CEYLON ELECTRICITY BOARD

LONG TERM GENERATION EXPANSION PLAN

2013-2032

Transmission and Generation Planning Branch
Transmission Division
Ceylon Electricity Board
Sri Lanka

October 2013

Long Term Generation Expansion Planning Studies
2013- 2032

Compiled and prepared by
The Generation Planning Unit
Transmission and Generation Planning Branch
Ceylon Electricity Board, Sri Lanka

Long-term generation expansion planning studies are carried out every two years by the Transmission & Generation Planning Branch of the Ceylon Electricity Board, Sri Lanka and this report is a bi-annual publication based on the results of the latest expansion planning studies. The data used in this study and the results of the study, which are published in this report, are intended purely for this purpose.

Price Rs. 3000.00

Foreword

The 'Report on Long Term Generation Expansion Planning Studies 2013-2032', presents the results of the latest expansion planning studies conducted by the Transmission and Generation Planning Branch of the Ceylon Electricity Board for the planning period 2013-2032, and replaces the last of these reports prepared in April 2011.

This report, gives a comprehensive view of the existing generating system, future electricity demand and future power generation options in addition to the expansion study results.

The latest available data were used in the study. The Planning Team wishes to express their gratitude to all those who have assisted in preparing the report. We would welcome suggestions, comments and criticism for the improvement of this publication.

October 2013.

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ADB	-	Asian Development Bank
BOO	-	Build, Own and Operate
CCY	-	Combined Cycle Power Plant
CEA	-	Central Environmental Authority
CEB	-	Ceylon Electricity Board
CECB	-	Central Engineering Consultancy Bureau
CIDA	-	Canadian International Development Agency
CIF	-	Cost, Insurance and Freight
CPC	-	Ceylon Petroleum Corporation
DSM	-	Demand Side Management
EIA	-	Environmental Impact Assessment
ENPEP	-	Energy and Power Evaluation Package
ENS	-	Energy Not Served
EOI	-	Expression Of Interest
EWE	-	Electrowatt Engineering
FGD	-	Flue Gas Desulphurization
FOR	-	Forced Outage Rate
GDP	-	Gross Domestic Product
GHG	-	Green House Gases
GIS	-	Geographic Information System
GT	-	Gas Turbine

HHV	-	Higher Heating Value
IAEA	-	International Atomic Energy Agency
IDC	-	Interest During Construction
IEA	-	International Energy Agency
IPCC	-	Inter-Governmental Panel on Climate Change
IPP	-	Independent Power Producer
ITDG	-	Intermediate Technology Development Group
JBIC	-	Japan Bank for International Cooperation
JICA	-	Japan International Cooperation Agency
LKR	-	Sri Lanka Rupees
KPS	-	Kelanatissa Power Station
LDC	-	Load Duration Curve
LF	-	Load Factor
LNG	-	Liquefied Natural Gas
LOLP	-	Loss Of Load Probability
LTGEP	-	Long Term Generation Expansion Plan
OECF	-	Overseas Economic Co-operation Fund
O&M	-	Operation and Maintenance
OTEC	-	Ocean Thermal Energy Conversion
NCRE	-	Non Conventional Renewable Energy
PF	-	Plant Factor
PPA	-	Power Purchase Agreement
PV	-	Present Value
RFP	-	Request For Proposals
SYSIM	-	SYstem SImulation Model
USAID	-	United States Agency for International Development
US$	-	American Dollars
WASP	-	Wien Automatic System Planning Package
WB	-	World Bank
WHO	-	World Health Organization
CDM	-	Clean Development Mechanism
CER	-	Certified Emission Reduction

EXECUTIVE SUMMARY

The Ceylon Electricity Board (CEB) is under a statutory duty to develop and maintain an efficient, coordinated and economical system of Electricity Supply for the whole of Sri Lanka. Therefore, CEB is required to generate or acquire sufficient amount of electricity to satisfy the demand. CEB methodically plans its development activities in order to provide reliable, quality electricity to the entire nation at affordable prices.

This report presents the Generation Expansion Planning Studies carried out by the Transmission and Generation Planning Branch of the Ceylon Electricity Board for the period 2013-2032. The Report also includes information on the existing generation system, generation planning methodology, system demand forecast and investment and implementation plans for the proposed projects and recommends the adoption of the least cost plant sequence derived for the base case and also emphasizes the need to implement the plan to avoid energy shortfalls. The Load Forecast used is given in Table E-1.

The methodology adopted in the studies optimally selects plant additions from given thermal as well as hydropower generation expansion candidates, which will, together with existing and committed power plants meet the forecast electricity demand with a given level of reliability complying with Mahinda Chinthana - Future Vision and National Energy Policy (2006).

Possible electricity demand growth variations, the impact on variation in discount rate and fuel price have been considered in the sensitivity studies. Each plant sequence presented in this report is the least cost plant sequence for the given scenario. The candidate thermal power options considered in the study were coal-fired and fuel oil-fired conventional steam plants, LNG fired combined cycle plants, Nuclear power plants, diesel-fired gas turbines and combined cycle plants. The proposed hydroelectric plants at Gin Ganga (49MW) and Moragolla (27MW) were also considered as candidate plants. Committed thermal power plants are 20MW Northern Power in 2014, 24MW Chunnakam Power Plant (Extension) in 2014, 1x300MW of Puttalam Coal fired Power Plant (Stage - II) in 2014 and 1x 300MW of Puttalam Coal fired Power Plant (Stage - III) in 2015. 35MW Broadlands Hydro Power Plant and 120MW Uma Oya Hydro Power Plant were considered as committed in 2016.

The earliest possible date for commissioning of candidate coal-fired power plants was taken as 2018 considering the present progress of the Trincomalee Coal Power Project. The other candidate coal-fired power plants were considered only after Trincomalee site was developed to

500MW.The earliest possible dates for commissioning of gas turbine and combined cycle plant were taken as 2015 and 2017 respectively.

In the Base Case Plan, the contribution from NCRE too was considered and the different NCRE technologies were modeled appropriately.

The viability of introducing LNG fired power plants was also studied. The LNG fuel option was considered with terminal cost and without terminal cost for the present LNG fuel prices to determine the breakeven price for LNG. LNG fuel prices are not economically competitive with the current coal prices. However, it will have to be addressed in the Energy Policy of the Government of Sri Lanka.

In the Base Case Plan, contracts of the IPP plants expired in 2012 have been considered for renewal for 5 years until January 2018. The economic viability of renewing these IPP contracts were studied based on the proposals submitted by the respective power plant operators. It was found that renewing these IPP contracts for another 5 years is economical. However, such option could be considered only if a decision is made by the Government to renew these IPP contracts. In which case, the purchasing price has to be negotiated.

Base Case Plan was revised considering following:

(i) IPP plants; ACE Matara, ACE Horana and Lakdhanavi were not considered for renewal after retirement.
(ii) 49MW Gin Ganga Hydro Power Plant was advanced to year 2022 from year 2029.
(iii) Coal plant development at Sampoor was limited to 2 x250MW.

Revised Base Case Plan is given in the Table E.2 and also in the Table Ad.1 of Annex: 11 - Addendum to the Long Term Generation Expansion Plan. Revised Capacity Balance, Revised Energy Balance and Revised Dispatch Schedule are given in Addendum Table No: Ad.2, Addendum Table No: Ad.3 and Addendum Table No: Ad.4 respectively.

Table E.1 - Base Load Forecast – 2012

Year	Demand Energy (GWh)	Losses* (%)	Net Generation Energy (GWh)	Peak (MW)
2013	11104	11.63%	12566	2451**
2014	12072	11.59%	13502	2692
2015	12834	11.54%	14509	2894
2016	13618	11.50%	15388	3017
2017	14420	11.37%	16270	3193
2018	15240	11.25%	17171	3383
2019	16075	11.12%	18087	3556
2020	16937	11.00%	19030	3731
2021	17830	10.90%	20010	3920
2022	18754	10.79%	21023	4125
2023	19713	10.69%	22072	4287
2024	20707	10.59%	23159	4499
2025	21737	10.49%	24284	4717
2026	22813	10.39%	25458	4948
2027	23932	10.29%	26677	5187
2028	25101	10.19%	27949	5369
2029	26318	10.10%	29273	5625
2030	27581	10.00%	30645	5893
2031	28899	9.91%	32079	6171
2032	30258	9.83%	33555	6461
2033	31670	9.74%	35087	6671
2034	33131	9.65%	36672	6978
2035	34652	9.57%	38320	7294
2036	36230	9.49%	40027	7621
2037	37873	9.40%	41804	7962
Growth %	5.2%		5.4%	4.9%

- Losses* includes Transmission and Distribution losses as a percentage of Net Generation.
- Peak ** includes contribution from NCRE and excludes 2013 northern peak.

Table E.2 Results of Generation Expansion Planning Studies – Revised Base Case Plan 2012

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	-	-	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi	1.821
2014	-	*4x5 MW Northern Power** *3x8 MW Chunnakum Extension** *1x300 MW Puttalam Coal (Stage II)*	-	1.357
2015	-	*1x300 MW Puttalam Coal (Stage II)**** **3x75 MW Gas Turbine**	6x16.6 MW Heladanavi Puttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.228
2016	*35 MW Broadlands* *120 MW Uma Oya*	-	-	1.017
2017	-	**1x105 MW Gas Turbine**	-	1.483
2018	**27 MW Moragolla Plant**	**2x250 MW Trincomalee Coal Power plant**	4x5 MW Northern Power 8x6.13 MW Asia Power	0.399
2019	-	**2x300 MW Coal plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.080
2020	-	-	-	0.247
2021	-	**1x300 MW Coal plant**	-	0.162
2022	**49 MW Gin Ganga ** **	**1x300 MW Coal plant**	-	0.085
2023	-	**2x300 MW Coal plant**	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.045
2024	-	-	-	0.169
2025	-	**1x300 MW Coal plant**	4x9 MW Sapugaskanda Diesel Ext.	0.162
2026	-	-	-	0.518
2027	-	**1x300 MW Coal plant**	-	0.466
2028	-	**1x300 MW Coal plant**	-	0.370
2029	-	-	-	1.078
2030	-	**1x300 MW Coal plant**	-	1.094
2031	-	**1x300 MW Coal plant**	-	1.140
2032	-	**1x300 MW Coal plant**	-	1.233
Total PV Cost up to year 2032, **US$ 14,049.05 million**				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics. All plant capacities are given in gross values.
- Above PV cost includes the cost of Projected Committed NCRE, US$ 689.98 million.

* Year of connection to national grid based on the estimated time schedule of Kilinochchi – ChunnakkamT x line.

** 49MW Gin ganga Hydro Power Plant is forced in year 2022 considering 4 years for securing approvals and finances, preliminary & detailed design, preparation of Tender Documents, Tendering and 4 years for construction & commission work from year 2014 as water resource distribution of this Project is still not decided by Irrigation Department.

*** Scheduled in operation by June 2014.

With regard to the energy, it is apparent that coal will be the major source of power during the study period with its share reaching almost 70% by 2025. However, the contribution from renewable energy power plants too will be considerable with a share of more than 25% by 2025. Hence, the green credentials of the country would stay intact. The coal requirement would increase significantly while the oil requirement will come down at a higher rate.

It is seen that, emission of local pollutants such as SO_X and NO_X will come down with the decrease of oil fired generation, however per unit emission of CO_2 would increase by almost 68% to the value 0.77kg/kWh. But, the total CO_2 emission from the electricity sector even in year 2032 would be around 26Million tons. Both total CO_2 emission and per capita CO_2 emission would be comparatively low.

The total investment required in the next 20 years is approximately USD 14.05 Billion without considering the projects for which funds have already been committed.

In the short term context up to year 2018, it is seen that there might be difficulty in operating the system resourcefully due to the delay in Trincomalee Coal Power Plant and practical limitations of implementing the 3x75MW Gas Turbines in year 2015 and 1x105MW Gas Turbine in year 2017. Requirement of the above Gas turbines arose mainly due to the retirement of 260MW of IPP Plants in year 2015 and to meet the forecast electricity demand by maintaining the planning criteria such as LOLP and reserve margin of the generation system. However, it is observed that LOLP values are below the maximum value of 1.5% specified in the Grid Code except in year 2013. Such situations were experienced previously and the demand was met with difficulty. Therefore, short-term developments such as demand growth, generator availability and hydrology have to be monitored closely to take action accordingly. Requirement of a self-start standby generator for Puttalam coal plant has been identified. Therefore, it is recommended to add a standby diesel generator to Puttalam Coal Power Station on an urgent basis

In the long term, it is important that coal plant development programme is implemented in accordance with the Revised Base Case Plan. Therefore, timely implementation of the Coal plants in the pipe line i.e. Puttalam 1x300MW by 2014, Puttalam 1x300MW by 2015, 2x250MW Trincomalee by 2018, 2x300MW by 2019, 1x300MW by 2021 and 1x300MW by 2022 is important and delaying these plants any further would be less economic to the Nation.

49MW Gin Ganga was forced in year 2022. However, development option of this Project has still not been finalized by the Irrigation Department.

Three scenarios were carried out restricting the implementation of coal power plants. In one scenario, coal plants were not allowed after year 2025. In the second scenario, coal plants were not allowed after 1000MW development at Trincomalee in 2019. In the third scenario, coal power development was restricted to 60% of the total generation throughout the study period. In all three scenarios, LNG power plants were selected and required to bridge the gap since development of coal power plants were restricted.

The summary of case studies analyzed during the preparation of the Long Term Generation Expansion Plan 2013-2032 are given in Table E-3.

Table E.3–Summary of Case Study Analyses

No.	Study Option	Total Cost (US$ million)	Analysis and Remarks
1	PUCSL Reference Case	13,637.26	Only existing NCRE plants are included.
2.	Base Case	13,740.02	
3.	Revised Base Case	14,049.05	
4.	High Discount Case (15%)	9,966.64	
5.	Low demand (Demand Side Management) case	11,379.61	Forecast with Demand Side Management (DSM) measures is considered as the Low Load forecast. Scenario was derived considering the estimation of energy savings of the study presently carried out by Sri Lanka Sustainable Energy Authority. Average Demand Growth 4.5 %
6.	No more coal plants permitted after 2025	13,947.82	Only 1800 MW (6x 300 MW) of coal plants will be permitted after Trincomalee 1000MW coal plants. LNG plants were added from year 2029 with the conversion of existing plants
7.	No additional coal plants permitted after Trincomalee 1000MW coal plants	15,065.20	No additional coal plants were permitted as candidate plants after the Trincomalee 1000MW plants. LNG plants were forced from year 2019 with the conversion of the existing plants
8.	HVDC Interconnection candidate case	13,729.49	HVDC interconnection was opened for selection from year 2020 onwards. 1x500 MW HVDC connection was selected in 2023.

No.	Study Option	Total Cost (US$ million)	Analysis and Remarks
9.	Maintaining 60% limit on Coal power generation for energy security	14,857.54	First LNG Terminal with plant is forced from year 2020 together with the conversion of existing plants Energy generation share of LNG fuel is more than 10% from year 2023 onwards
10.	Dendro Power Plant candidate with local fuel concession case	13,625.88	112 MW (28x4 MW) of Dendro plants were selected. In 2013 and 2014 addition of Dendro plants were restricted considering practical limitation in implementation and from 2015 onwards it was not restricted. 10% reduction in fuel cost considered to give preference to domestic fuel supplies. After introduction of coal plants Dendro plants were not selected
11.	Base case with CDM benefits	13,527.43	CER price of 14.2 $/MT was used for the study and applied for LNG, Dendro, Wind and Mini hydro. But LNG was not selected. Source: Carbon Market, World Bank Report
12.	NG fuel Breakeven price considering Natural Gas availability from year 2018 in Mannar Basin		Breakeven NG price is 8.2 $/MMBTU Breakeven NG price with CDM benefit 10.5 $/MMBTU (considering CER price of 14.2 $/MT)
13.	LNG fuel option with full terminal cost		Breakeven LNG price is 4.2 $/MMBTU Breakeven LNG price with CDM benefit 6.5 $/MMBTU (considering CER price of 14.2 $/MT) LNG breakeven price is 8.0 $/MMBTU, with ¼ terminal cost. Breakeven LNG price for this with CDM benefit is 10.3 $/MMBTU (considering CER price of 14.2 $/MT)
14.	Trincomalee coal 2 units permitted only in 2018	13,803.18	Only 2 units of Trincomalee coal plants permitted in 2018 and other 2 units delayed by one year.
15.	Coal price 50% High, Oil and LNG Base Price	16,226.68	LNG was not selected.
16.	Coal and Oil price 50% High, LNG Base Price	18,531.59	LNG was not selected.
17.	Low Discount case (3%)	23,534.36	
18.	Base case with Social and Environment Damage cost	13,864.55	Social Damage cost of 0.13 US Cents/kWh applied for the Coal. Source: EIPS, World Bank Study

No.	Study Option	Total Cost (US$ million)	Analysis and Remarks
19.	50% High ENS cost	13,754.78	50% increase of Energy Not Served value of 0.8USCents/kWh.
20.	High NCRE case	13,704.01	20% energy from NCRE by 2020. Assumed 50MW wind power parks of dispatchable nature are only allowed.
21.	High Demand case	18,048.61	High Demand Forecast with 1% high GDP growth and 0.4% high population growth from Intermediate High Demand Case. Average Demand Growth 7.4%
22.	Pumped Storage forced construction and forced operation in 2020	13,970.304	250MW Pump storage plant forced operation in year 2020.
23.	Intermediate High Demand Case	16,089.64	Considering base population growth and GDP growth rates projected by Central Bank of Sri Lanka. Average Demand Growth 6.5%

CHAPTER 1
INTRODUCTION

1.1 Background

The Electricity sector in Sri Lanka is governed by the Sri Lanka Electricity Act, No. 20 of 2009. Ceylon Electricity Board (CEB) , established by an CEB Act No. 17 of 1969 (as amended), is under legal obligation to develop and maintain an efficient, coordinated and economical system of Electricity supply in accordance with any Licenses issued. CEB is the sole Transmission Licensee in the country while being responsible for most of the generation and distribution of electricity as well. CEB has been issued a generation license, a transmission license and four distribution licenses. Lanka Electricity Company (LECO), a subsidiary of CEB is the other distribution licensee and there are several Independent Power Producers, whose production is also purchased by CEB. The Public Utilities Commission of Sri Lanka (PUCSL) is the regulator of the sector and was established by the PUCSL Act No. 35 of 2002 and empowered by the Electricity Act. The Sri Lankan system has a total dispatchable installed capacity of approximately 2970 MW. The maximum demand recorded in 2012 was 2146.4MW.

As stated above CEB has to develop and maintain an efficient and coordinated economical system of electricity supply to the country as well as to generate or acquire supplies of electricity. Generation expansion planning is a part of the process of achieving these objectives. In order to meet the increasing demand for electrical energy and to replace the thermal plants due for retirement, new generating stations need to be installed as and when necessary. The planning studies presented in this report are based on the Annual Report 2011 - Central Bank of Sri Lanka and electricity sector data up to 2012. The information presented has been updated to December 2011 unless otherwise stated.

The generating system has to be planned with careful consideration about system demand growth in relation to the economy and current energy demand, technology of generation, technical considerations and financial requirements. It is necessary to evaluate each type of candidate generating plant, both thermal and hydro and select the optimum plant mix schedule in the best interest of the country.

1.2 The Economy

In the last five years (2006-2010), the real GDP growth in the Sri Lanka economy has varied from - 7.7% in 2006 to 8.0% in 2010. In 2011, Sri Lanka achieved a growth rate of 8.3 with strong growth in the Industry and Services sectors. Details of some demographic and economic indicators are given in Table 1.1.

Table 1.1- Demographic and Economic Indicators of Sri Lanka

	Units	2006	2007	2008	2009	2010	2011	2012
Mid-Year Population	Millions	19.89	20.01	20.22	20.45	20.65	20.87	20.32
Population Growth Rate	%	1.1	1.1	1.0	1.1	1.0	1.0	n.a
GDP Real Growth Rate	%	7.7	6.8	6.0	3.5	8.0	8.2	6.4
GDP /Capita (Market prices)	US$	1,421	1,634	2,014	2,057	2,400	2,836	2,923
Exchange Rate (Avg.)	LKR/US$	103.96	110.62	108.33	114.94	113.06	110.57	127.60
GDP Const 2002 Prices	Mill LKR	2,090,564	2,232,656	2,365,501	2,449,214	2,645,542	2,863,854	3,047,277

Source: Annual Report 2012, Central Bank of Sri Lanka

1.2.1 Electricity and Economy

Electricity demand growth rate in the past has most of the times revealed a direct correlation with the growth rate of the country's economy. Figure 1.1 shows growth rates of electricity demand and GDP from 1993 to 2011.

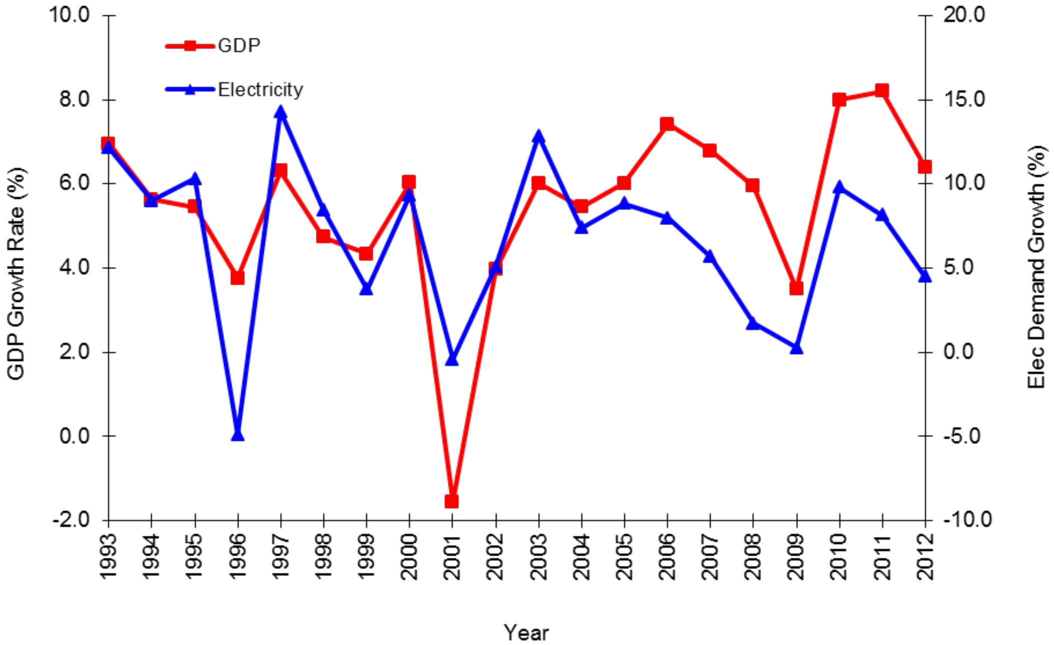


Figure 1.1 - Growth Rates of GDP and Electricity Sales

1.2.2 Economic Projections

The Central Bank of Sri Lanka expects 8 % average GDP growth rate in real terms in the four years from 2012 to 2015. The Central Bank forecast for this period is depicted in Table 1.2.

Table 1.2 - Forecast of GDP Growth Rate in Real Terms

Year	*2012*	*2013*	*2014*	*2015*
GDP Growth Rate (%)	7.2	8.0	8.3	8.5

Source: Annual Report 2011, Central Bank of Sri Lanka

1.3 Energy Supply and Demand

1.3.1 Energy Supply

Biomass or fuel wood, petroleum and hydro are the major primary energy supply sources, which cater the Sri Lanka energy demand with a per-capita consumption of about 0.4 tons of oil equivalent (TOE). Biomass or fuel wood, which is mainly a non-commercial fuel, at present provides approximately 46 percent of the country's total energy requirement. Petroleum turns out to be the major source of commercial energy, which covers about 42 percent of the energy demand.

Although electricity and petroleum products are the major forms of commercial energy, an increasing amount of biomass is also commercially grown and traded. Hydropower which covers 9% of the energy requirement is the main indigenous source of primary commercial electrical energy in Sri Lanka with an estimated potential of about 2000 MW, of which more than half has already been harnessed. Further exploitation of hydro resources is becoming increasingly difficult owing to social and/or environmental impacts associated with large-scale development. Apart from these, there is a considerable potential for wind power development and the first commercial wind power plants were established in 2010. A small quantity of Peat has been located in the extent of marshy lands to the North of Colombo. However, the master plan study, 1989 [4] has indicated that the quality and extent of the reserve would not prove to be commercially viable for extraction and use as a source in power generation. As at present, Sri Lanka has no proven resources of fossil fuels and the total fossil fuel requirement of the country is imported either as crude oil or as refined products and used for transport and power generation. Apart from this, initiatives have been launched in towards oil exploration with the prime intention of harnessing potential petroleum resources in the Mannar Basin. Exploration license has been awarded to explore for oil and natural gas in the Mannar Basin off the north-west coast and drilling of the test wells has been initiated.

In 2010 the primary energy supply consisted of Biomass 5042 ktoe, Petroleum 4544 ktoe, Hydro (1352 ktoe) and non-conventional sources (4.9 ktoe). The share of these in the gross primary energy supply from 2006 to 2010 is shown in Figure 1.2. Hydro electricity is adjusted to reflect the energy input required in a thermal plant to produce the equivalent amount of electricity.

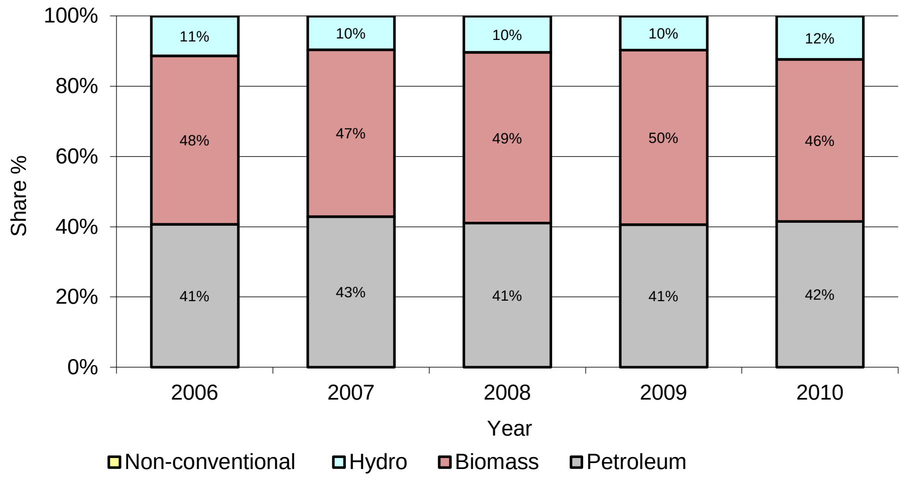
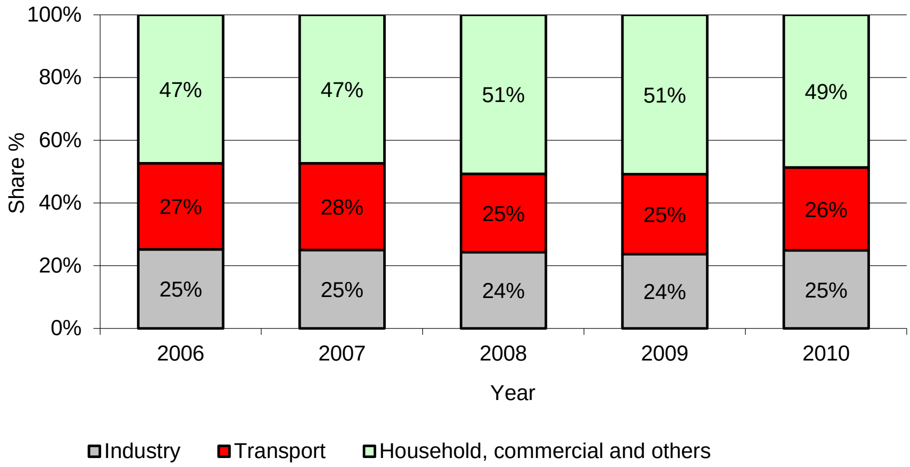


Figure 1.2 - Share of Gross Primary Energy Supply by Source

Source: Sri Lanka Energy Balance 2010

1.3.2 Energy Demand



Source: Sri Lanka Energy Balance 2010

Figure 1.3 - Gross Energy Consumption by Sectors including Non-Commercial Sources

Sectorial energy consumption trend from 2006 to 2010 is shown in Figure 1.3. According to the above chart, household and commercial sector appears to be the largest sector in terms of energy consumption when all the traditional sources of energy are taken into account. However, it shows a rather declining trend in percentage of household and commercial sector energy consumption.

The consumption for 2010 is made up of biomass (5054 ktoe), petroleum (2947 ktoe) and electricity (792 ktoe). Due to poor conversion efficiency of biomass, the composition of the net (or useful) energy consumption in the domestic sector could be different from the above. On the other hand, being the cheapest and most easily accessible source of energy, fuel wood still dominates the domestic sector consumption. Even though it is traded in urban and suburban areas fuel wood is still classified as a non-commercial form of energy.

1.4 Electricity Sector

1.4.1 Access to Electricity

By the end of December, 2012, approximately 93% of the total population had access to electricity from the national electricity grid When the planned electrification schemes are implemented it is expected that this will increase further. Figure 1.4 shows the percentage level of electrification district wise as in end 2012. Western province and Southern province have a level of more than 97% electrification in all districts.

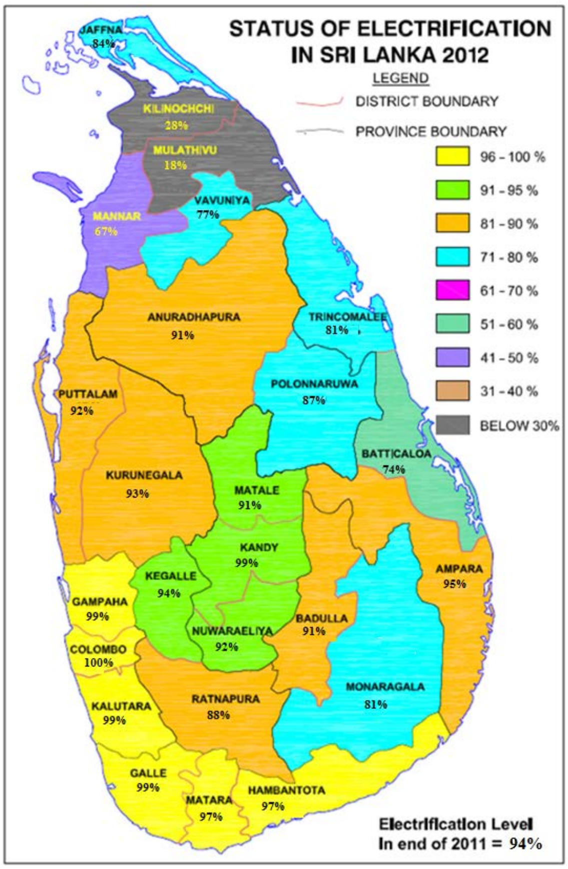


Figure 1.4 - Level of Electrification

1.4.2 Electricity Consumption

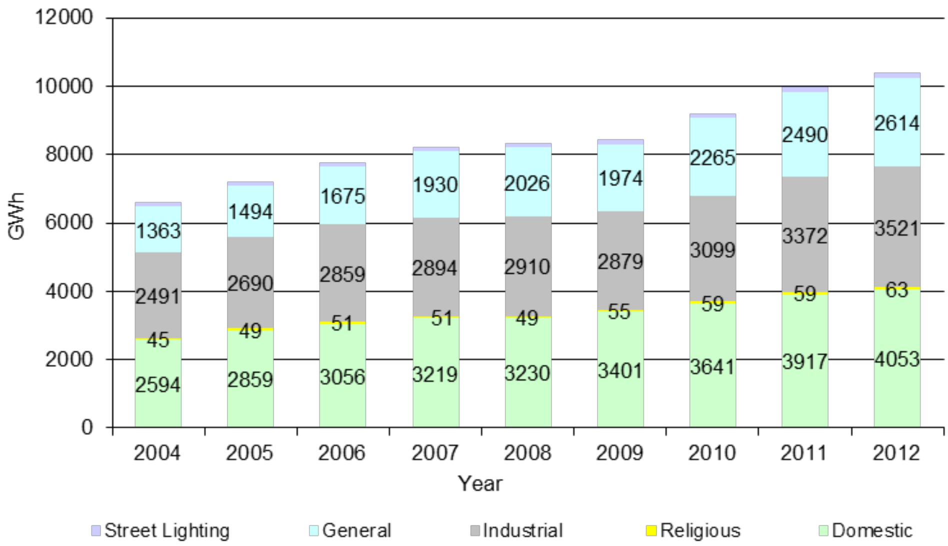


Figure 1.5 - Sectorial Consumption of Electricity (2005 - 2012)

The amount of energy consumed by each sector (i.e. each tariff category) from 2005 to 2012 is shown in figure 1.5 while figure 1.6 depicts sectorial electricity consumption share in 2012. These figures reveal that the industrial and commercial (general) sectors' consumption together is more than the consumption in the domestic sector. This is a pleasing situation for an economy with ambitious GDP growth projections.

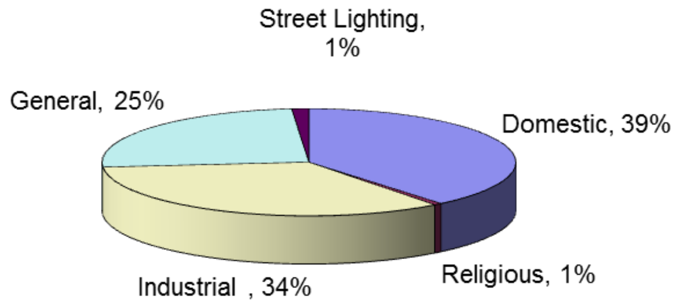


Figure 1.6 - Sectorial Consumption of Electricity (2012)

The average per capita electricity consumption in 2011 was 480 kWh/person and generally it has been rising steadily, however in the period 2007 – 2009 with the slowing of the electricity growth, the per capita consumption has stagnated. Figure 1.7 illustrates the trend of per capita electricity consumption from 2001 to 2011.

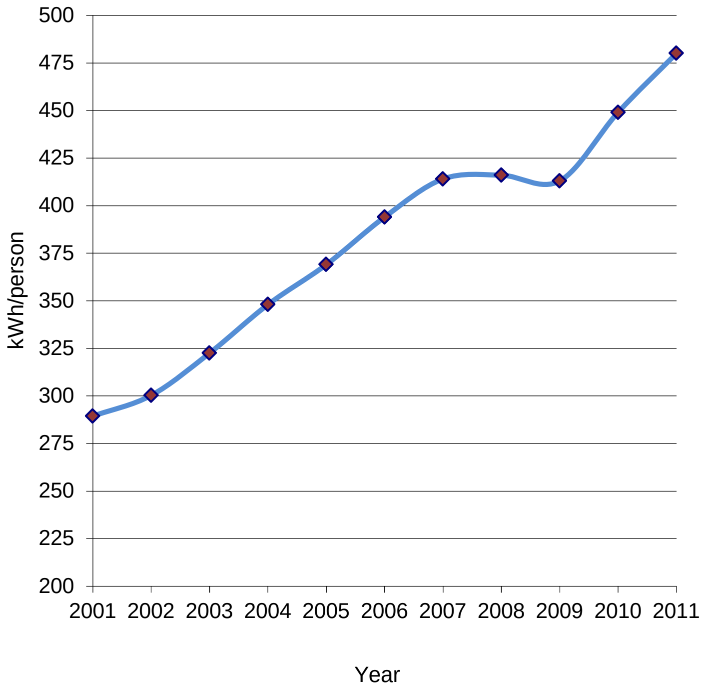


Figure 1.7 – Per Capita Electricity Consumption (2001-2011)

1.4.3 Capacity and Demand

Sri Lanka electricity requirement was growing at an average rate of 6-8% annually, and this trend is expected to continue in the foreseeable future. The total installed capacity and peak demand over the last twenty years are given in the Table 1.3 and graphically shown in Figure 1.8.

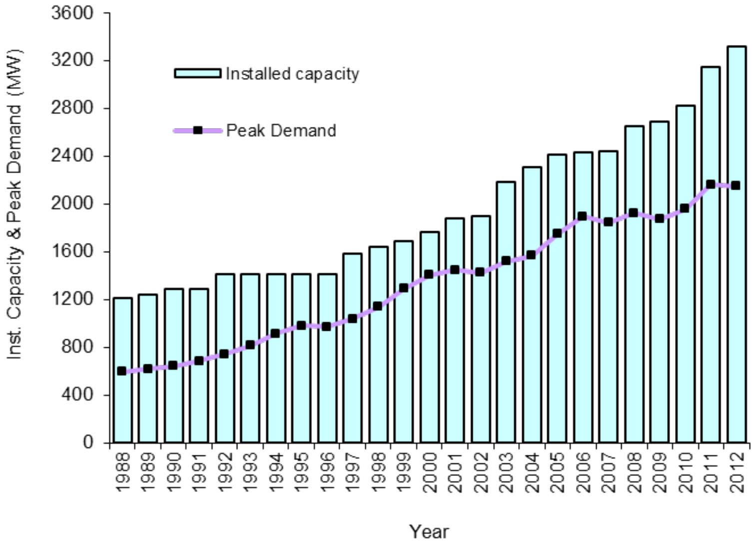


Figure1.8 - Installed Capacity and Peak Demand

Table 1.3 - Installed Capacity and Peak Demand

Year	Installed Capacity	Capacity Growth	Peak Demand	Demand Growth
	MW	**(%)**	**MW**	**(%)**
1992	1409	9	742	8
1993	1409	0	812	9
1994	1409	0	910	12
1995	1409	0	980	8
1996	1409	0	968	-1
1997	1585	12	1037	7
1998	1636	3	1137	10
1999	1682	3	1291	14
2000	1764	5	1404	9
2001	1874	6	1445	3
2002	1893	1	1422	-2
2003	2180	15	1516	7
2004	2280	5	1563	3
2005	2411	6	1748	12
2006	2434	1	1893	8
2007	2444	0.4	1842	-2.7
2008	2645	8	1922	4
2009	2684	1	1868	-3
2010	2818	5	1955	4
2011	3141	10	2163	10
2012	3312	5	2146	-1
Last 5 yr avg. growth		5.8		2.8
Last 10 yr avg. growth		4.8		3.9

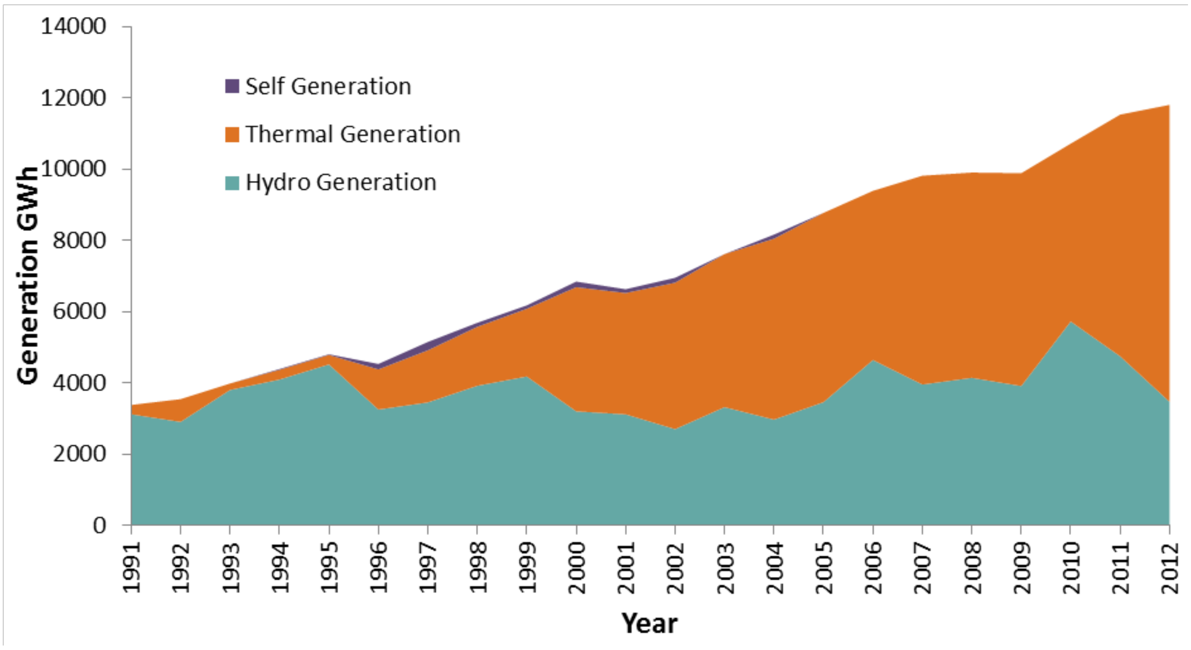


Figure 1.9 - Hydro Thermal Share in the Recent Past

1.4.4 Generation

In early stages the electricity demand of the country was mainly supplied by hydro generation and the contribution from thermal generation was minimal. With the time, thermal generation has become prominent. At present, thermal generation share is much higher than that of hydro. Electricity Generation during the last twenty years is summarized in Table 1.4 and graphically shown in Figure 1.9.

Table 1.4 - Electricity Generation 1992-2011

Year	Hydro Generation			Thermal Generation		Self-Generation		Total
	GWh		%	GWh	%	GWh	%	GWh
1990	3145		99.8	5	0.2	0	0.0	3150
1991	3116	-0.93%	92.3	260	7.7	0	0.0	3376
1992	2900	-7.45%	81.9	640	18.1	0	0.0	3540
1993	3796	23.60%	95.4	183	4.6	0	0.0	3979
1994	4089	7.17%	93.2	275	6.3	22	0.5	4386
1995	4514	9.42%	94.0	269	5.6	17	0.4	4800
1996	3249	-38.94%	71.8	1126	24.9	152	3.4	4527
1997	3448	5.77%	67.0	1463	28.4	235	4.6	5146
1998	3915	11.93%	68.9	1654	29.1	114	2.0	5683
1999	4175	6.23%	67.6	1901	30.8	97	1.6	6173
2000	3197	-30.59%	46.7	3486	51.0	158	2.3	6841
2001	3113	-2.70%	47.0	3407	51.4	105	1.6	6625
2002	2696	-15.47%	38.8	4114	59.2	136	2.0	6946
2003	3314	18.65%	43.5	4298	56.5	0	0.0	7612
2004	2964	-11.81%	36.3	5080	62.3	115	1.4	8159
2005	3455	14.21%	39.4	5314	60.6	0	0.0	8769
2006	4638	25.51%	49.4	4751	50.6	0	0.0	9385

2007	3950	-17.42%	40.3	5864	59.8	0	0.0	9811
2008	4138	4.54%	41.8	5763	58.3	0	0.0	9893
2009	3908	-5.89%	39.7	5975	60.6	0	0.0	9856
2010	5720	31.68%	53.8	4994	47.0	0	0.0	10628
2011	4743	-20.60%	41.1	6785	58.9	0	0.0	11528
2012	3463	-36.96%	29.3	8339	70.7	0	0.0	11801
Last 5 year av. Growth	-4.35%			9.68%				4.51%
Last 10 year av. Growth	0.49%			7.64%				4.99%

* Note: Wind & small hydro generation is included in hydro generation figure

1.5 Planning Process

CEB is under a statutory duty to develop and maintain an efficient, co-coordinated and economical system of electricity supply for the whole of Sri Lanka. In order to fulfill the above duty, CEB revises the Long Term Generation Expansion Plan (LTGEP) bi-annually. Intensive studies are conducted by the staff of the Transmission and Generation Planning Branch of the CEB in order to prepare this plan. A coordinating committee representing the relevant branches of CEB meets during the study period to review the study inputs and the findings.

Operating information on the existing generating plants is obtained from records maintained in the Generation Planning Branch and the individual power stations. Certain operational information and system limitations are obtained from the System Control Centre and the Generation Division of CEB. Details and costs of candidate thermal and hydro plants which are to be considered for system addition are obtained from various pre-feasibility and feasibility studies commissioned by CEB in the recent past. These data are used on computer models and a series of simulations are conducted to derive the feasible optimum generation expansion sequence.

The data used in this study and the results of the study, which are published in this report, are intended purely for this purpose.

1.6 Objectives

The objectives of the generation planning studies conducted by CEB are the followings.

(a) To investigate the feasibility of new generating plants for addition to the system in terms of plant and system characteristics.
(b) To specifically investigate the future operations of the hydro-thermal system in order to determine the most economical operating policy for reservoirs, hydro and thermal plant.
(c) To conduct system simulation studies to determine the economically optimum mix of generating plants to meet the forecast demand and the acceptable reliability levels in the 20 year period ahead.
(d) To investigate the robustness of the economically optimum plan by analyzing its sensitivity to changes in the key input parameters.

1.7 Organization of the Report

The next Chapter, Chapter 2 of the report, presents the existing and committed generation system of Sri Lanka. The past and forecast electricity demand with the forecasting methodology is explained in Chapter 3. Conventional and renewable generation options for the future system expansions are discussed in Chapters 4 and 5 respectively. Chapter 6 explains the Generation expansion planning methodology and the parameters while the expansion planning results are given in Chapter 7. Chapter 8 describes required implementation schedule and financing for the generation projects. Environmental implications of the expansion plan are discussed in Chapter 9 and finally, Chapter 10 provides a comparison of this year plan with the previous plan.

1.8 Codes / Guidelines in Generation Expansion Planning

PUCSL in April 2011 issued the Least Cost Generation Expansion Planning Code to CEB and it is part of the Grid Code issued in May 2012 and transmission licensee feedback. Further, the Ministry of Power and Energy issued a set of “Guidelines on Long Term Generation Expansion Planning” in October 2011.

Both PUCSL planning code and the Ministry guidelines were considered in preparing the Long Term Generation Expansion Plan 2013-2032.

CHAPTER 2
THE EXISTING AND COMMITTED GENERATING SYSTEM

The existing generating system in the country is mainly owned by CEB with a considerable share owned by the private sector. Until 1996 the total electricity system was owned by CEB. Since 1996, private sector has also participated in power generation. The existing generating system in the country has approximately 2970 MW of installed capacity by end 2012 and additionally non-dispatchable plants of capacity 290MW. The majority of dispatchable capacity is owned by CEB (i.e. about 75% of the total dispatchable capacity), which includes 1355 MW of hydro and 863 MW of thermal generation capacity. Balance dispatchable capacity, which is totally thermal plants, is owned by Independent Power Producers (IPPs).

2.1 Hydro and Other Renewable Power Generation

Hydropower is the main renewable source of generation in the Sri Lanka power system and it is mainly owned by CEB. However, other renewable sources such as wind, solar, dendro, and biomass are also connected to the system. These plants including mini hydro are owned by the private sector.

2.1.1 CEB Owned Hydro and Other Renewable Power Plants

Most of the comparatively large scale hydro resources in Sri Lanka have been developed by the CEB. At present, hydro projects having capacities below 10 MW (termed mini hydro), are allowed to be developed by private sector as run-of river plants and larger hydro plants are to be developed by the CEB. Since these run-of river type mini hydro plants are non-dispatchable, they are modeled differently from CEB owned hydro plants in the generation expansion planning simulations. The operation and maintenance cost of these CEB hydro power plants was taken as 5.56 US$/kW per annum.

(a) Existing System

The existing CEB generating system is predominantly based on hydropower (i.e., 1355 MW hydro out of 2218 MW of total CEB installed capacity). Approximately 61% of the total existing CEB system capacity is installed in 17 hydro power stations. In 2011, only 35 % of the total energy demand was met by the hydro plants, compared to 47% in 2010. Details of the existing and committed hydro system are given in Table 2.1 and the geographical locations of the Power Stations are shown in the Figure 2.1.

The major hydropower schemes already developed are associated with Kelani and Mahaweli river basins. Five hydro power stations with a total installed capacity of 335 MW (25% of the total hydropower capacity) have been built in two cascaded systems associated with the two main tributaries of Kelani River; Kehelgamu Oya and Maskeliya Oya (Laxapana Complex). The five stations in this complex are generally not required to operate for irrigation or other water requirements; hence they are primarily designed to meet the power requirements of the country. Castlereigh and Moussakelle are the major storage reservoirs in the Laxapana hydropower complex located at main tributaries Kehelgamu Oya and Maskeliya Oya respectively. Castlereigh reservoir with a storage of 44.8 MCM feeds the

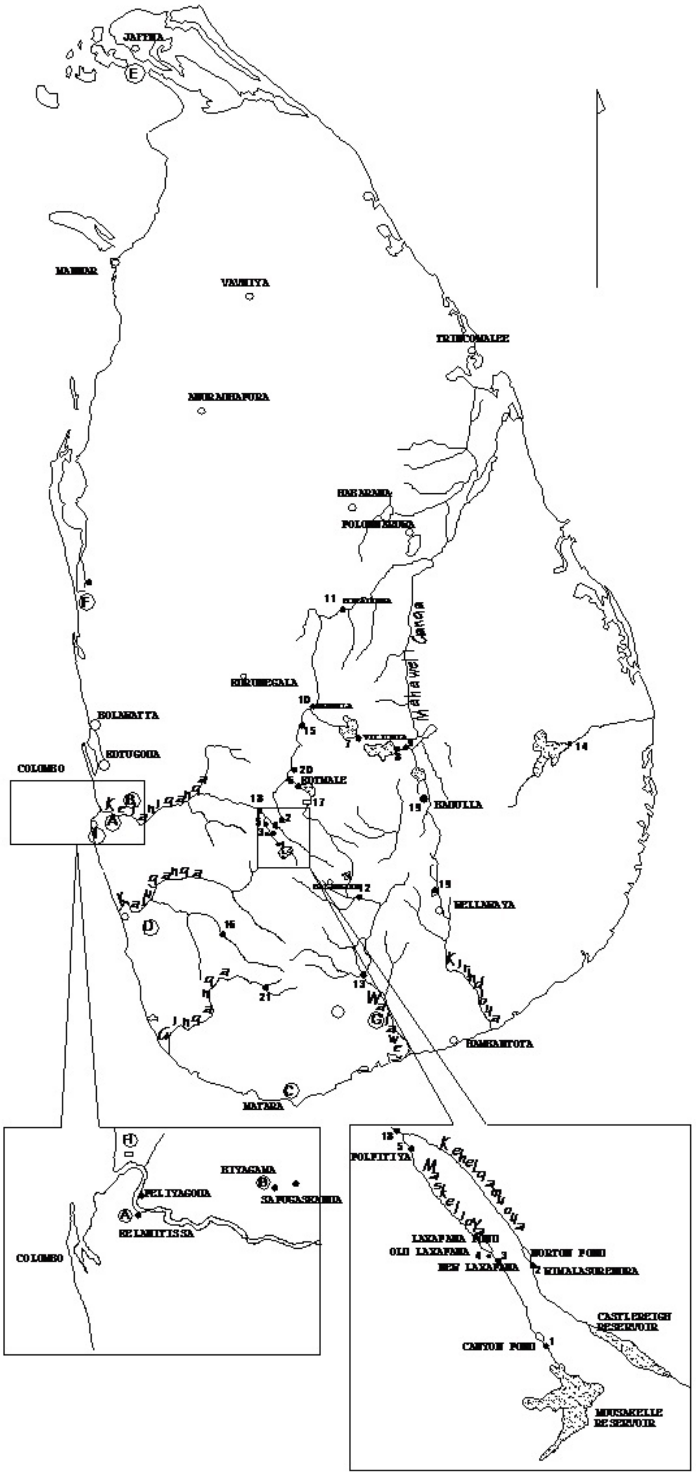
Wimalasurendra Power Station of capacity 2 x 25 MW at Norton-bridge, while Canyon 2 x 30 MW is fed from the Moussakelle reservoir of storage 123.4 MCM. Similarly in the downstream of these two tributaries, Canyon, Norton and Laxapana ponds having smaller storage capacity feed to New Laxapana, Old Laxapana and Polpitiya power stations respectively.

Table 2.1 - Existing and Committed Hydro and Other Renewable Power Plants

Plant Name	Units x Capacity	Capacity (MW)	Expected Annual Avg.** Energy (GWh)	Storage (MCM)	Commissioning
Laxapana Complex					
Canyon	2 x 30	60	160	123.4 (Moussakelle)	Unit 1 Mar 1983 Unit 2May 1989
Wimalasurendra	2 x 25	50	112	44.8 (Castlereigh)	Jan 1965
Old Laxapana	3 x 8.33+ 2 x 12.5	50	286	0.4 (Norton)	Dec 1950 Dec 1958
New Laxapana	2 x 50	100	552	1.2 (Canyon)	Unit 1 Feb 1974 Unit 2 Mar 1974
Polpitiya	2 x 37.5	75	453	0.4 (Laxapana)	Apr 1969
Laxapana		**335**	**1563**		
Mahaweli Complex					
Upper Kotmale	2 x 75	150	409	2.1	Unit 1 April 2012 Unit 2 Jun 2012
Victoria	3 x 70	210	865	721.2	Unit 1 Jan 1985 Unit 2 Oct 1984 Unit 3 Feb 1986
Kotmale	3 x 67	201	498	172.6	Unit 1 Apr 1985 Unit 2&3 Feb 1988
Randenigala	2 x 61	122	454	875.0	Jul 1986
Ukuwela	2 x 19	38	154	1.2 (Polgolla)	Unit 1 Jul 1976 Unit 2 Aug 1976
Bowatenna	1 x 40	40	48	49.9	Jun 1981
Rantambe	2 x 24.5	49	239	21.0	Jan 1990
Mahaweli		**810**	**2667**		
Other Hydro					
Samanalawewa	2 x 60	120	344	278.0	Oct 1992
Kukule	2 x 35	70	300	1.7	July 2003
Small hydro		20			
Other Hydro		**210**	**644**		
Wind plant		3*			
Existing Total		**1355**	**4874**		
Committed					
Broadlands	2x17.5	35	126	0.2	2016
Uma Oya	2x60	120	231	21.9	2016
Committed		**155**	**357**		

Note: * Wind is a non-dispatchable source of energy. Therefore, it has not been accounted for in the total.

***** According to feasibility studies***



No.	HYDROPOWER PLANT		CAPACITY (MW)
1	CANYON	•	60
2	WIMALASURENDRA	•	50
3	NEW LAXAPANA	•	100
4	OLD LAXAPANA	•	50
5	POLPITIYA	•	75
6	KOTMALE	•	201
7	VICTORIA	•	210
8	RANDENIGALA	•	122
9	RANTAMBE	•	49
10	UKUWELA	•	38
11	BOWATENNA	•	40
12	SAMANALAWEWA	•	120
13	UDAWALAWE	•	06
14	INGINIYAGALA	•	11
15	NILAMBE	•	03
16	KUKULE	•	70
17	UPPER KOTMALE	▭	150
18	BROADLANDS	▭	40
19	UMA OYA	▭	150
20	MORAGOLLA	X	27
21	GINGANGA	X	49

No.	THERMAL POWER PLANT		CAPACITY (MW)
Ⓐ	KELANITISSA POWER STATION		
	GAS TURBINE (OLD)	•	48
	GAS TURBINE (NEW)	•	115
	GAS TURBINE (JBIC)	•	65
	COMBINED CYCLE (AES)	•	163
	COLOMBO POWER (Pvt)Ltd.	•	60
	SAPUGASKANDA POWER STATION		
Ⓑ	DIESEL	•	144
	SAPUGASKANDA GRID SUBSTATION		
	LAKDANAVI		22.5
	ASIA POWER Ltd.		49
Ⓒ	ACE POWER MATARA	•	20
Ⓓ	ACE POWER HORANA	•	20
Ⓔ	CHUNNAKAM	•	08
Ⓕ	HELADANAVI	•	100
Ⓖ	ACE POWER EMBILIPITIYA	•	100
Ⓗ	COMBINED CYCLE PLANT KERAWALAPITIYA	•	300
Ⓘ	COLOMBO POWER Pvt. lTD.	•	

LEGEND

EXISTING PLANTS	•
CANDIDATES PLANTS	X
COMMITTED PLANTS	▭

Figure 2.1 - Location of Existing, Committed and Candidate Power Stations

The development of the major hydro-power resources under the Mahaweli project added seven hydro power stations (*Ukuwela, Bowatenna, Kotmale, Upper Kotmale, Victoria, Randenigala and Rantambe*) to the national grid with a total installed capacity of 810 MW (60% of the total hydropower capacity).

Three major reservoirs, *Kotmale, Victoria and Randenigala*, which were built under the accelerated Mahaweli development program, feed the power stations installed with these reservoirs.

In addition, Upper Kotmale hydropower project was conceived with the preparation of a master plan for hydroelectric development in Mahaweli basin in 1968. Further studying the concept in the master plan in 1985-1987, technically and economically feasible two sites were identified. The two sites were a reservoir type development at Caledonia and a run off river type development at Talawakelle. Considering the various social and environmental impacts and by further studying on the original run off river type development at Talawakelle was implemented, Pond which feeds Upper Kotmale hydropower plant (150 MW) is located near Talawakelle on the Kotmale Oya, a tributary of Mahaweli. After generating electricity at Upper Kothmale Power Stationwater is discharged to Kotmale oya.

Polgolla - diversion weir (across Mahaweli Ganga), downstream of Kotmale and upstream of Victoria, diverts Mahaweli waters to irrigation systems via Ukuwela power station (38 MW). After generating electricity at Ukuwela power station the water is discharged to Sudu Ganga, upstream of Amban Ganga, which carries water to Bowatenna reservoir. It then feeds both Bowatenna power station (40 MW) and mainly Mahaweli System-H by means of separate waterways. Water discharged through Bowatenna power station goes to Elahera Ela and is available for diversion to Mahaweli systems D and G.

The schematic diagrams of the hydro reservoir networks are shown in Annex 2.1. Unlike the Laxapana cascade, the Mahaweli system is operated as a multi-purpose system. Hence power generation from the associated power stations is governed by the down-stream irrigation requirements as well. These requirements being highly seasonal constrain the operation of power stations during certain periods of the year.

Samanalawewa hydro power plant of capacity 120 MW was commissioned in 1992. Samanalawewa reservoir, which is on Walawe River and with storage of 278 MCM, feeds this power plant. Kukule power project which was commissioned in 2003, is run-of river type plant located on Kukule Ganga, a tributary of Kalu Ganga. Kukule power plant is 70 MW in capacity and which provides an average of 300 GWh of energy per year.

The contribution of the three small hydro plants (Inginiyagala - 11MW, UdaWalawe - 6MW and Nilambe – 3MW) to the National Grid is comparatively small (20MW) and is dependent on irrigation water releases from the respective reservoirs.

In addition to the above hydro plants, CEB has a 3 MW wind plant at Hambantota. This project was implemented as a pilot project in order to see the feasibility of wind development in Sri Lanka.

(b) Committed Plants

The 35MW Broadlands hydropower project located near Kithulagala on the Maskeliyaoya was considered as a committed plant. The dam site of the project is to be located near Polpitiya power house and in addition to the main dam, there will be a diversion weir across Kehelgamuoya. The project has a 0.2 MCM storage reservoir and it is expected to generate126GWh energy per annum. It will be added to the system in 2016.In addition, 120 MW Uma Oya multipurpose hydro power project was considered as a committed plant. Under Uma Oya multipurpose hydro power project, two small reservoirs will be built close to Welimada. Where the water from these two reservoirs will be diverted through a tunnel to the underground power house located at Randeniya near Wellawaya. It is expected to generate 231 GWh annual energy and will be added to the system in 2016. This project is implemented by the Ministry of Irrigation and Water Resources.

2.1.2 Hydro and Other Renewable Power Plants Owned by IPPs

Government of Sri Lanka has taken a policy decision to develop hydropower plants below 10 MW capacities by the private sector. Many small hydro plants and a few other renewable power plants have been connected to the system since 1996. Total capacity of these plants is approximately 303 MW as at 31st October 2012. These plants are mainly connected to 33 kV distribution lines. CEB has signed standard power purchase agreements for another 249 MW.

In this study, a certain capacity and energy from these mini hydro and other non-conventional renewable energy plants were considered in the base case as committed and modeled accordingly. The figures were projected based on expected development according to current project pipeline records. The projected committed development used in this study is given in Table 2.2.

Table 2.2 –Projected Committed Development of NCRE

Projected Year	Committed NCRE Capacity Projection (MW)	Projected Year	Committed NCRE Capacity Projection (MW)
2013	327	2023	798
2014	364	2024	826
2015	390	2025	855
2016	556	2026	884
2017	614	2027	912
2018	653	2028	941
2019	684	2029	960
2020	713	2030	989
2021	742	2031	1018
2022	772	2032	1047

2.1.3 Capability of Existing Hydropower Plants

The Sri Lankan power system is still highly dependent on hydropower. Hence, it is necessary to assess the energy generating potential of the hydropower system to a high degree of accuracy. However, this assessment is difficult owing to the multipurpose nature of some reservoirs, which have to satisfy the downstream irrigation requirements as well. Further, the climatic conditions of Sri Lanka is characterized by the monsoons, causing inflows to the reservoirs as well as the irrigation demands to fluctuate over the year exhibiting a strong seasonal pattern.

