No.

Master Plan Study on the Development of Power Generation and Transmission System in Sri Lanka

Final Report

Volume 2

(Technical Background Report)

February 2006

Japan International Cooperation Agency
Economic Development Department

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the Development of Power Generation and
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Preface

In response to the request from the Government of the Democratic Socialist Republic of Sri Lanka, the Government of Japan decided to conduct the Master Plan Study on the Development of Power Generation and Transmission System in Sri Lanka, and entrusted the Study to the Japan International Cooperation Agency (JICA).

JICA sent the Study Team, headed by Mr. Yoshitaka SAITO of Chubu Electric Power Co., Inc. and organized by Chubu Electric Power Co., Inc. and Nomura Research Institute, Ltd. to Sri Lanka five times from December 2004 to February 2006.

The Study Team had a series of discussions with the officials concerned of the Government of the Democratic Socialist Republic of Sri Lanka and the Ceylon Electricity Board, and conducted related field surveys. After returning to Japan, the Study Team conducted further studies and compiled the final results in this report.

I hope that this report will contribute to the promotion of the plan and to the enhancement of amity between our two countries.

I wish to express my sincere appreciation to the officials concerned of the Government of Democratic Socialist Republic of Sri Lanka, Ceylon Electricity Board for their close cooperation throughout the Study.

February 2006

Tadashi IZAWA
Vice President
Japan International Cooperation Agency

February 2006

Mr. Tadashi IZAWA
Vice President
Japan International Cooperation Agency
Tokyo, Japan

Letter of Transmittal

We are pleased to submit to you the report of "Master Plan Study on the Development of Power Generation and Transmission System in Sri Lanka". This study was implemented by Chubu Electric Power Co., Inc. and Nomura Research Institute, Ltd. from December 2004 to February 2006 based on the contract with your Agency.

This report presents the comprehensive proposal, such as the long-term power development plan composed of power demand forecast, generation development plan and transmission plan to secure a stable power supply with reasonable price in Sri Lanka taking account of environmental and social considerations. In addition, organizational and institutional measures, and also financial measures are proposed in order to realize the plans.

We trust that the realization of our proposal will much contribute to sustainable development in the electric power sector, which will contribute to the development of economy in Sri Lanka as well, and recommend that the Government of Democratic Socialist Republic of Sri Lanka gives priority to the implementation of our proposal by applying results of technology transfer in the Study.

We wish to take this opportunity to express our sincere gratitude to your Agency, the Ministry of Foreign Affairs and the Ministry of Economy, Trade and Industry. We also wish to express our deep gratitude to Ministry of Power and Energy (MPE), Ceylon Electricity Board (CEB) and other authorities concerned for the close cooperation and assistance extended to us throughout the Study.

Very truly yours,

Yoshitaka SAITO
Team Leader
Master Plan Study on the Development of
Power Generation and Transmission System in Sri Lanka

Table of Contents

List of Figures and Tables

<List of Figures>

Chapter 1

Chapter 2

Chapter 3

Chapter 4

Chapter 7

<List of Tables>

Chapter 6

Chapter 7

List of Appendices

List of Abbreviations

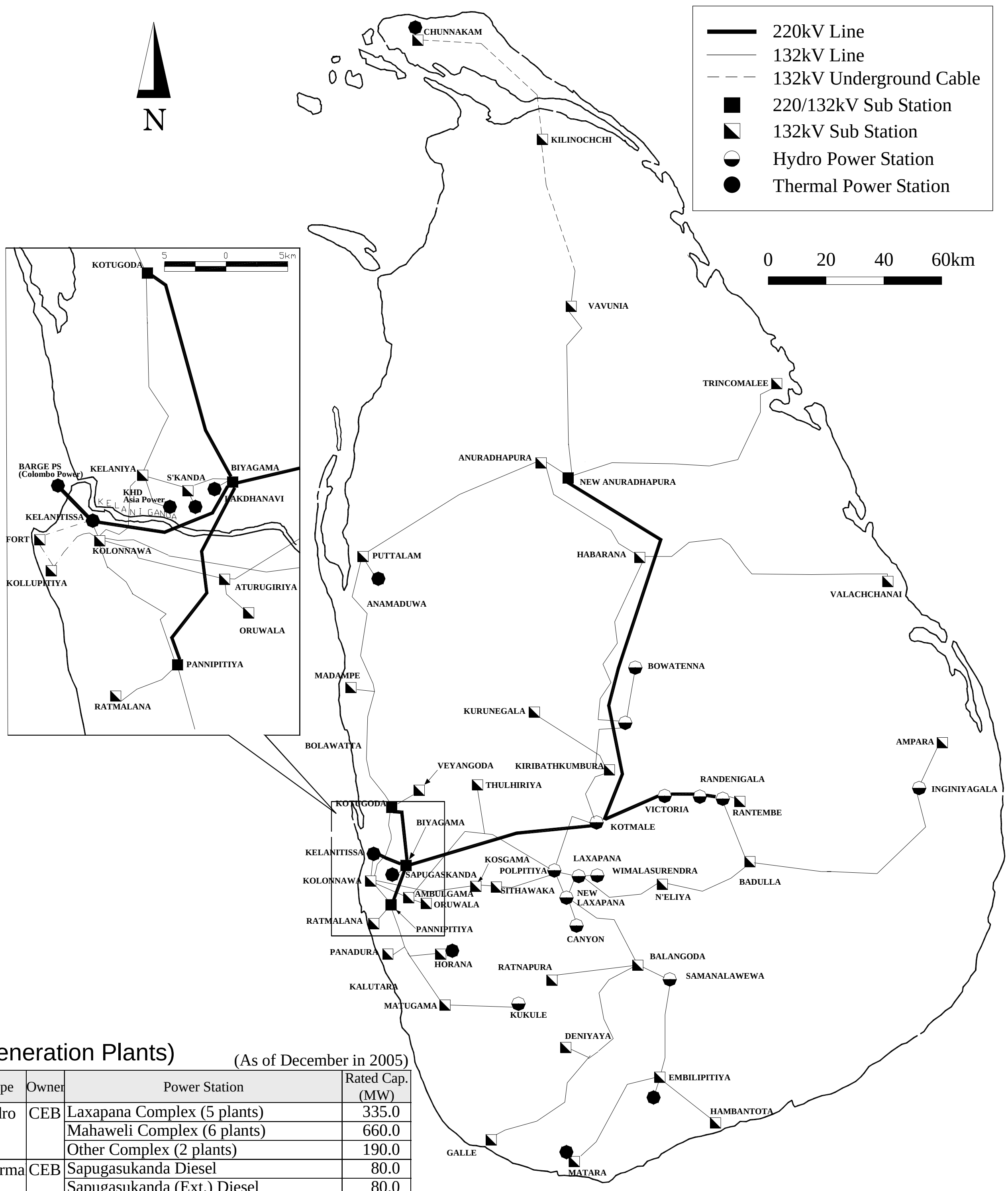
AAGR	Average Annual Growth Ratio
ACSR	Aluminum Conductor Steel Reinforced
ADB	Asian Development Bank
AGM	Assistant General Manager
APC	Annual Production Cost
APOM	Asia Power Operation & Maintenance Ltd.
AU	Administrative Unit (of the RERED project)
BBL	Barrel
BHEL	Bharat Heavy Electricals Limited
BII	Bureau of Investment of Infrastructure Investment
BL	Build and Lease
BOI	Board of Investment
BOO	Build-Own-Operate
BOOT	Build-Own-Operate-Transfer
BOT	Build-Own-Transfer
BT	Build and Transfer
CAARP	Conflict Affected Area Rehabilitation Program
CC、CCGT	Combined Cycle Gas Turbine Power Plant
CDM	Clean Development Mechanism
CEB	Ceylon Electricity Board
CECB	Central Engineering Consultancy Bureau
CIF	Cost, Insurance and Freight
CPC	Ceylon Petroleum Corporation
CPI	Consumer Price Index
DAC	Development Assistance Committee
DCC	Department of Coastal Conservation
DD、D/D	Detailed Design
CEA	Central Environment Authority
DFCC	Development Finance Corporation of Ceylon
DF/R	Draft Final Report
DGM	Deputy General Manager
DISCO	Distribution Company
DG	Diesel Generator
DOE	United States Department of Energy
DSM	Demand Side Management
DWG	Department of Wildlife Conservation
E/D	Engineering Design
EGAT	Electricity Generating Authority of Thailand
EIA	Environmental Impact Assessment
EIRR	Economic Internal Rate of Return
EMA	Environmental Management Authority

E/N	Exchange of Notes
ENS	Energy Not Served
EP	Electrostatic Precipitator
ERD	External Resources Department
ES、E/S	Engineering Service
ESC	Environmental Social Consideration
ESD	Energy Services Delivery
FC	Fuel Cost
FGD	Flue Gas Desulfurizer
FIC	Fuel Inventory Cost
FIRR	Financial Internal Rate of Return
FM	Frequency Modulation
FMA	Fisheries Management Area
FOB	Free On Board
F/R	Final Report
FS、F/S	Feasibility Study
GCal	Giga Calorie
GDP	Gross Domestic Product
GEF	Global Environmental Facility
GENCO	Generation Company
GIS	Gas Insulated Switchgear
GS	Grid Station
GT	Gas Turbine
GT7	Gas Turbine Unit No. 7
GTZ	Deutsche Gesellschaft fur Technische Zusammenarbeit
GWh	Giga watt-hour
HNB	Hatton National Bank
HP、HPP	Hydropower Plant
HRSG	Heat Recovery System Generator
HV	High Voltage
HWL	High Water Level
HZ	Hertz
IAEA	International Atomic Energy Agency
IBRD	International Bank for Reconstruction and Development
Ic/R	Inception Report
IDA	International Development Association
IDC	Interest During Construction
IEE	Initial Environmental Examination and Initial Environmental Evaluation
IMF	International Monetary Fund
IPP	Independent Power Producer
ITDG	Intermediate Technology Development Group
It/R	Interim Report
IUCN	International Union for Conservation of Nature and Natural Resources

JBIC	Japan Bank for International Cooperation
JCI	Japan Consulting Institute
JETRO	Japan External Trade Organization
JICA	Japan International Cooperation Agency
KFW	Kreditanstalt fur Wiederaufbau
kl	kilo litter
kW	kilo Watt
kWh	kilo Watt-hour
kV	kilo Volt
LECO	Lanka Electricity Company
LF	Load Factor
LKR	Sri Lanka Rupees
LNG	Liquefied Natural Gas
LOI	Letter Of Intent
LOLP	Loss of Load Probability
LTGEP	Long Term Generation Expansion Plan
LTTDS	Long Term Transmission Development Plan
LTTE	Liberation Tigers of Tamil Eelam
MAC	Monitoring and Advisory Committee
MCM	Million Cubic Meter
MENR	Ministry of Environment and Natural Resources
MGEA	Minimum Guarantee Energy Amount
MHP	Mini Hydropower Plant
MJ	Mega Joule
M/M	Minutes of Meeting
MMBTU	Million British Thermal Unit
MOL	Ministry of Land
MOU	Memorandum of Understanding
MP	Master Plan
MPE	Ministry of Power and Energy
MRRR	Ministry of Relief, Rehabilitation and Reconciliation
MT	Metric Tons
MVA	Mega Volt Ampere
MW	Mega Watt
MVar	Mega Var
NEA	National Environment Act
NGO	Non-Governmental Organization
NREL	National Renewable Energy Laboratory
NSCMA	National Steering Committee for Mine Action
NWEA	Environmental Authority of North Western province
NWRS	National Water Resources Secretariat
ODA	Official Development Assistance
OECF	Overseas Economic Cooperation Fund

O&M	Operation and Maintenance
OPEC	Organization of the Petroleum Exporting Countries
OPGW	Optical Ground Wire
PAA	Project Approving Agencies
PCI	Participating Credit Institutions
PCM	Pulse Code Modulation
PF	Plant Factor
PLC	Power Line Carrier
PPA	Power Purchase Agreement
PPP	Public and Private Partnership
P/S、PS	Power Station
PSS/E	Power System Simulator for engineering
PUCSL	Public Utility Commission of Sri Lanka
RCC	Roller Compacted Concrete
RERED	Renewable Energy for Rural Economic Development
ROE	Return On Equity
ROI	Return On Investment
RSLP	Regaining Sri Lanka Programme
SCADA	Supervisory Control And Data Acquisition
SDA	Special Dollar Account
SEA	Strategic Environmental Assessment
SEDZ	South-East Dry Zone
SEEDS	Sarvodaya Economic Enterprises Development Services
SHS	Solar Home System
SLCPI	Sri Lanka Consumer Price Index
S/S, SS	Substation
ST	Steam Turbine
SV	Super Vision
S/W	Scope of Work
SYSIM	System Simulation Package
TAFREN	Task Force for Rebuilding the Nation
TOR	Terms of Reference
TRANSCO	Transmission Company
UDA	Urban Development Authority
USAID	United States Agency for International Development
USTDA	United States Trade and Development Agency
WASP-IV	Wien Automatic System Planning - version IV
WB	World Bank

Power System in Sri Lanka (As of December in 2005)



(Generation Plants)

(As of December in 2005)

Type	Owner	Power Station	Rated Cap. (MW)
Hydro	CEB	Laxapana Complex (5 plants)	335.0
		Mahaweli Complex (6 plants)	660.0
		Other Complex (2 plants)	190.0
Therma	CEB	Sapugasukanda Diesel	80.0
		Sapugasukanda (Ext.) Diesel	80.0
		Kelanitissa Gas Turbine (Old)	120.0
		Kelanitissa Gas Turbine (New)	115.0
		Kelanitissa Combined Cycle	165.0
		Chunnakam Diesel (Jaffna isolated system)	8.0
	IPP	Lakdhanavi Diesel	22.5
		Asia Power Ltd. Diesel	51.0
		Colmbo Power (Priv.) Ltd Diesel	62.7
		ACE Power Horana Diesel	24.8
		ACE Power Matara Diesel	24.8
		Heladhanavi Ltd. Diesel	100.0
		ACE Power Embilipitiya Diesel	100.0
		AES Kelanitissa Combined Cycle	163.0
		Kool Air Diesel (Jaffna isolated system)	15.0
Wind	CEB	Hambantota (Pilot Plant)	3.0

Other Plants: Mini Hydropower (CEB: 20.45MW/3plants, IPP: 73MW/35plants)

(Transmission Line)

(As of 2004)

Type	Total Route Length	Total cct Length
220kV Line	330.7	478.9
132kV Line	1,651.0	2,987.0
132kV Underground Cable	13.0	13.0

(Sub Station)

(As of 2004)

Type	Capacity (MVA)	Number of Stsations
220/132/33kV Sub Station	2205/500	6
132/33kV Sub Station	2,150	33

Chapter 1 Introduction

1.1 Background

Power demand in Sri Lanka has been growing at an average rate of about 7-8 percent per year recently. Therefore, there are urgent needs to develop new generation facilities, transmission lines between the generation facilities and demand centers, and to reinforce existing power facilities. Ceylon Electricity Board (CEB), which is responsible for generation, transmission and distribution, has been making efforts to develop the transmission system based on the Master Plan Study on the Development of Power Transmission System conducted by JICA in 1995-1996. In Sri Lanka many hydropower sites have been developed so far, however there are few hydropower potential sites left at present and the composition of electric power generation will change widely. It is necessary to review the present planning methodology and to develop a comprehensive master plan including a generation development plan, a transmission development plan and other plans with environmental considerations.

After a prolonged conflict between the government of Sri Lanka and the Liberation Tigers of Tamil Eelam (LTTE), peace talks between the two parties started, advancing the peace process to the point where there was an agreement for an indefinite truce in February 2002.

Consideration must also be given to the North and East areas, where most of all the transmission facilities have been damaged due to the conflict.

1.2 Objective

The objectives of the Study are:

(1) To review the existing planning methodologies used for generation development and transmission system development,

(2) To make a comprehensive master plan for power development, and

(3) To transfer technology and expertise regarding the development of the comprehensive master plan

1.3 Work Plan

1.3.1 Flow of Overall Study

The Study is composed of the following 4 stages.

In the1st stage, namely the basic study stage, the JICA Study Team clarified the objectives and framework of the Study. The Study activities at the basic study stage are as follows:

- Collect the data and information for developing a comprehensive master plan and uncover issues through the analysis of collected data and information
- Review present development plans such as generation development plans and transmission development plans
- Collect information and analysis for operations, electricity facilities under-construction and development planning sites through surveys of these sites, taking into account technical aspects and environmental and social considerations.

In the 2nd stage, namely the review of the development planning system stage, the JICA Study Team analyzed the following contents based on the results of the 1st stage:

- Review input data and prerequisite conditions for power demand forecasting, generation development planning and the planning method for transmission system analysis

- Review and analyze construction costs based on the study of planned sites and the evaluation of the environmental and social impacts

In the 3rd stage, namely the master plan study drafting stage, the JICA Study Team drew up a draft master plan. The Study activities at this stage are as follows

- Formulate power demand forecast, an optimal generation development plan and a transmission development plan
- Formulate the site selection for large-scale power development
- Formulate a long-term investment plan
- Enforce the initial environmental examination (IEE) at new development sites

In the final stage, namely the comprehensive master plan study stage, the JICA Study Team drew up a comprehensive master plan and made recommendations for the implementation of this master plan, taking into consideration policies and institutions in the power sector and economic and finance aspects.

The overall work flow is shown in Figure 1.3.1.

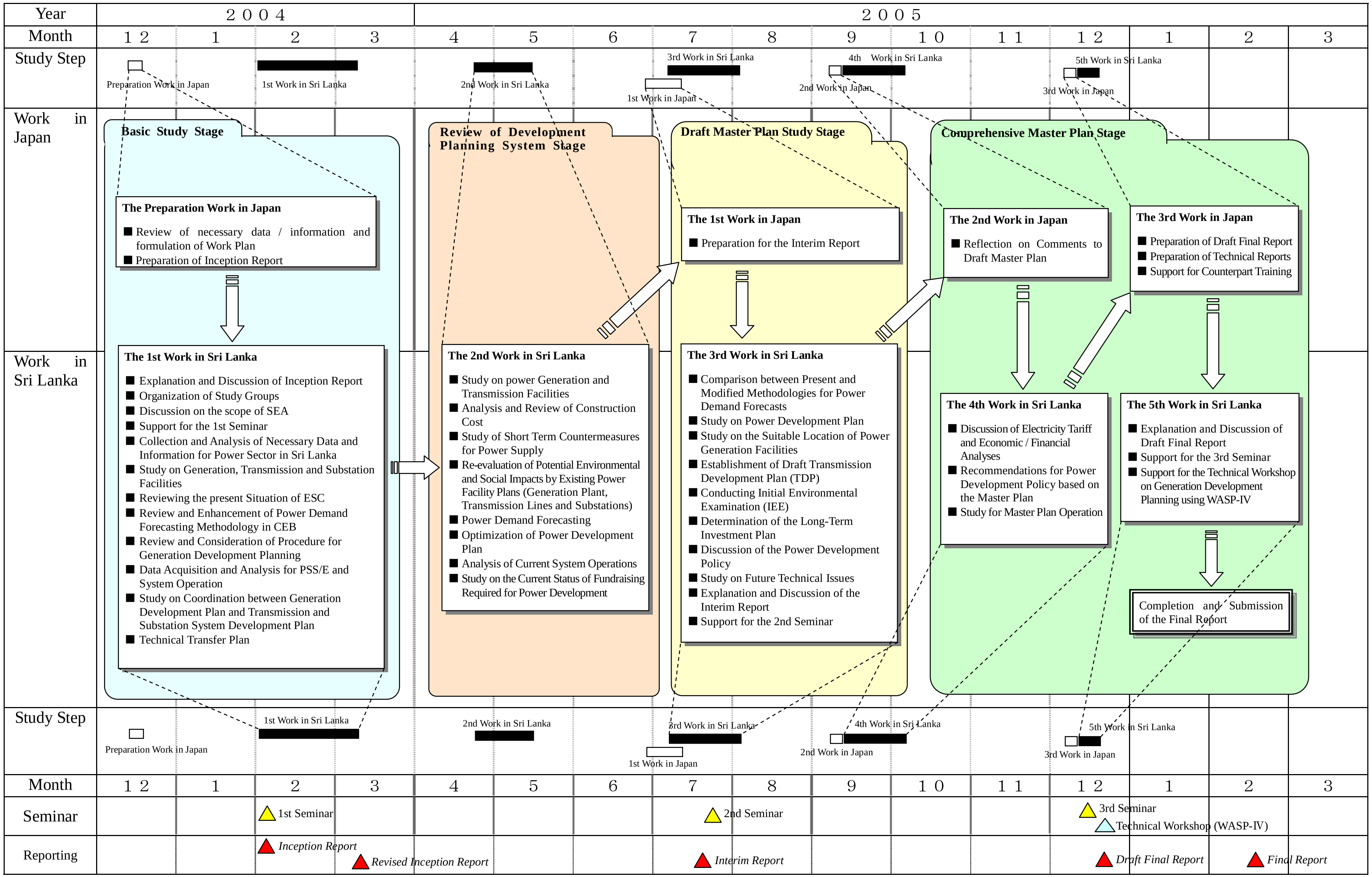
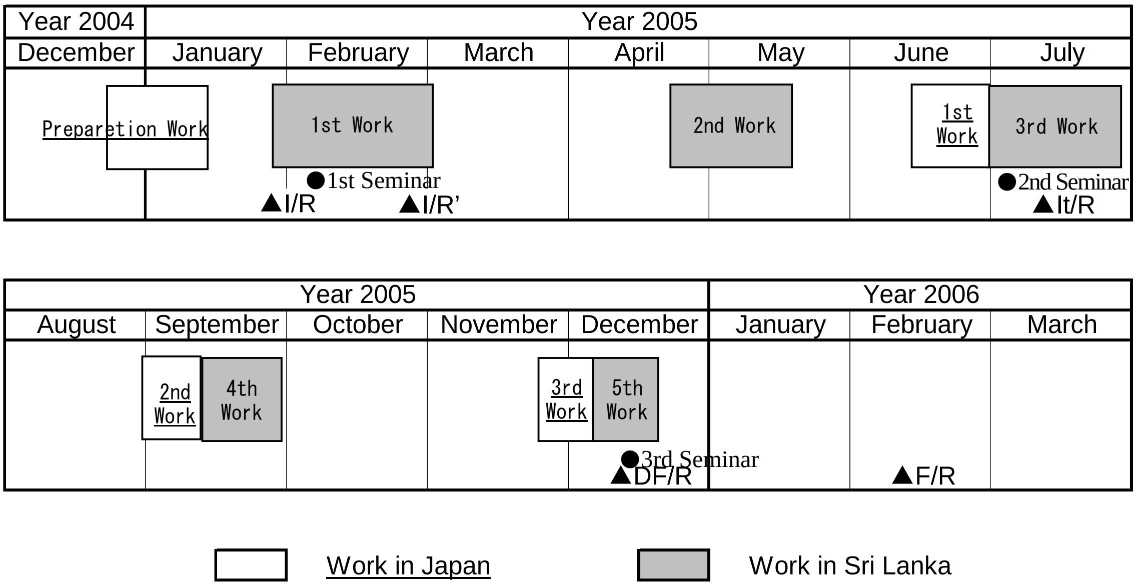


Figure 1.3.1 Overall Workflow of the Study

1.3.2 Study Schedule

The Study was composed of five works in Sri Lanka. Figure 1.3.3 shows the schedule of the study.



I/R: Inception Report   I/R': Revised Inception Report   It/R: Interim Report
DF/R: Draft Final Report   F/R: Final Report

Figure 1.3.3 Schedule of the Study

1.4 Study Groups and JICA Study Team

(1) Study Groups

Study Group	JICA Study Team	CEB
Power Development Policy	Yoshitaka Saito Masayasu Ishiguro	Gemunu Abayasekara (Deputy General Manager)
Power Development Plan / Transmission Development Plan	Hiroshi Hosomi (Tsutomu Nisikawa) Kazunori Irikura Akira Hirano Kenji Taguchi Hiroshi Ozawa	<u>Generation Planning</u> Madhavi Kudaligama FULL TIME (Electrical Engineer) Herath Samarakoon (Chief Engineer) Samitha Midigaspe (Electrical Engineer) <u>Transmission Planning</u> Jagath Fonseka FULL TIME (Electrical Engineer) Kamani Jayasekera (Chief Engineer) Tharanga Wickramaratne (Electrical Engineer) LDL Perera (Electrical Engineer)
Economic and Financial Analysis / Demand Forecast	Hiroo Yamagata Masaya Kawaguchi	Herath Samarakoon (Chief Engineer) Madhavi Kudaligama (Electrical Engineer)
Environmental and Social Considerations	Tsuyoshi Sasaka Hiroshi Hosomi (Tsutomu Nisikawa) Kenji Taguchi	R.K.W. Wijeratne (Environmental officer) Rohita Gunawardhana (Environmental officer)
Coordinator	Takashi Aoki	Samitha Midigaspe (Electrical Engineer)

(2) JICA Study Team

No.	Name	Field of Study
1	Mr. Yoshitaka SAITO	Team Leader / Power Development Planning
2	Mr. Hiroshi HOSOMI (Mr. Tsutomu NISHIKAWA)	Power Development Planning (Hydro Power)
3	Mr. Hiroo YAMAGATA	Demand Forecast
4	Mr. Kazunori IRIKURA	Transmission Planning
5	Mr. Tsuyoshi SASAKA	Environmental and Social Considerations
6	Mr. Akira HIRANO	Power System Analysis
7	Mr. Masayasu ISHIGURO	Power Development Policy
8	Mr. Masaya KAWAGUCH	Economic and Financial Analysis
9	Mr. Kenji TAGUCHI	Thermal Power Facilities
10	Mr. Hiroshi OZAWA	Optimal Power Development Planning / Data Base
11	Mr. Takashi AOKI	Coordinator

Chapter 2 Current Situation of the Power Sector in Sri Lanka

2.1 Overview of Sri Lanka

The Democratic Socialist Republic of Sri Lanka is located off the southwest coast of India. It has a land area of 65,610 km^2 and a population of approximately 19.30 million (as of 2003). It is a multi-ethnic country, with an ethnic composition that includes Sinhalese (72.9%), Tamils (18%) and Sri Lankan Moors (8%). The religious composition includes Buddhists (70%), Hindus (10%), Muslims (8.5%) and Roman Catholics (11.3%).

The major indices for Sri Lanka are shown in Table 2.1.1. The relationship between Sri Lanka and Japan has been friendly and centered on trade and economic and technical cooperation. There have been no major political issues between the two countries since diplomatic relations were established in 1952. Japan has actively supported the Sri Lanka peace process, for example by holding the Tokyo Conference on Reconstruction and Development of Sri Lanka in 2003.

Table 2.1.1 Outline of Sri Lanka

Nation	The Democratic Socialist Republic of Sri Lanka
Area	65,610 sq km
Population	19,300,000
Ethnic groups	Sinhalese 72.9%, Tamil 18.0%, Sri Lankan Moors 8.0%
Religions	Buddhist 70.0%, Hindu 10.0%, Muslim 8.5%, Christian 11.3%
Nominal GDP	18.24 billion US$
GDP per capita	947 US$
GDP real growth rate	5.9%
Inflation rate	6.3%
Unemployment rate	8.6%
Total amount of trade	Exports 5.13 billion FOB Imports 6.67 billion CIF
Commodities	Exports industrial goods (textiles and apparel, etc.); agricultural goods (tea, etc.); gem Imports intermediate goods (textile fabrics, etc.), commodity consumed (foodstuffs, etc.), Capital goods
Trading partner	Exports United States, United Kingdom, Belgium, Germany Imports India, Hong Kong, Singapore, Japan
Currency	Sri Lankan rupee (LKR)
Aid donor	(1) Japan (63%), (2) Norway (13%), (3) Holland (11%) (4) Sweden (7%) ((%) is the rate as a percentage of total DAC countries) Source: DAC data, 2002
Past aid result of Japan	(1) Loan aid (up to fiscal 2003, EN base) 622.544 billion yen (2) Grant aid (up to fiscal 2002, EN base) 165.294 billion yen (3) Technical assistance (up to fiscal 2002, JICA base) 50.989 billion yen

Source: Annual Report 2004, Central Bank of Sri Lanka and otherwise

2.2 Overview of the Power Sector

2.2.1 Organization of the Power Sector

The Ministry of Power and Energy (MPE) serves as the government's central policy organization with jurisdiction over national electric power and energy policy. The Ceylon Electricity Board (CEB), under the MPE, conducts power generation, transmission and distribution operations, in effect running the electric power industry in Sri Lanka.

2.2.2 Rate of Electrification

As presently organized, the CEB is responsible for rural electrification by extension of the power distribution lines. In remote regions where distribution lines cannot readily be extended, rural electrification is being carried out primarily using solar power generation introduced by aid organizations and the private sector.

The CEB issued a report in April 2004 called Rural Electrification Development. According to this report, the household electrification rate had reached 65% as of the end of 2003. This largely reflects the electrification rate on the west coast, centered on Colombo, where the electrification rate for houses exceeds 90%. The electrification rate is conspicuously low, however, in the northern, eastern, and Uva regions. The low rate of electrification in the northern and eastern regions highlights the strong impact of civil conflict in those areas.

The objective for Rural Electrification Development is a household electrification rate of 75% by the year 2007. Power distribution lines are supposed to further achieve a household electrification rate of 80% by 2010.

Following reform of the power sector, the responsibility for rural electrification will be taken over by the MPE.

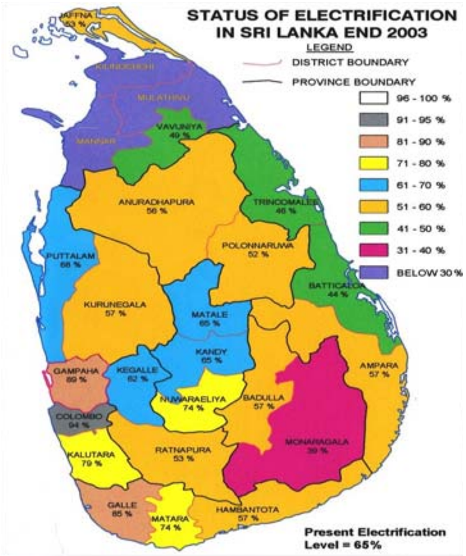


Figure 2.2.1 Rate of Electrification by Districts

2.2.3 Power Demand

Most of the power supplied in Sri Lanka is delivered through the supply system owned by the CEB. Power sales for the entire system in 2003 amounted to 6,208.6 GWh, a major increase (12.8%) from 5,502.3 GWh in 2002. A significant factor in this was the emergence of latent demand as a result of the resolution of power shortages caused by successive droughts, and the opening of new power stations. The average annual rate of increase in power sales during the decade from 1994 to 2003 was 6.4%.

2.2.4 Capacity and Generation of Generation Facilities

The capacity of generation facilities at the end of July 2004 was 2,193.95 MW. The generation composition was: CEB hydro power facilities 55.04%, CEB thermal power facilities 26.12%, CEB wind power facilities 0.14%, emergency power generation facilities 0.91%, small-scale generation facilities 1.78%, and IPP thermal generation facilities 16.02%. The generation composition leans largely toward hydropower.

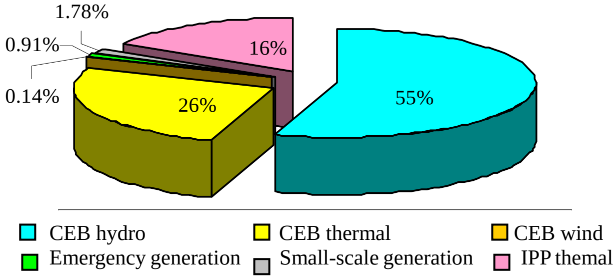


Figure 2.2.2 Generation Composition in Sri Lanka as of July 2004

Changes in the capacity of generation facilities are shown in Figure 2.2.3.

Generation development has been ongoing since 1980 to meet the increase in demand. This development has centered mainly on hydropower facilities.

Since 1992, however, there has been almost no growth in the installed capacity of hydropower facilities. Development in recent years has largely been in thermal power facilities, and the share of thermal power facilities in total installed capacity has been growing.

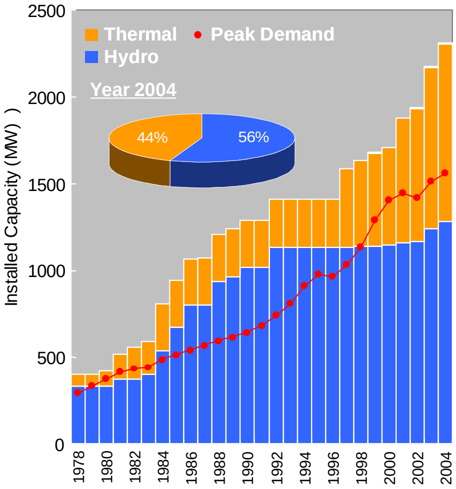


Figure 2.2.3 Trend of the Capacity

Figure 2.2.4 shows the changes in generation output by generation composition.

As with the capacity of generation facilities, the development of hydropower generation since the 1980s has increased the generation from hydropower facilities.

The generated energy of hydropower facilities has decreased since 1996 because of droughts. The increase in thermal power generation facilities was clearly a reaction to that decrease.

In this way, Sri Lanka has given priority to the development of hydropower as its domestically produced energy. This is quite reasonable in light of the fact that the country has no fossil fuel resources. The development of hydropower in Sri Lanka has depended to a significant extent on development of the combined watershed of the Mahaweli and Kelani rivers. The power stations on the Mahaweli river system make up 30.17% of total installed capacity. Development of the Mahaweli complex, however, has been a multipurpose water resource development, so the amount of power generated has been constrained by the downstream use of water for irrigation. There has consequently been very limited flexibility in terms of power generation operations.

The generation output of hydropower facilities also depends on the amount of rainfall received. A system with a generation composition largely centered on hydropower is consequently subject to a major impact on the overall system supply capacity when generation output is reduced by droughts such as those experienced since 1996.

Sri Lanka has also run out of locations where the remaining hydropower sits are of a high cost. The country's generation composition is likely, therefore, to shift away from hydropower and toward thermal power as its main component.

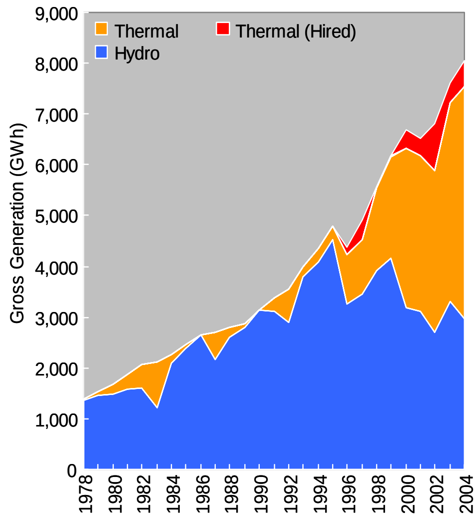


Figure 2.2.4 Trend of the Generation

2.2.5 Power Transmission and Distribution Facilities

The main power transmission system in Sri Lanka is made up of 220-kV and 132-kV transmission lines. The transmission lines that formerly linked the northern and eastern regions with the central region have been severed and left unrepaired as a result of the civil conflict. A system of 220-kV trunk lines follows two routes. One has two transmission lines that run from the hydropower stations in the Mahaweli river system to the main center of demand in Colombo and its surrounding areas, and the other has one line that runs from the Kotmale hydropower station to the New Anuradhapura substation in the central northern region. The other main power stations and substations are connected by 132-kV transmission lines, and some of them form a loop power system that encircles the northwest region, including Colombo. The power stations and substations in this loop system are connected by a double in and out. This simplifies load switching when the system experiences a fault.

The 220-kV transmission line that goes north (as it is a single circuit, it does not satisfy the N-1 reliability standard set under the CEB system plan) is connected to the 132-kV loop system encircling the North Western Province by means of a transformer in a substation, thus forming a loop system with differing voltages[1]. The use of such a loop system makes it possible to improve the supply reliability in the Colombo area and to enhance the supply reliability when connecting to the system in the northern region.

The short-circuit current that occurs during a system fault, however, could exceed the capacity of the circuit breaker in the substation connected to the loop system. The operation of such a system also becomes complicated in terms of system protection. Consequently, although the loop system with differing voltages is physically connected, it is not used, and this means the existing facilities are not being utilized to their maximum extent.

The current circumstances of the power transmission and distribution facilities held by CEB, together with its substations, are shown in Tables 2.2.1 and 2.2.2.

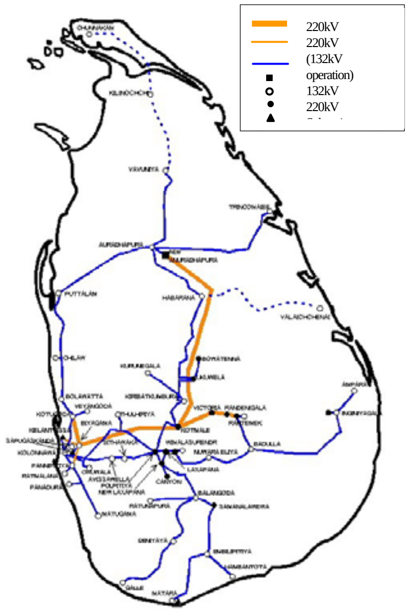


Figure 2.2.5 Power system in Sri Lanka
(Year 2003)

Table 2.2.1 Transmission and Distribution Line in Sri Lanka

Voltage	220kV	132kV	33kV	11kV	440/230V
Length (km)	331	1,664	18,809	2,454	76,102

Table 2.2.2 Substation Facilities in Sri Lanka

Voltage	132/33kV 220/132/33kV 220/132kV	132/11kV	33/11/3.3kV	33/11/LV
Units Capacity (ＭＶＡ)	33,5,1 2,154, 2100/500,105	2 180	126 1,078	15,395 3,993

2.2.6 Power Facility Development Plan

Sri Lanka's power plan is formulated annually in two development plans by CEB. Both of these development plans are coordinated by Transmission & Generation Planning[2]. The Long Term Generation Expansion Plan (LTGEP) concerning power generation facilities is drafted in the Generation Planning and Design Unit, while Long Term Transmission Development Studies (LTTDS) regarding transmission lines and substations are drafted in the Transmission Planning Section.

Figure 2.2.5 shows the CEB organizational structure.

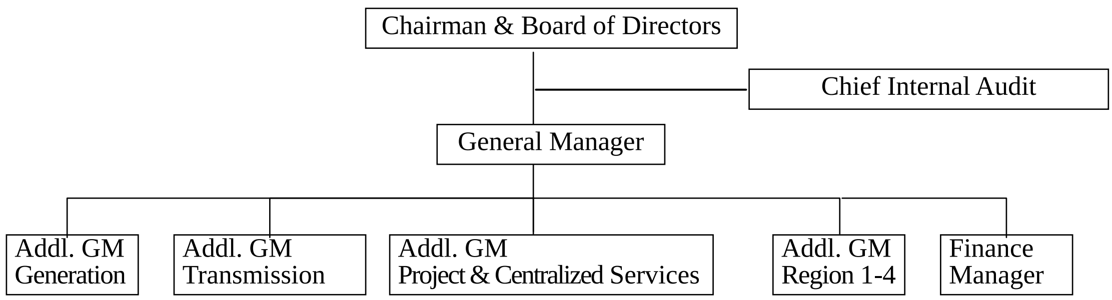


Figure 2.2.5 CEB Organization Chart

[1] Loop system with differing voltages: A loop system that more than two differing voltage systems form a loop through transformers

[2] Transmission & Generation Planning branch comes under Addl. GM Transmission in Figure 2.2.5 CEB Organization Chart.

2.2.7 Power Tariffs and Pricing of Power Purchases

The system of electric power tariffs has two parts, a fixed tariff and a metered tariff. The average power tariff charged by CEB in 2004 was 7.68 Rs/kWh (8.37 yen/kWh). This is high even by comparison with other Asian countries. One feature of the system is that the electric power tariffs for domestic and religious use are set lower than the average power tariff, while tariffs for general and industrial use are set higher. It is thus evident that the system is structured to provide cross-subsidization to domestic and religious users. CEB plans to eliminate these cross-subsidies in stages, but has not taken any specific steps in that direction as yet.

The cost of power purchases from IPPs in 2003, based on actual figures, was an average of 8.45 Rs/kWh for thermal power, 6.09 Rs/kWh for hydropower and 12.32 Rs/kWh for leased power generation for emergency use. It is apparent that the cost of thermal power purchased from IPPs is higher than the average power tariff (7.68 Rs/kWh), while power from leased power generation for emergency use is being purchased at an even higher price.

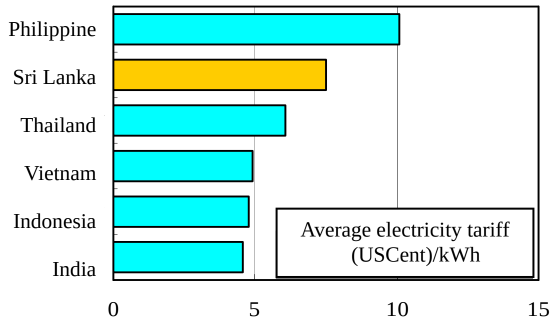


Figure 2.2.7 Ave. Electricity Tariff

Consumers (ratio)	Ave.Tariff (Rs/kWh)
Domestic (23.1%)	5.54
Religion (0.3%)	4.46
General (25.9%)	11.85
Industry (37.9%)	8.38
LECO (11.4%)	6.06
Street Light (1.4%)	7.80
Total	7.68

Figure 2.2.8 Ave. Tariff by User Type (2004)

2.2.8 Power Sector Reforms

Sri Lanka enacted Electricity Reform Act No. 28 of 2002 and Public Utilities Commission of Sri Lanka Act No. 35 of 2002 in October 2002. This legislation is intended to move the country's power sector away from the integrated framework of power generation, transmission and distribution conducted by CEB, and shift it toward the adoption of a competitive market mechanism on a single buyer model. The breakup and restructuring of the CEB and the Lanka Electricity Company (LECO) had not yet taken place as of November 2005. This is because the financial issues involved in the breakup and restructuring of CEB and LECO (the distribution of assets and liabilities), the technical issues, the personnel assignment issues and the issue of how to proceed with rural electrification following the reforms have not been decided.

The post-reform CEB will remain a state-owned enterprise. Apart from that, it is at present uncertain what shape the sector reforms will take.

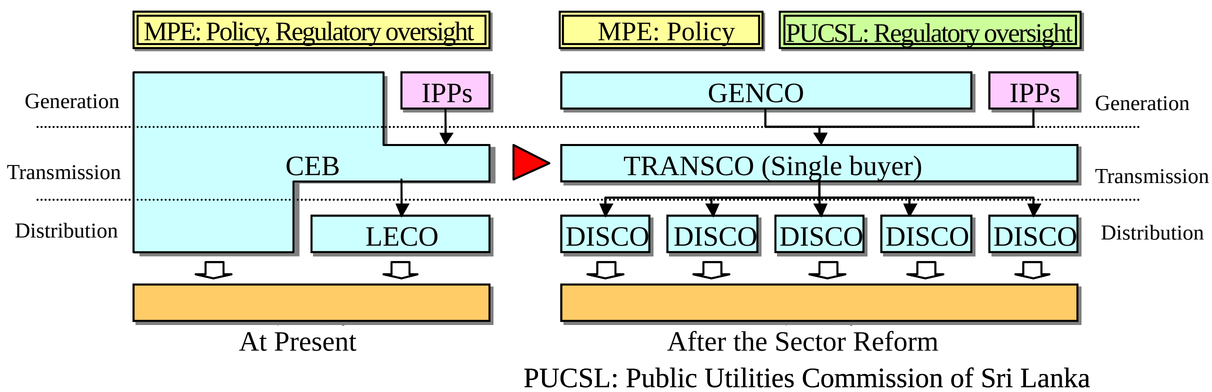


Figure 2.2.9 Power Sector Reform in Sri Lanka

Chapter 3 Current Status of Policy on Power Development in Sri Lanka

In the Democratic Socialist Republic of Sri Lanka, power sector policy has followed a line of restructuring supported by program loans furnished by the Asian Development Bank (ADB) and the Japan Bank for International Cooperation (JBIC).

In 2002, the government enacted the Electricity Reform Act and the Public Utilities Commission of Sri Lanka Act, and set in motion a program of reform revolving around the unbundling of the Ceylon Electricity Board (CEB) and establishment of an independent regulator. Nevertheless, there is also strong opposition to the reform led by labor unions. Although the legislation has been passed, the unbundling of the CEB, the centerpiece of the reform, has not yet been implemented because the government has not been able to reach an agreement with the ADB and the JBIC, which are providing financing for the reform.

The government therefore has not made a final determination on the shape of the CEB after unbundling, which is the key point of the reform. For this reason, the path to the rebuilding of CEB finances remains unclear. Naturally, this situation is greatly affecting the determination of power development investment plans and has made the future of the power sector uncertain.

3.1 Power Sector Policy Directions

The current basic policy on the power sector is based on the Power Sector Policy Directions[3] announced in August 1997 by the former Ministry of Irrigation and Power and revised in October 1998 (See page 3-11). Through this policy proposal, the government laid down the course of subsequent restructuring.

In the context of the Directions, the government explicitly made the following points:

- The existing power sector structure resting on vertical consolidation under the CEB has become anachronistic. This is causing major problems in respect of the power tariff scheme, CEB finances, procurement of funds needed for future investment, and the national fiscal burden of related subsidization.
- A far-reaching program of restructuring is required for resolution of these problems.
- The restructuring will break up the vertically integrated structure of monopoly by the CEB, promote private investment, erect a regulatory framework with sufficient transparency, and establish a tariff scheme that is commercially sustainable.
- The unbundling of the CEB will make it possible to exclude governmental interference in enterprises and clearly define the management responsibilities of enterprises in each division.
- The government is to break away from dependence on funding from official development assistance (ODA) and promote private-sector investment in the power sector by private-sector parties. The construction of thermal power stations is to be funded with private financing resting on build-own-operate (BOO) and build-operate-transfer (BOT) schemes.
- Power tariffs will be set on levels assuring funds for future investment by the enterprise as viewed from a commercial perspective.

3.2 Enactment of the Electricity Reform Act and Progress

The two laws (the Electricity Reform Act and the Public Utilities Commission of Sri Lanka Act) were passed in 2002 in order to erect a regulatory framework with transparency and promote the restructuring centered around CEB unbundling indicated in the Policy Directions announced in 1997 and 1998.

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[3] The Ministry subsequently revised the Directions and announced the revised version under the title “Proposed Power Sector Policy Guidelines” in November 2002 (this is the latest policy proposal), but the Guidelines have not yet been approved by the cabinet. As such, the Directions released in 1997 and revised in 1998 remain the official statement of policy in the sector.

3.2.1 Orientation of Restructuring

In accordance with the Electricity Reform Act, the Ministry of Power and Energy (MPE) began to study the following framework for the reform.

- The reform shall be based on the single buyer system.
- The CEB generation division shall be detached and set up as a single generation company[4].
- The transmission company shall also act as a single buyer and serve as the hub of the power sector by buying power from the generation companies and selling it to distribution companies and industrial customers. It shall also perform the local load dispatching.
- The distribution companies shall be formed by integration of the CEB distribution division and Lanka Electricity Company (LECO), followed by partitioning into at least three regional companies[5].
- The Public Utilities Commission (PUC) shall be in charge of regulating all power companies. The independent companies shall submit business plans to the PUC on an annual basis.

  The aims of the restructuring lie in endowment of the newly established power companies with autonomy and prevention of political interference in the operations. An additional aim is to put the corporate finances on sound footing by separating and clarifying the debt currently held by the CEB.

At present, however, the Electricity Reform Act is not completely effective.

In the legislative system in Sri Lanka, new laws only go into effect after declaration of enactment by the parliament, signature by the competent minister, and notification in the official gazette. Ordinarily, the minister signs laws with all articles written into them when they move into the stage of effectuation. In the case of the Electricity Reform Act, however, the minister is signing each article separately. At the core of the restructuring is the unbundling of the CEB, and the law has not been completely effected because the CEB has not yet been unbundled.

3.2.2 Establishment of an Independent Regulator

To date, the Ministry of Power and Energy (MOPE) has been in charge of drafting policy, supervising the industry inclusive of the CEB, and issuing all permits and approvals. To assure the transparency of regulatory authority, which is one of the pillars of the restructuring, the PUC was newly established as an independent regulator by passage of the Public Utility Commission of Sri Lanka Act.

The PUC will function as a regulator only when the Electricity Reform Act is completely effected. As noted above, however, this act has not yet been put into complete effect, and the licensing authority still remains in the MOPE[6].

Besides the power sector, the PUC is to supervise the sectors of water, oil, toll roads, and ports and harbors. This supervision must be grounded in individual industrial laws for the regulated industry, along the lines of the PUC Act. Because such laws do not yet exist for the sectors of water supply and oil, no concrete action can be taken yet.

For electrical power, base proposals are being prepared for tariff guidelines, operational guidelines, and other matters.

[4] Although the Electricity Reform Act stipulated the establishment of a single generation company, the government also considered the option of tripartite division for establishment of three generation companies (Mahaweli Hydropower, Laxapana Hydropower, and Thermal Power Generation).

[5] The Electricity Reform Act stipulates the establishment of at least three distribution companies, but the government also considered a further unbundling into five companies.

[6] Upon complete effectuation of the Electricity Reform Act, the old CEB Act and Electricity Act will be abolished and the regulatory authority will be transferred from the MOPE to the PUC.

3.2.3 Outlook for the Progress of Restructuring

There remain several issues related to the future progress of the restructuring.

Thus far, the government has shown a commitment to implementation of the reform, but faced strong opposition from labor unions and remained unable to embark on the CEB unbundling. As a result, it fell into a situation of temporary suspension of loans for the reform program from the ADB and the JBIC as donors. To achieve a breakthrough in this impasse, the governmental Committee on Power Sector Reforms made a study of the concept for the reform in June 2005 and compiled its findings into a report (Concept Paper) issued that July. The proposals presented in this report were approved by the cabinet in July.

(1) Concept Paper for the Reform (approved by the cabinet in July 2005)

Approved by the government, the Paper clearly states that the problems saddling the power sector at present derive from the following four causes.

- Large-scale power plants able to provide base load could not be constructed.
- The purchase of power from emergency diesel generators with high fuel costs drove up power supply costs.
- The increase in supply costs could not be reflected in power tariffs.
- There were structural problems in CEB management.

The Paper asserted the need for implementation of the following three measures for resolution of these problems.

- Revision of tariffs for establishment of realistic, fair, and transparent rates
- Prompt start of construction of coal-fired plants for base load
- Unbundling of the CEB and establishment of subsidiaries; separation of the existing debt and assurance of the operation of the CEB and the subsidiaries.

The Paper presents no more than an outline of the situation after CEB unbundling as the key part of the reform. It posits the establishment of one generation company, one transmission (and bulk electricity trade) company, and at least two distribution companies. As for the existing LECO, it envisions its continued subsistence as a separate company in the present form.

As indicated by these elements, the Paper presents some proposals for promotion of the reform around unbundling of the CEB, the solution of whose problems has been deferred by the government so far. Nevertheless, it does not go beyond the level of conceptualization, and leaves a problem in that it does not contain a concrete schedule for the CEB unbundling. The ADB submitted its view of the Paper in September, but has not yet reached a decision as regards resumption of the loans.

It should be added that it was decided in June 2005 to postpone implementation of the second tranche of the ADB loan for the power development program. The ADB has not retreated from its position that resumption requires satisfaction of the following five conditions.

- The government shall establish the PUC and appoint its members. (This has already been done.)
- The PUC shall set tariffs; issue licenses to generation, transmission, and distribution companies; and determine regulations and standards related to power sale and purchase, in accordance with the law.
- The newly established transmission, generation, and distribution companies shall acquire the requisite licenses and commence operations.
- The government shall unbundle the CEB in terms of functions (generation, transmission, and distribution) in accordance with a detailed plan for the same.
- The government, CEB, and LECO shall obtain written agreements to the effect that the main donors have no objection to the details of reform of the CEB and the LECO.

(2) Completion of the Reform

The final consummation of the reform based on the July Paper will require legal amendments to bring the Electricity Reform Act and the CEB Act into conformance with each other. The government is planning to place a bill for such amendment before the national assembly quite soon (in 2006), but the schedule still contains some factors of uncertainty.

3.3 Rural Electrification (RE)

In Sri Lanka, the electrification ratio accomplished a steep rise from 7% in 1976 to 60% in 2001, but construction of the distribution network is still lagging in rural areas. In 2001, the electrification rate reached 92% in the Colombo area but was less than 20% in some northern areas. The rate averaged about 60% nationwide but only 47% in rural areas.

In view of these circumstances, the government announced an official Rural Electricity Policy in November 2002 and presented its stance on promotion of RE.

In the context of this policy, the government posted the goal of raising the average electrification ratio nationwide to 75% by 2007. To attain this target, it made a clear commitment to application of the most economical measures, meaning promotion of electrification not only by extension of the grid but also off-grid systems in areas where the on-grid approach is unfeasible. The government is projecting that about 80% of the demand in the residential sector will be supplied by the grid, but the remaining areas will have to depend on off-grid electrification.

With a realization that it cannot depend entirely on the power utilities for RE, the government explicitly advocated effective use of the energies of other private-sector firms and public-sector organizations for RE, and committed itself to provision of the necessary legal, institutional, and financial support.

The government made it particularly clear that it was going to put a halt to the arbitrary cross-subsidization and provision of direct subsidies to certain areas thus far, and ensure that subsidies are available to all parties promoting RE on a both fair and competitive basis. To do so, it has decided to simplify licensing requirements for small and/or independent electrification systems, as well as to make provisions for the instatement of different tariff schemes enabling retrieval of investment as opposed to a single uniform tariff scheme. In addition, for small power producers, it indicated that they would be allowed third-party access in the future.

In advance of this policy announcement, RE applying renewable energy was promoted in the form of projects that were implemented by the private sector and given official support by the government, beginning in the second half of the 1990s. The biggest impetus was provided by the Energy Services Delivery (ESD) Project, which led to the Renewable Energy for Rural Economic Development (RERED) Project.

3.3.1 The Energy Services Delivery (ESD) Project

The ESD Project was implemented during the 1997-2002 period by the Government of Sri Lanka (GOSL), with World Bank and Global Environment Facility (GEF) assistance. The ESD Project comprised three components a credit programme, a pilot grid-connected wind farm of 3MW and a capacity building component for the CEB. The Administrative Unit (AU) set up within DFCC Bank was the executing agency for the ESD Credit Programme component and the CEB was the executing agency for the other two components.

(1) ESD Project Credit Programme

The ESD Project Credit Programme provided the basis for a market-based approach to the introduction of renewable energy development in Sri Lanka. It was designed to promote private sector and community based initiatives for the provision of electricity services through grid-connected mini hydro projects, off-grid village hydro schemes and solar photovoltaic electrification of rural homes. The ESD Credit Programme resulted in a dramatic increase in the development of grid-connected and off-grid renewable energy projects, prepared and implemented by the private sector and village communities. At completion, the ESD Project Credit Programme had met or exceeded all targets, as follows:

- 31 MW of mini hydro capacity installed through 15 projects against a target of 21 MW
- 20,953 SHS installed, with a total capacity of 985 kW, against a revised target of 15,000
- 350 kW of capacity through 35 village hydro schemes serving 1,732 beneficiary households against a target of 250 kW through 20 schemes.

The ESD Credit Programme was assisted by a US$19.7 million line of credit from the International Development Association (IDA) of the World Bank and a US$3.8 million grant from the GEF. Loans for individual investments or subprojects were disbursed through participating credit institutions, namely DFCC Bank, National Development Bank (NDB), Hatton National Bank (HNB), Sampath Bank, Commercial Bank and Sarvodaya Economic Enterprises Development Services (SEEDS).

The Credit Programme provided medium to long-term funding to private investors, non-governmental organizations (NGOs) and co-operatives for:

- off-grid electrification infrastructure through village hydro schemes and SHS
- grid-connected mini hydro projects and
- other renewable energy investments.

Off-Grid Projects, following an initial period of market development, entered a phase of rapid and sustained growth during the final two years. The follow-on RERED Project builds on the success of the ESD Project.

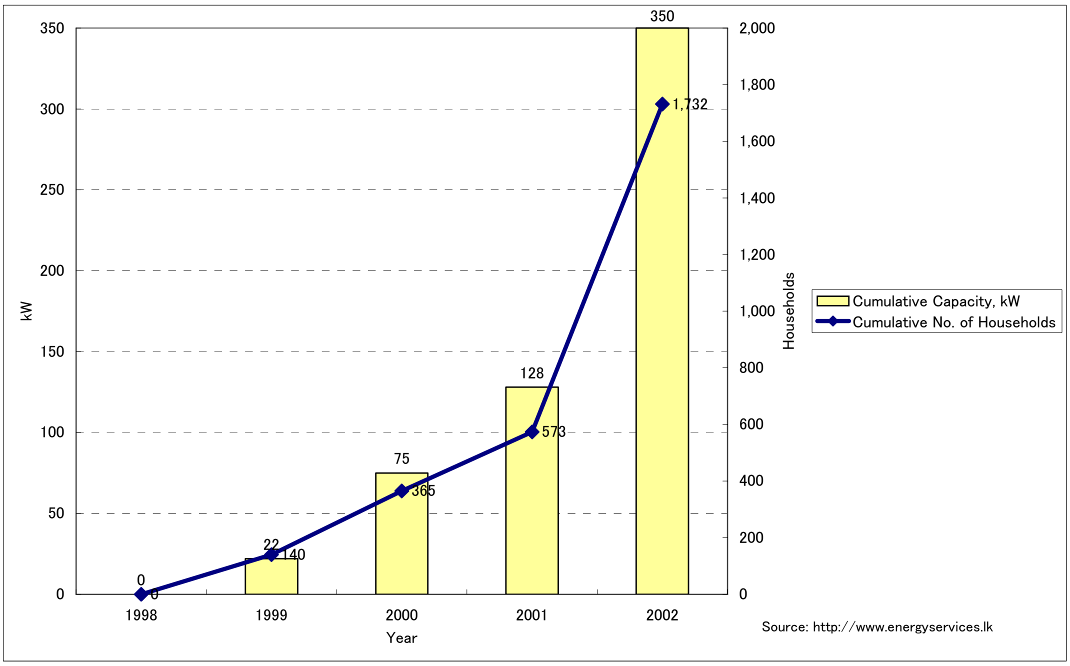


Figure 3.3.1 Off-Grid Village Hydro Schemes Completed under the ESD Project

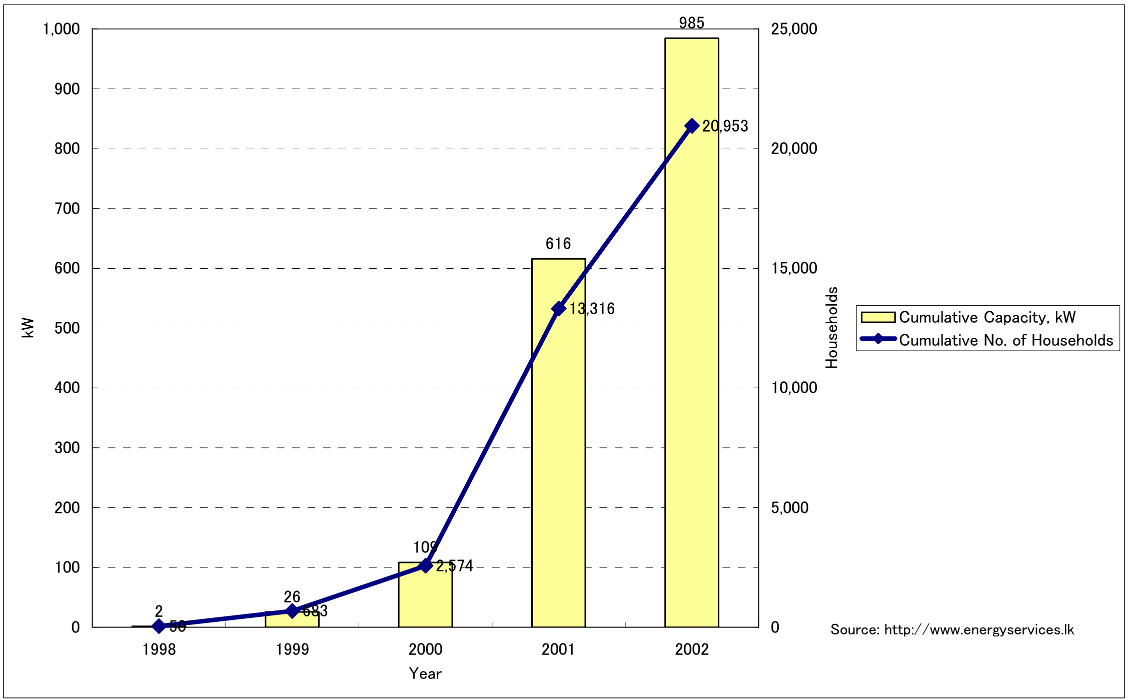


Figure 3.3.2 SHS Installed under the ESD Project

(2) Pilot Wind Farm

The wind farm comprises five 600 kW turbines designed to supply a total annual capacity of 4.5 GWh. The CEB continues to monitor and record operational data from the wind farm and learn from the experience in integrating such projects with the national grid.

