No.

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

## Final Report
## Volume 1
## ( Main Report )

February 2026

Japan International Cooperation Agency
Economic Development Department

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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

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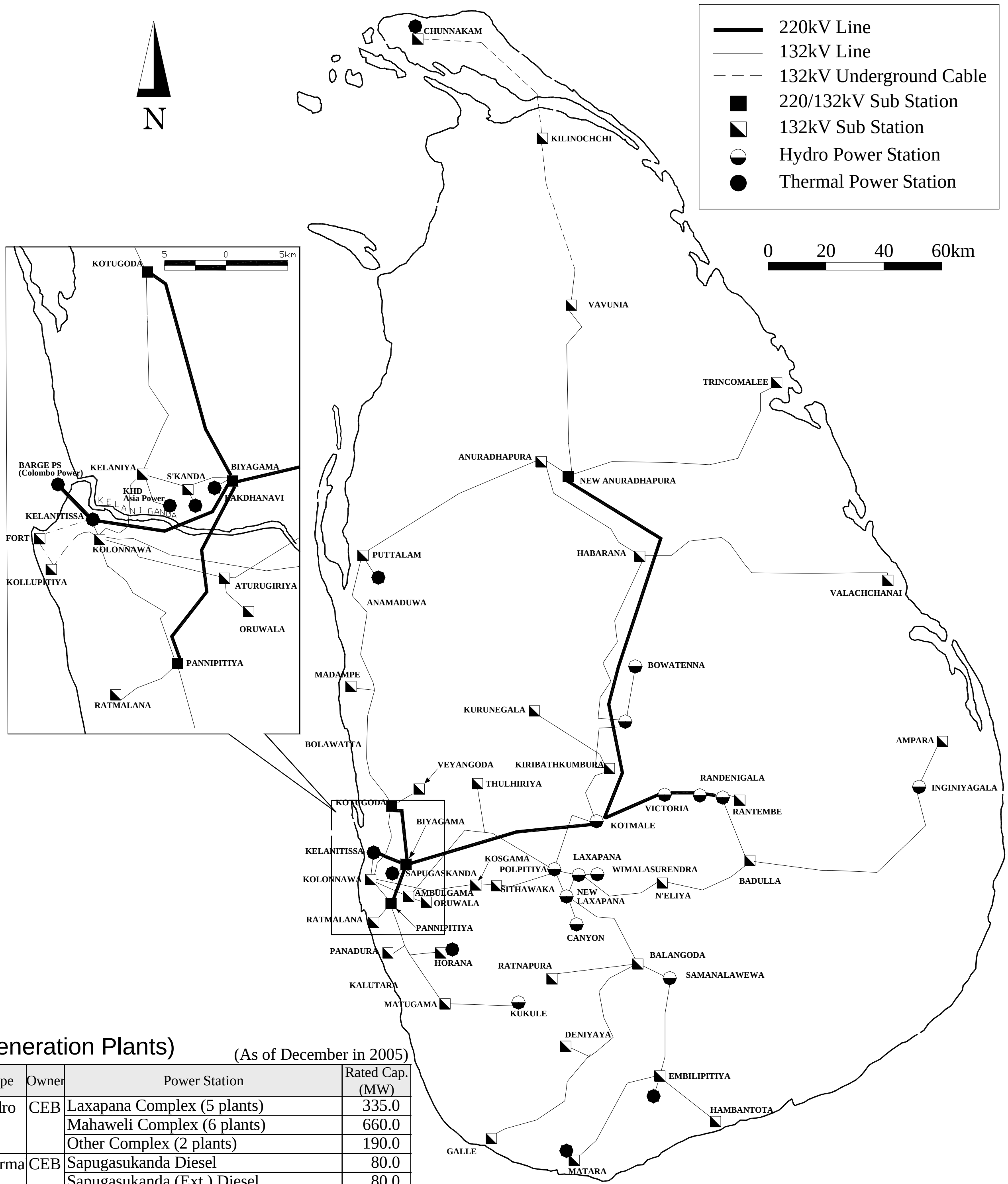
# Abbreviations

| | |
|---|---|
| AAGR | Average Annual Growth Ratio |
| ACSR | Aluminum Conductor Steel Reinforced |
| BBL | Barrel |
| BOO | Build-Own-Operate |
| BOT | Build-Own-Transfer |
| CC, CCGT | Combined Cycle Gas Turbine Power Plant |
| cct | Circuit |
| CEB | Ceylon Electricity Board |
| CPC | Ceylon Petroleum Corporation |
| DG | Diesel Generator |
| DSM | Demand Side Management |
| EIA | Environmental Impact Assessment |
| ESC | Environmental Social Consideration |
| FS, F/S | Feasibility Study |
| GCal | Giga Calorie |
| GDP | Gross Domestic Product |
| GT | Gas Turbine |
| GWh | Giga Watt-hour |
| IEE | Initial Environmental Examination and Initial Environmental Evaluation |
| IPP | Independent Power Producer |
| JBIC | Japan Bank for International Cooperation |
| JICA | Japan International Cooperation Agency |
| kA | kilo Ampere |
| kCal | kilo Calorie |
| kl | kilo Litter |
| kW | kilo Watt |
| kWh | kilo Watt-hour |
| kV | kilo Volt |
| LNG | Liquefied Natural Gas |
| LOLP | Loss of Load Probability |
| MJ | Mega Joule |
| MMBTU | Million British Thermal Unit |
| MPE | Ministry of Power and Energy |
| MVA | Mega Volt Ampere |
| MW | Mega Watt |
| MT | Metric Ton |
| MVAR | Mega Var |
| NGO | Non-Governmental Organization |
| ODA | Official Development Assistance |
| O&M | Operation and Maintenance |

| | |
|---|---|
| PPP | Public and Private Partnership |
| P/S, PS | Power Station |
| PUC, PUCSL | Public Utility Commission in Sri Lanka |
| SEA | Strategic Environmental Assessment |
| SHM | Stakeholder Meeting |
| SLCPI | Sri Lanka Consumer Price Index |
| S/S, SS | Substation |
| ST | Steam Turbine |
| S/W | Scope of Work |
| TPP | Thermal Power Plant |
| USAID | United States Agency for International Development |

# 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 |

# Executive Summary

Based on an agreement between the governments of Japan and Sri Lanka, this Master Plan Study was executed by the Japan International Cooperation Agency (JICA) with the Ceylon Electricity Board (CEB) acting as its counterpart.

In Sri Lanka, it has become necessary to develop additional power sources to keep abreast of the demand for electricity, which has been burgeoning since the 1990s. Because almost all of the economically feasible hydropower resources have already been developed, the power sector has entered a phase requiring a shift from hydropower to thermal power as the core of the generation mix.

In spite of these circumstances, the plans for development of large-scale coal-fired power plants that were formulated beginning in the late 1990s have failed to make much progress due to complications involving environmental and political considerations. In response, the CEB has been meeting supply shortages by purchasing power from independent power producers (IPPs). Many of these IPP power plants are installed with small diesel-engine generators and have higher costs than coal-fired plants. This, coupled with the jump in oil prices in recent years, has greatly driven up power supply costs at the CEB. As a result, the CEB has run up its debt and its financial position has steadily worsened since 2000.

Continued neglect to implement the plan for power source development could very well result in the occurrence of extensive outages and economic disruption in the near future. Similarly, continued delay in the construction of large-scale coal-fired plants would entail additional power purchasing from small diesel generation plants. This, in turn, would make the financial collapse of the CEB inevitable.

In Sri Lanka, the demand for power may be expected to exhibit a trend of firm increase. In 2025, the maximum demand is projected to reach 7,619 megawatts, or about 4.9 times as high as in 2004. This situation requires the development of additional power sources with a combined capacity of at least 6,000 megawatts.

As for the prospect of developing more hydropower sources, it may be noted that nearly 60 percent of the country's hydropower resources have already been developed. Even with the development at various candidate sites, including the plant being constructed at Upper Kotmale and other now in planning at Broadlands and other sites, the additional capacity would amount to less than 500 megawatts. Furthermore, although the CEB has adopted policy for vigorous development of renewable energy resources in the forms of mini-hydropower, wind power, and dendro-thermal power, the capacity that can be added through such means is limited and cannot be anticipated to evolve into the main component of the supply to meet the growing demand, due to the low levels of supply reliability and economic merit.

In other words, thermal power generation is the only remaining option for additional power generation development. As such, the construction of coal-fired plants, which offer the best economic merit, must be promoted as a matter of the highest priority. More specifically, the equivalent of one coal-fired plant in the 300-megawatt class has to be constructed each year of the 2010s.

The amount of investment required for construction of the generation, transmission, and transformation facilities over the years leading up to 2025 is estimated at about 8.4 billion US dollars. Procurement of funds in this enormous sum will be a crucial task.

As described above, the CEB is currently faced with a swelling accumulated debt due to the backspread between its supply costs and tariff revenue. Meanwhile, it cannot hike its tariffs because of political considerations. The problems saddling the power sector in Sri Lanka therefore can no longer by resolved by the CEB on its own.

In 2002, the government passed the Electricity Reform Act, but its enforcement has been delayed. This has put the dialogue with external public credit institutions at an impasse and compromised the program for improvement of the CEB management.

The perceptions on the current situation and outlook for the future related above are as described in detail in the process of preparation of the Master Plan. In light of the findings of the analyses and studies, the Study Team made the following recommendations to the CEB and the government.

(1) Construction of the combined-cycle and coal-fired thermal power plants at Kerawalapitiya and Norochcholai, respectively, as scheduled to avoid the power crisis anticipated to occur in the near future otherwise

(2) Implementation of the study for selection of sites for development of new power plants to succeed Norochcholai given the importance of coal-fired plants in the future power mix; now is the time to launch this study, considering the schedule leading up to the start of operation

(3) Completion of the structural reform in the power sector for resumption of dialogue with external public credit institutions

(4) Revision of the power sector policy characterized by excessive dependence on purchase from IPPs

(5) Prompt revision of power tariffs to resolve the CEB deficit

# 1 Background and Objective

## 1.1 Background: Issues in the Sri Lanka Power Sector

In the Democratic Socialist Republic of Sri Lanka, the power sector has a major role to play in self-supporting economic advancement on a long-term basis. Advancement requires a highly reliable supply of power at reasonable price to a wide range of consumers.

The Sri Lanka power sector has been operated by the Ministry of Power and Energy (MPE) and the Ceylon Electricity Board (CEB). The MPE is in general charge of policy-making for the sector and regulation of the various concerned entities. The CEB plays the central role in generation, transmission and distribution in Sri Lanka.

In correspondence with economic growth, the demand for power in Sri Lanka has exhibited a trend of firm increase. Since its establishment in 1969, the CEB has developed mainly hydropower as a domestic energy resource in order to meet the increasing demand. As a result, almost all of the most promising large-scale hydropower sites had been developed by the mid 1990s, and development has consequently come to focus on thermal power facilities in more recent years.

Development of thermal power plants required construction of large-scale facilities, particularly of the coal-fired type, to curtail the future increase in supply costs. Nevertheless, a lot of small-scale diesel generation plants were developed instead of large-scale coal-fired ones. This contributed to stable power supply in the system but also increased generation costs and squeezed the CEB's finances.

In this way, the power sector came to a major turning point in the 1990s. The Ministry of Irrigation and Power, the predecessor of the MPE, released the Power Sector Policy Directions in 1997 (the Directions were revised in 1998).

Current basic policy on the power sector is based on the Directions, and clearly sets forth the path for fundamental structural reform, led by unbundling of the CEB, with a view to procuring the investment funds needed for the requisite power development into the future, rebuilding CEB finances, and revising the power tariff scheme.

For development of generation facilities, it lays down the line of freedom from dependence on official development assistance (ODA) and encouragement of investment from the private sector through build-own and operate (BOO) and build-operate and transfer (BOT) schemes, especially for thermal power plants.

Under this policy, the current of structural reform was set in motion with assistance from the Asian Development Bank (ADB) and the Japan Bank for International Cooperation (JBIC). The passage of the Electricity Reform Act, No. 28 of 2002 and Sri Lanka Public Utilities Commission Act, No. 35 of 2002 signaled the start of the program of reform mainly through CEB unbundling and establishment of the Public Utilities Commission (PUC) as an independent regulatory organization.

Although many thermal power plants have been developed since 2000, development of large-scale coal-fired plants that are critical for curtailing generation cost increases has not gotten under way due to funding difficulties and opposition due to the prospective impact on the surrounding environment and community. Meanwhile, to meet supply deficiencies, IPPs have installed many small diesel generators and the CEB was compelled to install emergency diesel power plants. In November 2005, their combined capacity reached almost 50 % of the total thermal power capacity.

The increased dependence on thermal power plants with high generation costs has greatly increased the power supply costs. Since 2000, CEB finances have constantly been in deficit. Partly due to the impact of the soaring crude oil prices in recent years, the CEB is now on the verge of financial ruin.

This situation is obviously going to worsen if the development of small-scale diesel power plants instead of large-scale (coal-fired) ones is allowed to continue.

The structural reform in the power sector is not moving ahead smoothly, either. Its aims lie in endowment of the newly established power companies with autonomy and prevention of political interference in the operations, in order to increase levels of efficiency and transparency in the sector. An additional aim is to unbundle the CEB, off-load the huge debt it currently holds, clearly define its management responsibilities as a company, and put it on sound financial footing.

As of November 2005, nevertheless, the CEB had not been unbundled, and the government had not presented a detailed picture of the post-unbundling power sector or a concrete schedule for the unbundling. If the CEB were to be unbundled under these circumstances, numerous problems could very well arise later on. Similarly, the government has not resolved the problems connected with reform of the power tariff scheme indicated in the Directions. Since 2000, the CEB has raised rates to defray the increase in supply costs, but the hikes have not been enough to cover the entire cost, and this is another factor worsening CEB finances.

As the above suggests, the major tasks facing the power sector are early development of large-scale thermal power plants (as viewed from the standpoint of capacity expansion) and execution of the program for structural reform (as viewed from that of organizational and institutional improvement).

The top priority for development of large-scale thermal power plants (putting aside the feasibility of individual projects) is assurance of funding into the long term to see that the development can continue far into the future. To this end, it is essential to resolve the structural problems saddling the sector, i.e., to achieve fundamental solutions through disposal of the CEB debt and revision of the tariff scheme, which does not compensate completely for supply costs. This, in turn, absolutely demands the presentation of a clear path to execution of the reform as another task.

To provide for the sustained advancement of the power sector into the long term, all parties to the power sector must perceive the interrelationship among these tasks instead of viewing them in mutual isolation, and consequently work for a comprehensive solution embracing all of them alike.

## 1.2 Objective: Need for Formulation of the Comprehensive Master Plan

The ultimate objective of formulation of the Master Plan for the power sector in Sri Lanka is to pave the way for its sustained advancement on a long-term basis. The Master Plan is to clearly set forth specific plans for attainment of this objective and the orientation for related approaches.

The formulation of the Master Plan must take into account not only the technical, environmental, and social aspects considered in the power development plan but also organizational and institutional approaches for implementation of this plan. As such, the orientation it presents must be a product of studies encompassing all of these areas.

The Study Team took the following items as the objective of the Master Plan.

**Objective of Master Plan Formulation**

1) **Presentation of the long-term power development plan**

   Accurate forecast of the power demand from a long-term perspective and preparation of plans for economically rational expansion of power system taking full account of reliability and environmental and social considerations

2) **Identification of issues in the organizational and institutional aspect**

   Identification and examination of tasks in the aspect of existing sector organizations and institutions for execution of the prepared development plan

3) **Recommendations for the further advancement of the power sector**

   Presentation of agenda in the technical aspect for implementation of future power development and in the organizational and institutional aspect for achievement of the Master Plan

# 2 Process of Master Plan Formulation

## 2.1 Basic Concepts in Master Plan Formulation

The Study Team decided to take the following items as the basic concepts in formulation of the Master Plan.

**Basic Concept 1: Formulation of the Master Plan for the power sector as underpinning of self-supporting economic advancement on a long-term basis**

The Master Plan must make a positive contribution not only to the development of the power sector but also to Sri Lanka's overall economic advancement for the long term. For this reason, it was decided to extend the subject period to 2025 and the Study Team formulated the Master Plan based on the recognition that stable supply of power at reasonable price and with high levels of reliability over the long term will assist the country's economic advancement.

**Basic Concept 2: Formulation of the Master Plan with the comprehensiveness needed to heighten the feasibility of the power development plan**

The formulation of a highly workable power development plan demands not only the resolution of technical issues beginning right from the planning stage but also concern for impact on the surrounding environment and society (communities). Similarly, sure execution of the plan requires the identification of issues in the organizational and institutional aspect as well as studies and recommendations for their resolution.

In formulation of the Master Plan, the Study Team therefore examined tasks from a diversity of aspects to make the content comprehensive.

**Basic Concept 3: Formulation of a power development plan on a level that will obtain international trust**

The power development plan must consider the post-reform situation, when induction of investment for development will play an important role in the advancement of the power sector. Prospective investors will be looking at the international competitiveness of the sector as an industry in the context of the international market, and particularly the Southeast Asian region. As a result, in selecting procedures and setting values for various constraints as necessary for formulation of the power development plan, the Study Team made sure to choose levels that would win international trust.

**Basic Concept 4: Formulation of a power development plan based on studies on the community level**

One of the priorities for long-term economic advancement in Sri Lanka is rectification of domestic (regional) economic disparities. The key prerequisites for this purpose are economic development in districts where it is lagging and the accompanying rise in the quality of life in their communities. The power sector has a vital role to play in this connection as well.

The Study Team consequently had studies on the regional level included in the activities for formulation of the plan.

**Basic Concept 5: Formulation of the Master Plan in the process of sectoral reform**

The Master Plan was formulated in the process of structural reform in the power sector. An awareness of this point dictated portrayal of the advisable shape of organizations and institutions in the sector upon completion of the reform, along with identification and discussion of related issues. In response, the Study Team made recommendations for action to resolve these issues both while the reform was in progress and after its completion.

## 2.2 Composition of the Master Plan

The Master Plan consists of the following components.

**1) Power development plan**

- A long-term plan for system expansion, composed of a power demand forecast extending to 2025, generation development plan, and power system plan

**2) Identification of issues in the organizational and institutional aspects**

- Definition of problems related to the existing institutional framework of the power sector, identification of issues for promotion of structural reform, and presentation of the findings of studies in this area

**3) Recommendations for the future advancement of the power sector**

- Presentation of technical recommendations for implementation of the power development plan and recommendations for the organizational and institutional configuration under the reform

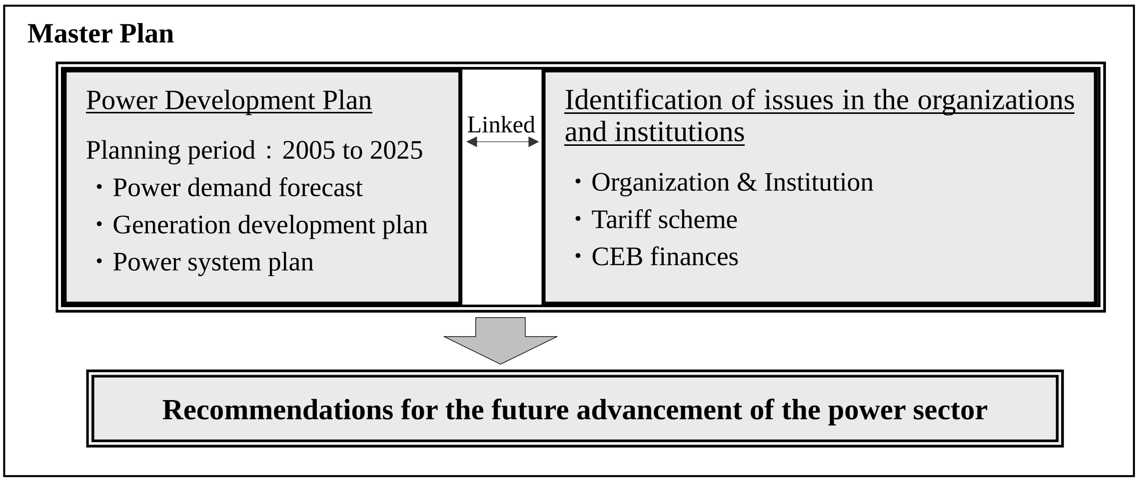



Figure 2.1 Composition of the Master Plan

## 2.3 Methodology for Formulation of the Master Plan

Figure 2.2 shows the flow of Master Plan formulation.

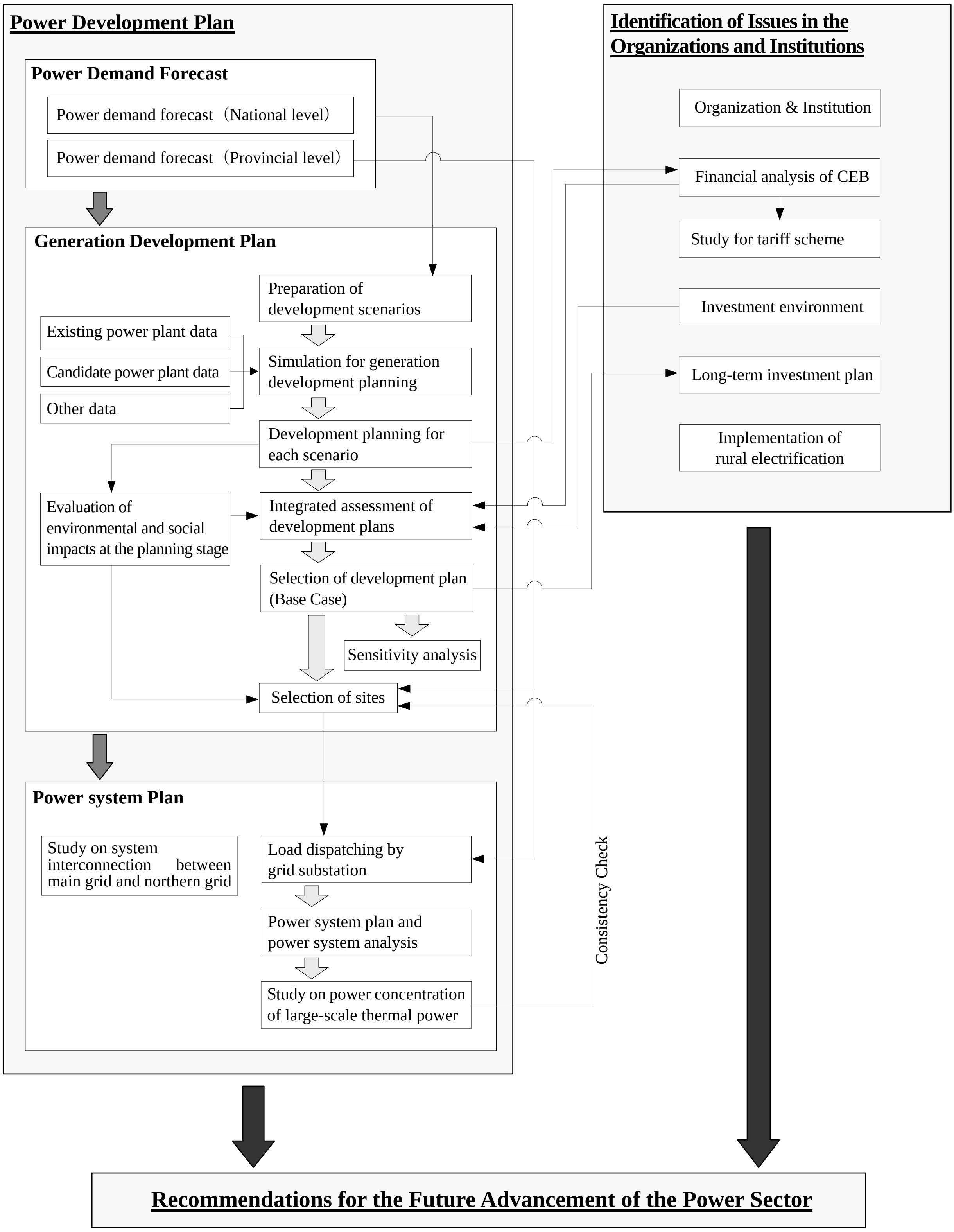



Figure 2.2 Flow of the Master Plan Formulation

### 2.3.1 Methodology for the Power Demand Forecast

Besides forecasting the demand in the power system nationwide, the Study Team made a forecast of the demand in each province[1] in order to ascertain regional demand gaps.

**(1) Power demand forecast on the national level**

Figure 2.3 shows the flow of the work for the power demand forecast on the national level.