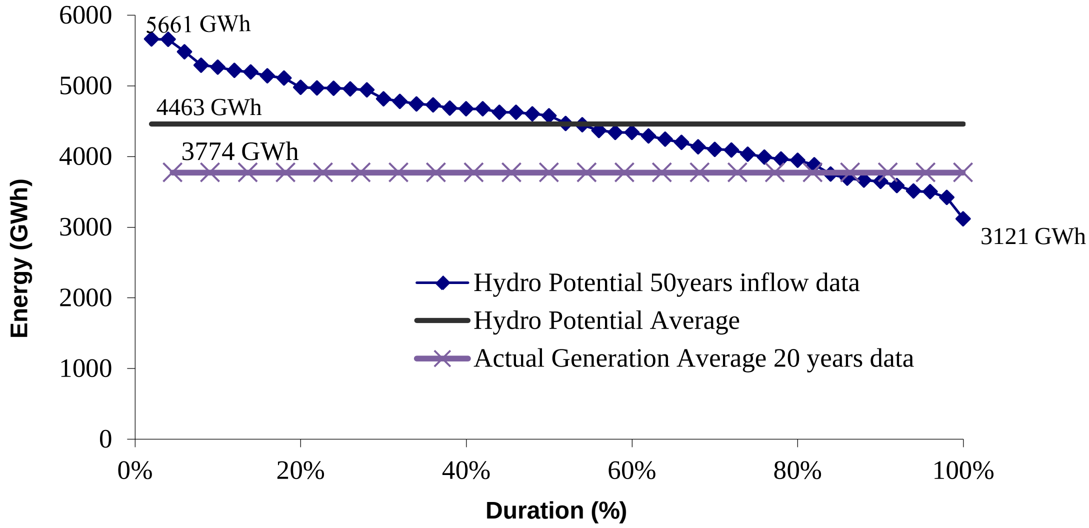


Figure 2.2 - Potential of Hydro power system from past 50 years hydrological data

The annual energy variation of the existing hydro system, using the inflow data from 1956 to 2006 and based on computer simulation is shown in Figure 2.2. This shows that the capability of the hydropower system could vary as much as from 3121 GWh to 5661 GWh provided the required thermal plants are available in the system for optimal dispatch. The corresponding summary of the hydrology simulation is given in Table 2.3 with probabilities of 10% (very wet), 20 %(wet), 40% (medium), 20% (dry) and 10% (very dry) hydro conditions.

However, actual average generation from 1990 to 2011 was approximately 3774GWh and probability values were selected to represent the actual average generation. Figure 2.3 shows the monthly variation of average hydro energy and capacity over a year after commissioning of Kukule Ganga Power plant. The expected energy under different hydro conditions of the Upper Kothmale Hydro Power Project is summarized in Table 2.4.

Table 2.3 – Expected Monthly Hydro Power and Energy Variation of the existing hydro plants for the Selected Hydro Conditions

→ Drier

Month	Very Wet		Wet		Medium		Dry		Very Dry		Average	
	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)
Jan	457.8	989.40	383.9	939.80	350.1	948.90	367.3	959.50	336.9	948.10	379.2	957.14
Feb	406.9	996.2	292.7	961.9	285.1	965.4	274	967.3	265.2	936.7	304.78	965.50
Mar	384	1032.6	320.8	1019.5	268.3	1017.3	248.5	999.6	237.8	984.5	291.88	1,010.70
Apr	269.4	1027.4	303.5	1023.7	249.7	974.8	237.8	947.7	213.8	917.4	254.84	978.20
May	487.7	1094.6	413.4	1077.2	367.7	1044.2	338.7	992.3	290.5	965.8	379.6	1,034.82
Jun	501.9	1074.4	498.1	1075.8	431.6	1031.3	334.6	963.6	291.6	899.3	411.56	1,008.88
Jul	510.2	1089	542.4	1082.8	447.6	1052	365.8	960.8	316	913.1	436.4	1,019.54
Aug	460.4	1034.5	442.9	1028.7	374.3	1002.6	286.8	908.2	261.3	829.1	365.14	960.62
Sep	507.8	1036.9	392.9	1025.5	373	1006.9	246.4	802.3	297.9	799.4	363.6	934.20
Oct	426.9	1035.7	416.5	1008.6	415.4	1023.5	402.9	986.9	308.7	904.6	394.08	991.86
Nov	510.5	1042.5	458.1	1023.3	416.6	1000.7	416.9	987.9	289.4	941.2	418.3	999.12
Dec	500.1	999.2	412.9	987.1	399.7	979.7	325.8	967.3	248.3	943.1	377.36	975.28
	5424		4878		4379		3846		3357		4377	

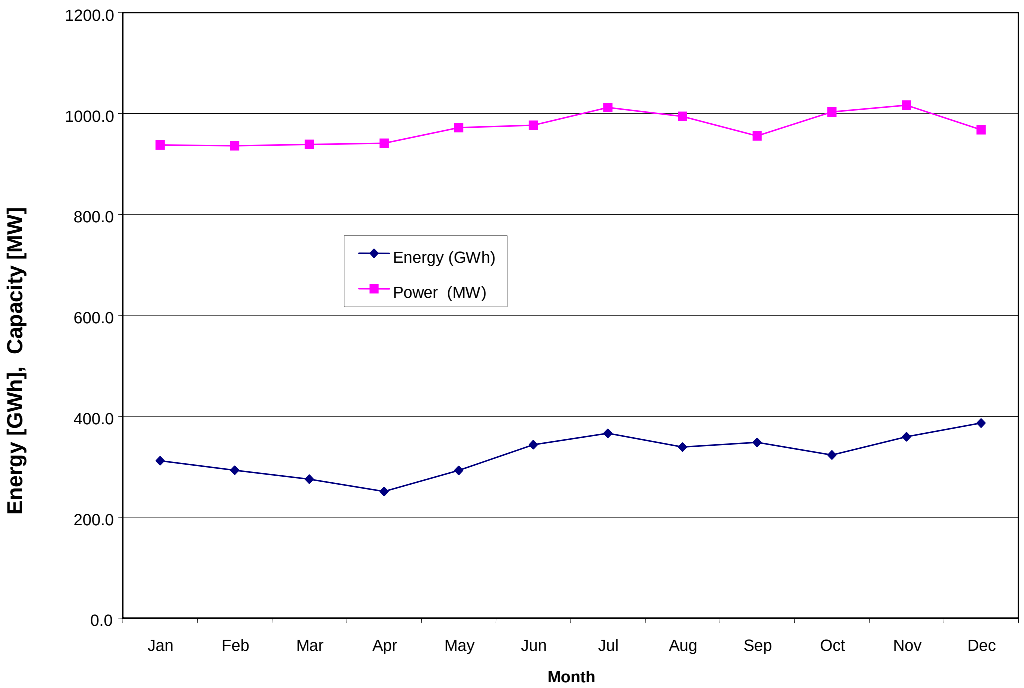


Figure 2.3 - Monthly average hydro energy and capacity variation

Table 2.4 – Expected Monthly Hydro Power and Energy Variation of the Upper Kotmale Hydro Power Plant for the Selected Hydro Conditions

→ Drier

Month	**Very Wet**		**Wet**		**Medium**		**Dry**		**Very Dry**		**Average**	
	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)	Energy (GWh)	Power (MW)
Jan	44	150	27	148	24	144	18	121	18	138	28	140
Feb	27	150	18	134	16	123	12	104	11	92	18	121
Mar	24	148	18	125	14	110	10	79	6	53	15	103
Apr	30	147	20	130	19	127	15	118	11	92	19	123
May	37	147	42	150	28	145	17	112	13	107	28	132
Jun	52	148	47	150	49	150	31	143	29	127	42	144
Jul	60	150	54	150	55	150	39	145	38	136	50	146
Aug	61	150	53	150	54	150	41	150	45	150	53	150
Sep	60	150	41	150	48	150	30	145	43	142	47	147
Oct	59	150	57	142	59	150	57	150	47	150	57	148
Nov	42	112	43	112	41	112	41	112	37	112	44	112
Dec	47	112	34	112	34	112	27	112	28	112	36	112
	543		454		441		338		326		437	

2.2 Thermal Generation

2.2.1 CEB Thermal Plants

(a) Existing

Majority of the present thermal power generating capacity in the country is owned by CEB with a total capacity of 863 MW. It is made up of Puttalam Coal plant 300MW, Kelanitissa Gas Turbines 215 MW, Kelanitissa Combined Cycle plant 165 MW, Sapugaskande Diesel plants 160 MW and 8 MW diesel plant at Chunnakam. The Puttalam Coal plant 300MW funded by EXIM Bank China commissioned in 2011 was the latest thermal power plant addition to the CEB system.

(b) Plant Retirements

For planning purposes, it was considered that 5x17 MW Gas Turbines at Kelanitissa and 4x18 MW diesel plants at Sapugaskanda are due for retirement in 2019. 115 MW Kelanitissa Gas Turbine and 4x9 MW Sapugaskanda were considered for retirement in 2023 and another 4x9 MW Sapugaskanda Diesel extension is due in 2025. Capacity and energy details of the existing and committed thermal plants are shown in Table 2.5. Cost and technical details of the existing thermal generation plant as input to the 2012 Expansion Planning Studies is summarized in Table 2.6.

(c) Committed

It was considered for the planning studies that the Puttalam Coal Power Project Stage II (Net 2x275MW) is committed. The two units will be in operation in 2014 and 2015. The Exim Bank of china finance finances the stage II of the project as well. In addition, 3x8MW Extension to Chunnakam Extension power plant and 4x5MW Northern Power plant in Jaffna peninsula were also considered as committed power plants in 2014.

Table 2.5 - Details of Existing and Committed Thermal Plants

Plant Name	No of Units x Name Plate Capacity (MW)	No of Units x Capacity used for Studies (MW)	Annual Max. Energy (GWh)	Commissioning
Puttalam Coal Power Plant				
Puttalam CPP-Phase I	1x300	1x275	-	2011
Puttalam Coal Total	**300**	**275**	**-**	
Kelanitissa Power Station				
Gas turbine (Old)	5 x 20	5 x 17	417	Dec 81, Mar 82, Apr 82,
Gas turbine (New)	1 x 115	1 x 115	707	Aug 97
Combined Cycle	1 x 165	1 x 165	1290	Aug 2002
Kelanitissa Total	**380**	**365**	**2414**	
Sapugaskanda Power Station				
Diesel	4 x 20	4 x 18	472	May 84, May 84, Sep 84, Oct 84
Diesel (Ext.)	8 x 10	8 x 9	504	4 Units Sept 97 4 Units Oct 99
Sapugaskanda Total	**160**	**144**	**976**	
Existing Total Thermal	**840**	**784**	**3390**	
Committed Total				
Puttalam CPP-Phase II	1x300	1x275	**-**	2014
Puttalam CPP-Phase II	1x300	1x275	**-**	2015
Chunnakam Extension	3 x8	3 x8		2014

Table 2.6 - Characteristics of Existing and Committed CEB Owned Thermal Plants

		Kelanitissa			Sapugaskanda		Puttalm Coal
Name of Plant	**Units**	**GT (Old)**	**GT (New)**	**Comb. Cycle (JBIC)**	**Diesel (Station A)**	**Diesel (Ext.) (Station B)**	**Coal (Phase I)**
Basic Data							
Engine Type		GE FRAME 5	FIAT (TG 50 D5)	VEGA 109E ALSTHOM	PIELSTIC PC-42	MAN B&W L58/64	-
Fuel Type		Auto Diesel	Auto Diesel	Naphtha	Res. Oil	Res. Oil	Coal
Inputs for expansion studies							
Number of sets		5	1	1	4	8	1
Unit Capacity	MW	17	115	165	18	9	300
Minimum operating level	MW	17	80	100	18	9	206*
Calorific Value of the fuel	kCal/kg	10550	10550	10905	10300	10300	6300
Heat Rate at Min. Load	kCal/kWh	4402	3213	2188	2365	2178	2674
Incremental Heat Rate	kCal/kWh	4402	1636	1375	2365	2178	3310
Heat Rate at Full Load	kCal/kWh	4402	2733	1868	2365	2178	2583
Fuel Cost	USCts/GCal	9114	9114	8902	6610	6610	2267
Full Load Efficiency	%	19.5	31.5	46.0	36.4	39.5	37.5
Forced Outage Rate	%	35.37	28.53	7.79	13.34	8.87	15
Scheduled Maintenance	Days/Year	35	55	30	50	47	42
Fixed O&M Cost	$/kWmonth	0.345	0.328	2.066	2.646	3.245	0.807
Variable O&M Cost	$/MWh	2.831	6.445	3.021	14.398	9.563	3.15

Note: All costs are in June 2012 US$ border prices. Fuel prices are based on World Bank Published and CPC provided average fuel prices of 2011. Heat rates and calorific values are given in HHV.

* Minimum operating level used for Generation Planning studies

2.2.2 Independent Power Producers (IPPs)

(a) Existing

Apart from the thermal generating capacity owned by CEB, four Independent Power Producers; Asia Power (Pvt.) Ltd, Colombo Power (Pvt) Ltd., Heladanavi (Pvt.) Ltd. and ACE Power Embilipitiya Ltd. have commissioned diesel power plants on Build, Operate and Own (BOO) basis. A 163 MW combined cycle power plant was commissioned in October 2003 by AES Kelanitissa (Pvt.) Ltd at Kelanitissa. Furthermore, a 270 MW combined cycle plant at Kerawalapitiya was commissioned in May 2010 by West Coast Power (Pvt) Ltd. Details of thermal IPPs are given in Table 2.7.The contract period of ACE Power Matara, ACE Power Horana, and Lakdhanavi power plants were ended during 2012, but for the generation planning studies those were considered as contract periods extended and expired in 2018.

Table 2.7 - Details of Existing and Committed IPP Plants

Plant Name	Name Plate Cap. (MW)	Cap. used for Studies	Min . Guarenteed Ann. Energy (GWh)	Commissioning	Contract Period. (Yrs.)
Independent Power Producers					
Asia Power Ltd	51	49	300	June 1998	20
Colombo Power (Pvt) Ltd	64	60	420	July 2000	15
AES Kelanitissa (Pvt.) Ltd	163	163	**	GT- March 2003	
				ST - October	20
Heladanavi (Pvt.) Ltd.	100	100	698	2003 October	
ACE Power Embilipitiya Ltd	100	100	697	2004	10
				March 2005	10
West Coast (pvt)Ltd.	270	270	**	May 2010	20
Lakdhanavi +	22.5	22.5	156	November 1997	
ACE Power Matara +	24.8	20	167	March 2002	
ACE Power Horana +	24.8	20	167	December 2002	
Existing Total IPP	**820.1**	**804.5**	**2605*****		
Committed					
Northern power *	30	20	-	2013	10
Committed Total IPP	**30**	**20**			

Note

* Northern Power 20MW has been connected to the Jaffna system. However since the grid connection was assumed to be in 2014, Nothern Power was used for in the studies as committed from 2014.

** AES Kelanitissa (Pvt.) Ltd & West Coast (Pvt.) Ltd availability factors are given for year 2012 as 94.4% and 70 % respectively

*** Existing total IPP given without AES Kelanithissa & West Coast energy

\+ The contract period of ACE Power Matara, ACE Power Horana, and Lakdhanavi power plants were ended during 2012, but for the generation planning studies those were considered as contract periods extended and expired in 2018.

CHAPTER 3
ELECTRICITY DEMAND: PAST AND THE FORECAST

3.1 Past Demand

Demand for electricity in the country during the last fifteen years is given in Table 3.1. It shows that the energy demand has been growing at an average rate of about 6.5 % per annum in the past 15 years while peak demand has been growing at a rate of 5.0% per annum. However the peak demand has grown at a slower rate of 2.8% during the last 5 years and energy has been growing at a rate of 5.4% per annum. In 2012, the total electricity generated to meet the demand amounted to 11801GWh, which had been only 6810GWh ten years ago. The recorded maximum demand within the year 2012 was 2146MW, which was 1422MW 10 years ago.

Table 3.1 - Electricity Demand in Sri Lanka, 1997 - 2012

Year	Demand* (GWh)	Avg. Growth (%)	Total energy Losses+ (%)	Generation (GWh)	Avg. Growth (%)	Load Factor ** (%)	Peak (MW)	Avg. Growth (%)
1997	4039	13	17.8	4911	12	54.1	1037	7
1998	4521	12	18.8	5569	13	55.9	1137	10
1999	4809	6	20.9	6076	9	53.7	1291	14
2000	5258	9	21.4	6687	10	54.2	1404	9
2001	5236	-0.4	19.7	6520	-2	51.5	1445	3
2002	5502	5	19.2	6810	4	54.7	1422	-2
2003	6209	13	18.4	7612	12	57.3	1516	7
2004	6781	9	17.1	8043	6	58.7	1563	3
2005	7255	7	17.2	8769	9	57.3	1748	11.8
2006	7832	8	16.6	9389	7	56.6	1893	6.1
2007	8276	5.7	15.6	9814	4.5	60.8	1842	-2.7
2008	8417	1.7	15.0	9901	0.9	58.6	1922	4.3
2009	8441	0.3	14.6	9882	-0.2	60.4	1868	-2.8
2010	9268	9.8	13.5	10714	8.4	62.6	1955	4.6
2011	10023	8.1	13.1	11528	7.6	60.8	2163	10.6
2012	10389	3.7	12.0	11801	2.4	62.8	2146	-0.8
Last 5 year		5.4 %			4.5 %			2.8 %
Last 10 year		6.6 %			5.6 %			4.2 %
Last 15 year		6.5%			6.0%			5.0 %

***Demand** includes self-generation
****Load Factor** excludes self-generation and NCRE peak
+Includes generation auxiliary consumption

As evident from Table 3.1 and Figure 3.1, percentage of the total or gross system losses (calculated based on gross generation and gross sales units), shows a considerable decrease during 2000-2012. Figure 3.2 shows Load factor calculated excluding NCRE (Mini hydro, wind) and self-generation.

Overall improvement in the load factor can also be observed in the linear trend shown in Figure 3.2. Considering Mini hydro power generation, load factor of the 2011 is calculated as 57%, accordingly average of 10% incremental improvement has been shown from year 1981.

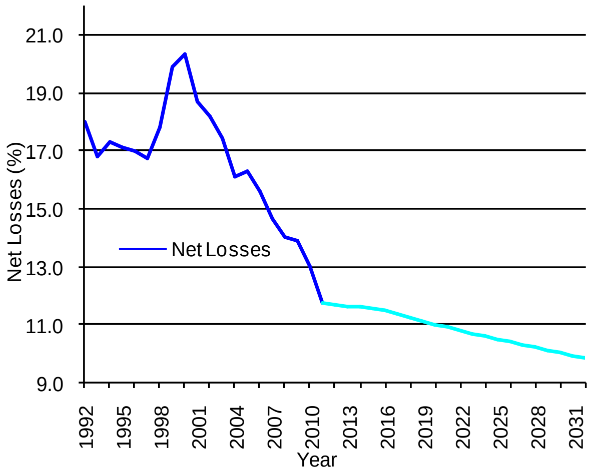


Figure 3.1 - Past Losses and Forecast Loss (Net)

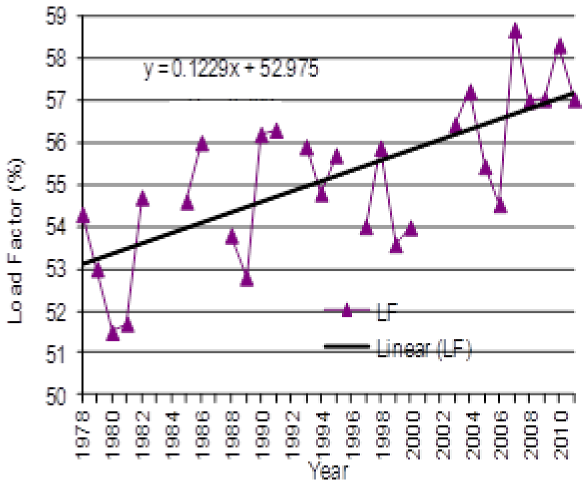


Figure 3.2 – Linear Trend in the Load Factor

Figure 3.3 shows the country's daily load curve recorded on the day of annual peak for selected years. From the Figure 3.3, it is seen that the shape of the load curve has not changed much during the last ten years. The system peak demand occurred only for a short period from about 19.00 to 22.00 hours daily. The recorded maximum system peak is 2163MW in 2011, while in 2012 the peak is 2146.4MW.

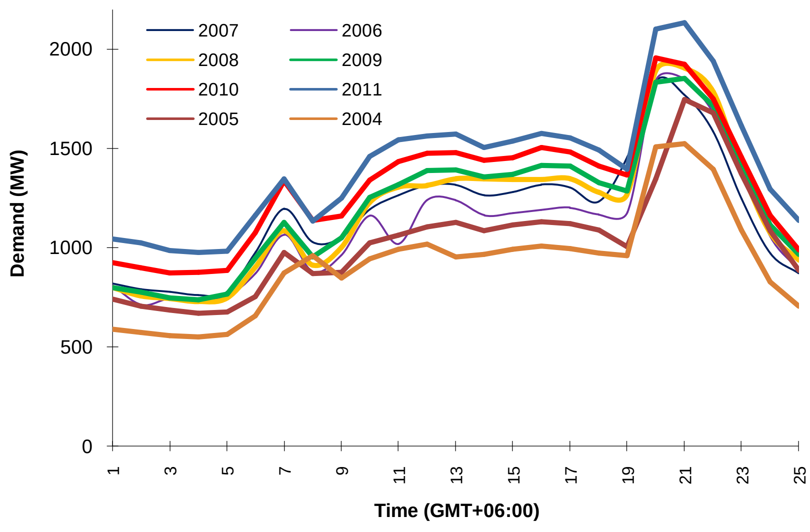


Figure 3.3 - Change in Daily Load Curve over the years

Figure 3.4 shows the consumption shares among different consumer categories in the recent past. In 2011, share of domestic consumption in the total demand was 39% while that of industrial and commercial sectors were34% and 25% respectively. Religious purpose consumers and street lighting, which is referred as the other category, together accounted only for 2%. Similarly in 2001 (10 years ago), share of domestic, industrial, commercial and religious purpose and street lighting consumption in the total demand, was 41%, 36%,21% and 2% respectively.

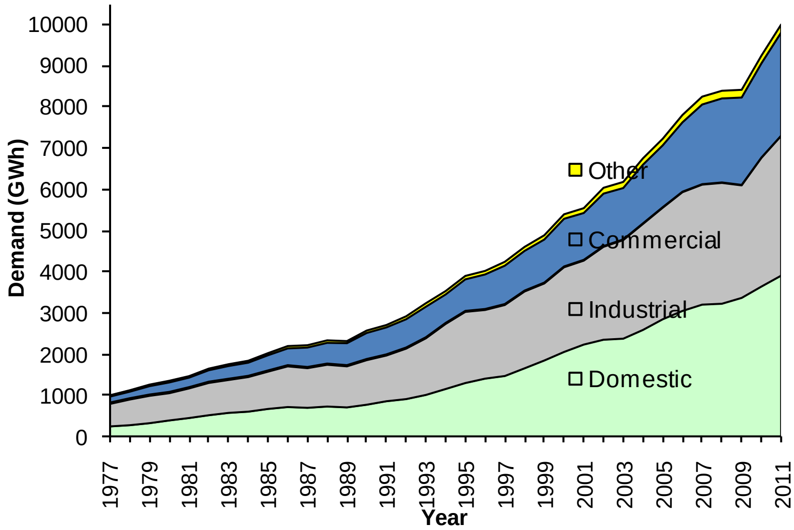


Figure 3.4 - Consumption Share among Different Consumer Categories

3.2 Demand Forecasting Methodology

Econometric modelling has been adopted by CEB for the future electricity demand forecast. In these models, the sales figures of the past were analysed against several independent variables given in Table 3.2 using regression technique. During the process some of the insignificant independent variables were removed depending on their inability to describe the behaviour of the dependent variable.

Table 3.2 – Variables Used for Econometric Modelling

Sector	Domestic	Industrial	Commercial	Other
Variables	Past Demand, GDP per Capita, Population, Avg. Electricity Price, Previous Year Demand, Domestic Consumer Accounts, Previous Year Dom. Consumer Accounts	Past Demand, GDP, Avg. Electricity Price, Previous Year Demand, Previous Year GDP, Population	Past Demand, GDP, Avg. Electricity Price, Previous Year Demand, Previous Year GDP, Population	Past Demand

The resulting final regression coefficients together with assumptions about the expected growth of the independent variables are then used to project the electricity demand for different sectors under investigation. To capture different consuming habits of various consumer categories, sector wise forecasts were prepared separately. Therefore, ‘Domestic’, ‘Industrial, Commercial’ (including Hotels) and ‘Other’ categories (religious purpose and street lighting) were analysed separately to capture the different consuming habits within categories. The following are the derived multiple linear regression models used in econometric analysis.

Domestic Sector

In regression analysis, it was found that three variables: Number of domestic consumer accounts, Gross domestic product per capita and previous year sector electricity demand were significant independent variables for the domestic sector demand growth.

$$Ddom(t)= -51.01+0.0037GDPPC(t)+0.00016CAdom(t)+ 0.74Ddom(t-1)$$

Where,

Ddom(t)	-	Demand for electricity in domestic consumer category (GWh)
GDPPC(t)	-	Gross Domestic Product Per Capita in year t (MLKR)
CAdom(t)	-	Number of Domestic Consumer Accounts
Ddom(t-1)	-	Previous year’s demand for electricity in domestic consumer category (GWh)

Industrial Sector

Industrial differs from domestic sector in terms of significant variables. The significant variables for electricity demand growth in this sector are GDP and previous year sector electricity demand.

$$D\ i\ (t) = -16.58 + 0.00036GDP(t) + 0.75Di(t-1)$$

Where,

Di(t)	-	Electricity Demand for electricity in Industrial consumer categories (GWh)
GDP(t)	-	Gross Domestic Product in year t(MLKR)
Di(t-1)	-	Previous year’s Electricity Demand for electricity in Industrial consumer categories (GWh)

Commercial (General Purpose) Sector

Commercial sector significant variables for electricity demand growth are GDP and previous year sector electricity demand, same as the industrial sector.

$$D\ i\ (t) = -228.07 + 0.0006GDP(t) + 0.48Di(t-1)$$

Where,

Di(t)	-	Demand for electricity in Commercial consumer categories (GWh)
GDP(t)	-	Gross Domestic Product in year t(MLKR)
Di(t-1)	-	Previous year’s Demand for electricity in Commercial consumer categories (GWh)

Other Sector

The two consumer categories: religious purpose and street lighting are considered in the 'other sector'. Because of the diverse nature of the consumers included in this category, this category was analysed without any links to other social or demographic variables. Hence, a time-trend analysis was performed to predict the demand in this sector.

$Ln(Dos(t)) = -108.4 + 0.057\ t$

Where,

t - Year

Cumulative Demand

Once the energy forecasts were derived for the three sectors separately, they were added together to derive the final forecast of energy demand.

Then estimated total net (transmission and distribution loss exclusive generation auxiliary) energy loss estimates were added to the forecast demand in order to derive the net energy generation forecast. A target of net Transmission and Distribution loss of 11.5% in 2016, 11% in 2020, 10% in 2030 was used in the studies. Total net energy loss forecast to be achieved with time as shown in table 3.3. In Figure 3.1, the light blue line shows the reductions of expected system losses from 2012 to 2032 with the expected improvements to the network, while rest of the graph shows the estimated net energy losses in the past.

In this exercise future load factors were derived by fitting a linear curve to the past load factors. Power cut years were disregarded in curve fitting. Since contribution of mini hydro& other such plants affects the peak demand, load factors were adjusted reducing mini hydro generation from total energy generation. Peak demand forecast was derived using the forecasted load factor and energy generation. (It was also assumed that the contribution of the wind power plants to the peak demand is insignificant while the contribution to energy was considered). Figure 3.2 shows the trend of load factor in the past 28 years excluding years when power cuts occurred.

3.3 Demand Forecast

Using the forecasted system losses and load factors as well as the GDP growth forecasted by the Central Bank of Sri Lanka (CBSL) (Table 1.2) and population forecast from Department of Census & Statistics, the expected system energy generation and peak demand are forecasted for the planning horizon. The low GDP growth from the GDP forecast given in CBSL 2011 annual report was used for 2012 to 2015 GDP forecast for the base case plan. In addition to that a number of forecasts are prepared in order to visualize the sensitivity of the factors considered for the forecast. Table 3.3 shows the 'Base Load Forecast'.

Table 3.3 - Base Load Forecast – 2012

Year	Demand	Growth Rate	Gross* Losses	Generation	Growth Rate	Peak
	(GWh)	(%)	(%)	(GWh)	(%)	(MW)
2013	11104	4.0	11.6	12566	4.0	2451**
2014	12072	8.7	11.6	13502	7.4	2692
2015	12834	6.3	11.6	14509	7.4	2894
2016	13618	6.1	11.5	15388	6.1	3017
2017	14420	5.9	11.4	16270	5.7	3193
2018	15240	5.7	11.3	17171	5.5	3383
2019	16075	5.5	11.1	18087	5.3	3556
2020	16937	5.4	11.0	19030	5.2	3731
2021	17830	5.3	10.9	20010	5.2	3920
2022	18754	5.2	10.8	21023	5.1	4125
2023	19713	5.1	10.7	22072	5.0	4287
2024	20707	5.0	10.6	23159	4.9	4499
2025	21737	5.0	10.5	24284	4.9	4717
2026	22813	5.0	10.4	25458	4.8	4948
2027	23932	4.9	10.3	26677	4.8	5187
2028	25101	4.9	10.2	27949	4.8	5369
2029	26318	4.8	10.1	29273	4.7	5625
2030	27581	4.8	10.0	30645	4.7	5893
2031	28899	4. 8	9.9	32079	4.7	6171
2032	30258	4.7	9.8	33555	4.6	6461
2033	31670	4.7	9.7	35087	4.6	6671
2034	33131	4.6	9.7	36672	4.5	6978
2035	34652	4.6	9.6	38320	4.5	7294
2036	36230	4.6	9.5	40027	4.5	7621
2037	37873	4.5	9.4	41804	4.4	7962
Average Growth	5.2%			5.1%		5.0%

***Net losses** include losses at the levels, transmission, Distribution and any non-technical losses. Generation (Including auxiliary consumption) losses are excluded.

**Peak includes contribution from NCRE and excludes 2013 Northern Peak

3.4 Sensitivities to the Demand Forecast

Sensitivity studies are carried out considering the variables of the main factors: population growth, GDP Growth, demand side management (DSM) scenarios. Sensitivity studies carried out for the demand forecast are listed below. The effects on the base case generation expansion plan due to these sensitivities are described in Chapter 7 to 10.

1. Low Load Forecast - Forecast with Demand Side Management (DSM) measures is considered as the Low Load forecast. DSM is required in order to improve the load factor of the system

and to improve the efficiency at load end. DSM scenario was derived considering the estimation of energy savings of the study presently carried out by Sri Lanka Sustainable Energy Authority.

2. Intermediate High Load Forecast - Considering base population growth and GDP growth rates projected by Central Bank of Sri Lanka.

3. High Load Forecast - Considering high population growth and high GDP growth. The system requirements in order to achieve higher economic targets are identified here. These are useful to identify the future economic goals.

4. Time Trend Forecast – The forecast in this instance was projected based purely on time trend and without using the econometric approach.

Load forecasts of the above sensitivity studies are presented in Annex 3.1. Figure 3.5 shows graphically, the energy generation and peak load forecasts for the above 5 scenarios including base load forecast.

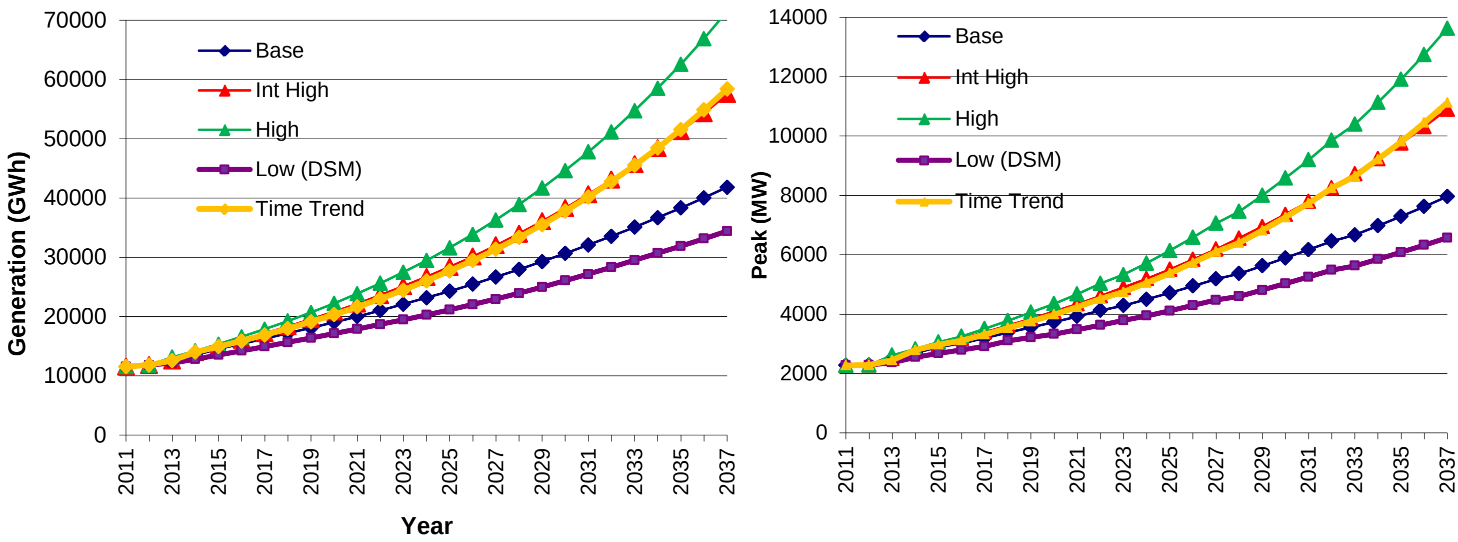


Figure 3.5 - Generation and Peak Load Forecasts of Demand Forecast Scenarios

3.5 Comparison with Past Forecasts

Demand forecast is reviewed bi-annually with the revision of Long Term Generation Expansion Plan. This enables to capture the latest changes in the electricity demand as well as associating econometric variables. Table 3.4 shows the comparison of various base case generation forecasts used in the previous expansion plans and their percentage variation against the actual generation. It is important to note that the demand forecast is prepared based on the expected future developments. The non-achievement of projected economic growth is also a reason for the negative deviation in demand from the forecast. Similarly, electricity system expansions are required to cater to the demand, which would result the expected developments. The system expansions are affected by several factors and that leads to delay the expected expansions. Therefore it always has a tendency to result a lower actual demand growth than the forecasted values.

Table 3.4 – Comparison of Past Forecasts with this year's forecast in GWh

Year	2007 Gen. Forecast	2008 Gen. Forecast	2009 Gen. Forecast	2010 Gen. Forecast	2011 Gen. Forecast	2012 Gen. Forecast	Actual Gen.
2007	9898 (+0.9%)						9814
2008	10314 (+4.2%)	9863 (-0.4%)					9901
2009	11313 (+14.5%)	10307 (+4.3%)	10045 (+1.6%)				9882
2010	12283 (+14.6%)	11250 (+5.0%)	10775 (+0.6%)	10740 (+0.2%)			10714
2011	13360 (+15.9%)	11959 (+3.7%)	11528 (+0.0%)	11715 (+1.6%)	11938 (+3.6)		11528
2012	14529 (+22.9%)	14382 (+21.9%)	12132 (+2.8%)	12464 (+5.6%)	12922 (+9.4)	12086 (+2.4)	11801

*Within bracket figures indicate the percentage deviation with reference to actual generation

CHAPTER 4
CONVENTIONAL GENERATION OPTIONS FOR FUTURE EXPANSION

Hydro power, fossil fuel based thermal power, nuclear-based thermal power are the primary energy options to be considered in meeting the future electricity demand. A large number of factors including cost of development, operation and maintenance costs and environmental effects have to be evaluated in order to consider the suitability of these primary options. All costs incurred in environmental mitigation measures are included in the cost figures given in this report. In addition to these conventional generation options, non-conventional generation options are also considered in order to serve the future electricity demand. Non conventional generation options are discussed in detail in Chapter 5 and the interconnection option is briefly described in latter part of this chapter.

4.1 Hydro Options with a Projected committed development

4.1.1 Candidate Hydro Projects

The hydro potential in the country has already been developed to a great extent. However some major hydro potential remains to be developed, especially Gin Ganga and Moragolla. Several prospective candidate hydro projects were identified in the Master Plan Study [4], 1989, These include 27 sites capable of generating electricity at a long-term average cost of less than 15 USCts/kWh (in 1988 prices) and having a total capacity of approximately 870 MW. The potential energy estimated was 3680 GWh/year under average hydrological conditions. A part of the above hydro potential already been exploited under the Upper Kotmale Hydro Power Project, which is in operation. Broadlands and Uma Oya hydro projects were considered as committed in this study.

Expansion planning studies presented in this report have considered two prospective hydro projects as candidates: 49 MW Gin Ganga and 27 MW Moragolla projects. Locations of these candidate projects are given in Figure 2.1.

The criteria given below were generally adopted in generation planning exercises in selecting the hydro projects from the large number of hydro sites identified in the master plan study.

a) Projects less than 15 MW were not considered as candidates in order to give priority for the large projects.

b) Whenever, feasibility study results were available for any prospective project, such results were used in preference to those of the Master Plan Study. (Studies conducted under the Master Plan study were considered to be at pre-feasibility level).

c) Estimated specific cost as well as physical and technical constraints are considered as the priority order for the selection of candidates.

However, with the implementation of many identified projects within these criteria by CEB, as well as by the private sector some times with reduced energy/capacity benefits, only Moragaolla and Gin Ganga were considered as candidate hydro in this study.

Further, private sector is allowed to develop hydro power projects below 10MW under a Standard Power Purchase Agreement.

4.1.2 Available Studies on Hydro Projects

In addition to 1989 Master Plan study, following studies of selected prospective hydro sites have been completed.

(a) Feasibility of the Broadlands Hydropower Project was studied under the "Study of Hydropower Optimization in Sri Lanka" in February 2004 by the J- Power and the Nippon Koei Co., Ltd., Japan [5]. This study was funded by the Japan International Cooperation Agency (JICA). Under this study, several alternative schemes studied previously by Central Engineering Consultancy Bureau (CECB) in 1986 and 1991 [6 and 7] were reviewed.

(b) A Pre-feasibility study on *Uma Oya* Multi-purpose Project (a trans-basin option) was completed by the CECB in July 1991 [8] where the diversion of Uma Oya, a tributary of Mahaweli Ganga was studied. The development proposed in this study was used as a candidate in the present expansion studies. In 2001, SNC Lavalin Inc. of Canada was engaged to conduct the feasibility study on Uma Oya with the assistance of Canadian International Development Agency (CIDA). However only Phase I of the study was completed by the consultants.

(c) A Pre-feasibility study for GING 074 project identified on the Mater Plan in Gin Ganga was carried out in 2008 by CECB.

(d) A feasibility study for Moragolla hydro power project was carried out in 2010/11 with Kuwait Fund For Arab Economic Development (KFAED. Nippon Koei Co Ltd is now engaged in to feasibility to carry out, detail designs and preparation of tender document with the assistance of Asian Development Bank.

4.1.3 Details of the Candidate hydro Projects

The basic technical data of the selected projects are summarized in Table 4.1 [see Annex 4.1 for further details]. A summary of the capital cost is given in Table 4.2 whereas Annex 4.2 provides information about the cost calculations of candidate hydro plants including adjustments made to their cost bases.

Table 4.1 - Characteristics of Candidate Hydro Plants

Project	River Basin	Ins. Capacity (MW)	Annu. Energy (GWh)	Storage (MCM)
Gin Ganga	Gin	49	143(@ 33.3%PF)	22.2
Moragolla	Mahaweli	27	81.5(@34.5%PF)	4.2

Based on expected energy and estimated project and maintenance cost; specific cost of the hydro plants were calculated (Table 4.3). These calculations were made for 10% discount rate, which is the rate used for planning studies. Furthermore, as an indicative comparison, specific cost at different capacities of the hydro projects are shown in the Figure 4.1 with the screening curves of some selected set of candidate thermal plants. In this specific cost calculation, capital costs of the projects are adjusted according to the plant capacity assuming water storage facilities and expected energy remains same.

Table 4.2 - Capital Cost Details of Hydro Expansion Candidates

Plant	Capacity (MW)	Pure Const. Cost US$/kW		Total Cost (US$/kW)	Const Period (Yrs)	IDC at 10% (% pure costs)	Const. Cost as Input to Analysis incl. IDC (US$/kW)		Total Cost incl. IDC (US$/kW)	Economic Life (Years)
		Local	Foreign				Local	Foreign		
Gin Ganga	49	691.0	1751.1	2442.1	5	23.78	855.3	2167.5	3022.8	50
Moragolla	27	1001.1	2414.5	3415.6	4	15.63	1186.6	2861.9	4048.6	50

All costs are in January 2012 border prices. Exchange rate US$ 1 = LKR113.9, IDC = Interest During Const.

Table 4.3 - Specific Cost of Candidate Hydro Plants

PROJECT/PLANT	CAPACITY (MW)	SPECIFIC COST (For maximum plant factor)	
		USCts/kWh	LKR/kWh
Gin Ganga	49	8.71	9.92
Moragolla	27	11.75	13.39

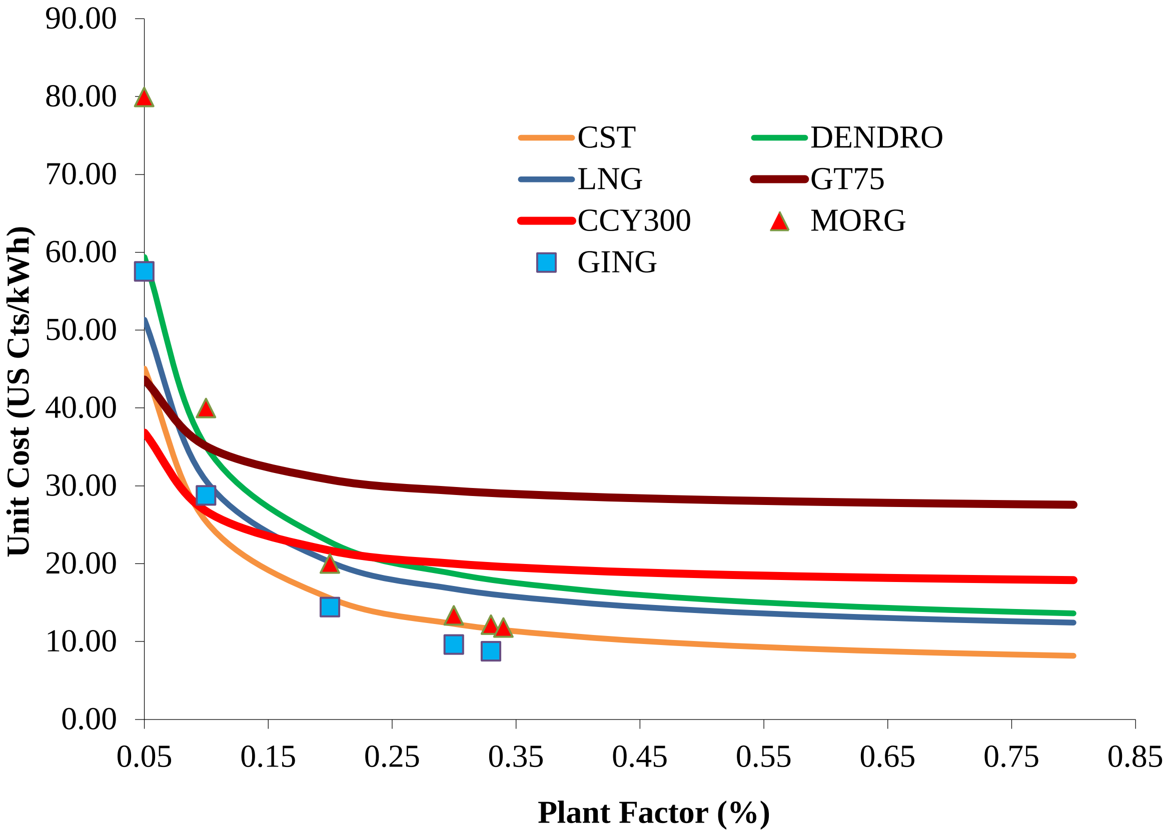


Figure 4.1 - Specific cost at different capacities of the hydro projects

4.1.4 Current status of non-Committed Hydro Projects

(a) Gin Ganga: A policy decision has been taken to develop Gin Ganga with trans-basin diversion for multi sector development mainly with irrigation benefits. Thus, the pre-feasibility study done by CECB for in-basin option in 2008 is to be reviewed in the context of trans-basin diversion.
(b) Moragolla: Kuwait Fund for Arab Economic Development (KFAED) funded the feasibility study completed in 2010. The Environmental Impact Assessment (EIA) process is still ongoing. The review of feasibility study, preparation of detail design and tender documents commenced with ADB funds in Octomber 2012.

4.2 Hydro Capacity Extensions

The Sri Lankan power system is gradually transforming into a thermal based system. In view of this, it would be pertinent to prepare the hydropower system for peaking duty. This aspect was further studied under the JICA funded "Hydro Power Optimization Study of 2004". Given below is a brief summary of possible expansions of existing hydro stations studied under the "Hydro Power Optimization Study"[5].

4.2.1 Samanalawewa

Samanalawewa project has a potential for additional peaking capacity. The existing Samanalawewa power station has two generators rated at 60 MW each. In addition to these, studies have indicated that further two units of 60 MW can be added for peaking duty. The facilities such as a bifurcation with bulk head gate and a space for an addition of two 60 MW units have been provided during the design and construction stage of the existing power station. However, the diversion of the Diyawini Oya water, studied prior to "Hydro Power Optimization Study" was not considered since it is infeasible.

4.2.2 Laxapana Complex

During the Phase E of the Master Plan for the Electricity Supply in Sri Lanka, 1990 [9], some upgrading measures at Laxapana Complex have been studied. Also, under the Hydro Power Optimization Study further studies were carried out to upgrade Wimalasurendra Power Station, New Laxapana power station & Old Laxapana Power Station. And also for upgrading of the Samanalawewa and Polpitiya Power Stations, studies were carried out during the period of February to June 2010 by POYRY Energt AG, Switzerland.

(a) Wimalasurendra and New Laxapana Project: Under the upgrading of Wimalasurendra and New Laxapana Power Stations, it is planned to replace generator, turbine governor excitation & controls and transformer protection. The upgrading of both power stations is scheduled to finish in 2013.

(b) Old Laxapana Project: It is planned to replace generator, turbine governor excitation & controls by 2013.

4.2.3 Mahaweli Complex

(a) ***Victoria Project:*** Victoria Hydro Power Extension (Stage II) was envisaged under feasibility study of existing Victoria Power Station in 1978. As studied under the "Hydro Power Optimization Study", the Stage II expansion consists of a headrace tunnel, a surge chamber, a high pressure tunnel, penstock and the power plant. (In this expansion, two options were identified as 2 x 70 MW and 3x70 MW in addition to the present capacity of the station 3 x 70 MW).

A JICA funded feasibility study on Expansion of Victoria Hydro Power Station was carried out in 2008. According to the selected option, 228MW(2 x 114MW) capacity is to be added to the system by connecting this project in to the existing intake and locating the new power house adjacent to the existing powerhouse with a waterway (tunnel) parallel to the existing waterway. This expansion could double the capacity of Victoria while the energy benefit will be minimal (11 GWh).

The EIA approval process is still on going and also CEB is waiting to complete a study on " The Project for the Development Planning on Optimal Power Generation for Peak Power Demand" in order to prioritize the options for implementation for peak capacity requirements. Therefore Victoria expansion Project was not considered as a candidate for the present study.

(b) Kotmale Project: Provision for capacity expansion has been identified in the existing Kotmale Power Station. At present 3 x 67 MW generators are installed in the Kotmale Power Station with an annual average energy output of 455 GWh. The amount of energy could be increased by about 20% by raising the dam crest from elevation 706.5m to 735.0 masl.

4.2.4 Pump Storage Option

In the context of committed and planned Coal power plants and the characteristics of the load curve (eg. prominent evening peak and low off peak) of the country, CEB has identified the need to study the requirement of and the potential for pumped storage hydro power plants. Initial desk studies have revealed that the potential sites may be available. Therefore CEB has sought funding and technical assistance from JICA through the Government of Sri Lanka to carry out a detailed feasibility study in this regard under " The Project for the Development Planning on Optimal Power Generation for Peak Power Demand" .

4.3 Thermal Options

4.3.1 Available Studies for Thermal Plants

Several studies had been conducted to assess the future thermal options for electricity generation in Sri Lanka. These studies include:

a) Feasibility Study for Trincomalee Coal-Fired Power Station conducted in 1988 [10]: The feasibility study on Trincomalee coal-fired power station considered a site capacity of 900 MW when fully developed (3x300 MW in a phased development). Site location is marked in Figure 2.1. The investment cost and other relevant parameters were reviewed during the 1995 Thermal Generation Options Study[12].

b) Thermal Generation Options, 1988 [11] and Thermal Generation Options, 1996 [12]

c) Special Assistance for Project Formulation (SAPROF) for Kelanitissa Combined Cycle Power Plant (1996) [13]

d) Review of Least Cost Generation Expansion Studies (1997) [14]

e) Coal Fired Thermal Development Project – West Coast (1998) [15]: Feasibility study and the preparation of contract documents (engineering services) for construction of the first 300 MW coal power plant on the West Coast in Kalpitiya in the Puttalam District with the assistance of Japan Bank for International Cooperation . The selected site with an area of 103 ha is suitable to accommodate the entire power plant in its final capacity of 900 MW with all auxiliary and ancillary buildings, the coal stockyard, ash disposal area, switchyard etc. and including a 43 ha buffer zone.

f) Feasibility Study for Combined Cycle Power Development Project at Kerawalapitiya -1999 [16]

g) Sri Lanka Electric Power Technology Assessment. Draft Report (Final), (July 2002) [17]

h) Master Plan Study for the Development of Power Generation and Transmission System in Sri Lanka, 2006 [27].

i) A note on stability of Diesel units on the Sri Lanka Power system, 2004 [25].

j) Study for Energy Diversification Enhancement by Introducing LNG Operated Power generation Option in Sri Lanka [29].

4.3.2 Thermal Power Candidates

Several power generation technologies were considered in the initial screening of generation options based on the studies listed above. The reciprocating diesel plants are not included for the planning studies considering the possible contribution from such plants to the system instability [25] and the recommendation made by the Committee on Policy on Addition of Diesel Engines. Following are the power generation technologies considered for the screening process.

(i) Coal Fired Steam Plants
(ii) Oil Fired Steam Plants
(iii) Oil fired Combined Cycle Power Plants
(iv) Natural Gas fired Combined Cycle Power Plant
(v) Oil fired Gas Turbine Plants
(vi) Nuclear Power Plant

However, several generation technologies with different capacities are not practical to be used for detailed studies. Therefore preliminary screening has to be done in order to reduce the number of alternatives. The screening curve method described in Chapter 6 was used for initial screening. After the initial screening seven alternative expansion options, which are described in Section 4.3.3, were chosen for the detailed planning studies. The results of the screening curve analysis are given in Annex 7.1.

4.3.3 Candidate Thermal Plant Details

Capital costs of projects are shown in two components: The foreign cost and the local cost. During the pre-feasibility and feasibility studies, capital costs have been estimated inclusive of insurance and freight for delivery to site (CIF basis). Local costs, both material and labour, have been converted to their border price equivalents, using standard conversion factors. The standard conversion factor applied to all local costs is 0.9. No taxes and duties have been added to the plant costs. Whenever results of the project feasibility studies were available, these were adopted after adjusting their cost bases to reflect January 2012 values.

The thermal plant cost data base, which was revised twice during the Thermal Generation Options Study [12] and the Review of the Least Cost Generation Plan [14], has been adjusted to accommodate US dollar to SL Rupees exchange rate variations as well as rupee and dollar escalations. No escalation is applied to capital costs during the study period, thus assuming that all capital costs will remain fixed in constant terms throughout the planning horizon.

A summary of the capital costs and economic lifetimes of candidate plants taken as input to the present studies after the preliminary screening is given in Table 4.4. Operating characteristics of these plants are shown in Table 4.5. The detailed characteristics of the candidate thermal plants are given in Annex 4.3.

Table 4.4 - Capital Cost Details of Thermal Expansion Candidates

Plant	Capacity* (MW)	Pure Construction Cost (US$/kW)		Total Cost (US$/kW)	Const. Period (Yrs)	IDC at 10% (% Pure costs)	Const. Cost Incl. of IDC (US$/kW)		Total Cost Incl. of IDC (US$/kW)	Economic life (Years)
		Local	Foreign				Local	Foreign		
Steam – Fuel Oil	144	385.2	1045.6	1430.8	4	18.53	456.5	1239.4	1695.9	30
Steam – Fuel Oil	288	325.6	883.8	1209.4	4	18.53	385.9	1047.6	1433.5	30
Steam – Coal	275	358.3	1298.6	1656.8	4	18.53	424.7	1539.2	1963.8	30
Steam – Coal (Trinco)	227	304.1	1130.1	1434.2	4	18.53	360.5	1339.5	1700	30
Gas Turbine	75	95.1	485.3	580.3	1.5	6.51	101.3	516.8	618.1	20
Gas Turbine	105	79.2	403.8	483	1.5	6.51	84.4	430	514.5	20
Combined Cycle	144	275	743.4	1018.4	3	13.54	312.3	844	1156.3	30
Combined Cycle	288	222.5	601.1	823.6	3	13.54	252.6	682.5	935.1	30
Combined Cycle (LNG)	240	248.5	896.1	1144.7	3	13.54	282.2	1017.5	1299.7	30

All costs are in January 2012 border prices. Exchange rate US$ 1 = LKR113.9, IDC = Interest during Construction,
* Net capacity

Table 4.5 - Characteristics of Candidate Thermal Plants

Name of Plant	Capacity (MW)	Heat Rate (kCal/kWh)		Full Load Efficiency %	FOR %	Scheduled Maint. Days/Yr	Fixed O&M Cost ($/kW Month)	Variable O&M Cost (USCts/ kWh)
		At Min. Load	Avg. Incr.					
Steam – Fuel Oil	144	2873	2248	35.8	2.74	40	1.001	0.548
Steam – Fuel Oil	288	2687	2162	37.4	2.74	40	0.692	0.271
Steam – Coal	275	2644	2310	33.3	3.5	40	1.018	0.559
Steam-Coal (Trinco)	227	2766	2157	33.1	2.74	40	0.807	0.316
Gas Turbine – Auto Diesel	75	4134	2310	30.1	8	30	0.577	0.460
Gas Turbine – Auto Diesel	105	4134	2310	30.1	8	30	0.507	0.402
Comb. Cycle – Natural Gas	240	2457	1453	48.1	8	30	0.370	0.308
Comb. Cycle – Auto Diesel	144	2614	1462	46.2	8	30	0.508	0.436
Comb. Cycle – Auto Diesel	288	2457	1454	47.7	8	30	0.384	0.329

All costs are in January 2012 border prices. Exchange rate US$ 1 = LKR113.9, FOR = Forced Outage Rate
Heat values of petroleum fuel based plants are in HHV

4.3.4 Fuel

Presently petroleum based fuels and coal are the only few feasible fuel options for thermal power generation. Other fuel options such as LNG and nuclear are being studied under the present systems' technical and other limitations. Some time ago CEB used the World Bank fuel Price forecasts. However considering the extreme volatility shown by fuel prices recently, constant fuel price were used in planning studies in recent past. Fixed prices in constant terms were used for the planning studies and price sensitivity of the plan was tested for 50 percent increase in price of each fuel type separately and their escalation.

(i) Petroleum products (Auto Diesel, Fuel oil, Residual Oil, Naphtha): In the present context all fossil fuel-based thermal generation in Sri Lanka would continue to depend on imports (However it has to be noted that oil exploration activity is presently on going in the Mannar basin). Ceylon Petroleum Corporation (CPC) presently provides all petroleum products required for thermal power stations. In this study, CPC oil prices were used. Table 4.6 shows the fuel characteristics and the fuel prices including insurance and freight charges used in the analyses. Further, it is important to note that all the heat contents given are based on higher heating value (HHV).

(ii) Coal: Coal is a commonly used fuel options for electricity generation in the world. CEB identified coal as an economically attractive fuel option for electricity generation in 1980's. But No coal plants were built due to several environmental and social issues. At present, 900MW first coal power plant is being built at puttalam in two stages. It is important to note that past fuel prices show that the coal prices are not closely tied up with the petroleum prices. However recently coal too has shown an increased volatility. The CIF value at Colombo on Coal prices were used in the studies. Characteristics of coal are also given in Table 4.6.

Table 4.6 - Characteristics of Fuel Used in the Study

Fuel Type	Heat Content (kCal/kg)*	Specific Gravity	Fuel Prices ($/bbl)**
Auto Diesel	10550	0.84	128.4
Fuel oil	10300	0.94	103.3
Residual oil	10300	0.94	101.8
Naphtha	10905	0.68	117.3
Crude oil	-	-	110.1
Coal	6300	-	142.8 (puttlam coal price)

*Source: Oil prices & fright from CPC, Coal price from Commodity price data (Pink sheet)
** Coal price is given in the units of $/ton

(iii) LNG

Liquefied Natural Gas (LNG) as a fuel for Gas Turbine and Combined Cycle plants is an attractive option from environmental perspective. LNG supply in Sri Lanka would add diversification to the country's fuel mix and in turn for the energy mix. Moreover, LNG has the advantage that it is readily burnt in combustion turbines that are characterized by high efficiency. There is no commercially developed gas field in Sri Lanka

though exploration is ongoing. The closest Gas fields to Sri Lanka are in Bangladesh and India. The reserves in India are insufficient for their use.
Bangladesh and other Gas sources are located far from Sri Lanka, which makes pipeline projects uneconomical. Hence natural gas transport by means of shipping as LNG is a better option for Sri Lanka. Following three recent studies have reviewed and evaluated LNG as a fuel option for Sri Lanka:

1. Sri Lanka Electric Power Technology Assessment Draft Report (Final), (July 2002) [17]
2. Sri Lanka Natural Gas Options Study, USAID-SARI/Energy Program (Revised June 2003) [18]
3. Study for Energy Diversification Enhancement by Introducing LNG Operated Power generation Option in Sri Lanka – 2010 (JICA funded),phase I [29]

The first two studies have concluded that the potential demand for gas in the country is very small since the demand for LNG is mainly from the power sector. However the above JICA funded study (phase I) conducted in 2010 concluded that under certain conditions, such as low LNG prices (similar to the price obtained by India in 2008/09) and obtaining of CDM benefits , LNG too could be competitive with coal and would be a viable fuel. However, the price assumptions made JICA Study seemed too optimistic in the global context. The second phase of the above study is expected to further study the aspects of the viability of LNG introduction to Sri Lanka.

A suitable LNG setup for Sri Lanka would consist of an LNG import facility (via tanker ships), domestic storage, regasification unit and a power plant. However, a recent development is the FSRU (Floating Storage and Regasification Unit) which can be moored in the sea and has a faster implementation possibility. Natural gas prices in recent years and technological advances have lowered costs of regasifying, shipping, and storing LNG in the global market. In addition, other sectors, such as vehicular fuel and industry can use LNG as a substitute.

(iv) Nuclear

Nuclear plants are inherently large compared to other technologies for power generation. Capacity of the present system is too small to accommodate a Nuclear power plant. However cabinet approval has been given to consider nuclear as an option to meet the future energy demand and also to consider Nuclear Power in the generation planning exercise and to carry out a pre feasibility study on the Nuclear Option. Nuclear option was included in this study as a candidate plant from year 2030 onwards. In addition, a project proposal too has been forwarded to IAEA for technical assistance in this regard.

4.3.5 Screening of Generation Options

A preliminary screen of generation options is carried out in order to identify most appropriate expansion options. In fact it is quite difficult to handle large number of generation options in detailed analysis. The screening curve analysis, which is based on specific generation cost described in Chapter 6, is employed in the initial screening.

Thermal plant database, which was updated by Electrowatt Engineering (EWE) during the Thermal Generation Options Study in 1996 [12] and again reviewed during the Review of Least Cost Generation Expansion Study in 1997 [14] and confirmed during the Master Plan study 2006 [27] was extensively used during the current planning study. However, adjustments have been made to the cost base to reflect January 2012 values. Whenever feasibility study results are available for any prospective project, such results were used in preference to the above studies.

4.3.6 Thermal Plant Specific Cost Comparison

The specific cost of the selected candidate plants are tabulated in Table 4.7. it shows coal based generation is attractive for higher plant factor operations. However, in actual simulations, the size of the generation units are taken into account and it would make a significant effect in the final plant selection.

Table 4.7 - Specific Cost of Candidate Thermal Plants in USCts/kWh (LKR/kWh)

Plant \ Plant factor	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8
150 MW Steam – Fuel Oil	34.2 (39.0)	25.2 (28.7)	22.2 (25.3)	20.7 (23.6)	19.8 (22.6)	19.2 (21.9)	18.8 (21.4)	18.4 (21.0)
300 MW Steam – Fuel Oil	30.7 (35.0)	23.2 (26.4)	20.7 (23.5)	19.4 (22.1)	18.7 (21.3)	18.2 (20.7)	17.8 (20.3)	17.5 (20.0)
250 MW Coal plant	23.9 (27.2)	14.6 (16.6)	11.5 (13.1)	10.0 (11.3)	9.0 (10.3)	8.4 (9.6)	8.0 (9.1)	7.6 (8.7)
250MW LNG plant	30.6 (34.8)	20.2 (23.0)	16.8 (19.1)	15.0 (17.1)	14.0 (15.9)	13.3 (15.1)	12.8 (14.6)	12.4 (14.2)
5MW Dendro plant	35.0 (39.8)	22.8 (25.9)	18.7 (21.3)	16.7 (19.0)	15.5 (17.6)	14.6 (16.7)	14.0 (16.0)	13.6 (15.5)
300 MW Coal Steam	25.4 (28.9)	15.5 (17.7)	12.3 (14.0)	10.6 (12.1)	9.6 (11.0)	9.0 (10.2)	8.5 (9.7)	8.2 (9.3)
75 MW Gas Turbine	35.1 (39.9)	30.8 (35.1)	29.4 (33.4)	28.6 (32.6)	28.2 (32.1)	27.9 (31.8)	27.7 (31.6)	27.6 (31.4)
105 MW Gas Turbine	33.6 (38.3)	30.0 (34.2)	28.8 (32.8)	28.2 (32.2)	27.9 (31.8)	27.6 (31.5)	27.5 (31.3)	27.3 (31.1)
150 MW Combined Cycle	29.8 (33.9)	23.5 (26.8)	21.4 (24.4)	20.4 (23.2)	19.8 (22.5)	19.4 (22.0)	19.1 (21.7)	18.8 (21.4)
300 MW Combined Cycle	26.7 (30.4)	21.7 (24.7)	20.0 (22.8)	19.2 (21.8)	18.6 (21.2)	18.3 (20.9)	18.1 (20.6)	17.9 (20.4)

Note: 1 US$ = LKR 113.9

4.3.7 Current status of non Committed Thermal Projects

(a) Trincomalee Coal Power Project

Government of Sri Lanka (GOSL) and Government of India (GOI) entered into an Memorandum of Agreement (MOA) to develop a coal power plant in Trincomalee as a joint venture between CEB and NTPC Ltd. of India. The initial plant capacity will be 2x250 MW and the MOA has provision for extension up to total 1000 MW. Finalization of negotiations is ongoing in this regard.

