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Democratic Socialist Republic of Sri Lanka
Power Subsector Review

July 25, 1986

Projects Department
South Asia Regional Office

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SRI LANKA

POWER SUBSECTOR REVIEW

Currency Equivalents

Mid-1983	US$1.00	= SL Rs 23.53
	SL Rs 1.00	= US$0.043
Mid-1984	US$1.00	= SL Rs 25.44
	SL Rs 1.00	= US$0.039
End-1984	US$1.00	= SL Rs 26.20
	SL Rs 1.00	= US$0.038
End-1985	USR1.00	= SL Rs 27.20
	SL Rs 1.00	= US$0.037

WEIGHTS AND MEASURES

1 kilometer (km)	= 0.621 mile
1 ton	= 1.102 short ton (sh ton)
	0.984 long ton (lg ton)
1 kilowatt (kW)	= 1,000 watts (W)
1 megawatt (MW)	= 1,000 kilowatts (10^3 kW)
1 gigawatt	= 1,000,000 kilowatts (10^6 kW)
1 kilowatt-hour (kWh)	= 1,000 watt-hours
1 megawatt-hour (MWh)	= 1,000 kilowatt-hours (10^3 kWh)
1 gigawatt-hour (GWh)	= 1,000,000 kilowatt-hours (10^6 kWh)
1 kilovolt (kV)	= 1,000 volts (10^3 V)
1 kilovolt-ampere (kVA)	= 1,000 volt-amperes (VA)
1 megavolt-ampere (MVA)	= 1,000 kilovolt-amperes (10^3 kVA)

ABBREVIATIONS AND ACRONYMS

ADB	-	Asian Development Bank
AMP	-	Accelerated Mahaweli Program
CEB	-	Ceylon Electricity Board
CPC	-	Ceylon Petroleum Corporation
DGEU	-	Department of Government Electrical Undertakings
ECT	-	Energy Coordinating Team
GOSL	-	Government of Sri Lanka
GTZ	-	German Agency for Technical Cooperation
HV	-	High Voltage
LV	-	Low Voltage
LECO	-	Lanka Electric (Private) Company
LRAIC	-	Long-Run Average Incremental Cost
LRMC	-	Long-Run Marginal Cost
MASL	-	Mahaweli Authority of Sri Lanka
MMD	-	Ministry of Mahaweli Development
MPE	-	Ministry of Power and Energy
MV	-	Medium Voltage
WMP	-	Water Management Panel

CEB's Fiscal Year is the calendar year

This report was prepared by M.G. Webb (Economist), R. Sharma (Financial Analyst), D.T. O'Leary (Engineer/Systems Planner) and W. Kupper (Consultant) on the basis of missions undertaken in September-October and December 1984. S. Mukherji (Consultant) also contributed to the report.

ABSTRACT

The principal purposes of this report are to update and extend the Bank's knowledge of Sri Lanka's power subsector, and to identify the principal issues in that subsector and the options open to the Sri Lankan authorities to deal with those issues. The report first reviews briefly the institutional organization of the energy sector and the country's energy resources whose development may have an impact on the power subsector, and recommends, among other things, a closer involvement of the Ceylon Electricity Board (CEB) in both the long term and operational planning of the Mahaweli-Ganga River Complex. The organizational structure of the power subsector is then examined, and attention is drawn to the need to increase the autonomy of CEB and to strengthen its management capability. Measures to improve both demand forecasting and planning the development of the power subsector are discussed, including the collection of detailed data on consumer characteristics at all voltage levels, increased use of sensitivity analysis in generation system planning, and improving the data base on potential hydropower projects. A detailed review of the system for electricity pricing indicates a number of weaknesses in CEB's existing tariff structure and the tariffs of some licensees. A number of recommendations are made, including that the basic tariff rates in CEB's tariff should be based on average hydrological conditions in order to improve the signalling function of tariffs, and that the size of the 'lifeline' block in the tariff for domestic consumers should be reduced. It is also proposed that a load management study should be undertaken to identify both price and non-price measures to prevent a deterioration of the system load factor as a result of the projected increase in the relative importance of consumption by consumers in the domestic and licensee tariff categories. Finally, the proposed investment program for the development of the subsector between 1985 and 1994 is evaluated in the light of Sri Lanka's existing and projected financial and resource constraints. Recommendations are formulated to increase resource mobilization by increasing tariff rates and to reduce arrears owed to CEB.

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POWER SUBSECTOR REVIEW

I. INTRODUCTION

1.01 Following the implementation of a number of economic reforms in 1977, Sri Lanka's annual real GDP growth rate averaged about 5.5% in the period 1977-1985. During this period the power subsector expanded rapidly; the installed capacity of the Ceylon Electricity Board increased by about 136% from 401 MW to 949 MW, and its sales of electricity increased by about 96% from 1,041 GWh to 2,042 GWh. A significant but undefined proportion of total public investment was accounted for by the power subsector in the period 1977-1984. The figure is undefined due to major power facilities being developed in multi-purpose schemes under the accelerated Mahaweli Development Program, and the difficulty of allocating the costs of such schemes to their individual outputs. Excluding the power related Mahaweli expenditures, the power sector accounted for about 4.1% of investment financed through the public sector budget in the period 1978-1983. Since 1980 the resources required to fund new public sector investments and complete ongoing investments have exceeded the inflow of concessionary finance and the Government turned to commercial loans and continued high levels of domestic borrowing to finance the resource gap. Part of the explanation for the large budget deficits experienced in the early 1980's (23.1% of GDP in 1980, and 10% in 1984), was persistently weak public revenue mobilization relative to expenditure levels.

1.02 The Government of Sri Lanka has projected that power subsector investment, excluding power projects undertaken in the Mahaweli program, financed through the public sector budget will account for about 5.7% of public investment in 1985 but will increase rapidly to a peak of about 25.0% in 1988. Consequently, it is important that very careful attention is given to ensure that not only are planned investments in the subsector warranted in terms of forecast load growth, but in addition that those projects constitute the least cost development program and that the power subsector institutions are organized to ensure the efficient development of the subsector. Similarly it is very important that careful consideration is given to electricity tariffs, both in terms of signalling appropriate cost information to consumers to promote an efficient allocation of resources and in terms of mobilizing resources.

1.03 This report concentrates on identifying the major issues in the power subsector and the options open to the Sri Lankan authorities to deal with them. (The issues and options are summarized in Table 1 below.) Consequently, the report should not be viewed as a comprehensive document covering all aspects of the power subsector, but as a policy orientated document that addresses those issues which, in the view of the Bank mission, deserve immediate attention.

1.04 The report is divided into two parts. The first part provides a brief review for the setting of each issue and the recommendations of the mission compartmentalized under six chapters. The second part includes six annexes which provide more detailed support for the analysis presented in the first part.

1.05 Chapter II deals with energy sector institutions and with the energy resources whose development would have an impact on the power subsector. Particular emphasis is given to hydropower and the need to improve the data base on potential hydropower projects.

1.06 Chapter III presents the institutional setting of the power subsector, paying particular attention to existing weaknesses of the Ceylon Electricity Board (CEB) and the problems posed by the existing institutional arrangements for the distribution of electricity.

1.07 Chapter IV addresses the past trends in the consumption and supply of electricity. Detailed energy and capacity balances for the subsector, together with supporting data, are presented as parts of Annexes 3 and 4, which provide an extensive review of the development of the subsector since 1973.

1.08 The forecast consumption and supply of electricity are presented in Chapter V, together with an assessment of CEB's demand forecasting methodology and its program to reduce system losses. The chapter also considers CEB's generation planning techniques, and various operational planning issues related to hydropower projects constructed under the Accelerated Mahaweli Program. Particular emphasis is given to the need to ensure that operational decisions regarding the allocation of water for irrigation and electricity generation are taken in the national interest. Projected energy and capacity balances for the subsector are presented as parts of Annexes 3 and 4.

1.09 The pricing of electricity is considered in Chapter VI. The structure and level of CEB's existing tariffs are compared with those suggested by the economic pricing of power. The tariffs adopted by two local authorities are also analyzed with a view to determining whether these tariffs are a contributory factor to the arrears typically owed by local authorities to CEB. The pricing of electricity is discussed and analyzed in detail in Annex 5.

1.10 Finally Chapter VII reviews CEB's investment program, and its financing, for the period 1978-1984, and identifies the major constraints experienced in implementing that program. The Chapter concludes with a detailed review and assessment of CEB's investment and financing plans for 1985-1994.

1.11 The main shortcoming of the report is the absence of a section on licensess (local authorities) development during the period 1977-1985, and plans for 1986-1990. This is due to the difficulty of gathering reliable information from the large number of licensees and the lack of a centralized data bank at the Ministry of Local Government and Housing. The report includes a recommendation to close this data gap.

TABLE 1

PROPOSED STRATEGY FOR THE DEVELOPMENT OF THE POWER SUBSECTOR

Issues	Objectives	Recommendations	Studies	Priority
(a) Lack of reliable data on Sri Lanka's remaining hydropower potential and technically feasible developments which might be included in CEB's least cost generation program beginning 1990 (para 2.08).	Preparation of inventory of potential hydropower projects, together with preliminary costings and ranking of potential projects, to: (a) ensure least cost development of the power system, and (b) maximize efficient use of indigenous energy resources (para 2.08).	Completion on schedule of the hydropower identification and ranking study funded by the Government of the Federal Republic of Germany.	Complete GTZ study to prepare an overall inventory of hydro potential and long term development of generation facilities (para 2.08). In addition detailed evaluation studies should be initiated for, say, the two most promising projects.	High
(b) Imbalance in the management of the Mahaweli-Ganga Complex, which gives insufficient weight to the electricity supply industry (paras 5.18 to 5.20).	To bring about a more logical balance in the management of the Mahaweli-Ganga Complex.	Appoint the Chairman of CEB as co-chairman of the Water management Panel, and appoint the General Manager and Additional General Manager Generation of CEB as members of the Water Management Panel (para 5.21).	No	High
(c) Insufficient attention given to the national economic consequence of decisions regarding the allocation of water between irrigation and power uses (para 5.22).	Ensuring that the national economic interest is taken into account in the allocation of water between irrigation and power uses.	Decision making by the Water Management Panel should use the available quantitative information from various studies on the tradeoffs between irrigation benefits and power benefits (para 5.23).	No	High

II. ORGANIZATIONAL STRUCTURE

Issues	Objectives	Recommendations	Studies	Priority
(a) Performance problems of local authorities with regard to their electricity distribution functions and possible future problems, including duplication of some functions, caused by the formation of the Lanka Electric Company (para 3.06).	To rationalize the organization of the power distribution industry.	The Government should undertake the formulation of an appropriate organizational structure for the power subsector, including rationalization of the power distribution industry (para 3.07).	Undertake a study of the appropriate long term organization of the power subsector, including the role to be played by local authorities (para 3.07).	Medium
(b) Existing autonomy of CEB is not appropriate for the requirements of a rapidly growing power utility (para 3.08).	To strengthen CEB and make it a more efficient power utility.	The Government should initiate actions to restore CEB's operational and financial autonomy within the framework of the 1969 CEB Act (para 3.08).	No	High
(c) CEB is overstaffed, partly because of the relatively small number of working days each year (para 3.09).	To make the use of manpower in CEB more efficient.	The Bank should monitor the situation regarding CEB staffing (para 3.09).	No	Low
(d) In recent years CEB has had considerable difficulty in retaining experienced engineers and accountants, leading to a dilution of effective management (paras 3.10 and 3.11).	To strengthen CEB's management capability, especially at middle levels.	CEB should formulate a promotion policy which rewards merit and introduce a scheme of incentives, including bonus payments, to assist in the retention of experienced personnel (para 3.11).	No	High
(e) Facilitating the growth of Lanka Electricity Company as a means of overcoming the problems of electricity distribution by local authorities (paras 3.13 to 3.18).	To smooth the acquisition of local authority distribution systems by Lanka Electricity Company (LECO).	The Government should institute appropriate procedures to prevent local authorities blocking the takeover of their distribution systems by LECO (para 3.19).	No	Medium

III. ELECTRICITY PRICING

Issues	Objectives	Recommendations	Studies	Priority
(a) Failure of published tariff rates to signal long run resource cost information to consumers due to an undue reliance on the fuel adjustment charges (paras 6.09 and 6.11).	To improve the signalling function of the price mechanism.	CEB should adopt, with GOSL approval, an annual cycle under which it reviews, and if necessary revises, tariff rates and relates published tariff rates to estimated fuel costs for forecast hydrological conditions in the year to which the rates would apply (para 6.09).	No	Medium
(b) The level of CEB's tariff rates is below the economic costs of supply and insufficient to (a) enable it to meet its target rate of return and (b) to maximize resource mobilization for its investment program (para 6.26).	To ensure that correct price signals are given to final consumers and that CEB achieves its financial objectives (para 6.25).	CEB should gradually bring its tariff rates more into line with the estimated economic costs of supply (para 6.26).	Use of RELCOMP Model to estimate marginal energy costs on CEB's supply system (para 6.08) and studies to improve data base on consumer characteristics (para 6.10).	Medium
(c) The structure of CEB's tariffs does not reflect the differences in the marginal costs of supplying consumers at different times of the day and week (paras 6.20 to 6.22).	To ensure that correct price signals are given to consumers while maintaining equity and simplicity in tariff design (para 6.25).	CEB should introduce time of day tariffs for all medium voltage consumers, with the exception of licensees, and for large domestic consumers (paras 6.22 and 6.26).	No	Medium
(d) The existing lifeline blocks in CEB's tariff for domestic consumers are too large and cause CEB to lose revenue (paras 6.12 and 6.14).	To meet an equity objective in CEB's tariff while minimizing the resulting distortion to the signalling function of the tariff (para 6.25).	CEB should reduce the size of the first block in the domestic tariff to 0-20 kWh/month and the size of the second block to 20-75 kWh/month (para 6.14).	No	Medium
(e) Lack of information on tariffs used by Licensees, and need to ensure that rates in those tariffs are set at levels to ensure the financial viability of licensees (paras 6.15, 6.18 and 6.23).	To ensure the financial viability of Licensees and reduce the arears which they owe to CEB.	Collection and analysis of required data on Licensees tariffs in order to determine whether existing tariff rates are a contributory factor to the existing arrears which they owe to CEB (paras 6.15-6.18 and 6.23).	Analytical study of Licensees' tariffs (para 6.18).	Medium
(f) Problem of financing CEB's proposed investment program (para 7.11).	To mobilize local resources for CEB's investment program.	GOSL and CEB should take all necessary actions, including tariff increases, to meet all costs of CEB's investment program (para 7.11).	No	High

IV. PLANNING

A. Demand Forecasting

Issues	Objectives	Recommendations	Studies	Priority
(a) CEB's demand forecasting approach is simply the extrapolation of past trends, modified by knowledge of short-term developments in industrial and other sectors (paras 5.05 and 5.06).	Ensure the electricity demand forecasts are consistent with projected economic developments and generally to improve CEB's load forecasts (paras 5.05 to 5.07).	CEB should prepare its demand forecasts using at least two appropriate methodologies (para 5.06).	No	Medium
(b) CEB's forecasts for Licensee consumers are hampered by an inadequate data base on the number and types of consumers served by Licensees and their retail sales to final consumers (para 4.01); similarly its forecasts for other consumer groups, particularly for LV consumers, are hampered by an inadequate data base (para 5.06).	Improve demand forecasting (para 5.05).	Collection, on a regular basis, of data on licensees' sales to final consumers and on losses occurring in their supply systems (para 4.01), and undertaking regular consumer surveys to prepare, and continually update, the data bases on consumers served, uses of electricity, and consumer characteristics (para 5.06).	No	Low
(c) Lack of long-term demand forecasts required for generation system planning (para 5.07).	To provide the demand forecasts required for the evaluation of optimal increments to generating capacity (para 5.07).	CEB should prepare 20 year demand forecasts, and also project system load duration curves and system load factor over the same period (para 5.07).	No	Low

B. Load Management

(1) Forecast changes in the proportions of total sales accounted for by the different consumer groups may exacerbate the evening peak and lower the system load factor (para 5.04).	To increase the system load factor and hence reduce CEB's capacity requirements.	CEB should initiate a study to determine its requirements for, and most suitable forms of, both price and non-price forms of load management. The study should build on similar work undertaken in connection with rural electrification (paras 5.04 and 3.23).	Load management study.	Medium

C. OPERATIONAL PLANNING

Issues	Objectives	Recommendations	Studies	Priority
(a) Lack of effective coordination between CEB and Ceylon Petroleym Corporation (para 5.11).	To enable the Ceylon Petroleum Corporation to improve its short-term crude oil and refined produce procurement strategies (para 5.11).	Once a month CEB should inform the Ceylon Petroleum Corporation of its projected hydrocarbon fuel requirements month by month on a rolling twelve month basis (para 5.11). For this purpose it should run the NEDECO Macro Model (Annex 2, Attachment 5).	No	High
(b) Inadequate maintenace of distribution systems, with resulting excessive losses (para 4.14).	To reduce system losses and improve the quality of electricity supply.	CEB should institute a regular maintenance program covering the entire distribution network (para 4.14).	No	Medium
(c) Need to strengthen CEB's operational planning capability (para 5.23).	Strengthen CEB's operational planning capabilities, particularly with regard to use of hydropower projects.	CEB should review the applicability of simulation techniques, such as the Acres Reservoir Simulation Program, to its operations planning needs at least for the rest of this decade (para 5.23).	No	High
(d) CEB needs to strengthen its capability in water resource planning in order to permit it to play an active role in multi-agency meetings concerned with the operation of new hydropower projects (para 5.25).	Strengthen CEB's capability in water resources planning.	CEB should add to its staff experienced personnel with a broad knowledge of both irrigation and hydroelectric systems operation, and should have two of its engineers trained in water resources planning (para 5.25).	No	Medium

V. INVESTMENT AND FINANCING

Issues	Objectives	Recommendations	Studies	Priority
(a) Implementation delays in the rural electrification program due to shortages of local funds and CEB's inadequate construction capability (paras 3.21 and 3.22).	Ensure completion of the ongoing rural electrification program according to schedule.	The Government should continue to disburse local funds required for the ongoing rural electrification project in a timely and efficient manner (para 3.24).	No	High
(b) Need to refine the method used to determine th costs of multi-purpose projects constructed under the Accelerated Mahaweli Development Program which are to be allocated to CEB upon the transfer of the power projects to CEB (paras 3.25 to 3.30).	To ensure that the costs of multi-purpose schemes which are allocated to CEB are determined in accordance with basic economic principles (para 3.27).	A revised methodology for allocating the costs of multi-purpose projects between their hydroelectric and irrigation functions should be formulated (para 3.31).	No	Medium
(c) Relatively high losses in CEB's supply network (paras 4.10 and 4.11).	To reduce total system losses.	The Bank should support CEB's loss reduction program, beginning with the proposed Transmission Expansion and Distribution Rehabilitation Project (para 4.11).	No	High
(d) High losses in the distribution systems operated by local authorities (para 4.12).	To reduce losses in local authorities distribution systems.	The Government should initiate studies to identify the magnitude and causes of losses in local authority distribution systems and require local authorities to initiate programs to address the causes of these losses (para 4.12).	Studies to identify causes and magnitude of losses in local authority distribution systems (para 4.12).	Medium
(e) Financing gap for investment program in period 1985-1993 (para 7.11).	Ensure an adequate foreign exchange availability to implement the least cost investment program, and also ensure institutional capability to execute the program.	GOSL and CEB should: (i) take all necessary actions to secure foreign cost financing to bridge the foreign cost financing gap (para 7.11).	No	High
(f) Excessive arrears owed by some consumer groups (para 7.05).	To mobilize local resources required for CEB's investment program.	GOSL should formulate and implement a monitorable program to reduce arrears owed by local authorities to CEB, and CEB should formulate and implement a similar program for its other consumers (para 7.05).	No	High
(g) Effect of increasing debt on CEB's financial position (para 7.07).	To ensure that CEB remains a financially viable utility.	CEB should assess the financing of future investments very carefully in order to obtain a reasonable balance between net internal cash generation and long-term borrowing (para 7.07).	No	Medium

II. THE ENERGY SECTOR

A. Institutions

2.01 No single organization is formally responsible for the energy sector in Sri Lanka. Until November 1982 a major institutional problem was the relatively large number of Ministries and line agencies involved in the different energy subsectors (Annex 1, Attachment 1), and the lack of effective coordination between them. Thus four organizations were concerned with electricity (the Ministry of Power and Energy - MPE, the Ceylon Electricity Board - CEB, the Ministry of Mahaweli Development, and the Mahaweli Authority of Sri Lanka), and two organizations were concerned with petroleum (Ministry of Industries and Scientific Affairs, and Ceylon Petroleum Corporation - CPC). The joint UNDP/World Bank Report Sri Lanka: Issues and Options in the Energy Sector 1/ drew attention to these institutional problems. The Government of Sri Lanka (GOSL) subsequently acted on most of the institutional recommendation made in that report2/.

2.02 The major reform was the setting up of the Energy Coordinating Team (ECT) in December 1982 in the Ministry of Power and Energy, under the supervision of the Senior Energy Advisor to the Minister. In September 1985, the Secretary, Ministry of Power and Energy, was appointed to manage ECT. The main purpose of ECT is coordinating the work of the relevant ministries and line agencies to prevent duplication, with its attendant waste of resources and time delays. ECT consists primarily of three coordinating task forces, covering energy planning, energy conservation and renewable energy, as follows:

(a) Energy Planning and Policy Analysis (EPPAN) task force. One of EPPAN's most important aims is the identification of the overall objectives of national energy policy and the formulation of an energy strategy to meet these objectives, including the maximization of Sri Lanka's development;

(b) Energy Efficiency, Demand Management and Conservation (EDMAC) task force. EDMAC concentrates on activities which are of immediate and short-term importance in the area of energy conservation. It was instrumental in setting up the loss reduction cell in CEB

1/ Report No. 3791-CE, May 1982.

2/ Energy Assessment Status Report, Activity Completion Report. No. 010/84, January 1984, Section III.

(para 4.11), and is also concerned with electricity and petroleum pricing policies; and

(c) New, Renewable and Rural Sources of Energy (NERSE) task force. The principal focus of NERSE has been on the coordination of R&D activities; reviewing potential technologies from the technical, economic and financial viewpoints to identify those which are most promising; and promoting, financing and generally encouraging the commercialization of the selected technologies.

The three task forces meet on a regular basis (approximately once a month). They include representatives of the major ministries and line agencies. The existing institutional framework including these task forces is shown in Annex 1, Attachment 2.

2.03 Although the ECT framework, with its regular meetings of representatives from the major ministries and line agencies, has improved institutional coordination in the energy sector, it has been hampered by a shortage of skilled and experienced personnel at all levels. It is thus recommended that every effort is made to ensure that the existing improvements in institutional coordination are consolidated and extended, and that requisite measures are taken to ensure an adequate provision of skilled and experienced personnel to work on each of the coordinating task forces.

2.04 Energy policy coordination was also strengthened in 1985 when the Ceylon Petroleum Corporation and the Colombo Gas Company Ltd. were transferred from the responsibility of the Ministry of Industries to the Ministry of Power and Energy, thus reducing the number of ministries involved in the energy sector. The coordination of energy policy had also been assisted by the creation, in 1983, of Lanka Electric Company (LECO) to gradually take over distribution systems from local authorities (paras 3.13 to 3.19).

B. Energy Resources

2.05 Sri Lanka has few indigenous energy resources. There are no known hydrocarbon reserves, but a modest petroleum exploration program is underway. The major indigenous energy resources are hydropower and fuelwood.

Hydropower

2.06 Sri Lanka's hydropower potential is estimated to be about 2,300 MW, with an energy potential, under average hydrological conditions, of 6,600 GWh a year. The major hydropower resources are concentrated in the southern half of Sri Lanka in basically five river systems: Mahaweli Ganga, Kelani Ganga, Kalu Ganga, Nilwala Ganga and Walawe Ganga. The hydro potential of the Kelani basin has been largely developed (Old Laksapana 50 MW, Wimalasurendra 50 MW, Bowatenne 40 MW, Polpitiya 75 MW, New Laksapana 100 MW and Canyon

30 MW projects). The only remaining project for this basin is the Broadlands 30 MW project. Two projects in the lower and central areas of the Mahaweli basin (Victoria 210 MW and Kotmale 201 MW) have been completed or are nearing completion and two projects are at various stages of planning or development (Randenigala 122 MW and Rantambe 49 MW). A major project, Samanalawewa 120 MW, is also planned on the Walawe Ganga. Projects which have been developed, are under construction or are planned by CEB for commissioning by 1990 mean that 1,280 MW of the potential 2,000 MW hydro capacity will be developed by that date.

2.07 The centerpiece of hydropower development has been the Accelerated Mahaweli Program (AMP), which will add 533 MW (Victoria, Kotmale and Randenigala) to CEB's installed capacity in the period 1984-88. This program represents the core development project in the country and was initiated to reduce foreign exchange payments for imports of food and oil. The program dominates the public investment program (about one third of the 1981-85 public investment program was devoted to Mahaweli - Chapter 7).

2.08 Sri Lanka faces a number of problems concerning the development of its hydro resources. One concerns a lack of detailed knowledge regarding the remaining hydropower potential and technically feasible developments which might be included in the least cost generation program in the period beginning 1990. The Government of the Federal Republic of Germany offered to fund, through the Gesellschaft fur Technische Zusammenarbeit (GTZ), a study of Sri Lanka's hydro potential and the long term development of the electricity supply system with particular reference to the use of hydropower. Terms of Reference (TOR) for the study include: preparation of an inventory of potential hydropower projects; preparation of preliminary costings for these projects; and ranking potential projects in terms of their benefit/cost ratios, although the TOR do not specify how benefits will be measured. Consultants (Lahmeyer/Decon) were appointed in January 1986, and the study commenced on April 1, 1986. It is recommended that high priority is given to completion of this study on schedule; that care is taken to ensure that both benefits and costs are measured appropriately in economic terms; and that detailed evaluation studies are initiated for, say, the two most promising projects to facilitate the least cost development of the supply system.

2.09 A set of problems concern the planning, execution, operation and management of multipurpose projects, particularly those in the Mahaweli Ganga (M-G) Complex. Issues relating to operational planning of the M-G Complex, and recommendations to improve such planning, are considered in paras 5.18 to 5.25. In this section, attention is confined to development and management problems concerned with the M-G Complex.

2.10 Planning in the M-G Complex did not incorporate a systems approach but rather was put together on a project by project basis, summing the results together to arrive at an overall acceptable internal rate of return

(originally 15%)1/. It seems likely that poor planning and investment decision making will result in the mature form of the M-G Complex suffering from inherent spatial and temporal conflicts in water allocation between power and energy. Although most of the benefits accruing to the AMP are from power generation, which will provide about 50% of CEB's capacity by 1990, CEB has played a very small role in the development and management of the M-G Complex. The management of the M-G Complex is under the overall direction of the Water Management Panel (WMP). The WMP is chaired by the Director-General of the Mahaweli Authority of Sri Lanka (MASL) and also includes two other senior management representatives of the MASL (in the areas of Engineering and Settlement), the Director of Agriculture, the Director of Irrigation, the Secretary of the Ministry of Agriculture Development and Research, the Secretary of the Ministry of Lands and Land Development, the Government Agents of seven districts and the Chairman of CEB. The Water Management Secretariat (WMS), a unit of the MASL, acts as Secretary to the panel. Possible reform of the WMP is considered in para 5.22.

2.11 The original imbalances evident in planning the development of the M-G Complex continue. Recent and current planning studies have concentrated on exploring ways for increasing irrigation acreage rather than/or in conjunction with ways for increasing the system firm energy supply. The studies do not seem to have included extensive sensitivity analysis on project benefits or costs (Annex 2). For example, the consultants based their calculations of the value of primary energy on the unit capacity, fuel and O&M costs of a coal-fired plant, similar to the one that is currently being studied at Trincomalee. Similarly, another study discussed the option of reducing the M-G Complex firm energy capacity by up to 24% and using the resultant saving in water to meet irrigation needs in another river basin. However, this study did not take into account the possibly serious consequences for CEB of such a policy, in particular its impact on CEB's least cost investment program.

2.12 A number of recent changes have improved the current operating situation of the M-G Complex, at both the working and management levels. Thus, since early 1984, a working group, consisting of representatives of CEB, MASL/WMS, the Mahaweli Economic Agency, the Irrigation Department (ID) and of consultants (NEDECO and Acres), has been using the Macro simulations model to develop weekly operational planning and monitoring procedures for the M-G Complex (Annex 2, Attachment 4). Projected target irrigation diversions, plus peak power and energy requirements together with projected rule curve levels, are used as inputs into the Macro model to predict the performance of the M-G Complex in its existing configuration. Monitoring

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1/ A Project Layout Map and Schematic Layout for the M-G Complex in 1990 are given in Annex 2, Attachments 2 and 3.

includes a comparison of actual system behaviour with the projected system behaviour for the week preceding that when the working group meets.

Fuelwood

2.13 Data inaccuracies and gaps mean that there is considerable uncertainty concerning the sources and uses of fuelwood. However, fuelwood is estimated to provide about 55% of Sri Lanka's gross energy supply (Table 2.1). Annual consumption of fuelwood is estimated to be about 5.0 million tons, but incremental wood production, from natural regeneration of forests, agricultural residues and rubber replanting, etc., is estimated to be less than half that figure. Deforestation will inevitably lead to some increase in commercial energy demand, with the substitution of petroleum products for fuelwood. This could lead to a substantial increase in the oil import bill, and to possible public finance problems if the petroleum product prices were subsidized.

2.14 The Government is aware of these problems and agreed that a key element in their resolution would be a large and comprehensive reforestation program. Reforestation programs are being developed within the context of ongoing USAID and ADB assisted fuelwood projects. When completed the USAID project aims at providing between 10% and 15% of the country's fuelwood requirements, partly through the establishment of 70,000 acres of fuelwood plantations and pilot village-cum fuelwood plots. The ADB-assisted project complements that of USAID, and focuses on encouraging villages in growing their own fuelwood needs. A Forestry Master Plan is being prepared as part of the Bank-assisted Forestry I Project (Credit 1317-CE). Efforts to increase the supply of wood fuel are being complemented by a testing program of improved woodstoves. NERSE has estimated that the replacement of open hearths by wood stoves with 20% efficiency would be in the national interest.

C. Energy Supply and Consumption

2.15 Energy balance tables for 1978 and 1983 are given in Annex 1 (Attachments 4 and 5). These tables provide snapshot summaries of the supply and consumption of energy in 1978 and 1983. In this section, the principal interest is in the identification of any trend changes in the supply and consumption of energy.

2.16 The supply of energy by main fuel type, over the period 1973-1982, is shown in Table 2.1. This shows that beginning 1978, there was an

Table 2.1

Sri Lanka Energy Supplies

Year	Gross Energy Supply ('000 TOE)	Energy Exports ('000 TOE)	Net Energy Supply ('000 TOE)	Net Energy Supply (% Share by Source)		
				Petroleum Products	Hydro	Fuelwood and Agr. Residual
1973	3931	770	3161	38	5	57
1974	3748	580	3168	31	7	62
1975	3921	647	3274	30	8	62
1976	3934	682	3252	29	8	63
1977	4267	681	3586	27	8	65
1978	3934	603	3331	23	10	67
1979	4354	639	3715	30	9	61
1980	4759	791	3968	31	9	60
1981	4883	682	4191	32	9	59
1982	4960	670	4290	36	9	55

Note: Hydro energy is estimated on the basis of fossil fuel equivalent of 4000 kcal/kWh.

Source: Energy Data Book, Energy Coordinating Team and Energy Unit, CEB, October 1983, page 1.

increase in the relative importance of imported petroleum products in net energy supply, which was matched by a decline in the relative importance of the supply of fuelwood and agricultural residues. Imports of petroleum fuels are shown in Table 2.2. It shows that, with the exception of 1981,

Table 2.2

Petroleum Product Imports 1972-84
('000 tons)

Year	Crude	Gasoline	Kerosene	Av. Tur.	Auto Diesel	Other Pet. Products	Total
1972	1818.29	0.00	23.59	3.07	18.41	22.41	1885.49
1973	1753.23	0.00	22.76	9.04	0.00	20.62	1805.67
1974	1526.47	0.00	10.05	0.00	9.21	19.85	1565.58
1975	1464.59	0.00	0.00	4.20	0.00	24.31	1493.09
1976	1447.14	0.00	9.77	0.00	9.20	18.13	1484.23
1977	1529.63	2.18	32.18	15.85	26.72	18.70	1625.25
1978	1443.90	3.72	25.45	55.71	82.66	24.33	1635.77
1979	1444.02	6.55	41.89	65.28	198.56	24.82	1781.11
1980	1861.16	0.00	0.00	58.42	42.58	39.49	2001.65
1981	1710.50	0.00	0.00	45.01	110.93	23.29	1889.74
1982	1940.54	0.00	43.43	5.38	183.91	59.48	2232.74
1983	1492.00	15.00	55.80	10.90	405.90	N.A.	
1984 a/	1733.20	0.00	8.80	0.00	120.21	N.A.	

a/ Provisional.

Source: Ceylon Petroleum Corporation.

petroleum product imports increased steadily following the change in GOSL economic policies in 1977 (Annex 3, para 4) until 1982. The average annual growth rate of petroleum product imports during the period 1977-1982 was about 7%.

2.17 Petroleum Supply Facilities. The Ceylon Petroleum Corporation (CPC), a state-owned agency, is responsible for all aspects of petroleum supply with the exception of the retail marketing of LPG which is the responsibility of another state-owned agency, the Colombo Gas and Water Company (CGWC), and some secondary marketing of petroleum products through small private dealers. Table 2.2 shows that the bulk of the country's petroleum product requirements is imported as crude oil which is processed at CPC's refinery on the outskirts of Colombo, with a design throughput capacity of 52,000 barrels/stream day. The refinery's aggregate throughput exceeds the total consumption of petroleum products in Sri Lanka; however, its production slate differs significantly from the mix of product demand. There is a deficit in the production of kerosene, aviation turbo and diesel oil, causing supplementary imports (Table 2.2) and a surplus of nathpa and fuel oil which has to be re-exported. CPC recently considered, but found unprofitable, a hydrocracker project to modify the refinery's production pattern.

Energy Consumption

2.18 Imported coal provided half of commercial energy supply in the 1950s, but less than 1% in 1982; however, it is expected to be important in the 1990s with the planned Trincomalee coal-fired power station (para 5.09). The annual consumption of energy, by main fuel type, over the period 1973-1982, is shown in Table 2.3. Total energy consumption increased from 2.88 million

Table 2.3

Sri Lanka Energy Consumption

Year	Final Energy Consumption ('000 TOE)	% Share by Source			Per Capita Energy Consumption (TOE)
		Petroleum	Electricity	Fuelwood and Agr. Residual	
1973	2877	35	3	62	0.219
1974	2869	29	3	68	0.216
1975	2934	27	3	70	0.216
1976	2935	27	3	70	0.212
1977	3210	26	3	71	0.229
1978	3259	30	3	67	0.227
1979	3300	30	3	67	0.227
1980	3439	29	3	68	0.232
1981	3599	29	4	69	0.238
1982	3612	32	4	64	0.237

Source: Energy Data Book, Energy Coordinating Team and Energy Unit, CEB, Colombo, October 1983

TOE in 1973 to 3.61 million TOE in 1982, equivalent to an annual growth rate of 2.5%. During this period per capita energy consumption increased by less than 1% a year. Fuelwood and agricultural residues took the major share of final energy consumption throughout the period, varying between 71% in 1977 and 62% in 1973. The share accounted for by petroleum was typically around 30%. The only discernible trend concerning changes in the relative shares of the different types of fuels in total energy consumption is the small increase in the relative importance of electricity, from 3% to 4% in 1981.

2.19 The sales volume of petroleum products in the period 1970-1984 is shown in Annex 1, Attachment 6. The most significant trends concern a trend decrease in the consumption of kerosene beginning 1978, at the average annual rate of -7.8%, and a trend increase in sales of automotive diesel, at the average annual rate of 7.7% over the period 1978-1984.

2.20 During the period 1977-1982 the consumption of petroleum fuels by power plants (Table 2.4), both CEB and auto generation, increased from 11,230 tons to 174,010 tons, equivalent to an average annual growth rate of 73%. The consumption of petroleum products by CEB power stations nearly doubled in 1983, due to drought conditions. However, this consumption was considerably lower in 1985 as hydroelectricity from Victoria, Kotmale and other hydro schemes was substituted for thermal generation.

Table 2.4

Consumption of Petroleum Products by Power Plants
('000 tons)

Year	F.O. By St. Plants	Diesel by Gas Turb.	Diesel Plants	F.O. for Auto Generation	Total
1972	29.92	0.00	2.95	N.A.	32.88
1973	83.64	0.00	4.97	12.59	101.21
1974	4.27	0.00	0.44	11.65	16.36
1975	0.50	0.00	0.13	11.10	11.64
1976	8.06	0.00	0.09	11.23	19.43
1977	0.70	0.00	0.13	10.46	11.23
1978	4.78	0.00	1.33	10.06	16.17
1979	18.48	0.00	1.39	10.16	30.04
1980	44.94	6.02	7.15	12.45	70.56
1981	33.56	60.41	4.82	19.87	118.67
1982	20.66	118.36	4.01	21.99	174.01
1983	49.99	--------251.98------		-	-
1984	4.00	39.39	8.63	-	-

Source: Energy Data Book, Energy Coordinating Team and Energy Unit, CEB, October 1983, page 7 and CEB.

Petroleum Product Pricing

2.21 The development of petroleum product prices over the period 1973-84 is shown in Table 2.5. Significant price increases occurred in 1974 and

Table 2.5

Price Trends of Major Petroleum Products 1973-1984
Inland Sales Bulk Fuels
(Rs/Gallon)

Date		Super Petrol	Super Kerosene	Heavy Diesel Low Sulphur	Heavy Diesel High Sulphur	Auto Diesel	Furnace Oil 500 Second	Furnace Oil 1000 Second
Jan.	1973	5.75	1.32	1.63	1.53	2.14	1.28	1.18
Jan.	1974	12.50	3.60	4.90	4.60	4.80	4.00	3.80
Oct.	1975	13.30	4.00	5.40	5.10	5.30	4.50	4.30
Sept.	1979	30.00	10.68	12.00	10.30	10.50	9.70	9.00
June	1980	40.00	15.18	23.00	20.80	21.00	20.20	19.50
Jan.	1981	42.50	17.68	30.00	25.80	27.00	20.20	19.50
Mar.	1983	54.58	23.64	35.91	29.32	30.69	20.20	19.50
July	1983	61.40	29.96	35.91	35.61	36.98	22.22	21.45
Oct.	1984	61.40	29.91	35.91	35.61	36.98	23.73	21.45

Source: Ceylon Petroleum Corporation

1979, and prices were on an increasing trend in the period 1979-83. In July 1983 prices were increased to reflect higher costs and the devaluation of the Rupee. The price of kerosene was increased by about 27% following the virtual elimination of the general subsidy on this product. The purchasing power of low income households was protected by a simultaneous increase in the value of kerosene stamps, which are provided to about half of the population. In 1984 petroleum product prices were at or above border price levels. Thus in June 1984 the cost of kerosene was US$34.30/bbl FOB Singapore, and about US$35.3/bbl at Colombo. The latter price corresponded to Rs 25.23/gallon, which was Rs 4.68/gallon less than the market price of Rs 29.91/gallon in Sri Lanka. Similarly, 1,000 seconds Redwood No. 1 fuel oil was US$28.94/bbl FOB Singapore, and about US$29.94/bbl at Colombo. The latter price corresponded to Rs 21.41/gallon, almost exactly equal to the market price in Sri Lanka. The Government did not reduce domestic prices of petroleum products following the fall in international traded prices in early 1986. Rather, it used the opportunity to mobilize resources to reduce the budget deficit.

III. ORGANIZATIONAL STRUCTURE

A. Power Subsector Organization

3.01 Sri Lanka's first public electricity supply was made available in Colombo in 1895 by Messrs. Boustead Bros. The business was soon taken over by United Planters Co., who extended it and in 1899 built the Colombo electric tramways. In 1902, the Colombo Electric Tramways and Lighting Co. Ltd. was formed and provided electricity supply until 1927 when the Department of Government Electrical Undertakings (DGEU) was established to control the utility, which had by then been purchased by the Government. DGEU was succeeded in 1969 by the Ceylon Electricity Board (CEB), a statutory corporation, which was established with responsibility for the generation, transmission and distribution of electricity. At that time distribution systems operated by local authorities under license from DGEU were left under the control of those authorities.

3.02 CEB supplies power direct to consumers and also sells in bulk to 218 licensees (local authorities) which retail to their own consumers. In 1985, CEB's sales accounted for about 80% of total sales at the distribution level, and licensees for the remaining 20%. Three Government Ministries are involved in the power subsector. The Ministry of Power and Energy is responsible for supervision of CEB's policies, while the Ministry of Local Government, Housing and Construction (MLGHC) is responsible for the overall administration of local authorities, including those licensed to distribute electricity. The Ministry of Mahaweli Development (MMD) is responsible for the development and implementation of a 30-year program to harness the Mahaweli Power System for agricultural use and hydro-power. In 1979, the Government established the Mahaweli Authority of Sri Lanka (MASL), an agency under MMD, to be responsible for the implementation of the Accelerated Mahaweli Program (para 2.07). This program includes the construction of about 580 MW of hydro capacity under the Victoria, Kotmale, Randenigala and Rantembe schemes (Annex 4). On completion of these schemes they are handed over to CEB for operation and become part of its generation system (Section E below).

B. Ceylon Electricity Board (CEB)

Organization

3.03 CEB was established by the CEB Act, No. 17 of 1969 (1969 CEB Act). It is governed by a seven member Board; members are appointed by the Minister of Power and Energy and may be removed at any time, serve a three to five-year term and may be reappointed. Four of the members must have experience in either engineering, commerce, administration or accountancy, and the others represent local authorities, industry and the Ministry of Finance. The Chairman is appointed from among the Board members. The

present Chairman is also the Secretary, Ministry of Power and Energy. While the Chairman is responsible through the Board for policy matters and close liaison with the Government, the General Manager is CEB's Chief Executive Officer. He is responsible for the overall direction and control of CEB's day-to-day business. The General Manager is appointed, on the basis of seniority and merit, from CEB's staff. In recent years, there has been a rapid turnover in the persons holding this position (there were three General Managers during 1982-1984), whereas the Chairman has been in position for five years, and this led to discontinuity and an increase in the Chairman's involvement in CEB's day-to-day business. However, the situation improved with the appointment of the present General Manager in 1984. The General Manager is assisted by three Additional General Managers, three Deputy General Managers, a Finance Manager and a Commercial Manager. With the exception of the Finance Manager, these top posts are filled by engineers.

3.04 CEB's original organizational structure was designed by Urwick International Ltd., management consultants, in the early 1970s under Loan 636-CE. In 1981, CEB again retained the services of these consultants to re-examine its organizational structure, since the existing structure was exhibiting various weaknesses and was considered to be inappropriate for the enlarged size and responsibilities of CEB. Urwick International Ltd. recommended a decentralized organization consisting of (i) CEB's Headquarters with seven departments; (ii) two operating regions with several divisions under them; and (iii) a Generation Group responsible for three complexes and a system control center. The Board agreed to the proposed reorganization in September 1982 and implementation began in January 1984 (CEB's organization chart is shown in Annex 1, Attachment 3). Financial control, personnel matters, and policy formulation are retained at Headquarters. It is envisaged that the Generation Group will sell electricity to the regions at a rate determined by the Board 1/. The regions are expected to be responsible for the extension and reinforcement of distribution systems and making service connections. They will also be responsible for the rural electrification program (para 3.20). Under the new organizational structure, CEB will cease to undertake major construction work using its own directly employed labor. Contracts for large projects will be let to outside contractors under control of CEB Headquarters. However, construction units will be established in the two operating regions to allow them to undertake distribution work and minor works.

3.05 CEB's existing centralized accounting and stores holding systems, which were designed in the early 1970s, are inappropriate for this decentralized organization. These systems are being decentralized to the

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1/ Consequently, CEB will need to introduce a bulk supply tariff for sales by the generation group to the regions when the reorganization has been completed.

regional and divisional levels and their equivalents in the Generation Group. However, implementation of the new organization has proceeded at a slower pace than expected, and consequently many of the new management systems are operating only partially. In an effort to expedite implementation, CEB requested the consultants to prepare detailed procedures for the new organization, provide systems training to selected staff, and prepare manuals for systems operations for all CEB's activities. The consultants produced drafts for twenty-six operating and four functional manuals for CEB approval and eventual distribution. The finalization of these manuals has proceeded slowly and some of the manuals are still in the draft stage. Thus some of the major benefits anticipated from the reorganization exercise have not materialized, and CEB is still operating many systems under the old procedures. In recognition of this problem, CEB extended its contract with Urwick International Ltd., to assist in monitoring the implementation of the new procedures. Subsequentially, CEB agreed to hire local consultants to, in effect, monitor the stage of implementation of the new procedures. Monitoring is now underway under the supervision of Urwick International Ltd. in association with M/s Macan Markar, a local firm of accountants. Full implementation of the new organizational structure and the finalization of the associated operating manuals is considered to be an important step in strengthening CEB, and is required to enable it to manage operations and investments efficiently. Therefore, in order to ensure that CEB's organizational structure does not hinder its development as a modern utility, it is recommended that CEB should, on a priority basis, put into effect fully the new organizational structure and related operating procedures. Furthermore, it should finalize and distribute all remaining operational and functional manuals, which were prepared by its consultants.

3.06 The new organization is concerned with improving the efficiency of CEB given its present functions. The perennial problems of local authorities with regard to their electricity distribution functions require longer term policy decisions by GOSL to rationalize the electricity distribution industry. Under the existing organization of the power subsector, CEB is directly responsible for about 80% of total sales at the distribution level, with licensees (local authorities) being responsible for the other 20%. The number of licensees is gradually being reduced as Lanka Electric Company (LECO), which GOSL formed in September 1983 in an effort to address the deterioration in the quality of service at the distribution level, takes over the distribution systems operated by licensees. LECO was established under the Companies Act. Its shares are held by CEB, the Urban Development Authority (UDA), and local authorities (non-voting shares only). One reason for the establishment of LECO under the Companies Act was to ensure that it would not be subject to Government regulations on conditions of service for its employees. LECO, has so far taken over five licensees and has identified another 15 to be taken over in the near future. GOSL's policy for the reorganization of electricity distribution is supported by both the Bank and the ADB. The latter is supporting LECO through its Secondary Towns Distribution Project.

3.07 A major defect with the current arrangements to reorganize the subsector is that LECO, in taking over licensees, does not achieve a viable consumer mix; in particular it has a preponderance of domestic consumers and insufficient high-voltage consumers. In addition, the long-term takeover of all licensees by LECO would lead to a fragmented area of operations due to the geographic separation of many licensees. The solution to this problem may involve LECO taking over both licensees and consumers served by CEB in areas contiguous to those now served, or to be served in the future, by LECO. In recognition of the issues posed by licensees, LECO has commissioned the development of a Master Plan (to be completed in 1986 by consultants funded by ADB) which will suggest a framework for its future development and determine the investment required to rehabilitate the distribution systems of licensees. This Master Plan should be complemented by a similar plan for the distribution systems operated by CEB, and the two plans integrated to provide an overall plan to rationalize electricity distribution in Sri Lanka. Consequently, it is recommended that CEB should prepare a master plan for the development of its distribution systems; and GOSL should formulate a dated and monitorable program to rationalize the institutional arrangements for the distribution of electricity, including the role to be played by any licensee which would not be taken over by either LECO or CEB.

Autonomy

3.08 The 1969 CEB Act gave CEB substantial autonomy, although the Government retained an important role in such policy matters as tariffs, investment, borrowing, and the appointment of the Chairman and General Manager 1/. However, subsequent legislation and Government regulation have effectively prevented CEB from operating as an autonomous and efficient commercial organization and converted it into a semi-government department. Thus, Government regulation of conditions of service for all CEB staff limits total remuneration to Rs 5,200/month (about US$200), even for the Chairman and General Manager, and is a major cause of CEB's management problems (para 3.11). CEB is subject to the provisions of the Finance Act, No. 38 of 1971 (1971 Finance Act) which regulates the finances of all public corporations in Sri Lanka. Regulations under this Act require all tender awards exceeding Rs 5.0 million (about US$190,000) to be approved by the Cabinet. The existing degree of autonomy is not appropriate for the requirements of a rapidly growing power utility. Failure to increase CEB's autonomy may impede the efficient development of the power subsector. It is, therefore, recommended that GOSL should initiate actions to restore CEB's operational and financial autonomy within the framework of the 1969 CEB Act in order to enable it to become an efficient commercial power utility. These

1/ Although the Board appoints the General Manager, his appointment is subject to approval by the Minister of Power and Energy.

actions should be dove-tailed into GOSL's proposals concerning CEB's salary structure and levels (para 3.11), and into the more fundamental decisions concerning the appropriate organization of the power subsector (para 3.07).

Staffing

3.09 In June 1985, CEB had about 12,500 employees and an authorized establishment of about 15,000. It has been suffering from a number of manpower problems, which means that it is simultaneously overstaffed and deficient in key personnel in virtually every key functional area. The consumer/employee ratio is about 32:1, which is one of the lowest ratios recorded for electricity utilities in the region 1/. One reason for this low ratio is that more than 2,000 employees are deployed on non-commercial activities such as maintenance of electrical installations e.g. lifts, air conditioning, electrical wiring, etc., in Government institutions such as hospitals, schools, offices, etc. Another reason for the low ratio is that head counts of available staff exaggerate the numbers actually available for work. The number of working days each year is relatively small due to the large number of 'leave' days and public holidays. The employees taken over by CEB from the Department of Government Electrical Undertakings are entitled to 21 days casual leave and 24 days vacation leave per year, while those recruited direct to the CEB are entitled to 7 days casual leave, 14 days annual leave and 21 days sick leave per year. Consequently, on an average, staff work for only about 16 days a month, which increases the number of required employees. CEB is aware of this problem and in July 1984 the Board approved the payment of a bonus equal to one month's salary to staff who do not take the sick leave/vacation leave (and pro-rata payment for lower levels of leave not taken). It is too early to ascertain the likely effectiveness of this measure. Thus the Bank should monitor the situation regarding CEB staffing. The overstaffing is probably linked to CEB's remuneration problems (paras 3.10-3.11) and is symtomatic of its organizational problems (para 3.08).

Conditions of Service

3.10 In recent years, CEB has had considerably difficulty in retaining experienced engineers and accountants. At the end of 1984, it had only about 300 qualified engineers, of whom less than 10% had more than five years experience with CEB. Many engineers have left to take posts in the private sector or overseas which offered substantially higher financial rewards. The exodus of staff has been increased by a promotion system which emphasizes seniority rather than merit, and the fact that the existing salary structure gives very little financial incentive to seek the more responsible positions

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1/ In 1984, the equivalent ratios were 103:1 for PLN in Indonesia, 73:1 for NEB in Malaysia, and 302:1 for Korea Electric Power Corporation.

in CEB. A consequence of these factors is that CEB now has an acute shortage of experienced engineers, in the 30-45 year age bracket, at middle and senior levels. Chief engineers and project managers are often overburdened due to the very small numbers of staff, sometimes zero, to whom they can delegate.