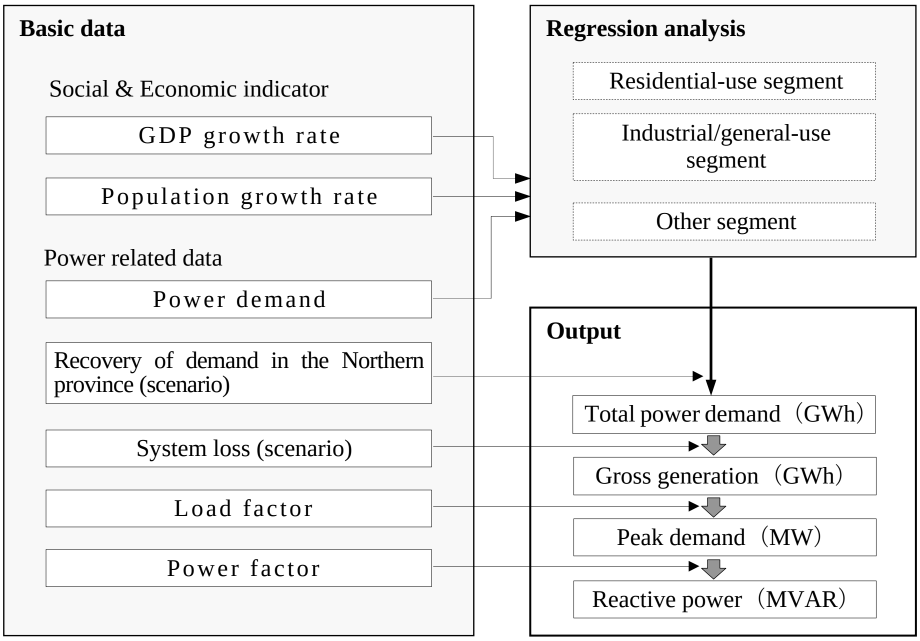



Figure 2.3 Flow of the Power Demand Forecast (National Level)

**<u>Power demand forecast procedure</u>**

The Study Team applied the econometric procedure, which is in general use for forecasting demand in power systems on the national level and facilitates acquisition of basic data and construction of forecasting models. In the econometric procedure, demand is forecast by means of correlations with economic and social indicators and trend data for the historical demand.

In addition, the Study Team divided the past power demand into three categories (residential, industrial, and "other"), and built forecasting models based on the results of a regression analysis.

**<u>Basic data</u>**

Table 2.1 presents basic data utilized in the demand forecast on the national level.

[1] The forecast utilized the supply area divisions of the CEB, which differ slightly from the administrative divisions. The former divides the Western Province into three areas - Western Province North, Western Province South, and Colombo - and has a total of 11 areas.

Table 2.1 Basic Data Utilized in the Power Demand Forecast (National Level)

| Data | Actual data | Future data |
|---|---|---|
| Annual power demand | 1985 - 2004（20 year）<br>Data source：CEB | |
| GDP[2] | 1985 - 2004（20 year）<br>Data source：Central Bank of Sri Lanka[3] | Assumed by scenario |
| Population | 1985 - 2004（20 year）<br>Data source：Department of census and statistics | Assumed by scenario |
| Power demand in the Northern province | | Assumed by scenario |
| System loss | | Assumed by scenario |
| Load factor | | 55.2% (Average during the past 20 years[4])<br>Data source：CEB |
| Power factor | | 0.894（Average during the past 6 years）<br>Data source：CEB |

**Scenario**

In making the demand forecast, the Study Team prepared a scenario for the future course of demand increase due to uncertain basic data factors such as growth in the gross domestic product (GDP) and population as well as special factors.

Table 2.2 shows the scenario used for the demand forecast on the national level. The detailed values applied in each scenario are shown in Appendix 1 (at the back of this report).

Table 2.2 Scenarios for the Power Demand Forecast (National Level)

| Item | Scenario | Estimate |
|---|---|---|
| Annual economic growth rate (%)<br>( GDP growth rate (%) ) | Low growth | 4.3%～6.0% (2005 – 2008), 6.0% (over 2009) |
| | Base case | 5.3%～7.0% (2005 – 2008), 7.0% (over 2009) |
| | High growth | 6.3%～8.0% (2005 – 2008), 8.0% (over 2009) |
| Annual population growth rate (%) | Low growth | 0.57% – -0.16% |
| | Base case | 0.99% – 0.29% |
| | High growth | 1.16% – 0.63% |
| Power demand<br>in the Northern province (GWh) | Demand recovery | Additional power demand 25.4GWh (2005 – 2007) |
| System loss (%) | System loss recovery | Decrease from 17.11% (2004) to 14.10% (2014) |

**(2) Power demand forecast on the provincial level**

For the demand forecast on the provincial level, the Study Team essentially applied the same procedure as for that on the national level, except that it used data on the provincial level.

It should be noted, however, that there were substantial constraints on the availability of time-series data and fluctuation in data values on the provincial level. For this reason, the Study Team assured conformance with the forecast values on the national level by making allocations of these values based on the estimated share of the national demand occupied by each province during the forecast period.

The basic data utilized in the forecast of the power demand on the provincial level and the details of the values applied in each scenario are shown in Appendices 2 and 3.

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[2] Gross Domestic Products
[3] Annual Report 2004, CENTRAL BANK OF SRI LANKA
[4] Excluding the years with power cuts

### 2.3.2 Methodology for Formulating Generation Development Plan

Formulation of the generation development plan required studies of not only technical factors (such as assurance of a proper degree of reliability and reduction of supply costs) but also factors in various other aspects, including consideration for the environment and society, procurement of fuel, and selection of sites.

In development of power plants, there is a particularly strong need for consideration of the impact on the environment and society. These factors, conversely, exert a strong influence on implementation of development plans. For this reason, the Study Team applied strategic environmental assessment (SEA) as a means of optimizing the development with consideration for the environment and society at the Master Plan stage.

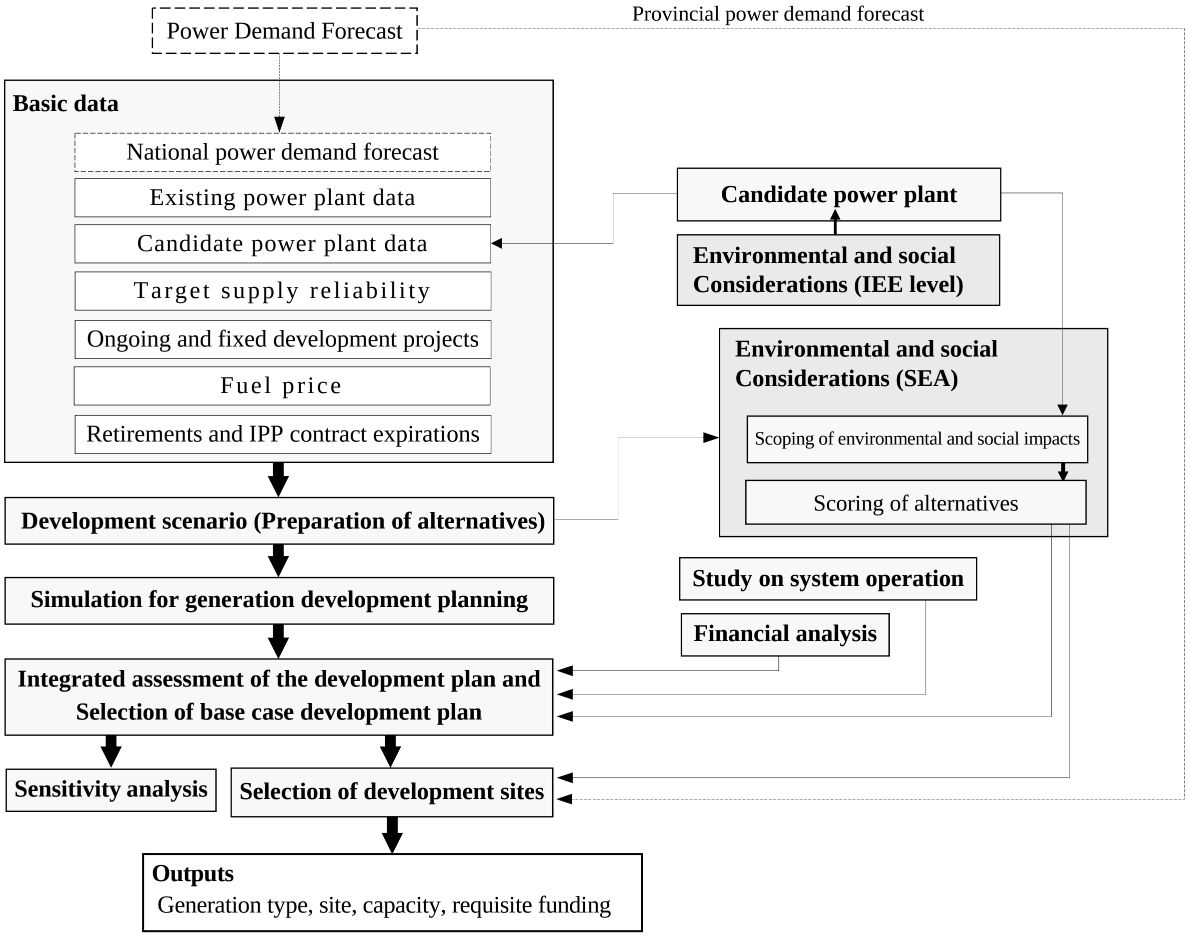



Figure 2.4 Flow of the Generation Development Planning

#### (1) Existing power plants for the plan

Considering actual operation condition, it is decided that total generation capacity of existing power plants as of 2005 for the plan is 2,211.5 MW. The list of the existing power plants for the plan is shown in Appendix 4.

#### (2) Candidate power plants

In Sri Lanka, all fuel for thermal power plants is imported, and this situation is not expected to change in the future. As a result, considering the possibilities for procurement of fossil fuels in the country, the Study Team chose facilities fueled with coal and various types of petroleum fuels as candidate thermal power plants. As the candidate sites for hydropower facilities, it selected the four sites that have already been identified as promising. It also conducted a supplementary study of the installation of power plants fueled with natural gas in order to estimate their necessity over the longer term. Table 2.3 shows the specifications of the various candidate power plants.

Furthermore, although the CEB has adopted policy for vigorous development of renewable energy resources in the forms of mini-hydropower, wind power, and dendro-thermal power, the capacity that can be added through such means is limited and cannot be anticipated to evolve into the main component of the supply to meet the growing demand, due to the low levels of supply reliability and economic merit.

Consequently, although the development of renewable energy is considered in this Master Plan, it was decided not to include these power plants as candidates in the generation development plan.

Table 2.3 Specifications of Candidate Power Plants

| | Thermal Power | | | | | | | | | | | Hydropower | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Steam Turbine | | | Gas Turbine | | | Combined Cycle*1 | | | | Diesel | 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

### (3) Preparation of development scenarios

The Study Team prepared a plural number of development plans grounded in the development scenarios and integrated assessments from a variety of standpoints including the environmental one.

For the Master Plan, the Study Team prepared four scenarios noted below for the generation development plan.

1) Scenario of development of large-scale thermal power plants
   - Absence of constraints on capacity
2) Scenario of no development of large-scale thermal power plants
   - Presence of constraints on capacity (no more than 150MW per generation unit)
3) Scenario of hydropower development oriented
   - Promotion of hydropower development for promising hydropower projects[5]
4) Scenario of natural gas introduction
   - Supply of Natural gas beginning in 2020

### (4) Retirements and IPP contract expirations

In preparing the plan, the Study Team took account of the number of IPP power plants that would be closed or taken off the grid due to expiration of power purchasing contracts. A list of such facilities, which were excluded from the supply capacity, is contained in Table 2.4.

[5] It was decided to take the results from the case of a 2% discount rate as reference and develop a total of 261 MW of facilities at four locations: Broadlands (in 2011), Gin Ganga (in 2014), Moragolla (in 2014), and Uma Oya (in 2016). This corresponds to approximately 30% of the total 877 MW of potential hydro energy identified in the master plan survey conducted in 1989.

Table 2.4 Retired or IPP Contract Expired Power Plants

| Owner | Power Plant | Unit Cap. (MW) | Retirement or expiration of IPP contract | Operating 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 1-10 | 10.00 | 2015 | | | | | | | | | | | | | | | | | |
| | IPP AES Kelanitissa (Private) Lmited | 163.00 | 2024 | | | | | | | | | | | | | | | | | |

**(5) Projects under way or anticipated**

The Study Team incorporated projects whose construction is now under way or anticipated to start into the development plan as capacity.

- Kerawalapitiya combined cycle thermal power plant
  - 2008: start of operation of gas turbine generators, 200 MW (100 MW x two units)
  - 2009: start of operation of additional steam turbine generators (achievement of a combined-cycle system), 300 MW (150 MW x two units)
- Upper Kotmale hydropower project
  - End of 2010: start of operation of 150 MW (75 MW x two units)

**(6) Targeted supply reliability**

The Study Team applied a loss of load probability (LOLP) of no more than 0.822 %[6], which is the target value used in the existing generation development plan.

**(7) Integrated assessment of the development plan**

The Study Team made a comparative assessment of the generation development plans prepared under each scenario with respect to economic merit, system operation, finances, and environmental impact, and adopted that regarded as the optimal one as the base-case plan.

**(8) Selection of development sites**

The Study Team made a review, in the technical, environmental, and social aspects, of sites that had been studied in the past, and selected candidate sites for future development. This was followed by identification of specific sites from the list of candidates with a view to assuring a proper supply-demand balance in each area, as far as possible. In addition, the propriety of selections was checked by examining the aspect of system operation, because the selection of sites has a big impact on formulation of the power system plan.

**(9) Sensitivity analysis**

The Study Team made a sensitivity analysis for fuel prices and discount rates in base case.

[6] The Study Team did not set a targeted supply reliability for the years 2006 - 2008, when no candidate plant is to be added.

### 2.3.3 Methodology for Formulating Power System Plan

Efficient supply of power generated at the plants to all parts of Sri Lanka requires expansion of the power system. In promoting this expansion, it is vital to consider factors such as the size of demand in each region, the economic merit of the plan as a whole, the system reliability and voltage to be assured, and the flexibility of system operation. Like that for generation development, the plan must also exhibit concern for the environmental and social aspect.

For the Master Plan, the Study Team formulated a power system plan that takes account of these aspects from a long-term perspective.

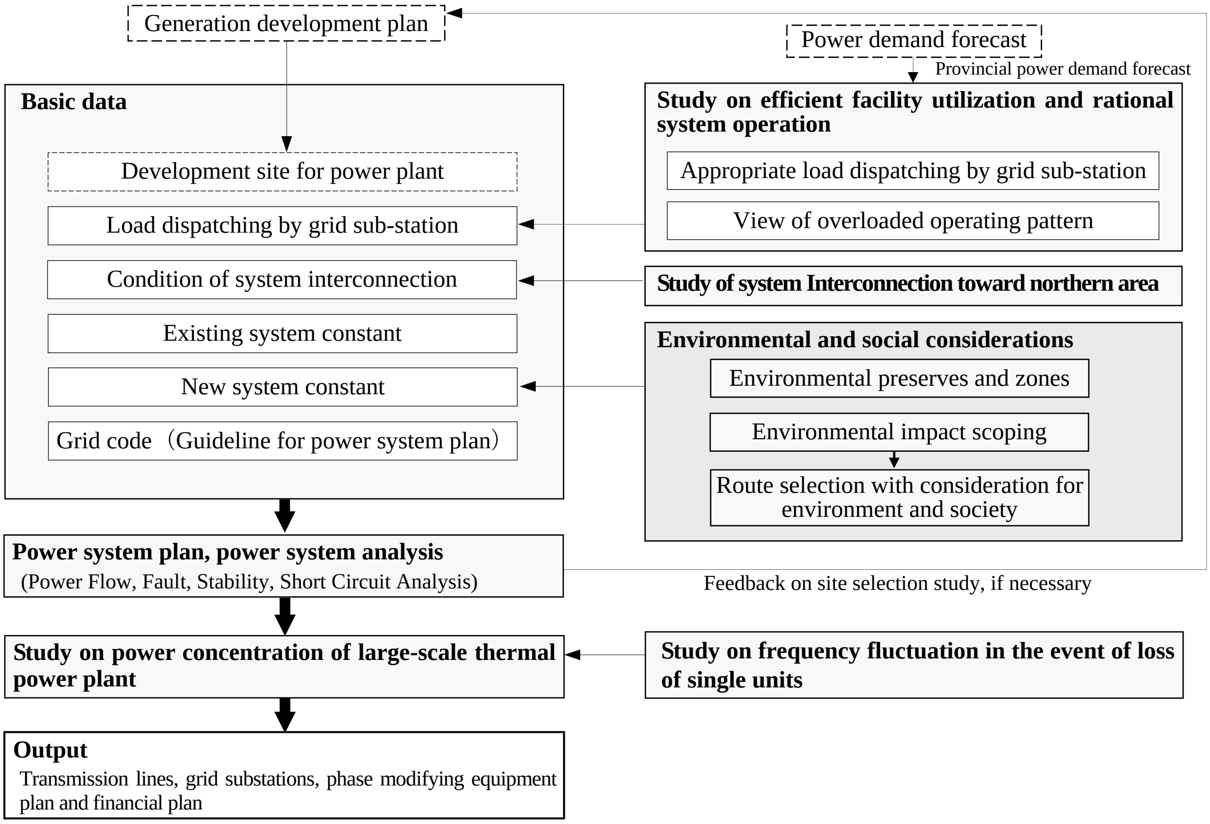



Figure 2.5 Flow of the Power System Planning

**(1) Efficient facility utilization and rational system operation**

The load on the major transformation facilities is a key parameter for determination of the system composition. Proper distribution of load among grid substations is linked to efficient operation, and therefore is a crucial priority. System switchover at times of facility failure is a way of making maximum use of the performance of transmission and substations. Due consideration of such switchover when formulating plans can yield major planning benefits, i.e., contraction of the required facility addition and deferral of the addition timing.

In light of these factors, the Study Team considered efficient facility use and rational system operation in formulation of the power system plan.

**(2) Study of system interconnection between main grid and northern grid**

The northern region is currently detached from the central grid. The Study Team made a comparative study of options for power supply to this region (independent system vs. system interconnection) with respect to economic merit and power supply reliability.

### (3) Study of power development sites from the aspect of system operation

In the future, the system configuration will come to depend heavily on the newly developed sites. As such, the selection of sites demands studies from the aspect of stable system operation further in the future as well. The northern and eastern regions currently lack power, and it could be difficult to provide them with a stable supply of power as the demand increases over the coming years. In response, the Study Team examined the need for and advantages of construction of power plants in these regions as regards system operation.

### (4) Study of concentration of large-scale thermal power plants

Of the sites selected in the generation development plan, the large-scale thermal power sites will have a particularly big influence on the plan for power system. To examine the propriety of the sites selected for large-scale thermal power plants in the power development plan, the Study Team studied the case of concentration of large-scale thermal power plants.

### (5) Study of frequency fluctuation in the event of loss of single units

Unforeseen failure and shutdown of generation facilities can result in a drop in the system frequency and, by extension, supply stability. If the frequency drop cannot be corrected, it could compel a suspension of the supply in the entire system. In the case of large-scale power plants, the loss of units would presumably have a bigger impact on system operation.

The Study Team therefore made a study of system frequency fluctuation in the event of the loss of generation units to assess the impact on system operation.

## 2.3.4 Methodology for Consideration of Environmental and Social Factors

In formulation of the generation development plan and power system plan in the Master Plan, the Study Team made studies for consideration of environmental and social factors. The Study Team applied the SEA perspective to comparison of alternatives in formulation of the generation development plan as the core of the power development plan

### (1) Consideration of environmental and social factors in the generation development plan

The Study Team applied the perspective used in SEA to its formulation. In other words, the Study Team compared alternative options based on different development scenarios to examine the relative merits of each option from a variety of perspectives including the environment, and integrated the assessment results to select the best generation development plan for the Master Plan.

In assessing the alternatives, the Study Team conducted environmental scoping applied to the Master Plan stage. More specifically, it assessed the major environmental and social impacts of each type of power facility using a preliminary checklist, and scored the degree of total impacts in each alternative plan to feed the findings back into the study of the plan.

In addition, the Study Team held stakeholder meetings (SHM) on the planning stage in order to obtain the views of various parties (e.g., administrative authorities, business people, NGOs, experts from universities and other organizations, and the general public) on the formulation and reflect them in the studies.

### (2) Consideration of environmental and social factors in the power system plan

In formulation of the power system plan, the Study Team identified areas where development is restricted and selected transmission line routes that would not to impinge on them.

# 3 Master Plan Features and Study Results

## 3.1 Power Development Plan

### 3.1.1 Power Demand Forecast

**(1) Results of the power demand forecast on the national level**

In the base-case scenario, the 2025 gross generation is projected to total 36,843 GWh, and the peak demand, 7,619 MW. These figures are about 4.9 times as high as those in 2004. Over the intervening years, the peak demand would grow by an annualized rate of 7.8 %.

In the low and high growth scenarios, it is estimated that the peak demand would grow by corresponding rates of 7.1 and 8.8 %, respectively.

Table 3.1 Power Demand Forecast on the National Level (Base Case)

| | Year | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
| Energy Sales (GWh) | 7,113 | 7,614 | 8,191 | 8,827 | 9,548 | 10,327 | 11,166 | 12,070 | 13,040 | 14,079 | 15,190 | 16,378 | 17,654 | 19,019 | 20,480 | 22,040 | 23,708 | 25,497 | 27,412 | 29,459 | 31,648 |
| Generation energy (GWh) | 8,547 | 9,112 | 9,764 | 10,482 | 11,295 | 12,172 | 13,114 | 14,127 | 15,210 | 16,390 | 17,683 | 19,066 | 20,552 | 22,141 | 23,842 | 25,658 | 27,600 | 29,682 | 31,912 | 34,295 | 36,843 |
| Peak Demand (MW) | 1,768 | 1,884 | 2,019 | 2,168 | 2,336 | 2,517 | 2,712 | 2,921 | 3,146 | 3,389 | 3,657 | 3,943 | 4,250 | 4,579 | 4,931 | 5,306 | 5,708 | 6,138 | 6,599 | 7,092 | 7,619 |
| Reactive Power (Mvar) | 886 | 944 | 1,012 | 1,086 | 1,171 | 1,262 | 1,359 | 1,464 | 1,577 | 1,699 | 1,833 | 1,976 | 2,130 | 2,295 | 2,471 | 2,659 | 2,861 | 3,077 | 3,308 | 3,555 | 3,819 |

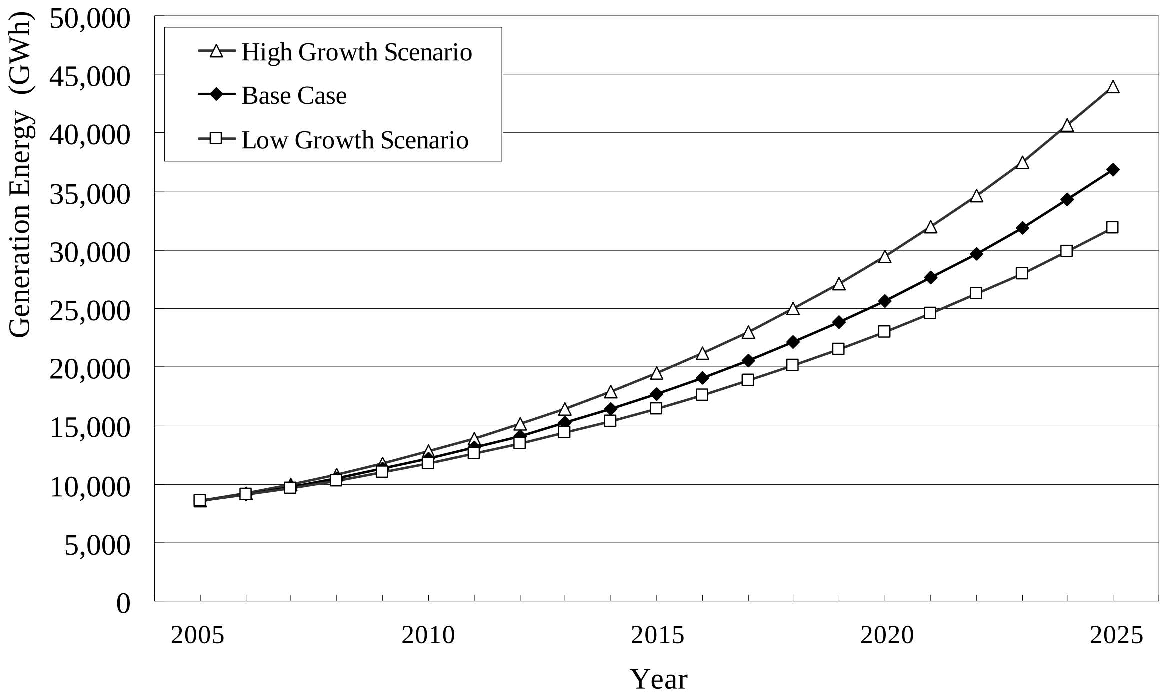



Figure 3.1 Generation Energy Forecast on the National Level

**(2) Results of the power demand forecast on the provincial level**

According to the results of the forecast of peak demand in each region, in 2025, the demand in the western coastal region (consisting of the Western Province North, Western Province South, and Colombo City areas) would account for more than 50 % of the total demand. This region is therefore expected to continue leading demand growth. Growth is expected to be particularly rapid in the Western Province North and South areas, and satisfaction of the demand in them will require the development of generation facilities and expansion of transmission and substation facilities.

