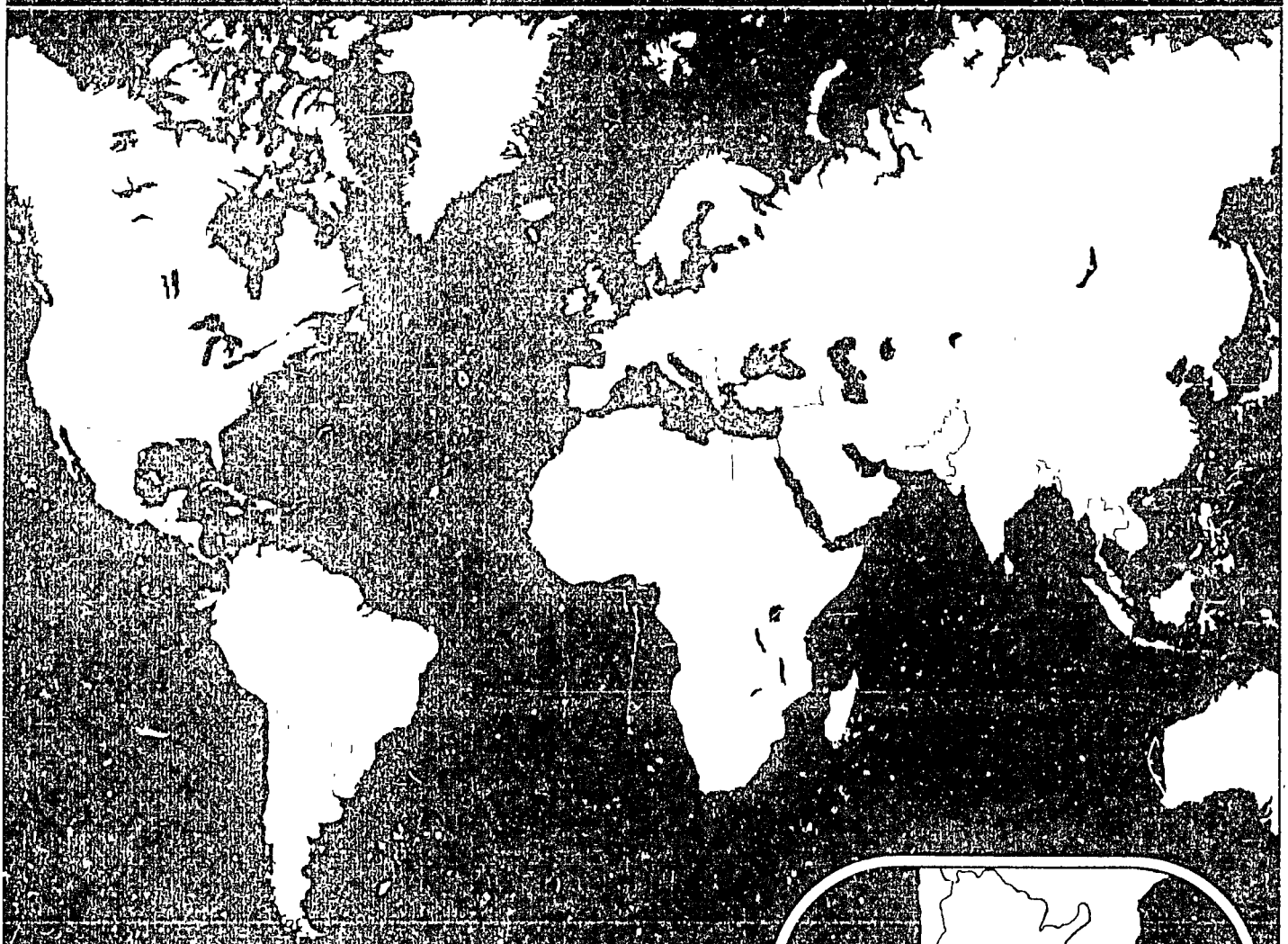
MARKET SURVEY FOR NUCLEAR POWER IN DEVELOPING COUNTRIES



ARGENTINA

MARKET SURVEY
FOR
NUCLEAR POWER
IN
DEVELOPING COUNTRIES

ARGENTINA

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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.

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

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

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

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

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

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

SCOPE AND IMPLEMENTATION

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

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

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

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

FINANCIAL AND MANPOWER SUPPORT OF SURVEY ACTIVITIES

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

Support in cash funds was made available from:

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

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

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

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

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

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

ACKNOWLEDGEMENTS

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

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

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

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

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

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

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

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

INTRODUCTION

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

TABLE OF CONTENTS

1.	ECONOMIC BACKGROUND	1
2.	NATIONAL ENERGY RESOURCES	9
3.	ELECTRICITY SUPPLY SYSTEM	27
4.	HISTORICAL SYSTEM DATA	45
5.	PROJECTED SYSTEM DATA	57
6.	NATIONAL CAPABILITIES AND LOCAL COSTS	68
7.	ECONOMIC AND FINANCIAL ASPECTS	72
8.	ADMINISTRATIVE AND REGULATORY	74
9.	ANALYTICAL APPROACH	76
10.	FORECASTS OF SYSTEM LOADS AND LOAD DURATION CURVES	79
11.	LIMITING FACTORS IN SYSTEM DEVELOPMENT	86
12.	CHARACTERISTICS OF THE EXISTING AND COMMITTED ELECTRIC POWER SYSTEM	96
13.	CAPITAL COST DATA	104
14.	CHARACTERISTICS OF ALTERNATIVE GENERATING UNITS CONSIDERED FOR EXPANSION DURING THE STUDY PERIOD	111
15.	ANALYSIS OF ALTERNATIVE EXPANSION PROGRAMS	114
16.	RESULTS	118
17.	SUMMARY AND CONCLUSIONS	124
APPENDIXES A-N		129

1. ECONOMIC BACKGROUND

1.1. Geographical features

Stretching over 33° of latitude from 22° south to 55° south approximately, Argentina covers a continental area of 2.8 million km^2 (see Fig. 1-1).

The country can be divided into four major regions:

(1) The Andes mountain chain and its foothills which limits the western border.

(2) The plains or Pampas which stretch northeastward from the base of the Andes to the Atlantic Ocean. These plains are composed of deep layers of alluvial material and form the base of the agricultural wealth of the country.

(3) The Paraná Plateau wedged between Paraguay and Brazil in the northeast.

(4) Patagonia which extends roughly from the Río Colorado southward from latitude 40° south and is composed of a series of steplike plateaus ending in cliffs on the Atlantic coast.

Along the Andean foothills, an almost arid zone extends from the northwest to the southeast from the Puna through Mendoza to Patagonia with average precipitation of the order of 193 mm.

A semi-arid crescent of the alluvial plains encircles a humid stretch extending to the coast with precipitation exceeding 1200 mm in the Buenos Aires area.

The Paraná Plateau region has a subtropical climate and precipitation ranges from more than 1000 mm at the Paraguayan and Brazilian borders down to less than 500 mm on the coast.

1.2. Population

The population of Argentina was approximately 23.4 million inhabitants at the end of 1970, corresponding to a density of 8.4 per square kilometer. The average rate of growth over the 1960-70 period was slightly higher than 1.5% (see Table I-(a)). 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, and that barring a sharp increase in the rate of immigration the expected population figures for 1980 and 1985 would be 27.3 million and 29.5 million respectively, rising to 31.8 million by 1990 (see Table I-1(b)).

It is worth noting that the percentage of the labour force employed in agriculture has steadily decreased from 24.4% in 1950 to 15.3% of the total in 1970. Since the fraction occupied in manufacturing and construction has remained practically constant over the same period, the difference has been essentially taken up by an increase in service industries and commerce as well as by a slight increase in unemployment over the period. The present plans for rapid industrial expansion over the next five years will be accompanied by a slight increase in the percentage of the labour force in the industrial sector and a further decrease in the relative percentage in agricultural employment.

It will be seen that considering the area of the country and its rich agricultural resources Argentina will not face, with its present rate of population growth, any very serious problems in achieving sustained increases of Gross Domestic Product per capita.

1.3. National economics[1]

The average growth rate of the real GDP over the period 1960 to 1970 averaged only 3.6% per annum. At the same time the rate of inflation was almost never below 10% while

[1] The unit of currency in the Argentine is the peso. The rate of exchange in relation to the US$ has varied during the past years, and the variation was particularly marked during the period 1971 to 1972. It would not, therefore, be useful to quote an indicative value at this point in the report. The value for a particular date and application is quoted in the text at the appropriate point.

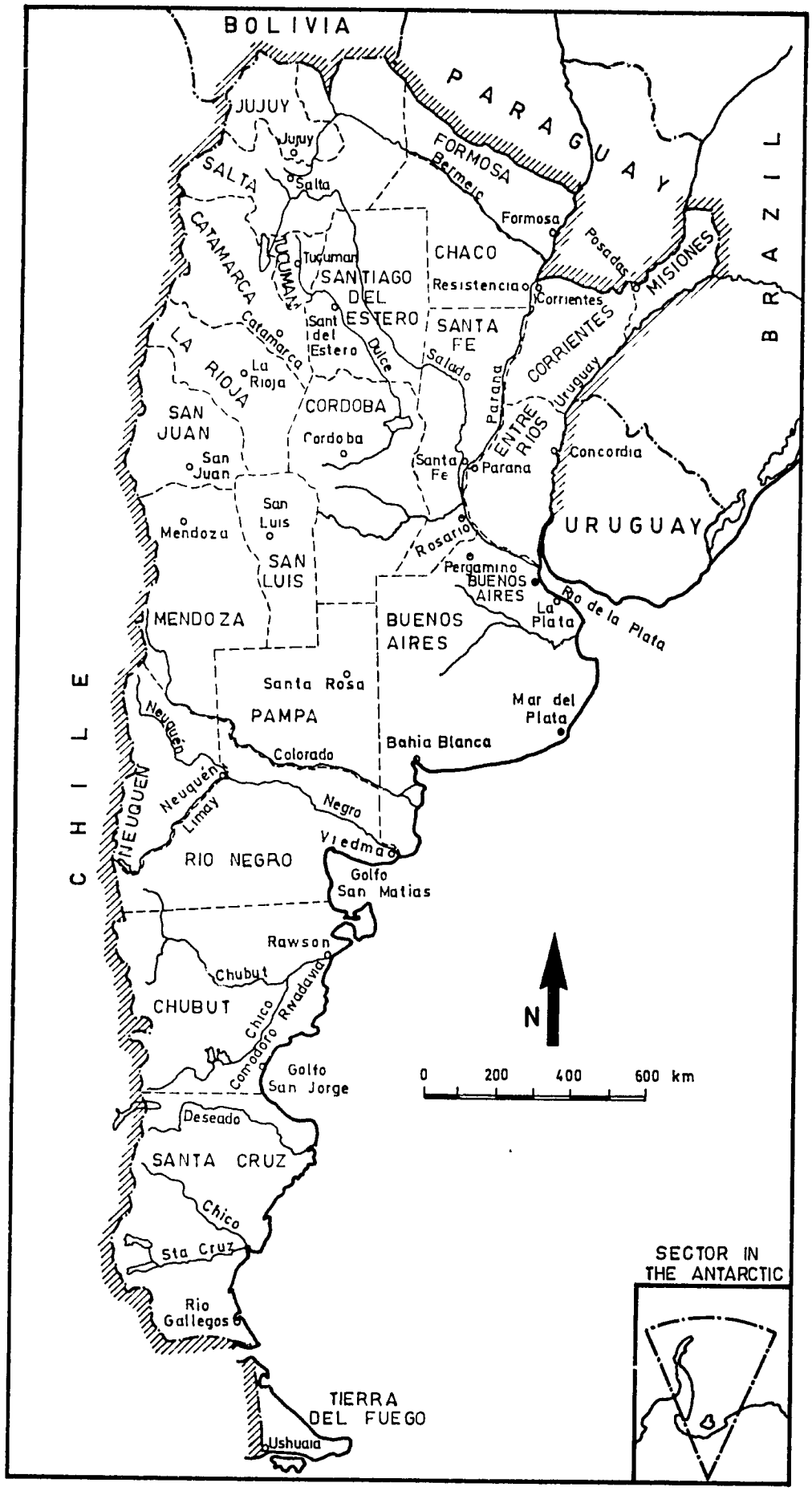


FIG. 1-1. MAP OF ARGENTINA

TABLE I-1(a). POPULATION DATA (1960-70)

Year	Crude birth rate	Crude death rate	Rate of natural increase	Net immigration	Total population	Rate of growth[a]
	per 10^3		%/yr		(10^3)	(%/yr)
1960	22.7	8.6	1.4	0.3	20 014	1.7
1961	22.5	8.3	1.4	0.2	20 356	1.6
1962	22.8	8.5	1.4	0.2	20 690	1.6
1963	22.5	8.6	1.4	0.1	21 030	1.5
1964	22.4	8.7	1.4	0.1	21 355	1.5
1965	21.4	8.7	1.3	0.1	21 675	1.4
1966	20.9	8.4	1.3	0.1	22 000	1.4
1967	20.9	8.4	1.3	0.1	22 330	1.4
1968	20.9	8.4	1.3	0.1	22 665	1.4
1969	20.9	8.4	1.3	0.2	23 015	1.5
1970	20.9	8.4	1.3	0.2	23 364	1.5

[a] Average rate of growth 1960-70: 1.56

TABLE I-1(b). POPULATION PROJECTIONS (1970-1990)

Year	1975	1980	1985	1990
Population (10^3)	25 250	27 300	29 500	31 800

it averaged 25%, and is at present approaching 58% per year. Per-capita gross income increased by an average of only 1.4% per annum. Very uneven development took place over the period. There were short spans of time (as for instance in the mid-1950's) when real GDP grew at a rate of more than 5% per annum. After this, however, periods of fast growth alternated with major recessions, as Table I-2 shows.

Argentina is not an under-developed country in the accepted sense of the word. It has the relatively high income per capita of 3144 pesos or (850 US$ at the 1970 exchange rate). Nor is its slow growth explainable in terms of inadequate savings and investments. The major cause seems to be the very slow growth of agricultural output since the last world war. From 1955 to 1970 the average growth rate of agricultural production was slightly more than 1% and it thus did not keep pace with the rate of population increase.

In industry, substantial development has taken place since the last world war and a more complex and developed industrial sector now exists than in many countries of comparable population, size and per-capita income (see Table I-3). The share of industrial production in total output was almost one third by 1969, a proportion which approaches that of several industrial countries (see Table I-4).

The rate of growth of industrial output has increased for the last three years, reaching a level of 7.5% by 1970. It should however be pointed out that this increase has to some extent been achieved by a deliberate policy of import substitution, leading to relatively high cost of production since most of the outputs are limited by the size of the domestic market.

The development plan for 1971-75, prepared by the National Council for Development, sets relatively high rates of growth for different sectors of the economy, which appear

TABLE I-2. GROWTH OF REAL NATIONAL OUTPUT AND POPULATION (1960-70)

Year	Real GDP (10^6 pesos)	Index (1969 = 100)	Annual change (%)	Population (10^3)	Real GDP per capita (pesos)	Index (1969 = 100)	Annual change (%)
1960	51 128	72.6	-	20 014	2 555	83.9	-
1961	54 590	77.5	6.7	20 356	2 682	88.1	5.0
1962	53 738	76.3	-1.6	20 690	2 597	85.3	-3.2
1963	51 836	73.6	-3.5	21 030	2 465	81.0	-5.0
1964	56 002	79.5	8.0	21 355	2 622	86.1	6.3
1965	60 758	86.3	8.6	21 675	2 803	92.0	6.8
1966	61 461	87.3	1.2	22 000	2 794	91.8	-0.2
1967	62 796	89.2	2.2	22 330	2 812	92.3	0.5
1968	65 756	93.4	4.7	22 665	2 901	95.3	3.2
1969	70 087	100.0	6.6	23 015	3 045	100.0	4.9
1970	73 455	104.8	4.8	23 364	3 144	103.3	3.3

somewhat ambitious in the light of the past record but which the inherent agricultural wealth, the relatively sophisticated industrial infrastructure and the availability of skilled labour and management might make less surprising than they at first sight appear. Table I-4 shows the projected rates of growth and the change in the relevant weights of the various sectors of the GDP which they would bring about. It will be seen that the total rate of growth of GDP for the period is expected to be about 7% – almost twice that which prevailed in the 1960-69 period. The rate of growth of agricultural output is expected to be doubled, from 2.2 to 4.4% annually, while industry should increase at an average annual rate of 8.6% compared with 4.3% and construction at 7.1% compared with 5% in the period 1960 to 1969.

1.4. Energy consumption

(a) Past trends and structure

The primary consumption of energy in Argentina rose from 20.76 million m^3 to 33.68 million m^3 of oil equivalent[2] between 1960 and 1970. The average annual growth rate of about 5.6% is particularly striking when compared with the average rates of growth of total GDP (3.6%) and of industrial output (4.3%). These relative elasticities of energy demand with respect to total and industrial products were apparently due to the rapid increase in availability of cheaply priced domestic petroleum products and natural gas. They could hardly be expected to prevail indefinitely in the future.

The expanded role of hydro-carbons 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 which stands in sharp contrast with the wealth of hydro resources available to the country. (See Table I-5.)

(b) Future projections

The ambitious targets of the Economic Development Plan for the country prepared by the Economic Development Council were initially combined with a sharp increase in the rate of growth of energy consumption. The latter was assumed to be 8.6% for the years 1970 - 1975. However, a revised forecast based on sectorial analyses prepared by the Sub-Secretary

[2] See Table I-5 for definition of "oil equivalent".

TABLE I-3. INDUSTRIAL PRODUCTION VOLUME INDEX (1961-70)
(Index 1960 = 100)

	1961	1962	1963	1964	1965	1966	1967	1968	1969	1st Qtr./70	2nd Qrt./70
Total	109.7	104.7	99.9	115.0	129.6	129.1	129.1	139.3	149.4	144.5	160.4
Food, beverages, tobacco	105.1	112.4	115.2	108.6	117.2	125.8	132.5	138.3	146.2	144.5	144.9
Textiles, leather, clothing	102.0	82.8	79.6	96.9	111.3	105.1	104.1	113.1	115.8	101.2	118.2
Chemical products	104.9	100.4	104.9	131.0	144.2	145.7	143.2	176.4	195.7	196.3	203.4
Stone, glass, pottery	116.5	113.8	100.2	111.5	131.9	140.9	144.8	156.5	165.3	174.4	195.2
Metals	110.5	101.6	102.8	141.4	157.2	135.5	136.5	171.5	199.9	178.3	218.1
Motor vehicles	142.5	151.4	127.9	183.3	219.9	2'2.2	217.9	224.9	246.4	218.8	250.7
Non-electrical machinery	98.5	80.4	70.1	76.4	78.6	72.9	67.3	69.4	73.9	74.8	92.1
Electrical machinery and equipment	116.4	97.4	80.8	99.2	116.9	112.9	108.8	100.3	107.0	128.0	164.6
Others	109.5	108.7	104.3	113.2	127.6	133.7	129.5	136.7	143.5	142.8	152.2

TABLE I-4. HISTORICAL AND PROJECTED GROWTH RATES OF GDP COMPONENTS AND PERCENTAGE SHARES

Sectors	Average annual rate of growth (%)		Percentage of total (%)	
	1960-69	1970-75	1969	1975
Agriculture	2.2	4.4	14.0	12.3
Construction	5.0	7.1	4.8	4.8
Industry	4.3	8.6	33.5	36.0
Energy	7.1	8.6	7.7	8.3
Commerce	3.0	6.6	17.7	17.4
Transport	4.7	8.4	5.4	5.8
Government services	1.2	0.3	5.3	3.8
Other services	3.0	6.9	11.6	11.6
GDP	3.6	7.0	100	100

TABLE I-5. PRIMARY ENERGY CONSUMPTION[a] (10^3 m^3 of oil equivalent)

Year	Solid fuels	Petroleum products	Natural gas	Vegetals	Hydro-electricity	Total
1960	1 077	15 186	1 371	2 829	299	20 762
1961	1 118	15 959	2 333	2 705	349	22 464
1962	954	16 284	2 998	2 530	376	23 142
1963	1 033	15 906	3 415	2 364	378	23 096
1964	1 077	17 641	3 739	2 392	398	25 247
1965	893	18 577	4 240	2 422	399	26 531
1966	816	18 937	4 545	2 519	466	27 278
1967	807	19 498	4 769	2 417	410	27 892
1968	861	20 362	5 301	2 276	481	29 286
1969	901	22 815	5 279	2 273	432	31 700
1970	995	24 009	5 902	2 340	434	33 680
1971	1 007	25 757	6 289	2 212	475	35 740

[a] Oil equivalent is 9.3×10^6 kcal/m^3

of Energy calls for the somewhat lower rate of growth of 7.5% for the decade 1970-1980. This would lead to a target of 69.3 million m^3 of oil equivalent by 1980.

The structure of demand is expected to change substantially with petroleum products decreasing in relative share to about 55% of the total and hydroelectricity increasing to more than 11% by 1980 (see Table I-6 and Fig. 1-2).

Both sets of figures reflect the Government's concern to ensure a maximum of self-sufficiency in the field of energy. Imports of crude and oil products were oscillating between 3% and 4% of total energy during the 1965-1970 period. They are expected to be completely discontinued by 1975 and it is then anticipated that a slight export surplus of heavy oil products will offset the natural gas imports from Bolivia.

TABLE I-6. 1980 PROJECTED ENERGY CONSUMPTION AND RELATIVE SHARES OF DIFFERENT ENERGY SOURCES IN 1972 AND 1980

Source	1980 energy consumption (10^3 m^3 of oil equivalent)	Relative shares (%)	
		1972	1980
Solid fuels	5 700	3.4	8.1
Petroleum products	37 900	71.1	54.7
Natural gas	12 600	18.3	18.2
Hydro-electricity	7 700	1.5	11.2
Nuclear energy	3 500	0	5.1
Vegetal fuels	1 900	5.7	2.7
Total	69 300	100.0	100.0

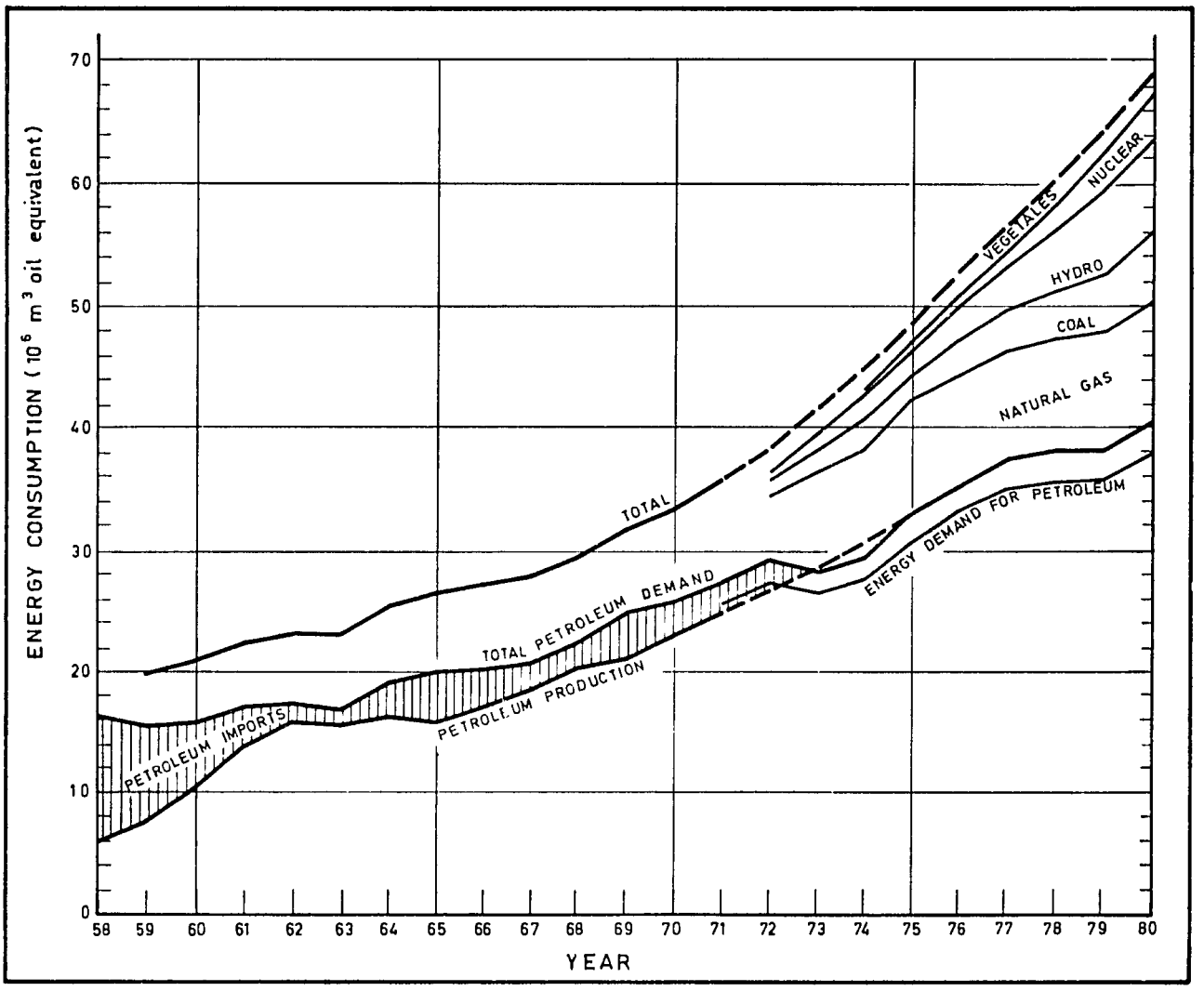


FIG. 1-2. HISTORICAL AND FORECAST CONSUMPTION OF ENERGY

(c) Electric energy (Table I-7)

Electric energy has increased at an annual rate of approximately 8% between 1961 and 1971 rising from 10 958 GWh to 23 653 kWh over that period. The growth rate forecast for the 1971 - 1976 five-year period is 11.5% with a subsequent decrease to 9.25% for the four years between 1976 and 1980. This would imply targets of 40 700 GWh and 58 000 GWh for 1976 and 1980 respectively.

The corresponding share of electricity in total energy production will accordingly rise from 15% in 1961 and 20.5% in 1971 to 24% in 1976 and 26% in 1980.

The growth rate of per-capita consumption implied in these figures is of the order of 10% for the 1971 - 1976 period, a very high figure. Its validity must, however, be assessed in the light of the five-year development targets for industrial growth. In fact, if these targets are achieved, the elasticity coefficient of electric energy consumption growth with regard to GDP increase would be lower than in the past decade (1.65 versus 2.22) and it would be in line with corresponding values for countries at a similar level of development. Hence the growth rates projected for electricity are in general accord with the GDP and industrial output objectives on which they are based.

TABLE I-7. ELECTRICITY AND TOTAL ENERGY PRODUCTION (past and projected) [a]

Years	Total energy (10^3 m^3 oil)	Growth rate (%)	Electricity (GWh)	Growth rate (%)	Share of electricity in total energy (%) [a]
1961	22 494	4.6	10958	8	15
1971	35740	8	23623	11.5	20.5
1976	52 800	7	40700	9.25	24
1980	69 300		58000		26

[a] Conversions were made on the basis of: 9.3×10^6 kcal per m^3 of oil equivalent and 2875 kcal per kWh

1.5. Interest in nuclear power

Argentina will be the first Latin American country to operate a nuclear power station: a 319 MW(e) heavy water moderated and cooled reactor which will be serving the Gran Buenos Aires Litoral system starting by the beginning of 1973. Furthermore, the award of a contract for a second nuclear power plant of 600 MW(e) to be built in the Córdoba Province is imminent.

The decisions to build both stations were preceded by exhaustive feasibility studies carried out by a special team established by the National Atomic Energy Commission and composed of technical and economic experts specialized in all aspects of nuclear power plants.

The decisions were based on a comprehensive analysis of the energy future of the country and fitted within the general plan outlined by the Commission which calls for more than 1500 MW(e) of nuclear power to be installed in the country by 1980.

Furthermore, the objective of the Commission which, in the last fifteen years, has assumed major responsibilities in the field of uranium prospecting and mining as well as in that of technological and industrial development is to achieve a maximum degree of domestic participation in the construction and fuelling of future nuclear power plants. Based on preliminary studies and on the specifications set out, this participation is expected to be of the order of 50% for the 600 MW Córdoba plant and it is hoped that it would reach approximately 70-80% of the total costs of stations commissioned after 1980.

The present Government has stated that it wishes its energy sector to pursue a nationally oriented policy, making greater use of substitute fuels, including nuclear fuels, thus saving petroleum and its derivatives for other uses, such as petrochemicals.

The Ministry of Public Works is interpreting this to mean that hydroelectric and nuclear power should be used as much as possible in future.

2. NATIONAL ENERGY RESOURCES

2.1. Hydroelectric potential

(a) Description of potential or undeveloped sites

The feasible hydro potential of Argentina was surveyed in 1969 by Agua y Energía Eléctrica which is a state enterprise directed by the Sub-Secretary of Energy. In this survey 43 small hydro stations which were in operation in 1968 are listed together with the estimated capacity and energy output of 118 investigated sites grouped according to six catchment basins. A summary of the 1969 survey is shown in Table II-1. The total potential listed in this table is about 149 000 GWh/yr output with an estimated 31 560 MW installed capacity. Some rivers in the comparatively dry northwest region (Catamarca) were not included in the survey. Regions distant from inhabited areas or industrial loads were also excluded. Finally, some of the minor sites included may not on closer scrutiny show sufficient economy for development.

No hydro stations have been brought into operation since 1968. Details of the existing stations are given in Table II-2.

There are at present six hydro stations under construction as listed in Table II-3. Carrizal is expected to go into operation at the end of this year. Construction on El Chocón is on schedule, the dam is practically complete and has been filled with this year's rich flood waters. The transmission line is advancing according to program and the first two units will operate in 1973, the next two will be in service in 1974 and the 5th and 6th units will be installed in the last quarter of 1975. A second major block of power will come in

TABLE II-1. INVENTORY OF HYDROPOTENTIAL BY AGUA Y ENERGIA ELECTRICA

Catchment	Operating 1968		Sites investigated		Total estimated potential	
	MW	GWh	MW	GWh	MW	GWh
River Plate Basin						
8 operating stations	88	238				
35 investigated sites			16 500	97 300	16 588	97 538
Central Basin						
20 operating stations	168	399				
24 investigated sites			349	1 080	517	1 479
Colorado River Basin						
7 operating stations	232	1 150				
41 investigated sites			3 870	12 400	4 102	13 550
Pampeana Basin						
no operating stations						
1 investigated site			12	87	12	87
Patagonia Pacific Basin						
2 operating stations	2	4				
8 investigated sites			872	4 500	874	4 504
Patagonia Atlantic Basin						
6 operating stations	64	305				
9 investigated sites			9 400	31 600	9 464	31 905
1968 known potential of 43 operating sites and 118 investigated sites	554	2 096	31 003	146 967	31 557	149 063

TABLE II-2. OPERATING HYDRO STATIONS (1972)

Catchment	River	Station	Year of commissioning	Units No. × MW	Capacity (MW)	Energy (GWh)	Remarks
Plata	Bermejo	Tilcara	1934	2 × 0.1	0.2	0.6	Separate
	"	Reyes	1959	2 × 3.6	7.2	14.8	Noroeste system
	Salado	Corralito	1961	2 × 6.6	13.2	28.6	Noroeste system
	"	Quijano	1939	2 × 0.1	0.7	1.0	Noroeste system
		"	1954	1 × 0.5			
	Carcarañá	Fitz Simon	1938	3 × 3.6	10.8	58.	Córdoba system
	Río Tercero	Cassaffousth	1953	3 × 5.7	17.2	72.	Córdoba system
	"	Reolin	1966	3 × 12.8	38.4	60.	Córdoba system
Mediterránea	Diamante	Coroneles	1970	2 × 3.5	7.0	27.	Noroeste system
	Salí	Lules	1930	1 × 2.5	2.5	17.	3 groups (1911) out of service
	"	Cadillal	1967	2 × 5.6	11.2	40.	Noroeste system
	"	(Tafi del Valle)		2 × 0.25	0.5	-	Separate, tourist season
	"	Pueblo Viejo	1967	2 × 7.5	15.	70.	Noroeste system
	"	Escaba	1955-56	3 × 8.0	24.	48.	Noroeste system
	Dulce	Los Quirogas	1968	2 × 0.95	1.9	10.4	Noroeste system
	Río Primero	San Roque	1960	4 × 6	24	60.	Córdoba system
		Calera	1911	4 × 1	4.	20.	Córdoba system
	Río Segundo	Los Molinos 1	1957	4 × 15	59.	93.	Córdoba system
		" " 2	1959	1 × 5	5.	20.	Córdoba system
	Los Sauces	La Viña 1	1957	2 × 8	16.	20.	Not yet connected to Córdoba system
	Cruz del Eje	C.d.E. 1	1957	2 × 0.8	1.6	6.4	Not yet connected to Córdoba system
	Varios San Luis	La Florida	1957	2 × 1.0	2.	3.7	San Luis system
	"	Cruz de Piedra	1958	1 × 0.2	0.2	-	San Luis system
	"	Los Puquios	1958	1 × 0.2	0.2	-	San Luis system
	Varios Catamarca	Andalgala	1951, 1955	4 × 0.1	0.4	0.7	Separate
	"	La Carrera	1955	2 × 0.5	1.	1.7	Noroeste system
	"	Saujil y Mutquin	1953	1 × 0.2	0.2	0.8	Separate
	Varios La Rioja	La Rioja	1935	2 × 0.15	0.3	1.2	"
	"	Chilecito y A. N.	1960	1 × 0.35	0.8	3.	"
Río Colorado	Jáchal	Salto de la Loma	1952	2 × 0.6	1.2	2.0	"
	San Juan	Ullun	1970	2 × 22.5	45.	257.	"
	Mendoza	Cacheuta	1926-28	3 × 3.0	8.9	62.2	Will become overdammed by Potrerillos
	"	Alvarez Condarco	1956	2 × 13.6	27.3	128.4	Cuyo system
	"	San Martín	1950	3 × 2.0	6.0	15.6	Cuyo system
	"	Luján de Cuyo	1912		1.0	4.7	Not operating?
	Atuel	Nihuil 1	1957	4 × 18.4	74.	338.	Cuyo system
	"	" 2	1968	4 × 21.3	85.1	346.	Cuyo system
	"	" " (extension)	1972	2 × 24	48.	-	Cuyo system
	"	Nihuil 3	1972	2 × 26	52.	138.	Cuyo system
Patagonia - Pacífico	Lago Mascardi	Emilio Frey	1959-60	2 × 0.55	1.1	2.5	Separate
	Lago Lacar	S. Martin de los Andes	1949	2 × 0.2	0.4	1.5	"
Patagonia - Atlántico	Neuquén	Chos Malal	1943	1 × 0.1	0.3	0.1	"
	Negro	Julián Romero	1960	2 × 3.1	6.2	40.	Río Negro system (Comahue)
	"	Cipoletti	1956	1 × 5.7	5.7	35.	Río Negro system (Comahue)
	"	General Roca	1958	1 × 1.2	1.2	5.	Río Negro system (Comahue)
	"	Guillermo Céspedes	1963	2 × 2.75	5.5	35.	Río Negro system (Comahue)
	"	Florentino Ameghino	1969	2 × 22.5	45.0	190.	Sep. later Futaleufú and C. Rivadavia system
			Total		672.4	2278.9	

TABLE II-3. HYDRO STATIONS UNDER CONSTRUCTION, SEPTEMBER 1972

Station	River	System	Expected year of operation	Units No. × MW	Capacity (MW)	Energy (GWh/yr)
Carrizal	Tunuyán	Cuyo	1972	2 × 9	18	72
El Chocón	Limay	Comahue	1973	6 × 200	1200	3320
Río Hondo	Dulce	Noroeste	1973	2 × 7.5	15	70
Futaleufú	Futaleufú	Futaleufú	1975	4 × 110	440	2350
Cabra Corral	Salado	Norceste	1975	3 × 34	102	290
Agua del Toro	Diamante	Cuyo	1976	2 × 65	130	244
			Total		1905	6346

1974 when C.H. Futaleufú is expected to start operation. This station will supply power to an aluminium smelter at Puerto Madryn on the Atlantic coast over a separate transmission line. Cabra Corral and Agua del Toro are two other plants under construction. The present plan is that these two plants will start operation in 1975 and 1976 respectively. The total capacity of all stations now under construction which will come into operation by 1976 amounts to 1905 MW with an energy output of 6346 GWh during an average rainfall year.

An investigation of hydro sites to be considered for planning was completed in the spring of 1972. The sites considered are listed in Table II-4. The table lists a total of 27 stations and shows the earliest possible date for commencing economic operation. Some of the future hydro sites are already committed; namely, C. H. Planicie Banderita which is presently scheduled for commencement of construction in 1973 (orders for equipment to be placed at the end of 1972). Alicurá will be the next station on the Limay. These two stations will add more than 3000 GWh/yr to El Chocón. A decision will soon be reached on two international projects, Salto Grande on the Uruguay river (1600 MW) and Apipé on the Paraná (3240 MW). Two international commissions between Argentina and Uruguay and between Argentina and Paraguay have prepared exhaustive feasibility studies with the aid of international consulting firms. The lay-out of the Salto Grande was agreed upon this year and the commission states that financing is also finalized. Similarly, on Apipé, an agreement in principle on the technical lay-out was reached this year and final agreement is hoped for in the spring of 1973. The relatively distant future output of these stations will be divided between Argentina and the neighbouring countries. In the first decade of operation, it is expected that all the power will be used by Argentina as the adjoining countries have insufficiently large networks to accept the large blocks of power. The first units of Salto Grande are not expected to come into operation before 1979/80 and the remainder of the 12 units as the load requires. Similarly, in Apipé ten units are planned to come into operation in 1981 with the remaining 20 units of 108 MW each to be added according to load needs. A third international station, Corpus, on the Paraná River in a location where 30 000 GWh/yr is available, is tentatively planned. Although no detailed studies have been made, some thought is being given to commencing the project in 1983. It is not likely, however, that such a large block of power could be utilized in Argentina in the next two decades. One purely Argentine site on the Paraná near Sante Fe (Paraná Medio) could, according to preliminary studies, deliver 15 000 GWh/yr at 3000 MW installed capacity. This site could be brought into service as early as 1984.

There is, in addition, considerable potential on the southeast coast for tidal generation of electricity. The tidal range there is some 16 m, and a specific site on the Valdés Peninsula to the South of the San Matías Gulf has been considered. The economic situation is such, however, that further development of this project is not likely to occur within the next two decades.

TABLE II-4. HYDRO SITES CONSIDERED IN PLANNING AND INVESTIGATION, 1 Sep. 1972

Name	Earliest operating year	System	River	Units No. × MW	Capacity (MW)	Energy (GWh/yr)
Planicie Banderita	1977	Comahue	Neuquén	3 × 150	450	1510
Florentino Ameghino	"	Patagonia	Chubut	1 × 22.5	22	(extension)
Reyunos P [a]	"	Cuyo	Diamante		216	175
Alicurá	"	Comahue	Limay	4 × 150	600	1660
La Brava P	"	GBA-L [b]	Laguna La Brava		600	(P)
Río Grande P	"	Centro	Río Grande	4 × 190	760	150
Los Blancos	1979	Cuyo	Tunuyán	2 × 124	248	869
Collón Curá	"	Comahue	Collon Curá	3 × 200	600	1877
Potrero del Clavillo	1980	Noroeste	Medina		339	445
Potrerillos P [c]	"	Cuyo	Mendoza		227	433
Alvarez Condarco	"	"	"	2 × 13.6	27	(extension)
Zanja del Tigre	1981	Noroeste	Bermejo		450	900
Anisacate P	1982	Centro	Anisacate		960	1408
Cordón del Plata	"	Cuyo	Tupungato		1200	1800
Chihuido	"	Comahue	Neuquén		2 000	3 000
Santa Cruz 1	"	Patagonia	Santa Cruz		600	3 038
La Viña P	1983	Centro	Los Sauces		900	1200
Valle Grande P	"	Cuyo	Atuel		90	154
El Tontal	"	"	San Juan		834	2 085
El Baqueano	"	"	Diamante		270	405
Piedra del Aguila	"	Comahue	Limay		2 400	5 500
Santa Cruz 2	"	Patagonia	Santa Cruz		400	2 000
Santa Cruz 3	"	"	"		800	4 000
Paraná medio	1984	GBA-L [b]	Paraná (Sta Fe)		3 000	15 000
			Subtotal		18 002	47 711
International Projects (Total Capacity and Energy quoted of which part only available to Argentina)						
Salto Grande	1978	GBA-L [b]	Uruguay	12 × 135	1620	6400
Apipé	1980	Noroeste	Paraná	30 × 108	3 240	17 300
Corpus	1983	Noroeste	Paraná		6 000	30 000
Total					28 862	101 411

[a] P = Pumped storage
[b] GBA-L = Gran Buenos Aires-Litoral.
[c] Potrerillos will overdam Cacheuta (Table II-2).

(b) Distance from load centres

All power stations presently in operation are small stations working separately close to local loads or interconnected to local systems at distances not exceeding 250 km from the load centre. In the period 1980-1990 most of these local stations will be brought into an interconnected grid. At that time the greatest transmission distance to Buenos Aires will

become more than 1000 km. An 1100 km transmission line from El Chocón to Buenos Aires is now under construction. For the remaining projects in the south on the Río Negro, the Colorado, the Limay and the Neuquén systems the transmission distance to Buenos Aires is also 1000 km. Some of these projects will be used to supply power to power-intensive industry such as the aluminium smelter plant in the area around the Gulf of San Matías. The future developments to the north will continue to be closer to the load centre of Buenos Aires. Salto Grande, for example, is 500 km away from Buenos Aires and Apipé about 1000 km. These will continue to supply loads south as the Buenos Aires Litoral continues to expand. Figure 2-1 is a map showing the locations and typical distances of major projects.

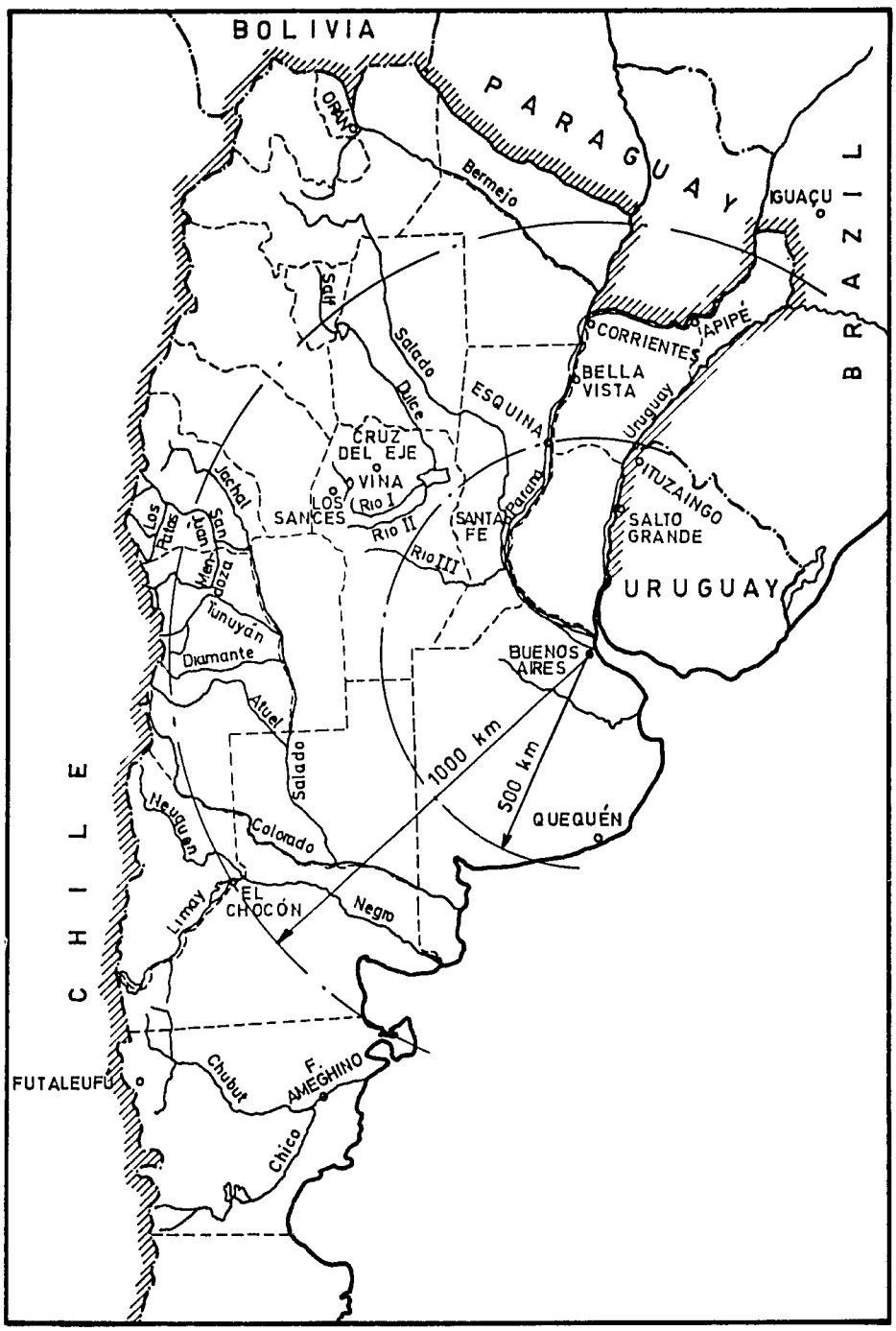


FIG. 2-1. DISTANCES OF HYDROELECTRIC SITES FROM BUENOS AIRES

(c) Energy and capacity potential of each

As mentioned previously, Table II-1 contains an inventory of the hydro potential of six major catchment basins. Table II-4 further breaks down the hydro sites on the various rivers in these catchment basins. The energy capacity of these sites and basins is given in these tables. A total energy output of 150 000 GWh/yr (Table II-1) could well be reached in the future when sites which at present appear remote could be connected at reasonable cost to an extended system of transmission lines. Installed capacity will mainly depend on the peak load in this future extended power system which will probably include large amounts of thermal capacity. Since hydro capacity can often be obtained at low marginal costs, a greater installed capacity than the 31 557 MW envisaged in the 1969 survey may be achieved. In the survey the hydro capacity was assumed to be used for 4700 h/yr which is not much less than the load factor of the system.

In the period between the first survey in 1969 and the present some of the smallest stations were abandoned and some new stations came into operation. Table II-2 lists 45 stations now in operation, the year of commissioning, the number and size of their units, installed capacity and average annual output. There is presently 672 MW total hydro capacity installed with 2279 GWh output in a year of average rainfall.

Future development has been discussed in Section 2.1(a). Argentina has large blocks of economic hydro power. Development to date has been slow because individual projects are large relative to the power requirement. As a result, the projects require the construction of a large dam with associated large capital expenditure and installation of equipment piecemeal as the need for power arises. In the future, these projects should play an important part in the development of the country.

(d) Current and projected costs

An economic study of El Chocón and Cerros Colorados, which are under construction, and on Salto Grande and Apipé, is available and summarized in Table II-5. This study shows a rate of return of between 9% and 11% for these fairly large projects using an energy value of 4 US mill/kWh and using the flood control and irrigation values assigned to the project by the Agua y Energía Eléctrica. Examination of the capital costs for El Chocón and Cerros Colorados shows that the interest during construction was assumed to be approximately 40%, which is a rather high figure but not unreasonable for a project the size of El Chocón. The capital costs of these projects require very high initial investments, which have been to date the largest deterrent to faster development.

Future development which will take place on the Paraná system will offer a somewhat higher degree of reliability since the river will be regulated by large developments in Brazil, which are already in operation or are under construction. The requirement to handle shipping on the river will increase the costs of the stations but, on the other hand there will be a compensating social benefit since, with adequate planning, larger shipping will be able to navigate the river more economically with the regulation resulting from the hydro project.

2.2. Coal

(a) Amount and location of reserves

In spite of extensive prospecting along the Andean foothills, the only economically exploitable coal field known in the country to date is located in the extreme south of the country in the Río Turbio area in the province of Santa Cruz, about 2500 km from Buenos Aires (see Fig. 2-2).

Reserves are estimated at 450 million tons in seams of 1.50 to 3 m thickness and located at varying depths down to 700 m. The coal produced is of sub-bituminous quality with an average higher calorific value of 6000 kcal/kg (see Table II-6).

The characteristics of the coal limit its use for metallurgical purposes for which it must at best be mixed with 85% of imported coking coals and the marketing is essentially oriented towards electric power plants.

TABLE II.5. COSTS OF HYDRO STATIONS

Station	Installed capacity (MW)	Energy (GWh/yr)	Benefit in 10^6 US$/yr				Total cost (US$ x 10^6)	Return (%)
			Capacity at 15 US$/kW	Energy at 4 US mill/kWh	Flood control and irrigation	Total		
Under construction								
Chocón and Cerros Colorados incl. transmission to Buenos Aires	1 650	4 830	24.75	19.32	~2.00	46.07	331[a] 132[b] 463[c]	9.9
Estimate for planned stations								
Salto Grande 12 x 135 MW units	1620	6400	24.30	25.60	-	49.90	480[d] 81[e] 561[c]	8.9
Apipé 30 x 108 MW units	3240	17300	49.60	69.2	~	118.8	787[f] 292[g] 1079[c]	10.9

a Incl. tender price for transmission to Buenos Aires.
b Interest during construction, assumed to be 40%.
c Cost at begin of operation.
d Estimate by IBRD.
e Approx. transmission cost.
f Total cost Apipé.
g Transmission to Buenos Aires and Asunción.

(b) Production and transportation

Production, which is carried out under the responsibility of a governmental organization, Yacimientos Carboníferos Fiscales (YCF), has more than doubled between 1965 and 1970 when it exceeded 600 000 t (see Table II-7(a)).

With the general objective of achieving energy self-sufficiency and import substitution, the targets for future production are being revised upwards. Whilst the Five-Year Development Plan initially called for a 1975 target of 1.5 million tons, the latest, tentative, target indicated by the Sub-Secretary of Energy requires a jump to 5 million tons by 1975 and to 8 million by 1980. These figures are based on a feasibility study which is now being carried out by a consulting engineering firm.

Purification and washing are carried out in a fairly modern plant with a capacity of 530 t/h which is expected to be expanded further.

Transport remains a major cost component with the coal carried by train over 260 km to the coast where it is loaded at the harbour of Río Gallegos and transported by sea to Bahía Blanca, Necochea and Buenos Aires (a journey of over 2400 km). A fleet of coal-carrying vessels is in the process of being built up, but the cost of purchasing the ships is still not clear.

(c) Current and projected costs

In spite of productivity increases (Table II-7(b)), production has remained substantially below 1 t/man-day up to the present time (0.6 in 1970). With relatively limited output and heavy social and initial installation expenditures, the operation has shown a string of deficits which exceeded 3.7×10^9 (1969) pesos in 1969 or about 10 million US$ at the then prevailing exchange rate.

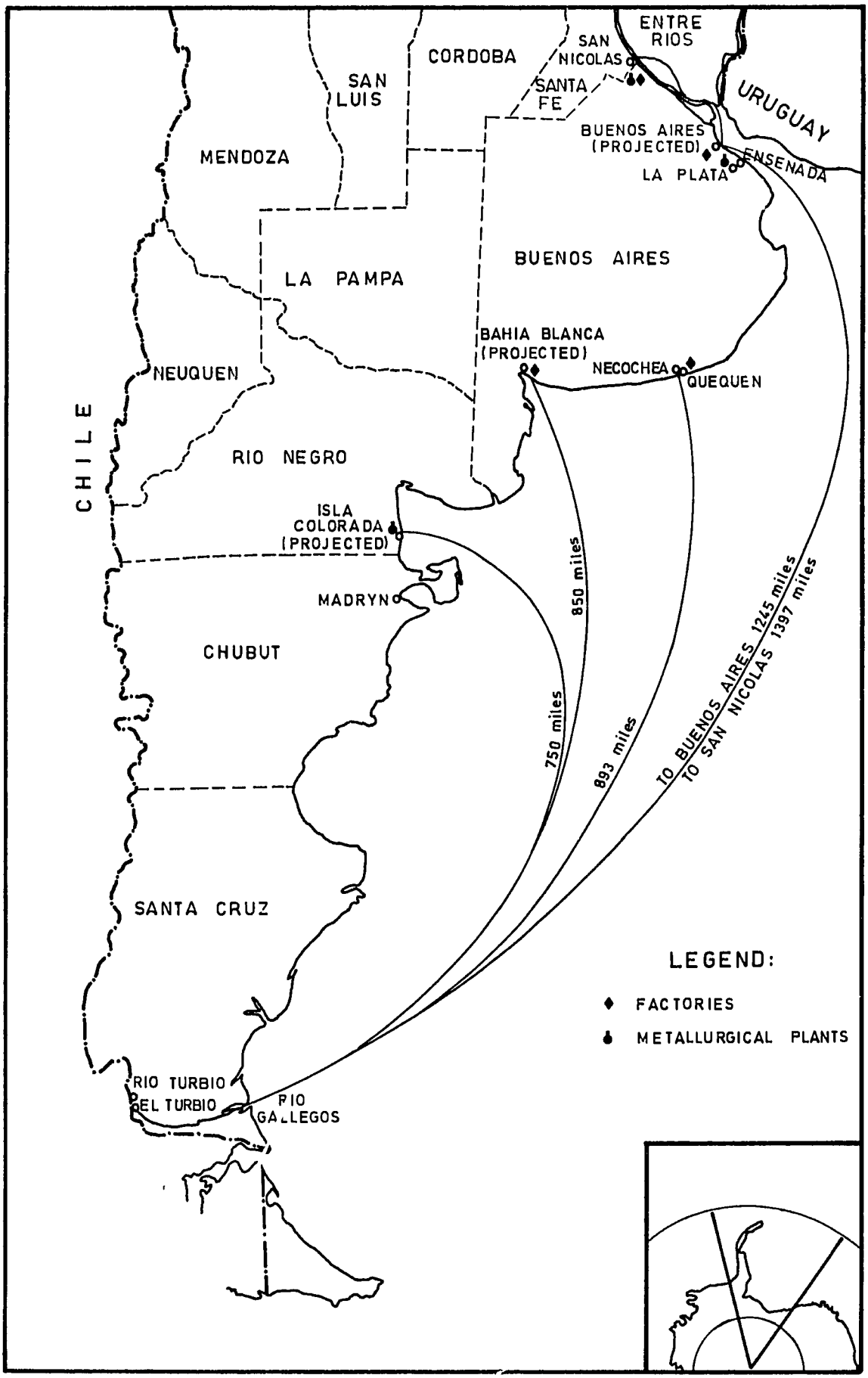


FIG. 2-2. COAL SUPPLY ROUTES

An analysis of the detailed earnings statement of YCF for 1969, when production of commercial coal was about 520 000 t, points to an average production cost of about 15 US $/t and a cost of transport of about 7 - 8 US $/t, the latter being equally divided between rail and sea freight. The resulting deficit was not surprising since the average selling price appeared to be about 7 US $/t during that year.

The cost, which is equivalent to about 3.6 - 3.8 US $ per million kcal or 90-95 US cents per million Btu for coal delivered in the Buenos Aires harbour, is likely to be substantially lowered as output expands and rail and sea transport are expanded and improved. A decrease of 50% is tentatively forecast.

TABLE II-6. CHARACTERISTICS OF RIO TURBIO COALS

Coal type	%				Heat content (kcal/kg)
	Water	Volatile materials	Carbon	Ashes	
1	10.1	37.6	38.2	14.1	5980
2	9.7	38.3	42.1	9.9	6355
3	14.3	35.2	38.6	11.9	5816

TABLE II-7(a). PAST AND PROJECTED COMMERCIAL COAL PRODUCTION

Years	1965	1966	1967	1968	1969	1970	1975	1980
Output (10^3 t/yr)	288	330	405	472	521	616	5000	8500

TABLE II-7 (b). AVERAGE LABOUR PRODUCTIVITY IN COAL MINING

Year	1965	1966	1967	1968	1969	1970
Productivity (t/man-month)	6.7	7.3	10.4	13.6	16.3	18.0

2.3. Oil and natural gas

(a) Amounts and locations of reserves

Argentina is relatively well endowed with oil and gas-bearing geological formations and, although the present primary proven reserve figures of slightly more than 200 million m^3 for crude and 120×10^9 m^3 of gas are not particularly impressive (see Table II-8 and II-9), the results of recent exploration and the extent of the areas assigned for intensive prospecting point to a probable rapid expansion in the coming years. Figure 2-3(a) and Table II-10 show the exploration areas allocated at the end of 1970 which total almost 15% of the country's surface.

