changing these conditions so that they are more favourable to nuclear plants does not increase the market for such plants.

## 2.4. Financing requirements

Total financing requirements by country for the reference total conventional thermal and nuclear plant expansion programs, covering units to be commissioned during the study period, are given in Table II-6. The figures given include only the investment costs associated with the thermal plants to be commissioned during the study period. It is seen in this table that total investment costs range from US $\$306 \times 10^6$ in the case of Jamaica to US $\$5849 \times 10^6$ for Mexico. More details of the financing requirements are given in Section 9.

Table II-7 gives the total annual financing requirements by years for the fourteen countries as a whole. It is seen in this table that with the low load forecasts, domestic financing requirements reach a peak of US $\$1046 \times 10^6$ and foreign financing requirements reach US $\$1670 \times 10^6$ in 1984. For the high forecast, corresponding peaks are US $\$1232 \times 10^6$ and US $\$2118 \times 10^6$, respectively, also in 1984.

The financing requirements for the nuclear fuel cycle investment are shown separately in Tables II-6 and II-7 because the financing arrangements for these costs may differ from those for the plant construction. The investment associated with the nuclear fuel amounts to US $\$1341 \times 10^6$ for the low forecast and US $\$1589 \times 10^6$ for the high forecast. Essentially all of the nuclear fuel investment costs will be foreign.

TABLE II-7. ANNUAL FINANCING REQUIREMENTS FOR NUCLEAR AND CONVENTIONAL PLANTS COMMISSIONED DURING STUDY PERIOD (US $\$ \times 10^6$)[a]

| Year | Low load forecast | | | | High load forecast | | | |
|---|---|---|---|---|---|---|---|---|
| | Plant investment | | Nuclear fuel cycle investment | Total | Plant investment | | Nuclear fuel cycle investment | Total |
| | Domestic | Foreign | | | Domestic | Foreign | | |
| 1975 | 8 | 9 | | 17 | 8 | 9 | | 17 |
| 1976 | 37 | 45 | | 82 | 40 | 48 | | 88 |
| 1977 | 155 | 203 | | 358 | 169 | 214 | | 383 |
| 1978 | 416 | 598 | 2 | 1 016 | 455 | 644 | 2 | 1 101 |
| 1979 | 637 | 902 | 19 | 1 557 | 693 | 980 | 19 | 1 692 |
| 1980 | 771 | 1 107 | 38 | 1 916 | 813 | 1 200 | 40 | 2 053 |
| 1981 | 870 | 1 295 | 69 | 2 234 | 922 | 1 449 | 84 | 2 455 |
| 1982 | 970 | 1 512 | 119 | 2 600 | 1 081 | 1 790 | 121 | 2 992 |
| 1983 | 1 025 | 1 629 | 153 | 2 807 | 1 183 | 1 998 | 155 | 3 336 |
| 1984 | 1 046 | 1 670 | 157 | 2 862 | 1 232 | 2 118 | 165 | 3 515 |
| 1985 | 1 036 | 1 628 | 196 | 2 860 | 1 194 | 2 084 | 267 | 3 545 |
| 1986 | 856 | 1 568 | 155 | 2 378 | 961 | 1 744 | 206 | 2 911 |
| 1987 | 501 | 838 | 222 | 1 451 | 568 | 1 077 | 259 | 1 904 |
| 1988 | 131 | 224 | 212 | 567 | 149 | 267 | 271 | 687 |
| Total | 8 458 | 13 028 | 1 341 | 22 827 | 9 468 | 15 621 | 1 589 | 26 678 |

[a] 1 January 1973 US dollar.

## 3. ECONOMIC AND SOCIAL FACTORS

### 3.1. Present and projected population and Gross National Product (GNP)

Table III-1 shows the present and projected population, GNP and GNP/capita along with corresponding growth rates for each of the countries being studied. The values are those used as the basis for the Market Survey load forecasts. The GNP values used were in terms of constant 1964 US dollars. Appendix F discusses the use of these values in forecasting energy requirements. These 1964 US dollar values were converted to 1 January 1973 US dollars by applying a 4%/yr inflation rate. The results were found to be somewhat higher or lower than recently published statistical data[2], particularly for countries experiencing significant changes in the foreign currency exchange rate. The effect of such variations on the forecasted loads is believed to be well within the accuracy limits of such forecasts.

### 3.2. Present and projected energy resources and consumption

Table III-2 gives the present and projected total energy consumption and hydro, fossil fuel and nuclear fuel resources for each participating country. Energy consumption and fossil fuel resources have been converted to tons of equivalent coal (TEC) for ease of comparison. The hydroelectrical potential in GWh/yr was converted to TEC using a heat rate of 2300 kcal/kWh which is about that obtainable in a modern thermal power plant. In cases where specific information was unavailable, the energy and fuel conversion factors given in Table III-3 were used. The fuel conversion factors shown are based on average net caloric values. Uranium and thorium resources were not converted into TEC because the amount of extractable energy from such resources depends very much on the reactor type (i.e. converter or breeder).

In regard to the historical and projected data on energy consumption and resources, it should be pointed out that the accuracy and confidence level of the data vary substantially from country to country. In some countries, for example, the consumption of non-commercial fuel such as straw, bagasse, dung etc. plays an important role. Under such conditions, statistical data on total energy consumption tend to be incomplete. In other cases, historical data are available for only a few years and are thus insufficient as a basis for long-range forecasts.

In considering the energy resources of each country, the question arose as to whether account should be taken only of the reserves which might be economically mined or the maximum estimated reserves. The latter were chosen as the basis because reserves which are not economical to be mined at present could become economical in the future as the result of improved mining techniques or increases in the price of competing fuels.

Table III-4 presents information on the ratios of energy resources to energy consumption. Such ratios provide an approximate indication of the ability of each country to meet present and future energy demand with indigenous resources. Again, it should be pointed out that the data given must be viewed with caution because variations in costs of developing the resources are not indicated. Also, energy consumption data, as well as energy resource data are constantly being subjected to revision.

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[2] United Nations Statistical Yearbook, 1971.

TABLE III-1. SUMMARY OF POPULATION AND GNP

| Country | Population [a] ($10^6$) | | | Population growth rate [b] (%/yr) | | GNP [c] ($10^9$ US $/yr) | | | GNP growth rate [b] (%/yr) | | GNP/capita growth rate [b] (%/yr) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1972 | 1980 | 1990 | 1972-80 | 1981-90 | 1972 | 1980 | 1990 | 1972-80 | 1981-90 | 1972-80 | 1981-90 |
| Argentina | 24.0 | 27.3 | 31.8 | 1.6 | 1.5 | 28.9 | 45.4 | 73.2 | 5.8 | 4.9 | 4.1 | 3.3 |
| Bangladesh | 72.1 | 88.6 | 114.5 | 2.6 | 2.6 | 3.8 | 6.1 | 11.0 | 6.1 | 6.1 | 3.4 | 3.4 |
| Chile | 10.2 | 11.9 | 14.5 | 2.0 | 2.0 | 6.7 | 10.0 | 16.4 | 5.1 | 5.1 | 3.0 | 3.0 |
| Egypt | 34.7 | 40.6 | 49.5 | 2.0 | 2.0 | 7.4 | 11.9 | 21.5 | 6.1 | 6.1 | 4.0 | 4.0 |
| Greece | 8.9 | 9.3 | 9.9 | 0.6 | 0.6 | 10.6 | 17.3 | 29.8 | 6.3 | 5.6 | 6.2 | 5.0 |
| Jamaica | 1.9 | 2.2 | 2.6 | 1.5 | 1.5 | 1.3 | 2.2 | 4.2 | 6.6 | 6.6 | 5.0 | 5.0 |
| Korea | 32.3 | 36.5 | 42.3 | 1.5 | 1.5 | 10.0 | 19.0 | 37.7 | 8.4 | 7.1 | 6.8 | 5.5 |
| Mexico | 54.2 | 71.5 | 96.0 | 3.5 | 3.0 | 39.4 | 68.3 | 129.3 | 7.1 | 6.6 | 3.5 | 3.5 |
| Pakistan | 55.7 | 65.2 | 79.5 | 2.0 | 2.0 | 11.3 | 17.9 | 31.7 | 5.9 | 5.9 | 3.8 | 3.8 |
| Philippines [d] | 20.7 | 25.2 | 30.9 | 2.5 | 2.0 | 5.7 | 9.9 | 18.7 | 7.1 | 6.6 | 4.5 | 4.5 |
| Singapore | 2.1 | 2.4 | 2.8 | 1.7 | 1.6 | 2.7 | 5.6 | 9.8 | 9.6 | 5.7 | 7.8 | 4.0 |
| Thailand | 38.3 | 48.6 | 62.5 | 3.0 | 2.5 | 8.3 | 15.1 | 29.2 | 7.8 | 6.8 | 4.7 | 4.2 |
| Turkey | 37.3 | 45.4 | 58.2 | 2.5 | 2.5 | 16.4 | 27.3 | 48.5 | 6.6 | 5.9 | 4.0 | 3.3 |
| Yugoslavia | 20.8 | 22.5 | 24.9 | 1.0 | 1.0 | 16.5 | 27.1 | 49.0 | 6.4 | 6.1 | 5.3 | 5.0 |

[a] Population forecast used for Market Survey (L) load forecast.
[b] Average annual compound rates over periods shown.
[c] In 1 January 1973 US dollars (converted from 1964 US $ at a 4%/yr inflation rate).
[d] Luzon only.

TABLE III-2. SUMMARY OF TOTAL ENERGY CONSUMPTION AND RESOURCES

| Country | Energy consumption ($10^6$ TEC/yr) [a] | | | Energy resources [d] | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Hydro | | | Fossil ($10^6$ TEC) | | | | | Nuclear ($10^3$ t) | |
| | 1970 | 1980 | 1990 | GWh/yr | $10^6$ TEC/yr | % dev. [b] | Coal | Lignite | Oil [c] | Gas [c] | Total | $U_3O_8$ | $ThO_2$ |
| Argentina | 44.9 | 92 | | 150 000 | 49.3 | 7 | 385 | 0 | 520 | 220 | 1 125 | 88.7 | 0 |
| Bangladesh | 2.3 | | | 900 | 0.3 | 87 | 670 | 0 | 0 | 730 | 1 400 | 0 | - [f] |
| Chile | 11.7 | | | 140 500 | 48.1 | 6 | 76 | 0 | 40 | 206 | 322 | 1 | 0 |
| Egypt | 10.2 | | | 17 300 | 5.7 | 59 | 0 | 0 | 390 | 470 | 860 | 28 | 370 |
| Greece | 12.3 | | | 20 700 | 6.8 | 27 | 0 | 280 | 0 | 0 | 280 | 0 | 0 |
| Jamaica | - [e] | | | 100 | 0.03 | 64 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Korea | 28.2 | 69 | | 6 000 | 2.0 | 35 | 1 450 | 0 | 0 | 0 | 1 450 | - [f] | - [f] |
| Mexico | 61.0 | 118.0 | | 50 000 | 16.5 | 50 | 8 600 | 0 | 700 | 400 | 9 700 | 5.2 | 0 |
| Pakistan | 8.1 | | | 26 000 | 8.5 | 40 | 300 | 0 | 7.2 | 500 | 807 | - [f] | 0 |
| Philippines | 10.8 | | | 16 200 | 5.3 | 31 | 108 | 0 | 0 | 0.1 | 108 | 0.2 | 0 |
| Singapore | 1.68 | | | 0 | 0.0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Thailand | 8.0 | 35.7 | 101 | 13 300 | 4.5 | 42 | 0 | 76 | 1 | 0 | 77 | 0 | 0 |
| Turkey | 28.3 | 57.4 | 88 | 70 000 | 23.0 | 15 | 900 | 1 300 | 96 | 0 | 2 296 | 3.2 | 4.5 |
| Yugoslavia | 31.0 | 59.5 | 98 | 64 000 | 21.0 | 40 | 100 | 6 800 | 1 220 | 184 | 8 304 | 22 | 0 |

[a] TEC = tons of coal equivalent = $7 \times 10^6$ kcal.
[b] Percentage of total which country plans to have developed by 1980.
[c] Except for special information, 9600 kcal/kg for oil and 9000 kcal/$m^3$ for gas were used as caloric values.
[d] Maximum estimated based on latest information available (i.e. 1970-1972 data).
[e] No information available.
[f] U or Th deposits were reported, but no information about the amount of reserves was available.

TABLE III-3. ENERGY AND FUEL CONVERSION FACTORS

| | TEC | kcal | GWh [a] | BTU |
|---|---|---|---|---|
| TEC | 1 | $7 \times 10^6$ | 0.003 | $27.7 \times 10^6$ |
| kcal | $0.143 \times 10^{-6}$ | 1 | $0.435 \times 10^{-9}$ | 3.96 |
| GWh [a] | 330 | $2.3 \times 10^9$ | 1 | $0.9108 \times 10^9$ |
| Btu | $0.036 \times 10^{-6}$ | 0.252 | $0.11 \times 10^9$ | 1 |
| Heavy fuel oil (t) | 1.37 | $9.6 \times 10^6$ | | |
| Heavy fuel oil ($m^3$) | 1.33 | $9.3 \times 10^6$ | | |
| Crude oil (t) [b] | 1.37 | $9.6 \times 10^6$ | | |
| Crude oil ($m^3$) [b] | 1.2 | $8.4 \times 10^6$ | | |
| Natural gas ($m^3$) | 1.285 | $9.0 \times 10^3$ | | |

[a] Based on thermal steam plant heat rate of 2300 kcal/kWh.
[b] Heat content after allowing for refinery losses.

TABLE III-4. PER-CAPITA ENERGY CONSUMPTION AND RATIOS OF ENERGY RESOURCES TO CONSUMPTION [a]

| Country | Per-capita energy consumption (TEC/capita/yr) 1970 | Fossil resources (TEC/capita) 1970 | Ratio energy resources to consumption (years of supply at 1970 consumption rate) | Ratio of hydroelectric resources to total electric energy consumption [b] | | |
|---|---|---|---|---|---|---|
| | | | | 1970 | 1980 | 1990 |
| Argentina | 1.9 | 48 | 25 | 7 | 3 | 1 |
| Bangladesh | 0.03 | 20 | 600 | 1 | 0.3 | 0.1 |
| Chile | 1.2 | 33 | 27 | 21 | 10 | 6 |
| Egypt | 0.3 | 26 | 84 | 2 | 1 | 0.5 |
| Greece | 1.4 | 32 | 23 | 2 | 1 | 0.4 |
| Jamaica | - [c] | 0 | | 0.1 | | |
| Korea | 0.9 | 47 | 51 | 0.6 | 0.2 | 0.1 |
| Mexico | 1.2 | 190 | 159 | 2 | 0.7 | 0.3 |
| Pakistan | 0.2 | 15 | 100 | 4 | 1.5 | 0.7 |
| Philippines | 0.3 | 3 | 10 | 1 [d] | 0.5 [d] | 0.2 [d] |
| Singapore | 0.8 | 0 | 0 | 0 | | |
| Thailand | 0.2 | 2 | 10 | 3 | 1 | 0.4 |
| Turkey | 0.8 | 65 | 81 | 8 | 3 | 1 |
| Yugoslavia | 1.5 | 410 | 270 | 2 | 1 | 0.5 |

[a] Maximum estimated resources; ratios rounded.
[b] Market Survey (L) electrical energy forecast.
[c] No information available.
[d] Luzon only.

## 4. BASES FOR ECONOMIC EVALUATION

### 4.1. Description of computer programs

The basic tool used in the analysis of the various alternative system expansion plans was the WASP program (see Appendix A). Two subsidiary programs were used to provide specific data for the WASP program – the ORCOST program (see Appendix B) for calculating the capital costs of various fossil and nuclear units and the polynomial regression program (see Appendix C) used to reduce the load duration curve data to a polynomial expression, derive the corresponding coefficients and plot the appropriate curves.

(a) Wien Automatic System Planning Package (WASP)

The WASP program consists of six modular programs to simulate the operation of the power stations on a seasonal (quarter-by-quarter) basis, evaluate the operating costs of each plant, calculate the present-worth value of these operating costs and the capital costs associated with all plant additions during the study period, and determine the total present-worth value of these costs to the year 2000. The six modular programs:

(i) Describe the forecasted peak loads and the load duration curves for the system.
(ii) Describe the existing power system and all future additions which are firmly scheduled.
(iii) Describe the alternative plants which are to be used to expand the power system during the study period.
(iv) Generate alternative expansion configurations (i. e. the size and timing of capacity additions being evaluated).
(v) Simulate operation of the system with each specific configuration (i. e. calculate energy generated by each unit during each quarter of the year).
(vi) Determine the present worth of all costs associated with the configuration being considered. In this regard, the WASP program has the capability of carrying out a dynamic program optimization to determine the minimum present worth of a variety of alternative expansion configurations. The application of this program, however, requires a very high-speed computer with a large storage capacity. In order to use it with the computer made available to the Market Survey, it was necessary to place constraints on the number of alternatives being considered at any one time and approach the optimum solution stepwise by removing the constraints one by one. Because this method of analysis resulted in an inordinate amount of both computer time and calendar time[3], it was decided to limit the dynamic program to only a few countries and carry out the evaluation using an empirical approach.

For each country numerous plausible patterns of power expansion for the study period were developed, their operation simulated under imposed constraints and the corresponding values of total present-worth costs computed to find the minimum cost configuration. In each case, 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 relative minor importance provided sound judgement was exercised in the selection of the alternative patterns used for simulation.

The minimum present-worth cost configuration is termed "near-optimum" since time limitations did not permit full relaxation of the constraints imposed on the choices available in those cases where the dynamic program was used. In the other cases where a number of specific alternative expansion plans were evaluated, it was not possible to consider all possible configurations for the 1980s and 1990s.

A comparison of the dynamic programming approach with the above-mentioned empirical approach was made for a few countries and the results were found to be substantially in agreement.

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[3] Improvements are being made to the WASP program which hopefully will enable the IAEA computer to handle the full dynamic program approach in future studies.

(b) Capital cost program

The very large amount of capital cost data required by the WASP program was determined by utilizing the ORCOST computer program described in Appendix B. This program was developed to provide estimates of power plant costs in various regions of the USA and has the capability of adjusting equipment, materials and labour costs from region to region. This capability made it possible to adjust the US costs to conditions prevailing in each country by utilizing data obtained by the missions during their visits. Section 7.5 describes these cost data. It is believed that this method of estimating power plant costs should remove any possible bias in favour of nuclear plants.

Although the ORCOST program was not originally designed to estimate costs of plants in the 100-300 MW size range, modifications to the program were made to permit it to handle such plants It is believed that the results are sufficiently accurate for the purposes of the Survey.

(c) Polynomial regression program

Load duration curves were obtained by the missions from the countries visited. The WASP program required that these curves be expressed as a fourth or fifth order polynomial. The polynomial expressions were developed by a least-square curve-fitting program that is described in more detail in Appendix C.

## 4.2. Economic methodology and parameters

(a) General approach

The purpose of the Survey was to estimate the possible role of nuclear power in meeting the electric energy requirements of the countries over the ten years from 1980-89. Ideally, this task would require estimating and comparing both direct and indirect benefits and costs arising from alternative power system development patterns, in order to determine in each case the power system 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. Consequently, the methodology described in detail in Appendix D represents an attempt at achieving a compromise between practical constraints and theoretical consistency The following paragraphs summarize the economic methodology and parameters used in the Survey.

(b) Definitions of costs and benefits

It was assumed that minimum costs rather than net benefits would be the measure of merit. This is equivalent to assuming that all alternative expansion plans being compared offer the same total benefits and that the minimum cost plans yield maximum benefits to the ultimate consumers. Moreover, only costs directly connected with electricity generation (i.e. excluding taxes, duties etc.) were taken into account. The exclusion of taxes was a particularly critical assumption in the case of those countries imposing a heavy fiscal burden on some types of fuel and in particular on fuel oil. Also, such external or social costs as those arising from environmental pollution in the case of both fossil-fuelled and nuclear stations were, in most part, disregarded in the base cases and only considered in a qualitative manner.

(c) Criteria for comparing costs

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 fully 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 achieving equilibrium between supply and the demand for foreign capital as evidenced by foreign exchange rationing and control, as well as by the existence of parallel markets. Although such an approach may substantially underestimate the true value of the ratio of foreign to domestic costs, the alternative procedure of estimating "shadow" foreign exchange rates during the study period is dependent on political and economic forecasting which involves even greater uncertainties. The effect of varying the shadow exchange rate, however, was considered in sensitivity studies for some of the countries and found to have very little influence on the overall results. The tendency would be to work against capital-intensive projects, such as nuclear power plants and against oil-fired plants fuelled with imported oil.

The theoretical inaccuracies of using official rates of foreign exchange were somewhat alleviated by the practices followed by some of the countries where the problem of economic instability was most acute In these countries all domestic cost items of future projects were converted into hard currency equivalents on the basis of experience in 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 the common denominator, the US dollar was chosen for purposes of convenience and not because of any expectations of particular stability.

The aggregation and comparison of time flows of costs was carried out using the present-worth discounting procedure with a reference constant price discount rate of 8% in all cases. The selection of present worth as the criterion of merit rather than an alternative such as internal rate of return was based on the fact that the latter approach requires estimates of benefits which the Survey deliberately refrained from making. The time origin for discounting was defined as 1 January 1973.

Increases of costs over time were assumed to take place at a rate identical for all countries and remain constant over time. This assumption implies the recognition of inflation as a permanent feature of the future economic development of both industrial and developing countries. Taking an identical rate of inflation for all countries is admittedly wrong, but justifiable in view of the impossibility of making realistic individual forecasts. The net result of an assumed constant inflation rate (4% for example) is that this can be subtracted from the representative average annual cost of money in the countries surveyed, yielding a net discount rate for present-worth calculations. On this basis, a cost of money of 12% compounded annually and a 4% inflation rate would result in a constant price discount rate of 8%. This is equivalent to computing all costs in terms of constant 1 January 1973 US dollars using an 8% interest rate and 0% inflation rate. Constant price discount rates of 6% and 10% were also used in sensitivity studies.

### (d) Bases for cost estimates

The economic evaluation of alternative expansion plans requires estimates of capital investment costs and operating costs of all types and sizes of plants being considered. To adequately cover the range of fuels and unit sizes encountered in the 14 participating countries meant that capital costs of more than 500 individual plants had to be estimated. These estimates were made with the use of the ORCOST computer program previously referred to. Briefly, this program was developed for the purpose of estimating the influence of regional differences in unit costs of equipment, materials and labour on the total capital costs of steam-electric power plants in the USA. By using equipment, materials and labour cost indices (i.e. costs relative to US base costs) applicable in each of the 14 participating countries, the ORCOST program provided unbiased estimates of plant costs in each of these countries for the sizes and types of plants being considered Since ORCOST was not designed to calculate costs of lignite-fuelled power stations, these were assumed for the purpose of the Survey to be 10% more costly than coal-fired plants. (This assumption was based on country data and information in the open literature.) Section 7.5 summarizes the capital cost data thus obtained.

The costs of indigenous fuels, particularly coal and lignite, were based on information received from each country having such fuels. The cost of imported oil was based on costs presently prevailing in the Persian Gulf as discussed in Appendix I, plus allowances for ocean and inland transport costs for each country. Nuclear fuel cycle costs were based on

costs presently prevailing in the USA In order to allow for anticipated trends in the prices of competing fuels, the reference case assumed that the price of oil and gas will escalate at a differential rate of 2% relative to nuclear fuel cycle costs. The effect of varying the escalation rates on all types of fuel was considered in the sensitivity studies.

Operating and maintenance costs of the plants being considered were obtained in those countries where they were available and used in the studies. Where such information was not available locally, US costs were used (see Appendix E) and adjusted to conditions believed to be prevailing in each country (e. g. labour rates).

(e) Plant economic lifetimes and time horizon

Plants were assumed to become operational on 1 January of the year in which they were commissioned and their economic plant lifetimes were assumed to be 50 years for hydro-electric stations, 30 years for thermal steam plants and 20 years for gas turbines. The time horizon (i. e. year in which the last plant was commissioned) was taken to be 2000. The selection of this time horizon was based on a 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 during the study 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. Since the study period was terminated before most plants had operated their full economic life, an arbitrary salvage value based on linear depreciation (i e. proportional to the unused portion of each plant's life) was credited at the end of the last year of the study period. The use of sinking fund depreciation rather than linear depreciation was also considered. Details of this approach are given in Appendix A. The Survey "reference case" economic parameters are summarized in Table IV-1.

TABLE IV-1. REFERENCE CASE ECONOMIC PARAMETERS

| Item | Study values [a] | Approximate equivalent real values |
|---|---|---|
| Discount rate | 8% | 12% |
| Capital and O & M cost escalation | 0% | 4% |
| Fuel oil and gas price escalation rate | 2% | 6% |
| Nuclear fuel price escalation rate | 0% | 4% |
| Plant capital costs | ORCOST-3 [b] | |
| Depreciation | Linear | |

[a] General inflation rate was assumed constant at 4%/yr.

[b] ORCOST-3 costs include added costs reflecting recent sharp increases in nuclear plant construction costs in the USA up to 1 January 1973. They show a ratio of PWR to oil-fired plant costs of 1.7 to 2.2 depending on country and MW rating. See Appendix B for details.

## 4.3. Technical parameters

In order to facilitate preparation of input data for the WASP program the types and characteristics of the various plants which might be used to expand the power system of each of the countries being studied were standardized as described in Appendix E. These are summarized as follows.

(a) Plant sizes and types

The standard units consisted of the types and sizes of generating plants as shown in Table 1 of Appendix E.

(b) Minimum operating capacities

The minimum operating capacity of the alternative generating plants was set at 50% of full load. Gas turbines were assumed to operate only at full load or completely shut down as required by the load duration curve.

(c) Heat rates

Full load, half load and incremental heat rates were derived from data supplied by the Bechtel Corporation and Lahmeyer International GmbH. Data are given in Appendix G.

(d) Scheduled maintenance days and forced outage rates

Scheduled maintenance days and forced outage rates were based on US experience. These are discussed in Appendix E.

## 4.4. Sensitivity studies

(a) Varying economic parameters

Starting with the reference set of economic parameters described in Section 4.2(e), the sensitivity of the resulting nuclear power markets to variations in these parameters was determined by means of a series of sensitivity studies for each country. The alternative values of the economic parameters which were varied are shown in Table IV-2.

TABLE IV-2. ECONOMIC PARAMETERS USED IN SENSITIVITY STUDIES

| Economic parameter | Study values [a] | Approximate equivalent real values |
|---|---|---|
| Discount rate | 6% and 10% | 10% and 14% |
| Fuel oil and gas escalation rate | 0% and 4% | 4% and 8% |
| Nuclear fuel price escalation rate | 2% | 6% |
| Plant capital costs | ORCOST-1 [b] | - |
| Depreciation [c] | Sinking fund | - |
| Shadow exchange rate [d] | 1.1, 1.2 and 1.3 | - |

[a] General inflation rate was assumed constant at 4%/yr.

[b] ORCOST-1 costs are based on mid-1971 nuclear plant costs in the USA updated to 1 January 1973 by escalating equipment and materials at 5%/yr and construction labour at 15%/yr. They show a ratio of PWR to oil-fired plants of 1.4 to 1.8 depending on country and MW rating. See Appendix B for details.

[c] In the reference case, the salvage value of plants at the horizon (end of year 2000) was based on straight line depreciation. Since this tends to penalize capital intensive projects (nuclear plants), studies were also carried out basing salvage values on sinking fund depreciation. See Appendix D for details.

[d] In a few instances, studies were carried out to determine the sensitivity of the results to variations in the rates of exchange between local and foreign currencies (shadow exchange rate). This is intended to show the effect of scarcity of foreign capital on capital intensive projects.

(b) Other sensitivity studies

The reference cases used load demand forecasts prepared for each country by the Market Survey as described in Appendix F. In most countries, these forecasts agreed quite well with those prepared by the countries; however, in five of the countries studied, a substantially higher load demand was forecasted. In these cases both the Market Survey forecast and the country forecast were analysed.

An additional sensitivity study was carried out, in effect, on the variation in the loss-of-load probability.[4] Since the loss-of-load probability depends on the sizes and timing of individual units and the total amount of capacity added, a desirable average of the yearly values during the study period of about 0.005 was used in the reference cases. In several instances, studies were also carried out to determine how the reference nuclear power market would be influenced by variations in this value. It should be pointed out here that in several countries with appreciable amounts of hydro capacity, particularly where the energy content is relatively low compared to installed capacity (i.e. low annual available capacity factor), extremely low values of LOLP are obtained while, at the same time, MW capacity reserve margins can be quite low. Note, for example, the case of Egypt shown in Table VII-4, which shows a LOLP of 0.00005 (0.005%) with an average critical quarter reserve margin of only 14.3%.

A qualitative treatment of the possible effects on the Survey results due to environmental considerations can be found in Appendix B and Section 7.5.

[4] For definition of loss-of-load probability (LOLP) refer to Appendix A and Section 6.2.

## 5. FORECASTS OF SYSTEM LOADS

### 5.1. Bases of forecasts

The method used by the Market Survey for forecasting the future peak demand in each country is described in detail in Appendix F. In general, it consists of forecasting the future energy demand using, as a basis, generalized correlations of electricity generation per capita and GNP per capita for 111 countries in the world, for which historical data were available[5]. The assumption is made that each country's future electricity demand will follow a characteristic path which depends on the historical relationship between the above two factors. Given that a forecast of the future growth of GNP per capita is available, the future demand for electrical energy is then calculated from the characteristic path determined from historical data on population growth, gross electricity generation and GNP. Using historical data as a basis, the expert assigned to the Survey has compared this approach with numerous other well-known methods of forecasting and found it to give the most reliable results for long-range forecasting of energy consumption. Quantitative statistical measures of the correlation of the data will be available in a forthcoming book on the subject.

Having established the future per-capita energy demand, the total demand is estimated from population forecasts. For Survey purposes, population and GNP forecasts based on information provided by each country were used. Future peak loads were then derived from forecasts of future system load factors.

In cases where the participating countries had developed their own forecasts of future energy demand and/or future peak loads, these were also considered in evaluating various power expansion plans, particularly where there was a substantial difference between the Market Survey and the country forecast.

The load description data required by the WASP program included annual peak loads, the ratios of quarterly peak loads to the annual peak, and coefficients describing the shape of the quarterly load duration curves. The computer integrated the areas under these curves and derived the quarterly and annual energy generation. Because of inaccuracies in curve fitting, the resulting annual energy generation data did not always agree precisely with the forecast energy generation data used to determine peak demand. In general, however, the differences were very slight.

### 5.2. Forecasts of energy generation

Table V-1 summarizes forecasts of gross energy generation for each country derived by the methods described above along with corresponding five-year interval growth rates. As seen in this table, two forecasts were analysed in the case of five countries and a single forecast used for the remaining nine countries. Forecasts for these latter countries were added to both the high and low forecast to give a total "low" load forecast and a total "high" load forecast as shown.

### 5.3. Forecasts of system load factors and peak demand

Table V-2 shows the forecasts of load factor and peak demand of each country. Except in the case of Egypt, load factors were assumed to remain constant over the entire period being considered. In the case of Egypt, the system load factor was assumed to drop from a high value of 71.9% in 1980 to 64% in 1990 and remain constant thereafter. The peak demand data shown in Table V-2 were derived by the method described in Appendix F and are consistent with the given energy generation and load factor data.

[5] The correlation was in terms of constant 1964 US dollars.

TABLE V-1. FORECASTS OF ELECTRIC ENERGY GENERATION AND RATES OF GROWTH

| Country | Electric energy generation (GWh x $10^3$)[a] | | | | | Rates of growth (%/yr)[b, c] | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 1980 | 1985 | 1990 | 1995 | 2000 | 1981-85 | 1986-90 | 1991-95 | 1996-2000 |
| Argentina | 42.00 | 61.25 | 84.22 | 112.29 | 148.02 | 7.8 | 6.6 | 5.9 | 5.7 |
| Bangladesh-L | 3.10 | 5.16 | 8.14 | 12.62 | 18.79 | 10.7 | 9.5 | 9.2 | 8.3 |
| Bangladesh-H | 4.82 | 10.12 | 21.68 | 44.32 | 90.60 | 16.0 | 16.4 | 15.3 | 15.1 |
| Chile | 11.39 | 16.57 | 23.67 | 32.30 | 42.73 | 7.8 | 7.4 | 6.4 | 5.8 |
| Egypt | 20.67 | 29.12 | 47.0 | 63.91 | 86.31 | 7.1 | 10.0 | 6.3 | 6.2 |
| Greece | 26.83 | 39.02 | 55.34 | 70.00 | 86.50 | 7.8 | 7.2 | 4.8 | 4.3 |
| Jamaica-L | 3.88 | 5.84 | 8.34 | 11.44 | 14.96 | 8.5 | 7.4 | 6.5 | 5.5 |
| Jamaica-H | 4.79 | 7.98 | 13.34 | 22.27 | 36.33 | 10.8 | 10.8 | 10.8 | 10.3 |
| Korea | 31.15 | 49.99 | 76.72 | 112.76 | 159.84 | 9.9 | 8.9 | 8.0 | 7.2 |
| Mexico | 72.73 | 116.36 | 178.85 | 265.05 | 377.10 | 9.9 | 9.0 | 8.2 | 7.3 |
| Pakistan | 16.95 | 24.84 | 36.17 | 52.68 | 76.55 | 7.9 | 7.8 | 7.8 | 7.8 |
| Philippines | 14.84 | 22.83 | 35.21 | 53.36 | 78.85 | 9.0 | 9.0 | 8.7 | 8.1 |
| Singapore-L | 8.52 | 12.63 | 17.29 | 22.50 | 28.29 | 8.2 | 6.5 | 5.4 | 4.7 |
| Singapore-H | 9.06 | 16.03 | 27.76 | 44.71 | 72.00 | 12.0 | 11.6 | 10.0 | 10.0 |
| Thailand | 15.67 | 26.02 | 39.32 | 60.13 | 77.48 | 10.7 | 8.6 | 8.9 | 5.2 |
| Turkey-L | 23.43 | 34.59 | 51.32 | 76.43 | 113.24 | 8.1 | 8.2 | 8.3 | 8.2 |
| Turkey-H | 28.95 | 49.09 | 81.45 | 126.63 | 187.44 | 11.1 | 10.6 | 9.2 | 8.2 |
| Yugoslavia-L | 64.44 | 91.05 | 122.38 | 159.19 | 202.20 | 7.2 | 6.1 | 5.4 | 4.9 |
| Yugoslavia-H | 87.53 | 123.67 | 165.49 | 221.46 | 296.37 | 7.2 | 6.0 | 6.0 | 6.0 |
| Total low forecast (L) | 354.38 | 533.54 | 781.46 | 1108.75 | 1528.27 | 8.5 | 8.0 | 7.2 | 6.7 |
| Total high forecast (H) | 387.38 | 604.62 | 886.22 | 1281.87 | 1751.32 | 9.3 | 8.0 | 7.8 | 6.5 |

[a] Based on computer integration of area under quarterly load duration curves.
[b] Average annual compound rate over periods shown for each country.
[c] "Totals" are averages for time periods.

TABLE V-2. FORECASTS OF LOAD FACTOR AND PEAK DEMAND

| Country | % load factor 1980 | Peak demand (MW) | | | | |
|---|---|---|---|---|---|---|
| | | 1980 | 1985 | 1990 | 1995 | 2000 |
| Argentina | 58.3 | 8 230 | 12 000 | 16 500 | 22 000 | 29 000 |
| Bangladesh-L | 55.0 | 640 | 1 070 | 1 690 | 2 620 | 3 900 |
| Bangladesh-H | 55.0 | 1 000 | 2 100 | 4 500 | 9 200 | 18 810 |
| Chile | 60.5 | 2 150 | 3 130 | 4 470 | 6 100 | 8 070 |
| Egypt | 71.9 | 3 280 | 4 830 | 8 380 | 11 400 | 15 390 |
| Greece | 65.0 | 4 710 | 6 860 | 9 720 | 12 300 | 15 200 |
| Jamaica-L | 68.0 | 650 | 980 | 1 400 | 1 920 | 2 510 |
| Jamaica-H | 68.0 | 810 | 1 340 | 2 240 | 3 740 | 6 100 |
| Korea | 66.0 | 5 360 | 9 400 | 13 200 | 19 400 | 27 500 |
| Mexico | 61.2 | 13 500 | 21 600 | 33 200 | 49 200 | 70 000 |
| Pakistan | 58.2 | 3 320 | 4 870 | 7 090 | 10 330 | 15 010 |
| Philippines | 65.0 | 2 610 | 4 010 | 6 190 | 9 370 | 13 850 |
| Singapore-L | 65.0 | 1 500 | 2 220 | 3 040 | 3 950 | 4 970 |
| Singapore-H | 68.0 | 1 520 | 2 680 | 4 650 | 7 480 | 12 050 |
| Thailand | 66.0 | 2 710 | 4 500 | 6 800 | 10 400 | 13 400 |
| Turkey-L | 63.0 | 4 200 | 6 200 | 9 200 | 13 700 | 20 300 |
| Turkey-H | 63.0 | 5 190 | 8 800 | 14 600 | 22 700 | 33 600 |
| Yugoslavia-L | 67.5 | 10 900 | 15 400 | 20 700 | 26 930 | 34 200 |
| Yugoslavia-H | 67.5 | 14 810 | 20 920 | 27 990 | 37 460 | 50 130 |
| Total low forecast (L) | 63.5[a] | 63 550 | 96 450 | 141 140 | 200 340 | 276 360 |
| Total high forecast (H) | 64.0[a] | 69 200 | 107 040 | 159 530 | 231 080 | 328 110 |

[a] Average of all countries.

## 6. FACTORS INFLUENCING SYSTEM DEVELOPMENT

### 6.1. Parameter constraints

In order that a meaningful comparison may be made of the alternative expansion plans for a particular country, each plan must satisfy certain requirements which give rise to parameter constraints as follows:

(a) The capacity additions in each year of the plan must satisfy a reasonable loss-of-load probability for the adopted demand and energy forecast with due regard to maintenance schedules, forced outage rates, seasonal load variations and hydrological conditions. This gives rise to minimum plant reserve margins.

(b) The main transmission network must be reasonably capable of meeting the normal and first contingency (security criteria) power flow requirements throughout the plan with due regard to load distribution, power station siting, available circuit and switchgear ratings and transient stability limits. This gives rise to transmission limitations and special requirements.

(c) The system must be capable of withstanding the sudden loss of the largest generating unit at each stage of the plan without undue disturbance. (The effects of generator size on plant and transmission reserves are taken into account in (a) and (b) above.) This gives rise to limits to generator unit sizes.

In addition, the security criteria associated with each of the above requirements must be consistent with achieving a reasonable overall system reliability.

The generalized approach to the assessment and choice of these limits to satisfy the above requirements in a consistent manner for all countries is briefly outlined in this section. Details of the application of these methods to individual countries and the resultant limits and special requirements are given in the respective Country Reports.

### 6.2. Minimum generating capacity reserve margins

The WASP computer program includes a routine for the assessment of the yearly loss-of-load probability (LOLP) expressed as a fraction of the time throughout the year during which load demand may exceed available generation capacity. The technique employed for the assessment of LOLP is detailed in Appendix A and further discussed in Appendix K.

LOLP values between 0.002 and 0.01 were regarded as acceptable and a median value of 0.005 was aimed for in most cases. The choice of minimum reserve margins was first estimated using the WASP program followed by a trial and error method until the desired LOLP levels were achieved.

Details of the choice of mimimum reserve margins are given in Section 14.3 of each Country Report. A summary is given in Table VII-4. It can be seen that average reserve margins during the study period varied between about 14% and 50% of peak load. The reason for each specific value and the wide variation in reserve margins are explained in the Country Reports which are summarized in Appendix N to this report.

### 6.3. Transmission system limitations and special requirements

As explained in Appendix E under the heading "Transmission costs", it is only necessary to take account of major differences in transmission requirements between one plan and another. For example the first costs in the establishment of a higher grid voltage can be a significant factor in the choice between two plans. However, in order to identify special transmission requirements, it is generally necessary to project the likely development of the transmission system in each country. A simplified approach is sufficient and is described in Appendix H.

The normal transmission limitations encountered are thermal ratings, excessive short-circuit levels, and transient stability limits and these may require special measures such as the introduction of a higher grid voltage. Transmission limitations and any special require-

TABLE VI-1. SUMMARY OF TRANSMISSION SYSTEM LIMITATIONS

| Country | Approximate peak load forecast (MW) | | Highest grid voltage in 1980 (kV) | Standard circuit thermal rating (MVA) | L Longest point-to-point transmission (km) | Estimated transient stability transmission limit for L[a] (MVA) | Standard short-circuit rating of switchgear (MVA) |
|---|---|---|---|---|---|---|---|
| | 1980 | 1990 | | | | | |
| Bangladesh | 500 | 1 500 | 132 | 150 | 250 | 75 | 5 000 |
| Jamaica | 500 | 2 000 | 138 | 150 | < 50 | n. a. | 5 000 |
| Singapore | 1 000 | 4 000 | 230 | 200 (cable) | 35 | n. a. | 10 000 |
| Chile | 2 500 | 5 000 | 400 | 1 200 | 300 | 750 | 15 000 |
| Philippines (Luzon) | 2 500 | 6 000 | 230 | 300 | 300 | 200 | 10 000 |
| Thailand | 2 500 | 6 000 | 230 | 300 | 400 | 150 | 10 000 |
| Pakistan | 3 000 | 7 000 | 500 | 1 800 | 600 | 750 | 15 000 |
| Egypt | 3 000 | 6 000 | 500 | 1 800 | 800 | 500 | 15 000 |
| Greece | 5 000 | 10 000 | 400 | 1 400 | 400 | 700 | 15 000 |
| Turkey | 4 000 | 12 000 | 380 | 1 200 | 700 | 600[b] | 15 000 |
| Korea | 6 000 | 12 000 | 345 | 800 | 350 | 500 | 15 000 |
| Argentina | 8 000 | 15 000 | 500 | 1 800 | 1 100 | 800[b] | 15 000 |
| Yugoslavia | 10 000 | 20 000 | 380 | 1 200 | 400 | 700 | 15 000 |
| Mexico | 13 500 | 30 000 | 400 | 1 500 | 500 | 600[b] | 11 000 |

[a] Basis for estimate is given in Appendix H.
n. a. – not applicable.
[b] With series capacitor compensation.

ments which should be taken into account, including transmission reliability, are discussed in detail in Section 11 of each Country Report. A summary of the transmission limitations by country is given in Table VI-1. In this table the countries are listed in order of magnitude of forecasted peak demands.

## 6.4. Limits to size of generating units

As explained in Appendix H, the choice of unit size limits is based on the permissible disturbance to the system which can be tolerated on the sudden loss of the largest generating unit. The disturbance is measured in terms of transient frequency deviation and whether or not automatic load shedding devices operate.

The complete analysis of the frequency transient following a sudden power change such as a loss in generation is a complex subject and requires detailed information on governor characteristics, machine inertias, variation of load with frequency etc. for an accurate solution. Appendix H describes an approximate analysis method and computer program which was developed by Associated Nuclear Services Ltd of London, England, for the study of typical system response to a sudden loss of generation. This analysis technique is regarded as sufficiently accurate for the Market Survey purposes while maintaining a consistent approach to the assessment of set size limits in all countries.

Details of the application of this method and the resultant recommendations on set size for each country are given in Section 11 of the respective Country Reports. Table VI-2 summarizes the results for each country for peak load levels corresponding to the beginning and end of the study period.

Generally an attempt was made to follow each country's policy or practice with respect to overall system reliability including the maximum size of generating units. However, all countries did not have such policies, therefore, except where stated country policy is to the contrary, recommendations on set size were based on load-shed not being permissible for sudden unit loss under peak load conditions and only small to moderate load-shed (0 to 10% of peak load) being permissible under light load conditions. For the typical response capabilities of hydro and thermal regulating units this criterion gives rise to sensible unit sizes while maintaining a reasonable consistency with normal reliability standards.

The main exceptions to this criterion are Bangladesh, Egypt, Pakistan, the Philippines and, possibly, Singapore, where a reduced reliability of supply is accepted at the beginning of the Survey period to take advantage of the economics of larger unit sizes. Small to moderate load-shed at peak load conditions is permitted in these cases based on the practices which the country stated would be their policy during the study period. Consistent with the general tendency for reliability standards to improve with increase in system size, some of the larger systems do not permit load-shedding even under light load conditions.

First stage load-shed relays are typically set at 49.0 to 48.5 Hz for 50 Hz systems or 59.0 to 58.5 Hz for 60 Hz systems and the maximum permissible frequency drop at peak load conditions is correspondingly 1.0 to 1.5 Hz following the sudden loss of the largest unit. For the more severe light load conditions the maximum permissible drop is typically 1.5 to 2.0 Hz. The resultant limits to unit size vary from 20% to 5% of the peak demand over the range of system sizes and types studied.

## 6.5. Factors affecting the potential nuclear power program

### (a) Local manufacturing capabilities

Information on the contributions of local manufacturing and construction firms to recent power plants was collected by each mission and used as a basis for projecting the percentage of total construction costs that might be expended by local firms for plants commissioned during the study period. The results are summarized in Table VI-3. It is seen that in the case of conventional fossil-fired plants, the projected domestic contributions range from 15% to 60%. The domestic contributions to nuclear plant construction costs are somewhat lower, ranging from 10% to 50%. It should be pointed out that the figures given represent an average of what might be achieved over the entire study period. The domestic contribu-

TABLE VI-2. SUMMARY OF RECOMMENDED LIMITS TO SIZE OF GENERATING UNITS

| Country | Approximate peak load[a] (P-MW) | Generation mix[b] (%) | | Peak load spinning reserve[c] (% P) | Nominal system frequency (Hz) | Frequency for first stage load shed[d] (Hz) | Load shed permissible[e] | | Recommended maximum unit size (% P) |
|---|---|---|---|---|---|---|---|---|---|
| | | Thermal | Hydro | | | | Peak load | Light load | |
| Bangladesh | 500 | 80 | 20 | 20 | 50 | 49.0[f] | Small | Moderate | 20 |
| | 1 500 | 93 | 7 | 20 | 50 | 49.0[f] | No | Moderate | 15 |
| Jamaica | 500 | 98 | 2 | 15 | 50 | 48.5 | No | Moderate | 15 |
| | 2 000 | 99 | 1 | 12.5 | 50 | 48.5 | No | Moderate | 13 |
| Singapore | 1 000 | 100 | 0 | 15 | 50 | 48.5[f] | No | Moderate | 15 |
| | 3 000 | 100 | 0 | 20 | 50 | 48.5[f] | No | Small | 10 |
| | 3 000 | 100 | 0 | 48 | 50 | 49.5[f] | Moderate | Severe | 20 |
| | 4 000 | 100 | 0 | 10 | 50 | 48.5[f] | No | Moderate | 10 |
| Pakistan | 1 000 (South) | 100 | 0 | 15 | 50 | 49.3 | Moderate | Severe | 20 |
| | 7 000 (Combined) | 70 | 30 | 15 | 50 | 49.0[f] | No | Moderate | 10 |
| Chile | 2 500 | 25 | 75 | 15 | 50 | 48.5 | No | Small | 12 |
| | 5 000 | 25 | 75 | 15 | 50 | 48.5 | No | Small | 10 |
| Thailand | 2 500 | 65 | 35 | 30 | 50 | 49.0 | No | Moderate | 12 |
| | 6 000 | 88 | 12 | 20 | 50 | 49.0 | No | Moderate | 10 |
| Philippines (Luzon) | 2 500 | 80 | 20 | 15 | 60 | 59.4 | Moderate | Severe | 20 |
| | 6 000 | 90 | 10 | 15 | 60 | 58.5 | No | Moderate | 10 |
| Egypt | 3 000 | 60 | 40 | 15 | 50 | 48.8 | Moderate | Severe | 20 |
| | 6 000 | 75 | 25 | 15 | 50 | 48.8 | No | Moderate | 10 |
| Turkey | 4 000 | 45 | 55 | 15 | 50 | 48.5[f] | No | No | 9 |
| | 12 000 | 45 | 55 | 15 | 50 | 48.5[f] | No | No | 7 |
| Greece | 5 000 | 60 | 40 | 10 | 50 | 48.5 | No | No | 7 |
| | 10 000 | 60 | 40 | 10 | 50 | 48.5 | No | No | 5 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Korea | 6 000 | 90 | 10 | 15 | 60 | 58.5 | No | Moderate | 10 |
| | 12 000 | 90 | 10 | 15 | 60 | 58.5 | No | Moderate | 7 |
| Argentina | 8 000 | 65 | 35 | 12 | 50 | 49.0 | No | Pumped storage only | 9 |
| | 15 000 | 70 | 30 | 12 | 50 | 49.0 | No | Pumped storage only | 7 |
| Yugoslavia | 10 000 | 50 | 50 | 10 | 50 | 49.0 | No | Pumped storage only | 6 |
| | 20 000 | 50 | 50 | 10 | 50 | 49.0 | No | Pumped storage only | 5 |
| Mexico | 13 500 | 55 | 45 | 7.5 | 50 | 49.0[f] | No | No | 6 |
| | 30 000 | 75 | 25 | 6.5 | 50 | 49.0[f] | No | Pumped storage only | 5 |

[a] Low value is generally at beginning year and high value at ending year of study period.
[b] Generation mix excluding gas turbine for reference plant program.
[c] Spinning reserve = hydro reserve (including pumped storage if any) + hot thermal spinning reserve.
[d] Not including pumped storage which will generally be shed prior to consumer load.
[e] Small – 0 to 5% P; Moderate – 5 to 10% P; Severe – 10% P and above.
[f] Assumed value.

TABLE VI-3. FACTORS INFLUENCING POSSIBLE NUCLEAR POWER PROGRAMS

| Country | Projected domestic expenditures, % of total | | | Availability of suitable nuclear plant sites | Status of manpower training for nuclear programs |
|---|---|---|---|---|---|
| | Fossil plants | Nuclear plants | Nuclear fuel production | | |
| Argentina | 60 | 50 | 50 | Excellent throughout country[b] | Already under way |
| Bangladesh | 20 | 10 | 0 | Limited because of poor terrain | Plan training institute |
| Chile | 35 | 25 | 0 | Good coastal sites[c] | Must be developed |
| Egypt | 25 | 25 | 0 | Good coastal sites[b] | Must be developed |
| Greece | 40 | 30 | 0 | Good coastal sites[b] | Must be developed |
| Jamaica | 15 | 15 | 0 | Limited to south side | Must be developed |
| Korea | 50 | 40 | 0 | Good coastal sites | Already under way |
| Mexico | 60 | 50 | 50 | Coastal sites only | Already under way |
| Pakistan | 25 | 20 | 10 | Fair throughout country[b] | Already under way |
| Philippines | 35 | 25 | 0 | Good throughout Luzon[b,c] | Partially developed |
| Singapore | 30 | 20 | 0 | Very limited | Must be developed |
| Thailand | 30 | 30 | 0 | Probably quite good[b] | Partially developed |
| Turkey | 25[a] | 20 | 0 | Two sites being considered | Partially developed |
| Yugoslavia | 60 | 50 | 10 | Good throughout country | Must be developed |

[a] Coal and lignite-fired plants 35%.
[b] Sites have been selected.
[c] Plants must be designed for possible seismic activity.

tions to the first one or two plants in the programs will be much lower; however, local skills and capabilities will improve with each new plant and the domestic contributions toward the end of the study period will be higher than shown.

(b) Nuclear plant siting considerations

The principal nuclear plant siting considerations are the availability of adequate cooling water, population density, seismic activity and accessibility of the sites for transport of heavy equipment. Information of this nature was obtained by each mission and used to assess the availability in each country of suitable nuclear plant sites. The results are summarized in Table VI-3. The incidence of high seismic activity is indicated in the table. In these cases, plants must be designed for accelerations up to 0.5 g; however, the added costs are believed to be well within the costs used in the evaluation.

(c) Manpower training programs

The status of programs for the training of operating, maintenance and supervisory personnel required in support of possible nuclear power programs is summarized in Table VI-3. Because of the long time interval between the ordering of a nuclear plant and its commissioning, the training of suitably qualified personnel should not be a serious problem. In general, this is accomplished through on-the-job training in conventional power stations, sending technicians and engineers abroad for training by the nuclear equipment supplier and final on-the-job training during the pre-commissioning phases of the nuclear project. In several of the countries studied, nuclear projects have already been initiated and the required manpower training programs are under way.

(d) Organizational capabilities of utilities to undertake nuclear programs

The organizational capabilities of utilities that might be involved in nuclear programs are reviewed in the Country Reports. In general there should be no real problem in this respect. Based on Survey findings, it appears that when a utility system becomes large enough to accept a nuclear plant, its organizational capabilities will have reached the point where the management of a nuclear program should be possible. Moreover, in almost all of the countries studied, there are Government commissions established to deal with nuclear energy matters. These commissions are in a position to cooperate with the utilities involved in respect to such matters as training of personnel, safety and regulatory aspects, nuclear fuel procurement and siting studies. The International Atomic Energy Agency is also in a position to assist with these matters upon request. Appendix L lists the kinds of services which can be provided.

## 7. CHARACTERISTICS OF ELECTRIC POWER SYSTEMS EVALUATED

### 7.1. Characteristics of each country's fixed system

Starting with information on existing and committed power expansion plans provided by each country (which generally were sufficient to meet peak load demands up to 1975-1977), generating units of the same type being considered by each country were assumed to be added to provide an adequate reserve margin in 1979, the year before the start of the study period. These assumed additions became part of the so-called fixed system, and therefore did not affect the economic evaluation of nuclear and conventional units introduced during the study period. The resulting installed capacities of each country's fixed system assumed to be in existence in 1979 are summarized in Table VII-1.

For the purpose of simplifying the computer calculations associated with the fixed system, the number of individual plants considered in each case was reduced by combining plants with approximately similar operating characteristics. Each combination of plants was then assumed to be a single plant consisting of groups of identical units (sets) operating at the same fuel costs and occupying the same position in the startup and loading order. The types of input data necessary to describe this hypothetical plant are the same as discussed in Section 4.3; however, the actual values used were derived from the technical characteristics of the plants comprising each combined unit, usually by weighting of either capacity or average annual energy generation. More details of the methods of deriving the fixed system characteristics are given in Section 12.2 of each Country Report.

TABLE VII-1. INSTALLED CAPACITIES OF ASSUMED FIXED SYSTEMS IN 1979 (MW)

| Country | Hydro | Pumped storage | Conventional steam | Gas turbine | Nuclear | Total |
|---|---|---|---|---|---|---|
| Argentina | 3 026 | - | 4 947 | 1 050 | 919 | 9 942 |
| Bangladesh-L | 130 | - | 399 | 255 | - | 784 |
| Bangladesh-H | 130 | - | 699 | 205 | - | 1 034 |
| Chile | 1 612 | - | 934 | - | - | 2 546 |
| Egypt | 1 310 [a] | - | 2 121 | 28 | - | 3 459 |
| Greece | 1 560 | - | 4 035 | 26 | - | 5 621 |
| Jamaica-L | 15 | - | 737 | 50 | - | 802 |
| Jamaica-H | 15 | - | 937 | - | - | 952 |
| Korea | 710 | - | 4 455 | 250 | 1 195 | 6 610 |
| Mexico | 6 200 | - | 7 581 | 760 | 670 | 15 211 |
| Pakistan | 839 | - | 2 428 | - | 125 | 3 392 [b] |
| Philippines | 569 | - | 2 799 | - | - | 3 368 |
| Singapore-L | - | - | 1 775 | 44 | - | 1 819 |
| Singapore-H | - | - | 1 775 | 66 | - | 1 841 |
| Thailand | 1 341 | - | 2 298 | 50 | - | 3 689 |
| Turkey-L | 2 490 | - | 2 200 | - | - | 4 690 |
| Turkey-H | 3 228 | - | 2 950 | - | - | 6 178 |
| Yugoslavia-L | 6 703 | - | 5 115 | 105 | 640 | 12 563 |
| Yugoslavia-H | 7 478 | 200 | 7 515 | 205 | 640 | 16 038 |

[a] Excludes 1135 MW emergency hydro.
[b] In critical (2nd) quarter.

## 7.2. Characteristics of generating units considered as expansion alternatives

Table VII-2 lists the range of sizes and types of thermal generating units considered for each country's power system expansion program. More details of these units are given, by country, in Appendix N. A typical printout of data describing the expansion alternatives is shown in Table VII-3.

TABLE VII-2. RANGE OF THERMAL GENERATING UNIT TYPES AND SIZES CONSIDERED AS EXPANSION ALTERNATIVES (MW)

| Country | Coal | Oil | Gas | Lignite | Gas turbine | Nuclear |
|---|---|---|---|---|---|---|
| Argentina | 400-1 000 | 400-1 000 | 0 | 0 | 100 | 400-1 000 |
| Bangladesh | 300-600 | 100-800 | 100-200 | 0 | 50 | 100-800 |
| Chile | 150-400 | 150-800 | 200-400 | 0 | 50 | 200-800 |
| Egypt | 0 | 0 | 100-1 000 | 0 | 50 | 300-1 000 |
| Greece | 0 | 140-800 | 0 | 125-300 | 0 | 300-800 |
| Jamaica | 0 | 100-800 | 0 | 0 | 50 | 100-800 |
| Korea | 0 | 300-1 000 | 0 | 0 | 50 | 600-1 000 |
| Mexico | 300 | 300-1 000 | 0 | 0 | 100 | 600-1 000 |
| Pakistan | 0 | 100-1 000 | 0 | 0 | 50 | 300-1 000 |
| Philippines | 0 | 200-1 000 | 0 | 0 | 100 | 300-1 000 |
| Singapore | 0 | 150-1 000 | 0 | 0 | 50 | 200-1 000 |
| Thailand | 0 | 300-1 000 | 0 | 0 | 50 | 300-1 000 |
| Turkey | 150 | 600 | 0 | 150-600 | 0 | 300-800 |
| Yugoslavia | 300-1 000 | 400-1 000 | 0 | 300-1 000 | 100 | 300-1 000 |

## 7.3. Capacity additions during study period (1980 - 1989)

As described in Section 6.2, the amount of capacity added each year to each country's fixed system was determined with the help of the WASP program which calculates the quarterly and annual LOLP for any given mixture of plants in the system. Table VII-4 shows the results of these calculations which served to define the capacity additions made to each system and the corresponding reserve margins and annual LOLP. It is seen that the reserve margins are quite high in a number of cases; however, as shown in the table, the corresponding LOLP are generally close to the desired value of 0.005.

As mentioned in Section 2.1, hydro power systems were assumed to be developed at a rate consistent with each country's hydro power expansion policy and therefore were not considered to be competing with thermal stations in meeting future peak loads. An exception was made in the case of Chile because the country's plans involve an expansion program based almost entirely on hydro capacity additions. Table VII-5 lists the annual additions to the hydro power systems in the countries having such systems. Similarly, pumped storage plants were assumed to be developed in accordance with each country's plans. Table VII-5 also lists the pumped storage capacity added during the study period.

TABLE VII-3(a). TYPICAL COMPUTER PRINTOUT OF CHARACTERISTICS OF GENERATING UNITS USED AS EXPANSION ALTERNATIVES[a]

| | NAME | NO. OF SETS | MIN. LOAD MW | CAP-CITY MW | BASE LOAD HEAT RATE | AVGE INCR HEAT RATE | FUEL COSTS CENTS/MIL_ION 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 | L300 | 0 | 150 | 300 | 2560. | 2396. | 134.00 | 0.0 | 3 | 1 | 8.70 | 28 | 300 | 0. | 0.310 | 0.0 | 2478. |
| 2 | L600 | 0 | 300 | 600 | 2553. | 2383. | 134.00 | 0.0 | 3 | 1 | 14.10 | 28 | 600 | 0. | 0.220 | 0.0 | 2468. |
| 3 | L800 | 0 | 400 | 800 | 2559. | 2381. | 134.00 | 0.0 | 3 | 1 | 14.50 | 35 | 800 | 0. | 0.200 | 0.0 | 2470. |
| 4 | L1T0 | 0 | 500 | 1000 | 2570. | 2360. | 134.00 | 0.0 | 3 | 1 | 14.50 | 35 | 1000 | 0. | 0.170 | 0.0 | 2465. |
| 5 | C300 | 0 | 150 | 300 | 2361. | 2199. | 123.00 | 0.0 | 4 | 1 | 8.70 | 28 | 300 | 0. | 0.300 | 0.0 | 2280. |
| 6 | C600 | 0 | 300 | 600 | 2354. | 2186. | 123.00 | 0.0 | 4 | 1 | 14.10 | 28 | 600 | 0. | 0.210 | 0.0 | 2270. |
| 7 | C800 | 0 | 400 | 800 | 2360. | 2184. | 123.00 | 0.0 | 4 | 1 | 14.50 | 35 | 800 | 0. | 0.190 | 0.0 | 2272. |
| 8 | C1T0 | 0 | 500 | 1000 | 2370. | 2166. | 123.00 | 0.0 | 4 | 1 | 14.50 | 35 | 1000 | 0. | 0.170 | 0.0 | 2268. |
| 9 | D400 | 0 | 200 | 400 | 2324. | 2098. | 0.0 | 187.00 | 1 | 1 | 9.80 | 28 | 400 | 0. | 0.240 | 0.0 | 2211. |
| 10 | D600 | 0 | 300 | 600 | 2328. | 2172. | 0.0 | 187.00 | 1 | 1 | 12.00 | 28 | 600 | 0. | 0.190 | 0.0 | 2250. |
| 11 | D800 | 0 | 400 | 800 | 2334. | 2170. | 0.0 | 187.00 | 1 | 1 | 12.20 | 35 | 800 | 0. | 0.170 | 0.0 | 2252. |
| 12 | D1T0 | 0 | 500 | 1000 | 2344. | 2152. | 0.0 | 187.00 | 1 | 1 | 12.20 | 35 | 1000 | 0. | 0.160 | 0.0 | 2248. |
| 13 | N400 | 0 | 200 | 400 | 2643. | 2362. | 0.0 | 57.00 | 0 | 1 | 9.80 | 28 | 400 | 0. | 0.420 | 0.0 | 2502. |
| 14 | N600 | 0 | 300 | 600 | 2638. | 2365. | 0.0 | 55.00 | 0 | 1 | 12.00 | 28 | 600 | 0. | 0.320 | 0.0 | 2501. |
| 15 | N800 | 0 | 400 | 800 | 2632. | 2369. | 0.0 | 53.00 | 0 | 1 | 12.20 | 35 | 800 | 0. | 0.270 | 0.0 | 2500. |
| 16 | N1T0 | 0 | 500 | 1000 | 2627. | 2372. | 0.0 | 51.00 | 0 | 1 | 12.20 | 35 | 1000 | 0. | 0.230 | 0.0 | 2499. |
| 17 | GT1H | 0 | 100 | 100 | 4000. | 4000. | 250.00 | 0.0 | 2 | 1 | 2.00 | 4 | 100 | 0. | 1.200 | 0.0 | 4000. |

[a] See Table VII-3(b) for explanation of column headings and units.