While the shares of the demand occupied by the Northern and Eastern provinces will not be very large even in 2025, their peak demands are forecast at 106 and 291MW, respectively, and the Study Team conducted a study on ways to supply power to these provinces (details are presented in section 3.1.3).

Table 3.2 and Appendix 5 show the results of the demand forecast for each province.

Table 3.2 Peak Demand Forecast on the Provincial Level (Base Case)

| | Year | | | | | | | | | | | | | | | | | | | | | Ratio | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2005 | 2025 |
| Western -North- | 308 | 329 | 353 | 381 | 412 | 446 | 483 | 522 | 564 | 611 | 662 | 717 | 776 | 840 | 909 | 983 | 1,063 | 1,150 | 1,243 | 1,343 | 1,451 | 17.4 | 19.0 |
| Western -South- | 405 | 432 | 465 | 501 | 542 | 587 | 635 | 688 | 744 | 805 | 873 | 945 | 1,024 | 1,108 | 1,199 | 1,297 | 1,402 | 1,516 | 1,639 | 1,771 | 1,914 | 22.9 | 25.1 |
| Colombo (Night) | 163 | 169 | 177 | 185 | 195 | 205 | 216 | 227 | 239 | 252 | 266 | 281 | 296 | 312 | 329 | 347 | 366 | 386 | 406 | 428 | 451 | 9.2 | 5.9 |
| Colombo (Day) | 219 | 227 | 238 | 249 | 262 | 276 | 291 | 306 | 322 | 339 | 358 | 377 | 398 | 420 | 443 | 467 | 492 | 519 | 547 | 576 | 607 | — | — |
| Southern | 153 | 165 | 180 | 195 | 212 | 231 | 251 | 272 | 295 | 319 | 346 | 375 | 406 | 438 | 473 | 511 | 550 | 593 | 638 | 686 | 737 | 8.6 | 9.7 |
| Sabaragamuwa | 103 | 109 | 116 | 124 | 132 | 141 | 151 | 162 | 174 | 186 | 200 | 214 | 230 | 246 | 264 | 283 | 303 | 324 | 346 | 370 | 395 | 5.8 | 5.2 |
| Central | 185 | 196 | 209 | 222 | 237 | 253 | 271 | 290 | 310 | 332 | 356 | 382 | 410 | 439 | 470 | 503 | 538 | 575 | 615 | 657 | 701 | 10.5 | 9.2 |
| Uva | 37 | 39 | 41 | 44 | 47 | 51 | 54 | 58 | 62 | 67 | 72 | 77 | 83 | 89 | 95 | 102 | 109 | 117 | 125 | 134 | 143 | 2.1 | 1.9 |
| Eeastern | 80 | 84 | 89 | 94 | 100 | 107 | 114 | 121 | 129 | 138 | 148 | 159 | 170 | 182 | 195 | 208 | 223 | 238 | 255 | 272 | 291 | 4.5 | 3.8 |
| North Western | 203 | 220 | 239 | 260 | 283 | 308 | 335 | 363 | 394 | 426 | 462 | 500 | 541 | 584 | 631 | 680 | 733 | 789 | 848 | 912 | 979 | 11.5 | 12.9 |
| North Central | 94 | 101 | 110 | 120 | 130 | 141 | 154 | 167 | 180 | 196 | 212 | 230 | 248 | 269 | 290 | 313 | 337 | 363 | 390 | 420 | 451 | 5.3 | 5.9 |
| Northern | 37 | 38 | 40 | 42 | 44 | 46 | 49 | 51 | 54 | 57 | 60 | 64 | 67 | 71 | 75 | 80 | 84 | 89 | 95 | 100 | 106 | 2.1 | 1.4 |
| Total* | 1,768 | 1,884 | 2,019 | 2,168 | 2,336 | 2,517 | 2,712 | 2,921 | 3,146 | 3,389 | 3,657 | 3,943 | 4,250 | 4,579 | 4,931 | 5,306 | 5,708 | 6,138 | 6,599 | 7,092 | 7,619 | 100.0 | 100.0 |

* Note : Night peak demand for Colombo City

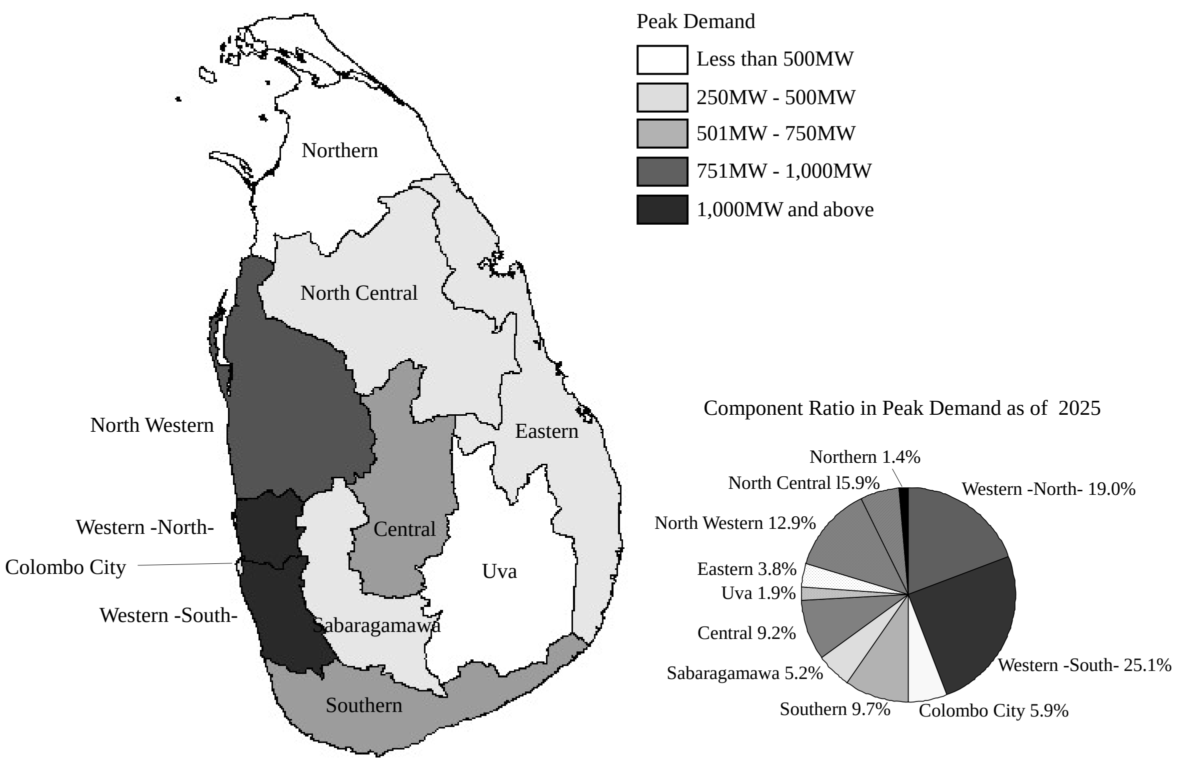



Figure 3.2 Forecasted Peak Demand on the Provincial Level as of 2005 (Base Case)

### 3.1.2 Generation Development Plan

**(1) Comparison of development plans**

Table 3.3 shows the capacities of power plants added in the years up to and including 2025 in each scenario.

Table 3.3 Generation Unit Capacity Added to 2025

Abbrev. TPP: Thermal Power Plant (Unit: MW)

| Scenario | | Thermal Power | | | | Hydropower | Total |
|---|---|---|---|---|---|---|---|
| | | Coal-fired ST | Diesel | Combined Cycle | Gas Turbine | | |
| Development of Large-scale TPP | | 5,100 | 0 | 300 | 1,615 | 150 | 7,165 |
| No Development of Large-scase TPP | Low speed unit | 0 | 4,900 | 300 | 2,170 | 234 | 7,604 |
| | Mid. speed unit | 0 | 5,300 | 300 | 1,890 | 150 | 7,640 |
| Hydropower Development Oriented | | 4,800 | 0 | 300 | 1,615 | 411 | 7,126 |
| Natural Gas Supply* (in and after 2020) | | 4,800 | 0 | 900 | 1,335 | 150 | 7,185 |

*Note: assumed 6.0USD/MMBTU

The result of the large-scale thermal power development scenario was that coal-fired thermal power plants would be developed as base power plants from the year 2011 on. By 2025, the additional capacity would amount to 5,100 MW (17 generation units of 300 MW capacity each). As peak power units, 1,615 MW of gas turbine thermal power plants would be developed by 2025. The development of hydropower plants would end with the 150 MW Upper Kotmale hydropower project (to begin operating at the end of 2010), which is a fixed project for development. The total cost[7] up to the year 2025 amounts to approximately 5.92 billion US dollars, of which fuel costs account for approximately 60% (See Figure 3.3).

Meanwhile, the scenario of no large-scale thermal power development calls for the development of 4,900 MW of diesel power units as base power sources by the year 2025 (in the case of low-speed generation units). The costs amount to approximately 7.32 billion US dollars, which is about 20% higher than in the other three scenarios. This cost difference is due primarily to the differing costs of fuels used in the coal-fired thermal power plants and the diesel power plants that would serve as the base power plants. In case of the development of middle-speed generation units[8], the total cost up to 2025 amounts to approximately 6.35 billion US dollars, which is also larger than in the other three scenarios, and the fuel cost is estimated to be about the same as that in the case of low-speed.

The hydropower-oriented scenario posits development of 261 MW of hydropower capacity at four locations that were considered promising for development.

As in the case of the large-scale thermal power development scenario, greater development of coal-fired thermal power as base power plants would be carried out. The total cost would amount to approximately 6.03 billion US dollars by the year 2025. Although this is more than in the large-scale thermal power development scenario, the difference is about 2%, so the costs are roughly equal.

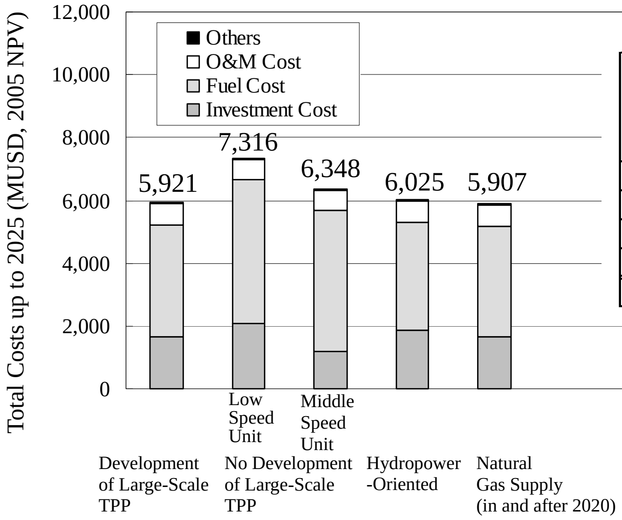
The natural gas supply scenario was similar to the large-scale thermal power development scenario in that coal-fired thermal power plants were to be developed for base power. Natural gas (6.0USD/MMBTU) would be supplied from the year 2020 on so that the development of combined-cycle power plants that use

[7] 2005 NPV of total cost up to 2025

[8] Development cost including interest during construction and life time were estimated as 700 US dollars per kW and 15 years, respectively.

natural gas as fuel would become more economically efficient. During the period from 2023 to 2025, combined-cycle power plants with the total capacity of 600 MW would be developed (300 MW x 2 generators).

The total cost up to the year 2025 would amount to approximately 5.91 billion US dollars. Although the reduction in fuel costs makes this total smaller than that of the large-scale thermal power development scenario, the difference is extremely small, and the two are nearly the same.




Abbrev. TPP: Thermal Power Plant (Unit: million USD, 2005 NPV)

| | Development of Large-Scale | No Development of Large-Scale TPP | | Hydropower -Oriented | Natural Gas Supply (2020-) |
|---|---|---|---|---|---|
| | | Low Speed Unit | Mid. Speed Unit | | |
| Investment Cost | 1,656 | 2,085 | 1,166 | 1,846 | 1,658 |
| Fuel Cost | 3,551 | 4,557 | 4,508 | 3,472 | 3,535 |
| O&M Cost | 669 | 631 | 632 | 662 | 669 |
| Others | 45 | 43 | 42 | 44 | 46 |
| Total | 5,921 | 7,316 | 6,348 | 6,025 | 5,907 |

Figure 3.3 Comparison of Total Costs (in terms of 2005 NPV)

The results show that development under the scenario of no development of large-scale thermal power plants would be difficult to assure a sufficient spinning reserve for the system as a whole because the system would include many small diesel facilities. Studies in the aspect of system operation revealed that a decline in frequency could not be avoided in the event of unscheduled shutdown due to an accidental failure, and this could very well compel supply suspension over the entire system.

Analysis of future CEB finances in the case of each plan revealed that, in that without development of large-scale thermal power plants, the finances would collapse if the current tariff scheme remains in place, because the generation costs would be driven up by the higher fuel costs. In the plan positing the addition of many coal-fired plants, on the contrary, the finances could be expected to improve due to the lower fuel costs (details are presented in Section 3.2.3).

As for the impact of the facility development and operation on the surrounding society and environment, the Study Team identified items of anticipated impact and assessed the degree of impact strength for each type of power plant. It then scored the environmental and social impact of each development plan based on the results of this assessment and the number of units of each type of plant to be added during the subject period. The results show that development plans under the no large-scale thermal power development scenario would have a greater impact than they would under the other three scenarios. As to the other two scenarios, the natural gas supply scenario was predicted to have a smaller impact than the large-scale thermal power development scenario, and the hydropower-oriented scenario, a greater impact. There was very little difference among the scenarios in this regard, however.

The total cost and environmental impact under the natural gas supply scenario were shown to be smaller than under the large-scale thermal power development scenario. The difference was of very slight magnitude, however, and the capacity of power plants added after 2020 remained at 600 MW for combined cycle generation facilities fueled by natural gas.

The natural gas supply scenario appears to lack feasibility at this point, considering the results of past surveys[9] conducted on the introduction of natural gas carried out in 2003, and the absence of any specific plan for the introduction of natural gas as of November 2005. The supply prices also vary for natural gas according to the project. At present, therefore, no specific supply prices are shown.

In this way, as a result of assessment of the each development plan from various perspectives including cost, system operation, impact on CEB finances, impact on environment, and feasibility, it was decided to employ the large-scale thermal power development scenario as the base case in the generation development plan of the Master Plan.

Table 3.4 Comparison of Generation Development Plan of each Development Scenario

| Development Scenario | Total Costs up to 2025[*1] | System Operation | CEB Finances | Environmental Impact Score | Others |
|---|---|---|---|---|---|
| Development of Large-scale TPP | 5,921 MUSD | stable operation | improved | 1,954 points | |
| No Development of Large-scale TPP[*2] | 7,316 MUSD | with possibility for total system failure | probable collapse | 2,428 points | |
| Hydropower-Oriented | 6,025 MUSD | stable operation | improved | 2,036 points | |
| Natural Gas Supply (in and after 2020) | 5,907 MUSD | stable operation | improved | 1,950 points | lack of clear prospects for natural gas introduction |

*1 : 2005 NPV
*2 : In the case of low-speed generation units

### (2) Generation Development Plan (Base Case)

The generation development plan in the base case would consist almost entirely of thermal power plants. The share of the total capacity occupied by hydropower would decline to about 16 % in 2025, or about one-third as high as the corresponding share of 51 % in 2005. In terms of generated output, the hydropower share would drop to about 14 %. The shift from hydropower to thermal power as the main type of power plant would therefore deepen over the coming years.

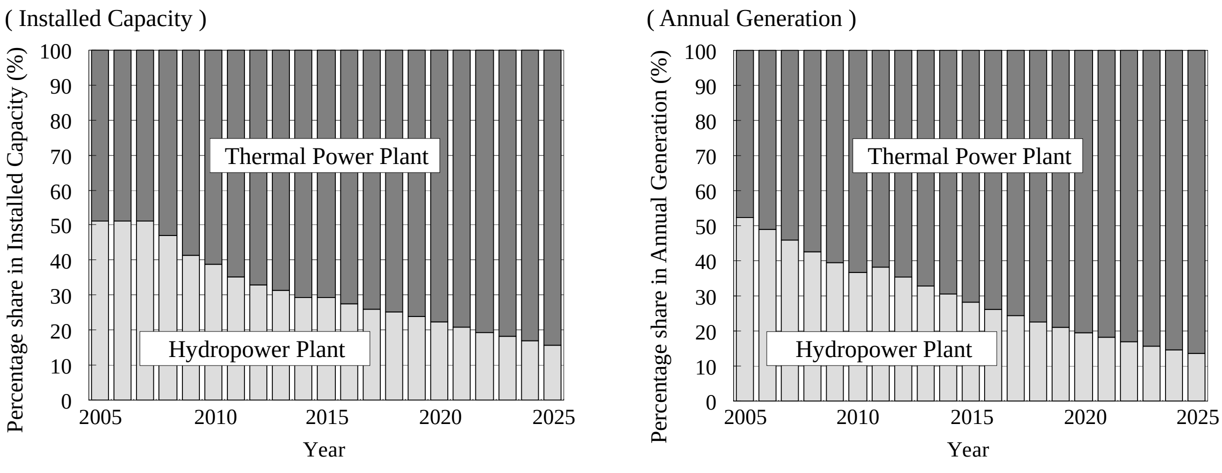



Figure 3.4 Capacity Mix and Generation Mix over next 20 years (Base Case)

9 The "Sri Lanka Natural Gas Options Study" conducted with funding from USAID in 2003 concluded that natural gas demand in Sri Lanka is below the level required to make a LNG project economic.

Over the years 2006 - 2008, the LOLP would exceed 1 %, and the power supply over this period would be tighter than in 2005 (See Figure 3.5). The LOLP would reach 3.76 and 2.79 % in 2007 and 2008, respectively. Unless there is an increase in the emergency supply capacity, short-term countermeasures in the demand aspect (e.g., demand-side management) would be required to equalize the supply-demand balance.

There are strong needs for prompt implementation of the project for construction of a combined-cycle power plant at Kerawalapitiya, as the supply situation would be particularly serious in 2008 if the plant is not in operation by then.

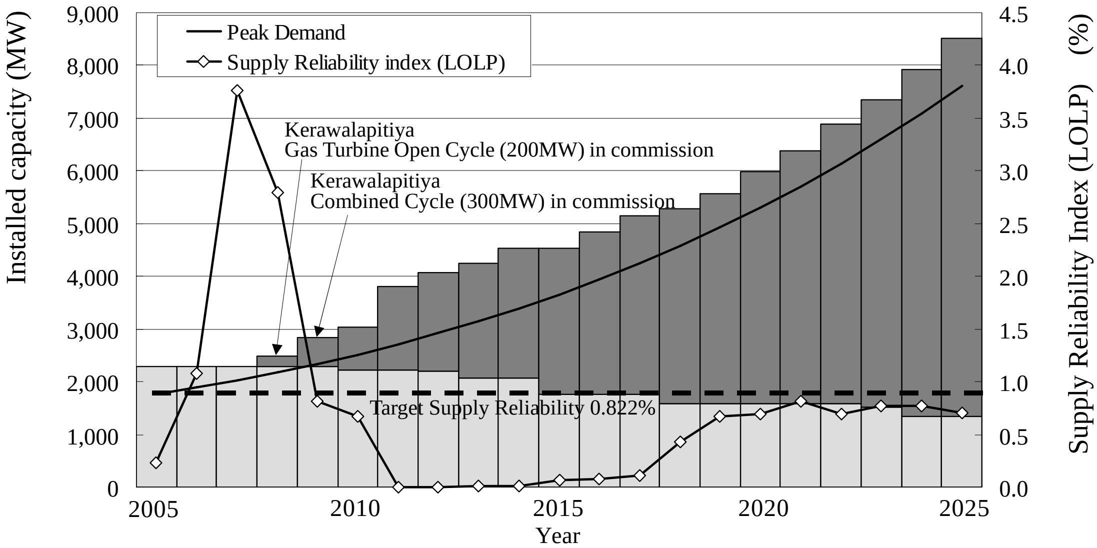



Figure 3.5 Supply Reliability Index (LOLP) over next 20 years (Base Case)

Coal consumption would increase rapidly beginning in 2011, and the annual consumption in 2025 is estimated at over 11 million MT. This means that an additional nearly 500,000 MT would have to be purchased every year. Sure purchase of this coal would be a prerequisite for execution of the plan. Meanwhile, it is essential to include appropriate considerations for social and environmental factors from the planning stage of the project, as well as to properly carry them out during the implementation stage.

A generation mix with a heavy dependence on coal is preferable as viewed from the standpoint of economical generation, but may not be preferable as viewed from that of energy security, seeing that Sri Lanka has to depend on import for all of its fossil fuel consumption. Therefore, appropriate operation and rehabilitation of existing hydropower should be conducted and also studies would have to be made of new fuel options and other aspects of energy policy in order to improve energy security after the addition of coal-fired plants.

Table 3.5 Fuel Requirement (Base Case)

| Fuel Type | | Year 2005 | 2010 | 2015 | 2020 | 2025 |
|---|---|---|---|---|---|---|
| Auto Diesel Oil | (millions of liters) | 55 | 813 | 102 | 117 | 256 |
| Furnace Oil | (millions of liters) | 451 | 490 | 0 | 0 | 0 |
| Residual oil | (millions of liters) | 281 | 281 | 78 | 21 | 0 |
| Naphtha | (millions of liters) | 106 | 224 | 55 | 35 | 34 |
| Coal | (kilotons) | 0 | 0 | 4,252 | 7,260 | 11,219 |

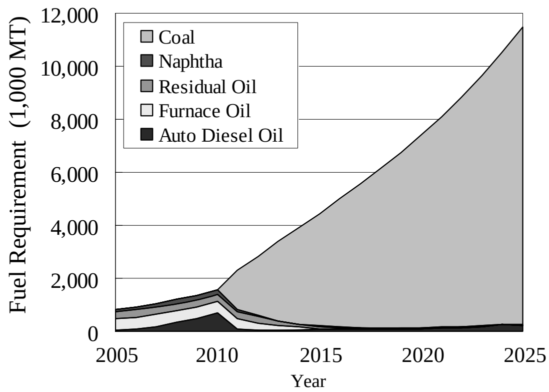



Figure 3.6 Fuel Requirement (Base Case)

The investment cost over the subject period would top 7.3 billion US dollars, and almost all of it would be spent on development of coal-fired plants beginning in 2011. Due to the development of coal-fired plants, which offer lower fuel costs, the fuel costs over the years 2011 - 2015 would be lower than before 2011 (See Table 3.6).

Table 3.6 Various Costs (Base Case)

( Unit : million USD )

| Costs | Period | | | | Total |
|---|---|---|---|---|---|
| | 2006 - 2010 | 2011 - 2015 | 2016 - 2020 | 2021 - 2025 | |
| Investment Cost | 244 | 2,347 | 2,002 | 2,781 | 7,374 |
| Fuel Cost | 1,967 | 1,621 | 2,333 | 3,703 | 9,624 |
| O&M Cost | 327 | 366 | 418 | 582 | 1,693 |
| ENS Cost | 49 | 0 | 13 | 29 | 91 |
| Period Total | 2,587 | 4,334 | 4,766 | 7,095 | 18,782 |

**(3) Selection of development sites**

Based on the results of the demand forecast on the provincial level, the Study Team defined two areas: the southwestern area consisting of the provinces on the western coast and the Southern Province, where rapid demand growth is anticipated, and the northern, central, and eastern area consisting of the other provinces. It then specified sites for generation development that would maintain the supply-demand balance in each area as far as possible, while taking account of the distance from the demand center.