(b) Production, refining and transportation

Production of crude, which reached 22.8 million m^3 in 1970, is almost entirely controlled (99.3%) by the State Petroleum Board, Yacimientos Petrolíferos Fiscales (YPF) and its contracted servicing companies, and that of natural gas, whose output reached 7.7×10^9 m^3 in 1970, by the State Gas Board, Gas de Estado.

TABLE II-8. PROVEN OIL RESERVES (31 Dec. 1970)

Basin	Primary (10^6 m^3)	Secondary recovery (10^6 m^3)	Total (10^6 m^3)
Noroeste	10.640		10.640
Cuyana	48.041	52.925	100.966
Neuquina	60.494	62.099	122.593
Golfo S. Jorge	72.976	72.659	145.635
Austral	11.241	1.419	12.660
General total	203.392	189.102	392.494

TABLE II-9. PROVEN GAS RESERVES (31 Dec. 1970)

	Reserves in oilfields (10^6 m^3)	Independent gas reserves (10^6 m^3)	Total (10^6 m^3)
Total	62 150	109 161	171 311
Minimum recoverable	12 001	109 161	121 162

TABLE II-10. EXPLORATION AREAS ALLOCATED AT THE END OF 1970

State-owned companies	
On land	350 000 km^2
Offshore	13 000 km^2
Private companies	
On land	53 000 km^2
Offshore	76 000 km^2

The 1980 production targets of 40.6 million m^3 for oil and of 12.5×10^9 m^3 for natural gas are relatively high, but they imply rates of growth which have been exceeded in the past.

Table II-11 gives details of refinery production for the years 1966 to 1970 inclusive. The 1970 refining capacity of about 36 million m^3 per year (see Table II-12) is expected to be expanded to close to 50 million m^3 per year by 1980.

It will be seen from Table II-11 that between 1966 and 1970 the proportion of fuel oil has decreased from about 40% to about 36% of the total crude processed. The reason for this lies essentially in the rapidly increasing use of natural gas which competes with fuel oil for many industrial uses.

Transport data for both crude oil and natural gas is summarized in Table II-13 and Fig. 2-3(b).

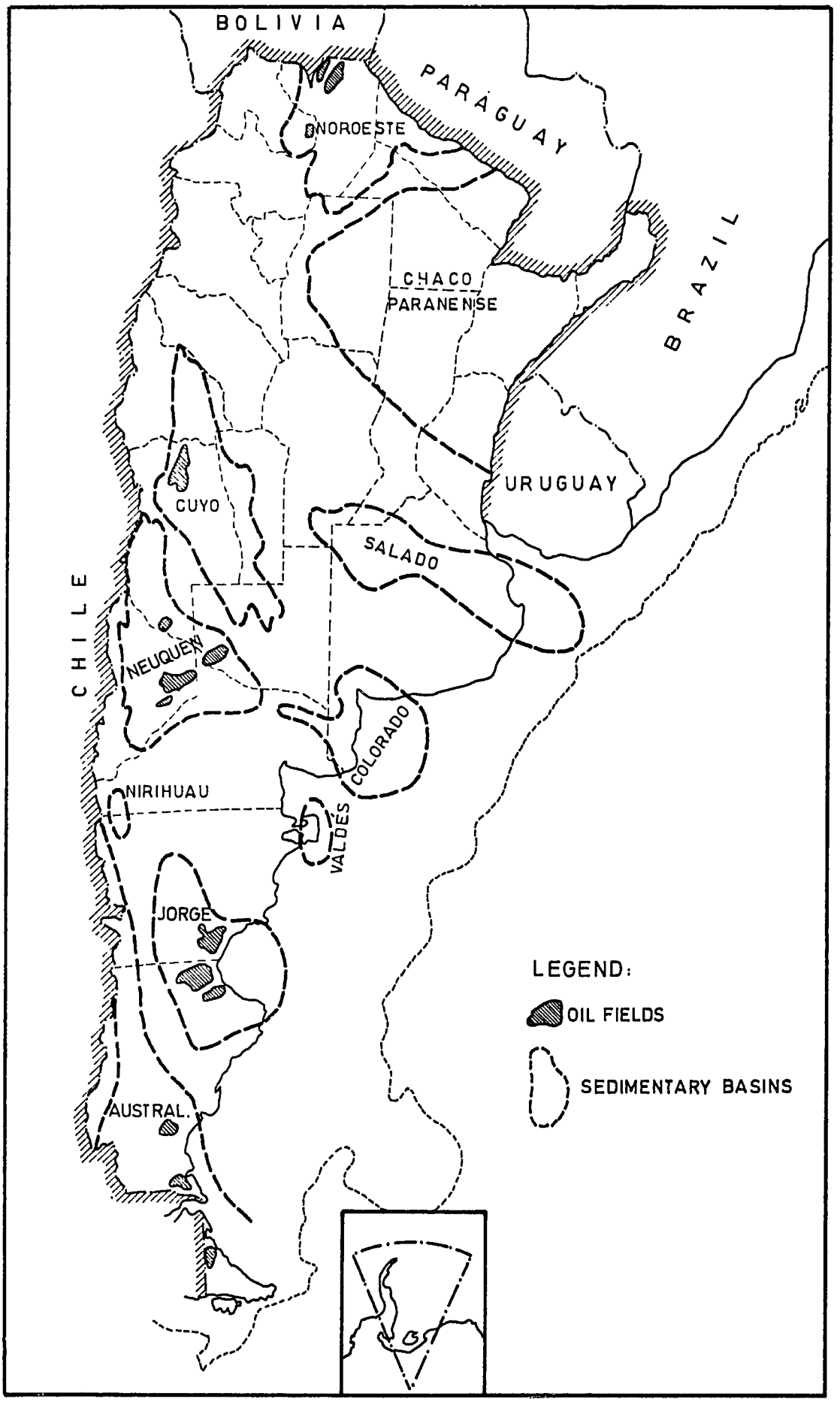


FIG. 2-3(a). OIL FIELDS AND EXPLORATION AREAS

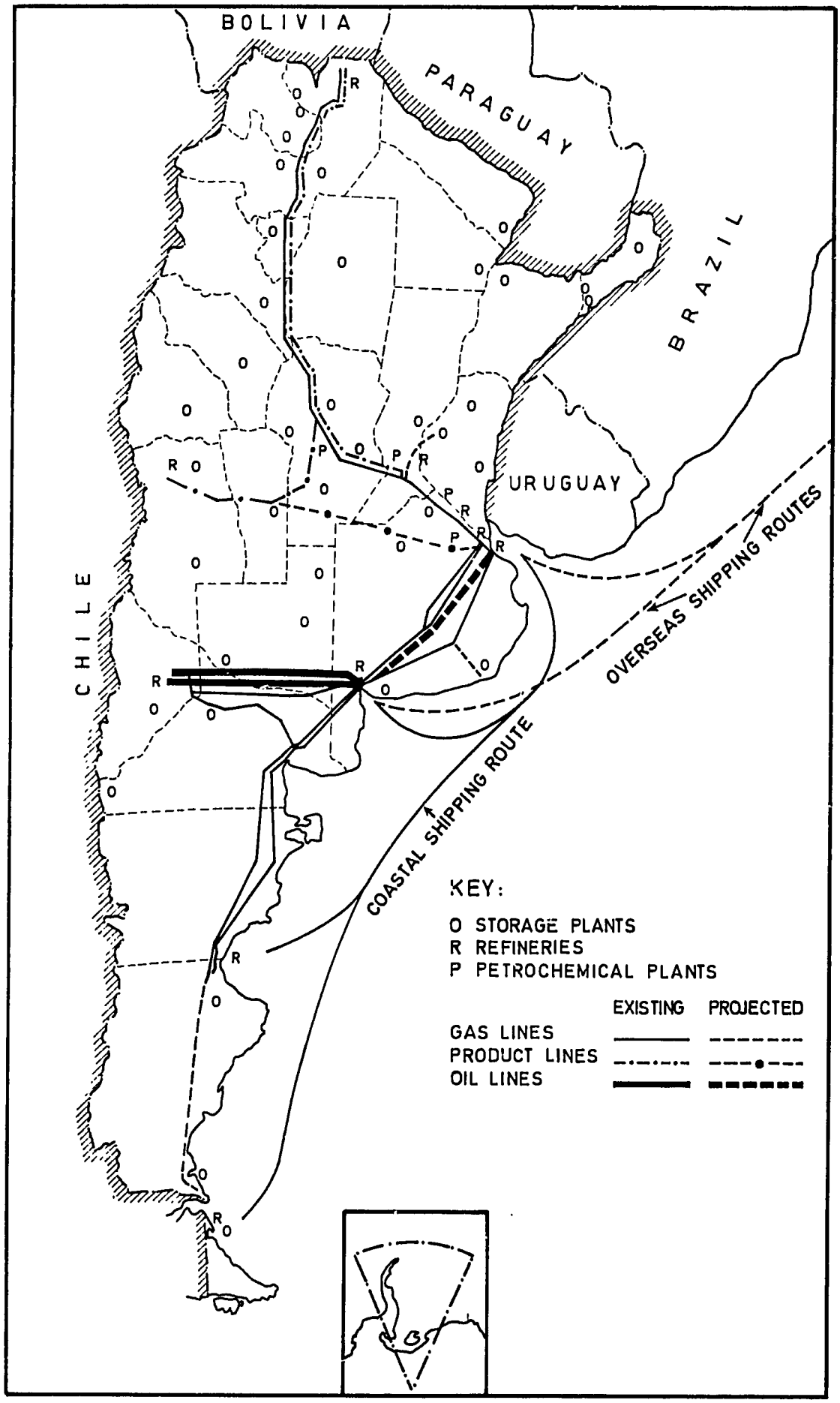


FIG. 2-3(b). OIL TRANSPORT, REFINING AND STORAGE

TABLE II-11. PROCESSED CRUDE AND PRODUCTS OBTAINED (m^3)

Years	1966	1967	1968	1969	1970
Crude processed					
National	16 536 237	17 936 023	19 471 969	20 470 386	22 750 051
Imported	4 030 200	2 913 996	2 358 504	2 602 261	1 749 754
Total	20 566 437	20 850 019	21 830 473	23 072 647	24 499 805
Products					
Aviation gasoline	72 480	87 420	74 791	66 664	60 034
Gasoline	3 279 397	3 124 943	2 959 201	3 422 571	3 285 816
Gasoline for reforming	625 129	653 757	639 927	724 532	688 518
Special gasolines	1 289 212	1 607 207	1 780 908	1 867 674	2 089 489
Solvents	66 755	63 258	62 099	62 815	65 241
Turpentine	41 880	44 844	36 274	35 225	55 665
Kerosene	1 045 158	974 072	997 634	1 021 887	1 093 788
Jet aircraft fuel	175 314	232 072	271 597	351 712	372 120
Agricultural fuels	89 768	93 391	901	-	-
Gas oil	2 844 634	3 010 581	3 172 919	3 336 506	3 657 641
Diesel oil	1 382 330	1 361 263	1 423 959	1 712 407	1 893 187
Fuel oil	8 622 359	8 431 165	8 615 232	8 236 839	8 950 330
Lubricants	147 337	130 741	142 349	151 530	159 555
Greases	8 987	8 407	10 390	13 143	12 845
Asphalts	289 761	329 342	588 493	763 667	668 587
Residual carbon (t)	423 723	435 476	435 959	528 645	662 784
Propane (t)	144 470	142 419	155 864	203 167	236 546
Butane (t)	180 253	196 516	261 181	268 214	325 917
Dry gas	305 084	314 744	272 280	416 186	417 353

TABLE II-12. INSTALLED REFINING CAPACITY

	No. of plants	Primary capacity	Cracking capacity	Reforming capacity
		10^3 m^3/day		
State	7	45	12	1.5
Private	10	31	6	3.8
Total	17	76	18	5.3

TABLE II-13. HYDROCARBON TRANSPORT DATA

Main oil product pipelines (over 10")	
Length	3 300 km
Conveying capacity approx.)	70 000 m^3/day
Main gas pipelines	
Length	4 500 km
Conveying capacity (approx.)	19 x 10^6/day
Tanker fleet	
State-owned:	
River cabotage	7 tankers totalling 30 000 m^3
Sea coast cabotage	20 tankers totalling 280 000 m^3
Privately-owned:	
River cabotage	18 tankers totalling 78 000 m^3
Sea coast cabotage	21 tankers totalling 597 000 m^3

It is expected that at least three oil tankers of 35 000 t will be added to the YPF fleet over the next five years and that a major oil and gas pipeline construction program will be carried out. This will involve the building of a pipeline in Patagonia from El Cóndor to Pico Truncado and of a pipeline parallel to the existing one from Bahía Blanca to Greater Buenos Aires. Provision is also made for the installation of compressor plants for the latter pipeline and for the Neuquén-Bahía Blanca pipeline. Planned investments include storage installations for natural and liquid gas in various parts of the country as well as improvement of gas mains in Greater Buenos Aires and Rosario.

By and large, the Government policies aim at strengthening the marketing position of YPF in refining and distribution and increasing utilization of its capacity which, at present, is only 58% of the total output of crude. A recent Government decision provides that the YPF share in refining is to be raised to 65% although the increment will continue to be marketed through the facilities of private companies.

(c) Prospecting

A major effort is expected to be applied to prospecting with a view to at least doubling the present primary reserves of 200 million m^3 of crude oil to about 400 - 500 million m^3 by 1980, thus achieving a 10 to 12 reserve to consumption ratio by that time. Table II-14 shows the rapid increase in drilling which has occurred in the last period for which figures are available and which is expected to continue over the next ten years.

(d) Present and projected prices

The internal prices for oil products and natural gas when expressed in dollars show wide variations over the last two years because of a relatively slow adjustment of the oil price structure to the inflationary process which has involved a constantly deteriorating rate of foreign exchange. Thus, prices of fuel oil, ex-refinery, have over the last two years ranged between 12 and 16 US $/$m^3$.

Since the relation of oil products prices to costs is also extremely difficult to trace even under stable conditions, it becomes almost impossible to establish a valid correlation in the inflationary phase through which the Argentinian economy is currently passing. Some light on the subject may, however, be shed by the prices paid for imported crude and fuel oil shown in Table II-15.

The c.i.f. price for crude in Buenos Aires harbour in 1970 was in the range of 18-19 US$/m^3. The figures given for fuel oil are not significant because of the extremely small amounts involved in the transaction. However, the value quoted in Table II-15 of 20.3 US $/m^3 for 1971 appears to be of the right order.

In any event the policy of the Government, which aims at total sufficiency in oil supply, also calls specifically 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 stations will be built from now on. Even if this decision were to be reconsidered, it is clear that fuel oil prices for power plants would then have to be based on the price range of imported rather than on that of domestically produced fuel oil. On the basis of the latest 1972 data this would mean a present Buenos Aires c.i.f. price of about 2 US $ per 10^6 kcal or 50 US cents per 10^6 Btu for fuel oil of the average quality of past imports.

TABLE II-14. DRILLING

	1970	Increase over 1969 (%)
Wells drilled	601	42.1
Productive wells	397	48.1
Dryholes	204	31.6
Wells drilled on land	581	39.6
Wells drilled offshore	20	400.0
Exploratory and outpost wells	260	45.0
Total depth drilled	1 245 000 m	41.5
Average depth drilled	2070 m	

TABLE II-15. IMPORTS AND COSTS OF CRUDE AND FUEL OIL (1966-1970)

Year	Crude oil			Fuel oil		
	Volume (10^3 m^3)	Total c.i.f. value (10^3 US$)	Average price (US$/m^3)	Volume (10^3 m^3)	Total c.i.f. value (10^3 US$)	Average price (US$/m^3)
1966	4 123	61 580	14.90			
1967	2 915	50 730	17.40	0		
1968	2 350	42 600	18.10	0		
1969	2 669	43 600	16.35	593	7 163	12
1970	1 684	31 240	18.55	168	2 092	12.45
1971	2 543	51 476	20.24	148	3 044	20.30

2.4. Uranium and thorium

(a) Amount and location of reserves

Fairly extensive prospecting for uranium has been carried out in Argentina with the result that 150 000 km^2 have been surveyed by aerial and terrestrial means. This amounts to roughly one third of the 400 000 km^2 where uranium deposits are most likely to be found. An additional area amounting to 600 000 km^2 may also contain uranium deposits. Thus more than 1 million km^2, or one third of the total continental territory, has uranium possibilities of which 15% has been surveyed.

The known uranium reserves of the country in July 1972 amounted to 16 300 t of U_3O_8 of which 8300 t could be processed at a cost of 10 US $/lb U_3O_8 or less. Another 19 500 t are characterised as being reasonably assured. These reserves exist for the most part in the north and west of the country. The most economically important deposit has been found in the Sierra Pintada. Here 11 000 t are reasonably assured whilst another 11 000 t may possibly occur. It should be noted, however, that only 7000 t of the reasonably assured and 5000 t of the possible reserve are in the cost category of less than 10 US $/lb. The exploitation of this reserve is hampered by the fact that a 60 m layer of overburden covers the uranium-containing mineral strata. This overburden must be removed and a small river has to be bypassed, so that quite a lot of earth-moving activities will have to be performed. In order to start this ambitious venture, the cooperation of large companies with experience in this field is necessary. Tenders will be invited in the immediate future.

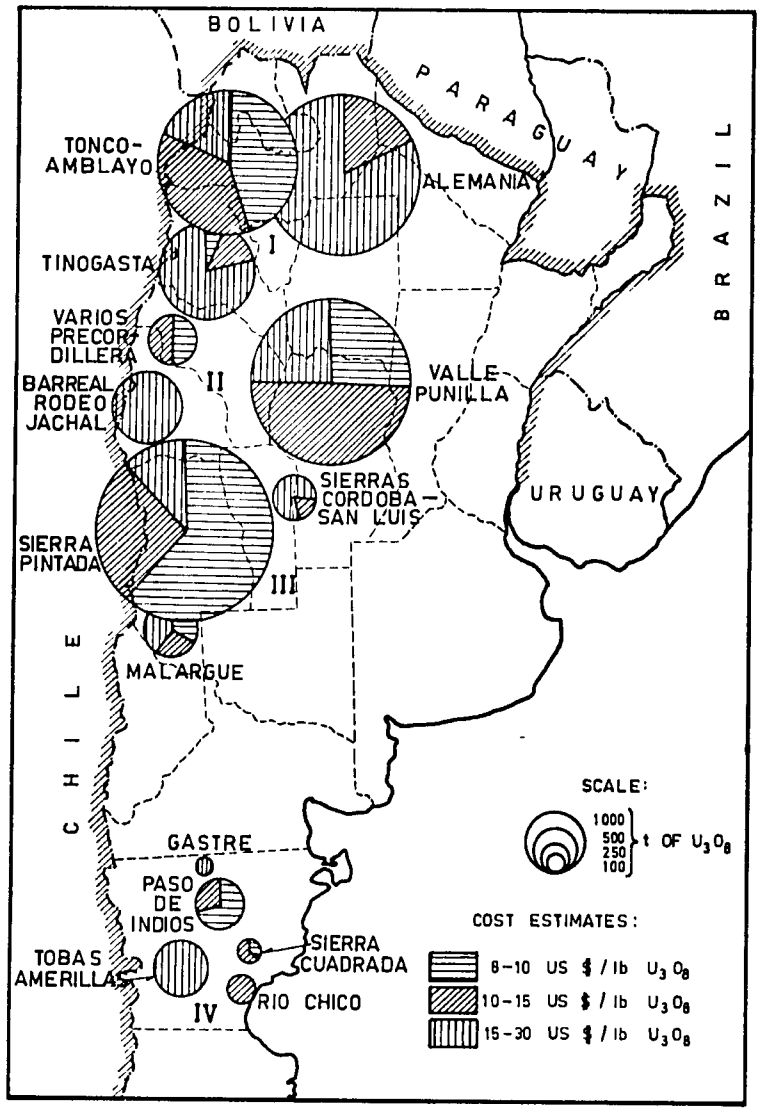


FIG. 2-4. LOCATION OF URANIUM DEPOSITS

Further large uranium deposits are located in the Valle Punilla (6200 t reasonably assured, plus 10 000 t possible), in Alemania (4200 t plus 6500 t) and in Tonco Amblayo (3500 t and 3000 t). The location of these deposits and some smaller ones are shown on the map (see Fig. 2-4). Table II-16 summarizes the amounts of reserves in each location.

There are two known thorium areas in the country. One consists of a number of small deposits at Rangel (Salta) with a total of 1500 t ThO_2. At present there is no search for further deposits and there are no plans for mining of thorium oxide.

(b) Estimated costs

Mines are worked in the Provinces of Salta and Mendoza, producing about 50 t U_3O_8 annually. Cost estimates as given by Argentine authorities are based on this experience and are given in Table II-16.

As can be seen from Table II-16, most of the uranium deposits – apart from the Sierra Pintada deposit – are of small or medium size. They are not very rich in uranium content and they are far from harbours or industrial zones. Therefore, the costs for transport and production will be rather high.

The Sierra Pintada deposit in this respect is the most promising as it is relatively near to Córdoba and Malargüe (Mendoza) where the two chemical plants for the production of uranium concentrate are located. In addition, there are plans for constructing a further plant in San Rafael near the Sierra Pintada site. Plans for the San Rafael plant call for a production of 450 t of uranium annually for a first period of ten years. The possibility of doubling the production if feasible is envisaged.

TABLE II-16. URANIUM DEPOSITS, JULY 1972 (t U_3O_8)

Region	District	8 - 10 US $/lb		10 - 15 US $/lb		15 - 30 US $/lb		Subtotal
		RA	AP	RA	AP	RA	AP	
Noroeste	Tonco-Amblayo	1 500	1 000	1 000	1 000	1 000	1 000	
	Alemania	-	-	1 200	1 500	3 000	5 000	
	Tinogasta	-	-	500	1 500	1 500	2 000	
	Subtotal	1 500	1 000	2 700	4 000	5 500	8 000	22 700
Centro	Valle Punilla	2 200	2 000	2 000	3 000	2 000	5 000	
	Sierras Córdoba - San Luis	500	1 000	500	1 000	1 000	2 000	
	SW La Rioja - N San Juan	100	100	300	500	500	500	
	Subtotal	2 800	3 100	2 800	4 500	3 500	7 500	24 200
Cuyo	Sierra Pintada	7 000	5 000	2 000	3 000	2 000	3 000	
	Barreal-Rodeo-Jáchal	-	-	-	-	1 500	5 000	
	Malargüe	100	100	200	200	300	500	
	Subtotal	7 100	5 100	2 200	3 200	3 800	8 500	29 900
Patagonia	Río Chubut	500	500	1 000	1 000	1 000	2 000	
	Sierra Cuadrada	-	300	200	300	500	1 000	
	Río Chico	-	200	200	200	-	500	
	Tobas Amerillas	-	-	-	-	500	2 000	
	Subtotal	500	1 000	1 400	1 500	2 000	5 500	11 900
RA - Reasonably assured amounts		11 900		9 100		14 800		35 800
AP - Additional possible amounts			10 200		13 200		29 500	52 900
Subtotal		22 100		22 300		44 300		88 700
Accumulated total		22 100		44 400		88 700		

Cost estimates produced by the Comisión Nacional de Energía Atómica (CNEA) range from 9.50 to 12 US $/lb U_3O_8 for the San Rafael plant.

The same cost range is estimated for another plant projected to be built at Don Otto (Salta); higher estimates (12-15 US $/lb) are given for the plant at Cosquín (Córdoba) because this deposit contains another type of ore.

(c) Exploration activities under way or planned

The intensive search for uranium is still under way. Until now only 15% of the areas where deposits are to be expected have been explored. CNEA personnel have been specially trained abroad and modern equipment for uranium prospecting is in use.

Judging from the experience of the past, a substantial increase in the amount of uranium reserves is to be expected. Figure 2-5 shows the growth in uranium reserves since 1960.

CNEA plans to provide the necessary amounts of uranium for domestic use. There is no no intention to sell surplus production on the world market.

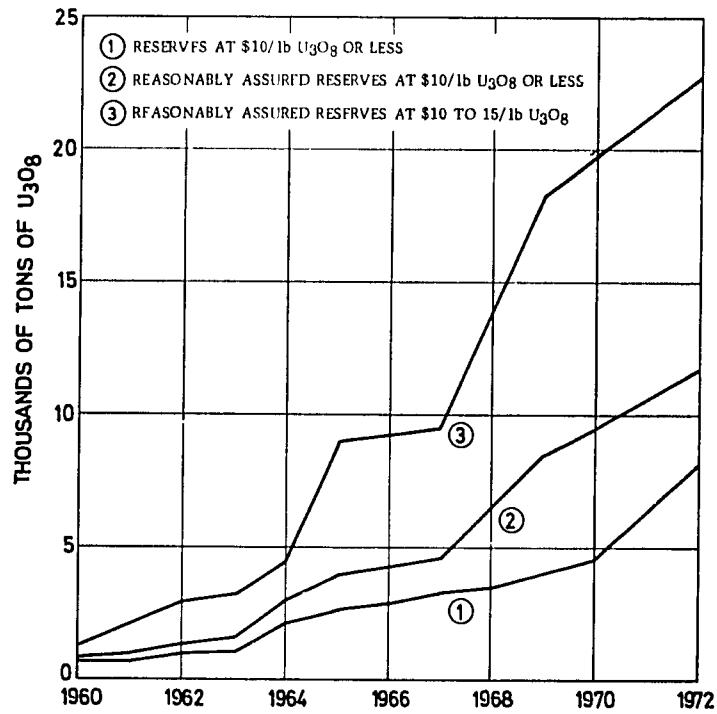


FIG. 2-5. GROWTH IN KNOWN URANIUM RESERVES

3. ELECTRICITY SUPPLY SYSTEM

3.1. Past history and development of electrical industry

The development of the electrical industry in Argentina started with small thermal plants operated by privately owned (mostly foreign) utilities and by autoproducers. The most important of the private utility groups were (1) ANSEC, a group of nine companies owned by American and Foreign Power (a holding company of EBASCO, New York), (2) CATE, a German transatlantic electric company, (3) CIAE, Italian-Argentine electric company, (4) SUDAM, owned by International Power Company, and (5) CSAE, Swiss-Argentine electric company. Starting in 1958 the Government took over the ownership of most electric utilities in the country by the termination of concessions or through negotiation prior to the termination of concessions. The one exception is CIAE which though controlled as a public utility reached an agreement with the Argentine Government and retained private ownership.

At the present time, five major companies plus hundreds of small autoproducers and cooperatives provide the country's electricity supply. The major companies are listed in order of capacity in Table III-1. Their interrelation is shown in Fig. 3-1. The historical development of each company and other sources of electricity supply is summarized in the following paragraphs.

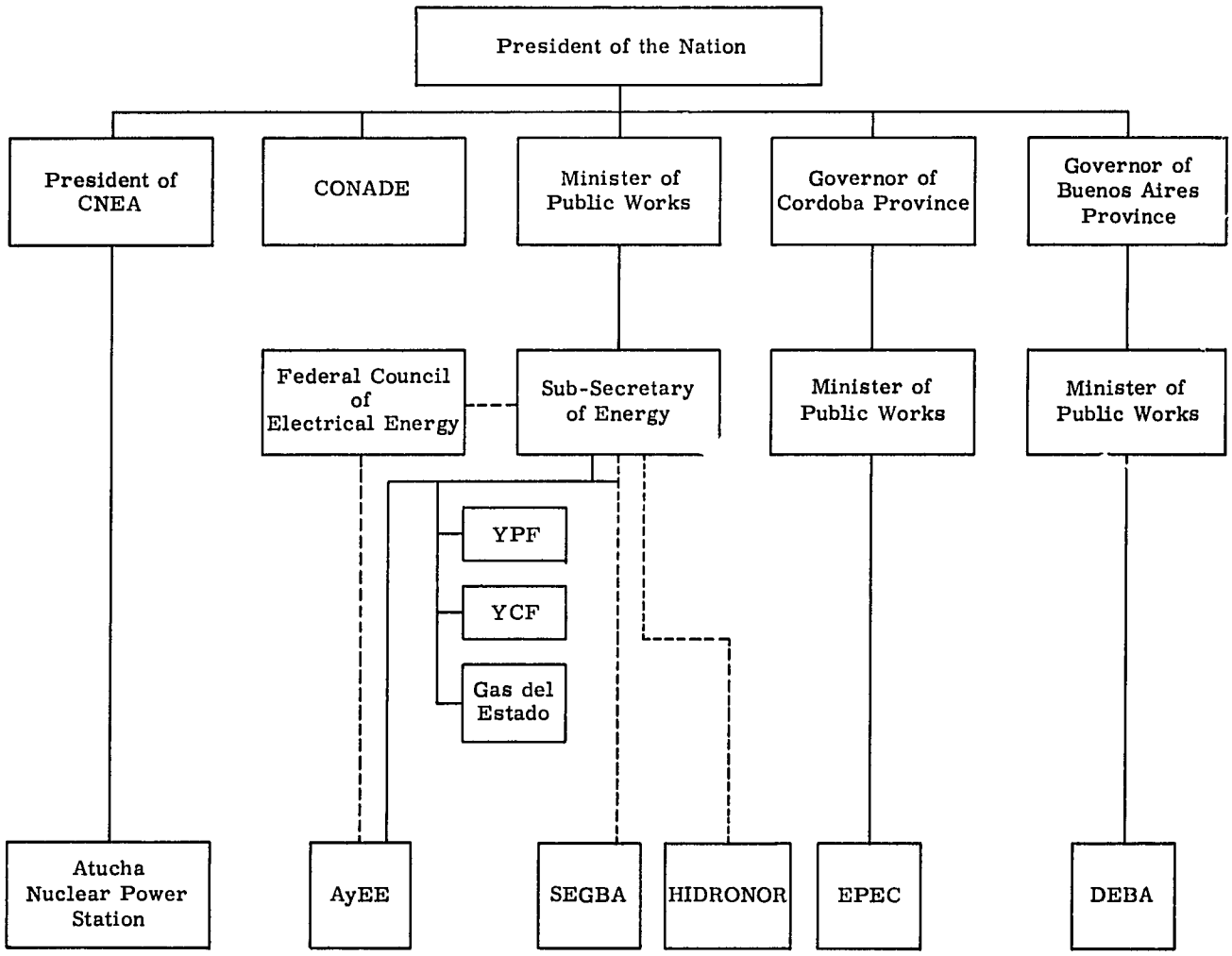
(a) SEGBA

In 1958, the Government reached an agreement with two privately owned companies, CADE and CEP (Compañía de Electricidad de la Provincia de Buenos Aires), whereby these companies retained the concession for services in the Greater Buenos Aires area (including La Plata) through their participation in a new company SEGBA which was partly owned by the Government. During the next ten years, SEGBA became totally owned by the Government through their purchase of the shares of CADE.

In 1961, SEGBA became a nationalized company with an independent corporate structure operating under a concessionary contract to supply services in the Greater Buenos Aires Area. While essentially all shares of SEGBA are owned by the Government, it operates under special terms of reference and has its own Board of Directors (see Fig. 3-2). World Bank collaboration was basic to this restructuring. Table III-2 shows the chronological development of SEGBA through its predecessors.

TABLE III-1. MAJOR UTILITIES IN ARGENTINA

Company designation	Name	Installed capacity in 1971 (MW)	Generation in 1971 (GWh)
SEGBA	Servicios Eléctricos del Gran Buenos Aires	1 930	7 840
AyEE	Agua y Energía Eléctrica	1 873	5 956
CIAE	Compañía Italo-Argentina de Electricidad	543	2 185
DEBA	Dirección de Energía de la Provincia de Buenos Aires	290	866
EPEC	Empresa Provincial de Energía de Córdoba	222	975
	Total	4 858	17 822



Legend:

CNEA	Comisión Nacional de Energía Atómica
CONADE	Consejo Nacional de Desarollo
YPF	Yacimientes Petrolíferos Fiscales
YCF	Yacimientes Carboníferos Fiscales
AyEE	Agua y Energía Eléctrica
SEGBA	Servicios Eléctricos del Gran Buenos Aires
HIDRONOR	Hidroeléctrica Norpatagónica
EPEC	Empresa Provincial de Energía de Córdoba
DEBA	Direccion de Energía de la Provincia de Buenos Aires

FIG. 3-1. ORGANIZATIONAL RELATIONSHIPS OF ELECTRIC UTILITIES AND GOVERNMENT DEPARTMENTS

(b) AyEE

This company was created by the Government in 1947 through the merging of an older group, Dirección Nacional de Irrigación, with the relatively newly formed Centrales Eléctricas del Estado. The objective of establishing AyEE was to develop the hydro potential of the country and to provide electrical service in the interior regions.

(c) CIAE

In 1912 a consortium based on Italian and Swiss financing obtained the concession to supply electric energy to the City of Buenos Aires. In 1961 the concession was renegotiated and CIAE presently continues supplying service in the Federal Capital and certain adjacent departments. CIAE is a private limited liability company with assets (in 1970) of 160 million dollars.

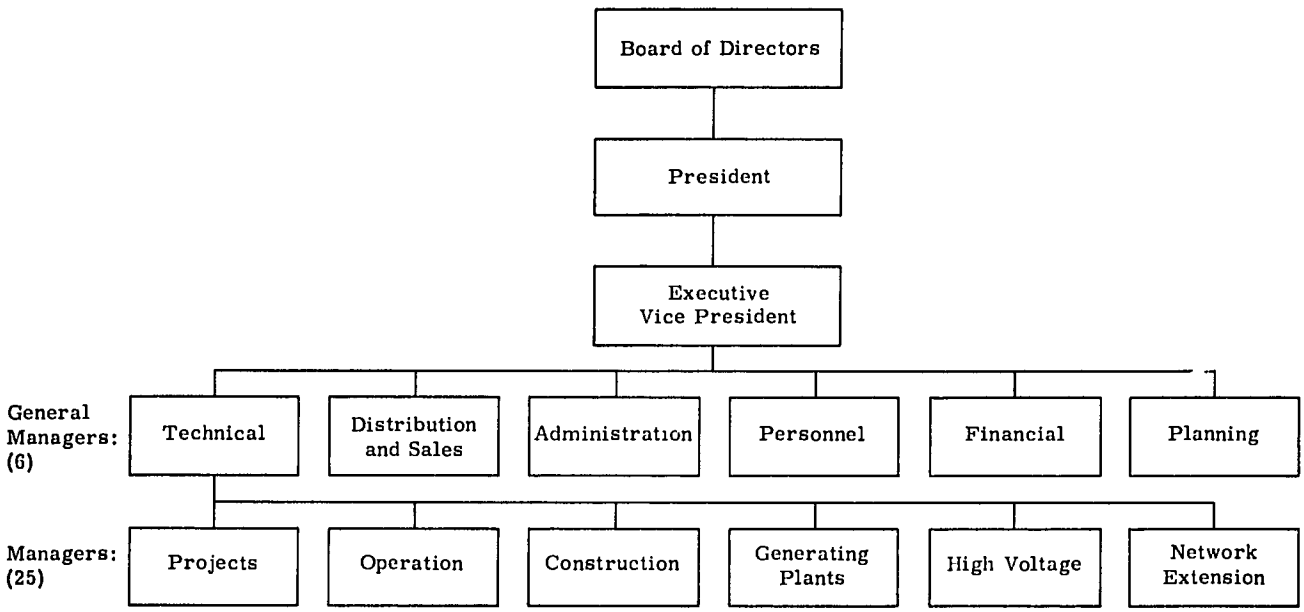


FIG. 3-2. THE ORGANIZATION OF SEGBA

TABLE III-2. SEGBA AND PREDECESSORS

Period	Designation	Company name	Installed capacity[a] (MW)
1898 - 1920	CATE	Compañía Alemana Transatlántica de Electricidad	103
1920 - 1936	CHADE	Compañía Hispano Americana de Electricidad	556
1936 - 1958	CADE	Compañía Argentina de Electricidad	693
1958 - 1971	SEGBA	Servicios Eléctricos del Gran Buenos Aires	1 927

[a] At end of period (31 December).

(d) DEBA

This organization had its origin in 1939, when the Provincial Government of Buenos Aires declared that the supply of electric energy should be a public service. The present organization was established in 1957 as a result of a provincial organization.

(e) EPEC

This utility was created in 1952 by joining two Government-owned utilities, the first of which provided electric service in the interior of the Province of Córdoba and the second in the provincial capital and environs. In 1959 those services which were still being provided by private companies were taken over by EPEC.

(f) Other public utilities

These include provincial administrations, municipal stations, cooperatives and others. In 1971, there were approximately 650 electric utility cooperatives serving over 800 localities throughout the interior of Argentina. These and other public utilities had a combined installed capacity of about 415 MW in 1971 which generated a total of 835 GWh.

(g) Autoproducers

During the decade of the 40's, autoproducers contributed about 18% of the electrical energy generated in the country. Because of uncertainties in supply by the public utilities, autoproduction increased from 12-14% in the early 50's to about 26% in the middle 60's. Since 1966, however, there has been a gradual decline in the percentage of electricity generated by autoproducers, which stood at 21% in 1971. The combined capacity of autoproducers in 1971 amounted to 1830 MW which generated a total of 4965 GWh. These generating units are not likely to play a part in the expansion of the interconnected system.

(h) Atucha nuclear power plant

The Atucha Nuclear Power Project was not assigned to an existing utility organization because of its unique nature.

The technical competence of the CNEA staff in nuclear engineering matters made it natural that they should take an important role in the planning of the first nuclear power station. For this and other reasons, the Government decided that CNEA should assume the leading role in construction of this plant. It has since further been decided that CNEA should also be in charge of operation of this station. Energy will be provided to the national interconnected system.

(i) HIDRONOR

Hidronor SA (Hidroeléctrica Norpatagónica) was established in 1967 to exploit the hydraulic resources of the Comahue region, in particular the El Chocón-Cerros complex on the rivers Limay and Neuquén in the provinces of Río Negro and Neuquén. They are also responsible for the high voltage transmission system to take this energy to the Gran Buenos Aires Litoral. These projects were not assigned to an existing utility organization to satisfy the requirements of the international banks which are providing the necessary foreign funds.

An energy tax of 5% on all electricity sold in the nation is being used to finance the local expenses.

3.2. Present organizational structure

The organizational relationships of the nationally owned utilities are shown in Fig. 3-1.

3.3. Geographical areas of responsibility

Figure 3-3 shows the supply areas of responsibility of SEGBA (including CIAE), DEBA, EPEC and AyEE. It is seen in this figure that AyEE has the largest area of responsibility,

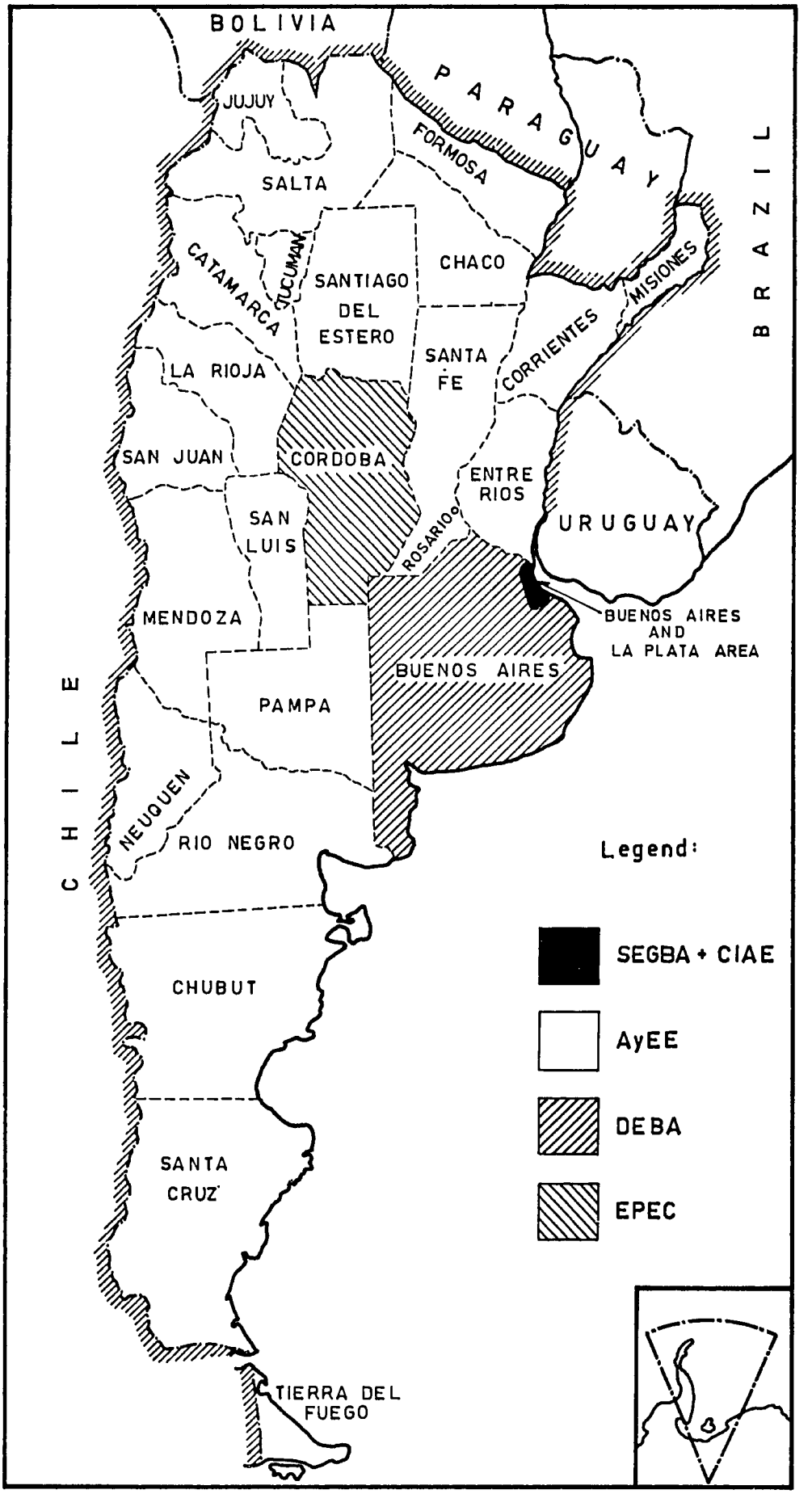


FIG. 3-3. GEOGRAPHICAL AREAS OF RESPONSIBILITY OF THE VARIOUS UTILITIES

operating throughout the country in areas not covered by the other companies. In addition to the area shown, AyEE also operates within the EPEC area and in two cities (Mar del Plata and San Nicolás) of the DEBA area.

The only exceptions to this simple picture are that a special authority (Hidronor) is responsible for developing and transmitting to Buenos Aires the hydroelectric power generated in Northern Patagonia, and that construction of the Salto Grande project is a joint responsibility of the Argentine and Uruguay Governments. The output of Salto Grande, however, is to be transmitted by AyEE.

As seen in Fig. 3-3, the smallest geographical area of responsibility is that of SEGBA and CIAE who operate in the densely populated region around the city of Buenos Aires, known as the GBA-Litoral. Approximately 40% of the total electricity generated in the country in 1971 (including all sources) was consumed in this small area.

Because of the very large area of responsibility covered by AyEE, eight regional distribution systems have been developed to serve local markets. These are described in the following paragraphs. [The Subsecretary of Energy (SSE) coordinates all electric energy activities in the nation and has established ten regional distribution systems. In this report, the GBA-Litoral and DEBA Buenos Aires Norte are combined (since they are operated as an integrated system), giving a total of nine systems. The corresponding AyEE regional names are given in brackets after the SSE name where these differ. Figure 3-4 shows the geographical location of the SSE regional systems.]

1. GBA-Litoral (incl. DEBA Buenos Aires Norte)

Interconnects Paraná, Santa Fe, Rosario, San Nicolás, Moron; provides public electric services between Entre Ríos and Santa Fe and part of the north east of the Province of Buenos Aires. It is interconnected with the rest of DEBA.

2. Buenos Aires Sud (incl. AyEE's Mar del Plata)

Provides public electric services in the southeast of the province of Buenos Aires. Mar del Plata is interconnected with Necochea through a DEBA transmission line.

3. Comahue (AyEE's Patagónico Norte)

Interconnects Cutral – Co, Neuquén, Cipolletti, Gral. Roca, Choele-Choel, Céspedes. Provides public service to the provinces of Neuquén and Río Negro.

4. Córdoba

Interconnects the cities of Córdoba and Río Cuarto with the hydrogenerating stations located in the Province of Córdoba. These provide bulk power to the Empresa Provincial de Energía de Córdoba (EPEC), to military installations, a few cooperatives and to large users.

5. Cuyo

Interconnects Mendoza and San Juan. Provides public electric service to both these provinces. Generates and services San Luis.

6. Patagónico centro

Provides energy to Trelew and Comodoro Rivadavia.

7. Noroeste (incl. AyEE's Norte)

Interconnects Salta and Jujuy, Tucumán and Sgo. del Estero, Tucumán and Catamarca, Tucumán and Salta. Provides public service to the provinces of Salta, Tucumán, Sgo. del Estero, Jujuy, Catamarca and La Rioja.

8. Noreste

Interconnects Resistencia, Barranqueras and Corrientes. Provides public electric service to the provinces of Chaco and Corrientes.

9. Misiones (not an AyEE system)

Provides local service within the system. Will be interconnected in 1973 with the electric power system of Acaray in the Republic of Paraguay, across the river Paraná.

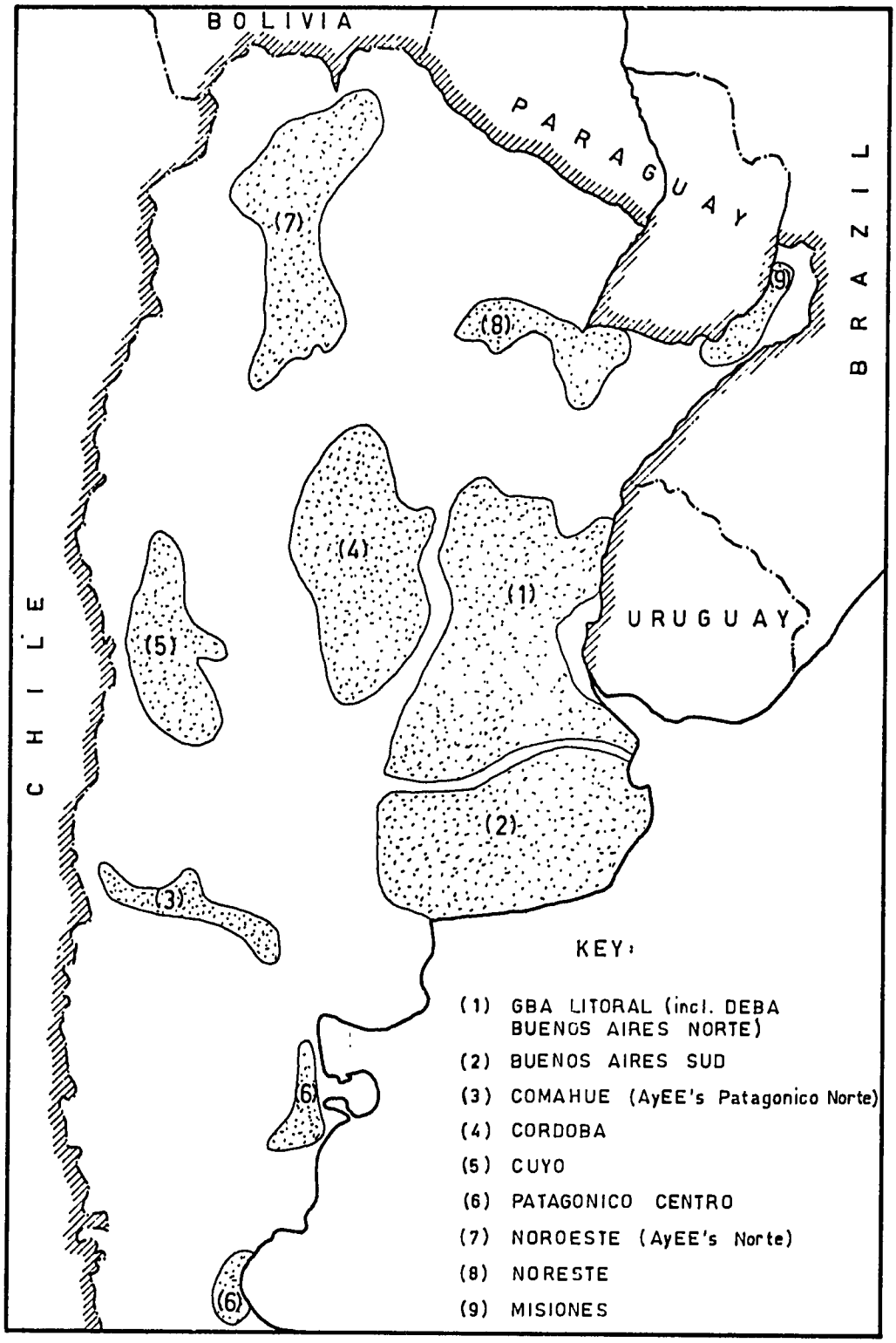


FIG. 3-4. REGIONAL DISTRIBUTION SYSTEMS

3.4. Generation and transmission facilities

(a) Generation

Table III-3 lists the principal generating plants installed for public supply at the end of 1971. The table is divided into nine regions within which interconnections already exist, are under construction, or are planned with the total capacity amounting to:

Thermal	3726 MW
Hydro	677 "
	4403 MW

The table omits diesel plant of some 860 MW capacity installed in numerous small stations which can be expected to be gradually shut down as the interconnected systems develop, together with 10 MW at remote points whose interconnection will probably be considerably delayed. Adding these gives 5 270 MW of installed capacity for public supply at the end of 1971. In addition there was a capacity of 1 830 MW installed by autoproducers.

Figure 3-5 shows the location of the main power stations, as well as the supply areas of SEGBA, DEBA and EPEC. Stations under construction are also shown.

Another utility, Compañía Italo Argentina de Electricidad (CIAE), operates within the city of Buenos Aires together with SEGBA.

(b) Transmission

In Figure 3-6 the shaded areas represent the nine regional networks, the two areas in Patagonia, which will be interconnected in 1974, being regarded as a single region. All regions are expected to be progressively linked during the next 10 - 15 years, beginning with Gran Buenos Aires Litoral, Buenos Aires Sud and Comahue in 1973, followed shortly by Córdoba. The dates indicated in Fig. 3-6 for the further linkages should be regarded as tentative. The voltage of interconnection will be mainly 500 kV.

The GBA-Litoral system comprises the SEGBA and CIAE networks, DEBA's Buenos Aires Norte, the southern section of the Province of Santa Fe and most of Entre Ríos. With an installed generating capacity (all thermal) of 2 900 MW at the end of 1971, representing more than half the national total for public supply, it constitutes the nucleus of the future national system and is operated from a load dispatching office in Buenos Aires.

Apart from a 220 kV double-circuit line between Buenos Aires and San Nicolás, all interconnecting circuits within this system at present operate at 132 kV or lower voltages. Development of the national interconnection system is further discussed in Section 5.4 and a circuit diagram for 1977/80 is given in Fig. 5-6.

(c) Construction costs for recent thermal stations

Table III-4 gives representative total cost data for thermal stations built by SEGBA and AyEE. Table III-5 gives the breakdown of unit capital costs for two of these stations.

(d) Transmission line construction costs

Table III-6 gives estimated cost particulars for the El Chocón-Ezeiza 500 kV scheme to transmit 1650 MW over a distance of 1100 km. This scheme, construction of which will be more than half completed by the end of 1972, is expected to have a final cost of approximately 140 million US $ (excluding engineering, purchase of land and right of way).

The scheme comprises two single-circuit lines, each 1100 km long, with two intermediate switching stations. The first line will be completed at the end of 1972 and the second a year later, with compensating equipment and further switchgear and transformers to follow.

The estimates were made in June 1972. Local expenditure, which contains an allowance for continuing inflation in relation to work still to be carried out, has been converted at a rate of 8.17 Argentine pesos = 1 US$. This rate, though only about half the current rate, is estimated to be an approximate effective average over the whole of the construction period.

Costs of 220 kV lines are detailed in Table III-7.

TABLE III-3. GENERATING PLANT AT END 1971

REGION 1: GRAN BUENOS AIRES - LITORAL

Station[a]		Year(s) commissioned	Unit No. and MW	Total installed capacity (MW)	Production in 1971 (GWh)[d]
Thermal					
Puerto Nuevo	O/G	1928 - 34	4 x 52.5	864[b]	4 048
	O/G	1942 - 49	2 x 52.5		
	O/G/C	1961 - 63	1 × 145, 1 × 194		
	O/G/C	1970	1 × 250		
Costanera	O/G	1963	5 × 120	600	3 161
Dock Sud	O/G	1926 - 30	2 × 21, 2 × 25	165[b]	499
	O/G	1939 - 56	2 × 21, 2 × 33		
Nuevo Puerto	O/G	1933 - 52	3 × 35, 1 × 60	516	2 158
	O/G	1965 - 70	1 × 110, 1 × 250		
Pedro de Mendoza	O/G	1950 - 51	3 × 12	27	27
San Nicolás	O	1954 - 57	2 × 10, 2 × 75	320	2 053
	C	1957	2 × 75		
Sorrento	O	1926	1 × 14	81	165
	O/G	1937 - 48	2 × 33		
Calchines	O	1926	2 × 7.5	70	227
	O	1950 - 56	2 × 5, 1 × 15		
	O	1965	1 × 30		
Caseros[c]			3 units	19	65
GT (various):					
SEGBA		1968 - 71	6 × 18, 7 × 17	227	126
DEBA			1 × 16, 1× 9.6	26	28
Paraná			1 × 6.4	6	2
Total thermal				2921	12 559
Hydro					
None				--	--
Total region				2921	12 559

REGION 2: BUENOS AIRES - SUD

Thermal					
Necochea			2 units	66	453
Bahía Blanca			4 units	65	190
Puerto			2 units	8	11
9 de Julio (Mar	O	1953 - 54	1 × 10, 2 × 5	50	299
del Plata)	O	1964	1 × 30		
GT stations			2 × 10.5, 2 × 17	55	42
			4 × 16	64	
Total thermal				308	995
Hydro					
None				-	-
Total region				308	995

[a] C = Coal
G = Gas
O = Oil
GT = Gas turbines

[b] Effective capacity.

[c] Interconnection under construction.

[d] Excludes diesel generation.

TABLE III-3 (cont.)

REGION 3: COMAHUE

Station		Year(s) commissioned	Number and size of units (MW)	Total installed capacity (MW)	Production in 1971 (GWh)
Thermal					
Alto Valle	O/G	1969	2 x 15	30	188
Total thermal				30	188
Hydro					
Small (11)			17 units	21	100
Total hydro				21	100
Total region				51	288

REGION 4: CORDOBA

Thermal					
Pilar	O/G		2 x 33	66	370
Dean Funes	O/G		1 x 33	33	267
Dean Funes	GT		2 x 15	30	133
V. María	GT		2 x 15	30	20
Total thermal				159	790
Hydro					
Los Molinos			4 x 14.8, 1 x 4.5	65	92
B. Reolín		1966	3 x 12.8	38	37
San Roque		1959	4 x 6.5	26	54
Others (8)			20 units	52	148
Total hydro				179	314
Total region				338	1 104

REGION 5: CUYO

Thermal					
Luján de Cuyo	O	1971	2 x 60	120	159
GT stations (4)		1964 - 69	7 units	82	481
Total thermal				202	640
Hydro					
El Nihuil No. 1		1957	4 x 18.6	74	228
El Nihuil No. 2		1968 - 72	4 x 21.3, 2 x 24	133	245
El Nihuil No. 3		1972	2 x 26	52	
Ullun		1969	2 x 22.5	45	97
A. Condarco		1955	2 x 13.7	27	127
Others (7)			14 units	18	78
Total hydro				349	775
Total region				551	1415

TABLE III-3 (cont.)