TABLE VII-3(b). LEGEND FOR TABLE VII-3(a)

| | |
|---|---|
| NAME | WASP code for plant names. |
| 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. |
| CAP-CITY, MW | Maximum load at which units will be operated. |
| BASE LOAD HEAT RATE | Unit heat rate at base load, in kcal/kWh. |
| AVGE INCR HEAT RATE | Unit heat rate for each kW above base load, in kcal/kWh. |
| FUEL COSTS, DOMESTIC | Fuel costs, in US ¢/kcal x $10^6$. |
| FUEL COSTS, FOREIGN | Same as above, except for imported fuel. |
| TYPE | A code where: 0 = nuclear<br>1 = oil-fired<br>2-4 = optional (coal, lignite, gas)<br>5 = hydro |
| LCTN | Not used. Defaulted to 1 in all cases. |
| FRCD OUTAGE RATE | Days lost due to forced outage. |
| DAYS SCHL MAIN | Days lost due to scheduled outage. |
| MAIN CLAS | An arbitrary assignment of unit size, for maintenance calculations. |
| ENERGY, GWh | Used only for hydro. |
| O & M (FIX) | Average O & M costs, in US $/kW-month. |
| 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. |

The capacity available from the installed hydro and pumped storage plants was subtracted from the total required to determine net thermal capacity additions. Such additions shown in Table VII-6 represent the total market for new capacity to be shared by nuclear and conventional plants during the study period.

## 7.4. Capacity additions after study period (1990 - 2000)

The WASP program evaluated the capital and operating costs of each alternative expansion plan for the period 1980 - 2000. Even though the study was specifically interested in the first decade of this period, the two-decade period was used in the evaluation in order to minimize the effect of not operating plants built during the study period to the end of their economic life. Table VII-7 summarizes the capacity additions made to each system during the 1990 - 2000 period.

TABLE VII-4. CHARACTERISTICS OF CAPACITY ADDITIONS DURING STUDY PERIOD

| Country | MW | | | Reserve margin (%) [a] | | | Annual loss-of-load probability (LOLP) (fraction) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Total installed capacity 1979 | Total installed capacity 1989 | Total added capacity 1980-89 | 1979 | 1989 | Period average | 1979 | 1989 | Period average |
| Argentina | 9 942 | 19 886 [b] | 9 944 | 18.8 | 14.2 | 15.1 | 0.0028 | 0.0010 | 0.0010 |
| Bangladesh-L | 784 | 2 084 | 1 300 | 33.0 | 31.8 | 29.3 | 0.0003 | 0.0013 | 0.0010 |
| Bangladesh-H | 1 034 | 4 835 | 3 801 | 24.0 | 26.0 | 22.1 | 0.003 | 0.0054 | 0.0049 |
| Chile | 2 546 | 5 016 | 2 470 | 27.6 | 20.2 | 23.3 | 0.005 | 0.0015 | 0.003 |
| Egypt | 3 459 | 8 498 | 5 039 | 11.7 | 13.2 | 14.3 | 0.00005 | 0.0049 | 0.0014 |
| Greece | 5 621 | 12 390 | 6 769 | 35.0 | 44.0 | 37.5 | 0.0025 | 0.0039 | 0.0042 |
| Jamaica-L | 802 | 1 802 | 1 000 | 37.0 | 29.0 | 37.0 | 0.0036 | 0.0011 | 0.0017 |
| Jamaica-H | 952 | 2 502 | 1 550 | 33.0 | 24.0 | 23.0 | 0.0039 | 0.0066 | 0.0075 |
| Korea | 6 610 | 15 710 | 9 100 | 30.1 | 26.4 | 21.2 | 0.0010 | 0.0027 | 0.0055 |
| Mexico | 15 211 | 36 591 | 21 380 | 24.7 | 19.6 | 18.9 | - | 0.0011 | 0.0007 |
| Pakistan | 3 392 | 6 863 | 3 471 | 19.6 | 13.2 | 16.7 | 0.0001 | 0.0003 | 0.0003 |
| Philippines | 3 368 | 8 603 | 5 235 | 41.0 | 52.0 | 50.0 | 0.0050 | 0.0024 | 0.0028 |
| Singapore-L | 1 819 | 3 769 | 1 950 | 33.0 | 32.0 | 33.5 | 0.0035 | 0.0056 | 0.0039 |
| Singapore-H | 1 841 | 6 366 | 4 525 | 37.0 | 51.0 | 44.0 | 0.0023 | 0.0021 | 0.0023 |
| Thailand | 3 689 | 8 439 | 4 750 | 50.5 | 35.0 | 47.2 | 0.0030 | 0.0062 | 0.0041 |
| Turkey-L | 4 690 | 11 649 | 6 959 | 20.7 | 23.0 | 21.0 | 0.0067 | 0.0006 | 0.0036 |
| Turkey-H | 6 178 | 16 949 | 10 771 | 31.0 | 21.7 | 21.6 | 0.0049 | 0.0031 | 0.0026 |
| Yugoslavia-L | 12 563 | 23 313 | 10 750 | 21.3 | 17.0 | 18.6 | 0.0020 | 0.0081 | 0.0041 |
| Yugoslavia-H | 16 038 | 30 913 | 14 875 | 15.6 | 15.1 | 15.0 | 0.0020 | 0.0064 | 0.0045 |

[a] In critical quarter.
[b] Includes 400 MW added by interconnection of sub-system.

TABLE VII-5. HYDRO AND PUMPED STORAGE TOTAL CAPACITY ADDITIONS (MW)[a]

| Country | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Argentina | 270<br>(150) | 270<br>(450) | 270<br>(150) | 800 | 300 | 300 | 300 | 300 | 300 | 300 | 3410<br>(750) |
| Bangladesh-L | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Bangladesh-H | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Chile | 0 | 260 | 260 | 0 | 0 | 0 | 0 | 0 | 200 | 0 | 720[b] |
| Egypt | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 50 | 40 | 50 | 420 |
| Greece | 170 | 360 | 0 | 300 | 307 | 288 | 400 | 170 | 210 | 360 | 2 565 |
| Jamaica-L | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Jamaica-H | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Korea | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mexico | 700 | (150) | (150) | (300) | (150) | (150) | (150) | (150) | (150) | (150) | 700<br>(1 500) |
| Pakistan | 86 | 87 | 0 | 0 | 86 | 87 | 0 | 0 | 1 125 | 0 | 1 471 |
| Philippines | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Singapore-L | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Singapore-H | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Thailand | 0 | 60 | 60 | 360 | 420 | 0 | 0 | 0 | 0 | 0 | 900 |
| Turkey-L | 176 | 0 | 562 | 30 | 524 | 527 | 0 | 1 100 | 580 | 520 | 4 019 |
| Turkey-H | 30 | 524 | 527 | 1 100 | 580 | 1 020 | 600 | 700 | 500 | 400 | 5 981 |
| Yugoslavia-L | 385<br>(200) | 390 | 450 | 388<br>(300) | 648 | 438 | 752<br>(389) | 0 | 0<br>(416) | 0 | 3 445<br>(1 305) |
| Yugoslavia-H | 450<br>(300) | 388<br>(389) | 648 | 438<br>(416) | 752 | 0<br>(500) | 0 | 0 | 0 | 0 | 2 670<br>(1 605) |

[a] Figures in brackets indicate pumped storage additions.
[b] Adjusted from country plans as a result of the evaluation studies.

TABLE VII-6. REQUIRED THERMAL CAPACITY ADDITIONS (MW)

| Country | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Argentina | 1 000 | 0 | 0 | 1 000 | 1 200 | 0 | 800 | 800 | 1 000 | 1 000 | 6 800 |
| Bangladesh-L | 100 | 100 | 100 | 100 | 100 | 100 | 200 | 200 | 0 | 300 | 1 300 |
| Bangladesh-H | 200 | 200 | 200 | 250 | 400 | 300 | 400 | 500 | 800 | 600 | 3 850 |
| Chile | 200 | 0 | 0 | 0 | 300 | 300 | 350 | 100 | 0 | 500 | 1 750 |
| Egypt | 600 | 0 | 0 | 600 | 0 | 600 | 600 | 600 | 1 200 | 600 | 4 800 |
| Greece | 0 | 300 | 400 | 400 | 400 | 600 | 600 | 600 | 600 | 600 | 4 500 |
| Jamaica-L | 100 | 100 | 100 | 50 | 100 | 100 | 100 | 100 | 200 | 50 | 1 000 |
| Jamaica-H | 100 | 50 | 100 | 150 | 150 | 150 | 150 | 200 | 200 | 300 | 1 550 |
| Korea | 0 | 600 | 900 | 600 | 1 200 | 600 | 1 200 | 1 200 | 1 400 | 1 400 | 9 100 |
| Mexico | 300 | 1 500 | 1 500 | 1 700 | 1 700 | 2 700 | 3 000 | 1 600 | 2 600 | 3 000 | 19 600 |
| Pakistan | 200 | 0 | 800 | 0 | 200 | 0 | 600 | 200 | 0 | 0 | 2 000 |
| Philippines | 400 | 400 | 600 | 100 | 1 200 | 0 | 800 | 800 | 100 | 1 000 | 5 400 |
| Singapore-L | 200 | 50 | 300 | 300 | 50 | 400 | 0 | 400 | 400 | 0 | 2 100 |
| Singapore-H | 300 | 300 | 300 | 400 | 400 | 400 | 600 | 600 | 600 | 800 | 4 7[illegible] |
| Thailand | 600 | 300 | 300 | 50 | 400 | 500 | 500 | 0 | 600 | 600 | 3 850 |
| Turkey-L | 450 | 300 | 0 | 300 | 450 | 0 | 300 | 0 | 600 | 600 | 3 000 |
| Turkey-H | 300 | 450 | 0 | 300 | 600 | 0 | 600 | 600 | 1 400 | 600 | 4 850 |
| Yugoslavia-L | 300 | 600 | 300 | 600 | 600 | 800 | 0 | 800 | 1 000 | 1 000 | 6 000 |
| Yugoslavia-H | 600 | 600 | 600 | 800 | [illegible] | 800 | 1 600 | 1 600 | 1 200 | 2 000 | 10 600 |

TABLE VII-7. CAPACITY ADDITIONS AFTER STUDY PERIOD, 1990-2000 (MW)

| Country | Nuclear | Conventional thermal | Hydro | Pumped storage | Gas turbine | Total |
|---|---|---|---|---|---|---|
| Argentina | 9 000 | 3 638[a] | 3 620 | 0 | 1 000 | 17 258 |
| Bangladesh-L | 1 800 | 1 300 | 0 | 0 | 0 | 3 100 |
| Bangladesh-H | 4 800 | 6 400 | 0 | 0 | 0 | 11 200 |
| Chile | 1 200 | 800 | 2 540 | 0 | 100 | 4 640 |
| Egypt | 5 000 | 3 564[a] | 600 | 0 | -28[a] | 8 536 |
| Greece | 600 | 6 100 | 5 700 | 0 | 0 | 12 400 |
| Jamaica-L | 700 | 500 | 0 | 0 | 0 | 1 200 |
| Jamaica-H | 3 000 | 1 400 | 0 | 0 | 150 | 4 550 |
| Korea | 8 800 | 10 200 | 0 | 0 | 0 | 19 000 |
| Mexico | 29 200 | 21 900 | 0 | 300 | 0 | 51 400 |
| Pakistan | 4 400 | 3 574[a] | 500 | 0 | 0 | 8 474 |
| Philippines[b] | 8 000 | 1 436[a] | 0 | 0 | 0 | 9 436 |
| Singapore-L[b] | 3 000 | -385[a] | 0 | 0 | 194 | 2 809 |
| Singapore-H | 5 000 | 3 618[a] | 0 | 0 | 250 | 8 868 |
| Thailand | 5 400 | 2 800 | 0 | 0 | 0 | 8 200 |
| Turkey-L | 2 600 | 4 200 | 7 210 | 0 | 0 | 14 010 |
| Turkey-H | 4 000 | 9 600 | 9 811 | 0 | 0 | 23 411 |
| Yugoslavia-L | 7 200 | 7 800 | 0 | 500 | 500 | 16 000 |
| Yugoslavia-H | 12 200 | 13 400 | 0 | 0 | 1 600 | 27 200 |

[a] Net including retirements.

[b] Based on dynamic program optimization.

## 7.5. Capital cost data

### (a) Description of base models

As described in Appendix B, the ORCOST computer program permits the conversion of base model costs to conditions prevailing at locations other than the base site through the use of equipment, materials and labour indexes. These indexes which represent the effective costs of these components relative to US costs were derived from information provided by each country and are discussed in detail in the Country Reports. Table VII-8 summarizes the indexes that were used in each case.

Two US base cost models were used in the ORCOST program. The first, called ORCOST-1, was based on costs prevailing in the USA as of mid-1971. These costs were adjusted to 1 January 1973 dollars by escalating materials and equipment at 5%/yr and construction labour at 15%/yr.

In the course of the Market Survey, it was learned that construction costs of nuclear plants (and to a lesser extent conventional plants) had risen sharply in 1972 as a result of environmental considerations and correspondingly more stringent construction codes. To reflect such increases in costs, the ORCOST-1 base model costs, particularly for nuclear plants, were increased resulting in ORCOST-3 costs. Table VII-9 shows a comparison of ORCOST-1 and ORCOST-3 costs for the countries studied having the maximum and minimum cost levels and for the USA. It is seen that the difference in capital costs between ORCOST-3 and ORCOST-1 PWR plants is substantial, whereas costs of oil-fired plants remained essentially unchanged. The ORCOST-3 costs were adopted for the reference case and ORCOST-1 costs used in sensitivity studies.

TABLE VII-8. EQUIPMENT, MATERIALS AND LABOUR COST INDICES (COUNTRY VERSUS US RATES)[a]

| Country | Fossil plant equipment | Nuclear plant equipment | Materials | Labour |
|---|---|---|---|---|
| Argentina | 0.9 | 1.0 | 0.9 | 0.5 |
| Bangladesh | 1.1 | 1.2 | 1.65 | 0.11 |
| Chile | 0.9 | 1.0 | 1.0 | 0.5 |
| Egypt | 0.9 | 1.0 | 0.95 | 0.21 |
| Greece | 0.9 | 1.05 | 0.85 | 0.38 |
| Jamaica | 0.9 | 1.0 | 1.0 | 0.51 |
| Korea | 0.9 | 1.0 | 1.0 | 0.3 |
| Mexico | 0.9 | 1.0 | 0.85 | 0.35 |
| Pakistan | 1.0 | 1.1 | 1.1 | 0.26 |
| Philippines | 0.9 | 1.0 | 0.85 | 0.27 |
| Singapore | 0.9 | 1.0 | 0.85 | 0.27 |
| Thailand | 0.9 | 1.0 | 0.91 | 0.22 |
| Turkey | 0.95 | 1.05 | 1.0 | 0.38 |
| Yugoslavia | 0.9 | 1.0 | 0.8 | 0.31 |

[a] Generally based on mid-1971 costs.

It is seen that in all cases, estimated capital costs of plants built in the countries covered by the Market Survey are lower than corresponding plants built in the USA. This results generally from the very high construction labour costs in the USA compared to those in developing countries. Table VII-9 shows, however, that the ratio of nuclear to oil-fired plant costs in all of the participating countries is higher than the ratio of these costs based on US conditions. This is because the nuclear plant equipment cost indices (see Table VII-8) were assumed to be higher than the fossil-fired plant equipment indices in all cases.

It is not clear whether environmental considerations will play an important role in the participating countries; therefore, other than using ORCOST-3 costs no allowance was made for these in the reference cases, except that all fossil-fuelled plant capital costs include electrostatic precipitators to clean up particulate matter in the stack gases. If future environmental considerations require the use of fuels of low sulphur content or equipment to alleviate effects of thermal or gaseous discharges, capital and/or operating costs would increase and thereby influence the competition between fossil and nuclear plants. This means that if environmental control equipment is included, such as cooling towers or the equivalent for all types of plants, $SO_2$ removal systems for fossil plants and near-zero radiation release for nuclear plants, the costs of fossil-fired plants would be increased substantially more than of nuclear plants, thus tending to be more favourable to nuclear plants. This factor was not treated in a quantitative manner in these studies; however, a qualitative and approximate quantitative discussion can be found in Appendix B.

(b) Verification of capital cost data

Data were obtained from each country on costs of recently constructed conventional steam plants. To compare these reported costs with costs developed using the ORCOST program, a series of computer runs was made to calculate the capital costs which the ORCOST model would give for the plants of the sizes, types and commissioning dates reported. Construction schedules, contingency and spare parts factors and the above-mentioned cost indexes were the same as used in the Market Survey; however, to put costs in terms of 1 January 1973 US dollars, equipment and materials costs were assumed to have

TABLE VII-9. COMPARISON OF NUCLEAR AND OIL-FIRED PLANT CAPITAL COSTS

| Plant size (MW) | Plant type | | ORCOST-1 | | | ORCOST-3 | | |
|---|---|---|---|---|---|---|---|---|
| | | | Maximum values[a] | Minimum values[a] | USA | Maximum values[a] | Minimum values[a] | USA |
| 300 | PWR | Capital costs (US $/kW) | 490 | 378 | 517 | 593 | 442 | 624 |
| | Oil | Capital costs (US $/kW) | 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 | Capital costs (US $/kW) | 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 | Capital costs (US $/kW) | 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 |

[a] Based on countries having maximum and minimum adjusted cost levels.

TABLE VII-10. COMPARISON OF REPORTED AND COMPUTED POWER PLANT COSTS

| Country | Power plant description | | | | Capital costs (US$/kW)[a] | | | | | | Ratio of ORCOST costs to reported costs | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Name | Size (MW) | Type | Comm. date | Reported[b] | | ORCOST-1 | | ORCOST-3 | | ORCOST-1 | | ORCOST-3 | |
| | | | | | Direct | Total | Direct | Total | Direct | Total | Direct | Total | Direct | Total |
| Argentina | Lujan de Cuyo | 60 | Oil | 12/71 | 169.3 | 215 | 186 | 354 | 193 | 332 | 1.1 | 1.65 | 1.4 | 1.55 |
| Argentina | Planned unit[c, d] | 600 | PWR | 78 | - | 360 | - | 309 | - | 368 | - | 0.86 | - | 1.02 |
| Bangladesh | Ashuganj | 60 | Gas | 7/70 | 240 | 337 | 168 | 342 | 177 | 319 | 0.7 | 1.02 | 0.74 | 0.95 |
| Chile | Bocamina | 125 | Coal | 12/67 | 133 | 203 | 132 | 255 | 142 | 249 | 0.99 | 1.26 | 1.07 | 1.23 |
| Egypt | Cairo West | 87 | Oil | 12/68 | 156 | 189 | 123 | 232 | 130 | 218 | 0.79 | 1.24 | 1.17 | 1.15 |
| Greece | Megalopolis | 125 | Lignite | 10/70 | - | 278 | 168 | 315 | 177 | 300 | - | 1.14 | - | 1.08 |
| Greece | St. George's Bay | 200 | Oil | 7/71 | - | 115 | 119 | 220 | 124 | 212 | - | 1.91 | - | 1.85 |
| Jamaica | Old Harbour | 68.5 | Oil | 6/72 | 165 | 187 | 190 | 362 | 199 | 343 | 1.16 | 1.93 | 1.21 | 1.84 |
| Korea | Seoul 5 | 250 | Oil | 12/69 | - | 136 | 102 | 187 | 106 | 181 | - | 1.37 | - | 1.33 |
| Korea | Inchon 1 | 250 | Oil | 12/70 | - | 138 | 107 | 198 | 113 | 192 | - | 1.43 | - | 1.39 |
| Korea | Planned unit[c, d] | 565 | PWR | 10/76 | - | 344 | - | 290 | - | 345 | - | 0.84 | - | 1.0 |
| Mexico | Salamanca | 150 | Oil | 1/71 | 95 | 119 | 124 | 230 | 129 | 219 | 1.31 | 1.93 | 1.36 | 1.84 |
| Mexico | Valle de México | 150 | Oil | 1/71 | 90 | 123 | 124 | 230 | 129 | 219 | 1.37 | 1.87 | 1.43 | 1.78 |
| Pakistan | Lyallpur | 66 | Oil | 12/67 | - | 209 | 142 | 273 | 150 | 254 | - | 1.31 | - | 1.22 |
| Pakistan | Korangi | 125 | Oil | 12/70 | - | 144 | 141 | 259 | 149 | 249 | - | 1.80 | - | 1.73 |
| Pakistan | Kanupp | 137 | PWR | 12/72 | - | 609 | 256 | 541 | 320 | 646 | - | 0.89 | - | 1.06 |
| Philippines | Gardner 2 | 200 | Oil | 12/70 | - | 157 | 108 | 199 | 114 | 192 | - | 1.27 | - | 1.22 |
| Philippines | Snyder 1 | 200 | Oil | 12/71 | - | 141 | 115 | 212 | 121 | 204 | - | 1.50 | - | 1.45 |
| Philippines | Bataan 1 | 75 | Oil | 12/72 | - | 202 | 162 | 307 | 169 | 289 | - | 1.52 | - | 1.43 |
| Singapore | Jurong | 120 | Oil | 12/72 | - | 136 | 142 | 263 | 148 | 251 | - | 1.93 | - | 1.85 |
| Thailand | South Bangkok 1 | 200 | Oil | 3/71 | 104 | 120 | 111 | 202 | 116 | 196 | 1.06 | 1.68 | 1.11 | 1.63 |
| Thailand | South Bangkok 2 | 200 | Oil | 3/72 | 96 | 108 | 118 | 214 | 123 | 207 | 1.23 | 1.98 | 1.28 | 1.92 |
| Turkey | Ambarli | 150 | Oil | 12/71 | - | 258 | 132 | 205 | 139 | 253 | - | 1.02 | - | 0.98 |
| Yugoslavia | Planned unit[c] | 250 | Oil | 12/72 | 114 | 147 | 115 | 212 | 121 | 205 | 1.02 | 1.45 | 1.06 | 1.4 |

[a] At indicated commissioning date.
[b] Excluding taxes and duties.
[c] Cost estimate.
[d] Costs in 1972 U S dollars.

escalated at 5%/yr and construction labour at 15%/yr from the dates of commissioning of individual plants. In cases where direct construction costs were made available, these, as well as total costs, were compared.

Table VII-10 shows the results of this comparison. As can be seen in this table, the direct costs computed by ORCOST are somewhat higher than the costs reported by the utilities, although the differences are not large in most cases. This is a rough indication of the validity of the equipment, materials and labour cost indices used in ORCOST. Since, as shown in Table VII-8, somewhat higher cost indices were used to estimate nuclear plant costs than those used for the conventional plants given in Table VII-10, a lowering of these indices to bring the ORCOST estimates more in line with the reported costs would tend to reduce the differential in the direct costs between nuclear and conventional plants. Thus, the ORCOST models as used tend to favour conventional plants.

The comparison of total plant costs shown in Table VII-10 indicates that ORCOST computed capital costs have constantly higher indirect costs than the utility reported costs. This may result from the base assumption used in ORCOST that all plants would be designed and engineered by a foreign consulting firm and plant construction would be supervised by personnel from this firm. In many of the examples given, the utilities have performed a large portion of this work themselves, presumably at lower costs than assumed in the ORCOST models. If the indirect cost indexes were reduced to reflect a greater contribution by local utilities in the design, engineering and construction supervision areas, the differential in total costs between nuclear and conventional plants would be reduced. While it may be assumed that the foreign architect-engineering approach may be necessary for any first-of-a-kind plant, it is not clear that this assumption is applicable for all plants commissioned during the study period. On this basis, it may be concluded that the indirect cost indices used in ORCOST are conservative with respect to nuclear plants and the ORCOST-1 cost levels might be considered to more nearly reflect the true situation.

Table VII-11 gives the unit capital costs of representative oil-fired and nuclear plants based on the ORCOST-3 cost model and assumed fuel oil prices delivered at the plant sites. In general, costs of gas-fired plants were about 10% below the costs of the oil-fired units, while coal-fired plants were 12% above the oil-fired plant costs. Lignite-fired plants were assumed to cost 10% more than coal-fired plants based on data provided by such countries as Greece and Yugoslavia and from information in the open literature.

## 7.6. Fuel costs and other operation costs

### (a) Indigenous fuel costs

Costs of local and indigenous fuels are given in Appendix N for each country for the systems assumed to be in existence at the start of the study period and for the expansion alternatives considered.

### (b) Imported oil

The method of estimating future oil prices is described in detail in Appendix I. The assumed costs of fuel oil delivered to the plant sites (as of 1 January 1973) are shown in Table VII-11[6].

### (c) Nuclear fuel cycle costs

The method of estimating future nuclear fuel cycle costs is described in detail in Appendix J. Base nuclear fuel cycle costs (as of 1 January 1973) are shown in Table VII-12.

### (d) Operating and maintenance costs

Base operating and maintenance costs are shown in Appendix E which also describes the method of estimating these costs.

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[6] The increases in oil prices subsequent to the February 1973 devaluation of the US dollar were not taken into consideration; however, these increases should be taken care of by the assumption of 2%/yr net escalation on oil prices used in the reference cases.

TABLE VII-11. CAPITAL COSTS OF OIL-FIRED AND NUCLEAR PLANTS AND BASE FUEL OIL PRICES[a]

| Country | Capital costs of oil-fired plants (US$/kW) | | | Capital costs of nuclear plants (US$/kW) | | | Imported fuel oil costs[b] (US¢/$10^6$ kcal) |
|---|---|---|---|---|---|---|---|
| | 300 MW | 600 MW | 1000 MW | 300 MW | 600 MW | 1000 MW | |
| Argentina | 240 | 193 | 169 | 502 | 368 | 304 | 182 |
| Bangladesh | 268 | 216 | 189 | 593 | 439 | 365 | 160 |
| Chile | 246 | 198 | 172 | 516 | 378 | 313 | 190 |
| Egypt | 207 | 170 | 147 | 445 | 325 | 268 | 151 |
| Greece | 222 | 182 | 157 | 478 | 351 | 290 | 185 |
| Jamaica | 247 | 199 | 173 | 517 | 379 | 314 | 177 |
| Korea | 221 | 181 | 156 | 471 | 345 | 284 | 159 |
| Mexico | 219 | 179 | 154 | 462 | 338 | 279 | 187 |
| Pakistan | 234 | 189 | 165 | 494 | 364 | 301 | 132 |
| Philippines | 209 | 172 | 148 | 445 | 325 | 268 | 150 |
| Singapore | 209 | 172 | 148 | 445 | 325 | 268 | 140 |
| Thailand | 206 | 170 | 146 | 442 | 322 | 266 | 150 |
| Turkey | 245 | 198 | 173 | 534 | 392 | 324 | 200 |
| Yugoslavia | 211 | 173 | 149 | 447 | 326 | 269 | 187 |

[a] All costs in 1 January 1973 US dollars.
[b] Estimated prices delivered at plant sites.

TABLE VII-12. NUCLEAR FUEL CYCLE COSTS AND HEAT RATES

| Plant capacity (MW) | Levelized fuel cycle costs (US mill/kWh) | | | Full load gross heat rate[a] (kcal/kWh) | Fixed fuel cycle costs (US$/kW) | Variable fuel cycle costs (US¢/$10^6$ kcal) |
|---|---|---|---|---|---|---|
| | Total | Fixed | Variable | | | |
| 100 | 1.93 | 0.43 | 1.50 | 2 504 | 38 | 59.8 |
| 200 | 1.89 | 0.41 | 1.48 | 2 503 | 36 | 58.9 |
| 300 | 1.84 | 0.39 | 1.45 | 2 503 | 34 | 57.9 |
| 400 | 1.79 | 0.37 | 1.43 | 2 502 | 32 | 57.0 |
| 600 | 1.70 | 0.32 | 1.38 | 2 501 | 28 | 55.1 |
| 800 | 1.60 | 0.27 | 1.33 | 2 500 | 24 | 53.2 |
| 1 000 | 1.51 | 0.23 | 1.28 | 2 499 | 20 | 51.3 |

[a] Gross heat rates were used to be consistent with the use of such heat rates in calculating conventional fuel costs.

## 8. PROJECTED MARKET FOR NUCLEAR POWER PLANTS

### 8.1. Market under reference conditions

Based on the reference values of economic parameters the projected markets for nuclear and conventional thermal plants which will be commissioned in each participating country during the study period are shown in Table VIII-1. Also shown in the table are the percentages of the total thermal market which might be served by nuclear plants in each country over the study period The distribution of nuclear additions by sizes of units is shown at the bottom of the table.

Table VIII-2 summarizes the system expansion schedules under the reference conditions. Table VIII-3 shows the conventional plant and nuclear plant additions for each year of the study period and corresponding percentages of the total thermal market served by nuclear plants. It is seen that during the first two years of the period studied, less than 30% of the power market are supplied by nuclear plants, however, during the final five years, 80% or more of the market is nuclear. During the entire study period, about 73% of the potential thermal market would be nuclear for the low load forecast and 75% for the high load forecast.

### 8.2. Sensitivity of market to varying parameter values

Tables VIII-4 to VIII-8 show the influence of changing economic parameters on the potential market for nuclear plants in each of the participating countries. These tables are generally self-explanatory.

For several countries special sensitivity studies were carried out, which are not shown in tabular form. These include the influence of LOLP variations, the use of shadow exchange rates of 1.1 and 1 3, sinking fund depreciation instead of linear depreciation, 0% escalation on coal prices and 2% and 4% escalation on nuclear fuel prices. The results of these studies are given in the Country Reports. General comments are as follows:

Because of the complex relationship between reserve margin, sizes and types of units and loss-of-load probability, it is not possible to quantify the influence of varying the LOLP on the reference case nuclear market. From a qualitative point of view, generally, the lower the LOLP the greater the installed capacity for a given peak demand. In some cases, the desired LOLP was achieved by adding 50 MW gas turbine units at intervals during the study period with a corresponding reduction in the amount of nuclear or conventional capacity added. The total gas-turbine capacity added, however, was less than 1% of the total thermal additions. Thus gas turbine additions had little effect on the final results.

Sensitivity studies using shadow exchange rates of 1.1 to 1.3 were carried out for several countries; however, the reference case nuclear market remained substantially unchanged. The reason was that a high shadow exchange rate not only penalizes nuclear plants (because of the high foreign exchange component of the investment costs) but also oil-fired plants (because of the high foreign exchange component of fuel costs).

The use of sinking fund depreciation as a basis for estimating the salvage value of plants at the end of the horizon had approximately the same effect as a 1% reduction in the discount rate. Since the reference case nuclear market increased by about 8% when using a 6% discount rate, it would have increased about 4% if sinking fund depreciation had been used throughout. In terms of MW, this increase would have amounted to about 2000 MW with the load forecast and to 2500 MW with the high load forecast.

The use of a 2%/yr escalation rate on nuclear fuel was evaluated for a number of countries and found to have about the same effect as the use of a 10% discount rate. In other words, the reference case nuclear market would have decreased by about 8% or 4000 MW.

The use of 0%/yr escalation rate simultaneously on both coal prices and nuclear fuel was evaluated for one country, Yugoslavia. Under such conditions, the reference case nuclear market in Yugoslavia would have decreased by 2 × 600 MW or less than 2% of the high forecast market. In almost all of the other countries either coal was an unimportant fuel, or there were limitations on the total amount of coal available for power production. Thus it appears that the use of 0% escalation rate on coal prices would have little effect on the total nuclear market.

TABLE VIII-1. PROJECTED ANNUAL THERMAL PLANT ADDITIONS DURING STUDY PERIOD BY COUNTRY (MW)[a, b]

| Country | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | Total conventional 1980-89 | Total nuclear 1980-89 | Nuclear % of total additions |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Argentina | 400<br>N600 | 0 | 0 | 400<br>N600 | 2×N600 | 0 | N800 | N800 | N1000 | N1000 | 800 | 6 000 | 88.2 |
| Bangladesh-L | 100 | 100 | 100 | 100 | 100 | 100 | 200 | | | 300 | 1 300 | 0 | 0 |
| Bangladesh-H | 200 | 200 | 200 | 250 | 2 × 200 | 300 | 400 | 200 | 0 | N600 | 3 250 | 600 | 15.6 |
| Chile | 200 | 0 | 0 | 0 | N300 | N300 | N300<br>50 | 500<br>100 | 2×400<br>0 | N300<br>200 | 550 | 120 | 68.6 |
| Egypt | 600 | 0 | 0 | N600 | 0 | N600 | N600 | N600 | 2×N600 | N600 | 600 | 4 200 | 87.5 |
| Greece | 0 | 300 | N400 | N400 | N400 | N600 | N600 | N600 | N600 | N600 | 300 | 4 200 | 93.3 |
| Jamaica-L | 100 | 100 | 100 | 50 | 100 | 100 | 100 | 100 | 200 | 50 | 1 000 | 0 | 0 |
| Jamaica-H | 100 | 50 | 100 | 150 | 150 | 150 | 150 | 200 | 200 | N300 | 1 250 | 300 | 19.3 |
| Korea | 0 | 300<br>N600 | N600 | N600 | 2×N600 | N600 | 2×N600 | 2×N600 | N600<br>N800 | N600<br>N800 | 300 | 8 800 | 96.7 |
| Mexico | 300 | 3×300<br>N600 [c] | 3×300<br>N600 | 300<br>N600<br>N800 | 3×300<br>N800 | 300<br>3×N800 | 2×300<br>3×N800 | 2×300<br>N1000 | 2×N800<br>N1000 | 3×N1000 | 4 800 | 14 800 | 75.6 |
| Pakistan | 200 | 0 | 200<br>600 | 0 | 200 | 0 | N600 | 200 | 0 | 0 | 1 400 | 600 | 20.0 |
| Philippines | 400 | 400 | N600 | 100 | 600<br>N600 | 0 | N800 | N800 | 100 | N1000 | 1 600 | 3 800 | 70.3 |
| Singapore-L | 200 | 50 | 300 | 300 | 50 | 400 | 0 | 400 | 400 | 0 | 2 100 | 0 | 0 |
| Singapore-H | 300 | 300 | 300 | 400 | 400 | 400 | N600 | N600 | N600 | N800 | 2 100 | 2 600 | 55.3 |
| Thailand | 2×300 | 300 | 300 | 50 | N400 | N400 | N600 | 0 | N600 | N600 | 1 250 | 2 600 | 67.5 |
| Turkey-L | 150<br>300 | 300 | 0 | 300 | 150<br>300 | 0 | 300 | 0 | N600 | N600 | 1 800 | 1 200 | 40.0 |
| Turkey-H | 300 | 150<br>300 | 0 | 300 | 600 | 0 | N600 | N600 | N600<br>N800 | N600 | 1 650 | 3 200 | 66.0 |
| Yugoslavia-L | 300 | 600 | 300 | N600 | N600 | N800 | 0 | N800 | N1000 | N1000 | 1 200 | 4 800 | 80.0 |
| Yugoslavia-H | 600 | 600 | N600 | N800 | N800 | N800 | 2×N800 | 2×N800 | N1000<br>200 | 2×N1000 | 1 400 | 9 200 | 86.8 |
| Nuclear additions low forecast (L) | 600 | 2×600 | 400<br>3×600 | 400<br>5×600<br>800 | 300<br>2×400<br>6×600<br>800 | 300<br>400<br>3×600<br>4×800 | 300<br>6×600<br>5×800 | 4×600<br>3×800<br>1000 | 6×600<br>3×800<br>3×1000 | 300<br>5×600<br>800<br>6×1000 | 19 000 [d] | 52 200 | 73.3 |
| Nuclear additons high forecast (H) | 600 | 2×600 | 400<br>4×600 | 400<br>4×600<br>2×800 | 300<br>2×400<br>5×600<br>2×800 | 300<br>400<br>3×600<br>4×800 | 300<br>8×600<br>7×800 | 6×600<br>4×800<br>1000 | 7×600<br>4×800<br>3×1000 | 2×300<br>6×600<br>2×800<br>7×1000 | 21 250 [d] | 62 100 | 74.5 |

[a] For reference conditions.
[b] Letter N indicates nuclear plants. All others are fossil-fuelled including gas turbine units.
[c] Actual rating used in Country Report is 670 MW.
[d] Conventional units only.

TABLE VIII-2. SUMMARY OF SYSTEM EXPANSION SCHEDULES (MW) [a]

| Country | Systems as of 1979 | | | | Additions 1980-1989 | | | | Thermal capacity retired | Systems as of 1989 | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Thermal | | Hydro and pumped storage | Total | Thermal | | Hydro and pumped storage | Total | | Thermal | | Hydro and pumped storage | Total |
| | Conv. | Nuclear | | | Conv. | Nuclear | | | | Conv. | Nuclear | | |
| Argentina | 5 997 | 919 | 3 026 | 9 942 | 800 | 6 000 | 4 160 | 10 960 | 1 016 | 5 781 | 6 919 | 7 186 | 19 886 |
| Bangladesh-L | 654 | - | 130 | 784 | 1 300 | - | - | 1 300 | - | 1 954 | - | 130 | 2 084 |
| Bangladesh-H | 904 | - | 130 | 1 034 | 3 250 | 600 | - | 3 850 | 49 | 4 105 | 600 | 130 | 4 835 |
| Chile | 934 | - | 1 612 | 2 546 | 550 | 1 200 | 720 | 2 470 | - | 1 484 | 1 200 | 2 332 | 5 016 |
| Egypt | 2 149 | - | 1 310 [b] | 3 459 | 600 | 4 200 | 420 | 5 220 | 181 | 2 568 | 4 200 | 1 730 | 8 498 |
| Greece | 4 061 | - | 1 560 | 5 621 | 300 | 4 200 | 2 565 | 7 065 | 296 | 4 065 | 4 125 | 4 200 | 12 390 |
| Jamaica-L | 787 | - | 15 | 802 | 1 000 | - | - | 1 000 | - | 1 787 | - | 15 | 1 802 |
| Jamaica-H | 937 | - | 15 | 952 | 1 250 | 300 | - | 1 550 | - | 2 187 | 300 | 15 | 2 502 |
| Korea | 4 705 | 1 195 | 710 | 6 610 | 300 | 8 800 | - | 9 100 | - | 5 005 | 9 995 | 710 | 15 710 |
| Mexico [c] | 8 341 | 670 | 6 200 | 15 211 | 4 800 | 14 800 | 2 200 | 21 800 | 490 | 12 651 | 15 470 | 8 400 | 36 521 |
| Pakistan | 2 428 | 125 | 839 | 3 392 | 1 400 | 600 | 1 471 | 3 471 | - | 3 828 | 725 | 2 310 | 6 863 |
| Philippines | 2 799 | - | 569 | 3 368 | 1 600 | 3 800 | - | 5 400 | 165 | 4 234 | 3 800 | 569 | 8 603 |
| Singapore-L | 1 819 | - | - | 1 819 | 2 100 | - | - | 2 100 | 150 | 3 769 | - | - | 3 769 |
| Singapore-H | 1 841 | - | - | 1 841 | 2 100 | 2 600 | - | 4 700 | 175 | 3 766 | 2 600 | - | 6 366 |
| Thailand | 2 348 | - | 1 341 | 3 689 | 1 250 | 2 600 | 900 | 4 750 | - | 3 598 | 2 241 | 2 600 | 8 439 |
| Turkey-L | 2 200 | - | 2 490 | 4 690 | 1 800 | 1 200 | 4 019 | 7 019 | 60 | 4 080 | 1 200 | 6 369 | 11 649 |
| Turkey-H | 2 950 | - | 3 128 | 6 178 | 1 650 | 3 200 | 5 981 | 10 831 | 60 | 4 680 | 3 200 | 9 069 | 16 949 |
| Yugoslavia-L | 5 200 | 640 | 6 703 | 12 563 | 1 200 | 4 300 | 4 750 | 10 750 | - | 6 420 | 5 440 | 11 453 | 23 313 |
| Yugoslavia-H | 7 720 | 640 | 7 678 | 16 038 | 1 400 | 9 200 | 4 275 | 14 875 | - | 9 120 | 9 840 | 11 953 | 30 913 |
| Total low forecast (L) | 44 442 | 3 549 | 26 505 | 74 496 | 19 000 | 52 200 | 21 205 | 92 405 | 2 358 | 61 224 | 55 749 | 47 570 | 164 543 |
| Total high forecast (H) | 48 114 | 3 549 | 28 218 | 79 881 | 21 250 | 62 100 | 22 692 | 106 042 | 2 432 | 67 072 | 65 649 | 50 770 | 183 491 |

[a] Reference conditions.
[b] Excludes 1135 MW emergency hydro.
[c] See footnote [c] Table VIII-1.

TABLE VIII-3. DISTRIBUTION OF THERMAL CAPACITY ADDITIONS

| Year | Low load forecast | | | | High load forecast | | | |
|---|---|---|---|---|---|---|---|---|
| | Conv. | Nuclear | Total | Nuclear % of total | Conv. | Nuclear | Total | Nuclear% of total |
| | MW | | | | MW | | | |
| 1980 | 3 850 | 600 | 4 450 | 13.5 | 4 200 | 600 | 4 800 | 12.5 |
| 1981 | 3 350 | 1 200 | 4 550 | 26.4 | 3 800 | 1 200 | 5 000 | 24.0 |
| 1982 | 2 800 | 2 200 | 5 000 | 44.0 | 2 600 | 2 800 | 5 400 | 51.9 |
| 1983 | 1 600 | 4 200 | 5 800 | 73.7 | 1 950 | 4 400 | 6 350 | 70.4 |
| 1984 | 2 400 | 5 500 | 7 900 | 75.3 | 3 250 | 5 700 | 8 950 | 68.3 |
| 1985 | 900 | 5 700 | 6 600 | 86.4 | 1 150 | 5 700 | 6 850 | 83.2 |
| 1986 | 1 250 | 7 900 | 9 150 | 86.3 | 1 200 | 10 700 | 11 900 | 89.9 |
| 1987 | 1 600 | 5 800 | 7 400 | 78.4 | 1 600 | 7 800 | 9 400 | 83.0 |
| 1988 | 700 | 9 000 | 9 700 | 87.3 | 1 300 | 10 400 | 11 700 | 88.9 |
| 1989 | 550 | 10 100 | 10 650 | 94.8 | 200 | 12 800 | 13 000 | 98.5 |
| Total | 19 000 | 52 200 | 71 200 | 73.3 | 21 250 | 62 100 | 83 350 | 74.5 |

## 8.3. Distribution of market by sizes or units

Table VIII-9 shows the market for small (200-400 MW) nuclear plants under reference conditions and under conditions which tend to favour conventional plants and nuclear plants respectively. As seen in this table, the market for small nuclear plants is very sensitive to oil-price escalation. With 0% escalation on oil prices, the potential market drops to zero from the reference case range of 3200-3500 MW. At 4% oil price escalation rate (or use of ORCOST-1 capital costs which give essentially the same result) the market for small nuclear plants increases to the range of 6500-7800 MW.

Table VIII-10 shows how the market for medium size (600 MW) nuclear plants would be affected by changes in these same parameters. Here it is seen that the market under reference conditions of 24 600 - 27 600 MW drops to the minimum market level of 10 200 - 10 800 MW with 0% escalation on oil prices. The maximum nuclear market was encountered with a 6% discount rate and 2% escalation on oil prices. In this case, the potential market was increased to the range of 26 400 - 31 200 MW.

Table VIII-11 shows the potential market for large (800-1000 MW) nuclear plants. In contrast to the situation pertaining to small nuclear plants, the market for large plants is relatively insensitive to changes in the economic parameters applied. The reason for this is that when systems become large enough to accept units in this size range, nuclear plants capture essentially all of the market even under conditions which tend to favour conventional plants. Thus, changing these conditions to make them more favourable to nuclear plants does not increase the market for such plants.

TABLE VIII-4. NUCLEAR POWER MARKETS WITH 6% DISCOUNT RATE (MW)[a]

| Country | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Argentina | 600 | | | 600 | 2×600 | | 800 | 800 | 1 000 | 1 000 | 6 000 |
| Bangladesh-L | | | | | | | | | | | 0 |
| Bangladesh-H | | | | | | | | | 2×400 | 600 | 1 400 |
| Chile | | | | | 300 | 300 | 300 | | | 300 | 1 200 |
| Egypt | 600 | | | 600 | | 600 | 600 | 600 | 2×600 | 600 | 4 800 |
| Greece | | | 400 | 400 | 400 | 600 | 600 | 600 | 600 | 600 | 4 200 |
| Jamaica-L | | | | | | | | | 200 | | 200 |
| Jamaica-H | | | | | | | | 200 | 200 | 300 | 700 |
| Korea | | 600 | 600 | 600 | 2×600 | 600 | 2×600 | 2×600 | 600, 800 | 600, 800 | 8 800 |
| Mexico | | 600 | 600 | 600, 800 | 800 | 3×800 | 3×800 | 1 000 | 2×800, 1000 | 3×1000 | 14 800 |
| Pakistan | | | 600 | | | | 600 | | | | 1 200 |
| Philippines | | | 600 | | 2×600 | | 800 | 800 | | 1 000 | 4 400 |
| Singapore-L | | | | | | | | 400 | 400 | | 800 |
| Singapore-H | | | | | | | 600 | 600 | 600 | 800 | 2 600 |
| Thailand | | | 300 | | 400 | 400 | 600 | | 600 | 600 | 2 900 |
| Turkey-L | | | | | | | | | 600 | 600 | 1 200 |
| Turkey-H | | | | | 600 | | 600 | 600 | 600, 800 | 600 | 3 800 |
| Yugoslavia-L | | 600 | | 600 | 600 | 800 | | 800 | 1 000 | 1 000 | 5 400 |
| Yugoslavia-H | 600 | 600 | 600 | 800 | 800 | 800 | 2×800 | 2×800 | 1 000 | 2×1000 | 10 400 |
| Total low forecast (L) | 1 200 | 1 800 | 3 100 | 4 200 | 6 100 | 5 700 | 7 900 | 6 200 | 9 600 | 10 100 | 55 900 |
| Total high forecast (H) | 1 800 | 1 800 | 3 700 | 4 400 | 6 900 | 5 700 | 10 700 | 8 000 | 11 400 | 12 800 | 67 200 |

[a] Other parameters at reference conditions.

TABLE VIII-5. NUCLEAR POWER MARKETS WITH 10% DISCOUNT RATE (MW)[a]

| Country | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Argentina | 600 | | | 600 | 2×600 | | 800 | 800 | 1 000 | 1 000 | 6 000 |
| Bangladesh-L | | | | | | | | | | | 0 |
| Bangladesh-H | | | | | | | | | | | 0 |
| Chile | | | | | 300 | 300 | 300 | | | 300 | 1 200 |
| Egypt | | | | | | 600 | 600 | 600 | 2×600 | 600 | 3 600 |
| Greece | | | 400 | 400 | 400 | 600 | 600 | 600 | 600 | 600 | 4 200 |
| Jamaica-L | | | | | | | | | | | 0 |
| Jamaica-H | | | | | | | | | | | 0 |
| Korea | | 600 | 600 | 600 | 2×600 | 600 | 2×600 | 2×600 | 600, 800 | 600, 800 | 8 800 |
| Mexico | | 600 | 600 | 600, 800 | 800 | 3×800 | 3×800 | 1 000 | 2×800, 1000 | 3×1000 | 14 800 |
| Pakistan | | | | | | | 600 | | | | 600 |
| Philippines | | 600 | | | | | 800 | 800 | | 1 000 | 3 200 |
| Singapore-L | | | | | | | | | | | 0 |
| Singapore-H | | | | | | | | 600 | 600 | 800 | 2 000 |
| Thailand | | | | | | 400 | 600 | | 600 | 600 | 2 200 |
| Turkey-L | | | | | | | | | 600 | | 600 |
| Turkey-H | | | | | | | 600 | 600 | 600, 800 | 600 | 3 200 |
| Yugoslavia-L | | | | | | 800 | | 800 | 1 000 | 1 000 | 3 600 |
| Yugoslavia-H | | | | 800 | 800 | 800 | 2×800 | 2×800 | 1 000 | 2×1000 | 8 600 |
| Total low forecast (L) | 600 | 1 800 | 1 600 | 3 000 | 3 900 | 5 700 | 7 900 | 5 800 | 9 000 | 9 500 | 48 800 |
| Total high forecast (H) | 600 | 1 800 | 1 600 | 3 800 | 4 700 | 5 700 | 10 100 | 7 800 | 10 400 | 11 900 | 58 400 |

[a] Other parameters at reference conditions.

TABLE VIII-6. NUCLEAR POWER MARKETS WITH 0% OIL PRICE ESCALATION RATE (MW)[a]

| Country | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Argentina | | | | | | | 800 | 800 | 1 000 | 1 000 | 3 600 |
| Bangladesh-L | | | | | | | | | | | 0 |
| Bangladesh-H | | | | | | | | | | | 0 |
| Chile | | | | | | | | | | | 0 |
| Egypt | | | | | | | | | | | 0 |
| Greece | | | | | | 600 | 600 | 600 | 600 | 600 | 3 000 |
| Jamaica-L | | | | | | | | | | | 0 |
| Jamaica-H | | | | | | | | | | | 0 |
| Korea | | 600 | 600 | | 600 | 600 | 600 | 600 | 800 | 800 | 5 200 |
| Mexico | | 600 | 600 | 600, 800 | 800 | 3×800 | 3×800 | 1 000 | 2×800, 1000 | 3×1000 | 14 800 |
| Pakistan | | | | | | | | | | | 0 |
| Philippines | | | | | | | 800 | | | 1 000 | 1 800 |
| Singapore-L | | | | | | | | | | | 0 |
| Singapore-H | | | | | | | | | | | 0 |
| Thailand | | | | | | | | | | | 0 |
| Turkey-L | | | | | | | | | 600 | 600 | 1 200 |
| Turkey-H | | | | | | | | | 600, 800 | 600 | 2 000 |
| Yugoslavia-L | | | | 600 | 600 | 800 | | 800 | 1 000 | 1 000 | 4 800 |
| Yugoslavia-H | | | 600 | 800 | 800 | 800 | 2×800 | 2×800 | 1 000 | 2×1000 | 9 200 |
| Total low forecast (L) | 0 | 1 200 | 1 200 | 2 000 | 2 000 | 4 400 | 5 200 | 3 800 | 6 600 | 8 000 | 34 400 |
| Total high forecast (H) | 0 | 1 200 | 1 800 | 2 200 | 2 200 | 4 400 | 6 800 | 4 600 | 7 400 | 9 000 | 39 600 |

[a] Other parameters at reference conditions.

TABLE VIII-7. NUCLEAR POWER MARKETS WITH 4% OIL PRICE ESCALATION RATE (MW)[a]

| Country | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Argentina | 600 | | | 600 | 2×600 | | 800 | 800 | 1 000 | 1 000 | 6 000 |
| Bangladesh-L | | | | | | | | 200 | | 300 | 500 |
| Bangladesh-H | | | | | | | 300 | 400 | 2×400 | 600 | 2 100 |
| Chile | | | | | 300 | 300 | 300 | | | 300 | 1 200 |
| Egypt | 600 | | | 600 | | 600 | 600 | 600 | 2×600 | 600 | 4 800 |
| Greece | | | 400 | 400 | 400 | 600 | 600 | 600 | 600 | 600 | 4 200 |
| Jamaica-L | | | | | | | | | 200 | | 200 |
| Jamaica-H | | | | | | | | 200 | 200 | 300 | 700 |
| Korea | | 600 | 600 | 600 | 2×600 | 600 | 2×600 | 2×600 | 600, 800 | 600, 800 | 8 800 |
| Mexico | | 600 | 600 | 600, 800 | 800 | 3×800 | 3×800 | 1 000 | 2×800, 1000 | 3×1000 | 14 800 |
| Pakistan | | | 600 | | | | 600 | | | | 1 200 |
| Philippines | | | 600 | | 2×600 | | 800 | 800 | | 1 000 | 4 400 |
| Singapore-L | | | | 300 | 300 | | | 400 | 400 | | 1 400 |
| Singapore-H | | | | 400 | 400 | 400 | 600 | 600 | 600 | 800 | 3 800 |
| Thailand | 2×300 | 300 | 300 | | 400 | 400 | 600 | | 600 | 600 | 3 800 |
| Turkey-L | | | | | | | | | 600 | 600 | 1 200 |
| Turkey-H | | | | | 600 | | 600 | 600 | 600, 800 | 600 | 3 800 |
| Yugoslavia-L | | | | 600 | 600 | 800 | | 800 | 1 000 | 1 000 | 4 800 |
| Yugoslavia-H | 600 | 600 | 600 | 800 | 800 | 800 | 2×800 | 2×800 | 1 000 | 2×1000 | 10 400 |
| Total low forecast (L) | 1 800 | 1 500 | 3 100 | 4 500 | 6 400 | 5 700 | 7 900 | 6 400 | 9 600 | 10 400 | 57 300 |
| Total high forecast (H) | 2 400 | 2 100 | 3 700 | 4 800 | 7 300 | 6 100 | 11 000 | 8 400 | 11 400 | 12 800 | 70 000 |

[a] Other parameters at reference conditions.

TABLE VIII-8. NUCLEAR POWER MARKETS WITH ORCOST-1 CAPITAL COSTS (MW)[a]

| Country | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Argentina | 600 | | | 600 | 2×600 | | 800 | 800 | 1 000 | 1 000 | 6 000 |
| Bangladesh-L | | | | | | | | | | 300 | 300 |
| Bangladesh-H | | | | | | | | 400 | 2×400 | 600 | 1 800 |
| Chile | | | | | 300 | 300 | 300 | | | 300 | 1 200 |
| Egypt | 600 | | | 600 | | 600 | 600 | 600 | 2×600 | 600 | 4 800 |
| Greece | | 300 | 400 | 400 | 400 | 600 | 600 | 600 | 600 | 600 | 4 500 |
| Jamaica-L | | | | | | | | | 200 | | 200 |
| Jamaica-H | | | | | | | | 200 | 200 | 300 | 700 |
| Korea | | 600 | 600 | 600 | 2×600 | 600 | 2×600 | 2×600 | 600, 800 | 600, 800 | 8 800 |
| Mexico | | 600 | 600 | 600, 800 | 800 | 3×800 | 3×800 | 1 000 | 2×800, 1000 | 3×1000 | 14 800 |
| Pakistan | | | 600 | | | | 600 | | | | 1 200 |
| Philippines | | | 600 | | 2×600 | | 800 | 800 | | 1 000 | 4 400 |
| Singapore-L | | | | 300 | | | | 400 | 400 | | 1 100 |
| Singapore-H | | | | | | 400 | 600 | 600 | 600 | 800 | 3 000 |
| Thailand | 2×300 | 300 | 300 | | 400 | 400 | 600 | | 600 | 600 | 3 800 |
| Turkey-L | | | | | | | | | 600 | 600 | 1 200 |
| Turkey-H | 300 | 300 | 300 | 300 | 600 | | 600 | 600 | 600, 800 | 600 | 5 000 |
| Yugoslavia-L | | 600 | | 600 | 600 | 800 | | 800 | 1 000 | 1 000 | 5 400 |
| Yugoslavia-H | 600 | 600 | 800 | 800 | 800 | 800 | 2×800 | 2×800 | 1 000 | 2×1000 | 10 400 |
| Total low forecast (L) | 1 800 | 2 400 | 3 100 | 4 500 | 6 100 | 5 700 | 7 900 | 6 200 | 9 600 | 10 400 | 57 700 |
| Total high forecast (H) | 2 700 | 2 700 | 4 000 | 4 700 | 6 900 | 6 100 | 10 700 | 8 400 | 11 400 | 12 800 | 70 400 |

[a] Other parameters at reference conditions.

TABLE VIII-9. POTENTIAL MARKET FOR SMALL (200-400 MW) NUCLEAR PLANTS (MW)

| Year of commissioning | Market under reference conditions[a] | | Minimum nuclear market conditions[b] | | Maximum nuclear market conditions[c] | |
|---|---|---|---|---|---|---|
| | Low forecast | High forecast | Low forecast | High forecast | Low forecast | High forecast |
| 1980 | - | - | | | 2 x 300 | 3 x 300 |
| 1981 | - | - | | | 300 | 300 |
| 1982 | 400 | 400 | No | No | 300, 400 | 300, 400 |
| 1983 | 400 | 400 | nuclear | nuclear | 300, 400 | 2 x 400 |
| 1984 | 300, 2 x 400 | 300, 2 x 400 | market | market | 2 x 300, 2 x 400 | 300, 3 x 400 |
| 1985 | 300, 400 | 300, 400 | | | 300, 400 | 300, 2 x 400 |
| 1986 | 300 | 300 | | | 300 | 2 x 300 |
| 1987 | - | - | | | 200, 400 | 200, 400 |
| 1988 | - | - | | | 200, 400 | 200, 2 x 400 |
| 1989 | 300 | 2 x 300 | | | 2 x 300 | 2 x 300 |
| Total | 3 200 | 3 500 | 0 | 0 | 6 500 | 7 800 |

[a] 8% discount rate, 2% oil price escalation rate.
[b] 8% discount rate, 0% oil price escalation rate.
[c] 8% discount rate, 4% oil price escalation rate.

TABLE VIII-10. POTENTIAL MARKET FOR MEDIUM (600 MW) NUCLEAR PLANTS (MW)

| Year of commissioning | Market under reference conditions[a] | | Minimum nuclear market conditions[b] | | Maximum nuclear market conditions[c] | |
|---|---|---|---|---|---|---|
| | Low forecast | High forecast | Low forecast | High forecast | Low forecast | High forecast |
| 1980 | 600 | 600 | - | - | 2 x 600 | 3 x 600 |
| 1981 | 2 x 600 | 2 x 600 | 2 x 600 | 2 x 600 | 2 x 600 | 3 x 600 |
| 1982 | 3 x 600 | 4 x 600 | 2 x 600 | 3 x 600 | 4 x 600 | 5 x 600 |
| 1983 | 6 x 600 | 4 x 600 | 3 x 600 | 600 | 6 x 600 | 4 x 600 |
| 1984 | 6 x 600 | 5 x 600 | 2 x 600 | 600 | 7 x 600 | 6 x 600 |
| 1985 | 3 x 600 | 3 x 600 | 2 x 600 | 2 x 600 | 3 x 600 | 4 x 600 |
| 1986 | 6 x 600 | 8 x 600 | 2 x 600 | 2 x 600 | 6 x 600 | 7 x 600 |
| 1987 | 4 x 600 | 6 x 600 | 2 x 600 | 2 x 600 | 4 x 600 | 6 x 600 |
| 1988 | 5 x 600 | 7 x 600 | 600 | 2 x 600 | 5 x 600 | 8 x 600 |
| 1989 | 5 x 600 | 6 x 600 | 2 x 600 | 2 x 600 | 5 x 600 | 6 x 600 |
| Total | 24 600 | 27 600 | 10 800 | 10 200 | 26 400 | 31 200 |

[a] 8% discount rate, 2% oil price escalation rate.
[b] 8% discount rate, 0% oil price escalation rate.
[c] 8% discount rate, 4% oil price escalation rate.

TABLE VIII-11. POTENTIAL MARKET FOR LARGE (800-1000 MW) NUCLEAR PLANTS (MW)

| Year of commissioning | Market under reference conditions[a] | | Minimum nuclear market conditions[b] | | Maximum nuclear market conditions[c] | |
|---|---|---|---|---|---|---|
| | Low forecast | High forecast | Low forecast | High forecast | Low forecast | High forecast |
| 1980 | - | - | - | - | - | - |
| 1981 | - | - | - | - | - | - |
| 1982 | - | - | - | - | - | - |
| 1983 | 800 | 2 x 800 | 800 | 2 x 800 | 800 | 2 x 800 |
| 1984 | 800 | 2 x 800 | 800 | 2 x 800 | 800 | 2 x 800 |
| 1985 | 4 x 800 | 4 x 800 | 4 x 800 | 4 x 800 | 4 x 800 | 4 x 800 |
| 1986 | 5 x 800 | 9 x 800 | 5 x 800 | 7 x 800 | 5 x 800 | 9 x 800 |
| 1987 | 3 x 800<br>1 000 | 4 x 800<br>1 000 | 2 x 800<br>1 000 | 3 x 800<br>1 000 | 3 x 800<br>1 000 | 4 x 800<br>1 000 |
| 1988 | 3 x 800<br>3 x 1 000 | 4 x 800<br>3 x 1 000 | 3 x 800<br>3 x 1 000 | 4 x 800<br>3 x 1 000 | 3 x 800<br>3 x 1 000 | 4 x 800<br>3 x 1 000 |
| 1989 | 800<br>6 x 1 000 | 2 x 800<br>7 x 1 000 | 800<br>6 x 1 000 | 800<br>7 x 1 000 | 800<br>6 x 1 000 | 2 x 800<br>7 x 1 000 |
| Total | 24 400 | 31 000 | 23 600 | 29 400 | 24 400 | 31 000 |

[a] 8% discount rate, 2% oil price escalation rate.
[b] 8% discount rate, 0% oil price escalation rate.
[c] 6 & 10% discount rates, 2 & 4% oil price escalation rates (all combinations).

## 9. FINANCING REQUIREMENTS

### 9.1. Basis for estimating cash flows

As a supplement to the basic analyses, 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 became operational during that year are outlined below. Plants were assumed to become operational on 1 January of the year of commissioning 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.

Required cash-flow input data:

(a) Plant construction schedule (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 S-curve (i.e. 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 year-by-year values were printed out together with the annual totals.

It should be noted that nuclear plants were entered in two parts, (i) the cash requirements of the plant excluding the first (fuel) core, and (ii) the cash requirements of the first core. These first core requirements were calculated on the basis of 90% cash being required during the year preceding operation, and 10% being required one year earlier.

### 9.2 Domestic and foreign cash flows

Table IX-1 gives the annual domestic expenditures for construction of the thermal plants given in the reference expansion schedules of each country. Costs of hydro and pumped storage plants are not included nor are the expenditures associated with plants commissioned after the study period (i.e. 1990-2000). The costs include interest during construction based on the assumption that such costs would be paid out of current earnings. It is seen that total domestic cash flows peak in 1984 at US $1046 x $10^6$ with the low load forecast and at US $1232 x $10^6$ with the high load forecast.