3.11 The need for strong and effective management is being emphasized by the rapid increase in CEB's installed capacity, largely as a result of the transfer of major hydropower schemes constructed under the Accelerated Mahaweli Program (para 2.07). This transfer and other planned additions to CEB's capacity, will inevitably place a heavy burden on CEB's management. CEB is aware of its existing and likely future manpower problems, and engaged management consultants (Urwick International Ltd.), to identify key jobs in the organization and develop proposals to attract and retain Sri Lankan engineers for these key jobs. In September 1984 the consultants submitted two reports concerned with these manpower problems. The first report (Key Manpower Study) identified the 30 or so key jobs in CEB and prepared specifications for each job. The second report (Staff Compensation Review) contained proposals for attracting and retaining well qualified engineers. The main proposal concerned the removal of the Government imposed ceiling on remuneration and the introduction of a new salary structure involving increases of 200% for engineers in the top grades, tapering down to increases of 25% in the lowest grades. The existence of appropriately qualified and well motivated staff is a basic requirement if CEB is to be a well managed and efficient power utility. However, proposals to improve conditions of service must be formulated within the public sector constraints set by the Finance Act. CEB does have some room for maneuver through the payment of risk and productivity allowances and bonuses up to the equivalent of one month's salary a year. Keeping in view both CEB's long-term manpower requirements and the Government imposed ceiling on remuneration, it is recommended that CEB should formulate a promotion policy which rewards merit and introduce a scheme of incentives, including productivity and other bonuses, to assist in the retention of experienced personnel.

Training

3.12 CEB appreciates the role to be played by training in meeting its staffing requirements, and in 1984 established a training function with a full-time director in its new organizational system. Much of the training currently undertaken by CEB is concerned with the orientation of new staff and imparting basic skills. Thus it is concerned largely with upgrading skill levels and redressing problems posed by the rapid turnover of staff. Existing training facilities are inadequate to meet the needs of a rapidly growing utility. The existing training centre at Castlereagh has the capacity to train only 40 staff annually. In 1983 CEB engaged Electricite de France (EDF) under bilateral financing to design a new training center in accordance with projections of CEB's manpower requirements to 1995. EDF recommended a training center to provide technical training for up to 1,000 staff a year in the maintenance of electrical and mechanical equipment,

operating power plant equipment, etc. This proposal was reviewed by the Bank, which recommended a smaller training center to train up to 400 staff a year, in keeping with the projected growth of CEB's operations. The construction of the center was to be financed from CEB's own resources. However, in view of the shortage of foreign exchange, the Government and CEB requested utilization of savings under on-going Bank Group financed projects to cover the foreign exchange cost of equipment and training instructors for the training center. This request is being considered by the Bank Group.

C. Organization of Electricity Distribution and Lanka Electric Company

3.13 Although CEB is responsible for electricity generation and transmission throughout Sri Lanka, it is only responsible for distribution to just over half the total number of consumers. Retail sales are the responsibility of three organizations; CEB, 218 licensees and the recently formed Lanka Electric Company (Private) Limited (LECO). The licensees (municipal councils, urban councils and district development councils) and LECO purchase bulk power from CEB. In June 1985 there were about 680,000 electricity consumers, of whom about 395,000 were served by CEB, about 275,000 by local authorities and about 13,000 by LECO.

3.14 LECO was established as a private company in September 1983 to progressively take over, operate and rehabilitate the distribution systems of local authorities. It was formed to overcome the continuing distribution problems of many local authorities. These are: first, the total arrears owed by local authorities to CEB, which in 1985 typically equalled twelve months of their bulk purchases from CEB; second, the poor and deteriorating condition of the distribution networks for many local authorities, which has led to high and growing technical losses in their supply systems; and, third, high non-technical losses. There are no reliable statistics on these losses, but they are estimated to vary between 20% and 35% of power purchased at the bulk supply points. These high losses mean that it is virtually impossible for many local authorities to achieve a position of financial break-even on the basis of their existing tariffs (para 6.16), even though tariff rates are typically higher than comparable CEB rates. Consequently, the local authorities are not only unable to make full payment for bulk supplies from CEB, but they are also failing to maintain their distribution systems. The latter has led to a decline in the quality of supply, manifested by both low supply voltage and supply interruptions.

3.15 In 1982 GOSL considered the possibility of CEB taking over responsibility for local authority distribution systems as a means of addressing these problems. However, this option was rejected, partly because it would have placed additional heavy demands on CEB's overburdened and weak management. GOSL subsequently decided to opt for a more radical solution and established LECO as a private company, to gradually take over, operate and rehabilitate local authority distribution systems.

3.16 LECO was set up under the companies act. Its shares are held by CEB, the Urban Development Authority (UDA) and local authorities (which have only non-voting shares). It is managed by a board consisting of six directors (who are appointed by CEB and UDA) and a chairman. One reason for the establishment of LECO as a private company was to ensure that it would not be subject to Government regulations on conditions of service for its employees and on procurement (conditions which impede the efficient operation of CEB). Salaries paid by LECO are governed principally by the capability of staff, and are on average about double those paid by CEB.

3.17 The area selected for the initial establishment of LECO adjoins the City of Colombo. To date, LECO has only taken over the electricity operations of five local authorities and has identified another 15 to be taken over in the near future. Institution building support for LECO is being provided by ADB. A loan of $25 million was initially proposed to rehabilitate the distribution systems of 18 local authorities, which LECO was expected to take over, in an area adjoining the City of Colombo. However, ADB subsequently reduced the amount of the proposed loan to $12.4 million, and this was approved in January 1985. The project is intended to provide for the takeover, rehabilitation and expansion by LECO of ten distribution systems operated by local authorities and to develop within LECO efficient corporate, management and financial structures.

3.18 Despite this ADB initiative, LECO faces a number of major problems, including:

(a) the need to establish an organizational base which is appropriate to its expansion as it takes over increasing numbers of local authorities;

(b) the need to increase its capital to enable it to take over and rehabilitate more distribution sytems currently operated by local authorities;

(c) the reluctance of some local authorities to hand over their electricity supply operations to LECO, since they consider these operations to be an important source of revenue; and

(d) the need to install accounting and billing systems suited to the number of consumers who ultimately may be served by LECO.

It is apparent that, as a result of the foregoing and other factors, LECO cannot be expected in the near future to resolve the twin problems of distribution network rehabilitation and chronic payment arrears.

3.19 To a large extent the success of LECO in acquiring distribution systems from local authorities and operating them efficiently will depend on its ability to attract the investment capital (from both the private and

public sectors) required to enable it to take over and rehabilitate distribution systems. In addition, its success will depend on it being given powers to acquire these distributing systems, since local authorities tend to regard electricity supply as confering various political benefits which they are reluctant to lose. It is, therefore, recommended that GOSL should institute appropriate procedures which would prevent local authorities blocking the take over of their electricity distribution functions by LECO. It is further recommended that GOSL should take whatever action is necessary to attract the investment capital required by LECO.

D. Rural Electrification

3.20 Prime responsibility for rural electrification rests with CEB, although local authorities have a minimal involvement through the occasional extension of their supply systems into rural areas. CEB's rural electrification department, headed by a project manager, is responsible for the management of the rural electrification program. The Government has recognized the importance of rural electrification not being undertaken in isolation but proceeding in a coordinated way with other developments in rural areas. Coordination is being encouraged by the establishment of an inter-agency coordinating group. Its Chairman is the Secretary of the Ministry of Plan Implementation, and it includes representatives from CEB, Chamber of Small Industries, and some Government organizations. The group recognizes the importance of an adequate supply of finance if rural electrification is to be successful, and it is expected that it will be joined by representatives from the Bank of Ceylon, Development Bank of Ceylon, and the People's Bank.

3.21 An ADB-OPEC Fund project to electrify 1,150 villages by 1984 was started in 1980. Estimated foreign costs of US$17.3 million were to be met by ADB (US$11.3 million) and OPEC Fund (US$6 millin) loans, while local costs were to be funded by a GOSL grant. Due to the failure of GOSL to supply this grant only 170 schemes had been completed by early 1983, although US$11.3 million had been spent on importing materials and equipment for the project. Following the failure of the project, a new agreement was made with ADB and OPEC Fund in 1983 to complete about 900 rural electrification schemes by December 1986. The donors agreed that US$5.8 million of the US$6 million remaining from the 1980 loans should be transferred to part finance the estimated local expenditure of US$16.5 million, while GOSL agreed to contribute US$10.7 million equivalent. ADB and OPEC Fund also agreed to increase their 1980 combined loan commitment by US$3.8 million to meet foreign costs.

3.22 Work on the revised project began in mid-1983. However, the project again fell behind schedule, although the promised local funds were made available by GOSL. The principal reason for the slow progress was the discovery that CEB's construction capability was inadequate to undertake the project. CEB decided that this inadequacy should be overcome by using

private contractors for low tension work. This decision led to two problems. First, it was found that local contractors did not have the requisite skills and experience to undertake the proposed low tension work. Consequently selected contractors would have to be supervised by CEB staff. Second, tenders for employment of the contractors exceeded Rs 6 million and nearly three months elapsed while the tender evaluation and approval procedure was followed to the award of contract. The contracts were finally let in the week beginning October 1, 1984.

3.23 The development of rural electrification loads can have an adverse effect on system load factors due to the character of the initial loads and the importance of lighting loads. The ADB project involved the appointment (in June 1984) of a load promotion consultant in an attempt to identify and develop high load factor loads (this expert left to join the Bank in January 1985 and was not replaced). The consultant recommended the formation of a load promotion and monitoring unit in CEB, and the recruitment of an assistant project manager, an economist and an engineer. CEB agreed to this proposal, and the assistant project manager was appointed in January 1985. However, the other appointments have not been made due to the problem of identifying suitable staff. This recruitment problem is believed to be partly due to CEB's existing salary levels and structure (para 3.10).

3.24 From the foregoing, it is apparent that the overall management of the rural electrification program has been weak. Some of its problems are endemic to the present organization of CEB, such as those involving delays in the evaluation of contracts exceeding Rs 5 million. Other problems have been caused by GOSL delays in disbursing local funds. Still other problems have been caused by a shortage of requisite staff to undertake and supervise the rural electrification project, even though CEB is, when judged overall, overstaffed. The problems encountered with regard to hiring local contractors are clearly relevant to the proposed Transmission Expansion and Distribution Rehabilitation Project (para 4.11) which the Bank Group has been requested to finance. In so far as these problems are manifestations of more widespread problems existing in CEB they could be ameliorated if the recommendations made in para 3.11 on salaries and award of contracts were implemented. However, it is also recommended that the Government should disburse local funds in a timely and efficient manner in order to avoid further delays to the rural electrification program. It is further recommended that CEB set up the proposed load promotion and monitoring unit without delay in an attempt to identify, promote and develop loads which would increase overall load factors associated with the rural electrification schemes.

E. Transfer of Power Projects from Mahaweli Development Authority to CEB

3.25 After completion of multipurpose projects by the Mahaweli Development Authority, the power components (beginning at the intake) are handed over to CEB for operation and maintenance. This action necessitates the

determination of the project costs for which CEB is to assume liability. A cost allocation methodology for multipurpose projects was agreed with the Bank Group in 1982, and was based on that used for the Polgolla project (Ukuwela power station) which was commissioned in 1976 (see Annex 1, Attachment 8). The following discussion is in terms of that methodology.

3.26 Two issues should be discussed: first, the rationale for the selected methodology and, second, the suitability of the data base used in its application. The selected cost allocation method is that which is known as separable costs: remaining benefits. The method begins by estimating the separable costs of the project which are incurred for its power function. These costs include costs of the powerhouse, turbines, generators, transformers, transmission line, etc. The remaining non-separable or common costs are then split between the power and irrigation functions in proportion to the project's estimated power and irrigation benefits. The rationale for the method would appear to be that these benefits represent consumers' willingness to pay for the power and irrigation outputs and constitute the limits of what the power and irrigation authorities would be willing to contribute towards common costs in a bargaining situation.

3.27 Any method for allocating common costs to particular outputs is arbitrary. While such an allocation is not required, and should not be made, in investment appraisal, institutional factors may make it necessary from an accounting point of view. In these circumstances, it is important that the chosen methodology should be consistent with basic economic principles, which essentially means that the result is consistent with that which could occur in a bargaining situation. The chosen methodology passes this test and thus may be taken as being acceptable.

3.28 The determination of the separable and common costs, power and irrigation benefits for the Polgolla project is shown in Annex 1, Attachment 8. The allocation of the individual cost items to the separable and non-separable cost categories appears to be acceptable. It is not clear, however, how total costs were determined and specifically whether they included interest during construction.

3.29 The major problems with the application of the selected methodology relate to the estimation of power benefits. Before discussing some points relating to this methodology it is important to note that estimated benefits (and costs) were not time discounted. It was implicitly assumed that benefits would be constant in every year of the project's life. Power benefits were estimated in terms of the average annual energy produced (net of average system losses) by the Ukuwela power station in 1977-79 and the average selling price of electricity in 1979. Five points should be noted in connection with the estimation of power benefits. First, no attempt was made to estimate average annual energy production on a lifetime basis under average hydrological conditions. Second, no allowance was made for the effects of water discharge policy on the value of annual energy production.

Third, the project was assumed to give only energy benefits, capacity (or demand) benefits were implicitly assumed to be zero. Fourth, energy was valued at the average selling price per kWh. No deductions were made for the operations and maintenance costs of the Ukuwela power station or for the separable costs. Power benefits were thus calculated on a gross rather than net basis and in consequence were overestimated. Consequently, the share of common costs allocated to power was probably too high. Fifth, no attempt was made to estimate the value of electricity in terms of consumers' willingness to pay or to relate tariff rates to long-run marginal costs.

3.30 Irrigation benefits were correctly estimated on a net basis. However, no details are available of the production costs used to estimate net benefits.

3.31 It is understood that the foregoing methodology will be applied to future multipurpose hydro projects to determine costs to be allocated to CEB. If this is the case, then it is important that the method is refined. Therefore, it is recommended that a revised methodology for allocating the costs of multipurpose projects between their hydroelectric and irrigation functions should be formulated for use with future projects. The revised methodology should include estimation of benefits on a lifetime basis, the incorporation of time discounting, estimation of both capacity and energy benefits, the use of the WASP-III model to estimate annual energy production under average hydrological conditions, and the calculation of net rather than gross benefits from electricity supply.

IV. HISTORICAL TRENDS IN THE CONSUMPTION AND SUPPLY OF ELECTRICITY

A. Past Trends in Electricity Consumption

Availability of Electricity Consumption Data

4.01 The data base on past electricity consumption is generally good. There are, however, three problems with available data, only one of which is important (Annex 3, Section A). The important problem arises from the inadequate data base for retail sales by licensees. Nearly 25% of CEB sales are made to licensees (local authorities), however no aggregative data is available on licensees' retail sales to final consumers or on the losses occurring in their subtransmission and distribution systems. This constitutes an important gap in the available data base and it is recommended that measures are instigated to rectify this situation as soon as possible. The Ministry of Local Government is probably the appropriate institution to organize the collection of this data, and it could require local authorities to make annual returns on purchases from CEB, total sales to consumers, and sales in the various tariff categories. The collection of this data could pose problems of definition and comparability between the tariff categories of the various local authorities; however, since most local authorities are understood to have adopted CEB tariff categories this problem is unlikely to be important.

Growth of Overall Consumption

4.02 Electricity sales by CEB increased at an average annual rate of 6.0% in the period 1973-1978 and 8.4% in the period 1978-1985 (Table 4.1 and Annex 3, Attachment 2). The increase in the rate of growth of electricity sales accompanied an increase in the real GDP growth rate (Annex 3, para 4). The GDP elasticity of demand for electricity1/ increased from an average value of 1.47 in the period 1973-1978 to 1.68 during the period 1978-1985, and reflected structural changes in the economy, with the relative growth of the industrial and service sectors compared to agriculture. Beginning in 1979 average real electricity prices increased rapidly (Annex 5, Table 1); they increased at the average rate of 20% a year in the period 1978-1984. These increases did not have any noticeable effect on the growth of demand for electricity. Per capita electricity consumption in Sri Lanka increased from 53 kWh/year in 1970 to 129 kWh/year in 1985.

1/ Defined as the percentage change in electricity sales divided by the percentage change in real GDP.

Table 4.1

Electricity Demand, CEB System, 1973-1985

	1973	1978	1983	1985	Annual Growth Rate (%) 1973-78	1978-85
No. of consumers (000)	92.1	143.9	311.2	395.1	9.3	15.5
Electricity sold (GWh)	867.4	1161.5	1792.3	2042.0	6.0	8.4
Electricity generated (GWh)	979.5	1385.1	2114.4	2464.0	7.2	11.3
Per capita consumption (kWh)	66.0	82.0	116.0	129.0	4.4	6.4
Electricity intensity (kWh sold/US$'000 of GDP, 1982 prices)	-	302.0	375.0	388.0	-	3.6
GDP elasticity	-	-	-	-	1.47	1.68
Unserved energy (GWh)	0	0	16.8	-	-	-
Maximum demand (MW)	198.8	291.4	437.0	515.0	7.9	8.5
Load factor (%)	56.2	54.2	55.2	53.0	-	-

Source: CEB and Bank estimates

Electricity Supplied by CEB

4.03 Most of the growth of sales was attributable to the connection of new consumers, which increased at 15.5% a year during the period 1978-1985. Overall average consumption per consumer fell by 5.7% a year during the period 1977-1985 (see Annex 3, Table 6), and only increased for the local authority consumer class (8.9% a year). The sectoral changes in average consumption per consumer, with a relative increase in the importance of domestic consumers, could be expected to lead to a decline in the system load factor. This occurred in the period 1973-1985. The relatively high load factor of 55.2% in 1983 was partly due to supply interruptions in peak hours in the later months of the year when the highest system peak is recorded. In 1984 about 40,600 new domestic consumers were added to the supply system, and they added about 5 MW to the evening peak load, thus reducing the load factor.

Electricity Consumption by Sector

4.04 The sectoral consumption of CEB supplied electricity is shown in Table 4.2, together with sectoral shares of total consumption. In the period 1977-1985 the fastest rates of growth were recorded by the residential (15.6%), local authority (8.9%), and commercial (8.5%) sectors. Within the local authority category most of the electricity consumption is understood to

be by residential consumers1/. The trends in relative shares indicate that the combined residential and local authority category may soon exceed the share of consumption accounted for by industrial consumers. This may reduce the system load factor and exacerbate the existing evening needle peak (para 4.07).

Table 4.2

CEB Electricity Sales by Sector, 1973-85

	1973		1977		1985		Annual Rate of Growth	
							1973-77	1977-85
	(GWh)	(%)	(GWh)	(%)	(GWh)	(%)	(%)	(%)
Sector								
Residential a/	82.37	9.5	106.52	10.3	339.0	16.6	6.6	15.6
Commercial	107.60	12.4	147.90	14.2	283.0	13.9	8.3	8.5
Large Industry	193.50	22.3	262.40	25.2	399.0	19.5	7.9	5.4
Small & Medium Industry	273.10	31.5	257.00	24.7	442.0	21.7	-1.5	7.0
Local Authority	198.40	22.9	252.80	24.3	499.0	24.4	6.2	8.9
Street Lighting	12.50	1.4	14.00	1.3	11.0	0.5	2.9	-2.9
Hotels b/	-	-	-	-	69.0	3.4	-	-
Total	867.42	100.0	1040.66	100.0	2042.0	100.0	4.7	8.8

a/ Residential includes religious and charitable consumers.

b/ The hotels category was introduced in the 1982 tariff. Previously hotels had been included in the commercial (general purpose) category.

Source: CEB

The data presented in Table 4.2 reveals a fundamental change in the trend electricity demand growth rates for small and medium industrial consumers following the economic reforms introduced by GOSL in 1977. During the period 1973-1977 consumption by this category fell at the average rate of 1.5% a year, but during 1977-1985 it increased at 7.0% a year. By contrast, the

1/ No aggregate data is available on electricity sales by local authorities to the different consumer categories.

trend growth rates for the large industry and commercial consumer categories were lower in the period 1977-1985 than in the period 1973-1977.

4.05 The total number of consumers served by CEB increased at an average rate of 15.3% a year during the period 1977-1985, which represented a doubling in less than five years (Annex 3, Table 5). The fastest growth rates were recorded by the residential (16.6%), and small and medium industry (10.6%) consumer categories. During the period 1979-1985 an average of 32,345 residential consumers were connected each year. This rapid rate of new connections was the driving force behind the observed increase in electricity consumption on the CEB system. Average consumption per consumer in the principal consumer classes during the period 1973-1985 is shown in Annex 3, Table 6. During this period average consumption per consumer fell for all consumer classes with the exception of local authorities. Unfortunately no data is available on the average consumption per consumer served by local authorities.

4.06 CEB analyzed February 1984 billing data for residential consumers to ascertain the frequency distribution of consumption per consumer and the frequency distribution of consumers by consumption level. The results of this analysis are presented in Annex 3, Attachments 2 and 3. The median consumption was 40/50 kWh/month, and 52.3% of residential consumers used less than 50 kWh/month. About 28.3% of residential consumers used no more than 30 kWh/month, which is the consumption level required to meet basic electricity requirements (defined as using three 60 W bulbs for four hours a day and one mobile fan). Attachment 3 shows that only about 11% of residential consumers used more than 150 kWh/month; however, these consumers accounted for about 50% of electricity used by residential consumers.

Load Characteristics

4.07 Daily maximum demand occurs from about 19.00 h to 20.00 h (a typical daily load curve is shown in Annex 3, Attachment 4). During weekdays the load curve has three distinct segments: (a) a night-time load from about midnight to 04.00 h; (b) a day load from about 06.00 h to 18.00 h; and (c) an evening peak. Each segment is bounded by shoulder periods. The day load is about 65% higher than the night load, and the evening peak demand is about 50% higher than the day load. On Sundays the load curve has only two segments, off-peak from about 23.00 h to 18.00 h and peak from 18.00 h to 23.00 h. The peak demand is about 100% (180 MW) higher than the off-peak demand. Most of the incremental demand during Sunday peak hours is believed to be caused by residential consumers. This incremental load is probably a reasonable indicator of the incremental load of residential consumers during weekday peak periods. During weekdays, however, part of this incremental load is offset by a decrease in the industrial and commercial loads at the end of the working day at around 17.00 h.

B. Past Trends in the Supply of Electricity

Generation

4.08 During the last decade, there has been a significant increase in installed capacity and a noticeable change in the plant mix on CEB's supply system. Table 4.3 shows that total installed capacity increased from 361 MW in 1975 to 949 MW in 1985, an annual growth rate of 10.2%. During this period the hydro thermal plant mix changed from 81:19 in 1975 to 72:28 in 1985. The 1985 plant mix, and the growth of capacity during the period 1975-1985, are presented in detail in Annex 4, Attachment 1.

Table 4.3

Growth of CEB Generating Capacity 1975-85
(MW)

	1975	1979	1983	1985	Annual Growth Rate 1975-1985 (%)
Maximum Demand (MW)	219	329	437	515	8.9
Gross Generation (GWh)	1079	1526	2114	2462	8.6
Load Factor (%)	56	53	55	53	-
Installed Capacity (MW)	316	401	589	949	10.2
of which hydro (MW, %)	291(81)	331(83)	399(68)	679(72)	8.8
Effective Capacity (MW)			423	831	-
of which hydro (MW)			308	635	-
of which thermal (MW)			125	196	-
Plant Margin (installed) MW			152	431	-
Plant Margin (effective) MW			(14)	316	-

Source: CEB

4.09 In a number of recent years a major problem on CEB's system has been an inadequate supply of energy. 1980, 1981, and 1983 were dry years and CEB had to introduce power cuts (equivalent to about 3% of total generation in 1980, 4.6% in 1981 and 0.8% in 1983). In addition, supply interruptions equivalent to 19.7 GWh (0.9% of total 1984 generation) were imposed in January and February 1984 following the failure of the northeast monsoon. The supply interruptions in 1983 were relatively small, largely because gas turbine capacity had been increased from 80 MW to 120 MW in 1982. These units generated 734 GWh in 1983, equivalent to 35% of total generation, at a fuel cost of Rs 2,034 million (US$86.44 million). In 1983, total fuel costs for thermal generation were Rs 2,399 million (US$101.96 million), equivalent to Rs 1.34/kWh sold. The extensive use of thermal generation in 1983 caused CEB to increase the fuel adjustment charge in its tariffs to Rs 1.40/kWh on a base cost of Rs 0.84/kWh (Annex 5, Table 7). 1984 was a more normal year in

terms of hydrological conditions and consequently thermal generation was only about 25% of the 1983 level. The energy supply situation improved significantly in 1985 with the full commissioning of the Bank financed (Credit 2187-CE) Sapugaskanda diesel station, and the partial commissioning of the Victoria and Kotmale hydro stations. Beginning in 1988 these hydro stations are projected to provide about 1010 GWh/year of firm energy.

Losses

4.10 Losses, as a percentage of gross generation, on CEB's supply system increased from 10.5% in 1975 to 17.2% in 1985 (Table 4.4). The 1975 loss level was reasonable, allowing for the fact that about 45% of CEB's total sales are sales to factories and bulk sales to licensees (local authorities).

Table 4.4

Losses in CEB Supply System
(1975-1985)

	1975	1979	1980	1981	1982	1983	1984	1985
Generation (GWh)	1079	1526	1668	1872	2066	2114	2261	2462
Network Losses (GWh)	108	218	259	352	363	301	373	411
(%)	10.0	14.2	15.5	18.8	17.6	14.2	16.5	16.7
Station Supply (GWh)	6	10	18	17	17	21	10.6	11
(%)	0.5	0.6	1.0	0.8	0.8	1.0	0.5	0.5
Total Losses (GWh)	114	228	277	369	369	322	383.6	422
(%)	10.5	14.8	16.5	19.6	18.4	15.2	17.0	17.2

Source: CEB

Total losses in Sri Lanka are substantially higher than those recorded for CEB's system, since these exclude losses in local authorities' distribution systems. In 1984, these losses were estimated to be about 27% of CEB's bulk supply to these authorities, that is about 124 GWh. On this basis total losses in 1984 were about 507 GWh, or about 22% of gross generation. A breakdown of existing energy and demand losses is shown in Annex 4, Table 3.

4.11 The problem of losses has been studied by the UNDP/World Bank Energy Sector Management Program1/, and in 1983 CEB established a Loss Reduction

1/ Sri Lanka: Power System Loss Reduction Study, July 1983; Joint UNDP/World Bank Energy Sector Management Program, Activity Completion Report No. 007/83.

Cell (LRC) to address this problem.1/ According to both that report and network analysis carried out by LRC, the principal cause of the high losses is under investment in medium and low voltage distribution lines resulting in overloading and poor voltage conditions, and low power factors on many lines. Studies undertaken by LRC indicate that relatively high rates of return could be earned on loss reduction projects for distribution and subtransmission systems. The projects would include investments in:

(a) reconductoring lines to larger cross sections;

(b) introduction of new lines (of larger cross sections);

(c) installation of capacitors for power factor improvement;

(d) change of voltage level and redesign of system layout; and

(e) reduced L.T. coverage per transformer and an increase in the number of substations.

The Distribution Expansion and Rehabilitation Project for which CEB has requested Bank financing (as the Ninth Power Project) addresses the problem of relatively high losses. Preliminary analysis indicates that a loss reduction program could be accompanied by substantial savings in fuel and capacity costs. CEB commenced a loss reduction program in 1983. It is recommended that the Bank should support this program, starting with the proposed Distribution Expansion and Rehabilitation Project in FY87.

4.12 The foregoing concerned losses in CEB's supply system. On a national level it is important that action should also be taken regarding losses in local authority distribution systems, where non-technical losses are frequently much higher than on the CEB system. For example, losses in the Kotte Supply System, which has been taken over by LECO, were estimated to be in the range 30-35% in 1985, including about 15% non-technical losses. LECO has implemented a number of measures to reduce these losses, including using seminars and other means to change meter readers attitudes to 'errors', using the legal system to prosecute consumers found stealing electricity and publicizing the results of such prosecutions, and using new payment systems whereby consumers make payments into banks rather than to collectors. Preliminary evidence suggests that these measures have been successful in reducing losses, and especially non-technical losses. It is recommended that GOSL should initiate studies to determine the magnitude and causes of losses in local authority supply systems and that it should require local

1/ In 1985 LRC was renamed the Distribution Development Rehabilitation Branch (DDRB).

authorities to initiate effective programs to address the causes of these losses.

Transmission

4.13 CEB operates an island wide 132 kV and 66 kV primary transmission system to feed grid substations. In 1985 the transmission system was comprised of the following facilities:

Table 4.5

CEB Transmission Facilities

kV	Facilities	km	kV	Facilities	Number	MVA
11	Lines	2500	220/132/33	Substation	3	N.A.
33	Lines	7800	132/66	Substation	2	N.A.
66	Lines	286	66/33	Substation	8	84
132	Lines	805	132/33	Substation	19	465
		11391			32	

The list of facilities does not include step-up transformers connected to the generators, since CEB does not record this information in its inventory list. Under the Seventh (Mahaweli Transmission) Power Project (Credit 1210-CE), 220 kV lines are being constructed for completion in 1986 to meet larger transmission capacities required to transmit the increasing Mahaweli hydro generation to the Colombo area. The older 66 kV transmission system is, generally, in good condition. Transmission expansion is planned by CEB's Transmission Planning Branch, and reviewed by its consultants since CEB has insufficient in-house expertise. It is recommended that CEB's Planning Department should formulate an action program, including the identification of required staff and the acquisition of necessary computer programs to increase its capability to execute this type of work in-house.

Distribution

4.14 The subtransmission system at 33 kV comprises about 7100 km of 33 kV transmission lines and about 5000 consumer substations (Annex 4, Table 6). The physical condition of the distribution networks is generally unsatisfactory, partly due to the fact that many of the networks are overloaded as a result of the large increase in the number of consumers in recent years (Annex 3, para 11), and partly due to poor maintenance. CEB is undertaking network studies to address the problems of overloaded subtransmission and distribution systems and resulting excessive losses. CEB's management consultants, Urwick International Ltd. recommended, and CEB accepted, that each area should prepare and maintain plant and equipment registers, and prepare quarterly maintenance plans. However, the consultants

have reported1/ that the implementation of maintenance plans in a number of areas is hindered by shortages of skilled linesmen and other staff. This is symptomatic of CEB's wider staffing problem (paras 3.09 and 3.11). Urwick's report also drew attention to the fact that in some areas the reports related to planned maintenance work rather than to work actually carried out. Since the existing situation regarding maintenance is unsatisfactory, it is recommended that CEB should institute a regular maintenance program covering the entire distribution network. The program should include the regular inspection, including an oil test, for all transformers.

1/ Ceylon Electricity Board, Report No. 81, Progress Report No. 42, dated December 14, 1984.

V. FORECAST CONSUMPTION AND SUPPLY OF ELECTRICITY

A. Growth of the Economy

5.01 GOSL initiated a number of basic economic reforms in 1977 which led to an increase in the GDP growth rate (Annex 3, para 4). The real GDP growth rate increased from an average annual rate of 2.9% in the period 1970-1977 to 5.8% in the period 1977-1985. However, the real GDP growth rate has declined slightly since 1978. It averaged 6.8% a year in the period 1977-1980, and 5.2% a year during the period 1980-1985, and is projected to grow at 4.5% about a year in the period 1985-1990 (Table 5.1). The crux of Sri Lanka's existing macroeconomic problems is an extremely high level of capital formation in relation to national savings and relatively slow growth of exports in relation to import requirements. In the period 1980-1985, the ratio of gross fixed capital formation to GDP (at current prices) was about 30%. Financing this level of investment has been difficult, especially since public sector savings were negative in the period 1980-1982. Foreign savings (current account deficit on balance of payments) financed about 63% of total investment in 1980, 43% in 1983, 16% in 1984 and 39% in 1985.

Table 5.1

Historical and Projected Real Growth Rates for the

Main Sectors of Sri Lanka's Economy
(%)

	Actual			Projected a/
	1970-77	1977-80	1980-85	1985-90
Gross Domestic Product	2.9	6.8	5.2	4.5
Agriculture	2.0	3.5	2.8	3.0
Industry	1.0	4.4	5.6	6.0
Services	3.7	7.8	6.2	4.5

a/ World Bank Projections.

B. Future Electricity Demand

CEB Load Forecast

5.02 The latest (July 1985) CEB load forecasts covering the 10-year period 1985 to 1995, are presented in Table 5.2. Total sales are projected to increase at 10.6% a year during the period 1985-1990 and 9.8% a year during

the period 1990-1995. Very rapid rates of growth are projected for the domestic, commercial, large industry and hotel sectors. Units generated are projected to increase at 10.0% a year during the period 1985-1990 and 9.0% a year in the period 1990-1995. System losses are expected to fall quite rapidly after 1986 with the completion of various stages of the planned loss reduction project (para 4.11). CEB derived the peak demand forecast from the generation forecast using an assumed annual system load factor of 54%. On this basis, peak demand is projected to increase by 59% during the period 1985-1990, and by 144% during the period 1985-1995.

Table 5.2

CEB JULY 1985 LOAD FORECASTS

Sales (GWh)										
	a/						b/		Annual Growth Rate (%)	
Sector	1983	1984	1985	1986	1987	1988	1990	1995	1985-90	1990-95
	--actual--									
Domestic	305	317	339	419	492	586	728	1301	16.5	12.3
Railway	-	-	-	-	-	-	70	300	-	33.8
Commercial	243	241	283	343	381	422	521	870	13.0	10.8
Large industry	383	387	399	452	476	512	567	744	7.3	5.6
Medium and Small Industry	369	404	442	478	504	530	589	771	8.2	5.5
Hotels	48	59	69	9	110	120	130	155	13.5	3.6
Local Authority	433	458	499	521	573	630	762	1228	8.8	10.0
Street Lighting	10	11	11	11	12	13	15	15	6.4	-
Total Sales	1791	1897	2042	2228	2548	2812	3380	5384	10.6	9.8
Total Generation	2214	2261	2464	2817	3071	3347	3976	6118	10.0	9.0
Losses (%)	15	17	18	18	17	16	15	12		
Peak Demand (MW)	437	487	529	595	649	707	840	1293	9.7	9.0
Load Factor (%)	55.2	53.0	53	54	54	54	54	54		

a/ Excludes unserved energy and potential consumers not served due to power shortages.

b/ Source: CEB.

5.03 The total number of consumer connections is projected to increase at the average annual rate of 5.0% during the period 1985-1990, with about 48,600 new connections being made in 1990 (Annex 3, Table 8). This would be about 13,500 more connections than have been made in any single year to date. No information is available on the capability of CEB and local contractors to make this number of connections. However, it is clearly of critical

importance that CEB ensures that there will be sufficient construction capability to make the projected number of new connections. It is, therefore, recommended that CEB liaise with local contractors to ensure that sufficient construction capability will be available to make the forecast number of annual connections of new consumers.

5.04 The trends in average consumption per consumer which are implicit in the July 1985 forecast represent an almost total reversal of the trends revealed by historic data to 1983. Annex 3, Table 6, shows that average consumption per consumer has decreased since 1977 for all consumer categories with the exception of local authorities. The average consumption estimates for domestic consumers incorporated in CEB's 1985 load forecasts may be optimistic. The reasons for this are, firstly, the forecast assumes a large increase in the number of new domestic consumers, many of whom will be connected under rural electrification schemes. These consumers typically have relatively low consumption levels and will tend to depress average consumption levels for the consumer class. Secondly, the forecast growth rates for GDP and GDP per capita are lower than those which occurred in the period 1977-85. The forecast decrease in the growth rate of GDP per capita would have to be combined with a substantial increase in the income elasticity of demand estimate if it was to lead to a large increase in average consumption levels. It is anticipated that the proportion of total sales accounted for by domestic and local authority consumers will increase in the period 1986-1995. These consumers are primarily responsible for the evening peak. In the absence of effective load management measures, the relative increase in sales to domestic and local authority consumers may lead to a decline in the system load factor. It is, therefore, recommended that CEB initiates a study to determine the requirements for, and most suitable forms of both price and non-price forms of load management. The study should build on the work undertaken in connection with rural electrification (para 3.24). It is further recommended that GOSL should consider the implementation of daylight saving as an interim measure to reduce the evening peak demand, as has been suggested by the EPPAN task force.

Improvements to Demand Forecasting

5.05 Analysis of errors in past CEB load forecasts (Annex 3, Table 10), suggest that there is considerable scope for improving CEB's demand forecasting methodology. More accurate load forecasts would be consistent with improved investment decision taking. Weaknesses in the existing forecasting methodology have been recognized by the Energy Planning and Policy Analysis (EPPAN) task force of the Energy Coordinating Team (Chapter 2). An energy economics group has been trained to carry out various types of statistical analysis, including multiple regression analysis. The work of this group does not, however, appear to have been incorporated adequately into CEB's July 1985 forecast.

5.06 Principal problems with CEB's existing forecasting methodology include: an undue reliance on forecasting by trend extrapolation; reliance on inadequate data bases; failure to analyze load factor by consumer class; and failure to prepare load forecasts over the period required for generation planning (para 5.07). CEB forecasts might be improved by using more than one methodology. It is, therefore, recommended that in future CEB prepares its load forecasts using at least two methodologies, such as the existing methodology (but amended to eliminate potential double counting of large new loads, Annex 5, para 22) and econometric methods. The 'adopted' forecast in any year would probably be a compromise between these separate forecasts. The basis for this approach already exists due to the action taken by EPPAN. A basic requirement for improved load forecasts is the preparation, and continual updating, of an improved data base. It is, therefore, recommended that CEB undertakes systematic and regular consumer surveys to ascertain, for example, the electrical appliances used by domestic consumers with different consumption levels, and the principal uses of electricity by industrial and commercial consumers. The surveys should include the collection of data on consumer characteristics, for example, the shapes of their daily load curves and daily, weekly and annual load factors. Much of this information is also required for tariff setting.

5.07 CEB's existing practice is to prepare 10 year demand forecasts. This is too short a time horizon for the evaluation of optimal increments to generating capacity. It is common practice to base generation planning on time horizons of at least 20 years. It is recommended that CEB prepares 20-year demand forecasts, and also projects system load factor and load duration curves over the same period.

C. Future Electricity Supply

Generation

5.08 Total installed capacity on CEB's supply system at the end of 1985 was 949 MW and available capacity,1/ was 728 MW. Available capacity should increase by 328 MW by end 1988 with the full commissioning of the 3x67 MW Kotmale and 122 MW Randenigala hydro projects constructed under the Accelerated Mahaweli Program, and the 30 MW Canyon (unit 2) hydro project (Annex 4, para 24). The 50 MW Kelanitissa steam station was taken out of operation in 1985 for rehabilitation. It is scheduled to be recommissioned in 1989. An additional 169 MW of hydroelectric capacity (49 MW Rantambe and

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1/ Available capacity is calculated by deducting the largest unit plus 25 MW for hydro stations, the largest unit plus 20 MW for thermal stations, and by ignoring the capacity of any hydro stations controlled by the irrigation authorities. Thus the 10 MW Inginiyagala and 6 MW Uda Walawe hydro stations are excluded.

120 MW Samanalawewa projects) is planned for commissioning by end 1991. All of these projects are considered as committed in CEB's generation plan. Their commissioning in accordance with the latest estimates would mean that CEB's installed capacity would increased by 44% period 1985-1987 and its available capacity would be increased by 58%.

5.09 CEB's September 1985 least cost generation program is shown in Table 5.3. The program involves the commissioning of an additional 268 MW of hydro capacity by end 1990. Allowing for plant requirements, total installed capacity is planned to nearly double during the period 1985-2000 from 949 MW to 2424 MW, equivalent to an annual growth rate of 6.5%. The planned commissioning program would result in about 60% of CEB's capacity being hydro in 2000, compared with 73% in 1983.

Table 5.3

CEB's Least Cost Generation Expansion Plan 1987-2000

Commissioning Year	Type	Plant	Installed Capacity (MW)
1987	Hydro (unit 2)	Canyon	30
	Hydro	Randenigala	122
1988	Hydro (unit 3)	Kotmale	67
1989	Thermal	Kelanitissa (Recommissioning)	50
1990	Hydro	Rantambee	49
1991	Hydro	Samanalawewa	120
1992	Hydro	Broadlands	20
1993	Coal (unit 1)	Trincomalee	150
1994	-	-	-
1995	Coal (unit 2)	Trincomalee	150
1996	-	-	-
1997	Coal (unit 3)	Trincomalee	300
1998	Hydro	Upper Kotmale	240
1999	Hydro	Kukule	180
2000	Coal (unit 4)	Trincomalee	300

Source: CEB

The least cost generation program shown in Table 5.3 should be regarded as simply indicative of possible developments (Annex 4, para 26). The least cost generation program will be reassessed by Black & Veatch International as part of the ongoing ADB financed feasibility study for the proposed

Trincomalee coal-fired power station and by the consultants funded by GTZ to study the long term development of CEB's supply system (para 2.08).

5.10 Prompt action will be required if the commissioning dates specified in the least cost development program for the Rantambe, Samanalawewa and Trincomalee projects are to be achieved. Important decisions are still to be finalized concerning the design of the Samanalawewa hydro project. The feasibility study for the Trincomalee coal-fired power station is due for completion in 1987, and project financing may not have been arranged by that date. However, the least cost study based on CEB's load forecast assumes that preliminary works for the project would be started in early 1988. The critical issue concerning CEB's power expansion plan concerns the availability of resources, and this is considered in Chapter 7.

Fuel Requirements

5.11 Annex 4, Attachments 7 and 8, show that if CEB's planting program proceeds according to the schedule established in the least cost development program, then it will have a minimal requirement for gas oil and heavy fuel oil in the period 1985-1988. If hydrological conditions were such that only firm energy was available from hydro stations, then most of the extra required energy could be generated by the Sapugaskanda diesel station. The gas turbine units would only be required to generate significant quantities of energy in 1985 and 1988. Under firm energy hydrological conditions and CEB's load forecast these stations would, however, be required to generate significant quantities of energy in 1989-1991. Requirements for gas oil and heavy fuel oil would be much lower in average hydrological conditions. However, irrespective of the size of these requirements CEB needs to provide more timely information on its hydrocarbon requirements to the Ceylon Petroleum Corporation (CPC) to enable CPC to improve its short-term crude oil and refined product procurement strategies. Therefore, it is recommended that CEB should inform CPC once a month of its projected fuel requirements month by month on a rolling twelve month basis. For this purpose CEB should run the NEDECO Macro Model (Annex 2, Attachment 4) once a month in both its operation and planning modes to give CPC its best estimate of its hydrocarbon fuel requirements for the coming month and over the coming year.

Transmission and Distribution

5.12 Future major transmission works include lines to connect the projected generating facilities at Rantambe, Samanalawewa and Trincomalee (Annex 4, Section C). These probably will be at 220 kV, although for Trincomalee a higher voltage also will be investigated. Steadily increasing demand will require the building of additional 132 kV lines and substations, as well as an extensive program to replace overloaded power transformers with larger ones. CEB plans to install larger transformers at eleven existing 132 kV substations between 1985 and 1988. New 132 kV or 220 kV substations are under construction or have recently been completed at nine locations, and

three additional ones are planned to go into service between 1986 and 1988. The load growth will necessitate corresponding increases also in the subtransmission and the distribution systems; this will be in addition to the work needed to bring neglected distribution systems up to acceptable standards. CEB also plans to construct 800 km of 33 kV subtransmission lines and 500 consumer substations in the period ending December 1988.

Losses

5.13 CEB has projected that losses (as a percentage of gross generation) on its supply system will decrease from about 18% in 1985 to about 12% in 1992 and thereafter, as a consequence of planned developments, including the Bank Group financed Ninth Power Distribution Expansion and Rehabilitation Project, in low and medium voltage distribution systems. The loss levels shown in Table 5.4 were incorporated into CEB's 1985 load forecast (Table 5.2), and hence were a determinant of required capacity in the least cost generation development program (Table 5.3). Any failure to achieve these loss reduction targets would increase CEB's capacity requirements to meet forecast load at a predetermined quality of supply. Thus, for example, CEB has forecast total sales of 3380 GWh in 1990, with an associated gross generation requirement of 3976 GWh with losses of 15% and a peak demand of 840 MW (load factor 54%). If losses remained at the 1985 level of 18%, the gross generation requirement would increase to 4122 GWh and the peak demand to 872 MW. With a reserve plant margin of 25%, the higher level of losses would be associated with an increased capacity requirement of 40 MW, and an increased energy requirement of 146 GWh. If these increased requirements were met by the installation and operation of additional diesel capacity, then the additional costs would be about Rs 665 million (US$25.4 million) for capacity and Rs 295 million (US$11.3 million) for fuel in 1990, both in terms of end 1985 prices.

Table 5.4

Projected Losses on CEB's Supply System

	1985	1986	1987	1988	1989	1990	1991	1992
Losses (% gross generation)	18	18	17	16	15	14	13	12

Source: CEB

D. Power System Planning

Institutional Responsibility

5.14 CEB is responsible for planning generation and transmission developments on its integrated supply system, and planning distribution systems supplying about 395,000 consumers. However, it has had only a minimal involvement in the selection and design of hydropower projects being implemented under the Accelerated Mahaweli Program (para 2.07). All projects have to be approved by the Cabinet, while the Ministry of Finance has to agree financing plans. Although CEB's project identification and planning functions have been improved in recent years they still need considerable strengthening. The identification and appraisal of generation projects has been improved with the use of the WASP-III computer optimization model. Due to the inadequacy of CEB computer facilities this model is run on a computer at the Water Management Secretariat/Mahaweli Development Authority. This inevitably causes some problems for CEB, principally those associated with access to the model. The planning of distribution projects has recently been strengthened by the establishment of the Distribution Development and Rehabilitation Project branch of the Transmission and Generation Planning Department. However, all planning functions are hampered by a shortage of experienced planning engineers.

5.15 Local authorities and LECO are responsible for planning and developing the subtransmission and distribution systems which supply about 300,000 consumers. LECO's planning capability is being strengthened by an ADB technical assistance loan (para 3.17). Very little information is available on either the planning capability or future plans of local authorities.

Generation

5.16 Generation planning for CEB's interconnected system is now carried out using the WASP-III computer optimization model. The latest generation expansion plan was prepared in September 1985. This has been reviewed by the Bank, and is presented in Annex 4, Table 7. Although the techniques being used for generation planning are well suited to CEB's supply system, CEB's generation planning procedures suffer from a number of problems and defects. These include:

(a) A shortage of experienced staff in the system planning branch of the Transmission and Distribution Department. This has been caused by the departure of planning engineers to take up better paid positions in the Middle East and, in one case, the ADB. This is part of the more general staffing problem facing CEB (para 3.10). The existing engineer in charge of generation planning was trained at the Argonne National Laboratory with IAEA staff. He is very competent and well suited for the position which he occupies. However, he lacks support

since it was only in September 1984 that two additional engineers were recruited to be trained in generation planning. There is a very real danger that CEB's developing capability in generation planning could be lost at some time in the future unless the root causes of its staffing problems are tackled quickly (para 3.11).

(b) Problems caused by the lack of reliable cost estimates for candidate plants. This can be illustrated considering the cost estimates used for two of the major plants in the 1984 planning studies, the 120 MW Samanalawewa hydro project and the Trincomalee coal-fired project in the 1984 planning studies 1/. The optimization studies assumed that Samanalawewa would cost Rs 5,000 million (US$1,771/kW) although the most recent assessment made by consultants (Balfour Beaty in 1984) was a cost of Rs 7,294 million (US$2,583/kW). The studies assumed that each 120 MW unit at Trincomalee would cost Rs 5,429 million (US$1,923/kW). These costs excluded both the infrastructure costs of developing coal importing and handling facilities at Trincomalee and possible costs of flue desulphurization if these are included in the project design. It thus follows that there are various reasons for questioning the reliability of the project cost estimates used for generation planning.

(c) Although the cost estimates excluded duties and the costs of imports were assessed on a c.i.f. basis, no attempt was made to estimate costs in terms of shadow or accounting prices. Domestic costs were not re-expressed in terms of border prices. This could lead to some bias against hydropower projects.

(d) The planning studies suffered from the absence of a good data based on candidate hydropower projects. This deficiency should be remedied by the GTZ study (para 2.08).

(e) The planning horizon used in the studies was, at 14 years, too short and should be extended to a minimum of 20 years 2/. The choice of an optimal generating project in any year depends on future generating projects, and a relatively long time horizon is required to capture this interdependence.

1/ All the cost estimates exclude interest during construction. The unit size of the first two units at Trincomalee was optimized as 150 MW in the 1985 planning studies.

2/ The September 1985 study period was 1986 to 2000. However, projects to be commissioned by end 1987 were taken as being committed even if work, such as on Canyon Stage II, had not been started.

(f) Long range system planning is hampered by the absence of appropriate load forecasts. The longest forecasts prepared by CEB's commercial branch are for a period of 10 years (para 5.02). The system planning branch extrapolates this forecast using trend growth rates. Suitable long range forecasts should be prepared by the commercial branch.

(g) The generation planning studies have not included sensitivity studies, except those undertaken at the request of the Bank. This constitutes a major deficiency of the studies. Sensitivity studies should be carried out on a routine basis, and should include variations in the load forecast, load factor (a decrease to allow for the projected increase in the relative importance of the loads of domestic and local authority consumers), estimated capital costs of candidate plants, estimated fuel costs for thermal plants and the discount rate.

(h) The planning studies assume that multipurpose hydro projects will be operated to give priority to electricity generation, but include expected irrigation releases as minimum releases in each season. The releases in the generation planning studies may not accord with those determined by the Water Management Panel (para 2.10). This planning problem is caused by the absence of an agreement specifying water release priorities.

Operational Planning

5.17 CEB uses a Deterministic Discrete Dynamic Programming (DDDP) algorithm for calculating the annual mix of thermal and hydroelectricity generation. The objective function minimizes the cost of thermal generation and includes penalties for unserved energy and irrigation demands. Assumptions are made on the system unregulated inputs, monthly irrigation requirements, reservoir initial and final operating levels, the load duration curve (LDC), generating unit forced outage probability and the stacking order for matching the operation of the generating plants with the LDC. Because of the large number of assumptions made and because the M-G Complex will grow in complexity over time and thereby make the application of the DDDP algorithm more difficult, this procedure does not have the same level of detail as the ARSP and MACRO procedures (Annex 2, Attachments 3 and 4). However, it is an optimization technique and is useful for framing discussions on the operation of the CEB generation system (and especially on the choice of reservoir rule curves) that would optimize system benefits.

Operational Planning Issues Related to Mahaweli Projects

5.18 A group of consultants, Acres International Limited, Canada, is undertaking the Mahaweli Resources Management Project under the overall direction of the Water Management Panel (WMP) and in close collaboration with the Water Management Secretariat (WMS). The major objective of the project

is to provide guidance to the WMP on existing non-structural policy alternatives and to improve the reliability of the M-G Complex in meeting irrigation and power demands, with a special emphasis on the impact of realistically achievable water duties. This, however, excludes the construction of dams, canals or other infrastructure items. Three criteria are used, as appropriate, for evaluating alternative policies. First, an analysis of irrigation and energy generation, involving a comparison of energy generation levels while assuming that irrigation demands must be met. Second, tradeoff analysis, involving the quantification of agricultural benefits (using detailed crop budgets) versus costs of (thermal) electricity generation to makeup for loss of hydro energy. Third, social and regional development priorities, with the requirement that commitments to new settlers must be met, and the sharing of water shortages must be equitable.