REGION 6: PATAGONIA

Station	Year(s) commissioned	Number and size of units (MW)	Total installed capacity (MW)	Production in 1971 (GWh)
Thermal				
None			-	-
Hydro				
F. Ameghino	1968	2 x 23.4	47	38
Others (2)		Very small	-	-
Total hydro			47	38
Total region			47	38

REGION 7: NOROESTE

Thermal				
Independencia		3 units	30	136
GT stations (4)	1970 - 71	6 units	31	40
Total thermal			61	176
Hydro				
Escaba	1955 - 56	3 x 8	24	47
Others (16)		36 units	57	205
Total hydro			81	252
Total region			142	428

REGIONS 8 AND 9: NORESTE AND MISIONES

Thermal				
Barranqueras		3 units	30	132
Corrientes		3 units	15	44
Total thermal			45	176
Hydro				
None			-	-
Total region			45	176

SUMMARY

Region	Installed capacity at end 1971 (MW)			Production 1971 (GWh)	
	Thermal	Hydro	Total	Excl. Diesels	Incl. Diesels
1. GBA-Litoral	2921	-	2921	12 559	12 635
2. Buenos Aires - Sud	308	-	308	995	1 176
3. Comahue	30	21	51	288	315
4. Córdoba	159	179	338	1 104	1 271
Total for regions to be interconnected by 1973/74	3418	200	3618	14 946	15 397
5. Cuyo	202	349	551	1 415	1 527
6. Patagonia	-	47	47	38	106
7. Noroeste	61	81	142	428	546
8. Noreste } 9. Misiones }	45	-	45	176	246
Total all regions	3726	677	4403	17 003	17 822

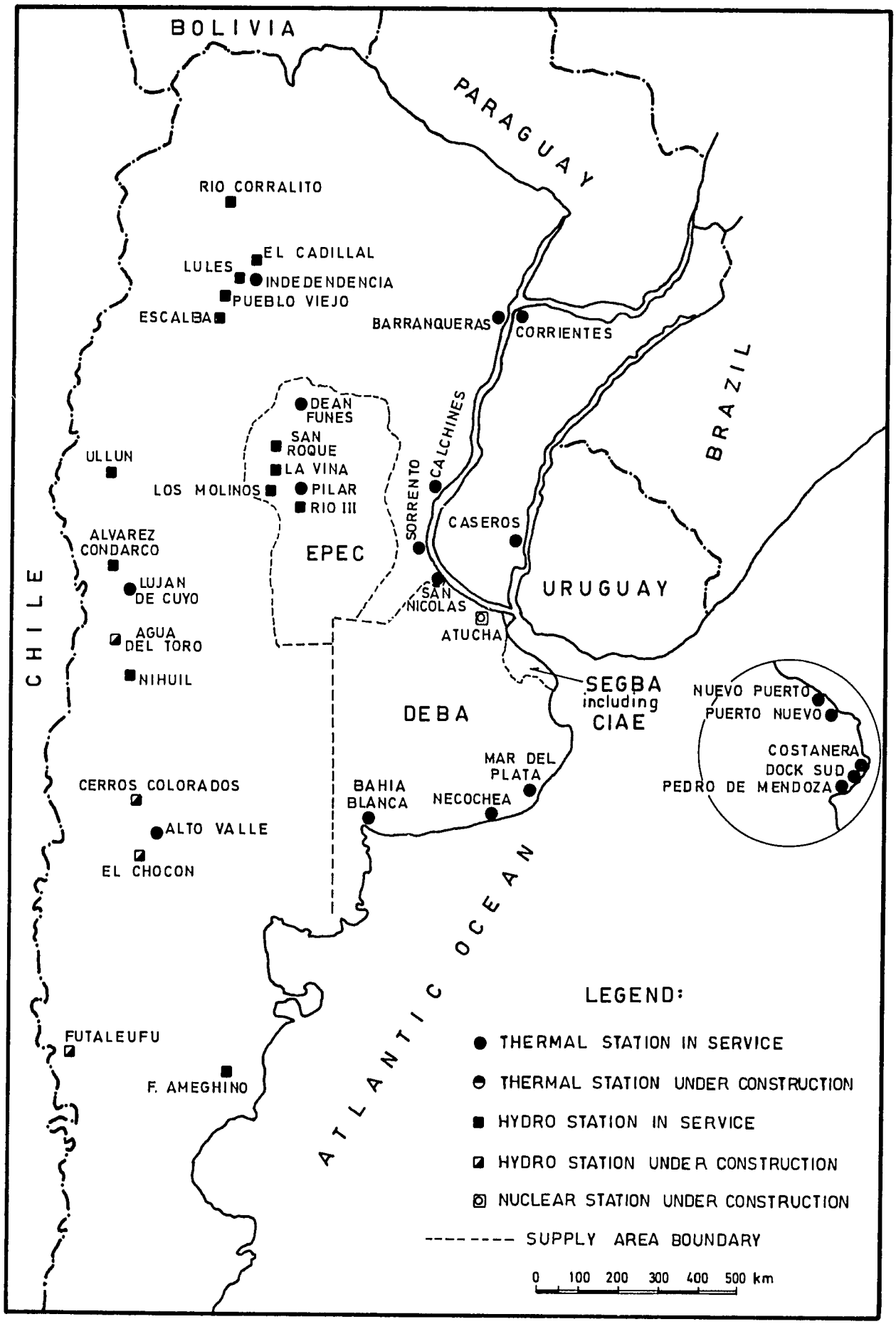


FIG. 3-5. LOCATION OF THE PRINCIPAL GENERATING STATIONS IN 1971

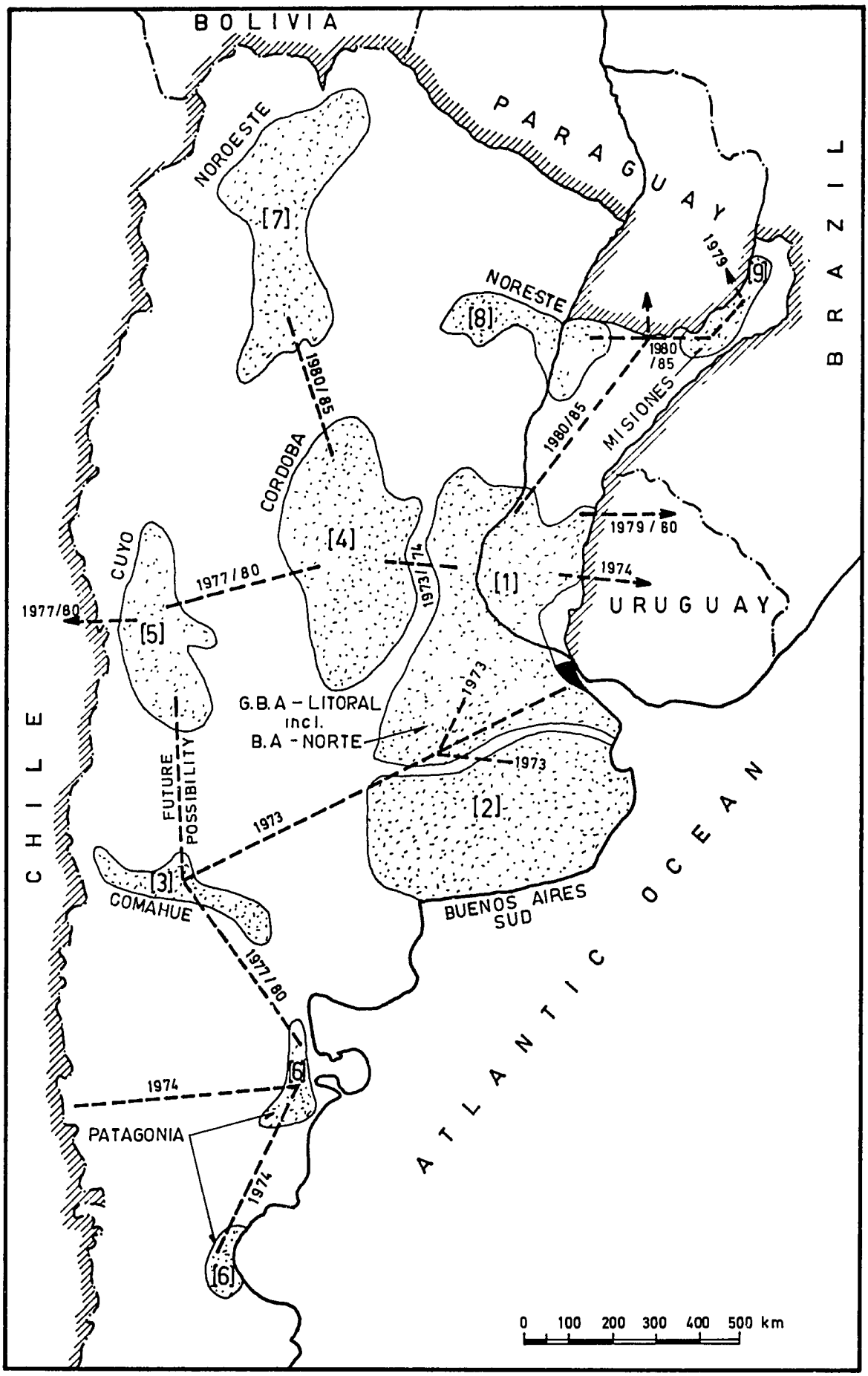


FIG. 3-6. TRANSMISSION NETWORK AREAS AND PLANNED OR FORECAST DATES OF INTERCONNECTION

TABLE III-4. TOTAL CONSTRUCTION COSTS FOR RECENT THERMAL STATIONS

Plant name	Utility	Unit No. x MW	Year commissioned	Total cost (US$/kW)
Costanera	SEGBA	5 x 120	1958 - 1966	225
Puerto Nuevo 7, 8	SEGBA	1 x 145 1 x 194	1961	181[a]
Puerto Nuevo 9	SEGBA	1 x 250	1970	125[a]
Luján de Cuyo	AyEE	2 x 60	1971	215[b]

[a] Excludes previously constructed civil works and cooling water system.
[b] Includes a heating system for asphaltic residue.

TABLE III-5. CAPITAL COST BREAKDOWN FOR THERMAL STATIONS

Plant component	US$/kW	
	Puerto Nuevo 7, 8	Lujan de Cuyo
Civil works	45.6[a]	33.7[c]
Boiler plant equipment	38.3	73.6
Turbine plant equipment	64.7[b]	62.0
Other	32.4	45.7
Total	181.0	215.0

[a] Excludes previously constructed civil works.
[b] Includes installation.
[c] Rough estimate only because unrelated hydraulic works were carried out under same contract.

TABLE III-6. ESTIMATED COSTS FOR EL CHOCON-EZEIZA 500 kV TRANSMISSION SCHEME[a]

Description	Foreign currency (US$ x 10^6)	Local currency (US$ x 10^6)	Total (US$ x 10^6)
2 single-circuit lines, each 1100 km. Guyed towers, lattice steel construction. 4 conductors in a "bundle" per phase. "Dove" steel-cored aluminium conductor Aluminium 26/3.72 mm Steel 7/2.89 mm	31.3	32.8	64.1
Switchgear and control equipment	15.2	10.6	25.8
500 kV step-down transformers (2700 MVA nominal)	8.2	1.4	9.6
Compensation equipment comprising 8 x 150 MVA shunt reactors, 6 x 125 MVA synchronous compensators, 727 MVA series capacitance.	22.9	4.1	27.0
Substation civil works	-	11.0	11.0
Total	77.6	59.9	137.5

[a] Costs for the connection to Cerros Colorados are excluded, as are also engineering costs, purchase of land and "right of way".

TABLE III-7. EXAMPLES OF COSTS FOR 220 kV TRANSMISSION LINES

1. Line from Ramallo (Prov. B. A.) to Rosario (Prov. Santa Fe)		
Length	78.km over flat land in the east of the country	
Conductors	Disposed in triangular geometry, 2 per phase Conductor diameter - 24.5 mm Distance between phases - 3.90 m Conductor AL/AC: 300/50 mm^2, 1227 kg/km Resistance at 20°C - 0.094875 Ω/km Normal span - 350 m.	
Cost	Oct. 1972	
	Excluding cost of conductor	35.425×10^6 pesos
	Cost of conductor (supplier's data)	15.575×10^6 pesos
	Total	51.000×10^6 pesos
2. Two lines from Henderson		
(a) Henderson to Bragado		
Length	177 km over flat country in Prov. B. A.	
Conductors	In one plane, 1 per phase Conductor diameter - 28.80 mm Distance between phases - 7.32 m Normal span - 400 m	
Cost	Oct. 1972 Excluding lightning protection, conductors, insulators and other hardware	28.000×10^6 pesos
(b) Henderson to Olavarría		
Length	144 km	
Conductors	Identical with (a)	
Cost	Oct. 1972 With same exclusions as (a)	28.600×10^6 pesos
For both lines, the provision by DEBA of conductors, insulators etc. will total		31.400×10^6 pesos
	Total for the 321 km	88.000×10^6 pesos

3.5. System reserve capacities

For a decade or more, expansion of generating capacity has not kept pace with growth of potential demand and there has had to be limitation in the connection of new customers. In these circumstances spinning reserve on the GBA-Litoral system has usually not sufficed to cover fully the loss of the largest generator, except at night, and not infrequently falls to zero during peak periods.

Gas turbines at present provide some 250 MW of "hot standby" when not required to meet system demand. With a further 350 MW in course of installation ability to withstand emergencies should soon be improved.

When load relief is needed the first step, if time permits, is to reduce distribution voltage down to 90% by transformer tap changing. A 10% voltage reduction reduces demand by 5-10% according to load conditions. Low-frequency relays operate at 49.0 Hz to shed up to 150 MW of peak load. Further disconnection of load, when required, can be quickly carried out manually according to a pre-arranged procedure.

Table III-8 gives particulars of ten recent instances of large loss of generation, showing minimum frequency and amounts of load shed. It demonstrates that the existing all-thermal system has survived sudden losses of generation of up to 22% with inadequate spinning reserves but that, except at night, losses above 10% are liable to entail load shedding even when spinning reserve is nominally adequate.

TABLE III-8. INSTANCES OF SUDDEN LOSS OF GENERATION OF GBA-LITORAL SYSTEM

Date	Time	Total generation (G) (MW)	Spinning reserve (MW)	Loss of generation			Lowest frequency (Hz)	Load shed			
				Unit	MW	% of G		Automatic (MW)	Manual (MW)	Total	
										MW	% of G
11.8.71	19.39	2 300	0	P. Nuevo 9	230	10.0	48.8	30	100	130	5.7
10.1.72	21.20	2 200	0	Costanera 5	120	5.5	49.2	-	80	80	3.6
17.1.72	02.40	1 100	800	P. Nuevo 8	160	14.5	49.2	-	-	-	-
11.2.72	05.55	1 180	500	N. Puerto 6	215	18.2	49.0	35	10	45	3.8
27.4.72	08.25	1 700	300	P. Nuevo 9	215	12.7	48.8	25	60	85	5.0
23.5.72	15.30	1 860	180	P. Nuevo 9	205	11.0	48.8	70	50	120	6.5
29.5.72	08.20	1 800	120	P. Nuevo 9	250	13.9	48.8	35	70	105	5.8
13.6.72	00.35	1 060	500	N. Puerto 6	120	11.3	49.0	-	-	-	-
17.6.72	10.50	1 300	100	N. Puerto 6	200	15.4	48.5	60	90	150	11.5
4.7.72	07.50	1 540	100	P. Nuevo 7, 8 (partial) 9 (total)	345	22.4	48.8	70	110	180	11.7

Note: Total generation (G) represents SEGBA, CIAE and AyEE stations and omits any generation in parallel by small authorities.

3.6. Operating and maintenance costs of recent thermal stations

(a) Number of personnel by types

Table III-9 gives the operating personnel for the Puerto Nuevo thermal station of SEGBA. This station has nine units with a total effective capacity of 864 MW (units 1-6 = 52.5 MW each, unit 7 = 145 MW, unit 8 = 194 MW, unit 9 = 250 MW).

(b) Salaries and associated costs

Table III-10 gives the monthly salaries of each type of station operating personnel for the Puerto Nuevo station. Taking the average cost given of 1600 pesos/month and using a conversion factor of 1 US$ = 9.60 pesos the annual cost of operating the station including 100% fringe benefits amounts to 4.8 million US$ or 5.5 US$/kW.

(c) Other operating costs per year

Other annual operating costs of Puerto Nuevo, excluding fuel, amount to 3.26 US$/kW, giving total annual operating and maintenance costs of 8.8 US$/kW. This corresponds to 1.87 US mill/kWh.

(d) Total costs per net kWh of station output

Total operating costs of various thermal stations in terms of US$/kW of capacity per year are given in Table III-11. Costs per kWh were not supplied but were calculated from the data given in the table and shown in the last column.

TABLE III-9. PERSONNEL OF PUERTO NUEVO THERMAL STATION

Classification	Number per shift
Shift supervisor	1
Assistant shift supervisor	1
Unit chief	
Units 1-6	4
Units 7-8	1
Unit 9	1
Overall plant	1
Control room operators	
Units 1-6	7
Units 7-8	5
Unit 9	3
Overall plant	5
Other operators	
Units 1-6	65
Units 7-8	4
Unit 9	2
Overall plant	-
Maintenance personnel	100
Total per shift	200
Total for 6 shifts	1200

TABLE III-10. SALARIES OF OPERATING PERSONNEL (PUERTO NUEVO)

Classification	pesos/month [a]	US $/month [b]
Assistant shift supervisor	3 000	313
Unit chief	2 300	240
Control-room operators	2 000	210
Other operators and maintenance personnel	1 500	156
Plant average	1 600	167

[a] Excluding fringe and social benefits at 100% of direct salaries
[b] At 1 US $ = 9.60 Argentine pesos.

TABLE III-11. TOTAL OPERATING AND MAINTENANCE COSTS OF THERMAL STATIONS

Station name	Effective capacity (MW)	Fuel type	Total O & M cost 1970 (US $/kW)	Generation 1971 (GWh)	Unit cost (US mill/kWh)
Puerto Nuevo	864	O/G/C	8.8	4 048	1.87
Costanera	600	O/G	6.2	3 161	1.18
Dock Sud	165	O/G	21.8 [a]	499	7.22
San Nicolás	320	O/C	8.1	2 053	1.26
Calchines	70	O	13.2	227	4.07
Sorrento	81	O	11.2	-	
Alto Valle	30	O/G	8.2	188	1.45

[a] Excluding gas turbines.

4. HISTORICAL SYSTEM DATA

4.1. Historical load growth

(a) Energy and demand

Table IV-1 gives the growth in energy generation from 1960 to 1971 for each of the power market regions (see Fig. 3-4) that will be interconnected by 1985. Table IV-2 gives the energy generation by autoproducers in the GBA-Litoral area, most of which are interconnected to the grid, and in the country as a whole. Table IV-3 gives the energy consumption by class of customer for seven of the interconnected systems. Data for the other systems were not available.

Table IV-4 gives the growth in installed capacity from 1960 to 1971 for each of the power market areas in the country.

Table IV-5 gives the longer range growth in total energy generation by utilities and autoproducers and the percentage of the total contributed by autoproducers. It is seen that this percentage reached a peak of 26.6% in 1963, but has generally declined since that time.

The total annual energy generation in the country between 1935 and 1971 is plotted in Fig.4-1.

The average annual growth rates of the public supply were:

1945 - 1965	6.9%
1965 - 1968	6.3%
1968 - 1971	11.4%

Table IV-6 gives the annual load factor by years for the SEGBA system.

Table IV-7 gives load duration data for the individual interconnected systems of GBA-Litoral, Córdoba, Cuyo and Buenos Aires Sud.

Table IV-8 gives the monthly maximum and minimum peak demands for the GBA-Litoral interconnected system for 1969.

Figure 4-2 shows the curves of maximum hourly demand for the SEGBA system in 1970 and 1971. Figure 4-3 shows the monthly variation in these curves for 1964.

(b) Generating capacity

Data on the growth in installed capacity of the five major utilities and other distributors from 1960 to 1969 are given in Table IV-9. Past trends in growth are plotted in Fig. 4-4. This figure also shows the growth of maximum demand for SEGBA only. In most other cases it is believed that simultaneous maximum demands are not recorded; and, on account of the considerable diversity to be expected, non-simultaneous aggregates would be of little value to the study.

(c) Transmission interconnection capacity

As described in Section 3.4, existing interconnections are regional, the only large system being GBA-Litoral. Present capacity within the GBA-Litoral system is two 132 kV lines of 70 MW each.

(d) Per-capita consumption of electricity

The growth in the per-capita consumption of electricity from 1935 to 1969 is shown in Fig. 4-5. The average growth rate for the period 1935-1969 is just over 5% per year but the period 1959-1969 shows a higher rate of 6% per year.

4.2. System reliability

(a) Reliability criteria

No specific information was available about reliability criteria. An inadequate margin of installed capacity in recent years has prevented achievement of the highest standards of reliability, as the incidence of load shedding shows. The accepted application of under-frequency relays for load shedding is recognition that, in its present state of development, the system cannot be considered fully reliable under all possible conditions of loading and under reasonable conditions of outage of generating units or major transmission circuits.

(b) Outage records

Table IV-10 gives records of scheduled and forced outage times for the generating plants at Costanera, Puerto Nuevo and San Nicolás.

In the case of Costanera and Puerto Nuevo, figures are given for 1970, 1971 and the seven months January-July 1972. For San Nicolás the figures are for the six-year period 1965-70.

Statistics of faults on 132 kV transmission lines are given in Table IV-11.

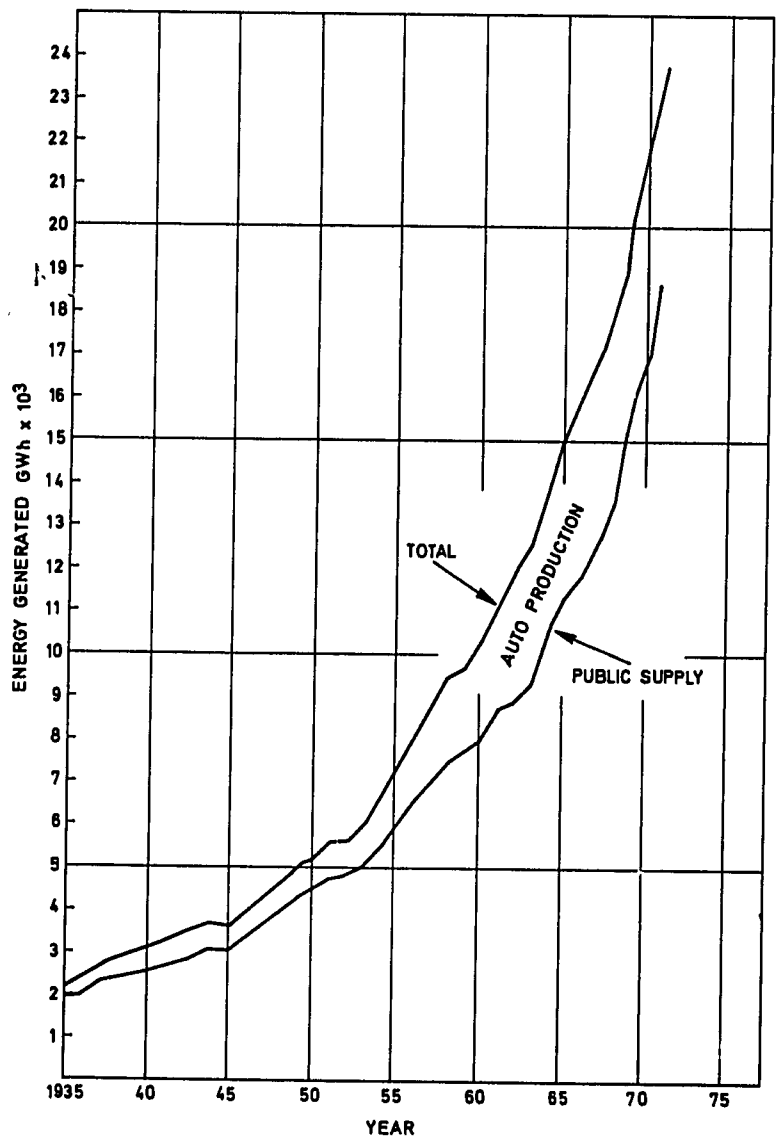


FIG. 4-1. ELECTRICAL ENERGY GENERATION 1935-1971

TABLE IV-1. ELECTRICAL ENERGY PRODUCTION FOR FUTURE INTERCONNECTED SYSTEMS, 1960 - 1971 (GWh)

Power market area	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971
1. GBA-Litoral and B. A. Norte	5 824	6 363	6 332	6 619	7 293	7 892	8 228	8 768	9 468	10 658	11 541	12 622
2. Buenos Aires Sud [a]	171	182	205	210	228	270	322	373	501	560	674	714 [b]
3. Comahue	65	71	76	87	98	119	117	129	133	156	237	293
4. Córdoba	437	526	569	562	672	787	831	859	922	1 026	1 105	1 266
5. Cuyo	415	474	522	554	639	742	816	833	954	1 109	1 301	1 533
6. Patagónico Centro	18	20	24	26	29	34	49	57	66	76	85 [b]	86 [b]
7. Noroeste	156	165	174	182	216	221	235	256	283	344	400	474
8. Noreste	62	69	71	80	84	94	104	116	124	148	161	178
9. Misiones	14	18	20	22	24	31	37	41	48	50	51	68
Sum of individual systems	7 162	7 888	7 993	8 342	9 283	10 190	10 739	11 432	12 399	14 127	15 555 [c]	17 234 [c]
Other public utilities	702	720	763	802	949	1 065	957	985	1 107	1 110	1 252 [d]	1 424 [d]
Total public utilities	7 864	8 608	8 756	9 144	10 232	11 255	11 696	12 417	13 506	15 237	16 807	18 658
Autoproducers	2 300	2 350	3 131	3 315	3 585	3 830	4 231	4 269	4 447	4 777	4 920	4 965
Total for country	10 164	10 958	11 887	12 459	13 817	15 085	15 927	16 686	17 953	20 014	21 727	23 623

[a] DEBA statistics for Centro Sudeste plus Sud.
[b] Estimated.
[c] SSE statistics show that AyEE, SEGBA, CIAE, DEBA and EPEC produced 16 001 GWh in 1970 and 17 822 GWh in 1971 (see Table III-3, summary).
[d] SSE statistics show that other utilities produced 806 GWh in 1970 and 836 GWh in 1971.

TABLE IV-2. ENERGY GENERATION BY AUTOPRODUCERS (GWh)

Year	GBA-Litoral	Country total
1960	1 487	2 300
1961	1 697	2 350
1962	1 818	3 131
1963	1 988	3 315
1964	2 357	3 585
1965	2 737	3 830
1966	2 666	4 231
1967	2 692	4 269
1968	2 773	4 447
1969	2 950 [a]	4 777
1970	3 030 [a]	4 920
1971	3 060 [a]	4 965

[a] Estimated.

TABLE IV-3. ELECTRICAL ENERGY CONSUMPTION BY CLASS OF CUSTOMER, 1960-1969 (Interconnected systems only) (GWh)

	1960	1962	1964	1966	1968	1969
GBA-Litoral						
Residential	1 693	2 064	2 347	2 661	3 092	3 392
Commercial	541	625	694	801	962	1 096
Industrial	1 386	1 374	1 640	1 988	2 284	2 711
Other	989	950	968	1 025	1 253	1 345
Total	4 608	5 012	5 649	6 475	7 591	8 544
Buenos Aires Sud						
Total (breakdown not available)	151	183	216	264	437	467
Comahue						
Residential	9	12	13	18	19	23
Commercial	5	5	8	9	10	11
Industrial	40	42	56	69	76	81
Other	5	6	7	9	11	13
Total	59	65	84	105	116	128
Córdoba						
Residential	107	154	173	209	235	262
Commercial	47	67	79	99	110	125
Industrial	159	200	250	313	342	367
Other	57	56	40	58	81	87
Total	370	478	543	620	768	841

TABLE IV-3. (cont.)

	1960	1962	1964	1966	1968	1969
Cuyo						
Residential	75	100	120	134	169	183
Commercial	34	43	45	46	53	62
Industrial	171	228	282	357	465	613
Other	70	88	88	88	81	82
Total	350	459	535	625	768	940
Patagónico Centro						
Residential	12	14	14	17	20	23
Commercial		3	9	11	12	14
Industrial	6	4	7	9	13	16
Other	2	7	8	12	15	21
Total	20	28	38	49	60	74
Noroeste						
Residential	46	54	66	75	94	108
Commercial	26	32	38	43	49	56
Industrial	25	26	36	39	44	65
Other	34	37	40	44	52	52
Total	131	149	180	201	239	281
Noreste						
Residential	15	22	25	31	38	45
Commercial	9	11	12	14	14	15
Industrial	11	14	17	23	27	38
Other	14	12	14	17	19	20
Total	49	59	68	85	98	118

Note: Totals may not be exact due to rounding off.

TABLE IV-4. INSTALLED CAPACITY FOR FUTURE INTERCONNECTED SYSTEMS 1960-1971 (MW)

Power market area	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970[a]	1971[a,b]
1. GBA-Litoral	1459	1611	1663	2178	2275	2402	2378	2397	2510	2751	3140	3230
2. Buenos Aires Sud	50	50	101	110	220	220	220	221	221	265	281	281
3. Comahue	17	21	21	27	31	40	38	38	38	68	78	79
4. Córdoba	172	184	189	183	229	290	328	317	330	331	342	379
5. Cuyo	159	165	168	180	202	201	196	192	263	376	377	587
6. Patagónico Centro	10	11	13	13	15	21	21	25	78	80	85	85
7. Noroeste	71	72	91	85	96	100	111	120	126	146	147	172
8. Noreste	19	25	23	23	23	23	30	58	48	48	50	55
9. Misiones	7	9	10	11	12	15	27	26	27	28	23	27

[a] Estimated.

[b] The total capacity is 4895 MW, i.e. 492 MW greater than the total of 4403 MW in Table III-3. The difference is due to the exclusion of diesel sets in Table III-3.

TABLE IV-5. GROWTH IN TOTAL NATIONAL ELECTRICITY GENERATION (1935-1971)

Year	Energy generation (GWh)			
	Utilities	Autoproducers	Total	Percentage by autoproducers
1935	1 861	285	2 146	13.3
1940	2 519	510	3 089	17.5
1945	2 945	630	3 575	17.6
1950	4 396	780	5 176	15.1
1955	5 905	1 300	7 205	18.0
1960	7 846	2 300	10 146	22.7
1961	8 608	2 350	10 958	21.4
1962	8 756	3 131	11 887	26.3
1963	9 144	3 315	12 459	26.6
1964	10 232	3 585	13 817	26.0
1965	11 255	3 830	15 085	25.4
1966	11 696	4 231	15 927	26.5
1967	12 417	4 269	16 686	25.3
1968	13 506	4 447	17 953	24.8
1969	15 237	4 777	20 014	23.8
1970	16 807	4 920	21 727	22.7
1971	18 658	4 965	23 623	21.0

TABLE IV-6. ANNUAL LOAD FACTORS BY YEARS FOR SEGBA SYSTEM

Year	Maximum demand (MW)	Production [a] (GWh)	h/yr	Load factor (%)
1960	780	3 800	4 870	55
1961	870	3 900	4 480	51
1962	900	4 200	4 650	53
1963	950	4 500	4 730	54
1964	1 100	4 900	4 460	51
1965	1 170	5 300	4 530	52
1966	1 220	5 800	4 750	54
1967	1 300	6 200	4 760	54
1968	1 380	6 800	4 930	56
1969	1 420	7 400	5 210	59
1970	1 697	8 300	4 890	56
1971	1 808	9 100	5 030	57

[a] From own generating stations plus purchases.

TABLE IV-7. LOAD DURATION DATA FOR 1971 FOR SYSTEMS WHICH WILL BE INTERCONNECTED BY 1980.

Time duration[a] (h)	Average peak demand			
	GBA-L (MW)	Córdoba (MW)	Cuyo (MW)	B. Aires Sud (MW)
365	2 199	220	224	255
365	2 027	200	213	247
365	1 879	191	220	223
365	1 795	180	224	197
365	1 733	177	203	191
365	1 703	172	185	186
365	1 653	171	188	191
365	1 647	169	179	180
365	1 625	168	175	184
365	1 604	161	173	175
365	1 563	158	177	172
365	1 500	156	186	173
365	1 443	151	184	158
365	1 377	141	181	145
365	1 300	136	171	130
365	1 214	121	178	121
365	1 123	120	180	123
365	1 077	115	160	123
365	1 022	113	160	119
365	988	103	153	110
365	954	103	137	115
365	924	101	137	110
365	896	94	131	106
365	798	87	136	85
Instantaneous peak demand	2 488	250	290	276

[a] 365 hours = 1/24th year.

TABLE IV-8. MONTHLY MAXIMUM AND MINIMUM PEAK DEMANDS (GBA-L Interconnected system, 1969)

Month	Maximum (MW)	Minimum (MW)
January	1 760	492
February	1 741	581
March	1 842	607
April	1 965	509
May	2 014	519
June	2 101	534
July	2 075	602
August	2 106	529
September	2 125	528
October	2 064	548
November	2 019	554
December	2 029	598

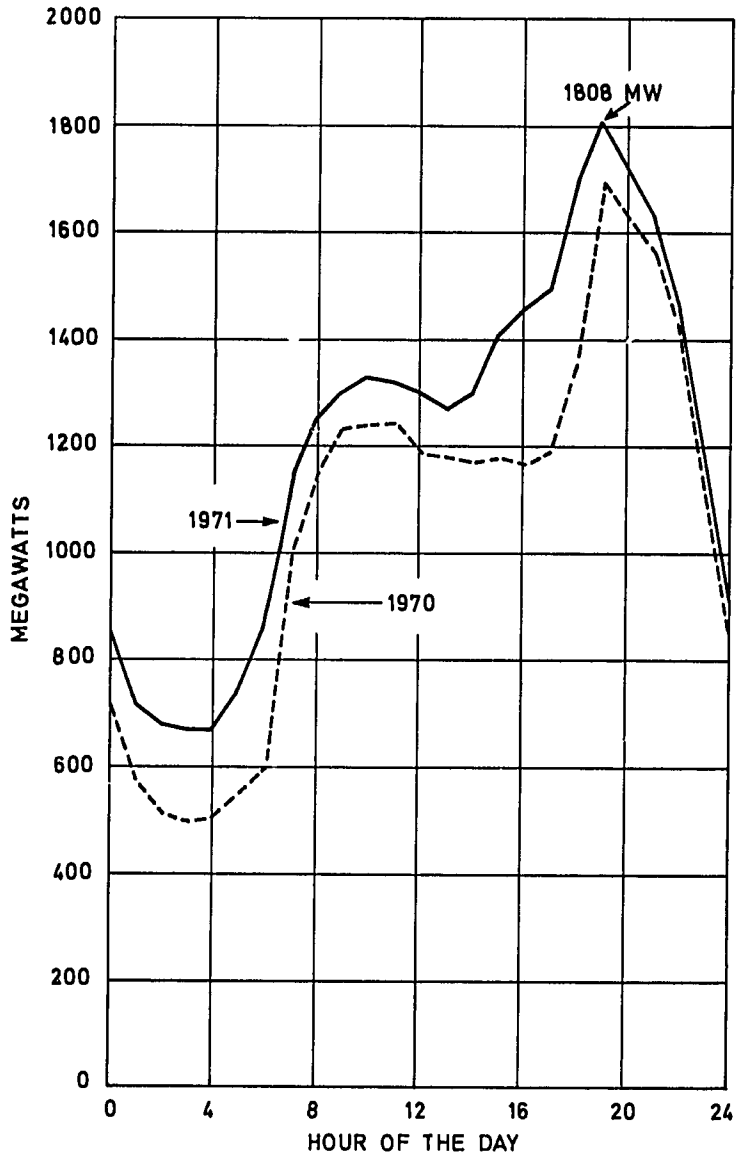


FIG. 4-2. MAXIMUM HOURLY DEMAND FOR THE SEGBA SYSTEM FOR 1970 AND 1971

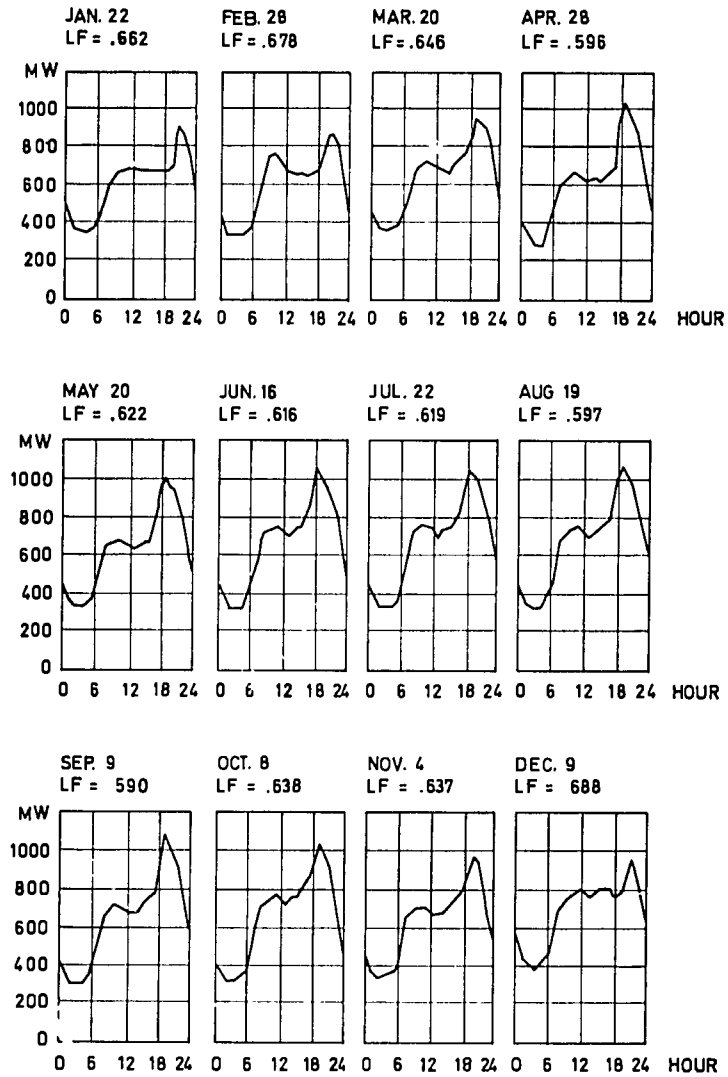


FIG. 4-3. MAXIMUM DAILY LOAD DEMAND CURVES BY MONTH FOR THE SEGBA SYSTEM FOR 1964

TABLE IV-9. GROWTH IN INSTALLED CAPACITY OF UTILITIES, 1960-1971 (MW)

Year	SEGBA	AyEE	CIAE	DEBA	EPEC	Others	Total
1960	693	979	246	70	64	235	2 287
1961	833	1 007	245	73	65	272	2 495
1962	884	1 032	245	125	64	300	2 650
1963	1 392	1 074	245	120	69	317	3 217
1964	1 472	1 145	255	195	105	339	3 511
1965	1 459	1 194	364	193	165	379	3 754
1966	1 434	1 252	364	190	165	384	3 789
1967	1 435	1 309	364	200	157	388	3 853
1968	1 575	1 424	335	200	169	415	4 118
1969	1 576	1 578	584	245	167	424	4 574
1970	1 843	1 574	543	290	181	429	4 860
1971	1 930	1 873	543	290	222	415	5 273

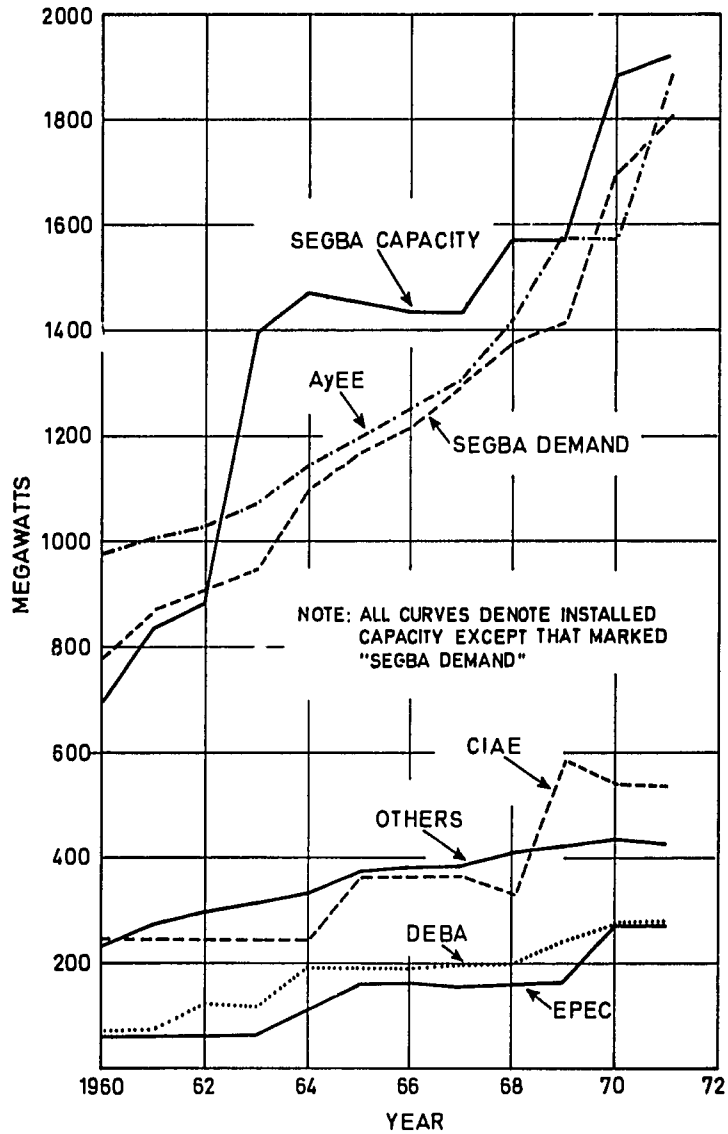


FIG. 4-4. GROWTH OF INSTALLED CAPACITY AND MAXIMUM DEMAND 1960-1971

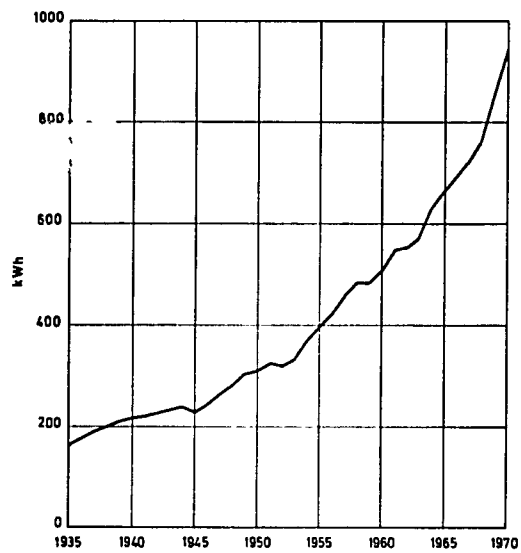


FIG. 4-5. GROWTH IN PER CAPITA CONSUMPTION OF ELECTRICITY 1935-1970

TABLE IV-10. GENERATION PLANT OUTAGES

Values are for hours of outage (or availability) expressed as percentages of total hours in year or, for 1972, of total hours to 31 July

COSTANERA

5 × 120 MW units, installed 1963

Unit No.	Year	Planned outage (%)	Forced outage (%)	Availability (%)
1	1970	6.9	6.9	86.2
	1971	58.9	2.9	38.2
	1972	-	5.1	94.9
2	1970	17.4	3.8	78.8
	1971	5.4	7.1	87.5
	1972	59.2	9.8	31.0
3	1970	8.1	5.6	86.3
	1971	8.5	3.6	87.9
	1972	-	19.3	80.7
4	1970	10.2	2.8	87.0
	1971	-	7.5	92.5
	1972	-	11.2	88.8
5	1970	7.7	5.1	87.2
	1971	-	11.1	88.9
	1972	-	8.4	91.6

PUERTO NUEVO

Units: No. 7 - 145 MW (1961), No. 8 - 194 MW (1963), No. 9 - 250 MW (1970)

7	1970	29.6	4.1	66.3
	1971	19.9	3.5	76.6
	1972	-	8.4	91.6
8	1970	-	4.6	95.4
	1971	9.9	1.9	88.2
	1972	-	3.6	96.4
9	1970[a]	7.8	5.8	86.4
	1971	-	10.0	90.0
	1972	48.9	3.2	47.9

[a] Period since commissioning in August.

SAN NICOLAS

4 × 75 MW units installed 1957

Total for all units	1965	6.1	27.3[a]	66.6
	1966	7.8	22.6[a]	69.6
	1967	20.0[b]	0.6	79.4
	1968	22.9[d]	5.4[c]	71.7
	1969	10.9[e]	0.8	88.3
	1970	19.8[f]	0.6	79.6

		Total outage (%)	
1	Total for 6 years 1965-1970	25.5	74.5
2		22.2	77.8
3		17.4	82.6
4		34.1	65.9

[a] Repair of faults in stator and rotor windings of No. 4 turbo-generator.
[b] Periodic overhaul of No. 1 turbo-generator.
[c] Repeated tube failures in various boilers.
[d] Modification and retubing of No. 2 boiler.
[e] Periodic overhaul of No. 3 turbo-generator.
[f] Modification and retubing of No. 1 boiler.

TABLE IV-11. FAULT STATISTICS FOR 132 kV TRANSMISSION LINES

Region/Line	Length (km)	Scheduled outages		Unscheduled outages	
		No./yr	Time (h/yr per km)	No./yr	Time (min/yr per km)
Centro 11.1.70 to 19.1.72 (2.8 yr)					
Molinos/Córdoba I	50	31 [a]	1.92	8	3.79
Molinos/Córdoba II	50	41	1.37	9	2.32
B. Reolín/Molinos	42	34	1.31	26	2.45
B. Reolín/Río IV	104	49	0.97	52	3.5
Interconnection AyEE/EPEC	2.5	2	0.17	9 [b]	24.7
Total	248.5	157	1.29	104	3.34
Norte 1.1.70 to 29.8.72 (2.66 yr)					
Independencia – Villa Quinteros	55	-	-	11	0.765
Villa Quinteros – Escaba	48	-	-	7	0.16
Villa Quinteros – La Banda	152	2	0.0173	14 [c]	115
Total	255	2	0.0103	32	1.09
Patagónico Norte in period 14.2.70 to 27.8.72					
Alto Valle – El Chocón [d] (2.84 yr)	80	9 [e]	0.38	2	22
Alto Valle – Cipolletti (2.84 yr)	10	1	0.28	-	-
El Chocón – Cutral Có (2.72 yr)	54.5	1	0.07	-	-
Alto Valle – Medanito (1.12 yr)	117	3 [f]	0.56	-	-
Total	261.5	14	-	2	22
Patagónico Centro 1.11.70 to 29.10.72 (2.83 yr)					
Fl. Ameghino – Trelew	112	2	0.06	4	0.9
C. Rivadavia – [g] – P. Truncado	140	7	0.05	30	15.4
Total	252	9	0.055	34	8.97

[a] One of these interruptions lasted 121 h for repair of breaker.
[b] Of these 9, 7 were due to low frequency which resulted from loss of load and/or incorrect operation.
[c] One line break lasted 9 h.
[d] This line had constructional defects.
[e] On one occasion disconnected for 36 h to allow the construction of the 500 kV line El Chocón to B.A.
[f] On one occasion disconnected for 73 h for same reason.
[g] This line has had abnormal problems due to insulator faults.

5. PROJECTED SYSTEM DATA

5.1. Projection of energy requirements

Table V-1 shows the latest projected growth of generated energy to the year 2000. Table V-2 shows the assumed rates of growth for these projections[3]. These rates, which greatly exceed the historical trend, are based on the expected industrial expansion and general growth of the economy recommended in the National Development Plan 1971-75. They take into account the limitation imposed by shortage of plant capacity during the early 1960's and anticipate the faster growth which should go with an unrestricted supply.

Under these conditions the proportion of autoproduction is expected to continue its decline, falling to 15% of the total generation by 1976 and 10% by year 2000. Projected average growth rates for the public supply thus reach 13% for 1971-76 and 10.6% for 1971-2000.

Generated energy within the interconnected system is expected to increase, as the system expands, from 67% of the total public supply in 1971 to 94% of the public supply by 1985, and to remain at that level thereafter.

Figure 5-1 gives a plot of these requirements showing the total generation, the public supply generation and that generated on the interconnected system.

Projections of kWh requirements by class of customer were not made available.

TABLE V-1. PROJECTED ELECTRICAL ENERGY REQUIREMENTS (GWh)

Year	Interconnected system	Public supply	Country total
1971	12 572 (1)	18 658	23 623
1976	25 000 (2)	34 400	40 700
1980	46 500 (3)	50 600	58 000
1985	82 500 (4)	88 000	99 000
2000	330 000	350 000	390 000

(1) Includes GBA-Litoral and Buenos Aires Norte
(2) Includes (1) plus Buenos Aires Sud, Comahue and Córdoba
(3) Includes (1) and (2), plus Cuyo and Patagónico Centro
(4) Includes (1), (2), (3), plus Noroeste, Noreste and Misiones.

TABLE V-2. ASSUMED RATES OF GROWTH

	Public supply (%/yr)	Autoproduction (%/yr)	Total (%/yr)
1971/76	13.00	4.75	11.5
1971/80	11.75	4.25	10.75
1971/85	11.75	6.0	10.5
1971/approx. 2000	10.60	7.25	10.5

[3] The numbers and rates given are slightly inconsistent with Table V-1 and Figure 5-1.

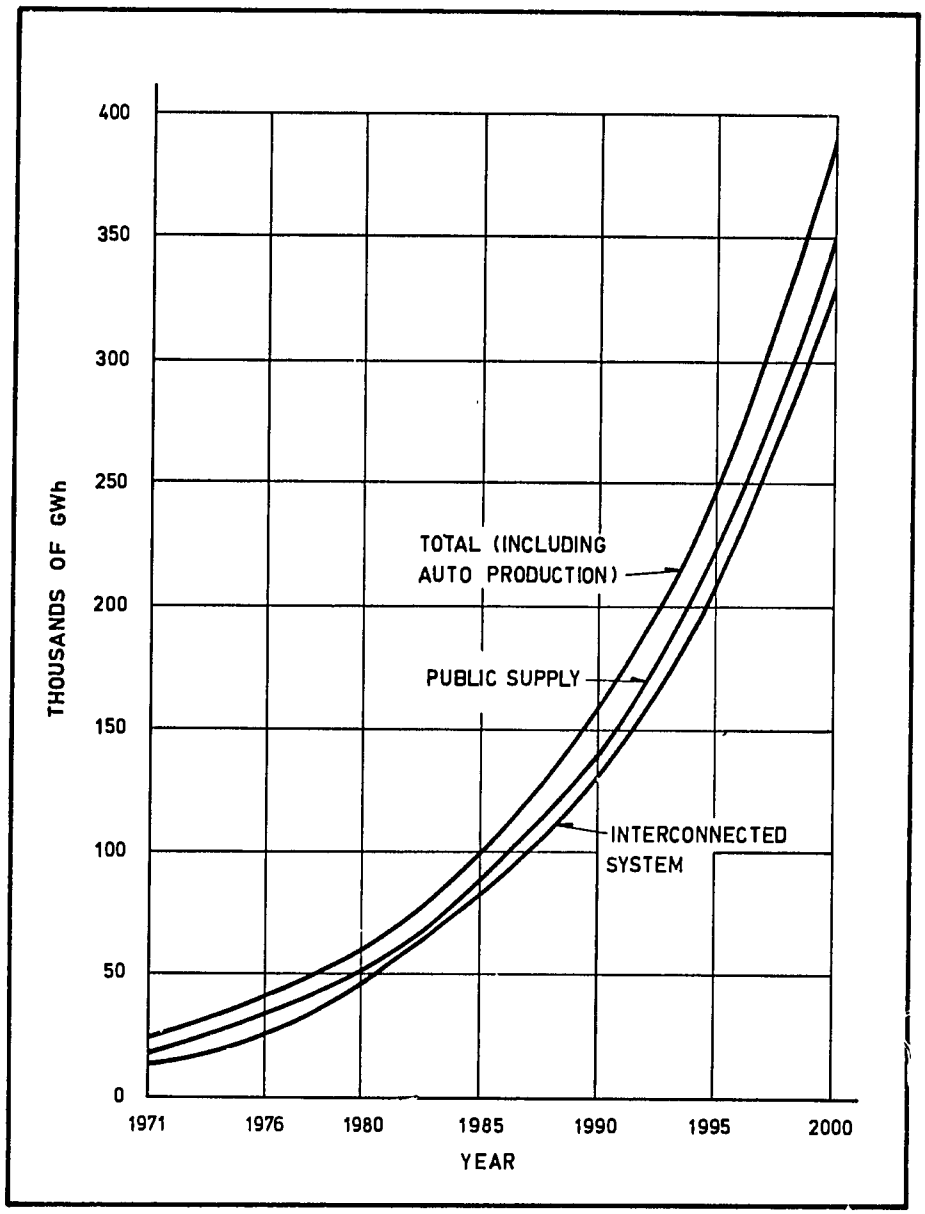


FIG. 5-1. PROJECTED GROWTH OF GENERATED ENERGY TO THE YEAR 2000

5.2. Projection of maximum demand and installed capacity

Table V-3 gives the projected capacity requirement, maximum demand and estimated reserve requirements. This reserve margin between maximum demand and installed capacity is further discussed in Section 5.5.

Figure 5-2 shows the projected growth of maximum demand and installed capacity on the interconnected system.

It is seen that the maximum demand is projected to rise to 9200 MW by 1980 and to 64 000 MW by year 2000.

It follows from the maximum demand and energy projections that the annual load factor is expected to remain at approximately 57.5% until 1980, rising to 63% by 1985 and then decreasing to 59% by year 2000.

Table V-4 gives data on the load duration projected for the interconnected systems in 1980. Figure 5-3 gives typical daily load forecasts for the GBA-L system for 1973.

TABLE V-3. PROJECTED CAPACITY REQUIREMENTS FOR THE INTERCONNECTED SYSTEM (MW)

Year	Installed + committed capacity	Required installed capacity	Maximum demand	Reserve
1971	2 900	2 900	2 488	412
1976	6 150	6 400	5 055	1 345
1980	9 304	11 500	9 200	2 300
1985	10 404	18 000	15 000	3 000
2000	-	70 000	64 000	6 000

Note: Footnotes to Table V-1 are also relevant to this table.

