CEYLON ELECTRICITY BOARD

LONG TERM GENERATION EXPANSION PLAN 2018-2037

Transmission and Generation Planning Branch
Transmission Division
Ceylon Electricity Board
Sri Lanka
June 2018

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Submitted to PUCSL for approval on 05th May 2017, PUCSL approval granted on 12th June 2018

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Compiled and prepared by
The Generation Planning Unit
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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 biennial 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. 4000.00

Foreword

The Report on 'Long Term Generation Expansion Planning Studies 2018-2037', 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 2018-2037, and replaces the Long Term Generation Expansion Plan 2015-2034.

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.

June 2018.

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ACRONYMS

ADB	-	Asian Development Bank
bcf	-	Billion Cubic Feet
BOO	-	Build, Own and Operate
BOOT	-	Build, Own, Operate and Transfer
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
CDM	-	Clean Development Mechanism
CER	-	Certified Emission Reduction
COP	-	Conference of Parties
DSM	-	Demand Side Management
DTF	-	Distance to Frontier
EIA	-	Environmental Impact Assessment
ENPEP	-	Energy and Power Evaluation Package
ENS	-	Energy Not Served
EOI	-	Expression of Interest
ESP	-	Electrostatic Precipitator
EWE	-	Electrowatt Engineering
FGD	-	Flue Gas Desulphurization
FOB	-	Free On Board
FOR	-	Forced Outage Rate
GDP	-	Gross Domestic Product
GHG	-	Green House Gases
GIS	-	Geographic Information System
GT	-	Gas Turbine
HHV	-	Higher Heating Value
HVDC	-	High Voltage Direct Current
IAEA	-	International Atomic Energy Agency
IDC	-	Interest During Construction
IEA	-	International Energy Agency
INDC	-	Intended Nationally Determined Contributions
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
LCC	-	Line Commutated Converter
LCOE	-	Levelised Cost of Electricity

LDC	-	Load Duration Curve
LF	-	Load Factor
LNG	-	Liquefied Natural Gas
LOLP	-	Loss of Load Probability
LTGEP	-	Long Term Generation Expansion Plan
mscfd	-	Million Standard Cubic Feet per Day
MAED	-	The Model for Analysis of Energy Demand
MMBTU	-	Million British Thermal Units
MTPA	-	Million Tons Per Annum
NDC	-	Nationally Determined Contributions
NEPS	-	National Energy Policy and Strategy
NG	-	Natural Gas
OECD	-	Organization for Economic Co-operation and Development
OECF	-	Overseas Economic Co-operation Fund
ORE	-	Other Renewable Energy
OTEC	-	Ocean Thermal Energy Conversion
O&M	-	Operation and Maintenance
PF	-	Plant Factor
PM	-	Particulate Matter
PPA	-	Power Purchase Agreement
PSPP	-	Pumped Storage Power Plant
PV	-	Present Value
RFP	-	Request For Proposals
SAM	-	System Advisor Model
SDDP	-	Stochastic Dual Dynamic Programming
ST	-	Steam Turbine
SYSIM	-	System Simulation Model
UNFCCC	-	United Nations Framework Convention on Climate Change
USAID	-	United States Agency for International Development
US$	-	American Dollars
WASP	-	Wien Automatic System Planning Package
WB	-	World Bank
WHO	-	World Health Organization
VSC	-	Voltage Source Converter

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 2018-2037. 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 Demand Forecasting methodology consists of combination of time trend modelling and Econometric approach while incorporating the expected new mega development projects identified by the government.

Sri Lanka Sustainable Energy Authority (SEA) has been entrusted the task of Operation Demand Side Management (ODSM) which will be carried out by a Presidential Task Force on Energy Demand Side Management (PTF on EDSM) and guided by a National Steering Committee (NSC). The formidable barriers to implementation of the DSM programme should be further analysed with associated costs, to gain a better understanding of the benefits and costs of the programme. In addition, in the present mode of implementation, utilities do not have a proper control over the implementation of DSM as it will depend on consumer attitudes. With the subsidies given to the electricity sector in different categories, ensuring deterministic demand reduction may not be feasible or realistic. Therefore, the DSM forecast having highly speculative public response dependent demand reduction, is not considered as a base in the determination of the future expansion plan. However the medium term time trend forecast model will capture the recent year trends including the impact on present DSM activities. It is noted the merits of the DSM program will benefit the electricity industry and is very much encouraged.

Separate Analysis was carried out with regard to night peak, day peak and off peak for the provinces and the country. It was observed that the growth rate of day peak is higher than the night peak. It is predicted that day peak will surpass the night peak by 2030. The Load Forecast used is given in Table E.1.

Sri Lanka, a country vulnerable to climate change impacts presented the Intended Nationally Determined Contributions (INDC) to strengthen the global efforts of both mitigation and adaptation. In response to challenges posed by climate change, Sri Lanka has taken several positive steps by introducing national policies, strategies and actions in order to address climate change induced impacts. While fulfilling the increasing national electricity demand and integrating more renewable sources in combination with conventional fossil source based energy sources; a detail electricity generation expansion plan has been developed. The National Energy Policy and Strategy (NEPS) anticipates increasing share of Other Renewable Energy resources and has encouraged use of competitive bidding. Further it is expecting to reduce energy losses by improving of energy distribution infrastructure and energy saving through introduction of Demand Side Management (DSM). Proposed INDCs are to suggest further actions and sub actions which could directly or indirectly influence to reduction of GHG emission in the energy sector by modifying, adapting and applying new technology in the field. The establishment of large scale wind power farms and adapting of advanced technologies available for broadening the solar power electricity generation is envisioned, while promoting the use of biomass (fuel wood) and waste (municipal waste, industrial and agricultural waste) by elevating its use in the power generation as a modern and convenient energy source. Mini and Micro Hydro Power generation projects are absorbed as an environmental friendly power generation option to national economy. These major contributors will fulfil the Sri Lanka's obligations on Climate Change mitigation commitment from Electricity Sector which were considered during the preparation of LTGEP 2018-2037.

The methodology adopted in the studies optimally selects plant additions from given thermal as well as renewable 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 National Energy Policy & Strategies (2008).

Several analyses have been carried out to facilitate identification of Energy Mix & Fuel Diversification Policies and Climate Change Mitigation Actions. 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 plant options considered in the study were 35MW & 105MW Diesel-fired Gas Turbines, 150MW & 300MW diesel operated Combined Cycle Plants, 150 MW & 300MW LNG fired combined cycle plants, 300MW high efficient sub critical and 600MW

Super critical coal-fired steam plants, 600MW Nuclear power plants, 15 MW Reciprocating Engines and 5 MW Dendro Power Plants.

The renewable energy projects of 35MW Broadlands (2020), 122MW Uma Oya (2019) and 30.2MW Morogolla (2022) were considered as committed Power Projects. The commissioning schedules of the hydro projects given by the respective Project were used in the preparation of the Long Term Generation Expansion Plan. The proposed hydro power plants, 15MW Thalpitigala by year 2020 and 20MW Gin Ganga by year 2022 were considered as candidate plants considering the Cabinet approvals secured by the Ministry of the Irrigation and Water Resource Management. The proposed 20MW Seethawaka Ganga will be developed by Ceylon Electricity Board by year 2022.

The first 100MW Semi dispatchable wind farm developed by Ceylon Electricity Board is considered committed and is expected to be commissioned by 2020. The remaining 275 MW of wind power in Mannar will be developed in stages. The main objective of the development of the wind farm by Ceylon Electricity Board is to pass the economic benefit of the indigenous resource to all the electricity users in the Country.

The 3 x 35 MW Gas turbines at Kelanitissa (2019/2020) and 300 MW multi-fuel combined cycle power plant on a BOOT basis, to be constructed in Kerawalapitiya (2019/2020) is identified as committed thermal power plants. Furthermore Capacities of 100 MW and 70 MW furnace oil plants is expected to be commissioned by 2018.

In the Base Case Plan, the contribution from Other Renewable Energy (ORE) was considered and the different ORE technologies were modelled appropriately. The energy contribution from ORE plants were maintained above 20% from 2020 onwards complying with the Government Policies. Capacity contribution from Biomass, Wind and Solar plants were taken in to the consideration and delays in implementation would cause impacts in capacity and energy balances. A separate Renewable integration study was carried out to identify the renewable resource allocation by minimizing the costs. The operational flexibility reflecting the transmission system constraints were considered in this study. A strong renewable energy development is envisioned which shall increase the annual renewable capacity absorption level to 4 times higher than the previous 12 years. The total addition of renewable energy within the 20 year period is 1205 MW of wind power, 1232 MW of Solar power 200 MW of Mini Hydro power and 80 MW of Bio mass Power. The increased absorption levels of ORE shall maximize the utilization of indigenous natural resources. However during the dry period associated energy from the ORE shall reduce significantly.

Decentralized solar power generation is a promising technology to cater the growing energy needs. Apart from the utility scale developments, small scale (1MW) and roof top solar takes plays a significant role and considered effective since energy sources are located at the end user. In view of further enhancing the renewable energy portfolio in the electricity generation in Sri Lanka, the Government of Sri Lanka (GOSL) has launched accelerated solar development program in 2016 to promote roof top solar installations in the country. The objective of the above program is to reach an installed capacity of roof top solar to 200MW by 2020. In order to support the GOSL's renewable energy promotional drive, the Net Metering Concept was further enhanced by introducing another two schemes.

The scheduled 2x250MW Coal Plants by Trincomalee Power Company Limited which had a prolonged development process over the past years was not granted the approval by PUCSL in the Long Term Generation Expansion Plan 2015-2034, indicating the letter sent by the Secretary to the MOPRE for the undertaking given to the Supreme Court Case No SCFR 179/2016. However future coal power development has been identified as an integral requirement for catering the power sector demand at lower cost. The Foul point in Trincomalee identified in the NEDO, Japan team study is the most promising site of the available locations for future coal development. All the future coal fired power plant are proposed to be high efficient with strict emission controls, Indoor coal storages and enclosed coal handling and management facilities. Such mitigation measures result in an additional capital cost of approximately 700USD/kW compared with conventional coal power plant. In order to countermeasure for environmental impacts the Supercritical Power plants were selected instead of subcritical coal power plants for development beyond 2025. The possibility of evaluating the introduction of super critical technology for the coal power plants proposed before year 2025 would be carried out. Supercritical technology based units have enhanced efficiency of power generation which shall reduce coal consumption and overall emissions. The transmission system limitations is considered when identifying possible integration period of introducing the super critical power plants. The environmental impact mitigation costs are reflected through adoption of superior eco-friendly technologies. These proposed coal power plants shall strictly comply with the prevailing Sri Lankan and International emission standards.

Incorporating LNG fired power plants to Sri Lankan power system was also studied. The present trend of LNG fuel prices were considered with the possibility of recovering the capital cost of LNG infrastructure. The option of adopting a land based LNG terminal or Floating Storage Regasification Unit (FSRU) is to be further evaluated. However LNG infrastructure must be established by 2020 in order gain the maximum benefit of environmental impact mitigation.

The combined cycle plants which are operating using oil in western region shall be converted to LNG immediately when the facility is made available in 2020. The main load center of Sri Lanka is also located in the western region. In order to minimize the Transmission losses, development of power plants closer to the load center is identified. Therefore the development of LNG operated Power plants in western region is identified which will comply with the environmental requirements in the western region.

Due consideration was given to the availability of natural gas in the Mannar Basin and utilization of the natural gas as a fuel option for the power sector. Possibility of introducing indigenous Natural Gas in Mannar Basin by year 2020 is considered although the determination of the quantity and appropriate price is to be validated. Discovery of the natural gas resources is still at very early stages in Mannar Basin. However high priority for the local natural gas utilization shall be considered when the price is competitive with foreign markets.

Social damage should be evaluated independently in terms location of specific studies. During the implementation stage all necessary measures are evaluated and addressed through the Environmental Impact Assessment of each project. The damage from air pollutants can be mitigated by complying with relevant guideline related to emissions and the damage from thermal pollution could be mitigated by complying with appropriate procedures for thermal discharges. Social and ecological aspects and mitigation actions will be identified during Environmental Impact Assessment. Damage costs are influenced by income level of a country, population density around power plants and the specifications of each type of power plant and therefore will not be considered for evaluation.

It was considered that 163MW Sojitz Kelanitissa Power Plant would be operated by CEB after acquiring the plant at the end of the Power Purchase Agreement in 2023. All the other IPP Plants were retired as the contract agreements expire. However Ministry of Power and Renewable Energy has appointed several committees to look into the feasibility of acquiring and operating the asset by CEB once the contract period expires.

Base Case Plan is given in the Table E.2 and also in the Table 7.1 of the Long Term Generation Expansion Plan. The Capacity Balance, Energy Balance and Dispatch Schedule are given in Annex: 7.2, Annex: 7.3 and Annex: 7.4 respectively.

Scenarios were carried out restricting the implementation of coal power plants to determine the cost impact with Base Case Plan. In first scenario, future coal power development was restricted to 1800MW. LNG and Nuclear plants were forced to bridge the gap. The second scenario, development of coal plants were not allowed and LNG power plants were selected to bridge the gap.

Table E.1 - Base Load Forecast: 2018-2042

Year	Demand		Net Losses*	Net Generation		Peak Demand
	(GWh)	Growth Rate (%)	(%)	(GWh)	Growth Rate (%)	(MW)
2018	14588	6.8%	9.88	16188	6.8%	2738
2019	15583	6.8%	9.84	17285	6.8%	2903
2020	16646	6.8%	9.81	18456	6.8%	3077
2021	17478	5.0%	9.77	19370	5.0%	3208
2022	18353	5.0%	9.73	20331	5.0%	3346
2023	19273	5.0%	9.69	21342	5.0%	3491
2024	20242	5.0%	9.65	22404	5.0%	3643
2025	21260	5.0%	9.61	23522	5.0%	3804
2026	22332	5.0%	9.58	24697	5.0%	3972
2027	23459	5.0%	9.54	25933	5.0%	4149
2028	24639	5.0%	9.50	27225	5.0%	4335
2029	25867	5.0%	9.46	28570	4.9%	4527
2030**	27164	5.0%	9.42	29990	5.0%	4726
2031	28388	4.5%	9.38	31328	4.5%	4939
2032	29637	4.4%	9.35	32692	4.4%	5157
2033	30926	4.3%	9.31	34099	4.3%	5381
2034	32251	4.3%	9.27	35546	4.2%	5612
2035	33642	4.3%	9.23	37063	4.3%	5854
2036	35090	4.3%	9.19	38642	4.3%	6107
2037	36613	4.3%	9.15	40302	4.3%	6372
2038	38165	4.2%	9.12	41992	4.2%	6642
2039	39733	4.1%	9.08	43699	4.1%	6915
2040	41324	4.0%	9.04	45431	4.0%	7193
2041	42967	4.0%	9.02	47227	4.0%	7481
2042	44700	4.0%	9.00	49121	4.0%	7784
5 Year Average Growth	5.9%			5.9%		5.1%
10 Year Average Growth	5.4%			5.4%		4.7%
20 Year Average Growth	5.0%			4.9%		4.5%
25 Year Average Growth	4.8%			4.7%		4.4%

***** Net losses include losses at the Transmission & Distribution levels and any non-technical losses, Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depend on the hydro thermal generation mix of the future.

** It is expected that day peak would surpass the night peak from this year onwards

Table E.2 Base Case Plan 2018-2037

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2018	Mini Hydro 15 MW Solar 160 MW Biomass 5 MW	*100 MW Furnace Oil fired Power Plant ** *70 MW Furnace Oil fired Power Plant ** *150 MW Furnace Oil fired Power Plant **	8x6.13 MW Asia Power	1.245
2019	Major Hydro *122 MW (Uma Oya HPP)* Mini Hydro 15 MW Wind 50 MW Solar 95 MW Biomass 5 MW	*2x35 MW Gas Turbine* *1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region*[+]	-	0.220
2020	Major Hydro *35 MW (Broadlands HPP)* **15 MW (Thalpitigala HPP)** *Wind 100 MW (Mannar Wind Park)* Mini Hydro 15 MW Wind 120 MW Solar 105 MW Biomass 5 MW	*1x35 MW Gas Turbine*	6x5 MW Northern Power	0.237
2021	Mini Hydro 10 MW Wind 75 MW Solar 55 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**	4x17 MW Kelanitissa Gas Turbines	0.107
2022	Major Hydro *30 MW (Moragolla HPP)* **20 MW (Seethawaka HPP)** **20 MW (Gin Ganga HPP)** Mini Hydro 10 MW Wind 50 MW Solar 6 MW Biomass 5 MW			0.237
2023	Mini Hydro 10 MW Wind 60 MW Solar 55 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** *163 MW Combined Cycle Power Plant (KPS–2)* •	115 MW Gas Turbine** 4x9 MW Sapugaskanda Diesel Ext.** 163 MW Sojitz Kelanitissa Combined Cycle Plant •	0.205
2024	Mini Hydro 10 MW Wind 45 MW Solar 55 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)**	4x18 MW Sapugaskanda Diesel	0.145
2025	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 85 MW Solar 104 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)**	4x9 MW Sapugaskanda Diesel Ext. 4x15 MW CEB Barge Power Plant	0.026
2026	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Solar 55 MW Biomass 5 MW	-	-	0.019
2027	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 25 MW Solar 54 MW Biomass 5 MW	-	-	0.012
2028	Mini Hydro 10 MW Wind 45 MW Solar 105 MW Biomass 5 MW	**1x600 MW New Supercritical Coal Power Plant**	-	0.002
2029	Mini Hydro 10 MW Wind 25 MW Solar 54 MW Biomass 5 MW	-	-	0.008
2030	Mini Hydro 10 MW Wind 70 MW Solar 55 MW Biomass 5 MW		-	0.027
2031	Mini Hydro 10 MW Wind 35 MW Solar 54 MW Biomass 5 MW	**1x600 MW New Supercritical Coal Power Plant**	-	0.005
2032	Mini Hydro 10 MW Wind 45 MW Solar 55 MW	-	-	0.019
2033	Mini Hydro 10 MW Wind 70 MW Solar 54 MW Biomass 5 MW	**2x300 MW Natural Gas fired Combined Cycle Power Plants -Western Region**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS- 2)	0.023
2034	Mini Hydro 10 MW Wind 70 MW Solar 55 MW		-	0.108
2035	Mini Hydro 10 MW Wind 70 MW Solar 54 MW Biomass 5 MW	**1x600 MW New Supercritical Coal Power Plant**	300MW West Coast Combined Cycle Power Plant	0.058
2036	Mini Hydro 10 MW Wind 95 MW Solar 55 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant -Western Region**	-	0.057
2037	Mini Hydro 10 MW Wind 70 MW Solar 104 MW Biomass 5 MW	-	-	0.230
Total PV Cost up to year 2037, **USD 14,568 million** (LKR 2,168.93 billion)[++]				

GENERAL NOTES:

- * To meet the demand from year 2018 until major power plants are implemented, 70 MW, 100MW and 150MW power plants are proposed with operation by FO.
- \+ Grid integration of 1x300 MW Natural Gas fired Combined Cycle Power Plant would be possible once the Kerawalapitiya- Port 220kV cable is available in June 2018. Gas Turbine operation of the Combined Cycle Power Plant is expected to commence in 2019 and the combined cycle operation is expected in 2020.
- ** Retirement of these plants would be evaluated based on the plant conditions.
- ++ PV Cost includes the cost of projected ORE, USD 2004.6 million based on economic cost (excluding the future Dendro power development) and an additional spinning reserve capacity is kept to compensate for the intermittency of ORE.
- • Sojitz Kelanitissa is scheduled to be retired in 2023 will be operated as a CEB Natural Gas fired power plant from 2023 to 2033 with the conversion. West Coast and Kelanithissa Combined Cycle plant are converted to Natural Gas in 2020 with the development of LNG based infrastructure.
- ✓ Committed plants are shown in Italics. All plant capacities are given in gross values.
- ✓ Thalpitigala and Gin Ganga multipurpose hydro power plants proposed by Ministry of Irrigation are forced considering secured Cabinet approval for the implementation of the Projects.
- ✓ Seethawaka HPP and PSPP units are forced in 2022, 2025, 2026 and 2027 respectively.
- ✓ Moragahakanda HPP will be added in to the system by 2017, 2020 and 2022 with capacities of 10 MW, 7.5 MW and 7.5 MW respectively.

In order to ensure environmental conservation commitment total of 2717MW ORE capacity shall be developed during the planning horizon. This shall avoid the construction of 900MW coal power plants during the planning horizon which shall in return reduce the CO_2 emissions by 17%. The additional present value cost of USD 153 Million is absorbed by the electricity sector in order to mitigate climate change impacts in accordance with the government policies.

During the past years Reserve Margin violation situations were experienced and the demand was met with difficulty. Therefore, the study emphasizes on maintaining the Reserve Margin levels within standards during the worst hydro condition throughout planning horizon. It is important to keep regular monitoring of short-term developments such as demand growth, generator availability and hydrology. .

In the short term context up to year 2023, it is observed that there might be difficulty in operating the system resourcefully due to the foreseen delays in implementation of Uma Oya and Broadlands hydro power projects and the withholding of Coal power project in Sampoor. A severe capacity shortage is identified for the period from 2018-2023. It is recommended to install 320 MW of Reciprocating engine power plants during this critical period, preferably in scattered locations throughout the island. The plants are expected to be kept as stand by power plants beyond the year 2023.

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 40% by 2025 and 50% by 2034. However, the contribution from renewable energy power plants shall also be considerable with a share of more than 40% by 2025 and 33% by 2034. LNG operated plants shall initially serve the up to 25 % of energy for year 2025, even though its energy share shall gradually decrease to 15% in 2034 due to the dispatching of Super Critical Coal Power Plants.

Due to the introduction of a capacity mix of Supercritical coal plants, LNG fired combined cycle plants and high integration of ORE, the rate of increase of CO_2 emissions gradually decreases. The CO_2, NO_x and SO_x is observed to decrease by 17 %, 10% and 6% respectively by adopting the Base Case Plan instead of adopting the least cost solution. The total CO_2 emission from the electricity sector even in year 2037 would be around 24 Million tons and both the total CO_2 emission and the per capita CO_2 emission would still remain low.

The introduction of 3x200MW Pump Storage Power Plant (PSPP) is important with the development of coal power as well as with the prominent peak and off-peak characteristics of the daily demand pattern. The implementation of 3 x 200 MW Pump Storage Power Plant will reduce the off-peak coal power operational issues and improve the efficiency of the coal power plants. Also, PSPP will enhance the ORE absorption capability to the system and reduce the curtailment of ORE power generation. However for the no future coal power development case, which has an additional present value cost of USD 1039 Million compared to the Base case, the integration of PSPP is removed since the combined cycle plants have the possibility of load variation to absorb renewables. However curtailment of LNG operated combined cycle plants should be reviewed as it will reduce the plant factor of these power plants to undesirable levels for LNG contract agreements. Therefore in such circumstances, LNG procurements contracts should be negotiated to minimize the 'Take or Pay' risks.

In the long term, it is important to recognise that coal plant development program will have favorable influence on the economy. Timely implementation of the coal plants in the pipe line is essential and delaying these plants any further will increase the price of electricity and also affect the economic development of the country. Therefore it is crucial that proposed power plants are implemented in accordance with the Base Case Plan.

The total investment required for implementing the Base Case Plan 2018-2037 in the next 20 years is approximately USD 14.568 Billion without considering the projects for which funds have already been committed.

It is imperative that the power plants are implemented as scheduled in Base Case 2018-2037.

Immediate Actions to be taken:

(i) Commissioning of 122MW Uma Oya, 35 MW Broadlands and 30.2 MW Moragolla by year 2019, 2020 and 2022 respectively.

Expected annual energy generation of Uma Oya, Broadlands and Moragolla hydro power projects are 290GWh, 126GWh and 97.6 GWh respectively. All plants will also serve as low cost peaking plants in the future. These plants will be the final least cost major hydro power plants available to the system and it is required to expedite their completion.

(ii) Commissioning of 100MW Wind farm by year 2020.

100MW wind farm is expected to generate approximately 320 GWh annually and wind farm will be one of the major energy contributors to the system from year 2020 onwards.

(iii) 320MW Reciprocating Engine Power plants by 2018.

The severe capacity shortage for the foreseen period till 2023 is to be met through the scattered development of Reciprocating engine power plants. Development of these power plants expeditiously is essential to avoid the imminent power shortage. These power plants could be used as standby power plants once the major power plants are commissioned.

(iv) 3 x 35MW of Gas Turbines by year 2019/2020

In a total power failure situation, immediate restoration of Colombo power could be achieved using gas turbine power plants. Further, these plants will have the capability of operating in the sync-con mode to provide reactive power to improve voltage levels. Power plant would operate to provide peak power as well reduce the dependency on the availability hydro power for peak power generation. It is important to note that this Power plant will have very low plant factor.

(v) 2x300MW Multi Fuel Combined Cycle Power Plants at Kerawalapitiya by 2019 and 2021 respectively and associated LNG import infrastructure by 2020.

The first 300 MW Multi Fuel Combined Cycle Power Plant is much needed to cater the increasing demand in western region and it is anticipated to commence open cycle operation in 2019. The combined cycle operation must be made available at least by 2020. The associated LNG importing infrastructure must also be developed on a fast track process with sufficient capacity to cater both the new power plant and also to cater the conversion of other oil fired combined cycle power plants in the western region. Furthermore another 300 MW Multi Fuel Combined Cycle Power Plant must be made available by 2021.

(vi) 2 x300MW High Efficient Coal Power Plants must be available by year 2023 and 2024 respectively and therefore necessary studies and site allocations must be commenced immediately.

In order to evaluate the impact of risk events, which could lead to inadequacy of supply a separate contingency analysis was prepared for the next five years, i.e. from 2018 to 2022. The risks considered for evaluation were the variation in hydrology, variation in demand, delays in implementation of power plants and outage of major power plant. By considering the various combinations of these occurrences, it is suggested to consider of having an additional capacity of 150MW in the system to mitigate the risk of capacity and energy shortage.

The Summary of Case Studies during the preparation of the Long Term Generation Expansion Plan 2018-2037 are given in Table E.3.

Table E.3 - Summary of Case Study Analyses

No.	Study Option	Total Cost (mn US$)	Remarks
1	Base Case	14,568	20% Energy from ORE considered from 2020 onwards. 3x200MW PSPP introduced in 2025.
2.	Reference Case	14,415	Only existing ORE plants as at 1st January 2017 were included.
3.	High Demand Case	16,604	Demand forecast considering 1% increase of the annual growth rate in Base Load Forecast. Twenty year average demand growth is 6.0%.
4.	Low Demand Case	13,055	Demand forecast considering 1% reduction from the annual growth rate in Base Load Forecast. Twenty year average demand growth is 4.0%.
5.	High Discount Case	10,915	Discount Rate taken as 15%
6.	Low Discount Case	24,065	Discount Rate taken as 3%
7.	Fuel Price Escalation Case	15,828	Fuel price escalation based on International Energy Agency forecast, WEO-2016
	Fuel Diversification Cases		
8.	Future Coal Power Development Limited to 1800MW Case	14,895	No additional coal plants were permitted as candidate plants after developing 1800 MW of Coal plants.
9.	No Future Coal Power Development Case	15,608	No additional coal plants are permitted for development.
10.	Energy Mix with Nuclear Power Development Case	15,126	Energy mix including Nuclear Power Plant Development is considered after 2030. The identified Coal Power units of Base Case Plan beyond 2030, are replaced by two 600MW Nuclear power units in 2032 and 2035.

CHAPTER 1
INTRODUCTION

1.1 Background

The Electricity sector in Sri Lanka is governed by the Sri Lanka Electricity Act, No. 20 of 2009 amended by Act No. 31 of 2013 [1]. Ceylon Electricity Board (CEB) , established by 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 Licenses issued. CEB is responsible for most of the generation and distribution licenses while being sole licensee for transmission. 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 power system has a total installed capacity of approximately 4054MW by end of year 2016 with a total dispatchable capacity of 3538 MW. The maximum demand recorded in 2016 was 2453MW and total generation was 14250GWh.

Generation expansion planning is a part of the process of achieving the above 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 2015 of Central Bank of Sri Lanka [2] and electricity sector data up to 2016. The information presented has been updated to December 2016 unless otherwise stated.

The generating system has to be planned taking into consideration the electricity demand growth, generation technologies, environmental 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 (2011-2015), the real GDP growth in the Sri Lanka economy has varied from 8.4% in 2011 to 4.8% in 2015. In 2015, Sri Lanka has achieved a growth rate of 4.8%. Details of some demographic and economic indicators are given in Table 1.1.

Table 1.1- Demographic and Economic Indicators of Sri Lanka

	Units	2010	2011	2012	2013	2014	2015
Mid-Year Population	Millions	20.68	20.87	20.42	20.58	20.77	20.97
Population Growth Rate	%	1.0	1.0	0.7	0.8	0.9	0.9
GDP Real Growth Rate	%	8	8.4	9.1	3.4	4.9	4.8
GDP /Capita (Market prices)	US$	2,744	3,129	3,351	3,610	3,853	3,924
Exchange Rate (Avg.)	LKR/US$	113.06	110.57	127.60	129.11	130.56	135.94
GDP Constant 2010 Prices	Mill LKR	6,413,668	6,952,720	7,588,517	7,846,202	8,228,986	8,622,825

Source: Annual Report 2015, 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 1994 to 2015.

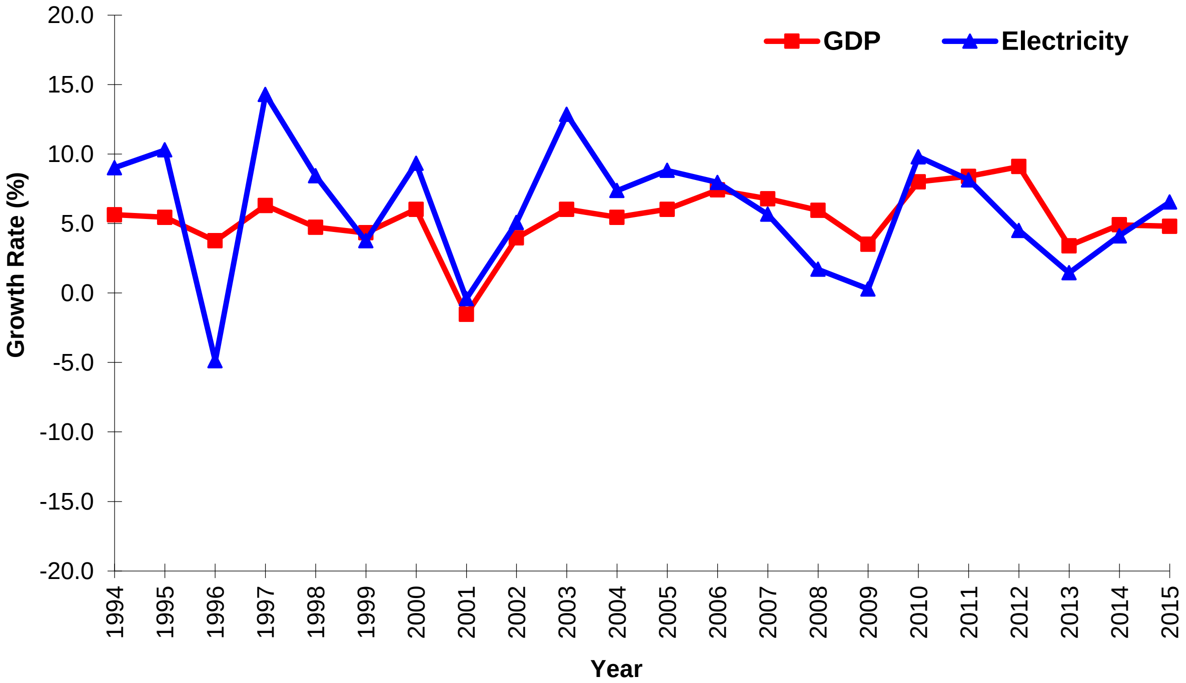


Figure 1.1 - Growth Rates of GDP and Electricity Sales

1.2.2 Economic Projections

The Central Bank of Sri Lanka has forecasted the latest GDP growth rates in real terms for four consecutive years, which is published in Annual Report 2015 of Central Bank of Sri Lanka [2] Annual Report 2014 of Central Bank of Sri Lanka [3] as depicted in Table 1.2.

Table 1.2 - Forecast of GDP Growth Rate in Real Terms

Year	*2015*	*2016*	*2017*	*2018*	*2019*
2014 Forecast	7.0	7.5	8.0	8.0	
2015 Forecast		5.8	6.3	7.0	7.0

Source: Annual Reports 2015 & 2014, Central Bank of Sri Lanka

1.3 Energy Sector

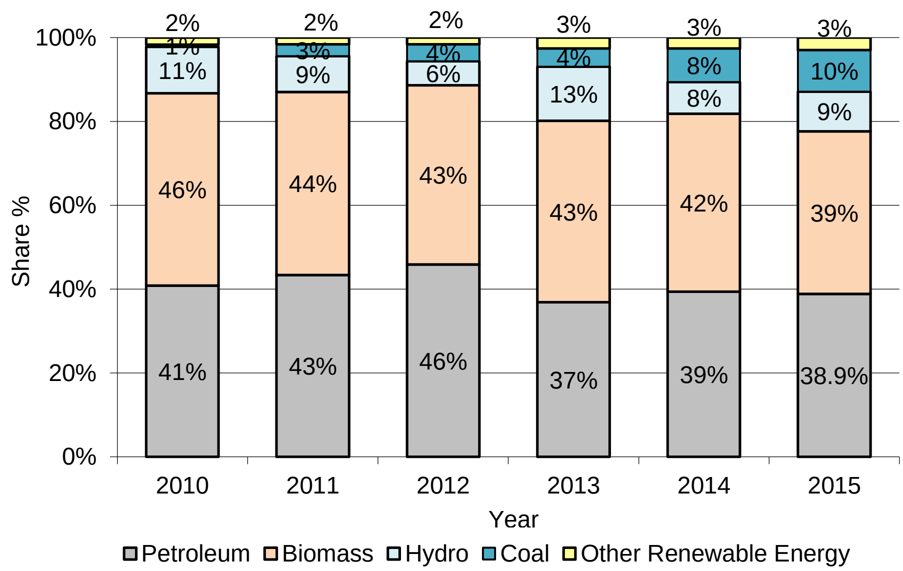
1.3.1 Energy Supply

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 0.5 tons of oil equivalent (TOE). Biomass or fuel wood, which is mainly a non-commercial fuel, at present provides approximately 40 percent of the country’s total energy requirement. Petroleum turns out to be the major source of commercial energy, which covers about 40 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 total primary energy supply is the main indigenous source of primary commercial energy in Sri Lanka. Estimated potential of hydro resource is about 2000MW, 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 and solar power development. The first commercial wind power plants were established in 2010 and the total capacity of wind power plants by end of 2016 is 127MW. 100MW wind farm at Mannar Island is at the implementation stage. The steps have been initiated to harness the economical wind and solar potential in Sri Lanka in an optimal manner. The first commercial solar power plants were commissioned in year 2016 and the total capacity of commercial solar power plants by end of 2016 was 21MW and nearly 50MW of solar roof tops were also connected by end of 2016. Scattered developments of small scale solar power plants have been already initiated and feasibility studies were initiated to develop solar power plants in park concept. 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, the total fossil fuel requirement of the country is imported either as crude oil or as refined products and used for transport, power generation, industry and other applications. 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 carried out. At present, natural gas has been discovered in Mannar basin (off shore from Kalpitiya Pennisula) with a potential of 70 mscfd. Discoverable gas amount of this reserve is estimated approximately 300 bcf. This may even extend beyond the potential of 2TCF with daily extraction rates of 100 mscfd but further exploration should be carried out in order to verify these figures. .

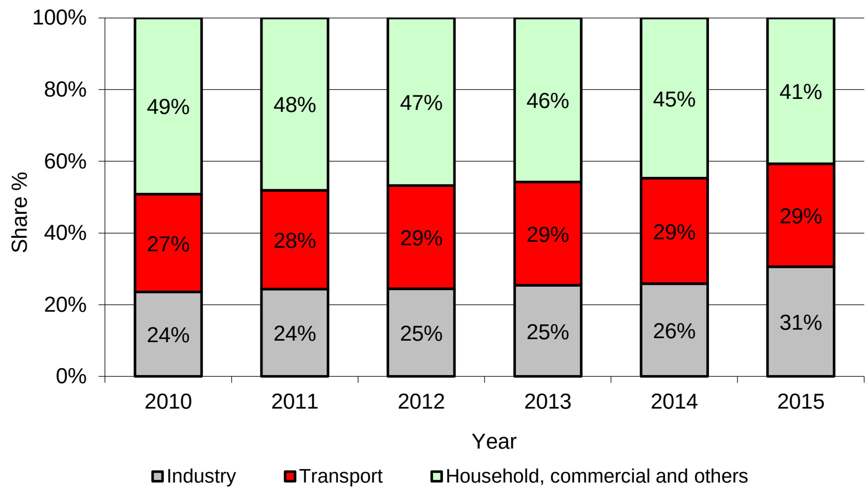
In 2015 the primary energy supply consisted of Biomass (4831 ktoe), Petroleum (4840 ktoe), Coal (1239 ktoe), Hydro (1177 ktoe) and other renewable sources (366 ktoe). The share of these in the gross primary energy supply from 2010 to 2015 is shown in Figure 1.2. Hydro electricity is adjusted to reflect the energy input required in a thermal plant to produce the equivalent amount of electricity.



Source: Sri Lanka Sustainable Energy Authority

Figure 1.2 - Share of Gross Primary Energy Supply by Source

1.3.2 Energy Demand



Source: Sri Lanka Sustainable Energy Authority

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

Sectorial energy consumption trend from 2010 to 2015 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. Further, it shows a decreasing trend while industry sector shows an increasing trend.

The consumption for 2015 is made up of biomass (4793 ktoe), petroleum (4093 ktoe), coal (55 ktoe) and electricity (1010 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.

1.3.3 Emissions from Energy Sector

The Total CO_2 Emission levels of Sri Lanka are 16.7 Million tons, which is approximately only 0.05 % of the total CO_2 emissions generated in the World. The absolute emission levels as well as the per capita emission levels are much below compared to many other countries in the world as tabulated in Table 1.3.

Table 1.3 - Comparison of CO_2 Emissions from Fuel Combustion

Country	kg CO_2/2010 US$ of GDP	kg CO_2/2010 US$ of GDP Adjusted to PPP	Tons of CO_2 per Capita	Total CO_2 Emissions (Million tons)
Sri Lanka	**0.23**	**0.08**	**0.81**	**16.7**
Pakistan	0.67	0.17	0.74	137.4
India	0.92	0.29	1.56	2019.7
Indonesia	0.46	0.17	1.72	436.5
Malaysia	0.70	0.31	7.37	220.5
Thailand	0.64	0.24	3.6	243.5
China	1.08	0.53	6.66	9134.9
Japan	0.21	0.27	9.35	1188.6
France	0.10	0.17	4.32	285.7
Denmark	0.11	0.15	6.12	34.5
Germany	0.20	0.21	8.93	723.3
Switzerland	0.06	0.09	4.61	37.7
United Kingdom	0.16	0.17	6.31	407.8
USA	0.32	0.32	16.22	5176.2
Canada	0.31	0.37	15.61	554.8
Australia	0.26	0.36	15.81	373.8
South Africa	1.06	0.66	8.10	437.4
Qatar	0.48	0.27	35.73	77.6
Brazil	0.20	0.16	2.31	476
World	0.44	0.32	4.47	32381

Even though electricity sector is the major contributor for emissions in the world, the transport sector contributes for majority of the emissions in Sri Lanka. The contribution to emissions from electricity sector of recent four years is tabulated in Table 1.4 and sector wise comparison of CO_2 emissions in 2014 is shown in Figure 1.4.

Table 1.4 - CO_2 Emissions in the Recent Past

Year	World CO_2 Emissions (Million tons)	Sri Lanka CO_2 Emissions (Million tons)	Electricity Sector CO_2 Emissions (Million tons)
2011	31342.2	14.98	5.46
2012	31734.3	15.86	6.45
2013	32189.7	13.74	4.04
2014	32381.0	16.74	6.79

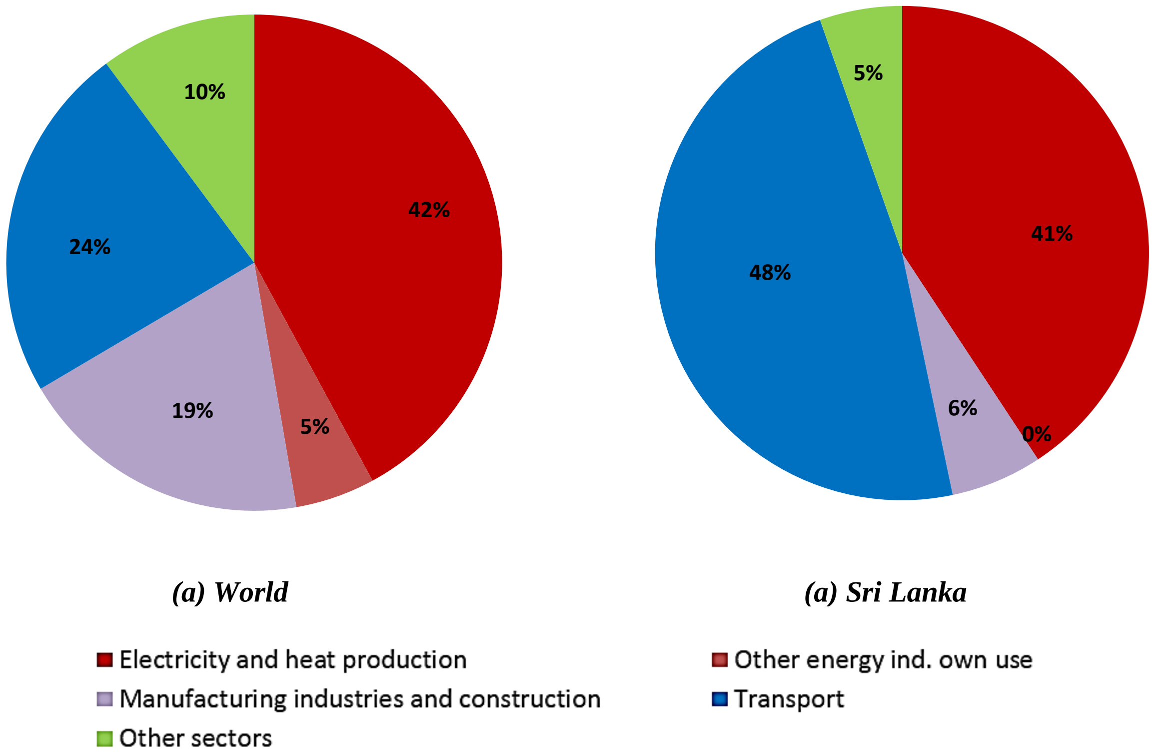


Figure 1.4 - CO_2 Emissions from Fuel Combustion 2014

Source: IEA CO_2 Emissions from Fuel Combustion (2016 Edition) [04] -2014 Data

1.4 Electricity Sector

1.4.1 Ease of Doing Business

The "Ease of Doing Business" index ranks countries based on capability of starting businesses with an overall Distance to Frontier (DTF) score. The score is determined by several factors which includes the subsection of "Getting Electricity". The Getting Electricity index is based on the procedures, time and cost required for a business to obtain a permanent electricity connection for a newly constructed warehouse, while assessing efficiency of connection process, Reliability of supply and transparency of tariff index measures, reliability of power supply and the price of electricity.

The Doing the business 2017 [05] report published by World Bank Group, classified Sri Lanka at an overall Distance to Frontier (DTF) score of 58.79 creating a Ease of Doing Business rank of 110th out of 190 countries, with the subsection of Getting Electricity DTF score of 71.12 which ranked 86th out of all 190 countries.

.4.2 Access to Electricity

By the end of June, 2016, approximately 98.7% 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 1.5 shows the percentage level of electrification district wise as at end of June 2016.

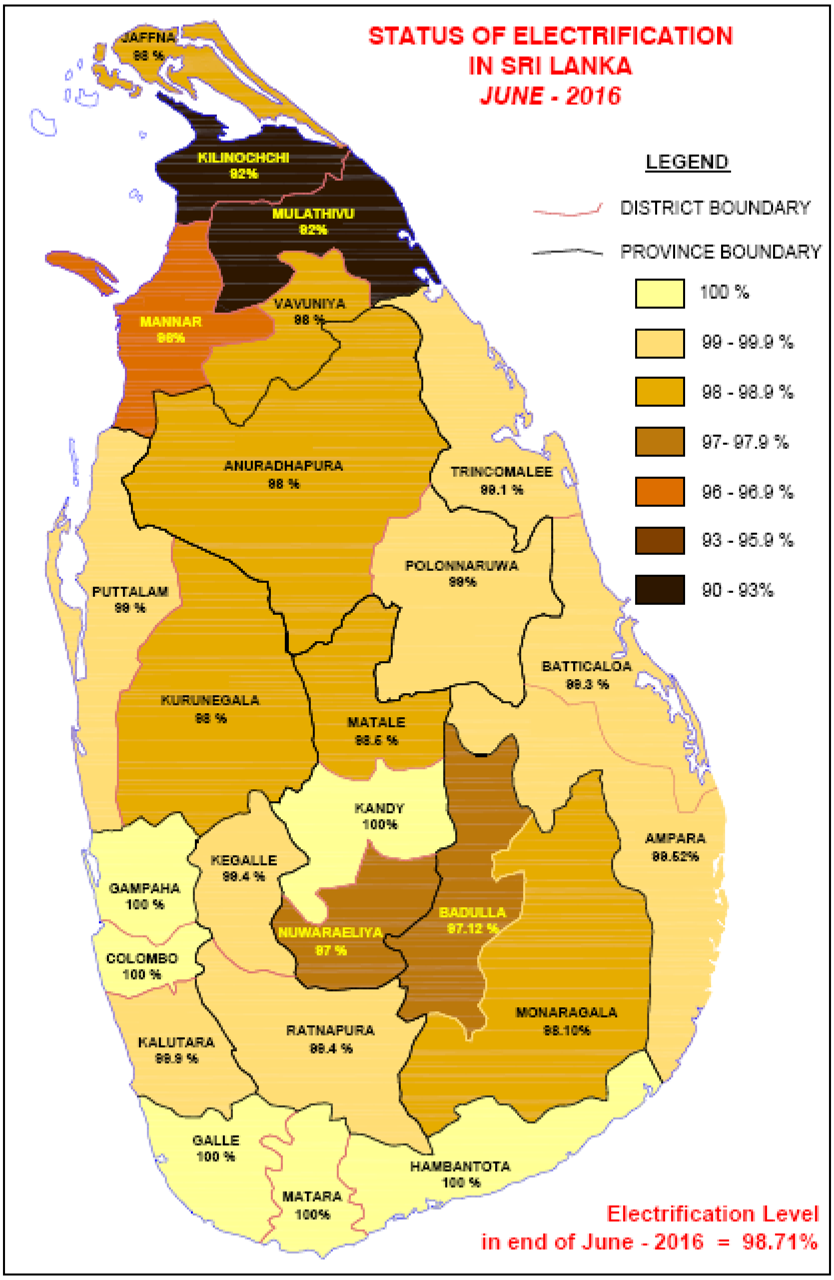


Figure 1.5 - Level of Electrification

1.4.3 Electricity Consumption

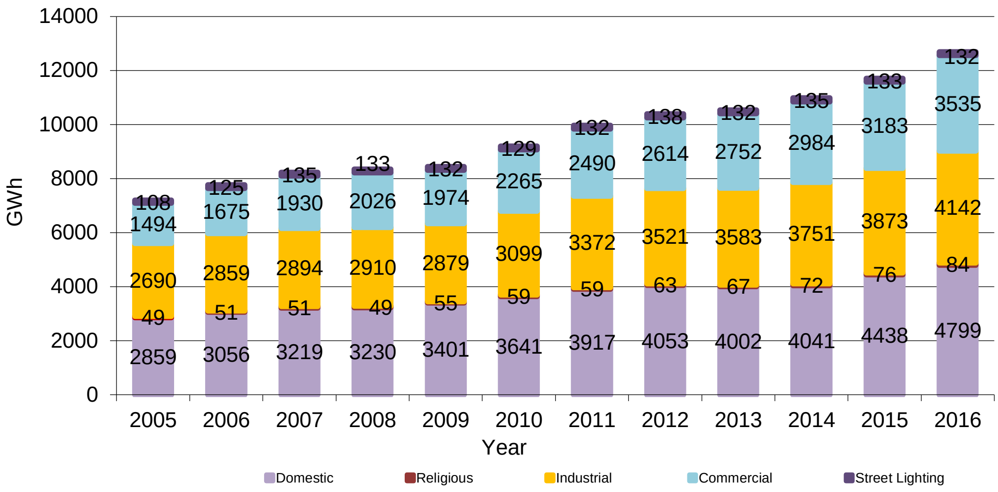


Figure 1.6 - Sectorial Consumption of Electricity (2005 - 2016)

The amount of energy consumed by each sector (i.e. each tariff category) from 2005 to 2016 is shown in Figure 1.6 while Figure 1.7 depicts sectorial electricity consumption share in 2016. These Figures reveal that the industrial and commercial (general purpose, hotel, government) 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.

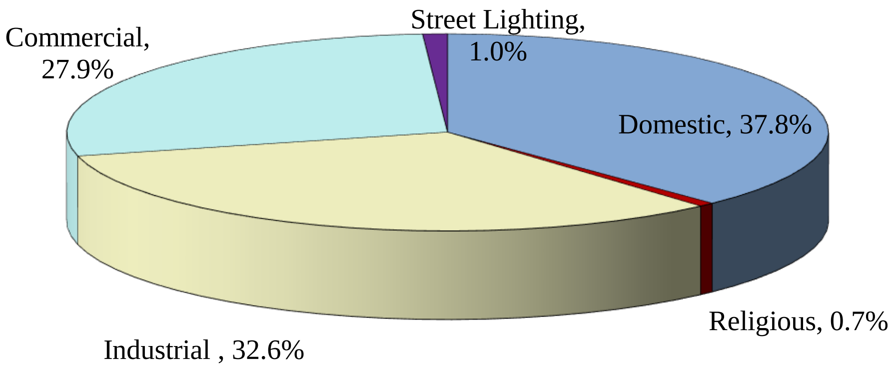


Figure 1.7 - Sectorial Consumption of Electricity (2016)

The average per capita electricity consumption in 2015 and 2016 were 562kWh per person and 603 kWh per person respectively. Generally it has been rising steadily; however in the period 2007 – 2009 with the slowing down of the electricity growth, the per capita consumption has stagnated. A similar trend is observed during 2012 to 2013. Figure 1.8 illustrates the trend of per capita electricity consumption of Sri Lanka from 2004 to 2016. It is compared to other Asian countries per capita electricity consumption variation from 2004 to 2013 as depicted in Figure 1.9.

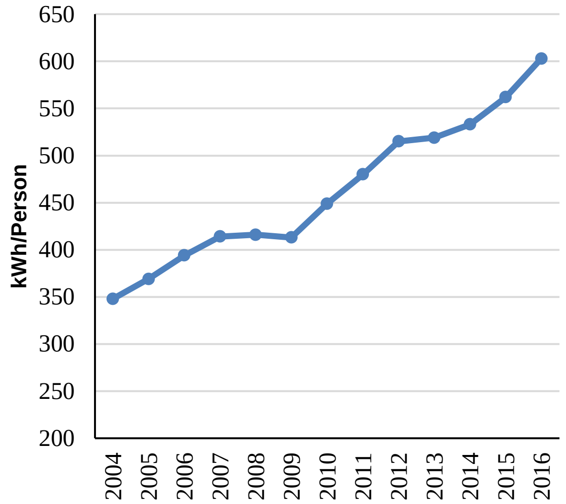


Figure 1.8 – Sri Lanka Per Capita Electricity Consumption (2004-2016)

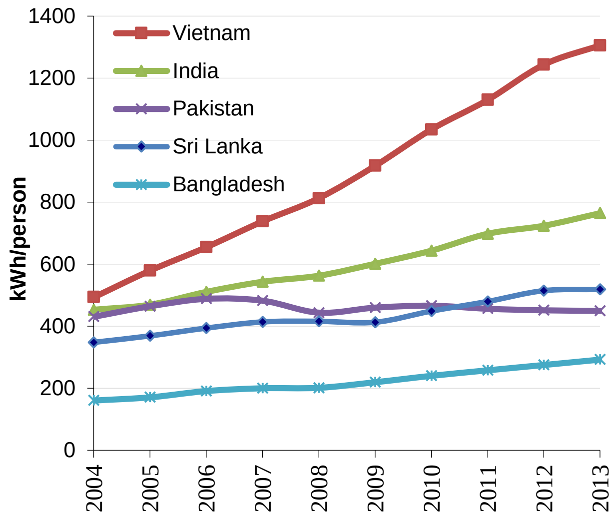


Figure 1.9 – Asian Countries Per Capita Electricity Consumption (2004-2013)

1.4.4 Capacity and Demand

Sri Lanka electricity requirement was growing at an average annual rate of around 5%-6% during the past 20 years, and this trend is expected to continue in the foreseeable future. The total installed capacity peak demand over the last twenty years are given in the Table 1.5 and graphically shown in Figure 1.10. The development of other renewables through the past years is illustrated in Figure 1.11

Table 1.5 - Installed Capacity and Peak Demand

Year	Installed Capacity	Capacity Growth	Peak Demand	Peak Demand Growth
	MW	(%)	MW	(%)
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	5%

Year	Installed Capacity	Capacity Growth	Peak Demand	Peak Demand Growth
	MW	(%)	MW	(%)
2012	3312	5%	2146	-1%
2013	3355	1%	2164	1%
2014	3932	17%	2152	-1%
2015	3847	-2%	2283	6%
2016	4054	6%	2453	7%
`Last 5 year avg. growth		5.25%		3.71%
Last 10 year avg. growth		5.82%		3.37%
Last 20 year avg. growth		5.08%		4.70%

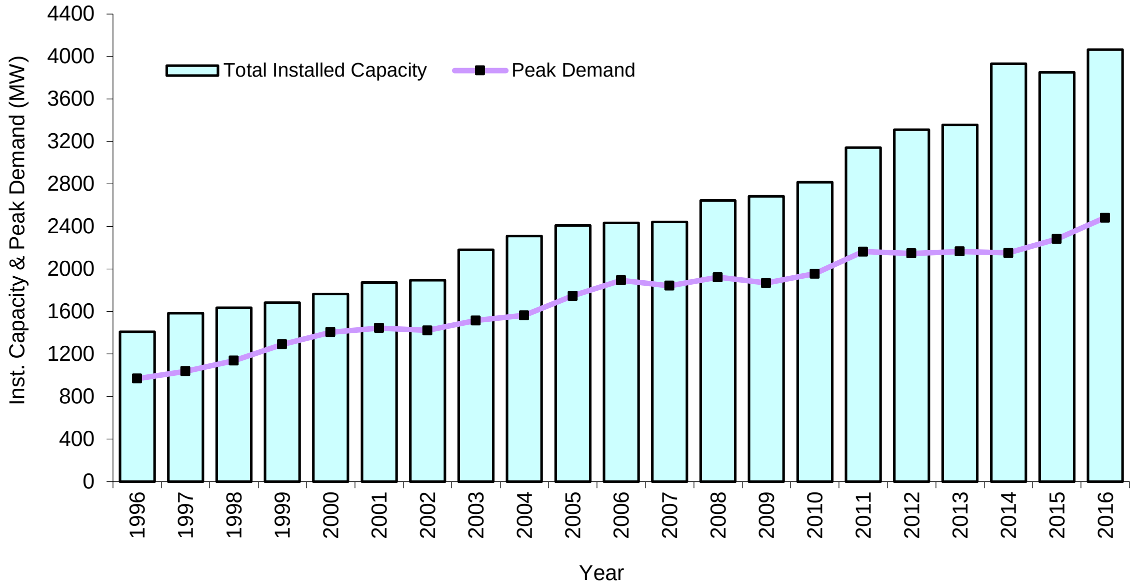


Figure 1.10 – Total Installed Capacity and Peak Demand

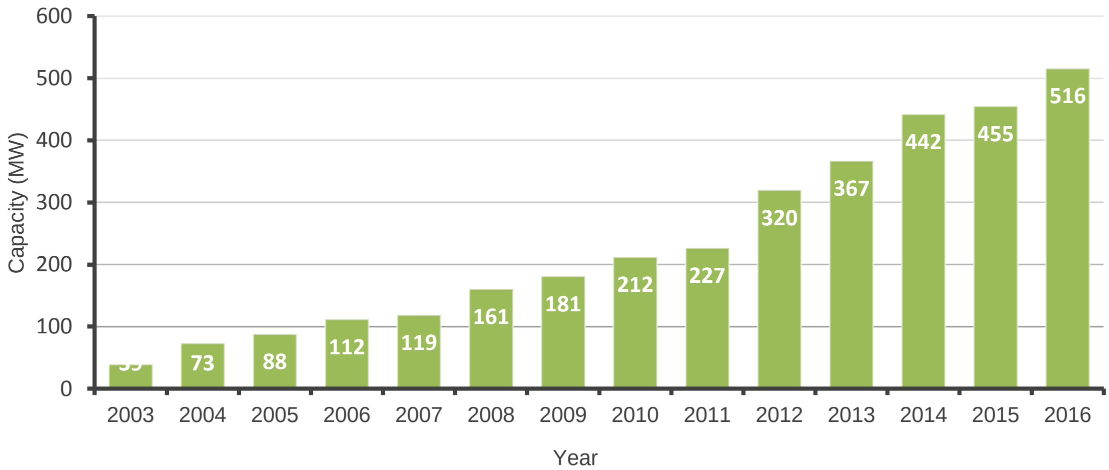


Figure 1.11 – Other Renewable Energy Capacity Development

1.4.5 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. Further the other renewable energy generation from mini hydro, wind, solar, dendro etc is also increasing. Electricity Generation during the last twenty years is summarized in Table 1.6 and graphically shown in Figure 1.12.