5.19 Preliminary findings of the Mahaweli Water Resources Project point to a cropping intensity of 2 for small holdings if they are to be financially viable, and to an exacerbation of the physical and temporal water use conflicts as the irrigation area increases (Annex 2). Thus, the role of the WMP will become even more vital in deciding prudent operating guidelines for the M-G Complex.

5.20 Political and social objectives will ensure that irrigation needs will have the first priority in water use. However, there is plenty of scope for reducing the consumptive use of water through improved water management practices and different crop selection. The benefits are especially high when they result in increasing the energy generating capabilities of the M-G River Basin Complex. The following recommendations are made to bring about a more logical balance in the management, operations planning and long-term planning of the M-G Complex.

5.21 To correct the imbalance in the management of the M-G Complex, as reflected in the composition of the Water Management Panel (WMP) (para 2.10), it is recommended that the Chairman of CEB should be appointed as co-chairman of the WMP and that the General Manager and the Additional General Manager Generation of CEB should be appointed to the WMP. In addition, the Secretary of the Ministry of Industry and Scientific Affairs should also be appointed to the WMP to reflect the interest of the industrial sector in ensuring a reliable power supply. Because of its relatively large size (currently 16 members), it is recommended that the WMP have a core Policy Committee, consisting of five members - the Director General of the MASL, the Chairman of CEB, one Government Agent, the Secretary of the Ministry of Agriculture Development and Research, and the Secretary of the Ministry of Industry and Scientific Affairs. The Policy Committee would be responsible for developing seasonal operating policies in the M-G Complex, subject to subsequent ratification by the WMP.

5.22 Decision Making by the WMP should be in terms of both political and regional considerations (which would give first priority to meeting

irrigation needs), and also take into account the national economic interest, especially in times of low stream flow when the conflicting objectives of minimizing fuel oil imports (for meeting CEB's thermal generation needs) and maximizing the benefits of irrigation cropping are brought into sharp relief. Therefore, it is recommended that WMP decision making should use the available quantitative information (from the previously mentioned system studies) on the tradeoffs between irrigation benefits and power benefits. Since operations planning in the M-G Complex will become even more important in the future with the planned addition of the Randenigala and Rantambe dams, it is recommended that the current collaboration between CEB and MASL, through their joint participation in the Interagency Working Group on Weekly Operations and Planning, should be continued.

5.23 In order to strengthen CEB's operational planning capabilities, it is recommended that CEB should review the applicability of simulation techniques, such as the MACRO model and the Acres Reservoir Simulation Program (ARSP), to its operations planning needs at least for the rest of this decade i.e. before the M-G Complex is converted into its mature form.1/ Other structural options (such as reservoir and irrigation tanks) should be studied to find ways to improve the stability and the reliability of the M-G Complex. In particular, CEB should include in the Terms of Reference for the proposed feasibility study for the Calidonia/Talawakele Project, in the Upper Kotmale River Basin, a detailed assessment of the impact of this project on improving system firm energy generation capabilities and on improving the reliability of irrigation water supply.

5.24 The planning of future developments in the M-G Complex should continue to balance its irrigation and power generating capabilities. Consequently, it is recommended that all system planning studies in the M-G Complex should be under the overall direction of a modified Water Management Panel (WMP) (para 5.21); be managed jointly by staff from CEB and MASL; and that their Terms of Reference should: (a) include the determination of the impact of any future plans on CEB's least cost generation and transmission investment program, and (b) ensure that the data and assumptions used are consistent with those employed by CEB in planning studies.

5.25 Given the increasing importance of multipurpose projects in CEB's supply system, it is imperative that it strengthens it capability in water resources planning. This would allow it to play an active role in multiagency meetings concerned with the operation of new projects, and enable it to appreciate fully the potential impact of possible decisions on its interests. Therefore, it is recommended that CEB should strengthen its capabilities in water resources planning, by having two of its engineers

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1/ Brief descriptions of the ACRES Reservoir Simulation Program (ARSP) and the NEDECO macro models are given in Annex 4, Attachments 4 and 5.

trained in this topic, possibly under the aegis of the GTZ Study (para 2.08), and, that it should add to its staff experienced personnel with a broad knowledge of both irrigation and hydroelectric systems operation.

VI. ELECTRICITY PRICING

A. Institutional Responsibility for Tariffs

6.01 Tariff setting is the responsibility of organizations selling electricity, namely CEB, local authorities and, since June 1984, LECO. CEB has a bulk supply tariff for sales to licensees (218 local authorities, including five which have been taken over by LECO) and retail tariffs. Licensees do not have the technical capability to determine their own tariffs. Consequently they tend to adopt CEB tariff structures, although their rates may differ from those in corresponding CEB tariffs. However, LECO's functions include the establishment of a consultancy service to assist other licensees in setting tariffs.

B. Historical Review

6.02 CEB's tariffs were unchanged between April 1972 and December 1978. However, the average tariff rate was increased by about 75% in December 1978, about 110% in October 1980, about 42% in June 1982, and about 80% in March 1985. These increases were accompanied by significant changes to the tariff structure. The 1978 tariff revision included provision for a fuel adjustment charge (para 6.11), which was first activated in February 1980. During the period 1970-1985, (Table 6.1), nominal electricity prices, including the fuel adjustment charge, were increased at the average annual rate of about 17%, and in real terms by about 7%. Dividing the period into two sub-periods, 1970-1978 and 1978-1985, it can be seen that in the former period real electricity prices fell at an average annual rate of about 4%, while in the later period they increased at the average annual rate of about 20%. Thus during the period 1970-1978 electricity tariffs failed to signal to consumers increases in real energy costs.

Table 6.1

CEB Average Revenue from Electricity Sales 1970-1985
(Rs/kWh)

Year	Current Prices Without FAC	Current Prices With FAC	Cost of Living Index a/	With FAC 1970 Prices	With FAC Index
1970	0.14	0.14	100.0	0.140	100
1971	0.14	0.14	102.7	0.136	97
1972	0.15	0.15	109.1	0.137	98
1973	0.15	0.15	119.7	0.125	89
1974	0.16	0.16	134.4	0.119	85
1975	0.16	0.16	143.5	0.112	80
1976	0.16	0.16	145.2	0.110	79
1977	0.16	0.16	147.0	0.109	78
1978	0.17	0.17	164.8	0.103	74
1979	0.30	0.30	182.6	0.164	117
1980	0.37	0.60	230.2	0.261	186
1981	0.59	1.00	271.6	0.368	262
1982	0.78	1.49	301.1	0.495	354
1983	0.84	1.56	343.1	0.455	325
1984	0.78	1.66	400.3	0.415	296
1985	1.51	1.51	406.1	0.372	266

a/ Colombo Cost of Living Index.

6.03 CEB's financial performance deteriorated during the period 1970-1978, largely due to the fact that tariffs were unchanged throughout this period. Its after tax rate of return on revalued average net fixed assets in use fell from 6.9% in 1974 to 2.1% in 1978. Subsequent increases in tariff rates, and the activation of the fuel adjustment charge in February 1980, improved the rate of return to 9.4% in 1980 and 11.4% in 1981. The rate of return fell to 5.6% in 1983, partly due to a heavy income tax liability which CEB had underestimated when setting tariffs for that year. The March 1985 tariff increase was instrumental in raising the rate of return to about 9.5% in 1985.

C. Economic Costs of Supply

6.04 In recent years CEB has carried out two long run marginal cost (LRMC) tariff studies, one in 1981 and one in 1984 1/. The 1981 tariff study

1/ CEB agreed under Credit 1048-CE to carry out a LRMC tariff study, with technical assistance from the Bank, and to implement any agreed findings.

estimated marginal capacity costs of generation as the weighted average (50:50) annuitized costs of the planned Canyon II hydropower station (for commissioning in 1987) and planned additional gas-turbine capacity at the Kelanitissa station (for commissioning in 1982). The marginal capacity costs of transmission and distribution were estimated using the long run average incremental cost (LRAIC) method. Marginal energy costs were estimated for the period 1982-1989. Throughout this period peak energy was assumed to be generated by gas-turbine plants. These plants were also assumed to supply marginal off-peak energy in the period 1982-1984, but thereafter this energy was assumed to be supplied by new diesel capacity and base load hydropower plants. LRMC was estimated for different voltage levels, peak and off-peak times of the day, and for different consumer categories. The latter estimates utilized assumptions on diversity factors and average load factors for the different consumer groups. CEB did not have an adequate data base on consumer characteristics and thus had to estimate the diversity and load factors. It is recommended that CEB undertakes appropriate consumer surveys to gather information on consumer characteristics (para 6.10). The main results of the 1981 study are presented in Table 2, Annex 5.

6.05 CEB prepared a new LRMC tariff study in 1984. Although CEB was using WASP-III for generation planning in 1984 it did not use this model to estimate marginal capacity costs of generation. Instead it used the same LRAIC method as was used for the 1981 study. Marginal capacity costs of generation were estimated with reference to the average annual cost (Rs/kW/year) of four hydro plants scheduled to be added to the supply system in the period 1985-1990. The plants and associated costs (estimated after allocating a variable proportion of their capital costs to energy production) used in the study were as follows:

Date	Plant	Capacity Cost Rs/kW/year	Average Capacity Cost Rs/kW/year
1985	Victoria Stage II	1,586)	
January 1986	Kotmale 3rd Set	497)	1,306
January 1988	Rantambe	1,642)	
1990	Samanalawewa	1,499)	

The first two of these projects were committed and firm projects and thus should not have been used in the LRMC calculations, which are concerned with bringing capacity forward to meet a permanent demand increment. The marginal project, in the sense that its commissioning date could be brought forward in a revised least cost generation program, was either Samanalawewa or the first unit of the proposed coal-fired station at Trincomalee (estimated capital cost Rs 3,802/kW/year). The capacity cost for incremental generating capacity used in the 1984 tariff study was thus probably too low.

6.06 The 1984 tariff study did not estimate the marginal capacity costs of supplying different consumer groups. The Bank has reviewed and revised that tariff study and extended it by estimating these costs using the 1981 study assumptions on consumer characteristics (Annex 5, Tables 3 and 4). These costs have been used to derive marginal capacity costs in terms of Rs/kW, which are presented in Table 6.2.

Table 6.2

Estimated Marginal Capacity Costs
(Rs/kWh)

Bulk Supply	Load Factor	Diversity Factor	CEB Study	CEB Samanalawewa a/	Bank Trincomalee
HV	0.40	1.10	0.64	0.85	1.65
MV					
Industry	0.47	1.25	0.83	0.98	1.67
General Purpose	0.41	1.33	0.89	1.06	1.80
Hotels	0.55	1.10	0.81	0.95	1.62
Licensees	0.47	1.10	0.94	1.12	1.90
LV					
Industry	0.23	6.67	0.46	0.52	0.83
General Purpose	0.46	2.00	0.77	0.87	1.39
Hotels	0.55	1.10	1.17	1.32	2.12
Licensees	0.36	1.10	1.79	2.02	3.23
Retail					
LV					
Domestic	0.27	1.10	2.38	2.69	4.27
Industry	0.30	20.00	0.12	0.13	0.21
General Purpose	0.40	10.00	0.18	0.20	0.32
Street Lighting	0.50	1.00	1.42	1.60	2.56

Source: Based on CEB data.

a/ Total cost of the Samanalawewa project is that given in the 1984 tariff study, Rs 7,500 million, with 43.2% (Rs 3,240 million) allocated to capacity and 56.8% allocated to energy.

6.07 Marginal energy costs in the 1984 study were estimated assuming that marginal generation would be from diesel sets in both peak and off-peak periods in both wet and dry seasons throughout the study period (1985-1991).

CEB's recent generation planning studies show, as would be expected, that the marginal thermal plant is a function of assumed hydrological conditions. The generation planning studies show that diesel units will be the marginal plants, as assumed in the tariff study, if the output of hydro stations is calculated at the 70% probability level. Analysis on the basis of firm hydro availability shows that marginal plants in both wet and dry seasons will be gas turbines, at least until 1991. Similar analysis shows that gas-turbines will be the marginal plants in the dry season if the output from hydro stations is taken as firm plus 25% of secondary energy. Estimated marginal energy costs in Table 6.3 are given on two bases; first, the 1984 study basis and, second, with marginal generation from gas-turbines, as projected when hydro conditions correspond to firm energy plus 25% of secondary energy, or worse. The difference between peak and off-peak energy costs in the tariff study is due solely to the difference in peak and off-peak energy losses.

Table 6.3

Estimated Marginal Energy Costs a/
(Rs/kWh)

	-CEB 1984 Tariff Study--		------Alternative------	
	Peak	Off-Peak	Peak	Off-Peak
At Generation	1.44	1.44	3.11	1.44
HV Level	1.53	1.50	3.31	1.50
MV Level	1.68	1.57	3.61	1.57
Cons. SS	1.71	1.59	3.68	1.59
LV Level	1.88	1.66	4.05	1.66

Source: CEB tariff study

6.08 Marginal energy costs in the 1984 study were estimated using pragmatic reasoning and data from energy balance tables. In the absence of more sophisticated analytical methods this is a perfectly acceptable approach. However, CEB is now using WASP-III for generation planning (Annex 4, para 18). The technical data, including the economic cost of fuel by plant type, used in the WASP optimization runs can be adopted for the estimation of marginal energy costs (which basically are short run marginal costs - SRMC) using the Reliability and Cost Model for Electrical Generation Planning (RELCOMP) computer model (Annex 5, Attachment 1). The use of the RELCOMP model would enable marginal energy costs to be estimated for different times of the day and year for selected years. These estimates would be consistent with data used to determine optimal additions to generating capacity on the CEB system. However, CEB does not have the RELCOMP model. It is thus recommended that the Bank either undertakes or

funds a study using RELCOMP to estimate marginal energy costs on CEB's system. The study would be undertaken in recognition of the needle peak problem on CEB's system and the need for any revised tariff structures to be stable and endure for a number of years. It is further recommended that a CEB officer should be associated closely with this study so as to include a requisite training element.

D. Existing Tariff Rates

CEB Tariffs

6.09 Existing CEB tariffs (Annex 5, Table 7) were introduced in March 1985, following the 1984 updating of the 1981 tariff study. The economic philosophy underlying the study was that tariff structures and rates should be stable to provide consumers with the long-run cost information required to make investment decisions. In practice CEB tariffs have failed to signal this long-run cost information to consumers. A principal reason for this has been the policy decision that published tariff rates should be based on the assumption that all generation will be from hydropower plants and that any costs from thermal generation should be recouped through fuel adjustment charges (para 6.11). Reliance on the fuel adjustment charge in the form used in the period October 1980 to May 1982 was inconsistent with marginal cost pricing since consumers were only informed of the price of electricity after they had made their consumption decisions. The signalling function of the price mechanism would be improved if:

(a) published tariff rates were related to the supply system which is expected to exist;

(b) a regular and relatively short period, say one year, tariff revision cycle was instituted; and

(c) the fuel adjustment charge was used only to recoup thermal fuel costs in excess of those incorporated in published tariff rates set in relation to forecast hydrological conditions in the year to which the rates would apply.

Therefore, it is recommended that the CEB adopts, with GOSL approval, an annual cycle under which it reviews and, if necessary, revises tariff rates and relates published tariff rates to the estimated fuel costs for forecast hydrological conditions in the year to which the rates would apply. The adoption of these recommendations would reduce some of the problems which have been experienced with the operation of the fuel adjustment charge and would improve the signalling function of the price mechanism. A notable feature of the results of the 1981 tariff study was the appreciable difference between estimated peak and off-peak energy costs (Annex 5, Table 2). These cost differences were not incorporated into the tariff for any consumer groups.

1984 Tariff Study and Existing Tariff Rates

6.10 In the absence of appropriate detailed studies (Annex 5, para 11), there is considerable uncertainty regarding LRMC of supply on CEB's system. The following comparison of 1985 tariffs and 1984 estimates of LRMC (Table 6.4) is probably on the conservative side. It assumes that Samanalawewa is the marginal station (and that 43.0% of its investment costs are allocable to capacity), and that marginal energy costs can be calculated with reference to diesel plants. The energy rates are the rates published in the tariffs and exclude any fuel adjustment charge which may be levied. Table 6.4 indicates that basic energy rates in the existing tariff are typically close to estimated off-peak marginal energy costs. Demand charges are between 6% (LV licensees) and 114% (LV industrial) of estimated marginal capacity costs. The existing tariff for bulk supply to licensees is badly out of line with estimated LRMC. The deviations of rates from LRMC shown in Table 6.4 would almost certainly change if CEB had a better data base on consumer characteristics, and it is recommended that CEB initiates the studies and other activities required to improve this data base (para 5.07). However, an improved data base would not change the general picture of tariff rates being below LRMC.

Table 6.4

Comparison between 1985 Tariff Levels and LRMC

Consumer Type	1985 Tariff		LRMC		
			Energy		
	Energy Rs/kWh	Capacity Rs/kW/month	Peak Rs/kWh	Off-Peak Rs/kWh	Capacity Rs/kW/month
MV					
Industrial	1.25	90	1.68	1.57	337
General Purpose	1.50	115	1.68	1.57	317
Hotels	1.50	140	1.68	1.57	383
Licensees	1.35a/	25	1.68	1.57	383
LV					
Domestic	0.5-2.25	0	1.88	1.66	2.69/kWh
Industrial	1.45	100	1.88	1.66	88
General Purpose	1.60	125	1.88	1.66	293
Street Lighting	1.60	0	1.88	1.66	1.60/kWh
Hotels	1.60	150	1.88	1.66	531
Licensees	1.35	30	1.88	1.66	531

a/ The energy rate for licensees is that applicable in the third block of the tariff.

Fuel Adjustment Charge

6.11 Published tariff rates have been derived on the assumption that all CEB's generation will be from hydropower plants, although this is known to be a false assumption. Since February 1980 fuel costs from operating thermal plants have been recouped from sales in specified tariff categories through the use of a fuel adjustment charge (FAC)1/. The history of the FAC since October 1980 is shown in Table 8, Annex 5. Fuel adjustment charges can be an effective way of passing unanticipated increases in fuel costs on to consumers with a minimum of delay. This both enables consumers to be given up-to-date information on relative energy prices (which is consistent with an efficient allocation of resources) and protects a utility's financial position, especially when procedures to change published tariff rates are protracted. However, CEB's FAC policy has given undue attention to its financial consequences to the neglect of its effects on the signalling

1/ The fuel adjustment charge was set at zero for twelve months when the March 1985 revised tariff was introduced.

function of the price mechanism. The prime cause of this has been the failure to include estimated fuel costs in average hydrological conditions in published tariff rates (para 6.09).

6.12 The FAC effectively introduced a second lifeline rate (the second block) into the 1982 tariff. The smaller is the proportion of sales on which the FAC is levied the larger is the required charge on each kWh to which it is applied. In addition, with an increasing block tariff the fewer are the blocks on which the charge is levied the larger will be the difference in marginal tariff rates between adjacent blocks. It is understood that one cause of non-technical losses is collusion between consumers and meter readers to avoid reporting consumption above 150 kWh/month due to the high marginal tariff rate on incremental consumption, especially when the FAC is activated. It is thus recommended that the increase in effective marginal tariff rates (with FAC) for domestic consumers be smoothed out by introducing a FAC of one-half the full rate on the second consumption block.

Lifeline Rates

6.13 Tariffs for supply to domestic consumers and to licensees incorporate lifeline rates. The domestic tariff is shown in Table 6.5. The tariff is of the increasing block type with substantial increases occurring at the margin of adjacent blocks, especially between the second and third blocks. This difference is accentuated when the FAC is activated. Lifeline rates are justified in terms of an equity or income distribution objective. Their purpose is to enable low income consumers, who are equated to small consumers, to afford the electricity required to meet their basic needs. The definition of these needs is arbitrary, but is generally considered to cover lighting and perhaps the use of a fan, for which total monthly requirements would be about 20 kWh (Annex 5, para 27).

Table 6.5

CEB March 1985 Domestic Tariff

Consumption Block/Month kWh	Basic Rate Rs/kWh	Fuel Adjustment Charge Applicable
0 - 30	0.50	No
31 - 150	0.90	No
151 - 500	1.80	Yes
500+	2.25	Yes

6.14 A lifeline rate which is applicable to all consumers in a tariff category always confers greater absolute monetary benefits on larger

consumers, since their consumption is sufficiently large to take advantage of all the units sold at the lifeline rate. If the size of the first block is too large then not only is relatively more monetary benefit given to large consumers, but in addition the smaller is the number of kWh sold at prices reflecting marginal costs. Analysis presented in Annex 5, Section D, suggests that the size of the first block is too large. It is, therefore, recommended that the size of the first block be reduced to 20 kWh/month. It is also recommended that the size of the second block should be reduced to 20-75 kWh/month, which would be sufficient to allow for the use of a small refrigerator, a black and white television set and additional lighting.

Licensee Tariffs

6.15 CEB provides bulk supplies to 218 licensees, including five licensees which have been taken over by LECO, each of which sets its own tariffs subject to the approval of the Chief Electrical Inspector. In practice, it is understood, the structure of licensees' tariffs are based on those of the CEB, although their rates may differ from those in comparable CEB tariffs. Copies of licensees' tariffs are held by the Ministry of Power and Energy. The Bank has reviewed the 1984 tariffs of two licensees, LECO and Negambo Municipality. These are analyzed and discussed briefly below, and in more detail in Annex 5.

6.16 LECO Tariff. LECO's 1984 tariff (Annex 5, Attachment 2) was taken over from Kotte Urban Council, the only council which had joined LECO by December 1984. A worked example of CEB's 1984 monthly bill to Kotte U.C. is presented in Annex 5, Attachment 3. The following discussion utilizes data given in those attachments. Licensees purchase bulk electricity under a rate structure based on CEB's retail tariff (Annex 5, Table 6), which allows for 20% losses measured as the ratio of bulk supply point purchases to retail sales (e.g. 120:100). Losses in excess of the level allowed for in the bulk supply tariff are in effect paid for by the licensee at the marginal rate in the tariff, which was Rs 1.375/kWh in 1984, allowing for the 150% fuel adjustment charge. This had the effect of increasing substantially the cost of electricity purchased by a licensee, and increased the total cost to LECO of each kWh purchased in the first block to Rs 0.94 (Annex 5, para 43). Consequently, LECO made a loss on each unit sold under its general purpose tariff and on sales below 150 kWh/month under its domestic tariff (Annex 5, Table 13). These losses occurred before LECO's own costs were added to the bulk supply costs. It just covered bulk supply costs for sales above 150 kWh/month under the domestic tariff and on all sales under the street lighting tariff. However, allowing for its own costs LECO's sales under these tariffs were probably made at a loss.

6.17 Negambo Municipality Tariff. Negambo municipality's 1984 tariff schedule is presented in Annex 5, Attachment 4, and monthly sales in the different tariff categories in 1983 are presented in Annex 5, Attachment 5. Losses (sales over purchases) in the Negambo distribution system were

estimated to be 23% (equivalent to 30% on the basis of purchases over sales in 1984). Negambo Municipality 1984 tariffs are compared with the costs of bulk supply from CEB in Annex 5, Table 14. This shows that, with the exception of the first block in the domestic tariffs, Negambo's 1984 tariff rates exceeded bulk supply costs and provided a margin to cover Negambo Municipality's own costs of supply. It is understood that this margin was sufficient for Negambo Municipality to make a profit on its electriciy account.

6.18 Adequacy of Licensee Tariffs. Analysis of the tariffs of two licensees indicates that the level of tariff rates for one was inadequate (Kotte) but adequate for the other. Information is required on a reasonable sample of licensee's tariffs before firm conclusions can be reached as to whether inadequate tariffs are a contributory factor to arrears owed by licensees to CEB. It is recommended that future sector work undertaken by the Bank should be address the issue of licensee tariffs.

E. Structure of Existing CEB Tariffs

6.19 Existing CEB (1985) tariffs include simple flat rate tariffs for religious and street lighting consumers, increasing block tariffs for domestic consumers, increasing block with a demand charge for licensees, separate demand and energy charges for general purpose, hotel and industrial consumers, and optional time-of-day tariffs for industrial and hotel consumers. Consumers in each tariff category pay the full costs of connection; for domestic consumers this is usually about Rs 3,000. In addition, domestic consumers pay about Rs 1,000 for house wiring to contractors.

6.20 Some features of the existing tariffs are consistent with charging consumers the costs which they impose on the supply system. This is most noticeable with respect to connection charges. To a lesser extent it also occurs by charging for demand in terms of kVA instead of kW since this gives an incentive to improve power factors. There are, however, a number of problems associated with the structure of existing tariffs, the most important of which are: (i) the absence of effective time-of-day pricing, and (ii) tariffs for licensees.

6.21 Time-of-Day Pricing. The 1981 tariff study estimated peak and off-peak energy costs for MV consumers to be Rs 2.59/kWh and Rs 1.49/kWh respectively, with a larger difference at the LV level. None of the 1982 tariffs which were introduced following that study included time-of-day kWh charges. The failure of tariffs to signal this substantial difference in costs was probably one of the reasons for the continuing needle peak problem on CEB's system. The March 1985 tariffs introduced optional time-of-day metering for some hotel and industrial consumers (Annex 5, Table 7). Although demand charges (Rs/kVA) in the optional tariff are at least 50% lower than those in the standard tariff, only marginal changes were made to

energy rates. Thus for MV hotel consumers the demand charge was reduced from Rs 140/kVA to Rs 45/kVA, and the peak and off-peak energy rates set at Rs 1.75/kWh and Rs 1.20/kWh respectively, compared with the standard tariff rate of Rs 1.50/kWh. With the introduction of this optional tariff, CEB missed an opportunity to introduce an effective load management measure to reduce potential peak demand. This was because the time-of-day tariff reduced the monthly bills of consumers who opted for it, without giving them any incentive to reduce their peak demand. The basic reason for this is simply that the peak energy rate is less than the sum of the energy rate in the standard tariff plus the kWh equivalent charge estimated as the difference between the demand charges in the two tariffs.

6.22 There is considerable uncertainty regarding differences in peak and off-peak energy costs in the period 1985-1991 (para 6.07). However, there is no doubt that marginal capacity costs are higher than those reflected in existing tariff rates and that these costs are demand related. Many consumers are charged for capacity on a kVA basis. From a demand management point of view the effectiveness of this charging basis depends on the relative timing of the consumer's maximum demand and that of the supply system. Demand management is likely to become more important as the CEB system grows. Recognizing these various factors CEB should consider introducing effective time-of-day tariffs for, say, all MV consumers with the exception of licensees. The peak rate should include some capacity costs. Remaining capacity costs would be recouped through maximum demand charges using kVA metering in order to give consumers continued incentives to improve power factors. Time-of-day metering could also be applied to other consumer groups. Domestic consumers are believed to be largely responsible for the existing evening peak. Although it is clearly not socially acceptable, or economic, to have time-of-day pricing for the majority of domestic consumers, it could be both socially acceptable and economic to introduce it for large domestic consumers. Monthly billing data for February 1983 (Annex 3, Attachments 2 and 3) shows that although only 1.65% of domestic consumers used more than 300 kWh/month these consumers used about 28% of all kWh billed to domestic consumers. The costs of introducing time-of-day meters for these consumers would be relatively low, but the use of these meters could have an impact on both the pattern and amount of electricity consumed by domestic consumers. <u>It is thus recommended that CEB consider introducing time-of-day metering for large domestic consumers. The introduction of compulsory and effective time-of-day tariffs for other consumers, such as all MV consumers with the exception of licensees, is strongly recommended.</u>

6.23 <u>Tariffs for Licensees</u>. The bulk supply tariff for licensees is designed to enable licensees with 20% losses in their distribution systems to charge the same tariff rates to their domestic consumers as are charged by CEB. This explains the increasing block design of the bulk supply tariff. This tariff structure, however, does not reflect the marginal costs of meeting demand from licensees. The bulk supply tariff structure raises a fundamental question with regard to tariff setting by CEB. The question is

whether CEB should signal relevant marginal cost information to bulk supply consumers so that they have the appropriate information upon which to design their own tariffs (since they are responsible for tariff setting), or whether CEB should assume that it knows best and thus continues to set bulk supply tariff rates which enable bulk supply consumers to apply CEB retail tariffs to their own consumers since licensees lack tariff setting expertise (para 6.01). It is recommended that CEB gives urgent consideration to answering this question, even though LECO is establishing a consultancy wing to advise licencees on tariff setting.

F. Future Tariff Policy

6.24 Electricity pricing in Sri Lanka should be considered against the background described above, the main elements of which are described below:

(a) although there is considerable uncertainty regarding the calculation of LRMC there is little doubt that CEB tariff rates (and probably those of licensees) are below LRMC for all classes of consumer;

(b) an increase in basic tariff rates is required to ensure that CEB earns a minimum net of tax rate of return of 8% on revalued net assets in use in 1986;

(c) the structure of tariffs does not conform to the costs incurred on CEB's supply system when meeting consumers' demands, even though optional time-of-day tariffs have been introduced for hotel and industrial consumers;

(d) published tariff rates have not been related to the energy costs which CEB expects to incur in average hydrological conditions. These rates should be related to the supply system which is expected to exist. Tariff setting could be improved with the adoption of an annual revision cycle for tariff rates;

(e) too much reliance has been placed on the operation of the fuel adjustment charge;

(f) the lifeline blocks in CEB's domestic tariff appear to be too large; and

(g) tariffs used by some licensees, with rates below supply costs, may be a contributing factor to the arrears owed by many licensees to CEB.

6.25 There appear to be five main objectives for electricity pricing in Sri Lanka:

(a) to ensure the financial viability of CEB and the licensees;

(b) to encourage the least cost supply of electricity from the national viewpoint;

(c) to mobilize resources to finance investment;

(d) to ultimately bring the price of electricity into line with LRMC; and

(e) to ensure that electricity prices are equitable and socially acceptable.

It is recommended that the GOSL formulates and implements an energy pricing strategy to achieve these objectives. This strategy must address points (a) to (g) raised in paragraph 6.24. The priority elements in this strategy are described below.

6.26 The present tariff structure does not provide incentives to shift peak demand to off-peak periods. It is recommended that:

(a) compulsory and effective time-of-day tariffs should be introduced for MV consumers, with the exception of licensees;

(b) time-of-day tariffs should be introduced for large (say above 300 kWh/month) domestic consumers;

(c) CEB should carry out load research to improve its data base on consumer characteristics as a prerequisite of improving its estimates of LRMC; and

(d) CEB should consider using a model such as RELCOMP to improve its estimates of marginal energy costs.

Tariff levels should be increased to enable CEB to meet its financial objectives, including earning funds to finance planned investments (para 7.11). Therefore, it is recommended that GOSL authorizes CEB to gradually increase its average tariff rate towards LRMC in order to promote the efficient use of fuels and to mobilize additional resources required to finance CEB's investment program.

VII. INVESTMENT AND FINANCING

7.01 Analysis and discussion of investment in the power subsector should consider the investment undertaken and planned by CEB, MASL, LECO and local authorities. The involvement of these organizations, however, poses a number of problems. Firstly, no data is available on past or projected investment expenditure by local authorities (licensees), which means that the available data on investment for the expansion and rehabilitation of distribution systems understates actual expenditure for these purposes. Secondly, there is the problem of allocating the joint costs of multipurpose hydro projects undertaken by MASL to their separate functions, including power and irrigation. The allocation of these joint costs to the separate functions will involve arbitrary decisions (paras 3.25-3.31).1/ Since major power projects both have been and are being undertaken by MASL this poses a significant problem for the analysis of power subsector investment. Thirdly, CEB's project accounting records have not been maintained adequately, which complicates the derivation of reliable data on past investments undertaken by that organization. The combined effect of the foregoing and other factors is that the available data base on past and projected investment in the power subsector is weak.

A. Past Investment

7.02 CEB's actual and planned investments during the period 1978-1984 are summarized in Table 7.1:

1/ Under Credit 372-CE, GOSL agreed to ensure that the power assets of multipurpose hydro projects are transferred on completion to CEB on terms which are satisfactory to IDA.

Table 7.1

Summary of Investments by CEB - 1978-1984

	-------Rs Million------		Actual as %
	Actual	Planned	of Planned
1978	358	N.A.	N.A.
1979	311	438	71
1980	688	869	79
1981	941	1488	63
1982	982	2003	49
1983	1660	2630	63
1984	1827	1980	92

Source: The data on actual investment was taken from CEB's sources and applications of funds statements given to various Bank Group missions, while the data on planned investment was taken from the SARs for the Sixth and Eighth Power Projects. The figures for 1984 are net of Mahaweli (Victoria) investments.

No data is available on planned investment for 1978. For those years for which the planned amounts are available, viz. 1979 to 1984, actual investments were, on average, only 69% of planned investments.

7.03 Analysis of financial data pertaining to the main categories of CEB's operating assets for the period to 1979 shows that about 48% of CEB's past investment was for generation, 21% for transmission and 27% for distribution. Table 7.2 shows a similar allocation up to 1984. However, these figures give a distorted view of the investment mix since they exclude investment, including transmission, in multipurpose hydro projects (such as Victoria and Kotmale) constructed under the Accelerated Mahaweli Program (para 7.04), and these projects constituted the major generation projects undertaken in Sri Lanka.1/

1/ GOSL's current practice in treating the projects under the Accelerated Mahaweli Program is to transfer, at cost, the completed power component of the scheme to CEB as equity or part equity/part loan, and concurrently to treat that cost as a part of CEB's investment program for the year in which the asset is transferred.

Table 7.2

CEB Past Investment Mix
(Current Prices)

	1979		1984	
	Rs million	%	Rs million	%
Generation	2,121	48	6,355	49
Transmission	910	21	2,556	20
Distribution	1,182	27	3,679	28
Other	172	4	388	3
Total	4,385	100	12,978	100

Source: CEB

The data presented in Table 7.2 does not reveal the under investment which has occurred in distribution facilities, which has resulted in their being generally overloaded since the distribution systems have not been expanded in line with the growth in the number of consumers. This has been a major reason for the significant increase in system losses (para 4.10).

7.04 Investment in broadly defined power subsector projects accounted for about 16.9% of the public investment program in the period 1978-1983. Table 7.3 shows the power subsector investment which passed through the public investment program (PIP) on two bases, first investment which is classified in the PIP as power, which is investment undertaken by CEB,1/ and second adjusted power investment which includes estimates of the power components of

1/ Investment financed by CEB out of retained earnings is excluded from the PIP figures since it is treated as private capital formation for purposes of compiling the PIP.

Table 7.3

Power Subsector Investment in the Public Investment Program
(Constant 1982 prices)

		1978	1979	1980	1981	1982	1983	1978-83
Total PIP	Rs min	12,912	15,463	17,581	15,320	16,056	14,635	91,967
Power	Rs min	543	424	895	1,070	409	415	3,756
Power % of PIP		4.2	2.7	5.1	7.0	2.5	2.8	4.1
Power (Adjusted)	Rs min	1,083	1,758	3,139	3,196	3,622	2,773	15,571
Adjusted Power as % of PIP		8.4	11.4	17.9	20.9	22.6	19.0	16.9

Mahaweli projects. The latter estimates were derived as follows. Capital expenditure on Mahaweli projects was divided into three categories; separable costs for the power components of the projects, separable costs for the agricultural components, and costs which were joint to both of these functions. The joint costs were allocated in the ratio 45:55 to the electricity and agricultural functions. It is recognized that this cost allocation is arbitrary; however, the approach is considered to be justified insofar as it gives a broad indication of the relative importance of the power component of Mahaweli projects, and the exclusion of this component gives a totally false view of the importance of power subsector investment in the PIP. Table 7.3 shows that whereas narrowly defined power investments accounted for only 4.1% of the PIP in the period 1978-1983, the adjusted power investments accounted for 16.9%. This finding gives emphasis to the point made in para 7.03 concerning the imbalance in the past investment program due to the dominance of expenditure on generation facilities.

B. Financing Past Investment

7.05 CEB's financial statements for the period 1980-85 are presented in Annex 6, Attachments 1, 2 and 3. CEB's investment during the period 1979-1984 was financed from long-term loans, internal cash generation, increase in equity and consumer contributions, as summarized in Table 7.4.

Table 7.4

Summary of Sources of Financing by CEB 1979-1984
(Rs million)

Year	Int. Gen. Gross (i)	Int. Gen. Net a/ (ii)	Equity Increase (iii)	Long-Term Loan (iv)	Other Contributions (v)	Total (ii) to (v)
1979	296	77	58	167	9	311
1980	484	(378)	117	635	314	688
1981	814	473	55	292	121	941
1982	1142	299	238	162	285	984
1983	1202	(453)	95	1371	647	1660
1984 b/	1263	631	128	948	120	1827
Total 1979-84	5201	649	563	2755	1496	6411

a/ Available for investment, net of debt service, taxes and change in working capital.
b/ Net of Mahaweli (Victoria) transfers.

During the period under review, long-term loans were the major source of financing, accounting for 43% of requirements. Other contributions, including consumer contributions, accounted for 22% while the increase in equity accounted for 9%. CEB's internally-generated funds (gross), which totalled about Rs 5,201 million, indicate a strong and growing earnings position. However about 23% of the internal cash generated was used to service CEB's debt, about 50% was used to finance the increase in working capital requirement, and about 15% to pay taxes. Consequently, only about 13% of internal cash generation was available for investment, and this financed about 10% of capital expenditures during the period. Further analysis shows that large working capital requirements were created as a result of payment arrears on energy sales, as evidenced by the unusually high current ratios and accounts receivables level (in months of sales) shown in Table 7.5.

Table 7.5

CEB Current Ratios a/ and Accounts Receivable Levels
(As of December 31 of each year)

Year	Current Ratio	Accounts Receivables (Months of Sales)
1979	1.7	5.0
1980	3.7	4.4
1981	2.8	3.7
1982	2.3	6.5
1983	2.9	6.3
1984	4.1	8.5
Average 1979-84	2.9	5.9

a/ Ratio of current assets to current liabilities.

The serious bills collection problem imposed on CEB by some of its major consumers, particularly licensees, has meant that a significant amount of the internal funds generated during the period 1979-84 had to be diverted from investment to finance working capital requirements. CEB's staffing constraints, which frequently cause delays in taking remedial measures against consumers with significant arrears, have aggravated the problem. Any measures which can be taken to resolve the billing problem will release substantial funds to finance system expansion. It is thus crucially important that arrears are reduced. Given the role of licensees, this will require action by GOSL. Consequently, it is recommended that GOSL formulates and implements a monitorable program to reduce arrears owed by licensees and that CEB formulates and implements a similar program for its other consumers.

7.06 Despite the foregoing, the gross internal cash generation performance of CEB has been good as a result of revenue increases, partly because of tariff increases and partly through levying a fuel adjustment charge (para 6.11). Between 1979 and 1985 three rate increases, together with the activation of the fuel adjustment charge, raised the average revenue from Rs 0.30/kWh to Rs 1.51 kWh. CEB's measure of financial performance, as agreed with the Bank Group, is an after tax minimum rate of return of 8% on revalued average net fixed assets in use. The rate of return was 9.4%, 11.4% and 8.7% for the three years 1980, 1981, and 1982, respectively. In 1983, however, the rate of return was only 5.6%, due to the heavy income tax liability which was underestimated by CEB when it set tariffs for that year. The tax is levied on operating income after deducting a depreciation allowance of 12.5% for newly commissioned assets and based on straight line method for all other assets. A smaller depreciation expense for income tax purposes, caused by the delays in the transfer of Mahaweli assets contrary to CEB's projections, resulted in a larger taxable income and therefore in a bigger tax liability than estimated for 1983. Excluding this tax liability, the rate of return

was 11.2% in 1983. Moreover, as result of the delays in the transfer of the Mahaweli assets from 1983 as originally planned to 1984, the asset base in 1984 was higher than projected and, consequently, the rate of return was 7.4%.

7.07 Long-term borrowing financed much of past investment (para 7.05), and will be needed to finance future investments. However, due to the risks associated with long-term debt, it must be remembered that CEB's potential for borrowing is limited. In 1979, long-term debt provided Rs 167 million, but in 1984 it provided about Rs 2,948 million (including Rs 2,000 million debt incurred on transfer of Mahaweli Assets). This pattern of borrowing shows a somewhat unrestrained trend which could force CEB into taking unsustainable financial risks, as the accumulating debt burden results in a heavy cash drain for debt servicing. In 1979, CEB's capital structure showed a capitalization ratio 1/ with a low leverage of 6/94; at this level, CEB had a comfortable debt service coverage ratio of 3.4; but by 1984, as a result of the increased borrowing, the capitalization ratio had increased to 24/76, which in turn was responsible for the deterioration in the estimated debt service ratio to 2.6 in that year. In future, the transfer of power plants constructed under the Accelerated Mahaweli Program to CEB in the form of long-term debt will inevitably lead to a capital structure which will have a much greater leverage and will also impose higher financial risks on CEB. Restoring financial stability, therefore, will require higher internal funds generation and thus increased tariffs (para 7.11). 2/ It is, therefore, recommended that the financing of future investments should be assessed very carefully in order to obtain a reasonable balance between net internal cash generation and long-term borrowing.

C. Project Implementation

7.08 One of the major reasons for the difference between CEB's planned and actual investment shown in Table 7.1 was its unsatisfactory performance in implementing projects in recent years. Although some projects have suffered delays due to forces beyond CEB's control, such as riot, insurrection and shortages of equipment, major delays have also been caused by ineffectual project management and protracted procurement procedures (para 3.08).

1/ Defined as the long-term debt as a percentage of total capitalization.

2/ This need not be entirely in the form of loans to CEB. For example, CEB could receive a portion of these assets in the form of capital contributions which would, coupled with increased internal cash generation through upward adjustments in tariffs, enable the Board to maintain a strong capitalization position.

7.09 The New Laksapana 100-MW hydro project (Loan 636-CE) was completed two years behind schedule in 1974. A change of consultants between the feasibility and design phases caused considerable delay, as did insurrection and food shortages in the country. The Project Completion Report for this project drew attention to the absence from CEB's records of any details of the cost of the project, as well as a lack of interest by senior management in the financial control of projects. The Fifth project (Credit 372-CE) was a small transmission project which was completed in 1980, having taken more than twice as long as scheduled, almost entirely because of poor project management. The Sixth project (Credit 1048-CE), also a transmission and distribution project, was started in 1980 but has made unsatisfactory progress and, currently, is two years behind schedule mainly as a result of CEB's awarding a key contract to an unsatisfactory contractor. More satisfactory was the Eighth project (Loan 2187-CE), in which the diesel generating sets went on line in 1984, only five to seven months behind schedule. Most of this delay arose when unsuccessful bidders challenged a procurement decision. CEB's role in implementing this project was minor, since the project consisted essentially of one turnkey contract administered by consultants.

Investment Program and Financing Plan

7.10 CEB's investment program for the period 1986-95 is presented in Annex 6, Attachment 6 and summarized in Table 7.5:

Table 7.5
CEB's Investment Program 1986-1995
(in current prices)

	Rs Million	US$ Million	%	(%) Foreign Exchange
Generation	59,986	2,189	65	40
Transmission	12,671	462	14	45
Distribution	14,514	530	16	24
Other	4,220	154	5	4
Total	90,792	3,301	100	56

Expenditures to increase generation capacity would account for 65% of the planned investment, about 14% for extension and reinforcement of the transmission system, and about 16% for distribution. The remaining 5% would cover the cost of a training center and other miscellaneous capital expenditures. Traditionally, investment in development of the transmission system accounts for about 20% of the overall investment; however, in view of the fact that over the past few years considerable investments have been made in transmission facilities, including those under the Sixth and Seventh Power

Projects (Credits 1048-CE and 1210-CE), the proposed investment in transmission development is considered satisfactory in order to evacuate power to the load centers. As for distribution, the planned investments are for the extension and reinforcement of CEB's distribution systems and thus do not include the investments being made by LECO and local authorities. Nevertheless, planned investment in distribution is considered to be satisfactory pending the preparation of the Master Plan for the optimal development of the distribution systems (para 3.07).

Table 7.8

CEB Financing Plan for its 1986-1995 Investment Program

	Rs million	US$ million	% of Planned Investment
Planned Investment			
Local Costs	40,633	1,483	44
Foreign Costs	50,758	1,852	56
Total Investment	91,391	3,335	100
Local Cost Financing			
Internal Cash Generation	28,798	1,051	31
Equity Contribution	6,756	247	7
Consumer and Other Contribution	5,079	185	6
	40,633	1,483	44
Foreign Cost Financing			
Grants to GOSL*	1,392	51	2
Committed Sources	11,297	412	12
Identified Sources	29,439	1,071	32
Financing Gap	8,630	315	10
	50,758	1,852	56
Total Financing	91,391	3,335	100

* Loans to CEB

7.11 Based on the above investment program, a forecast sources and applications of funds statement for the period 1986-1995 is shown in Annex 6, Attachment 2. The financing plan reflects the tariff increases required to enable CEB to meet the entire local cost requirement of Rs 40,633 million (US$1,483 million) over the 10-year period from internally generated funds. This is an objective set by CEB and agreed to by GOSL. The objective allows CEB to take all necessary actions, including tariff increases, to ensure that

all local costs for the development program are met from internal sources. The foreign exchange requirement of Rs 50,758 million (US$1,852 million) would be financed through borrowings. CEB's capital investment includes an investment of Rs 4,500 million (US$164 million) for Mahaweli facilities, although the actual investment is being undertaken directly by GOSL. Of the total sources of funds, net internal cash generated from operations would contribute Rs 28,798 million (US$1,051 million) while equity contributions by GOSL would be Rs 6,756 million (US$247 million). GOSL's equity contributions would consist of Rs 4,500 million (US$164 million) in the form of transfer of Mahaweli (Randenigala) assets and Rs 2,256 million (US$82 million) as a financial contribution to the utility. Consumer contributions would amount to Rs 5,[illegible] million (US$185 million). About 37% of the requirements would be met from [illegible]rnal sources (para 4.18) and about 7% from equity. Borrowings would finance the balance 56%, or Rs 50,758 million (US$1,788 million). About Rs 11,297 million (US$412 million), or 25% of the required borrowings have been secured and sources for another Rs 29,439 million (US$1,041 million), or about 58% have been identified, leaving a financing gap of Rs 8,630 million (US$315 million) representing 17% of the total borrowing requirement. The financing gap would occur in the later years, particularly 1989 and thereafter. Given GOSL's and CEB's past successes in securing external financing, the AMP being a case in point, it is expected that the foreign financing gap would be bridged in a timely manner. To ensure that the utility's development program is implemented on schedule, it is recommended that GOSL and CEB take all necessary actions to obtain commitments to bridge the foreign financing gap. Furthermore, in order to ensure adequate Rupee resources are available, GOSL should continue to enable CEB to take all necessary actions, including tariff increases, to meet all local costs of investments from internal sources.