(b) Coal power plants in the Southern Coast

Southern Coal Power Project: The Government of Sri Lanka (GOSL) / Ceylon Electricity Board (CEB) invited Expressions of Interest from reputed firms for developing, building and operating of four coal fired generating units of 300 MW capacity on BOO basis. However, this process did not continue.
CEB has identified locations near KaraganLewaya, Mirijjawila, Mirissaand, Mawellaas prospective sites in southern coast and Athuruwella in the Western Coast.

Mawella Coal Power Development Project: The Mawella site was studied to a pre-feasibility level as a candidate site for coal power development together with the other thermal options in 1988. The study proposed 600 MW coal power plant at the site. This site was reviewed during the 1996 under Thermal Generation Options Study and remains as a potential site for future coal power development.

4.4 India-Sri Lanka Transmission Interconnection

The present discussion on the interconnection was initiated in 2006 and a primary level study was conducted by Power Grid Corporation, India and Nexant in 2006. According to the primary level studies, 500 MW transmission connection is considered as the first stage and is to be expanded up to 1000 MW later. A Memorandum of Understanding was signed for feasibility study in 2010.According to the MOU, a feasibility study is to be carried by CEB and Power Grid Corporation Indian Limited jointly. The feasibility work is in progress as at present.

CHAPTER 5
NON CONVENTIONAL RENEWABLE GENERATION OPTIONS FOR FUTURE EXPANSION

Renewable energy sources are continuously replenished by natural processes. A renewable energy system converts the energy found in sunlight, wind, falling water, sea-waves, geothermal heat, or biomass into a form we can use such as heat or electricity without exhausting the source. Most of the renewable energy comes either directly or indirectly from sun and wind and can never be exhausted, and therefore they are called renewable.

The large or regulated hydro plants are considered as conventional generation options. Therefore only other renewable options – non conventional renewable options are considered in this chapter. Most of the non conventional renewable energy sources available for system expansion described in this chapter are mainly non-dispatchable due to their intermittent nature and are developed in small capacities. Therefore, presently system penetration is allowed considering the system limitations. However, with system expansion and development a higher penetration would be possible. This has been continued in parallel with the conventional generation expansion options.

Sri Lanka has exploited large conventional renewable resources (hydro) to almost its maximum economical potential. Non Conventional Renewable Energy (NCRE) has become a prime potential source of energy for the future due to the low impact on environment compared with conventional sources of energy. Sri Lanka has a history of enabling local development of renewable energy resources in the electricity systems. This includes:

- Hydropower
- Wind Energy
- Biomass
- Solar Power
- Power from Municipal Solid Waste

As of 31st December 2012, approximately 314MW of embedded NCRE plants are connected to the National Grid. Out of this, contribution from mini hydro is 227 MW while biomass-agricultural & industrial waste penetration is 11.5 MW. Contribution to the system from solar power and wind power is 1.4MW and 74MW respectively.

Though, the Ceylon Electricity Board initiated renewable energy development, it is presently the private sector, which is mainly involved in the NCRE development process. The renewable energy industry is rapidly growing in the country with both local and foreign investment. In comparison with the conventional large power plants, the total contribution from the NCRE sector to the National Grid still remains small but continues to increase and in 2011 the energy share of NCRE was 6.3%. Table 5.1 shows the system development and renewable energy development during the last 10 years in the Sri Lanka system. Recently a 'Cost based technology specific three tiered tariff' has been introduced as an incentive for NCRE development. Annex 5.1 gives the NCRE tariff announced in 2011 by the Public Utilities Commission of Sri Lanka.

The reliability level of electricity supply from plants running on renewable sources is also low since the renewable sources are directly affected by changes in natural phenomena like wind, sun, water flow in streams etc. Further, the mode of operation of these plants are non dispatchable. As stated in Chapter 2.1.2 the existing mini hydro/NCRE plants were included in this study in the base case. Table 5.2 gives the projected future development up to 2032 as considered in this study. Also a high renewable scenario was considered separately. The projected NCRE development used for the high re4newable scenario is given in Annex 5.2.

Table 5.1 – Energy and demand contribution from non conventional renewable sources

Year	Energy Generation (GWh)		Capacity (MW)	
	Non Conventional Renewable	System Total	Non Conventional Renewable	Total System Installed Capacity
2002	107	6946	38	1772
2003	124	7612	43	1849
2004	206	8159	77	2115
2005	280	8769	89	2322
2006	346	9389	111	2256
2007	353	9821	119	2256
2008	435	9901	150	2645
2009	549	9882	184	2684
2010	727	10714	217	2817
2011	725	11528	244	3141

Table 5.2 – Projected future development of NCRE
(Assumed as committed in revised base case plan)

Year	Cumulative mini hydro addition (MW)	Cumulative Wind addition (MW)	Cumulative biomass addition (MW)	Cumulative solar addition (MW)	Cumulative Total NCRE Capacity (MW)	Annual Total NCRE Generation (GWh)	Share of NCRE from Total Generation %
2013	219	90	17	1.3	327	1179	9.4%
2014	232	90	21	21	364	1284	9.5%
2015	244	90	25	31	390	1371	9.5%
2016	256	220	29	51	556	1838	11.9%
2017	279	230	33	72	614	2010	12.4%
2018	294	240	37	82	653	2136	12.4%
2019	308	250	41	85	684	2248	12.4%
2020	320	260	45	88	713	2353	12.4%
2021	332	270	49	91	742	2457	12.3%
2022	345	280	53	94	772	2566	12.2%
2023	354	290	57	97	798	2659	12.0%
2024	365	300	61	100	826	2760	11.9%
2025	377	310	65	103	855	2865	11.8%
2026	389	320	69	106	884	2970	11.7%
2027	400	330	73	109	912	3071	11.5%
2028	412	340	77	112	941	3175	11.4%
2029	414	350	81	115	960	3243	11.1%
2030	426	360	85	118	989	3348	10.9%
2031	438	370	89	121	1018	3453	10.8%
2032	450	380	93	124	1047	3557	10.6%

Note: Incremental cost of assumed as committed of NCRE is approximately 100mUSD
Plant factors- Mini Hydro- 42%, Biomass-80%, Solar-17% and Wind-32%

5.1 Mini / Micro Hydro

Harnessing of hydro resources in major projects are dealt with elsewhere in the report while certain aspects of small and micro hydro potential in the country is discussed here. Well over 400 micro hydro sites have been reported in the country especially in the central hilly areas. Most of these sites are now abandoned and studies have revealed that only about 140 such sites could be developed to generate useful energy. Eighty three of such sites are already rehabilitated and are in operation. The Master Plan Study carried out in 1988 reveals that there is potential for,

a) Development of new sites

b) Harnessing the head from irrigation canals, tanks and reservoirs

c) Rehabilitation, upgrading or extension of existing sites.

According to the Master Plan, it was estimated that 30 MW of small hydro potential exists in about 60 undeveloped sites while further 8 MW exist in about 290 irrigation tanks and reservoir sites. Another 50 MW of small hydro potential can be tapped in about 140 sites, which can either be rehabilitated or re-developed.

According to a study carried out by the ITDG in 1999 [19], in addition to the 50 MW potential identified by the Master Plan as mentioned above, the exploitable small hydro potential in Sri Lanka has been estimated to be around 100 MW from about 250 identified sites.

However, the present development of mini hydro (less than 10MW) has surpassed the above estimates. As of 31st October 2012, 217MW of mini hydro plants are connected to the grid while another 153MW have signed the Standard Power Purchase Agreement (SPPA) with CEB. More projects are at the initial provisional approval state with the Sri Lanka Sustainable Energy Authority (SEA). This development was mainly due to the very attractive tariff offered to developers, first based on the avoided cost principle and presently on the cost reflective principle.

5.2 Wind

Studies have revealed that wind is the most promising option of the available renewable sources, for power generation in Sri Lanka. The Pre-Electrification Unit of CEB carried out a resource assessment study of solar and wind potential in 1992 [20]. This study revealed an overall wind potential of 8 MW/sqkm in open land area or an overall potential of approximately 200 MW in the South-eastern quarter of the island.

In March 1999, CEB commissioned a pilot scale 3 MW wind power plant in Hambantota, which is in the Southeast of the country. In year 2011, the Wind plant operated at a plant factor of 10.1% while in 2010 the plant factor was 11.4%.

A study of wind energy resource assessment of Puttalam and Central regions carried out by the CEB in 2002, [21] too has produced encouraging results on wind energy potential in both Puttalam and Central regions.

The wind mapping study conducted by the US National Renewable Energy Laboratory (NREL) in 2004 [23] has also confirmed that Sri Lanka has many areas estimated to have good wind resources. These resources tend to be located in the North-western coastal region from Kalpitiya Peninsular to Mannar Island, Jaffna Peninsular and the Central highlands. NREL estimates suggest that nearly 5000 sq. km of wind resource potential exists in Sri Lanka where they recommend additional studies to assess the practical resources by accounting for the transmission grid accessibility.

Renewable Energy Resource Development Plan 1/2012 prepared by Sri Lanka Sustainable Energy Authority identified the district wise distribution of gross availability of renewable energy resources of different type of renewable energy sources.

By end October 2012, the private sector has developed wind power plants around Puttalam, Kalpitiya and Ambewela areas adding 74MW to the National Grid. Further, Power Purchase agreements have been signed for another 31MW. The next step in the wind power development in the country is expected to be the wind park concept to be implemented in the Mannar area. CEB is currently pursuing a novel concept to develop a 100MW Wind Farm at Mannar Island on Semi Dispatchable basis to overcome absorption constraints in Wind Technology.

5.3 Wood Fuel / Dendro Power

Use of biomass mainly wood fuel in thermal plants have attracted widespread interest as a primary energy source for electricity generation, due to its potential as an indigenous source of energy for the country. In addition to this, there are other benefits mainly resulting from reduced soil erosion, restoration of degraded lands, creation of local employment and various potential environmental benefits. Maintaining a regular supply of biomass to fuel the plant is foreseen as a major hindrance for effective implementation of commercial scale dendro plants. The perceived spectrum of benefits from dendro power is based on the presumption that the fuel for power generation is from dedicated plantations and that forests or existing vegetation would not be affected. By 31st October 2012 , 0.5MW dendro plant in operation and SPPA had been signed for 62MW.

The use of agricultural or industrial waste for Electricity Generation is similar to wood fuel use. As at the above date, there were 11MW of such plants in operations and contracts have been signed for 4MW.

5.4 Solar

There are two distinct approaches to generating electricity from solar energy:

- Solar Thermal engines
- Photovoltaic (PV) cells

Solar thermal engines use a solar collector to create temperatures sufficient to raise steam and drive a turbine generator. This technology is normally used in the areas that are hot, dry and sunny. A PV cell converts sunlight directly into electricity and is a well-established technology particularly for sites that are far from the distribution network.

Electricity generated directly from solar energy is still a quite costly option for grid connection. However, solar electricity is a viable option by itself, or as a component of hybrid systems for off grid power systems, which cater to electricity demand in far remote areas. Grid connected capacity of solar power projects was 1.4MW by end October 2012.

5.5 Municipal Solid Waste

Power generation using solid waste is being considered by the most of Local Authorities in the country. This could be a satisfactory solution for proper disposal of solid wastes generated by the human activities. Disposal of solid waste is the primary function of such facility and the power generation is a secondary function. Since this is directly linked with solid waste disposal of urban areas, CEB considers these plants separately taking into account the importance of solid waste disposal. However, so far waste to power project has been implemented even though several Letters of Intent (LOI) had been issued by Ceylon Electricity Board and Sri Lanka Sustainable Energy Authority to many developers.

5.6 Other

Other forms of renewable energy such as Wave, OTEC, Solar Chimney, and other solar thermal applications are still at the demonstration stage. However they have been given the opportunity to implement these technologies by offering the other tariff category in the NCRE tariff as “other”, Solar too comes under this category.

5.7 Net Metering

The “Energy Banking Facility” for such micro-scale generating facilities, commonly known as the “Net Energy Metering Facility” by the electricity utilities for their electricity consumers has been introduced in Sri Lanka. This scheme allows any electricity consumer to install a renewable energy based electricity generating facility and connect it to the CEB’s electricity network. The electricity network connection scheme shall be approved by CEB.

The utility energy meter is replaced with an Import/Export meter. The electrical energy consumed from the grid is considered as import energy and electrical energy generated and supplied to the grid is considered as export energy.

At the end of each billing period, CEB reads the consumer’s export energy meter reading and the import meter reading. The electricity bill will be prepared giving credit to the export, and charging the consumer for the difference between the import and the export. If the export is more than the import in any billing period, the consumer receives an export credit, and is credited towards his next month’s consumption. Such credits may be carried-over to subsequent months, as long as there is no change in the legal consumer for the premises.

The key factor in this process is that there will be no financial compensation for the excess energy exported by the consumer. All exports are set-off against the consumer’s own consumption, either in the current billing period or future billing periods. Accordingly, consumers are compelled to select the capacity of the renewable energy equipment to reasonably match his requirements. Facilities with maximum demand less than 42kVA (Upper capacity limit has been increased from 42 kVA to 10 MW at present) are allowed to install “net” metering equipment and generally it is installed on the low voltage side.

5.8 Inclusion of NCRE in the LTGEP

Renewable sources of energy will play a supplementary role in the national context while playing a very important role in decentralised applications, in meeting electrical energy needs of rural and remote communities. NCRE has not been considered as a candidate in this study due to its intermittent nature. However, an expected development in NCRE has been assumed as committed (Table 5.2) and modelled accordingly. The four major types of NCRE technologies were modelled in different ways and described in detail in section 6.4.8.

5.9 Development of NCRE

According to the National Energy Policy and the "Mahinda Chinthana 10 year development framework", a 10% share is targeted from NCRE source by 2015 in electricity generation.

Government of Sri Lanka established the Sustainable Energy Authority (SEA) on 01 October 2007, enacting the Sri Lanka Sustainable Energy Authority Act No. 35 of 2007 of the Parliament of the Democratic Socialist Republic of Sri Lanka. SEA is expected to develop indigenous renewable energy resources and drive Sri Lanka towards a new level of sustainability in energy generation and usage; to declare energy development areas; to implement energy efficiency measures and conservation programmes; to promote energy security, reliability and cost effectiveness in energy delivery and information management.

The objective of the SEA is to identify, promote, facilitate, implement and manage energy efficiency improvements and energy conservation programmes in domestic, commercial, agricultural, transport, industrial and any other relevant sector. SEA will guide the nation in all its efforts to conserve energy resources through exploration, facilitation, research & development and knowledge management in the journey of national development. Also SEA will promote energy security, reliability and cost-effectiveness of energy delivery to the country by policy development and analysis and related information management. Further the authority will ensure that adequate funds are available to implement its objects, consistence with minimum economic cost of energy and energy security for the nation, thereby protecting natural, human and economic wealth by embracing best sustainability practices. Relating to power development, SEA will hold two key sensitive parts namely declaration of energy development area and on-grid & off-grid renewable energy resources. CEB and SEA will have to play a complementary role to each other in the future in order to optimise the power generation from NCRE.

Further, Government of Sri Lanka established the Sri Lanka Energies (Pvt) Ltd, a 100% Ceylon Electricity Board owned company on 12th July 2012 to accelerate the electricity generation through renewable energy resources and to provide facilities.

CHAPTER 6
GENERATION EXPANSION PLANNING METHODOLOGY AND PARAMETERS

CEB considers the project concepts from all possible sources including CEB owned generation developments, large thermal plants from the independent power producers and supply of non-conventional energy sources in order to meet the system demands. Several factors are taken in to account in this process of selecting the appropriate power development project. Commercially exploitable potential, technical feasibility studies, environment impact assessment and economic feasibility are the main factors of this selection process. In parallel with these factors, the Grid Code of Public Utilities Commission of Sri Lanka, planning guidelines of Ministry of Power and Energy and National Energy Policy are also accounted in the planning process. Long-term generation expansion plan is the outcome of the selection process. The methodology adopted in the process is described in this chapter.

6.1. Grid Code Generation Planning

Both following Grid codes and the Ministry guidelines are considered in preparing the Long Term Generation Expansion Plan 2013-2032.

- Draft Generation Planning Code under the Grid Code issued by the Transmission Licensee based on the PUCSL Grid Code issued in April and in May 2012.
- The Ministry of Power and Energy issued a set of “Guidelines on Long Term Generation Expansion Planning” in October 2011.

6.2. National Energy Policy

Ministry of Power and Energy published the National Energy Policy of Sri Lanka in July 2006 for the public comments. This document spells out the implementing strategies, specific targets and milestones through which the Government of Sri Lanka and its people would endeavor to develop and manage the energy sector in the coming years. Specific new initiatives are included in this policy to expand the delivery of affordable energy services to a larger share of the population, to improve energy sector planning, management and regulation.

Institutional responsibilities to implement each policy element and associated strategies to reach the specified targets are also stated in this document. The “National Energy Policy and Strategies of Sri Lanka” is elaborated in three sections in this policy document as follows.

- “Energy Policy Elements” consists of the fundamental principles that guide the development and future direction of Sri Lanka’s Energy Sector.
- “Implementing Strategies” states the implementation framework to achieve each policy element.
- “Specific Targets, Milestones and Institutional Responsibilities” state the national targets, and the planning and institutional responsibilities to implement the strategies.

Some policy elements, specific targets and milestones related to electricity sector are to be addressed in the plan in order to identify financial and other institutional requirement related to the policy. These policy elements include:

- Providing electricity at the lowest possible cost to enhance the living standard of the people,
- Ensuring energy security by diversified energy mix,
- Consideration of efficiency improvements and indigenous resources for the future developments,
- Consideration of system reliability, proven technologies, appropriate unit sizes etc. to improve quality of supply,
- Consideration of environmental impacts.

National Energy Policy and Strategies of Sri Lanka shall be reviewed and revised after a period of three years. Since the revised document has not been published 2006 guidelines were used in the preparation of the Long-Term Generation Expansion Plan 2013-2032.

At present, committee has been appointed for development of a 'Road Map to Achieve Energy Security', considering the other alternative options of fuels giving due consideration for other aspects such as CO_2 emission, renewable integration, fuel diversity etc. In the Long-Term Generation Expansion Plan 2013-2032, case studies were carried out to facilitate the information required for reviewing of the National Energy Policy to include the fuel diversity on the basis of achieving Energy Security.

6.3 Preliminary Screening of Generation Options

There are many technologies from many prime sources of energy in various stages of development. However, it is difficult to analyze in detail all these options together. Therefore, several power generation technologies are considered in the initial screen of generation options to select the technologies and prime source of energy to be included in the LTGEP.

When alternative plants with varying capital investments, operation costs, maintenance and repair costs and lifetimes etc. are to be analyzed, it is necessary to employ an indicator common to all plants. Therefore, screening curve method, in which specific generation costs expressed in US Cents/kWh are calculated at different plant factors for all available thermal plants, is employed primarily in order to select the appropriate options among all the available thermal options. Details of the screening curve methodology are given in Annex 6.1. Then the detailed planning methodology described in section 6.4is used to finalize the Least Cost Generation Expansion Plan. Several conventional thermal generation technologies at different capacities and a number of selected hydro options are to be studied together in order to identify the Long term Generation Expansion Plan.

6.4 Detailed Planning Exercise

State of the art optimization and simulation models are used in the detailed generation planning exercise. Internationally accepted planning methodologies, wherever possible, are adopted during the formulation of the Long term Generation Expansion Plan.

The SYstem SIMulation package (SYSIM), developed during the Master Plan Study in 1989 and updated in 2006 and Wien Automatic System Planning (WASP)package -WASP IV developed by International Atomic

Energy Agency (IAEA)tools were extensively used in conducting the system expansion planning studies to determine optimal Long Term Generation Expansion Plan.

6.4.1 SYSIM Simulation Model

System Simulation package is used to simulate the operating performance of integrated water resources provided that adequate thermal capacity is available for optimal generation dispatch. It is also used to evaluate the potential contribution that candidate hydro power plants could be expected to make in meeting future demands for electricity. Rainfall data of past 50 years in the catchment areas of the existing and candidate hydro plants are taken into account to derive the energy and capacity availabilities associated with plants.

The potential of hydro power projects/systems evaluated using SYSIM is used as input information to the WASP IV package. Since WASP package could accommodate only a maximum of five hydro conditions, five representative hydrological conditions were selected with different probability levels depicting very wet, wet, average, dry and very dry hydro conditions.

6.4.2 WASP Package

Generation Planning section uses the latest version of the WASP package (WASP IV) for its expansion planning studies. WASP is used to find the economically optimal expansion policy for a power generating system within user-specified constraints. WASP IV has seven modules. It utilizes probabilistic estimation of system production costs, expected cost of unserved energy and reliability to produce the optimal generation expansion sequence for the system for the stipulated study period. Also, it can be used to carry out power generation expansion planning taking into consideration fuel availability and environment constraints.
Probabilistic Simulation, Linear Programming and Dynamic Programming are the simulation and optimization methods used in WASP-IV tool.

6.4.3 Hydro Power Development

Hydro resource is one of the main indigenous sources of energy and lifetime of a hydro plant is quite high compared to the other alternative sources. Therefore, these hydro plants are considered separately outside the LTGEP in addition to the hydrothermal simulation. In this alternate process, economic analysis is carried out for each project with the consideration of avoided thermal plant of the LTGEP. Then technical feasibility studies and environmental impact assessments are processed for economically feasible projects. Next step is sourcing funds. Once all these requirements are fulfilled, the project is incorporated to the LTGEP as a committed plant.

6.4.4 Assessment of Environmental Implications and Financial Scheduling

Though the environmental effects of each thermal and hydro option are considered in the initial selection, overall assessment of environmental implications is carried out for the proposed LTGEP. That assessment is for the plant emission after the possible environmental mitigation measures are taken.

Other two aspects of the planning process are the implementation and financing. In fact, the total period of implementation of a project including feasibility studies varies from 4 years for a gas turbine and 8 years for a coal-fired plant. Similarly implementation period of a hydro plant is in the range of 7 to 8 years. Therefore, implementation scheduling is an important event of the planning process. Furthermore, generation system expansion is highly capital cost intensive. Therefore, during the planning period financial schedule is prepared in order to identify the financial requirement which is essential for negotiation and sourcing of funds from various sources and for projecting tariffs.

6.4.5 Modeling of NCRE

As stated in Chapter 5, NCRE was not included as candidates. According to the Grid code published by PUCSL existing NCRE plants are considered as committed for the Reference Case. But a projected development was considered as committed and incorporated to the Base case of the LTGEP. The main technologies of NCRE; mini-hydro, wind, solar and dendro were modeled differently in the WASP. Dendro which was modeled as a thermal plant, which is a thermal plant having a non-fossil fuel. The energy contribution from the projected wind and solar development were considered as available and reduced from the generation forecast. But a capacity contributions from wind and solar were not considered. Mini hydro was included in the WASP as lumped 'run of the river' hydro plants. The probabilistic monthly energy was calculated based on past performance of mini hydro plants. In the high NCRE development of scenario, wind power plants were modeled as considering capacity contribution to the dispatch.

6.5 Study Parameters

The preparation of the plan is based on several parameters and constraints. These include technical and economical parameters and constraints which are to be used as input to WASP IV. Parameters and constraints given in Grid Code of PUCSL were used for in the studies and those are described in detail.

6.5.1 Study Period

The results of base case and all sensitivity studies are presented in the report for a period of 20 years (2013-2032). In this regard, the studies were conducted for a period of 25 years (2013-2037).

6.5.2 Economic Ground Rules

All analyses were performed based on economic (border) prices for investments and operations. The exchange rate used in the present study is 113.89 LKR/USD. This is the average value of January 2012 exchange rates. All costs are based on 1st of January 2012.

6.5.3 Plant Commissioning and Retirements

It is assumed that the power plants are commissioned or retired at the beginning of each year. Such limitations are common in the long term planning tools.

6.5.4 Cost of Energy Not Served (ENS)

The average loss to the economy due to electrical energy not supplied has been estimated as0.5335USD/kWh (in 2012 prices). This value has been derived by escalating the ENS figure given by PUCSL as 0.5USD/kWh in 2011.

6.5.5 Loss of Load Probability (LOLP)

According to the Draft Grid Code LOLP maximum value is given as 1.5%. This corresponds to cumulative failure duration of 5.5 days/year for the generating system. However, this is not used as a constraint in the development of optimal expansion plans in the initial 2 years of the planning horizon.

6.5.6 Reserve Margin

Reserve margin is the other available reliability criteria of the WASP-IV module. Minimum value of 2.5% and Maximum value of 20% have been applied for the studies. However, minimum 2.5% of reserve margin is not being used as a constrain in the development of optimal expansion plan up to year 2015 due to the limitations in the construction of new plants.

6.5.7 Discount Rate

The discount rate is used in order to analyze the economic costs and benefits at different times. The discount rate accounts several factors such as time value of money, earning power, budget constraints, purchasing power, borrowing limitations and utility of the money. Considering these facts, 10% discount rate was used for planning studies. Sensitivity to the discount rate is analyzed by applying two discount rates.

6.5.8 Assumptions and Constraints Applied

The following were the assumptions and constraints that were applied to all cases studied.

a) All costs are based on economic prices for investment on generating plants. Furthermore, thermal plants will be dispatched in strict merit order, resulting in the lowest operating cost.

b) All plant additions and retirements are carried out at the beginning of the year.

c) Gas Turbine plants can be available only by January 2015. For Gas Turbines, the construction period is about 1.5 years, but in the absence of any detailed designs for a power station, it may require 2 years for the pre-construction and construction activities.

d) 20MW Northern Power Diesel Plant is considered as a committed plant in 2014.This plant is already supplying power to the isolated Northern Power System. However, the Northern Grid is expected to be interconnected to the National Grid in late 2013 with the reconstruction of Killinochchi-Chunnakam132kV transmission line. Additionally 24MW Diesel engines running on furnace oil has been added as an extension to Chunnakam Power Station, Jaffna in 2013. This is also considered as a committed plant in 2014.

e) Puttalam coal power plant Stage II and Stage III(2x300MW) are considered as committed plants in 2014 and 2015 respectively.

f) Trincomalee Coal Development consisting of four 250MW units(4x250MW) is considered as a candidate from 2018 onwards. The total capacity of the plant is limited to 1000MW.

g) 35MW Broadlands and 120MW UmaOya Hydro Power Plants are considered as committed plants in 2016.

h) LNG operated combined cycle power plant is considered as a candidate from 2018 onwards for all the scenarios.

i) 4MW Dendro Power Plant is modeled from the data received from Sustainable Energy Authority. Where the number of Dendro power plants allowable for a particular year of base case study was predefined. In scenario studies, total Dendro power plant capacity is limited to108MW.

j) 5x17 MW and 115MW Gas turbine plants at Kelanitissa will be retired in January 2019 and January 2023 respectively.

k) 4x18 MW power plants at Sapugaskanda will be retired in 2019. 8x9MW Sapugaskanda extensions will be retired in two stages in January 2023 and January 2025.

l) Term of contracts of IPP Plants; 22.5MW Lakdhanavi, 20MW ACE Power Matara and 20MW ACE Power Horana , expired in 2012 will be extended by 5 years until January 2018 by following the policy framework developed for the extension of IPPs.
   - Refurbishment and operational cost data were obtained from the proposals received by the Energy Purchases Branch of CEB.
   - Following studies were carried out to check the economic viability of the extension of IPP plants expired in 2012: .
     - With No IPP extensions.
     - ACE Matara, Horana and Lakdhanavi with 5 year extension.
     - ACE Matara, Horana 5 year and Lakdhnavi 2 year extension.
     - ACE Matara and Horana 5 Year extension.

   It was found that extension of all three plants by 5 years would be beneficial.

m) The contracts of 60 MW Colombo Power, 100MW Heladanavi and 100MW ACE Embilipitiya will expire in 2015.Contracts of 20MW Northern Power and 49 MW Asia Power Plant will expire in 2018. In addition, the contract of 163 MW AES Power Plant at Kelanitissa will expire in 2023.

n) 27MW Moragolla and 49MW Gin Ganga Hydro Power Plants are considered as candidates from 2018 and 2024 onwards respectively.

o) 600MW Nuclear Power Plant considered as a candidate from year 2030 onwards.

p) Net generation values were used in planning studies instead of gross values.

CHAPTER 7
RESULTS OF GENERATION EXPANSION PLANNING STUDY

7.1 Results of the Preliminary Screening of Generation Options

For the preliminary screening exercise, a coal fired steam plant, two oil fired steam plants, three oil-fired gas turbines, two oil fired combined cycle plants, LNG fired combined cycle plant and nuclear plant are considered. Discount rate, 10%, which is considered as the base discount rate of the planning studies, is used for the preliminary screening of options. The sensitivity of the preliminary screening is tested for 3% and 15% discount rates. The specific generation costs for selected thermal plants calculated for 3%, 10% and 15 % discount rates are shown in Annex 7.1.Comparing alternative plants with varying capital investments, Operation costs, Maintenance costs and life time etc., it is necessary to employ an indicator common for all plants. Specific generation cost expressed in US Cents/ kWh calculated at different plant factors for all available thermal plants was used to screen unscreened options before carrying out expansion planning studies.

From the screening curves, the following candidate technologies were selected as suitable options for future generation expansion planning studies.

- 150 MW Oil fired steam plants
- 300 MW Oil fired steam plants
- 300 MW Coal fired steam plants
- 75 MW Auto diesel fired gas turbines
- 105 MW Auto diesel fired gas turbines
- 150 MW Auto diesel fired combined cycle plants
- 300 MW Auto diesel fired combined cycle plants
- 250 MW LNG fired combined cycle plants
- 600 MW Nuclear plants

Detailed generation planning studies are conducted based on the above results in order to identify the least cost plant sequence to meet the base forecast demand.

7.2 Base Case Plan

The Base Case Plan is given in Table 7.1 and required capacity additions according to the Base Case Plan are given in the Table 7.2. In this study, committed power plants have been fixed according to the present implementation schedule.

The net present value (NPV) of the Base Case Plan including the cost of NCRE for the period 2013-2032 is USD 13,740million (LKR 1,564,983 million) in January 2012 values.

Generally, in LTGEP studies only the costs which affect future decision making are considered. Hence the capital costs of committed plants and expenditure arising out of capital costs of existing plants (e.g. loan repayment of CEB plants or capacity payment to IPP plants) are not reflected in the total least system cost (PV) which is the optimized result of WASP studies.

The reference case was developed following the PUCSL guidelines in addition to the Base Case Plan. Considering only the NCRE power plants in operation as of 1st January 2013, The Net present value (NPV) of the PUCSL reference case plan for the period 2013-2032 is USD 13,637 million.

Table 7.1 – Generation Expansion Planning Study – Base Case (2013 – 2032)

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	-	-	-	1.155
2014	-	*4x5 MW Northern Power** *3x8 MW Chunnakum Extension** *1x300 MW Puttalam Coal (Stage II)*	-	0.819
2015	-	*1x300 MW Puttalam Coal (Stage II)* **1x75 MW Gas Turbine** **1x105 MW Gas Turbine**	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.103
2016	*35 MW Broadlands* *120 MW Uma Oya*	-	-	0.854
2017	-	**1x105 MW Gas Turbine**	-	1.320
2018	**27 MW Moragolla Plant**	**3x250 MW Trincomalee Coal Power plant**	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi 4x5 MW Northern Power 8x6.13 MW Asia Power	0.133
2019	-	**1x250 MW Trincomalee Coal Power plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.183
2020	-	**1x300 MW Coal plant**	-	0.106
2021	-	**1x300 MW Coal plant**	-	0.067
2022	-	**1x300 MW Coal plant**	-	0.048
2023	-	**1x300 MW Coal plant**	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.134
2024	-	**1x300 MW Coal plant**	-	0.102
2025	-	**1x300 MW Coal plant**	4x9 MW Sapugaskanda Diesel Ext.	0.099
2026	-	-	-	0.346
2027	-	**1x300 MW Coal plant**	-	0.310
2028	-	-	-	0.804
2029	**49 MW Gin Ganga**	**1x300 MW Coal plant**	-	0.633
2030	-	**1x300 MW Coal plant**	-	0.654
2031	-	**1x300 MW Coal plant**	-	0.697
2032	-	**1x75 MW Gas Turbine**	-	1.469
Total PV Cost up to year 2032, **US$ 13,740.02 million** [LKR 1,564,983.12 million]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9)
- All additions/retirements are carried out at the beginning of each year.
- Committed plants are shown in Italics.
- Above PV cost includes the cost of Projected NCRE, US$ 689.98 million and five year IPP extension cost (ACE Matara, ACE Horana and Lakdanavi), US$ 9.83 million. It is recommended to negotiate for a better price if these plants need to be extended.
- All plant capacities are given in gross values.

  * Year of connection to national grid based on the estimated time schedule of Kilinochchi-ChunnakkamTx line.

Table 7.2– Generation Expansion Plan 2013–2032Base Case Capacity Additions

Year	Peak Demand (MW)	Capacity Addition (MW) Medium Term Diesel	Gas Turbine	Coal	Major Hydro	NCRE	Total	LOLP (%)
2013	2451					73	73	1.155
2014	2692	44		300		27	371	0.819
2015	2894		180	300		26	506	1.103
2016	3017				155	116	271	0.854
2017	3193		105			27	132	1.320
2018	3383			750	27	45	822	0.133
2019	3556			250		38	288	0.183
2020	3731			300		41	341	0.106
2021	3920			300		36	336	0.067
2022	4125			300		27	327	0.048
2023	4287			300		23	323	0.134
2024	4499			300		25	325	0.102
2025	4717			300		39	339	0.099
2026	4948					26	26	0.346
2027	5187			300		25	325	0.310
2028	5369					26	26	0.804
2029	5625			300	49	16	365	0.633
2030	5893			300		26	326	0.654
2031	6171			300		26	326	0.697
2032	6461		75			26	101	1.469
Total		44	360	4600	231	714	5949	

7.2.1 System Capacity Distribution

Capacity additions by plant type are summarised in five year periods in Table 7.3 and graphically shown in Figure 7.1. The major share of the total capacity (75.7%) is from coal-based power plants. Hence coal-fired thermal power plants will play an important role in the supply of future electricity demand of Sri Lanka. In 2015, 1 x 75MW gas turbines and 1 x 105MW gas turbine are selected and another 1 x 105MW Combined cycle plant is selected in 2017. Three units with the capacity 250 MW each of the Trincomalee Coal power plant are selected in 2018 and another one unit selected in 2019. Two major hydro plants,27 MW Moragolla and 49 MW Gin Ganga hydro power plants are selected in 2018 and 2029 respectively. Also in 2020 and onwards several units of 300MW Coal power plants are selected.

Present dispatchable installed capacity of the system is approximately 2,970 MW and it will increase to6, 958 MW by the year 2032. Within the next 20 years, a capacity of 5004 MW thermal plants needs to be added to the system while 900 MW of thermal plants will be retired. Present share of the thermal capacity 49% will be increased to 68% by the year 2032. The present thermal capacity consists of petroleum fuel based plants and coal plant. New thermal capacity to be added to the system by 2032 is in the form of diesel plants, gas turbines and coal plants. The percentage variation of hydro-thermal share of capacity over next 20 years is shown in Figure 7.2. The capacity wise renewable share is given in Figure 7.3. The capacity balance of the system with NCRE/ non-dispatchableduring the planning horizon is given in Annex 7.2.

Table 7.3– Capacity Additions by Plant Type

Type of Plant	2013 - 2017 (MW)	2018 - 2022 (MW)	2023-2027 (MW)	2028-2032 (MW)	Total capacity addition (MW)	Total capacity addition %
Major Hydro	155	27		49	**231**	3.88%
NCRE	269	187	138	120	**714**	12.00%
Coal	600	1900	1200	900	**4600**	77.32%
Gas Turbines	285			75	**360**	6.05%
Medium Diesel	44				**44**	0.74%
Total	**1,353**	**2,114**	**1,338**	**1,144**	**5,949**	100.00%

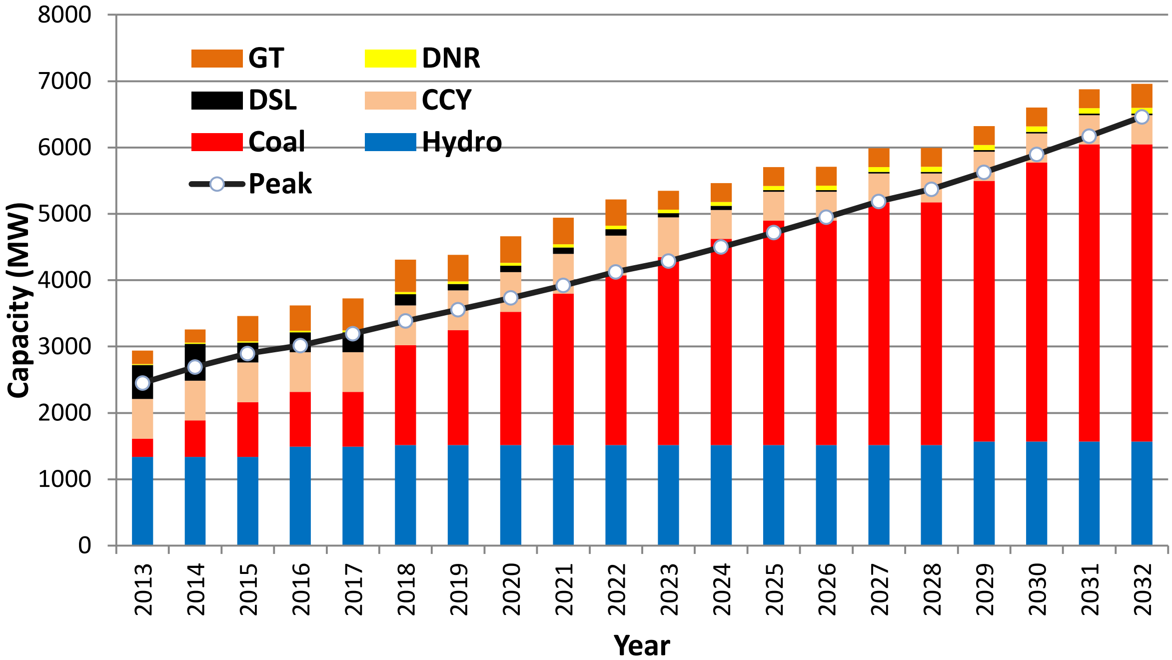


Figure 7.1 –Cumulative Capacity by Plant Type in Base Case

*****NCRE non-dispachable capacity is not included

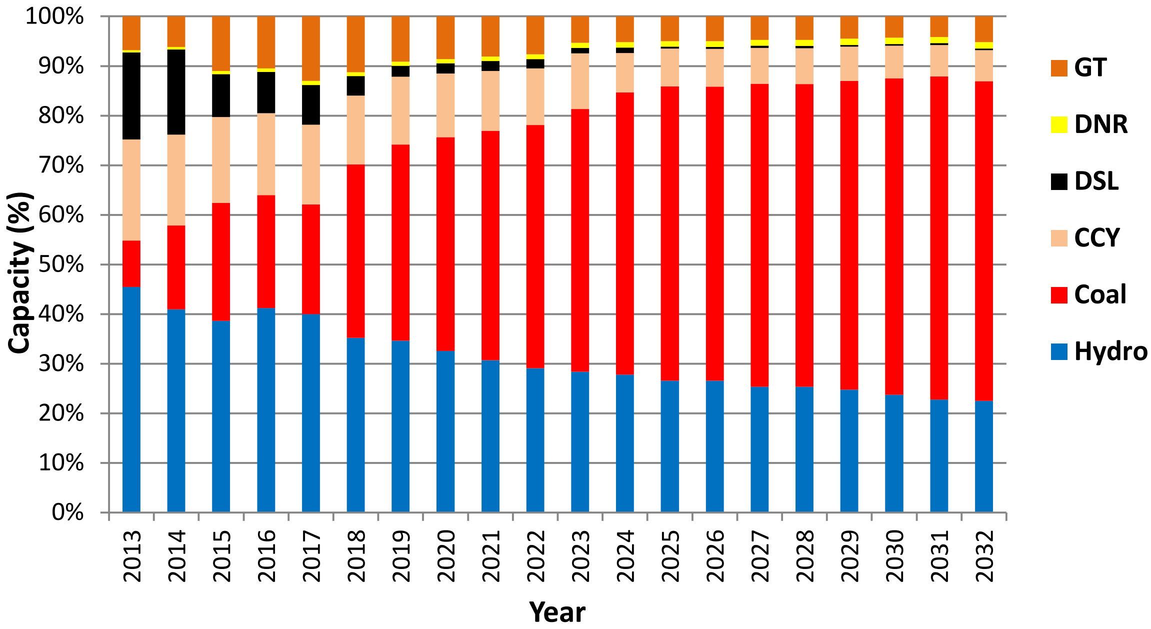


Figure 7.2 – Capacity Mix over next 20 years in Base Case

*NCRE non-dispachable capacity is not included

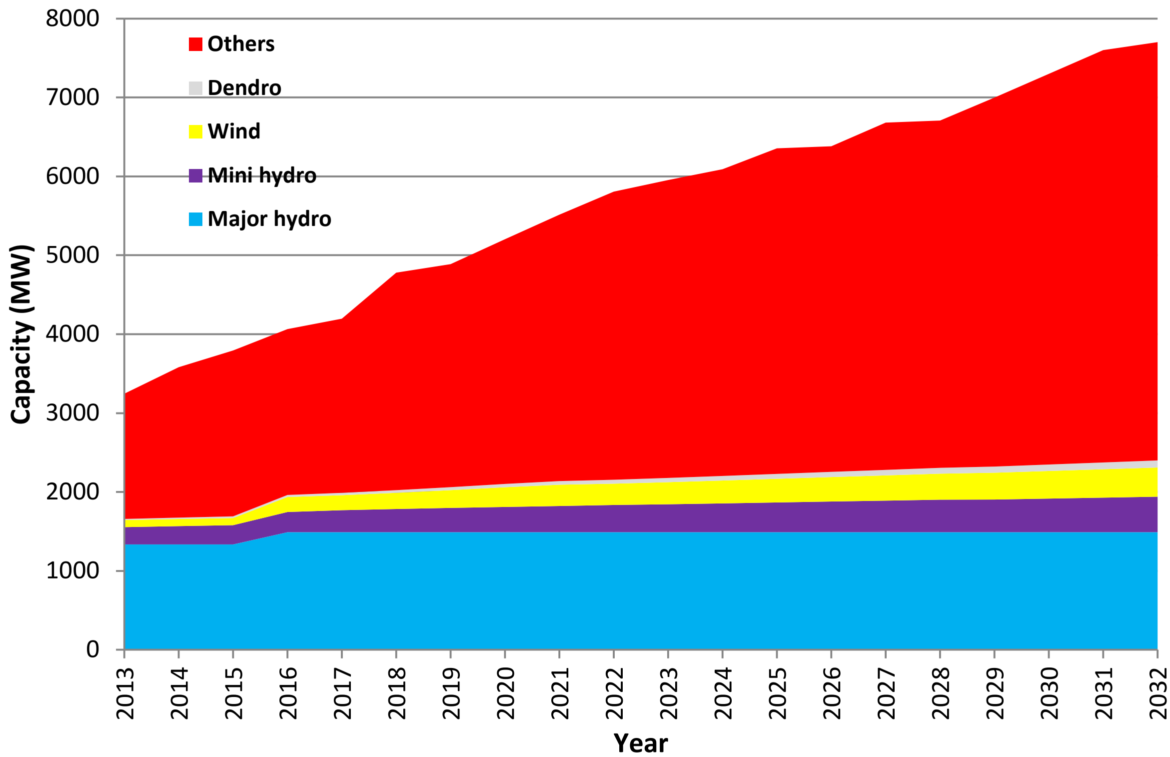


Figure 7.3 – Capacity wise Renewable Contribution over next 20 years

7.2.2 System Energy Share

In 2013, the thermal plants will meet 61% of the energy demand. By the year 2017, 2025 and 2032 thermal plants will supply 65%, 75% and 80%of the energy demand respectively. The distribution of thermal energy supply between coal and petroleum based fuels varies with fuel prices. Energy supply situation of the power system based on the plant types is graphically represented in Figure 7.4. Percentage share is given in Figure 7.5 While energy balances of the system is given in Annex

7.3annual expected generation and plant factors under different hydro conditions for the Base Case Plan are given in Annex 7.4. Energy source based renewable contribution is indicated in Figure 7.6 and Figure 7.7 shows the renewable share for the study period.

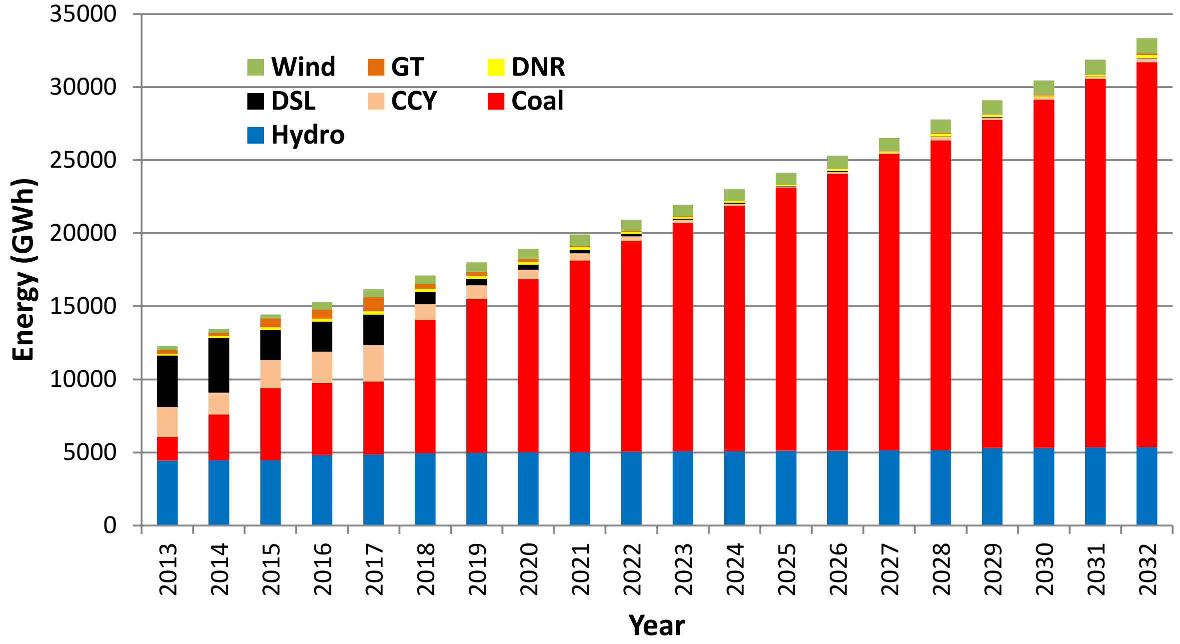


Figure 7.4– Energy Mix over next 20 years in Base Case

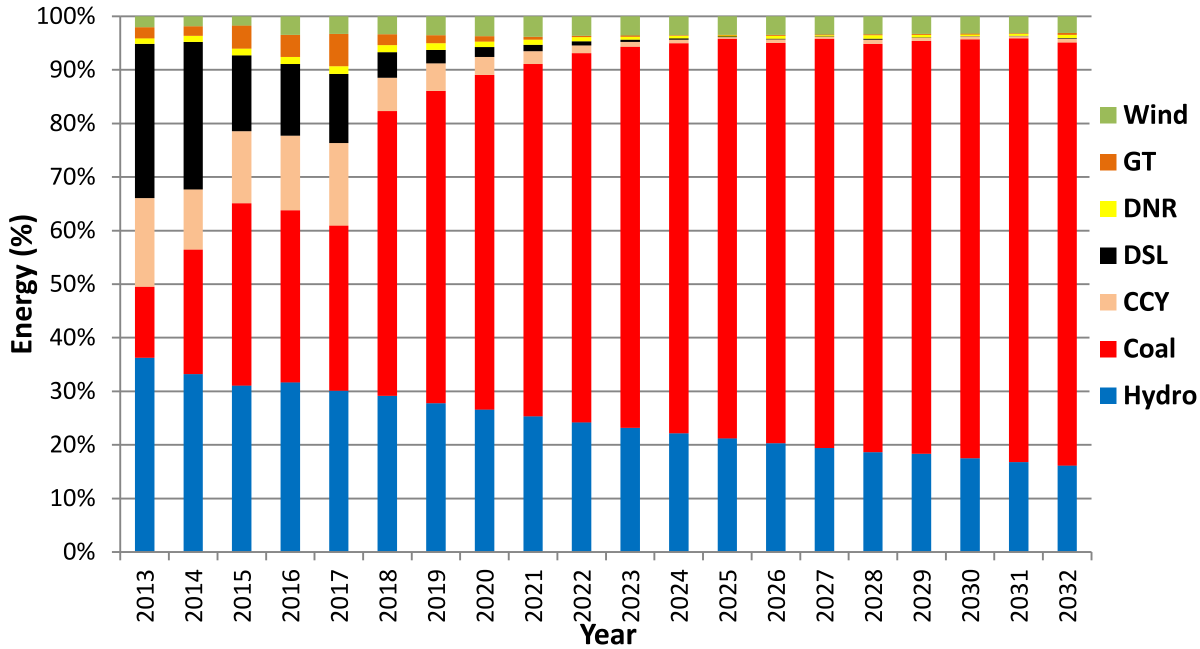


Figure7.5 – Percentage Share of Energy Mix over next 20 years in Base Case

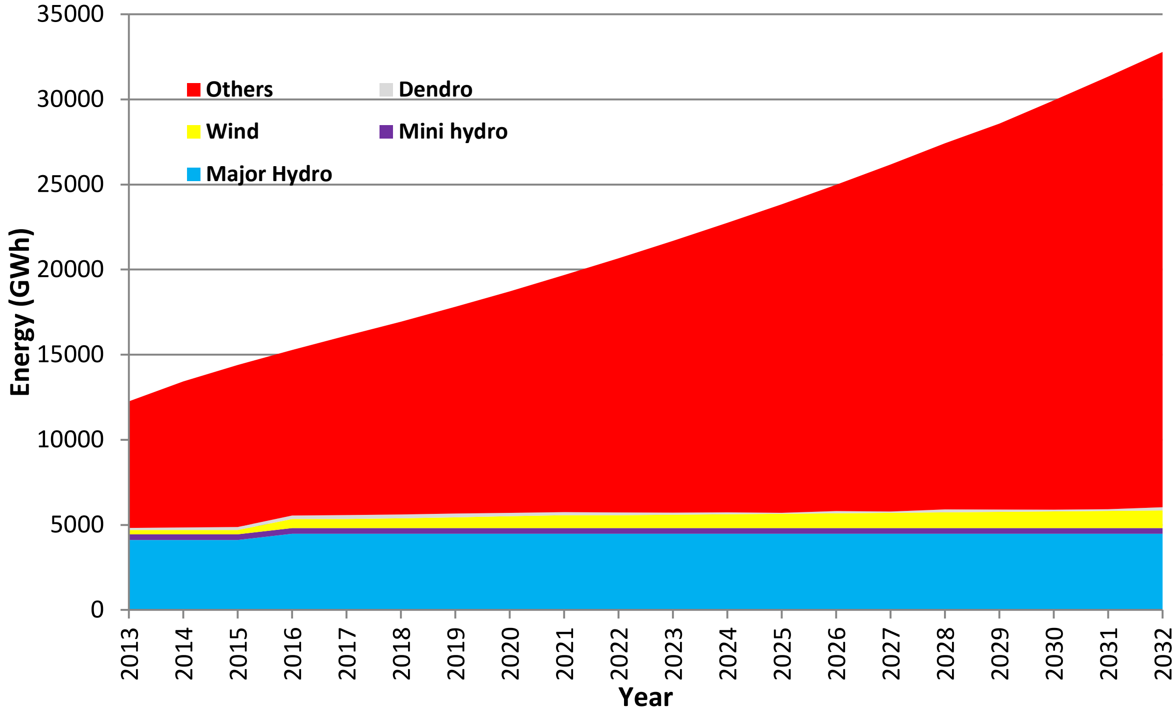


Figure 7.6 –Renewable Contribution over next 20 years based on energy resource

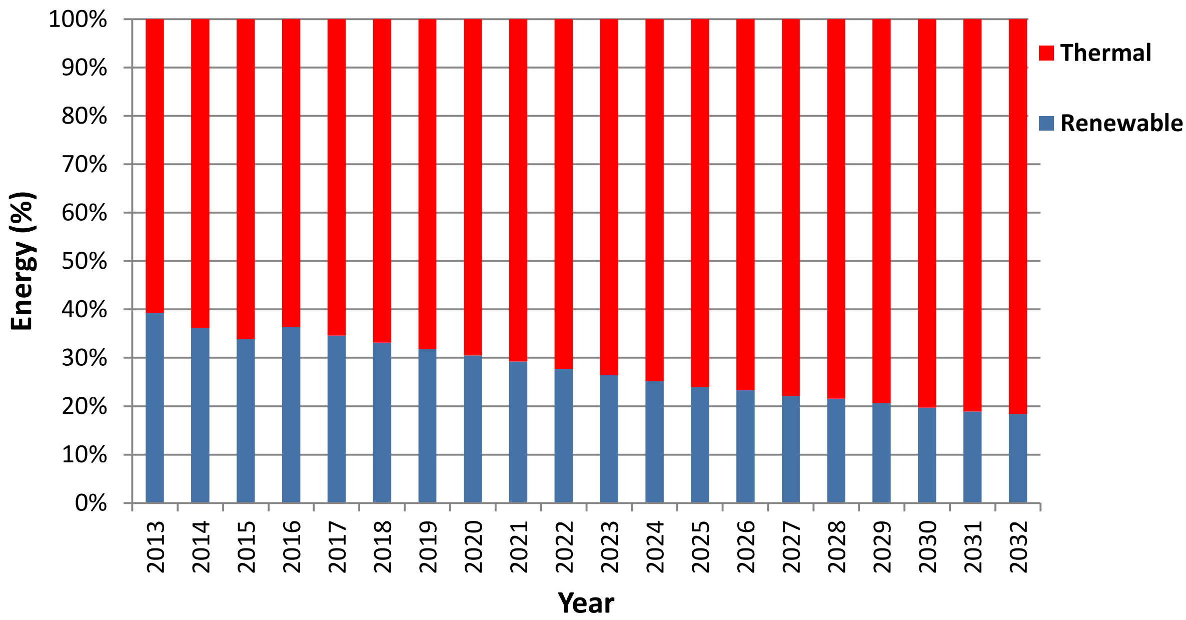


Figure 7.7 Percentage Share of Renewables over next 20 years in Base Case

7.2.3 Fuel, Operation and Maintenance

The expenditure on fuel, operation and maintenance (O&M) over the period 2013-2032 is summarized in Table 7.4. Fuel quantities required and the expenditure on fuel over the next 20 years for Base Case Plan is given in Annex 7.5. Fuel requirement is graphically represented in Figure 7.8.Fuel cost up to year 2032 is expected to be in the order of around 24,316MUSD.

Table 7.4 - Cost of Fuel, Operation and Maintenance in Base Case

Units: million US$

Year	Operation and Maintenance			Fuel
	Hydro	Thermal	Total	
2013 – 2017	45.2	561.6	606.8	6250.1
2018 – 2022	50.7	489.5	540.2	5059.1
2023 – 2027	52.3	649.3	701.6	5596.0
2028 – 2032	55	864.3	919.3	7411.6

Total fixed and variable O&M cost over next 20 years is in the order of about 2768 MUSD.

The base expansion plan shows that the consumption of fossil fuels in the power sector is rising considerably. A coal power plant of capacity 300 MW consumes coal at a rate of 826,000 tons per annum. With the increased use of coal, the consumption of oil will be reduced drastically. In year 2013, about 1,004,960 tons of heavy fuel (residual and fuel oil) will be burnt in all power stations. This consumption will be reduced to 15,760 tons in 2025. Diesel consumption is expected to be 155,480 tons in 2013 and 4,720 tons in 2025.

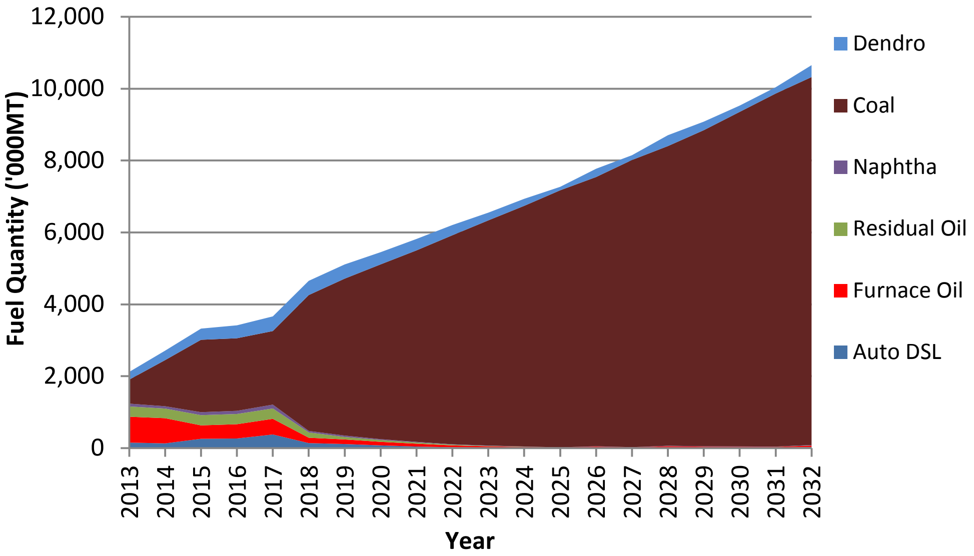


Figure 7.8- Fuel Requirement in Base Case

7.2.4 Reserve Margin and LOLP

Comparably high LOLP is expected in initial years from 2013 up to 2018. Three IPP thermal plants which are scheduled to retire in 2013, considered to be in operation for five more years. Slight improvement of LOLP could be observed in 2014 with the commissioning of the first unit of Puttalam Coal Project Stage 2, while in the same year national grid will extend to the Jaffna peninsula. With a major thermal retirement in 2015, LOLP has increased although the second unit of Puttlam Coal Project Stage 2 is commissioning in the same year. Hydro plant additions (Broadlands and Uma Oya) are expected in 2016. Sudden reduction of LOLP observed with the commissioning of Trincomalee3 x 250MW coal plants in 2018 and remaining 1 x 250 MW unit in 2019. LOLP and Reserve Margin variation over the planning period for the Base Case is given in Figure 7.9.

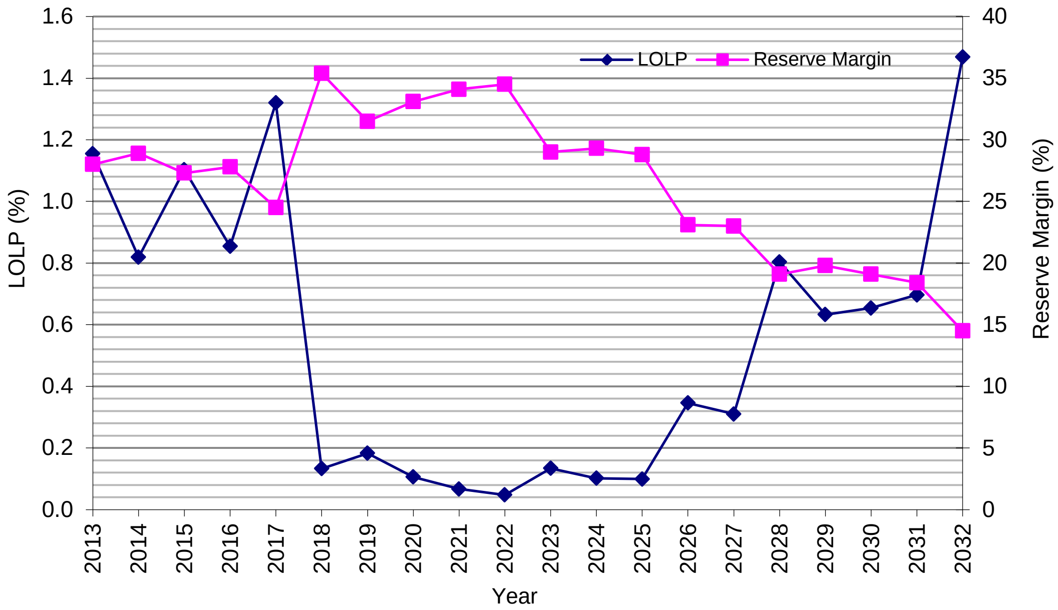


Figure 7.9 – Variation of Reserve Margin and LOLP in Base Case

7.2.5 Investment, Pricing and Environmental Implications

Investment requirement for the Base Case Plan is discussed in Chapter 8. Environmental implications of the Base Case Plan are presented in chapter 9. Deviations of the base plan from previous year plan are discussed in Chapter 10.