(3) Capacity Building

The ESD Project provided capacity building assistance to the Demand Side Management (DSM) Branch of CEB.

3.3.2 Renewable Energy for Rural Economic Development (RERED) Project

The GOSL, with the assistance of the World Bank and the GEF has established the RERED Project, which aims to expand the commercial provision and utilization of renewable energy resources, with a focus on improving the quality of life and economic development in rural areas by providing access to electricity generated from such resources. The project, which is being implemented over the 2002-2007 period, follows the successful ESD Project that was implemented during the 1997-2002 period. Two major development objectives are:

- Provision of off-grid electricity services to invigorate the rural economy, empower the poor and improve their standard of living
- Setting up of grid-connected investment projects to encourage competition in the power sector, provide capacity addition and diversity, and achieve greater sector efficiency and transparency.

These objectives translate into the following key indicators of performance for the Project:

- 85 MW of grid-connected electricity generation capacity addition through renewable energy resources
- 100,000 rural homes electrified through SHS and off-grid electricity connections to households through independent mini grids powered by village hydro, wind or bio mass
- 1,000 off-grid electricity connections to small and medium enterprises and public institutions

- Measurable increases in socio-economic activity in project areas and incomes of households gaining access to electricity
- 1.25 million tons of carbon dioxide emission avoided as a result of the project
- Increase in the number of energy service companies in operation from two at present to at least six by project completion.

(1) Project Financing Arrangement

The RERED Project is funded by a US$75 million line of credit from the IDA and a US$8 million grant from the GEF. Loans for individual investments (sub-projects) are disbursed through Participating Credit Institutions (PCI), who make their independent credit assessments while ensuring that sub-projects are financially viable, environmentally sound, meet required engineering standards and are economically justifiable. The executing agency of the RERED Project is the Administrative Unit (AU) set up within DFCC Bank.

Table 3.3.1 Indicative financing plan, US$ million

Component	IDA credit*	GEF grant	PCI**	Private equity	Other ***	Indicative cost
Grid-connected sub-projects: mini hydro, wind, biomass	49.2	0	12.3	22.6	6.2	90.3
Solar PV investments	18.8	3.9	4.2	1.4	0	28.3
Community investments: off-grid village hydro, wind, biomass	3.6	0	0.6	0.2	0	4.4
Energy efficiency, conservation and demand side management investments	0.6	0	0.1	0.3	0	1.0
Cross-sectoral energy applications	2.3	0.8	0.5	1.0	0	4.6
Technical assistance (non-component specific)	0.5	3.3	0.2	0.3	0.8	5.1
Total	75.0	8.0	17.9	25.8	7.0	133.7

* US$2.5m of IDA credit to be converted to grant by GOSL and provided to investment enterprises. However, as GOSL's grant component will be sought only after the GEF grant has been utilized. The actual breakdown of GEF financing within the six components will vary somewhat.
** Participating Credit Institutions
*** US$6.2m from CDM for grid connected investments and US$0.8m from GOSL for technical assistance.
Source: http://www.energyservice.lk

(2) Project Implementation

<u>Administrative Unit</u>

The GOSL, in consultation with the World Bank, has appointed DFCC Bank as the RERED Project Administrative Unit (AU) to implement the project. To avoid conflicts of interest, the AU is independent of and separated from the Participating Credit Institution (PCI) function of DFCC Bank. The AU is primarily responsible for the administration of the IDA credit line and GEF grant funds, and provision of project support.

Eligible Sub-projects and Investment Enterprises

Sub-projects are investment projects utilizing the credit and/or grant funding provided by the RERED Project. Eligible sub-projects are private investment proposals for:

- Grid-connected renewable energy power projects (with capacity not more than about 10 MW)
- Off-grid village based renewable energy power projects
- SHS
- Other renewable energy investments
- Energy efficiency, conservation and demand side management (DSM) investments

An investment enterprise eligible for financing may be any private enterprise, non-governmental organization (NGO), co-operative or individual operating in Sri Lanka. Subject to meeting PCI's credit worthiness assessment, they obtain medium or long-term sub-loans from PCIs to establish eligible sub-projects and procure assets.

Procedures

Project administration is carried out by the Administrative Unit (AU). Lending to sub-projects is carried out by the participating credit institutions (PCIs). Counterpart funds for technical assistance are provided by project beneficiaries and GOSL.

Two Special Dollar Accounts (SDAs) are maintained at the Central Bank of Sri Lanka to deposit the proceeds of the IDA credit and the GEF grant. The credit SDA is used to refinance PCIs, who approve sub-loans to project beneficiaries following their own credit evaluation procedures while ensuring compliance with Project requirements. Once the sub-loan has been approved, PCIs forward a completed loan Refinance Application (RA) form to the AU requesting commitment for a maximum of 80% of the approved sub-loan amount. As and when the PCI disburses funds against the approved sub-loan amount, a Loan Disbursement Request (LDR) form is forwarded by the PCI (with appropriate supporting documents) to the AU for obtaining a maximum refinance of 80% of the amount disbursed to the beneficiary. Release of grant funds by the AU is based on evidence of work done.

(3) Small Power Purchase by the CEB

The CEB has in place a standardized small power purchase agreement and tariff, whose formula is based on the avoided cost principle, for grid-connected renewable energy power generation projects up to 10MW capacity.

Table 3.3.2 Small Power Purchase Tariff, Rs/kWh

	Dry Season (February - April)	Wet Season (balance months)
1997	3.38	2.89
1998	3.51	3.14
1999	3.22	2.74
2000	3.11	2.76
2001	4.20	4.00
2002	5.13	4.91
2002*	5.9	5.65
2003	6.06	5.85
2004	5.70	4.95
2005	6.05	5.30

*: For Agreements executed between February1, 2002 and December 31, 2002.
Source: http://www.energyservice.lk

3.4 Incentives for Promotion of Private-Sector Investment

The Board of Investment (BOI[7]) offers various incentives for power sector investment from other countries. These incentives include tax holidays, preferential taxes, and tariff exemptions.

3.4.1 Preferential Treatment from the BOI

Investment incentives are provided under BOI Act, No. 4, which was enacted in 1978 (and amended three times, in 1980, 1983, and 1992).

Among the investment fields stipulated in Article 17 of the BOI Act, investment in the power sector falls under that of large-scale infrastructure projects. Upon approval by the BOI, the projects are eligible for preferences and exemptions as regards income tax, tariffs, foreign currency controls, and import controls.

Investment in excess of 10 million dollars is eligible for a tax holiday ranging from 6 to 12 years in correspondence with the amount, and a low income tax rate of 15% thereafter. Materials imported for facility construction are exempt from tariffs. With a BOI ruling, projects may also be exempt from application of law for control of foreign exchange (see Table 2-4).

Table 3.4.1 Preferential Treatment Provided by the BOI

Category	Qualifying Criteria		Full tax Holiday (year)	Concessional tax			Import Duty Exemption		Exemption from Exchange Control
	Min. Inv. (mil. US$)	Min. Export Req. (% of output)		10 %	15 %	20 %	Capital Goods	Raw Material	
Large-scale Infrastructure Projects -Power generation, transmission & Distribution -Development of Highways, Sea Ports, Air Ports, Public transport, Water Services -Establishment of Industrial Estates -Any other Infrastructure Project approved by the BOI	10	NA	6	NA	The reafter	NA	Yes*note	No	Determined by the BOI
	25		8						
	50		10						
	75		12						

Note: During the project establishment/implementation period.
Source: BOI, Make it in Sri Lanka

3.4.2 Support by the Bureau of Infrastructure Investment (BII)

Although it does not offer one-stop services, the Bureau of Infrastructure Investment (BII) within the BOI provides support for infrastructural investment. To receive such support, the projects must be either entirely private ones or rest on cooperation between the private and public sectors. They usually take the form of BOO or build-own-operate-transfer (BOOT) projects.

The basic role of the BII is as follows:

- Collaborating with relevant ministries and government agencies to determine infrastructure projects suitable for implementation by the private sector.

[7] Originally established in 1987 as the Greater Colombo Economic Commission, and reorganized into the BOI in 1992.

- Coordinating the preparation of project documents with the relevant line ministry or agency, such as feasibility studies, request for proposals, and joining the local and foreign issue of such documents
- Negotiating products with investors in collaboration with line (industrial) ministries/agencies
- Receiving and reviewing unsolicited proposal (where possible), presenting such proposals to the relevant government agencies for appropriate action and coordinating the implementation of such project, if acceptable.
- Providing specialized consultancy support and the drafting of relevant document including Letters of Intent and Implementation Agreement.
- Granting of tax and other concessions under the authority of the BOI Law.
- Marketing infrastructure projects to prospective investors

Power Sector Policy Directions (Abstract)

Introduction	● While, traditionally, power sectors were monopolies, which were generally state-owned, the power sectors all over the world are being restructured and reformed. Sri Lanka is no exception, and there is a need to develop a policy package in keeping with this trend. ● Cost of electricity is a key element in attracting foreign investors in to the country. Further, electricity has a direct bearing on the competitiveness of local industry in international market. ● Power prices should be comparable and have a competitive edge in relation to prices in the region including South Asia and South East Asia. ● This document sets out the basic principles on which the power sector may be restructured and reformed.
1. Sector Objective	● Basic goal of the sector is to meet the demand for energy services at all times at least economic, social and environmental cost, and thereby promote economic development and social well-being.
2. Present Status	● For almost one funded year, except for a short period, the electricity supply industry was in the hands of the public sector. ● This is reflected by the fact that the establishment of the Department of Government Electrical Undertakings in 1927, promulgation of Electricity Act in 1951, establishments of Ceylon Electricity Board (CEB) in 1969 and Lanka Electricity Company (LECO) in 1983, and the complete take-over of local authority distribution schemes by the CEB in 1992.
2.1 Organization	● The power sector is organized under the Ministry of Irrigation and Power, and the CEB is responsible for generation and transmission of electrical power in the whole country and distribution in areas other than those served by LECO.
2.2 Governance	● The sector presently exhibits the characteristics of classic closed command-and-control governance. ● The CEB is vertically integrated government-owned monopoly with a centralized management structure. Although the CEB was set up as an independent autonomous body, both investments a tariff require government approval.
2.3 Sector Regulation	● The Electricity Act of 1951 provides the regulatory framework for the sector. Generation and transmission is carried out by a public utility, and distribution to consumers by local authorities. ● The office charged with the administration of the act does not function effectively. Technical regulation is almost absent and economic regulation is a consequence of loan investment.
2.4 Financing	● The sector's investments have so far financed through tariff revenue (domestic resource) and soft loan from bi- and multi-lateral institutions.
2.5 Sector Operation	● The CEB is expected to function on sound commercial principles. ● However, tariff formulation severely affected by conflicting social ad commercial objectives of the government. The CEB is also expected to expand electricity supplies to rural areas where the returns are low, and required to provide variety of ancillary services such as maintenance of electrical installation in government building, and security and street lightings.
3. Future Demand and Investment	● Demand for electricity for the middle of the next decade is expected to grow at around 10% p.a. ● The present generation capacity has to be doubled in seven years time with an investment order of US$1.5 bill. Another US$1 bill would be required for concomitant transmission and distribution expansion.
4. Vision	● The country will have an effective and dramatic power sector, which would facilitate economic growth.

	● A reliable supply of grid electricity will be available to at least 80% of the population at affordable prices. ● The industrial sector will have reasonably prices reliable power supply to sustain their competitiveness in the international market. ● There will be transparent regulatory processes. ● There will be a non-monopolistic situation in the power sector, and the private sector will have substantial investments. ● There will be reliable distribution and transmission systems with losses reduced to internationally accepted levels.
5. Basic Policy	● Restoration of price stability, promotion of private investment, and address of problems of poverty and unemployment are the main element of the government economic development strategy ● Within the strategy, special emphasis is placed on public enterprise reforms, reform of the public administration system, reduction of the budget deficit, trade reforms, and rationalization of the poverty alleviation and social welfare payment. ● In the contest of this policy framework, the new policy package for the power sector aims to lower prices, ensure a high level of service, supply reliability, and sustain an adequate level of investments by harnessing the participation of the private sector.
5.1 Private Sector Participation	● The private sector is expected to play a key role in power development. Future thermal power generation projects will be using private financing on BOO/BOT basis. ● Soft loans and other types of public financing will not be used for the purpose of investment in thermal power generation except for project already committed as at July 1, 1997. ● However, the Power Committee shall have the discretion on case by case basis to recommend the allocation of concessionary finance to large scale power projects, as follows: ➢ To reduce the development costs of the private sector, using concessionary loans for the improvement of general infrastructure of the project, contributing to a reduction in development costs to the private sector. ➢ The confessional lean is made available by the government to the project development company as an alternative to loan financing at commercial rate from the private sector in circumstances where the per unit cost of generation of power plants is higher due to financing cost as a result of developing the required infrastructure facilities. ➢ Under this structure strategic private sector investors will be invited through a competitive process to contribute equity into the project company. ➢ This approach is expected to be considerably advantages to the government in terms of price in relation to allocation of risks. ➢ For the purpose of using private sector financing for power generation, an enabling environment will be created. The selection of developers will be through competitive procedures. IN selecting future power generation projects, the unit cost of generation is the principal criterion. ➢ Only solicited proposal will be considered for future generation project as a BOO/BOT basis. Procedures outlined on guidelines on government tender procedures shall be adapted for solicited power projects. ● However, the Power Committee on case by case basis may consider unsolicited proposal for thermal generation if such a proposal accompanied by: ➢ An investment proposal to set up an industrial park; ➢ An investment proposal to set up a large scale manufacturing project of national significance

	• The CEB shall not enter into power purchase agreement (PPAs) unless the above guidelines are adopted and after PPA is cleared by the Power Committee prior to approval of the cabinet. • Unsolicited proposals for alternate sources of energy may be considered if such a proposal is based on new technology and is more cost effective in other forms of energy. • Hydro power generation potential of the country will be developed to its full potential as it is a major indigenous resource for power generation. All large scale hydro generation facilities will remain under government control for the foreseeable future. Transmission system shall remain within the management of the public sector.
5.2 Restructuring of the Sector	• The power sector will be restructured to accommodate competition and to facilitate private sector participation in order to create a non-monopolistic situation within the power sector. • The roles of the government as owner, regulator and operator will be clearly defined and separated. Sector entities will be allowed to operate as independent autonomous bodies. • The presently vertically integrated power sector will be decentralized. The decentralized units will be responsible for their profit and loss and they will be fully accountable. • During this process generation, transmission and distribution function will be sub-divided horizontally to form a number of entities to form strategic business units.
5.3 Transparent Regulatory Process	• Regulation of the sector operations is important in view of the inherent natural monopolistic nature of transmission and distribution and also because of the critical role electrical power plays in all economic activities. • An important function of the regulatory framework is to ensure an appropriate balance between the interest of the producers and those of the consumers. • The government will establish a transparent regulatory framework and enact the enabling legislation to provide a sound basis for the establishment of power sector economic, financial, environmental and service policies.
5.4 Commercialization and computerization	• The power sector will operate on sound commercial and business principles and after identifying and removing constraints to achieving this objective. • This means they will pay interest and taxes, earn commercially-competitive rates on equity capital, and have responsibility for their own budgets, borrowing, procurement, pay and staff conditions. • Power sector entities, as commercial enterprises, will be allowed to recover their costs. • The government will explore the possibility of employing other means to address social equity issues rather than power sector subsidies. • When financially unattractive activities have to be undertaken in pursuance of government policy, the government will fully compensate the entities. For example, when services such as maintenance of electrical installations in government-owned buildings are provided by the CEB, it will be given the option of charging the respective organization for the service period.
5.5 Planning	• Power sector planning for resource acquisition will follow the paradigm for integrated resource planning: ➢ Improve supply side efficiency ➢ Improve demand side efficiency ➢ Employ decentralized sources where they are cost effective ➢ Expand generation

	• All these potions will be examined on a level playing field and the least cost strategy will be selected for meeting the demand for electricity. • The least-cost expansion planning methodology for the generation sub sector will be used to identify the most economic generation options. Subsequently, these options will be revised using other planning methodologies, if necessary, to prepare expansion plans. Investment, whether public or private, in the sector will only be in accordance with the plan. • It is necessary that the plan takes into account the important issues concerning the security of supply and the optimization of the fuel mix.
5.6 Security of Supplies	• The system will be so planned to ensue reliability even during drought years when the emery capability of the hydro system is low. • The fuel mix will be optimized to ensure security of supplies so that there is no undue dependence on one fuel. • Development of hydro resources will be encouraged because it is thee only indigenous resource.
5.7 Tariff Policy	• The tariff charged should have some relationship to tariff levels in other courtiers, since it has an important bearing on our competitiveness in international trade. • In making tariffs the relationship between the demand and the price need to be kept in mind. • The tariff structure will be based on sound commercial principles which would take into account a commercially based allocation of costs among consumers according to the burdens they imposes on the system. • Assurance of a reasonable degree of price stability. • Provision, where economically feasible, of a minimum levels of service to low-income consumers. • Power prices that generate sufficient revenues to meet the financial requirement of the sector. • A tariff structure simple enough to facilitate metering and billing.
5.8 Transmission	• Transmission of electricity will be handled by a separate public-owned transmission authority. It will be the responsibility of the authority to provide for easy exit and entry for generators and to satisfy the demand from distribution enmities. • They will also be responsible for load dispatching, system operation and control.
5.9 Distribution	• A number of distribution entities will be set up. These entities will be responsible for distributing power within a franchised area and for providing all other consumer services within the area. Distribution reforms will take into account the need to continue with on-going rural electrification projects and the attendant need for subsidies.
5.10 Rural Electrification	• A rural electrification policy directed towards the improvement of the quality of life and acceleration of economic development in rural areas will be adapted. • The government will make the necessary institutional and financial arrangements in order to compensate the distribution entities as such schemes may not be commercially viable.
6. Implementation of Proposal	• Implementation of proposed policies must necessarily involve the setting up of detailed and intricate procedure, and necessary legal provisions. • Failure to so could result in a serious breakdown in sector operations. Therefore, the process shall be sequenced for orderly implementation. • Whilst the involvement of the private sector in power generation can proceed without hindrance priority should be given to put in place the regulatory framework as a matter of urgency. In the meantime, the restructuring of the existing power sector will commence.

Source: Ministry of Irrigation and Power (1998), Power Sector Policy Directions

Concept for Power Sector Reforms (Abstract)

1. Four Root Causes of the Present Crisis in the Power Sector
   (1) Obstacles faces by the CEB during the past one or two decades, in implementing the plans for setting up large scale, low cost base load plants, particularly those using coal as fuel and large scale hydropower projects.
   (2) The proliferation of relatively low capacity thermal power generating plants using petroleum fuels, the prices of which have risen sharply.
   (3) The CEB was enable to increase tariffs commensurate with the increase of fuel prices, depreciation of the Sri Lankan rupee, consequential higher prices paid to IPPs in terms of their counteract.
   (4) Structural and managerial weakness and operational inefficiencies within the monopolistic CEB as well as an inadequate level of empowerment in its decision making process.

2. Tripod of Strategic Initiatives
   (1) Immediate adjustment of the tariff at least to reflect the direct costs consequence to the steep increase in the price of fuel. This should be followed by a realistic, fair and transparent mechanism for setting tariffs and compensation for tariff subsides.
   (2) Urgent implementation of the lower large-scale thermal base-load generating plants using coal, until they meet a substantial part of the energy requirement. This should not be any room for vacillation and diversionary moves in this respect.
   (3) Restructuring the power sector by unbundling the CEB and establishing independent, self-contained and commercially oriented companies fully owned by the CEB and ensuring their continued viability by offloading debt and subject to an independent and transparent regulatory mechanism.

3. Details of the Recommended Strategic Initiatives and Other Relevant Issues

3.1 Urgent Needs to Revise the Tariffs
   (1) It is necessary to establish reasonable financial stability in the electricity industry even before the reforms are implemented.
   (2) Although the cost of electricity could be brought down by off loading all the sector debt, it is not possible to reduce or even to stabilize the electricity prices, at current levels.
   (3) It is imperative that financial stability of the CEB be implemented by immediate revision of tariffs to at least reflect the steep increase of fuel prices.

3.2 Reduction of Generation Cost
   (1) The government or the CEB or the subsidiary companies will not initiate projects, call for proposals or entertain proposals, or appoint committee to investigate proposals, whether solicited to unsolicited, to build any new power plants that would operate on oil or other fuels of which the prices is linked to world oil prices, except in accordance with the approved Long Term Generation Expansion Plan.
   (2) To reduce electricity production costs, coal-fired thermal power plants, which the Long Term Generation Expansion Plan recommends, should be implemented.
   (3) The existing policy objective of building all future thermal power plants only by the private sector should be suspended for the first 900MW coal-fired thermal power plant. The public sector should build this plant expeditiously by securing a long-term low-interest loan and provide relief to electricity consumers within the shortest possible time.
   (4) A conductive environment should be created for the state sector to compete with the private sector for thermal power generation.
   (5) The coal-fired power plant proposed to be built at Puttalam shall be the first coal-fired power plant. The government shall process the concessionary financing proposal without delay, enter into the required agreements, and target to build the power plants to produce electricity from year 2010 onwards. All relevant government institutions, CEB and the institutions established under the reform process will be instructed to strictly adhere to this schedule.
   (6) No substantial quantity of the annual electrical energy requirement shall be contracted to be purchased either from one power plant r a group of power plants belonging to one privately owned entity. A 10% share of energy is considered to be substantial in the power sector.
   (7) All obstacles to the rapid construction of the Upper Kotomale Hydropower Project should be cleared and the project should be implemented to produce electricity from year 2009.

(8) Efficiency improvement of existing power plants should be undertaken to reduce the operational costs.

3.3 Power Sector Reform Process

3.3.1 Sector Structure

(1) The sector will be restructured to ensure increased efficiency, transparency, autonomy, accountability, competition and financial viability. Presently vertically integrated functions of generation, transmission and distribution of the CEB will be vertically and horizontally unbundled.

(2) The CEB will retain as a statutory body subject to the necessary changes in keeping with these proposals. Autonomy and authority of the CEB will be granted by introducing necessary legislation. The CEB should be allowed to form subsidiary companies and/or hold shares of those companies. Relevant legislation should be suitably emended/replaced or integrated to endure the aforesaid.

(3) CEB owned subsidiary companies will be established for the following functions presently handled by the CEB, and they will operate independently as separate legal entities.

- Generation - one company
- Transmission and bulk electricity trade - one company
- Distribution - two or more companies

(4) The CEB Employees Provident and Pensions Funds will continue under the CEB.

(5) LECO will retain and continue as a separate entity at this stage of reforms.

(6) The PUC will act as the economic, technical and safety regulator for the electricity industry.

(7) The independent Monitoring and Advisory Committee (MAC) will be retained to monitor the performance of these companies and advise the Minister of Power & Energy on operational and financial matters of the relevant subsidiary companies and the CEB. MAC will make recommendations to the minister on matters relating to the appointment and removal of the board of directors of the CEB.

3.3.2 Future of the Sector Entities

(1) The board of directors of the CEB will be nominated by MAC and appointed the Minister of Power & Energy. Two persons of the CEO of the CEB nominated by the Power Trade Unions will be appointed to the board of directors.

(2) The board of directors of the subsidiary companies will be appointed by the board of directors of the CEB with the concurrence of the MAC. The board of directors of subsidiary companies will include at least one member selected from the nominees of the Trade Unions.

(3) Necessary legislation should be introduced so that the CEB or its subsidiary companies cannot be brought under the management control of any other external entities, agencies or bodies.

(4) A management-Employee Cooperation Committee for each subsidiary company will be established to act an advisory capacity, without management powers.

(5) There will be an internal auditor under the board of directors of the CEB who will audit the activities of the subsidiary companies and report directly to the board of directors of the CEB.

(6) Adequate number of shares will be transferred in the form of a share trust to be held for the benefit of employees. This share trust will be established at the time of incorporation of the subsidiary companies. The adequacy of the number of shares to be transferred shall mean the number sufficient t grant a minority shareholder status to the trust.

(7) The subsidiary companies that will be established under the CEB will not be privatized. The following measures will be taken to prevent privatization of these subsidiary companies.

- Any proposal or board resolution with regard to the disposal of shares will be referred to a committee, the composition of which shall be provided for by regulations. The committee, which shall be constituted for the sole purpose of studying such proposal or resolution, shall include representatives of the trade unions or their nominees. The committee shall make tits recommendations to the board of directors.
- After considering the recommendation of the committee, it will be necessary for the resolution for the alienation or otherwise disposal of the shares, to have 2/3 consent of

the board of directors of the CEB and relevant subsidiary company for the resolution to take effect.

- Such resolution will be placed before Parliament.
- Establishment of a share trust with an adequate number of shares of each of the subsidiary companies for and on behalf of the employees. The purpose of such is to allow the trust to act as a minority shareholder in the event of a move to substantially change the ownership structure or revision of memorandum and articles of association of any of the subsidiary companies.
- Additional subsidiary companies/join-venture company can be established to provide services required by the CEB, and abovementioned subsidiary companies.
- Legal provisions against the theft of electricity will be strengthened.

3.3.3 Financial Stability and Viability of the Subsidiary Companies

(1) A debt restructuring study shall be undertaken and the amount of debts that need to be off-loaded shall be identifies. There shall be a memorandum of understanding between the government and the CEB. Subsidiary companies established under the reform process, including the CEB, shall be free from paying the principal and the interest on the amount of debt so identified and off-loaded

(2) Once the agreed debts are off-loaded as above, the Power Sector Reform Office in conjunction with the CEB shall identify, in advance of the vesting date, the electricity tariffs to be charged by the distribution companies including LECO from consumers, and the transfer prices between all the subsidiary companies shall be allowed to charge these tariffs and transfer prices from their first day of operation.

(3) If the government desires that any consumers or group of consumers should receive a subsidy on the electricity bill, such amounts shall be clearly stated in the monthly electricity bills issued by the new distribution subsidiary companies to their customers. If the government fails to reimburse this subsidy to the relevant subsidiary company within one month, the subsidy shall be charged to the consumer.

(4) The PUC shall be the regulator.

3.3.4 Addressing Employees Concerns in the Implementation

(1) In assigning employees to the subsidiary companies, offering voluntary retirement scheme to the employees and provision of terms of conditions of employment should be carried out.

(2) A collective agreement will be entered between the trade unions and the CEB/subsidiary companies in addressing employment related issues.

(3) Any shortfall of the CEB employees pension fund as at the vesting date will be replenished by the government.

(4) The government, the CEB and the trade unions will enter a memorandum of understanding on the implementation of the contents of this concept paper.

(5) Subsidiary companies will be established under the CEB as early as possible after the passage of necessary legislative enactments. Until such time, strategic business units within the CEB will be formed immediately, in line with the proposed subsidiary companies, in order to facilitate the easy transfer of CEB functions to the subsidiary companies.

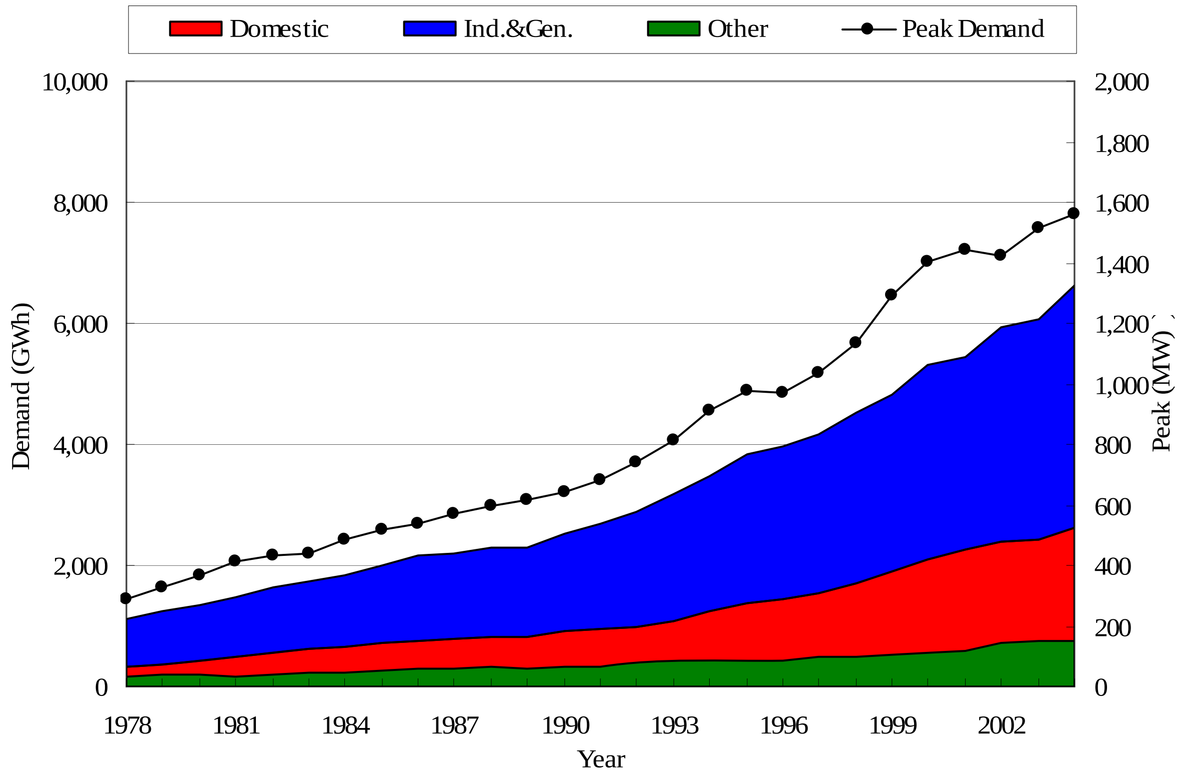
Source: Report of the Committee on Power Sector Reforms, July 12, 2005

Chapter 4 Power Demand Forecast

4.1 Changes in Power Demand in Sri Lanka

Sri Lanka's power industry was initiated by a number of privately-owned companies in the latter half of the 1890s. These companies were nationalized in 1927, and the power sector became the responsibility of the Department of Government Electrical Undertakings (DGEU). With the passage of the Electricity Act in 1951, the DGEU retained responsibility for the generation and transmission of electricity, while authorized licensees, mainly local authorities, assumed responsibility for power distribution. In 1969, the Ceylon Electricity Board (CEB) was established on the basis of the Ceylon Electricity Board Act to take over the functions of the DGEU. At the time, more than 200 power distributors were licensed by the government, but most were poorly equipped and lacking in funds. Management efficiency suffered, and the distribution companies were gradually absorbed by the CEB and the Lanka Electricity Company (LECO). At present, the CEB not only oversees power generation and transmission, but also distributes power in regions other than those in which the LECO is the official distributor.

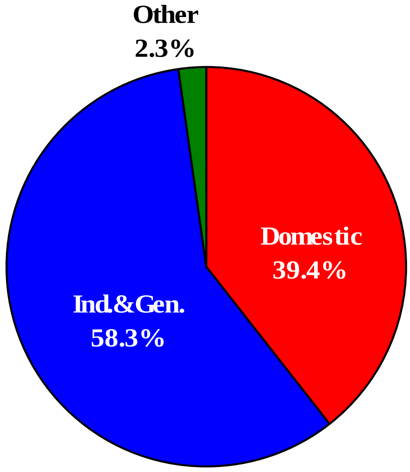
Figure 4.1.1 shows the total amount of electricity sold by the CEB and changes in peak demand from 1978 to the present. Since 1978, the amount of electricity sold by the CEB has increased steadily by an average of 6-7% per year. Increased economic growth has seen increases of 7% or greater since 1990. Despite the fact that figures for peak demand fell against the preceding fiscal year in 1996 and 2002, they recovered from the following year, and peak demand, like total sales, has since shown a yearly average increase of 6-7%.



Source: CEB

Figure 4.1.1 Changes in Peak Demand and Energy Sales

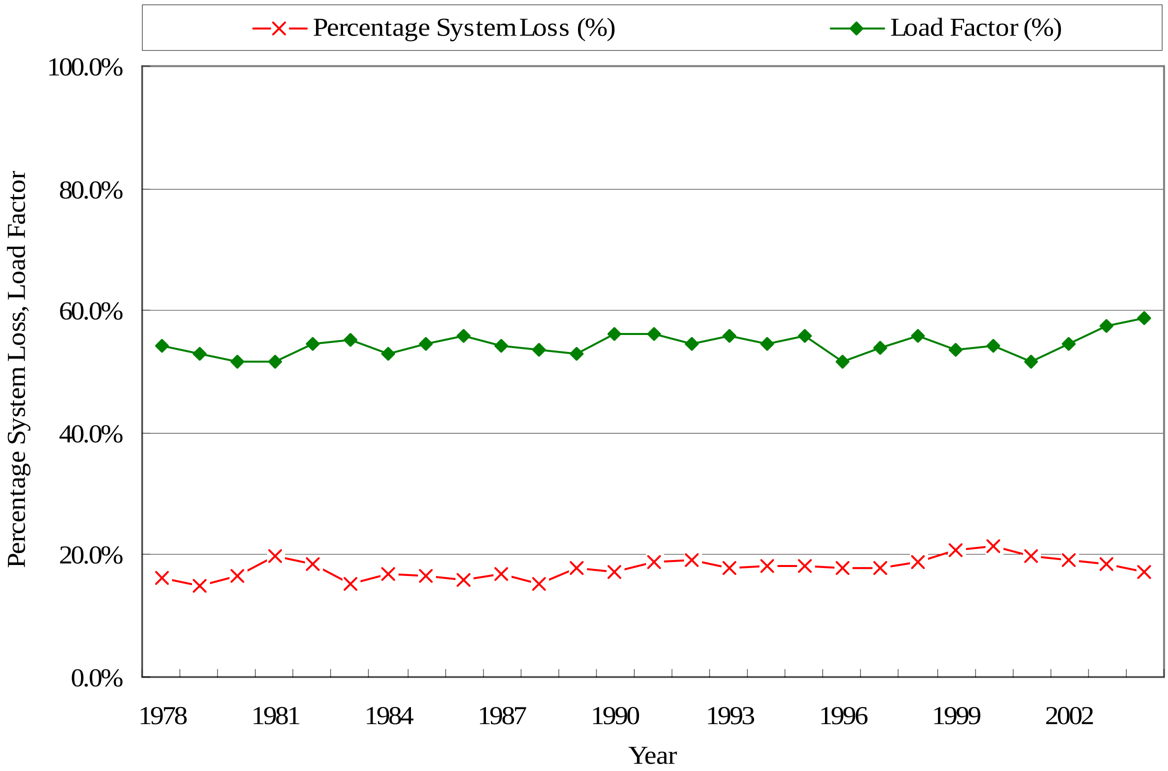
Tariff Category	Share
Domestic	39.4 %
Industrial & General	58.3 %
Other	2.3 %



Source: CEB

Figure 4.1.2 Share of each Tariff Category

Figure 4.1.3 shows system loss and load factor. Both parameters are basically constant.



Source: CEB

Figure 4.1.3 Changes in System Loss and Load Factor

4.2 Review of Methodology for Demand Forecasting in CEB

4.2.1 Methodology Outlines

CEB prepares a 20-year national demand forecast every year (See Table 4.2.1 for Long Term National Demand Forecast[8] 2004-2024) and an econometric approach is employed for the forecasting. CEB prepares the forecasting models by regression analyses and conducts national demand forecasts in each tariff category such as the domestic, industrial & general and other purpose sectors. Appropriate independent variables and coefficients are selected with the statistical analysis tool[9] based on the historical data[10] including GDP and population as a socio-economic indicator, and average electricity price, energy sales and customer accounts as electricity-related indicators.

(1) Energy sales (GWh)

According to the *National Demand Forecast 2004 - 2024*, the forecasting models of energy sales for each tariff category are as follows:

<Domestic Purpose Sector[11]>

Ddom(t)i = -316.436 + 0.01815 GDPPC(t)i + 0.815 Ddom(t-1)i

Where,

Ddom(t)i	: Demand for electricity in domestic purpose consumer category (GWh)
GDPPC(t)i	: Gross Domestic Product per capita (million LKR[12]/capita)
Ddom(t-1)i	: Demand in domestic consumer category in previous year (GWh)

<Industrial & General Purpose Sector[13]>

Di&g(t)i = -350.134 + (-)0.00258 GDP(t-1)i + 0.00482 GDP(t)i + 0.515 Di&g(t-1)i

Where,

Di&g(t)i	: Demand for electricity in Ind. & Gen. purpose consumer category (GWh)
GDP(t)i	: Gross Domestic Product (million LKR)
GDP(t-1)i	: Gross Domestic Product in previous year (million LKR)
Di&g(t-1)i	: Demand for electricity in Ind. & Gen. purpose consumer category in previous year (GWh)

<Other Purpose Sector[14]>

In Demand(t) = -106.035 + 0.0554 t

Where,

t : Year

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[8] Besides the *Long Term National Demand Forecast* prepared by the Transmission & Generation Planning Branch, there are three other demand forecasts: the *System Demand Forecast* by the System Control Branch and the forecast used in the Medium Voltage Distribution Development Plan by the Planning & Dvelopment Branches of each Region 1, 2, 3 and 4. Each of these demand forecasts are made using different methodology and forecasting periods.

[9] SPSS, SPSS Inc.

[10] From 1978 to now.

[11] Domestic Purpose Sector consists of the domestic tariff category and the domestic portion in LECO including its losses.

[12] Sri Lanka Rupees

[13] Industrial & General Purpose Sector consists of the industrial & general purpose tariff category and the industrial & general portion in LECO including their losses.

[14] Other Purpose Sector consists of the religious & charitable institute tariff category, street lighting tariff category, and the other purpose portion in LECO including its losses.

Finally, electricity demands achieved from the models for each category are summed up as the total national electricity demand[15].

Regarding the scenarios of the socio-economic indicators, the GDP growth scenario for the next four years (High, Medium, Low) by the Central Bank of Sri Lanka[16] and the population growth scenario (High, Medium, Low) by the Department of Census & Statistics are used for demand forecasting.

CEB prepares the 6 load forecast scenarios shown below.

- Base Demand Forecast (GDP: Medium, Population: Medium)
- Low Demand Forecast (GDP: Low, Population: Low)
- High Demand Forecast (GDP: High, Population: High)
- Demand Forecast with RSLP[17] (10% of GDP growth target)
- Demand Forecast with Constant Energy Losses (Constant system loss rate)
- Demand Forecast with DSM[18] Measures

(2) Gross Generation (GWh)

Gross generation is calculated by adding system losses to forecasted energy sales. A system loss scenario is set based on the CEB Business Plan[19].

(3) Peak Demand (MW)

Peak demand is calculated by a load factor and calculated gross generation. The average of the load factor for the past 20 years, excluding the years in which power cuts were employed, is used as the future load factor.

Table 4.2.1 National Demand Forecast – Base Demand Forecast 2004

Year	Energy Sales (GWh)	Losses (%)	Gross Generation (GWh)	Load Factor (%)	Peak Demand (MW)
2004	6,573	18.2	8,038	55.0	1,668
2005	7,032	17.3	8,506	55.0	1,765
2006	7,569	15.3	8,937	55.0	1,855
2007	8,149	14.8	9,565	55.0	1,985
2008	8,804	14.1	10,245	55.0	2,126
2009	9,515	14.1	11,072	55.0	2,298
2010	10,284	14.1	11,967	55.0	2,484
2011	11,112	14.1	12,931	55.0	2,684
2012	12,005	14.1	13,970	55.0	2,900
2013	12,965	14.1	15,087	55.0	3,131
2014	13,995	14.1	16,286	55.0	3,380
2015	15,100	14.1	17,571	55.0	3,647
2016	16,283	14.1	18,948	55.0	3,933
2017	17,556	14.1	20,429	55.0	4,240
2018	18,920	14.1	22,017	55.0	4,570
2019	20,383	14.1	23,719	55.0	4,923
2020	21,949	14.1	25,541	55.0	5,301
2021	23627	14.1	27,494	55.0	5,707
2022	25,429	14.1	29,591	55.0	6,142
2023	27,361	14.1	31,839	55.0	6,608

Source: National Demand Forecast 2004 – 2024, CEB

[15] The Northern Province has rapidly recovered its potential electricity demand since 1999 due to the peace process. Therefore additional demand for the Northern Province is also considered based on the scenario that the province will increase 25.4GWh per year for the next three years.

[16] Released on May 1st every year.

[17] Regaining Sri Lanka (RSL) Programme

[18] Demand Side Management

[19] According to the CEB Business Plan, CEB plans to improve their system loss rate from 18.4% in 2003 to 14.1% over the next five years.

4.2.2 Points for Fine-tuning Forecasting Methodology in CEB

(1) Base Data

As mentioned above, CEB has conducted regression analyses based on all historical data from 1978. Consequently, even if a rapid increase in electricity demand has occurred in recent years, such a trend might be ignored because the statistical analysis tool seeks the optimum formula matching all data from 1978 as well as possible, which shows a moderate growth. On the other hand, using only data from recent years, for example data for the past 5 or 10 years, as the base data might lead to the overestimation of the future electricity demand.

The expected period for the base data is therefore 15 or 20 years. This study uses data for 20 years in consideration of the forecasting period in the *National Demand Forecast* in CEB. When it is indicated that a trend in electricity demand for the past 10 years has changed dramatically, the period of base data should be revised comparing the actual demand with each forecast achieved from the data for 20 and 15 years.

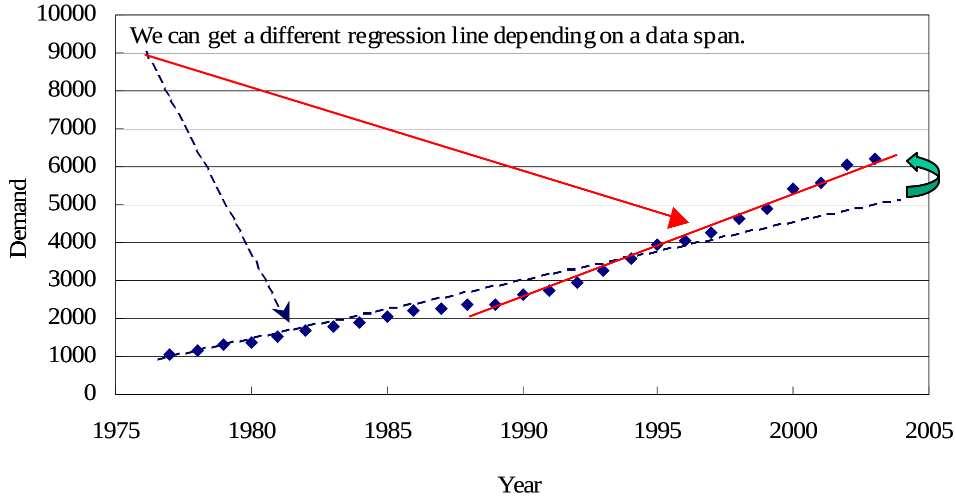

Figure 4.2.1 Image of Data Span on Regression Model

(2) Power Demand Forecasting Model

In the econometrics model, energy demand is expressed by the function of income (or GDP) and a price in general. Energy intensities can be also introduced in the manufacturing industry sub-sector[20].

The power demand forecasting model of CEB in 2004 includes income related parameters of GDP per capita (for the domestic purpose sector) and GDP (for the industrial and general purpose sectors). However, there is no price parameter in their models in 2004, because the statistical analysis tool has not selected any price parameter for the power demand forecasting models.

<Domestic Purpose Sector>

Fundamentally, the demand forecasting model for the domestic purpose sector is acceptable. In this section, the study verifies whether or not a price parameter should be added to the model.

[20] JICA (2002), *Study on the Optimal Electric Power Development and Operation in Indonesia (Main Report)*

Table 4.2.2 shows the correlation coefficient between the average electricity price of the domestic sector and base data from 1978 in the sector. There is a negative correlation coefficient between the price and electricity demand.

Table 4.2.2 Correlation Coefficient between Electricity Demand and Price (Domestic)

	Ddom	GDPpc	LDdom	**Avg. DomPrice**	DomConAcc	LDomConAcc	Pop
Ddom	1						
GDPpc	0.99760	1					
LDdom	0.99083	0.98757	1				
Avg. DomPrice	**-0.49534**	**-0.47930**	**-0.51091**	**1**			
DomConAcc	0.99296	0.98941	0.99449	**-0.54572**	1		
LDomConAcc	0.99475	0.99176	0.99260	**-0.54063**	0.99923	1	
Pop	0.93000	0.92694	0.96541	**-0.50130**	0.94696	0.93796	1

Then, focusing on the coefficient of a price parameter in the forecasting model below, the coefficient "*c*" is supposed to be negative, because an increase in an electricity price results in a decrease in electricity demand in general[21].

$$Ddom(t)i = d + a*GDPPC(t)i + b*Ddom(t-1)i + c*APdom(t)i$$

Where,

Ddom(t)i : Demand for electricity in domestic purpose consumer category (GWh)
GDPPC(t)i : Gross Domestic Product per capita (million LKR/capita)
Ddom(t-1)i : Demand in domestic consumer category in previous year (GWh)
APdom(t)i : Average electricity price in domestic purpose consumer category (Rs/kWh)

According to Table 4.2.3, which shows the coefficient of each independent variable in the different data spans, the coefficient "*c*" of the price term is negative in the case of using the data from 1997 to 2004, which means that there is a price impact on electricity demand. On the other hand, in the cases of the data from 1981 to 1988 and from 1989 to 1996, the coefficient is positive and there is no price impact.

One of the reasons is that the increase of consumer accounts contributed largely to the electricity demand until the middle of 1990s. On the other hand, in the most recent 10 years, new consumers have accounted for below 10% of the total consumer accounts in each year and the electricity consumption trend for the existing consumers has affected the electricity demand largely in comparison with the impact of the increase in new consumers. Therefore, it is assumed that the price impact is from changes in recent years.

[21] When the sign for the price term is positive, this means that electricity demand will increase according to a rise in electricity price. Such a situation is unrealistic in general.

This price impact is small at present based on the analyses in the study[22]. However, the impact of a price change on electricity consumption by each consumer will be larger than now according to the completion of electrification in Sri Lanka. It is not necessary to introduce a price term into the forecasting model immediately. However, by about the year 2010[23], the target year for grid electrification, CEB will need to consider whether or not a price team should be selected for the model.

Table 4.2.3 Sign of Price Term in each Data Span (Domestic)

Data Span	*a*	*b*	*c*	*d*
1981-1988	0.02662	0.566	8.949	-422.622
1989-1996	0.03246	0.824	86.673	-1091.835
1997-2004	0.03671	0.780	-255.464	-377.424
1978-2004	0.01698	0.834	-12.090	-258.575

<Industrial & General Purpose Sector>

The equation below is the CEB forecasting model in 2004 for the industrial and general purpose sectors shown before.

Di&g(t)i = -350.134 + (-)0.00258 GDP(t-1)i + 0.00482 GDP(t)i + 0.515 Di&g(t-1)i

According to the model, GDP in the previous year has a negative impact on electricity demand for the industrial and general purpose sectors. This means that the electricity demand will decrease according to an increase in the previous year's GDP. However, focusing on the correlation between the previous year's GDP and the electricity demand so far, the correlation is obviously positive (See Figure 4.2.2).

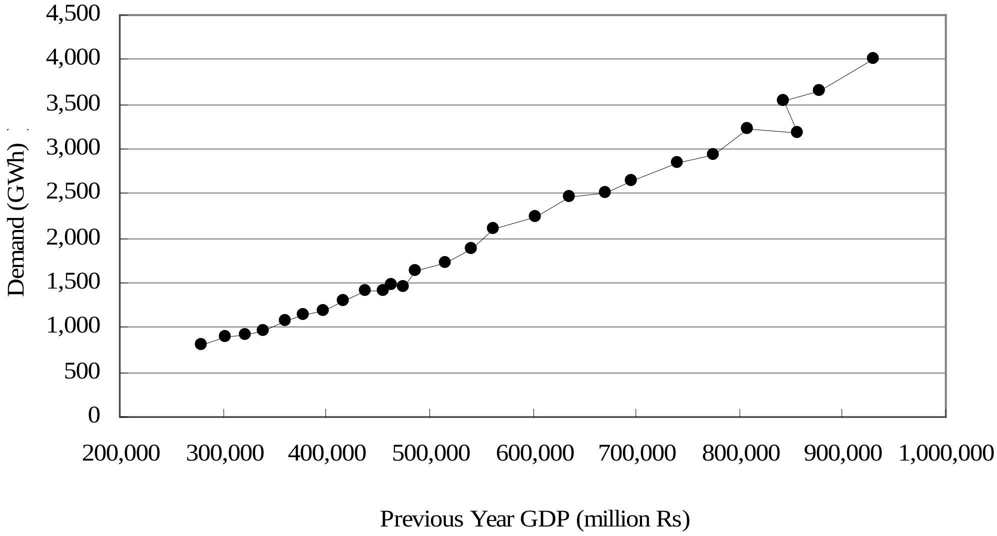

Figure 4.2.2 Correlation between Previous Year's GDP and Electricity Demand (Ind.&Gen.)

[22] See Section 3.5 for further details.
[23] According to the Rural Electrification Development released on April 2004, Sri Lanka plans to achieve a rate of electricity access from the national grid of 75% by 2007 and 80% by 2010. It is assumed that the remaining 20% will be supplied by off-grid electrification including dispersed power sources.

Therefore, the previous year's GDP with a negative sign is unpractical and is unsuitable as an independent variable for the model. This fault is caused by a multi-colinearity[24] problem (See Table 4.2.4 for correlations among independent variables used for the regression analysis).

In this study only the GDP(t) term is employed for the forecasting model to avoid multi-colinearity problems in consideration of the fact that electricity demand in the industrial sector is largely dependent on economic activities in the reference year in general.

Table 4.2.4 Correlation among Independent Variables (Ind.&Gen.)

	Di&gp	GDP	Avg. i&gPrice	LDi&gp	LGDP	Pop
Di&gp	1					
GDP	**0.99728**	1				
Avg. i&gPrice	0.22093	0.21854	1			
LDi&gp	**0.99540**	**0.99607**	0.21340	1		
LGDP	**0.99455**	**0.99797**	0.21738	**0.99728**	1	
Pop	0.95584	0.96967	0.22090	0.95623	0.96785	1

Next, the advisability of adding a price term to the model is studied by using the forecasting model below. As shown in Table 4.2.3, it is obvious that the correlation between the electricity demand for the industrial & general purpose sectors and the average electricity price of the sectors is positive and not very strong.

Di&g(t)i = *d* + *a**GDP(t)i + *c**APi&g(t)i

Where,

Di&g(t)i : Demand for electricity in the industrial & general purpose consumer categories (GWh)
GDP(t)i : Gross Domestic Product (million LKR)
APi&g(t)i : Average electricity price in domestic purpose consumer category (Rs/kWh)

According to Table 4.2.5, the regression coefficient sign in the average price is positive for all data spans as well as for the sign of the correlation coefficient. Therefore, no price impact is identified in the industrial & general purpose sectors.

Table 4.2.5 Sign of Price Term in each Data Span (Ind.&Gen.)

Data Span	*a*	*c*	*d*
1981-1988	0.00442	22.718	-751.394
1989-1996	0.00508	30.624	-1145.180
1997-2004	0.00554	22.405	-1578.759
1978-2004	0.00469	3.022	-752.378

Though at present there is no necessity to introduce a price term to the forecasting model judging from the above, the CEB should continue to focus on the price impact when they revise *the National Demand Forecast* every year and they need to consider whether or not a price term will be employed if the price impact is identified.

[24] When dependent variables have strong correlations with each other, multi-colinearity problems occur. The problems of multi-colinearity are;
(1) The regression coefficient sign differs from that of a correlation coefficient.
(2) The regression coefficient value undergoes a lot of changes or is underspecified.

In conclusion, several fine-tuning points were identified through the revision of the CEB methodology to decide demand forecasting models and the models in 2004. Most of the points are avoidable provided the independent variables of the models are not achieved by only the statistical tool. The tool can obtain the mathematically optimum equation from data sets, however, it is not always true that the equation is an appropriate equation for expressing future electricity demand.

Therefore, it is very important that those who are responsible for power demand forecasting determine a basic model structure and independent variables for each tariff category in consideration of the economic structure and the distinctive characteristic of the power sector in Sri Lanka[25].

(3) Power Demand Forecasting Model

To calculate an actual load factor in a certain year, the actual record of the maximum demand and gross generation in that year is needed. According to the CEB system control center, the maximum demand was 1563.4MW[26] and the gross generation was 8043.3GWh[27] in 2004. The load factor in 2004 was, consequently, 58.7%.

The recorded maximum demand of CEB did not include the contribution of the mini IPPs[28] and self generations connected to the CEB system. Since s load factor plays a very important role in determining peak demand in power demand forecasting, it is better to monitor those loads in order to set a load factor reflecting the actual situation in demand forecasting.

4.3 Demand Forecasting Methodology

4.3.1 Methodology through National Level Approach

(1) Econometric approach and bottom-up approach

There are two different approaches to power demand forecasting in general. One is the econometric approach and the other is the bottom-up approach. In the econometric approach, future power demand is forecasted through the analysis of the historical correlation between power demand and an economic indicator (such as GDP or population) or historical power demand trends. In the bottom-up approach, the components of power demand are estimated individually and future power demand is obtained by adding up the components. Each method has its own advantages and disadvantages. For data collection, the econometric approach needs time-series data over a long period of time. In contrast, the bottom-up approach requires a wide variety of data.

The econometric approach can be easily applied to model building by the preparation of time-series data and it can introduce the concept of GDP elasticity, which is commonly used. Model building and data revisions can be easily handled as well. CEB has already employed the econometric approach. Based on these various reasons, this study employs the econometric approach[29]. In addition, the forecasting data and models that this study uses are the revised versions of those from CEB based on the fine-tuning points mentioned before. Other conditions that are not mentioned are the same as those from CEB's.

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[25] While there are cases in which the electrification rate has been factored into the power demand forecasting model, in the case of Sri Lanka the electrification rate is calculated by dividing the total number of users in three categories (<1>Domestic Purpose, <2>General Purpose 1 [which broadly divides industrial users into Industrial Purpose and General Purpose, and contains a further six subcategories for the former and a further three subcategories for the latter] and <3>Religious Purpose by the projected number of residences (assuming a 5% annual increase on census figures). Therefore, figures for electrification targets cannot be directly used in the demand-forecasting models used in the present method of forecasting, in which models are formulated for Domestic, Industrial and Other Purposes. For reference, according to the Regional Electrification Department of the CEB, the electrification rate was 66% as of the end of 2004 (Users: 3,270,773; Projected number of residences: 4,931,992).

[26] On Monday the 6th of December 2004

[27] Excluding self generation portion

[28] Less than 10MW

[29] The bottom-up approach is useful for forecasting potential electricity demand in rural areas without access to electricity. Because there might be no historical data on socioeconomic activities, electricity demand in those areas and the structure of expected electricity consumption is relatively simple and so building a model is easy.

(2) Work flow of national level approach

Figure 4.3.1 shows a schematic flow diagram for power demand forecasting using the national level approach. Regarding the independent variables for the forecasting models in this study, GDP per capita and previous year electricity demand are applied for the domestic purpose sector, GDP for the industrial and general purpose sectors, and time trends for the other purpose sector as a result of the reviews explained in Section 4.3.1.

The study team firstly prepares the necessary data for the regression analyses, secondly conducts the regression analyses, thirdly forecasts electricity demand for each tariff category by using each forecasting model obtained and finally achieves national energy sales by aggregating forecasted results by each category and supplemental demand based on the recovery scenario for the Northern Province. Then, gross generation is calculated by using the forecasted national energy sales and an assumed loss rate and peak demand is achieved by the calculated gross generation and projected load factor.

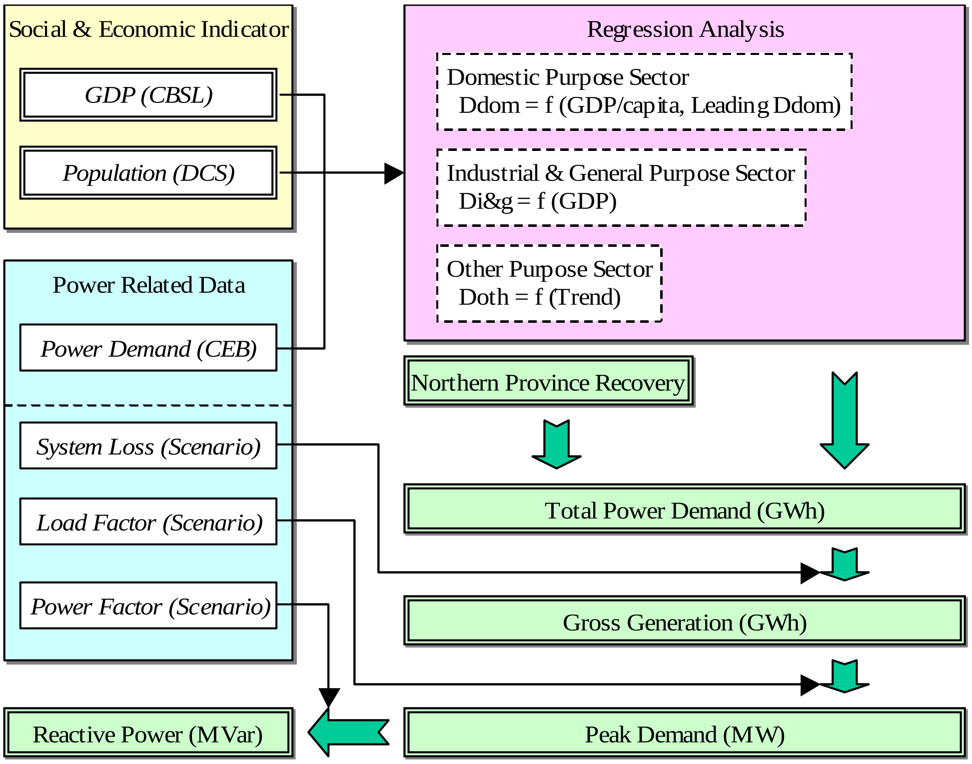

Figure 4.3.1 Schematic Flow Diagram of Power Demand Forecasting (National Level Approach)

(3) Data source and scenario for national level approach

(a) Applied or referred data source

Time series data applied or referred for the model building are as follows:

GDP growth scenario: Central Bank of Sri Lanka[30]
Population growth scenario: Department of Census and Statistic
Historical data for the regression analyses: Statistical Unit, CEB

(b) Basic framework

Observation year: 1985 - 2004 (20 years)
Base year: 2004
Target year: 2029 (20 years)

[30] Annual Report 2004, Central Bank of Sri Lanka

(c) Scenario

The economic scenario (Base Scenario) from 2005 to 2008 is set as shown in Table 4.3.1. In the table, the value for the year 2004 is the actual economic growth rate. The growth rate from 2009 to 2029 is assumed to be the same as the rate for the year 2008 in this study. In addition, the High and Low Growth scenarios are also set at 1% above and below the Base Scenario, respectively.

Table 4.3.1 Economic Scenario (National Level Approach)

Year	Low Growth	Base Growth	High Growth
2004	*5.4 %*	*5.4 %*	*5.4 %*
2005	4.3 %	**5.3 %**	6.3 %
2006	5.0 %	**6.0 %**	7.0 %
2007	5.5 %	**6.5 %**	7.5 %
2008	6.0 %	**7.0 %**	8.0 %
2009-2029	6.0 %	7.0 %	8.0 %

Source: CBSL
Note: Post-tsunami scenario. The value for 2004 is an actual growth rate.

Table 4.3.2 shows the DCS population scenario.

Table 4.3.2 Population Scenario (National Level Approach)

Year	Low Growth	Base Growth	High Growth
2005-2006	0.57 %	0.99 %	1.16 %
2007-2011	0.44 %	0.88 %	1.04 %
2012-2016	0.25 %	0.77 %	0.94 %
2017-2021	0.14 %	0.58 %	0.83 %
2022-2026	0.00 %	0.42 %	0.73 %
2027-2029	-0.16 %	0.29 %	0.63 %

Source: DCS

Table 4.3.3 shows the supplemental electricity demand scenario for the Northern Province.

Table 4.3.3 Supplemental Demand Scenario for Northern Province

Year	Demand Scenario (GWh)	Supplemental Demand (GWh)
2004	*98.5*	-
2005	123.9	25.4
2006	149.3	25.4
2007	174.7	25.4

Source: Northern Provincial office, CEB
Note: The value for 2004 is the actual demand.

The system loss scenario is set as shown in Table 4.3.4. This scenario assumes that the system will achieve 14.1% of its loss rate in 10 years.