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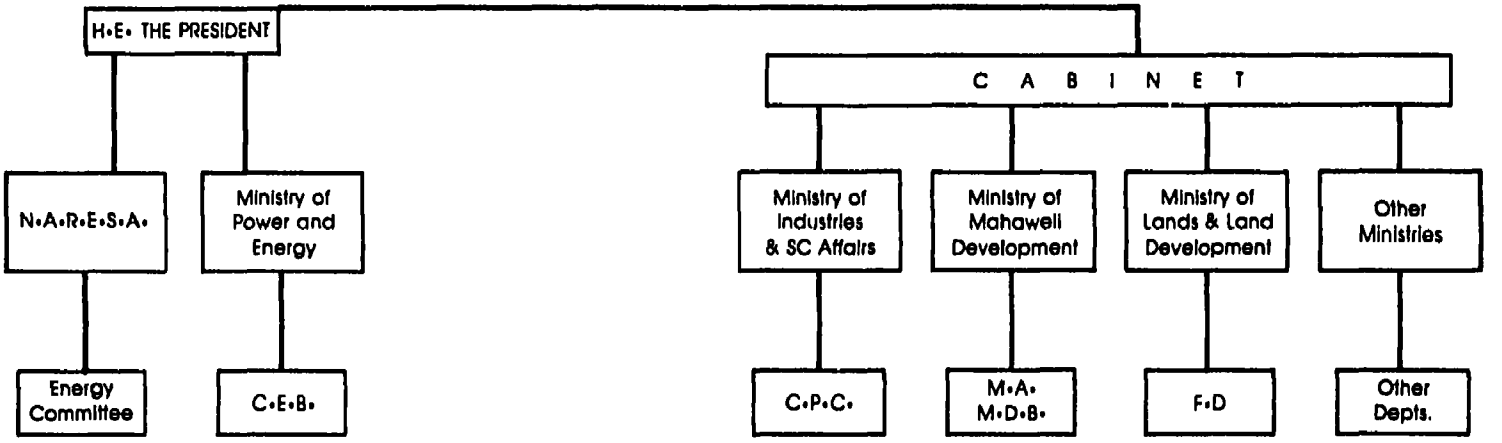
POWER SUBSECTOR REVIEW
Organization of the Energy Sector Prior to November 1982



Keys:

▬	Direct Link
C.E.B.	Ceylon Electricity Board
N.A.R.E.S.A.	Natural Resources, Energy & Science Authority
C.P.C.	Ceylon Petroleum Corporation
M.A/M.D.B.	Mahaweli Authority/ Mahaweli Development Board
F.D.	Forest Department

World Bank—30731:1

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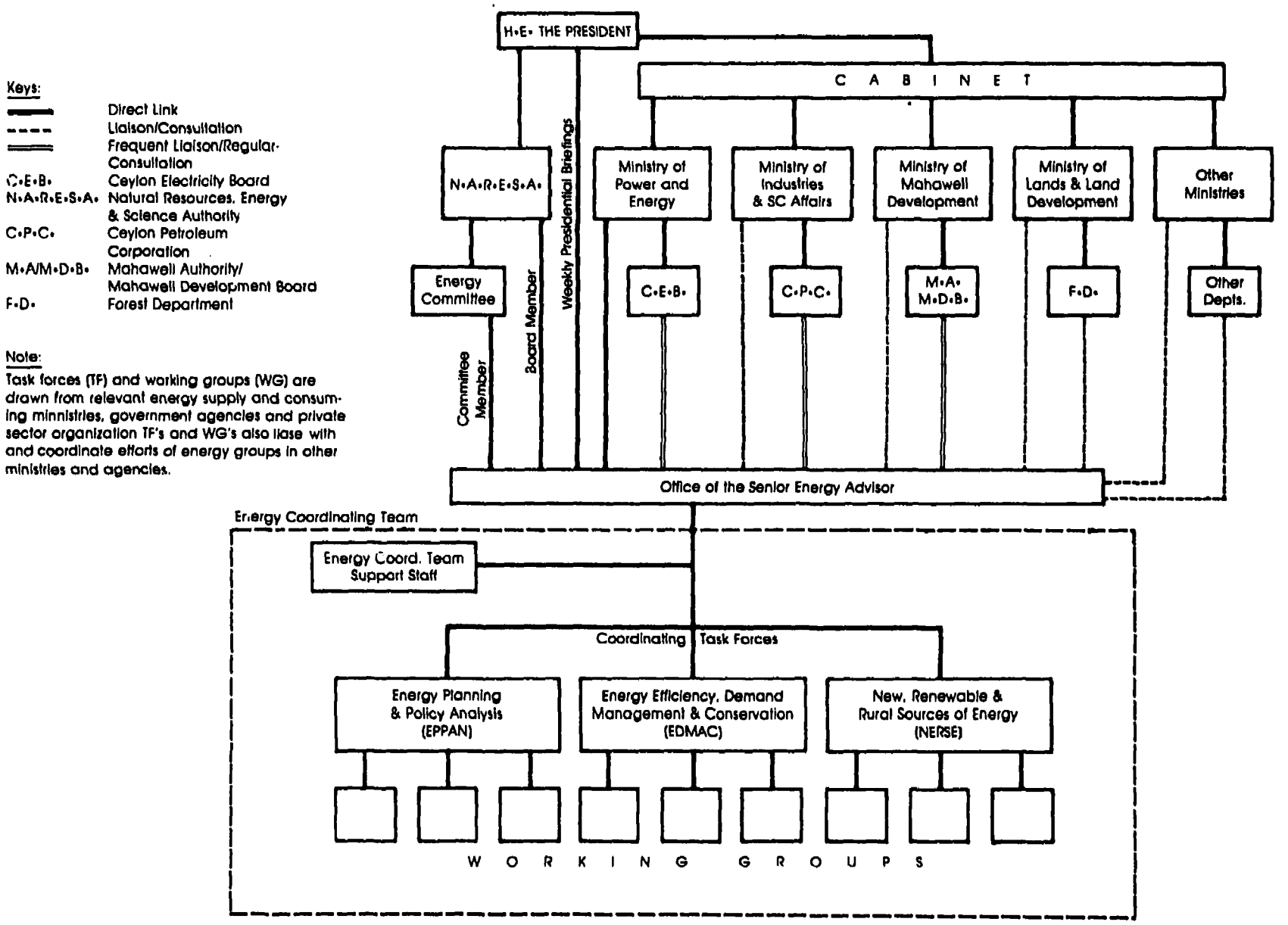
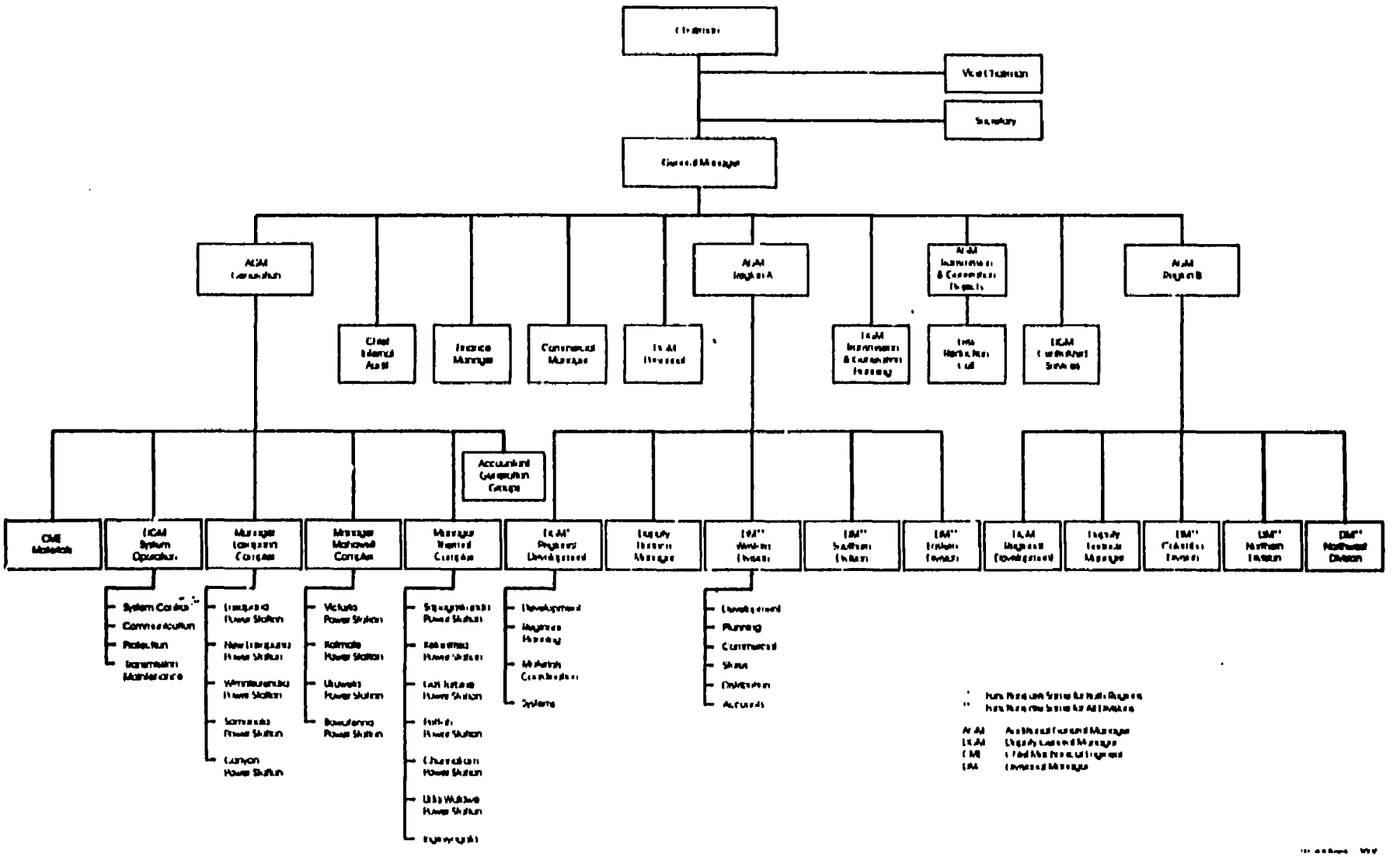
POWER SUBSECTOR REVIEW
Organization of New Energy Coordinating Team (ECT)



World Bank—30731:2

Ceylon Electricity Board
Organization Chart



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POWER SUBSECTOR REVIEW

Energy Balance - 1978
('000 TOE)

	PRIMARY ENERGY							SECONDARY ENERGY											
	NON-COMMERCIAL		COMMERCIAL					PETROLEUM PRODUCTS											
	Comm. Bagg.	Fuel Wood	Coal	Hydro	Crude Oil	Char-coal	Elec-tricity	LPG	Gaso-line	Naphtha	Aviation Fuel	Kero-sene	Av. Tur.	Diesel	Fuel Oil	Resi-duals	Sol-vents	Total	ROW TOTALS
Sources of Supply																			
Domestic Production	44	2184	-	327	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2555
Imports	-	-	4	-	1487	-	-	-	4	-	-	27	59	87	-	-	22	199	1690
Exports	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Stock Changes	-	-	(1)	-	19	1	-	(3)	8			10	(2)	5	(8)		(2)	(2)	21
Gross Supply	44	2184	3	327	1506	1	-	(3)	12	(7)	1	37	57	92	(8)	-	20	197	4266
Conversion																			
Refinery	-	-	-	-	(1506)	-	-	40	131	89	-	221	36	376	535	38	24	1490	(16)
Electricity Generation	-	-	-	327	-	-	119	-	-	-	-	-	-	(1)	(5)	-	-	(6)	(214)
Charcoal Production	-	(48)	-	-	-	21	-	-	-	-	-	-	-	-	-	-	-	-	(27)
Self Consumption	-	-	-	-	-	-	(1)	(34)	-	-	-	-	-	-	-	(38)	-	(72)	(73)
Losses in Transmission and Distribution	-	-	-	-	-	(2)	(18)	-	(1)	-		(1)	-	(1)	(3)	-	-	(6)	(26)
Net Supply	44	2136	3	-	-	20	100	3	142	82	1	257	93	466	519	-	44	1607	3910
Exports	-	-	-	-	-	(20)	-	-	-	(82)	-	-	(85)	-	(86)	-	-	(253)	(273)
Bunker Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	(72)	(258)	-	-	(330)	(330)
Net Domestic Consumption	44	2136	3	-	-	-	100	3	142	-	1	257	8	394	175	-	44	1024	3307
Consumption by Sector																			
Agriculture	-	321	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	321
Industry	44	328	-	-	-	-	55	-	-	-	-	-	-	64	155	-	-	219	646
Transport	-	-	3	-	-	-	-	-	142	-	1	-	8	330	20	-	-	501	504
Road	-	-	-	-	-	-	-	-	142	-	-	-	-	289	-	-	-	431	431
Rail	-	-	3	-	-	-	-	-	-	-	-	-	-	35	-	-	-	35	38
Air	-	-	-	-	-	-	-	-	-	-	1	-	8	-	-	-	-	9	9
Waterways	-	-	-	-	-	-	-	-	-	-	-	-	-	6	20	-	-	26	26
Household Commercial - Other	-	1478	-	-	-	-	45	3	-	-	-	257	-	-	-	-	-	260	1792
Non-Energy Use	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	44	44

Source: Energy Coordinating Team
Colombo, October 1984

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POWER SUBSECTOR REVIEW

Energy Balance - 1983
('000 TOE)

	PRIMARY ENERGY							SECONDARY ENERGY											
	NON-COMMERCIAL		COMMERCIAL					PETROLEUM PRODUCTS											
	Comm. Bagg.	Fuel Wood	Coal	Hydro	Crude Oil	Char-coal	Elec-tricity	LPG	Gaso-line	Naphtha	Aviation Fuel	Kero-sene	Av. Tur.	Diesel	Fuel Oil	Resi-duals	Sol-vents	Total	ROW TOTALS
Sources of Supply																			
Domestic Production	34	3930	-	292	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4256
Imports	-	-	20	-	1537	-	-	-	15	-	-	59	11	426	-	-	17	528	2085
Exports	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Stock Changes	-	-	8	-	(61)	(2)	-	1	9			(24)	34	(25)			(10)	67	12
Gross Supply	34	3930	28	292	1476	(2)	-	1	24	7	1	35	45	401	70	4	7	595	6353
Conversion																			
Refinery	-	-	-	-	(1476)	-	-	33	96	147	-	139	69	409	405	111	23	1432	(44)
Electricity Generation	-	-	-	(292)	-	-	182	-	-	-	-	-	-	(264)	(49)	-	-	(313)	(423)
Charcoal Production	-	(79)	-	-	-	31	-	-	-	-	-	-	-	-	-	-	-	-	(48)
Self Consumption	-	-	-	-	-	(3)	(2)	-	-	-	-	-	-	-	-	(34)	-	(34)	(39)
Losses in Transmission and Distribution	-	-	-	-	-	-	(26)	(25)	-	-	-	-	-	-	-	-	-	(25)	(51)
Net Supply	34	3850	28	-	-	26	154	9	120	154	1	174	114	546	426	81	30	1655	5748
Exports	-	-	-	-	-	(21)	-	-	-	(57)	-	(3)	-	-	(119)	-	-	(179)	(200)
Banker Sales	-	-	-	-	-	-	-	-	-	-	-	-	(77)	(40)	(191)	-	-	(308)	(308)
Net Domestic Consumption	34	3850	28	-	-	5	154	9	120	97	1	171	37	506	116	81	30	1168	5241
Consumption by Sector																			
Agriculture	-	294	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	294
Industry	34	302	27	-	-	3	70	-	-	19	-	-	-	-	90	81	-	190	626
Transport	-	-	1	-	-	-	-	-	120	-	1	-	37	506	26	-	-	690	691
Road	-	-	-	-	-	-	-	-	-	-	-	-	-	468	-	-	-	468	-
Rail	-	-	1	-	-	-	-	-	-	-	-	-	-	29	-	-	-	29	-
Air	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	1	-
Waterways	-	-	-	-	-	-	-	-	-	-	-	-	-	9	26	-	-	35	-
Household Commercial - Other	-	3254	-	-	-	2	84	9	-	-	-	171	-	-	-	-	-	180	3520
Non-Energy Use	-	-	-	-	-	-	-	-	-	78	-	-	-	-	-	-	30	108	108

Source: Energy Coordinating Team
Colombo, October 1984

SRI LANKA

POWER SUBSECTOR REVIEW

LOCAL SALES VOLUME OF PETROLEUM PRODUCTS, 1970-84
(tons)

	1970	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984 a/
LPG b/	35	582	807	3,108	2,432	6,404	7,110	6,663	8,197	7,150	8,718
Gasoline	148,411	95,057	101,065	111,491	129,994	115,146	107,691	109,028	114,217	117,477	118,814
Kerosene	272,514	209,764	206,593	212,886	244,832	229,918	188,288	168,266	174,098	159,146	150,229
Diesel, Automotive	254,530	245,515	257,557	261,988	308,792	349,404	397,710	420,912	464,594	464,268	481,902
Diesel, Marine c/	-	5,232	5,183	5,497	5,869	3,726	3,027	2,585	5,515	7,829	3,859
Diesel, Industrial	87,831	37,314	35,663	46,245	62,015	64,188	63,953	105,000	143,121	295,885	78,552
Furnace Oil, Domestic	208,810	143,664	125,578	135,530	162,556	183,539	259,731	240,326	247,138	253,098	211,560
Furnace Oil, Marine	-	20,108	20,088	18,762	21,233	16,099	12,887	22,884	26,974	26,881	8,577
Avtur	-	13,571	8,614	16,499	6,749	8,169	22,843	30,967	31,415	34,262	43,806
Lubricants d/	16,128	15,648	19,696	14,523	17,345	18,899	21,312	20,430	20,614	20,715	20,294
Bitumen	30,924	22,444	26,023	25,152	26,190	24,265	10,259	16,477	21,116	24,423	33,212
Naphtha	-	-	-	-	-	-	33,642	66,063	98,021	75,044	78,428

a/ Provisional.
b/ Since March 1977, reflects transfers to Colombo Gas & Water Company.
c/ Includes Marine Gas Oil, Marine Diesel Oil and Heavy Diesel.
d/ Other than marine and aviation lubricants.

Source: Ceylon Petroleum Corporation.

SRI LANKA

POWER SUBSECTOR REVIEW

Salary and Allowances Paid to CEB Personnel

Salaries are paid to CEB personnel based on the salary scales approved for each category. In addition to salaries on these salary scales, the undermentioned allowances are paid to all CEB personnel:

(a) Special Living Allowance of Rs 140/month.

(b) An allowance equivalent to 10% of the basic salary but not less than Rs 50/month.

(c) A fixed Cost of Living Allowance of Rs 70/month.

(d) A Supplementary Allowance of Rs 55/month.

(e) A Cost of Living Allowance based on the Living Index. (This allowance varies according to the variations in the Living Index. The Cost of Living Allowance paid for the month of September 1984 was Rs 404).

2. In the particular case of engineers an "Exodus" Allowance is paid in addition to the above mentioned allowances. The amount paid as Exodus Allowance is Rs 250/month during the first four years of employment after acquiring the qualifications for appointment. Rs 400/month during the next four years and Rs 500/month thereafter. Those who are Fellows of the Institution of Engineers, Sri Lanka, are paid an extra Rs 100/month.

3. In addition to the allowances referred to in paras 1 and 2 above, a few officers are paid a Special Professional Allowance which ranges from Rs 250/month to Rs 500/month (post graduate qualification - engineers or accountants).

4. In the particular case of the ex-employees of the Department of Government Electrical Undertakings in certain specified technical grades serving in the Ceylon Electricity Board an "Electricity" Allowance is also paid up to a maximum of Rs 111/month.

5. The salary scales adopted for the various categories of CEB personnel are given in the attached statement. This statement also gives the gross salary paid to them excluding the undermentioned allowances:

(a) Cost of Living Allowance based on the Living Index.

(b) Special Professional Allowance (in the case of Engineers).

(c) Risk Allowance.

C.E.B. 1985 SALARY STRUCTURE

Categories	Salary Scales (Basic)/month and Corresponding Gross Salary
1) General Manager and Addl. G. MM	Rs. 3200 - 3 x 100 - 3500/month (Rs. 4285 - Rs. 4615)
2) Deputy General Managers, Class I Engineers and Finance Manager	Rs. 2500 - 10x75 - 3250/month (Rs. 3515 - Rs. 4340)
3) Divisional Managers, Chief Engineers, Class II Grade I Engineers, Deputy Finance Managers, Senior Accountants, Manager Workshop and Central Garage and Manager Supplies	Rs. 2200 - 10x75 - 2950/month (Rs. 3185 - Rs. 4010)
4) Class II Grade II Engineers and Accountants	Rs. 1250 - 15x50 - 2000/month (Rs. 1890 - Rs. 2965) Rs. 1800 - 10x50 - 2300/month (Rs. 2745 - Rs. 3295)
5) Personnel Officers and Security Manager	Rs. 1800 - 10x50 - 2300/month (Rs. 2245 - Rs. 2795)
6) Chemist and Statistician	Rs. 1800 - 10x50 - 2300/month (Rs. 2745 - Rs. 3295)
7) Administrative Officers	Rs. 1250 - 15x50 - 2000/month (Rs. 1640 - Rs. 2465)
8) Senior Engineering Assistants, Engineering Assistancts, Administrative Assistants, Accounting Assistants, Commercial Assistants, Supplies Assistants, Welfare Officer, Confidential Secretaries, Senior Security Officers, Press Officer and Co-ordinating Officer	Rs. 1150 - 15x50 - 1900/month (Rs. 1530 - Rs. 2355)

9) Electrical Superintendents Class I and parallel technical grades	Rs. 1000 - 10x40 - 1400/month (Rs. 1365 - Rs. 1805)
10) Electrical Superintendents Class II Segment 'A' and parallel technical grades	Rs. 800 - 12x30 - 1160/month (Rs. 1145 - Rs. 1541)
11) Electrical Superindents Class II Segment 'B' and parallel technical grades	Rs. 650 - 9x25 - 875/month (Rs. 980 - Rs. 1227)
12) Clerical and Allied Grades	Rs. 1000 - 10x40 - 1400/month (Rs. 1365 - Rs. 1805) (for Special Grade Clerks and Typists only)
	Rs. 800 - 12x40 - 1280/month (Rs. 1145 - Rs. 1673)
	Rs. 700 - 12x30 - 1060/month (Rs. 1035 - Rs. 1431)

SRI LANKA

POWER SUBSECTOR REVIEW

Polgolla Project - Transfer of Assets of the Ukuwela Power Station to the CEB by the MDB

1. The Ukuwela Power Station has been functioning from mid-1976, when the Scheme was commissioned. The total construction cost of the Polgolla Project has been computed to be Rs 230.3 million.

2. During 1977, 1978 and 1979 the average energy production at the Ukuwela Power Station was 190 million units.

3. The diversion at Polgolla, ignoring the further diversion effected at Bowatenna after an additional investment, made it possible for supplementing the irrigation of 94,000 acres of land as listed below:

	Total Acreage	Additional Crop Acres from Mahaweli Waters
Giritale	7,500	5,000
Minneriya	18,000	6,000
Kaudulla	13,000	13,000
Kantalai	23,000	16,000
Parakrama Samudra	25,000	8,000
Elahera	6,600	4,000
	94,000	52,000

4. Benefits

(a) Irrigation

Total additional crop area cultivated per annum	52,000	acres
Average yield per acre - paddy	70	bushels
- i.e. rice	1	ton
Therefore, total annual increase in production - rice	52,000	tons
Import price of rice per ton assumed at	3,000	Rs
Cost of production per acre (or per ton or rice)	1,600	Rs
Therefore, net return per ton	1,400	Rs
Therefore, net annual income	72.8	Rs m

(b) Power

Total average annual energy production	190 mill.units
Total saleable energy per annum 0.85x190	160 mill.units
Average sale price per unit	0.30 Rs
Therefore total income from sale of energy	48 Rs m

Revised Statement of Expenditure - Ukuwela Power Station
(February 1980)

Nature of Work	Payments Made	Liabilities
Part A		
Civil Const. Ukuwela Power House	44,823,786.3	-
Penstock Treatment Works	972,999.0	-
Supply of Turbines (PS2)	10,375,861.0	-
Supply of Generators (PS3)	11,610,917.0	-
Supply of Transformers (PS4)	3,894,707.0	300,018.0
Supply of Standby Generators (PS5)	592,000.33	89,776.92
Supply of Tele-transmission Meter Equipment (PS7)	1,022,423.3	133,157.55
132 kVA Power Line	176,351.17	-
CEB Quarters	153,714.03	1,650,000.00
Telephone to Ukuwela Power House	300,000.00	-
Consultancy Services	6,484,193.22	-
FEECS Paid	25,346,000.00	-
	105,752,952.35	2,172,952.47
Part B		
Pologolla Diversion Dam, Tunnel	72,519,038.0	
Supply of Gates for Polgolla Diversion Unit	13,004,141.0	
Supply of Penstocks (PS6)	5,420,743.0	
Consultancy Services for Polgolla	5,515,710.0	
Sudu Ganga Training Works	2,055,000.0	
FEECS Paid	24,418,000.0	
	122,932,632.0	

(c) The total investment cost will be allocated on the basis of "Separable Costs/Remaining Benefits".

Separable cost that can be allocated to power (Part A of Annex)		105.75 Rs m
Residual cost to be allocated between power and irrigaton (Part B of Annex)		122.9 Rs m
Ratio or power benefits to irrigation benefits is 48:72 or		2:3
Therefore cost to be shared by power		
$= 122.9 \times \frac{2}{5}$	=	49.0 Rs m
Cost allocated to irrigation		52.7 Rs m
Therefore total value of assets to be handed over to CEB = 105.75 + 49		154.75 Rs m
		(say 155.0 Rs m)

Source: CEB

SRI LANKA

POWER SUBSECTOR REVIEW

TRADEOFFS BETWEEN IRRIGATION AND POWER GENERATION IN THE MAHAWELI GANGA (M-G) COMPLEX; CURRENT STATUS AND FUTURE PROSPECTS

1. Some of the principal operating policy issues in the Mahaweli Ganga Complex (including trade-offs between irrigation and power) are discussed in this Annex, together with some suggestions to safeguard and possibly enhance its power generation capabilities. It is divided into the following sections:

A. Background
B. System Studies
C. Weekly Operation Planning
D. Staffing

A. BACKGROUND

2. By 1990, the CEB generating system will have expanded to the point that it may be divided into four categories with the following projected capacity allocations:

	Capacity (MW)	Capacity (%)
1. The K-M Complex 1/	355	2.6
2. The Mahaweli Ganga (M-G) Complex	593	47.8
3. Major Thermal System (including Kelanitissa, Sapugaskanda)	266	21.5
4. Other (Minor Thermal/Hydro Plants)	26	2.1
Total	1,240	100.0

1/ The K-M Complex consists of the hydroelectric power plants located in the Kelani Ganga and the Maskeliya Oya River basins.

CEB has the sole responsibility for the management and operation of the generating systems included under categories 1, 3 and 4. The Mahaweli Ganga (M-G) Complex is a multipurpose system, designed to meet irrigation and power generation needs and is under the overall direction of a Water Management Panel (WMP), in which CEB has only a minority voice (see para 5). Not only will the M-G Complex provide nearly one half of CEB's

total capacity, it is also projected to provide at least one quarter of its nominal firm energy needs.1/ In view of the key role the M-G Complex plays in CEB's generating system, CEB needs to play a more active role in all aspects of its planning and operation, and especially in ensuring that water is allocated efficiently to meet power and irrigation needs.

3. The M-G Complex, in its projected mature form in 1990, will consist of the power generation and irrigation systems listed in Attachment 1, the relative locations of which are shown in the schematic layout of the complex in Attachment 2. Besides meeting the objectives of reducing imports of food grain and fossil fuels, the M-G Complex in its mature form, has an important income distribution objective of settling about 100,000 families on newly developed land and providing increased employment opportunities in the linked upstream and downstream agrobusiness sectors.

4. The M-G Complex subsumes not only the M-G River Basin but also the adjoining Amban Ganga River Basin. Upstream the two river basins are linked by the Polgolla tunnel, of capacity 56.7 cubic meters per second (m^3/s), which diverts water from the Mahaweli Ganga to the Amban Ganga to meet irrigation needs in the M/1H/MH system and to a lesser extent in the D_1, D_2 and G systems. At the same time, advantage is taken of the transfer system to generate electricity at the Ukuwela and Bowatenne power facilities (see Attachment 2).

5. The management of the M-G Complex is under the overall direction of the Water Management Panel (WMP). The WMP is chaired by the Director-General of the Mahaweli Authority of Sri Lanka (MASL) and also includes two other senior management representatives of the MASL (in the areas of Engineering and Settlement), the Director of Agriculture, the Director of Irrigation, the Secretary of the Ministry of Agricultural Development and Research, the Secretary of the Ministry of Lands and Land Development, the Government Agents of seven districts and the Chairman of CEB. The Water Management Secretariat, a unit of the MASL, acts as Secretary to the panel.

6. The development of the M-G Complex has involved the GOSL and a multiplicity of multilateral donors, development banks and funds. The Bank Group involvement has concentrated primarily on irrigation projects with a limited involvement in power. Under Mahaweli I, the Bank Group financed diversion headworks at Polgolla (plus a 30 MW hydropower plant at

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1/ Acres International Limited. Mahaweli Water Resources Management Project - Policy Studies Briefing Document, Colombo, January 1984, p.30.

Ukuwela) in the M-G River Basin, and at Bowatenne, in the Amban Ganga River Basin. This project, completed in 1978, provides an improved water supply to about 52,000 ha of existing irrigated land and a full supply for 29,000 ha previously unirrigated land in System H. Under Mahaweli II, the Bank Group contributed towards financing construction work on irrigation and social infrastructure for about 60% of the newly irrigated area in System H (the GOSL independently carried out development of the other 40%). Under Mahaweli III, the Bank Group concentrated its efforts in providing a full irrigation supply for about 24,100 ha of newly irrigated lands and in supplementing water supply for a further 3,000 ha in System C, through financing irrigation and social infrastructure works and settlement and agriculture development assistance. Under Mahaweli IV, funds would be provided for: (i) new irrigation of about 14,000 ha and the settlement of about 18,000 families in System B; (ii) enhancement of irrigation to about 1,800 ha of existing cultivated areas; (iii) establishment of fuelwood and cashew plantations in non-irrigated project areas; and (iv) provision of related technical assistance. 1/

7. A number of observations may be made on the development of the M-G Complex:

(i) Planning of the M-G Complex did not incorporate a systems approach. The original "master plan" for the development of the M-G Complex was put together by a UNDP/FAO team in 1968 on a phase by phase and project by project basis, summing the results to arrive at an overall internal rate of return of 15%. A later modification of this plan, prepared by NEDECO (September 1979) entitled an "Implementation Strategy Study" that formulated the Accelerated Mahaweli Program (AMP) also utilized a component specific approach to determine the economic worth of individual projects. However, NEDECO did attempt to sequence project implementation to maximize overall benefits.

(ii) The balance between system irrigation and power benefits changed drastically. The original UNDP/FAO master plan (1968) envisaged that power would contribute only a minimal part of the overall benefits (less than 10%). By September 1979, the price of fossil fuels had climbed so radically that the NEDECO study concluded that most of the benefits accruing to the construction of the three major reservoirs in the M-G Complex would be in energy

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1/ Further details on the history of the Mahaweli Ganga Development Program and on the Bank Group's involvement in the program may be found by consulting the report: Sri Lanka: Mahaweli Ganga Development Project IV. SAR No. 4885-CE, May 4, 1984.

generation. In spite of this situation, CEB has played a very limited role in the development of the M-G Complex.

(iii) The M-G Complex, in its mature form, would suffer from inherent spatial and temporal conflicts in water allocation, that are exacerbated in times of low flow. For example, the water that is diverted at Polgolla, primarily to meet irrigation needs in the Amban Ganga Basin, could alternatively be used to generate substantial energy benefits in the M-G River Basin. Also, in the M-G system, releases for irrigation in Systems B and C could decrease the firm energy capability of the Randenigala Reservoir. Finally, the M-G Complex has little flexibility in handling these situations, partly because of the very limited storage (173 mcm at Kotmale) upstream of the Polgolla diversion.

8. To correct the imbalance in the management of the M-G Complex, as reflected in the composition of the Water Management Panel (WMP) (see para 5), it is recommended that the Chairman of CEB should seek to be made co-chairman of the WMP and to be joined by the General Manager and the Additional G.M. Generation of CEB. To reflect the interests of the industrial sector in ensuring a reliable power supply, the Secretary of the Ministry of Industry and Scientific Affairs should also be appointed to the WMP. Because of its unwieldy size (currently 16 members), the WMP should have a core Policy Committee, consisting of 5 members - the DG of the MASL, the Chairman of CEB, 1 Government Agent, the Secretary of the Ministry of Agricultural Development and Research and the Secretary of the Ministry of Industry and Scientific Affairs. The Policy Committee would be responsible for developing seasonal operating policies in the M-G Complex subject to subsequent ratification by the WMP.

9. The use of the systems approach is now being used to look at planning and operation issues in the M-G Complex. The following section describes three such ongoing planning studies while Section C describes the procedures being used in Weekly Operation Planning (See Attachment 7).

B. SYSTEM STUDIES

Water Resources Management.

10. Under the overall direction of the WMP and in close collaboration with the WMS, a group of consultants (Acres International Limited of Niagara Falls, Ontario) implemented the Mahaweli Water Resources Management Project (MWRP). Essentially, the objectives of this project were to provide answers to the following six questions:

Question 1 - With what reliability can currently planned cropped areas be served, assuming presently achieved water duties, 1/ by the combination of the Victoria + Randenigala + Kotmale + Rantembe combination of reservoirs?

Question 2 - Given the answer to Question 1, what target cropped areas can be supplied with adequate reliability? What effect would a realistically achievable reduction in water duties have?

Question 3 - How can uncontrolled emptying of the Victoria, Kotmale and Randenigala reservoirs be avoided during periods of low inflows and high irrigation demands? How will alternative rationing policies affect irrigation and hydroelectric operations?

Question 4 - Questions 1, 2 and 3 presuppose a Polgolla diversion policy that requires maximum possible flows in the Bowatenne irrigation tunnel. If significant cutbacks in Polgolla diversion volumes are made, what effects would be observed on:

(i) reliable cropped areas in the Amban Ganga System

(a) with present water duties,
(b) with realistically achievable reduced water duties;

(ii) hydroelectric energy and thermal energy generation;

(iii) economic returns,

(a) with present water duties,
(b) with realistically achievable reduced water duties?

Question 5 - What changes in reservoir rule curves would be beneficial to the irrigation and electrical systems, assuming the irrigation demands, that were defined in answering Question 2?

Question 6 - Under representative alternative diversion policies, what water surplus will be available in the lower Mahaweli Ganga for use in additional irrigation developments?

1/ Water duties refer to the crop water requirements during a growing season. They are dependent on the crop under cultivation, efficiency of water distribution and other factors.

11. The approach taken by the consultants to executing the projects included the following steps:

(i) Definition and modelling of a series of scenarios to compare system performance under base case and alternative conditions.

(ii) Use of two computer models to examine system performance. A monthly time step model, the Acres Reservoir Simulation Program (ARSP) (described in Attachment 3) is used to examine broad operating alternatives. A weekly time-step model, the NEDECO Macro Model (described in Attachment 4) is used to conduct more detailed analysis of some of the policy options. The Macro Model includes the three main elements of the CEB electrical generating system (the K-M system, the M-G Complex and the Kelanitissa/Sapugaskanda thermal system) while the ARSP only includes the hydroelectric generating stations in the M-G Complex. Both models represent the principal irrigation diversions.

(iii) Use of three criteria, as appropriate, to evaluate alternative policies:

(a) Irrigation and Energy Generation - comparison of energy generation levels while assuming that irrigation demands must be met;

(b) Economic Criteria (Tradeoff Analysis) - quantification of agricultural benefits (using detailed crop budgets) versus costs of (thermal) electricity generation to make up for loss of hydro energy; and

(c) Social and Regional Development Priorities - commitments to new settlers (especially in System H) must be met, together with fair sharing of water shortages.

12. The consultants presented their final report in June 1985 1/. Among the principal conclusions of the study were:

- The average family, with a holding of 1 ha, needed a cropping intensity (CI) of approximately 2 to be financially viable.

- Using 'present' case water duties, a hydrological record of 32 years and full storage level (FSL) rule curves for irrigation

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1/ Acres International Ltd. "Mahaweli Water Resources Project: Studies of Operating Policy Options". Niagara Falls, Ontario, June 1985.

tanks and the main stem reservoirs of the M-G Complex, all systems could be reliably supported with a CI of 2, except for System H which could only be reliably supported with a CI of 1.65.

- Taking as a base case, present irrigation water duties and full storage levels (FSL) rule curves for tanks and the main stem reservoirs, the consultants estimated annual additional benefits of Rs 182 million for non-structural policy modifications that consisted of : a) improving overall system irrigation efficiency by 10%; and b) changing the yield cropping pattern in System H to include a larger percentage of upland crops. The benefits accrued from increasing the reliably supported CI for System H to 1.9 (while maintaining a CI of 2.0 for all other irrigation systems) and also from increasing power benefits by reducing average annual diversions at Polgolla by 54 Mm^3 1/. These benefits could be increased even further by using optimal tank and main stem rule curves, through reducing diversions at Polgolla by approximately 35%, as compared to the base case.

13. In addressing question number 5, the consultants concluded that a cubic meter (CM) of Mahaweli water considered at its diversion point at Polgolla has approximately the same benefit for use in irrigation and power generation in the Amban Ganga Basin and for power generation in the Mahaweli Ganga Basin2/. However, the analysis does not give credit for possible downstream irrigation benefits resulting from the use of this water in the M-G River Basin, and neither does it seem to take into account firm energy impacts.

14. In subsequent work, the consultants looked at the impacts of reducing diversions at Polgolla to meet only the Maha 3/ needs of the Amban Ganga irrigation systems, compared to the base case (see para 12). Applying average energy rule curves for both the M-G and K-M Complexes and valuing the Yala economic crop benefits at Rs 10,250/ha, they concluded that a) the CI in System H would be reduced from 1.65 to 1 and in System

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1/ Firm energy was valued at Rs 1.73 per kWh and secondary energy at Rs 1.13 per kWh, in 1984 rupees.

2/ See Attachment 8 for more details on the economic features of this study.

3/ The Yala irrigation cropping season lasts from April-September. The other season is called the Maha Season (October-March) when irrigation/power conflicts are not likely to occur.

D_1 from 2 to 1.25 with a resultant loss in benefits of Rs 419 million per year; b) average power generation would increase by 328 GWh per year (with a gain of 525 GWh in firm energy) resulting in increased power benefits of Rs 685 million/year; and c) net system benefits would increase by Rs 266 million/year. This type of major policy change, if implemented over the long term, would have a devastating effect on the economic viability of farms, particularly in System H, and thus would not be politically or socially desirable. However, the analysis is extremely useful in providing a framework for short-term policy discussions between CEB and other agencies in the WMP, in those periods when the firm energy shortfall of the power system could be reduced by diversion cutbacks (see also para 15).

15. Decision making by the WMP should not only be in terms of political and regional considerations (which would give first priority to meeting irrigation needs) but also take into account the national economic interest, especially in times of low streamflow when the conflicting objectives of minimizing fuel oil imports (for meeting CEB's thermal generation needs) vs the benefits of irrigation cropping are brought into sharp relief. Therefore, it is recommended that the WMP decision making should take into account the available quantitative information (from the previously mentioned system studies) on the tradeoffs between irrigation benefits and power benefits (in the Amban Ganga River Basin) and power benefits (in the Mahaweli River Basin) for water that could be diverted at the Polgolla barrage for realistic ranges of flows, water duties and cropping patterns, when it decides on diversion policies at Polgolla.

16. The studies described looked only at non-physical alternatives since the consultants' TOR did not permit them to consider additional physical additions to the system (such as reservoirs, irrigation storage tanks, etc.) to improve the system reliability. However, other structural options (such as reservoirs and irrigation tanks) in both the M-G and Amban Ganga River Basins should be studied to find ways to improve the stability and reliability of the M-G Complex. In particular, CEB should include in the TOR for the proposed feasibility study for the Calidonia/Talawakele Project, in the Upper Kotmale River Basin, a detailed look at the impact of this project on improving system firm energy generation capabilities and on improving the reliability of irrigation water supply.

CEB's Procedure for Calculating the Annual Mix of Thermal and Hydro Generation 1/

17. CEB uses a Deterministic Discrete Dynamic Programming (DDDP) algorithm for calculating the annual mix of thermal and hydro electricity generation. The objective function minimizes the cost of thermal generation and includes penalties for unserved energy and irrigation demands. Assumptions are made on the system unregulated inputs, monthly irrigation requirements, reservoir initial and final operating levels, the load duration curve (LDC), generating unit forced outage probability and the stacking order for matching the operation of the generating plants with the LDC.

18. Because of the large number of assumptions made and because the M-G Complex will grow in complexity over time and thereby make the applicability of the DDDP algorithm more difficult, this procedure does not have the same level of detail as the MACRO and ARSP procedures. However, it is an optimization technique and is useful for framing discussions on the operation of the CEB generation system (and especially on the choice of reservoir rule curves), that would optimize system benefits.

The Transbasin Diversion Study 2/

19. Up to now this section has covered operating policy issues; the following five paragraphs deal with long-term planning studies. These reconnaisance level studies have been underway since 1980. Their principal objective was "to investigate alternative plans for conveying and utilizing surplus water of the Mahaweli Ganga, together with local inflows, to irrigate selected areas in the North Central River Basins (NCRB) and/or the Northwest (NWDZ) and Southeast Dry Zones (SEDZ) and to recommend the best plan, both technically and economically, including the determination of which subprojects should be developed under the selected plan and integrated into the Mahaweli Program."

20. In the first sequences of studies, the consultants evaluated the three alternatives against a base case consisting solely of the hydroelectric and irrigation schemes that form the Accelerated Mahaweli Program (AMP). The economic criterion used for evaluating the various alternatives was the maximization of annual net benefits attributable to developing irrigation schemes, in the three zones considered, using a discount

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1/ See Attachment 5 for more details on the methodology.

2/ See Attachment 6 for a more detailed description of these studies.

rate of 10%. The benefits consisted of the additional value of agricultural production, over and above that of rainfed production, due to the irrigation project less (i) the annual capital and operating cost of the irrigation system; (ii) the cost of the supplementary Mahaweli Ganga Transbasin Conveyance System together with the conveyance system pumping energy costs; and (iii) any resulting reduction in firm and secondary hydroelectric energy in the AMP base case. The only system that produced a net positive economic benefit was the SEDZ: this project yields net benefits of Rs 121 million per year at a capital cost of Rs 3,727 million. The consultants concluded that there were no power related penalties attributable to the diversion of water to the SEDZ from the Mahaweli Ganga at Minipe and also that there were no pumping costs.

21. These studies were based on a number of assumptions including:

(a) using a Kotmale reservoir storage capacity of 405 MCM; in fact Kotmale has a storage capacity of 173 MCM;

(b) using average monthly unregulated inflows; and

(c) a fixed diversion policy (875 MCM per year) through the Polgolla tunnel from the Mahaweli Ganga River Basin into the Amban Ganga River Basin.

22. The latest study 1/ took another look at the NWDZ (System NW1) under the assumption that the diversion policy at Polgolla could be changed from a constant average monthly diversion of 73 MCM per month to a cumulative average annual diversion of 875 MCM with month to month deviations allowed. Based on (i) a primary crop of sugarcane and equipped irrigation acreages of about 20,000 ha approximately; (ii) construction of a new reservoir for flow regulation in the Amban Ganga River Basin; (iii) irrigation of paddy only in the Maha season; (iv) definition of reservoir requirements on the assumption that irrigation shortages will be shared between systems D, G, H and NW1; and (v) a storage capacity at Kotmale of 173 MCM, the consultants calculated an economic rate of return of about 10%. This calculation allows for a loss of about 24% of the system firm energy of the Kotmale-Victoria-Randenigala-Rantambe cascade. Slightly improved rates of return and similar losses in firm energy would result from raising Kotmale dam to its originally planned height.

1/ Joint Venture Mahaweli Transbasin Diversion (JVMTD), August 1983. Supplementary Report on the Additional Studies of System NW1 (of the North West Dry Zone).

23. None of the studies appear to have included extensive sensitivity analysis on project benefits or on project costs. For example, the consultants based their calculations of the value of primary energy on the unit capacity, fuel and O&M costs of an oil-fired steam power generation plant. It would be useful to reevaluate project feasibility using the corresponding costs of a coal-fired plant similar to the one that is currently being studied at Trincomalee. In considering the latest study, a diversion policy at Polgolla, that lowers the M-G River Basin firm energy capability by approximately 20% could have serious consequences for CEB, primarily by a restructuring of its investment program. In addition, it would be useful to review the alternative of constructing a reservoir in the Amban Ganga (such as the proposed Moragahakanda reservoir) to reduce needed diversions at Polgolla and thereby increase firm energy generation in the M-G River Basin.

24. The planning of future developments in the M-G Complex should continue balancing its irrigation and power generation capabilities. Consequently, it is recommended that all long-term planning studies in the M-G Complex should be under the overall direction of the modified Water Management Panel (WMP) (see para 8); be managed jointly by staff from CEB and the MASL; and that their Terms of Reference (TOR) explicitly include the determination of the impact of any future plans on CEB's investment program and on the need to restructure electricity tariffs.

C. WEEKLY OPERATIONAL PLANNING

25. A working group consisting of representatives of CEB, MASL/WMS, the Mahaweli Economic Agency, the Irrigation Department (ID) and of the consultants (NEDECO and Acres) has been operating since early 1984 in using the MACRO model for developing weekly operational planning and monitoring procedures of the M-G Complex. Projected target irrigation diversions plus peak power and energy demand together with projected rule curve levels are used as inputs into the MACRO model to project the performance of the M-G Complex, as it is currently configured. Monitoring includes a comparison of actual system behavior with the projected system behavior for the week preceeding each time that the working group meets. Since operations planning in the M-G Complex, will become even more important in the future with the addition of the Randenigala and possibly the Rantambe dams, it is recommended that the current collaboration between CEB and MASL, through their participation in the Interagency Working Group on Weekly Operations and Planning be continued. It is also recommended that CEB should review the applicability of simulation techniques, such as the MACRO model and the Acres Reservoir Simulation Program (ARSP), in terms of its operations planning needs for the rest of this decade, i.e., before the M-G Complex is converted into its mature form.

D. STAFFING

26. CEB should be in a position to defend its interests better in discussions with other agencies on the allocation of water in M-G Complex. It is thus recommended that CEB add to its staff in generation, experienced personnel with a broad knowledge of both irrigation and hydroelectric systems operation. In particular, these staff could be very useful in (i) ensuring that realistic policies are implemented by reducing irrigation water duties through increased efficiency in water distribution and use and/or modifications in cropping patterns and (ii) evaluating the impacts of future proposed transbasin diversions on CEB's generation system. It is further recommended that CEB strengthen its in-house capabilities in water resources planning by having two of its engineers trained on this topic (one in planning, the other in generation) under the aegis of the proposed GTZ Technical Assistance program (see para 2.07). This training should also include "hands on" familiarity with policy simulation models/program such as the NECECO Macro Model and the Acres Reservoir Simulation Program.

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POWER SUBSECTOR REVIEW

The Mahaweli Complex in 1990:

List of Projected Installed Power Generation and Irrigation Systems

Power Generation

System	Total Available Capacity (MW)	Nominal Firm Energy (GWh/Yr) 1/	River Basin 2/
Ukuwela	38	168	P
Bowatenne	40	108	A
Kotmale 3/	134	310	M
Victoria	210	626	M
Randenigala	122	366	M
Rantambe	49	156	M
	593	1,734	

Irrigation 4/

System	Net Irrigated Area (ha) 5/	River Basin	Comments
B	39,800	M	In series with system C
C	22,600	M	Essentially a run of the river project
D_1	25,700	A	
D_2	10,100	A	
E	6,100	M	
G	5,600	A	
H/IH/MH	45,600	A	Dependent on diversions from the Mahaweli Ganga River Basin
Total	156,500		

1/ Source: Mahaweli Projects and Programme 1983, Colombo, 1983.
2/ A = Amban Ganga, M = Mahaweli, P = Polgolla Diversion.
3/ A third unit of 67 MW total available capacity could also be operational 1990.
4/ Does not include information on System A, which eventually is planned to consist of 20,300 ha.
5/ Source: Mahaweli Authority of Sri Lanka, Water Management Secretariat, January 1984, Mahaweli Water Resources Project Policy Studies.

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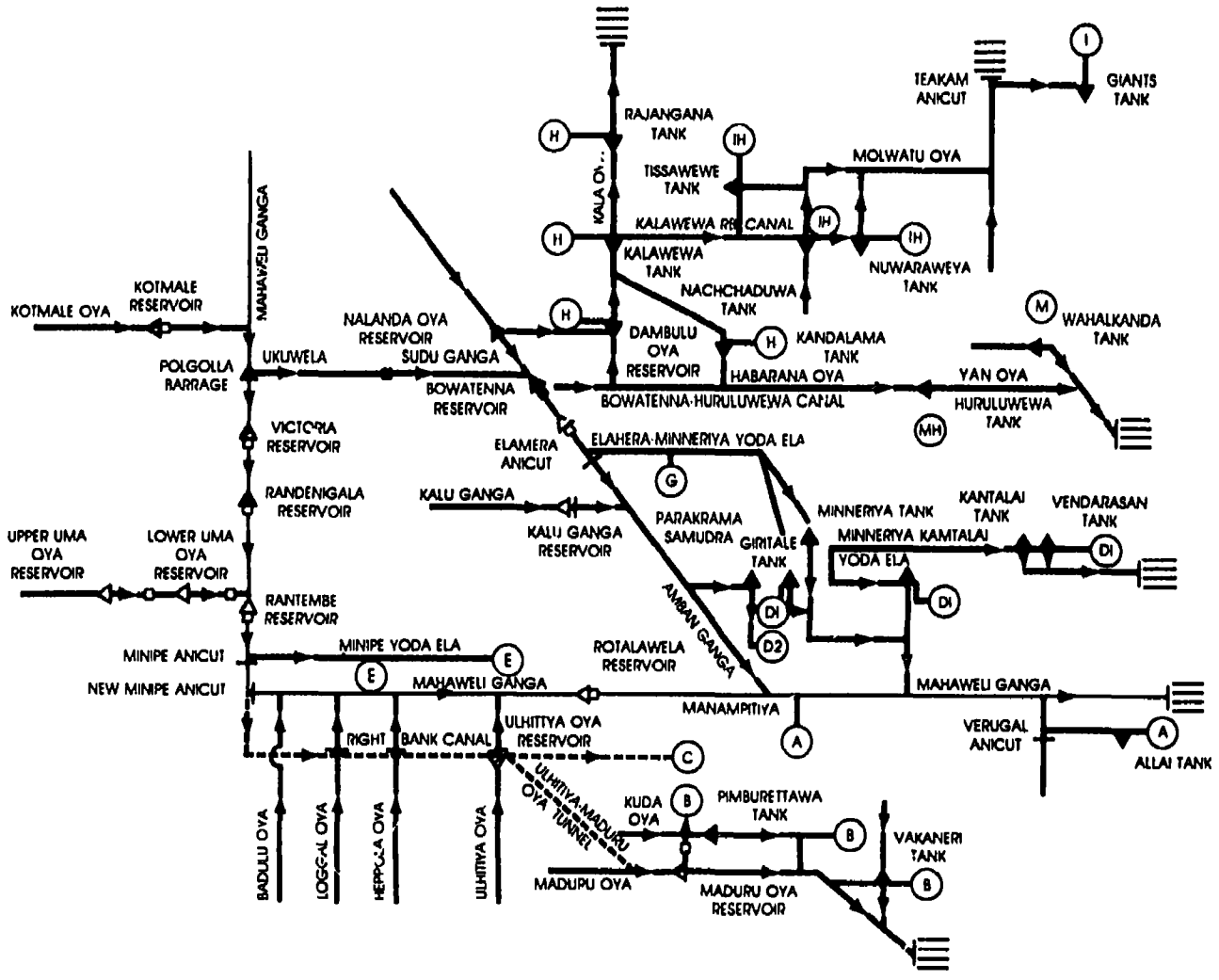
POWER SUBSECTOR REVIEW
Schematic Layout of Mahaweli System



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POWER SUBSECTOR REVIEW

ACRES Reservoir Simulation Program (ARSP) 1/

Brief Description

Objective: Given the current storage level in each reservoir of the system and predicted net systems inflows and demands (for irrigation and power), determine the set of reservoir releases, that will minimize overall violations from the reservoir rule curves.

Model Description:

1) Reservoir storage is divided into 5 zones (spill, flood control, conservation (where the rule curve applies), buffer and "inactive" (usually "dead") (consult page 3 of this attachment).

2) Flows in each channel are divided into 5 categories (upper extreme, upper extended, normal, lower extended, lower extreme) (consult page 4 of this attachment).

3) For each violation from the rule curve, assign a small penalty as long as the storage level remains in the conservation zone. As storage moves into adjacent zones (flood control and buffer), apply higher penalties. Assign even higher penalties, when storage moves into the spill and "inactive" zones. The penalty weights may be chosen to reflect different operating policies such as (a) a "priority policy" that gives higher weights to appropriate operation of upstream reservoirs over downstream reservoirs and thereby penalizes higher upstream infractions from the rule curve than downstream and (b) "equal function relationships" where no priority is given to the operation of any reservoir and the same penalty coefficient is assigned to the corresponding zones (e.g., upper extended) of all reservoirs.

4) Similar principles are used in routing water flows through the channels. Flows in the adjacent categories (upper extended, lower extended) to the

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1/ This description is partly based on the following paper, Sigvaldason, O. "A Simulation Model for Operating a Multipurpose Multireservoir System" Water Resources Research, April 1976.

normal category are assigned a relatively modest penalty; flows in the remaining categories are assigned an even higher penalty.

Model Structure: 5) The model structure is that of a linear minimum cost circulation problem:

Minimize: $\sum_{I,J} C(I,J)\, X(I,J) = Z$

Subject to: $\sum_{\substack{J \\ I \neq J}} X(J,I) + \sum_{\substack{J \\ I \neq J}} X(I,J) = 0$ for all I

$$L(I,J) \leq X(I,J) \leq U(I,J) \text{ FOR ALL } I,J$$

where

Z is the objective function;

X(I,J) is the flow in the arc from node I to node J;

C(I,J) is the cost of each unit of flow in the arc (I,J);

L(I,J) and U(I,J) are the lower and upper bounds respectively on X(I,J).

Optimization Algorithm: 6) The special structure of the model (a capacitated network) allows it to be solved by a very efficient and simple procedure known as the out-of-kilter algorithm (OKA). The computer technology is such that this kind of model is now usable on a micro computer such as the IBM XT.

Model Output/ Applications: a) Weekly realtime reservoir releases (e.g. in the Chao Phraya River Basin, Thailand).

b) Seasonal operating policies (such as in the fall-winter drawndown period) in the Trent River Basin in Ontario, Canada.