7.3 Demand Effect on Base Plan

Low demand and high demand growth cases were analyzed in order to identify the demand effect on the base plan. Intermediate high demand growth case was also considered for the comparison with the Base Case Plan. Low demand growth scenario constructed by applying Demand Side Management (DSM) to the Base Demand forecast which is described in section 7.9. This demand deviation leads to 17.2% reduction in the total present worth cost of the base case over the planning horizon. Demand growth in intermediate high demand forecast is 6.5% which is 1.3% higher than the growth in base case demand forecast. Demand growth in high demand forecast is 7.4%. This demand increase results an increase of 17.1%for intermediate high demand and 30.8% for the high demand in the total present worth cost of the base case over the planning horizon. The expansion plans for the high, intermediate high and low demand cases are given in Annex 7.7, 7.24and 7.8respectively.The respective demand forecasts used for the sensitivities are given in Annex 3.1.

7.3.1 Capacity Distribution

Figure 7.10 shows the capacity additions in selected years of Low, Intermediate High and Base demand cases. In comparison with base case, the requirement of coal plant capacity in low demand case is reduced by 900 MW and the gas turbine capacity is decreased by 180 MW over the period 2013 – 2032. In contrast1800MW of coal plants,105 MW of gas turbines and 300 MW of Combined Cycle plant are required to meet the intermediate high demand case over the period 2013 – 2032.

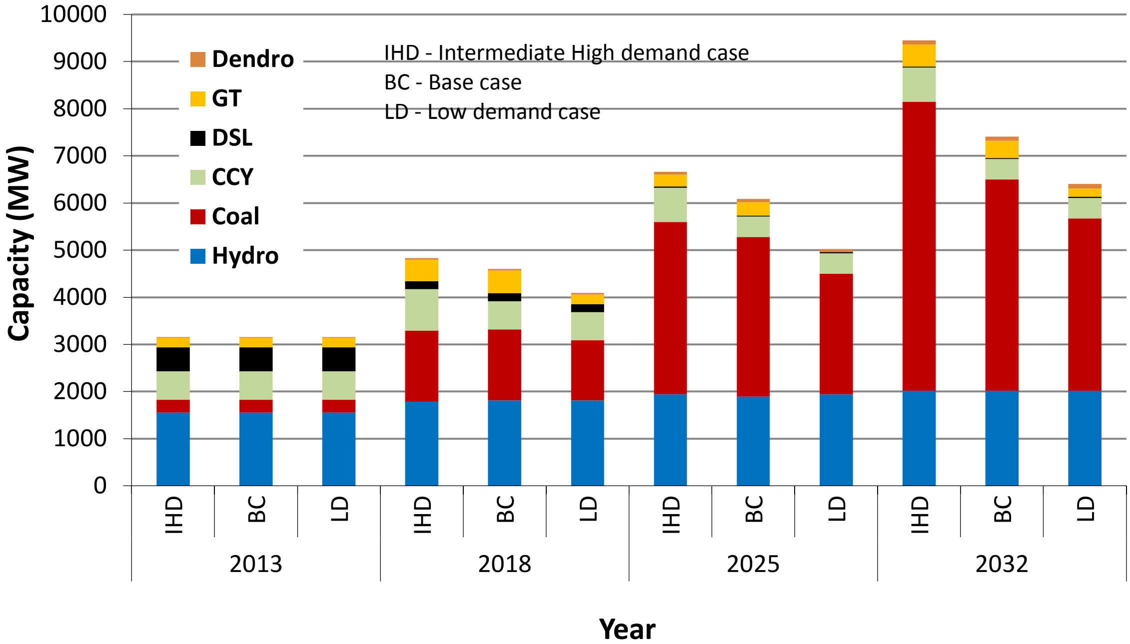


Figure 7.10- The Capacity Additions in Low, Intermediate High and Base Demand Cases

7.3.2 Fuel requirement

Similar to the capacity requirement, to meet the increased demand over the period 2013 – 2032 the consumption of coal increases as elaborated in Figure 7.11.

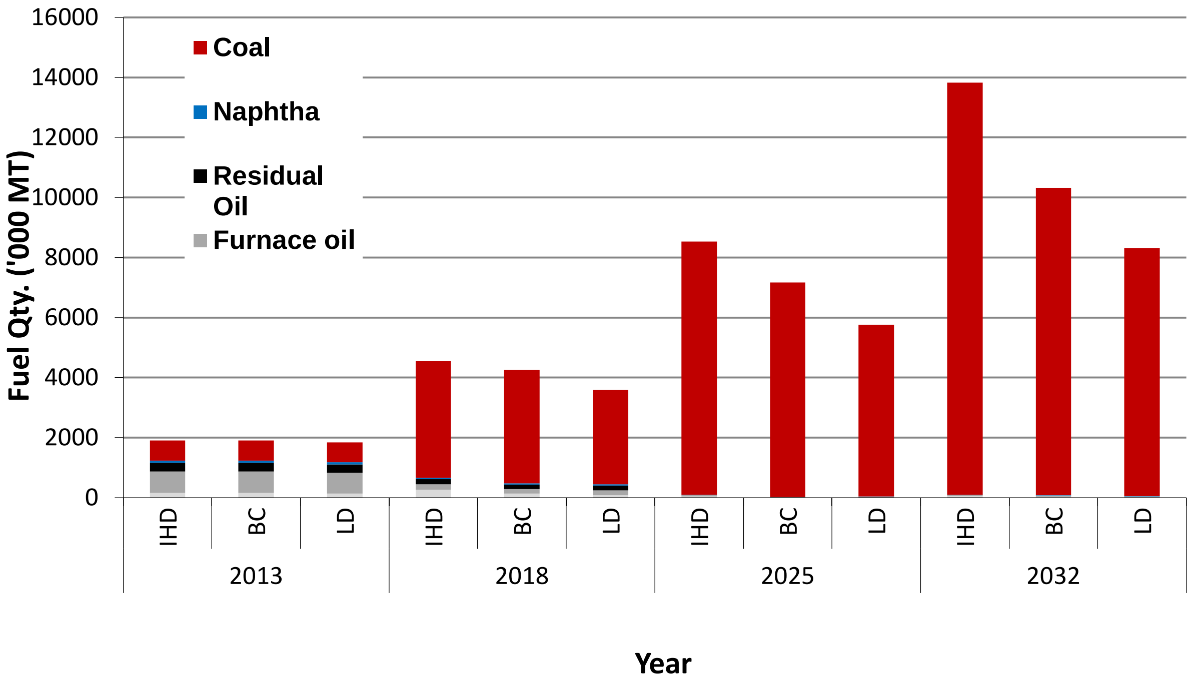


Figure 7.11 - Fuel Requirements in Low, Intermediate High and Base Demand Cases

7.4 Effects of Discount rate on Base Case Plan

To analysis the effect of discount rate on Base Case Plan, two additional generation expansion planning studies were carried for discount rates 15% and 3%and plant sequences for the same are given in Annex 7.9and Annex 7.10respectively.

7.4.1 Capacity Distribution

Considering both these cases, the major significant change in capacity is that the Moragolla hydro power project is not selected in high discount rate case. For low discount rate case, Morogalla plant has picked up in 2018, gas turbine capacity is reduced by75MW and 300MW more coal plants are selected. For high discount rate case,45MW more gas turbines have been selected but coal plant capacity requirement remains same.

7.4.2 Fuel requirement

There is a slight reduction of fuel requirement in low discount rate case compared to the high discount rate case due to selection of Moragolla hydro plant and the reduction of120 MW of gas turbine capacity.

7.5 Effect of Cost of Energy Not Served (ENS) over Base Case

In high ENS cost case, the base case plan was re-optimised with 0.8USCents for a unit of energy not served (50% increase) against the value of 0.53USCents in the base case and observed no significant difference between the two results in plant selection. The effect of the variation of ENS cost on the total cost is quite small compared to the effect of other factors.A 50% increase in ENS cost would result a 0.11%increase in the total cost during the planning horizon (i.e.14.7 million USD). The resulting plan of high ENS case is shown in the Annex 7.11.

7.6 Fuel Price Effect on Base Case Plan

The fuel prices used for the base case analysis were based on a crude oil price (CIF) of 110.1 US$/bbl anda coal (West Coast CIF) price of 142.8 USD/t and constant fuel prices were used for the study period. Two high fuel price scenarios were performed. One scenario assumed a 50% increase in all petroleum and coal prices and LNG price remain unchanged. In the other, a 50% increase in coal price was assumed and petroleum and LNG price main unchanged. An increase in 50% in petroleum and coal prices would increase the total cost over the planning horizon by 4791.6million USD, which is equivalent to 34.9% of the total cost. Similarly an increase of coal price by 50% would lead to increase the total cost over the planning horizon by 2486.7million USD (i.e., equivalent to 18.1%of the total cost). However, LNG plants are not selected although coal price is increased by 50%.
The plant sequence for 50% increase in petroleum and coal price with base LNG price case is given in Annex 7.12. The scenario for 50% increase in coal price with base petroleum and base LNG price case is given in Annex 7.13.

7.7 High NCRE Scenario

The base case plan was re-optimized considering a high NCRE penetration to achieve 20% energy share from NCRE by year 2020. The projected NCRE development used for this scenario is given in Annex 5.2 and resulting plan is shown in Annex 7.14.

7.8 Restricted Coal Development to achieve Energy Security

Case (i) :- No Coal Plants permitted after Trincomalee 1000MW Development

The Scenario was studied to find out the impact of restricting the non-committed Coal Development to 1000MW (total Coal development 1900MW inclusive of 900MW Puttalam CPP). It was assumed that in such a case 1000MW limited development would occur in Trincomalee in 250MW units. The resulting plan is shown in Annex 7.15.

Case (ii) :- No Coal Plants permitted after year 2025

The Scenario was studied by restricting the coal development after year 2025 onwards to analyze the impact on the least cost generation expansion schedule and resulting plan is shown in Annex 7.19.

Case (iii) :- Coal Plants Limited to 60% of Total Generation

To analyse the energy security options, scenario was studied by imposing 60% limit on coal power development to find out the impact on financial implications on the least cost generation expansion plan. The provisional energy dispatch and percentage from Coal, LNG and Nuclear from the total energy are given in Table 7.5 and resulting plan is shown in Annex 7.15.

Table 7.5 Energy share in percentage for coal restricting to 60% case

Year	Coal (GWh)	Coal (%)	LNG (GWh)	LNG (%)	Nuclear (GWh)	Nuclear (%)
2013	1625	14%	-	-	-	-
2014	3128	23%	-	-	-	-
2015	4911	34%	-	-	-	-
2016	4923	32%	-	-	-	-
2017	4990	31%	-	-	-	-
2018	9100	53%	-	-	-	-
2019	10491	58%	-	-	-	-
2020	10782	57%	1301	7%	-	-
2021	11001	55%	1907	10%	-	-
2022	12562	60%	1598	8%	-	-
2023	13049	59%	2186	10%	-	-
2024	13243	57%	2989	13%	-	-
2025	14911	61%	2627	11%	-	-
2026	15218	60%	3409	13%	-	-
2027	15504	58%	4237	16%	-	-
2028	15699	56%	5108	18%	-	-
2029	17524	60%	4505	15%	-	-
2030	17742	58%	5590	18%	-	-
2031	16238	51%	4552	14%	3774	12%
2032	17936	53%	4357	13%	3730	11%

The LNG price (CIF) of13.5 US$/MMBTU was used in the study as a benchmarking LNG price for Sri Lanka is not available. The price was based on the 2009 average import price of Japan obtained from the 2010 LNG study [29].However at present LNG market price vary between 15–18US$/MMBTU.

In Coal restricted cases, LNG price of 13.5 US$/MMBTU was used and combined cycle plants using LNG were included to the candidate plant list. In this case LNG plants were selected.

Capacity and fuel requirement for the high NCRE, Coal restricted and fuel options introduction for energy security scenarios in comparison with the base case are given in Figure 7.14 and Figure 7.15 respectively. The Plant schedule for the three cases are given in Annex 7.14, Annex 7.15, Annex 7.16and Annex 7.19 respectively.

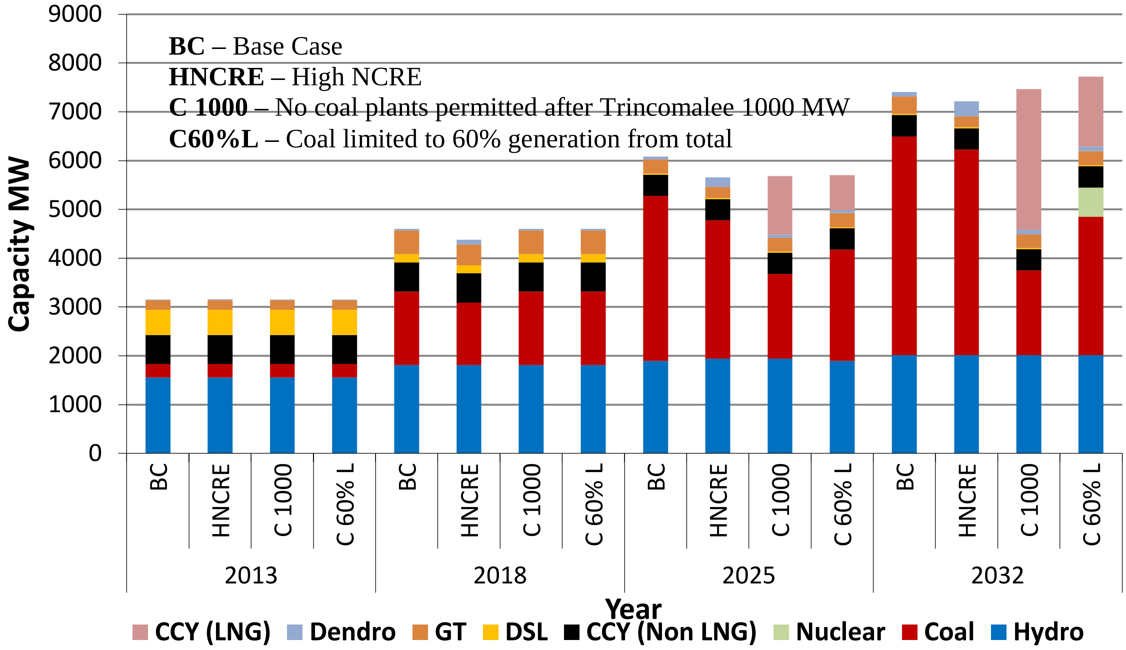


Figure 7.12– Capacity Mix of High NCRE, Coal Restricted, Coal Limited (60%) andBase Case

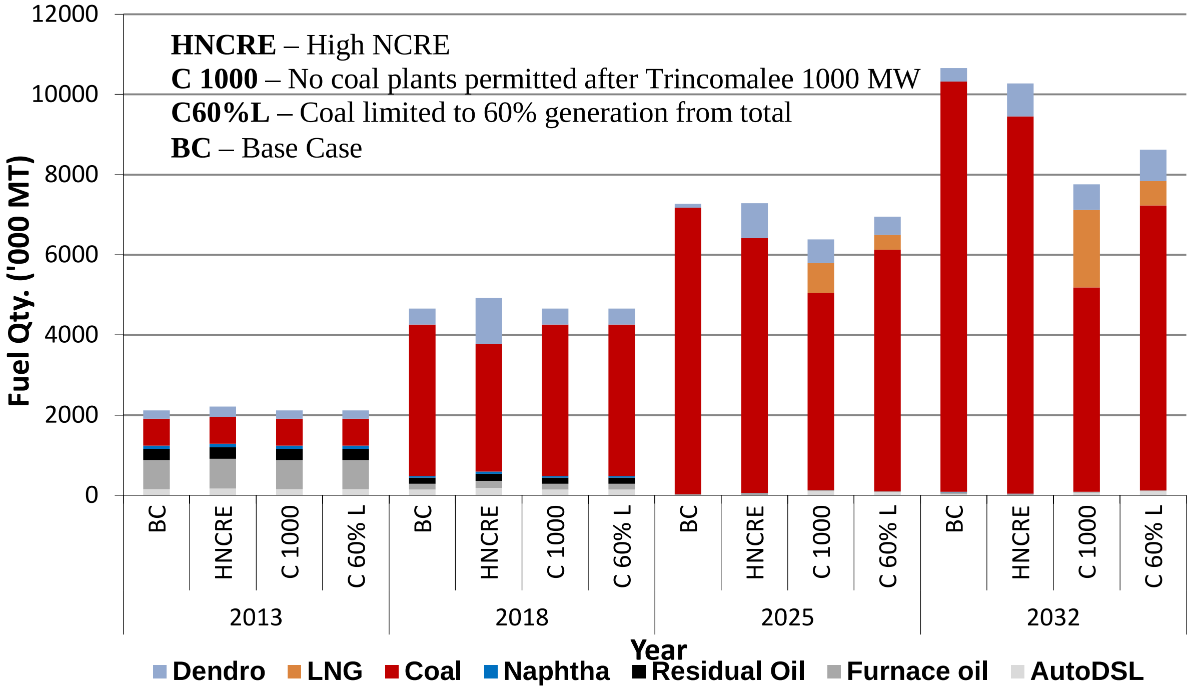


Figure 7.13– Fuel Requirement of High NCRE, Coal Restricted, Coal Limited (60%) and Base Case

Further a scenario was studied with Dendro as a candidate plant. The practical aspects of fuel wood supply were not considered but a reasonable time limitation for annual development in initial years was applied. The investment cost used was 1767.4 USD/kW and the fuel cost used was 5.5 LKR/kg. Fixed operation and maintenance cost was taken as 3.07 USD/kW/month and the variable O&M cost was taken as 5.62USCents/kWh. In order to promote the domestic preference for the locally available fuel wood, 10% price reduction was applied for the fuel cost of Dendro plants.The data for the studies were provided by SLSEA and the results of the expansion schedule are attached as Annex 7.17.

It is observed that a total of 108 MW of Dendro plants within the given development parameters are selected in addition to existing plants in the base case.

7.9 Determination of LNG Fuel Breakeven price and CDM Benefits

Studies were carried out to determine the breakeven price of Natural Gas. The LNG price (CIF) of 13.5 US$/MMBTU was used in the Base Case study. However, at present market price is varied between 15 -18 US$/MMBTU. It is assumed that 1MTPA LNG terminal could cater 4 x250MW of CCY LNG Plants and terminal cost is apportioned among the 4 plants equally for the reasonable comparison purposes.

The breakeven price of LNG was found as 8.2 US$/MMBTU without applying any CDM (Clean Development Mechanism) benefit. Considering CER (Certified Emission Reduction) price of 14.2 US$/MT (Source: Carbon Market, World Market Report), LNG Price will breakeven at price of 10.5 US$/MMBTU. The calculations were done without apportioning the ¼ of terminal cost in both cases.

Same breakeven prices were calculated with apportioning the ¼ of terminal cost and found that 8.0 US$/MMBTU without CDM benefit and 10.3 US$/MMBTU with CDM benefit for CER price of 14.2 US$/MT.

The same CER price of 14.2 US$/MT applied for the LNG plants, Dendro, wind and mini hydro plants in the Base case with CDM scenario and found that LNG plants are not selected in the Base case. The result of the expansion schedule is attached in Annex: 7.23.

7.10 Effect on Demand Side Management on Base Case

The DSM values given by SLSEA as energy saving targets were used in the studies without cost implication of implementation of such DSM action. The main objective of the SLSEA was to achieve energy saving target of 20% of year 2010 energy demand by year 2020. The same concept was applied throughout the planning horizon and the result of the expansion schedule is attached in Annex: 7.8. This DSM applied case to Base Case is considered as the low demand case which is discussed in section 7.3.

However, due consideration must be given to save energy through DSM activities in long term in order to obtain the maximum economic benefit to the Country.

7.11Social and Environmental Damage Cost Scenario

A scenario was studied to investigate the effect of coal power plants in the Base Case by giving a monetary value to the social and environmental damage. The damage cost 0.1 €-cent/kWh was taken from the report “Environmental Issues in the Power Sector: Sri Lanka”. The resulting expansion schedule is attached in Annex 7.20.No plants selection is observed in this scenario.

7.12 Pump Storage Plant and HVDC Interconnection Scenarios

The base case plan was re-optimized considering a pump storage forced construction and operation in year 2020 to analyze the impact of introducing Pump storage plant in to the system. The expansion schedule is attached in Annex7.18.

The base case plan was re-optimized considering a 500MW HVDC Interconnection between Sri Lanka and India and the expansion schedule is attached in Annex 7.22. The HVDC interconnection was opened for selection from 2020.Cost data for this study was taken from the report “India-Sri Lanka Grid Interconnection Study”.

7.13 Summary

The total net present values over the planning horizon for Base case and 20 different cases/ scenarios studied are summarized in Table 7.7.

Table 7.6 Comparison of the Results of Expansion Scenarios Studied

Case	Net Present Value during the planning horizon *	Deviation of NPV from Base Case	
	(Million USD)	(Million USD)	%
1. Base case	13,740.02		
2. PUCSL Reference case	13,637.26	-102.76	-0.7
3. High demand scenario	18,048.61	4,308.59	31.4
4. Intermediate High demand	16,089.64	2,349.61	17.1
5. Low demand scenario (DSM)	11,379.62	-2,360.41	-17.2
6. Discount rate 15 percent scenario	9,966.64	-3,773.83	-27.5
7. Discount rate 3 percent scenario	23,534.36	9,794.3	71.9
8. High ENS scenario (0.8USCents/kWh)	13,754.77	14.75	0.11
9. 50% increase in coal price scenario	16,226.68	2,486.657	18.1
10. 50% increase in coal and petroleum price scenario	18,531.59	4,791.57	34.9
11. High NCRE scenario	13,704.01	-36.02	-0.3
12. Trincomalee coal restricted to 2 units in 2018	13,803.18	63.16	0.5
13. Energy security scenario (Restricted Coal development to 60% and forced introduction of LNG and Nuclear)	14,857.54	1117.52	8.1
14. No more coal permitted after 2025 scenario	13,947.82	207.8	1.5
15. No more coal permitted after Trincomalee 1000 MW coal plants scenario	15,065.20	1325.17	9.6
16. HVDC candidate scenario	13,729.50	-10.52	-0.08
17. Dendro Plant candidate scenario	13,625.89	-114.14	-0.8
18. Base case CDM benefit scenario	13,527.43	-212.59	-1.5
19. Base case with Social and Environment Damage cost scenario	13,864.55	124.527	0.9
20. Pumped Storage forced construction and forced operation in year 2020 scenario	13,978.1	238.08	1.7

* The total PV cost up to 2032 is calculated by having the base year 2012 January

CHAPTER 8
IMPLEMENTATION AND FINANCING OF GENERATION PROJECTS

This Chapter elaborates on the required investment and the implementation plan for the generation projects in the base case and the issues related to that.

8.1 Committed Power Plants in the Base Case

8.1.1 Committed Plants

Puttalam Coal Fired Steam Plant stage – II (2x 300 MW), Broadlands Hydro Power Project (35 MW), Uma Oya Hydro Power Project (120 MW), CEB Chunnakam Power Extension (24 MW) and Northern Power (20 MW) (after the system integration of northern part of the island by 2014) have been considered as firmly committed in the present study.

8.1.2 Present Status of the Committed Power Plants

A brief description of the current status (as of end 2012) of the committed projects and proposed projects on which commitments should be made are given below.

1. Feasibility of the Broadlands hydro power project was investigated under the "Study of Hydro power Optimization in Sri Lanka" in February 2004 by the JICA consultants ‚J-Power and the Nippon Koei Co. Ltd., Japan [5]. Under this study several alternative schemes are studied by Central Engineering Consultancy Bureau (CECB) in 1989 and 1991 [6 and 7] were reviewed. Tenders have been called for construction of the project under Design & Build basis. The contractual agreement has been signed between CEB and the selected contractor.
2. Puttlam Coal Power plant: The government signed the agreement to construct the Puttlam Coal Power plant in Norochcholai in March 2006. Stage 1 of the project with the capacity 300 MW was commissioned in mid 2011. Construction of the stage 2 with the capacity 2x 300 MW is under way and the two units are expected to be commissioned in October 2013 and July 2014.
3. A Pre-feasibility study on *Uma Oya* Multi-purpose Project (a trans-basin option) was completed by the CECB in July 1991 [8] where the diversion of Uma Oya, a tributary of Mahaweli Ganga was studied. In 2001, SNC Lavalin Inc. of Canada was engaged to conduct the feasibility study on Uma Oya with the assistance of Canadian International Development Agency (CIDA). Financial agreement has been signed with the Government of Iran to commence the construction along with feasibility study. The contract affects from April 2010 and the plant is scheduled to be commissioned by end of 2015.
   Civil technical specifications have been already finalized and 90% Electrical technical specifications have been finalized with respect to the project progress in addition to the completion of access tunnels.

4. After the expected re-linking of national grid to the northern part of the island especially Jaffna peninsula an isolated generation system prevailed during the past at Chunnakam, will be added to the total generation option pool of Sri Lanka by 2014.
5. National Thermal Power Corporation (NTPC) of India and CEB had entered into a MOA on 29th December 2006 for the development of 2 x250MW Coal based thermal power project in Trincomalee forming a Joint Venture agreement. The detail technical negotiations are going on between NTPC and CEB to finalize the project development.
6. CEB has submitted a request to External Recourses Department of Sri Lanka to seek financial resources to construct next 2 x 250MW Coal power development identified in the least cost generation expansion plan in Trincomalee.

8.2 Proposed Power Plants in the Base Case

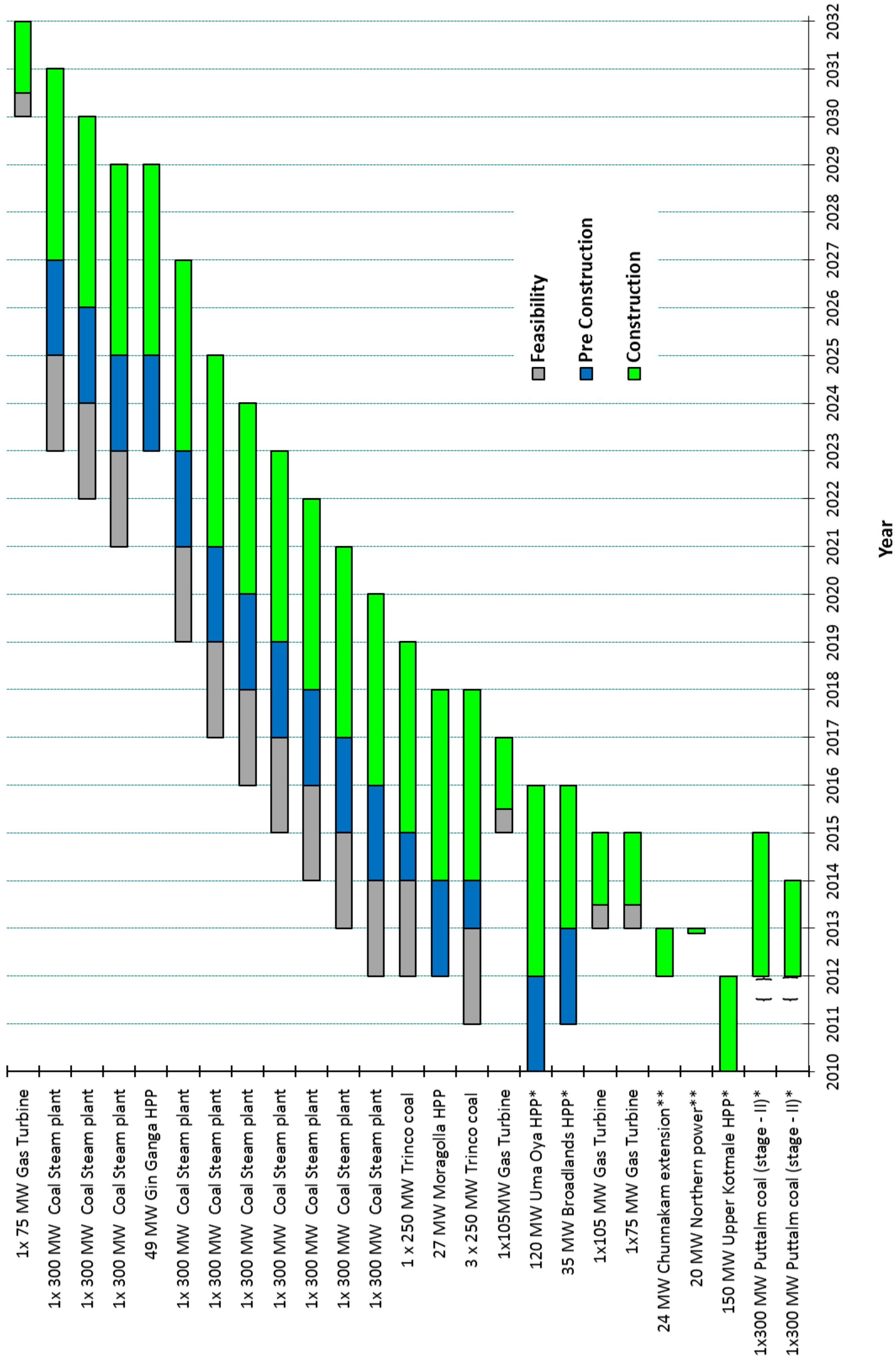
The proposed plants up to 2025 according to the base case are given below.

- (1x75) MW Gas Turbine in 2015
- (1x105) MW Gas Turbine in 2015
- (1x105) MW Gas Turbine in 2017
- (3x250) MW Trinco Coal in 2018
- (1x27) MW Moragolla HPP in 2018
- (1x250) MW Trinco Coal in 2019
- (1x300) MW Coal Plant in 2020
- (1x300) MW Coal Plant in 2021
- (1x300) MW Coal Plant in 2022
- (1x300) MW Coal Plant in 2023
- (1x300) MW Coal Plant in 2024
- (1x300) MW Coal Plant in 2025

In the present study, 2019 was considered as the earliest possible year of commissioning of the first candidate coal plant except Trincomalee 4 x 250MW coal power development.

8.3 Implementation Schedule

The implementation schedule for both committed and proposed power plants in the base case is shown in Figure 8.1.



*Committed Plants

** Year of connection to national grid in 2014

Plants assumed as in operation from 1st January each year

Figure 8.1 - Implementation Plan 2013 – 2032

8.4 Required Investment for Base Case 2013 – 2032

The annual investment requirement for the twenty year period from 2013 to 2032 is graphically shown in Figure 8.2. The details of the costs are tabulated in Table 8.1. Costs with regard to committed/on-going projects are not included in this table, and only new projects' investments are included.

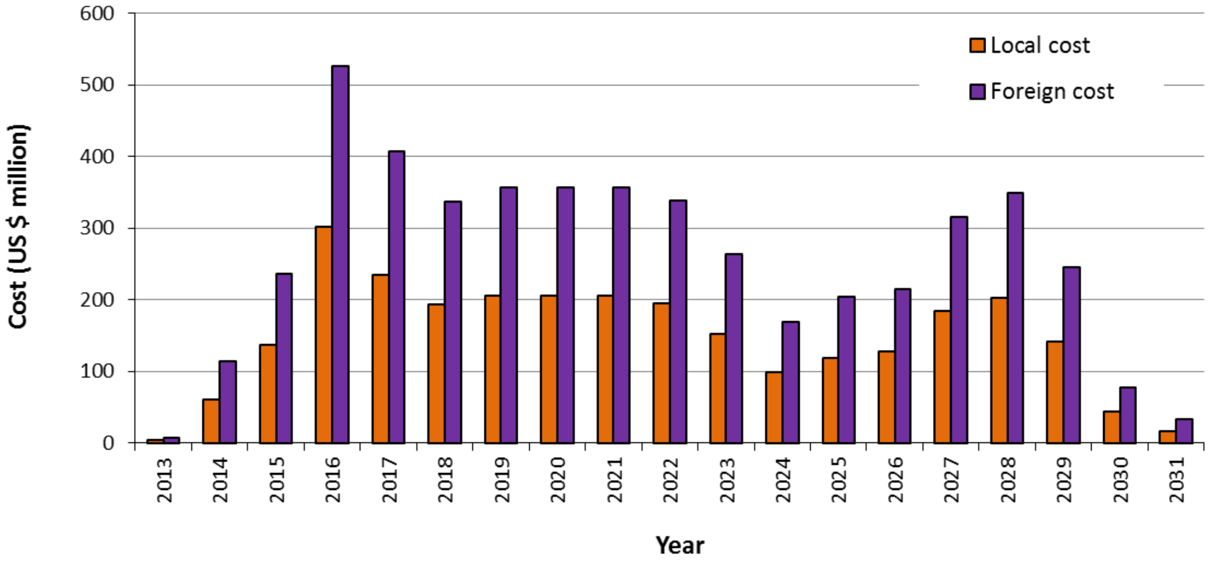


Figure 8.2 - Investment Plan for Base Case 2013 – 2032

8.5 Recommendations for Base Case

It is observed that the system can operate within the LOLP used even in year 2013. Main reason for this is the availability of adequate installed capacity and dependable committed plants that are under construction.

The major recommendations for Revised Base case;

(a) To ensure the on time implementation of the 2x300 MW Coal plant at Puttalum.

(b) To ensure the implementation of Broadlands and Uma Oya (hydro power projects) as per scheduled.

(c) To ensure the implementation of 3x 250MW coal power plant in year 2018 and 1x250MW in year 2019 at Trincomalee.

(d) To identify a suitable location for the remaining coal plants identified in the base case plan and to carry out feasibility studies.

(e) To take an early decision with regard to the Gas Turbines requirement in 2015 and 2017.

(f) Requirement of a self-start standby generator for Puttalam coal plant has been identified. Therefore, it is recommended to add a standby generator to Puttalam Coal Power Station on an urgent basis from the identified Gas Turbines in the plan.

8.6 Investment requirement variation for scenarios

The investment requirements for following scenarios are compared against the base case investment requirement.

1. Sensitivity of investment due to Intermediate High and Low Demand.
2. Sensitivity of investment due to Discount Rate.
3. Coal development Restricted to 60% of energy mix.
4. Introduction of Pump Storage Power Plant.

Figure 8.3 shows the total investments for the above scenarios and the base case. High demand scenario has the largest overall investment requirement while low demand scenario has the lowest overall investment requirement for the period 2013 - 2032. Effect of the Discount rate on the investment plan is comparatively shown in the graph. A sudden increment in investment has observed in restricted coal development to 60% from total for energy security mainly due to disbursing of investments for LNG plant with a terminal before the commissioning of plants.

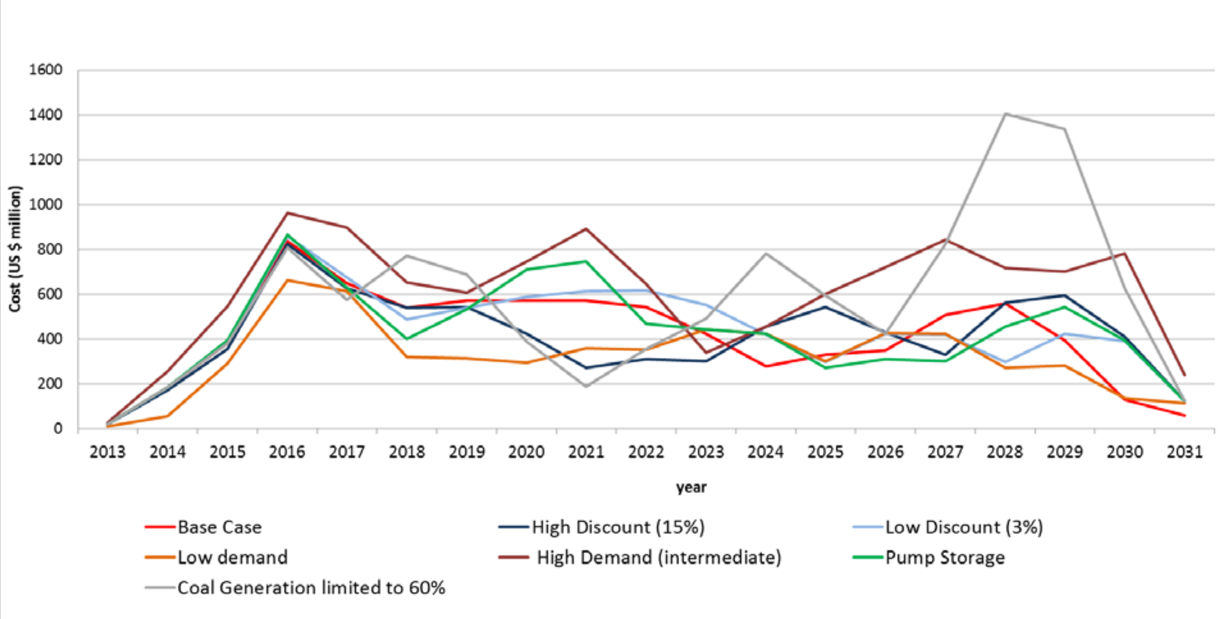


Figure 8.3 – Investment Requirement in Scenarios

Table 8.1 Investment Programme for Expansion Projects (Base Case), 2013-2025 (Costs in million US$, Exch. Rate:113.9 LKR/US$)

YEAR & PLANT	2013		2014		2015		2016		2017		2018		2019		2020		2021		2022		**Total**		**Grand Total**
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	**L.C**	**F.C**	
2015 - 75 MW Gas Turbine - 1unit																							
Base Cost	0.6	3.1	5.6	28.5																	**6.2**	**31.6**	**37.8**
Contingencies	0.1	0.5	0.8	4.3																	**0.9**	**4.8**	**5.7**
Taxes & duties (30%)		1.1		9.8																	**0.0**	**10.9**	**10.9**
Total	0.7	4.7	6.4	42.6																	**7.1**	**47.3**	**54.4**
2015 - 105 MW Gas Turbine - 1 unit																							
Base Cost	0.7	3.7	6.5	33.2																	**7.2**	**36.9**	**44.1**
Contingencies	0.1	0.5	1.0	5.0																	**1.1**	**5.5**	**6.6**
Taxes & duties (30%)		1.3		11.5																	**0.0**	**12.8**	**12.8**
Total	0.8	5.5	7.5	49.7																	**8.3**	**55.2**	**63.5**
2017 - 105 MW Gas Turbine - 1 uni																							
Base Cost					0.7	3.7	6.5	33.2													**7.2**	**36.9**	**44.1**
Contingencies					0.1	0.5	1.0	5.0													**1.1**	**5.5**	**6.6**
Taxes & duties (30%)						1.3		11.5													**0.0**	**12.8**	**12.8**
Total					0.8	5.5	7.5	49.7													**8.3**	**55.2**	**63.5**
2018 - 250 MW Trinco Coal Plant - 3 units																							
Base Cost			9.4	34.9	47.1	175.2	86.8	322.3	36.8	136.8											**180.1**	**669.2**	**849.3**
Contingencies			1.4	5.2	7.1	26.3	13.0	48.4	5.5	20.5											**27.0**	**100.4**	**127.4**
Taxes & duties (30%)				12.0		60.5		111.2		47.2											**0.0**	**230.9**	**230.9**
Total			10.8	52.1	54.2	262.0	99.8	481.9	42.3	204.5											**207.1**	**1000.5**	**1207.6**
2018 - 27 MW Moragolla HPP-1 unit																							
Base Cost			1.2	3.0	6.2	14.9	11.3	27.3	4.8	11.6											**23.5**	**56.8**	**80.3**
Contingencies			0.2	0.4	0.9	2.2	1.7	4.1	0.7	1.7											**3.5**	**8.4**	**11.9**
Taxes & duties (30%)				1.0		5.1		9.4		4.0											**0.0**	**19.5**	**19.5**
Total			1.4	4.4	7.1	22.2	13.0	40.8	5.5	17.3											**27.0**	**84.7**	**111.7**
2019 - 250 MW Trinco Coal Plant - 1 unit																							
Base Cost					3.1	11.7	15.7	58.4	29.0	107.5	12.3	45.6									**60.1**	**223.2**	**283.3**
Contingencies					0.5	1.7	2.4	8.8	4.3	16.1	1.8	6.8									**9.0**	**33.4**	**42.4**
Taxes & duties (30%)						4.0		20.2		37.1		15.7									**0.0**	**77.0**	**77.0**
Total					3.6	17.4	18.1	87.4	33.3	160.7	14.1	68.1									**69.1**	**333.6**	**402.7**
2020 - 300 MW Coal Plant- 1 unit																							
Base Cost							4.4	16.2	22.4	81.3	41.3	149.6	17.5	63.5							**85.6**	**310.6**	**396.2**
Contingencies							0.7	2.4	3.4	12.2	6.2	22.4	2.6	9.5							**12.9**	**46.5**	**59.4**
Taxes & duties (30%)								5.6		28.1		51.6		21.9							**0.0**	**107.2**	**107.2**
Total							5.1	24.2	25.8	121.6	47.5	223.6	20.1	94.9							**98.5**	**464.3**	**562.8**
2021 - 300 MW Coal Plant- 1 unit																							
Base Cost									4.4	16.2	22.4	81.3	41.3	149.6	17.5	63.5					**85.6**	**310.6**	**396.2**
Contingencies									0.7	2.4	3.4	12.2	6.2	22.4	2.6	9.5					**12.9**	**46.5**	**59.4**
Taxes & duties (30%)										5.6		28.1		51.6		21.9					**0.0**	**107.2**	**107.2**
Total									5.1	24.2	25.8	121.6	47.5	223.6	20.1	94.9					**98.5**	**464.3**	**562.8**
Annual Total	**1.5**	**10.2**	**26.1**	**148.8**	**65.7**	**307.1**	**143.5**	**684.0**	**112.0**	**528.3**													

Continued in the next page

Table 8.1 Investment Programme for Expansion Projects (Base Case), 2013-2025 (Cont.) (Costs in million US$, Exch. Rate:113.9 LKR/US$)

YEAR & PLANT	2018		2019		2020		2021		2022		2023		2024		2025		2026		2027		**Total**		**Grand**
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	**L.C**	**F.C**	**Total**
2022 - 300 MW Coal Plants - 1 unit																							
Base Cost	4.4	16.2	22.4	81.3	41.3	149.6	17.5	63.5													**85.6**	**310.6**	**396.2**
Contingencies	0.7	2.4	3.4	12.2	6.2	22.4	2.6	9.5													**12.9**	**46.5**	**59.4**
Taxes & duties (30%)		5.6		28.1		51.6		21.9													**0.0**	**107.2**	**107.2**
Total	5.1	24.2	25.8	121.6	47.5	223.6	20.1	94.9													**98.5**	**464.3**	**562.8**
2023 - 300 MW Coal Plant- 1 unit																							
Base Cost			4.4	16.2	22.4	81.3	41.3	149.6	17.5	63.5											**85.6**	**310.6**	**396.2**
Contingencies			0.7	2.4	3.4	12.2	6.2	22.4	2.6	9.5											**12.9**	**46.5**	**59.4**
Taxes & duties (30%)				5.6		28.1		51.6		21.9											**0.0**	**107.2**	**107.2**
Total			5.1	24.2	25.8	121.6	47.5	223.6	20.1	94.9											**98.5**	**464.3**	**562.8**
2024 - 300 MW Coal Plants - 1 unit																							
Base Cost					4.4	16.2	22.4	81.3	41.3	149.6	17.5	63.5									**85.6**	**310.6**	**396.2**
Contingencies					0.7	2.4	3.4	12.2	6.2	22.4	2.6	9.5									**12.9**	**46.5**	**59.4**
Taxes & duties (30%)						5.6		28.1		51.6		21.9									**0.0**	**107.2**	**107.2**
Total					5.1	24.2	25.8	121.6	47.5	223.6	20.1	94.9									**98.5**	**464.3**	**562.8**
2025- 300 MW Coal Plants - 1 unit																							
Base Cost							4.4	16.2	22.4	81.3	41.3	149.6	17.5	63.5							**85.6**	**310.6**	**396.2**
Contingencies							0.7	2.4	3.4	12.2	6.2	22.4	2.6	9.5							**12.9**	**46.5**	**59.4**
Taxes & duties (30%)								5.6		28.1		51.6		21.9							**0.0**	**107.2**	**107.2**
Total							5.1	24.2	25.8	121.6	47.5	223.6	20.1	94.9							**98.5**	**464.3**	**562.8**
2027- 300 MW Coal Plants - 1 unit																							
Base Cost											4.4	16.2	22.4	81.3	41.3	149.6	17.5	63.5			**85.6**	**310.6**	**396.2**
Contingencies											0.7	2.4	3.4	12.2	6.2	22.4	2.6	9.5			**12.9**	**46.5**	**59.4**
Taxes & duties (30%)												5.6		28.1		51.6		21.9			**0.0**	**107.2**	**107.2**
Total											5.1	24.2	25.8	121.6	47.5	223.6	20.1	94.9			**98.5**	**464.3**	**562.8**
Annual Total	**92.5**	**437.5**	**98.5**	**464.3**	**98.5**	**464.3**	**98.5**	**464.3**	**93.4**	**440.1**	**72.7**	**342.7**											

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Table 8.1 Investment Programme for Expansion Projects (Base Case), 2013-2025 (Cont.) (Costs in million US$, Exch. Rate:113.9 LKR/US$)

YEAR & PLANT	2024		2025		2026		2027		2028		2029		2030		2031		2032		Total		Grand
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	Total
2029 - 300 MW Coal Plant- 1 unit																					
Base Cost			4.4	16.2	22.4	81.3	41.3	149.6	17.5	63.5									**85.6**	**310.6**	**396.2**
Contingencies			0.7	2.4	3.4	12.2	6.2	22.4	2.6	9.5									**12.9**	**46.5**	**59.4**
Taxes & duties (30%)				5.6		28.1		51.6		21.9									**0.0**	**107.2**	**107.2**
Total			5.1	24.2	25.8	121.6	47.5	223.6	20.1	94.9									**98.5**	**464.3**	**562.8**
2030 - 49 MW Ginganga HPP - 1 unit																					
Base Cost	1.0	2.7	4.4	11.3	10.1	25.5	10.4	26.5	3.4	8.5									**29.3**	**74.5**	**103.8**
Contingencies	0.2	0.4	0.7	1.7	1.5	3.8	1.6	4.0	0.5	1.3									**4.5**	**11.2**	**15.7**
Taxes & duties (30%)		0.9		3.9		8.8		9.2		2.9									**0.0**	**25.7**	**25.7**
Total	1.2	4.0	5.1	16.9	11.6	38.1	12.0	39.7	3.9	12.7									**33.8**	**111.4**	**145.2**
2030 - 300 MW Coal Plants - 1 unit																					
Base Cost					4.4	16.2	22.4	81.3	41.3	149.6	17.5	63.5							**85.6**	**310.6**	**396.2**
Contingencies					0.7	2.4	3.4	12.2	6.2	22.4	2.6	9.5							**12.9**	**46.5**	**59.4**
Taxes & duties (30%)						5.6		28.1		51.6		21.9							**0.0**	**107.2**	**107.2**
Total					5.1	24.2	25.8	121.6	47.5	223.6	20.1	94.9							**98.5**	**464.3**	**562.8**
2031- 300 MW Coal Plants - 1 unit																					
Base Cost							4.4	16.2	22.4	81.3	41.3	149.6	17.5	63.5					**85.6**	**310.6**	**396.2**
Contingencies							0.7	2.4	3.4	12.2	6.2	22.4	2.6	9.5					**12.9**	**46.5**	**59.4**
Taxes & duties (30%)								5.6		28.1		51.6		21.9					**0.0**	**107.2**	**107.2**
Total							5.1	24.2	25.8	121.6	47.5	223.6	20.1	94.9					**98.5**	**464.3**	**562.8**
2032 - 75 MW Gas Turbine - 1unit																					
Base Cost													0.6	3.1	5.6	28.5			**6.2**	**31.6**	**37.8**
Contingencies													0.1	0.5	0.8	4.3			**0.9**	**4.8**	**5.7**
Taxes & duties (30%)														1.1		9.8			**0.0**	**10.9**	**10.9**
Total													0.7	4.7	6.4	42.6			**7.1**	**47.3**	**54.4**
Annual Total	**47.1**	**220.5**	**57.7**	**264.7**	**62.6**	**278.8**	**90.4**	**409.1**	**97.3**	**452.8**	**67.6**	**318.5**	**20.8**	**99.6**	**6.4**	**42.6**			**1352.8**	**6378.2**	**7731.0**

CHAPTER 9
ENVIRONMENTAL IMPLICATIONS

The impacts of electricity generation on the environment could be due to one or several factors including: particulate emissions; gaseous emissions (CO_2, SO_X, NO_X etc.); warm water discharges into lakes, rivers or sea; liquid and solid waste (sludge, ash); inundation (in the case of large reservoirs) and changes of land use. Although many of these are common to any development project, particulate and gaseous emissions are of primary importance in the case of electricity generation using fossil fuels. This chapter describes the environmental impacts of the implementation of Base Case Generation Expansion Plan and other selected scenarios.

9.1 Greenhouse Gases

The current IPCC (Intergovernmental Panel on Climate Change) guidelines define six major greenhouse gases. These include three direct Green House Gases (GHGs); Carbon dioxide (CO_2), Methane (CH_4), Nitrous Oxide (N_2O) and three precursor gases; Carbon monoxide (CO), Oxides of Nitrogen (NOx), and Non-Methane Volatile Organic Compounds (NMVOC). In addition, atmospheric ozone (O_3) (though present only in very minute quantities) is also considered as a GHG. Apart from these, water vapour (H_2O) is one of the biggest contributors for global warming though it is not commonly categorised as a GHG with other gases.

9.2 Country Context

GHG emissions in Sri Lanka from fuel combustion, both in absolute as well as in per capita terms are low even in comparison to other countries in South Asia (Table 9.1). Emission level calculated per unit of GDP is also less in Sri Lanka when compared to other countries in the World. This could be mainly due to dominance of Hydropower generation in the electricity sector and the low energy intensity in the production sectors.

Table 9.1 - Comparison of CO_2 Emissions from fuel combustion

Country	kg CO_2/2005 US$ of GDP	kg CO_2/2005 US$ of GDP Adjusted to PPP	tons of CO_2 per Capita
Sri Lanka	**0.40**	**0.14**	**0.64**
Pakistan	1.00	0.32	0.78
India	1.30	0.35	1.39
Indonesia	1.09	0.43	1.71
China	1.79	0.77	5.40
France	0.16	0.19	5.52
Japan	0.25	0.29	8.97
Germany	0.26	0.28	9.32
USA	0.41	0.41	17.31
World	0.59	0.44	4.44

Source: IEA CO_2 database, Figures are based on 2012 edition

Until mid-nineties, significant thermal generation occurred only in the drought years as seen in Figure 1.9. Hence, the power sector has so far contributed very little to GHG emissions. However, this situation has been changing. Suggested expansion sequence predicts an increase in the thermal generation share to 80% by 2032 from 61% share of present thermal generation as most of the new plants to be added to the system in the foreseeable future are fossil fuelled. Hence, a substantial increase in the use of fossil fuels in the power sector seems inevitable.

In 1994,Government of Sri Lanka has approved ambient air quality standards, while only a proposed set of emission standards is currently in place. Nevertheless, these proposed standards are used as a guide in the EIA process of thermal power plants of Sri Lanka. At present, all thermal power projects have to comply with these ambient air quality standards (Table 9.2).

Table 9.2 - Ambient Air Quality Standards and Proposed Stack Emission Standards of Sri Lanka

Pollutant Type	Ambient Air Quality Std. ($\mu g/m^3$)		Stack Emission Std. (mg/MJ)	
	Annual level	1 hour/24 hour* level	Coal	Liquid Fuel
Nitrogen Oxides (NO_X)	190	250/100*	300	130
Sulphur Oxides (SO_X)	75	200/80*	520	340
Total Suspended Particles(TSP)	150	500*	40	40

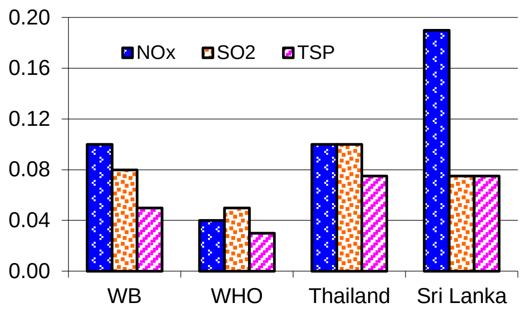
Source: Central Environmental Authority

Table 9.3 - Comparison of Ambient Air Quality Standards of Different Countries and Organisations

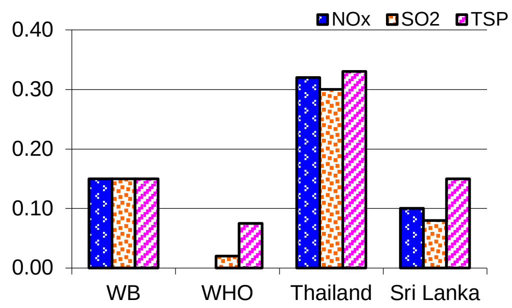
(all values in mg/m^3)

Pollutant	Averaging time	World Bank	WHO	Indonesia	Thailand	**Sri Lanka**
Nitrogen Dioxide	Annual	0.10	0.04	0.10	0.057	**0.190**
	1 hour	-	0.20	0.40	O.32	**0.250**
	24 hours	0.15	-	0.15	-	**0.100**
Sulphur Dioxide	Annual	0.08	-	0.06	0.10	**0.075**
	24 hours	0.15	0.020	0.36	0.30	**0.080**
Suspended Particulate	Annual	0.05	0.03	-	0.075	**0.075**
	24 hours	0.15	0.075	0.15	0.17	**0.150**

Source: World Wide Web, Central Environmental Authority



(a) Annual



(b) 24 hour Average

Figure 9.1 - Comparison of Ambient Air Quality Standards

When compared with the standard specified by the World Bank (Existing) and WHO (Table 9.3 and Figure 9.1), it is evident that Sri Lanka has very stringent ambient air quality standards for SOx emissions. The standard for particulate matter is also higher than the existing WB standards though not the highest of all.

A comparison of proposed emission standards with those of WB and some Asian countries is shown in Table 9.4. It can be seen that proposed Sri Lankan Emission standards are somewhere between the European Commission standards and the standards of some neighbouring Asian countries such as China, Thailand and Vietnam. China does not have restrictions on NO_x released by thermal plants.

Table 9.4 - Comparison of Emission Standards of Different Countries and Organisations
(All values in mg/MJ)

Pollutant	**Sri Lanka (Proposed)**	World Bank (Proposed)	Vietnam	China (Industry)	Thailand	European Commission
Nitrogen Oxides	**300**	365	487	450	500	200
Sulphur Dioxide	**520**	700	175	400	350	200
Suspended Particulate	**40**	50	200	50	700	30

Source: Central Environmental Authority, EPDC Database

9.3 Emission Control Technologies

According to the expansion sequence of base case mentioned in Chapter 7 (Table 7.1), 4,600 MW of Coal plants, 44MW Diesel plants, and 360 MW of Gas Turbines are to be added to the Sri Lankan system in the next 20 years starting from 2013. The impact on the environment due to particulate and air-emissions from these additions and the effectiveness of using control devices to mitigate those impacts are analysed here. Three types of gaseous emissions were considered in the analysis, viz. SO_x, NO_x and CO_2.

When applying control technologies, it is always necessary to have an idea about the availability and capability of different control technologies. Studies have shown that, in many cases, the use of state-of-the-art engineering practices could meet the stipulated air quality standards without specific control devices. However, there are instances where emission control is mandatory. For example in the case of coal plants, the use of high-quality, low-sulphur coal (0.65% S) reduces SO_X emissions to levels below the standard, but definitely there has to be some form of control over particulate emissions. The Low-NO_x burners are an integrated part of most of the commercially available combined cycle plants, which are capable of reducing NO_x emissions to very low levels.

Hence, in the present study control technologies considered are as follows; Electrostatic Precipitators (ESPs) for the control of particulate emissions in Coal plants and low NO_x burners for the control of NO_x in both coal plants and combined cycle plants. Coal power plants in Sri Lanka are generally designed for low sulphur coal (0.65% sulphur) as fuel, while no specific control devices were employed for the control of SO_x emissions. However, Puttalam coal power plant has a Flue Gas Desulfurization unit (FGD) installed. Table 9.5 shows the abatement factors of typical control technologies available for controlling emissions, during and/or after combustion. The values used in the study are shown shaded. The costs of the control technologies considered are included in the project costs of candidate plants of the LTGEP.

Table 9.5 - Abatement Factors of Typical Control Devices

(Factors in %)

Device	SO_2	NO_X	TSP	Other Part.	CO	CH_4	NMVOC
Fabric Filter			99.5	99.5			
Electro Static Precipitator			99.2	90			
Dry FGD	50						
Wet FGD	92.5		90	90			
Low NOx Burner – Coal		25			-10	-10	-10
Low NOx Burner – CCY *		80					

Sources: Decades Manual & Coal feasibility Study

TSP – Total Suspended Particles

FGD – Flue Gas Desulphurisation

NMVOC – Non Methane Volatile Organic Compounds

CCY - Combined Cycle Plants

* - (NOx abatement % for CCY plants is based on a reduction from 350 ppm to 70 ppm)

9.4 Emission Factors Used

One of the problems in analysing the environmental implications of electricity generation is correctly assessing the 'emission coefficients' or more commonly the 'emission factors'. Choice of different sources can always lead to overestimation or underestimation of real emissions. In the present study, emission factors were either calculated based on stoichiometry or chosen from a single source.

Table 9.6 - Uncontrolled Emission Factors (by Plant Technology)

Plant Type	Fuel Type	NCV	Sulphur Content	Emission Factor			
				Particulate	CO_2	SOx	NOx
		(kJ/kg)	(%)	(mg/MJ)	(g/MJ)	(g/MJ)	(g/MJ)
Diesel Engine	Fuel Oil	40968	3.5	13.0	75.5	1.7087	1.20
Diesel Engine	Residual FO	40968	3.5	13.0	76.6	1.7087	1.20
Oil Steam	Fuel Oil	40968	3.5	11.0	75.5	1.7087	0.13
Coal Steam	Coal	25058	0.65	40.0	92.7	0.4929	0.30
Gas Turbine	Auto Diesel	41962	0.5	5.0	73.3	0.2383	0.28
Comb. Cycle	Auto Diesel	41962	0.5	5.0	73.3	0.2383	0.28
Comb. Cycle	Naphtha	44786	0.0	0.0	72.6	0.0	0.28
Comb. Cycle	Natural Gas	51907	0.0	0.0	54.4	0.0	0.02
Dendro	Dendro	1960	0.0	255.1	0.0	0.01	0.20

Sources: IPCC Guidelines, Thermal Generation Options Study, CEB

Table 9.6 lists the uncontrolled emission factors *(emissions without considering the effect of control technologies in addition to the standard emission control devices used in planning studies)* used in the study for all types of plants. Basically, CO_2 and SO_2 emission factors are calculated based on the fuel characteristics, while NO_x emissions, which depend on the plant technology, are obtained from a single source [12]. Generally, particulate emissions depend both on the plant technology and the type of fuel burned.

9.5 Environmental Implications – Base Case

Presented below is a quantitative analysis of the environmental implications associated with the base case generation expansion plan described in Chapter 7. The total particulate and gaseous emissions (controlled) under the base case plan are shown in Table 9.7 and Figure 9.2.

Table 9.7 - Air Emissions - Base Case Scenario

Year	**Particulate**	**SO_x**	**NO_x**	**CO_2**
	(1000 tons/year)			
2013	1.28	67.6	44.1	5750
2014	1.9	76.8	49	6970
2015	2.5	63.5	37.7	8290
2016	2.51	63.9	37.9	8390
2017	2.59	66.4	39.9	9010
2018	4.09	64.3	32.8	10800
2019	4.62	65.3	31.6	11800
2020	5.15	69.8	33.2	12700
2021	5.64	74	34.5	13600
2022	6.15	78.8	36.3	14600
2023	6.63	83.5	38.1	15600
2024	7.1	88.9	40.4	16600
2025	7.6	94.4	42.8	17700
2026	7.98	99.6	45.3	18600
2027	8.52	106	47.9	19800
2028	8.91	111	50.6	20900
2029	9.41	117	53.1	22000
2030	9.98	124	56.3	23300
2031	10.6	131	59.5	24600
2032	11	138	62.6	25800

With the introduction of coal based generation, the continuous increasing trend of SO_X and NO_X emissions starts to decrease from 2014 and decreasing trend will continue until 2019. Thereafter again an increasing trend can be observed for SO_X and NO_X emissions. CO_2 emission would not be affected by the change of system generation pattern (i.e. introduction of coal based generation). However the particulate would start to increase with the change of generation pattern.

According to Figure 9.3, per kWh emissions of SO_x and NO_x shows a levelised trend while per unit CO_2 emissions would rise annually .The decrease in SO_x and NO_x emissions is mainly due to the use of low sulphur fuels (such as coal) and control measures taken to reduce NO_x emissions.