Table 4.3.4 System Loss Scenario

Year	Syst. Loss	Year	Syst. Loss	Year	Syst. Loss
2004	*17.11%*	2008	15.79%	2012	14.56%
2005	16.77%	2009	15.47%	2013	14.27%
2006	16.44%	2010	15.16%	2014-2029	**14.10%**
2007	16.11%	2011	14.86%		

Source: JICA Study Team
Note: The value for 2004 is the actual demand.

Regarding the load factor scenario, this study employed 55.2%, which is the average load factor for the past 20 years[31].

Reactive power is also forecasted by using 0.894, the average power factor for the past six years.

4.3.2 Methodology through Provincial Level Approach

(1) Basic policy

Though the span of data used in provincial demand forecasting is different from that used in national demand forecasting due to the limited amount of provincial historical data available at present, the basic methodology for provincial demand forecasting is the same as for national demand forecasting.

In addition, a new analysis called "Share Trend Analysis" has been added to the work flow. In the Share Trend Analysis the provinces and areas[32] are divided into discrete groups focusing on the chronological changes in the share of electricity demand for each province in order to minimize errors. This is because errors caused by the limited data span or wide data fluctuations for each province may have a large influence on forecasting results if a regression model is prepared for each province.

For these reasons, the nationwide electricity demand, which is the total of the demand forecasts in the provincial level approach, is different in number from the national demand forecast. Therefore, this study assumed that the national demand forecast is correct and allocates the demand to each province based on the electricity demand share for each province obtained from the provincial demand forecast.

[31] Excluding the years with power cuts
[32] CEB boundary: Central Province, Eastern Province, Northern Province, North Central Province, North Western Province, Sabaragamuwa Province, Southern Province, Uva Province, Western Province -North-, Western Province -South- and Colombo City

(2) Work flow of provincial level approach

Figure 4.3.2 shows a schematic flow diagram of power demand forecasting using the provincial level approach. Independent variables for the forecasting models in the provincial forecast are basically the same as the national forecast[33].

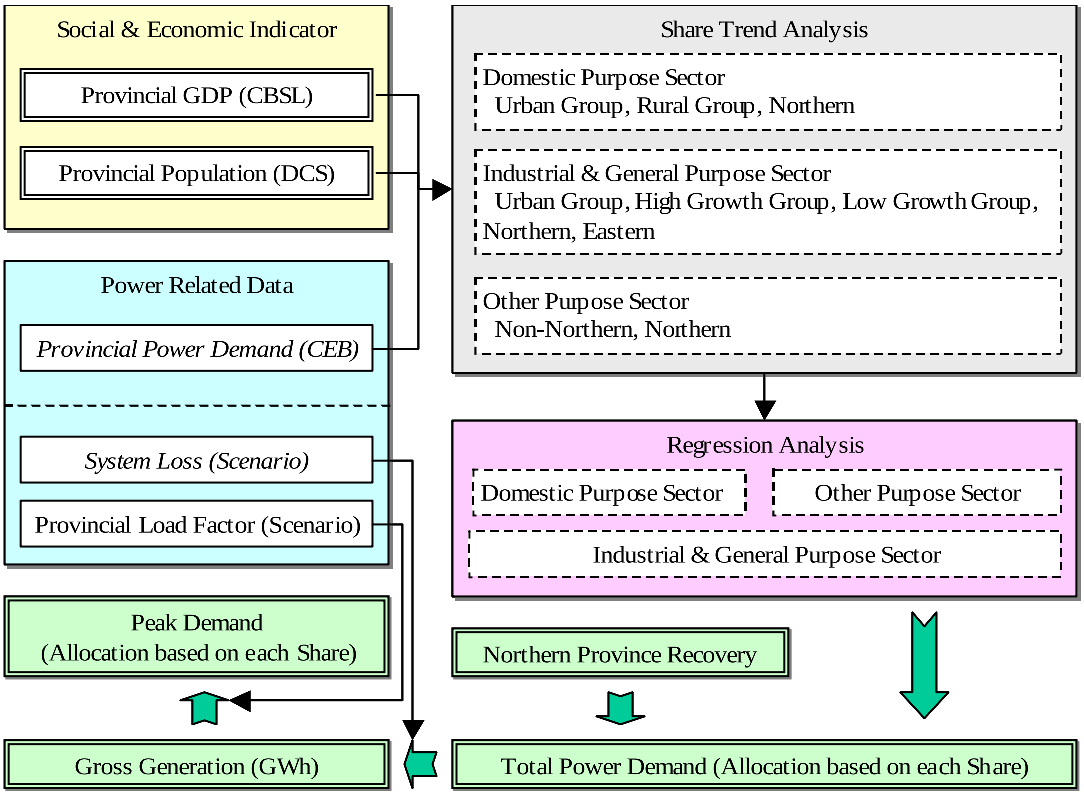

Figure 4.3.2 Schematic Flow Diagram of Power Demand Forecasting (Provincial Level Approach)

(3) Data source and scenario for provincial level approach

(a) Applied or referred data source

Time series data applied or referred for the model building are as follows:

GDP growth scenario: Central Bank of Sri Lanka
Population growth scenario: Department of Census and Statistic
Historical socioeconomic data: Central Bank of Sri Lanka
Historical electricity data for the regression analyses: Generation Unit, CEB

(b) Basic framework

Available provincial data for the analyses were limited to the years from 1996 to 2004.

Observation year: 1996 - 2004 (9 years)
Base year: 2004
Target year: 2029 (20 years)

(c) Scenario

Since there is no forecast on GDP growth at the provincial level now, an annual change in growth rate at the national level from 2004 to 2008 is applied to the actual growth rate of each province in 2004. The growth rate from 2009 to 2029 is assumed to be the same as the rate for the year 2008 in this study. Table 4.3.5 shows the provincial economic scenario (Base Case) from 2005 to 2029 in this study.

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[33] See 4.3.1 (2).

Table 4.3.5 Economic Scenario (Provincial Level Approach)

Year	WE	SO	SA	CE	UV	EA	NW	NC	NO
2004	*6.07%*	*5.88%*	*3.42%*	*4.65%*	*4.04%*	*5.17%*	*4.08%*	*4.79%*	*5.02%*
2005	6.00%	5.82%	3.38%	4.60%	3.99%	5.11%	4.04%	4.74%	4.97%
2006	6.79%	6.59%	3.82%	5.21%	4.52%	5.79%	4.57%	5.37%	5.62%
2007	7.36%	7.13%	4.14%	5.64%	4.90%	6.27%	4.95%	5.81%	6.09%
2008	7.93%	7.68%	4.46%	6.08%	5.27%	6.75%	5.33%	6.26%	6.56%
2009-2029	7.93%	7.68%	4.46%	6.08%	5.27%	6.75%	5.33%	6.26%	6.56%

Source: CBSL and JICA Study Team

Note: CE-Central Province, EA-Eastern Province, NO-Northern Province, NC-North Central Province, NW-North Western Province, SA- Sabaragamuwa Province, SO-Southern Province, UV-Uva Province, WE-Western Province

Western Province consists of Western Province -North-, Western Province -South- and Colombo City according to the CEB boundary.

The values for 2004 are the actual growth rates for each province.

As in the case of the economic scenario, the provincial population scenario is assumed to be based on the actual growth in each province and the population forecast at national level. The population scenario in this study is shown in Table 4.2.6.

Table 4.3.6 Population Scenario (Provincial Level Approach)

Year	WN	WS	CC	SO	SA	CE	UV	EA	NW	NC	NO
2005-2006	0.48%	0.74%	1.61%	0.95%	0.82%	1.29%	1.41%	1.45%	0.82%	1.15%	1.45%
2007-2011	0.43%	0.66%	1.43%	0.84%	0.73%	1.15%	1.25%	1.29%	0.73%	1.02%	1.29%
2012-2016	0.37%	0.58%	1.25%	0.74%	0.64%	1.01%	1.10%	1.13%	0.64%	0.89%	1.12%
2017-2021	0.28%	0.43%	0.94%	0.55%	0.48%	0.75%	0.82%	0.84%	0.48%	0.67%	0.84%
2022-2026	0.20%	0.31%	0.68%	0.40%	0.35%	0.55%	0.59%	0.61%	0.35%	0.48%	0.61%
2027-2029	0.14%	0.22%	0.47%	0.28%	0.24%	0.38%	0.42%	0.43%	0.24%	0.34%	0.43%

Source: DCS and JICA Study Team

Note: WN-Western-North-, WS-Western-South-, CC-Colombo City

Regarding the load factor scenario, the average load factor[34] for the past nine years is employed. In addition, the load factor for Colombo City in the daytime is also used because the maximum demand in Colombo City occurs in the daytime. Table 4.3.7 shows the load factor scenario used in this study.

Table 4.3.7 Load Factor Scenario (Provincial Level Approach)

Year	WN	WS	CC Night	SO	SA	CE	UV	EA	NW	NC	NO	CC Day
1996	54.4%	58.6%	70.5%	48.0%	38.9%	41.8%	85.5%	62.0%	39.7%	23.7%	-	-
1997	63.3%	54.9%	83.5%	56.2%	36.8%	43.3%	61.7%	42.5%	42.4%	28.1%	-	-
1998	67.5%	54.2%	75.7%	59.8%	41.5%	44.3%	64.5%	52.4%	44.4%	32.4%	-	61.2%
1999	68.3%	55.4%	79.9%	51.7%	38.5%	41.8%	60.1%	39.7%	41.2%	28.1%	57.3%	66.6%
2000	71.1%	57.0%	85.1%	55.4%	42.7%	37.8%	60.8%	34.4%	39.8%	27.5%	-	61.2%
2001	64.7%	53.8%	81.9%	50.3%	34.7%	41.4%	56.7%	34.2%	43.4%	27.0%	69.0%	52.5%
2002	65.9%	58.7%	78.6%	58.8%	53.8%	46.5%	59.2%	36.6%	42.0%	27.0%	26.2%	55.2%
2003	72.2%	55.4%	82.9%	62.5%	46.5%	48.5%	54.6%	43.8%	49.3%	32.5%	32.5%	61.0%
2004	69.8%	58.8%	82.0%	64.4%	66.1%	49.7%	50.3%	33.9%	49.4%	39.0%	35.5%	58.7%
Ave.	**66.4%**	**56.3%**	**80.0%**	**56.3%**	**44.4%**	**43.9%**	**61.5%**	**42.2%**	**43.5%**	**29.5%**	**44.1%**	**59.5%**

Source: CEB and JICA Study Team

Note: The load factor for Colombo City at nighttime is calculated by its gross generation and demand when the system peak occurred during each year.

The supplemental electricity demand scenario for the Northern Province and the system loss scenario are the same as the scenarios used in the national level approach.

[34] The load factor for each province during the nighttime is calculated based on the provincial gross generation and the demand in each province when the system peak occurred during each year.

4.4 Results of Power Demand Forecast

4.4.1 National Demand Forecast

The results of the regression analyses are as follows:

<Domestic Purpose Sector>

Ddom(t)i = -512.444 + 0.02580 GDPPC(t)i + 0.750 Ddom(t-1)i

Where,

Ddom(t)i	: Demand for electricity in domestic purpose consumer category (GWh)
GDPPC(t)i	: Gross Domestic Product per capita (million LKR/capita)
Ddom(t-1)i	: Demand in domestic consumer category in previous year (GWh)

<Industrial & General Purpose Sector>

Di&g(t)i = -838.822 + 0.004824 GDP(t)i

Where,

Di&g(t)i	: Demand for electricity in Ind. & Gen. purpose consumer category (GWh)
GDP(t)i	: Gross Domestic Product (million LKR)

<Other Purpose Sector>

In Demand(t) = -102.960 + 0.05386 t

Where,

t	: Year

Power demand forecasts were carried out using the forecasting models and scenarios. The results of the forecasts are shown in Table 3.4.1 for the energy sales forecast by tariff category and Table 3.4.2 for the national demand forecast.

In the Base Growth Scenario, the total energy sales will increase to 42,052 GWh in the target year of 2029 and 29,459GWh in 2024 from 6,781GWh in 2004. The annual average growth rate for the next 20 years is 7.68%. In the Low and High Growth Scenario, the total energy sales will come to 35,344GWh (6.92%) and 51,771GWh (8.59%) in 2029, respectively.

The total peak demand will increase to 10,124 MW in the target year of 2029 and 7,092MW in 2024 from 1,563MW in 2004 (Base Case Scenario). The annual average growth rate for the next 20 years is 7.54%. In the Low and High Growth Scenario, the peak demand will come to 8,509MW (6.78%) and 12,464MW (8.45%) in 2029, respectively.

Table 4.4.1 Energy Sales Forecast by Tariff Category (National Level Approach)

Year	Energy Sales (GWh)				Year	Energy Sales (GWh)			
	Domestic	Ind.&Gen.	Other	Total		Domestic	Ind.&Gen.	Other	Total
2004	2,626	4,001	154	6,781	2018	7,723	10,989	308	19,019
2005	2,796	4,139	153	7,088	2019	8,338	11,817	325	20,480
2006	2,991	4,438	161	7,589	2020	8,995	12,703	343	22,040
2007	3,215	4,781	170	8,166	2021	9,695	13,651	362	23,708
2008	3,474	5,174	180	8,827	2022	10,450	14,665	382	25,497
2009	3,763	5,595	190	9,548	2023	11,258	15,750	403	27,412
2010	4,082	6,045	200	10,327	2024	12,122	16,912	425	29,459
2011	4,428	6,527	211	11,166	2025	13,045	18,154	449	31,648
2012	4,805	7,043	223	12,070	2026	14,030	19,484	474	33,987
2013	5,211	7,594	235	13,040	2027	15,090	20,906	500	36,496
2014	5,647	8,185	248	14,079	2028	16,224	22,428	527	39,180
2015	6,112	8,816	262	15,190	2029	17,438	24,057	557	42,052
2016	6,610	9,492	276	16,378					
2017	7,147	10,215	292	17,654	AAGR (%)	7.92%	7.61%	5.53%	

Table 4.4.2 National Power Demand Forecast

Year	Energy Sales (GWh)			System	Gross Generation (GWh)			Load	Peak Demand (MW)			React. P.
	Low	**Base**	High	Loss	Low	**Base**	High	Factor	Low	**Base**	High	(Mvar)
2004		***6,781***		*17.1%*		***8,043***		*58.7%*		***1,563***		**Base**
2005	7,100	**7,113**	7,159	16.8%	8,531	**8,547**	8,602	55.2%	1,764	**1,768**	1,779	**886**
2006	7,570	**7,614**	7,723	16.4%	9,059	**9,112**	9,243	55.2%	1,874	**1,884**	1,911	**944**
2007	8,097	**8,191**	8,380	16.1%	9,652	**9,764**	9,989	55.2%	1,996	**2,019**	2,066	**1,012**
2008	8,668	**8,827**	9,114	15.8%	10,293	**10,482**	10,822	55.2%	2,129	**2,168**	2,238	**1,086**
2009	9,308	**9,548**	9,950	15.5%	11,011	**11,295**	11,771	55.2%	2,277	**2,336**	2,434	**1,171**
2010	9,992	**10,327**	10,863	15.2%	11,777	**12,172**	12,804	55.2%	2,436	**2,517**	2,648	**1,262**
2011	10,720	**11,166**	11,856	14.9%	12,591	**13,114**	13,925	55.2%	2,604	**2,712**	2,880	**1,359**
2012	11,499	**12,070**	12,935	14.6%	13,459	**14,127**	15,139	55.2%	2,783	**2,921**	3,131	**1,464**
2013	12,329	**13,040**	14,103	14.3%	14,381	**15,210**	16,450	55.2%	2,974	**3,146**	3,402	**1,577**
2014	13,211	**14,079**	15,364	14.1%	15,380	**16,390**	17,886	55.2%	3,181	**3,389**	3,699	**1,699**
2015	14,148	**15,190**	16,725	14.1%	16,470	**17,683**	19,470	55.2%	3,406	**3,657**	4,027	**1,833**
2016	15,141	**16,378**	18,192	14.1%	17,626	**19,066**	21,178	55.2%	3,645	**3,943**	4,380	**1,976**
2017	16,199	**17,654**	19,777	14.1%	18,858	**20,552**	23,023	55.2%	3,900	**4,250**	4,761	**2,130**
2018	17,322	**19,019**	21,486	14.1%	20,165	**22,141**	25,013	55.2%	4,170	**4,579**	5,173	**2,295**
2019	18,513	**20,480**	23,327	14.1%	21,552	**23,842**	27,156	55.2%	4,457	**4,931**	5,616	**2,471**
2020	19,777	**22,040**	25,310	14.1%	23,023	**25,658**	29,464	55.2%	4,761	**5,306**	6,093	**2,659**
2021	21,116	**23,708**	27,445	14.1%	24,582	**27,600**	31,950	55.2%	5,084	**5,708**	6,607	**2,861**
2022	22,543	**25,497**	29,751	14.1%	26,243	**29,682**	34,634	55.2%	5,427	**6,138**	7,163	**3,077**
2023	24,058	**27,412**	32,236	14.1%	28,007	**31,912**	37,527	55.2%	5,792	**6,599**	7,761	**3,308**
2024	25,666	**29,459**	34,913	14.1%	29,879	**34,295**	40,644	55.2%	6,179	**7,092**	8,405	**3,555**
2025	27,373	**31,648**	37,798	14.1%	31,866	**36,843**	44,002	55.2%	6,590	**7,619**	9,100	**3,819**
2026	29,182	**33,987**	40,904	14.1%	33,972	**39,566**	47,618	55.2%	7,026	**8,182**	9,848	**4,101**
2027	31,113	**36,496**	44,258	14.1%	36,220	**42,487**	51,523	55.2%	7,490	**8,786**	10,655	**4,404**
2028	33,165	**39,180**	47,874	14.1%	38,609	**45,611**	55,732	55.2%	7,984	**9,433**	11,526	**4,728**
2029	35,344	**42,052**	51,771	14.1%	41,146	**48,955**	60,269	55.2%	8,509	**10,124**	12,464	**5,074**
AAGR	6.92%	**7.68%**	8.59%		6.78%	**7.54%**	8.45%		6.78%	**7.54%**	8.45%	7.54%

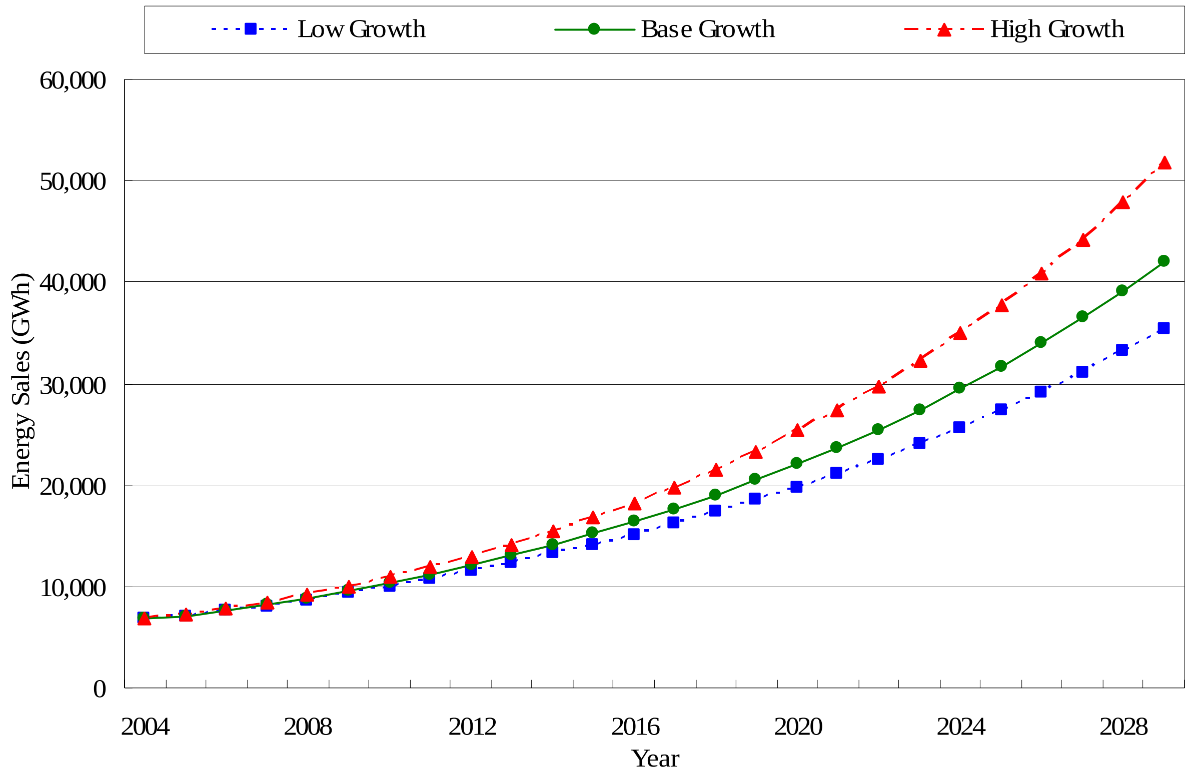


Figure 4.4.1 National Demand Forecast (Energy Sales)

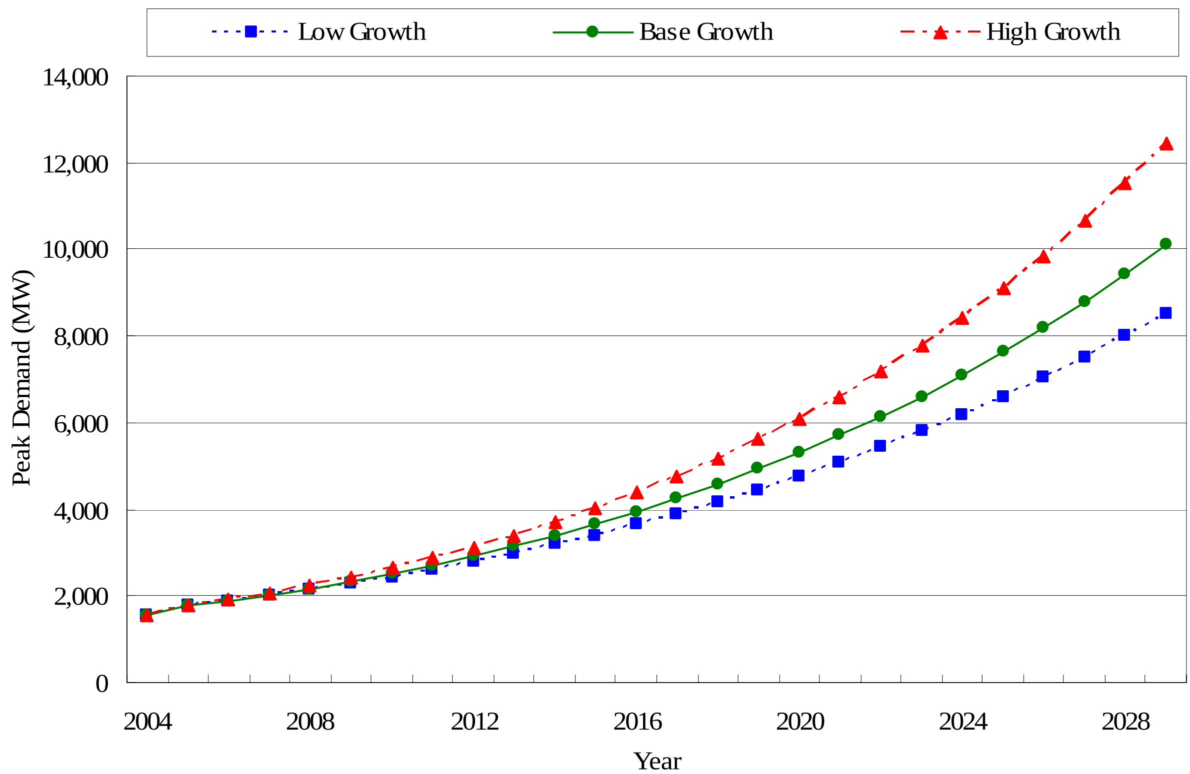


Figure 4.4.2 National Demand Forecast (Peak Demand)

4.4.2 Provincial Demand Forecast

(1) Share Trend Analysis

<Domestic Purpose Sector>

Figure 4.4.3 shows the chronological shares in provincial electricity demand[35] for the domestic purpose sector.

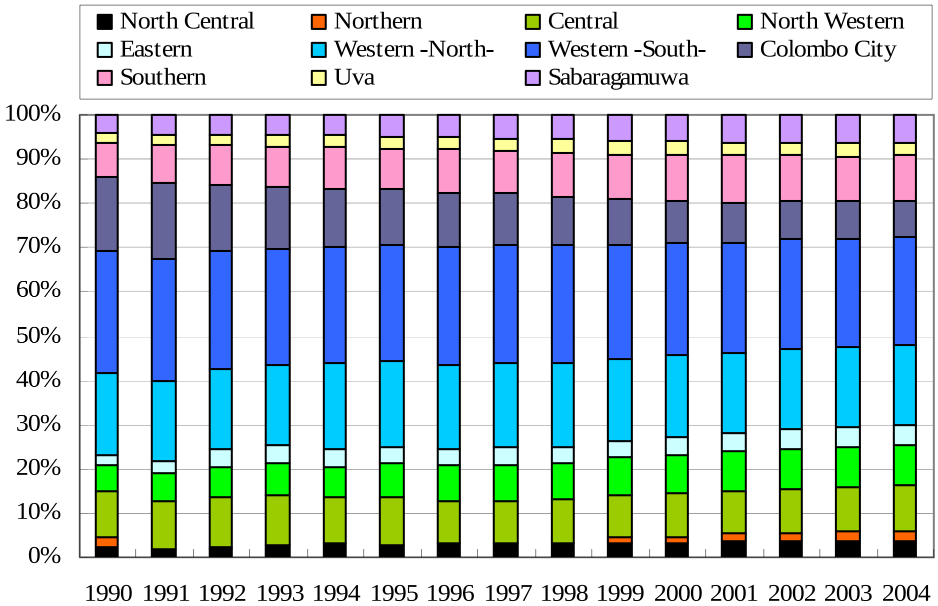


Figure 4.4.3 Chronological Shares by Province (Domestic)

Focusing on the electricity demand growth trends for each province, all provinces are classified as belonging to one of the following groups: Urban Group (Western Province -North-, Western Province -South- and Colombo City), Rural Group (Central Province, Eastern Province, North Central Province, North Western Province, Southern Province, Sabaragamuwa Province and Uva Province) and Northern Province.

[35] Based on the CEB boundary in 2001. Central Province (7): Nawarapitiya, Peradeniya, Nuwara Eliya, Matale, Kundasale, Katugastota and Kandy City, Eastern Province (4): Trincomalee, Ampara, Batticaloa and Kalmunai, Northern Province (2): Jaffna and Kilinochchi, North Central Province (3): Anuradhapura, Minneriya and Kekirawa, North Western Province (5): Kurunegara, Wennappuwa, Chilau, Kuliyapitiya and Wariyapola, Southern Province (5): Galle, Ambalangoda, Hambantota, Matara and Weligama, Sabaragamuwa Province (4): Kegalle, Ratnapura, Kahawatta and Ruwanwella, Uva Province (2): Badulla and Diyatalawa, Western Province -North- (5): Gampaha, Veyangoda, Negombo, Kelaniya and Ja_Era, Western Province -South- (7): Ratmalana, Homagama, Sri Jaye'pura, Kalutara, Dehiwala, Avissawelle and Horana, and Colombo City

Urban Group

Figure 4.4.4 shows the shares held by each province in the Urban Group. The shares for the Western Province -North- and -South- are fairly constant (-North- : -South- = 41.9% : 58.2%). The Colombo City share has decreased at an average rate of 3.1% for the past eight years. Therefore, this study assumes that each province in the group will keep the same share trends until 2029. Finally, the provincial share scenario for the Urban Group is set as shown in Table 4.4.3.

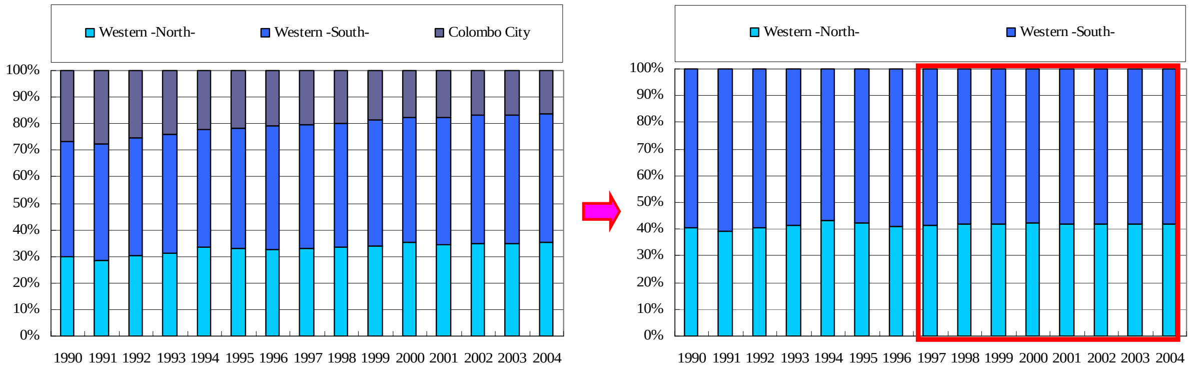


Figure 4.4.4 Provincial Shares in Urban Group (Domestic)

Table 4.4.3 Provincial Share Scenario for Urban Group (Domestic)

Year	CC	WN	WS	Year	CC	WN	WS
2004	*16.2%*	*35.3%*	*48.5%*	2017	10.8%	37.4%	51.8%
2005	15.7%	35.3%	49.0%	2018	10.4%	37.5%	52.0%
2006	15.2%	35.5%	49.3%	2019	10.1%	37.7%	52.2%
2007	14.7%	35.7%	49.5%	2020	9.8%	37.8%	52.4%
2008	14.3%	35.9%	49.8%	2021	9.5%	37.9%	52.6%
2009	13.8%	36.1%	50.1%	2022	9.2%	38.0%	52.7%
2010	13.4%	36.3%	50.3%	2023	8.9%	38.2%	52.9%
2011	13.0%	36.4%	50.5%	2024	8.7%	38.3%	53.1%
2012	12.6%	36.6%	50.8%	2025	8.4%	38.4%	53.2%
2013	12.2%	36.8%	51.0%	2026	8.1%	38.5%	53.4%
2014	11.8%	36.9%	51.2%	2027	7.9%	38.6%	53.5%
2015	11.5%	37.1%	51.4%	2028	7.6%	38.7%	53.7%
2016	11.1%	37.2%	51.6%	2029	7.4%	38.8%	53.8%

Note: The values for 2004 are the actual shares for each province.

Rural Group

As shown in Figure 4.4.5, the share of each province in the Rural Group has been virtually constant since 1997. Therefore, this study assumes that each province in the group will keep the same share trend until 2029. Finally, the provincial share scenario for the Rural Group is set based on the average share of each province for the past eight years as shown in Table 4.4.4.

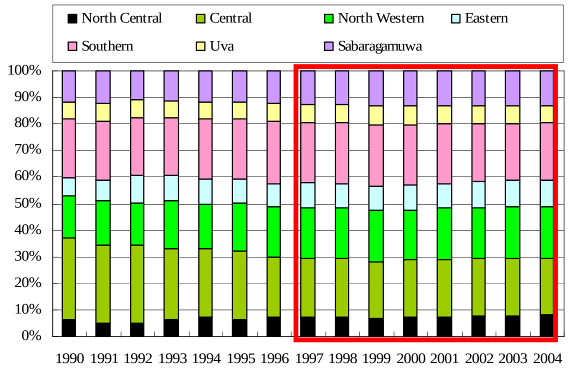


Figure 4.4.5 Provincial Shares in Rural Group (Domestic)

Table 4.4.4 Provincial Share Scenario for Rural Group (Domestic)

Province	NC	CE	NW	EA	SO	UV	SA
Share	7.4%	21.7%	19.2%	9.4%	22.4%	6.8%	13.0%

Northern

The electricity demand for the domestic sector in the Northern Province has been almost nothing since 1991 due to the damage inflicted by the civil war. The province is now in the process of recovering its former level of demand (See Figure 4.4.6). In the regression analysis for the Northern Province, the data after 1998 are used in light of the importance of its growth trend in recent years.

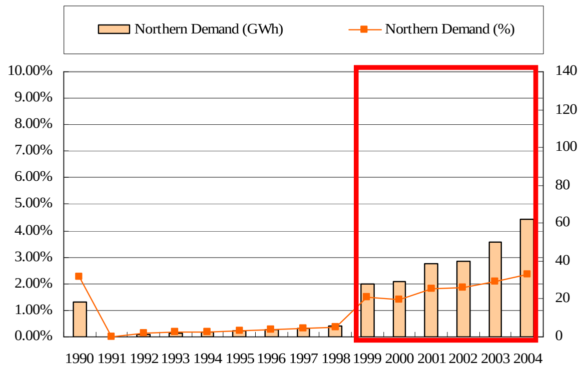


Figure 4.4.6 Electricity Demand Trend in Northern Province (Domestic)

<Industrial & General Purpose Sector>

The chronological shares of provincial electricity demand for the industrial and general purpose sectors are shown in Figure 4.4.7.

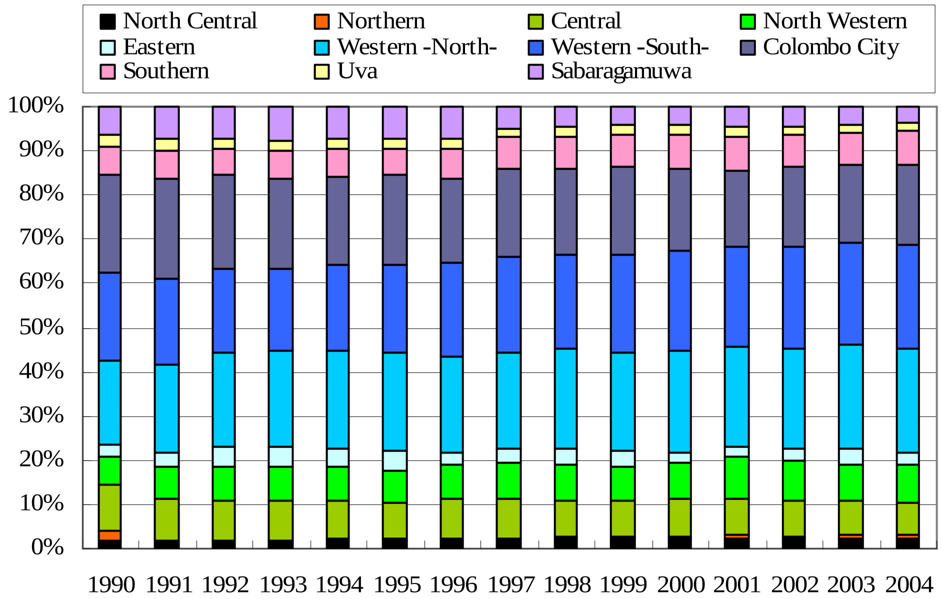


Figure 4.4.7 Chronological Shares by Province (Ind.&Gen.)

Focusing on the electricity demand growth trends for each province, all provinces are classified as belonging to one of the following groups: Urban Group (Western Province -North-, Western Province -South- and Colombo City), High Growth Group (North Central Province, North Western Province and Southern Province), Low Growth Group (Central Province, Sabaragamuwa Province and Uva Province), the Eastern Province and the Northern Province.

Urban Group

Figure 4.4.8 shows the share of each province in the Urban Group. The share of the Western Province -North- and -South- is fairly constant (-North- : -South- = 50.4% : 49.6%). The Colombo City share has decreased at an average rate of 1.9% for the past eight years. Therefore, this study assumes that each province in the group will keep the same share trend until 2029. Finally, the provincial share scenario for the Urban Group is set as shown in Table 4.4.5.

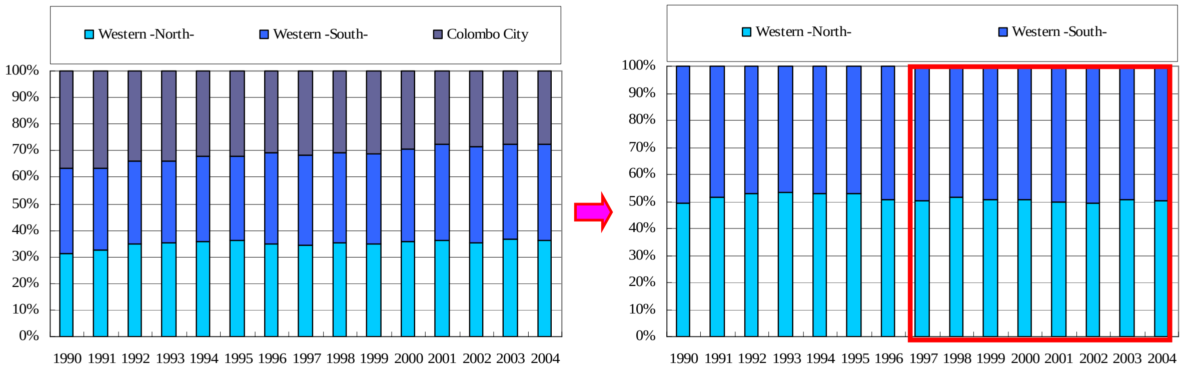


Figure 4.4.8 Provincial Share in Urban Group (Ind.&Gen.)

Table 4.4.5 Provincial Share Scenario for Urban Group (Ind.&Gen.)

Year	CC	WN	WS	Year	CC	WN	WS
2004	*27.8%*	*36.1%*	*36.1%*	2017	21.7%	39.4%	38.9%
2005	27.2%	36.7%	36.1%	2018	21.3%	39.7%	39.1%
2006	26.7%	36.9%	36.4%	2019	20.9%	39.9%	39.3%
2007	26.2%	37.2%	36.6%	2020	20.5%	40.1%	39.5%
2008	25.7%	37.4%	36.9%	2021	20.1%	40.2%	39.6%
2009	25.2%	37.7%	37.1%	2022	19.7%	40.4%	39.8%
2010	24.8%	37.9%	37.3%	2023	19.4%	40.6%	40.0%
2011	24.3%	38.1%	37.6%	2024	19.0%	40.8%	40.2%
2012	23.8%	38.4%	37.8%	2025	18.6%	41.0%	40.4%
2013	23.4%	38.6%	38.0%	2026	18.3%	41.2%	40.6%
2014	23.0%	38.8%	38.2%	2027	17.9%	41.3%	40.7%
2015	22.5%	39.0%	38.4%	2028	17.6%	41.5%	40.9%
2016	22.1%	39.2%	38.7%	2029	17.3%	41.7%	41.1%

Note: The values for 2004 are the actual shares for each province.

High Growth Group

As shown in Figure 4.4.9, the share of each province in the High Growth Group has been virtually constant since 1997. Therefore, this study assumes that each province in the group will keep the same share trend until 2029. Finally, the provincial share scenario for the High Growth Group is set based on the average share of each province for the past eight years as shown in Table 4.4.6.

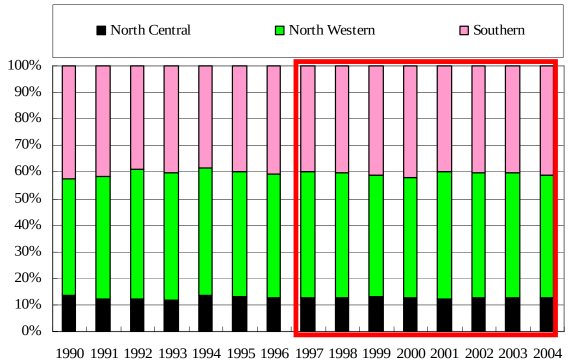


Figure 4.4.9 Provincial Shares in High Growth Group (Ind.&Gen.)

Table 4.4.6 Provincial Share Scenario for High Growth Group (Ind.&Gen.)

Province	NC	NW	SO
Share	12.7%	46.7%	40.6%

Low Growth Group

As shown in Figure 4.4.10, the share of each province in the Low Growth Group has been also virtually constant since 1997. Therefore, this study assumes that each province in the group will keep the same share trend until 2029. Finally, the provincial share scenario for the Low Growth Group is set based on the average share of each province for the past eight years as shown in Table 4.4.7.

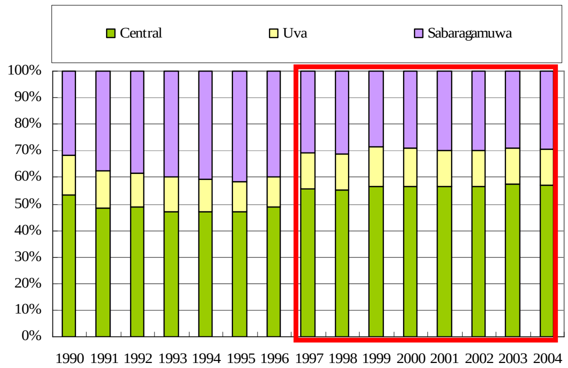


Figure 4.4.10 Provincial Shares in Low Growth Group (Ind.&Gen.)

Table 4.4.7 Provincial Share Scenario for Low Growth Group (Ind.&Gen.)

Province	CE	UV	SA
Share	56.5%	13.8%	29.7%

Northern

This province is in the process of recovering its former demand level from 1999, as is the case for the domestic purpose sector (See Figure 4.4.11). In the regression analysis for the Northern Province, the data after 1999 are used in light of the importance of its growth trend in recent years.

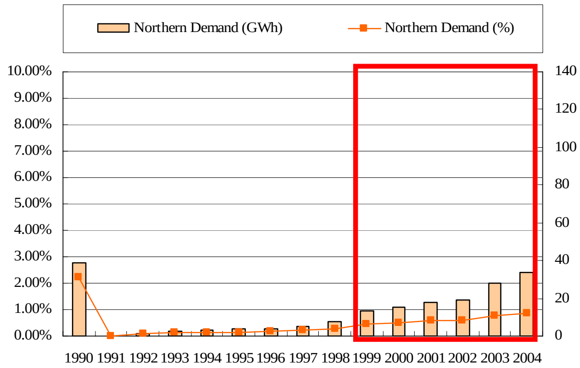


Figure 4.4.11 Electricity Demand Trend in Northern Province (Ind.&Gen.)

Eastern

The electricity demand for the Eastern Province has fluctuated wildly until now as shown in Figure 4.4.12. As a result, this study employs the same method used with the other purpose sector for the Eastern Province because it is difficult to get an appropriate regression result due to the volatility.

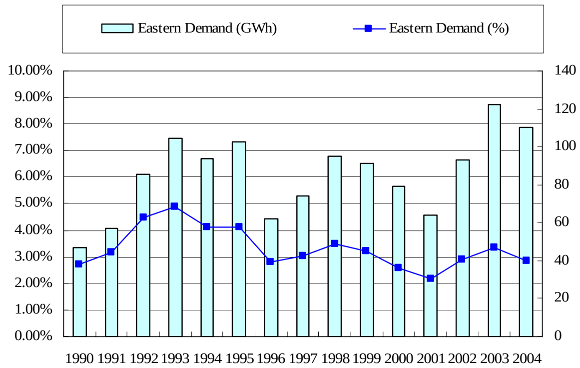


Figure 4.4.12 Electricity Demand Trend in Eastern Province (Ind.&Gen.)

<Other Purpose Sector>

The chronological shares in provincial electricity demand for the industrial and general purpose sectors are shown in Figure 4.4.13.

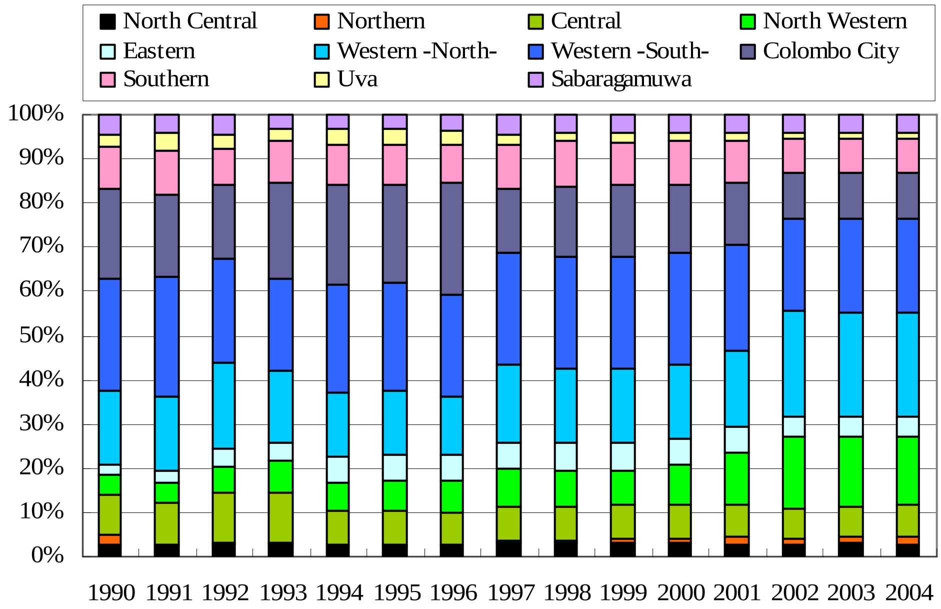


Figure 4.4.13 Chronological Share by Province (Other)

Focusing on the electricity demand growth trend for each province, all provinces are classified as belonging to one of the following groups: Non-Northern Group (Central Province, Eastern Province, North Central Province, North Western Province, Southern Province, Sabaragamuwa Province, Uva Province, Western Province -North-, Western Province -South-and Colombo City) and the Northern Province.

<u>Non-Northern</u>

As shown in Figure 4.4.14, though the shares for each province in the Non-Northern Group had fluctuated until 2001, they have been fairly constant after 2001. Therefore, this study assumes that each province in the group will keep the same share trend until 2029. Finally, the provincial share scenario for the Non-Northern Group is set based on the average share of each province for the past 3 three years as shown in Table 4.4.8.

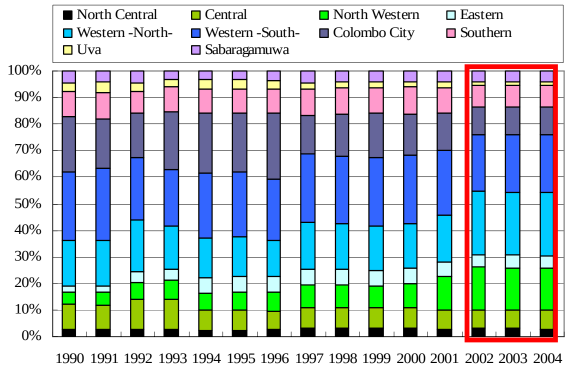


Figure 4.4.14 Provincial Shares in Non-Northern Group (Other)

Table 4.4.8 Provincial Share Scenario for Non-Northern Group (Other)

Province	NC	CE	NW	EA	WN	WS	CC	SO	UV	SA
Share	3.0%	7.0%	15.9%	4.8%	23.9%	21.6%	10.4%	8.0%	1.5%	4.0%

<u>Northern</u>

Regarding the electricity demand forecast for the Northern Province, this study assumed that the province will increase at the same growth rate as that of the Non-Northern Group.

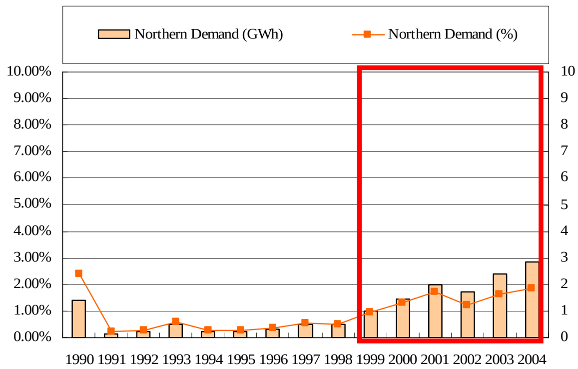


Figure 4.4.15 Electricity Demand Trend in Northern Province (Other)

(2) Results of provincial demand forecast

The results of the regression analyses by tariff category and group are as follows:

<Domestic Purpose Sector>

Urban Group

$$\text{DdomUG(t)i} = -404.435 + 0.01181\ \text{GDPPCUG(t)i} + 0.557\ \text{DdomUG(t-1)i}$$

Where,

DdomUG(t)i	: Demand for electricity in domestic purpose consumer category -Urban Group- (GWh)
GDPPCUG(t)i	: Gross Domestic Product per capita -Urban Group- (million LKR/capita)
DdomUG(t-1)i	: Demand in domestic consumer category in previous year -Urban Group- (GWh)

Rural Group

$$\text{DdomRG(t)i} = -278.991 + 0.01222\ \text{GDPPCRG(t)i} + 0.942\ \text{DdomRG(t-1)i}$$

Where,

DdomRG(t)i	: Demand for electricity in domestic purpose consumer category -Rural Group- (GWh)
GDPPCRG(t)i	: Gross Domestic Product per capita - Rural Group- (million LKR/capita)
DdomRG(t-1)i	: Demand in domestic consumer category in previous year - Rural Group- (GWh)

Northern

$$\text{DdomNo(t)i} = -11.059 + 0.002482\ \text{GDPPCNo (t)i} + 0.148\ \text{DdomNo (t-1)i}$$

Where,

DdomNo(t)i	: Demand for electricity in domestic purpose consumer category -Northern Province- (GWh)
GDPPCNo(t)i	: Gross Domestic Product per capita -Northern Province- (million LKR/capita)
DdomNo(t-1)i	: Demand in domestic consumer category in previous year -Northern Province- (GWh)

<Industrial & General Purpose Sector>

Urban Group

$$\text{Di\&gUG(t)i} = -431.498 + 0.005895\ \text{GDPUG(t)i}$$

Where,

Di&gUG(t)i	: Demand for electricity in Ind. & Gen. purpose consumer category -Urban Group- (GWh)
GDPUG(t)i	: Gross Domestic Product -Urban Group- (million LKR)

High Growth Group

$$\text{Di\&gHGG(t)i} = -803.68 + 0.006707\ \text{GDPHGG(t)i}$$

Where,

Di&gHGG(t)i	: Demand for electricity in Ind. & Gen. purpose consumer category -High Growth Group- (GWh)
GDPHGG(t)i	: Gross Domestic Product -High Growth Group- (million LKR)

Low Growth Group

$$Di\&gLGG(t)i = -226.166 + 0.003852\ GDPLGG(t)i$$

Where,

Di&gLGG(t)i : Demand for electricity in Ind. & Gen. purpose consumer category -Low Growth Group- (GWh)

GDPLGG(t)i : Gross Domestic Product -Low Growth Group- (million LKR)

Northern

$$Di\&gNo(t)i = -30.305 + 0.0023\ GDPNo(t)i$$

Where,

Di&gNo(t)i : Demand for electricity in Ind. & Gen. purpose consumer category -Northern Province- (GWh)

GDPNo(t)i : Gross Domestic Product -Northern Province- (million LKR)

Eastern

$$\ln Di\&gEa(t)i = -108.822 + 0.05664\ t$$

Where,

t : Year

<Other Purpose Sector>

Non-Northern

$$\ln DemNonNo(t) = -126.027 + 0.06538\ t$$

Northern

As a result of the Non-Northern Group, a 6.76% growth rate is applied to the forecast for the Northern Province.

Provincial power demand forecasts were carried out through the forecasting models and the scenarios by group. The results of the provincial energy sales forecasts[36] are shown in tables 4.4.9 to 4.4.12.

[36] Without the supplemental electricity demand for the Northern Province

Table 4.4.9 Provincial Energy Sales Forecast (Domestic)

(Unit: GWh)

Year	NC	NO	CE	NW	EA	WN	WS	CC	SO	UV	SA	Total	Diff.
2004	98	62	264	238	124	469	645	215	268	81	162	2,626	
2005	99	58	291	257	126	501	695	222	301	91	174	2,816	0.7%
2006	108	60	316	280	137	543	754	233	327	99	190	3,047	1.9%
2007	118	64	345	306	150	595	825	245	357	108	207	3,320	3.3%
2008	129	68	378	335	164	656	909	261	391	119	227	3,637	4.7%
2009	141	72	415	368	180	724	1,005	278	429	130	249	3,991	6.1%
2010	155	76	456	404	198	800	1,109	296	472	143	274	4,382	7.4%
2011	171	81	501	444	217	882	1,223	315	518	157	301	4,808	8.6%
2012	187	86	550	487	239	971	1,347	334	569	173	330	5,274	9.8%
2013	206	91	604	535	262	1,068	1,481	355	625	190	363	5,777	10.9%
2014	226	97	662	587	287	1,171	1,624	375	685	208	397	6,320	11.9%
2015	247	103	725	642	314	1,283	1,779	397	750	228	435	6,903	12.9%
2016	270	109	793	703	344	1,402	1,945	419	820	249	476	7,529	13.9%
2017	295	116	866	767	376	1,533	2,126	442	896	272	520	8,209	14.9%
2018	322	123	945	837	410	1,673	2,321	466	978	297	567	8,939	15.8%
2019	351	131	1,029	912	446	1,825	2,531	491	1,065	323	618	9,722	16.6%
2020	382	139	1,120	993	486	1,987	2,756	516	1,159	352	673	10,561	17.4%
2021	415	147	1,217	1,078	528	2,161	2,997	542	1,259	382	731	11,458	18.2%
2022	450	157	1,320	1,170	573	2,351	3,261	570	1,367	415	793	12,426	18.9%
2023	488	166	1,431	1,269	621	2,555	3,544	599	1,482	450	860	13,464	19.6%
2024	528	177	1,550	1,374	672	2,775	3,849	628	1,604	487	931	14,575	20.2%
2025	571	187	1,676	1,486	727	3,011	4,176	659	1,735	527	1,007	15,762	20.8%
2026	617	199	1,811	1,605	785	3,265	4,528	690	1,874	569	1,087	17,030	21.4%
2027	666	212	1,954	1,732	848	3,540	4,910	723	2,023	614	1,174	18,396	21.9%
2028	718	225	2,107	1,868	914	3,837	5,321	758	2,181	662	1,265	19,857	22.4%
2029	774	239	2,270	2,012	985	4,156	5,764	794	2,350	713	1,363	21,419	22.8%

Note: "Diff." refers to the difference of the forecasts between the provincial and national level approaches.

Table 4.4.10 Provincial Energy Sales Forecast (Ind.&Gen.)

(Unit: GWh)

Year	NC	NO	CE	NW	EA	WN	WS	CC	SO	UV	SA	Total	Diff.
2004	91	34	285	325	110	916	916	704	291	68	147	3,887	
2005	99	34	295	366	115	958	944	712	318	72	155	4,068	-1.7%
2006	111	38	315	407	121	1,040	1,024	753	355	77	166	4,406	-0.7%
2007	123	42	338	455	128	1,135	1,118	801	396	83	178	4,795	0.3%
2008	138	46	363	509	136	1,244	1,226	856	443	89	191	5,241	1.3%
2009	154	51	389	566	144	1,364	1,344	914	493	95	205	5,719	2.2%
2010	170	57	417	627	152	1,493	1,471	976	546	102	219	6,230	3.1%
2011	188	62	446	692	161	1,633	1,609	1,041	602	109	235	6,778	3.9%
2012	206	68	477	761	170	1,785	1,758	1,110	662	117	251	7,365	4.6%
2013	226	75	509	835	180	1,949	1,920	1,182	726	125	268	7,994	5.3%
2014	248	81	543	913	191	2,126	2,095	1,258	794	133	285	8,667	5.9%
2015	270	89	578	996	202	2,318	2,284	1,338	867	142	304	9,388	6.5%
2016	294	96	616	1,085	214	2,526	2,488	1,423	944	151	324	10,160	7.0%
2017	320	104	655	1,179	226	2,750	2,709	1,512	1,026	161	345	10,987	7.6%
2018	347	113	697	1,280	239	2,992	2,947	1,606	1,114	171	366	11,872	8.0%
2019	376	122	740	1,387	253	3,254	3,205	1,705	1,207	181	389	12,820	8.5%
2020	407	132	786	1,501	268	3,537	3,484	1,809	1,306	193	413	13,836	8.9%
2021	440	142	834	1,622	284	3,842	3,785	1,919	1,412	204	439	14,923	9.3%
2022	475	153	885	1,751	300	4,172	4,110	2,035	1,524	217	465	16,088	9.7%
2023	513	165	938	1,889	318	4,528	4,460	2,157	1,644	230	493	17,335	10.1%
2024	552	177	994	2,035	336	4,912	4,839	2,286	1,771	244	523	18,670	10.4%
2025	595	190	1,053	2,191	356	5,327	5,247	2,422	1,907	258	554	20,100	10.7%
2026	640	204	1,115	2,357	376	5,774	5,688	2,565	2,051	273	586	21,631	11.0%
2027	688	219	1,180	2,534	398	6,257	6,164	2,716	2,205	289	621	23,271	11.3%
2028	739	235	1,249	2,722	422	6,778	6,677	2,875	2,369	306	657	25,027	11.6%
2029	793	251	1,321	2,923	446	7,340	7,230	3,042	2,543	324	695	26,907	11.8%

Note: "Diff." refers to the difference of the forecasts between the provincial and national level approaches.

Table 4.4.11 Provincial Energy Sales Forecast (Other)

(Unit: GWh)

Year	NC	NO	CE	NW	EA	WN	WS	CC	SO	UV	SA	Total	Diff.
2004	4	3	11	23	7	36	33	16	12	2	6	154	
2005	5	3	11	25	8	38	34	16	13	2	6	161	5.1%
2006	5	3	12	27	8	40	36	18	13	2	7	171	6.3%
2007	5	3	13	29	9	43	39	19	14	3	7	183	7.5%
2008	6	4	13	30	9	46	41	20	15	3	8	195	8.8%
2009	6	4	14	32	10	49	44	21	16	3	8	209	10.0%
2010	6	4	15	35	10	52	47	23	17	3	9	223	11.3%
2011	7	4	16	37	11	56	50	24	19	3	9	238	12.6%
2012	7	5	17	40	12	60	54	26	20	4	10	254	13.9%
2013	8	5	19	42	13	64	57	28	21	4	11	271	15.2%
2014	8	5	20	45	14	68	61	30	23	4	11	289	16.6%
2015	9	6	21	48	14	73	65	32	24	4	12	309	17.9%
2016	10	6	23	51	15	77	70	34	26	5	13	330	19.3%
2017	10	7	24	55	16	83	75	36	28	5	14	352	20.7%
2018	11	7	26	59	18	88	80	38	29	5	15	376	22.1%
2019	12	8	28	62	19	94	85	41	31	6	16	401	23.5%
2020	12	8	29	67	20	101	91	44	34	6	17	428	24.9%
2021	13	9	31	71	21	107	97	47	36	7	18	457	26.4%
2022	14	9	34	76	23	115	103	50	38	7	19	488	27.8%
2023	15	10	36	81	24	122	110	53	41	8	20	521	29.3%
2024	16	10	38	87	26	131	118	57	44	8	22	556	30.8%
2025	17	11	41	92	28	139	126	61	47	9	23	594	32.3%
2026	18	12	44	99	30	149	134	65	50	9	25	634	33.9%
2027	20	13	47	105	32	159	143	69	53	10	26	677	35.4%
2028	21	14	50	113	34	170	153	74	57	11	28	722	37.0%
2029	22	15	53	120	36	181	163	79	61	11	30	771	38.6%

Note: “Diff.” refers to the difference of the forecasts between the provincial and national level approaches.

Table 4.4.12 Provincial Energy Sales Forecast (All Tariff Categories)

(Unit: GWh)

Year	NC	NO	CE	NW	EA	WN	WS	CC	SO	UV	SA	Total	Diff.
2004	194	99	560	587	241	1,421	1,594	934	571	152	314	6,667	
2005	203	95	596	648	248	1,497	1,672	951	632	166	336	7,044	-1.0%
2006	223	101	643	714	266	1,624	1,814	1,003	695	179	362	7,625	0.1%
2007	246	109	695	789	287	1,773	1,982	1,065	767	194	392	8,298	1.3%
2008	273	118	754	874	309	1,946	2,177	1,136	849	211	426	9,073	2.8%
2009	301	127	819	966	333	2,137	2,392	1,213	938	229	462	9,919	3.9%
2010	332	137	888	1,066	360	2,345	2,627	1,295	1,035	249	502	10,835	4.9%
2011	365	148	963	1,173	389	2,571	2,882	1,380	1,139	270	545	11,824	5.9%
2012	401	159	1,044	1,288	421	2,816	3,159	1,470	1,251	293	591	12,893	6.8%
2013	440	171	1,131	1,412	455	3,080	3,458	1,564	1,372	318	641	14,042	7.7%
2014	482	184	1,225	1,545	491	3,366	3,780	1,663	1,502	345	694	15,276	8.5%
2015	526	197	1,324	1,687	531	3,673	4,128	1,767	1,641	374	752	16,600	9.3%
2016	574	212	1,431	1,839	573	4,005	4,502	1,875	1,790	405	813	18,019	10.0%
2017	625	227	1,545	2,002	618	4,365	4,909	1,990	1,950	438	878	19,548	10.7%
2018	680	243	1,667	2,176	667	4,754	5,348	2,110	2,121	473	948	21,187	11.4%
2019	739	260	1,797	2,362	718	5,173	5,821	2,236	2,304	511	1,023	22,944	12.0%
2020	801	279	1,935	2,560	774	5,624	6,330	2,369	2,499	551	1,103	24,825	12.6%
2021	868	298	2,082	2,772	833	6,111	6,879	2,508	2,707	593	1,187	26,838	13.2%
2022	939	319	2,239	2,998	896	6,638	7,474	2,655	2,929	639	1,277	29,002	13.7%
2023	1,015	341	2,406	3,239	963	7,206	8,115	2,809	3,166	687	1,373	31,320	14.3%
2024	1,096	364	2,582	3,496	1,034	7,818	8,806	2,971	3,419	739	1,475	33,801	14.7%
2025	1,183	389	2,770	3,769	1,110	8,478	9,550	3,141	3,688	793	1,584	36,455	15.2%
2026	1,275	415	2,969	4,061	1,191	9,188	10,350	3,320	3,975	851	1,699	39,295	15.6%
2027	1,373	443	3,181	4,371	1,278	9,957	11,217	3,508	4,281	913	1,821	42,343	16.0%
2028	1,478	473	3,406	4,703	1,369	10,785	12,151	3,706	4,607	979	1,950	45,606	16.4%
2029	1,589	505	3,644	5,055	1,467	11,677	13,157	3,914	4,954	1,048	2,088	49,097	16.8%

Note: “Diff.” refers to the difference of the forecasts between the provincial and national level approaches.