In specifying sites for development of gas turbine and combined-cycle power plants, aside from the sites already surveyed and others in the vicinity of existing generation facilities, it made selections from sites in the vicinity of places where port and harbor facilities exist or are planned, in light of the need to procure (import) fuel.

The sites that were surveyed in past years for siting of coal-fired plants number only three (Puttalam, Hambantota, and Trincomalee), and the possibilities of development in other places remain unclear. The Study Team therefore took these three as the prospective areas for development of coal-fired plants.

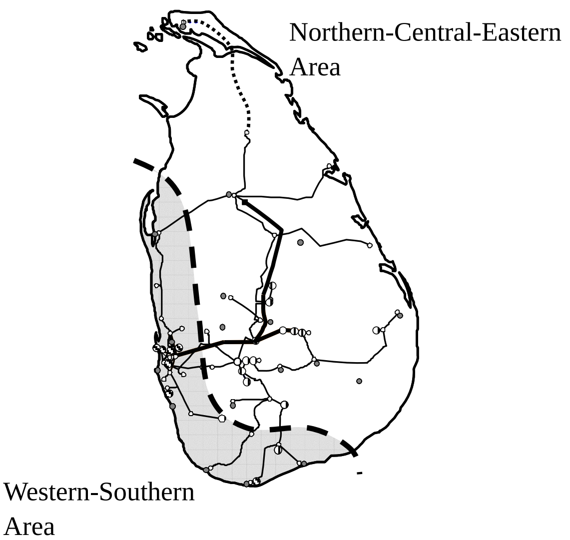



Figure 3.7 Areas for Supply-demand Balance

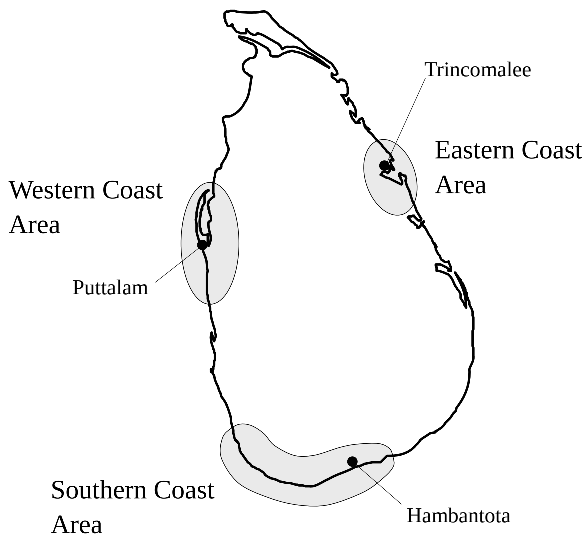



Figure 3.8 Prospective Areas for Development of Coal-fired Plants

Appendix 6 shows figures for the supply-demand balance over the subject period in each area.

In the southwestern area, the province with the most rapid demand growth would be the Western Province (northern half). For supply mainly to this area and Colombo, a coal-fired thermal power plant in the 900-megawatt class is to be constructed at Puttalam beginning in 2011. The demand is also forecast to increase in the Western Province (southern half) and the Southern Province, and this is motivating the construction of another coal-fired plant in Southern Coast Area beginning in 2013. The plans for construction of a third coal-fired plant in Eastern Coast Area beginning in 2017 are aimed at meeting the demand increase in the northern, central, and eastern area. The Study Team indicated areas where coal-fired plants should be developed. It is necessary to make an effort to explore new prospective candidate sites in these areas for future development and evaluate their feasibility.

The Study Team also examined the supply stability in the Northern, Eastern, and Southern provinces over the subject period. It found that it would be necessary to site power plant in these provinces for the purpose of system operation. As such, the Study Team posited the siting of gas turbine thermal power plants in these areas.

Table 3.7 Detailed Generation Development Plan (Base Case)

| Year | Coal-fired TPP | Gas Turbine TPP | Combined Cycle TPP | Hydropower Plant |
|---|---|---|---|---|
| 2009 | | Kerawalapitiya 105MW<br>Galle 105MW<br>Trincomalee 35MW | Kerawalapitiya 300MW | |
| 2010 | | Kerawalapitiya 105MW<br>Paddirippu* 75MW<br>Ampara* 75MW<br>Jaffna 35MW | | |
| 2011 | Western Coast Area (Puttalam) 600MW | | | Upper Kotmale 150MW |
| 2012 | Western Coast Area (Puttalam) 300MW | | | |
| 2013 | Southern Coast Area (Hambantota) 300MW | | | |
| 2014 | Southern Coast Area (Hambantota) 300MW | | | |
| 2015 | Southern Coast Area (Hambantota) 300MW | | | |
| 2016 | Southern Coast Area (Hambantota) 300MW | | | |
| 2017 | Eastern Coast Area (Trincomalee) 300MW | | | |
| 2018 | Eastern Coast Area (Trincomalee) 300MW | | | |
| 2019 | Eastern Coast Area (Trincomalee) 300MW | | | |
| 2020 | Western Coast Area 300MW | Puttalam 105MW<br>Jaffna 35MW | | |
| 2021 | Western Coast Area 300MW | Galle 105MW | | |
| 2022 | Western Coast Area 300MW | Kerawalapitiya 105MW<br>Puttalam 105MW | | |
| 2023 | Western Coast Area 300MW | Panipitiya 210MW | | |
| 2024 | Southern Coast Area 300MW | Sapugasukanda 105MW<br>Sapugasukanda 105MW<br>Panipitiya 105MW<br>Matara 105MW | | |
| 2025 | Southern Coast Area 600MW | | | |
| Total | 5,100MW | 1,620MW | 300MW | 150MW |

*Note : Development of gas turbine power plants in eastern coast area premises implementation of a harbor project at Oluwil

**(4) Impact of Introducing Natural Gas into the Power Sector**

In the scenario of natural gas supply, the capacity of combined-cycle power plants added over the subject period would come to 900 MW, 600 more than in the base case as the result of giving an assumption that natural gas (6.0 USD/MMBTU) will be available for the power sector in and after 2020. In contrast, the additional capacity of coal-fired and gas turbine plants would be less than in the base case at 300 and 280 MW, respectively.

The total cost over the subject period is estimated at 5.91 billion US dollars (2005 NPV), about 14 million US dollars less than in the base case. This indicates that initiation of natural gas supply would bring a better generation mix.

Natural gas would presumably have the additional benefits of curtailing the substantial increase in $CO_2$ emissions due to the operation of coal-fired plants, improvement of energy security through diversification of energy sources, and stabilization of the system operation through installation of combined-cycle systems with a high load-following flexibility. As such, it must be termed a highly promising fuel option in the power sector after the construction of coal-fired plants.

**(5) Results of the sensitivity analysis**

Appendices 7 and 8 present the detailed results of the sensitivity analysis.

(i) Fuel prices

Fuel prices utilized in the generation development plan were set on the basis of crude oil prices in Colombo. In the base case, the crude oil price was about 42 US dollars per barrel.

If crude oil prices in Colombo rose to 80 US dollars per barrel, hydropower plants would take precedence over thermal power ones in development, and an additional three with a combined capacity of 234 MW would be built over the subject period. The addition of coal-fired capacity would be 300 MW higher than in the base case, and that of gas turbine capacity, 405 MW lower.

(ii) Discount rates

At a discount rate of 2 %, all candidate hydropower sites would be developed, and an additional five plants with a combined capacity of 411 MW would be built over the subject period. As compared to the base case, the addition of coal-fired capacity would be 600 MW higher, and that of gas turbine capacity, 875 MW lower. At a discount rate of 6 %, the addition mix over the subject period would be the same as in the base case.

### 3.1.3 Power System Plan

#### (1) Development projects to 2025

Along with the generation development plan, the network of transmission and substation facilities would have to be built up, mainly through construction of 220 kV facilities.

The Study Team envisioned the construction, in 2008, of a second 220 kV line stringing from Kotmale to Anuradhapura, and a new 220 kV transmission line with the start of the gas turbine open-cycle plant at Kerawalapitiya.

This would be followed in 2011 by the construction of a second outer loop of 220 kV trunk transmission lines linking Veyangoda, Kirindiwela, Ambulgama, and Matugama, in order to supply stable power to Colombo and vicinity.

The development of large-scale coal-fired plants beginning in 2011 would have to be accompanied by the construction of 220 kV transmission and substation facilities to take their power. Appendices 9 and 10 present lists of all development projects in the power system plan.

Table 3.8 Power System Plan for Trunk System (220kV)

| Year | Transmission Lines（220kV） | | | | | Year | Grid Substations, Switching Stations (220kV) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Line Section | Type | Bundles | cct* | Length (km) | | G/S | Capacity (MVA) | Units* |
| 2005 | | | | | | 2005 - 2010 | Kotmale | 250 | 1 |
| 2006 | | | | | | | | | |
| 2007 | | | | | | | | | |
| 2008 | Kotugoda～Kerawalapitiya | zebra | 2 | 2 | 18.0 | | | | |
| | Kerawalapitiya～Kelanitissa | CV1600 | 1 | 2 | 14.4 | | | | |
| | Kotmale～Anuradhapura | zebra | 1 | +1 (2) | 163.0 | | | | |
| 2009 | | | | | | | | | |
| 2010 | Randenigala～Rantembe | zebra | 1 | +1 (2) | 3.1 | | | | |
| 2011 | Kotmale～Upper Kotmale | zebra | 2 | 2 | 18.5 | 2011 - 2015 | Habarana | 250 | 2 |
| | Veyangoda～Kirindiwela | zebra | 4 | 2 | 14.4 | | Kelanttissa | 150 | +1 (3) |
| | Kirindiwela～Ambulgama | zebra | 4 | 2 | 22.2 | | Pannipitiya | 250 | +1 (3) |
| | Ambulgama～Arangala | zebra | 4 | 2 | 11.4 | | Matugama | 250 | 2 |
| | Ambulgama～Matugama | zebra | 4 | 2 | 58.2 | | Hambantota | 250 | 2 |
| | Puttalam～New Chilaw | zebra | 4 | 2 | 70.0 | | N-CHW | 250 | 2 |
| | New Chilaw～Veyangoda | zebra | 4 | 2 | 45.0 | | Ambulgama (S/S) | 250 | 0 |
| 2012 | | | | | | | Arangama (S/S) | 250 | 0 |
| 2013 | Matugama～Hambantota | zebra | 4 | 2 | 135.6 | | Kirindiwela (S/S) | 250 | 0 |
| 2014 | | | | | | | | | |
| 2015 | | | | | | | | | |
| 2016 | | | | | | 2016 - 2020 | Rantembe | 250 | +1 (2) |
| 2017 | Trincomalee～New Habarana | zebra | 4 | 2 | 95.0 | | N-CHW | 250 | +2 (4) |
| | New Habarana～Veyangoda | zebra | 2 | 2 | 145.0 | | Kotmale | 250 | +1 (2) |
| 2018 | | | | | | | Rantembe | 250 | +1 (3) |
| 2019 | | | | | | | Ambulgama | 250 | +3 (3) |
| 2020 | Puttalam～New Chilaw | zebra | 4 | 2 | 70.0 | | Arangama | 250 | +3 (3) |
| | | | | | | | Matugama | 250 | +1 (3) |
| | | | | | | | Biyagama | 250 | +1 (3) |
| | | | | | | | Hambantota | 250 | +1 (3) |
| | | | | | | | Habarana | 250 | +1 (3) |
| | | | | | | | Trincomalee | 250 | 1 |
| 2021 | Hambantota～Bandarawela | zebra | 4 | 2 | 105.0 | 2021 - 2025 | Kotugoda | 250 | +1 (3) |
| | Bandarawela～Upper Kotmale | zebra | 2 | 2 | 48.0 | | Kotmale | 250 | +1 (3) |
| 2022 | | | | | | | Trincomalee | 250 | +1 (2) |
| 2023 | | | | | | | Bandarawela | 250 | 2 |
| 2024 | | | | | | | | | |
| 2025 | | | | | | | | | |

*Note : "+" represents the number of additional lines or units.
The number in parentheses represents total after augmentation.

#### (2) Power system in 2025

In 2025, about 65 % of the power demand would consist of consumption in Colombo and nearby areas. For this reason, most of the generation facilities in the power system would be located along the western coast.

The coal-fired plants at Puttalam and Hambantota would supply base power to the western and southern coastal zones. The coal-fired plant at Trincomalee would supply base power over a wide area in the northern, eastern, and central regions.

Meanwhile, the combined-cycle and gas turbine plants built in and around Colombo would supply mainly power for peak times of day in this region. The peak-load power in the northern, eastern, and southern regions would be provided by gas turbine plants built in Jaffna, Paddirippu, and Ampara and Galle, respectively.

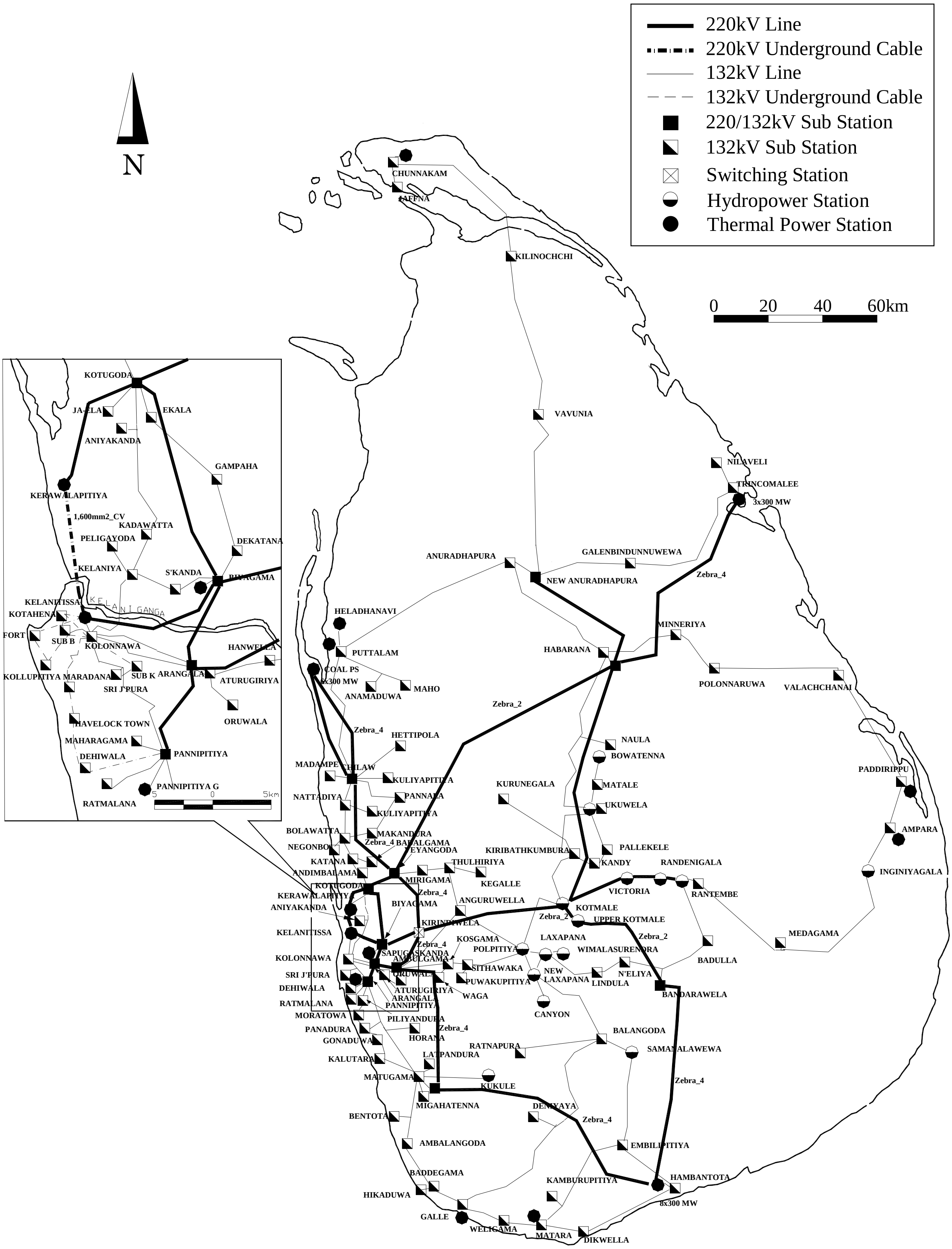



Figure 3.9 Power System Diagram as of 2025

### (3) Results of the study regarding the concentration of coal-fired plants

The concentration of coal-fired power plants in the future will exert a great influence on the power system plan.

In the event of a concentration of coal-fired plant development over the subject period in the Puttalam area on the western coast, under the existing grid code, system stability could be hurt if a failure occurred on the transmission line between the plants and New Chilaw. While measures such as the installation of a 400 kV system and construction of additional switching stations could possibly be taken to resolve this problem, they are not realistic options because of the huge investment cost increase they entail.

In the event of a concentration of development in the vicinity of Hambantota on the southern coast, too, system stability problems would result from failure on transmission lines between plants and the substations at Matugama or Bandarawela, or substation facilities at Hambantota. These problems would not be resolved even with the construction of additional facilities.

For these reasons, the concentration of coal-fired plants would not be desirable as far as system operation is concerned. It is important to take account of the size of demand and see that the development of coal-fired plants is balanced with it.

Table 3.9 shows the sites of coal-fired plant development in the Master Plan and the capacity that could be developed as viewed from the standpoint of system operation (as of 2025).

Table 3.9 Maximum Capacity of Coal-fired TPP[10] Development in each Area (as of 2025)

| Item | | Coal-fired Thermal Power Development Site | | |
|---|---|---|---|---|
| | | Puttalam Area | Hambantota Area | Trincomalee Area |
| Transmission Lines | | Puttalam - New Chilaw<br>Zebra_4 2cct x 2 Routes<br>New Chilaw - Veyangoda<br>Zebra_4 2cct x 1 Route | Hambantota - Matugama<br>Zebra _4 2cct x 1 Route<br>Hambantota - Bandarawela<br>Zebra_4 2cct x 1 Route | Trincomalee - Habarana<br>Zebra_4 2cct x 1 Route |
| Maximum capacity. of coal-fired TPP development | Stability | 2,100MW<br>(2,400MW is available with high speed relay system) | 2,400MW<br>(3,000MW is available with high speed relay system) | |
| | N-1 | 2,700MW | 3,000MW | |
| | Short Circuit | - 2,700MW in case that unit size is 300MW due to short circuit capacity limitation. (Short circuit capacity of 220kV system is 40kA)<br>- 3,000MW and more with bus and circuit breaker whose capacity is 50kA | | |

Note: "_4" represents 4-bundle conductor

### (4) Results of the study of the method for power supply in the northern region

A study was made of the method for power supply in the northern region from a long-term perspective. This study found that interconnection with the main grid would be preferable to an independent system in respect of supply reliability and economic merit. It was therefore decided to take account of system interconnection between the main grid and the northern grid in preparation of the power system.

[10] Thermal Power Plant

Table 3.10  Comparison of Methods for Power Supply in the Northern Region

| | Isolated System | | Interconnection system |
|---|---|---|---|
| | Supply only with new power plants | Expectations of an existing IPP power plant as backup | |
| Cost over the subject period (2005 NPV) | 230.0 million US dollars | 2215 million US dollars | 117.5 million US dollars |
| Characteristics | High initial investment for plant construction | Fairly low initial investment, but high operating cost | Low initial investment and operating cost |

Owing to voltage stability problem, nevertheless, it would be difficult to supply power from plants in the central and eastern regions to meet the demand for power in the northern region in 2025 (about 90 MW).  These problems could be resolved by installing a double conductor system or 220 kV transmission lines for the interconnection, but both of these options are not desirable ones because they would greatly increase the development costs.  As a result, it was decided to meet the demand in this region by having some of the small-scale gas turbine generators contained in the generation development plan sited in it.

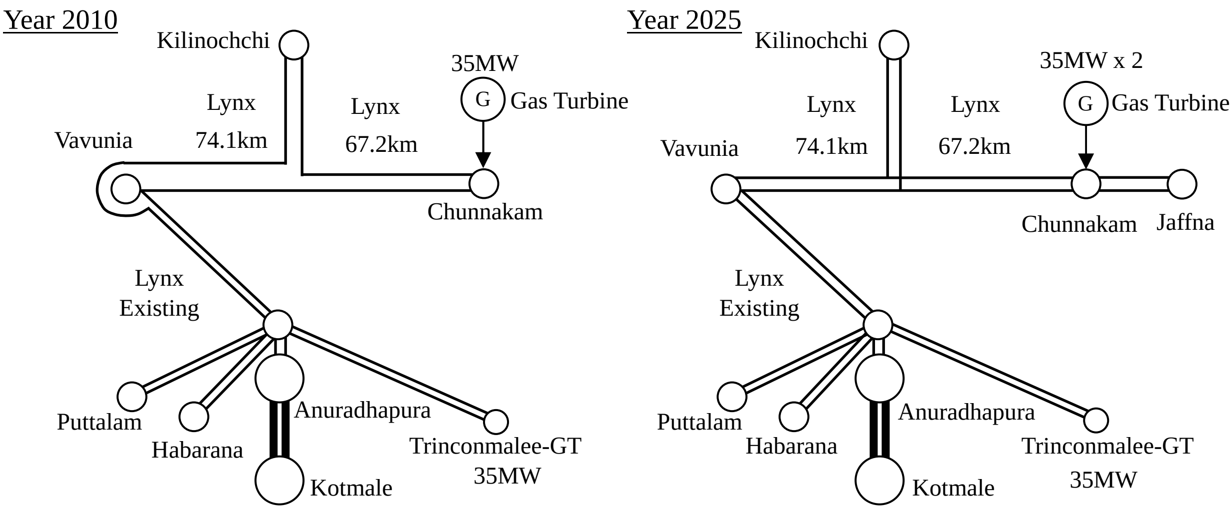



Figure 3.10  Power System Diagram in Northern Area as of 2010 and 2025

### 3.1.4  Total Requisite Funding for Power Development

The total amount of funds required for development of generation, transmission, and substation facilities over the subject period was estimated at about 8.33 billion US dollars.  Most of this amount would be directed to generation development; improvement of transmission and substation facilities would account for only about 12 % of the total.  As this indicates, procurement of the funds needed for generation development would be the major agendum for implementation of the Master Plan.

Table 3.11  Total Requisite Funding for Power Development

| | |
|---|---|
| 1. Generation Development | 7,374.01 MUS$ |
| 2. Power System Development | 959.33 MUS$ |
| a) Transmission Line | 415.66 MUS$ |
| b) Substation / Switching Station | 478.09 MUS$ |
| c) Others | 65.58 MUS$ |
| Total | 8,333.34 MUS$ |

Note : Cost as of 2005

### 3.1.5 Environmental and Social Considerations

#### (1) Consideration for the environment and society in formulation of the Master Plan

To take account of environmental and social considerations in formulation of the Master Plan, the Study Team held meetings with a wide range of stakeholders, (including administrative authorities, business people, experts, NGO representatives, and members of the general public) from the SEA perspective to learn their opinions and reflect them in the planning.

#### (2) Consideration for environment and society in formulation of the generation development plan

In formulation of the generation development plan, the Study Team applied the SEA perspective in examination of alternatives at the planning stage, and incorporated the following process for environmental and social consideration into the planning studies.

- Presentation of alternative plans under different development scenarios
- Evaluation of the possible major environmental and social impact through environmental scoping
- Integrated assessment of the overall plan based on the results of evaluation on the environmental and social impacts and the other non-environmental perspectives
- Staging of stakeholder meetings to reflect opinions of the stakeholders and the general public into the plan

To assess the impact of the development plan on the environment and society, the Study Team identified items of impact anticipated to accompany facility development. It also did environmental scoping for each type of generation facility and major project, using a preliminary checklist. Appendix 11 shows the results of the environmental scoping.

Based on the scoping results, the Study Team made an assessment by scoring the overall environmental and social impact of each alternative plan proceeding from the scenarios, and compared the plans in respect of the size of their impact. In assessment of the plans, the Study Team classified impact items into two categories: impact of the facility development itself and impact deriving from operation after development. For the items in the latter category, it reflected the plant factor of each type of power plant in each alternative plan in the assessment of the impact scale.

For major projects, the Study Team conducted a review of the existing environmental impact assessments on the level of initial environmental examinations (IEE). As a result, it found that the Air Navigation Law would currently rule out implementation of the project at Trincomalee, for which a feasibility study had been made for construction of a coal-fired plant previously, because the prospective site is next to the airport. However, suitable sites that do not violate the Law may be found in the area.

#### (3) Consideration for environment and society in formulation of the power system plan

In formulation of the power system plan, the Study Team took environmental and social impact into consideration, by the following means.