Table IX-2 gives the annual foreign expenditures for construction of these same thermal plants. These expenditures peak in 1984 at US $1670 x $10^6$ with the low load forecast and US $2188 x $10^6$ with the high load forecast.

Table IX-3 gives the total domestic and foreign cash flows for plant investment. These totals peak in 1984 at US $2705 x $10^6$ with the low load forecast and at US $3350 x $10^6$ with the high load forecast.

### 9.3 Nuclear fuel working capital requirements

The investments associated with the nuclear fuel cycle (i.e. investment in first core and other fuel cycle working capital charges) are not included in the above-mentioned tables because financing arrangements for the nuclear fuel may differ from those for plant investment. The annual cash flow requirements for these costs are given in Table IX-4. It is seen that the annual fuel cycle investment costs peak in 1985 at US $196 x $10^6$ with the low load forecast and at US $267 x $10^6$ with the high load forecast.

Summaries of the financing requirements are given in Tables II-5 and II-6.

TABLE IX-1. DOMESTIC CASH FLOWS OF INVESTMENT FOR THERMAL PLANTS COMMISSIONED DURING 1980-1989 (US $ x $10^6$)

| Country | 1975 | 1976 | 1977 | 1978 | 1979 | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Argentina | 6 | 22 | 49 | 72 | 60 | 77 | 116 | 122 | 107 | 126 | 132 | 104 | 58 | 14 | 1 068 |
| Bangladesh-L | | | 2 | 5 | 7 | 6 | 4 | 4 | 9 | 11 | 10 | 7 | 7 | 4 | 76 |
| Bangladesh-H | | | 2 | 8 | 12 | 12 | 15 | 20 | 21 | 23 | 30 | 28 | 13 | 1 | 187 |
| Chile | | | 1 | 10 | 9 | 6 | 19 | 31 | 32 | 21 | 11 | 13 | 24 | 14 | 191 |
| Egypt | | | 5 | 14 | 16 | 19 | 29 | 34 | 48 | 60 | 64 | 55 | 28 | 6 | 378 |
| Greece | | | 2 | 17 | 44 | 56 | 55 | 59 | 62 | 63 | 60 | 48 | 28 | 7 | 501 |
| Jamaica-L | | | | 2 | 5 | 5 | 3 | 2 | 5 | 5 | 5 | 7 | 4 | 0 | 44 |
| Jamaica-H | | | | 2 | 3 | 3 | 6 | 7 | 7 | 7 | 11 | 15 | 12 | 3 | 77 |
| Korea | 1 | 4 | 20 | 47 | 81 | 116 | 126 | 130 | 141 | 162 | 165 | 133 | 77 | 19 | 1 222 |
| Mexico | 1 | 7 | 32 | 105 | 218 | 274 | 287 | 343 | 382 | 374 | 354 | 285 | 158 | 39 | 2 859 |
| Pakistan | | | 1 | 6 | 12 | 21 | 17 | 15 | 20 | 15 | 12 | 6 | 0 | 0 | 125 |
| Philippines | | | 6 | 27 | 41 | 35 | 32 | 50 | 47 | 41 | 38 | 26 | 19 | 6 | 370 |
| Singapore-L | | | 1 | 7 | 8 | 12 | 17 | 10 | 12 | 11 | 15 | 20 | 8 | 0 | 121 |
| Singapore-H | | | 2 | 12 | 19 | 20 | 25 | 32 | 42 | 43 | 39 | 31 | 19 | 5 | 289 |
| Thailand | | | 4 | 21 | 27 | 27 | 33 | 43 | 43 | 37 | 35 | 37 | 25 | 7 | 341 |
| Turkey-L | | 4 | 19 | 34 | 27 | 20 | 31 | 37 | 32 | 32 | 29 | 22 | 12 | 2 | 302 |
| Turkey-H | | 3 | 14 | 30 | 34 | 28 | 37 | 46 | 48 | 52 | 49 | 34 | 15 | 2 | 394 |
| Yugoslavia-L | | | 13 | 48 | 81 | 96 | 100 | 89 | 84 | 87 | 105 | 92 | 52 | 12 | 860 |
| Yugoslavia-H | | 4 | 30 | 83 | 116 | 119 | 124 | 148 | 182 | 207 | 193 | 145 | 91 | 25 | 1 466 |
| Total low forecast (L) | 8 | 37 | 155 | 416 | 637 | 771 | 870 | 970 | 1 025 | 1 046 | 1 036 | 856 | 501 | 131 | 8 458 |
| Total high forecast (H) | 8 | 40 | 169 | 455 | 693 | 813 | 922 | 1 081 | 1 183 | 1 232 | 1 194 | 961 | 568 | 149 | 9 468 |

TABLE IX-2. FOREIGN CASH FLOWS OF INVESTMENT FOR THERMAL PLANTS COMMISSIONED DURING 1980-1989 (US $ x $10^6$)

| Country | 1975 | 1976 | 1977 | 1978 | 1979 | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Argentina | 6 | 21 | 45 | 62 | 55 | 77 | 116 | 122 | 107 | 156 | 132 | 104 | 58 | 14 | 1 047 |
| Bangladesh-L | | | 6 | 21 | 29 | 24 | 16 | 33 | 36 | 43 | 38 | 29 | 30 | 14 | 320 |
| Bangladesh-H | | 1 | 9 | 32 | 47 | 55 | 63 | 89 | 96 | 115 | 161 | 158 | 80 | 12 | 919 |
| Chile | | 2 | 2 | 20 | 18 | 19 | 56 | 92 | 95 | 63 | 41 | 49 | 60 | 33 | 548 |
| Egypt | | 1 | 14 | 42 | 49 | 57 | 87 | 103 | 142 | 180 | 192 | 165 | 84 | 17 | 1 133 |
| Greece | | | 5 | 34 | 87 | 121 | 130 | 139 | 146 | 147 | 138 | 112 | 65 | 17 | 141 |
| Jamaica-L | | | 1 | 14 | 29 | 28 | 16 | 20 | 29 | 29 | 31 | 38 | 21 | 6 | 262 |
| Jamaica-H | | | 1 | 13 | 16 | 20 | 35 | 38 | 38 | 43 | 64 | 86 | 69 | 19 | 443 |
| Korea | 1 | 7 | 30 | 70 | 120 | 165 | 183 | 196 | 212 | 243 | 247 | 199 | 115 | 29 | 1 818 |
| Mexico | 1 | 7 | 30 | 92 | 184 | 237 | 263 | 316 | 356 | 352 | 331 | 275 | 158 | 39 | 2 642 |
| Pakistan | | | 2 | 21 | 36 | 64 | 54 | 53 | 74 | 61 | 40 | 17 | 0 | 0 | 421 |
| Philippines | | 1 | 14 | 61 | 97 | 95 | 91 | 139 | 128 | 124 | 113 | 80 | 70 | 18 | 1 032 |
| Singapore-L | | | 2 | 16 | 19 | 33 | 40 | 25 | 34 | 26 | 35 | 46 | 18 | 0 | 295 |
| Singapore-H | | | 4 | 27 | 44 | 48 | 61 | 92 | 134 | 161 | 155 | 126 | 75 | 19 | 946 |
| Thailand | | | 9 | 49 | 64 | 63 | 79 | 105 | 101 | 87 | 83 | 87 | 60 | 15 | 802 |
| Turkey-L | 1 | 8 | 35 | 62 | 51 | 39 | 60 | 78 | 83 | 99 | 102 | 86 | 48 | 10 | 762 |
| Turkey-H | 1 | 6 | 27 | 57 | 65 | 67 | 108 | 159 | 188 | 210 | 194 | 139 | 58 | 10 | 1 289 |
| Yugoslavia-L | | | 8 | 34 | 62 | 83 | 96 | 89 | 84 | 88 | 105 | 92 | 51 | 12 | 805 |
| Yugoslavia-H | | 3 | 22 | 64 | 98 | 113 | 124 | 148 | 182 | 207 | 193 | 147 | 113 | 25 | 1 440 |
| Total low forecast (L) | 9 | 45 | 203 | 598 | 902 | 1 107 | 1 295 | 1 512 | 1 629 | 1 670 | 1 628 | 1 368 | 838 | 224 | 13 028 |
| Total high forecast (H) | 9 | 48 | 214 | 644 | 980 | 1 200 | 1 449 | 1 790 | 1 998 | 2 118 | 2 084 | 1 744 | 1 077 | 267 | 15 621 |

TABLE IX-3. TOTAL CASH FLOWS OF INVESTMENT FOR THERMAL PLANTS COMMISSIONED DURING 1980-1989
(US $ x $10^6$)

| Country | 1975 | 1976 | 1977 | 1978 | 1979 | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Argentina | 1 | 43 | 94 | 135 | 114 | 154 | 233 | 215 | 253 | 264 | 264 | 208 | 116 | 28 | 2 115 |
| Bangladesh-L | | | 8 | 26 | 26 | 29 | 20 | 45 | 44 | 48 | 48 | 36 | 37 | 18 | 396 |
| Bangladesh-H | | 1 | 12 | 40 | 60 | 67 | 79 | 117 | 138 | 191 | 191 | 186 | 94 | 13 | 1 106 |
| Chile | | | 3 | 30 | 27 | 25 | 75 | 127 | 84 | 52 | 52 | 62 | 84 | 47 | 739 |
| Egypt | | 1 | 19 | 56 | 65 | 76 | 116 | 190 | 239 | 256 | 256 | 220 | 112 | 38 | 1 511 |
| Greece | | 1 | 7 | 50 | 131 | 177 | 185 | 208 | 209 | 199 | 199 | 159 | 93 | 24 | 1 642 |
| Jamaica-L | | | 1 | 16 | 34 | 33 | 19 | 34 | 34 | 36 | 36 | 45 | 25 | 6 | 306 |
| Jamaica-H | | | 1 | 16 | 19 | 23 | 41 | 45 | 50 | 75 | 75 | 102 | 82 | 22 | 520 |
| Korea | 2 | 12 | 50 | 117 | 201 | 281 | 309 | 354 | 405 | 412 | 412 | 332 | 192 | 48 | 3 040 |
| Mexico | 2 | 14 | 62 | 197 | 402 | 511 | 550 | 738 | 726 | 685 | 685 | 560 | 317 | 77 | 5 501 |
| Pakistan | | | 3 | 27 | 48 | 85 | 71 | 92 | 76 | 52 | 52 | 23 | 0 | 0 | 546 |
| Philippines | | 1 | 21 | 88 | 138 | 130 | 123 | 174 | 166 | 151 | 151 | 107 | 89 | 25 | 1 402 |
| Singapore-L | | | 3 | 23 | 27 | 44 | 57 | 46 | 37 | 50 | 50 | 66 | 26 | 0 | 416 |
| Singapore-H | | | 6 | 39 | 63 | 84 | 86 | 176 | 204 | 194 | 194 | 158 | 93 | 23 | 1 235 |
| Thailand | | | 12 | 71 | 91 | 89 | 112 | 145 | 125 | 118 | 118 | 124 | 85 | 22 | 1 143 |
| Turkey-L | 1 | 12 | 54 | 96 | 79 | 59 | 91 | 113 | 131 | 131 | 113 | 108 | 60 | 12 | 1 064 |
| Turkey-H | 1 | 10 | 41 | 87 | 98 | 95 | 144 | 237 | 263 | 243 | 243 | 174 | 73 | 72 | 1 683 |
| Yugoslavia-L | | 1 | 21 | 82 | 142 | 179 | 195 | 167 | 175 | 211 | 211 | 184 | 103 | 25 | 1 665 |
| Yugoslavia-H | | 7 | 52 | 147 | 214 | 232 | 249 | 364 | 415 | 386 | 386 | 292 | 204 | 49 | 2 906 |
| Total low forecast (L) | 17 | 82 | 358 | 1 014 | 1 538 | 1 878 | 2 165 | 2 654 | 2 705 | 2 664 | 2 664 | 2 223 | 1 339 | 355 | 21 486 |
| Total high forecast (H) | 17 | 88 | 383 | 1 099 | 1 673 | 2 013 | 2 371 | 3 181 | 3 350 | 3 278 | 3 278 | 2 705 | 1 645 | 416 | 25 089 |

TABLE IX-4. CASH FLOWS OF NUCLEAR FUEL CYCLE INVESTMENT FOR PLANTS COMMISSIONED DURING 1980-89 (US $ x $10^6$)[a]

| Country | 1978 | 1979 | 1980 | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Argentina[b] | 2 | 15 | 0 | 2 | 18 | 30 | 2 | 19 | 19 | 20 | 18 | 144 |
| Bangladesh-L | | | | | | | | | | | | 0 |
| Bangladesh-H | | | | | | | | | | 2 | 15 | 17 |
| Chile | | | | | 1 | 10 | 10 | 9 | | 1 | 10 | 41 |
| Egypt | | | | 2 | 15 | 2 | 17 | 17 | 18 | 32 | 15 | 117 |
| Greece | | | 1 | 13 | 13 | 13 | 17 | 17 | 17 | 17 | 15 | 122 |
| Jamaica-L | | | | | | | | | | | | 0 |
| Jamaica-H | | | | | | | | | | 1 | 9 | 10 |
| Korea | | 2 | 17 | 17 | 18 | 32 | 18 | 33 | 34 | 36 | 32 | 239 |
| Mexico | | 2 | 18 | 18 | 34 | 21 | 57 | 54 | 27 | 60 | 58 | 348 |
| Pakistan[c] | | | | | | | 2 | 15 | 0 | 0 | 0 | 17 |
| Philippines | | | 2 | 15 | 2 | 15 | 2 | 19 | 17 | 2 | 18 | 92 |
| Singapore-L | | | | | | | | | | | | 0 |
| Singapore-H | | | | | | | 2 | 17 | 17 | 17 | 17 | 69 |
| Thailand | | | | | 1 | 13 | 15 | 13 | 2 | 17 | 15 | 76 |
| Turkey-L | | | | | | | | | 2 | 17 | 15 | 34 |
| Turkey-H | | | | | | | 2 | 17 | 19 | 34 | 15 | 86 |
| Yugoslavia-L[c] | | | | 2 | 17 | 17 | 17 | 2 | 18 | 20 | 18 | 111 |
| Yugoslavia-H[c] | | | 2 | 17 | 19 | 19 | 21 | 38 | 36 | 22 | 36 | 211 |
| Total low forecast (L) | 2 | 19 | 38 | 69 | 119 | 153 | 157 | 196 | 155 | 222 | 212 | 1 341 |
| Total high forecast (H) | 2 | 19 | 40 | 84 | 121 | 155 | 165 | 267 | 206 | 259 | 271 | 1 589 |

[a] Assumed to be foreign expenditure unless otherwise indicated.
[b] 50% of fuel cycle investment was domestic.
[c] 10% of fuel cycle investment was domestic.

## APPENDIXES

A. WIEN AUTOMATIC SYSTEM PLANNING PACKAGE (WASP)

B. GENERATING PLANT CAPITAL COSTS (ORCOST)

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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.

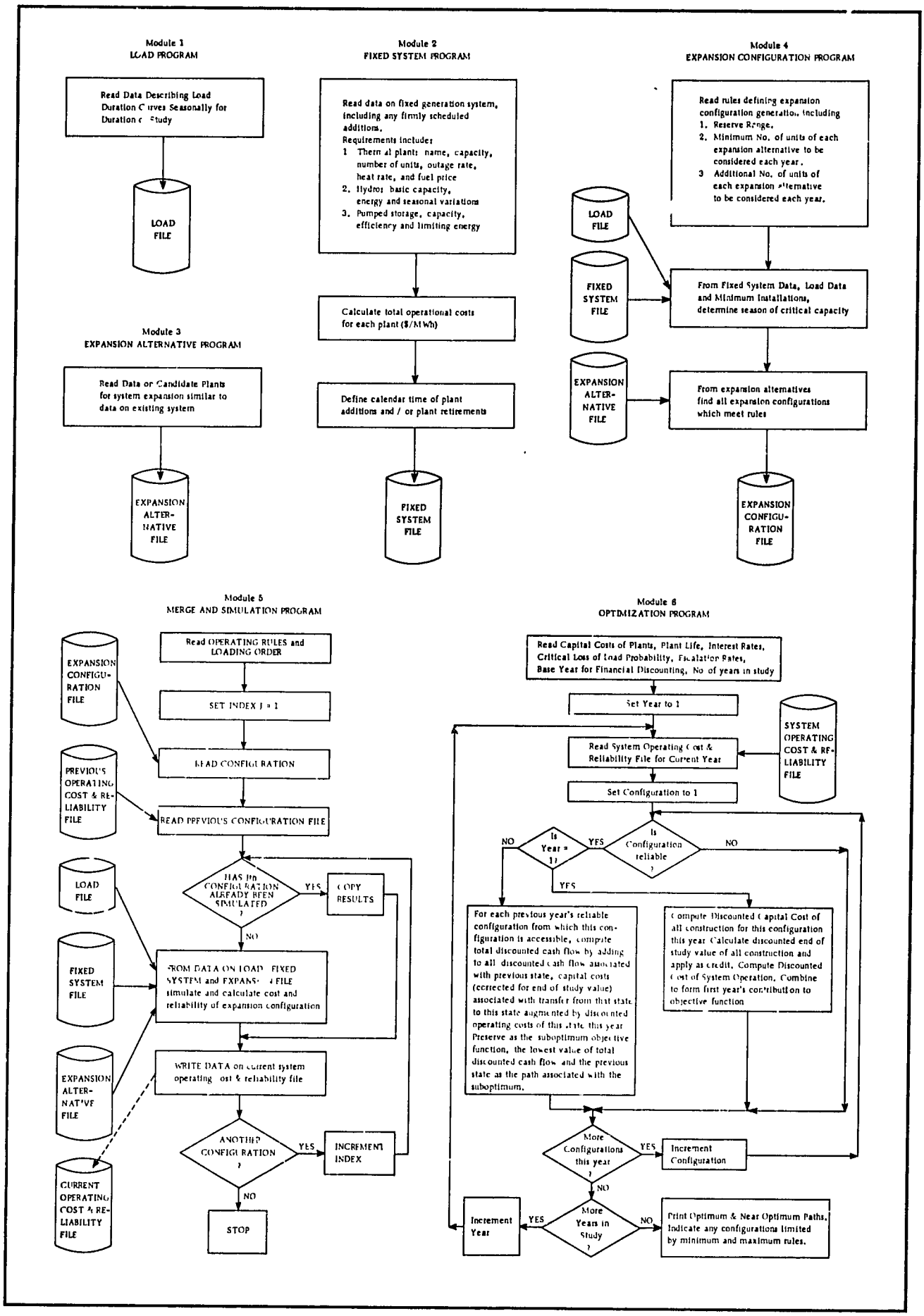


FIG A-1. WASP PROGRAM FLOW SHEET.

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

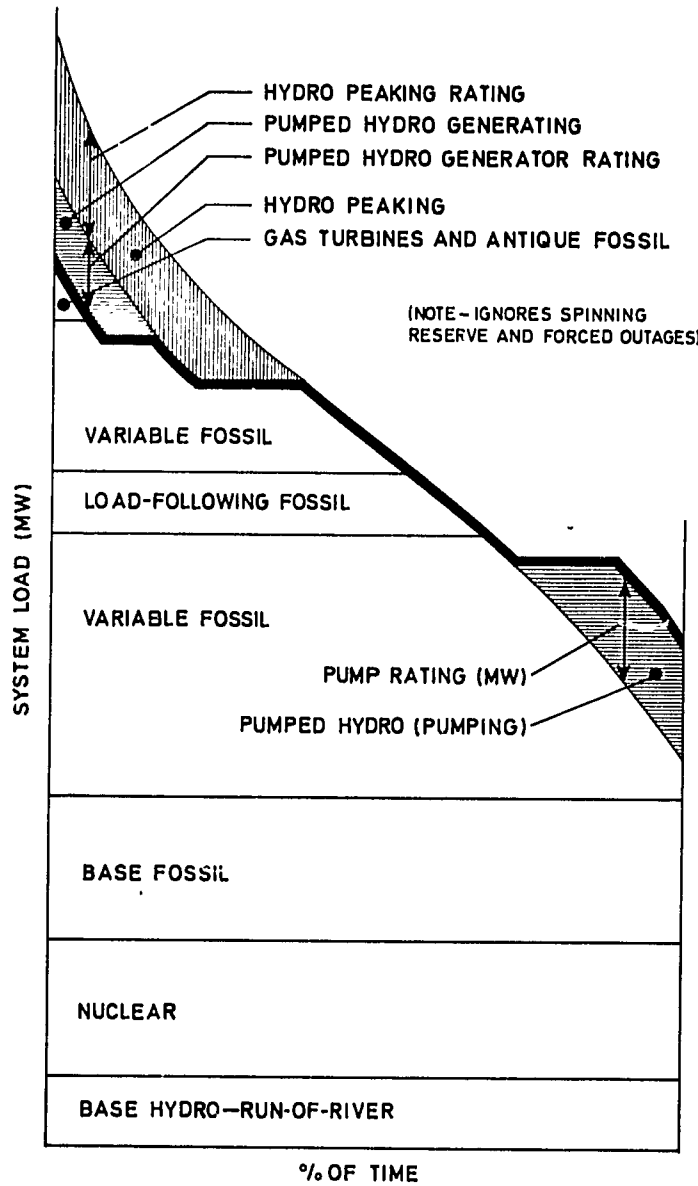


FIG. A-2. IDEALIZED PLACING OF VARIOUS TYPES OF STATION UNDER THE LOAD DURATION CURVE.

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.

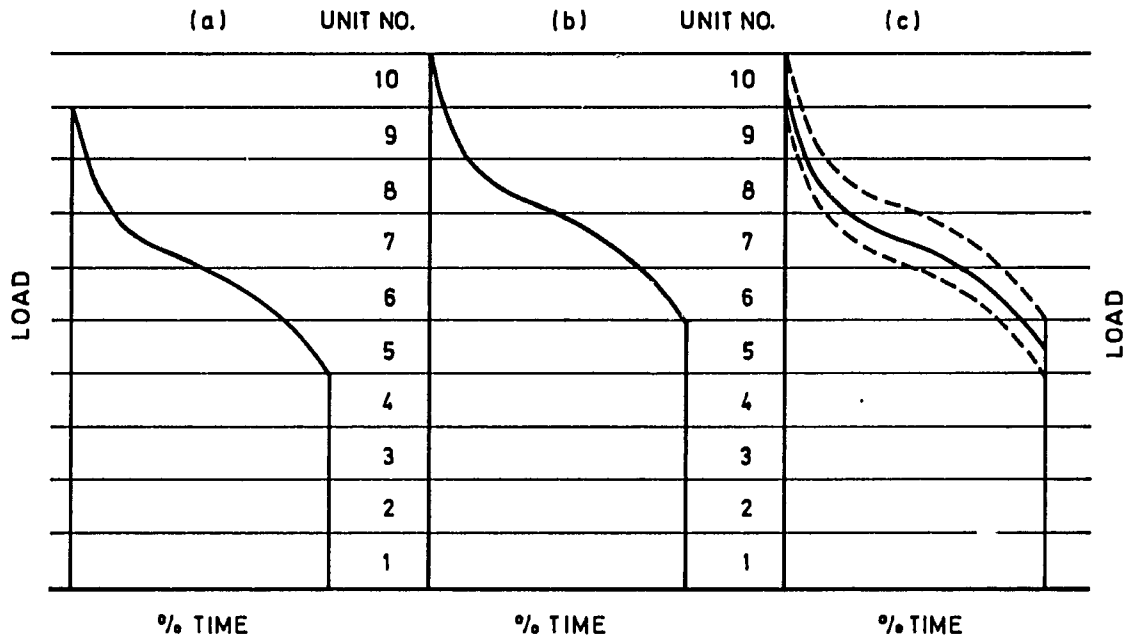


FIG. A-3. ILLUSTRATION OF THE METHOD OF STACKING THERMAL UNITS UNDER THE LOAD CURVE.

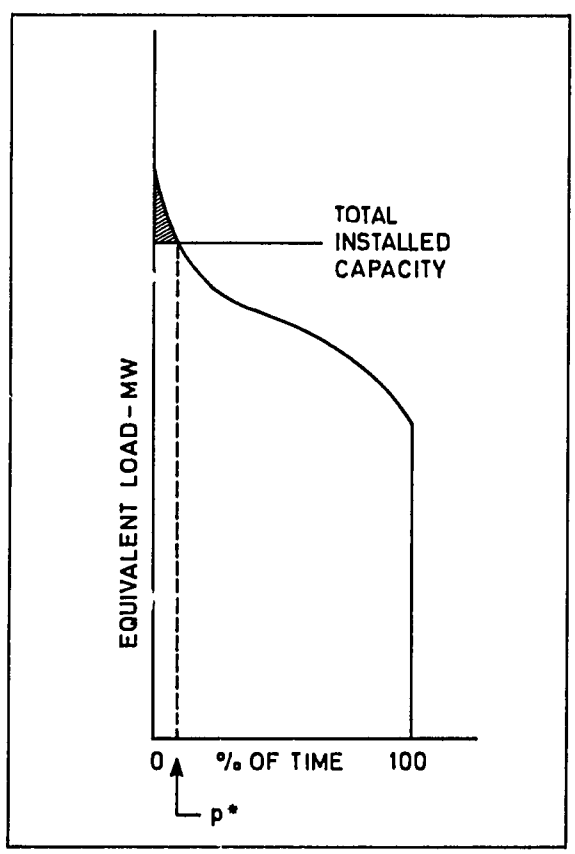


FIG. A-4. EQUIVALENT LOAD CURVE FOR AN ENTIRE SYSTEM.

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

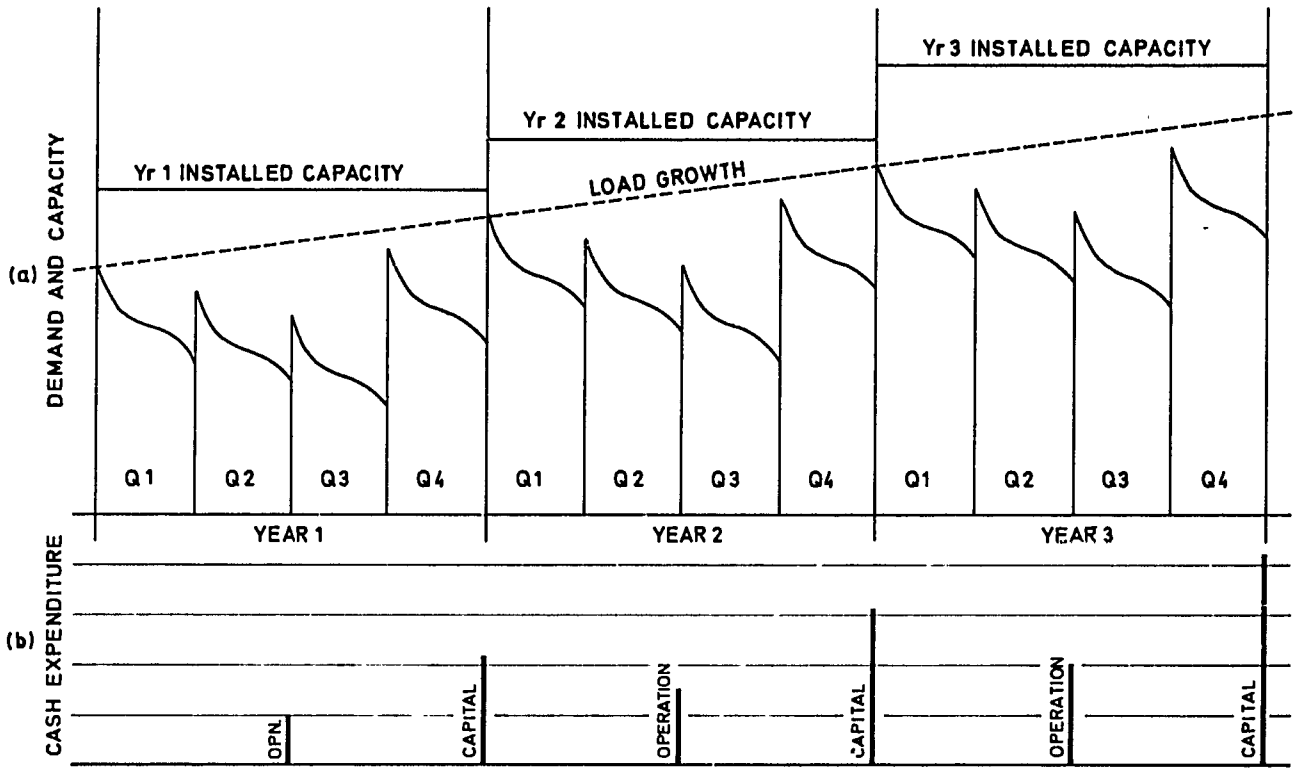


FIG. A-5. SCHEMATIC DIAGRAM OF LOAD GROWTH AND CORRESPONDING CASH FLOWS.

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 $\ell$th plant
$C_\ell$ — capital cost of the $\ell$th plant
$P_{NYRS,\ell}$ — present-worth factor for the horizon and the $\ell$th plant
$P_{(k+\frac{1}{2}),m}$ — present-worth factor for the mth fuel in the kth year
$L_\ell$ — plant life of the $\ell$th 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

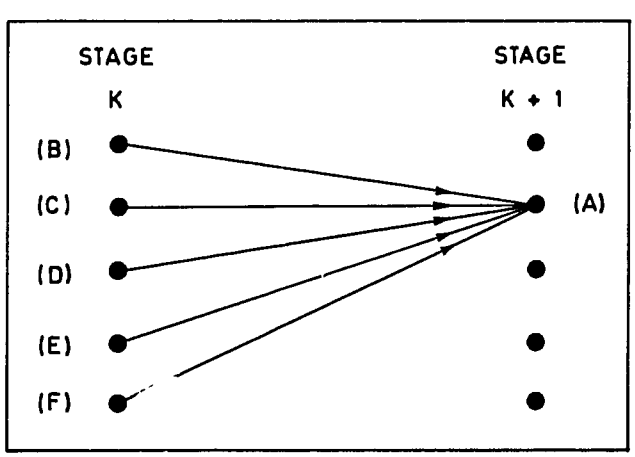


FIG. A-6. ILLUSTRATION OF A DYNAMIC PROGRAM STEP.

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 expansior 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.

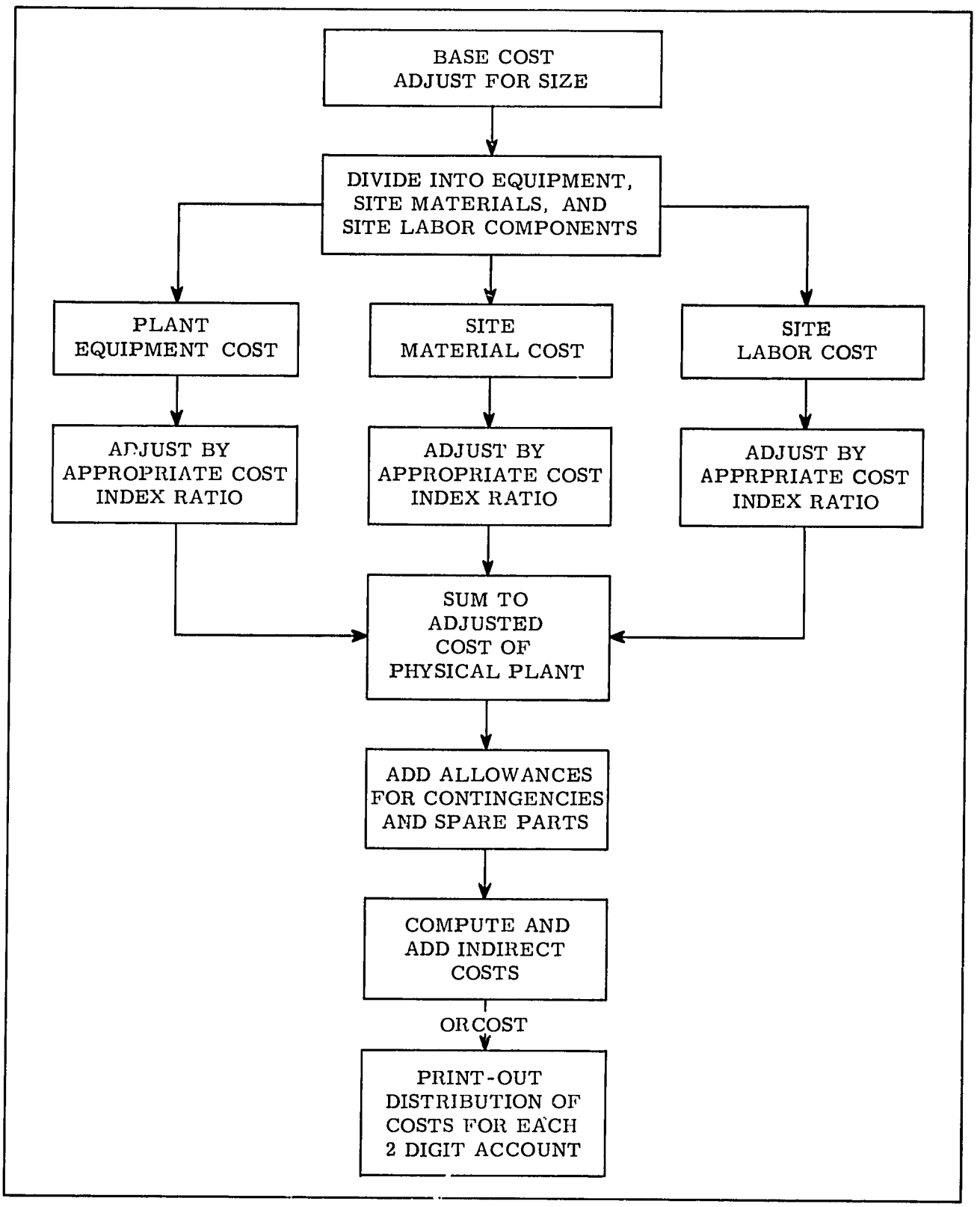


FIG. B-1. SCHEMATIC ILLUSTRATION OF ORCOST (AND CONCEPT II) PROCEDURE.

## 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 | 0.80 | 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, ironworker, 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 $MILLION | EXPONENT | COST BREAKDOWN FACTORS 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.[illegible] | 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. | 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) | 37.3 | 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.

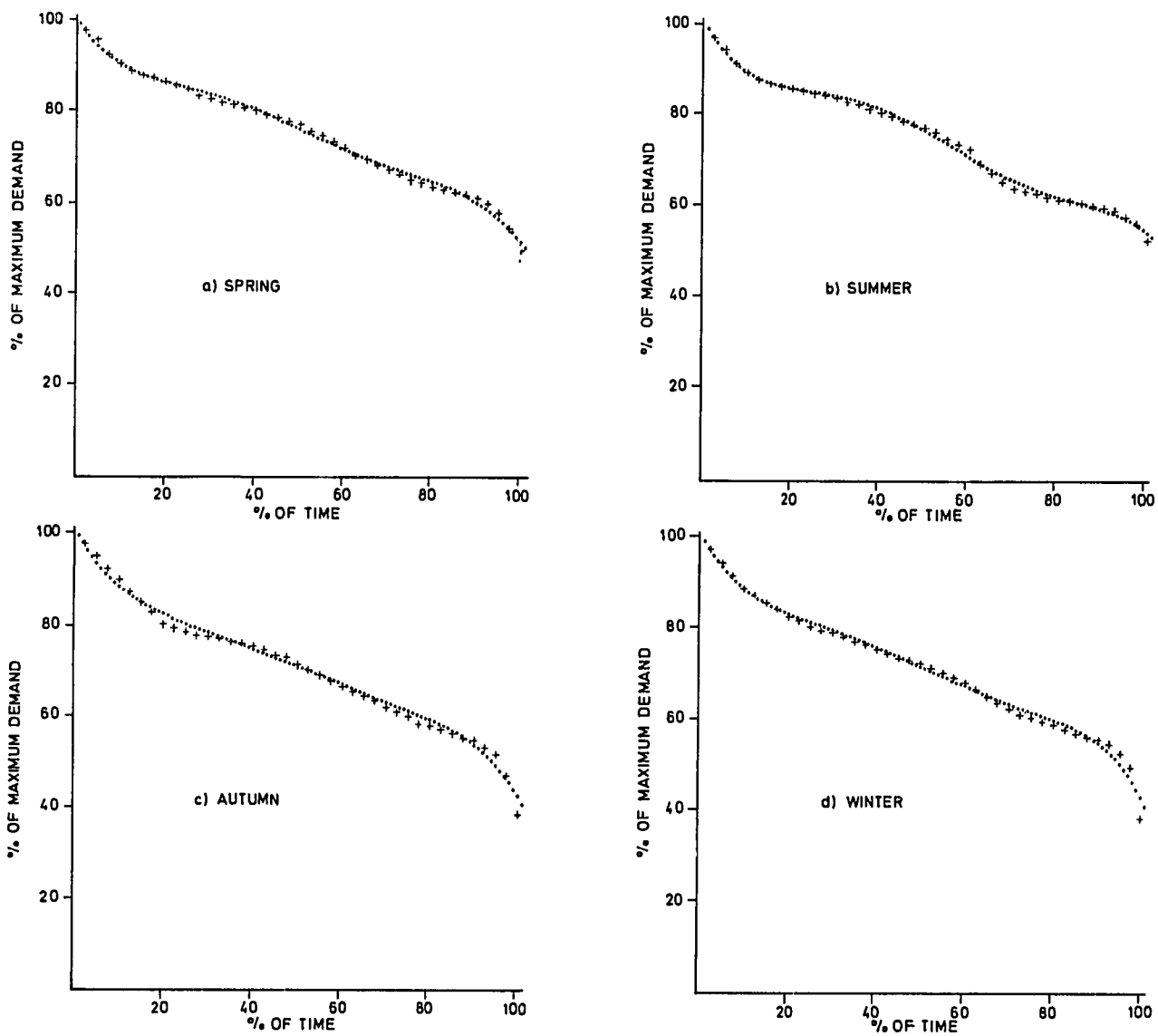


FIG. C-1. EXAMPLES OF THE FITTING OF A FIFTH ORDER POLYNOMIAL TO LOAD DURATION CURVES.

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

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

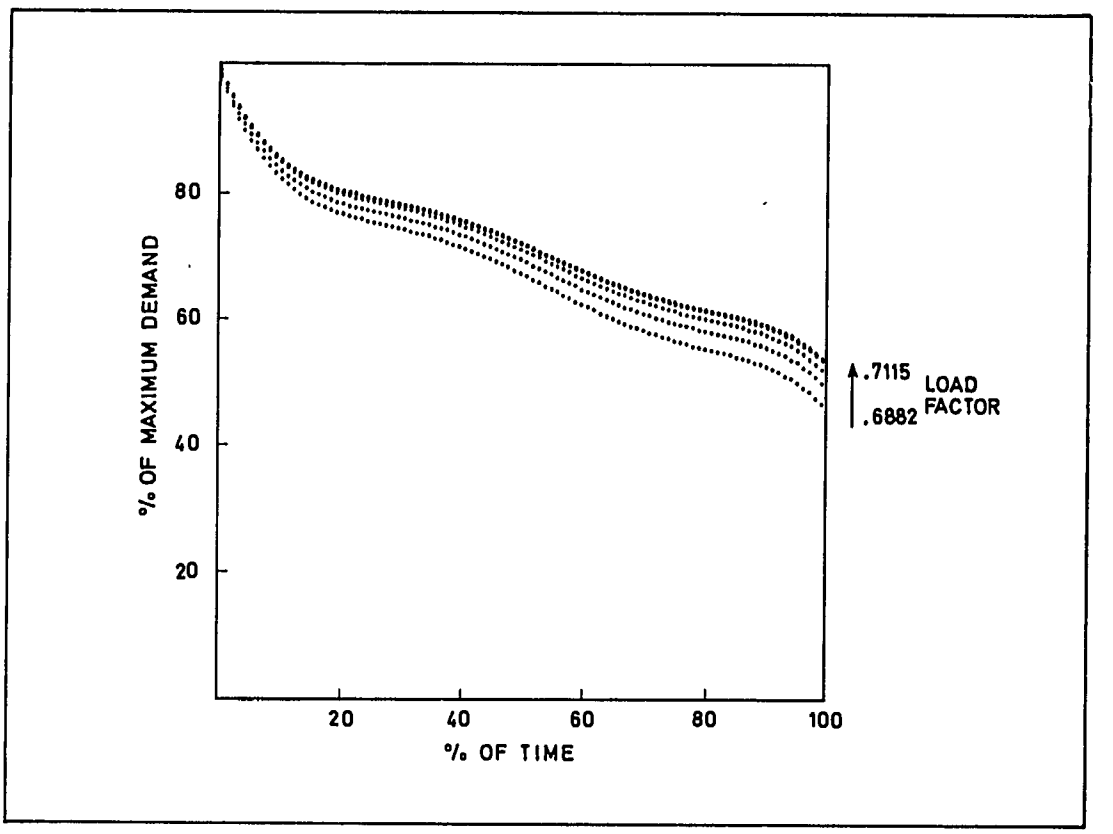


FIG. C-2. ILLUSTRATION OF THE EFFECT OF LOAD FACTOR ON A LOAD DURATION CURVE.

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 $\ell$ 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.

## REFERENCES

[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

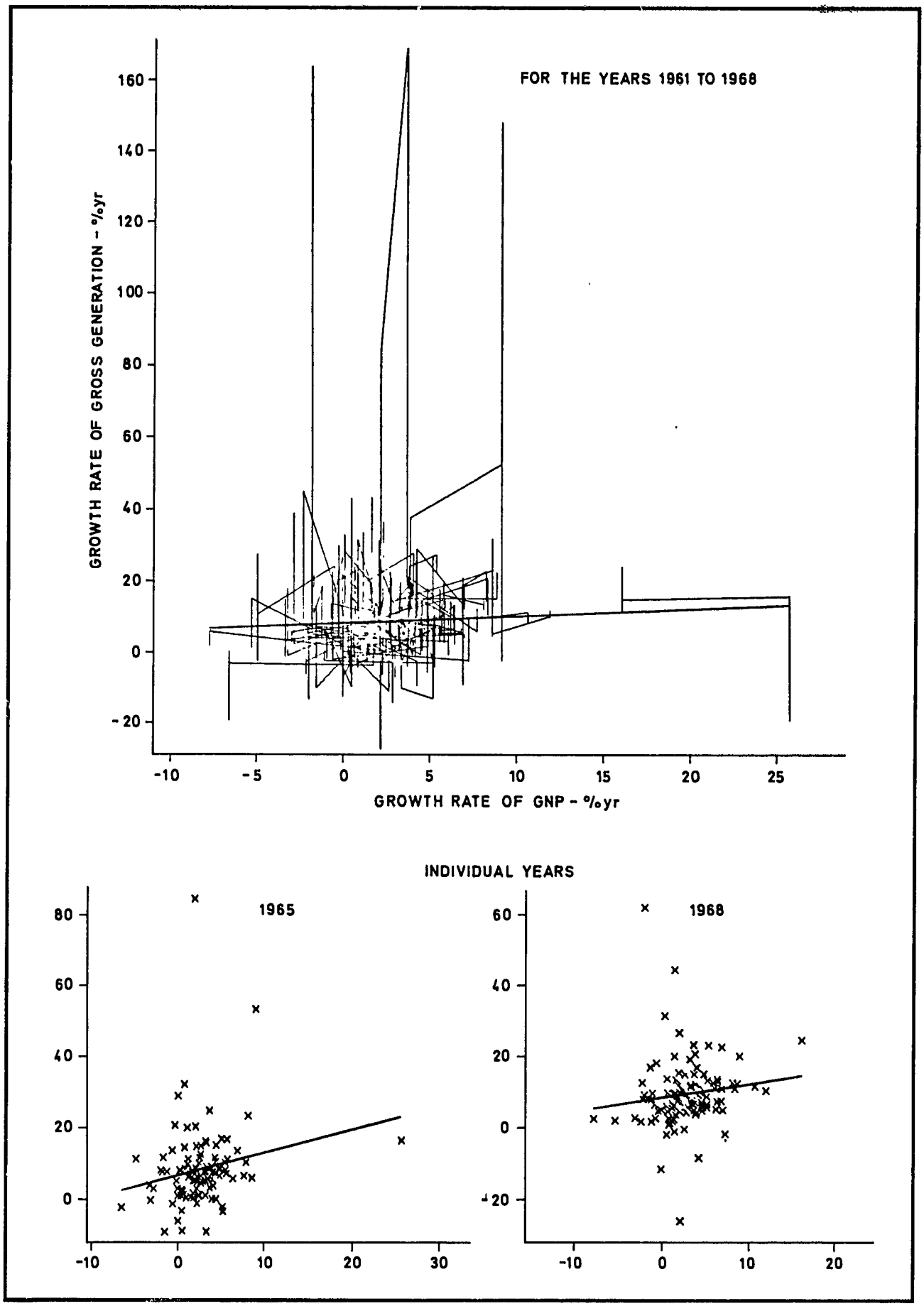


FIG. F-1. CORRELATION BETWEEN GROWTH RATE OF GROSS GENERATION AND OF GNP.

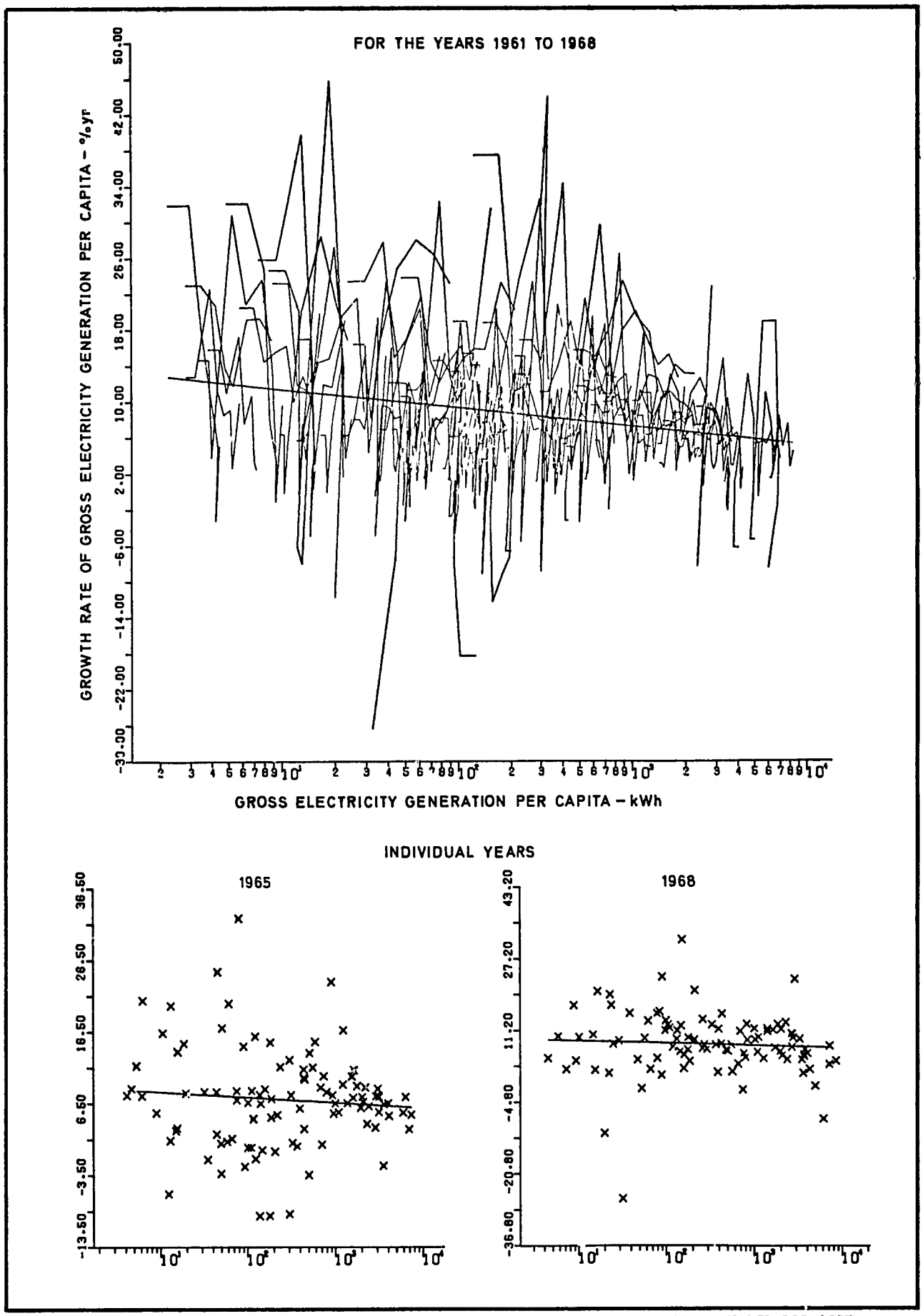


FIG. F-2. CORRELATION BETWEEN GROWTH RATE OF GROSS GENERATION AND OF GROSS GENERATION PER CAPITA.

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

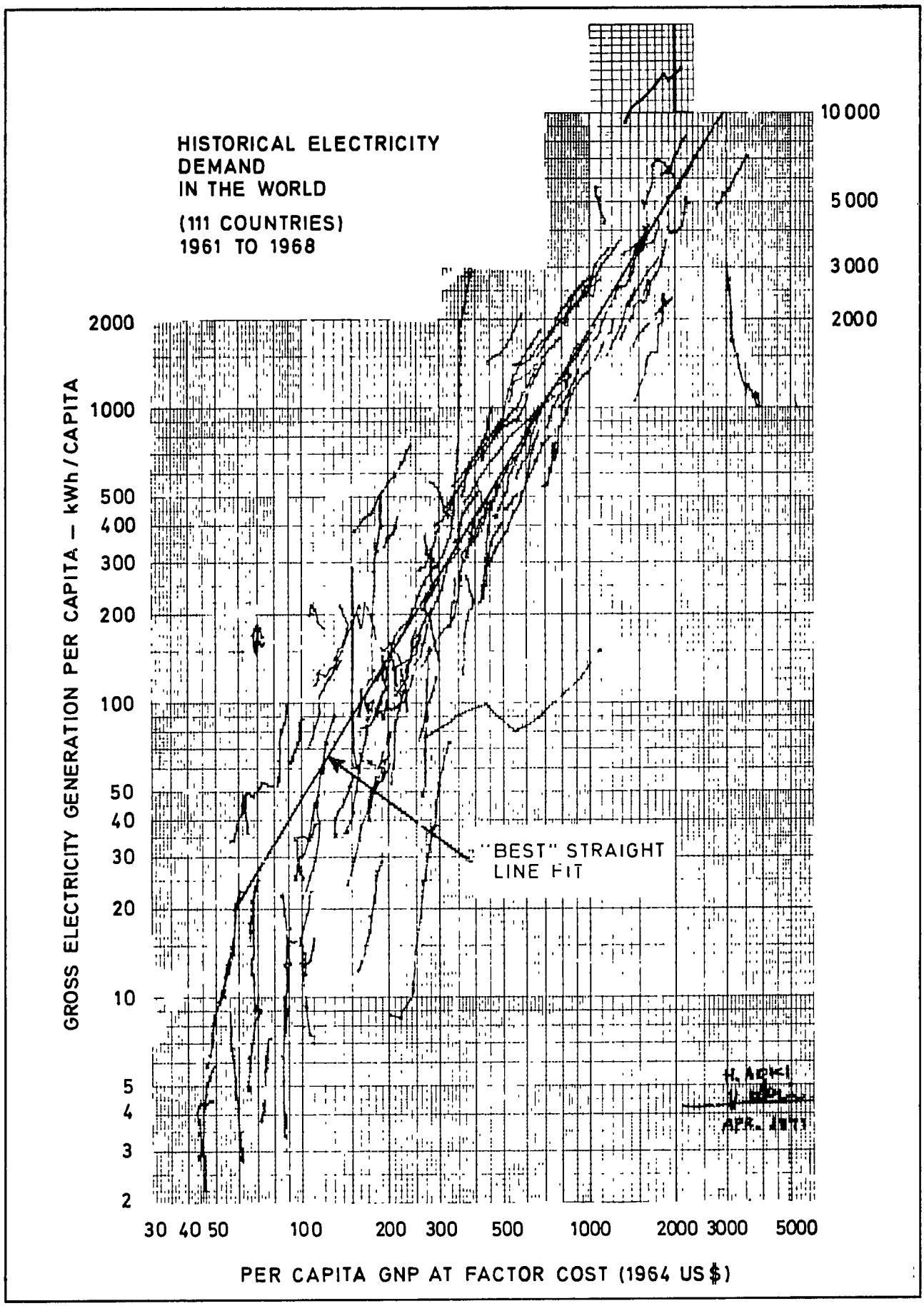


FIG. F-3. CORRELATION BETWEEN GROSS GENERATION PER CAPITA AND GNP PER CAPITA FOR 111 COUNTRIES FOR 1961 - 1968.

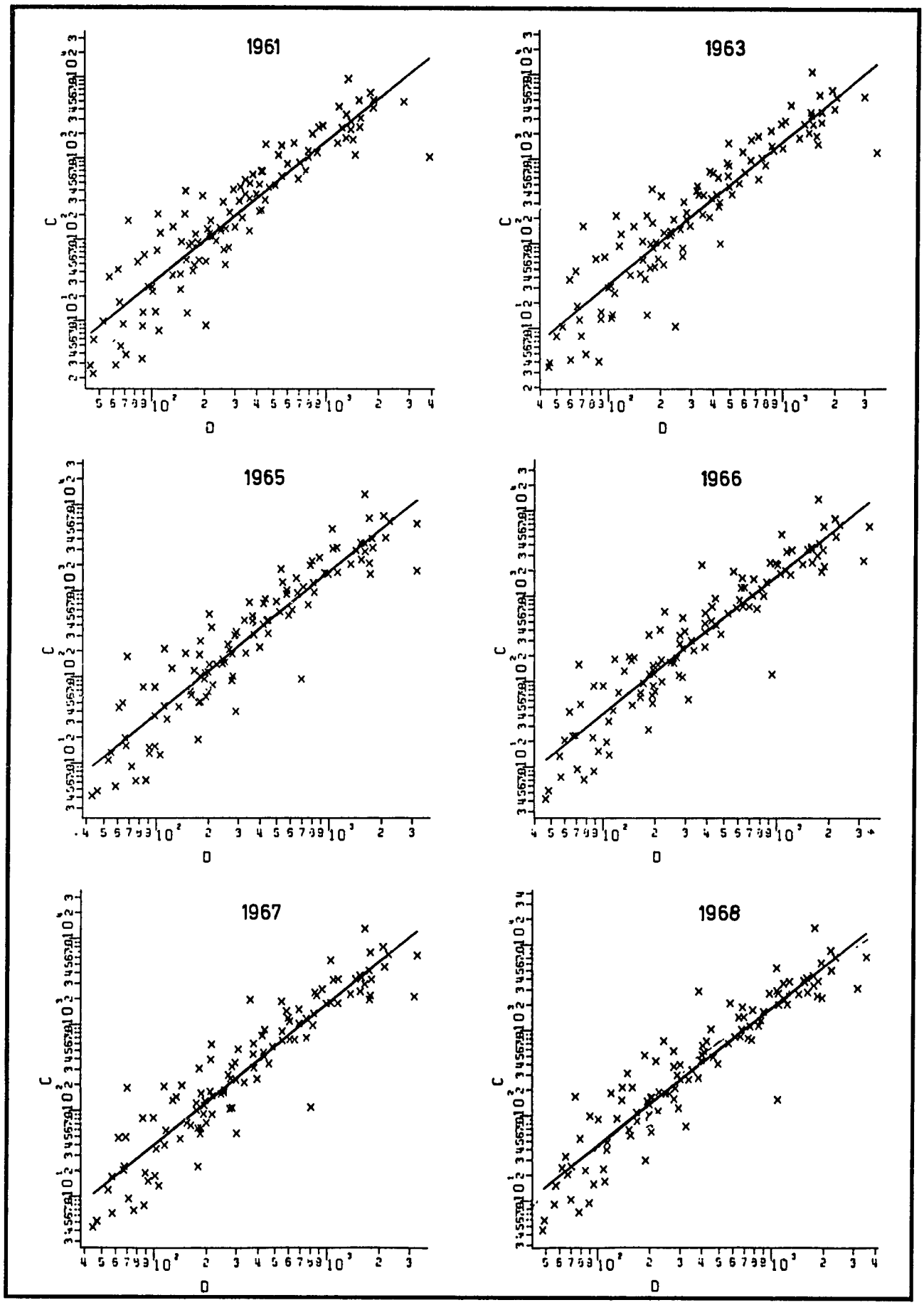


FIG. F-4. REGRESSION ANALYSIS OF THE PLOT OF GROSS GENERATION PER CAPITA VERSUS GNP PER CAPITA FOR 1968.

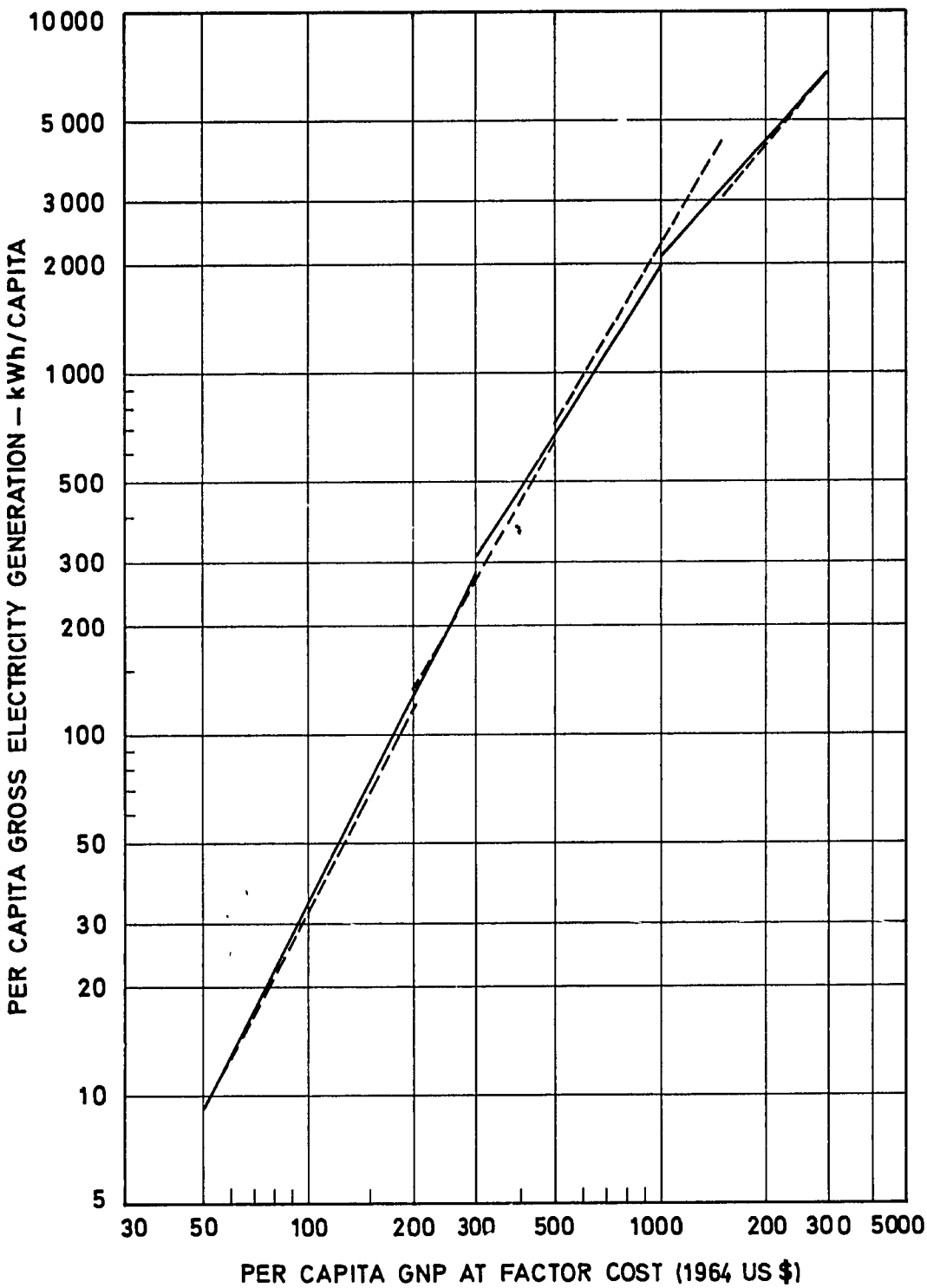


FIG. F-5. CORRELATION FOR INDIVIDUAL YEARS.