As shown in Table 4.4.12, the forecasted electricity demand in 2029 through the provincial level approach is approximately 17% higher that through the national level approach. One of reasons for this difference is the limitation of the available data.

As mentioned before, the span of the available provincial data is nine years from 1996 to 2004 in the provincial level approach. Consequently, the regression models achieved from these data forecast higher electricity demand than the models in the national level approach because the electricity demand in recent years has increased at a higher growth rate than the past.

The sensitivity analyses of the data span identified, incidentally, that the results of the national demand forecast achieved from the past 15 years and 20 years are 2.6% and 7.0% higher than that achieved using data from the past 20 years[37]. The difference caused by data limitations will get smaller as the data span gets longer[38].

Finally, the allocation of the national demand to each province based on the share of each province achieved from the provincial demand forecast was carried out[39] (See Table 4.4.13 for the provincial energy sales forecast[40] and Table 4.4.14 for the provincial peak demand forecast).

Table 4.4.13 Provincial Demand Forecast (Energy Sales)

(Unit: GWh)

Year	NC	NO	CE	NW	EA	WN	WS	CC	SO	UV	SA	Total
2004	194	99	560	587	241	1,421	1,594	934	571	152	314	6,667
2005	204	121	599	652	249	1,508	1,682	961	635	166	337	7,114
2006	222	125	639	710	264	1,618	1,805	1,003	691	178	359	7,615
2007	242	132	682	776	281	1,747	1,950	1,053	754	190	384	8,191
2008	264	139	730	848	298	1,892	2,111	1,110	823	203	411	8,827
2009	288	147	783	928	318	2,057	2,296	1,173	899	218	441	9,548
2010	315	155	841	1,013	340	2,236	2,496	1,240	982	235	474	10,327
2011	343	164	903	1,105	364	2,429	2,714	1,311	1,071	253	510	11,166
2012	374	173	970	1,204	390	2,639	2,949	1,386	1,167	272	548	12,070
2013	407	183	1,042	1,310	417	2,864	3,203	1,464	1,269	292	589	13,040
2014	442	193	1,119	1,422	447	3,108	3,476	1,546	1,379	314	633	14,079
2015	479	204	1,201	1,543	479	3,369	3,769	1,633	1,496	338	680	15,190
2016	519	216	1,288	1,671	513	3,650	4,084	1,723	1,621	363	730	16,378
2017	562	229	1,381	1,808	550	3,954	4,425	1,818	1,755	390	783	17,654
2018	608	242	1,480	1,953	589	4,282	4,792	1,918	1,897	418	840	19,019
2019	656	256	1,585	2,109	630	4,635	5,187	2,023	2,049	449	900	20,480
2020	708	271	1,697	2,274	675	5,015	5,612	2,134	2,211	481	964	22,040
2021	763	287	1,815	2,450	722	5,423	6,068	2,249	2,383	515	1,032	23,708
2022	822	304	1,941	2,638	772	5,864	6,563	2,371	2,566	552	1,105	25,497
2023	884	321	2,075	2,837	826	6,340	7,095	2,500	2,761	590	1,182	27,412
2024	951	340	2,217	3,050	882	6,852	7,668	2,635	2,969	631	1,263	29,459
2025	1,022	361	2,367	3,276	943	7,403	8,284	2,776	3,191	675	1,350	31,648
2026	1,097	382	2,526	3,516	1,007	7,997	8,947	2,925	3,426	721	1,441	33,987
2027	1,178	405	2,696	3,773	1,076	8,637	9,664	3,082	3,677	770	1,539	36,496
2028	1,263	429	2,875	4,045	1,148	9,328	10,436	3,247	3,944	822	1,642	39,180
2029	1,354	455	3,065	4,335	1,226	10,071	11,268	3,421	4,228	878	1,751	42,052
AAGR	8.21%	5.69%	7.04%	8.21%	6.87%	8.23%	8.25%	5.43%	8.22%	7.17%	7.11%	7.68%

[37] See Appendix for further details on the results of the sensitivity analyses.
[38] There are some other reasons for the difference. For example, there are the limitations of provincial forecasts on GDP growth and population.
[39] In calculating peak demand, there was a difference due to the use of assumed provincial load factors. However, the difference was 2.2% and is assumed to be an acceptable level. Therefore, the total of each provincial forecast was adjusted to the national demand forecast.
[40] With the supplemental electricity demand for the Northern Province

Table 4.4.14 Provincial Demand Forecast (Peak Demand)

(Unit: MW)

Year	NC	NO	CE	NW	EA	WN	WS	CC	SO	UV	SA	Total	CC-Day
2004	68	38	155	164	98	280	374	157	122	41	65	1,563	219
2005	94	37	185	203	80	308	405	163	153	37	103	1,768	219
2006	101	38	196	220	84	329	432	169	165	39	109	1,884	227
2007	110	40	209	239	89	353	465	177	180	41	116	2,019	238
2008	120	42	222	260	94	381	501	185	195	44	124	2,168	249
2009	130	44	237	283	100	412	542	195	212	47	132	2,336	262
2010	141	46	253	308	107	446	587	205	231	51	141	2,517	276
2011	154	49	271	335	114	483	635	216	251	54	151	2,712	291
2012	167	51	290	363	121	522	688	227	272	58	162	2,921	306
2013	180	54	310	394	129	564	744	239	295	62	174	3,146	322
2014	196	57	332	426	138	611	805	252	319	67	186	3,389	339
2015	212	60	356	462	148	662	873	266	346	72	200	3,657	358
2016	230	64	382	500	159	717	945	281	375	77	214	3,943	377
2017	248	67	410	541	170	776	1,024	296	406	83	230	4,250	398
2018	269	71	439	584	182	840	1,108	312	438	89	246	4,579	420
2019	290	75	470	631	195	909	1,199	329	473	95	264	4,931	443
2020	313	80	503	680	208	983	1,297	347	511	102	283	5,306	467
2021	337	84	538	733	223	1,063	1,402	366	550	109	303	5,708	492
2022	363	89	575	789	238	1,150	1,516	386	593	117	324	6,138	519
2023	390	95	615	848	255	1,243	1,639	406	638	125	346	6,599	547
2024	420	100	657	912	272	1,343	1,771	428	686	134	370	7,092	576
2025	451	106	701	979	291	1,451	1,914	451	737	143	395	7,619	607
2026	484	113	748	1,051	311	1,567	2,067	476	791	153	422	8,182	640
2027	520	119	798	1,128	332	1,693	2,232	501	849	163	451	8,786	674
2028	558	126	852	1,209	354	1,828	2,411	528	911	174	481	9,433	710
2029	598	134	908	1,296	378	1,974	2,603	556	976	186	513	10,124	748
AAGR	8.02%	5.50%	6.85%	8.03%	6.68%	8.05%	8.06%	5.25%	8.04%	6.99%	6.92%	7.54%	5.25%

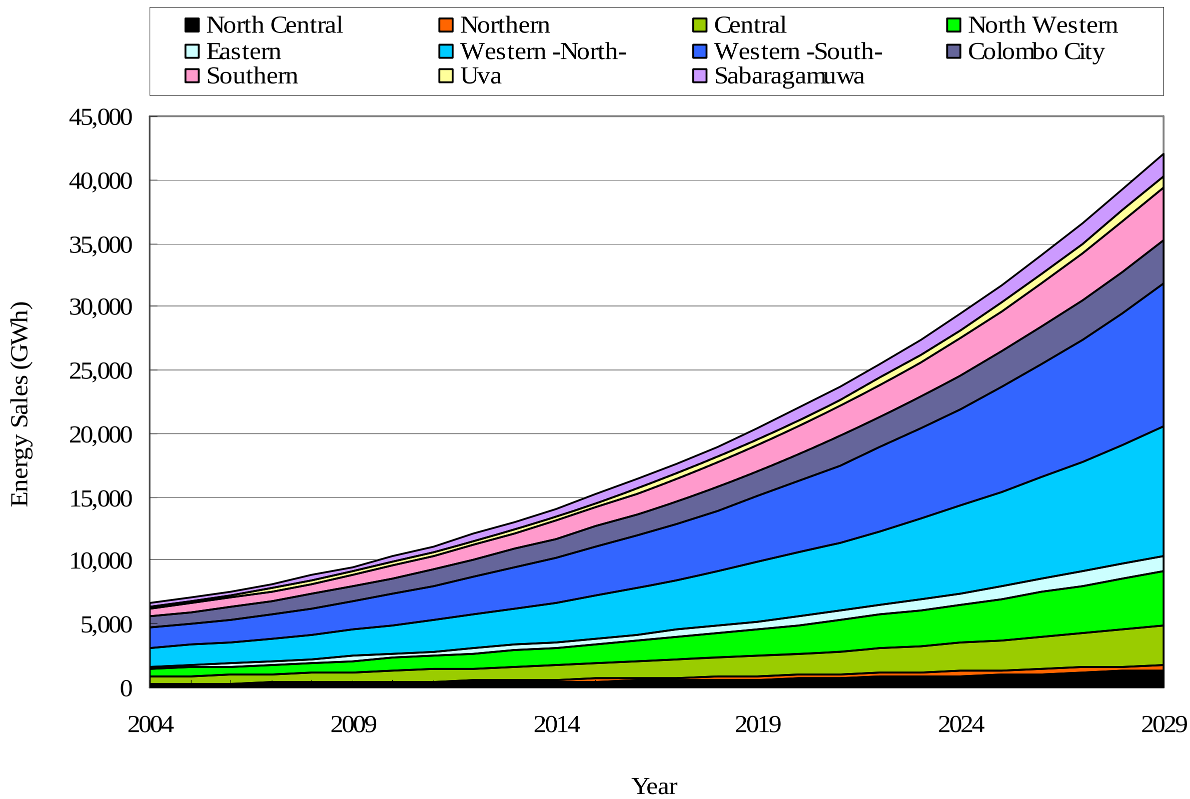


Figure 4.4.16 Provincial Demand Forecast (Energy Sales)

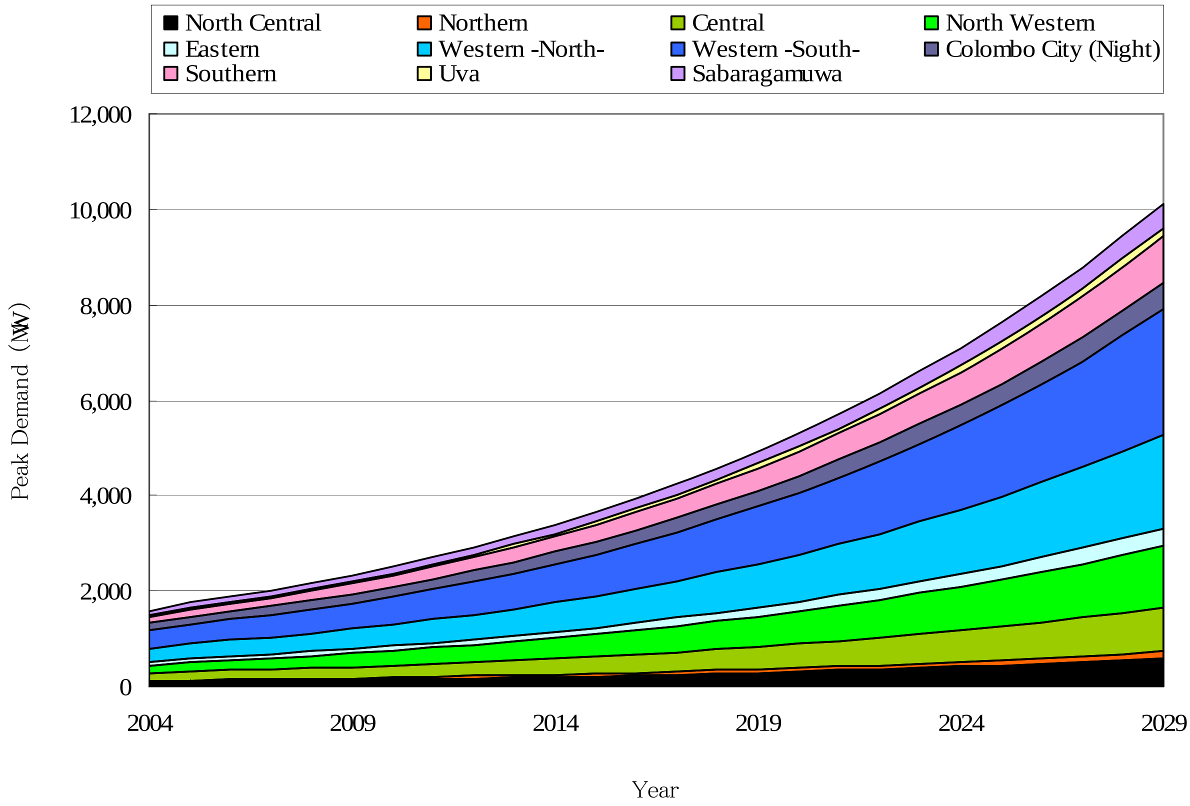


Figure 4.4.17 Provincial Demand Forecast (Peak Demand)

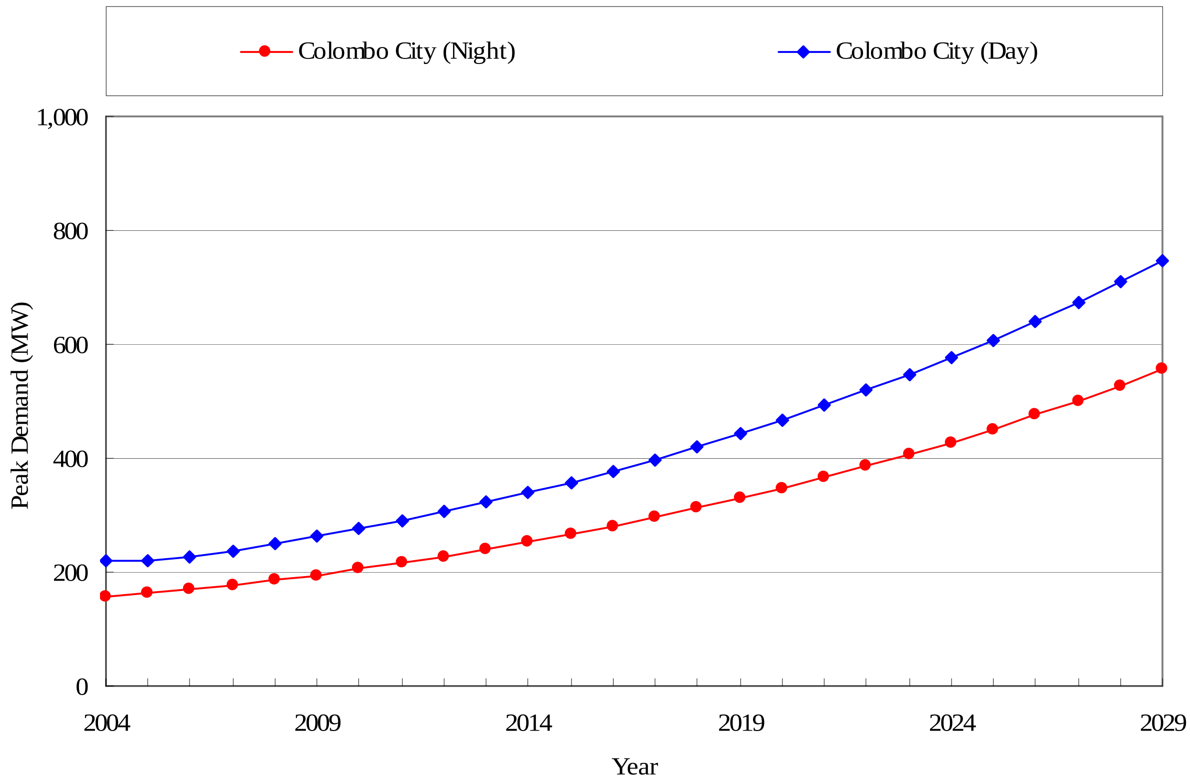


Figure 4.4.18 Peak Demand Forecast in Colombo City (Daytime & Nighttime)

4.5 Effect of Power Tariffs on Demand

Although it was indicated in 4.2.2(2) that at present it is unnecessary to introduce price as an element in the forecasting model due to the minimal effect of price on demand, as a case study in this section, we attempted to determine the effect on demand at the national level of changes in domestic tariffs, on the basis of specific scenarios. The model was formulated as follows from basic data for the past 20 years (1985-2004):

<Domestic Purpose Sector>

DdomP(t)i = -431.148 + 0.0239 GDPPC(t)i + 0.768 Ddom(t-1)i + (-) 11.247 AvePrice(t)i

Where,

Ddom(t)i	: Demand for electricity in domestic purpose consumer category (GWh)
GDPPC(t)i	: Gross Domestic Product per capita (million LKR/capita)
Ddom(t-1)i	: Demand in domestic consumer category in previous year (GWh)
AvePrice(t)I	: Average electricity price in domestic purpose consumer category (LKR/kWh)

Here, the scenarios shown in 4.3.1 (3) are used for factors other than average prices for domestic use. The following two scenarios were established for average prices for domestic use:

・An increase in average tariffs for domestic use (Tariff Increase Scenario)

・A gradual reduction in average power tariffs (Gradual Tariff Reduction Scenario)

(1) Increase in average electricity tariffs for domestic use

The average electricity price charged by the CEB for electricity in 2004 was 7.66 Rs/kWh. By use category, the average prices were 5.53 Rs/kWh for domestic use and 9.21 Rs/kWh for industrial use (Figure 4.5.1).

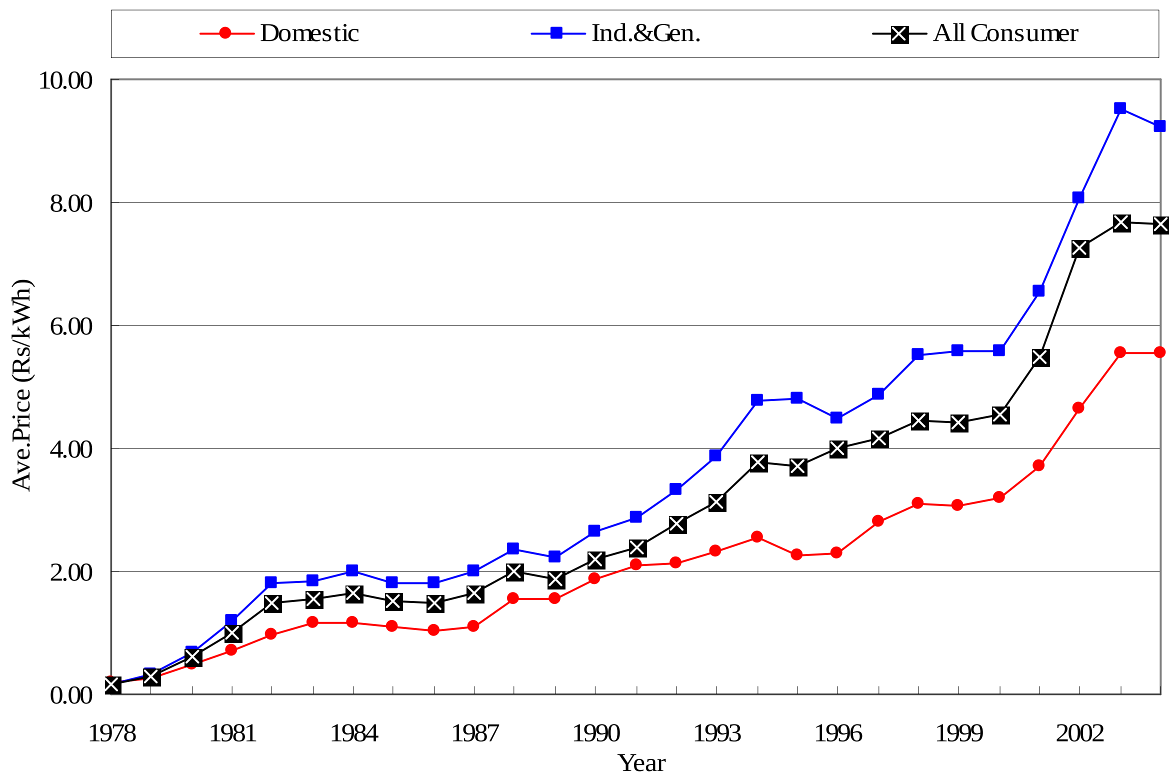


Figure 4.5.1 Changes in Average Electricity Price (nominal price)

Here, we study the change in demand assuming that domestic use tariffs increase to equal the 2004 average price for all users over a 10-year period. Table 4.5.1 shows the tariff scenario used in the tariff increase scenario.

Table 4.5.1 Tariff Increase Scenario

Year	Electricity Tariff	Year	Electricity Tariff	Year	Electricity Tariff
2004	*2.90*	2008	3.30	2012	3.77
2005	3.00	2009	3.41	2013	3.89
2006	3.10	2010	3.53	2014-2029	4.02
2007	3.20	2011	3.65		

Source: JICA Study Team

Note: The value for 2004 are the actual price for domestic purpose category

The prices are real price (1996FCP＝100 (1996), 190.5 (2004))

Table 4.5.2 shows estimates of the volume of power sales for domestic use obtained based on the price effect model and the tariff increase scenario discussed above.

Table 4.5.2 Price Effect Demand Forecast (Tariff Increase Scenario)

Year	Energy Sales (GWh)		Diff.	Year	Energy Sales (GWh)		Diff.
	Price Term On	Price Term Off			Price Term On	Price Term Off	
2004	2,626			2018	7,564	7,723	-2.10%
2005	2,793	2,796	-0.13%	2019	8,166	8,338	-2.11%
2006	2,981	2,991	-0.32%	2020	8,809	8,995	-2.11%
2007	3,198	3,215	-0.55%	2021	9,495	9,695	-2.10%
2008	3,446	3,474	-0.80%	2022	10,235	10,450	-2.10%
2009	3,725	3,763	-1.04%	2023	11,028	11,258	-2.09%
2010	4,031	4,082	-1.26%	2024	11,875	12,122	-2.08%
2011	4,364	4,428	-1.46%	2025	12,781	13,045	-2.07%
2012	4,728	4,805	-1.63%	2026	13,747	14,030	-2.05%
2013	5,119	5,211	-1.79%	2027	14,787	15,090	-2.04%
2014	5,540	5,647	-1.92%	2028	15,901	16,224	-2.04%
2015	5,993	6,112	-2.00%	2029	17,092	17,438	-2.03%
2016	6,477	6,610	-2.05%				
2017	7,001	7,147	-2.08%	AAGR (%)	7.82%	7.90%	

Table 4.5.2 indicates that if the average tariff of power for domestic use was to increase to 4.02 Rs/kW over a 10-year period[41], demand would decline by a maximum of approximately 2% compared to when no price effects are considered.

[41] Here, the price of power is the real price, and the nominal price therefore varies with changes in commodity prices.

(2) Gradual reduction in average power tariffs

In this section, we study the change in demand assuming that electricity tariffs are reduced gradually according to the tariff forecast shown in Section 8.4. Table 4.5.3 shows the tariff scenario used in the gradual tariff reduction scenario.

Table 4.5.3 Gradual Tariff Reduction Scenario

Year	Electricity Tariff	Year	Electricity Tariff	Year	Electricity Tariff	Year	Electricity Tariff
2004	*2.90*	2011	3.21	2018	2.78	2025	3.12
2005	2.69	2012	2.09	2019	2.82	2026	3.12
2006	2.99	2013	2.71	2020	2.94	2027	3.12
2007	2.83	2014	2.70	2021	2.76	2028	3.12
2008	2.94	2015	2.83	2022	2.89	2029	3.12
2009	3.39	2016	2.83	2023	2.97		
2010	3.12	2017	2.74	2024	2.73		

Source: JICA Study Team
Note: The value for 2004 are the actual price for domestic purpose category
The prices are real price (1996FCP＝100 (1996), 190.5 (2004))
Exchange Rate: 99.6422 Rs/US$

Table 4.5.4 shows estimates of the volume of power sales for domestic use obtained based on the price effect model and the gradual tariffs reduction scenario discussed above.

Table 4.5.4 Price Effect Demand Forecast (Gradual Tariff reduction Scenario)

Year	Energy Sales (GWh)		Diff.	Year	Energy Sales (GWh)		Diff.
	Price Term On	Price Term Off			Price Term On	Price Term Off	
2004	2,626			2018	7,617	7,723	-1.38%
2005	2,796	2,796	-0.01%	2019	8,220	8,338	-1.43%
2006	2,985	2,991	-0.19%	2020	8,863	8,995	-1.49%
2007	3,205	3,215	-0.33%	2021	9,551	9,695	-1.51%
2008	3,456	3,474	-0.52%	2022	10,291	10,450	-1.54%
2009	3,732	3,763	-0.83%	2023	11,082	11,258	-1.59%
2010	4,041	4,082	-1.00%	2024	11,932	12,122	-1.60%
2011	4,377	4,428	-1.16%	2025	12,834	13,045	-1.64%
2012	4,756	4,805	-1.02%	2026	13,798	14,030	-1.68%
2013	5,155	5,211	-1.09%	2027	14,837	15,090	-1.70%
2014	5,582	5,647	-1.15%	2028	15,949	16,224	-1.73%
2015	6,038	6,112	-1.23%	2029	17,139	17,438	-1.75%
2016	6,525	6,610	-1.29%				
2017	7,053	7,147	-1.34%	AAGR (%)	7.83%	7.90%	

Table 4.5.4 indicates that if the average tariff of power for domestic use was to change according to the tariff scenario shown in Section 8.4, demand would decline by a maximum of approximately 1.5% compared to when no price effects are considered.

Chapter 5 Transition and Current Status of Power Supply

5.1 Transition and Current Status of Power Supply

5.1.1 Transition of Installed Capacity

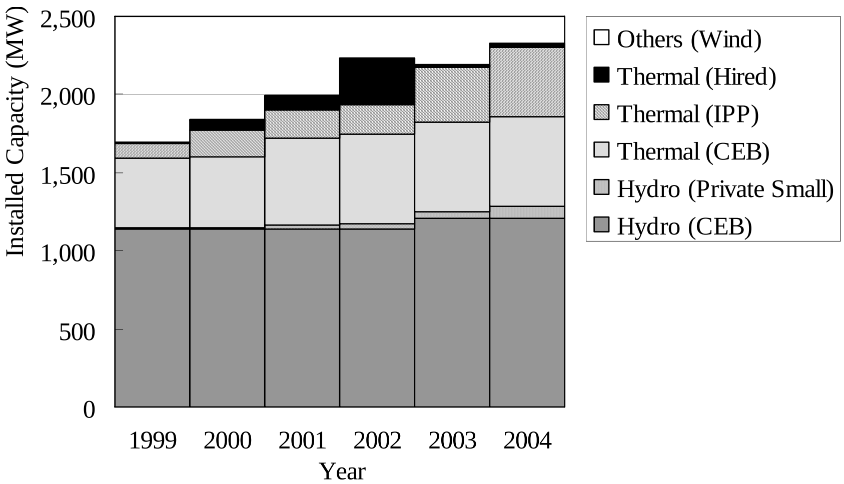
Table 5.1.1 and Figure 5.1.1 show the transition of installed capacity for the CEB system from 1999 to 2004.

Table 5.1.1 Transition of Installed Capacity (1999 - 2004)

(Unit : MW)

Type	Owner	Year					
		1999	2000	2001	2002	2003	2004
Hydropower	CEB	1,137.5	1,137.5	1,137.5	1,137.5	1,207.5	1,207.5
	Private Small	5.9	13.0	24.1	34.0	39.0	74.0
Thermal Power	CEB	453.0	453.0	563.0	573.0	573.0	573.0
	IPP	91.7	172.5	172.5	188.5	351.5	451.5
	Hired	0.0	58.0	98.0	300.0	20.0	20.0
Others		3.0	3.0	3.0	3.0	3.0	3.0
Total		1,691.1	1,836.9	1,998.0	2,236.0	2,194.0	2,329.0

Source: CEB System Control and Operations Annual Report (1999 - 2004)



Source: CEB System Control and Operations Annual Report (1999 - 2004)

Figure 5.1.1 Transition of Installed Capacity (1999 - 2004)

The installed capacity of the system is increasing and it reached 2,329MW as of 2004 year-end. The incremental capacity in installed capacity during the period from 1999 to 2004 was 637.9MW and the lion's share of incremental capacity has come from the newly developed thermal power plants.

However, the installed capacity of CEB-owned power plants was 1,593.5MW and 1,783.5MW in 1999 and 2004, respectively. The incremental capacity was 190.0MW, which is only around 30% of all incremental capacity.

The results show that in recent years the introduction of power plants owned by those other than CEB, such as IPP, contributed to the development of more installed capacity in the system. Especially in 2002, around 200MW from hired thermal power plants, which enter into power purchase contacts with CEB for one year, was introduced into the system as an emergency short-term countermeasure against supply shortages before the start of commercial operations for a 163MW IPP thermal power plant in 2003.

5.1.2 Transition of Annual Generation Energy

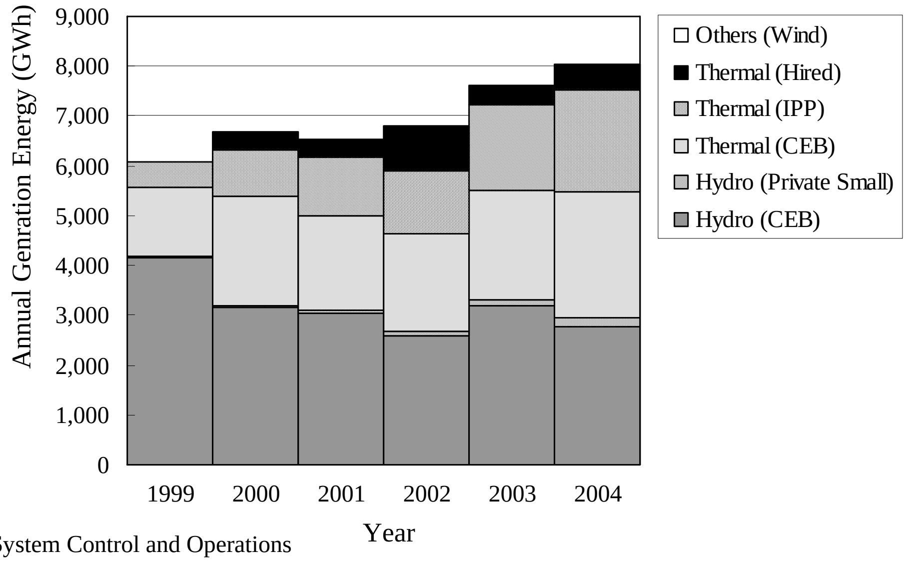
Table 5.1.2 and Figure 5.1.2 show the transition of annual generation energy from 1999 to 2004.

Table 5.1.2 Transition of Annual Generation Energy (1999 - 2004)

(Unit : GWh)

Type	Owner	Year					
		1999	2000	2001	2002	2003	2004
Hydropower	CEB	4,151.9	3,153.8	3,044.9	2,588.6	3,190.0	2,754.8
	Private Small	17.8	43.3	64.8	103.5	120.3	205.6
Thermal Power	CEB	1,396.2	2,205.3	1,895.5	1,952.6	2,193.2	2,506.9
	IPP	507.4	916.4	1,170.2	1,248.0	1,710.6	2,064.2
	Hired	0.0	363.7	341.1	913.4	394.4	509.2
Others (Wind)	CEB	3.5	3.4	3.5	3.6	3.4	2.7
Total		6,076.8	6,685.9	6,519.9	6,809.8	7,612.0	8,043.3

Source: CEB System Control and Operations Annual Report (1999 - 2004)



Source: CEB System Control and Operations Annual Report (1999 - 2004)

Figure 5.1.2 Transition of Annual Generation Energy (1999 - 2004)

Annual generation energy in the system is increasing as along with the increasing installed capacity, and annual generation energy in the system in 2004 was 8,43.3GWh/year. However, generation energy from hydropower owned by CEB was remarkably decreased due to the shortage of rainfall water after 1999. The averaged annual generation energy from hydropower during 2000 to 2004 was around 2,900GWh/year, which is around 70 percentage of the annual generation of 4,151.9GWh/year in 1999. The component ratio of hydropower generation to the system total also remarkably decreased from 68.6% in 1999 to 36.8% in 2004.

By contrast, annual generation energy from thermal power plants has increased remarkably in recent years. Especially, generation energy from CEB-owned thermal power plants has increased from 1,369.2 GWh/year in 1999 to 2,506.9GWh/year in 2004, which is around 1.8 times level in 1999. As shown in Table 5.1.1, the installed capacity of CEB-owned thermal power plants has increased slightly from 1999 to 2004. Therefore, it seems that the plant factor of CEB-owned thermal power plants has increased during this period.

5.1.3 Transition of Plant Factor

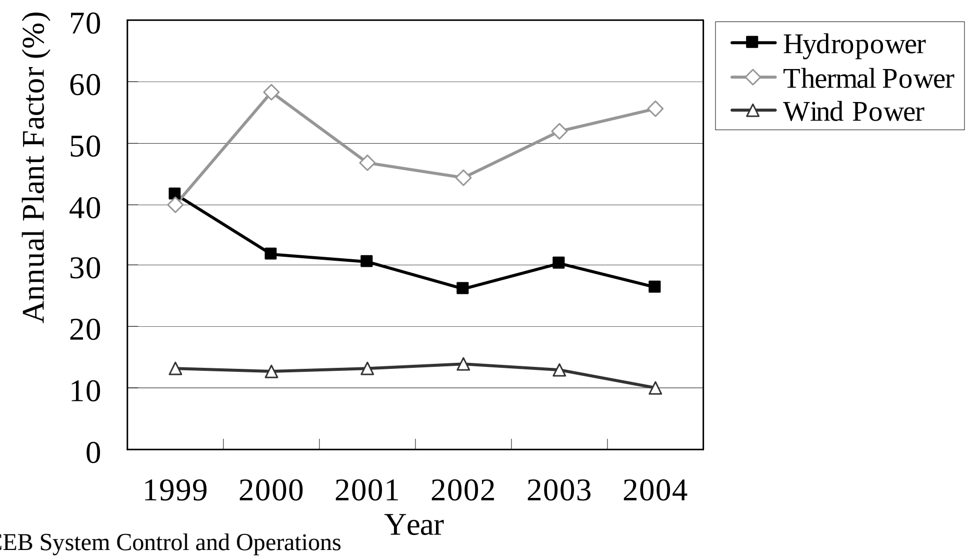
Table 5.1.3 and Figure 5.1.3 show the transition of annual plant factor for each plant type.

Table 5.1.3 Transition of Annual Plant Factor (1999 - 2004)

(Unit : %)

Type	Year					
	1999	2000	2001	2002	2003	2004
Hydropower	41.6	31.7	30.6	26.2	30.3	26.4
Thermal Power	39.9	58.2	46.7	44.2	51.9	55.5
Wind Power	13.2	12.8	13.1	13.9	12.9	10.1

Source: CEB System Control and Operations Annual Report (1999 - 2004)



Source: CEB System Control and Operations Annual Report (1999 - 2004)

Figure 5.1.3 Transition of Annual Plant Factor (1999 - 2004)

The plant factor for hydropower decreased from 41.6% in 1999 to 26.4% in 1999 due to the water shortage after 2000. Consequently, the annual plant factor increased from 39.9% in 1999 to 55.5% in 2004.

The figure shows that the increasing plant factor for thermal power plants covered the decline of generation energy from hydropower caused by the water shortage.

5.1.4 List of Existing Power Plants (as of November 2005)

Table 5.1.4 shows the list of existing power plants in the system as of November 2005.

Table 5.1.4 List of Existing Power Plants (as of November 2005)

Type	Location	Power Plant	Owner	Plant Type	Installed Capacity (MW)	Unit No.	Unit Capacity (MW)	Commissioning Year	Running Year (year)	Remarks
Hydro	Laxapana Complex	New Laxapana	CEB	Run-of-River	60.000	1	30.000	Feb. 1974	31	
						2	30.000	Mar. 1974	31	
		Old Laxapana	CEB	Run-of-River	49.960	1	8.330	Dec. 1958	46	
						2	8.330	Dec. 1958	46	
						3	8.300	Dec. 1958	46	
						4	12.500	Dec. 1958	46	
						5	12.500	Dec. 1958	46	
		Wimalasurandra	CEB	Reservoir	50.000	1	25.000	Dec. 1950	54	
						2	25.000	Dec. 1950	54	
		Polpitiya	CEB	Run-of-River	75.000	1	37.500	Apr. 1969	36	
						2	37.500	Apr. 1969	36	
		Canyon	CEB	Reservoir	60.000	1	30.000	Mar. 1983	22	
						2	30.000	Jan. 1965	40	
	Mahaweli Complex	Kotmale	CEB	Reservoir	201.000	1	67.000	Apr. 1985	20	
						2	67.000	Feb. 1988	17	
						3	67.000	Feb. 1988	17	
		Victoria	CEB	Reservoir	210.000	1	70.000	Jan. 1985	20	
						2	70.000	Oct. 1984	20	
						3	70.000	Feb. 1986	19	
		Ukuwela	CEB	Run-of-River	38.000	1	19.000	Jul. 1976	28	
						2	19.000	Aug. 1976	28	
		Bowatenna	CEB	Reservoir	40.000	1	40.000	Jun. 1981	24	
		Randenigala	CEB	Reservoir	122.000	1	61.000	Jul. 1986	18	
						2	61.000	Jul. 1986	18	
		Rantambe	CEB	Reservoir	49.000	1	24.500	Jan. 1990	15	
						2	24.500	Jan. 1990	15	
	Others	Samanalawewa	CEB	Reservoir	120.000	1	60.000	Oct. 1992	12	
						2	60.000	Oct. 1992	12	
		Kukule ganga	CEB	Run-of-River	70.000	1	35.000	Jul. 2003	1	
						2	35.000	Jul. 2003	1	
Thermal	Kelanitissa	Kelanitissa Steam Turbine	CEB	Steam Turbine	50.000	1	25.000	1965	40	
						2	25.000	1965	40	
		Kelanitissa Gas Turbine (Old)	CEB	Gas Turbine	120.000	1	20.000	Dec. 1981	23	
						2	20.000	1982	23	
						3	20.000	Mar. 1982	23	
						4	20.000	1982	23	
						5	20.000	Apr. 1982	23	
						6	20.000	1982	23	
		Kelanitissa Gas Turbine (New)	CEB	Gas Turbine	115.000	1	115.000	Aug. 1997	7	
		Kelanitissa Combined Cycle	CEB	Combined Cycle	165.000	1	165.000	Aug. 2002	2	
	Sapugasukanda	Sapugasukanda Diesel	CEB	Diesel	80.000	1	20.000	May. 1984	21	
						2	20.000	May. 1984	21	
						3	20.000	Sep. 1984	21	
						4	20.000	Oct. 1984	20	
		Sapugasukanda Diesel (Extension)	CEB	Diesel	80.000	1	10.000	Sep. 1997	7	
						2	10.000	Sep. 1997	7	
						3	10.000	Sep. 1997	7	
						4	10.000	Sep. 1997	7	
						5	10.000	Oct. 1999	5	
						6	10.000	Oct. 1999	5	
						7	10.000	Oct. 1999	5	
						8	10.000	Oct. 1999	5	
	Others	Chunnakam	CEB	Diesel	14.000	1	1.000	1958	6	
						2	1.000	1958	6	
						3	1.000	1958	6	
						4	1.000	1958	6	
						5	2.000	1965	6	
						6	2.000	1965	6	
						7	2.000	1965	6	
						8	2.000	1965	6	
						9	2.000	1965	6	
		Lakdhanavi	IPP	Diesel	22.520	1	5.630	Nov. 1997	7	
						2	5.630	Nov. 1997	7	
						3	5.630	Nov. 1997	7	
						4	5.630	Nov. 1997	7	
		Asia Power	IPP	Diesel	51.000	1	6.375	Jun. 1998	7	
						2	6.375	Jun. 1998	7	
						3	6.375	Jun. 1998	7	
						4	6.375	Jun. 1998	7	
						5	6.375	Jun. 1998	7	
						6	6.375	Jun. 1998	7	
						7	6.375	Jun. 1998	7	
						8	6.375	Jun. 1998	7	
		Colombo Power	IPP	Diesel	62.724	1	15.681	Jul. 2000	5	
						2	15.681	Jul. 2000	5	
						3	15.681	Jul. 2000	5	
						4	15.681	Jul. 2000	5	
		ACE Power Matara	IPP	Diesel	24.800	1	6.200	Mar. 2002	3	
						2	6.200	Mar. 2002	3	
						3	6.200	Mar. 2002	3	
						4	6.200	Mar. 2002	3	
		ACE Power Horana	IPP	Diesel	24.800	1	6.200	Dec. 2002	2	
						2	6.200	Dec. 2002	2	
						3	6.200	Dec. 2002	2	
						4	6.200	Dec. 2002	2	
		ACE Power Embilipitiya	IPP	Diesel	100.000	1	10.000	Mar. 2005	0	
						2	10.000	Mar. 2005	0	
						3	10.000	Mar. 2005	0	
						4	10.000	Mar. 2005	0	
						5	10.000	Mar. 2005	0	
						6	10.000	Mar. 2005	0	
						7	10.000	Mar. 2005	0	
						8	10.000	Mar. 2005	0	
						9	10.000	Mar. 2005	0	
						10	10.000	Mar. 2005	0	
		AES Kelanitissa	IPP	Combined Cycle	163.000	1	163.000	Feb. 2003	2	
		Heladhanavi	IPP	Diesel	96.000	1	16.000	Dec. 2004	0	
						2	16.000	Dec. 2004	0	
						3	16.000	Dec. 2004	0	
						4	16.000	Dec. 2004	0	
						5	16.000	Dec. 2004	0	
						6	16.000	Dec. 2004	0	
		Kool Air	IPP	Diesel	20.000	1	20.000	2002	3	
		Aggreko Chunnakam	Hired	Diesel	20.000	1	20.000	Oct. 2003	2	
Wind	Hambantota	Hambantota	CEB	Wind	3.000	1	3.000	1999	6	

Source: CEB Sales and Generation Data Book 2003, CEB System Control and Operation Annual Report 2004

5.1.5 System Unserved Energy

System unserved energy is the result of problems with power plants and the transmission system. CEB has been recording past unserved energy and results are summarized in a monthly report that is issued from the CEB System Control Branch.

Table 5.1.5 shows system unserved energy recorded from 1999 to 2004.

Table 5.1.5 Historical System Unserved Energy (1999 - 2000)

(Unit : MWh)

Reason for Unserved	Year					
	1999	2000	2001	2002	2003	2004
Power Cut	0.0	644.8	291,223.0	524,590.0	0.0	0.0
Generator Tripping	126.8	244.3	290.0	278.6	560.6	434.5
Transmission Tripping	2,281.1	2,024.3	1,074.2	4,502.5	3,377.7	443.0
Transformer Tripping	403.8	522.0	384.2	304.0	331.1	243.1
Total Failure	1,730.0	2,069.0	1,196.1	3,573.0	6,616.9	2,668.4
Total (A)	4,541.7	5,504.4	294,167.5	533,248.1	10,886.3	3,789.0
Annua Generation Energy (B)	6,076,767.0	6,685,922.0	6,519,866.0	6,809,791.0	7,611,957.0	8,043,325.0
(A) / (B) (%)	0.07	0.08	4.51	7.83	0.14	0.05

Source: CEB System Control and Operation Annual Report (1999 - 2004)

System unserved energy was 294,167.5MWh in 2001 and 533,248.1MWh in 2002, which correspond to 4.5% and 7.8% of total annual generation of the system, respectively. In 2001 and 2002 generation energy from hydropower declined dramatically due to the water shortage. Therefore, the forced power cuts carried out during those years were unavoidable.

Unserved energy caused by other reasons, such as the forced outage of power facilities, is relatively small. Consequently, the power facilities in the system were basically stable during this period.

(1) Planned Power Cuts

Electricity will not be served in the event that the system does not have enough supply capacity to meet demand. CEB has not been able to avoid the conducting of power cuts in past years.

Table 5.1.6 shows historical unserved energy due to planed power cuts from 1999 to 2004.

Table 5.1.6 Historical Unserved Energy due to Planned Power Cut (1999 - 2004)

(Unit : MWh)

Month	Year					
	1999	2000	2001	2002	2003	2004
January	0.0	112.3	23.8	78,063.0	0.0	0.0
February	0.0	146.5	0.0	102,197.0	0.0	0.0
March	0.0	0.0	0.0	177,030.0	0.0	0.0
April	0.0	29.4	48.0	140,301.0	0.0	0.0
May	0.0	10.0	0.0	26,999.0	0.0	0.0
June	0.0	0.0	0.0	0.0	0.0	0.0
July	0.0	32.8	42,470.6	0.0	0.0	0.0
August	0.0	0.0	48,167.4	0.0	0.0	0.0
September	0.0	184.6	112,312.2	0.0	0.0	0.0
October	0.0	0.0	75,667.8	0.0	0.0	0.0
November	0.0	0.0	8,256.3	0.0	0.0	0.0
December	0.0	129.3	4,277.0	0.0	0.0	0.0
Total (A)	0.0	644.9	291,223.1	524,590.0	0.0	0.0
Annua Generation Energy (B)	6,076,767.0	6,685,922.0	6,519,866.0	6,809,791.0	7,611,957.0	8,043,325.0
(A) / (B) (%)	0.0	0.0	4.5	7.7	0.0	0.0

: Month for Energy Unservice due to Planned Power Cut

Source: CEB System Control and Operation Annual Report (1999 - 2004)

CEB carried out the planned power cuts from July 2001 due to the lack of supply caused by the water shortage. Planned power cuts have not been carried out since June 2002 because the supply capacity in the system was increased by continuously introducing new power plants to the system, such as the 105MW Kelanitissa GT open cycle in November 2001, 22MW IPP ACE Matara diesel power plant in March 2003 and 60MW Kelanitissa ST (addition).

The amount of unserved energy due to planned power cuts was 291.2GWh in 2001 and 524.6GWh in 2002, which corresponds to 4.5% and 7.7% of annual generation energy, respectively. These figures are below the target supply reliability in CEB generation planning, which is set as less than 3 days per year in LOLP, and they indicate a severe situation for the demand and supply balance in those years.

After June 2002 the system appeared to have enough supply capacity to meet demand.

(2) Accidental Generator Outage

There is the possibility that the system cannot serve power to consumers due to temporary declines in supply capacity caused by accidental generator outages even though the system has enough supply capacity to meet demand.

CEB also has been recording the unserved energy due to generator tripping.

Table 5.1.7 shows historical unserved energy due to accidental generator outages.

Table 5.1.7 Historical Unserved Energy due to Accidental Generator Tripping (1999 - 2004)

(Unit : MWh)

Month	Year					
	1999	2000	2001	2002	2003	2004
January	2.1	8.7	0.5	14.0	104.2	38.4
February	0.0	37.2	2.3	14.6	12.8	96.2
March	2.0	4.5	5.7	12.2	0.0	77.5
April	1.8	18.5	11.1	48.4	12.4	68.0
May	42.8	36.9	12.2	61.7	12.3	21.9
June	2.3	34.2	0.0	42.1	63.9	2.8
July	8.5	24.2	125.0	10.5	72.5	13.9
August	5.2	20.9	14.8	0.2	34.1	0.0
September	0.0	9.3	18.0	12.7	64.7	0.7
October	27.2	7.3	49.4	5.6	97.9	38.1
November	21.1	0.0	39.6	18.7	64.2	56.8
December	13.8	42.7	11.4	38.9	21.6	20.2
Total (A)	126.8	244.4	290.0	279.6	560.6	434.5
Annua Generation Energy (B)	6,076,767.0	6,685,922.0	6,519,866.0	6,809,791.0	7,611,957.0	8,043,325.0
(A) / (B) (%)	0.002	0.004	0.004	0.004	0.007	0.005

: Month for Energy Unservice due to Accidental Generator Outage

Source: CEB System Control and Operation Annual Report (1999 - 2004)

Accidental generator outages occurred in almost every month and so the power was not served. However, the amount of unserved energy due to such outages is negligible compared to the amount of annual generation energy.

5.2 Current Status of Existing Power Plant

5.2.1 Hydropower Plant

(1) CEB Existing Hydropower Plants

CEB's existing hydro-generating system, excluding small-scale hydropower, produces 1,185MW as of November 2005. Details of these hydropower plants are shown in Table 5.2.1. The geographical locations of the hydropower plants are shown in Figure 5.2.1.

Table 5.2.1 List of Existing Hydropower Plants (As of November 2005)

Plant Name	Unit	Unit Capacity (MW)	Total Capacity (MW)	Annual Average Energy (GWh)	Plant Factor (%)	Storage Capacity (MCM)	Name of Reservoir	Commissioning
Laxapana Complex								
(1) Canyon	2	30	60	160	30%	123.4	Moussakelle	Unit 1: Mar.1983 Unit 2: 1988
(2) Wimalasurendra	2	25	50	112	26%	44.8	Castleriegh	Jan.1965
(3) Old Laxapana	3	8.33						Dec. 1950
	2	12.5						Dec. 1958
Total	5		50	286	65%	0.4	Norton	
(4) New Laxapana	2	50	100	552	63%	1.2	Canyon	Unit 1: Feb.1974 Unit 2: Mar.1974
(5) Polpitiya	2	37.5	75	453	69%	0.4	Laxapana	Apr.1969
Laxapana Total	**13**		**335**	**1,563**	**53%**			
Mahaweli Complex								
(6) Victoria	3	70	210	865	47%	721.2	Victria	Unit 1: Jan.1981 Unit 2: Oct.1984
(7) Kotmale	3	67	201	498	28%	172.6	Kotmale	Unit 1: Apr.1985 Unit 2 & 3:
(8) Randenigala	2	61	122	454	42%	875.0	Randenigala	July 1986
(9) Ukuwela	2	19	38	154	46%	1.2	Polgolla	Unit 1: July 1976 Unit 2: Aug.1976
(10) Bowatenna	1	40	40	48	14%	49.9	Bowatenna	June 1981
(11) Rantambe	2	24.5	49	239	56%	21.0	Rantambe	Jan.1990
Mahaweli Total	**13**		**660**	**2,258**	**39%**			
Other Hydro Complex								
(12) Samanalawewa	2	60	120	344	33%	278.0	Samanalawewa	Oct.1992
(13) Kukule	2	35	70	300	49%	1.7		July 2003
Other Hydro Total	**4**		**190**	**644**	**39%**	**279.7**		
Existing Total	**30**		**1,185**	**4,465**	**43%**			

Source: Long Term Generation Expansion Plan 2005-2019, Transmission & Generation Planning Branch, CEB, Nov. 2004

(i) Laxapana Complex

The major hydropower schemes already developed are associated with the Kelani and Mahaweli river basins. Five hydropower stations with a total installed capacity of 335MW have been constructed in two cascaded systems associated with the two main tributaries of the Kelani River; specifically Kehelgamu Oya and Maskeliya Oya (Laxapana Complex). The five stations in this complex are not required to operate for the support of irrigation or other water requirements. In other words, they are primarily designed to meet the power requirements of the country.

Castlereigh and Moussakelle are the two major storage reservoirs in the Laxapana hydropower complex. The Castlereigh reservoir, which feeds the Wimalasurendra Power Station, is fed from the Moussakelle reservoir. The Canyon, Norton and Laxapana ponds feed the New Laxapana, Old Laxapana and Polpitiya power stations, respectively.

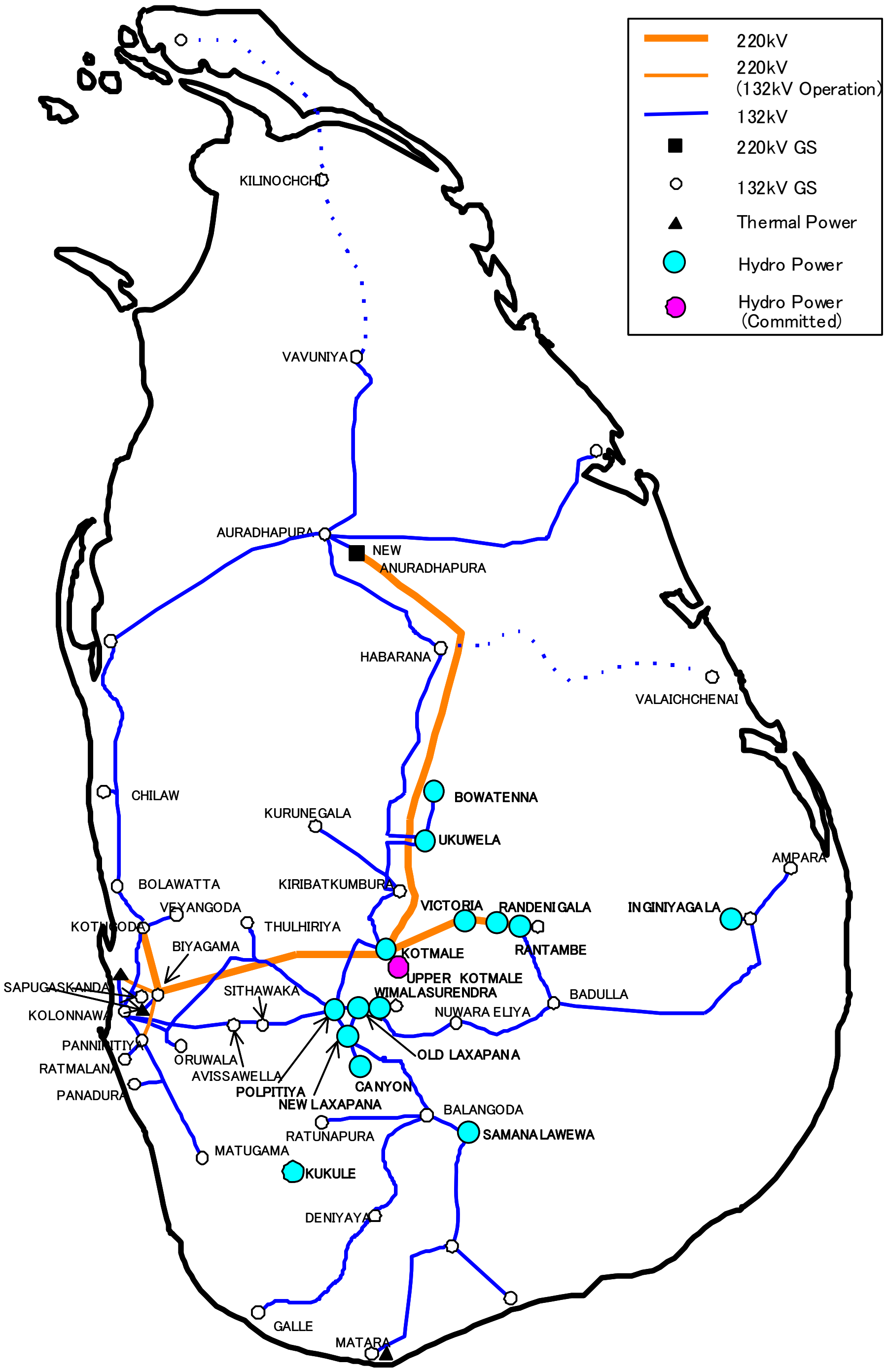
(ii) Mahawelli Complex

The development of the major hydropower resources under the accelerated Mahaweli project added six hydropower stations (Ukuwela, Bowatenna, Kotmale, Victoria, Randenigala and Rantambe) to the national grid with a total installed capacity of 660 MW. The three major reservoirs of Victoria, Kotmale and Randenigala, were also developed within the Mahaweli development program.

The Polgolla-diversion weir (across Mahaweli Ganga), downstream of Kotmale and upstream of Victoria, diverts Mahaweli waters to irrigation systems via the Ukuwela power station (38MW). After generating electricity at the Ukuwela power station the water is discharged to Sudu Ganga, which carries water to the Bowatenna reservoir. It then feeds both the Bowatenna power station (40MW) and Mahaweli System-H by means of separate waterways. The Mahaweli system is operated as a multi-purpose system. Hence, power generation from the associated power stations is governed by the down-stream irrigation requirements as well. These requirements, being highly seasonal, constrain the operations of the power station during certain periods of the year.

(iii) Other river basins

The Samanalawewa hydropower plant is allocated to the multi-purpose dam for irrigation in the upper section of the Walawe river basin. The Kukule power plant is a run-of river type plant located on Kukule Ganga, a tributary of Kalu Ganga.