Table 1.6 - Electricity Generation 1992-2016

Year	Hydro Generation		Other Renewable		Thermal Generation		Self-Generation		Total
	GWh	%	GWh	%	GWh	%	GWh	%	GWh
1992	2900	81.9			640	18.1	0	0.0	3540
1993	3796	95.4			183	4.6	0	0.0	3979
1994	4089	93.2			275	6.3	22	0.5	4386
1995	4514	94.0			269	5.6	17	0.4	4800
1996	3249	71.8			1126	24.9	152	3.4	4527
1997	3443	66.9			1463	28.4	235	4.6	5146
1998	3915	68.9			1654	29.1	114	2.0	5683
1999	4175	67.6			1901	30.8	97	1.6	6173
2000	3154	46.1	46.7	0.7	3486	51.0	158	2.3	6841
2001	3045	46.0	68.3	1.0	3407	51.4	105	1.6	6625
2002	2589	37.3	107.1	1.5	4114	59.2	136	2.0	6946
2003	3190	41.9	123.4	1.6	4298	56.5	0	0.0	7612
2004	2755	33.8	208.7	2.6	5080	62.3	115	1.4	8159
2005	3173	36.2	282.0	3.2	5314	60.6	0	0.0	8769
2006	4290	45.7	348.0	3.7	4751	50.6	0	0.0	9385
2007	3603	36.7	347.0	3.5	5864	59.8	0	0.0	9811
2008	3700	37.4	438.0	4.4	5763	58.3	0	0.0	9893
2009	3356	34.1	551.0	5.6	5975	60.6	0	0.0	9856
2010	4988	46.9	732.0	6.9	4994	47.0	0	0.0	10628
2011	4018	34.9	725.0	6.3	6785	58.9	2.9	0.0	11528
2012	2727	23.1	736.0	6.2	8339	70.7	1.4	0.0	11801
2013	5990	50.1	1178.0	9.8	4773	39.9	0	0.0	11962
2014	3632	29.2	1217.0	9.8	7556	60.8	0	0.0	12418
2015	4904	37.5	1467.0	11.2	6718	51.3	0	0.0	13089
2016	3499	24.6	1160.2	8.1	9591	67.3	0	0.0	14248
Last 5 year av. Growth	6.43%				3.56%				4.83%
Last 10 year av. Growth	-0.33%				5.62%				4.23%

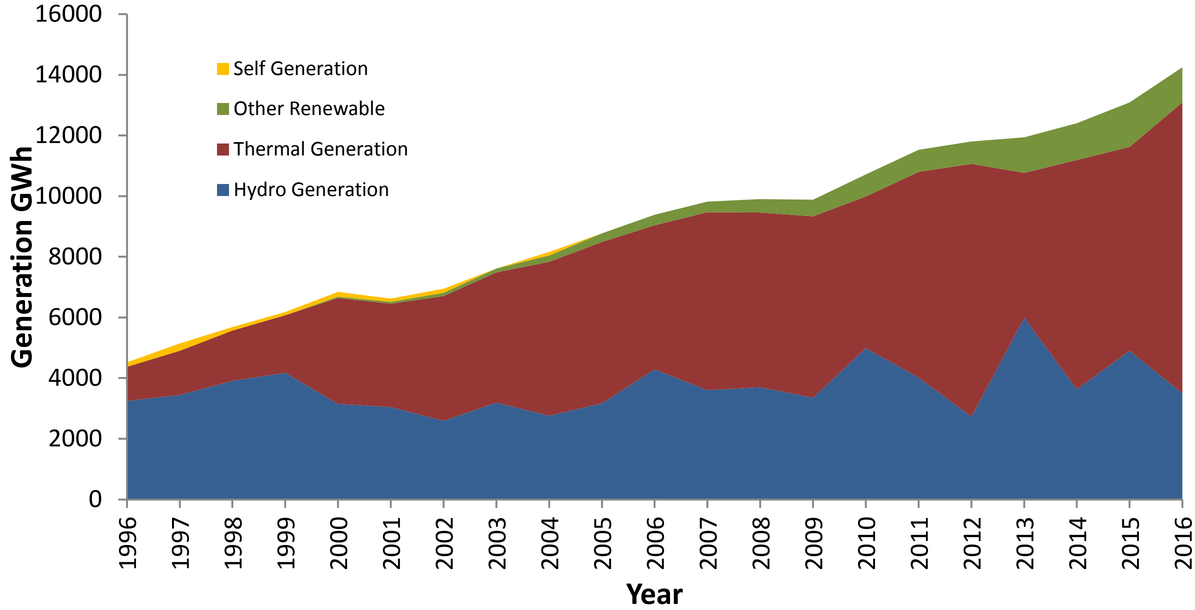


Figure 1.12 - Hydro Thermal Share in the Recent Past

Sri Lankan Power System has operated maintaining 40%-60% share of renewable energy throughout the recent years. This trend will be continued in the future also with the optimum amount of renewable energy integration to the system. Total renewable energy share over the past ten years are shown in Figure 1.13.

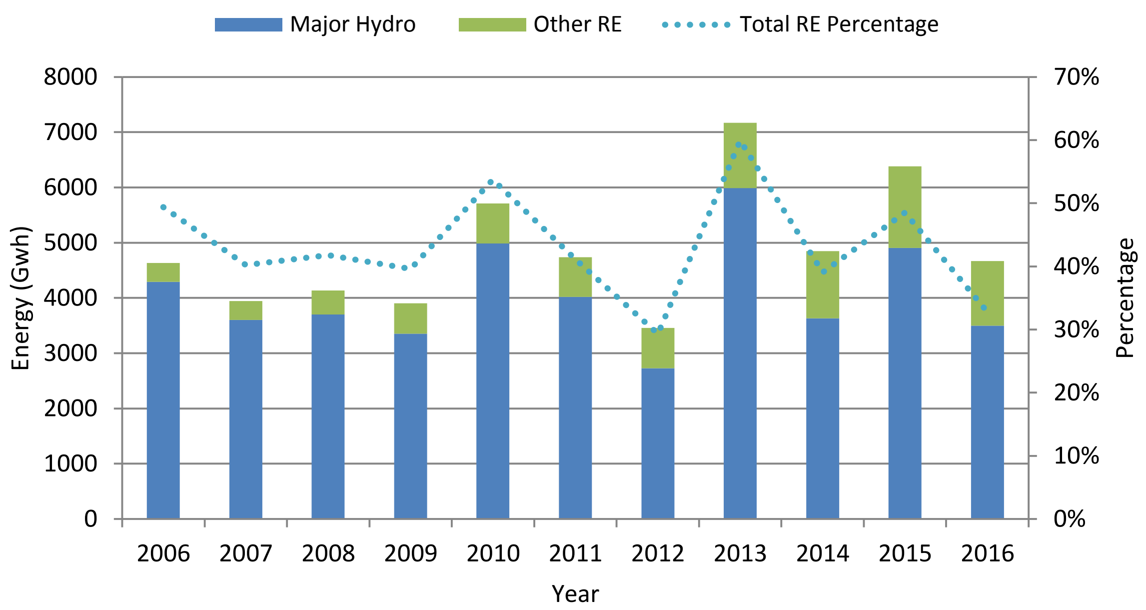


Figure 1.13 – Renewable Share in the Recent Past

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) once in two years complying with Section 43 of SLSEA ACT, No 31 of 2013. Intensive studies are conducted by 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.

1.6 Objectives

The objectives of the generation planning studies conducted by CEB are,

(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 plants.
(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. Thermal and Renewable Generation options for the future system expansions are discussed in Chapters 4 and 5 respectively. Chapter 6 explains the Generation expansion planning guidelines, 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. Chapter 11 will conclude on the contingency analysis on the provided plan.

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 4054 MW of installed capacity by end of 2016 including non-dispatchable plants of capacity 516 MW owned by private sector developers. The majority of dispatchable capacity is owned by CEB (i.e. about 82% of the total dispatchable capacity), which includes 1379.25MW of hydro and 1506.7 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 mini hydro, wind, solar, dendro, and biomass are also connected to the system, which are owned by the private sector developers.

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 10MW (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 12.48 US$/kW per annum.

(a) Existing System

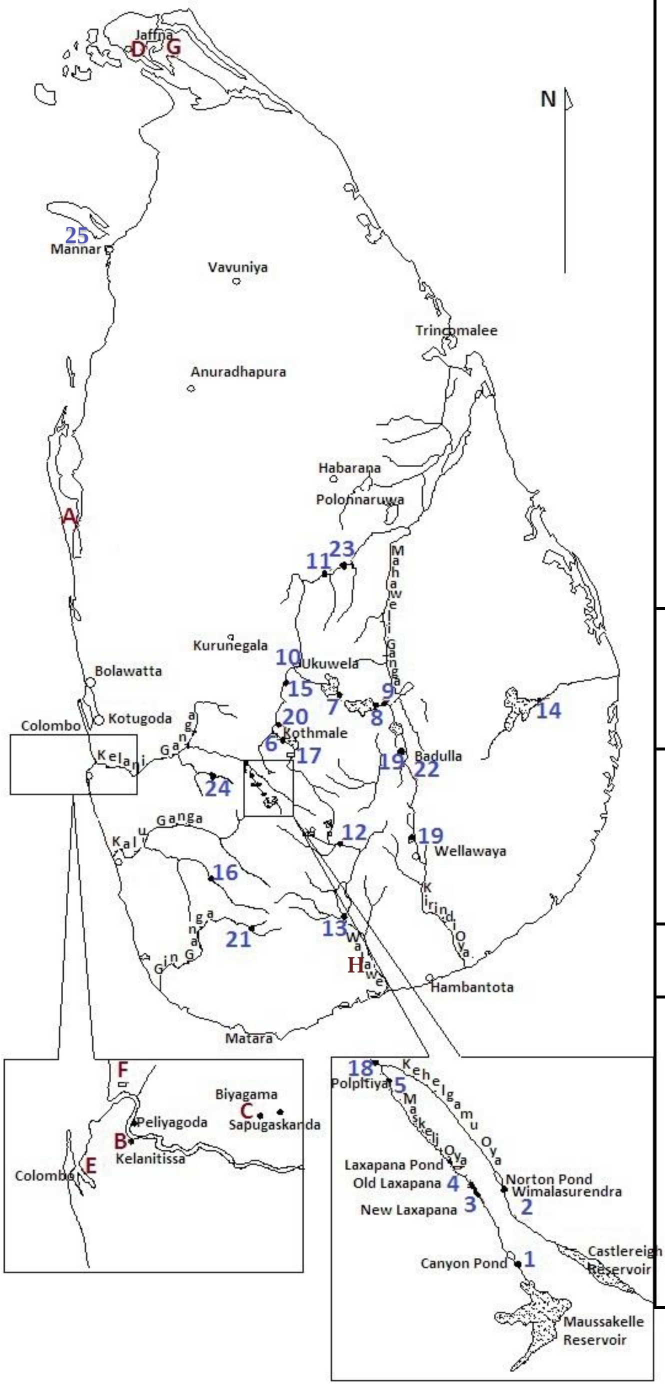
The existing CEB generating system has a large share based on hydropower (i.e.1379.25MW hydro out of 2885.95MW of total CEB installed capacity). Approximately 48% of the total existing CEB system capacity is installed in 17 hydro power stations and only 24.55 % of the total energy demand was met by the large hydro plants compared to 37.4% in 2015. 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 354.8MW (26% 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 storage of 60 MCM feeds the Wimalasurendra Power Station of capacity 2 x 25MW at Norton-bridge, while Canyon 2 x 30MW is fed from the Moussakelle reservoir of storage 115 MCM.

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

Plant Name	Units x Capacity	Capacity (MW)	Expected Annual Avg. Energy (GWh)	Active Storage (MCM)	Rated Head (m)	Year of Commissioning
Canyon	2 x 30	60	160	108.8 (Moussakelle)	192.7	1983 - Unit 1 1989 - Unit 2
Wimalasurendra	2 x 25	50	112	53.58 (Castlereigh)	225.6	1965
Old Laxapana	3x 9.6+ 2x12.5	53.5	286	0.245 (Norton)	472.4	1950 1958
New Laxapana	2 x 58	116	552	0.629 (Canyon)	541	Unit 1 1974 Unit 2 1974
Polpitiya	2 x 37.5	75	453	0.113 (Laxapana)	259.1	1969
Laxapana Total		**354.8**	**1563**			
Upper Kotmale	2 x 75	150	409	0.8	473.1	Unit 1 - 2012 Unit 2 - 2012
Victoria	3 x 70	210	865	688	190	Unit 1 - 1985 Unit 2 - 1984 Unit 3 - 1986
Kotmale	3 x 67	201	498	154	201.5	Unit 1 - 1985 Unit 2&3 –'88
Randenigala	2 x 61	122	454	558	77.8	1986
Ukuwela	2 x 18.5	37	154	2.1	75	Unit 1&2 – '76
Bowatenna	1 x 40	40	48	36.53	52	1981
Rantambe	2 x 24.5	49	239	4.4	32.7	1990
Mahaweli Total		**809**	**2667**			
Samanalawewa	2 x 60	120	344	218	320	1992
Kukule	2 x 37.5	75	300	1.67	186.4	2003
Small hydro		20.45				
Samanala Total		**215.45**	**644**			
Existing Total		**1379.25****	**4874**			
Committed						
Broadlands	2x17.5	35	126	0.198	56.9	2020
Moragolla	2x15.1	30.2	97.6	1.98	69	2022
Mannar Wind Park		100	320			2020
Multi-Purpose Projects						
Uma Oya	2x61	122	290	0.7	722	2019
Gin Ganga	2x10	20	66	0.2	-	2022
Thalpitigala	2x7.5	15	51.3	11.42	93	2020
Moragahakanda	(2x5) + 7.5 + 7.5	25	114.5	430	38 34 34	Unit 1-2017 Unit 2-2020 Unit 3-2022
Total		**347.2**	**1065.4***			

Note: * ***According to feasibility studies.*** ***** 3MW wind project at Hambantota not included.***



No.	Power Plant	Capacity MW
	Hydro Power Plants (Existing)	
1	Canyon	60
2	Wimalasurendra	50
3	New Laxapana	116
4	Old Laxapana	53.5
5	Polpitiya	75
6	Kotmale	201
7	Victoria	210
8	Randenigala	122
9	Rantambe	49
10	Ukuwela	37
11	Bowatenna	40
12	Samanalawewa	120
13	Udawalawe	6
14	Inginiyagala	11.25
15	Nilambe	3.2
16	Kukule	75
17	Upper Kotmale	150
	Hydro Power Plants (Committed)	
18	Broadlands	35
19	Uma Oya	122
20	Moragolla	30.2
	Hydro Power Plants (Candidate)	
21	Gin Ganga	20
22	Thalpitigala	15
23	Moragahakanda	25
24	Seethawaka	20
	Other Renewable (Committed)	
25	Mannar Wind Park	100
	Thermal Power Plants	
A	Lakvijaya Coal Power Plant	900
B	Kelanithissa PP, Sojitz PP	523
C	Sapugaskanda PP, Asia Power	211
D	Uthuru Janani	27
E	CEB Barge Mounted Plant	60
F	West Coast PP	300
G	Northern Power	38
H	ACE Power Embilipitiya	100

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 809MW (58.2% 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. The latest power station in this system is 150MW Upper Kotmale hydro power plant.

Polgolla - diversion weir (across Mahaweli Ganga), downstream of Kotmale and upstream of Victoria, diverts Mahaweli waters to irrigation systems via Ukuwela power station (37MW). 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 (40MW) 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 which in turn affects the operation of these power stations during certain periods of the year.

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

The contribution of the three small hydro plants (Inginiyagala – 11.25MW, UdaWalawe - 6MW and Nilambe – 3.2MW) to the National Grid is comparatively small (20.45MW) and is dependent on irrigation water releases from the respective reservoirs.

Due to recent rehabilitation work carried out at New Laxapana, Old Laxapana ,Wimalasurendra, and Polpitiya Power Stations, the efficiency of above plants has been increased which has resulted in the increase of capacity.

In addition to the above hydro plants, CEB has a 3MW 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 0.216 MCM storage and it is expected to generate 126GWh energy per annum. It will be added to the system in 2020.

122MW 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 231GWh of annual energy and will be added to the system in 2019. This project is implemented by the Ministry of Mahaweli Development and Environment.

Moragolla Hydro Power project with a reservoir of 4.66MCM is located on the Mahaweli River close to Ulapane village in Kandy District of Central Province. This committed power plant is having a capacity of 30.2MW and 97.6 GWh of mean annual energy. This plant will be added to the system in 2022.

Mannar Wind Park is the first semi dispatchable wind park developed in Sri Lanka. During the 1st stage 100 MW of wind power will be developed by CEB in the southern coast of the Mannar Island which would contribute 320 GWh of mean annual energy.

Gin Ganga (20MW), Thalpitigala (15MW) and Moragahakanda (25MW) are three Irrigation Projects with a power generation component. These projects will add another 233GWh to the system. Gin Ganga (20MW) and Thalpitigala (15MW) will be developed by Ministry of Irrigation and Water Resource Management. Moragahakanda (25MW) will be developed by Ministry of Mahaweli Development and Environment

2.1.2 Other Renewable Power Plants Owned by IPPs

Government of Sri Lanka has taken a policy decision to develop hydropower plants below 10MW capacities through private sector participation. Many small hydro plants and other renewable power plants have been connected to the system since 1996. Total capacity of these plants is approximately 543.5MW as at 28th February 2017. These plants are mainly connected to 33kV distribution lines. CEB has signed standard power purchase agreements for another 261MW of small power producers. The existing Capacity contributions from other renewables as of are tabulated in Table 2.2.

Table 2.2 –Existing Development of ORE

Project Type	Number of Projects	Capacity (MW)
Mini Hydro Power	178	349.64
Wind Power	15	123.45
Biomass Agricultural & Industrial Waste	4	13.08
Biomass Dendro Power	5	11.02
Solar Power	7	41.36

In this study, a capacity and energy contributions 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 and further explained in chapter 5.

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.

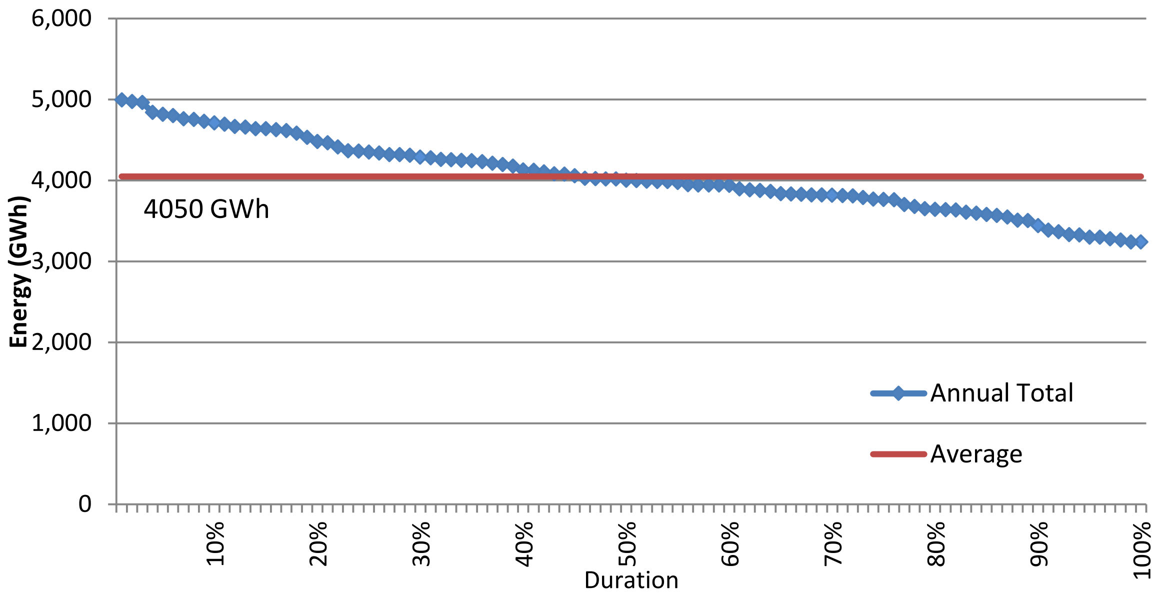


Figure 2.2 - Potential of Hydropower System from Past 35 years Hydrological Data

The annual energy variation of the existing hydro system, using the inflow data from 1979 to 2014 and based on SDDP computer simulation is shown in Figure 2.2. This shows that the capability of the major hydro system (Mahaweli, Laxapana and Samanala) could vary as much as from 3238 GWh to 4994 GWh. For 2018 expansion studies the worst conditions in dry and very dry scenarios were considered in calculating the average and it resulted in a reduction in the weighted average figure. The corresponding summary of the hydro potential is given in Table 2.3 with probabilities of 10% (very wet), 20 %(wet), 50% (medium), 15% (dry) and 5% (very dry) hydro conditions.

Table 2.3 – Expected Monthly Hydro Power and Energy Variation of the Existing Hydro Plants for the Selected Hydro Conditions

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	300.1	890.6	299.1	897.1	293.6	884.5	293.2	880.4	287.2	802.5	295.0	882.9
Feb	241.0	840.3	228.9	848.8	205.0	809.1	178.7	811.3	166.7	775.4	207.5	818.8
Mar	261.4	845.5	233.8	830.3	215.3	794.7	180.5	772.6	157.8	696.9	215.5	798.7
Apr	268.5	802.6	246.0	788.4	225.7	751.0	199.9	691.2	198.9	641.1	228.8	749.2
May	418.4	858.8	399.0	856.8	333.6	835.3	280.0	808.8	299.9	801.3	345.4	836.3
Jun	464.2	978.7	450.9	986.5	378.1	981.8	322.9	943.7	333.9	902.9	390.8	972.8
Jul	423.3	985.8	414.8	976.3	348.4	899.7	316.5	880.3	291.3	849.7	361.6	918.2
Aug	409.0	957.6	390.4	948.3	325.7	894.6	270.0	858.0	255.7	841.4	335.1	903.5
Sep	471.3	992.1	410.7	979.4	344.4	938.4	277.8	906.4	256.8	815.6	356.0	941.0
Oct	588.9	1122.3	514.9	1117.7	463.8	1075.6	388.0	1033.1	344.7	940.8	469.2	1075.6
Nov	457.0	1073.0	377.6	1053.1	342.7	1022.8	298.6	993.9	262.3	911.4	350.5	1024.0
Dec	531.1	1198.1	517.6	1192.3	489.8	1178.9	483.1	1168.7	408.3	1096.5	494.4	1177.8
Total	4834.		4484		3966		3489		3264		4050	

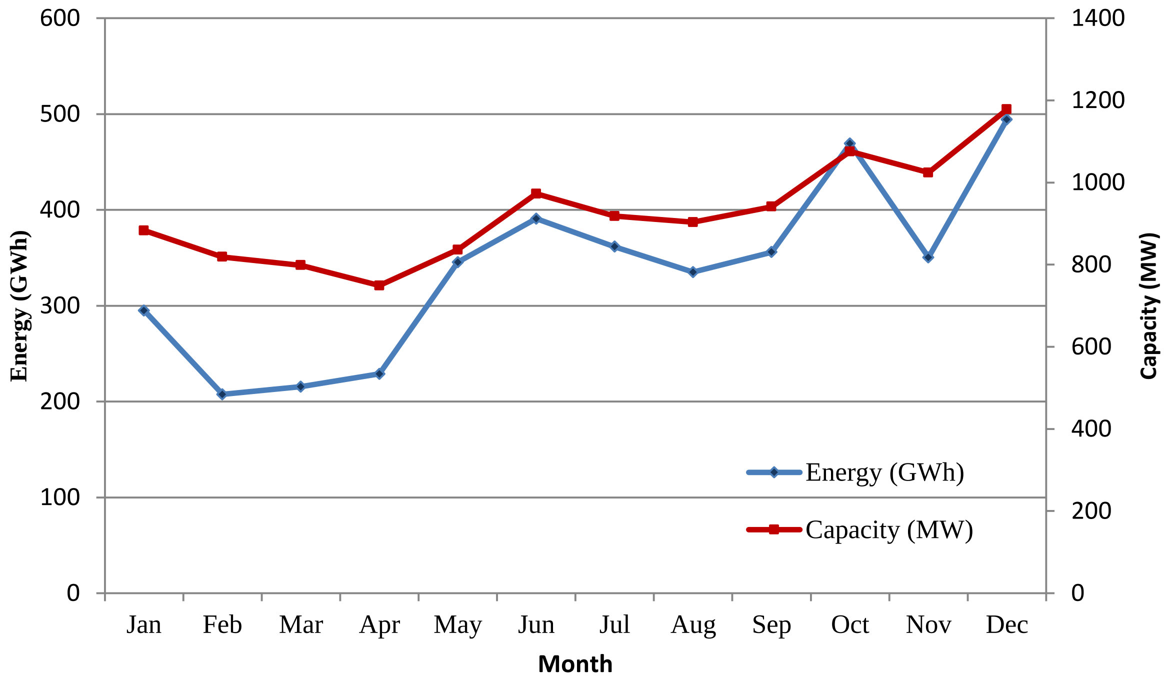


Figure 2.3 - Monthly Average Hydro Energy and Capacity Variation

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 1506.7 MW. It is made up of name plate capacities of Lakvijaya Coal power plant of 900MW, Kelanitissa Gas Turbines of 195MW, Kelanitissa Combined Cycle plant of 165MW, Sapugaskanda Diesel power plants of 160MW, Uthuru Janani diesel power plant of 26.7 MW and Barge Mounted Plant of 60MW. The Lakvijaya Coal plant 900MW funded by EXIM Bank China commissioned in 2011 (Phase I) and 2014 (Phase II) was the latest thermal power plant addition to the CEB system.

(b) Plant Retirements

For planning purposes, it was considered that 4x17MW Gas Turbines at Kelanitissa and 4x18MW diesel plants at Sapugaskanda are due for retirement in 2021 and 2023 respectively. 113MW Kelanitissa Gas Turbine was considered for retirement in 2023. A 4x9MW Sapugaskanda Diesel extension are due to be retired in 2024 and the other 4x9MW Sapugaskanda Diesel extension are to be retired in 2025. Capacity and energy details of the existing and committed thermal plants are shown in Table 2.4. Cost and technical details of the existing thermal generation plants as input to the 2016 Expansion Planning Studies is summarized in Table 2.5.

(c) Committed

Table 2.4 - 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				
Lakvijaya CPP	3 x 300	3 x 275	-	2011 & 2014
Puttalam Coal Total	**900**	**825**	**-**	
Kelanitissa Power Station				
Gas turbine (Old)	4 x 20	4 x 16.3	417	Dec 81, Mar 82, Apr 82,
Gas turbine (New)	1 x	1 x 113	707	Aug 97
Combined Cycle (JBIC)	1 x	1 x 161	1290	Aug 2002
Kelanitissa Total	**360**	**339.2**	**2414**	
Sapugaskanda Power Station				
Diesel	4 x 20	4 x 17.4	472	May 84, May 84, Sep 84, Oct 84
Diesel (Ext.)	8 x 10	8 x 8.7	504	4 Units Sept 97 4 Units Oct 99
Sapugaskanda Total	**160**	**139.2**	**976**	
Other Thermal Power Plants				
UthuruJanani	3 x 8.9	3 x 8.67		Jan 2013
Barge Mounted Plant	4 x 16	4 x 15		Acquired in 2015
Existing Total Thermal	**1510.7**	**1389.4**	**3390**	
Committed				
Kelanitissa Gas	3 x 35	105		2019/2020
Committed Total Thermal	**105**			

Table 2.5 - Characteristics of Existing and Committed CEB Owned Thermal Plants

		Kelanitissa			**Sapugaskanda**		**Lakvijaya Coal**	**Other**	
Name of Plant	**Units**	**GT (Old)**	**GT (New)**	**Comb. Cycle (JBIC)**	**Diesel (Station A)**	**Diesel (Ext.) (Station B)**	**Coal (Phase I II)**	**Uthuru Janani**	**Barge Mounted Plant**
Basic Data									
Engine Type		GE FRAME 5	FIAT (TG 50 D5)	VEGA 109E ALSTHOM	PIELSTIC PC-42	MAN B&W L58/64	-	Wartsila 20V32	Mitsui MAN B&W 12K50MC-S
Fuel Type		Auto Diesel	Auto Diesel	Naphtha	Heavy fuel oil	Heavy fuel oil	Coal	Fuel Oil	Fuel Oil
Inputs for studies									
Number of sets		4	1	1	4	8	3	3	4
Unit Capacity	MW	16.3	113	161	17.4	8.7	275	8.67	15
Minimum operating level	MW	16.3	79	100	17.4	8.7	200	8.67	15
Calorific Value of the fuel	kCal/kg	10500	10500	10650	10300	10300	6300	10300	10300
Heat Rate at Min. Load	kCal/kWh	4022	3085	2168	2246	2059	I-2750 II -2597	2136	2210
Incremental Heat Rate	kCal/kWh	0	2337	1359	0	0	I -1792 II-1793	0	0
Heat Rate at Full Load	kCal/kWh	4022	2860	1850	2246	2059	I-2489 II-2378	2136	2210
Fuel Cost	USCts/GCal	7235	7235	6864	5550	5550	1205	5550	5550
Full Load Efficiency	%	21.4	30.1	46.5	38.3	41.8	I -35 II -36	40.3	38.9
Forced Outage Rate	%	29	25.4	8.4	11.1	7.7	I – 14 II -U2 7.7 U3-11.8	22.9	4.9
Scheduled Maintenance	Days/Year	35	52	30	50	47	52	38	58
Fixed O&M Cost	$/kWmonth	3.35	0.2	2.06	9.35	8.56	1.7	1.93	5.4
Variable O&M Cost	$/MWh	0.72	5.56	3.01	6.34	1.88	3.15	9.21	11.03

Note: All costs are in January 2017 US$ border prices. Fuel prices are based on CPC & Lanka Coal Company data based on market price of average fuel prices of 2016. Heat rates and calorific values are given in HHV.

2.2.2 Independent Power Producers (IPPs)

(a) Existing

Apart from the thermal generating capacity owned by CEB, Independent Power Producers have commissioned diesel power plants and combined cycle power plants given in Table 2.6.

Table 2.6 - 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	50.8	330	1998 June	20
Sojitz Kelanitissa (Pvt.) Ltd	163	163	-	GT- March 2003 ST - October 2003	20
ACE Power Embilipitiya Ltd +	100	99.5	697	2005 April	10
West Coast (pvt) Ltd.	300	270	-	2010 May	25
Northern Power	38	30	-	2009 December	10
Existing Total IPP	**652**	**613.3**			
Committed	-	-	-		
Furnace Oil based++	100 +70	100+70		2018	
LNG Combined Cycle	300	287		2019 Open cycle 2020 Combined cycle	
Committed Total IPP	**470**	**457**	**-**		

Note

+ The contract of ACE Power Embilipitiya Power Plant which expired was extended on short term basis.

++ The Furnace Oil Based Power Plant is expected to be operated as IPP.

CHAPTER 3
ELECTRICITY DEMAND: PAST AND THE FORECAST

3.1 Past Demand

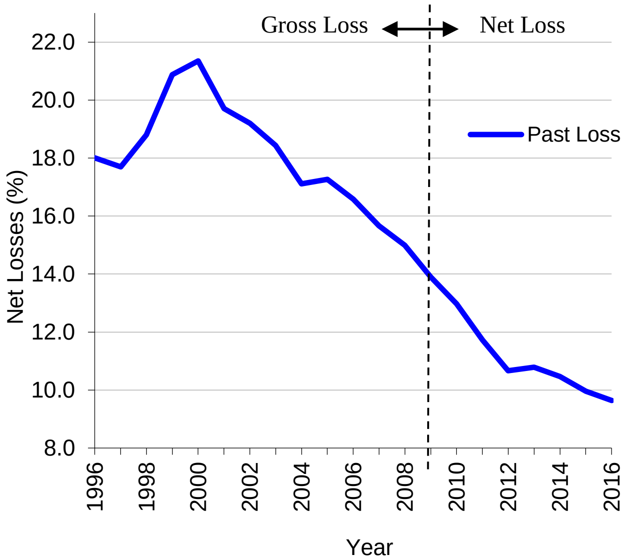
Demand for electricity in the country during the last fifteen years has been growing at an average rate of about 6.0 % per annum while peak demand has been growing at a rate of 4.0 % per annum as shown in Table 3.1. However the peak demand has grown at a rate of 3.4% during the last 5 years and energy demand has been growing at a rate of 5.1% per annum. In 2016, the total electricity generated to meet the demand amounted to 14,250GWh, which had been only 9,814GWh ten years ago. The recorded maximum demand within the year 2016 was 2,453MW which was 2,283MW in year 2015 and 1,842MW ten years ago.

Table 3.1 - Electricity Demand in Sri Lanka, 2002– 2016

Year	Demand	Avg. Growth	Total energy Losses+	Generation	Avg. Growth	Load Factor	Peak	Avg. Growth
	(GWh)	(%)	(%)	(GWh)	(%)	(%)	(MW)	(%)
2002	5638*	5.6	19.2	6810	4.4	54.7	1422	-1.6
2003	6209	10.1	18.4	7612	11.8	57.3	1516	6.6
2004	6782*	9.2	17.1	8043	5.7	58.7	1563	3.1
2005	7255	7.0	17.3	8769	9.0	57.3	1748	11.8
2006	7832	8.0	16.6	9389	7.1	56.6	1893	8.3
2007	8276	5.7	15.7	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	4.7
2011	10026*	8.2	13.1	11528	7.6	60.8	2163	10.6
2012	10475*	4.5	11.2	11801	2.4	62.8	2146	-0.8
2013	10624	1.4	11.2	11962	1.4	63.1	2164	0.8
2014	11063	4.1	10.9	12418	3.8	65.9	2152	-0.6
2015	11786	6.5	10.4	13154	5.9	65.8**	2283	6.1
2016	12785	8.5	10.3	14250	8.3	66.3**	2453	7.4
Last 5 year		5.1%			4.8%			3.4%
Last 10 year		5.0%			4.2%			3.2%
Last 15 year		6.0%			5.4%			4.0%

*Include Self-Generation
**Load Factor includes Other RE
+Includes generation auxiliary consumption

Figure 3.1 shows a considerable decrease in percentage of system losses during 2000-2016. The major contribution towards this decrement is the decrease in Transmission & Distribution Losses. Figure 3.2 shows the System Load Factor which calculated including Other RE (Mini hydro, Wind & Solar) and Self-Generation. Overall improvement in the load factor can be observed as shown in Figure 3.2 and in 2016 it was calculated as 66.3%.



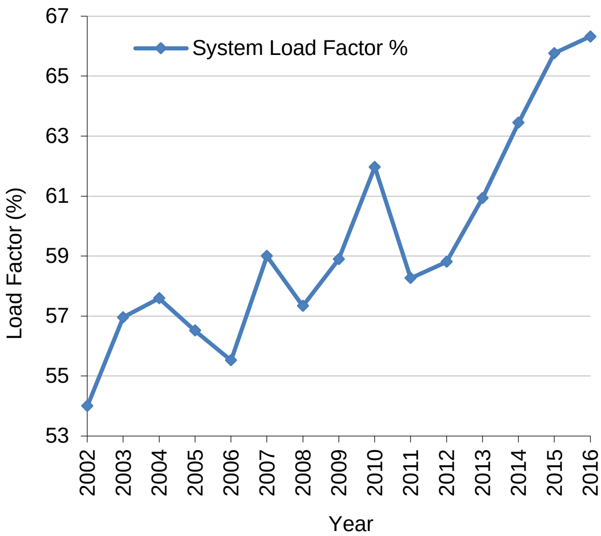


Figure 3.1 - Past System Loss

Figure 3.2 – Past Trend in the Load Factor

Figure 3.3 shows the country's daily load curve recorded on the day of annual peak for previous eight years. From the Figure 3.3, it could be observed that the shape of the load curve remain as the same. However, significant growth in the day peak could be seen during 2015 & 2016 compared to other years. The system peak demand occurred for short period from about 18.30 to 22.00 hours daily. The recorded maximum system peak is 2, 283MW in year 2015, while in year 2016 the peak is 2,453MW.

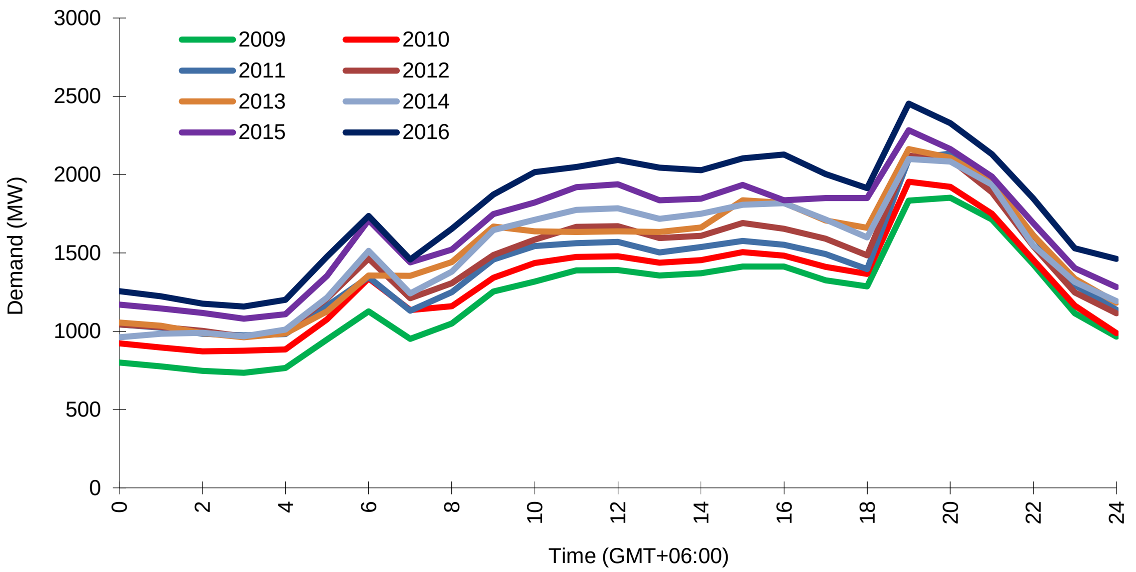


Figure 3.3 - Change in Daily Load Curve Over the Years

Figure 3.4 shows the percentage consumption shares among different consumer categories from 1977 to 2016.In 2016, share of domestic consumption in the total demand was 38% while that of industrial and commercial sectors were 33% and 28% respectively. Religious purpose consumers and street lighting, which is referred as the other category, together accounted only for 2%. Similarly in 2006 (10 years ago), share of domestic, industrial, commercial and religious purpose & street lighting consumptions in the total demand, were 39%, 37%, 22% and 2% respectively.

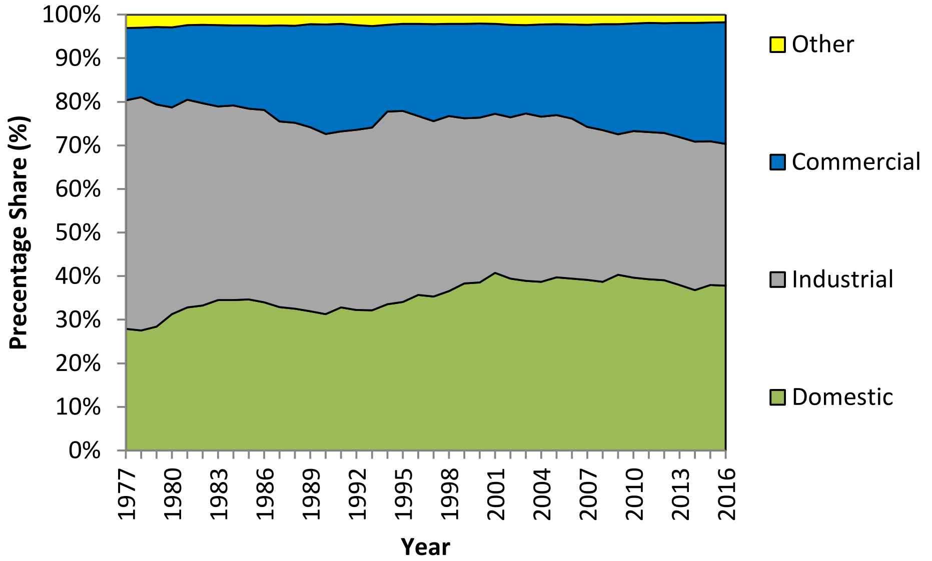


Figure 3.4 - Consumption Share among Different Consumer Categories

3.2 Government Policies and Future Major Developments

3.2.1 Government Policies

The Electricity Demand Forecast 2018-2042 prepared complying with the following government policies and guidelines.

- National Energy Policy and Strategies of Sri Lanka in 2008
- General Policy Guidelines on the Electricity Industry for the Public Utilities Commission of Sri Lanka in 2009

3.2.2 Future Major Developments

The Government has proposed and planning for large scale developments which will lead to increase in demand in the future. The major developments plans are identified by Western Region Megapolis Plan and Hambantota Port Development Plan in Southern Region.

The Western Region Megapolis Plan identifies following major clusters for the development.

- Transport
- Multi Model Transport Hub (Pettah)

- Colombo Central Business District
- Housing Development
- Horana & Mirigama Industrial Township
- SME Industry
- Colombo Port City
- Science and Technology City
- Tourism

The cumulative electricity demand requirements due to the above developments are indicatively estimated as 390MW by 2020, 975MW by 2025 and 1949MW by 2030. The Colombo Port City Development Project is the significant project under the Western Region Megapolis Plan and indicative cumulative electricity demand requirement estimated as 30MW by 2020, 177MW by 2025, 313MW by 2030 and 393MW by 2040.

Hambantota Port Development Plan in Southern Region also estimated approximately 400MW electricity demand for the initial stage in the present development plan.

The Electricity Demand Forecast 2018-2042 was prepared considering major portions of power requirements identified in the above projects, since those will be developed over a period of time. For the long term planning purpose, it is required to identify the time based load requirement to determine the load pattern which would impact on electricity demand.

3.3 Demand Forecasting Methodology

A combination of Time Trend modelling and Econometric approach has been adopted by CEB for the preparation of future electricity demand forecast. For the medium term as first four years, Time Trend modelling has been adopted by capturing recent electricity sales pattern and the growth. For the long term, econometric approach has been adopted by analysing past electricity sales figures with significant independent variables.

Further, the End User Approach was adopted separately through MAED model as described in section 3.5.In End user modelling, extensive analysis of end user energy demand considered by identifying technological, social and economic driving factors in Industry, Transportation, Household and Service sectors separately.

3.3.1 Medium Term Demand Forecast (2017-2020)

Time trend modelling has been adopted for the electricity demand forecast for 2017-2020 and the sales figures of the past four years taken for the analysis [6]. Additionally the five year sales forecasts from the CEB Distribution Divisions and LECO were collected and compared with medium term demand forecast.

3.3.2 Long Term Demand Forecast (2021-2042)

Econometric model was used for Long Term Demand Forecast from 2021-2042, giving due consideration to the energy conservation, electricity consumer tariff categories (multisector) and economic growth of sectors [6]. Separate forecasts were prepared for Domestic, Industry and Commercial sectors to comply with multi sector approach.

In the 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 eliminated.

Table 3.2 – Variables Used for Econometric Modeling

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

According to the Central Bank Annual Report 2015, sector wise GDP and its percentage share to the total GDP were analysed for the period from 1978 to 2015. Base year was taken as 2015 and the percentage share for Agriculture, Industry and Services are 7.9%, 26.2% and 56.6% respectively.

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.

To capture different consuming habits of various consumer categories, sector wise forecasts were prepared separately. Therefore, 'Domestic', 'Industrial', 'Commercial' (including General Purpose, Hotels and Government) and 'Other' (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 two variables: Gross Domestic Product Per Capita and Previous year Domestic Consumer Accounts were significant independent variables for the domestic sector demand growth. Also the population forecast given by the Department of Census and Statistics was used.

Ddom (t) i = 203.55 + 1.36 GDPPC (t) i + 0.71 CAdom (t-1)

Where,

Ddom (t) - Electricity demand in domestic consumer category (GWh)

GDPPC (t) - Gross Domestic Product Per Capita ('000s LKR)

CAdom (t-1) - Domestic Consumer Accounts in previous year (in '000s)

Industrial Sector

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

Di (t) i = 11.35 + 0.29 GDPi (t) + 0.87 Di (t-1)

Where,

Di (t) - Electricity demand in Industrial consumer categories (GWh)

GDPi - Industrial Sector Gross Domestic Product (in '000 LKR)

Di (t-1) - Previous year Electricity demand in Industrial consumer category (GWh)

Commercial (General Purpose, Hotel and Government) Sector

Significant variables for electricity demand growth in the commercial sector are Service Sector GDP and previous year Electricity demand in Commercial consumer category, same as the industrial sector. Although there are differences between the identification of Commercial (General Purpose, Hotel & Government) sector in CEB Tariff category and Service sector identified in the statistics of Central Bank of Sri Lanka, Service sector GDP was selected as the most significant variable in regression analysis.

Dcom (t) i = -104.41 + 0.16 GDPser (t) + 0.83 Dcom (t-1)

Where,

Dcom (t) - Electricity demand in Commercial consumer categories (GWh)

GDPser - Service Sector Gross Domestic Product (in '000 LKR)

Dcom (t-1) - Previous year Electricity demand in Commercial consumer category (GWh)

Other Sector

The two consumer categories: Religious purpose and Street Lighting were 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, the time-trend analysis was performed to predict the demand in this sector.

ln (Dos(t)) = -103.30 + 0.055 t

Where,

t - Year

Impacts of External effects on the Electricity Demand

To capture the impact of influence on external factors such as tariff revisions and seasonal effects on electricity demand in Domestic, Industrial and Commercial (sum of General Purpose, Hotel and Government) sectors from 2013 to 2016 were separately analysed and reflected in long term forecast.

Cumulative Demand

Once the electricity demand forecasts were derived for the four sectors separately, they were added together to derive the demand forecast from 2021 to 2042. Total demand forecast 2018-2042 is a combination of Time Trend modelling and Econometric approach.

Net Losses

Estimated total net (transmission and distribution loss excluding generation auxiliary) energy loss were added to the total demand forecast in order to derive the net electricity generation forecast.

A target of net Transmission and Distribution loss of 9.61% in year 2025, 9.42% in year 2030, 9.23% in year 2035 and 9.00% in year 2042 was used in the studies. Total net energy loss forecast to be achieved throughout the planning period is shown in Figure 3.5 with the expected improvements of the network. The actual losses would be vary depend on the generation combination of each year and 9.64% of net loss was reported in 2016.

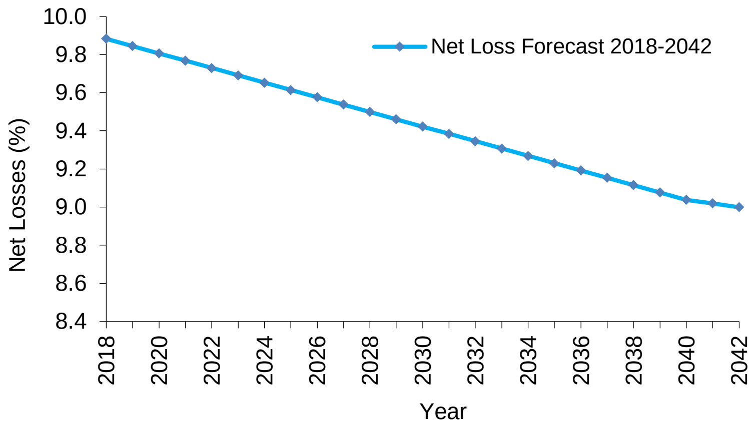


Figure 3.5–Net Loss Forecast 2018-2042

Load Factor and Peak

The System Load Factor which is illustrated in Figure 3.2 is calculated by including Other RE (Mini hydro, Wind & Solar) and Self-Generation in the past sixteen years and in 2016 it was 66.3%.

Separate analysis was carried out by considering actual monthly records of the night peak, day peak and off peak from 2011 to 2016 for the provinces and whole country. It was observed that the night peak, day peak and off peak shows increasing trends. However, it could be observed that the growth of day peak is higher than the growth of night peak resulting in higher growth rate in total energy compared to the peak growth rate. Therefore, in the future more energy will be relatively filled in the day time of the load profile resulting in the shape of the daily load profile to gradually change and it could be expected that the day peak of the country will become higher than the night peak.

Accordingly, we have predicted that the crossover of the load profile shape would occur in 2030. This would occur when the ratio of the peaks of the day and night become equal and resultant normalised load profiles are shown in Figure 3.6.

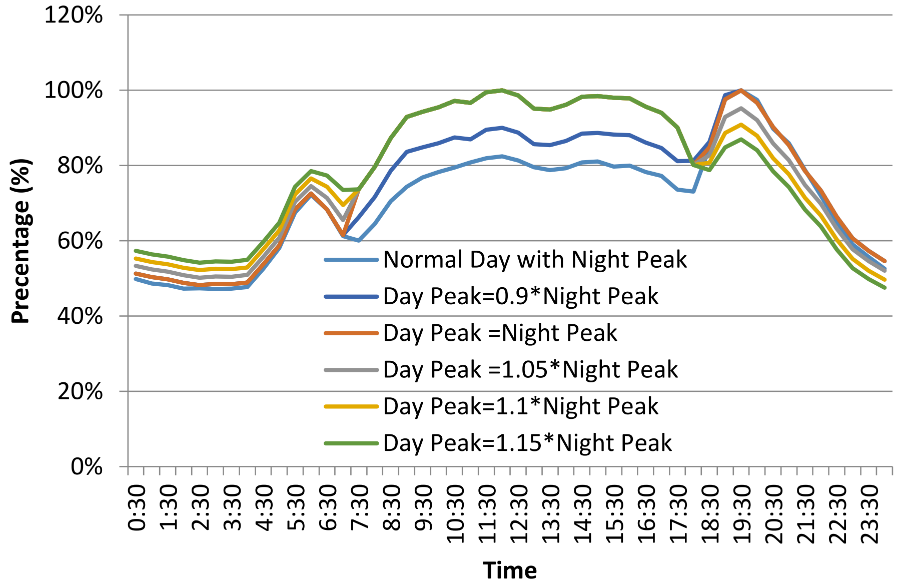


Figure 3.6 – Load Profile Shape Forecast

It is assumed that the load factor becomes maximum in 2030. The forecast of annual load factor up to 2042 was done based on the relationship between the ratio of the day and night peak demands and the load factor of the peak day. Sales growth variation of the each tariff category could result for the increasing trend of the load factor in future. Accordingly the system load factor shows the increasing trend with 72.4% by 2030 and Figure 3.7 shows the system load factor forecast for the planning horizon.

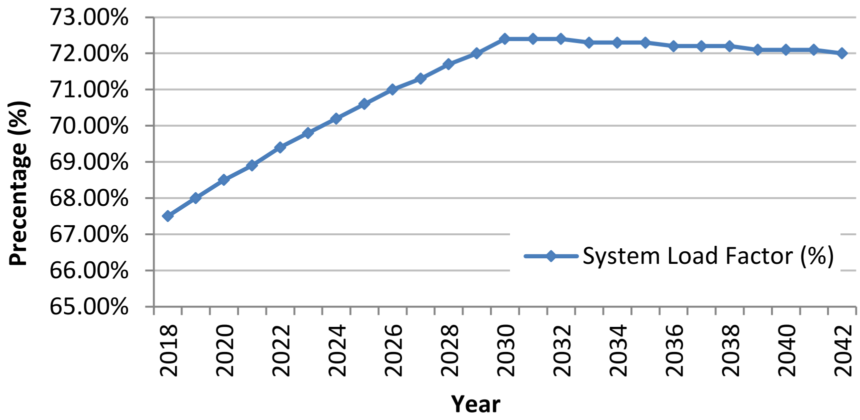


Figure 3.7 – System Load Factor Forecast 2018-2042

Finally the Peak demand forecast was derived using the electricity generation forecast and load factor forecast.

3.4 Base Demand Forecast 2018-2042

Base demand forecast for 2018-2042 was prepared as described in Section 3.3 for the planning horizon. In addition to that a number of demand forecast scenarios are prepared as described in section 3.6.

Table 3.3 shows the 'Base Load Forecast 2018-2042'.

Table 3.3 - Base Load Forecast 2018-2042

Year	Demand		Net Loss*	Net Generation		Peak Demand
	(GWh)	Growth Rate (%)	(%)	(GWh)	Growth Rate (%)	(MW)
2018	14588	6.8%	9.88	16188	6.8%	2738
2019	15583	6.8%	9.84	17285	6.8%	2903
2020	16646	6.8%	9.81	18456	6.8%	3077
2021	17478	5.0%	9.77	19370	5.0%	3208
2022	18353	5.0%	9.73	20331	5.0%	3346
2023	19273	5.0%	9.69	21342	5.0%	3491
2024	20242	5.0%	9.65	22404	5.0%	3643
2025	21260	5.0%	9.61	23522	5.0%	3804
2026	22332	5.0%	9.58	24697	5.0%	3972
2027	23459	5.0%	9.54	25933	5.0%	4149
2028	24639	5.0%	9.50	27225	5.0%	4335
2029	25867	5.0%	9.46	28570	4.9%	4527
2030**	27164	5.0%	9.42	29990	5.0%	4726
2031	28388	4.5%	9.38	31328	4.5%	4939
2032	29637	4.4%	9.35	32692	4.4%	5157
2033	30926	4.3%	9.31	34099	4.3%	5381
2034	32251	4.3%	9.27	35546	4.2%	5612
2035	33642	4.3%	9.23	37063	4.3%	5854
2036	35090	4.3%	9.19	38642	4.3%	6107
2037	36613	4.3%	9.15	40302	4.3%	6372
2038	38165	4.2%	9.12	41992	4.2%	6642
2039	39733	4.1%	9.08	43699	4.1%	6915
2040	41324	4.0%	9.04	45431	4.0%	7193
2041	42967	4.0%	9.02	47227	4.0%	7481
2042	44700	4.0%	9.00	49121	4.0%	7784
5 Year Average Growth	5.9%			5.9%		5.1%
10 Year Average Growth	5.4%			5.4%		4.7%
20 Year Average Growth	5.0%			4.9%		4.5%
25 Year Average Growth	4.8%			4.7%		4.4%

*****Net losses include losses at the Transmission & Distribution levels and any non-technical losses, Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depend on the hydro thermal generation mix of the future
**It is expected that day peak would surpass the night peak from this year onwards

3.5 Development of END USER Model (MAED) for Load Projection

Model for Analysis of Energy Demand (MAED) developed by International Atomic Energy Agency (IAEA) for Load Projection with Bottom-Up approach. Energy Demand Calculation module utilize extensive analysis of end use energy demand data and identify technological, economic and social driving factors influencing each category of final consumption and their relations to the final energy.

Final Electricity demand projection then separately taken into Electric Power Demand module for further analysis. In that module Industry, Transportation, Household and Service sectors are considered separately. Secondary electricity demands (net generation) is calculated taking into consideration Transmission & Distribution losses.

Model was developed based on year 2010 as the base year and rest of the years from 2015-2045 adjusted considering the present situation of the economy, demography, energy intensity etc. for each 5 year periods. Sub Sector wise load profiles are selected based on the clients having the same load profile patterns. Main Sector is represented by the aggregated load profile determined by the model. Peak electricity demand is calculated by the Load Factor % determines from the above load profiles. Also the rural and urban household % share assumed as 80%: 20% in 2015, 70%:30% in 2030 and 60%:40% in 2040.

Table 3.4, shows the Main and Sub sector client breakdown used for electricity demand calculation.

Table 3.4 – Main & Sub Sector Breakdown

<table>
<tr><th>Main Sector</th><th colspan="2">Sub Sectors (Clients)</th></tr>
<tr><td rowspan="5">Industry</td><td colspan="2">Process Industry</td></tr>
<tr><td colspan="2">Petroleum & Gas Industry</td></tr>
<tr><td rowspan="3">Industries with different working patterns</td><td>7 working days with constant load</td></tr>
<tr><td>6 working days with constant load</td></tr>
<tr><td>6 working days with day time operation</td></tr>
<tr><td rowspan="5">Service</td><td colspan="2">Public & Private sector offices</td></tr>
<tr><td colspan="2">Hotel</td></tr>
<tr><td colspan="2">Public & Private Hospital</td></tr>
<tr><td colspan="2">Educational Institutes</td></tr>
<tr><td colspan="2">Marine & Aviation</td></tr>
<tr><td rowspan="2">Household</td><td colspan="2">Urban</td></tr>
<tr><td colspan="2">Rural</td></tr>
</table>

Three scenarios were developed to analyse demographic, socio-economic and technological parameter development of the country as follows;

Reference Scenario (RS)

This is the baseline scenario which carries historic growth rates of all sectors to the future years and anticipated energy demand predictions which would most likely to occur in the future. GDP growth rate projections are in line with the base demand forecast.

Low Economic Growth Scenario (LEG Scenario)

In this scenario economic growth was reduced compared to the Reference Scenario and more pessimistic approach was taken in projecting sector wise energy demands.

High Electricity Penetration Scenario (HEP Scenario)

This scenario was developed with the assumption that demands for electricity will increase shifting from other energy forms. This assumption is based on that the cost of electricity generation will decrease with the addition of low cost power plants to the system. The demography and the GDP composition remain in line with the Reference Scenario. Electricity use in all the sectors, Industry, Transport, Household and Services will increase compared to the Reference Scenario.

Table 3.5 shows the annual average growth rate of Total Energy Demand and Electricity Demand for 2015-2040 planning horizon for each scenario.

Table 3.5 – Annual Average Growth Rate 2015 – 2040

Scenario	Total Energy Demand Growth Rate %	Electricity Demand Growth Rate %
Reference	5.1	4.6
Low Economic Growth	4.2	3.9
High Electricity Penetration	5.5	5.2

Table 3.6, shows the sectoral total secondary electricity consumption for Reference scenario, its percentage share, Peak electricity demand & the load factor percentage over the planning horizon.

Table 3.6 – MAED Reference Scenario

Sector	Unit	2020	2025	2030	2035	2040
Industry	GWh	6,544	9,409	13,078	17,013	21,872
Transport	GWh	32	64	114	177	261
Households	GWh	6,369	7,520	8,909	10,441	11,955
Services	GWh	4,031	5,335	6,930	8,599	10,586
Total	GWh	16,975	22,329	29,031	36,230	44,673
Industry	%	38.55	42.14	45.05	46.96	48.96
Transport	%	0.19	0.29	0.39	0.49	0.59
Households	%	37.52	33.68	30.69	28.82	26.76
Services	%	23.74	23.89	23.87	23.73	23.70
Peak	MW	2,921	3,644	4,685	5,847	7,193
Load Factor	%	66.34%	69.94%	70.73%	70.73%	70.71%

Total electricity demand of the MAED reference scenario and Base Demand Forecast 2018-2042 compared in section 3.6 and it was observed that those two are in line for the planning horizon.

However, more accurate sector wise end user information is required to capture the real end user impacts for the electricity demand.

Projected final energy demands for Reference, Low Economic Growth and High Electricity Penetration scenarios are given in Figure 3.8 and peak demand projection is given in Figure 3.9.