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SUMMARY OF PENALTY COEFFICIENTS

	Penalty Coefficient	Violation	Typical Values "Priority" Policy	"Equal Function" Policy
Reservoir Rule Curve Violations	$p^t_{uc_j}$	above rule curve in conservation zone	1.0 → 1.5	1.0
	$p^t_{fc_j}$	flood control zone	100.0 → 150	100.0
	$p^t_{s_j}$	spill zone	10,000.0 → 15,000.0	10,000.0
	$p^t_{lc_j}$	below rule curve in conservation zone	1.0 → 1.5	1.0
	$p^t_{b_j}$	buffer zone	100.0 → 150.0	100.0
	$p^t_{i_j}$	inactive zone	10,000.0 → 15,000.0	10,000.0
Channel Flow Violations	$p^t_{ud_{ij}}$	above normal flow range in extended zone	2.0	2.0
	$p^t_{e_{ij}}$	in extreme zone	200.0	200.0
	$p^t_{ld_{ij}}$	below normal flow range in extended zone	2.0	2.0
	$p^t_{le_{ij}}$	in extreme zone	200.0	200.0

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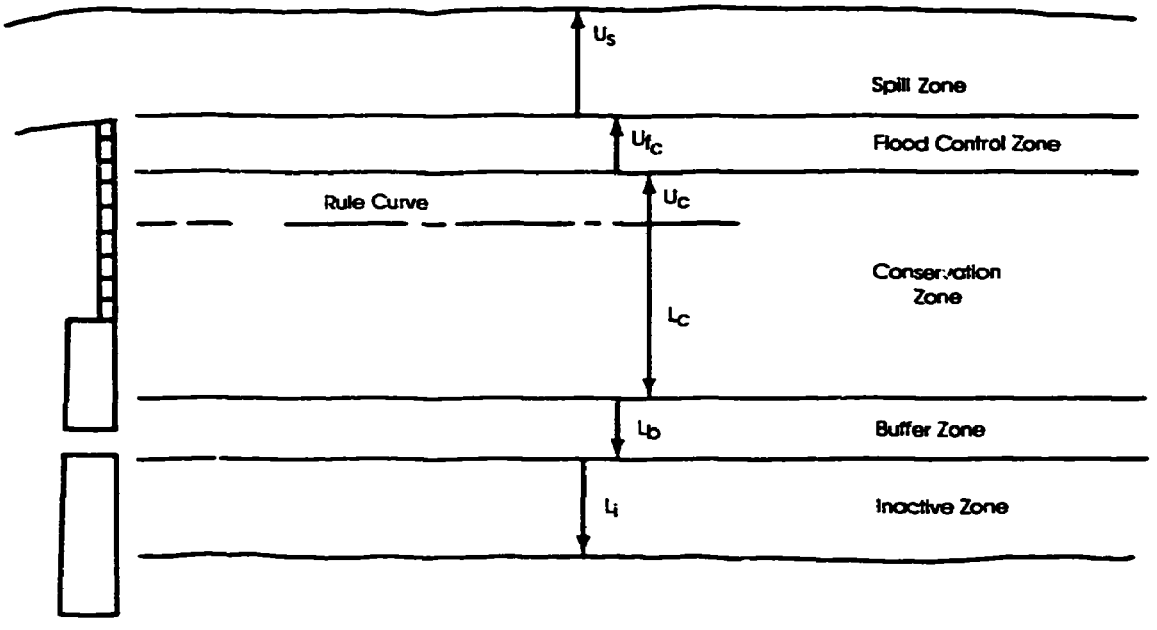
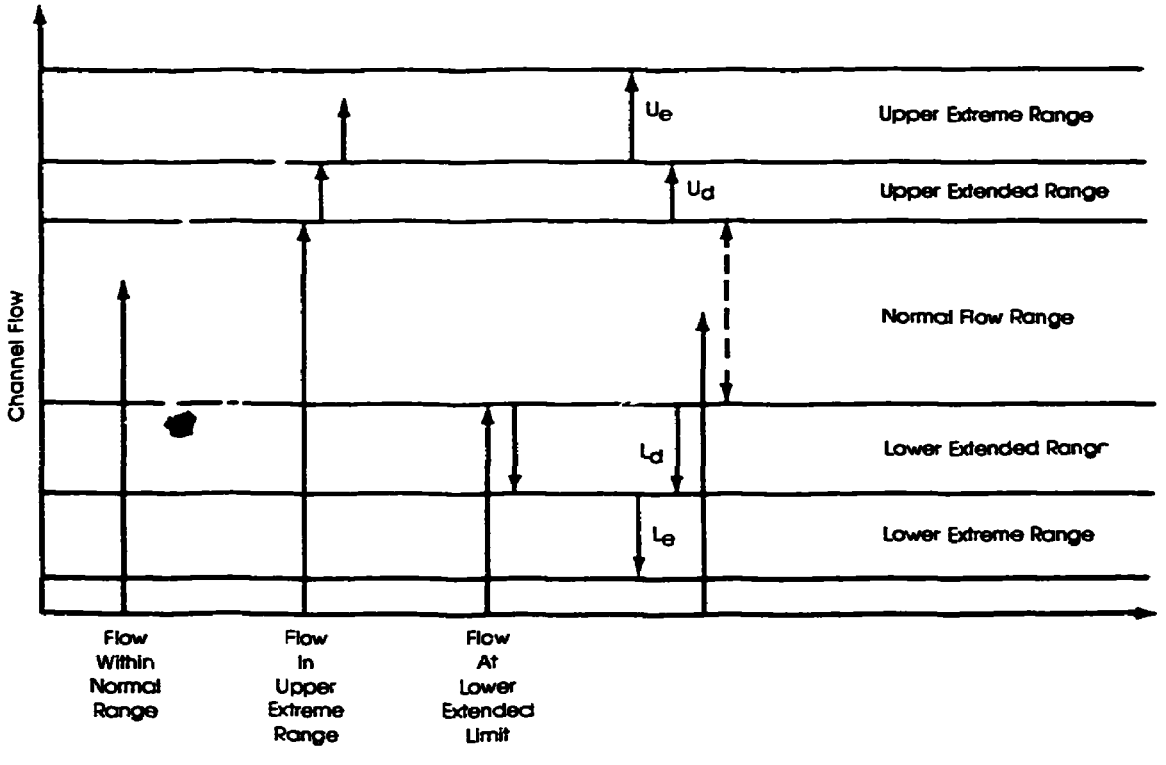
REPRESENTATION OF COMPONENT ARCS FOR RESERVOIR STORAGE AND CHANNEL FLOW
Channel Flow Representation



Reservoir Representation



Channel Flow Representation

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POWER SUBSECTOR REVIEW

NEDECO Macro Model - Description

The NEDECO Macro Model is a deterministic simulation model that is used to guide the operations planning (over a year or over a season) or the operation (on a week to week basis) of the main reservoirs and diversions of the Mahaweli Ganga Complex. To meet prespecified power generation and irrigation needs, some operating policies, such as the reservoir rule curves and the preferenial drawdown order may be specified by the user; other operating policies such as reservoir balancing, primary and secondary irrigation supply (i.e. which reservoirs are the primary and secondary sources of supply for which irrigation area), energy priority (the Macro Model always looks to the K-M complex first for meeting regional energy demands) are specified in the computer program itself and may only be modified by computer code changes. The remaining paragraphs describe some other salient points of the model:

Structure: The model is structured around a series of nodes (that may represent inflow points, confluences, reservoirs, hydropower plants and diversions), that are connected by a series of arcs (natural channels, canals and hydro tunnels). The model only includes the major reservoirs and diversion points in the Mahaweli Ganga Complex plus CEB's other principal hydro and thermal generating stations. Operation of the irrigation systems must be handled by separate models (such as the Micro Model that has been developed by NEDECO for system H/IH/MH).

Procedure: Rule curves are specified for meeting irrigation and energy needs - whenever practicable, the algorithm will endeavour to minimize the use of thermal energy while meeting prespecified energy and irrigation demands.

Output: For each time period:

- A series of reservoir releases,
- A listing of water availability at each diversion point.

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POWER SUBSECTOR REVIEW

CEB's Procedure for Calculating the Annual Mix of Thermal and Hydroelectricity Generation

CEB uses a deterministic discrete dynamic programming optimization algorithm for calculating the annual mix of thermal and hydro/electricity generation. The objective function minimizes the cost of thermal generation and includes penalties for unserved energy and irrigation demands. The following assumptions are made:

(a) Unregulated inflows into the system are assumed equal to the 70% 'dry' value of the flow-duration curve - i.e., 70% of the flows in the historical record are higher than the assumed values.

(b) Annual irrigation requirements, on a month by month basis, are lumped for the main diversion points at Elehara (System G, D_1), Angamadilla (System D_2), Bowatenna (H/IH/MH) and Minipe (Systems B, C and E) and at the Transbasin diversion point at Polgolla.

(c) Only major elements of the CEB generating system are considered (i.e., Canyon, New Laxapana, Wimalasurendra, Old Laxapana, Politiya in the K-M Complex and Ukuwela, Bowatenna, Victoria and Kotmale in the Mahaweli Ganga Complex) and 4 thermal systems (including the Sapungaskanda diesel set and the Kelanitissa thermal and gas turbine sets). Reservoir discharge rules are calculated for the Moussakelle and Castlereigh Reservoirs (in the K-M Complex) and for the Victoria Reservoir in the Mahaweli Ganga Complex, on the assumption that reservoir levels are the same at the beginning and at the end of the year. The exception is for the Kotmale reservoir, because it is being filled for the first time.

(d) The Load Duration Curve (LDC) is provided and a forced outage probability for each plant is assumed. A stacking order is used for matching the operation of the generation plants with the LDC.

Comments

Dynamic Programming (DP) is a useful technique for optimizing systems of relatively simple structure by decomposing larger problems into more manageable problems either spatially or temporarily. As systems become more complex and more interactive, dynamic programming tends to

become a more inefficient algorithm because of the rapidly (frequently geometric) increases in memory and computational requirements.

The CEB hydroelectric system in place right now is relatively uncomplicated. It consists of 2 reservoirs with very weak interactions (Moussakelle and Castlereigh) and two systems that are serially linked (Kotmale and Victoria) plus the small pondage Bowatenna Reservoir. For this system some major assumptions were made (including consolidation of information on irrigation demands) when using the dynamic programming algorithm. Once the planned additional hydroelectric projects are in place (at Randenigala and Rantambe), the system complexity will have increased enormously with a concomitant increase in computaticnal requirements.

The use of simplifying assumptions in determining irrigation demands also limits the applicability of the technique for calculating the tradeoffs between satisfying irrigation and energy demands. However, DP is an optimization technique and is useful for framing discussions on the operation of the CEB generation system (and especially on the choice of reservoir rule curves) that would optimize system benefits.

SRI LANKA

POWER SUBSECTOR REVIEW

The Transbasin Diversion Study

This study was financed as part of Cr. 979-CE and was prepared for the Mahaweli Authority of Sri Lanka (MASL) by the Joint Ventrure Mahaweli Transbasin Diversion (JVMTD) - a consortium of Electrowatt Engineering Services Ltd., Zurich, Salzgitter Consult GMBH, Salzgitter and Agrar and Hydrotechnik, GMBH, Essen.

The objectives of the study were: 1/

(i) to investigate, at reconnaissance level, alternative plans for conveying and utilizing surplus water of the Mahaweli Ganga, together with local inflows, to irrigate selected areas in the North Central River Basins (NCRB) and/or the Northwest (NWDZ) or Southeast Dry Zones (SEDZ). The study would recommend the best plan, both technically and economically, including the determination of which subprojects should be developed under the selected plan and integrated into the Mahaweli Program.

(ii) to prepare the terms of reference for feasibility studies for the selected plan and related subprojects.

The TOR for the study included the following instructions for dealing with power issues in the Mahaweli Ganga Complex.

> "(The Consultants shall) carry out studies to determine the best plan, technically and economically for conveying the surplus water of the Mahaweli Ganga (transbasin canal) for distributing this water together with the local inflows to the various potential subprojects for the development of irrigation and hydroelectric power."

For the first studies, the consultants worked under the following assumptions: 2/

1/ Mahaweli Ganga Technical Assistance Project, Report No. P-2086-CE, January 10, 1980, p. 15.

2/ JVMTD, June 1981. Transbasin Diversion Study, Planning Report, Volume I.

(i) Irrigation schemes under the accelerated program were given priority for water supply from the Mahaweli Ganga;

(ii) A fixed diversion policy (875 MCM per year) through the Polgolla tunnel from the Mahaweli Ganga River Basin into the Amban Ganga River Basin;

(iii) Irrigation benefits in the NCRB, NWDZ and SEDZ were based on a cropping pattern of paddy in the lowlands and cotton, maize, soyabeans and groundnuts in the uplands;

(iv) The system hydrology used was the average monthly inflows, month by month in an average year.

(v) The Kotmale reservoir was assumed to have a storage capacity of approximately 405 MCM (corresponds to the retention water level of 731.5 m). 1/ In fact, the reservoir capacity is 173 MCM (retention water levels of 703.0 m), a reduction in capacity of 57%.

The three alternatives were evaluated against a base case, consisting solely of the hydroelectric and irrigation schemes that form the Accelerated Program. The economic criterion used for evaluating the various alternatives was the maximization of annual net benefits attributable to developing irrigation schemes in the three zones considered using a discount rate of 10%. The benefits consisted of:

- The additional value of agricultural production, over and above that of rainfed production, due to the irrigation project.

Less

- The annual capital and operation and maintenance costs of the irrigation system, plus the supplementary Mahaweli Ganga transbasin conveyance system,

- The conveyance system pumping energy costs,

1/ Original retention water level reported in JVMBTD, November 28, 1980 Transbasin Diversion Study: Review Report, Table 4.1. Current retention water level and elevation - area storage data reported in MASL/WMS, Mahaweli Water Resources Management Project Policy Studies Briefing Document, Colombo, January 1984, p. 1-15.

- Any reduction in firm and secondary hydroelectric energy resulting,

as compared with the A.P. base case, resulting from the diversion of water from the Mawaheli Ganga complex to the proposed irrigation system.

The only irrigation system that produced a net positive economic benefit was the SEDZ; this project yields net benefits of Rs 121 million per year, at a capital cost of Rs 3,727 billion. 1/ Major factors that influence the benefits are:

(i) There are no power related penalties attributable to the diversion of water to the SEDZ from the Mahaweli Ganga at Minipe and there are no pumping costs either.

(ii) The SEDZ has a high proportion of lowland soils on which paddy can be cultivated.

1/ JVMTD, June 1981. Transbasin Diversion Study, Volume I, Table 13.1.

SRI LANKA

POWER SUBSECTOR REVIEW

Weekly Operational Planning and Procedures

A working group consisting of representatives of CEB, MASL/WMS, the Mahaweli Economic Agency, the Irrigation Department (ID) and of the consultants (NEDECO and Acres) has been functioning since early 1984 in using the MACRO Model for developing weekly operational planning and monitoring procedures. The consultants have defined:

- data requirements and collecting requirements,
- the processing required for planning and monitoring,
- procedures for conveying the simulation monitoring results to the decision makers.

Assuming that decisions need to be taken for the week (N) and also weeks N+1 and N+2, information is available for the reservoir operations at Victoria, Mousakella, Castlereagh and Bowatewna, in week N-1 (storage, releases, rule curve levels, etc.) and for recorded irrigation diversions at the principal control points for week, N-2 (there is a lag of about 1 week in reporting irrigation diversions), and energy generation for CEB's total system (the K-M complex, the Mahaweli Ganga Complex and the thermal system) for week N-1.

Projected target irrigation diversions plus peak power demand and energy demand together with projected rule curve levels for weeks N, N+1 and N+2 are provided to the working group. Projections of the MACRO system performances are based on simulations made with the MACRO model using 30 historical sequences for average, dry and wet conditions.

The monitoring process includes a comparison of actual system behaviour with the projected system behaviour for week N-1.

SRI LANKA

POWER SUBSECTOR REVIEW

Economic Benefits of Water Use for Irrigation and Power

1. In its mature form, the M-G Complex will be subject to inherent spatial and temporal conflicts:

- spatial conflicts arise in deciding whether or not water should be diverted from the M-G River Basin into the Amban Ganga River Basin; and

- temporal conflicts arise because of the conflicting timing for reservoir releases for irrigation and peak power generation.

Possibly, the most critical conflict occurs during the Yala season, when the decision has to be made to divert water at Polgolla from the M-G River Basin into the Amban Ganga River Basin. At this point, the possible benefits from using 1 CM of water are:

River Basin	Rated Net Head (M)	Energy Benefits (Gwh)	Irrigation System
Amban Ganga	133 a/	0.31 c/	D_1,D_2,G
M-G	300 b/	0.83	B, C, E

a/ At Ukuwela (78 m); at Bowatenne (55 m).
b/ At Victoria (190 m); at Randenigala (78 m); at Rantambe (32 m).
c/ if water is diverted to the H/IH/MH system, even less (energy) benefits are realized - 0.18 Gwh.

2. A useful concept for guiding thinking on this issue is to assign an opportunity cost to a unit of water at Polgolla for consumptive use (irrigation) and non-consumptive use (energy generation). The following paragraphs summarize a straightforward methodology for estimating the opportunity cost of water.1/

1/ Procedure developed at Acres International Ltd., Niagara Falls, Ontario for the report "Mahaweli Water Resources Management Project: Studies of Operating Policy Options", op. cit.

Non-Consumptive Opportunity Cost of Water

3. In energy terms, the opportunity cost of water, depends on whether firm or secondary energy is generated. The opportunity cost for secondary energy, is the cost of generating the lowest cost existing thermal equivalent. The opportunity cost of firm energy is the unit capacity and energy costs of the next most likely thermal generating station.

4. A viable procedure for calculating the generating cost for the lowest cost existing thermal equivalent is to examine the likely mix of unit energy costs (based on border prices) in terms of maximum demand met in MW (which could differ from installed capacity because of inadequate maintenance), plant factor, type and cost of fuel used, unit heat rate, thermal efficiency and O&M cost. Thus, the opportunity cost of secondary energy would be the unit with the lowest energy cost.

5. The procedure for calculating the capacity and energy costs of the next most likely thermal generating system (which is planned to be an imported coal-fired station at Trincomalee) would be in terms of an annualized unit capacity capital cost (that takes into account the capital cost, economic life, opportunity cost of capital and plant capacity), plant factor, incremental heat rate, fuel cost (based on border prices) and O&M cost.

Consumption Opportunity Cost of Water

6. A representative mix of crops are assumed as well as the net incremental value of production. For this crop mix, a budget is prepared in terms of yield (tons/ha), price/ton, giving gross revenue less costs (fertilizers, crop protection, farm power, hired labor and water charges) to give net revenue. Economic prices are used for crop selling price (in terms of imported product price, CIF, at the farm gate), for fertilizers (by removal of subsidies from market prices) and for labor rates (shadow priced).

7. Assuming that no water shortages occur in the Maha season, a linear relationship was established between net revenue (economic) and water availability in the Yala season. This analysis was repeated using financial prices to estimate the budget from the farmers' viewpoint and especially its dependence on cropping intensity.

Synthesis

8. The opportunity cost of one unit of water can then be found by combining the information, given in the table in paragraph 1, with the results of the analysis described in paragraphs 3-7 for the following situations:

	Firm Energy (1)	Secondary Energy (2)	Irrigation (3)	Combination (1) + (3)	Combination (2) + (3)
River Basin					
Amban Ganga	x	x	x	x	x
M-G	x	x	x	x	x

SRI LANKA

POWER SUBSECTOR REVIEW

Electricity Demand: Past and Projected

A. Available Data on Electricity Demand

Availability of Electricity Consumption Data

1. The data base on past electricity consumption is generally good. There are, however, three problems with available data, only one of which is important. The important problem arises from the data base being applicable to CEB tariff categories. Nearly 25% of CEB sales are made to local authorities (licensees) and no aggregative data is available on retail sales made by these authorities to final consumers or on the losses occurring in the subtransmission and distribution systems of these authorities. This constitutes an important gap in the available data base and it is recommended that measures are instigated to rectify this situation as soon as possible. The Ministry of Local Government is probably the appropriate institution to organize the collection of this data. It could require local authorities to make annual returns on purchases from CEB, total sales to consumers, and sales in the various tariff categories. There could be problems of definition and comparability of the different tariff categories, but it is understood that most local authorities have adopted CEB tariff categories.

2. A second problem concerns the lack of time series data on installed capacity and generation by auto-generators. The only data which is available concerns companies which receive CEB incentive payments (to use their auto-generators) in years when it is short of energy, such as 1983. The installed capacity of these companies, and their generation in 1983-1984, is shown in Annex 4, Attachment 4. The figures given in that Attachment suggest that the exclusion of generation from auto-generators is unlikely to introduce serious bias into the electricity consumption data, since in 1983 they accounted for only about 1% of total sales by CEB.

3. The third, and least important problem, concerns a lack of time series data on some of CEB consumer categories, such as hotels, small industry and medium industry. The reason for this lack of data is simply that CEB has, over time, been refining its tariff categories, especially in 1982. Time series data on existing categories naturally begins at the date when the tariff category was introduced. Fortunately, relatively long time series are available for the major consumer categories.

B. Growth of the Economy

4. GOSL initiated a number of basic economic reforms in 1977 which were successful in increasing the GDP growth rate. The most important policy

measures were: (a) a reduction in government intervention in commodity markets; (b) reduced government consumption subsidies to help restore public savings and finance public investment; and (c) the creation of a favorable environment for private (foreign and domestic) investment through tax concessions, the creation of an Investment Promotion Zone, and the unification and depreciation of the exchange rate.1/ Responding to these measures, the real GDP growth rate increased from the average rate of 2.9% a year in the period 1970-1977 to 5.8% a year in the period 1977-1985. However, the real GDP growth rate has been declining since 1978. It averaged 7.3% in the period 1977-1979 and 5.0% a year during the period 1981-1985. The crux of Sri Lanka's existing macroeconomic problems is an extremely high level of capital formation in relation to national savings and the slow growth of exports in relation to import requirements. In the period 1980-1984 the ratio of gross fixed capital formation, at current prices, to GDP was nearly 30%. Financing this level of investment has been a problem, especially since public sector savings were negative in the period 1980-1982. Foreign savings (current account deficit on balance of payments) financed about 63% of total investment in 1980, 43% in 1983 and 13.4% in 1984.

5. The historical and projected growth rates of the main sectors of Sri Lanka's economy are presented in Table 1.

Table 1

Historical and Projected Real Growth Rates for the Main Sectors of Sri Lanka's Economy
(%)

	Actual			Projected /a
	1970-77	1977-80	1980-85	1985-90
Gross Domestic Product	2.9	6.8	5.2	4.5
Agriculture	2.0	3.5	2.8	3.0
Industry	1.0	4.0	5.6	6.0
Services	3.7	7.8	6.2	4.5

/a World Bank projections.

1/ Sri Lanka: Recent Economic Developments, Prospects and Policies, The World Bank, Report No. 5083-CE. May 4, 1984, Chapter 1.

C. Past Electricity Demand

Growth of Overall Consumption

6. Electricity sales increased at an average annual rate of 6.0% in the period 1973-1978 and 8.6% in the period 1978-1985 (Table 2). The increase in the rate of growth of electricity sales accompanied the increase in the real GDP growth rate. The GDP elasticity of demand for electricity1/ increased from an average value of 1.47 in the period 1973-1978 to 1.68 during the period 1978-1985. This increase probably accompanied structural changes in the economy, with the relative growth of the industrial and service sectors compared to agriculture. Beginning in 1979 average real electricity prices increased rapidly (Table 1, Annex 5). They increased at the average rate of 26% a year during the period 1978-1985. These increases did not have any noticeable effect on the growth of demand for electricity. Per capita electricity consumption in Sri Lanka increased from 53 kWh/year in 1970 to 129 kWh/year in 1985. In 1983 per capita generation in Sri Lanka was about 116 kWh, which can be compared with the following figures for other countries in the region: Bangladesh 34 kWh, Burma 34 kWh, Pakistan 204 kWh and Philippines 351 kWh,

Table 2

Growth in Electricity Demand 1973-84
(CEB System)

	1973	1975	1978	1980	1983	1985	Annual Growth Rate (%) 1973-78	1978-85
Energy sold (GWh)	866.1	965.2	1161.0	1391.6	1790.6	2070.1	6.0	8.6
Energy generated (GWh)	979.5	1078.8	1385.1	1668.0	2114.4	2464.0	7.2	8.6
Per capita consumption (kWh)	66	72	82	94	116	129	4.4	6.7
Electricity intensity (kWh sold/US$'000 of GDP, 1982 prices)	-	-	302	321	375	388	N.A.	3.6
GDP elasticity							1.47	1.68

Source: CEB, Bank estimates.

1/ Defined as the percentage change in electricity demand divided by the percentage change in real GDP.

Electricity Supplied by CEB

7. The growth of electricity demand on CEB's supply system during the period 1973-1985 is shown in Attachment 1 and summarized in Tables 2 and 3. Total electricity sales increased by 6.0% a year during the period 1973-1978 and 8.6% a year during the period 1978-1985. Most of the growth was attributable to the connection of new consumers, which increased at 15.5% a year during the period 1978-1985. Overall average consumption per consumer fell by 5.7% a year during the period 1977-1985 (see Table 6), and only increased for the local authority consumer category (increase of 8.9% a year). The sectoral changes in average consumption per consumer, with a relative increase in the importance of domestic consumers, could be expected to lead to a decline in the system load factor. The relatively high load factor in 1983 of 55.2% was partly due to supply interruptions in peak hours in the later months of the year when the highest system peak is recorded. In 1984 about 40,600 new domestic consumers were added to the supply system, and they added about 5 MW to the evening peak load, thus reducing the load factor in 1985.

Table 3

Electricity Demand, CEB System

	1973	1978	1983	1985	Annual Growth Rate (%) 1973-78	1978-85
No. of consumers (end year)	92061	143860	311195	395072	9.3	15.5
Electricity sold (GWh)	866.1	1161.0	1790.6	2070.1	6.0	8.6
Electricity generated (GWh)	979.5	1385.1	2114.4	2464.0	7.2	8.6
Unserved energy (GWh)	0	0	16.8	-	-	-
Maximum demand (MW)	198.8	291.4	437.0	529.0	7.9	8.9
Losses (%) /a	12.9	19.3	18.0	18.0	-	-
Load factor (%)	56.2	54.2	55.2	53.0	-	-

/a Losses defined in terms of sales.

Source: CEB

8. Electricity generated grew faster than energy sold during the period 1973-1978 (Table 2), due to an increase in system losses from 12.9% to 19.3%.1/ Subsequently, however, electricity generated grew with sales (both at 8.6% during the period 1978-1985) due to a small fall in system losses from 19.3% to 18.0% in 1985.

1/ These are losses on the CEB system. They exclude losses in local authority distribution and subtransmission systems.

Electricity Consumption by Sector

9. The sectoral consumption of CEB supplied electricity is shown in Table 4 below, together with sectoral shares of total consumption. In recent years (1977-85) the fastest rates of growth have been recorded by the residential (15.6%), local authority (8.9%), and commercial (8.5%) sectors. Within the local authority category most of the electricity consumption is understood to be by residential consumers. The trends in relative shares indicate that the combined residential and local authority category may soon exceed the share of consumption accounted for by industrial consumers. This may reduce the system load factor and exacerbate the existing evening needle peak (para 14).

Table 4

CEB Electricity Sales by Sector, 1973-1985

Sector	1973 (GWh)	1973 (%)	1977 (GWh)	1977 (%)	1985 (GWh)	1985 (%)	Annual Rate of Growth (%) 1973-77	Annual Rate of Growth (%) 1977-85
Residential/a	82.37	9.5	106.52	10.3	339.0	16.6	6.6	15.6
Commercial	107.60	12.4	147.90	14.2	283.0	13.9	8.3	8.5
Large Industry	193.50	22.3	262.40	25.2	399.0	19.5	7.9	5.4
Small & Medium Industry	273.10	31.5	257.00	24.7	442.0	21.7	-1.5	7.0
Local Authority	198.40	22.9	252.80	24.3	499.0	24.4	6.2	8.9
Street Lighting	12.50	1.4	14.00	1.3	11.0	0.5	2.9	-2.9
Hotels/b	-	-	-	-	69.0	3.4	-	-
Total	867.42	100.0	1040.66	100.0	2042.0	100.0	4.7	8.8

/a Residential includes religious and charitable consumers.

/b The hotels category was introduced in the 1982 tariff. Previously hotels had been included in the commercial (general purpose) category.

Source: CEB

10. The data presented in Table 4 does not reveal any fundamental changes in trend electricity demand growth rates for large industrial and commercial consumers following the economic reforms introduced by GOSL in 1977. However, these reforms were followed by a substantial change in the rate of growth of electricity demand for small and medium industrial consumers. During the period 1973-1977 consumption by this category fell at the average rate of 1.5% a year, but subsequently during the period 1977-1985 it increased at 7.0% a year.

11. Table 5 shows that the number of consumers served by CEB increased at the average annual rate of 15.3% during the period 1977-1985, which represented a doubling of the number of consumers in less than five years. The fastest growth rates were recorded by the residential (16.6%) and small and medium industry (10.6%) consumer categories. During 1979-85 an average of 29,787 new residential consumers were connected each year. This rapid rate of new connections was the driving force behind the observed increase in electricity consumption on the CEB system.

Table 5

CEB Number of Consumers by Sector, 1973-1985

Sector	1973	1975	1977	1979	1981	1983	1985	Annual Rate of Growth (%) 1977-85
Residential /a	69924	81674	97998	142224	195025	259687	336294	16.6
Commercial /b	19090	20957	24311	31408	37839	44440	50833	9.7
Industry								
Large	51	55	56	61	63	73	80	4.6
Small & Medium	2626	2911	3246	3817	5239	6419	7289	10.6
Local Authority	218	218	218	218	218	218	218	0.0
Street Lighting	152	219	249	323	319	358	358	0.5
Total	92061	106034	126078	178051	238703	311195	395072	15.3

/a Includes religious and charitable consumers.

/b Includes hotels.

Source: CEB

12. Average consumption per consumer in the principal consumer classes during the period 1973-1985 is shown in Table 6 below. During this period average consumption per consumer fell for all consumer classes, with the exception of local authorities which recorded an increase of 8.9% a year. Unfortunately, no data is available on the average consumption per consumer served by local authorities.

Table 6

Average Consumption Per Consumer, 1973-1985
(kWh)

Sector	1973	1977	1981	1983	1985	Annual Rate of Growth (%) 1977-85
Residential /a	1178	1087	1110	1174	1008	-0.9
Commercial /b	5637	6084	5811	5483	5567	-1.1
Industrial	174292	157311	127790	115838	114127	-3.9
Local Authority	910092	1159633	1746055	1987018	2288991	8.9
Street Lighting	82237	56225	26646	28883	30726	-7.3
All Consumers	9422	8254	6297	5760	5169	-5.7

/a Includes religious and charitable consumers.

/b Includes hotels.

Source: Tables 4 and 5.

Electricity Consumption by Households

13. CEB analyzed February 1984 billing data for residential consumers to ascertain the frequency distribution of consumption per consumer and the frequency distribution of consumers by consumption level. The results of this analysis are presented in Attachments 2 and 3 to this Annex. Attachment 2 shows that the median consumption was 40/50 kWh/month, and that 52.3% of residential consumers used less than 50 kWh/month. About 28.3% of these consumers used no more than 30 kWh/month, which is the consumption level required to meet basic electricity requirements (defined as using three 60 W bulbs for four hours a day and one mobile fan). Attachment 2 also shows that only about 11% of residential consumers used more than 150 kWh/month. Attachment 3, however, shows that these consumers accounted for about 50% of electricity used by residential consumers. That Attachment also shows that nearly 29% of sales to residential consumers was to consumers using more than 400 kWh/month. This suggests that these consumers had an air-conditioning load.

Load Characteristics

14. Daily maximum demand occurs from about 19.00 h to 20.00 h, as is shown on the daily load curve in Attachment 4 (a typical daily load duration curve is shown in Attachment 4). Minimum load during night hours is typically only about 40% of daily peak load. During week days the load curve has three distinct segments: (a) a night-time load from about midnight to 04.00 h; (b) a day load from about 06.00 h to 18.00 h; and (c) an evening peak. Each segment is bounded by shoulder periods. The day load is about 65% higher than the night load, and the evening peak demand is about 50%

higher than the day load. On Sundays the load curve has only two segments, off-peak from about 23.00 h to 18.00 h and peak from 18.00 h to 23.00 h. The peak demand is about 100% (180 MW in 1984) higher than the off-peak demand. Most of the incremental demand during Sunday peak hours is believed to be caused by residential consumers. This incremental load is probably a reasonable indicator of the incremental load of residential consumers during weekday peak periods. During weekdays, however, part of this incremental load is offset by a decrease in the industrial and commercial loads at the end of the working day at around 17.00 h.

D. Projected Demand for Electricity

CEB Load Forecasts

15. CEB load forecasts are prepared annually by its Commercial Division. Five year forecasts are prepared on the basis of major consumer categories, and ten year forecasts are prepared for generation and maximum demand. The forecasts are prepared using trend analysis of past usage by the different consumer categories. For the first few years of the forecast period the trend analysis is modified to allow for anticipated large new loads. Thus the latest forecast (1985) for residential consumers allowed for the expected connection of new consumers under the on-going rural electrification project, while the forecast for commercial consumers allowed for anticipated new Urban Development Authority (UDA) loads, such as hotels and new office complexes. The forecast for industrial consumers allows for both expected new loads and changes in the level of industrial production. Sole reliance is placed on trend analysis for the period beyond that where special allowance is made for anticipated new loads (generally two to three years ahead). Peak demand is calculated using an assumed annual load factor.

16. The latest (July 1985) CEB load forecasts are shown in Table 7. Total sales are projected to increase at 9.4% a year during the period 1983-1988 and 9.7% a year during the period 1988-1995. Very rapid rates of growth are projected for the domestic, commercial, large industry and hotel sectors. Units generated are projected to increase at 8.6% a year during the former period and 9.0% a year in the latter period. The slower growth of units generated compared with sales in the latter period is due solely to expected reduction of system losses. System losses are expected to fall quite rapidly after 1986 with the completion of various stages of the distribution/transmission loss reduction project. The peak demand forecast has been obtained from the generation forecast with the application of an assumed annual load factor of 55%. On this basis peak demand is projected to increase by 62% during the period 1983-1988, and by 196% during the period 1983-1995.

Table 7

CEB July 1985 Load Forecasts

Sales (GWh)

Sector	1983 /a	1984	1985	1986	1987	1988	1990	1995	Average Growth (%) Rate 1983-88	Average Growth (%) Rate 1988-95
	Actual			Forecast						
Domestic	305	317	339	419	492	586	728	1301	13.9	12.1
Railways	-	-	-	-	-	-	70	300	-	-
Commercial	243	241	283	343	381	422	521	870	11.7	10.9
Large Industry	383	387	399	452	476	512	567	744	5.9	5.5
Medium & Small Industry	369	404	442	478	504	530	589	771	7.5	5.5
Hotels	48	59	69	9	110	120	130	155	20.1	3.7
Local Authority	433	458	499	521	573	630	762	1228	7.8	10.0
Street Lighting	10	11	11	11	12	12	13	15	3.7	3.2
Total Sales	1791	1877	2042	2228	2548	2812	3380	5384	9.4	9.7
Total Generation	2214	2261	2464	2817	3071	3347	3976	6118	8.6	9.0
Losses (%)	15	17	18	18	17	16	15	12		
Peak Demand (MW)	437	487	529	595	649	707	840	1293	10.1	9.0
Load Factor (%)	55.2	53.0	53.0	54.0	54.0	54.0	54.0	54.0		

/a Excludes unserved energy and potential consumers not served due to power shortages.

Source: CEB

17. Forecast numbers of consumers for the period 1985-1995 are shown in Table 8. The number of domestic (residential) consumers is projected to increase by 10.4% a year during the period, involving about 84,400 new connections in 1995. This rapid rate of new connections has been determined to allow for the on-going rural electrification projects and the expected effect of improved financing of connection charges. The amount which consumers can borrow under a CEB initiated bank loan scheme to finance connection charges was increased from Rs 1,000 to Rs 3,000 in 1984. The latter figure is close to the average connection cost for domestic consumers in Colombo (underground connection). To date the largest number of new domestic consumer connections was made in 1983, when 31,821 connections were made.

18. The total number of connections is projected to increase at the average rate of 9.9% a year during the period 1985-1988, with 46,581 new connections being made in 1988. This would be about 9,000 more connections than were made in any single year to date. No information is available on

the capability of CEB and local contractors to make this number of connections. However, it is clearly of critical importance that the CEB ensures that there will be sufficient construction capability to make the projected number of new connections.

Table 8

CEB July 1985 Forecasts Numbers of Consumers, 1985-1995

Sector	1985	1986	1987	1988	1990	1995	Annual Growth ---Rate (%)---- 1985-88	1988-95
Domestic	336294	362764	400991	442961	536762	885796	10.5	10.4
Commercial	50833	55166	59026	63344	75521	101715	7.1	7.0
Large Industry	80	78	79	80	82	87	1.3	1.2
Medium & Small Industry	7289	7714	8101	8359	9310	11431	4.7	4.6
Local Authority	218	218	216	215	213	207	-0.5	-0.5
Street Lighting	358	612	647	682	762	1100	5.4	7.1
Total	395072	426552	469060	515641	622650	1000336	9.9	9.9

Source: CEB

19. The average consumption levels which are implicit in the July 1985 load forecasts are shown in Table 9 below. Average consumption per consumer is projected to increase for all consumer classes. Excluding local authorities, the highest growth rates are projected for hotels, large industry and domestic consumers. Average consumption per consumer in each of these sectors is assumed to double in ten years or less.

Table 9

CEB July 1985 Forecasts Average Consumption Per Consumer
(MWh)

	1985	1986	1987	1988	1990	1995	Annual Growth Rate (%) 1985-88	1988-95
Domestic	1.03	1.16	1.23	1.32	1.36	1.47	5.71	1.55
Commercial	5.48	6.22	6.45	6.66	6.90	8.55	4.72	3.63
Large Industry	5181.82	5794.87	6025.31	6400.00	6914.63	8551.72	5.94	4.23
Medium & Small Industry	60.65	61.97	62.21	63.40	63.26	67.45	0.85	0.89
Local Authority	2288.99	2389.91	2652.78	2930.23	3577.46	5932.37	9.34	10.60
Street Lighting	18.90	17.97	18.55	17.60	17.06	13.64	-2.03	-3.58
All Consumers	5.26	5.22	5.43	5.43	5.43	5.38	0.64	-0.19

Source: Tables 7 and 8

20. The trends in average consumption per consumer which are implicit in the July 1985 forecast represent an almost total reversal of the trends revealed by historic data to 1983. The data presented in Table 6 showed that average consumption per consumer has been decreasing steadily for commercial and industrial consumers, and has increased only marginally for domestic consumers since 1977. There are a number of reasons why the average consumption estimates for domestic consumers which are built into the 1985 load forecasts appear to be optimistic. Two are as follows. First, the forecast assumes a large increase in the number of new domestic consumers, many of whom will be connected under rural electrification schemes. These consumers typically have relatively low consumption levels and thus they will tend to depress average consumption levels for the consumer class. Second, the forecast growth rates of GDP and GDP per capita are lower than those which occurred in the period 1977-1985. Thus the forecast decrease in the growth rate of GDP per capita would have to be combined with a substantial increase in the income elasticity of demand estimate if it was to lead to a large increase in average consumption levels.

Sources of Demand Forecast Error

21. Recent CEB demand forecasts have tended to be optimistic. Table 10 considers errors in the 1981 forecast by comparing forecast and actual values for 1983. It is unfortunate that 1983 is the latest year for which data is available since sales in that year were depressed due to the draught induced energy shortage. CEB has, however, estimated the impact of this shortage in terms of increased autogeneration, power cuts,and potential loads which it had to refuse to connect. Estimated losses of sales due to these purposes are included in Table 10.

Table 10

Sources of Demand Forecast Error
(Forecast for 1983 made in 1981)

A. Sales Forecast

Sector	Actual (GWh)	Forecast (GWh)	% Error
Domestic /a	304.8	272	- 12.1
Commercial /b	302.3	413	36.6
Large Industry /c	427.4	555	29.9
Small and Medium Industry	368.6	473	28.3
Local Authorities	433.2	483	11.5
Total Sales	1,836.3	2,196	19.6
Power Cuts	16.8	0	0
Total Sales with Cuts	1,853.1	2,196	18.5

B. Number of Consumers

Residential /a	259,678	217,600	- 19.3
Commercial /b	44,807	42,700	- 4.9
Large Industry /d	75	64	- 17.2
Small and Medium Industry	6,419	5,300	- 21.1
Local Authorities	218	218	0.0
Total	311,197	265,882	- 17.0

/a Includes religious purpose consumers.
/b Includes hotels, street lighting and Urban Development Authority (UDA) projects in Colombo and Kotte.
/c The sales figures include 20.02 GWh of autogeneration and 23.8 GWh for refused loads (3.8 GWh for Balfour Betty and 20 GWh for Lanka Cement).
/d Includes Balfour Betty and Lanka Cement, for which loads were refused.

Source: CEB

22. The 1981 forecast overestimated sales in 1983 for all consumer groups with the exception of residential consumers, but underestimated the number of consumers in all groups. The largest percentage errors occurred in the sales forecasts for industrial and commercial consumers. With the exception of residential consumers the cause of errors appears to be the same for all consumer groups, and that was the overestimation of sales per consumer. This may be caused by the load forecasting methodology used by CEB, which is trend extrapolation plus the addition of expected large new loads. There is thus an implicit assumption that the trend does not include large new loads, which is clearly false and leads to some double counting.

Improvements in Demand Forecasting

23. The demand forecasting errors identified in Table 10 suggest that there is considerable scope for improving CEB's demand forecasting methodology. More accurate load forecasting would be consistent with improved investment decision taking. Weaknesses in the existing forecasting methodology have been recognized by the Energy Planning and Policy Analysis (EPPAN) task force of the Energy Coordinating Team (Chapter 2). An energy economics group has been trained to carry out various types of statistical analysis, including multiple regression analysis. The work of this group does not, however, appear to have been incorporated adequately into CEB's July 1985 forecast.

24. Principal problems with CEB's existing forecasting methodology include: an undue reliance on forecasting by trend extrapolation; reliance on inadequate data bases; failure to analyze load factor by consumer class; and failure to prepare load forecasts over the period required for generation planning. CEB forecasts might be improved by using more than one methodology. It is, therefore, recommended that in future CEB prepares its load forecasts using at least two methodologies, such as the existing methodology (but amended to eliminate potential double counting of large new loads) and econometric methods. The 'adopted' forecast in any year would probably be a compromise between these separate forecasts. The basis for this approach already exists due to the action taken by EPPAN.

25. A basic requirement for improved load forecasts is the preparation, and continual updating, of an improved database. It is therefore, recommended that CEB undertakes systematic and regular consumer surveys to ascertain, for example, the electrical appliances used by domestic consumers with different consumption levels, and the principal uses of electricity by industrial and commercial consumers. The surveys should include the collection of data on consumer characteristics, for example, the shapes of their daily load curves and daily, weekly and annual load factors. Much of this information is also required for tariff setting.

26. CEB's existing practice is to prepare 10 year demand forecasts. This is too short a time horizon for the evaluation of optimal increments to generating capacity. It is common practice to base generation planning on time horizons of at least 20 years. It is recommended that CEB prepares 20 year demand forecasts, and also projects system load factor and load duration curves over the same period.

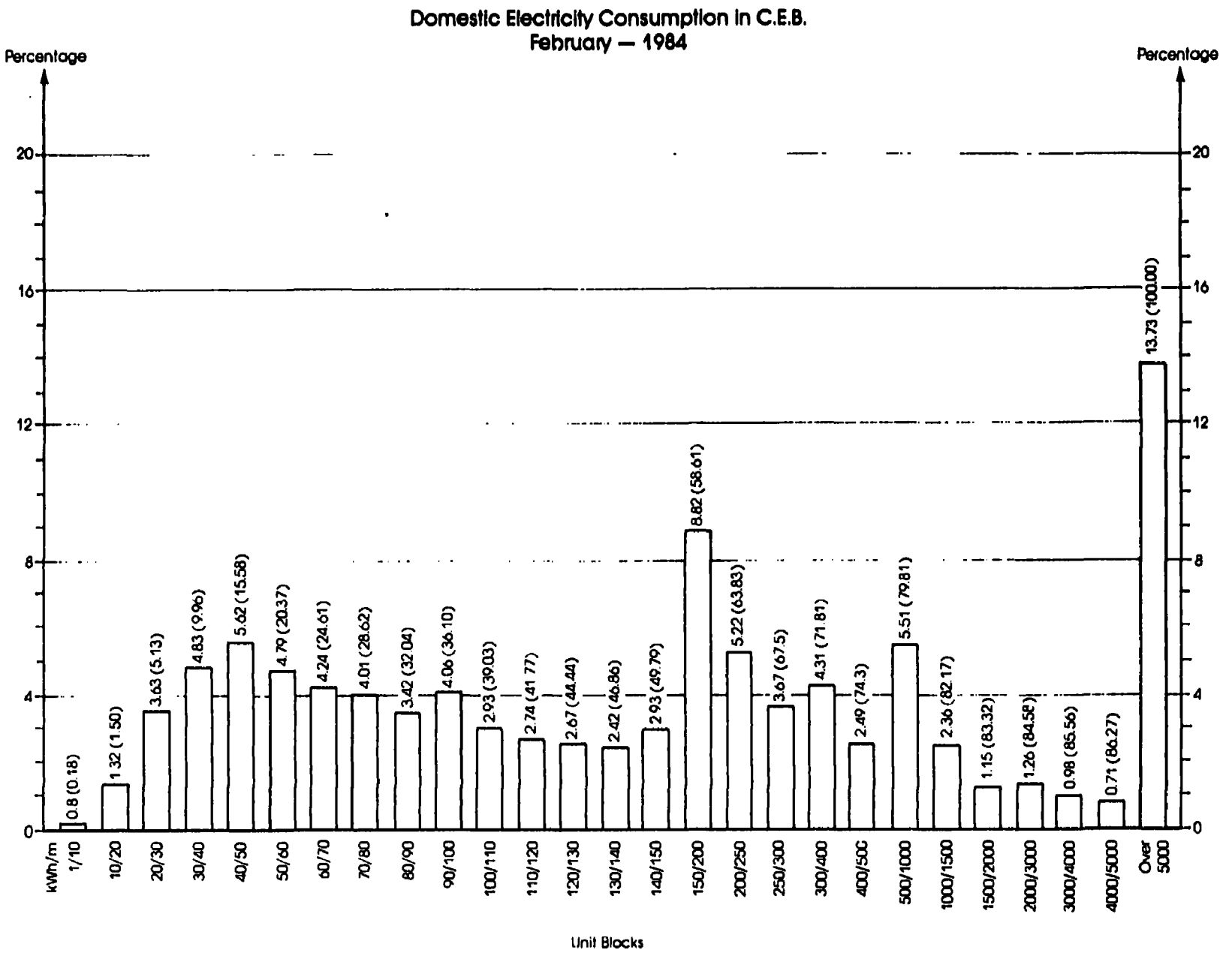
SRI LANKA

POWER SUBSECTOR REVIEW

CEB - Numbers of Consumers, Electricity Sales and Demand 1973-1985

	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
1. Number of Customers													
Residential	69,924	75,364	81,674	89,753	97,998	113,017	142,224	167,991	195,025	227,857	259,687	301,483	336,294
Commercial	19,090	20,042	20,957	22,372	24,311	26,712	31,408	34,869	37,839	41,510	44,440	48,538	50,833
Industrial													
i. High Voltage	51	55	55	56	56	61	61	61	63	70	73	73	80
ii. Medium Voltage)	2,626	2,773	2,911	2,207	3,246	3,575	3,817	4,411	5,239	6,052	6,419	6,959	7,289
iii. Low Voltage)													
Local Authorities	218	218	218	218	218	218	218	218	218	218	218	218	218
Street Lighting	152	176	219	246	249	277	323	325	319	353	358	358	358
Total Customers	92,061	98,628	106,034	114,852	126,078	143,860	178,051	207,875	238,703	276,060	311,195	357,631	395,072
2. Electricity Sales (GWh)													
Residential	82.37	82.60	86.99	95.21	106.52	118.72	153.17	190.76	216.56	258.26	304.77	316.90	339.00
Commercial	107.60	117.36	119.23	134.50	147.90	153.50	201.12	223.24	219.89	235.17	243.72	240.60	283.00
Industrial	466.58	477.98	523.41	516.50	519.44	593.30	631.75	625.62	677.54	739.17	752.02	791.00	841.00
Local Authority	193.40	201.91	222.74	237 27	252.30	276.00	296.29	335.46	380.64	417.54	433.17	458.00	499.00
Street Lighting	12.50	12.50	13.00	13.50	14.00	15.00	16.00	16.50	8.49	8.57	10.34	11.00	11.00
Hotels	-	-	-	-	-	-	-	-	-	27.28	48.30	59.00	69.00
Total Sales	867.42	892.35	965.40	996.93	1,040.66	1,161.50	1,298.33	1,391.53	1,503.13	1,685.97	1,792.32	1,876.50	2,042.00
3. Losses													
Network Losses	90.46	113.12	107.37	123.77	169.53	214.26	217.54	259.19	351.80	363.03	301.40	373.00	411.00
Station Supply	21.62	6.25	5.50	7.08	6.34	9.34	9.68	17.51	16.73	16.65	20.67	10.60	11.00
Total Losses	112.08	119.37	113.37	135.85	175.92	223.60	227.22	276.70	368.53	379.72	322.07	383.60	422.00
Losses % Generation	11.00	12.00	11.00	12.00	14.00	16.00	15.00	17.00	20.00	18.00	15.00	17.00	17.20
4. Total Revenue from Electricity Sales (M. Rs)	135.40	141.86	155.63	162.44	172.18	202.98	388.26	839.63	1,509.27	2,523.61	2,794.46		
5. Average Revenue per kWh (Rs)	0.15	0.16	0.16	0.16	0.16	0.17	0.30	0.60	1.00	1.49	1.56		
6. Maximum Demand (MW)	198.80	215.60	218.90	240.30	261.00	291.40	328.90	368.50	412.95	430.80	437.00	486.70	529.00
7. System Load Factor (%)	56.24	53.57	56.26	53.81	53.21	54.21	52.95	51.68	51.70	54.70	55.20	55.20	53.00