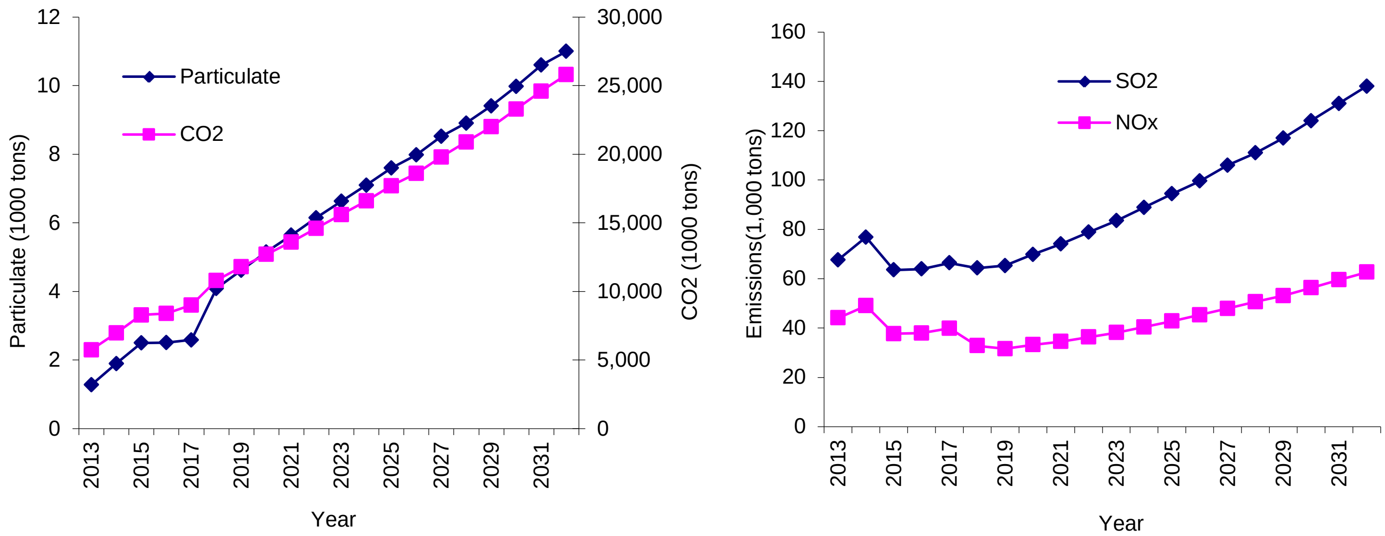


Figure 9.2 –SOx, NOx, Particulate and CO_2Emissions

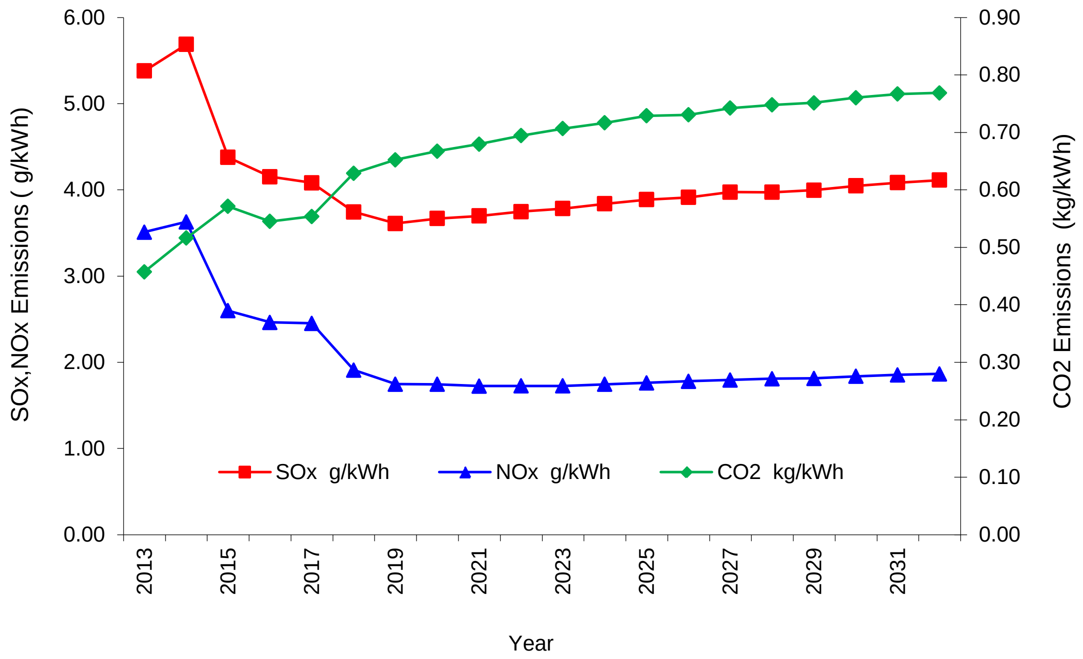


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Figure 9.3 – CO_2, SO_x and NO_x Emissions per kWh Generated

9.6 Environmental Implications – Other Scenarios

The scenarios, which are expected to have significant effects on environment, are evaluated against the base case emission quantities. The scenarios under consideration are as follows.

1. Effects on emissions, if Demand Side Management plans are implemented in future.
2. Effects on emissions, if coal power development is limited to 900MW at Puttlam and 1000MW at Trincomalee.
3. Effects on emissions, due to High penetration of Non-conventional Renewable (NCR) in to the system,20% NCRE by 2020.

4. Effects of variations of discount rate on emissions (15% and 3%)
5. Effects on emissions with Demand Side Management
6. Effects on emissions due to fuel price variation (50% high in coal price)
7. Effects on emissions due to coal power generation limit to 60%
8. Effects on emissions due to Dendro candidate with local fuel subsidy
9. Effects on emissions due to applying of social and environment damage cost for coal power generation
10. Effects on emissions due to forced construction and forced operation of pump storage plant

Except coal limited scenarios all other scenarios have a number of coal power plants scheduled to be constructed throughout the planning horizon. From the Figure 9.4, it is evident that SO_x emissions of the coal power limited scenarios have lower than other scenarios due to zero SO_x emissions from LNG fired combined cycle plants and high sulphur contents in the coal &petroleum fuel. Coal power construction restricted to Puttlam 900MW and Trincomalee 1000MW has the least quantity of SO_x emissions. Until 2019, Demand Side Management scenario has the least SO_x emission due to energy saving.

CO_2, SO_x ,NO_x and Particulate matters emission values for the base case, 50% coal price high, high discount rate, low discount rate, applying of social and environmental damage cost for coal energy, dendro candidate with local fuel subsidy, forced construction and operation of pump storage plant scenarios are in the same region.

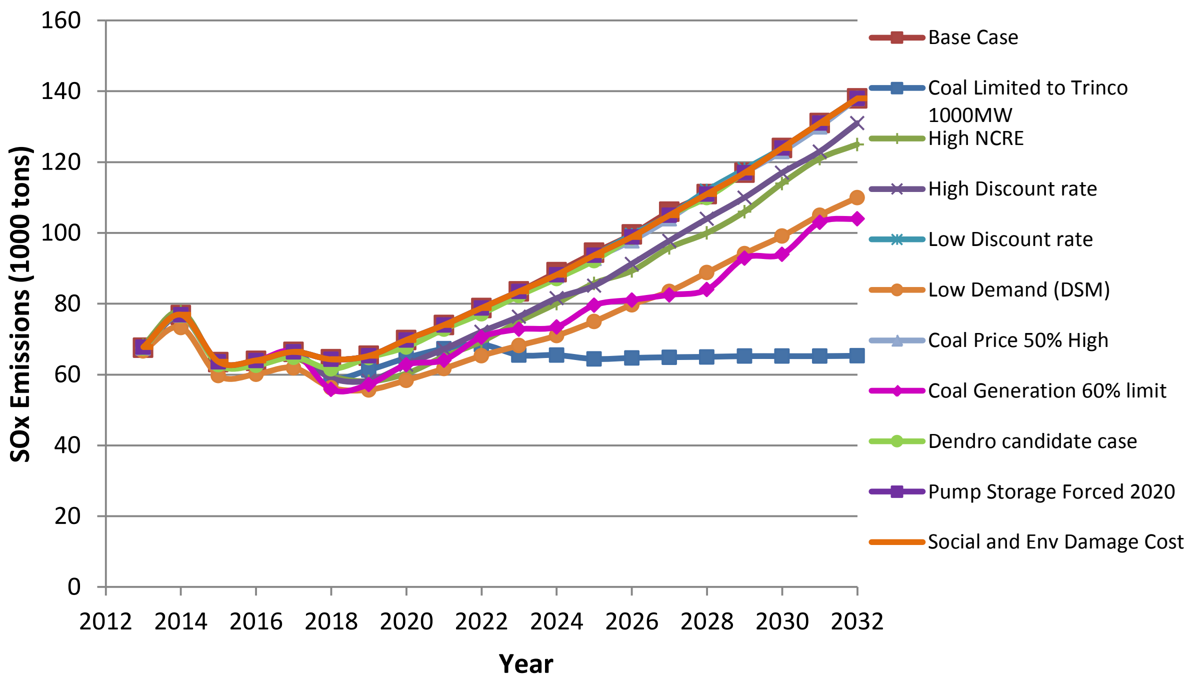

Figure 9.4 - SO_x Emissions

The NO_x emission factors of LNG fired combined cycle plants are less than the coal fired power plants. Therefore, NO_x emissions in coal power limited scenarios are lower than that of other scenarios. In coal power construction restricted to Puttlam 900MW and Trincomalee 1000MW and introducing LNG has the least NO_x emissions. (Figure 9.5). Also DSM scenario and High NCRE scenario have the lower NO_x emission than the Base case.

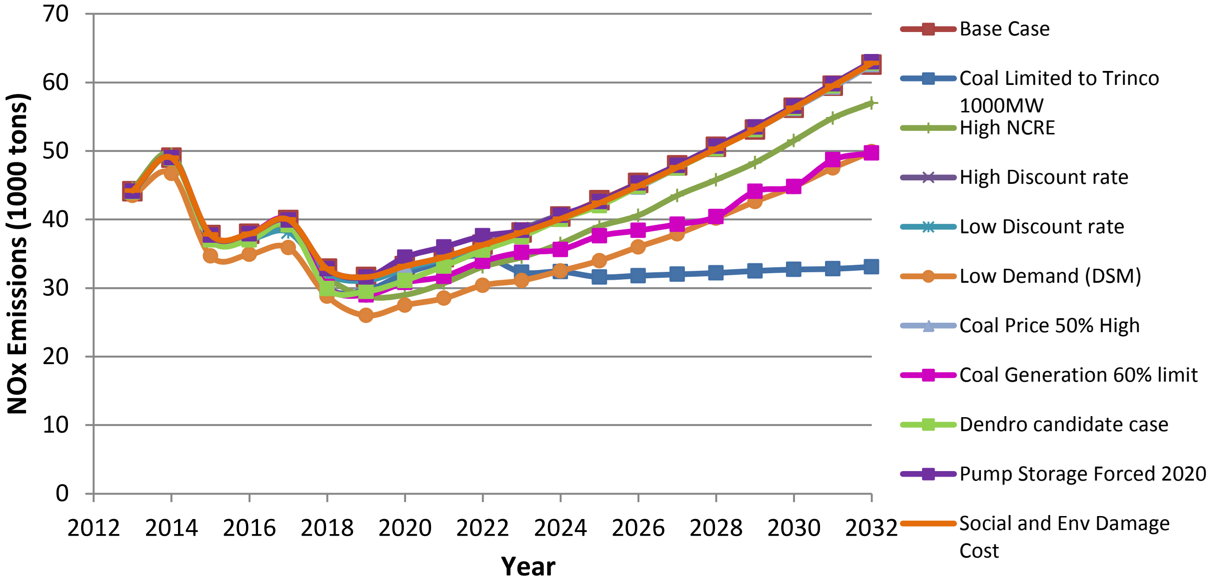

Figure 9.5 - NO_x Emissions

The CO_2 emission factors of LNG fired combined cycle plants are about 50% less than that of coal fired power plants. Therefore, CO_2 emission in the coal power construction limited to 1900MW and introduction of LNG is lower than that of other scenarios (Figure 9.6). Similarly particulate emission factors of LNG fired combined cycle plants are equal to zero compare to coal fired power plants. That would result a lower particulate emissions in the coal power limited to 1900MWscenario than that of other scenarios (Figure 9.7).Demand Side Management scenario is the next best scenario for less CO_2 emissions after coal limited to 1900MW scenario.

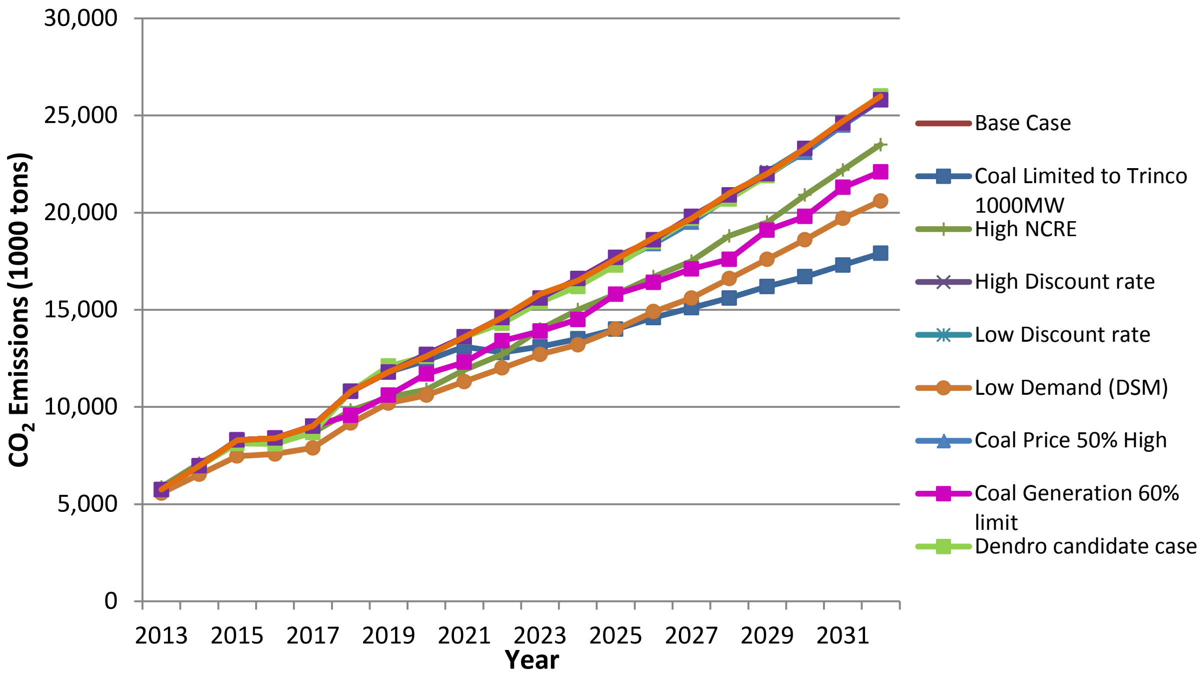

Figure 9.6 –CO_2 Emissions

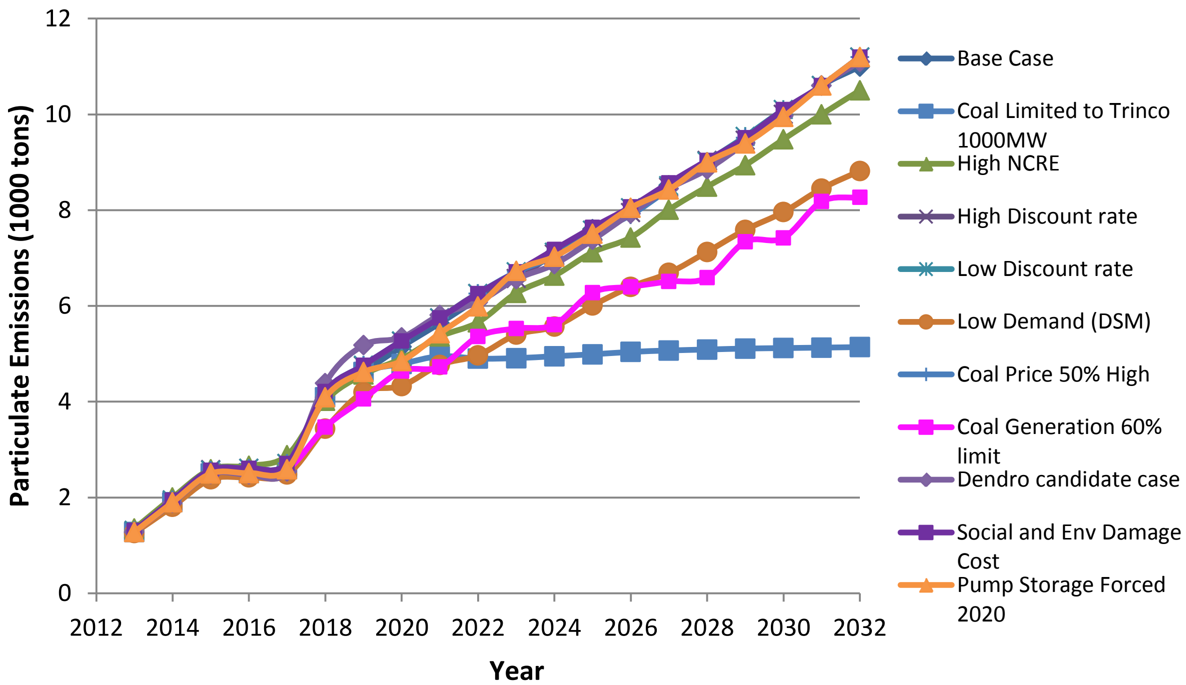

Figure 9.7 – Particulate Emissions

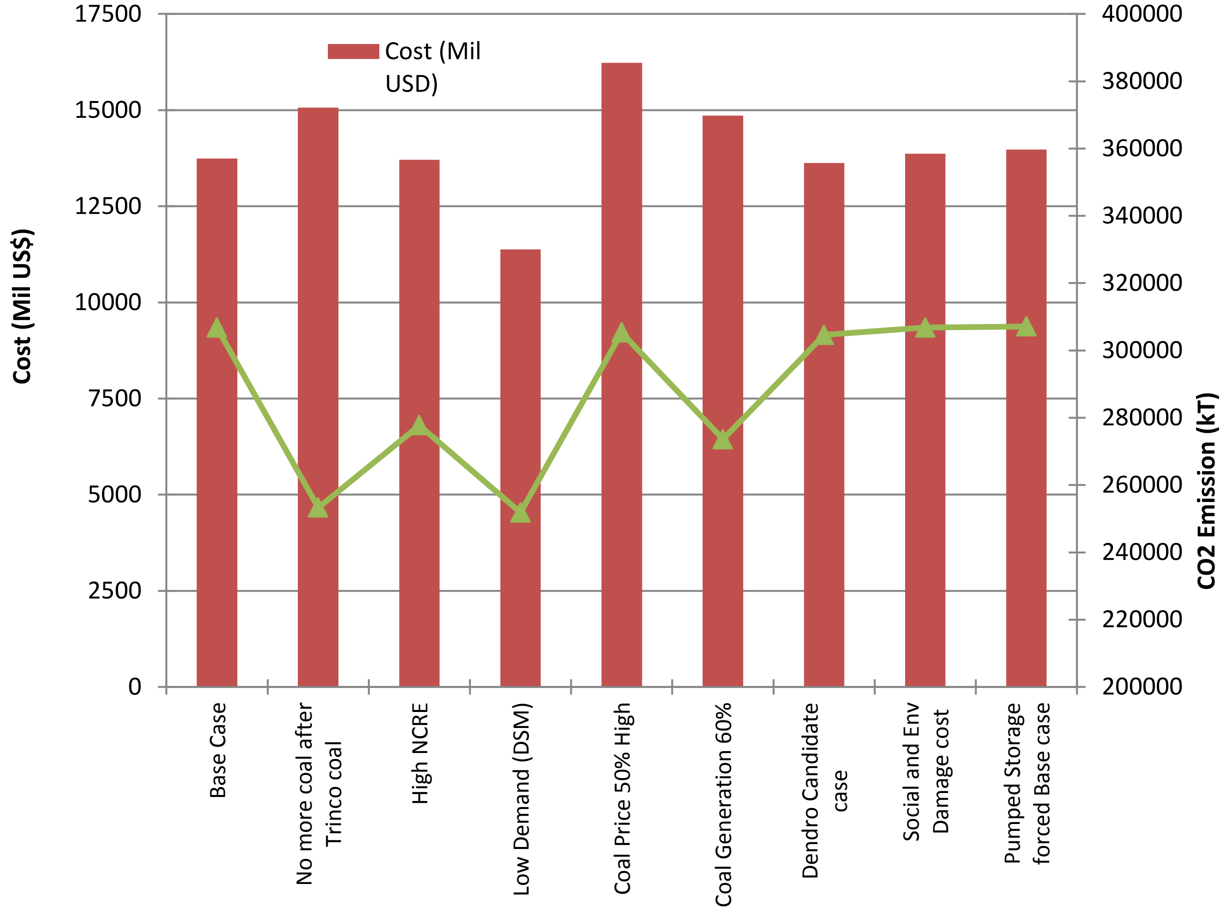

Figure 9.8 – Comparision of System Cost with CO_2 Emissions

Comparison of total CO_2 emission with total system cost is shown in Figure 9.8. It is observed that Demand Side Management scenario is the least CO_2 emission scenario but investment cost is not reflected the cost for DSM measures. The second lowest CO_2 emission scenario, coal power limited to 1900MW has highest system cost under base fuel price.

9.7 Climate Change

The term Climatic change is used to refer specifically to climate change caused by human activity; for example, the United Nations Framework Convention on Climate Change defines climate change as "a change of climate which is attributed directly or indirectly to human activity that alters the composition of the global atmosphere and which is in addition to natural climate variability observed over comparable time periods." In the latter sense climate change is synonymous with global warming.

Due to the increasing global concern on climate change, in 1988, the United Nations Environment Programme and the World Meteorological Organisation jointly established the Intergovernmental Panel on Climate Change (IPCC) with a directive to assess the best scientific options on climate change, its potential impacts, and possible response strategies. With the increased political concerns about climate change, the United Nations Framework Convention on Climate Change (UNFCCC) was formulated on the basis of initial IPCC findings. In 1992, the UNFCCC was established and signed by almost all countries at the Rio Summit.

The decision making body of UNFCCC is known as Conference of Parties (COP) which meets annually. The Kyoto Protocol was accepted in COP3 in Kyoto, Japan in 1997. The major feature of the Kyoto Protocol is that it sets binding targets for 37 industrialised counties and the European Community for reducing Green House Gas (GHG) emissions. It will amount to an average of 5% against 1990 levels over the five year period 2008-2012 (European Union at United Nations, 2008). Energy related carbon dioxide emission is one of the main GHG courses of climate change. But the goal of Kyoto Protocol is to lower overall emissions of six greenhouse gases - carbon dioxide, methane, nitrous oxide, sulphur hexafluoride, hydro-fluorocarbons and per-fluorocarbons (UNFCCC, 2008). Recognising that industrialised counties (countries in Annex I of the Kyoto Protocol) are principally responsible for the current high levels of GHG emissions in the atmosphere as a result of more than 150 years of industrial activity, the protocol places the heavier burden on developed nations under the principle of "common but differentiated responsibilities". The Kyoto Protocol was adopted in Kyoto, Japan, on 11 December 1997 and entered in to force on 16th February 2005. Under the Kyoto Protocol, Annex I counties must meet their targets primarily through national measures. However the Kyoto protocol offers them an additional means of meeting their target by the way of three market based mechanisms.

- Emission trading – known as "the carbon market"
- The Clean Development Mechanism (CDM)
- Joint implementation (JI)

Under the Protocol, countries' actual emissions have to be monitored and precise records have to be kept to the trades carried out. Only the Clean Development Mechanism allows economical emission credit trading among Annex I and non-Annex I countries.

Thirteenth Conference of Parties (COP13) was held at Bali in December 2007. This conference resulted in the adoption of Bali Road Map which consisted of several forward looking climate decisions. Launching of Adaptation Fund, A review of Kyoto Protocol, Decisions on Technology transfer and Reducing Deforestation related emissions and Ad-Hoc Working Group (AWG) negotiations on a Long Term Corporative Agreement (LCA) and Kyoto Protocol (KP) were included in this road map.

The efforts to take a decision on the extension of the Kyoto Protocol prior to the ending of its 1st commitment period on 31st December 2012, specially at the COP15/CMP5 in Copenhagen, COP 16/CMP6 in Cancun and COP17/CMP7 in Durban failed and only in at the COP18/CMP8 in Doha that an agreement was reached. Accordingly at Doha, parties agreed for a second commitment period up to 31.12.2020, a revised list of greenhouse gases and commitment by parties to reduce GHG emission by at least 18% below 1990 levels. However, the expected reductions are comparatively low and there is a significance difference in the parties to the second commitment compared to the previous with parties such as Japan, Canada, Russia not being included for the second commitment.

At the COP17/CMP7, in Durban in 2011, a significant development in the climate change negotiations occurred. The parties agreed to launch a process to develop a protocol or a legal instrument or a legally binding agreement under the convention applicable to all parties. This process is implemented through subsidiary body under the convention, the Ad Hoc Working Group on the Durban Platform for Enhanced Action (ADP) This legally binding agreement is to be agreed upon on or before 2015 and is to be implemented by 2020.

From 2014, according to AWGLCA recommendations accepted by COP, non-Annexure I parties have to submit a Bi-annual Updated Report (BUR) which should update the information in the National Communiqués. The BUR is required to include information on inventory, mitigation, adaptation , NAMA (Nationally Appropriate Mitigation Action) etc. The BUR will also be externally reviewed.

Kyoto Protocol has not imposed any obligation for non-Annex I countries. As a non-Annex I country, Sri Lanka ratified the Kyoto Protocol in 2002. It is estimated that the total emission contribution of GHG emissions from Sri Lanka is less than .05% of the global total. Although emission levels are much less than the global values, Sri Lanka has adopted many policy measures that would result in mitigating emissions.

The National Energy policy and strategies of Sri Lanka states that by 2015,Sri Lanka will endeavour to reach a target of at least 10% of the total energy supplied to the grid from Non-Conventional renewable resources by a process of facilitation including access to green funding such as CDM. Also, it states that a review of technical limits and financial constraints of absorbing NCRE will be carried out and will be followed by a technical and financial barrier removal exercise, with external support and expertise where necessary. Introduction of high NCRE tariff structure, implementation of remaining hydro power projects are some examples.

Generation, Transmission and Distribution Loss reduction is also an important measure implemented by CEB towards the path of providing sustainable energy. In 1999 the total system loss (including generation auxiliaries) was 20.9% and by 2012 it has been reduced to 11.6%. Energy conservation from demand side management which involves education and awareness of the consumers on purchasing energy efficient appliances, designing households and commercial establishments to be more energy efficient are some measures being carried out in the power sector. All those measures reduce the thermal power generation to the system and results in reduction of GHG emissions.

Even up to mid-nineties the Sri Lankan power sector was mainly hydro based with the contribution being over 90%. With the almost full utilization of the available major hydro power potential, CEB had to turn to thermal power which was mainly oil. The first Coal plant of 300MW capacity was only established in 2011. Sri Lanka has achieved a level of economic development of close to 3000 USD per capita income with a comparatively low effect on the global GHG emission. Therefore Sri Lanka has every right to utilise available resources in order to continue in the development path with the least economic effect on its people.

LTGEP has been worked out based on the least cost economically optimal plant additions in order to meet the forecast electricity demand. Coal power will be the major share of the optimised energy mix in the near future and will contribute significantly to the GHG emissions in comparison with current level. Any proposal to shift from Coal to higher cost technology / fuel in order to reduce the GHG emissions should include suitable compensation by an international mechanism.

CHAPTER 10
REVISIONS TO PREVIOUS PLAN

10.1 Introduction

It is worthwhile to examine the deviations of the results of the present study from the last generation expansion plan, and to analyse the causal factors for such deviations. The causes for the differences between the current study (LTGEP 2012 for the period of 2013-2032) and LTGEP 2010 for the period of 2011 – 2025 are as follows.

- Demand forecast
- Fuel price variations
- Revised hydro power generation potential
- Applying PUCSL generation planning code
- Applying planning guide lines of Ministry of Power and Energy
- Net generation values instead of gross generation values are used in planning studies.

10.2 Demand Forecast

This year too the demand forecast study was developed adopting a sector-wise approach and the econometric method was used to derive demand projections for each sector as described in Chapter 3. The new Peak demand and Energy demand forecast are1.1% and 0.9% lower than LTGEP 2010 respectively. Figure 10.1(a) & (b) and Figure 10.2 show the Comparison of 2010 and 2012 load forecasts and installed capacity additions between LTGEP 2010 and current plan respectively.

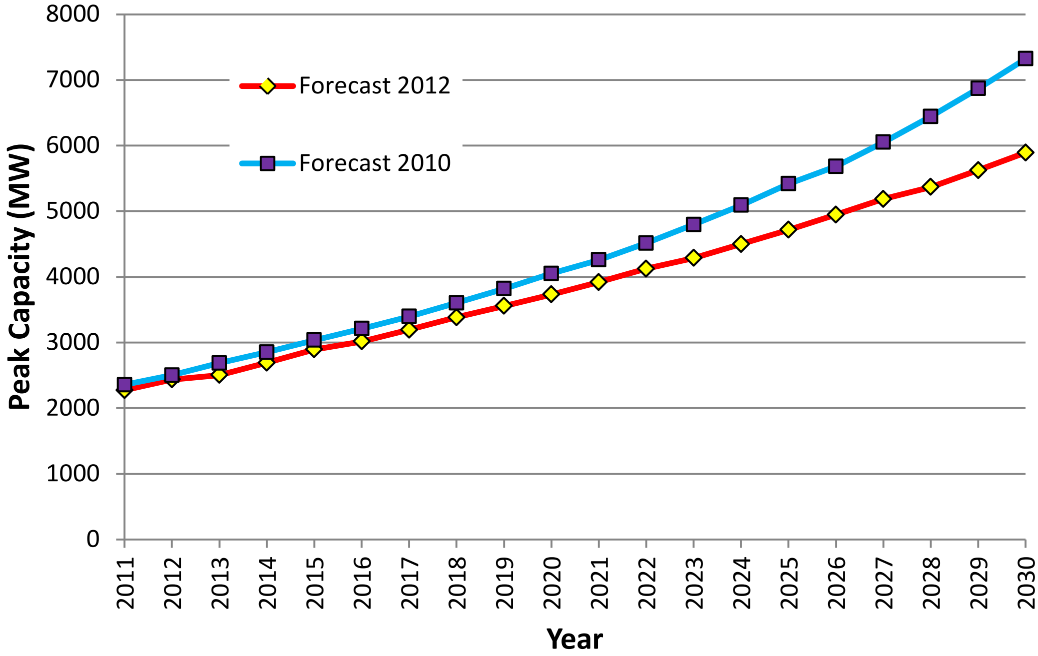

Figure 10.1(a) - Comparison of 2010 and 2012 Energy Demand Forecasts

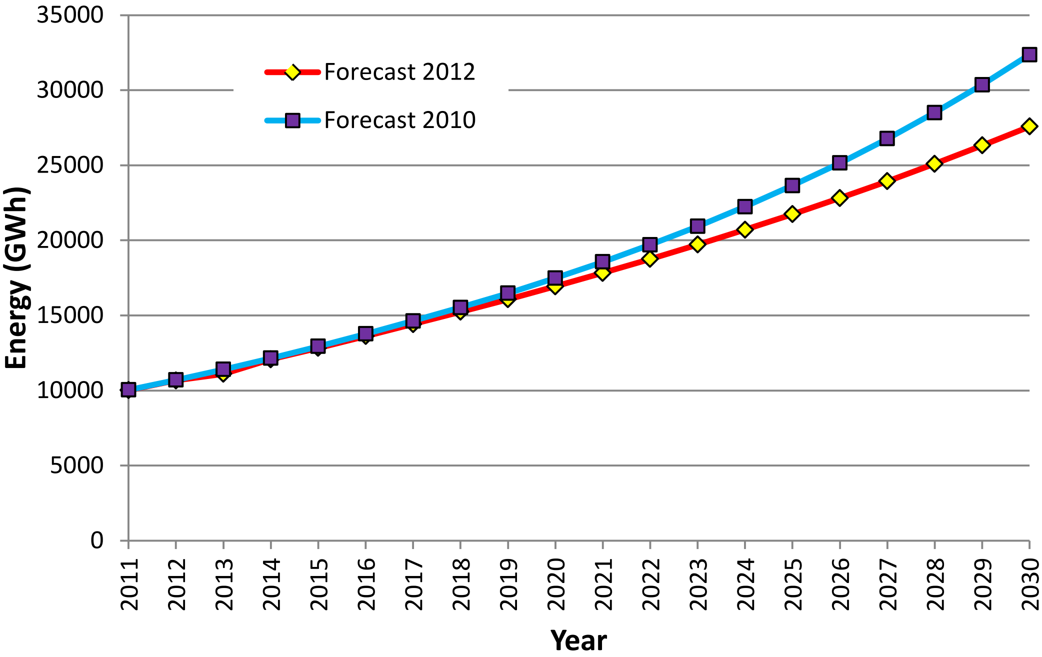

Figure 10.1(b) - Comparison of 2010 and 2012 Peak Demand Forecast

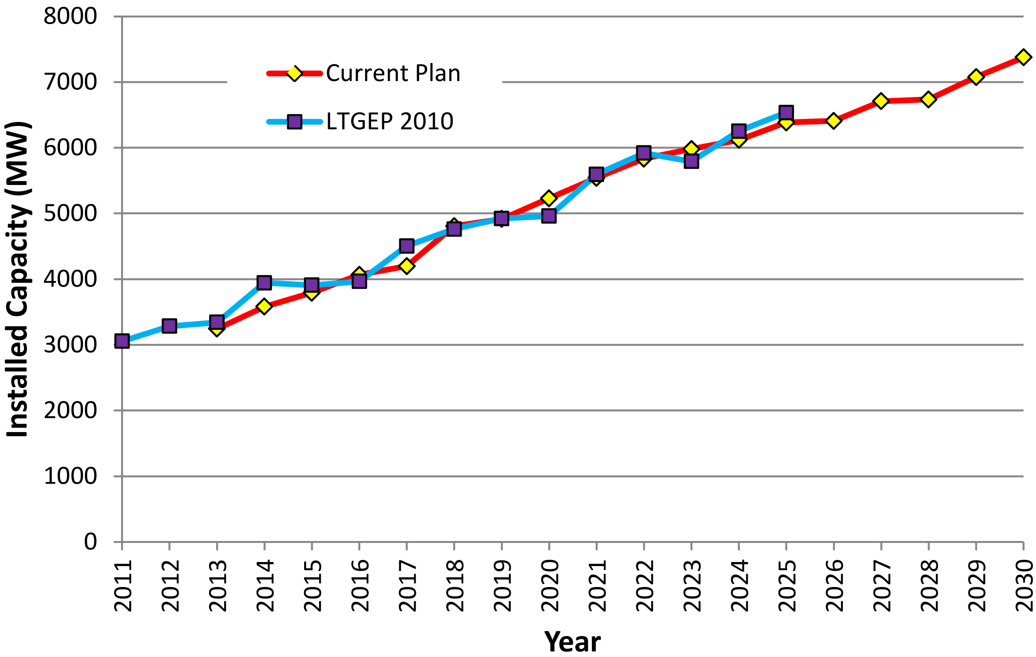

Figure 10.2 – Comparison of Installed capacity Addition between LTGEP (2010) and Current Plan (2012)

Figures 10.3 and 10.4 show the capacity mix and energy mix in the selected years 2013, 2016, 2019, 2022 and 2025 for both LTGEP 2010 and the current plan (LTGEP 2012).

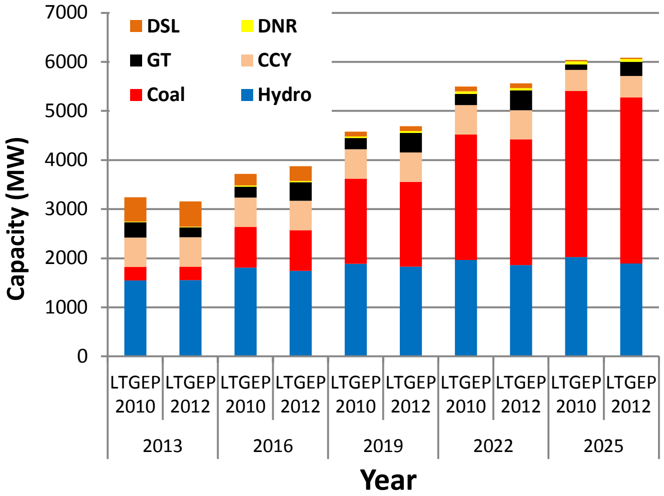

Figure 10.3 - Capacity Mix

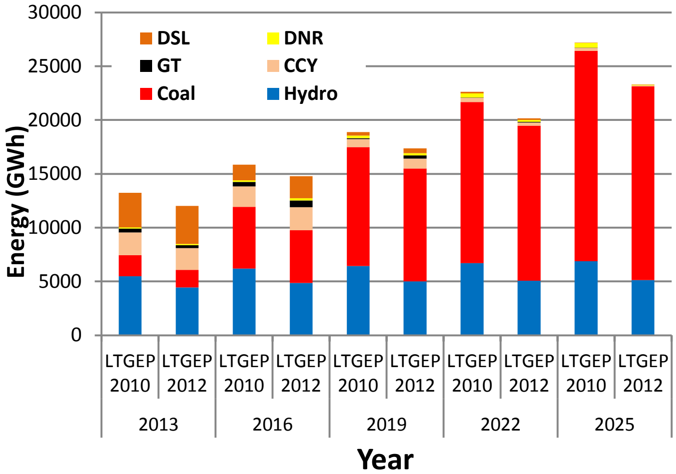

Figure 10.4 - Energy Mix

Projected demand in LTGEP 2012 is about 1% less from the previous plan. Minimum reserve margin of 2.5% was used in LTGEP 2012 whereas minimum reserve margin of 0% was used for the LTGEP 2010 plan. Maximum reserve margin values of LTGEP 2012 and LTGEP 2010 are 20% and 30% respectively. Finally, capacity addition of LTGEP 2012 and LTGEP 2010 are almost similar.

Probability values of hydro conditions have been revised to represent actual hydro generation of last 20 years. Hence, available hydro power in LTGEP 2012 is less than that of LTGEP 2010. Therefore, dispatch of thermal plants is higher in LTGEP 2012 compared to the LTGEP 2010.SO_x and NO_x emissions are higher in the LTGEP 2012 than the expected level of emission in LTGEP 2010. Comparison of SOx and NOx emissions depicts in Figure 10.5. Also the comparison of CO_2 and Particulate emissions is shown in Figure 10.6.

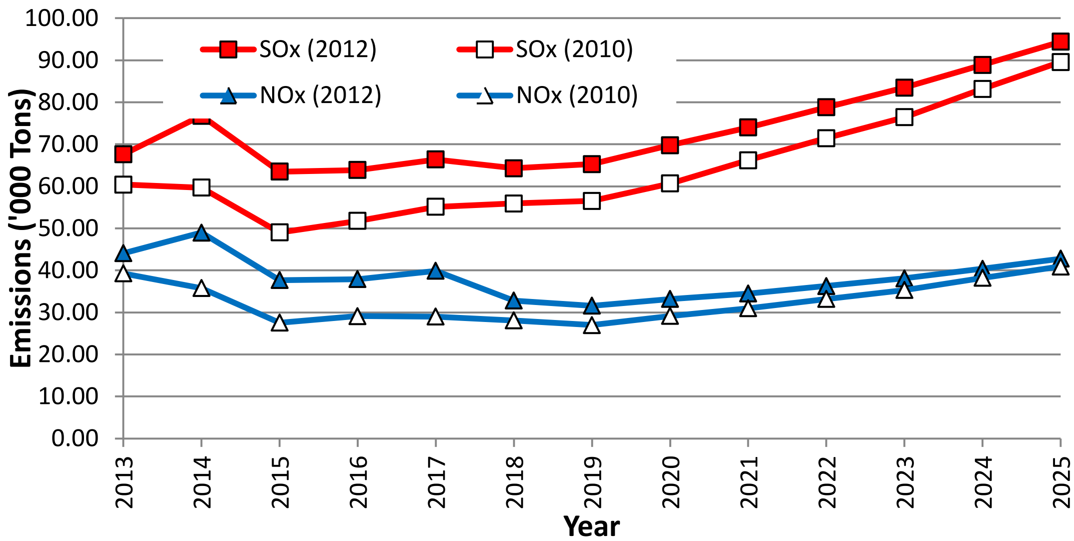

Figure 10.5 - SO_x and NO_x Emissions

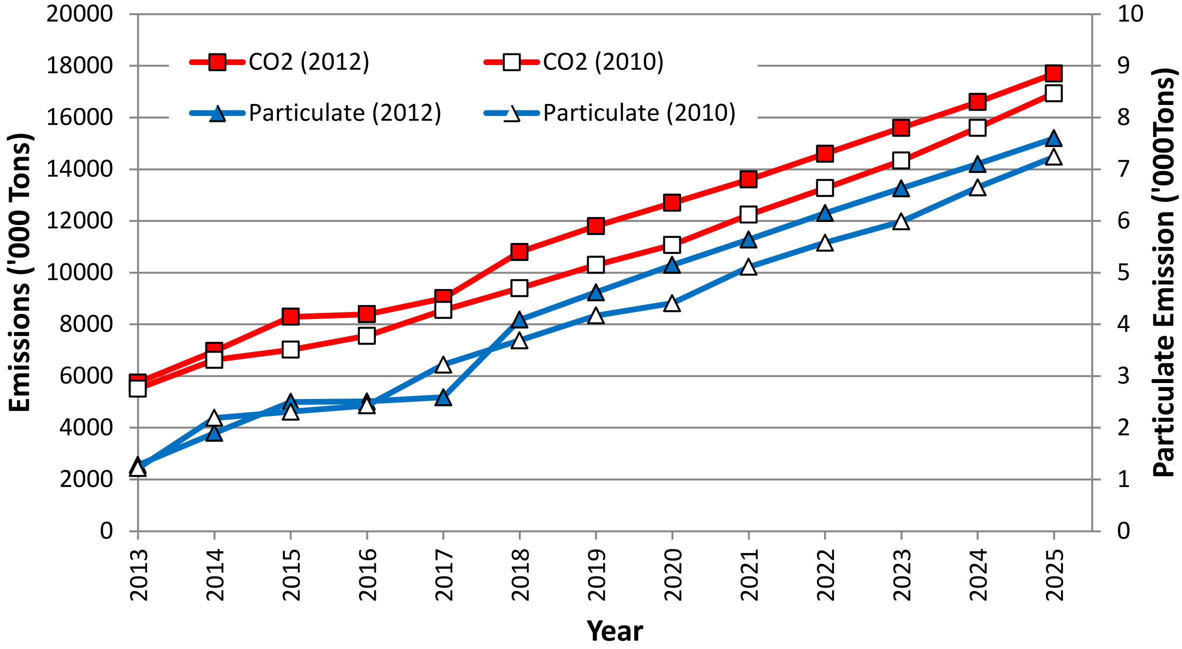

Figure 10.6 – CO_2 and Particulate Emissions

Although demand forecast is 1% less than LTGEP 2010, due to the reduction in hydro power energy, similar number of coal power plants have been selected in the LTGEP 2012 as well. Due to the reduction of hydro power energy, dispatch of coal has been increased and increase of CO_2 and particulate pollutant emissions are observed for LTGEP 2012 with compared to LTGEP 2010. Since the delay in coal plants in initial years, reduction of particulate pollutant emissions were observed in LTGEP 2012.

10.3 Fuel Prices

Fuel Prices for the present study were obtained from the Lanka Coal Company, Ceylon Petroleum Corporation and World Bank report for the previous years. The two fuel price values used in the respective studies are shown in Figure 10.7. Almost all fuel prices used for LTGEP 2012 have increased with different portions from the prices that were used in LTGEP 2010[28]. Figure 10.8 shows the fuel quantities expected to be consumed according to two base cases in LTGEP 2010 and LTGEP 2012.

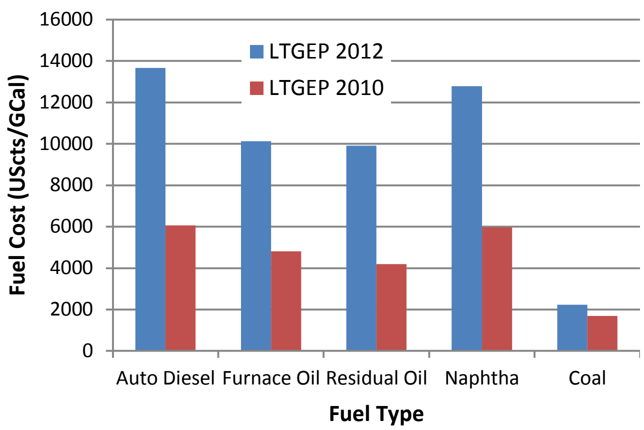

Figure 10.7 - Review of Fuel Prices

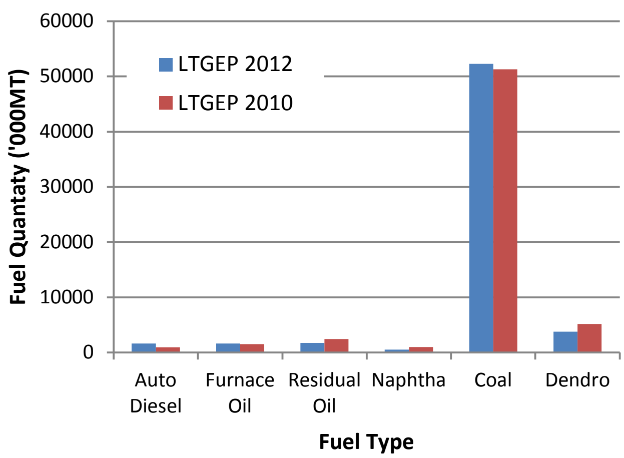

Figure 10.8 - Review of Fuel Quantities

10.4 Status of Last Year Base Case Plan

Since the planning period of LTGEP 2010 is 15 years and LTGEP 2012 is 20 years, it is not rational to compare the total system cost of two plans. However, the total system cost of the base plan of LTGEP 2010 for 2011-2025 is 7,142 USD million in 2010 price, whereas the cost of the base plan of LTGEP 2012 for 2013-2032 is 13,740 USD million in 2012 price. A brief description is provided in Table 10.1, indicating the present status of each of the power project proposed in the previous study in LTGEP 2010[28].

Table 10.1 – Comparison with LTGEP 2010- Base Case Plan

Project pipelined in LTGEP – 2010	For Year	Present Status and LTGEP 2012 Recommendations
150 MW Upper Kotmale hydro power project Retirement of 4 x5MW ACE Power Matara 75MW Gas Turbine	2012	Upper Kotmale plant was commissioned in 2012. 5 Year extension to contract period of 4x5MW ACE Power Matara was recommended. 75MW Gas Turbine is not committed.
4x5MW Northern Power 4x6MW Chunnakam Power Extension Retirement of 4x5MW ACE Power Horana and 4x5.63MW Lakdanavi 35MW Gas Turbine	2013	4x5MW Northern power and 3x8MW Chunnakam Extension addition rescheduled to 2014. 5 Year extension to contract period of 4x5MW ACE Power Horana and 4x5.63MW Lakdanavi were recommended. Not committed.
2x 315 MW Puttalum Coal (Stage – 2 & 3) Retirement of 5x17 MW Kelanitissa Gas Turbines	2014	Puttalum Coal (Stage -2) rescheduled second unit in 2014 and third unit in 2015. 5x17 MW Kelanitissa Gas Turbines retirement has been delayed until 2019
35MW Broadlands 120MW Uma Oya 49MW Gin Ganga	2015	35MW Broadlands and 120MW Uma Oya are rescheduled to 2016 and 49MW Gin Ganga was selected in 2029 1x75MW and 1x105MW Gas Turbine plants are selected.
No plant addition	2016	35 MW BroadlandsHPP and 120 MW Uma Oya HPP are committed.
2x 250 MW Trinco Coal	2017	2x 250 MW Trincomalee coal will be delayed to 2018.1x105 MW Gas Turbine plant has been selected.
1x 250 MW Trinco Coal	2018	3x 250 MW Trincomalee coal has been selected. 27 MW Moragolla HPP has been selected.

Project pipelined in LTGEP – 2010	For Year	Present Status and LTGEP 2012 Recommendations
1x 250 MW Trinco Coal	2019	No Change
No plant addition	2020	27 MW Moragolla HPP has been advanced to 2018. 1x 300 MW Coal plant has been selected.
2x 300 MW Coal Steam	2021	1x 300 MW Coal plant has been selected
1x 300 MW Coal Steam	2022	No Change
No plant addition	2023	1x 300 MW Coal plant has been selected.
2x 300 MW Coal Steam	2024	1x 300 MW Coal plant has been selected.
1x 300 MW Coal Steam	2025	No Change

All plants are assumed to be commissioned at the beginning of the year.

10.5 Overall Comparison

The overall comparison of generation expansions proposed by plans for last 20 years and actual expansion took place is shown in Annex 10.1

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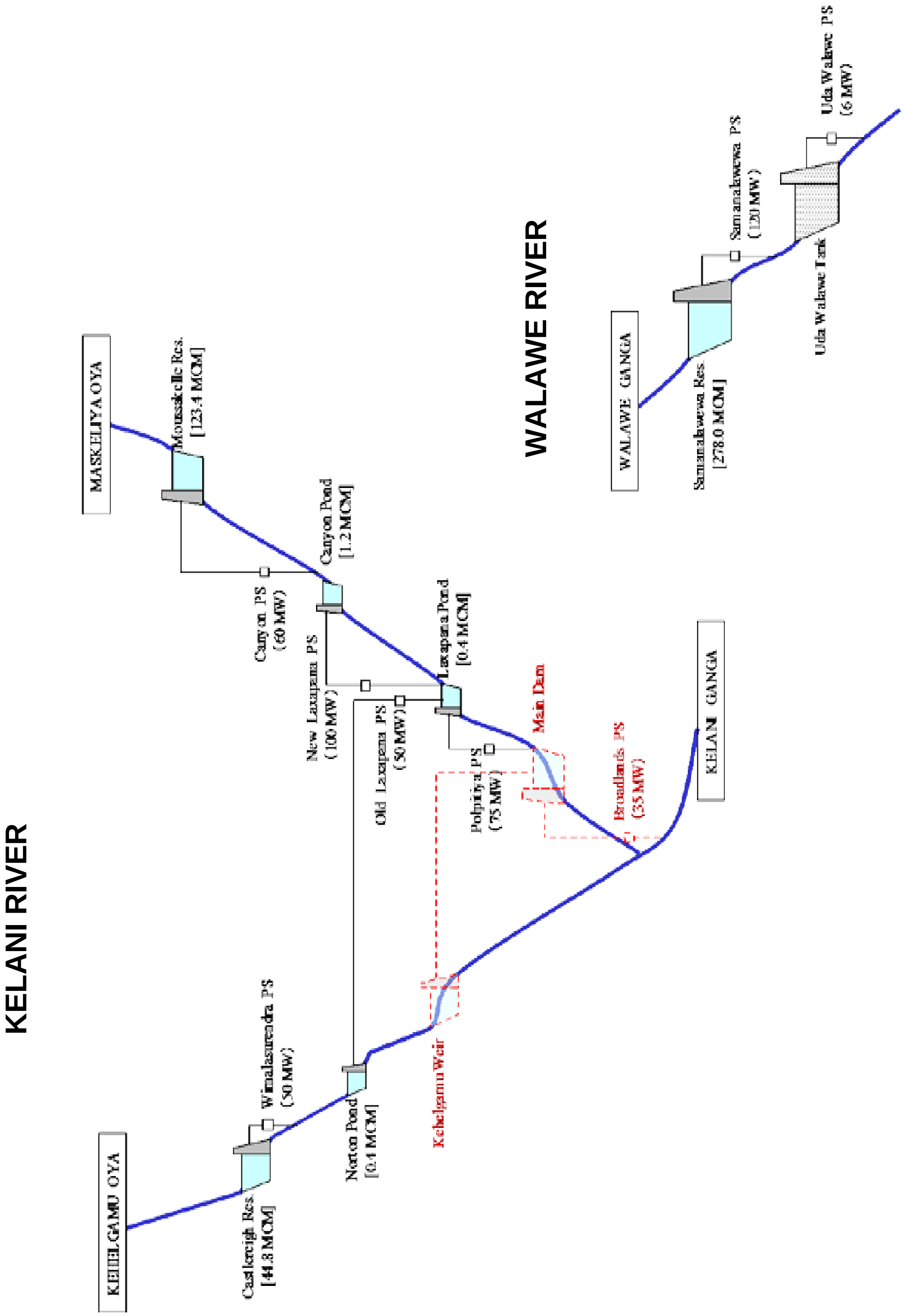
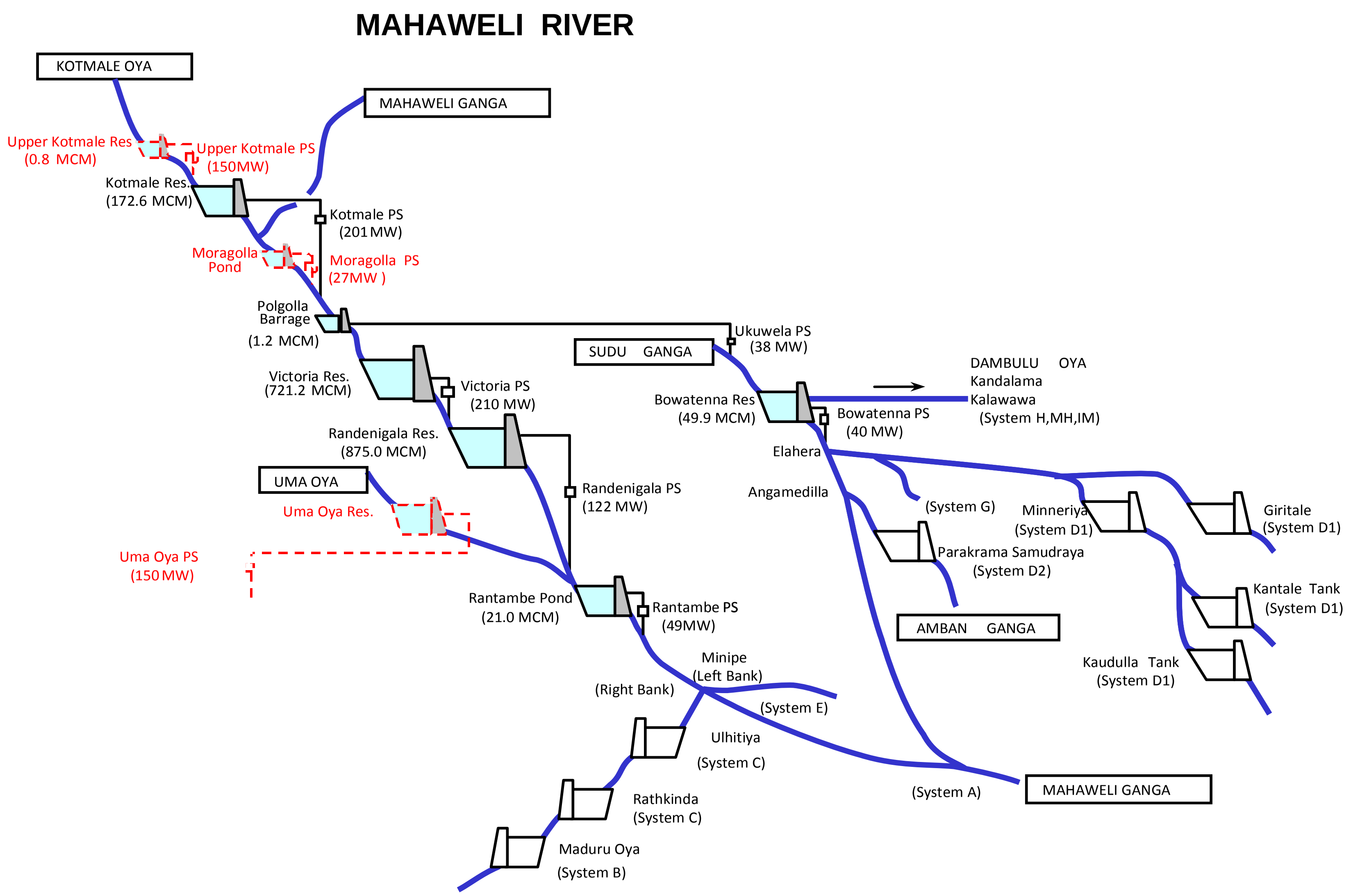
Annex 2.1

Reservoir Systems in Mahaweli, Kelani and Walawe River Basins

A2.1.1 Reservoir Systems in Kelani and Walawe River basins



A2.1.2 Reservoir System in Mahaweli River Basin



Annex 3.1
Sensitivities of Demand Forecast

Table A3.1 - Low Demand Forecast
(Demand Forecast with Demand Side Management Measures)

Year	Ene.Dem. (GWh)	Losses (%)	Ene. Gen.(GWh)	Peak (MW)
2013	10719	11.63%	12130	2371
2014	11323	11.59%	12807	2553
2015	11961	11.54%	13522	2681
2016	12583	11.50%	14218	2797
2017	13223	11.37%	14920	2986
2018	13883	11.25%	15643	3104
2019	14548	11.12%	16368	3217
2020	15243	11.00%	17127	3331
2021	15940	10.90%	17889	3477
2022	16672	10.79%	18690	3638
2023	17387	10.69%	19468	3789
2024	18119	10.59%	20264	3943
2025	18912	10.49%	21127	4114
2026	19733	10.39%	22021	4294
2027	20581	10.29%	22942	4406
2028	21486	10.19%	23925	4602
2029	22449	10.10%	24970	4810
2030	23444	10.00%	26049	5028
2031	24477	9.91%	27171	5255
2032	25538	9.83%	28321	5392
2033	26634	9.74%	29509	5625
2034	27731	9.65%	30694	5855
2035	28831	9.57%	31882	6086
2036	29998	9.49%	33143	6328
2037	31169	9.40%	34405	6534
Avg. Growth (%)	4.5		4.4	4.2

Table A3.2 – Intermediate High Demand Forecast

Year	Ene.Dem. (GWh)	Losses (%)	Ene. Gen.(GWh)	Peak (MW)
2013	11104	11.6%	12566	2451
2014	12124	11.6%	13713	2727
2015	13237	11.5%	14965	2970
2016	14202	11.5%	16048	3178
2017	15212	11.4%	17164	3392
2018	16270	11.3%	18332	3615
2019	17372	11.1%	19547	3846
2020	18533	11.0%	20824	4089
2021	19759	10.9%	22175	4345
2022	21052	10.8%	23599	4614
2023	22418	10.7%	25101	4898
2024	23859	10.6%	26684	5196
2025	25380	10.5%	28354	5509
2026	26993	10.4%	30122	5841
2027	28699	10.3%	31991	6190
2028	30511	10.2%	33974	6560
2029	32428	10.1%	36069	6950
2030	34451	10.0%	38278	7361
2031	36594	9.9%	40621	7795
2032	38845	9.8%	43078	8249
2033	41221	9.7%	45669	8728
2034	43722	9.7%	48395	9229
2035	46367	9.6%	51274	9759
2036	49153	9.5%	54305	10314
2037	52099	9.4%	57507	10900
Avg. Growth (%)	6.5		6.4	6.2

Table A3.3- High Demand Forecast

Year	Ene.Dem. (GWh)	Losses (%)	Ene. Gen.(GWh)	Peak (MW)
2013	11610	11.63%	13138	2617
2014	12540	11.59%	14183	2826
2015	13566	11.54%	15336	3058
2016	14664	11.50%	16570	3252
2017	15831	11.37%	17862	3512
2018	17069	11.25%	19232	3782
2019	18377	11.12%	20677	4061
2020	19771	11.00%	22214	4356
2021	21258	10.90%	23858	4679
2022	22847	10.79%	25611	5033
2023	24542	10.69%	27480	5330
2024	26351	10.59%	29472	5721
2025	28281	10.49%	31594	6137
2026	30348	10.39%	33866	6587
2027	32558	10.29%	36292	7065
2028	34926	10.19%	38890	7464
2029	37458	10.10%	41665	8003
2030	40159	10.00%	44621	8581
2031	43049	9.91%	47786	9197
2032	46117	9.83%	51143	9854
2033	49389	9.74%	54719	10397
2034	52870	9.65%	58520	11131
2035	56588	9.57%	62576	11911
2036	60546	9.49%	66892	12741
2037	64774	9.40%	71498	13627
Avg. Growth (%)	7.4		7.3	7.1

Table A3.4 – Time Trend Demand Forecast

Year	Ene.Dem. (GWh)	Losses (%)	Ene. Gen.(GWh)	Peak (MW)
2013	11104	11.63%	12566	2451
2014	12383	11.59%	14006	2792
2015	13190	11.54%	14911	2974
2016	14049	11.50%	15875	3113
2017	14964	11.37%	16885	3316
2018	15940	11.25%	17959	3535
2019	16978	11.12%	19103	3753
2020	18084	11.00%	20319	3984
2021	19263	10.90%	21618	4238
2022	20518	10.79%	23000	4517
2023	21855	10.69%	24470	4748
2024	23279	10.59%	26035	5055
2025	24795	10.49%	27701	5380
2026	26411	10.39%	29473	5732
2027	28132	10.29%	31359	6103
2028	29965	10.19%	33365	6404
2029	31917	10.10%	35501	6819
2030	33997	10.00%	37774	7264
2031	36212	9.91%	40196	7736
2032	38571	9.83%	42774	8242
2033	41084	9.74%	45518	7318
2034	43761	9.65%	48438	7726
2035	46613	9.57%	51546	8146
2036	49650	9.49%	54854	8592
2037	52885	9.40%	58374	8956
Avg. Growth (%)	6.6		6.5	6.3

Annex 4.1
Candidate Hydro Plant Data Sheets

A4.1.1 Gin (Ganga) Project

- **General**

The dam site is to be located on the upper Gin Ganga near Deniyaya town, about 2.2 km down stream of the confluence with a right bank tributary named Aranuwa Dola. The powerhouse is to be located some 9 river-kilometers downstream, at the end of a high gradient river stretch.