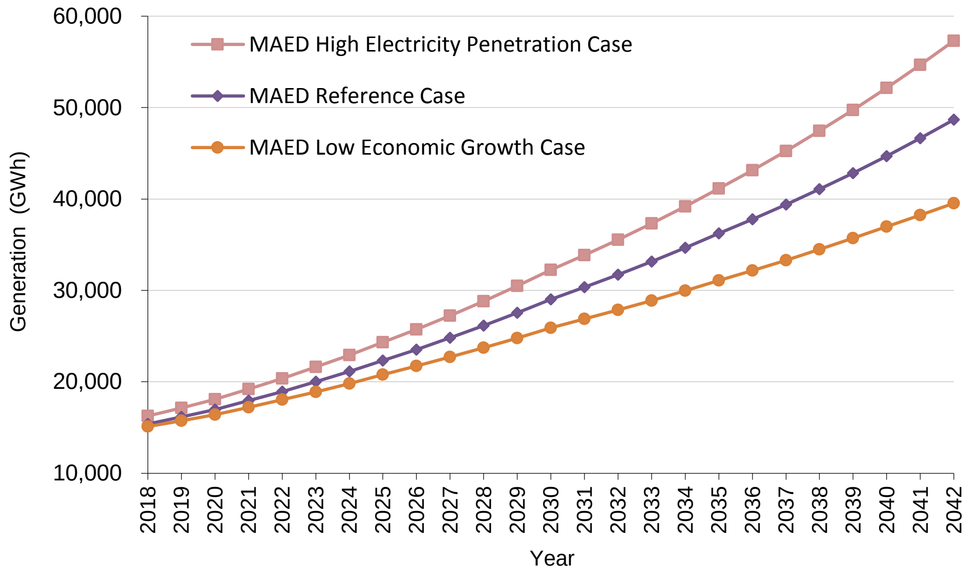


Figure 3.8 - Generation Forecast Comparison

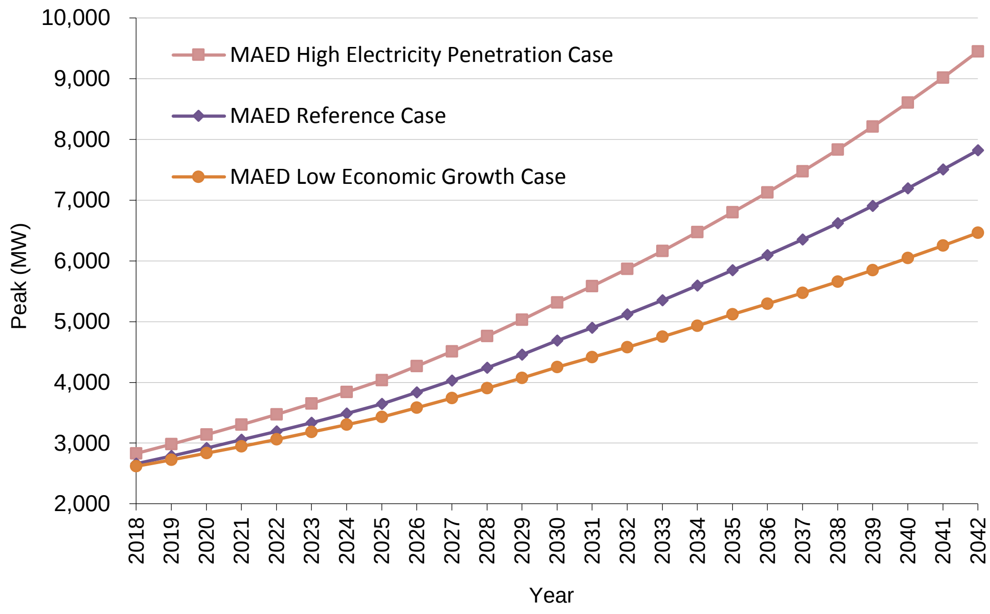


Figure 3.9 – Peak Demand Forecast Comparison

3.6 Demand Forecast Scenarios

Different demand forecast scenarios were prepared considering growth rate variations to the base demand forecast, long term time trend approach and end user approach. Those are listed below and the effects of these variations on the base case generation expansion plan are described in Chapter 7 to 11.

1. **High Load Forecast-** Considering 1% increase of the annual growth rate in Base Load Forecast

2. **Low Load Forecast -** Considering 1% reduction from the annual growth rate in Base Load Forecast

3. **Long Term Time Trend Forecast -** This forecast was projected purely based on time trend approach. A long term time trend forecast was prepared using the past 25 year generation figures, starting from 1991.

4. **MAED Load Projection –** This is derived from MAED software by considering end user energy demand data and identifying technological, economic and social driving factors influencing each category of final consumption and their relations to the final energy.

Load forecast of the above scenarios are presented in Annex 3.1. Figure 3.10 & Figure 3.11 shows graphically, the electricity generation and peak load forecast for the above four scenarios including base load forecast.

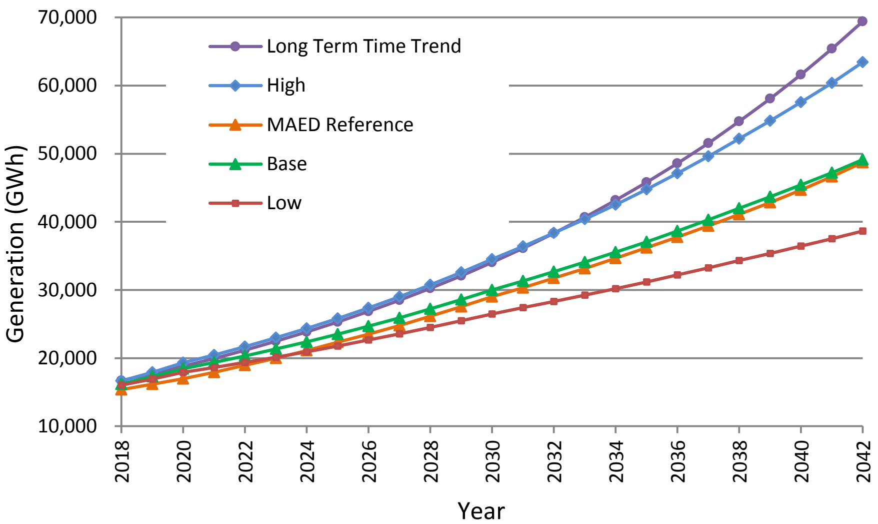


Figure 3.10 - Generation Forecast of Low, High, Long Term Time Trend and MAED with Base

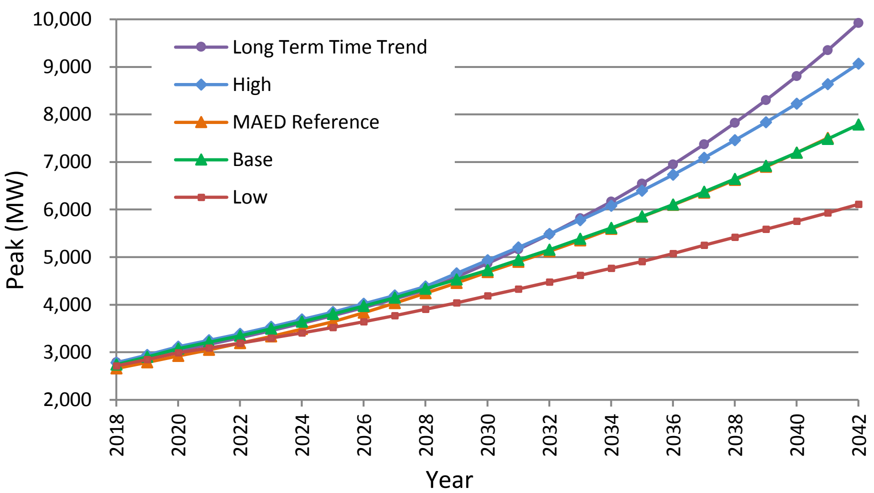


Figure 3.11–Peak Demand Forecast of Low, High, Long Term Time Trend and MAED with Base

3.7 Comparison with Past Forecasts

Demand forecast is reviewed once in two years with the revision of Long Term Generation Expansion Plan. This enables to capture the latest changes in the electricity demand as well as associated socio economic variables. Table 3.7 shows the comparison of past demand forecasts used in the previous expansion plans and their percentage variation against the actual demand. Electricity demand forecast is determined based on information considering:

- National economic development
- National population growth
- Increase in Electricity tariff consumer account
- Increase of per capita income etc.

The under achievement or over achievement of above facts will contribute to negative or positive deviation in actual demand from the forecast.

Table 3.7 – Comparison of Past Demand Forecast with Actuals (in GWh)

Year	2008 Demand Forecast	2009 Demand Forecast	2010 Demand Forecast	2011 Demand Forecast	2012 Demand Forecast	2014 Demand Forecast	Actual Demand
2009	8923 (+5.7%)	8568 (+1.5%)					8441
2010	9523 (+2.8%)	9195 (-0.8%)	9190 (-0.8%)				9268
2011	10165 (+1.4%)	9859 (-1.7%)	10036 (+0.1%)	10409 (+3.8%)			10026
2012	10849 (+3.6%)	10419 (-0.5%)	10698 (+2.1%)	11289 (+7.8%)	10675 (+1.9%)		10475
2013	11579 (+9.0%)	10967 (+3.2%)	11402 (+7.3%)	12249 (+15.3%)	11104 (+4.5%)		10624
2014	12359 (+11.7%)	11556 (+4.5%)	12149 (+9.8%)	13258 (+19.8%)	12072 (+9.1%)		11063
2015	13191 (+11.9%)	12171 (+3.3%)	12941 (+9.8%)	14240 (+20.8%)	12834 (+8.9%)	11516 (-2.3%)	11786
2016	14079 (+10.1%)	12816 (+0.2%)	13773 (+7.7%)	13773 (+7.7%)	13618 (+6.5%)	12015 (-6.0%)	12785

Note: Within bracket figures indicate the percentage deviation of demand forecast with reference to actual demand

3.8 Electricity Demand Reduction and Demand Side Management

Energy Efficiency Improvement and Conservation (EEI&C) efforts are identified as one of the nine elements in National Energy Policy, 2008. These efforts will reduce the overall cost of energy to the consumer while saving valuable resources of the country and reducing the burden on the environment. Therefore, demand reduction and demand side management will be an important thrust in the future. Efficient use of energy will be promoted in all sectors and across the energy value chain, engaging both the suppliers and users, even extending the services to newer markets such as transport and agriculture.

Sri Lanka Sustainable Energy Authority (SEA) has been entrusted the task of implementing the EEI&C programme, named Operation Demand Side Management (ODSM). This programme will be carried out by a Presidential Task Force on Energy Demand Side Management (PTF on EDSM) and guided by a National Steering Committee (NSC) and implemented by a Programme Management Unit (PMU) within the SEA.

The main objectives of the ODSM programme will be to implement the strategies on:

- Energy systems will be efficiently managed and operated while ensuring efficient utilisation and conservation of energy. Efficient utilisation of energy by all concerned, from utilities (supply-side management) to final customers (demand-side management) will be pursued.
- A national energy efficiency improvement and conservation programme will be launched engaging all stakeholders in residential, industrial and commercial sectors.
- Energy efficiency improvement and conservation will be promoted through minimum energy performance standardisation and labelling of appliances.
- Fiscal measures and monetary policies that encourage investments on improving energy efficiency will be introduced.
- Private sector participation in providing expert services on energy efficiency will be promoted and facilitated.
- Efficiency of power generation facilities will be enhanced.
- A strategic plan for street lighting will be formulated for the country to ensure proper management of street lighting, which will enhance the safety of motorists and pedestrians and also contribute to energy conservation with a better aesthetic sense.
- Automated demand response technologies will be introduced.
- Network losses incurred will be brought down to the optimum levels.
- Energy efficiency gains using newer technologies such as efficient pumping and drip irrigation in the agriculture sector will be explored and realised.
- Transport energy use will be reduced by undertaking avoid, shift and improve strategies with strong focus on high quality public transport.
- Economic activities will be developed in dense clusters to benefit from lower logistical costs and improved synergies in special zones identified as smart cities, served by smart grids.
- Sustainable built environment will be used in urban development with the objective of reducing energy demand.
- Energy efficiency will be a primary concern in new building designs which will be evaluated for their energy performance on a mandatory basis.

- Smart grid technologies, including smart buildings and smart metering will be promoted to alter customer demand to reduce the overall cost of energy.

Demand Side Management (DSM) is a set of activities which encourage consumers to modify their level and pattern of electricity usage. DSM refers not only to energy reduction but also for load shifting, peak shaving etc. which will help to change load profiles to constant flat load curves by allowing more electricity to be provided by less expansive base load generation.

Recently, SEA has done a study on the energy usage pattern, technologies and processes of the household, commercial and industrial sectors. In that study, SEA has identified key thrust areas which can have a deep impact on the energy saving as listed below:

- Efficient Lighting
- Efficient Fans
- Efficient Refrigerators
- Efficient Air Conditioning
- Efficient Pumps
- Efficient Motors
- Eliminating Incandescent Lamps
- Green Buildings
- Energy Management System & Building Management Systems
- Smart Homes

Implementation of the programme will be targeted to serve three market segments, i.e. industrial, commercial and residential/SME/Government segments. The first two market segments will served mainly by the utilities, in association with Energy Services Companies (ESCOs), Energy Auditors, Energy Managers and a panel of consultants. The large volume residential/SME/government segment will be served by SEA through an appliance control initiative and an on-site electricity generation facility using solar PV roof top systems. An approximate estimation of energy savings (kWh) and demand savings (MW) realizable indicates that the programme can save 1,104 GWh by 2020 and differ a 417 MW capacity in generation expansion. Similarly, the Smart Home initiative focusing on solar PV roof top systems can avoid 139.2GWh by 2020 and differ a 100MW capacity in day time grid generation.

The formidable barriers to implementation of the DSM programme should be further analysed with associated costs, to gain a better understanding of the benefits and costs of the programme. In addition, in the present mode of implementation, utilities do not have a proper control over the implementation of DSM as it will depend on consumer attitudes, best moulded through strict Government policies including fines on wasteful consumption of electricity. With the subsidies given to the electricity sector in different categories, ensuring deterministic demand reduction may not be realistic. Therefore, the DSM forecast having high speculative public response dependent demand reduction should not considered in the determination of the future expansion plan and medium term time trend forecast model will capture the recent year trends including the impact on present DSM activities. On the other hand, interventions with little or no room for human response factors, ranging from automated demand response technologies to large scale plant improvement investments can be taken into future planning exercises, as they are proven to provide very predictable demand reductions and energy savings.

CHAPTER 4
THERMAL POWER GENERATION OPTIONS FOR FUTURE EXPANSION

Renewable energy based power, fossil fuel based thermal power and nuclear-based thermal power is the primary energy options to be considered in meeting the future electricity demand. The predominant thermal energy sources are based on oil, natural gas, coal and nuclear fuel combinations. 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. Environmental mitigation measures are included in the cost figures given in this report. In addition to these thermal generation options, renewable energy generation options are also considered in order to serve the future electricity demand. Renewable energy generation options are discussed in detail in Chapter 5 and the India-Sri Lanka Electricity Grid Interconnection option is briefly described in latter part of this chapter.

4.1 Thermal Options

4.1.1 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 [7]: The feasibility study on Trincomalee coal-fired power station considered a site capacity of 900MW when fully developed (3x300MW in a phased development). The investment cost and other relevant parameters were reviewed during the 1995 Thermal Generation Options Study [8].

b) Thermal Generation Options, 1988 [9] and Thermal Generation Options, 1996 [8]

c) Special Assistance for Project Formulation (SAPROF) for Kelanitissa Combined Cycle Power Plant (1996) [10]

d) Review of Least Cost Generation Expansion Studies (1997) [11]

e) Coal Fired Thermal Development Project – West Coast (1998) [12]: Feasibility study and the preparation of contract documents (engineering services) for construction of the first 300MW 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 900MW 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 [13]

g) Sri Lanka Electric Power Technology Assessment. Draft Report (Final), (July 2002) [14]

h) Master Plan Study for the Development of Power Generation and Transmission System in Sri Lanka, 2006 [15].

i) Study for Energy Diversification Enhancement by Introducing LNG Operated Power generation Option in Sri Lanka [16].

j) Energy Diversification and Enhancement Project Phase IIA- Feasibility Study for Introducing LNG to Sri Lanka,2014 [17]

k) Pre-Feasibility Study for High Efficiency and Eco Friendly Coal Fired Thermal Power Plant in Sri Lanka, 2014. [18]

l) Project on Electricity Sector Master Plan Study in Democratic Socialist Republic of Sri Lanka 2016 (on going).

4.1.2 Thermal Power Candidates

Several power generation technologies were considered in the initial screening of generation options based on the studies listed above. Following are the thermal power generation technologies considered for the initial screening process:

(i) Diesel fired Gas Turbine Power Plants
(ii) Diesel fired Combined Cycle Power Plants
(iii) Natural Gas fired Combined Cycle Power Plant
(iv) High Efficient Coal Fired Thermal Power Plant
(v) Super Critical Coal Fired Thermal Power Plant
(vi) Nuclear Power Plant
(vii) Reciprocating Engines
(viii) Dendro Power Plants

Large number of generation technology alternatives with different capacities cannot be used in the detailed study at once due to practical and computational difficulties. The preliminary screening has to be done in order to reduce the number of alternatives by choosing the most economical optimum set of generation technologies. The Screening Curve Method was used to reduce the number of alternatives. After the initial screening nine alternative expansion options, which are described in Section 4.1.3, were considered for the detailed planning studies. The results of the screening curve analysis are given in Annex 7.1.

4.1.3 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. 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 2017values.

The thermal plant cost database, which was revised during the Project on Electricity Sector Master Plan Study in Democratic Socialist Republic of Sri Lanka 2016 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 4.1. Operating characteristics of these plants are shown in Table 4.2. The detailed characteristics of the candidate thermal plants are given in Annex 4.1.

Table 4.1 - Capital Cost Details of Thermal Expansion Candidates

Plant	***NET Capacity (MW)***	***Pure Unit Construction Cost -NET basis- (US$/kW)***		***Total Unit Cost (US$/ kW)***	***Const: Period (Yrs)***	***IDC at 10% (% of Pure capital cost)***	***Const. Cost Incl. of IDC (US$/kW) -NET basis- (US$/kW)***		***Total Unit Cost Incl. of IDC (Net) (US$/kW)***	***Economic life (Years)***
		Local	Foreign				Local	Foreign		
Gas Turbine-Auto Diesel	35	110.7	627.2	737.8	1.5	6.51	117.9	668.0	785.9	20
Gas Turbine-Auto Diesel	105	75.4	426.5	501.8	1.5	6.51	80.3	454.2	534.5	20
Combined Cycle -Auto Diesel	144	294	1175.9	1469.9	3	13.54	323.8	1335.1	1668.9	30
Combined Cycle -Auto Diesel	288	228.8	891.2	1114.0	3	13.54	253.0	1011.9	1264.9	30
Combined Cycle –LNG	144	231.5	925.9	1157.3	3	13.54	262.8	1051.2	1314.0	30
Combined Cycle –LNG-plant	287	138.5	976.5	1114.9	3	13.54	157.2	1108.7	1265.9	30
High Efficient Coal Plant	270	373.2	1413.0	1786.2	4	18.53	442.3	1674.9	2117.2	30
Super Critical Coal Plant	564	354.1	1567.2	1916.8	4	18.53	419.7	1852.3	2272.0	30
Nuclear Power Plant	552	931.2	3663.5	4594.7	5	23.78	1152.7	4534.6	5687.3	60
Reciprocating Engine	15	190.0	760.0	950.0	1.5	6.51	202.4	809.5	1011.9	20
Dendro Plant	5	131.7	1571.6	1703.3	1.5	6.51	140.3	1673.9	1814.2	30

All costs are in January 2017border prices. Exchange rate US$ 1 = LKR148.88, IDC = Interest during Construction

Table 4.2 – Characteristics of Candidate Thermal Plants

Plant	NET Capacity (MW)	Heat Rate (kCal/kWh)		Full Load Efficiency (Net,HHV) %	FOR %	Scheduled Maint. Days (Yr)	Fixed O&M Cost ($/kW Month)	Variable O&M Cost (USCts/ kWh)
		At Min. Load	Avg. Incr.					
Gas Turbine-Auto Diesel	35	3060	-	28.1	8	30	0.690	0.552
Gas Turbine-Auto Diesel	105	4105	2310	30.1	8	30	0.520	0.414
Combined Cycle Plant -Auto Diesel	144	2614	1462	46.7	8	30	0.54	0.467

Combined Cycle Plant -Auto Diesel	288	2457	1454	48.2	8	30	0.41	0.352
Combined Cycle Plant- LNG	144	2574	1462	48	8	30	0.25	0.497
Combined Cycle Plant- LNG	287	2462	1462	48	8	30	0.38	0.497
High Efficient Coal Plant	270	2810	1935	38.4	3	45	4.47	0.582
Super Critical Coal Plant	564	2248	1833	41.3	3	45	4.79	0.582
Nuclear Power Plant	552	2723	2340	32.0	0.5	40	8.42	1.752
Reciprocating Engine	15	2210	-	38.9	5	60	2.38	0.634
Dendro Plant	5	5694	-	15.1	2	74	2.43	4.460

All costs are in January 2017border prices. Exchange rate US$ 1 = LKR148.88, FOR = Forced Outage Rate
Heat values of petroleum fuel and coal based plants are in HHV

4. 2 Fuel

Petroleum based fuels, coal, natural gas being the primary sources of fuel, were considered for this long term power generation expansion plan. Additionally Nuclear fuel was considered under the present context considering technical constraints. Considering the volatility present in fuel prices, constant fuel prices are mainly used in long term planning studies. Therefore, the fixed prices in constant terms were used for this planning study. The price sensitivity of the plan was tested for fuel price escalation based on International Energy Agency forecast, WEO-2016.

(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 should 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, oil prices used were obtained from Ceylon Petroleum Corporation. The CIF prices and market prices are shown in Table 4.3 with the fuel characteristics and the fuel prices used in the analyses. Further, all the heat contents given are based on higher heating value (HHV).

Table 4.3 – Oil Prices and Characteristics for Analysis

Fuel Type	Heat Content (kCal/kg)	Specific Gravity	Market Prices of fuel types		CIF Price	
			($/bbl)	Rs/l	($/bbl)	Rs/l
Auto Diesel	10500	0.84	101.5	95	53.1	47.9
Fuel oil	10300	0.94	85.4	80	46.2	41.7
Residual oil	10300	0.94	85.4	80	45.3	40.9
Naphtha	10880	0.76	79.03	74	48.8	44

Source: Oil prices based on Ceylon Petroleum Corporation and Platts December 2016

(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 until 2011 due to several environmental and social issues. At present, 900MW first coal power plant is in operation at Puttalam which was built in two stages. It is important to note that past fuel prices show that the coal prices are not closely linked with the petroleum prices. However, recently coal prices too has shown an increased volatility. Two coal types were defined in the study based on the calorific value for different expansion alternatives as shown in Table 4.4.

Table 4.4 – Coal Prices and Characteristics for Analysis

Fuel Type	Heat Content (kCal/kg)	Market Price ($/MTon)	Remarks
Coal type1	6300	75.9	Lakvijaya Power Plant
Coal type2	5900	69.8	High Efficiency Coal Power Plants and Super Critical Coal Power Plants

Source: Coal prices from Lanka Coal Pvt Ltd.

(iii) Liquefied Natural Gas

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. 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 discoverable gas reserves have been identified.

Indian, Bangladesh and other Gas sources are located far from Sri Lanka, which makes cross border pipeline projects economically unattractive. Hence natural gas transport by means of shipping as LNG is a better option for Sri Lanka. Following four 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) [14]
2. Sri Lanka Natural Gas Options Study, USAID-SARI/Energy Program (Revised June 2003) [19]
3. Study for Energy Diversification Enhancement by Introducing LNG Operated Power generation Option in Sri Lanka – 2010 (JICA funded), phase I [16]
4. Energy diversification enhancement by introducing Liquefied Natural Gas operated power generation option in Sri Lanka. –Phase IIA [17]

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), LNG too could be competitive with coal and would be a viable fuel. However, the price assumptions made by JICA Study seems too optimistic in the global context.

The second phase of the above study identified that the Colombo North Port as the best site for development of a LNG terminal from several promising candidate sites including Hambantota and

Trincomalee. LNG requirement of the country was determined considering the conversion possibilities of the existing Combined Cycle power plants located in Colombo and other sectors such as Industrial and Transport sectors. The study has also identified, Kerawalapitiya as the most suitable location for the development of new LNG fired power plants by considering the technical, economic, social and environmental aspects. LNG facility suitable 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 of the FSRU (Floating Storage and Regasification Unit) which can be moored in the sea 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.

According to the "Study for Energy diversification enhancement by introducing LNG Operated Power Generation options in Sri Lanka", there are different LNG pricing mechanisms adopted in different regions of the world and the current LNG pricing system particularly in Asian market is linked with the Japanese average import LNG price (CIF) which is indexed against the Average Japanese imported Crude oil price, i.e. Japanese Crude Oil Cocktail (JCC). The above study suggests that the linkage variation between 11% to 17% with Japanese Crude Cocktail (JCC) reflection is the appropriate LNG FOB price for Sri Lanka. Actual price shall vary based on long term contract agreements and minimum order quantity. Platts Japanese Korean Marker (JKM) is another benchmark price for the Asian region and has been comparable to the JCC linked prices in the recent past. It is expected to incorporate Platts JKM based pricing mechanism into future planning work as it is not an oil price linked gas price assessment.

In order to identify a possible rate for LNG supply price to Sri Lanka it is useful to analyze the Indian scenario. The revised sale purchase agreement between Qatar and Indian Companies of 7.5mtpa LNG, consist of FOB Price is based on a 12.67% Brent price and a constant addition of US$ 0.6/MMBtu. Similarly the proposed sale purchase agreement to import 1.4 mtpa of LNG from Australia on a 20 year deal is proposed at a FOB Price rate of 14% slope to the JCC price. Accordingly, considering the average JCC prices, LNG CIF Price of 7.5 $/MMBtu is considered. In addition to the CIF price, the price of fuel delivered to the power plant is calculated which includes the handling charge consisting of regasification and transportation of fuel. A handling charge of 2.5$/MMBtu is considered in addition to the CIF price of LNG. Table 4.5 illustrates the associated cost for construction and operation of LNG infrastructure on 2014 base prices. Thus for the long term generation expansion planning study LNG price of 10$/MMBtu is utilized.

Table 4.5 – Associated Cost for LNG Development

Land Based Terminal	Cost
1 Mtpa Terminal Capital Cost (MUS$)	488
2 Mtpa Terminal Upgrade Cost(MUS$)	206
Fixed O & M Cost(MUS$/ year)	2.1
Variable O & M Cost(MUS$/Mtpayear)	1.8
Floating Storage Regasification Unit	
1 Mtpa Terminal Capital Cost (MUS$)	170
Annual Cost(MUS$/ year)	50

Source: Energy Diversification Enhancement Project Phase IIA Feasibility Study for Introducing LNG to Sri Lanka

(iv) Natural Gas

In September 2007, the Petroleum Resources Development Secretariat (PRDS) which was established under the Petroleum Resources Act, N0 26 of 2003 to ensure proper management of the petroleum resources industry in Sri Lanka, launched its first Licensing Round for exploration of oil and gas in the Mannar Basin off the north-west coast and in 2008 exploration activities initiated with the awarding of one exploration block (3000 sqkm) in Mannar Basin. Two wells namely 'Dorado and 'Barracuda' have been drilled, 'Dorado' indicates the availability of natural gas and it is estimated to have approximately 300 bcf of recoverable gas reserves. Gas production rate predicted is 70 mscfd. This amount is equivalent to approximately 0.5 mtpa. Based on the above most likely quantity of natural gas, it is estimated that it could cater 1000MW capacity for approximately 15 years with a plant factor of 30-50%.

The volumetric estimate of the technically complex "Barracuda" discovery exceeds 1.8 TCF. In addition to that the Mannar Basin analysis shows a remarkable natural gas potential that is yet to be explored. However exploitation of domestic natural gas adds many economic benefits to the country in terms of direct fiscal gains to state through agreed contractual fiscal terms (tax, royalty, bonus, profit share, other levies, etc.) and value added externalities such as new industry, employment creation and development of local knowledge base and supplier chain. Therefore the effective gas price to the state could be more attractive compared to other imported fuels and energy sources."

In early 2016 PRDS signed a joint Study agreement with an international oil company and have already selected a seismic contractor to explore two new blocks off the east coast. PRDS has already announced the international marketing campaign to select a suitable operator to appraise and develop the two previous gas discoveries and prospects in the offshore Block in Mannar Basin. It is expected to drill more test wells during 2018 to 2019 depending on the success of the prospects analysis of the exploration program. In support of commercialization of these identified reserves, PRDS has already taken the initiative to recruit a NG consultant and is in the process of preparing a NG policy for Sri Lanka.

(v) Nuclear

Alternative fuel options such as Nuclear Power have to be explored by avoiding excessive dependence of power sector in Sri Lanka on the imported fossil fuel. Nuclear plants are inherently large in capacity compared to other technologies for power generation. From technical point of view, the capacity of the present system is considerably small to accommodate a Nuclear power plant of typical size. 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.

Ministry of Power & Renewable Energy(MOPRE) requested further assistance from IAEA for "Establishing a Roadmap for the Nuclear Power Programme in Sri Lanka" with the objective of providing a strong technological, financial, environmental and social understanding for policy makers to take firm decision on the Nuclear Power Development in Sri Lanka. MOPRE acts as the Nuclear Energy Programme Implementing Organization (NEPIO) and is initiating the Phase 1 of the IAEA milestones approach to prepare the comprehensive report addressing the 19 milestones by the end of 2020. Further International Atomic Energy Agency (IAEA) assistance is expected on nine major areas to prepare a comprehensive report covering the 19 milestones for Nuclear Power Development. The nine major areas are as follows.

- Legal and regulatory
- Communications
- Commercial and Policy
- Electricity market and generation mix
- Nuclear Power Technology
- Siting of NPPs/Nuclear facilities
- Economics and finance
- Localization assessment
- Human Resource & Security

4.3. Screening of Generation Options

A preliminary screen of generation options is carried out in order to identify most appropriate candidate options. It is computationally difficult process to handle large number of generation options in a detailed analysis. The screening curve analysis which is based on specific Generation cost is employed in the initial screening and the method is described in the section 6.3 in detail.

The thermal plant cost database, which was revised during the Project on Electricity Sector Master Plan Study in Democratic Socialist Republic of Sri Lanka 2016 was extensively used during the current planning study However, adjustments have been made to the cost base to reflect January 2017 values. Whenever feasibility study results are available for any prospective project, such results were used in preference to the above studies.

4.3.1 Thermal Plant Specific Cost Comparison

The specific costs of the selected candidate plants for different plant factors are tabulated in the Table 4.6. These specific costs are derived in the screening curve methodology which considers the capital Investments cost, Operation and Maintenance cost, Fuel cost and economic life time of a given generation alternative. (Market prices of oil is used for derivation while LNG terminal cost and Coal jetty costs are excluded) It reveals how different technologies perform at different plant factors. Accordingly, Peak Load Power plants are cost effective at low plant factor operation whereas base load plants such as Coal and Nuclear are attractive options 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 4.6 - 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
35MW Gas Turbine	33.55 (49.94)	28.12 (41.87)	26.31 (39.18)	25.41 (37.83)	24.87 (37.02)	24.51 (36.49)	24.25 (36.10)	24.06 (35.81)
105MW Gas Turbine	28.60 (42.58)	24.88 (37.04)	23.64 (35.19)	23.02 (34.27)	22.64 (33.71)	22.40 (33.34)	22.22 (33.08)	22.09 (32.88)
150MW Combined Cycle Plant Auto Diesel	34.25 (50.99)	24.02 (35.77)	20.62 (30.69)	18.91 (28.16)	17.89 (26.63)	17.21 (25.62)	16.72 (24.89)	16.36 (24.35)
300MW Combined Cycle Plant Auto Diesel	27.33 (40.69)	20.30 (30.22)	17.96 (26.73)	16.79 (24.99)	16.08 (23.94)	15.61 (23.25)	15.28 (22.75)	15.03 (22.37)
150MW Combined Cycle Plant Natural Gas	21.96 (32.69)	14.78 (22.00)	12.39 (18.44)	11.19 (16.66)	10.47 (15.59)	9.99 (14.88)	9.65 (14.37)	9.39 (13.99)
300MW Combined Cycle Plant Natural Gas	21.64 (35.21)	14.62 (21.77)	12.29 (18.29)	11.12 (16.55)	10.42 (15.51)	9.95 (14.81)	9.62 (14.32)	9.37 (13.94)
300MW High Efficient Coal Plant	30.99 (46.13)	17.11 (25.47)	12.48 (18.59)	10.17 (15.14)	8.78 (13.08)	7.86 (11.70)	7.20 (10.72)	6.70 (9.98)
600MW Super Critical Coal Plant	32.82 (48.83)	17.93 (26.68)	12.97 (19.30)	10.49 (15.61)	9.00 (13.39)	8.01 (11.91)	7.30 (10.86)	6.77 (10.07)
600MW Nuclear Plant	69.08 (102.84)	37.00 (55.08)	26.31 (39.16)	20.96 (31.20)	17.75 (26.43)	15.61 (23.24)	14.09 (20.97)	12.94 (19.26)
15MW Reciprocating Engines	28.89 (43.02)	20.89 (31.11)	18.23 (27.14)	16.89 (25.15)	16.09 (23.96)	15.56 (23.17)	15.18 (22.60)	14.89 (22.17)
5MW Dendro Plant	36.36 (54.13)	24.38 (36.30)	20.39 (30.35)	18.39 (27.38)	17.19 (25.60)	16.40 (24.41)	15.83 (23.56)	15.40 (22.92)

Note: 1 US$ = LKR 148.88

4.4 Current Status of Non-Committed Thermal Projects

(a) **Trincomalee Coal Power Project**

Government of Sri Lanka (GOSL) and Government of India (GOI) entered into a Memorandum of Agreement (MOA) in 2006 to develop a coal power plant in Trincomalee as a joint venture between Ceylon Electricity Board and National Thermal Power Corporation Ltd. of India. Trincomalee Power Company Limited (TPCL) was established as the joint venture company for the implementation of the Trincomalee Power Project with the total capacity of 500MW. Several alternative sites were explored in 2008 under a Strategic Environmental Assessment for setting up the proposed power project in Trincomalee region and based on various techno economical and environmental considerations a site near Sampoor village was identified for the Feasibility Study.

Agreements for Power purchase, Implementation, Land Lease, Coal Supply and agreements with Board of Investment were signed and the feasibility study of the project was completed. The Environmental clearance was received subjected to further studies.

The Project had acquired around 500 acres for the implementation and consists of the main power block, coal handling plant, coal storage yard, ash disposal system, sea water cooling system, other building facilities and a green belt.

However, the project was not granted the approval by PUCSL in the Long Term Generation Expansion Plan 2015-2034 [20], as per the letter sent by the Secretary to the MOPRE for the undertaking given to the Supreme Court Case No SCFR 179/2016.

(b) **New Coal fired Power Plant – Foul Point, Trincomalee**

Ceylon Electricity Board completed the Pre-Feasibility Study for High Efficiency and Eco Friendly Coal Fired Thermal Power Plant in Sri Lanka with the financial assistance of New Energy and Industrial Technology Development Organization (NEDO) of Japan and the study was carried out by Electric Power Development Co., Ltd. (J-POWER) in 2013 and 2014. Under the above study, candidate sites were studied from South-West to South Coast Area and in Trincomalee Bay area considering, technical, environmental and social conditions and finally three sites at southern coast, site in Hambantota port area and a site at Sampur area in Trincomalee were selected as the most suitable sites for future coal power development.

In 2014, the Feasibility Study for High Efficient and Eco Friendly Coal Fired Thermal Power Plant in Sri Lanka commenced under the same program and the study was conducted for the site in Sampur area in Trincomalee. Basic thermal plant design has been prepared for 1200MW (either 300MW High efficient advanced subcritical power plants or 600MW super critical power plants) development considering technical, geological and environmental considerations. High Efficient and Eco Friendly Coal fired thermal power plant equipped with several emission control technologies to reduce emission levels significantly was studied. The Environmental Impact Assessment of the proposed project was temporarily suspended due to the non-availability of the identified land for the power plant development. However an alternate land at Foul Point area has been identified and process of acquisition is initiated. Necessary feasibility studies for the alternate land are to recommence once the land acquisition is finalized..

(c) **Coal Power Plants in the Southern Coast**

Southern Coal Power Project: CEB has identified locations near Karagan Lewaya, Mirijjawila, Mirissaand, Mawellaas prospective sites in Southern coast and Athuruwella in the Western Coast for future Coal fired power plants. This procurement process was not continued. Recent Pre-Feasibility Study for High Efficient and Eco Friendly Coal Fired Thermal Power Plant in Sri Lanka selected Hambantota port and Mawalla locations as prospective sites in southern coast for coal power development.

Mawella Coal Power Development Project: The Mawella site was studied under a pre-feasibility level as a candidate site for coal power development together with the other thermal options in 1988. The study proposed 600MW coal power plants at the site. Further the above mentioned recent Pre-Feasibility Study for High Efficient and Eco Friendly Coal Fired Thermal Power Plant in Sri Lanka has also identified Mawella Site as a suitable candidate site for future coal power development.

4.5 India-Sri Lanka Electricity Grid Interconnection

Governments of India and Sri Lanka signed a Memorandum of Understanding (MOU) in 2010 to conduct a feasibility study for the interconnection of the electricity grids of the two countries. This feasibility study was carried by CEB and Power Grid Corporation Indian Limited (POWERGRID) jointly with the main objective to provide the necessary recommendations for implementation of 1000MW HVDC interconnection project.

In 2002, NEXANT with the assistance of USAID carried out the Pre-feasibility for Electricity Grid Interconnection. In 2006, POWERGRID, India reviewed and updated the study with USAID assistance.

Various Line route options and connection schemes were analyzed during the pre-feasibility studies. Consequently the route option was selected for the feasibility study consist of 130km 400kV HVDC overhead line segment from Madurai to Indian sea coast , 120km of 400kV Under-Sea cable from Indian sea coast to Sri Lankan Sea coast, 110km Overhead line segment of 400kV from Sri Lankan sea coast to Anuradhapura and two converter stations at Madurai and Anuradhapura. Both HVDC technologies; Conventional Line Commuted Conversion and Voltage Source Conversion have been considered in the feasibility study.

The Broad Scope of Work is identified as follows:

1000MW HVDC bipole line from India (Madurai) to Sri Lanka (New Anuradhapura)	: 360km
Indian Territory: Overhead Line: Madurai to Panaikulam	: 130km
Sea Route: Submarine Cable: Panaikulam (India) to Thirukketiswaram (SL)	: 120km
Sri Lankan Territory: Overhead Line: Thirukketiswaram to New Anuradhapura	: 110km

The interconnection has been envisaged to be implemented with 2x500MW VSC based HVDC terminal in two stages.

Stage-I : 1 x 500 MW Monopole
Stage- II : 2 x 500 MW Bipole

Possibility of Reduction of Cost:

Reduction in length of Submarine Cable: Termination of Cable at Talaimannar in Sri Lankan Territory in place of Thirukketiswaram. This would reduce the length of the submarine cable by 30km.Conventional HVDC (LCC) instead of VSC based HVDC

Possibility of further reduction of cost would be explored during implementation stage. The feasibility study has considered the technical, economical, legal, regulatory and commercial aspects in trading electricity between India and Sri Lanka. The feasibility study is yet to be finalized.

CHAPTER 5
RENEWABLE GENERATION OPTIONS FOR FUTURE EXPANSION

5.1 Introduction

Sri Lanka is blessed with several forms of renewable energy resources owing to its geo-climatic conditions. As a developing nation, country has been reaping the benefits from indigenous renewable energy sources for decades that supported the sustainable economic growth. Country's electricity energy needs were predominantly met by renewable energy sources over decades and the development of major hydro power resources has reached its full potential at present. That has enabled the country to maintain green credential with low carbon per capita emission level in electricity generation throughout the past years.. However, the rising economic growth and the energy demand necessitate the development of power generation sources. In a context where global consensus is in place to combat climate change, Sri Lanka is ambitious and progressing towards low carbon pathways through renewable energy development. Increasing the contribution of indigenous renewable energy sources is envisaged in the electricity sector and it will reduce the greenhouse gas emission as well as enhance the energy security aspects.

Renewable energy sources encompass a broad range of continuously replenishing natural energy resources and technologies. A renewable energy system converts the energy in sunlight, wind, falling water, sea-waves, geothermal heat or biomass into heat or electricity without exhausting the source. The large or regulated hydro power plants which are major renewable energy sources have been the major contributor in the past. However, other technologies such as small hydro, wind, solar biomass etc. are the leading forms of renewable technologies globally and it is expected to be a dominant contributor in the future.

Sri Lanka has harnessed major renewable resources (large hydro) to almost its maximum economical potential. Secondly, as indigenous resources, Other Renewable Energy potentials have become alternate source of energy for the future due to the low impact on environment compared to other fossil fuel based sources of energy. Sri Lanka has a history of enabling the development of distributed renewable energy resources in the electricity sector and continues to scale up the renewable energy contribution as the electricity demand grows. Developing and harnessing the energy from following renewable energy forms are underway at present.

- Hydro power
- Wind Power
- Solar Power
- Biomass Power
- Power from Municipal Solid Waste

Hydro power and biomass power generation are dispatchable and not intermittent in performance. On the other hand Wind and Solar Photovoltaic sources are highly intermittent and seasonal in nature. These physical characteristics of the resource make the challenges in grid integration and different power systems has different integration capacities based on resource and system characteristics and economic performance. Prior to the preparation of Long Term Generation Expansion Plan, a comprehensive Renewable Energy Integration Study is carried out in order to optimize the contribution of renewable energy while giving due consideration to technical, operational and economic performance.

Government of Sri Lanka established the Sustainable Energy Authority (SEA) on 1st October 2007, enacting the Sri Lanka Sustainable Energy Authority Act No. 35 of 2007. SEA is expected to develop indigenous renewable energy resources and drive the country 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. Also SEA will promote energy security, energy conservation 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 jointly play a complementary role to each other in enhancing the contribution of other renewable energy resources. CEB and SEA facilitated the private sector for other renewable energy development and recently CEB also has undertaken the development of large scale renewable energy projects. CEB is in the process of developing an initial 100MW of wind park in Mannar island.

5.2 Major Renewable Energy Development

Sri Lanka was a Hydro Power dependent nation till the late 90s in which majority of the power requirement was met from hydro power plants. The hydro power potential in the country has been vastly exploited and only a limited amount of generation projects remain in the pipeline. Several prospective candidate hydro projects have been identified in the Master Plan Study [21], 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 870MW. A part of this hydro potential has been already exploited under the Upper Kotmale Hydro Power Project, which is the latest addition to large scale hydro power projects in Sri Lanka.

5.2.1 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 [22]. 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 [23 and 24] 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 [25] 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) The Pre-Feasibility study on Gin 074 Hydro Power Project in July 2008 proposes four options for the energy development using Gin Ganga basin. Considering above proposed four options in the study, Generation Development Studies Section of CEB is investigating the possibility of harnessing energy from the remaining water of Gin Ganga after the diversion of Gin- Nilwala Diversion Project.

(d) A feasibility study for Moragolla hydro power project was carried out in 2010/11 with Kuwait Fund for Arab Economic Development (KFAED). In 2013, Nippon Koei Co Ltd carried out the detail designs and preparation of tender document with the assistance of Asian Development Bank.

(e) In October 2013 Sri Lanka Energies (Pvt) Ltd studied two options for Seethawaka Hydro Power Project and CEB had decided to develop the option with a reservoir for maximum use of the river for power generation.

(f) "Development Planning on Optimal Power Generation for Peak Power Demand in Sri Lanka" carried out by JICA funds [26] in December 2014 explore the future options to meet the peak power demand. This study lists the options to meet the peak power requirement and their environmental, social and financial impacts are analyzed. Pumped storage power plant option has been selected as the most suitable option and several sites have been proposed in priority order considering social, environmental and financial impacts.

5.2.2 Committed Hydro Power Projects

Some major hydro projects identified in the Master Plan Study as Broadlands (35MW) and Moragolla (31MW) which are under development by CEB and is considered as committed power plants in this study. Ministry of Irrigation and Water Management is developing the Uma Oya Multipurpose project which shall include the construction of a 120MW Hydro Power Plant within its scope.

i. **Broadlands Hydro Power Project**

The Broadlands Hydropower Project is a run-of-river type project planned to build in the Kelani River. It is expected to generate 126GWh of electrical energy annually. The Broadlands Hydropower Project is the first large scale hydropower plant which has obtained Carbon Development Mechanism registration in Sri Lanka in December 2012. Concurrence has been established to maintain a firm water release to safeguard White Water Rafting sport in Kithulgala area and as a result there will be a reduction in the annual energy generation. China National Electric Equipment Corporation (CNEEC) was selected as the main Contractor of the project. The total project cost is USD 82 million. The 85% of funding is provided by Industrial & Commercial Bank of China (ICBC) and the balance was obtained from Hatton National Bank. The construction work is in Progress in parallel at Main Dam Site, Main Tunnel, Diversion Tunnel and Power House Site and the project is scheduled to be completed in June 2019.

ii. Moragolla Hydro Power Project

The 30MW Moragolla Hydropower Project located downstream of the Kotmale power station and approximately 3.5 km downstream from the confluence of the Mahaweli Ganga with the Kotmale Oya. Total storage capacity of the reservoir is 4.66 MCM and the annual mean energy expectated is 97.6 GWh. The Moragolla Hydropower Project was first identified in "Report on a Survey of Resources of the Mahaweli Ganga Basin, Ceylon, Hunting Survey Corporation, 1962." prepared in cooperation with the Survey General of Ceylon. The location was highlighted as one of potential hydropower sites in "Master Plan for the Electricity Supply of Sri Lanka, German Agency of Technical Cooperation, 1988". Central Engineering Consultancy Bureau of Sri Lanka (CECB) in association with Al-Habshi Consultants with the finance of the Kuwait Fund for Arab Economic Development in 2009. Nippon Koei Co., Ltd. in joint venture with Nippon Koei India Pvt. Ltd. to conducted a review of the Feasibility Study and detailed design work in 2012. At present the project is under construction and expected to be operational in 2022.

iii. Uma Oya Multipurpose Project

Uma Oya Hydro Power project is one of the largest remaining sites of hydro potential. The project is a Multipurpose Development project and it will transfer water from Uma Oya to Kirindi Oya in order to develop hydropower and to irrigate the dry and less developed south-eastern region of the central highlands. The project is implemented by the Ministry of Mahaweli Development & Environment in coordination with the Ministry of Power & Energy and Ceylon Electricity Board. The total capacity is 122MW and expected annual energy is 290 GWh. The financial assistance for the project is provided by the Government of Iran and currently the project is under construction and expected to be completed by December 2019.

5.2.3 Candidate Hydro Power Projects

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 15MW 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, many identified projects within these criteria have been developed by CEB, as well as by the private sector sometimes with reduced energy/capacity benefits.

Further, private sector is allowed to develop hydro power projects below 10MW under a Standard Power Purchase Agreement. Following projects are identified as the candidate large scale hydro power projects.

i. Seethawaka Hydro Power Project

Seethawaka River project was identified in the Master Plan produced by CEB in 1989 as Sita014. The project was initially identified as a 30MW capacity producing 123 GWh per year. However, due to Social and Environmental considerations, the project is scaled down to 20MW hydro power plant with an 8 MCM pond, expected to annually generate around 48 GWh. CEB has conducted the initial feasibility studies together with the procurement of consultancy services for Environmental Impact Assessment (EIA) of the project. A separate Project Management unit in CEB is now conducting the detailed feasibility study prior to its implementation.

ii. Moragahakanda Hydro Development Project

Moragahakanda Kaluganga Development Project is one of the major multi-purpose development projects of the country and it is implemented by the Ministry of Mahaweli Development and Environment with the Mahaweli Authority of Sri Lanka. Moragahakanda reservoir and the hydro power plant are located on the Aban Ganga downstream of the existing Bowathanna hydro power plant. This multipurpose project is mainly aimed on providing irrigation and other water requirements and the project is capable of generating 25MW of hydro power and expected to generate 114.5GWh of annually on average.

iii. Other Hydro Power Projects

Irrigation projects such as Gin Gaga (20MW) and Thalpitigala (15MW) are to be developed in future by Ministry of Irrigation and Water Resource Management. The preliminary feasibility studies and EIA studies of the Thalpitigala Hydro Power Project have been finalized and approved. Estimated annual energy contribution of Thalpitigala hydro project is 52.4GWh and that of the Gin Ganga project is 66GWh.

5.2.4 Details of the Candidate hydro Power Projects

The basic technical data of the selected projects are summarized in Table 5.1 (see Annex 5.1 for further details). A summary of the capital cost is given in Table 5.2.

Table 5.1 - Characteristics of Candidate Hydro Plants

Project	River Basin	Ins. Capacity (MW)	Annu. Energy (GWh)	Storage (MCM)
Seethawaka	Kelani	20	48(@ 29% PF)	8.0
Thalpitigala	Uma Oya	15	51.3(@39% PF)	15.56
Gin Gaga	Gin	20	66 (@37% PF)	0.3

Specific cost of the hydro plants was calculated using the expected energy and the estimated project and maintenance costs which are shown in Table 5.3. These calculations are based on 10% discount rate, which is the rate used for planning studies.

Table 5.2 - 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		
Seethawaka[1]	20	638.4	1449.5	2087.9	4	18.53	756.7	1718.1	2474.8	50
Thalpitigala[2]	15	2088	4872	6960	3.5	16	2422.0	5651.5	8073.6	50
Gin Gaga	20	4546.8	9356.2	13903	7	35.14	6144.5	12644	18788.6	50

Exchange rate US$ 1 = LKR 148.88, IDC = Interest during Construction

1. Estimated Project cost is by Generation Development studies unit, Ceylon Electricity Board

2. Detail cost breakdown is not feasible as hydro power is a secondary benefit and developed by Ministry of Irrigation and Water Resource Management. However for comparison 60% of the total project cost is assumed for Power generation

Table 5.3 - Specific Cost of Candidate Hydro Plants

Project/plant	Capacity (MW)	Specific cost (for maximum plant factor)	
		Uscts/kWh	Lkr/kWh
Seethawaka	20	8.60	12.79
Thalpitigala	15	20.39	30.34
Gin gaga	20	39.9	59.41

5.3 Hydro Power 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” [22].

5.3.1 Mahaweli Complex

The “Hydro Power Optimization Study of 2004” suggested possible expansions of Ukuwela, Victoria and Rantambe Power Stations due to high plant factors. Out of those it is difficult to expand Rantambe for peaking requirements because it has to comply with water release for irrigation demand as a priority.

(a) Victoria Power Station

(i) Victoria Expansion:

CEB has identified expansion of Victoria Hydro Power Plant as an option to meet the peak power demand. A feasibility study for expansion of Victoria Hydro Power station has been done in 2009 [27] and had considered three options for the expansion. They are of addition of another power house nearby existing power plant (Base option), addition of a surface type power house 2km downstream of the existing power house (Downstream Option) and using Victoria and Randenigala reservoirs as a pump storage power plant (pump storage option). From the feasibility study, it was concluded that the addition of the new power house closer to the existing power plant is an economically viable option as provisions have already been made for the expansion when the existing power plant was constructed. Under this expansion, two units of 114MW each will be added. This expansion could double the capacity of Victoria while the energy benefits are as follows.

Table 5.4 – Details of Victoria Expansion

	Annual Energy (GWh)	Peak Energy (GWh)	Off-Peak Energy (GWh)	95% Dependable Capacity
Spilled Discharge Deducted				
Existing Only	634	230	404	209
Existing + Expansion	635	467	168	379
Spilled Discharge not Deducted				
Existing Only	689	230	459	209
Existing + Expansion	716	469	247	385

Source: Feasibility Study for Expansion of Victoria Hydropower Station, June 2009

This expansion scheme has an advantage of not lowering the reservoir water level during construction period since the intake facilities for the expansion project were already constructed during the initial construction phase of the existing power plant. As of October 2008, this project requires approximately US$ 222 million for implementation. Further analysis of the project is required before incorporating into the Long Term Generation Expansion Plan.

(ii) Victoria Upgradation:

An alternate proposal has been proposed by the Generation Division of CEB to upgrade the existing capacity of Generation units installed in Victoria. The proposal elaborates on rehabilitation works on the turbine and generator while upgrading the capacity of a single unit from 70MW to 92.8 MW by increasing the turbine discharge to 52.8m^3/s. The total output from the Victoria Power Station is expected to be 273 MW. It shall enable usage of excess water in high inflow seasons and also enhance the operating flexibility of the Victoria power station for system frequency controlling requirements.

The Ministry of Mahaweli Development and Environment is engaged in the project "Mahaweli water security Investment program" and it is a largescale investment program for constructing water infrastructure to transfer water from Mahaweli River to North Central province. The project has proposed to transfer water from the Randenigala reservoir to Kaluganga reservoir. The operation of the scheme affects the reservoir operation of the Mahaweli complex. Therefore, the Victoria expansion and capacity upgradation project implementation and operation depend on the outcome of the ongoing study of the "Mahaweli water security Investment program".

(b) Upper Kotmale Diversion:

Diversion of Pundalu Oya and Pundal Falls tributary is proposed under this project. The Upper Kothmale diversion project will increase the annual energy generation of Upper Kothmale Hydro Power Plant by 39GWh. For the implementation of above project, Operation of Upper Kothmale Hydro Power Plant needs to be interrupted for 6 months resulting reduction of 150MW capacity and 200GWh on average over the six month period.

(c) Kotmale Project:

Provision for capacity expansion has been kept in the existing Kotmale Power Station. At present 3 x 67MW 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.

5.3.2 Samanala Complex

Samanalawewa hydro power project has a potential for additional peaking capacity. The existing Samanalawewa power station has two generators rated at 60MW each. In addition to these, studies have indicated that further two units of 60MW can be added for peaking operation. During construction stage of Samanalawewa, provisions such as a bifurcation with bulk head gate and a space for an addition of two 60MW units have been made to extend the capacity of the power plant to 240MW. The extension comprises of construction of Diyawini Oya reservoir.

The Stage II Feasibility Study report done by CECB in April 2002 recommends installation of one additional 60MW capacity without developing the Diyawini Oya dam. The major factor in consideration for selecting single unit expansion was the impact on financial revenue caused by decrease of total annual energy due to the head loss occurred by high velocity in existing low pressure tunnel. A summary of expansion details are shown in Table 5.5.

Table 5.5 – Expansion Details of Samanalawewa Power Station

	Unit	Existing	Existing + 1 Unit Expansion	Existing + 2 Units Expansion
Plant Capacity	MW	120	180	240
Peak Duration	Hrs	6	4	3
95% Dependable Capacity	MW	120	172	225
Primary Energy	GWh	262	259	254
Secondary Energy	GWh	89	55	0
Total Energy	GWh	351	314	254

Source: The Study of Hydropower Optimization in Sri Lanka, Feb 2004

5.3.3 Laxapana Complex

During the Phase E of the Master Plan for the Electricity Supply in Sri Lanka, 1990 [28], 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. Under the upgrading of Wimalasurendra and New Laxapana Power Stations, planned replacement of generator, turbine governor excitation & controls and transformer protection have been completed by the Generation Division. Capacity of the New Laxapana Power Station has been increased from 100MW to 115.2MW. Planned replacement of generator, turbine governor excitation & controls of the old Laxapana Project were completed increasing the plant efficiency and also the plant capacity has been increased from 50MW to 53.5MW.

(a) Polpitiya Project: Expansion of Polpitiya Power Station is currently being implemented and the plant capacity will be increased to 86MW from 75MW from 2018 onwards.

5.4 Pumped Storage Hydro Power for Peak power Generation

At present the daily electricity demand pattern composed of a notable peak component which typically occurs between 6.00pm and 10.00pm. Currently the peak demand is met by existing hydro and thermal power generation. In the future with the limited development of hydro potentials and the retirement of aged thermal power plants, new solutions for meeting the peak demand have to be explored. With the expected development of coal fired base load power plants and with the prominent peak and off-peak characteristics of the daily demand pattern, CEB has taken timely initiative to study the peak power generation options specially pump storage hydro power plant. Accordingly, CEB initiated the study on "Development Planning on Optimal Power Generation for Peak Power Demand in Sri Lanka" with the technical assistance from JICA.

During the study, all the possible peaking options were examined and following options were considered as feasible.

- Hydro Power Plant Capacity Extension
- Pump Storage Power Plant
- LNG Combined Cycle Power Plant
- Gas Turbine Power Plant

Mainly load following capability and power plant characteristics, environmental and social considerations and economic aspects of above options were evaluated and the study concluded that the Hydro Plant Capacity Extensions and Pump Storage Hydro Power Plants are the most suitable options for future development. The scope of the Study "Development Planning on Optimal Power Generation for Peak Power Demand in Sri Lanka" includes the identification of most promising candidate site for the future development of pump storage power plant. At the initial stage the study identified 11 potential sites for the development of 600MW Pump Storage Power Plant and all the sites were investigated and ranked in terms of Environmental, Topographical, Geological and Technical aspects. The preliminary screening process identified three promising sites for the detailed site investigations as shown in Figure 5.1. According to the ranking Halgran Oya, Maha Oya and Loggal Oya which were located in NuwaraEliya, Kegalle and Badulla districts were selected as the most suitable sites for future development.

After the detail site investigations carried out for the above three sites the study concluded that the Maha Oya site location as the most promising site for the development of the future Pumped Storage Power Plant. The study concludes that the optimum capacity of the proposed Pump Storage power plant should be 600MW considering the peaking requirement beyond 2025.The unit capacity of pump storage power plant was determined considering the System limitations in terms of frequency deviations and manufacturing limitations of high head turbines. The study considered 200MW unit size for the baseline case and 150MW. Unit size is also analyzed as an alternative. Unit size will be finalized during the detail design stage.

Pumped storage hydro power plant as a large scale storage medium is able to serve several secondary purposes other than providing the peaking power. Pumping operation of off-peak period enables the base load power plant to be operated at higher loading level with higher efficiency. Further it is proposed to employ the adjustable speed type technology since it enables the frequency regulation functions and stability improvement by fast reaction to system supply and demand fluctuations. A recent focused on the behaviour of the electricity demand anticipates that the day time peak will be prominent than the evening peak in the coming years. Under that context the technical, operational and economic aspects of introducing a pump storage power plant should be further reviewed.

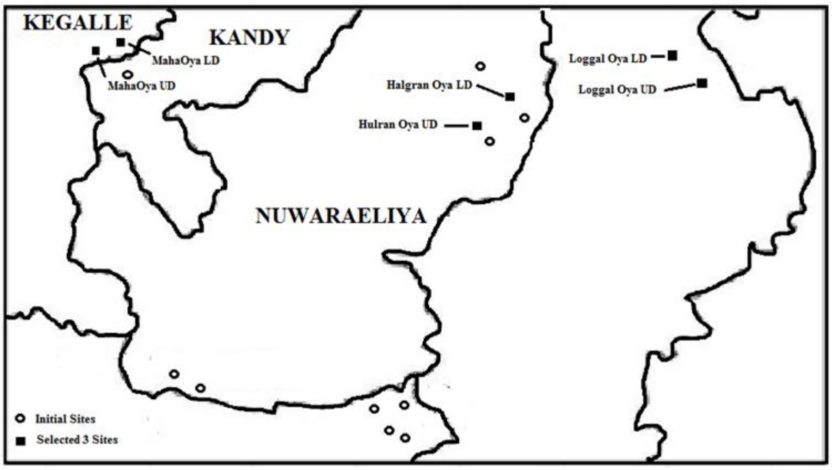


Figure 5.1: Three Selected Sites for PSPP after Preliminary Screening

The Relevant Cost details of Pump Storage Power Plants are as mentioned in table 5.6.

Table 5.6 – Pump Storage Power Plant Details

Plant	Capacity (MW)	Capital Cost Pure ($/kW)	Capital Cost With IDC ($/kW)	Constriction Period (years)	Economic Plant Life (Years)
Pumped Storage PP	600	1043.1	1291.2	5.0	50

5.5 Other Renewable Energy Development

Ceylon Electricity Board initiated the development of other renewable energy sources years ago and thereafter the development was continued largely by the private sector. At present Ceylon Electricity Board also has started developing large scale renewable energy projects for power generation. The renewable energy industry is continuously growing in the country with both local and foreign investment.

Share of Other Renewable Energy based generation at present is 11% of total energy generation in Sri Lanka and it is expected to increase its contribution in the future. At the end of 2016, approximately 516 MW of other renewable energy power plants have been connected to the national grid. Out of this, contribution from mini hydro is 342.1 MW while biomass-agricultural & industrial waste penetration is 24.1MW. Contribution to the system from solar power and wind power is 21.3 MW and 128.4 MW respectively.