- Identification of the distribution of protected environmental areas, cultural assets and etc.
- Avoidance of transmission routes passing through the above areas and recommendation of items of consideration at the stage of construction.

## 3.2 Identification of Issues in the Organizational and Institutional Aspect

### 3.2.1 Structural Reform

To focus exclusively on the power development plan, the immediate task facing the power sector at present is execution of projects for construction of coal-fired plants that has been delayed. This is, however, only one of the many tasks confronting the sector, which (inclusive of the CEB) is saddled with problems that are of a more structural nature and have deeper roots.

Even assuming that technical and siting issues surrounding the execution of a project for a coal-fired plant were to be resolved, the sector still could not look forward to sustained advancement of the power industry, including the investment needed for development of power plants into the future, without a resolution of various structural problems, such as disposal of the debt held by the CEB, correction of the tariff scheme that does not cover costs, and assurance of the autonomy of CEB management.

**(1) Problems associated with CEB unbundling**

The biggest reason for unbundling of the CEB is the political intervention in its management problems in various ways. This intervention is making it impossible for the CEB to manage itself autonomously. As a result, its management has been criticized as inefficient by external parties. Moreover, it has piled up a debt big enough to jeopardize its continued sustenance.

One of the areas where politics has been heavily involved is the tariff question. Thus far, political considerations have worked against attempts to raise tariffs, and tariff revisions to reflect the costs have consequently been delayed.

To put a halt to political intervention in CEB management as well, it is necessary to lay down the proper conditions for corporate business. This is to be done by unbundling the current CEB, which is a vertically integrated government-owned monopoly; making the generation, transmission, and distribution divisions completely independent; clarifying the cost structures and management responsibilities in each division; and reducing costs through improvement of efficiency.

The main factor behind the tardy progress of the reform is questions about the shape of CEB after unbundling. The proposal presented in the Concept Paper released by the Committee on Power Sector Reforms in July 2005 envisioned a transfer of the generation, transmission, and distribution functions to subsidiaries after the unbundling, with CEB having a shareholder status. More specifically, the Committee proposed the establishment of one generation subsidiary, one transmission subsidiary (also acting as the single buyer), and two or more distribution subsidiaries, whose stock would be owned by the CEB. The Report still leaves some uncertainty regarding the autonomy of subsidiary management, and contains the following problems.

- Labor problems have come prominently to the fore. The proposal notes fairly detailed measures on this front, such as the nomination of corporate directors by labor unions and initiatives for prevention of attempts to block privatization, but makes absolutely no mention of the organizational structure of each subsidiary after unbundling, the division of responsibilities and authority between the CEB and the subsidiaries, and the schedule for unbundling.

- The proposal states that there would be one generation company but does not mention the findings of studies as to whether it would be advisable to establish a single enterprise for both thermal power and hydropower, which have completely different cost structures.
- Unions are involved fairly deeply in management. Union problems could very well escalate into political problems, and there is an undeniable possibility that management problems at the new subsidiaries could do so as well.
- It is important to protect employment levels, but this is a matter for discussion between management and the unions as representatives of the employees on equal footing. Heavy involvement of labor in management per se is liable to invite a conflict of interests between the two.

**(2) Problems related to policy on investment in generation facilities**

Governmental policy clearly states that the execution of thermal power projects is to be left to private-sector investment based on the BOT or BOO schemes as a general rule. However, to keep abreast of the growth in the demand for power will require construction of an additional thermal power plant in the 300,000-kW class every year, on the average. In reality, this addition could by no means be accomplished with investment from IPPs alone.

Meanwhile, risks attached to power sector investment in Sri Lanka are still quite high in the eyes of private-sector investors. Viewed from the standpoint of these investors, if projects are promoted through BOT/BOO schemes, they should be regarded as unable to assume the investment risks without full guarantees by the government.

In light of this investment climate, it would be utterly impossible to develop thermal power plants solely with private-sector investment. This point demands a revision of the prevailing official policy.

### 3.2.2 Finances of CEB

**(1) Financial analysis of CEB**

CEB sales have shown a steady increase for the past 10 years. As the power sales (kWh) increased by 7-8 % annually, the sales revenue has increased 15% annually during the same period, due to tariff hikes.

The cost structure, on the other hand, has shown a drastic change. The level of fuel cost as percentage of sales came to only 7% in 1994 but reached 34% in 2004. The corresponding figure for the cost of power purchasing, which began in 1996, is 39%. Other costs, such as transmission and distribution, have also increased, but only 18% annually, just slightly higher than the rate of revenue growth. These costs seem to be in check. Depreciation has increased by 10% annually. This rate would have been higher had the CEB made the proper investment, but with very little additional generation capacity, the investment has been low, and depreciation remained low.

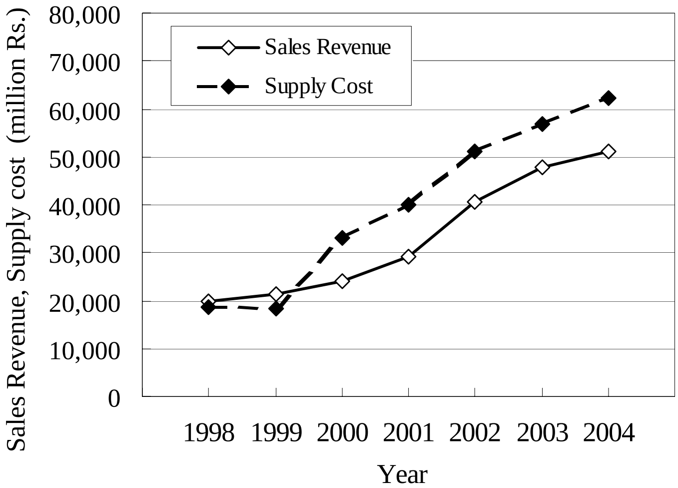



Figure 3.11 Sales Revenue and Supply Cost (1998-2004)

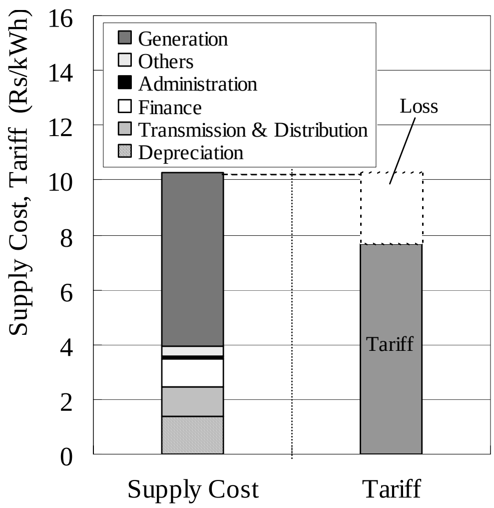



Figure 3.12 Supply Cost Breakdown (2004)

As Figure 3.11 indicates, the power supply cost has constantly exceeded the sales revenue, causing a continuous loss. Since 2000, the extent of loss has decreased slightly. This was due mainly to the tariff hike, which is still far from solving the problem. In 2004, the amount of loss reached a record-high level.

The main reason for this situation is the soaring generation cost, especially the fuel cost and the power purchase cost. In order to solve the financial issues of CEB, it is therefore imperative to solve the generation cost issue. The CEB must escape from its reliance on expensive power purchasing, and move to a fuel composition that would bring a lower generation cost.

The CEB's finances are not in very good shape. The generation cost alone wipes out all the revenue, leading to steady deficit. The tariff hike also led to a sharp increase in the sales receivable, which means that cash income has not increased as much as the sales on paper. To compensate for this, the CEB has increased its accounts payable, and this indicates that it is deferring its obligations to cope with its cash shortage.

Although the demand of power has steadily increased, since the cost exceeds revenue, the increase only means larger loss because the cost exceeds the revenue. In 2005, the demand showed further growth, which translates into worse financial position. The seriousness of the situation is evidenced by the fact that cash on hand has been negative for several years.

The important point here, however, is that their financial problems mostly concern their short-term cash situation. The total debt of the CEB is only 43 percent of their total asset. This level in itself is not a problem. In many other Asian countries, power sector utilities often take on much more debt that may rise above even 70 percent of the total asset. Since power generation is capital intensive, this is quite natural. For CEB, the level of long-term debt is rather too low, due to the stalling of their power plant investments.

Their short-term debt, on the other hand, is truly alarming. In order to cover for their operational losses, they are cash strapped to the extent that they must rely a huge portion of their cash demand on the increasing accounts payable. They are delaying their payment obligation to their suppliers in order to save cash. As a result, their current debt and non-current debt are at the same level, which is highly unusual.

Therefore, their most important financial issue at hand is to show some profits on their Profit and Loss statement. If this is achieved, their short-term cash problem would be eased, and it would be easier to get long term financing to pursue the necessary large-scale investment.

### 3.2.3 Long-term Investment Plan

#### (1) Long-term investment plan

Table 3.12 shows the long-term investment plan for base case in the Master Plan.

Table 3.12 Long-term Investment Plan (Base Case)

| Year | Gross Generation Energy (GWh) | Investment Cost (billion Rs.) | | | |
|---|---|---|---|---|---|
| | | Generation | Transmission | Other | Total |
| 2005 | 8,549 | 0.0 | 5.9 | 10.0 | 15.9 |
| 2006 | 9,105 | 0.0 | 7.6 | 10.0 | 17.6 |
| 2007 | 9,732 | 0.0 | 5.0 | 10.0 | 15.0 |
| 2008 | 10,464 | 0.0 | 3.0 | 10.0 | 13.0 |
| 2009 | 11,291 | 10.6 | 5.4 | 10.0 | 26.0 |
| 2010 | 12,168 | 12.2 | 8.2 | 10.0 | 30.4 |
| 2011 | 13,115 | 65.8 | 3.7 | 10.0 | 79.5 |
| 2012 | 14,125 | 32.9 | 4.8 | 10.0 | 47.7 |
| 2013 | 15,214 | 32.9 | 4.5 | 10.0 | 47.4 |
| 2014 | 16,390 | 32.9 | 2.9 | 10.0 | 45.7 |
| 2015 | 17,684 | 32.9 | 5.0 | 10.0 | 47.9 |
| 2016 | 19,068 | 32.9 | 7.6 | 10.0 | 50.5 |
| 2017 | 20,551 | 32.9 | 5.3 | 10.0 | 48.1 |
| 2018 | 22,140 | 32.9 | 4.4 | 10.0 | 47.3 |
| 2019 | 23,839 | 32.9 | 5.0 | 10.0 | 47.9 |
| 2020 | 25,653 | 37.2 | 6.8 | 10.0 | 53.9 |
| 2021 | 27,594 | 37.2 | 3.2 | 10.0 | 50.4 |
| 2022 | 29,676 | 41.4 | 2.1 | 10.0 | 53.5 |
| 2023 | 31,903 | 50.0 | 1.8 | 10.0 | 61.8 |
| 2024 | 34,287 | 43.5 | 0.9 | 10.0 | 54.4 |
| 2025 | 36,837 | 65.8 | 0.1 | 10.0 | 75.9 |
| Total | | 626.8 | 93.2 | 210.0 | 930.0 |

The investment costs of the generation development and transmission development are based on the base case for the power development plan. For other investments, it is assumed that the current level of investment would continue indefinitely.

As shown in the table, the total amount of necessary investment during the period of 2005-25 for the sector as a whole would be about Rs 930 billion. This translates into an annual average of Rs 44.3 billion, or USD 443 million. If we focus on the period after 2012, the annual average is about Rs 50 billion. The high level of investment is unavoidable, since in order to meet the soaring demand, a 300 MW class generation capacity needs to be installed almost every year. Figure 3.13 shows the relation between the annual generation energy and the annual investment.

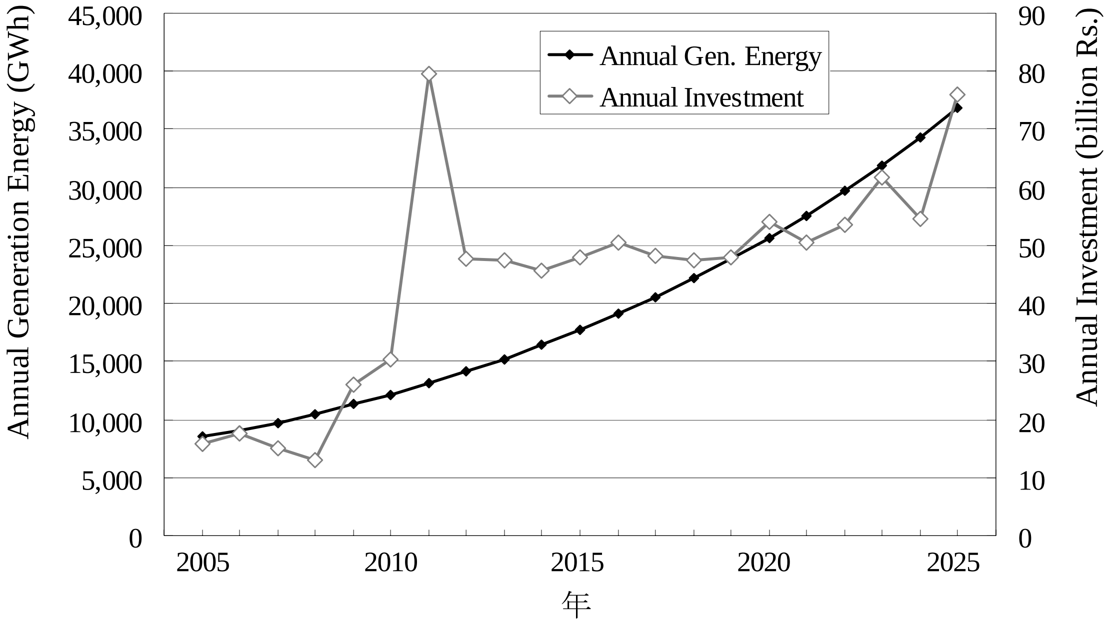



Figure 3.13  Annual Generation Energy and Annual Investment

The sharp peak of investment in 2011 represents the addition of 600MW generation capacity.

The current annual investment of CEB is about Rs 16 billion.  Therefore, the future level of investment would be 2.8 times the current level.

The bearer of this high level of investment would be determined by the future development of the power sector reform.  For example, if it is decided that all the generation capacity would be installed by IPPs, CEB (or the remaining public power utility) would only bear the investment for transmission and other investments.  In this case, the CEB's annual investment would remain at Rs 15-16 billion, which is the same as the current level.

In this case, the power purchase payment to these IPPs would become an issue.  Even now, the cost of the expensive purchased power has contributed significantly to the power supply cost, and consequently, the increasing loss.  Although the details would differ with the specific power purchase agreement, relying on IPPs as the base power supply would more likely increase the supply cost.

Also, according to interviews with the existing IPPs reveal that private operators consider 300MW plants to be too large and risky as an attractive investment.  Since risk preference may change overtime, there may be other investors that would be willing to bear such risk, although this seems unlikely in the near future.  Therefore, the scenario that all of the planned generation capacity would be procured by IPPs would be rather unrealistic.

Therefore, in order to utilize the large-scale coal thermal plants in the most effective way, it would be practical for the public sector to procure most of the planned generation capacity by themselves.

### (2) Power supply cost forecast based on the Power Development Plan

The future power supply cost was estimated on the basis of the proposed Power Development Plan. Here, we compare the situation in the case of construction of large-scale thermal power plants and that of continued reliance on small diesel generators[11]. In order to exclude the effects of financing structures, all investments are assumed to be financed by cash in the year of construction. For the diesel generators, profit margins for the IPPs have also been excluded.

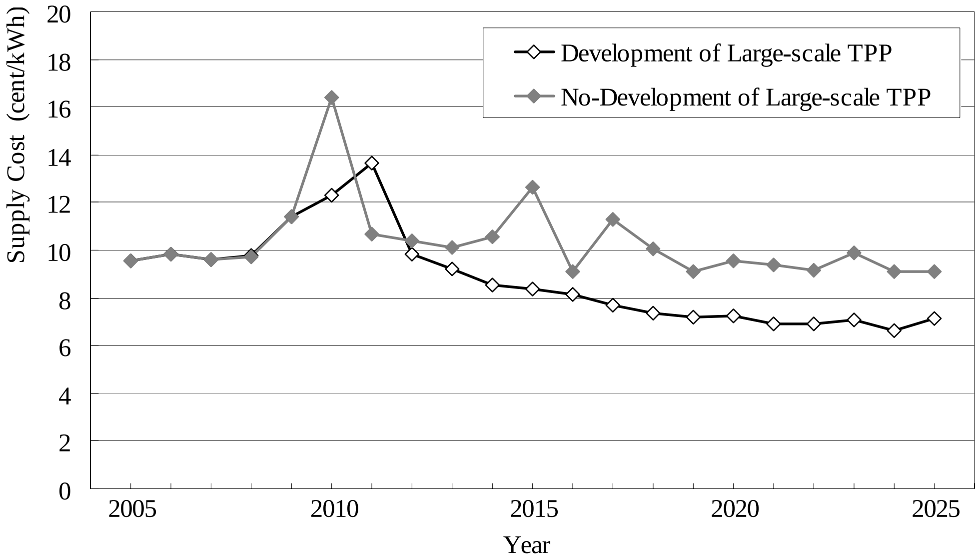



Figure 3.14 Forecast of the Power Supply Cost

If a series of large-scale coal plants were to be developed, the large investment would cause the supply cost increase in 2010-2011. Once these plants come on line, however, the cost drops dramatically because of the lower fuel cost. As shown in Figure 3.14, if the equivalent of one 300MW power plant could be constructed almost every year over the subject period, power costs would come down to an acceptable level. Even taking profit margins into account, the cost would be highly competitive with those in other Asian countries.

If, on the other hand, no large-scale thermal plants are built the entire additional demands is handled by a series of small diesel generators, the costs will remain the same at best. Because of higher investments in certain years, the overall effect would be a tariff increase relative to the current level.

Because the current tariff level has not been favorably received by consumers, an equal or even higher one would probably not be welcomed. Many have expressed concern about the loss of competitiveness and decrease in foreign investment caused by the higher power costs. Small-scale diesel power generation does not address those concerns.

In the case of construction of large-scale thermal power plants, it would be easier to attract development aid under favorable terms. This would allow the investment to be distributed over a long term. Assuming that a typical term for a large multi-donor is applied for the first years, the investment

[11] Low-speed diesel generation units

cost will be distributed over 20 years, leading to an immediate decrease in the unit supply cost and the tariff (See Appendix 12). The current financial condition of the CEB, however, makes it difficult to receive such huge loans indefinitely. Therefore, some form of structural reform, including corporatization of various divisions in CEB, would be necessary to restore financial health.

Development based on diesel generation would also be able to distribute its investment over the long term using various sources. However, it is unlikely obtain terms as favorable as those of the aid donors, and its effect on the cost on the cost and tariff would therefore be limited.

### 3.2.4 Power Tariffs

Tariff is ultimately determined by the power supply cost. If it is lower than the supply cost, and lacking subsidies or other source of income, the difference must be borrowed, which is unsustainable in the long run.

Transmission and distribution costs have increased only a little more rapidly than sales since 2000 in spite of the expanding gap (deficit) between costs and revenue as was found by the financial analysis in this study, and the self-help efforts of the CEB are therefore taking effect. The biggest cause of the increase in the deficit, on the other hand, is the rise in prices paid for purchase of power from emergency diesel power generators. The increase in oil fuel prices, which have jumped in recent years, has been an especially big factor.

As mentioned, however, this problem is the short-term debt. The long term debt has not show much increase since there has been not much large scale investment that requires long term debt. It is the short-term debt, especially the accounts payable that is ballooning to come up with the required cash. If the operation turns a profit, this cash shortage would be eased and long-term finance would be obtainable.

Therefore, the tariff needs to be revised so that the operation shows some profit, and maintain that profit into the future. To achieve this, the following points need to be met;

- Raise the tariff temporally by about 25%. This should be a short-term raise, maybe up until 2012.
- When increasing, there should be a commitment that with the future completion of the large-scale coal thermal power plant, the tariff would come down.
- There should be a tariff adjustment formula that allows the pass-through of the fuel cost, the power purchase cost, and foreign exchange.

The temporary tariff increase would improve CEB's financial health. In order to make this increase more acceptable, there should be a clear commitment that this would be brought down with the completion of the large coal thermal plants. This should also provide additional support for the faster procurement of the future plants.

The pass-through formula is also important. The recent rise in the fuel cost and the power purchase cost is beyond CEB's control. They should not be held responsible. This was one of the main causes of the recent increase in its operational loss. To avoid such situation in the future, an automatic tariff adjustment formula that includes a pass-through clause for fuel, power purchase, and foreign exchange. The current rise in oil prices is likely to peak off in the near future. Therefore, such formulas would more likely lower the tariff levels in the near future. By introducing the formula when it would lower the tariff, it would become more acceptable for the customers.

The current tariff structure consists of the base tariff (capacity charge) and the power tariff. Under the current condition of power shortage, it is desirable to increase the power factor as much as possible to increase the effective power. Tariff structure can assist such improvement. In the case of Japan, customers above 85% power factor will receive a discount, while those lower than that would be charged extra. This induces the customers to install capacitors to improve the power factor. Similar methods can be employed in Sri Lankan tariff structure to make better use of the existing generation capacity.

# 4 Recommendations for the Future Advancement of the Power Sector

**Recommendations related to the power development plan**

- **Prompt implementation of the combined-cycle project at Kerawalapitiya**

  The project for construction of a combined-cycle power plant at Kerawalapitiya as intended by the CEB is a major key for power supply prospects in near future. If this project is not completed or delayed, supply will fall into a status of critical tightness especially in 2008. Considering the construction period and lead-time before construction, a financing agreement for the project must be concluded by the beginning of 2006 for its commissioning in the middle of 2009.

- **Prompt and sure execution of projects now under way for construction of large-scale coal-fired power plants**

  Development of large-scale coal-fired power plants is indispensable for economical system operation. While there has been opposition to the project for considerations related to siting and environmental concerns, the course of the current project for construction of a coal-fired plant at Norochcholai will have a great impact on future generation development. It consequently should be swiftly and surely implemented.

- **Identification of new sites for large-scale coal-fired plants and ordering in terms of priority**

  Relative to the capacity of large-scale coal-fired plants that must be developed over the coming years, only a very few candidate sites have been the subject of reliable studies, and this is a problem. Studies should be promptly made to identify candidate sites throughout Sri Lanka in order to expand the options for site selection and execute development at more economical sites. This should be accompanied by an ordering of all candidate sites, including those already studied, in terms of development priority.

- **Importance of energy source diversification**

  The future generation mix will depend heavily on coal-fired plants. For reasons of energy security, there is a strong need for development of generation facilities applying hydropower (as a domestic energy resource) and renewable energy. Efforts to develop these facilities should be continued.

  Natural gas is another new fuel option that would presumably have the additional benefits of improvement of energy security through diversification of energy sources and stabilization of the system operation through installation of combined-cycle systems with a high load-following flexibility. As such, if natural gas is supplied to the power sector at reasonable price, it will become a promising fuel option after installation of coal-fired plants.

- **Importance of expansion of the trunk system**

  In the plans for development of transmission and substation facilities over the subject period, emphasis ought to be placed on expansion of the trunk system by, for example, construction of the 220 kV No. 2 outer loop trunk transmission line in the Colombo area, where the demand is concentrated, and 220 kV transmission and substation facilities for supply from large-scale thermal power facilities.

- **Importance of system interconnection between the main grid and the northern grid**

  For reasons of both economical expansion of power facilities and supply reliability, the northern grid should be connected to the main grid. For this purpose, the current project for reconstruction of transmission lines should be completed on schedule.

**Recommendations related to organizations and institutions**

- **Completion of the structural reform**

  A fundamental reform of the sector is absolutely essential for promotion of long-term investment and increase in the overall efficiency. To this end, the government must present a detailed vision and schedule for CEB unbundling, and swiftly complete the reform, which is currently stalled.

- **Clear statement of the approach to disposal of CEB accumulated debt**

  Accumulated debt must be off-loaded from the post-unbundling CEB and the subsidiaries by establishment of a separate organization to dispose of it, for example, so that they can develop their business in a self-supporting and stable manner.

  The task in this connection is to clarify the method of debt repayment or amortization. This demands the determination of financial sources for debt disposal and detailed study of procedure for assurance of these sources and repayment.

- **Assurance of the autonomy of subsidiary management free of involvement by CEB**

  As a holding company for the subsidiaries in the new order, CEB should not become directly involved in the power development planning or formulation of other business plans by the subsidiaries. This is necessary to assure the fairness of power transactions after the reform and the autonomy of subsidiary management.