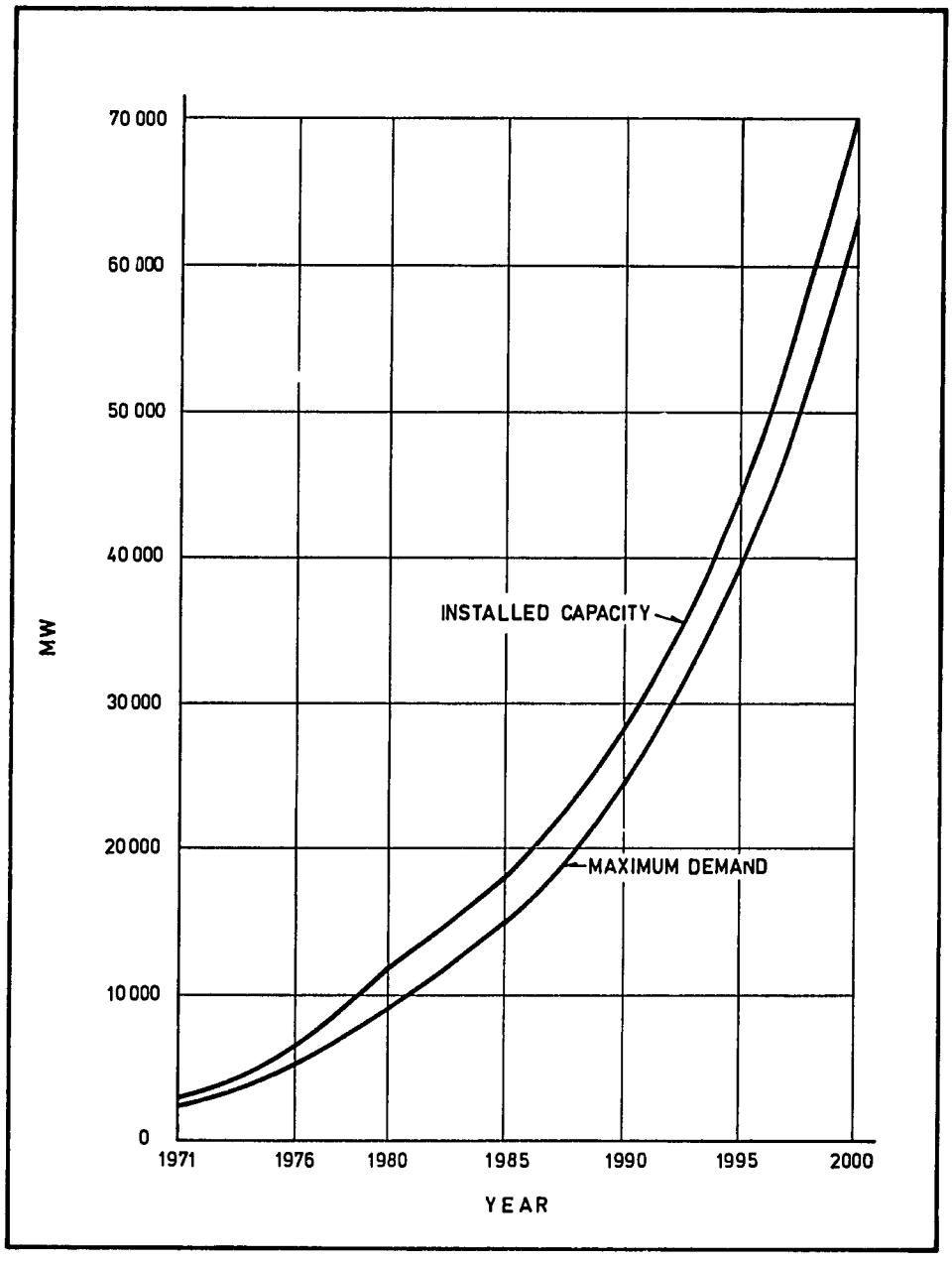


FIG. 5-2. PROJECTED GROWTH OF MAXIMUM DEMAND AND OF INSTALLED CAPACITY TO THE YEAR 2000

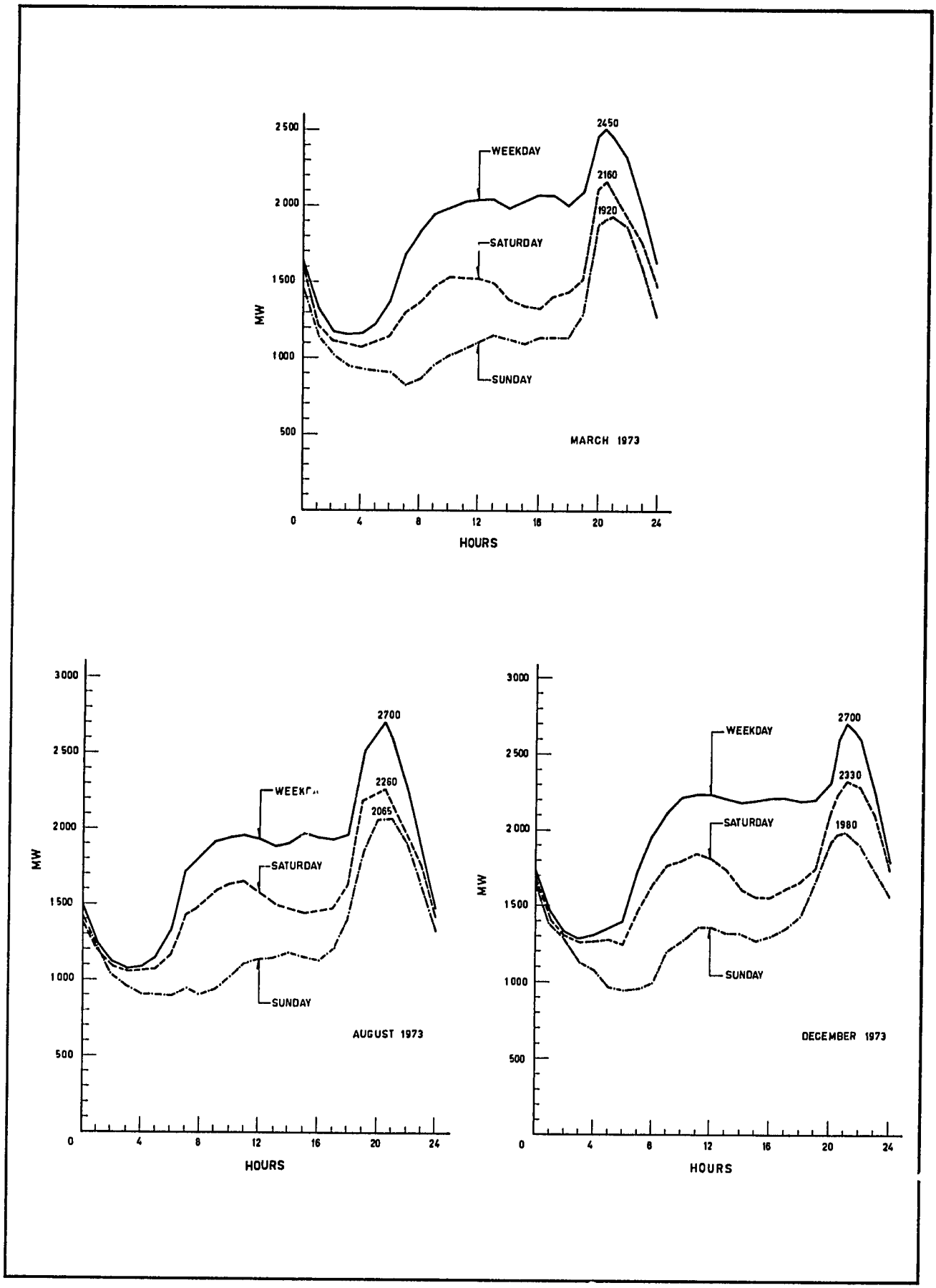


FIG. 5-3. TYPICAL DAILY LOAD FORECASTS FOR GBA-L SYSTEM FOR 1973

TABLE V-4. PROJECTED LOAD DURATION CURVES – INTERCONNECTED SYSTEMS, 1980 (MW)

Time duration (h)	Total interconn. system	Average Peak Demand (MW)			
		GBA-L	Córdoba	Cuyo	Buenos Aires Sud
365	7360	5186	553	854	768
365	6842	4749	501	828	764
365	6417	4452	479	836	650
365	6127	4237	453	853	584
365	5879	4036	449	778	616
365	5717	4004	436	726	551
365	5619	3935	425	709	551
365	5529	3890	424	671	544
365	5467	3833	421	665	549
365	5377	3769	407	664	538
365	5274	3680	400	678	517
365	5163	3532	392	704	535
365	4951	3436	373	694	449
365	4728	3249	356	682	441
365	4452	3064	341	657	390
365	4210	2866	303	675	366
365	4005	2653	300	682	371
365	3810	2538	292	611	369
365	3666	2403	281	626	357
365	3504	2321	263	573	346
365	3379	2264	255	532	328
365	3286	2185	253	516	332
365	3167	2113	240	495	320
365	2875	1892	217	510	256
Assumed growth rate (%/yr) [a]		10%	10.75%	16%	13%

[a] With reference to Table IV-7.

5.3. Planned plant installation program

Investigation of possible future projects is carried out by the individual supply authorities (including CNEA for nuclear stations). They submit proposals and cost estimates to the Sub-Secretary of Energy whose responsibility is to coordinate and approve suitable projects to meet requirements for at least five years ahead.

Table V-5 shows, in Part I, the projects under construction or approved, which form the committed plan for 1972-78. Part II lists further projects at various stages of investigations, from which a selection can be made for future committed plans. The geographical location of existing plants and those under construction is shown in Fig. 3-5 (see Section 3). The location of possible future stations is shown in Fig. 5-4.

In Part 1 of Table V-5 a total of 6907 MW of plant installed on the interconnected system is shown for 1976. This compares with the figure of 6150 MW appearing in Table V-3. The difference is due to the fact that Table V-3 shows effective capacity whilst Table V-5 lists the rated capacity.

TABLE V-5. PLANT INSTALLATION PROGRAM FOR INTERCONNECTED SYSTEMS

PART I. COMMITTED PLAN FOR 1972-78

Year	Region No.	Station	Type	Capacity (MW)	Cumulative installed capacity (MW)			
					Thermal	Hydro	Nuclear	Total
1971	1-4	Existing capacity at end 1971			3 418	200	-	3 618
1972	1	GT (SEGBA) 17 units	T	321				
	1	GT (CIAE) 2 units	T	32				
	3	GT (AyEE) 1 unit	T	15				
	2	9 de Julio (Mar del Plata) 2 units (oil)	T	60				
	2	Necochea 1, 2	T	140	3 986	200	-	4 186
1973	1	GT (AyEE) 4 units	T	72				
	3	El Chocón 1, 2	H	400				
	4	GT (EPEC) 4 units	T	60	4 118	600		4 718
1974	3	El Chocón 3, 4	H	400				
	1	Costanera (oil)	T	350				
	1	Atucha	N	319				
	4	Pilar 1, 2 (oil)	T	150				
	1	Retirements (CIAE, SEGBA)	T	- 80	4 538	1 000	319	5 857
1975	1	San Nicolás (coal)	T	350				
	1	Sorrento (oil)	T	160				
	2	Bahía Blanca (coal)	T	140	5 188	1 000	319	6 507
1976	3	El Chocón 5, 6	H	400	5 188	1 400	319	6 907
1977	3	Planicie Banderita 1, 2	H	300	5 188	1 700	319	7 207
1978	4	Nuclear II	N	600				
	3	Planicie Banderita 3	H	150				
	1	Salto Grande	H	- [a]	5 188	1 850	919	7 957
1977/ 1980		Inclusion of regions Cuyo and Patagonia:						
	5, 6	Existing at end 1971	T	202				
	5, 6	Existing at end 1971	H	396				
	6	Futaleufú (1974)	H	440				
	5	Agua del Toro (1976)	H	130				
	5	Los Reyunos (1977)	H	216	5 390	3 032	919	9 341

[a] Although Salto Grande is a committed project, its construction program is as yet too uncertain for initial output to be expected by 1978. When completed the capacity will be 1 620 MW (12 units of 135 MW each) to be shared with Uruguay. Maximum output available to Argentina is expected to be 1100 MW in 1985, falling to 810 MW by 1990.

TABLE V-5 (cont.)

PART II. POSSIBLE FUTURE PROJECTS

Region No.	Station	Earliest possible commissioning year	Site capacity (MW)	Average annual output (GWh)	Equivalent hours at full capacity
	Hydro (conventional)				
3	Alicurá [a]	1978	600	1600	2667
5	Los Blancos [a]	1979	248	869	3500
3	Callon Curá	1979	600	2200	3667
8/9	Apipé	1980	2100	14700	7000
3	Piedra del Aguila	1981	2400	5500	2292
3	Chihuido	1982	2000	3000	1500
5	Cordón del Plata	1982	1200	1800	1500
6	Santa Cruz I	1982	600	3000	5000
6	Santa Cruz II	1983	400	2000	5000
6	Santa Cruz III	1983	800	4000	5000
9	Corpus	1983	6000	36000	6000
5	El Tontal	1983	834	2100	2520
5	El Baqueano	1983	270	405	1500
1	Paraná Medio I	1984	3000	15000	5000
	Total		21052	92174	
	Hydro (pumped storage)				
4	Río Grande [a]	1978	750		
2	La Brava	1978	1200		
5	Cerro Mesón	1980	115		
5	Potrerillos	1980	200		
4	Anisacate	1982	960		
4	Córdoba area [b]	1983	8100		
5	Valle Grande	1983	100		
	Total		11425		
	Thermal or nuclear	Fuel			
1	Atucha/Santa Fe area (several sites)	Nuclear	Unlimited		
5	Luján de Cuyo [c]	Oil	350		
2	Bahía Blanca	Nuclear or coal	600		
2	Necochea	Nuclear or coal	600		
4	Córdoba II	Nuclear	600		
5	Mendoza	Nuclear	600		

[a] Assumed selected for commissioning by 1980.
[b] Conversion of existing conventional hydro schemes.
[c] There are doubts whether oil would be a practicable fuel for Lujan de Cuyo because of doubts about its availability.

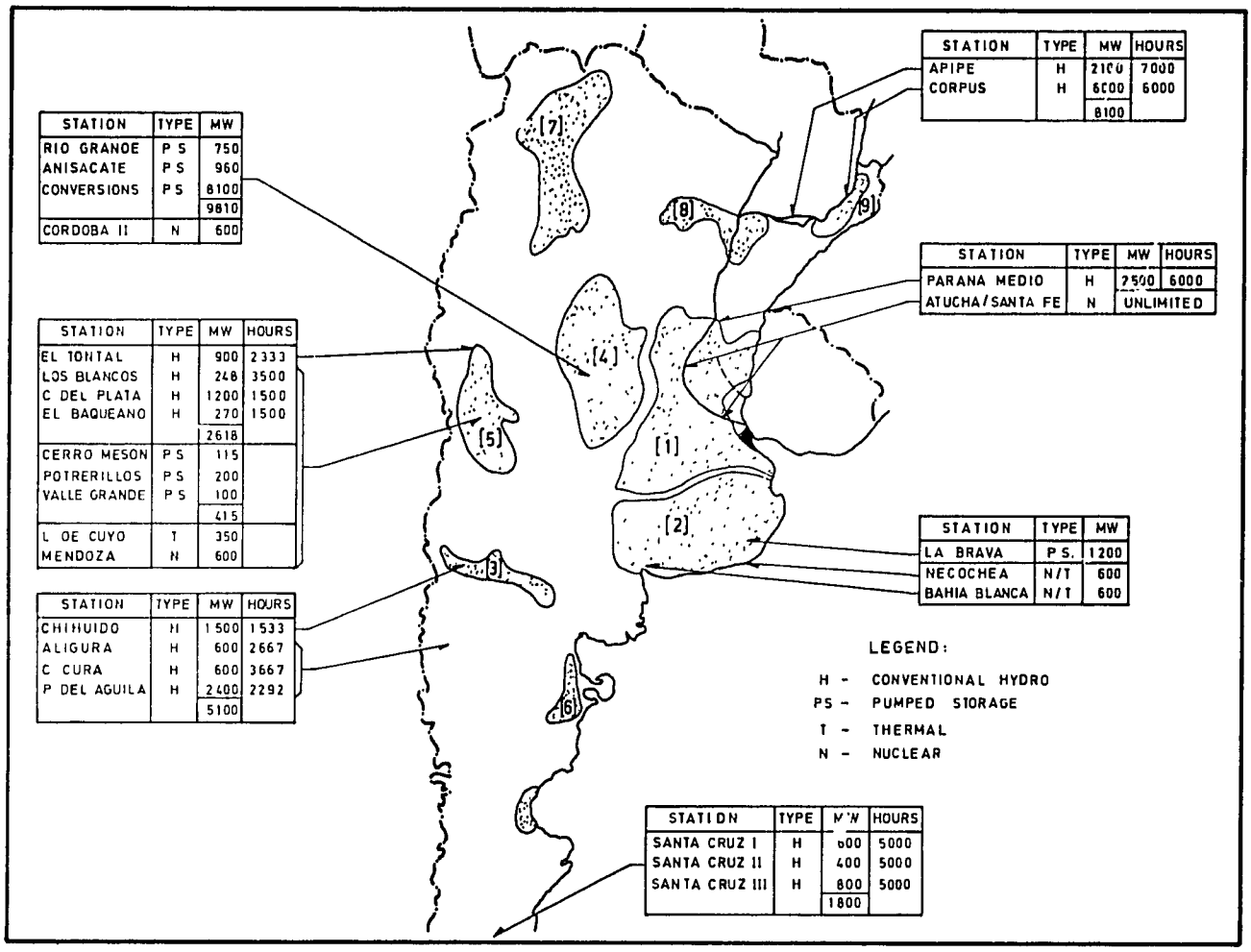


FIG. 5-4. LOCATION OF POSSIBLE FUTURE POWER STATIONS

TABLE V-6. CNEA NUCLEAR POWER PLANT PROGRAM

Station name/unit	Capacity (MW)	Year of operation
Atucha-1	319	1973
Córdoba-1	600	1978
Bahía Blanca-1	600	1979-80
Atucha-2	600	1980-81
Atucha/Santa Fe-3	600	1982
Mendoza-1	600	1983
Atucha/Santa Fe-4	600	1984
Córdoba-2	600	1985
Necochea-1	600	1986
Atucha/Santa Fe-5	600	1987
Atucha/Santa Fe-6	600	1988
Atucha/Santa Fe-7	600	1989
Atucha/Santa Fe-8	600	1989
Total	7 519	

Although not finally decided, the effect is shown, as the last item in Part 1, of linking the Cuyo and Patagonia systems to the interconnected system which would then comprise 9341 MW of committed plant. Over 2000 MW of new plant would be needed to make up the projected effective capacity requirement of 11 500 MW for 1980 (see Table V-3). This could be provided by the three projects marked (a) in Part II of the table, by Salto Grande (which is included in the committed plan for 1972-78) and by an additional nuclear unit.

In considering the prospective selection of projects for the period 1980-90, there are two points of particular importance:

(i) A law has recently been enacted under which all new thermal stations (or extensions of existing stations) on the sea coast or on rivers accessible by sea must burn coal. However, oil-burning stations will still be permissible inland.

(ii) Provision must be made for economically meeting the increasing requirement of base-load energy.

It will be seen that the conventional hydro projects listed in Part II of Table V-5 have a total average annual output of nearly 92 000 GWh. Omitting the output of Alicura and Los Blancos, which are assumed to be needed by 1980, and of Santa Cruz I, II, III on account of their remote location in southern Patagonia, there remains about 80 000 GWh which falls only slightly short of the projected 84 500 GWh increase in energy requirement of the interconnected system between 1980 and 1990 (from Table V-1). However, 50 700 GWh corresponds to two projects, Apipé and Corpus. Apipé, for which a feasibility study is under way, has been under international negotiation for 30 years. No negotiations have been initiated for Corpus, and the studies are preliminary and only deal with technical problems. Both projects are on international rivers and negotiations to date have not been easy. The only comparable experience is that with Salto Grande, for which negotiations began 40 years ago and which is expected to become a project in 1973. It will therefore be essential to include a proportion of thermal and/or nuclear plant in the program.

In regard to the projected nuclear program, of which Atucha-1 is the first unit, Table V-6 summarizes current plans of CNEA up to 1989. Except for Atucha-1 all units are planned to be of 600 MW capacity.

5.4. Transmission planning

The committed program of main transmission lines includes:

(1) Two 500 kV single-circuit lines, each 1100 km long, from El Chocón to Ezeiza. The first line will be completed at the end of 1972 and the second at the end of 1973. When full compensation has been installed, this scheme will transmit 1650 MW, less a small local supply, from the hydro plants under construction at El Chocón and Cerros Colorados to Buenos Aires.

(2) A number of 220 kV lines in the SEGBA and DEBA areas to distribute the power received from El Chocón.

(3) A 220 kV double-circuit line, convertible to one 500 kV circuit, from Rosario to Río III, to be commissioned in 1973/74, to link the Córdoba region to the GBA-Litoral region.

(4) A 330 kV line in Patagonia, for commissioning in 1974, to supply an aluminium plant at Puerto Madryn, near the east coast, from a new 440 MW hydro station at Futaleufú in the west.

Later developments now under study are a 500 kV line from Mendoza to Río III to link the Cuyo and Córdoba regions, and 500 kV connections to Salto Grande and to the projected Córdoba nuclear station and Río Grande pumped storage station. 220 kV interconnections with Uruguay and Chile are also envisaged. The form of construction of the new 500 kV lines have not yet been decided.

These developments, together with those already committed, are shown geographically in Figs 3-6 and 5-5 and diagrammatically in Fig. 5-6.

These depict the national interconnected system provisionally planned for completion by 1977/80 and beyond. Figure 5-5 does not show the projected onnection between the Comahue and Patagonia regions which, although under consideration for 1977/80, is at a less advanced stage of investigation.

Plans for transmission line connections to the Noroeste, Noreste and Misiones areas are in an even less advanced stage of consideration; however, present thinking is that they will be installed in the 1980 - 1985 period as shown in Figure 3-5.

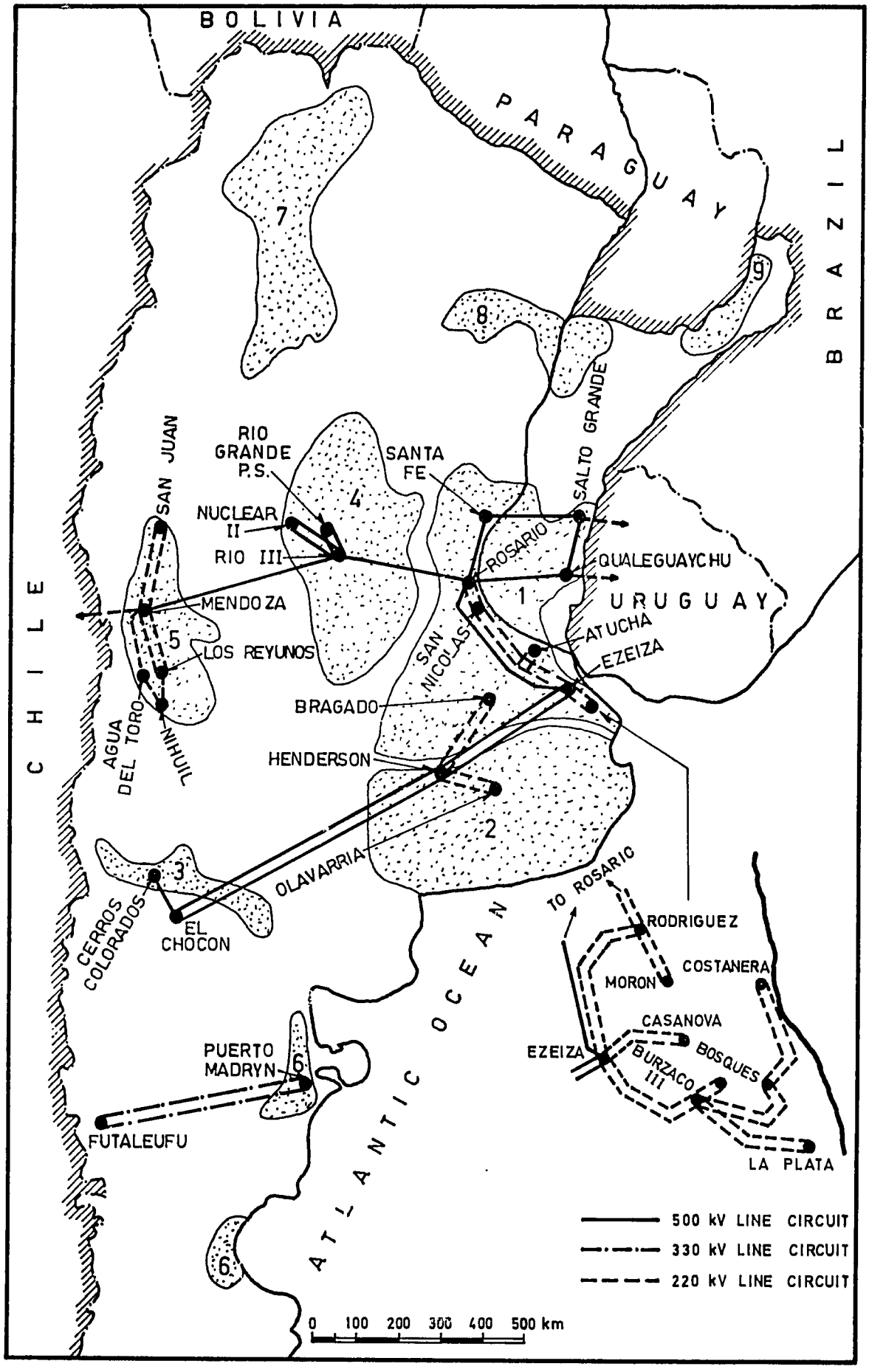


FIG. 5-5. TRANSMISSION LINES PLANNED FOR COMPLETION BY 1977/80

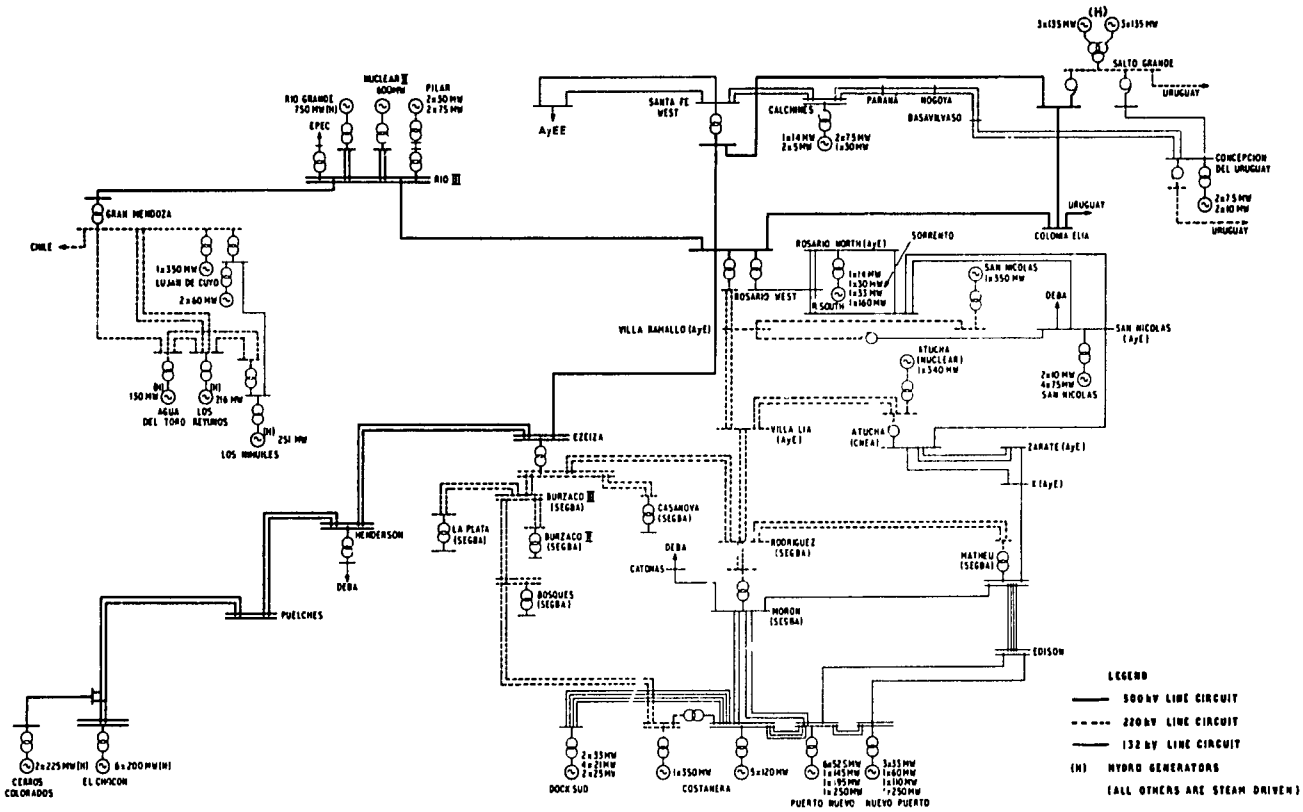


FIG. 5-6. SINGLE LINE DIAGRAM OF THE NIS IN 1977/80

5.5. Planned future reserve capacity

Methods of determining a suitable margin of reserve capacity for planning the national interconnected system are still at an experimental stage. Probability calculations have been made on the basis of several different risks of failure to meet the demand, assuming completely reliable transmission interconnections, and a method of making specific allowance for the forced outage risk of transmission circuits, as well as generators, is being investigated. These calculations lead to reserve requirement during 1975-80 ranging between 20% and 27% of the maximum demand.

The projections of maximum demand and installed capacity in Table V-3 lead to the reserve margins shown in Table V-7.

TABLE V-7. PROJECTED RESERVE MARGINS

Year	Reserve as % of projected max. demand
1976	26.6
1980	25.0
1985	20.0
1990	16.3
1995	12.7
2000	9.4[a]

[a] The country has noted that this low reserve figure would not be satisfactory.

6. NATIONAL CAPABILITIES AND LOCAL COSTS

6.1. Contribution of Argentine industry to power projects

Argentina is keenly interested in a large contribution by its own industry. Home-made equipment is generally given preference if the price is not too high in comparison with imported equipment.

The contribution of Argentine industry to the Atucha plant (a 319 MW HWR-type to be completed in 1973) was around 40%. It consisted mainly of civil engineering such as site preparation, earth moving, construction of buildings, welding and mechanical assembly of components. The Argentine contribution to civil works was about 90% of the total whilst it made up some 12% of the electromechanical part. A limited number of experimental fuel elements were fabricated by CNEA from domestic uranium. In addition, the fuel elements for the Argentine research reactors were totally fabricated by CNEA in its Nuclear Research Centre "Constituyentes" in Buenos Aires. There are plans to supply Atucha and future power reactors from a fuel element fabrication plant with an initial capacity of at least 50 t annually. A study for construction of a heavy water production plant is under way.

6.2. Targets for future local industrial participation in power projects

Argentina aims at a 50% contribution by domestic industry to the Córdoba Power Station, the second nuclear power plant to be built in the country. It is to be a 600 MW plant sited near Córdoba, the second most important industrial centre of the country.

The anticipated 50% contribution by national industry includes civil engineering work (as in the case of Atucha) which will amount to 13.5%. In addition, it is intended that some of the electronic equipment for the reactor control and safety system will be produced in Argentina.

The national targets for future industrial participation in the construction of nuclear power plants are given in Table VI-1 (average for the next four 600 MW nuclear power plants).

TABLE VI-1. NATIONAL TARGET FOR INDUSTRIAL PARTICIPATION IN NUCLEAR PLANT CONSTRUCTION

Nuclear steam supply system	64%
Turbo-generator and cooling circuit	28%
Electric system	90%
Instrumentation and control system	50%
Auxiliary installations	90%
Workshops and spare parts	59%
Subtotal; weighted average	59%
Engineering design	90%
Assembly on the site	95%
Civil works	98%
Start-up procedure, etc.	90%
Transport and insurance	83%
First core	66%
Total; weighted average	74%

6.3. Local construction costs and practices

Due to a rapid inflation, which is running at about 58% per year at present, figures for construction costs are not very significant for future projects. However, some indication of the wage levels in Argentina may be taken from the official minimum wage of 500 pesos/month (50 US$/month at the official rate of exchange, 10 pesos = 1 US$ in late 1972). Since wages are lower there than in highly industrialized countries, the tendency is to employ somewhat more labour for construction than is usual in North America or Western Europe. Exact figures on hourly costs of selected classes of labour were not available. CNEA estimates that labour costs considering rates and productivity in Argentina are roughly about 70% of those in the USA.

It was reported that experience with local labour was good. After proper instruction, the work was done well. For example the reject rate for welding parts was reduced to 1.5% at the Atucha site compared with 4% which is usual in industrialized countries. CNEA rates the labour efficiency in the country to be about 80% of that in the USA.

Costs of selected construction materials were not made available.

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

According to CNEA plans up to 1990, the following are regarded as possible sites for future nuclear power plants:

Paraná River (Atucha/Santa Fe area)
Córdoba
Bahía Blanca
Mendoza
Necochea

In Table VI-2 data are listed showing local grids, cooling and transportation media, and local seismic activities. Based on these data, the following comments can be given:

No major site problems are foreseen with the Atucha/Santa Fe area, Bahía Blanca, and Necochea areas, because of their favourable location relative to the load centres of the interconnected national grid, the virtually unlimited cooling capacity, easy transportation of heavy equipment by ocean-going ship directly to the site, and very low seismic activity.

As for the Córdoba site, problems of transporting parts of the pressure vessel or other heavy equipment by rail or road may occur. Transportation by rail or road will cause additional costs. Furthermore, moderate seismic activity may occur, see Fig. 6-1. Fresh-water cooling from the Río Tercero reservoir will undergo stronger limitations than cooling from sea water or from the Paraná river.

TABLE VI-2. DATA ON POSSIBLE SITES FOR NUCLEAR POWER PLANTS

Proposed Site	Data on local grid		Cooling capacity	Method of transport	Seismic activity
	Capacity end of 1971 (MW)	Connection to GBL grid (yr)			
Atucha/Santa Fe area	2 921		Virtually unlimited	River	<0.1
Bahía Blanca	308	1973	Virtually unlimited	Ocean	<0.1
Córdoba	338	1973/74	Limited	Rail or road	0.12
Mendoza	551	1977/78	Limited	Rail or road	1
Necochea	308	1973	Virtually unlimited	Ocean	<0.1

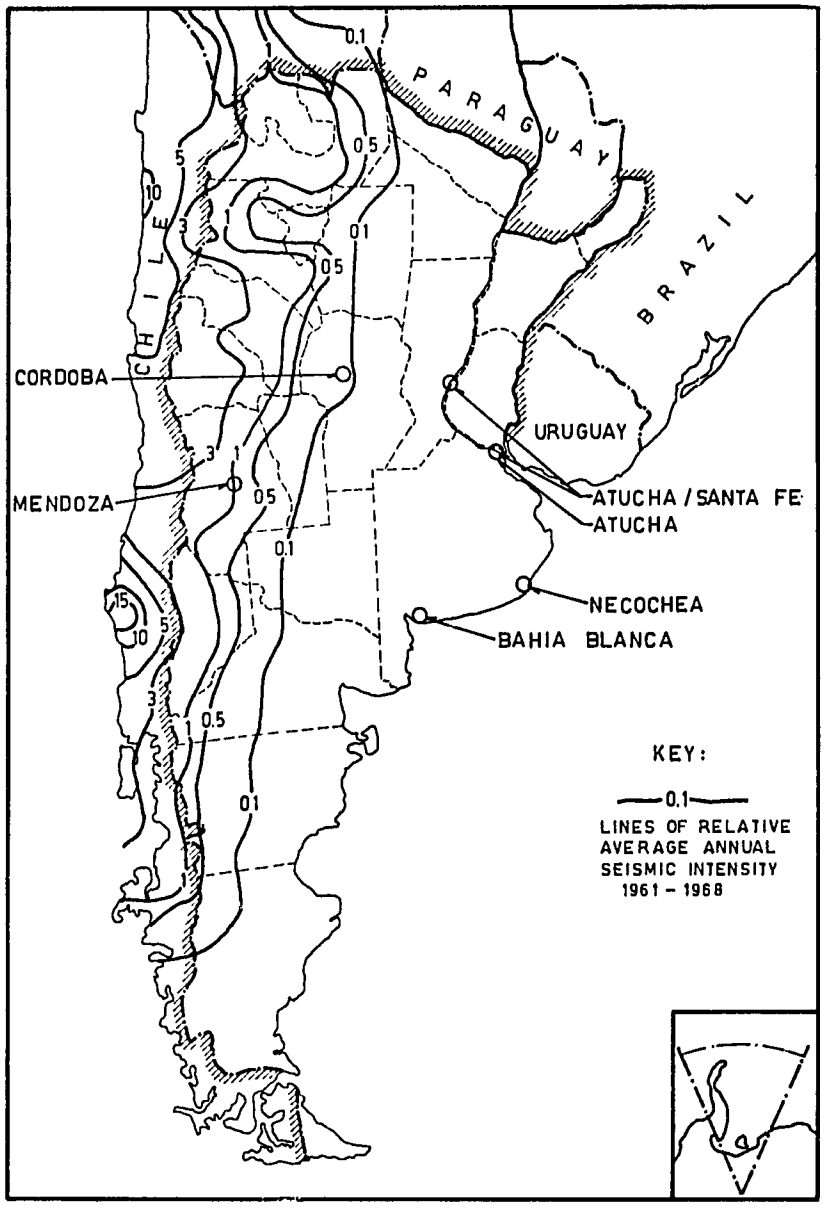


FIG. 6-1. LOCATION OF POSSIBLE FUTURE NUCLEAR STATIONS IN RELATION TO SURFACE SEISMIC ACTIVITY

At the Mendoza site more problems and additional costs than on the Córdoba site can be expected because of the greater seismic activity and longer distances for the transportation of heavy equipment by rail or road. The cooling capacity will also be limited, but for the Mendoza site no data were at hand regarding the amount of fresh water available for cooling purposes.

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

As can be seen in detail from Table VI-3, 170 persons are planned for the staffing of the Atucha nuclear power plant. Twenty of these have been trained in the Federal Republic of Germany in the special requirements of nuclear power plants. Table VI-3 also shows staffing estimates for future conventional and nuclear units together with anticipated personnel costs based on the salaries given in the same table.

TABLE VI-3. POWER PLANT STAFFING ESTIMATES

Name	Atucha	Córdoba	San Nicolás	San Nicolás
Type	Nuclear	Nuclear	Coal	Coal
Capacity	319 MW	600 MW	350 MW	75 MW
In service	1973	1978	1974	1957
Total staff	170	240	200	75
Professional	24	40	20	-
Technician	117	120	100	-
Auxiliary	29	80	80	-
(Trainees)	(50)			
Approximate number of persons /MW	0.5	0.4	0.6	1.0
Costs[a] (US $/yr)				
Professionals at 5 000 US $/yr	120 000	200 000	100 000	-
Technicians at 2 200 US $/yr	258 000	264 000	220 000	-
Auxiliaries at 1 000 US $/yr	29 000	80 000	80 000	-
Total	407 000	544 000	400 000	

[a] Salaries of operating personnel include overall services.

7. ECONOMIC AND FINANCIAL ASPECTS

7.1. Economic ground rules

In a country like Argentina where inflation has proceeded at an average annual rate exceeding 25% over the last decade with peaks of 68.8% as in the case of the last twelve months before November 1972, and a rate of foreign exchange periodically revised downward, estimating and comparing the present worth values of alternative investment schemes involving cash flows extending far into the future and different percentages of domestic and foreign currency components can only be an approximate procedure.

The approximation chosen at present consists of:

(a) translating all estimated domestic costs into US $ at the rate of exchange prevailing at the time of the feasibility study;
(b) assuming all foreign currency costs to remain at the constant levels estimated at the time of the study. General inflation is thus disregarded although provision may be made for special factors influencing the relative cash ratio of nuclear and fossil fuel prices;
(c) comparing the cash flows relevant to each alternative investment by discounting them to their present worth value at a relatively low rate of interest (8% at present).

This general approach together with other ground rules used in Argentina for economic comparisons of alternative electric power projects are summarized in Table VII-1.

TABLE VII-1. ECONOMIC GROUND RULES FOR THE FEASIBILITY STUDY FOR NUCLEAR PLANT USED IN ARGENTINA

Rate of present worth discount	8%
Rate of foreign exchange	Rate in effect at time of study
Rate of escalation on domestic currency construction cost component	Costs are expressed in US $ and not escalated for domestic inflation
Rate of escalation on foreign currency construction cost component	As given by bidder
Fossil and nuclear fuel costs	Projected in US $ without escalation for general inflation
O & M costs	Projected in US $ without escalation for general inflation
Insurance	
(a) Nuclear	0.8% of direct and indirect costs (Atucha) 0.25% of direct and indirect costs (Córdoba)
(b) Fossil	0.25% of direct and indirect costs
Interim replacements	
(a) Nuclear	1% of direct costs
(b) Fossil	1% of direct costs
Construction time	
(a) Nuclear plant	62 months
(b) Fossil plant	48 months
Life of plant (technical minimum)	30 years
Taxes	None
Custom duties	None

7.2. Current methods and sources of financing

In view of the variety of utilities with their widely different structures of expansion expenditures and the difficulty of predicting accurately who will be responsible for securing and coordinating financing of future nuclear power plants, an analysis of the sources and applications of funds by existing utilities would not be relevant. Consequently, the best approximate forecast is that given by the feasibility study for the Córdoba Nuclear Power Station, which is summarized in column 2 of Table VII-2.

If the national participation in construction costs were to be raised to 50% as projected by the CNEA, the share of foreign long-term financing would drop to 50% and that of domestic loans would have to increase to 20%.

TABLE VII-2. SOURCES OF FINANCING FOR NEW NUCLEAR PLANTS

	Up to 1980	1980 - 1990
Internal cash	30%	30%
National currency long-term loans	10%	20%
Foreign currency long-term loans	60%	50%

7.3. Foreign exchange considerations in evaluating capital and fuel costs

The process of rapid inflation which has been described in Section 1 of this report has been accompanied by a parallel though discontinuous worsening of the rate of foreign exchange. The average exchange rate of the Argentine peso to the US $ which was about 3.50 in 1969 increased to close on 10 in the second half of 1972.

Not surprisingly the inflow of long-term international credits has been inadequate in the recent past. This applies especially to loans from international lending institutions which supplied only 7% of total external credits in the 1960-70 period, the rest coming from suppliers, private financial institutions and to a lesser extent from bond issues in the international market.

The projections for external capital requirements are a function of the GNP and the export growth targets forecast. If the targets of the present development plan are achieved, the external public debt of the country would only grow from 2090 million US $ in 1971 to 2570 million US $ by 1976; the external capital requirements in the latter year would be of the order of 630 million US $ compared with 3360 million US $ worth of exports of goods and services, giving an acceptable ratio of 1 to 13.

The desirability of this achievement is reinforced by the fact that Argentina's credit worthiness has suffered in the past by the difficulties of meeting outstanding obligations and on three occasions debt service has proven unmanageable and obligations had to be renegotiated.

In any event, there is little expectation of full stability of foreign exchange in the immediate future. In these conditions the only practical approach to bringing foreign and domestic expenditures to a common denominator for purposes of economic comparison of alternative projects seems to be in a conversion of the domestic component into hard currency at the rate prevailing at the time of the feasibility study, a procedure which was already mentioned as one of the main ground rules in 7.1.

7.4. Taxes and duties

For the purpose of economic feasibility studies at the national level, no taxes and duties are taken into account, except for those duties which form part of salaries, labour and internal prices of the national industry.

8. ADMINISTRATIVE AND REGULATORY

8.1. Organization of the Atomic Energy Commission

The Comisión Nacional de Energía Atómica (CNEA) is an autonomous agency reporting directly to the Presidency of the Nation. It has no direct connection with other governmental authorities. The CNEA was established in May 1950 by decree No.10986/50. The present structure as a National Commission was effected in 1956 (decree No.2498).

The objectives of the CNEA are:

(a) to promote and conduct research, and scientific and industrial applications of nuclear transmutations and reactions,
(b) to exert any needed control over the applications referred to in the preceding paragraph, for reasons of public usefulness or to prevent any damage they may cause.

CNEA is divided into seven divisions and three departments. The divisions are concerned with

Raw materials,
Technology,
Safety and Health Physics,
Research and Development,
Applications of Nuclear Energy,
Infrastructure of CNEA, and
Finance,

the departments are

Nuclear Programs,
Organization and Methods, and
Feasibility Studies for Nuclear Stations.

The nuclear research centre Bariloche (1600 km southwest of Buenos Aires) is operated by the Division of Research and Development.

The organization chart is given in Fig. 8-1. The main headquarters of CNEA are at Buenos Aires. CNEA now employs about 3000 persons (1000 scientists and technicians, 2000 auxiliary workers).

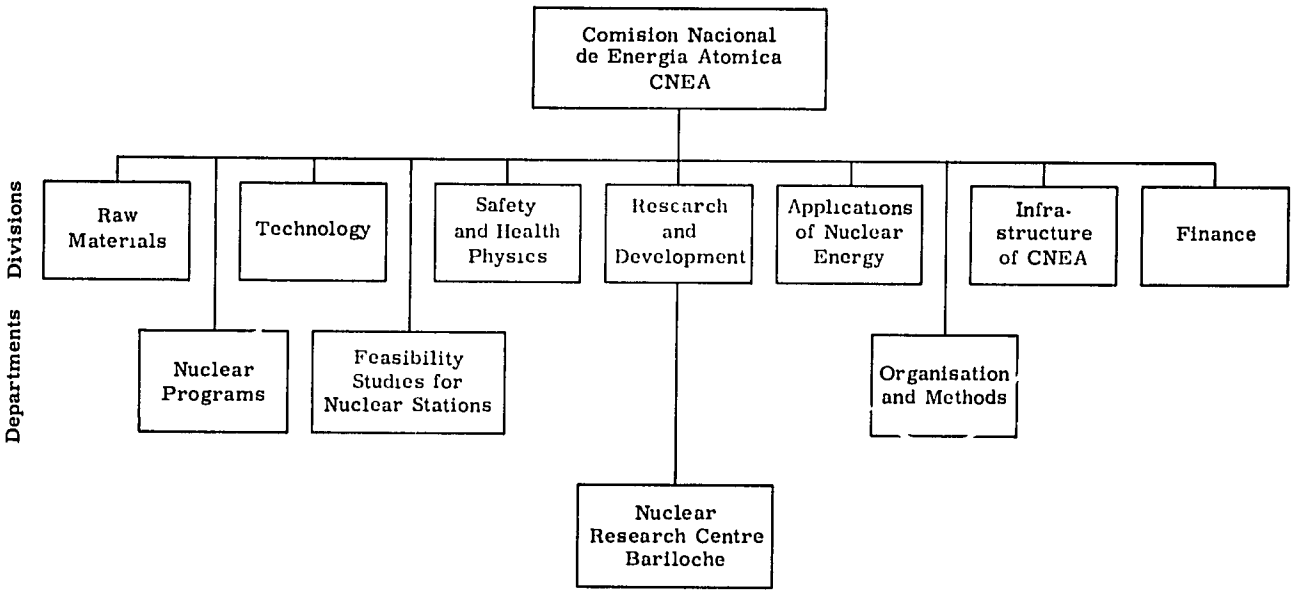


FIG. 8-1. ORGANIZATION CHART OF THE CNEA

8.2. Relationship of Atomic Energy Commission to other interested organizations

CNEA is supervised directly by the Presidency. According to the organization scheme (Fig. 3-1) issued to the visiting team, CNEA has no direct official connection with other governmental authorities or public utilities.

Planning of the country's total energy supply is carried out by the Subsecretary of Energy (SSE) which belongs – among other planning authorities – to the Ministry of Public Works. SSE is responsible for the management of the national coal, oil and natural gas resources, as well as electricity supply of the Gran Buenos Aires region. There are connections to the regional energy agencies. Figure 3-1 indicates these connections to the Buenos Aires and Córdoba agencies (DEBA and EPEC).

It should be mentioned that CNEA is in the unique position of having full responsibility for the Atucha nuclear power plant. The power produced will be sold directly to the utilities by the Commission for transmission and distribution in the Gran Buenos Aires region. For the next nuclear stations CNEA will retain full responsibility for the nuclear fuel cycle and safety aspects and construction too, although operation responsibility has not been decided.

8.3. Regulatory bodies and procedures for licensing and safety assessment

According to the law that established CNEA and fixed its objectives, licensing and safety assessments are done by bodies of CNEA. The CNEA Division of Safety and Health Physics is concerned with safety assessment, while reactor licensing is done by the Assessment Committee for Nuclear Reactor Licences, which is staffed by members of the following divisions: Safety and Health Physics, Applications of Nuclear Energy, and Technology.

8.4. Nuclear legislation

The first act of nuclear legislation in Argentina happened as early as 1945, when export of uranium minerals was prohibited by decree No. 22 855. CNEA has been authorized to draft nuclear legislation and regulations. The CNEA set up basic safety regulations and health physics standards in 1966 following the patterns of legislation in other countries.

9. ANALYTICAL APPROACH

9.1. Approach and bases of analysis

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

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

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

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

9.2. Description of computer programs

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

(a) Wien Automatic System Planning Package (WASP)

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

The data required for this analysis are as follows:

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

(ii) Fixed system description – consisting of a list of the generating units that will be in operation at the start of the first study year (1979), their maximum and minimum operating levels, their minimum load and incremental heat rates, 1 January 1973 fuel costs, expected scheduled and forced outage rates, and expected operating and maintenance costs. The description also includes data on the retirement of existing plants, on specific firmly planned additions and on seasonal factors affecting the operation of the hydro units in the system.

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

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

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

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

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

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

(b) Capital cost program

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

(c) Polynomial regression program

Load duration curves were obtained from the Office of the Sub-Secretary of Energy. The WASP program requires quarterly load duration curves expressed as the coefficients of a fifth order polynomial. The coefficients were calculated by a least-squares curve-fitting program that is described in more detail in Appendix C. The coefficients and the actual shapes of the quarterly load duration curves defined by the polynomial expressions are shown and discussed in Section 10.

9.3. Economic methodology and parameters

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

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

	Study values	Equivalent real values (at 4% inflation)
Discount rate	8%	12%
Capital cost escalation rate	0%	4%
Oil and gas price escalation rate	2%	6%
Nuclear fuel price escalation rate	0%	4%
Depreciation schedule	Linear	
Loss-of-load probability (fraction)	Maximum - 0.0025	
	Average - 0.0011	
	Minimum - 0.0004	

The fuel oil costs are those prevailing in the Persian Gulf at 1 January 1973, plus ocean and inland transport costs.

9.4. Technical methodology and parameters

The plants considered for expansion alternatives for Argentina were as shown in Table IX-1. However, except for the first two years of the study (1979 and 1980) when specific coal-fired plants were considered to be a distinct possibility, it was assumed that all conventional thermal plant expansion would be with oil-fired plant units. (If coal-fired plant units are built instead they are assumed to burn Río Turbio coal at a price which gives a fuel price equivalent to that of oil-fired plant units, since it was not the purpose of this study to establish the relative market for different types of conventional plant units in Argentina.)

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

Type of plant	Rated capacities (MW)
Coal-fired	400, 600, 1 000
Oil-fired	400, 600, 800, 1 000
Nuclear	400, 600, 800, 1000
Gas-turbine	100

While a large number of hydro projects are possible in Argentina, some of these involve international waters and it is difficult to predict the timing when negotiations may be completed; others have not been studied sufficiently to establish the date of operation. Firm data were available on the Salto Grande project located on the border between Argentina and Uruguay, and in this study it was assumed that two 135 MW units would enter service in each of the years 1980, 1981 and 1982 (i.e. a total of 810 MW, this being Argentina's total share of the project). It was further assumed that other hydro projects, totally within Argentina, would be placed in service during the balance of the study decade with an average capacity of 300 MW being added in each of the years 1983 through 1989.

The pumped storage project of 750 MW at Río Grande was assumed to become operational in the study decade with one unit of 150 MW generating capacity entering service in 1980, three units in 1981 and the fifth unit in 1982.

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

9.5. Sensitivity studies

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

	Study values	Equivalent real values (at 4% inflation)
Discount rate	6% & 10%	10% & 14%
Oil price escalation rate	0% & 4%	4% & 8%

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

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

10. FORECASTS OF SYSTEM LOADS AND LOAD DURATION CURVES

10.1. Review of load forecasts

(a) Study forecast

Table X-1 shows the results of the Market Survey forecast including the historical data used as a basis for the forecast. It is to be noted here that this forecast includes the energy (kWh) projections for both the total country and for the utilities only. However, the country presently is divided into a number of regions most of which are not interconnected although there is a long-range plan to ultimately interconnect most of these. The separate regions and the planned dates of interconnection are shown in Fig. 3-6.

In order to obtain the correct peak demand (MW) for the years of the study period and 1990-2000, a forecast was prepared taking account of the fact that individual systems would be added to the basic interconnected system at specific dates in the future. Thus, using the basic kWh forecasts of Table X-1 and the known relationships of the total public utility and interconnected system generation to the total country generation, the forecast shown in column 7 of Table X-2 was prepared. The detailed projections of energy production by region by year are shown in Table X-3.

Using the energy forecast for the actual interconnected system (Table X-2, column 7) and an assumed load factor of 0.58 (see Section 10.1 (c)), the peak demand for the interconnected system was calculated as shown in Table X-2, column 10.

(b) SSE forecast

Tables V-1 and V-3, respectively, show projections of gross generation and peak demand until 2000 as provided by the Sub-Secretary of Energy (SSE). It can be noted that the SSE projections give the same electrical energy requirement of 25 000 GWh for the interconnected system in 1976 as assumed in the Market Survey forecast for this year; thus the SSE peak demand forecast for 1976 of 5055 MW is close to the Market Survey forecast of 4920 MW (Table X-2). The SSE and Market Survey forecasts assume load factors of 56.5% and 58%, respectively.

Thereafter, however, the Survey forecasts show a progressively lower level than the SSE forecasts (in 1980 and 1985 the Survey forecasts of energy from column 7 of Table X-2 are 41 800 GWh and 61 300 GWh compared with SSE forecasts for these years of 46 500 GWh and 82 500 GWh as shown in Tables X-2 and V-1.

(c) System load factor

Historical data on annual load factors are given in Table IV-6 for the SEGBA system which represented half of the public utility generation in 1971. It averaged 57% in the years 1969-71 inclusive.

Historical load duration data for 1971 for four of the six systems which will be interconnected by 1980 are given in Table IV-7. In Table V-4 these data have been extrapolated at the assumed growth rates given in Table V-2 to arrive at the projected load duration curves for 1980.

By the calculation method shown in Table X-4, it is possible to arrive at an assumed instantaneous peak demand of 8432 MW for the four systems included in Table V-4. The energy associated with these four systems was projected by SSE as 42 600 GWh (from computer data provided to the mission) giving a projected load factor of 57.7% for 1980 based on the systems given in Tables IV-7 and V-4. The addition of Cuyo and Patagónico Centro (which will be joined in 1979) will represent a small per cent of the national interconnected system in 1980 Thus, it can be assumed that the same load factor will apply for the total interconnected system including Cuyo and Patagónico Centro.

It was noted that Table V-3 gives a maximum demand of 9200 MW for the interconnected system in 1980 (i.e. six sub-systems). The energy requirement for 1980 given in Table V-1 is 46 500 GWh giving a calculated load factor of 57.7%. Other calculated load factors are given in Table X-5. Based on these values, a load factor of 58% was assumed for the complete study period.

TABLE X-1. FORECASTS OF GROSS ELECTRICAL ENERGY GENERATION[a]

	1960	1965	1968	1970	1975	1980	1985	1990	1995	2000
Population (10^6)	20.01	21.68	22.67	23.36	25.25	27.30	29.50	31.80	34.25	36.89
Annual growth rate	1.6	1.5	1.5	1.6	1.6	1.6	1.5	1.5	1.5	
Gross National Product										
GNP/capita (1964 US$)	681	756	770	802	1 000	1 205	1 420	1 670	1 970	2 280
Annual growth rate	2.1	0.6	2.1	4.5	3.8	3.3	3.3	3.0	3.0	
Gross electric generation										
kWh/capita	505	696	794	930	1 430	2 000	2 500	3 120	3 850	4 720
kWh (10^6) - Total	10 100	15 100	18 000	21 700	[illegible]	54 800	73 700	99 100	132 000	174 000
- Public utilities	7 864	11 255	13 500	16 807	29 500	47 700	65 000	87 200	117 000	157 000

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

TABLE X-2. DEVELOPMENT OF THE GROSS GENERATION AND PEAK DEMAND FORECAST FOR THE NATIONAL INTERCONNECTED SYSTEM

	Gross generation									
	Year	Country total (10^6 kWh)	Public utility (10^6 kWh)	Ratio columns 3:2	Sum of nine systems (10^6 kWh)	Ratio columns 5:2	Actual interconnected system (10^6 kWh)	Ratio columns 7:2	Load factor for interconnected system	Peak demand for interconnected system (MW)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	1960	10 146	7 864	0.775	7 162	0.706	5 824	0.574		
	1961	10 958	8 608	0.786	7 888	0.720	6 363	0.581		
	1962	11 887	8 756	0.737	7 993	0.672	6 332	0.533		
	1963	12 459	9 144	0.734	8 342	0.670	6 619	0.531		
	1964	13 817	10 232	0.741	9 283	0.672	7 293	0.528		
	1965	15 085	11 255	0.746	10 190	0.676	7 892	0.523		
	1966	15 927	11 696	0.734	10 739	0.674	8 228	0.517		
	1967	16 686	12 417	0.744	11 432	0.685	8 768	0.525		
	1968	17 953	13 506	0.752	12 399	0.691	9 468	0.527		
	1969	20 014	15 237	0.761	14 127	0.706	10 658	0.533		
	1970	21 727	16 807	0.774	15 555	0.716	11 541	0.531		
	1971	23 623	18 658	0.790	17 234	0.730	12 622	0.534	0.577	2 488
%/yr increase		8.01	8.23		8.36		7.4			
	1972	26 200	20 900	0.798	19 300		14 100	0.538	0.58	2 780
	1973	29 200	23 500	0.805	21 700		17 100	0.582	0.58	3 370
	1974	32 400	26 300	0.812	24 300		20 500	0.642	0.58	4 030
	1975	36 000	29 500	0.819	27 300		22 700	0.644	0.58	4 470
	1976	39 200	33 100	0.845	30 600	(0.845 x 0.925)	25 000	0.658	0.58	4 920
	1977	42 600			33 500		26 500	0.660	0.58	5 210
	1978	46 300			36 700		28 800	0.657	0.58	5 670
	1979	50 400			40 200		38 100	0.756	0.58	7 500

TABLE X-2. (cont.)