5.5.1 Projected Future Development

Table 5.7 shows the system development and the growth in the renewable energy contribution during the last 13 years in the Sri Lankan system. Other renewable energy sources have been under the cost reflective technology specific tariff from 2012 onwards and the tariff is given is given in the Annex 5.2. Further the future projects will be developed under the competitive bidding process also and at present this is considered mainly wind and solar projects developments.

Table 5.7 – Energy and Demand Contribution from Other Renewable Sources

Year	Energy Generation (GWh)		Capacity (MW)	
	Other Renewable	System Total	Other Renewable	Total System Installed Capacity
2003	120	7612	39	2483
2004	206	8043	73	2499
2005	280	8769	88	2411
2006	346	9389	112	2434
2007	344	9814	119	2444
2008	433	9901	161	2645
2009	546	9882	181	2684
2010	724	10714	212	2818
2011	722	11528	227	3141
2012	730	11801	320	3312
2013	1178	11962	367	3355
2014	1215	12418	442	3932
2015	1466	13154	455	3850
2016	1160	14250	516	4018

Optimum capacity additions have been projected for above technologies based on the detailed study considering the system stability, system operational implications, resource quality, global technology costs, economic aspects and transmission infrastructure development. Additionally, the factors such as past experience in project development, availability of land and other infrastructure were considered when making the projection given below.

Projected future development of other renewable energy considered for the long term generation expansion plan for the period of 2018-2037 is given in the Table 5.8 below. Projected capacity additions have been assumed as committed and modelled accordingly. Furthermore the projections of ORE development for the low demand scenario and for the no future coal power development scenario is presented in Annex 5.3.

Table 5.8 – Projected Future Development of ORE (Assumed as Committed in Base Case Plan)

Year	Cumulative Mini hydro Capacity (MW)	Cumulative Wind Capacity (MW)	Cumulative Biomass Capacity (MW)	Cumulative Solar Capacity (MW)	Cumulative Total ORE Capacity (MW)	Annual Total ORE Generation (GWh)	Share of ORE from Total Generation %
2018	344	144	39	210	737	2103	13.0%
2019	359	194	44	305	902	2471	14.3%
2020	374	414	49	410	1246	3402	18.4%
2021	384	489	54	465	1392	3784	19.5%
2022	394	539	59	471	1463	4022	19.8%
2023	404	599	64	526	1592	4338	20.3%
2024	414	644	69	581	1708	4620	20.6%
2025	424	729	74	685	1912	5084	21.6%
2026	434	729	79	740	1982	5229	21.2%
2027	444	754	84	795	2076	5447	21.0%
2028	454	799	89	900	2242	5796	21.3%
2029	464	824	94	954	2336	6014	21.1%
2030	474	894	99	1009	2476	6365	21.2%
2031	484	929	104	1064	2580	6601	21.1%
2032	494	974	104	1119	2691	6844	20.9%
2033	504	1044	109	1173	2830	7193	21.1%
2034	514	1114	109	1229	2965	7509	21.1%
2035	524	1184	114	1283	3105	7860	21.2%
2036	534	1279	114	1338	3265	8252	21.4%
2037	544	1349	119	1442	3454	8670	21.5%

Note: Further additions of Mini-hydro and Biomass capacities could be considered project by project depending on the feasibility and implementation.

Contribution of major hydro resources is expected to increase first five years with the completion of ongoing hydro power projects and continue to remain at the same level afterwards. Total other renewable capacity is 737MW at the beginning of the planning period in 2018 and it doubles in the initial 5 year period. According to the other renewable energy projection, Wind and Solar growth is more significant, whereas a moderate growth is expected in Mini-hydro and Biomass technologies. Beyond 2025, the major share of the other renewable capacity is projected to be solar power followed by wind power. Other renewable energy technologies will become dominant as it will exceed the major hydro capacity by 2023. Subsequently, the total other renewable capacity increases to nearly 3454MW by the end of the planning horizon which brings the total renewable energy capacity to 5030MW. Figure 5.2 illustrates the future capacity development of renewable energy technologies.

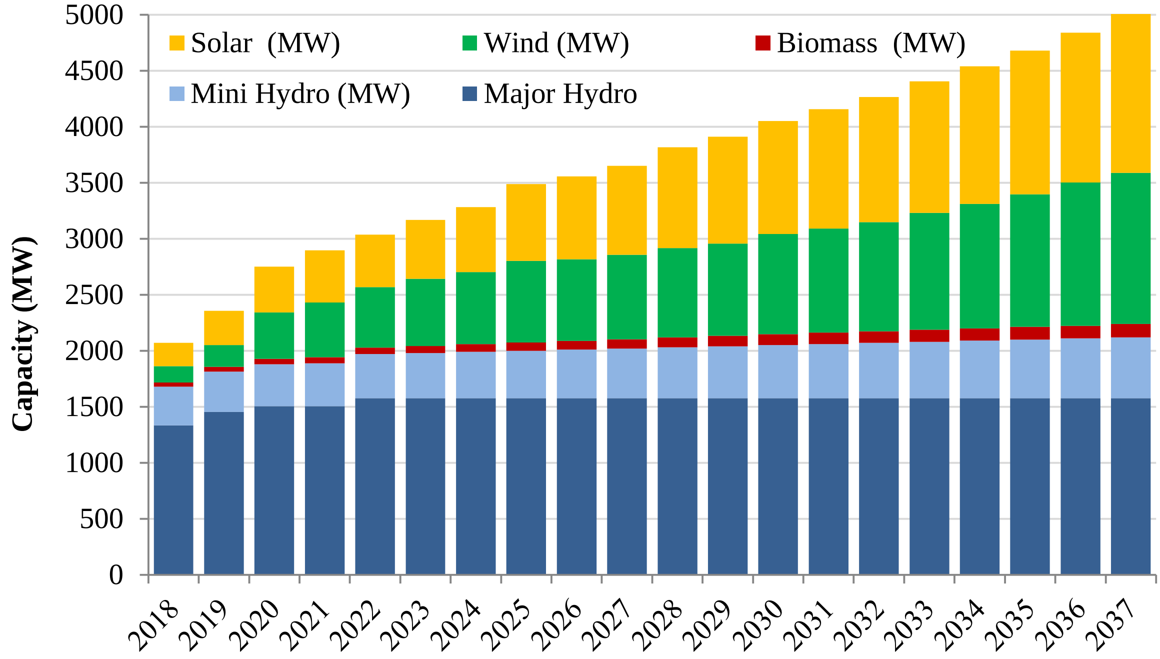


Figure 5.2: Renewable Energy Capacity Development

In terms of energy, Mini hydro is the largest contributor in the other renewable energy sector at present. It will be surpassed by wind in 2020 with the expected development and continue to be the largest other renewable energy contributor for the entire planning period. Even though the solar has an equal capacity share as the wind, its energy share will take the third place owing to the lower plant factor but its energy contribution will grow steadily over the planning period with the expected development. Total renewable energy share at present is around 40% will continue to remain above 40% until 2025 and will decline marginally to 35% with the sluggish growth of major hydro as the system demand increases. However, renewable energy share continues to be significant over the next 20 year period due to scaling up of other renewable energy technologies. ORE contribution increases with the system growth and continue to stay above 20% energy share beyond 2020. ORE contribution will exceed the major hydro energy production beyond 2024 and will dominate the renewable energy sector. Figure 5.3 below illustrates the energy contribution of renewable energy sources and the percentage energy share variation over the next 20 years period. Plant factors considered for each resource is taken from the resource assessment study and is given the table 5.9 below.

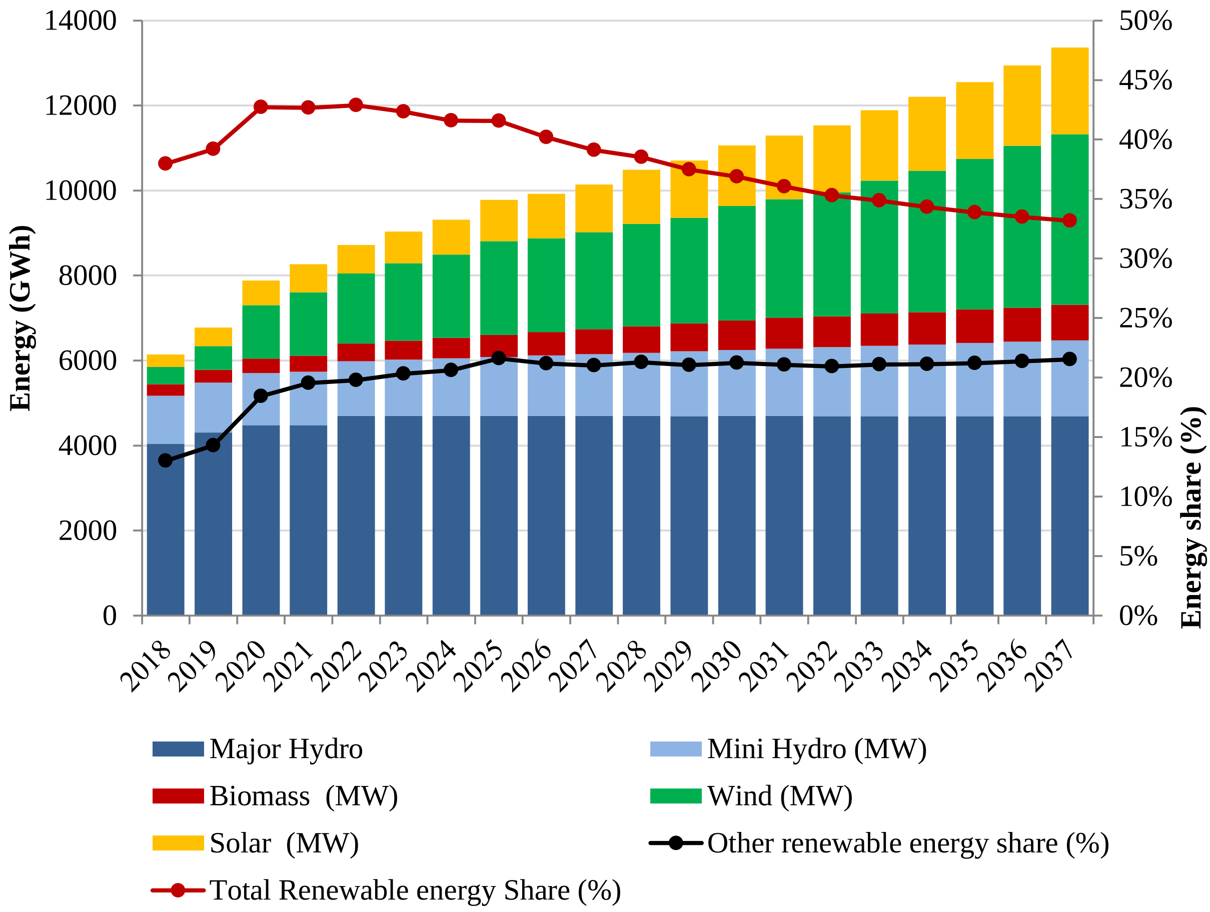


Figure 5.3: Energy Contribution of Renewable Energy Sources and Energy Share for Next 20 Years

Table 5.9: Plant Factors of Wind and Solar Regimes Considered for the Study

Resource	Plant factor (%)	Resource	Plant factor (%)
Mini Hydro	37.4	Wind - Eastern	27.3
Biomass-	80.0	Wind - Hill Country	19.1
Wind - Mannar	36.7	Solar - Hambanthota	16.3
Wind - Nothern	34.1	Solar - Kilinochchi	15.9
Wind - Puttalam	32.1		

Characteristics of new renewable energy technologies are relatively different from conventional power generation technologies and this in turn possesses new challenges to power systems as the renewable energy share increases. Hydro and Biomass technologies are dispatchable in nature whereas Wind and Solar are more intermittent. Thus the Wind and Solar PV technologies are often designated as variable renewable energy sources. Power systems are able to accommodate certain level of variable renewable energy sources depending on the system characteristics. However, further integration of variable renewable energy sources requires system enhancements and various integration measures with associated costs. Therefore it is essential to study the system specific challenges and the effective integration measures in detail to determine the economically optimum integration of large amount of VRE.

5.5.2 Development Mannar Wind Farm Project

Mannar area in the Northern Province has been identified as an attractive resource for future wind power development of the country. Ceylon Electricity Board has taken the initiative to develop the first 100MW wind farm in the Mannar Island with the assistance of Asian Development Bank (ADB). The project is located in the southern coast of the Mannar island and the necessary wind park infrastructure will be developed. 100MW project will contribute with nearly 320 GWh of annual energy for the national electricity demand.

At present, the feasibility study, Initial environmental assessment and land procurement process have been completed and the final stage of the Environmental Impact assessment and the process of securing financing are expected to be completed in 2017. Project completion and commercial operation is planned from the year 2020.

5.5.3 Development of Rooftop Solar PV Installations

Decentralized solar power generation is a promising technology to cater the growing energy needs. Apart from the utility scale developments, small scale and roof top solar takes plays a significant role and considered effective since energy sources are located at the end user. With the reducing cost for solar Photovoltaics, small scale on site solar PV generation has gained much attention.

Several schemes are adopted worldwide to create an enabling environment for small scale and roof top PV penetration. The "Energy Banking Facility" for such micro-scale generating facilities, commonly known as the "Net Energy Metering Facility" for electricity consumers was introduced in Sri Lanka in 2010 by the Ministry of power and renewable energy, Ceylon Electricity Boards (CEB) and Lanka Electric Company (LECO). This scheme allows any electricity consumer to participate as a producer to generate electricity with a renewable energy source for own usage as well as to export any excess energy. The installed capacity of the generating facility shall not exceed the contract demand of the Producer. The consumer is not paid for the export of energy, but is given credit (in kWh) for consumption of same amount of energy for subsequent billing periods. No financial compensation is paid for the excess energy exported by the consumer. The electricity bill is prepared taking into account the difference between the import and the export of energy. At present, country has about 5500 such installations amounting to around 40MW of solar power.

In view of further enhancing the renewable energy portfolio in the electricity generation in Sri Lanka, the Government of Sri Lanka (GOSL) has launched accelerated solar development program in 2016 to promote roof top solar installations in the country. The objective of the above program is to reach an installed capacity of roof top solar to 200MW by 2020. In order to support the GOSL's renewable energy promotional drive, the Net Metering Concept was further enhanced by introducing another two schemes.

"Net Accounting" concept is the second scheme initiated. It is an extension to the existing new metering scheme where consumer is compensated for the exported energy with a two tier tariff for 20 year period. The generating capacity of the facility is limited to the contract demand of the consumer and this scheme is limited only to solar power generation. The third scheme is the "Net Plus" scheme where the consumer can install a solar PV generation unit and all the generated energy will be exported to the grid. The installed capacity is limited to the contract demand of the consumer and unlike previous two schemes there is no linkage between the consumption and electricity generation. Solar PV installations for above three schemes are restricted to roof top type installations and to be connected to the low voltage distribution network.

These three schemes change the role of the traditional electricity consumer to a consumer and producer. This initiative will gradually raise the solar PV contribution and the expected total contribution has been incorporated in the preparation of the renewable energy development plant as stipulated in Table 5.7.

5.5.4 Development of 60 x 1MW Solar PV Projects

In line with the second phase of the accelerated solar development program of the government, Ceylon Electricity Board has opened the opportunity for the development of 60 numbers of 1MW Solar PV projects at 20 selected Grid substations. International competitive bidding process for the 60MW development was initiated and the contract period will be 20 years under BOO basis. This initiative will further enhance the contribution of solar PV for the national energy mix and that has been incorporated in this long term generation expansion plan 2018-2037.

5.5.5 Renewable Energy Integration Study 2018 - 2028

The transition from a conventional generation technologies to a system with a higher share of variable renewable energy technologies creates new challenges. Assessment of technical, operational, economic aspects and exploring integration measures is the key for enabling the effective utilization of renewable energy sources while maintaining a quality and reliable supply of electricity. The latest study “Integration of Renewable Based Generation into Sri Lankan Grid 2017-2028” [29] was carried out by CEB in 2016 with the objective of investigating main challenges and to determine the optimum level of renewable energy based generation to the grid.

Non-dispatchable technologies such as Wind and Solar PV have notable differences in performance compared to dispatchable technologies such as Hydro power, Biomass. Intermittency of Wind and Solar PV power generation is significant for the power system and that increases the variations in the supply side. In order to accommodate these variations, the power system needs to be operationally flexible and stable. Therefore to determine the stability and operational constraints and to determine the required countermeasures, a detail system operation analysis and a power system stability analysis were carried out in the study.

The scope of the study covers the areas of renewable energy resource estimation, future renewable energy projection with optimized long term generation expansion planning, transmission infrastructure availability and development, system stability and operation, economics of integration. Regulatory reserve requirements and variable renewable energy curtailment requirement for various ORE integration possibilities and impact of pump storage hydro power on renewable energy integration have also been assessed. WASP (Wien Automatic System Planning), SDDP (Stochastic Dual Dynamic Programming), NCP (Short-term dispatch simulation), SAM (System Advisor Model) and PSSE (Power System Simulation for Engineering) software tools were used for long term to short term planning and simulation work of the study. The outline of the study methodology is given in the Annex 5.4.

5.6 Renewable Energy Resource Estimation

Resource estimation is an important initial step in the process of integration of Renewable Energy based Generation. Proper estimation of resource performance, seasonality and intermittencies is required for the modelling, simulation and optimization.

5.6.1 Estimating Major Hydro Capacity and Energy Contribution

Major hydro is the largest renewable energy contributor at present and the determination of its hydrological characteristics and total resource capability is vital. Sri Lankan hydro system is a complex multipurpose system with a strong seasonal pattern both on inflow energy and downstream water requirement. The probabilistic assessment of existing hydro system is based on the Stochastic Dual Dynamic Program (SDDP) computer simulation with inflow data from 1979 to 2014 and the detailed information is given in the section 2.1.3 in the chapter 2. Potential of the present hydropower system assessed to be is 4050GWh annually for power generation on average condition. This will further increased with the additions of committed and new hydro power projects.

5.6.2 Estimating Wind Capacity and Energy Contribution

Considering availability of wind measurement data and to capture the diversity of wind profiles, five regimes Mannar, Puttalam, Northern, Eastern and Hill Country were modelled. Wind speed measurement data contains hourly and 10 minutes information. Wind data collected by the Sustainable Energy Authority (SEA) and by existing power plants have been used to determine the wind profiles. 10-minute information is more useful for integration studies, since it provides sub-hourly information critical for determining short-term variability and system impacts. Wind measurement data shown in Table 5.10 has been used in the study. The latest recorded site measurements or the best set of quality data have been used for modelling the wind patterns and energy production of each regime.

Table 5.10: Wind Measurement Data Availability of Five Wind Regimes

	Wind Regime	Location	2009	2010	2011	2012	2013	2014	2015
1	Northern	Jaffna							Mar-Dec
		Pooneryn							Mar-Dec
2	Mannar	Nadukuda			June-Dec	Jan Feb	Jan-May		Jan-Dec
		Nannattan			May- Dec	Jan-Dec	Jan		
		Silawathu			June-Dec	Jan-Oct			
3	Puttalam	Udappuwa	Feb-May/ Sept-Dec	Jan-Oct					
4	Eastern	Kokilai							Mar- Dec
5	Hill Country	Seethaeliya		June-Dec	Jan-July			Apr- Oct	
		Balangoda						Mar-Dec	Jan-Sep

Wind plant modeling to estimate annual energy production and hourly capacity variation were carried out using the software named System Advisory Model (SAM) developed by National Renewable Energy Laboratory (NREL). SAM model is designed to make performance predictions and cost estimates of energy for grid-connected renewable power projects based on installation, operating costs and system design parameters that user specifies as inputs to the model. Hourly wind speed data prepared for each site location is given as an input to the SAM software and then the wind plant/farm should be modeled specifying turbine and farm characteristics. Basic design parameters given in Table 5.11 were considered in modeling each wind plant. The results obtained for the each wind resources with wind plant modelling are given in the table 5.12 below.

Table 5.11: Main Parameters of Plant Modelling of Each Wind Regime

Parameter	Mannar	Puttalam	Hill Country	Northern	Eastern
Turbine capacity (MW)	2.5	2.0	0.55	2.0	2.0
Block Capacity (MW)	25.0	20.0	10.45	20.0	20.0
Plant availability (%)	91	91	91	91	91
Wind measurement Data (location -Year)	Nadukuda 2015	Udappuwa 2009-2010	Seethaeliya 2012-2014	Pooneryn 2015	Kokkilai 2015
Hub Height (m)	80	80	50	80	80

Table 5.12 Results on Annual Energy Production of Each Wind Regime

	Mannar	Puttalam	Hill country	Northern	Eastern
Block Capacity (MW)	25.0	20.0	10.45	20.0	20.0
Annual Plant Factor (%)	36.7	31.4	19.1	34.1	37.3
Annual Energy(GWh)	80	55	17	59.7	47.9

Wind speed variations and turbine characteristics used for the study and the Hourly variations of wind plant output obtained from the study for five wind regimes are given in the Annex 5.5

5.6.3 Estimating Solar Capacity and Energy Contribution

Solar irradiance measurements were obtained from the Sustainable Energy Authority (SEA) to estimate the energy production using solar PV panels. Irradiance measurements of two locations namely, Hambantota and Kilinochchi were considered for this study. Global Horizontal Irradiance (GHI) and Diffuse Horizontal Irradiance (DHI) measurements were available with ten minute time step. Direct Normal Irradiance (DNI) was estimated with the available GHI and DHI using solar zenith angle. Input data was screened to identify discontinuities and variations. Complete year data was used as input to the System Advisor Model (SAM).

Sites available for future large scale solar power development were identified by the Sustainable Energy Authority (SEA) and they were incorporated for this renewable integration study. Hourly inputs of solar irradiance measurements (W/m2) were constructed for the SAM software representation and it was used with site location inputs (latitude, longitude), elevation, and hourly temperature profile. In these two sites, only GHI and DHI was available and DNI was calculated with available GHI and DHI. Availability of the plant was assumed as 90% for the study purpose and typical commercial PV module and inverter characteristics available within the SAM software tool were used and resulting plant factors for the two locations are given in the Table 5.13 below.

Table 5.13: Annual Plant Factor of Two Modelled Solar Regions

Location	**Annual Plant Factor (%)**
Hambantota	16.3
Kilinochchi	15.6

Annex 5.6 includes the solar irradiance variation with one minute resolution in two days in January and February 2015 in Kilinochchi showing the degree of intermittency of the resource as a highly variable renewable energy source.

5.6.4 Estimating Mini Hydro Capacity and Energy Contribution

Mini-hydro energy production is directly related to the hydrological condition of a given year and exhibits a clear seasonal pattern. Historical data on Mini-hydro energy production were analysed for deriving a production profile for mini Hydro model for study purpose and the production profile is given in Annex 5.6. The annual plant factor of each model is 36.3 % in the average Hydro Condition.

5.6.5 Estimating Biomass Capacity and Energy Contribution

Biomass Plants were considered as thermal plants of dispatchable nature and hence its operation and energy production is computed by both short-term and long-term Optimization software programs according to the economic dispatch principles.

5.6.6 Municipal Solid Waste Based Power Generation

Developments of grid scale waste-to-energy projects are identified as essential and timely requirement since municipal solid waste is accumulated in large volumes in urban areas. Converting Municipal Solid Waste to energy has a tremendous potential in waste management reducing the negative social, health and environmental effects as large amount of solid waste is accumulated throughout the country. Different technologies are available for the energy conversion process and the composition and characteristics of accumulated waste as a fuel is important when utilizing for power generation purpose.

Ceylon Electricity Board and Sustainable Energy Authority have facilitated the development by providing a tariff and several Letters of intent (LOIs) have been issued. However, the projects have not been able to reach the commercial operation stage yet. The opportunity for the future development of waste to energy projects is available under the offered tariff category.

5.6.7 Other Forms of Renewable Energy Technologies

Other forms of renewable energy such as Concentrating Solar Power (CSP), Bioenergy, Geothermal, Tidal wave, Ocean Thermal Energy Conversion and other forms of low carbon technologies are yet to be assessed and developed for the commercial scale operation.

Relevant Cost details of Other Renewable Energy Sources are shown in Annex 5.7

CHAPTER 6
GENERATION EXPANSION PLANNING METHODOLOGY AND PARAMETERS

CEB considers the project options from all possible sources including CEB owned generation developments, large thermal plants from the independent power producers and other renewable energy sources in order to meet the system demand. Several factors are taken in to account in this process of selecting the appropriate power development project. Commercially exploitable potential, technical feasibility studies, operational & dispatch studies, environment impact assessment and economic feasibility are the main factors of this selection process. Together with these factors, the Draft Grid Code of CEB Transmission Licensee, Planning Guidelines issued by the Ministry of Power and Energy, General Policy Guidelines on the Electricity Industry for the Public Utilities Commission of Sri Lanka and National Energy Policy are also taken into consideration 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. Generation Planning Code

Draft Generation Planning Code in the Grid Code issued by the Transmission Division of CEB (August 2015) [30] is considered in preparing the Long Term Generation Expansion Plan 2018-2037.

6.2. National Energy Policy and Strategies

Ministry of Power and Energy gazette the National Energy Policy & Strategies of Sri Lanka in June 2008 [31]. 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.

Following nine major policy elements are addressed in the "Energy Policy Elements",

- Providing Basic Energy Needs
- Ensuring Energy Security
- Promoting Energy Efficiency and Conservation

- Promoting Indigenous Resources
- Adopting an Appropriate Pricing Policy
- Enhancing Energy Sector Management Capacity
- Consumer Protection and Ensuring a Level Playing Field
- Enhancing the Quality of Energy Services
- Protection from Adverse Environmental Impacts of Energy Facilities

"Implementing Strategies" elaborate the broad strategies to implement the above policy elements. It covers all the policy elements separately and clear strategies are proposed to implement them.

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 should be reviewed and revised after a period of three years. A new 'National Energy Policy and Strategies of Sri Lanka' is being drafted by relevant authorities which further enhances the existing policy guidelines.

Electricity generation targets were envisaged for the year 2015 under specific targets and milestones for Fuel Diversity and Security in the guidelines published in 2008 are shown in Table 6.1.

Table 6.1– Electricity generation targets envisaged for the year 2015

Year	Electrical Energy Supplied to the Grid as a Share of the Total			
	Conventional Hydroelectric	Maximum from oil	Coal	Minimum from Non-conventional Renewable Energy
2015	28%	8%	54%	10%

Considering the present installed capacity and operation of power plants, these targets were achieved in year 2015. For the preparation of the LTGEP 2018-2037 the guidelines published in 2008 were used.

Presently, it is being discussed how to achieve energy security, considering the other alternative options of fuels, giving due consideration to environmental aspects such as CO_2 emission, renewable energy integration, fuel diversity etc. Fuel diversification road map should be developed by considering all sectors of the economy. In the Long-Term Generation Expansion Plan 2018-2037, case studies were carried out to facilitate the information required for reviewing of the National Energy Policy to enhance 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.
Details of the screening curve methodology are given in Annex 6.1. The results of the screening curve analysis are explained in section 7.1 in Chapter 7. The detailed planning methodology described in section 6.4 to section 6.7 is used to finalize the Least Cost Generation Expansion Plan.

6.4. Planning Software Tools

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 Stochastic Dual Dynamic Programming (SDDP) and NCP software tools developed by PSR (Brazil), Model For Analysis of Energy Demand (MAED), Model for Energy Supply Strategy Alternatives and their General Environmental Impacts (MESSAGE) and Wien Automatic System Planning (WASP) package WASP IV developed by International Atomic Energy Agency (IAEA) were extensively used in conducting the system expansion planning studies to determine optimal Long Term Generation Expansion Plan.

6.4.1 SDDP and NCP Models

Stochastic Dual Dynamic Programming (SDDP) model is an operation planning tool which simulates the hydro and thermal generation system to optimize the operation of hydro system. More than 30 years of historical inflow data for existing, committed and candidate hydro plants were taken into account by the model to stochastically estimate the future inflow patterns and then simulates with total system to estimate energy and capacity availabilities associated with plants. Hydro plant cascade modeling and reservoir level detail modeling has been done to accurately represent the actual operation. Maximum of hundred scenario simulations could be considered in the model to represent different hydro conditions.

The potential of hydropower system estimated using SDDP model is used as input information to WASP IV package. Since WASP package could accommodate only a maximum of five hydro conditions, hundred scenario outputs of SDDP were rearranged and divided into five hydro conditions, Very Wet, Wet, Average, Dry and Very Dry considering probability levels.

Short term dispatch analysis was carried out using NCP software in order to observe the operational issues of the developed Base Case Plan.

6.4.2 MAED Model

The Model for Analysis of Energy Demand (MAED) relies upon the end use demand projection methodology that was originally developed at IAEA of the University of Grenoble, France and known as MEDEE-2. Respecting the general structure of MEDEE-2, the International Atomic Energy Agency

(IAEA) developed the present MAED model by introducing important modifications concerning the parameters required to be specified as input data, equations used to calculate energy demand of some sectors, and some additional modules to analyse hourly electricity consumption to construct the load duration curve of the power system. MAED consists with mainly two modules, namely a module for energy demand analysis (MAED_D) and module for hourly electric power demand calculations (MAED_EL).

Details and results of the scenario analysis is given in Chapter 3. Output of MAED demand projection was compared with the base demand forecast which was prepared using econometric method and the comparison is given in chapter 3.

6.4.3 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 techniques are used in the WASP IV package for the simulation and optimization of expansion plan.

6.4.4 MESSAGE Software

Model for Energy Supply Strategy Alternatives and their General Environmental Impacts (MESSAGE) is designed for setting up models of energy systems for optimization. MESSAGE was originally developed at International Institute for Applied Systems Analysis (IIASA). The IAEA later acquired MESSAGE software and several enhancements have been made in it.

MESSAGE is designed to formulate and evaluate alternative energy supply strategies considering user defined constraints. The modelling procedure is based on building the energy flow network which describes the whole energy system, starting from available energy resources, moving to primary and secondary level energy and ending with modelling the final level demand categorizing the demand types such as heat, motor fuel and electricity. Energy demand and supply patterns can be included in to the model. The underlying principle of MESSAGE is optimization of an objective function under a set of constraints that define the feasible region containing all possible solutions of the problem. Although, MESSAGE is a long term optimization model it is possible to model the chronological demand curve.

MESSAGE software was used to analyze the Base Case Plan. All the parameters from final demand of electricity to primary and secondary level input fuel for power plants were modeled as energy chains in the system, and 20 year time horizon was used in the study. Energy flow chart of the electricity system is given in Annex 6.2. Model results for the Base Case Plan are given in chapter 7.

6.4.5 OPTGEN Software

Generation Planning Section acquired the OPTGEN software developed by PSR (Brazil) as a new long term expansion planning model that determines the least cost sizing and timing decisions for construction, retirement and reinforcement of generation capacities and transmission network. The model optimizes the trade-off between investment costs to build new projects and the expected value of operative costs obtained from SDDP, the transmission constrained stochastic hydrothermal dispatch model, which allows a detailed representation of the system's operation under uncertainty. In order to solve the expansion problem, OPTGEN model uses advanced optimization techniques of mixed-integer programming and Benders decomposition.

6.5 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 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. Once all these requirements are fulfilled and funds are committed, the project is incorporated to the LTGEP as a committed plant.

6.6 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. The plant emissions are assessed 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 approximately from 4 years for a gas turbine, 6 years for a LNG power plant 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 item of the planning process. Furthermore, generation system expansion is highly capital intensive. Therefore, financial schedule is prepared in order to identify the financial requirement which is essential for sourcing of funds and for projecting electricity tariffs.

6.7 Modeling of Other Renewable Energy

As stated in Chapter 5, ORE was not included as candidates. According to the Grid Code, only the existing ORE plants are considered as committed in the Reference Case. However, a projected development was considered as committed and incorporated in to the Base Case of the LTGEP. The main technologies of ORE; mini-hydro, wind, solar and dendro were modeled in the WASP. Dendro plants were modeled as thermal power plants. Wind and solar additions were projected annually and taking into account the actual resource profiles of wind and solar. The demand profiles were modified to reflect both capacity and energy contributions from these ORE power plants. Mini hydro was included in the WASP as lumped 'run of the river' hydro power plants. The probabilistic monthly energy was calculated based on past performance of mini hydro plants. A comprehensive ORE integration study was conducted by CEB to determine integration of ORE resources prior to preparation of the LTGEP 2018-2037 as described in chapter 5.5.

6.8 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 were used in the studies and those are described in detail.

6.8.1 Study Period

The results of Base Case and all sensitivity studies are presented in the report for a period of 20 years (2018-2037). In this regard, the studies were conducted for a period of 25 years (2018-2042).

6.8.2 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 148.88 LKR/USD. This is the average value of December 2016 exchange rates. All costs are based on 1st of January 2017.

6.8.3 Plant Commissioning and Retirements

It was 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.

6.8.4 Cost of Energy Not Served (ENS)

The average loss to the economy due to electrical energy not supplied has been estimated as 0.663 USD/kWh (in 2017 prices). This value has been derived by escalating the ENS figure given by PUCSL as 0.5 USD/kWh in 2011.

6.8.5 Loss of Load Probability (LOLP)

LOLP is a reliability index that indicates the probability that some portion of the load will not be satisfied by the available generation capacity. It is defined as the percentage of time during the system load exceeds the available generation capacity in the system. 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.

6.8.6 Reserve Margin

Reserve margin is the other available reliability criteria of the WASP-IV module. This is a deterministic reliability index which is the measure of the generation capacity available over and above the amount required to meet the system load requirements. Minimum value of 2.5% and Maximum value of 20% have been applied for the studies.

6.8.7 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 lower and higher discount rates.

6.8.8 Plant Capital Cost Distribution among Construction Years

The distribution of plant capital cost among construction period is carried out by assuming "S" curve function relating expenditure to time based on 10% discount rate. The resultant annual cost distributions for individual power plants are given in the Investment Program shown in Table 8.1 in Chapter 8. However optimization process considers only the total cost and is not affected by this cost distribution.

6.8.9 Assumptions and Constraints Applied

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

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

d) Committed Power Plants are shown in the Table 6.2 below.

Table 6.2 Committed Power Plants

Power Plant	**Capacity (MW)**	**Year of Operation**
Thermal		
Furnace Oil based Thermal Power Plant	100 70	2017/2018
Kelanitissa Gas Turbines	3x35	2 Units by 2019 1 Unit by 2020
LNG operated Combined Cycle Power Plant	300	Open Cycle – 2019 (Open Cycle operation with Diesel as initial fuel) Combined Cycle – 2020
Hydro		
Uma Oya HPP	122	2019
Broadlands HPP	35	2020
Moragolla HPP	30.2	2022
Wind		
Mannar Wind Power Plant	100	2020

e) Gas Turbine plants can be available only by January 2019. 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.

f) The Candidate Power Plants with earliest possible commissioning year are depicted in the Table 6.3 below.

Table 6.3 Candidate Power Plants

Power Plant	Capacity (MW)	Year of Operation
Thermal		
Gas Turbine	35 / 105	2020
Diesel operated Combined Cycle Plant	150 / 300	2021
LNG operated Combined Cycle Plant	150 / 300	2021
High Efficiency Coal Plant	300	2023
Supercritical Coal Plant	600	2025
Nuclear Power Plant	600	2030
Reciprocating Engines	15	
Hydro		
Thalpitigala HPP	15	2020
Seethawaka HPP	20	2022
Gin Ganga HPP	20	2022
Pumped Storage Power Plant	3x200	2025

g) 5MW Dendro Power Plant is modeled from the data received from Sustainable Energy Authority. The integration capacity of Dendro Power Plants could be considered on project by project basis depending on the feasibility.

h) The integration of Mini Hydro capacity could be considered on project by project basis depending on the feasibility.

i) Future Wind Farms are to be developed as Semi-dispatchable Power Plants.

j) All new ORE Plants are capable to curtail the generation when necessary.

k) Plant Retirements of CEB owned and IPP plants are given in Table 6.4.

Table 6.4 Plant Retirement Schedule

CEB Power Plants	Year	IPP Power Plants	Year
1. KPS Frame5 GTs all units	2021	1. Asia Power	2018
2. Sapugaskanda PS B - 4 units	2023	2. Ace Embilipitiya	2018
3. KPS GT7	2023	3. Northern Power	2020
4. Sapugaskanda PS A	2024	4. Sojitz Combined Cycle Plant *	2023
5. Sapugaskanda PS B - 4 units	2025	5. Kerawalapitiya West CCY Plant	2035
6. Barge Mounted Power Plant	2025		
7. Kelanithissa Combined Cycle	2033		

l) The contract of 163 MW Sojitz Power Plant at Kelanitissa will expire in 2023 and it will be operated as a CEB plant until 2033.

CHAPTER 7

RESULTS OF GENERATION EXPANSION PLANNING STUDY

This chapter presents the results of the Base Case analysis for 2018-2037 planning horizon in detail and describes the key results of the scenario analysis on policy directions and sensitivity analysis on selected technical and economic parameters. Results on Environmental Impacts of case analysis are discussed in the Chapter 9.

7.1 Results of the Preliminary Screening of Generation Options

For the preliminary screening of alternative options, two coal fired steam plant technologies, , two oil-fired gas turbines, two oil fired combined cycle power plants, two Natural Gas fired combined cycle plants, an oil fired reciprocating engine and a Nuclear Power plant were considered. For evaluating alternative generation technologies with varying capital investments, operational costs, maintenance costs and life time, 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 each plant was used to screen the initial alternatives before carrying out the detailed expansion planning studies. Discount rate of 10%, which is considered as the base discount rate for the National Planning studies, is used for the above screening process and 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.
From the screening curve analysis, the following candidate technologies were selected as suitable options for detailed generation expansion planning studies.

- 35MW Auto Diesel fired gas turbine
- 105MW Auto Diesel fired gas turbine
- 150MW Auto Diesel fired combined cycle power plant
- 300MW Auto Diesel fired combined cycle power plant
- 300MW Coal fired thermal power plant
- 600MW Super Critical Coal power plant
- 150MW NG fired combined cycle power plant
- 300MW NG fired combined cycle power plant
- 600MW Nuclear Power plant
- 15MW Furnace oil Reciprocating Engine

Detailed generation expansion planning studies were conducted with the above alternatives in order to identify the least cost plant development sequence to meet the Base Demand Forecast.

In addition to the above alternatives derived from the screening analysis, 3x200MW Pump Storage Power Plant (PSPP) was introduced to the system. Introduction of PSPP was based on the results of two studies, “Development Planning on Optimal Power generation for Peak Demand in Sri Lanka” [26] and “Integration of Non-Conventional Renewable Energy Based Generation into Sri Lanka Power Grid” [29]. In base scenario, PSPP was introduced to the system where 1800MW of coal plants are in operation to overcome the system limitation. PSPP unit with adjustable speed type will also facilitate the reduction of curtailment of ORE in the Base Case Plan.

7.2 Base Case Plan

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

The total present value (PV) cost of the Base Case Plan including the cost of development of ORE for the period 2018-2037 is USD 14,568 million (LKR 2,168.93 billion) in January 2017 values.

Generally, in Long Term Generation Expansion studies only the costs which affect future decision making process are considered. Hence the capital costs of committed plants and expenditure arising from the 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 cost of the system (PV) which is the optimized result of WASP studies.

Table 7.1– Generation Expansion Planning Study - Base Case (2018 – 2037)

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2018	Mini Hydro 15 MW Solar 160 MW Biomass 5 MW	*100 MW Furnace Oil fired Power Plant ** *70 MW Furnace Oil fired Power Plant ** *150 MW Furnace Oil fired Power Plant **	8x6.13 MW Asia Power	1.245
2019	Major Hydro *122 MW (Uma Oya HPP)* Mini Hydro 15 MW Wind 50 MW Solar 95 MW Biomass 5 MW	*2x35 MW Gas Turbine* *1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region*+	-	0.220
2020	Major Hydro *35 MW (Broadlands HPP)* **15 MW (Thalpitigala HPP)** *Wind 100 MW (Mannar Wind Park)* Mini Hydro 15 MW Wind 120 MW Solar 105 MW Biomass 5 MW	*1x35 MW Gas Turbine*	6x5 MW Northern Power	0.237
2021	Mini Hydro 10 MW Wind 75 MW Solar 55 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**	4x17 MW Kelanitissa Gas Turbines	0.107
2022	Major Hydro *30 MW (Moragolla HPP)* **20 MW (Seethawaka HPP)** **20 MW (Gin Ganga HPP)** Mini Hydro 10 MW Wind 50 MW Solar 6 MW Biomass 5 MW			0.237
2023	Mini Hydro 10 MW Wind 60 MW Solar 55 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated)** *163 MW Combined Cycle Power Plant (KPS–2)* •	115 MW Gas Turbine** 4x9 MW Sapugaskanda Diesel Ext.** 163 MW Sojitz Kelanitissa Combined Cycle Plant •	0.205
2024	Mini Hydro 10 MW Wind 45 MW Solar 55 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated)**	4x18 MW Sapugaskanda Diesel	0.145
2025	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 85 MW Solar 104 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated)**	4x9 MW Sapugaskanda Diesel Ext. 4x15 MW CEB Barge Power Plant	0.026
2026	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Solar 55 MW Biomass 5 MW	-	-	0.019
2027	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 25 MW Solar 54 MW Biomass 5 MW	-	-	0.012
2028	Mini Hydro 10 MW Wind 45 MW Solar 105 MW Biomass 5 MW	**1x600 MW New Supercritical Coal Power Plant**	-	0.002
2029	Mini Hydro 10 MW Wind 25 MW Solar 54 MW Biomass 5 MW	-	-	0.008
2030	Mini Hydro 10 MW Wind 70 MW Solar 55 MW Biomass 5 MW		-	0.027
2031	Mini Hydro 10 MW Wind 35 MW Solar 54 MW Biomass 5 MW	**1x600 MW New Supercritical Coal Power Plant**	-	0.005
2032	Mini Hydro 10 MW Wind 45 MW Solar 55 MW	-	-	0.019
2033	Mini Hydro 10 MW Wind 70 MW Solar 54 MW Biomass 5 MW	**2x300 MW Natural Gas fired Combined Cycle Power Plants -Western Region**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS- 2)	0.023
2034	Mini Hydro 10 MW Wind 70 MW Solar 55 MW		-	0.108
2035	Mini Hydro 10 MW Wind 70 MW Solar 54 MW Biomass 5 MW	**1x600 MW New Supercritical Coal Power Plant**	300MW West Coast Combined Cycle Power Plant	0.058
2036	Mini Hydro 10 MW Wind 95 MW Solar 55 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant -Western Region**	-	0.057
2037	Mini Hydro 10 MW Wind 70 MW Solar 104 MW Biomass 5 MW	-	-	0.230
Total PV Cost up to year 2037, **USD 14,568 million** (LKR 2,169 billion)++				

GENERAL NOTES:

- * To meet the demand from year 2018 until major power plants are implemented, 70 MW, 100MW and 150MW power plants are proposed with operation by FO.
- \+ Grid integration of 1x300 MW Natural Gas fired Combined Cycle Power Plant would be possible once the Kerawalapitiya- Port 220kV cable is available in June 2018. Gas Turbine operation of the Combined Cycle Power Plant is expected to commence in 2019 and the combined cycle operation is expected in 2020.
- ** Retirement of these plants would be evaluated based on the plant conditions.
- ++ PV Cost includes the cost of projected ORE, USD 2004.6 million based on economic cost (excluding the future Dendro power development) and an additional spinning reserve capacity is kept to compensate for the intermittency of ORE.
- • Sojitz Kelanitissa is scheduled to be retired in 2023 will be operated as a CEB Natural Gas fired power plant from 2023 to 2033 with the conversion. West Coast and Kelanithissa Combined Cycle plant are converted to Natural Gas in 2020 with the development of LNG based infrastructure.
- ✓ Committed plants are shown in Italics. All plant capacities are given in gross values.
- ✓ Thalpitigala and Gin Ganga multipurpose hydro power plants proposed by Ministry of Irrigation are forced considering secured Cabinet approval for the implementation of the Projects.
- ✓ Seethawaka HPP and PSPP units are forced in 2022, 2025, 2026 and 2027 respectively.
- ✓ Moragahakanda HPP will be added in to the system by 2017, 2020 and 2022 with capacities of 10 MW, 7.5 MW and 7.5 MW respectively.

Table 7.2: Generation Expansion Planning Study - Base Case Capacity Additions (2018 – 2037)

Year	Peak Demand (MW)	Capacity Addition (MW)								Retirements	LOLP %
		Gas Turbines	Reciproca-ting Engines	Coal	LNG	Major Hydro	Pumped Hydro	ORE	Total		
2018	2738		320					180	500	(51)	1.245
2019	2903	70			300	120		165	655		0.220
2020	3077	35				50		344	429	(30)	0.237
2021	3208				300			146	446	(65)	0.107
2022	3346					71		71	142		0.237
2023	3491			300				129	429	(150)	0.205
2024	3643			300				116	416	(70)	0.145
2025	3804			300			200	204	704	(95)	0.026
2026	3972						200	70	270		0.019
2027	4149						200	94	294		0.012
2028	4335			600				166	766		0.002
2029	4527							94	94		0.008
2030	4726							140	140		0.027
2031	4939			600				104	704		0.005
2032	5157							111	111		0.019
2033	5381				600			139	739	(328)	0.023
2034	5612							135	135		0.108
2035	5854			600				140	740	(300)	0.058
2036	6107				300			160	460		0.057
2037	6372							189	189		0.230
Total		**105**	**320**	**2700**	**1500**	**241**	**600**	**2897**	**8363**	**(1089)**	

7.2.1 System Capacity Distribution

The supply mix of the power sector is moving towards thermal based generation system with the increase of demand since the total hydro capacity remains nearly the same over the planning horizon in the Base Case scenario. Retirement of existing thermal capacities also necessitates new capacity additions and plant retirement details are given in Table 7.1. In the year 2025, the share of coal based generation capacity is 25% and it only increases up to 32% by 2037. Current Major Hydro capacity contribution is 32% under average hydro condition where as it will be 23% and 15% in the year 2025 and 2037 respectively. Current share of oil based capacity is 31% and it gradually decreases with the introduction of NG and Coal based thermal power plants in the first half of the planning period and then the capacity share becomes negligible leading up to only 4% in 2037. Pumped Hydro capacity will be introduced to the system in 2025 and its capacity contribution in 2037 is 5%.

Present total installed capacity is 4054 MW and out of that 3413 MW is dispatchable power plants and the Chapter 2 includes the detailed information of the existing generation system. 1090 MW of existing thermal capacity is due to retire during the 20 year planning period and three units of 35 MW gas turbine are added to the system in 2019 and 2020 for operational requirements. Future addition of hydro capacity is 241 MW including 186MW of committed plants and 55MW of new hydro power plants as shown in the Table 7.1. 2700 MW of coal power plants are added during the planning period of 2018-2037 and a mix of NG and coal based generation units serve the base load requirement of the system. As shown in the Table 5.7, 2897 MW of ORE capacity additions over the 20 year period is expected and the total ORE capacity increases to 1912 MW in 2025 and 3454 MW in 2037. The first 200MW Pumped Storage Hydro power plant unit is added in 2025 followed by another two units of same capacity in 2026 and 2027. The Wind Power Park of 375MW capacity in Mannar Island is expected to be implemented in phases starting from year 2020.

Capacity additions by plant type are summarised in five year periods in Table 7.3 and graphically represented in Figure 7.1. Capacity balance of the system is presented in Annex 7.2. Information on the capacity share is illustrated in the Figure 7.2 and the variation of the total renewable capacity contribution over the years is shown in the Figure 7.3.

Table 7.3: Capacity Additions by Plant Type

Type of Plant	2018 (MW)	2019-2022 (MW)	2023-2027 (MW)	2028-2032 (MW)	2033-2037 (MW)	Total capacity addition	
						(MW)	%
Gas Turbines		105				**105**	1.26%
Reciprocating Engines	320					**320**	3.83%
Coal			900	1,200	600	**2,700**	32.29%
LNG		600			900	**1,500**	17.94%
Major Hydro		241				**241**	2.88%
Pumped Hydro			600			**600**	7.17%
ORE	180	726	613	615	763	**2,897**	34.64%
Total	**500**	**1,672**	**2,113**	**1,815**	**2,263**	**8,363**	100.00%

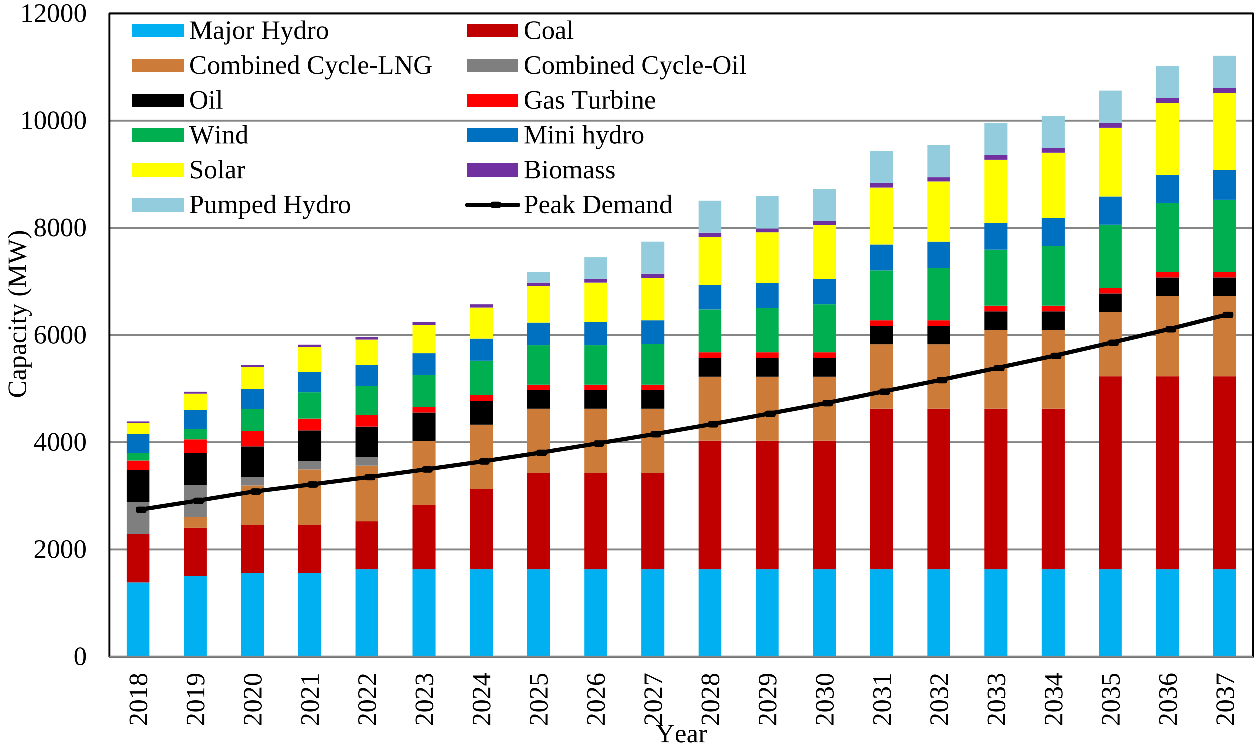


Figure 7.1 –Cumulative Capacity by Plant Type in Base Case

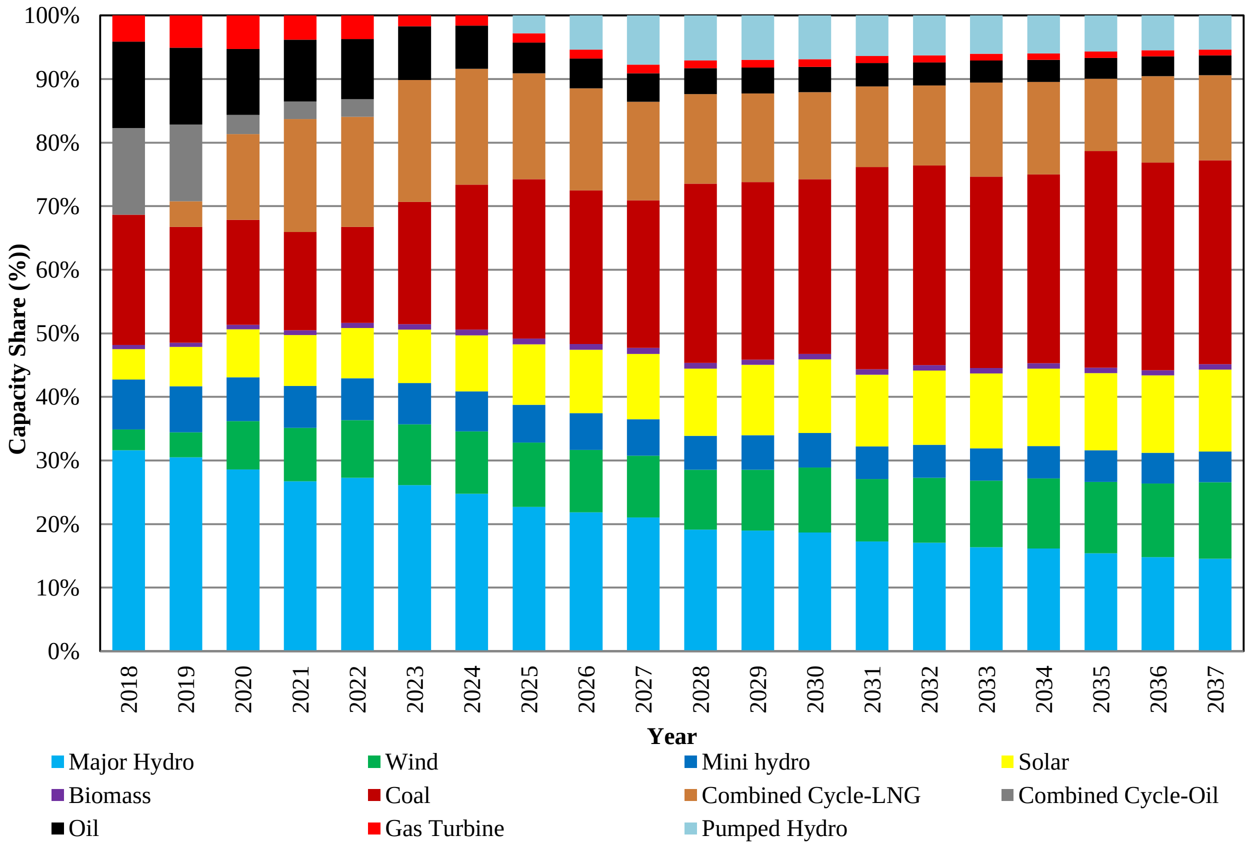


Figure 7.2 – Capacity Mix over next 20 years in Base Case

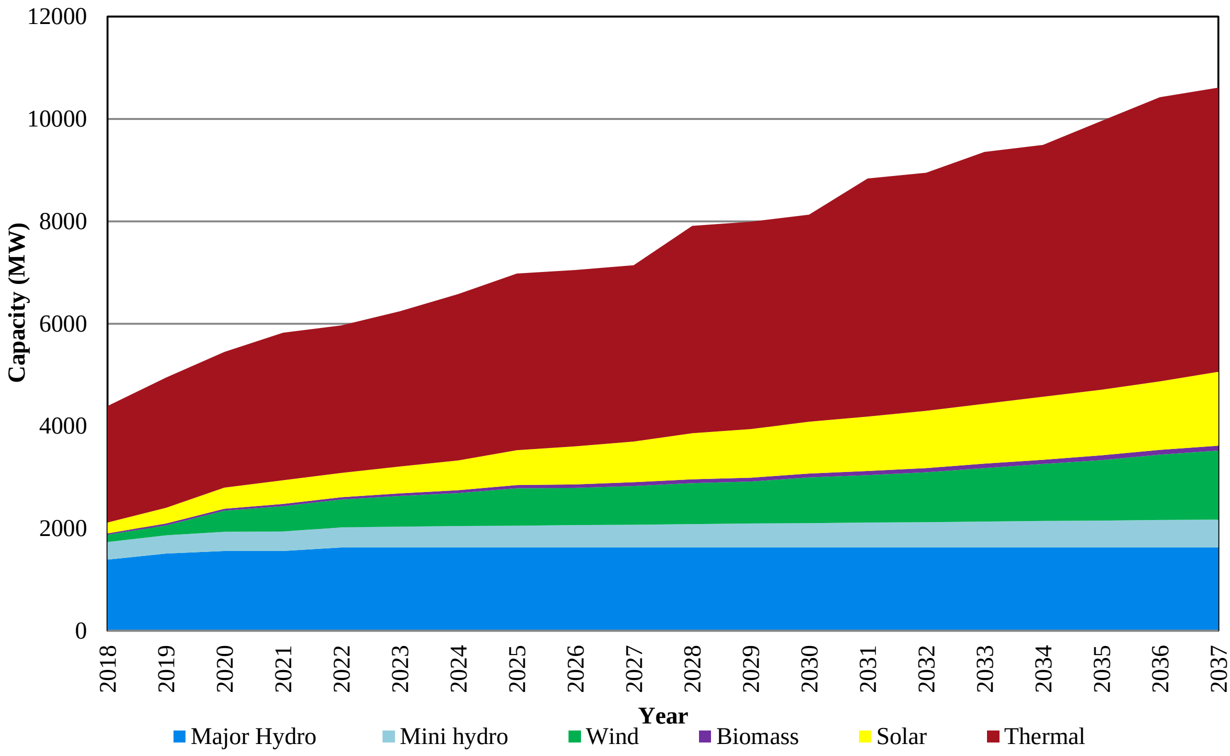


Figure 7.3 – Capacity wise Renewable Contribution over next 20 years

7.2.2 System Energy Share

At present, on average 35% of the total energy demand is met by hydro generation whereas 55% is met by thermal generation. Current ORE contribution to the National Electricity Demand is 10%. Future energy supply scenario of the Base Case Plan is graphically represented in Figure 7.4. The hydro generation share slightly increases with addition of new hydro power plants during the first half of the planning period and thereafter continues to contribute at the same level. Beyond 2020, Coal and NG become the major energy contributors of the system and the energy share gradually increases with the addition of new Coal and NG power plants to cater the increasing national demand. Coal energy share is 23% in 2020 and will gradually increase up to 53% by 2037. As shown in the Figure 7.4 NG based Combined Cycle plants also contribute to energy share over the planning period with 10% ~ 20% and the energy contribution from other oil fired power plants including Diesel power plants and IPPs decreases from 24% in 2018 to 1% by 2023 with the gradual retirement of oil plants. Energy contribution from ORE increases from present 10% to 20% by 2020 and thereafter continues to maintain the same contribution over the planning period which is the optimum ORE penetration levels to the system. Percentage energy share of each plant type is given in Figure 7.5 and Energy Balance of the system is given in Annex 7.3. The Annual expected generation and plant factors under different hydro conditions for the Base Case Plan are given in Annex 7.4.