- **Project Overview**

Project Code	GING 074 Hydropower Project
Province / District	Southern / Galle
Catchment	Ging
Catchment Area / Reservoir Surface Area	154 km^2 / 1.7 km^2
Reservoir Full Supply Level / Storage	260 masl / 22.248 MCM
Average Tailwater Elevation	77.4 masl
Catchment Rainfall / Mean Stream flow	3700 mm/year / 16.4 m^3/s
Dam Type	Rock Fill
Dam Height / Crest level / Crest length	51 m / 263 masl / 440 m
Optimum Drawdown level	245 masl
Minimum operating level	215 masl
Spillway Type	Gated, incorporated in dam
Length / Diameter Headrace Tunnel	6100 m / 4.2 m
Length / Diameter Penstock	600 m / 2.9 m
Type of Powerhouse	Open-air
Plant Capacity	49 MW
Average Annual Generation	143 GWh
No of Houses/ Buildings Inundated	59
Inundation area at Full Supply Level	112 ha
Declared Forest Area Inundated	20.45 ha
Estimated Forest Area Inundated	31.05 ha

A4.1.2 Moragolla Project

- **General**

The MAHW263 project is to be located on the Mahaweli Ganga, near Moragolla town, downstream of the confluence of Kotmale Oya, but upstream of the tailrace outlet of the existing Lower Kotmale hydro scheme. The project was earlier, (in 1962) identified by the Hunting Survey Corporation of Canada. It was then known as "Moragolla".

MAHW263 is a run-of-river project, downstream of the candidate projects MAHW288 (long version) and MAHW287, which are mutually exclusive. Downstream of the MAHW263 project, the Mahaweli water is partly diverted through the Polgolla diversion, to serve Mahaweli Irrigation System D and H, while the remainder of the flow passes through the existing Victoria and Randenigala reservoirs.

The feasibility study further studied this project and the data below are according to the feasibility study.

- **Project Overview**

Project Code	MAHW263 Hydropower Project
Province / District	Central / Kandy
Catchment	Mahaweli
Catchment Area / Reservoir Surface Area	832 km^2 / 0.7 km^2
Reservoir Full Supply Level / Storage	548 masl / 4.23 MCM (run-of-river)
Average Tail water Elevation	473 masl
Catchment Rainfall / Mean Stream flow	3100 mm/year / 26.1 m^3/s
Dam Type	Concrete Gravity Dam
Dam Height / Crest Length	35.0 m / 214.5 m
Spillway Type	Gated, incorporated in dam
Length / Diameter Headrace Tunnel	2980 m / 4.5 m
Length / Diameter Penstock	185 m / 2.7 m
Type of Powerhouse	Open-air
Rated Head	75 m
Turbines, Rating at 50% Plant Factor	2 Francis, 13.25 MW each
Plant Capacity	27 MW
Mean Annual Generation	81.65 GWh
Optimum Drawdown Level	546 masl
Resettlement	24 families

Annex 4.2

Cost Calculations of Candidate Hydro Plants

Hydro Plant Basic Costs

Plant	Source	Capacity	Construction Cost (US $ million)		Cost Basis	Exchange Rate	New Exchange Rate **
			Foreign	Local		(LKR/US$)	(LKR/US$)
Ginganga	[1]	49	83.24	20.81	2008	110	114.35
Moragolla	[2]	27	60.14	24.90	2009	112	114.35

Sources of Information:

[1]* GING074 Hydropower Project Pre-Feasibility Study - CECB
[2]* Moragolla Hydropower Project CECB feasibility Study - CECB

* Updated in December 2008, Refer Page 79, Table 11.1 of Pre-Feasibility Study Final Report
** Updated in February 2010, Refer page 127, Table 9.2 of Feasibility Study Volume 2 Main report

Hydro Plant costs used for the 2012 Expansion Planning

Plant	Capacity (MW)	Pure Const. Cost US$/kW		Total Cost (US$/kW)	Const Period (Yrs)	IDC at 10% (% pure costs)	Const. Cost as Input to Analysis incl. IDC (US$/kW)		Total Cost incl. IDC (US$/kW)
		Local	Foreign				Local	Foreign	
Gin Ganga	49	691.0	1751.1	2442.1	5	23.78	855.32	2167.5	3022.80
Moragolla	27	1001.1	2414.5	3415.6	4	18.53	1186.6	2861.9	4048.56

* All costs in Jan 2012 prices

Annex 4.3

Candidate Thermal Plant Data Sheets

• **Basic data**	**LNG**	**LNG with terminal**	**Coal Steam**	**Nuclear**
Installed capacity (MW)	250	250	300	600
Fuel Type	LNG	LNG	Coal	Nuclear
Fuel Supply	-	-	-	-
• **Information input to studies**				
Annual fixed O&M cost (US$/kW-month)	0.370	0.370	1.018	7.210
Variable O&M cost (USCts/kWh)	0.3083	0.3083	0.5589	1.6948
Time Availability * (Maximum annual PF) (%)	-	-	-	-
Scheduled annual maintenance duration (days)	30	30	42	40
Forced outage rate (%)	8	8	3.5	0.5
Calorific value (kCal/kg)	13000	-	6300	-
Minimum operating level (%)	33	-	75	50
Heat rate at minimum operating level (kCal/kWh)	2457	2457	2337	2496
Heat rate at full load operating level (kCal/kWh)	1788	1788	2293	2418
Capital Cost Incl. IDC (US$/kW)	1299.7	4327.5	1963.8	5061
Construction Period (years)	3	4.5	4	
Economic Life time (years)	30	30	30	
Flue Gas Treatment costs	-	-	-	-

- Time Availability = (Total Time - Sche. Annual Maint.) x (1-FOR)

• **Basic data**	**Gas Turbine**	**Gas Turbine**
Installed capacity (MW)	75	105
Fuel Type	Auto Diesel	Auto Diesel
Fuel Supply	-	-
• **Information input to studies**		
Annual fixed O&M cost (US$/kW-month)	0.577	0.507
Variable O&M cost (USCts/kWh)	0.4601	0.4024
Time Availability * (Maximum annual PF) (%)	84.4	84.4
Scheduled annual maintenance duration (days)	30	30
Forced outage rate (%)	8	8
Calorific value (kCal/kg)	10550	10550
Minimum operating level (%)	30	30
Heat rate at minimum operating level (kCal/kWh)	4134	4134
Heat rate at full load operating level (kCal/kWh)	2857	2857
Capital Cost Incl. IDC (US$/kW)	618.1	514.5
Construction Period (years)	1.5	1.5
Economic Life time (years)	20	20
Flue Gas Treatment costs	-	-

- Time Availability = (Total Time - Sche. Annual Maint.) x (1-FOR)

• **Basic data**	**Combined Cycle**	**Combined Cycle**	**Dendro**
Installed capacity (MW)	150	300	5
Fuel Type	Auto Diesel	Auto Diesel	Bio-mass
Fuel Supply	-	-	-
• **Information input to studies**			
Annual fixed O&M cost (US$/kW-month)	0.508	0.384	3.067
Variable O&M cost (USCts/kWh)	0.4357	0.3286	0.5618
Time Availability * (Maximum annual PF) (%)	84.4	84.4	-
Scheduled annual maintenance duration (days)	30	30	74
Forced outage rate (%)	8	8	2
Calorific value (kCal/kg)	10550	10550	3224
Minimum operating level (%)	33	33	100
Heat rate at minimum operating level (kCal/kWh)	2614	2457	5694
Heat rate at full load operating level (kCal/kWh)	1462	1454	5694
Capital Cost Incl. IDC (US$/kW)	1156.3	935.1	1767.4
Construction Period (years)	3	3	1.5
Economic Life time (years)	30	30	30
Flue Gas Treatment costs	-	-	-

- Time Availability = (Total Time - Sche. Annual Maint.) x (1-FOR)

Annex 5.1

2011 NCRE Tariff Announced by the PUCSL

Option 1: Three-tier Tariff

This will consist of a fixed rate, operations and maintenance (O&M) rate and a fuel rate.

Technology	Escalable	Escalable	Non-escalable fixed rate		Escalable Year 16+ Base rate	Royalty to Govt, paid direct by the power purchaser Year 16+
	Base O&M Rate	Base Fuel rate	Year 1-8	Year 9-15		
Mini-hydro	1.61	None	12.64	5.16	1.68	10% of total tariff
Mini-hydro - Local	1.65	None	12.92	5.28	1.68	10% of total tariff
Wind	3.03	None	17.78	7.26	1.68	10% of total tariff
Wind - Local	3.11	None	18.28	7.47	1.68	10% of total tariff
Biomass (Dendro)	1.29 (1-15 years) 1.61 (16^{th} year onwards)	9.10	7.58	3.10	1.68	No royalty
Biomass (Agricultural & Industrial Waste)	1.29 (1-15 years) 1.61 (16^{th} year onwards)	4.55	7.58	3.10	1.68	No royalty
Municipal Waste	4.51	1.75	15.16	6.19	1.68	No royalty
Waste Heat Recovery	0.43	None	7.13	2.65	1.68	No royalty
Escalation rate for year 2010	7.64%	5.09%	None	None	5.09%	

Option 2: Flat Tariff

Technology	All inclusive rate (LKR/kWh) for years 1-20
Mini-hydro	13.04
Mini-hydro - Local	13.32
Wind	19.43
Wind - Local	19.97
Biomass (Dendro)	20.70
Biomass (Agricultural & Industrial Waste)	14.53
Municipal Waste	22.02
Waste Heat Recovery	6.64

Annex 5.2

Renewable generation addition in high NCRE Scenario

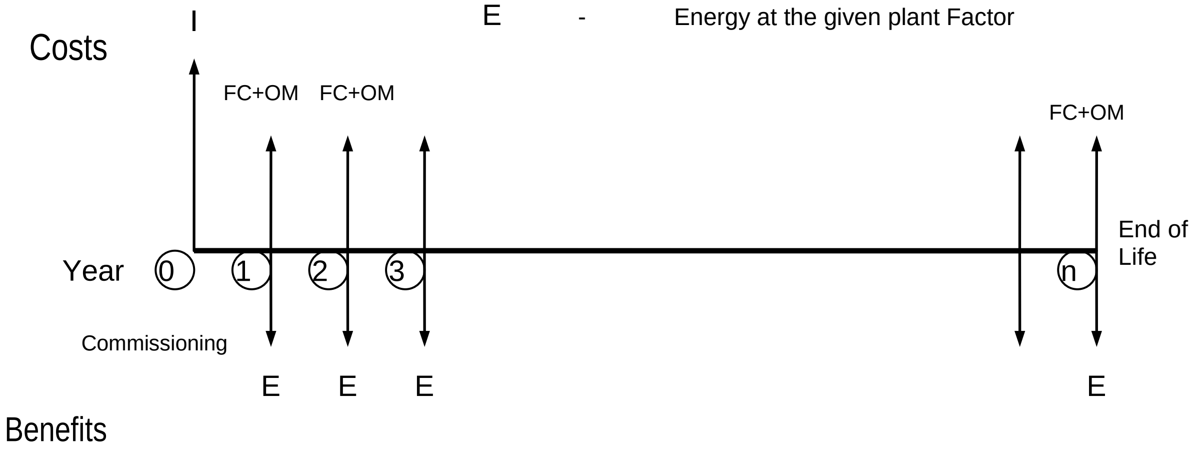
Year	Annual CapacityAdditions				Cumulative Capacity Addition				Cumulative	Cumulative Energy Generation				Cumulative Annual	Total Generation Forecasted (GWh)	% of NCRE from total energy
	Mini Hydro (MW)	Wind (MW)	Solar (MW)	Dendro (MW)	Mini Hydro Hydro (MW)	Wind (MW)	Solar (MW)	Dendro (MW)	Total NCRE Capacity (MW)	Mini Hydro Energy (GWh)	Wind (GWh)	Solar Energy (GWh)	Dendro Energy (GWh)	Total NCRE Energy (GWh)		
2013	25	20	10	4	221	96	11	20	337	813	269	16	140	1238	12566	9.9%
2014	25	14	10	5	246	110	21	25	381	905	308	31	175	1419	13502	10.5%
2015	25	50	10	5	271	160	31	30	461	997	449	46	210	1702	14509	11.7%
2016	25	40	0	15	296	200	31	45	541	1089	561	46	315	2011	15388	13.1%
2017	35	30	11	25	331	230	42	70	631	1218	645	63	491	2417	16270	14.9%
2018	40	30	0	30	371	260	42	100	731	1365	729	63	701	2858	17171	16.6%
2019	50	55	10	35	421	315	52	135	871	1549	883	77	946	3455	18087	19.1%
2020	65	75	10	45	486	390	62	180	1056	1788	1093	92	1261	4234	19030	22.2%
2021	30	10	0	15	516	400	62	195	1111	1898	1121	92	1367	4478	20010	22.4%
2022	30	0	10	15	546	400	72	210	1156	2009	1121	107	1472	4709	21023	22.4%
2023	30	0	0	15	576	400	72	225	1201	2119	1121	107	1577	4924	22072	22.3%
2024	25	0	10	15	601	400	82	240	1241	2211	1121	122	1682	5136	23159	22.2%
2025	25	0	13	15	626	400	95	255	1281	2303	1121	141	1787	5352	24284	22.0%
2026	20	50	0	10	646	450	95	265	1361	2377	1121	141	1857	5496	25458	21.6%
2027	20	0	10	10	666	450	105	275	1391	2450	1121	156	1927	5654	26677	21.2%
2028	20	0	0	10	686	450	105	285	1421	2524	1121	156	1997	5798	27949	20.7%
2029	15	50	10	10	701	500	115	295	1496	2579	1121	171	2067	5938	29273	20.3%
2030	15	0	0	5	716	500	115	300	1516	2634	1121	171	2102	6028	30645	19.7%
2031	15	0	10	5	731	500	125	305	1536	2689	1233	186	2137	6245	32079	19.5%
2032	10	50	0	5	741	550	125	310	1601	2726	1360	186	2172	6444	33555	19.2%
2033	10	50	10	5	751	600	135	315	1666	2763	1500	201	2208	6672	35087	19.0%
2034	10	50	0	5	761	650	135	320	1731	2800	1654	201	2243	6898	36672	18.8%
2035	5	50	10	5	766	700	145	325	1791	2818	1822	216	2278	7134	38320	18.6%
2036	5	50	15	5	771	750	160	330	1851	2837	2004	238	2313	7392	40027	18.5%
2037	5	50	15	5	776	800	175	335	1911	2855	2201	261	2348	7665	41804	18.3%

Annex 6.1

Methodology of the Screening of Curve

Present value of specific energy cost of thermal plants is calculated for a range of discount rates and plant factors, in order to mimic the procedure adopted in the WASP planning package used for the expansion studies.

I - Investment
FC - Fuel Cost
OM - Operations & Maintenance Cost
E - Energy at the given plant Factor



Investment cost with interest during construction is assumed to occur at the beginning of the commissioning year as presented in above figure. Yearly fixed and variable operation, maintenance and repair costs are discounted to the beginning of the commissioning year while annual fuel costs are also discounted considering the fuel escalation rates. Energy is calculated for each year of operation over the life time for various plant factors.

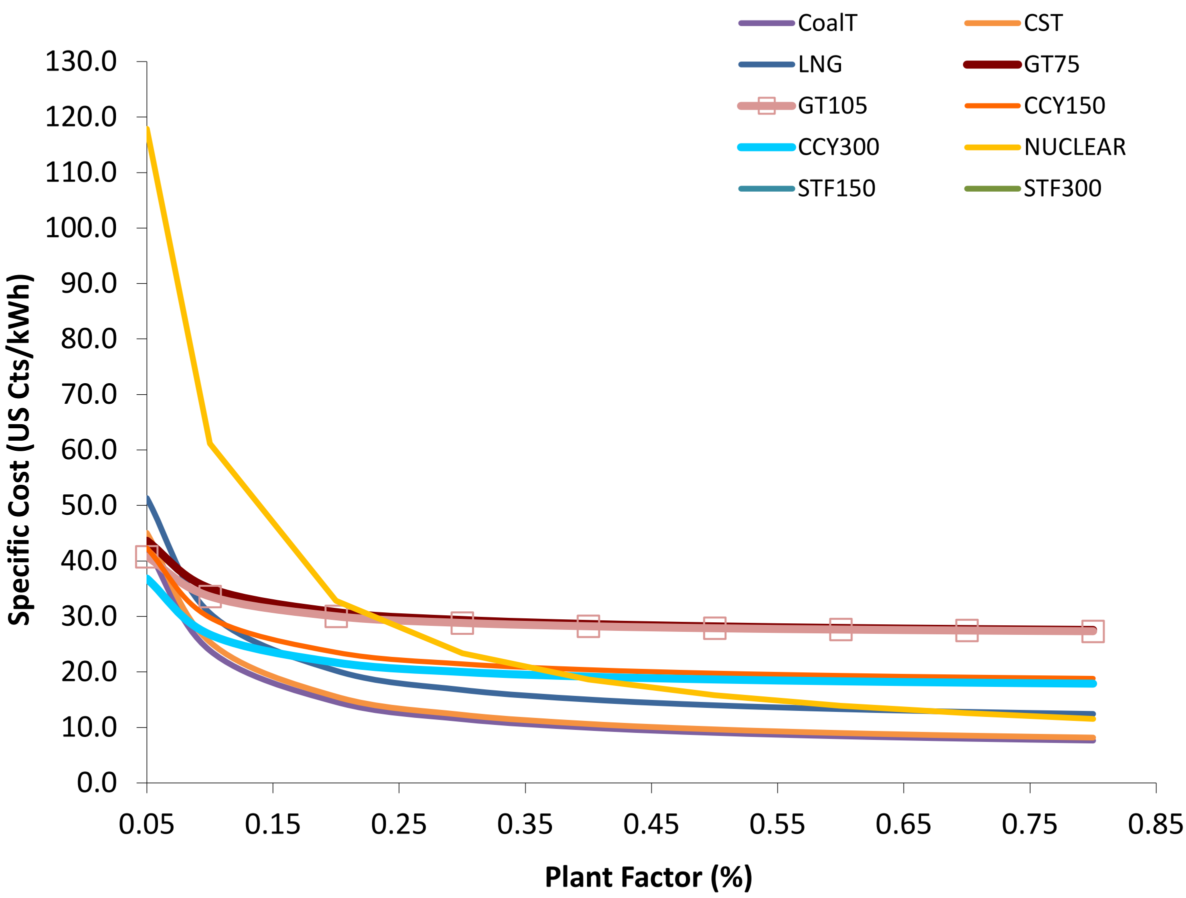
Specific Cost = [I + { Σ Fixed OM + (FC + Var. OM) * E } * PV Factor] / E * PV Factor

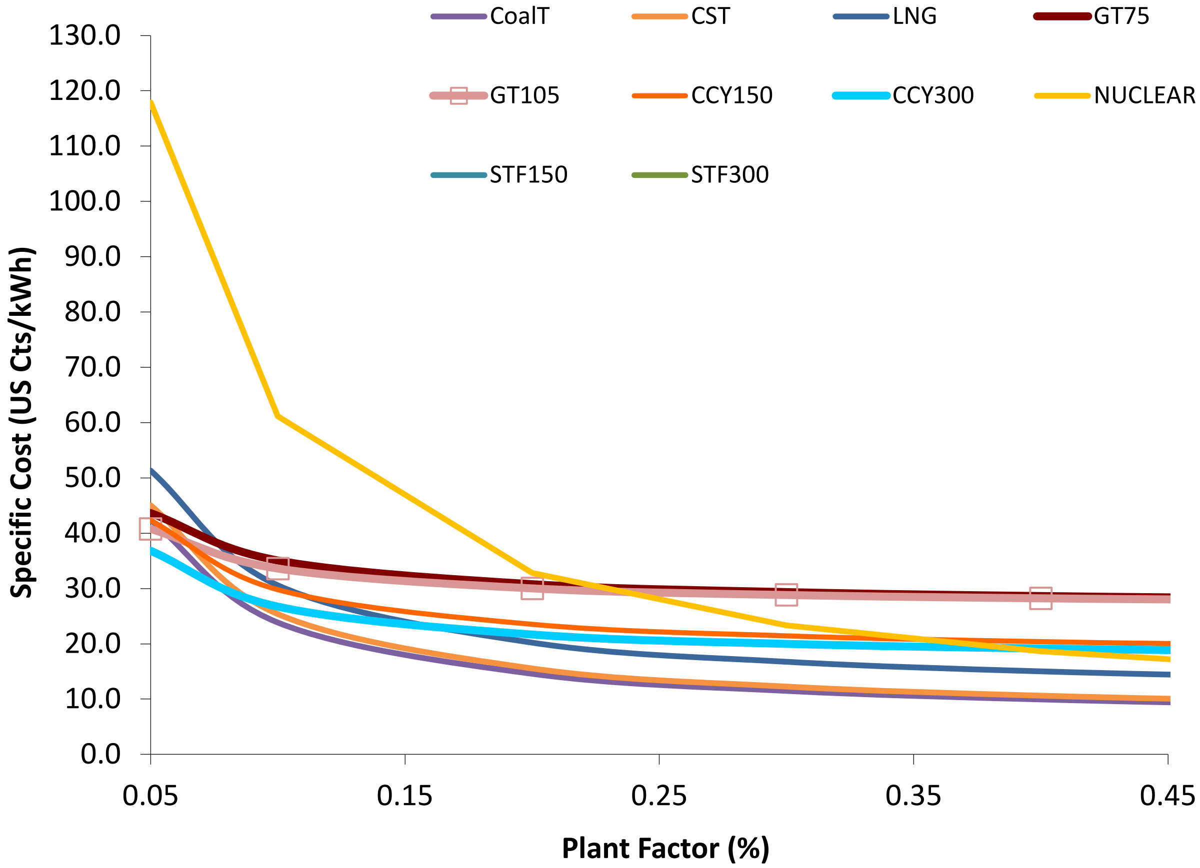
Screening of Generation Options

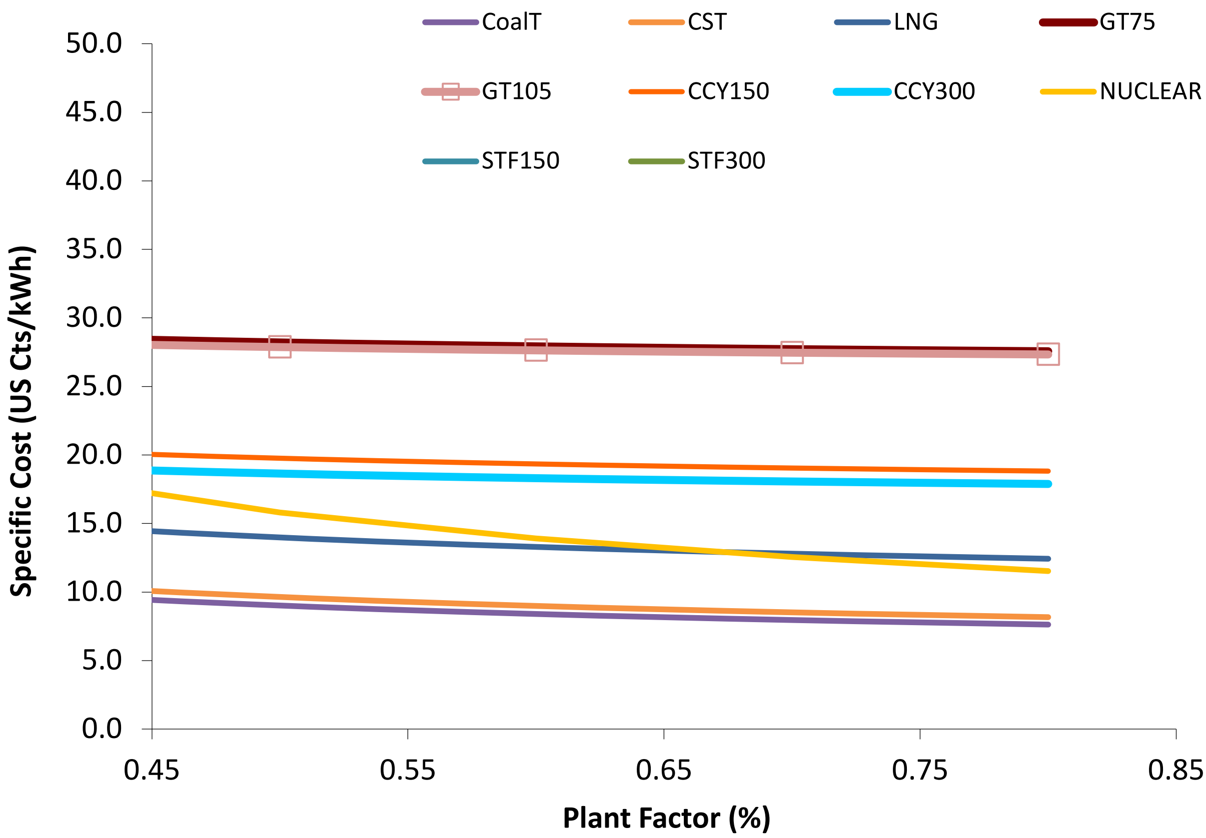
The screening curves were developed for the following plants.

1. STF1 – 150 MW furnace oil fired steam power plants
2. STF3 – 300 MW furnace oil fired steam power plants
3. CoalT – 250 MW Trinco coal plant
4. CST – 300 MW coal fired steam power plants
5. GT75 – 75 MW auto diesel fired gas turbines
6. GT105 – 105 MW auto diesel fired gas turbines
7. CCY150 – 150 MW auto diesel fired combined cycle power plants
8. CCY300 – 300 MW auto diesel fired combined cycle power plants
9. LNG – 250 MW LNG fired combine cycle plants
10. NUCLEAR – 600MW

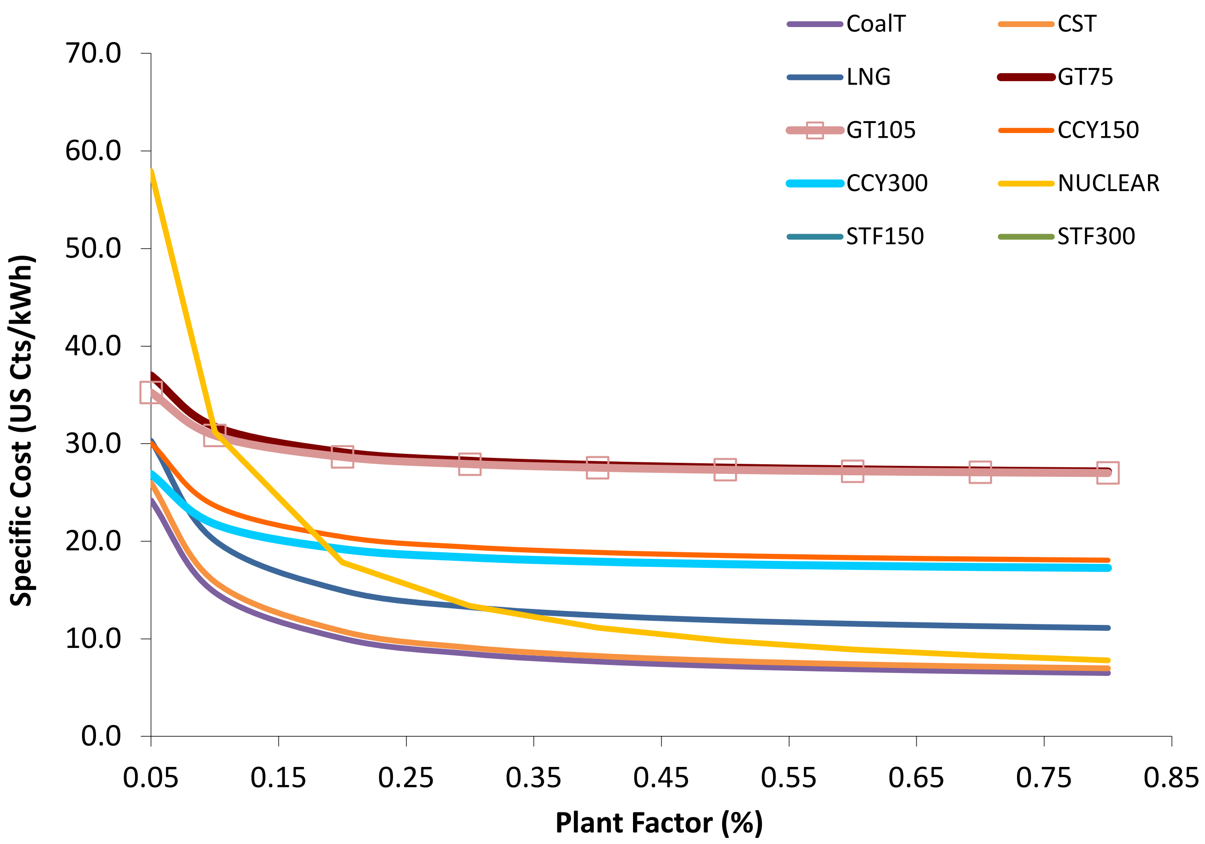
A7.1.1 Screening Curves of the Generation Options at 10% Discount Rate



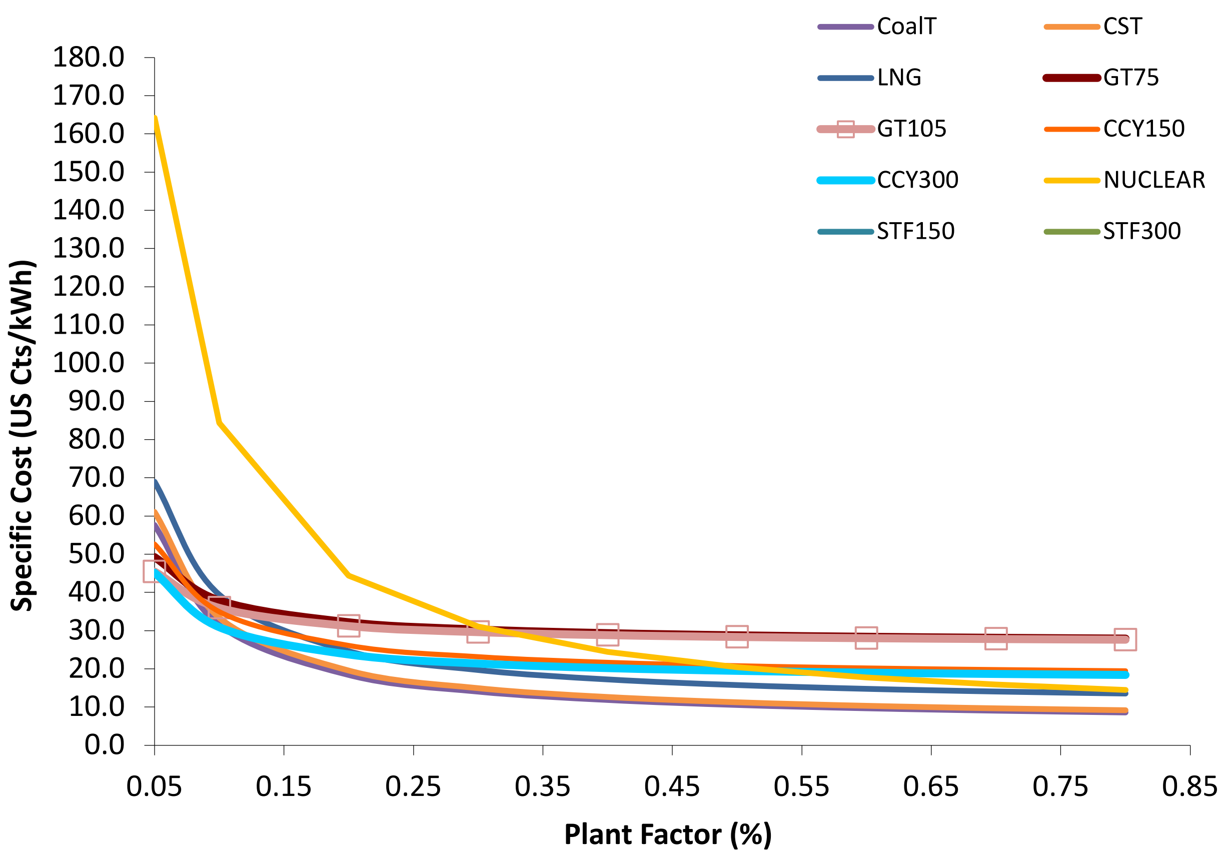

CoalT
CST
LNG
GT75
GT105
CCY150
CCY300
NUCLEAR
STF150
STF300
Specific Cost (US Cts/kWh)
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
0.05
0.15
0.25
0.35
0.45
Plant Factor (%)


CoalT
CST
LNG
GT75
GT105
CCY150
CCY300
NUCLEAR
STF150
STF300
Specific Cost (US Cts/kWh)
50.0
45.0
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
0.0
0.45
0.55
0.65
0.75
0.85
Plant Factor (%)

A7.1.2 Screening Curves of the Generation Options at 3% Discount Rate



7.1.3 Screening Curves of the Generation Options at 15% Discount Rate



Annex 7.2

Capacity Balance for the Base Case – 2012

Plant Name	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hydro																				
Existing Major Hydro	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335
New Major Hydro	0	0	0	155	155	182	182	182	182	182	182	182	182	182	182	182	231	231	231	231
Mini hydro	219	232	244	256	279	294	308	320	332	345	354	365	377	389	400	412	414	426	438	450
Sub Total	1554	1567	1579	1746	1769	1811	1825	1837	1849	1862	1871	1882	1894	1906	1917	1929	1980	1992	2004	2016
NCRE-Wind	90	90	90	220	230	240	250	260	270	280	290	300	310	320	330	340	350	360	370	380
NCRE-Solar	1.3	21	31	51	72	82	85	88	91	94	97	100	103	106	109	112	115	118	121	124
Thermal Existing and Committed																				
Small Gas Turbines	85	85	85	85	85	85	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Sapugaskanda	72	72	72	72	72	72	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesl Ext.Sapugaskanda	72	72	72	72	72	72	72	72	72	72	36	36	0	0	0	0	0	0	0	0
Gas Turbine No7	115	115	115	115	115	115	115	115	115	115	0	0	0	0	0	0	0	0	0	0
Lakdhanavi	23	23	23	23	23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Asia Power	49	49	49	49	49	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KPS Combined Cycle	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165
AES Combined Cycle	163	163	163	163	163	163	163	163	163	163	163	0	0	0	0	0	0	0	0	0
Colombo Power	60	60	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ACE Power Horana	20	20	20	20	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ACE Power Matara	20	20	20	20	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Heladhanavi	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ACE Power Embilipitiya	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass (Dendro)	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Kerawalapitiya CCY	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270
Puttalum Coal	275	550	825	825	825	825	825	825	825	825	825	825	825	825	825	825	825	825	825	825
Northern Power	0	20	20	20	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Chunnakkam Power Extension	0	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Sub Total	1,598	1,917	1,933	1,933	1,933	1,801	1,644	1,644	1,644	1,644	1,493	1,330	1,294	1,294	1,294	1,294	1,294	1,294	1,294	1,294
New Thermal Plants																				
Coal	0	0	0	0	0	0	0	275	550	825	1,100	1,375	1,650	1,650	1,925	1,925	2,200	2,475	2,750	2,750
Gas Turbine 75 MW	0	0	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	150
Gas Turbine 105 MW	0	0	105	105	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210
Coal Trinco	0	0	0	0	0	681	908	908	908	908	908	908	908	908	908	908	908	908	908	908
NCRE- Biomass (Dendro)	4	8	12	16	20	24	28	32	36	40	44	48	52	56	60	64	68	72	76	80
Sub Total	4	8	192	196	305	990	1221	1500	1779	2058	2337	2616	2895	2899	3178	3182	3461	3740	4019	4098
Total Installed Capacity (A)	**3247**	**3603**	**3825**	**4146**	**4309**	**4924**	**5025**	**5329**	**5633**	**5938**	**6088**	**6228**	**6496**	**6525**	**6828**	**6857**	**7200**	**7504**	**7808**	**7912**
Installed Capacity without NCRE* (B)	**2937**	**3260**	**3460**	**3619**	**3728**	**4308**	**4382**	**4661**	**4940**	**5219**	**5347**	**5463**	**5706**	**5710**	**5989**	**5993**	**6321**	**6600**	**6879**	**6958**
Peak Demand (C)	**2451**	**2692**	**2894**	**3016**	**3193**	**3383**	**3556**	**3731**	**3920**	**4125**	**4287**	**4499**	**4717**	**4948**	**5187**	**5369**	**5625**	**5893**	**6171**	**6461**
Difference without NDRE* (B-C)	**486**	**568**	**566**	**603**	**535**	**925**	**826**	**930**	**1020**	**1094**	**1060**	**964**	**989**	**762**	**802**	**624**	**696**	**707**	**708**	**497**
Difference (%)	**19.8**	**21.1**	**19.5**	**20.0**	**16.7**	**27.3**	**23.2**	**24.9**	**26.0**	**26.5**	**24.7**	**21.4**	**21.0**	**15.4**	**15.5**	**11.6**	**12.4**	**12.0**	**11.5**	**7.7**

Note : All the Capacities are in MW; Above total includes NCRE plants Maintenance and FOR outages Operational aspects not reflected

* Non Dispatchable Renewable Energy - Wind & Minihydro

Annex 7.3

Energy Balance for the Base Case – 2012

Plant Name	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hydro																				
Existing Major Hydro	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112
New Major Hydro	0	0	0	366	366	443	443	443	443	443	443	443	443	443	443	443	579	579	579	579
Sub Total	4112	4112	4112	4478	4478	4556	4556	4556	4556	4556	4556	4556	4556	4556	4556	4556	4692	4692	4692	4692
Total NCRE	620	652	688	968	1003	1064	1159	1268	1339	1373	1421	1481	1546	1592	1654	1700	1761	1793	1854	1901
Thermal Existing and Committed																				
Small Gas Turbines	5	4	3	5	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Sapugaskanda	456	425	453	455	461	308	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesl Ext.Sapugaskanda	491	485	487	487	490	355	310	239	156	94	37	28	0	0	0	0	0	0	0	0
Gas Turbine No7	249	234	258	249	290	107	79	54	22	9	0	0	0	0	0	0	0	0	0	0
Lakdhanavi	126	111	140	141	146	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Asia Power	326	284	326	327	335	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KPS Combined Cycle	469	386	494	524	639	245	237	134	105	57	60	34	18	48	28	68	56	48	38	90
AES Combined Cycle	390	301	425	467	538	229	197	121	70	52	0	0	0	0	0	0	0	0	0	0
Colombo Power	419	417	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ACE Power Horana	165	156	164	164	166	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ACE Power Matara	161	148	160	160	164	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Heladhanavi	696	696	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ACE Power Embilipitiya	692	672	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass (Dendro)	94	94	94	94	94	85	74	58	50	42	31	25	12	28	17	33	25	18	15	40
Kerawalapitiya CCY	1,169	819	1,020	1,134	1,314	594	496	378	301	190	147	111	59	114	58	144	119	113	102	163
Puttalum Coal	1,625	3,128	4,911	4,923	4,990	4,231	4,065	4,048	4,082	4,135	4,218	4,271	4,352	4,519	4,710	4,832	4,956	5,030	5,098	5,373
Northern Power	0	131	137	137	138	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Chunnakkam Power Extension	0	183	183	183	183	151	140	110	93	65	43	32	20	42	17	51	29	27	27	41
Sub Total	7,533	8,676	9,255	9,449	9,953	6,304	5,599	5,142	4,878	4,644	4,536	4,500	4,462	4,751	4,828	5,128	5,185	5,236	5,279	5,707
New Thermal Plants																				
Coal	0	0	0	0	0	0	0	1,278	2,421	3,640	4,699	5,761	6,877	7,584	8,714	9,511	10,602	11,916	13,241	14,089
Gas Turbine 75 MW	0	0	145	145	159	57	41	32	20	6	10	5	4	8	7	13	11	10	10	10
Gas Turbine 105 MW	0	0	215	228	524	180	157	109	74	44	46	19	14	45	25	46	41	38	34	110
Coal Trinco	0	0	0	0	0	4,869	6,426	6,511	6,589	6,642	6,708	6,754	6,786	6,814	6,834	6,849	6,864	6,869	6,873	6,876
Biomass (Dendro)	27	54	82	109	137	140	150	134	130	119	91	84	40	103	59	138	109	81	84	147
Sub Total	27	54	441	482	820	5247	6773	8065	9234	10451	11555	12622	13721	14553	15638	16557	17627	18914	20243	21232
Total Generation	**12293**	**13495**	**14497**	**15377**	**16254**	**17170**	**18086**	**19030**	**20006**	**21023**	**22067**	**23159**	**24283**	**25452**	**26676**	**27941**	**29265**	**30634**	**32067**	**33532**
System Demand	**12303**	**13502**	**14509**	**15388**	**16270**	**17170**	**18086**	**19034**	**20009**	**21023**	**22072**	**23159**	**24284**	**25457**	**26676**	**27949**	**29273**	**30645**	**32078**	**33555**
Unserved Energy	**11**	**7**	**12**	**11**	**16**	**0**	**0**	**4**	**3**	**0**	**5**	**0**	**0**	**5**	**0**	**9**	**8**	**11**	**11**	**23**

Note:- 1. Numbers may not add exactly due to rounding off.

2. Aggregation of hydro dispatches for individual plant is not possible owing to integrated operation and dispatch of hydro energy

3. All energy figures are shown for weighted average hydrological condition in GWh.

Annual Generation and Plant Factors - Base Case 2012

Year / Plant	Annual Energy (GWh) – Hydrology condition 1	2	3	4	5	Avg.	Annual Plant Factor (%) – Hydrology condition 1	2	3	4	5	Avg.
2013												
Kelanitissa Gas Turbines (17 MW)	0	1	1	2	17	5	0.0	0.1	0.2	0.3	2.4	0.8
Sapugaskanda Diesel Plant (4x18 MW)	178	347	447	458	462	456	29.2	57.0	73.3	75.1	75.7	74.8
Sapugaskanda Diesel Ext. (8x9 MW)	399	488	490	491	491	491	65.5	80.1	80.4	80.6	80.6	80.5
115 MW Kelanitissa Gas Turbine	9	67	125	243	296	249	0.9	6.8	12.7	24.6	29.9	25.2
Lakdanavi Plant	24	49	81	124	143	126	12.3	24.8	40.9	62.8	72.3	63.7
Asia Power Plant	86	169	276	328	333	326	20.1	39.4	64.3	76.5	77.7	75.9
Kelanitissa Combined Cycle Plant	92	151	363	452	568	469	6.6	10.8	25.9	32.3	40.5	33.5
AES Combined Cycle Plant	47	131	180	367	512	389	3.3	9.2	12.6	25.7	35.9	27.3
Colombo Power Plant	387	418	419	419	419	419	73.6	79.6	79.7	79.7	79.7	79.7
ACE Power Plant (Horana)	73	147	164	166	167	165	41.6	83.7	93.3	94.7	95.1	94.4
ACE Power Plant (Matara)	52	88	153	162	164	161	29.7	50.0	87.3	92.3	93.4	91.7
Heladanavi Plant (Puttalam)	694	696	696	696	696	696	79.5	79.8	79.8	79.8	79.8	79.8
ACE Power Plant (Embilipitiya)	390	678	689	694	694	692	44.8	77.8	79.0	79.6	79.7	79.4
Kerawalapitiya CombinedCycle 270 MW	596	675	850	1,154	1,290	1,169	25.2	28.5	35.9	48.8	54.5	49.4
275 MW Puttalam Coal Plant	1,387	1,450	1,498	1,610	1,705	1,625	57.6	60.2	62.2	66.8	70.8	67.4
Dendro	94	94	94	94	94	94	89.7	89.8	89.8	89.8	89.8	89.8
DNRO	27	27	27	27	27	27	77.7	77.7	77.7	77.7	77.7	77.7
Total hydro	7,483	6,342	5,465	4,525	3,903	4,447						
Total thermal	4,537	5,677	6,553	7,489	8,079	7,560						
Total generation	12,020	12,019	12,018	12,014	11,981	12,007						
Total demand	12,021	12,021	12,021	12,021	12,021	12,021						
Deficit	0	1	3	7	39	13						
2014												
Kelanitissa Gas Turbines (17 MW)	0	1	1	2	13	4	0.0	0.1	0.1	0.3	1.8	0.6
Sapugaskanda Diesel Plant (4x18 MW)	132	236	366	429	434	425	21.6	38.7	60.0	70.3	71.2	69.8
Sapugaskanda Diesel Ext. (8x9 MW)	295	469	479	486	488	485	48.4	76.9	78.6	79.7	80.0	79.6
115 MW Kelanitissa Gas Turbine	29	76	91	232	266	234	2.9	7.7	9.2	23.4	26.9	23.6
Lakdanavi Plant	15	35	56	109	129	111	7.6	17.7	28.3	55.5	65.5	56.5
Asia Power Plant	63	114	231	282	307	284	14.7	26.6	53.8	65.7	71.5	66.1
Kelanitissa Combined Cycle Plant	38	100	198	369	488	386	2.7	7.1	14.1	26.3	34.8	27.5
AES Combined Cycle Plant	39	95	148	288	380	301	2.7	6.6	10.4	20.1	26.6	21.1
Colombo Power Plant	330	409	415	417	418	417	62.8	77.8	78.9	79.4	79.5	79.3
ACE Power Plant (Horana)	47	86	152	157	159	156	26.7	48.9	86.8	89.8	90.8	89.2
ACE Power Plant (Matara)	41	66	124	150	152	148	23.7	37.9	70.5	85.4	86.8	84.7
Heladanavi Plant (Puttalam)	679	695	696	696	696	696	77.8	79.6	79.7	79.8	79.8	79.8
ACE Power Plant (Embilipitiya)	263	595	659	674	680	672	30.1	68.3	75.6	77.3	78.0	77.1
Kerawalapitiya CombinedCycle 270 MW	558	579	721	795	935	819	23.6	24.5	30.5	33.6	39.5	34.6
275 MW Puttalam Coal Plant	2,739	2,824	2,905	3,103	3,267	3,128	56.9	58.6	60.3	64.4	67.8	64.9
20 MW Northern	44	96	128	132	133	131	25.1	54.8	72.8	75.2	75.9	74.9
Dendro	94	94	94	94	94	94	89.1	89.7	89.8	89.8	89.8	89.8
Chunnakum ext.	181	183	183	183	183	183	86.1	87.1	87.2	87.2	87.2	87.2
DNRO	54	54	54	54	54	54	77.0	77.7	77.7	77.7	77.7	77.7
Total hydro	7,560	6,394	5,499	4,542	3,914	4,464						
Total thermal	5,641	6,807	7,701	8,653	9,277	8,730						
Total generation	13,202	13,201	13,200	13,195	13,191	13,195						
Total demand	13,202	13,202	13,202	13,202	13,202	13,202						
Deficit	1	2	3	7	11	8						

Note: Hydrological Conditions: 1. Very Wet(0.5%) 2.Wet(1%) 3. Medium(1.5%) 4. Dry(77%) 5. Very Dry(20%)
Shown within brackets is the probability of occurrence of each Hydro Condition.

Year	Annual Energy (GWh)						Annual Plant Factor (%)					
	Hydrology condition						Hydrology condition					
Plant	1	2	3	4	5	Avg.	1	2	3	4	5	Avg.
2015												
Kelanitissa Gas Turbines (17 MW)	0	1	2	3	4	3	0.1	0.1	0.2	0.4	0.6	0.5
Sapugaskanda Diesel Plant (4x18 MW)	217	401	446	455	456	453	35.5	65.8	73.2	74.6	74.8	74.3
Sapugaskanda Diesel Ext. (8x9 MW)	418	474	483	487	489	487	68.5	77.7	79.2	79.9	80.2	79.9
115 MW Kelanitissa Gas Turbine	55	107	185	255	289	258	5.5	10.8	18.7	25.8	29.2	26.1
Lakdanavi Plant	42	87	135	141	143	140	21.5	44.0	68.2	71.4	72.5	71.0
Asia Power Plant	110	262	317	327	330	326	25.7	61.0	73.9	76.1	76.9	75.8
Kelanitissa Combined Cycle Plant	128	283	391	483	566	494	9.1	20.2	27.9	34.4	40.3	35.3
AES Combined Cycle Plant	111	201	290	418	480	425	7.8	14.1	20.3	29.3	33.7	29.8
ACE Power Plant (Horana)	121	157	161	164	165	164	68.9	89.5	92.1	93.6	94.1	93.5
ACE Power Plant (Matara)	63	131	156	160	161	160	36.2	74.6	89.2	91.5	92.2	91.1
Kerawalapitiya CombinedCycle 270 MW	562	632	813	980	1,221	1,020	23.8	26.7	34.4	41.5	51.6	43.1
275 MW Puttalam Coal Plant	4,162	4,351	4,529	4,897	5,043	4,911	57.6	60.2	62.7	67.8	69.8	68.0
20 MW Northern	109	131	135	137	137	136	62.3	74.8	76.9	78.0	78.3	77.9
Dendro	92	94	94	94	94	94	87.5	89.1	89.5	89.7	89.7	89.7
Chunnakum ext.	177	181	182	183	183	183	84.3	86.2	86.8	87.1	87.1	87.1
GT75	33	60	95	142	165	145	5.0	9.2	14.5	21.7	25.1	22.0
GT105	59	101	154	211	240	214	6.4	11.0	16.7	23.0	26.1	23.3
DNRO	79	81	81	82	82	82	75.5	77.0	77.4	77.6	77.6	77.6
Total hydro	7,652	6,455	5,538	4,563	3,928	4,485						
Total thermal	6,539	7,735	8,650	9,619	10,248	9,696						
Total generation	14,192	14,190	14,188	14,182	14,176	14,181						
Total demand	14,193	14,193	14,193	14,193	14,193	14,193						
Deficit	1	3	5	11	17	12						
2016												
Kelanitissa Gas Turbines (17 MW)	0	1	1	2	14	5	0.1	0.1	0.2	0.3	2.0	0.6
Sapugaskanda Diesel Plant (4x18 MW)	303	431	446	455	459	455	49.8	70.8	73.1	74.6	75.3	74.6
Sapugaskanda Diesel Ext. (8x9 MW)	383	473	482	487	489	487	62.9	77.6	79.0	79.8	80.2	79.8
115 MW Kelanitissa Gas Turbine	67	127	181	241	295	249	6.8	12.9	18.3	24.3	29.8	25.1
Lakdanavi Plant	43	105	136	142	144	141	22.0	53.0	69.0	71.8	73.2	71.6
Asia Power Plant	153	266	318	328	332	327	35.7	62.1	74.2	76.4	77.4	76.2
Kelanitissa Combined Cycle Plant	152	294	429	503	631	523	10.9	21.0	30.6	35.9	45.0	37.3
AES Combined Cycle Plant	107	220	339	451	558	467	7.5	15.4	23.7	31.6	39.1	32.7
ACE Power Plant (Horana)	117	157	161	164	165	164	66.7	89.7	92.0	93.6	94.3	93.6
ACE Power Plant (Matara)	88	135	156	161	162	160	50.0	76.8	89.3	91.6	92.7	91.4
Kerawalapitiya CombinedCycle 270 MW	523	658	851	1,117	1,260	1,134	22.1	27.8	36.0	47.2	53.3	48.0
275 MW Puttalam Coal Plant	4,160	4,356	4,567	4,901	5,085	4,923	57.6	60.3	63.2	67.8	70.4	68.1
20 MW Northern	102	132	134	137	137	136	58.3	75.1	76.7	77.9	78.4	77.9
Dendro	91	94	94	94	94	94	86.7	89.2	89.6	89.8	89.9	89.8
Chunnakum ext.	176	181	182	183	183	183	83.5	86.2	86.7	87.0	87.1	87.0
GT75	41	68	106	141	169	145	6.3	10.3	16.2	21.5	25.8	22.1
GT105	60	117	156	226	248	228	6.5	12.7	16.9	24.6	27.0	24.8
DNRO	105	108	109	109	109	109	74.9	77.2	77.7	77.9	78.0	77.9
Total hydro	8,118	6,867	5,939	4,942	4,241	4,852						
Total thermal	6,673	7,922	8,849	9,841	10,537	9,931						
Total generation	14,791	14,789	14,788	14,783	14,778	14,782						
Total demand	14,791	14,791	14,791	14,791	14,791	14,791						
Deficit	1	2	4	8	13	9						

Hydrological Conditions:1. Very Wet 2. Wet 3. Medium 4. Dry 5. Very Dry
Shown within brackets is the probability of occurrence of each Hydro Condition.

Year	Annual Energy (GWh)						Annual Plant Factor (%)					
	Hydrology condition						Hydrology condition					
Plant	1	2	3	4	5	Avg.	1	2	3	4	5	Avg.
2017												
Kelanitissa Gas Turbines (17 MW)	1	1	2	3	16	6	0.1	0.2	0.2	0.5	2.2	0.8
Sapugaskanda Diesel Plant (4x18 MW)	405	443	455	461	463	461	66.4	72.7	74.7	75.6	76.0	75.6
Sapugaskanda Diesel Ext. (8x9 MW)	464	480	487	490	491	490	76.2	78.7	79.8	80.3	80.5	80.3
115 MW Kelanitissa Gas Turbine	86	189	257	289	305	290	8.7	19.0	26.0	29.2	30.8	29.3
Lakdanavi Plant	74	119	142	147	149	146	37.3	60.1	71.9	74.3	75.5	74.2
Asia Power Plant	226	311	328	335	339	335	52.7	72.5	76.3	78.1	78.9	78.0
Kelanitissa Combined Cycle Plant	255	381	489	622	739	639	18.2	27.2	34.9	44.4	52.8	45.6
AES Combined Cycle Plant	159	301	407	509	682	538	11.1	21.0	28.5	35.6	47.8	37.7
ACE Power Plant (Horana)	144	161	164	166	166	166	82.3	91.7	93.6	94.6	95.0	94.6
ACE Power Plant (Matara)	124	156	161	164	165	163	70.8	88.9	91.6	93.3	94.1	93.3
Kerawalapitiya CombinedCycle 270 MW	577	740	970	1,311	1,394	1,313	24.4	31.3	41.0	55.5	58.9	55.5
275 MW Puttalam Coal Plant	4,243	4,458	4,691	4,971	5,131	4,990	58.7	61.7	64.9	68.8	71.0	69.1
20 MW Northern	121	134	136	138	138	138	69.2	76.5	77.9	78.6	78.9	78.6
Dendro	93	94	94	94	94	94	88.3	89.6	89.8	89.8	89.9	89.8
Chunnakum ext.	179	182	183	183	183	183	85.2	86.6	87.0	87.1	87.2	87.1
GT75	34	105	143	154	187	159	5.2	16.0	21.8	23.4	28.5	24.2
GT105	135	341	433	512	597	524	7.4	18.6	23.5	27.8	32.4	28.5
DNRO	134	136	136	137	137	137	76.4	77.6	77.9	77.9	78.0	77.9
Total hydro	8,203	6,924	5,975	4,961	4,254	4,871						
Total thermal	7,455	8,732	9,679	10,685	11,376	10,773						
Total generation	15,658	15,656	15,654	15,646	15,630	15,643						
Total demand	15,660	15,660	15,660	15,660	15,660	15,660						
Deficit	1	3	6	13	29	16						
2018												
Kelanitissa Gas Turbines (17 MW)	0	0	0	0	1	0	0.0	0.0	0.0	0.1	0.1	0.1
Sapugaskanda Diesel Plant (4x18 MW)	38	119	201	299	364	308	6.3	19.6	33.0	49.1	59.7	50.4
Sapugaskanda Diesel Ext. (8x9 MW)	48	141	236	350	399	354	7.9	23.1	38.8	57.4	65.5	58.1
115 MW Kelanitissa Gas Turbine	4	22	43	103	135	107	0.4	2.2	4.3	10.4	13.7	10.8
Kelanitissa Combined Cycle Plant	33	64	143	232	317	245	2.4	4.6	10.2	16.6	22.6	17.5
AES Combined Cycle Plant	19	69	93	224	270	229	1.3	4.8	6.5	15.7	18.9	16.0
Kerawalapitiya CombinedCycle 270 MW	77	242	452	585	670	594	3.3	10.2	19.1	24.7	28.3	25.1
275 MW Puttalam Coal Plant	3,212	3,788	4,026	4,209	4,375	4,231	44.5	52.4	55.7	58.2	60.5	58.5
Dendro	24	60	70	85	87	84	22.8	57.1	66.4	80.6	83.2	80.4
Chunnakum ext.	35	92	132	149	166	151	16.7	43.6	62.6	71.1	79.1	72.0
GT75	3	13	31	54	75	57	0.4	2.0	4.7	8.2	11.4	8.7
GT105	10	41	92	161	272	180	0.6	2.2	5.0	8.8	14.8	9.8
Trinco coal	4,536	4,670	4,768	4,866	4,910	4,869	76.0	78.3	79.9	81.6	82.3	81.6
DNRO	43	98	119	138	151	140	20.5	46.8	56.5	65.9	71.7	66.5
Total hydro	8,452	7,115	6,129	5,078	4,340	4,983						
Total thermal	8,083	9,419	10,405	11,456	12,193	11,550						
Total generation	16,535	16,535	16,534	16,534	16,533	16,534						
Total demand	16,535	16,535	16,535	16,535	16,535	16,535						
Deficit	0	0	0	1	1	1						

Hydrological Conditions:1. Very Wet 2. Wet 3. Medium 4. Dry 5. Very Dry
Shown within brackets is the probability of occurrence of each Hydro Condition.

Year	Annual Energy (GWh)						Annual Plant Factor (%)					
	Hydrology condition						Hydrology condition					
Plant	1	2	3	4	5	Avg.	1	2	3	4	5	Avg.
2019												
Sapugaskanda Diesel Ext. (8x9 MW)	45	93	161	307	352	310	7.4	15.2	26.4	50.3	57.8	50.9
115 MW Kelanitissa Gas Turbine	4	7	43	69	126	79	0.4	0.7	4.4	7.0	12.7	8.0
Kelanitissa Combined Cycle Plant	33	65	93	234	270	237	2.3	4.6	6.6	16.7	19.3	16.9
AES Combined Cycle Plant	28	54	80	187	259	197	2.0	3.8	5.6	13.1	18.1	13.8
Kerawalapitiya CombinedCycle 270 MW	70	177	327	486	574	496	3.0	7.5	13.8	20.5	24.3	21.0
275 MW Puttalam Coal Plant	2,535	3,388	3,774	4,047	4,228	4,065	35.1	46.9	52.2	56.0	58.5	56.3
Dendro	17	30	64	74	80	74	16.1	28.9	60.5	70.1	76.4	70.5
Chunnakum ext.	22	55	99	140	151	140	10.4	26.2	46.8	66.6	72.0	66.7
GT75	3	5	25	34	69	41	0.4	0.8	3.8	5.3	10.4	6.2
GT105	15	48	88	145	215	157	0.8	2.6	4.8	7.9	11.7	8.5
Trinco coal	6,026	6,208	6,329	6,405	6,534	6,426	75.8	78.1	79.6	80.5	82.2	80.8
DNRO	25	64	123	149	162	150	10.2	26.0	50.2	60.7	66.0	61.0
Total hydro	8,558	7,186	6,174	5,102	4,356	5,007						
Total thermal	8,823	10,194	11,206	12,277	13,022	12,372						
Total generation	17,380	17,380	17,380	17,379	17,378	17,379						
Total demand	17,380	17,380	17,380	17,380	17,380	17,380						
Deficit	0	0	0	1	2	1						
2020												
Sapugaskanda Diesel Ext. (8x9 MW)	15	48	89	226	315	239	2.5	7.8	14.6	37.0	51.7	39.1
115 MW Kelanitissa Gas Turbine	2	5	8	56	54	54	0.2	0.5	0.8	5.6	5.5	5.5
Kelanitissa Combined Cycle Plant	11	36	75	116	213	134	0.8	2.6	5.4	8.3	15.2	9.5
AES Combined Cycle Plant	9	32	68	115	151	120	0.6	2.2	4.8	8.1	10.6	8.4
Kerawalapitiya CombinedCycle 270 MW	28	89	146	372	443	378	1.2	3.8	6.2	15.7	18.7	16.0
275 MW Puttalam Coal Plant	2,941	3,635	3,877	4,040	4,142	4,048	40.7	50.3	53.7	55.9	57.3	56.0
Dendro	5	17	33	56	71	58	4.9	15.9	31.7	53.3	67.5	55.2
Chunnakum ext.	9	31	60	107	132	110	4.1	14.5	28.5	50.9	63.0	52.4
CST	369	642	1,095	1,260	1,414	1,278	15.3	26.7	45.4	52.3	58.7	53.0
GT75	2	3	5	29	46	32	0.2	0.5	0.7	4.5	7.0	4.9
GT105	7	27	60	97	164	109	0.4	1.5	3.2	5.3	8.9	5.9
Trinco coal	6,169	6,381	6,429	6,505	6,555	6,511	77.6	80.2	80.8	81.8	82.4	81.9
DNRO	11	39	75	130	162	134	4.0	14.1	26.6	46.5	57.8	47.9
Total hydro	8,657	7,252	6,216	5,124	4,370	5,029						
Total thermal	9,579	10,983	12,019	13,111	13,864	13,206						
Total generation	18,236	18,235	18,235	18,235	18,234	18,235						
Total demand	18,235	18,235	18,235	18,235	18,235	18,235						
Deficit	0	0	0	1	1	1						
2021												
Sapugaskanda Diesel Ext. (8x9 MW)	12	42	90	143	219	156	2.0	6.9	14.8	23.5	36.0	25.6
115 MW Kelanitissa Gas Turbine	1	3	5	18	41	22	0.1	0.3	0.5	1.8	4.2	2.2
Kelanitissa Combined Cycle Plant	8	28	37	98	143	105	0.6	2.0	2.6	7.0	10.2	7.5
AES Combined Cycle Plant	6	11	41	60	115	70	0.4	0.8	2.9	4.2	8.1	4.9
Kerawalapitiya CombinedCycle 270 MW	23	63	136	291	368	301	1.0	2.7	5.7	12.3	15.6	12.7
275 MW Puttalam Coal Plant	3,303	3,744	3,935	4,075	4,155	4,082	45.7	51.8	54.5	56.4	57.5	56.5
Dendro	5	14	29	49	58	50	4.4	13.4	27.5	46.9	55.6	47.8
Chunnakum ext.	8	19	53	92	102	93	3.7	9.2	25.3	43.9	48.7	44.0
CST	672	1,437	1,945	2,381	2,703	2,421	13.9	29.8	40.4	49.4	56.1	50.3
GT75	1	2	4	18	31	20	0.2	0.3	0.5	2.7	4.8	3.1
GT105	4	8	13	68	107	74	0.2	0.5	0.7	3.7	5.8	4.0
Trinco coal	6,364	6,449	6,542	6,592	6,590	6,589	80.0	81.1	82.2	82.9	82.8	82.8
DNRO	12	30	77	130	142	130	3.7	9.5	24.4	41.2	44.9	41.2
Total hydro	8,741	7,309	6,252	5,143	4,383	5,048						
Total thermal	10,418	11,851	12,907	14,016	14,776	14,111						
Total generation	19,159	19,159	19,159	19,159	19,159	19,159						
Total demand	19,159	19,159	19,159	19,159	19,159	19,159						
Deficit	0	0	0	0	1	0						

Hydrological Conditions:1. Very Wet 2. Wet 3. Medium 4. Dry 5. Very Dry
Shown within brackets is the probability of occurrence of each Hydro Condition.