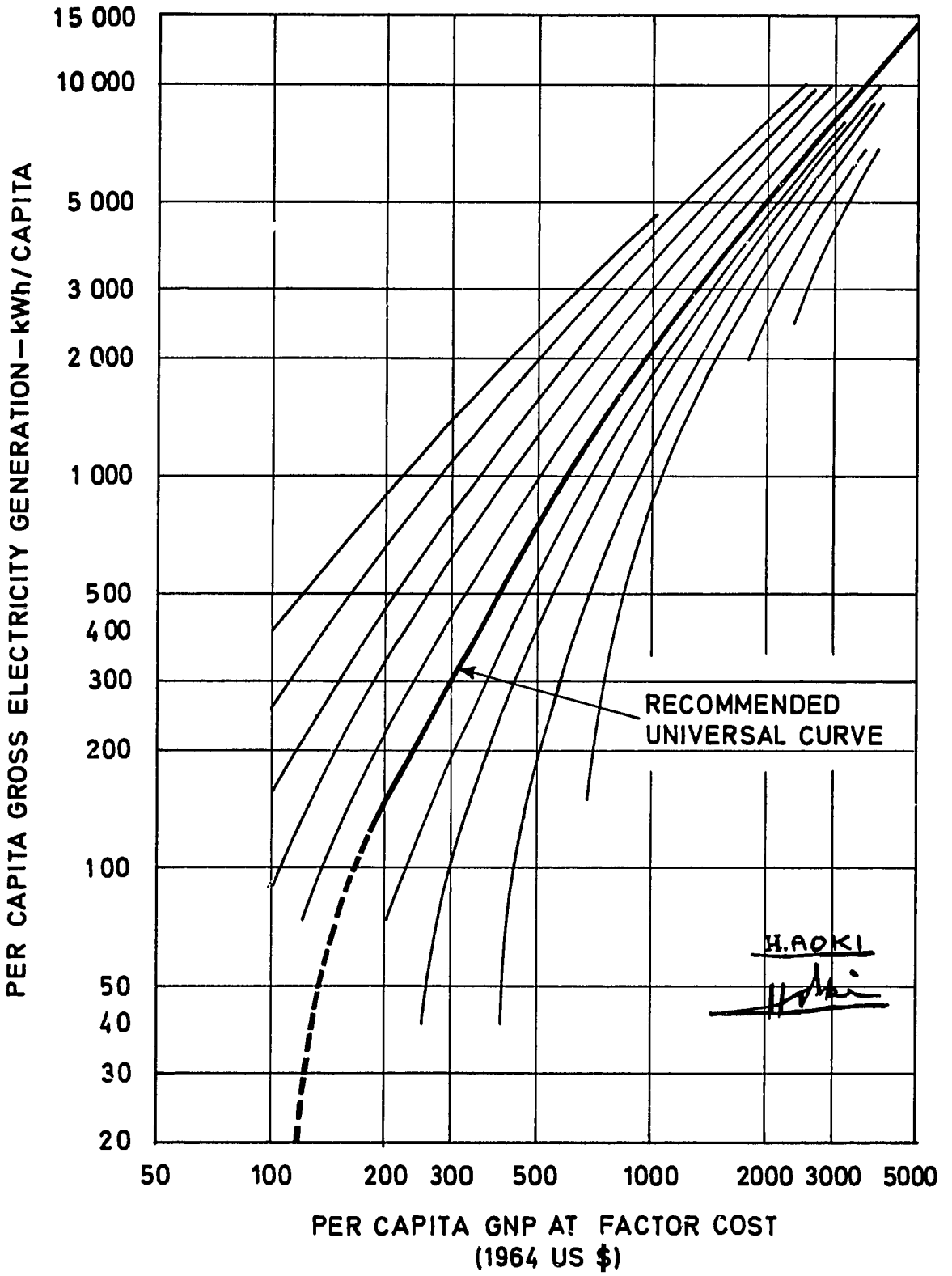


FIG. F-6. RECOMMENDED RELATION BETWEEN GROSS GENERATION PER CAPITA AND GNP PER CAPITA.

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.

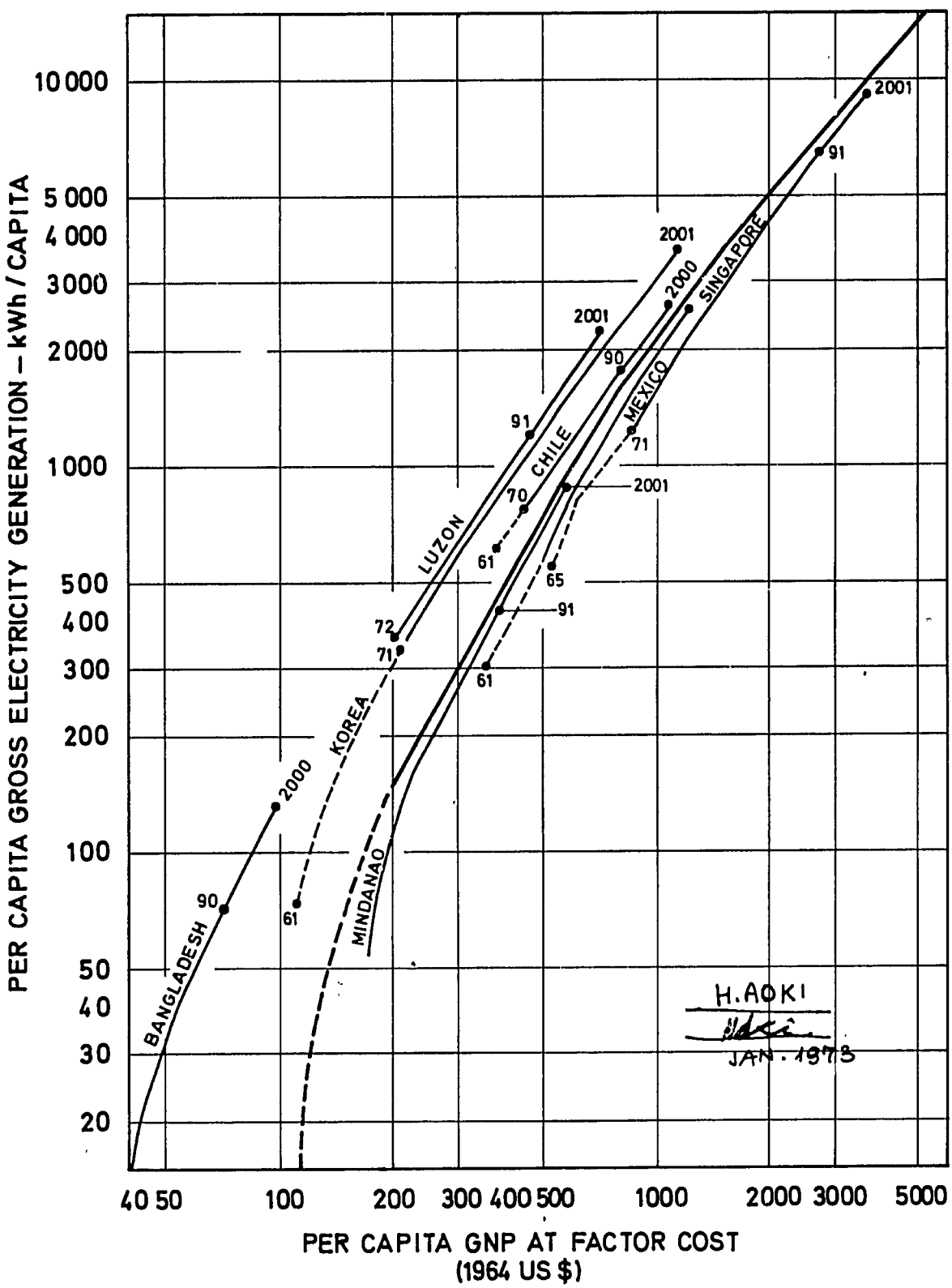


FIG. F-7. SURVEY COUNTRIES PLOTTED ON RECOMMENDED CURVE.

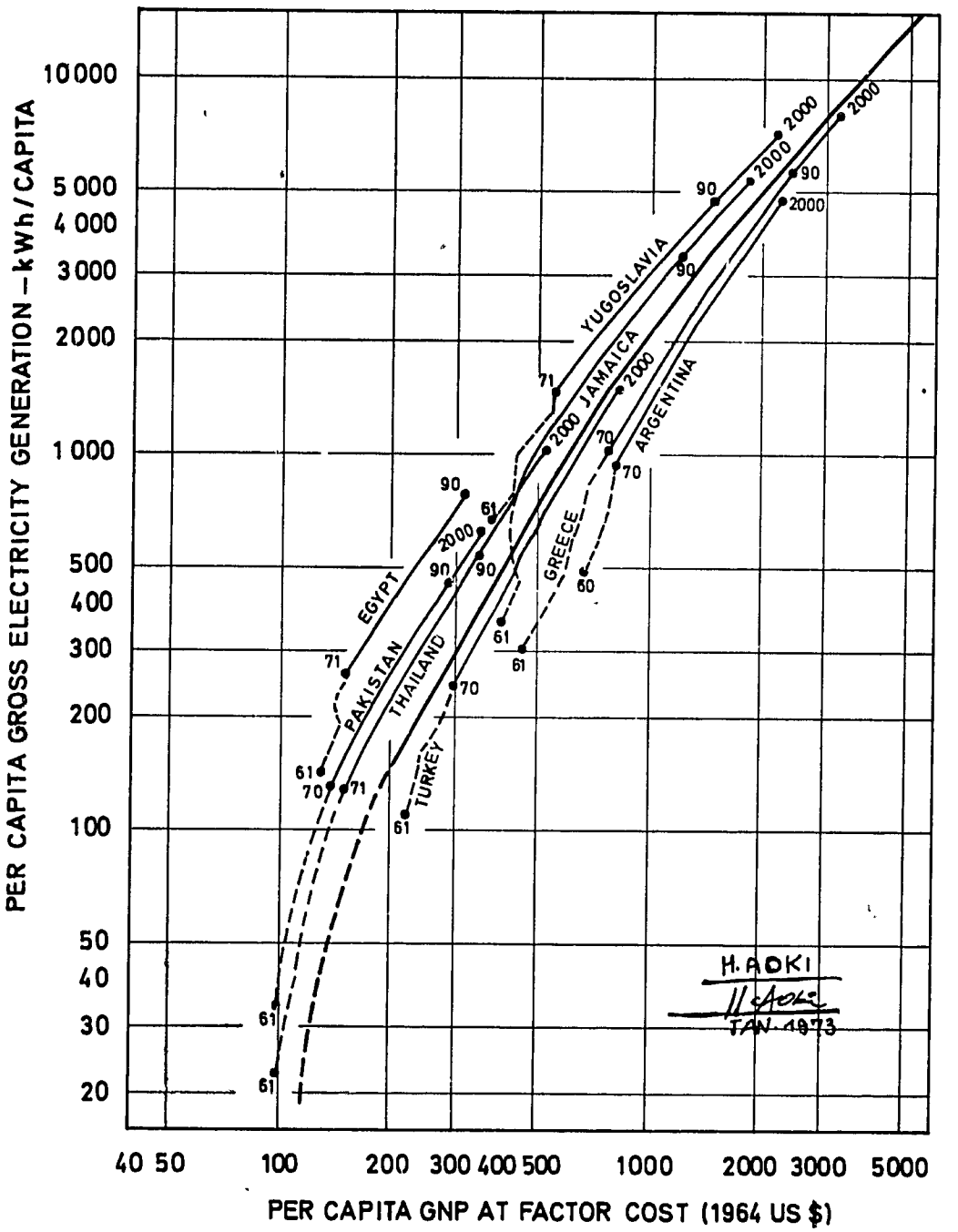


FIG. F-8. SURVEY COUNTRIES PLOTTED ON RECOMMENDED CURVE.

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 | 2 248 |
| | 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 | 2 500 |
| | 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 | 2 577 | 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),

$\Sigma P_{mk}$ 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.

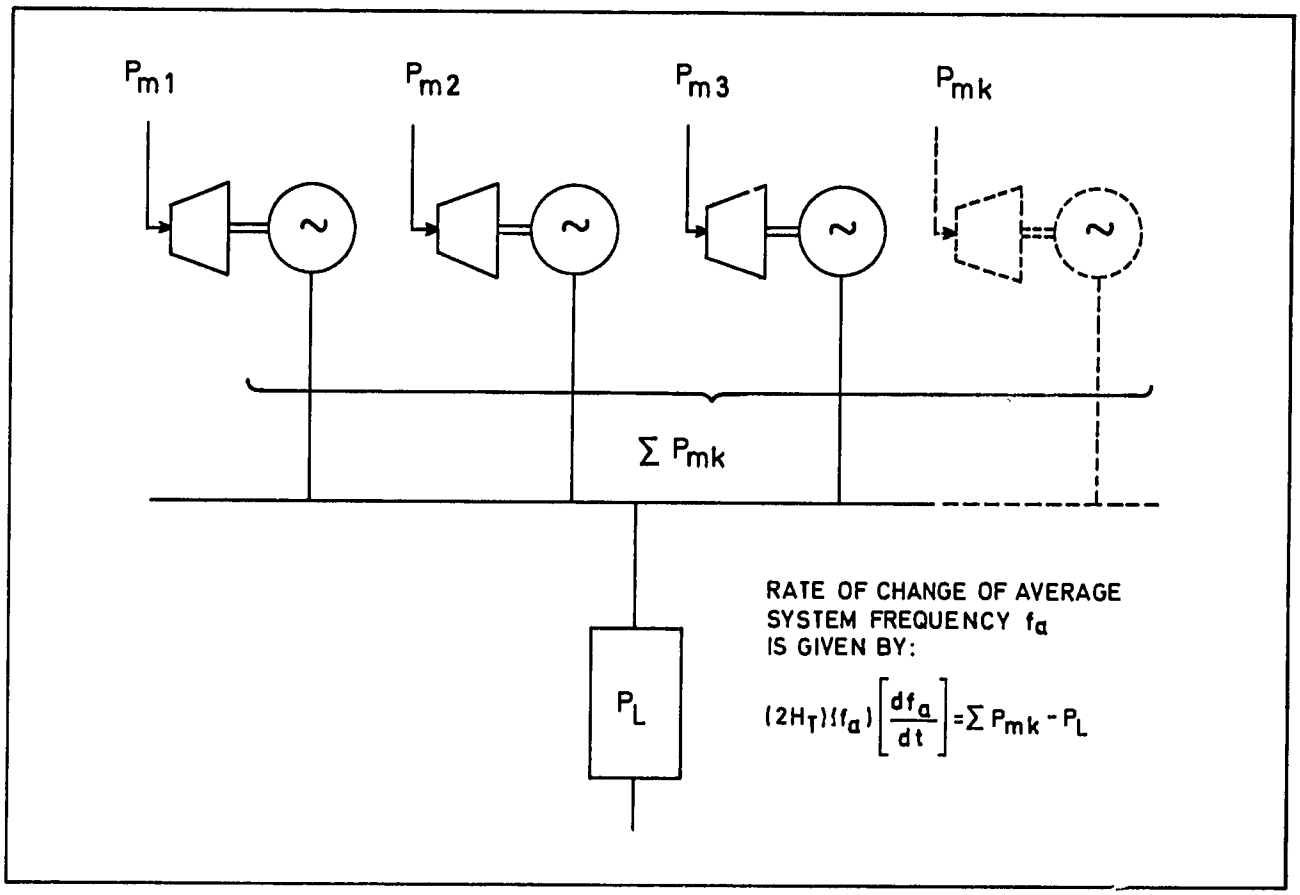


FIG. H-1. AVERAGE SYSTEM FREQUENCY MODEL.

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 $T_3 = \dfrac{T_g + T_d\,(\delta + \delta_t)}{\delta}$

$T_d$ 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),
$\delta$ is the permanent droop (typically 0.04 p.u., range 0.03 - 0.06 p.u.),
$\delta_t$ is the temporary droop (typically 0.31 p.u., range 0.2 - 1.0 p.u.),
$\sigma_a$ 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, ,
$\alpha$ 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 $\alpha$. Thus a typical value for $\alpha$ 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 $\Sigma P_{mk0}$ 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 $\Delta P$ $(= P_{L0} - \Sigma P_{mk0})$ 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 $30 \times 10^9$ 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 $60 \times 10^9$ tons are often advanced for proven oil reserves while ultimate potential reserves which were estimated at around $90 \times 10^9$ as late as 1960 are now quoted as exceeding $900 \times 10^9$ 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 $900 \times 10^9$ tons of presently estimated ultimate reserves would only last 55 years instead of the 15 years assured by $50 \times 10^9$ 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 | |
|---|---|---|
| | $2 \times 10^6$ t/yr (10-in diam. pipeline) | $5 \times 10^6$ 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 $50 \times 10^6$ t/yr it would drop to less than 20 US cents/t per 100 miles, or to about 1/3 of the $5 \times 10^6$ 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 x $10^6$ Btu.
= 10.15 x $10^6$ 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, uch 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.

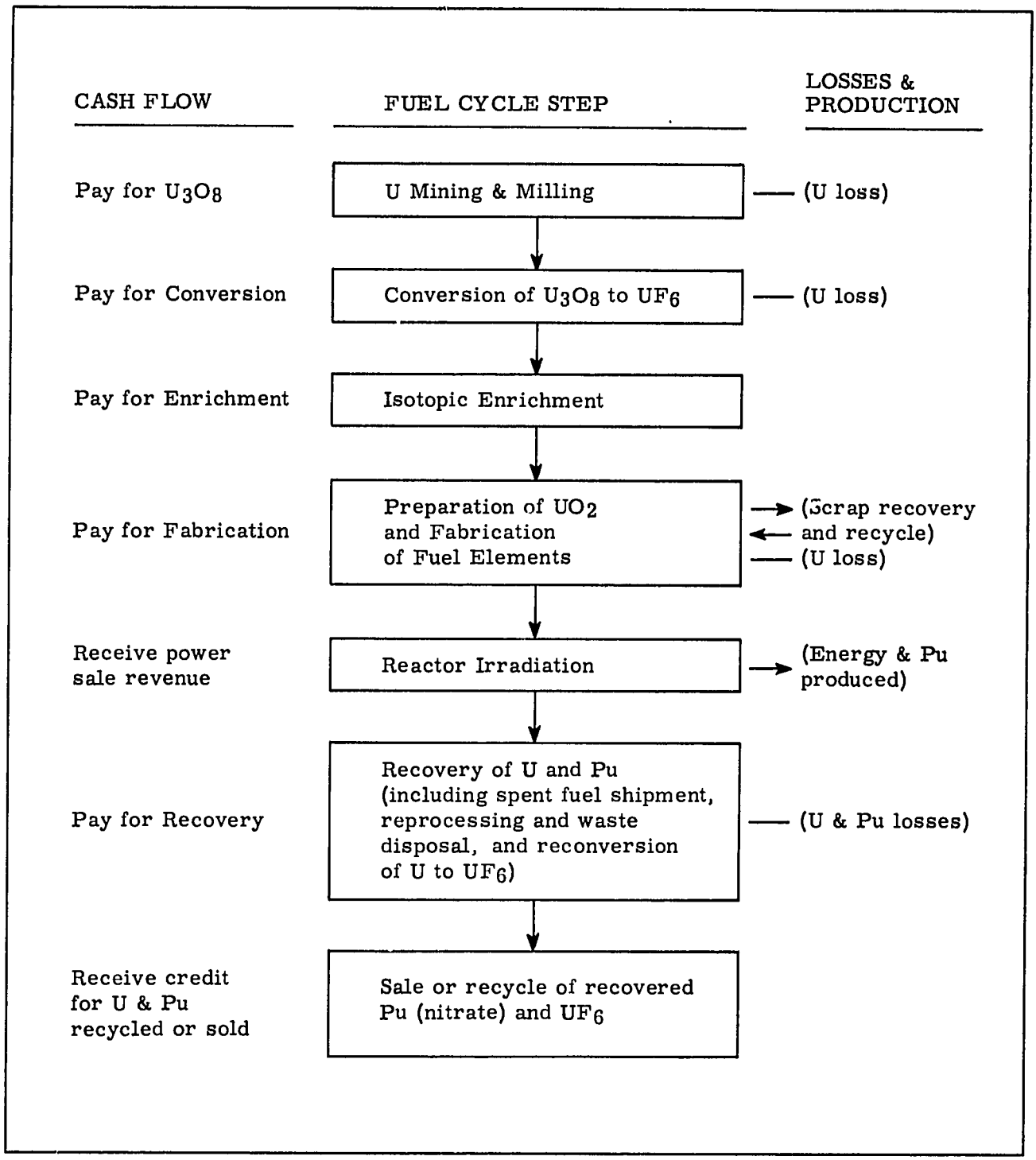


FIG. J-1. GENERALIZED SCHEMATIC DIAGRAM OF LWR FUEL CYCLE.

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.

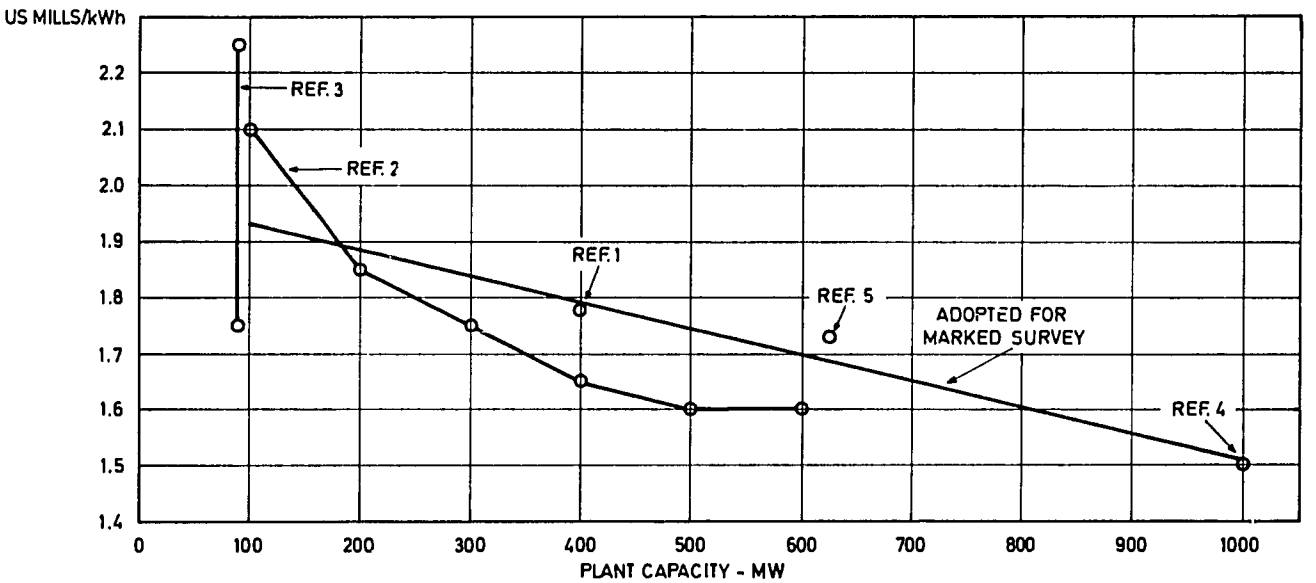


FIG. J-2. TOTAL FUEL CYCLE COSTS.

## FUEL CYCLE WORKING CAPITAL COSTS

For the purpose of the WASP 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.

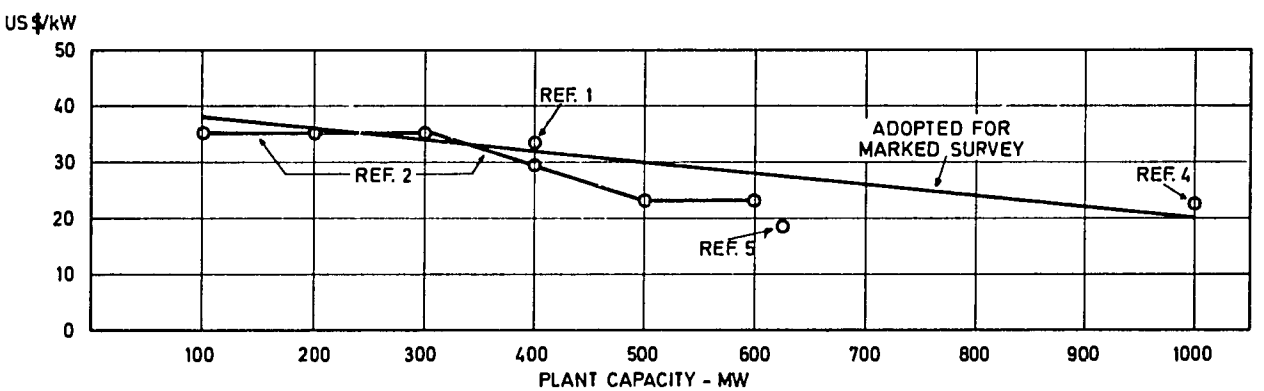


FIG. J-3. LEVELIZED FUEL CYCLE CAPITAL COSTS.

## 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.

APPENDIX K

# 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.

APPENDIX M

## 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

# SUMMARIES OF THE COUNTRY REPORTS

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APPENDIX N

# SUMMARIES OF THE COUNTRY REPORTS

Appendix N presents brief summaries of each Country Report. The following points are common to all of these summaries:

(a) The gross energy production values shown in Tables N- -1 of each of these summaries may differ slightly from the energy production values shown in the Country Reports. The values shown herein are taken directly from the computer printout of the amount of energy under the actual load duration curves.
Identification of the column headings of the computer printouts showing the characteristics of the existing plants and those plants used as expansion alternatives is given in Table VII-3(b) of the General Report.

(b) Starting with the given load forecast, trial computer runs were made to establish the sizes of capacity additions required to give the desired loss-of-load probability for each year of the study period. These runs also served to indicate which of the various fossil fuels being considered resulted in minimum costs with the reference economic parameters.

(c) In carrying out the analyses, it was assumed that the schedule of hydro and pumped storage additions would be fixed and was therefore held constant for all cases considered. The net thermal capacity additions represented the potential market for nuclear and conventional plants.

(d) The economic merit of the various alternatives was determined from the present worth of all costs associated with the construction of generating units being considered and operation of all units in the system. External or social costs were disregarded, as were taxes and restraints on foreign capital. Although the study period (1980-1989) 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 total costs. Thus changes in the present worth are essentially caused by changes in the types and sizes of units added during the study period.

(e) In establishing the basic parameter values all costs are related to 1 January 1973 levels. That is, although a long-term general escalation rate of 4%/yr is anticipated, a zero rate was assumed for these analyses and all other parameter values established relative to this zero rate; e. g. a real discount rate of 12% becomes an effective rate of 8%. The reference case for the studies thus uses a discount rate of 8%/yr, an oil price escalation rate of 2%/yr with nuclear fuel remaining at 0%/yr, capital cost estimates from the ORCOST-3 code (Appendix B), and no shadow exchange rate to penalize cost components requiring foreign exchange. All of these parameters were, however, varied in a series of calculations of the present worth for selected expansion plans in order to study the sensitivity of the results to variations. Details of the sensitivity studies are given in Section 16 of each Country Report.

(f) The possible nuclear markets are based entirely on economic considerations and do not take into account other factors, such as possible scarcity of required investment capital, local manufacturing and construction capabilities and availability of trained staff, all of which may limit the projected programs.

# 1. ARGENTINA

## 1. ECONOMIC AND SOCIAL FACTORS

### 1.1. Population growth

Argentina had a population of over 23 million inhabitants at the end of 1970; the average rate of growth over the 1960-1970 period was slightly less than 1.5%. An analysis of the age and sex distribution of the population and of the fertility rates indicates that there is little reason to expect much change in the past rate over the next 15 years. The population forecast shows 27.3 million in 1980 and 31.8 million in 1990.

### 1.2. Economic development and goals

The average rate of growth of the real GDP over the period 1960-1970 averaged only 3.6%/yr. The total rate of growth of GDP projected for 1970-75 is about 7%, i.e. almost twice that of the prior decade.

### 1.3. Energy needs and resources

The primary consumption of energy rose during the 1960-70 decade at an average annual growth rate of about 5.9%. This was apparently due to the rapid increase in availability of cheaply priced domestic petroleum and natural gas, a factor which can hardly be expected to prevail indefinitely in the future.

The expanded role of hydrocarbons in meeting energy demand in 1971 is reflected in the structure of consumption where oil and gas accounted for almost 90% of the total compared with 80% in 1960. Coal represented less than 3% and hydro less than 1.5%, a proportion that stands in sharp contrast with the wealth of hydro resources available to the country.

Electric energy increased at an annual rate of approximately 8% between 1961 and 1971; the growth rate forecast for the 1971-1976 period is 11.5% with a subsequent decrease to 9.25% for the period until 1980. The corresponding share of electricity in total energy production would accordingly rise from over 20% in 1971 to 26% in 1980.

As noted above, there is a significant hydroelectric potential of about 80 000 GWh/yr, which is approximately equal to the projected increase in energy requirement of the interconnected system between 1980 and 1990. The Salto Grande project will furnish over 3 000 GWh/yr and over 47 000 GWh/yr are attributed to two projects, Apipé and Corpus.

The only exploitable coal field in the country is located in the extreme south, in the Río Turbio area, about 2500 km from Buenos Aires. Production exceeded 600 000 t in 1970 with reserves being estimated at 850 million t. The present cost, which is equivalent to about 90-95 US ¢/$10^6$ Btu delivered in Buenos Aires harbour, is likely to be substantially lowered as output expands. A decrease of 50% is tentatively forecast.

Argentina is relatively well endowed with oil and gas-bearing geological formations and although present primary power reserves of crude oil and gas are not particularly impressive, the results of recent exploration point to a probable rapid growth in the coming years. The policy of the Government calls for a stringent limitation in the use of fuel oil and natural gas in electric power plants and the targets for consumption and production of fuel oil are based on a decision that no further fuel oil or natural gas power plants will be built in the future.

### 1.4. Interest in nuclear power

Argentina will have the first nuclear power station in Latin America: a 320 MW heavy water reactor, starting in 1973. A contract has been awarded for a second nuclear power plant of 600 MW to be built in Córdoba province. The general plan outlined by the National Atomic Energy Commission calls for more than 1500 MW(e) of nuclear power to be installed in the country by 1980.

## 2. PARAMETERS USED IN THE ANALYSIS

### 2.1. Basic conditions

Table N-1-1 summarizes the conditions used in the analyses of various alternative expansion plans for the national interconnected system in Argentina during the period 1980-1989. From the figures given in the table it can be shown that during the study period there is a total addition of over 10 000 MW of new capacity, of which 6 400 MW is new thermal capacity.

The hydro additions assumed for the analyses represent a composite of the hydro projects being considered for construction in Argentina. While the load forecast used is substantially lower than that proposed by Argentina, it was assumed that if the load growth does prove to be higher during the next few years, this will give further incentive to the development of Argentina's substantial hydroelectric resources; the growth in thermal capacity would thus not be expected to be greater than that estimated in the study.

TABLE N-1-1. SUMMARY OF CONDITIONS USED IN THE ANALYSIS

| | 1979 | 1989 |
|---|---|---|
| Population ($10^6$) | 26.88 | 31.33 |
| GNP/capita (US $/yr) | 1 188 [a] | 1 649 [a] |
| Gross energy production (GWh/yr) [b] | 38 100 | 78 000 |
| Peak demand (MW) [b] | 7 500 | 15 500 |
| Total installed capacity (MW) [b] | 9 942 | 19 886 [c] |
| Total installed thermal capacity (MW) [b] | 5 866 | 11 650 [d] |
| Installed capacity, critical period (MW) [b] | 8 913 [e] | 17 697 [e] |
| Average reserve margins (%) | 18.8 [e] | 14.2 [e] |
| Average loss-of-load probability | 0.0028 | 0.0010 |

[a] 1964 US $.
[b] National interconnected system.
[c] Net after deduction of 1016 MW of capacity retirement and addition of 900 MW through interconnection of a sub-system in 1983.
[d] Net after deduction of 1016 MW of thermal capacity retirement and addition of 400 MW of thermal capacity through interconnection of a sub-system in 1983.
[e] In fourth quarter of year (peak hydro capacity = 66% total hydro capacity).

### 2.2. Characteristics of system as of 1979

The existing and committed power expansion plans of utilities in Argentina are only sufficient to meet peak load demand up to about 1978. For this reason 100 MW of conventional plant capacity additions were assumed to be made to the system to meet the 1979 peak demand and provide a sufficient reserve margin for adequate loss-of-load probability. For the purpose of the computer analyses, the existing and committed units were grouped into so-called hypothetical units having common characteristics as shown in Table N-1-2. The technical and economic characteristics of each hypothetical plant shown in the table were computed from the characteristics of the actual plants of each unit.

### 2.3. Characteristics of alternative generating units

The characteristics of alternative thermal generating units considered in the evaluation of possible system expansion configurations (i.e. schedules of additions) are shown in Table N-1-3. These characteristics were derived by methods described in Appendixes E, G, I and J.

TABLE N-1-2. CHARACTERISTICS OF GENERATING PLANTS IN "FIXED SYSTEM"

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HYDR | 1 | 750 | 3026 | 0. | 0. | 0.0 | 0.0 | 5 | 1 | 0.0 | 0 | 0 | 9090. | 0.250 | 0.0 | 0. |
| PNVO | 3 | 100 | 100 | 3375. | 3375. | 182.00 | 0.0 | 1 | 1 | 7.50 | 21 | 100 | 0. | 0.540 | 0.0 | 3375. |
| PNO7 | 1 | 75 | 145 | 2400. | 2010. | 182.00 | 0.0 | 4 | 1 | 7.50 | 21 | 200 | 0. | 0.310 | 0.0 | 2212. |
| PNO8 | 1 | 97 | 194 | 2400. | 2010. | 182.00 | 0.0 | 4 | 1 | 7.50 | 21 | 200 | 0. | 0.280 | 0.0 | 2205. |
| PNO9 | 1 | 125 | 250 | 2150. | 1860. | 182.00 | 0.0 | 4 | 1 | 8.10 | 28 | 200 | 0. | 0.250 | 0.0 | 2005. |
| COST | 5 | 60 | 120 | 2430. | 2010. | 182.00 | 0.0 | 1 | 1 | 5.90 | 21 | 100 | 0. | 0.340 | 0.0 | 2220. |
| DSNP | 3 | 100 | 100 | 3600. | 3600. | 182.00 | 0.0 | 1 | 1 | 7.50 | 21 | 100 | 0. | 0.540 | 0.0 | 3600. |
| NPO4 | 1 | 60 | 60 | 2965. | 2965. | 182.00 | 0.0 | 1 | 1 | 7.50 | 21 | 50 | 0. | 0.490 | 0.0 | 2965. |
| NPO5 | 1 | 55 | 110 | 2750. | 2320. | 182.00 | 0.0 | 1 | 1 | 6.50 | 21 | 100 | 0. | 0.360 | 0.0 | 2535. |
| NPO6 | 1 | 125 | 250 | 2280. | 1900. | 0.0 | 182.00 | 3 | 1 | 5.90 | 28 | 200 | 0. | 0.250 | 0.0 | 2090. |
| PMZA | 1 | 36 | 36 | 3600. | 3600. | 182.00 | 0.0 | 1 | 1 | 8.00 | 21 | 50 | 0. | 0.620 | 0.0 | 3600. |
| SNNK | 4 | 40 | 80 | 2800. | 2400. | 182.00 | 0.0 | 4 | 1 | 9.20 | 21 | 100 | 0. | 0.440 | 0.0 | 2600. |
| GT | 1 | 1050 | 1050 | 3800. | 3800. | 319.00 | 0.0 | 2 | 1 | 0.50 | 60 | 50 | 0. | 1.000 | 0.0 | 3800. |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NERB | 1 | 100 | 100 | 2785. | 2785. | 182.00 | 0.0 | 4 | 1 | 10.C0 | 21 | 100 | 0. | 0.660 | 0.0 | 2785. |
| MDPL | 1 | 83 | 83 | 2800. | 2800. | 182.00 | 0.0 | 1 | 1 | 8.00 | 21 | 100 | 0. | 0.780 | 0.0 | 2800. |
| ALVA | 1 | 30 | 30 | 2990. | 2990. | 200.00 | 0.0 | 1 | 1 | 8.00 | 21 | 50 | 0. | 0.700 | 0.0 | 2990. |
| PRDF | 1 | 99 | 99 | 2785. | 2785. | 206.00 | 0.0 | 1 | 1 | 8.00 | 21 | 100 | 0. | 0.660 | 0.0 | 2785. |
| LCUY | 3 | 60 | 60 | 2600. | 2600. | 218.00 | 0.0 | 1 | 1 | 7.00 | 21 | 50 | 0. | 0.490 | 0.0 | 2600. |
| NCHA | 2 | 35 | 70 | 2600. | 2300. | 182.00 | 0.0 | 1 | 1 | 7.00 | 21 | 100 | 0. | 0.450 | 0.0 | 2450. |
| COST | 1 | 175 | 350 | 2330. | 2100. | 0.0 | 182.00 | 3 | 1 | 8.10 | 28 | 400 | 0. | 0.230 | 0.0 | 2215. |
| ATCH | 1 | 160 | 319 | 2645. | 2360. | 29.00 | 29.00 | 0 | 1 | 6.50 | 28 | 400 | 0. | 0.500 | 0.0 | 2503. |
| PILR | 2 | 38 | 75 | 2800. | 3000. | 206.00 | 0.0 | 1 | 1 | 7.00 | 21 | 100 | 0. | 0.430 | 0.0 | 2899. |
| SNIC | 1 | 175 | 350 | 2330. | 2100. | 182.00 | 0.0 | 4 | 1 | 10.30 | 28 | 400 | 0. | 0.230 | 0.0 | 2215. |
| SORR | 1 | 80 | 160 | 2340. | 2190. | 182.00 | 0.0 | 1 | 1 | 5.30 | 21 | 200 | 0. | 0.290 | 0.0 | 2265. |
| BBCA | 1 | 70 | 140 | 2347. | 2193. | 182.00 | 0.0 | 4 | 1 | 7.50 | 21 | 200 | 0. | 0.320 | 0.0 | 2270. |
| NUC2 | 1 | 300 | 600 | 2637. | 2365. | 27.00 | 28.00 | 0 | 1 | 12.00 | 28 | 600 | 0. | 0.320 | 0.0 | 2501. |
| REG7 | 0 | 100 | 100 | 2600. | 2600. | 228.00 | 0.0 | 1 | 1 | 7.50 | 21 | 100 | 0. | 0.540 | 0.0 | 2600. |
| REG8 | 0 | 100 | 100 | 2700. | 2700. | 228.00 | 0.0 | 1 | 1 | 8.00 | 21 | 100 | 0. | 0.780 | 0.0 | 2700. |
| REG9 | 0 | 100 | 100 | 2700. | 2700. | 228.00 | 0.0 | 1 | 1 | 8.00 | 21 | 100 | 0. | 0.780 | 0.0 | 2700. |

TABLE N-1-3. CHARACTERISTICS OF GENERATING PLANTS FOR SYSTEM EXPANSION ALTERNATIVES

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| N400 | 0 | 200 | 400 | 2643. | 2362. | 28.00 | 29.00 | 0 | 1 | 9.80 | 28 | 400 | 0. | 0.420 | 0.0 | 2502. |
| N600 | 0 | 300 | 600 | 2638. | 2365. | 27.10 | 28.00 | 0 | 1 | 12.00 | 28 | 600 | 0. | 0.320 | 0.0 | 2501. |
| N800 | 0 | 400 | 800 | 2632. | 2369. | 26.20 | 27.00 | 0 | 1 | 12.20 | 35 | 800 | 0. | 0.270 | 0.0 | 2500. |
| N1T0 | 0 | 500 | 1000 | 2627. | 2372. | 25.30 | 26.00 | 0 | 1 | 12.20 | 35 | 1000 | 0. | 0.230 | 0.0 | 2499. |
| O400 | 0 | 200 | 400 | 2324. | 2098. | 0.0 | 182.00 | 3 | 1 | 9.80 | 28 | 400 | 0. | 0.210 | 0.0 | 2211. |
| O600 | 0 | 300 | 600 | 2328. | 2172. | 0.0 | 182.00 | 3 | 1 | 12.00 | 28 | 600 | 0. | 0.170 | 0.0 | 2250. |
| O800 | 0 | 400 | 800 | 2334. | 2170. | 0.0 | 182.00 | 1 | 1 | 12.20 | 35 | 800 | 0. | 0.170 | 0.0 | 2252. |
| O1T0 | 0 | 500 | 1000 | 2344. | 2152. | 0.0 | 182.00 | 3 | 1 | 12.20 | 35 | 1000 | 0. | 0.140 | 0.0 | 2248. |
| C400 | 0 | 200 | 400 | 2351. | 2115. | 182.00 | 0.0 | 4 | 1 | 12.00 | 28 | 400 | 0. | 0.220 | 0.0 | 2233. |
| C600 | 0 | 300 | 600 | 2354. | 2186. | 182.00 | 0.0 | 4 | 1 | 14.10 | 28 | 600 | 0. | 0.190 | 0.0 | 2270. |
| C1T0 | 0 | 500 | 1000 | 2370. | 2166. | 182.00 | 0.0 | 4 | 1 | 14.50 | 35 | 1000 | 0. | 0.160 | 0.0 | 2268. |
| GT50 | 0 | 100 | 100 | 4000. | 4000. | 319.00 | 0.0 | 2 | 1 | 2.00 | 4 | 100 | 0. | 0.700 | 0.0 | 4000. |
| HYDR | 20 | 0 | 0 | 0. | 0. | 0.0 | 0.0 | 5 | 1 | 0.0 | 0 | 0 | 0. | 0.0 | 0.0 | 0. |

## 3. RESULTS

### 3.1. Summary of cases considered

The results of trial computer runs showed that the addition of 400 and 600 MW units in the early to mid-1980s and of 800 and 1000 MW units in the late 1980s would give a near-optimum program. Having established the desired schedule of capacity additions, six computer runs were carried out to evaluate the competition between nuclear and conventional oil-fired plant units. It was found that a program incorporating all of these units as nuclear units gave a lower objective function (present worth) than any combination of oil-fired plant units.

### 3.2. Reference expansion schedule

Table N-1-4 shows the near-optimum expansion schedule for the assumed load forecast based on the reference conditions. It is seen that the schedule calls for the further introduction of single 600 MW nuclear units in each of the years 1980 and 1983, of two 600 MW nuclear units in 1984, of single 800 MW nuclear units in each of the years 1986 and 1987, and of 1000 MW units in 1988 and 1989. On this basis, the total nuclear capacity added during the study period amounts to 6000 MW out of a total thermal capacity added of 6400 MW (400 MW added in 1983 is from interconnection of existing sub-systems) and an overall total of 10060 MW of new capacity added. At the end of 1989 the nuclear capacity would correspond to 34.8% of the total capacity, compared to 23.8% for conventional steam plants, 32.3% for hydro, 5.3% for pumped storage and 3.8% for gas turbines.

### 3.3. Sensitivity studies

The influence of variations in economic parameters on the nuclear power market is shown in Table N-1-5. It is seen that the market for nuclear plants remains unchanged with essentially all of the parameter variations considered. Only if oil prices have a 0% net escalation rate relative to capital costs and nuclear fuel costs will the market be lowered.

### 3.4. Financing requirements

The domestic, foreign and total financing requirements associated with the construction of the thermal plants in the reference expansion schedule (see Table N-1-4) are summarized in Table N-1-6. It is seen that the total annual expenditures reach a peak of US $264.4 \times 10^6$ in 1985. These costs include interest during construction based on the assumption that interest would be paid currently with expenditures. The total cost of the 10-year expansion program amounts to US $2114.8 \times 10^6$.

The nuclear fuel cycle working capital costs (i.e. investment in first core etc.) amounting to US $144.2 \times 10^6$ are also shown in Table N-1-6 as a separate item because financing arrangements for such costs may differ from those for the plant construction program. The total annual investment costs, however, are shown for completeness.

The given costs do not include annual operating and maintenance costs and variable fuel costs.

### 3.5. Conclusions

(a) The estimated total market for new generating units which will be commissioned during the 1980-1989 period is about 10000 MW. Because of abundance of economically exploitable hydroelectric power, however, the market for new thermal plants will probably be 6400 MW.

(b) An evaluation of the four conventional fuels available in Argentina (domestic coal, domestic oil, imported oil and natural gas) indicates that the price of imported oil will set the competition level for conventional fuel with respect to nuclear power. The reasons for this conclusion are as follows:

The production of coal at the large deposits in Río Turbio will continue but costs will not be lower than those of imported oil. As a result, coal costs will probably be set at levels which are competitive with imported oil.

The production of natural gas will be insufficient to meet increasing industrial needs, thus very little will be used for power production.

TABLE N-1-4. REFERENCE SYSTEM EXPANSION SCHEDULE

| Year | Capacity (MW) | | | | | | | % Reserve [a] | Annual loss-of-load probability |
|---|---|---|---|---|---|---|---|---|---|
| | Retirements | Nuclear | Conventional steam | Hydro | Pumped storage | Gas turbines | Total | | |
| Total system 1978 | 0 | 919 | 4 347 | 3 026 | 0 | 1 050 | 9 342 | | |
| Additions 1979 | 0 | 0 | 600 | 0 | 0 | 0 | 600 | | |
| Total system 1979 | 0 | 919 | 4 947 | 3 026 | 0 | 1 050 | 9 942 | 18.8 | 0.0028 |
| 1980[b] | -500[c] | 600 | 400 | 270 | 150 | 0 | 920 | 18.4 | 0.0025 |
| 1981 | -36[c] | 0 | 0 | 270 | 3 x 150 | 0 | 684 | 17.4 | 0.0012 |
| 1982 | -60[c] | 0 | 0 | 270 | 150 | 0 | 360 | 13.4 | 0.0017 |
| 1983 | 0 | 600 | 400[e] | 300<br>500[e] | 0 | 0 | 1 800 | 15.5 | 0.0006 |
| 1984 | 0 | 2 x 600 | | 300 | 0 | 0 | 1 500 | 17.6 | 0.0004 |
| 1985 | 0 | 0 | 0 | 300 | 0 | 0 | 300 | 14.4 | 0.0006 |
| 1986 | -100[c] | 800 | | 300 | 0 | 0 | 1 100 | 12.5 | 0.0011 |
| 1987 | -320[c] | 800 | 0 | 300 | 0 | 0 | 780 | 13.3 | 0.0010 |
| 1988 | 0 | 1 000 | 0 | 300 | 0 | 0 | 1 300 | 13.8 | 0.0010 |
| 1989 | 0 | 1 000 | 0 | 300 | 0 | 0 | 1 300 | 14.2 | 0.0010 |
| Total additions 1980-89 | - 1 016[d] | 6 000 | 800 | 3 410 | 750 | 0 | 9 944[f] | Average 15.1 | Average 0.0011 |
| Total system 1989 | - | 6 919 | 5 747<br>-1 016[d]<br>4 731 | 6 436 | 750 | 1 050 | 19 886[d] | 14.2 | 0.0010 |
| Additions 1990-2000 | -1 162[d] | 9 000 | 4 800 | 3 620 | 0 | 1 000 | 17 258[d] | | |
| Total system 2000 | | 15 919 | 9 531<br>-1 162[d]<br>8 369 | 10 056 | 750 | 2 050 | 37 144 | 16.3 | 0.0006 |

[a] Critical quarter.
[b] Additions and retirements each year.
[c] Total of several small units.
[d] All retirements are thermal and are netted out in year 1989 or 2000.
[e] Interconnection of sub-system.
[f] 9 944 equals 10 060 MW of new capacity additions plus 900 MW from interconnection of a sub-system minus 1 016 MW of retirements.

TABLE N-1-5. SUMMARY OF NUCLEAR MARKET FROM SENSITIVITY STUDIES (MW)

| Year | Reference | Sensitivity studies | | | | |
|---|---|---|---|---|---|---|
| | | 6% discount rate | 10% discount rate | 0% fuel escalation rate | 4% fuel escalation rate | ORCOST-1 |
| Period | | | | | | |
| At 12/31/1972[a] | 319 | 319 | 319 | 319 | 319 | 319 |
| Added 1973-79[b] | 600 | 600 | 600 | 600 | 600 | 600 |
| At 12/31/1979[a] | 919 | 919 | 919 | 919 | 919 | 919 |
| 1980 | 600 | 600 | 600 | 0 | 600 | 600 |
| 1981 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1982 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1983 | 600 | 600 | 600 | 0 | 600 | 600 |
| 1984 | 2 x 600 | 2 x 600 | 2 x 600 | 0 | 2 x 600 | 2 x 600 |
| 1985 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1986 | 800 | 800 | 800 | 800 | 800 | 800 |
| 1987 | 800 | 800 | 800 | 800 | 800 | 800 |
| 1988 | 1 000 | 1 000 | 1 000 | 1 000 | 1 000 | 1 000 |
| 1989 | 1 000 | 1 000 | 1 000 | 1 000 | 1 000 | 1 000 |
| Total additions 1980-89 | 6 000 | 6 000 | 6 000 | 3 600 | 6 000 | 6 000 |
| Total system 1989 | 6 919 | 6 919 | 6 919 | 4 519 | 6 919 | 6 919 |
| Nuclear % of system installed capacity 1989 | 34.8 | 34.8 | 34.8 | 22.7 | 34.8 | 34.8 |

[a] Units in operation or under construction.
[b] Units expected to be committed during period.

(c) An evaluation of the competitiveness of nuclear versus oil-fired plant units indicates that under the reference conditions (8% discount rate, 2% escalation on fuel-oil prices) nuclear plant units are more competitive than oil-fired plant units. Assuming that one 400 MW coal-fired unit is installed in 1980, all of the 600 MW and larger units considered for introduction in the study decade would be nuclear, giving an aggregate potential nuclear market of about 6000 MW.

(d) An evaluation of the sensitivity of the results to various economic parameters indicates that under economic conditions which tend to favour nuclear plants (6% discount rate, 4% fossil fuel escalation, lower capital cost differential) the nuclear market would remain at 6000 MW. However, under economic conditions which tend to favour conventional plants (0% oil price escalation) the nuclear market would drop to 3 600 MW.

(e) The thermal plant financing requirements for the reference expansion schedule amount to US $2114.8 $\times 10^6$ for plant investment plus US $144.2 $\times 10^6$ for nuclear fuel cycle working capital.

TABLE N-1-6. FINANCING REQUIREMENTS FOR REFERENCE THERMAL PLANTS EXPANSION SCHEDULE (US $ × $10^6$)

| Year | Plant investment | | | Nuclear fuel working capital[a] | Total |
|---|---|---|---|---|---|
| | Domestic | Foreign | Subtotal | | |
| 1974 | 0.6 | 0.6 | 1.2 | | |
| 1975 | 5.5 | 5.5 | 11.0 | | |
| 1976 | 21.7 | 21.3 | 43.0 | | 43.0 |
| 1977 | 49.3 | 44.7 | 94.0 | | 94.0 |
| 1978 | 72.3 | 62.5 | 134.8 | 1.6 | 136.4 |
| 1979 | 59.8 | 54.6 | 114.4 | 15.0 | 129.4 |
| 1980 | 77.2 | 77.2 | 154.4 | 0 | 154.4 |
| 1981 | 116.3 | 116.3 | 232.6 | 1.6 | 234.2 |
| 1982 | 122.2 | 122.2 | 244.4 | 18.4 | 262.8 |
| 1983 | 107.4 | 107.4 | 214.8 | 30.0 | 244.8 |
| 1984 | 126.3 | 126.3 | 252.6 | 1.8 | 254.4 |
| 1985 | 132.2 | 132.2 | 264.4 | 19.0 | 283.4 |
| 1986 | 103.9 | 103.9 | 207.8 | 19.2 | 227.0 |
| 1987 | 58.1 | 58.1 | 116.2 | 19.8 | 136.0 |
| 1988 | 14.0 | 14.0 | 28.0 | 17.8 | 45.8 |
| Total | 1 067.6 | 1 047.2 | 2 114.8 | 144.2 | 2 259.0 |

[a] Domestic expenditures for the nuclear fuel working capital were assumed to amount to 50% of the total.

## 2. BANGLADESH

### 1. ECONOMIC AND SOCIAL FACTORS

#### 1.1. Population growth

Bangladesh has a population estimated to reach 74 million in January 1973, growing at a rate of about 2.7%/yr. The population density is one of the highest in the world with 520 persons/km$^2$. Nearly 85% of the population live in rural areas and from agriculture. The per-capita income is extremely low, about 450 Tk/yr = US $59/yr.

#### 1.2. Economic development and goals

The GDP has had a low rate of increase of 4.4%/yr in the past, and the war in 1971 meant a severe setback for the economic development. The present Government hopes to achieve a growth rate of between 6 and 7%/yr from 1973 - 1974 onwards after conditions have been normalized to the 1969/70 level.

## 1.3. Social considerations

About half of the population lives to the west of the Brahmaputra river, which in the rainy season may swell to a width of 14 miles in some locations and over which so far not a single bridge has been built. The lack of road and rail communications between the two sides has hindered the development of an interconnected electric power network for both zones. The Western Zone is less developed than the Eastern Zone.

## 1.4. Energy needs and resources

The data for energy consumption are incomplete but indicate extremely low values of some 35 kg of coal equivalent per capita and year. In 1969 27% of the total energy consumed was for the production of electricity. Electric energy consumption increased at a rate of 17.8%/yr in the 1960s, but the per-capita consumption is still extremely low (20 kWh/yr in 1970).

There are only small indigenous energy resources readily available to meet future demands. Hydroelectric potential is limited to the Chittagong Hill Track in the south-east, where at present 80 MW are installed, 50 MW are under construction, and an additional 190 MW may be built in the future. A barrage across the Brahmaputra in the north could yield some 400 - 1000 MW. Substantial deposits of good quality coal have been discovered in the northern part of the Western Zone, but they are at a depth of 2000 to 4000 ft and will require sophisticated and costly mining techniques, including freezing. Any substantial coal mining for power production cannot be achieved before 1985, when coal at US $0.52/10$^6$ Btu could conceivably support a 200 MW(e) plant.

In spite of extensive exploration no oil resources have been discovered and all oil is imported. Natural gas fields in the north-eastern part of the country constitute an important indigenous source of energy with total reserves estimated to some $600 \times 10^9$ m$^3$ of high quality gas. Present consumption of natural gas is low and the pipeline system is small. There are plans for pipelines to Chittagong and possibly also to the Western Zone, for which delivered gas costs have been estimated to be US $0.38/10$^6$ Btu exclusive of all taxes.

## 1.5. Interest in nuclear power

Since 1961 the feasibility of a nuclear power station in the Western Zone has been studied and the studies have been continued after the war by a group associated with the Atomic Energy Centre in Dacca. The establishment of an Atomic Energy Commission is expected soon.

# 2. PARAMETERS USED IN THE ANALYSIS

## 2.1. Basic conditions

Table N-2-1 summarizes the conditions assumed in the analyses of various alternative expansion plans for the Bangladesh system during the period 1980 to 1989. As shown in the table, two differing load forecasts were considered. The low load forecast was developed by a Market Survey expert using the method described in Appendix F. The high load forecast represents an extrapolation of the 1980-85 forecast made by the Rooppur Working Group, using a constant annual load factor of 55%. During the study period there are 1300 MW of thermal capacity additions with the low load forecast and additions of 3800 MW with the high load forecast. The two forecasts should be considered as extreme alternatives considered for the development during the study period.

In both cases it was assumed that the east-west interconnector is in operation during the whole study period. All hydro capacity was assumed to have been added before 1979 and the possible Brahmaputra dam project in the northern part of the country was not considered to be implemented during the study period. No gas-fired plants were considered explicitly for the expansion plans as gas-fired plants would be very close to oil-fired stations in economic competitive position. It was furthermore assumed that fertilizer production and other chemical industries would have priority over electricity production for the use of the relatively limited gas reserves.

TABLE N-2-1. SUMMARY OF CONDITIONS USED IN THE ANALYSIS

| | Low load forecast | | High load forecast | |
|---|---|---|---|---|
| | 1979 | 1989 | 1979 | 1989 |
| Population ($10^6$) | 86.3 | 111.6 | 86.3 | 111.6 |
| GNP/capita (US$/yr) [a] | 48.9 | 68.3 | 48.9 | 68.3 |
| Energy generation (GWh/yr) | 2698 | 7468 | 3854 | 18308 |
| Peak demand (MW) | 560 | 1550 | 800 | 3800 |
| Total installed capacity (MW) | 784 | 2084 | 1034 | 4835 |
| Installed capacity, critical period (MW) [b] | 744 | 2044 | 994 | 4795 |
| Thermal capacity (MW) | 654 | 1954 | 904 | 4705 |
| Reserve margin (%) | 33.0 | 31.8 | 24.4 | 26.0 |
| Annual loss-of-load probability | 0.0003 | 0.0003 | 0.0063 | 0.0054 |

[a] In 1964 US $.
[b] In first quarter of each year the available peak hydro capacity = 70% of total hydro capacity.

## 2.2. Characteristics of system as of 1979

The existing and committed power expansion plans of the Power Development Board are almost sufficient to meet peak load demand up to 1979 with the low load forecast. In this case only 2 × 50 MW gas turbine additions were assumed to be made to the system to meet the 1979 peak demand and provide a sufficient reserve margin. In the high forecast case, a 300 MW fossil-fired plant and one 50 MW gas turbine were added. For the purpose of the computer analyses, the existing and committed units were grouped into so-called hypothetical units having common characteristics as shown in Table N-2-2. The technical and economic characteristics of each hypothetical plant shown in the the table were computed from the characteristics of the actual plants comprising each unit.

## 2.3. Characteristics of alternative generating units

The characteristics of alternative thermal generating units considered in the evaluation of possible system expansion configurations (i.e. schedules of additions) are shown in Table N-2-3. These characteristics were derived by methods described in Appendixes E, G, I and J.

# 3. RESULTS

## 3.1. Summary of cases considered

The two widely differing load forecasts made it necessary to develop two series of substantially different expansion schemes for the electrical power supply system. Using the criterion that the size of a single unit should not be greater than 15% of the total installed capacity at the time of introduction on the grid, the expansion plans were developed by successively adding thermal units of 100, 200 and 300 MW to the system existing in 1979 for the low forecast and units of 150, 200, 300, 400 and 600 MW for the high load forecast. Gas turbine plants of 50 MW or 2 × 50 MW were added in both cases as required for peaking capacity and for maintaining an approximately constant loss-of-load probability. (A definition of loss-of-load probability is given in Appendix A.) For the high load forecast a loss-of-load probability of approximately 0.005 (=0.5%) was maintained during the study period while for the low load forecast the main criterion was to maintain an adequate reserve margin to cover simultaneous outage of the two biggest units in the system. This more conservative approach resulted in a loss-of-load probability of approximately 0.001.

TABLE N-2-2. CHARACTERISTICS OF GENERATING PLANTS IN "FIXED SYSTEM"

| 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 | L C T N | FRCD OUT-AGE RATE | DAYS SCHL MAIN | MAIN CLAS | ENRGY GWH | O&M (FIX) | O&M (VAR) | FULL LOAD HEAT RATE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GOBE | 6 | 4 | 4 | 4350. | 4350. | 10.00 | 150.00 | 1 | 1 | 8.00 | 25 | 5 | 0. | 0.350 | 0.140 | 4350. |
| KUL1 | 1 | 8 | 8 | 2970. | 2970. | 20.00 | 155.00 | 2 | 1 | 4.00 | 10 | 10 | 0. | 0.200 | 0.100 | 2970. |
| KUL2 | 2 | 13 | 13 | 4220. | 4220. | 20.00 | 155.00 | 2 | 1 | 4.00 | 10 | 15 | 0. | 0.220 | 0.110 | 4220. |
| KUL3 | 1 | 8 | 8 | 4220. | 4220. | 20.00 | 155.00 | 2 | 1 | 4.00 | 10 | 10 | 0. | 0.220 | 0.110 | 4220. |
| KUL4 | 1 | 15 | 60 | 3250. | 2420. | 10.00 | 150.00 | 1 | 1 | 8.00 | 25 | 60 | 0. | 0.350 | 0.140 | 2628. |
| RAJI | 3 | 1 | 1 | 2970. | 2970. | 20.00 | 155.00 | 2 | 1 | 5.00 | 30 | 5 | 0. | 0.870 | 0.400 | 2970. |
| SERA | 5 | 1 | 1 | 2970. | 2970. | 20.00 | 155.00 | 2 | 1 | 5.00 | 30 | 5 | 0. | 0.870 | 0.400 | 2970. |
| SAID | 3 | 4 | 4 | 2970. | 2970. | 20.00 | 155.00 | 2 | 1 | 6.00 | 25 | 5 | 0. | 0.350 | 0.140 | 2970. |
| SID1 | 3 | 10 | 10 | 2970. | 2970. | 60.00 | 0.0 | 1 | 1 | 8.00 | 25 | 10 | 0. | 0.350 | 0.140 | 2970. |
| SID2 | 7 | 1 | 1 | 2970. | 2970. | 20.00 | 155.00 | 2 | 1 | 4.00 | 7 | 5 | 0. | 0.200 | 0.100 | 2970. |
| SID3 | 1 | 20 | 50 | 3250. | 2420. | 60.00 | 0.0 | 1 | 1 | 8.00 | 25 | 60 | 0. | 0.350 | 0.140 | 2752. |
| ASHU | 2 | 20 | 64 | 3250. | 2420. | 35.00 | 0.0 | 1 | 1 | 8.00 | 25 | 60 | 0. | 0.350 | 0.140 | 2679. |
| CHIT | 1 | 10 | 10 | 2970. | 2970. | 20.00 | 140.00 | 2 | 1 | 8.00 | 25 | 10 | 0. | 0.350 | 0.140 | 2970. |
| CHIT | 2 | 7 | 7 | 4500. | 4500. | 60.00 | 0.0 | 2 | 1 | 4.00 | 10 | 10 | 0. | 0.220 | 0.110 | 4500. |
| SIKA | 1 | 15 | 60 | 3250. | 2420. | 60.00 | 0.0 | 1 | 1 | 8.00 | 25 | 60 | 0. | 0.350 | 0.140 | 2628. |
| SHAH | 4 | 16 | 16 | 4220. | 4220. | 60.00 | 0.0 | 2 | 1 | 4.00 | 10 | 15 | 0. | 0.220 | 0.110 | 4220. |
| SHA2 | 3 | 15 | 15 | 4220. | 4220. | 60.00 | 0.0 | 2 | 1 | 4.00 | 10 | 15 | 0. | 0.220 | 0.110 | 4220. |
| HYDO | 1 | 0 | 130 | 0. | 0. | 0.0 | 0.0 | 5 | 1 | 0.0 | 0 | 0 | 791. | 0.230 | 0.0 | 0. |

TABLE N-2-3. CHARACTERISTICS OF GENERATING PLANTS FOR SYSTEM EXPANSION ALTERNATIVES

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| N100 | 0 | 50 | 100 | 2651. | 2357. | 0.0 | 59.80 | 0 | 1 | 6.50 | 28 | 100 | 0. | 1.260 | 0.0 | 2504. |
| N200 | 0 | 100 | 200 | 2648. | 2359. | 0.0 | 58.90 | 0 | 1 | 5.40 | 28 | 200 | 0. | 0.710 | 0.0 | 2503. |
| N300 | 0 | 150 | 300 | 2645. | 2360. | 0.0 | 57.90 | 0 | 1 | 6.50 | 28 | 300 | 0. | 0.520 | 0.0 | 2503. |
| N400 | 0 | 200 | 400 | 2643. | 2362. | 0.0 | 57.00 | 0 | 1 | 9.80 | 28 | 400 | 0. | 0.420 | 0.0 | 2502. |
| N600 | 0 | 300 | 600 | 2638. | 2365. | 0.0 | 55.10 | 0 | 1 | 12.00 | 28 | 600 | 0. | 0.320 | 0.0 | 2501. |
| N800 | 0 | 400 | 800 | 2632. | 2369. | 0.0 | 53.20 | 0 | 1 | 12.20 | 35 | 800 | 0. | 0.270 | 0.0 | 2500. |
| O100 | 0 | 50 | 100 | 2388. | 2192. | 10.00 | 150.00 | 1 | 1 | 6.50 | 21 | 100 | 0. | 0.610 | 0.0 | 2290. |
| O150 | 0 | 75 | 150 | 2347. | 2193. | 10.00 | 150.00 | 1 | 1 | 5.30 | 21 | 150 | 0. | 0.450 | 0.0 | 2270. |
| O200 | 0 | 100 | 200 | 2280. | 2146. | 10.00 | 150.00 | 1 | 1 | 5.40 | 21 | 200 | 0. | 0.360 | 0.0 | 2213. |
| O300 | 0 | 150 | 300 | 2335. | 2183. | 10.00 | 150.00 | 1 | 1 | 6.50 | 28 | 300 | 0. | 0.280 | 0.0 | 2259. |
| O400 | 0 | 200 | 400 | 2324. | 2098. | 10.00 | 150.00 | 1 | 1 | 9.80 | 28 | 400 | 0. | 0.240 | 0.0 | 2211. |
| O600 | 0 | 300 | 600 | 2328. | 2172. | 10.00 | 150.00 | 1 | 1 | 12.00 | 28 | 600 | 0. | 0.190 | 0.0 | 2250. |
| O800 | 0 | 400 | 800 | 2334. | 2170. | 10.00 | 150.00 | 1 | 1 | 12.20 | 35 | 800 | 0. | 0.170 | 0.0 | 2252. |
| GT50 | 0 | 50 | 50 | 4000. | 4000. | 20.00 | 155.00 | 2 | 1 | 2.00 | 15 | 75 | 0. | 0.250 | 0.0 | 4000. |

In the basic expansion scheme developed in this way for each forecast the thermal unit additions were assumed to be oil-fired during the study period. For the second decade (1990-2000) the plants to be added were chosen in such a way that nuclear units would provide the whole base load.