Source: CEB



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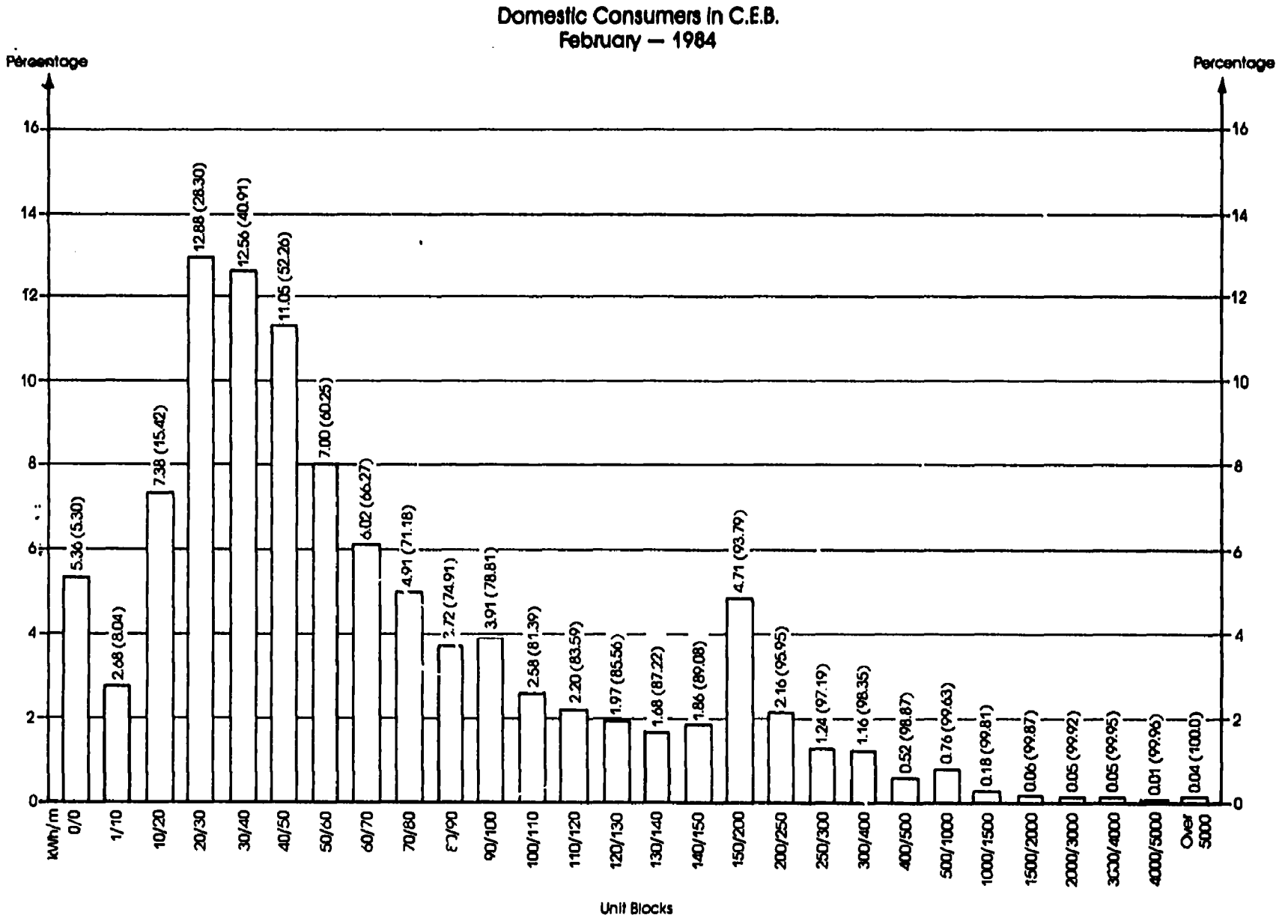
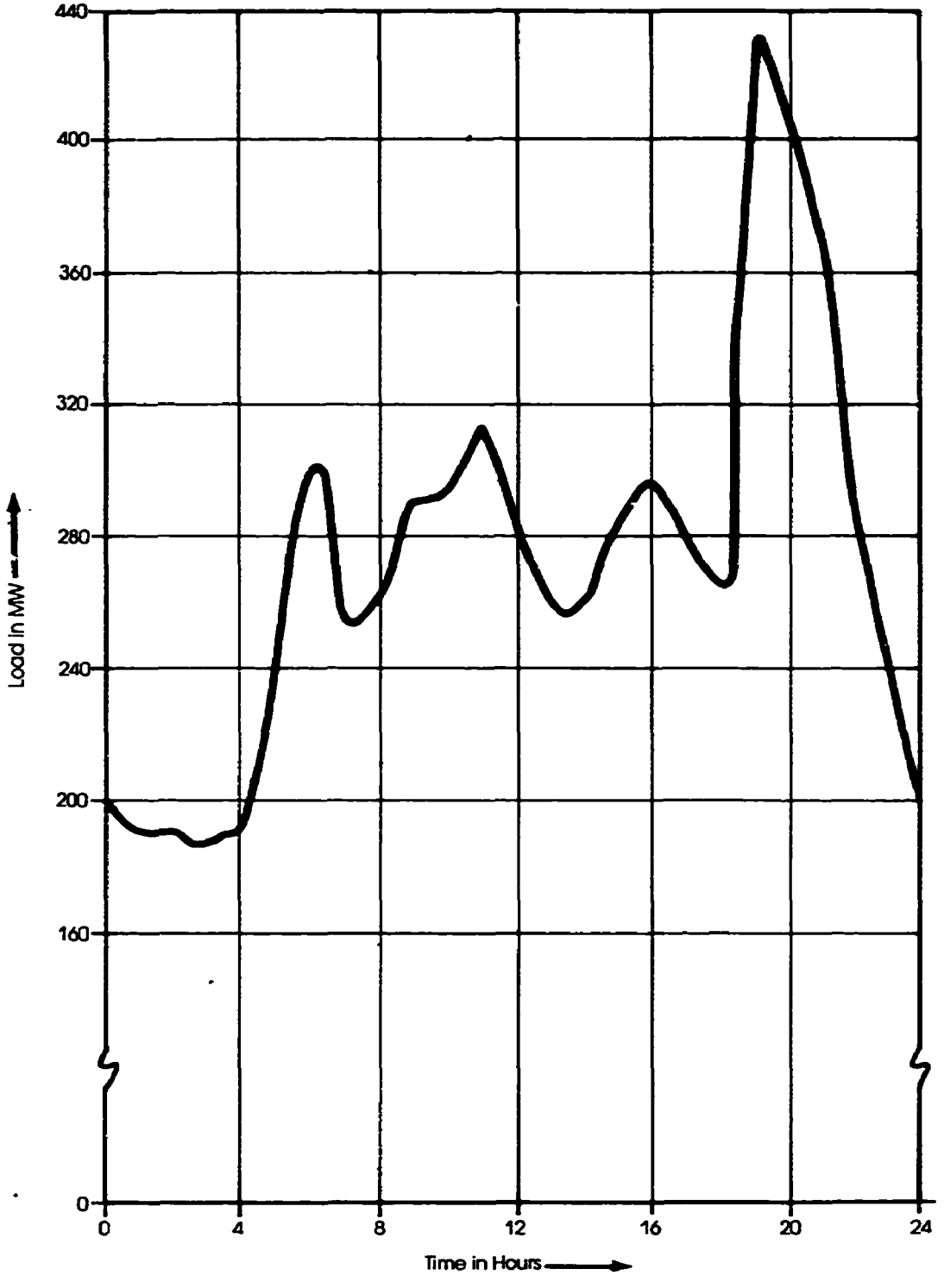


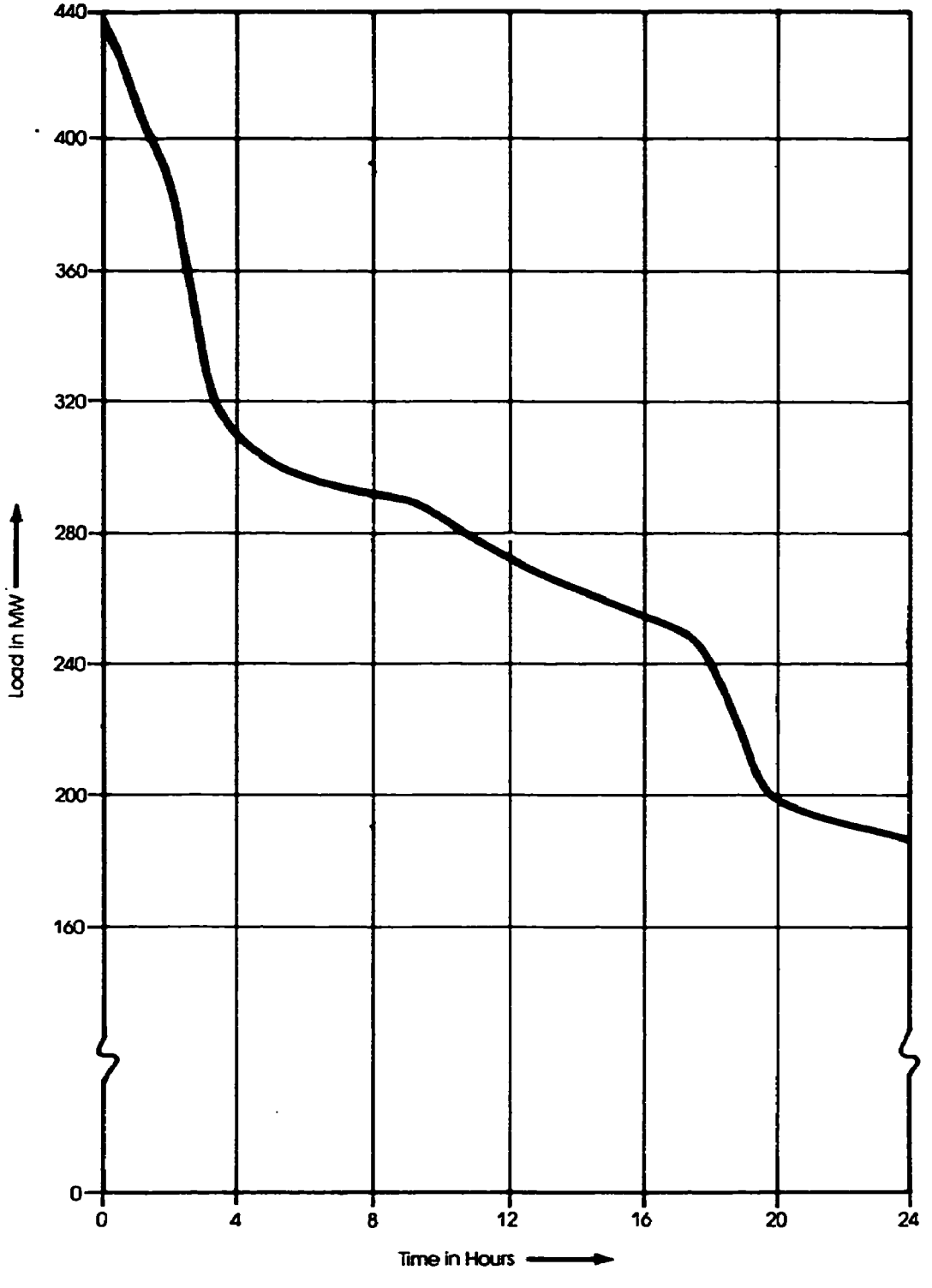
World Bank—27416

Typical Daily Load Curve
(Week Day — 1982)



World Bank—27417

Typical Daily Load Duration Curve
(Week Day — 1982)



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SRI LANKA

POWER SUBSECTOR REVIEW

Electricity Supply

A. Past Electricity Supply

Generating Capacity

1. During the last decade, there has been a significant increase in installed capacity and a noticeable change in the plant mix on CEB's supply system. Table 1 shows that total installed capacity increased from 361 MW in 1975 to 949 in 1985, equivalent to an annual growth rate of 10.2%. During this period the hydrothermal plant mix changed from 81:19 in 1975 to 72:28 in 1985. The 1984 plant mix, and the growth of capacity during the period 1975-84, are presented in detail in Attachment 1.

Table 1

GROWTH OF CEB GENERATING CAPACITY 1975-85

	1975	1979	1983	1985	Annual Growth Rate 1975-85(%)
Maximum Demand MW	219	329	437	515	8.9
Load Factor %	56	53	55	53	-
Installed Capacity MW	361	401	589	949	10.2
of which hydro MW (%)	291(81)	331(83)	399(68)	679(72)	8.8
Effective Capacity MW			433	728	-
of which hydro MW			308	568	-
of which thermal MW			125	160	-
Plant Margin (installed) MW			152	431	-
Plant Margin (effective) MW			(14)	316	-

Source: CEB

2. Attachment 1 shows that CEB's estimate of effective capacity in 1985 was 728 MW compared with a peak demand of 515 MW. CEB defines effective capacity as follows: for thermal capacity it is installed capacity minus the largest unit and 20 MW, and for hydro capacity it is installed capacity minus the sum of the largest unit, 25 MW and the capacity of any hydro stations controlled by the irrigation authorities.1/

1/ These are the 3x2 MW Uda Walawe and the 2x2 MW + 2x3 MW Inginiyagala hydro stations.

3. In a number of recent years a major problem on CEB's system has been an inadequate supply of energy. 1980, 1981, and 1983 were dry years and CEB had to introduce power cuts (equivalent to 3% of total generation in 1980, 4.6% in 1981 and 0.8% in 1983). Supply interruptions in 1983 were relatively small, largely because gas turbine capacity had been increased from 80 MW to 120 MW in 1982. These units generated 734 GWh in 1983, equivalent to 35% of total generation, at a fuel cost of Rs 2,034 million (US$86.44 million). In 1983, total fuel costs for thermal generation were Rs 2,399 million (US$101.96 million), equivalent to Rs 1.34/kWh (Annex 5). 1984 was a more normal year in terms of hydrological conditions and consequently thermal generation was only about 25% of the 1983 level. However, the electricity supply situation improved in mid-1985 when the Bank financed (Loan 2187-CE) Sapugaskanda diesel station became fully operational and the Victoria and Kotmale hydro stations are commissioned. From 1987 onwards these hydro stations are projected to provide about 1040 GWh/year of firm energy.

Losses

4. Losses, as a percentage of gross generation, on CEB's supply system increased from about 10.5% in 1975 to 17.0% in 1984 (Table 2). In 1975 losses were at the reasonable level of 10%, allowing for the fact that about 45% of CEB's total sales are sales to factories and bulk sales to licensees (local authorities).

Table 2

LOSSES IN CEB SUPPLY SYSTEM
(1975-1985)

	1975	1979	1980	1981	1982	1983	1984	1985
Generation(GWh)	1079	1526	1668	1872	2066	2114	2261	2464
Network Losses(GWh)	108	218	259	352	363	301	373	411
(%)	10.0	14.2	15.5	18.8	17.6	14.2	16.5	16.7
Station Supply(GWh)	6	10	18	17	17	21	10.6	11.0
(%)	0.5	0.6	1.0	0.8	0.8	1.0	0.5	0.5
Total Losses (GWh)	114	228	277	369	380	322	383.6	422.0
(%)	10.5	14.8	16.5	19.6	18.4	15.2	17.0	17.2

Source: CEB

Total losses are substantially higher than those recorded for CEB's system, since these exclude losses in local authorities' distribution systems. In 1985, these losses were estimated to be about 27% of CEB's bulk supply to

these authorities, that is about 135 GWh. On this basis total losses in 1984 were about 557 GWh, or about 23% of gross generation.

5. CEB's estimate of the source of these losses, including non-technical losses, in its supply system in 1982, is shown in Table 3.

Table 3

ESTIMATED SOURCE OF LOSSES ON CEB SUPPLY SYSTEM 1982

	Energy losses as % gross generation	Peak power losses as % gross generation
Power Stations & Unit Transformers	2.0	2.0
Transmission and Substations	4.5	6.0
Middle Voltage Distribution	8.0	12.0
Distribution Transformers	2.0	2.0
Low Voltage Distribution	2.0	3.5
Non-Technical Losses	1.5	-
	20.0	25.5

Source: CEB

Non-technical losses at 1.5% appear to be low, since they represent the total of thefts, meter errors (CEB does not have a program for the systematic recalibration of meters, and there are no statistics relating to meters which have been replaced for whatever reason), and meter reading and billing errors. However, CEB states that these losses have been reduced from about 3% in 1980 as a result of the detection and correction of errors (mainly wrong phasing) in bulk supply meters.

6. The problem of losses has been studied by the UNDP/World Bank Energy Sector Management Program1/ and in 1983 CEB established (under the Bank's Seventh Power Project Credit 1210-CE) a Loss Reduction Cell (LRC) to address this problem. According to both that report and preliminary analysis carried out by LRC, the principal cause of the high losses is underinvestment in medium and low voltage distribution lines resulting in overloading and poor voltage conditions, and low power factors on many lines. Studies undertaken

1/ Sri Lanka: Power System Reduction Study, Joint UNDP/World Bank Energy Sector Management Program, Activity Completion Report No. 007/83, July 1983.

by LRC indicate that relatively high rates of return could be earned on loss reduction projects for distribution systems. The projects would include investments in:

(a) reconductoring lines to larger cross sections;

(b) introduction of new lines (of larger cross sections);

(c) installation of capacitors for power factor improvement;

(d) change of voltage level and redesign of system layout;

(e) reduced L.T. coverage per transformer and an increase in the number of substations.

The Distribution and Expansion Rehabilitation Project for which CEB has requested Bank financing (as the Ninth Power Project) addresses the problem of relatively high losses.

7. The impact of these loss levels on CEB can be indicated by assessing the incremental fuel and capacity financial costs which they impose on the Board. Considering 1983, the actual gross generation of 2114 GWh would have been only 1992 GWh if losses had remained at the 1975 level of 10.5%. If the difference of 122 GWh is allocated proportionally to hydro and thermal generation (the latter was 42.4% of total generation) - which is a very conservative assumption - then thermal generation would have been lower by about 51.7 GWh, or 5.8% of total thermal generation. Since 301,000 tons of fuel were consumed in 1983 (Attachment 2), at a cost of Rs 2,300 million (US$97.75 million), fuel savings would have been of the order of Rs 133 million (US$5.7 million). The reduction in losses would have reduced system maximum demand by about 20 MW, from 437 MW to 416 MW, assuming the same system load factor of 55%. This would have given a capacity cost saving equivalent to the cost of one 20 MW unit at the new Sapugaskanda diesel station, a saving of about US$12.7 million.

8. Depending on the efficient use of water at the hydro stations (i.e. the amounts passing through the turbines and not spilled), for which no information is available, the reduction in thermal generation could have exceeded 51.7 GWh and fuel savings could have exceeded US$5.7 million. The commissioning of the Sapugaskanda diesel station, with unit fuel costs about half those of the gas turbine units, means that the fuel cost savings accompanying a loss reduction program could be less than those indicated, depending on which thermal units would be the marginal units. However, the analysis is sufficient to indicate that a loss reduction program could be accompanied by substantial savings in fuel and capacity costs. CEB commenced such a program in 1983. The Bank is supporting this program, starting with the proposed Distribution and Expansion Rehabilitation Project in FY87.

9. The foregoing analysis related to losses in CEB's supply system. On a national level it is important that action also be taken regarding losses in local authority distribution systems, where non-technical losses are believed to be much higher than on the CEB system. For example, losses in the Kotte Supply System, which has been taken over by LECO, are estimated to be in the range 30-35%, including about 15% non-technical losses. LECO has implemented a number of measures to try to reduce these losses, including using seminars and other means to change meter readers attitudes to 'errors', using the legal system to prosecute consumers found stealing electricity and publicizing the results of such prosecutions, and using new payment systems whereby consumers make payments into banks rather than to collectors. It is recommended that GOSL should initiate studies to determine the magnitude and causes of losses in local authority supply systems and that it should require local authorities to initiate effective programs to address the causes of these losses.

Fuel Efficiency

10. The use of thermal fuel was very small during the period 1970-77, but since 1978 its use has grown exponentially (Attachment 2). Thus the consumption of heavy diesel fuel increased from 38,000 tons in 1975 to 251,800 tons in 1983. In 1983 installed thermal capacity comprised the 2 x 24 MW Kelanitissa steam station and 6 x 20 MW gas turbines installed between 1980 and 1982 at the same station, and diesel stations at Pettah (2 x 3 MW) and Chunnakam (5 x 2 + 4 x 1 MW). Except for the gas turbines, the physical condition of the thermal capacity is poor. A consequence of this was that in 1983 the Kelanitissa steam units only operated at a plant load factor of 33%, generating 147 GWh. The largest load was carried by the marginally higher cost gas turbine units, which operated at a plant load factor of 77%. Data on the efficiency of the various thermal plants is given in Table 4.

Table 4

FUEL CONSUMPTION OF THERMAL PLANTS

Plant	Fuel Consumption tons/GWh	Energy Consumption Kcal/kWh	Energy Consumption Btu/kWh	Heat Rate (%)	Fuel Type
Kelanitissa					
i. steam	332	3,320	13,175	25.9	Fuel oil
ii. gas turbines	335	3,536	14,030	24.3	Diesel oil
Diesel Stations	239	2,521	10,003	34.1	Diesel oil
Average	329	3,450	13,690	24.9	

The commissioning of the Sapugaskanda diesel station (80 MW) in 1985, which is fueled by residual oil, will reduce the fuel costs of thermal generation.

It has an energy consumption of about 2,300 kcal/kWh, or about 220 tons/GWh, and a fuel cost, including some diesel oil for starting and low load conditions, of about Rs 1.2/kWh (1983 prices) compared with the average fuel cost of thermal plant of Rs 2.56/kWh in 1983.

Captive Plant

11. No reliable statistical information is available on the installed capacity of captive plant. However, in 1983, it is estimated to have been about 30 MVA (some 25 MW), and estimated to have generated about 20 GWh (Attachment 4). This generation was largely due to the extremely dry conditions which forced factories to use auto-generators to supply a significant portion of their requirements. Normally energy is purchased from CEB and captive plant remains on standby. However, the national energy balance is confusing on this matter because on the one hand it states that "Autogeneration, steam" amounted to 48.2 GWh in 1982 (twice the above 20 GWh) and on the other hand that "Fuel oil for auto generation" amounted to 21,987 tons, which is inconsistent with the generation of 48.2 GWh. It appears that the use of fuel oil for heating purposes was included in the autogeneration figure.

Transmission

12. CEB operates a countrywide primary transmission system connecting the generating stations to each other and to grid substations at the major load centers. In 1985, the transmission system was comprised of the following facilities:

Table 5

CEB TRANSMISSION FACILITIES
(1985)

kV	Facilities	km	kV	Facilities	Number	MVA
11	lines	2,500	220/132/33	Substation	3	NA
33	lines	7,800	132/66	Substation	2	NA
66	lines	286	66/33	Substation	8	84
132	lines	800	132/33	Substation	19	465
		11,391			32	

Table 5 does not include step-up transformers connected to the generators. since CEB does not record this information in its inventory list. Under the Seventh (Mahaweli Transmission) Power Project (Credit 1210-CE), 220-kV lines are being constructed to meet larger transmission capacities required to transmit the increasing Mahaweli hydro generation to the Colombo area. The

older 66-kV transmission system is expected to be replaced largely by 132-kV connections. The network is, generally, in good condition. Transmission expansion is planned by CEB's consultants since CEB has insufficient in-house expertise. It is recommended that the Planning Department should program for executing this type of work in-house, including the acquisition of the necessary computer programs. A new "control center" (which in the future can also be used as a "despatch center" for least cost operation of the system) is being commissioned.

Distribution

13. The subtransmission system of 33-kV comprises about 7100 kM of 33-kV transmission lines and about 5000 consumer substations (Table 6). The physical condition of the distribution networks is generally unsatisfactory, partly due to the fact that many of the networks are overloaded due to the large increase in the number of consumers in recent years (para. 4.04), and partly due to poor maintenance. CEB is undertaking network studies to address the problems of overloaded subtransmission and distribution systems and resulting excessive losses.

Table 6

CEB DISTRIBUTION FACILITIES
(1984)

kV	Facilities	km	kV	Facilities	Number	MVA
33	line	7,140	33/11	Substation	93	294
33	cable	9	33/3.3	Substation	10	50
11	line	1,555	6.6/3.3	Substation	6	N.A.
11	cable	109	33 or 11/ 400/230 V	Distribution Substation	4,888	844
6.6	line	1				
					4,997	1,188
6.6	cable	5				
		8,819				

CEB's management consultants, Urwick International Ltd. recommended, and CEB accepted, that each Area should prepare and maintain Plant and Equipment registers, and prepare quarterly maintenance plans. The consultant's report for December 1984 1/ showed that the implementation of maintenance plans in

1/ Ceylon Electricity Board, Report No. 81, Progress Report No.42, dated December 14, 1984.

a number of Areas was being hindered by shortages of skilled linesmen and other staff. This was symptomatic of CEB's wider staffing problem (Chapter 3). Urwick's report also drew attention to the fact that the reports prepared by some Areas related to planned maintenance work rather than to work actually carried out. Since the existing situation regarding maintenance is unsatisfactory, it is recommended that CEB should institute a regular maintenance program covering the entire distribution network. The program should include the regular inspection, including an oil test, for all transformers.

14. The management consultants (Urwick International Ltd.) who addressed CEB's general organizational and administrative/accounting problems (para. 3.04), were not instructed to study the technical-organizational aspects of CEB, which are particularly complicated in distribution. Consequently, little is known about the efficient use (or misuse) of CEB's personnel. It is recommended that a diagnostic manpower study should be made as soon as possible. This would be a necessary input for organizing the above maintenance program in conjunction with the coordinated execution of works for development. The recruitment of consulting distribution engineers may be required for the implementation of any recommendations resulting from such a manpower study.

B. Power System Planning

Institutional Responsibility

15. CEB is responsible for planning generation and transmission developments on its integrated supply system and planning distribution systems supplying nearly 400,000 consumers. However, it has had only a minimal involvement in the selection and design of hydropower projects being implemented under the Accelerated Mahaweli Program (para 2.07). All projects have to be approved by the Cabinet, while the Ministry of Finance has to agree financing plans. Although CEB's project identification and planning functions have been improved in recent years they still need considerable strengthening. The identification and appraisal of generation projects has been improved with the use of the WASP-III computer optimization model. Due to the inadequacy of CEB computer facilities this model is run on a computer at the Water Management Secretariat/Mahaweli Development Authority. This inevitably causes some problems for CEB, principally those associated with access to the model. The planning of distribution projects has recently been strengthened by the establishment of the Distribution Development and Rehabilitation Project branch of the Transmission and Generation Planning Department. However, all planning functions are hampered by a shortage of experienced planning engineers.

16. Local authorities and LECO are responsible for planning and developing the subtransmission and distribution systems which supply about 300,000

consumers. LECO's planning capability is being strengthened by an ADB technical assistance loan (para 3.17). Very little information is available on either the planning capability or future plans of local authorities.

Generation

17. Generation planning for CEB's interconnected system is now carried out using the WASP-III computer optimization model. Two generation expansion plans were prepared in 1984, one in January and the other in August, and one in September 1985. These plans have been reviewed by the Bank. The January 1984 study considered potential coal-fired, oil-fired, diesel and hydropower projects. The diesel and oil-fired projects were found to be uneconomic. Potential dual fired (oil and coal) projects were not considered. All of the studies were concerned essentially with the determination of the optimal plant mix and optimal project timing. The optimization of unit sizes was considered only for the proposed coal-fired station at Trincomalee.

18. Although the techniques being used for generation planning are well suited to CEB's supply system, its generation planning procedures suffer from a number of problems and defects. These include:

(a) A shortage of experienced staff in the system planning branch of the Transmission and Distribution Department. This has been caused by the departure of planning engineers to take up better paid positions in the Middle East and, in one case, the ADB. This is part of the more general staffing problem facing CEB (para 3.10). The existing engineer in charge of generation planning was trained at the Argonne National Laboratory with IAEA staff. He is very competent and well suited for the position which he occupies. However, he lacks support since it was only in September 1984 that two additional engineers were recruited to be trained in generation planning. There is a very real danger that CEB's developing capability in generation planning will be lost at some time in the future unless the root causes of its staffing problems are tackled quickly (para 3.11).

(b) Problems are caused by the lack of reliable cost estimates for candidate plants. This can be illustrated considering the cost estimates used for two of the major plants, the 120 MW Samanalawewa hydro project and the Trincomalee coal-fired project, in the 1984 studies.1/ The optimization studies assumed that Samanalawewa would cost Rs 5,000 million (US$1,771/kW) although the most recent assessment made by consultants (Balfour Beaty in 1984) was a cost of Rs 7,294 million (US$2,583/kW). The studies assumed that each 120 MW

1/ All the cost estimates exclude interest during construction.

unit at Trincomalee would cost Rs 5,429 million (US$1,923/kW). These costs exclude both the infrastructure costs of developing coal importing and handling facilities at Trincomalee and possible costs of flue desulphurization if these are included in the project design. It thus follows that there are various reasons for questioning the reliability of the project cost estimates used for generation planning.

(c) Although the cost estimates excluded customs duties and the costs of imports were assessed on a c.i.f. basis, no attempt was made to estimate costs in terms of shadow or accounting prices. Domestic costs were not re-expressed in terms of border prices. This could lead to some bias against hydropower projects.

(d) The planning studies suffered from the absence of a good data base on candidate hydropower projects. This should be remedied by undertaking the proposed GTZ study (para 2.08).

(e) The planning horizon used in the studies was, at 13 years, too short, and should be extended to a minimum of 20 years.1/ The choice of an optimal generating project in any year depends on future generating projects, and a relatively long time horizon is required to capture this interdependence.

(f) Long range system planning is hampered by the absence of appropriate load forecasts. The longest forecasts prepared by the commercial branch are for a period of 10 years (para 5.02). The system planning branch extrapolates this forecast using trend growth rates. Suitable long range forecasts should be prepared by the commercial branch.

(g) The generation planning studies have not included sensitivity studies, except those undertaken at the request of the Bank. This constitutes a major deficiency of the studies. Sensitivity studies should be carried out on a routine basis, and should include variations in the load forecast, load factor (a decrease to allow for the projected increase in the relative importance of the loads of domestic and local authority consumers), estimated capital costs of candidate plants, estimated fuel costs for thermal plants and the discount rate.

1/ The January 1984 study period was 1984 to 1994, while the period for the August study was 1985-2000. However, projects to be commissioned by end August 1987 were taken as being committed even if work, such as Canyon Stage II, had not been started. The effective planning period for the August study was thus 13 years.

(h) The planning studies assume that multipurpose hydro projects will be operated to give priority to electricity generation, but include expected irrigation releases as minimum releases in each season. The releases in the generation planning studies may not accord with those determined by the Water Management Panel (para 2.10). This planning problem is caused by the absence of an agreement specifying water release priorities.

Operation Planning

19. CEB uses a Deterministic Discrete Dynamic Programming (DDDP) algorithm for calculating the annual mix of thermal and hydroelectricity generation. The objective function minimizes the cost of thermal generation and includes penalties for unserved energy and irrigation demands. Assumptions are made on the system unregulated inputs, monthly irrigation requirements, reservoir initial and final operating levels, the load duration curve (LDC), generating unit forced outage probability and the stacking order for matching the operation of the generating plants with the LDC. Because of the large number of assumptions made and because the M-G Complex will grow in complexity over time and thereby make the applicability of the DDDP algorithm more difficult, this procedure does not have the same level of detail as the ARSP and MACRO procedures (Annex 2, Attachments 4 and 5). However, it is an optimization technique and is useful for framing discussions on the operation of the CEB generation system (and especially on the choice of reservoir rule curves) that would optimize system benefits.

Transmission

20. CEB's most recent long-term planning transmission development report was written in 1979, when the introduction of the 220-kV voltage level was imminent. It looked towards a first horizon in 1989, when the accelerated Mahaweli developments would be complete, and a second horizon in 1996. CEB's consultants, Preece Cardew and Rider of the UK, have since prepared several studies in connection with subsequent transmission developments, including detailed consideration of the Bank's Sixth and Seventh Power projects. Although numerous changes have been made to the 1979 report, no revised long-term plan has been produced. Transmission studies should follow closely behind generation planning. Transmission planning suffers from the combination of CEB's inability to retain competent personnel, and its reluctance to give sufficiently comprehensive terms of reference to consultants. It is, therefore, recommended that CEB's Planning Department should formulate an action program, including the identification of required staff and the acquisition of necessary computer programs, aimed at the execution of this type of work in-house.

Distribution

21. In the past distribution planning in CEB received little attention from senior management and responsibility for this was left with the engineers on the spot. Because of the general lack of training, and the rapid turnover of many staff, the results were uneven. Standard designs were not revised for many years, and were not reoptimized taking into account present day energy costs. Under the Bank's Seventh (Mahaweli Transmission Credit 1210-CE) Power Project, a loss reduction cell was formed in CEB, and US consultants Scott & Scott were employed to assist the cell. Distribution circuits are now designed with the aid of computer programs, thus ensuring the proper optimization of both new circuits and of existing circuits which are being rehabilitated.

22. Resulting from the work of management consultants, Urwick International, under the Sixth Power Project (Credit 1048-CE), the Regions have been given more autonomy and the training of their personnel has been much improved. The Regions are now responsible for all aspects of distribution, and CEB's performance in this aspect can be expected to improve, provided that CEB can offer remuneration sufficient to attract and retain competent engineering and accounting staff.

C. Future Electricity Supply

Generation

23. Total installed capacity on CEB's supply system at the end of 1985 was 949 MW, consisting of 679 MW hydro and 270 MW thermal capacity (see Attachment 1). Effective capacity 1/ was 728 MW, comprising 568 MW hydro and 160 MW thermal capacity. Available capacity should, however, increase by 328 MW by mid-1988 with the full commissioning of the Kotmale hydro project constructed under the Accelerated Mahaweli Program and the Randenigala and Canyon (Unit 2) hydro projects. The 50 MW Kelanitissa steam station which was taken out of operation for rehabilitation is planned to be recommissioned in 1989. All of these projects are considered as committed in CEB's generation expansion plan. Their commissioning in accordance with the latest estimates would mean that CEB's installed capacity would increase by 66% in the period 1984-89 and its available capacity would be increased by 72%.

1/ Effective, or available, capacity is calculated by deducting the largest unit plus 25 MW for hydro stations, the largest unit plus 20 MW for thermal stations, and ignoring the capacity of any hydro stations controlled by the irrigation authorities. Thus the 10 MW Inginiyagala and 6 MW Uda Walawe hydro stations are excluded.

24. CEB's September 1985 least cost generation program is shown in Table 7 below. The program involves the commissioning of an additional 268 MW of hydro capacity by end-1990 (30 MW Canyon, and 122 MW Randenigala projects in 1987, 67 MW Kotmale Unit 3 in 1988, and 49 MW Rantambe project in 1990). Subsequently the program involves commissioning seven coal-fired units with an installed capacity of 900 MW in the period 1991-2000 and 560 MW of hydro capacity in the period 1991-2000. During the period 1988-98 the least cost plan involves the retirement of 6 x 20 MW gas turbine units (two in 1990 and four in 1996). Allowing for plant retirements, total installed capacity is planned to more than double during the period 1990-2000, from 1,246 MW to 2,716 MW, equivalent to an annual growth rate of 8.1%. In this context the planned commissioning of 150 MW coal-fired units from 1993 onwards appears acceptable since the first unit would represent only 9.7% of total installed capacity. The planned commissioning program would result in about 58% of CEB's capacity being hydro in 2000, compared with 71% in 1985.

Table 7

CEB's LEAST COST GENERATION EXPANSION PLAN 1987-2000

Commissioning Year	Type	Plant	Installed Capacity (MW)
1987	Hydro (Unit 2)	Canyon	30
	Hydro (Unit 1 & 2)	Randenigala	122
1988	Hydro (Unit 3)	Kotmale	67
1989	Thermal	Kelantissa Recommissioning	50
1990	Hydro	Rantambe	49
1991	Hydro	Samanalawewa	120
1992	Hydro	Broadlands	20
1993	Coal (Unit 1)	Trincomalee	150
1994	-	-	-
1995	Coal (Unit 2)	Trincomalee	150
1996	-	-	-
1997	Coal (Unit 1)	Trincomalee	300
1998	Hydro	Upper Kotmale	240
1999	Hydro	Kukule	180
2000	Coal (Unit 2)	Trincomalee	300

Source: CEB

25. The least cost generation program shown in Table 7 should be regarded as simply indicative of possible developments. There are a number of reasons for this. One is that the generation study did not include adequate sensitivity analysis (para 18(g)). A second reason is that the least cost

generation program will be reassessed by Black & Vetch International as part of the ADB financed feasibility study for the Trincomalee coal-fired power station. The entire study is to be completed by mid-1987. Thirdly, the list of candidate hydro plants may change following the GTZ study (para 2.08).

26. Prompt action will be required if the commissioning dates specified in the least cost development program for the Rantambe, Samanalawewa and Trincomalee projects are to be achieved. Important decisions are still to be finalized concerning the design of the Samanalawewa hydro project. The feasibility study for the Trincomalee coal-fired power station is due for completion only in mid-1987, and project financing may not have been arranged by that date. However, the least cost study assumes that preliminary works for the period will be started in early 1988.

27. Capacity and energy balances for the least cost development program are presented in Attachments 5 and 6. The capacity balances show that, using CEB's definition of available plant, CEB will have a capacity surplus in every year 1985-1995. However, the capacity balances also show 1996 and 1997 to be critical years. The reserve plant margin in 1996 would be only 13.0%. However, CEB's system planning studies show that this is still acceptable in terms of the loss of load probability (LOLP) criterion. The capacity balances suggest that any slippage of the Rantambe project would not be critical in terms of meeting maximum demand.

28. The energy balances presented in Attachment 6 are based on CEB's estimates of firm energy. This is defined as energy available with a probability of 98% based on hydrological data for the last 30 years. Attachment 6 shows that the commissioning of the Rantambe project in 1990 is required to meet CEB's sales forecast at its selected reliability of supply level. Similarly it shows the critical importance of major new capacity being commissioned around 1993, unless there is a substantial downward revision of the load forecast.

29. Attachment 6 shows that if CEB's planting program proceeds according to the schedule established in the least cost development program, and its load forecast is correct, then it will have a minimal requirement for gas oil and heavy fuel oil in the period 1985-89. If hydrological conditions were such that only firm energy was available from hydro stations then most of the extra required energy could be generated by the Sapugaskanda diesel station. The gas turbine units would only be required to generate significant quantities of energy in 1992 and 1996. Requirements for gas oil and heavy fuel oil would, however, be minimal in average hydrological conditions in the period 1986-1991. Irrespective of the size of these requirements, CEB needs to provide more timely information on its hydrocarbon requirements to the Ceylon Petroleum Corporation (CPC) to enable CPC to improve its short-term crude oil and refined petroleum product procurement strategies. Therefore, it is recommended that CEB should inform CPC once a month of its projected

hydrocarbon fuel requirements month by month on a rolling twelve month basis. For this purpose CEB should run the NEDECO Macro Model once a month in both its operation and planning modes to give CPC its best estimate of its hydrocarbon fuel requirements for the coming month and over the coming year.

Transmission

30. Beyond completion of IDA financed 220-kV and 132-kV facilities (Credits 1048-CE and 1210-CE), planned transmission expansion is modest until the end of the decade, except for the 220-kV line required to connect the future coal fired power station at Trincomalee to the main grid, that is to the 220-kV system between the Mahaweli projects and Colombo. Although the maximum size of this plant is presently being studied, it is expected that several hundreds of MWs will be installed, requiring the extension of the 220-kV system as described above.

31. Further planned transmission expansion, until 1990, is as follows:

North. A 80 km long 132-kV line across the north-west region from Anuradhapura to the coastal area and the island of Mannar.

Center. The present 66-kV operated system between Kandy and Kurunegala is to be converted to 132-kV with a new substation at both locations and direct (in-out) supply from the existing 132-kV line running north from Polpitia to Habanara; the existing 66-kV line between Laxapana and Kandy is to be retired. Service would be extended and strengthened by the construction of a 132-kV line from Badulla (which is presently supplied by 66-kV and still has to be connected to the 132-kV system interconnecting future and existing hydro plants) to Inginiyagala in the east. The connection of the future substation at the latter location to Valachenai, along the east coast, is expected to follow soon afterwards in order to close a 132-kV ring.

South. The 132-kV line to Galle would be tapped at Balagoda for Embilipitiya and surroundings to the main system.

Substations. Many substations are reaching full load conditions and running out of reserve capacity. An extensive program of installing larger new transformers at certain substations is required, together with moving existing transformers to other substations.

32. Beyond 1990, the main development would be substantially at 220-kV. By about 1995 the overlying grid would reach from Trincomalee, via Habanara, to the Mahaweli area as a double circuit line and from there to Colombo as two double circuit lines to feed the Colombo area at two points, one north and one south of the area. A new network study is required to be completed

by about 1987, to reflect planned generation developments and the expansion of the distribution system. A preliminary five-year transmission program has been defined as follows:

(a) 220-kV lines and substations - 200 km and 2 substations appears to be a reasonable estimate of the initial extension; and

(b) 150 km of 132-kV lines, 4 new substations and 11 reinforcements of existing substations.

The physical possibilities of executing the above program within about five years appear to be reasonable since most of the work can be given to contractors and execution can be supervised by consultants.

Distribution

33. The rapid growth of domestic connections (about 15.2% a year in the period 1975-1985) is expected to continue for at least the next five years. No comprehensive distribution program to cover this massive growth has been prepared by CEB. Its efforts are presently mainly concentrated on planning for strengthening and renovation of the 33-kV system to meet future demand at reasonably low losses and reasonable standards of reliability. The question of the overall expansion at 33-kV and low tension systems will be addressed under the Ninth Power Project (para 9), together with the efficient use of manpower required for this type of work.

34. Although only preliminary information is available, the size of the necessary expansion can be measured approximately against the size of the existing 33-kV system which has a length of 7,100 km. A five-year program, excluding the ongoing IDA/Saudi financed program of 500 miles (or 800 km), would comprise about 1000 km of 33-kV lines and 600-33-kV/LV transformer stations. Because the new program would, in part, overlap the ongoing program, an average of some 300-400 km of lines would have to be constructed annually. The physical size of this requirement would severely strain CEB's organization unless basic improvements are made to it. The fact that CEB has recently been regionalized adds another dimension to this problem. The qualifications of manpower - particularly at the supervisory level - will vary widely in the regions, which could cause regional performance to vary widely. Centralized directives for planning, procurement, training and project execution will be required to improve the situation. Thus, there may be a clash between the ongoing decentralization and required centralization of some activities. Great care will have to be exercised by CEB to ensure that the regionalized organization does not lead to a lack of cohesion and of common and centrally enforced standards and practices, since that would severely tax CEB's capabilities and its overall performance with respect to distribution would be lowered.

35. A preliminary four-year distribution program for 1987-1990 is expected to comprise:

(a) construction of about 250 km of double circuit and about 550 km of single circuit 33-kV main distribution lines;

(b) construction of about 150 km of single circuit 33-kV lines, about 50 km of single circuit 11-kV lines, and about fifty 33-kV switching stations; installation of about 50 MVAR of capacitors; and strengthening and upgrading of about 500 km of 11-kV lines;

(c) installation of about 1,200 33-kV/LV and about 300 11-kV/LV distribution transformer stations and transformers, and the conversion of about 200 km of LV lines to three phase;

(d) construction of two 33-kV/11-kV and 125 11-kV/LV substations, the installation of about 15 km of 33-kV, 120 km of 11-kV and 125 km of low-voltage cables for the underground network in the city of Colombo;

(e) line materials, vehicles, tools and instruments, to rehabilitate the low voltage network; and

(f) consulting services for detailed engineering, project management, project accounting, training CEB staff in modern methods for the construction and maintenance of the distribution systems, and preparation of a distribution master plan.

36. Compared with transmission, physical constraints are expected to be large if the program has to be completed in four years. The work is extremely diverse and its smooth organization in numerous locations, together with adequate and well-timed procurement, maintenance of adequate supervision and a strongly centralized organization, is probably beyond CEB's present capabilities. Ample assistance by consultants will thus probably be necessary. This assistance is included in the Ninth Power Project.

Losses

37. CEB has projected that losses (as a percentage of gross generation) in its supply system will decrease from 18% to 12% in 1994 and thereafter, as a consequence of planned developments in low and medium voltage distribution systems. The loss levels shown in Table 8 were incorporated into CEB's 1985 load forecast (Table 5.2) and hence were a determinant of required capacity in the generation least cost development program.

Table 8

PROJECTED LOSSES ON CEB'S SUPPLY SYSTEM

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Losses % gross generation	18	18	17	16	16	15	15	14	14	12

Source: CEB

Any failure to achieve these loss reduction targets would increase CEB's capacity requirements to meet forecast load at a predetermined quality of supply. Thus, for example, CEB has forecast total sales of 3380 GWh in 1990, with an associated gross generation requirement of 3976 GWh with losses of 15% and a peak demand of 840 MW. If losses remained at the 1985 level of 18%, then the gross generation requirement would be 4080 GWh and the peak demand 862 MW. With a reserve plant margin of 25% the higher level of losses would be associated with an increased capacity requirement of 27.5 MW, and an increased energy requirement of 104 GWh. If these increased requirements were met by the installation and operation of additional diesel capacity, then the additional costs would be Rs 457.5 million (US$17.5 million) for capacity and Rs 368.1 million (US$14.1 million) for fuel in 1990, both in terms of mid-1985 prices.

D. Rural Electrification

38. Prime responsibility for rual electrification rests with CEB, although local authorities have a minimal involvement through the occasional extension of their supply systems into rural areas. The number of villages electrified each year in the period 1971-1983, together with the cost of electrification, are shown in Attachment 7. CEB's rural electrification department, headed by a project manager, is responsible for the management of the rural electrification program. The Government understands the importance of rural electrification not being undertaken in isolation, but proceeding in a coordinated way. Coodination of the various agencies, etc. concerned with rural electrification is being pursued through an inter-agency coordinating group. Its chairman is the Secretary of the Ministry of Plan Implementation, and it includes representatives from CEB, Chamber of Small Industries, and some government organizations. The group is fully cognizant of the importance of an adequate supply of finance if rural electrification is to be successful, and it is expected that it will be joined by representatives from the Bank of Ceylon, Development Bank of Ceylon, and the People's Bank.

39. An ADB-OPEC Fund project to electrify 1,150 villages by 1984 was started in 1980. Estimated foreign costs of US$17.3 million were to be met by ADB (US$11.3 million) and OPEC Fund (US$6 million) loans, while local costs

were to be funded by a GOSL grant. Due to the failure of GOSL to supply this grant, only 170 schemes had been completed by early 1983, although US$11.3 million had been spent on importing materials and equipment for the project.Following the failure of the project, a new agreement was made with ADB and OPEC Fund in early 1983 to complete about 900 rural electrification schemes by December 1986. They agreed that US$5.8 million of the US$6 million remaining from the 1980 loans should be transferred to part finance the estimated local expenditure of US$16.5 million, while GOSL agreed to contribute US$10.7 million equivalent. ADB and OPEC Fund also agreed to increase their 1980 loan commitment by US$3.8 million to meet additional foreign costs.

40. Work on the revised project began in mid-1983. However, the project is already behind schedule, although the promised funds have been made available by GOSL. The principal reason for the slow progress was the discovery that CEB's construction capability was inadequate to undertake the project. CEB proposed that this inadequacy should be overcome by using private contractors for low tension work, and this was agreed by the Cabinet. This decision, however, led to two problems. First it was found that local contractors did not have the requisite skills and experience to undertake the proposed low tension work. Consequently selected contracts will have to be supervised by CEB staff. Second, tenders for employment of the contractors exceed Rs 5.0 million and this led to delays of nearly three months, while the Cabinet considered and approved the tenders (para 3.08). The contracts were finally let in the week beginning October 1, 1984.

41. The development of rural electrification loads can have an adverse effect on system load factors due to the character of the initial loads and the importance of lighting loads. The ADB project involved the appointment (in June 1984) of a load promotion consultant in an attempt to identify and develop high load factor loads (this expert left to join the Bank in January 1985 and has not been replaced). The consultant recommended the formation of a load promotion and monitoring unit in CEB, and the recruitment of an assistant project manager, an economist and an engineer. CEB agreed to this proposal, but no appointments had been made by end-November 1984 due to the problem of identifying suitable staff. This recruitment problem is believed to be partly due to the existing salary levels and structure (para 3.11).

42. From the foregoing, it is apparent that the overall management of the rural electrification program has been weak. Some of its problems are endemic to the present organization of CEB, such as those involving delays in the award of contracts exceeding Rs 5.0 million. Other problems have been caused by Government delays in disbursing local funds. Still other problems have been caused by a shortage of requisite staff to undertake the rural electrification project, even though CEB is, when judged overall, over-staffed. The problems encountered with regard to hiring local contractors are clearly

relevant to the proposed transmission expansion and distribution rehabilitation project which the Bank has been requested to finance. Insofar as these problems are manifestations of more widespread problems existing in CEB, they could be solved if the recommendations made in paras 3.08 and 3.11 on CEB's autonomy and salaries were implemented. However, it is also recommended that the Government should disburse local funds in a timely and efficient manner in order to avoid further delays to the rural electrification program. It is further recommended that CEB set up the proposed load promotion and monitoring unit without delay in an attempt to identify, promote and develop loads which would increase overall load factors associated with the rural electrification schemes.

SRI LANKA

POWER SUBSECTOR REVIEW

ANNEX 4
Attachment 1

CEB - Electricity Supply Statistics 1975-1985

	1975	1976	1977	1978	1979	1980	1981	1982	1983		1984		1985	
Capacity Balance (MW)														
Maximum Demand	219	240	261	291	329	369	413	431	437		487		515	
Installed (and Effective Capacity)	361	401	401	401	401	421	519	589	589	(433)	719	(613)	949	(728)
of which:														
Hydro														
Old Laksapana (3x8.33 + 3x12.5)	50	50	50	50	50	50	50	50	50	(50)	50	(50)	50	(50)
Inginiyagala (2x2 + 2x3)	10	10	10	10	10	10	10	10	10	(-)	10	(-)	11	(-)
Uda Walawe (3x2)	6	6	6	6	6	6	6	6	6	(-)	6	(-)	6	(-)
Wimalasulendra (2x25)	50	50	50	50	50	50	50	50	50	(25)	50	(25)	50	(25)
Polpitia (Samanala)(2x37.5)	75	75	75	75	75	75	75	75	75	(75)	75	(75)	75	(75)
New Laksapana (2x50)	100	100	100	100	100	100	100	100	100	(50)	100	(100)	100	(100)
Ukuwela (2x20)		40	40	40	40	40	40	40	40	(40)	40	(40)	40	(40)
Bowutenna (1x30)							38	38	38	(38)	38	(38)	40	(38)
Canyon (1x30)									30	(30)	30	(30)	30	(30)
Victoria (1x70)											70	(70)	210	(210)
Kotmale (1x67)													67	(-)
Total hydro	291	331	331	331	331	331	369	369	399	(308)	469	(428)	679	(568)
Thermal														
Kelanitissa: Steam (2x25)	50	50	50	50	50	50	50	50	50	(25)	50	(25)	50	(-)
Gas turbines (6x20)						20	80	120	120	(80)	120	(100)	120	(100)
Pettah: Diesel (2x3)	6	6	6	6	6	6	6	6	6	(6)	6	(6)	6	(-)
Chunnaka: Diesel (5x2 + 4x1)	14	14	14	14	14	14	14	14	14	(14)	14	(14)	14	(-)
Sapugaskanda: Diesel (4x20)											60	(40)	80	(60)
Total Thermal	70	70	70	70	70	90	150	190	190	(125)	250	(185)	270	(160)
Plant Margin														
Capacity, installed (and effective) MW	142	161	140	110	72	52	106	128	152	(-14)	232	(126)	431	(316)
Capacity, % of installed (and effective)	39	40	35	27	18	12	20	23	26	(-3)	32	(21)	46	(38)
Load Factor (%)	56	54	53	54	53	52	52	55	55		53		53	
Generation (GWh)	1078.8	1132.8	1216.6	1385.1	1525.5	1668.2	1871.6	2065.7	2114.4		2261		2464	
of which:														
Hydro	1077.5	1108.5	1214.4	1365.8	1461.2	1479.4	1571.3	1608.1	1217.2		2091		2395	
Thermal														
Kelanitissa-steam	1.2	23.9	1.8	14.0	58.0	140.1	97.9	89.1	147.0		11.0		-	
-gas turbines						18.4	182.7	352.5	735.0		117.0		9.0	
Pettah-diesel				1.0	2.0	12.0	7.0	5.0	7.0		2.0		-	
Chunnakan-diesel	0.1	0.4	0.4	4.0	5.0	19.0	13.0	11.0	8.0		1.0		-	
Sapugaskanda-diesel											39.0		60.0	
Total Thermal	1.3	24.3	2.2	19.3	65.0	188.8	300.6	457.6	897.0		170.0		69.0	
Losses (GWh)														
Network	107.9	128.7	169.6	214.3	217.5	259.2	351.8	363.0	301.4		374.0		411.0	
Station Supply	5.5	7.1	6.3	9.3	9.7	17.5	16.7	16.7	20.7		10.6		11.0	
Total	113.4	135.8	175.9	223.6	227.7	276.7	368.5	379.9	322.1		384.6		422.0	

Source: CEB

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POWER SUBSECTOR REVIEW

PAST FUEL USAGE IN CEB POWER STATIONS 1970-1983

	1970 `000 tons	1975 `000 tons	1976 `000 tons	1977 `000 tons	1978 `000 tons	1979 `000 tons	1980 `000 tons	1981 `000 tons	1982 `000 tons	1983 `000 tons
Kelanitissa P.S. Furnace Oil	0.953 (0.221)	0.500 (0.116)	8.065 (1.871)	0.690 (0.160)	4.776 (1.108)	18.478 (4.287)	44.935 (10.425)	33.560 (7.786)	29.659 (6.881)	49.987 (11.597)
Pettah Diesel P.S. Heavy Diesel	0.038 (0.010)	0.008 (0.002)	0.004 (0.001)	0.004 (0.001)	0.352 (0.092)	0.333 (0.087)	2.720 (0.710)	1.525 (0.398)	1.130 (0.295)	1.736 (0.453)
Chunnakam Die. P.S. Heavy Diesel	10.517 (2.745)	0.031 (0.008)	0.134 (0.035)	0.084 (0.022)	0.981 (0.256)	1.138 (0.297)	4.433 (1.157)	3.295 (0.860)	2.877 (0.751)	2.096 (0.547)
Kelanitissa Gas Turbine P.S. Heavy Diesel	-	-	-	-	-	-	6.019 (1.571)	60.414 (15.768)	118.360 (30.892)	247.942 (64.713)
Total Heavy Diesel	10.556 (2.755)	0.038 (0.010)	0.138 (0.036)	0.088 (0.023)	1.333 (0.348)	1.471 (0.384)	13.172 (3.432)	65.234 (17.026)	122.368 (31.398)	251.774 (65.713)

Notes:

The figures in brackets is the Quantity of fuel in Million Gallons.