Year	Gross generation: Country total (10^6 kWh)	Public utility (10^6 kWh)	Ratio columns 3:2	Sum of nine systems (10^6 kWh)	Ratio columns 5:2	Actual interconnected system (10^6 kWh)	Ratio columns 7:2	Load factor for interconnected system	Peak demand for interconnected system (MW)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1980	54 800	47 700	0.87	44 100	(0.87 x 0.926)	41 800	0.763	0.58	8 230
1981	58 100	50 900		47 100		44 700	0.769	0.58	8 800
1982	61 700	54 200		50 200		47 500	0.770	0.58	9 350
1983	65 500	57 700	0.881	53 600	(0.881 x 0.928)	53 600	0.818	0.58	10 500
1984	69 500	61 500		57 300	0.824	57 300	0.824	0.58	11 500
1985	73 700	65 000	0.882	61 300	0.832	61 300	0.832	0.58	12 000
1986						65 000		0.58	13 000
1987						69 000		0.58	13 500
1988						74 000		0.58	14 500
1989						78 000		0.58	15 500
1990	99 100	87 200	0.88	83 200	0.84	83 200	0.84	0.58	16 500
1991						88 000		0.58	17 500
1992						93 000		0.58	18 500
1993						99 000		0.58	19 500
1994						105 000		0.58	21 000
1995	132 000	117 000	0.89	111 000	0.845	111 000	0.845	0.58	22 000
1996						118 000		0.58	23 000
1997						125 000		0.58	24 500
1998						132 000		0.58	26 000
1999						140 000		0.58	27 500
2000	174 000	157 000	0.9	148 000	0.85	148 000	0.85	0.58	29 000

TABLE X-3. PROJECTION OF ELECTRICAL ENERGY PRODUCTION FOR INDIVIDUAL SYSTEMS AND INTERCONNECTED SYSTEM, 1971 - 1989 (10^6 kWh)[a]

Power market area	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
1. GBA-Litoral and Buenos Aires Norte	12 622	14 100	15 600	17 000	18 400	20 000	21 000	22 700	24 800	27 000	28 700	30 000	31 600	33 300	35 000	36 700	38 500	41 000	42 800
2. Buenos Aires Sud	714	900	1 100	1 400	1 600	2 400	2 700	3 000	3 300	3 700	4 000	4 400	4 800	5 300	5 800	6 200	6 700	7 300	7 700
3. Comahue (Alto Valle)	293	300	400	400	500	500	600	700	800	1 000	1 100	1 300	1 400	1 600	1 800	2 000	2 200	2 400	2 700
4. Córdoba	1 266	1 400	1 400	1 700	1 900	2 100	2 200	2 400	2 600	2 800	3 000	3 200	3 500	3 700	4 000	4 300	4 600	5 000	5 200
5. Cuyo	1 533	1 700	2 000	2 300	2 700	3 100	3 400	3 800	4 300	5 000	5 400	6 000	6 700	7 500	8 300	9 100	9 900	10 900	11 800
6. Patagónico Centro	86	100	200	400	700	1 200	2 100	2 200	2 300	2 400	2 500	2 600	2 600	2 700	2 800	2 800	2 900	2 900	3 000
7. Noroeste	474	500	600	700	800	900	1 000	1 100	1 300	1 400	1 500	1 600	1 800	1 900	2 100	2 300	2 400	2 600	2 800
8/9. Noreste and Misiones	246	300	300	400	400	400	500	800	800	900	900	1 100	1 200	1 300	1 500	1 600	1 800	1 900	2 000
Total of 9 individual systems	17 234	19 300	21 600	24 300	27 000	30 600	33 500	36 700	40 200	44 200	47 100	50 200	53 600	57 300	61 300	65 000	69 000	74 000	78 000
Total of interconnected systems	12 622	14 100	17 100	20 500	23 700	25 000	26 500	28 800	38 100	41 800	44 700	47 500[b]							

[a] Figures above the line indicate that the system is part of the interconnected system.
[b] In 1983 all 9 individual systems are assumed to be interconnected and both sums become the same.

TABLE X-4. CALCULATION OF PEAK DEMAND IN 1980 FOR FOUR INDIVIDUAL SYSTEMS OF THE INTERCONNECTED SYSTEM

	GBA-L	Córdoba	Cuyo	Buenos Aires Sud	Total
(1) Instantaneous peak demand 1971 (MW)	2488	250	290	276	-
(2) Highest 365 h period 1971 (MW)	2199	220	224	255	-
(3) Ratio (1) : (2)	1.131	1.136	1.295	1.082	-
(4) Highest 365 h period 1980 (MW)	5186	553	854	768	7360
(5) Instantaneous peak demand 1980 (MW) (4) × (3)	5865	630	1106	831	8432

TABLE X-5. SSE PROJECTED LOAD FACTORS FOR THE INTERCONNECTED SYSTEM

Year	Energy requirements (GWh)	Maximum demand (MW)	Calculated load factor
1971	12572	2488	57.7
1976	25000	5055	56.5
1980	46500	9200	57.7
1985	82500	15000	62.8[a]
2000	330000	64000	58.9

[a] Inconsistency not explainable by addition of Noroeste, Noreste and Misiones in 1983 since they only amount to an incremental increase of less than 6.0% of energy generation in 1985.

(d) Forecast used in the study

As noted above, the SSE forecast is substantially higher than the Survey forecasts of energy for the study period. Based on the assumed load factor of 58% the difference in peak demand is 970 MW in 1980 rising to 6500 MW by 1989. In view of the vast amount of hydroelectric capacity remaining undeveloped as described in Section 2.1, it was decided to use only the study forecast together with a modest hydroelectric program as discussed in Section 9.4. It was assumed that if a larger rate of growth were, in fact, to take place as forecast by SSE, the additional capacity required to meet the larger demand would be hydroelectric capacity. This is particularly true since the more rapid rate of growth would justify the introduction of larger blocks of such power over a shorter period making a number of these projects more attractive economically.

The maximum demand forecast used in the study was that shown in Table X-2, column 10.

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

(a) Study increment

In carrying out the computations associated with the load duration curves, it is necessary to select a "study increment" as discussed in Appendix C. For the forecast used in the study, this increment was taken as 100 MW.

(b) Peak load demand for each year of study

Peak load demand forecasts are shown in Table X-2, column 10.

(c) Seasonal peak load demands

The projected annual load duration data for 1980 given in Table V-4 were used, based on the assumed maximum instantaneous peak demand of 8400 MW, with the WANG Model 700

computer with plotter, to obtain coefficients of the fifth order polynomial describing the curve by the method described in Appendix C. The coefficients for the entire year are shown in the top line of Table X-6.

TABLE X-6. POLYNOMIAL COEFFICIENTS FOR ANNUAL AND SEASONAL LOAD DURATION CURVES

Period	Load factor	Coefficients					
		b_0	b_1	b_2	b_3	b_4	b_5
Year	0.579	1	-3.194 881	12.841 935	-25.485 405	22.488 265	-7.299 767
1st quarter	0.623	1	-2.958 504	11.891 811	-23.599 841	20.824 448	-6.759 686
2nd quarter	0.593	1	-3.193 929	12.838 109	-25.477 813	22.481 566	-7.297 592
3rd quarter	0.601	1	-3.131 149	12.585 763	-24.977 020	22.039 668	-7.154 150
4th quarter	0.621	1	-2.974 199	11.454 898	-23.725 039	20.934 922	-6.795 546

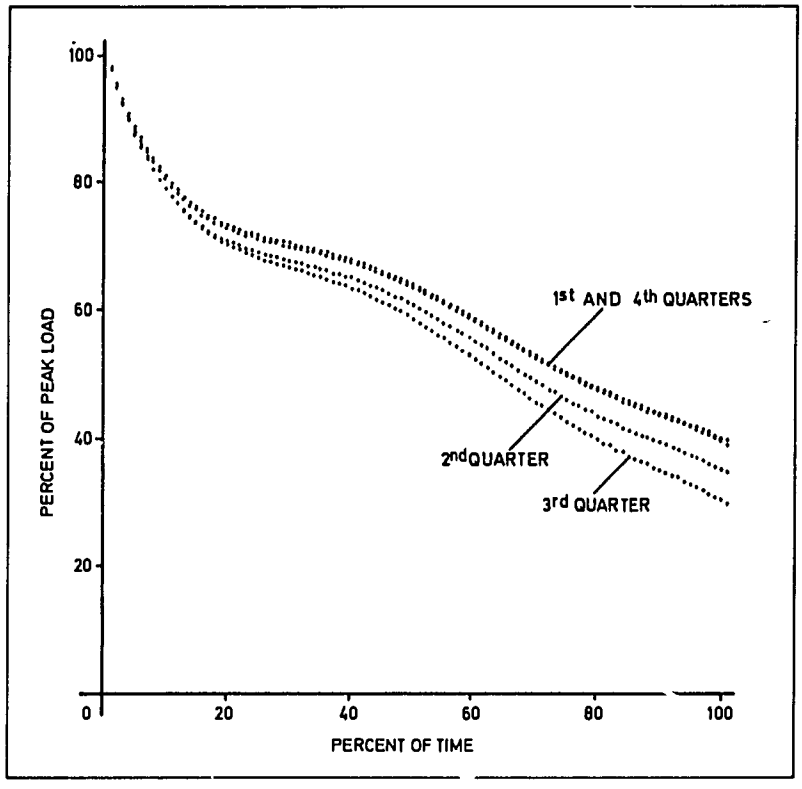


FIG. 10-1. QUARTERLY LOAD DURATION CURVES.

The data in Fig. 4-3 were used to estimate the quarterly load factors and these are shown in the second column of Table X-6. The coefficients, by quarters, associated with the adjusted polynomial curves to give these load factors are also given in Table X-6. The resulting computed annual load factor is 58.26% which is close to the 58% used in the projections of peak demand (Table X-2). The resulting quarterly load duration curves are plotted in Fig. 10-1.

The WASP program requires that quarterly peak load data be assumed. The factors relating the quarterly peak demand to the annual peak demand were based on the data provided in Table IV-8, and are as follows:

1st quarter	0.867
2nd quarter	0.989
3rd quarter	1.000
4th quarter	0.971

11. LIMITING FACTORS IN SYSTEM DEVELOPMENT

11.1. General philosophy

Interconnection of the various regions at 500 kV is proceeding, as outlined in Section 3.4 and Fig. 3-6. It is expected that Regions 1-6 will be linked by 1980, with Regions 7-9 following by 1985.

Figure 11-1 shows diagramatically the regional configuration and the principal 500 kV circuits which are assumed, for the purposes of this analysis, to exist in 1985 to 1989. (The connection to Regions 8 and 9 is likely to be at a lower voltage than 500 kV pending major hydro developments projected for after 1989.) The situation is assumed to be the same in 1980 except that Regions 7, 8 and 9 will not yet have been connected. 220 kV interconnections with Uruguay, via Region 1, and with Chile, via Region 5, are envisaged.

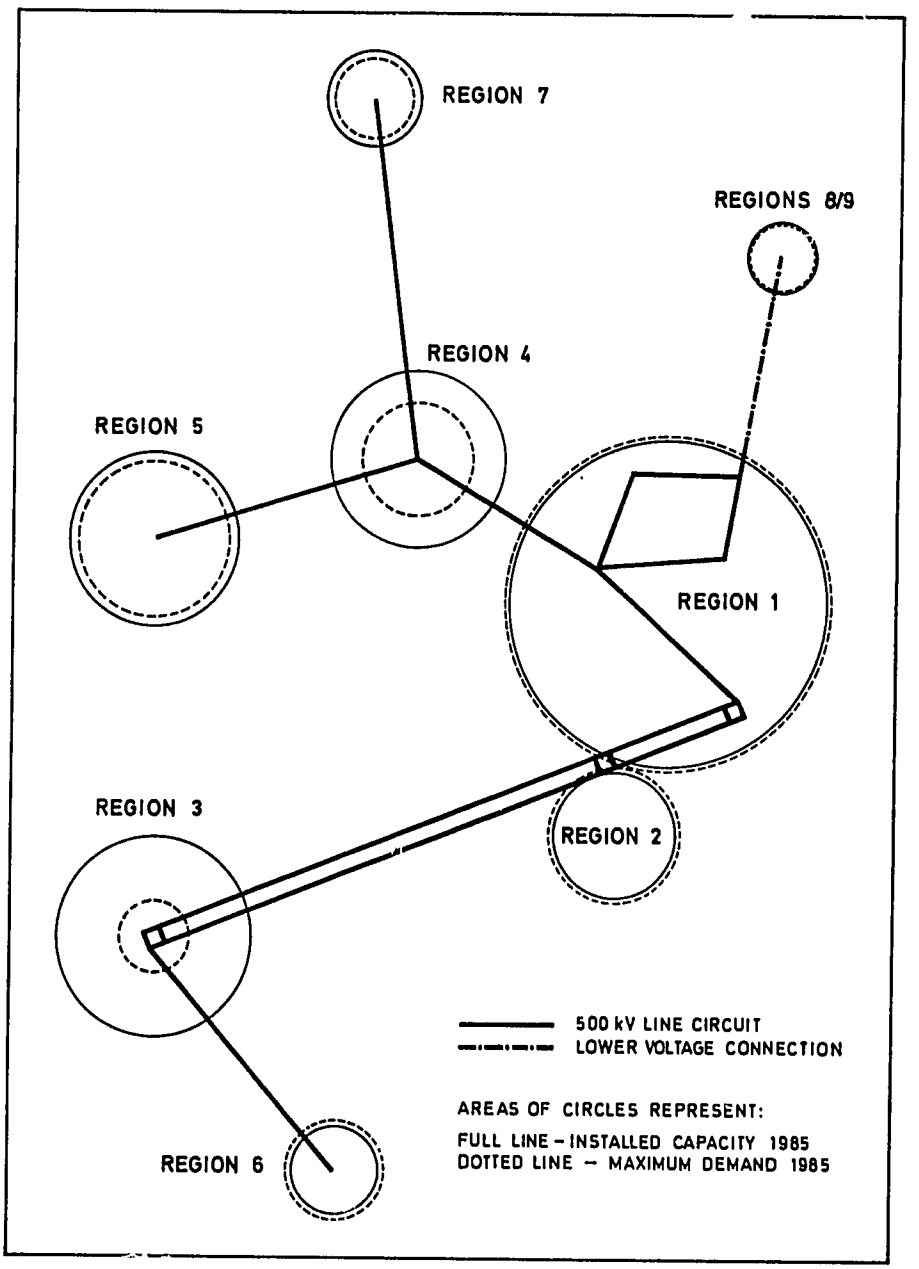


FIG. 11-1. REGIONAL CONFIGURATION AND PRINCIPAL 500 kV TRANSMISSION LINES 1985-89.

The areas of the full circles in Fig. 11-1 are proportional to expected regional installed capacity and of the dotted circles to regional maximum demand in 1985. Regions 1 and 2 together contain about half the total plant capacity and two-thirds of the total demand. The proportions in 1980 and 1989 do not differ greatly.

An important feature is the large transfer of hydro power from Region 3 to Regions 1 and 2. Apart from this and a substantial plant surplus in Region 4, resulting from 600 MW of nuclear power and 750 MW of pumped storage, no major regional imbalances of plant and load are foreseen during the study period.

The following studies are based on the assumed load projection and plant expansion program. Years 1980, 1985 and 1989 have been chosen for the frequency stability analysis and years 1980 and 1988 for the frequency stability studies, 1988 being the programmed year of introduction of a 1000 MW nuclear unit (800 MW having been introduced in 1986 and 600 MW before 1980).

11.2. Load flow/transient stability

Figures 11-2, 11-3 and 11-4 show plant/load balances at times of peak load in 1980, 1985 and 1989 respectively.

The breakdown of the total load between regions has been deduced for Regions 1-6 mainly from forecasts for the years 1977 and 1981 provided by the office of the Secretary of Energy, and for Regions 7-9 from current statistics.

Table XI-1 shows the assumed regional disposition of the new generating capacity to be installed from 1979 onwards. Unnamed nuclear and conventional thermal plants are identified on the plant/load balance diagrams (Figs 11-2, 3, 4) by programmed year of installation.

Regional generation has been assumed to be proportional to regional installed capacity without regard to type of plant. The resulting figures for regional import or export are thus approximate average expectations for peak load periods taken over the year as a whole, and will vary appreciably according to plant and water availability and economic loading. Consideration has been given, however, to the possible effects of 100% utilization of hydro and nuclear capacity and of below average plant availability in importing regions.

1980: 8230 MW peak load (Fig. 11-2)

The large import of Region 1 is met mainly by hydro export from Region 3, assisted by export from Region 4. The planned regional interconnection capacity is adequate.

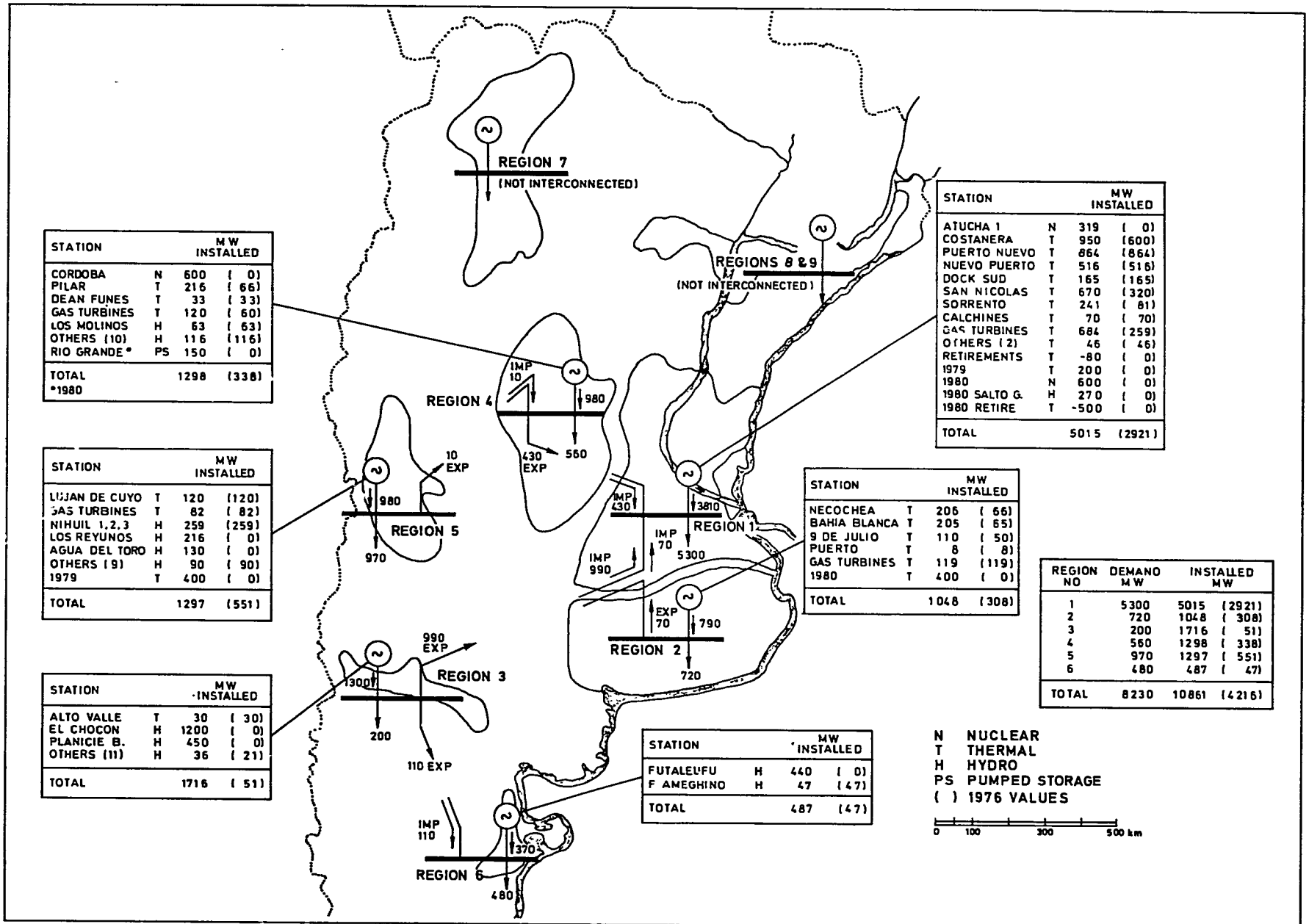
1985: 12000 MW peak load (Fig. 11-3)

The transfers between Regions 1, 2, 3 and 4 are substantially higher than in 1980. With full utilization of hydro capacity the peak load transfer from Region 3 to Regions 1 and 2 will approach 2000 MW (with possibly slightly more off peak), which exceeds the capacity of the two 500 kV lines. A third line outlet from Region 3 will therefore be required at this stage. By taking this to Region 5 an advantageous ring arrangement would be created. This would improve the security of Region 5 in particular, and generally permit greater freedom in the location of future new generating capacity.

The demand in Region 6 now exceeds the local installed generating capacity and there is dependence on import via the single 500 kV line from Region 3. Unless additional generating plant is installed, a transmission reinforcement will be required either from Region 3 or from a power source in Region 2, the latter arrangement possibly creating a second 500 kV ring.

1989: 15500 MW peak load (Fig. 11-4)

With the plant and load developments envisaged, the plant/load balance is very similar to that foreseen for 1985.



STATION		MW INSTALLED	
CORDOBA	N	600	(0)
PILAR	T	216	(66)
DEAN FUNES	T	33	(33)
GAS TURBINES	T	120	(60)
LOS MOLINOS	H	63	(63)
OTHERS (10)	H	116	(116)
RIO GRANDE*	PS	150	(0)
TOTAL		1298	(338)

*1980

STATION		MW INSTALLED	
LUJAN DE CUYO	T	120	(120)
GAS TURBINES	T	82	(82)
NIHUIL 1,2,3	H	259	(259)
LOS REYUNOS	H	216	(0)
AGUA DEL TORO	H	130	(0)
OTHERS (9)	H	90	(90)
1979	T	400	(0)
TOTAL		1297	(551)

STATION		MW INSTALLED	
ALTO VALLE	T	30	(30)
EL CHOCON	H	1200	(0)
PLANICIE B.	H	450	(0)
OTHERS (11)	H	36	(21)
TOTAL		1716	(51)

STATION		MW INSTALLED	
ATUCHA 1	N	319	(0)
COSTANERA	T	950	(600)
PUERTO NUEVO	T	864	(864)
NUEVO PUERTO	T	516	(516)
DOCK SUD	T	165	(165)
SAN NICOLAS	T	670	(320)
SORRENTO	T	241	(81)
CALCHINES	T	70	(70)
GAS TURBINES	T	684	(259)
OTHERS (2)	T	46	(46)
RETIREMENTS	T	-80	(0)
1979	T	200	(0)
1980	N	600	(0)
1980 SALTO G.	H	270	(0)
1980 RETIRE	T	-500	(0)
TOTAL		5015	(2921)

STATION		MW INSTALLED	
NECOCHEA	T	206	(66)
BAHIA BLANCA	T	205	(65)
9 DE JULIO	T	110	(50)
PUERTO	T	8	(8)
GAS TURBINES	T	119	(119)
1980	T	400	(0)
TOTAL		1048	(308)

STATION		MW INSTALLED	
FUTALEUFU	H	440	(0)
F AMEGHINO	H	47	(47)
TOTAL		487	(47)

REGION NO	DEMAND MW	INSTALLED MW	
1	5300	5015	(2921)
2	720	1048	(308)
3	200	1716	(51)
4	560	1298	(338)
5	970	1297	(551)
6	480	487	(47)
TOTAL	8230	10861	(4216)

FIG. 11-2. REGIONAL PLANT/LOAD BALANCE FOR MAXIMUM DEMAND OF 8250 MW (1980).

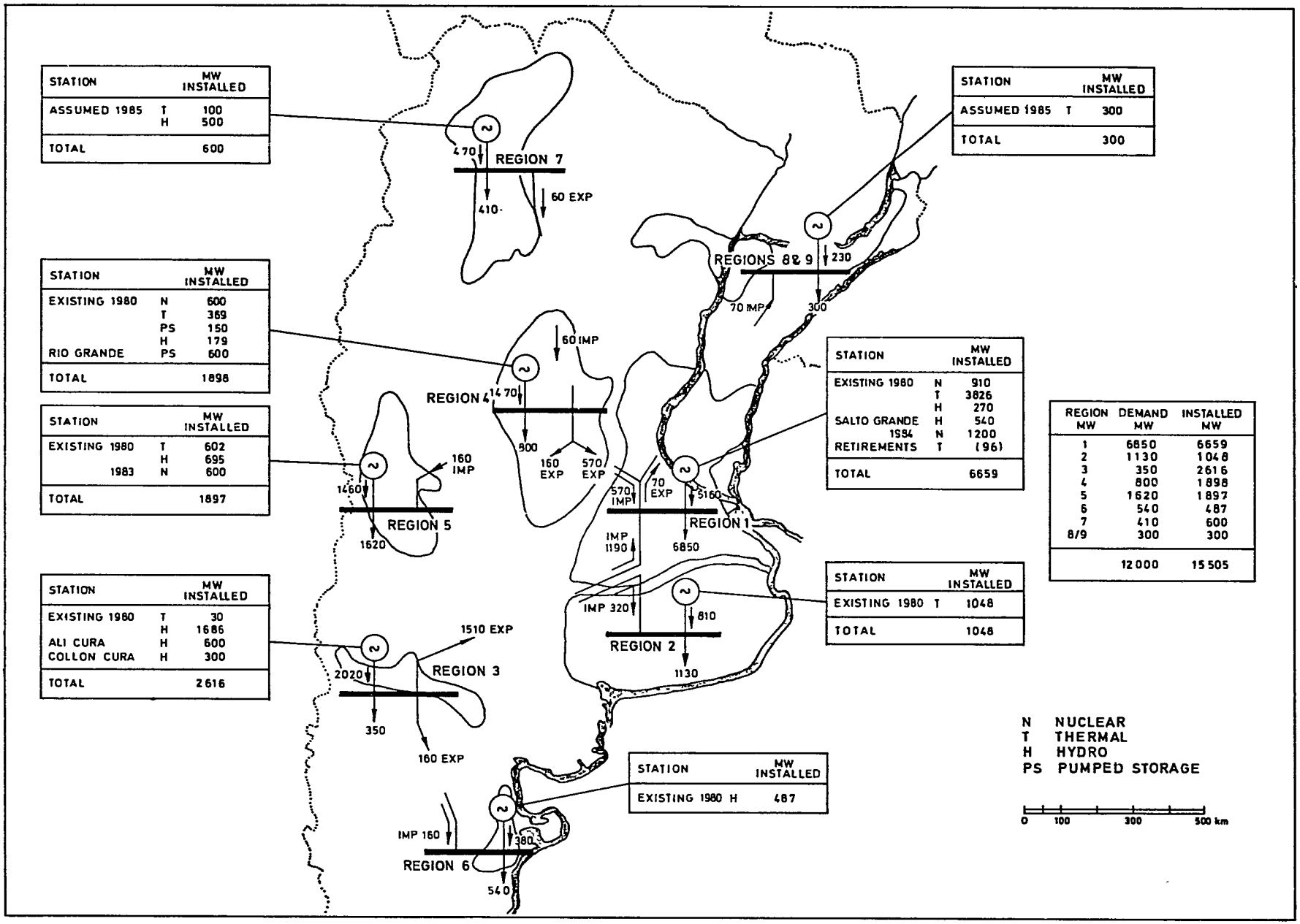


FIG. 11-3. REGIONAL PLANT/LOAD BALANCE FOR MAXIMUM DEMAND OF 12 000 MW (1985).

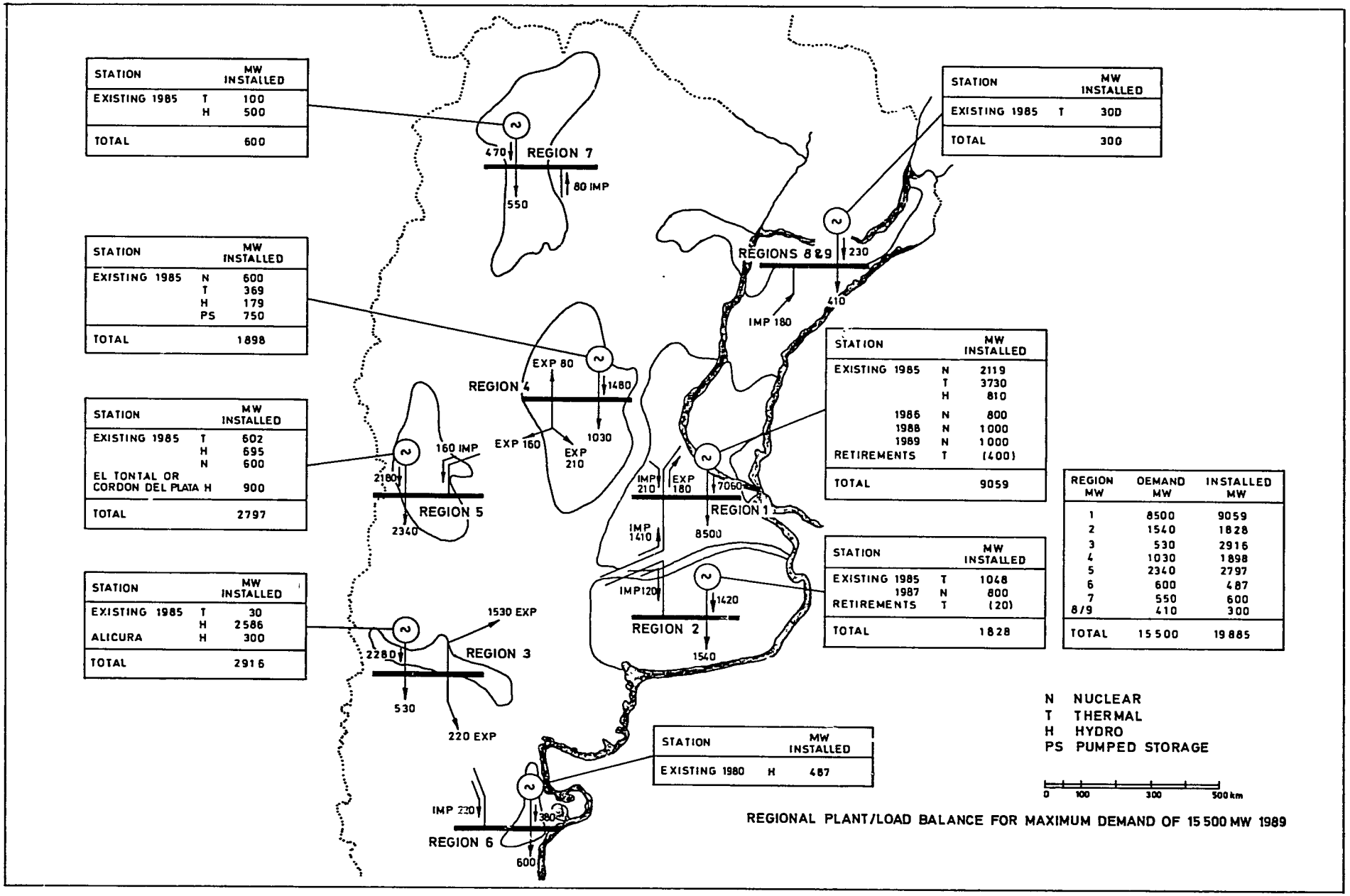


FIG. 11-4. REGIONAL PLANT/LOAD BALANCE FOR MAXIMUM DEMAND OF 15 500 MW (1989).

TABLE XI-1. ASSUMED REGIONAL DISPOSITION OF NEW GENERATING CAPACITY (from 1979)

Type	Year	Capacity (MW)	Location
Hydro	1980	2× 135	Region 1 (Salto Grande)
	1981 - 82	4× 135	Region 1 (Salto Grande)
	1983 - 84	4× 150	Region 3 (Alicura)
	1985	2× 150	Region 3 (Collón Cura)
	1986	2× 150	Region 3 (Collón Cura)
	1987 - 89	6× 150	Region 5 (El Tontal or Cordón del Plata)
Pumped storage	1980	1× 150	Region 4 (Río Grande)
	1981 - 82	4× 150	Region 4 (Río Grande)
Conventional thermal	1979	400	Region 5
	1979	200	Region 1
	1980	400	Region 2
Nuclear	1980	1× 600	Region 1
	1983	1× 600	Region 5
	1984	2× 600	Region 1
	1986	1× 800	Region 1
	1987	1× 800	Region 2
	1988 - 89	2×1000	Region 1

TABLE XI-2. RECOMMENDED LIMITS OF GENERATOR SIZE

Year	Maximum demand[a] (MW)	Maximum unit size (MW)
1980	8200	700
1985	12000	800
1990	16500	1000
1995	22500	1200
2000	30000	1500

[a] Rounded figures.

Conclusions

A 500 kV main transmission system, having circuit capacities of the order of 1500 MW, will be well able to meet requirements as now foreseen throughout the study period, including the accommodation of generator sizes up to the limits of 700 - 1000 MW shown in Table XI-2. The 1000 MW size, however, should preferably be confined to Region 1.

11.3. Frequency stability

The rate of fall of system frequency due to the loss of a large generator is limited initially by the quick response of the thermal plant and later by load shedding resulting from the operation of underfrequency relays. Recovery tends to be delayed until the slow response

of the hydro generation becomes effective. In general, therefore, the amount of effective thermal reserve capacity is more important than the amount of hydro reserve.

Effective thermal reserve, that is, the increase in output which is immediately available, is limited to a small proportion of the spinning reserve capacity and, for the generation mix chosen, is greater during light load than during peak load periods. Despite this advantage and the larger apparent total reserve, the reduced system inertia resulting from the significant reduction in system plant makes the system more sensitive to generation loss during light-load periods than at other times.

Load shedding as a function of underfrequency is an established practice which has been assumed to be retained for the future. The present proposed arrangement is four stages of load shedding: 300 MW at 49.5 Hz, 600 MW at 49.0 Hz, 200 MW at 48.5 Hz and 200 MW at 49.0 Hz. It was assumed that this arrangement would apply for 1980, but that for 1988 the underfrequency settings would be reduced by 0.5 Hz for all stages, the sizes of which remain the same in proportion to peak load.

1980

Two studies were carried out for light load and peak load conditions based on the loss of 600 MW, alternatively 800 MW, of generation depicting the loss of generator units of these ratings or larger partly loaded units.

Figures 11-5 and 11-6 are frequency/time characteristics corresponding to the loss of generation during the lightly loaded period with 3300 MW system load and spinning reserve capacity divided in the proportions of 750 MW hydro and 1270 MW thermal. One stage of load is shed when 600 MW of generation is lost and this compares with two stages operating to shed three times the amount of load when 800 MW of generation is lost.

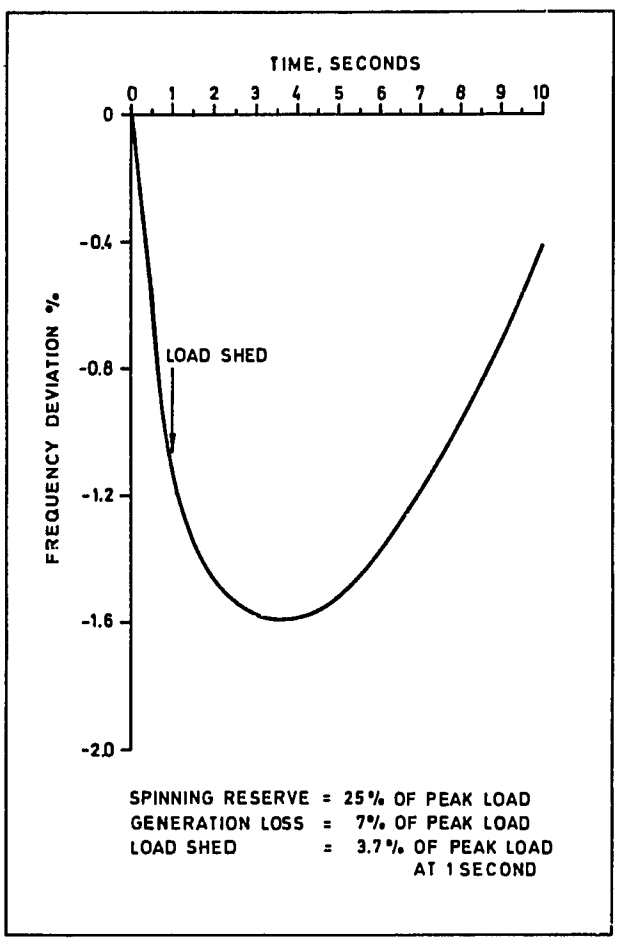


FIG. 11-5. SYSTEM FREQUENCY VARIATION FOLLOWING 7% GENERATION LOSS AT 1980 LIGHT LOAD.

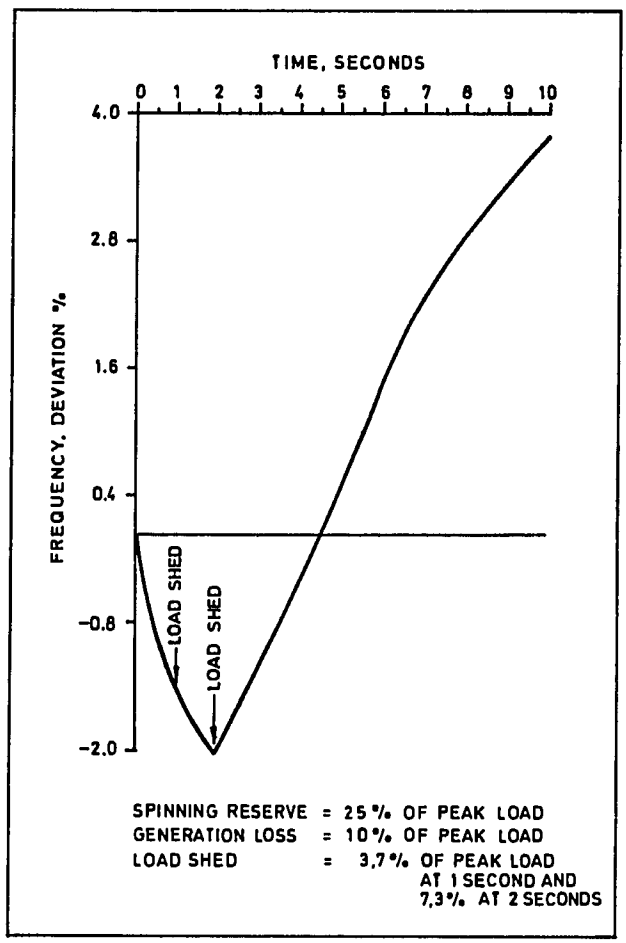


FIG. 11-6. SYSTEM FREQUENCY VARIATION FOLLOWING 10% GENERATION LOSS AT 1980 LIGHT LOAD.

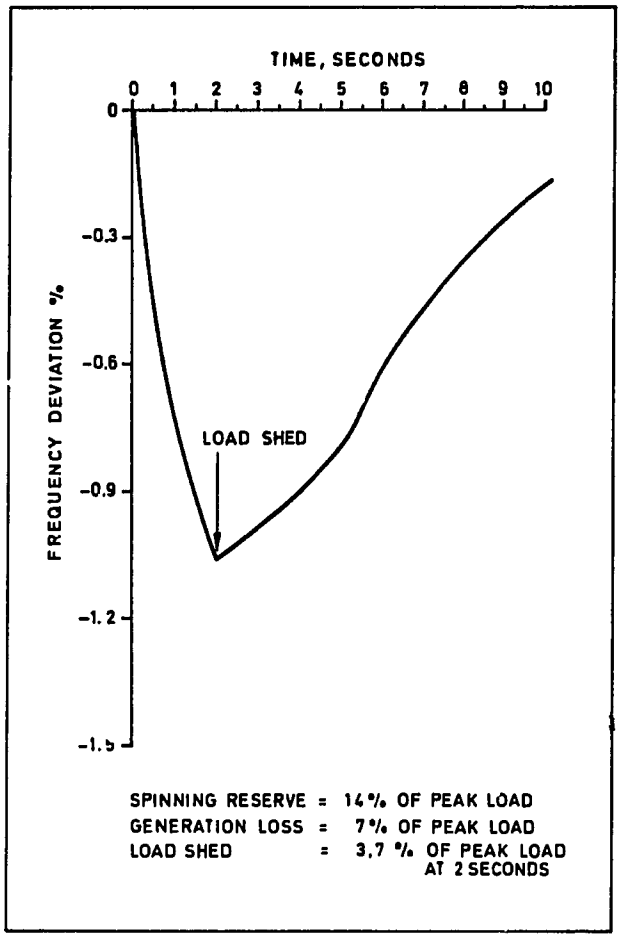


FIG. 11-7. SYSTEM FREQUENCY VARIATION FOLLOWING 7% GENERATION LOSS AT 1980 PEAK LOAD.

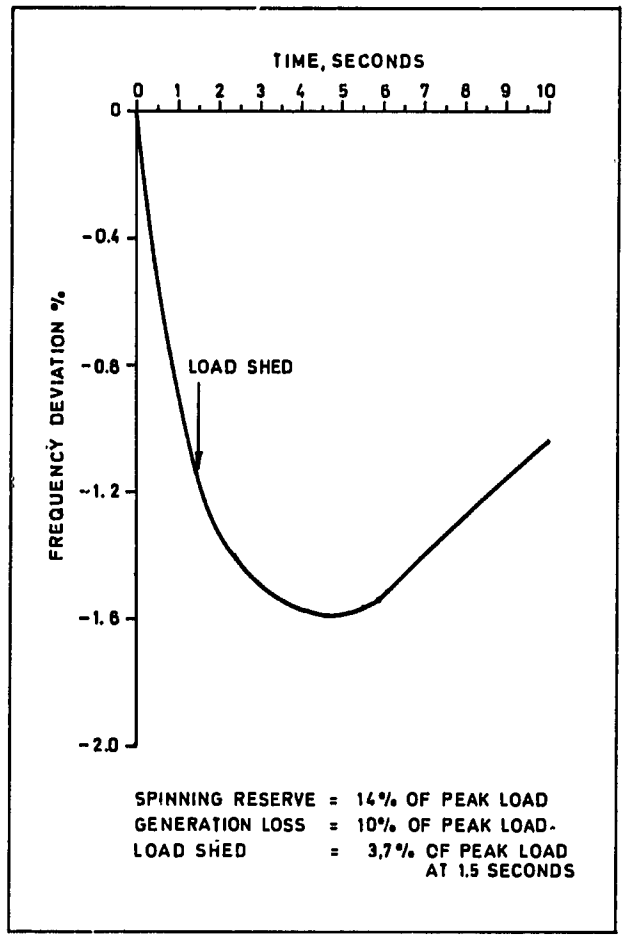


FIG. 11-8. SYSTEM FREQUENCY VARIATION FOLLOWING 10% GENERATION LOSS AT 1980 PEAK LOAD.

Conditions are easier during the peak period as shown by Figs 11-7 and 11-8, which give the frequency/time characteristics resulting from the dropping of 600 MW and 800 MW of generation respectively. For these conditions, system load is 8230 MW and the spinning reserve capacity is divided between 700 MW hydro and 429 MW thermal generation.

The fall of frequency following the loss of 600 MW of generation is limited by the first stage of load shedding, the maximum frequency dip being just in excess of the under-frequency relay setting. Without load shedding the dip in frequency would be considerably increased.

Recovery after operation of the first stage of load shedding is not so rapid when 800 MW of generation is lost. The frequency continues to fall but not sufficiently to cause second-stage shedding.

1988

One study representing the loss of a generator unit during light load period was made together with three further studies representing a range of generator loss conditions during a peak load period.

Figure 11-9 is the frequency/time characteristic for the loss of a 1000 MW generator unit during the light load period when the system load is 6550 MW and spinning reserve capacity is in the proportions of 1200 MW hydro and 2250 MW thermal. The frequency dip results in a single stage load shed of 550 MW.

Figure 11-10 shows the corresponding characteristic for the peak load conditions when the system load is 14500 MW and spinning reserve capacity is 1250 MW hydro and 450 MW thermal. Although conditions are easier, the same amount of load is shed, the maximum

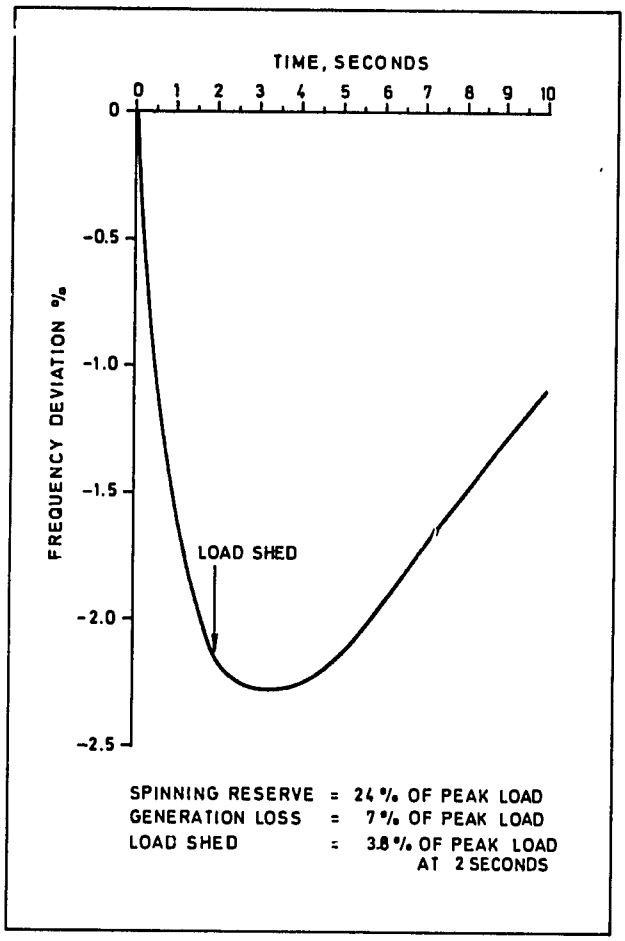


FIG. 11-9. SYSTEM FREQUENCY VARIATION FOLLOWING 7% GENERATION LOSS AT 1988 LIGHT LOAD.

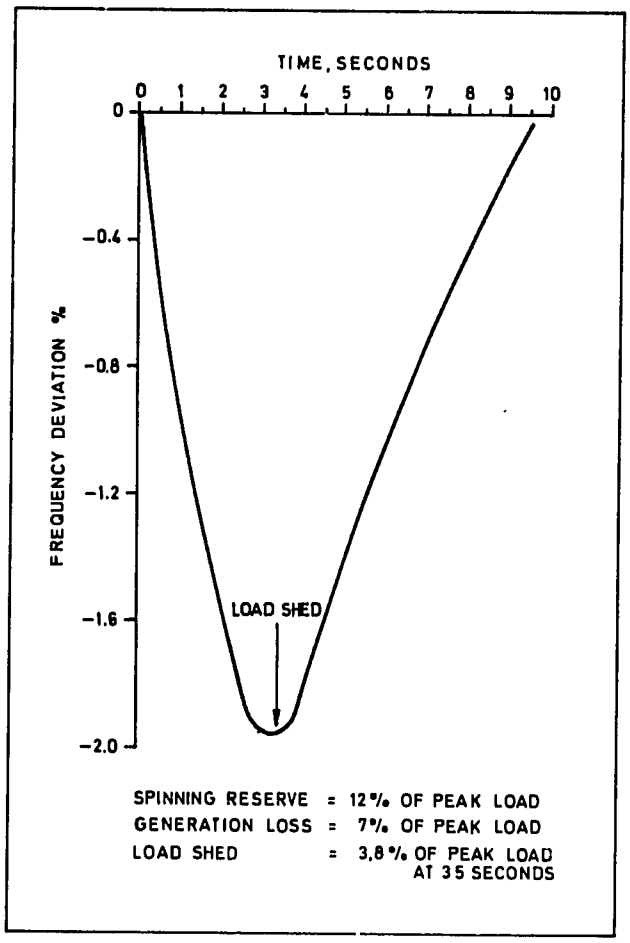


FIG. 11-10. SYSTEM FREQUENCY VARIATION FOLLOWING 7%GENERATION LOSS AT 1988 PEAK LOAD.

frequency dip in this case corresponding to the underfrequency load-shedding relay setting. Without load shedding, nevertheless, the frequency dip would be considerably increased.

For comparison, Figs 11-11 and 11-12 show the frequency characteristic for the loss of 800 and 1000 MW of generation respectively. There is no load shedding after dropping 800 MW of generation and the load shed after dropping 1200 MW of generation is the same as when dropping 1000 MW of generation, but conditions are slightly more severe.

Effect of pumped storage

The plant expansion program includes 150 MW of pumped storage for 1980 increasing to 750 MW by 1982. It can be expected that pumping at full capacity will be a normal routine for about 5-6 hours at night and that this load can be tripped automatically instead of consumer feeders as a first stage of emergency load shedding. From 1982 onwards, therefore, the choice of generator size limit can be based mainly on the peak load condition.

Conclusions

Having regard to the appreciable load shedding risk, already accepted, in introducing a 600 MW unit in 1978, it is considered in the light of the above studies for 1980, that an increase to 700 MW would be acceptable in that year.

The studies for 1988 suggest that a limit of 1000 MW in 1990 would largely eliminate load shedding risk, and an intermediate size of 800 MW appears reasonable for 1985.

To further reduce the degree of system disturbance on sudden loss of generation, size limits representing a decreasing proportion of system demand seem advisable for 1995 and 2000.

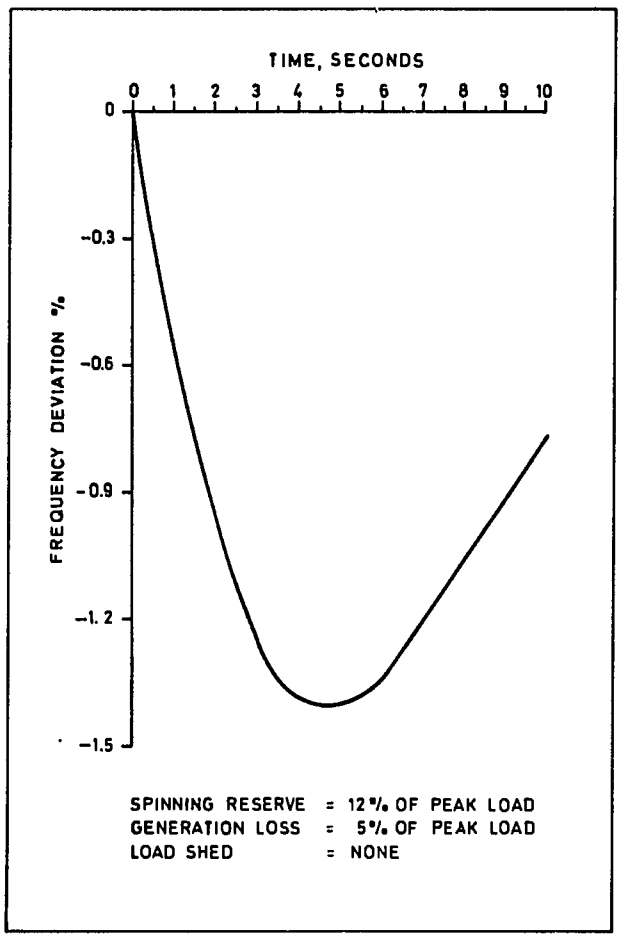


FIG. 11-11. SYSTEM FREQUENCY VARIATION FOLLOWING 5% GENERATION LOSS AT 1988 PEAK LOAD.

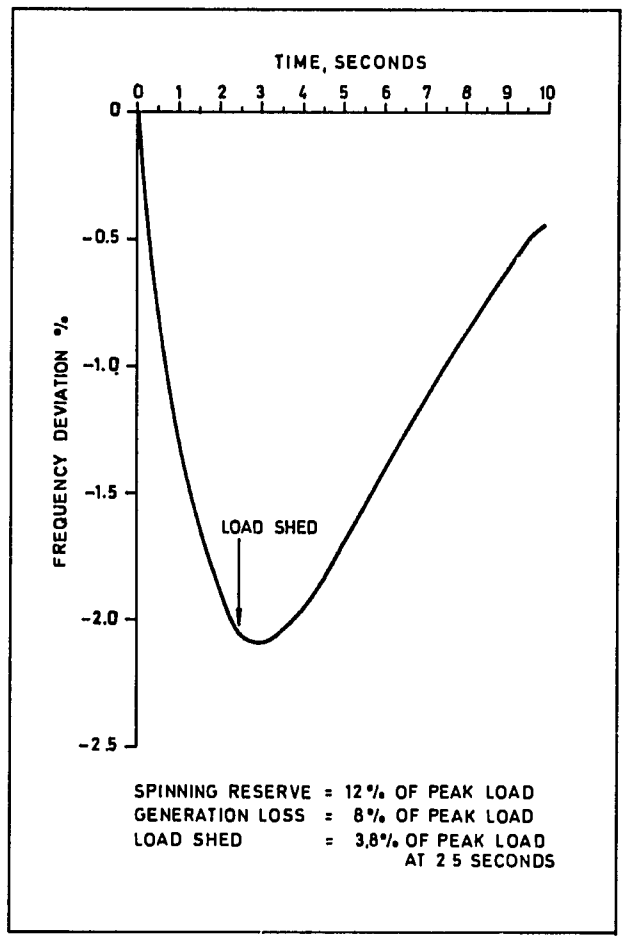


FIG. 11-12. SYSTEM FREQUENCY VARIATION FOLLOWING 8% GENERATION LOSS AT 1988 PEAK LOAD.

11.4. Limits to introduction of large units

Table XI-2 shows the proposed limits of generator rated capacity at 5-year intervals from the year 1980 to 2000, based on the considerations in Sections 11.2 and 11.3.

11.5. System reliability

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

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

A modern 500 kV line equipped with single-phase auto-reclosing can be expected to have an average outage rate not exceeding 1 in 5 years per 100 km, and a typical line section will therefore be at least as reliable as a large generator unit. With duplicate line circuits, as under construction between Region 3 and Regions 2 and 1, the risk of supply failure should be negligible.

However, reliability of supply in regions which are connected by a single 500 kV line circuit (Regions 5, 6 and 7 as at present envisaged) will be partly dependent on arranging that local installed capacity does not fall short of, and preferably somewhat exceeds, peak demand, so that imports occurring during normal operation can be kept within safe and acceptable limits of load shedding in the event of a 500 kV line failure.

12. CHARACTERISTICS OF THE EXISTING AND COMMITTED ELECTRIC POWER SYSTEM

12.1. Existing power system and committed plans for expansion

Figures 3-5 and 3-6 show the location of the principal power stations and transmission network areas, respectively, as of 1971 and planned. The names and installed capacities of the power stations at the end of 1971 are given in Table III-3 amounting to a total installed capacity of 4 403 MW.

(a) Existing and committed thermal stations

The thermal plant units scheduled for operation or retirement in the period from the end of 1971 to the end of 1978 are shown in Table V-5, Part I. This results in a total installed thermal capacity of the interconnected system at that time (i.e. Regions 1-6) of 6 309 MW by the end of 1978. In the computer program input this total was 6 316 MW.

Thermal plant capacity in operation at the end of 1971 was 3 418 MW for the regions to be interconnected by 1973/1974 (i.e. Regions 1-4) and 3 726 MW for all regions (see Table III-3, Summary).

(b) Existing and committed hydro stations

The hydro plant capacity in operation at the end of 1971 is given in Table III-3 and was equal to 200 MW for Regions 1-4 and 677 MW for all regions.

Hydro plant units scheduled for operation in the period from the end of 1971 to the end of 1978 are shown in Table V-5, Part I. This results in a total installed hydro capacity for the interconnected system (Regions 1-6) of 3 032 MW by the end of 1978. In the computer program this was taken as 3 026 MW.

The anticipated average annual production of these stations at the end of 1978 is 9 090 GWh, based on the information in Table XII-1.

(c) Additions made to bring the existing and committed system up to the first year of study

The system installed capacity at the end of 1978 is planned to be 9341 MW as shown in Table V-5, Part I. Since 1980 is the first year of study, consideration must be given to possible additions during the year 1979. The load in 1979 is forecasted to be 7500 MW (Table X-2) and the installed capacity 9341 MW, as indicated above, of which 3032 MW is hydro. In the critical quarter, however, this hydro capacity would be only 2000 MW (based on a seasonal factor of 0.66 as shown in Table XII-6), giving a total critical quarter capacity of only 8310 MW. This would mean a reserve margin of only about 11%, as contrasted to the values indicated in Table V-7 which vary from 16.3% to 25.0% during the 1980-90 decade.

TABLE XII-1. HYDRO ENERGY GENERATION AT THE END OF 1978

	Installed capacity (MW)	Energy generation (GWh/yr)
Regions 1-6 (end 1971)	596	1234 [a]
Under construction (1972-1976)	1907	6346
Planicie Banderitos (1977)	450	1510
Total	2953 [b]	9090

[a] Table III-3: 1971 total for Regions 1 to 6 is 1227 MW. This value, which was obtained from corrected data, is in substantial agreement with the 1234 MW used in the study.

[b] Table V-5, Part I, gives a total of 3 032 MW; it includes Los Reyunos (216 MW committed for 1977) but excludes Carrizal, Río Hondo, Atucha (pumping) and Cabra Corral (137 MW).

If, however, a 600 MW thermal unit is added, the critical quarter capacity becomes 8910 MW, giving a critical quarter reserve margin of 18.8%. The addition of this 600 MW would then give an installed capacity of 9941 MW or an installed capacity reserve margin of about 32%. A summary of the projected system capacities and reserves is shown in Table XII-2, and Table XII-3 shows the characteristics of the fixed system assumed to be in existence at the end of 1979, i.e. at the beginning of the first study year.

TABLE XII-2. PROJECTED INTERCONNECTED SYSTEM CAPACITIES AND RESERVES

End of year	System capacity	Critical quarter capacity	Peak demand	Per-cent reserve based on	
	MW			system capacity	critical quarter capacity
1971 [a]	2921	2921	2488	17.4	17.4
1972	3274	3274	2780	17.8	17.8
1979 [b]	9941	8913	7500	32.6	18.8

[a] GBA-Litoral only system.
[b] Buenos Aires Sud, Comahue, Córdoba, Cuyo and Patagónico Centro systems added.

TABLE XII-3. CHARACTERISTICS OF INTERCONNECTED SYSTEM ASSUMED AT START OF FIRST STUDY YEAR

	Capacity (MW)	Production (GWh)
Hydro stations		
In operation at end of 1971 [a]	200	9090
Under construction until end of 1978	2832	
Assumed additions 1979	0	
Subtotal	3032	9090
Thermal stations		
In operation at end of 1971	3418	
Under construction until end of 1978	2891	
Assumed additions 1979	600	
Subtotal	6909	
Total capacity	9941	

[a] Regions 1-4.