In alternative expansion schemes, oil-fired units were substituted by nuclear units of the same size during the study period while the plant types and sizes to be added during the second decade were always held constant. To study the effect of successively earlier introduction of nuclear power first the 1989 additions were changed from oil-fired to nuclear plants, then the 1988 additions etc., and the objective function was computed for each scheme in order to show the effect of the plant type choice on the total present worth of costs.

## 3.2. Reference expansion schedule

Table N-2-4 shows the near-optimum expansion schedule based on the reference condition.

It was found that in the reference case the optimum solution for the low load forecast was to choose oil-fired plants throughout the study period while for the high load forecast the economic optimum scheme used oil-fired plant additions up to 1988 and a 600 MW nuclear unit in 1989. The influence of variations in the main economic parameters on optimum solution is discussed in the following section.

TABLE N-2-4. REFERENCE SYSTEM EXPANSION SCHEDULES[a]

| Year | Low load forecast (MW) | | | | | High load forecast (MW) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Nuclear | Conventional steam | Hydro | Gas turbines | Total | Nuclear | Conventional steam | Hydro | Gas turbines | Total |
| Total system 1978 | 0 | 399 | 130 | 155 | 684 | 0 | 399 | 130 | 155 | 684 |
| Additions 1978-1979 | 0 | 0 | 0 | 2 x 50 | 100 | 0 | 300 | 0 | 50 | 350 |
| Total system 1979 | 0 | 399 | 130 | 255 | 784 | 0 | 699 | 130 | 205 | 1 034 |
| 1980 | | 100 | | | 100 | | 150 | | 50 | 200 |
| 1981 | | 100 | | | 100 | | 200 | | | 200 |
| 1982 | | 100 | | | 100 | | 200 | | | 200 |
| 1983 | | 0 | | 2 x 50 | 100 | | 200 | | 50 | 250 |
| 1984 | | 100 | | | 100 | | 2 x 200 | | | 400 |
| 1985 | | 100 | | | 100 | | 300 | | | 300 |
| 1986 | | 200 | | | 200 | | 300 | | 2 x 50 | 400 |
| 1987 | | 200 | | | 200 | | 400 | | 2 x 50 | 500 |
| 1988 | | | | | 0 | | 2 x 400 | | | 800 |
| 1989 | | 300 | | | 300 | 600 | 0 | | | 600 |
| Add. 1980-89 | 0 | 1 200 | 0 | 100 | 1 300 | 600 | 2 450 | 0 | 300 | 3 801 |
| Retirements | 0 | 0 | 0 | 0 | 0 | 0 | -49 | 0 | 0 | -49 |
| Total system 1989 | 0 | 1 599 | 130 | 355 | 2 084 | 600 | 3 600 | 130 | 505 | 4 835 |
| Additions 1990-2000[b] | 1 800 | 1 300 | 0 | 0 | 3 100 | 4 800 | 6 400 | 0 | 0 | 11 200 |
| Total system 2000[b] | 1 800 | 2 899 | 130 | 355 | 5 184 | 5 400 | 10 000 | 130 | 505 | 16 035 |

[a] 8% discount rate, 2% escalation on oil-prices, ORCOST-3 capital costs.

[b] In the high forecast case the expansion was carried only to the year 1997.

## 3.3. Sensitivity studies

The potential market for nuclear plants in Bangladesh under varying economic conditions is shown in Table N-2-5, for both the low and high forecast cases. It is seen that with the low forecast the potential nuclear market varies from 0 to 500 MW and with the high forecast from 600 to 2100 MW. The results of sensitivity studies indicated that in all other cases not explicitly covered in the table the results fall within the extremes shown.

It should, however, be emphasized that the economic differences between some alternatives may be rather small. Thus the objective function for the all oil-fired plant expansion alternative in the reference case for the low forecast is lower by only 0.9% compared with the objective function if a 300 MW nuclear power station is introduced in 1989. If the discount rate is changed to 6%/yr, the advantage of the all oil-fired plant alternative becomes only 0.1%.

## 3.4. Financing requirements

The domestic, foreign and total financing requirements associated with the construction of the thermal plants in the reference expansion schedules (see Table N-2-4) are summarized in Table N-2-6. These costs include interest during construction based on the assumption that interest would be paid currently with expenditures. It is seen that total annual expenditures reach a peak of US $\$57 \times 10^6$ for the low load forecast (in 1984) and US $\$191 \times 10^6$ for the high load forecast (in 1985). The total costs of the 10-year expansion programs amount to US $\$424 \times 10^6$ and US $\$1107 \times 10^6$, respectively, for the two given forecasts.

The nuclear fuel cycle working capital costs (i.e. investment in first core etc.) are not included in these investment costs. Table N-2-6 shows these costs separately because financing arrangements for such costs may differ from those for the plant construction programs. The total annual investment costs, however, are shown for completeness.

The given costs do not include annual operating and maintenance costs and variable fuel costs.

## 3.5. Conclusions

(a) The estimated total market for generating units which will be commissioned during the 1980 - 1989 period ranges from 1300 MW to 3800 MW depending on the load forecast used. All capacity additions will have to be thermal plants.

(b) Three conventional fuels may be available in Bangladesh, i.e. oil, natural gas and coal. Of these oil has been used as the alternative to nuclear fuel for the following reasons:

Gas-fired plants would be very close to oil-fired plants in economic competitive position and it was further assumed that fertilizer production and other chemical industries would have priority for the use of the relatively limited gas reserves.

Coal is not presently mined and can only become available from known reserves after 1985 and then only enough to supply less than 800 MW in 1990. The cost would again be very closely the same as that of oil or somewhat higher, and oil-fired plants thus remain the alternative against which nuclear plants would have to compete.

In view of the small plant sizes that can be used for additions to the system (200 MW up to 1987 for the low forecast, up to 1984 for the high forecast) it is natural that nuclear plants have difficulty competing with oil-fired plants under reference conditions. For the low forecast no nuclear plant would be competitive up to 1989 while for the high forecast one 600 MW nuclear unit would be competitive in 1989.

(c) An evaluation of the sensitivity of the results to various economic parameters indicates that under economic conditions which tend to favour nuclear plants (6%/yr discount rate and a higher escalation rate on oil prices of 4%/yr), the nuclear market would range from 500 MW to 2100 MW depending on the forecast used.

TABLE N-2-5. POTENTIAL MARKET FOR NUCLEAR POWER PLANTS IN BANGLADESH (PLANTS COMMISSIONED 1980-89) (MW)

| Year | Low load forecast | | | High load forecast | | | |
|---|---|---|---|---|---|---|---|
| | Reference (8% discount rate, 2% oil escalation rate) | 6% discount rate, 2% oil escalation rate | 8% discount rate, 4% oil escalation rate | Reference (8% discount rate, 2% oil escalation rate) | 6% discount rate, 2% oil escalation rate | 8% discount rate, 4% oil escalation rate | 8% discount rate, 0% oil escalation rate |
| 1980-85 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1986 | 0 | 0 | 0 | 0 | 0 | 300 | 0 |
| 1987 | 0 | 0 | 200 | 0 | 0 | 400 | 0 |
| 1988 | 0 | 0 | 0 | 0 | 2 × 400 | 2 × 400 | 0 |
| 1989 | 0 | 0 | 300 | 600 | 600 | 600 | 0 |
| Total | 0 | 0 | 500 | 600 | 1 400 | 2 100 | 0 |

TABLE N-2-6. PLANT INVESTMENT AND NUCLEAR FUEL FINANCING REQUIREMENTS FOR REFERENCE THERMAL PLANT EXPANSION SCHEDULES[a] ($10^6$ US $)

| Year | Low load forecast | | | | High load forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Plant investment | | | Total | Plant investment | | | Nuclear fuel cycle investment[b] | Total |
| | Domestic | Foreign | Subtotal | | Domestic | Foreign | Subtotal | | |
| 1976 | | 0.3 | 0.3 | | 0.1 | 0.5 | 0.6 | | 0.6 |
| 1977 | 1.5 | 6.0 | 7.5 | | 2.3 | 9.4 | 11.7 | | 11.7 |
| 1978 | 5.2 | 20.8 | 26.0 | | 7.9 | 31.9 | 39.8 | | 39.8 |
| 1979 | 7.2 | 29.1 | 36.3 | | 11.6 | 47.3 | 58.9 | | 58.9 |
| 1980 | 5.9 | 23.6 | 29.5 | | 12.3 | 54.9 | 67.2 | | 67.2 |
| 1981 | 3.6 | 15.9 | 19.5 | | 15.4 | 63.1 | 78.5 | | 78.5 |
| 1982 | 5.2 | 32.3 | 37.8 | | 20.3 | 89.3 | 109.6 | | 109.6 |
| 1983 | 8.6 | 34.5 | 43.1 | | 21.3 | 95.5 | 116.8 | | 116.8 |
| 1984 | 11.4 | 34.6 | 57.0 | | 23.2 | 115.2 | 138.4 | | 138.4 |
| 1985 | 11.3 | 45.3 | 56.6 | | 29.7 | 161.4 | 191.1 | | 191.1 |
| 1986 | 9.2 | 37.0 | 46.2 | | 28.2 | 157.7 | 185.9 | | 185.9 |
| 1987 | 8.7 | 34.9 | 43.6 | | 13.4 | 80.5 | 93.9 | 1.7 | 95.6 |
| 1988 | 4.0 | 16.0 | 20.0 | | 1.3 | 12.0 | 13.3 | 15.0 | 28.3 |
| Total | 82.3 | 341.9 | 424.2 | 424.2 | 187.5 | 919.4 | 1 106.9 | 16.7 | 1 123.6 |

[a] Rounded.
[b] Domestic expenditures for the nuclear fuel cycle working capital were assumed to be 0% of the total.

# 3. CHILE

## 1. ECONOMIC AND SOCIAL FACTORS

### 1.1. Population growth

The population of Chile was about 9.8 million in 1970. The present annual growth rate is about 1.9% and the population is estimated to be about 10.2 million at the end of 1972 and 14.2 million by 1990. About 65% of the population live in urban areas and a third live in the province which contains Santiago, the capital. Chile's economically active population was estimated at about 3.1 million persons but unemployment has always been high, averaging about 5.4% in 1969.

### 1.2. Economic development and goals

Chile is the world's second largest exporter of copper. Copper sales earn about 80% of the country's foreign exchange. In addition Chile has important deposits of nitrate, gold, silver, coal and iron-ore. Chile also has a good agricultural potential and produces some of the world's finest wines. The GNP per capita in 1970 was about 600 US $, increasing at about 3%/yr.

Government policy is toward increasing participation in the country's economy by nationalizing the country's production enterprises.

### 1.3. Environmental considerations

The Government has not emphasized environmental control and the people have accepted the present level of environmental pollution (rather high in Santiago). There is a concern with power plant safety and even for fossil fuel plants special precautions are taken in view of the seismic conditions prevailing.

### 1.4. Energy needs and resources

The total energy consumption was about 18 311 GWh equivalent energy in 1970. The growth in energy consumption was 3.5%/yr over the last three decades. The growth in oil and hydro power increased 5.9% and 5.8%, respectively. The electrical energy production rate of growth was considerably higher at 7.2%. This approximate rate of growth will continue, resulting in a generation requirement of about 21 200 GWh by 1990 and 41 000 GWh in the year 2000.

Chile has an abundant supply of fairly expensive hydroelectric energy with a generating potential of about 146 000 GWh/yr in an average rainfall year. Much of this is some distance from load centres and will not be developed immediately. The load growth for the next two decades could, however, be met by hydro projects. Chile has large reserves of high-cost coal and respectable amounts of oil and gas – again with high recovery costs.

### 1.5. Interest in nuclear power

Chile has had a permanent interest in the possibilities offered by nuclear power for generating electricity and for other purposes such as desalination of water. A number of feasibility studies for power and desalination projects have been carried out since the 1950s by Empresa Nacional de Electricidad (ENDESA), and later jointly with the Comisión Chilena de Energía Nuclear. These studies have concluded that nuclear projects are not economically feasible in the near future.

### 1.6. Other factors

Chile has established a "social value" system. This is used in project evaluation, and the economic prices are adjusted to reflect the social costs of resource utilization. An example of the application of this system is the Bocamina coal-fired plant, which is justified because it helps keep the miners of the area employed. Nuclear projects benefit from a "social value" analysis when a certain proportion of the project is locally manufactured.

## 2. PARAMETERS USED IN THE ANALYSIS

### 2.1. Basic conditions

Table N-3-1 summarizes the conditions assumed in the various alternative expansion plans in the analysis of the integrated system in Chile during the period 1980-1989. From the figures given in the table it is seen that during the study period there is a total market of 1750 MW of thermal capacity additions assuming that the hydro expansion schedule is revised as described in Section 16 of the Country Report.

Initially in carrying out the analysis it was assumed that the schedule of hydro installations as described in Section 14.2 was fixed. The hydro additions in the study period represent projects being planned for the period by ENDESA. During the analysis the substitution of nuclear and oil-fired projects for hydro projects showed that ENDESA's proposed expansion schedule was not the most economical of the various alternative schedules considered.

TABLE N-3-1. SUMMARY OF CONDITIONS USED IN THE ANALYSIS

| | 1979 | 1989 |
|---|---|---|
| Population ($10^6$) | 11.86 | 14.80 |
| GNP/capita (US $/yr)[a] | 588 | 791 |
| Energy consumption (GWh/yr) | 10 572 | 22 080 |
| Total installed capacity (MW) | 2 546 | 5 016 |
| Installed capacity, critical period (MW)[b] | 2 546 | 5 016 |
| Thermal capacity (MW) | 934 | 2 684 |
| Peak demand, critical period (MW)[b] | 1 995 | 4 170 |
| Reserve margin (%) | 27.6 | 20.3 |
| Loss-of-load probability | 0.005 | 0.001 |

[a] 1964 US $.
[b] In the second period the hydro capacity is equal to the rated capacity.

### 2.2. Characteristics of system as of 1979

The existing and committed power expansion plans of Chile are only sufficient to meet peak load demand up to about 1976. For this reason, 600 MW of conventional plant capacity were assumed to be added to the system to meet the 1979 peak demand and provide a sufficient reserve margin for adequate loss-of-load probability. The resulting system consisted of 934 MW of thermal capacity plus 1612 MW of hydro capacity. The technical and economic characteristics of the existing (1975) system to which the additions were made are shown in Table N-3-2.

### 2.3. Characteristics of alternative generating units

The characteristics of alternative thermal generating units considered in the evaluation of possible system expansion configurations (i.e. schedules of additions) are shown in Table N-3-3. These characteristics were derived by methods described in Appendixes E, G, I and J.

TABLE N-3-2. CHARACTERISTICS OF GENERATING PLANTS IN "FIXED SYSTEM" (1975)

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LAG1 | 0 | 27 | 27 | 4100. | 4100. | 400.00 | 0.0 | 4 | 1 | 5.00 | 50 | 30 | 0. | 1.050 | 0.400 | 4100. |
| GUY1 | 4 | 1 | 1 | 2900. | 2900. | 200.00 | 0.0 | 2 | 1 | 5.00 | 40 | 1 | 0. | 0.870 | 0.400 | 2900. |
| HUA1 | 0 | 8 | 8 | 3300. | 3300. | 400.00 | 0.0 | 4 | 1 | 5.00 | 47 | 10 | 0. | 0.870 | 0.400 | 3300. |
| REN1 | 2 | 12 | 45 | 3480. | 2585. | 400.00 | 0.0 | 4 | 1 | 9.00 | 47 | 50 | 0. | 0.850 | 0.300 | 2824. |
| VEN1 | 1 | 28 | 115 | 2860. | 2102. | 360.00 | 0.0 | 4 | 1 | 9.00 | 47 | 100 | 0. | 0.810 | 0.300 | 2287. |
| BOC1 | 1 | 31 | 125 | 2820. | 2075. | 290.00 | 0.0 | 4 | 1 | 9.00 | 50 | 100 | 0. | 0.800 | 0.280 | 2260. |
| HYDO | 1 | 350 | 1312 | 0. | 0. | 0.0 | 0.0 | 5 | 1 | 0.0 | 0 | 0 | 5451. | 0.350 | 0.150 | 0. |

TABLE N-3-3. CHARACTERISTICS OF GENERATING PLANTS FOR SYSTEM EXPANSION ALTERNATIVES

| NAME | NO. OF SETS | MIN. LOAD MW | CAP-CITY MW | BASE LOAD HEAT RATE | AVGE INCR HT 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| N200 | 0 | 100 | 200 | 2648. | 2359. | 0.0 | 58.90 | 0 | 1 | 5.40 | 28 | 200 | 0. | 0.710 | 0.0 | 2503. |
| N300 | 0 | 150 | 300 | 2645. | 2360. | 0.0 | 57.90 | 0 | 1 | 6.50 | 28 | 300 | 0. | 0.520 | 0.0 | 2503. |
| N400 | 0 | 200 | 400 | 2643. | 2362. | 0.0 | 57.00 | 0 | 1 | 9.80 | 28 | 400 | 0. | 0.420 | 0.0 | 2502. |
| N600 | 0 | 300 | 600 | 2638. | 2365. | 0.0 | 55.10 | 0 | 1 | 12.00 | 28 | 600 | 0. | 0.320 | 0.0 | 2501. |
| N800 | 0 | 400 | 800 | 2632. | 2369. | 0.0 | 53.20 | 0 | 1 | 12.20 | 35 | 800 | 0. | 0.270 | 0.0 | 2500. |
| O150 | 0 | 75 | 150 | 2347. | 2193. | 10.00 | 180.00 | 1 | 1 | 5.30 | 21 | 150 | 0. | 0.450 | 0.0 | 2270. |
| O200 | 0 | 100 | 200 | 2280. | 2146. | 10.00 | 180.00 | 1 | 1 | 5.40 | 21 | 200 | 0. | 0.360 | 0.0 | 2213. |
| O300 | 0 | 150 | 300 | 2335. | 2183. | 10.00 | 180.00 | 1 | 1 | 6.50 | 28 | 300 | 0. | 0.280 | 0.0 | 2259. |
| O400 | 0 | 200 | 400 | 2324. | 2098. | 10.00 | 180.00 | 1 | 1 | 9.80 | 28 | 400 | 0. | 0.240 | 0.0 | 2211. |
| O600 | 0 | 300 | 600 | 2328. | 2172. | 10.00 | 180.00 | 1 | 1 | 12.00 | 28 | 600 | 0. | 0.190 | 0.0 | 2250. |
| O800 | 0 | 400 | 800 | 2334. | 2170. | 10.00 | 180.00 | 1 | 1 | 12.20 | 35 | 800 | 0. | 0.170 | 0.0 | 2252. |
| C150 | 0 | 75 | 150 | 2374. | 2206. | 290.00 | 0.0 | 4 | 1 | 7.50 | 21 | 150 | 0. | 0.480 | 0.0 | 2290. |
| C200 | 0 | 100 | 200 | 2306. | 2160. | 290.00 | 0.0 | 4 | 1 | 7.50 | 21 | 200 | 0. | 0.390 | 0.0 | 2233. |
| C300 | 0 | 150 | 300 | 2361. | 2199. | 290.00 | 0.0 | 4 | 1 | 8.70 | 28 | 300 | 0. | 0.300 | 0.0 | 2280. |
| C400 | 0 | 200 | 400 | 2351. | 2115. | 290.00 | 0.0 | 4 | 1 | 12.00 | 28 | 400 | 0. | 0.250 | 0.0 | 2233. |
| G200 | 0 | 100 | 200 | 2415. | 2273. | 200.00 | 0.0 | 1 | 1 | 5.40 | 21 | 200 | 0. | 0.360 | 0.0 | 2344. |
| G400 | 0 | 200 | 400 | 2461. | 2227. | 200.00 | 0.0 | 1 | 1 | 9.80 | 28 | 400 | 0. | 0.240 | 0.0 | 2344. |
| GT50 | 0 | 50 | 50 | 4000. | 4000. | 250.00 | 0.0 | 2 | 1 | 2.00 | 4 | 100 | 0. | 0.650 | 0.0 | 4000. |

## 3. RESULTS

### 3.1. Summary of cases considered

Starting with ENDESA's proposed system expansion schedule, 900 MW of capacity were added to the system during the 1976-1979 period to provide an adequate reserve margin at the start of the study. The assumed schedule of capacity additions during the study period was such that the annual loss-of-load probability was of the order of 0.005. In ENDESA's original schedule, only 500 MW of thermal capacity were added during the entire decade interspersed among the hydro additions. It is obvious that under such conditions nuclear power would play little or no role; therefore, either oil-fired plants or nuclear plants were substituted for the hydro stations not yet in the firm planning stage.

Seven computer runs were carried out to compare the economics of the predominately hydro expansion plan proposed by ENDESA and varying mixtures of hydro and thermal capacity additions. Case 1 consists of 1970 MW of hydro capacity additions and 500 MW of thermal capacity. In case 2, the 2 × 150 MW Maule Melado 1 hydro station was replaced by a 300 MW nuclear plant and in case 3 by a 300 MW oil-fired plant. In cases 4 and 5 both the 300 MW Maule Melado hydro station and the 350 MW Neltume station were replaced respectively with 300 MW nuclear or oil-fired plants plus 1 × 50 MW gas turbine. Finally, cases 4 and 5 were used as a basis for cases 6 and 7 in which the 120 MW Machicura hydro station and the 4 × 120 MW Porvenir hydro station were replaced either by 2 × 300 MW nuclear plants or 2 × 300 MW oil-fired plants. The results indicated that a program involving the commissioning of four 300 MW nuclear or oil-fired plants during the period 1984-1989 would be more economical than ENDESA's proposed program.

### 3.2. Reference expansion schedule

Table N-3-4 shows a near-optimum expansion schedule based on reference conditions. It is seen that the schedule calls for the introduction of one 300 MW nuclear plant in 1984 followed by three more in 1985, 1986 and 1989 respectively. It should be pointed out that the 4 × 30 MW Machicura hydro station is not included in the expansion schedule shown here, even though ENDESA has firm plans for adding this station to the system. The reason for not including Machicura is that the schedule shown provides a sufficient reserve margin and is a more economic expansion schedule. On this basis, the economics of adding the Machicura station should be re-evaluated by ENDESA.

### 3.3. Sensitivity studies

Sensitivity studies were carried out to find the near-optimum expansion schedule for each set of economic conditions. The resulting markets for nuclear plants are shown in Table N-3-5. It is seen that except for the situation where the price of imported oil would be subject to 0%/yr net escalation, the reference market for 4 × 300 MW nuclear plants remains unchanged. In the case of 0% oil price escalation, the substitution of 4 × 300 MW oil-fired plants for the hydro plants would be a more economical schedule of additions.

Replacing the two 200 MW oil-fired plants shown in Table N-3-4 with 200 MW nuclear plants was evaluated during preliminary computer runs and found to be uneconomic under all parameter variations being considered. On this basis, these two oil-fired stations (or they could be gas-fired) were kept in the schedule of additions for all cases valuated. It is likely that increasing the size of the 1988-1989 nuclear stations to 400 MW and dropping the 200 MW oil-fired station added in 1989 would result in lower present-worth values than shown for case 6; however, because of lack of time this case was not carried out.

### 3.4. Financing requirements

The domestic, foreign and total financing requirements associated with the construction of the thermal plants in the reference expansion schedule (see Table N-3-4) are summarized in Table N-3-6. It is seen that the total annual construction expenditures reach a peak of

US $126.7 \times 10^6$ in 1983. These costs include interest during construction which is also shown separately based on the assumption that interest would be paid currently with expenditures. The total cost of the 10-year construction program amounts to US $738.9 \times 10^6$ of which about US $548 \times 10^6$ is in foreign currency.

The nuclear fuel working capital expenditures are also shown separately since the financing method of these costs may differ from that for the plant costs. The total investment in the fuel cycle is seen to amount to US $40.8 \times 10^2$, all of which requires foreign capital. (Note: all of the above are 1973 costs with no allowance for escalation.)

TABLE N-3-4. REFERENCE SYSTEM EXPANSION SCHEDULE

| Year | Capacity (MW) | | | | | % Reserve[a] | Annual loss-of-load probability |
|---|---|---|---|---|---|---|---|
| | Nuclear | Conventional steam | Hydro | Gas turbines | Total | | |
| Total system 1975 | - | 334 | 1 312 | - | 1 646 | 15.1 | - |
| Additions 1976-79 | - | 600 | 300 | - | 900 | - | - |
| Total system 1979 | - | 934 | 1 612 | - | 2 546 | 27.6 | 0.005 |
| Additions 1980 | - | 200 | - | - | 200 | 27.7 | 0.0028 |
| 1981 | - | - | 260 | - | 260 | 29.6 | 0.0018 |
| 1982 | - | - | 260 | - | 260 | 30.6 | 0.0013 |
| 1983 | - | - | - | - | - | 20.9 | 0.0072 |
| 1984 | 300 | - | - | - | 300 | 23.0 | 0.0040 |
| 1985 | 300 | - | - | - | 300 | 23.5 | 0.0031 |
| 1986 | 300 | - | - | 50 | 350 | 24.7 | 0.0015 |
| 1987 | - | - | - | 2 × 50 | 100 | 19.9 | 0.0022 |
| 1988 | - | - | 200 | - | 200 | 16.7 | 0.0043 |
| 1989 | 300 | 200 | - | - | 500 | 20.2 | 0.0015 |
| Total additions 1980-1989 | 1 200 | 400 | 720 | 150 | 2 470 | 23.3[b] | 0.0030[b] |
| Total system 1989 | 1 200 | 1 334 | 2 332 | 150 | 5 016 | | |
| Additions 1990-2000 | 1 200 | 800 | 2 540 | 100 | 4 640 | 18.7[b] | 0.0018[b] |
| Total system 2000 | 2 400 | 2 134 | 4 872 | 250 | 9 656 | | |
| Percentage distribution of capacity 1989 | 23.9 | 26.6 | 46.5 | 3.0 | 100.0 | | |
| Percentage distribution of capacity 2000 | 24.9 | 22.1 | 50.5 | 2.5 | 100.0 | | |

[a] In critical quarter (2nd quarter).
[b] Average for 1980-89 period

TABLE N-3-5. SENSITIVITY OF NUCLEAR MARKET TO VARYING ECONOMIC PARAMETERS (MW)

| Year | Reference conditions | Conditions for maximum nuclear additions[a] | Conditions for minimum nuclear additions[b] |
|---|---|---|---|
| 1980 | - | - | no nuclear market |
| 1981 | - | - | |
| 1982 | - | - | |
| 1983 | - | - | |
| 1984 | 300 | 300 | |
| 1985 | 300 | 300 | |
| 1986 | 300 | 300 | |
| 1987 | - | - | |
| 1988 | - | - | |
| 1989 | 300 | 300 | |
| Total additions | 1 200 | 1 200 | 0 |

[a] 6% or 10% discount rate, 4% oil-price escalation rate, ORCOST-1 capital costs, shadow exchange rate = 1.3.
[b] 0% oil-price escalation rate.

TABLE N-3-6. CASH FLOW FOR THERMAL PLANTS IN REFERENCE EXPANSION SCHEDULE ($10^6 \times$ US $)

| Year | Construction costs | | | Interest during construction | | | Total construction costs | Nuclear fuel working capital | Grand total |
|---|---|---|---|---|---|---|---|---|---|
| | Dom. | For. | Total | Dom. | For. | Total | | | |
| 1977 | 1.1 | 2.0 | 3.1 | - | 0.1 | 0.1 | 3.2 | - | 3.2 |
| 1978 | 10.0 | 18.8 | 28.9 | 0.5 | 0.9 | 1.3 | 30.2 | - | 30.2 |
| 1979 | 7.6 | 15.5 | 23.1 | 1.2 | 2.2 | 3.4 | 26.5 | - | 26.5 |
| 1980 | 6.1 | 18.4 | 24.5 | 0.3 | 1.0 | 1.4 | 25.9 | - | 25.9 |
| 1981 | 17.3 | 51.8 | 69.1 | 1.3 | 3.8 | 5.1 | 74.2 | - | 74.2 |
| 1982 | 27.7 | 82.9 | 110.6 | 3.1 | 9.2 | 12.3 | 122.9 | 1.0 | 123.9 |
| 1983 | 26.5 | 79.3 | 105.8 | 5.2 | 15.7 | 20.9 | 126.7 | 10.2 | 136.9 |
| 1984 | 16.5 | 50.0 | 66.5 | 4.4 | 13.0 | 17.4 | 83.9 | 10.2 | 94.1 |
| 1985 | 8.7 | 32.5 | 41.2 | 2.8 | 8.5 | 11.3 | 52.5 | 9.2 | 61.7 |
| 1986 | 12.2 | 46.1 | 58.4 | 1.0 | 3.3 | 4.3 | 62.7 | - | 62.7 |
| 1987 | 21.6 | 53.5 | 75.1 | 2.3 | 6.4 | 8.7 | 83.8 | 1.0 | 84.8 |
| 1988 | 10.1 | 23.2 | 33.3 | 3.6 | 9.5 | 13.1 | 46.4 | 9.2 | 55.6 |
| Total | 165.5 | 474.0 | 639.6 | 25.6 | 73.7 | 99.3 | 738.9 | 40.8 | 779.7 |

### 3.5. Conclusions

(a) The estimated total market for generating units which will be commissioned during the 1980-1989 period is 2470 MW. Of this amount, the market for new thermal plants will probably be of the order of 1600 MW.

(b) An evaluation of the fuel resources available in Chile (coal, oil and natural gas) indicates that oil will be the fuel which will be most competitive with respect to nuclear power. Coal quality is poor and recovery costs too high to increase its rate of consumption beyond that planned prior to the study period for social reasons. The oil recovery costs are also higher at present than world market prices but world market prices were used as the economic value, the excess being considered a social cost.

(c) Although ENDESA's planned program involves predominantly hydro plants, the addition of either oil-fired or nuclear plants would be more economical, with the latter being preferred.

(d) Varying the economic parameters such as discount rates, oil price escalation rates and capital costs for generating plant did not alter the market, except in the case involving zero escalation of oil prices which resulted in no market for nuclear plants.

(e) The results described above are based entirely on economic factors and do not take into consideration other factors, such as the possible scarcity of the required investment capital, local manufacturing and construction capabilities or the desire for greater diversification of fuel supply, all of which might influence the choice of generation units by which the system will be expanded.

# 4. EGYPT

## 1. ECONOMIC AND SOCIAL FACTORS

### 1.1. Population growth

The total population in 1972 is estimated to have been 34.8 million and is projected to be 36.8 million in 1975 and 40.6 million in 1980. If the family planning program, which was started in 1965, continues to be successful, these projections will prove to be somewhat too high.

### 1.2. Economic development and goals

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. The economic development, as measured by the GNP, has been 5%/yr in real terms in spite of the disruptions due to war. For the purpose of the Survey, the GNP growth rate was assumed to be 6.1%/yr to 1990.

### 1.3. Social considerations

The population is concentrated in the Nile valley and around the oases, resulting in a population density of 980 per km$^2$, one of the highest in the world. As a result of the increasing industrialization and internal migration, the urban population is growing at a much faster rate than the total population, increasing from 33% of the total population in 1947 to 37% in 1960 and 40% in 1966. This places high requirements on expenditures for education, health and social services. Furthermore, 45% of the population is under 15 years of age and thus not within the employment age range.

## 1.4. Energy needs and resources

The total energy consumption in Egypt in 1960 was about 7650 thousand tons of coal equivalent (TEC), amounting to about 300 kg coal equivalent per person. The annual growth of energy usage since then has been very irregular, but has averaged 3% The energy usage reached 11 000 TEC in 1968.

Prior to 1960 there was essentially no hydro power in Egypt. During the 1960s, with the construction of the Aswan Dam, and later of the Aswan High Dam 7 km upstream from the Aswan Dam, hydro power became very important and by 1968 was supplying 25% of the total.

Additional hydro projects are limited to only two projects, the Qattara Project, wherein Mediterranean seawater would be channelled to the Qattara Depression some 100 km inland, generating power as it flows into the Depression; and the installation of hydro plants on three existing and seven potential barrages on the Nile. Each of the two projects has a potential capacity of about 600 MW.

There are no significant coal deposits in Egypt suitable for the production of power.

The petroleum industry has had an increasingly important role in Egypt's economy during the past decade. The output increased from 3.3 million tons in 1960 to 14.[illegible] million tons in 1971 and it is expected to increase to 45.0 million tons by 1982. During the next decade natural gas, which today is of no importance, is expected to become the principal fuel for fossil power stations and domestic use, reaching 5 million tons per year in production by 1982.

## 1.5. Interest in nuclear power

By about 1980 the capacity of the existing and planned stations will fall short of that required by some 600 to 800 MW. The Atomic Energy Establishment (AEE) and the General Electricity Corporation (GEC) of the Ministry of Electricity are studying the possibility of installing two 400 MW nuclear units to become operational about that time, and thereafter they foresee that an increasing proportion of power generation would be nuclear.

# 2. PARAMETERS USED IN THE ANALYSIS

## 2.1. Basic conditions

Table N-4-1 summarizes the conditions assumed in the analysis of various alternative expansion plans in Egypt during the period 1980-89. In carrying out the analysis it was assumed that no hydro additions would be made during the study period. Additions now

TABLE N-4-1. SUMMARY OF CONDITIONS USED 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.

planned or under construction will result in a system capacity in 1979 of 3459 MW (excluding emergency hydro). Note: the average capacity factor of the hydro unit of the Aswan High Dam is not high due both to water flow restrictions and to transmission system limitations. A part of this excess capacity could be used in an emergency and was considered as emergency hydro. The emergency hydro is not included in the system capacity figures given in this report, but is included in the loss-of-load calculations. The alternative expansion plan selected required 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. (During sensitivity studies, one condition at a time was varied to determine the effect on the year of introduction of nuclear power.)

## 2.2. Characteristics of system as of 1979

The existing and committed power expansion plans of Egypt are sufficient to meet peak load demand up to about 1979 with reserve margin for adequate loss-of-load probability. For the purpose of the computer analyses, these existing and committed units were grouped into so-called hypothetical units having common characteristics as shown in Table N-4-2. The technical and economic characteristics of each hypothetical plant shown in the table were computed from the characteristics of the actual plants comprising each unit.

## 2.3. Characteristics of alternative generating units

The characteristics of alternative thermal generating units considered in the evaluation of possible system expansion configurations (i.e. schedules of additions) are shown in Table N-4-3. These characteristics were derived by methods described in Appendixes E, G, I and J.

# 3. RESULTS

## 3.1. 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[1], (b) the unit size permitted, consistent with system stability (600 MW during the study period), (c) the maximum demand and annual growth of maximum demand, and (d) the relative costs of various size units.

## 3.2. Reference expansion schedule

The resulting alternative system expansion plan consisted of the addition of a series of 600 MW units on the schedule shown in Table N-4-4.

## 3.3. Sensitivity studies

Seven sensitivity studies were made, in each case holding all reference case conditions constant except the condition under study. The most likely market for nuclear plants in Egypt under these varying economic conditions is shown in Table N-4-5. It is seen that this 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 schedules of nuclear plant additions shown in the table covered all of the variations in economic parameters.

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[1] 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 N-4-2. CHARACTERISTICS OF GENERATING PLANTS IN "FIXED SYSTEM"

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CAN1 | 2 | 4 | 10 | 3994. | 2778. | 151.00 | 0.0 | 1 | 1 | 2.50 | 30 | 20 | 0. | 0.600 | 0.0 | 3264. |
| CAN2 | 1 | 8 | 20 | 3994. | 2778. | 151.00 | 0.0 | 1 | 1 | 3.00 | 30 | 40 | 0. | 0.600 | 0.0 | 3264. |
| CAN3 | 2 | 12 | 30 | 3994. | 2138. | 151.00 | 0.0 | 1 | 1 | 2.70 | 30 | 40 | 0. | 0.600 | 0.0 | 2880. |
| CAW1 | 3 | 35 | 87 | 2544. | 2548. | 151.00 | 0.0 | 1 | 1 | 2.00 | 30 | 100 | 0. | 0.300 | 0.0 | 2546. |
| CAS1 | 4 | 24 | 60 | 3379. | 2307. | 151.00 | 0.0 | 1 | 1 | 3.50 | 30 | 80 | 0. | 0.300 | 0.0 | 2736. |
| TAL1 | 3 | 12 | 30 | 3648. | 2368. | 151.00 | 0.0 | 1 | 1 | 4.00 | 30 | 40 | 0. | 0.500 | 0.0 | 2880. |
| TAL2 | 3 | 5 | 12 | 3648. | 2800. | 151.00 | 0.0 | 1 | 1 | 4.00 | 30 | 20 | 0. | 0.500 | 0.0 | 3153. |
| TEB1 | 3 | 6 | 15 | 4061. | 2732. | 151.00 | 0.0 | 1 | 1 | 2.00 | 30 | 20 | 0. | 0.900 | 0.0 | 3264. |
| DAH1 | 3 | 26 | 65 | 3091. | 2349. | 151.00 | 0.0 | 1 | 1 | 2.00 | 30 | 80 | 0. | 0.300 | 0.0 | 2646. |
| DAH2 | 2 | 6 | 15 | 3091. | 2559. | 151.00 | 0.0 | 1 | 1 | 5.00 | 30 | 20 | 0. | 0.300 | 0.0 | 2772. |
| SIO1 | 2 | 12 | 30 | 3360. | 2560. | 151.00 | 0.0 | 1 | 1 | 6.00 | 30 | 40 | 0. | 0.500 | 0.0 | 2880. |
| SIO2 | 2 | 11 | 27 | 3360. | 2539. | 151.00 | 0.0 | 1 | 1 | 3.00 | 30 | 40 | 0. | 0.500 | 0.0 | 2873. |
| SUZ1 | 4 | 10 | 25 | 3955. | 2403. | 151.00 | 0.0 | 1 | 1 | 4.00 | 30 | 40 | 0. | 0.600 | 0.0 | 3024. |
| MAX1 | 2 | 6 | 14 | 5030. | 2779. | 151.00 | 0.0 | 2 | 1 | 5.00 | 30 | 20 | 0. | 0.900 | 0.0 | 3744. |
| AST1 | 3 | 4 | 30 | 3504. | 2805. | 151.00 | 0.0 | 1 | 1 | 4.50 | 30 | 40 | 0. | 0.600 | 0.0 | 2898. |
| KAFD | 2 | 27 | 110 | 3171. | 2378. | 151.00 | 0.0 | 1 | 1 | 6.50 | 21 | 150 | 0. | 0.300 | 0.0 | 2573. |
| CAS2 | 2 | 37 | 150 | 3119. | 2341. | 151.00 | 0.0 | 1 | 1 | 5.30 | 21 | 150 | 0. | 0.280 | 0.0 | 2533. |
| ABUA | 2 | 37 | 150 | 3119. | 2341. | 151.00 | 0.0 | 1 | 1 | 5.30 | 21 | 150 | 0. | 0.280 | 0.0 | 2533. |
| HYDE | 1 | 345 | 1280 | 0. | 0. | 0.0 | 0.0 | 5 | 1 | 0.0 | 0 | 0 | 8912. | 0.600 | 0.0 | 0. |
| EHYD | 1 | 1165 | 1165 | 3119. | 2341. | 400.00 | 0.0 | -1 | 1 | 0.0 | 0 | 0 | 0. | 0.0 | 0.0 | 3119. |

TABLE N-4-3. CHARACTERISTICS OF GENERATING PLANTS FOR SYSTEM EXPANSION ALTERNATIVES

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| N300 | 0 | 150 | 300 | 2645. | 2360. | 0.0 | 57.90 | 0 | 1 | 6.50 | 28 | 300 | 0. | 0.0 | 0.0 | 2503. |
| N400 | 0 | 200 | 400 | 2643. | 2362. | 0.0 | 57.00 | 0 | 1 | 9.80 | 28 | 400 | 0. | 0.420 | 0.0 | 2502. |
| N600 | 0 | 300 | 600 | 2638. | 2365. | 0.0 | 55.10 | 0 | 1 | 12.00 | 28 | 600 | 0. | 0.320 | 0.0 | 2501. |
| N800 | 0 | 400 | 800 | 2632. | 2369. | 0.0 | 53.20 | 0 | 1 | 12.20 | 35 | 800 | 0. | 0.270 | 0.0 | 2500. |
| N1T0 | 0 | 500 | 1000 | 2627. | 2372. | 0.0 | 51.30 | 0 | 1 | 12.20 | 35 | 1000 | 0. | 0.230 | 0.0 | 2499. |
| G100 | 0 | 50 | 100 | 2526. | 2314. | 151.00 | 0.0 | 1 | 1 | 6.50 | 21 | 100 | 0. | 0.610 | 0.0 | 2420. |
| G150 | 0 | 75 | 150 | 2486. | 2322. | 151.00 | 0.0 | 1 | 1 | 5.30 | 21 | 150 | 0. | 0.450 | 0.0 | 2404. |
| G200 | 0 | 100 | 200 | 2415. | 2273. | 151.00 | 0.0 | 1 | 1 | 5.40 | 21 | 200 | 0. | 0.360 | 0.0 | 2344. |
| G300 | 0 | 150 | 300 | 2473. | 2313. | 151.00 | 0.0 | 1 | 1 | 6.50 | 28 | 300 | 0. | 0.280 | 0.0 | 2393. |
| G400 | 0 | 200 | 400 | 2461. | 2227. | 151.00 | 0.0 | 1 | 1 | 9.80 | 28 | 400 | 0. | 0.240 | 0.0 | 2344. |
| G600 | 0 | 300 | 600 | 2465. | 2301. | 151.00 | 0.0 | 1 | 1 | 12.00 | 28 | 600 | 0. | 0.190 | 0.0 | 2383. |
| G800 | 0 | 400 | 800 | 2471. | 2299. | 151.00 | 0.0 | 1 | 1 | 12.20 | 35 | 800 | 0. | 0.170 | 0.0 | 2385. |
| G1T0 | 0 | 500 | 1000 | 2482. | 2280. | 151.00 | 0.0 | 1 | 1 | 12.20 | 35 | 1000 | 0. | 0.160 | 0.0 | 2381. |
| GT50 | 0 | 50 | 50 | 4000. | 4000. | 151.00 | 0.0 | 2 | 1 | 2.00 | 4 | 75 | 0. | 0.750 | 0.0 | 4000. |

TABLE N-4-4. POTENTIAL MARKET FOR NUCLEAR POWER PLANTS IN EGYPT (PLANTS COMMISSIONED 1980-89) (MW)

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 | 13.2 | |
| 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.

TABLE N-4-5. 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 |

## 3.4. Financing requirements

The domestic, foreign and total financing requirements associated with the construction of the thermal plants in the reference expansion schedule (see Table N-4-4) are summarized in Table N-4-6. It is seen that the total annual expenditures reach a peak of US $\$255.5 \times 10^6$ in 1985. These costs include interest during construction based on the assumption that interest would be paid currently with expenditures. The total cost of the 10-year expansion program amounts to US $\$1510 \times 10^6$.

The nuclear fuel cycle working capital costs (i.e. investment in first core etc.) are also shown in Table N-4-6 as a separate item because financing arrangements for such costs may differ from those for the plant construction program. The total annual investment costs, however, are shown for completeness.

The given costs do not include annual operating and maintenance costs and variable fuel costs.

## 3.5. Conclusions

(a) The estimated total market for generating units that will be commissioned during the 1980-89 period is 4800 MW, all of which will be thermal plants (except if substituted by the Nile barrage hydro units that the study assumed would not be built during this period).

(b) Of these 4800 MW of thermal plants, the 600 MW required in 1980 would be more economical as a fossil-fuelled unit and the 4200 MW required thereafter would be more economical as nuclear units under reference conditions.

(c) Variations in parameters within the ranges studied could expand the nuclear market to 4800 MW or reduce it to 2400 MW.

(d) In regard to fossil plants, gas was selected as the fuel for future plants as a matter of policy. However, gas was valued on a parity with oil based on heating value and the study results would not be changed appreciably had oil been used instead of gas.

(e) The total financial requirements associated with the reference thermal expansion schedule amount to US $1627.2 million of which US $1250.1 million may be foreign currency financing.

TABLE N-4-6. FINANCING REQUIREMENTS FOR REFERENCE THERMAL PLANTS EXPANSION SCHEDULE ($10^6$ US $)

| Year | Plant investment | | | Nuclear fuel working capital [a] | Total |
|---|---|---|---|---|---|
| | Domestic | Foreign | Subtotal | | |
| 1976 | 0.2 | 0.7 | 0.9 | | 0.9 |
| 1977 | 4.7 | 14.3 | 19.0 | | 19.0 |
| 1978 | 14.0 | 42.0 | 56.0 | | 56.0 |
| 1979 | 16.3 | 49.1 | 65.4 | | 65.4 |
| 1980 | 18.9 | 56.7 | 75.6 | | 75.6 |
| 1981 | 28.9 | 86.7 | 115.6 | 1.7 | 117.3 |
| 1982 | 34.3 | 103.2 | 137.5 | 15.0 | 152.5 |
| 1983 | 47.5 | 142.5 | 190.0 | 1.7 | 191.7 |
| 1984 | 59.8 | 179.5 | 239.3 | 16.7 | 256.0 |
| 1985 | 63.8 | 191.7 | 255.5 | 16.7 | 272.2 |
| 1986 | 55.0 | 165.1 | 220.1 | 18.4 | 238.5 |
| 1987 | 28.0 | 84.3 | 112.3 | 31.8 | 144.1 |
| 1988 | 5.7 | 17.3 | 23.0 | 15.0 | 38.0 |
| Total | 377.1 | 1 133.1 | 1 510.2 | 117.0 | 1 627.2 |

[a] Domestic expenditures for the nuclear fuel working capital were assumed to amount to 0% of the total.

# 5. GREECE

## 1. ECONOMIC AND SOCIAL FACTORS

### 1.1. Population growth

In 1971 Greece had a population of about 9 million persons. The present annual growth rate is about 0.6%/yr and total population is estimated to be about 10 million by 1990. About 65% of the population live in urban areas and 35% live in cities. There is a shortage of skilled labour. However, educational and social planning are improving this situation.

### 1.2. Economic development and goals

Rapid economic growth since the mid-1950s has been accompanied by significant changes in the structure of the economy. The economic policy has promoted private enterprises with the State providing social services and basic economic and institutional infrastructure. It is anticipated that the GNP will be increasing up to 1985 at an average annual rate of about 6%. In addition to the vigorous growth of the economy, the most important development is its structural change. The share of industry in the gross domestic product has been increasing at the expense of agriculture. This trend is anticipated to continue up to 1985.

### 1.3. Energy needs and resources

By 1970, total annual energy consumption reached 12 million TEC. Total energy consumption increased at an average annual rate of 10%. The greatest rate of increase was

in hydro generation at 18.8%/yr. The consumption of oil and lignite increased at an average rate of 9.5%. The greatest increase in energy consumption was registered in the industrial sector which grew at an average annual rate of 14.5%. This was followed by domestic and commercial consumption growth at 10.1% and land transportation at 9.3%. Greece has identified hydro capacity, which could be developed by the year 2000, of over 8000 GWh/yr, in addition to the over 6000 GWh/yr which is presently planned up to 1983. There are no known coal deposits in Greece. There are two reasonably large lignite deposits amounting to over $1300 \times 10^6$ t which will be used principally for power generation. A large peat deposit of about $2000 \times 10^6$ $m^3$ will be tested to determine if it is economically usable for power generation. There are no presently known usable reserves of crude oil, natural gas, uranium or thorium.

### 1.4. Interest in nuclear power

The Public Power Corporation (PPC) and the Government had made plans in 1968 to integrate a nuclear unit into the electric supply system. This plan, however, was not implemented. Subsequently, PPC decided, with the concurrence of the Government, to utilize all local energy resources before embarking on a nuclear power program.

A study of the introduction of nuclear power into the integrated Greek power supply system was prepared during 1971 jointly by staff members of PPC and the Greek Atomic Energy Commission (GAEC). It concluded in a preliminary outline of the size and timing of nuclear units to be put in operation in Greece that the first plant should be a 600 MW unit to be commissioned early in the 1980s. This study and outline have since been used as a starting point for the planning for nuclear power and the outline has been published in the Greek and foreign press.

PPC has, as of 1 January 1971, established a Nuclear Power Stations Service within its organization. It has also called for bids form consulting firms to assist PPC on all aspects of issuing and evaluating bids for nuclear power plants.

## 2. PARAMETERS USED IN THE ANALYSIS

### 2.1. Basic conditions

Table N-5-1 summarizes the conditions used in the analyses of various alternative expansion plans for the electric generation system in Greece during the period 1980 to 1989. Two energy forecasts were considered. One forecast was developed by the Market Survey using the method described in Appendix F. The other forecast represents an extrapolation of

TABLE N-5-1. SUMMARY OF CONDITIONS USED IN THE ANALYSIS

| | 1979 | 1989 |
|---|---|---|
| Population ($10^6$) | 9.2 | 9.8 |
| GNP/capita (US $/yr) [a] | 1315 | 2110 |
| Energy consumption (GWh/yr) | 23660 | 49170 |
| Peak demand (MW) | 4175 | 8676 |
| Total installed capacity (MW) | 5621 | 12390 |
| Installed capacity, critical period (MW) | 5621 [b] | 11770 [c] |
| Total thermal capacity (MW) | 4061 | 8265 |
| Average reserve margins (%) | 37.5 | |
| Average loss-of-load probability | 0.0042 | |

[a] 1964 US $.
[b] Fourth quarter (hydro capacity = total hydro capacity).
[c] Third quarter (hydro capacity = 85% of total hydro capacity).

the 1970-1990 forecast presented to the Market Survey team by PPC. Since the two forecasts were less than 1% apart, the PPC energy data were assumed and used as a basis for determining the system capacity demand. From the figures given in the table, it is seen that during the study period a total of 4200 MW of thermal capacity is added.

The selected hydro schedule is given in Table N-5-4. These additions represent appropriate selections from the hydro projects being considered for construction by PPC.

## 2.2. Characteristics of system as of 1979

The existing and committed power expansion plans of PPC are only sufficient to meet peak load demand up to about 1976. For this reason about 900 MW of conventional plant capacity additions were assumed to be made to the system to meet the 1979 peak demand and provide a sufficient reserve margin for adequate loss-of-load probability. For the purpose of the computer analyses, the existing and committed units were grouped into so-called hypothetical units having common characteristics as shown in Table N-5-2. The technical and economic characteristics of each hypothetical plant shown in the table were computed from the characteristics of the actual plants comprising each unit.

## 2.3. Characteristics of alternative generating units

The characteristics of alternative thermal generating units considered in the evaluation of possible system expansion configurations (i.e. schedules of additions) are shown in Table N-5-3. These characteristics were derived by methods described in Appendixes E, G, I and J.

# 3. RESULTS

## 3.1. Summary of cases considered

A number of trial computer runs were made to establish the sizes of capacity additions required to give the desired loss-of-load probability each year of the study period. These runs also served to indicate which of the various fossil fuels resulted in minimum costs with the reference economic parameters. The results showed that the addition of 400 MW units in the 1982-84 period and 600 MW units starting in 1985 would give near-optimum programs and that lignite would be the most economic fossil fuel.

Since lignite reserves are indicated only to meet the demand of about 2800 MW of lignite-fired power plants for 30 years, no lignite-fired plant additions beyond a total of 2800 MW were considered.

Having established the desired schedule of capacity additions, six additional computer runs were carried out to evaluate the competition between nuclear plants and lignite plants.

## 3.2. Reference expansion schedules

Table N-5-4 shows the near-optimum expansion schedules determined when using the reference case parameters. It is seen that the system calls for the introduction of 400 MW nuclear plants from 1982 to 1984 and 600 MW nuclear plants from 1985 onwards. Table N-5-4 also shows that the total market for nuclear plants over the study period will be 4200 MW.

## 3.3. Sensitivity studies

The analysis carried out to evaluate the sensitivity of the reference case to the various key parameters, such as fuel escalation, discount rate and lower nuclear capital cost, are summarized in Table N-5-5. It is seen that the market varies from 3000 MW to 4500 MW depending on whether the assumed economic conditions favoured nuclear or conventional plants. The ranges in the nuclear markets shown in the table cover all of the other sensitivity studies carried out. These included changing one of the reference parameters to 6% discount rate, 10% discount rate, 4% oil price escalation or a shadow exchange rate of 1.3. Penalizing foreign capital expenditures resulted in the same nuclear market as for reference conditions, whereas 2% escalation on nuclear fuel prices (i.e. the same escalation as for oil prices) resulted in the same nuclear market as for 0% oil price escalation.

TABLE N-5-2. CHARACTERISTICS OF GENERATING PLANTS IN "FIXED SYSTEM"

| 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 | L C T N | FRCD OUT-AGE RATE | DAYS SCHL MAIN | MAIN CLAS | ENRGY GWH | O&M (FIX) | O&M (VAR) | FULL LOAD HEAT RATE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PTO | 1 | 18 | 70 | 3340. | 2470. | 125.00 | 0.0 | 3 | 1 | 8.60 | 30 | 75 | 0. | 0.390 | 0.0 | 2694. |
| PTL | 2 | 32 | 125 | 3300. | 2500. | 125.00 | 0.0 | 3 | 1 | 7.50 | 30 | 100 | 0. | 0.390 | 0.0 | 2705. |
| PTM | 4 | 75 | 300 | 3120. | 2340. | 125.00 | 0.0 | 3 | 1 | 8.70 | 30 | 300 | 0. | 0.390 | 0.0 | 2535. |
| MEG | 2 | 31 | 125 | 3300. | 2500. | 187.00 | 0.0 | 3 | 1 | 7.50 | 30 | 100 | 0. | 0.390 | 0.0 | 2698. |
| ALI | 1 | 38 | 150 | 3270. | 2450. | 0.0 | 185.00 | 1 | 1 | 7.50 | 30 | 150 | 0. | 0.390 | 0.0 | 2658. |
| ALV | 2 | 40 | 40 | 3025. | 3025. | 160.00 | 0.0 | 3 | 1 | 8.60 | 30 | 75 | 0. | 0.420 | 0.0 | 3025. |
| ALF | 2 | 38 | 150 | 2970. | 2230. | 0.0 | 185.00 | 1 | 1 | 5.30 | 30 | 150 | 0. | 0.440 | 0.0 | 2417. |
| STG | 1 | 50 | 200 | 2920. | 2195. | 0.0 | 185.00 | 1 | 1 | 5.40 | 30 | 200 | 0. | 0.440 | 0.0 | 2376. |
| STE | 1 | 40 | 160 | 2970. | 2230. | 0.0 | 185.00 | 1 | 1 | 5.30 | 30 | 150 | 0. | 0.440 | 0.0 | 2415. |
| STR | 2 | 15 | 60 | 3020. | 2265. | 0.0 | 185.00 | 1 | 1 | 6.50 | 30 | 75 | 0. | 0.440 | 0.0 | 2454. |
| STS | 1 | 30 | 30 | 2640. | 2640. | 0.0 | 185.00 | 1 | 1 | 6.50 | 30 | 75 | 0. | 0.440 | 0.0 | 2640. |
| LAR | 1 | 75 | 300 | 2840. | 2130. | 0.0 | 185.00 | 1 | 1 | 6.50 | 30 | 300 | 0. | 0.440 | 0.0 | 2308. |
| GAT | 2 | 13 | 13 | 3450. | 3450. | 394.00 | 0.0 | 2 | 1 | 2.00 | 15 | 75 | 0. | 0.860 | 0.0 | 3450. |
| HYD | 1 | 300 | 1400 | 0. | 0. | 0.0 | 0.0 | 5 | 1 | 0.0 | 0 | 0 | 4522. | 0.130 | 0.0 | 0. |

TABLE N-5-3. CHARACTERISTICS OF GENERATING PLANTS FOR SYSTEM EXPANSION ALTERNATIVES

| 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 | L C T N | FRCD OUT-AGE RATE | DAYS SCHL MAIN | MAIN CLAS | ENRGY GWH | O&M (FIX) | O&M (VAR) | FULL LOAD HEAT RATE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ALIR | 0 | 70 | 140 | 2487. | 2249. | 0.0 | 185.00 | 1 | 1 | 5.40 | 30 | 150 | 0. | 0.440 | 0.0 | 2368. |
| PHIL | 0 | 65 | 125 | 2810. | 2499. | 200.00 | 0.0 | 3 | 1 | 8.00 | 30 | 100 | 0. | 0.390 | 0.0 | 2661. |
| KARD | 0 | 150 | 300 | 2702. | 2446. | 125.00 | 0.0 | 3 | 1 | 8.70 | 30 | 300 | 0. | 0.390 | 0.0 | 2574. |
| N800 | 0 | 400 | 800 | 2632. | 2369. | 0.0 | 53.20 | 0 | 1 | 12.20 | 35 | 800 | 0. | 0.270 | 0.0 | 2500. |
| N600 | 0 | 300 | 600 | 2638. | 2365. | 0.0 | 55.10 | 0 | 1 | 12.00 | 28 | 600 | 0. | 0.320 | 0.0 | 2501. |
| N400 | 0 | 200 | 400 | 2643. | 2362. | 0.0 | 57.00 | 0 | 1 | 9.80 | 28 | 400 | 0. | 0.420 | 0.0 | 2502. |
| N300 | 0 | 150 | 300 | 2645. | 2360. | 0.0 | 57.90 | 0 | 1 | 6.50 | 28 | 300 | 0. | 0.520 | 0.0 | 2503. |
| O800 | 0 | 400 | 800 | 2334. | 2170. | 0.0 | 185.00 | 1 | 1 | 12.20 | 35 | 800 | 0. | 0.440 | 0.0 | 2252. |
| O600 | 0 | 300 | 600 | 2328. | 2172. | 0.0 | 185.00 | 1 | 1 | 12.00 | 28 | 600 | 0. | 0.440 | 0.0 | 2250. |
| O500 | 0 | 250 | 500 | 2404. | 2203. | 0.0 | 185.00 | 1 | 1 | 11.00 | 30 | 600 | 0. | 0.440 | 0.0 | 2304. |
| O400 | 0 | 200 | 400 | 2324. | 2098. | 0.0 | 185.00 | 1 | 1 | 9.80 | 28 | 400 | 0. | 0.440 | 0.0 | 2211. |
| O300 | 0 | 150 | 300 | 2335. | 2183. | 0.0 | 185.00 | 1 | 1 | 6.50 | 28 | 300 | 0. | 0.440 | 0.0 | 2259. |

TABLE N-5-4. REFERENCE SYSTEM EXPANSION SCHEDULES[a]

| Year | Capacity (MW) | | | | | | % Reserve[b] | Annual loss-of-load probability |
|---|---|---|---|---|---|---|---|---|
| | Retirements | Nuclear | Conventional steam | Hydro | Gas turbines | Total | | |
| Total system 1977 | 0 | 0 | 3 080 | 1 400 | 26 | 4 506 | | |
| Additions 1977-1979 | 0 | 0 | 955 | 160 | 0 | 1 115 | | |
| Total system 1979 | | 0 | 4 035 | 1 560 | 26 | 5 621 | 35 | 0.0025 |
| 1980 | | 0 | 0 | 170 | | 170 | 29 | 0.0053 |
| 1981 | | 0 | 300 | 360 | | 660 | 34 | 0.0034 |
| 1982 | | 400 | 0 | 0 | | 400 | 30 | 0.0045 |
| 1983 | -80 | 400 | 0 | 300 | | 620 | 35 | 0.0055 |
| 1984 | | 400 | 0 | 307 | | 707 | 36 | 0.0047 |
| 1985 | | 600 | 0 | 288 | | 888 | 40 | 0.0035 |
| 1986 | -126<br>-26 | 600 | 0 | 400 | | 854 | 42 | 0.0044 |
| 1987 | | 600 | 0 | 170 | | 770 | 42 | 0.0032 |
| 1988 | | 600 | 0 | 210 | | 810 | 43 | 0.0034 |
| 1989 | -70 | 600 | 0 | 360 | | 890 | 44 | 0.0039 |
| Total additions 1980-89 | -296[c] | 4 200 | 300 | 2 565 | 0 | 6 769[c] | Average 37.5 | Average 0.0042 |
| Total system 1989 | - | 4 200 | 4 335<br>-270<br>4 065[c] | 4 125 | 26<br>-26<br>0[c] | 12 390[c] | - | - |
| Additions 1990-2000 | - | 5 200 | 3 400 | 4 480 | 0 | 13 080 | - | - |
| Total system 2000 | - | 9 400 | 7 465 | 8 605 | 0 | 25 470 | - | - |

[a] 8% discount rate, 0% escalation on capital and nuclear fuel costs, 2% escalation on oil price, ORCOST-3 capital costs.
[b] Critical quarter.
[c] 270 MW thermal units and 26 MW of gas turbines netted out during period.

## 3.4. Financing requirements

The domestic, foreign and total financing requirements associated with the construction of the thermal plants in the reference expansion schedule (see Table N-5-4) are summarized in Table N-5-6. These costs include interest during construction based on the assumption that interest would be paid currently with expenditures. It is seen that total annual expenditures for plant investment reach a peak of US $\$209 \times 10^6$ in 1984. The total plant investment costs of the 10-year expansion program amount to US $\$1642 \times 10^6$.