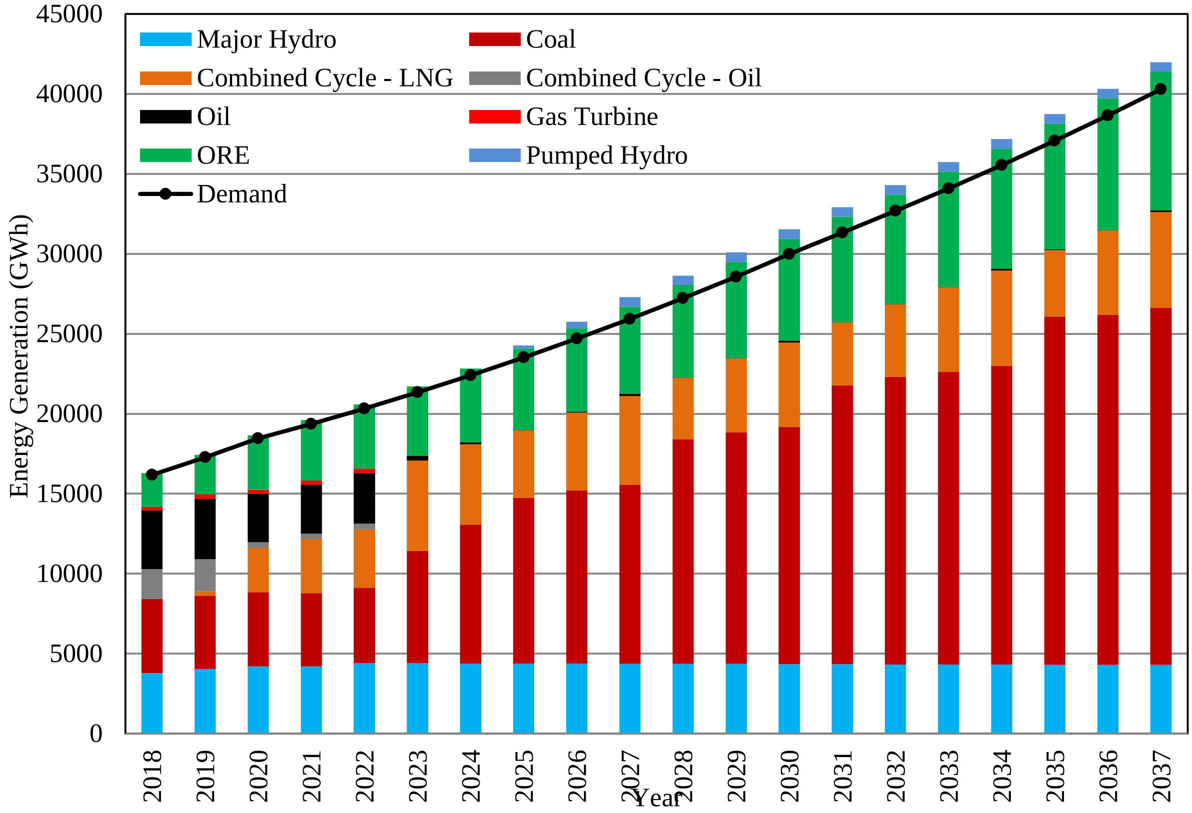


Figure 7.4– Energy Mix over next 20 years in Base Case

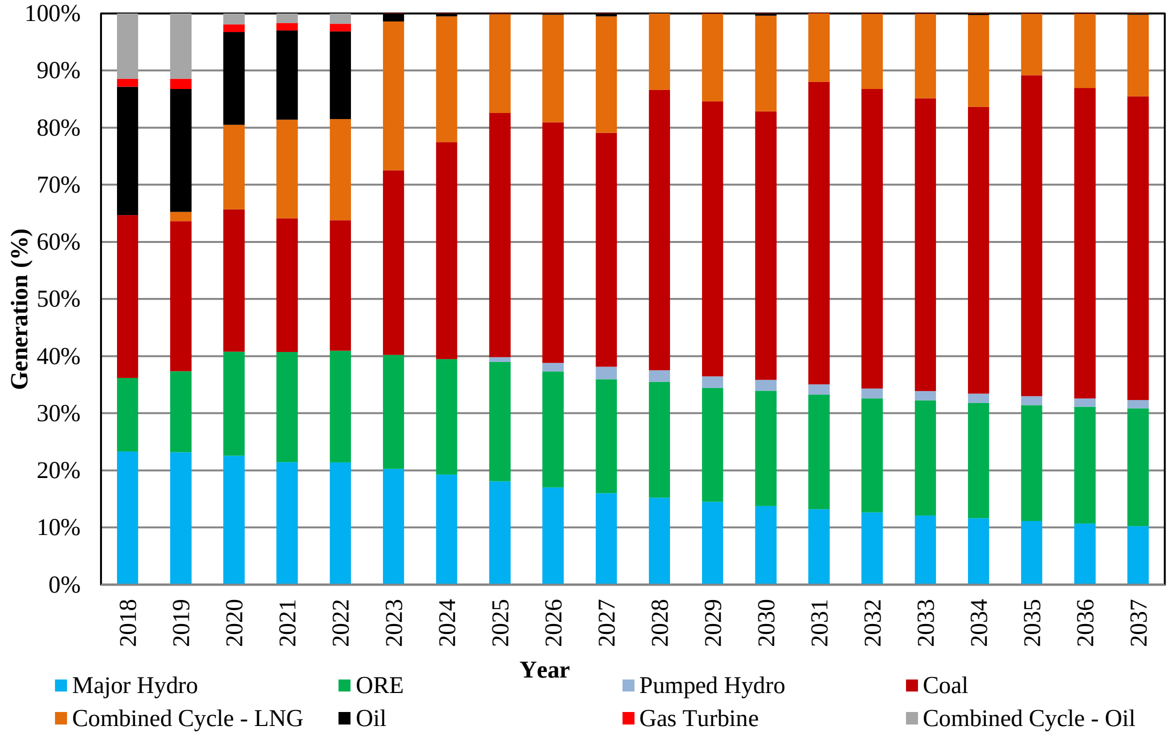


Figure7.5 – Percentage Share of Energy Mix over next 20 years in Base Case

Contribution from ORE based generation is highlighted in Figure 7.6 and the Figure 7.7 illustrates the variation of total renewable share in the total system for the 20 year study period. It is observed that beyond 2022, ORE energy curtailments are increasing [29]. The introduction of PSPP by year 2025 facilitates the operation of ORE capacities without curtailments [29]. To implement the optimum ORE Energy share, major coal plants identified in the Base Case plan must be implemented on schedule to ensure the stability of the power system.

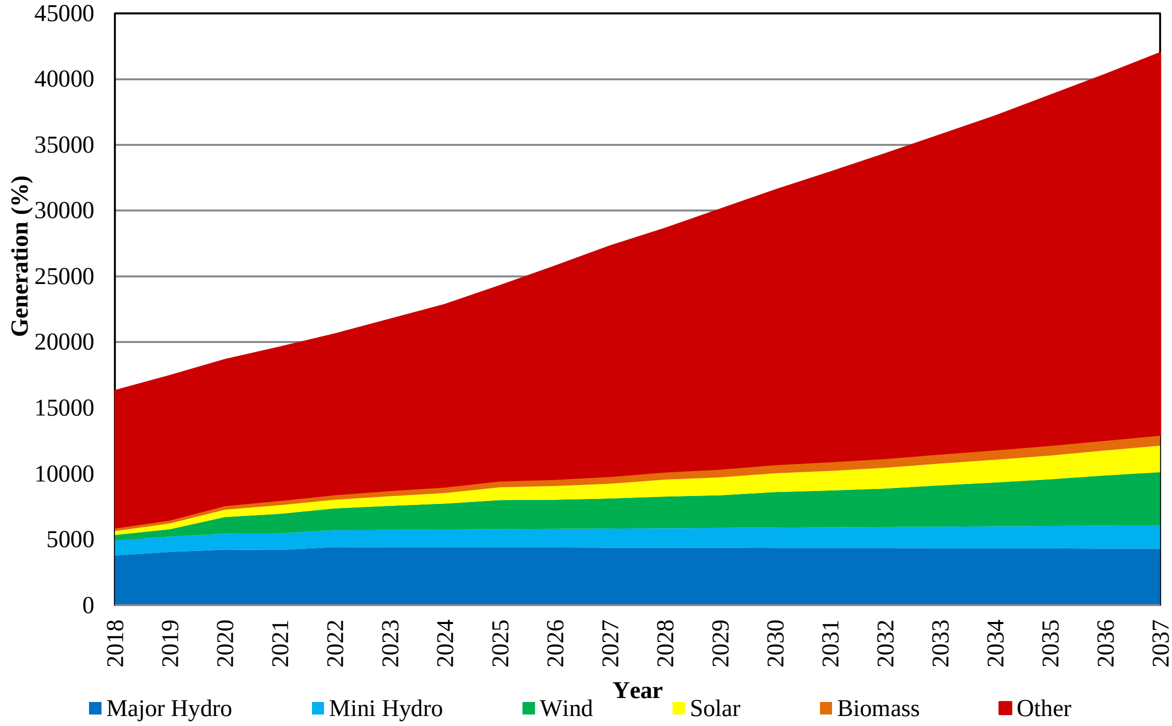


Figure 7.6 –Renewable Contribution over next 20 years based on energy resource

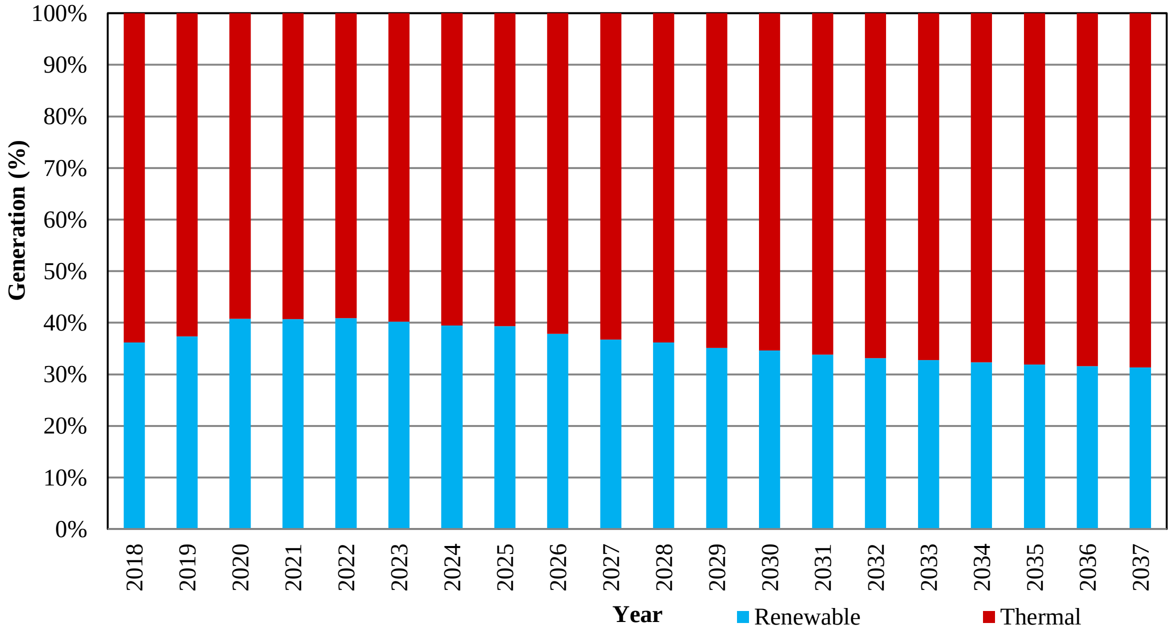


Figure 7.7 Percentage Share of Renewables over next 20 years in Base Case

7.2.3 Fuel, Operation and Maintenance Cost

Expected expenditure on fuel, operation and maintenance (O&M) of the Generation System from 2018 to 2037 is summarized in Table 7.4 in five year periods. Required Fuel quantities and the expected expenditure on fuel for the Base Case Plan over the next 20 years are given in Annex 7.5. Total fuel cost up to year 2037 is expected to be in the order of around 18,519 million US Dollars in constant terms. Expected fuel quantities and associated costs of fuel in the Base Case are graphically represented in Figure 7.8 and Figure 7.9.

Table 7.4: Cost of Fuel, Operation and Maintenance of Base Case

Units: million US$

Year	Operation and Maintenance					Fuel
	Hydro	Pump Hydro	Thermal	ORE	Total	
2018-2022	92.2	0.0	579.0	172.4	843.6	4954.0
2023-2027	98.4	12.0	734.1	240.2	1084.7	3790.3
2028-2032	98.5	30.0	1146.9	294.7	1570.1	4442.8
2033-2037	98.4	30.0	1487.2	357.9	1973.5	5332.2

Total fixed and variable O&M cost over next 20 years is in the order of about 5,472 million USD and total fuel cost about 18,519 million USD in constant terms.

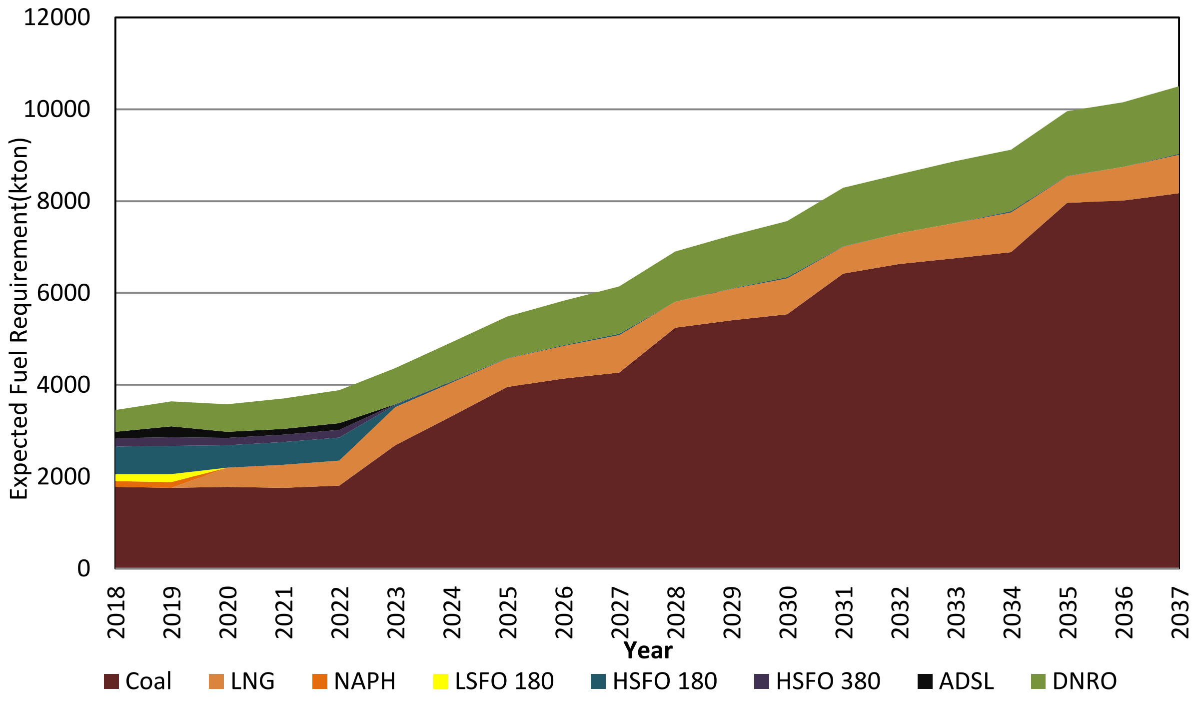


Figure 7.8- Fuel Requirement of Base Case

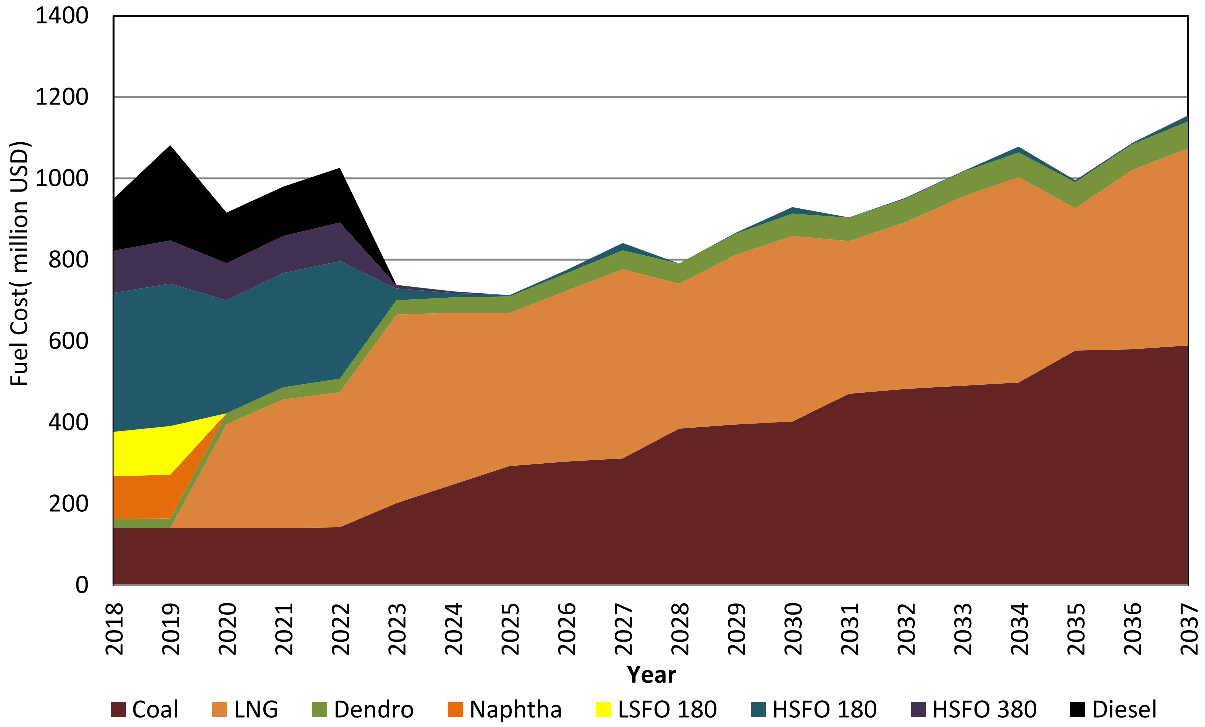


Figure 7.9- Expected Variation of Fuel Cost of Base Case

In the initial years of the planning period, the oil requirement is relatively high with the coal remaining constant and NG requirement increasing gradually. After 2023, the oil quantity requirement becomes negligible with the minimal dispatch of the oil based thermal power plants while the coal requirement increases gradually with the introduction of new coal plants. A base load coal power plant of capacity 300MW typically consumes approximately 800,000 tons per annum and it can vary depending on energy generated, plant characteristics and fuel characteristics.

In year 2018, nearly 779,610 tons of heavy fuel (residual and furnace oil) will be burnt in oil power stations and this consumption will decrease to 5,790 tons in 2025 in an average hydro condition. Diesel consumption is estimated to be 137,770 tons in 2018 and 60 tons in 2025. The total consumption of oil decreases within the first 10 years to a minimal value with the phasing out of oil plants and introduction of coal and NG power plants including the conversion of existing oil power plants to NG. Expected growth of Biomass plant capacities requires a notable amount of fuel quantity annually due to its own characteristics as a fuel.

The expected annual coal requirement for the existing Lakvijaya Coal Power Plant , the future development of coal plants and the annual NG requirement for the future development of combined cycle power plants as per the Base Case Plan is shown in the Figure 7.10 and details are given in Annex 7.5

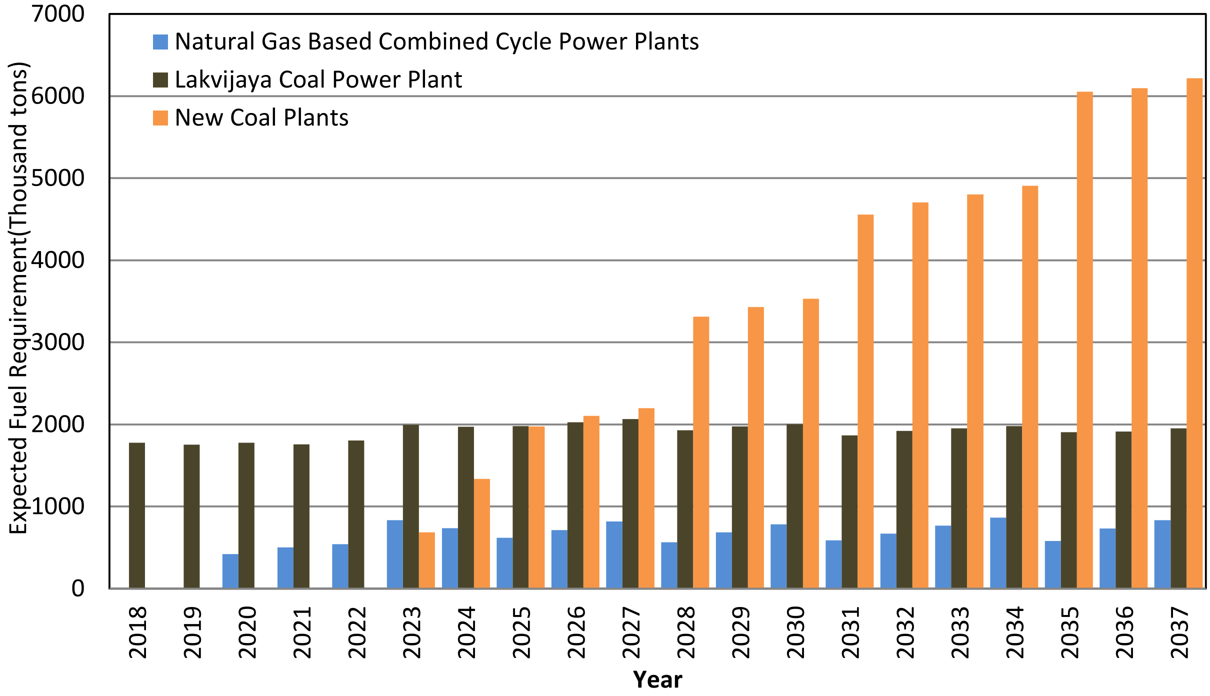


Figure 7.10- Expected Annual Coal and Natural Gas Requirement of the Base Case

7.2.4 Reserve Margin and LOLP

System Reserve Capacity in the worst hydro condition is maintained within the stipulated limits during the initial years of the planning period despite the retirement of several power plants by thermal capacity additions in this period. In years 2028 and 2031, due to the addition of 600 MW supercritical coal power plants the reserve margin increases close to the stipulated upper limit, but gradually decreases in the subsequent years. Reserve Margin variation throughout the 20 year period is shown in the Figure 7.11. System Reserve Margin with total installed capacity including intermittent ORE capacities appears to be higher than the actual available Reserve Margin in the critical hydro condition.

Loss of Load Probability of the system does not exceed the maximum limit of 1.5% during the planning period thereby ensuring the reliability of the system from LOLP perspective. In 2018, the value starts from 1.245% and decreases to well below 0.5% throughout the planning period. The variation clearly shows the inverse relationship of LOLP to the reserve margin in the Figure 7.11.

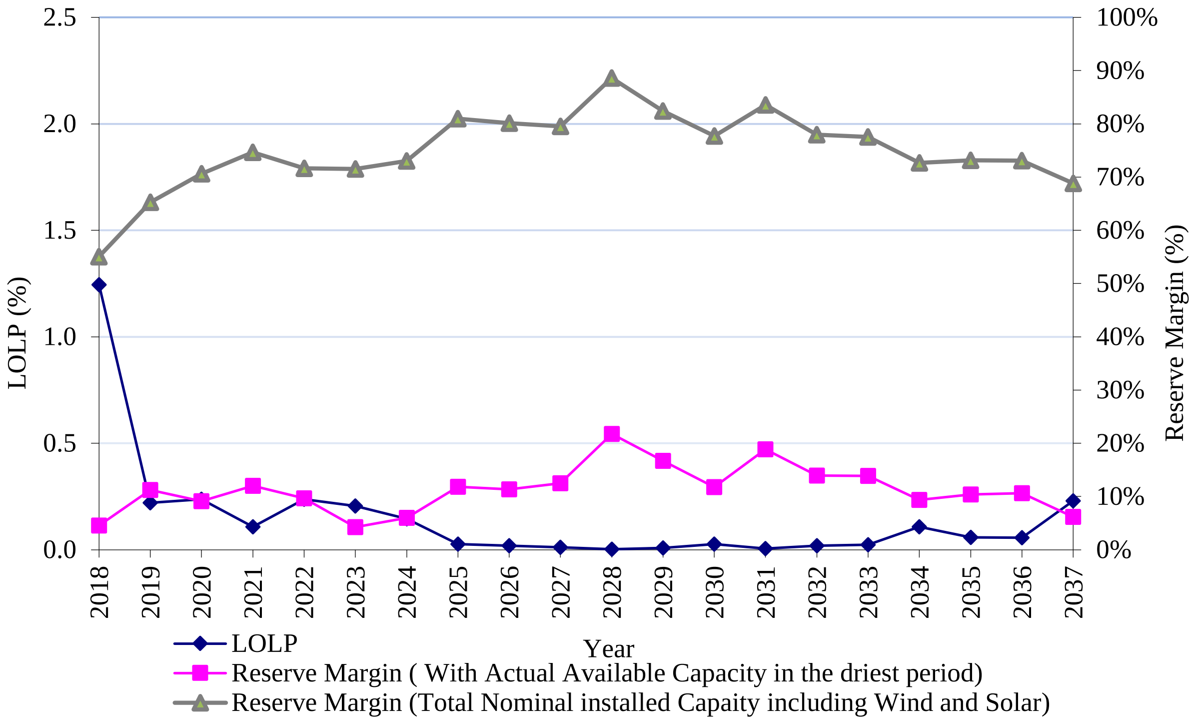


Figure 7.11 – Variation of Critical Reserve Margin and LOLP in Base Case

7.2.5 Spinning Reserve Requirement

The Operating Reserve requirement for the system operation is considered in long term expansion planning exercise. An operating reserve equivalent to the largest unit in operation was kept in previous long term planning studies for contingency purpose. As the Base Case Plan 2018-2037 focuses on higher penetration levels of intermittent ORE capacities; requirement of additional operating reserve has been considered. Therefore, 5% of the installed ORE capacity is kept as operating reserve for regulation purpose in addition to the largest unit capacity for contingency purpose at a given operating condition. Additional operating reserve of 5% over the nominal 10% spinning reserve requirement is to be reviewed through dispatch analysis and using experience in system operation with higher levels of ORE penetration.

7.2.6 Base Case analysis using MESSAGE

MESSAGE energy planning tool was used to further analyze the Base Case Plan. Base demand projection and supply side options were modelled linking with energy conversion technologies. Selected years were modelled in detail to represent seasonal demand variation. Daily demand profiles were used to represent seasons. Year 2016 demand data was used to construct daily demand curves. Resulting operating pattern of power plants in year 2028 during the dry season (March/April) is given in Figure 7.12.

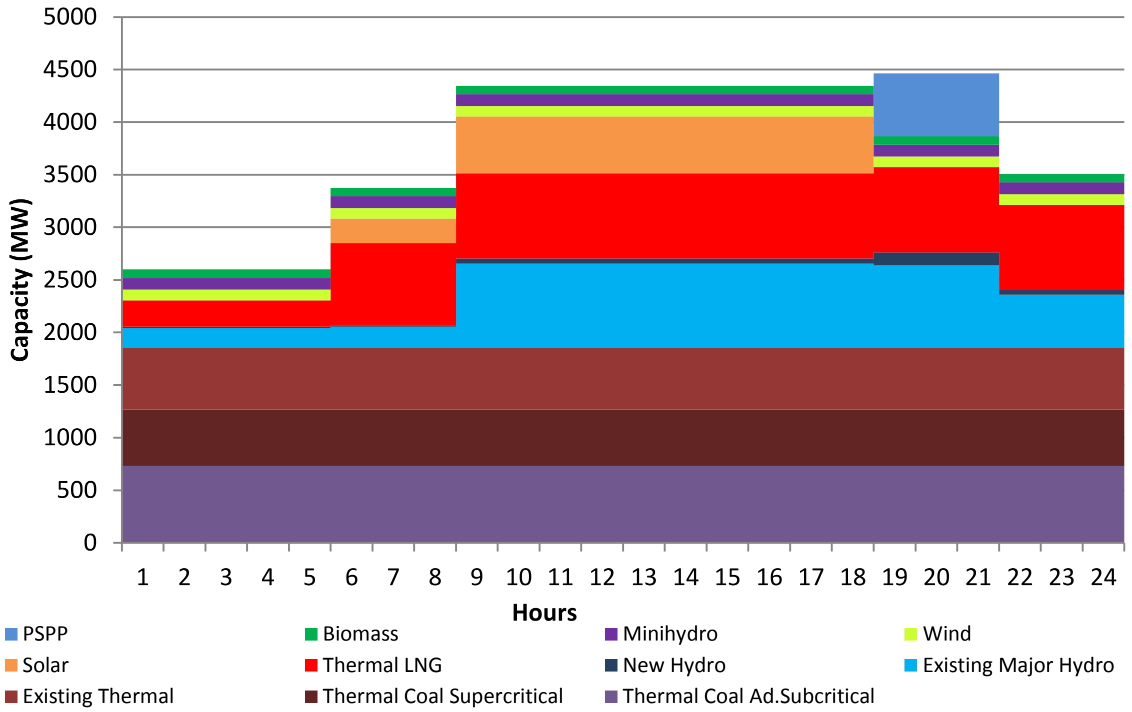


Figure 7.12 – Capacity Contribution from Power Plant in a Day in March /April 2028

It is observed that LNG fired thermal combined cycle power plants operate mainly in day time and evening peak period while reducing its capacity in low demand periods. Pumped storage power plants (PSPP) generate electricity during evening peak period. Other renewable energy (ORE) contributes to a considerable share of energy during the day dominated by solar generation.

7.2.7 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 Case Plan from previous year plan are discussed in Chapter 10.

7.2.8 Reference Case

The Reference Case was developed following the PUCSL guidelines in addition to the Base Case Plan and it considers only the ORE power plant capacities already in operation as of 1st January 2017. The Total present value (PV) of the Reference Case plan for the period 2018-2037 is USD 14,415 million.

Capacity additions by plant type are summarised in five year periods in Table 7.5 and the resulting plant sequence is given in Annex 7.6.

Table 7.5: Capacity Additions by Plant Type – Reference Case

Type of Plant	2018 (MW)	2019-2022 (MW)	2023-2027 (MW)	2028-2032 (MW)	2033-2037 (MW)	Total capacity addition	
						(MW)	%
Gas Turbines		175				**175**	3%
Reciprocating Engines	320					**320**	5%
Coal			1,200	1,200	1,200	**3600**	55%
LNG		600			900	**1500**	23%
Major Hydro		241				**241**	4%
Pumped Hydro			600			**600**	10%
ORE						**0**	0
Total	**320**	**1016**	**1800**	**1200**	**2100**	**6,436**	100%

The base case plan contains 2700 MW of coal based power plants and 1500 MW NG based combined cycle power plants while the reference case consists of same capacity of NG based combined cycle power plants and 3600 MW coal based power plants. When compared with the base case plan, the reference case contains 900 MW of additional coal based power plants to compensate for the capacity and energy contribution from 2897 MW of ORE plants in the base case plan.

The incremental PV cost of the base case plan over the reference case is USD 153 million and the reduction in CO_2 emissions achieved with the inclusion of ORE in the base case plan is presented in Table 7.6.

Table 7.6: Reduction in Annual CO_2 Emissions in Base Case Plan (In CO_2 million tons)

Year/Scenario	2025	2030	2037
Reference Case	9.33	13.55	24.20
Base Case	7.41	11.32	19.25
Difference	**1.92**	**2.23**	**4.95**

7.3 Fuel Diversification Scenarios

Considering the energy policy element to ensure energy security through enhancing fuel diversification, two separate scenarios were studied by imposing limits on Coal power development and replacing it with Natural Gas fired combined cycle power plants to estimate the financial implications compared with the least cost generation expansion plan.

The two scenarios studied are as follows:

1. Future coal power development limited to 1800 MW
2. No future coal power development

7.3.1 Future Coal Power Development Limited to 1800 MW

In this scenario future coal power development is limited only to 1800 MW with the remaining energy requirement catered through other candidate technologies. The plant schedule in line with the least cost principle for this scenario contains the capacity additions by plant type which are summarised in five year periods in Table 7.7 and graphically represented in Figure 7.13.

The total PV cost of this scenario is USD 14,895 million and the plant schedule is presented in Annex 7.7.

Table 7.7: Capacity Additions by Plant Type – Future Coal Development Limited to 1800MW

Type of Plant	2018 (MW)	2019-2022 (MW)	2023-2027 (MW)	2028-2032 (MW)	2033-2037 (MW)	Total capacity addition (MW)	%
Gas Turbines		105				**105**	1%
Reciprocating Engines	320					**320**	4%
Coal	-	-	600	1200	-	**1800**	22%
LNG	-	600	600	-	1200	**2400**	29%
Major Hydro		241				**241**	3%
Pumped Hydro			600			**600**	7%
ORE	180	726	614	614	763	**2897**	35%
Total	**500**	**1672**	**2414**	**1814**	**1963**	**8,363**	100%

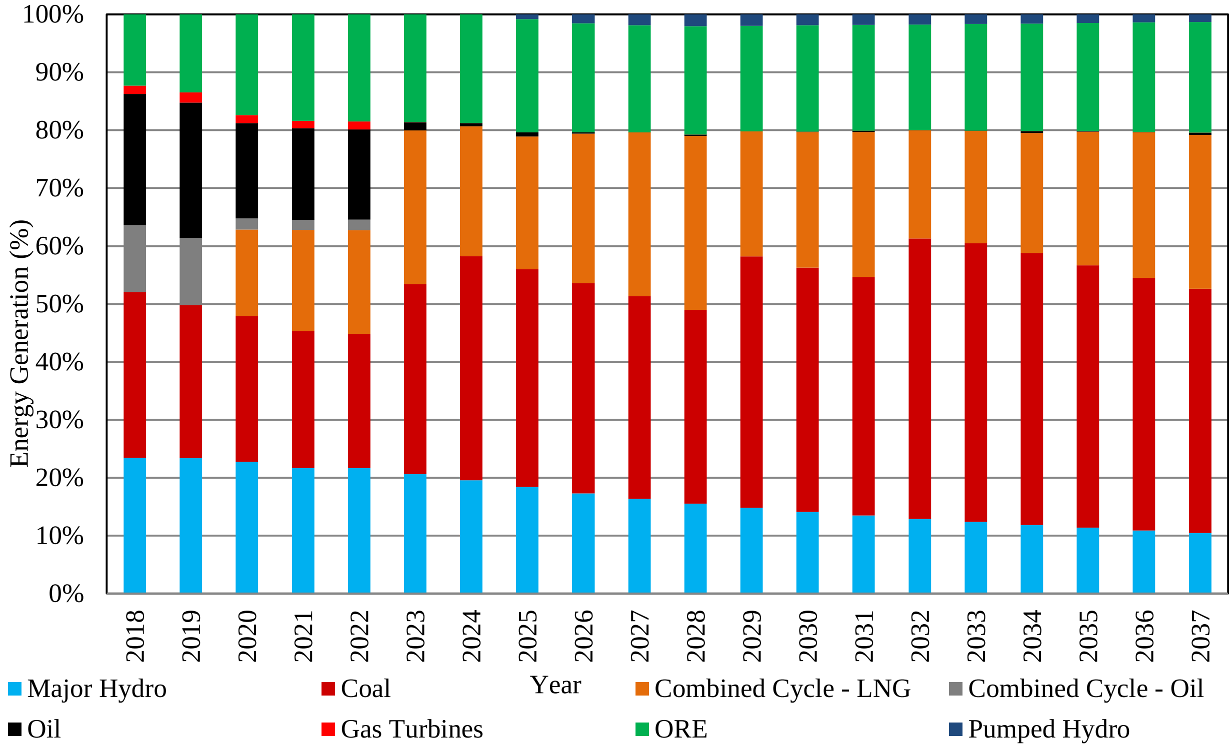


Figure 7.13 –Percentage Energy Contribution by Plant Type of Future Coal Development Limited to 1800MW Case

7.3.2 No Future Coal Power Development

In this scenario no future coal power development is permitted and the whole energy requirement is catered through other candidate technologies. The plant schedule in line with the least cost principle for this scenario contains the capacity additions by plant type which are summarised in five year periods in Table 7.8 and graphically represented in Figure 7.14.

The total PV cost of this scenario is USD 15,608 million and the plant schedule is presented in Annex 7.8.

Table 7.8: Capacity Additions by Plant Type – No Future Coal Power Development

Type of Plant	2018 (MW)	2019-2022 (MW)	2023-2027 (MW)	2028-2032 (MW)	2033-2037 (MW)	Total capacity addition (MW)	Total capacity addition %
Gas Turbines	-	105	-	-	-	**105**	1%
Reciprocating Engines	320	-	-	-	-	**320**	4%
Coal	-	-	-	-	-	**0**	0%
LNG	-	600	1500	1200	1500	**4800**	58%
Major Hydro	-	241	-	-	-	**241**	3%
Pumped Hydro	-	-	-	-	-	**0**	0%
ORE	180	726	483	615	763	**2767**	34%
Total	**500**	**1672**	**1983**	**1815**	**2263**	**8,233**	100%

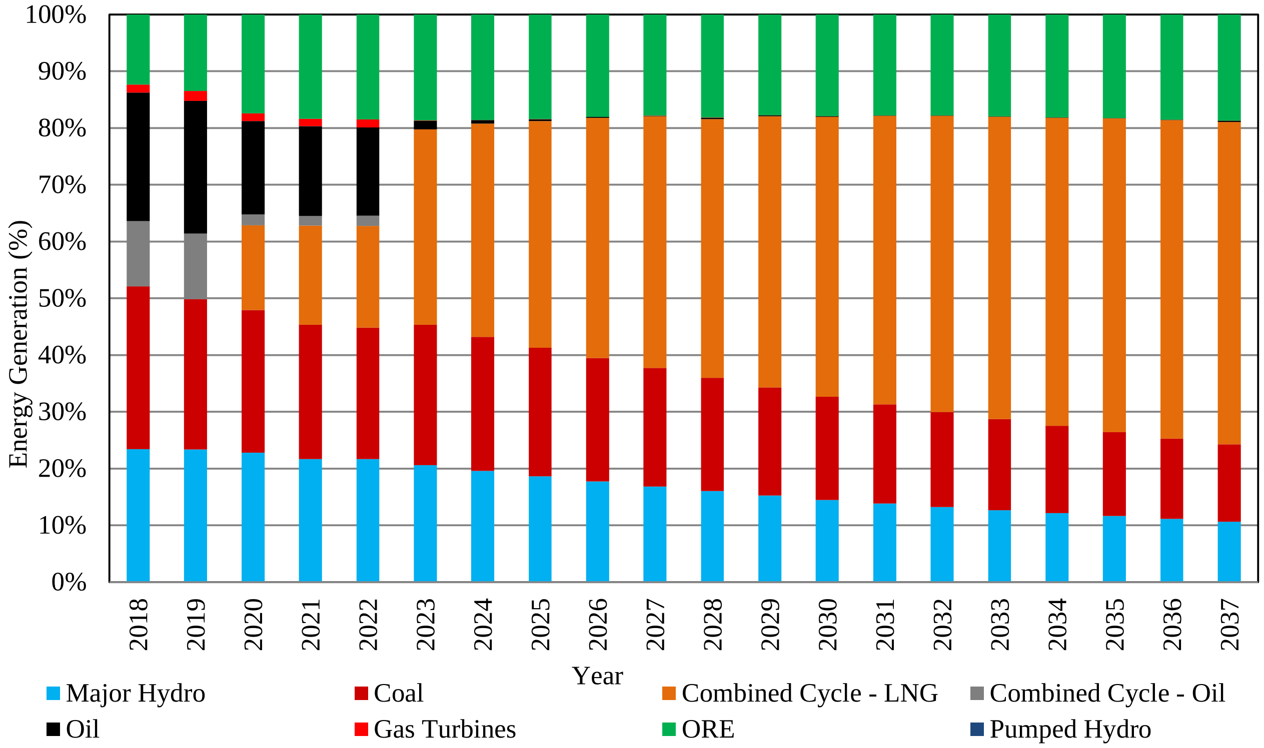


Figure 7.14 –Percentage Energy Contribution by Plant Type of No Future Coal Power Development Case

The option of introducing Pumped Storage Power Plants is not considered in this scenario as improvement of the operational restrictions of coal power plants during off peak is not required due to the non-inclusion of coal power plants in the schedule.

For the integration of ORE to the system, it is essential to utilize the operational capabilities of the NG based combined cycle power plants by operating at the minimum loading level to avoid the curtailment of ORE.

7.3.3 Comparison of the Results

The comparison of the total PV cost of the each fuel diversification scenario with the base case and the reference case is presented in Table 7.9.

Table 7.9: Comparison of the scenarios

Case	Capacity Additions by 2037	Total PV Cost (MUSD)	Difference of PV Cost (MUSD)
Reference Case	Coal = 3600 MW LNG =1500 MW	14,415	-
Base Case	Coal = 2700 MW LNG =1500 MW	14,568	153
Future Coal Power Development Limited to 1800 MW	Coal = 1800 MW LNG =2400 MW	14,895	480
No Future Coal Power Development	Coal = 0 MW LNG =4800 MW	15,608	1,193

7.4 Impact of Demand Variation on Base Case Plan

Low Demand and High Demand cases were analysed in order to identify the demand effect on the Base Case Plan. The demand forecasts used for these two cases are shown in Annex 3.1.

Twenty year average electricity demand growth in high demand forecast is 6.0% which is 1.0% higher than the growth in base demand forecast. This demand increase results an increase of 14.0% in the total present worth cost compared to the Base Case over the planning horizon. Also the twenty year average electricity demand growth in low demand forecast is 4.0% which is 1.0% lower than the growth in base demand forecast. This demand reduction results to the reduction of 10.4% in the total present worth cost of the Base Case over the planning horizon.

Overall thermal and renewable capacity additions and fuel requirement of High and Low Demand cases vary over the planning horizon 2018-2037.The resulting plans for the two cases are given in Annex 7.9 and Annex 7.10 respectively.

7.5 Impact of Discount Rate Variation on Base Case Plan

To analyse the effect of discount rate on Base Case Plan, two additional Scenarios were carried out for discount rates of 3% and 15%.

3% discount rate Scenario was carried out to investigate whether high capital cost plants are selected at lower discount rate. Coal power plants with high capital cost were advanced in this scenario. Pump Storage Power Plant was selected towards the end of the study period. Therefore, it was considered in 2025 as in the Base Case Plan due to technical requirements.

Plant sequences for the above High Discount Rate & Low Discount Rate Scenarios are given in Annex 7.11 and Annex 7.12 respectively.

7. 6 Impact of Fuel Price Sensitivity on Base Case Plan

For the Base Case Plan, fuel prices were assumed to be constant throughout the planning horizon. The impact of global fuel price escalations is an important input variable and the sensitivity of the base case to fuel price variations needs to be investigated in the planning process. Therefore, a separate scenario was studied applying the year by year fuel price escalations projected by the International Energy Agency.

World Energy Outlook 2016, published by International Energy Agency announces the latest indicative price variations of Coal, Oil and Gas up to 2040. The IEA's methodology considers the impact of supply demand balance, future energy policies, global economic activities and demographic trends for projecting future fuel prices trajectories. Following fuel prices escalations given in table 7.10 have been projected under the current policies scenario and prices escalations are comparatively high than other scenario based forecast of IEA and forecast made by other international financial institutions. According to the forecast, oil price escalation is the highest for the period of 2018-2040. Coal price escalation is the second highest followed by the natural gas price escalations.

Table 7.10: Fuel Price Escalation percentages (from 2018 prices)

Fuel	2018	2020	2025	2030	2035	2040
Coal	Base	6.0%	17.5%	30.3%	36.6%	43.2%
Natural Gas	Base	-1.6%	13.7%	31.3%	34.5%	37.7%
Crude Oil	Base	20.9%	50.5%	87.3%	100.8%	115.3%

Above fuel price escalations have been used throughout the planning period for the Base Case and the "No future coal power development" Scenario. It is observed that the plant additions in each year remain unchanged in both cases and the operation cost increases due to the fuel price escalation. The table 7.11 below includes the costs comparison of simulated scenarios. According to the results the Total PV cost for 2018-2040 period increase by 1,259 million USD for and the Base Case and 1,785 mill USD for the "No future coal power development Scenario".

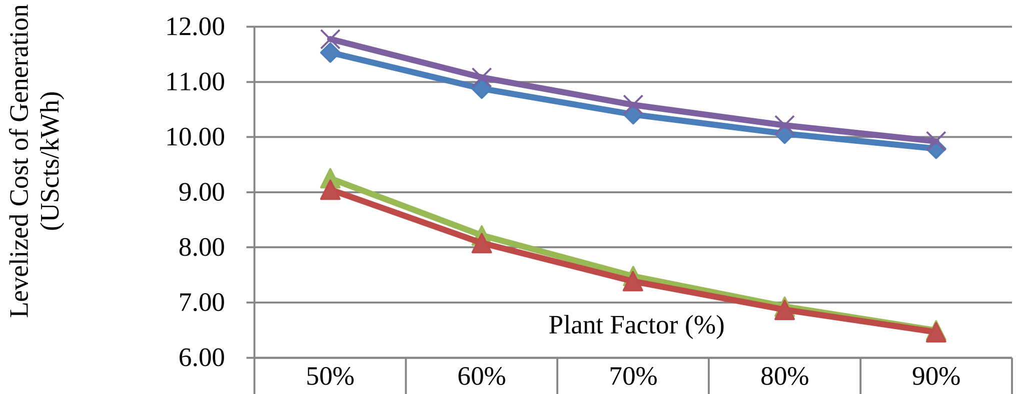
Table 7.11: Cost impact of fuel price escalation of Base case and No Future Coal case (million US$)

Scenario	Constant Fuel Prices	Fuel Price Escalation	Difference
Base Case	14568	15828	1260
No future coal power development Scenario	15608	17393	1785

7.7 Natural Gas Breakeven Price Analysis

300MW Natural Gas combined cycle power plants, 300MW High Efficient Coal power plants and 600MW super critical coal power plants being the major base load power plants in the proposed expansion plan, analysis was carried to determine the breakeven price of Natural Gas. Analysis considered 1200MW of power plant capacity and the required fuel handling infrastructure ie. terminal or FSRU for LNG power plant and coal handling jetty for coal power plants. It was assumed that LNG terminal of capacity of 1MTPA could cater for 4 plants of 300MW of Combined Cycle Power Plants.

Levelized cost of electricity for different plant factors for above power plants is given in Figure 7.15. Fuel costs used are 10 $/MMBTU for imported Natural Gas and 69.80 $/Ton for coal. The levelized cost includes the construction cost, operation & maintenance cost and energy costs and discounted with 10% discount factor.



	50%	60%	70%	80%	90%
LNG (4x300MW+ Terminal)	11.53	10.88	10.41	10.06	9.79
LNG (4x300MW+ FSRU)	11.78	11.08	10.59	10.22	9.93
Coal (2x600MW +Jetty)	9.25	8.22	7.48	6.93	6.49
Coal (4x300MW +Jetty)	9.05	8.08	7.39	6.87	6.46

Figure 7.15*: *Screening Curves for LNG and Coal Power Plants of 1200MW

Studies were carried out to determine the breakeven price of LNG by comparing with 4x300MW coal power plants with a coal handling jetty. Breakeven price is derived with respect to Colombo CIF price of 69.8 US$/MT for coal at 70% plant factor.

7.7.1 Breakeven Price of Imported Natural Gas

Breakeven price for imported LNG when considering 4x300MW LNG power plants with 1 MTPA terminal is 5.8US$/MMBTU. Furthermore, the breakeven price for imported LNG by considering 4x300MW LNG power plants with FSRU is determined as 5.5US$/MMBTU.

Table 7.12 shows the infrastructure cost which was used in the analysis.

Table 7.12: Fuel Handling Infrastructure Cost

	Capital Cost (USD million)	Operational Cost (USD million/year)
Terminal (1MTPA)	492	Fixed O&M : 2.1 Variable O&M : 1.8
FSRU	173	Fixed O&M & Rental : 50
Coal Jetty	118	

7.7.2 Breakeven Price of Local Natural Gas

Breakeven price of local Natural Gas was determined by comparing 4x300MW coal power plants with a coal handling jetty with 4x300MW LNG power plants. Breakeven price is determined as 6.9 US$/MMBTU. It is slightly higher than the imported LNG breakeven price due to the reason that a Terminal or FSRU infrastructure cost need not be incurred in the local NG Scenario.

Analysis in section 7.7.1 and 7.7.2 does not consider the pipeline infrastructure cost and the breakeven prices are considered to be the price delivered at power plant.

7.8 Energy Mix with Nuclear Power Development Scenario

Energy Mix with Nuclear Power Development scenario was carried out to study the impact of diversification of fuel options in electricity generation mix rather than adhering conventional thermal energy sources such as petroleum or coal in future. National Energy Policy also identified “Ensuring Energy Security” as a major policy element which could be achieved through enhancing fuel diversification. Therefore, this scenario was studied by introducing Nuclear power plants with the limitations on Coal power development.

Nuclear plants are introduced in year 2030, first 600MW was selected in 2032 and thereafter another 600MW was added in 2035. Energy Mix with Nuclear Power Development scenario gives a diversified fuel mix including Coal, LNG and Nuclear. Energy share in 2037 from Coal, LNG and Nuclear from the total energy are shown in Figure 7.16 and the resulting plant addition and cost variation is given in Annex 7.13.

7.9 HVDC Interconnection Scenario

According to the Memorandum of Understanding (MOU) signed between Governments of India and Sri Lanka in 2010, a feasibility study was carried by CEB and Power Grid Corporation Indian Limited (POWERGRID) jointly for the implementation of 1000MW HVDC interconnection project. The feasibility study has considered the technical, economical, legal, regulatory and commercial aspects in trading electricity between India and Sri Lanka. The feasibility study is yet to be finalized.

According to the initial proposals on feasibility study and also with the Economic & Financial Analysis the project is not economically or financially viable[32]. Major items which are affecting the project cost are Submarine cable and HVDC Technology selection.

7.9.1 Possibility of Reduction of Cost

- Reduction in length of Submarine Cable: Termination of Cable at Talaimannar in Sri Lankan Territory in place of Thirukketiswaram. This would reduce the length of the submarine cable by 30km.

- Conventional HVDC (LCC) instead of VSC based HVDC

Possibility of further reduction of cost would be explored during implementation stage.

According to the present context, India has total installed capacity of Coal power plants 192GW [33] with 59% capacity share. Also government of India has launched a scheme called "Power for All" [34] in order to address the lack of adequate electricity availability to all the people in the country. Therefore, power requirement of India should be further studied with current situation. Also in Sri Lanka, Coal power development, off peak improvement and renewable development are the important factors when considering HVDC interconnection. Therefore both India and Sri Lanka must consider the present situation and carry out further studies on HVDC interconnection feasibility considering economics, power system stability, power quality etc.

7.10 Externalities

Power generation gives rise to a range of costs due to local air pollution as well as global climate change impacts from GHG emissions. Such external social and environmental costs which are known as externalities are unaccounted cost arising as a result of impacts on climate, human health, crops, structures and biodiversity. These costs are accompanied with all types of electricity generating technologies in different scale and need to be considered if the true cost of generation is to be estimated. Therefore, until these costs are properly identified and quantified in monetary terms, it will play a limited role in technology selection.

7.10.1 Local Environmental Damage Cost

Major local environmental damage costs are location specific and known to be arising from

- local air pollutants released as a result of fuel combustion
- thermal pollutants including disposal of waste heat and effluents
- Social and Ecological aspects

The health damage costs associated with air pollutants and thermal discharges need to be evaluated for Sri Lankan scenario. The damage from air pollutants can be mitigated by complying with relevant guideline related to emissions and the damage from thermal pollution could be mitigated by complying with appropriate procedures for thermal discharges. Social and ecological aspects and mitigation measures will be identified during Environmental Impact Assessment.

The main concern to be examined in this process is to determine the monetary value to the local damage costs which would be considered in the choice of generation technology.

7.10.2 Global Damage Cost of GHG Emissions

Global damage cost of carbon is highly uncertain and meant to be a comprehensive estimate of climate change damages which includes changes in net agricultural productivity, human health, property damages from increased flood risk and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. This value must be set by the policy makers of a country since it will have a direct impact if this valuation is considered for decision making among investment.

When the valuation is carried out it should be decided whether to include only the combustion emissions of a project or the life-cycle emissions associated with extraction and transportation of fuel and particularly liquefaction and regasification processes when considering LNG.

When it comes to reducing GHG emissions, Sri Lanka has obligations under Nationally Determined Contributions (NDC) to reduce emissions unconditionally as well conditionally depending on availability of carbon finance. NDC targets are described in Chapter 9-Section 9.8.3 (b).

7.10.3 Environmental and Social Damage Cost Estimates

There are number of different literature which provides estimates for the damage cost of power generation.

The report "Environmental Externalities from Electric Power generation" by Regional Center for Renewable Energy and Energy Efficiency published in 2013 presents average externalities for different sources of power generation in several European countries. According to the report highest amount of externalities in the European Union originate from coal and oil followed by gas and finally the renewable energy sources such as wind and PV which has a minimum damage cost.

With reference to **"Addendum: Responses by the Transmission Licensee" in Annex 11 of Long Term Generation Expansion Plan 2015-2034**, estimates for social and environmental damage cost of coal from different country specific studies are given in Table 7.13.

Table 7.13: Estimates for Social and Environmental Damage Cost

Study	**Estimated Damage Cost of Coal USc/kWh**	**Estimated Damage Cost of other technologies USc/kWh**
National Academy of Science, USA. Hidden costs of energy: unpriced consequences of energy production and use.	3.2	
P. Epstein, Full cost accounting for the life cycle of coal, Annals of the NYS Academy of Sciences,2009	18	
W. Nordhaus, Environmental accounting for Pollution in the US economy, August 2011	2.8	0.85 Natural Gas
Hidden costs of electricity: Externalities of power generation in Australia	1.3	
Health and Environmental Costs of electricity generation in Minnesota, Sept 2013	6	
Environmental Externalities from Electric Power Generation, Sept 2013	3 - 9.5 (mean 5.4)	Oil 4 – 9 (5.9) NG 0.49 - 3 (1.7) PV 0.25 – 0.6 (0.5) Wind 0.001 – 0.25 (0.1) Hydro 0.03 – 1 (0.4) Biomass 0.08 – 3.5 (1.3)
Air Pollution economics: Health costs of air pollution in the greater Sydney metropolitan area	No estimates for unit of power generation is presented	
Health and Social Harms of coal mining in local communities, 2012	Not relevant. Sri Lanka has no coal mining	

It is well known that damage costs are a function of income level of a country, population density around power plants and the specifications of each type of power plant that are considered to contribute to the damage cost. Therefore unless country and locations specific study is carried out, it is difficult to estimate the damage cost with reasonable accuracy.

When comparing the unit cost of major base load power plants at 70% plant factor, 300MW LNG combined cycle power plant is 9.62 USCts/kWh and 600MW supercritical coal power plant is 7.3 USCts /kWh. Therefore, the incremental damage cost from coal has to be more than 2.32 USCts /kWh in order to justify the technology selection from coal to LNG. The part of the damage cost is already incorporated in the unit cost of coal power plant when selecting the technology of super critical coal power plant over conventional coal power plant for comparison.

7.11 Comparison of Energy Supply alternatives in 2037

7.11.1 Global Context

Table 7.14 shows the present and projected energy mix in a number of different countries. When considering China, Japan, India, Malaysia and Vietnam the major portion of the power generation is projected to be from coal at the end of the projected time horizon according to current policies. It is projected to be even more than 50% in countries such as China, India and Malaysia in 2040 and in Vietnam in 2030. Renewable share in most of these countries is maintained between 20% to 40%. Malaysia's use of renewable sources other than hydropower, in the power sector remains fairly limited.

In contrast European Union (EU) energy mix mainly consists of renewable energy since the power grid is interconnected among EU countries and hence the technical limitations of absorbing renewable energy are less. Renewable energy share is projected to be maintained at 43% in 2040.

When considering Asian countries major source of power generation is coal and it remains to be the same in 2040 according to the projections.

Table 7.14: Present & Projected Power Generation Mix in Other Countries

		LNG	Coal	Nuclear	Renewable	Other	Source
USA	2014	27%	40%	19%	13%	1%	IEA-World Energy Outlook 2016
	2040	34%	25%	16%	24%	0%	
China	2014	2%	73%	2%	23%	0%	IEA-World Energy Outlook 2016
	2040	7%	58%	9%	26%	0%	
EU	2014	14%	27%	28%	29%	2%	IEA-World Energy Outlook 2016
	2040	28%	13%	17%	43%	0%	
Japan	2014	41%	34%	0%	13%	11%	IEA-World Energy Outlook 2016
	2040	27%	31%	16%	27%	1%	
Russia	2014	50%	15%	17%	17%	1%	IEA-World Energy Outlook 2016
	2040	45%	14%	20%	21%	0%	
India	2014	5%	75%	3%	15%	2%	IEA-World Energy Outlook 2016
	2040	10%	65%	4%	20%	1%	
Non OECD Asia	2014	8%	67%	3%	19%	2%	IEA-World Energy Outlook 2016
	2040	11%	58%	6%	23%	1%	
South East Asia	2013	44%	32%	0%	18%	6%	IEA-South East Asia Energy Outlook 2015
	2040	26%	50%	1%	22%	1%	

		LNG	Coal	Nuclear	Renewable	Other	Source
Malaysia	2013	50%	38%	0%	8%	3%	IEA-South East Asia Energy Outlook 2015
	2040	27%	58%	0%	16%	0%	
Vietnam	2015	30%	34%	0%	34%	2%	Vietnam Power Development Plan VII (Revised) - Approved in 2016
	2030	17%	53%	6%	23%	1%	
Thailand	2015	64%	20%	0%	15%	1%	Thailand Power Development Plan 2015-2036
	2036	37%	23%	5%	36%	0%	

7.11.2 Sri Lankan Context

The Figure 7.16 illustrates the energy mix in different key scenarios in 2037. The Base Case Scenario is complied with the National Energy Policy Elements with realistic cohesiveness. Compared with Base Case Scenario, Reference Scenario shows lower PV Cost and with low integration of ORE. Energy Mix Scenario enhances the energy security policy by diversifying the fuel mix further in to Nuclear, but it shows much higher PV cost. In the fuel diversification scenarios, the no future coal power development scenario results in considerable increase in to total PV cost compared with the Base Case Scenario.