- **Revision of policy on thermal power projects**

  In light of the prevailing investment climate, dependence solely on private funds for construction of the thermal power plants that must be developed over the coming years would not be a realistic option. The government should revise its current policy on wholly private sector funding of thermal power projects and make arrangements for procurement of funds through public-private partnership (PPP) schemes.

- **Establishment of power plants developed with public funds as separate companies**

  Inclusion of future power plants constructed with public funds within the CEB generation subsidiary is liable to distort the market by inducing preferential treatment for and expansion of a certain entrant (i.e., the CEB generation subsidiary). Therefore, any power plants built with the input of public funds ought to be established as entities separate from this generation company.

- **Clear definition of the role of government (separation of policy-making and regulation)**

  As a result of the reform, the regulatory authority in the power sector will be transferred from the MPE to the PUC. Under this arrangement, the MPE ought to function as a policy-making authority.

  In addition, revision of power tariffs is urgently needed for resolution of the current financial problems at the CEB, and the PUC ought to become involved in the revision process starting right from the present.

- **Instatement of an automatic adjustment formula into the tariff scheme**

  The power tariff scheme should be revised by instating a formula for automatic adjustment to enable cost increases caused by external factors (i.e., fuel costs, exchange rate fluctuation, and fluctuation in prices applied in power purchasing based on contracts concluded between generation companies and the single buyer) to be smoothly passed on to the tariffs paid by the final consumers. Even at a stage prior to completion of the reform, the PUC should make checks to assure the transparency of this work..

# Appendices

Scenario Parameters for Power Demand Forecast on the National Level Approach

Economic Scenario (National Level Approach)

| Year | Low Growth | Base Case | 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: Annual Report 2004 of the Central Bank of Sri Lanka and JICA Study Team
Note: Post-tsunami scenario. The value for 2004 is an actual growth rate.

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: Department of Census and Statistics

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: CEB, Generation Unit
Note: The value for 2004 is the actual demand.

System Loss Scenario

| Year | System Loss | Year | System Loss | Year | System 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 system loss.

## Basic Data for Power Demand Forecast on the Provincial Level Approach

CE-Central Province, EA-Eastern Province, NO-Northern Province, NC-North Central Province, NW-North Western Province, SA- Sabaragamawa Province, SO-Southern Province, WE-Western Province Western Province consists of Western Province -North-, Western Province -South- and Colombo City, UV-Uva Province, WN-Western-North-, WS-Western-South-, CC-Colombo City

### Provincial Energy Sales（GWh）

| Year | NC | No | Ce | NW | Ea | WN | WS | CC | So | Uv | Sa | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1990 | 54 | 59 | 271 | 159 | 68 | 491 | 579 | 537 | 175 | 70 | 143 | 2,608 |
| 1991 | 51 | 0 | 274 | 181 | 84 | 533 | 607 | 571 | 191 | 73 | 176 | 2,742 |
| 1992 | 58 | 3 | 289 | 213 | 127 | 589 | 631 | 552 | 204 | 71 | 179 | 2,916 |
| 1993 | 69 | 5 | 314 | 246 | 150 | 662 | 688 | 602 | 240 | 83 | 211 | 3,270 |
| 1994 | 89 | 6 | 326 | 265 | 145 | 751 | 782 | 627 | 262 | 86 | 227 | 3,565 |
| 1995 | 89 | 7 | 356 | 289 | 159 | 831 | 872 | 685 | 286 | 90 | 250 | 3,915 |
| 1996 | 87 | 8 | 326 | 282 | 116 | 734 | 837 | 598 | 286 | 85 | 229 | 3,588 |
| 1997 | 102 | 11 | 365 | 328 | 140 | 837 | 954 | 679 | 323 | 96 | 204 | 4,039 |
| 1998 | 116 | 14 | 393 | 378 | 166 | 953 | 1,055 | 739 | 376 | 106 | 225 | 4,521 |
| 1999 | 124 | 42 | 417 | 389 | 173 | 999 | 1,134 | 779 | 400 | 124 | 229 | 4,809 |
| 2000 | 141 | 46 | 469 | 439 | 173 | 1,113 | 1,239 | 786 | 459 | 136 | 257 | 5,258 |
| 2001 | 148 | 58 | 474 | 481 | 161 | 1,081 | 1,243 | 723 | 466 | 131 | 271 | 5,236 |
| 2002 | 156 | 61 | 487 | 495 | 199 | 1,140 | 1,308 | 780 | 470 | 128 | 278 | 5,502 |
| 2003 | 174 | 81 | 535 | 552 | 240 | 1,328 | 1,465 | 876 | 516 | 145 | 295 | 6,209 |
| 2004 | 194 | 99 | 560 | 587 | 241 | 1,421 | 1,594 | 934 | 571 | 152 | 314 | 6,667 |

Source: CEB Sales and Generation Data Book
Note: Exclude the generation of captive power

### Provincial Population (1,000 person)

| Year | NC | No | Ce | NW | Ea | WN | WS | CC | So | Uv | Sa | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1990 | 1,027 | 1,303 | 2,200 | 2,013 | 1,204 | 1,525 | 940 | 1,950 | 2,223 | 1,057 | 1,679 | 17,120 |
| 1991 | 1,044 | 1,316 | 2,217 | 2,039 | 1,225 | 1,538 | 949 | 1,980 | 2,254 | 1,071 | 1,696 | 17,326 |
| 1992 | 1,062 | 1,329 | 2,223 | 2,066 | 1,247 | 1,549 | 957 | 2,010 | 2,284 | 1,079 | 1,709 | 17,512 |
| 1993 | 1,078 | 1,350 | 2,247 | 2,093 | 1,270 | 1,562 | 965 | 2,044 | 2,315 | 1,094 | 1,727 | 17,742 |
| 1994 | 1,095 | 1,371 | 2,279 | 2,121 | 1,294 | 1,575 | 974 | 2,079 | 2,346 | 1,112 | 1,745 | 17,989 |
| 1995 | 1,110 | 1,388 | 2,306 | 2,147 | 1,317 | 1,589 | 984 | 2,112 | 2,375 | 1,129 | 1,761 | 18,214 |
| 1996 | 1,123 | 1,404 | 2,334 | 2,171 | 1,341 | 1,602 | 993 | 2,146 | 2,402 | 1,145 | 1,776 | 18,434 |
| 1997 | 1,137 | 1,418 | 2,368 | 2,194 | 1,367 | 1,615 | 1,003 | 2,182 | 2,428 | 1,162 | 1,793 | 18,663 |
| 1998 | 1,151 | 1,432 | 2,411 | 2,216 | 1,392 | 1,629 | 1,013 | 2,217 | 2,455 | 1,182 | 1,813 | 18,909 |
| 1999 | 1,166 | 1,451 | 2,473 | 2,240 | 1,416 | 1,646 | 1,025 | 2,254 | 2,485 | 1,210 | 1,839 | 19,201 |
| 2000 | 1,140 | 1,252 | 2,461 | 2,205 | 1,421 | 1,861 | 1,046 | 2,254 | 2,389 | 1,198 | 1,821 | 19,046 |
| 2001 | 1,112 | 1,068 | 2,429 | 2,166 | 1,446 | 2,072 | 1,065 | 2,250 | 2,288 | 1,180 | 1,796 | 18,870 |
| 2002 | 1,125 | 1,100 | 2,459 | 2,185 | 1,497 | 2,083 | 1,073 | 2,286 | 2,312 | 1,197 | 1,815 | 19,130 |
| 2003 | 1,139 | 1,114 | 2,490 | 2,205 | 1,529 | 2,094 | 1,081 | 2,324 | 2,335 | 1,215 | 1,833 | 19,357 |
| 2004 | 1,155 | 1,134 | 2,530 | 2,228 | 1,557 | 2,107 | 1,091 | 2,370 | 2,363 | 1,236 | 1,851 | 19,621 |

Source: Annual Report, Central Bank of Sri Lanka

### Provincial Load Factor (2005-2025)

| NC | No | Ce | NW | Ea | WN | WS | CC | So | Uv | Sa |
|---|---|---|---|---|---|---|---|---|---|---|
| 29.46% | 44.12% | 43.91% | 43.51% | 42.18% | 66.36% | 56.30% | 80.00% | 56.33% | 61.48% | 44.38% |

Appendix 3

## Scenario Parameters for Power Demand Forecast on the Provincial Level Approach

CE-Central Province, EA-Eastern Province, NO-Northern Province, NC-North Central Province, NW-North Western Province, SA- Sabaragamawa Province, SO-Southern Province, WE-Western Province Western Province consists of Western Province -North-, Western Province -South- and Colombo City, UV-Uva Province, WN-Western-North-, WS-Western-South-, CC-Colombo City

### 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% |

Note:：The value for 2004 is an actual growth rate

### 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% |

### Load Factor Scenario（Provincial Level Approach）

| Year | WN | WS | CC night | SO | SA | CE | UV | EA | NW | NC | NO | CC daytime |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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% |
| Average | 66.4% | 56.3% | 80.0% | 56.3% | 44.4% | 43.9% | 61.5% | 42.2% | 43.5% | 29.5% | 44.1% | 59.5% |

Note：Load Factor of CC(night) is based on the relations between peak power demand and annual generation.

# List of Existing Power Plants as of 2005 for the Generation Development Plan

| Type | Owner | Name of River System and Power Station | | Rated Capacity (MW) | Maximum Capacity used for the Study (MW) |
|---|---|---|---|---|---|
| Hydropower | CEB | Laxapana Complex | Canyon | 60.0 MW (2units x 30.0MW) | 60.0 MW (2units x 30.0MW) |
| | | | Wimalasurendra | 50.0 MW (2units x 25.0MW) | 50.0 MW (2units x 25.0MW) |
| | | | Old Laxapana | 50.0 MW (3units x 8.33MW + 2units x 12.5MW) | 50.0 MW (3units x 8.33MW + 2units x 12.5MW) |
| | | | New Laxapana | 100.0 MW (2units x 50.0MW) | 100.0 MW (2units x 50.0MW) |
| | | | Polpitiya | 75.0 MW (2units x 37.5MW) | 75.0 MW (2units x 37.5MW) |
| | | Mahaweli Complex | Victoria | 210.0 MW (3units x 70.0MW) | 210.0 MW (3units x 70.0MW) |
| | | | Kotmale | 201.0 MW (3units x 67.0MW) | 201.0 MW (3units x 67.0MW) |
| | | | Randenigala | 122.0 MW (2units x 61.0MW) | 122.0 MW (2units x 61.0MW) |
| | | | Ukuwela | 38.0 MW (2units x 19.0MW) | 38.0 MW (2units x 19.0MW) |
| | | | Bowatenna | 40.0 MW (1unit x 40.0MW) | 40.0 MW (1unit x 40.0MW) |
| | | | Rantambe | 49.0 MW (2units x 24.5MW) | 49.0 MW (2units x 24.5MW) |
| | | Other Hydro Complex | Samanalawewa | 120.0 MW (2units x 60.0MW) | 120.0 MW (2units x 60.0MW) |
| | | | Kukule | 70.0 MW (2units x 35.0MW) | 70.0 MW (2units x 35.0MW) |
| | Sub Total | | | 1,185 MW | 1,185 MW |
| Thermal Power | CEB | Sapugasukanda Diesel | | 80.0 MW (4units x 20.0MW) | 72.0 MW (4units x 18.0MW) |
| | | Sapugasukanda Diesel（Extension） | | 80.0 MW (8units x 10.0MW) | 72.0 MW (8units x 9.0MW) |
| | | Kelanitissa Gas Turbine（Old） | | 120.0 MW (6units x 20.0MW) | 68.0 MW (4units x 17.0MW) |
| | | Kelanitissa Diesel（New） | | 115.0 MW (1unit x 115.0MW) | 115.0 MW (1unit x 115.0MW) |
| | | Kelanitissa Combined Cycle | | 165.0 MW (1unit x 165.0MW) | 165.0 MW (1unit x 165.0MW) |
| | IPP | IPP Lakdhanavi Limited | | 22.5 MW (4units x 5.63MW) | 22.5 MW (4units x 5.63MW) |
| | | IPP Asia Power Limited | | 51.0 MW (8units x 6.375MW) | 49.0 MW (8units x 6.125MW) |
| | | IPP Colombo Power（Private）Limited | | 62.7 MW (4units x 15.681MW) | 60.0 MW (4units x 15.0MW) |
| | | IPP ACE Power Horana | | 24.8 MW (4units x 6.2MW) | 20.0 MW (4units x 5.0MW) |
| | | IPP ACE Power Matara | | 24.8 MW (4units x 6.2MW) | 20.0 MW (4units x 5.0MW) |
| | | IPP Heladhanavi (Private) Limited | | 100.0 MW (6units x 6.66MW) | 100.0 MW (6units x 6.66MW) |
| | | IPP ACE Power Embilipitiya Limited | | 100.0 MW (14units x 7.14MW) | 100.0 MW (14units x 7.14MW) |
| | | IPP AES Kelanitissa (Private) Limited | | 163.0 MW (1unit x 163.0MW) | 163.0 MW (1unit x 163.0MW) |
| | Sub Total | | | 1,108.8 MW | 1,026.5 MW |
| Total | | | | 2,293.8 MW | 2,211.5 MW |

Appendix 5

# Provincial Demand Forecast

CE-Central Province, EA-Eastern Province, NO-Northern Province, NC-North Central Province,
NW-North Western Province, SA- Sabaragamawa Province, SO-Southern Province, WE-Western Province Western Province consists of Western Province -North-, Western Province -South- and Colombo City, UV-Uva Province, WN-Western-North-, WS-Western-South-, CC-Colombo City

## 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 | 7,113 |
| 2006 | 222 | 125 | 639 | 710 | 264 | 1,618 | 1,805 | 1,003 | 691 | 178 | 359 | 7,614 |
| 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 |
| Average | 8.21% | 5.69% | 7.04% | 8.21% | 6.87% | 8.23% | 8.25% | 5.43% | 8.22% | 7.17% | 7.11% | 7.69% |

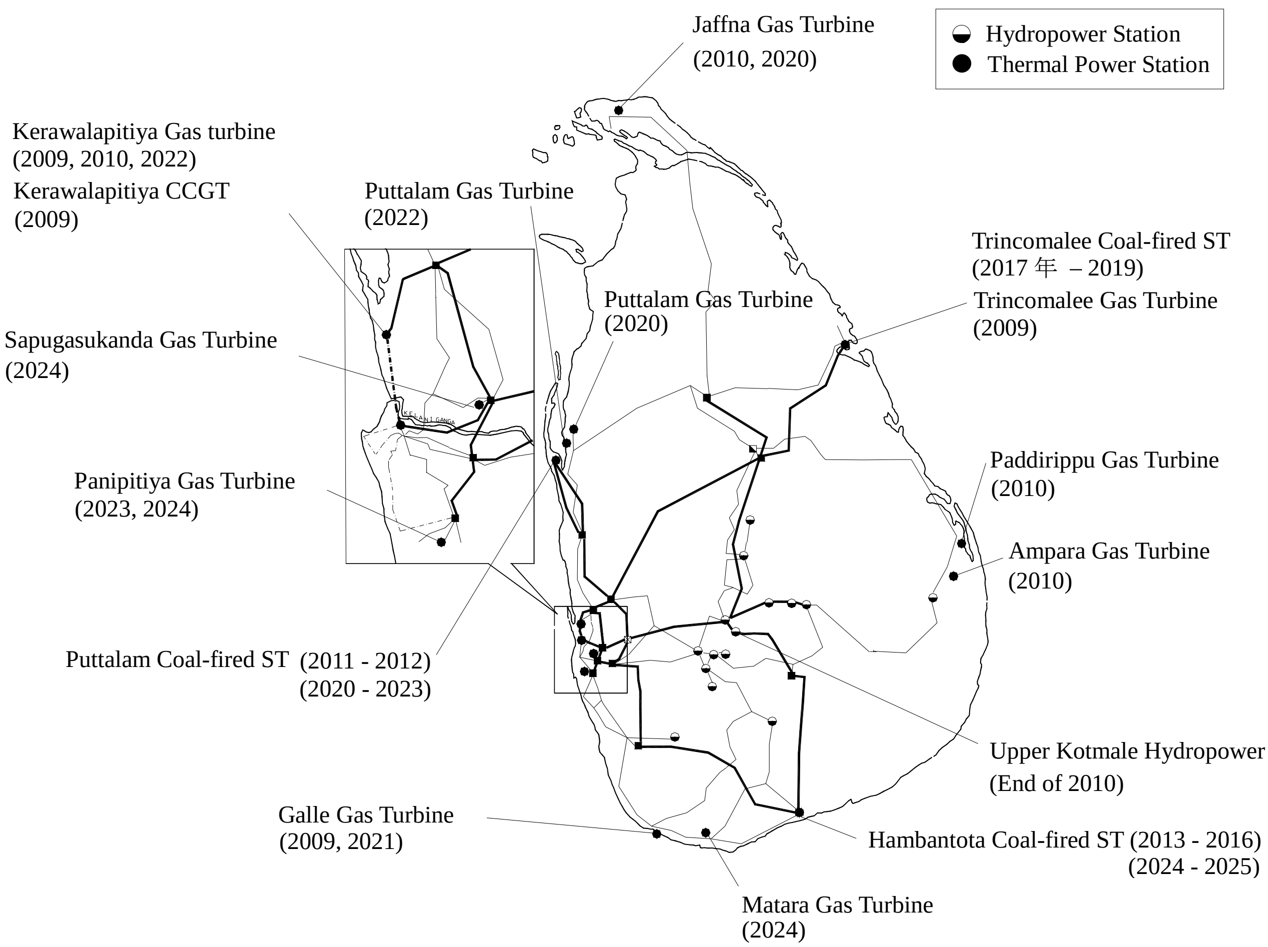
## Provincial Demand Forecast (Peak Demand)

( 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 |
| Average | 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% |

# Regional Supply-Demand Balance (2005-2025)

| Area | Item | | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Western - Southern | Peak Demand (MW) | | 1,232 | 1,316 | 1,414 | 1,522 | 1,645 | 1,777 | 1,919 | 2,072 | 2,236 | 2,414 | 2,609 | 2,818 | 3,042 | 3,283 | 3,542 | 3,818 | 4,114 | 4,432 | 4,774 | 5,140 | 5,532 |
| | Supply Capacity (MW) | | 1,160 | 1,160 | 1,160 | 1,360 | 1,670 | 1,695 | 2,295 | 2,570 | 2,743 | 3,043 | 3,038 | 3,338 | 3,338 | 3,172 | 3,172 | 3,577 | 3,982 | 4,492 | 4,922 | 5,479 | 6,079 |
| | Existing Plant (MW) | | 1,160 | 1,160 | 1,160 | 1,160 | 1,160 | 1,080 | 1,080 | 1,055 | 928 | 928 | 623 | 623 | 623 | 457 | 457 | 457 | 457 | 457 | 377 | 214 | 214 |
| | Fixed Development Plant (MW) | | 0 | 0 | 0 | 200 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| | Candidate Power Plants (MW) | | 0 | 0 | 0 | 0 | 210 | 315 | 915 | 1,215 | 1,515 | 1,815 | 2,115 | 2,415 | 2,415 | 2,415 | 2,415 | 2,820 | 3,225 | 3,735 | 4,245 | 4,965 | 5,565 |
| | Coal-fired ST (MW) | Puttalam | | | | | | | 600 | 300 | | | | | | | | 300 | 300 | 300 | 300 | | |
| | | Hambantota | | | | | | | | | 300 | 300 | 300 | 300 | | | | | | | | 300 | 600 |
| | Combined Cycle (MW) | | | | | | | | | | | | | | | | | | | | | | |
| | Gas Turbine (MW) | Kerawalapitiya | | | | | 105 | 105 | | | | | | | | | | | | 105 | | | |
| | Gas Turbine (MW) | Sapugasukanda | | | | | | | | | | | | | | | | | | | | 210 | |
| | Gas Turbine (MW) | Galle | | | | | 105 | | | | | | | | | | | | 105 | | | | |
| | Gas Turbine (MW) | Panipitiya | | | | | | | | | | | | | | | | | | | 210 | 105 | |
| | Gas Turbine (MW) | Puttalam | | | | | | | | | | | | | | | | 105 | | 105 | | | |
| | Gas Turbine (MW) | Matara | | | | | | | | | | | | | | | | | | | | 105 | |
| | Hydropower (MW) | | | | | | | | | | | | | | | | | | | | | | |
| | Reserve Margin (%) | | -6 | -12 | -18 | -11 | 2 | -5 | 20 | 24 | 23 | 26 | 16 | 18 | 10 | -3 | -10 | -6 | -3 | 1 | 3 | 7 | 10 |
| Northern - Central - Eastern | Peak Demand (MW) | | 535 | 569 | 606 | 646 | 691 | 740 | 793 | 849 | 910 | 976 | 1,048 | 1,125 | 1,208 | 1,295 | 1,389 | 1,488 | 1,594 | 1,706 | 1,826 | 1,953 | 2,088 |
| | Supply Capacity (MW) | | 787 | 787 | 787 | 787 | 822 | 1,007 | 1,157 | 1,157 | 1,157 | 1,157 | 1,157 | 1,157 | 1,457 | 1,757 | 2,057 | 2,092 | 2,092 | 2,092 | 2,092 | 2,092 | 2,092 |
| | Existing Plant (MW) | | 787 | 787 | 787 | 787 | 787 | 787 | 787 | 787 | 787 | 787 | 787 | 787 | 787 | 787 | 787 | 787 | 787 | 787 | 787 | 787 | 787 |
| | Fixed Development Plant (MW) | | 0 | 0 | 0 | 0 | 0 | 0 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 | 150 |
| | Candidate Power Plants (MW) | | 0 | 0 | 0 | 0 | 35 | 220 | 220 | 220 | 220 | 220 | 220 | 220 | 520 | 820 | 1,120 | 1,155 | 1,155 | 1,155 | 1,155 | 1,155 | 1,155 |
| | Coal-fired ST (MW) | Trincomalee | | | | | | | | | | | | | 300 | 300 | 300 | | | | | | |
| | Gas Turbine (MW) | Trincomalee | | | | | 35 | | | | | | | | | | | | | | | | |
| | Gas Turbine (MW) | Paddirippu | | | | | | 75 | | | | | | | | | | | | | | | |
| | Gas Turbine (MW) | Ampara | | | | | | 75 | | | | | | | | | | | | | | | |
| | Gas Turbine (MW) | Jaffna | | | | | | 35 | | | | | | | | | | 35 | | | | | |
| | Hydropower (MW) | | | | | | | | | | | | | | | | | | | | | | |
| | Reserve Margin (%) | | 47 | 38 | 30 | 22 | 19 | 36 | 46 | 36 | 27 | 19 | 10 | 3 | 21 | 36 | 48 | 41 | 31 | 23 | 15 | 7 | 0 |



# Results of Sensitivity Analysis on Fuel Price in Generation Development Plan

## Output of WASP Simulation (Crude oil Price: 60US$/barrel)

Abbrev. ST: Steam Turbine, GT: Gas Turbine, CCGT: Combined Cycle, DS: Diesel ( Unit: MW )

| Year | Peak Demand (MW) | Thermal Power | | | | | | | | | | Hydropower | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | ST | | | GT | | | CCGT | | | DS | Upper Kotmale | Broadlands | Gin Ganga | Moragolla | Uma Oya |
| | | Oil -fired 150MW | Oil -fired 300MW | Coal -fired 300MW | Oil -fired 35MW | Oil -fired 75MW | Oil -fired 105MW | Kerawala -pitiya 150MW | Oil -fired 150MW | Oil -fired 300MW | Diesel 100MW | 150MW | 35MW | 49MW | 27MW | 150MW |
| 2005 | 1,768 | | | | | | | | | | | | | | | |
| 2006 | 1,884 | | | | | | | | | | | | | | | |
| 2007 | 2,019 | | | | | | | | | | | | | | | |
| 2008 | 2,168 | | | | | | | | | **Fixed Development Project** | | | | | | |
| 2009 | 2,336 | | | | 70 | 75 | 105 | 300 | | | | | | | | |
| 2010 | 2,517 | | | | | 150 | 105 | | | | | | | | | |
| 2011 | 2,712 | | | 600 | | | | | | | | 150 | | | | |
| 2012 | 2,921 | | | 300 | | | | | | | | | | | | |
| 2013 | 3,146 | | | 300 | | | | | | | | | | | | |
| 2014 | 3,389 | | | 300 | | | | | | | | | | | | |
| 2015 | 3,657 | | | 600 | | | | | | | | | | | | |
| 2016 | 3,943 | | | | | | | | | | | | | | | |
| 2017 | 4,250 | | | 300 | | | | | | | | | | | | |
| 2018 | 4,579 | | | 300 | | | | | | | | | | | | |
| 2019 | 4,931 | | | 300 | | | | | | | | | | | | |
| 2020 | 5,306 | | | 300 | | | 105 | | | | | | | | | |
| 2021 | 5,708 | | | 600 | | | | | | | | | | | | |
| 2022 | 6,138 | | | 300 | | | | | | | | | | | | |
| 2023 | 6,599 | | | 300 | | | 315 | | | | | | | | | |
| 2024 | 6,599 | | | 600 | | | 105 | | | | | | | | | |
| 2025 | 7,092 | | | 300 | 35 | | 210 | | | | | | | | | |
| Number of Units Developed | | 0 | 0 | 18 | 3 | 3 | 9 | 2 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 |
| | | Total: 36 units | | | | | | | | | | | | | | |
| Developed Capacity (MW) | | 0 | 0 | 5,400 | 105 | 225 | 945 | 300 | 0 | 0 | 0 | 150 | 0 | 0 | 0 | 0 |
| | | Total: 7,125 MW | | | | | | | | | | | | | | |