TABLE N-5-5. NUCLEAR POWER MARKET WITH VARYING ECONOMIC CONDITIONS (MW)

| Year | Reference case | Sensitivity studies | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | 6% discount rate | 10% discount rate | 0% fuel escala-tion rate | 4% fuel escala-tion rate | ORCOST-1 | Shadow exchange rate 1.3 | 2% nuclear fuel escalation rate |
| 1981 | | | | | | 300 | | |
| 1982 | 400 | 400 | 400 | | 400 | 400 | 400 | |
| 1983 | 400 | 400 | 400 | | 400 | 400 | 400 | |
| 1984 | 400 | 400 | 400 | | 400 | 400 | 400 | |
| 1985 | 600 | 600 | 600 | 600 | 600 | 600 | 600 | 600 |
| 1986 | 600 | 600 | 600 | 600 | 600 | 600 | 600 | 600 |
| 1987 | 300 | 600 | 600 | 600 | 600 | 600 | 600 | 600 |
| 1988 | 600 | 600 | 600 | 600 | 600 | 600 | 600 | 600 |
| 1989 | 600 | 600 | 600 | 600 | 600 | 600 | 600 | 600 |
| Total additions 1980-89 | 4200 | 4200 | 4200 | 3000 | 4200 | 4500 | 4200 | 3000 |
| Total system 1989 | 4200 | 4200 | 4200 | 3000 | 4200 | 4500 | 4200 | 3000 |
| Nuclear % of total system capacity 1989 | 34 | 34 | 34 | 24 | 34 | 26 | 34 | 24 |

The nuclear fuel cycle working capital costs (i.e. investment in first core etc.) are not included in these investment costs. Table N-5-6 shows these costs separately, amounting to US $ 121.6 $\times 10^6$, because financing arrangements for such costs may differ from those for the plant construction programs. The total annual investment costs of US $1763.9 $\times 10^6$, however, are shown for completeness.

The given costs do not include annual operating and maintenance costs or variable fuel costs.

## 3.5. Conclusions

(a) The estimated total market for generating units which will be commissioned during the 1980 to 1989 period is approximately 7000 MW. Because of the abundance of economically exploitable hydroelectric power, however, the market for thermal plants will probably be in the approximate range of only 4500 MW

(b) An evaluation of the conventional fuels available in Greece indicates that lignite is the fuel which will be most competitive with respect to nuclear power. The reasons for this conclusion are as follows:

There are no known coal deposits although there are reasonably large lignite deposits.

Only occurrences of natural gas and oil have been found.

The present price of fuel oil at the refineries is fixed by the Government. Early 1972 prices were set at 781-2Dr./t compared to the f.o.b. Persian Gulf posted heavy crude oil prices of about 690 Dr./t. Even if the price of fuel oil drops to a level equal to that prevailing on the world market, such a level will probably be subject to an annual escalation rate of 2% to 4%. Under such conditions, lignite would be the preferred fuel.

TABLE N-5-6. PLANT INVESTMENT AND NUCLEAR FUEL FINANCING REQUIREMENTS FOR REFERENCE THERMAL PLANT EXPANSION SCHEDULES ($10^6$ US $)[a]

| Year | Plant investment | | | Nuclear fuel cycle investment[b] | Total |
|---|---|---|---|---|---|
| | Domestic | Foreign | Subtotal | | |
| 1975 | | | | | |
| 1976 | 0.2 | 0.5 | 0.7 | | 0.7 |
| 1977 | 2.1 | 4.6 | 6.7 | | 6.7 |
| 1978 | 16.8 | 33.5 | 50.3 | | 50.3 |
| 1979 | 43.6 | 87.3 | 130.9 | | 130.9 |
| 1980 | 55.6 | 121.4 | 177.0 | 1.2 | 178.2 |
| 1981 | 55.4 | 129.5 | 184.9 | 12.7 | 197.6 |
| 1982 | 59.4 | 138.8 | 198.2 | 12.7 | 210.9 |
| 1983 | 62.4 | 145.8 | 208.2 | 13.2 | 221.4 |
| 1984 | 62.7 | 146.6 | 209.3 | 16.7 | 226.0 |
| 1985 | 59.6 | 139.2 | 198.8 | 16.7 | 214.2 |
| 1986 | 47.8 | 111.6 | 159.4 | 16.7 | 165.4 |
| 1987 | 27.8 | 65.0 | 92.8 | 16.7 | 109.5 |
| 1988 | 7.1 | 16.7 | 23.8 | 15.0 | 38.8 |
| Total | 501.1 | 1 141.2 | 1 642.3 | 121.6 | 1 763.9 |

[a] In terms of 1 January 1973 US dollars.
[b] Domestic expenditures for the nuclear fuel cycle working capital were assumed to be 0% of the total.

(c) An evaluation of the competitiveness of nuclear versus lignite plants indicates that under the reference conditions (8% discount rate, 0% escalation on fuel prices) both types of plants give essentially the same present worth at a rated capacity of 400 MW; however, the nuclear plants are more competitive (give lower present worth) at capacities of 600 MW and above.

(d) The computer analysis indicated that under reference conditions the installation of 4200 MW nuclear capacity during the study period would be the most economical solution. This would mean that in 1989 34% of the total installed capacity would be nuclear.

## 6. JAMAICA

### 1 ECONOMIC AND SOCIAL FACTORS

#### 1.1. Population growth

The population of Jamaica in 1970 was 1.891 million. The growth rate for 1960 to 1970 was about 1.53%/yr. At this growth rate the population is estimated to be about 2.56 million by 1990. The labour force in 1970 was 750 000 or 40% of the population.

#### 1.2. Economic development and goals

The economy is presently based on agriculture and mining. The dominant agricultural crop is sugar, with molasses and rum as important by-products. The principal mineral

is bauxite and the bauxite-alumina industry contributes about 16% to the GDP. Tourism is also a fast growing contributor both to GNP and to foreign exchange.

The Jamaican Government is pursuing the establishment of an oil refinery and transshipment complex and an aluminium smelter. These processing industries will compete on the international rather than the domestic market.

### 1.3. Social considerations

The planning authorities in Jamaica are aware of pollution problems. The importance of the tourist trade makes it imperative that at least the north (tourist) coast be protected. Present Government policy limits power plant construction to the south coast. Nuclear plants would presumably also be built on this coast. Future restrictions as the population becomes more aware of pollution problems will probably be more stringent.

### 1.4. Energy needs and resources

Total energy consumption in Jamaica is not available since domestic energy is obtained from vegetable materials such as wood and bagasse. Electrical energy consumption has grown from about 250 in 1960 to almost 850 GWh in 1970 achieving an annual growth rate of 12.5%. The Jamaica Public Service Company (JPS) felt it would maintain the growth rate and achieve a generation level of 13 740 GWh/yr by 1990. The Market Survey load forecast, however, calculated a forecast which reached about 8 600 GWh/yr by 1990. The study analysed both forecasts.

Jamaica has very small hydro resources and no known resources of gas, coal or oil.

### 1.5. Interest in nuclear power

Since the country has to rely on imported fossil fuel for generation of electricity it is very susceptible to oil price variation. It is, therefore, interested in diversifying its energy sources. Furthermore, the industrial plans for aluminium smelting require a source of energy at a known and stable cost.

### 1.6. Other factors

The high Jamaican forecast for energy consumption is based on an ambitious industrialization program in capital intensive industry, which requires high foreign investment. One of the main products of this program, aluminium, must compete on a world market which is presently facing a slump. It would not be surprising if the industrial program is not fully realized.

## 2. PARAMETERS USED IN THE ANALYSIS

### 2.1. Basic conditions

Table N-6-1 summarizes the conditions assumed in the analyses of various alternative expansion plans for the associated system in Jamaica during the period 1980 to 1989. As shown in this table, two load forecasts were considered. The low load forecast was developed for the Market Survey, using the method described in Appendix F. The high load forecast was based on extending the projected JPS forecast for total energy requirements to the year 2000. The system was assumed to be gradually interconnected by 1980 (i.e. private generation connected to the JPS system). From the figures given, it is seen that there is an addition of 1000 MW of thermal capacity with the low forecast and an addition of 1550 MW with the high forecast.

In the case of Jamaica no additional hydro resources exist and pumped storage capacity has not been considered as yet by the utility. Although pumped storage may, in the future, have a place in the Jamaica system in conjunction with water supply reservoir schemes, it was felt that such schemes would not be brought into service in the study period.

TABLE N-6-1. SUMMARY OF CONDITIONS USED IN THE ANALYSIS

| | Low forecast | | High forecast | |
|---|---|---|---|---|
| | 1979 | 1989 | 1979 | 1989 |
| Population ($10^6$) | 2.167 | 2.522 | 2.167 | 2.522 |
| GNP/capita (US $/year) [a] | 701 | 1 139 | 701 | 1 139 |
| Energy consumption (GWh/yr) | 3 700 | 8 050 | 4 380 | 12 400 |
| Peak demand (MW) | 595 | 1 315 | 715 | 2 020 |
| Total installed capacity (MW) | 802 | 1 802 | 952 | 2 502 |
| Installed thermal capacity (MW) [b] | 787 | 1 787 | 937 | 2 487 |
| Average reserve margins | 37% | | 23% | |
| Average loss-of-load probability | 0.0017 | | 0.0075 | |

[a] 1964 US $.
[b] The critical period was the fourth. The hydro was not seasonally adjusted since it makes up a very small proportion of total capacity.

## 2.2. Characteristics of system as of 1979

The existing and committed power expansion plans of JPS are only sufficient to meet peak load demand up to about 1978. For this reason, 150 MW of conventional plant capacity additions were assumed to be made to the system to meet the 1979 peak demand and provide a sufficient reserve margin for adequate loss-of-load probability. The characteristics of the existing and committed units are shown in Table N-6-2, computed from the characteristics of the actual plants comprising each unit.

## 2.3. Characteristics of alternative generating units

The characteristics of alternative thermal generating units considered in the evaluation of possible system expansion configurations (i.e. schedules of additions) are shown in Table N-6-3. These characteristics were derived by methods described in Appendixes E, G, I and J.

# 3. RESULTS

## 3.1. Summary of cases considered

Starting with the low load forecast, ten trial computer runs were made to establish the sizes of capacity additions required to give the desired loss-of-load probability each year of the study period. Since Jamaica has no indigenous fuel resources, the initial runs were done using oil-fired fossil stations. Subsequently, runs replacing some of the oil-fired stations with nuclear units were carried out to determine the competitiveness of these units. Since in the reference case imported oil was escalated at a 2% differential rate, nuclear plants gained a progressively more favourable position throughout the study period. Thus, it was found that under reference conditions 100 MW and 200 MW plants were not competitive until after 1989. Larger plants were not considered because of restrictions, although they would have been competitive.

A similar series of seven computer runs was carried out for the high load forecast with essentially the same results. In the high forecast a nuclear plant of 300 MW was in fact permissible by the system analysis and was used.

TABLE N-6-2. CHARACTERISTICS OF GENERATING PLANTS IN "FIXED SYSTEM"

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| OLD1 | 1 | 8 | 30 | 3620. | 2910. | 0.0 | 177.00 | 1 | 1 | 5.00 | 40 | 30 | 0. | 0.340 | 0.200 | 3099. |
| OLD2 | 1 | 15 | 60 | 3460. | 2710. | 0.0 | 177.00 | 1 | 1 | 5.00 | 40 | 64 | 0. | 0.340 | 0.200 | 2898. |
| OLD3 | 1 | 17 | 68 | 3400. | 2629. | 0.0 | 177.00 | 1 | 1 | 5.00 | 40 | 64 | 0. | 0.340 | 0.200 | 2822. |
| HUN1 | 2 | 2 | 10 | 6700. | 5885. | 0.0 | 177.00 | 1 | 1 | 7.00 | 45 | 15 | 0. | 0.900 | 0.400 | 6048. |
| HUN3 | 2 | 4 | 15 | 4350. | 3624. | 0.0 | 177.00 | 1 | 1 | 7.00 | 45 | 15 | 0. | 0.900 | 0.400 | 3818. |
| HUN5 | 1 | 5 | 20 | 4030. | 3293. | 0.0 | 177.00 | 1 | 1 | 7.00 | 45 | 15 | 0. | 0.900 | 0.400 | 3477. |
| GAS1 | 2 | 14 | 14 | 4284. | 4284. | 43.00 | 177.00 | 2 | 1 | 1.00 | 30 | 15 | 0. | 1.200 | 0.600 | 4284. |
| SMAL | 22 | 1 | 1 | 2900. | 2900. | 43.00 | 177.00 | 2 | 1 | 3.00 | 50 | 1 | 0. | 1.500 | 0.800 | 2900. |
| GAS2 | 1 | 20 | 20 | 4284. | 4284. | 43.00 | 177.00 | 2 | 1 | 1.00 | 30 | 15 | 0. | 1.100 | 0.550 | 4284. |
| OLD4 | 1 | 17 | 68 | 3400. | 2629. | 0.0 | 177.00 | 1 | 1 | 5.00 | 40 | 64 | 0. | 0.340 | 0.200 | 2822. |
| HUN6 | 1 | 17 | 68 | 3400. | 2629. | 0.0 | 177.00 | 1 | 1 | 5.00 | 40 | 64 | 0. | 0.340 | 0.200 | 2822. |
| OLD5 | 1 | 25 | 100 | 3020. | 2265. | 0.0 | 177.00 | 1 | 1 | 4.00 | 40 | 100 | 0. | 0.300 | 0.150 | 2454. |
| EAK1 | 1 | 25 | 100 | 3020. | 2265. | 0.0 | 177.00 | 1 | 1 | 4.00 | 40 | 100 | 0. | 0.300 | 0.150 | 2454. |
| HYDO | 1 | 10 | 18 | 0. | 0. | 0.0 | 0.0 | 5 | 1 | 0.0 | 0 | 0 | 113. | 0.900 | 0.200 | 0. |

TABLE N-6-3. CHARACTERISTICS OF GENERATING PLANTS FOR SYSTEM EXPANSION ALTERNATIVES

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| N100 | 0 | 50 | 100 | 2651. | 2357. | 0.0 | 59.80 | 0 | 1 | 6.50 | 28 | 100 | 0. | 1.070 | 0.0 | 2504. |
| N200 | 0 | 100 | 200 | 2648. | 2359. | 0.0 | 58.90 | 0 | 1 | 5.40 | 28 | 200 | 0. | 0.580 | 0.0 | 2503. |
| N300 | 0 | 150 | 300 | 2645. | 2360. | 0.0 | 57.90 | 0 | 1 | 6.50 | 28 | 300 | 0. | 0.410 | 0.0 | 2503. |
| N400 | 0 | 200 | 400 | 2643. | 2362. | 0.0 | 57.00 | 0 | 1 | 9.80 | 28 | 400 | 0. | 0.330 | 0.0 | 2502. |
| N600 | 0 | 300 | 600 | 2638. | 2365. | 0.0 | 55.10 | 0 | 1 | 12.00 | 28 | 600 | 0. | 0.240 | 0.0 | 2501. |
| N800 | 0 | 400 | 800 | 2632. | 2369. | 0.0 | 53.20 | 0 | 1 | 12.20 | 35 | 800 | 0. | 0.200 | 0.0 | 2500. |
| 0100 | 0 | 50 | 100 | 2388. | 2192. | 0.0 | 177.00 | 1 | 1 | 6.50 | 21 | 100 | 0. | 0.570 | 0.0 | 2290. |
| 0150 | 0 | 75 | 150 | 2347. | 2193. | 0.0 | 177.00 | 1 | 1 | 5.30 | 21 | 150 | 0. | 0.410 | 0.0 | 2270. |
| 0200 | 0 | 100 | 200 | 2280. | 2146. | 0.0 | 177.00 | 1 | 1 | 5.40 | 21 | 200 | 0. | 0.330 | 0.0 | 2213. |
| 0300 | 0 | 150 | 300 | 2235. | 2183. | 0.0 | 177.00 | 1 | 1 | 6.50 | 28 | 300 | 0. | 0.250 | 0.0 | 2259. |
| 0400 | 0 | 200 | 400 | 2324. | 2098. | 0.0 | 177.00 | 1 | 1 | 9.80 | 28 | 400 | 0. | 0.210 | 0.0 | 2211. |
| 0600 | 0 | 300 | 600 | 2328. | 2172. | 0.0 | 177.00 | 1 | 1 | 12.00 | 28 | 600 | 0. | 0.170 | 0.0 | 2250. |
| 0800 | 0 | 400 | 800 | 2334. | 2170. | 0.0 | 177.00 | 1 | 1 | 12.20 | 35 | 800 | 0. | 0.150 | 0.0 | 2252. |
| GT50 | 0 | 50 | 50 | 3450. | 3450. | 43.00 | 177.00 | 2 | 1 | 2.00 | 15 | 75 | 0. | 1.000 | 0.0 | 3450. |

## 3.2. Reference expansion schedules

Table N-6-4 shows the near-optimum expansion schedules for the two forecasts considered. It is seen that with the low load forecast, no nuclear capacity can be economically added during the study period.

An expansion schedule using smaller unit sizes and a number of gas turbines was found to have a lower objective function. However, the input data on gas turbines and the straight line depreciation used by the program tended to reduce the objective function of this run and the case was thus not considered entirely valid. For actual optimum system expansion studies gas turbines and combined cycle plants warrant careful study in this system. With the high load forecast, one nuclear station of 300 MW can be competitively incorporated into the system in 1989.

TABLE N-6-4. REFERENCE SYSTEM EXPANSION SCHEDULES[a]

| Year | Low load forecast (MW) | | | | | High load forecast (MW) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Nuclear | Conventional steam | Hydro and pumped storage | Gas turbines | Total | Nuclear | Conventional steam | Hydro and pumped storage | Gas turbines | Total |
| 1978 | 0 | 637 | 15 | 0 | 652 | 0 | 637 | 15 | 0 | 652 |
| Additions 1978-1979 | 0 | 100 | 0 | 50 | 150 | 0 | 3 x 100 | 0 | 0 | 300 |
| Total system 1979 | 0 | 737 | 15 | 50 | 802 | 0 | 937 | 15 | 0 | 952 |
| 1980 | | 100 | | | 100 | | 100 | | | 100 |
| 1981 | | 100 | | | 100 | | | | 50 | 50 |
| 1982 | | 100 | | | 100 | | 100 | | | 100 |
| 1983 | | | | 50 | 50 | | 150 | | | 150 |
| 1984 | | 100 | | | 100 | | 150 | | | 150 |
| 1985 | | 100 | | | 100 | | [illegible] | | | 150 |
| 1986 | | 100 | | | 100 | | 150 | | | 150 |
| 1987 | | 100 | | | 100 | | 200 | | | 200 |
| 1988 | | 200 | | | 200 | | 200 | | | 200 |
| 1989 | | | | 50 | 50 | 300 | | | | 300 |
| Total additions 1980-89 | 0 | 900 | 0 | 100 | 1000 | 300 | 1200 | 0 | 50 | 1550 |
| Total system 1989 | 0 | 1637 | 15 | 150 | 1802 | 300 | 2137 | 15 | 50 | 2502 |
| Additions 1990-2000 | 700 | 500 | | | 1200 | 3000 | 1400 | | 150 | 4550 |
| Total system 2000 | 700 | 2137 | 15 | | 3002 | 3300 | 3537 | 15 | 200 | 7052 |

[a] 8% discount rate, 0% escalation on capital and nuclear fuel costs, 2% escalation on oil price, ORCOST-3 capital costs.

## 3.3. Sensitivity studies

The potential market for nuclear plants in Jamaica under varying economic conditions is shown in Table N-6-5 for both the low load forecast and the high load forecast. It is seen that with the low load forecast the potential market varies from 0 to one 200 MW station. In the high forecast the market varies from 0 to 700 MW, the maximum consisting of three stations. The variation depends mainly on fuel oil price escalation and on discount rates.

TABLE N-6-5. POTENTIAL MARKET FOR NUCLEAR PLANTS WITH VARYING ECONOMIC PARAMETERS (MW)

| | Low load forecast | | | | | | High load forecast | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Discount rate | 8 | 6 | 10 | 8 | 8 | 8 | 8 | 6 | 10 | 8 | 8 | 8 |
| Differential oil escalation rate | 2 | 2 | 2 | 0 | 4 | 2 | 2 | 2 | 2 | 0 | 4 | 2 |
| Capital cost program ORCOST | 3 | 3 | 3 | 3 | 3 | 1 | 3 | 3 | 3 | 3 | 3 | 1 |
| 1985 | | | | | | | | | | | | |
| 1986 | | | | | | | | | | | | |
| 1987 | | | | | | | | 200 | | | 200 | 200 |
| 1988 | | 200 | | | 200 | 200 | | 200 | | | 200 | 200 |
| 1989 | | | | | | | 300 | 300 | | | 300 | 300 |
| Total | 0 | 200 | 0 | 0 | 200 | 200 | 300 | 700 | 0 | 0 | 700 | 700 |

## 3.4. Financing requirements

The domestic, foreign and total financing requirements associated with the construction of the thermal plants in the reference expansion schedules (see Table N-6-4) are summarized in Table N-6-6. These costs include interest during construction based on the assumption that interest would be paid currently with expenditures. It is seen that total annual expenditures reach a peak of US $45.1 \times 10^6$ for the low load forecast (in 1986) and US $101.6 \times 10^6$ for the high forecast (in 1986). The total costs of the 10-year expansion programs amount to US $305.8 \times 10^6$ and US $520.6 \times 10^6$, respectively, for the two given load forecasts.

The nuclear fuel cycle working capital costs (i.e. investment in first core etc.) are not included in these investment costs. These amount to US $10.1 \times 10^6$. Table N-6-6 shows these costs separately because financing arrangements for such costs may differ from those for the plant construction programs. The total annual investment costs, however, are shown for completeness.

The given costs do not include annual operating and maintenance costs and variable fuel costs.

## 3.5. Conclusions

(a) The estimated total market for thermal generating units which will be commissioned during the 1980-1989 period ranges from 900 MW to 1550 MW depending on the load forecast used as a basis.

(b) Since Jamaica has no indigenous fuel resources, imported fuel oil power provides the competition to nuclear power in the study period. The price of fuel oil used was the world market price delivered at the Kingston Harbour. This was calculated to be approximately US $18/t.

TABLE N-6-6. PLANT INVESTMENT AND NUCLEAR FUEL FINANCING REQUIREMENTS FOR REFERENCE THERMAL PLANT EXPANSION SCHEDULES ($10^6$ US $)[a]

| Year | Low load forecast | | | | High load forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Plant investment | | | Total[b] | Plant investment | | | Nuclear fuel cycle investment[c] | Total[b] |
| | Domestic | Foreign | Subtotal | | Domestic | Foreign | Subtotal | | |
| 1977 | 0.1 | 0.6 | 0.7 | | 0.1 | 0.6 | 0.7 | | 0.7 |
| 1978 | 2.4 | 14.1 | 16.5 | | 2.3 | 13.4 | 15.7 | | 15.7 |
| 1979 | 5.1 | 28.9 | 34.0 | | 2.7 | 16.0 | 18.7 | | 18.7 |
| 1980 | 4.9 | 28.2 | 33.1 | | 2.6 | 20.4 | 23.0 | | 23.0 |
| 1981 | 2.7 | 16.0 | 18.7 | | 6.1 | 34.6 | 40.7 | | 40.7 |
| 1982 | 2.4 | 19.7 | 22.1 | | 6.7 | 38.3 | 45.0 | | 45.0 |
| 1983 | 5.1 | 28.9 | 34.0 | | 6.7 | 38.3 | 45.0 | | 45.0 |
| 1984 | 5.1 | 28.9 | 34.0 | | 7.5 | 42.7 | 50.2 | | 50.2 |
| 1985 | 5.4 | 30.8 | 36.2 | | 11.3 | 64.1 | 75.4 | | 75.4 |
| 1986 | 6.7 | 38.4 | 45.1 | | 15.2 | 86.4 | 101.6 | | 101.6 |
| 1987 | 3.6 | 21.3 | 24.9 | | 12.7 | 69.5 | 81.7 | 1.0 | 82.7 |
| 1988 | 0 | 5.6 | 5.6 | | 3.2 | 18.6 | 21.8 | 9.1 | 30.9 |
| Total | 44.0 | 261.8 | 305.8 | 305.8 | 77.1 | 443.5 | 520.6 | 10.1 | 530.7 |

[a] In terms of 1 January 1973 US dollars.
[b] Totals may not add due to rounding.
[c] Domestic expenditures for the nuclear fuel cycle working capital were assumed to be 10% of the total.

(c) An evaluation of the competitiveness of nuclear and oil-fired plants under reference conditions which along with an 8% interest rate include a differential escalation of fuel oil of 2% shows that the smallest size of nuclear plant to be competitive is a 300 MW unit which becomes competitive in 1986. System restrictions, however, make that size too large throughout the study period under the low load forecast and until 1989 under the high load forecast. Therefore, the market under reference conditions is either 0 or 300 MW depending on the forecast used as a basis.

(d) An evaluation of the sensitivity of the results to various parameters indicates that under economic conditions which tend to favour nuclear plants (6% interest rate, 4% differential fossil fuel escalation and lower relative capital costs of nuclear generating plants) the nuclear market could range from 1 × 200 MW station (200 MW) to 2 × 200 MW and one 300 MW station (700 MW). However, under economic conditions which favour oil-fired plants (10% interest rate, higher capital costs, 0% differential escalation on fuel oil) the nuclear market would be eliminated.

(e) The total financing requirements for the reference expansion schedule amount to US $305.8 × $10^6$ for the low load forecast and US $520.6 × $10^6$ for the high load forecast.

# 7. KOREA

## 1. ECONOMIC AND SOCIAL FACTORS

### 1.1. Population growth

The annual rate of growth of population has declined from about 2.9% in the early 1960s to 1.8% in 1970. Family planning programs are expected to stabilize the population at 1.5% during 1973-1976. There has been a significant recent shift of population to the urban centres with the rural population showing a decline.

### 1.2. Economic development and goals

At constant prices, the GNP increased at an average annual rate of 7.8% during the First Five-Year Economic Development Plan (1962-66 inclusive), and 10.5% during the Second Plan (1967-71). The target for the Third Plan (1972-76) is an average of 8.5%/yr and the projection for the 1977-81 period is 10.6%/yr. The growth rate projected for the Third Plan is considered to depend on the capacity to improve balance of payments and on an increase in exports at an average annual rate of 24% (compared with the very rapid increase of 40% during the First and Second Plan periods).

### 1.3. Energy needs and resources

Total energy consumption increased by 62.1% during the Second Plan period but fossil fuel requirements for electric plants increased by over 100%. Total energy consumption is expected to increase by 57.3% and 50.4% during the Third Plan and the 1977-81 period.

The petroleum share of total energy consumption was about 8% in 1961 jumping to almost 50% by 1971; the share is expected to be approximately 70 and 90% for the years 1980 and 1990, respectively.

Korea has been reported to have no reserves of oil and natural gas. The hydro potential is limited and is expected to be harnessed only as an adjunct to an irrigation project. The only fossil fuel is anthracite coal, the reserves of which are estimated to be about 1 500 million tons. However, the amount minable economically is estimated at 500 million tons. Recent annual production has been about 11 million tons, with an annual rate of growth of only about 4.5% (coal being more expensive per kcal at present than imported oil); the consumption by the electric power sector has dropped from 10-15% of the total in the 1960s to about 5% in 1972.

The rapid increase in importation of petroleum from abroad has required the allocation of a considerable amount of foreign exchange. (The quantity of petroleum imported in 1971 was 13 times more than in 1961.) This increase is likely to exert considerable pressure on the foreign exchange balance if allowed to continue.

### 1.4. Interest in nuclear power

The growing utilization of electric power – electric power sales increased 5.4 times in the decade ending in 1970 while total energy consumption incrased 2.1 times – suggests that nuclear power should be considered for electric power generation. Korea is now constructing its first nuclear power plant, the Ko-Ri unit No. 1 of 595 MW gross capacity, based on economic studies which showed that it could generate electricity at lower cost than an oil-fired plant. The second unit, which will probably have the same output as the first one, is assumed to go critical in 1970/80. Tentative plans for nuclear power development suggest that between 5 and 7 units (ranging from 600 MW to 1000 MW in size) with a total installed capacity of between 3800 and 5800 MW may be installed by 1989.

## 2. PARAMETERS USED IN THE ANALYSIS

### 2.1. Basic conditions

Table N-7-1 summarizes the conditions used in the analyses of various alternative expansion plans for the associated system in Korea during the period 1980 to 1989. The load forecast was developed by a Market Survey expert using the method described in Appendix F. From the figures in the table, it can be seen that during the study period there is a total market of 9 100 MW of thermal capacity additions.

As described in the Country Report, it was decided not to consider any hydro (or pumped storage) additions during the study period.

TABLE N-7-1. SUMMARY OF CONDITIONS USED IN THE ANALYSIS

| | 1979 | 1989 |
|---|---|---|
| Population ($10^6$) | 35.92 | 41.68 |
| GNP/capita (US $/yr) [a] | 415 | 746 |
| Energy consumption (GWh/yr) | 28 200 | 76 722 |
| Peak demand (MW) | 4 857 | 12 200 |
| Total installed capacity (MW) | 6 610 | 15 710 |
| Installed capacity, critical period (MW) [b] | 6 318 | 15 418 |
| Installed thermal capacity (MW) | 5 900 | 15 000 |
| Average reserve margins (%) [b] | 30.1 | 26.4 |
| Average loss-of-load probability | 0.0001 | 0.0027 |

[a] 1964 US $.
[b] In fourth quarter of year peak hydro capacity = 58.9% total hydro capacity.

### 2.2. Characteristics of system as of 1979

The existing and committed power expansion plans of the Korean Electric Company (KECO) are only sufficient to meet peak load demand up to about 1976. For this reason, conventional plant capacity additions amounting to 600 MW were assumed to be made to the system to meet the 1979 peak demand and provide a sufficient reserve margin for adequate loss-of-load probability. For the purpose of the computer analyses, the existing and committed units were grouped into so-called hypothetical units having common characteristics as shown in Table N-7-2. The technical and economic characteristics of each hypothetical plant shown in the table were computed from the characteristics of the actual plants comprising each unit.

TABLE N-7-2. CHARACTERISTICS OF GENERATING PLANTS IN "FIXED SYSTEM"

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HYDR | 1 | 71 | 710 | 0. | 0. | 0.0 | 0.0 | 5 | 1 | 0.0 | 0 | 0 | 2600. | 0.250 | 0.0 | 0. |
| KORI | 1 | 300 | 595 | 2850. | 2340. | 0.0 | 55.10 | 0 | 1 | 12.00 | 28 | 600 | 0. | 0.320 | 0.0 | 2597. |
| INC3 | 1 | 157 | 313 | 2425. | 2040. | 0.0 | 186.00 | 1 | 1 | 6.50 | 28 | 250 | 0. | 0.230 | 0.0 | 2233. |
| INC2 | 1 | 125 | 250 | 2360. | 1970. | 0.0 | 186.00 | 1 | 1 | 6.00 | 28 | 250 | 0. | 0.250 | 0.0 | 2165. |
| YOS2 | 1 | 150 | 300 | 2450. | 2062. | 16.00 | 159.00 | 1 | 1 | 6.50 | 28 | 250 | 0. | 0.230 | 0.0 | 2256. |
| YEDO | 1 | 63 | 125 | 2570. | 2350. | 16.00 | 159.00 | 1 | 1 | 6.00 | 21 | 100 | 0. | 0.330 | 0.0 | 2461. |
| SEO5 | 1 | 125 | 250 | 2342. | 2044. | 33.00 | 159.00 | 1 | 1 | 6.00 | 28 | 250 | 0. | 0.250 | 0.0 | 2193. |
| DGHA | 3 | 110 | 220 | 2172. | 1882. | 16.00 | 159.00 | 1 | 1 | 6.00 | 21 | 250 | 0. | 0.260 | 0.0 | 2027. |
| HONM | 2 | 150 | 300 | 2530. | 2248. | 16.00 | 159.00 | 1 | 1 | 6.50 | 28 | 250 | 0. | 0.230 | 0.0 | 2389. |
| YGNM | 2 | 100 | 200 | 2251. | 2083. | 16.00 | 159.00 | 1 | 1 | 5.40 | 21 | 250 | 0. | 0.270 | 0.0 | 2167. |
| INC1 | 1 | 125 | 250 | 2379. | 1969. | 0.0 | 186.00 | 1 | 1 | 6.00 | 29 | 250 | 0. | 0.250 | 0.0 | 2174. |
| KGIN | 2 | 81 | 162 | 2520. | 2196. | 0.0 | 186.00 | 1 | 1 | 5.30 | 21 | 100 | 0. | 0.290 | 0.0 | 2358. |
| YOS1 | 1 | 100 | 200 | 2450. | 2078. | 16.00 | 159.00 | 1 | 1 | 5.40 | 21 | 250 | 0. | 0.270 | 0.0 | 2264. |
| PU34 | 2 | 53 | 105 | 2536. | 2362. | 12.00 | 159.00 | 1 | 1 | 6.50 | 21 | 100 | 0. | 0.360 | 0.0 | 2450. |
| SEO4 | 1 | 69 | 138 | 2600. | 2322. | 33.00 | 159.00 | 1 | 1 | 7.50 | 21 | 100 | 0. | 0.310 | 0.0 | 2461. |
| YGWL | 2 | 50 | 50 | 3180. | 3180. | 190.00 | 0.0 | 4 | 1 | 8.60 | 21 | 50 | 0. | 0.540 | 0.0 | 3180. |
| GNSN | 1 | 75 | 75 | 3112. | 2288. | 16.00 | 159.00 | 1 | 1 | 8.60 | 21 | 50 | 0. | 0.440 | 0.0 | 3112. |
| PULM | 4 | 65 | 65 | 2912. | 2912. | 12.00 | 159.00 | 1 | 1 | 8.60 | 21 | 50 | 0. | 0.470 | 0.0 | 2912. |
| PPYG | 2 | 50 | 50 | 2580. | 2580. | 15.00 | 263.00 | 2 | 1 | 6.50 | 21 | 50 | 0. | 0.700 | 0.0 | 2580. |
| ULSN | 3 | 50 | 50 | 4000. | 4000. | 0.0 | 279.00 | 2 | 1 | 2.00 | 4 | 50 | 0. | 0.700 | 0.0 | 4000. |

## 2.3. Characteristics of alternative generating units

The characteristics of alternative thermal generating units considered in the evaluation of possible system expansion configurations (i.e. schedules of additions) are shown in Table N-7-3. These characteristics were derived by methods described in Appendixes E, G, I and J.

# 3. RESULTS

## 3.1. Summary of cases considered

Based on the assumed load forecast, a number of trial computer runs were made to establish the sizes of capacity additions required. The results showed that the addition of 600 MW units during the 1980s and of 800 MW units in the late 1980s would give near-optimum programs.

Having established the desired schedule of capacity additions, fourteen computer runs were carried out to evaluate the competition between nuclear plant units and oil-fired plant units. It was found that a program incorporating all of the 600 MW and 800 MW units as nuclear units gave a lower present worth than any combination of oil-fired plant units.

## 3.2. Reference expansion schedule

Table N-7-4 shows a near-optimum expansion schedule (case 6A) for the load forecast assumed based on the reference conditions. It is seen that the schedule confirms the desirability of ordering Ko-Ri unit No. 2 for service in 1979 (i.e. during the "transition period" between the end of KECO firm planning, 1976, and the start of the study period, 1980) and calls for the further introduction of single 600 MW nuclear units in each of the years 1981,1982,1983 and 1985, of two 600 MW nuclear units in each of the years 1984, 1986 and 1987, and of one 600 MW and one 800 MW nuclear unit in each of the years 1988 and 1989. On this basis, the total nuclear capacity added during the study period amounts to 8 800 MW out of a total of 9 100 MW of capacity added. At the end of 1989 the nuclear capacity would correspond to about 63.6% of the total capacity, compared to about 30.3% for conventional steam plants, 4.5% for hydro and 1.6% for gas turbines.

## 3.3. Sensitivity studies

The potential market for nuclear plants in Korea in the reference case and for various sensitivity studies is shown in Table N-7-5. It is seen that the potential nuclear market varies from 5200 MW to 8800 MW.

## 3.4. Financing requirements

The domestic, foreign and total financing requirements associated with the construction of the thermal plants in the reference expansion schedule (see Table N-7-4) are summarized in Table N-7-6. It is seen that the total annual plant construction expenditures reach a peak of US $\$411.9 \times 10^6$ in 1985. These costs include interest during construction based on the assumption that interest would be paid currently with expenditures. The total cost of the 10-year expansion program amounts to US $\$3040.9 \times 10^6$.

The nuclear fuel cycle working capital costs (i.e. investment in first core etc.) are also shown in Table N-7-6 as a separate item because financing arrangements for such costs may differ from those for the plant construction program. These costs amount to US $\$238.9 \times 10^6$. The total annual investment costs amounting to US $3279.2 are shown for completeness.

The given costs do not include annual operating and maintenance costs and variable fuel costs.

TABLE N-7-3. CHARACTERISTICS OF GENERATING PLANTS FOR SYSTEM EXPANSION ALTERNATIVES

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0300 | 0 | 150 | 300 | 2335. | 2183. | 16.00 | 159.00 | 1 | 1 | 6.50 | 28 | 300 | 0. | 0.280 | 0.0 | 2259. |
| 0600 | 0 | 300 | 600 | 2328. | 2172. | 16.00 | 159.00 | 1 | 1 | 12.00 | 28 | 600 | 0. | 0.190 | 0.0 | 2250. |
| 0800 | 0 | 400 | 800 | 2334. | 2170. | 16.00 | 159.00 | 1 | 1 | 12.20 | 35 | 800 | 0. | 0.170 | 0.0 | 2252. |
| 01T0 | 0 | 500 | 1000 | 2344. | 2152. | 16.00 | 159.00 | 1 | 1 | 12.20 | 35 | 1000 | 0. | 0.160 | 0.0 | 2248. |
| N600 | 0 | 300 | 600 | 2638. | 2365. | 0.0 | 55.10 | 0 | 1 | 12.00 | 28 | 600 | 0. | 0.320 | 0.0 | 2501. |
| N800 | 0 | 400 | 800 | 2632. | 2369. | 0.0 | 53.20 | 0 | 1 | 12.20 | 35 | 800 | 0. | 0.270 | 0.0 | 2500. |
| N1T0 | 0 | 500 | 1000 | 2627. | 2372. | 0.0 | 51.30 | 0 | 1 | 12.20 | 35 | 1000 | 0. | 0.230 | 0.0 | 2499. |
| GT | 0 | 50 | 50 | 4000. | 4000. | 0.0 | 279.00 | 2 | 1 | 2.00 | 4 | 50 | 0. | 0.700 | 0.0 | 4000. |

TABLE N-7-4. REFERENCE SYSTEM EXPANSION SCHEDULE[a]

| Year | Installed capacity (MW) | | | | | % Reserve[b] | Annual loss-of-load probability |
|---|---|---|---|---|---|---|---|
| | Nuclear | Conventional steam | Hydro | Gas turbines | Total | | |
| Total system 1976 | 595 | 4 455 | 710 | 250 | 6 010 | 61.9 | 0.0001 |
| Additions 1976-1979 | 600 | 0 | 0 | 0 | 600 | - | - |
| Total system 1979 | 1195 | 4 455 | 710 | 250 | 6 610 | 30.1 | 0.0010 |
| Additions 1980 | 0 | 0 | 0 | 0 | 0 | 17.8 | 0.0058 |
| 1981 | 600 | 0 | 0 | 0 | 600 | 17.3 | 0.0073 |
| 1982 | 600 | 1x300 | 0 | 0 | 900 | 20.3 | 0.0051 |
| 1983 | 600 | 0 | 0 | 0 | 600 | 18.56 | 0.0074 |
| 1984 | 2 x 600 | 0 | 0 | 0 | 1 200 | 23.3 | 0.0042 |
| 1985 | 600 | 0 | 0 | 0 | 600 | 18.8 | 0.0082 |
| 1986 | 2 x 600 | 0 | 0 | 0 | 1 200 | 21.5 | 0.0058 |
| 1987 | 2 x 600 | 0 | 0 | 0 | 1 200 | 22.5 | 0.0048 |
| 1988 | 600<br>800 | 0 | 0 | 0 | 1 400 | 25.2 | 0.0032 |
| 1989 | 600<br>800 | 0 | 0 | 0 | 1 400 | 26.4 | 0.0027 |
| Total additions 1980-89 | 8 800 | 300 | 0 | 0 | 9 100 | 21.2 | 0.0055 |
| Total system 1989 | 9 995 | 4 755 | 710 | 250 | 15 710 | 26.4 | 0.0027 |
| Additions 1990-2000 | 8 800 | 10 200 | 0 | 0 | 19 000 | - | - |
| Total system 2000 | 18 795 | 14 955 | 710 | 250 | 34 710 | 25.2 | 0.0024 |

[a] 8% discount rate, 0% escalation on capital and nuclear fuel, 2% escalation on oil prices, ORCOST-3 capital costs.
[b] In critical quarter (4th quarter).

## 3.5. Conclusions

(a) The estimated total market for generating units which will be commissioned during the 1980 - 1989 period is 9100 MW. Because of the few economically exploitable hydroelectric power sites, most of which would operate at very low capacity factor, and the lack of detailed information thereon, it was assumed that the market for new thermal plants will probably be equal to the total generating unit market (i.e. 9100 MW). (It is estimated that hydro capacity additions would not exceed 5% of the total additions.)

(b) An evaluation of the conventional fuel available in Korea (domestic coal and imported oil) indicates that oil is the fuel which will be most competitive with respect to nuclear power.

The reason for this conclusion is that the use of coal for electric power generation will be limited by costs of mining, which are rising rapidly and will rise above levels which are competitive with oil.

(c) An evaluation of the competitiveness of nuclear versus oil-fired plant units indicates that under the reference conditions (8% discount rate, 2% escalation on fuel prices) nuclear plant units are more competitive than oil-fired units. Assuming that for regional economic reasons one 300 MW conventional unit will be built in the study decade, all of the 600 M[illegible] [illegible]d 800 MW units considered would be nuclear, giving an aggregate potential nuclear marke[illegible] 8 800 MW (i.e. essentially the total market for new generating plant units).

(d) An evaluation of the sensitivity of the results to various economic parameters indicates that under economic conditions which tend to favour oil-fired plants (10% discount rate, 0% fossil fuel escalation rate) the nuclear market would drop to 5 300 MW.

TABLE N-7-5. POTENTIAL MARKET FOR NUCLEAR PLANTS WITH VARYING ECONOMIC PARAMETERS (MW)

| Year | Reference | 6% discount rate | 10% discount rate | 0% fuel escalation rate | 4% fuel escalation rate | ORCOST-1 |
|---|---|---|---|---|---|---|
| Period | | | | | | |
| At 31/12/1972 [a] | 595 | 595 | 505 | 595 | 595 | 595 |
| Added 1973-79 [b] | 600 | 600 | 600 | 600 | 600 | 600 |
| At 31/12/1979 [a] | 595<br>600 | 595<br>600 | 595<br>600 | 595<br>600 | 595<br>600 | 595<br>600 |
| 1980 [b] | 0 | 0 | 0 | 0 | 0 | 0 |
| 1981 | 600 | 600 | 600 | 600 [c] | 600 | 600 |
| 1982 | 600 | 600 | 600 | 600 [c] | 600 | 600 |
| 1983 | 600 | 600 | 600 | 0 | 600 | 600 |
| 1984 | 2×600 | 2×600 | 2×600 | 600 [c] | 2×600 | 2×600 |
| 1985 | 600 | 600 | 600 | 600 [c] | 600 | 600 |
| 1986 | 2×600 | 2×600 | 2×600 | 600 [c] | 2×600 | 2×600 |
| 1987 | 2×600 | 2×600 | 2×600 | 600 [c] | 2×600 | 2×600 |
| 1988 | 600<br>800 | 600<br>800 | 600<br>800 | 800 [c] | 600<br>800 | 600<br>800 |
| 1989 | 600<br>800 | 600<br>800 | 600<br>800 | 800 [c] | 600<br>800 | 600<br>800 |
| Total nuclear additions 1980-89 | 8 800 | 8 800 | 8 800 | 5 200 [c] | 8 800 | 8 800 |
| Total system 1989 | 9 945 | 9 945 | 9 945 | 6 395 | 9 945 | 9 945 |
| Nuclear % of total system capacity 1989 | 63.5 | 63.5 | 63.5 | 40.5 | 63.5 | 63.5 |

[a] Units in operation, under construction or committed (number and size of each unit).
[b] Units expected to be committed during period or year (number and size of each unit).
[c] Under certain conditions these could be zero. See explanation in Section 16.3(c).

TABLE N-7-6. FINANCING REQUIREMENTS FOR REFERENCE THERMAL PLANTS EXPANSION SCHEDULE ($10^6$ US $)

| Year | Plant investment | | | Nuclear fuel working capital [a] | Total |
|---|---|---|---|---|---|
| | Domestic | Foreign | Subtotal | | |
| 1975 | 0.5 | 0.7 | 1.2 | | 1.2 |
| 1976 | 4.6 | 6.9 | 11.5 | | 11.5 |
| 1977 | 20.0 | 30.1 | 50.1 | | 50.1 |
| 1978 | 46.8 | 70.2 | 117.0 | | 117.0 |
| 1979 | 80.9 | 119.7 | 200.6 | 1.7 | 202.3 |
| 1980 | 115.8 | 165.3 | 281.1 | 16.7 | 297.8 |
| 1981 | 126.3 | 183.2 | 309.5 | 16.7 | 326.2 |
| 1982 | 130.4 | 195.7 | 326.1 | 18.4 | 344.5 |
| 1983 | 141.4 | 212.2 | 353.6 | 31.8 | 385.4 |
| 1984 | 161.9 | 243.0 | 404.9 | 18.4 | 423.3 |
| 1985 | 164.7 | 247.2 | 411.9 | 33.5 | 445.4 |
| 1986 | 132.8 | 199.3 | 332.1 | 33.7 | 365.8 |
| 1987 | 76.6 | 115.2 | 191.8 | 35.8 | 227.6 |
| 1988 | 19.3 | 29.1 | 48.4 | 32.2 | 80.6 |
| Total | 1222.5 | 1818.4 | 3040.9 | 238.9 | 3279.8 |

[a] Domestic expenditures for the nuclear fuel working capital were assumed to amount to 0% of the total.

# 8. MEXICO

## 1. ECONOMIC AND SOCIAL FACTORS

### 1.1. Population growth

Mexico has the fastest population growth rate of all the countries in the world with a similar or larger population; a rate of about 3.5% has been steadily maintained between 1960 and 1970 and shows no signs of decreasing. As a result, almost two thirds of the total population is below 25 years of age. Population forecasts are based on bringing the net population growth rate to 1.4% towards the year 2000; this would result in a population of 117 million by this date and of 180 million by the year 2050 when a stable population may be achieved.

### 1.2. Economic development and goals

The rapid growth in population will place a severe stress on the growth of national per-capita income. During the decade of 1960-1970, the GNP in real terms recorded an average rate of growth of slightly more than 7.0%/yr; the per-capita growth rate thus averaged more than 3.5%, a significant achievement especially since it has been coupled with relative price stability. This factor together with political stability, high savings and investment rates, and the consequent climate of confidence at home and abroad, make it reasonable to project an overall GNP growth rate above 6% to 1990.

## 1.3. Energy needs and resources

During the period 1960-1970, the total energy demand grew at an average annual growth rate of 6.3%. The bulk of this demand was covered by hydrocarbons, the share of which varied between 85 and 90% of the total during the period. National production of primary energy increased at practically the same rate, with petroleum products accounting for 85% of the total production in 1971, while hydro represented 11.5% and coal about 3.5%.

For the 1970-1980 period, an average annual rate of growth of 7.2% is forecast - about 1.3 times the average growth rate of GNP during this decade. For the 1980-1990 period no projections are available but an energy growth rate of 6.6%/yr may be assumed. A comparison of demand and supply projections up to 1980 shows a deficit of about 10% of the projected demand by 1980 which will have to be met by fuel imports. Barring major oil discoveries, it would be reasonable to expect that this gap will further widen during the 1980-1990 period since the production of hydroelectricity is expected to level off by the end of the present decade.

The gross consumption of electrical energy for the whole country has grown at an annual rate of about 9.8% in the last ten years. The annual rate of growth used for forecasting total electric energy consumption from 1971 to 1980 is 11.5% and this rate is assumed to continue until 1990. This is an average rate for the country as a whole and the rate of growth of the expanding interconnected system will be substantially larger especially during the next five-year period. After 1980, however, the whole country, with the exception of the two peninsulas of Yucatán and Lower California, will be interconnected and the two rates will practically coincide. Extrapolations to 1990 on the basis of an 11.5% annual increase have been made, implying a rise in the ratio of the electricity to energy growth rate to 1.75 and leading to a share of electricity exceeding 45% of the total energy consumption. A revision of either the electricity or the total energy growth rates for the period may, therefore, be required.

Hydroelectric power has provided a major component of total electricity production with its share of generation exceeding 50% of the total between 1965 and 1970. Up to 1980 hydro generation will supply an ever decreasing proportion of total electricity generation; this proportion will decrease at an accelerated rate after 1980. One major project, with an economically exploitable potential of 4000 to 5000 MW in the area of Usumacinta, would require the flooding of a large area in Guatemalan territory and call for lengthy bilateral negotiation.

Practically all of the coal reserves in Mexico are concentrated in a series of basins in the State of Coahuila in the north-east. This coal is presently reserved for the metallurgical industry. The Mexican Petroleum Institute suggests that the reserves are only sufficient for the needs of the steel industry until the end of the century and that as a result it is very unlikely that coal could become an important fuel for power production. The Comisión Federal de Electricidad (CFE), however, feels that there is more than enough coal and that the balance should be used for power generation. Mine-mouth plants could be built near the Río Escondido mine, with a potential of 1500 MW, to serve the regional needs.

Mexico is a significant producer of oil and gas, and oil exploration activities continue at a substantial level; however, the trend towards rapidly increasing costs is unmistakable and a possibility of an increasing share of imports in total supply is a likely development.

## 1.4. Interest in nuclear power

The interest in nuclear power dates back to the early 1960s. Studies during the latter half of the 1960s led to the conclusion that a major role might be played by nuclear power. In mid-1972 the first nuclear power plant of 670 MW was committed at Laguna Verde, 70 km north of Vera Cruz on the Atlantic seaboard. An option for the purchase of a twin unit NSSS is available.

In 1972, the Mexican Government approved the legislation necessary for establishing a National Institute of Nuclear Energy as successor to the earlier National Commission for Nuclear Energy, emphasizing at the same time the intention to expand the peaceful uses of atomic energy.

## 2. PARAMETERS USED IN THE ANALYSIS

### 2.1. Basic conditions

Table N-8-1 summarizes the conditions used in the analysis of various alternative expansion plans for the associated system in Mexico during the period 1980 to 1989. The load forecast was developed for the Market Survey using the method described in Appendix F. From the figures given it can be shown that during the study period there is a total market of over 20 000 MW of thermal capacity additions.

In carrying out the analysis, it was assumed that the schedule of pumped storage capacity additions would be fixed. As described in the Country Report, no hydro additions were considered during the study period.

TABLE N-8-1. SUMMARY OF CONDITIONS USED IN THE ANALYSIS

| | 1979 | 1989 |
|---|---|---|
| Population ($10^6$) | 69.03 | 93.23 |
| GNP/capita (US $/yr) [a] | 674 | 951 |
| Energy consumption (GWh/yr) | 65 205 | 163 390 |
| Peak demand (MW) | 12 200 | 30 600 |
| Total installed capacity (MW) | 15 211 | 36 591 [c] |
| Installed capacity, critical period (MW) [b] | 15 211 | 36 591 [c] |
| Thermal capacity (MW) | 9 011 | 28 191 [c] |
| Average reserve margins (%) | 24.7 | 19.6 |
| Average annual loss-of-load probability | - | 0.0011 |

[a] 1964 US $.
[b] In fourth quarter of year (peak hydro capacity = 100% total hydro capacity).
[c] Net total after deduction of 490 MW of capacity retired during 1980-1989.

### 2.2. Characteristics of system as of 1979

CFE's projected National Interconnected System capacity for 1979 is 15 276 MW. For the purpose of this study, a slight readjustment was made resulting in an installed capacity of 15 211 MW. For the purpose of the computer analysis, some of these existing and committed units were grouped into so-called hypothetical units having common characteristics as shown in Table N-8-2. The technical and economic characteristics of each hypothetical plant shown in the table were computed from the characteristics of the actual plants comprising each unit.

### 2.3. Characteristics of alternative generating units

The characteristics of alternative thermal generating units considered in the evaluation of possible system expansion configurations (i.e. schedules of additions) are shown in Table N-8-3. These characteristics were derived by methods described in Appendix E, G, I and J.

TABLE N-8-2. CHARACTERISTICS OF GENERATING PLANTS IN "FIXED SYSTEM"

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HYDR | 1 | 1 | 6200 | 0. | 0. | 0.0 | 0.0 | 5 | 1 | 0.0 | 0 | 0 | 22865. | 0.250 | 0.0 | 0. |
| CF09 | 4 | 30 | 30 | 3686. | 3686. | 347.00 | 0.0 | 1 | 1 | 8.00 | 30 | 30 | 0. | 0.890 | 0.510 | 3686. |
| DEL1 | 1 | 100 | 100 | 3059. | 3059. | 377.00 | 0.0 | 1 | 1 | 6.00 | 30 | 80 | 0. | 0.250 | 0.320 | 3059. |
| LAG2 | 1 | 30 | 30 | 2894. | 2894. | 346.00 | 0.0 | 1 | 1 | 8.00 | 30 | 30 | 0. | 0.390 | 0.320 | 2894. |
| LAG3 | 1 | 40 | 40 | 2702. | 2702. | 346.00 | 0.0 | 1 | 1 | 8.00 | 30 | 30 | 0. | 0.300 | 0.320 | 2702. |
| TG37 | 1 | 480 | 480 | 4082. | 4082. | 560.00 | 0.0 | 2 | 1 | 3.00 | 49 | 300 | 0. | 0.400 | 0.0 | 4082. |
| JERO | 1 | 30 | 30 | 3678. | 3678. | 195.00 | 0.0 | 1 | 1 | 8.00 | 30 | 30 | 0. | 0.530 | 0.400 | 3678. |
| JERV | 1 | 74 | 74 | 2890. | 2890. | 195.00 | 0.0 | [illegible] | 1 | 7.00 | 30 | 80 | 0. | 0.250 | 0.320 | 2890. |
| MONT | 3 | 75 | 75 | 2701. | 2701. | 195.00 | 0.0 | 1 | 1 | 8.00 | 30 | 80 | 0. | 0.280 | 0.200 | 2701. |
| BRAV | 1 | 76 | 76 | 2898. | 2898. | 187.00 | 0.0 | 1 | 1 | 6.00 | 30 | 80 | 0. | 0.400 | 0.320 | 2898. |
| NAVA | 1 | 37 | 37 | 2868. | 2868. | 135.00 | 0.0 | 4 | 1 | 8.00 | 30 | 30 | 0. | 0.580 | 0.420 | 2868. |
| MO11 | 5 | 30 | 30 | 3559. | 3559. | 209.00 | 0.0 | 1 | 1 | 8.00 | 30 | 30 | 0. | 0.500 | 0.510 | 3559. |
| VMEX | 3 | 67 | 133 | 2415. | 2200. | 187.00 | 0.0 | 1 | 1 | 5.30 | 30 | 150 | 0. | 0.180 | 0.220 | 2308. |
| JC04 | 1 | 160 | 160 | 2772. | 2772. | 195.00 | 0.0 | 1 | 1 | 6.00 | 30 | 150 | 0. | 0.070 | 0.270 | 2772. |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CEN8 | 1 | 280 | 280 | 4066. | 4066. | 203.00 | 0.0 | 2 | 1 | 4.00 | 21 | 300 | 0. | 1.000 | 0.0 | 4066. |
| OJ05 | 1 | 37 | 37 | 3619. | 3619. | 217.00 | 0.0 | 1 | 1 | 8.00 | 30 | 30 | 0. | 0.560 | 0.720 | 3619. |
| POR1 | 3 | 39 | 39 | 2664. | 2664. | 196.00 | 0.0 | 1 | 1 | 8.00 | 30 | 30 | 0. | 0.310 | 0.320 | 2664. |
| SM04 | 4 | 75 | 150 | 2415. | 2200. | 187.00 | 0.0 | 1 | 1 | 5.30 | 30 | 150 | 0. | 0.200 | 0.200 | 2308. |
| UA03 | 1 | 120 | 120 | 2929. | 2929. | 187.00 | 0.0 | 1 | 1 | 6.00 | 30 | 150 | 0. | 0.150 | 0.400 | 2929. |
| MONV | 3 | 84 | 84 | 2633. | 2633. | 299.00 | 0.0 | 1 | 1 | 7.00 | 30 | 80 | 0. | 0.270 | 0.240 | 2633. |
| VT05 | 5 | 150 | 300 | 2401. | 2189. | 187.00 | 0.0 | 1 | 1 | 6.50 | 30 | 300 | 0. | 0.160 | 0.170 | 2295. |
| UAY3 | 2 | 87 | 87 | 2644. | 2644. | 187.00 | 0.0 | 1 | 1 | 7.00 | 30 | 80 | 0. | 0.260 | 0.240 | 2644. |
| TAMV | 2 | 80 | 160 | 2399. | 2200. | 187.00 | 0.0 | 1 | 1 | 5.30 | 30 | 150 | 0. | 0.190 | 0.190 | 2300. |
| MS07 | 7 | 150 | 300 | 2287. | 2085. | 187.00 | 0.0 | 1 | 1 | 6.50 | 30 | 300 | 0. | 0.160 | 0.170 | 2186. |
| ESCO | 2 | 80 | 160 | 2399. | 2200. | 135.00 | 0.0 | 4 | 1 | 5.30 | 30 | 150 | 0. | 0.190 | 0.190 | 2300. |
| LAMP | 2 | 150 | 300 | 2286. | 2085. | 187.00 | 0.0 | 4 | 1 | 6.50 | 30 | 300 | 0. | 0.160 | 0.170 | 2186. |
| LAVE | 1 | 335 | 670 | 2636. | 2366. | 30.00 | 30.00 | 0 | 1 | 12.10 | 30 | 800 | 0. | 0.300 | 0.0 | 2501. |

TABLE N-8-3. CHARACTERISTICS OF GENERATING PLANTS FOR SYSTEM EXPANSION ALTERNATIVES

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0300 | 0 | 150 | 300 | 2335. | 2183. | 187.00 | 0.0 | 1 | 1 | 6.50 | 28 | 300 | 0. | 0.140 | 0.150 | 2259. |
| 0300 | 0 | 150 | 300 | 2335. | 2183. | 209.00 | 0.0 | 1 | 1 | 6.50 | 28 | 300 | 0. | 0.140 | 0.150 | 2259. |
| 0600 | 0 | 300 | 600 | 2328. | 2172. | 0.0 | 187.00 | 3 | 1 | 12.00 | 28 | 600 | 0. | 0.110 | 0.120 | 2250. |
| 0600 | 0 | 300 | 600 | 2328. | 2172. | 22.00 | 187.00 | 3 | 1 | 12.00 | 28 | 600 | 0. | 0.110 | 0.120 | 2250. |
| N670 | 0 | 335 | 670 | 2636. | 2366. | 27.00 | 28.00 | 0 | 1 | 12.10 | 30 | 800 | 0. | 0.300 | 0.0 | 2501. |
| N800 | 0 | 400 | 800 | 2632. | 2369. | 26.00 | 27.00 | 0 | 1 | 12.20 | 35 | 800 | 0. | 0.270 | 0.0 | 2500. |
| C300 | 0 | 150 | 300 | 2361. | 2199. | 187.00 | 0.0 | 4 | 1 | 8.70 | 28 | 300 | 0. | 0.150 | 0.170 | 2280. |
| GT1H | 0 | 100 | 100 | 4000. | 4000. | 327.00 | 0.0 | 2 | 1 | 2.00 | 4 | 100 | 0. | 0.0 | 1.000 | 4000. |
| N1T2 | 0 | 600 | 1200 | 2622. | 2375. | 25.00 | 26.00 | 0 | 1 | 12.20 | 35 | 1200 | 0. | 0.220 | 0.0 | 2498. |
| N1T5 | 0 | 750 | 1500 | 2614. | 2380. | 25.00 | 26.00 | 0 | 1 | 12.20 | 35 | 1500 | 0. | 0.200 | 0.0 | 2497. |
| 01T0 | 0 | 500 | 1000 | 2344. | 2152. | 0.0 | 187.00 | 3 | 1 | 12.20 | 35 | 1000 | 0. | 0.100 | 0.070 | 2248. |
| 0800 | 0 | 400 | 800 | 2334. | 2170. | 0.0 | 187.00 | 3 | 1 | 12.20 | 35 | 800 | 0. | 0.110 | 0.090 | 2252. |
| N600 | 0 | 300 | 600 | 2638. | 2365. | 27.00 | 28.00 | 0 | 1 | 12.00 | 28 | 600 | 0. | 0.320 | 0.0 | 2501. |
| N1T0 | 0 | 500 | 1000 | 2627. | 2372. | 25.00 | 26.00 | 0 | 1 | 12.20 | 35 | 1000 | 0. | 0.250 | 0.0 | 2499. |

## 3. RESULTS

### 3.1. Summary of cases considered

Based on the assumed load forecast, a number of trial computer runs were made to establish the sizes of capacity additions required. The results showed that the addition of 300 MW and 600 MW units in the early 1980s, 300 MW, 600 MW and 800 MW units in the mid-1980s and 800 MW, 1000 MW and 1200 MW units in the late 1980s would give a near-optimum program.

Having established the desired schedule of capacity additions, eight computer runs were carried out to evaluate the competition between 600 MW and larger nuclear plants and oil-fired plants. It was found that a program incorporating all of these units as nuclear units gave a lower present worth than any combination of oil-fired plant units.

A special schedule where a 300 MW oil-fired plant unit, planned for operation in 1980, was replaced by a nuclear plant unit was also studied.

### 3.2. Reference expansion schedule

Table N-8-4 shows a near-optimum expansion schedule (case 10) for the load forecast assumed based on the reference conditions. It is seen that the schedule confirms the desirability of introducing the second nuclear unit at Laguna Verde in 1981 and calls for the further introduction of 600 MW nuclear units in 1982, 1983, 1984 and 1988, of 800 MW nuclear units in 1983, 1985 (3 units), 1986 (3 units), 1988 and 1989, and of 1200 MW nuclear units in 1987, 1988 and 1989, respectively. On this basis, the total nuclear capacity added during the study period amounts to 14 870 MW out of a total of 21 870 MW capacity added. At the end of 1989, the nuclear capacity would correspond to 42.5% of the total capacity, compared with 32.5% for conventional steam plants, 23.0% for hydro and pumped storage and 2.0% for gas turbines.