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

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

For the purpose of the WASP computations, it was necessary to group the plants comprising the fixed system into plants with identical capacities, fuel types, heat rates, fuel costs and other characteristics. In addition, in order to simplify the work of calculation, smaller units have been grouped together into fewer larger units with essentially the same installed capacity.

The grouping of thermal plants in the fixed system (as of the end of 1978) is shown in Table XII-4.

TABLE XII-4. GROUPING OF THERMAL PLANTS IN FIXED SYSTEM

Computer data			Actual data			
Code name	No. of units	Total capacity (MW)	Plant name	Unit No. or No. of units	Total capacity (MW)	Full load heat rate (kcal/kWh)
PNVO	3	300	Puerto Nuevo	Nos. 1-6	315	3 377
PNO7	1	145	Puerto Nuevo	No. 7	145	2 305
PNO8	1	194	Puerto Nuevo	No. 8	194	2 300
PNO9	1	250	Puerto Nuevo	No. 9	250	2 090
COST	5	600	Costanera	Nos 1-5	600	2 222
DSNP	3	300	Dock Sud	Nos 1, 2,	66	4 324
			Dock Sud	3, 8, 9, 12	84	3 453
			Dock Sud	Nos 10, 11	50	
			Nuevo Puerto	Nos 1, 2, 3	105	3 550
NPO4	1	60	Nuevo Puerto	No. 4	60	2 963
NPO5	1	110	Nuevo Puerto	No. 5	110	2 535
NPO6	1	250	Nuevo Puerto	No. 6	250	2 089
PMZA	1	36	Pedro de Mendoza	Nos 1, 2, 3	36	3 600
SNNK	4	320	San Nicolás	Nos 1-4	300	2 603
			San Nicolás	Nos 5, 6	20	3 440
GT	1	1 050	SEGBA (end 1971)	13 units	227	3 800
			DEBA (end 1971)	2 units	26	
			Paraná (end 1971)	1 unit	6	
			Region 2 (end 1971)	8 units	119	
			Region 4 (end 1971)	4 units	60	
			Region 5 (end 1971)	7 units	82	
			SEGBA (1972-1978)	17 units	321	
			CIAE (1972-1978)	2 units	32	
			AYEE (1972-1978)	5 units	87	
			EPEC	4 units	60	3 500
NEBB	1	100	Necochea	2 units	66	
			Bahía Blanca	4 units	65	
			Puerto	2 units	8	
MDPL	1	83	9 de Julio (Mar	1 unit	10	2 800
			del Plata)	2 units	10	2 950
				1 unit	30	2 783
ALVA	1	30	Alto Valle	2 units	30	2 991
PRDF	1	99	Pilar	2 units	66	2 800
			Dean Funes	1 unit	33	2 800
LCUY	3	180	Luján de Cuyo	2 units	120	2 602
			9 de Julio	1 unit	60	2 306

TABLE XII-4. (cont.)

Computer data			Actual data			
Code name	No. of units	Total capacity (MW)	Plant name	Unit No. or No. of units	Total capacity (MW)	Full load heat rate (kcal/kWh)
NCHA	2	140	Necochea	Nos 1; 2	140	
COST	1	350	Costanera	No. 6	350	1 980
ATCH	1	319	Atucha	No. 1	319	
PILR	2	150	Pilar	Nos 1, 2	150	2 500
SNIC	1	350	San Nicolás	No. 7	350	
SORR	1	160	Sorrento	1 unit	160	2 133
BBCA	1	140	Bahía Blanca	1 unit	140	
NUC2	1	600	Nuclear II	1 unit	600	

(b) Minimum and maximum operating capacity

Information provided indicated that thermal plant units have a minimum operating level of 25-30% of existing rated capacity. In the simulations it was assumed that plant units larger than 60 MW would operate at minimum levels of 50%; however, to simplify the calculation work, plant units of 60 MW or less were operated at full load or not at all. (Where a number of such small units are regrouped into one or more units larger than 60 MW they were also operated at full load or not at all.)

(c) Base load and incremental heat rates

Full load heat rates were obtained from information provided for existing plants as given in Table XII-4. Half load and incremental heat rates were derived from curves for similar sized units. The actual values of calculated base load and incremental heat rates are given in Table XII-5.

(d) Fuel costs

The estimated cost of crude oil delivered to Buenos Aires harbour is given in Appendix I, Table IX, as 182 US ¢/10^6 kcal. Transportation costs of 18, 24 and 36 US ¢/10^6 kcal were added for stations in Regions 3, 4 and 5, respectively.

Delivered costs of fuel for the gas turbines were based on 175% of the basic crude oil cost (i.e. 319 US ¢/10^6 kcal).

The cost of coal for the coal-fired units was assumed to be equivalent to the cost of imported oil delivered at the site since no information was available on present or future prices.

Nuclear fuel cycle costs for the Atucha and Córdoba plants were obtained from the data given in Appendix J. (While both plants will be natural uranium fuelled, the higher fuelling costs for enriched reactors is balanced by a higher capital cost for natural uranium reactors.)

(e) Forced outage rates

Forced outage rates were provided by SEGBA as shown in Table IV-10. For consistency, however, the forced outage rates given in Appendix E were used. For the GT units – since approximately 70 gas turbine sets were grouped as one unit of 150 MW for the WASP program – an average outage rate of 0.5 days per year was used. This was calculated to be an average outage rate of about 2% based on equivalent loss of energy.

TABLE XII-5(a). FIXED SYSTEM COMPUTER INPUT DATA (WASP MODULE 2)[a]

	NAME	NO. OF SETS	MIN. LOAD MW	CAP-CITY MW	BASE LOAD HEAT RATE	AVGE INCR HEAT RATE	FUEL COSTS CENTS/MILLION DMSTC	FORGN	TYPE	LCTN	FRCD OUT-AGE RATE	DAYS SCHL MAIN	MAIN CLAS	ENRGY GWH	O&M (FIX)	O&M (VAR)	FULL LOAD HEAT RATE
1	HYDR	1	750	3026	0.	0.	0.0	0.0	5	1	0.0	0	0	9090.	0.250	0.0	0.
2	PNVO	3	100	100	3375.	3375.	182.00	0.0	1	1	7.50	21	100	0.	0.540	0.0	3375.
3	PNO7	1	75	145	2400.	2010.	182.00	0.0	4	1	7.50	21	200	0.	0.310	0.0	2212.
4	PNO8	1	97	194	2400.	2010.	182.00	0.0	4	1	7.50	21	200	0.	0.280	0.0	2205.
5	PNO9	1	125	250	2150.	1860.	182.00	0.0	4	1	8.10	28	200	0.	0.250	0.0	2005.
6	COST	5	60	120	2430.	2010.	182.00	0.0	1	1	5.90	21	100	0.	0.340	0.0	2220.
7	DSNP	3	100	100	3600.	3600.	182.00	0.0	1	1	7.50	21	100	0.	0.540	0.0	3600.
8	NPO4	1	60	60	2965.	2965.	182.00	0.0	1	1	7.50	21	50	0.	0.490	0.0	2965.
9	NPO5	1	55	110	2750.	2320.	182.00	0.0	1	1	6.50	21	100	0.	0.360	0.0	2535.
10	NPO6	1	125	250	2280.	1900.	0.0	182.00	3	1	5.90	28	200	0.	0.250	0.0	2090.
11	PMZA	1	36	36	3600.	3600.	182.00	0.0	1	1	8.00	21	50	0.	0.620	0.0	3600.
12	SNNK	4	40	80	2800.	2400.	182.00	0.0	4	1	9.20	21	100	0.	0.440	0.0	2600.
13	GT	1	1050	1050	3800.	3800.	319.00	0.0	2	1	0.50	60	50	0.	1.000	0.0	3800.

14	NERB	1	100	100	2785.	2785.	182.00	0.0	4	1	10.00	21	100	0.	0.660	0.0	2785.
15	MDPL	1	83	83	2800.	2800.	182.00	0.0	1	1	8.00	21	100	0.	0.780	0.0	2800.
16	ALVA	1	30	30	2990.	2990.	200.00	0.0	1	1	8.00	21	50	0.	0.700	0.0	2990.
17	PRDF	1	99	99	2785.	2785.	206.00	0.0	1	1	8.00	21	100	0.	0.660	0.0	2785.
18	LCUY	3	60	60	2600.	2600.	218.00	0.0	1	1	7.00	21	50	0.	0.490	0.0	2600.
19	NCHA	2	35	70	2600.	2300.	182.00	0.0	1	1	7.00	21	100	0.	0.450	0.0	2450.
20	COST	1	175	350	2330.	2100.	0.0	182.00	3	1	8.10	28	400	0.	0.230	0.0	2215.
21	ATCH	1	160	319	2645.	2360.	29.00	29.00	0	1	6.50	28	400	0.	0.500	0.0	2503.
22	PILR	2	38	75	2800.	3000.	206.00	0.0	1	1	7.00	21	100	0.	0.430	0.0	2899.
23	SNIC	1	175	350	2330.	2100.	182.00	0.0	4	1	10.30	28	400	0.	0.230	0.0	2215.
24	SORR	1	80	160	2340.	2190.	182.00	0.0	1	1	5.30	21	200	0.	0.290	0.0	2265.
25	BBCA	1	70	140	2347.	2193.	182.00	0.0	4	1	7.50	21	200	0.	0.320	0.0	2270.
26	NUC2	1	300	600	2637.	2365.	27.00	28.00	0	1	12.00	28	600	0.	0.320	0.0	2501.
27	REG7	0	100	100	2600.	2600.	228.00	0.0	1	1	7.50	21	100	0.	0.540	0.0	2600.
28	REG8	0	100	100	2700.	2700.	228.00	0.0	1	1	8.00	21	100	0.	0.780	0.0	2700.
29	REG9	0	100	100	2700.	2700.	228.00	0.0	1	1	8.00	21	100	0.	0.780	0.0	2700.

[a] For legend see Table XII-5(b).

TABLE XII-5(b). LEGEND FOR TABLE XII-5(a)

NAME	WASP code for existing plants (see Table XII-4 for fossil plants), HYDR = hydro.
NO. OF SETS	Number of units of a given size located at a given plant.
MIN. LOAD, MW	Minimum load at which units will be operated (see 12.2(b)).
CAP-CITY, MW	Maximum load at which units will be operated (see 12.2(b)).
BASE LOAD HEAT RATE	Unit heat rate at base load, in kcal/kWh (see 12.2(c)).
AVGE INCR HEAT RATE	Unit heat rate for each kW above base load, in kcal/kWh. (see 12.2(c)).
FUEL COSTS, DOMESTIC	Fuel costs in US ¢/kcal × 10^6 (see 12.2(d)).
FUEL COSTS, FOREIGN	Same as above.
TYPE	A code where: -1 = emergency hydro 0 = nuclear 1 = oil-fired 2-4 = optional 5 = hydro
LCTN	Not used. Defaulted to 1 in all cases.
FRCD OUTAGE RATE	Days lost due to forced outage (see 12.2(e)).
DAYS SCHL MAIN	Days lost due to scheduled outage (see 12.2(f)).
MAIN CLAS	An arbitrary assignment of unit size, for maintenance calculations.
ENRGY, GWh	Used only for hydro (see 12.3(b)).
O & M (FIX)	Average O & M costs, in US $/kW-month (see 12.2(g)).
O & M (VAR)	Not used.
FULL LOAD HEAT RATE	Full load heat rate, as calculated by WASP based on the base load heat rate and average incremental heat rate data above.

(f) Days per year of scheduled maintenance

Historical data on scheduled maintenance of SEGBA plants are also shown in Table IV-10. Again, for reasons of consistency, the data in Appendix E were used.

(g) Fixed and variable operating and maintenance costs

Information available regarding operating and maintenance costs of thermal power stations in operation is described in Section 3.6 and in Tables III-9, III-10 and III-11. It is apparent that operating costs for these units are lower than those that would prevail in the USA (e.g. salaries of assistant shift supervisors average about US $ 3 800 per annum).

To reflect the lower personnel costs for conventional plant units it was therefore decided to reduce the costs given in Appendix E in the smaller sizes as shown in Table XII-6.

However, in view of the limited information in Atucha and Córdoba, it was decided to use the Appendix E costs for the nuclear plant units.

TABLE XII-6. OPERATING AND MAINTENANCE COSTS FOR FIXED SYSTEM CONVENTIONAL THERMAL PLANT UNITS

MW	50	100	150	200	300
US $/kW-month	0.54	0.36	0.30	0.27	0.23
(Appendix E)	-	(0.61)	(0.45)	(0.36)	(0.28)

12.3. Derivation of hydro plant data required for WASP Module 2

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

The installed capacity for the hydro units in operation in Regions 1-4 in 1978 was 3026 MW. It was assumed that 25% of this capacity would be base load and the balance available for peaking capacity.

(b) Energy generation

The total annual energy generation for the hydro stations in the fixed system amounted to 9 090 GWh, as shown in Section 12.1 (b).

(c) Quarterly energy factors and capacity factors

The quarterly energy allocation factor for the hydro stations was determined based on hydrological data for the general region and assumed to apply for the whole country. The resulting factors are given in Table XII-7.

Seasonal variation of the hydro peak and base capacities was estimated. These coefficients are also shown in Table XII-7.

TABLE XII-7. HYDRO SEASONAL FACTORS

Quarter	Energy allocation	Capacity multiplier	
		Peak	Base
1	0.3	1.0	1.0
2	0.3	1.0	1.0
3	0.2	0.66	0.8
4	0.2	0.66	0.8

(d) Operating and maintenance costs

No data were obtained on the operating and maintenance costs of existing and committed hydro stations. Experience in the USA shows that these costs are 1 US mill/kWh or 0.30 US $/kW. A figure of 0.25 US $/kW was used. Since the hydro stations are assumed to produce a constant amount of energy per year, the O& M costs of such stations are constant and do not affect the economic evaluation.

12.4. Computer printout showing the characteristics of the fixed system assumed to be in existence at start of study year

Table XII-5 shows the actual printout from the WASP Module 2 computer program (fixed system) summarizing the above characteristics of the system.

13. CAPITAL COST DATA

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

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

(a) Interest rate

ORCOST-1 and ORCOST-3 capital cost estimates were based on an assumed 8% interest rate during construction. This was assumed to be constant for all cases considered even though the present-worth discount rate was varied to 6% and 10%.

(b) Construction schedules

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

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

Plant size (MW)	Oil-fired	Nuclear
400	3.2	5.2
600	3.5	5.5
800	3.75	5.75
1000	4.0	6.0

(c) Contingency and spare parts factors

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

(d) Other considerations

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

13.2. Derivation of equipment, materials and labour cost indices

(a) Equipment cost index

A review of recent world market prices of conventional plant equipment indicated that on a competitive bid basis these should be about 85% of the prices used in ORCOST. Allowing 5% additional for transportation costs of such equipment gave an equipment index for conventional thermal plants of 0.9. In the case of nuclear plant equipment, however, it was decided that world market prices would be only about 95% of the prices used in ORCOST. After allowing for transportation costs, this gave an equipment index of 1.0 for nuclear plants.

(b) Materials cost index

The costs of construction materials in Argentina were not available. An analysis of the materials used for the Atucha nuclear power plant indicated that much of this material was domestic. After assuming a mix of domestic and imported material and after allowing 5% for transportation costs for these imported materials it was decided to use a materials cost index of 1.0.

(c) Labour cost index

Section 6.3 discusses labour costs and labour productivity in Argentina. Tables III-4 and III-5 give cost details of recent thermal stations. An analysis of these data would suggest that low labour costs could be expected. This plus an analysis of Córdoba cost estimate data indicates that a labour cost index of 0.3 may be appropriate for Argentina. This value was used as ORCOST input.

(d) Indirect cost indices

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

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

ORCOST-3 printouts of capital costs of 600 MW oil-fired and PWR plants are shown in Tables XIII-2 and XIII-3 respectively. Summaries of costs calculated by ORCOST-3 of

TABLE XIII-2. ORCOST-3, CAPITAL COST ESTIMATES FOR A 600 MW OIL PLANT (10^6 US $)[a]

	DIRECT COSTS				
20	LAND AND LAND RIGHTS				0.1
	PHYSICAL PLANT	EQU.	MAT.	LABOUR	TOTAL
21	STRUCTURES AND SITE FACILITIES	0.5	6.2	5.4	12.1
22	REACTOR/BOILER PLANT EQUIPMENT	16.2	4.1	6.4	26.7
23	TURBINE PLANT EQUIPMENT	17.1	5.4	5.1	27.6
24	ELECTRIC PLANT EQUIPMENT	3.9	1.5	2.6	8.1
25	MISCELLANEOUS PLANT EQUIPMENT	0.9	0.7	0.9	2.4
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)	38.7	17.9	20.3	76.9
	CONTINGENCY ALLOWANCE				4.9
	SPARE PARTS ALLOWANCE				0.6
	SUBTOTAL (PHYSICAL PLANT)				82.3
	OVERTIME ALLOWANCE (40.0 HR WORKWEEK)				0.0
	SUBTOTAL (TOTAL PHYSICAL PLANT)				82.3
	INDIRECT COSTS				
91	CONSTRUCTION FACILITIES, EQUIPMENT, AND SERVICES				6.8
92	ENGINEERING AND CONSTRUCTION MANAGEMENT SERVICES				10.8
93	OTHER COSTS				3.0
94	INTEREST DURING CONSTRUCTION (8.0 PCT- 3.50 YRS)				13.0
	SUBTOTAL (TOTAL INDIRECT COSTS)				33.6
	SUBTOTAL (TOTAL PLANT COST)				116.1
	CAPABILITY PENALTY (0.0 PCT- 0.0 MW(E))				0.0
	TOTAL PLANT CAPITAL COST (AT START OF PROJECT)				116.1
	$ / KW(E)				193.
	ESCALATION DURING CONSTRUCTION (0.0 PCT)				0.0
	TOTAL PLANT CAPITAL COST (AT COMMERCIAL OPERATION)				116.1
	$ / KW(E)				193.

[a] In 1972 constant dollars.

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

		EQU.	MAT.	LABOUR	TOTAL
	DIRECT COSTS				
20	LAND AND LAND RIGHTS				0.1
	PHYSICAL PLANT	EQU.	MAT.	LABOUR	TOTAL
21	STRUCTURES AND SITE FACILITIES	1.2	12.3	12.1	25.5
22	REACTOR/BOILER PLANT EQUIPMENT	29.5	10.7	7.7	48.0
23	TURBINE PLANT EQUIPMENT	26.9	7.6	7.2	41.7
24	ELECTRIC PLANT EQUIPMENT	4.7	6.3	4.4	15.4
25	MISCELLANEOUS PLANT EQUIPMENT	1.8	0.2	1.3	3.3
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	37.1	32.7	133.9
	CONTINGENCY ALLOWANCE				8.3
	SPARE PARTS ALLOWANCE				1.0
	SUBTOTAL (PHYSICAL PLANT)				143.2
	OVERTIME ALLOWANCE (40.0 HR WORKWEEK)				0.0
	SUBTOTAL (TOTAL PHYSICAL PLANT)				143.2
	INDIRECT COSTS				
91	CONSTRUCTION FACILITIES, EQUIPMENT, AND SERVICES				9.5
92	ENGINEERING AND CONSTRUCTION MANAGEMENT SERVICES				24.5
93	OTHER COSTS				5.3
94	INTEREST DURING CONSTRUCTION (8.0 PCT- 5.50 YRS)				37.8
	SUBTOTAL (TOTAL INDIRECT COSTS)				77.2
	SUBTOTAL (TOTAL PLANT COST)				220.5
	CAPABILITY PENALTY (0.0 PCT- 0.0 MW(E))				0.0
	TOTAL PLANT CAPITAL COST (AT START OF PROJECT)				220.5
	$ / KW(E)				368.
	ESCALATION DURING CONSTRUCTION (0.0 PCT)				0.0
	TOTAL PLANT CAPITAL COST (AT COMMERCIAL OPERATION)				220.5
	$ / KW(E)				368.

[a] In 1972 constant dollars.

other plants considered as possible future additions for the electric power system expansion are given in Table XIII-4 and XIII-5. Similar summaries of costs calculated by ORCOST-1 (used in some sensitivity studies) are given in Tables XIII-6 and XIII-7.

13.4. Treatment of transmission costs

Costs of transmission lines added to the system after 1979 were assumed to be the same regardless of the type of thermal unit being considered as an expansion alternative and were therefore omitted since they did not influence the economic comparison of thermal plant additions.

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

It was assumed that 270 MW per year of hydro capacity would be commissioned in the years 1980, 1981 and 1982 on the assumption that the Salto Grande project would be completed by 1982 and that there would be two units of 135 MW commissioned in each of these years. In the years 1983 - 89 an additional 300 MW per year were assumed. The capital

TABLE XIII-4. SUMMARY OF CAPITAL COSTS OF OIL-FIRED AND COAL-FIRED PLANTS CALCULATED BY ORCOST-3 (10^6 US $)

Account No.	Oil-fired plants				Coal-fired plants		
	400 MW	600 MW	800 MW	1 000 MW	400 MW	600 MW	1 000 MW
Direct costs							
20	0.1	0.1	0.1	0.1	0.1	0.1	0.1
21	8.8	12.1	15.0	17.7	9.8	13.3	19.5
22	18.6	26.7	34.6	42.4	22.7	32.6	51.6
23	20.0	27.6	34.7	41.6	20.0	27.7	41.7
24	6.7	8.1	9.2	10.1	8.5	10.2	12.9
25	2.2	2.4	2.7	2.8	2.3	2.6	3.0
Subtotal	56.4	77.0	96.3	114.7	63.4	86.5	128.8
Contingencies	3.6	4.9	6.1	7.8	4.0	5.5	8.1
Spare parts	0.4	0.6	0.7	0.8	0.5	0.6	0.9
Indirect costs							
Accts 91-93	18.8	20.6	22.5	24.5	19.9	21.6	26.0
Interest during construction	9.1	13.0	17.1	21.4	11.8	16.6	27.2
Total costs	88.3	116.1	142.7	169.2	99.6	130.8	191.0
Unit costs (US $/kW)	221	193	178	169	249	218	191

TABLE XIII-5. SUMMARY OF CAPITAL COSTS OF PWR PLANTS CALCULATED BY ORCOST-3 (10^6 US $)

Account No.	400 MW	600 MW	800 MW	1 000 MW
Direct costs				
20	0.1	0.1	0.1	0.1
21	21.7	25.5	28.6	34.1
22	37.5	48.0	57.0	65.2
23	30.2	41.7	52.5	62.8
24	12.1	15.4	18.3	20.9
25	2.9	3.3	3.6	3.8
Subtotal	104.5	134.0	160.1	186.9
Contingencies	6.5	8.3	9.9	11.6
Spare parts	0.8	1.0	1.2	1.4
Indirect costs				
Accts 91-93	35.1	39.4	43.5	47.5
Interest during construction	28.6	37.8	46.6	56.4
Total costs	175.5	220.5	261.3	303.9
Unit costs (US $/kW)	439	368	327	304

TABLE XIII-6. SUMMARY OF CAPITAL COSTS OF OIL-FIRED AND COAL-FIRED PLANTS CALCULATED BY ORCOST-1 (10^6 US $)

Account No.	Oil-fired plants				Coal-fired plants		
	400 MW	600 MW	800 MW	1 000 MW	400 MW	600 MW	1 000 MW
Direct costs							
20	1.0	1.0	1.0	1.0	1.0	1.0	1.0
21	7.9	10.8	13.4	15.8	8.8	11.9	17.5
22	17.1	24.6	31.8	38.9	21.0	30.4	47.9
23	19.9	27.6	34.7	41.6	20.0	27.6	41.7
24	6.0	7.2	8.2	9.1	6.6	7.9	10.0
25	2.2	2.4	2.7	2.8	2.2	2.4	2.8
Subtotal	54.1	73.6	91.8	109.2	59.6	81.2	120.9
Contingencies	3.3	4.6	5.7	6.8	3.7	5.0	7.5
Spare parts	0.4	0.5	0.7	0.8	0.4	0.6	0.9
Indirect costs							
Accts 91-93	21.5	24.7	25.9	27.9	22.7	24.7	29.4
Interest during construction	9.4	13.3	17.1	21.4	11.8	16.5	26.6
Total costs	88.7	116.7	141.2	166.1	98.2	128.0	185.3
Unit costs (US $/kW)	222	195	176	166	245	213	185

TABLE XIII-7. SUMMARY OF CAPITAL COSTS OF PWR PLANTS CALCULATED BY ORCOST-1 (10^6 US $)

Account No.	400 MW	600 MW	800 MW	1 000 MW
Direct costs				
20	1.0	1.0	1.0	1.0
21	15.9	18.7	20.9	25.0
22	30.6	39.0	46.4	53.0
23	27.9	38.6	48.6	58.1
24	7.0	8.9	10.6	12.1
25	2.7	3.1	3.4	3.6
Subtotal	85.1	109.3	130.9	152.8
Contingencies	5.2	6.6	7.9	9.3
Spare parts	0.6	0.8	1.0	1.2
Indirect costs				
Accts 91-93	33.2	36.6	39.8	43.1
Interest during construction	24.5	32.1	39.4	47.5
Total costs	148.6	185.4	219.0	253.9
Unit costs (US $/kW)	372	309	274	254

costs of these projects are given in Table XIII-8 with the details for Salto Grande and Apipé developed in Table XIII-9. During the period following the study decade other projects and costs were assumed, as also shown in Table XIII-8.

TABLE XIII-8. COSTS OF HYDROELECTRIC PROJECTS

Year	Project	Unit No. and MW each year	Costs (US $/kW)		
			Total	Local	Foreign
1980	Salto Grande[a]	2×135	1040	811	239
1981	Salto Grande	2×135	97	5	92
1982	Salto Grande	2×135	97	5	92
1983-89	Various	300	800	528	272
1990	Apipé[a]	3×108	1512	1149	363
1991-94	Apipé	3×108	62	3	59
1995-99	Various	400	700	462	238

[a] See Table XIII-9.

TABLE XIII-9. PROJECT COSTS FOR ARGENTINE SHARE OF SALTO GRANDE AND APIPE PROJECTS

Year	Item	Costs (10^6 US $)			US $/kW
		Local	Foreign	Total	
SALTO GRANDE (6×135 MW units)					
1	Dam	180	-	180[a]	
	Equipment (2×135 MW)	1	19	20[a]	
	Transmission	36	45	81[b]	
	Subtotal	217	64	281	1040
2	Equipment (2×135 MW)	1	19	20[a]	97
3	Equipment (2×135 MW)	1	19	20[a]	97
	Total (6×135 MW)			321	396
APIPE (15×108 MW units)					
1	Dam	295	-	295[c]	
	Equipment (3×108 MW)	1	19	20	
	Transmission	77	98	175[d]	
	Subtotal	373	117	490	1512
2	Equipment (3×108 MW)	1	19	20[c]	62
3	Equipment (3×108 MW)	1	19	20[c]	62
4	Equipment (3×108 MW)	1	19	20[c]	62
5	Equipment (3×108 MW)	1	19	20[c]	62
	Total (15×108 MW)			570	3552

[a] 180 + 3×20 = 240 = ½ 480 (see Table II-5).
[b] 81 = 100% × 81 (see Table II-5).
[c] 295 + 5×20 = 395 = ½ 787 (see Table II-5).
[d] 175 = 60% × 292 (see Table II-5).

It should be noted that since the hydro additions were not varied during any of the study alternatives, this cost does not influence the economic comparison of thermal plant additions.

Pumped storage additions were also considered for introduction at a cost of US $250/kW (of which the local cost portion was US $150 and the foreign cost portion was US $100).

13.6. Cost of gas turbines

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

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

14.1. Review of SSE plans for system expansion

There are no firmly committed plans for adding units to the system after 1978. Possible future projects are shown in Table V-5, Part II. The major uncertainty concerns hydroelectric capacity and information is conflicting regarding the rate of introduction of hydroelectric generation. Table V-5 indicates that over 21 000 MW of conventional hydro capacity and about 11 500 MW of pumped storage might possibly be commissioned by 1984. Section 2.1(a) presents information gathered by the mission in Argentina which is essentially in agreement with these data. However, in Section 5.3 it is noted that Apipé and Corpus are international projects which could be delayed for a number of years.

Possible thermal and nuclear units also are listed in Table V-5, Part II, and in Table V-6, the latter showing that 6 600 MW of nuclear capacity are presently planned to be installed during the study decade (i.e. 7 519 - 919 = 6 600 MW).

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

The hydro projects which could go into service during the period 1980 - 2000 were assumed to have the characteristics shown in Table XIV-1. The computer program treats all hydro together, and it was decided to assume the same hydro seasonal factors for the new projects as for the overall hydro systems shown in Table XII-7.

The pumped storage projects which were considered for service in the period 1980 - 2000 were assumed to have the characteristics shown in Table XIV-2. While a large number of pumped storage projects were shown as possible in Table V-5, Part II, in the study only the 750 MW Río Grande project was included, with one 150 MW unit entering service in 1980, three units in 1981 and the fifth unit in 1982.

TABLE XIV-1. FUTURE HYDRO PROJECT CHARACTERISTICS

Year	Project	No. of units	Unit capacity (MW)	Total capacity (MW)	Total base capacity (MW)	Total annual energy (GWh)
1980	Salto Grande	2	135	270	70	1183
1981	Salto Grande	2	135	270	70	1183
1982	Salto Grande	2	135	270	70	1183
1983	Various	-	-	300	75	1314
1990	Apipé	3	108	324	80	1419
1995	Various	-	-	400	100	1752

TABLE XIV-2. CHARACTERISTICS OF PUMPED STORAGE UNITS

Pumping load	200 MW
Generating capacity	150 MW
Maximum energy per quarter	60 GWh
Pumping efficiency	0.85
Generating efficiency	0.88
Cycle efficiency (0.85 × 0.88)	0.748

TABLE XIV-3. CHARACTERISTICS OF SELECTED ALTERNATIVE GENERATING UNITS[a]

	NAME	NO. OF SETS	MIN. LOAD MW	CAP-CITY MW	BASE LOAD HEAT RATE	AVGE INCR HEAT RATE	FUEL COSTS CENTS/MILLION DMSTC	FORGN	TYPE	LCTN	FRCD OUT-AGE RATE	DAYS SCHL MAIN	MAIN CLAS	ENRGY GWH	O&M (FIX)	O&M (VAR)	FULL LOAD HEAT RATE
1	N400	0	200	400	2643.	2362.	28.00	29.00	0	1	9.80	28	400	0.	0.420	0.0	2502.
2	N600	0	300	600	2638.	2365.	27.10	28.00	0	1	12.00	28	600	0.	0.320	0.0	2501.
3	N800	0	400	800	2632.	2369.	26.20	27.00	0	1	12.20	35	800	0.	0.270	0.0	2500.
4	N1T0	0	500	1000	2627.	2372.	25.30	26.00	0	1	12.20	35	1000	0.	0.230	0.0	2499.
7	D400	0	200	400	2324.	2098.	0.0	182.00	3	1	9.80	28	400	0.	0.210	0.0	2211.
8	D600	0	300	600	2328.	2172.	0.0	182.00	3	1	12.00	28	600	0.	0.170	0.0	2250.
9	D800	0	400	800	2334.	2170.	0.0	182.00	1	1	12.20	35	800	0.	0.170	0.0	2252.
10	D1T0	0	500	1000	2344.	2152.	0.0	182.00	3	1	12.20	35	1000	0.	0.140	0.0	2248.
11	C400	0	200	400	2351.	2115.	182.00	0.0	4	1	12.00	28	400	0.	0.220	0.0	2233.
12	C600	0	300	600	2354.	2186.	182.00	0.0	4	1	14.10	28	600	0.	0.190	0.0	2270.
13	C1T0	0	500	1000	2370.	2166.	182.00	0.0	4	1	14.50	35	1000	0.	0.160	0.0	2268.
14	GT50	0	100	100	4000.	4000.	319.00	0.0	2	1	2.00	4	100	0.	0.700	0.0	4000.

[a] For legend see Table XII-5(b).

14.3. Minimum and maximum thermal capacity additions required

The schedule of total thermal capacity additions required was based on provision of adequate system reliability. This was defined for Argentina as an average annual loss-of-load probability not to exceed 0.0010. Trial calculations were made to establish the thermal capacity needed to stay within a reasonable range of this figure. It was possible to stay within a range of 0.0025 and 0.0004.

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

(a) Choice of unit sizes and types of plants

The WASP program for evaluating alternative generating units being considered as possible additions to the electric power system is limited to 18 types of thermal plants, plus the hydro and pumped storage additions. The thermal units considered as possible alternative generating units in this study are listed in Table IX-1.

(b) Minimum operating capacities

Minimum operating capacities were assumed to be 50% of the nameplate rating except for gas turbines which were assumed to operate only at 100% as discussed in Appendix E.

(c) Heat rates

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

(d) Other data

Operating and maintenance costs, forced outage rates and scheduled maintenance days were taken from data given in Appendix E. Fuel oil costs were derived from the base cost of 182 US $¢/10^6$ kcal (see Appendix I). Coal-fired plants were assumed to have fuel costs equal to the base cost of oil. Oil-fired plants were assumed to use foreign oil and coal-fired plants domestic coal. Gas turbine fuel prices were 175% of the fuel oil base cost. Nuclear fuel cycle costs were taken from data given in Appendix J and the domestic portion was assumed to be 50%.

14.5. Computer printout of characteristics of selected alternative generating units

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

15. ANALYSIS OF ALTERNATIVE EXPANSION PROGRAMS

15.1. Methods of analysis

(a) Selection of thermal unit sizes

Trial computer runs were made to establish the relationship between sizes of units added each year and loss-of-load probability. The sizes of units assumed to be added to the system were selected from the list of standard sizes described in Appendix E after applying the restraints on limiting sizes discussed in Section 11. Units were added to give an average annual loss-of-load probability of about 0.001. The resulting assumed capacity additions are shown in Table XV-1 along with the corresponding critical quarter reserve margins and annual loss-of-load probabilities. The capacity additions shown were maintained constant for all runs. For consistency of results, the capacity additions for the years 1990-2000 were also selected to give loss-of-load probabilities in the same general range and these were maintained identical for all runs.

(b) Selection of schedules of thermal plant additions

The most likely competing fuels under the reference conditions (2% escalation on fuel oil prices compared to nuclear fuel) would be fuel oil and nuclear. Coal was assumed to be equivalent to oil as in Section 9.4, therefore a 2% escalation rate was applied to coal as well as oil, since the cost was limited by the cost of alternative fuel oil.

The units shown in Table XV-1 were first assumed to be either oil-fired or nuclear. Runs were made starting with all additions in the decade being nuclear, then replacing each nuclear unit with an oil-fired unit starting in 1980/81 and continuing for successive years until the minimum cost solution became evident.

Five runs were made as shown in Table XV-2, to evaluate the competition between nuclear and oil-fired plants.

Run No. 13 is, essentially, all nuclear and run No. 17 all oil-fired, with the runs in between giving different ratios of oil and nuclear units.

TABLE XV-1. ASSUMED ANNUAL THERMAL CAPACITY ADDITIONS

Year	Assumed capacity additions (MW)	Critical quarter reserve margin (%)	Annual loss-of-load probability
1980	1×400 1×600	18.4	0.0025
1981	0	17.4	0.0012
1982	0	13.4	0.0017
1983	1×600	15.5	0.0006
1984	2×600	17.6	0.0004
1985	0	14.4	0.0006
1986	1×800	12.5	0.0011
1987	1×800	13.3	0.0010
1988	1×1000	13.8	0.0010
1989	1×1000	14.2	0.0010
Total	6400	-	-
Average for decade	-	15.1	0.0011

TABLE XV-2. SUMMARY OF CASES STUDIED

Case No.	Year of first nuclear plant[a]	Type and size of plants introduced during 1980 - 89 (MW)							
		Nuclear			Oil (coal)[b]				Pumped storage
13	1980	4×600	2×800	2×1000	1×400	0	0	0	5×150
	1981 - 1982	No thermal units added							
14	1983	3×600	2×800	2×1000	1×400	1×600	0	0	5×150
15	1984	2×600	2×800	2×1000	1×400	2×600	0	0	5×150
	1985	No thermal units added							
16	1986	0	2×800	2×1000	1×400	4×600	0	0	5×150
17	after 1989	0	0	0	1×400	4×600	2×800	2×1000	5×150

[a] First nuclear plant added after Atucha and Córdoba.
[b] The cost of oil and coal was assumed to be equivalent, thus no comparison was made between these two fuels.

15.2. Derivation of input data required for WASP (Modules 4, 5 and 6)

(a) Schedules of plant additions during study period

Schedules of plant additions were prepared for each run based on the assumed capacity additions given in Table XV-1 and the types of plants given in Table XV-2. The results are summarized in Table XV-3.

TABLE XV-3. SCHEDULE OF PLANT ADDITIONS DURING STUDY PERIOD

Year	Case 13	Case 14	Case 15	Case 16	Case 17	Additional pumped storage all cases
1980	C400[a] N600	C400 0	C400 O600[a]	C400 O600	C400 O600	PS150
1981	0	0	0	0	0	PS150 PS150 PS150
1982	0	0	0	0	0	0
1983	N600	N600	O600	O600	O600	0
1984	N600 N600	N600 N600	N600 N600	O600 O600	O600 O600	0
1985	0	0	0	0	0	0
1986	N800	N800	N800	N800	O800	0
1987	N800	N800	N800	N800	O800	0
1988	N1T0	N1T0	N1T0	N1T0	O1T0	0
1989	N1T0	N1T0	N1T0	N1T0	O1T0	0

[a] The 400 MW unit was assumed to be coal-fired; other fossil units were considered to be oil-fired; however, since the price of coal and oil was assumed to be equivalent, the coal-fired units could also be oil-fired.

(b) Expansion schedules from end of study period to horizon

A schedule of plant additions from 1990 to 2000 was established for each forecast and maintained constant in all runs. Although it was recognized that the composition of the configurations making up the schedules could influence to some extent the loading of plants commissioned during the 1980-89 period, as a compromise measure it was decided that the added capacity should be divided nearly equally between nuclear plants and all other types. The resulting expansion schedule shown in Table XV-4 approximates this requirement, because of the need to add only specified standard size units.

(c) Minimum and maximum reserve margins

In order to carry out the dynamic program, the minimum and maximum reserve margin during the critical period must be specified. In many systems this reserve margin lies between 2 and 3 times the size of the largest unit in the system. In the systems being considered in this study, as shown in Table XV-5, the margin required for an adequate loss-of-load probability lies in this range except for 1983 and 1985 when it is less than two times the largest unit assumed to be in the system.

This can be compared with the limitations on unit sizes specified in Section 11 which, it is believed, could be relaxed to permit units of 1000 MW in 1988 and 1989.

(d) Loading order of all plants in the system

The loading order of plants in the system was established on the basis of incremental fuel costs of each plant, but also giving due consideration to size and type of units. The resulting loading order of alternative generation units from the base to the peak of the load duration curve, as shown in Table XV-6 being base hydro, nuclear base, nuclear peak, large oil-fired base, large oil-fired peak, small oil-fired, gas turbines and pumped storage. With regard to hydro peaking capacity, the WASP program calculates the position of this capacity under the load duration curve that makes use of all of the available generated energy. More details are given in Appendix A.

(e) Other input data

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

TABLE XV-4. FIXED EXPANSION SCHEDULE ASSUMED FOR 1990 - 2000 PERIOD (MW)

Year	Oil (or coal) fired	Nuclear			Gas turbines	Hydro
1990	1×800	1×600			100	324
1991	0	1×600			100	324
1992	1×800	1×600			100	324
1993	1×800		1×800		100	324
1994	0		1×800		100	324
1995	0		1×800		100	400
1996	0		1×800		100	400
1997	0			1×1000	100	400
1998	1×800			1×1000	100	400
1999	1×800			1×1000	100	400
2000	1×800			1×1000	-	400
Total units	6×800	3×600	4×800	4×1000	10×100	5×324 6×400
Total MW	4 800		9 000		1 000	4 020

TABLE XV-5. RATIO OF RESERVE MARGINS TO LARGEST UNIT IN SYSTEM

Year	Peak demand (MW)	Generating capacity, critical (3rd) quarter (MW)	Reserve (MW)	Capacity of largest unit (MW)	Ratio
1979	7 500	8 913	1 413	600	2.36
1980	8 230	9 741	1 511	600	2.52
1981	8 800	10 333	1 533	600	2.56
1982	9 350	10 601	1 251	600	2.09
1983	10 500	11 529	1 029	600	1.72
1984	11 500	12 927	1 427	600	2.38
1985	12 000	13 125	1 125	600	1.88
1986	13 000	14 623	1 623	800	2.03
1987	13 500	15 301	1 801	800	2.25
1988	14 500	16 499	1 999	1 000	2.00
1989	15 500	17 697	2 197	1 000	2.20

TABLE XV-6. LOADING ORDER OF PLANTS IN SYSTEMS

Loading order	Station unit code[a]	Unit capacity (MW)	Base or peak	Loading order	Station unit code	Unit capacity (MW)	Base or peak
1	HYDR	3 026	-	37	O800	800	Peak
2	N1T5	1 500	Base	38	O600	600	Peak
3	N1T2	1 200	Base	39	C600	600	Peak
4	N1T0	1 000	Base	40	O400	400	Peak
5	N800	800	Base	41	C400	400	Peak
6	N600	600	Base	42	SN1C	350	Peak
7	N400	400	Base	43	COST	350	Peak
8	NUC2	600	Base	44	PNO9	250	Peak
9	ATCH	319	Base	45	NPO6	250	Peak
10	N1T5	1 500	Peak	46	SORR	160	Peak
11	N1T2	1 200	Peak	47	BBCA	140	Peak
12	N1T0	1 000	Peak	48	PNO8	194	Peak
13	N800	800	Peak	49	PNO7	145	Peak
14	N600	600	Peak	50	COST	120	Peak
15	N400	400	Peak	51	NPO5	110	Peak
16	NUC2	600	Peak	52	REG7	100	Peak
17	ATCH	319	Peak	53	PILR	75	Base
18	O1T0	1 000	Base	54	NCHA	70	Base
19	C1T0	1 000	Base	55	LCUY	60	Peak

[a] Refer to Table XII-4 for code identifications.

16. RESULTS

The basic system expansion schedule developed from the previous data and procedures is shown in Table XVI-1 for the reference case conditions.

16.1. Variations of objective function for reference conditions

Values of the objective function for the cases considered are shown in Table XVI-2. The various cases correspond to different dates of introduction of further nuclear units as shown. The amounts of nuclear power for each case studied are shown in Tables XV-3 and XV-4. The reference conditions are as given in Section 9.3. From cases 13-17 it is seen that the minimum value of the objective function (lowest present worth) occurs when further nuclear plants are introduced into the system beginning in 1980 at the start of the study period (i.e. case 13).

16.2. Market for nuclear plants during study period

(a) New plant unit market

Table XVI-1 shows that the near-optimum expansion schedule is case 13 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 each of the years 1988 and 1989. On this basis, the total nuclear capacity added during the study period amounts to 6 000 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 10 060 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.

(b) Retirements

It can be noted from Table XVI-1 that a number of older thermal plants were assumed to be retired (at the end of 30 years of operation) during the study period. Details of their retirements are given in Table XVI-1.

16.3. Sensitivity analyses

A summary of the nuclear power market as affected by the changes in certain economic parameters is shown in Table XVI-3.

(a) Influence of discount rate

Table XVI-2 shows the effect on the objective functions of using different discount rates. It can be seen that there is no change in the conclusions reached for the reference conditions, that is, that the optimum year for further introduction of nuclear units is 1980 or earlier and, referring to Table XVI-3, that the total nuclear capacity added during the study period is 6000 MW. However, it can be noted that in the 10%-discount case the difference between the objective functions for cases 13 and 14 (i.e. further nuclear unit introduction in 1980 and 1983) is only one part in 20 000.

(b) Influence of capital costs

The effect of the use of capital cost data generated by ORCOST-1 (see Appendix B) which has lower nuclear plant-fossil plant differential costs is also shown in Table XVI-2.

The conclusion remains the same as for the reference case. Again, the optimum year for introduction of further nuclear units is 1980 or earlier and the total nuclear capacity added during the study period is 6000 MW.

TABLE XVI-1. SYSTEM CAPACITY EXPANSION SCHEDULE – REFERENCE CASE

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]	300 500[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 -1 016[d] 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 -1 162[d] 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 XVI-2. COMPARISON OF SENSITIVITY STUDIES TO REFERENCE CASE OBJECTIVE FUNCTIONS (10^3 US $)

Case No.	Year of introduction [a, b]	Reference case [c]	Sensitivity studies [d]				
			Discount rates		Oil price escalation rates		ORCOST-1
			6%	10%	0%	4%	
13	1980	3 517 812	4 359 158	2 840 881	3 369 630	3 706 002	3 314 739
14	1983	3 528 155	4 385 885	2 840 975	3 359 014	3 746 039	3 348 565
15	1984	3 538 670	4 410 837	2 843 002	3 347 018	3 784 108	3 381 111
16	1986	3 569 468	4 474 246	2 854 598	3 335 038	3 874 033	3 451 920
17	1990	3 676 511	4 670 019	2 910 002	3 362 404	4 097 141	3 613 868

[a] The first nuclear plant unit, Atucha 1, will be operational in 1973 and Córdoba may become operational by 1979.
[b] With the exception of one coal-fired 400 MW unit introduced in 1980, all new plants added, starting on the "introduction date", are assumed to be nuclear.
[c] Reference conditions are stated in Section 9.3.
[d] All other conditions, except for discount rates, same as in [c].

TABLE XVI-3. SUMMARY OF NUCLEAR UNITS FROM SENSITIVITY STUDIES

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) Influence of fuel oil escalation rates

In the reference case, the price escalation rate for imported oil was taken to be 2%/yr relative to the general inflation rate of 4%. To evaluate the effect of this assumed escalation rate, other price escalation rates of 0% and 4% for imported oil were studied. The results are also shown in Tables XVI-2 and XVI-3. With the higher fuel oil price escalation rate of 4% the conclusion for the reference case is thoroughly reinforced with the total nuclear capacity added during the study period being 6000 MW. However, with an oil price escalation rate of 0% relative to the general inflation rate, further nuclear power additions could be deferred until 1986 and the nuclear capacity added during the study period then becomes 3600 MW. Thus a variation in the fuel oil escalation rates relative to the general inflation can have a major influence on the nuclear power market.

(d) Effect of depreciation method used

In the reference case, the salvage value of plants at the end of the year 2000 was based on linear depreciation which tends to penalize capital intensive alternatives. The effect of using sinking fund depreciation instead of linear depreciation was not studied for Argentina. From studies done for other countries, however, it can be concluded that using sinking fund depreciation is roughly equivalent to reducing the discount rate by 1%. The conclusions in 16.3(a) above are thus applicable.

16.4. Financial considerations associated with reference case expansion program

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

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

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

(a) Plant construction schedule (same schedule, in years, that was used in the ORCOST calculations). The ORCOST-3 total plant capital costs (including interest during construction) are distributed over the construction period according to the expenditure-time schedules (S-curves) assumed in ORCOST.

(b) Per cent of expenditure that was domestic (the foreign being 100 minus this value).

(c) Capital cost, in US $/kW (same value as used in the WASP program; this value includes interest during construction).

(d) Unit capacity, in MW.

The cash-flow program, using a 4th order polynomial approximation of the S-curve used in the ORCOST program, developed the year-by-year domestic and foreign expenditures associated with each plant. These values were printed in tabular forms, 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 required during the year preceding operation, and 10% being required one year earlier.

Table XVI-4 displays the domestic and foreign cash flows associated with capital investments for the near-optimum solution, based on reference conditions, i.e. that of Table XVI-1. The cash flows are given for each plant and for the total program. Only plants

TABLE XVI-4. CASH FLOW FOR THERMAL PLANTS ADDED IN 1980-1989

DOMESTIC CASH FLOW

YEAR	PLANT	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	TOTAL
1980	C400	.0	.0	1.2	13.7	29.1	15.6	.0	.0	.0	.0	.0	.0	.0	.0	.0	59.7
	N600	.6	5.5	20.5	34.9	36.1	12.4	.0	.0	.0	.0	.0	.0	.0	.0	.0	110.4
	Fuel	.0	.0	.0	.0	.8	7.5	.0	.0	.0	.0	.0	.0	.0	.0	.0	8.4
1981	No Plants Added																
1982	No Plants Added																
1983	N600	.0	.0	.0	.6	5.5	20.5	34.9	36.1	12.4	.0	.0	.0	.0	.0	.0	110.4
	Fuel	.0	.0	.0	.0	.0	.0	.0	.8	7.5	.0	.0	.0	.0	.0	.0	8.4
1984	2xN600	.0	.0	.0	.0	1.3	11.0	41.0	69.9	72.3	24.9	.0	.0	.0	.0	.0	220.8
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	1.7	15.0	.0	.0	.0	.0	.0	16.8
1985	No Plants Added																
1986	N800	.0	.0	.0	.0	.0	.0	1.2	8.9	26.1	40.8	40.3	13.3	.0	.0	.0	130.7
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.9	8.6	.0	.0	.0	9.6
1987	N800	.0	.0	.0	.0	.0	.0	.0	1.2	8.9	26.1	40.8	40.3	13.3	.0	.0	130.7
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.9	8.6	.0	.0	9.6
1988	N1TO	.0	.0	.0	.0	.0	.0	.0	.0	2.2	13.1	32.0	46.4	44.1	13.9	.0	152.0
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	1.0	8.9	.0	10.0
1989	N1TO	.0	.0	.0	.0	.0	.0	.0	.0	.0	2.2	13.1	32.0	46.4	44.1	13.9	152.0
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	1.0	8.9	10.0
Domestic total		.6	5.5	21.7	49.3	73.1	67.3	77.2	117.1	131.4	122.4	127.2	141.7	113.5	68.0	22.9	1139.7
Total - nuclear fuel only		.0	.0	.0	.0	.8	7.5	.0	.8	9.2	15.0	.9	9.5	9.6	9.9	8.9	72.1

FOREIGN CASH FLOW

YEAR	PLANT	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	TOTAL
1980	C400	.0	.0	.8	9.1	19.4	10.4	.0	.0	.0	.0	.0	.0	.0	.0	.0	39.8
	N600	.6	5.5	20.5	34.9	36.1	12.4	.0	.0	.0	.0	.0	.0	.0	.0	.0	110.4
	Fuel	.0	.0	.0	.0	.8	7.5	.0	.0	.0	.0	.0	.0	.0	.0	.0	8.4
1981	No Plants Added																
1982	No Plants Added																
1983	N600	.0	.0	.0	.6	5.5	20.5	34.9	36.1	12.4	.0	.0	.0	.0	.0	.0	110.4
	Fuel	.0	.0	.0	.0	.0	.0	.0	.8	7.5	.0	.0	.0	.0	.0	.0	8.4
1984	2xN600	.0	.0	.0	.0	1.3	11.0	41.0	69.9	72.3	24.9	.0	.0	.0	.0	.0	220.8
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	1.7	15.0	.0	.0	.0	.0	.0	16.8
1985	No Plants Added																
1986	N800	.0	.0	.0	.0	.0	.0	1.2	8.9	26.1	40.8	40.3	13.3	.0	.0	.0	130.7
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.9	8.6	.0	.0	.0	9.6
1987	N800	.0	.0	.0	.0	.0	.0	.0	1.2	8.9	26.1	40.8	40.3	13.3	.0	.0	130.7
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.9	8.6	.0	.0	9.6
1988	N1TO	.0	.0	.0	.0	.0	.0	.0	.0	2.2	13.1	32.0	46.4	44.1	13.9	.0	152.0
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	1.0	8.9	.0	10.0
1989	N1TO	.0	.0	.0	.0	.0	.0	.0	.0	.0	2.2	13.1	32.0	46.4	44.1	13.9	152.0
	Fuel	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	1.0	8.9	10.0
Foreign total		.6	5.5	21.3	44.7	63.3	62.1	77.2	117.1	131.4	122.4	127.2	141.7	113.5	68.0	22.9	1119.8
Total - nuclear fuel only		.0	.0	.0	.0	.8	7.5	.0	.8	9.2	15.0	.9	9.5	9.6	9.9	8.9	72.1

commissioned during the 1980s are included, so the cash flows begin in 1974 and peak in 1982 though in fact they will continue to increase after that because of expenditures on plants to be commissioned during the 1990s.

For the nuclear plants the fuel cycle working capital requirements are also shown. Although individual fuel purchases are normally financed over short terms, e.g. three to five years, there is in fact a substantial investment outstanding in fuel over the life of the plant. Also, the fuel capital investments used in the WASP economic evaluation are the present-worth levelized average investment over plant life. Thus they may be used as an approximation to the cost of the first core and in Table XVI-4 they have been distributed over the two years preceding commissioning more or less according to the payment schedule for the first core (Appendix J.). The total cash requirements are about US $ 2 260 million, about US $ 1 120 million being in foreign currency. The nuclear fuel costs are shown separately by years and in total in Table XVI-4. The total is about US $ 144 million of which 50% requires foreign exchange. (Note: all of these are 1973 costs with no allowance for escalation.)

17. SUMMARY AND CONCLUSIONS

17.1. Basic conditions

Table XVII-1 summarizes the conditions used in the analyses of various alternative expansion plans for the national interconnected system in Argentina during the period 1980 to 1989 From the figures given in Table XVII-1, it can be shown that during the study period there is a total addition of nearly 10 000 MW of new capacity, of which 6400 MW is new thermal capacity

In carrying out the analyses, it was assumed that the schedule of hydro and pumped storage capacity additions would be fixed and therefore held constant for all cases considered. The hydro and pumped storage schedules selected are described in Section 14.2. These additions 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 XVII-1. SUMMARY OF CONDITIONS USED IN THE ANALYSES

	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).

17.2. Economic basis

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

The economic data used as a basis for present-worth calculations are summarized in Table XVII-2. The capital costs were derived for construction conditions in Argentina as described in Section 13. The heat rates given are based on data in Appendix G and the unit fuel costs, operating and maintenance costs and annual availabilities are as given in Section 14.4(d).

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

Plant type	Capital cost (US $/kW)			Full load heat rate (kcal/kWh)	Fuel cost (US ¢/10 kcal)			O & M cost (US $/kW-month)	Annual availability (%) [b]
	Local	Foreign	Total		Local	Foreign	Total		
C400	150	99	249	2 233	182	0	182	0.22	80
C600	131	87	218	2 270	182	0	182	0.19	78
C1T0	115	76	191	2 268	182	0	182	0.16	78
O400	133	88	221	2 211	0	182	182	0.21	83
O600	116	77	193	2 250	0	182	182	0.17	80
O1T0	101	68	169	2 248	0	182	182	0.14	78
N400	236	235	471	2 502	28	29	57	0.42	83
N600	198	198	396	2 501	27	28	55	0.32	80
N1T0	162	162	324	2 499	25	26	51	0.23	78
GT50	-	125	125	4 000	319	0	319	0.7	97

[a] In terms of 1 January 1973 dollars.
[b] Based on maintenance and forced outage times (refer Appendix E, Table 5).

17.3. 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 to give the desired loss-of-load probability each year of the study period. The results 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 five 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.

In all of these runs, the sensitivity of the results to variations in economic parameters such as discount rate, fuel escalation rates and capital costs of generation units was considered. The results of these studies are described in detail in Section 16.

17.4. Potential 1980-1989 nuclear power market

The potential market for nuclear plants in Argentina in the referenc case and for various sensitivity studies is shown in Table XVI-3. It is seen that the potential nuclear market in the study decade varies from 3600 MW to 6000 MW.

17.5. Conclusions

(a) The estimated total market for new generating units which will be commissioned during the 1980-1989 period is about 10 000 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.

(c) An evaluation of the competitiveness of nuclear versus oil-fired plant units indicates that under the reference conditions 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 plant (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 fossil plants (0% fossil fuel escalation) the nuclear market would drop to 3600 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. Thus, the given nuclear plant market statistics probably represent an upper limit to what will actually be achieved.

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APPENDIXES

A. WIEN AUTOMATIC SYSTEM PLANNING PACKAGE (WASP)

B. GENERATING PLANT CAPITAL COSTS (ORCOST)

C. LOAD DESCRIPTION DATA FOR WASP PROGRAM

D. ECONOMIC METHODOLOGY AND PARAMETERS

E. STANDARDIZED DATA FOR GENERATING UNITS CONSIDERED AS EXPANSION ALTERNATIVES

F. LONG-RANGE FORECASTING OF THE DEMAND FOR ELECTRICAL ENERGY

G. BASIS FOR HEAT RATE DETERMINATION

H. GENERALIZED POWER SYSTEM ANALYSIS APPROACH TO DETERMINE SYSTEM LIMITATIONS

I. FUTURE FOSSIL FUEL PRICES

J. NUCLEAR FUEL CYCLE COST TREATMENT

K. SENSITIVITY STUDIES

L. IAEA SERVICES AND ASSISTANCE IN CONNECTION WITH NUCLEAR POWER

M. ABBREVIATIONS USED IN THE MARKET SURVEY REPORTS

N. COOPERATING ORGANIZATIONS AND PARTICIPANTS IN THE MARKET SURVEY MISSION

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.