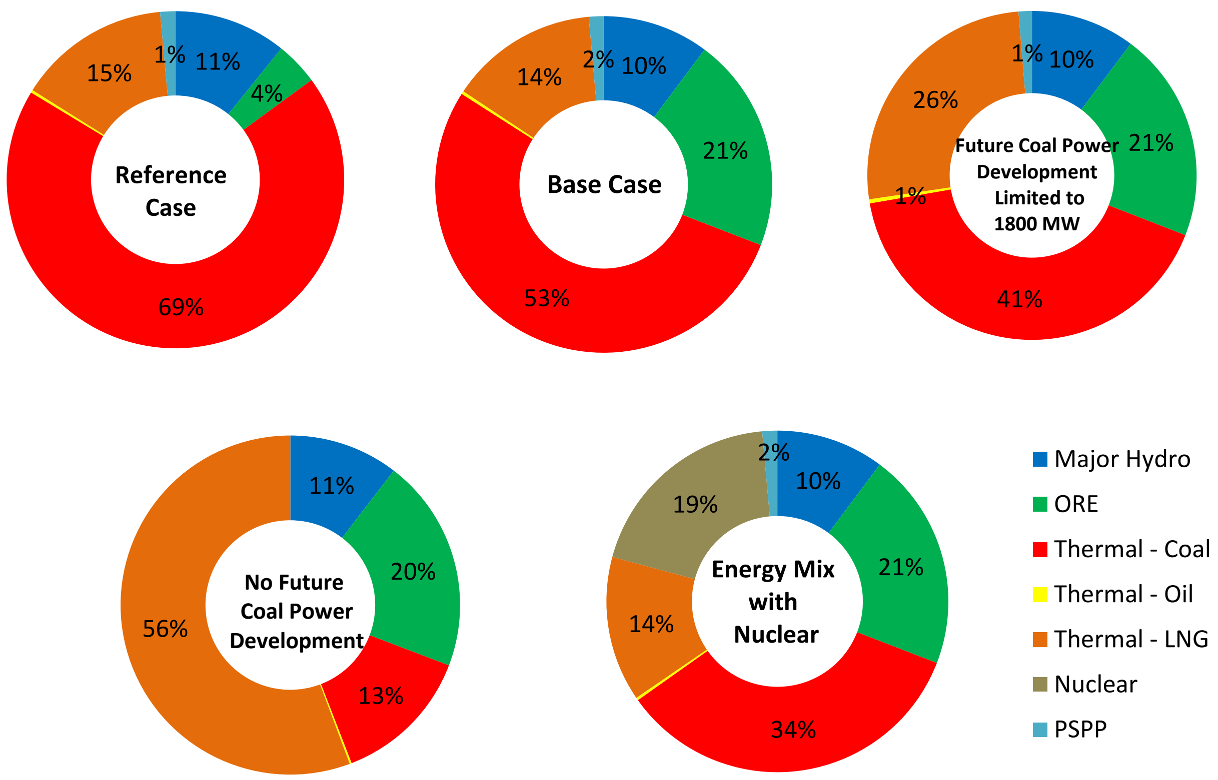


Figure 7.16: Energy share comparison in 2037

7.12 Summary

The total present value of cost over the planning horizon for Base Case and different Scenarios and Sensitivities studied are summarized in Table 7.15.

Table 7.15: Comparison of the Results of Expansion Planning Scenarios and Sensitivities

	Present Value of costs during the planning horizon	Deviation of PV Cost from Base Case	
	(Million USD)	(Million USD)	%
Base Case	14,568	-	-
Scenarios			
Reference Case	14,415	(153)	(1)
Fuel Diversification			
Future Coal Power Development Limited to 1800 MW	14,895	327	2
No Future Coal Power Development	15,608	1,040	7
Energy Mix with Nuclear Power Development	15,126	558	4
Sensitivities on Base Case			
Demand Variation			
High Demand	16,604	2,036	14
Low Demand	13,055	(1,513)	(10)
Discount Rate Variation			
High Discount	10,915	(3,653)	(25)
Low Discount	24,065	9,497	65
Fuel Price Escalation	15,828	1,260	9

CHAPTER 8
IMPLEMENTATION AND INVESTMENT OF GENERATION PROJECTS

This chapter elaborates on the required implementation and the investment plan for the generation projects identified in the Base Case Plan (and the issues related to that).

8.1 Committed and Candidate Power Plants in the Base Case Plan

8.1.1 Committed Plants

Following power plants are considered as committed projects in the present study.

- Hydro and other renewable power projects - Uma Oya (122MW), Broadlands (35MW), Moragolla (30MW), Moragahakanda (25MW), Gin Ganga (20MW), Thalpitigala (15MW) and Mannar Wind Park (100MW)
- Thermal power projects - Kelanitissa Gas Turbine (3x35MW), LNG Combined Cycle Power Plant (300MW) and Furnace Oil based power plant (170MW)

8.1.2 Present Status of the Committed and Candidate Power Plants

A brief description of the current status of the committed and candidate power projects on which the commitments should be made are given below.

(i) Uma Oya Multipurpose Project

This project is a multipurpose development project and it is implemented by the Ministry of Mahaweli Development and Environment in coordination with the Ministry of Power and Renewable Energy and Ceylon Electricity Board. Financial agreement has been signed with the Government of Iran to commence the construction along with feasibility study. The contract is effective from April 2010 and the plant is scheduled to be commissioned by June, 2018. Currently the civil works, hydro mechanical works and electro mechanical works are in progress.

(ii) Broadlands Hydro Power Project

China National Electric Equipment Corporation (CNEEC) was selected as the main Contractor for the Broadlands Hydro Power Project and the main construction works were commenced in 2013. At present, the construction work is in progress at Main Dam Site, Main Tunnel, Diversion Tunnel and Power House Site and the project is scheduled to be complete in June, 2019.

(iii) Moragolla Hydro Power Project

Review of feasibility study and detail design has been completed in 2014 by Nippon Koei, joint venture with Nippon Koei India Pvt Ltd. Preconstruction work including detailed design and tendering commenced in July 2014. Funds from ADB were obtained for implementation of this project. Civil works, electro mechanical and hydro mechanical works will commence in 2017 and the power plant is expected to be in operation by December, 2021.

(iv) Moragahakanda Hydro Development Project

Moragahakanda Kaluganga Development Project is one of the major multi-purpose development projects of the country and it is implemented by the Ministry of Mahaweli Development and Environment with the Mahaweli Authority of Sri Lanka. Main aim of the project is to provide irrigation, other water requirements as well as power generation. The construction work of the Moragahakanda reservoir has been completed and the power station is under construction. The project consists of three hydro power stations with total capacity of 25MW and expected to generate annual energy of 114.5GWh under average hydro condition. These power stations are expected to be commissioned by 2017, 2020 and 2022 respectively.

(v) Other Multipurpose Projects (Gin Ganga, Thalpitigala)

Gin Gaga and Thalpitigala Hydro power projects are to be developed by Ministry of Irrigation and Water Resource Management. The preliminary feasibility studies and EIA studies of the Thalpitigala Hydro Power Project have been finalized and the preconstruction activities are ongoing. Thalpitigala and Gin Ganga hydro power plants are expected to be in operation in 2020 and 2022 respectively.

(vi) 100MW Mannar Wind Park

Ceylon Electricity Board has taken the initiative to develop the first 100MW wind farm in the Mannar Island with the assistance of Asian Development Bank (ADB). At present, the feasibility study, Initial environmental assessment and land procurement process have been completed and the final stage of the Environmental Impact assessment is ongoing. Required funds are to be secured and completed in 2017. Expected date of completion of the project is end 2019.

(vii) Seethawaka Hydro Power Project

CEB has conducted the initial feasibility study together with the procurement of consultancy services for Environmental Impact Assessment (EIA) of the project. Presently a separate Project Management Unit has been formed within CEB. It has already initiated the EIA study and detailed feasibility study prior to its implementation.

(viii) Pumped Storage Power Project

CEB initiated the study on "Development Planning on Optimal Power Generation for Peak Power Demand in Sri Lanka" with the technical assistance from JICA through the Government of Sri Lanka in 2013. This study was completed in December 2014 and identifies the future options to meet the peak power demand in Sri Lanka. Pumped Storage Power Plant option has been selected as the most suitable option and several sites have been suggested in priority order considering their social, environmental and financial impacts. However, the recent analysis on the behavior of the electricity demand shows that the day time peak will be prominent than the evening peak in the future. Under that context the technical, operational and economic aspects of introducing a pump storage power plant should be further reviewed.

(ix) 3x35MW Kelanitissa Gas Turbine Power Plant

A land area has been identified within Kelanitissa Power Station premises and environmental clearance from Central Environmental Authority has been already obtained for the project.

Presently a separate Project Management Unit has been formed within CEB for the implementation of the power plant and it is expected to be in operation in 2019.

(x) 300MW LNG Combined Cycle Power Plant

Energy Diversification and Enhancement Project Phase IIA- Feasibility Study for Introducing LNG to Sri Lanka, 2014 has identified, Kerawalapitiya as the most suitable location for the development of new LNG fired power plants by considering the technical, economic, social and environmental aspects. Presently, CEB has called for the Request for Proposals (RFP) for the development of a 300MW Natural Gas fired Combined Cycle Power Plant at Kerawalapitiya. It is expected to be in operation in 2019/2020.

(xi) 170MW Furnace Oil based Power Plant

LTGEP 2015-2034 identified the short term capacity requirement of 170MW. The documents for Request for Proposals (RFP) for the development of 170MW Furnace Oil based Power Plant are under preparation and expected to be in operation by 2018.

(xii) New Coal fired Power Plant – Foul Point, Trincomalee

Pre-feasibility study on High Efficient Coal Fired Thermal Power Plant in Sri Lanka was initiated in June 2013 by the financial assistance from New Energy and Industrial Technology Development Organization (NEDO), Japan. The purpose of the study is to identify a suitable location to implement High-Efficient Coal Fired Thermal Power Plant to Sri Lanka. CEB and Japanese experts identified a land area in Sampur, Trincomalee which is most suitable for 1200 MW (either 300MW High efficient advanced subcritical power plants or 600MW Super critical power plants) coal power development. CEB received the Terms of Reference (TOR) for EIA from Central Environmental Authority in January 2015 and accordingly in May 2015 called for Expression of Interest for Consultancy to carry out the EIA of the project. However, the EIA of the proposed project was temporarily suspended due to the non-availability of the identified land for the power plant development. Presently an alternate land at Foul Point area has been identified and process of acquisition is initiated. Necessary feasibility studies for the alternate land are to recommence once the land acquisition is finalized.

8.2 Power Plants Identified in the Base Case Plan from 2018 to 2028

The proposed major hydro, thermal and other renewable energy plants up to 2028 according to the Base Case Plan are given below.

Major Thermal Power Plants:

- 320MW Furnace Oil Power Plants in 2018
- 2x35MW Gas Turbine in 2019
- 300MW Natural Gas Fired Combined Cycle Power Plant in 2019
- 35MW Gas Turbine in 2020
- 300MW Natural Gas Fired Combined Cycle Power Plant in 2021
- 300MW New Coal Power Plant in 2023 (Change to super critical will be evaluated)
- 300MW New Coal Power Plant in 2024 (Change to super critical will be evaluated)
- 300MW New Coal Power Plant in 2025 (Change to super critical will be evaluated)
- 600MW New Supercritical Coal Power Plant in 2028

Major Hydro Power Plants:

- 122MW Uma Oya HPP in 2019
- 35MW Broadlands HPP in 2020
- 15MW Thalpitigala HPP in 2020
- 30MW Moragolla HPP in 2022
- 20MW Gin Ganga HPP in 2022
- 20MW Seethawaka HPP in 2022
- 200 MW Pump Storage Power Plant in 2025
- 200 MW Pump Storage Power Plant in 2026
- 200 MW Pump Storage Power Plant in 2027

Other Renewable Energy (ORE) Plants:

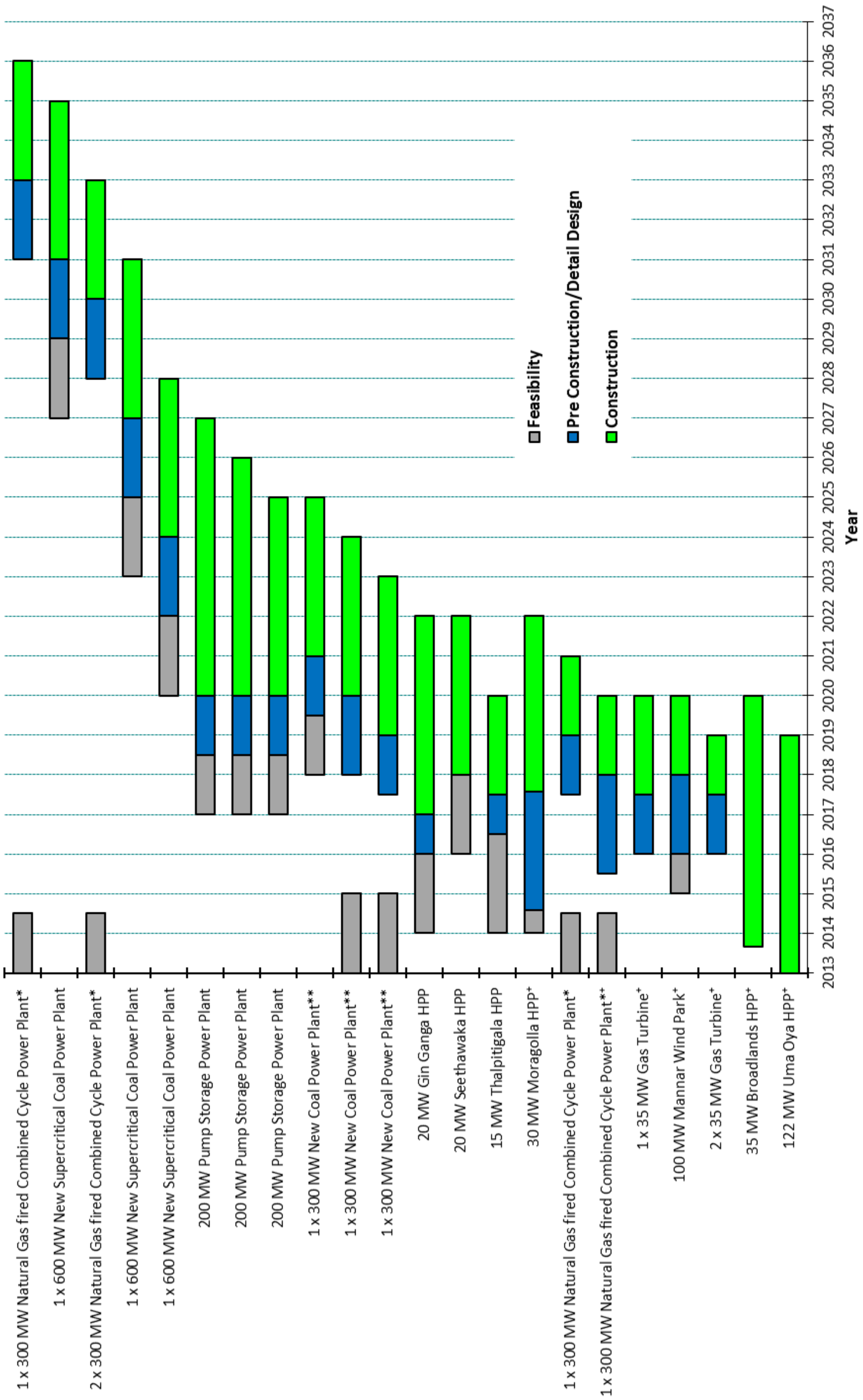
Table 8.1 – ORE Additions 2018-2028

Year	Mini Hydro	Wind	Solar	Biomass
2018-2020	45MW	270MW	360MW	15MW
2021-2025	50MW	315MW	275MW	25MW
2026-2028	30MW	70MW	215MW	15MW

Note: Wind developments in Mannar, Puttalam, Hill Country, Northern & Eastern Regions
Solar developments in Northern, Eastern, Uva & Southern Regions

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

*Natural Gas fired Combined Cycle Power Plants – Western Region

** Change to super critical will be evaluated

Plants assumed as in operation from 1st January each year

Figure 8.1 - Implementation Plan 2018 – 2037

8.4 Investment Plan for Base Case 2018–2037 and Financial Options

8.4.1 Investment Plan for Base Case 2018–2037

The annual investment requirement for the twenty year period from 2018 to 2037 is graphically shown in Figure 8.2. The cost details of the investment plan for major hydro & thermal projects and major wind & solar developments are tabulated in Table 8.2 and Table 8.3 respectively. Construction cost of Coal jetty & LNG terminal development were excluded and only the plant by plant pure construction cost includes in Table 8.2.

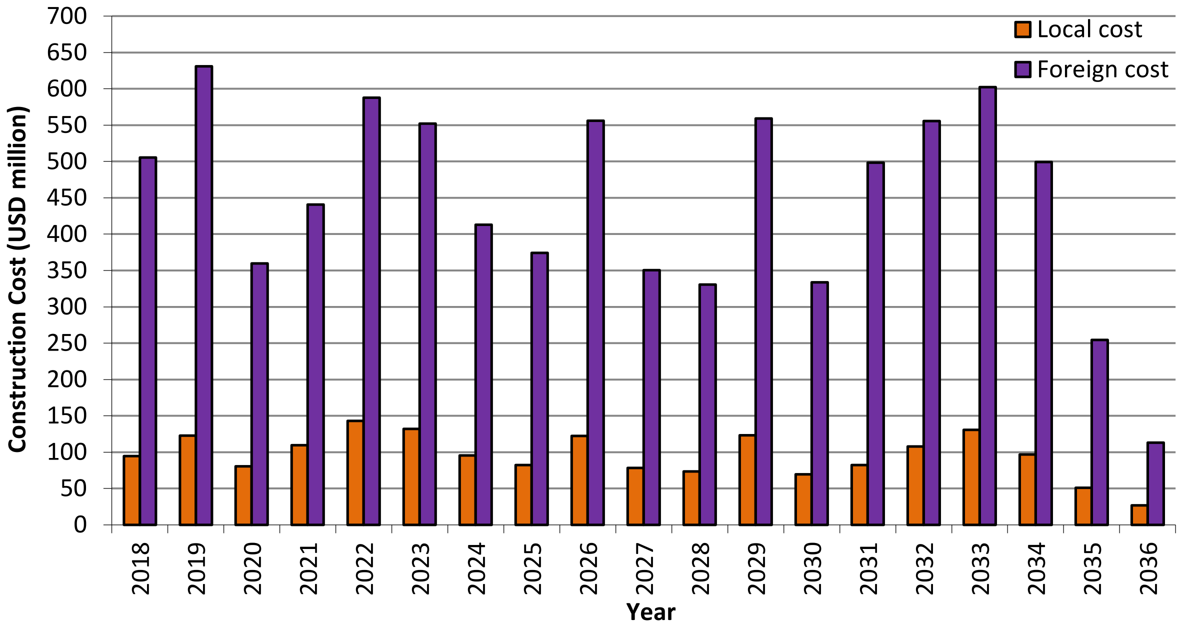


Figure 8.2 - Investment Plan for Base Case 2018 – 2037

8.4.2 Financial Options

Capital required for investment in new power facilities could be in the form of GOSL/CEB funds, private funds (such as Independent Power Producers-IPP and Joint Ventures-JV) and Public and Private Partnerships (PPP). The funding could be obtained through sources such as Official Development Assistance (ODA), Export credit, Local Commercial Loans, Concessionary loans and Grants by other developed countries.

The financial terms such as interest rate, commitment fee, exposure fee, grace period and loan repayment period of these funding options would be determined based on,

- Financial performance of the country
- Financial performance of the utility
- Granting of government guarantee
- Credit risk ratings etc.

Most favourable scheme out of above funding options should be selected based on the financial analysis.

Financial analysis of individual projects shall be performed based on financial indicators which determine the viability of individual project. The financial indicators includes,

- Internal Rate of Return (IRR)
- Financial Internal Rate of Return (FIRR)
- Return on Equity (RoE)
- Weighted Average Cost of Capital (WACC)
- Levelised Cost of Electricity (LCOE)

IRR & FIRR should be compared with prevailing financial market rates in order to evaluate the viability of the project. RoE is an indicator of the equity providers' expectation on return and WACC is an indicator of average return on the investment. LCOE will vary depending on the type of the project and it is usually taken as a representation for the average price that the generating asset must receive in a market to break even over its lifetime.

8.5 Investment Plan Variation for Scenarios

The investment requirement for No Future Coal Power Development Scenario (All LNG Development) was compared against the Base Case Plan investment requirement for the 20 year period from 2018 to 2037.

Figure 8.3 & Figure 8.4 show the annual operational cost and total annual cost variation of No Future Coal Power Development Scenario compared with Base Case.

Annual cost of operation in No Future Coal Power Development Scenario shows the higher figure due to high operation & maintenance cost throughout the planning horizon including fuel.

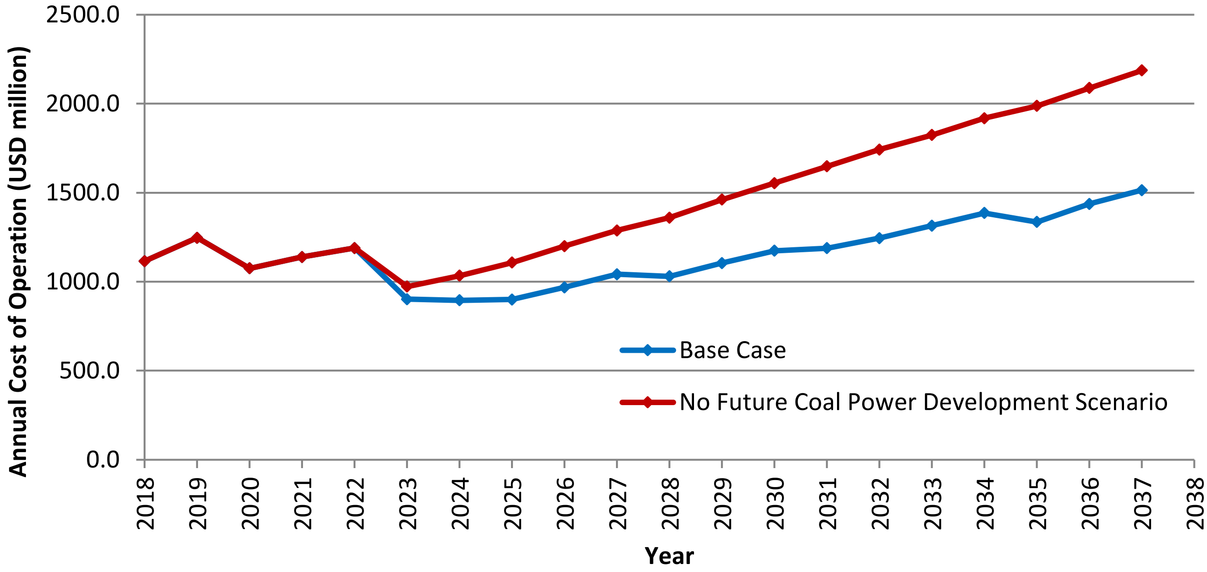


Figure 8.3 – Annual Cost of Operation

Figure 8.4 shows the total annual cost (construction cost of major hydro, thermal, wind, solar & operational costs) including Coal jetty and LNG terminal development cost of No Future Coal Power Development Scenario compared with Base Case. It can be seen that the latter part of the planning horizon, No Future Coal Power Development Scenario shows higher total annual cost than the Base Case Plan.

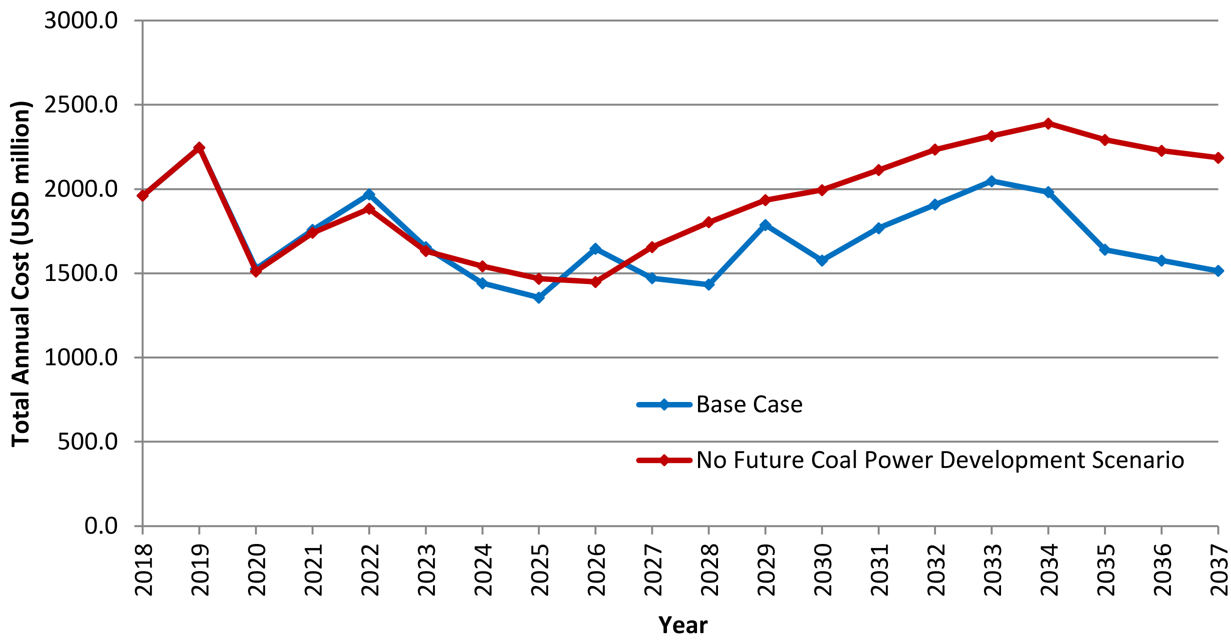


Figure 8.4 – Total Annual Cost Comparison

8.6 Recommendations for the Base Case Plan

As discussed in previous chapters, base case plan is consist of thermal, hydro and other renewable energy generation facilities. Timely implementation of proposed plants is crucial to avoid capacity shortages, energy shortages and high cost alternative generation in future.

Major recommendations for the Base Case Plan are as follows.

- Base Case Plan has identified 1500MW LNG, 2700MW Coal, 105MW Gas Turbine and 320MW Furnace Oil Power developments by 2037. Timely implementations of these power plants are very much important to avoid capacity shortages, energy shortages and costly emergency generation in the future. Furthermore, these power plants will reduce the environmental impacts from electricity generation produced from conventional lower efficient thermal power generation.

- Timely implementation of all the committed and candidate hydro power plants considered in the Base Case Plan is important to avoid power shortages in future.

- Other Renewable Energy (ORE) additions projected in the Base Case Plan consist of 1205MW Wind, 1392MW Solar, 215MW Mini Hydro and 85MW Biomass during the planning horizon. Timely implementations of these ORE plants as per the schedule are crucial to avoid energy & capacity shortage of power system.

- Implementation of 3x200MW Pump Storage Power Plant as per the Base Case Plan will facilitate peak operation by minimizing high cost thermal generation, ORE absorption and reduce the curtailment of ORE generation.

- Identification and securing of suitable locations for future power plant development is important for timely implementation of those projects.

- The LNG Power Plants may require minimum plant factors as high as 70% so that LNG Contracts be viable and competitive in the Global market. This would lead to curtailment of more RE sources in order to dispatch the LNG operated power plants. Therefore, LNG procurements contracts should be negotiated to minimize the ‘Take or Pay’ risks.

- As discussed in Contingency Analysis of Chapter 11, timely implementation of planned power plants in the Base Case is very much important. Contingency analysis identified 150MW as the short term capacity requirement for the period 2018-2022.

- Recommendations for the integration of Variable Renewable Energy (VRE) in to the Base Case Plan;

  – Day ahead, hourly basis and accurate Wind and Solar PV energy forecasting system should be implemented as early as possible.

  – 24 hour (round the clock), renewable energy desk has to be set up and output from each renewable energy sources have to be monitored (if existing plants are not equipped with communication facilities, measures have to be taken for establishing them).

  – In order for smooth operation of power system, Variable Renewable Energy (VRE) curtailment rights have to be given to system operator. Feasibility of implementing compensation mechanism has to be studied to future VRE plants.

  – Planned network strengthening projects must be completed as scheduled.

  – Future base load power plants should be designed to de-load in order to keep the VRE curtailment at a minimum level.

  – The ORE locations should be prioritized based on the plant factors, availability and cost of transmission network and developed accordingly.

  – If the proposed conventional plants are not commissioned as scheduled, the VRE addition in the plan has to be revised accordingly. Thus it is proposed to review this planning methodology once in two years.

Table 8.2 Investment Plan for Major Hydro & Thermal Projects (Base Case), 2018-2037

(Costs in million US$, Exch. Rate:148.88 LKR/US$)

YEAR & PLANT	2018		2019		2020		2021		2022		2023		2024		2025		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	Total
2019 - 35 MW Gas Turbine - 2 units																			
Base Cost	6.1	34.4															**6.1**	**34.4**	**40.5**
Contingencies	0.9	5.2															**0.9**	**5.2**	**6.1**
Port Handling & other charges (5%)		2.0															**0.0**	**2.0**	**2.0**
Total	7.0	41.6															**7.0**	**41.6**	**48.6**
2019 - 300 MW Natural Gas Fired Combined Cycle Power Plant - 1 unit																			
Base Cost	23.1	162.5	11.5	81.2													**34.6**	**243.7**	**278.3**
Contingencies	3.4	24.3	1.7	12.2													**5.1**	**36.5**	**41.6**
Port Handling & other charges (5%)		9.3		4.7													**0.0**	**14.0**	**14.0**
Total	26.5	196.1	13.2	98.1													**39.7**	**294.2**	**333.9**
2020 - 35 MW Gas Turbine - 1 unit																			
Base Cost	0.3	1.9	3.0	17.2													**3.3**	**19.1**	**22.4**
Contingencies	0.1	0.3	0.5	2.6													**0.6**	**2.9**	**3.5**
Port Handling & other charges (5%)		0.1		1.0													**0.0**	**1.1**	**1.1**
Total	0.4	2.3	3.5	20.8													**3.9**	**23.1**	**27.0**
2020 - 15 MW Thalpitigala HPP - 1 unit	**(Constructed by Ministry of Irrigation & Water Resource Managment)**																		
Base Cost																			
Contingencies																			
Port Handling & other charges (5%)																			
Total																			
2021 - 300 MW Natural Gas Fired Combined Cycle Power Plant - 1 unit																			
Base Cost	3.4	23.9	20.3	142.8	10.9	77.0											**34.6**	**243.7**	**278.3**
Contingencies	0.5	3.6	3.0	21.4	1.6	11.5											**5.1**	**36.5**	**41.6**
Port Handling & other charges (5%)		1.4		8.2		4.4											**0.0**	**14.0**	**14.0**
Total	3.9	28.9	23.3	172.4	12.5	92.9											**39.7**	**294.2**	**333.9**
2022 - 20 MW Gin Ganga HPP - 1 unit	**(Constructed by Ministry of Irrigation & Water Resource Managment)**																		
Base Cost																			
Contingencies																			
Port Handling & other charges (5%)																			
Total																			
2022 - 20 MW Seethawaka HPP - 1 unit																			
Base Cost	0.6	1.3	2.9	6.6	5.4	12.2	2.3	5.1									**11.2**	**25.2**	**36.4**
Contingencies	0.1	0.2	0.4	1.0	0.8	1.8	0.3	0.8									**1.6**	**3.8**	**5.4**
Port Handling & other charges (5%)		0.1		0.4		0.7		0.3									**0.0**	**1.5**	**1.5**
Total	0.7	1.6	3.3	8.0	6.2	14.7	2.6	6.2									**12.8**	**30.5**	**43.3**
Annual Total	**38.5**	**270.5**																	

Continued in the next page

Table 8.2 Investment Plan for Major Hydro & Thermal Projects (Base Case), 2018-2037

(Costs in million US$, Exch. Rate:148.88 LKR/US$)

YEAR & PLANT	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**	**Total**
2023 - 300 MW New Coal Power Plant - 1 unit (Change to super critical will be evaluated)																					
Base Cost	4.6	17.3	23.0	86.9	42.2	159.8	17.9	67.8											**87.7**	**331.8**	**419.5**
Contingencies	0.7	2.6	3.4	13.0	6.3	24.0	2.7	10.2											**13.1**	**49.8**	**62.9**
Port Handling & other charges (5%)		1.0		5.0		9.2		3.9											**0.0**	**19.1**	**19.1**
Total	5.3	20.9	26.4	104.9	48.5	193.0	20.6	81.9											**100.8**	**400.7**	**501.5**
2024 - 300 MW New Coal Power Plant - 1 unit (Change to super critical will be evaluated)																					
Base Cost			4.6	17.3	23.0	86.9	42.2	159.8	17.9	67.8									**87.7**	**331.8**	**419.5**
Contingencies			0.7	2.6	3.4	13.0	6.3	24.0	2.7	10.2									**13.1**	**49.8**	**62.9**
Port Handling & other charges (5%)				1.0		5.0		9.2		3.9									**0.0**	**19.1**	**19.1**
Total			5.3	20.9	26.4	104.9	48.5	193.0	20.6	81.9									**100.8**	**400.7**	**501.5**
2025 - 300 MW New Coal Power Plant - 1 unit (Change to super critical will be evaluated)																					
Base Cost					4.6	17.3	23.0	86.9	42.2	159.8	17.9	67.8							**87.7**	**331.8**	**419.5**
Contingencies					0.7	2.6	3.4	13.0	6.3	24.0	2.7	10.2							**13.1**	**49.8**	**62.9**
Port Handling & other charges (5%)						1.0		5.0		9.2		3.9							**0.0**	**19.1**	**19.1**
Total					5.3	20.9	26.4	104.9	48.5	193.0	20.6	81.9							**100.8**	**400.7**	**501.5**
2025 - 200 MW Pump Storage Power Plant- 1 unit																					
Base Cost			1.2	5.4	5.1	22.4	11.6	50.5	12.0	52.4	3.9	17.0							**33.8**	**147.7**	**181.5**
Contingencies			0.2	0.8	0.8	3.4	1.7	7.6	1.8	7.9	0.6	2.5							**5.1**	**22.2**	**27.3**
Port Handling & other charges (5%)				0.3		1.3		2.9		3.0		1.0							**0.0**	**8.5**	**8.5**
Total			1.4	6.5	5.9	27.1	13.3	61.0	13.8	63.3	4.5	20.5							**38.9**	**178.4**	**217.3**
2026 - 200 MW Pump Storage Power Plant- 1 unit																					
Base Cost					1.2	5.4	5.1	22.4	11.6	50.5	12.0	52.4	3.9	17.0					**33.8**	**147.7**	**181.5**
Contingencies					0.2	0.8	0.8	3.4	1.7	7.6	1.8	7.9	0.6	2.5					**5.1**	**22.2**	**27.3**
Port Handling & other charges (5%)						0.3		1.3		2.9		3.0		1.0					**0.0**	**8.5**	**8.5**
Total					1.4	6.5	5.9	27.1	13.3	61.0	13.8	63.3	4.5	20.5					**38.9**	**178.4**	**217.3**
2027 - 200 MW Pump Storage Power Plant- 1 unit																					
Base Cost							1.2	5.4	5.1	22.4	11.6	50.5	12.0	52.4	3.9	17.0			**33.8**	**147.7**	**181.5**
Contingencies							0.2	0.8	0.8	3.4	1.7	7.6	1.8	7.9	0.6	2.5			**5.1**	**22.2**	**27.3**
Port Handling & other charges (5%)								0.3		1.3		2.9		3.0		1.0			**0.0**	**8.5**	**8.5**
Total							1.4	6.5	5.9	27.1	13.3	61.0	13.8	63.3	4.5	20.5			**38.9**	**178.4**	**217.3**
2028 - 600 MW New Supercritical Coal Power Plant - 1 unit																					
Base Cost											9.0	39.9	45.5	200.7	83.7	369.2	35.5	156.6	**173.7**	**766.4**	**940.1**
Contingencies											1.4	6.0	6.8	30.1	12.5	55.4	5.3	23.5	**26.0**	**115.0**	**141.0**
Port Handling & other charges (5%)												2.3		11.5		21.2		9.0	**0.0**	**44.1**	**44.1**
Total											10.4	48.2	52.3	242.3	96.2	445.8	40.8	189.1	**199.7**	**925.5**	**1125.2**
Annual Total	**48.6**	**320.1**	**51.8**	**239.9**	**90.1**	**358.6**	**116.1**	**474.4**	**102.1**	**426.3**	**62.6**	**274.9**	**70.6**	**326.1**	**100.7**	**466.3**					

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Table 8.2 Investment Plan for Major Hydro & Thermal Projects (Base Case), 2018-2037

(Costs in million US$, Exch. Rate:148.88 LKR/US$)

YEAR & PLANT	2027		2028		2029		2030		2031		2032		2033		2034		2035		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**	
2031 - 600 MW New Supercritical Coal Power Plant - 1 unit																					
Base Cost	9.0	39.9	45.5	200.7	83.7	369.2	35.5	156.6											**173.7**	**766.4**	**940.1**
Contingencies	1.4	6.0	6.8	30.1	12.5	55.4	5.3	23.5											**26.0**	**115.0**	**141.0**
Port Handling & other charges (5%)		2.3		11.5		21.2		9.0											**0.0**	**44.1**	**44.1**
Total	10.4	48.2	52.3	242.3	96.2	445.8	40.8	189.1											**199.7**	**925.5**	**1125.2**
2033 - 300 MW Natural Gas Fired Combined Cycle Power Plant - 2 units																					
Base Cost							6.8	47.8	40.6	285.6	21.8	154.0							**69.2**	**487.4**	**556.6**
Contingencies							1.0	7.2	6.0	42.8	3.2	23.0							**10.2**	**73.0**	**83.2**
Port Handling & other charges (5%)								2.8		16.4		8.9							**0.0**	**28.0**	**28.0**
Total							7.8	57.8	46.6	344.8	25.0	185.9							**79.4**	**588.4**	**667.8**
2035 - 600 MW New Supercritical Coal Power Plant - 1 unit																					
Base Cost									9.0	39.9	45.5	200.7	83.7	369.2	35.5	156.6			**173.7**	**766.4**	**940.1**
Contingencies									1.4	6.0	6.8	30.1	12.5	55.4	5.3	23.5			**26.0**	**115.0**	**141.0**
Port Handling & other charges (5%)										2.3		11.5		21.2		9.0			**0.0**	**44.1**	**44.1**
Total									10.4	48.2	52.3	242.3	96.2	445.8	40.8	189.1			**199.7**	**925.5**	**1125.2**
2036 - 300 MW Natural Gas Fired Combined Cycle Power Plant - 1 unit																					
Base Cost													3.4	23.9	20.3	142.8	10.9	77.0	**34.6**	**243.7**	**278.3**
Contingencies													0.5	3.6	3.0	21.4	1.6	11.5	**5.1**	**36.5**	**41.6**
Port Handling & other charges (5%)														1.4		8.2		4.4	**0.0**	**14.0**	**14.0**
Total													3.9	28.9	23.3	172.4	12.5	92.9	**39.7**	**294.2**	**333.9**
Annual Total	**51.2**	**237.3**	**52.3**	**242.3**	**96.2**	**445.8**	**48.6**	**246.9**	**57.0**	**393.0**	**77.3**	**428.2**	**100.1**	**474.7**	**64.1**	**361.5**	**12.5**	**92.9**			

Note:

(i) The cost included only the Pure Construction Cost of Power Plants and excluded the cost for Feasibility, EIA, Pre-Construction, Detail Design etc.

(ii) Distribution of the Pure Costruction Cost over the construction period of the plants is carried out by assuming a "S" Curve. S Curve parameters are shown in the Chapter 6.

Table 8.3 Investment Plan for Major Wind & Solar Developments (Base Case), 2018-2037

(Costs in million US$, Exch. Rate:148.88 LKR/US$)

YEAR & PLANT	2018		2019		2020		2021		2022		2023		2024		2025		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**	**Total**
2019 - 90 MW Solar Power Development																			
Base Cost	13.9	55.5															**13.9**	**55.5**	**69.4**
Contingencies	2.5	9.8															**2.5**	**9.8**	**12.3**
Port Handling & other charges (5%)		3.3															**0.0**	**3.3**	**3.3**
Total	16.3	68.6															**16.3**	**68.6**	**84.9**
2019 - 50 MW Wind Power Development																			
Base Cost	8.9	35.4															**8.9**	**35.4**	**44.3**
Contingencies	1.6	6.2															**1.6**	**6.2**	**7.8**
Port Handling & other charges (5%)		2.1															**0.0**	**2.1**	**2.1**
Total	10.4	43.7															**10.4**	**43.7**	**54.2**
2020 - 100 MW Solar Power Development																			
Base Cost	6.8	27.1	14.6	58.4													**21.4**	**85.5**	**106.9**
Contingencies	1.2	4.8	2.6	10.3													**3.8**	**15.1**	**18.9**
Port Handling & other charges (5%)		1.6		3.4													**0.0**	**5.0**	**5.0**
Total	8.0	33.5	17.2	72.1													**25.1**	**105.6**	**130.7**
2020 - 100 MW Mannar Wind Park																			
Base Cost	8.2	32.9	17.7	70.8													**25.9**	**103.7**	**129.6**
Contingencies	1.5	5.8	3.1	12.5													**4.6**	**18.3**	**22.9**
Port Handling & other charges (5%)		1.9		4.2													**0.0**	**6.1**	**6.1**
Total	9.7	40.6	20.8	87.5													**30.5**	**128.1**	**158.6**
2020 - 120 MW Wind Power Development																			
Base Cost	9.9	39.4	21.2	85.0													**31.1**	**124.4**	**155.6**
Contingencies	1.7	7.0	3.7	15.0													**5.5**	**22.0**	**27.5**
Port Handling & other charges (5%)		2.3		5.0													**0.0**	**7.3**	**7.3**
Total	11.6	48.7	25.0	105.0													**36.6**	**153.7**	**190.3**
2021 - 50 MW Solar Power Development																			
Base Cost			3.2	12.8	6.9	27.5											**10.1**	**40.3**	**50.4**
Contingencies			0.6	2.3	1.2	4.9											**1.8**	**7.1**	**8.9**
Port Handling & other charges (5%)				0.8		1.6											**0.0**	**2.4**	**2.4**
Total			3.8	15.8	8.1	34.0											**11.9**	**49.8**	**61.7**
2021 - 75 MW Wind Power Development																			
Base Cost			6.2	24.7	13.3	53.1											**19.4**	**77.8**	**97.2**
Contingencies			1.1	4.4	2.3	9.4											**3.4**	**13.7**	**17.2**
Port Handling & other charges (5%)				1.5		3.1											**0.0**	**4.6**	**4.6**
Total			7.3	30.5	15.6	65.6											**22.9**	**96.1**	**119.0**
2022 - 50 MW Wind Power Development																			
Base Cost					4.1	16.4	8.9	35.4									**13.0**	**51.9**	**64.8**
Contingencies					0.7	2.9	1.6	6.2									**2.3**	**9.2**	**11.4**
Port Handling & other charges (5%)						1.0		2.1									**0.0**	**3.1**	**3.1**
Total					4.8	20.3	10.4	43.7									**15.3**	**64.1**	**79.3**
Annual Total	**56.0**	**235.2**	**74.0**	**310.9**	**28.6**	**119.9**													

Continued in the next page

Table 8.3 Investment Plan for Major Wind & Solar Developments (Base Case), 2018-2037

(Costs in million US$, Exch. Rate:148.88 LKR/US$)

YEAR & PLANT	2021		2022		2023		2024		2025		2026		2027		2028		2029		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**	
2023 - 50 MW Solar Power Development																					
Base Cost	2.8	11.2	6.1	24.2															**8.9**	**35.5**	**44.3**
Contingencies	0.5	2.0	1.1	4.3															**1.6**	**6.3**	**7.8**
Port Handling & other charges (5%)		0.7		1.4															**0.0**	**2.1**	**2.1**
Total	3.3	13.9	7.1	29.9															**10.4**	**43.8**	**54.2**
2023 - 60 MW Wind Power Development																					
Base Cost	4.9	19.7	10.6	42.5															**15.6**	**62.2**	**77.8**
Contingencies	0.9	3.5	1.9	7.5															**2.7**	**11.0**	**13.7**
Port Handling & other charges (5%)		1.2		2.5															**0.0**	**3.7**	**3.7**
Total	5.8	24.4	12.5	52.5															**18.3**	**76.9**	**95.2**
2024 - 50 MW Solar Power Development																					
Base Cost			2.6	10.5	5.6	22.6													**8.3**	**33.0**	**41.3**
Contingencies			0.5	1.8	1.0	4.0													**1.5**	**5.8**	**7.3**
Port Handling & other charges (5%)				0.6		1.3													**0.0**	**1.9**	**1.9**
Total			3.1	12.9	6.6	27.9													**9.7**	**40.8**	**50.5**
2024 - 45 MW Wind Power Development																					
Base Cost			3.7	14.8	8.0	31.9													**11.7**	**46.7**	**58.3**
Contingencies			0.7	2.6	1.4	5.6													**2.1**	**8.2**	**10.3**
Port Handling & other charges (5%)				0.9		1.9													**0.0**	**2.7**	**2.7**
Total			4.4	18.3	9.4	39.4													**13.7**	**57.6**	**71.4**
2025 - 100 MW Solar Power Development																					
Base Cost					4.9	19.4	10.4	41.8											**15.3**	**61.2**	**76.5**
Contingencies					0.9	3.4	1.8	7.4											**2.7**	**10.8**	**13.5**
Port Handling & other charges (5%)						1.1		2.5											**0.0**	**3.6**	**3.6**
Total					5.7	24.0	12.3	51.6											**18.0**	**75.6**	**93.6**
2025 - 85 MW Wind Power Development																					
Base Cost					7.0	27.9	15.1	60.2											**22.0**	**88.1**	**110.2**
Contingencies					1.2	4.9	2.7	10.6											**3.9**	**15.6**	**19.4**
Port Handling & other charges (5%)						1.6		3.5											**0.0**	**5.2**	**5.2**
Total					8.2	34.5	17.7	74.4											**25.9**	**108.9**	**134.8**
2026 - 50 MW Solar Power Development																					
Base Cost							2.4	9.7	5.2	20.9									**7.7**	**30.6**	**38.3**
Contingencies							0.4	1.7	0.9	3.7									**1.4**	**5.4**	**6.8**
Port Handling & other charges (5%)								0.6		1.2									**0.0**	**1.8**	**1.8**
Total							2.9	12.0	6.1	25.8									**9.0**	**37.8**	**46.8**
Annual Total	**19.5**	**82.0**	**27.1**	**113.6**	**29.9**	**125.7**	**32.9**	**138.0**													

Continued in the next page

Table 8.3 Investment Plan for Major Wind & Solar Developments (Base Case), 2018-2037

(Costs in million US$, Exch. Rate:148.88 LKR/US$)

YEAR & PLANT	2025		2026		2027		2028		2029		2030		2031		2032		2033		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	
2027 - 50 MW Solar Power Development																					
Base Cost	2.4	9.7	5.2	20.9															**7.7**	**30.6**	**38.3**
Contingencies	0.4	1.7	0.9	3.7															**1.4**	**5.4**	**6.8**
Port Handling & other charges (5%)		0.6		1.2															**0.0**	**1.8**	**1.8**
Total	2.9	12.0	6.1	25.8															**9.0**	**37.8**	**46.8**
2027 - 25 MW Wind Power Development																					
Base Cost	2.1	8.2	4.4	17.7															**6.5**	**25.9**	**32.4**
Contingencies	0.4	1.5	0.8	3.1															**1.1**	**4.6**	**5.7**
Port Handling & other charges (5%)		0.5		1.0															**0.0**	**1.5**	**1.5**
Total	2.4	10.2	5.2	21.9															**7.6**	**32.0**	**39.7**
2028 - 100 MW Solar Power Development																					
Base Cost			4.9	19.4	10.4	41.8													**15.3**	**61.2**	**76.5**
Contingencies			0.9	3.4	1.8	7.4													**2.7**	**10.8**	**13.5**
Port Handling & other charges (5%)				1.1		2.5													**0.0**	**3.6**	**3.6**
Total			5.7	24.0	12.3	51.6													**18.0**	**75.6**	**93.6**
2028 - 45 MW Wind Power Development																					
Base Cost			3.7	14.8	8.0	31.9													**11.7**	**46.7**	**58.3**
Contingencies			0.7	2.6	1.4	5.6													**2.1**	**8.2**	**10.3**
Port Handling & other charges (5%)				0.9		1.9													**0.0**	**2.7**	**2.7**
Total			4.4	18.3	9.4	39.4													**13.7**	**57.6**	**71.4**
2029 - 50 MW Solar Power Development																					
Base Cost					2.4	9.7	5.2	20.9											**7.7**	**30.6**	**38.3**
Contingencies					0.4	1.7	0.9	3.7											**1.4**	**5.4**	**6.8**
Port Handling & other charges (5%)						0.6		1.2											**0.0**	**1.8**	**1.8**
Total					2.9	12.0	6.1	25.8											9.0	**37.8**	**46.8**
2029 - 25 MW Wind Power Development																					
Base Cost					2.1	8.2	4.4	17.7											**6.5**	**25.9**	**32.4**
Contingencies					0.4	1.5	0.8	3.1											**1.1**	**4.6**	**5.7**
Port Handling & other charges (5%)						0.5		1.0											**0.0**	**1.5**	**1.5**
Total					2.4	10.2	5.2	21.9											**7.6**	**32.0**	**39.7**
2030 - 50 MW Solar Power Development																					
Base Cost							2.4	9.7	5.2	20.9									**7.7**	**30.6**	**38.3**
Contingencies							0.4	1.7	0.9	3.7									**1.4**	**5.4**	**6.8**
Port Handling & other charges (5%)								0.6		1.2									**0.0**	**1.8**	**1.8**
Total							2.9	12.0	6.1	25.8									**9.0**	**37.8**	**46.8**
2030 - 70 MW Wind Power Development																					
Base Cost							5.8	23.0	12.4	49.6									**18.1**	**72.6**	**90.7**
Contingencies							1.0	4.1	2.2	8.7									**3.2**	**12.8**	**16.0**
Port Handling & other charges (5%)								1.4		2.9									**0.0**	**4.3**	**4.3**
Total							6.8	28.4	14.6	61.2									**21.4**	**89.7**	**111.0**
Annual Total	**11.4**	**48.0**	**21.4**	**89.9**	**26.9**	**113.1**	**21.0**	**88.1**													

Continued in the next page

Table 8.3 Investment Plan for Major Wind & Solar Developments (Base Case), 2018-2037

(Costs in million US$, Exch. Rate:148.88 LKR/US$)

YEAR & PLANT	2029		2030		2031		2032		2033		2034		2035		2036		2037		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	
2031 - 50 MW Solar Power Development																					
Base Cost	2.4	9.7	5.2	20.9															7.7	30.6	38.3
Contingencies	0.4	1.7	0.9	3.7															1.4	5.4	6.8
Port Handling & other charges (5%)		0.6		1.2															0.0	1.8	1.8
Total	2.9	12.0	6.1	25.8															9.0	37.8	46.8
2031 - 35 MW Wind Power Development																					
Base Cost	2.9	11.5	6.2	24.8															9.1	36.3	45.4
Contingencies	0.5	2.0	1.1	4.4															1.6	6.4	8.0
Port Handling & other charges (5%)		0.7		1.5															0.0	2.1	2.1
Total	3.4	14.2	7.3	30.6															10.7	44.8	55.5
2032 - 50 MW Solar Power Development																					
Base Cost			2.4	9.7	5.2	20.9													7.7	30.6	38.3
Contingencies			0.4	1.7	0.9	3.7													1.4	5.4	6.8
Port Handling & other charges (5%)				0.6		1.2													0.0	1.8	1.8
Total			2.9	12.0	6.1	25.8													9.0	37.8	46.8
2032 - 45 MW Wind Power Development																					
Base Cost			3.7	14.8	8.0	31.9													11.7	46.7	58.3
Contingencies			0.7	2.6	1.4	5.6													2.1	8.2	10.3
Port Handling & other charges (5%)				0.9		1.9													0.0	2.7	2.7
Total			4.4	18.3	9.4	39.4													13.7	57.6	71.4
2033 - 50 MW Solar Power Development																					
Base Cost					2.4	9.7	5.2	20.9											7.7	30.6	38.3
Contingencies					0.4	1.7	0.9	3.7											1.4	5.4	6.8
Port Handling & other charges (5%)						0.6		1.2											0.0	1.8	1.8
Total					2.9	12.0	6.1	25.8											9.0	37.8	46.8
2033 - 70 MW Wind Power Development																					
Base Cost					5.8	23.0	12.4	49.6											18.1	72.6	90.7
Contingencies					1.0	4.1	2.2	8.7											3.2	12.8	16.0
Port Handling & other charges (5%)						1.4		2.9											0.0	4.3	4.3
Total					6.8	28.4	14.6	61.2											21.4	89.7	111.0
2034 - 50 MW Solar Power Development																					
Base Cost							2.4	9.7	5.2	20.9									7.7	30.6	38.3
Contingencies							0.4	1.7	0.9	3.7									1.4	5.4	6.8
Port Handling & other charges (5%)								0.6		1.2									0.0	1.8	1.8
Total							2.9	12.0	6.1	25.8									9.0	37.8	46.8
2034 - 70 MW Wind Power Development																					
Base Cost							5.8	23.0	12.4	49.6									18.1	72.6	90.7
Contingencies							1.0	4.1	2.2	8.7									3.2	12.8	16.0
Port Handling & other charges (5%)								1.4		2.9									0.0	4.3	4.3
Total							6.8	28.4	14.6	61.2									21.4	89.7	111.0
Annual Total	**27.0**	**113.3**	**20.6**	**86.7**	**25.1**	**105.6**	**30.4**	**127.5**													

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Table 8.3 Investment Plan for Major Wind & Solar Developments (Base Case), 2018-2037

(Costs in million US$, Exch. Rate:148.88 LKR/US$)

YEAR & PLANT	2033		2034		2035		2036		Total		Grand Total
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	
2035 - 50 MW Solar Power Development											
Base Cost	2.4	9.7	5.2	20.9					**7.7**	**30.6**	**38.3**
Contingencies	0.4	1.7	0.9	3.7					**1.4**	**5.4**	**6.8**
Port Handling & other charges (5%)		0.6		1.2					**0.0**	**1.8**	**1.8**
Total	2.9	12.0	6.1	25.8					**9.0**	**37.8**	**46.8**
2035 - 70 MW Wind Power Development											
Base Cost	5.8	23.0	12.4	49.6					**18.1**	**72.6**	**90.7**
Contingencies	1.0	4.1	2.2	8.7					**3.2**	**12.8**	**16.0**
Port Handling & other charges (5%)		1.4		2.9					**0.0**	**4.3**	**4.3**
Total	6.8	28.4	14.6	61.2					**21.4**	**89.7**	**111.0**
2036 - 50 MW Solar Power Development											
Base Cost			2.4	9.7	5.2	20.9			**7.7**	**30.6**	**38.3**
Contingencies			0.4	1.7	0.9	3.7			**1.4**	**5.4**	**6.8**
Port Handling & other charges (5%)				0.6		1.2			**0.0**	**1.8**	**1.8**
Total			2.9	12.0	6.1	25.8			**9.0**	**37.8**	**46.8**
2036 - 95 MW Wind Power Development											
Base Cost			7.8	31.2	16.8	67.3			**24.6**	**98.5**	**123.1**
Contingencies			1.4	5.5	3.0	11.9			**4.3**	**17.4**	**21.7**
Port Handling & other charges (5%)				1.8		4.0			**0.0**	**5.8**	**5.8**
Total			9.2	38.6	19.8	83.1			**29.0**	**121.7**	**150.7**
2037 - 100 MW Solar Power Development											
Base Cost					4.9	19.4	10.4	41.8	**15.3**	**61.2**	**76.5**
Contingencies					0.9	3.4	1.8	7.4	**2.7**	**10.8**	**13.5**
Port Handling & other charges (5%)						1.1		2.5	**0.0**	**3.6**	**3.6**
Total					5.7	24.0	12.3	51.6	18.0	**75.6**	**93.6**
2037 - 70 MW Wind Power Development											
Base Cost					5.8	23.0	12.4	49.6	**18.1**	**72.6**	**90.7**
Contingencies					1.0	4.1	2.2	8.7	**3.2**	**12.8**	**16.0**
Port Handling & other charges (5%)						1.4		2.9	**0.0**	**4.3**	**4.3**
Total					6.8	28.4	14.6	61.2	**21.4**	**89.7**	**111.0**
Annual Total	**30.4**	**127.5**	**32.8**	**137.6**	**38.4**	**161.3**	**26.9**	**112.9**			

Note:

(i) The cost included only the Pure Construction Cost of Power Plants and excluded the cost for Feasibility, EIA, Pre-Construction, Detail Design etc.

(ii) Distribution of the Pure Costruction Cost over the construction period of the plants is carried out by assuming a "S" Curve. S Curve parameters are shown in the Chapter 6.

CHAPTER 9
ENVIRONMENTAL IMPLICATIONS

Sri Lankan power system until mid-nineties, was a 100% renewable system with only hydro power catering the Country's' power demand. Share of thermal generation increased only during the drought period and hence the power sector had only minor impact on the environment. However, after exploiting most of the major hydro potential, alternative fuel types had to be looked at to cater the growing electricity demand. Thereafter, fossil fuel was introduced into the power system which has an impact on the environment. Even at present, around 50% of renewable energy share is maintained from major hydro and other renewable energy resources.

The impact 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 impact of the implementation of Base Case Generation Expansion Plan and other selected scenarios.

9.1 Greenhouse Gases

Greenhouse gases are that which absorb and emit thermal infrared radiation which causes the gradual heating of Earths' atmosphere which is known as the greenhouse effect. There are natural as well as anthropogenic compounds which contribute to this effect. Water vapour (H_2O), Carbon Dioxide (CO_2), Methane (CH_4), Nitrous Oxide (N_2O) and Atmospheric Octane (O_3) (though present only in very minute quantities) are primary greenhouse gases in the Earths' atmosphere. There are also anthropogenic greenhouse gases such as Hydrofluorocarbons (HFCs), Perfluorocarbons (PFCs) and Sulphur hexafluoride (SF_6).

9.2 Country Context

9.2.1 Overview of Emissions in Sri Lanka

When considering the greenhouse gases, CO_2 is one of the primary gases which contribute towards warming of earths' atmosphere. Table 9.1 indicate CO_2 emissions from fuel combustion in each sector in Sri Lanka for the year 2014. It could be observed that approximately 41% of CO_2 emission from the electricity sector while major contributor for CO_2 emission is the transport sector which account for 48% approximately.

Table 9.1 - CO_2 Emissions from fuel combustion

	CO_2 emissions *Million tons of CO_2*	
Total	**16.74**	**100.0%**
Electricity and heat production	6.79	40.6%
Other energy industry own use	0.04	0.3%
Manuf. industries and construction	0.99	5.9%
Transport	7.99	47.8%
Other sectors	0.91	5.5%

Source: IEA CO_2 Emissions from Fuel Combustion (2016 Edition) -2014 data

Further the average emission factor from electricity generation in the past is shown in Figure 9.1

Source: Sustainable Energy Authority

Figure 9.1 – Average Emission Factor

Until thermal generation was introduced to Sri Lankan power system, it only contributed very little to GHG emissions. However, at present the focus is on reducing GHG emissions by integrating more renewable energy in to the power system. In global context, renewable energy resources are playing vital role to reduce GHG emissions and promoted through Government policies.

With these new trends, generation expansion planning also needs to adopt accordingly. With the focus on increasing renewable energy, more complicated analyses are required to overcome the uncertainties and intermittency in renewable energy generation in generation expansion planning modelling.

Proposed expansion sequence predicts an increase in the thermal generation and an increase in the use of fossil fuels in the power sector seems inevitable. The capacity share from thermal power plants is maintained approximately at 50% and renewable capacity share is at 50% in year 2037.

9.2.2 Ambient Air Quality & Stack Emission Standards

In 1994, Government of Sri Lanka has approved ambient air quality standards and it was amended in 2008. But 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 standards as shown in Table 9.2.