Furnace Oil - Conversion 232 Imperial Gallons = One Ton
Heavy Diesel - Conversion 261 Imperial Gallons = One Ton

Source: CEB

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POWER SUBSECTOR REVIEW

Fuel Details for CEB Thermal Power Stations - 1983

	Unit	K.P.S.	P.P.S.	C.P.S.	GT.PS.	Total
Type of Fuel Used		L.F.O.	L.H.D.	L.H.D.	L.H.D.	-
S.G. of Fuel Used		0.95	0.85	0.85	0.85	-
Cal. Value of Fuel	BTU/Lb.	18,400	19,000	19,000	19,000	-
Qty. of Fuel Used	M. Gal.	11.597	0.453	0.547	64.713	77.311
Total cost of Fuel	M. Rs.	233.474	14.540	16.863	2033.763	2298.640
Cost per Gallon	Rs.	20.13	32.10	30.83	31.43	-
Cost per kWh	Rs.	1.519	1.95	2.10	2.76	2.56
Fuel Rate/Unit Generated	Lb./kWh	0.749	0.517	0.581	0.749	-
Heat Rate/Unit Generated	BTU/kWh	13,777	9,816	11,031	14,228	-
Fuel Rate Unit Sent Out	Lb./kWh	0.827	0.530	0.618	0.749	-
Heat Rate Unit Sent Out	BTU/kWh	15,214	10,080	11,744	14,236	-
Ave. Overall Thermal Efficiency	%	24.8	34.8	30.9	24.0	-

Source: CEB

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POWER SUBSECTOR REVIEW

Private Sector - Installed Capacity and Generation

Company	Installed Capacity kVa	Generation in kWh 1983	1984 (Jan-Aug)
Thulhiriya Textile Mills	200	29,414	161,095
Associated Cables Ltd., Kalutura	1,247	84,700	22,640
Craig State Plantation	140	35,620	27,780
Lodge Hotel, Habarana	190	-	6,280
Village Hotel, Habarana	110	-	8,325
Kelani Cables, Kelaniya	455	6,328	9,407
Duro Synthetic, Kelaniya	512	10,180	5,510
Village Hotel, Sigiriya	100	-	255
Royal Air Force, Katunayake	1,000	-	5,770
Eskimo Factory	500	-	5,380
Ice Plant, Katuneriya	388	-	105,520
Ceramic Factory, Periyamulla	482	-	27,194
Browns Beach Hotel	250	-	16,830
Goldi Sand Hotel	250	-	1,840
Blue Lagoon Hotel	256	-	3,470
Kundanmals	350	-	3,470
Star Garments	500	-	19,800
Sierindo Electro Ltd.	350	-	5,820
Sugar Factory, Higurana	2,500	2,498,476	-
Powedered Milk Factory, Ambewela	2,000	-	7,250
Interfashion Company	245	-	2,750
Prima Flour Mill, Trincomalee	9,000	14,081,500	454,900
Marine Foods & Services	300	169,970	89,270
Ceylon Glass Company	500	254,882	56,323
Pegasas Reef Hotel	500	16,887	-
Blue Peacock Diamond Hotel	280	13,130	-
Lanka Milk Foods Ltd.	1,000	132,751	-
Union Carbide Ltd.	500	6,042	-
Mineral Sands Corporation	1,500	16,598	-
Sugar Factory, Kanthale	1,155	2,349,400	-
Lanka Walltiles Ltd.	1,160	316,620	-
	27,920	20,022,498	1,128,879

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POWER SUBSECTOR REVIEW

Capacity Balance

CEB June 1985 Load Forecast
(MW)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Generation																
A. Existing Plant																
Hydro	679	679	679	679	679	679	679	679	679	679	679	679	679	679	679	679
Thermal	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
B. Under Construction/Planned																
Kotmale		67	67	134	134	134	134	134	134	134	134	134	134	134	134	134
Canyon II			30	30	30	30	30	30	30	30	30	30	30	30	30	30
Randenigala			122	122	122	122	122	122	122	122	122	122	122	122	122	122
Rantambe						49	49	49	49	49	49	49	49	49	49	49
Broadlands							-	20	20	20	20	20	20	20	20	20
Samanalawewe							120	120	120	120	120	120	120	120	120	120
Trincomalee									150	150	300	300	600	600	600	900
Upper Kotmale														240	240	240
Kukule															180	180
Total Supply	929	996	1148	1215	1215	1264	1384	1404	1554	1554	1704	1704	2004	2244	2424	2424
C. Retirements/Rehabilitation	50	50	50	50	0	40	40	40	40	40	40	120	120	120	120	120
D. Outages, reserves	135	135	135	135	165	165	165	165	265	265	265	265	415	415	415	415
E. Net Capability	744	811	963	1030	1050	1059	1179	1199	1249	1249	1399	1319	1469	1709	1889	1889
F. Demand	515	595	649	707	771	840	916	996	1086	1187	1293	1403	1522	1651	1792	1944
G. Surplus/Deficit	229	216	314	323	279	219	263	203	163	62	106	-84	-53	58	97	-54

Source: CEB

Forced outages reserves are estimated as the largest hydro unit plus 25 MW and the largest thermal unit plus 20 MW. The Kelanitissa steam station was taken as unavailable in 1985, and recommissioned after rehabilitation in 1989.

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POWER SUBSECTOR REVIEW

Energy Balance - CEB June 1985 Load Forecast
(GWh)

YEARS	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Gen. required	2815	3017	3345	3648	3975	4334	4727	5153	5616	6118	6639	7202	7812	8479	9198
HYDRO															
K-M Complex	1406	1406	1406	1406	1406	1406	1406	1406	1406	1406	1406	1406	1406	1406	1406
Ukuwela - Bowatenna	214	214	214	214	214	214	214	214	214	214	214	214	214	214	214
Victoria	702	702	702	702	702	702	702	702	702	702	702	702	702	702	702
Kotmale	339	339	339	339	339	339	339	339	339	339	339	339	339	339	339
Randenigala	-	352	352	352	352	352	352	352	352	352	352	352	352	352	352
Rantambe	-	-	-	-	192	192	192	192	192	192	192	192	192	192	102
Broadlands	-	-	-	-	-	-	91	91	91	91	91	91	91	91	91
Samanalawewa	-	-	-	-	-	431	431	431	431	431	431	431	431	431	431
Upper Kotmale	-	-	-	-	-	-	-	-	-	-	-	-	413	413	413
Kukule	-	-	-	-	-	-	-	-	-	-	-	-	-	386	386
Total Hydro	2661	3013	3013	3013	3205	3636	3727	3727	3727	3727	3727	3727	4140	4526	4526
Thermal required	154	58	332	635	770	698	1000	1426	1889	2391	2912	3475	3672	3953	4672
THERMAL															
Diesels	154	58	332	540	540	540	540	466	540	471	540	-	-	193	-
KPS Steam	-	-	-	95	230	158	302	-	302	-	302	-	-	-	-
KPS GTS's	-	-	-	-	-	-	158	-	87	-	150	-	-	-	-
Coal I (150MW)	-	-	-	-	-	-	-	960	960	960	960	960	960	960	960
Coal II (150MW)	-	-	-	-	-	-	-	-	-	960	960	960	960	960	960
Coal III (300MW)	-	-	-	-	-	-	-	-	-	-	-	1555	1752	1840	1840
Coal IV (300MW)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	912
Total Thermal	154	58	332	635	770	698	1000	1426	1889	2391	2912	3475	3672	3953	4672
Total Generation	2815	3071	3345	3648	3975	4334	4727	5153	5616	6118	6639	7202	7812	8479	9198
Deficit	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Note: i) Plant Factors: Gas Turbine 0.69
Diesel 0.77
Coal Steam 0.70

ii) Energy Balance is based on firm energy plus 25% of Secondary Energy.

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POWER SUBSECTOR REVIEW

CEB Rural Electrification Program

Year	No. of Villages Electrified	% of Total Villages Electrified in Year	Actual Expend. Rs.
1970			
1971	52	0.208	2,803,243
1972	59	0.236	5,080,377
1973	66	0.264	6,376,758
1974	101	0.404	9,304,801
1975	116	0.464	12,847,032
1976	168	0.672	18,474,451
1977	166	0.664	23,835,871
1978	272	1.088	34,761,795
1979	481	1.924	88,817,621
1980	312	1.248	48,561,174
1981	314	1.256	51,690,696
1982	570	2.280	
1983	457	1.828	91,300,000/-
1984			77,400,000/- up to June

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POWER SUBSECTOR REVIEW

ELECTRICITY PRICING

A. Institutional Responsibility for Tariffs

1. Tariff setting is the responsibility of organizations selling electricity, namely CEB, local authorities and, since June 1984, LECO. CEB has a bulk supply tariff for sales to licensees (218 local authorities, including five which have been taken over by LECO) and retail tariffs. The 218 local authorities do not have the technical capability to determine their own tariffs. Consequently, they tend to adopt CEB tariff structures, although their rates may differ from those in corresponding CEB tariffs. However, LECO's functions include the establishment of a consultancy service to assist other licensees in setting tariffs. All proposed changes in tariff structures and rates have to be approved by the Government, whose responsible officer is the Chief Electrical Inspector.

B. Historical Review

2. CEB's tariff rates were unchanged between April 1972 and December 1978. However, the average tariff rate was increased by about 75% in December 1978, about 110% in October 1980, about 42% in June 1982, and about 80% in March 1985. These increases were accompanied by significant changes to tariff structures. The 1978 tariff revision included a fuel adjustment charge (para 21), which was first activated in February 1980.

3. Table 1 shows that the average revenue received by CEB from electricity sales increased, in nominal terms, at an average annual rate of about 17% during the period 1970-1985. In real terms, however, the increase was only about 7%. Dividing the period into two sub-periods, 1970-1978 and 1978-1985; in the former period real electricity prices fell at an average annual rate of about 4%, while in the latter period they increased at the average annual rate of about 20%. Thus, during the period 1970-1978 electricity tariffs failed to signal to consumers increases in real energy costs.

Table 1

CEB AVERAGE REVENUE FROM ELECTRICITY SALES 1970-1985
(Rs/kWh)

	Without FAC Current Prices	With FAC Living Index	Cost of a/ 1970 Prices	With FAC Year Index	
1970	0.14	0.14	100.0	0.140	100
1971	0.14	0.14	102.7	0.136	97
1972	0.15	0.15	109.1	0.137	98
1973	0.15	0.15	119.7	0.125	89
1974	0.16	0.16	134.4	0.119	85
1975	0.16	0.16	143.5	0.112	80
1976	0.16	0.16	145.2	0.110	79
1977	0.16	0.16	147.0	0.109	78
1978	0.17	0.17	164.8	0.103	74
1979	0.30	0.30	182.6	0.164	117
1980	0.37	0.60	230.2	0.261	186
1981	0.59	1.00	271.6	0.368	262
1982	0.78	1.49	301.1	0.495	354
1983	0.84	1.56	343.1	0.455	325
1984	0.78	1.66	400.3	0.415	296
1985	1.51	1.51	406.1	0.372	266

a/ Colombo Cost of Living Index.

4. CEB's financial performance deteriorated during the period 1970-1978, largely due to the fact that tariffs were unchanged throughout this period. Its after tax rate of return on revalued average net fixed assets in use fell from 6.9% in 1974 to 2.1% in 1978. Subsequent increases in tariff rates, and the activation of the fuel adjustment charge in February 1980, improved the rate of return to 9.4% in 1980 and 11.4% in 1981. The rate of return fell to 5.6% in 1983, partly due to a heavy income tax liability which CEB had underestimated when setting tariffs for that year. The March 1985 tariff increase was instrumental in raising the rate of return to about 9.5% in 1985.

C. Economic Costs of Supply

Long-Run Marginal Cost

5. The economic cost of electricity supply with the efficiency objective is equal to the short-run marginal resource cost. However, when a supply system is in equilibrium, and there are no significant indivisibilities, this cost is equal to the long-run marginal cost (LRMC). It is frequently argued that LRMC is the appropriate basis for electricity tariffs because it leads to relatively stable tariffs and contains the information required for consumers' investment decisions. The following discussion is in terms of this base.

6. LRMC is derived from the least cost program for the development of the power subsector. It refers to the increase in capital and operating costs (generation, transmission and distribution) needed to meet future demand for additional kW and kWh. LRMC thus has two principal elements. First, the cost of 1kW of demand sustained into the future, which is essentially the capital and fixed operating costs of expanding system capacity. Second, the cost of an extra kWh of energy at each time of the day and year, which consists mainly of the fuel costs of incremental generation. The costs of meeting in increment of demand can be broken down into the costs of generation, transmission and distribution.

7. Demand related costs can be estimated in a number of different ways. A widely used method which recognizes the lumpiness of investment in power facilities is the calculation of the long-run average incremental cost (LRAIC), which is taken as a proxy of LRMC. This method is particularly suitable for the calculation of demand related costs of transmission and distribution. An alternative, and preferable method, for the calculation of marginal capacity costs of generation is to use a computer model (such as WASP) to optimize the least cost generation program twice; first under base case load conditions, and second, with a constant incremental load added to the base case load. The difference in the discounted present values of the cost streams of the resultant two optimized planting programs can be used to derive the marginal costs of generation. An advantage of this second approach for utilities using generation planning models is that investment and pricing decisions are made on a consistent basis.

CEB Tariff Studies

8. In recent years, CEB has carried out two LRMC tariff studies, one in 1981 and one in 1984. 1/

1/ CEB agreed under Credit 1048-CE to carry out a LRMC tariff study, with technical assistance from the Bank, and to implement any findings.

9. 1981 Tariff Study. The 1981 study estimated marginal capacity costs of generation as the weighted average (50:50) annuitized costs of the planned Canyon II hydropower station (to be commissioned in 1987)and planned additional gas-turbine capacity at the Kelanitissa station (to be commissioned in 1982). It should be noted that the inclusion of the costs of the gas-turbine capacity was technically incorrect since it was committed capacity and thus its costs were, to a large extent, bygones. The marginal capacity costs of transmission and distribution were estimated using the LRAIC method. Marginal energy costs were estimated for the period 1982-1989. Throughout this period peak energy was assumed to be generated by gas-turbine plants. These plants were also assumed to supply marginal off-peak energy in the period 1982-1984, but thereafter this energy was assumed to be supplied by new diesel capacity and base load hydropower plants.

10. LRMC was estimated for different voltage levels, peak and off-peak times of the day, and for different consumer categories. The latter estimates utilized assumptions on diversity factors and average load factors for the different consumer groups. CEB did not have an adequate data base on consumer characteristics and thus had to estimate the diversity and load factors. The main results of this study are summarized in Table 2. The estimates have not been adjusted to allow for CEB's financial and social objectives.

Table 2

PRINCIPAL RESULTS OF CEB 1981 TARIFF STUDY

Consumer Marginal Category	Marginal Capacity Costs Rs/kW/month	Marginal Energy Costs Peak Rs/kWh	Marginal Energy Costs Off-Peak Rs/kWh	Total Rs/kWh
Bulk Supplies				
HV (all consumers)	132	0.45	2.34	1.42
2.05				
MV Industrial	178	0.47)		2.18
General Purpose	167	0.41)	2.59	1.49
Hotels	202	0.55)		2.27
Licensees	202	0.47)		2.43
				2.63
LV Industrial	41	0.23)		1.88
General Purpose	136	0.46)	2.87	1.57
Hotels	246	0.55)		2.24
Licensees	246	0.36)		2.83
				3.15

Source: CEB.

11. 1984 Tariff Study. CEB prepared a new LRMC study in 1984. Although CEB was using WASP-III for generation planning in 1984 it did not use this model to estimate marginal capacity costs of generation. Instead it used the same LRAIC method as was used for the 1981 study.

12. Marginal capacity costs of generation were estimated with reference to the average annual cost (Rs/kW/year) of four hydro plants scheduled to be added to the supply system in the period 1985-1990. The capacity costs of these hydro plants were estimated after allocating a variable proportion of their capital costs to energy production. The plants and cost figures used in the study were as follows:

Commissioning Date	Plant	Capacity Cost Rs/kW/year	Average Capacity Cost Rs/kW/year
1985	Victoria Stage II	1,585	
January 1986	Kotmale 3rd Set	497	
January 1988	Rantambe	1,642	1,306
1990	Samanalawewa	1,499	

The first two of these projects were committed and firm and thus should not have been used in the LRMC calculations, which are concerned with bringing capacity forward to meet a permanent demand increment. Financing for the Rantambe project had not been arranged in 1984 and it could not be brought forward to meet an increase in forecast load. The marginal project, in the sense that it would be brought forward in a revised least cost generation program and could be constructed earlier was either Samanalawewa or the first unit of the proposed coal-fixed station at Trincomalee (estimated capital cost of Rs 3,802/kW/year). The capacity cost for incremental generating capacity used in the 1984 tariff study was thus probably too low.

13. The 1984 tariff study did not estimate the marginal capacity costs of supplying different consumer groups. The Bank has reviewed and revised the CEB tariff study and extended it by estimating these costs using the 1981 study assumptions on consumer characteristics. Table 3 shows estimated bulk supply marginal capacity costs (generation, transmission, consumer substations and distribution) on three different bases; CEB 1984 tariff study, that study modified to make Samanalawewa the marginal generating station, and that study modified to make the first 150 MW unit at Trincomalee the marginal station.

Table 3

ESTIMATED MARGINAL CAPACITY COSTS
Rs/kW/month

Bulk Supply	Diversity Factor	CEB Study	CEB Samanalawewa	Bank Trincomalee
HV	1.10	189	248	482
MV				
Industry	1.25	283	337	574
General Purpose	1.33	266	317	539
Hotels	1.10	323	383	652
Licensees	1.10	323	383	652
LV				
Industry	6.67	77	88	140
General Purpose	2.00	258	293	468
Hotels	1.10	470	531	850
Licensees	1.10	470	531	850

Source: Based on CEB data.

14. These costs have been used to derive marginal capacity costs in terms of Rs/kWh, which are presented in Table 4.

Table 4

ESTIMATED MARGINAL CAPACITY COSTS
(Rs/kWh)

Bulk Supply	Load Factor /a	Diversity Factor	Study	Samanalawewa /b	Bank Trincomalee
HV	0.40	1.10	0.64	0.85	1.65
MV					
Industry	0.47	1.25	0.83	0.98	1.67
General Purpose	0.41	1.33	0.89	1.06	1.80
Hotels	0.55	1.10	0.81	0.95	1.62
Licensees	0.47	1.10	0.94	1.12	1.90
LV					
Industry	0.23	6.67	0.46	0.52	0.83
General Purpose	0.46	2.00	0.77	0.87	1.39
Hotels	0.55	1.10	1.17	1.32	2.12
Licensees	0.36	1.10	1.79	2.02	3.23
Retail					
LV					
Domestic	0.27	1.10	2.38	2.69	4.27
Industry	0.30	20.00	0.12	0.13	0.21
General Purpose	0.40	10.00	0.18	0.20	0.32
Street Lighting	0.50	1.00	1.42	1.60	2.56

Source: Based on CEB data.

/a These are the load factors assumed by CEB. They do not appear to be consistent with a system load factor of 55%. There is thus a need to improve the data base used in tariff studies.

/b Total cost of the Samanawewa project assumed to be that given in 1984 tariff study, which is Rs 7,500 million, with 43.2% (Rs 3,240 million) allocated to capacity and 56.8% allocated to energy.

Marginal Energy Costs

15. Marginal energy costs in the 1984 study were estimated assuming that marginal generation would be from diesel sets in both peak and off-peak periods in both wet and dry seasons throughout the study period (1985-1991). CEB's recent generation planning studies show, as would be expected, that the marginal thermal plant is a function of assumed hydrological conditions. Analysis on the basis of firm hydro availability shows that marginal plants

in both wet and dry seasons will be gas turbines, at least until 1991. Similar analysis shows that gas-turbines will be the marginal plants in the dry season if the output from hydro stations is taken as firm plus 25% of secondary energy. The generation planning studies show that diesel will be the marginal plants, as assumed in the tariff study, if the output of hydro stations is calculated at the 70% probability level.

16. Estimated marginal energy costs are given in Table 5 on two bases; first, the 1984 study basis and, second, with marginal generation from gas-turbines, as is forecast when hydro conditions correspond to firm energy plus 25% of secondary energy, or worse. The difference between peak and off-peak energy costs in the tariff study is due solely to the difference in peak and off-peak energy losses.

Table 5

ESTIMATED MARGINAL ENERGY COSTS /a
(Rs/kWh)

	1984 CEB Tariff Study		Alternative	
	Peak	Off-Peak	Peak	Off-Peak
At Generation	1.44	1.44	3.11	1.44
HV Level	1.53	1.50	3.31	1.50
MV Level	1.68	1.57	3.61	1.57
Cons. SS	1.71	1.59	3.68	1.59
LV Level	1.88	1.66	4.05	1.66

Source: CEB tariff study.

/a The costs are in terms of domestic prices. Border prices have been divided by 0.9 in line with the assumption made in the tariff study.

17. Marginal energy costs in the 1984 study were estimated using pragmatic reasoning and data from energy balance tables. In the absence of more sophisticated analytical methods this is a perfectly acceptable approach. However, CEB is now using WASP-III for generation planning (Annex 4). The technical data, including the economic cost of fuel by plant type, used in the WASP optimization runs can be adopted for the determination of marginal energy costs (which are basically short run marginal costs — SRMC) using the Reliability and Cost Model for Electrical Generation Planning (RELCOMP) computer model. A simple description of the RELCOMP model is given in Attachment 1.

18. RELCOMP is a detailed production cost and reliability model that provides hourly computations of LOLP and expected unserved energy (EUE), as well as hourly energy production and cost data. Marginal energy costs can be estimated by running RELCOMP using base case hourly load data for one or more reference years and then repeating the runs with a marginal increase (say 2-3%) in the hourly loads. The SRMC of energy would then be calculated as:

$$SRMC_t = \frac{C_t^1 - C_t}{G_t^1 - G_t}$$

where:

$SRMC_t$ = short run marginal energy cost for period t

C_t = variable cost of generation in period t for base case

G_t = the generation in time t (kWh) for base load case

C_t^1 = variable cost of generation in period t for increased load case

G_t^1 = the generation in time t (kWh) for increased load case

19. The use of the RELCOMP model would enable marginal energy costs to be estimated for different times of the day and year for selected years. These estimates would be consistent with data used to determine optimal additions to generating capacity on the CEB system. However, CEB does not have the RELCOMP model. It is thus recommended that the Bank either undertakes or funds a study using RELCOMP to estimate marginal energy costs on CEB's system. The study would be undertaken in recognition of the needle peak problem in CEB's system and the need for any revised tariff structures to be stable and endure for a number of years. It is further recommended that a CEB officer should be associated closely with this study in order to include a requisite training element.

D. Existing Tariff Rates

CEB Tariffs

20. CEB's tariffs which were introduced in June 1982 following the completion of the 1981 tariff study are shown in Table 6. The economic philosophy underlying the tariff studies was that tariff structures and rates should be stable in order to provide consumers with the long-run cost information required to make investment decisions. In practice CEB tariffs have failed to signal this long-run information to consumers. A principal reason for this has been the policy decision that published tariff rates should be based on the assumption that all generation will be from hydropower plants

and that any costs from thermal generation would be recouped through fuel adjustment charges (para 21). Although this policy decision gave stable published tariff rates, these rates were not consistent with long-run marginal cost pricing. Reliance on the fuel adjustment charge in the form used in the period October 1980 to May 1982 was inconsistent with both short and long-run marginal cost pricing since consumers were only informed of the price of electricity after they had made their consumption decisions. The signalling function of the price mechanism would be improved if:

Table 6

Tariff Structure and Rates March 1984

Tariff Category	Voltage Specification	Block kWh/month	Basic Energy Charge Rs/kWh	Fuel Adjustment	Rate Including 185% Fuel Adj. Rs/kWh	Demand Charge Per Month	Minimum Charge Per Month
1. Domestic		0 - 50	0.40	x	0.40	x	R10
		51 - 150	0.80	x	0.80	x	R10
		151 - 500	0.80		2.28	x	R10
		500+	1.00		2.85	x	R10
2. Charitable			0.40	x	0.40	x	R10
3. Street Lighting			0.80		2.28	x	
4. Bulk Supply to Licensees	L.1 400V or less	(1)	0.30	x	0.30	R50/kVA of MD	R30/kVA of AD
		(2)	0.50	x	0.50		
		(3)	0.55	x	0.55		
		(4)	0.55		1.57		
	L.2 Above 400V	(1)	0.30	x	0.30	R45/kVA of MD	R30/kVA of AD
		(2)	0.50	x	0.50		
		(3)	0.55	x	0.55		
		(4)	0.55		1.57		
5. General Purpose	GP.1 400V or less and MD < 50 KVA		0.70		1.995	x	R120 upto AD 10kVA then R100+R60/kVa above 10kVa
	GP.2 400V or less and MD > 50 kVA		0.65		1.853	R125/kVA of MD	R60/kVA of AD
	GP.3 400V +		0.60		1.71	R115/kVA of MD	R55/kVA of AD
6. Industrial	I.1 400V or less and MD < 50 kVA		0.65		1.85	x	R100 up to AD 10kVA then R100+R50/kVA above 10kVA
	I.2 400V or less and MD > 50 kVA		0.60		1.71	R100/kVA of MD	R50/kVA of AD
	I.3 400V +		0.52		1.48	R90/kVA of MD	R45/kVA of AD
7. Hotels	H.1 400V or less and MD < 50 kVA		0.70		1.995	x	R120 upto AD 10kVA then R100+R60/kVA above 10kVA
	H.2 400V or less and MD > 50 kVA		0.85		2.42	R150/kVA of MD	R75/kVA of AD
	H.3 400V +		0.80		2.28	R140/kVA of MD	R70/kVA of AD

Notes and Definitions

1. The first block of units equals 120% of the sum of units used per month by domestic consumers consuming up to 50 units per month plus 120% of 50 units times the number of domestic consumers consuming above 50 units a month at a basic rate of 30 cents a unit.

2. The second block of units equals 120% of the sum of units used in excess of 50 units/month by domestic consumers consuming in excess of 50 units and up to 100 units/month plus 120% of 50 units times number of domestic consumers consuming above 100 units/month at a basic rate of 50 cents a unit.

3. The third block of units equals 120% of the sum of units in excess of 100 units/month by domestic consumers consuming in excess of 100 units and up to 150 units/month plus 120% of 50 units times the number of domestic consumers above 150 units a month at a basic rate of 55 cents a unit.

4. Fourth block of units consisting of all units purchased each month by the licensee in excess of the units in the First, Second and Third Blocks at a basic rate of 55 cents a unit plus the applicable fuel adjustment charge.

MD = maximum demand

AD = assessed demand

X = fuel adjustment charge not appl

(a) published tariff rates were related to the supply system which is expected to exist; and

(b) a regular and relatively short period, say one year, tariff revision cycle is instituted.

It is thus recommended that CEB adopts, with GOSL approval, an annual cycle under which it reviews and, if necessary, revises tariff rates and relates published tariff rates to the estimated fuel costs for forecast hydrological conditions in the year to which the rates would apply. The adoption of these recommendations would reduce some of the problems which have been experienced with the operation of the fuel adjustment charge and would improve the signalling function of the price mechanism.

Fuel Adjustment Charge

21. Published tariff rates have been derived on the assumption that all CEB's generation is from hydropower plants, although this is known to be a false assumption. Since February 1980 fuel costs from operating thermal plants have been recouped from sales in specified tariff categories through the use of a fuel adjustment charge (FAC). the history of the FAC since October 1980 is shown in Table 7.

Table 7

FUEL ADJUSTMENT CHARGE
(%)

Month/Year	1980	1981	1982	1983	1984	1985
January		70	225	110	185	150
February		110	210	110	185	150
March		125	241	110	185	0
April		195	283	110	185	0
May		160	186	110	185	0
June		85	110	110	150	0
July		45	110	110	150	0
August		15	110	185	150	0
September		45	110	185	150	0
October	23	65	110	185	150	0
November	50	35	110	185	150	0
December	60	130	110	185	150	0

22. In the period October 1980 to May 1982 the FAC was calculated monthly by dividing the total fuel costs of generating thermal units in a month by the total selling price of units in that month for which the FAC was applicable, and multiplying by 100 to express the result as a percentage. The FAC was applied retrospectively and often varied substantially from month

to month. A consequence of this was a failure of the price mechanism to signal appropriate cost information to electricity consumers subject to the FAC, since they did not know how much each kWh cost until after they had made their consumption decision. Following customer complaints regarding fluctuations in the FAC the basis on which it was calculated was changed with the introduction of new tariffs in June 1982. The charge was now based on estimated fuel costs for a period three years ahead, and was estimated to be 110% for the period 1982-1984 with average hydrological conditions. Actual conditions in 1983 were below average and CEB once again changed the basis for calculating the FAC. CEB estimated that a rate of 225% was required in 1983 to recover thermal fuel costs, but considered this to be unacceptable to consumers and instead set the charge at 185% from August 1983. In June 1984 the rate was reduced to 150% following good hydrological conditions and a substantial reduction in the use of thermal plant. This rate was to be maintained at least until December 1984, although it was considerably in excess of the fuel costs being incurred by the CEB, in order to recoup the under recovery of fuel costs which occurred in 1983. The FAC was set at zero for at least twelve months following the introduction of the new tariff in March 1985 (Table 8).

23. Fuel adjustment charges can be an effective way of passing unanticipated increases in fuel costs on to consumers with a minimum of delay. This both enables consumers to be given up-to-date information on relative energy prices (which is consistent with an efficient allocation of resources) and protects a utility's financial position, especially when procedures to change published tariff rates are protracted. However, CEB's FAC policy has given undue attention to its financial consequences to the neglect of its effects on the signalling function of the price mechanism. The prime cause of this has been the failure to include estimated fuel costs in average hydrological conditions in published tariff rates. Therefore, it is recommended that published tariff rates relate to the estimated fuel costs for forecast hydrological conditions in the year to which the rates would apply.

24. At the present time the FAC is not applied to charitable (religious) consumers, to the first 150 kWh/month used by domestic consumers, and to most of the bulk sales to licensees (Table 8). The exemption limit for sales to domestic consumers has fluctuated over time. It was set at 50 kWh/month in the 1978 tariff, raised to 200 kWh/month in the 1980 tariff and reduced to 150 kWh/month in the 1982 tariff. The exemption limit meant that the FAC was paid by only about 11% of domestic consumers in 1983. However, these consumers used about 50% of total units sold to domestic consumers.

25. The FAC effectively introduced a second lifeline rate (the second block) into the 1982 tariff. The smaller is the proportion of sales on which the FAC is levied the larger is the required charge on each kWh to which it is applied. In addition, as can be seen from Table 8, with an increasing block tariff the fewer are the blocks on which the charge is levied the larger will be the difference in marginal tariff rates between adjacent blocks. It is understood that one cause of non-technical losses is collusion

TABLE 8

CEB TARIFF - EFFECTIVE FROM MARCH 1, 1985

DOMESTIC — First 30 units @ Rs. 0.50 cts. per unit
31 — 150 units @ Rs. 0.90 cts. per unit
151 — 500 units @ Rs. 1.80 cts. per unit
Above 500 units @ Rs. 2.25 cts. per unit

Minimum Charge for a month is Rs. 5/-.

Fuel Adjustment Charge when in operation is applicable on units in excess of 150 per month.

For a period of 12 months from 1985-03-01, the Fuel Adjustment Charge is zero percent.

RELIGIOUS & CHARITABLE INSTITUTIONS— 50 cents per unit.

No Fuel Adjustment Charge.

Minimum Charge for a month is Rs. 5/-.

OTHER CATEGORIES

	General Purpose	*Industrial*	*Hotels*	*Industrial (Time of Day)*	*Hotels (Time of Day)*
Supply at 400/230V. Contract demand less than 50 kVA					
Unit Charge (Rs./Unit)	1.70	1.55	1.70	—	—
Fixed Charge (upto 10 kVA.). (Rs.)	+ 20.00 or	+ 20.00 or	+ 20.00 or	—	—
Fixed Charge (above 10 kVA.) (Rs.)	100.00	100.00	100.00	—	—
Supply at 400/230V Contract Demand 50 kVA and above					
Demand Charge (Rs. kVA.)	125.00	100.00	150.00	50.00	50.00
Unit Charge (Rs. Unit)	— 1.60	— 1.45	— 1.60	— 1.35 (Off Peak) — 1.90 (Peak 6 pm. to 9 pm.)	— 1.35 (Off Peak) — 1.90 (Peak 6 pm. to 9 pm.)
Fixed Charge (Rs.)	— 200.00	— 200.00	— 200.00	— 200.00	— 200.00
HT Supply at 11kV 33 kV. and 132 kV.					
Demand Charge (Rs. kVA.)	115.00	90.00	140.00	45.00	45.00
Unit Charge (Rs. Unit)	— 1.50	— 1.25	— 1.50	— 1.20 (Off Peak) — 1.75 (Peak 6 pm. to 9 pm.)	— 1.20 (Off Peak) — 1.75 (Peak) 6 pm. to 9 pm.)
Fixed Charge (Rs.)	— 200.00	— 200.00	— 200.00	— 200.00	— 200.00

NOTE : For the 12 months period from 1985-03-01, the Fuel Adjustment Charge will be zero percent.

The Fuel Adjustment Charge will be expressed as a percentage and is applicable on the Unit Charges only.

The Fuel Adjustment Charge when in operation shall apply to all General Purpose, Industrial and Hotel consumers.

between consumers and meter readers to avoid reporting consumption above 150 kWh/month due to the high marginal tariff rate on incremental consumption. It is thus recommended that the increase in effective marginal tariff rates (with FAC) for domestic consumers be smoothed out by introducing a FAC of one-half the full rate on the second consumption block.

Lifeline Rates

26. Tariffs for supply to domestic consumers and to licensees incorporate lifeline rates. The domestic tariff is shown in Table 9. The tariff is of the increasing block type with substantial increases occurring at the margin of adjacent blocks, especially between the second and third blocks. With a zero fuel adjustment charge the tariff would incorporate only a single lifeline rate (Rs 0.50/kWh), but when the fuel adjustment charge is levied the tariff, in effect, contains a second lifeline rate in the second consumption block. It is thus important to consider whether the sizes of these blocks have been well chosen.

Table 9

CEB 1985 DOMESTIC TARIFF

Consumption Block/Month kWh	Basic Rate Rs/kWh	Fuel Adjustment Charge Applicable
0 - 30	0.50	No
31 - 150	0.90	No
151 - 500	1.80	Yes
500+	2.25	Yes

27. Lifeline rates are justified in terms of an equity or income distribution objective. Their purpose is to enable low income consumers, who are equated to small consumers, to afford the electricity required to meet their basic needs. The definition of these needs is arbitrary, but is generally considered to cover lighting and perhaps the use of a fan. One 60W bulb used for four hours a day uses 7.30 kWh/month. Assuming that two bulbs are each used for four hours a day, about 15 kWh/month are required for lighting. Allowing for one fan total monthly requirements for basic needs would be about 20 kWh.

28. When determining the size of the lifeline block (or blocks) it is important to remember that the benefit of the low price to cover basic needs is received by all domestic consumers, including those with very large monthly consumption. In 1983 average monthly consumption by domestic consumers was about 95kWh. CEB analysis of February 1984 billing data for domestic consumers (Annex 3, Attachment 3), showed that 15.4% used no more

than 20 kWh/month, 52.3% no more than 50 kWh/month and 89.1% no more than 150 kWh/month. Analysis for that month also showed that about 1.5% of total domestic consumption was accounted for by consumers using no more than 20 kWh/month, 16% by those using no more than 50 kWh/month, and 50% by those using no more than 150 kWh/month (Annex 3, Attachment 2).

29. The preceding sales analysis data can be used to indicate which consumers receive the greatest monetary benefit from the lifeline rate. The following analysis assumes that the sales distribution data derived for February 1984 is applicable to the 1983 sales data. The February 1984 distribution data is applied to 1983 data on total sales to domestic consumers and number of consumers in Table 10.

Table 10

ANALYSIS OF 1983 SALES TO DOMESTIC CONSUMERS

	Sales to Domestic Consumers MWh		Number of Consumers		Average Consumption kWh/month
A. Totals					
Total 1983		297,465.0		259,678	95.46
up to 20kWh/m	(1.5%)	4,462.0	(15.4%)	39,990	8.96
up to 50kWh/m	(16%)	47,594.4	(52.3%)	135,812	29.20
up to 150kWh/m	(50%)	148,732.5	(89.1%)	231,373	53.57
B. Increments					
up to 20kWh/m	(1.5%)	4,462.0	(15.4%)	39,990	8.96
20 to 50kWh/m	(14%)	41,645.0	(36.8%)	95,562	43.58
50 to 150kWh/m	(34%)	101,138.1	(36.8%)	95,561	88.20
more than 150kWh/m	(50%)	148,732.0	(10.9%)	28,305	437.88

30. Part B of Table 10 shows that the average monthly consumption of consumers using less than 20kWh/month was about 9kWh, and for consumers using more than 20kWh/month but less than 50kWh/month was about 44kWh, and so on. A lifeline rate which is applicable to all consumers in a tariff category always confers greater absolute monetary benefits on larger consumers, since their consumption is sufficiently large to take advantage of all the units sold at the lifeline rate. Thus part B of Table 10 shows that the average consumer using more than 50kWh but less than 150kWh/month consumed about 88kWh/month, 50kWh of which was at the subsidized lifeline rate, compared with the 9kWh/month which was subsidized for the average consumer using no more than 20kWh/month.

31. If the size of the first block is too large, then not only is relatively more monetary benefit given to large consumers, but in addition the smaller is the number of kWh sold at prices reflecting marginal costs. The preceding analysis suggests that the size of the first block is too large. It is recommended that it be reduced to 0-20kWh/month. It is also recommended that the size of the second block should be reduced to 20-75kWh/month, which would be sufficient to allow for the use of a small refrigerator, a black and white television set and additional lighting. In terms of this recommendation, it is important to note that CEB reduced the size of the lifeline block from 50kWh/month to 30kWh/month in the March 1985 tariff (Tables 6 and 8).

Comparison of CEB Tariffs with LRMC

32. 1981 Tariff Study and 1982 Tariff. Tariff levels in the revised 1982 tariff were determined considering CEB's financial objectives, the need for prices to signal resource cost information to consumers (the efficiency objective) and the requirement that tariff levels should be consistent with GOSL's social objectives (the equity objective). The tariff rates which were selected in accordance with the requirements of this multiple objective function are compared with the 1981 tariff study estimates of marginal costs in Table 11. This table shows that while demand charges in the 1982 tariff were generally too low they were substantially too high for LV industrial consumers. Demand charges in the tariff were between 18% (for LV bulk supply) and 83% (for LV general purpose) of estimated marginal capacity costs. Energy rates in the tariff were between 11% (first block in the domestic tariff and for charitable consumers) and 41% (for HV hotels) of estimated marginal energy costs.

Table 11

COMPARISON BETWEEN 1981 TARIFF STUDY AND JUNE 1982 REVISED TARIFF RATES

Consumer Category	Tariff Study: Energy Costs Peak Rs/kWh	Tariff Study: Energy Costs Off-peak Rs/kWh	Tariff Study: Energy Costs Weig.Av. Rs/kWh	Tariff Study: Capacity Costs Rs/kWh/month	Revised Tariff: Energy Rates Rs/kWh	Revised Tariff: Energy Costs with 110% FAC /1 Rs/kWh	Revised Tariff: Energy Costs with 185% FAC /2 Rs/kWh	Revised Tariff: Demand Charge /3 Rs/kWh/month
HV	2.34	1.42	1.60	132	-	-	-	-
MV								
1. Industrial)			1.66	178	0.52	1.09	1.48	81
2. General Purpose)			1.71	167	0.60	1.26	1.71	104
3. Hotels)	2.59	1.49	1.93	202	0.80	1.68	2.28	126
4. Bulk Supply)			2.04	202	0.55 *	1.16 *	1.57	41
LV								
1. Industrial)			1.64	41	0.60	1.26	1.71	90
2. General Purpose)			1.83	136	0.65	1.37	1.85	113
3. Hotels)	2.87	1.57	2.22	246	0.85	1.79	2.42	135
4. Bulk Supply)			2.22	246	0.55 *	1.16 *	1.57	45
5. Domestic								
0-50 kWh/month				3.52	0.44	0.40	1.14	0
151-500 kWh/month					0.80	2.28	2.28	0
500 kWh/month +					1.00	2.85	2.85	0

Notes:
1. Applicable in the period June 1982 to July 1983
2. Applicable in the period August 1983 to May 1984.
3. The demand charges have been calculated assuming a power factor of 0.9.

* The energy rates shown are the marginal rates applicable to bulk sales in the fourth block to licensees. Most of the sales to licensees are made at rates which exclude the fuel adjustment charge.

33. The gap between estimated marginal energy costs and energy rates in the tariff was partially closed for some tariff categories by the 110% fuel adjustment charge which was operative in the period June 1982 to July 1983. Allowing for this charge effective energy rates ranged from 87% of estimated marginal costs for HV hotels to 57% for HV bulk supply. With the raising of the fuel adjustment charge to 185% in August 1983 effective energy charges to some consumer groups exceeded estimated marginal energy costs (for both HV and LV hotels, and LV industrial and general purpose). For MV general purpose consumers effective rates equalled estimated marginal energy costs.

34. A number of points should be noted about the effect of the fuel adjustment charge on closing the gap between estimated marginal energy costs and effective tariff rates. First, the comparison assumes that the marginal energy costs which were estimated in 1981 were relevant to the system operating conditions encountered by CEB in 1983 and 1984. In fact this assumption was almost certainly false; the severe draught conditions prevailing in 1983 were not anticipated in the 1981 tariff study. Marginal energy costs in 1983 were almost certainly higher than those estimated in the tariff study. Second, the fuel adjustment charge is calculated on an average rather than a marginal basis and thus it is not relevant for the calculation of marginal costs. Third, following from the previous point, any resemblance between effective rates (with FAC) and published rates is purely accidental. Fourth, the estimated marginal energy costs were calculated on a long-run basis while the fuel adjustment charge was, at best, calculated on a medium-run basis. Fifth, the fuel adjustment charges which were applied from 1983 to December 1984 (185% then 150%) did not correspond to the calculated fuel costs of running thermal plants. For policy reasons (para 22) the FAC was first set below these estimated costs and later above them. These policy reasons were not concerned with equating effective energy rates with estimated marginal energy costs. Sixth, the FAC was only applied to some tariff categories with the result that there were substantial differences between tariff rates and estimated marginal costs for the unaffected tariff categories.

35. A notable feature of the results of the 1981 tariff study was the appreciable difference between estimated peak and off-peak energy costs. Thus, for LV consumers peak marginal energy costs were estimated to be Rs 2.87/kWh and off-peak marginal energy costs to be Rs 1.57/kWh. These cost differences were not incorporated into the tariff for any consumer groups. The failure of the tariff to signal the difference between peak and off-peak costs may be one of the reasons for the exacerbation of the needle peak problem facing CEB (Annex 3, para 14).

36. 1984 Tariff Study and Existing Tariff Rates. In the absence of appropriate detailed studies there is considerable uncertainty regarding LRMC of supply on CEB's system. The following comparison of existing tariffs and 1984 estimates of LRMC (Table 12) is probably on the conservative side. It assumes that Samanalawewa is the marginal station (and that 43.2% of its investment costs are allocable to capacity), and that marginal energy costs can be calculated with reference to diesel plants. The LRMC estimates have

not been adjusted to conform to CEB's financial and social objectives. The energy rates are the rates published in the March 1985 tariff (Table 8) and assume a zero fuel adjustment charge.

37. Table 12 indicates that basic energy rates in the existing tariff are typically around 95% of estimated off-peak marginal energy costs. Demand charges are between 6% (LV licensees) and 114% (LV industrial) of estimated marginal capacity costs. The existing tariff for bulk supply to licensees is badly out of line with estimated LRMC. The deviations of tariff rates from LRMC shown in Table 12 would almost certainly change if CEB had a better data base on consumer characteristics, and it is recommended that CEB initiates the studies and other activities required to improve this data base. However, an improved data base would not change the general picture of tariff rates being below LRMC.

Table 12

COMPARISON BETWEEN 1985 TARIFF LEVELS AND LRMC

	1985 Tariff		Energy		
	Energy	Capacity	Peak	Off-Peak	Capacity
	Rs/kWh	Rs/kWh/month	Rs/kWh	Rs/kWh	Rs/kWh/month
Consumer Type					
MV					
Industrial	1.25	90	1.68	1.57	337
General Purpose	1.50	115	1.68	1.57	317
Hotels	1.50	140	1.68	1.57	383
Licensees	1.35	25	1.68	1.57	383
LV					
Domestic	0.5-2.25	0	1.88	1.66	2.69/kWh
Industrial	1.45	100	1.88	1.66	88
General Purpose	1.60	125	1.88	1.66	293
Street Lighting	1.60	0	1.88	1.66	1.60/kWh
Hotels	1.60	150	1.88	1.66	531
Licensees	1.35/a	30	1.88	1.66	531

/a The energy rate for licensees is that applicable in the fourth block of the tariff.

Licensee Tariffs

38. CEB provides bulk supplies to 218 licensees, including five which have been taken over by LECO. Each licensee can set its own tariffs subject to the approval of the Chief Electrical Inspector. In practice, it is understood, the structure of licensees' tariffs are based on those of the CEB, although their rates may differ from those in comparable CEB tariffs. Copies

33. The gap between estimated marginal energy costs and energy rates in the tariff was partially closed for some tariff categories by the 110% fuel adjustment charge which was operative in the period June 1982 to July 1983. Allowing for this charge effective energy rates ranged from 87% of estimated marginal costs for HV hotels to 57% for HV bulk supply. With the raising of the fuel adjustment charge to 185% in August 1983 effective energy charges to some consumer groups exceeded estimated marginal energy costs (for both HV and LV hotels, and LV industrial and general purpose). For MV general purpose consumers effective rates equalled estimated marginal energy costs.

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of licensees' tariffs are held by the Ministry of Power and Energy. The Bank has reviewed the 1984 tariffs of two licensees, Kotte and Negambo Municipality. These are analyzed and discussed below.

39. LECO Tariff. LECO's existing tariff was taken over from Kotte Urban Council, the only council which had joined LECO by December 1984. Kotte's tariff is presented in Attachment 2. A worked example of CEB's monthly bill to Kotte U.C. is presented in Attachment 3. The following discussion utilizes data given in those attachments.

40. Licensees purchase bulk electricity under a rate structure based on CEB's retail tariff. Selected parts of CEB's 1984 retail tariff, bulk supply tariff and retail prices of Kotte U.C. as adopted by LECO are presented in Table 13. The bulk supply prices are those applied to supplies delivered and metered at 400V or less (Rate L.1).

Table 13

COMPARATIVE CEB AND LECO ELECTRICITY PRICES IN 1984
(Rs/kWh)

Tariff Category	CEB 1984 Bulk Supply Tariff	16.7% Losses /b	20% Losses /c	30% Losses /d	LECO 1984 Retail Tariffs	CEB 1984 Retail Tariffs
1. Domestic						
0-50 kWh/month	0.30	0.38	0.44	0.69	0.40	0.40
51-100 kWh/month	0.50	0.62	0.68	0.93	0.60	0.80
101-150 kWh/month	0.55	0.68	0.74	0.99	0.60	0.80
151-500 kWh/month /a	1.375	1.67	1.73	1.98	2.00	2.00
Over 500 kWh/month /a	1.375	1.67	1.73	1.98	2.00	2.50
MD charge	50.00/kVA	/e	/e	/e	-	-
2. General Purpose 1						
Energy /a	1.375	1.65	1.72	1.97	1.88	1.75
Assessed MD up to 10 kVA					60 min.	60 min.
Assess MD over 10 kVA	50/kVA	50/kVA	50/kVA	50/kVA	60/kVA	60/kVA +R 120
3. General Purpose 2						
Energy /a	1.375	1.65	1.72	1.97	1.75	1.625
MD charge	50/kVA				125/kVA	125/kVA
4. Street Lighting /a	1.375	1.67	1.73	1.98	2.00	2.00

Notes: /a Includes the fuel adjustment charge of 150%.
/b Cost to LECO = bulk tariff x 1.2 MD charge, see note /e.
/c Cost to LECO = bulk tariff x 1.2 + (0.05 x 1.375) MD charge, see note /e.
/d Cost to LECO = bulk tariff x 1.2 + (0.23 x 1.375) MD charge, see note /e.
/e MD charge of Rs 50/kVA at average power factor 0.9 and load factor 0.5, peak losses equal average energy losses.

Sources: CEB, LECO and Bank estimates.