## Output of WASP Simulation (Crude oil Price: 80US$/barrel)

Abbrev. ST: Steam Turbine, GT: Gas Turbine, CCGT: Combined Cycle, DS: Diesel ( Unit: MW )

| Year | Peak Demand (MW) | Thermal Power | | | | | | | | | | Hydropower | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | ST | | | GT | | | CCGT | | | DS | Upper Kotmale | Broadlands | Gin Ganga | Moragolla | Uma Oya |
| | | Oil -fired 150MW | Oil -fired 300MW | Coal -fired 300MW | Oil -fired 35MW | Oil -fired 75MW | Oil -fired 105MW | Kerawala -pitiya 150MW | Oil -fired 150MW | Oil -fired 300MW | Diesel 100MW | 150MW | 35MW | 49MW | 27MW | 150MW |
| 2005 | 1,768 | | | | | | | | | | | | | | | |
| 2006 | 1,884 | | | | | | | | | | | | | | | |
| 2007 | 2,019 | | | | | | | | | | | | | | | |
| 2008 | 2,168 | | | | | | | | | **Fixed Development Project** | | | | | | |
| 2009 | 2,336 | | | | 105 | 150 | | 300 | | | | | | | | |
| 2010 | 2,517 | | | | | 150 | 105 | | | | | | | | | |
| 2011 | 2,712 | | | 600 | | | | | | | | 150 | 35 | | | |
| 2012 | 2,921 | | | 300 | | | | | | | | | | | | |
| 2013 | 3,146 | | | 300 | | | | | | | | | | | | |
| 2014 | 3,389 | | | 300 | | | | | | | | | | 49 | | |
| 2015 | 3,657 | | | 600 | | | | | | | | | | | | |
| 2016 | 3,943 | | | | | | | | | | | | | | | |
| 2017 | 4,250 | | | 300 | | | | | | | | | | | | |
| 2018 | 4,579 | | | 300 | | | | | | | | | | | | |
| 2019 | 4,931 | | | 300 | | | | | | | | | | | | |
| 2020 | 5,306 | | | 300 | | | | | | | | | | | | |
| 2021 | 5,708 | | | 600 | | | | | | | | | | | | |
| 2022 | 6,138 | | | 300 | | | | | | | | | | | | |
| 2023 | 6,599 | | | 300 | 70 | | 210 | | | | | | | | | |
| 2024 | 6,599 | | | 600 | | | 105 | | | | | | | | | |
| 2025 | 7,092 | | | 300 | | | 315 | | | | | | | | | |
| Number of Units Developed | | 0 | 0 | 18 | 5 | 4 | 7 | 2 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | 0 |
| | | Total: 39 units | | | | | | | | | | | | | | |
| Developed Capacity (MW) | | 0 | 0 | 5,400 | 175 | 300 | 735 | 300 | 0 | 0 | 0 | 150 | 35 | 49 | 0 | 0 |
| | | Total: 7,144 MW | | | | | | | | | | | | | | |

# Results of Sensitivity Analysis on Discount Rate in Generation Development Plan

## Output of WASP Simulation (Discount Rate: 2%)

Abbrev. ST: Steam Turbine, GT: Gas Turbine, CCGT: Combined Cycle, DS: Diesel ( Unit: MW )

| Year | Peak Demand (MW) | Thermal Power | | | | | | | | | | Hydropower | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | ST | | | GT | | | CCGT | | | DS | Upper Kotmale | Broadlands | Gin Ganga | Moragolla | Uma Oya |
| | | Oil -fired 150MW | Oil -fired 300MW | Coal -fired 300MW | Oil -fired 35MW | Oil -fired 75MW | Oil -fired 105MW | Kerawala -pitiya 150MW | Oil -fired 150MW | Oil -fired 300MW | Diesel 100MW | 150MW | 35MW | 49MW | 27MW | 150MW |
| 2005 | 1,768 | | | | | | | | | | | | | | | |
| 2006 | 1,884 | | | | | | | | | | | | | | | |
| 2007 | 2,019 | | | | | | | | | | | | | | | |
| 2008 | 2,168 | | | | | | | | | **Fixed Development Project** | | | | | | |
| 2009 | 2,336 | | | | 35 | | 210 | 300 | | | | | | | | |
| 2010 | 2,517 | | | | | 75 | 210 | | | | | | | | | |
| 2011 | 2,712 | | | 600 | | | | | | | | 150 | 35 | | | |
| 2012 | 2,921 | | | 300 | | | | | | | | | | | | |
| 2013 | 3,146 | | | 300 | | | | | | | | | | | | |
| 2014 | 3,389 | | | 300 | | | | | | | | | | 49 | 27 | |
| 2015 | 3,657 | | | 600 | | | | | | | | | | | | |
| 2016 | 3,943 | | | | | | | | | | | | | | | 150 |
| 2017 | 4,250 | | | 300 | | | | | | | | | | | | |
| 2018 | 4,579 | | | 300 | | | | | | | | | | | | |
| 2019 | 4,931 | | | 300 | | | | | | | | | | | | |
| 2020 | 5,306 | | | 300 | | | | | | | | | | | | |
| 2021 | 5,708 | | | 300 | | | | | | | | | | | | |
| 2022 | 6,138 | | | 600 | | | | | | | | | | | | |
| 2023 | 6,599 | | | 300 | | | 105 | | | | | | | | | |
| 2024 | 6,599 | | | 600 | | | 105 | | | | | | | | | |
| 2025 | 7,092 | | | 600 | | | | | | | | | | | | |
| Number of Units Developed | | 0 | 0 | 19 | 1 | 1 | 6 | 2 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 |
| | | Total: 34 units | | | | | | | | | | | | | | |
| Developed Capacity (MW) | | 0 | 0 | 5,700 | 35 | 75 | 630 | 300 | 0 | 0 | 0 | 150 | 35 | 49 | 27 | 150 |
| | | Total: 7,151 MW | | | | | | | | | | | | | | |

## Output of WASP Simulation (Discount Rate: 6%)

Abbrev. ST: Steam Turbine, GT: Gas Turbine, CCGT: Combined Cycle, DS: Diesel ( Unit: MW )

| Year | Peak Demand (MW) | Thermal Power | | | | | | | | | | Hydropower | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | ST | | | GT | | | CCGT | | | DS | Upper Kotmale | Broadlands | Gin Ganga | Moragolla | Uma Oya |
| | | Oil -fired 150MW | Oil -fired 300MW | Coal -fired 300MW | Oil -fired 35MW | Oil -fired 75MW | Oil -fired 105MW | Kerawala -pitiya 150MW | Oil -fired 150MW | Oil -fired 300MW | Diesel 100MW | 150MW | 35MW | 49MW | 27MW | 150MW |
| 2005 | 1,768 | | | | | | | | | | | | | | | |
| 2006 | 1,884 | | | | | | | | | | | | | | | |
| 2007 | 2,019 | | | | | | | | | | | | | | | |
| 2008 | 2,168 | | | | | | | | | **Fixed Development Project** | | | | | | |
| 2009 | 2,336 | | | | 35 | | 210 | 300 | | | | | | | | |
| 2010 | 2,517 | | | | | 75 | 210 | | | | | | | | | |
| 2011 | 2,712 | | | 600 | | | | | | | | 150 | | | | |
| 2012 | 2,921 | | | 300 | | | | | | | | | | | | |
| 2013 | 3,146 | | | 300 | | | | | | | | | | | | |
| 2014 | 3,389 | | | 300 | | | | | | | | | | | | |
| 2015 | 3,657 | | | 300 | | | | | | | | | | | | |
| 2016 | 3,943 | | | 300 | | | | | | | | | | | | |
| 2017 | 4,250 | | | 300 | | | | | | | | | | | | |
| 2018 | 4,579 | | | 300 | | | | | | | | | | | | |
| 2019 | 4,931 | | | 300 | | | | | | | | | | | | |
| 2020 | 5,306 | | | 300 | | | 105 | | | | | | | | | |
| 2021 | 5,708 | | | 300 | | | 105 | | | | | | | | | |
| 2022 | 6,138 | | | 300 | | | 210 | | | | | | | | | |
| 2023 | 6,599 | | | 600 | | | | | | | | | | | | |
| 2024 | 6,599 | | | 300 | 35 | | 315 | | | | | | | | | |
| 2025 | 7,092 | | | 300 | | | 315 | | | | | | | | | |
| Number of Units Developed | | 0 | 0 | 17 | 2 | 1 | 14 | 2 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 |
| | | Total: 37 units | | | | | | | | | | | | | | |
| Developed Capacity (MW) | | 0 | 0 | 5,100 | 70 | 75 | 1,470 | 300 | 0 | 0 | 0 | 150 | 0 | 0 | 0 | 0 |
| | | Total: 7,165 MW | | | | | | | | | | | | | | |

# Transmission Development Plan (2005-2025)

| Year | Transmission Lines 220KV System | | | | | | Transmission Lines 132KV System | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | From | To | Types | bundles | cct | km | From | To | Types | bundles | cct | km |
| 2005 | | | | | | | Horana | Horana-T | zebra | 1 | 2 | 20.0 |
| 2006 | | | | | | | Col_I (Maradana) | Kolonnawa | CV1000 | 1 | 1 | 4.8 |
| | | | | | | | Col_A (Havelock Town) | Col_I (Maradana) | CV800 | 1 | 1 | 4.9 |
| | | | | | | | Col_A (Havelock Town) | Dehiwara | CV800 | 1 | 1 | 7.5 |
| | | | | | | | Dehiwara | Pannipitiya | CV1000 | 1 | 1 | 8.5 |
| 2007 | | | | | | | Matugama | Ambalangoda | zebra | 1 | 2 | 28.0 |
| | | | | | | | Aniyakanda | Aniyakanda-T | zebra | 1 | 2 | 5.0 |
| | | | | | | | Puttalam | Maho | zebra | 1 | 2 | 42.0 |
| | | | | | | | Pannala | Pannla-T | zebra | 1 | 2 | 15.0 |
| | | | | | | | Vavunia | Kilinochchi | Lynx | 1 | 2 | 74.1 |
| | | | | | | | Kilinochchi | Chunnakam | Lynx | 1 | 2 | 67.2 |
| | | | | | | | Habarana | Valachchanai | zebra | 1 | 1 | 99.7 |
| | | | | | | | Kotomale | Kiribathukumbra | zebra | 2 | 2 | 22.5 |
| | | | | | | | Rantambe | Ampara | zebra | 1 | 2 | 130.0 |
| 2008 | Kotugoda | Kerawalapitiya | zebra | 2 | 2 | 18.0 | Ukuwela | Palleke | zebra | 1 | 2 | 18.0 |
| | Kerawalapitiya | Kelantissa | CV1600 | 1 | 2 | 14.4 | | | | | | |
| | Kotmale | Anuradhapura | zebra | 1 | +1 (2) | 163.0 | | | | | | |
| 2009 | | | | | | | Valachchanai | Paddirippu | zebra | 1 | 2 | 69.0 |
| | | | | | | | Ampara | Paddirippu | zebra | 1 | 2 | 35.0 |
| 2010 | Randenigala | Rantembe | zebra | 1 | +1 (2) | 3.1 | Ambalangoda | Baddegama | zebra | 1 | 1 | 19.2 |
| | | | | | | | Baddegama | Galle | zebra | 1 | 1 (Future 2) | 16.8 |
| | | | | | | | Galle | Welligama | zebra | 1 | 1 (Future 2) | 19.5 |
| | | | | | | | Matara | Welligama | zebra | 1 | 1 (Future 2) | 14.5 |
| | | | | | | | Thulhiliya | Kegalle | zebra | 1 | 2 | 18.7 |
| | | | | | | | Veyangoda | Thulhiriya | zebra | 1 | 2 | 25.0 |
| | | | | | | | New Chilaw | Bolawata | zebra | 1 | 2 | 22.6 |
| 2011 | Kotmale | Upper Kotmale | zebra | 2 | 2 | 18.5 | Biyagama | Dekatana | zebra | 1 | 2 | 6.0 |
| | Veyangoda | Kirindiwela | zebra | 4 | 2 | 14.4 | Peligayoda | Kelaniya | Lynx | 1 | 2 | 5.4 |
| | kirindiwela | Ambulgama | zebra | 4 | 2 | 22.2 | New Chilaw | Kuliyapitiya | zebra | 1 | 2 | 21.0 |
| | Ambulgama | Arangala | zebra | 4 | 2 | 11.4 | Hambantota | Matara | zebra | 1 | 2 | 83.4 |
| | Ambulgama | Matugama | zebra | 4 | 2 | 58.2 | Kolonnawa (North) | Arangala (North) | zebra | 1 | 2 | 14.0 |
| | Puttalam | New Chilaw | zebra | 4 | 2 | 70.0 | Kolonnawa (South) | Arangala (South) | zebra | 1 | 2 | 14.0 |
| | New Chilaw | Veyangoda | zebra | 4 | 2 | 45.0 | Arangala | Ambulgama | zebra | 1 | 2 | 11.4 |
| | | | | | | | Ambulgama | Kosgama T | zebra | 1 | 2 | 10.1 |
| | | | | | | | Kosgama T | Kosgama | zebra | 1 | 2 | 0.5 |
| | | | | | | | Kosgama T | Polpitiya | zebra | 1 | 2 | 34.0 |
| 2012 | | | | | | | Kalutara | Matugama | zebra | 1 | 2 | 19.2 |
| 2013 | Matugama | Hambantota | zebra | 4 | 2 | 135.6 | | | | | | |
| 2014 | | | | | | | Col_C(Kotahena) | Kelantissa | CV500 | 1 | 1 | 1.6 |
| | | | | | | | Col_C(Kotahena) | Col_B | CV500 | 1 | 1 | 2.0 |
| | | | | | | | Col_B | Kolonnawa | CV500 | 1 | 1 | 4.2 |
| | | | | | | | Moratowa | Pannipitiya | zebra | 1 | 2 | 6.0 |
| | | | | | | | Moratowa | Panadura | zebra | 1 | 2 | 9.0 |
| | | | | | | | Matugama | Latpandura | Lynx | 1 | 2 | 13.2 |
| | | | | | | | Kiribathkumbura | Kandy | zebra | 1 | 2 | 10.8 |
| | | | | | | | Kandy | Palleke | zebra | 1 | 2 | 9.0 |
| 2015 | | | | | | | Bolawatta | Makandura | zebra | 1 | 2 | 16.20 |
| | | | | | | | Makandura | Pannala | zebra | 1 | 2 | 6.00 |
| 2016 | | | | | | | Pannala_T | N_Chilaw | zebra | 1 | 2 | 5.00 |
| | | | | | | | Gampaha | Dekatana | zebra | 1 | 2 | 15.0 |
| | | | | | | | Kotugoda | Gampaha | zebra | 1 | 2 | 16.2 |
| | | | | | | | Bolawatta | Negonbo | Lynx | 1 | 2 | 13.2 |
| 2017 | Trincomalee | N_Habarana | zebra | 4 | 2 | 95.0 | Bentota | Bentota-T | zebra | 1 | 2 | 12.0 |
| | N_Habarana | Veyangoda | zebra | 2 | 2 | 145.0 | Anamaduwa | Anamaduwa-T | Lynx | 1 | 2 | 10.8 |
| | | | | | | | Hettipola | Chilaw | zebra | 1 | 2 | 30.0 |
| 2018 | | | | | | | Kolonnawa | Col_K | CV500 | 1 | 1 | 5.0 |
| | | | | | | | Col_K | Sri J'pura | CV500 | 1 | 1 | 5.0 |
| | | | | | | | Sithawaka | Puwakupitiya | Lynx | 1 | 2 | 4.0 |
| | | | | | | | Kosgama | Waga | Lynx | 1 | 2 | 4.8 |
| | | | | | | | Katana | Badalgama | zebra | 1 | 2 | 10.8 |
| | | | | | | | Kotugoda | Ja-Ela | zebra | 1 | 2 | 4.2 |
| 2019 | | | | | | | Pannipitiya | Maharagama | zebra | 1 | 2 | 4.8 |
| | | | | | | | Hikaduwa | Baddegama | Lynx | 1 | 2 | 10.2 |
| | | | | | | | Jaffna | Chunnakam | Lynx | 1 | 2 | 10.8 |
| 2020 | Puttalam | N_Chilaw | zebra | 4 | 2 | 70.0 | Bandarawela | Bandarawela-T | zebra | 1 | 2 | 18.0 |
| 2021 | Hambantota | Bandarawela | zebra | 4 | 2 | 105.0 | Kamburupitiya | Kamburupitiya-T | Lynx | 1 | 2 | 7.5 |
| | Bandarawela | Upper Kotmale | zebra | 2 | 2 | 48.0 | Thulhiliya | Thulhiriya-T | zebra | 1 | 2 | 23.9 |
| | | | | | | | Kosgama | Kosgama-T | zebra | 1 | 2 | 0.5 |
| | | | | | | | Galle | Baddegama | zebra | 1 | +1 (2) | 16.8 |
| | | | | | | | Galle | Welligama | zebra | 1 | +1 (2) | 19.5 |
| | | | | | | | Matara | Welligama | zebra | 1 | +1 (2) | 14.5 |
| | | | | | | | Ambulgama | Anguruwela | zebra | 1 | 2 | 36.0 |
| | | | | | | | Habarana | Minneriya | zebra | 1 | +1 (2) | 19.8 |
| 2022 | | | | | | | Matugama | Migahatenna | zebra | 1 | 2 | 16.2 |
| | | | | | | | Nilaveli | Trincomalee | Lynx | 1 | 2 | 15.0 |
| 2023 | | | | | | | | | | | | |
| 2024 | | | | | | | | | | | | |
| 2025 | | | | | | | | | | | | |

*Note : "+" represents the number of additional lines or units.
The number in parentheses represents total after augmentation.

# Substation Development Plan (2005-2025)

| Year | Grid Stations, Switching Stations 220kV System | | | Year | Grid Stations, Switching Stations 132kV System | | |
|---|---|---|---|---|---|---|---|
| | G/S | Size(MVA) | units | | G/S | Size(MVA) | units |
| 2005 - 2010 | Kotmale | 250 | 1 | 2005 | Horana | 31.5 | 2 |
| | | | | 2006 | Ampara | 31.5 | 1 |
| | | | | | Havelock Town(Col A) | 31.5 | 2 |
| | | | | | Maradana(Col I) | 31.5 | 2 |
| | | | | | Sri J'Pura | 31.5 | 2 |
| | | | | | Dehiwala | 31.5 | 2 |
| | | | | | Madampe | 31.5 | 1 |
| | | | | 2007 | Ambalangoda | 31.5 | 2 |
| | | | | | Galle | 31.5 | 3 |
| | | | | | Deniyaya | 31.5 | 2 |
| | | | | | Aniyakanda | 31.5 | 2 |
| | | | | | Pannala | 31.5 | 2 |
| | | | | | Maho | 31.5 | 1 |
| | | | | | Chunnakam | 31.5 | 2 |
| | | | | | Kilinochchi | 31.5 | 1 |
| | | | | | Polonnaruwa | 31.5 | 1 |
| | | | | | Medagama | 31.5 | 1 |
| | | | | 2008 | Katana | 31.5 | 2 |
| | | | | | Kotugoda | 31.5 | 2 |
| | | | | | Kurunegara | 31.5 | 1 |
| | | | | | Pallekele | 31.5 | 2 |
| | | | | | Naula | 31.5 | 1 |
| | | | | 2009 | Havelock Town (Col A | 31.5 | 1 |
| | | | | | Maradana(Col I) | 31.5 | 1 |
| | | | | | Veyangoda | 31.5 | 1 |
| | | | | | Vavunia | 31.5 | 2 |
| | | | | | Padirippu | 31.5 | 2 |
| | | | | 2010 | Kosgama | 31.5 | 1 |
| | | | | | Kolonawa New | 31.5 | 1 |
| | | | | | Panadura | 31.5 | 1 |
| | | | | | Athurigiriya | 31.5 | 1 |
| | | | | | Baddegama | 31.5 | 2 |
| | | | | | Weligama | 31.5 | 2 |
| | | | | | Kegalle | 31.5 | 2 |
| | | | | | Kelaniya | 31.5 | 1 |
| | | | | | Puttalam | 31.5 | 1 |
| | | | | | Anuradhapura | 31.5 | 1 |
| | | | | | Habarana | 31.5 | 1 |
| | | | | | Wimalasurendra | 31.5 | 1 |
| 2011 - 2015 | Habarana | 250 | 2 | 2011 | Pannipitiya | 31.5 | 1 |
| | Kelanttissa | 150 | +1(3) | | Dekatana | 31.5 | 2 |
| | Pannipitiya | 250 | +1(3) | | Peligayoda | 31.5 | 2 |
| | Matugama | 250 | 2 | | Kuliyapitiya | 31.5 | 2 |
| | Hambantota | 250 | 2 | | Pannala | 31.5 | 1 |
| | N-CHW | 250 | 2 | | Valachchnai | 31.5 | 2 |
| | Ambulgama(S/S) | 250 | 0 | 2012 | Kalutara | 31.5 | 2 |
| | Arangama(S/S) | 250 | 0 | | Matara | 31.5 | 1 |
| | Kirindiwela(S/S) | 250 | 0 | | Hambantota | 31.5 | 2 |
| | | | | | Aniyakanda | 31.5 | 1 |
| | | | | | Katana | 31.5 | 1 |
| | | | | | Anuradhapura | 31.5 | 1 |
| | | | | | Ukuwela | 31.5 | 1 |
| | | | | 2013 | Horana | 31.5 | 1 |
| | | | | | Maho | 31.5 | 1 |
| | | | | | Naula | 31.5 | 1 |
| | | | | | Badulla | 31.5 | 1 |
| | | | | 2014 | Colombo Sub B | 31.5 | 2 |
| | | | | | Kotahena(Col C) | 31.5 | 2 |
| | | | | | Moratuwa | 31.5 | 2 |
| | | | | | Latpandura | 31.5 | 2 |
| | | | | | Sri J'Pura | 31.5 | 1 |
| | | | | | Sithawakapura | 31.5 | 1 |
| | | | | | Deniyaya | 31.5 | 1 |
| | | | | | Kelaniya | 31.5 | 1 |
| | | | | | Polonnaruwa | 31.5 | 1 |
| | | | | | Trincomalee | 31.5 | 1 |
| | | | | | Kandy | 31.5 | 2 |
| | | | | | Matale | 31.5 | 2 |
| | | | | 2015 | Dehiwala | 31.5 | 1 |
| | | | | | Embilipitiya | 31.5 | 1 |
| | | | | | Makandura | 31.5 | 2 |
| | | | | | Nuwara Eliya | 31.5 | 1 |

*Note : "+" represents the number of additional lines or units.
The number in parentheses represents total after augmentation.