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

Pollutant **Type**	Ambient Air Quality Std. (μg/m³)				Stack Emission Std. Previous (mg/MJ)		Stack Emission Std. New* (mg/Nm³)	
	Annual Level	24 hour level	8 hour Level	1 hour Level	Coal	Liquid Fuel	Coal	Oil
Nitrogen dioxides (NO_2)	-	100	150	250	300	130	650	450
Sulphur Dioxides (SO_2)	-	80	120	200	520	340	850	850
PM10	50	100	-	-	-	-		
PM2.5	25	50	-	-	-	-		
Total Suspended Particles(TSP)	-	-	-	-	40	40	150	150

Source: Central Environmental Authority

* *Draft "Interim Source Emission Regulations"*

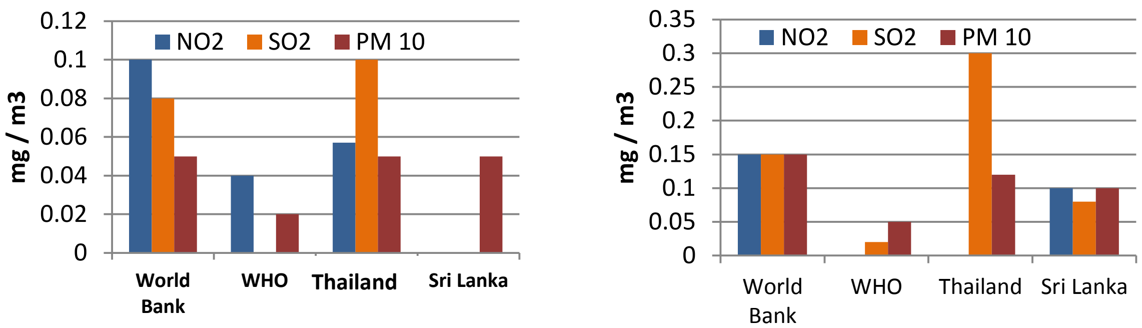
When compared with the standard specified by the World Bank (Existing) and WHO as shown in Table 9.3 and Figure 9.2, it is evident that Sri Lanka has very stringent ambient air quality standards for SO_2 emissions. The standard for particulate matter is also higher than the existing World Bank standards though not the highest of all.

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

(All values in mg/m3)

Pollutant	Averaging time	World Bank	WHO	India	Indonesia	Thailand	Pakistan	**Sri Lanka**
Nitrogen Dioxide (NO_2)	Annual	0.1	0.04	0.04	0.1	0.057	0.04	**-**
	24 hours	0.15	-	0.08	0.15	-	0.08	**0.1**
	8 hour						-	**0.15**
	1 hour	-	0.2	-	0.4	0.32	-	**0.25**
Sulphur Dioxide (SO_2)	Annual	0.08	-	0.05	0.06	0.1	0.08	**-**
	24 hours	0.15	0.02	0.08	0.365	0.3	0.12	**0.08**
	8 hour						-	**0.12**
	1 hour				0.9	0.78	-	**0.2**
	10 minute	-	0.5	-			-	**-**
PM 10	Annual	0.05	0.02	0.06		0.05	0.12	**0.05**
	24 hours	0.15	0.05	0.1	0.15	0.12	0.15	**0.1**
PM 2.5	Annual	-	0.01	0.04		0.025	0.015	**0.025**
	24 hours	-	0.025	0.06		0.05	0.035	**0.05**
Total Suspended	Annual	0.08	-	-	0.09	0.1		**-**
Particulate	24 hours	0.23	-	-	0.23	0.33		**-**
Suspended	Annual						0.36	**0.1**
Particulate Matter	24 hours						0.5	**0.3**

Source: World Wide Web, Central Environmental Authority



(a) Annual Average ***(b) 24 hour Average***

Figure 9.2 - Comparison of Ambient Air Quality Standards

A comparison of proposed stack emission standards is shown in Table 9.4.

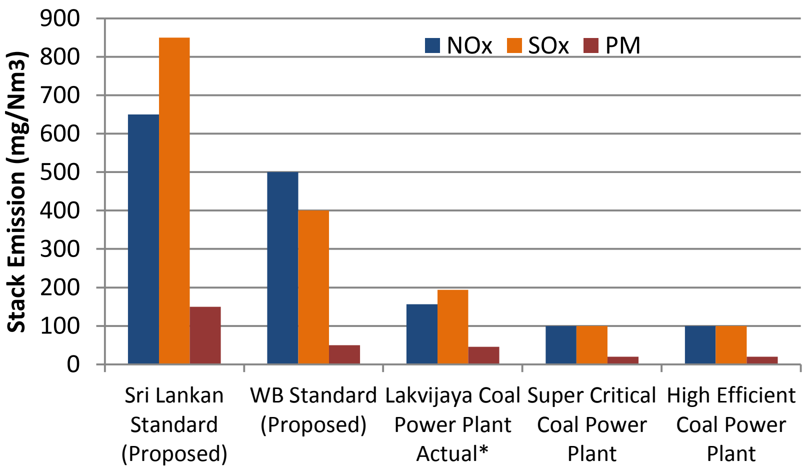
Table 9.4 - Comparison of Emission Standards for Coal Power Plants of Different Countries and Organisations

(All values in mg/Nm^3)

Pollutant	**Sri Lanka*** **(Proposed)**	World Bank (non-degraded airshed, ≥50MWth to <600MWth)	India (new plants)	China (new plants)	European Union (new plants >300MW)
Nitrogen Oxides	**650**	500	100	100	150
Sulphur Dioxide	**850**	400	100	100	150
Suspended Particulate	**150**	50	30	30	10

*Source: * Draft "Interim Source Emission Regulations" of Central Environmental Authority, WB IFC, IEA Clean Coal Center*

Figure 9.3 compares the stack emission levels of existing and proposed coal power plants in Sri Lanka with the standards. In addition to the low NOx burners used in the proposed coal power plants they also include Selective Catalytic Reduction (SCR) to achieve very low levels of NOx emissions.



Note: LVPS values correspond to actual test results in October 2016*

Figure 9.3 - Comparison of Stack Emission of Coal Power Plants

9.3 Uncontrolled Emission Factors

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. Table 9.5 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)* which are based on the given calorific values.

Table 9.5 - Uncontrolled Emission Factors (by Plant Technology)

Plant Type	Fuel Type	GCV (kcal/kg)	GCV (kJ/kg)	Sulphur Content (%)	Emission Factor Particulate (mg/MJ)	CO_2 (g/MJ)	SO_2 (g/MJ)	NOx (g/MJ)
Diesel Engine	Fuel Oil	10300	43124	3.5	13.0	76.3	1.709	1.200
Diesel Engine	Residual FO	10300	43124	3.5	13.0	77.4	1.639	1.200
Coal Steam	Coal	6300	26377	0.6	40.0	94.6	0.455	0.300
Gas Turbine	Auto Diesel	10500	43961	1.0	5.0	74.1	0.453	0.280
Comb. Cycle	Auto Diesel	10500	43961	1.0	5.0	74.1	0.453	0.280
Comb. Cycle	Naphtha	10880	45552	0	0	73.3	0	0.28
Comb. Cycle	Natural Gas	13000	54428	0	0.0	56.1	0.000	0.020
Dendro	Dendro	3224	13498	0	255.10	0.0	0.0	0.2

Sources: Thermal Generation Options Study [8], 2006 IPCC Guidelines

Basically, CO_2 and SO_2 emission factors are calculated based on the fuel characteristics, while NOx emissions, which depend on the plant technology, are obtained from a single source [8]. Generally, particulate emissions depend both on the plant technology and the type of fuel burned. Therefore, the emissions could be controlled by varying the fuel characteristics and by adopting various emission control technologies.

9.4 Emission Control Technologies

According to the expansion sequence of Base Case mentioned in Chapter 7 (Table 7.1), 2700MW of Coal power plants, 105MW of Gas Turbines, 1500MW Natural Gas combined cycle power plants, 320MW furnace oil fired power plants are to be added as thermal power plants to the Sri Lankan system in the next 20 years starting from 2018. 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. Particulate matter (PM) and three types of gaseous emissions were considered in the analysis, viz. SO_2, NOx 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 there has to be some form of control over particulate emissions. Lakvijaya coal power plant has a Sea Water Flue Gas Desulfurization unit (FGD) installed for further reduction of SOx emissions and an Electrostatic Precipitator (ESP) for control of PM.

Hence, in the present study control technologies considered in the proposed coal plants are as follows; ESPs for the control of particulate emissions, sea water FGD for control of SOx and low NOx burners and two stage combustion for the control of NOx. Coal power plants in Sri Lanka are mostly designed for low sulphur coal (0.65% sulphur) as fuel. Selective Catalytic Reduction (SCR) is also considered as an option for reduction of NOx.

The Low-NOx burners are an integrated part of most of the commercially available combined cycle plants, which are capable of reducing NOx emissions to a very low level.

Carbon Capture and Storage (CCS) is a technology that collects and concentrates the CO_2 emitted from large point sources such as power plants, transports it to a selected site and deposit it, preventing the release into the atmosphere. With the rising global energy consumption, technologies such as CCS becomes inevitable to avoid atmospheric greenhouse gas emissions and related climate consequences. Nevertheless, the technology is still being developed and improved.

Table 9.6 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 stricter the emission standards and environmental regulations are, higher the cost it has to be incurred to incorporate mitigation measures. Such costs of the control technologies considered are included in the project costs of candidate plants of the LTGEP which is also a part of the environmental damage cost.

Table 9.6 - Abatement Factors of Typical Control Devices

(Factors in %)

Device	SOx	NO_X	TSP	PM	CO	CH_4	NMVOC
Fabric Filter			99.5	99.5			
Electro Static Precipitator				99.8			
Selective Catalytic Reduction		75.7					
Dry FGD	50						
Wet FGD	92.5		90	90			
Sea Water FGD	93.9						
Low NOx Burner – Coal		25			-10	-10	-10
Low NOx Burner – CCY *		80					

Sources: Decades Manual & Coal feasibility Study Reports

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)

9.5 Emission Factors Used

In the present study, emission factors were either calculated based on stoichiometry or taken from the actual measured values or calculated based on design and operational data for candidate plants. Emission factors were chosen from a single source [8] where sufficient data were not available. Table

9.7 shows the actual and proposed coal power plant data used in the study. When comparing with the standard values for coal power plants in Table 9.5 it is clear that the performance of the coal power plants in Sri Lanka is much satisfactory.

Table 9.7 - Emission Factors of the coal power plants

Plant Type	GCV of coal	GCV of coal	Sulphur Content	Emission Factor			
				Particulate	CO_2	SO_x	NO_x
	(kcal/kg)	(kJ/kg)	(%)	(mg/MJ)	(g/MJ)	(g/MJ)	(g/MJ)
Candidate - High Efficient Coal Power Plant	5900	24702	0.8	7.00	94.6	0.035	0.140
Candidate - Super Critical Coal Power Plant	5900	24702	0.8	7.00	94.6	0.035	0.035
Coal Steam-Lakvijaya Power Station	6300	26377	0.7	15.00	94.6	0.4	0.260

Taking into consideration the emission factors mentioned in Table 9.5, Table 9.7 and the characteristics of the power plants, emissions per unit of electricity generated is calculated as shown in Table 9.8

Table 9.8 - Emission Factors per Unit Generation

(a) Coal Power Plants

Plant Type	Fuel Type	GCV	Full Load Heat Rate	Emission Factor			
				Particulate	CO2	SOx	NOx
		(kcal/kg)	kcal/kWh	kg/kWh	kg/kWh	kg/kWh	kg/kWh
Coal Steam-LakVijaya Power Station (unit 1)	Coal	6300	2489	0.0002	0.9858	0.0041	0.0027
Coal Steam-LakVijaya Power Station (unit 2 & 3)	Coal	6300	2378	0.0001	0.9419	0.0039	0.0026
Coal Steam-High Efficient Coal Candidate	Coal	5900	2241	0.0001	0.8876	0.0003	0.0013
Coal Steam-Super Critical Coal Candidate	Coal	5900	2082	0.0001	0.8246	0.0003	0.0003

(b) Other Candidate Power Plants

Plant Type	Fuel Type	GCV	Full Load Heat Rate	Emission Factor			
				Particulate	CO2	SOx	NOx
		(kcal/kg)	kcal/kWh	kg/kWh	kg/kWh	kg/kWh	kg/kWh
Natural Gas 150MW	Natural Gas	13000	1830	0.0000	0.4298	0.0000	0.0002
Natural Gas 300MW	Natural Gas	13000	1793	0.0000	0.4211	0.0000	0.0002
Reciprocating Engines	Fuel Oil	10300	2210	0.0012	0.7060	0.0158	0.0111
GT 35MW	Auto Diesel	10500	3060	0.0001	0.9493	0.0058	0.0036
GT 105MW	Auto Diesel	10500	2857	0.0001	0.8864	0.0054	0.0033

CCY 150MW	Auto Diesel	10500	1842	0.0000	0.5715	0.0035	0.0022
CCY 300MW	Auto Diesel	10500	1785	0.0000	0.5538	0.0034	0.0021
Dendro	Dendro	3224	5694	0.0061	0.0000	0.0000	0.0048

9.6 Environmental Implications – Base Case

Presented below is a quantitative analysis of the emissions 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 9.9 and Figure 9.4.

Table 9.9 – Air Emissions of Base Case

1000 tons/year

Year	PM	SO2	NOx	CO_2
2018	2.3	83.3	38	5,049
2019	2.5	86.2	39.3	5,259
2020	2.5	59.8	31.6	4,152
2021	2.8	60.1	31.9	4,557
2022	3.0	61.9	32.9	4,763
2023	3.0	12.8	10.0	4,824
2024	3.3	10.0	10.0	6,116
2025	3.6	8.4	10.7	7,412
2026	3.8	9.2	11.8	7,897
2027	4.0	10.4	12.8	8,326
2028	4.4	8.8	11.1	10,448
2029	4.7	9.3	11.8	10,879
2030	4.9	10.9	13.2	11,324
2031	5.3	9.7	11.8	13,377
2032	5.3	10.2	12.4	13,882
2033	5.5	10.4	13.2	15,151
2034	5.5	11.8	14.2	15,662
2035	5.9	11.3	13.9	18,040
2036	5.9	11.1	13.9	18,657
2037	6.1	12.6	15.2	19,249

With the introduction of coal and natural gas based generation, CO_2 emission shows a continuous increasing trend. However, the introduction of Natural Gas Combined Cycle power plants to the system reduces the increasing rate of CO_2 emissions. The sudden reduction of particulate, SO_x and NO_x emissions is due to the low dispatch of furnace oil fired power plant after introducing the coal power plant in 2023. Apart from that particulate, SO_x and NO_x has an increasing trend with time.

According to Figure 9.5, SO_x and NO_x emissions per kWh shows a levelised trend while per unit CO_2 emissions has an increasing trend. The lower energy dispatch of furnace oil fired power plants with heavy SO_x and NO_x pollutants has led to much lower per unit emission levels in the longer run.

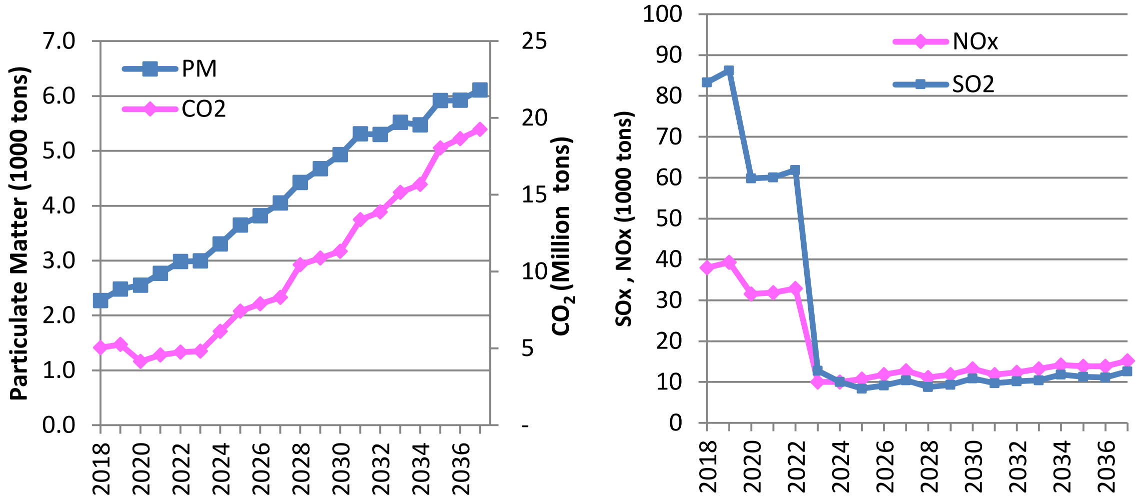


Figure 9.4 – PM, SO_2, NO_x and CO_2 emissions of Base Scenario

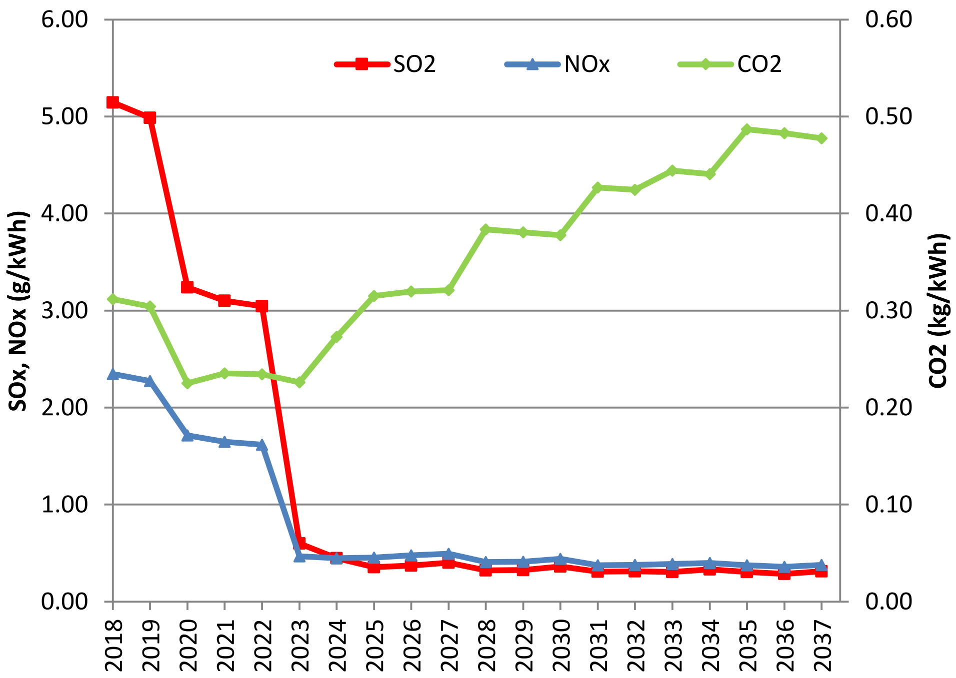


Figure 9.5 – SO_2, NO_x and CO_2 emissions per kWh generated

9.7 Environmental Implications – Other Scenarios

9.7.1 Comparison of Emissions

The scenarios, which are expected to have significant effects on environment, are evaluated against the Base Case emission quantities. The effects on emissions under following scenarios were analysed.

1. Reference Scenario
2. Future Coal Development Permitted to 1800MW Scenario
3. No Future Coal Development Permitted Scenario
4. Energy Mix with Nuclear Scenario

From Figure 9.5 and Figure 9.6 it can be seen that the SO_2 and NOx emissions are higher in initial five years of the planning period due to the higher dispatch of oil power plants. After introduction of coal power plant as one of the major base load power plants in 2023, dispatch of oil power plants reduces and hence the huge reduction of SO_2 and NOx emissions.

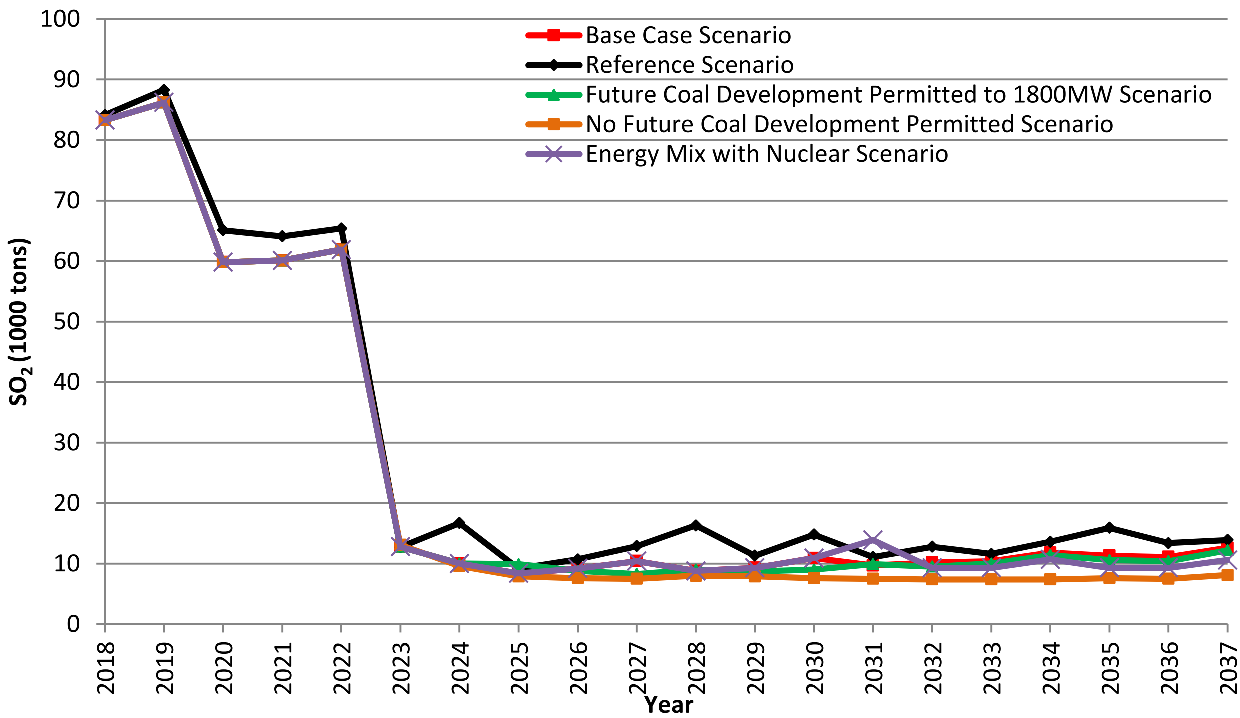


Figure 9.6 – SO_2 Emissions

After 2023 the rate of increase of SO_2 is minimal since NG has negligible SO_2 emissions. Scenario with no future coal development permitted has minimum SO_2 emissions. NOx emissions show a gradually increasing trend because coal and NG both has NOx emissions. Comparing the scenarios, when the coal development is restricted the NOx emissions becomes lesser.

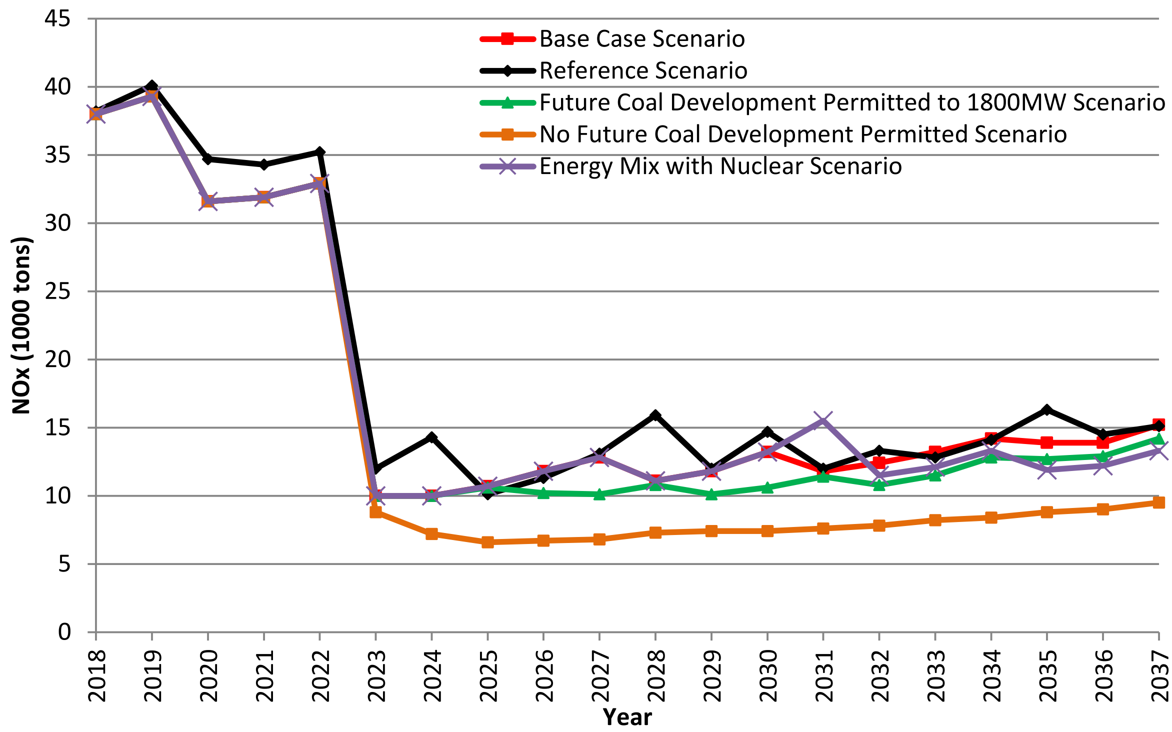


Figure 9.7 – NOx Emissions

Reference Scenario has higher CO_2 emissions compared to Base Case Scenario due to non integration of future renewable energy penetration to the system. The CO_2 emission factors of NG fired combined cycle plants are about 50% less than that of coal fired power plants. Therefore when the number of NG fired combined cycle power plants in the energy mix increases by restricting the development of coal power plants the CO_2 emissions are reduced.

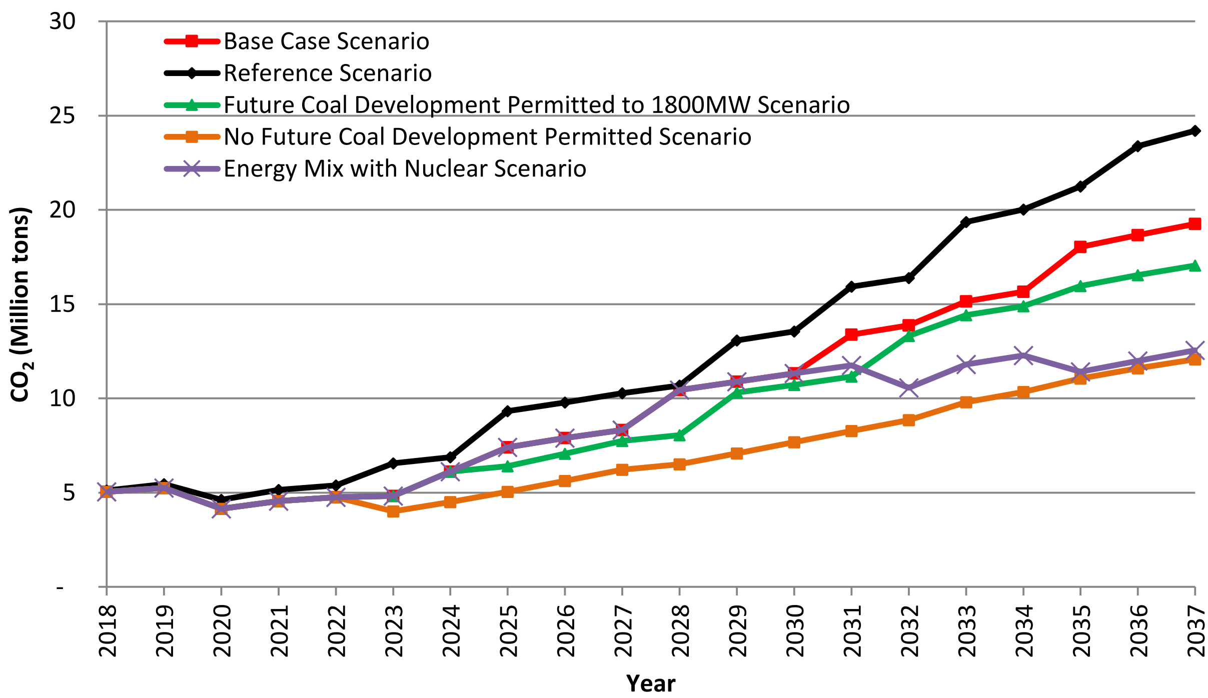


Figure 9.8 – CO_2 Emissions

Similarly particulate emission factors of NG fired combined cycle plants are negligible compared to coal fired power plants. Figure 9.8 shows the comparison of PM emission related to various scenarios.

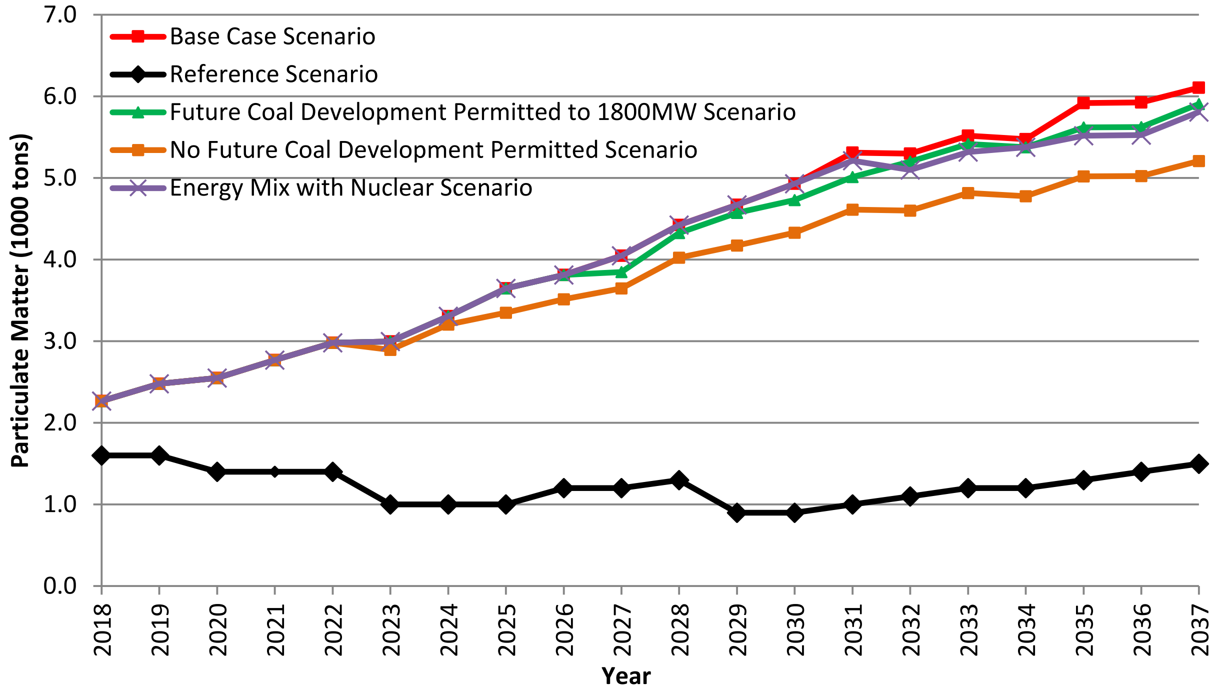


Figure 9.9 – Particulate Matter Emissions

Figure 9.10 shows the past actual and forecast values of average emission factors for the Base Case and the Reference Scenarios.

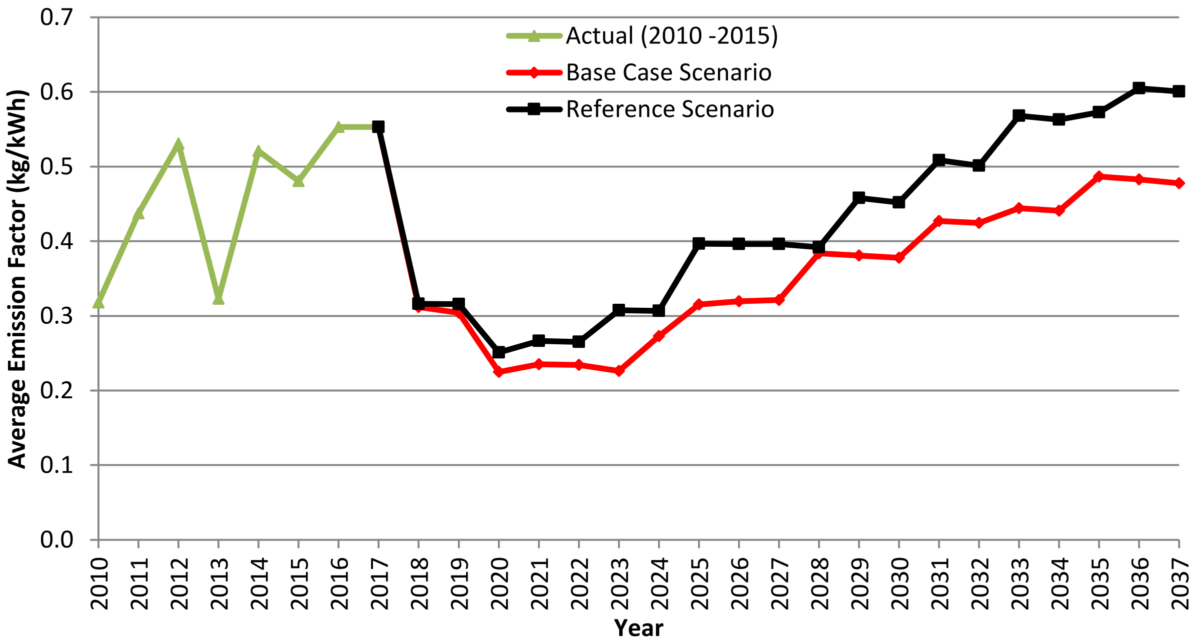


Figure 9.10 – Average Emission Factor Comparison

9.7.2 Cost Impacts of CO_2 Emission Reduction

Comparison of total CO_2 emission with total system cost is shown in Figure 9.11.

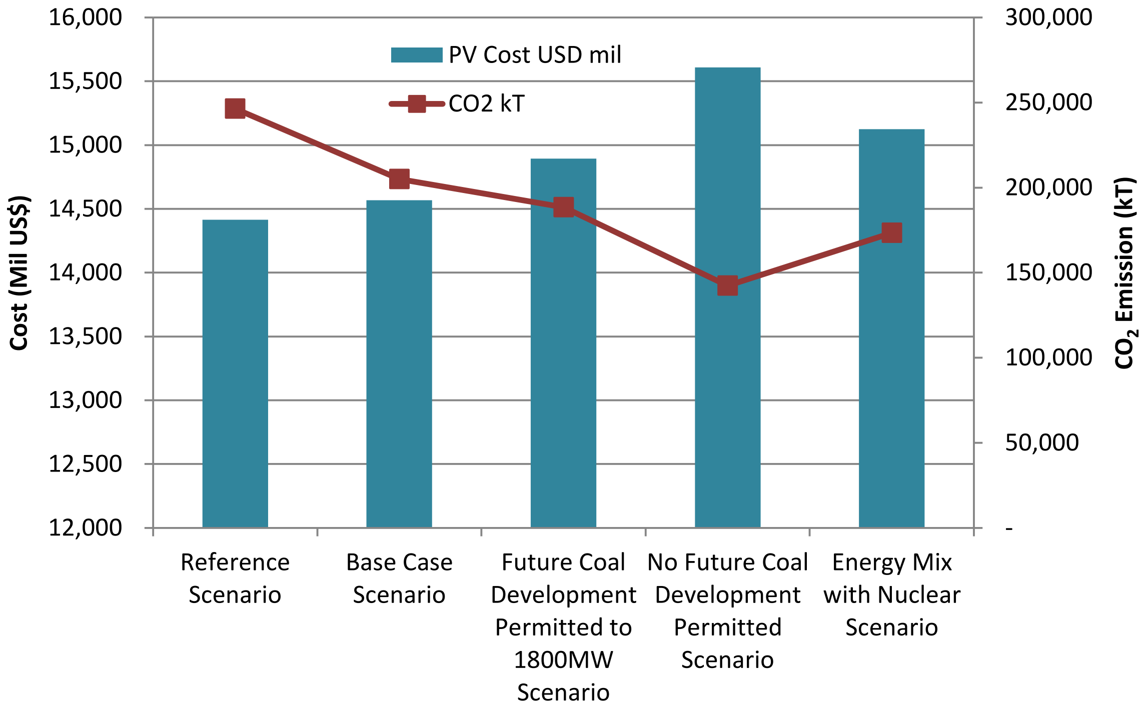


Figure 9.11 – Comparison of System Cost with CO_2 Emissions

Further, the incremental cost of each case was analysed by comparing the cost differences and the reduction of CO_2 emissions in each case compared to Reference Case and shown in Figure 9.12.

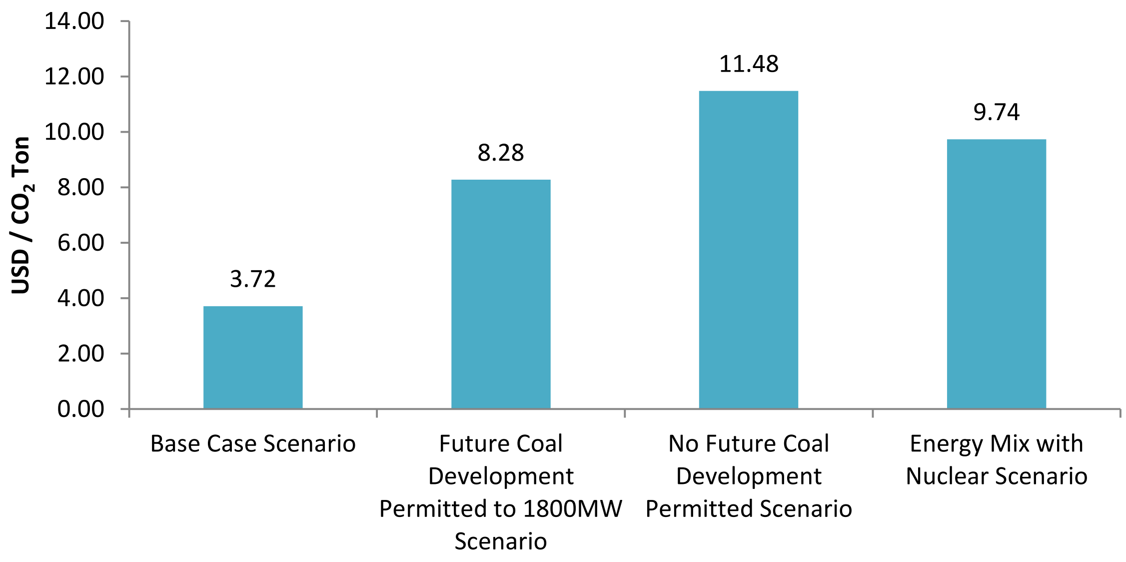


Figure 9.12 – Comparison of Incremental Cost for CO_2 reduction

There are other tools and techniques developed in order to identify the cost-effectiveness of different mitigation options. Marginal Abatement Cost Curve (MACC) is a technique developed to identify the cheapest abatement options among several techniques and in which order they should be prioritised. It is a visual representation showing GHG abatement potentials of various abatement options as a function of GHG abatement costs, and placing these mitigation measures in ascending order of cost-effectiveness. This could be useful in identifying the price of carbon for different GHG emission reduction options and also the overall cost to the economy of meeting specific emission targets. Therefor it can be a useful analytical tool for Sri Lanka in defining a cost-effective, low carbon investment program for Sri Lanka.

9.8 Climate Change

9.8.1 Background

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 countries (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 countries 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.

Major events and decisions by Conference of Parties are summarized in Table 9.10.

Table 9.10 – Summary of Major COP Decisions

COP	Events and Decisions
COP 3 Kyoto, Japan 1997	Kyoto protocol was accepted
COP13 Bali, Indonesia 2007	Adoption of Bali Road Map which included, – Launching of Adaptation Fund – A review of Kyoto Protocol – Decisions on Technology transfer and Reducing Deforestation related emissions – Ad-Hoc Working Group (AWG) negotiations on a Long Term Corporative Agreement (LCA) and Kyoto Protocol (KP)
COP17/CMP7 Durban, South Africa 2011	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 was to be agreed upon on or before 2015 and to be implemented by 2020.
COP18/CMP8 Doha, Qatar 2012	Extension of the Kyoto protocol Developed country 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, and Russia not being included for the second commitment. As a part of negotiations pursuant to the Bali Action Plan, developing country Parties agreed to take Nationally Appropriate Mitigation Actions (NAMAs) in the context of sustainable development.
COP19/CMP9 Warsaw, Poland 2013	Governments advanced the timeline for the development of the 2015 agreement with a view to enabling the negotiations to successfully

COP	Events and Decisions
	conclude in December 2015. Countries decided to initiate or intensify domestic preparation for their Intended Nationally Determined Contributions (INDCs) towards the 2015 agreement, which will come into force from 2020.
COP21/CMP11 Paris, France 2015	Governments agreed a long-term goal of keeping the increase in global average temperature to well below 2°C above pre-industrial levels and to aim to limit the increase to 1.5°C, since this would significantly reduce risks and the impacts of climate change. Before and during the Paris conference, countries submitted comprehensive national climate action plans (INDCs). This agreement was opened for signature for one year from 22 April 2016. This was to enter into force after 55 countries that account for at least 55% of global emissions have deposited their instruments of ratification. On 5 October 2016, the threshold for entry into force of the Paris Agreement was achieved. The Paris Agreement entered into force on 4 November 2016. Sri Lanka ratified in September 2016 and by October 2016, 77 Parties have ratified of 197 Parties to the Convention and it has increased to 143 parties by April 2017.
COP22/CMP12/CMA1 Marrakech, Morocco 2016	The first session of the Conference of the Parties serving as the Meeting of the Parties to the Paris Agreement (CMA1) took place. The Conference successfully demonstrated to the world that the implementation of the Paris Agreement is underway and the constructive spirit of multilateral cooperation on climate change continues.

9.8.2 Climate Finance

Climate finance refers to local, national or transnational financing, which may be drawn from public, private and alternative sources of financing. Climate finance is equally important for both mitigation and adaptation activities. Massive investment is required in order to reduce greenhouse gases significantly as well as for countries to adapt to the adverse effects and reduce the impacts of climate change.

At COP 16 Parties decided to establish the Standing Committee on Finance to assist the COP in exercising its functions in relation to the Financial Mechanism of the Convention.

This was established with the aim of assisting the COP, with regards to, transparency, efficiency, and effectiveness in the delivery of climate finance. Furthermore, the Standing Committee on Finance is designed to improve the linkages and to promote the coordination with climate finance related actors and initiatives within and outside the Convention.

The Convention, under its Article 11, states that the operation of the Financial Mechanism is entrusted to one or more existing international entities. The operation of the Financial Mechanism is partly entrusted to the Global Environment Facility (GEF). In addition to providing guidance to the GEF, Parties have established four special funds: the Special Climate Change Fund (SCCF), the Least Developed Countries Fund (LDCF), both managed by the GEF, and the Green Climate Fund (GCF) under the Convention; and the Adaptation Fund (AF) under the Kyoto Protocol.

The Financial Mechanism is accountable to the COP, which decides on its climate change policies, programme priorities and eligibility criteria for funding.

9.8.3 Sri Lankan Context

Responding to climate change involves two possible approaches: reducing and stabilizing the levels of heat-trapping greenhouse gases in the atmosphere ("mitigation") and/or adapting to the climate change already in the pipeline ("adaptation").

Sri Lanka, being highly vulnerable to climate change impacts has adopted many policy measures that would result in climate change adaptation and mitigation although emission levels are much less than the global values. It is estimated that the total emission contribution of GHG emissions from Sri Lanka is as minute as 0.05% of the global total. Even though Kyoto Protocol has not imposed any obligation for non-Annex I countries, Sri Lanka also ratified the Kyoto Protocol as a non-Annex I country in 2002.

In order to address the issues in climate change a separate dedicated institution named Climate Change Secretariat was created under the Ministry of Mahaweli Development and Environment in 2008. National Climate Change Adaptation Strategy for Sri Lanka 2011-2016 (NCCAS) was developed in 2010, but mitigation strategies are still being developed. Further 'The National Climate Change Policy of Sri Lanka' has been developed by the Climate Change Secretariat of Sri Lanka under Ministry of Mahaweli Development and Environment.

Energy sector is mainly involved in mitigation aspects of climate change and CEB actively participated in developing a 'Low Carbon Development Strategy' (mitigation strategy) which was carried out by Climate Change Secretariat during the recent past.

Further CEB is an active member of the National Expert Committee on Climate Change Mitigation which conducts various activities related to mitigation such as feasibility of introducing Variable Speed Drives to hotel sector, preparation of Low Carbon Development Strategy and preparing a GHG inventory for the country.

Following section further describe the different aspects towards reducing GHG emissions and providing sustainable energy to Sri Lankan consumers.

(a) Amendment of National Energy Policy

The National Energy Policy and Strategies of Sri Lanka (2008) stated 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. This target was successfully achieved.

Government of Sri Lanka has given more priority for the Energy sector which is highly dependent on imported fossil fuel which is 49% in 2015 and to reduce the present trend, sustainable energy policies are enforced to absorb more renewable energy to the system. The proposed amendment of the National Energy Policy and Strategies adds further focus into enhancing the share of renewable energy.

(b) Nationally Determined Contributions (NDCs)

In accordance with the LTGEP 2015-2034 Sri Lanka also prepared Intended Nationally Determined Contributions (INDCs) and submitted to UNFCC. Among mitigation strategies, Energy Sector INDCs stated that Sri Lanka expects 4% unconditional and 16% conditional reduction of greenhouse gas emissions with compared to Reference scenario in 2030. After ratification INDCs became NDCs and Sri Lanka has an obligation to achieve the target.

(c) Contribution from Renewable Energy

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 and subsequently next phase in 2014. In 2015, Sri Lanka has achieved a level of economic development of close to 3900 USD per capita income with a comparatively low effect on the global GHG emission. Therefore, Sri Lanka has a 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 plants will be the major share of the optimised energy mix in the near future and also the introduction of LNG combined cycle power plants within the Western Region. Any proposal to shift from Coal to higher cost technology / fuel in order to reduce the GHG emissions should include a suitable compensation by an international mechanism.

CEB has taken a steps to reduce emissions through efficient technologies for coal power plants by introducing high efficient super critical technology instead of subcritical technologies. By introducing high efficient technologies, CO_2 emissions could be reduced 12%-16% comparatively with subcritical technologies. CEB has initiated to develop remaining major hydro power projects although they involve higher capital cost.

In LTGEP, Other Renewable Energy share is optimized and maintained more than 20% by 2020 onwards and would result in reduction of emissions from power generation considerably. With the proposed introduction of 3x200MW Pumped Storage Power Plant and high ORE, green credential of the system would be maintained around 50% of the country's energy share.

By comparing Reference Case and Base Case Plan, It could be observed that by introducing 2897MW of ORE power plants, 900MW of coal power plants were eliminated. This would reduce the CO_2 emissions as shown in the Figure 9.13.

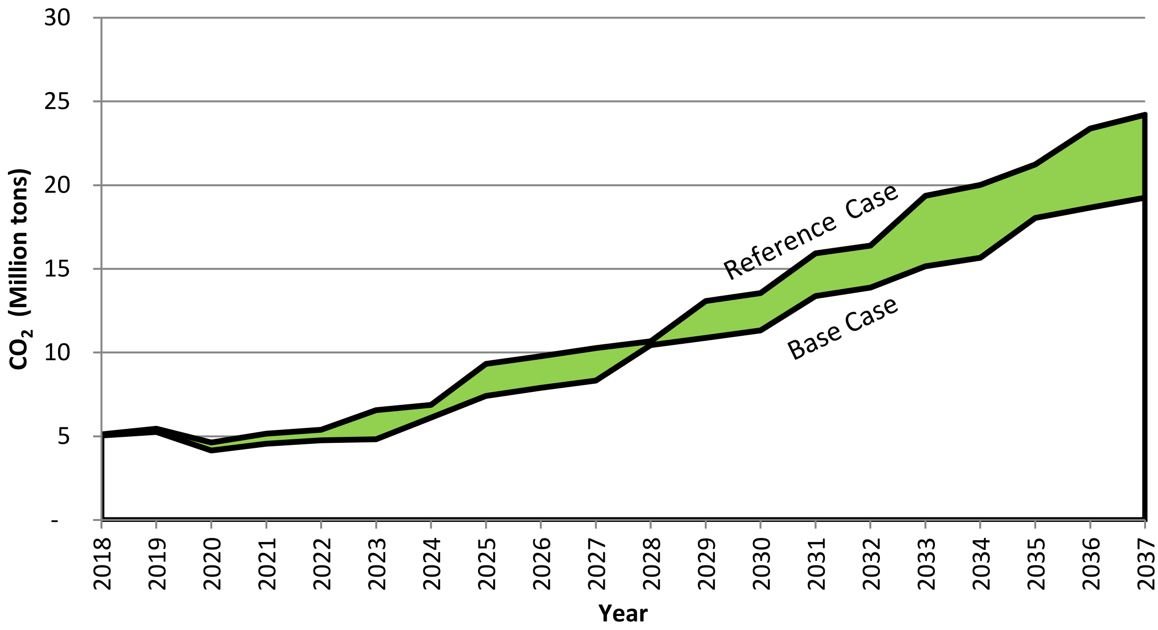


Figure 9.13 – CO_2 Emission Reduction in Base Case Compared to Reference Case

(d) Clean Development Mechanism

In February 2009, the Ministry of Environment and Natural Resources as the Designated National Authority (DNA), to the UNFCC and Kyoto protocol, at the time, developed a draft national CDM policy. The objective of the national CDM policy is *"to achieve sustainable development a) through developing and establishing the institutional, financial, human resources and legal/legislative framework necessary to participate in Clean Development Mechanism (CDM) activities and b) through developing a mechanism for trading of "Certified Emission Reduction" earned through CDM activities for the Government of Sri Lanka."*

The CDM allows emission reduction projects in developing countries to earn Certified Emission Reduction (CER) credits, which can be traded and used by industrialized countries to meet part of their emission reduction targets under the Kyoto Protocol. In Sri Lanka, the key sectors to implement CDM projects can be identified as energy, industry, transport, agriculture, waste management, forestry and plantation. Among these, the energy sector has been identified as having the highest potential.

First CDM project in Sri Lanka was registered in 2005 with UNFCCC. Since then, 17 projects have been registered by the end of 2013. CEB has undertaken one of the large scale projects which is Broadlands Hydro Power Project. The estimated emission reduction from the project is approximately 83 kilo tonnes of CO_2 equivalent per annum.

(e) Carbon Partnership Facility

Sri Lanka has initiated a carbon crediting program with the World Bank where the emission reductions above the NDC targets will be transferred to Carbon Partnership Facility (CPF) of World Bank. CEB act as the trustee and any Private Power Producer who is willing to join the scheme will have to transfer the carbon credits through CEB. Carbon revenue received in this manner may be used to overcome technical and financial barriers for renewable development.

There are different pricing approaches to determine the terms of the carbon finance payment. Diverse country and sectoral context as well as relationship with countries NDC targets also need to be considered during the process of price determination.

Since there is no valid market reference point various techniques such as administrative pricing including incremental cost analysis, investment analysis, economic evaluation or auctions can be used. Economic evaluation option under administrative pricing can be carried out without the need of detailed data. In here the price should be determined by negotiation between buyers and sellers taking into account the sellers' Willingness to Accept and Buyers' Willingness to Pay.

(f) Fuel Quality Road Map

An action plan has been developed for fuel quality road map by the Air Resource Management & National Ozone Unit of Ministry of Mahaweli Development & Environment.

Introduction of low sulphur Diesel, switching to alternative fuels for transport such as biofuel, railway electrification, promoting electric vehicles, development of fuel quality standards and introducing LNG as a cleaner fuel are some of the activities identified in the fuel quality road map.

(g) Loss Reduction

Generation, Transmission and Distribution Loss reduction is also an important measure implemented by CEB towards the path of providing sustainable energy. In 2009 the transmission and distribution loss (as a percentage of net generation) was 13.9% and by 2016 it has been reduced to approximately 10%.

(h) Demand Side Management & Energy Conservation

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 and results in reduction of GHG emissions.

CHAPTER 10
REVISIONS TO PREVIOUS PLAN

This chapter examines 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 2017 for the period of 2018-2037) and LTGEP 2014 for the period of 2015-2034 are as follows.

- Base Demand Forecast
  - A combination of Time Trend modelling and Econometric approach has been used.
  - The impact of influence of external factors (tariff variation and seasonal effects) on electricity demand was analysed.
  - Assumed major portions of proposed new developments in future reflected in the growth of Industrial Sector and Commercial Sector GDP.
  - Change in the daily load profile shape that is maximum demand shifting from night peak to day peak was considered by analysing past trends of provincial data.
  - Load Factor variation with load profile change and demand growth trends of each tariff category.
- Fuel price variations
- Revised capability of existing hydro power generation potential
- Integration of higher capacity in Other Renewable Energy (ORE) based on the results of the study “Integration of Renewable Based Generation in to Sri Lankan Grid 2017-2028”
- Introduction of Super Critical Coal Power Plant as a candidate
- Reduction in environmental emissions

10.1 Demand Forecast

10.1.1 Analysis of Provincial Demand Profiles

Actual monthly records of the night peak, day peak and off peak were analysed from 2011 to 2016 for the provinces and whole country. All the provinces show the higher growth rate in day peak than the night peak while the day peak in Western Province has already exceeded the night peak.

Figure 10.1(a) & 10.1(b) show the demand variation of whole country with and without Western Province. Accordingly, the night peak, day peak and off peak shows an increasing trend but in particular the growth of day peak is higher than the growth of night peak. Therefore, the shape of the daily load profile will gradually change. Trend line interception point can be taken as the day peak and night peak equalization point and then the day peak will become dominant. Accordingly, it is estimated that the crossover of the load profile shape would occur in 2030.

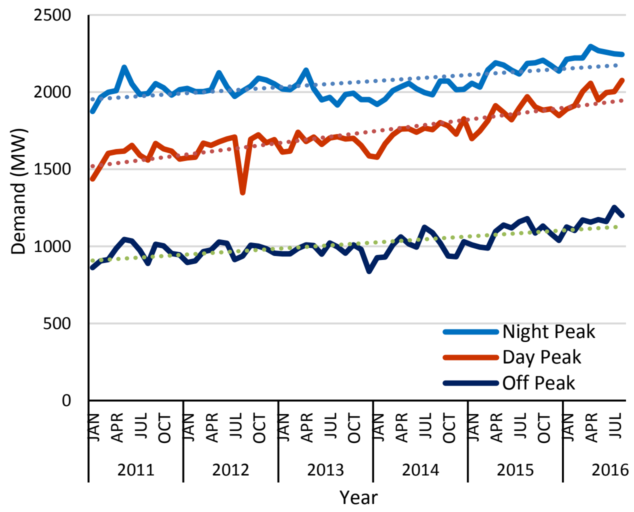


Figure 10.1(a) - Demand variation of Whole Country

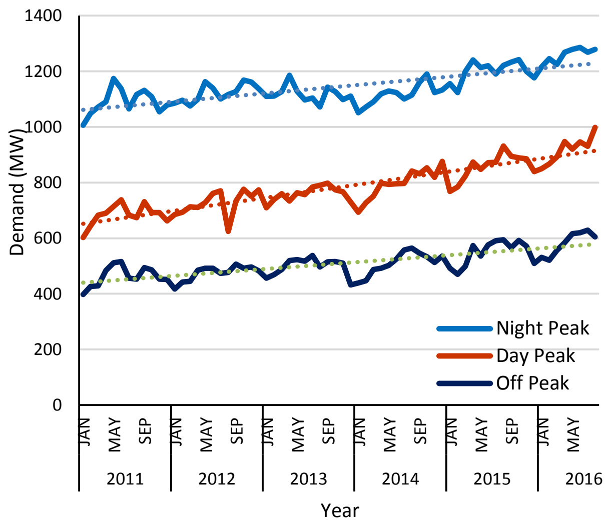


Figure 10.1(b) - Demand variation of Whole Country without Western Province

10.1.2 Base Demand Forecast

Base Demand Forecast 2018-2042 was a combination of Time Trend modelling and Econometric approach as described in section 3.3 of Chapter 3. Twenty five year average growth rates of Energy demand and Peak forecasts of LTGEP 2017 are 4.8% and 4.4% while Energy demand and Peak forecast of LTGEP 2014 are 5.2% and 4.6% respectively. Figure 10.2(a) & (b) show the Energy demand and Peak forecast comparison of LTGEP 2014 and LTGEP 2017.

According to the figure 10.2(a) & (b), annual energy demand of LTGEP 2017 is higher than the LTGEP 2014 while annual peak demand shows slight reduction in LTGEP 2017 compared with LTGEP 2014.

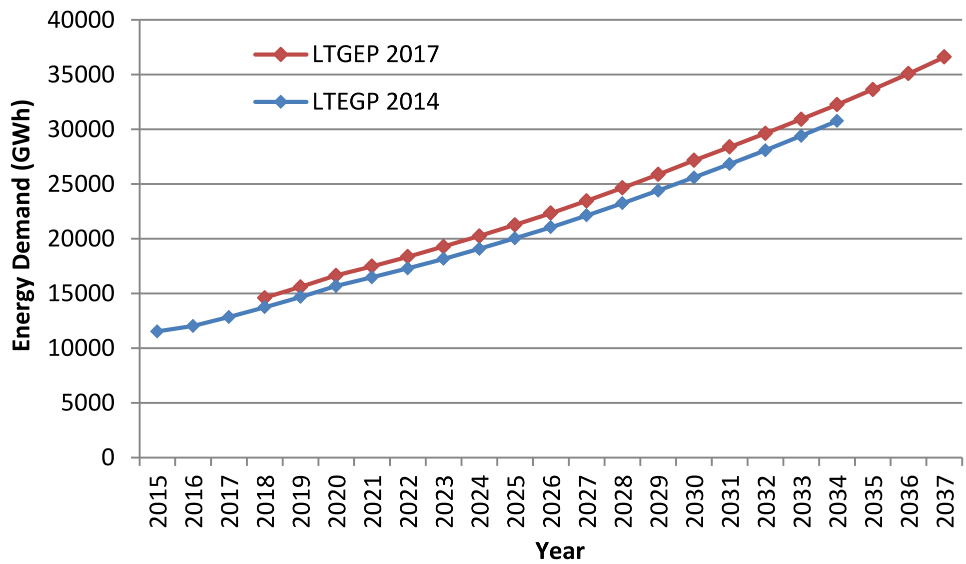


Figure 10.2(a) - Comparison of 2017 and 2014 Energy Demand Forecasts

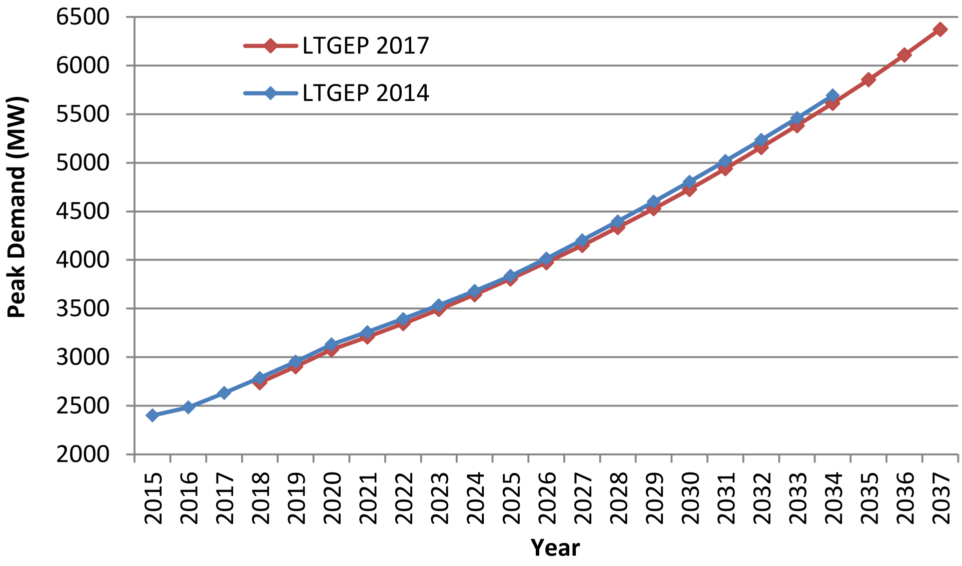


Figure 10.2(b) - Comparison of 2017 and 2014 Peak Demand Forecasts

10.2 Fuel Prices Variation

Oil and Coal prices for the present study (LTGEP 2017) were obtained from the Ceylon Petroleum Corporation (CPC) and Lanka Coal Pvt Ltd. LNG price was derived by considering the linkage variation with Japanese Crude Cocktail (JCC) and PLATTS JKM (JAPAN KOREA MARKER) Gas price assessment as described in Chapter 4. Fuel prices used in the LTGEP 2017 and LTGEP 2014 are shown in Figure 10.3. All the fuel prices show a reduction in present study compared to LTGEP 2014. LNG price shows a significant reduction while other prices have minor reduction.