41. CEB's tariff for licensees allows for 20% losses measured as the ratio of bulk supply point purchases to retail sales (e.g. 120:100). This level of losses corresponds to losses of 16.7% when losses are measured by

the ratio of LECO retail sales to bulk supply point purchases (e.g. 100:120). In 1985 LECO estimated that its total losses (on the basis of sales in terms of purchases) were at least 30% (130:100). This level of losses is equivalent to losses of 43% measured on the basis of bulk supply purchases over retail sales (143:100).

42. Losses in excess of the level allowed for in the bulk supply tariff are in effect paid for by the licensee at the marginal rate in the tariff, which was Rs 1.375/kWh in 1984 allowing for the fuel adjustment charge of 150%. Thus LECO, with total losses of about 30%, in effect bought 23% losses (43%-20%, measured on basis of purchases over sales) at a marginal cost of Rs 1.375/kWh. This had the effect of increasing substantially the cost of electricity purchased by a licensee. Consider the first block in the bulk supply tariff. The basic tariff rate was Rs 0.30/kWh. Allowing for 20% losses the cost became Rs 360/kWh. Incremental losses (to make total losses equal to 43%) cost 0.23x1.375=Rs 316/kWh. The total energy cost was thus Rs 0.676/kWh. Demand charges must be added. The maximum demand charge in the bulk supply tariff was Rs 50/kVA. If the coincidence factor for domestic consumers is 1, power factor 0.9 and load factor 0.5 (which is probably too high), and, for simplicity, peak losses are assumed to equal average energy losses 1/, then with 30% losses the demand charge was equivalent to Rs 0.018/kWh. The total cost to LECO of each unit purchased in the first block was thus Rs 0.694. Other entries in Table 13 were derived in a similar manner.

43. Table 13 shows that LECO made a loss on each unit sold under the 1984 general purpose tariff and on sales below 150kWh/month under the domestic tariff. These losses occurred before LECO's own costs were added to the bulk supply costs. The table also shows that LECO only just covered bulk supply costs for sales above 150kWh/month under the domestic tariff and on all sales under the street lighting tariff. Allowing for its own costs LECO's sales under these tariffs were probably made at a loss.

44. Negambo Municipality Tariff. Negambo municipality's 1984 tariff schedule is presented in Attachment 4, and monthly sales in the different tariff categories in 1983 are presented in Attachment 5. Losses (sales over purchases) in the Negambo distribution system are estimated to be 23% (equivalent to 30% on the basis of purchases over sales). Table 14 compares Negambo Municipality tariffs with the 1984 costs of bulk supply from CEB. It can be seen that, with the exception of the first block in the domestic tariff, Negambo's tariff rates exceeded bulk supply costs and provided a margin to cover the municipality's own costs of supply.

1/ Although this assumption understates peak losses, it only causes a small error (affecting the third decimal place with 30% losses) in the cost calculations.

Table 14

COMPARATIVE CEB AND NEGAMBO MUNICIPALITY ELECTRICITY PRICES
(Rs)

Tariff Category	CEB 1984 Supply Tariff	Cost to Negambo/Unit Sold 16.7% Losses /b	Cost to Negambo/Unit Sold 23% Losses /c	Negambo 1984 Retail Tariff	CEB 1984 Retail Tariff
1. Domestic					
0.50 kWh/month	0.30	0.38	0.52	0.50	0.40
51-100 kWh/month	0.50	0.62	0.75	0.90	0.80
101-150 kWh/month	0.55	0.68	0.81	0.90	0.80
151-500 kWh/month/a	1.375	1.67	1.80	2.25	2.00
Over 500 kWh/month/a	1.375	1.67	1.80	2.50	2.50
MD charge	50/kVa	/d	/d		
2. Religious	0.30	0.38	0.52	0.50	0.40
3. General Purpose 2					
energy /a	1.375	1.65	1.79	2.00	1.75
MD charge	50/kVA			130/kVA	125/kVA
4. Industrial 2					
energy /a	1.374	1.65	1.79	2.00	1.50
	50/kVA			130/kVA	125/kVA
5. Hotel 3	1.375	1.65	1.79	2.00	2.00
energy /a	50/kVA			15/kVA	140/kVA
MD charge					

/a Includes fuel adjustment charge of 150%.
/b Cost to Negambo = bulk tariff x 1.2 plus MD charge - see note /d.
/c Cost to Negambo = bulk tariff x 1.2 + (0.099 x 1.375) + MD charge (note /d).
/d MD charge of Rs 50/kVA at average power factor of 0.9 and load factor of 0.5, assuming peak losses equal average energy losses.

Source: CEB, Negambo Municipality and Bank estimates.

45. Adequacy of Licensee Tariffs. Analysis of the 1984 tariffs of two licensees indicates that the level of tariff rates for one was inadequate (LECO-Kotte) but adequate for the other. Information is required on a reasonable sample of licensee's tariffs before firm conclusions can be reached as to whether inadequate tariffs are a contributory factor to arrears

owed by licensees to CEB. It is recommended that the Bank's future sector work should address the issue of licensee tariffs.

E. Structure of CEB Existing Tariffs

46. Existing CEB tariffs include simple flat rate tariffs for religious and street lighting consumers, increasing block tariffs for domestic consumers, increasing block with a demand charge for licensees, and separate demand and energy charges for general purpose, hotel and industrial consumers, and optional time-of-day tariffs for hotel and industrial consumers.

47. Consumers in each tariff category pay the full costs of connection; for domestic consumers this is around Rs 3,000 and in rural electrification schemes is around Rs 1,000. In addition domestic consumers pay about another Rs 1,000 for house wiring to contractors.

48. Some features of the existing tariffs are consistent with charging consumers the costs which they impose on the supply system. This is most noticeable with respect to connection charges. To a lesser extent it also occurs by charging for demand in terms of kVA instead of kW since this gives an incentive to improve power factors.

49. There are, however, a number of problems associated with the structure of existing tariffs, the most important of which are: (i) the absence of time of day pricing; and (ii) tariffs for licenses.

Time-of-Day Pricing

50. Existing CEB tariffs fail to signal to consumers the different energy costs which their consumption causes the supply system to incur at different times of the day. The 1981 tariff study estimated peak and off-peak energy costs for MV consumers to be Rs 2.59/kWh and Rs 1.49/kWh respectively, with a larger difference at the LV level. None of the 1982 tariffs which were introduced following this study included time-of-day kWh charges. Although the March 1985 tariff includes optional time-of-day prices for industrial and hotel consumers it does not give them an incentive to reduce peak demand. The peak energy rate in the optional tariffs is less than the sum of the energy rate in the standard tariff plus the kWh equivalent charge estimated as the difference between the demand charges in the two tariffs. Thus, consumers opting for the time-of-day tariff will: (a) reduce the size of their monthly bill, and (b) not be subject to an effective incentive to reduce peak demand.

51. There is considerable uncertainty regarding potential differences in peak and off-peak energy costs in the period 1985-1991 (paras 16 and 17). However, there is no doubt that marginal capacity costs are higher than those reflected in existing tariff rates and that these costs are demand related. Many consumers are charged for capacity on a kVA basis. From a demand management point of view the effectiveness of this charging basis depends on

the relative timing of the consumer's maximum demand and that of the supply system. Demand management is likely to become more important as the CEB system grows. Recognizing these various factors CEB should consider introducing time of day tariffs for, say all MV consumers with the exception of licensees. The peak rate should include some capacity costs. Remaining capacity costs would be recouped through maximum demand changes using kVA metering in order to give consumers continued incentives to improve power factors.

52. Time-of-day metering could also be applied to other consumer groups. Domestic consumers are believed to be largely responsible for the existing evening peak. Although it is clearly not socially acceptable, or economic, to have time-of-day pricing for the majority of domestic consumers, it could be both socially acceptable and economic to introduce it for large domestic consumers. Monthly billing data for February 1983 (Annex 3, Attachments 2 and 3), shows although only 1.65% of domestic consumers used more than 300 kWh/month these consumers used about 28% of all kWh billed to domestic consumers. The costs of introducing time-of-day meters for these consumers would be relatively low, but the use of these meters could have an impact on both the pattern and amount of electricity consumed by domestic consumers. It is thus recommended that CEB consider introducing time-of-day metering for large domestic consumers. Its introduction for other consumers, such as MV consumers with the exception of licensees, is strongly recommended.

Tariffs for Licensees

53. The bulk supply tariff for licensees is designed to enable licensees with losses of 20% in their distribution systems to charge the same tariff rates to their domestic consumers as are charged by CEB to its domestic consumers. This explains the increasing block design of the bulk supply tariff. This tariff structure does not reflect the marginal costs of meeting demand from licensees. The bulk supply tariff structure raises a fundamental question with regard to tariff setting by CEB. The question is whether CEB should signal relevant marginal cost information to bulk supply consumers so that they have the appropriate information upon which to design their own tariffs (since they are responsible for tariff setting), or whether CEB should assume that it knows best and thus sets bulk supply tariff rates which enable bulk supply consumers to apply CEB retail tariffs to their own consumers.

54. This question would be easy to answer if the electricity supply industry was reorganized on the lines discussed in chapter 3, i.e. CEB responsible for generation and transmission and a separate organization (or organizations) responsible for distribution. In these circumstances, CEB tariffs should be designed to signal appropriate cost information to the distribution organizations. At the present time the answer to this question is complicated by the fact that, in general, licensees do not have the expertise to design their own tariffs based on cost information contained in a bulk supply tariff. The analysis of the LECO retail tariffs (paras 39-43)

shows the problems which some licensees are encountering. The dominant objective in CEB's present decision regarding the bulk supply tariff for licensees appears to be that of equity in the sense of trying to ensure that similar consumers face similar tariffs irrespective of the organization responsible for retail sales. However, comparison of the tariff rates charged by LECO and Negambo Municipality (Tables 13 and 14) shows that there are substantial differences in tariff rates for similar consumers. This may be interpreted as prima facie evidence of CEB failure to achieve this equity objective. This failure would support argument for CEB to revise its bulk supply tariff rates to reflect costs of supply.

F. Future Tariff Policy

55. Electricity pricing in Sri Lanka should be considered against the background described above, the main elements of which are described below:

(a) although there is considerable uncertainty regarding the calculation of LRMC there is little doubt that CEB tariff rates and (probably those of licensees) are below LRMC for all classes of consumer;

(b) an increase in basic tariff rates is required to enable CEB to earn a minimum rate of return on revalued net assets of 8% in 1986;

(c) the structure of tariffs does not conform to the costs incurred on CEB's supply system when meeting consumer's demands. There is no effective time-of-day pricing;

(d) published tariff rates have not been related to the energy costs which CEB expects to incur in average hydrological conditions. These rates should be related to the supply system which is expected to exist. Tariff setting could be improved with the adoption of an annual tariff revision cycle;

(e) too much reliance has been placed on the operation of the fuel adjustment charge;

(f) the lifeline blocks in CEB's domestic tariff appear to be too large;

(g) tariffs used by some licensees, with rates below supply costs, may be a contributing factor to the arrears owed by many licensees to CEB.

56. There appear to be five main objectives for electricity pricing in Sri Lanka:

(a) to ensure the financial viability of CEB and the licensees;

(b) to encourage the least cost supply of electricity from the national viewpoint;

(c) to mobilize resources to finance investment;

(d) to ultimately bring the price of electricity into line with LRMC; and

(e) to ensure that electricity prices are equitable and socially acceptable.

57. It is recommended that the Government implements a strategy to achieve these objectives. The strategy should address points (a) to (g) raised in paragraph 55. The priority elements in this strategy are described below.

58. The present Tariff Structure does not provide incentives to shift peak demand to off-peak periods. It is recommended that:

(a) time-of-day tariffs should be introduced for all MV consumers, with the exception of licensees;

(b) time-of-day tariffs should be introduced for large (say about 300 kWh/month) domestic consumers;

(c) CEB should carry out load research to improve its data base on consumer characteristics as a prerequisite of improving its estimates of LRMC; and

(d) CEB should consider using a model such as RELCOMP to improve its estimates of marginal energy costs.

59. Tariff levels should be increased to enable CEB to meet its financial objectives, including earning funds to finance planned investments.

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POWER SUBSECTOR REVIEW

Simple Description of RELCOMP Model

1. The Reliability and Cost Model for Electrical Generation Planning, RELCOMP, is a system planning tool that assesses the reliability and economic performance of electric utility generating systems. Given input information such as capacity, forced outage rate, number of weeks of annual scheduled maintenance, specific maintenance dates (optional), and economic data for individual units, along with the expected utility load characteristics, this non-optimizing model calculates a system maintenance schedule, the loss-of-load probability, unserved demand for electrical energy, time between system failures to meet the load, the average duration of failures to meet the load, required reserve to meet a specified reliability criterion, the effects of emergency interties, expected energy generation from each unit, block-by-block energy costs, generating system energy costs, and fuel use. Firm purchases and sales can be included in the analysis.

2. The model uses probilistic simulation to calculate expected energies, costs, and most of the reliability characteristics of a generating system. The calculation is broken down into five distinct categories: maintenance scheduling, system reliability, energy allocation for each generating unit, capacity required to meet a specified reliability standard, and energy costs. RELCOMP has been used to study utility expansion patterns, effects of new technologies on system reliability, utility avoided costs, and effects of shutdowns of particular generating units. This attachment documents briefly the technical workings of the model.

Program Flow

3. RELCOMP has five main functions:

- schedule maintenance;
- calculate system reliability in terms of frequency and duration;
- calculate the expected energy generation and other reliability characteristics;
- calculate capacity requirements to meet reliability criteria; and
- calculate energy costs.

A brief description follows of what goes on in each of the five main functions.

4. After the user describes the generation system and the demand, a maintenance schedule must be defined. The program begins by scheduling all units that have a specified time for maintenance, then it fits in the remaining units to form a maintenance schedule.

5. After defining the maintenance schedule for the year, RELCOMP performs period-by-period calculations of system reliability. The reliability calculation determines the frequency of combined forced outages on the basis of their probability and duration. Outages are treated individually as much as possible, and outage states that fall in small outage intervals are combined when storage space becomes scarce.

6. The energy allocation segment is the most complex of the five functions. RELCOMP calculates the energy expected from each unit scheduled to be available in the period, plus the energy from firm purchases and sales, emergency interties, and the fixed energy technology. Calculations of capacity requirements are actually done in the energy allocation subroutine of the program. RELCOMP calculates the amount of totally reliable capacity needed for the system to meet the specified LOLP. When comparing several systems, this reliability calculation provides a good indication of how much adjustment the system needs to achieve the specified reliability index.

7. Lastly, the generation costs are calculated for each period. These calculations are done in the energy-allocation subroutines. Capital costs and fixed costs are available annually by unit; fixed costs are also available by period and variable costs are available annually, by period and by block. The energy generation calculations and input cost data are used to determine overall generation costs.

8. The program gives annual summaries of generation, cost, and other statistics. Annual reserve deficit and a present value estimate are calculated (discounting to arrive at a present value is most useful when comparing multi-year plans).

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POWER SUBSECTOR REVIEW

LECO 1984 Retail Tariff

By virtue of the power vested in me under Section 36 of the Electricity Act No. 19 of 1950 (Chapter 205 of the revised legislative enactment of Ceylon 1956), I hereby approve the following tariff table with effect from 1st June 1982 in lieu of existing tariff table issued to the Kotte U.C.

Chief Electrical Inspector, 1982

This 23rd day of August

Section 1 - Domestic Tariff

This tariff shall apply to a supply of electricity to private residences and to such residences where not more than 400 square feet are used for professional or business purposes.

Monthly Charges

1. For first 50 units at 40 cts. per unit) exempted from
) the fuel charge
   For the units in excess of 50 units and up to)

   150 units at 60 cts. per unit

   For all units in excess of 150 units at 80 cts per unit plus fuel charge

Minimum Charge

2. The above charges shall be subject to a minimum charge of Rs 10 in respect of any month.

3. For the floor area used for professional or business purposes an additional charge as shown below shall be levied in addition to the normal unit charge:

Up to 200 sq. ft.	Rs 20
Between 200 to 300 sq. ft.	Rs 30
Between 300 to 400 sq. ft.	Rs 40

Section 2 - Religious Premises and Charitable Institutions Tariff

This tariff shall apply to a supply of electricity to a place of public religious worship and to the residences of the priests situated within the same premises and also to the approved charitable institutions. The installation should not include any buildings used mainly or wholly for commercial purposes.

Monthly Charge

1. For all units at 40 cts. per unit (exempted from the fuel charge).

2. Minimum Charge

   The above charges shall be subject to a minimum charge of Rs 10 in respect of any month.

Section 3 - General Purposes Tariff

The rates for general purposes (1) and (2) shown below shall apply to a supply of electricity used in shops, offices, Banks, Warehouses, public buildings, Hospitals, Educational establishments, places of entertainment and other similar premises.

General Purposes (1) Rates

1. This rate shall apply to supplies at each individual point of supply delivered at 400 volts or less and where the assessed demand is less than 50 K.V.A.

Minimum Charge

2. Upto an assessed demand of 10 K.V.A., the monthly minimum charge is Rs 60.

   When the assessed demand exceeds 10 K.V.A. the monthly minimum charge Rs 60 plus Rs 60 per K.V.A. of the balance of assessed demand.

General Purposes (2) Rate

1. This rate shall apply to supplies at each individual points of supply delivered at 400 volts or less and where the assessed demand is equal to or exceeds 50 K.V.A.

2. The monthly charge for supplies under this tariff shall be the sum of the unit charge and the maximum demand charge as shown below subject to a monthly minimum charge of Rs 60 per K.V.A. of the assessed demand.

Unit Charge

3. For all units at 40 cts. per unit plus fuel charge.

Maximum Demand Charge

4. A maximum demand charge at the rate of Rs 125 per K.V.A. made during the month.

Section 4 - Industrial Tariff

The rates industrial (1) and (2) shown below shall apply to a supply of electricity used wholly or mainly in factories, workshops, oil mills, fibre mills, spinning and weaving mills, pumping stations and other similar industrial installations.

Industrial (1) Rate

1. This rate shall apply to supplies at each individual point of supply, delivered at 400 volts or less and where the assessed demand is less than 50 K.V.A.

Monthly Charges

2. For all units at 40 cts. per unit plus fuel charge.

Minimum Charge

3. Up to an assessed demand of 10 K.V.A. the monthly minimum charge is Rs 100.

When the assessed demand exceeds 10 K.V.A. the monthly minimum charge Rs 100 plus Rs 50 per K.V.A. of the balance assessed demand.

Industrial (2) Rate

1. This rate shall apply to supplies at each individual point of supply delivered at 400 volts or less and where the assessed demand is equal to or exceess 50 K.V.A.

2. The monthly charge for supplies under this tariff shall be the sum of unit charge and the maximum demand charge as shown below subject to a monthly minimum charge of Rs 50 per K.V.A. of the assessed demand.

Unit Charge

3. For all units at 65 cts. per unit plus fuel charge.

Maximum Demand Charge

A maximum demand charge at the rate of Rs 100 per K.V.A. made during the month.

Section 5 - Hotels Tariff

The rates Hotels (1) and (2) shown below shall apply to a supply of electricity used in Hotels - Tourist Hotels, Restaurants, Cafes and other similar premises.

Hotels (1) Rate

1. This rate shall apply to supplies of at each individual point of supply delivered at 400 volts or less and where the assessed demand is less than 50 K.V.A.

Monthly Charges

2. For all units at 75 cts. per unit plus fuel charge.

Minimum Charges

3. Up to an assessed demand of 0.5 K.V.A. the monthly minimum charge is Rs 60.

From an assessed demand of 0.5 K.V.A. up to 10 K.V.A. the monthly minimum charge is 12 per K.V.A.

When the assessed demand exceeds 10 K.V.A. the monthly minimum charge Rs 120 plus Rs 60 per K.V.A. of the balance assessed demand.

Hotels (2) Rate

1. The rate shall apply to supplies at each individual point of supply delivered at 400 volts or less and where the assessed demand is equal to or exceeds 50 K.V.A.

2. The monthly charge for supplies under this tariff shall be the sum of the unit charge and the maximum demand charge as shown below subject to a monthly minimum charge of Rs 75 per K.V.A. of the assessed demand.

Unit Charge

3. For all units at 85 cts. per unit plus fuel charge.

Maximum Demand Charge

4. A maximum demand charge at the rate of Rs 150 per K.V.A. made during the month.

Section 6 - Street Lighting Tariff

1. This rate shall apply to a supply of electricity for the purpose of public street lighting only.

Unit Charge

For all units at 80 cts. per unit plus fuel charge.

Section 7 - Temporary Illumination for Existing Consumers

1. Existing consumers shall be allowed a load of one (1) K.V.A. in addition to the load declared on the normal unit rate of the respective tariff subject to an additional charge of Rs 25 provided that the existing meter could be utilized for the additional load. A load of more than one (1) K.V.A. shall be treated as temporary supplies.

Temporary Supplies

2. For all units at Rs 1/25 per unit plus fuel charge.

3. In addition to this, an additional charge of Rs 50 plus labor etc. shall be levied.

4. If the service wire is hired by the licensees 10% of the total cost of same shall be levied. (It is better to refrain from providing temporary supply for a longer period to those who require permanent supply).

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POWER SUBSECTOR REVIEW

Example of CEB Monthly Bill to KOTTE U.C. (November 1982)

Units consumed = 2,032,319 units; KVA = 6125

Consumption	Block	Units	Consumers
Domestic	0 - 50	63712	1935
	51 - 100	178461	2172
	101 - 150	238639	1949
	over 150	738309	3455

1st Block, No. of Units = 1.2 x 63712 + 1.2 x 50 (2172+1949+3455)

= 76454 + 454560 = 531014 units

2nd Block, No. of Units = 1.2 (178461-50 x 2172)+1.2 x 50 (1949+3455)

= 83833 + 324240 = 408073 units

3rd Block, No. of Units = 1.2 (238639-100 x 1949)+1.2 x 50 x 3455

= 52487 + 207300 = 259787 units

4th Block, No. of Units = 2,032,319 - (531014 + 408073 + 259787)

= 833445 units

Cost of the Units

1st Block = 531014 x 0.30	=	Rs	159,304.00
2nd Block = 408073 x 0.50	=	Rs	204,036.00
3rd Block = 259787 x 0.55	=	Rs	142,883.00
4th Block = 833445 x 0.55	=	Rs	458,395.00
F.A.C. 185% on the 4th Block	=	Rs	848,031.00
Maximum demand charge 6,125 K.V.A. at Rs 50 per K.V.A.	=	Rs	306,250.00
Total Bill to consumer	=	Rs	2,118,899.00

Revenue for One Month

Domestic

1st Block 442512 Units at Rs 0.40/kWh	=	Rs	177,005
2nd Block 556550 Units at Rs 0.80/kWh	=	Rs	445,240
3rd Block 220059 Units at Rs 0.80/kWh	=	Rs	176,047
F.A.C. 185% on 3rd Block	=	Rs	325,687
TOTAL	=	Rs	1,123,979

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POWER SUBSECTOR REVIEW

Negambo Municipality Tariff Schedule
(1984)

Charges	Per Unit Rs	Fuel Adjustment Charge 185%	Minimum Charge/ Month Rs	Maximum Demand
1. Premises				
Unit 1 to 50	0.50	without	10.00	-
Unit 51 to 150	0.90	- do -	"	-
Unit 151 to 500	0.90	with	"	-
Unit 500 to and over	1.00	with	"	-
2. Religous				
For all units	0.50	without	"	-
3. General Purposes				
For all units	0.80	with	K.V.A.	-
- do -	0.80	with	"	130.00
4. Industrial				
< 50 K.V.A. for all units	0.80	"	"	-
> 50 K.V.A. for all units	0.80	"	"	100.00

5. Hotel				
For all units	0.80	"	"	-
- do -	0.90	"	"	150.00
6. Temporary				
For all units	1.25	"	"	-

Source: Negambo Municipality

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POWER SUBSECTOR REVIEW

Number of Units Sold by Negambo Municipality According to Tariff Category - 1983

Tariff	January	February	March	April	May	June	July	August	September	October	November	December	TOTAL
D	524,965	451,644	509,030	487,741	434,967	390,615	448,473	421,250	421,067	421,799	440,380	534,173	5,486,104
GP1	166,374	150,166	207,426	167,907	166,431	145,421	106,902	100,482	98,374	100,338	105,511	99,067	1,614,399
GP2	25,783	35,874	28,700	18,540	23,651	27,192	19,838	30,470	26,353	13,731	20,930	25,874	296,936
I1	2,245	1,534	1,387	1,298	13,451	10,530	6,726	16,838	13,564	13,813	14,948	23,197	119,531
I2	22,580	27,371	25,274	19,059	18,049	21,837	21,232	16,511	13,240	17,136	19,307	21,588	243,184
H1	21,003	27,825	29,240	51,990	31,089	15,883	29,090	28,498	22,719	22,850	23,030	25,259	328,476
H2	14,637	186,363	13,540	106,690	126,250	112,841	136,707	75,981	58,176	151,160	13,760	125,627	1,400,532
R	8,821	7,565	9,567	10,216	7,767	7,007	7,391	8,555	7,472	7,471	7,619	8,910	98,361
	918,108	888,342	946,264	863,441	821,655	751,326	776,359	698,585	660,965	748,298	650,485	863,695	9,587,523

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POWER SUBSECTOR REVIEW
CEYLON ELECTRICITY BOARD
ACTUAL AND FORECAST INCOME STATEMENTS
(YEAR ENDING DECEMBER 31ST)
(RUPEES MILLION)

	ACTUAL					(Unaud.)	(Budget)	FORECAST								
	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
KWh GENERATED (MILLIONS)	1668	1872	2066	2114	2261	2464	2815	3071	3345	3648	3975	4334	4728	5153	5617	6118
KWh SOLD (MILLIONS)	1392	1503	1679	1792	1877	2061	2308	2549	2810	3064	3379	3684	4066	4432	4943	5384
KWh SOLD/KWh GENERATED(%)	83	80	81	85	83	84	82	83	84	84	85	85	86	86	88	88
AVE. TARIFF/KWh SOLD(CENTS)	37.36	58.62	77.55	84.49	78.00	136.20	149.00	165.39	170.35	182.28	202.33	220.54	227.15	233.97	240.99	248.22
OPERATING REVENUE																
SALES OF ELECTRICITY	520	881	1302	1514	1464	2807	3439	4216	4787	5586	6836	8124	9236	10368	11912	13364
FUEL SURCHARGE	367	758	1140	2507	566	114	41	106	309	659	1005	840	1555	1325	2181	2255
OTHER OPERATING REVENUES	...	...	...	...	224	146	153	161	169	177	186	196	205	216	226	238
OTHER REVENUE	...	...	...	...	...	169	244	231	279	381	423	343	376	463	558	542
TOTAL OPERATING REVENUES	887	1639	2442	4021	2254	3236	3878	4714	5544	6803	8451	9504	11373	12372	14877	16398
OPERATING EXPENSES																
FUEL COST	254	560	971	2311	489	111	40	103	300	640	976	816	1510	1286	2117	2189
OPERATION & MAINTENANCE	85	132	167	207	288	341	479	598	710	873	1009	1193	1370	1549	1750	1997
TURNOVER TAX	12	31	51	46	20	88	104	130	153	187	235	269	324	351	423	469
ADMINISTRATION & OTHER	52	101	110	255	187	172	189	208	229	252	277	305	335	369	406	446
DEPRECIATION	154	256	329	371	460	641	958	1197	1419	1685	2018	2386	2740	3098	3500	3995
TOTAL OPERATING EXPENSES	557	1081	1628	3190	1444	1353	1770	2236	2811	3607	4516	4969	6279	6653	8195	9095
NET OPERATING INCOME	330	558	814	831	810	1883	2108	2478	2733	3196	3935	4534	5093	5719	6682	7303
INCOME TAX	0	0	282	438	46	169	31	155	0	0	0	0	0	0	0	0
NET INCOME AVAILABLE	330	558	532	393	764	1714	2077	2323	2733	3196	3935	4534	5093	5719	6682	730[illegible]
INTEREST	27	63	95	108	321	409	607	686	980	1369	1959	2619	3073	3122	3580	4367
INTEREST CHARGED OPERATIONS	27	63	95	108	321	409	607	686	980	1369	1959	2619	3073	3122	3580	4367
INCOME	303	495	436	285	443	1305	1470	1637	1753	1827	1976	1915	2020	2597	3102	2936
LESS:RESEARCH & DEVELOPMENT	0	0	0	0	7	40	164	69	34	0	0	0	0	0	0	0
NET PROFIT	303	495	436	285	436	1265	1306	1568	1719	1827	1976	1915	2020	2597	3102	2936
RATE OF RETURN ON AVERAGE NET FIXED ASSETS IN OPERATION	9.40	11.38	8.66	5.64	7.38	10.67	9.09	8.07	8.11	8.06	8.32	8.13	8.02	8.08	8.46	8.15

ANNEX 6
Attachment 1

SRI LANKA
POWER SUBSECTOR REVIEW
CEYLON ELECTRICITY BOARD
ACTUAL AND FORECAST SOURCES AND APPLICATIONS OF FUNDS STATEMENTS
(YEAR ENDING DECEMBER 31ST)
(RUPEES MILLION)

	ACTUAL					(Unaud.)	(Budget)	FORECAST								
	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
SOURCES OF FUNDS																
INTERNAL SOURCES																
NET INCOME AVAILABLE	330	558	814	831	810	1883	2108	2478	2733	3196	3935	4534	5093	5719	6682	7303
DEPRECIATION	154	256	329	371	460	641	958	1197	1419	1685	2018	2386	2740	3098	3500	3995
LESS:RESEARCH & DEVELOPMENT	0	0	0	0	7	40	164	69	34	0	0	0	0	0	0	0
TOTAL INTERNAL FUNDS GENERATED	485	814	1142	1202	1263	2484	2902	3606	4118	4881	5953	6921	7834	8817	10182	11297
EQUITY CONTRIBUTIONS	117	55	238	95	1434	4537	4957	245	166	167	179	190	199	208	217	228
OTHER CONTRIBUTIONS	314	121	285	647	121	255	196	259	339	436	566	600	627	655	685	716
BORROWINGS																
RUPEE LOANS	511	238	65	0	2000											
FOREIGN LOANS	124	54	96	1371	948	433	1227	2026	3136	3555	6770	5509	3722	4105	7324	10195
PROPOSED IDA CREDIT								97	431	542	331	24				
PROPOSED ODA LOAN								29	75	150	110	6				
TOTAL BORROWINGS	635	292	161	1371	2948	433	1227	2152	3642	4247	7211	5539	3722	4105	7324	10195
TOTAL SOURCES OF FUNDS	1550	1282	1826	3315	5765	7709	9282	6262	8265	9731	13910	13250	12382	13786	18408	22436
APPLICATIONS OF FUNDS																
CAPITAL INVESTMENTS																
THE PROJECT								177	836	1275	961	102				
OTHER INVESTMENTS	0	0	0	0	0	70	10	10	10	10	10	10	10	10	10	10
CONSTRUCTION PROGRAM	688	941	982	1660	5133	4659	7837	4275	5325	5936	10940	9258	6837	7584	12645	17404
TOTAL CONSTRUCTION PROGRAM	688	941	982	1660	5133	4729	7847	4461	6170	7221	11911	9370	6847	7594	12655	17414
DEBT SERVICE																
INTEREST	27	63	95	108	321	409	607	686	980	1369	1959	2619	3073	3122	3580	4367
AMORTIZATION	39	97	86	120	155	344	359	356	362	366	374	524	1077	1703	1677	1984
TOTAL DEBT SERVICE	66	160	181	228	476	753	966	1042	1342	1735	2333	3143	4150	4825	5257	6351
INCOME TAX	0	0	282	438	46	169	31	155	0	0	0	0	0	0	0	0
INSURANCE ESCROW ACCOUNT							142	43	51	61	74	85	97	109	124	142
CHANGES IN RESERVE						917										
VARIATION IN WORKING CAPITAL																
CASH INCREASE	106	-159	98	-163	781	1667	-132	481	1016	421	-799	326	873	949	-160	-1945
OTHER THAN CASH INCREASE	690	340	283	1152	-671	-525	428	79	-314	293	391	325	415	308	531	474
NET INCREASE	796	181	380	989	110	1141	297	560	702	714	-408	651	1288	1257	372	-1471
TOTAL APPLICATIONS OF FUNDS	1550	1282	1826	3315	5765	7709	9282	6262	8265	9731	13910	13250	12382	13786	18408	22436
DEBT SERVICE COVERAGE	7.40	5.09	6.30	5.26	2.65	3.30	3.00	3.46	3.07	2.81	2.55	2.20	1.89	1.83	1.94	1.78
SELF FINANCING RATIO (%)	0	68	72	24	21	14	30	36	40	33	48	39	37	36	41	46

SRI LANKA
POWER SUBSECTOR REVIEW
CEYLON ELECTRICITY BOARD
ACTUAL AND FORECAST BALANCE SHEETS
(AS ON DECEMBER 31ST)
(RUPEES MILLION)

	ACTUAL					(Unaud.)	(Budget)	FORECAST								
	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
ASSETS																
FIXED ASSETS																
FIXED ASSETS IN OPERATION	6461	8641	11006	12978	19722	27276	36559	43228	51391	60950	73611	85485	97203	109334	123966	142334
LESS:CUM.DEPRECIATION	1802	2557	3310	3947	5009	6306	7894	9880	12189	14849	17996	21192	24886	29104	33913	39434
NET FIXED ASSETS IN OPERATION	4659	6085	7696	9032	14713	20970	28665	33348	39202	46101	55615	64293	72317	80230	90053	102900
CONSRTUCTION IN PROGRESS	376	812	1033	1790	2462	1800	3082	4520	6408	8171	12044	12842	11808	11635	14568	19183
TOTAL FIXED ASSETS	5035	6897	8729	10821	17175	22770	31747	37868	45610	54272	67659	77135	84125	91865	104621	122083
INVESTMENTS	2	8	8	8	13	83	93	103	113	123	133	143	153	163	173	183
INSURANCE ESCROW ACCOUNT							142	185	236	297	371	456	553	663	787	929
CURRENT ASSETS																
CASH	221	62	159	-3	777	2444	2312	2793	3809	4231	3432	3758	4631	5580	5420	3475
INVENTORIES	284	717	776	1046	820	922	1828	2161	1285	1524	1840	2137	2430	2733	3099	3558
ACCOUNTS RECEIVABLE	326	507	1317	1545	1604	1169	1305	1080	1274	1561	1960	2241	2698	2923	3523	3905
OTHER RECIEVABLES.	572	578	576	1319	346	452	497	547	602	662	728	801	881	969	1066	1172
TOTAL CURRENT ASSETS	1403	1864	2828	3907	3549	4987	5943	6582	6970	7977	7960	8937	10640	12205	13108	12110
TOTAL ASSETS	6440	8769	11565	14736	20737	27840	37924	44738	52929	62669	76123	86671	95471	104896	118689	135305
CAPITAL AND LIABILITIES																
EQUITY																
EQUITY	677	732	969	1065	2498	7035	11992	12237	12403	12570	12749	12939	13138	13346	13563	13791
OTHER CONTRIBUTION	348	468	753	1400	1521	1776	1972	2231	2570	3006	3572	4172	4800	5455	6140	6856
REVALUATION SURPLUS	2721	3900	5067	5871	7352	8931	11029	13895	16897	20033	23537	26040	28933	32187	35797	39850
RETAINED EARNINGS	1060	1563	1999	2814	3687	4033	5339	6907	8626	10454	12430	14345	16365	18962	22065	25000
TOTAL EQUITY	4806	6664	8788	11150	15058	21775	30332	35271	40496	46062	52288	57496	63236	69950	77565	85497
LONG TERM DEBT	1261	1453	1539	2259	4820	4909	5777	7573	10853	14734	21571	26586	29231	31633	37280	45491
CURRENT LIABILITIES	373	653	1237	1327	859	1156	1815	1894	1580	1873	2264	2590	3004	3313	3844	4318
TOTAL CAPITAL AND LIABILITIES	6440	8769	11564	14736	20737	27840	37924	44738	52929	62669	76123	86671	95471	10489	118689	135305
DEBT AS % OF DEBT+EQUITY	21	18	15	17	24	18	16	18	21	24	29	32	32	31	32	35
EQUITY AS % OF DEBT+EQUITY	79	82	85	83	76	82	84	82	79	76	71	68	68	69	68	65

ANNEX 6
Attachment 3

ANNEX 6
Attachment 4

SRI LANKA
POWER SUBSECTOR REVIEW
CEYLON ELECTRICITY BOARD
ASSUMPTIONS FOR FINANCIAL PROJECTIONS

Income Statement

Load Forecast:	CEB's Load Forecast as agreed with the Bank.
Sales Revenue:	Tariff increases assumed to satisfy the covenanted 8% Rate of Return and to meet entire Local costs of the Investment Program.
Fuel Surcharge:	The Fuel Cost and Turnover Tax on fuel would be recovered by levy of the Surcharge.
Other Revenue:	Overhead Recoveries Price variance etc. Assumed to increase at 5% p.a.
Income From Excess Cash:	10% of Previous Year's Cash Balance
Operation & Maintenance:	1.5 % of Average Gross Fixed Assets in Use.
Turnover Tax:	3 % of Total Operating Revenue
Administration & Other:	Increases annually by 10 %
Depreciation:	3 % of Average Gross Fixed assets in use.

Balance Sheet

Fixed Assets:	Current Cost.
Cash:	Minimum 2 Months' Cash Operating Expenses.
Inventories:	Forecast as % of Gross Fixed Assets as follows:
	1986 5.0
	1987 5.0
	1988 2.5
	1989 2.5
	1990-95 2.5
Accounts Receivables:	Forecast in Months of Sales as follows:
	1986 4.5
	1987 3.0
	1988 3.0
	1989 3.0
	1990-95 3.0
Other Receivables:	Assumed to increase by 10% each year.
Current Liabilities:	Forecast as 50% of Current Assets Other Than Cash

Flow of Funds Statements

Other Contributions:	Increases assumed to finance Service & Bulk Supplies.
Capital Investment:	CEB's 10-year Investment Program in Current Prices

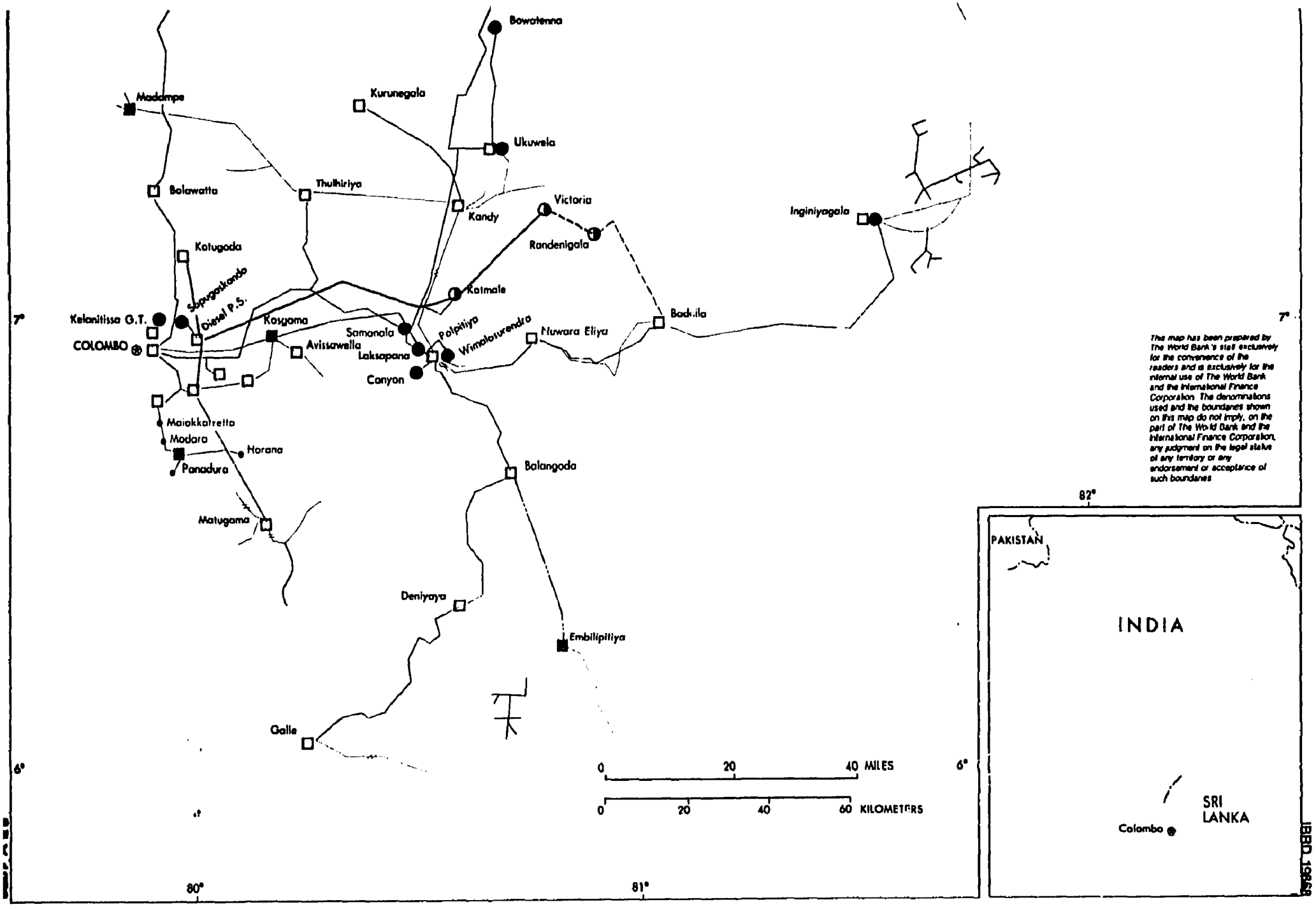
Inflation Rate	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Local	10	10	9	8	7.6	4.5	4.5	4.5	4.5	4.5
Foreign	7.0	7.0	7.5	7.6	7.8	4.2	4.6	4.6	4.45	4.5
Escalation Factors										
Local	1.050	1.155	1.264	1.362	1.479	1.567	1.638	1.711	1.788	1.869
Foreign	1.035	1.107	1.188	1.268	1.376	1.458	1.524	1.593	1.664	1.739

Other Investments:	At Rs. 10 million a year beginning 1986.
Debt Service Coverage:	Defined as number of times debt service covered by gross internal cash generation, to be not less than 1.5 beginning 1986.
Self-financing Ratio:	Ratio of internally generated cash. net of Debt Service and Change in Working Capital, to Investments averaged over the preceeding, current and succeeding years.
Insurance Escrow Account	0.1% of G.F.A.

ANNEX 6
Attachment 5

SRI LANKA
POWER SUBSECTOR REVIEW
CEYLON ELECTRICITY BOARD
INVESTMENT PROGRAM - 1986 TO 1985
(RS MILLION)

PROJECT	1986		1987		1988		1989		1990		1991		1992		1993		1994		1995	
	Foreign	Total	Foreign	Total	Foreign	Total	Foreign	Total	Foreign	Total	Foreign	Total	Foreign	Total	Foreign	Total	Foreign	Total	Foreign	Total
Ongoing Generation																				
Canyon Unit 2	0	222	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Kotmale Unit 3	239	275	37	44	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Kelanitissa Rehab.	40	49	27	53	10	12	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Randenigala	---	4500	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Nilambe	101	195	48	60	13	17	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Sub Total	380	5240	113	157	23	29	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Feasibility Studies																				
Coal Project	67	85	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
GTZ Study	16	31	17	34	12	25	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Upper Kotmale	25	47	13	25	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Belihul Oya	---	---	3	9	3	9	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Sub Total	107	163	33	68	15	34	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Planned - Generation																				
Rantembe - 51 MW	48	76	470	755	1075	1564	389	540	---	---	---	---	---	---	---	---	---	---	---	---
Broadlands - 30 MW	---	---	---	---	---	---	125	183	809	1312	429	695	---	---	---	---	---	---	---	---
Samanalawewa - 120 MW	223	426	1085	1868	1302	1764	1804	2274	2282	2712	632	737	---	---	---	---	---	---	---	---
Coal Unit I - 150 MW	---	---	---	---	63	93	337	503	2176	3256	3458	5172	1526	2283	---	---	---	---	---	---
Coal Unit II - 150 MW	---	---	---	---	---	---	---	---	47	69	249	363	1559	2276	2444	3569	1078	1575	---	---
Coal Unit III - 300 MW	---	---	---	---	---	---	---	---	---	---	---	---	96	140	501	731	3137	4582	4917	7183
Upper Kotmale - 240 MW	---	---	---	---	---	---	---	---	---	---	---	---	---	---	313	508	763	1237	2847	4617
Coal Unit IV - 300 MW	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	109	159
Kukule - 180 MW	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	244	401	595	972
Sub Total	270	502	1555	2623	2439	3402	2655	3500	5314	7547	4767	6967	3181	4799	3258	4808	5222	7795	8468	12937
Ongoing Transmission																				
Transmission IV	312	604	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Transmission VI	374	621	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Sub Total	686	1225	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Planned - Transmission																				
Transmission Development	---	---	146	205	275	388	296	418	79	99	---	---	---	---	---	---	---	---	---	---
Coal Project Trans. I	---	---	---	---	---	---	265	403	1108	1682	606	922	360	547	---	---	---	---	---	---
Other Transmission	---	---	---	---	62	83	18	25	0	0	135	189	181	262	221	327	82	121	72	100
Coal Project Trans. II	---	---	---	---	---	---	---	---	---	---	---	---	---	---	626	951	1764	2649	1367	2076
Sub Total	---	---	146	205	337	471	579	846	1186	1780	742	1111	541	809	847	1278	1826	2770	1438	2176
Ongoing Distribution																				
Rural Electrification	105	166	80	185	89	155	96	167	103	180	109	190	114	199	120	208	125	217	131	227
Planned - Distribution																				
33 kV Subtransmission	0	0	186	277	197	299	212	322	229	347	0	0	0	0	0	0	276	420	289	439
Substations & Spur Lines	0	373	0	478	0	604	0	727	0	876	0	556	0	678	0	818	0	948	0	1138
Dist. Expansion & Rehab.	0	0	126	177	606	836	789	1275	483	961	29	102	---	---	---	---	---	---	--	---
Sub Total	0	373	310	931	804	1738	1001	2324	711	2185	29	658	0	678	0	818	276	1368	289	1577
Other Investment																				
Office Equip. & Buildings	0	69	0	60	0	51	0	55	---	77	---	81	---	85	---	89	---	93	---	97
Training	38	53	49	85	37	56	12	24	---	---	---	---	---	---	---	---	---	---	---	---
Motor Vehicles	0	70	0	77	0	84	0	91	---	98	---	104	---	109	---	114	---	119	---	124
Other	0	140	0	148	0	174	0	203	---	234	---	248	---	259	---	270	---	283	---	295
Sub Total	38	331	49	370	37	366	12	373	---	409	---	433	---	453	---	473	---	495	---	517
Total Investment	1586	8001	2286	4519	3742	6182	4343	7211	7515	11901	5648	9360	3836	6837	4225	7584	7449	12645	11526	17404



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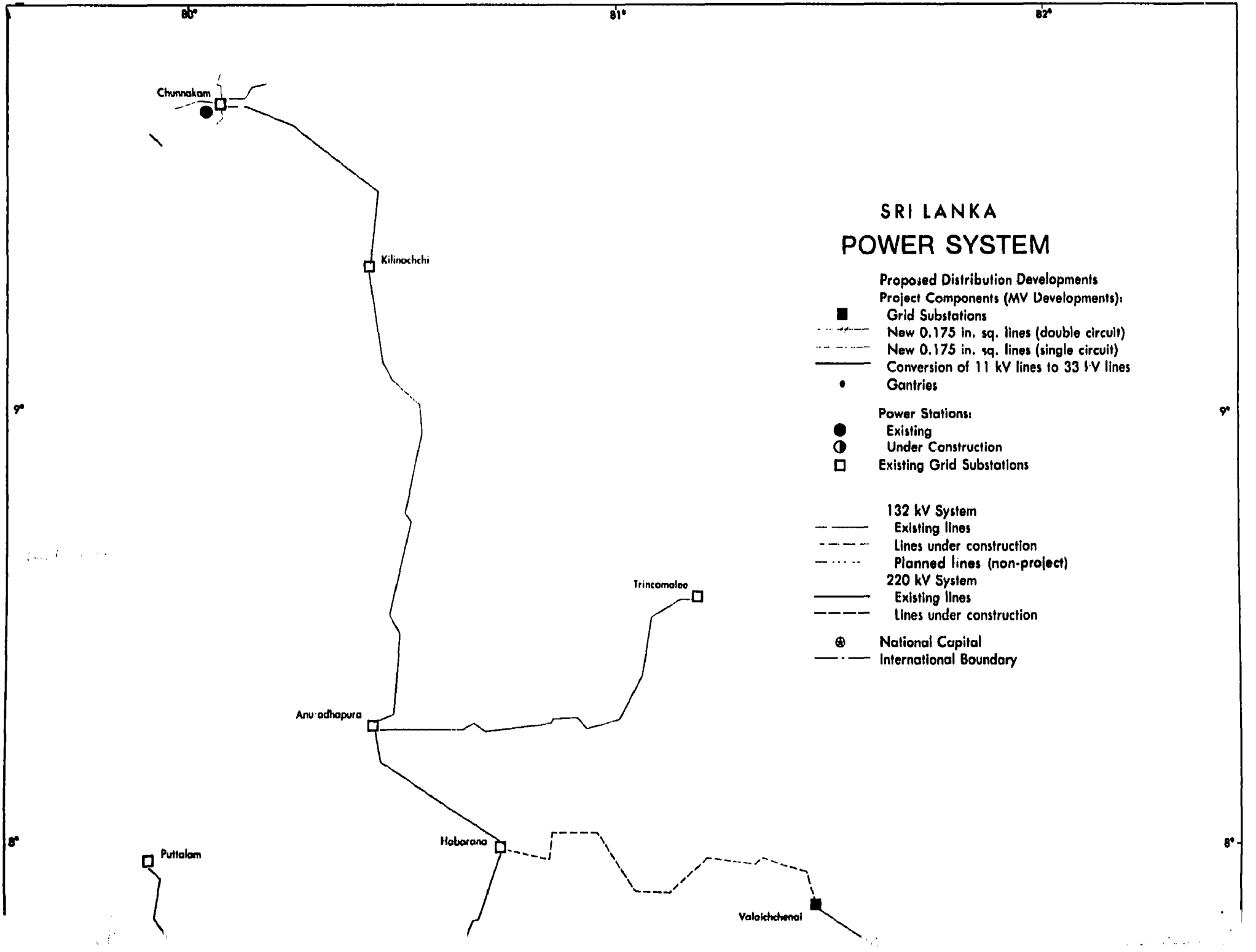
80°
81°
82°
9°
8°
Chunnakam
Kilinochchi
Trincomalee
Anuradhapura
Habarana
Puttalam
Valaichchenai
SRI LANKA
POWER SYSTEM
Proposed Distribution Developments
Project Components (MV Developments):
Grid Substations
New 0.175 in. sq. lines (double circuit)
New 0.175 in. sq. lines (single circuit)
Conversion of 11 kV lines to 33 kV lines
Gantries
Power Stations:
Existing
Under Construction
Existing Grid Substations
132 kV System
Existing lines
Lines under construction
Planned lines (non-project)
220 kV System
Existing lines
Lines under construction
National Capital
International Boundary