Source: JICA Study team

Figure 5.2.1 Location of Existing Hydropower Plants (As of November 2005)

Mahaweli Complex

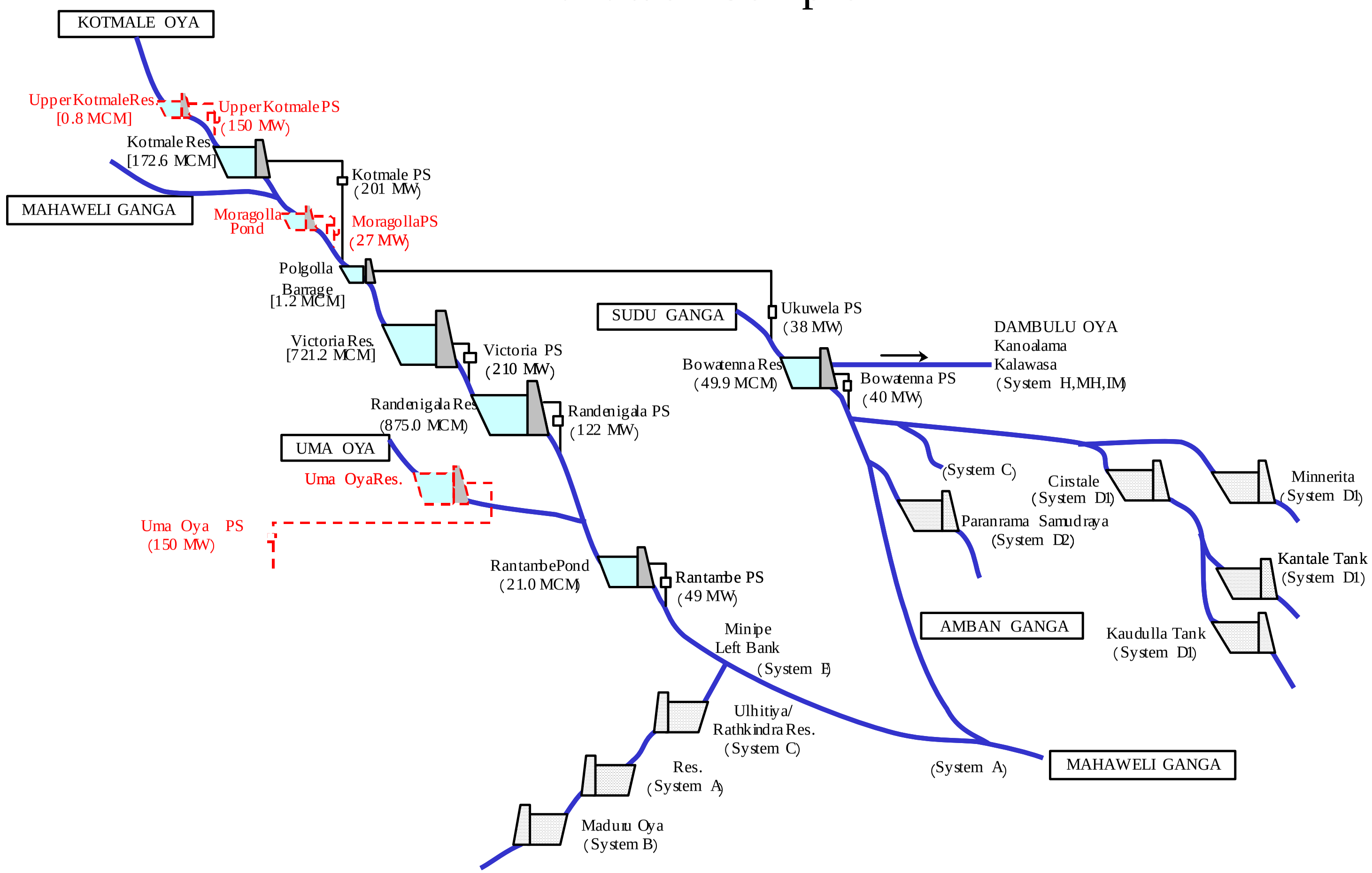


Figure 5.2.2 Diagram of Hydropower Projects in Mahaweli Complex

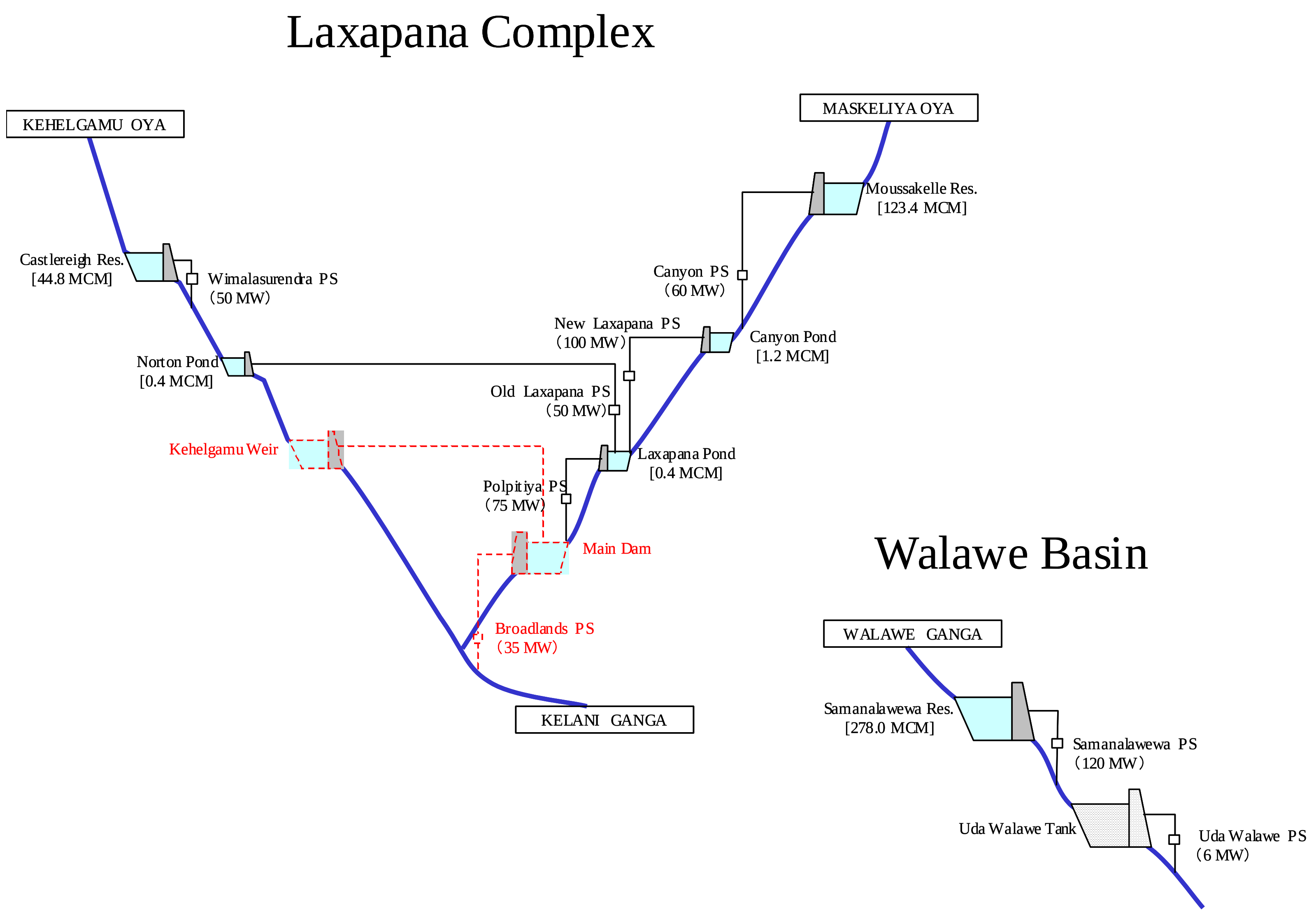


Figure 5.2.3 Diagram of Hydropower Projects in Kelani Complex and Walawe Basin

(2) Current Status of Hydropower Plants

The details of the present status of existing hydropower stations, according to JICA's February 2004 Study of the Hydropower Optimization Study, are shown in Tables 5.2.2 and 5.2.3.

After this study, the Follow-up Study on the Rehabilitation of Hydropower Stations in the Kelani River Basin has been conducted since August 2004. Until August 2005 the results of the study will be developed.

In addition, CEB has improved its operation and maintenance by means of repair and inspection programs. Actual planning was carried out to combat the water leakage at the headrace tunnel in the Wimalasurendra hydropower station in February 2005.

Table 5.2.2 Current Status of Existing Hydropower Plants (1)

System	Plant Name	Unit	Capacity (MW)	Annual Average Energy (GWh)	Plant Factor (%)	Commissioning	Description
Laxapana Complex	Wimalasurendra	2	50	112	26	Jan.1965	Muddy discharge has been observed at the outlet. This implies a collapse somewhere inside the pressure tunnel. Despite this, the plant has been operated following the instructions from CEB headquarters. -No options are left except for investigations by dewatering. -No other significant problems have been observed. -Periodic inspections to check degradation of generating equipment should be made and records of the conditions should be kept.
	Old Laxapana	5	50	279	64	Dec.1950 Dec.1958	Notable defects have not been found in civil structures. Periodic inspections should be made to check degradation of generating equipment and records of the conditions should be kept. In particular, degradation of the inlet valve, needle and oil filter has affected plant operations. Some units have been forced to continue operating during nights and weekends to prevent equipment malfunctions. Repair of the defective equipment, including replacement, should be made immediately.
	Canyon	2	60	163	31	#1:Mar.1983 #2:1988	The waterway structure of the power plant was not suitably designed for a 60MW-capacity power plant。 Therefore, there has been heavy friction loss due to tunnel diameters that are too small. In particular, there have been cases of negative pressure between the intake and portal of the headrace tunnel. An anti-negative pressure valve has been installed, but the valve has often caused malfunctions.
	New Laxapana	2	100	467	53	#1:Feb.1974 #2:Mar.1974	A massive amount of water is leaking from the vicinity of the surge chamber and flowing down slope. The leakage may cause not only economic losses, but may also have a negative impact on slope stability if it remains unchecked for a long period. Unit 1 has been forced to continue operating during the night and on weekends because the governor has often failed to operate the power system in a parallel manner. The malfunction of the unit 1 governor has made governor-free operation of system frequency control impossible, and only unit 2 is carrying out the function of frequency control for the power system at night.
	Polpitiyia	2	75	409	62	Apr.1969	Sediment originating from surface exfoliation of the unlined headrace tunnel could be flowing into the turbines. However, this has not been confirmed yet. Both hydraulic turbines have had vibration and shaft run-out problems, so that only operation patterns at 5MW, 32MW or 37.5MW per unit have been allowed, in order to prevent vibration. Detailed investigations should be made for these two units.

Source: Hydropower Optimization Study in Sri Lanka, EPDC & Nippon Koei Feb. 2004

Table 5.2.3 Current Status of Existing Hydropower Plants (2)

System	Plant Name	Unit	Capacity (MW)	Annual Average Energy (GWh)	Plant Factor (%)	Commissioning	Description
Mahaweli Complex	Kotmale	3	201	498	28	#1:Apr.1985 #2:Feb.1988	The power plant has been well maintained and no serious problems have been reported.
	Victoria	3	210	865	47	#1:Jan.1985 #2:Oct.1984 #3:Feb.1984	No serious problem has been reported with the electromechanical equipment. There is a capacity extension plan for three units with 70MW output each (210MW) Will need to install an additional two units.
	Randenigala	2	122	454	42	Jul.1986	Hydraulic turbines have had vibration problems when they were operated at a partial load. Therefore, the operations have been restricted in accordance with the operation range curve between the reservoir water level and the output. In particular, operation below 40MW has been avoided to prevent the occurrence of vibration. Draft tubes with compressed air supply systems have not been installed as a countermeasure against vibration. Detailed inspections should be done. No serious problems have been reported with the other electromechanical equipment.
	Rantambe	2	49	239	56	Jan.1990	Estimated specific speed of the turbine is about 350m-kW, which is almost the upper limit of a Francis type turbine. Therefore, the operations have been restricted in accordance with the operation range curve between the reservoir water level and the output. Draft tubes with compressed air supply systems have been installed as a countermeasure against the vibration. The systems have worked effectively. However operations below 15MW have been avoided to prevent the occurrence on vibration.
	Ukuwela	2	38	154	46	#1:Jul.1976 #2:Aug.1976	No serious problems have been reported with the electromechanical equipment. Major components of the electromechanical equipment were manufactured in Japan.
	Bowatenna	1	40	48	14	Jun.1981	No serious problems have been reported with the major electromechanical equipment. All major equipment, such as hydraulic turbines, generators and transformers, were manufactured in Japan. The power plant originally planned to install two generating units. So far, however, CEB has not had a concrete expansion plan. Although the estimated specific speed is about 280m-kW which is relatively high for a Francis type turbine, a non-compressed air supply system for draft tubes has worked effectively.
	Nilambe	2	3.2			Jul, 1988	No serious problems have been found.
The Other Basin	Samanalawewa	2	120	344	33	Oct.1992	No serious problems have been reported. Since the power plant has an expansion plan of two units with 60MW output each (120MW), it is possible to install two units as peal power supply. The existing switchyard has also has space for new two feeders, but one space is not well situated for connecting with a generator feeder. Therefore, GIS will be applied to the switchyard if two generators are installed.
	Kukule	2	70	300	49	Jul.2003	No serious problems have been reported.

Source: Hydropower Optimization in Sri Lanka, EPDC & Nippon Koei February 2004

5.2.2 Thermal Power Plant

(1) Existing Thermal Power Plants

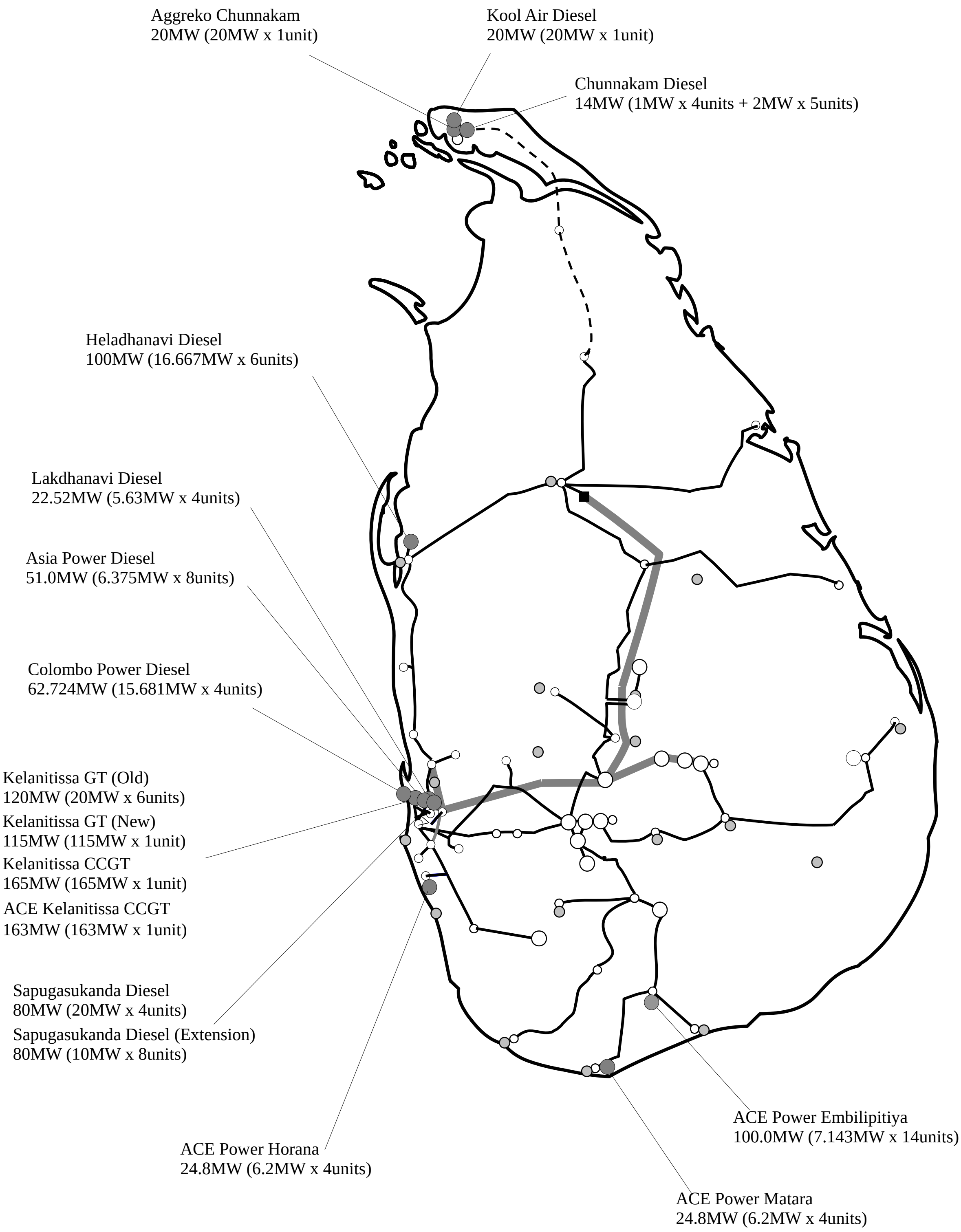
As of November 2005, there were 16 thermal power plants with a total output of 1,163 MW in Sri Lanka, as shown in Table 5.2.4. Six of these plants were owned by the CEB (574 MW), nine were owned by IPPs (569 MW) and one was rented by the CEB (20 MW).

Figure 5.2.4 shows the location of each of these thermal power plants.

Table 5.2.4 List of Existing Thermal Power Plants (As of November 2005)

Site	Power Plants	Owner	Generation Type	Installed Capacity (MW)	Unit No.	Unit Capacity (MW)	Commissioning Year	Operation Years (As of Nov. in 2005)	Remarks
Kelanitissa	Kelanitissa Gas Turbine (Old)	CEB	Gas Turbine	120.000	1	20.000	Dec. 1981	23	
					2	20.000	1982	23	
					3	20.000	Mar. 1982	23	
					4	20.000	1982	23	
					5	20.000	Apr. 1982	23	
					6	20.000	1982	23	
	Kelanitissa Gas Turbine (New)	CEB	Gas Turbine	115.000	1	115.000	Aug. 1997	7	
	Kelanitissa Combined Cycle	CEB	Combined Cycle	165.000	1	165.000	Aug. 2002	2	
Sapugasukanda	Sapugasukanda Diesel	CEB	Diesel	80.000	1	20.000	May. 1984	21	
					2	20.000	May. 1984	21	
					3	20.000	Sep. 1984	21	
					4	20.000	Oct. 1984	20	
	Sapugasukanda Diesel (Extension)	CEB	Diesel	80.000	1	10.000	Sep. 1997	7	
					2	10.000	Sep. 1997	7	
					3	10.000	Sep. 1997	7	
					4	10.000	Sep. 1997	7	
					5	10.000	Oct. 1999	5	
					6	10.000	Oct. 1999	5	
					7	10.000	Oct. 1999	5	
					8	10.000	Oct. 1999	5	
Ohters	Chunnakam	CEB	Diesel	14.000	1	1.000	1958	6	
					2	1.000	1958	6	
					3	1.000	1958	6	
					4	1.000	1958	6	
					5	2.000	1965	6	
					6	2.000	1965	6	
					7	2.000	1965	6	
					8	2.000	1965	6	
					9	2.000	1965	6	
	Lakdhanavi	IPP	Diesel	22.520	1	5.630	Nov. 1997	7	
					2	5.630	Nov. 1997	7	
					3	5.630	Nov. 1997	7	
					4	5.630	Nov. 1997	7	
	Asia Power	IPP	Diesel	51.000	1	6.375	Jun. 1998	7	
					2	6.375	Jun. 1998	7	
					3	6.375	Jun. 1998	7	
					4	6.375	Jun. 1998	7	
					5	6.375	Jun. 1998	7	
					6	6.375	Jun. 1998	7	
					7	6.375	Jun. 1998	7	
					8	6.375	Jun. 1998	7	
	Colombo Power	IPP	Diesel	62.724	1	15.681	Jul. 2000	5	
					2	15.681	Jul. 2000	5	
					3	15.681	Jul. 2000	5	
					4	15.681	Jul. 2000	5	
	ACE Power Matara	IPP	Diesel	24.800	1	6.200	Mar. 2002	3	
					2	6.200	Mar. 2002	3	
					3	6.200	Mar. 2002	3	
					4	6.200	Mar. 2002	3	
	ACE Power Horana	IPP	Diesel	24.800	1	6.200	Dec. 2002	2	
					2	6.200	Dec. 2002	2	
					3	6.200	Dec. 2002	2	
					4	6.200	Dec. 2002	2	
	ACE Power Embilipitiya	IPP	Diesel	100.000	1	7.143	Mar. 2005	0	
					2	7.143	Mar. 2005	0	
					3	7.143	Mar. 2005	0	
					4	7.143	Mar. 2005	0	
					5	7.143	Mar. 2005	0	
					6	7.143	Mar. 2005	0	
					7	7.143	Mar. 2005	0	
					8	7.143	Mar. 2005	0	
					9	7.143	Mar. 2005	0	
					10	7.143	Mar. 2005	0	
					11	7.143	Mar. 2005	0	
					12	7.143	Mar. 2005	0	
					13	7.143	Mar. 2005	0	
					14	7.143	Mar. 2005	0	
	AES Kelanitissa	IPP	Combined Cycle	163.000	1	163.000	Feb. 2003	2	
	Heladhanavi	IPP	Diesel	100.000	1	16.667	Dec. 2004	0	
					2	16.667	Dec. 2004	0	
					3	16.667	Dec. 2004	0	
					4	16.667	Dec. 2004	0	
					5	16.667	Dec. 2004	0	
					6	16.667	Dec. 2004	0	
	Kool Air	IPP	Diesel	20.000	1	20.000	2002	3	
	Aggreko Chunnakam	Hired	Diesel	20.000	1	20.000	Oct. 2003	2	

Source: CEB Sales And Generation Data Book 2003, CEB System Control And Operation Annual Report 2004



Source: CEB LTGEP 2005-2019

Figure 5.2.4 Location of Existing Thermal Power Plants (As of November 2005)

(2) Current Status of Thermal Power Plants

(i) CEB thermal power plants

a) Kelanitissa Power Plant

This power plant was divided into two areas, one is simple cycle gas turbine generation plants (old; 20MW x 6 units [John Brown and Alstom], new; 115MW x 1 unit [Fiat Avio]) and another is for the combined cycle power generation plant (165MW).

There are six old gas turbines that started operations in 1981/1982. One of them, the No.6 G/T, can no longer be operated because of serious trouble with a rotor. A new 115MW gas turbine (No.7 G/T) started operations from October of 1997, but had frequent troubles regarding its combustor and rotor rubbing. However, the current operating condition has improved.

The old gas turbine power plants are extremely depleted, and age-related performance degradation has reduced output to around 17 MW. When available generation capacity drops to 16 MW, the turbine is washed with water, which raises it to 18 MW, but available capacity declines again soon after the unit is put back into operation.

A combined cycle plant has been supplied by Marubeni Power System Corp. with gas turbines and steam turbines (manufactured by Alstom), capable of being operated using two types of fuel, auto diesel oil and naphtha. The plant usually uses naphtha supplied by the CPC, and uses auto diesel oil when naphtha is unavailable. The fuels are stored in two 4,442 kl tanks for naphtha, two 10,000 kl tanks and one 4,000 kl tank for auto diesel oil.

The combined cycle plant has been operating well from the commissioning of the plant except for one problem involving the main oil pump of the steam turbine in June of 2004.

The simple cycle gas turbines are mainly used for peak-demand operations because two CEB and IPP combined power plants adjacent to this power station are used for base load operations. Therefore, the plant factors of the simple cycle gas turbines are lower than the ones at the combined cycle plants.

The facility also contains two steam generators (25 MW each), but they were disconnected from the grid when the combined cycle plant commenced operation. In early 2005, the dangerously corroded smoke stacks were judged to be in danger of collapse and were removed, and the plant can no longer be used for generation.

b) Sapugasukanda Power Plant

Station A consists of four diesel generators that started operations from 1984. Station B consists of eight diesel generators. Four of these generators were started in September 1997 and the other four were started in October 1999. The utilization ratios of the plants in 2003 were high at between 71% and 73%.

These power plants are fueled by residual oil, which is piped from CPC -owned refinery.

Despite a certain amount of derating for aging, these plants generate at around 90% of its rated output.

c) Chunnakam Power Plant

Four sets of 1MW diesel generators (Deuch) began operations in 1958, and five sets of 2MW diesel generators (Mirrlees) began operations in 1965. Now two sets of 1MW generators (No.4 and 5) and three sets of 2MW generators (No.7, 8 and 9) are available for operation. The other machines were removed as they are no longer usable after parts had to be used for repairs of others machines due to the unavailability of spare parts supply from the original manufacturers. Even though total nominal capacity for these machines is 8MW, the actual power generating capabilities is only 4MW and these machines have served as back up units for the IPP power plant (Kool Air) from the end of 2003. This is because they have troubles with their cooling water systems and other problems. Acid cleaning of these cooling water systems could help them recover their performance, but this has not been done on grounds that the cost is too high compared to the expected results. The local relevant people want to introduce new machines rather than repair these old machines.

(ii) IPP thermal Power Plants

In Sri Lanka, the power plants owned by IPP are diesel power plants, except for a combined cycle power plant at Kelanitissa owned by AES. The commissioning years for IPP power plants and their IPP contract periods are showed in Table 5.2.5.

Table 5.2.5 List of Existing IPP Thermal Power Plants (As of November 2005)

Power Plant	Plant Type	Plate Capacity (MW)	Nominal Capacity (MW)	Minimum Generation Energy Amount (GWh)	Commissioning Year	Contract Period (Years)
Lakdhanavi	Diesel	6.217MW x 4	22.5	156	Nov. 1997	15
Asia Power	Diesel	6.375MW x 8	49	330	Jun. 1998	20
Colombo Power	Diesel	15.681MW x 4	60	420	Jul. 2000	15
ACE Power Matara	Diesel	6.2MW x 4	20	167	Mar. 2002	10
ACE Power Horana	Diesel	6.2MW x 4	20	167	Dec. 2002	10
AES Kelanitissa	Combined Cycle	163 MW	163	1,314	GT : Mar. 2003 ST : Oct. 2003	20
Heladhanavi	Diesel	17MW x 6	100	698	Oct. 2004	10
ACE Power Embilipitiya	Diesel	7.14MW x 14	100	697	Apr. 2005	10
Kool Air	Diesel	20.0MW x 1	15	なし		1

a) Lakdhanavi Power Plant

The Lakdhanavi power plant is Sri Lanka’s first IPP-owned thermal power plant, established under a Build-Own and Operate (BOO) scheme. The plant is owned by the Sri Lankan transformer manufacturer Lanka Transformer Ltd., and is operated entirely by local staff.

The plant houses four diesel generators (name plate output capacity: 6.217 MW; rated output: 6.0 MW) manufactured by Finland’s Wärtsilä. The generators are fueled by furnace oil, which is brought in once every six days in 33 kl tanker lorries and stored in two 1,500 kl storage tanks.

b) Asia Power Plant

This plant is located adjacent to the CEB’s Sapugasukanda substation, and is owned by Asia Power (Private) Ltd. Deutz-UK and Denmark’s BWSC constructed the facility under a BOO scheme, and formed a company, Asia Power Operation & Maintenance Ltd. (APOM) to oversee its operation.

The plant houses eight diesel generators (unit rated output: 6.375 MW) manufactured by Deutz-UK. It is fueled by residual oil, which is, like the CEB’s Sapugasukanda facility, piped from the CPC refinery. 2,700 kl is supplied to two 3,000 kl tanks every ten days.

c) Colombo Power Plant

This is Sri Lanka’s only barge-mounted power plant. The plant is owned by Colombo Power (Private) Ltd., an IPP established on a 50/50 basis by Kawasho Corporation and Mitsui Engineering and Shipbuilding Co. Ltd.

The barge is anchored at the Colombo shipbuilding docks, which are under the jurisdiction of the Sri Lanka Port Authority.

The power plant is equipped with four low-speed diesel engines (unit rated output: 15.681 MW) manufactured by Mitsui. The engines are fueled by furnace oil piped from the CPC refinery over a distance of approximately 16 km. Each generator is provided with a 2,350 kl oil storage tank. The tanks are irregularly filled once per month. To date there has been no restriction on the fuel supply.

The tsunami resulting from the Sumatra-Andaman earthquake of late December 2004 raised the level of the barge by almost one meter and damaged water pipes and fences, but did not seriously affect the fuel pipes.

d) ACE Power Matara Power Plant

This plant was established at Matara on Sri Lanka’s south coast in March 2003, and is owned by ACE Power.

The Matara Power Plant is one of the facilities that have recently been established in remote locations because soaring land prices since 2000 have made it difficult to build stations in Colombo or surrounding areas.

The Matara Power Plant houses four diesel generators (rated output: 6.2 MW), fueled by furnace oil transported from Colombo by tanker lorry.

e) ACE Power Horana Power Plant

This power plant, owned by ACE Power, was established in December 2002 at Horana, 35 km southeast of Colombo.

It uses four diesel generators (unit rated output: 6.2 MW), fueled by furnace oil transported from Colombo by tanker lorry.

f) AES Kelanitissa Power Plant

The Kelanitissa Power Plant is owned by the major U.S. energy company AES, and is Sri Lanka's only IPP-owned combined cycle plant.

The power plant is located adjacent to the CEB's Kelanitissa power plants. It uses gas turbines and steam turbines manufactured by BHEL in India and exhaust gas boilers (HRSG) manufactured by India's Larsen & Toubro Ltd.

The equipment is fueled by automotive diesel supplied by pipeline from the CPC refinery. The facility is equipped with four 6,100 m^3 fuel oil tanks.

The power plant commenced combined cycle operation in October 2003, but damage caused by a fire in March 2004 forced a suspension of operations for several months.

g) Heladhanavi Power Plant

Like the Lakdhanavi Power Plant, it is a diesel generator facility developed by Lanka Transformer. It is located at Puttalam, 120 km north of Colombo.

The power plant uses six furnace oil-fueled diesel generators (unit rated capacity: 16.667 MW) manufactured by Finland's Wärtsilä. The fuel is transported in 33 kl tankers at an average rate of 18 per day. The facility is provided with a 7,500 kl oil storage tank, containing enough for approximately three days' operation.

The construction process was extremely smooth, due to thorough preparation and sensitivity to the requirements of local residents such as compensation to fisheries for constructing a temporary jetty, and reinforcement of bridges to enable transportation of materials.

h) ACE Power Embilipitiya Power Plant

This is Sri Lanka's newest IPP-operated thermal power plant, located at Embilipitiya in the southwest. Like ACE Matara and ACE Horana, it is a diesel generator facility owned by ACE Power.

Construction was initially planned in conjunction with a plan to stimulate factory development in Hambantotta, but that plan was aborted and the facility now bears the burden of increased costs for transportation of fuel.

The facility employs 14 diesel generators (unit rated capacity: 7.143 MW) manufactured by the U.S. company Caterpillar. The generators are fueled by furnace oil shipped from Colombo by tanker lorry.

The IPP-owned power plants were all constructed with new equipment and, with the exception of the AES Kelanitissa Power Station, have operated continuously without serious problems since they commenced generation. Asia Power and Colombo Power have prepared adequate spare equipment, but the Lakdhanavi and Heladhanavi power stations are not provided with any spares.

As of November 2005 the AES Kelanitissa Power Station was operating normally, and the problem of spare equipment was not particularly severe. Given this, prospects seem good for the IPP-owned facilities, in the absence of a major unexpected contingency, to continue supplying their minimum guaranteed energy amount (MGEA).

5.2.3 Non Conventional Renewable Energy Power Plants

Small SHS projects, as used in the electrification of off-grid regions, represent a significant proportion of Sri Lanka's use of renewable energy sources. In this section, however, we will be focusing on the status of renewable energy power plants connected to the grid.

(1) Existing Renewable Energy Power Plants

As of December 2004, 42 renewable energy generation facilities were connected to the national grid in Sri Lanka, with a combined output of 98.3 MW (Table 4.2.6). Of these, 38 represented small hydropower facilities with a combined capacity of 93.6 MW, one was a solar facility with a capacity of 18 kW, one was a biomass (dendro-power) plant with a capacity of 1 MW, one was a wind power facility with a capacity of 3 MW, and one was a waste heat recovery facility with a capacity of 500 kW.

Table 5.2.6 shows a list of all renewable energy power plants connected to the grid, while Figure 5.2.5 shows the locations of the power plants other than small hydropower facilities.

Table 5.2.6 List of Existing Renewable Energy Power Plants connected to the Grid (As of the end of 2004)

Plant Type	Power Plant	Owner	Installed Capacity (MW)	Commissioning Year	Sub Station connected	Remarks
Small-scale Hydropopwer	Inginiyagala	CEB	11.250	1954 - Jun. 1963		
	Uda Wa;awe	CEB	6.000	Apr. 1969		
	Nilambe	CEB	3.200	Jul. 1988		
	Dick Oya	Private	0.960	Apr. 1996	Wimalasurendra	
	Rakwana Ganga	Private	0.760	Feb. 1998	Deniyaya	
	Kolonna	Private	0.780	Feb. 1999	Deniyaya	
	Ellapita Ella	Private	0.550	Jun. 1999	Seethawake	
	Carolina	Private	2.500	Jun. 1999	Wimalasurendra	
	Mandagal Oya	Private	1.284	Jan. 2001	Seethawake	
	Delgoda	Private	2.650	Mar. 1999	Balangoda	
	Glassaugh	Private	2.256	Mar. 2000	Nuwara Eliya	
	Minuwanella	Private	0.640	Apr. 2001	Seethawake	
	Kabaragala	Private	1.500	May 2001	Nuwara Eliya	
	Bambarabatu	Private	3.200	Jun. 2001	Balangoda	
	Galatha Oya	Private	1.200	Jun. 2001	Kiribathkumbara	
	Hapugastenna-1	Private	4.862	Aug. 2001	Balangoda	
	Belihul Oya	Private	2.500	May 2002	Balangoda	
	Watawala	Private	1.300	Jun. 2002	Wimalasurendra	
	Niriella	Private	3.000	Aug. 2003	Ratnapura	
	Hapugastenna- II	Private	2.445	Sep. 2002	Balangoda	
	Deiyanwala	Private	1.500	Oct. 2002	Kiribathkumbara	
	Hulganga -1	Private	3.000	Jun. 2003	Kiribathkumbara	
	Ritigaha Oya II	Private	0.800	Dec. 2003	Seethawake	
	Sanquhar	Private	1.600	Dec. 2003	Kiribathkumbara	
	Karawita	Private	0.750	Jan. 2004	Seethawake	
	Sithagala	Private	0.800	Apr. 2004	Balangoda	
	Bruswic	Private	0.600	Mar. 2004	Wimalasurendra	
	Way Ganga	Private	8.925	May 2004	Balangoda	
	Alupola	Private	2.522	Jun. 2004	Balangoda	
	Rathganga	Private	2.000	Jul. 2004	Ratnapura	
	Waranagala	Private	9.900	Jul. 2004	Kosgama	
	Nakkavita	Private	1.008	Aug. 2004	Seethawake	
	Gampola	Private	4.206	Sep. 2004	Deniyaya	
	Mylanawita	Private	0.600	Nov. 2004	Seethawake	
	Atabage Oya	Private	2.211	Nov. 2004	Kiribathkumbara	
	Seetha Eliya	Private	0.072	Mar. 1996	Nuwara Eliya	sell excess power to CEB
	Talawakelle	Private	0.112	Aug. 1998	Nuwara Eliya	sell excess power to CEB
	Weddemulle	Private	0.200	Jun. 1999	Nuwara Eliya	sell excess power to CEB
	Sub Total		93.643			
Photo Voltaic	Worldview Global Media Ltd. Solar PV System	Worldview Global Media Ltd.	0.018	Jan. 2002	Sapugasukanda	
Biomass (Dendro)	Walapane Dendro Power Plant	Lanka Transformers ltd.	1.000	Nov. 2004	Rantambe	
Wind power		CEB	3.000	Mar. 1999	Embilipitiya	
Others (Waste heat)	Madampe Waste Heat Power Plant		0.100	Dec. 1998	Madampe	
Total			97.761			

Source: System Control & Operations, Monthly Review Report, December 2004, System Control Center, Ceylon Electricity Board
Sales and Generation Data Book 2003, Statistical Unit, Commercial Branch, Ceylon Electricity Board

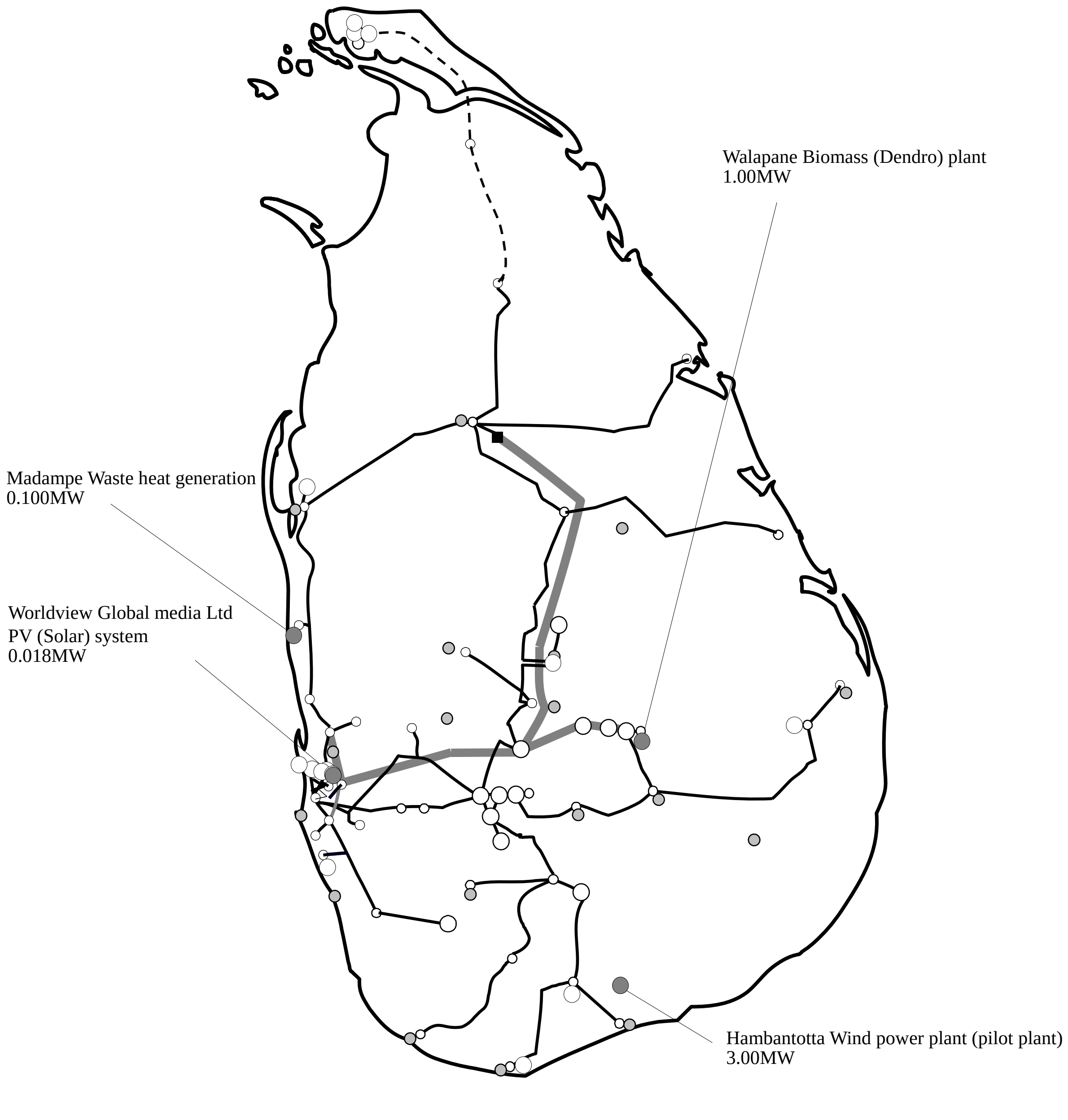


Figure 5.2.5 Location of Existing Renewable Energy Power Plants (As of November 2005)

(2) Current Status of Renewable Energy Power Plants

(i) CEB-owned renewable energy power plants

a) Small-scale hydropower plant

CEB owns three small-scale hydropower plants and the total output is 20.45MW. Table 5.2.7 shows a list of existing small-scale hydropower plants owned by CEB.

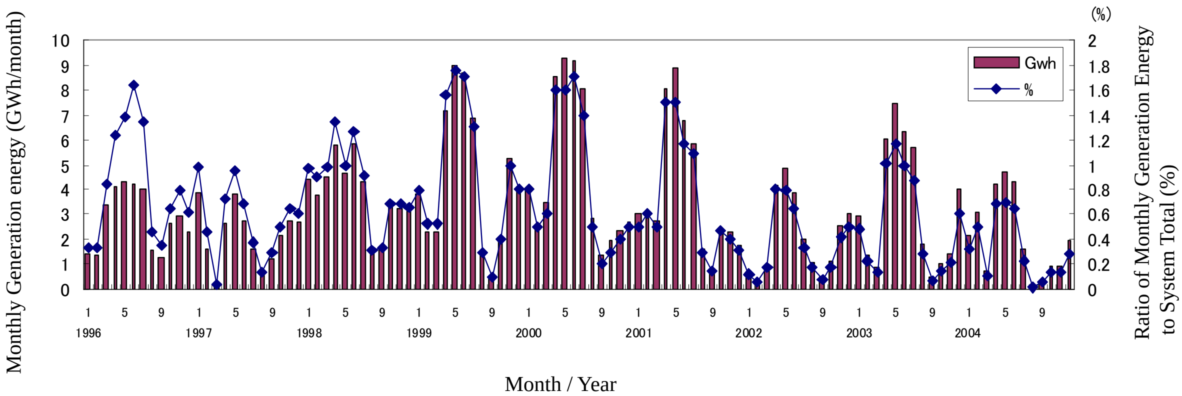
Table 5.2.7 List of Existing Small-scale Hydropower Plants owned by CEB (As of November 2005)

Plant Name	Unit	Unit Capacity (kW)	Plant Capacity (kW)	Commissioning
Inginyagala	2	2,475	4,950	
	2	3,150	6,300	
Sub total	4		11,250	Jun.1954-1963
Uda Walawe	2	3,000	6,000	Apr.1969
Nilambe	2	1,600	3,200	Jul.1988
Total	8		20,450	

Source: Sales and Generation Data Book 2003, CEB

The Inginyagala hydropower plant has been allocated to the Senanayake Samundra Reservoir in the Gal Oya river basin. The Uda Walawe hydropower plant has been allocated to the Uda Walwe Reservoir, which is located the downstream of the Samanarawewa hydropower plant. The Nilambe hydropower plant has been allocated to an irrigation pond, which is located in the Mahaweli river basin.

Figure 5.2.6 shows historical record of monthly generation energy and the ratio of monthly generation energy to system total.



Source: CEB System Control And Operations Monthly Review Report

Figure 5.2.6 Historical Operation Record of Small-scale Hydropower Plant owned by CEB

b) Wind power plant

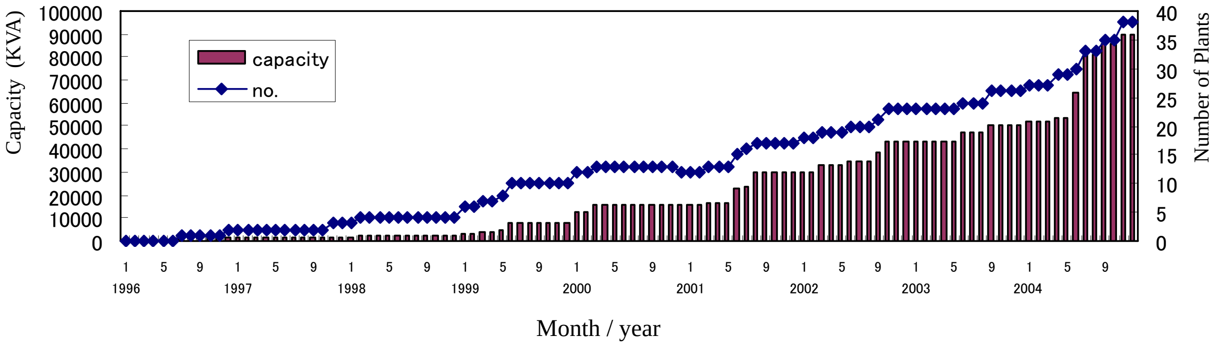
With support from the World Bank and the Global Environment Facility, the CEB commenced a 3 MW wind power pilot project in Hambantota in 1999. This pilot project is being used to gather technological data concerning wind power generation and assess the effect on the grid. The next section discusses in section 5.2.3 (3).

The CEB is still at the stage of testing wind power generation, and does not intend to grant approval to IPPs to enter the field until it gathers more data on transmission capacity, frequency fluctuations and other relevant technical issues via its pilot project.

(ii) Private-owned renewable energy power plants

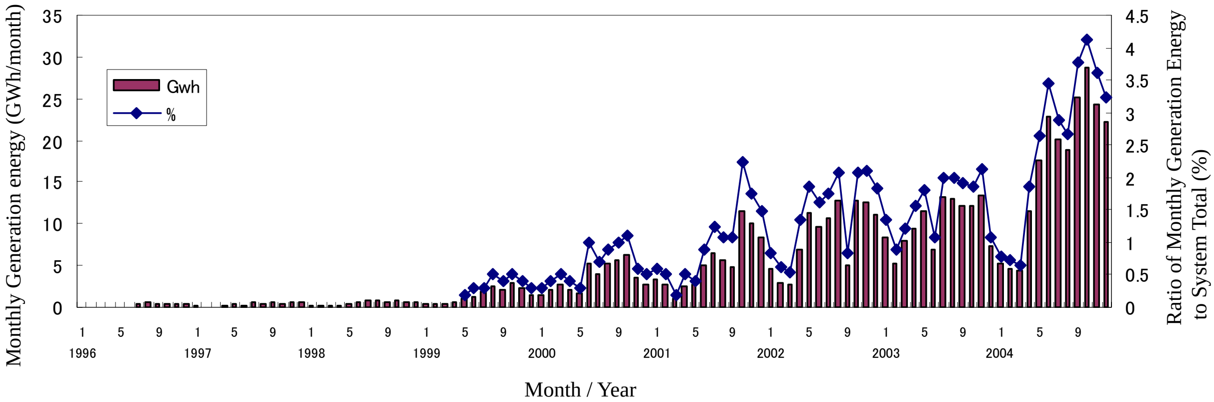
According to the CEB's monthly generation report, as of December 2004, 38 generation facilities run by IPPs were connected to the CEB grid. Of these, 35 represented small private hydropower plants with a capacity of 73 MW, one was a solar generation plant with a capacity of 18 kW, one was a biomass (dendro-power) facility with a capacity of 1 MW, and one was a waste-heat recovery facility with a capacity of 500 kW.

Figure 5.2.7 shows the trend in the number of IPP-owned renewable energy power plants. The capacity of these facilities and their capacity as a percentage of total capacity are shown in Figure 5.2.8.



Source: CEB System Control & Operations, Monthly Review Report

Figure 5.2.7 Trend in Capacity and Number of IPP-owned Renewable Energy Power Plants connected to the Grid



Source: CEB System Control & Operations, Monthly Review Report

Figure 5.2.8 Trend in Monthly Generation Energy of IPP-owned Renewable Energy Power Plants connected to the Grid

a) Small-scale hydropower plant

The majority of Sri Lanka's small-scale renewable energy power facilities (below 10 MW) are small-scale IPP hydropower plants, and their number is increasing annually. Table 5.2.8 shows a list of small-scale IPP hydropower plants connected to the grid.

Table 5.2.8 List of Small-scale IPP Hydropower Plants connected to the Grid

No.	Private Hydro Station	Capacity (MVA)	Maximum Power (MW)	Date of Grid Connection
Directly Connected to the System				
1	Dick Oya MHP	1.200	0.960	1996.04.30
2	Rakwana Ganga MHP	0.950	0.760	1998.02.09
3	Kolonna MHP	0.975	0.780	1999.02.23
4	Ellapita Ella MHP	0.700	0.550	1999.06.15
5	Carolina MHP	2.520	2.500	1999.06.26
6	Mandagal Oya MHP	1.600	1.284	2001.01.20
7	Delgoda MHP	3.643	2.650	1999.03.31
8	Glassaugh MHP	3.200	2.256	2000.03.21
9	Minuwanella MHP	0.800	0.640	2001.04.17
10	Kabaragala MHP	1.875	1.500	2001.05.18
11	Bambarabatu MHP	4.000	3.200	2001.06.01
12	Galatha Oya MHP	1.500	1.200	2001.06.23
13	Hapugastenna-1 MHP	6.000	4.862	2001.08.14
14	Belihul Oya MHP	3.125	2.500	2002.05.20
15	Watawala	1.655	1.300	2002.06.14
16	Niriella	3.750	3.000	2003.08.14
17	Hapugastenna-Ⅱ MHP	3.000	2.445	2002.09.02
18	Deiyanwala MHP	1.875	1.500	2002.10.08
19	Hulganga MHP-1	3.600	3.000	2003.06.03
20	Ritigaha Oya Ⅱ	1.000	0.800	2003.12.02
21	Sanquhar	2.000	1.600	2003.12.02
22	Karawita	2.000	0.750	2004.01.19
23	Sithagala MHP	1.000	0.800	2004.04.24
24	Bruswic MHP	0.803	0.600	2004.03.16
25	Way Ganga MHP	10.500	8.925	2004.05.24
26	Alupola MHP	3.000	2.522	2004.06.13
27	Rathganga MHP	2.500	2.000	2004.07.15
28	Waranagala MHP	11.000	9.900	2004.07.21
29	Nakkavita MHP	1.008	1.008	2004.08.13
30	Gampola MHP	4.206	4.206	2004.09.10
31	Mylanawita	0.600	0.600	2004.09.10
32	Atabage Oya MHP	2.211	2.211	2004.11.23
	total	87.796	72.809	
Give only exess Energy				
33	Seetha Eliya MHP	0.135	0.072	1996.03.28
34	Talawakelle MHP	0.140	0.112	1998.08.01
35	Weddemulle MHP	0.250	0.2	1999.06.01
	total	0.525	0.384	
	Grand Total	88.321	73.193	

Source: CEB System Control & Operations, Monthly Review Report, December 2004

b) Photo voltaic system

One small (18 kW) photovoltaic system connected to the CEB grid on January 11, 2002. It supplies a monthly average of 0.001-0.002 GWh.

c) Biomass (dendro) power plant

A biomass (dendro-power) facility (1000 kW) that uses lumber from thinning of the plantations and a by-product of agricultural or forest activity, connected to the CEB grid on November 9, 2004. In December 2004, it generated 0.002 GWh of power.

(3) Status of CEB Wind Power Pilot Project

(i) Background of wind power pilot project

Wind power generation is an attractive large-scale renewable energy generation technology, and is being introduced throughout the world. The CEB also has plans to develop wind power generation. The CEB commenced its efforts in this direction by conducting a survey[42] of wind power resources in Sri Lanka's south from 1992 to 1998, and establishing a 3 MW pilot project connected to its grid at Hambantota. The survey identified a coastal site with greater wind power generation potential than the Hambantota location, but it was in the vicinity of a national park and conservation areas, and the Hambantota site was therefore selected

The pilot project is enabling the CEB to gather technological data and assess the impact of wind power generation on the grid.

The project is being supported by the World Bank and the Global Environment Facility.

(ii) Outline of the wind power pilot project[43]

- Site : Hambantota
- Installed Capacity : 3 MW (600kW wind generation unit x 5 units)
- Annual Generation : 4.5 GWh (assumed)
- Height of Tower : 46m
- Fund Source

Source	Amount (MUS$)
IDA	2.08
GEF	0.69
CEB	1.03
Total	3.80

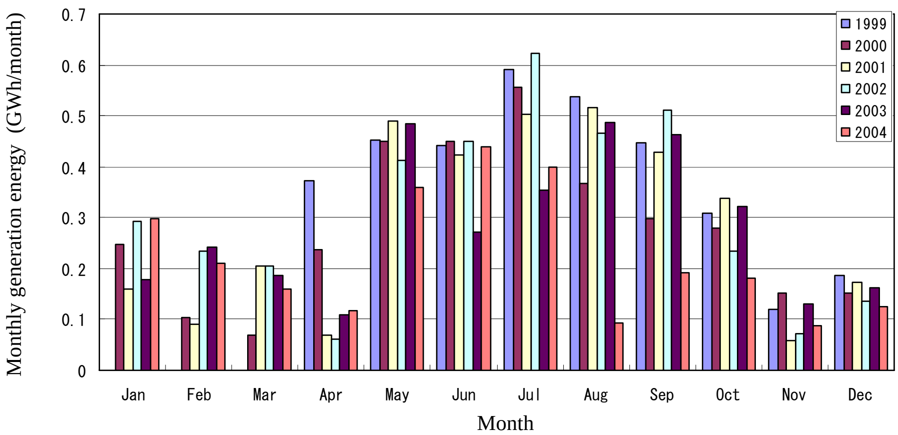
Funding is being provided to the pilot project as part of the ESD Project Program. The International Development Association (IDA), part of the World Bank, is providing loans, and the Global Environment Facility is offering grants.

(iii) Current status of the wind power pilot plant

a) Generation energy

As was indicated in the abovementioned survey of wind power potential, the area surrounding Hambantota in Sri Lanka's south is affected by a southwestern monsoon with strong winds between June and September, and generation capacity increases at this time.

Annual average generation energy of the plant in the period from 1999 to 2004 is 2.86 GWh, while capacity in FY2004 was around 2.0 GWh. Figure 5.2.9 shows monthly production figures.



Source: CEB System Control & Operations, Monthly Review Report

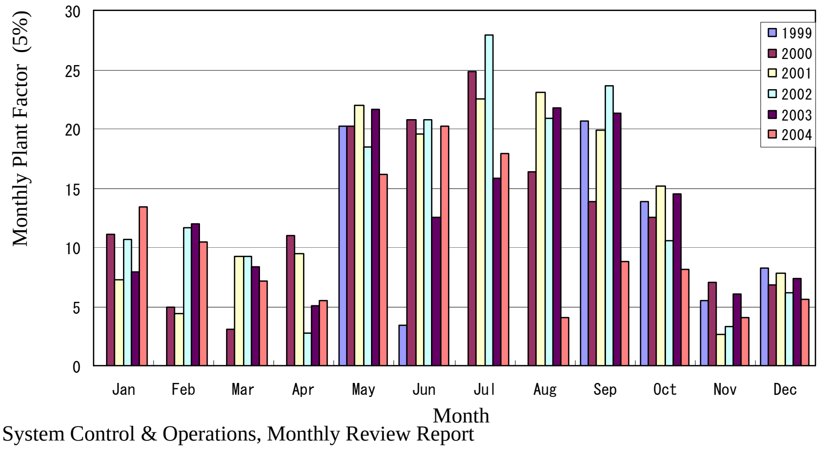
Figure 5.2.9 Monthly Generation Energy of Wind Power Pilot Plant (1999 - 2004)

[42] Wind Energy Resources Assessment Southern Lowlands of Sri Lanka

[43] 3MW Pilot Wind Power Project Analysis on Cost of Generation, May 2001, CEB

b) Plant factor

The CEB estimated an annual plant factor of 17% in a survey report, but the monthly average since commencement of operation has been around 12.5%. Figure 5.2.10 shows the plant factor by month.

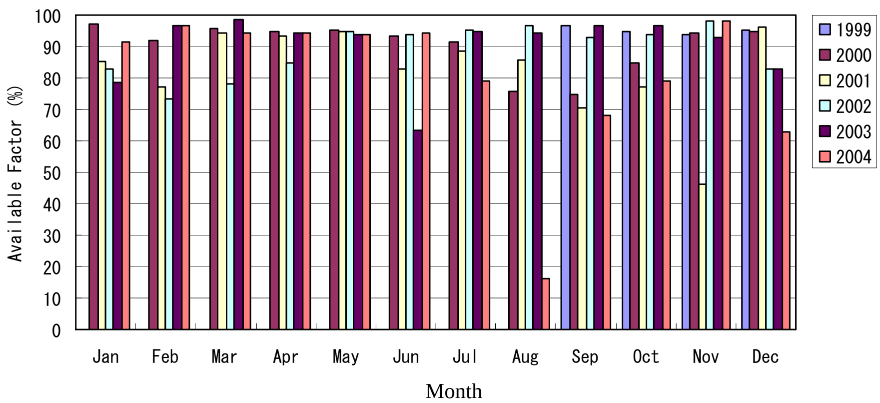


Source: CEB System Control & Operations, Monthly Review Report

Figure 5.2.10 Monthly Plant Factor of Wind Power Pilot Plant (1999 - 2004)

c) Available factor for operation hours

The available factor for operation hours of the plant is almost 90%. The drop in this figure in August 2004 was due to the time required to obtain parts and repair a breakdown. Available factor are shown in Figure 5.2.11.

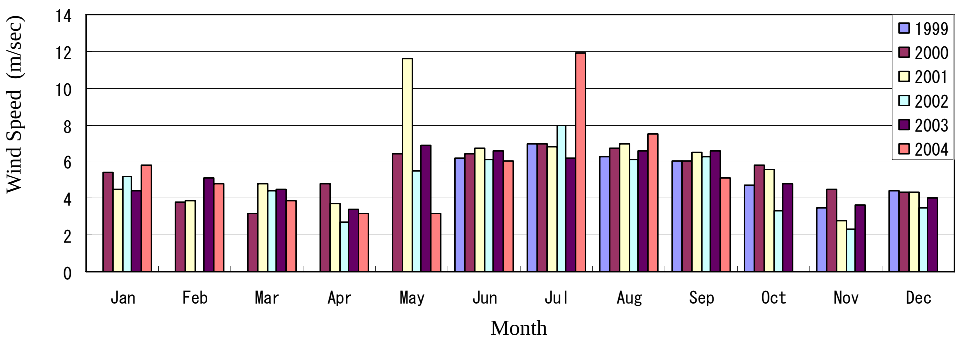


Source: CEB System Control & Operations, Monthly Review Report

Figure 5.2.11 Available Factor of Wind Power Pilot Plant (1999 - 2004)

d) Average wind speed

The average monthly wind speed at the project location for 1999-2004 was 5.4 m/s. Average monthly wind speeds are shown in Figure 5.2.12.



Source: CEB System Control & Operations, Monthly Review Report

Figure 5.2.12 Monthly Average Wind Speed at Wind Power Pilot Plant Site (1999 - 2004)

e) Generation cost

The construction cost of the wind power pilot project was US$3.8 million, which represents US$1,269/kW. The CEB's project analysis[44] projected a generation cost of 11.94 US cents/kWh[45] if all necessary funds were provided by bank loans and the facility was operated at a utilization rate of 17%. However, an analysis of the actual status of use to date shows that the utilization rate has not reached 17%, and in fact the average utilization rate from 1999 to 2004 was 13%. Recalculating the generation cost for this rate gives a figure of 15.6 US cents/kWh, which is relatively high compared to the power tariff of 7.67 Rs/kWh, or the price of 6.05 Rs/kWh[46] at which the CEB buys power generated by small-scale facilities.

5.3 Development Project

5.3.1 Hydropower Development Project

(1) On-going Project

The LTGEP 2005-2019, formulated in November 2004, contains a new hydropower development project at Upper Kotmale, which is categorized to reservoir type hydropower plant.

According to the LTGEP, funding for the Upper Kotmale hydropower project has been received from the JBIC. The procurement of the work is planned to be done by international competitive bidding for the Lot 1 preparatory work

The outline of Upper Kotmale project are shown in Table 5.3.1.

Table 5.3.1 General Characteristics of Upper Kotmale Hydropower Plan

Type	Run-of-river type with a regulating pond
Water levels Full Supply Level (FSL) Minimum Operating Level (MOL) Normal tail water level	 1,194 masl 1,190 masl 703 masl
Effective Storage Capacity, Reservoir Area	0.8 MCM, 0.25km^2
Maximum plant discharge	36.9 m^3/s
Head Maximum gross head Net head at full operation	 491 m 473 m
Installed capacity	150 MW, (75MW x 2 units)
Annual energy	409GWh
Plant factor	0.4
Transmission line	220kV double circut to Kotmale Switchyard (17.5 km)
Basic Project Cost	US$ 280 millon
Project Cost with IDC, taxes, escalation	US$ 384 million
Construction period	6 years

Note: masl - meters above mean sea level,
MCM - million cubic meters
IDC - Interest During Construction

According to LTGEP 2005-2019, the project is expected to be commissioned in March 2009. The Cabinet of Sri Lanka has postponed the commissioning of the plant until September of 2010.

[44] 3MW Pilot Wind Power Project Analysis on Cost of Generation, May 2001, CEB

[45] In the case that the grant (US$690,000) from the Global Environment Facility is taken into consideration, the generation cost is estimated to be 9.84 US cents/kWh.

[46] CEB purchase price during dry season (Feb. - Apr.) in 2005. 5.30 Rs./kWh for rainy season,

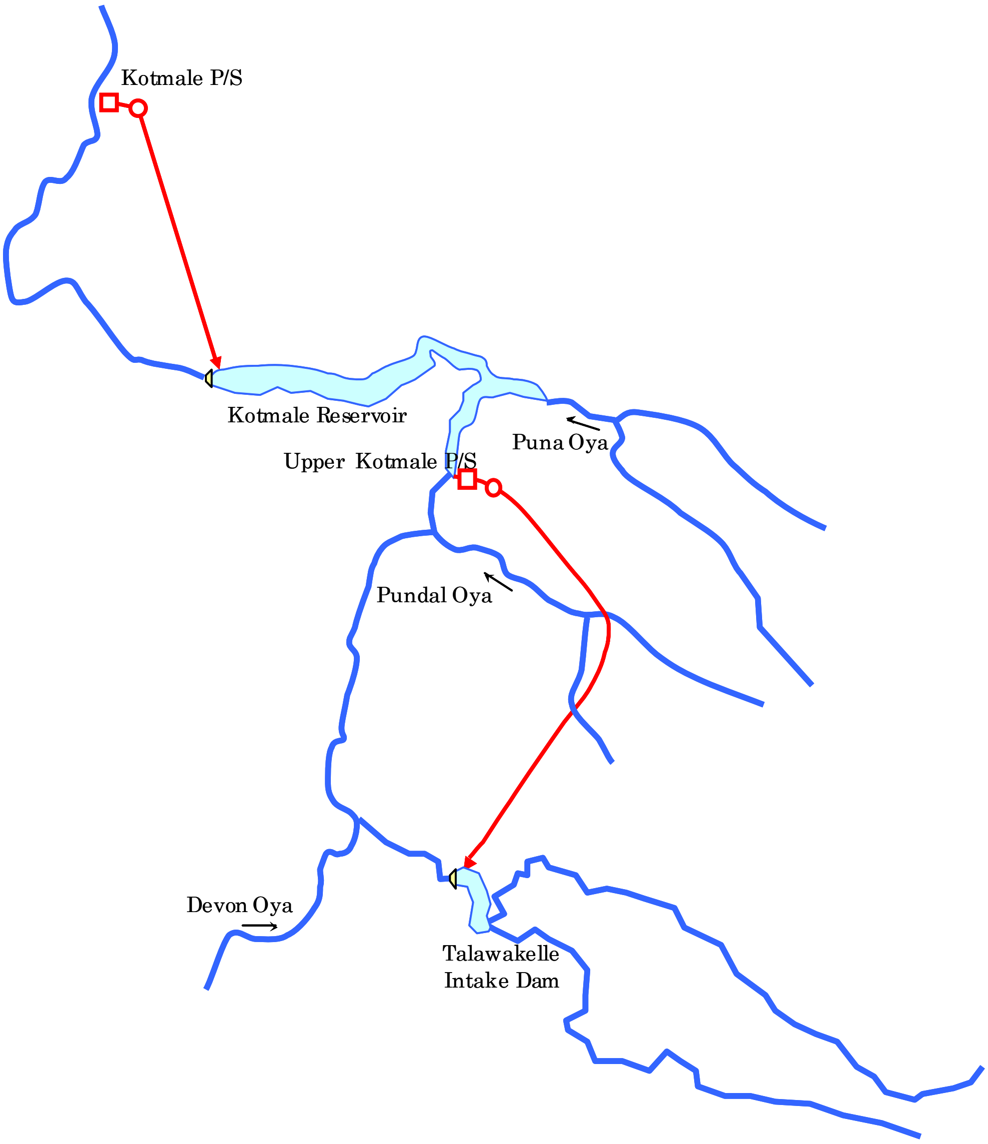


Figure 5.3.1 Upper Kotmale Hydropower Plant Overview

(2) New Development Projects

According to LTGEP 2005-2009, four prospective hydropower projects are considered as new candidates. They are summarized in Table 5.3.2.