| Year | Grid Stations, Switching Stations 220kV System | | | Year | Grid Stations, Switching Stations 132kV System | | |
|---|---|---|---|---|---|---|---|
| | G/S | Size(MVA) | units | | G/S | Size(MVA) | units |
| 2016 - 2020 | Rantembe | 250 | +1(2) | 2016 | Gonaduwa | 31.5 | 2 |
| | N-CHW | 250 | +2(4) | | Ambalangoda | 31.5 | 1 |
| | Kotmale | 250 | +1(2) | | Baddegama | 31.5 | 1 |
| | Rantembe | 250 | +1(3) | | Gampaha | 31.5 | 2 |
| | Ambulgama | 250 | +3(3) | | Negombo | 31.5 | 2 |
| | Arangama | 250 | +3(3) | | Mirigama | 31.5 | 2 |
| | Matugama | 250 | +1(3) | | Peligayoda | 31.5 | 1 |
| | Biyagama | 250 | +1(3) | | Nattandiya | 31.5 | 2 |
| | Hambantota | 250 | +1(3) | | Minneriya | 31.5 | 2 |
| | Habarana | 250 | +1(3) | 2017 | Bentota | 31.5 | 2 |
| | Trincomalee | 250 | 1 | | Weligama | 31.5 | 1 |
| | | | | | Kegalle | 31.5 | 1 |
| | | | | | Anamaduwa | 31.5 | 2 |
| | | | | | Hettipola | 31.5 | 2 |
| | | | | | Galenbindunnuwewa | 31.5 | 2 |
| | | | | 2018 | Colombo Sub K | 31.5 | 2 |
| | | | | | Puwakupitiya | 31.5 | 2 |
| | | | | | Waga | 31.5 | 2 |
| | | | | | Badalgama | 31.5 | 2 |
| | | | | | Ja-Ela | 31.5 | 2 |
| | | | | | Kadawatta | 31.5 | 2 |
| | | | | | Dekatana | 31.5 | 1 |
| | | | | | Lindula | 31.5 | 2 |
| | | | | | Pallekele | 31.5 | 1 |
| | | | | 2019 | Kolonawa New 2 | 31.5 | 2 |
| | | | | | Arangala | 31.5 | 2 |
| | | | | | Maharagama | 31.5 | 2 |
| | | | | | Kalutara | 31.5 | 1 |
| | | | | | Latpandura | 31.5 | 1 |
| | | | | | Moratuwa | 31.5 | 1 |
| | | | | | Dikwella | 31.5 | 2 |
| | | | | | Hikaduwa | 31.5 | 2 |
| | | | | | Kegalle | 31.5 | 1 |
| | | | | | Negombo | 31.5 | 1 |
| | | | | | Makandura | 31.5 | 1 |
| | | | | | Jaffna | 31.5 | 2 |
| | | | | | Valachchanai | 31.5 | 1 |
| | | | | 2020 | Anguruwella | 31.5 | 2 |
| | | | | | Balangoda | 31.5 | 1 |
| | | | | | Kuliyapitiya | 31.5 | 1 |
| | | | | | Maho | 31.5 | 1 |
| | | | | | Polonnaruwa | 31.5 | 1 |
| | | | | | Bandarawela | 31.5 | 2 |
| 2021 - 2025 | Kotugoda | 250 | +1(3) | 2021 | Piliyandula | 31.5 | 2 |
| | Kotmale | 250 | +1(3) | | Kamburupitiya | 31.5 | 2 |
| | Trincomalee | 250 | +1(2) | | Hambantota | 31.5 | 1 |
| | Bandarawela | 250 | 2 | | Ratnapura | 31.5 | 1 |
| | | | | | Hanwella | 31.5 | 2 |
| | | | | | Ekala | 31.5 | 2 |
| | | | | | Andimbalama | 31.5 | 2 |
| | | | | | Mirigama | 31.5 | 1 |
| | | | | | Kadwatta | 31.5 | 1 |
| | | | | | Chilaw | 31.5 | 2 |
| | | | | | Hettipola | 31.5 | 1 |
| | | | | | Kandy | 31.5 | 1 |
| | | | | 2022 | Colombo Sub B | 31.5 | 1 |
| | | | | | Migahatenna | 31.5 | 2 |
| | | | | | Maharagama | 31.5 | 1 |
| | | | | | Puwakupitiya | 31.5 | 1 |
| | | | | | Waga | 31.5 | 1 |
| | | | | | Ja-Ela | 31.5 | 1 |
| | | | | | Gampaha | 31.5 | 1 |
| | | | | | Nattandiya | 31.5 | 1 |
| | | | | | Nilaveli | 31.5 | 2 |
| | | | | | Padirippu | 31.5 | 1 |
| | | | | 2023 | Ambulgama | 31.5 | 2 |
| | | | | | Arangala | 31.5 | 1 |
| | | | | | Hikaduwa | 31.5 | 1 |
| | | | | | Badalgama | 31.5 | 1 |
| | | | | | Anamaduwa | 31.5 | 1 |
| | | | | | Kilinochchi | 31.5 | 1 |
| | | | | | Matale | 31.5 | 1 |
| | | | | | Lindula | 31.5 | 1 |
| | | | | 2024 | Kotahena(Col C) | 31.5 | 1 |
| | | | | | Colombo Sub K | 31.5 | 1 |
| | | | | | Pilyandula | 31.5 | 1 |
| | | | | | Dikwella | 31.5 | 1 |
| | | | | | Kamburupitiya | 31.5 | 1 |
| | | | | | Hanwella | 31.5 | 1 |
| | | | | | Ekala | 31.5 | 1 |
| | | | | | Andimbalama | 31.5 | 1 |
| | | | | | Chilaw | 31.5 | 1 |
| | | | | | Galenbindunnuwewa | 31.5 | 1 |
| | | | | | Minneriya | 31.5 | 1 |
| | | | | 2025 | | | |

*Note : "+" represents the number of additional lines or units.
The number in parentheses represents total after augmentation.

# Scoping Table for Environmental and Social Consideration

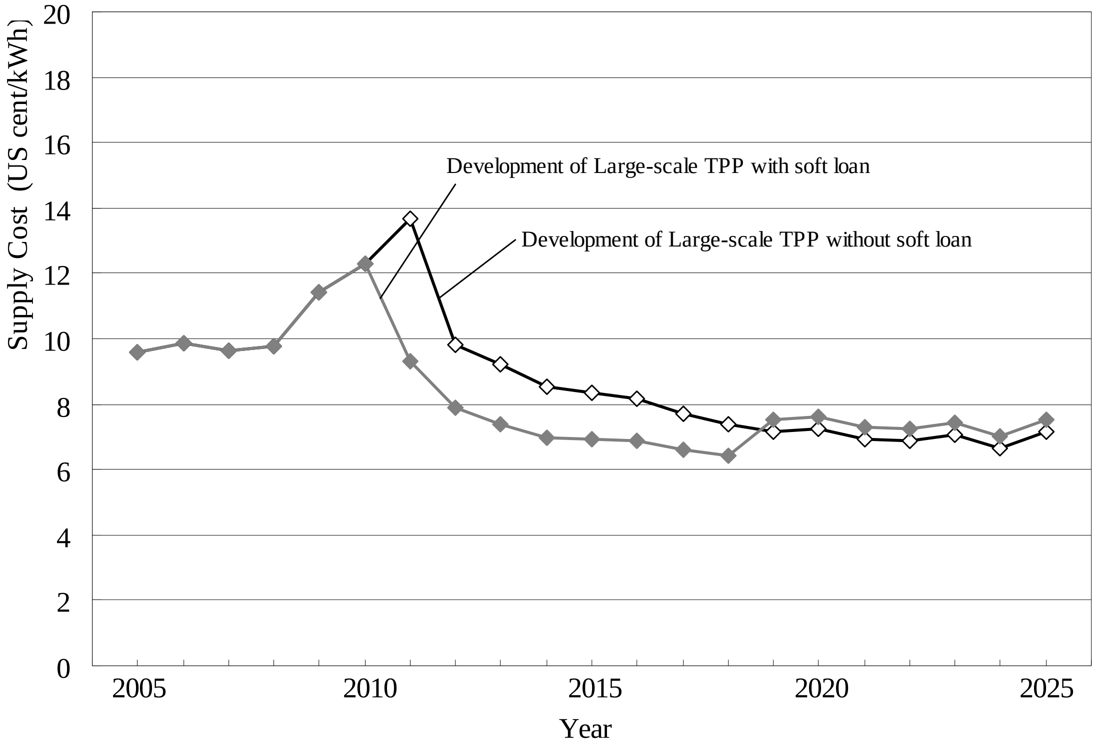
| Item Grade | Weight |
|---|---|
| **A** | 3.0 |
| **B** | 2.0 |
| **C** | 1.0 |

| Impact | Score |
|---|---|
| **A** | 3 |
| **B** | 1 |
| **C** | 0.1 |

| | Item | Item Grade | Affected Impact | Hydropower | | | | | Thermal Power | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | New Steam Turbine | | | | | | | New Combined Cycle | | | | Gas Turbine | | Diesel |
| | | | | Mora -golla | Gin Ganga | Broad -lands | Uma Oya | Upper Kotmale | Coal* | | Gas* | | Oil* | | Kerawala -pitiya | Gas* | | Oil* | | Gas | Oil | Oil |
| Social Environment | Involuntary Resettlement | *A* | Facility | **B** | **A** | **B** | **B** | **A** | **B** | **B** | **B** | **B** | **B** | **B** | **C** | **B** | **B** | **B** | **B** | **C** | **C** | **C** |
| | Minority or weak people of society | *C* | Facility | **C** | **B** | **C** | **B** | **B** | **B** | **B** | **B** | **B** | **B** | **B** | **C** | **B** | **B** | **B** | **B** | **C** | **C** | **C** |
| | Inequality and separation in society | *B* | Facility | **B** | **B** | **B** | **A** | **B** | **B** | **B** | **B** | **B** | **B** | **B** | **C** | **B** | **B** | **B** | **B** | **C** | **C** | **C** |
| | Cultural heritage | *A* | Facility | **C** | **C** | **C** | **C** | **A** | **B** | **B** | **B** | **B** | **B** | **B** | **C** | **B** | **B** | **B** | **B** | **C** | **C** | **C** |
| | Local landscape | *A* | Facility | **B** | **A** | **B** | **B** | **A** | **A** | **A** | **A** | **A** | **A** | **A** | **C** | **A** | **A** | **A** | **A** | **C** | **C** | **C** |
| | Economic activities (regional or local) | *C* | Facility | **C** | **B** | **B** | **B** | **A** | **A** | **A** | **A** | **A** | **A** | **A** | **C** | **A** | **A** | **A** | **A** | **B** | **B** | **B** |
| | Water Usage | *B* | Facility | **A** | **A** | **A** | **A** | **A** | **A** | **C** | **A** | **C** | **A** | **C** | **B** | **A** | **C** | **A** | **C** | **C** | **C** | **C** |
| | Contagious or Infectious disease | *C* | Facility | **B** | **B** | **B** | **B** | **B** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** |
| | Accidents | *C* | Facility | **B** | **B** | **B** | **B** | **B** | **B** | **B** | **B** | **B** | **B** | **B** | **B** | **B** | **B** | **B** | **B** | **C** | **C** | **C** |
| Natural Environment | Protected Area | *A* | Facility | **C** | **A** | **B** | **C** | **C** | **A** | **A** | **A** | **A** | **A** | **A** | **C** | **A** | **A** | **A** | **A** | **B** | **B** | **B** |
| | Geographical /Geological Features | *B* | Facility | **C** | **B** | **C** | **A** | **A** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** |
| | Sediment & Hydrology | *C* | Facility | **B** | **A** | **B** | **A** | **A** | **C** | **C** | **C** | **C** | **C** | **C** | **B** | **C** | **C** | **C** | **C** | **C** | **C** | **C** |
| | Ecosystems/ Wildlife | *A* | Facility | **C** | **A** | **B** | **B** | **B** | **A** | **C** | **A** | **C** | **A** | **C** | **C** | **A** | **C** | **A** | **C** | **C** | **C** | **C** |
| | Global warming | *B* | Operation | **C** | **C** | **C** | **C** | **C** | **A** | **A** | **A** | **A** | **A** | **A** | **A** | **A** | **A** | **A** | **A** | **B** | **B** | **B** |
| Pollutions & Public Hazards | Air Pollution | *A* | Operation | **C** | **C** | **C** | **C** | **C** | **A** | **A** | **B** | **B** | **A** | **A** | **B** | **B** | **B** | **A** | **A** | **C** | **B** | **A** |
| | Water Pollution | *A* | Facility | **B** | **B** | **B** | **B** | **B** | **A** | **B** | **A** | **B** | **A** | **B** | **A** | **A** | **B** | **A** | **B** | **C** | **C** | **C** |
| | Soil Contamination | *C* | Facility | **C** | **C** | **C** | **C** | **C** | **B** | **B** | **B** | **B** | **B** | **B** | **B** | **B** | **B** | **B** | **B** | **C** | **C** | **C** |
| | Wastes | *B* | Operation | **B** | **B** | **B** | **A** | **B** | **A** | **A** | **C** | **C** | **B** | **B** | **B** | **C** | **C** | **B** | **B** | **C** | **B** | **B** |
| | Noise & Vibration | *B* | Operation | **B** | **B** | **B** | **C** | **C** | **A** | **A** | **A** | **A** | **A** | **A** | **B** | **A** | **A** | **A** | **A** | **A** | **A** | **A** |
| | Others | *C* | Facility | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** | **C** |
| | Accidents | *B* | Facility | **A** | **B** | **B** | **A** | **B** | **B** | **B** | **A** | **A** | **A** | **A** | **A** | **A** | **A** | **A** | **A** | **A** | **A** | **A** |

*: Right side row is applied to thermal power plants with cooling tower system for condenser cooling water.

Soft Loan Effect for Supply Cost



# SCOPE OF WORK
# FOR
# THE MASTER PLAN STUDY ON
# THE DEVELOPMENT OF POWER GENERATION AND
# TRANSMISSION SYSTEM
# IN SRI LANKA

## AGREED UPON BETWEEN
## CEYLON ELECTRICITY BOARD
## AND
## JAPAN INTERNATIONAL COOPERATION AGENCY

02nd September 2004

Mr.P. Weerahandi
Secretary
Ministry of Power and Energy

Mr. J. H. J. Jayamaha
Additional Director General
Department of External Resources
Ministry of Finance

Mr.Ranjit F.Fonseka
General Manager
Ceylon Electricity Board

Mr. Toshio Sugihara
Resident Representative,
Sri Lanka Office
Japan International Cooperation
Agency

## I. Introduction

In response to the request of the Government of Democratic Socialist Republic of Sri Lanka (hereinafter referred to as "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 (hereinafter referred to as "the Study" ) in accordance with the relevant laws and regulations in force in Japan.

Accordingly, the Japan International Cooperation Agency (hereinafter referred to as "JICA" ), the official agency responsible for the implementation of the technical cooperation programs in the Government of Japan, will undertake the Study in close cooperation with the authorities concerned in Sri Lanka.

The present document sets forth the scope of work with regard to the Study.

## II. Objectives of the Study

The Study aims at developing a comprehensive master plan of twenty (20) years for generation and transmission system expansion for the whole country.

## III. Study Area

The Study will cover the whole country of Sri Lanka including North and East provinces.

## IV. Scope of the Study

The Study shall be carried out as follows:

(1) Data Collection

- Collect and review the existing data, reports and other relevant information for the Study;
- Investigate and evaluate existing power generating facilities, and transmission lines and substations, as well as the existing plans for power generation, transmission and substation development , and rehabilitation, for updating estimated costs and construction plans, and reviewing the environmental and social considerations;

(2) Demand forecast

- Review demand centers;
- Review the present methodology for demand forecast employed by CEB;
- Based on the result of the review, revise the present demand forecast model in order to reflect the present conditions of power demand;
- Prepare demand forecast for the period of the master plan based on the macro-economic method and detailed break-down method considering the demand side management, transmission and distribution line loss reduction, the progress of rural electrification, and other necessary factors;

(3) Least cost generation expansion planning

- Investigate the existing data, information and plans of non-conventional renewable energy, and evaluate its potential and technical viability;
- Review the present least cost method, and review the data and information for planning the generating capacity expansion employed by CEB;
- Based on the result of the review, revise the existing method, and revise the existing data and information for the least cost method;
- Prepare the long-term generation expansion plan based on the least cost method;

(4) Transmission system development planning

- Review the present method of power system analysis, and review the data and information for the system analysis employed by CEB;
- Based on the result of the review, revise the existing method, and revise the existing data and information for power system analysis;
- Prepare the long-term transmission system development plan based on the optimum result of the system analysis;

(5) Long—term investment planning

- Prepare investment plan based on the least cost generation expansion plan and rehabilitation plan, and the transmission development plan;

(6) Tariff study

- Calculate long-run marginal cost based on the least cost generation expansion plan and transmission development plan, and long-term investment plan, for high, middle and low voltage users respectively;
- Study and evaluate the present tariff level and structure based on the long-run-marginal cost;
- Suggest the guideline of power tariff;
- Carry out economic analysis of insufficient power supply that would be

brought about by delayed implementation of future power development projects;

- Carry out sensitive analysis based on the reasonable assumptions;

(7) Financial analysis

- Appraise the financial impact the long-term investment plan would bring about to CEB;
- Carry out sensitive analysis based on the reasonable assumptions;

(8) Environmental and social considerations

- Investigate CEB' s necessary capacity for managing environmental and social considerations, and suggest practical measures to be taken;
- Facilitate information dissemination and stakeholders' participation in the process of the Study through seminars and public relations;

(9) Power sector development policy study

- Investigate and evaluate the present policy arrangement and mechanism for introducing private money to increase the power generation capacity, and suggest some alternative policy arrangement and mechanism for introducing private money to increase the power generation capacity;
- Investigate and evaluate the present policy arrangement and mechanism for rural electrification, and suggest some alternative policy arrangement and mechanism for rural electrification under the envisaged new environment of restructured power sector;
- Investigate and evaluate the present usage of renewable energy such as Photovoltaic and micro hydropower for village electrification, and identify some policy issues for efficient and appropriate usage of renewable energy for village electrification;

(10) Preparation of Master Plan

- Prepare Master Plan including demand forecast, least cost generation expansion plan, transmission system development plan, rehabilitation plan, long-term investment plan, tariff study, economic and financial analyses, environmental and social considerations, and power sector development policy;
- Suggest a strategic plan of power supply in the Master Plan to eliminate the present acute power shortage;
- Suggest an appropriate process of efficient implementation of the Master Plan; and
- Identify other remaining technical issues that require further investigation and study, such as the improvement of communication system and power control system, and energy conservation, and include the Terms of Reference in the Master Plan.

## V. Schedule of the Study

The Study shall be conducted in accordance with the tentative schedule in Appendix I attached herewith.

## VI. Reports

JICA shall prepare and submit the following reports in English to the Government of Sri Lanka, in accordance with tentative schedule attached in Appendix I .

(1) Inception Report (30 copies)

(2) Interim Report (20 copies)

(3) Draft Final Report (30 copies)

The Government of Sri Lanka shall provide JICA with written comments on the Draft Final Report, within one (1) month after receipt.

(4) Final Report and Executive Summary (40 copies)

## VII. Division of Technical Undertaking

The division of technical undertaking of the Study by JICA and CEB is detailed in Appendix II attached herewith.

## VIII. Undertaking of the Government of Sri Lanka

1. To facilitate the smooth conduct of the Study, the Government of Sri Lanka shall take necessary measures:

(1) To permit the members of the Team to enter, leave and sojourn in Sri Lanka for the duration of their assignments therein and exempt them from foreign registration requirements and consular fees;

(2) To exempt the members of the Team from taxes, duties and any other charges on equipment, machinery and other material brought into Sri Lanka for the implementation of the Study;

(3) To exempt the members of the Team from income tax and charges of any kind imposed on or in connection with any emoluments or allowances paid to the members of the team for their services in connection with the implementation of the Study;

(4) To provide necessary facilities to the Team for the remittance as well as utilization of the funds introduced into Sri Lanka from Japan in connection with the implementation of the study;

2. The Government of Sri Lanka shall bear claims, if any arises, against the members of the Team resulting from, occurring in the course of, or otherwise connected with, the discharge of their duties in the implementation of the Study, except when such claims arise from gross negligence or willful misconduct on the part of the team.

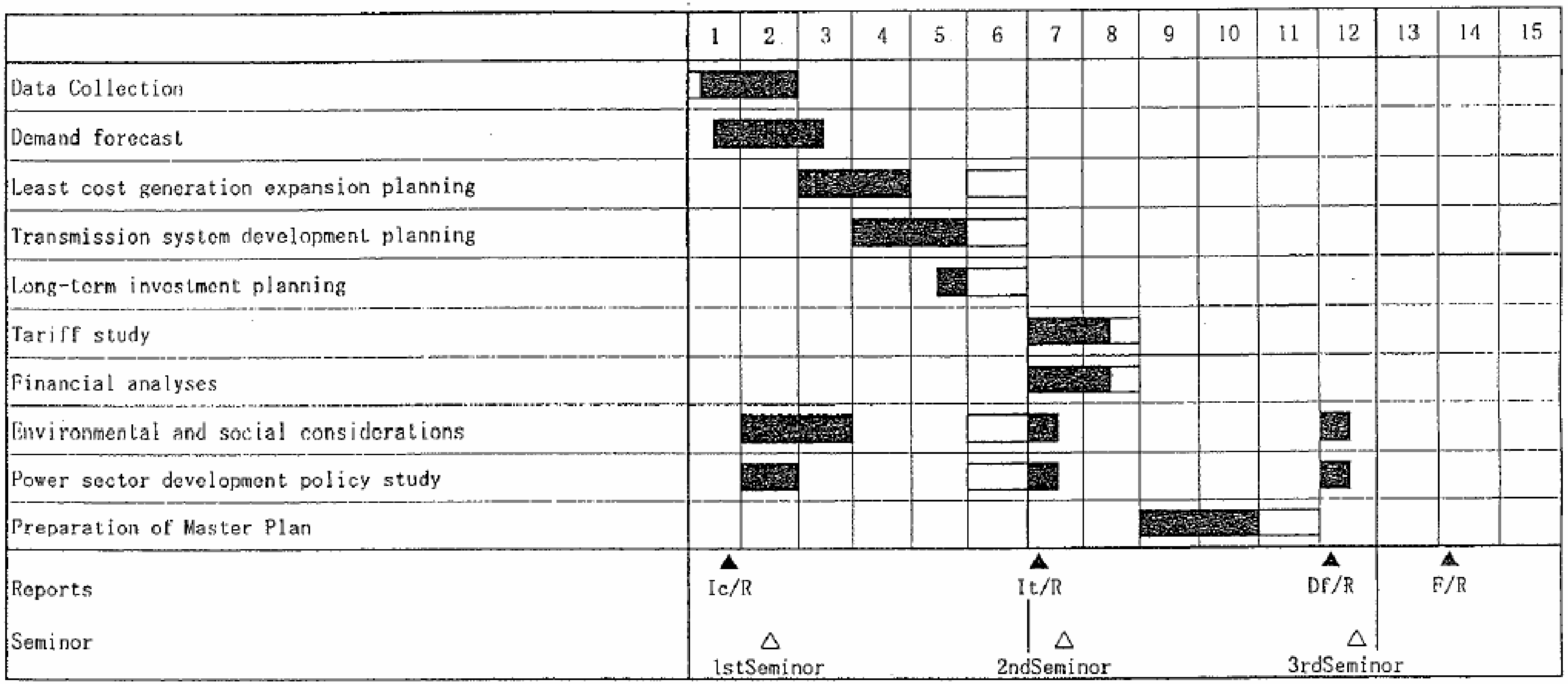
3. CEB shall, at its own expense, provide the Team with the following, in cooperation with other organizations concerned :

(1) Security-related information on as well as measures to ensure the safety of the Team;
(2) Information on as well as support in obtaining medical service;
(3) Available data (including maps and photographs) and information related to the Study;
(4) Counterpart personnel;
(5) Suitable office space with necessary equipment; and
(6) Credentials or identification cards.

## IX. Consultation

JICA and CEB shall consult with each other in respect of any matter that may arise from or in connection with the Study.

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




Legend : Work in Japan
Work in Sri Lanka

Reports: Ic/R : Inception Report
It/R : Interim Report
Df/R : Draft Final Report
F/R : Final Report

The Master Plan Study on the Development of Power Generation and Transmission System in Sri Lanka
Division of Technical Undertaking

| | Undertaking of JICA | Undertaking of CEB |
|---|---|---|
| (1) Data Collection | Review by JICA study team | Data Provision |
| (2) Demand forecast | Study by JICA study team | Couterpart provision and discussion |
| (3) Least cost generation expansion planning | Study by JICA study team | Couterpart provision and discussion |
| (4) Transmission system development planning | Study by JICA study team | Couterpart provision and discussion |
| (5) Long-term investment planning | Study by JICA study team | Couterpart provision and discussion |
| (6) Tariff study | Study by JICA study team | Couterpart provision and discussion |
| (7) Financial analysis | Study by JICA study team | Couterpart provision and discussion |
| (8) Environmental and social considerations | Study by JICA study team | Study by CEB |
| (9) Power sector development policy study | Study by JICA study team | Couterpart provision and discussion |
| (10) Preparation of Master Plan | Study by JICA study team | Study by CEB |