Year / Plant	Annual Energy (GWh) Hydrology condition 1	2	3	4	5	Avg.	Annual Plant Factor (%) Hydrology condition 1	2	3	4	5	Avg.
2022												
Sapugaskanda Diesel Ext. (8x9 MW)	8	16	44	89	123	94	1.4	2.6	7.2	14.6	20.2	15.4
115 MW Kelanitissa Gas Turbine	1	2	4	7	20	9	0.1	0.2	0.4	0.7	2.0	0.9
Kelanitissa Combined Cycle Plant	5	10	32	56	64	57	0.4	0.8	2.3	4.0	4.6	4.0
AES Combined Cycle Plant	3	7	26	49	72	52	0.2	0.5	1.9	3.4	5.0	3.7
Kerawalapitiya CombinedCycle 270 MW	19	67	132	171	278	190	0.8	2.8	5.6	7.2	11.8	8.0
275 MW Puttalam Coal Plant	3,572	3,887	4,030	4,126	4,202	4,135	49.4	53.8	55.8	57.1	58.2	57.2
Dendro	4	14	27	41	53	42	3.7	13.3	25.9	38.5	50.5	40.3
Chunnakum ext.	7	26	48	58	96	65	3.1	12.2	22.9	27.5	45.9	30.9
CST	1,150	2,132	2,825	3,609	3,957	3,640	15.9	29.5	39.1	49.9	54.8	50.4
GT75	1	1	2	5	12	6	0.1	0.2	0.4	0.7	1.8	0.9
GT105	2	5	10	40	65	44	0.1	0.3	0.5	2.2	3.6	2.4
Trinco coal	6,552	6,586	6,615	6,636	6,670	6,642	82.4	82.8	83.2	83.4	83.9	83.5
DNRO	11	43	79	113	152	119	3.1	12.4	22.5	32.2	43.4	34.0
Total hydro	8,826	7,365	6,289	5,163	4,395	5,066						
Total thermal	11,335	12,796	13,873	14,998	15,766	15,095						
Total generation	20,161	20,161	20,161	20,161	20,161	20,161						
Total demand	20,161	20,161	20,161	20,161	20,161	20,161						
Deficit	0	0	0	0	0	0						
2023												
Sapugaskanda Diesel Ext. (8x9 MW)	3	5	8	33	58	37	0.8	1.8	2.7	10.8	19.1	12.2
Kelanitissa Combined Cycle Plant	4	8	12	51	103	60	0.3	0.6	0.9	3.7	7.3	4.3
Kerawalapitiya CombinedCycle 270 MW	12	23	55	139	190	147	0.5	1.0	2.3	5.9	8.0	6.2
275 MW Puttalam Coal Plant	3,744	3,974	4,075	4,206	4,299	4,218	51.8	55.0	56.4	58.2	59.5	58.4
Dendro	3	8	12	29	40	31	2.5	7.7	11.4	27.9	38.1	29.3
Chunnakum ext.	4	7	15	43	52	43	1.9	3.4	7.2	20.2	24.6	20.6
CST	1,886	3,015	3,922	4,647	5,111	4,699	19.6	31.3	40.7	48.2	53.0	48.8
GT75	1	1	2	10	12	10	0.1	0.2	0.4	1.6	1.8	1.6
GT105	3	6	10	43	64	46	0.1	0.3	0.5	2.3	3.5	2.5
Trinco coal	6,595	6,684	6,708	6,707	6,716	6,708	82.9	84.0	84.3	84.3	84.4	84.3
DNRO	8	19	31	85	123	91	2.0	5.0	8.1	22.1	31.9	23.6
Total hydro	8,918	7,426	6,328	5,183	4,409	5,087						
Total thermal	12,260	13,752	14,850	15,994	16,768	16,091						
Total generation	21,179	21,179	21,178	21,177	21,177	21,177						
Total demand	21,180	21,180	21,180	21,180	21,180	21,180						
Deficit	1	1	1	2	3	2						
2024												
Sapugaskanda Diesel Ext. (8x9 MW)	2	4	6	27	34	28	0.6	1.3	2.0	8.9	11.1	9.1
Kelanitissa Combined Cycle Plant	3	6	9	32	47	34	0.2	0.4	0.7	2.3	3.4	2.5
Kerawalapitiya CombinedCycle 270 MW	8	16	24	104	150	111	0.3	0.7	1.0	4.4	6.3	4.7
275 MW Puttalam Coal Plant	3,929	4,049	4,172	4,266	4,318	4,271	54.4	56.0	57.7	59.0	59.8	59.1
Dendro	2	3	7	25	26	25	1.8	3.1	6.8	23.7	24.9	23.4
Chunnakum ext.	3	5	8	28	50	32	1.4	2.5	3.7	13.4	23.6	15.1
CST	2,540	3,905	4,854	5,686	6,287	5,761	21.1	32.4	40.3	47.2	52.2	47.8
GT75	0	1	2	4	10	5	0.1	0.2	0.3	0.6	1.5	0.7
GT105	2	4	7	16	34	19	0.1	0.2	0.4	0.8	1.9	1.0
Trinco coal	6,750	6,753	6,762	6,753	6,755	6,754	84.9	84.9	85.0	84.9	84.9	84.9
DNRO	6	11	19	87	95	86	1.5	2.5	4.6	20.6	22.6	20.5
Total hydro	8,982	7,469	6,355	5,198	4,418	5,101						
Total thermal	13,244	14,757	15,871	17,027	17,806	17,124						
Total generation	22,226	22,226	22,226	22,225	22,224	22,225						
Total demand	22,227	22,227	22,227	22,227	22,227	22,227						
Deficit	1	1	1	2	3	2						

Hydrological Conditions:1. Very Wet 2. Wet 3. Medium 4. Dry 5. Very Dry
Shown within brackets is the probability of occurrence of each Hydro Condition.

Year / Plant	Annual Energy (GWh) Hydrology condition						Annual Plant Factor (%) Hydrology condition					
	1	2	3	4	5	Avg.	1	2	3	4	5	Avg.
2025												
Kelanitissa Combined Cycle Plant	2	5	8	18	20	18	0.2	0.4	0.6	1.3	1.5	1.3
Kerawalapitiya CombinedCycle 270 MW	6	13	20	53	87	59	0.3	0.6	0.8	2.3	3.7	2.5
275 MW Puttalam Coal Plant	4,078	4,200	4,295	4,333	4,443	4,352	56.4	58.1	59.4	60.0	61.5	60.2
Dendro	1	3	7	9	26	12	1.3	2.5	6.4	8.6	25.0	11.8
Chunnakum ext.	2	4	6	16	37	20	1.0	2.0	2.8	7.5	17.4	9.3
CST	3,373	4,750	5,764	6,819	7,379	6,877	23.3	32.9	39.9	47.2	51.0	47.6
GT75	0	1	2	4	5	4	0.1	0.1	0.3	0.5	0.7	0.6
GT105	1	4	7	13	18	14	0.1	0.2	0.4	0.7	0.9	0.8
Trinco coal	6,775	6,793	6,793	6,787	6,783	6,786	85.2	85.4	85.4	85.3	85.3	85.3
DNRO	5	9	13	35	74	42	1.0	2.0	2.9	7.7	16.3	9.2
Total hydro	9,059	7,521	6,388	5,215	4,430	5,118						
Total thermal	14,243	15,782	16,915	18,087	18,872	18,184						
Total generation	23,303	23,303	23,303	23,302	23,302	23,302						
Total demand	23,304	23,304	23,304	23,304	23,304	23,304						
Deficit	1	1	1	2	2	2						
2026												
Kelanitissa Combined Cycle Plant	7	12	18	41	81	48	0.5	0.9	1.3	2.9	5.8	3.5
Kerawalapitiya CombinedCycle 270 MW	16	28	66	94	199	114	0.7	1.2	2.8	4.0	8.4	4.8
275 MW Puttalam Coal Plant	4,205	4,352	4,409	4,511	4,575	4,519	58.2	60.2	61.0	62.4	63.3	62.5
Dendro	3	5	12	25	40	28	2.9	4.4	11.2	24.0	37.6	26.2
Chunnakum ext.	5	8	19	37	66	42	2.3	3.7	8.9	17.4	31.6	19.9
CST	4,239	5,615	6,612	7,541	8,004	7,584	29.3	38.8	45.8	52.2	55.4	52.5
GT75	1	3	4	8	10	8	0.2	0.4	0.6	1.2	1.5	1.2
GT105	5	10	16	41	65	45	0.3	0.6	0.9	2.2	3.5	2.4
Trinco coal	6,808	6,817	6,818	6,814	6,811	6,813	85.6	85.7	85.7	85.7	85.6	85.7
DNRO	11	17	46	94	147	103	2.2	3.5	9.3	19.3	29.9	21.0
Total hydro	9,144	7,578	6,424	5,234	4,442	5,137						
Total thermal	15,300	16,866	18,019	19,207	19,997	19,304						
Total generation	24,444	24,444	24,443	24,441	24,439	24,441						
Total demand	24,445	24,445	24,445	24,445	24,445	24,445						
Deficit	1	2	2	4	6	5						
2027												
Kelanitissa Combined Cycle Plant	6	10	16	24	41	28	0.4	0.7	1.1	1.8	3.0	2.0
Kerawalapitiya CombinedCycle 270 MW	14	24	43	52	84	58	0.6	1.0	1.8	2.2	3.5	2.5
275 MW Puttalam Coal Plant	4,346	4,459	4,559	4,714	4,724	4,710	60.1	61.7	63.1	65.2	65.4	65.2
Dendro	3	4	11	13	32	17	2.5	3.9	10.9	12.3	30.2	15.8
Chunnakum ext.	4	7	17	12	37	17	1.9	3.1	8.2	5.8	17.4	8.1
CST	5,179	6,623	7,608	8,643	9,263	8,714	30.7	39.3	45.1	51.3	54.9	51.7
GT75	1	2	4	7	9	7	0.2	0.3	0.6	1.0	1.3	1.1
GT105	4	9	14	24	30	25	0.2	0.5	0.8	1.3	1.6	1.4
Trinco coal	6,829	6,837	6,841	6,834	6,834	6,834	85.9	85.9	86.0	85.9	85.9	85.9
DNRO	10	16	51	45	113	59	2.0	3.1	9.7	8.6	21.5	11.1
Total hydro	9,229	7,634	6,460	5,254	4,454	5,156						
Total thermal	16,396	17,991	19,164	20,368	21,166	20,466						
Total generation	25,625	25,625	25,624	25,622	25,620	25,622						
Total demand	25,626	25,626	25,626	25,626	25,626	25,626						
Deficit	1	1	2	4	6	4						

Hydrological Conditions:1. Very Wet 2. Wet 3. Medium 4. Dry 5. Very Dry
Shown within brackets is the probability of occurrence of each Hydro Condition.

Year / Plant	Annual Energy (GWh) Hydrology condition 1	2	3	4	5	Avg.	Annual Plant Factor (%) Hydrology condition 1	2	3	4	5	Avg.
2028												
Kelanitissa Combined Cycle Plant	12	19	48	57	114	68	0.8	1.4	3.5	4.1	8.1	4.8
Kerawalapitiya CombinedCycle 270 MW	26	42	102	123	236	144	1.1	1.8	4.3	5.2	10.0	6.1
275 MW Puttalam Coal Plant	4,520	4,644	4,724	4,829	4,871	4,832	62.5	64.3	65.4	66.8	67.4	66.9
Dendro	4	9	18	31	46	33	4.1	8.4	16.7	29.3	43.8	31.6
Chunnakum ext.	7	10	32	46	76	51	3.3	4.7	15.2	21.8	36.3	24.3
CST	6,118	7,550	8,469	9,475	9,909	9,511	36.3	44.8	50.2	56.2	58.8	56.4
GT75	3	5	7	12	18	13	0.4	0.7	1.1	1.8	2.8	2.0
GT105	10	18	32	40	73	46	0.5	1.0	1.8	2.2	3.9	2.5
Trinco coal	6,844	6,850	6,853	6,848	6,850	6,849	86.0	86.1	86.2	86.1	86.1	86.1
DNRO	18	33	85	127	195	138	3.2	5.9	15.1	22.6	34.7	24.6
Total hydro	9,307	7,686	6,493	5,271	4,466	5,173						
Total thermal	17,561	19,180	20,371	21,588	22,388	21,685						
Total generation	26,868	26,866	26,864	26,859	26,854	26,858						
Total demand	26,868	26,868	26,868	26,868	26,868	26,868						
Deficit	1	2	4	10	14	10						
2029												
Kelanitissa Combined Cycle Plant	9	15	22	56	62	56	0.6	1.1	1.5	4.0	4.5	4.0
Kerawalapitiya CombinedCycle 270 MW	20	34	80	107	172	119	0.9	1.4	3.4	4.5	7.3	5.0
275 MW Puttalam Coal Plant	4,683	4,872	4,908	4,956	4,970	4,956	64.8	67.4	67.9	68.6	68.8	68.6
Dendro	4	5	12	23	34	25	3.3	4.9	11.8	22.3	32.0	23.8
Chunnakum ext.	5	8	22	25	48	29	2.6	4.0	10.6	11.7	23.0	13.9
CST	6,998	8,423	9,479	10,530	11,163	10,602	36.3	43.7	49.2	54.6	57.9	55.0
GT75	2	4	6	10	16	11	0.3	0.6	0.9	1.5	2.5	1.6
GT105	7	14	20	39	55	41	0.4	0.7	1.1	2.1	3.0	2.3
Trinco coal	6,857	6,863	6,861	6,864	6,862	6,864	86.2	86.3	86.3	86.3	86.3	86.3
DNRO	16	24	61	100	154	109	2.7	4.0	10.3	16.9	25.9	18.4
Total hydro	9,548	7,886	6,674	5,432	4,601	5,330						
Total thermal	18,601	20,262	21,472	22,710	23,538	22,812						
Total generation	28,149	28,148	28,146	28,142	28,139	28,142						
Total demand	28,149	28,149	28,149	28,149	28,149	28,149						
Deficit	0	1	3	7	11	8						
2030												
Kelanitissa Combined Cycle Plant	9	15	21	43	73	48	0.6	1.1	1.5	3.1	5.2	3.4
Kerawalapitiya CombinedCycle 270 MW	21	33	56	105	154	113	0.9	1.4	2.4	4.4	6.5	4.8
275 MW Puttalam Coal Plant	4,893	5,019	5,049	5,031	5,029	5,030	67.7	69.4	69.9	69.6	69.6	69.6
Dendro	4	5	11	16	28	18	3.4	4.6	10.5	15.0	26.4	17.0
Chunnakum ext.	6	8	21	26	36	27	2.7	3.7	10.1	12.2	16.9	13.0
CST	8,104	9,603	10,699	11,848	12,481	11,916	37.4	44.3	49.3	54.7	57.6	55.0
GT75	2	4	6	9	12	10	0.3	0.6	0.9	1.4	1.8	1.5
GT105	7	14	20	32	61	37	0.4	0.8	1.1	1.8	3.3	2.0
Trinco coal	6,866	6,869	6,870	6,869	6,870	6,869	86.3	86.4	86.4	86.4	86.4	86.4
DNRO	17	24	52	69	134	81	2.8	3.8	8.3	11.0	21.2	12.9
Total hydro	9,562	7,895	6,680	5,436	4,603	5,333						
Total thermal	19,928	21,594	22,807	24,047	24,877	24,149						
Total generation	29,490	29,489	29,487	29,483	29,479	29,482						
Total demand	29,491	29,491	29,491	29,491	29,491	29,491						
Deficit	0	2	3	8	11	8						

Hydrological Conditions:1. Very Wet 2. Wet 3. Medium 4. Dry 5. Very Dry
Shown within brackets is the probability of occurrence of each Hydro Condition.

Year	Annual Energy (GWh)						Annual Plant Factor (%)					
	Hydrology condition						Hydrology condition					
Plant	1	2	3	4	5	Avg.	1	2	3	4	5	Avg.
2031												
Kelanitissa Combined Cycle Plant	8	15	21	32	64	38	0.6	1.0	1.5	2.3	4.5	2.7
Kerawalapitiya CombinedCycle 270 MW	20	33	46	92	148	102	0.8	1.4	1.9	3.9	6.3	4.3
275 MW Puttalam Coal Plant	5,035	5,111	5,116	5,097	5,099	5,098	69.7	70.7	70.8	70.5	70.6	70.5
Dendro	3	5	8	14	23	15	3.2	4.5	7.7	13.1	21.4	14.5
Chunnakum ext.	5	8	10	24	37	27	2.6	3.8	4.8	11.6	17.8	12.6
CST	9,263	10,841	12,026	13,168	13,834	13,241	38.5	45.0	49.9	54.7	57.4	55.0
GT75	2	4	6	9	15	10	0.3	0.6	0.9	1.4	2.3	1.6
GT105	7	14	21	32	44	34	0.4	0.8	1.1	1.7	2.4	1.9
Trinco coal	6,872	6,874	6,874	6,873	6,873	6,873	86.4	86.4	86.4	86.4	86.4	86.4
DNRO	17	25	34	78	117	84	2.5	3.7	5.2	11.6	17.5	12.6
Total hydro	9,647	7,952	6,717	5,455	4,615	5,352						
Total thermal	21,234	22,928	24,161	25,419	26,254	25,521						
Total generation	30,881	30,880	30,878	30,873	30,869	30,873						
Total demand	30,882	30,882	30,882	30,882	30,882	30,882						
Deficit	1	2	4	8	12	9						
2032												
Kelanitissa Combined Cycle Plant	19	29	46	85	117	90	1.4	2.1	3.3	6.0	8.3	6.4
Kerawalapitiya CombinedCycle 270 MW	42	61	105	143	254	163	1.8	2.6	4.4	6.0	10.7	6.9
275 MW Puttalam Coal Plant	5,139	5,172	5,177	5,158	5,160	5,158	71.1	71.6	71.6	71.4	71.4	71.4
Dendro	5	7	15	33	35	33	5.2	6.7	14.4	31.3	33.2	31.1
Chunnakum ext.	9	12	20	35	65	41	4.3	5.7	9.6	16.8	31.1	19.4
CST	10,452	12,076	13,198	14,251	14,794	14,303	43.4	50.1	54.8	59.2	61.4	59.4
GT75	10	16	23	33	64	39	0.8	1.3	1.7	2.5	4.9	3.0
GT105	18	30	41	75	112	82	1.0	1.6	2.2	4.1	6.1	4.4
Trinco coal	6,874	6,875	6,875	6,875	6,875	6,875	86.4	86.4	86.4	86.4	86.4	86.4
DNRO	30	39	68	148	197	155	4.2	5.5	9.8	21.1	28.0	22.1
Total hydro	9,732	8,008	6,753	5,474	4,628	5,371						
Total thermal	22,598	24,318	25,569	26,836	27,673	26,938						
Total generation	32,330	32,326	32,321	32,310	32,301	32,309						
Total demand	32,333	32,333	32,333	32,333	32,333	32,333						
Deficit	3	7	12	23	32	24						

Hydrological Conditions:1. Very Wet 2. Wet 3. Medium 4. Dry 5. Very Dry
Shown within brackets is the probability of occurrence of each Hydro Condition.

Annex 7.4.1

Annual Energy Generation Dispatch with NCRE Reconciliation for the Base Case-2012

Plant Name	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hydro																				
Existing Major Hydro	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112
New Major Hydro	0	0	0	366	366	443	443	443	443	443	443	443	443	443	443	443	579	579	579	579
Mini Hydro	335	352	373	373	391	428	451	471	490	509	529	547	564	583	601	619	637	641	659	678
Sub Total	4447	4465	4485	4851	4870	4983	5006	5027	5045	5064	5085	5102	5119	5138	5157	5174	5329	5332	5351	5370
Thermal (Existing and Committed)	7533	8676	9255	9449	9953	6304	5599	5142	4878	4644	4536	4500	4462	4751	4828	5128	5185	5236	5279	5707
New Thermal Plants	27	54	441	482	820	5242	6773	8065	9234	10451	11555	12622	13721	14553	15638	16557	17627	18914	20243	21232
Total Thermal	7,560	8,730	9,696	9,931	10,773	11,546	12,372	13,207	14,112	15,095	16,091	17,122	18,182	19,304	20,466	21,685	22,812	24,150	25,521	26,939
Wind	252	252	252	533	533	575	631	701	757	757	785	813	841	869	897	925	953	981	1,009	1,037
Solar	33	48	63	63	79	62	77	96	92	107	107	122	141	141	156	156	171	171	186	186
Other NCRE Total	285	300	315	596	612	637	708	797	849	864	892	935	982	1,010	1,053	1,081	1,124	1,152	1,195	1,223
Total Generation	**12293**	**13495**	**14497**	**15377**	**16254**	**17165**	**18086**	**19030**	**20006**	**21023**	**22067**	**23159**	**24283**	**25452**	**26676**	**27940**	**29265**	**30634**	**32067**	**33532**
Generation Forecast	**12303**	**13502**	**14509**	**15388**	**16270**	**17170**	**18086**	**19034**	**20009**	**21023**	**22072**	**23159**	**24284**	**25457**	**26676**	**27949**	**29273**	**30645**	**32078**	**33555**
Deficit	**11**	**8**	**12**	**11**	**15**	**5**	**1**	**4**	**3**	**0**	**5**	**0**	**1**	**5**	**0**	**9**	**8**	**11**	**11**	**23**

Note:- 1. Numbers may not add exactly due to rounding off.

2. All energy figures are shown for weighted average hydrological condition in GWh.

Annex 7.5

Fuel Requirement and Expenditure on Fuel – 2012

Year	Auto Diesel		Furnace Oil		Residual Oil		Naphtha		Coal		Dendro	
	1000MT	US $ million	1000MT	US $ million	1000MT	US $ million	1000MT	US $ million	1000MT	US $ million	1000MT	US $ million
2013	155.5	199.2	719.4	522.4	285.6	194.4	79.0	103.5	666.2	96.3	214.8	12.2
2014	133.9	177.1	700.1	520.8	267.9	182.4	64.9	84.6	1282.6	186.2	262.8	14.9
2015	261.3	346.0	373.3	287.9	284.1	193.4	83.1	107.5	2013.7	290.7	310.6	17.6
2016	269.9	351.5	396.4	300.1	284.7	193.8	88.1	111.4	2018.6	291.4	359.7	20.4
2017	381.1	482.2	434.9	320.7	288.6	196.5	107.5	127.0	2046.0	294.9	407.9	23.1
2018	141.4	198.4	149.5	139.3	148.3	101.0	41.3	60.0	3778.9	539.5	396.0	22.4
2019	115.4	162.6	127.6	121.2	68.2	46.4	39.8	58.1	4364.6	621.7	395.3	22.4
2020	77.9	109.2	98.0	95.9	52.4	35.7	22.5	32.8	4861.0	702	339.6	19.2
2021	45.4	64.3	78.9	77.5	34.3	23.3	17.6	25.7	5325.4	776.3	318.1	18.0
2022	26.1	37.6	51.1	49.6	20.7	14.1	9.5	13.8	5815.5	855	285.1	16.1
2023	15.3	20.8	38.1	37	8.2	5.6	10.1	14.7	6264.9	926	215.1	12.2
2024	6.5	8.6	28.6	27.9	6.1	4.1	5.8	8.3	6694.0	994.7	195.6	11.1
2025	4.7	6.2	15.8	14.9			3.1	4.3	7149.7	1067.4	96.0	5.4
2026	14.2	18.6	31.2	28.6			8.1	11.3	7488.3	1119.4	230.5	13.1
2027	8.6	10.9	15.0	13			4.6	6	7988.1	1198	132.7	7.5
2028	16.1	19.8	39.1	34.9			11.4	15.5	8336.3	1252	302.7	17.1
2029	14.1	17.7	29.7	27.2			9.4	12.8	8792.5	1323.8	237.5	13.5
2030	12.7	15.7	28.1	25.5			8.1	10.9	9305.9	1405.6	175.3	9.9
2031	12.0	14.6	25.7	23			6.3	8.2	9820.1	1487.7	175.0	9.9
2032	32.6	39.4	40.9	35.7			15.1	19.8	10234.5	1552.6	331.1	18.8

Results of Generation Expansion Planning Studies - 2012

PUCSL Reference Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	-	-	-	1.270
2014	-	*4x5 MW Northern Power*** *3x8 MW Chunnakum Extension*** *1x300 MW Puttalam Coal (Stage II)*	-	0.974
2015	-	*1x300 MW Puttalam Coal (Stage II)* **1x75 MW Gas Turbine** **1x105 MW Gas Turbine**	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.246
2016	*35 MW Broadlands* *120 MW Uma Oya*	-	-	1.092
2017	-	**1x150 MW Combined Cycle**	-	1.334
2018	**27 MW Moragolla Plant**	**3x250 MW Trinco Coal Power plant**	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi 4x5 MW Northern Power 8x6.13 MW Asia Power	0.154
2019	-	**1x250 MW Trinco Coal Power plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.221
2020	-	**1x300 MW Coal plant**	-	0.133
2021	-	**1x300 MW Coal plant**	-	0.088
2022	-	**1x300 MW Coal plant**	-	0.066
2023	-	**1x300 MW Coal plant**	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.202
2024	-	**1x300 MW Coal plant**	-	0.160
2025	**49 MW Gin Ganga**	**1x300 MW Coal plant**	4x9 MW Sapugaskanda Diesel Ext.	0.119
2026	-	**1x300 MW Coal plant**	-	0.107
2027	-	-	-	0.401
2028	-	**1x300 MW Coal plant**	-	0.301
2029	-	-	-	0.966
2030	-	**1x300 MW Coal plant**	-	1.006
2031	-	**1x300 MW Coal plant**	-	1.085
2032	-	**1x300 MW Coal plant**	-	1.212
Total PV Cost up to year 2032, **US$ 13,637.26 million** [LKR 1,553,278.23 million]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9)
- All additions/retirements are carried out at the beginning of each year.
- Committed plants are shown in Italics.
- All plant capacities are given in gross values.

** Year of connection to national grid based on the estimated time schedule of Kilinochchi-Chunnakkam Tx line.

Results of Generation Expansion Planning Studies - 2012

High Demand Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	-	-	-	4.255
2014	-	*4x5 MW Northern Power*** *3x8 MW Chunnakum Extension*** *1x300 MW Puttalam Coal (Stage II)*	-	1.972
2015	-	*1x300MW Puttalam Coal (Stage II)* **4x75 MW Gas Turbine**	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.401
2016	*35 MW Broadlands* *120 MW Uma Oya*	**1x300 MW CCY plant**	-	0.398
2017	-	-	-	1.464
2018	**27 MW Moragolla Plant**	**4x250 MW Trinco Coal Power plant**	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi 4x5 MW Northern Power 8x6.13 MW Asia Power	0.086
2019	-	**1x300 MW Coal plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.183
2020		**2x300 MW Coal plant**	-	0.048
2021	-	**1x300 MW Coal plant**	-	0.076
2022	-	**1x300 MW Coal plant**	-	0.138
2023	-	**2x300 MW Coal plant**	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.181
2024	**49 MW Gin Ganga**	**1x300 MW Coal plant**	-	0.280
2025	-	**1x300 MW Coal plant**	4x9 MW Sapugaskanda Diesel Ext.	0.636
2026	-	**1x300 MW Coal plant**	-	1.227
2027	-	**2x300 MW Coal plant**	-	1.058
2028	-	**2x300 MW Coal plant**	-	0.776
2029	-	**1x300 MW Coal plant** **1x105 MW Gas Turbine**	-	1.324
2030	-	**2x300 MW Coal plant** **1x105 MW Gas Turbine**	-	1.173
2031	-	**2x300 MW Coal plant**	-	1.468
2032	-	**2x300 MW Coal plant** **2x105 MW Gas Turbine**	-	1.250
Total PV Cost up to year 2032, **US$ 18,048.608 million** [LKR 2,055,729.23 million]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9)
- All additions/retirements are carried out at the beginning of each year.
- Committed plants are shown in Italics.
- Above PV cost includes the cost of Projected NCRE, US$ 689.98 million and five year IPP extension cost (ACE Matara, ACE Horana and Lakdanavi), US$ 9.83 million
- All plant capacities are given in gross values.

** Year of connection to national grid based on the estimated time schedule of Kilinochchi-Chunnakkam Tx line.

Results of Generation Expansion Planning Studies - 2012

Low Demand (Demand Side Management) Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	-	-	-	0.668
2014	-	*4x5 MW Northern Power*** *3x8 MW Chunnakum Extension*** *1x300 MW Puttalam Coal (Stage II)*	-	0.329
2015	-	*1x300 MW Puttalam Coal (Stage II)*	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	0.913
2016	*35 MW Broadlands* *120 MW Uma Oya*	-	-	0.705
2017	-	-	-	1.459
2018	**27 MW Moragolla Plant**	**2x250 MW Trinco Coal Power plant**	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi 4x5 MW Northern Power 8x6.13 MW Asia Power	0.441
2019	-	**2x250 MW Trinco Coal Power plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.098
2020	-	-	-	0.207
2021	-	**1x300 MW Coal plant**	-	0.098
2022	-	-	-	0.260
2023	-	**1x300 MW Coal plant**	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.589
2024	**49MW Gin Ganga**	-	-	0.941
2025	-	**1x300 MW Coal plant**	4x9 MW Sapugaskanda Diesel Ext.	0.695
2026	-	**1x300 MW Coal plant**	-	0.467
2027	-	-	-	1.063
2028	-	**1x300 MW Coal plant**	-	0.608
2029	-	**1x300 MW Coal plant**	-	0.470
2030	-	-	-	1.177
2031	-	**1x300 MW Coal plant**	-	1.001
2032	-	**1x75 MW Gas Turbine** **1x105 MW Gas Turbine**	-	1.216
Total PV Cost up to year 2032, **US$ 11,379.616 million** [LKR 1,296,133.71 million]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics.
- All plant capacities are given in gross values.
- Above PV cost includes the cost of Projected NCRE, US$ 689.98 million and five year IPP extension cost (ACE Matara, ACE Horana and Lakdanavi), US$ 9.83 million

** Year of connection to national grid based on the estimated time schedule of Kilinochchi-Chunnakkam Tx line.

Annex 7.9

Results of Generation Expansion Planning Studies - 2012

High Discount (15%) Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	-	-	-	1.155
2014	-	*4x5 MW Northern Power*** *3x8 MW Chunnakum Extension*** *1x300 MW Puttalam Coal (Stage II)*	-	0.819
2015	-	*1x300 MW Puttalam Coal (Stage II)* **2x75 MW Gas Turbine**	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.277
2016	*35 MW Broadlands* *120 MW Uma Oya*	-	-	1.070
2017	-	**2x75 MW Gas Turbine**	-	1.198
2018	**27 MW Moragolla Plant**	**3x250 MW Trinco Coal Power plant**	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi 4x5 MW Northern Power 8x6.13 MW Asia Power	0.119
2019	-	**1x250 MW Trinco Coal Power plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.164
2020	-	**1x300 MW Coal plant**	-	0.094
2021	-	**1x300 MW Coal plant**	-	0.060
2022	-	**1x300 MW Coal plant**	-	0.043
2023	-		163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.499
2024		**1x300 MW Coal plant -**	-	0.396
2025	-		4x9 MW Sapugaskanda Diesel Ext.	1.212
2026	-	**1x300 MW Coal plant**	-	1.041
2027	-	**1x300 MW Coal plant**	-	0.926
2028	-	**1x300 MW Coal plant**	-	0.755
2029	-	**1x75 MW Gas Turbine**	-	1.492
2030	-	**1x300 MW Coal plan**	-	1.497
2031	**49 MW Gin Ganga**	**1x300 MW Coal plant**	-	1.306
2032	-	**1x300 MW Coal plant**	-	1.403
Total PV Cost up to year 2032, **US$ 9,966.644 million** [LKR 1,135,200.752 million]				

Notes:

- Discount rate 15%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9).
- All additions/retirements are carried out at the beginning of each year.
- Committed plants are shown in Italics.
- All plant capacities are given in gross values.
- Above PV cost includes the cost of Projected Committed NCRE, US$ 525.98 million and five year IPP extension cost (ACE Matara, ACE Horana and Lakdanavi), US$ 9.83 million.

** Year of connection to national grid based on the estimated time schedule of Kilinochchi-Chunnakkam Tx line.

Annex 7.10

Results of Generation Expansion Planning Studies - 2012

Low Discount Rate (3%) Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	-	-	-	1.155
2014	-	*4x5 MW Northern Power*** *3x8 MW Chunnakum Extension*** *1x300 MW Puttalam Coal (Stage II)*	-	0.819
2015	-	*1x300 MW Puttalam Coal (Stage II)* **1x75 MW Gas Turbine** **1x105 MW Gas Turbine**	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.103
2016	*35 MW Broadlands* *120 MW Uma Oya*	-	-	0.854
2017	-	**1x105 MW Gas Turbine**	-	1.320
2018	-	**3x250 MW Trinco Coal Power plant**	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi 4x5 MW Northern Power 8x6.13 MW Asia Power	0.160
2019	-	**1x300 MW Coal plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.172
2020	**27 MW Moragolla Plant**	**1x250 MW Trinco Coal Power plant**	-	0.106
2021	-	**1x300 MW Coal plant**	-	0.067
2022	-	**1x300 MW Coal plant**	-	0.048
2023	-	**1x300 MW Coal plant**	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.134
2024	**49 MW Gin Ganga**	**1x300 MW Coal plant**	-	0.074
2025	-	**1x300 MW Coal plant**	4x9 MW Sapugaskanda Diesel Ext.	0.073
2026	-	**1x300 MW Coal plant**	-	0.063
2027	-	-	-	0.241
2028	-	**1x300 MW Coal plant**	-	0.189
2029	-	**1x300 MW Coal plant**	-	0.190
2030	-	-	-	0.654
2031	-	**1x300 MW Coal plant**	-	0.697
2032	-	**1x300 MW Coal plant**	-	0.775
Total PV Cost up to year 2032, **US$ 23,979.994 million** [LKR 2,731,321.31 million]				

Notes:

- Discount rate 3 %, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics
- Above PV cost includes the cost of Projected NCRE, US$ 1135.61 million and five year IPP extension cost (ACE Matara, ACE Horana and Lakdanavi), US$ 9.83 million.
- All plant capacities are given in gross values.

** Year of connection to national grid based on the estimated time schedule of Kilinochchi-Chunnakkam Tx line.

Results of Generation Expansion Planning Studies - 2012

50% high ENS Cost Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	-	-	-	1.155
2014	-	*4x5 MW Northern Power*** *3x8 MW Chunnakum Extension*** *1x300 MW Puttalam Coal (Stage II)*	-	0.819
2015	-	*1x300 MW Puttalam Coal (Stage II)* **1x75 MW Gas Turbine** **1x105 MW Gas Turbine**	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.103
2016	*35 MW Broadlands* *120 MW Uma Oya*	-	-	0.854
2017	-	**1x105 MW Gas Turbine**	-	1.320
2018	**27 MW Moragolla Plant**	**3x250 MW Trinco Coal Power plant**	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi 4x5 MW Northern Power 8x6.13 MW Asia Power	0.133
2019	-	**1x250 MW Trinco Coal Power plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.183
2020		**1x300 MW Coal plant**	-	0.106
2021	-	**1x300 MW Coal plant**	-	0.067
2022	-	**1x300 MW Coal plant**	-	0.048
2023	-	**1x300 MW Coal plant**	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.134
2024	-	**1x300 MW Coal plant**	-	0.102
2025	-	**1x300 MW Coal plant**	4x9 MW Sapugaskanda Diesel Ext.	0.099
2026	-	-	-	0.346
2027	-	**1x300 MW Coal plant**	-	0.310
2028	-	-	-	0.804
2029	**49 MW Gin Ganga**	**1x300 MW Coal plant**	-	0.633
2030	-	**1x300 MW Coal plant**	-	0.654
2031	-	**1x300 MW Coal plant**	-	0.697
2032	-	**1x75 MW Gas Turbine**	-	1.469
Total PV Cost up to year 2032, **US$ 13,754.777million** [LKR 1,566,669.1 million]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9)
- All additions/retirements are carried out at the beginning of each year.
- All plant capacities are given in gross values.
- Committed plants are shown in Italics
- Above PV cost includes the cost of Projected NCRE, US$ 689.98 million and five year IPP extension cost (ACE Matara, ACE Horana and Lakdanavi), US$ 9.83 million.
- 50% increase of Cost of Energy Not Served value is taken as 0.8USCents/kWh

** Year of connection to national grid based on the estimated time schedule of Kilinochchi-Chunnakkam Tx line.

Results of Generation Expansion Planning Studies - 2012

Coal & Oil 50% Price High, LNG Base Price Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	-	-	-	1.155
2014	-	*4x5 MW Northern Power*** *3x8 MW Chunnakum Extension*** *1x300 MW Puttalam Coal (Stage II)*	-	0.819
2015	-	*1x300 MW Puttalam Coal (Stage II)* **1x75 MW Gas Turbine** **1x105 MW Gas Turbine**	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.103
2016	*35 MW Broadlands* *120 MW Uma Oya*	-	-	0.854
2017	-	**1x105 MW Gas Turbine**	-	1.320
2018	**27 MW Moragolla Plant**	**3x250 MW Trinco Coal Power plant**	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi 4x5 MW Northern Power 8x6.13 MW Asia Power	0.133
2019	-	**1x250 MW Trinco Coal Power plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.183
2020	-	**1x300 MW Coal plant**	-	0.106
2021	-	**1x300 MW Coal plant**	-	0.067
2022	-	**1x300 MW Coal plant**	-	0.048
2023	-	**1x300 MW Coal plant**	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.134
2024	**49 MW Gin Ganga**	**1x300 MW Coal plant**	-	0.074
2025	-	**1x300 MW Coal plant**	4x9 MW Sapugaskanda Diesel Ext.	0.073
2026	-	-	-	0.268
2027	-	**1x300 MW Coal plant**	-	0.241
2028	-	-	-	0.648
2029	-	**1x300 MW Coal plant**	-	0.633
2030	-	**1x300 MW Coal plant**	-	0.654
2031	-	**1x300 MW Coal plant**	-	0.697
2032	-	**1x300 MW Coal plant**	-	0.775
Total PV Cost up to year 2032, **US$ 18,531.594 million** [LKR 2,110,741.14 million]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics
- Above PV cost includes the cost of Projected NCRE, US$ 689.98 million and five year IPP extension cost (ACE Matara, ACE Horana and Lakdanavi), US$ 9.83 million.
- All plant capacities are given in gross values.

** Year of connection to national grid based on the estimated time schedule of Kilinochchi-Chunnakkam Tx line.

Results of Generation Expansion Planning Studies - 2012

Coal 50% Price High, Oil, LNG Base Price Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	-	-	-	1.155
2014	-	*4x5 MW Northern Power*** *3x8 MW Chunnakum Extension*** *1x300 MW Puttalam Coal (Stage II)*	-	0.819
2015	-	*1x300 MW Puttalam Coal (Stage II)* **1x75 MW Gas Turbine** **1x105 MW Gas Turbine**	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.103
2016	*35 MW Broadlands* *120 MW Uma Oya*	-	-	0.854
2017	-	**1x105 MW Gas Turbine**	-	1.320
2018	**27 MW Moragolla Plant**	**3x250 MW Trinco Coal Power plant**	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi 4x5 MW Northern Power 8x6.13 MW Asia Power	0.133
2019	-	**1x250 MW Trinco Coal Power plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.183
2020	-	**1x300 MW Coal plant**	-	0.106
2021	-	**1x300 MW Coal plant**	-	0.067
2022	-	**1x300 MW Coal plant**	-	0.048
2023	-	**1x300 MW Coal plant**	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.134
2024	**49 MW Gin Ganga**	-	-	0.331
2025	-	**1x300 MW Coal plant**	4x9 MW Sapugaskanda Diesel Ext.	0.311
2026	-	-	-	0.886
2027	-	**1x300 MW Coal plant**	-	0.794
2028	-	**1x300 MW Coal plant**	-	0.648
2029	-	**1x300 MW Coal plant**	-	0.633
2030	-	**1x75 MW Gas Turbine**	-	1.327
2031	-	**1x300 MW Coal plant**	-	1.371
2032	-	**1x300 MW Coal plant**	-	1.469
Total PV Cost up to year 2032, **US$ 16,226.68 million** [LKR 1,848,212.36 million]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics.
- Above PV cost includes the cost of Projected NCRE, US$ 689.98 million and five year IPP extension cost (ACE Matara, ACE Horana and Lakdanavi), US$ 9.83 million.
- All plant capacities are given in gross values.

** Year of connection to national grid based on the estimated time schedule of Kilinochchi-Chunnakkam Tx line.

Annex 7.14

Results of Generation Expansion Planning Studies - 2012

High NCRE 20% at 2020-Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	**2x4 MW Dendro plant**	-	-	1.307
2014	**1x4 MW Dendro plant**	*4x5 MW Northern Power*** *3x8 MW Chunnakum Extension*** *1x300 MW Puttalam Coal (Stage II)*	-	0.934
2015	**1x4 MW Dendro plant** **1x50 MW Wind power**	*1x300 MW Puttalam Coal (Stage II)* **2x75 MW Gas Turbine**	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.014
2016	*35 MW Broadlands* *120 MW Uma Oya* **3x4 MW Dendro plant** **1x50 MW Wind power**	-	-	0.839
2017	**7x4 MW Dendro plant**	**1x75 MW Gas Turbine**	-	1.285
2018	**8x4 MW Dendro plant** **1x50 MW Wind power** **27 MW Moragolla Plant**	**2x250 MW Trinco Coal Power plant**	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi 4x5 MW Northern Power 8x6.13 MW Asia Power	0.260
2019	**6x4 MW Dendro plant** **1x50 MW Wind power**	**1x250 MW Trinco Coal Power plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.245
2020	**2x4 MW Dendro plant** **2x50 MW Wind power**	**1x250 MW Trinco Coal Power plant**	-	0.105
2021	**2x4 MW Dendro plant**	**1x300 MW Coal plant**	-	0.064
2022	**3x4 MW Dendro plant**	-	-	0.220
2023	**3x4 MW Dendro plant**	**2x300 MW Coal plant**	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.117
2024	**49 MW Gin Ganga** **4x4 MW Dendro plant**	**1x300 MW Coal plant**	-	0.058
2025	**5x4 MW Dendro plant**	-	4x9 MW Sapugaskanda Diesel Ext.	0.246
2026	**6x4 MW Dendro plant** **1x50 MW Wind power**	**1x300 MW Coal plant**	-	0.152
2027	**6x4 MW Dendro plant**	-	-	0.480
2028	**3x4 MW Dendro plant**	**1x300 MW Coal plant**	-	0.356
2029	**4x4 MW Dendro plant** **1x50 MW Wind power**	-	-	0.892
2030	**6x4 MW Dendro plant**	**1x300 MW Coal plant**	-	0.839
2031	**1x4 MW Dendro plant**	**1x300 MW Coal plant**	-	0.882
2032	**1x4 MW Dendro plant** **1x50 MW Wind power**	**1x300 MW Coal plant**	-	0.832
Total PV Cost up to year 2032, **US$ 13,704.007 million** [LKR 1,560,880.92 million]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics
- Above PV cost includes the cost of Projected Mini hydro, US$ 479 million and five year IPP extension cost (ACE Matara, ACE Horana and Lakdanavi), US$ 9.83 million
- All plant capacities are given in gross values.

** Year of connection to national grid based on the estimated time schedule of Kilinochchi-Chunnakkam Tx line.

Annex 7.15

Results of Generation Expansion Planning Studies - 2012

No Coal Plants permitted after Trinco Coal Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	-	-	-	1.155
2014	-	*4x5 MW Northern Power*** *3x8 MW Chunnakum Extension*** *1x300 MW Puttalam Coal (Stage II)*	-	0.819
2015	-	*1x300 MW Puttalam Coal (Stage II)* **1x75 MW Gas Turbine** **1x105 MW Gas Turbine**	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.103
2016	*35 MW Broadlands* *120 MW Uma Oya*	-	-	0.854
2017	-	**1x105 MW Gas Turbine**	-	1.320
2018	**27 MW Moragolla Plant**	**3x250 MW Trinco Coal Power plant**	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi 4x5 MW Northern Power 8x6.13 MW Asia Power	0.133
2019	-	**1x250 MW Trinco Coal Power plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.183
2020	-	-	-	0.503
2021	-	-	-	1.240
2022	-	**1x250 MW LNG Power Plant with Terminal**	-	1.119
2023	-	**2x250 MW LNG Power Plant**	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.961
2024	**49 MW Gin Ganga**	**1x250 MW LNG Power Plant with Terminal**	-	0.731
2025	-	**1x250 MW LNG Power Plant**	4x9 MW Sapugaskanda Diesel Ext.	0.810
2026	-	**1x250 MW LNG Power Plant**	-	0.828
2027	-	**1x250 MW LNG Power Plant**	-	0.865
2028	-	**1x250 MW LNG Power Plant with Terminal**	-	0.831
2029	-	**1x250 MW LNG Power Plant**	-	0.923
2030	-	**1x250 MW LNG Power Plant**	-	1.068
2031	-	**1x250 MW LNG Power Plant**	-	1.252
2032	-	**1x250 MW LNG Power Plant with Terminal**	-	1.495
Total PV Cost up to year 2032, **US$ 15,065.197 million** [LKR 1,715,919.91 million]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9)
- All additions/retirements are carried out at the beginning of each year.
- Committed plants are shown in Italics.
- All Plant capacities are given in gross values.
- Social damage cost of 0.13USCents/kWh applied for the Coal.
- Above PV cost includes the cost of Projected NCRE, US$ 689.98 million and five year IPP extension cost (ACE Matara, ACE Horana and Lakdanavi), US$ 9.83 million.

** Year of connection to national grid based on the estimated time schedule of Kilinochchi-Chunnakkam Tx line.

Results of Generation Expansion Planning Studies - 2012

Coal Limited around 60% from Total Generation

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	-	-		1.155
2014	-	*4x5 MW Northern Power*** *3x8 MW Chunnakum Extension*** *1x275 MW Puttalam Coal (Stage II)*	-	0.819
2015	-	*1x275 MW Puttalam Coal (Stage II)* **1x75 MW Gas Turbine** **1x105 MW Gas Turbine**	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.103
2016	*35 MW Broadlands* *120 MW Uma Oya*	-	-	0.854
2017	-	**1x105 MW Gas Turbine**	-	1.320
2018	**27 MW Moragolla Plant**	**3x250 MW Trinco Coal Power plant**	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi 4x5 MW Northern Power 8x6.13 MW Asia Power	0.133
2019	-	**1x250 MW Trinco Coal Power plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.183
2020		**1x250 MW LNG Power Plant with Terminal**	-	0.142
2021	-	**1x250 MW LNG Power Plant**	-	0.124
2022	-	**1x300 MW Coal plant**	-	0.088
2023	-	-	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.804
2024	-	**1x250 MW LNG Power Plant**	-	0.755
2025	-	**1x300 MW Coal plant**	4x9 MW Sapugaskanda Diesel Ext.	0.715
2026	-	**1x250 MW LNG Power Plant with Terminal**	-	0.730
2027	-	**1x250 MW LNG Power Plant**	-	0.766
2028	-		-	1.661
2029	**49 MW Gin Ganga**	**1x300 MW Coal plant**	-	1.331
2030	-	**1x250 MW LNG Power Plant**	-	1.516
2031	-	**1x600 MW Nuclear Power plant**	-	0.478
2032	-	**1x300 MW Coal plant**	-	0.537
Total PV Cost up to year 2032, **US$ 14,857.544 million** [LKR 1,692,274.262 million]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics
- Above PV cost includes the cost of Projected NCRE, US$ 689.98 million and five year IPP extension cost (ACE Matara, ACE Horana and Lakdanavi), US$ 9.83 million.
- All plant capacities are given in gross values.

** Year of connection to national grid based on the estimated time schedule of Kilinochchi-Chunnakkam Tx line.

Results of Generation Expansion Planning Studies - 2012

Dendro Candidate with Local Fuel Concession Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	**2x4 MW Dendro plant**	-	-	1.123
2014	**1x4 MW Dendro plant**	*4x5 MW Northern Power*** *3x8 MW Chunnakum Extension*** *1x300 MW Puttalam Coal (Stage II)*	-	0.801
2015	**5x4 MW Dendro plant**	*1x300 MW Puttalam Coal (Stage II)* **2x75 MW Gas Turbine**	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.162
2016	*35 MW Broadlands* *120 MW Uma Oya* **7x4 MW Dendro plant**	-	-	0.791
2017	**7x4 MW Dendro plant**	**1x75MW Gas Turbine**	-	1.284
2018	**27 MW Moragolla Plant** **6x4 MW Dendro plant**	**3x250 MW Trinco Coal Power plant**	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi 4x5 MW Northern Power 8x6.13 MW Asia Power	0.113
2019	-	**1x250 MW Trinco Coal Power plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.160
2020	-	**1x300 MW Coal plant**	-	0.094
2021	-	**1x300 MW Coal plant**	-	0.061
2022	-	**1x300 MW Coal plant**	-	0.045
2023	-	**1x300 MW Coal plant**	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.128
2024	**49MW Gin Ganga**	-	-	0.326
2025	-	**1x300 MW Coal plant**	4x9 MW Sapugaskanda Diesel Ext.	0.313
2026	-	**1x300 MW Coal plant**	-	0.275
2027	-	-	-	0.823
2028	-	**1x300 MW Coal plant**	-	0.686
2029	-	**1x300 MW Coal plant**	-	0.679
2030	-	**1x300 MW Coal plant**	-	0.709
2031	-	**1x300 MW Coal plant**	-	0.764
2032	-	**1x105 MW Gas Turbine**	-	1.469
Total PV Cost up to year 2032, **US$ 13,625.885 million** [LKR 1,551,982.85 million]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics
- Above PV cost includes the cost of Projected NCRE, US$ 689.98 million and five year IPP extension cost (ACE Matara, ACE Horana and Lakdanavi), US$ 9.83 million.
- All plant capacities are given in gross values.

** Year of connection to national grid based on the estimated time schedule of Kilinochchi-Chunnakkam Tx line.

Results of Generation Expansion Planning Studies - 2012

Pump Storage Forced Operation Forced Construction in 2020 Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	-	-	-	1.155
2014	-	*4x5 MW Northern Power*** *3x8 MW Chunnakum Extension*** *1x300 MW Puttalam Coal (Stage II)*	-	0.819
2015	-	*1x300 MW Puttalam Coal (Stage II)* **1x75 MW Gas Turbine** **1x105 MW Gas Turbine**	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.103
2016	*35 MW Broadlands* *120 MW Uma Oya*	-	-	0.854
2017	-	**1x105 MW Gas Turbine**	-	1.320
2018	**27 MW Moragolla Plant**	**3x250 MW Trinco Coal Power plant**	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi 4x5 MW Northern Power 8x6.13 MW Asia Power	0.133
2019	-	**1x250 MW Trinco Coal Power plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.183
2020	**250 MW Pump storage plant**	-	-	0.088
2021	-	**1x300 MW Coal plant**	-	0.055
2022	-	**1x300 MW Coal plant**	-	0.039
2023	-	**2x300 MW Coal plant**	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.020
2024	**49 MW Gin Ganga**	-	-	0.063
2025	-	**1x300 MW Coal plant**	4x9 MW Sapugaskanda Diesel Ext.	0.062
2026	-	**1x300 MW Coal plant**	-	0.054
2027	-	-	-	0.216
2028	-	**1x300 MW Coal plant**	-	0.165
2029	-	-	-	0.575
2030	-	**1x300 MW Coal plant**	-	0.597
2031	-	**1x300 MW Coal plant**	-	0.639
2032	-	**1x300 MW Coal plant**	-	0.715
Total PV Cost up to year 2032, **US$ 13,970.304 million** [LKR 1,591,212.04 million]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics.
- Above PV cost includes the cost of Projected NCRE, US$ 689.98 million and five year IPP extension cost (ACE Matara, ACE Horana and Lakdanavi), US$ 9.83 million.
- All plant capacities are given in gross values

** Year of connection to national grid based on the estimated time schedule of Kilinochchi-Chunnakkam Tx line.

Results of Generation Expansion Planning Studies - 2012

No Coal plants permitted after 2025 Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	-	-	-	1.155
2014	-	*4x5 MW Northern Power*** *3x8 MW Chunnakum Extension*** *1x300 MW Puttalam Coal (Stage II)*	-	0.819
2015	-	*1x300 MW Puttalam Coal (Stage II)* **1x75 MW Gas Turbine** **1x105 MW Gas Turbine**	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.103
2016	*35 MW Broadlands* *120 MW Uma Oya*	-	-	0.854
2017	-	**1x105 MW Gas Turbine**	-	1.320
2018	**27 MW Moragolla Plant**	**3x250 MW Trinco Coal Power plant**	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi 4x5 MW Northern Power 8x6.13 MW Asia Power	0.133
2019	-	**1x250 MW Trinco Coal Power plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.183
2020	-	**1x300 MW Coal plant**	-	0.106
2021	-	**1x300 MW Coal plant**	-	0.067
2022	-	**1x300 MW Coal plant**	-	0.048
2023	-	**1x300 MW Coal plant**	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.134
2024	-	**1x300 MW Coal plant**	-	0.102
2025	-	**1x300 MW Coal plant**	4x9 MW Sapugaskanda Diesel Ext.	0.099
2026	**49 MW Gin Ganga**	-	-	0.268
2027	-	-	-	0.794
2028	-	**1x105 MW Gas Turbine**	-	1.240
2029	-	**1x250 MW LNG Power Plant with Terminal**	-	1.368
2030	-	**2x250 MW LNG Power Plant**	-	0.711
2031	-	**1x250 MW LNG Power Plant with Terminal**	-	0.868
2032	-	**1x250 MW LNG Power Plant**	-	1.080
Total PV Cost up to year 2032, **US$ 13,947.819million** [LKR 1,588,651.01 million]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9)
- All additions/retirements are carried out at the beginning of each year.
- Committed plants are shown in Italics.
- Above PV cost includes the cost of Projected NCRE, US$ 689.98 million and five year IPP extension cost (ACE Matara, ACE Horana and Lakdanavi), US$ 9.83 million.
- All plant capacities are given in gross values.

** Year of connection to national grid based on the estimated time schedule of Kilinochchi- Chunnakkam Tx line.

Results of Generation Expansion Planning Studies - 2012

Social and Environment Damage Cost Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	-	-	-	1.155
2014	-	*4x5 MW Northern Power*** *3x8 MW Chunnakum Extension*** *1x300MW Puttalam Coal (Stage II)*	-	0.819
2015	-	*1x300 MW Puttalam Coal (Stage II)* **1x75 MW Gas Turbine** **1x105 MW Gas Turbine**	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.103
2016	*35 MW Broadlands* *120 MW Uma Oya*	-	-	0.854
2017	-	**1x105 MW Gas Turbine**	-	1.320
2018	**27 MW Moragolla Plant**	**3x250 MW Trinco Coal Power plant**	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi 4x5 MW Northern Power 8x6.13 MW Asia Power	0.133
2019	-	**1x250 MW Trinco Coal Power plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.183
2020	-	**1x300 MW Coal plant**	-	0.106
2021	-	**1x300 MW Coal plant**	-	0.067
2022	-	**1x300 MW Coal plant**	-	0.048
2023	-	**1x300 MW Coal plant**	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.134
2024	-	**1x300 MW Coal plant**	-	0.102
2025	-	**1x300 MW Coal plant**	4x9 MW Sapugaskanda Diesel Ext.	0.099
2026	-	-	-	0.346
2027	-	**1x300 MW Coal plant**	-	0.310
2028	-	-	-	0.804
2029	**49 MW Gin Ganga**	**1x300 MW Coal plant**	-	0.633
2030	-	**1x300 MW Coal plant**	-	0.654
2031	-	**1x300 MW Coal plant**	-	0.697
2032	-	**1x105 MW Gas Turbine**	-	1.346
Total PV Cost up to year 2032, **US$ 13,864.55 million** [LKR 1,579,166.70 million]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9)
- All additions/retirements are carried out at the beginning of each year.
- Committed plants are shown in Italics.
- All Plant capacities are given in gross values.
- Social damage cost of 0.13USCents/kWh applied for the Coal.
- Above PV cost includes the cost of Projected NCRE, US$ 689.98 million and five year IPP extension cost (ACE Matara, ACE Horana and Lakdanavi), US$ 9.83 million.

** Year of connection to national grid based on the estimated time schedule of Kilinochchi-Chunnakkam Tx line.

Results of Generation Expansion Planning Studies - 2012

Trincomalee 2 coal units permitted only in 2018 Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	-	-	-	1.155
2014	-	*4x5 MW Northern Power*** *3x8 MW Chunnakum Extension*** *1x300 MW Puttalam Coal (Stage II)*	-	0.819
2015	-	*1x300 MW Puttalam Coal (Stage II)* **2x75 MW Gas Turbine**	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.277
2016	*35 MW Broadlands* *120 MW Uma Oya*	-	-	1.070
2017	-	**1x150 MW CCY plant**	-	1.260
2018	**27 MW Moragolla Plant**	**2x250 MW Trinco Coal Power plant**	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi 4x5 MW Northern Power 8x6.13 MW Asia Power	0.491
2019	-	**2x250 MW Trinco Coal Power plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.174
2020	-	**1x300 MW Coal plant**	-	0.101
2021	-	**1x300 MW Coal plant**	-	0.064
2022	-	**1x300 MW Coal plant**	-	0.046
2023	-	**1x300 MW Coal plant**	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.128
2024		**1x300 MW Coal plant**	-	0.097
2025	-		4x9 MW Sapugaskanda Diesel Ext.	0.387
2026	-	**1x300 MW Coal plant**	-	0.334
2027	-	**1x300 MW Coal plant**	-	0.299
2028	-	-	-	0.779
2029	**49 MW Gin Ganga**	**1x300 MW Coal plant**	-	0.613
2030	-	**1x300 MW Coal plant**	-	0.634
2031	-	**1x300 MW Coal plant**	-	0.677
2032	-	**1x75 MW Gas Turbine**	-	1.433
Total PV Cost up to year 2032, **US$ 13,803.182 million** [LKR 1,572,182.43 million]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9)
- All additions/retirements are carried out at the beginning of each year.
- Committed plants are shown in Italics.
- All Plant capacities are given in gross values.
- Above PV cost includes the cost of Projected NCRE, US$ 689.98 million and five year IPP extension cost (ACE Matara, ACE Horana and Lakdanavi), US$ 9.83 million.

** Year of connection to national grid based on the estimated time schedule of Kilinochchi-Chunnakkam Tx line.

Annex 7.22

Results of Generation Expansion Planning Studies - 2012

HVDC Candidate Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	-	-	-	1.155
2014	-	*4x5 MW Northern Power*** *3x8 MW Chunnakum Extension*** *1x300 MW Puttalam Coal (Stage II)*	-	0.819
2015	-	*1x300 MW Puttalam Coal (Stage II)* **1x75 MW Gas Turbine** **1x105 MW Gas Turbine**	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.103
2016	*35 MW Broadlands* *120 MW Uma Oya*	-	-	0.854
2017	-	**1x105 MW Gas Turbine**	-	1.320
2018	**27 MW Moragolla Plant**	**3x250 MW Trinco Coal Power plant**	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi 4x5 MW Northern Power 8x6.13 MW Asia Power	0.133
2019	-	**1x250 MW Trinco Coal Power plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.183
2020	-	**1x300 MW Coal plant**	-	0.106
2021	-	**1x300 MW Coal plant**	-	0.067
2022	-	**1x300 MW Coal plant**	-	0.048
2023	-	**1x500 MW Indu Lanka HVDC interconnection**	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.021
2024	**49 MW Gin Ganga**	-	-	0.065
2025	-	**1x300 MW Coal plant**	4x9 MW Sapugaskanda Diesel Ext.	0.066
2026	-	-	-	0.244
2027	-	**1x300 MW Coal plant**	-	0.220
2028	-	**1x300 MW Coal plant**	-	0.173
2029		**1x300 MW Coal plant**	-	0.175
2030	-	-	-	0.612
2031	-	**1x300 MW Coal plant**	-	0.656
2032	-	**1x300 MW Coal plant**	-	0.731
Total PV Cost up to year 2032, **US$ 13,729.499 million** [LKR 1,563,784.44 million]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9)
- All additions/retirements are carried out at the beginning of each year.
- Committed plants are shown in Italics.
- All plant capacities are given in gross values.
- Above PV cost includes the cost of Projected NCRE, US$ 689.98 million and five year IPP extension cost (ACE Matara, ACE Horana and Lakdanavi), US$ 9.83 million.