### 3.3. Sensitivity studies

The potential market for nuclear plants in Mexico in the reference case and for various sensitivity studies is shown in Table N-8-5 in the study decade. It is seen that the potential nuclear market is constant at 14 870 MW.

### 3.4. Financing requirements

The domestic, foreign and total financing requirements associated with the construction of the thermal plants in the reference expansion schedule (see Table N-8-4) are summarized in Table N-8-6. It is seen that the total annual plant construction expenditures reach a peak of US $\$736.5 \times 10^6$ in 1983. These costs include interest during construction based on the assumption that interest would be paid currently with expenditures. The total cost of the 10-year expansion program amounts to US $\$5200.2 \times 10^6$.

The nuclear fuel cycle working capital costs (i.e. investment in first core etc.) amounting to US $\$348.0 \times 10^6$ are also shown in Table N-8-6 as a separate item because financing arrangements for such costs may differ from those for the plant construction program. The total annual investment costs, however, are shown for completeness.

The given costs do not include annual operating and maintenance costs and variable fuel costs.

### 3.5. Conclusions

(a) The estimated total market for generating units which will be commissioned during the 1980-1989 period is 21 870 MW. Because of the shortage of economically exploitable hydroelectric power, however, the market for new thermal plants will probably be almost 20 000 MW.

TABLE N-8-4. REFERENCE SYSTEM EXPANSION SCHEDULE

| Year | Capacity (MW) | | | | | | | % Reserve [a] | Annual loss-of-load probability |
|---|---|---|---|---|---|---|---|---|---|
| | Retirements | Nuclear | Conventional steam | Hydro | Pumped storage | Gas turbines | Total | | |
| Total system 1979 | | 670 | 7 581 | 6 200 | 0 | 760 | 15 211 | 24.7 | |
| 1980 [b] | 0 | 0 | 1 x 300 | 1 x 300<br>1 x 400 | 0 | 0 | 1 000 | 20.1 | 0.0013 |
| 1981 | 0 | 670 | 3 x 300 | 0 | 150 | 0 | 1 720 | 19.5 | 0.0007 |
| 1982 | - 120 [c] | 600 | 3 x 300 | 0 | 150 | 0 | 1 530 | 17.2 | 0.0007 |
| 1983 | - 30 [c] | 600, 800 | 1 x 300 | 0 | 2 x 150 | 0 | 1 970 | 17.8 | 0.0005 |
| 1984 | - 150 [c] | 600 | 3 x 300 | 0 | 150 | 0 | 1 500 | 15.8 | 0.0007 |
| 1985 | 0 | 3 x 800 | 1 x 300 | 0 | 150 | 0 | 2 850 | 19.4 | 0.0004 |
| 1986 | 0 | 3 x 800 | 2 x 300 | 0 | 150 | 0 | 3 150 | 22.1 | 0.0002 |
| 1987 | 0 | 1 200 | 2 x 300 | 0 | 150 | 0 | 1 950 | 19.2 | 0.0007 |
| 1988 | - 190 [c] | 600, 800, 1 200 | 0 | 0 | 150 | 0 | 2 560 | 18.6 | 0.0011 |
| 1989 | 0 | 800, 1 000, 1 200 | 0 | 0 | 150 | 0 | 3 150 | 19.6 | 0.0011 |
| Total additions 1980 - 89 | - 490 [d] | 14 870 | 4 800 | 700 | 1 500 | 0 | 21 380 | Average 18.9 | Average 0.0007 |
| Total system 1989 | - | 15 540 | 12 381<br>- 490 [d]<br>11 891 | 6 900 | 1 500 | 760 | 36 591 | 19.6 | |
| Additions 1990-2000 | 0 | 29 200 | 21 900 | 0 | 300 | | 51 400 | | |
| Total system 2000 | | 44 740 | 33 791 | 6 900 | 1 800 | 760 | 87 991 | 25.7 | |

[a] Critical quarter.
[b] Additions and retirements each year.
[c] Total of several small units.
[d] All retirements are thermal and are netted out in year 1989.

TABLE N-8-5. POTENTIAL MARKET FOR NUCLEAR PLANTS WITH VARYING ECONOMIC PARAMETERS (MW)

| Case | Reference case | 6% discount rate | 10% discount rate | 0% fuel escalation rate | 4% fuel escalation rate | ORCOST-1 |
|---|---|---|---|---|---|---|
| Period | | | | | | |
| At 12/31/1972 [a] | 670 | 670 | 670 | 670 | 670 | 670 |
| Added 1973-79 [b] | 0 | 0 | 0 | 0 | 0 | 0 |
| At 12/31/1979 [a] | 670 | 670 | 670 | 670 | 670 | 670 |
| 1980 [b] | 0 | 0 | 0 | 0 | 0 | 0 |
| 1981 | 670 | 670 | 670 | 670 | 670 | 670 |
| 1982 | 600 | 600 | 600 | 600 | 600 | 600 |
| 1983 | 600 | 600 | 600 | 600 | 600 | 600 |
| | 800 | 800 | 800 | 800 | 800 | 800 |
| 1984 | 600 | 600 | 600 | 600 | 600 | 600 |
| 1985 | 3 x 800 | 3 x 800 | 3 x 800 | 3 x 800 | 3 x 800 | 3 x 800 |
| 1986 | 3 x 800 | 3 x 800 | 3 x 800 | 3 x 800 | 3 x 800 | 3 x 800 |
| 1987 | 1 200 | 1 200 | 1 200 | 1 200 | 1 200 | 1 200 |
| 1988 | 600 | 600 | 600 | 600 | 600 | 600 |
| | 800 | 800 | 800 | 800 | 800 | 800 |
| | 1 200 | 1 200 | 1 200 | 1 200 | 1 200 | 1 200 |
| 1989 | 800 | 800 | 800 | 800 | 800 | 800 |
| | 1 000 | 1 000 | 1 000 | 1 000 | 1 000 | 1 000 |
| | 1 200 | 1 200 | 1 200 | 1 200 | 1 200 | 1 200 |
| Total additions 1980 - 89 | 14 870 | 14 870 | 14 870 | 14 870 | 14 870 | 14 870 |
| Total system 1989 | 15 540 | 15 540 | 15 540 | 15 540 | 15 540 | 15 540 |
| Nuclear % of system installed capacity | 42.5 | 42.5 | 42.5 | 42.5 | 42.5 | 42.5 |

[a] Units in operation, under construction or committed (number and size of each unit).
[b] Units expected to be committed during period or year (number and size of each unit).

(b) An evaluation of the four conventional fuels available in Mexico (domestic coal, oil and natural gas, and imported oil) indicates that oil (domestic and imported oil was assumed to be priced at internationally prevailing levels) is the fuel which will be most competitive with respect to nuclear power. The reasons for these conclusions are as follows:

The production of coal will be limited by the amount of known reserves (mostly in the north) and these are reserved mainly for the metallurgical industry. (However, about four 300 MW coal-fired mine-mouth units are assumed to be built in the northern region.)

The production of natural gas will be insufficient to meet increasing industrial needs, thus very little will be used for power production.

(c) An evaluation of the competitiveness of nuclear versus oil-fired plant units indicates that under the reference conditions (8% discount rate, 2% escalation on fuel prices) nuclear plant units are more competitive than oil-fired plant units. Assuming that for regional economic reasons a number of 300 MW oil and coal-fired units will continue to be built in

certain regions during the study decade, all of the 600 MW and larger units considered would be nuclear giving an aggregate potential nuclear market of about 15 000 MW.

(d) An evaluation of the sensitivity of the results to various economic parameters indicates that under economic conditions which tend to favour nuclear plants (6% discount rate, 4% fossil fuel escalation, lower capital cost differential) the nuclear market would remain at about 15 000 MW. Under economic conditions which tend to favour oil-fired plants (10% discount rate, 0% fossil fuel escalation) the nuclear market would still remain at about 15 000 MW. Thus the nuclear market shows little sensitivity to changes in the economic parameters.

TABLE N-8-6. FINANCING REQUIREMENTS FOR REFERENCE THERMAL PLANTS EXPANSION SCHEDULE ($10^6$ US $)

| Year | Plant investment | | | Nuclear fuel working capital[a] | Total |
|---|---|---|---|---|---|
| | Domestic | Foreign | Subtotal | | |
| 1975 | 0.7 | 0.7 | 1.4 | | |
| 1976 | 6.8 | 6.8 | 13.6 | | |
| 1977 | 32.0 | 30.5 | 62.5 | | |
| 1978 | 104.7 | 92.1 | 196.8 | | |
| 1979 | 217.5 | 184.3 | 401.8 | 1.8 | 403.6 |
| 1980 | 274.1 | 236.7 | 510.8 | 18.4 | 529.2 |
| 1981 | 287.3 | 262.4 | 550.2 | 18.4 | 568.6 |
| 1982 | 342.9 | 316.0 | 658.9 | 33.8 | 692.7 |
| 1983 | 382.3 | 356.2 | 738.5 | 20.8 | 759.3 |
| 1984 | 374.0 | 352.1 | 726.1 | 57.4 | 783.5 |
| 1985 | 353.7 | 330.8 | 684.5 | 54.0 | 738.5 |
| 1986 | 285.0 | 274.9 | 559.9 | 27.2 | 587.1 |
| 1987 | 158.4 | 158.4 | 316.8 | 59.8 | 376.6 |
| 1988 | 38.5 | 38.5 | 77.0 | 56.4 | 133.4 |
| Total | 2 858.6 | 2 641.6 | 5 500.2 | 348.0 | 5 848.2 |

[a] Domestic expenditures for the nuclear fuel working capital were assumed to amount to 50% of the total.

# 9. PAKISTAN

## 1. ECONOMIC AND SOCIAL FACTORS

### 1.1. Population growth

The total population of Pakistan was estimated at about 55.7 million at end 1972[1]. In 1961 (the time of the latest published census)[1], the urban population was 22.5% of the total. Though urbanization has been rapidly increasing in subsequent years as a result of increasing industrialization, the rural population remains the majority.

[1] The 1972 census (unavailable at the time the Market Survey was undertaken) shows a much higher population growth rate during the 1961-72 period resulting in a present population of 64.9 million.

The average annual population growth of Pakistan is not well known but was taken to be 2% for the Survey assuming that the birth control program is successful. Both higher and lower estimates have been made. Based on 2%/yr growth rate, the population is expected to increase to about 80 million by 1990. If the population growth continues at its present rate, the population in 1990 could be more than 130 million.

## 1.2. Economic development and goals

At independence, Pakistan had practically no industry and only a rudimentary banking, commercial and governmental structure. About every tenth person was a refugee. Agriculture was and continues to be the major economic activity though its importance is decreasing. At present it contributes more than one-third to the national product of Pakistan and employs more than half of the labour force.

During the later half of the 1950s rapid industrial growth occurred and by the 1960s export of capital goods increased. At the same time agriculture began to expand rapidly as a result of increased irrigation from tube-wells and the use of more modern practices. The average annual growth rate of GNP has been 6.0% during the past decade. The 1972-73 target for the growth of GNP is 6.6%. The per-capita GNP will nevertheless remain among the lower levels for developing countries, even if this rate is achieved over an extended period.

## 1.3. Energy needs and resources

Total energy consumption in 1971 was 10 854 tons of coal equivalent (TEC). The electrical portion of this total was about 25%. (It should be noted that non-commercial fuels such as wood, dung etc. are not included in these totals.)

Hydro is, and will continue to be, a significant source of electrical energy in Pakistan. However, practically all of the hydro potential is situated in the Northern zone. It is estimated that the total hydro potential is about 20 000 MW out of which about 670 MW have been developed by the end of 1972. As hydro dams in Pakistan are multi-purpose projects and as most of the potential sites are situated in inaccessible regions away from load centres, it is not possible to develop more than about 7500 MW by the end of the century.

All of the coal reserves are more lignites than coal, with high moisture, ash and sulphur content. The coal in the Quetta area (Baluchistan) is unsuitable for direct conversion into metallurgical coke but can be used in brick-kilns and for electric power. It cannot be transported to other areas because of its friability and poor stacking characteristics. Perhaps the most important coal deposit from a power generation point of view are the quite large reserves located at Lakhra, 85 miles north-east of Karachi. This coal is a high quality lignite. It is non-coking, susceptible to spontaneous combustion and has a high sulphur content. For power production the coal can only be used in mine-mouthed power stations. The total amount of reserves at the Lakhra fields is still uncertain, being variously reported as 130 to 240 million tons.

Pakistan has some good reserves of natural gas. The total estimated proven reserves of all fields are about $13.9 \times 10^{12}$ ft$^3$ (in terms of 1000 Btu per ft$^3$ gas). The 1986 consumption forecast is $336 \times 10^9$ ft$^3$. If this value is reached, the gas fields would be exhausted in about 30 years.

In spite of large exploration activities, only very small oil fields have been found.

## 1.4. Interest in nuclear power

The first nuclear power station in Pakistan, KANUPP, was recently commissioned and is being operated as a base load plant, supplying power to the Karachi Electric Supply Company (KESC). The plans for expansion of the KESC system show a second nuclear unit being considered for 1981. The Water and Power Development Authority (WAPDA) has just completed a power demand forecast and they anticipate the need for at least 500 MW in the Northern Grid by 1978 - 79, which may be nuclear. The Pakistan Atomic Energy Commission (PAEC) has good relations with both organizations and is working with WAPDA in regard to the Northern Grid studies.

## 2. PARAMETERS CONSIDERED IN THE ANALYSIS

### 2.1. Basic conditions

Table N-9-1 summarizes the conditions assumed in the analysis of various alternative expansion plans for the Combined system (Karachi, Lower Sind and Northern systems) in Pakistan during the period 1980 - 1989, and the resulting capacities, reserve margins and annual loss-of-load probability of the selected expansion alternatives. In carrying out the analysis, the hydro station additions associated with Tarbela Dam (now under construction), and the hydro project at Kalabagh were considered to be firmly committed additions. The total Combined system capacity in 1972 was 1833 MW of which 567 MW was hydro. The total hydro capacity added during the 1972 - 79 period was 272 MW. Thermal additions now planned or under construction (less retirements of 33 MW) amount to 1287 MW, bringing the total capacity at the start of the study period to 3392 MW.

TABLE N-9-1. SUMMARY OF CONDITIONS USED IN THE ANALYSIS

| | 1979 | 1989 |
|---|---|---|
| Population ($10^6$) | 63.9 | 77.9 |
| GNP/capita (US $/yr) | 192.7 | 279.5 |
| Energy consumption-utility (GWh/yr) | 15720 | 33560 |
| Peak demand (MW) | 3080 | 6581 |
| Total installed capacity (MW) | 4320 | 8845 |
| Installed capacity, critical period (MW) | 3392[a] | 6863[b] |
| Thermal capacity (MW) | 2553 | 4553 |
| Reserve margin in critical quarter[a] (%) | 19.6[c] | 13.2 |
| Annual loss-of-load probability | 0.0001[c] | 0.0003 |

[a] 2nd quarter (hydro capacity = 47.5% of installed capacity).
[b] 2nd quarter (hydro capacity = 53.8% of installed capacity).
[c] Systems will not be combined until 1985 and in 1979 the reserve margin is 22.1% in the Karachi - Lower Sind system and 14.2% in the Northern - Upper Sind system. The respective loss-of-load probabilities for 1979 are 0.0067 and 0.0005.

### 2.2. Characteristics of system as of 1979

The existing and committed power expansion plans of Pakistan are only sufficient to meet peak load demand up to about 1978. For this reason, conventional plant capacity additions amounting to about 1560 MW were assumed to be made to the system to meet the 1979 peak demand and provide a sufficient reserve margin for adequate loss-of-load probability. For the purpose of the computer analyses, the existing and committed units were grouped into so-called hypothetical units having common characteristics as shown in Table N-9-2. The technical and economic characteristics of each hypothetical plant shown in the table were computed from the characteristics of the actual plants comprising each unit.

### 2.3. Characteristics of alternative generating units

The characteristics of alternative thermal generating units considered in the evaluation of possible system expansion configurations (i.e. schedules of additions) are shown in Table N-9-3. These characteristics were derived by methods described in Appendixes E, G, I and J.

TABLE N-9-2. CHARACTERISTICS OF GENERATING PLANTS IN "FIXED SYSTEM"

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| KOR1 | 2 | 25 | 66 | 3125. | 2557. | 132.00 | 0.0 | 1 | 1 | 5.00 | 30 | 80 | 0. | 0.300 | 0.0 | 2772. |
| KOR2 | 1 | 45 | 125 | 2645. | 2252. | 132.00 | 0.0 | 1 | 1 | 5.00 | 30 | 150 | 0. | 0.300 | 0.0 | 2393. |
| KANP | 1 | 25 | 125 | 3465. | 2528. | 0.0 | 46.00 | 0 | 1 | 8.00 | 30 | 150 | 0. | 0.320 | 0.0 | 2715. |
| KOR3 | 1 | 45 | 125 | 2646. | 2252. | 132.00 | 0.0 | 1 | 1 | 5.00 | 30 | 150 | 0. | 0.300 | 0.0 | 2394. |
| WWH1 | 1 | 45 | 95 | 4560. | 2682. | 132.00 | 0.0 | 1 | 1 | 5.00 | 30 | 100 | 0. | 0.300 | 0.0 | 3572. |
| WWH2 | 10 | 10 | 10 | 3433. | 3433. | 132.00 | 0.0 | 1 | 1 | 5.00 | 30 | 20 | 0. | 1.000 | 0.0 | 3433. |
| WWH3 | 1 | 40 | 150 | 2600. | 2250. | 132.00 | 0.0 | 1 | 1 | 6.00 | 30 | 150 | 0. | 0.300 | 0.0 | 2343. |
| KOT1 | 3 | 14 | 14 | 4208. | 4208. | 132.00 | 0.0 | 1 | 1 | 3.00 | 20 | 20 | 0. | 0.800 | 0.0 | 4208. |
| HYD1 | 5 | 9 | 9 | 4306. | 4306. | 132.00 | 0.0 | 1 | 1 | 2.00 | 30 | 20 | 0. | 1.000 | 0.0 | 4306. |
| MUL1 | 4 | 40 | 65 | 3178. | 2154. | 164.00 | 0.0 | 1 | 1 | 5.00 | 30 | 80 | 0. | 0.300 | 0.0 | 2784. |
| LYL1 | 2 | 40 | 66 | 3178. | 2098. | 180.00 | 0.0 | 1 | 1 | 6.00 | 30 | 80 | 0. | 0.500 | 0.0 | 2753. |
| OTHR | 4 | 26 | 38 | 4479. | 3993. | 156.00 | 0.0 | 2 | 1 | 4.00 | 20 | 80 | 0. | 0.800 | 0.0 | 4326. |
| GUD1 | 2 | 40 | 110 | 2600. | 2250. | 132.00 | 0.0 | 1 | 1 | 5.00 | 30 | 150 | 0. | 0.300 | 0.0 | 2377. |
| GUD2 | 1 | 50 | 200 | 2920. | 2195. | 132.00 | 0.0 | 1 | 1 | 6.00 | 30 | 150 | 0. | 0.300 | 0.0 | 2376. |
| HYDO | 1 | 0 | 1767 | 0. | 0. | 0.0 | 0.0 | 5 | 1 | 0.0 | 0 | 0 | 8264. | 0.0 | 0.0 | 0. |

TABLE N-9-3. CHARACTERISTICS OF GENERATING PLANTS FOR SYSTEM EXPANSION ALTERNATIVES

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| N300 | 0 | 150 | 300 | 2645. | 2360. | 0.0 | 57.90 | 0 | 1 | 6.50 | 28 | 300 | 0. | 0.520 | 0.0 | 2503. |
| N400 | 0 | 200 | 400 | 2643. | 2362. | 0.0 | 57.00 | 0 | 1 | 9.80 | 28 | 400 | 0. | 0.420 | 0.0 | 2502. |
| N600 | 0 | 300 | 600 | 2638. | 2365. | 0.0 | 55.10 | 0 | 1 | 12.00 | 28 | 600 | 0. | 0.320 | 0.0 | 2501. |
| N800 | 0 | 400 | 800 | 2632. | 2369. | 0.0 | 53.20 | 0 | 1 | 12.20 | 35 | 800 | 0. | 0.270 | 0.0 | 2500. |
| 0100 | 0 | 50 | 100 | 2388. | 2192. | 132.00 | 0.0 | 1 | 1 | 6.50 | 21 | 100 | 0. | 0.300 | 0.0 | 2290. |
| 0200 | 0 | 100 | 200 | 2280. | 2146. | 132.00 | 0.0 | 1 | 1 | 5.40 | 21 | 200 | 0. | 0.250 | 0.0 | 2213. |
| 0300 | 0 | 150 | 300 | 2335. | 2183. | 132.00 | 0.0 | 1 | 1 | 6.50 | 28 | 300 | 0. | 0.230 | 0.0 | 2259. |
| 0400 | 0 | 200 | 400 | 2324. | 2098. | 132.00 | 0.0 | 1 | 1 | 9.80 | 28 | 400 | 0. | 0.220 | 0.0 | 2211. |
| 0600 | 0 | 300 | 600 | 2328. | 2172. | 132.00 | 0.0 | 1 | 1 | 12.00 | 28 | 600 | 0. | 0.200 | 0.0 | 2250. |
| 0800 | 0 | 400 | 800 | 2334. | 2170. | 132.00 | 0.0 | 1 | 1 | 12.20 | 35 | 800 | 0. | 0.200 | 0.0 | 2252. |
| GT50 | 0 | 50 | 50 | 4000. | 4000. | 132.00 | 0.0 | 2 | 1 | 2.00 | 2 | 100 | 0. | 0.750 | 0.0 | 4000. |
| N400 | 0 | 200 | 400 | 2643. | 2362. | 0.0 | 57.00 | 0 | 1 | 9.80 | 28 | 400 | 0. | 0.420 | 0.0 | 2502. |
| N600 | 0 | 300 | 600 | 2638. | 2365. | 0.0 | 55.10 | 0 | 1 | 12.00 | 28 | 600 | 0. | 0.420 | 0.0 | 2501. |
| N800 | 0 | 400 | 800 | 2632. | 2369. | 0.0 | 53.20 | 0 | 1 | 12.20 | 35 | 800 | 0. | 0.270 | 0.0 | 2500. |
| N1T0 | 0 | 500 | 1000 | 2627. | 2372. | 0.0 | 51.30 | 0 | 1 | 12.20 | 35 | 1000 | 0. | 0.230 | 0.0 | 2499. |
| 0400 | 0 | 200 | 400 | 2324. | 2098. | 0.0 | 172.00 | 1 | 1 | 9.80 | 28 | 400 | 0. | 0.240 | 0.0 | 2211. |
| 0600 | 0 | 300 | 600 | 2328. | 2172. | 0.0 | 172.00 | 1 | 1 | 12.00 | 28 | 600 | 0. | 0.190 | 0.0 | 2250. |
| 01T0 | 0 | 500 | 1000 | 2344. | 2152. | 132.00 | 0.0 | 1 | 1 | 12.20 | 35 | 1000 | 0. | 0.200 | 0.0 | 2248. |
| GT50 | 0 | 50 | 50 | 4000. | 4000. | 0.0 | 172.00 | 2 | 1 | 2.00 | 4 | 100 | 0. | 0.750 | 0.0 | 4000. |

## 3. RESULTS

### 3.1. Summary of cases considered

In developing the near-optimum expansion plans, consideration was given to: (a) the reserve margin required to maintain a reasonable loss-of-load probability[2]; (b) the maximum unit size permitted, consistent with system stability (200 MW in the Karachi and Lower Sind system until 1987 and 300 MW for 1988-89, and 600 MW in the Northern and Upper Sind System); (c) the maximum demand and the annual growth of maximum demand; and (d) the relative costs of various size units.

### 3.2. Reference expansion schedules

The resulting system expansion plan consisted of the additions of 200, 300 and 600 MW units on the schedule shown in Table N-9-4.

### 3.3. Sensitivity studies

Various sensitivity studies were made for each system, in each case holding all reference case conditions constant except the condition under study. The most likely market for nuclear plants in Pakistan under these varying economic conditions is shown in Table N-9-5. It is seen that this nuclear market varies from 0 - 1200 MW. The sensitivity studies were carried out varying fuel escalation rates, discount rates and capital costs. It was found that the schedule of nuclear plant additions shown in the table covered all of the variations in economic parameters.

### 3.4. Financing requirements

The domestic, foreign and total financing requirements associated with the construction of the thermal plants in the reference expansion schedule (see Table N-9-4) are summarized in Table N-9-6. It is seen that the total annual expenditures reach a peak of US $\$93.5 \times 10^6$ in 1983. These costs include interest during construction based on the assumption that interest would be paid currently with expenditures. The total cost of the 10-year expansion program amounts to US $\$562.2 \times 10^6$.

The nuclear fuel cycle working capital costs (i.e. investment in first core etc.) are also shown in Table N-9-4 as a separate item because financing arrangements for such costs may differ from those for the plant construction program. The total annual investment costs, however, are shown for completeness.

The given costs do not include annual operating and maintenance costs and variable fuel costs.

### 3.5. Conclusions

(a) The estimated total market for thermal generating units that will be commissioned during the 1980 - 89 period is 2000 MW. (In addition, 8 × 175 MW hydro units at Tarbela (a total of 346 MW firm) and 1125 MW at Kalabagh will be commissioned.

(b) Under the reference conditions of the study, nuclear power will not be as economical as other alternatives until there is a reliable 500 kV transmission system interconnecting the Karachi-Lower Sind system and the Northern-Upper Sind system.

(c) Assuming that a reliable Combined system exists in the mid-1980s, 600 MW of the 800 MW required in the 1985 - 1989 period would be more economical as nuclear than as oil-fired capacity.

(d) In regard to fossil plants, oil was selected as the fuel for future plants in view of the limited and heavily committed gas reserves. Oil was valued at world market prices plus transportation allowances. The coal at Lakhra may prove to be more economical than

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[2] 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 N-9-4. COMBINED SYSTEM CAPACITY EXPANSION SCHEDULE - REFERENCE CASE

| Year | | Installed capacity (MW)[a] | | | | | % Reserve[b] | Annual loss-of-load probability |
|---|---|---|---|---|---|---|---|---|
| | | Retirements | Nuclear | Conventional steam | Hydro[b] | Total | | |
| 1972 | | - | 125 | 597 S<br>544 N | 567 | 1833 | - | - |
| Additions 1972-1979 | | - 33 S[c] | 0 | 600 S<br>720 N | 272 | 1559[c] | - | - |
| Total system 1979 | | - | 125 | 1164 S<br>1264 N | 839[c] | 3392[c] | - | - |
| Additions 1980 | Systems not combined | none | | 200 S | + 86 | 286 | - | - |
| 1981 | | | | | + 87 | 87 | - | - |
| 1982 | | | | 200 S<br>600 N | | 800 | - | - |
| 1983 | | | | | | 0 | - | - |
| 1984 | | | | 200 S | + 86 | 286 | - | - |
| 1985 | Systems combined | | | | + 87 | 87 | 10.0 | 0.0007 |
| 1986 | | | 600 N | | | 600 | 14.5 | 0.0005 |
| 1987 | | | | 200 S | | 200 | 10.0 | 0.0011 |
| 1988 | | | | | +1125 | 1125 | 22.1 | 0.0000 |
| 1989 | | | | | | 0 | 13.2 | 0.0003 |
| Total additions 1980-89 | | 0 | 600 | 1400 | 1471 | 3471 | - | - |
| Total system 1989 | | - | 725 | 3828 | 2310 | 6863 | 13.2 | 0.0003 |
| Additions 1990-2000 | | -726[d] | 1200 S<br>3200 N | 1950 S<br>2350 N | +500 | 8474 | - | - |
| Total system 2000 | | - | 5125 | 7402[d] | 2810 | 15337 | 10.9 | 0.0091 |

[a] S - represents South (Karachi) System
N - represents North System
[b] Critical quarter (2nd quarter)
[c] All are thermal units netted out in year 1979
[d] All are thermal units netted out in year 2000

oil, in which case it would displace oil-fired units in the expansion plan. However, in view of the unproved costs of coal, coal-fired plants were not included in the study.

(e) In addition to the savings associated with the nuclear plant made more economical by the Combined system there are further advantages of the high voltage transmission system, in particular the transmission of hydro generated power to the Karachi-Lower Sind system during the third and fourth quarters and the transmission of thermal generated power to the Northern-Upper Sind system during the critical second quarter; the evaluation of the advantages, however, was beyond the scope of this study.

(f) The total financial requirements associated with the reference thermal expansion schedule amount to US $562 million of which US $435 million may be foreign.

TABLE N-9-5. POTENTIAL MARKET FOR NUCLEAR PLANTS WITH VARYING ECONOMIC PARAMETERS (MW)

| Year | Reference case | 6% discount rate | 0% oil price escalation rate |
|---|---|---|---|
| 1980 | | | ↑ |
| 1981 | | | |
| 1982 | | 600 | |
| 1983 | | | |
| 1984 | | | no nuclear market |
| 1985 | | | |
| 1986 | 600 | 600 | |
| 1987 | | | |
| 1988 | | | |
| 1989 | | | ↓ |
| Total | 600 | 1200 | 0 |

TABLE N-9-6. FINANCING REQUIREMENTS FOR REFERENCE THERMAL PLANTS EXPANSION SCHEDULE ($10^6$ US $)

| Year | Plant investment | | | Nuclear fuel working capital[a] | Total |
|---|---|---|---|---|---|
| | Domestic | Foreign | Subtotal | | |
| 1976 | 0 | 0 | 0 | | 0 |
| 1977 | 0.7 | 2.2 | 2.9 | | 2.9 |
| 1978 | 6.8 | 20.6 | 27.4 | | 27.4 |
| 1979 | 12.0 | 36.1 | 48.1 | | 48.1 |
| 1980 | 21.1 | 63.6 | 84.7 | | 84.7 |
| 1981 | 16.9 | 53.9 | 70.8 | | 70.8 |
| 1982 | 14.8 | 52.9 | 67.7 | | 67.7 |
| 1983 | 19.8 | 73.7 | 93.5 | | 93.5 |
| 1984 | 15.3 | 60.6 | 75.9 | 1.6 | 77.5 |
| 1985 | 11.7 | 39.9 | 51.6 | 15.0 | 66.6 |
| 1986 | 5.7 | 17.3 | 23.0 | | 23.0 |
| 1987 | 0 | 0 | 0 | | 0 |
| 1988 | 0 | 0 | 0 | | 0 |
| Total | 124.8 | 420.8 | 545.6 | 16.6 | 562.2 |

[a] Domestic expenditures for the nuclear fuel working capital were assumed to amount to 10% of the total.

# 10. PHILIPPINES

## 1. ECONOMIC AND SOCIAL FACTORS

### 1.1. Population growth

The population of the Philippines was about 36.7 million according to the 1970 census, about 49.5% of which was in Luzon proper and about 20.5% in Mindanao proper. The rate of population growth averaged about 2%/yr during 1918-1948 but increased to about 3.0%/yr during 1960-1970, mainly as the result of a declining mortality rate. The Government's Population Commission is encouraging family planning to reduce the growth rate and the 1972-1975 Four-Year Development Plan calls for a reduction to 2.3 - 2.7%/yr by 1975. It is hoped that the figure can be reduced to 2%/yr by 1978-1980.

### 1.2. Economic development and goals

For the period 1961-1971 GDP increased at an average annual rate of 13.0% measured at market prices or 5.6% at constant prices. The indices of production for agriculture, mining and manufacturing grew at average annual rates of 4.0%, 8.9% and 5.7%, respectively, during the same period. In 1971, mining and quarrying, manufacturing, construction, transportation, storage, communication and utilities accounted for 27.4% of NDP, compared with 37.6% for agriculture, 14.0% for commerce, and 20.7% for services.

The 1971 GDP per capita was equivalent to US $208. The target under the 1972-1975 Four-Year Development Plan for average growth rate during 1971-75 of GNP at constant prices is about 6.9%/yr.

### 1.3. Environmental considerations

Present practice is to control air and water pollution by dilution and dispersion; for example, ground level sulphur dioxide concentration is controlled by power plant stack height rather than by restricting the sulphur content of fuel oil. The authorities are aware of the importance of environmental protection and could impose some emission restrictions in the Manila area, for example, in the future. It is currently assumed, however, that power plants commissioned in the 1980s would be located such that dilution and dispersal would continue to be satisfactory. For sea-coast sites, at least, there seem to be adequate cooling water supplies.

### 1.4. Energy needs and resources

Energy consumption per capita in 1970 was about 0.28 TEC per year, of which about 97% was based on fuel imports, mostly crude oil. Total energy consumption grew at an average annual rate of about 9.8% during 1967-70.

Electric energy production accounts for about 20% of the total and is growing somewhat faster than total energy consumption. Electric energy consumption in Luzon was about 360 kWh per capita in 1972; in Mindanao it was only about one-fifth as much; and in the rest of the country much lower still. Only about 23% of the population is now served by electricity. Of this number more than two-thirds are located in the Greater Manila area and other chartered cities. The present three-year rural electrification program contemplates the establishment of 36 electric cooperative systems initially serving two million of the five million population in the areas served.

Of the 2400 MW hydroelectric potential in Luzon, 438 MW are in operation and another 100 MW are scheduled for operation by 1976. In Mindanao, of the 1250 MW hydro potential, 155 MW are in operation and another 305 MW scheduled for operation by 1979. No other hydro projects are included in the current ten-year program.

Coal is found in many parts of the Philippines but only a few mines are in commercial operation because most of the deposits are either limited in size or have low heating value. After a lull of six years, oil exploration drilling was started again in 1970 in the south. Initial results are considered to be encouraging but no major discoveries have been reported. Gas reserves are estimated to be 2500 million $ft^3$, with no current commercial production.

A first geothermal power plant, of 11 MW capacity, is being installed in Tiwi, Albay (Luzon). Assuming that it is successful, the National Power Corporation has tentative plans to commission five 55 MW units during 1977-1981.

### 1.5. Interest in nuclear power

The President has established a "Coordinating Committee for Nuclear Power Study" and a feasibility study for a nuclear power station in Luzon has been carried out in 1972-73 by Electrowatt Engineering Services in joint venture with Sargent & Lundy, with the IAEA as Executing Agency. The study indicates that the introduction of twin 600 MW nuclear units into the Luzon Grid during 1980-84 is technically and economically feasible. This study was a follow-up of a 1964-66 UNDP-sponsored study which indicated a long-term need for nuclear power in Luzon.

The Philippines Atomic Energy Commission was established in 1958. Legislation was enacted in 1968 providing for the licensing and regulation of atomic energy facilities and materials, establishing the rules on liability for nuclear damages, and tax exemption for importation of nuclear fuel for the first facility for a period of ten years.

### 1.6. Other factors

In addition to the usual economic considerations there are strategic considerations of diversification of types of energy sources. At present there is a heavy dependence on imported oil. Nuclear power is an alternative source of imported energy. Development of geothermal resources and increased hydro development are domestic energy source alternatives.

## 2. PARAMETERS USED IN THE ANALYSIS

### 2.1. Basic conditions

Table N-10-1 summarizes the conditions used in the analysis of various generation expansion plans for the Luzon Grid during the two decades 1980-1999. From the figures in the table it is seen that there is a total market of about 5400 MW during the 1980-89

TABLE N-10-1. SUMMARY OF CONDITIONS USED IN THE ANALYSIS (LUZON ONLY)

| | 1979 | 1989 |
|---|---|---|
| Population ($10^6$) | 24.6 | 30.3 |
| GNP/capita (US $/yr) [a] | 271 | 421 |
| Energy consumption (GWh/yr) | 13 614 | 32 228 |
| Peak demand (MW) | 2 391 | 5 660 |
| Total installed capacity (MW) | 3 368 | 8 603 |
| Installed capacity, critical period (MW) | 3 177 [b] | 8 583 [c] |
| Installed thermal capacity (MW) | 2 799 | 8 034 |
| Reserve margin (%) | 41 [b] | 52 [c] |
| Annual loss-of-load probability | 0.0050 | 0.0024 |

[a] 1964 US $.
[b] In 2nd quarter (peak hydro = 66% of total capacity).
[c] In 4th quarter (peak hydro = 96.5% of total capacity).

study decade. This total market would be somewhat smaller if a higher loss-of-load probability than the indicated 0.28% is acceptable, since less reserve margin would be required; however, the base load market for which the nuclear plants are competing would not be greatly affected. The size of the total market is also affected by the size of units added, since smaller units tend to be more reliable and thus less reserve margin is required for a given loss-of-load probability. The reference expansion plan for this study assumes a continuation of past and projected local practice of adding relatively large size units, i.e. up to about 20% of annual peak load; however, an alternative expansion plan based on smaller units was also studied.

### 2.2. Characteristics of system as of 1979

The existing and committed power expansion plans of Manila Electric Co. (MECO) and the National Power Corporation (NPC) are only sufficient to meet peak load demand up to 1976. For this reason, conventional plant capacity additions amounting to 730 MW were assumed to be made to the system to meet the 1979 peak demand and provide a sufficient reserve margin for adequate loss-of-load probability. For the purpose of the computer analyses, the existing and committed units with a total capacity of 2638 MW were grouped into so-called hypothetical units having common characteristics as shown in Table N-10-2. The technical and economic characteristics of each hypothetical plant shown in the table were computed from the characteristics of the actual plants comprising each unit.

### 2.3. Characteristics of alternative generating units

The characteristics of alternative thermal generating units considered in the evaluation of possible system expansion configurations (i.e. schedules of additions) are shown in Table N-10-3. These characteristics were derived by methods described in Appendixes E, G, I and J.

## 3. RESULTS

### 3.1. Summary of cases considered

Table N-10-4 shows the two expansion plans studied, one based on relatively large units and the other on relatively smaller units. The large-unit plan assumes addition of units up to 20% of annual peak load during the 1980s, decreasing to 8% by the end of the 1990s. This large unit policy is consistent with past practice in Luzon, and is indicated by WASP studies to be lower-cost than the alternative policy based on expansion with smaller units and to have acceptably low values of loss-of-load probability and energy not served. It does imply, however, acceptance of load shedding on loss of the largest unit, if frequency is to be maintained within limits normally acceptable. The small unit plan assumes size limits of about 11% of peak load during the 1980s, decreasing to 6% by the end of the 1990s. In spite of the fact that the large unit size case had significantly better average reliability and significantly higher average reserve margin it gave a lower cost near-optimum solution at reference conditions and for all sensitivity studies except at 0% oil cost escalation rate. Thus the large unit case was selected as the basis for further study using the dynamic programming optimization method.

### 3.2. Reference expansion schedule

Table N-10-5 shows the near-optimum expansion schedule for the large unit size additions under the reference conditions. It is seen that under these conditions, the first 600 MW nuclear plant would be introduced in 1982 and the total market for nuclear plants during the study period would amount to 3800 MW.

TABLE N-10-2. CHARACTERISTICS OF GENERATING PLANTS IN "FIXED SYSTEM"

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BLDL | 1 | 30 | 30 | 17114. | 17114. | 8.00 | 150.00 | 1 | 1 | 7.50 | 21 | 40 | 0. | 0.990 | 0.0 | 17114. |
| RCKA | 5 | 27 | 27 | 13766. | 13766. | 8.00 | 150.00 | 1 | 1 | 7.50 | 21 | 40 | 0. | 0.800 | 0.0 | 13766. |
| RCKB | 3 | 30 | 60 | 2388. | 2192. | 8.00 | 150.00 | 1 | 1 | 7.50 | 21 | 40 | 0. | 0.500 | 0.0 | 2290. |
| BAT1 | 1 | 38 | 76 | 2388. | 2192. | 8.00 | 150.00 | 1 | 1 | 7.00 | 28 | 100 | 0. | 0.400 | 0.0 | 2290. |
| TEGN | 2 | 55 | 110 | 2388. | 2192. | 8.00 | 150.00 | 1 | 1 | 6.50 | 28 | 100 | 0. | 0.320 | 0.0 | 2290. |
| GIB2 | 2 | 82 | 164 | 2347. | 2193. | 8.00 | 150.00 | 1 | 1 | 5.30 | 28 | 200 | 0. | 0.240 | 0.0 | 2270. |
| G2S1 | 2 | 110 | 220 | 2280. | 2146. | 8.00 | 150.00 | 1 | 1 | 5.40 | 28 | 200 | 0. | 0.190 | 0.0 | 2213. |
| S2M1 | 2 | 165 | 330 | 2335. | 2183. | 8.00 | 150.00 | 1 | 1 | 6.50 | 28 | 300 | 0. | 0.150 | 0.0 | 2259. |
| HYDR | 1 | 176 | 569 | 0. | 0. | 0.0 | 0.0 | 5 | 1 | 0.0 | 0 | 0 | 1916. | 0.300 | 0.0 | 0. |

TABLE N-10-3. CHARACTERISTICS OF GENERATING PLANTS FOR SYSTEM EXPANSION ALTERNATIVES

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GT1H | 0 | 100 | 100 | 4000. | 4000. | 8.00 | 262.00 | 2 | 1 | 7.50 | 28 | 40 | 0. | 0.200 | 0.0 | 4000. |
| 0200 | 0 | 100 | 200 | 2280. | 2146. | 8.00 | 150.00 | 1 | 1 | 5.40 | 28 | 200 | 0. | 0.190 | 0.0 | 2213. |
| 0300 | 0 | 150 | 300 | 2335. | 2183. | 8.00 | 150.00 | 1 | 1 | 6.50 | 28 | 300 | 0. | 0.150 | 0.0 | 2259. |
| 0400 | 0 | 200 | 400 | 2324. | 2098. | 8.00 | 150.00 | 1 | 1 | 9.80 | 28 | 400 | 0. | 0.130 | 0.0 | 2211. |
| 0600 | 0 | 300 | 600 | 2328. | 2172. | 8.00 | 150.00 | 1 | 1 | 12.00 | 28 | 600 | 0. | 0.100 | 0.0 | 2250. |
| 0800 | 0 | 400 | 800 | 2334. | 2170. | 8.00 | 150.00 | 1 | 1 | 12.20 | 35 | 800 | 0. | 0.090 | 0.0 | 2252. |
| 01T0 | 0 | 500 | 1000 | 2344. | 2152. | 8.00 | 150.00 | 1 | 1 | 12.20 | 35 | 1000 | 0. | 0.090 | 0.0 | 2248. |
| N300 | 0 | 150 | 300 | 2645. | 2360. | 0.0 | 58.00 | 0 | 1 | 6.50 | 28 | 300 | 0. | 0.320 | 0.0 | 2503. |
| N400 | 0 | 200 | 400 | 2643. | 2362. | 0.0 | 57.00 | 0 | 1 | 9.80 | 28 | 400 | 0. | 0.260 | 0.0 | 2503. |
| N600 | 0 | 300 | 600 | 2637. | 2365. | 0.0 | 55.00 | 0 | 1 | 12.00 | 28 | 600 | 0. | 0.200 | 0.0 | 2501. |
| N800 | 0 | 400 | 800 | 2632. | 2368. | 0.0 | 53.00 | 0 | 1 | 12.20 | 35 | 800 | 0. | 0.170 | 0.0 | 2500. |
| N1T0 | 0 | 500 | 1000 | 2627. | 2372. | 0.0 | 51.00 | 0 | 1 | 12.20 | 35 | 1000 | 0. | 0.140 | 0.0 | 2500. |
| GEOT | 0 | 55 | 55 | 0. | 0. | 0.0 | 0.0 | 3 | 1 | 7.50 | 28 | 40 | 0. | 0.200 | 0.0 | 0. |

TABLE N-10-4. ALTERNATIVE EXPANSION PLANS STUDIED

| Year | Large unit size | | | Small unit size | | |
|---|---|---|---|---|---|---|
| | Capacity added (MW) | Type of capacity | Loss-of-load probability | Capacity added (MW) | Type of capacity | Loss-of-load probability |
| 1980 | 400 | Oil/nucl. | 0.0047 | 300 | Oil, | 0.0052 |
| | | | | 100 | gas turbine | |
| 1981 | 400 | Oil/nucl. | 0.0034 | 300 | Oil/nucl. | 0.0043 |
| 1982 | 600 | Oil/nucl. | 0.0020 | 300 | Oil/nucl. | 0.0044 |
| 1983 | 100 | Gas turbine | 0.0050 | 300 | Oil/nucl. | 0.0057 |
| 1984 | 2 x 600 | Oil/nucl. | 0.0007 | 400 | Oil/nucl. | 0.0052 |
| 1985 | - | | 0.0028 | 400 | Oil/nucl. | 0.0059 |
| 1986 | 800 | Oil/nucl. | 0.0018 | 400 | Oil/nucl. | 0.0068 |
| 1987 | 800 | Oil/nucl. | 0.0012 | 2 x 400 | Oil/nucl. | 0.0028 |
| 1988 | 100 | Gas turbine | 0.0036 | 400 | Oil/nucl. | 0.0045 |
| 1989 | 1 000 | Oil/nucl. | 0.0024 | 600 | Oil/nucl. | 0.0053 |

## 3.3. Sensitivity studies

Table N-10-6 indicates the range of results obtained for the expansion studies with relatively large units. For the varying economic conditions studied the potential 1980-89 nuclear market is indicated to vary from 1000 MW to 4800 MW, these extremes corresponding to 0% and 4% oil cost escalation rates, respectively, and with linear salvage values. The market ranges shown covered all other sensitivity studies, including imposing a 20% penalty on foreign exchange costs, studies using ORCOST-1 capital costs, the use of the sinking fund method of calculating salvage values, and 2% escalation on nuclear fuel prices.

## 3.4. Financing requirements

The domestic, foreign and total financing requirements associated with the construction of the thermal plants in the reference expansion schedule (see Table N-10-5) are summarized in Table N-10-7. It is seen that the total annual expenditures reach a peak of US $188.8 \times 10^6$ in 1982. These costs include interest during construction based on the assumption that interest would be paid currently with expenditures. The total cost of the 10-year expansion program amounts to US $1401.8 \times 10^6$.

The nuclear fuel cycle working capital costs (i.e. investment in first core etc.) are also shown in Table N-10-5 as a separate item because financing arrangements for such costs may differ from those for the plant construction program. These costs amount to US $91.5 \times 10^6$. The total annual investment costs amounting to US $1493.3 \times 10^6$ are shown for completeness.

The given costs do not include annual operating and maintenance costs and variable fuel costs.

## 3.5. Conclusions

(a) The estimated total market in Luzon for generating units which will be commissioned during the 1980-89 period amounts to 5400 MW. Because of the lack of economically exploitable hydroelectric power near load centres, this market must be served by new thermal plants.

(b) An evaluation of the energy resources available in Luzon indicates that there are no indigenous fuels sufficient to support a thermal plant of reasonable size. An 11 MW geothermal power plant is being installed at Tiwi. If successful, NPC has tentative plans for five 55 MW units. In any event, to meet the growing demand for power it will be necessary to rely on imported oil or on nuclear power.

(c) The total tax-free cost of high sulphur heavy fuel oil, c.i.f. Luzon, as discussed in Appendix I, is 157 US ¢/$10^6$ kcal as of 1 January 1973. The tax-free domestic currency portion of this total cost is taken to be approximately equal to 1972 MECO costs equivalent to about 8 US ¢/$10^6$ kcal. There is a reasonable expectancy that this fuel oil cost will escalate at a rate of 2%/yr above an assumed general inflation rate of 4%/yr.

(d) Under such conditions, the market for nuclear plants which will be commissioned during the 1980s amounts to 3800 MW or 70% of the total thermal additions.

(e) The total financing requirement associated with the construction of new plants in accordance with the reference expansion schedule amounts to US $1401.8 × $10^6$. The nuclear fuel cycle working capital charges will add US $91.5 × $10^6$, bringing the total investment to US $1493.3 × $10^6$.

TABLE N-10-5. REFERENCE SYSTEM EXPANSION SCHEDULE - LARGE UNIT SIZES[a]

| Year | Capacity (MW) | | | | | | % Reserve[b] | Annual loss-of-load probability |
|---|---|---|---|---|---|---|---|---|
| | Retirements | Nuclear | Conventional steam | Hydro | Gas turbines | Total | | |
| Total system 1976 | | | 2069 | 569 | | 2638 | 38 | 0.0053 |
| Additions 1976-1979 | | | 730 | | | 730 | Average 43 | Average 0.0039 |
| Total system 1979 | | | 2799 | 569 | | 3368 | 41 | 0.0050 |
| 1980[c] | 30[d] 2 × 27[e] | | 400 | | | 316 | 40 | 0.0047 |
| 1981 | | | 400 | | | 400 | 43 | 0.0034 |
| 1982 | | 600 | | | | 600 | 51 | 0.0020 |
| 1983 | 27[e] | | | | 100 | 73 | 41 | 0.0050 |
| 1984 | | 600 | 600 | | | 1200 | 63 | 0.0007 |
| 1985 | 27[e] | | | | | (27) | 49 | 0.0028 |
| 1986 | | 800 | | | | 800 | 54 | 0.0018 |
| 1987 | | 800 | | | | 800 | 58 | 0.0012 |
| 1988 | 27[e] | | | | 100 | 73 | 46 | 0.0036 |
| 1989 | | 1000 | | | | 1000 | 52 | 0.0024 |
| Total additions 1980-89 | 165 | 3800 | 1400 | | 200 | 5235 | Average 50 | Average 0.0028 |
| Total system 1989 | | 3800 | 4034 | 569 | 200 | 8603 | 52 | 0.0024 |
| Additions 1990-99 | 564[f] | 8000 | 2000 | | | 9436 | Average 50 | Average 0.0036 |
| Total system 1999 | | 11800 | 5470 | 569 | 200 | 18039 | 41 | 0.0067 |

[a] "Large units" defined to mean up to 20% of annual peak demand.
[b] Critical quarter.
[c] Additions and retirements each year.
[d] Blaisdell.
[e] Rockwell 1-5.
[f] Rockwell 6-8, Tegen, Gardner.

TABLE N-10-6. POTENTIAL MARKET FOR NUCLEAR POWER PLANTS WITH VARYING ECONOMIC PARAMETERS – LARGE UNIT SIZES (MW)

| Year | Reference conditions | Discount rate | | Oil cost escalation rate | |
|---|---|---|---|---|---|
| | | 6%/yr | 10%/yr | 0%/yr | 4%/yr |
| 1980 | - | - | - | - | - |
| 1981 | - | - | - | - | - |
| 1982 | 600 | 600 | 600 | - | 600 |
| 1983 | - | - | - | - | - |
| 1984 | 600 | 2 x 600 | - | - | 2 x 600 |
| 1985 | - | - | - | - | - |
| 1986 | 800 | 800 | 800 | 800 | 800 |
| 1987 | 800 | 800 | 800 | - | 800 |
| 1988 | - | - | - | - | - |
| 1989 | 1 000 | 1 000 | 1 000 | 1 000 | 1 000 |
| Total 1980-89 | 3 800 | 4 400 | 3 200 | 1 800 | 4 400 |

TABLE N-10-7. FINANCING REQUIREMENTS FOR REFERENCE THERMAL PLANTS EXPANSION SCHEDULE ($10^6$ US $)

| Year | Plant investment | | | Nuclear fuel working capital [a] | Total |
|---|---|---|---|---|---|
| | Domestic | Foreign | Subtotal | | |
| 1976 | 0.4 | 1.1 | 1.5 | | 1.5 |
| 1977 | 6.2 | 14.4 | 20.6 | | 20.6 |
| 1978 | 27.0 | 60.8 | 87.8 | | 87.8 |
| 1979 | 41.0 | 96.6 | 137.6 | | 137.6 |
| 1980 | 35.2 | 94.6 | 219.8 | 1.7 | 131.5 |
| 1981 | 32.4 | 90.7 | 123.1 | 15.0 | 138.1 |
| 1982 | 49.6 | 139.2 | 188.8 | 1.7 | 190.5 |
| 1983 | 46.5 | 127.6 | 174.1 | 15.0 | 189.1 |
| 1984 | 41.5 | 124.5 | 166.0 | 1.9 | 167.9 |
| 1985 | 37.7 | 113.3 | 151.0 | 19.1 | 170.1 |
| 1986 | 26.3 | 80.3 | 106.6 | 17.2 | 123.8 |
| 1987 | 19.4 | 69.6 | 89.0 | 2.0 | 91.0 |
| 1988 | 6.1 | 18.5 | 24.6 | 17.9 | 42.5 |
| Total | 369.8 | 1 032.0 | 1 401.8 | 91.5 | 1 493.3 |

[a] Domestic expenditures for the nuclear fuel working capital were assumed to amount to 0% of the total.

# 11. SINGAPORE

## 1. ECONOMIC AND SOCIAL FACTORS

### 1.1. Population growth

The population growth rate in Singapore increased from 2.9%/yr during 1901-1911 to 4.4%/yr during 1947-1957. Between 1960 and 1970, however, as a result of the raising of the standard of living, a higher literary rate, a more sophisticated urban way of life, increased minimum age of marriage, and increased emphasis on family planning, the population growth rate dropped from 3.5%/yr to 1.7%/yr. Because of the present age distribution of females in the population it is unlikely that this rate of decrease in growth rate could be sustained indefinitely. Based on the 1970 census the present population is about 2.1 million.

### 1.2. Economic development and goals

Singapore has been experiencing a vigorous economic expansion. GDP at market prices increased at an average annual rate of 11.2% during 1961-1971 and at 13.9% during 1966-1971. The GDP in 1971 was equivalent to more than US $1100.

The traditional economic structure of the Republic was that of an entrepôt port until the last decade when diversification into the manufacturing sector was accelerated under an industrialization program.

The major fields of industrial activities are in petroleum refining and distribution, shipbuilding and repairing, manufacture of electronic/electrical goods and components, and timber (sawmilling and plywood manufacture). The manufacturing sector now contributes one-fifth of GDP, compared to one-tenth a decade ago.

Local economic planning targets call for economic growth rates to continue at about 15%/yr during the 1970s and at about 10%/yr during the 1980s.

### 1.3. Energy needs and resources

Total energy consumption in Singapore in 1970 was equivalent to about 0.82 TEC per capita, about 45% of which is accounted for by electricity production, which increased from 424 to 1225 kWh per capita from 1961 to 1971. Singapore has no known energy resources and depends completely on imported crude oil and its products to meet energy requirements. The Public Utilities Board (PUB) has projected electricity production to grow at an average annual rate of 15% during the 1970s and 12% during the 1980s.

### 1.4. Interest in nuclear power

PUB has expressed an interest in introducing nuclear power when it is economically justified. Their long-range expansion plan shows a "possible" 500 MW nuclear plant about 1983, the year projected to have a peak demand of 2140 MW. They are planning to conduct a full-scale feasibility study of a nuclear plant before making a final decision. Several preliminary studies have been made during 1968-1972, including a visit by an IAEA Nuclear Power Station Siting Mission in 1972.

### 1.5. Other factors

Projecting a continually growing demand for both potable and industrial-quality water, and considering that Singapore at present relies largely on water imported from Johore (Malaysia), there is a long-term interest in water desalination, possible in a dual-purpose nuclear power plant.

## 2. PARAMETERS USED IN THE ANALYSIS

### 2.1. Basic conditions

Table N-11-1 summarizes the conditions used in the analysis of various generation expansion plans for the Singapore electricity system during the decade 1980-89. As shown in this table, two load forecasts were considered. The low load forecast was developed for the Market Survey using the method described in Appendix F. The high load forecast is that of the Singapore Public Utilities Board to 1990, extrapolated to 2000. From the figures given in the table, it is seen that there is a total market of about 2100 MW of thermal capacity additions during the study decade for the low load forecast and of about 4700 MW for the high load forecast.

In the low load forecast case, the dynamic programming optimization method gave optimal solutions (within the constraints imposed) for both the 1980s and the 1990s. In the high load forecast case the capacity additions during the 1990s were held constant and therefore their capital costs contributed a constant amount to the objective function, so that the changes in the objective function were caused by changes in additions during the 1980s. Similarly, operation and additions during 1977-79 were the same for all cases and hence did not affect optimization during the 1980s.

TABLE N-11-1. SUMMARY OF CONDITIONS USED IN THE ANALYSIS[a]

| | Low forecast | | High forecast | |
|---|---|---|---|---|
| | 1979 | 1989 | 1979 | 1989 |
| Population ($10^6$)[a] | 2.38 | 2.76 | n.a.[e] | n.a. |
| GNP/capita (1964 US $)[a] | 1580 | 2560 | n.a. | n.a. |
| Electric energy production[b] | | | | |
| kWh/yr/capita | 3266 | 5910 | n.a. | n.a. |
| GWh/yr total | 7772 | 16313 | 8035 | 25235 |
| Peak demand (MW)[b] | 1365 | 2865 | 1345 | 4224 |
| Total installed capacity (MW)[c] | 1819 | 3769 | 1841 | 6366 |
| New capacity added, 1980-89, inclusive (MW)[d] | 2100 | | 4700 | |
| Average reserve margin, 1980-89 (%) | 34 | | 44 | |
| Average annual loss-of-load probability, 1980-89 (%) | 0.39 | | 0.23 | |

a These population and GNP/capita forecasts were the basis of the low energy production forecast (by Aoki: see Appendix F). The corresponding information for the high forecast is not applicable.
b Annual load factor 65% for low forecast, 68.2% for high forecast.
c All thermal (oil-fired, nuclear or gas turbine).
d Retirements during the period account for the difference between new capacity added and increase in total installed capacity.
e n.a. - not available.

### 2.2. Characteristics of system as of 1979

The existing and committed power expansion plans for Singapore are only sufficient to meet peak load demand up to about 1976-1977. For this reason, 400 MW of conventional plant capacity additions were assumed to be made to the system to meet the 1979 peak demand and provide a sufficient reserve margin for adequate loss-of-load probability. For the purpose of the computer analysis, the existing and committed units were grouped into so-called hypothetical units having common characteristics as shown in Table N-11-2. The technical and economic characteristics of each hypothetical plant shown in the table were computed from the characteristics of the actual plants comprising each unit.

TABLE N-11-2. CHARACTERISTICS OF GENERATING PLANTS IN "FIXED SYSTEM"

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PPAA | 7 | 12 | 25 | 3347. | 3199. | 0.0 | 140.00 | 1 | 1 | 7.50 | 34 | 40 | 0. | 0.700 | 0.0 | 3270. |
| PBJ1 | 8 | 30 | 60 | 2958. | 2500. | 0.0 | 140.00 | 1 | 1 | 3.80 | 47 | 40 | 0. | 0.370 | 0.0 | 2729. |
| J2S1 | 6 | 60 | 120 | 2574. | 2406. | 0.0 | 140.00 | 1 | 1 | 6.20 | 26 | 120 | 0. | 0.150 | 0.0 | 2490. |
| SNGT | 2 | 22 | 22 | 3528. | 3528. | 0.0 | 229.00 | 2 | 1 | 2.00 | 4 | 40 | 0. | 0.230 | 0.0 | 3528. |
| SJGT | 2 | 11 | 11 | 4864. | 4864. | 0.0 | 229.00 | 2 | 1 | 2.00 | 4 | 40 | 0. | 0.780 | 0.0 | 4864. |

## 2.3. Characteristics of alternative generating units

The characteristics of alternative generating units considered in the evaluation of possible expansion plans are shown in Table N-11-3. These were derived by methods described in Appendixes E, G, I and J. The 250 MW and 500 MW sizes in this table are not "standard" Market Survey sizes. They were included because there are units of these sizes in the tentative expansion plan of PUB; however, time did not permit evaluation of them.

# 3. RESULTS

## 3.1. Summary of cases considered

The low load forecast case was studied using the dynamic programming optimization feature of WASP, though it was necessary to impose some restraints on the range of possible solutions in order to keep within computer time and calendar time limits. The high load forecast case was studied by considering a limited number of alternative expansion plans involving a fixed schedule of capacity additions, because of time limitations. In this case during the 1990s the capacity addition mix was held fixed at approximately half nuclear and half oil-fired as a reasonable though arbitrary basis for optimizing the nuclear/oil addition mix during the 1980s. Starting with an all-oil expansion plan for the 1980s, nuclear plants were substituted for oil-fired plants beginning with 1989 and working back toward 1980 a year at a time until a minimum cost solution was obtained. This was considered to be a "near-optimum" solution, obviously it cannot be said to be the optimum since all possibilities for the 1980s could not be considered and since only two possible schedules of additions during the 1990s were considered, the second one as a sensitivity study.

For both load forecast cases the reference schedules assumed a continuation of past and projected local practice of adding relatively large size units, i.e. up to about 20% of annual peak load. Preliminary studies with the WASP computer codes indicated that expansion with these relatively large units gave a lower cost solution than for smaller units, for the same loss-of-load probability. The system stability analysis in Section 11 indicates, however, that the use of larger units implies acceptance of load shedding on loss of the largest unit if frequency is to be maintained within the limits normally acceptable. The WASP probabilistic simulation code calculates loss-of-load probability and the probable amount of energy not served, both of which were indicated to be acceptably low. The energy not served measures the product of the frequency and severity of load shedding, but does not indicate how severe an individual occurrence might be. The balancing of cost against risk must be left to the local authorities. A change to a relatively smaller unit size limit would lead to a smaller total market, because less reserve margin would be required for a given loss-of-load probability, and to a smaller nuclear fraction of that market, because nuclear units are less competitive in smaller sizes.

## 3.2. Near-optimum expansion schedules

Table N-11-4 shows the near-optimum expansion plans based on the reference conditions. It is seen that with the low load forecast there is no market during the 1980s under reference conditions, though 600 MW nuclear plants are indicated to be very competitive in the 1990s, as optimized by the dynamic program.

For the high load forecast case, the indicated nuclear power market during the 1980s is 2600 MW for reference conditions. The expansion during the 1990s was held fixed in this case.

## 3.3. Sensitivity studies

The potential market for nuclear power plants in Singapore under varying economic assumptions is given in Table N-11-5 for both load forecasts.