Table 5.3.2 Characteristics of Hydropower Generating Plants Considered as New Candidates

Name of Project	River Basin	Capacity (MW)	Annual Energy Production (GWh)	Effective Storage ($10^6 m^3$)
Gin Ganga	Gin	49	210	23.2
Broadlands	Kelani	35	127	0.2
Uma Oya	Mahaweli	150	457	21.9
Moragolla	Mahaweli	27	111	5.0

Source: CEB LTGEP 2005-2019

These sites were selected among 27 preferable sites (total capacity: 877MW) in the 1989 Master Plan 1989. The selection was carried out based on the following criteria.

(a) The candidate hydropower projects identified and studied under the Master Plan Study were taken as the basis for selection.
(b) Projects with capacity of less than 15MW were not considered as candidates.
(c) Whenever feasibility study results were available for any prospective project, such results were used in preference to those of the Master Plan Study. (Studies conducted under the Master Plan were considered to be at the pre-feasibility level.)
(d) Candidates with long-term average electricity generation cost of less than 15 US Cent/kWh (in 1988 price) were considered as candidates.

Table 5.3.3 Results of the Selected Candidate Hydropower Projects

No.	Project	Capacity (MW)	Energy (GWh/a)	Specific Cost (USc/kWh) (Ave.)	Resettlement (persons)	Remarks
1	MADU003	72	298	3.1	0	
2	KOTM025	64	268	3.5	0	Upper Kotmale HP (committed)
3	GING074	49	211	4.3	1,560	Gin Ganga (LEGEP 2005-2019)
4	NALA005	8	27	5.0	0	
5	UMAO034	42	173	5.4	0	replaced with Uma Oya (LTGEP 2005-2019)
6	KELA085	39	170	5.6	0	Broadlands (LTGEP 2005-20019)
7	BELI009	10	43	5.6	0	
8	BELO014	13	53	5.8	0	
9	MAHW263	27	111	6.0	0	Moragolla (LTGEP 2005-2019)
10	BELO015	17	73	6.1	0	
11	HASS006	10	35	6.3	50	
12	KELA071	26	114	6.8	5,200	
13	KOTM033	93	390	7.3	1,700	Upper Kotmale (committed)
14	MAHW235	21	83	7.3	0	
15	KUKU022	116	512	7.5	9,100	Kukule HP (developed)
16	MAHW288	18	75	7.5	0	
17	UMAO042	42	172	7.7	1,300	Dam site of Uma Oya (LTGEP 2005-2019)
18	UMAO063	14	58	7.7	0	
19	SUDU017	25	113	7.9	2,600	
20	MAGA029	19	78	8.5	0	
21	SITA014	30	123	8.8	3,600	
22	BAMB010	10	40	8.9	180	
23	KULU075	36	149	9.7	5,000	
24	SUDU009	18	79	9.9	1,000	
25	GING052	38	159	12.0	950	
26	AGRA003	7	28	12.1	3,100	Upper Kotmale (committed)
27	BADU029	13	47	13.0	100	
	Total	877	3,682	-		

Note: 10% discount rate
50% plant factor
Secondary costs included

Remarks: The candidates and developed sites do not necessarily correspond with actual projects.

Source: Master Plan for the Electricity Supply of Sri Lanka, June 1989, CEB, GTZ, LIDE, CECB

The capacity and cost details of the candidate hydropower projects are given in Table 5.3.4.

Table.5.3.4 Construction Costs for Candidate Hydropower Projects for the 2004 Plan

Plant	Capacity (MW)	Pure Construction Cost (US$/kW)			Construction Period (years)	IDC at 10% interest rate (% of pure cost)	Construction Cost as input to analysis including IDC (US$/kW)			Economic Life (years)
		Local	Foreign	Total			Local	Foreign	Total	
Gin Ganga	49	440.2	2,214.7	2,654.9	4	18.53	521.7	2,625.1	3,147	50
Broadlands	35	549.8	1,987.3	2,537.1	4	18.53	651.7	2,355.5	3,007	50
Uma Oya	150	446.9	2,115.1	2,562.0	5	23.78	553.1	2,618.1	3,171	50
Moragolla	27	461.6	3,301.3	3,762.9	4	18.53	547.2	3,913.1	4,460	50

All costs are in January 2004 border prices. Exchange rate US$1=Rs.96.86, IDC= Interest During Construction.

Source: CEB LTGEP 2005-2019

(3) Expansion Projects

Hydropower capacity expansion plans being described in LTGEP 2005-2019 are based on the Study of Hydropower Optimization in Sri Lanka, which is supported by JICA.

The Sri Lanka power system, which is predominantly hydropower-based at present, will have to steadily transform into a thermal-based system in the future. In view of this, it would be pertinent to prepare the hydropower system for peaking duty. A brief summary of possible expansion of existing hydropower plants studied under the "Hydropower Optimization Study" is as follows:

Table 5.3.5 Expansion Plan of Existing Hydropower Plant

River Basin	Plant Name	Existing Plant			Expansion Plan				Outline of Extension Plan
		Capacity (MW)	Annual Average Energy (GWh)	Plant Factor (%)	Expansion Capacity	Total Capacity after Expansion (MW)	Additional Enrgy Production (GWh)	Plant Factor after Expansion (%)	
Laxapana Complex	New Laxapana	100 (2@50MW)	552	63.0%	72.5	172.5	80 together with Polpitia	36.5%	Before the expansion work, repair work of civil structure should be carried out. During the expansion work, the operation of both New Laxapana and Polpitia hydropower plant should be suspended.
	Polpitia	75 (2@37.5MW)	453	68.9%	47.9	122.9	(80) together with New Laxapana	42.1%	Before the expansion work, repair work of civil structure should be carried out. During the expansion work, the operation of both New Laxapana and Polpitia hydropower plant should be suspended.
Mahaweli Complex	Kotmale	201 (3@67MW)	455	25.8%	- (Dam height raising)	-	90	31.0%	The ammount of energy could be oncreased by about 20% by raiseing the dam crest from elevation 706.5m to 735.0 masl.
	Victoria	210 (3@70MW)	847	46.0%	140 (2@70MW)	350	-31	26.6%	As the intake gates for expansion has already been built, shut down of the existing power plant or draw down of Victoria reservoir during the expansion work may not be necessary. Existing access road and tunnnel are available.
					210 (3@70MW)	420	-14	22.6%	In case of cost raising of altenative power, additional study of the expansion including cost evaluation shuld be carried out.
the Others	Samanalawewa	120 (2@60MW)	351	33.4%	60 (1@60MW)	180	-37	19.9%	The existing low pressure tunnnel was designed a velocity of 2.6m/s. After expanding the project, the velocity of the tunnel will be increased. This will cause significant problems in hydraulic conations of the tunnel.
					120 (2@60MW)	240	-97	12.1%	Increased diccharge of the low pressure tunnel will cause more fluctuation of the surge water level and negative pressure in the tunnel by operating at peak energy with the present minimum operation level of Samanalawewa reservoir. Total annual energy of the 2 units expansion plan is decreased by 100GWh/year.
	Maduru	7.5 (3@2.5MW)							Provision has been made for 2X2.5MW generators at the left bank and 1X2.5MW generator at the right bank.

Source: CEB LTGEP 2005-2019

(4) Rehabilitation Plan

The rehabilitation plan was studied under the "Follow-Up Study for the Rehabilitation of Hydropower Stations in the Kelani River Basin". A brief summary of possible rehabilitation projects for existing hydropower plants is shown in Table 5.3.6.

Table 5.3.6 Rehabilitation Plan of Existing Hydro

	River Basin	Laxapana Complex				
	Plant Name	**Wimalasurendra**	**Old Laxapana**	**Canyon**	**New Laxapana**	**Polpitiya**
	Capacity (MW)	50	50	60	100	75
	Annual Average Energy (GWh)	112	286	160	552	453
	Plant Factor (%)	26%	65%	30%	63%	69%
	Commissioning	1965	1950, 1958	1983	1974	1969
Civil Structures	Reservoir/ Pondage	–	–	–	Sedimentation	Sedimentation
	Dam	Modification of spillway	Leakage at right bank Installation of flashboard	-	Cavity in foundation rock	Installation of rain gauge station Reinforcement of spillway
	Intake	–	–	Improvement on anti-negative pressure valve	Sedimentation	Vortex at intake Landslide
	Headrace Tunnel	Small collapse in tunnel	–	-	–	–
	Surge Tank	-	Turbulance and expoisive noise	-	Leakage on slope near surge	–
	Penstock	-	–	Erosion in foundation of anchor block concrete	Erosion in foundation of anchor block concrete Leakage at expansion joint	Erosion in foundation of anchor block concrete
	Powerhouse	-	–	-	–	Landslide Leakage in wall concrete
	Tailrace	Excessive turbulence of outlet	–	Displacement of retaining wall concrete	Erosion in concretewall	Erosion in concrete wall
	Common	Re-drilling of drainage relief hole				
		Removal of vegatation near civil structures				
		Allocation of civil engineer				
		Periodic inspection				
Hydro-Mechanical Equipmet	Spillway	Plan for regulating the spillway gates	Plan for regulating the spillway gates	Installation of accesses to anchorage	Installation of accesses to anchorage	Touch up painting Drain holes at gate leafs Installation of accesses to anchorage Plan
	Intake	Repairing the intake equipment by CEB	–	Plan for intake air valve modification	Plan for raking machine	Plan for raking machine
	Penstock	–	Repair for the remote control of the penstock valve	Leakage from expansion joints	Repair the drain and passages	Touch up painting for corroded portions
	Bottom Outlet	CEB plans for repairing the needle valve	–	–	–	–
	Tailrace	–	No gate	Repairing the tailrace gate by	No gate	–
	Other				Plan for removing sedimentation	Plan for removing sedimentation
Elctro-Mechanical Equiment	Turbine	Periodical overhauls. Replace of consumable and demand parts	Complete replacement of turbines, inlet valves, governors and associated accessories.	Periodic overhauls	Replacement of the needle and deflector servomortors	Entire replacement with the turbines and accessories Increase of turbin output for 40MW Replacement of thrust bearing
	Inlet Valve	Procurement and replacement of the spare valve seats and the seal rings	Replacement of the inlet valves(#1-#3) Periodic replacement of valve	–	Procurement of normal repairment	Procurement of spare parts
	Governor	Replacement with the latest numerical governor system	Replacement of the governors including oil pressure sysytem and compressed air systems.	–	Replacement with the latest numerical governor system	Modification of the pressure oil cylinder of the governor
	Other Auxialiary Equipment	Replacement for new one	Replacement of the cooling water supply sysytem, lubrication oil sysytem and compressd air system for generator brake.(#1-#3) Replacement of the compressed air sysytem for generator	–	Replacement of the compressed air sysytem, grease lubrication system and water supply system	Replacement of the cooling water supply system, drainage system, brake sir system and grease lubrication system.
	Electrical Equipment Generator	Comparison between a total generator replacement and the coil and the iron core	Replacement of the generators after the turbines are replaced.	Overhaul of each unit	Replacement of the generators	–
	Exciter	Replacement with the numerical type equipped with automatic voltage regulator.	Above described	–	Replacement with bush-less exciter systems tigether with the generators	–
	Transformer	Replacement with all of the transformaers	Preperation of spare parts	–	–	Replacement with all of the transformaers
	Other Electrical Equipment	The time for 132kV switchgears replacement	Preperation of spare parts	–	Replacement of the circuit along with that of the generator.	Preperation of spare parts
	Control Equipment Control and Protection Equipment	Replacement with new control and protection equipment	–	Preparation of replacement withcontrol and protection equipment	Replacement with new control and protection equipment	–
	Control Power Source Equipment	Replacement with power station control and protection sysytem, 220V battery and battery charger	Restration of failed equipment	Replacement of 220V battery(#1)	Replacement of 220V battery and battery charger Installation of uninterruptible power source equipment	Investigation of the ground phenomenon in the positive turminal for replacement
	Communication Equipment	Installation of the communication line OPGW between both hydropower plants of Old Laxapana and	Installation of the communication line OPGW between the relevant hydropower plants and Old	Installation of the communication line OPGW between both hydropower plants of Old Laxapana and Canyon	Installation of the communication line OPGW to Old Laxapana	Installation of the communication line OPGW between both hydropower plants of Old Laxapana and Polpitiya
	Dam Distribution Equipment	–	–	–	–	–

Source: The Follow-Up Study on the Rehabilitation of Hydropower Stations in the Kelani River Basin for Hydropower Optimization in Sri Lanka, EPDC, May, 2005

5.3.2 Thermal Power Development Project

(1) On-going Project

As of November 2005, no thermal power projects were under construction.

(2) New Development Projects

LTGEP 2005-2019, formulated in November 2004, specifies a new thermal power project in the form of a combined cycle thermal power plant to be constructed at Kerawalapitiya.

A feasibility study[47] of the Kerawalapitiya project was conducted by JICA in 1999. The implementation of the transmission line between Kerawalapitiya and Kotugoda has been signed by JBIC in March 2003 and JBIC will be funding this project. Table 5.3.7 shows an outline of the results of the feasibility study.

Table 5.3.7 Outline of Results of FS on Kerawalapitiya Combined Cycle Plant

Implementing Agency	JICA
Study Period	December 1997 - January 1999
Project Contents	150MW Combined Cycle Plant Gas Turbine : 50MW x 2units, or 100MW x 1unit (Depends on plant configuration) Steam Turbine : 50MW x 1unit HRSG : 1 or 2 units (1 unit for 1 Gas Turbine) Generator : 118MVA (for GT), 59MVA (for ST) Fuel : Auto Diesel Oil Sea Water Desalination Plant : Multiple-effect distillation system 1unit, 1,500ton/day Fuel Storage Tank : 8,000kl x 2units Control Equipment : 1unit Transmission Line : Length: 18km (PS - existing Kotugoda S/S), 220kV x 2 cct
Planned Periods	Total 49 months (L/A: 5 months, Tender Preparation: 6 months, Contract: 7months, Construction: 31months
Project Cost	Case-1: 163.24 million USD (Price as of 1998) Case-2: 126.72 million USD (Price as of 1998)
Results of Financial Analysis	Case-1: EIRR=11.50%, FIRR=14.95% Case-2: EIRR= 8.99%, FIRR=11.54%

Note: Case 1: Construction of 150 MW facility as first of multiple facilities
Case 2: Construction of 150 MW facility without consideration of other facilities

Source: The Feasibility Study On Combined Cycle Power Development Project at Kerawalapitiya, The Democratic Socialist Republic of Sri Lanka, Final Report, Jan. 1999, JICA

The feasibility study assumed a 150 MW combined cycle facility with two different equipment scenarios: One 50 MW steam turbine and either one 100 MW gas turbine or two 50 MW gas turbines.

In addition, because the CEB's long-term generation development plan specified the development of five facilities to achieve a combined output of 750 MW, the study included economic and financial analyses of two cases: Case 1, assuming the development of multiple facilities, and Case 2, assuming the development of one 150 MW facility in isolation. The study concluded that the development of one 150 MW facility was the more feasible project, as indicated by its Economic Internal Rate of Return (EIRR) of 11.50% and its Financial Internal Rate of Return (FIRR) of 14.95%.

The required construction period for this project from conclusion of a contract to commencement of commercial operation of gas turbine open cycle plant and combined cycle plant are 22 months and 31 months, respectively. This construction period can be considered reasonable.

Initially, the CEB envisioned the project as a 300 MW plant, and it was scheduled to proceed using ODA funds provided by the Japanese government. However, it was eventually decided that the project would be completed earlier and at a lower cost if implemented by an IPP, and IPP tenders were therefore called for on a Build-Own-Operate-Transfer（BOOT）basis. Six companies were prequalified in June 2002. Contractual negotiations were commenced with two companies at the beginning of 2005, but difficulties arose over

[47] The Feasibility Study On Combined Cycle Power Development Project at Kerawalapitiya, The Democratic Socialist Republic of Sri Lanka, Jan. 1999, JICA

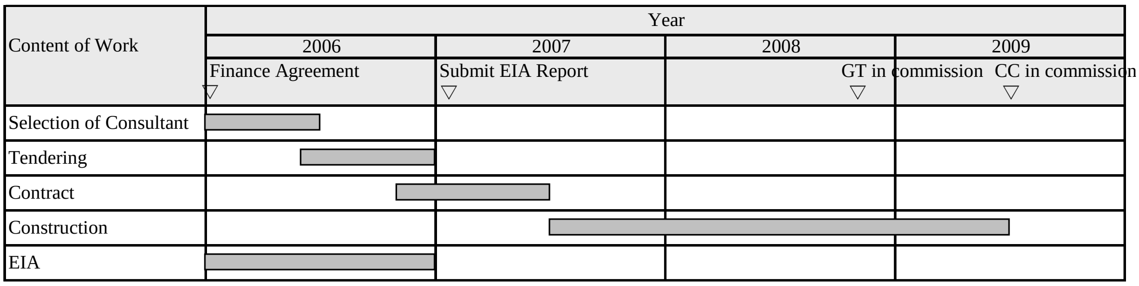
conditions and the negotiations were broken off.

In September 2005, the CEB applied to the External Resources Department for funding to implement the project as a CEB-owned rather than an IPP-owned facility.

In the LTGEP formulated in 2005, the CEB projected commencement of combined cycle operation at Kerawalapitiya at an output of 300 MW (150 MW x 2 units) in 2009 (2008 for gas turbine open cycle operation).

The feasibility study suggests a construction periods alone of 31 months for the combined cycle facility. Considering the EIA implementation period, even if the construction period could be reduced and preparation works before construction carried out in parallel, funding would have to be ensured by early 2006.

Table 5.3.8 Schedule for Kerawalapitiya Combined Cycle Project (Commencement of CC operation in 2009)



(3) Expansion Projects

The LTGEP 2005-2019 does not include any plans for the extension of thermal power facilities. However, a feasibility study was conducted relating to the modernization of the CEB's existing Kelanitissa gas turbine power plant No7, which commenced operation in 1997 and has a total output of 115 MW, to combined cycle operation. As of November 2005, this was the only concrete plan for the extension of a thermal power plant under discussion.

The feasibility study concerning the modernization of the Kelanitissa gas turbine power plant (GT7) to combined cycle operation was conducted by the Japan Consulting Institute (JCI).

Table 5.3.9 shows an outline of the results of the study.

Table 5.3.9 Outline of the Results of FS on Modernization of Kelanitissa GT7

Implementing Agency	JCI (Japan Consulting Institute)
Study Period	November 2002 - March 2003
Project Contents	Modernization of existing gas turbine power plant to combined cycle power plant Removal of existing oil-fired steam turbine power plant Rehabilitation of existing gas turbine power plant Replacement of Instruments and Control System Installation of Bottoming cycle System Steam Turbine : 52MW x 1unit HRSG : 1 unit Generator : 65MVA x 1unit Fuel Storage Tank : 8,000kl x 2units Control System : 1unit Fuel Conversion to Naphtha
Planned Periods	Total 37months (Technical Appraisal: 2months, Contract: 4 - 7months, Construction: 28months)
Project Cost	97.05 million USD (2003 Price)
Results of Financial Analysis	EIRR=40.77%, ROI=13.44%, ROE=31.28% (JBIC soft loan is adopted, Interest 2.65%)

Source: Feasibility Study Report On The Modernization Project of Kelanitissa Power Station GT7 Gas Turbine For Ceylon Electricity Board in Democratic Socialist Republic Of Sri Lanka, Mar. 2003, JCI

The aim of this project is to enable an existing auto diesel oil-fueled gas turbine plant to also burn naphtha and to operate steam turbine generators using heat recovery boilers, to increase output without an increase in fuel costs.

The required development period for this project from design proposals to commencement of operation is 37 months, with 28 months estimated to be required for construction alone. This construction period can be considered reasonable, taking into consideration the removal of the existing steam turbines, among other factors.

The feasibility study indicates that the initial investment will be relatively high at 97 million U.S. dollars (1,763 USD/kW), but the savings in fuel costs and maintenance costs make the cost of the project lower than the construction of a new diesel facility, and the results of the economic and financial analysis also indicate that the project is promising.

The economic and financial analysis assumes an annual plant factor of 85% after the facility is converted to combined cycle operation. However, as coal-fired power plants are introduced in the future, the combined cycle facility will be operated as middle or peak generation plant rather than a base power generation plant. This will cause a marked decline in the annual plant factor of the facility, resulting in a significant reduction of the project's economic efficiency.

With regard to the use of naphtha, the CPC is able to supply only half of the annual requirements of the CEB's Kelanitissa combined cycle plant. Taking into consideration the capacity of the CPC's refinery, the possibility of its being able to supply naphtha to the planned facility is low.

5.3.3 Renewable Energy Power Development Projects

No specific development projects for renewable energy generation facilities to be connected to the grid are indicated in the LTGEP 2005-2019. However, feasibility studies of wind power facilities are being conducted in several locations.

In addition, surveys of Sri Lanka's endowment of renewable energy resources have been conducted in the past. In this section the Study Team provide an overview of the results of past surveys of small hydropower and wind power generation potential.

(1) Wind Power Development Project

The Japan External Trade Organization (JETRO) conducted a feasibility study in 2002, focusing on Palatupana and Mirijjawila in the south, the extension of a 3 MW pilot plant at Karagan Lewaya, also in the south, and Kalpitiya in the northwest as candidates for wind power generation. At Mirijjawila the wind is weaker than in the other locations. At Karagan Lewaya there was insufficient space for a facility, and development was judged economically unfeasible. The potential site at Palatupana was adjacent to Yala National Park and conservation areas, and it would therefore be necessary to coordinate detailed plans with the Department of Wildlife Conservation. Kalpitiya was therefore judged to be the most feasible site from the technological, environmental and economic perspectives. The optimum development at Kalpitiya was projected as a facility of 50 wind power generators producing 600 kW for a total of 30 MW, giving an annual generation of 84.7 GWh at a facility utilization rate of 32%.

(2) Renewable Energy Potential in Sri Lanka

(i) Small-scale hydropower potential

Small-scale hydropower projects (micro hydropower project) have been started in more than 400 locations in Sri Lanka, chiefly in the central highlands. The majority of these projects have been abandoned. Studies have indicated that approximately 140 of these locations have the potential to be redeveloped to provide usable energy. Of these, 60 have already been rehabilitated, and are currently in operation.

The study conducted in 1989 in association with the Master Plan for the Electricity Supply of Sri Lanka considered the following three types of hydropower potential:

Category (A): New, previously undeveloped locations
Category (B): Hydropower development using irrigation channels, tanks and reservoirs
Category (C): Redevelopment, enhancement or extension of existing facilities

As Table 5.3.10 shows, the study identified 62 undeveloped sites with 5 MW or less potential, making a total of 30 MW; a potential for 8 MW from 290 irrigation tanks and reservoirs; and a potential for 50 MW from approximately 140 facilities available for extension or rehabilitation.

Table 5.3.10 Small-scale Hydropower Potential in Sri Lanka

Installed Capacity	Number of Sites		
	Small Scale Hydro Potential at Undeveloped Sites	Small Scale Hydroprojects at Irrigation Tanks and Reservoirs	Existing Small Scale Hydroprojects which may be Rehabilitated
0 - 0.1 MW	29	269	6
0.1 - 0.5 MW	17	19	28
0.5 - 1.0 MW	10	2	1
1.0 - 5.0 MW	6	-	3
Total	62 projects 30MW	290 projects 8MW	140 projects 50MW
Average Capacity	0.48MW	0.028MW	0.35MW

Source: Master Plan for the Electricity Supply of Sri Lanka, June 1989, CEB, GTZ, LIDE, CECB

According to a study[48] carried out by ITDG in 1999, in addition to the potential identified by the Master Plan mentioned above, the exploitable small-scale hydropower potential in Sri Lanka has been estimated to be around 100MW from about 250 identified sites.

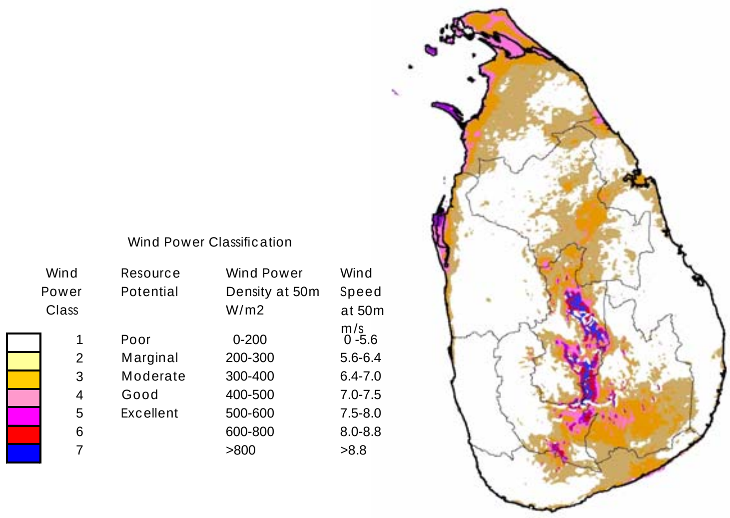
Currently the total capacity of small / mini hydroelectric plants for the national grid system is around 74MW and all these sites were developed by private developers. A further 47 MW is expected from private plants under construction and Letters of Intent have been issued for another 132MW[49].

(ii) Wind Power Generation Potential Survey and Site Selection Survey

A wind energy resource study[50] conducted in 2003 by the U.S. National Renewable Energy Laboratory (NREL) estimated that approximately 6% of Sri Lanka's total area of 65,600 km^2, or 4,100 km^2, represented excellent wind power resources. Assuming an output of 5 MW per square kilometer, the NREL estimated a potential of 20,000 MW. However, it also indicated that follow-up surveys of existing transmission line and wind power facility sites would be required. Figure 4.3.8 shows Sri Lanka's wind power resources. The most promising regions extend from the Kalpitiya Peninsula to the Jaffna Peninsula, taking in Mannar Island along the northwest coast, and also in the inland plateau.

Via the NREL, the U.S. Department of Energy (DOE) has been collaborating with the United States Agency for International Development (USAID) in a survey[51] of potential wind power generation sites in Sri Lanka.

Based on the findings of the NREL's survey of wind power resources, five areas (southeast coast - Hambantota to Buthawa; west coast - Kalpitiya Peninsula; northwest coast - Mannar Island; north coast - Jaffna District; central provinces - Ambewela area) have been selected, screening standards were established, and the five areas were then placed on an evaluation table. Of these areas, the Kalpitiya Peninsula was evaluated most highly.



Source: Wind Energy Resource Atlas of Sri Lanka and the Maldives

Figure 5.3.2 Potential Map of Wind Energy Resource in Sri Lanka

48 An Assessment of the Small Hydro Potential in Sri Lanka, April 1999
49 CEB LTGEP 2005-2019
50 Wind Energy Resource Atlas of Sri Lanka and the Maldives, August 2003, NREL
51 Sri Lanka Wind Farm Analysis and Site Selection Assistance, August 2003, NREL

Chapter 6 Generation Development Planning

In formulating a generation development plan a planner should consider that the plan has to show an appropriate plan for the development of generation units by reviewing preconditions such as future demand, supply capacity, required supply reliability and costs. The appropriate plan not only shows a process for improving supply cost and supply reliability in the system, but it must also contribute to a further understanding of the future conditions for the balance between demand and supply in the system.

Conversely, if the plan produces an inappropriate development plan, it may lead to serious conditions for the electricity supply in the future such as increased supply cost and a lack of supply capacity in the system.

This chapter discusses the generation development plan for the power system in Sri Lanka up to 2025.

6.1 Generation Development Planning Procedure

6.1.1 Target System for the Study

The power system stretching across the country of Sri Lanka is the target system for power development planning in the Study. At present the northern transmission line (Vavunia - Kilinochchi - Chunnakam), which was damaged during the civil war, is now under reconstruction. It is expected that the reconstruction will be completed and the transmission line will be in commission by 2007.

Figure 6.1.1 shows the power system in Sri Lanka as of May 2005.

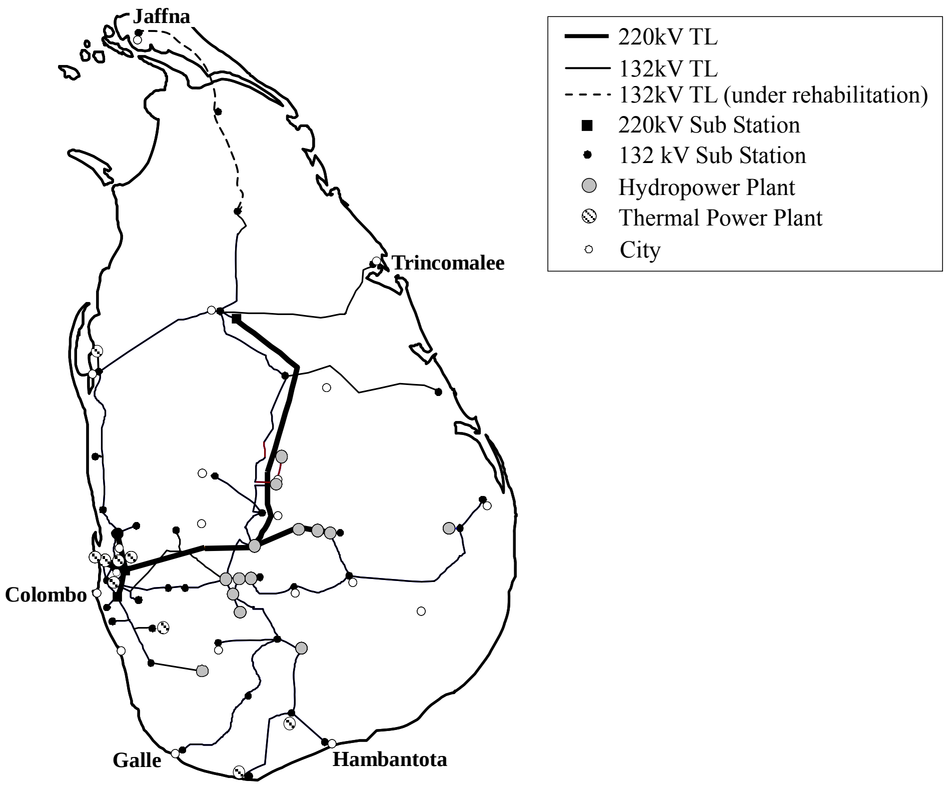


Figure 6.1.1 Power System in Sri Lanka (as of May 2005)

6.1.2 Workflow of Generation Development Planning

Figure 6.1.2 shows a workflow for the formulation of a generation development plan in the Study.

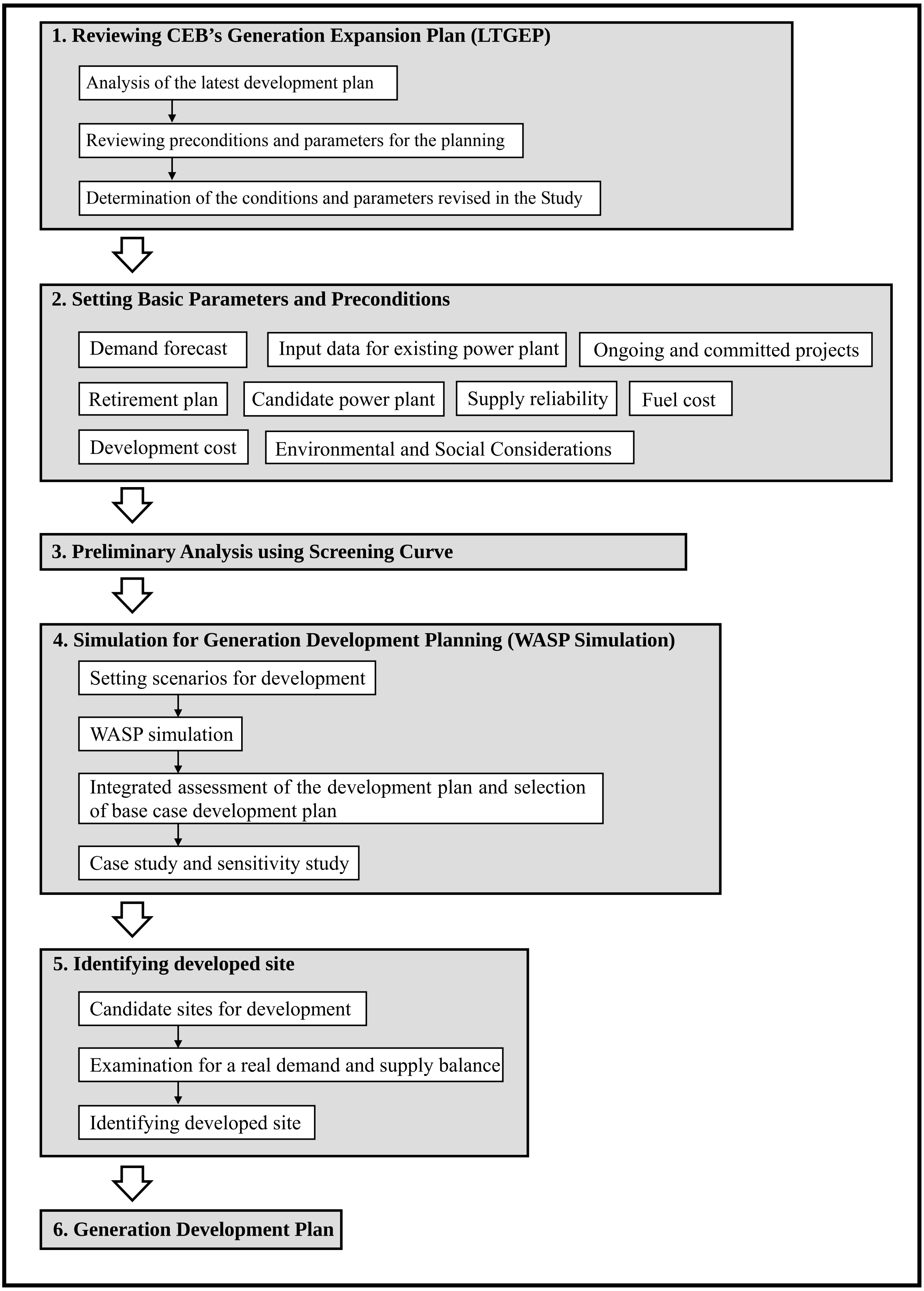


Figure 6.1.2 Workflow of Generation Development Planning

6.2 Reviewing CEB Long Term Generation Expansion Plan (LTGEP)

CEB formulates a Long-Term Generation Expansion Plan (LTGEP) every year. The plan covers the CEB power system for all of Sri Lanka and the planning period is for the next 15 years.

As discussed in section 5.1, the generation structure of the system in Sri Lanka is now in transition from a dependence on hydropower to a dependence on thermal power, and it seems that the transition will continue further. Also it seems that the power system will have a big change to its generation structure due to the installation of a coal-fired thermal power plant that is expected to be developed in the future.

The changes to the generation structure in the future will strongly effect plan formulation. Therefore, the planner should endeavor to formulate plans with sufficient attention and consideration and the plan formulated must be examined from various angles.

The Study team reviewed the latest LTGEP (2005 - 2019)[52] published by CEB in November 2004. Also the Study team proposed the items that should be updated or changed in the Study and it examined the details of the plan.

6.2.1 Long-Term Generation Expansion Plan (LTGEP) formulated by CEB

LTGEP is published every year by the CEB Generation Planning Branch. The latest LTGEP was issued in November 2004.

In the formulating LTGEP, the studies of concerns are introduced to the plan and the technical data and cost parameters for power development planning are updated. Moreover, electricity demand forecasts made by CEB are presented in the LTGEP.

The formulated plan is transferred to the Transmission Planning Branch and it is used for formulating LTTDS[53] by the members of that branch. However, the LTGEP formulated during the previous year is used for LTTDS because the works for both are carried out in parallel and there is a deviation in the plans.

Table 6.2.1 shows a standard schedule of the work for LTGEP.

Table 6.2.1 Standard Schedule of Work for LTGEP

Work	Month											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Demand Forecast												
Hydro System Simulation (SYSIM)												
Simulation for Generation Development (WASP)												
Reporting												

Source: JICA Study Team

6.2.2 Planning Period

The period for LTGEP is the next 15 years and the next LTGEP that will be formulated in 2005 will present the generation development plan up to 2020.

For formulating LTGEP, CEB carries out electricity demand forecasts for the next 20 years, which is five years longer than LTGEP. Correspondingly, the simulation analysis for generation development planning using WASP is carried out for 20 years, and the development plan for the next 15 years is presented in LTGEP.

[52] CEB Long Term Generation Expansion Plan (2005 - 2019)
[53] CEB Long Term Transmission Development Study

The results of the WASP simulation tend to select generation units with small initial investment costs in the years at the end of the study period. Therefore, the simulation should be carried out for a longer period than the actual planning period for the purpose of excluding the impacts of this tendency. From this viewpoint, the setting of the study period and planning period for LTGEP is appropriate.

6.2.3 Electricity Demand for Generation Development Planning

The data on future forecasted demand is one of the most important preconditions for formulating generation development plan. Therefore, the Study team reviewed the forecasted demand data that was used in LTGEP.

In Chapter 4, the methodology and procedures for making demand forecasts in the Study were discussed. Therefore, this section will focus on the accuracy for simulating electricity demand in the WASP simulation.

(1) Peak Demand

In LTGEP the peak demand for each month in the future is prepared by calculating the annual peak demand from demand forecasting and actual monthly peak demand during the previous year. This is used for accurately simulating the seasonal fluctuation of the hydropower contribution.

In WASP the user can divide a year into 12 periods and CEB uses the function at maximum.

Consequently, from the viewpoint of maintaining consistency with the hydropower input data for each month, the setting of 12 periods in a year in LTGEP is appropriate.

Table 6.2.2 and 6.2.3 show the forecasted peak demand for the Study and the ratio of period peak demand to annual peak demand in 2004.

Table 6.2.2 Forecasted Peak Demand for Generation Development Planning in the Study

(Unit : MW)

Year	Base Demand Case	Low Demand Case	High Demand Case
2006	1,884	1,874	1,911
2007	2,019	1,996	2,066
2008	2,168	2,129	2,238
2009	2,336	2,277	2,434
2010	2,517	2,436	2,648
2011	2,712	2,604	2,880
2012	2,921	2,783	3,131
2013	3,146	2,974	3,402
2014	3,389	3,181	3,699
2015	3,657	3,406	4,027
2016	3,943	3,645	4,380
2017	4,250	3,900	4,761
2018	4,579	4,170	5,173
2019	4,931	4,457	5,616
2020	5,306	4,761	6,093
2021	5,708	5,084	6,607
2022	6,138	5,427	7,163
2023	6,599	5,792	7,761
2024	7,092	6,179	8,405
2025	7,619	6,590	9,100
2026	8,182	7,026	9,848
2027	8,786	7,490	10,655
2028	9,433	7,984	11,526
2029	10,124	8,509	12,464
2030	10,863	9,066	13,475

Source: JICA Study Team

Table 6.2.3 Monthly Peak Demand Ratio (in 2004)

	Month											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Actual Peak Demand (MW)	1,510.1	1,490.7	1,512.7	1,528.6	1,506.5	1,501.8	1,513.4	1,526.4	1,515.7	1,496.5	1,548.8	1,533.5
Peak Demand Ratio	0.9750	0.9625	0.9767	0.9870	0.9727	0.9697	0.9771	0.9855	0.9786	0.9662	1.0000	0.9901

: Annual Peak Demand in 2004

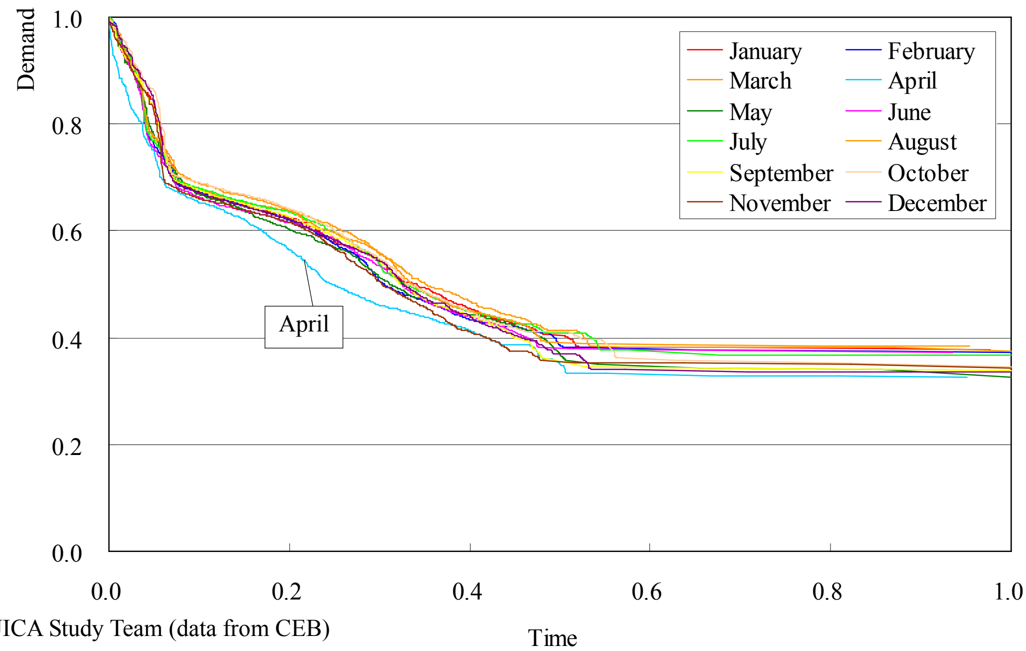
Source: JICA Study Team (data from CEB)

(2) Load Duration Curve

WASP simulation applies a load duration curve for simulating actual load curve.

LTGEP uses only one load duration curve for simulating a load curve for each month.

Figure 6.2.1 shows the normalized load duration curves for each month made from actual demand data in 2004.



Source: JICA Study Team (data from CEB)

Figure 6.2.1 Monthly Normalized Load Duration Curves in 2004

The shapes of normalized load duration curves for each month are almost same throughout the year of 2004. The shape of the curve for April is a little different from those for other months due to Sri Lanka's New Year holiday in April. However, it seems that its impact on formulating the plan is marginal.

Consequently, setting the load duration curve in CEB LTGEP is adequate.

It is expected that the shape of the load duration curve will change due to the change in consumption patterns by consumers in the future. To reflect the change faithfully, CEB should check the shape of the monthly load duration curve in the formulation of LTGEP every year. Also, it should be changed if the shape of the load duration curve each month is obviously different from other months. Then the revised data should be used for simulation analysis using WASP.

(3) Accuracy of Simulating Load Pattern by Load Duration Curve

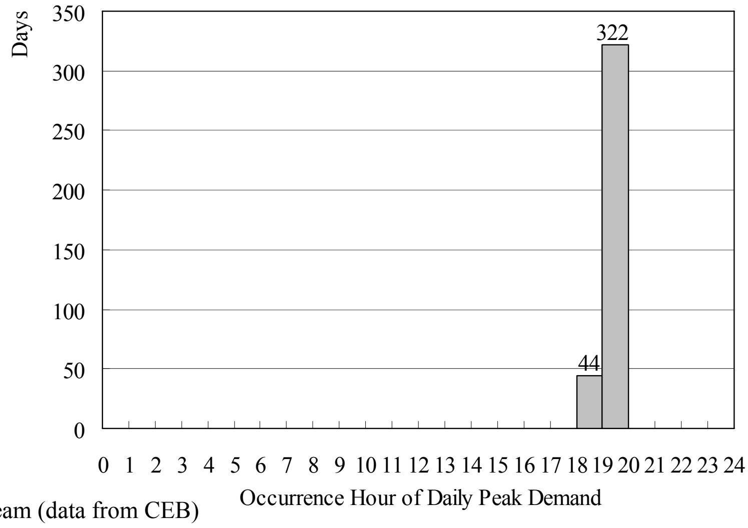
As described above, WASP simulates the pattern of demand occurrence by using a load duration curve in the WASP simulation but actual demand occurs chronologically. Therefore, to be exact, the simulation using load duration curve does not match actual demand occurrence.

For example, if the demand during the peak-time on a Sunday is lower than the demand during the off-peak time on weekdays, the demand during the peak time on Sunday is to be located on the off-peak time on the load duration curve.

In the case of such a demand pattern, the simulation using a load duration curve would underestimate demand during peak-time and the accuracy of the simulation might be lower.

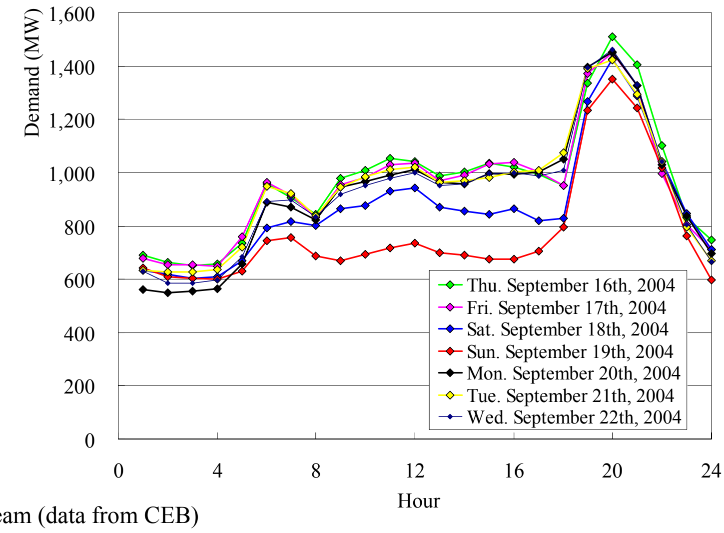
Consequently, the Study team examined the accuracy of simulations for the pattern of demand occurrence by using historical demand data in 2004.

Figure 6.2.2 shows the results of the analysis on the occurrence time of daily peak demand and Figure 6.2.3 shows typical daily load curves in 2004.



Source: JICA Study Team (data from CEB)

Figure 6.2.2 Occurrence Time of Daily Peak Demand in 2004



Source: JICA Study Team (data from CEB)

Figure 6.2.3 Typical Daily Load Curve in 2004

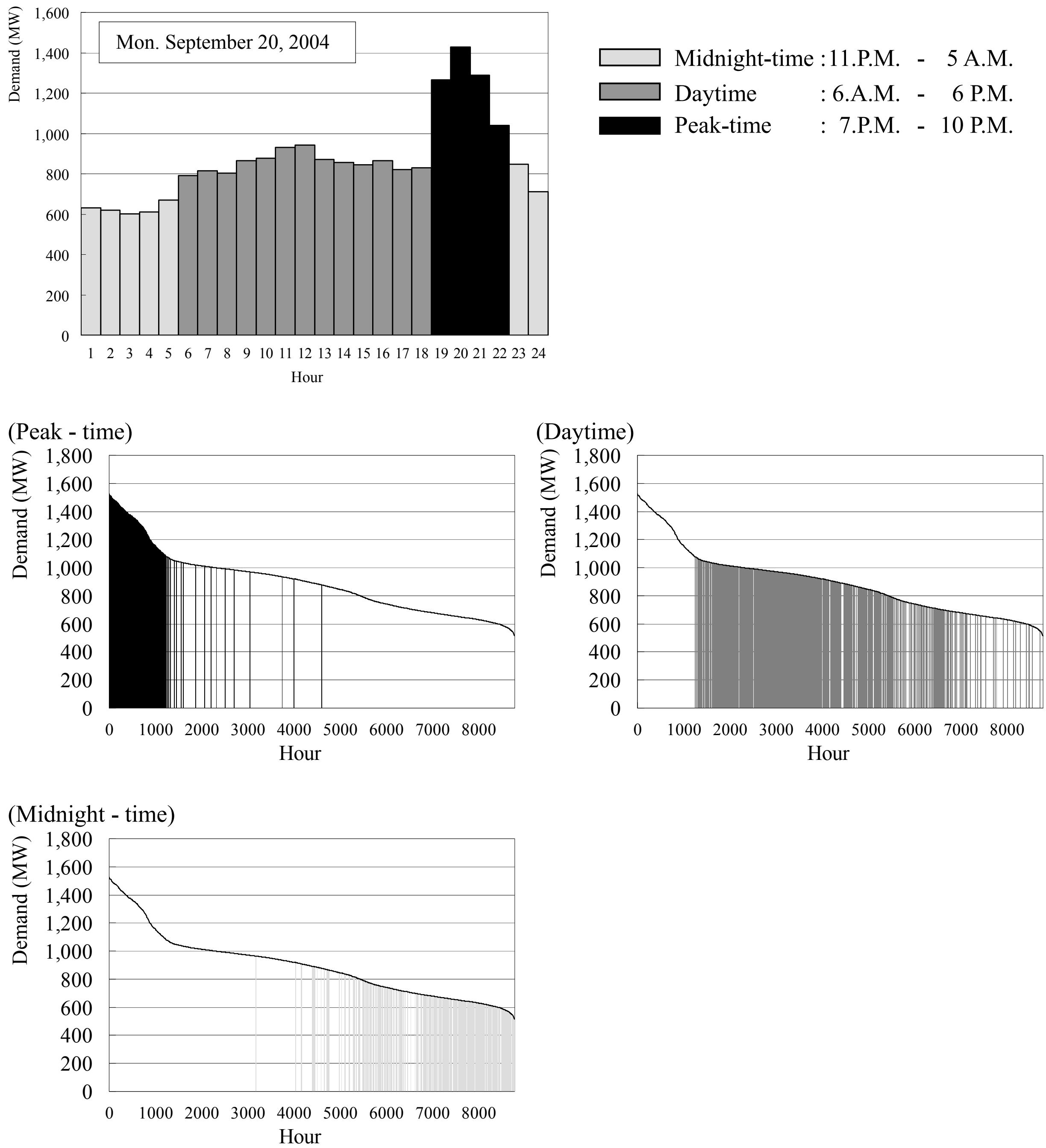
Figure 5.3.2 shows that the peak demand occurred at 8 P.M. or 9 P.M. throughout the year. Figure 5.3.3 shows that the peak-time was around 4 hours from 7 P.M. to 10 P.M. during a day. The daytime demand occurred from 6 A.M. to 6 P.M. and this demand has only small fluctuations.

In the Study the accuracy of simulating the characteristics on the demand occurrence shown in the above figures was examined by using actual demand in 2004.

In the examination the demand was categorized by occurrence hour and the distribution of demand by each of the time zones shown below was checked.

1) Midnight-time : 11 P.M. - 5 A.M.
2) Daytime : 6 A.M. - 6 P.M.
3) Peak-time : 7 P.M. - 10 P.M.

Figure 6.2.4 shows the results of the examination.



Source: JICA Study Team
(data from CEB)

Figure 6.2.4 Distribution of Demand on Load Duration Curve by Time Zone in 2004

The demand for each time zone is clearly distributed on the load duration curve. This means that the actual demand that occurred chronologically is faithfully simulated on the load duration curve.

Consequently, CEB simulation using WASP considers the actual pattern of demand occurrence with sufficient accuracy.

6.2.4 Data for Existing Thermal Power Plants

(1) Number of Generation Units

Table 6.2.4 shows the data on the number of generation units of existing thermal power plants, which is used in LTGEP (2005-2019).

Table 6.2.4 The Number of Generation Units of Existing Thermal Power Plants (LTGEP 2005-2019)

Owner	Power Plant	Unit Type	No. of Units
CEB	Sapugaskanda Diesel 1,2,3,4	Diesel	4
	Sapugaskanda Diesel (Extension) 1,2,3,4,5,6,7,8	Diesel	8
	Keranitissa GT (Old) 1,2,3,4,5,6	Gas Turbine	3
	Keranitissa GT (New) 1	Gas Turbine	1
	Kelanitissa CCGT	Combined Cycle	1
IPP	IPP Lakdhanavi Limited	Diesel	1
	IPP Asia Power Limited	Diesel	1
	IPP Colombo Power (Private) Limited	Diesel	1
	IPP ACE Power Horana	Diesel	1
	IPP ACE Power Matara	Diesel	1
	IPP Heladanavi (Private) Limited 1,2,3,4,5,6	Diesel	10
	IPP ACE Power Embilipitaya Limited 1,2,3,4,5,6,7,8,9,10	Diesel	10
	IPP AES Kelanitissa (Private) Lmited	Combined Cycle	1

Source: CEB LTGEP (2005 - 2019)

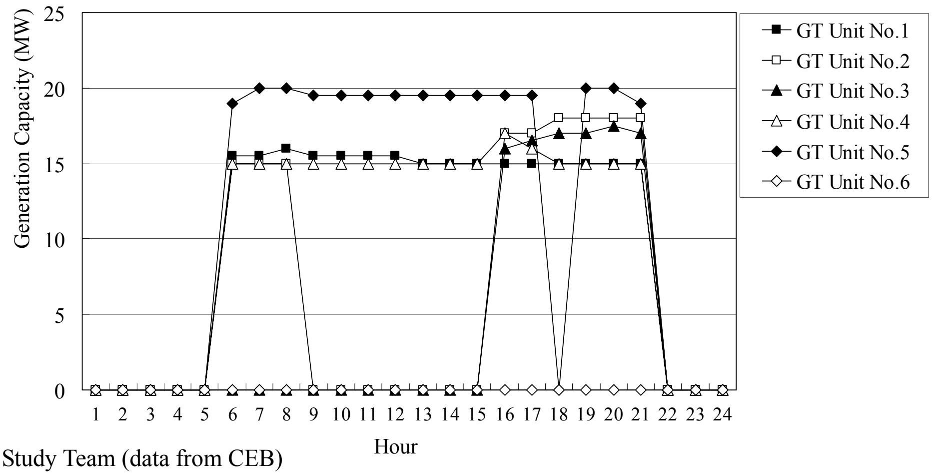
Considering the actual number of available units, the number of units for each power plant was determined in this Study for formulating generation development planning.

The number of units that should be changed in the Study is discussed below. As for hydropower plants, the number of units does not need to be changed because hydropower plants are simulated as a merged power plant in WASP simulation.

(i) Kelanitissa GT (Old) No.1 - No. 6

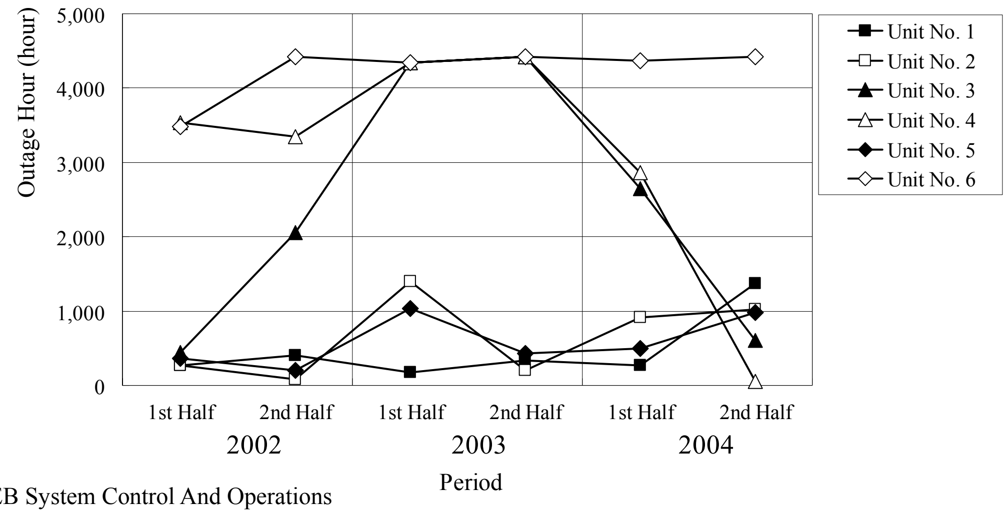
Six units are available in the latest LTGEP 2005-2019.

Figure 6.2.5 shows the typical daily operation pattern for each generation unit in 2004 and Figure 6.2.6 shows the transition of the outage hour from 2002 to 2004.



Source: JICA Study Team (data from CEB)

Figure 6.2.5 Typical Daily Operation Pattern (Kelanitissa GT Old No.1 - No.6, Nov. 16 in 2004)



Source: CEB System Control And Operations Monthly Report（Jan. 2002～Dec. 2004）

Figure 6.2.6 Transition of Outage Hour (Kelanitissa GT Old No.1 - No. 6)

As shown in Figure 6.2.5, five units except for generator No.6 were available for operation on that day in 2004. Also as shown in Figure 6.2.6, only the three units of No.1, 2 and 5 were available for operation in 2003, the two units of No. 1 and 2 were recovered and a total of five units were available for operate in 2004. However, only 4 units are available for operation at same time as of November 2005.

Consequently, the number of units available for operation for Kelanitissa GT Old Power Plant was set as four units in the Study.

(ii) IPP thermal power plant

As shown in Table 6.2.4, IPP diesel power plants, except for Heladhanavi Power Plant and ACE Embilipitiya power plant, were introduced into WASP simulation as each power plant consists of only one generation unit in the CEB simulation for LTGEP.

For conditions like this, WASP simulates the operation of those power plants as all units in a power plant will stop at the same time when there is an accidental outage and the maintenance work will be carried out for all power plants at the same time.

The actual operations of IPP diesel power plants are remarkably different. Therefore, the actual number of generation units available for operation is used in the simulation. In regards to IPP Heladhanavi, the number of units was changed from 10 units to six units because six is the actual number of installed units.

Table 6.2.5 shows the number of generation units of existing power plants used in the Study.

Table 6.2.5 Number of Generation Units of Existing Thermal Power Plants (MP Study)

Owner	Power Plant	Unit Type	No. of Units
CEB	Sapugaskanda Diesel 1,2,3,4	Diesel	4
	Sapugaskanda Diesel (Extension) 1,2,3,4,5,6,7,8	Diesel	8
	Keranitissa GT (Old) 1,2,3,4,5,6	Gas Turbine	4
	Keranitissa GT (New) 1	Gas Turbine	1
	Kelanitissa CCGT	Combined Cycle	1
IPP	IPP Lakdhanavi Limited	Diesel	4
	IPP Asia Power Limited	Diesel	8
	IPP Colombo Power (Private) Limited	Diesel	4
	IPP ACE Power Horana	Diesel	4
	IPP ACE Power Matara	Diesel	4
	IPP Heladanavi (Private) Limited 1,2,3,4,5,6	Diesel	6
	IPP ACE Power Embilipitaya Limited 1,2,3,4,5,6,7,8,9,10	Diesel	14
	IPP AES Kelanitissa (Private) Lmited	Combined Cycle	1

: Data revised in the Study

Source: JICA Study Team

(2) Maximum and Minimum Operation Capacities

Table 6.2.6 shows the data for the maximum and minimum operation capacities of the existing thermal power plants, which is used in the CEB simulation for LTGEP 2005-2019.