** Year of connection to national grid based on the estimated time schedule of Kilinochchi-Chunnakkam Tx line.

Results of Generation Expansion Planning Studies - 2012

Base case with CDM benefit Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	-	-	-	1.155
2014	-	*4x5 MW Northern Power*** *3x8 MW Chunnakum Extension*** *1x300 MW Puttalam Coal (Stage II)*	-	0.819
2015	-	*1x300 MW Puttalam Coal (Stage II)* **1x75 MW Gas Turbine** **1x105 MW Gas Turbine**	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.103
2016	*35 MW Broadlands* *120 MW Uma Oya*	-	-	0.854
2017	-	**1x105 MW Gas Turbine**	-	1.320
2018	**27 MW Moragolla Plant**	**3x250 MW Trinco Coal Power plant**	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi 4x5 MW Northern Power 8x6.13 MW Asia Power	0.133
2019	-	**1x250 MW Trinco Coal Power plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.183
2020	-	**1x300 MW Coal plant**	-	0.106
2021	-	**1x300 MW Coal plant**	-	0.067
2022	-	**1x300 MW Coal plant**	-	0.048
2023	-	**1x300 MW Coal plant**	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.134
2024	-	**1x300 MW Coal plant**	-	0.102
2025	-	-	4x9 MW Sapugaskanda Diesel Ext.	0.400
2026	-	**1x300 MW Coal plant**	-	0.346
2027	-	**1x300 MW Coal plant**	-	0.310
2028	-	-	-	0.804
2029	**49 MW Gin Ganga**	**1x300 MW Coal plant**	-	0.633
2030	-	**1x300 MW Coal plant**	-	0.654
2031	-	**1x300 MW Coal plant**	-	0.697
2032	-	**1x75 MW Gas Turbine**	-	1.469
Total PV Cost up to year 2032, **US$ 13,527.433 million** [LKR 1,540,769.21 million]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9)
- CER price 14.2 $/MT.
- All additions/retirements are carried out at the beginning of each year.
- Committed plants are shown in Italics.
- Above PV cost includes the cost of Projected NCRE, US$ 590.33 million and five year IPP extension cost (ACE Matara, ACE Horana and Lakdanavi), US$ 9.83 million.
- All plant capacities are given in gross values.

** Year of connection to national grid based on the estimated time schedule of Kilinochchi-Chunnakkam Tx line.

Results of Generation Expansion Planning Studies - 2012

Intermediate High Demand Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	-	-	-	1.161
2014	-	*4x5 MW Northern Power*** *3x8 MW Chunnakum Extension*** *1x300 MW Puttalam Coal (Stage II)*	-	1.158
2015	-	*1x300 MW Puttalam Coal (Stage II)* **2x75 MW Gas Turbine** **1x105 MW Gas Turbine**	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.237
2016	*35 MW Broadlands* *120 MW Uma Oya*	-	-	1.286
2017	-	**1x300 MW CCY Plant**	-	0.953
2018	-	**3x250 MW Trinco Coal Power plant**	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi 4x5 MW Northern Power 8x6.13 MW Asia Power	0.174
2019	-	**1x250 MW Trinco Coal Power plant** **1x300 MW Coal plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.069
2020	-	**1x300 MW Coal plant**	-	0.063
2021	-	**1x300 MW Coal plant**	-	0.068
2022	-	**1x300 MW Coal plant**	-	0.085
2023	-	**2x300 MW Coal plant**	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.079
2024	**27 MW Moragolla Plant** **49 MW Gin Ganga**	**1x300 MW Coal plant**	-	0.070
2025	-	-	4x9 MW Sapugaskanda Diesel Ext.	0.452
2026	-	**1x300 MW Coal plant**	-	0.662
2027	-	**1x300 MW Coal plant**	-	0.973
2028	-	**1x300 MW Coal plant**	-	1.175
2029		**2x300 MW Coal plant**	-	0.800
2030	-	**1x300 MW Coal plant**	-	1.358
2031	-	**1x300 MW Coal plant** **2x105 MW Gas Turbine**	-	1.321
2032	-	**2x300 MW Coal plant**	-	1.168
Total PV Cost up to year 2032, **US$ 16,089.64 million** [LKR 1,832,602.99 million]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9).
- All additions/retirements are carried out at the beginning of each year.
- Committed plants are shown in Italics.
- Above PV cost includes the cost of Projected NCRE, US$ 689.98 million and five year IPP extension cost (ACE Matara, ACE Horana and Lakdanavi), US$ 9.83 million.
- All plant capacities are given in gross values.

** Year of connection to national grid based on the estimated time schedule of Kilinochchi-Chunnakkam Tx line.

Annex 10.1

Actual Generation Expansions and the Plans from 1994-2013

Year	Actual expansions	1989-2002	1991-2005	1992-2006	1993-2007	1994-2008	1995-2009	1996-2010	1998-2012	1999-2013	2000-2014	2002-2016	2003-2017	2005-2019	2006-2020	2008-2022	2011-2025	2013-2032
1994	-	80-DS 80-DS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1995	-	120-DS	-	40-DS	40-DS 22-GT	-	-	-	-	-	-	-	-	-	-	-	-	-
1996	-	80-DS	-	20-DS	60-DS	66-GT 40-DS	-	-	-	-	-	-	-	-	-	-	-	-
1997	-	136-CCY	40-DS	40-BDL 44-GT	60-DS 40-BDL	110-DS	66-GT 170-DS	40-DS 36-DS (Referbish)	-	-	-	-	-	-	-	-	-	-
1998	22.5-LKV 115-GT 40-DS	150-CO	72-MAD 66-GT	-	66-GT	40-DS	22-GT 20-DS	140-GT 90-DS	-	-	-	-	-	-	-	-	-	-
1999	49-Asia	150-CO	40-DS 44-GT	150-CO	22-GT 70-KUK	70-KUK	68-CCY	150-CCY	40-DS 51-Asia 100-CCY	-	-	-	-	-	-	-	-	-
2000	40-DS	150-CO	64-UPK 40-DS 22-GT	-	150-CO 123-UPK	123-UPK	70-KUK	150-CCY	105-GT 50-CCY	40-DS 60-Col	60-Col	-	-	-	-	-	-	-
2001	60-Col	300-CO 136-CC	40-BDL 60-DS 44-GT	150-CO	150-CO	150-CO	150-CO 150-UPK	-	300-CCY	100-CCY 150-CCY	40-DS	-	-	-	-	-	-	-
2002	20-ACE	300-CO	49-GIN 22-GT	150-CO	300-CO	150-CO	22-GT	150-CO 70-KUK	70-KUK	50-CCY	100-CCY 100-AES	20-ACE 109-AES	-	-	-	-	-	-
2003	20-ACE 165-CCY	-	150-CO	60-GT (Referbish)	60-GT (Referbish)	60-GT (Referbish)	150-CO 60-GT (Referbish)	150-CO 60-GT (Referbish)	-	70-KUK 150-CCY	50-CCY 50-AES	61-CCY 54-AES 20-ACE 22-DS	20-ACE	-	-	-	-	-
2004	70-KUK 163-AES	-	150-CO	150-CO 60-GT (Referbish)	300-CO 60-GT (Referbish)	300-CO 60-GT (Referbish)	60-GT (Referbish)	300-CO 60-GT (Referbish)	300-CO	300-CO	70-KUK 150-CCY	70-KUK	70-KUK 163-AES	-	-	-	-	-
2005	100-HLV 100-ACE	-	22-GT	300-CO	44-GT	-	300-CO	-	105-GT	-	-	300-CCY	200-DS	100-HLV 100-ACE	-	-	-	-
2006	-	-	-	-	49-GIN 44-GT 68-CCY	22-GT 49-GIN	-	300-CCY	300-CO	150-UPK	300-CO	-	300-CCY	-	-	-	-	-
2007	-	-	-	-	150-CO 22-GT	300-CO	300-CO	-	-	-	150-UPK	105-GT	-	200-GT PART	-	-	-	-
2008	-	-	-	-	-	66-GT	49-GIN	300-CO	300-CO	300-CO	300-CO	150-UPK 300-CO	300-CO	100-ST PART 105-GT	200-GT PART	-	-	-
2009	-	-	-	-	-	-	300-TRNC	300-CO	300-TRNC	105-GT	35-GT	-	150-UPK	140-GT	100-ST PART 2*105-GT 35-GT	200-GT PART	-	-
2010	270-WC CCY	-	-	-	-	-	-	300-CO	105-GT	300-CO	300-CO	300-CO	-	300-CO 150-UPK	75-GT 2*105-GT	300-CCY 200-GS	-	-
2011	285-PUT	-	-	-	-	-	-	-	300-TRNC	-	300-TRNC	-	300-CO	300-CO	2*300-CO 150-UPK	325-GT	285-PUT	-
2012	150-UPK	-	-	-	-	-	-	-	210-GT	300-TRNC	105-GT	300-CO	300-CO	300-CO	300-CO	285-PUT 150-UPK	75-GT 150-UPK	-
2013	-	-	-	-	-	-	-	-	-	105-GT 10-DS	300-TRNC	300-TRNC	105-GT	300-CO	300-CO	285-PUT(ST2) 500-TRNC	20-Northern 24-CPE 35-GT	-

Note: NCRE Plants are not indicated

KUK – Kukule hydro power station, BDL – Broadlands hydro power station, UPK – Upper Kotmale hydro power station, GIN – Gin ganga hydro power station, MAD – Madulu oya hydro power station

ST – Steam plant, DS – Diesel plant, CPE-Chunnakum Power Extension, CCY – Combined cycle plant, CO – Coal fired steam plant, GT – Gas turbine, LKV – Lakdanavi power plant, Asia – Asia power plant, Col – Colombo power plant, ACE – ACE power plant,HLV-Heladanavi power station, TRNC-Trinco Coal Power Plant, Northern-Northern Power plant

Annex 11

Addendum

Results of Generation Expansion Planning Studies
Revised Base Case

Results of Generation Expansion Planning Studies

Revised Base Case 2012

Table Ad.1 Revised Base Case Plan

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2013	-	-	4x5 MW ACE Power Matara 4x5 MW ACE Power Horana 4x5.63 MW Lakdanavi	1.821
2014	-	*4x5 MW Northern Power** *3x8 MW Chunnakum Extension** *1x300 MW Puttalam Coal (Stage II)*		1.357
2015	-	*1x300 MW Puttalam Coal (Stage II)**** **3x75 MW Gas Turbine**	6x16.6 MW HeladanaviPuttalam 14x7.11 MW ACE Power Embilipitiya 4x15 MW Colombo Power	1.228
2016	*35 MW Broadlands* *120 MW Uma Oya*	-	-	1.017
2017	-	**1x105 MW Gas Turbine**	-	1.483
2018	**27 MW Moragolla Plant**	**2x250 MW Trincomalee Coal Power plant**	4x5 MW Northern Power 8x6.13 MW Asia Power	0.399
2019	-	**2x300 MW Coal plant**	5x17 MW Kelanitissa Gas Turbines 4x18 MW Sapugaskanda diesel	0.080
2020	-	-	-	0.247
2021	-	**1x300 MW Coal plant**	-	0.162
2022	**49 MW Gin Ganga** **	**1x300 MW Coal plant**	-	0.085
2023	-	**2x300 MW Coal plant**	163 MW AES Kelanitissa Combined Cycle Plant 115 MW Gas Turbine 4x9 MW Sapugaskanda Diesel Ext.	0.045
2024	-	-	-	0.169
2025	-	**1x300 MW Coal plant**	4x9 MW Sapugaskanda Diesel Ext.	0.162
2026	-	-	-	0.518
2027	-	**1x300 MW Coal plant**	-	0.466
2028	-	**1x300 MW Coal plant**	-	0.370
2029	-	-	-	1.078
2030	-	**1x300 MW Coal plant**	-	1.094
2031	-	**1x300 MW Coal plant**	-	1.140
2032	-	**1x300 MW Coal plant**	-	1.233
Total PV Cost up to year 2032, **US$ 14,049.05 million** [LKR 1,600,181.18 million]				

Notes:

- Discount rate 10%, Exchange Rate as an average of January 2012 (US$ 1 = LKR. 113.9)
- All additions/retirements are carried out at the beginning of each year
- Committed plants are shown in Italics. All plant capacities are given in gross values.
- PV cost includes the cost of Projected Committed NCRE, US$ 689.98 million.

* Year of connection to national grid based on the estimated time schedule of Kilinochchi – Chunnakkam Tx line.

** 49MW Ging ganga Hydro Power Plant is forced in year 2022 considering 4 years for securing approvals and finances, preliminary & detailed design, preparation of Tender Documents, Tendering and 4 years for construction & commission work from year 2014 as water resource distribution of this Project is still not decided by Irrigation Department.

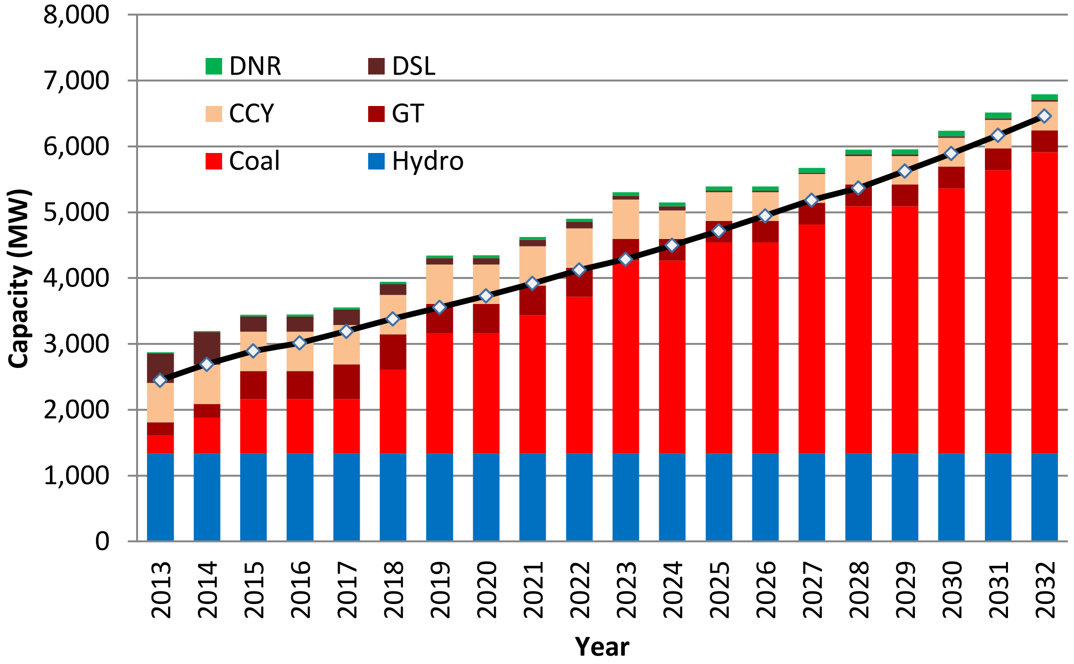
*** Scheduled in operation by June 2014.

Ad.2 System Capacity Distribution for the Revised Base Case and Cumulative Capacity by Plant type

Table Ad.2 System Capacity Distribution for the Revised Base Case

Type of Plant	2013 - 2017	2018 - 2022	2023- 2027	2028- 2032	Total capacity addition	
	(MW)	(MW)	(MW)	(MW)	**(MW)**	**%**
Major Hydro	155	76			**231**	**3.8%**
NCRE	287	158	140	135	**720**	**11.9%**
Coal	600	1700	1200	1200	**4700**	**78.0%**
Gas Turbines	330				**330**	**5.5%**
Medium Diesel	44				**44**	**0.7%**
Total	**1,416**	**1,934**	**1,340**	**1,335**	**6,025**	**100.00%**

Figure Ad.2 Cumulative Capacity by Plant type



*NCRE non-dispatchable capacity is not included

Annex 11 : Addendum

Table Ad.3. Capacity Balance for the Revised Base Case – 2012

Plant Name	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hydro																				
Existing Major Hydro	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335	1335
New Major Hydro	0	0	0	155	155	182	182	182	182	231	231	231	231	231	231	231	231	231	231	231
Mini hydro	219	232	244	256	279	294	308	320	332	345	354	365	377	389	400	412	414	426	438	450
Sub Total	1554	1567	1579	1746	1769	1811	1825	1837	1849	1911	1920	1931	1943	1955	1966	1978	1980	1992	2004	2016
NCRE - Wind	90	90	90	220	230	240	250	260	270	280	290	300	310	320	330	340	350	360	370	380
NCRE - Solar	1.3	21	31	51	72	82	85	88	91	94	97	100	103	106	109	112	115	118	121	124
Thermal Existing and Committed																				
Small Gas Turbines	85	85	85	85	85	85	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Sapugaskanda	72	72	72	72	72	72	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesl Ext.Sapugaskanda	72	72	72	72	72	72	72	72	72	72	36	36	0	0	0	0	0	0	0	0
Gas Turbine No7	115	115	115	115	115	115	115	115	115	115	0	0	0	0	0	0	0	0	0	0
Lakdhanavi	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Asia Power	49	49	49	49	49	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KPS Combined Cycle	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165
AES Combined Cycle	163	163	163	163	163	163	163	163	163	163	163	0	0	0	0	0	0	0	0	0
Colombo Power	60	60	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ACE Power Horana	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ACE Power Matara	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Heladhanavi	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ACE Power Embilipitiya	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass (Dendro)	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Kerawalapitiya CCY	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270
Puttalum Coal	275	550	825	825	825	825	825	825	825	825	825	825	825	825	825	825	825	825	825	825
Northern Power	0	20	20	20	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Chunnakkam Power Extension	0	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Sub Total	1,535	1,854	1,870	1,870	1,870	1,801	1,644	1,644	1,644	1,644	1,493	1,330	1,294	1,294	1,294	1,294	1,294	1,294	1,294	1,294
New Thermal Plants																				
Coal	0	0	0	0	0	0	550	550	825	1,100	1,650	1,650	1,925	1,925	2,200	2,475	2,475	2,750	3,025	3,300
Gas Turbine 75 MW	0	0	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225
Gas Turbine 105 MW	0	0	0	0	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105
Coal Trinco	0	0	0	0	0	454	454	454	454	454	454	454	454	454	454	454	454	454	454	454
Biomass (Dendro)	4	8	12	16	20	24	28	32	36	40	44	48	52	56	60	64	68	72	76	80
Sub Total	4	8	237	241	350	808	1362	1366	1645	1924	2478	2482	2761	2765	3044	3323	3327	3606	3885	4164
Total Installed Capacity (A)	**3184**	**3540**	**3807**	**4128**	**4291**	**4742**	**5166**	**5195**	**5499**	**5853**	**6278**	**6143**	**6411**	**6440**	**6743**	**7047**	**7066**	**7370**	**7674**	**7978**
Installed Capacity without NCRE*(B)	**2874**	**3197**	**3442**	**3601**	**3710**	**4126**	**4523**	**4527**	**4806**	**5134**	**5537**	**5378**	**5621**	**5625**	**5904**	**6183**	**6187**	**6466**	**6745**	**7024**
Peak Demand (C)	2451	2692	2894	3016	3193	3383	3556	3731	3920	4125	4287	4499	4717	4948	5187	5369	5625	5893	6171	6461
Difference without NCRE* (B-C)	**423**	**505**	**548**	**585**	**517**	**743**	**967**	**796**	**886**	**1009**	**1250**	**879**	**904**	**677**	**717**	**814**	**562**	**573**	**574**	**563**
Difference (%)	**17.3**	**18.8**	**18.9**	**19.4**	**16.2**	**22.0**	**27.2**	**21.3**	**22.6**	**24.5**	**29.2**	**19.5**	**19.2**	**13.7**	**13.8**	**15.2**	**10.0**	**9.7**	**9.3**	**8.7**

Note : All the Capacities are in MW; Above total includes NCRE plants; Maintenance and FOR outages not considered. Operational aspects not reflected

* Non Dispatchable Renewable Energy - Wind & Minihydro

Annex 11 : Addendum

Table Ad.4. Energy Balance for the Revised Base Case – 2012

Plant Name	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hydro																				
Existing Major Hydro	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112	4112
New Major Hydro	0	0	0	366	366	443	443	443	443	579	579	579	579	579	579	579	579	579	579	579
Sub Total	4112	4112	4112	4478	4478	4556	4556	4556	4556	4692	4692	4692	4692	4692	4692	4692	4692	4692	4692	4692
Total NCRE	613	658	692	961	1008	1071	1158	1268	1340	1373	1421	1481	1546	1593	1655	1699	1762	1792	1854	1901
Thermal Existing and Committed																				
Small Gas Turbines	16	6	4	5	6	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Sapugaskanda	459	431	456	457	463	407	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesl Ext.Sapugaskanda	491	485	487	487	490	443	292	323	276	175	19	38	0	0	0	0	0	0	0	0
Gas Turbine No7	290	250	286	288	302	197	44	75	31	27	0	0	0	0	0	0	0	0	0	0
Lakdhanavi	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Asia Power	334	309	332	333	339	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
KPS Combined Cycle	550	454	549	575	718	408	208	257	204	129	28	56	38	87	61	53	102	77	79	74
AES Combined Cycle	491	362	474	505	605	328	181	234	182	77	0	0	0	0	0	0	0	0	0	0
Colombo Power	419	417	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ACE Power Horana	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ACE Power Matara	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Heladhanavi	696	696	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ACE Power Embilipitiya	692	672	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass (Dendro)	94	94	94	94	94	92	69	74	70	56	24	33	23	36	28	23	34	32	29	18
Kerawalapitiya CCY	1,325	935	1,138	1,265	1,370	825	407	528	395	323	87	163	99	182	128	115	218	190	159	150
Puttalum Coal	1,665	3,241	4,996	4,970	5,068	4,653	4,335	4,484	4,460	4,494	4,555	4,703	4,831	4,960	5,051	5,119	5,178	5,235	5,284	5,373
Northern Power	0	131	137	137	138	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Chunnakkam Power Extension	0	183	183	183	183	177	124	140	124	107	26	58	34	61	38	33	57	48	37	41
Sub Total	7,523	8,668	9,135	9,296	9,773	7,530	5,661	6,112	5,741	5,388	4,740	5,051	5,025	5,325	5,306	5,341	5,589	5,583	5,588	5,656
New Thermal Plants																				
Coal	0	0	0	0	0	0	3,025	3,221	4,637	5,918	7,716	8,354	9,469	10,156	11,416	12,614	13,509	14,864	16,262	17,649
Gas Turbine 75 MW	0	0	477	522	560	347	123	222	95	58	12	24	21	57	41	33	79	75	52	52
Gas Turbine 105 MW	0	0	0	0	300	176	95	121	78	34	8	18	18	43	26	28	45	44	36	34
Coal Trinco	0	0	0	0	0	3,337	3,331	3,360	3,381	3,400	3,416	3,425	3,432	3,435	3,437	3,438	3,438	3,438	3,439	3,439
Biomass (Dendro)	27	54	82	109	137	158	138	169	179	160	62	114	79	147	99	100	145	137	136	120
Sub Total	27	54	559	631	996	4018	6712	7092	8370	9568	11213	11935	13020	13838	15020	16212	17215	18559	19925	21294
Total Generation	**12275**	**13493**	**14499**	**15367**	**16256**	**17174**	**18086**	**19028**	**20006**	**21021**	**22066**	**23158**	**24283**	**25448**	**26673**	**27944**	**29258**	**30626**	**32059**	**33543**
System Demand	12296	13508	14513	15380	16275	17178	18086	19034	20010	21023	22072	23159	24284	25458	26677	27949	29273	30645	32078	33555
Unserved Energy	**21**	**15**	**14**	**13**	**19**	**4**	**0**	**6**	**4**	**2**	**6**	**1**	**1**	**10**	**4**	**5**	**15**	**19**	**19**	**12**

Note:- 1. Numbers may not add exactly due to rounding off.
2. Aggregation of hydro dispatches for individual plant is not possible owing to integrated operation and dispatch of hydro energy
3. All energy figures are shown for weighted average hydrological condition in GWh.

Annual Energy Generation and Plant Factors

Table Ad.5. Revised Base Case: 2013 to 2032

Year / Plant	Annual Energy (GWh) Hydrology condition 1	2	3	4	5	Avg.	Annual Plant Factor (%) Hydrology condition 1	2	3	4	5	Avg.
2013												
17 MW Kelanitissa Gas Turbines	0	1	2	11	36	16	0.1	0.1	0.3	1.6	5.1	2.3
4x18 MW Sapugaskanda Diesel Plant	194	377	452	461	464	459	31.8	61.8	74.1	75.6	76.0	75.3
8x9 MW Sapugaskanda Diesel Ext.	396	488	490	491	491	491	64.9	80.1	80.4	80.6	80.6	80.5
115 MW Kelanitissa Gas Turbine	24	94	137	288	328	290	2.4	9.5	13.9	29.1	33.1	29.3
Asia Power Plant	110	227	324	336	339	334	25.7	53.0	75.6	78.2	79.0	77.8
Kelanitissa Combined Cycle Plant	114	199	432	518	710	550	8.2	14.2	30.8	37.0	50.7	39.2
AES Combined Cycle Plant	83	144	323	479	579	491	5.8	10.1	22.6	33.5	40.6	34.4
Colombo Power Plant	388	418	419	419	419	419	73.8	79.6	79.7	79.7	79.7	79.7
Heladanavi Plant (Puttalam)	694	696	696	696	696	696	79.5	79.8	79.8	79.8	79.8	79.8
ACE Power Plant (Embilipitiya)	390	678	689	694	695	692	44.8	77.8	79.0	79.6	79.7	79.4
270 MW Kerawalapitiya CombinedCycle	628	767	936	1,315	1,437	1,324	26.6	32.4	39.6	55.6	60.7	56.0
275 MW Puttalam Coal Plant	1,393	1,464	1,529	1,655	1,731	1,665	57.8	60.8	63.5	68.7	71.9	69.1
Dendro	94	94	94	94	94	94	89.7	89.8	89.8	89.8	89.8	89.8
DNRO	27	27	27	27	27	27	77.7	77.7	77.7	77.7	77.7	77.7
Total hydro	7,483	6,342	5,465	4,525	3,903	4,447						
Total thermal	4,537	5,676	6,551	7,485	8,047	7,550						
Total generation	12,020	12,018	12,016	12,009	11,949	11,997						
Total demand	12,021	12,021	12,021	12,021	12,021	12,021						
Deficit	1	2	5	11	71	23						
2014												
17 MW Kelanitissa Gas Turbines	0	1	2	3	17	6	0.1	0.1	0.2	0.5	2.3	0.8
4x18 MW Sapugaskanda Diesel Plant	136	246	389	434	439	431	22.3	40.3	63.8	71.2	72.0	70.7
8x9 MW Sapugaskanda Diesel Ext.	291	469	479	486	488	485	47.7	76.9	78.6	79.8	80.0	79.6
115 MW Kelanitissa Gas Turbine	33	84	99	248	284	250	3.4	8.5	10.0	25.0	28.7	25.2
Asia Power Plant	79	141	259	312	317	309	18.5	32.8	60.4	72.7	73.8	72.0
Kelanitissa Combined Cycle Plant	62	133	307	437	556	454	4.4	9.5	21.9	31.2	39.7	32.4
AES Combined Cycle Plant	56	115	177	348	450	362	3.9	8.1	12.4	24.4	31.5	25.4
Colombo Power Plant	335	409	415	418	418	417	63.7	77.7	78.9	79.4	79.5	79.3
Heladanavi Plant (Puttalam)	677	695	696	696	696	696	77.6	79.6	79.7	79.8	79.8	79.8
ACE Power Plant (Embilipitiya)	263	598	659	674	680	672	30.2	68.6	75.6	77.4	78.0	77.1
270 MW Kerawalapitiya CombinedCycle	563	610	796	904	1,089	935	23.8	25.8	33.6	38.2	46.1	39.5
275 MW Puttalam Coal Plant	2,770	2,894	2,962	3,224	3,357	3,241	57.5	60.1	61.5	66.9	69.7	67.3
20 MW Northern	46	80	128	132	133	131	26.2	45.5	73.1	75.4	76.0	74.9
Dendro	94	94	94	94	94	94	89.1	89.7	89.8	89.8	89.8	89.8
Chunnakum ext.	181	183	183	183	183	183	86.1	87.1	87.2	87.2	87.2	87.2
DNRO	54	54	54	54	54	54	76.9	77.7	77.7	77.7	77.7	77.7
Total hydro	7,560	6,394	5,499	4,542	3,914	4,464						
Total thermal	5,641	6,806	7,699	8,649	9,256	8,723						
Total generation	13,201	13,200	13,198	13,191	13,170	13,187						
Total demand	13,202	13,202	13,202	13,202	13,202	13,202						
Deficit	1	3	5	11	33	15						

Note : Hydrological Conditions:1. Very Wet (0.5%) 2. Wet (1%) 3. Medium (1.5%) 4. Dry (77%) 5. Very Dry (20%)
Shown within brackets is the probability of occurrence of each Hydro Condition.

Year / Plant	Annual Energy (GWh) Hydrology condition						Annual Plant Factor (%) Hydrology condition					
	1	2	3	4	5	Avg.	1	2	3	4	5	Avg.
2015												
17 MW Kelanitissa Gas Turbines	1	1	2	3	9	4	0.1	0.2	0.3	0.5	1.2	0.6
4x18 MW Sapugaskanda Diesel Plant	268	435	448	457	459	456	43.9	71.4	73.6	75.0	75.3	74.8
8x9 MW Sapugaskanda Diesel Ext.	416	474	483	487	489	487	68.3	77.7	79.2	79.9	80.2	79.9
115 MW Kelanitissa Gas Turbine	78	130	202	287	302	286	7.9	13.1	20.4	29.0	30.5	28.9
Asia Power Plant	136	283	324	333	335	332	31.8	66.0	75.5	77.5	78.0	77.2
Kelanitissa Combined Cycle Plant	149	316	421	530	652	549	10.6	22.5	30.0	37.8	46.5	39.2
AES Combined Cycle Plant	123	244	388	463	540	474	8.6	17.1	27.2	32.4	37.8	33.2
270 MW Kerawalapitiya CombinedCycle	566	680	876	1,106	1,317	1,138	23.9	28.8	37.0	46.8	55.7	48.1
275 MW Puttalam Coal Plant	4,199	4,398	4,642	4,987	5,106	4,996	58.1	60.9	64.2	69.0	70.7	69.1
20 MW Northern	112	132	135	137	138	137	63.7	75.1	77.1	78.2	78.6	78.1
Dendro	92	94	94	94	94	94	87.4	89.1	89.5	89.7	89.7	89.7
Chunnakum ext.	177	181	182	183	183	183	84.2	86.2	86.8	87.1	87.1	87.1
75 MW GT	142	286	371	467	541	477	7.2	14.5	18.8	23.7	27.5	24.2
DNRO	79	81	81	82	82	82	75.4	77.0	77.4	77.6	77.6	77.6
Total hydro	7,652	6,455	5,538	4,563	3,928	4,485						
Total thermal	6,539	7,734	8,649	9,617	10,246	9,694						
Total generation	14,192	14,190	14,187	14,180	14,174	14,179						
Total demand	14,193	14,193	14,193	14,193	14,193	14,193						
Deficit	2	3	6	13	19	14						
2016												
17 MW Kelanitissa Gas Turbines	0	1	1	3	15	5	0.1	0.1	0.2	0.4	2.1	0.7
4x18 MW Sapugaskanda Diesel Plant	316	435	448	458	459	457	51.8	71.4	73.6	75.0	75.3	74.9
8x9 MW Sapugaskanda Diesel Ext.	392	473	482	487	489	487	64.3	77.6	79.0	79.8	80.2	79.8
115 MW Kelanitissa Gas Turbine	88	158	228	287	306	288	8.9	15.9	23.0	29.0	31.0	29.1
Asia Power Plant	185	304	325	333	336	333	43.0	70.8	75.6	77.6	78.2	77.5
Kelanitissa Combined Cycle Plant	213	333	464	547	711	575	15.2	23.8	33.1	39.0	50.7	41.0
AES Combined Cycle Plant	141	266	383	481	627	505	9.9	18.6	26.8	33.7	43.9	35.4
270 MW Kerawalapitiya CombinedCycle	521	708	913	1,263	1,343	1,264	22.0	29.9	38.6	53.4	56.8	53.5
275 MW Puttalam Coal Plant	4,205	4,409	4,657	4,947	5,129	4,970	58.2	61.0	64.4	68.4	71.0	68.8
20 MW Northern	105	132	135	137	138	137	59.9	75.1	77.1	78.1	78.7	78.1
Dendro	91	94	94	94	94	94	86.7	89.2	89.6	89.8	89.9	89.8
Chunnakum ext.	175	181	182	183	183	183	83.1	86.2	86.7	87.0	87.1	87.0
75 MW GT	137	320	427	512	590	522	6.9	16.2	21.6	26.0	29.9	26.5
DNRO	105	108	109	109	109	109	74.9	77.3	77.7	77.9	78.0	77.9
Total hydro	8,118	6,867	5,939	4,942	4,241	4,852						
Total thermal	6,673	7,922	8,849	9,840	10,529	9,928						
Total generation	14,790	14,789	14,787	14,782	14,771	14,780						
Total demand	14,791	14,791	14,791	14,791	14,791	14,791						
Deficit	1	2	4	9	21	11						
2017												
17 MW Kelanitissa Gas Turbines	1	1	2	4	17	6	0.1	0.2	0.3	0.5	2.3	0.9
4x18 MW Sapugaskanda Diesel Plant	396	447	457	463	464	463	65.0	73.3	74.9	75.9	76.1	75.9
8x9 MW Sapugaskanda Diesel Ext.	456	481	487	490	491	490	74.8	78.9	79.8	80.3	80.4	80.3
115 MW Kelanitissa Gas Turbine	91	209	274	300	318	302	9.2	21.1	27.7	30.3	32.2	30.5
Asia Power Plant	276	323	332	339	341	339	64.3	75.3	77.4	79.0	79.4	78.9
Kelanitissa Combined Cycle Plant	307	443	538	710	783	718	21.9	31.6	38.4	50.7	55.8	51.2
AES Combined Cycle Plant	248	352	435	568	780	605	17.4	24.6	30.5	39.8	54.6	42.3
270 MW Kerawalapitiya CombinedCycle	586	765	1,036	1,368	1,451	1,369	24.8	32.4	43.8	57.8	61.3	57.9
275 MW Puttalam Coal Plant	4,304	4,593	4,847	5,056	5,173	5,068	59.5	63.6	67.1	70.0	71.6	70.1
20 MW Northern	119	135	137	138	139	138	68.1	76.8	78.2	78.8	79.1	78.8
Dendro	93	94	94	94	94	94	88.3	89.6	89.8	89.8	89.9	89.8
Chunnakum ext.	179	182	183	183	183	183	85.2	86.7	87.0	87.1	87.2	87.1
75 MW GT	151	389	460	544	645	560	7.7	19.8	23.3	27.6	32.7	28.4
105 MW GT	114	181	260	290	354	300	12.4	19.7	28.3	31.5	38.5	32.6
DNRO	134	136	136	137	137	137	76.5	77.7	77.9	77.9	78.0	77.9
Total hydro	8,203	6,924	5,975	4,961	4,254	4,871						
Total thermal	7,455	8,732	9,678	10,684	11,369	10,770						
Total generation	15,658	15,655	15,653	15,645	15,623	15,641						
Total demand	15,660	15,660	15,660	15,660	15,660	15,660						
Deficit	2	4	7	15	37	19						

Year	Annual Energy (GWh)						Annual Plant Factor (%)					
	Hydrology condition						Hydrology condition					
Plant	1	2	3	4	5	Avg.	1	2	3	4	5	Avg.
2018												
17 MW Kelanitissa Gas Turbines	0	0	0	1	2	1	0.0	0.0	0.1	0.2	0.2	0.2
4x18 MW Sapugaskanda Diesel Plant	114	241	348	408	421	407	18.6	39.5	57.1	67.0	69.0	66.7
8x9 MW Sapugaskanda Diesel Ext.	155	283	407	444	456	443	25.4	46.5	66.7	72.8	74.7	72.6
115 MW Kelanitissa Gas Turbine	29	54	108	189	244	197	2.9	5.5	10.9	19.1	24.6	19.9
Kelanitissa Combined Cycle Plant	79	184	283	401	465	408	5.7	13.1	20.2	28.6	33.2	29.1
AES Combined Cycle Plant	54	130	237	319	387	328	3.8	9.1	16.6	22.3	27.1	23.0
270 MW Kerawalapitiya CombinedCycle	317	492	671	787	1,014	825	13.4	20.8	28.4	33.3	42.9	34.9
275 MW Puttalam Coal Plant	3,854	4,207	4,338	4,625	4,823	4,653	53.3	58.2	60.0	64.0	66.7	64.4
Dendro	59	86	90	92	93	92	56.3	81.9	85.3	87.4	88.3	87.3
Chunnakum ext.	112	162	171	177	179	177	53.1	77.2	81.4	84.1	85.0	84.0
75 MW GT	51	128	205	343	391	347	2.6	6.5	10.4	17.4	19.9	17.6
105 MW GT	27	73	96	170	210	175	3.0	8.0	10.4	18.5	22.9	19.1
Trinco coal	3,133	3,229	3,295	3,338	3,344	3,337	78.8	81.2	82.9	83.9	84.1	83.9
DNRO	100	148	155	159	160	158	47.5	70.4	73.8	75.4	76.2	75.3
Total hydro	8,452	7,115	6,129	5,078	4,340	4,983						
Total thermal	8,083	9,419	10,404	11,453	12,189	11,547						
Total generation	16,534	16,534	16,533	16,531	16,529	16,531						
Total demand	16,535	16,535	16,535	16,535	16,535	16,535						
Deficit	0	1	1	3	6	4						
2019												
8x9 MW Sapugaskanda Diesel Ext.	19	100	149	288	334	292	3.1	16.4	24.4	47.3	54.8	47.9
115 MW Kelanitissa Gas Turbine	2	4	7	33	92	44	0.2	0.4	0.7	3.3	9.3	4.4
Kelanitissa Combined Cycle Plant	13	58	67	204	245	208	0.9	4.1	4.8	14.6	17.5	14.8
AES Combined Cycle Plant	9	35	78	172	237	181	0.6	2.4	5.5	12.0	16.6	12.7
270 MW Kerawalapitiya CombinedCycle	34	113	216	397	485	407	1.4	4.8	9.1	16.8	20.5	17.2
275 MW Puttalam Coal Plant	3,969	4,077	4,206	4,314	4,447	4,335	54.9	56.4	58.2	59.7	61.5	60.0
Dendro	15	33	55	68	76	69	14.5	31.1	52.8	65.0	72.1	65.7
Chunnakum ext.	19	47	91	121	143	124	9.1	22.4	43.4	57.8	68.0	59.0
CST	1,530	2,361	2,827	3,010	3,170	3,025	31.8	49.0	58.7	62.5	65.8	62.8
75 MW GT	5	10	43	104	209	123	0.3	0.5	2.2	5.3	10.6	6.2
105 MW GT	4	17	41	93	112	95	0.4	1.9	4.5	10.1	12.2	10.3
Trinco coal	3,174	3,282	3,314	3,336	3,320	3,331	79.8	82.5	83.3	83.9	83.5	83.8
DNRO	29	58	112	136	152	138	11.8	23.8	45.7	55.6	62.2	56.2
Total hydro	8,558	7,186	6,174	5,102	4,356	5,007						
Total thermal	8,823	10,194	11,206	12,278	13,023	12,373						
Total generation	17,380	17,380	17,380	17,380	17,379	17,380						
Total demand	17,380	17,380	17,380	17,380	17,380	17,380						
Deficit	0	0	0	0	1	0						
2020												
8x9 MW Sapugaskanda Diesel Ext.	51	121	211	317	368	323	8.4	19.9	34.6	52.0	60.4	52.9
115 MW Kelanitissa Gas Turbine	5	9	56	58	149	75	0.5	0.9	5.7	5.8	15.0	7.6
Kelanitissa Combined Cycle Plant	32	91	124	247	318	257	2.3	6.5	8.9	17.6	22.7	18.3
AES Combined Cycle Plant	16	53	129	228	280	234	1.1	3.7	9.1	15.9	19.6	16.4
270 MW Kerawalapitiya CombinedCycle	90	212	381	524	580	528	3.8	8.9	16.1	22.1	24.5	22.3
275 MW Puttalam Coal Plant	4,048	4,177	4,281	4,452	4,646	4,484	56.0	57.8	59.2	61.6	64.3	62.0
Dendro	22	45	69	73	80	74	21.3	42.6	65.6	69.2	75.9	70.0
Chunnakum ext.	44	78	127	138	151	140	21.1	37.0	60.2	65.8	71.7	66.4
CST	1,917	2,702	2,970	3,207	3,353	3,221	39.8	56.1	61.7	66.6	69.6	66.8
75 MW GT	11	37	91	218	264	222	0.5	1.9	4.6	11.1	13.4	11.3
105 MW GT	7	23	49	118	143	121	0.8	2.5	5.3	12.8	15.6	13.1
Trinco coal	3,285	3,336	3,371	3,364	3,347	3,360	82.6	83.9	84.8	84.6	84.2	84.5
DNRO	50	100	159	167	183	169	17.9	35.7	56.8	59.5	65.3	60.2
Total hydro	8,657	7,252	6,216	5,124	4,370	5,029						
Total thermal	9,579	10,983	12,019	13,109	13,862	13,205						
Total generation	18,235	18,235	18,235	18,234	18,232	18,233						
Total demand	18,235	18,235	18,235	18,235	18,235	18,235						
Deficit	0	0	1	2	3	2						

Year	Annual Energy (GWh)						Annual Plant Factor (%)					
	Hydrology condition						Hydrology condition					
Plant	1	2	3	4	5	Avg.	1	2	3	4	5	Avg.
2021												
8x9 MW Sapugaskanda Diesel Ext.	38	86	118	267	335	276	6.2	14.1	19.3	43.8	54.9	45.2
115 MW Kelanitissa Gas Turbine	3	6	13	27	46	31	0.3	0.6	1.3	2.8	4.7	3.1
Kelanitissa Combined Cycle Plant	32	61	89	192	270	204	2.3	4.4	6.3	13.7	19.2	14.6
AES Combined Cycle Plant	12	49	77	170	248	182	0.8	3.4	5.4	11.9	17.4	12.8
270 MW Kerawalapitiya CombinedCycle	80	150	306	384	465	395	3.4	6.3	12.9	16.2	19.7	16.7
275 MW Puttalam Coal Plant	4,079	4,207	4,321	4,434	4,593	4,460	56.4	58.2	59.8	61.3	63.5	61.7
Dendro	17	37	55	70	72	70	16.0	35.5	52.0	66.7	68.9	66.3
Chunnakum ext.	29	48	101	123	135	124	13.8	22.7	48.2	58.4	64.4	58.9
CST	2,711	3,710	4,211	4,637	4,765	4,637	37.5	51.3	58.3	64.2	65.9	64.2
75 MW GT	7	13	48	78	171	95	0.4	0.7	2.5	3.9	8.7	4.8
105 MW GT	5	18	41	73	106	78	0.5	2.0	4.4	8.0	11.5	8.5
Trinco coal	3,360	3,383	3,385	3,380	3,383	3,381	84.5	85.1	85.1	85.0	85.1	85.0
DNRO	45	83	143	179	186	178	14.2	26.2	45.3	56.9	58.8	56.6
Total hydro	8,741	7,309	6,252	5,143	4,383	5,048						
Total thermal	10,418	11,851	12,907	14,015	14,774	14,110						
Total generation	19,159	19,159	19,159	19,158	19,157	19,158						
Total demand	19,159	19,159	19,159	19,159	19,159	19,159						
Deficit	0	0	0	1	2	1						
2022												
8x9 MW Sapugaskanda Diesel Ext.	12	43	106	155	267	175	2.0	7.0	17.5	25.4	43.8	28.6
115 MW Kelanitissa Gas Turbine	1	3	5	21	50	27	0.1	0.3	0.5	2.2	5.0	2.7
Kelanitissa Combined Cycle Plant	8	32	65	120	178	129	0.6	2.3	4.6	8.6	12.7	9.2
AES Combined Cycle Plant	6	11	31	70	113	77	0.4	0.8	2.2	4.9	7.9	5.4
270 MW Kerawalapitiya CombinedCycle	50	109	171	314	383	323	2.1	4.6	7.2	13.3	16.2	13.6
275 MW Puttalam Coal Plant	4,158	4,228	4,357	4,478	4,587	4,494	57.5	58.5	60.3	62.0	63.5	62.2
Dendro	8	19	35	55	66	56	8.0	18.2	32.9	52.5	62.5	53.7
Chunnakum ext.	14	33	58	106	123	107	6.8	15.7	27.5	50.4	58.3	51.1
CST	3,498	4,708	5,383	5,901	6,143	5,918	36.3	48.9	55.9	61.2	63.8	61.4
75 MW GT	4	7	12	51	89	58	0.2	0.4	0.6	2.6	4.5	2.9
105 MW GT	3	5	8	30	52	34	0.3	0.5	0.8	3.2	5.7	3.7
Trinco coal	3,394	3,402	3,413	3,398	3,405	3,400	85.3	85.6	85.8	85.4	85.6	85.5
DNRO	22	53	84	157	186	160	6.3	15.1	24.1	44.8	53.2	45.6
Total hydro	8,983	7,508	6,434	5,305	4,518	5,205						
Total thermal	11,179	12,653	13,728	14,856	15,643	14,956						
Total generation	20,161	20,161	20,161	20,161	20,160	20,161						
Total demand	20,161	20,161	20,161	20,161	20,161	20,161						
Deficit	0	0	0	0	1	0						
2023												
8x9 MW Sapugaskanda Diesel Ext.	1	2	4	17	30	19	0.4	0.8	1.4	5.5	9.7	6.2
Kelanitissa Combined Cycle Plant	2	4	6	26	38	27	0.1	0.3	0.4	1.8	2.7	2.0
270 MW Kerawalapitiya CombinedCycle	6	11	17	77	137	87	0.2	0.5	0.7	3.3	5.8	3.7
275 MW Puttalam Coal Plant	4,213	4,364	4,408	4,562	4,557	4,555	58.3	60.4	61.0	63.1	63.1	63.0
Dendro	1	2	4	23	30	24	1.3	2.3	3.4	22.3	28.5	23.0
Chunnakum ext.	2	4	6	22	47	26	0.9	1.8	2.7	10.3	22.5	12.5
CST	4,462	5,794	6,829	7,637	8,261	7,716	30.9	40.1	47.3	52.8	57.2	53.4
75 MW GT	1	2	4	9	27	12	0.0	0.1	0.2	0.4	1.4	0.6
105 MW GT	1	2	3	6	16	8	0.1	0.2	0.3	0.6	1.7	0.8
Trinco coal	3,412	3,417	3,414	3,416	3,416	3,416	85.8	85.9	85.8	85.9	85.9	85.9
DNRO	4	7	11	58	87	62	1.0	1.8	2.7	14.9	22.7	16.1
Total hydro	9,075	7,569	6,473	5,325	4,531	5,225						
Total thermal	12,104	13,609	14,705	15,853	16,647	15,953						
Total generation	21,179	21,179	21,178	21,178	21,178	21,178						
Total demand	21,180	21,180	21,180	21,180	21,180	21,180						
Deficit	1	1	1	2	2	2						

Year / Plant	Annual Energy (GWh) Hydrology condition 1	2	3	4	5	Avg.	Annual Plant Factor (%) Hydrology condition 1	2	3	4	5	Avg.
2024												
8x9 MW Sapugaskanda Diesel Ext.	3	6	9	32	65	38	1.0	1.9	2.8	10.6	21.4	12.5
Kelanitissa Combined Cycle Plant	5	9	14	46	102	56	0.3	0.7	1.0	3.3	7.3	4.0
270 MW Kerawalapitiya CombinedCycle	14	24	75	149	235	163	0.6	1.0	3.2	6.3	9.9	6.9
275 MW Puttalam Coal Plant	4,383	4,492	4,625	4,705	4,722	4,703	60.7	62.2	64.0	65.1	65.3	65.1
Dendro	3	4	15	30	46	33	2.7	4.1	14.2	28.9	44.0	31.3
Chunnakum ext.	5	7	28	54	79	58	2.2	3.4	13.3	25.5	37.6	27.4
CST	5,240	6,623	7,474	8,307	8,766	8,354	36.3	45.8	51.7	57.5	60.7	57.8
75 MW GT	3	6	10	19	48	24	0.1	0.3	0.5	0.9	2.4	1.2
105 MW GT	2	4	7	12	44	18	0.2	0.5	0.7	1.3	4.8	2.0
Trinco coal	3,421	3,425	3,424	3,425	3,425	3,425	86.0	86.1	86.1	86.1	86.1	86.1
DNRO	9	14	46	107	151	114	2.2	3.3	11.0	25.5	35.9	27.0
Total hydro	9,138	7,612	6,500	5,340	4,541	5,239						
Total thermal	13,088	14,614	15,726	16,885	17,683	16,985						
Total generation	22,226	22,226	22,226	22,224	22,224	22,224						
Total demand	22,227	22,227	22,227	22,227	22,227	22,227						
Deficit	1	1	2	3	4	3						
2025												
Kelanitissa Combined Cycle Plant	4	8	13	35	56	38	0.3	0.6	0.9	2.5	4.0	2.7
270 MW Kerawalapitiya CombinedCycle	11	20	29	89	149	99	0.5	0.9	1.2	3.8	6.3	4.2
275 MW Puttalam Coal Plant	4,530	4,702	4,769	4,826	4,867	4,831	62.7	65.1	66.0	66.8	67.3	66.8
Dendro	2	4	11	21	34	23	2.2	3.5	10.6	20.1	32.1	22.1
Chunnakum ext.	4	6	9	32	48	34	1.7	2.8	4.0	15.0	22.8	16.2
CST	6,095	7,443	8,471	9,397	10,007	9,469	36.1	44.1	50.2	55.7	59.3	56.2
75 MW GT	2	5	9	20	27	21	0.1	0.3	0.5	1.0	1.4	1.1
105 MW GT	2	4	6	18	20	18	0.2	0.4	0.7	2.0	2.2	2.0
Trinco coal	3,429	3,433	3,431	3,432	3,432	3,432	86.2	86.3	86.3	86.3	86.3	86.3
DNRO	8	13	21	74	109	79	1.7	2.9	4.7	16.3	24.0	17.4
Total hydro	9,216	7,664	6,533	5,357	4,552	5,256						
Total thermal	14,087	15,639	16,769	17,944	18,749	18,045						
Total generation	23,303	23,303	23,302	23,302	23,301	23,301						
Total demand	23,304	23,304	23,304	23,304	23,304	23,304						
Deficit	1	1	2	3	3	3						
2026												
Kelanitissa Combined Cycle Plant	10	18	25	78	131	87	0.7	1.3	1.8	5.6	9.3	6.2
270 MW Kerawalapitiya CombinedCycle	24	40	106	167	254	182	1.0	1.7	4.5	7.1	10.7	7.7
275 MW Puttalam Coal Plant	4,722	4,874	4,900	4,959	4,976	4,960	65.3	67.4	67.8	68.6	68.8	68.6
Dendro	4	9	21	34	46	36	4.0	9.0	20.0	32.8	44.2	34.5
Chunnakum ext.	7	17	32	56	85	61	3.2	8.0	15.3	26.6	40.5	28.9
CST	6,915	8,268	9,245	10,105	10,596	10,156	41.0	49.0	54.8	59.9	62.8	60.2
75 MW GT	7	14	21	50	91	57	0.4	0.7	1.0	2.5	4.6	2.9
105 MW GT	5	9	13	38	69	43	0.5	0.9	1.4	4.1	7.5	4.7
Trinco coal	3,433	3,436	3,436	3,435	3,435	3,435	86.3	86.4	86.4	86.4	86.4	86.4
DNRO	16	39	74	141	188	147	3.2	8.0	15.1	28.6	38.3	30.0
Total hydro	9,301	7,720	6,569	5,376	4,564	5,275						
Total thermal	15,143	16,723	17,873	19,062	19,871	19,163						
Total generation	24,444	24,443	24,442	24,439	24,436	24,438						
Total demand	24,445	24,445	24,445	24,445	24,445	24,445						
Deficit	2	2	3	7	10	7						

Year / Plant	Annual Energy (GWh) Hydrology condition 1	2	3	4	5	Avg.	Annual Plant Factor (%) Hydrology condition 1	2	3	4	5	Avg.
2027												
Kelanitissa Combined Cycle Plant	9	16	22	55	92	61	0.6	1.1	1.6	3.9	6.5	4.4
270 MW Kerawalapitiya CombinedCycle	21	34	73	110	208	128	0.9	1.4	3.1	4.7	8.8	5.4
275 MW Puttalam Coal Plant	4,875	4,974	5,049	5,051	5,059	5,051	67.5	68.8	69.9	69.9	70.0	69.9
Dendro	4	9	14	27	36	28	3.5	8.2	13.4	25.5	34.2	26.8
Chunnakum ext.	6	9	25	34	56	38	2.9	4.2	12.1	16.1	26.7	18.0
CST	7,864	9,321	10,318	11,355	11,926	11,416	40.8	48.4	53.5	58.9	61.9	59.2
75 MW GT	6	12	18	40	52	41	0.3	0.6	0.9	2.0	2.6	2.1
105 MW GT	4	8	11	24	36	26	0.4	0.8	1.2	2.6	3.9	2.8
Trinco coal	3,435	3,437	3,437	3,437	3,437	3,437	86.4	86.4	86.4	86.4	86.4	86.4
DNRO	15	29	49	91	138	99	2.8	5.4	9.3	17.3	26.2	18.8
Total hydro	9,386	7,777	6,605	5,396	4,577	5,294						
Total thermal	16,239	17,847	19,018	20,224	21,041	20,326						
Total generation	25,625	25,624	25,623	25,620	25,617	25,620						
Total demand	25,626	25,626	25,626	25,626	25,626	25,626						
Deficit	1	2	3	6	9	6						
2028												
Kelanitissa Combined Cycle Plant	7	12	18	52	60	53	0.5	0.9	1.3	3.7	4.3	3.8
270 MW Kerawalapitiya CombinedCycle	16	28	59	99	186	115	0.7	1.2	2.5	4.2	7.9	4.8
275 MW Puttalam Coal Plant	5,016	5,121	5,131	5,121	5,112	5,119	69.4	70.9	71.0	70.8	70.7	70.8
Dendro	3	5	12	20	35	23	2.9	4.4	11.5	19.3	32.9	21.6
Chunnakum ext.	5	7	18	26	63	33	2.2	3.5	8.6	12.3	29.9	15.6
CST	8,901	10,393	11,472	12,552	13,143	12,614	41.0	47.9	52.9	57.9	60.6	58.2
75 MW GT	4	9	14	29	50	32	0.2	0.5	0.7	1.5	2.5	1.6
105 MW GT	3	6	9	27	32	28	0.3	0.6	1.0	3.0	3.5	3.0
Trinco coal	3,437	3,438	3,438	3,438	3,438	3,438	86.4	86.4	86.4	86.4	86.4	86.4
DNRO	13	20	57	88	156	100	2.3	3.5	10.1	15.7	27.8	17.8
Total hydro	9,463	7,829	6,638	5,413	4,588	5,311						
Total thermal	17,405	19,039	20,229	21,452	22,274	21,553						
Total generation	26,868	26,868	26,867	26,865	26,863	26,864						
Total demand	26,868	26,868	26,868	26,868	26,868	26,868						
Deficit	0	1	1	4	6	4						
2029												
Kelanitissa Combined Cycle Plant	16	25	56	88	167	102	1.1	1.8	4.0	6.3	11.9	7.3
270 MW Kerawalapitiya CombinedCycle	35	53	125	198	314	218	1.5	2.2	5.3	8.4	13.3	9.2
275 MW Puttalam Coal Plant	5,145	5,197	5,194	5,179	5,172	5,178	71.2	71.9	71.9	71.7	71.6	71.7
Dendro	8	13	18	32	45	34	7.4	12.8	17.5	30.5	42.8	32.5
Chunnakum ext.	8	19	33	54	71	57	4.0	8.9	15.8	25.9	33.8	27.0
CST	9,899	11,426	12,449	13,464	13,955	13,509	45.7	52.7	57.4	62.1	64.4	62.3
75 MW GT	12	21	37	75	100	79	0.6	1.1	1.9	3.8	5.1	4.0
105 MW GT	8	13	25	41	62	44	0.8	1.4	2.7	4.5	6.7	4.8
Trinco coal	3,438	3,438	3,438	3,438	3,438	3,438	86.4	86.5	86.4	86.4	86.4	86.4
DNRO	32	55	94	133	203	145	5.4	9.3	15.7	22.3	34.1	24.3
Total hydro	9,548	7,886	6,674	5,432	4,601	5,330						
Total thermal	18,600	20,260	21,468	22,703	23,528	22,804						
Total generation	28,148	28,146	28,143	28,135	28,129	28,134						
Total demand	28,149	28,149	28,149	28,149	28,149	28,149						
Deficit	1	4	7	14	21	15						

Year	Annual Energy (GWh) Hydrology condition						Annual Plant Factor (%) Hydrology condition					
Plant	1	2	3	4	5	Avg.	1	2	3	4	5	Avg.
2030												
Kelanitissa Combined Cycle Plant	15	24	44	71	107	77	1.1	1.7	3.1	5.1	7.6	5.5
270 MW Kerawalapitiya CombinedCycle	34	51	86	175	268	190	1.4	2.2	3.7	7.4	11.3	8.1
275 MW Puttalam Coal Plant	5,220	5,246	5,250	5,235	5,235	5,235	72.2	72.6	72.7	72.4	72.4	72.4
Dendro	5	7	17	30	42	32	4.7	6.2	15.8	29.0	39.6	30.5
Chunnakum ext.	8	11	20	47	57	48	3.8	5.2	9.4	22.3	27.0	22.8
CST	11,164	12,750	13,818	14,797	15,397	14,864	46.3	52.9	57.4	61.4	63.9	61.7
75 MW GT	12	21	30	72	97	75	0.6	1.1	1.5	3.7	4.9	3.8
105 MW GT	8	13	17	40	67	44	0.8	1.4	1.9	4.3	7.2	4.8
Trinco coal	3,438	3,438	3,438	3,438	3,438	3,438	86.5	86.5	86.5	86.5	86.5	86.5
DNRO	24	31	82	135	159	137	3.7	5.0	13.1	21.3	25.3	21.7
Total hydro	9,562	7,895	6,680	5,436	4,603	5,333						
Total thermal	19,927	21,592	22,803	24,040	24,866	24,142						
Total generation	29,489	29,487	29,483	29,476	29,469	29,475						
Total demand	29,491	29,491	29,491	29,491	29,491	29,491						
Deficit	1	4	7	15	21	16						
2031												
Kelanitissa Combined Cycle Plant	15	24	32	73	113	79	1.0	1.7	2.3	5.2	8.1	5.7
270 MW Kerawalapitiya CombinedCycle	33	50	73	147	222	159	1.4	2.1	3.1	6.2	9.4	6.7
275 MW Puttalam Coal Plant	5,270	5,296	5,295	5,283	5,286	5,284	72.9	73.3	73.3	73.1	73.1	73.1
Dendro	5	9	11	28	35	29	4.5	8.1	10.7	27.0	33.1	27.7
Chunnakum ext.	8	11	18	33	57	37	3.7	5.1	8.8	15.5	26.9	17.5
CST	12,421	14,032	15,184	16,203	16,779	16,262	46.9	53.0	57.3	61.2	63.3	61.4
75 MW GT	12	21	30	47	77	52	0.6	1.1	1.5	2.4	3.9	2.7
105 MW GT	7	13	18	32	54	36	0.8	1.4	1.9	3.4	5.9	3.9
Trinco coal	3,438	3,439	3,439	3,439	3,439	3,439	86.5	86.5	86.5	86.5	86.5	86.5
DNRO	24	33	58	127	183	136	3.6	4.9	8.7	19.1	27.5	20.4
Total hydro	9,647	7,952	6,717	5,455	4,615	5,352						
Total thermal	21,233	22,926	24,157	25,411	26,244	25,513						
Total generation	30,880	30,878	30,874	30,866	30,859	30,865						
Total demand	30,882	30,882	30,882	30,882	30,882	30,882						
Deficit	2	4	8	16	23	17						
2032												
Kelanitissa Combined Cycle Plant	15	24	33	76	75	74	1.1	1.7	2.3	5.4	5.3	5.3
270 MW Kerawalapitiya CombinedCycle	33	51	84	144	184	150	1.4	2.2	3.5	6.1	7.8	6.3
275 MW Puttalam Coal Plant	5,317	5,336	5,333	5,326	5,322	5,326	73.6	73.8	73.8	73.7	73.7	73.7
Dendro	5	6	13	20	35	22	4.5	6.0	12.1	18.7	33.5	21.4
Chunnakum ext.	8	11	15	31	52	35	3.6	5.0	7.3	14.9	24.7	16.6
CST	13,737	15,384	16,537	17,628	18,263	17,696	47.5	53.2	57.2	61.0	63.2	61.2
75 MW GT	12	22	31	48	73	52	0.6	1.1	1.6	2.4	3.7	2.6
105 MW GT	8	13	18	31	48	34	0.9	1.4	2.0	3.4	5.3	3.7
Trinco coal	3,439	3,439	3,439	3,439	3,439	3,439	86.5	86.5	86.5	86.5	86.5	86.5
DNRO	25	34	69	98	190	115	3.6	4.9	9.8	14.0	27.1	16.4
Total hydro	9,732	8,008	6,753	5,474	4,628	5,371						
Total thermal	22,599	24,320	25,571	26,841	27,680	26,943						
Total generation	32,331	32,328	32,324	32,315	32,307	32,314						
Total demand	32,333	32,333	32,333	32,333	32,333	32,333						
Deficit	2	5	9	18	26	19						