For the low forecast the potential market is most sensitive to the oil cost escalation rate, varying from none in the 1980s or 1990s at 0% escalation to 1400 MW in the 1980s and 3000 MW in the 1990s at 4% escalation. The 4% oil cost escalation rate is not necessarily to

TABLE N-11-3. CHARACTERISTICS OF GENERATING PLANTS FOR SYSTEM EXPANSION ALTERNATIVES

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GT50 | 0 | 50 | 50 | 3528. | 3528. | 0.0 | 229.00 | 2 | 1 | 2.00 | 4 | 38 | 0. | 0.200 | 0.0 | 3528. |
| 0150 | 0 | 75 | 150 | 2347. | 2193. | 0.0 | 140.00 | 1 | 1 | 5.30 | 28 | 120 | 0. | 0.240 | 0.0 | 2270. |
| 0200 | 0 | 100 | 200 | 2280. | 2146. | 0.0 | 140.00 | 1 | 1 | 5.40 | 28 | 200 | 0. | 0.190 | 0.0 | 2213. |
| 0250 | 0 | 125 | 250 | 2308. | 2164. | 0.0 | 140.00 | 1 | 1 | 6.00 | 28 | 300 | 0. | 0.170 | 0.0 | 2236. |
| 0300 | 0 | 150 | 300 | 2335. | 2183. | 0.0 | 140.00 | 1 | 1 | 6.50 | 28 | 300 | 0. | 0.150 | 0.0 | 2259. |
| 0400 | 0 | 200 | 400 | 2324. | 2098. | 0.0 | 140.00 | 1 | 1 | 9.80 | 28 | 400 | 0. | 0.130 | 0.0 | 2211. |
| 0500 | 0 | 250 | 500 | 2326. | 2137. | 0.0 | 140.00 | 1 | 1 | 10.90 | 28 | 600 | 0. | 0.120 | 0.0 | 2232. |
| 0600 | 0 | 300 | 600 | 2328. | 2172. | 0.0 | 140.00 | 1 | 1 | 12.00 | 28 | 600 | 0. | 0.100 | 0.0 | 2250. |
| 0800 | 0 | 400 | 800 | 2334. | 2170. | 0.0 | 140.00 | 1 | 1 | 12.20 | 35 | 800 | 0. | 0.090 | 0.0 | 2252. |
| 01T0 | 0 | 500 | 1000 | 2344. | 2152. | 0.0 | 140.00 | 1 | 1 | 12.20 | 35 | 1000 | 0. | 0.090 | 0.0 | 2248. |
| N200 | 0 | 100 | 200 | 2648. | 2359. | 0.0 | 59.00 | 0 | 1 | 5.40 | 28 | 200 | 0. | 0.430 | 0.0 | 2504. |
| N250 | 0 | 125 | 250 | 2647. | 2360. | 0.0 | 58.50 | 0 | 1 | 6.00 | 28 | 300 | 0. | 0.380 | 0.0 | 2504. |
| N300 | 0 | 150 | 300 | 2645. | 2360. | 0.0 | 58.00 | 0 | 1 | 6.50 | 28 | 300 | 0. | 0.320 | 0.0 | 2503. |
| N400 | 0 | 200 | 400 | 2643. | 2362. | 0.0 | 57.00 | 0 | 1 | 9.80 | 28 | 400 | 0. | 0.260 | 0.0 | 2503. |
| N500 | 0 | 250 | 500 | 2640. | 2364. | 0.0 | 56.00 | 0 | 1 | 10.90 | 28 | 600 | 0. | 0.230 | 0.0 | 2502. |
| N600 | 0 | 300 | 600 | 2637. | 2365. | 0.0 | 55.00 | 0 | 1 | 12.00 | 28 | 600 | 0. | 0.200 | 0.0 | 2501. |
| N800 | 0 | 400 | 800 | 2632. | 2368. | 0.0 | 53.00 | 0 | 1 | 12.20 | 35 | 800 | 0. | 0.170 | 0.0 | 2500. |
| N1T0 | 0 | 500 | 1000 | 2627. | 2372. | 0.0 | 51.00 | 0 | 1 | 12.20 | 35 | 1000 | 0. | 0.140 | 0.0 | 2500. |

TABLE N-11-4. REFERENCE SYSTEM EXPANSION SCHEDULES [a]

| Year | Low load forecast (MW) | | | | High load forecast (MW) | | | |
|---|---|---|---|---|---|---|---|---|
| | Nuclear | Conventional steam | Gas turbines | Total | Nuclear | Conventional steam | Gas turbines | Total |
| Total system 1977 | | 1 375 | 66 [b] | 1 419 | | 1 375 | 66 | 1 441 |
| Additions 1977-1979 | | 400 | | 400 | | 400 | | 400 |
| Total system 1979 | | 1 775 | 44 | 1 819 | | 1 775 | 66 | 1 841 |
| 1980 | | 200 | | 200 | | 300 | | 300 |
| 1981 | | | 50 | 50 | | 300 | | 300 |
| 1982 | | 300 | | 300 | | 300 | | 300 |
| 1983 | | 300 | | 300 | | 400 | | 225 |
| 1984 | | | 50 | 50 | | 400 | | 400 |
| 1985 | None | 400 | | 400 | | 400 | | 400 |
| 1986 | | | | | 600 | | | 600 |
| 1987 | | 400 | | 400 | 600 | | | 600 |
| 1988 | | 400 | | 400 | 600 | | | 600 |
| 1989 | | | | | 800 | | | 800 |
| Additions 1980-1989 | 0 | 2 000 | 100 | 2 100 | 2 600 | 2 100 | 0 | 4 700 |
| Retirements | 0 | - 150 | 0 | - 150 | 0 | 175 | 0 | 175 |
| Total system 1989 | 0 | 3 625 | 144 | 3 769 | 2 600 | 3 700 | 66 | 6 366 |
| Additions 1990-2000 | 3000 [c] | 0 | 50 | 3 050 | 5 000 | 4 000 | 250 | 9 250 |
| Retirements | 0 | - 385 | 0 | - 385 | 0 | - 360 | -22 | - 382 |
| Total system 2000 | 3000 | 3 240 | 194 | 6 434 | 7 600 | 7 340 | 294 | 15 234 |

[a] 8% discount rate, 0% escalation on capital and nuclear fuel costs, 2% escalation on oil price, ORCOST-3 capital costs.
[b] 2 x 11 MW were assumed to be retired in 1977.
[c] Based on dynamic program optimization.

be considered an extreme, however, since the base oil price is for fuel with 3.5% or more sulphur. Fuel with only 1.5% sulphur costs about 40% more in Singapore. Thus the difference between 2% and 4% oil cost escalation rates corresponds to a very gradual reduction in sulphur content from 3.5% to $1\frac{1}{2}$%, over a 17-year period. It is entirely possible that environmental protection regulations will call for a more rapid rate of reduction than this and an ultimate sulphur content lower than this.

For the high forecast, the market varies from zero MW a 0% oil cost escalation rate to 3800 MW at a 4% oil cost escalation rate. The potential markets with other sensitivity studies fall within the ranges shown in Table N-11-5.

## 3.4. Financing requirements

The domestic, foreign and total financing requirements associated with the construction of the thermal plants in the reference expansion schedules (see Table N-11-4) are summarized in Table N-11-6. These costs include interest during construction based on the assumption that interest would be paid currently with expenditures. It is seen that total annual expenditures reach a peak of US $66.1 \times 10^6$ for the low load forecast (in 1986) and

TABLE N-11-5. POTENTIAL MARKET FOR NUCLEAR PLANTS WITH VARYING ECONOMIC PARAMETERS (MW)

| Year | Low load forecast | | | High load forecast | | |
|---|---|---|---|---|---|---|
| | Reference conditions [a] | 6% discount rate | 4% oil price escalation rate | Reference conditions [a] | 0% oil price escalation rate | 4% oil price escalation rate |
| 1980 | no nuclear market | - | - | 600 | no nuclear market | - |
| 1981 | | - | - | | | - |
| 1983 | | - | 300 | | | 400 |
| 1984 | | - | 300 | | | 400 |
| 1985 | | - | - | | | 400 |
| 1986 | | - | - | | | 600 |
| 1987 | | 400 | 400 | 600 | | 600 |
| 1988 | | 400 | 400 | 600 | | 600 |
| 1989 | | - | - | 800 | | 800 |
| Total | | 800 | 1 400 | 2 000 | | 3 800 |

[a] 8% discount rate, 0% escalation on capital and nuclear fuel costs, 2% escalation on oil price, ORCOST-3 capital costs.

TABLE N-11-6. PLANT INVESTMENT AND NUCLEAR FUEL FINANCING REQUIREMENTS FOR REFERENCE THERMAL PLANT EXPANSION SCHEDULES ($10^6$ US $)[a]

| Year | Low load forecast | | | | High load forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Plant investment | | | Total | Plant investment | | | Nuclear fuel cycle investment [b] | Total |
| | Domestic | Foreign | Subtotal | | Domestic | Foreign | Subtotal | | |
| 1976 | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 |
| 1977 | 0.7 | 1.8 | 2.5 | | 1.9 | 4.4 | 6.3 | | 6.3 |
| 1978 | 7.0 | 16.4 | 23.4 | | 11.6 | 27.1 | 38.7 | | 38.7 |
| 1979 | 8.0 | 19.4 | 27.4 | | 18.9 | 44.1 | 63.0 | | 63.0 |
| 1980 | 11.6 | 32.7 | 44.3 | | 20.4 | 48.0 | 68.4 | | 68.4 |
| 1981 | 17.0 | 39.7 | 56.7 | | 24.6 | 61.1 | 85.7 | | 85.7 |
| 1982 | 10.3 | 24.8 | 35.1 | | 32.4 | 91.5 | 123.9 | | 123.9 |
| 1983 | 12.0 | 33.7 | 45.7 | | 41.8 | 134.3 | 176.1 | | 176.1 |
| 1984 | 11.2 | 26.1 | 37.3 | | 43.4 | 160.6 | 204.0 | 1.7 | 205.7 |
| 1985 | 15.1 | 35.2 | 50.3 | | 38.7 | 155.1 | 193.8 | 16.7 | 210.5 |
| 1986 | 19.8 | 46.3 | 66.1 | | 31.5 | 126.3 | 157.8 | 16.7 | 174.5 |
| 1987 | 7.9 | 18.4 | 26.3 | | 18.6 | 74.6 | 93.2 | 16.9 | 110.1 |
| 1988 | 0 | 0 | 0 | | 4.6 | 18.8 | 23.4 | 17.2 | 40.6 |
| Total | 121.0 | 295.0 | 416.0 | 416.0 | 288.9 | 946.5 | 1 235.4 | 69.2 | 1 304.6 |

[a] Rounded.
[b] Domestic expenditures for the nuclear fuel cycle working capital were assumed to be 0% of the total.

US $204.0 × $10^6$ for the high forecast (in 1984). The total costs of the 10-year expansion programs amount to US $416.0 × $10^6$ and US $1235.4 × $10^6$, respectively, for the two given load forecasts.

The nuclear fuel cycle working capital costs (i.e. investment in first core etc.) for the high load forecast are not included in these investment costs. Table N-11-6 shows these costs separately because financing arrangements for such costs may differ from those for the plant construction programs. The total annual investment costs, however, are shown for completeness.

The given costs do not include annual operating and maintenance costs and variable fuel costs.

### 3.5. Conclusions

(a) The estimated total market in Singapore for thermal generating units which will be commissioned during the 1980-89 period ranges from 2100 MW to 4700 MW depending on the forecast used. Because of lack of hydro power, this total market will be shared by conventional and nuclear units.

(b) Singapore has no known energy resources and depends completely on imported crude oil and its products to meet energy requirements.

(c) The estimated tax-free cost of high sulphur fuel oil as of 1 January 1973 in Singapore was estimated to amount to 140 US ¢ / $10^6$ kcal derived by the method described in Appendix I. There is a reasonable expectancy that this fuel oil cost will escalate at a rate of 2%/yr above an assumed general inflation rate of 4%/yr.

(d) Even with such escalation with the low load forecast, there is no market for nuclear plants during the study period, though 600 MW nuclear plants are indicated to be competitive in the 1990s. For the high load forecast case, the indicated nuclear power market amounts to 2600 MW.

(d) Total financing requirements for the reference expansion schedules amount to US $416.0 × $10^6$ with the low load forecast and US $1235.4 × $10^6$ with the high load forecast.

## 12. THAILAND

## 1. ECONOMIC AND SOCIAL FACTORS

### 1.1. Population growth

The April 1970 census gave a total population of roughly 35.5 million which resulted from an average growth rate of about 5%/yr from 1960 to 1970. Future growth is expected to result in a population of over 60 million by 1990. At present about 50% of the population can be considered economically active with an average per capita income of about US $150/yr.

### 1.2. Economic development

Thailand has enjoyed rapid economic development as shown by a GDP growth rate which has averaged 10% over the last few years. GDP per capita will be just under US $400 by 1990. National objectives at present are to produce industrialization and self-sufficiency in manufactured products. The Government encourages manufacturing industries by a system of tax exemptions.

## 1.3. Social considerations

Thailand does not have pollution regulations which limit discharges of pollutants into the air or into water. The largest power station presently being built, a 300 MW station at South Bangkok, does not have any stack precipitating equipment. The Electricity Generating Authority of Thailand (EGAT), however, takes pride in its civic responsibilities and will probably take the lead in environmental protection once the need and the techniques are established.

## 1.4. Energy needs and resources

The total energy consumption is expected to rise by more than 10%/yr to a total of $710 \times 10^{12}$ kcal/yr by 1990. The electrical energy consumption is expected to grow faster than general energy consumption at more than 13% and is expected to reach about 36 600 GWh by 1990. The country has sizeable hydroelectric energy resources within the national boundaries (13 800 GWh) and shares the Mekong and Salween river basins with neighbouring countries. The Salween is as yet unexplored, but the potential of the Mekong has been estimated at 175 000 GWh. Thailand has some lignite resources at a distance from load centres and small quantities of oil.

## 1.5. Interest in nuclear power

The Government has supported a nuclear power program to cope with the rapidly increasing electric power demand in the future. The first power plant has been approved in principle and a site survey is in progress. The object is to invite bids in 1973 for a plant to go into service in 1979-80. The public seems generally in favour of introducing nuclear power.

## 1.6. Other factors

Thailand has had political and economic stability in the past ten years. It is, however, located in an area of the world where political and economic stress predominates. The political problems of Thailand's neighbours are a contributing factor to the slow progress on the Mekong agreements. Thailand requires an improvement in the political stability of the neighbouring countries to permit the maintenance of economic growth enjoyed in the past.

# 2. PARAMETERS USED IN THE ANALYSIS

## 2.1. Basic conditions

Table N-12-1 summarizes the conditions used in the analyses of various alternative expansion plans for the electrical system in Thailand. From the figures given in the table it is seen that during the study period there is a total addition of 3 850 MW of thermal capacity.

## 2.2. Characteristics of system as of 1979

The existing and committed power expansion plants of EGAT are only sufficient to meet peak load demand up to about 1978. For this reason, 710 MW of conventional plant capacity additions were assumed to be made to the system to meet the 1979 peak demand and provide a sufficient reserve margin for adequate loss-of-load probability. For the purpose of the computer analyses, the existing and committed units were grouped into so-called hypothetical units having common characteristics as shown in Table N-12-2. The technical and economic characteristics of each hypothetical plant shown in the table were computed from the characteristics of the actual plants comprising each unit.

TABLE N-12-1. SUMMARY OF CONDITIONS USED IN THE ANALYSIS

| | 1979 | 1989 |
|---|---|---|
| Population ($10^6$) | 47.31 | 61.07 |
| GNP/capita (US $/yr)[a] | 215 | 324 |
| Energy consumption (GWh/yr) | 13 500 | 34 700 |
| Peak demand (MW) | 2 450 | 6 200 |
| Total installed capacity (MW) | 3 689 | 8 439 |
| Installed thermal capacity (MW) | 2 348 | 6 198 |
| Installed capacity, critical period (MW)[b] | 3 689 | 8 439 |
| Average reserve margin (%) 1979-89 | 47.2 | |
| Average loss-of-load probability 1979-89 | 0.0041 | |

[a] 1964 US $.
[b] In the fourth quarter of the year peak hydro capacity = 100% of total.

## 2.3. Characteristics of alternative generating units

The characteristics of alternative thermal generating units considered in the evaluation of possible system expansion configurations (i.e. schedules of additions) are shown in Table N-12-3. These characteristics were derived by methods described in Appendixes E, G, I and J.

# 3. RESULTS

## 3.1. Summary of cases considered

A number of trial runs were made to establish the sizes of capacity additions required. Additional runs were carried out to determine the economy of adding large units with greater reserve margin rather than adding small units with less reserve margin. The largest units which can be added, within the system restriction as discussed in Section 11 of the Country Report proceed to be the most economic, even with proportionally larger reserve margins to maintain adequate loss-of-load probability. On the basis of the resources available, it was decided that the thermal additions would be either oil-fired or nuclear stations.

## 3.2. Reference expansion schedules

With the desired schedule of capacity additions and the competing types of thermal plants established, five computer runs were prepared to evaluate the competition between nuclear plants and oil-fired plants. It was found that under reference conditions 400 MW nuclear plants were competitive after 1984. Larger plants, i.e. 500 MW and 600 MW plants were competitive but were too large for the system until the latter part of the study period. (See Table N-12-4.)

## 3.3. Sensitivity studies

In the five runs in which oil and nuclear plants were compared, the sensitivity to variation in discount rate, fuel escalation rates and capital costs of generating units was

TABLE N-12-2. CHARACTERISTICS OF GENERATING PLANTS IN "FIXED SYSTEM"

| 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 | L C T N | FRCD OUT-AGE RATE | DAYS SCHL MAIN | MAIN CLAS | ENRGY GWH | O&M (FIX) | O&M (VAR) | FULL LOAD HEAT RATE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NBA1 | 2 | 19 | 75 | 3200. | 2460. | 0.0 | 150.00 | 1 | 1 | 7.00 | 21 | 80 | 0. | 0.300 | 0.110 | 2647. |
| NBA3 | 1 | 22 | 88 | 3200. | 2460. | 0.0 | 150.00 | 1 | 1 | 7.00 | 21 | 80 | 0. | 0.300 | 0.110 | 2645. |
| GTN1 | 11 | 15 | 15 | 4220. | 4220. | 0.0 | 400.00 | 2 | 1 | 4.00 | 10 | 20 | 0. | 0.050 | 0.240 | 4220. |
| DIN1 | 2 | 3 | 3 | 2970. | 2970. | 0.0 | 220.00 | 2 | 1 | 4.00 | 10 | 5 | 0. | 0.150 | 0.100 | 2970. |
| SBA1 | 2 | 50 | 200 | 2950. | 2208. | 0.0 | 150.00 | 1 | 1 | 5.40 | 21 | 200 | 0. | 0.160 | 0.050 | 2394. |
| DIL1 | 1 | 18 | 18 | 2970. | 2970. | 0.0 | 220.00 | 2 | 1 | 5.00 | 15 | 20 | 0. | 0.150 | 0.080 | 2970. |
| DIT1 | 2 | 4 | 4 | 2970. | 2970. | 0.0 | 220.00 | 2 | 1 | 4.00 | 10 | 5 | 0. | 0.150 | 0.080 | 2970. |
| KRA1 | 3 | 5 | 20 | 4080. | 3344. | 75.00 | 0.0 | 4 | 1 | 10.20 | 21 | 20 | 0. | 0.430 | 0.160 | 3528. |
| DIP1 | 1 | 11 | 11 | 2970. | 2970. | 0.0 | 220.00 | 2 | 1 | 4.00 | 10 | 10 | 0. | 0.150 | 0.080 | 2970. |
| MMH2 | 2 | 2 | 6 | 4330. | 3521. | 111.00 | 0.0 | 4 | 1 | 10.50 | 21 | 5 | 0. | 0.950 | 0.480 | 3791. |
| SBA3 | 2 | 75 | 300 | 2950. | 2208. | 0.0 | 150.00 | 1 | 1 | 6.50 | 28 | 300 | 0. | 0.160 | 0.050 | 2394. |
| SUTH | 1 | 8 | 30 | 3380. | 2636. | 121.00 | 0.0 | 4 | 1 | 10.00 | 21 | 30 | 0. | 0.330 | 0.130 | 2834. |
| NMMO | 2 | 35 | 75 | 3642. | 2719. | 111.00 | 0.0 | 4 | 1 | 10.00 | 21 | 80 | 0. | 0.400 | 0.160 | 3150. |
| HYDO | 1 | 20 | 1281 | 0. | 0. | 0.0 | 0.0 | 5 | 1 | 0.0 | 21 | 30 | 2878. | 0.330 | 0.130 | 0. |

TABLE N-12-3. CHARACTERISTICS OF GENERATING PLANTS FOR SYSTEM EXPANSION ALTERNATIVES

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| N300 | 0 | 150 | 300 | 2645. | 2360. | 0.0 | 57.90 | 0 | 1 | 6.50 | 28 | 300 | 0. | 0.520 | 0.0 | 2503. |
| N400 | 0 | 200 | 400 | 2643. | 2362. | 0.0 | 57.00 | 0 | 1 | 9.80 | 28 | 400 | 0. | 0.420 | 0.0 | 2502. |
| N600 | 0 | 300 | 600 | 2638. | 2365. | 0.0 | 55.10 | 0 | 1 | 12.00 | 28 | 600 | 0. | 0.320 | 0.0 | 2501. |
| N800 | 0 | 400 | 800 | 2632. | 2369. | 0.0 | 53.20 | 0 | 1 | 12.20 | 35 | 800 | 0. | 0.270 | 0.0 | 2500. |
| N1T0 | 0 | 500 | 1000 | 2627. | 2372. | 0.0 | 51.30 | 0 | 1 | 12.20 | 35 | 1000 | 0. | 0.230 | 0.0 | 2499. |
| 0300 | 0 | 150 | 300 | 2335. | 2183. | 0.0 | 150.00 | 1 | 1 | 6.50 | 28 | 300 | 0. | 0.280 | 0.0 | 2259. |
| 0400 | 0 | 200 | 400 | 2324. | 2098. | 0.0 | 150.00 | 1 | 1 | 9.80 | 28 | 400 | 0. | 0.240 | 0.0 | 2211. |
| 0600 | 0 | 300 | 600 | 2328. | 2172. | 0.0 | 150.00 | 1 | 1 | 12.00 | 28 | 600 | 0. | 0.190 | 0.0 | 2250. |
| 0800 | 0 | 400 | 800 | 2334. | 2170. | 0.0 | 150.00 | 1 | 1 | 12.20 | 35 | 800 | 0. | 0.170 | 0.0 | 2252. |
| 01T0 | 0 | 500 | 1000 | 2344. | 2152. | 0.0 | 150.00 | 1 | 1 | 12.20 | 35 | 1000 | 0. | 0.160 | 0.0 | 2248. |
| GT50 | 0 | 50 | 50 | 4000. | 4000. | 0.0 | 180.00 | 2 | 1 | 2.00 | 4 | 100 | 0. | 0.740 | 0.0 | 4000. |
| N500 | 0 | 250 | 500 | 2900. | 2580. | 0.0 | 56.00 | 0 | 1 | 10.90 | 28 | 500 | 0. | 0.370 | 0.0 | 2740. |
| 0500 | 0 | 250 | 500 | 2685. | 2012. | 0.0 | 150.00 | 1 | 1 | 10.90 | 28 | 500 | 0. | 0.220 | 0.0 | 2349. |

TABLE N-12-4. REFERENCE SYSTEM CAPACITY EXPANSION SCHEDULE[a]

| Year | Installed capacity (MW) | | | | | % Reserve[b] | Annual loss-of-load probability |
|---|---|---|---|---|---|---|---|
| | Nuclear | Conventional steam | Hydro | Gas turbines | Total | | |
| Total system 1978 | - | 1 698 | 1 281 | - | 2 979 | | |
| Addition 1979 | - | 2 x 300 | 60 | 50 | 710 | | |
| Total system 1979 | - | 2 298 | 1 341 | 50 | 3 689 | | |
| Additions | | | | | | | |
| 1980 | | 2 x 300 | | | 600 | 58 | 0.0030 |
| 1981 | | 1 x 300 | 60 | | 360 | 55 | 0.0027 |
| 1982 | | 1 x 300 | 60 | | 360 | 49 | 0.0029 |
| 1983 | | | 360 | 50 | 410 | 46 | 0.0048 |
| 1984 | 400 | | 420 | | 820 | 54 | 0.0032 |
| 1985 | 500 | | | | 500 | 49 | 0.0032 |
| 1986 | 500 | | | | 500 | 49 | 0.0025 |
| 1987 | | | | | 0 | 37 | 0.0071 |
| 1988 | 600 | | | | 600 | 37 | 0.0058 |
| 1989 | 600 | | | | 600 | 35 | 0.0062 |
| Total additions 1980 - 1989 | 2 600 | 1 200 | 900 | 50 | 4 750 | 47 | 0.0041 |
| Total system 1989 | 2 600 | 3 498 | 2 241 | 100 | 8 439 | | |
| Additions 1990 - 2000 | 5 400 | 2 800 | 0 | 0 | 8 200 | | |
| Total system 2000 | 8 000 | 6 298 | 2 241 | 100 | 16 639 | | |

[a] 8% discount rate, 0% escalation on capital and nuclear fuel, 2% escalation on oil prices, ORCOST-3 capital costs.
[b] In critical quarter (4th quarter)

considered (see Table N-12-5). In the reference case a 400 MW nuclear unit became competitive in 1984. Reduction of the discount rate to 6% made a 300 MW nuclear station competitive as early as 1982, while an increase to 10% eliminated the 400 MW unit in 1984 resulting in nuclear being competitive starting only in 1985. Fossil fuel escalation variations had by far the greatest effect. A reduction of the 2% escalation rate on oil to 0% eliminated all nuclear plants considered during the study period while an increase to 4% suggested nuclear plants should have been in service prior to the study period. Lowering the relative capital costs of nuclear and fossil plants resulted, as might be expected, in 300 MW plant being competitive early in the study period.

The potential market for nuclear plants in Thailand under varying economic conditions is shown in Table N-12-5. It is seen that the potential nuclear market varies from 1 700 MW to 3800 MW. The market under reference conditions is 2600 MW. The conditions which suggested nuclear plants in operation prior to the study period were not elaborated further since it is impractical to consider bringing a nuclear station into commercial operation much before the study period.

TABLE N-12-5. POTENTIAL MARKET FOR NUCLEAR PLANTS WITH VARYING ECONOMIC PARAMETERS (MW)

| Case | Reference | 6% discount rate | 10% discount rate | 0% fuel escalation rate | 4% fuel escalation rate | ORCOST-1 | 2% nuclear fuel escalation rate |
|---|---|---|---|---|---|---|---|
| Period | | | | | | | |
| At 31/12/1972[a] | 0 | 0 | 0 | 0 | 0 | 0 | |
| Added 1973-79[b] | 0 | 0 | 0 | 0 | 2 x 300 | 2 x 300 | |
| At 31/12/1979[a] | 0 | 0 | 0 | 0 | c | c | |
| 1980[b] | | | | | 2 x 300 | 2 x 300 | |
| 1981 | | | | | 300 | 300 | |
| 1982 | | 300 | | | 300 | 300 | |
| 1983 | | | | | | | |
| 1984 | 400 | 400 | | | 400 | 400 | |
| 1985 | 500 | 500 | 500 | | 500 | 500 | |
| 1986 | 500 | 500 | 500 | | 500 | 500 | 500 |
| 1987 | | | | | | | |
| 1988 | 600 | 600 | 600 | | 600 | 600 | 600 |
| 1989 | 600 | 600 | 600 | | 600 | 600 | 600 |
| Total additions 1980-89 | 2 600 | 2 900 | 2 200 | | 3 800 | 3 800 | 1 700 |
| Total nuclear capacity 1989 | 2 600 | 2 900 | 2 200 | | 4 400 | 4 400 | 1 700 |
| Nuclear % of total system capacity 1989 | 30.8 | 34.4 | 26.1 | 0 | 52.1 | 52.1 | 20.1 |

a Units in operation, under construction or committed (number and size of each unit).
b Units expected to be committed during period or year (number and size of each unit).
c Nuclear should have already been planned under these conditions.

## 3.4. Financing requirements

The domestic, foreign and total financing requirements associated with the construction of the thermal plants in the reference expansion schedule (see Table N-12-4) are summarized in Table N-12-6. It is seen that the total annual expenditures reach a peak of US $158 × 10^6 in 1983. These costs include interest during construction based on the assumption that interest would be paid currently with expenditures. The total costs of the 10-year expansion program amount to US $1220 × 10^6.

The nuclear fuel cycle working capital costs (i.e. investment in first core etc.) are also shown in Table N-12-6 as a separate item, because financing arrangements for such costs may differ from those for the plant construction program. The total annual investment costs, however, are shown for completeness.

## 3.5. Conclusions

(a) The estimated total market for generating units which will be commissioned in the 1980 to 1989 period will be 4750 MW. Of this 900 MW will be in new hydroelectric power and 3850 MW in thermal plants including 50 MW of gas turbine.

(b) An evaluation of the fuel resources available in Thailand indicates that oil will be most nearly competitive with respect to nuclear power. While some of this oil will be domestic, most will be imported and world market prices will prevail. Lignite, the other possible fuel, is too far from load centres and to date insufficient in quantity or quality to be effectively competitive.

(c) An evaluation of the competitiveness of nuclear versus oil plants indicates that with reference conditions (8% discount rate, 2% escalation on oil), a 400 MW nuclear plant becomes competitive in 1989. All larger nuclear plants brought into service later in the study period are competitive and the complete thermal expansion to 1989 can be nuclear. The potential nuclear market then is five stations, totalling 2600 MW.

(d) An evaluation of the sensitivity of the results indicates that under economic conditions which tend to favour nuclear plants (6% discount rate, sinking fund depreciation, lower capital cost differential, higher oil escalation), the nuclear market would range from 2900 MW to 3800 MW. However, under economic conditions which tend to favour oil plants (i.e. 10% discount rate, straight line depreciation, lower oil price escalation, higher nuclear fuel price escalation) the nuclear market would drop to the range of 0 to 2200 MW.

(e) The nuclear markets described above are based entirely on economic factors and do not take into consideration other factors such as the possible scarcity of the required investment capital, local manufacturing and construction capabilities or the desire for greater diversification of fuel supply, all of which might limit the rate at which nuclear plants can be built.

TABLE N-12-6. FINANCING REQUIREMENTS FOR REFERENCE THERMAL PLANTS EXPANSION SCHEDULE ($10^6$ US $)

| Year | Plant investment | | | Nuclear fuel working capital[a] | Total |
|---|---|---|---|---|---|
| | Domestic | Foreign | Subtotal | | |
| 1976 | 0 | 0 | 0 | | 0 |
| 1977 | 3.7 | 8.7 | 12.4 | | 12.4 |
| 1978 | 21.2 | 49.5 | 70.7 | | 70.7 |
| 1979 | 27.3 | 63.7 | 91.0 | | 91.0 |
| 1980 | 26.8 | 62.6 | 89.4 | | 89.4 |
| 1981 | 33.3 | 78.8 | 112.1 | | 112.1 |
| 1982 | 42.7 | 105.4 | 148.1 | 1.2 | 149.3 |
| 1983 | 43.4 | 101.4 | 144.8 | 13.0 | 157.8 |
| 1984 | 37.4 | 87.4 | 124.8 | 14.9 | 139.7 |
| 1985 | 35.3 | 82.5 | 117.8 | 13.4 | 131.2 |
| 1986 | 37.3 | 87.1 | 124.4 | 1.7 | 126.1 |
| 1987 | 25.5 | 59.7 | 85.2 | 16.7 | 101.9 |
| 1988 | 6.5 | 15.4 | 21.9 | 15.0 | 36.9 |
| Total | 341.0 | 802.2 | 1143.2 | 76.3 | 1219.5 |

[a] Domestic expenditures for the nuclear fuel workirg capital were assumed to amount to 0% of the total.

# 13. TURKEY

## 1. ECONOMIC AND SOCIAL FACTORS

### 1.1. Population growth

The population of Turkey in 1970 was about 35 million persons. The present annual growth rate is about 2.5%/yr and total population is estimated to be about 52 million by 1985. About 65% of the population live in urban areas and a third live in cities. About half a million work abroad and in Turkey itself there is a shortage of skilled labour.

### 1.2. Economic development and goals

The GNP per capita in 1970 was about US $350, and increasing at about 6.7%/yr with a target of yearly growth rate of 7.9% for the present decade.

### 1.3. Energy needs and resources

The gradually changing structure of the Turkish economy from agriculture to increased industrialization will be accompanied by increasing energy requirements. At present the total annual energy consumption reaches 30 million TEC. The share of the domestically produced resources averages 80% of the requirements and is mainly coal, petroleum and lignite. Of the 4.6 million tons of coal produced in 1971 only 0.8 million tons were used for power generation. Production in 1980 is expected to increase to 5.85 million tons and only coal not required by industry will be allowed for power generation. Lignite production in 1971 of 6.5 million tons will be increased to 10.0 million tons by 1980. In 1971, 1.37 million tons were used for power generation and the same proportion is expected to exist in 1980. Turkey has identified hydro resources amounting to about 50 000 GWh/yr in addition to the nearly 25 000 GWh/yr that is planned to be in operation by 1986. The overall energy consumption is expected to increase at an average yearly rate of 7.5% during this decade.

### 1.4. Interest in nuclear power

Consideration of the introduction of nuclear power began by a study carried out by the Nuclear Energy Institute of the University of Istanbul. Based on this study the Turkish Atomic Energy Commission (TAEC) outlined the national nuclear policy as follows: (a) rapid introduction of nuclear power starting in about 1985; (b) exploration of local deposits of uranium. A feasibility study was carried out in 1968-69 by TAEC and a consultant.

At present, studies concerning the nuclear generation program, the site and the economic evaluation of nuclear power plants are being carried out by TAEC and TEK (Turkiye Elektrik Kurumu). The former has submitted a nuclear energy program in connection with the preparation of the 1973-77 economic plan for Turkey. The latter has established a Nuclear Energy Division, and is giving consideration to the erection of a small experimental nuclear power plant in order to gain technological experience.

### 1.5. Other factors

Recently a better co-ordination of the various authorities involved in the energy field has been developed and the efforts to create a central electricity authority granted TEK with broad responsibilities in planning, designing and constructing power plants

## 2. PARAMETERS USED IN THE ANALYSIS

### 2.1. Basic conditions

Table N-13-1 summarizes the conditions used in the analyses of various alternative expansion plans for the electric generating system in Turkey during the period 1980 to 1989.

TABLE N-13-1. SUMMARY OF CONDITIONS USED IN THE ANALYSIS

| | Low forecast | | High forecast | |
|---|---|---|---|---|
| | 1979 | 1989 | 1979 | 1989 |
| Population ($10^6$) | 44 | 56 | | |
| GNP/capita (US $/yr)[a] | 420 | 580 | | |
| Energy consumption (GWh/yr) | 21 477 | 46 869 | 25 940 | 73 636 |
| Peak demand (MW) | 3 850 | 8 400 | 4 650 | 13 200 |
| Total installed capacity (MW) | 4 690 | 11 649 | 6 178 | 16 949 |
| Installed thermal capacity (MW) | 2 200 | 5 140 | 2 950 | 7 740 |
| Average reserve margins (%)[b] | 21.6 | | 21.0 | |
| Average loss-of-load probability | 0.0026 | | 0.0036 | |

[a] 1964 US $.
[b] Critical quarter (1st quarter peak hydro = 75% of total hydro capacity).

As shown in this table, two load forecasts were considered. The low load forecast was developed for the Market Survey using the method described in Appendix F. The high load forecast shows the (maximum) forecast presented to the Market Survey team by TEK. From figures given in the table it is seen that during the study period there is a total addition of 2940 MW of thermal capacity with the low load forecast and an addition of 4790 MW with the high forecast.

The hydro schedules are referred to in Section 14.2. of the Country Report. These additions represent appropriate selections from the hydro projects being considered for construction by the various responsible agencies in Turkey and, in the case of the high forecast, the schedule is essentially the same as proposed by TEK.

## 2.2. Characteristics of system as of 1979

The existing and committed power expansion plans of TEK are only sufficient to meet peak load demand up to about 1977. For this reason, conventional plant capacity additions were assumed to be made to the system to meet the 1979 peak demand and provide a sufficient reserve margin for adequate loss-of-load probability. For the purpose of the computer analyses, these plants plus the existing and committed units were then grouped into so-called hypothetical units having common characteristics, as shown in Table N-13-2. The technical and economic characteristics of each hypothetical plant shown in the table were computed from the characteristics of the actual plants comprising each unit.

## 2.3. Characteristics of alternative generating units

The characteristics of alternative thermal generating units considered in the evaluation of possible system expansion configurations (i.e. schedules of additions) are shown in Table N-13-3. These characteristics were derived by methods described in Appendixes E, G, I and J.

# 3. RESULTS

## 3.1. Summary of cases considered

Starting with the high load forecast, a number of trial computer runs were made to establish the sizes of capacity additions required. The results showed that the addition of 300 MW units in the early 1980s, 600 MW units in the mid-1980s and 800 MW units in the late 1980s would give near-optimum programs and that lignite would be the most economic fossil fuel. These same conditions also applied to the low load forecast case.

TABLE N-13-2. CHARACTERISTICS OF GENERATING PLANTS IN "FIXED SYSTEM"

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SOA1 | 1 | 38 | 150 | 3940. | 2453. | 109.00 | 0.0 | 3 | 1 | 6.00 | 30 | 150 | 0. | 0.600 | 0.0 | 2830. |
| SOM2 | 2 | 22 | 22 | 2770. | 2770. | 109.00 | 0.0 | 3 | 1 | 7.00 | 30 | 50 | 0. | 0.600 | 0.0 | 2770. |
| SEY4 | 4 | 38 | 150 | 3940. | 2453. | 128.00 | 0.0 | 3 | 1 | 6.00 | 30 | 150 | 0. | 0.600 | 0.0 | 2830. |
| TUN1 | 1 | 17 | 65 | 3377. | 2524. | 128.00 | 0.0 | 3 | 1 | 7.00 | 30 | 100 | 0. | 0.600 | 0.0 | 2747. |
| TUC2 | 2 | 32 | 32 | 2750. | 2750. | 128.00 | 0.0 | 3 | 1 | 7.00 | 30 | 50 | 0. | 0.600 | 0.0 | 2750. |
| CAT6 | 6 | 22 | 22 | 2569. | 2569. | 130.00 | 0.0 | 4 | 1 | 7.00 | 30 | 50 | 0. | 0.690 | 0.0 | 2569. |
| ELB1 | 1 | 75 | 300 | 3124. | 2343. | 200.00 | 0.0 | 3 | 1 | 4.00 | 30 | 300 | 0. | 0.600 | 0.0 | 2538. |
| AMB2 | 2 | 38 | 150 | 2970. | 2230. | 200.00 | 0.0 | 1 | 1 | 6.00 | 30 | 150 | 0. | 0.140 | 0.0 | 2417. |
| AMA3 | 3 | 28 | 110 | 3020. | 2265. | 200.00 | 0.0 | 1 | 1 | 6.00 | 30 | 100 | 0. | 0.140 | 0.0 | 2457. |
| HOP2 | 2 | 25 | 25 | 2542. | 2542. | 130.00 | 0.0 | 4 | 1 | 7.00 | 30 | 50 | 0. | 0.690 | 0.0 | 2542. |
| EPD2 | 2 | 20 | 20 | 2550. | 2550. | 130.00 | 0.0 | 4 | 1 | 7.00 | 30 | 50 | 0. | 0.690 | 0.0 | 2550. |
| KAR1 | 1 | 8 | 8 | 2550. | 2550. | 130.00 | 0.0 | 4 | 1 | 7.00 | 30 | 50 | 0. | 0.690 | 0.0 | 2550. |
| GAT6 | 6 | 20 | 20 | 3450. | 3450. | 500.00 | 0.0 | 2 | 0 | 2.00 | 15 | 50 | 0. | 0.600 | 0.0 | 3450. |
| HYDL | 1 | 800 | 2490 | 0. | 0. | 0.0 | 0.0 | 5 | 1 | 0.0 | 0 | 0 | 12500. | 0.280 | 0.0 | 0. |

TABLE N-13-3. CHARACTERISTICS OF GENERATING PLANTS FOR SYSTEM EXPANSION ALTERNATIVES

| 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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ELBX | 0 | 150 | 300 | 2560. | 2396. | 200.00 | 0.0 | 3 | 1 | 4.00 | 30 | 300 | 0. | 0.600 | 0.0 | 2478. |
| SOM2 | 0 | 75 | 150 | 2574. | 2406. | 109.00 | 0.0 | 3 | 1 | 6.00 | 30 | 150 | 0. | 0.600 | 0.0 | 2490. |
| ZONG | 0 | 75 | 150 | 2374. | 2206. | 130.00 | 0.0 | 4 | 1 | 7.00 | 30 | 150 | 0. | 0.690 | 0.0 | 2290. |
| SOMB | 0 | 150 | 300 | 2560. | 2396. | 109.00 | 0.0 | 3 | 1 | 4.00 | 30 | 300 | 0. | 0.600 | 0.0 | 2478. |
| N600 | 0 | 600 | 600 | 2637. | 2365. | 0.0 | 55.10 | 0 | 1 | 12.00 | 30 | 600 | 0. | 0.320 | 0.0 | 2637. |
| N300 | 0 | 150 | 300 | 2645. | 2360. | 0.0 | 57.90 | 0 | 1 | 6.50 | 30 | 300 | 0. | 0.520 | 0.0 | 2503. |
| O600 | 0 | 300 | 600 | 2328. | 2172. | 200.00 | 0.0 | 1 | 1 | 6.00 | 30 | 600 | 0. | 0.140 | 0.0 | 2250. |
| N800 | 0 | 800 | 800 | 2632. | 2368. | 0.0 | 53.20 | 0 | 1 | 12.20 | 35 | 800 | 0. | 0.270 | 0.0 | 2632. |
| L300 | 0 | 150 | 300 | 2560. | 2396. | 200.00 | 0.0 | 3 | 1 | 4.00 | 30 | 300 | 0. | 0.600 | 0.0 | 2478. |
| LIG6 | 0 | 300 | 600 | 2694. | 2436. | 200.00 | 0.0 | 3 | 1 | 8.00 | 30 | 600 | 0. | 0.600 | 0.0 | 2565. |

## 3.2. Reference expansion schedules

Table N-13-4 shows near-optimum expansion schedules based on the reference conditions. It can be seen that with the low load forecast the first 600 MW nuclear plant would be introduced in 1988, while with the high forecast the year of introduction is advanced to 1986. The total market for nuclear plants amounts to 1200 MW - 3200 MW, depending on the load forecast used as a basis.

TABLE N-13-4. REFERENCE SYSTEM EXPANSION SCHEDULES [a]

| Year | Low load forecast (MW) | | | | High load forecast (MW) | | | |
|---|---|---|---|---|---|---|---|---|
| | Nuclear | Conventional steam | Hydro | Total | Nuclear | Conventional steam | Hydro | Total |
| Total system 1977 | 0 | 2 200 | 2 490 | 4 690 | 0 | 2 200 | 2 490 | 4 690 |
| Additions 1977-1979 | 0 | 0 | 0 | 0 | 0 | 750 | 738 | 1 488 |
| Total system 1979 | 0 | 2 200 | 2 490 | 4 690 | 0 | 2 950 | 3 228 | 6 178 |
| 1980 | | 450 | 176 | 626 | | 300 | 30 | 300 |
| 1981 | | 300 | | 300 | | 450 | 524 | 974 |
| 1982 | | | 562 | 562 | | | 527 | 467 |
| 1983 | | 300 | 30 | 330 | | 300 | 1 100 | 1 400 |
| 1984 | | 450 | 524 | 974 | | 600 | 580 | 1 180 |
| 1985 | | | 527 | 467 | | | 1 020 | 1 020 |
| 1986 | | 300 | | 300 | 600 | | 600 | 1 200 |
| 1987 | | | 1 100 | 1 100 | 600 | | 700 | 1 300 |
| 1988 | 600 | | 580 | 1 180 | 600<br>800 | | 500 | 1 900 |
| 1989 | 600 | | 520 | 1 120 | 600 | | 400 | 1 000 |
| Additions 1980-89 | 1 200 | 1 800 | 4 019 | 7 019 | 3 200 | 1 650 | 5 981 | 10 831 |
| Retirements | 0 | 60 | 0 | 60 | 0 | 60 | 0 | 60 |
| Total system 1989 | 1 200 | 3 940 | 6 409 | 11 649 | 3 200 | 4 540 | 9 209 | 16 949 |
| Additions 1990-2000 | 2 600 | 4 200 | 7 210 | 14 010 | 4 000 | 9 600 | 9 811 | 23 411 |
| Total system 2000 | 3 800 | 8 140 | 13 619 | 25 659 | 7 200 | 14 140 | 19 020 | 40 360 |

[a] 8% discount rate, 0% escalation on capital and nuclear fuel costs, 2% escalation on oil price, ORCOST-3 capital costs.

## 3.3. Sensitivity studies

The potential market for nuclear plants in Turkey under varying economic conditions is shown in Table N-13-5. It is seen that with the low load forecast the potential nuclear market varies from 600 MW to 1200 MW. In the high forecast case, the potential nuclear plant market varies from 2000 MW to 5000 MW. The variations in the nuclear market with all other sensitivity studies fell within these ranges.

TABLE N-13-5. POTENTIAL MARKET FOR NUCLEAR PLANTS WITH VARYING ECONOMIC PARAMETERS (MW)

| Year | Low load forecast | | | High load forecast | | |
|---|---|---|---|---|---|---|
| | Reference | 10% discount rate | 4% fuel escalation rate | Reference | 0% fuel escalation rate | ORCOST-1 capital costs |
| 1980 | | | | | | 300 |
| 1981 | | | | | | 300 |
| 1982 | | | | | | 300 |
| 1983 | | | | | | 300 |
| 1984 | | | | | | 600 |
| 1985 | | | | | | - |
| 1986 | | | | 600 | | 600 |
| 1987 | | | | 600 | | 600 |
| 1988 | 600 | 600 | 600 | 600<br>800 | 600<br>800 | 600<br>800 |
| 1989 | 600 | - | 600 | 600 | 600 | 600 |
| Total 1980-89 | 1 200 | 600 | 1 200 | 3 200 | 2 000 | 5 000 |

## 3.4. Financing requirements

The domestic, foreign and total financing requirements associated with the construction of the thermal plants in the reference expansion schedules (see Table N-13-4) are summarized in Table N-13-6. These costs include interest during construction based on the assumption that interest would be paid currently with expenditures. It is seen that total annual expenditures reach a peak of US $\$130.9 \times 10^6$ for the low load forecast (in 1984) and US $\$262.8 \times 10^6$ for the high forecast (in 1984). The total costs of the 10-year expansion programs amount to US $\$1064.0 \times 10^6$ and US $\$1683.3 \times 10^6$, respectively, for the two given load forecasts.

The nuclear fuel cycle working capital costs (i.e. investment in first core etc.) are not included in these investment costs. Table N-13-6 shows these costs separately because financing arrangements for such costs may differ from those for the plant construction programs. The total annual investment costs, however, are shown for completeness.

The given costs do not include annual operating and maintenance costs and variable fuel costs.

## 3.5. Conclusions

(a) The estimated total market for generating units which will be commissioned during the 1980-1989 period is either nearly 7000 or 11 000 MW depending on the load forecast used as a basis. Because of the abundance of economically exploitable hydroelectric power, however, the market for new thermal plants will probably be in the approximate range of about 2900 MW to 4800 MW.

(b) An evaluation of the conventional fuels available in Turkey (lignite, coal and oil) indicates that lignite is the fuel which will be most competitive with respect to nuclear power. The reasons for this conclusion are as follows:

The production of bituminous coal will continue to be limited by mining difficulties. As a result, coal costs will rise above levels which are competitive with lignite.

The production of natural gas is essentially nil. Thus, Turkey will be forced to import natural gas and very little will be used for power production.

TABLE N-13-6. PLANT INVESTMENT AND NUCLEAR FUEL FINANCING REQUIREMENTS FOR REFERENCE THERMAL PLANT EXPANSION SCHEDULES ($10^6$ US $)[a]

| Year | Low load forecast | | | | | High load forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Plant investment | | | Nuclear fuel cycle investment[b] | Total | Plant investment | | | Nuclear fuel cycle investment[b] | Total |
| | Domestic | Foreign | Subtotal | | | Domestic | Foreign | Subtotal | | |
| 1975 | 0.3 | 0.6 | 0.9 | | 0.9 | 0.2 | 0.4 | 0.6 | | 0.6 |
| 1976 | 4.3 | 8.1 | 12.4 | | 12.4 | 3.4 | 6.4 | 9.8 | | 9.8 |
| 1977 | 19.0 | 35.3 | 54.3 | | 54.3 | 14.3 | 26.6 | 40.9 | | 40.9 |
| 1978 | 33.6 | 62.4 | 96.0 | | 96.0 | 30.2 | 56.7 | 86.9 | | 86.9 |
| 1979 | 27.6 | 51.3 | 78.9 | | 78.9 | 33.5 | 64.8 | 98.3 | | 98.3 |
| 1980 | 20.5 | 38.6 | 59.1 | | 59.1 | 28.4 | 66.9 | 95.3 | | 95.3 |
| 1981 | 31.1 | 60.2 | 91.3 | | 91.3 | 36.6 | 107.8 | 144.4 | | 144.4 |
| 1982 | 36.7 | 77.8 | 114.5 | | 114.5 | 45.9 | 158.8 | 204.7 | | 204.7 |
| 1983 | 31.6 | 82.6 | 113.2 | | 113.2 | 48.4 | 188.3 | 236.7 | | 236.7 |
| 1984 | 32.1 | 98.8 | 130.9 | | 130.9 | 52.5 | 210.3 | 262.8 | 1.7 | 264.5 |
| 1985 | 28.6 | 102.1 | 130.7 | | 130.7 | 48.5 | 194.3 | 242.8 | 16.7 | 259.5 |
| 1986 | 21.6 | 86.4 | 108.0 | 1.7 | 109.7 | 34.8 | 139.3 | 174.1 | 18.6 | 192.7 |
| 1987 | 12.0 | 48.1 | 60.1 | 16.7 | 76.8 | 14.5 | 58.5 | 73.1 | 33.9 | 110.9 |
| 1988 | 2.3 | 9.6 | 11.9 | 15.0 | 26.9 | 2.3 | 9.6 | 11.9 | 15.0 | 26.9 |
| Total | 301.8 | 762.2 | 1 064.0 | 33.6 | 1 097.6 | 394.2 | 1 289.1 | 1 683.3 | 86.3 | 1 769.6 |

[a] Rounded.
[b] Domestic expenditures for the nuclear fuel cycle working capital were assumed to be 0% of the total.

The present price of fuel oil at the refineries is fixed by the Government in relation to international prices and transportation costs. July 1972 fuel oil from Turkish refineries was priced at TL 420/t compared to the f. o. b. Persian Gulf posted heavy crude prices of less than TL 200/t. Even if the price of fuel oil drops to a level equal to that prevailing on the world market, such a level will probably be subject to an annual escalation rate of 2% to 4%. Under such conditions, lignite would be the preferred fuel.

(c) An evaluation of the competitiveness of nuclear versus lignite plants indicates that under the reference conditions (8% discount rate, 0% escalation on fuel prices) both types of plants are essentially equally competitve at a rated capacity of 600 MW; however, the nuclear plants are more competitive at capacities of 800 MW.

(d) An evaluation of the sensitivity of the results to various economic parameters indicates that under economic conditions which tend to favour nuclear plants (6% discount rate, lower capital cost differential) the nuclear market would range from 1200 MW to 500 MW. However, under economic conditions which tend to favour lignite plants (10% discount rate, 0% fuel oil price escalation rate, higher capital cost differentials), the nuclear market would drop to a range of 1200 MW to 3200 MW.

## 14. YUGOSLAVIA

At the request of the Government of Yugoslavia
the publication of their Country Report is being deferred.

APPENDIX O

# COOPERATING ORGANIZATIONS AND LIAISON OFFICERS IN PARTICIPATING COUNTRIES

| | |
|---|---|
| ARGENTINA | National Atomic Energy Commission (CNEA)<br>The Planning Department of the Secretariat for Energy<br>Water and Electrical Energy Company (AyEE)<br>Hydroelectric Company of North Patagonia (HIDRONOR)<br>The Fuels Department of the Secretariat for Energy<br>The Council of Economic Development (CONADE)<br>Electricity Company of Greater Buenos Aires (SEGBA)<br>Directorate of Energy for the Province of Buenos Aires (DEBA)<br>Provincial Energy Company of Córdoba (EPEC)<br>National Coal Board (YCF)<br><br>Liaison officer: Mr. D. Béla José Csik, CNEA |
| BANGLADESH | Ministry of Power, Natural Resources, Scientific and Technical Research<br>Power Development Board<br>Dacca Atomic Energy Centre (AEC)<br>Planning Commission<br>Fertilizer Pharmaceutical and Chemical Corporation<br>Ministry of Foreign Affairs<br>Minerals, Oil and Gas Corporation<br>Eastern Refinery<br><br>Liaison officer: Dr. Anwar Hossain, Bangladesh Atomic Energy Commission |
| CHILE | Chilean Nuclear Energy Commission (CCEN)<br>National Electrical Company (ENDESA)<br>Production Development Corporation (CORFO)<br><br>Liaison officer: Mr. Sergio Alvarado, CCEN |
| EGYPT | Atomic Energy Establishment<br>Atomic Energy Establishment Laboratories<br>President - Academy of Science<br>Ministry of Electricity<br>General Electricity Corporation (GEC)<br>Rakte Paper Factory<br>Kafr El-Dawar Textile Factory<br>General Petroleum Corporation<br><br>Liaison officer: Dr. Kamal Effat, Atomic Energy Establishment |

| | |
|---|---|
| GREECE | Public Power Corporation (PPC)<br>(Nuclear Power Department, Planning Division, System Planning Division, Lignite Mines Department, Hydro Station Engineering, Construction Department, Geology Department)<br>Greek Atomic Energy Commission (GAEC)<br><br>Liaison officers: Mr. D. Christophilopoulos, PPC<br>Mr. P. Papadimitropoulos, GAEC |
| JAMAICA | Ministry of Mining and Natural Resources<br>Ministry of Public Utilities, Communications and Transport<br>Ministry of Finance<br>Public Utilities Commission (PUC)<br>Jamaica Public Service Company (JPS)<br>Bank of Jamaica<br>Alumina and Bauxite Company Council<br>Esso West Indies Ltd<br><br>Liaison officer: Mr. W. St. L. Leiba, Ministry of Mining and Natural Resources |
| KOREA | Office of Atomic Energy (in Ministry of Science and Technology)<br>Atomic Energy Research Institute<br>Economic Planning Board<br>Ministry of Commerce and Industry<br>Korea Electric Company (KECO)<br>Ministry of Construction<br>Geological Survey of Korea<br><br>Liaison officer: Dr. Young-Ku Yoon, Atomic Energy Research Institute |
| MEXICO | National Nuclear Energy Institute (INEN)<br>Secretariat of the President of the Republic<br>Federal Power Commission (CFE)<br>Mexican Petroleum Board (PEMEX)<br>Mexican Petroleum Institute (IMP)<br>Council for Non-Renewable Natural Resources<br>Mexican Office for the Economic Commission for Latin America<br><br>Liaison officer: Dr. Carlos Velez, INEN |
| PAKISTAN | Pakistan Atomic Energy Commission (PAEC)<br>Lahore Mineral Centre<br>Lyallpur Research Centre<br>Karachi Electric Supply Company (KESC)<br>Water and Power Development Authority (WAPDA)<br>Government Planning Commission<br>Karachi Master Planners<br>Chief Engineering Advisor's Office<br>Natural Resources Division<br><br>Liaison officer: Mr. M. Shafique, Pakistan Institute of Nuclear Science and Technology (PINSTECH) |

| | |
|---|---|
| PHILIPPINES | Philippines Atomic Energy Commission (PAEC)<br>National Power Corporation (NPC)<br>Manila Electric Company (MECO)<br>Power Development Council (PDC)<br>National Economic Council<br>Presidential Economic Staff<br>National Science Development Board<br>Petroleum Institute of the Philippines<br>Oil Industry Commission<br>Bureau of Mines<br>Commission on Volcanology<br><br>Liaison officer: Dr. Librado D. Ibe, PAEC |
| SINGAPORE | Ministry of Science and Technology<br>Public Utilities Board (PUB)<br>Department of Geography, University of Singapore<br>Economic Development Board<br>Ministry of Finance<br>Jurong Town Corporation<br>Petroleum Sub-Committee, International Chamber of Commerce<br><br>Liaison officer: Mr. Tay Sin Yan, PUB |
| THAILAND | Electricity Generating Authority Thailand (EGAT)<br>Metropolitan Electricity Authority (MEA)<br>Provincial Electricity Authority (PEA)<br>Economic Committee for Asia and the Far East (ECAFE)<br>Mekong River Committee<br>Office of Atomic Energy for Peace<br>National Statistics Office<br>National Energy Authority<br><br>Liaison officer: Mr. Tongroj Pochanart, EGAT |
| TURKEY | Ministry of Energy and Natural Resources<br>Turkish Atomic Energy Commission (TAEC)<br>Turkish Electricity Company (TEK)<br>DSI State Hydraulic Works<br>Mineral Research and Exploration Institute<br><br>Liaison officer: Professor Dr. Sadik Kakaç, TAEC |
| YUGOSLAVIA | Union of Yugoslav Electric Power Industry (JUGEL)<br>Energoproject<br><br>Liaison officer: Mr. Slavko Vrhovac, JUGEL |

APPENDIX P

# PARTICIPANTS IN MARKET SURVEY MISSIONS

| | Mission | Country | Status[a] |
|---|---|---|---|
| R. Alami, Engineer, IAEA | Greece-Turkey | France | 1 |
| H. Aoki, Utility expert, Electric Power Development Co. Ltd, Tokyo | Korea-Philippines-Singapore | Japan | 2 |
| E. de Bellmond, Hydro Project and Systems Planning expert, State Power Board, Vällingby | Greece-Turkey, Argentina, Chile | Sweden | 3 |
| A. Böttcher, Nuclear expert, Nuclear Research Centre, Jülich | Greece, Egypt | FRG | 2 |
| J. von Bruchhausen, Nuclear Power expert, Lahmeyer International GmbH, Frankfurt | Korea-Philippines-Singapore | FRG | 2 |
| P.W. Cash, Electric Utility Systems Planning expert, Associated Nuclear Services, London | Mexico-Argentina, Pakistan-Egypt | UK | 4 |
| D.B.A. Chase, Engineer, IAEA | Mexico-Argentina, Korea | Canada | 1 |
| A.P. Coleman, Electric Utility Systems Planning expert, Associated Nuclear Services, Lordon | Korea-Philippines-Singapore | UK | 4 |
| C.B. von der Decken, Nuclear expert, Nuclear Research Centre, Jülich | Pakistan | FRG | 2 |
| O.B. Falls, Jr., Project Manager, IAEA | Greece-Turkey, Argentina, Jamaica-Chile, Yugoslavia | USA | 5 |
| J. Fassbender, Nuclear expert, Nuclear Research Centre, Jülich | Jamaica-Chile | FRG | 2 |
| Y. Fujiwara, Load Forecast expert, Tokyo Engineering Corporation | Pakistan-Egypt | Japan | 2 |
| M.N. John, Electric Utility System Planning expert, Associated Nuclear Services, London | Greece-Turkey | UK | 4 |

| | Mission | Country | Status[a] |
|---|---|---|---|
| J.P. Karger, Engineer, IAEA | Jamaica-Chile, Thailand-Bangladesh | Canada | 1 |
| B. Kolbasov, Engineer, IAEA | Egypt | USSR | 1 |
| S. Krawczynski, Nuclear expert, Nuclear Research Centre, Jülich | Turkey | FRG | 2 |
| R. Krymm, Economist, IAEA | Mexico-Argentina | France | 1 |
| F.J. Lane, Electric Utility Systems Planning expert, Associated Nuclear Services, London | Thailand-Bangladesh | UK | 4 |
| J.A. Lane, Nuclear Power expert, IAEA consultant | Jamaica-Chile, Yugoslavia | USA | 5 |
| S. Liberatore, Engineering Economist, Inter-American Development Bank | Jamaica | USA | 6 |
| J.S. McConnach, Electric Utility Systems Planning expert, Associated Nuclear Services, London | Turkey, Jamaica-Chile | UK | 4 |
| J.R. Mortlock, Electric Utility Systems Planning expert, Associated Nuclear Services, London | Yugoslavia | UK | 4 |
| O. Pedersen, Economist, IAEA | Greece-Turkey, Pakistan-Egypt | Denmark | 1 |
| A. Polliart, CEA, Nuclear expert, Paris | Pakistan-Egypt | France | 2 |
| J.T. Roberts, Economist, IAEA | Korea-Philippines-Singapore | USA | 1 |
| W. Schnurr, Nuclear Research Centre, Karlsruhe | Mexico-Argentina | FRG | 2 |
| R. Skjöldebrand, Engineer, IAEA | Thailand-Bangladesh | Sweden | 1 |
| K.S. Subramaniam, Nuclear expert, Madras Atomic Power Project | Thailand-Bangladesh | India | 2 |
| M. Takahashi, Power Demand expert, Central Research Institute of Electric Power Industry, Tokyo | Thailand-Bangladesh | Japan | 2 |

| | Mission | Country | Status[a] |
|---|---|---|---|
| R. Wawersik, Coal/lignite expert, Lahmeyer International GmbH, Frankfurt | Greece-Turkey | FRG | 4 |
| J.R. Wilson, Engineer, IAEA | Pakistan-Egypt | USA | 1/5 |

Other participants in Market Survey work

| | Activity | Country | Status[a] |
|---|---|---|---|
| J.L. Dickson Atomic Energy Establishment, Winfrith, UKAEA | Technical editor | UK | 2 |
| E. Ehrlich-Adám, IAEA | Editor | Austria | 1 |
| R.T. Jenkins Tennessee Valley Authority, Chattanooga, Tennessee | Computer programming | USA | 5 |
| D. Joy Oak Ridge National Laboratory, USAEC | Computer programming | USA | 5 |
| H.B. Merlin Atomic Energy of Canada Ltd, Chalk River, Ontario | Computer operations | Canada | 2 |
| M. Rückert Nuclear Research Centre, Jülich | Computer operations | FRG | 2 |
| G. Woite Nuclear Research Centre, Karlsruhe | Technical analyst | FRG | 2/3 |

[a] Status 1 = IAEA staff member.

Status 2 = Cost-free expert with salary, travel and per diem paid by the sponsoring country.

Status 3 = Expert provided salary-free with Agency paying travel and per diem.

Status 4 = Expert provided by contract with Engineering Consulting firm, the firm having the status of an independent contractor.

Status 5 = Consultant to IAEA under special services agreement.

Status 6 = Employee of Inter-American Development Bank with all expenses paid by IDB.