Table 6.2.6 Maximum and Minimum Operation Capacities of Existing Thermal Power Plants (LTGEP 2005-2019)

Owner	Power Plant	Unit Type	Installed Capacity (MW)	Max. Operation Capacity (MW)	Min. Operation Capacity (MW)
CEB	Sapugaskanda Diesel 1,2,3,4	Diesel	20.00	18.0	18.0
	Sapugaskanda Diesel (Extension) 1,2,3,4,5,6,7,8	Diesel	10.00	9.0	9.0
	Keranitissa GT (Old) 1,2,3,4,5,6	Gas Turbine	20.00	17.0	17.0
	Keranitissa GT (New) 1	Gas Turbine	115.00	115.0	80.0
	Kelanitissa CCGT	Combined Cycle	165.00	165.0	120.0
IPP	IPP Lakdhanavi Limited	Diesel	22.50	22.50	22.50
	IPP Asia Power Limited	Diesel	51.00	49.0	49.0
	IPP Colombo Power (Private) Limited	Diesel	64.00	60.0	60.0
	IPP ACE Power Horana	Diesel	24.80	20.0	20.0
	IPP ACE Power Matara	Diesel	24.80	20.0	20.0
	IPP Heladanavi (Private) Limited 1,2,3,4,5,6	Diesel	100.00	100.0	100.0
	IPP ACE Power Embilipitaya Limited 1,2,3,4,5,6,7,8,9,10	Diesel	100.00	100.0	100.0
	IPP AES Kelanitissa (Private) Lmited	Combined Cycle	163.00	163.0	49.0

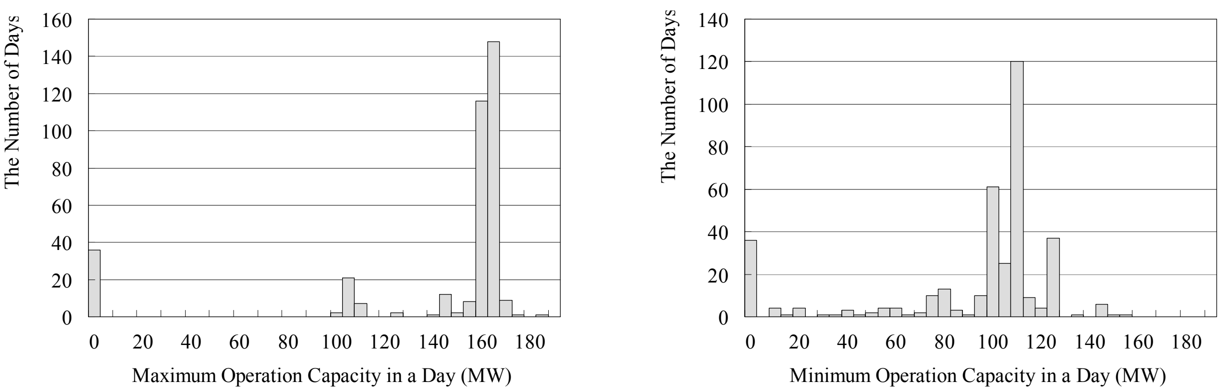
Source: CEB LTGEP (2005 - 2019)

WASP simulation requires technical data on the maximum and minimum operation capacities of thermal power plants. These figures should be prepared for the simulation in consideration of technical availability and expectations for the actual operation situations.

In the latest LTGEP (2005-2019), CEB considers the derating capacity due to the aging of existing generators at the Sapugasukanda diesel (Old) power plant, Sapugasukanda diesel (Extension) power plant and Kelanitissa gas turbine power plant. Upon reviewing the actual operation capacity of these power plants, it was learned that the actual available capacity was close to the maximum operation capacity shown in Table 6.2.6.

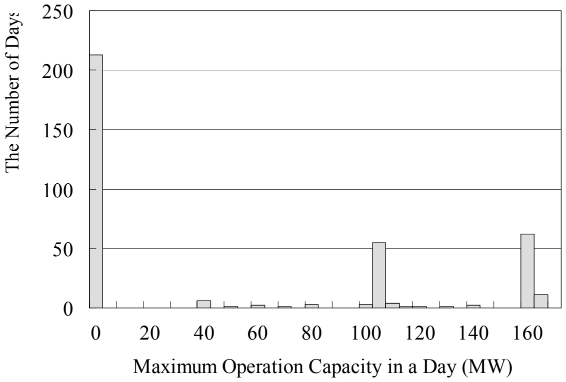
The Study team reviewed actual generation records for 2004 to examine the actual operation capacity at the maximum and minimum levels. Consequently, most of the data regarding the capacities in CEB LTGEP were appropriately prepared. In regards to Kelanitissa GT (new) and IPP AES Kelanitissa CCGT, their capacities were a little different from the actual operation capacity.

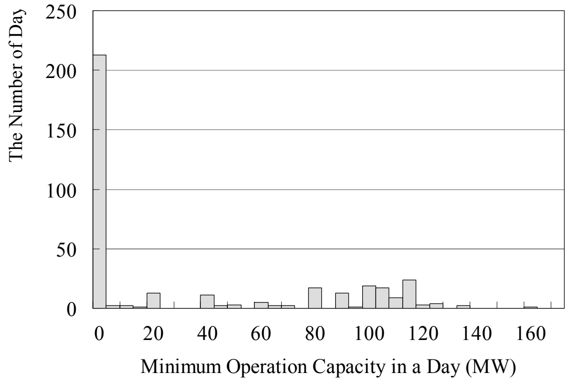
Figures 6.2.7 and 6.2.8 show the results from the analysis of actual generation capacity for Kelanitissa CCGT and IPP AES Kelanitissa CCGT.



Source: JICA Study Team
(Data from CEB)

Figure 6.2.7 Maximum and Minimum Operation Capacities in 2004 (Kelanitissa CCGT)





Source: JICA Study Team
(Data from CEB)

Figure 6.2.8 Maximum and Minimum Operation Capacities in 2004 (IPP Kelanitissa CCGT)

Figures 6.2.7 shows that the minimum operation capacity for Kelanitissa CCGT is 110MW.

Consequently, the Study team used the minimum operation capacity of 110MW for Kelanitissa CCGT. Regarding AES Kelanitissa CCGT, the Study Team used the minimum operation capacity of 49MW described in the Power Purchase Agreement.

As described above, the installed capacity of IPP plants in the Study is the capacity of a generation unit. Therefore, the maximum and minimum operation capacities are changed to the capacity of a generation unit.

Table 6.2.7 shows the maximum and minimum operation capacities of existing thermal power plants in the Study.

Table 6.2.7 Maximum and Minimum Operation Capacities of Existing Thermal Power Plants (MP Study)

Owner	Power Plant	Unit Type	Installed Capacity (MW)	Max. Operation Capacity (MW)	Min. Operation Capacity (MW)
CEB	Sapugaskanda Diesel 1,2,3,4	Diesel	20.000	18.000	18.000
	Sapugaskanda Diesel (Extension) 1,2,3,4,5,6,7,8	Diesel	10.000	9.000	9.000
	Keranitissa GT (Old) 1,2,3,4,5,6	Gas Turbine	20.000	17.000	17.000
	Keranitissa GT (New) 1	Gas Turbine	115.000	115.000	80.000
	Kelanitissa CCGT	Combined Cycle	165.000	165.000	110.000
IPP	IPP Lakdhanavi Limited	Diesel	5.630	5.630	5.630
	IPP Asia Power Limited	Diesel	6.375	6.125	6.125
	IPP Colombo Power (Private) Limited	Diesel	15.681	15.000	15.000
	IPP ACE Power Horana	Diesel	6.200	5.000	5.000
	IPP ACE Power Matara	Diesel	6.200	5.000	5.000
	IPP Heladanavi (Private) Limited 1,2,3,4,5,6	Diesel	17.000	16.660	16.660
	IPP ACE Power Embilipitaya Limited 1,2,3,4,5,6,7,8,9,10	Diesel	10.000	7.140	7.140
	IPP AES Kelanitissa (Private) Lmited	Combined Cycle	163.000	163.000	49.000

: Data revised in the Study

Source: JICA Study Team

(3) Heat Rate

The figures for the heat rate of existing thermal power plants owned by the CEB that are to be presented in the LTGEP have been calculated from actual operation record. The CEB revises these figures every year when the LTGEP is formulated, and the way it manages data in the course of formulating this plan can be considered appropriate.

Regarding the IPP thermal power plants, the Study team uses the heat rate data shown in PPA as well as from the latest LTGEP. These heat rate data were received from the CEB Energy Purchase Branch.

Table 6.2.8 shows the heat rate of the existing thermal power plants.

Table 6.2.8 Heat Rate of Existing Power Plants (MP Study)

Owner	Power Plant	Plant Type	Heat Rate			
			at Max. Operation		at Min. Operation	
			in PPA	For MP Study (kcal/kWh)	in PPA	For MP Study (kcal/kWh)
CEB	Sapugaskanda Diesel 1,2,3,4	Diesel		2,252		
	Sapugaskanda Diesel (Extension) 1,2,3,4,5,6,7,8	Diesel		2,073		
	Keranitissa GT (Old) 1,2,3,4,5,6	Gas Turbine		4,192		
	Keranitissa GT (New) 1	Gas Turbine		2,603		3,060
	Kelanitissa CCGT	Combined Cycle		1,791		1,884
IPP	IPP Lakdhanavi Limited	Diesel	9,154 kJ/kWh	2,186		
	IPP Asia Power Limited	Diesel	9,154 kJ/kWh	2,186		
	IPP Colombo Power (Private) Limited	Diesel	0.2160 kJ/kWh	2,102		
	IPP ACE Power Horana	Diesel	0.2258 kJ/kWh	2,200		
	IPP ACE Power Matara	Diesel	0.2270 kJ/kWh	2,212		
	IPP Heladanavi (Private) Limited 1,2,3,4,5,6	Diesel	0.2060 Litter/kWh	1,891		
	IPP ACE Power Embilipitaya Limited 1,2,3,4,5,6,7,8,9,1(	Diesel	0.2217 kJ/kWh	2,160		
	IPP AES Kelanitissa (Private) Lmited	Combined Cycle	5,477 kJ/kWh	1,904	405,000,000 kJ/kWh	3,287

Note: Not prepared minimum heat rate for Sapugasukanda diesel power plants because these plants operates for peak load at max. operation capacity.
Not prepared minimum heat rate for IPP-owned diesel power plants because these plants operates for base load at constant operation capacity.

Source: JICA Study Team (Data from CEB)

(4) Spinning Reserve

LTGEP assumed that Kelanitissa GT (new), Kelanitissa CCGT and IPP AES Kelanitissa CCGT, which can be operated flexibly, have reserve margins of 10% of their installed capacity.

According to the CEB System Control Center, as of 2005 CEB reluctantly operates the power system without spinning reserve because the system does not have reserve capacity against demand. However, CEB expects to be able to operate the power system with a reserve margin in the future.

It seems that this assumption in LTGEP is appropriate.

(5) Forced Outage Rate

The figures for the thermal efficiency of existing thermal power facilities owned by the CEB that are to be used for the LTGEP have been calculated from outage performance. The CEB revises these figures every year when the LTGEP is formulated, and the way it manages data in the course of formulating this plan can be considered appropriate.

According to the CEB System Control and Operations Monthly Report, there have been few IPP generator outages, which is little more than zero. The forced outage rates for IPP plants used in LTGEP are around 15% at the maximum, which is much higher than the actual outage ratio.

Consequently, the Study team modified the forced outage rate and annual maintenance period of each IPP power plant so that the annual generation energy from IPPs could be close to MGEA[54].

Table 6.2.9 shows the forced outage rate for existing power plants used in the Study[55].

[54] Minimum Guarantee Energy Amount

[55] The forced outage rate for IPP diesel generator facilities was assumed to be 5%. Figures for the ACE Matara and ACE Horana generation facilities were adjusted for the annual number of maintenance days to an assumed 1% and 2%, respectively.

Table 6.2.9 Forced Outage Rate of Existing Thermal Power Plants (MP Study)

Owner	Power Plant	Plant Type	Forced Outage Rate
CEB	Sapugaskanda Diesel 1,2,3,4	Diesel	17.0%
	Sapugaskanda Diesel (Extension) 1,2,3,4,5,6,7,8	Diesel	12.0%
	Keranitissa GT (Old) 1,2,3,4,5,6	Gas Turbine	20.0%
	Keranitissa GT (New) 1	Gas Turbine	10.0%
	Kelanitissa CCGT	Combined Cycle	6.0%
IPP	IPP Lakdhanavi Limited	Diesel	5.0%
	IPP Asia Power Limited	Diesel	5.0%
	IPP Colombo Power (Private) Limited	Diesel	5.0%
	IPP ACE Power Horana	Diesel	1.0%
	IPP ACE Power Matara	Diesel	2.0%
	IPP Heladanavi (Private) Limited 1,2,3,4,5,6	Diesel	5.0%
	IPP ACE Power Embilipitaya Limited 1,2,3,4,5,6,7,8,9,1(	Diesel	5.0%
	IPP AES Kelanitissa (Private) Lmited	Combined Cycle	2.5%

: Data revised in the Study

Source: JICA Study Team (Data from CEB)

(6) Annual Maintenance Days

The numbers of maintenance and repair days for existing thermal power facilities owned by the CEB that are to be used for the LTGEP are figures calculated from past outage performance due to maintenance. The CEB revises these figures every year when the LTGEP is formulated, and the way it manages data in the course of formulating this plan can be considered appropriate.

As discussed above, the data on maintenance days in a year with the forced outage rate shown in Table 6.2.9 are calculated so that the annual generation energy from IPPs could be close to MGEA.

Table 6.2.10 shows the annual maintenance days for existing thermal power plants used in the Study.

Table 6.2.10 Annual Maintenance Days of Existing Thermal Power Plants (MP Study)

Owner	Power Plant	Plant Type	Maintenance Days in a Year
CEB	Sapugaskanda Diesel 1,2,3,4	Diesel	50日
	Sapugaskanda Diesel (Extension) 1,2,3,4,5,6,7,8	Diesel	50日
	Keranitissa GT (Old) 1,2,3,4,5,6	Gas Turbine	36日
	Keranitissa GT (New) 1	Gas Turbine	41日
	Kelanitissa CCGT	Combined Cycle	30日
IPP	IPP Lakdhanavi Limited	Diesel	61日
	IPP Asia Power Limited	Diesel	70日
	IPP Colombo Power (Private) Limited	Diesel	58日
	IPP ACE Power Horana	Diesel	14日
	IPP ACE Power Matara	Diesel	9日
	IPP Heladanavi (Private) Limited 1,2,3,4,5,6	Diesel	65日
	IPP ACE Power Embilipitaya Limited 1,2,3,4,5,6,7,8,9,1(	Diesel	59日
	IPP AES Kelanitissa (Private) Lmited	Combined Cycle	19日

: Data revised in the Study

Source: JICA Study Team (Data from CEB)

(7) Maintenance Capacity

The Study team set the maintenance capacity data to be the same as the maximum operation capacity. In the version of WASP-III+, which CEB is using for formulating LTGEP as of 2005, the maintenance capacity is input in every 10MW. Therefore, the figures were changed when the WASP-IV version was introduced in the Study.

The planned maintenance work for inspecting steam turbines at Kelanitissa CCGT Power Plant was carried out from May 28 to July 20, 2005. The gas turbines did not operate during this maintenance period. Consequently, the Study team set the annual maintenance days for Kelanitissa CCGT as 165MW, the same as the maximum operation capacity for the plant.

As described above, the installed capacity of IPP plants in the Study is the capacity of a generation unit. Therefore, the maintenance capacity was changed to the capacity of a generation unit.

Table 6.2.11 shows annual maintenance capacity of existing power plants.

Table 6.2.11 Maintenance Capacity of Existing Power Plants (MP Study)

Owner	Power Plant	Plant Type	Maintenance Capacity
CEB	Sapugaskanda Diesel 1,2,3,4	Diesel	18.000 MW
	Sapugaskanda Diesel (Extension) 1,2,3,4,5,6,7,8	Diesel	9.000 MW
	Keranitissa GT (Old) 1,2,3,4,5,6	Gas Turbine	17.000 MW
	Keranitissa GT (New) 1	Gas Turbine	115.000 MW
	Kelanitissa CCGT	Combined Cycle	165.000 MW
IPP	IPP Lakdhanavi Limited	Diesel	5.630 MW
	IPP Asia Power Limited	Diesel	6.125 MW
	IPP Colombo Power (Private) Limited	Diesel	15.000 MW
	IPP ACE Power Horana	Diesel	5.000 MW
	IPP ACE Power Matara	Diesel	5.000 MW
	IPP Heladanavi (Private) Limited 1,2,3,4,5,6	Diesel	16.660 MW
	IPP ACE Power Embilipitaya Limited 1,2,3,4,5,6,7,8,9,1(	Diesel	7.140 MW
	IPP AES Kelanitissa (Private) Lmited	Combined Cycle	163.000 MW

: Data revised in the Study

Source: JICA Study Team (Data from CEB)

(8) Fuel Use

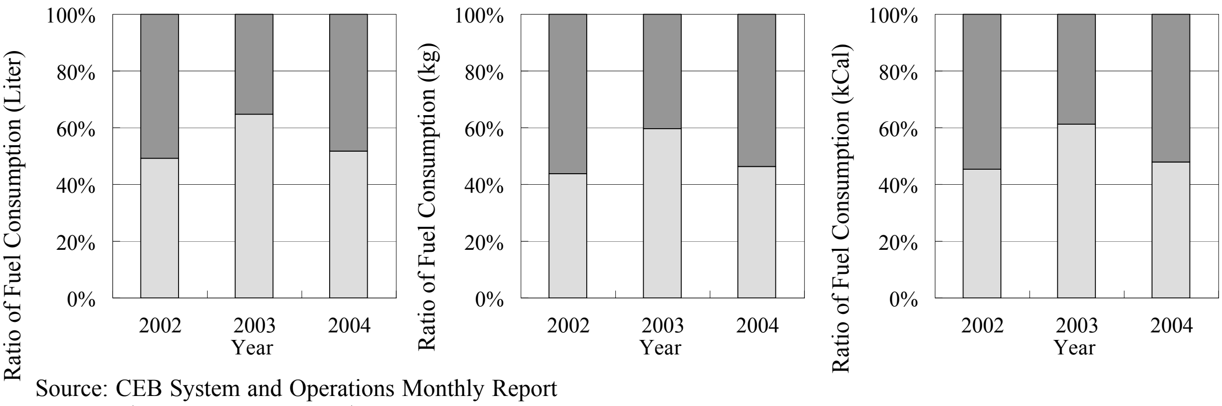
CPC (Ceylon Petroleum Corporation) provides all of the fuel used by thermal power plants in Sri Lanka.

Reviewing the CEB System Controls and Operations Monthly Report, the Study team checked the fuel types that are actually used at each thermal power plant.

It was determined that the fuel type LTGEP is appropriate.

In LTGEP, a combined cycle power plant known as Kelanitissa CCGT uses naphtha and auto diesel oil with the ratio of 1 to 2 based on the actual fuel consumption supplied from CPC.

As shown in Figure 6.2.9, the actual ratio of fuel consumption of naphtha and auto diesel oil at Kelanitissa CCGT is 1 to 1. Therefore, the ratio was changed to 1 to 1 in the Study.



Source: CEB System and Operations Monthly Report
(Jan. 2002 – Dec. 2004)

Figure 6.2.9 Ratio of Fuel Consumption at Kalanitissa CCGT (2002 - 2004)

(9) Fuel Prices

The price of fuel provided from CPC is updated based on the price sheet in formulation of LTGEP.

The CPC price sheet shows both FOB prices of fuel products in Singapore and the freight to Colombo Port. CPC calculates the border price at Colombo Port based on the prices shown in the sheet.

According to CPC, the rough estimate of demand for auto diesel oil in all of Sri Lanka is around 1,700kilo MT per year, which is much larger than the maximum production of around 650kilo MT per year from the CPC owned refinery. Therefore, CPC covers this gap by importing auto diesel from Singapore.

LTGEP takes into account the actual fuel supply situation in Sri Lanka for the calculation of fuel prices. Consequently, those prices are deemed to be appropriate.

The Study team uses the average fuel prices (CIF price at Colombo) from May of 2004 to April of 2005 calculated in the same manner as CEB LTGEP.

Table 6.2.12 shows the fuel prices used in the Study

Table 6.2.12 Fuel Prices (MP Study)

Item	Unit	Auto Diesel Oil	Furnace Oil	Residual Oil	Naphtha	Naphta and Auto Diesel Oil (1:1)
Fuel Price	USD/BLL	53.46	33.85	27.39	40.95	47.21
	USD/kg	0.40	0.23	0.18	0.38	0.39
	USD/litter	0.34	0.21	0.17	0.26	0.30
	cent/GCal	3,794	2,199	1,780	3,364	3,582
Heat Content	kCal/kg	10,550	10,300	10,300	11,260	10,905
Specific Gravity	kg/litter	0.84	0.94	0.94	0.68	0.76

Source: JICA Study Team (Data from CPC)

(10) Operation and Maintenance Cost

The figures for operating and maintenance costs for existing thermal power facilities owned by the CEB that are to be used for the LTGEP are calculated from actual past expenditures for operations and maintenance. The CEB revises these figures every year when the LTGEP is formulated, and the way it manages data in the course of formulating this plan can be considered appropriate.

Regarding the IPP plants, actual expenses in April 2005 was used for the operation and maintenance costs of IPP plants in the Study.

Table 6.2.13 shows operation and maintenance costs for existing power plants used in the Study.

Table 6.2.13 Operation and Maintenance Costs of Existing Thermal Power Plants (MP Study)

Owner	Power Plant	Plant Type	O&M Cost	
			Fixed (USD/kW-month)	Variable (USD/MWh)
CEB	Sapugaskanda Diesel 1,2,3,4	Diesel	2.650	9.410
	Sapugaskanda Diesel (Extension) 1,2,3,4,5,6,7,8	Diesel	4.100	6.530
	Keranitissa GT (Old) 1,2,3,4,5,6	Gas Turbine	0.370	2.810
	Keranitissa GT (New) 1	Gas Turbine	0.340	2.330
	Kelanitissa CCGT	Combined Cycle	1.730	1.580
IPP	IPP Lakdhanavi Limited	Diesel	2.7990	12.2040
	IPP Asia Power Limited	Diesel	3.3060	9.5520
	IPP Colombo Power (Private) Limited	Diesel	5.6730	6.6870
	IPP ACE Power Horana	Diesel	4.1730	5.9330
	IPP ACE Power Matara	Diesel	3.9840	6.1670
	IPP Heladanavi (Private) Limited 1,2,3,4,5,6	Diesel	0.5150	8.4680
	IPP ACE Power Embilipitaya Limited 1,2,3,4,5,6,7,8,9,10	Diesel	1.0690	5.9460
	IPP AES Kelanitissa (Private) Lmited	Combined Cycle	1.3930	0.8510

Source: JICA Study Team (Data from CEB)

6.2.5 Data for Existing Hydropower Plants

(1) SYSIM Simulation

The available generation capacity and the annual available generation energy for existing hydropower facilities that are to be used for the LTGEP are set conducting the SYSIM simulation.

It was decided to use this data resulting from simulation for the present study. This section examines the current situation of the simulation and evaluates the data employed by it.

(i) Current Status of SYSIM Simulation

The System SIMulation package (SYSIM), developed during the Master Plan Study in 1989[56], and Energy and Power Evaluation Program (ENPEP), developed by International Atomic Energy Agency (IAEA), were extensively used in conducting the system expansion planning studies. The ELECTRIC module of ENEP (previously called WASP) is used to determine the optimal generation expansion plan.

The Sri Lanka power system is presently dominated by hydropower. Hence, it is necessary to assess the energy generating potential of the hydropower system to a high degree of accuracy. However, this assessment is difficult owing to the multi-purpose nature of some reservoirs, which have to satisfy the downstream irrigation requirements as well. Furthermore, the climate conditions of Sri Lanka are characterized by the monsoons, causing fluctuations to the inflows to the reservoirs as well as the irrigation demands over the year, exhibiting strong seasonal patterns.

SYSIM is used to simulate the operating performance of integrated water resources and hydropower / thermal power generating systems. It is also used to evaluate the potential contribution that candidate hydropower plants could be expected to make in meeting future demands for electricity. Rainfall data for the past 50 years in the catchment areas of the existing and candidate hydropower plants are taken into account to derive the energy and capacity availability associated with plants.

The potential evaluated using SYSIM is used as input information for the ELECTRIC module of the ENPEP package. Since ELECTRIC module can accommodate only a maximum of hydropower conditions, five representative hydrological conditions were selected with probability labels of 10%, 20%, 40%, 20%, and 10% depicting very wet, wet, average, dry and very dry hydropower conditions.

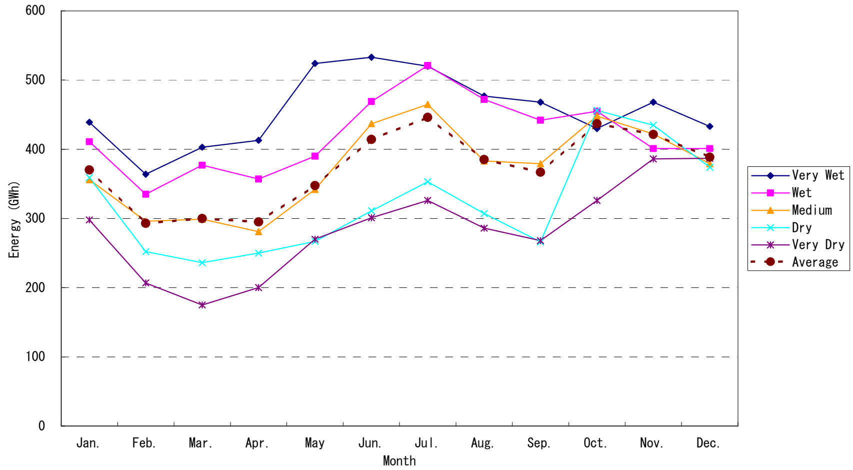
The summary of the simulation is given in Table 6.2.14, after representative hydrological conditions have been established. Figures 6.2.10 and 6.2.11 show the monthly variations of average hydropower energy and capacity.

Table 6.2.14 Monthly Hydropower and Energy Variations of Selected Hydropower Conditions

Month	Very Wet (probability:10%)		Wet (probability:20%)		Medium (probability:40%)		Dry (probability:20%)		Very Dry (probability:10%)		Average	
	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)
Jan.	439	1,003	411	953	356	865	359	881	298	804	370	894
Feb.	364	842	335	820	296	855	252	850	207	760	293	836
Mar.	403	851	377	850	299	882	236	830	175	720	300	846
Apr.	413	1,058	357	870	281	886	250	840	200	750	295	877
May	524	1,082	390	1,046	342	920	267	918	270	818	348	951
Jun.	533	1,075	469	1,065	437	1,015	311	905	301	826	414	990
Jul.	520	1,082	521	1,074	465	1,041	353	933	326	864	446	1,012
Aug.	477	1,057	472	1,050	383	971	307	881	286	827	385	963
Sep.	468	1,032	442	1,026	379	973	266	788	268	721	367	928
Oct.	430	1,040	455	1,016	448	1,031	456	1,012	326	898	437	1,012
Nov.	468	1,012	401	1,014	422	1,017	435	1,026	386	960	421	1,012
Dec.	433	992	401	996	379	982	374	979	387	969	389	984
Total	5,472		5,030		4,489		3,867		3,429		4,465	

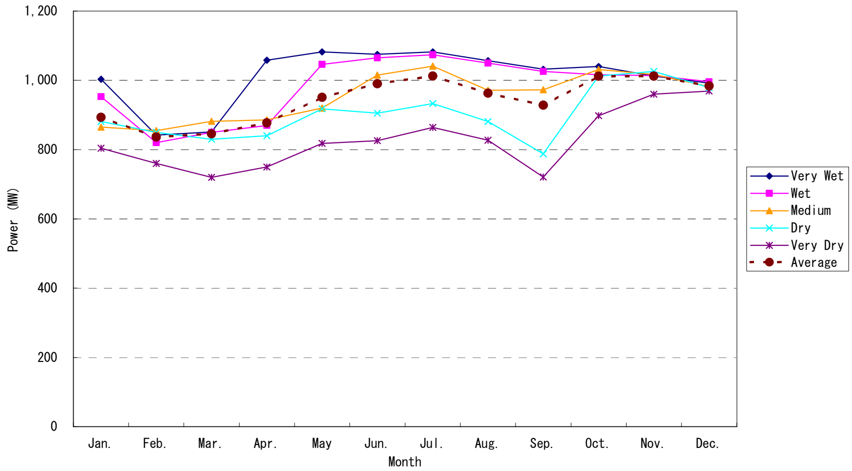
Source: CEB LTGEP 2005-2019

[56] Master Plan for the Electricity Supply of Sri Lanka, June 1989, CEB, GTZ, LIDE, CECB



Source: JICA Study Team (Data from CEB LTGEP 2005-2019)

Figure 6.2.10 Monthly Hydropower Energy Variation



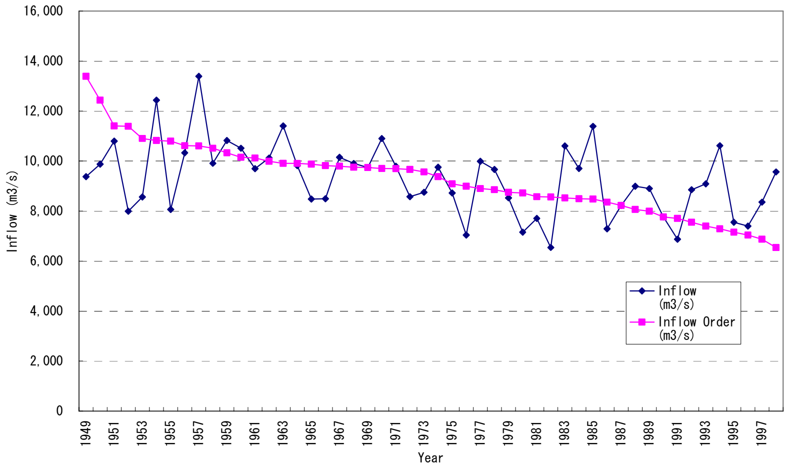
Source: JICA Study Team (Data from CEB LTGEP 2005-2019)

Figure 6.2.11 Monthly Hydropower Capacity Variation

(2) Collected Data Review

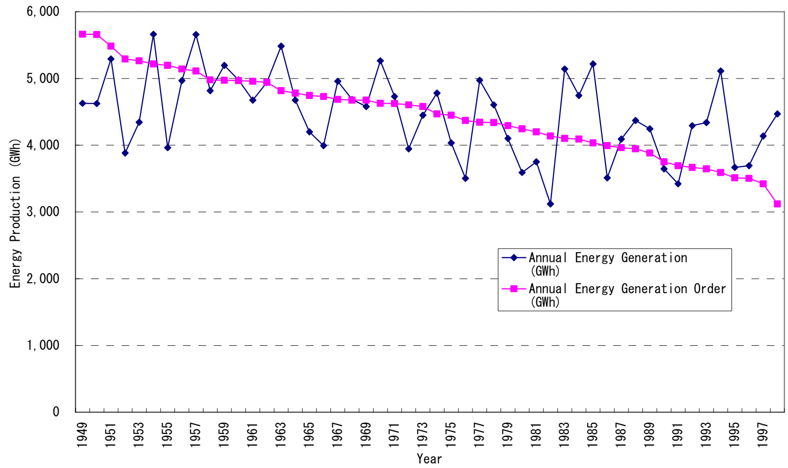
SYSIM simulates hydropower generation and capacity for the past 50 years. It is obviously a statistical and analytical method, even though there is the fact that SYSIM also contains some assumptions. This is the reason why SYSIM simulates hydro generation as if all the existing the hydropower plants and irrigation system have been there for 50 years. Therefore SYSIM can not simulate the historical transitions.

Taking such characteristics into consideration, a review was carried out in 2002. As a result, it was determined that the input data period it should be reviewed to create a more accurate simulation. The conditions of inflow, simulated energy and capacity are shown in Figures 6.2.12, 6.2.13 and 6.2.14.



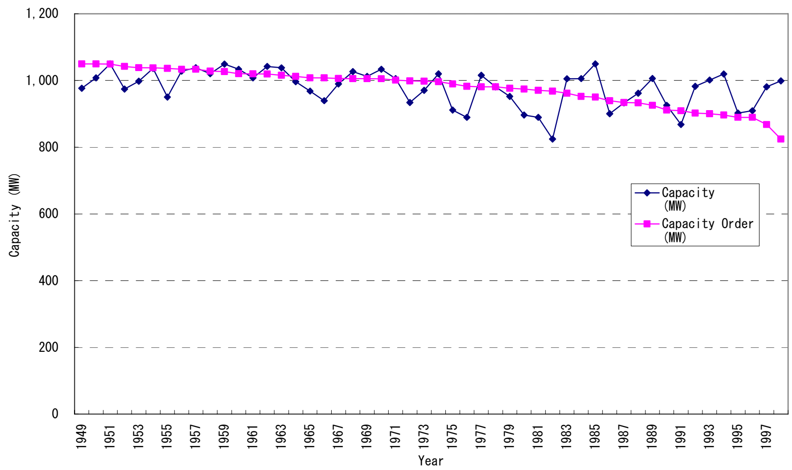
Source: JICA Study Team (Data from CEB LTGEP 2005-2019)

Figure 6.2.12 Annual Inflow Data Variation and Order



Source: JICA Study Team (Data from CEB LTGEP 2005-2019)

Figure 6.2.13 Annual Energy Output Variation and Order

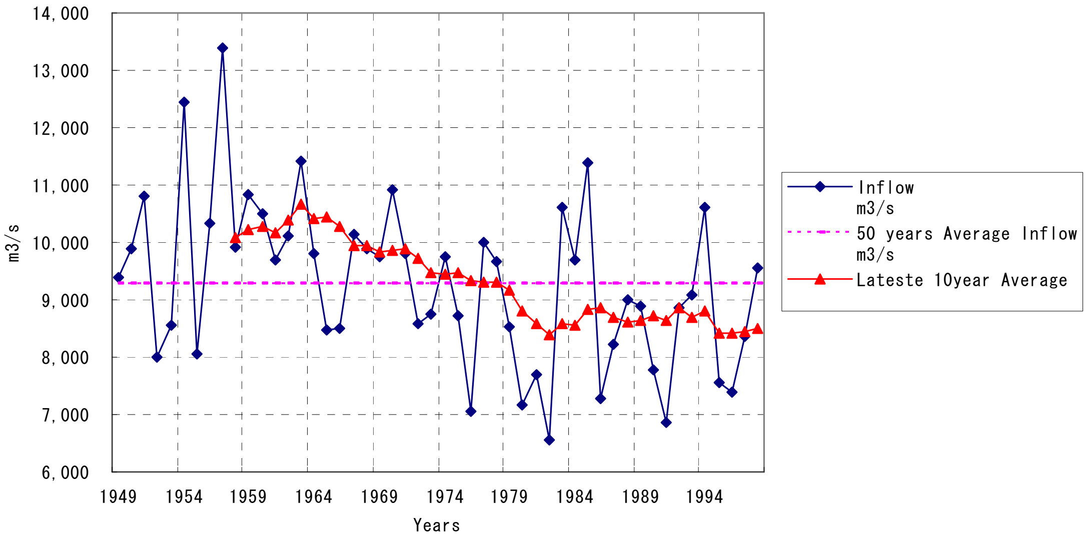


Source: JICA Study Team (Data from CEB LTGEP 2005-2019)

Figure 6.2.14 Annual Capacity Output Variation and Order

It is clear that the range of fluctuation of the amount of hydro generation is from 3000GWh to 6000Gwh.On the other hand, the range of fluctuation of the power does not change so much. This result shows that hydropower generation is used as supply power corresponding to a peak demand.

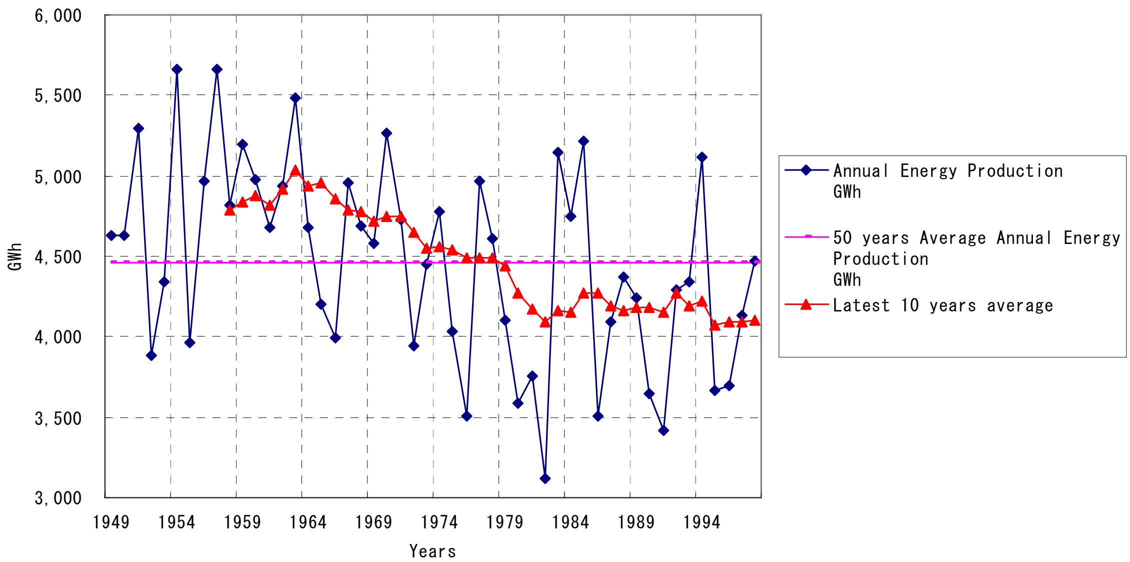
The record of the annual inflow shows in Fig. 6.2.15. The red point of this figure shows the moving average for ten years. The moving average of the annual inflow changes its value at the beginning of 1980s. It means that the condition of inflow is different from before 1970s and henceforth. Therefore, it is recommended that the amount of hydropower generation for the past 30 years should be applied to the SYSIM simulation.



Source: JICA Study Team (Data from CEB LTGEP 2005-2019)

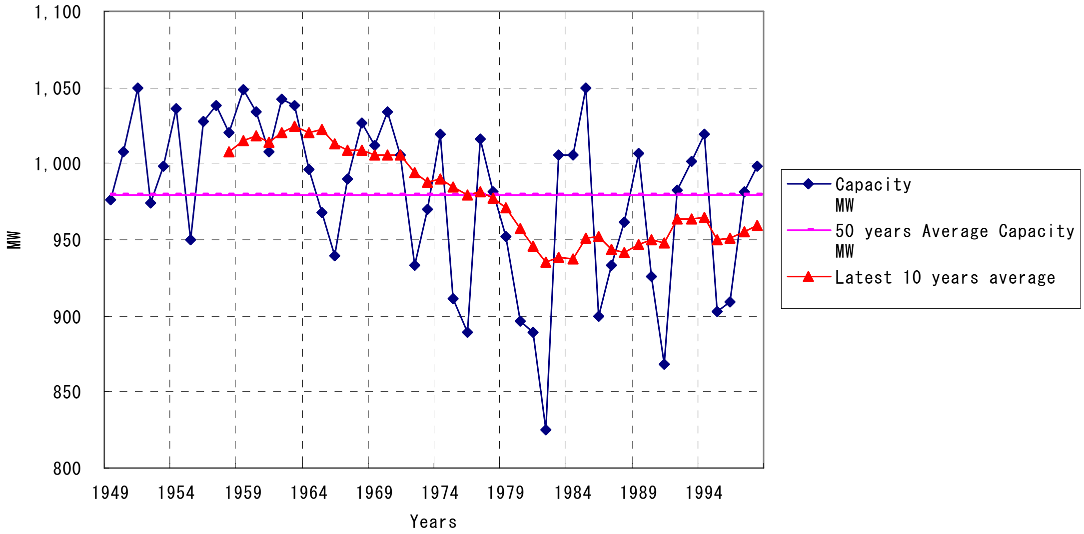
Figure 6.2.15 Annual Inflow Data Variation and Moving Average for 10 Years

The SYSIM output and the moving average during each 10 years related with the annual energy and the capacity are shown in figures 6.2.16 and 6.2.17, respectively.



Source: JICA Study Team (Data from CEB LTGEP 2005-2019)

Figure 6.2.16 Annual Energy Output Variation and Moving Average for 10 Years



Source: JICA Study Team (Data from CEB LTGEP 2005-2019)

Figure 6.2.17 Annual Capacity Output Variation and Moving Average for 10 Years

(2) Available Generation Capacity and Available Generation Energy

As shown in section 6.2.5 (1) in detail, the available generation capacity and available generation energy that is used in the CEB WASP simulation is estimated for each month and each hydropower condition by conducting a system simulation using SYSIM. The Study team does not change the output of available generation capacity and energy from the SYSIM simulation.

Table 6.2.15 shows the available generation capacity and available generation energy of existing hydropower plants used for the Study.

Table 6.2.15 Available Generation Capacity and Energy of Existing Hydropower Plants (MP Study)

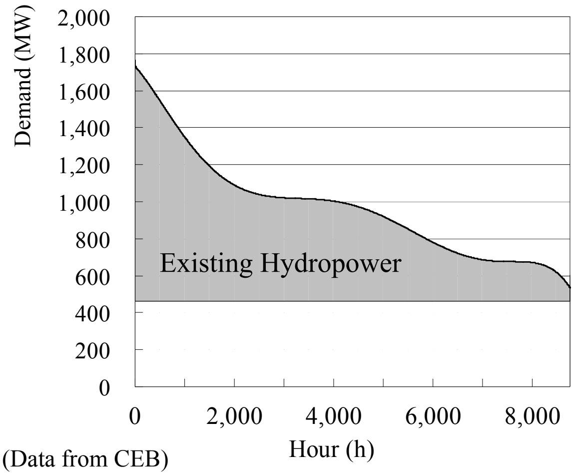
Month	Hydro Condition										Averaged	
	Very Wet (Probability : 10%)		Wet (Probability : 20%)		Midium (Probability : 40%)		Dry (Probability : 20%)		Very Dry (Probability : 10%)			
	Aveilable Energy (GWh)	Available Capacity (MW)	Aveilable Energy (GWh)	Available Capacity (MW)	Aveilable Energy (GWh)	Available Capacity (MW)	Aveilable Energy (GWh)	Available Capacity (MW)	Aveilable Energy (GWh)	Available Capacity (MW)	Aveilable Energy (GWh)	Available Capacity (MW)
Jan	439	1,003	411	953	356	865	359	881	298	804	370	894
Feb	364	842	335	820	296	855	252	850	207	760	293	836
Mar	403	851	377	850	299	882	252	830	175	720	300	846
Apr	413	1,058	357	870	281	886	250	840	200	750	295	877
May	524	1,082	390	1,046	342	920	267	918	270	818	348	951
Jun	533	1,075	469	1,065	437	1,015	311	908	301	826	414	990
Jul	520	1,082	521	1,074	465	1,041	353	933	326	864	446	1,012
Aug	477	1,057	472	1,050	383	971	307	881	286	827	385	963
Sep	468	1,032	442	1,026	379	973	266	788	268	721	367	928
Oct	430	1,040	455	1,016	448	1,031	456	1,012	326	898	437	1,012
Nov	468	1,012	401	1,014	422	1,017	435	1,026	386	960	421	1,012
Dec	433	992	401	996	379	982	374	979	387	969	389	984
Total	5,472		5,031		4,487		3,882		3,430		4,465	

Source: CEB LTGEP (2005 - 2019)

(3) Simulating Operation Pattern

In the CEB simulation of WASP, input data regarding the minimum inflow energy that corresponds to the inflow energy for base capacity is set as zero.

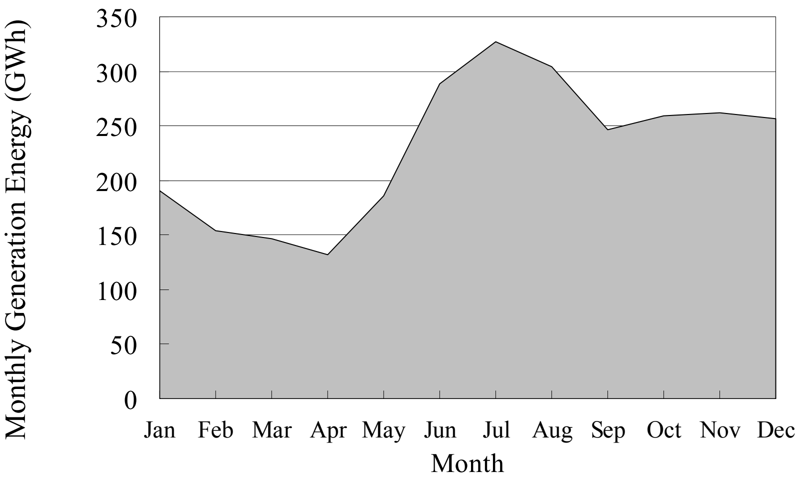
Based on this condition, WASP simulates as if all generation energy from existing hydropower is dispatched as peak energy (shown in Figure 6.2.18).



Source: JICA Study Team (Data from CEB)

Figure 6.2.18 Energy Allocation of Existing Hydropower in WASP Simulation (LTGEP 2005-2019)

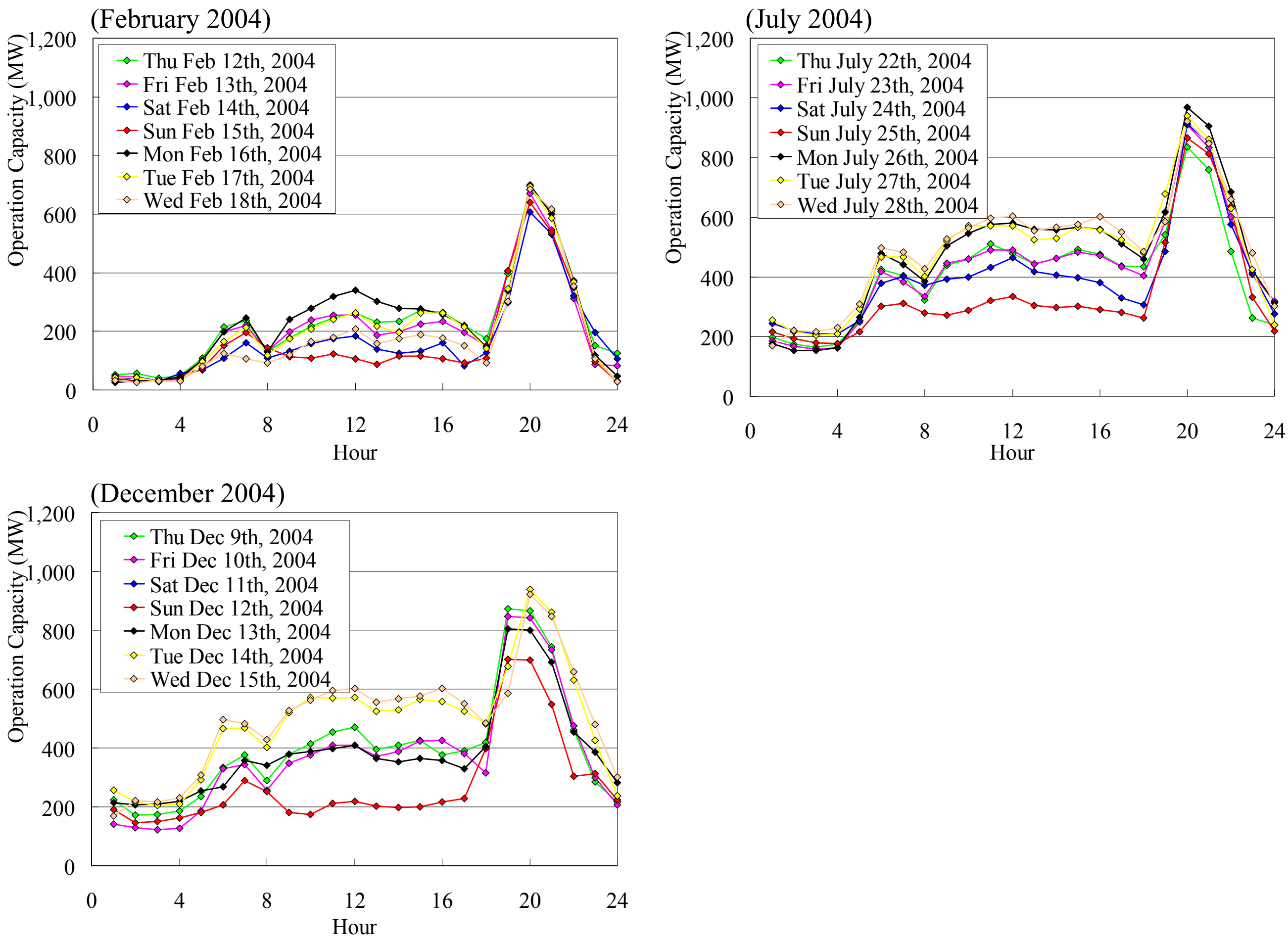
Figure 6.2.19 shows the historical monthly generation energy for existing hydropower plants in 2004.



Source: JICA Study Team (Data from CEB)

Figure 6.2.19 Monthly Generation Energy from Existing Hydropower in 2004

Figure 6.2.20 shows the typical daily operation pattern for existing hydropower in February, July and December in 2004.



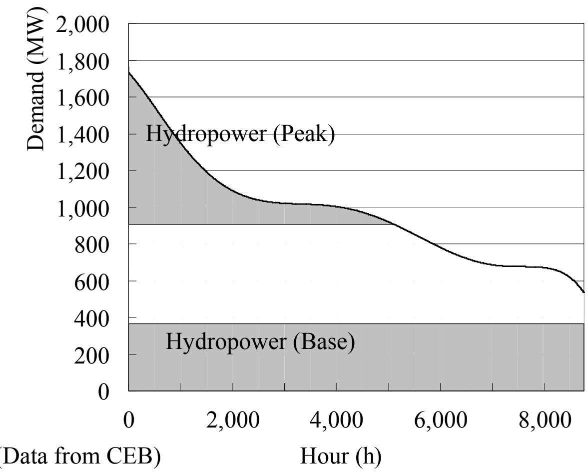
Source: JICA Study Team (Data from CEB)

Figure 6.2.20 Monthly Generation Energy for Existing Hydropower in 2004

Figure 6.2.20 shows that hydropower has base capacity of around 200MW in July and December 2004, though the capacity is less in February. Also the figure shows that there are mainly two portions, base and middle-peak, for hydropower operations.

To simulate the operation pattern in this manner, the Study team changed the input data regarding existing hydropower for the WASP simulation. The available capacity and energy in each period and hydropower conditions were not changed to create consistency with output from SYSIM, and the input data regarding minimum inflow energy was changed in the Study.

Figure 6.2.21 shows the dispatch of generation energies from existing hydropower plants in the Study.



Source: JICA Study Team (Data from CEB)

Figure 6.2.21 Energy Allocation for Existing Hydropower Plants in WASP Simulation

6.2.6 Fixed Development Project

CEB has a committed project for 150MW Upper Kotmale hydropower, which is expected to be in commission at the end of 2010. Regarding the 300-MW IPP combined cycle plant at Kerawalapitiya, CEB had originally planned to proceed with it as a 300-MW facility project using ODA from the Japanese government. Subsequently, however, it was changed to an IPP project, and an IPP bidding was conducted on a BOOT basis. Six companies prequalified in June 2002, and contract negotiations were carried out with two companies from the beginning of 2005, but negotiations stalled over the contract conditions and then broke off.

In September 2005, the CEB approached the External Resources Department to request funding as a project for generation facilities owned by CEB rather than for IPPs.

A feasibility study conducted by JICA in 1999 indicated that from the start of construction to placing an open cycle gas turbine power plant it would require approximately 22 months. The time needed to place a combined cycle plant would be 31 months. Beginning in 2008 for the commencement of combined cycle plant as stated in the LTGEP 2005-2019 must be considered impossible at this point.

In general, the net time required for construction of 300 MW class combined cycle generation facilities is about two to four years. The time required for implementation of an environmental impact assessment (EIA) and for auditing the EIA is about one to one and a half years. The time required can sometimes be shortened somewhat by abbreviating processes such as selecting consultants and concluding contracts, or by conducting such processes in parallel.

Consequently, the earliest that a Kerawalapitiya combined cycle generation project could enter operation would probably be mid-2009.

In order for the combined cycle generating facility to commence commercial operation in mid-2009, however, funding to implement the project would have to be secured by the beginning of 2006. Even if this were achieved, it would also be necessary to overcome numerous other issues, such as prompt and appropriate preparation for the EIA, EIA implementation, shortening of the contract procedures, and very demanding schedule control.

Table 6.2.16 shows an example of the shortest implementation schedule for the Kerawalapitiya combined cycle project.

Table 6.2.16. Earliest Implementation Schedule for Kerawalapitiya Combined Cycle Project (Example)

Content of Work	Year			
	2006	2007	2008	2009
	Finance Agreement ▽	Submit EIA Report ▽	GT in commission ▽	CC in commission ▽
Selection of Consultant				
Tendering				
Contract				
Construction				
EIA				

Source: JICA Study Team

Consequently, in the Study the 300 MW Kerawalapitiya combined cycle power plant project is considered as a fixed development project and the contribution to the supply capacity is 200MW from the gas turbine open cycle power plant in 2008 and 300MW from the combined cycle power plant in and after 2009.

6.2.7 Retired and Contract-Expired Units

CEB has a plan for retiring CEB-owned generation units. In consideration of the declining efficiency due to aging, the generation development plan in the Study follows the retirement plan.

IPP power plants have long-term contracts with CEB and the contract periods vary from 10 years to 20 years.

Considering the expiry of the contracts, the capacity of expired IPP plants should be excluded from the total supply capacity in the system.

Table 6.2.17 shows the retired units and units with expired contracts in the Study.

Table 6.2.17 Retired and Contract-Expired Units in the Study

Owner	Power Plant	Unit Capacity (MW)	Retired or Contract Expired Year	Period																
				2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CEB	Sapugaskanda Diesel 1,2,3,4	20.000	2013																	
	Sapugaskanda Diesel (Extension) 1-8	10.000	2023																	
	Keranitissa GT (Old) 1,2,3,4,5,6	20.000	2010																	
	Keranitissa GT (New) 1	115.000	2018																	
	Kelanitissa CCGT	165.000																		
IPP	IPP Lakdhanavi Limited	5.630	2013																	
	IPP Asia Power Limited	6.375	2018																	
	IPP Colombo Power (Private) Limited	15.681	2015																	
	IPP ACE Power Horana	6.200	2013																	
	IPP ACE Power Matara	6.200	2012																	
	IPP Heladanavi (Private) Limited 1-6	17.00	2015																	
	IPP ACE Power Embilipitaya Limited 1-1(	10.00	2015																	
	IPP AES Kelanitissa (Private) Lmited	163.00	2024																	

Source: JICA Study Team (Data from CEB)

6.2.8 Candidate Power Plants for Development

(1) Fuel Options

Of the fuel currently being supplied to the CEB by the Ceylon Petroleum Corporation (CPC), the supply of naphtha is already subject to limitations because of the capacity of the CPC refinery. It has been decided, therefore, that naphtha will not be considered as a fuel option for future generation development candidates. Supplies of the residual oil being supplied to the existing diesel power Sapugasukanda Power Station owned by the CEB and diesel power plant of the IPP Asia Power are also limited. It has therefore been decided that this will likewise not be considered as a fuel option for future generation development candidates.

The furnace oil and auto diesel oil that are currently being used are imported as products. It is supposed that their supplies will basically remain unlimited in the future.

The introduction of LNG should be considered in the Study. However, a feasibility study on the gas supply to Sri Lanka was conducted through a USAID fund in 2003 and at that time the report concluded that the gas supply to Sri Lanka is not feasible mainly due to the small-anticipated consumption in the country in the future

Small hydropower and wind power plants, among have been indicated as renewable energy sources with the potential to be connected to the grid. However, there are doubts concerning the economic efficiency of such power plants as development projects, and even greater doubts concerning their potential capacity and the stability of their generation. They were therefore judged unsuitable to be considered as reliable supply sources of power in long-term generation development plans, and have not been included as candidates for generation development planning.

(2) Candidate Sites for Development

The LTGEP 2005-2019 refers to four candidate locations for new hydropower development candidates and five locations for expansion projects for existing hydropower plant. It also refers to a coal-fired thermal power project with candidate locations for new development of thermal power facilities in Trincomalee, Mawella and Kalpitiya (in the Puttalam area on the west coast). There are no references to plans for expansion of existing thermal power facilities.

This section will review the past results from surveys of these candidate sites for future development. It will also review the existing survey of the Kelanitissa Gas Turbine Power Station (Kelanitissa GT7) for conversion into a combined cycle facility as part of the plan for expansion of existing thermal power facilities.

(i) Candidate sites for hydropower development (New Development)

a) Gin Ganga project

The Gin Ganga project was studied as the third economical site among the 27 preferable project sites in the 1989 Master Plan. This project was identified as GING074 in the Master Plan. The characteristics of the Gin Ganga project, being faithful to the 1989 Master Plan, are shown in Table 6.2.18. The project layout is shown in Figure 6.1.1.

Table 6.2.18 Gin Ganga Project Outline

Items	**Discription**
Project Code	GING 074 (Masterplan)
Province/ District	Southern/ Galle
Catchment	Ging
Catchment Area/ Reservoir Surface Area	154km2/ 1.7km2
Reservoir Full Supply Level/ Storage	263masl/ 23.2MCM
Average Tailwater Elevation	77.4masl
Catchment Rainfall/ Mean Stream Flow	3700mm/yr/ 16.4m3/s
Diversion/ Design Flood	730/ 1600m3/s
Dam Type	Concrete Gravity
Dam Height/ Crest Length/ Volume	**50m/ 231m/ 93000m3**
Spillway Type	Gated, incorporated in dam
Spillway Crest Level/ Hydraulic Width	253masl/ 25.5m
Max. Flood Level/ Spillway Discharge	263masl/ 1600m3/s
Length/ Diameter Headrace Tunnel	7440m/ 4.2m
Height/ Diameter Surge Tank	63.5m/ 13.6m
Length/ Diameter Penstock	360m/ 3.1m
Type of Powerhouse	Open-air
Rated Head	171.5m
Turbines, Rating at 50% Plant Factor	2 Francis, 24.8MW
Plant Capacity (ex-transformer) Source: 1989 Master Plan	**48.9MW**
Average/ Guaranteed Continuous Power	48.3MW/ 23.8MW
Average Annual Generation	209.4GWh
HV Feeder Line	132kV, 23km
New Access Road	11km
Resettlement	**1560persons**
Forest/ Agricultural Land Inundated	**114ha/ 56ha**

Source: Master Plan Study in 1989

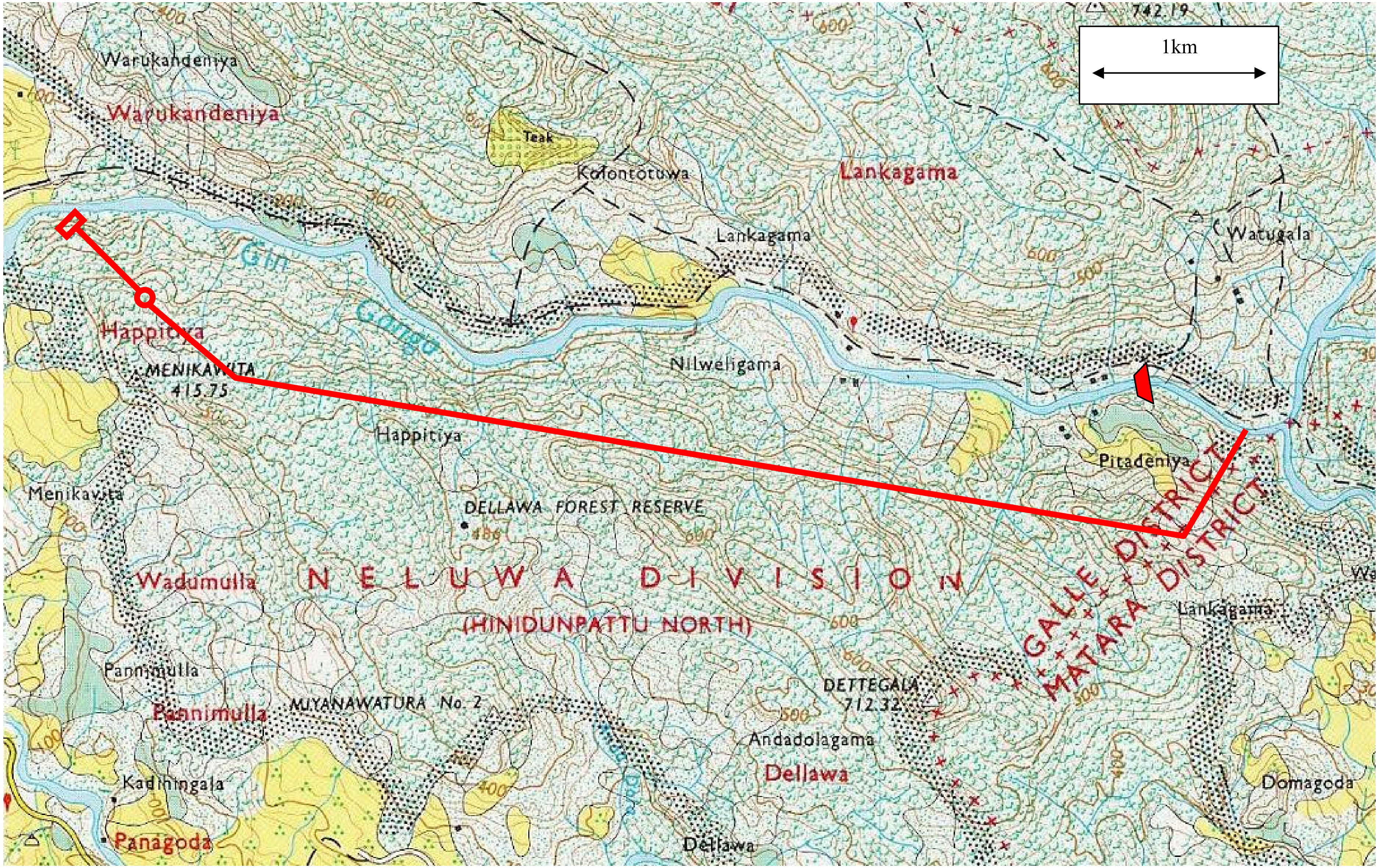


Figure 6.2.22 Gin Ganga Hydropower Project Plan

6-26

The dam site is to be located on the upper Gin Ganga near Deniyaya town, about 1 km down stream of the confluence with a right bank tributary named Aranuwa Dola. The powerhouse is to be located some 9 river-kilometers downstream, at the end of a high gradient river stretch.