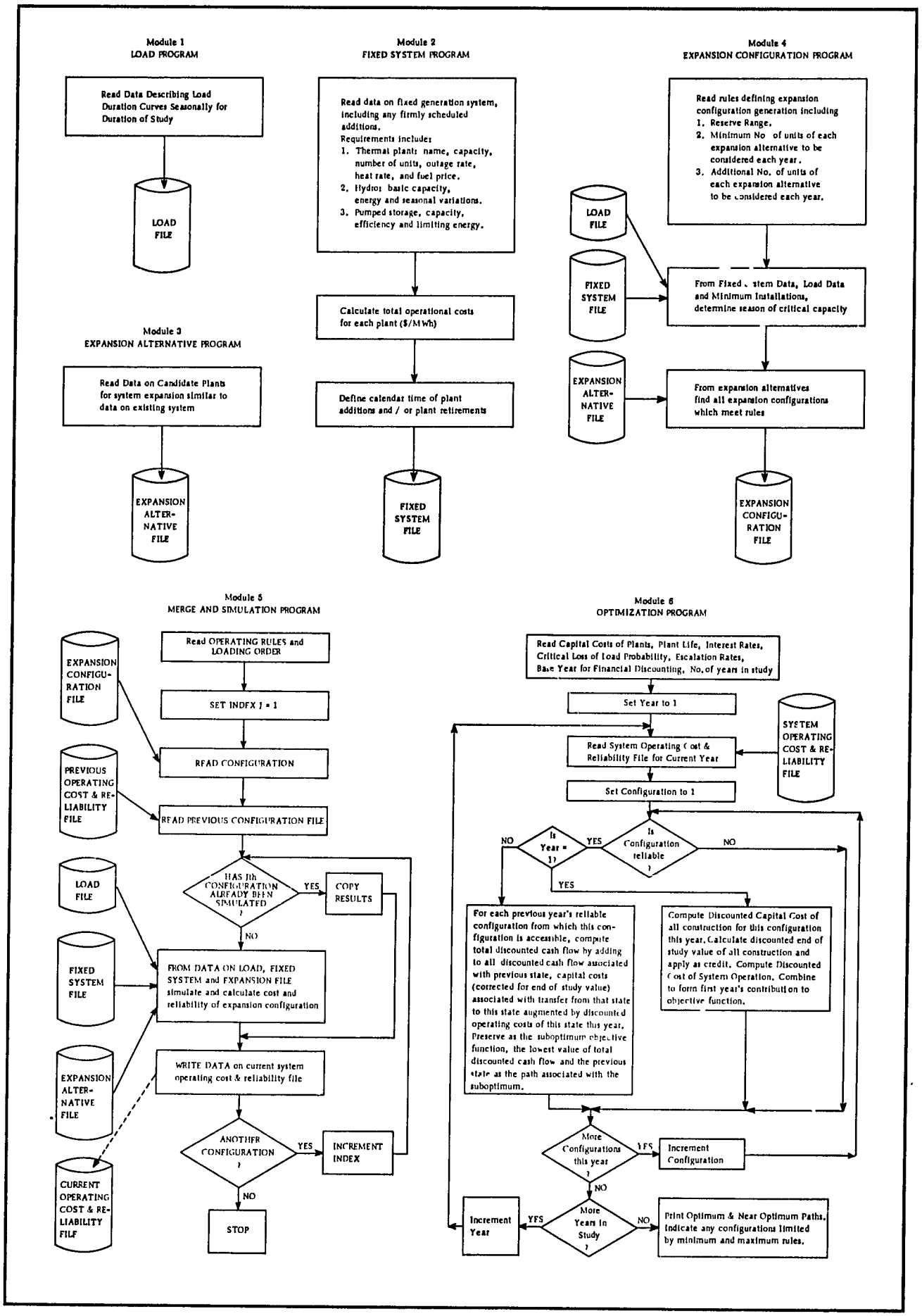

FIG. A-1. WASP PROGRAM FLOW SHEET.

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

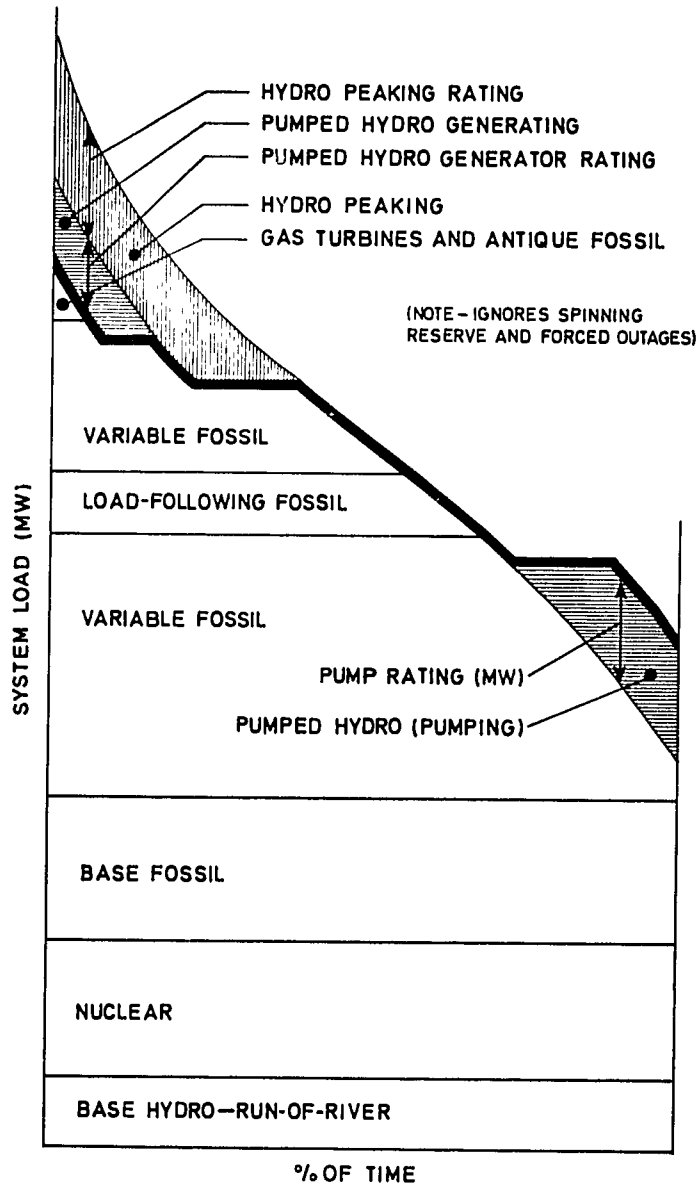

FIG. A-2. IDEALIZED PLACING OF VARIOUS TYPES OF STATION UNDER THE LOAD DURATION CURVE.

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.

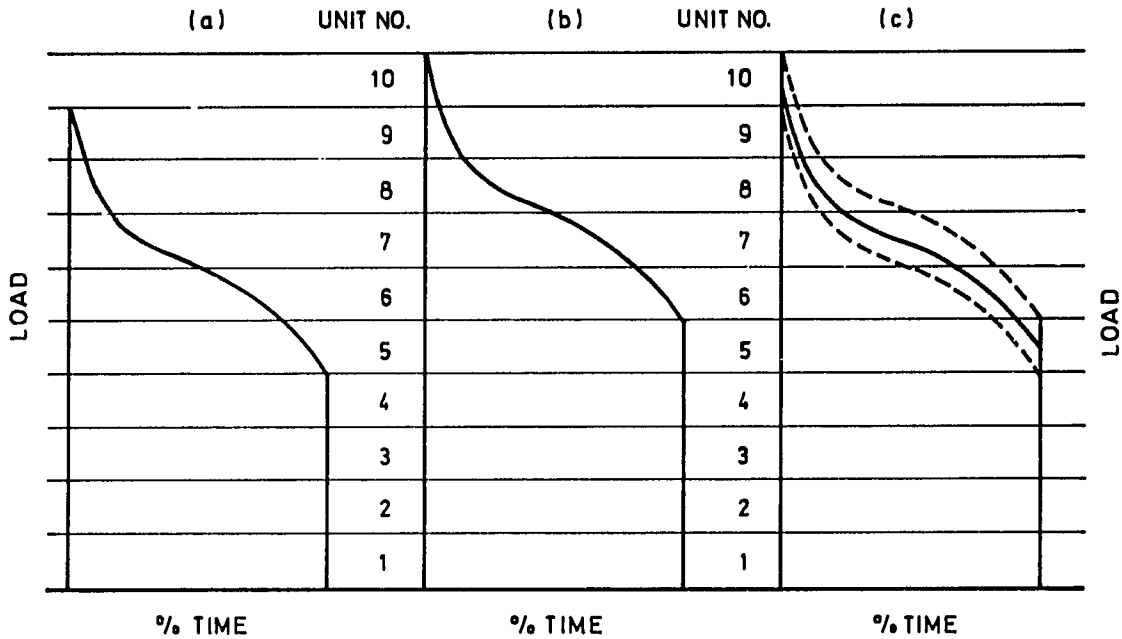

FIG. A-3. ILLUSTRATION OF THE METHOD OF STACKING THERMAL UNITS UNDER THE LOAD CURVE.

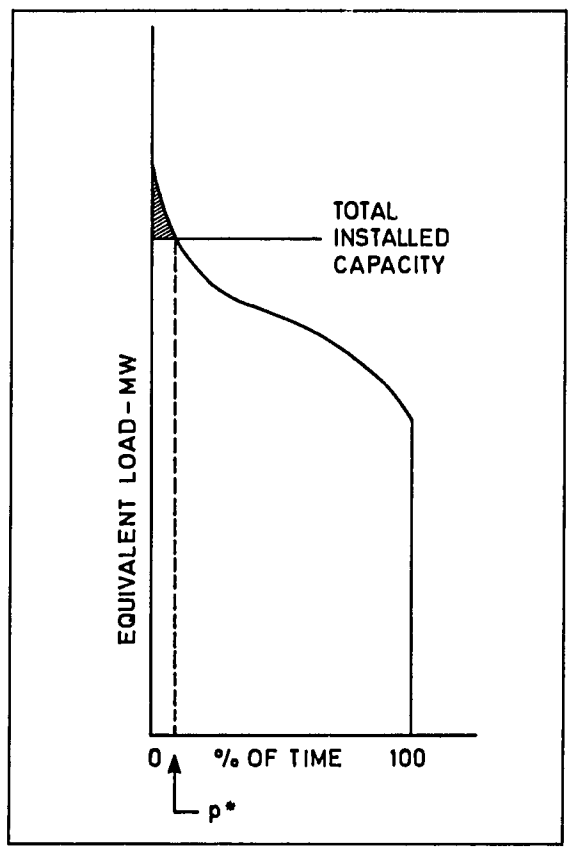

FIG. A-4. EQUIVALENT LOAD CURVE FOR AN ENTIRE SYSTEM.

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

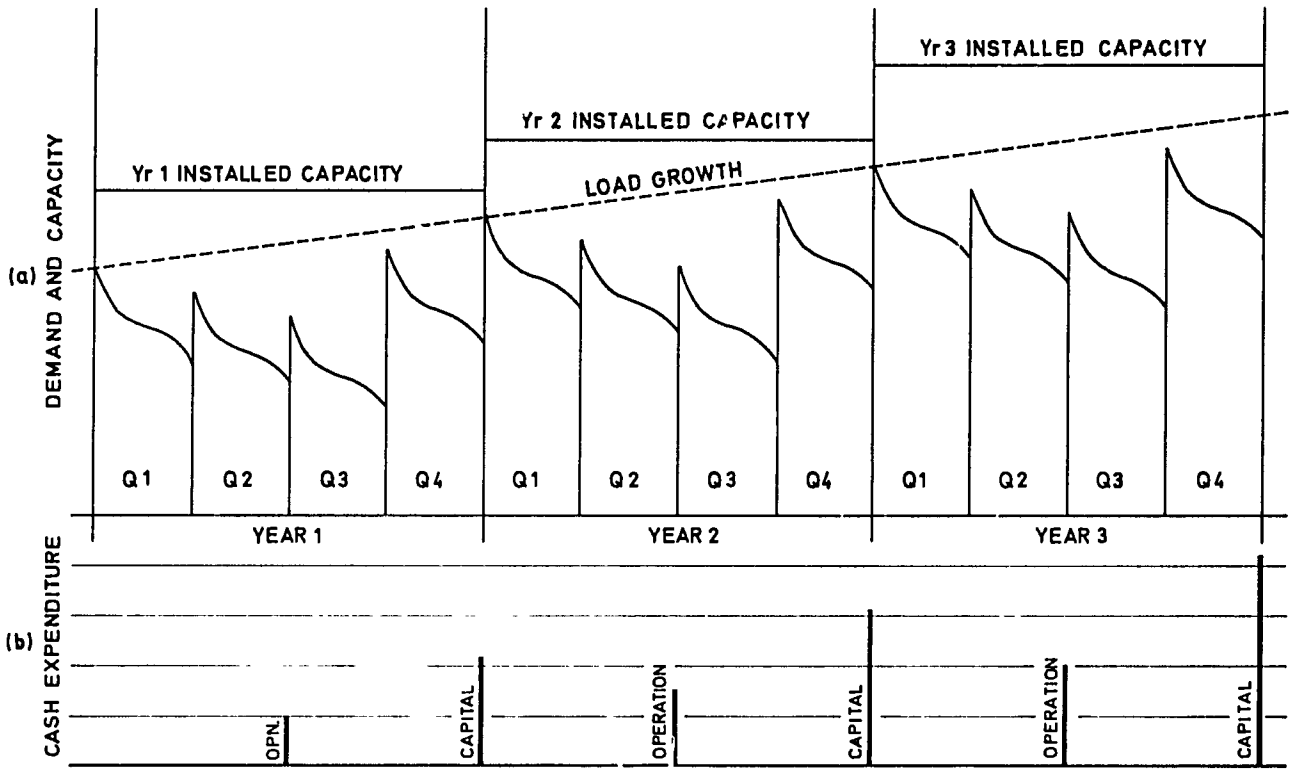

FIG. A-5. SCHEMATIC DIAGRAM OF LOAD GROWTH AND CORRESPONDING CASH FLOWS.

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

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

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

Dynamic programming

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

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

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

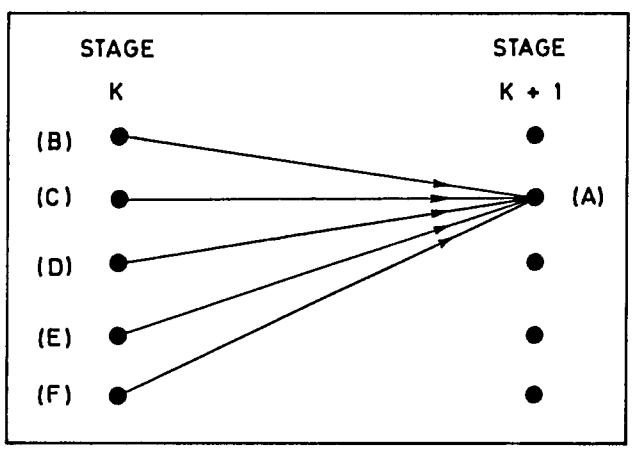

FIG. A-6. ILLUSTRATION OF A DYNAMIC PROGRAM STEP.

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

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

LIMITATIONS OF THE PACKAGE

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

ACKNOWLEDGEMENTS

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

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GENERATING PLANT CAPITAL COSTS (ORCOST)

STEAM-ELECTRIC POWER PLANTS

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

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

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

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

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

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

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

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

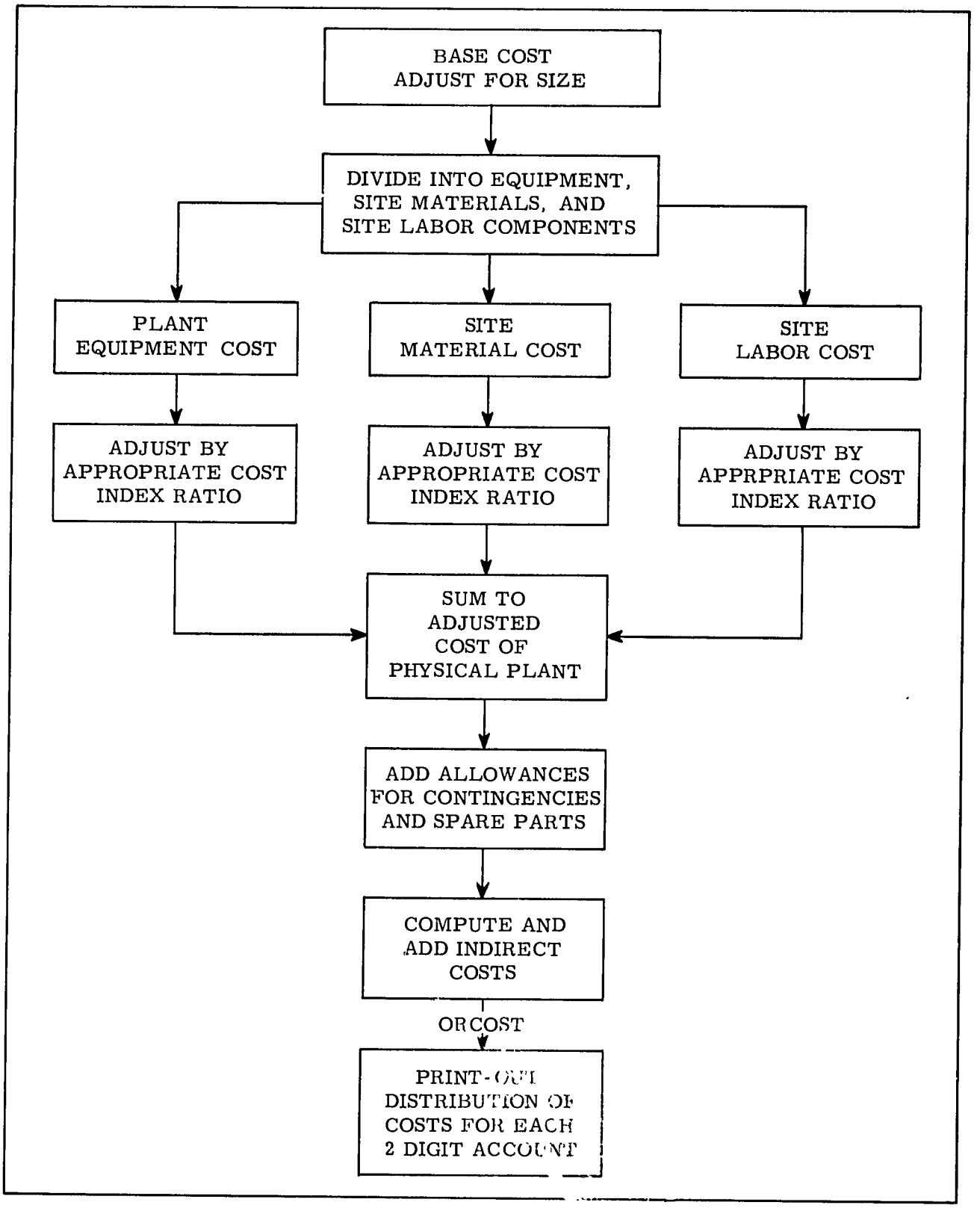

FIG. B-1. SCHEMATIC ILLUSTRATION OF ORCOST (AND CONCEPT II) PROCEDURE.

Selection of nuclear reactor type

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

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

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

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

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

The base cost model

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Modifications of indirect costs

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

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

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

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

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

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

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

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

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

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

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

Derivation of country cost indices

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

(a) Equipment cost index

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

(b) Materials cost index

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

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

(c) Labour cost index

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

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

ORCOST input and output

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Land costs

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

GAS TURBINE PLANTS

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

HYDROELECTRIC PLANTS

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

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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

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

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.

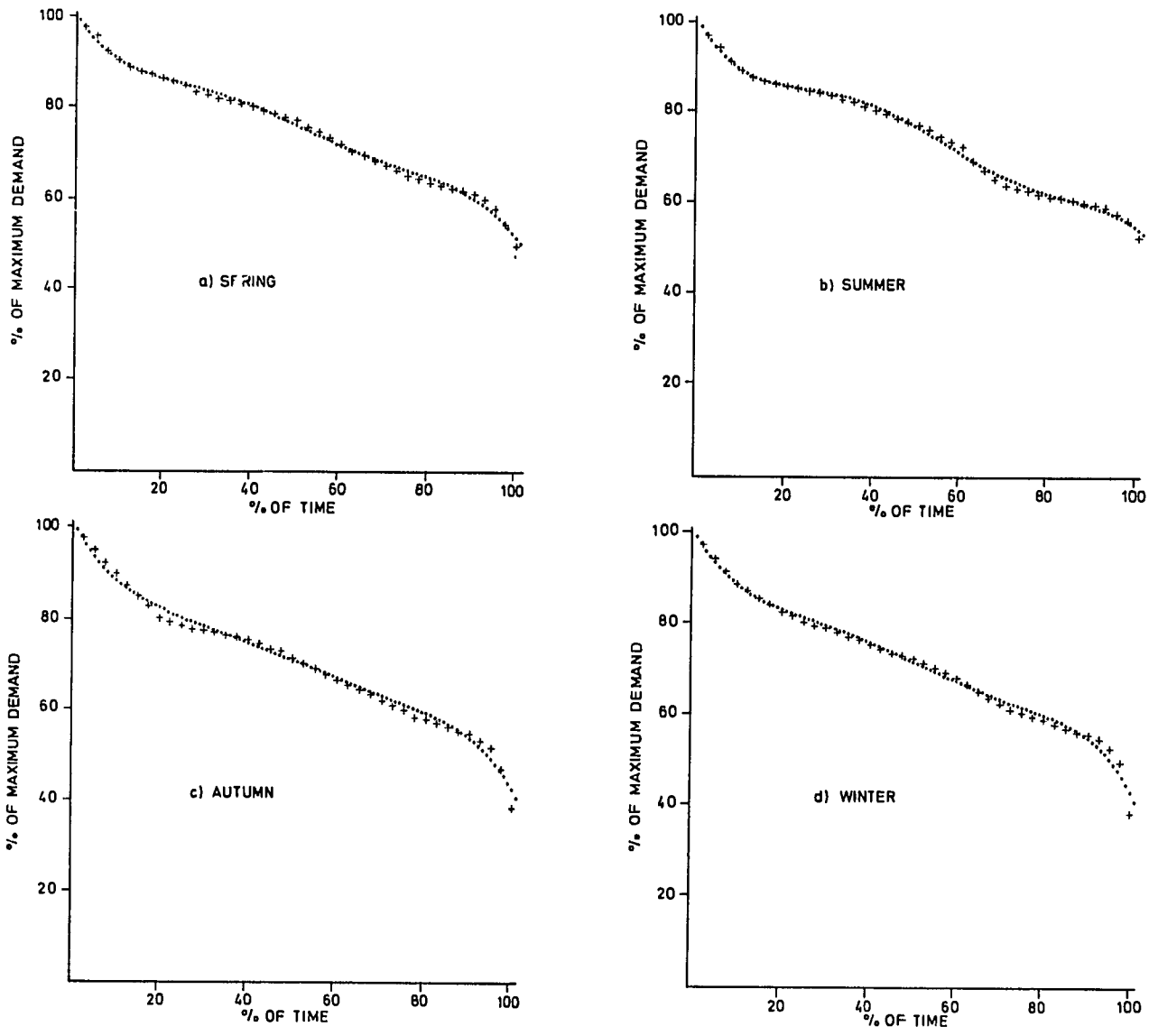

FIG. C-1. EXAMPLES OF THE FITTING OF A FIFTH ORDER POLYNOMIAL TO LOAD DURATION CURVES.

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

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

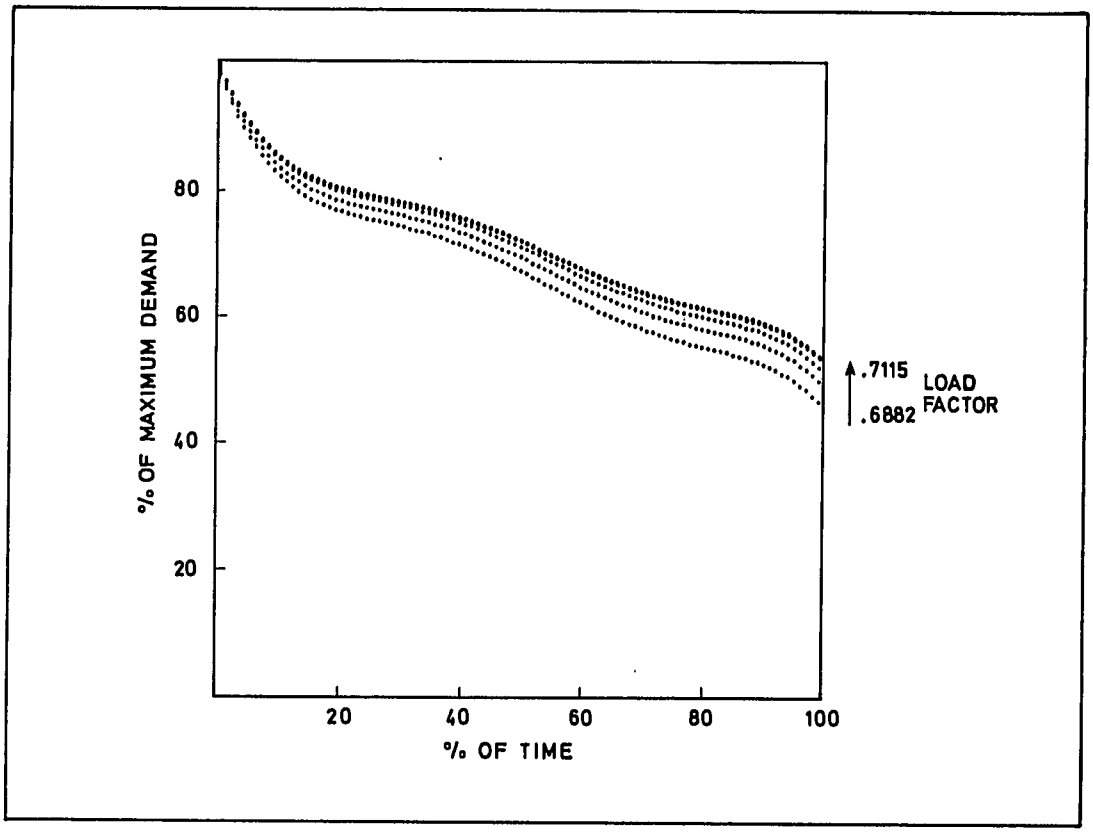

FIG. C-2. ILLUSTRATION OF THE EFFECT OF LOAD FACTOR ON A LOAD DURATION CURVE.

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 1.

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

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

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

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

METHODS OF OPTIMIZATION AND TIME HORIZON

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

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

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

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

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

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

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

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

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

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

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

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

according to strict sinking fund depreciation.

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

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

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

APPENDIX E

STANDARDIZED DATA FOR GENERATING UNITS CONSIDERED AS EXPANSION ALTERNATIVES

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

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

CHOICE OF UNIT SIZES, TYPES OF PLANTS AND NOMENCLATURE

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

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

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

MINIMUM OPERATING CAPACITIES

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

HEAT RATES

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

OPERATING AND MAINTENANCE COSTS

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

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

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

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

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

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

[a] Based on US conditions.

SCHEDULED MAINTENANCE TIMES AND FORCED OUTAGE RATES

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

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

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

TABLE E-5. PERCENTAGE UNAVAILABILITY OF ALTERNATIVE GENERATING PLANTS

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

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

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

PLANT LIFETIME

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

STUDY HORIZON

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

TRANSMISSION COSTS

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

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

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

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

APPENDIX F

LONG RANGE FORECASTING OF THE DEMAND FOR ELECTRICAL ENERGY

H. Aoki

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

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

VARIOUS METHODS

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

(a) Simple extrapolation

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

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

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

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

Both methods can be useful for comparatively short range forecasts.

(c) Accumulative method

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

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

(d) Sentiment method

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

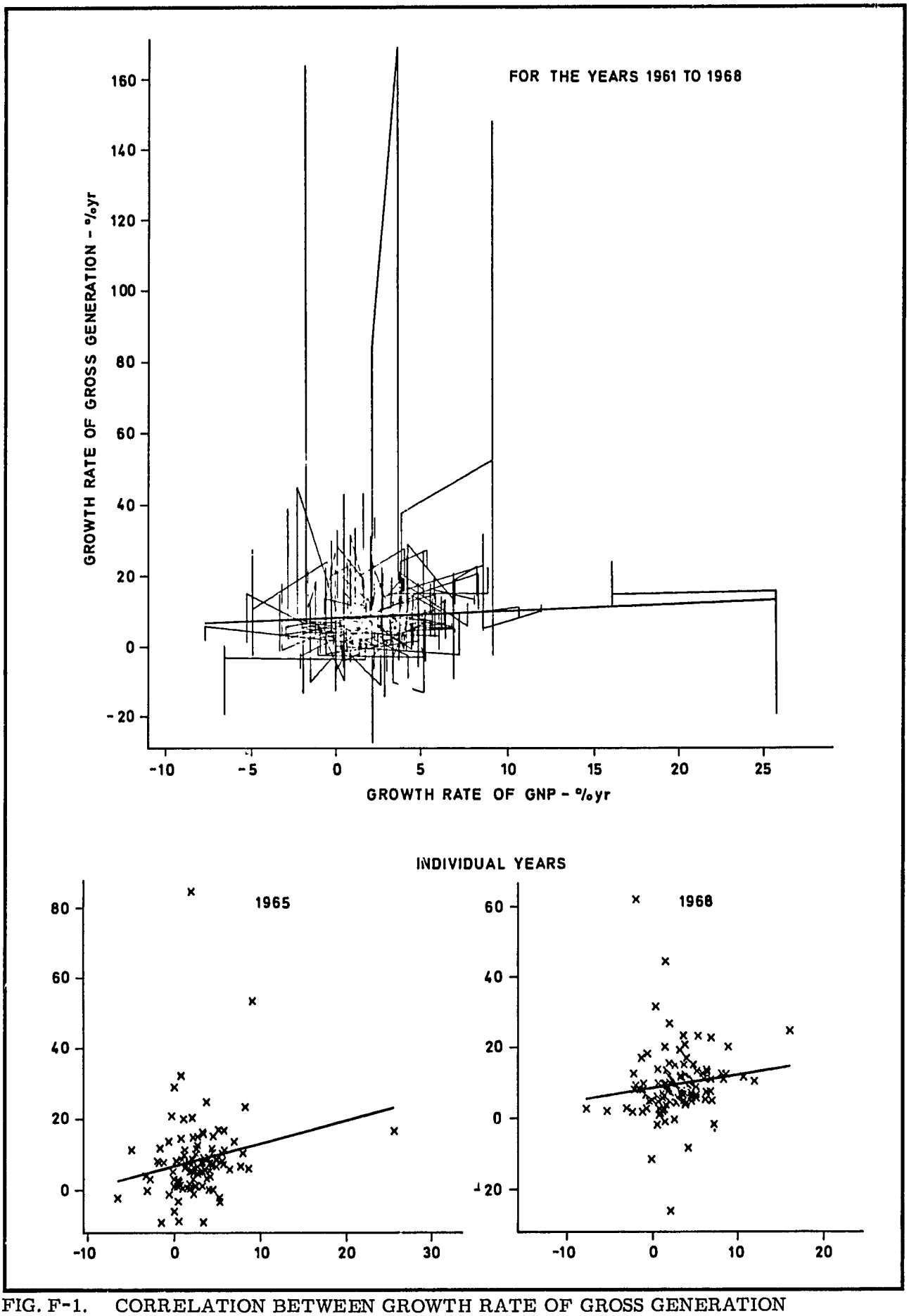

FIG. F-1. CORRELATION BETWEEN GROWTH RATE OF GROSS GENERATION AND OF GNP.

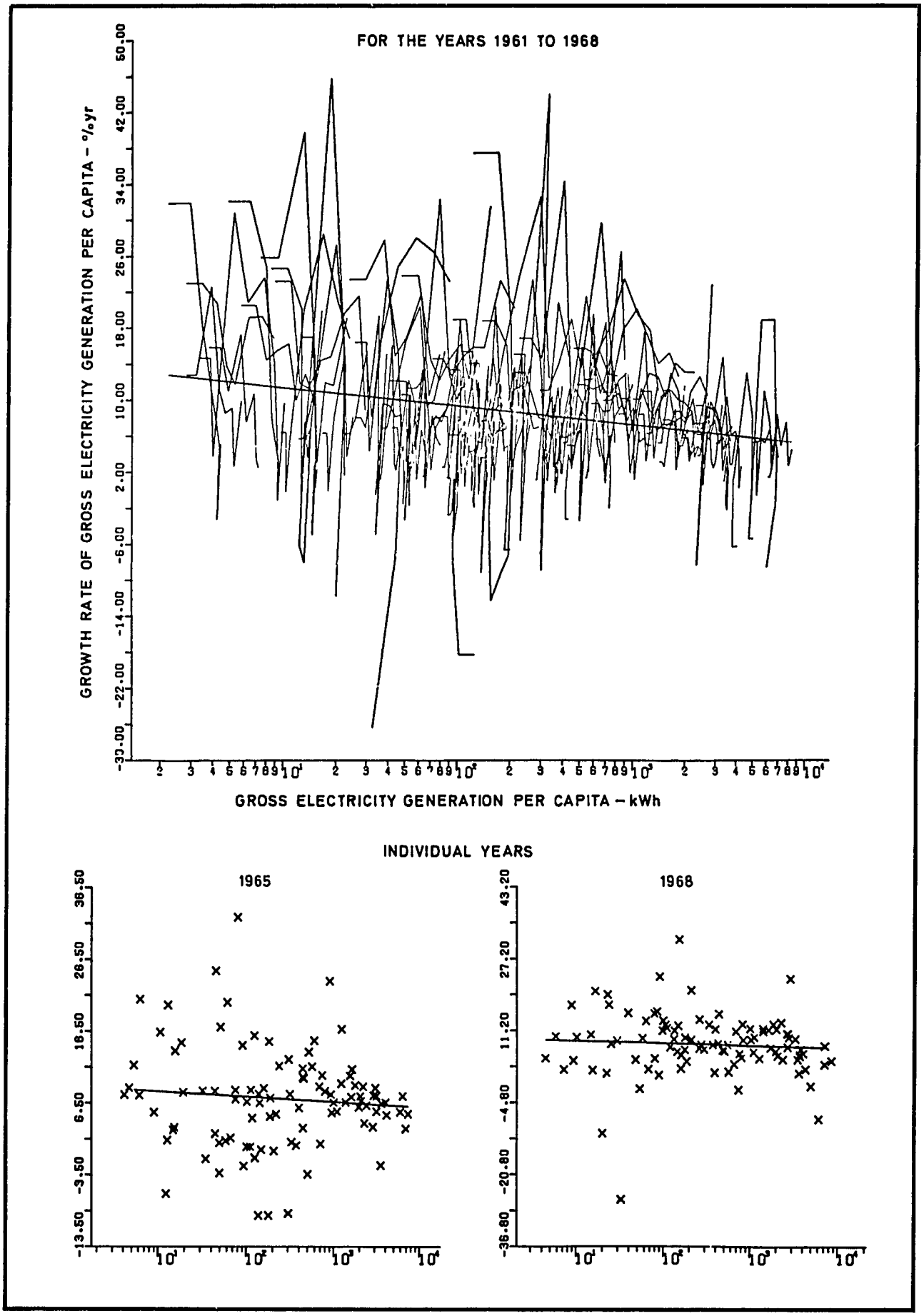

FIG. F-2. CORRELATION BETWEEN GROWTH RATE OF GROSS GENERATION AND OF GROSS GENERATION PER CAPITA.

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

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

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

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

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

THE AOKI METHOD USED FOR THE MARKET SURVEY

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

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

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

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

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

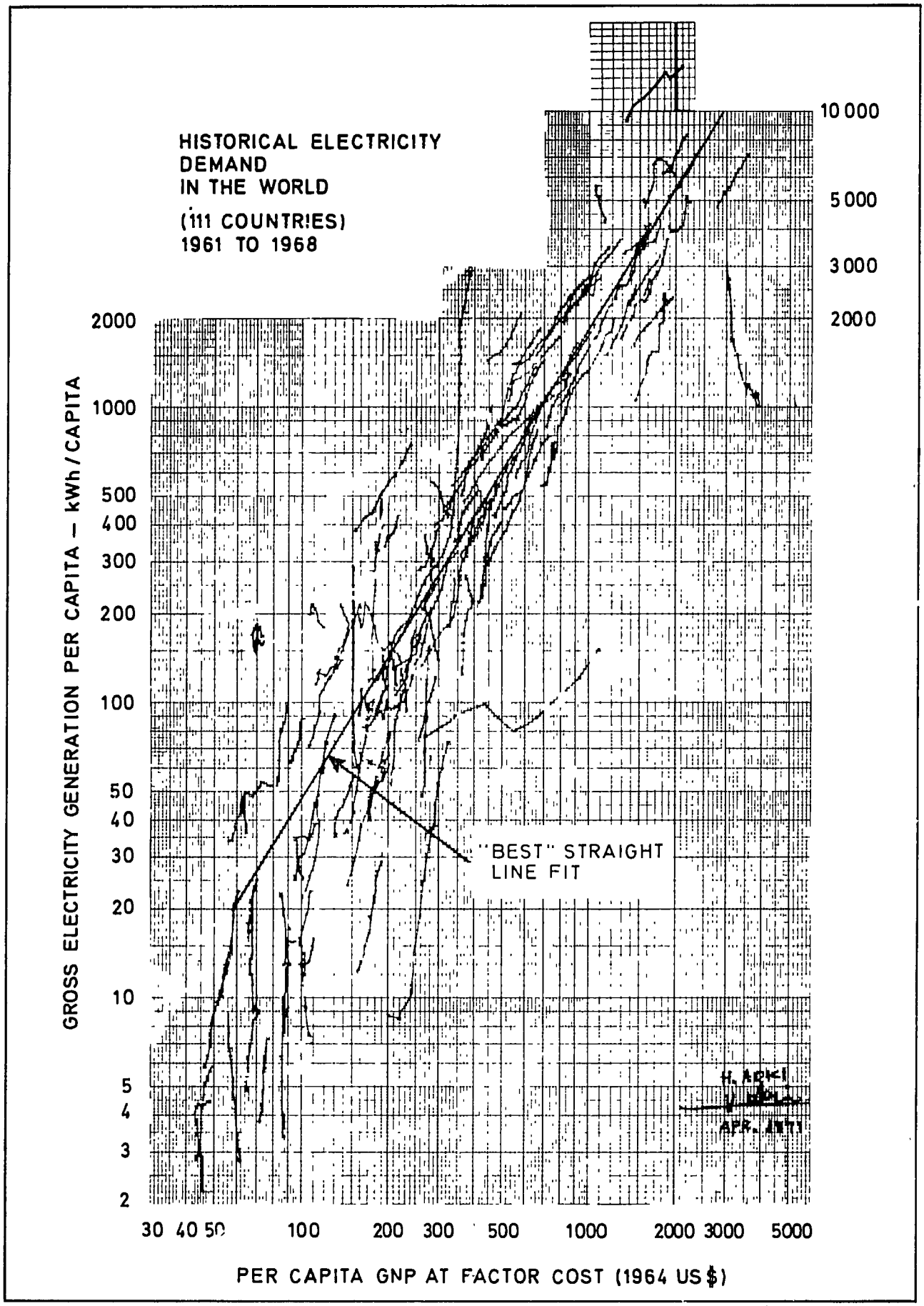

FIG. F-3. CORRELATION BETWEEN GROSS GENERATION PER CAPITA AND GNP PER CAPITA FOR 111 COUNTRIES FOR 1961 - 1968.

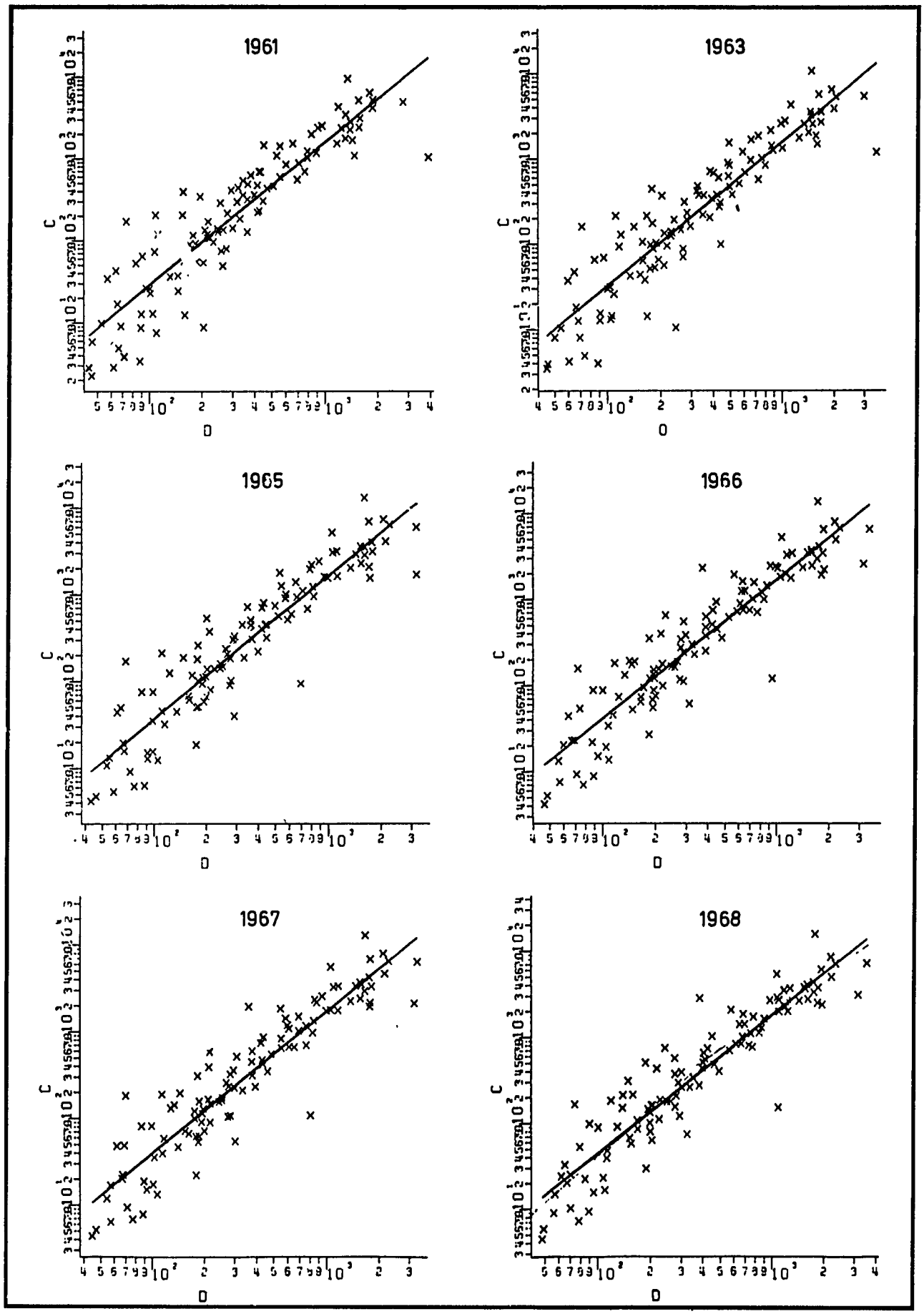

FIG. F-4. REGRESSION ANALYSIS OF THE PLOT OF GROSS GENERATION PER CAPITA VERSUS GNP PER CAPITA FOR 1968.

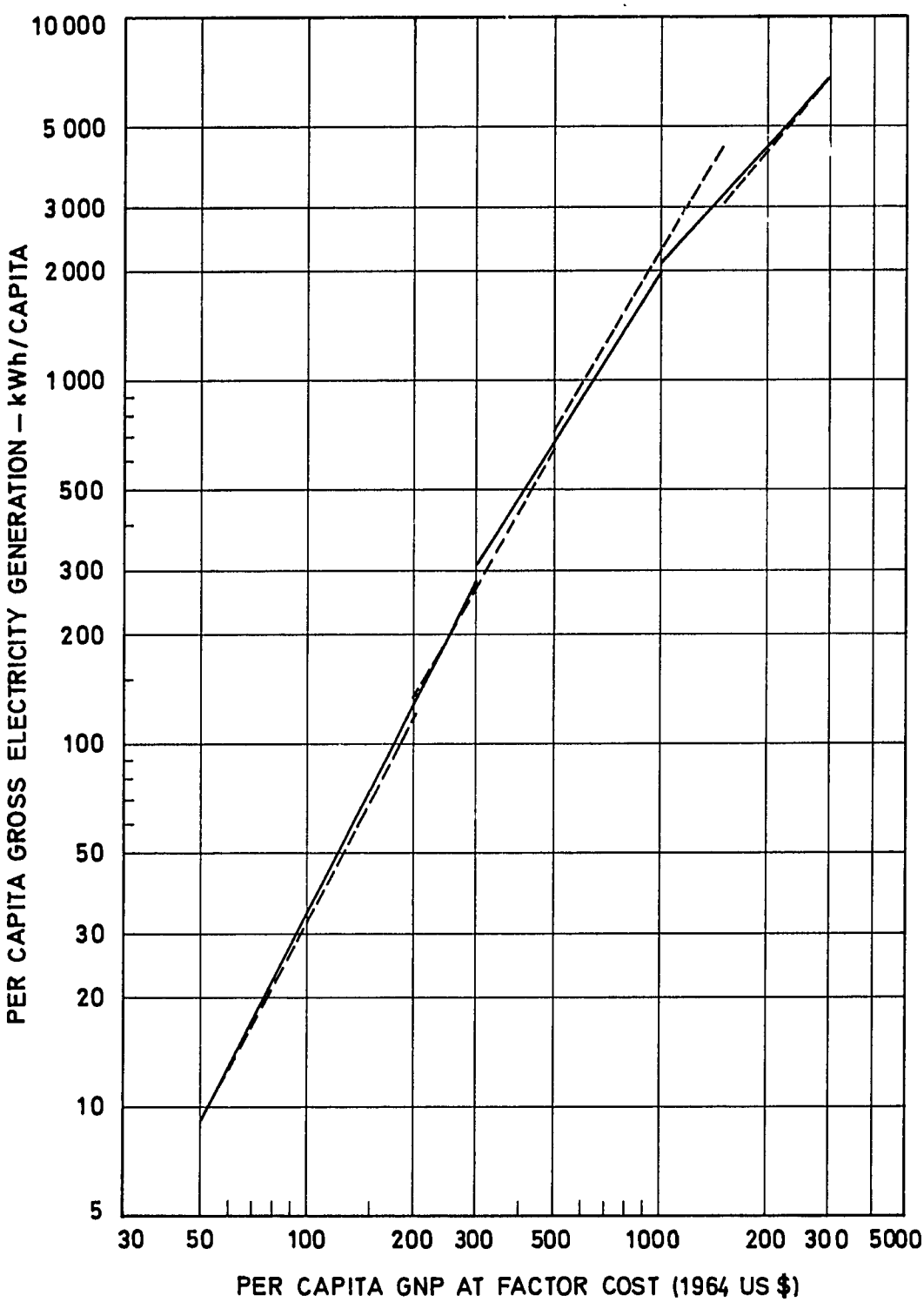

FIG. F-5. CORRELATION FOR INDIVIDUAL YEARS.

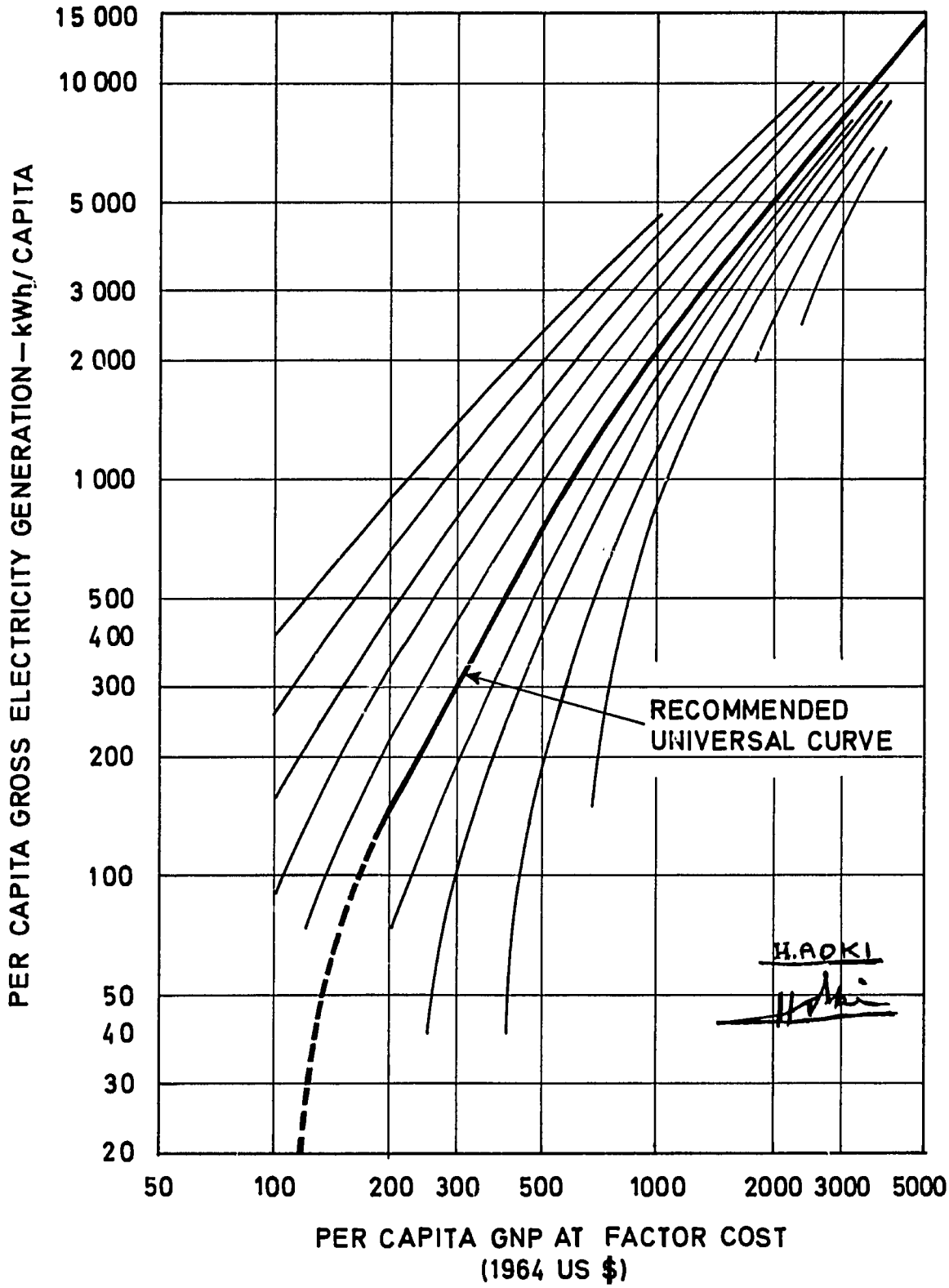

FIG. F-6. RECOMMENDED RELATION BETWEEN GROSS GENERATION PER CAPITA AND GNP PER CAPITA.

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

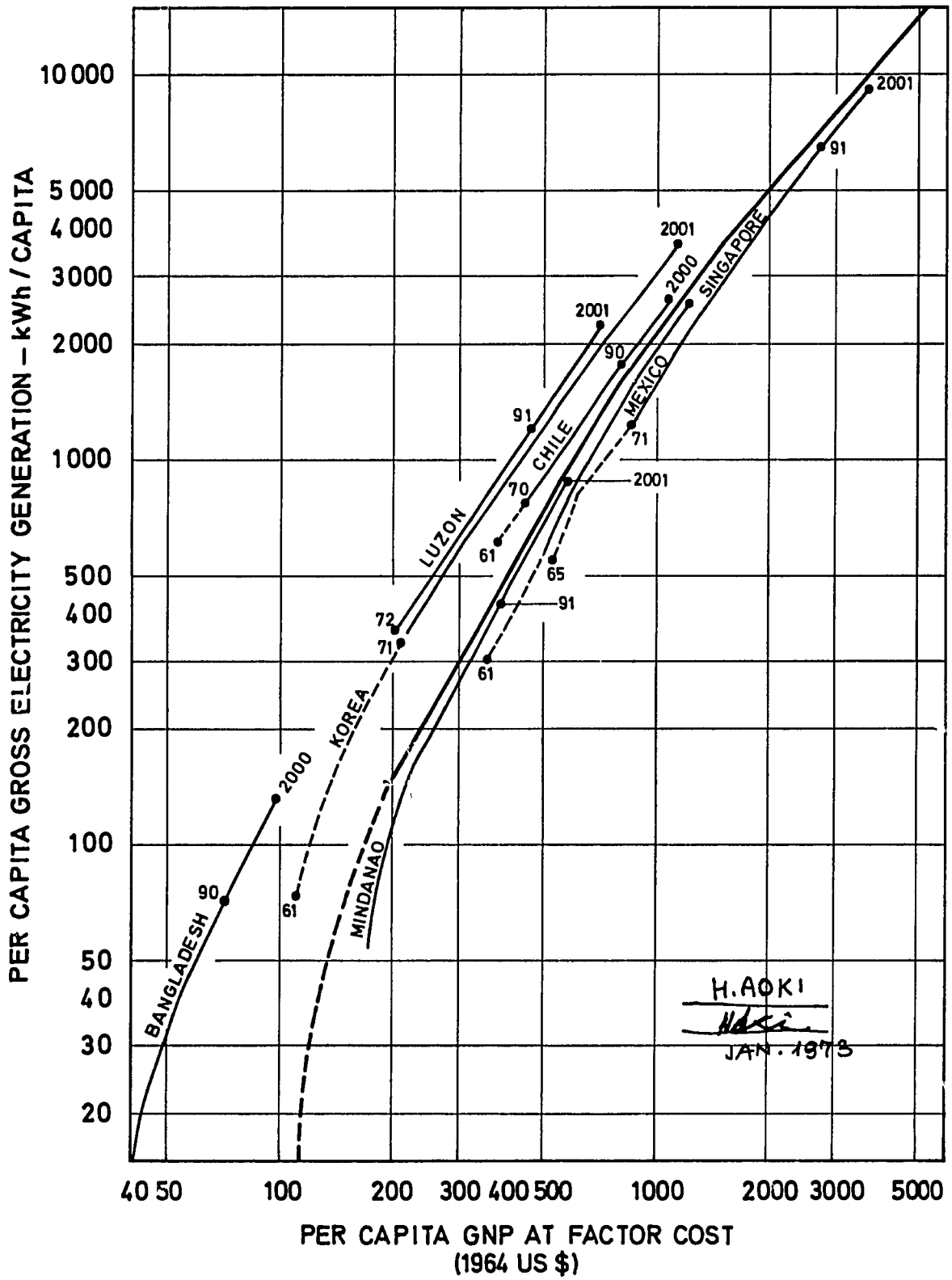

FIG. F-7. SURVEY COUNTRIES PLOTTED ON RECOMMENDED CURVE.