The Gin Ganga project was estimated to have 49MW installed capacity, 209.4GWh average annual generation and 60.9 million US$ construction cost in the 1989 Master Plan. Soon after this Master Plan was completed, the project was revised in 1992. As a result the estimates were changed to 47.3 MW installed capacity, 202.4GWh average annual generation and 97.082 million US$ in construction costs (March 1992).

It was reported that a forest conservation area exists at the right-bank side of the dam site from the time of Master Plan investigation. When the site survey was carried out with a counter part, it was confirmed that a part of the site is a reserve area specified to be a World Heritage (Shinharaja Forest Reserve) site. Some stakes believed to be marking the border of the reserve area on the right-bank side road were found. Since the dam reservoir of a right-bank side tributary is located in the reserve area, a review of the reservoir scale should be carried out. Moreover, though the scale of the reservoir is reduced, the site is still bordering a reserve area. Then JICA Study Team recommends that a project review should be carried out.

Moreover, in the 1988 Master Plan, the number of people to be resettled was estimated as 1,560 or more persons. During the site survey, schools and the dwellings were investigated near the dam site. It was concluded that a review of the project is needed, after taking the present social environmental situation into consideration.

Table 6.2.19 Estimated Numbers of Persons to be Resettled

Village	No. of People in Reservoir Area
Watugala	180
Mederipitiya	745
Dambagoda	210
Poddana	255
Lankagama	170
Total	1,560

Source: Master Plan Study in 1989

b) Moragolla project

The MAHW 263 project is to be located on the Mahaweli Ganga, near Moragolla town, downstream of the confluence of Kotmale Oya, but upstream of the tailrace outlet of the existing Kotmale hydropower plant. The project was earlier (in 1962) identified by the Hunting Survey Corporation of Canada. It was then known as “Moragolla”.

The Moragolla project is a run-of-river project. Downstream of the Moragolla project the Mahaweli water is partly diverted through the Polgolla diversion to serve the Mahaweli Irrigation Systems D and H, while the remainder of the flow passes through the existing Victoria and Randenigala reservoirs.

The characteristics of the Moragolla project, being faithful to the 1989 Master Plan, are shown in Table 6.2.20. The project layout is described in Figure 6.2.23.

Table 6.2.20 Moragolla Hydropower Project Outline

Items	Discription
Project Code	MAHW 263(Masterplan)
Province/ District	Central/ Kandy
Catchment	Mahaweli
Catchment Area/ Reservoir Surface Area	832km2/ 0.7km2
Reservoir Full Supply Level/ Storage	550masl/ 5MCM (run-of-river)
Average Tailwater Elevation	77.4masl
Catchment Rainfall/ Mean Stream Flow	3100mm/yr/ 26.1m3/s
Diversion/ Design Flood	2,700m3/s / 6,200m3/s
Dam Type	Concrete Gravity Dam
Dam Height/ Crest Length/ Volume	**40.0m/ 173m/ 52,300m3**
Spillway Type	Gated, incorporated in dam
Spillway Crest Level/ Hydraulic Width	534.5masl/ 47.4m
Max. Flood Level/ Spillway Discharge	550masl/ 6200m3/s
Length/ Diameter Headrace Tunnel	2550m/ 5.0m
Height/ Diameter Surge Tank	30m/ 16m
Length/ Diameter Penstock	128m/ 4.0m
Type of Powerhouse	Open-air
Rated Head	61.7m
Turbines, Rating at 50% Plant Factor	2 Francis, 14.2MW each
Plant Capacity (ex-trsnsformer)	**27.3MW**
Average/ Guaranteed Continuous Power	12.6MW/ 3.4MW
Average Annual Generation	110.7GWh
HV Feeder Line	132kV, 2.8km
New Access Road	1.3km
Resettlement	**None**
Forest/ Agricultural Land Inundated	**70ha**

The dam site is to be located on between the Kotmale reservoir and Kotmale powerhouse. This is because the Moragolla project is not available for the discharge of the upper Kotmale reservoir.

The Moragolla project was estimated to have 27.3MW installed capacity, 110.7GWh average annual generation and carry construction costs of 47.45 million US$ in the 1989 Master Plan. After the Master Plan this project was revised in 1992 along with the Gin Ganga project. This resulted in the project being estimated to have 26.5 MW in installed capacity, 108.7GWh average annual generation and construction costs of 73.208 million US$ (in March 1992).

It was reported that the small reservoir area is uninhabited and resettlement would therefore not needed. When the site survey was carried out with a counter part, it was confirmed that no households would need to be resettled.

Only the existing road on the right bank may be located in or near the reservoir area. Therefore, the slope stability analysis focusing on accumulated water in the reservoir should be conducted in future studies.

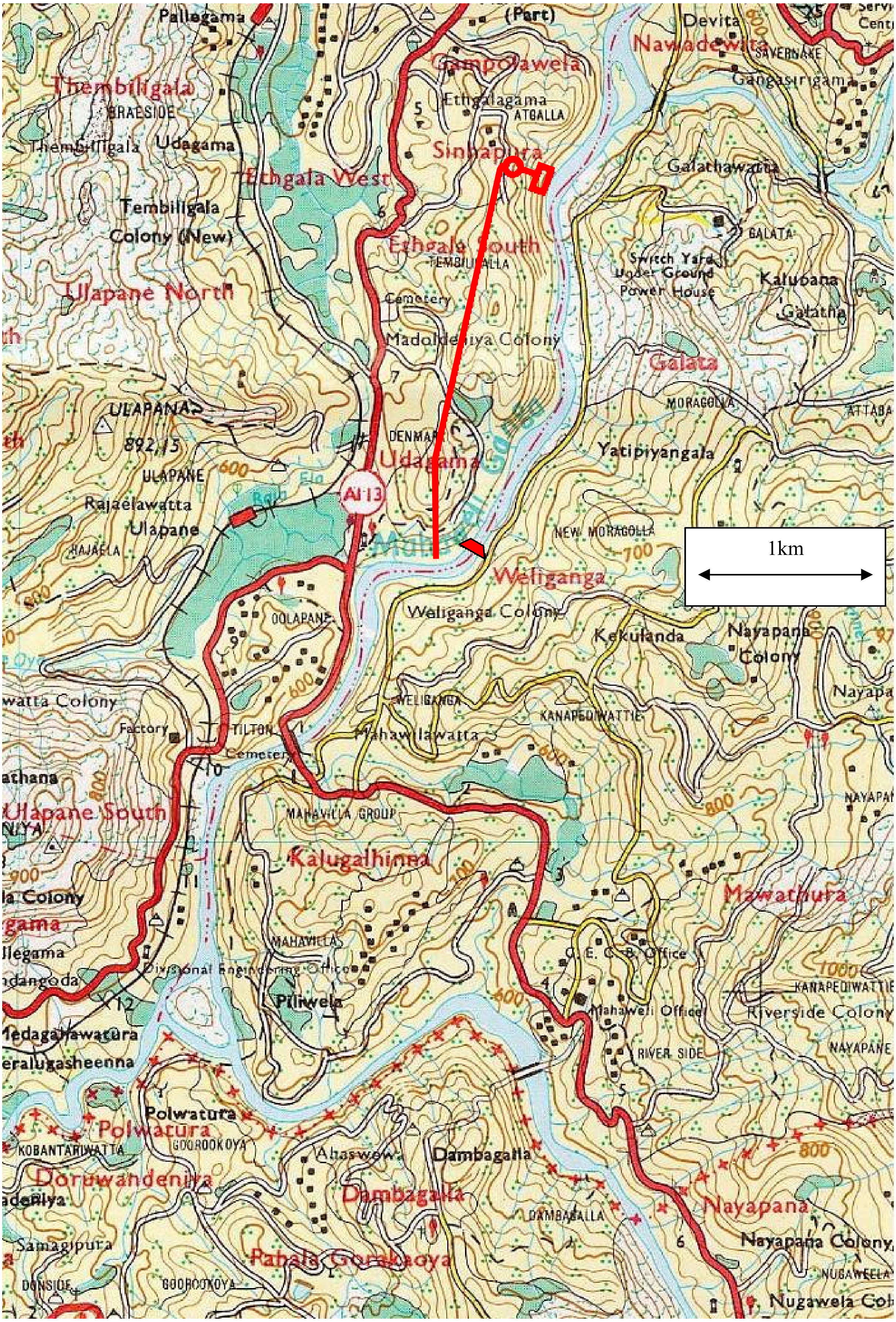


Figure 6.2.23 Moragolla Hydropower Project Plan

c) Broadlands project

According to the study entitled “Hydropower Optimization Study in Sri Lanka”, this project is to be located on Kelani Ganga, below the existing Polpitiya Power station. This development consists of a diversion weir across the Maskeliya Oya, down stream of the Polpitiya tailrace with water conveyed through a 3.4 km long tunnel on the left bank of Kelani Ganga terminating in a 35MW Power Station. The Kehelgamu Oya is to be diverted to a pond formed by the weir across the Maskeliya Oya through a separate diversion, which consist of a weir across the Kehelgamu Oya, an intake structure and a tunnel.

Table 6.2.21 Broadlands Hydropower Project Outline

Items	Discription
General	
Catchment Area	Main Dam: 201km2 Kehelgamu Weir: 176km2
Tail Water Level	EL 56.2m
Reservoir	
Full Supply Level	EL 121.0m
Minimum Draw Down Level	EL 111.0m
Effective Storege Volume	198,000m3
Main Dam	
Dam Type	Concrete Gravity
Dam Crest Elevation/ Length	EL 124.0m/114.0m
Dam Height	**24.0m**
Spillway Gate	3 Nos. Tainter gate
Width/ Height	7.2m/ 15.0m
Kehelgamu Weir	
Dam Type	Concrete Gravity
Dam Crest Length	48.0m
Dam Height	**19.0m**
Dam Volume	10,000m3
Headrace	
Total Length	3,404.7m
Intake Tunnel	Concrete lined pressure tunnel
Length/ Cross Section	150.0m/ Standard horse-shoe shape (D=5.4m)
Cut-and-Cover Conduit	Steel lined pressure conduit
Length/ Cross Section	719.6m/ Circular section (D=5.0m)
Main Tunnel	Steel lined & Concrete lined pressure tunnel
Length	3.4km
Cross Section	(1) Circular section (D=5.0m) (2) Standard horse-shoe shape (D=5.4m)
Penstock	
Length	243.0m, 248.4m
Diameter	4.6m (before bifurcation) 3.3m (after bifurcation)
Tailrace	
Type of Tunnel	Trapezoid open channel
Length	352.5m
Kehelgamu Diversion Tunnel	
Type of Tunnel	Concrete lined non-pressure tunnel
Length	811.0m
Powerhouse	
Type of Powerhouse	Semi-underground type
Turbine	2 Francis units
Rated Effective Head	56.9m
Rated Discharge (per unit)	**35.0m3/sec**
Generator	2 units of 3-phase synchronous
Transmission Line	
	132kV overhead transmission line connected to Polpitiya-Kolonnawa line No.3 (π-
Resettlement	16 houses (17 families or business buildings)

The Broadland project was identified as having 40MW installed capacity, 170GWh average annual generation and 5.6 UScent/kWh generation cost (based on 1988 prices) in the 1989 Master Plan. After this identification, the project was revised by JICA’s Support Study in February 2002. As a result the project was identified as having 35 MW installed capacity, 126GWh average annual generation and cost 87.225 million US$. (in February 2004).

Figure 6.2.24 Broadlands Hydropower Project Plan

d) Uma Oya Project

This project is to be located on Uma Oya, one of the major tributaries of Mahaweli Ganga, and joins Mahaweli Ganga on its right bank at the Rantanbe reservoir just upstream of Minipe.

This is a multi-purpose project and the pre-feasibility studies were carried out by CECB in July 1991 (revised in 1992).

According to the revised study carried out in 1992, the water from Uma Oya is to be diverted via Mahatotila Oya through a trans-basin tunnel to the upper Kitindi Oya basin. This development consists of a dam across Uma Oya, an 18 km long low-pressure trans-mountain tunnel to the Randeniya power station (capacity 150MW), a pickup dam across Mhahatotila Oya about 5.3 km upstream of its confluence with Uma Oya, a drop shaft to feed water from the Mahatotila Oya reservoir to a low-pressure tunnel and a weir and a drop shaft to feed water from Krindi Oya to a low-pressure tunnel.

The Uma Oya project was identified as having 150MW installed capacity, 431GWh average annual generation and construction costs of 181.3 million US$ (based on January 1991 prices) in the 1992 revised pre-feasibility study.

The dam site is located on the Uma Oya, about 500m upstream of the confluence with its tributary Mahatotila, within a river stretch with a very high gradient. The Puhulpola Dam was identified as having a 92m height and 390m crest length forming a concrete arch dam across Uma Oya to create a reservoir of 17MCM gross storage with 965 masl. Another dam site is located on the Mahatitila Oya, 4.6km upstream of the confluence with Uma Oya. The Mahatotilya Dam was identified as having a 20m height, 100m crest length forming a roller compacted concrete (RCC) dam across Mahatotiya Oya.

The review of the pre-feasibility study by the JICA Study Team is summarized as follows:

The topological situation of the Puhulpola Dam site is not sufficiently adequate for the building of a concrete arch dam. Although, generally it is preferable for the ratio of the dam height to crest length to be from 1 to less than 3, the ratio of dam height to crest length for the identified project was 1 to more than 4. In addition, it has been proposed that the dam being constructed in Mahatotiya Oya should be built by the Roller Compacted Concrete (RCC) method. Therefore, mutually compatible construction methods should be studied in any further studies.

Table 6.2.22 Uma Oya Hydropower Project Outline

Items	Description
Catchment	Mahaweli
Catchment Area/	Uma: 204km2 Mahathotila: 157km2
Reservoir at Puhulpola	
Reservoir Full Supply Level/ Storage	965masl/ 17MCM
Min. Reservoir Operating Level/ Storage	930masl/ 4MCM
Reservoir Area	52ha
Catchment Rainfall/ Mean Stream Flow	1,920mm/yr/ 6m3/s
Dam Type	Concrete Arch
Dam Height/ Crest Length/ Volume	92m/ 390m
Dam Top Elevation	970masl
Dam across Mahathotila Oya	
Reservoir Full Supply Level/ Storage	975masl/ 2.2MCM
Min. Reservoir Operating Level/ Storage	970masl/ 1.0MCM
Reservoir Area	9ha
Catchment Rainfall/ Mean Stream Flow	1,920mm/yr/ 2.3m3/s
Dam Type	Roller Compacted Concrete
Dam Height/ Crest Length/ Volume	20m/ 100m
Dam Top Elevation	980masl
Water Conductor System & Power Station Complex	
Length/ Diameter Low pressure Tunnel	19km/ 3.5 to surge shaft
Length/ Cross-section Tailrace Tunnel	4.3km/ 35m2 horse shoe
Out fall	Alikota Oya
Length/ Diameter Pressure Shaft	700m steel lined/ 2.5m x 2
Type of Power Station	Underground
Rated Head	708m
Turbines	2 vertical shaft Pelton
Rated Turbine discharge	12.5m3/s per unit
Plant Capacity (ex-transformer)	150MW
Ave. Annual Generation	431GWh
HV Feeder Line	25km/ 220kV 2 ccts to Badulla Switch yard
Resettlement	50 households

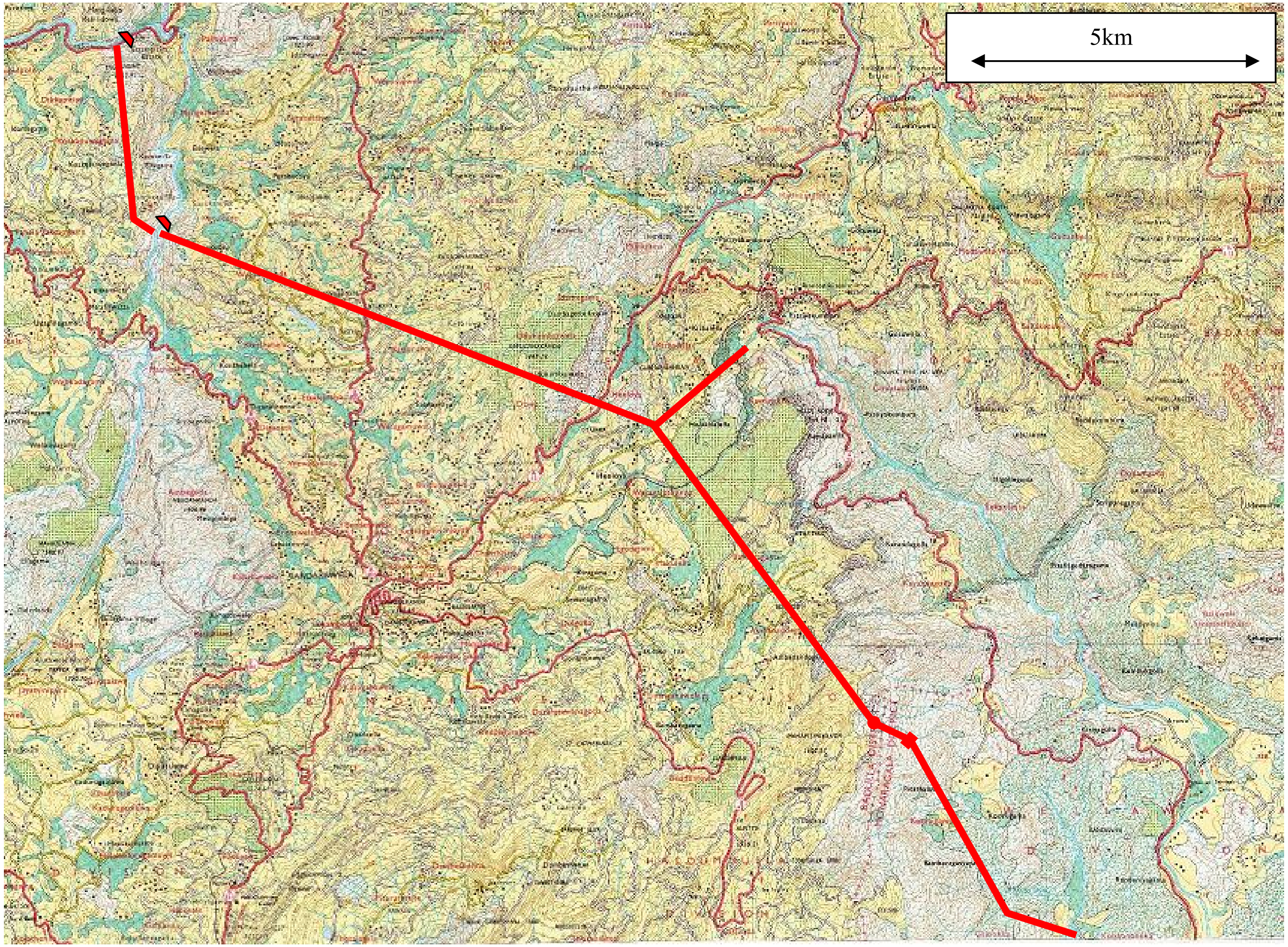


Figure 6.2.25 Uma Oya Hydropower Project Plan

(ii) Candidate sites for hydropower development (Expansion)

a) Laxapana Complex

According to the study entitled "Hydropower Optimization Study", it can be said that Old Laxapana, New Laxapana and Polpitiya power plants have the possibility of expansion due to their high plant factors. It was concluded that the concurrent expansion plan for the New Laxapana and Polpitiya power plants is the most attractive one. The outline of existing expansion plan for Laxapana Complex is shown in Table 6.2.23.

Table 6.2.23 Expansion Plan of Existing Hydropower in Laxapana Complex

Items	New Laxapana	Polpitiya
Maximum Discharge (m3/s)	15.6	23.2
Effective Head(m)	531	235
Maximum Capacity (MW)	72.5	47.9
Additional Annual Generation (GWh)	80	

It was concluded that the following aspects should be kept in mind during further investigation and study as part of an overall evaluation.

- Prior to the expansion of the power stations, defective civil structures in the existing New Laxapana and Polpitiya power plants must be improved.
- Since shutdowns of the existing power stations are not appropriate considering the tight electricity supply-and-demand balance, it is necessary to carefully weigh the timing of the expansion construction work. As a matter of course, any expansion project requiring additional capital investment to create substitute power generation facilities to cover for power plant shutdowns may lose economic viability.
- The effect of shutdowns on the economic viability of the expansion project is so large that careful construction scheduling is necessary.

b) Mahaweli Complex

The Ukuwela, Victoria and Rantambe hydropower plants were studied in the Mahaweli Complex. It was concluded that it will be difficult to expand the power stations for the Ukuwela and Rantambe hydropower plants for peaking operation due to some reasons. Therefore, only the Victoria hydropower plant has no restrictions on irrigation demand and has high expansion capacity in the Mahaweli Complex.

As a result, the outline of the existing expansion plan for the Victoria hydropower plant is shown in Table 6.2.24.

Table 6.2.24 Victoria Hydropower Plant Expansion Plan

Items	2 units expansion	3 units expansion
Maximum Discharge (m3/s)	90	135
Effective Head (m)	190	190
Expansion Capacity (MW)	140	210
Total Capacity (MW)	350	420
Annual Generation (GWh)	816	833
Loss of Generation (GWh)	31	14

It was concluded that the following merits should be taken up in more detailed study, mainly in terms of cost reductions for civil works and hydro-electrical works.

- Since existing power stations already have intake facilities including intake gates for expansion, the existing power stations only need to be shut down a small number of times during construction, and a draw down of the Victoria reservoir is not necessary during the construction.
- The access road, tunnel work and other temporary facilities, which were constructed for stage I (existing power station), were utilized for the expansion.

c) Walawe River Basin

Regarding the Samanalawewa hydropower plant, the addition of two 60MW units has been taken into consideration since the planning stage of the project to cope with the increase in peak demand. In the construction stage of the existing power plant, a bifurcation with head was installed in the penstock and a space for another two 60 MW units was prepared for future additions.

The existing switchyard has also had space for new feeders, but it is difficult to connect one space to the generator feeder. Therefore, GIS will be applied to the switchyard if two generators are added to the Samanalawewa hydropower plant.

According to the previous JICA Study, two expansion projects were identified. The outline of these projects is shown in Table 6.2.25.

Table 6.2.25 Samanalawewa Hydropower Plant Expansion Plan

Items	1 unit expansion	2 units expansion
Maximum Discharge (m3/s)	21	42
Effective Head (m)	332	325
Expansion Capacity (MW)	60	120
Total Capacity (MW)	180	240
Annual Generation (GWh)	314	254
Loss of Generation (GWh)	37	97

It was concluded that the following aspects should be kept in mind for further investigation and study as part of the overall evaluation.

- Since shutting down existing power plants is not acceptable considering the tight balance between electricity demand and supply, it is necessary to carefully weigh the timing of the expansion construction work.
- The increased discharge of the low pressure tunnel will cause greater fluctuation in the surge water level and negative pressure in the tunnel by operating at peak energy with the present minimum operation level of the Samanalawewa reservoir. In order to avoid this negative pressure, a higher minimum operation water level should be adopted. If the water level were draw down below the new minimum operation level in order to meet irrigation demands, the power plant will be forced to reduce the maximum output to avoid negative pressure in the low-pressure tunnel.

(iii) Candidate sites for thermal power development (New Development)

Candidate sites for thermal power development as new construction have been the subjects of study in the past in connection with the development of coal-fired thermal power facilities in three main areas. The CEB has also conducted its own site selection surveys.

The coal-fired thermal power generation development sites that were surveyed in the past are shown in Table 6.2.26.

Table 6.2.26 Coal-Fired Thermal Development Sites surveyed in the Past

Location	Survey and Description
West Coast Puttalam District (Norochcholai site)	・Pre-feasibility study funded by JCI (1993) ・Engineering design funded by JBIC (1998)
East Coast Trincomalee District	・Feasibility study funded by ADB (January 1985–November 1988)
South Coast Hambantota District	・Site selection survey by CEB[57] (March 2001)

Source: JICA Study Team

CEB has studied the site selection for a large coal-fired power station several times. There are three candidate areas namely the Puttalam area along the west coast, the Trincomalee area along the east coast and the Hambantota area along the south coast.

At first, CEB studied the Trincomalee cases under the ADB (Asian Development Bank) fund from Jan. 1985 to Nov. 1988. After this investigation, the project plan in the east coast could not be moved forward due to the affects of the civil war. CEB therefore started to study the Puttalam plan for the west coast. The pre-feasibility study of the projects located in north Colombo was done by JCI (Japan Consulting Institute) in 1993. As CEB had intended to implement this project by funding from a Japanese yen-based loan from JBIC (OECF at that time), the detailed design of the coal-fired power plant was done with funding from a Japanese engineering service loan fund from 1998 to 2000. Soon after it was learned that, the Sri Lankan government asked the Japanese government for the yen-based loan needed, the project faced some opposition by the Catholic Church. So the Cabinet of the Sri Lankan government decided to postpone it in August 2000. Thereafter, CEB conducted a site survey in order to find a suitable candidate site for installing a large coal-fired power station in the south coast area in March 2001.

Taking the degree of maturity of the study into consideration, the Study Team find that the project in the Puttalam area on the west coast has proceeded as far as a complete engineering design. There is already a completed environmental impact assessment (EIA), as well. This gives it a higher level of feasibility than the other projects at present.

a) Puttalam region on the west coast (Norochcholai site)

Candidate sites for development of thermal power facilities were listed in a thermal power generation study[58], conducted by the U.S. firm Black & Veatch in 1988. These included four locations in west coast regions listed as candidate development sites for coal-fired thermal power plant. Subsequently, those sites were screened by Electrowatt Engineering Services Ltd. in 1996. Candidate sites other than Puttalam and Mundal were removed from consideration because of the large numbers of people living in those vicinities.

Figure 6.2.26 shows the candidate development sites for coal-fired thermal power in west coast regions that were surveyed for the 1988 study of options for the adoption of thermal power.

[57] The study does not include preliminaly design, only site identification was done.
[58] Thermal Generation Option Study, 1988

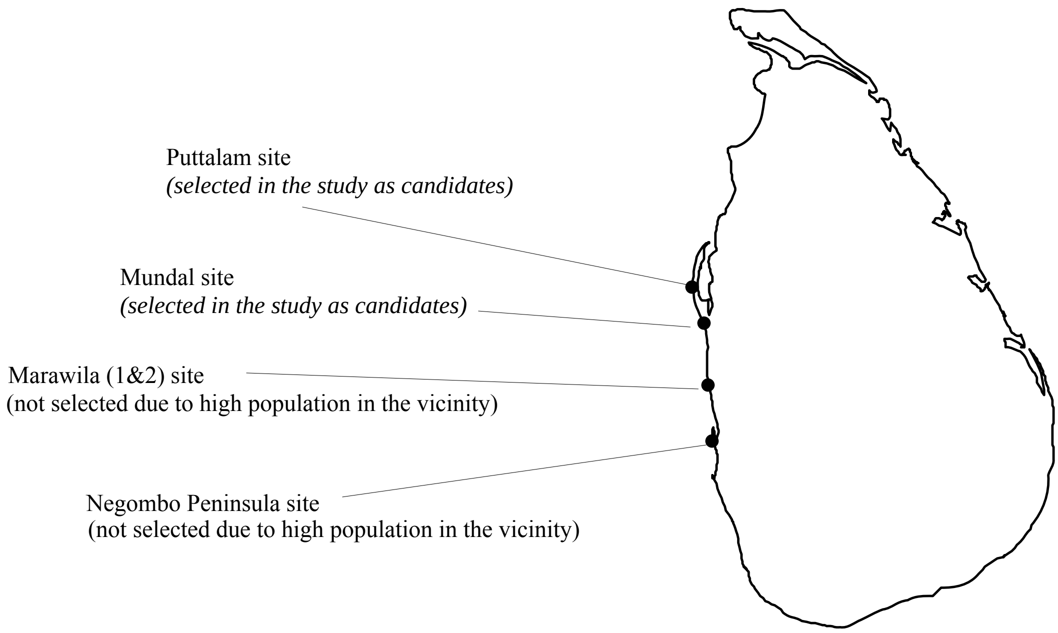


Figure 6.2.26 West Coast Candidate Development Sites for Coal-Fired Thermal Power Plant (1988 study)

Engineering design was implemented with JBIC funding in 1998. The plant capacity ultimately amounts to 900 MW, with individual 300 MW generator units separated into three stages for phased development.

The development period for the first 300 MW unit is approximately 5.5 years from the submission of the EIA to start of commercial operation. The period from initiation of construction to the start of operation is approximately 4.5 years. Other expected processes include 0.5 year for project finance assurance, 0.5 year for bidding preparation, 0.5 year for bidding, and 0.8 year for reviewing and contract negotiation.

In the study, it is assumed that the coal used for fuel will be imported from Australia, Indonesia and South Africa. Two methods of unloading the coal are given. One is to offload it at a point about 4.2 km off the coast, with a jetty put in place by which the coal can be transported to the stockyard by conveyor belt. The other is to offload it onto small transport vessels that will carry it to the stockyard.

Development costs for the first stage include the construction of the 300 MW generation facilities for approximately US$323.6 million. The cost of constructing offshore facilities for unloading coal is estimated at approximately US$65.3 million.

The site surveys conducted in the Study resulted in the determination that highway conditions in the area planned for development are good, and there are also railways nearby. Therefore there should be no major problems in transporting materials by land. The planned area is approximately 1,800 m by 450 m in area, and it is located 100 m inland from the shoreline.

The above engineering design specifies two approaches for offloading coal, with the corresponding maritime facilities. Considering the impact on the local landscape, the building of a jetty to a point 4.2 km off the coast would appear to have a greater impact, and using small bunker boats to haul the coal in would have less of an impact.

Numerous churches were seen in the area, and many Muslims. There appeared to be few Buddhists, however. A visit was made to one church whose bishop had previously opposed development. He explained that the reason for his opposition at that time had been "concern that the churches by the seashore would be damaged by acid rain, erosion of the coastline and so on."

There were also groups of nomadic fishermen living in temporary dwellings in the coastal area. (They are not always there.)

Cash-crop farming was found to be widely practiced in the region containing the area planned for development. Irrigation was carried out using simple wells and pumps for small individual sections. The main crops were tobacco, red onions, green peppers, cabbage and radishes. The landowners on the Kalpitiya and Puttalam peninsulas appear to have invested in irrigation facilities and have local residents working as tenant farmers. There is also a coconut plantation on the north side of the area scheduled for development. These may necessitate compensation when development takes place.

b) Trincomalee region on the east coast

A feasibility study was implemented with ADB funding in 1988. The ultimate capacity of the plant facilities is 900 MW.

Four locations were named as candidate sites for development. The most promising of these was site number 2A. All the sites are favorable in terms of highway conditions and should face no major ground transportation problems.

Site surveys conducted in the Study showed favorable conditions for the transportation of coal, including access by sea-going vessels. There also appeared to be a good balance between cuts and embankments, and the situation with respect to the foundation were also positive.

The most promising location, site number 2A, was in the possession and use of the Sri Lankan military as of November 2005. Site number 1 is adjacent to an air force base. This base is used as a training airfield, and it has been designated a protected flight area under the laws governing aerial navigation. This means that permission will not be given to build structures 45 m high or higher within 1.5 km of the runway, and structures 100 m high or higher within 4 km of it. It would not be possible to build the 100 m stack described in the feasibility study. The other candidate sites are likewise within 4 km of the runway. Under present circumstances, therefore, development cannot be implemented at the four sites named in the feasibility study.

Southern Trincomalee would not infringe on the above air traffic control restrictions. As this area is controlled by the LTTE at present, it was not possible to visit it for this study. Judging by the maps, however, this area appears to present possibilities in terms of topography as a site for development of a coal-fired thermal power station.

Areas occupied by the armed forces are considered High Security Zones. As such, there are no particular regional development plans for those areas, nor are they designated as nature reserves.

There used to be several elephants on Elephant Island in the bay, but they have long since died out.

The fishing industry is centered largely on offshore fishing. There is no fishing on the coastline. Culturing of crustaceans and pearl oysters is apparently not practiced.

c) Hambantota region on the south coast

The study[59] for introduction of thermal power plant, conducted by Electrowatt Engineering Services Ltd. in 1996, named Mawella, on the south coast, as a site for development of coal-fired thermal power sources.

The Norochcholai coal-fired thermal power development project in Puttalam was postponed by a Cabinet decision in October 2000. The CEB therefore conducted surveys in March 2001 to identify alternative development sites for coal-fired thermal power plant in the Hambantota and Matara areas on the south coast.

The survey explored these areas from the perspective of assuring supplies of cooling water for power generation, the existence of offshore facilities for handling coal, the availability of adequate land for disposing of cinders, and so on. The results showed that there were seven candidate development sites on the coastline from Matara to Hambantota.

Figure 6.2.27 shows the sites that were identified.

[59] Thermal Generation Option Study, 1996

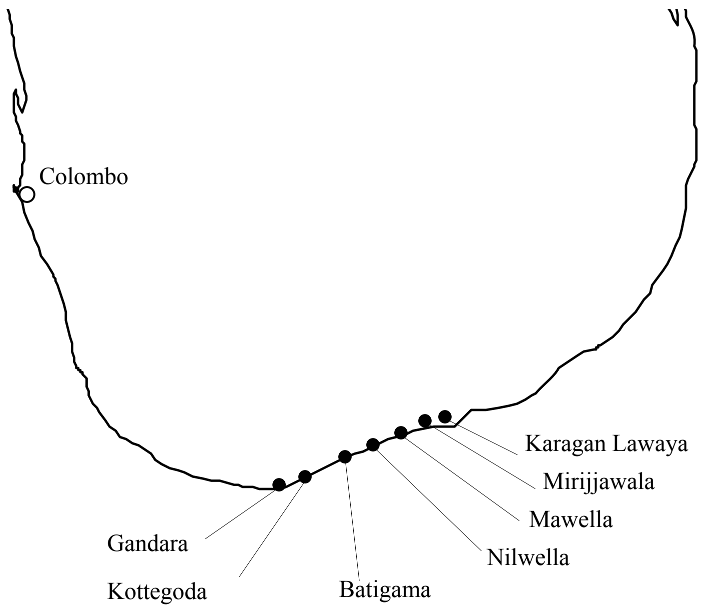


Figure 6.2.27 South Coast Candidate Sites for Coal-fired Thermal Power Plant (CEB study in 2001)

The distance from the coastline to anchorage locations capable of handling a 60,000-ton coal carrier (Panamax-size ship) is shorter for all the candidate sites on the south coast than it for the Norochcholai project site on the west coast. The offshore facilities required for coal handling could be on a smaller scale, and the construction costs would be correspondingly lower.

The areas surrounding these south coast sites are generally rather highly populated and relatively highly developed. The effects from relocation of residences and facilities in conjunction with the development would be greater than at the Norochcholai project site. In other words, the obstacles to development appear to be greater.

The major elements involved in development of these areas were subjected to comparison. The results show that the greater existence of potential contractors to deal with cinders in the development site vicinity, the smaller number of residential relocations due to the development, and the smaller impact on the neighboring environment and community make Norochcholai a more promising site for development than the south coast locations. It was concluded that of these seven locations, the Mirijjawila and Karagan Lewaya sites in Hambantota area are relatively more promising, even though they do present some problems for development.

Table 6.2.27 shows the results of site evaluation for development of coal-fired power plant in the study conducted by CEB in 2001.

Table 6.2.27 Result of Site Evaluation for Development of Coal-fired Power Plant (CEB study in 2001)

Items	Mawela	Mirijjawala	Karagan Lawaya	Nilwella	Batigama	Kottegoda	Gandara	Norochcholai	Remarks
Land Utilization	Lagoon fishery. Tourism. Residences. Offshore fishing. A2 Road. OO	Proposed harbour&BOI area. A2 Road. Office buildings. Residences. OOO	Saltern OOOO	Fishery harbor. Residences. Coconut lands. Garment factory. Housing scheme. O	Residences. Paddy / Coconut lands. OOO	Residences. Coconut & Paddy cultivation. Fishery. O	Residences. Fishery. Garment factory. Plywood factory. Housing scheme. O	No permanent houses. Beach scene fishing. Coconut and cash crops (about 25% of the area) OOOO	Observations were made during the suite visits. Also referred the available literature.
Land Availability	~ 40-50 ha vacant closer to lagoon. OOO	UDA allocated this land for port & BOI industrial state. OO	More than half of the Lawaya to be closedown. OOO	No sufficient land. O	~ 20-30 ha land. Mainly paddy field may be available. OO	No sufficient land. O	No sufficient land. O	70% of bare land. OOOO	Availability of undeveloped lands were considered.
Resettlement	~ 250-300 families O	~ 250-300 families O	A few OOOO	~ 250-300 families. O	~ 200-350 families OO	~ 350-400 families. O	~ 500-600 families. O	43 families. OOOO	Rough estimation. Details to be studied.
Offshore facilities Jetty length Conveyor length Coast Line	~ 200-400 m ~ 1.5 km Rocky. OOOO	~ 1.3 km ~ 2 km Sandy. OOOO	~ 1.5 km ~ 2 km Sandy. OOOO	~ 0.6 km ~ 1.5 km Rocky. OOOO	~ 1.5 km ~ 2.25 km Sandy / Rocky. OO	~ 1 km ~ 2.5 km Rocky. OO	~ 1 km ~ 2 km Sandy / Rocky. OO	4.2 km, or Barging 4.6 km or 0.9 km Sandy. OO	In Norochcholai barging option is also considered for coal handling.
Fresh Water Source & Availability	Niwala River (~ 24 km) Supply not sufficient. OO	Walawe River (~ 20-40km) Supply not sufficient. OOO	Walawe River (~ 20-30 km) Supply not sufficient OOO	Niwala River (~ 20 km). Supply not sufficient. OO	Niwala River (~ 13km). Supply not sufficient. OO	Niwala River (~ 9 km) Supply not sufficient. OO	Niwala River (~ 7 km). Supply not sufficient. OO	Ground water. Quantity not sufficient. OO	Detail studies needed to determine sufficiency of the river water.
Cooling Water Length of cooling water pipe	Sea Water Cooling ~ 1 km OO	Sea Water Cooling ~ 1 km OOOO	Sea Water Cooling ~ 1.5 km OOO	Sea Eater Cooling. ~ 1.5km OO	Sea Water Cooling. ~ 2 km OO	Sea water Cooling. ~ 2 km OO	Sea Water Cooling. ~ 2 km OO	Sea Water Cooling. ~ 0.5 km OOOO	Considered the laying of cooling water pipe up to 200 m offshore from the site.
Transmission Line Length (220kV)	~ 140 km OOO	~ 170 km OO	~ 170 km OO	~ 135 km OOO	~ 135 km OOO	~ 130 km OOO	~ 130 km OOO	115 km OOOO	Line connected at Panipitiya. (Colombo)
Ash Disposal	Dump in Lagoon/Land OOO	Dump in Land. OO	Dump in Land OOO	Dump in Land OO	Dump in Land. OO	Dump in Land. OO	Dump in Land OO	Part will be dumped in the site. 70 % of the ash will be used bye cement factory. OOOOO	In southern sites it is considered that the total ash will be dumped at the site.
Environmental & Social	Influence to lagoon. Tourism. Fishing activities. Loss of developed property. O	Loss of developed property. Affect Gem mining 6 fishery. OO	Loss of an economic activity. Ecological impacts. Protective areas. OO	Loss of developed property. Fishery & garment industry. OO	Loss of developed property. Cultivation. OO	Loss of developed property. Fishery & Cultivation. OO	Loss of developed property. Fishery & other industries. O	Fishing small way. Cultivation no significant effect. OOOO	More studies to be dome to ascertain the impacts.
Total points	21	23	28	18	20	16	15	33	

Note: Equal weightage is given to all parameters. OOOOO: 5 points, OOOO: 4 points, OOO: 3 points, OO: 2 points, O: 1 point

Site surveys of the Mirijjawila and Karagan Lewaya locations in the vicinity of Hambantotta were conducted in the Study. The results show that the highway distance by motor vehicle from Colombo to Hambantota is approximately 240 km, with paved roadway almost the entire way. There would appear to be no major problems in transporting materials by land.

The offshore waters appear to be deep judging from the land features of the surrounding area. A depth of 15 m is likely to be found even less than 1 km from the shore. There is little reclaimed land In the Mirijjawila site, the development seems to required little land filling. There would probably be a relatively large number of residential relocations, however, amounting to approximately 300 households. Meanwhile, the Karagan Lewaya site has a larger amount of reclaimed land, and the residential relocations would amount to several households.

The built-up area of Hambantota has a large number of Muslim residents. The surrounding villages appear to be largely Buddhist

As shown above, therefore, past coal-fired thermal power development sites included west coast areas (the vicinity of Puttalam), east coast areas (the vicinity of Trincomalee), and south coast areas (the vicinity of Hambantota). Development in the area of Trincomalee where the feasibility study was implemented is currently impossible because of aviation control restrictions. Development should be possible, however, in outlying areas that are not subject to these restrictions.

There is also the matter of the scale of facilities to be developed at the various locations. There would not be any significant constraints on the amount of facility development at the Puttalam location because extensive land similar to the slated development site is available all around the site. It was not possible to conduct a site survey at the Trincomalee location. It appears that development should be possible over a wide area south of the bay, however, where it would not be affected by aviation control restrictions. It appears, therefore, that the constraints on the amount of facility development would not be particularly great. Although development in the Hambantota area on the south coast presents some issues, seven development sites were identified, if the Matara area is included. In the Study, the Study team assumed that there is almost no constraints on the amount of facility development there.

(iv) Candidate site for thermal power development (expansion)

The LTGEP 2005-2019 contains no references to expansion plans for thermal power plants. In the past, however, the CEB did conduct a feasibility study on converting its existing Kelanitissa gas turbine plant (Installed capacity: 115 MW, commissioned in 1997) to a combined cycle operation.

This feasibility study anticipated a construction period of approximately three years from the start of the technical appraisal to the start of operation as a combined cycle plant. Even if the technical review were to be initiated at the start of 2006, the start of operations would not take place until early 2009.

Also, as described in section 5.3.2 (3), the plant factor for combined cycle generation facilities declines after installation of coal-fired thermal power plant. This is thought to considerably reduce the economic efficiency of such a project.

(3) Development Period

Construction period is not the only factor involved in the time it takes to get a power station operational. There are also the preceding stages, which include placing construction orders, implementing and evaluating environmental assessments, and other such processes that must be taken into consideration. It may also be necessary to conduct feasibility studies or pre-feasibility studies, depending on the degree of maturity of the plan.

The construction periods for the various generation facilities in the LTGEP 2005-2019 are shown in Table 6.2.28.

Table 6.2.28. Construction Periods for Development of Power Plants in LTGEP 2005-2019

Abbrev. ST : Steam Turbine
GT : Gas Turbine
CCGT : Combined Cycle

Type	Plant Type, Site		Construction Period (years)
Thermal Power	Oil-fired ST	150MW	4.0
	Oil-fired ST	300MW	4.0
	Coal-fired ST	300MW	4.0
	Oil-fired GT	35MW	1.5
	Oil-fired GT	75MW	1.5
	Oil-fired GT	105MW	1.5
	Oil-fired CCGT	150MW	3.0
	Oil-fired CCGT	300MW	3.0
	Diesel	100MW	2.0
Hydropower	Gin Ganga	49MW	4.0
	Moragolla	27MW	4.0
	Broadlands	35MW	4.0
	Uma Oya	150MW	5.0

Source: CEB LTGEP (2005-2019)

The construction period for thermal power plants is within the general range of such construction periods worldwide. The construction period for hydropower facilities varies greatly by project, and efforts must therefore be made to ensure that these construction periods are consistent with those in existing development plans.

The construction periods for these hydropower projects were verified in the Study. The construction period for the Gin Ganga site was given as five years, which is the construction period specified in the pre-feasibility study. The construction periods for the other sites were consistent with those in their plans.
Table 6.2.29 shows the construction periods for expansion projects shown in the studies conducted in the past.

Table 6.2.29 Construction Period for Expansion Projects

Type	Project	Construction Period (years)
Hydropower	New Laxapana&Polpitiya	2.0
	Victoria (2 units added)	5.0
	Victoria (3 units added)	5.0
	Samanalawewa (1 unit added)	3.0
	Samanalawewa (2 units added)	3.0
Thermal Power	Kelanitissa GT7 conversion to combined cycle	3.0

Source: Hydro Optimization Study, JICA 2004
Feasibility Study Report on the Modernization project of Kelanitissa Power Station GT7 Gas Turbine, March 2003

As described above, before construction work begins, the implementation of new development projects requires time for implementation and evaluation of an EIA, and for procedures for placing construction orders and other such processes. Consequently, combining the development of new generation facilities with a generation development plan requires consideration of these lead-times.

For the Study, it is assumed that these various processes involved prior to the start of construction will proceed in the shortest possible time. The earliest operation start time has been set for these power plants accordingly.

The expansion of hydropower and thermal power plants can potentially affect system operation in a variety of ways, such as by having to stop power generation during construction. Therefore, it is important to examine the feasibility in consideration of supply capacity during construction of these expansion projects.

Table 6.2.30 shows the development periods and the earliest year for starting commercial operation times for the Study. The project implementation start time is assumed to be the beginning of 2006 for the purposes of figuring the earliest year.

Table 6.2.30 Required Period and Earliest Commissioning Year for Development of Power Plant

Type	Plant Type, Site		Period before construction[1)]	Construction Period[4)]	Total Required Period for Development	Earliest Commissioning Year
Thermal Power	Oil-fired ST	150MW	1.5-2.0	4.0	5.5	2011 (mid 2011)
	Oil-fired ST	300MW	1.5-2.0	4.0	5.5	2011 (mid 2011)
	Coal-fired ST	300MW	1.0-1.5[2)]	4.0	5.0-5.5	2011 (mid 2011)
	Oil-fired GT	35MW	1.5-2.0	1.5	3.0	2009 (beg. 2009)
	Oil-fired GT	75MW	1.5-2.0	1.5	3.0	2009 (beg. 2009)
	Oil-fired GT	105MW	1.5-2.0	1.5	3.0	2009 (beg. 2009)
	Oil-fired CCGT	150MW	1.5-2.0	3.0	4.5	2010 (mid 2010)
	Oil-fired CCGT	300MW	1.5-2.0	3.0	4.5	2010 (mid 2010)
	Diesel	100MW	1.5-2.0	3.0	4.5	2010 (mid 2010)
Hydropower	Gin Ganga	49MW	3.0	5.0	8.0	2014 (beg. 2014)
	Moragolla	27MW	3.0	4.0	7.0	2013 (beg. 2013)
	Broadlands	35MW	1.5[3)]	4.0	5.5	2011 (beg. 2011)
	Uma Oya	150MW	3.0	5.0	8.0	2014 (beg. 2014)

1) Includes periods of EIA implementation, EIA procedures, bidding preparation and contract procedures
2) Depends on the project. For the Norochcholai project, a period of about one year is assumed because EIA completed.
3) Since the feasibility study has ended, a period of about 1.5 years is assumed.
4) From the completion of contract procedures to the start of operation

Source: JICA Study Team

(4) Construction Cost

(i) Construction cost for development of power plant (new development)

The Study Team estimated construction cost at January 2005 for each project. The basic parameters for the estimation of the construction cost are as follows:

Exchange rate

Exchange rate is 99.64Rs/US$. This was the average exchange rate in January 2005.

Price escalations

The price escalation rate is the same as CEB's rate. The local portion is adopted for the "Change in Price Indices in Sri Lanka (SLCPI)" of the Central Bank of Sri Lanka. The foreign portion is adopted for the "Consumer Prices (Advanced Economics)" of the World Economic Outlook (IMF). These values are given in Table.6.2.1.

Table 6.2.31 Price Escalations in Sri Lanka

year	1992	1993	1994	1995	1996	1997	1998
Foreign	4.4%	1.3%	3.4%	2.3%	2.3%	2.2%	2.2%
Local	11.4%	11.7%	8.4%	7.7%	15.9%	9.6%	9.4%
year	1999	2000	2001	2002	2003	2004	2005
Foreign	2.2%	2.3%	2.2%	2.5%	1.8%	2.0%	-
Local	4.7%	6.2%	14.2%	10.2%	2.6%	7.9%	-

Interest during construction (IDC)

The Study Team used the figure of IDC which is adopted in WASP simulation.

Penalty for uncertainty

In the LTGEP 2005-2019, the CEB took the degree of maturity of plans into consideration in determining the uncertainty of new development sites. It therefore added a premium to the construction cost for new hydropower development projects as shown below. This method of reflecting the maturity of the plan by project is effective in maintaining the reliability of the plan as a whole, and the evaluations here seem appropriate.

- 1989 master plan stage: 10% premium for construction expenses (Gin Ganga site, Moragolla site)
- Pre-feasibility study stage for individual sites: 5% premium for construction expenses (Uma Oya site)
- Feasibility study ended, environmental impact assessment stage: 2% premium for construction expenses (Broadlands site)

These premiums will also be applied in the Study.

Application to similar projects with close construction costs

Construction cost as of2003 is estimated for Broadlands hydropower project in the feasibility study conducted in 2003.

In the Study, the both the Gin Ganga project and Uma Oya project were concluded that it is necessary to conduct a further study that includes a study of dam height and type selection before re-estimation of construction cost of these projects.

The Study Team, therefore reviewed the construction cost for the Moragolla project in the study.

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The Broadlands project is a similar project to the project of Moragolla. Therefore, the Study team reviewed the construction cost of Moragolla project by making comparison between both costs and estimate a construction cost as of January 2005.

Table 6.2.32 shows the basic construction costs for newly development of power plants, and Table 6.2.33 shows the results of construction cost revision.

Table 6.2.32 Basic Construction Costs for Newly Development of Power Plants

Abbrev. ST : Steam Turbine
GT : Gas Turbine
CCGT : Combined Cycle

Type	Plant Type, Site	Capacity (MW)	Construction Cost (mUSD)		Cost Base Year	Ex. Rate (Old) (Rs./USD)	Ex. Rate (New) (Rs./USD)	Source
			Foreign	Local				
Thermal Power	Oil-fired ST	150	108.50	27.13	Jan. 1995	50	99.64	[1]
	Oil-fired ST	300	183.43	45.86	Jan. 1995	50	99.64	[1]
	Coal-fired ST	300	226.23	75.57	Jan. 2000	72	99.64	[2]
	Oil-fired GT	35	15.67	2.34	Jan. 1997	59	99.64	[3]
	Oil-fired GT	75	27.44	4.10	Jan. 1997	59	99.64	[3]
	Oil-fired GT	105	31.97	4.78	Jan. 1997	59	99.64	[3]
	Oil-fired CCGT	150	80.73	22.77	Jan. 1997	59	99.64	[3]
	Oil-fired CCGT	300	130.56	36.84	Jan. 1997	59	99.64	[3]
	Diesel	100	10.32	1.08	Jan. 1997	59	99.64	[3]
Hydropower	Gin Gnaga	49	76.38	16.47	Mar. 1992	42	99.64	[4]
	Broadlands	35	68.19	19.04	Sep. 2003	96	99.64	[5]
	Uma Oya	150	233.94	53.61	Mar. 1992	42	99.64	[6]
	Moragolla	27	62.74	9.52	Mar. 1992	42	99.64	[7]

[1] Thermal Generation Option Study, 1995
[2] West Coast Coal Plant Phase 1 Report, 2000
[3] Review Of Least Cost Generation Plan, 1997
[4] Masterplan Project Report GING074
[5] Hydro Power Optimization study, 2004
[6] OECE Pre-feasibility Study, 1997
[7] Masterplan Project Report MAHW263

Table 6.2.33. Revised Construction Costs for Newly Development of Power Plant (Prices as of 2005)

Abbrev. ST : Steam Turbine
GT : Gas Turbine
CCGT : Combined Cycle

Type	Plant Type, Site	Capacity (MW)	Pure Construction Cost (USD/kW)		Constructio n Period	I.D.C.* (%)	Constructiono Cost for WASP (USD/kW)		
			Foreign	Local			Foreign	Local	Total
Thermal Power	Oil-fired ST	150	890.40	210.40	4.0	18.53	1,055.4	249.4	1,304.8
	Oil-fired ST	300	752.70	177.90	4.0	18.53	892.1	210.8	1,102.9
	Coal-fired ST	300	831.00	269.30	4.0	18.53	984.9	319.2	1,304.1
	Oil-fired GT	35	526.70	73.60	1.5	6.51	561.0	78.4	639.4
	Oil-fired GT	75	430.40	60.10	1.5	6.51	458.4	64.0	522.4
	Oil-fired GT	105	358.20	50.00	1.5	6.51	381.5	53.3	434.8
	Oil-fired CCGT	150	628.80	165.90	3.0	13.54	713.9	188.3	902.2
	Oil-fired CCGT	300	511.90	135.10	3.0	13.54	581.2	153.4	734.6
	Diesel	100	1,032.00	107.80	2.0	8.79	1,452.6	141.9	1,594.5
Hydropower	Gin Gnaga	49	2,259.01	461.66	5.0	23.78	2,796.2	571.4	3,367.7
	Broadlands	35	2,027.00	576.69	4.0	18.53	2,402.6	683.6	3,086.2
	Uma Oya	150	2,157.41	468.71	5.0	23.78	2,670.4	580.2	3,250.6
	Moragolla	27	2,438.90	673.16	4.0	18.53	2,890.8	797.9	3,688.7

*Note: I.D.C. for discount rate of 10%

(ii) Construction cost for development of power plant (expansion)

The Study Team revised the construction costs for expansion projects in a same manner as revision for new development projects.

The cost calculations for expansion projects are reviewed based on the January 2005 price. The cost is estimated for both foreign and local costs by adjusting each price escalation rate. The distribution of foreign/local cost for each construction work is shown in Table 6.2.34.

Table 6.2.34 Distribution of Foreign/Local Cost for Construction Work

Type, Project		Work	Foreign	Local
Thermal Power	Kelanitissa GT7 conversion to combined cycle plant		80%	20%
Hydropower	New Laxapana&Polpitiya	Civil Work	75%	25%
	Victoria 2units added, 3units added	Mechanical Work	90%	10%
	Samanaklawewa 1unit added, 2units added	Electric Work	95%	5%
		Transmission Wor	80%	20%

Table 6.2.35 shows the basic construction costs for expansion projects, and Table 6.2.36 shows the construction costs as revised.

Table 6.2.35 Basic Construction Costs for Expansion Project

Type	Plant Type, Site	Capacity (MW)	Construction Cost (mUSD) Foreign	Local	Cost Base Year	Ex. Rate (Old) (Rs./USD)	Ex. Rate (New) (Rs./USD)
Thermal Power	Kelanitissa GT7 conversion to combined cycle plant	55	97.05		Jan. 2002	50	99.64
Hydropower	New Laxapana	72.5	56.73	7.22	Jan. 2002	96	99.64
	Polpitiya	47.9	34.41	4.40	Jan. 2002	96	99.64
	Victoria 2units added	140	85.58	16.53	Jan. 2002	96	99.64
	Victoria 3units added	210	127.18	24.36	Jan. 2002	96	99.64
	Samanalawewa 1unit added	60	33.51	4.17	Jan. 2002	96	99.64
	Samanalawewa 2units added	120	59.20	6.77	Jan. 2002	96	99.64

Table 6.2.36. Revised Construction Costs for Expansion Project (Prices as of 2005)

Type	Plant Type, Site	Additional Capacity (MW)	Pure construction cost (USD/kW)			Construction Period (years)	I.D.C.* (%)	Constructiono Cost for WASP (USD/kW)		
			Foreign	Local	Total			Foreign	Local	Total
Thermal Power	Kelanitissa GT7 conversion to combined cycle plant	55	1,500.95	417.25	1,918.20	3.0	13.54	1,704.2	473.8	2,177.9
Hydropower	New Laxapana	72.5	824.69	117.02	941.71	2.0	8.79	897.2	127.3	1,024.5
	Polpitiya	47.9	757.12	108.00	865.12	2.0	8.79	823.7	117.5	941.2
	Victoria 2units added	140	644.26	138.81	783.07	5.0	23.78	797.5	171.8	969.3
	Victoria 3units added	210	638.28	136.36	774.64	5.0	23.78	790.1	168.8	958.9
	Samanalawewa 1unit added	60	588.62	81.63	670.25	3.0	13.54	668.3	92.7	761.0
	Samanalawewa 2units added	120	519.94	66.29	586.23	3.0	13.54	590.3	75.3	665.6

*Note: I.D.C. for discount rate of 10%

(5) Candidate Plants for Development in the Study

The candidate power plants for development were determined from the above results of studies and from the existing LTGEP. In the LTGEP 2005-2019, it is assumed that there will be two 300 MW coal-fired thermal power plants, one on the west coast site and the other at the Trincomalee site.

As there is almost no difference in project costs between the two sites, and since the WASP simulation does not take site location into account, the Study assumes that there is only one candidate site for a coal-fired thermal power plant. Table 6.2.37 shows the specifications of the candidate power plants for development in the Study.

Table 6.2.37 Characteristics of Candidate Power Plants for Development

	Thermal Power											Hydropower			
	Steam Turbine			Gas Turbine			Combined Cycle*1				Diesel*4	Gin Ganga	Mora -golla	Broad -lands	Uma Oya
	Oil-fired 150MW	Oil-fired 300MW	Coal-fired 300MW	Oil-fired 35MW	Oil-fired 75MW	Oil-fired 105MW	Oil-fired 150MW	Gas-fired 150MW	Oil-fired 300MW	Gas-fired 300MW	Oil-fired 10MW				
Installed Capacity (MW)	150	300	300	35	75	105	150	150	300	300	10	49	27	35	150
Development Cost*2 (USD/kW)	1,304.8	1,102.9	1,304.1	639.4	522.4	434.8	902.2	902.2	734.6	734.6	1,594.5	3,367.6	3,688.7	3,086.2	3,250.6
Life Time (y)	30	30	30	20	20	20	30	30	30	30	25	50	50	50	50
Construction Period (y)	4.0	4.0	4.0	1.5	1.5	1.5	3.0	3.0	3.0	3.0	2.0	5.0	4.0	4.0	5.0
Commissioning Year	2011	2011	2011	2009	2009	2009	2010	2020	2010	2020	2010	2014	2013	2011	2014
Fuel Type	Furnace Oil	Furnace Oil	Coal	Auto Diesel	Auto Diesel	Auto Diesel	Auto Diesel	Natural Gas	Auto Diesel	Natural Gas	Furnace Oil				
Fuel Price (USD/fuel-unit)	33.85 (USD/BBL)	33.85 (USD/BBL)	67.32 (USD/ton)	53.46 (USD/BBL)	53.46 (USD/BBL)	53.46 (USD/BBL)	53.46 (USD/BBL)	6.00 (USD/MMBTU)	53.46 (USD/BBL)	6.00 (USD/MMBTU)	33.85 (USD/BBL)				
Fuel Price (cent/Gcal)	2,199	2,199	1,069	3,794	3,794	3,794	3,794	2,381	3,794	2,381	2,199				
Heat Rate*3 (kCal/kWh)	2,404	2,293	2,293	3,060	2,857	2,857	1,846	1,846	1,788	1,788	1,954				

*1: Gas-fired unit is available beginning in 2020 only under the scenario of natural gas supply
*2: including Interest During Construction
*3: at maximum operation capacity
*4: Low-speed Diesel Unit

(6) Specification of Development Sites

For the LTGEP formulated by the CEB, a simulation for generation development was implemented using a WASP simulation. This produced a generation development plan that spans the next 15 years.

The development plan ultimately presented in the LTGEP provides the plant type developed and the capacity required for development for each year. The specific development sites are not shown.

The CEB likewise formulates Long-Term Transmission Development Studies (LTTDS). The development study formulates expansion plans for transformation facilities in line with the generation development plan presented in the preceding year's LTGEP.

The study refers to specific sites for future development that are not given in the LTGEP. According to the CEB, decisions on location are made by the Generation Planning Branch. Apparently, they do not have any particular, procedure for determining locations.

The development of large-scale thermal power plants that have comparatively long development periods will be sought on an annual basis in the future. It will be important, therefore, to specify future development sites in specific terms from a more long-term perspective.

Moreover, as explained in detail in Chapter 7, the results of generation development plans have extremely significant effects on transmission planning. It will be important for decisions on future generation development sites to be made from the perspective of system operation.

The formulation of generation development plans should, therefore, be coordinated with the formulation of power system planning. If this is not done, then the CEB's power development plans as a whole will suffer in terms of both reliability and feasibility.