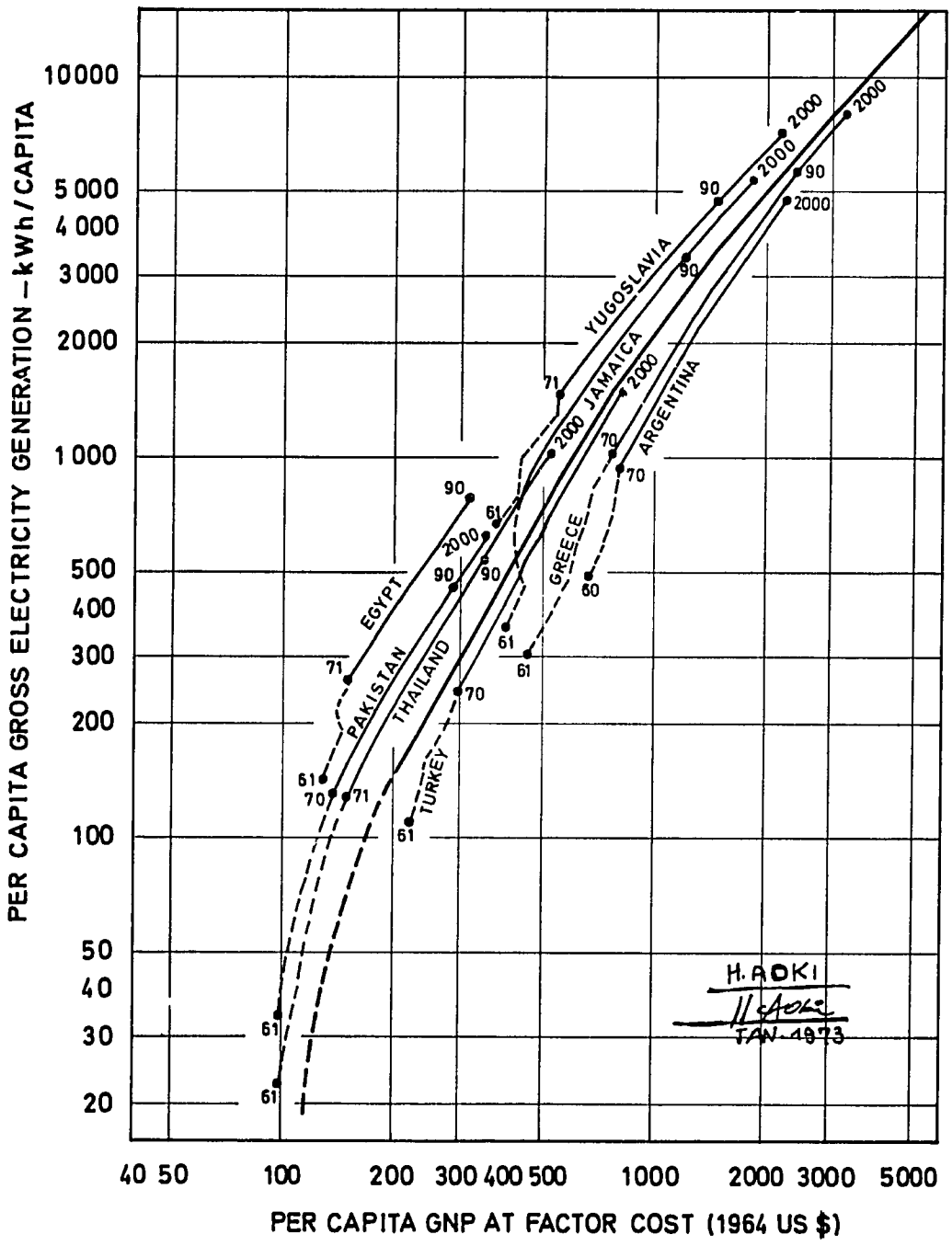

FIG. F-8. SURVEY COUNTRIES PLOTTED ON RECOMMENDED CURVE.

APPENDIX G

BASIS FOR HEAT RATE DETERMINATION

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

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

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

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

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

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

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

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

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

Type	Full load		Half load		Incremental energy rate[b] (kcal/kWh)
	Power (MW)	Heat rate (kcal/kWh)	Power (MW)	Heat rate (kcal/kWh)	
Coal	100	2 443	50	2 592	2 294
	150	2 421	75	2 551	2 291
	200	2 378	100	2 501	2 255
	300	2 360	150	2 474	2 246
	400	2 358	200	2 463	2 253
	600	2 350	300	2 467	2 233
	800	2 352	400	2 472	2 232
	1 000	2 348	500	2 483	2 213
Lignite	100	2 666	50	2 832	2 500
	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. 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.

* London, United Kingdom.

The normal eventuality of excessive short-circuit levels is the introduction of a higher voltage grid, other measures such as system segregation merely introducing a time delay which will be approximately equal for all plans. Hence the timing of a higher grid voltage in a particular system as dictated by short-circuit ratings will tend to be a common factor in all practical plant programs and will generally have little influence on the economic comparison of programs. Thus it was only necessary to check grid switchgear ratings against normal practice and where applicable to identify any special limitations or requirements.

Load flow transient stability

To achieve a reasonable standard of supply security the transmission grid should be capable of meeting the normal and 1st contingency power flow requirements throughout each plan without exceeding cricuit thermal ratings, loss of system stability (system splitting) or recourse to load shedding.

Information on standard grid circuit thermal ratings was generally available from each country. Transient stability limits were estimated using the 30° transmission angle criterion. This is a guiding criterion which, for the typical fault types and fault clearance times encountered on present-day systems, will ensure the retention of transient stability in the majority of cases. In the few cases where unforeseen difficulties arise, it is usually possible to retrieve the situation by introducing or increasing shunt and/or series compensation. With transmission costs of typically 15% to 20% of total plant costs and compensation costs at 10% to 15% maximum of transmission costs, the rare maximum error thus involved in this approach is of the order of 2% of total plant costs. This is regarded as being well within the accuracy of the capital cost data available to the Survey and there is no justification for a more elaborate approach to transient stability assessment, barring perhaps some well recognized exceptions.

The most common restriction to power flows in category (i) transmission are the thermal capabilities of circuits. However, this will tend to be a common factor in all generating plant programs considered for a particular country and detailed load flow studies within major load or generation regions were not necessary for the Market Survey.

For category (ii) transmission, the power flow requirement was simply estimated from the capacity of the power station less any local load to be supplied. Inter-regional power flow requirements (categories (ii) and (iii)) were determined by a simple regional plant/load balance tabulation taking into account generating set size and outage criteria and varying hydrological conditions. The number of transmission circuits at grid voltage to meet the power flow requirements so determined for categories (ii), (iii) or (iv) was then estimated to sufficient accuracy, taking into account thermal ratings, transient stability limits and transmission security criteria. If the number of circuits was excessive, then a higher voltage was considered and first establishment costs and also step-down transformer capacity were taken into account.

A further consideration in determining the capacity of category (iv) transmission is the integrity of the interconnected system following faults or a sudden loss of load or generation. Experience of interconnected systems in particular in the USA and the Scandinavian countries [1, 2] indicates that for a reasonable stability performance the capacity of system interconnectors should be at least 10% of the installed generating capacity of the smallest of the two systems interconnected. This was used as a guiding criterion for analysis purposes.

Details of any existing or proposed international interconnections (category (v)) were obtained from the Survey countries. In all cases these were found to be of insufficient capacity to have any noticeable influence on the Survey results.

LIMITS TO SET SIZE

The economics of scale play a major role in reducing the specific cost of installed generation and this is particularly so for nuclear power generation. On the other hand, increased unit size has associated penalties in system requirements such as generation and transmission reserve capacity. Thus there exists an optimum size for overall minimum cost of power delivered to the consumer [1].

The effects of increased unit size on the transmission system are taken into account in the network analysis described in this appendix. Any special transmission requirements can be allowed for by adjusting plant input data to the WASP computer program as described in Appendix E. The effect of increased unit size on non-availability rates and generation reserves can be directly allowed for in the corresponding input data items of the WASP computer program as required by the loss-of-load probability routine described in Appendix A. In this manner the 'economic optimum' set size can be determined. However, in addition to the economic optimum set size there is what may be termed a 'technical limit' set size (or reactor size in the case of nuclear stations) dictated by the permissible disturbance effects following the sudden loss of the largest generating unit. In cases where this technical limit is less than the economic optimum (which is highly probable in smaller systems) this can have a dominant influence on the economics of introducing large units into such systems.

The system frequency transient following sudden loss of a large generation unit has been found of prime interest in the assessment of this technical limit. The complete representation of this transient, termed 'frequency stability', is very complex, but a simplified analysis method and computer program was developed by ANS for the sudy of typical system response to sudden loss of generation. Although approximate, the analysis technique is regarded as adequate for the Market Survey purposes, bearing in mind the relatively large tolerances in data inherent in a forecasting exercise. The technique and computer program are described in the following paragraphs.

The average system frequency model

The dynamic response of a power system to a sudden loss of generation is generally characterized by two distinct components of power variation in the period of 10 to 20 seconds immediately following the disturbance. These are the faster transient oscillations in synchronizing power (time period typically 1 - 2 s) which arise due to angular disturbances from the steady state and the slower variation in prime mover power (time period typically 10 - 20 s) due to the primary regulation effects of the governor/turbine response to frequency change. The ability of a system to remain in synchronism following a given angular disturbance is mainly dependent on the transfer impedances between sources, i.e. on the transmission network. System faults will usually give rise to much larger angular deviations than loss of generation and will thus dictate the requirements of the transmission network for retention of transient stability. Thus, provided the transmission network has been designed with due regard to transient fault studies and the emergency redistribution of power flow resulting from plant outages, it is reasonable to assume that synchronous stability will be retained following a sudden loss of generation. (A possible exception to this premise is the case of a sudden loss of generation immediately following a severe system fault. However, such second contingency events are not considered here.)

Assuming that the system remains in synchronism then, neglecting losses (which may be assumed constant throughout the disturbance), the rate of change of stored kinetic energy (i.e. frequency) at any instant is equal to the difference between power input to the system (i.e. prime mover power) and power output (i.e. load),

$$(2H_T)(f_a)\left[\frac{df_a}{dt}\right] = \Sigma P_{mk} - P_L \qquad (1)$$

where H_T is the total inertia constant of connected machines including rotating loads (typically 3.0 to 5.0),

ΣP_{mk} is the sum of prime mover input power of connected generators,

P_L is the total connected load,

f_a is the average system frequency.

All quantities are in p.u. on the base of nominal system frequency and total nominal power of connected generation.

Since the system is assumed to remain in synchronism the transmission network may be neglected and Eq. (1) may be modelled by a number of prime movers and their generating units feeding a single block load as indicated in Fig. 1 and referred to as 'the average system frequency model' [3]. Simplified equations modelling the variation of prime mover power and load are described in the next section.

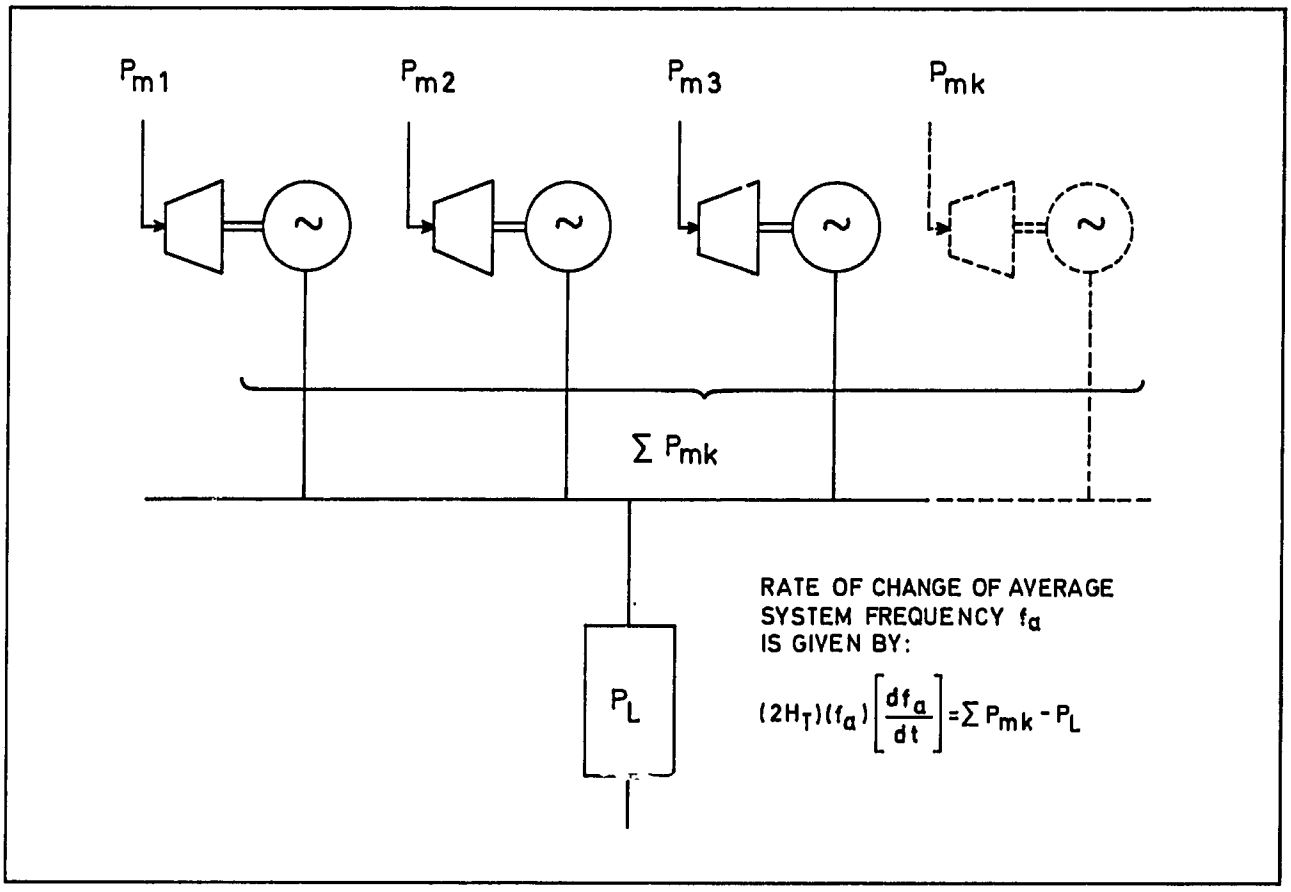

FIG. H-1. AVERAGE SYSTEM FREQUENCY MODEL.

Prime mover and load regulation

Maximum frequency dip before recovery (if it occurs), the time of maximum dip and the amount of load shed (if load shedding is permitted) are the main items of interest and thus the following assumptions can be made:

(i) Non-regulating base load units are assumed to have constant power output.
(ii) Only the governor/turbine response of regulating units is considered. Boiler response is neglected in thermal plants.
(iii) Secondary regulation is neglected.
(iv) Governor response is based on average system frequency. (The oscillating component due to synchronizing swings is generally at a much shorter time period than the governor/turbine response time and does not appreciably affect the prime mover output.)
(v) The total load P_L is assumed to depend only on average system frequency. Variations due to the oscillating component arising from synchronizing swings are neglected. Load variation with voltage, if desired, can be sufficiently represented by conversion to an equivalent variation with frequency.

Three types of regulating units are modelled:

(a) Thermal – non-reheat
(b) Thermal -- reheat
(c) Hydro including pumped storage

For the time period of interest (about 10 s) thermal units will generally permit faster power change rates than hydro units, but with a limit on sustained change (typically up to 15%

of nominal power). Hydro units on the other hand can give much larger sustained variations in output approaching their nominal rating with total response times of typically 10 to 20 seconds.

(a) Thermal – Non-reheat model

It is assumed that the disturbance is of sufficient magnitude to drive the steam valve to its limiting position at constant rate. The time constant of a non-reheat turbine may be neglected and thus the change in power output of this type of unit may be represented to a first approximation by the equation

$$P_1 = \left[\frac{P_{1c}}{T_1}\right] (t) \text{ with limit of } P_{1c} \tag{2}$$

where P_{1c} is the maximum permissible power change,
T_1 is the time for the valve to move to its limiting position,
t is the time from loss of generator

(b) Thermal – Reheat model

As for the previous type the movement of the steam valve may be approximated by the equation

$$V_2 = \left[\frac{P_{2c}}{T_2}\right] (t) \text{ with limit of } P_{2c} \tag{3}$$

where P_{2c} is the maximum permissible power change,
T_2 is the time for the valve to move to its limiting position.

The change in power output of this type of regulating unit may thus be represented by

$$P_2 = \frac{1 + (m)(T_h)(p)}{1 + (T_h)(p)} (V_2) \tag{4}$$

where m is the proportion of power developed by the high pressure turbine
T_h is the reheat time constant
p is the Laplace operator

The maximum permissible power change for both reheat and non-reheat type generation will depend on the allocation of spinning reserve but will be typically about 10% of the nominal power of the generation block and may lie in the range 5% to 20%. The valve motion time is typically one second and may vary between 0.5 and 1.5 seconds. The factor m is typically 0.3 and the reheat time constant T_h may lie in the range 5 to 12 seconds.

(c) Hydro model

In Ref. [4] a simplified transfer function is derived which gives a very good approximation to the response of a hydro governor with dashpot. From this the change in gate opening may be represented by the equation

$$G = \frac{1 + (T_d\, p)}{1 + (T_3\, p)} \left[\frac{\sigma_a}{\delta}\right] (P_{n3}) \text{ with limit } P_{3c} \tag{5}$$

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

- T_d is the dashpot time constant (typically 5 s, range 2.5 - 25 s),
- T_g is the governor response tin e or the inverse of governor open loop gain (typically 0.2 s, range 0.2 - 0.4 s),
- δ is the permanent droop (typically 0.04 p.u., range 0.03 - 0.06 p.u.),
- δ_t is the temporary droop (typically 0.31 p.u., range 0.2 - 1.0 p.u.),
- σ_a is the average frequency deviation ($= f_a - f_0$),
- P_{n3} is the nominal rated power output of regulating hydro generation,
- P_{3c} is the maximum available change in power output (hydro spinning reserve).

Thus the change in power output for this type of regulating unit is given by

$$P_3 = \frac{1 - (T_w)(p)}{1 + 0.5(T_w)(p)} (G) \tag{6}$$

where T_w is water starting time and is inversely proportional to water head and directly proportional to penstock length. Typical values of T_w lie in the range 0.5 to 5.0 seconds.

The above model was also used to represent pumped storage plant operating in the generating mode.

Load regulation model

The variation of load with frequency may be represented by an equation of the type

$$P_L = (1 + (\alpha)(\sigma_a))\,(P_{L0} - P_s) \tag{7}$$

where P_{L0} is the total connected load at $t = 0$ and $f_a = f_0$,
- P_s is the load shed as function of frequency and time,,
- α is the load frequency regulation coefficient.

In those countries where load shed schemes are in existence, frequency settings and the amount of load shed for each stage were based accordingly. In other cases typical values were assumed. The determination of whether or not load shedding occurs is generally the prime factor of interest and thus the first stage frequency setting is the major item of load shed data. This is typically 48.5 to 49.0 Hz for 50 Hz systems and 58.5 to 59.0 Hz for 60 Hz systems.

The special case of pumping load being shed by under-frequency detection can be included in the load shedding scheme.

In Ref. [5] a range of values for the load/frequency regulation coefficient from 0 to 2.5 is given. The effects of load/voltage regulation can generally be adequately represented by increasing α. Thus a typical value for α of 2.0 was used except where more accurate information was available from the country studied.

Total regulation

The total prime mover power of connected units at instant t is given by

$$\Sigma P_{mk} = \Sigma P_{mk0} + P_m \tag{8}$$

where ΣP_{mk0} is the pre-disturbance power output of connected generating units excluding the lost generator, and

$P_m = P_1 + P_2 + P_3$ is the total change in prime mover outputs of connected regulating units.

Let the loss of generation be ΔP $(= P_{L0} - \Sigma P_{mk0})$ and since $\frac{d\sigma_a}{dt} = \frac{df_a}{dt}$, Eq. (1) becomes

$$(2H_T)(f_a)\ \frac{d\sigma_a}{dt} = P_m - \Delta P - (\alpha)(\sigma_a)(P_{L0} - P_s) + P_s \tag{9}$$

The effect of variations in f_a on the solution of Eq. (9) is small and may be neglected, hence

$$\sigma_a = \frac{1}{\alpha(P_{L0} - P_s) + (2H_T)(p)}\ (P_m - \Delta P + P_s) \tag{10}$$

The computer program

The computer program AVSYF (Average system frequency) for the step-by-step solution of Eq. (10) has been obtained by appropriately "patching" an existing digital program representation of an analogue simulator. Transfer functions of the type of Eqs (4-6), integral functions and limit functions exist as standard routines. Integration is performed by a simple three-step method, but provided a small enough time step is used, accuracy is sufficient. The program also includes a plot routine which permits an immediate plot of the frequency variation to be obtained as output.

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APPENDIX I

FUTURE FOSSIL FUEL PRICES

R. Krymm

INTRODUCTION

Although practically all countries covered by the Market Survey possess and exploit domestic fossil fuel resources, fuel oil either imported or derived from imported crude remains in most cases the main competitor of nuclear fuels for future electric power production.

This fact alone suggests the use of fuel oil as the "reference fuel" and the validity of this assumption is further strengthened by the tight supply and demand relationship which is expected to prevail for oil products in the foreseeable future. The latter consideration suggests that the few Market Survey countries which are domestic producers of oil and gas in substantial quantities would be perfectly justified in pricing these resources on the basis of opportunity uses; that is, on the basis of thermal costs parity with imported fuel oil with due correction for transportation expenses.

Also, prices of coal and lignite are dependent on local conditions and must be considered separately in each specific case.

It is, therefore, not surprising that the bulk of this section is devoted to the problem of costs and prices of crude and fuel oils entering international trade.

It was, however, clear from the beginning that the fuel oil picture in developing countries could not be seriously studied without reviewing the world-wide structure of the oil industry and its rapidly changing trends.

It was, therefore, decided to consider in turn:

(1) The present and expected demand and supply structure of crude oil and the major producing and consuming areas.
(2) The changing cost and price structure of crude oil and its future trends.
(3) The cost of transport of oil by tanker and pipelines.
(4) The relationship between crude and oil product prices.
(5) The treatment of domestically produced fossil fuels.

DEMAND AND SUPPLY OF CRUDE OIL

Table I-1 shows the actual 1970 and estimated 1980 demands for oil in major areas of the world. The forecast is based on conservative rates of growth and the average annual rate of 5.4% for the world should be viewed against the 7.8% rate which prevailed during the 1950-1970 period.

TABLE I-1. PAST AND ESTIMATED DEMAND FOR CRUDE OIL (10^6 t)

	1970 (10^6 t)	1980 (10^6 t)	Rate of growth of demand (%)
USA	750	1 160	4.5
Western Europe	600	980	5
USSR and Eastern Europe	390	700	6
Japan	200	400	7
China	20	80	15
Rest of world	300	500	5
Total world	2 260	3 820	5.4

TABLE I-2. WORLD ESTIMATED CRUDE OIL PRODUCTION[a]

Countries	1970	1971	1972	% Change 1971/72	1972: % of Total
		10^3 t			
NORTH AMERICA[b]					
USA	533 677	530 385	532 000	+12.3	
Canada	69 954	75 025	87 500	+16.6	
	603 631	603 410	619 500	+2.7	23.9
CARIBBEAN AREA					
Venezuela	193 209	184 921	167 400	-9.5	
Colombia	11 071	11 127	10 400		
Trinidad	7 225	6 690	[illegible]		
	211 505	202 738	185 200	-8.7	[illegible].9
OTHER LATIN AMERICA					
Mexico	21 877	21 920	22 600	+3.0	
Argentina	19 969	21 494	22 150	+3.0	
Brazil	8 009	8 376	8 400		
Ecuador	191	174	3 500		
Peru	3 450	3 048	3 300		
Bolivia	1 124	1 714	1 900		
Chile	1 620	1 652	1 700		
	56 240	58 378	63 550	+8.9	2.4
MIDDLE EAST					
Saudi Arabia	176 851	223 515	285 500	+27.7	
Iran	191 663	227 346	254 000	+11.7	
Kuwait	137 398	146 787	152 000	+3.6	
Iraq	76 550	84 000	67 000	-20.2	
Abu Dhabi	33 288	44 797	50 000	+11.6	
Kuwait/SA "Neutral Zone" ..	26 724	29 118	30 300	+3.9	
Qatar	17 257	20 201	23 300	+15.3	
Oman	17 169	14 106	13 600	-3.6	
Egypt	16 404	14 706	11 000		
Dubai	4 306	6 252	7 500		
Sinai[c]	4 500	6 000	6 000		
Syria	4 353	5 254	5 300		
Bahrain	3 834	3 728	3 500		
Turkey	3 461	3 253	3 350		
Israel	77	62	50		
	713 835	829 125	912 400	+10.0	35.0
AFRICA (excluding Egypt)					
Libya	159 201	132 250	105 000	-20.5	
Nigeria	53 420	75 306	89 500	+18.8	
Algeria	47 253	36 346	52 000	+42.1	
Angola	5 065	5 830	7 200		
Gabon/Congo	5 442	5 794	6 600		
Tunisia	4 151	4 097	4 100		
Morocco	46	22	30		
	274 578	259 645	264 430	+1.8	10.2

TABLE I-2. (cont.)

Countries	1970	1971	1972	% Change 1971/72	1972: % of Total
		10^3 t			
WESTERN EUROPE					
West Germany	7 535	7 420	7 100		
Austria	2 798	2 516	2 500		
Norway	-	301	1 700		
Netherlands	1 919	1 715	1 630		
France	2 309	1 858	1 500		
Italy	1 408	1 294	1 200		
Spain	156	120	250		
Denmark	-	-	100		
UK	83	84	84		
	16 208	15 308	16 064	+4.9	0.6
FAR EAST					
Indonesia	42 102	44 521	54 000	+21.3	
Australia	8 292	14 373	15 150		
Brunei	6 916	6 528	9 200		
India	6 809	7 191	7 500		
Malaysia	859	3 275	4 450		
Burma	750	840	900		
Japan	750	751	730		
Pakistan	486	487	450		
Taiwan	90	112	100		
	67 054	78 078	92 480	+18.4	3.6
Western Hemisphere.. ..	871 376	866 526	868 250	+0.2	33.4
Eastern Hemisphere	1 071 675	1 182 156	1 285 374	+8.8	49.4
	1 943 051	2 048 682	2 153 624	+5.0	82.8
EASTERN EUROPE AND CHINA					
USSR	352 574	376 992	394 000	+4.5	
Romania	13 377	13 794	14 000		
Yugoslavia	2 854	2 953	3 100		
Hungary	1 937	1 955	1 950		
Albania	1 199	1 350	1 575		
Poland	424	395	370		
Bulgaria	334	304	250		
East Germany	200	200	250		
Czechoslovakia	203	193	195		
China[d]	20 000	25 500	29 600	+16.0	
	393 102	423 636	445 300	+5.1	17.2
World totals	2 336 153	2 472 319	2 598 924	+5.1	100.0

[a] Excluding small-scale production in Cuba, Thailand, New Zealand, Mongolia and Afghanistan.
[b] Including natural gas liquids, in Canada also synthetic oils.
[c] Under Israeli occupation.
[d] Including oil from shale and coal.

Even under these modest assumptions, Tables I-1, I-2, I-3 and I-4 demonstrate some striking developments, the most important being:

(a) A growing dependence of the USA on imported oil and, in particular, on Middle Eastern oil even though allowance has been made for Alaskan production at the end of the decade.

(b) A growing Western European dependence on imported and Middle Eastern oil even though allowance has been made for maximum North Sea production and the percentage share of imports is expected to decrease.

(c) A continuation of Japan's total dependence on oil imports.

(d) A sharp rise in Middle Eastern production which is expected to double over the 1970-80 decade from 700 to 1500 million tons per year when it will represent close to 40% of total world production and more than 50% of that of the non-socialist countries while bringing to the countries of the region annual revenues of the order of 30×10^9 US $/yr.

TABLE I-3. NATIONAL PRODUCTION AND IMPORTS IN THREE MAIN CONSUMING AREAS (10^6 t)

	National production		Total imports		Imports from Middle East	
	1970	1980	1970	1980	1970	1980
USA	534	660	214	500	30	300
(% of consumption)	(71)	(57)	(29)	(43)	(6)	(26)
Western Europe	16	160	584	820	300	600
(% of consumption)	(2.6)	(24)	(97.4)	(76)	(50)	(61)
Japan	1	2	199	398	170	300
(% of consumption)	(0.5)	(0.5)	(99.5)	(99.5)	(85)	(75)
Total	551	822	98[illegible]	1 718	500	1 200

TABLE I-4. PAST AND ESTIMATED PRODUCTION IN MAJOR EXPORTING AREAS[a] (10^6 t)

	1970	Share of world consumption (%)	1980	Share of world consumption (%)
Middle East	714	31.6	1 500	39.3
Africa	274	12	330	8.6
Caribbean	212	9.3	220	6
Total	1 190	52.6	2 050	54

[a] For exact definition of the geographical areas, see Table I-2.

No mention is made at this stage of estimated world oil reserves, not because the subject is not important, but because the figures usually advanced are highly questionable and cover an extremely wide range. Thus, for instance, figures of the order of 60×10^9 tons are often advanced for proven oil reserves while ultimate potential reserves which were estimated at around 90×10^9 as late as 1960 are now quoted as exceeding 900×10^9 tons if account is taken of probable off-shore oil fields, secondary recovery methods, oil-bearing shales and tar sands. It thus appears that the question for the next few decades is not one of exhaustion, but of costs.

It should, however, be noted that if demand continues to expand indefinitely at the 5.4% rate forecast for the next seven years, even the 900×10^9 tons of presently estimated ultimate reserves would only last 55 years instead of the 15 years assured by 50×10^9 of proven fields. Consequently, the 15 to 1 ratio between the two reserve figures should not be construed too optimistically.

COST AND PRICE STRUCTURE OF OIL AND ITS FUTURE TRENDS

The question of cost and prices of oil is fraught with difficulties unparallelled in any other industry:

(a) Technical difficulties in accurately defining a particular type of crude. Oils of different characteristics have, of course, historically sold at different prices, but the problem has become particularly acute recently because of environmental consideration which could restrict drastically the sulphur emissions from oil-fired stations in most industrial countries. Without going into the intricate problem of costs of desulphurization it should be noted that differentials of 50% and more can exist between prices of crudes in the same producing area depending on their sulphur content.

(b) Accounting difficulties in ascertaining the real price of crude rooted in the structure of the international oil industry which has, up to now, controlled the production, distribution and marketing of petroleum through vertically integrated operations. As a result, most of the oil entering international trade was moved from producing to refining and marketing subsidiaries at accounting prices fixed internally by the integrated companies essentially in the light of fiscal considerations, while only small amounts of crude were sold to outsiders at what might have been considered market prices.

(c) Political difficulties arising from the relatively small share of production costs in the total selling price. As Table I-5 shows, the cost of production represents less than 10% of the price of crude in the Middle East, the remaining 90% being divided between revenues to host countries and profits to producing companies. Historically, the split between two groups has been the result of a constant power struggle which has recently turned in favour of the countries which now collect more than three-fourths of the f.o.b. price of crude. The latest steps of the struggle were marked by the Teheran Agreement which sharply increased the share of the host nations and provided for automatic increases every year until January 1975. A no less important step was taken at the beginning of 1973 with the Participation Agreement entered into by several of the Arab countries and, in particular, by Saudi-Arabia and Kuwait, providing for a 25% ownership of production by the countries with a final objective of 51% participation by 1981. While Iran and Libya may follow different approaches, there is an unmistakable trend towards control of production by the countries of origin. For the time being, the participating countries plan to re-sell their share of production to the international oil companies which control the necessary distribution and marketing channels, but the situation may well change over the present decade.

(d) Economic difficulties arising from the theoretical impossibility of allocating costs of crude oil to the variety of oil products obtained as a result of refining. Gasoline, kerosene, naphtha, light fuel oil, and heavy fuel oil obtained from a single input of crude are priced separately by private companies according to market conditions in order to maximize total profits. There is no way in which the cost of producing, transporting and refining one ton of crude oil can actually be allocated to the different products derived from it.

TABLE I-5. ILLUSTRATIVE BREAKDOWN OF PRICE OF HEAVY KUWAIT CRUDE IN PERSIAN GULF AND WESTERN EUROPEAN HARBOURS[a] (US $/t)

Production cost	1
Producing country royalties and taxes	10
Company profit	2
Total	13
Transport cost to Rotterdam by 130 000 t tanker	6
Delivered cost at harbour refinery	19

[a] Needless to say, this table and Table I-6 are presented as illustrations rather than precise cost breakdowns which would require an analysis of the refining, distribution, marketing and fiscal situation in a specific country.

To this should be added another important consideration affecting the whole price structure of oil products. Table I-6 illustrates two important and connected points: the heavy impact of indirect and direct taxes levied by oil importing countries on the total costs of oil products to the ultimate consumers and the wide gap between these total final costs paid by the users and the "technical production costs", however widely these may be defined. Although the values given in this table are approximate averages and although Western Europe is one of the areas with the heaviest burden of taxation on oil products, the conclusions are nevertheless generally valid.

TABLE I-6. ILLUSTRATIVE AVERAGE COST STRUCTURE OF OIL PRODUCTS OBTAINED FROM ONE TON OF CRUDE IN WESTERN EUROPEAN COUNTRIES (US $/t)

Cost of crude at harbour	19
Cost of refining	3.50
Storage, inland transit, distribution and marketing	20
Profits of distributing companies	2.50
Taxes levied by consuming countries (excise taxes on products and corporate income taxes)	40
Total	85

With regard to the incidence of taxation by industrial countries, it will be seen that it represents close to 50% of the costs of the ultimate products, and about 4 times the amount of taxes levied by producing countries. True, these taxes fall mainly on gasoline (although several Western European and some developing countries also tax heavy fuel oil) and the fiscal revenues are used for highway maintenance, traffic control etc.; in other words, for tasks which actually make the use of oil products possible. Nevertheless, the fact remains that the impact on final costs is extremely heavy.

This leads to the second point, i.e. the almost total divorce of costs of production from ultimate revenues derived from a given quantity of crude oil, a situation radically different from that of for instance coal for which the relationship is much more rigid.

Production costs in the Middle East are less than 2% of the ultimate total (1.2% of US $35/t in the example given). If company profits, transportation and refining costs are added, the combined cost would still remain less than 20%. Finally, even if distributing and marketing costs are counted, the percentage would only increase to 41%, so that close to 60% of final outlay go to taxes levied by governments of either the producing or consuming countries. This cost structure has several consequences, one of the most important being the relative insensitivity of final product costs to variations in the costs of production at the oil field. In the example given, an increase of the cost of production of crude oil in the Middle East by a factor of 10, from US $1 to 10 per ton, would only lead to a 12% rise in the ultimate product costs to the consumers. This goes a long way towards explaining the wide disparity of actual oil production costs throughout the world. It also points to the probability that higher costs connected with off-shore production, shale oil recovery and other potential reserves will prove no serious obstacle to their future exploitation.

Finally, it should be pointed out that taxes on heavy fuel oil may seriously affect its competitive position and lead to major distortions in the selection of power plants with a resultant economic loss for the country concerned.

Taking these difficulties in turn, the following assumptions are made for the purpose of estimating prices of fuel oil for the Market Survey:

(a) Since none of the Survey countries had expressed special reservations on environmental constraints, one of the cheaper types of crude oil with no limitation on sulphur content was selected as the basis. This was Kuwait crude of 31° API.

(b) Its price was based on data available for transactions between producing companies and independent third parties to which this type of crude was sold in the Persian Gulf in 1972 and escalated to 1 January 1973[1]. Transport costs to the major harbours of the countries concerned were estimated on the basis of data summarized in Table VII.

(c) It was assumed that the strong position of the producing countries will permit them to maintain and probably increase the growing revenues already provided for by the Teheran and Participation Agreements. Consequently, an annual rate of growth of oil prices of 5% was considered minimal while 6% was viewed as probable.

(d) The relationship between the prices of crude and heavy fuel oil was assumed on a basis explained at greater length in Section 4 of this Appendix.

COST OF TRANSPORT OF OIL BY TANKER AND BY PIPELINES

These costs are given in detail in Tables I-7 and I-8. The sensitivity of unit transport cost to size of tanker and pipeline must be stressed. Consequently, future transport costs will depend critically on the existence of harbour facilities capable of handling the largest type of tanker size compatible with the demand of the country.

RELATIONSHIP BETWEEN CRUDE AND OIL PRODUCT PRICES

As has already been pointed out, there is no generally valid relationship between the two products and the price of fuel oil is entirely dependent on supply and demand. There are, however, lower and upper limits imposed by the availability of substitutes.

Regarding fuel oil for power plants, an immediate substitute is available in the form of crude oil itself which, subject to certain precautions, can and has been used as a fuel. Consequently, and except for short-lived special cases, the price of a given quality of crude in a specific location sets an upper limit to the price of heavy fuel oil of comparative sulphur content.

With regard to a lower limit, the situation is much more complex since it depends on the availability of alternative fuels as well as on the possibility of altering the proportion of different refinery products, both in the short and long term. A historical study of the relationship between long term prices of fuel and crude oils of similar characteristics shows that the differential between them has seldom exceeded 10% (except in the special case of the US Eastern Seaboard and the Caribbean area).

It was, therefore, decided to use as reference prices for heavy fuel oil landed in the major harbours of the countries covered by the Survey the price of landed crude as a maximum and 90% of the price of crude as a minimum. In fact, 95% of the price of crude was chosen as a representative single value.

CONCLUSIONS

The procedure finally selected for estimating fuel oil prices for the countries of the Market Survey was based on four main assumptions each one being open to some objections:

(a) The price of crude in the Persian Gulf was used as the basis even though some of the countries covered, particularly in Latin America, are not importing crude from this

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[1] At the time these estimates were made, the impact of the 1973 devaluation of the US $ on the amount of taxes paid to the producing countries was still not officially agreed. It seems, however, that an increase of 10% in the payments to the countries would be a minimum expectation. Such an increase would result in the assumed price of Kuwait crude being more than US $14 per ton rather than the value of US $13 per ton f.o.b. Persian Gulf used in the Survey analyses. While further discontinuous increases of this nature are obviously difficult to forecast, their possibility emphasizes the advisability of assuming for oil prices a rate of escalation substantially exceeding that of general inflation.

TABLE I-7. COMPARATIVE TRANSPORTATION COSTS FROM PERSIAN GULF TO ROTTERDAM[a] IN VARIOUS SIZES OF TANKERS

Year of delivery	Size of tanker (dwt)	50 000	70 000	90 000	130 000	250 000	500 000
	Days at sea	58.2	58.2	56.4	58.2	58.2	58.2
	Days in port	3.2	3.2	3.3	3.3	3.5	3.5
	Trips per annum[b]	5.7	5.7	5.9	5.7	5.7	5.7
	Cargo (tons per trip)	47 200	66 300	85 000	123 400	240 000	480 700
	Voyage costs (US $ × 10^3)						
1971	Fixed direct costs	132.8	150.0	164.2	204.9	317.0	-
	Capital costs	121.0	154.7	175.0	246.7	396.7	-
	Bunkers[c]	50.5	70.7	98.2	126.6	163.1	-
	Port charges	13.0	17.2	19.5	24.8	43.6	-
	Total	317.3	392.6	456.9	603.0	920.4	-
1973	Fixed direct costs	171.4	192.1	209.8	260.9	405.6	18.2
	Capital costs	142.1	184.2	211.9	301.5	476.0	914.0
	Bunkers[c]	45.5	63.7	88.4	114.0	146.8	276.8
	Port charges	18.6	23.7	29.4	35.2	66.3	136.5
	Total	377.6	463.7	539.5	711.6	1 094.7	2 045.5
1975	Fixed direct costs	195.1	218.0	237.4	294.3	441.1	748.5
	Capital costs	173.7	228.4	276.3	397.5	740.4	1 269.2
	Bunkers[c]	51.4	71.9	99.9	128.8	165.9	312.7
	Port charges	20.5	26.1	32.4	38.8	73.0	150.7
	Total	440.7	544.4	646.0	859.4	1 420.4	2 481.1
	Costs (US $/t of cargo)						
1971	Direct costs	4.16	3.59	3.32	2.89	2.18	-
	Capital costs	2.56	2.33	2.06	2.00	1.65	-
	Total costs	6.72	5.92	5.38	4.89	3.83	-
1973	Direct costs	4.99	4.22	3.85	3.32	2.58	2.35
	Capital costs	3.01	2.78	2.49	2.44	1.98	1.90
	Total costs	8.00	7.00	6.34	5.76	4.56	4.25
1975	Direct costs	5.66	4.77	4.35	3.74	2.83	2.52
	Capital costs	3.68	3.44	3.25	3.22	3.09	2.64
	Total costs	9.34	8.21	7.60	6.96	5.92	5.16
	Costs (1972 world-scale equivalent)						
1971		68	60	55	50	39	-
1973		81	71	64	59	46	43
1975		95	83	77	71	60	53

[a] Distance for round trip 22 338 miles.

[b] All vessels in operation for 350 days each year.

[c] Bunker prices (US $/t) 1971 Persian Gulf 13.50, North Europe 21.00
1973 Persian Gulf 13.00, North Europe 18.00
1975 Persian Gulf 15.00, North Europe 20.00

TABLE I-8. ILLUSTRATIVE COSTS OF INLAND TRANSPORT BY PIPELINE

	Throughput	
	2×10^6 t/yr (10-in diam. pipeline)	5×10^6 t/yr (16-in diam. pipeline)
Costs (US cents/t per 100 miles)		
Capital	60	39
Other fixed	18	10
Variable	4	8
Total	82	57
Total cost (US cents/10^6 kcal per 100 mile)	8.1	5.6

Note: The table is restricted to pipeline sizes most likely to be encountered in oil-importing developing countries. The cost per ton of oil transported is, however, quite sensitive to size up to very large throughputs. Thus, for a pipeline with a transport capacity of 50×10^6 t/yr it would drop to less than 20 US cents/t per 100 miles, or to about 1/3 of the 5×10^6 t/yr figure.

[a] Assumes: flat country, no major river crossing; capital cost of pipeline US $2000/in diameter per mile; fixed charge rate 13.38%/yr based on an interest rate of 12% yr and on 20-yr sinking fund depreciation.

[b] Sufficient for supplying 1200 MW of oil-fired plants at 80% load factor.

[c] Sufficient for supplying 3000 MW of oil-fired plants at 80% load factor.

source. This is not as serious a flaw as it may seem since the policy of pricing oil from various sources on the basis of equality of delivered cost, with the main producing region serving as a reference point, has been a recurring feature of past price policies.

(b) An annual escalation rate of 6% was proposed for the 1973-1980 period, which is higher than the approximately 4% which the Teheran Agreement alone would imply, but takes into account the progressive impact of participation of the Arab countries in production and the sharp rise in oil demand.

(c) A fixed relationship was assumed between the prices of crude and of heavy fuel oil while the actual connection is flexible and complex. As has been explained this is a simplification but its impact on actual results is unlikely to involve errors of more than 5%.

(d) Taxes levied on fuel oil by consuming countries were ignored since they are internal revenues to the governments and should not affect the economic selection of power plants. There is no question that even though from the standpoint of the electric utilities taxes levied by their own country on a particular type of fuel are an element of total costs, the same taxes appear as a revenue item in national accounting. Since the purpose of the Market Survey is to estimate national costs of alternative power programs, domestic taxes on fuel should be excluded, at least in the basic reference cases.

(e) Estimated base prices, resulting from the above, for crude and heavy fuel oil in major harbours of the countries participating in the Market Survey are given in Table I-9.

(f) Gas turbine fuels were arbitrarily priced at 175% of fuel oil on the basis of an averaging of existing data.

(g) Domestically produced oil and gas was priced on the basis of parity of thermal costs with imported fuel oil or fuel oil refined from imported crude.

(h) Prices of domestically produced lignite and coal were estimated independently on the basis of the data supplied by the countries and escalated at the general rate of 4%/yr except in cases where there were convincing arguments to depart from this general procedure.

TABLE I-9. ESTIMATED BASE PRICES FOR CRUDE AND HEAVY FUEL OIL IN MAJOR HARBOURS OF MARKET SURVEY COUNTRIES[a], 1 January 1973

Harbour	Sea transport cost[b] (US $/t)	CIF Price of crude in harbour (US $/t)	Corresponding prices of fuel oil (US $/t)	US cents/10^6 kcal
Egypt				
Alexandria	3	16	15.2	150
Greece				
Piraeus	5	18	17.1	168
Turkey				
Izmet	5	18	17.1	168
Yugoslavia				
Trieste	6	19	18	177
Argentina				
Buenos Aires	6.5	19.5	18.5	182
La Plata				
Chile				
Valparaiso	7	20	19	187
Quintero				
Jamaica				
Kingston	6	19	18	177
Mexico				
Tampico	7	20	19	187
Vera Cruz				
Pakistan				
Karachi	1	14	13.3	131
Bangladesh				
Chittagong	2.5	15.5	14.7	145
Singapore	2	15	14.3	140
Thailand				
Bangkok	3	16	15.2	150
Philippines				
Bantangas	3	16	15.2	150
Korea				
Pusan-Ulsan	4	17	16.1	159

[a] Kuwait heavy crude 31° API with no sulphur restriction estimated at US $1.80/bbl or US $13/t f.o.b. in the Persian Gulf.
1 t crude = 7.2 bbl
1 t heavy fuel oil = 6.8 bbl
1 t heavy fuel oil = 40.3×10^6 Btu.
= 10.15×10^6 kcal.

[b] Transport costs by sea estimated on the basis of journey by tankers of size suitable for country harbours except for Mediterranean countries where special allowances were made for possible transport by pipeline or canal through Suez in the future.

APPENDIX J

NUCLEAR FUEL CYCLE COST TREATMENT

James A. Lane

INTRODUCTION

Fuel cycle costs in a nuclear power plant depend on a wide variety of economic parameters, such as the costs of uranium, of separative work and of industrial operations which vary with time. It is likely that some of these costs, such as those for natural U_3O_8 and separative work will increase with time, while other cost components such as fuel fabrication and fuel recovery will decrease. To complicate the situation even more, the value of fissile plutonium recovered from spent fuel can go up or down depending on its marketability as recycle fuel.

In addition to dependence on the above economic factors nuclear fuel costs also depend on engineering parameters such as the fuel burn-up per cycle, the fuel management scheme employed etc., which the reactor designer or plant operator can vary to optimize overall generating costs. Because of this balancing of economic and engineering factors, total nuclear fuel cycle costs tend to remain relatively constant with time. In the case of light-water reactors, fuel costs lie within the rather narrow range 20 ± 5 US cents/10^6 Btu (80 ± 20 US cents/10^6 kcal) regardless of size or plant design. Unlike oil costs, moreover, nuclear fuel costs are not sensitive to where the plant is located in the world. In view of this situation, it was decided that it would be sufficient for the purpose of the Market Survey to base the economic evaluation on current nuclear fuel costs taken from studies published in the open literature. For the reference case, these fuel costs were assumed to follow the general inflation rate of 4%/yr, the same as all other capital costs (see Appendix D). Sensitivity studies were also carried out using a 6% escalation rate, the same as that used in the reference case for oil and gas.

FUEL CYCLE COSTS FOR A 400 MW PWR

In a paper by J. T. Roberts and R. Krymm [1], a variety of numerical examples of nuclear fuel cost calculations for a hypothetical 400 MW pressurized water reactor are presented and discussed in detail. Figure J-1 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.

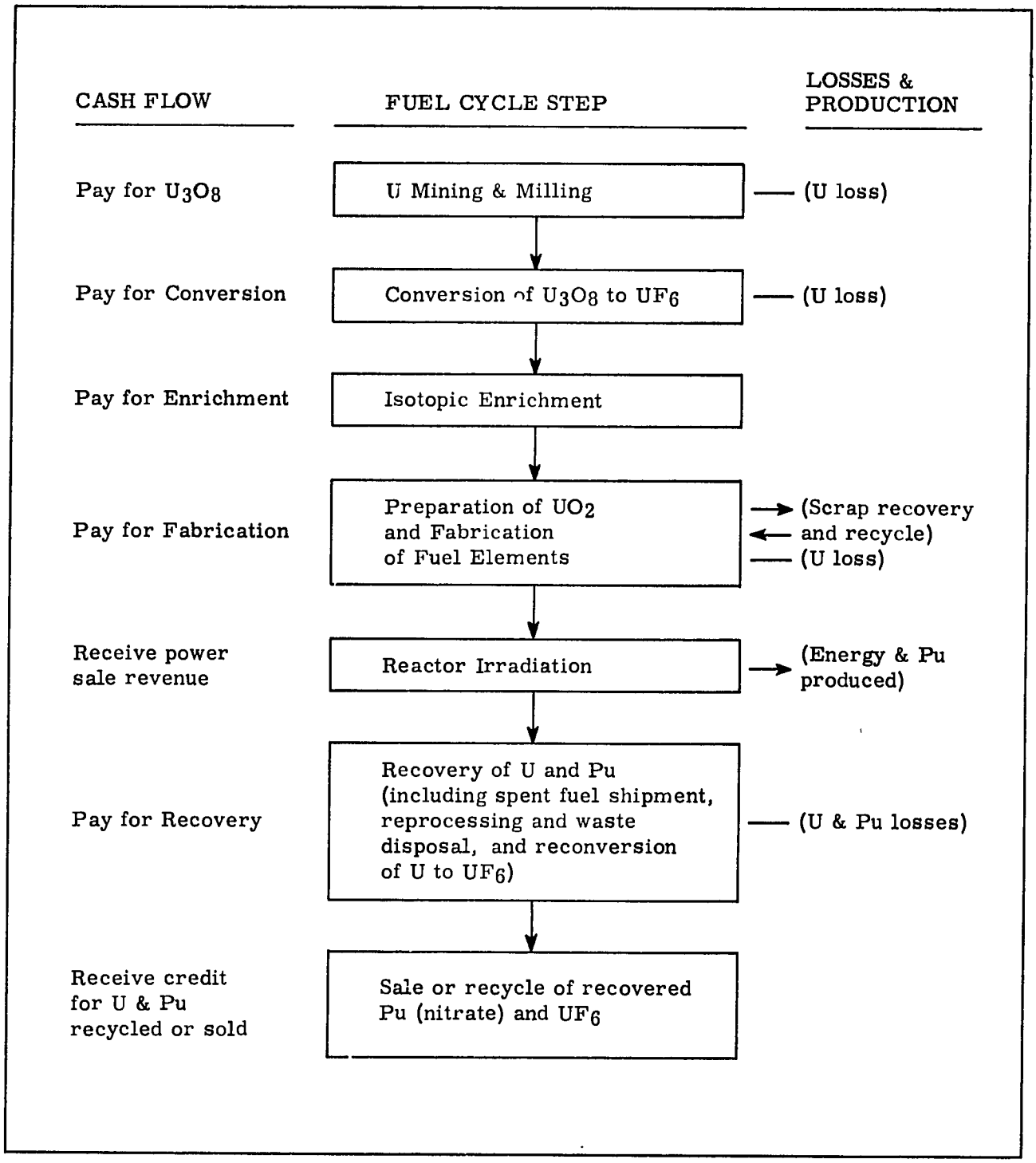

FIG. J-1. GENERALIZED SCHEMATIC DIAGRAM OF LWR FUEL CYCLE.

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.

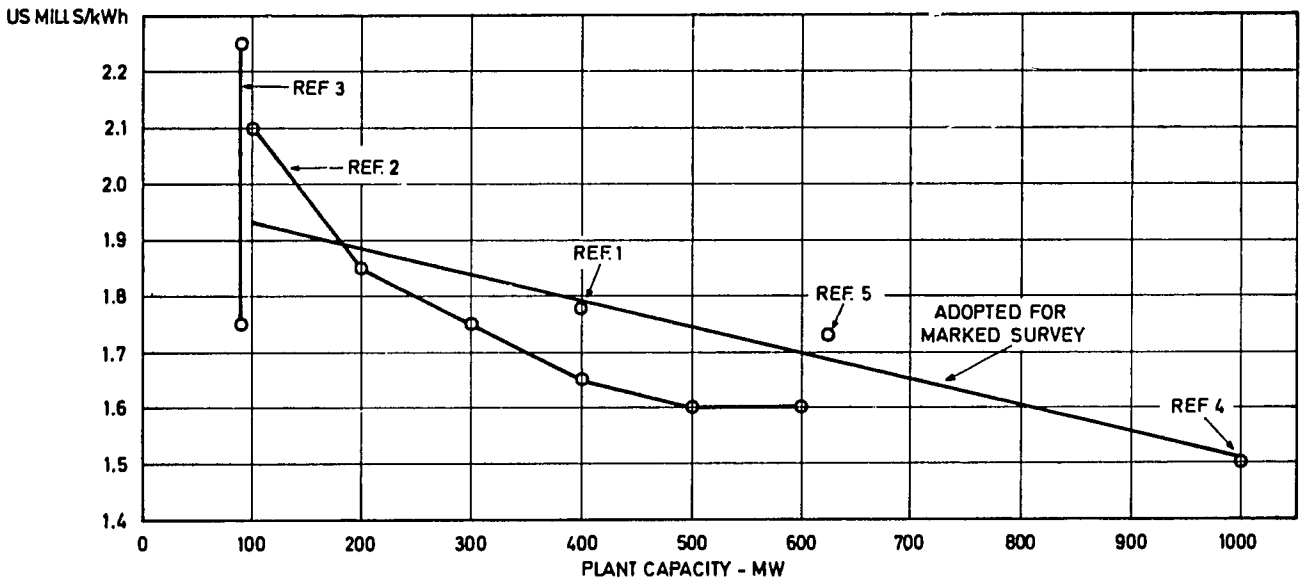

FIG. J-2. TOTAL FUEL CYCLE COSTS.

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.

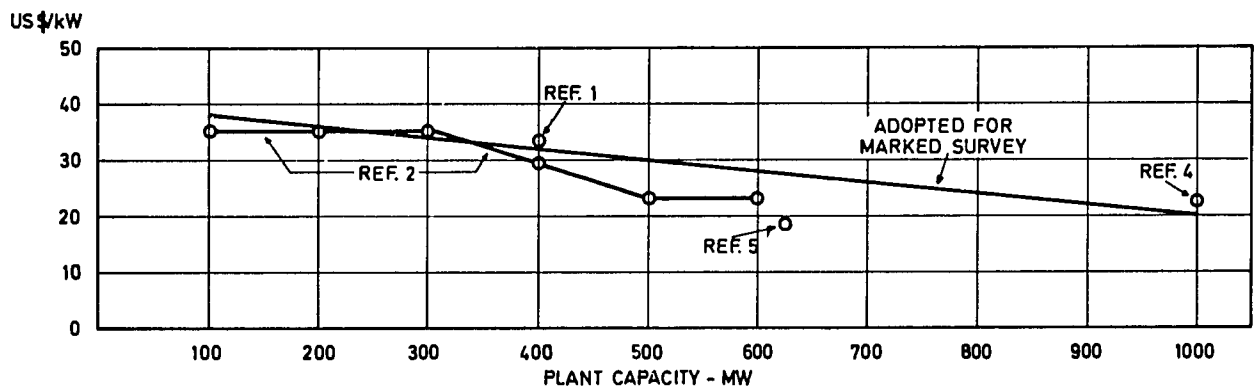

FIG. J-3. LEVELIZED FUEL CYCLE CAPITAL COSTS.

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.

ABBREVATIONS USED IN THE MARKET SURVEY REPORTS

ampere	A
approximately	approx.
barrels	bbl
billion	10^9
board feet	bd. ft.
British thermal unit	Btu
calorie	cal
centimetre	cm
cubic foot	ft^3
cubic metre	m^3
cubic yard	yd^3
cycles per second	Hz
degree centigrade	°C
degree Fahrenheit	°F
direct current	DC
feet	ft
figure(s)	Fig., Figs.
foot	ft
Gigawatt	GW
Gigawatt-hour	GWh
Hertz (cycles per second)	Hz
horse-power	hp
hour	h
hundredweight	cwt
kilocalorie	kcal
kilogram	kg
kilometre	km
kilovolt	kV
kilovolt-ampere	kVA
kilowatt	kW
kilowatt-hour	kWh
litre	l
maximum	max.
megawatt	MW
megawatt-hour	MWh
metre	m
normal cubic metre	Nm^3
million	10^6
number	No.
per annum	p.a.
per cent	%
pound (weight)	lb
pounds per square inch	lb/in^2
square foot/feet	ft^2
square metre	m^2
thousand	10^3
ton	t (always metric, unless specified otherwise as ton (UK) – long ton or ton (USA) – short ton.
tons of coal equivalent	TEC
volt	V
volt-ampere	VA
watt	W
yard	yd

APPENDIX N

COOPERATING ORGANIZATIONS AND PARTICIPANTS IN THE MARKET SURVEY MISSION

21 August - 1 September 1972

National Atomic Energy Commission (CNEA)
The Planning Department of the Secretariat for Energy
Water and Electrical Energy Company (AyEE)
Hydroelectric Company of North Patagonia (HIDRONOR)
The Fuels Department of the Secretariat for Energy
The Council of Economic Development (CONADE)
Electricity Company of Greater Buenos Aires (SEGBA)
Director of Energy for the Province of Buenos Aires (DEPA)
Provincial Energy Company of Córdoba (EPEC)
National Coal Board (YCP)

Liaison officer: Mr. D. Béla José Csik, CNEA

	Country	Status [a]
E. de Bellmond, Hydro Project and Systems Planning expert, State Power Board, Vällingby	Sweden	1
P. W. Cash, Electric Utility Systems Planning expert, Associated Nuclear Services, London	UK	2
D. Chase, Engineer, IAEA	Canada	3
O. B. Falls, Jr., Project Manager, IAEA	USA	3
R. Krymm, Economist, IAEA	France	3
W. Schnurr, Nuclear Research Institute, Karlsruhe	FRG	4

[a] Status 1 = Expert provided salary-free with Agency paying travel and per diem

Status 2 = Expert provided by contract with Engineering Consulting firm, the firm having the status of an independent contractor

Status 3 = IAEA staff member

Status 4 = Cost-free expert with salary, travel and per diem paid by the sponsoring country