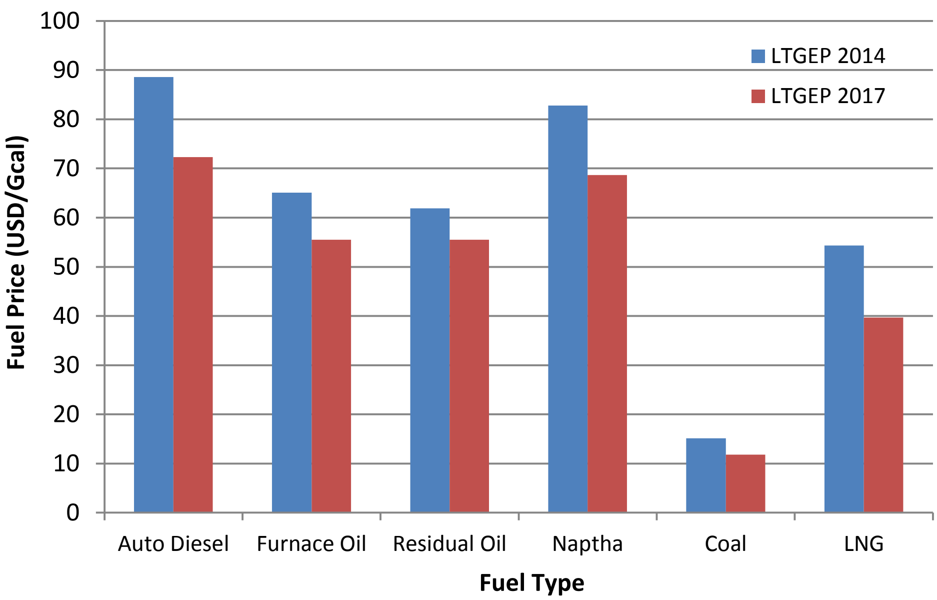


Figure 10.3 – Fuel price variation of LTGEP 2017 and LTGEP 2014

10.3 Revised Capability of Existing Hydro Power Plants

Probability values of hydro condition have been revised based on the estimated outputs of SDDP model as described in Chapter 2. Annual average energy of existing hydro system estimated as 4050GWh in LTGEP 2017 which is lower compared to LTGEP 2014. For LTGEP 2017, the probabilities of 10% (very wet), 20 %(wet), 50% (medium), 15% (dry) and 5% (very dry) hydro conditions were considered to determine the average and it resulted in a reduction in the weighted average figure.

10.4 Integration of Other Renewable Energy (ORE)

Figure 10.4 shows the variation of Other Renewable Energy (ORE) capacity contribution in the selected years 2020, 2025, 2030 & 2034 for both LTGEP 2017 and the LTGEP 2014. The total ORE capacity increases to 2965MW by 2034 in LTGEP 2017 which is 56% higher than LTGEP 2014 total ORE capacity.

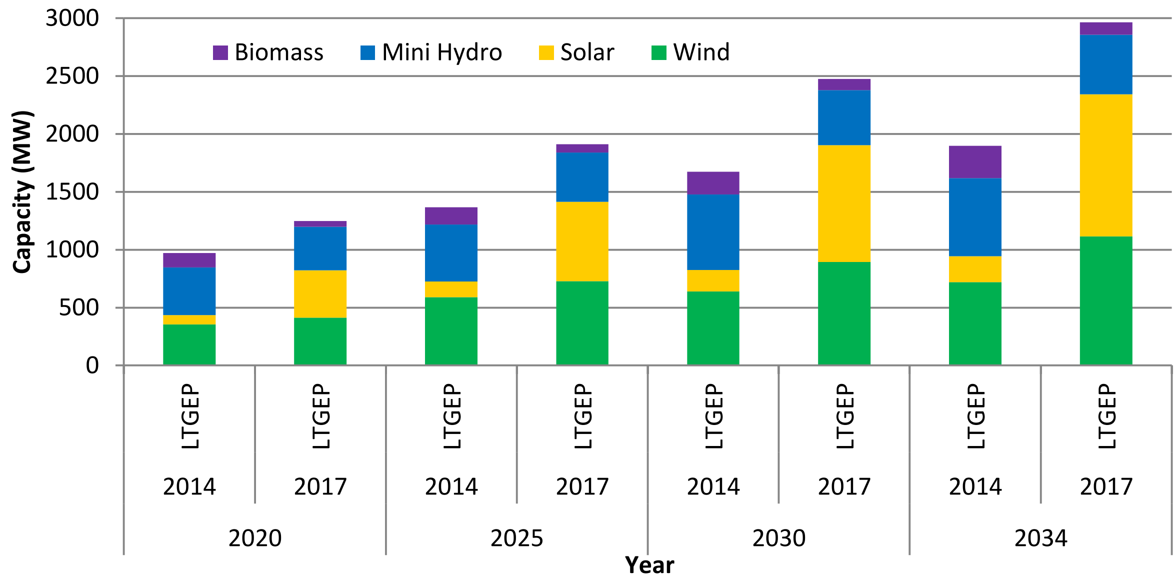


Figure 10.4 – Comparison of ORE Capacity Addition between LTGEP 2017 & LTGEP 2014

10.5 Introduction of Super Critical Coal Power Plants

Due to global environment consideration, it is crucial to mitigate the impact on the environment due to particulate and air-emissions from future least cost thermal options. In LTGEP 2017, it has taken a step to reduce emissions by introducing high efficient super critical technology instead of subcritical technologies in Coal Power Plants. By introducing high efficient technologies, CO_2 emissions could be reduced by 12%-16% comparatively with subcritical technologies. Further, this would lead to the additional investment cost of 700USD/kW compared to conventional Coal technologies.

10.6 Reduction in Environmental Emissions

CO_2 and Particulate emissions are lower in LTGEP 2017 than the emission level in the LTGEP 2014. Comparison of CO_2 and Particulate emissions depicts in Figure 10.5. Also SO_x and NO_x emissions LTGEP 2017 compared to LTGEP 2014 is shown in the Figure 10.6. Initial years of the study shows that SO_x and NO_x emissions are higher in LTGEP 2017 and later the NO_x emissions become lower compared to LTGEP 2014. Higher level of SOx and NOx in LTGEP 2017 in initial years is due to the higher dispatch of oil power plants until major base load power plants are added from 2023 onwards.

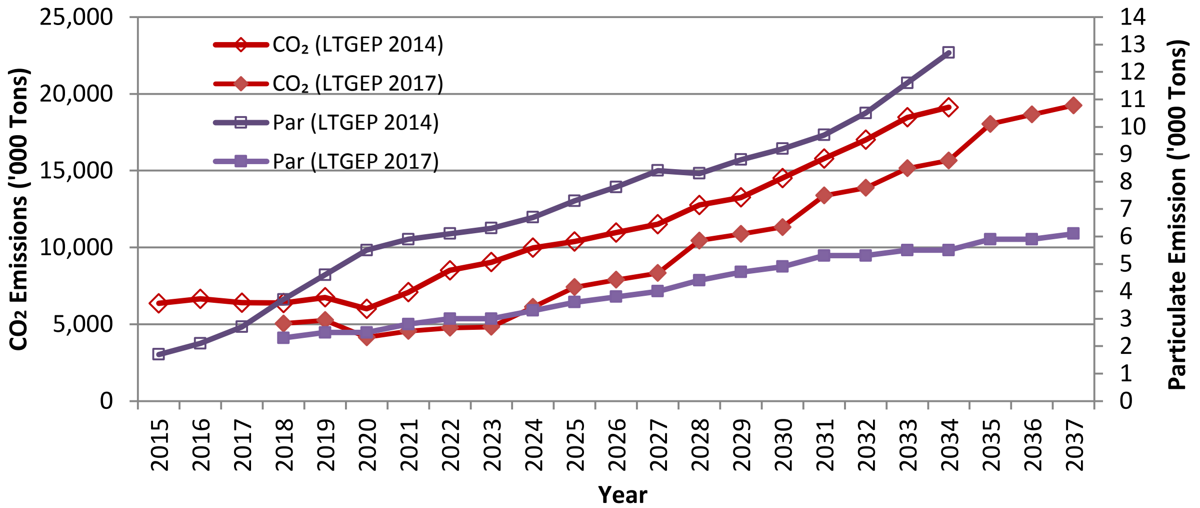


Figure 10.5 - CO_2 and Particulate Emissions

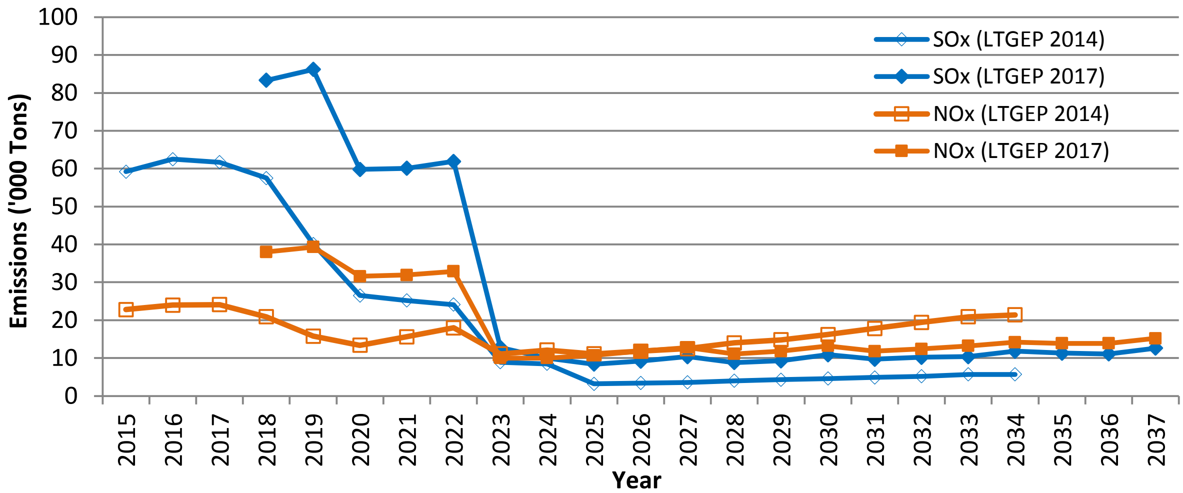


Figure 10.6 – SO_x and NO_x Emissions

10.7 Overall Comparison

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

CHAPTER 11
CONTINGENCY ANALYSIS

This chapter analyses the impact of both controllable and uncontrollable risk events, which could lead to inadequacy of supply to meet the capacity and energy demand in immediate future years from 2018 to 2022. The Contingency Analysis focus to identify the main risk events, which are given below:

(i) Variation in Hydrology
(ii) Variation in Demand
(iii) Delays in implementation of Power Plants
(iv) Long period outage of a Major Power Plant

11.1 Risk Events

11.1.1 Variation in Hydrology

Hydrology is one of the foremost uncertainty that could lead to energy supply shortage, especially when there is no major power plant to be implemented to backup additional energy. Table 11.1 depicts the annual energy output projected for the five hydro conditions, and the difference of energy with respect to the annual average hydro energy of 4,050 GWh.

Table 11.1 – Expected Annual Energy Output of Five Hydro Conditions and Difference Compared with Annual Average Hydro Energy

Hydro Condition	Expected Annual Energy (GWh)	Difference of Energy (GWh)
Very dry	3,264	-786
Dry	3,489	-561
Average	3,966	-84
Wet	4,484	+434
Very wet	4,834	+784

11.1.2 Variation in Demand

Variation in demand from the base demand projection is considered as the second uncertainty. Difference of energy in high demand and low demand scenarios with comparison to the base demand is shown in the graph in figure 11.1 for the five year period 2018 to 2022.

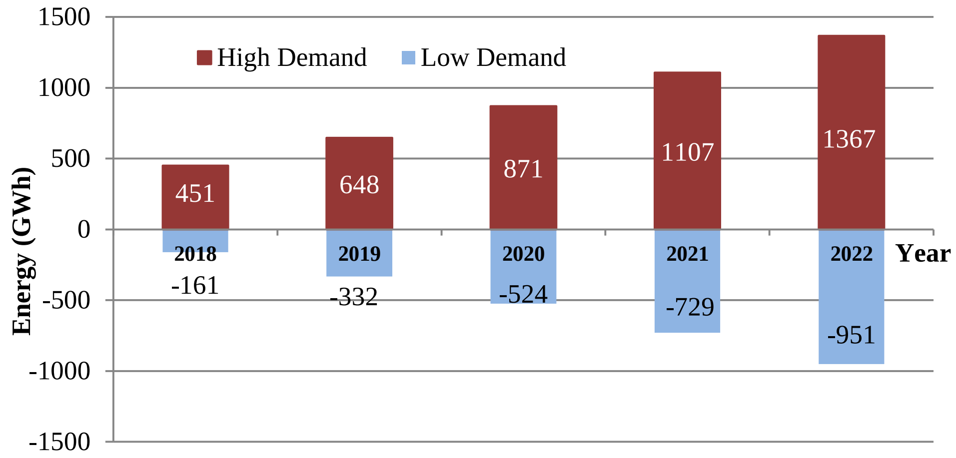


Figure 11.1 – High and Low Energy Demand Variation Compared to the Base Demand

11.1.3 Delays in Implementation of Power Plants

Implementation of committed power plants on schedule is critical to avoid energy shortfalls in short term. However unexpected deviations can occur and in the contingency analysis following power plants were considered as delayed.

Table 11.2 – Implementation Delays of Committed Power Plants

Project	LTGEP 2018-2037	Contingency Analysis
120 MW Uma Oya HPP	2019	2020
35 MW Broadlands HPP	2020	2021
100 MW Mannar Wind Park Phase II	2020	2021
300 MW NG fired Combined Cycle Power Plant	2019 (Simple Cycle) 2020 (Combined Cycle)	2020 (Simple Cycle) 2021 (Combined Cycle)
300 MW NG fired Combined Cycle Power Plant	2021	2022

11.1.4 Long Period Outage of a Major Power Plant

Outage of a major power plant for a prolonged time period during dry season is also considered as a major risk event. For the contingency analysis, outage of one unit of Lakvijaya Coal Power Plant during the dry season in first four months from January to April was considered. Details of this risk event is given in Table 11.3.

Table 11.3 – Details of Risk Event Outage of a Major Power Plant

Risk Event	One unit outage of Lakvijaya Coal Power Plant
Period	Four months (January – April)
Loss of Capacity	275MW
Loss of Energy	500GWh
Remarks	Capacity and Energy shortage can be supplied with existing power plants

11.2 Evaluation of Contingencies

Single occurrence of these risk events were considered at first and then simultatious occurrence of several events were analysed to identify the short term energy and capacity shortage.

11.2.1 Single Occurrence of Risk Events

Considering the indiviual risk event, possibility of capacity and energy shortage is given in Table 11.4.

Table 11.4 – Single Occurrence of Risk Events

Risk Event	Capacity Shortage Risk	Energy Shortage Risk	Remarks
Hydrology Reduction	No	No	Energy reduction of 786 GWh could be catered by existing power plants.
High Demand	Yes	Yes	120MW capacity of thermal power plants identified in High Demand Scenario should be implemented.
Plant Implementation Delay	No	No	Detail given in Table 11.5.
Outage of a Major Power Plant	No	No	Detail given in Table 11.3.

Table 11.5 – Estimation of Annual Energy Shortage Risk with Plant Implementation Delay

Unit: GWh

Year	2018	2019	2020	2021	2022
Delay in Plant Implementation					
Uma Oya HPP (from 2019 to 2020)		(252)			
Broadlands HPP (from 2020 to 2021)			(124)		
Mannar Wind Park Phase II (from 2020 to 2021)			(320)		
NG fired CCY1 (from 2019/2020 to 2021)		(292)	(724)		
NG fired CCY2 (from 2021 to 2022)				(1,050)	
Loss of Energy	**-**	**(544)**	**(1,168)**	**(1,050)**	**-**
Energy Shortage Risk	**No**	**No**	**No**	**No**	**No**

11.2.2 Simultaneous Occurrence of Several Risk Events

Several contingency events were analysed to identify the severity of these events and mitigation measures were suggested where necessary.

a) Contingency Event 1- Hydrology Reduction and Delays in Power Plant Implementation

The event of worst hydro condition and delays of power plant implementation were taken as the first contingency event. The parameter variations given in (1) and (3) in sectoin 11.1 were taken as the basis for the analysis.

Interms of mitigating this risk, possibility of supply the energy deficit from avalilable power plants was studied. Total annual energy deficit in this contingency event is given in the Table 11.6. Power plant dispatch in the Base Case was taken as the reference. Table 11.7 shows available plant capacities in the critical period having minimum hydro availability with the peak demand.

Table 11.6 – Estimation of Annual Energy Deficit and Energy Shortage Risk

Unit: GWh

Year	**2018**	**2019**	**2020**	**2021**	**2022**
Risk 1 :Dry Hydro Condition	**(786)**	**(786)**	**(786)**	**(786)**	**(786)**
Risk 2:Delay in Plant Implementation					
Uma Oya HPP (from 2019 to 2020)		(252)			
Broadlands HPP (from 2020 to 2021)			(124)		
Mannar Wind Park Phase II (from 2020 to 2021)			(320)		
NG fired CCY1 (from 2019/2020 to 2021		(292)	(724)		
NG fired CCY2 (from (2021 to 2022)				(1,050)	
Sub Total – Risk 2	**-**	**(544)**	**(1,168)**	**(1,050)**	**-**
Total Energy Deficit	**(786)**	**(1,330)**	**(1,954)**	**(1,836)**	**(786)**
Energy Shortage Risk	**No**	**No**	**Yes**	**No**	**No**

Table 11.7 – Available Plant Capacities in Critical Period for Each Year

Unit: MW

Available Capacity	**2018**	**2019**	**2020**	**2021**	**2022**
Existing Plant Capacity	2,493	2,493	2,442	2,377	2,377
Available Capacity of ORE	259	364	363	533	544
New Major Hydro	-	-	81	115	145
FO Plants (Committed)	320	320	320	320	320
New Gas Turbine	-	70	105	105	105
New CCY Plants	-	-	200	273	545
New FO Plants	-	75	75	75	75
Total Available Capacity	**3,073**	**3,323**	**3,586**	**3,798**	**4,110**
Peak Demand	**2,738**	**2,903**	**3,077**	**3,208**	**3,346**

It was observed that an annual energy shortage of 172 GWh in year 2020 while in other years existing themal power plants could meet the additional demand of energy. Only one unit of Lakvijaya coal power plant was considered to supply its additional energy requirement in this analysis.

Capacity requirement to mitigate the risk of capacity shortage was studied seperately and 75MW of addiional reciprocating engines were required by 2019 as shown in Table 11.7 to operate during this period. Installed capcity graph for this contingency event is given in the Figure 11.2 with peak demand and Figure 11.3 shows the available capacities in the critical period with minimum hydro availability.

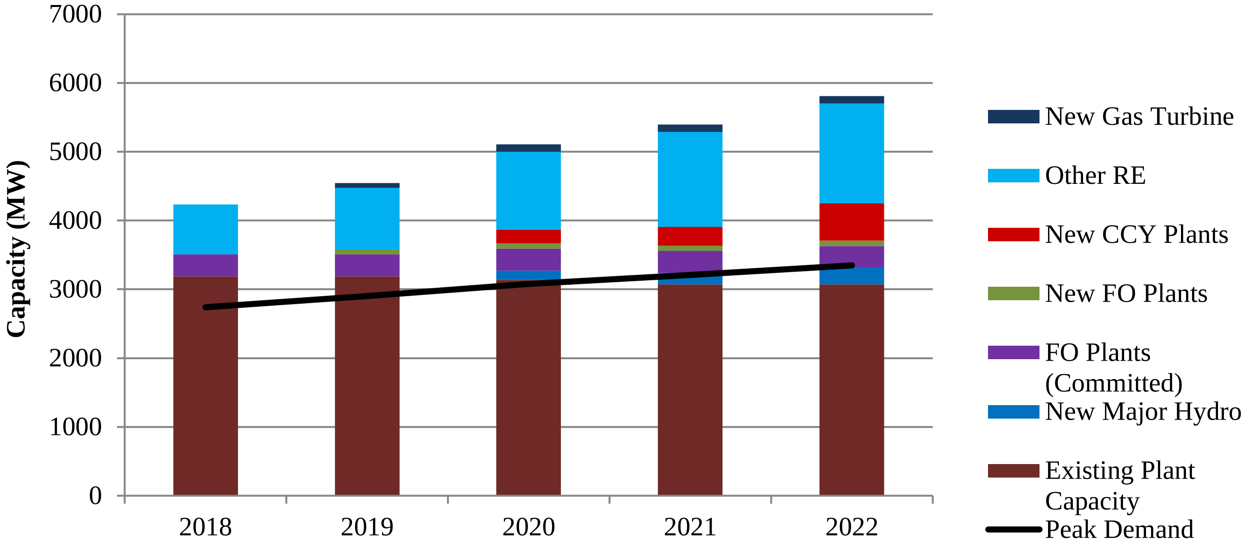


Figure 11.2 – Installed Capacity with Peak Demand (Contingency Event 1)

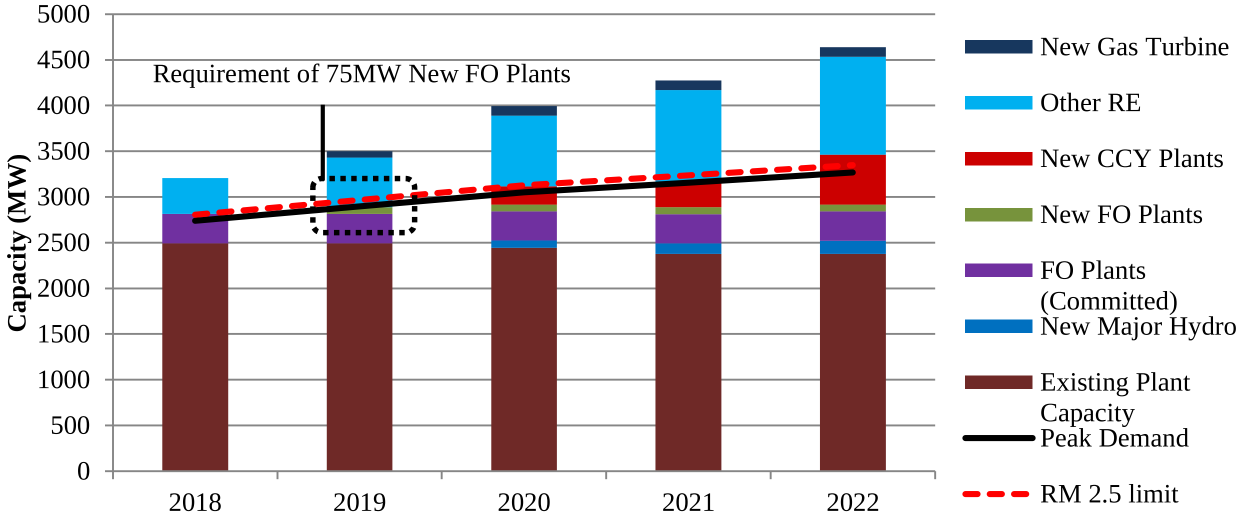


Figure 11.3 - Available Capacity in Critical Period with Peak Demand (Contingency Event 1)

b) Contingency Event 2- Hydrology Reduction, Delays in Power Plant Implementation and Outage of One Unit of Lakvijaya Coal Power Plant

An adverse contingency event with the loss of one unit of Lakvijaya Coal Power Plant simultaniously with all the risk events in section (a) is considered for the analysis.
The unit outage was assumed to occur in the dry season during first four months of the year. It was observed that both energy and capacity shortage occur in short term in this contingency event.

Additional capacity of 150MW was required to mitigate the contengency event. Figure 11.4 shows the avalilable capacity in the critical period.

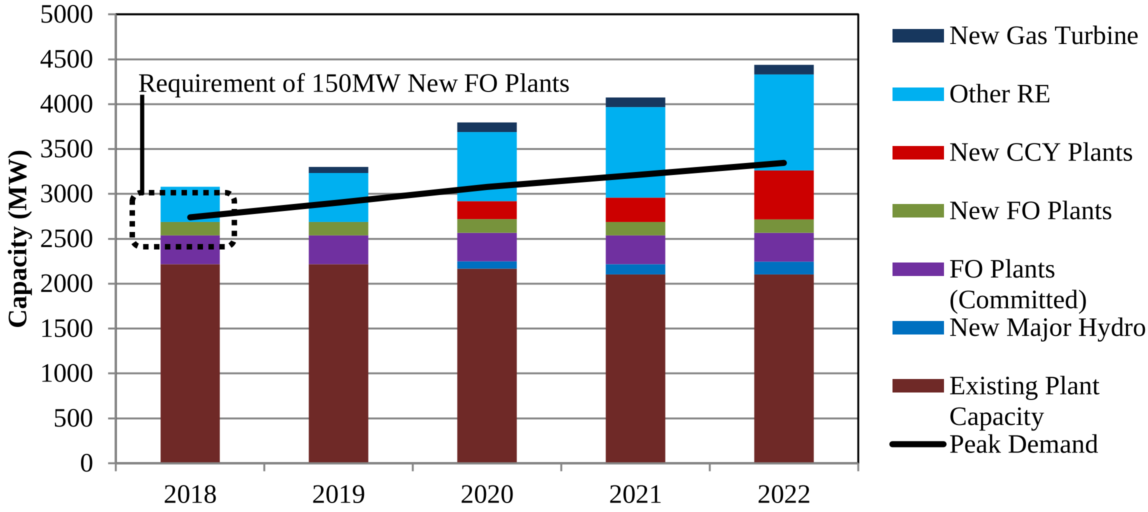


Figure 11.4 - Available Capacity in Critical Period with Peak Demand (Contingency Event 2)

c) Contingency Event 3- High Demand, Hydrology Reduction and Delays in Power Plant Implementaion

The risk event of exceeding base demand projection is considered to occur simultaneously with worst hydro condition and power plant implementation delays in this contingency event. High demand scenario is given in Chapter 7 under scenario analysis and 120MW additional capacity requirement was identified in that scenario. In this contingency event with power plant implementation delay and hydrology reduction, additional capacity requirement of 45MW was identified. Available plant capacity in critical period is given in the figure 11.5.

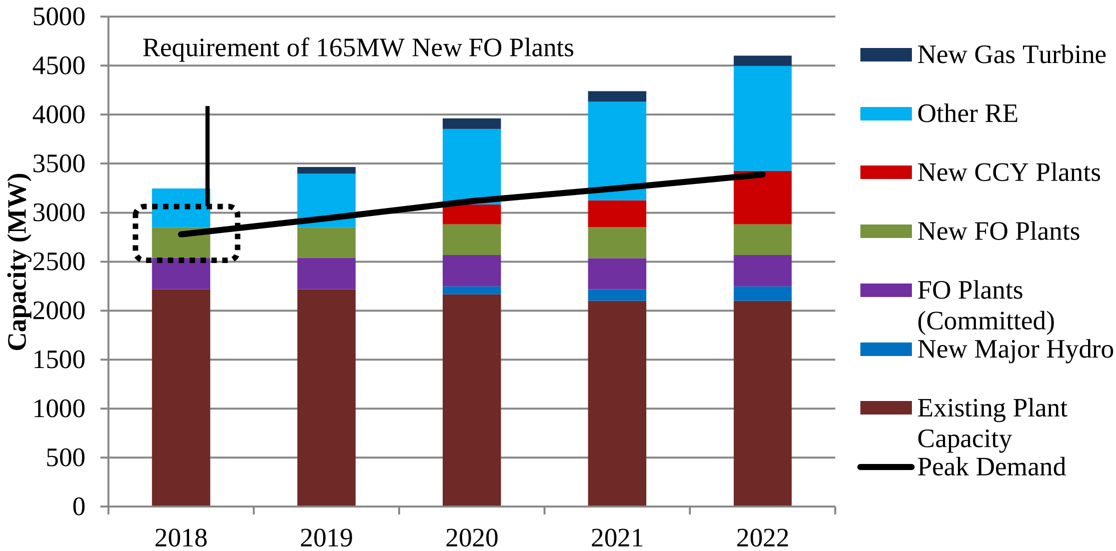


Figure 11.5 - Available Capacity in Critical Period with Peak Demand (Contingency Event 3)

11.3 Conclusion

(1) Except high demand event, there is no capacity or energy shortage observed in single occurrence of risk event. Therefore, hydrology variation, Plant implementation delays and one unit outage of coal power plant could be mitigated with existing and future committed power plants if only one of these events occur at a time during the period.

(2) In simultaneous occurrence of several risk events, in contingency event 2, with one unit outage of Lakvijaya coal power plant, reduced hydro availability and plant implementation delays, it is necessary to have an additional capacity of 150 MW.

(3) If high demand occurs simultaneous with hydrology reduction and plant implementation delays, additional capacity of 165MW is required to mitigate this contingency event. However, an additional capacity of 120MW is already identified in the high demand scenario.

(4) From these contingency events, it is observed that an additional capacity of 150MW in the system needs to mitigate the risk of capacity and energy shortage.

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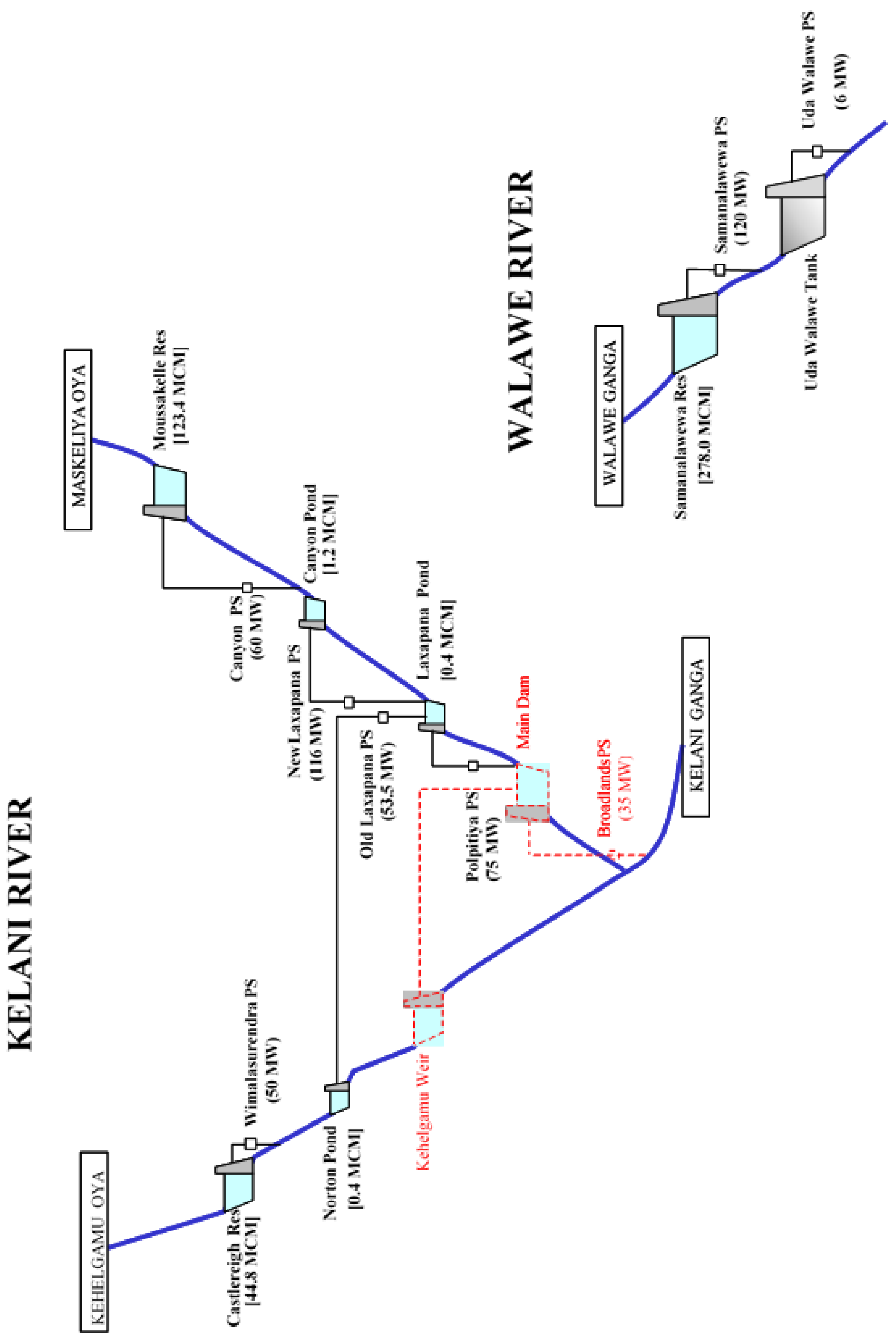
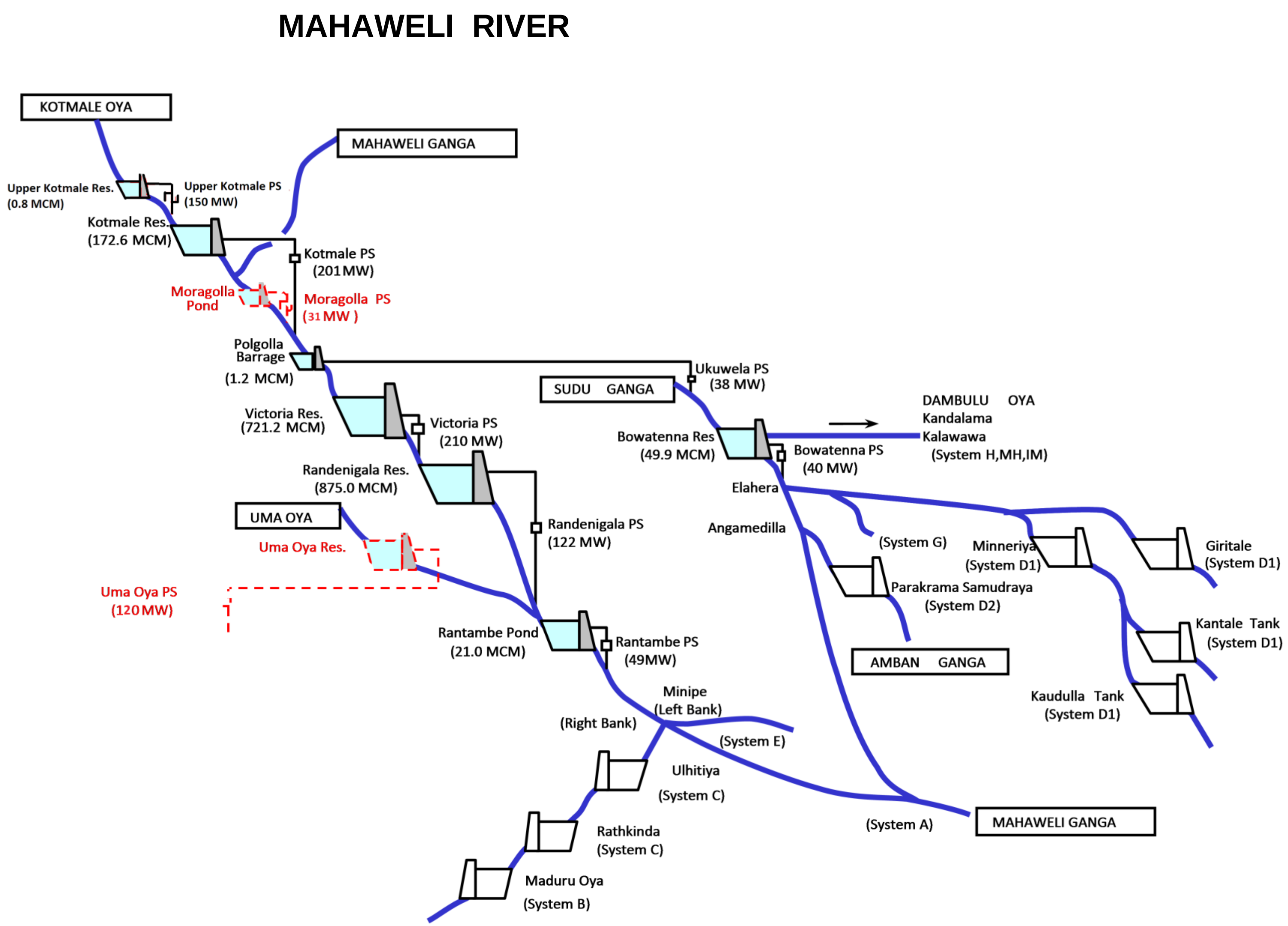
Reservoir Systems in Mahaweli, Kelani and Walawe River Basins

A2.1.1 Reservoir Systems in Kelani and Walawe River Basins



A2.1.2 Reservoir System in Mahaweli River Basin



Annex 3.1

Scenarios of the Demand Forecast

Table A3.1 – High Demand Forecast

Year	Demand (GWh)	Net Losses* (%)	Net Generation (GWh)	Peak Demand (MW)
2018	14994	9.88	16638	2778
2019	16167	9.84	17932	2943
2020	17432	9.81	19327	3119
2021	18477	9.77	20477	3250
2022	19587	9.73	21698	3388
2023	20765	9.69	22993	3534
2024	22016	9.65	24368	3686
2025	23344	9.61	25827	3847
2026	24754	9.58	27376	4016
2027	26251	9.54	29019	4193
2028**	27834	9.50	30755	4383
2029	29499	9.46	32582	4656
2030	31273	9.42	34527	4934
2031	32995	9.38	36412	5203
2032	34777	9.35	38363	5482
2033	36637	9.31	40397	5773
2034	38574	9.27	42514	6076
2035	40623	9.23	44753	6396
2036	42778	9.19	47108	6732
2037	45062	9.15	49602	7089
2038	47423	9.12	52179	7457
2039	49845	9.08	54821	7835
2040	52340	9.04	57541	8224
2041	54945	9.02	60392	8631
2042	57710	9.00	63418	9064
5 Year Average Growth	6.9%		6.9%	5.1%
10 Year Average Growth	6.4%		6.4%	4.7%
20 Year Average Growth	6.0%		5.9%	5.1%
25 Year Average Growth	5.8%		5.7%	5.1%

***** Net losses include losses at the Transmission & Distribution levels and any non-technical losses, Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depend on the hydro thermal generation mix of the future.

** It is expected that day peak would surpass the night peak from this year onwards

Table A3.2 – Low Demand Forecast

Year	Demand (GWh)	Net Losses* (%)	Net Generation (GWh)	Peak Demand (MW)
2018	14443	9.88	16027	2711
2019	15284	9.84	16953	2847
2020	16174	9.81	17932	2990
2021	16820	9.77	18641	3088
2022	17494	9.73	19380	3189
2023	18197	9.69	20149	3296
2024	18929	9.65	20951	3407
2025	19692	9.61	21787	3523
2026	20488	9.58	22657	3644
2027	21317	9.54	23565	3771
2028	22176	9.50	24503	3901
2029	23059	9.46	25469	4036
2030	23985	9.42	26480	4188
2031	24826	9.38	27397	4330
2032	25670	9.35	28316	4474
2033	26529	9.31	29252	4619
2034	27401	9.27	30201	4766
2035**	28309	9.23	31187	4906
2036	29244	9.19	32205	5078
2037	30221	9.15	33266	5247
2038	31200	9.12	34329	5417
2039	32169	9.08	35381	5586
2040	33137	9.04	36429	5754
2041	34123	9.02	37506	5927
2042	35158	9.00	38635	6108
5 Year Average Growth	4.9%		4.9%	4.1%
10 Year Average Growth	4.4%		4.4%	3.7%
20 Year Average Growth	4.0%		3.9%	3.5%
25 Year Average Growth	3.8%		3.7%	3.4%

***** Net losses include losses at the Transmission & Distribution levels and any non-technical losses, Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depend on the hydro thermal generation mix of the future.

** It is expected that day peak would surpass the night peak from this year onwards

Table A3.3- Long Term Time Trend Demand Forecast

Year	Demand (GWh)	Net Losses* (%)	Net Generation (GWh)	Peak Demand (MW)
2018	15049	9.88	16700	2788
2019	15976	9.84	17720	2908
2020	16960	9.81	18804	3034
2021	18004	9.77	19953	3167
2022	19113	9.73	21173	3306
2023	20290	9.69	22467	3453
2024	21539	9.65	23841	3607
2025	22866	9.61	25298	3768
2026	24274	9.58	26845	3938
2027	25769	9.54	28486	4116
2028	27356	9.50	30227	4308
2029	29040	9.46	32075	4584
2030	30829	9.42	34036	4864
2031	32727	9.38	36117	5161
2032	34743	9.35	38324	5477
2033	36882	9.31	40667	5812
2034	39154	9.27	43153	6167
2035	41565	9.23	45792	6544
2036	44124	9.19	48591	6944
2037	46842	9.15	51561	7369
2038	49726	9.12	54714	7819
2039	52789	9.08	58059	8297
2040	56040	9.04	61608	8805
2041	59491	9.02	65389	9345
2042	63154	9.00	69400	9919
5 Year Average Growth	6.2%		6.1%	4.4%
10 Year Average Growth	6.2%		6.1%	4.4%
20 Year Average Growth	6.2%		6.1%	5.2%
25 Year Average Growth	6.2%		6.1%	5.4%

***** Net losses include losses at the Transmission & Distribution levels and any non-technical losses, Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depend on the hydro thermal generation mix of the future.

Table A3.4 – MAED Load Projection

Year	Demand (GWh)	Net Losses* (%)	Net Generation (GWh)	Peak Demand (MW)
2018	13870	9.90	15393	2661
2019	14560	9.93	16165	2788
2020	15301	9.86	16975	2921
2021	16185	9.74	17932	3053
2022	17121	9.61	18942	3191
2023	18111	9.49	20010	3336
2024	19158	9.36	21138	3487
2025	20266	9.24	22329	3644
2026	21365	9.21	23532	3832
2027	22525	9.18	24801	4030
2028	23746	9.15	26137	4237
2029	25035	9.12	27546	4456
2030	26393	9.09	29031	4685
2031	27595	9.06	30346	4897
2032	28852	9.04	31721	5119
2033	30166	9.02	33158	5351
2034	31538	9.01	34660	5594
2035	32965	9.01	36230	5847
2036	34380	9.00	37780	6094
2037	35851	9.00	39397	6352
2038	37385	9.00	41083	6621
2039	38985	9.00	42840	6901
2040	40653	9.00	44673	7193
2041	42443	9.00	46641	7501
2042	44313	9.00	48696	7821
5 Year Average Growth	5.4%		5.3%	4.6%
10 Year Average Growth	5.5%		5.4%	4.7%
20 Year Average Growth	5.1%		5.1%	4.7%
25 Year Average Growth	5.0%		4.9%	4.6%

***** Net losses include losses at the Transmission & Distribution levels and any non-technical losses, Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depend on the hydro thermal generation mix of the future.

Candidate Thermal Plant Data Sheets

• Basic data	35 MW Gas Turbine	105 MW Gas Turbine	150 MW Diesel Combined Cycle	300 MW Diesel Combined Cycle
Installed capacity (MW)- Gross	35	105	150	300
Net capacity (MW)	35	105	144	288
Fuel Type	Auto Diesel	Auto Diesel	Auto Diesel	Auto Diesel
• Information input to studies				
Annual fixed O&M cost (US$/kW-month)	0.69	0.52	0.54	0.41
Variable O&M cost (USCts/kWh)	0.552	0.414	0.467	0.352
Time Availability * (Maximum annual PF) (%)	308.2(84.4)	308.2(84.4)	308.2(84.4)	308.2(84.4)
Scheduled annual maintenance duration (days)	30	30	30	30
Forced outage rate (%)	8	8	8	8
Calorific value (kCal/kg)	10500	10500	10500	10500
Minimum operating level (%)	100	30	33.3	33.3
Net Heat rate at minimum operating level (kCal/kWh)	3060	4105	2614	2457
Net Heat rate at full load operating level (kCal/kWh)	3060	2857	1842	1785
Capital Cost Incl. IDC (US$/kW) Net Basis	785.9	534.5	1668.9	1264.9
Construction Period (years)	1.5	1.5	3	3
Economic Life time (years)	20	20	30	30

• **Basic data**	**150 MW LNG Combined Cycle**	**300 MW LNG Combined Cycle**	**300 MW High Efficient Coal Plant**	**600 MW Super Critical Coal Plant**
Installed capacity (MW) - Gross	150	300	300	600
Net capacity (MW)	144	286.9	270	564
Fuel Type	LNG/NG	LNG/NG	Coal	Coal
• **Information input to studies**				
Annual fixed O&M cost (US$/kW-month)	0.25	0.38	4.47	4.79
Variable O&M cost (USCts/kWh)	0.497	0.497	0.582	0.582
*Available Days per year (Maximum annual PF %)	308.2(84.4)	308.2(84.4)	310.4(85.0)	310.4(85.0)
Scheduled annual maintenance duration (days)	30	30	45	45
Forced outage rate (%)	8	8	3	3
Calorific value (kCal/kg)	13000**	13000**	5900	5900
Minimum operating level (%)	33	33	35	60
Net Heat rate at minimum operating level (kCal/kWh)	2574	2462	2810	2248
Net Heat rate at full load operating level (kCal/kWh)	1834	1793	2241	2082
Capital Cost Incl. IDC (US$/kW) - Net	1314	1265.9	2117.2	2272.0
Construction Period (years)	3	3	4	4
Economic Life time (years)	30	30	30	30

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

**LNG values were used for NG and actual values for NG to be determined

• **Basic data**	**600 MW Nuclear**	**15 MW Reciprocating Engine**	**5 MW Dendro**
Installed capacity (MW)- Gross	600	15	5
Net capacity (MW)	552	15	5
Fuel Type	Nuclear	Furnace Oil	Bio mass
• **Information input to studies**			
Annual fixed O&M cost (US$/kW-month)	8.42	2.38	2.43
Variable O&M cost (USCts/kWh)	1.752	0.634	4.460
Time Availability * (Maximum annual PF) (%)	323.4(88.5)	289.7(79.4)	285.2(78.1)
Scheduled annual maintenance duration (days)	40	60	74
Forced outage rate (%)	0.5	5	2
Calorific value (kCal/kg)	-	10300	3224
Minimum operating level (%)	90	100	100
Net Heat rate at minimum operating level (kCal/kWh)	2723	2210	5694
Net Heat rate at full load operating level (kCal/kWh)	2685	2210	5694
Capital Cost Incl. IDC (US$/kW) Net Basis	5687.3	1011.9	1814.2
Construction Period (years)	5	1.5	1.5
Economic Life time (years)	60	20	30

Annex 5.1
Candidate Hydro Plant Data Sheets

A 5.1.1 Seethawaka Hydro Power Project

- **General**

Seethawaka power project is to be located in the Rue-castle/ Hinguralakanda villages in Dehiovita Divisional Secretariat Division in Kegalle District.

- **Project Overview**

Project Code	Sita 014
Province / District	Sabaragamuwa / Kegalle
Catchment	Seethawaka
Reservoir Full Supply Level at Flooding	67 msl
Reservoir Full Supply Level at Dry	68.4 msl
Pond Area	31 ha
Pond Capacity	8 MCM
Weir/Barrage Height	27 m
Weir Top level elevation above MSL	67 m
Weir length	105 m
Spillway Type	Radial Gates
Length / Diameter Penstock	1470 m / 4.5 m
Length Tail Race Channel	20 m
Type of Powerhouse	Open-air
Gross Head	42 m
Plant Capacity	20MW
Average Annual Generation	47.6GWh
Island Area Inundated	0.25 ha
Land Area Inundated	6 ha

A 5.1.2 Thalpitigala Hydro Power Project

- **General**

Thalpitigala Hydro Power Project is to be developed by Ministry of Irrigation and Water Resource Management. The envisages the construction of a 45.7 m. high dam across Uma Oya at Thalpitigala and the reservoir will have a capacity of 15.6 million cu.m. It will provide improved irrigation water for 810 hectares in the Bathmedilla Scheme. The secondary objective of the project is the construction of a power house to supply electricity to the national grid.

- **Project Overview**

Province / District	Uva Province
No of Units	2
Plant Capacity	15 MW
Average Annual Generation	51.3 GWh
Rated Flow	15.54 m^3/s
Rated Head	93.1 m
Reservoir Capacity	15.56 MCM

Other Renewable Energy Tariff

The Ceylon Electricity Board is pleased to announce the new tariff for purchase electricity from Non-Conventional Renewable Energy (NCRE) Sources according to the Cabinet Approval dated 07/03/2014. The SPPA will continue for NCRE projects with a capacity up to 10 MW. The tariff will be three-tire-tariff and effective from 01/01/2012 until further notice.

Three-tier Tariff

All prices are in Sri Lanka Rupees per kilowatt-hour (LKR/kWh)

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

Technology/ Source	Escalable Base O&M Rate (year 1-20)	Escalable Base Fuel Rate (year 1-20)	Non-escalable (fixed rate)		
			Tier 1: Years 1-8	Tier 2: Years 9-15	Tier 3: Year 16-20
Mini-hydro	1.83	None	15.56	5.98	3.40
Mini-hydro-local	1.88	None	15.97	6.14	3.49
Wind	1.30	None	22.05	8.48	4.82
Wind-local	1.33	None	22.60	8.69	4.94
Biomass	1.52	12.25	9.67	3.72	2.11
Biomass 16yr onwards	1.90				
Agro & Industrial waste	1.52	6.13	9.65	3.71	2.11
Agro & Indus 16yr onwards	1.90				
Waste Heat	0.48	None	9.14	3.52	2.00
Escalation rate for year 2013	5.16%	3.44%			

Any other renewable energy technology other than those specified above would be offered a flat tariff of Rs. 23.10 / kWh (non-escalable for 20 years).

Annex 5.3

Other Renewable Energy Projections for Low Demand Scenario and No Future Coal Power Development Scenario

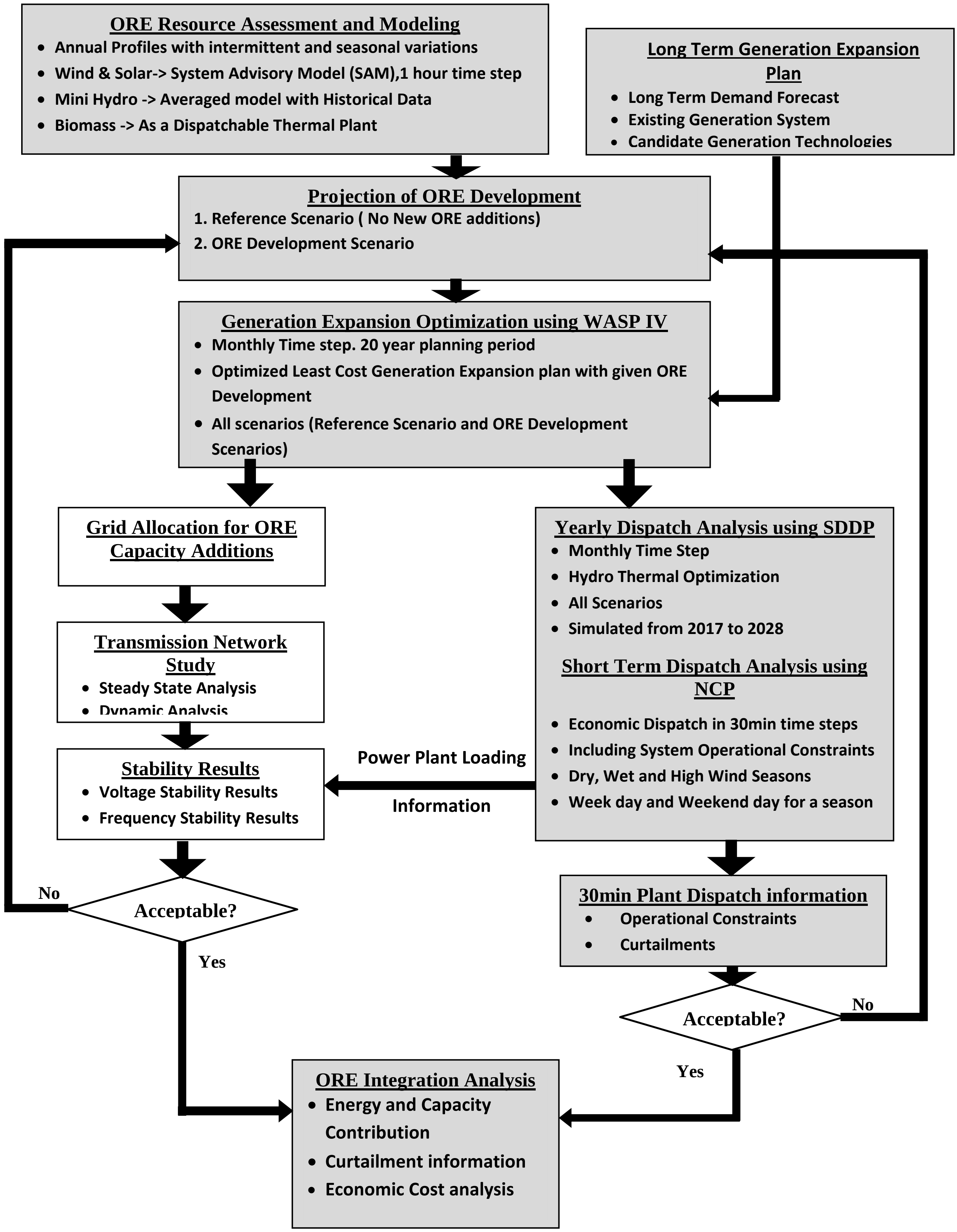
Projected Future Development of ORE for the Low Demand Scenario

Year	Cumulative Mini hydro Capacity (MW)	Cumulative Wind Capacity (MW)	Cumulative Biomass Capacity (MW)	Cumulative Solar Capacity (MW)	Cumulative Total ORE Capacity (MW)	Annual Total ORE Generation (GWh)	Share of ORE from Total Generation %
2018	344	144	39	210	737	2103	13.1%
2019	359	194	44	305	902	2471	14.6%
2020	374	414	49	410	1246	3402	19.0%
2021	384	489	54	465	1392	3784	20.3%
2022	394	539	59	471	1463	4022	20.8%
2023	404	584	59	501	1547	4232	21.0%
2024	414	609	59	531	1613	4388	20.9%
2025	424	649	59	560	1692	4579	21.0%
2026	434	649	64	615	1762	4724	20.8%
2027	444	674	69	670	1856	4942	21.0%
2028	454	694	69	775	1992	5181	21.1%
2029	464	719	74	829	2086	5399	21.2%
2030	474	764	79	884	2201	5675	21.4%
2031	484	774	84	914	2255	5802	21.2%
2032	494	819	84	969	2366	6044	21.3%
2033	504	864	89	998	2455	6284	21.5%
2034	514	909	89	1029	2540	6490	21.5%
2035	524	954	89	1058	2625	6696	21.5%
2036	534	999	89	1088	2710	6903	21.4%
2037	544	1044	94	1142	2824	7177	21.6%

Projected Future Development of ORE for No Future Coal Power Development Scenario

Year	Cumulative Mini hydro Capacity (MW)	Cumulative Wind Capacity (MW)	Cumulative Biomass Capacity (MW)	Cumulative Solar Capacity (MW)	Cumulative Total ORE Capacity (MW)	Annual Total ORE Generation (GWh)	Share of ORE from Total Generation %
2018	344	144	39	210	737	2103	13.0%
2019	359	194	44	305	902	2471	14.3%
2020	374	414	49	410	1246	3402	18.4%
2021	384	489	54	465	1392	3784	19.5%
2022	394	539	59	471	1463	4022	19.8%
2023	404	599	59	526	1592	4338	20.3%
2024	414	624	59	581	1688	4563	20.4%
2025	424	649	59	635	1782	4789	20.4%
2026	434	649	64	690	1852	4934	20.0%
2027	444	674	69	745	1946	5152	19.9%
2028	454	719	69	850	2112	5502	20.2%
2029	464	744	74	904	2206	5720	20.0%
2030	474	814	79	959	2346	6070	20.2%
2031	484	849	84	1014	2450	6307	20.1%
2032	494	894	84	1069	2561	6550	20.0%
2033	504	964	89	1123	2700	6899	20.2%
2034	514	1034	89	1179	2835	7214	20.3%
2035	524	1104	89	1233	2975	7565	20.4%
2036	534	1199	89	1288	3135	7957	20.6%
2037	544	1269	94	1392	3324	8375	20.8%

Methodology of the Renewable Energy Integration Study 2018-2028



1. Mannar 25MW Wind Power Plant - Power Output

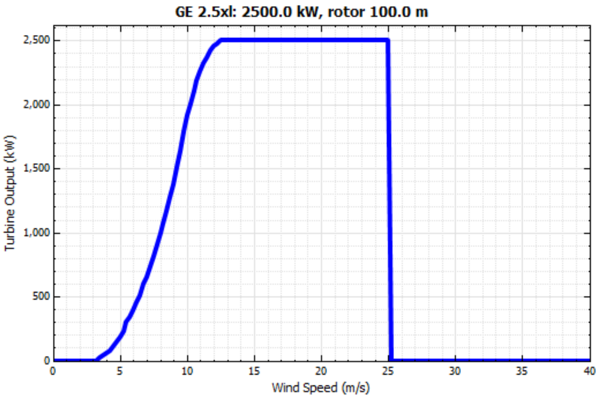


Fig. A5.1: Power curve of the modelled wind turbine

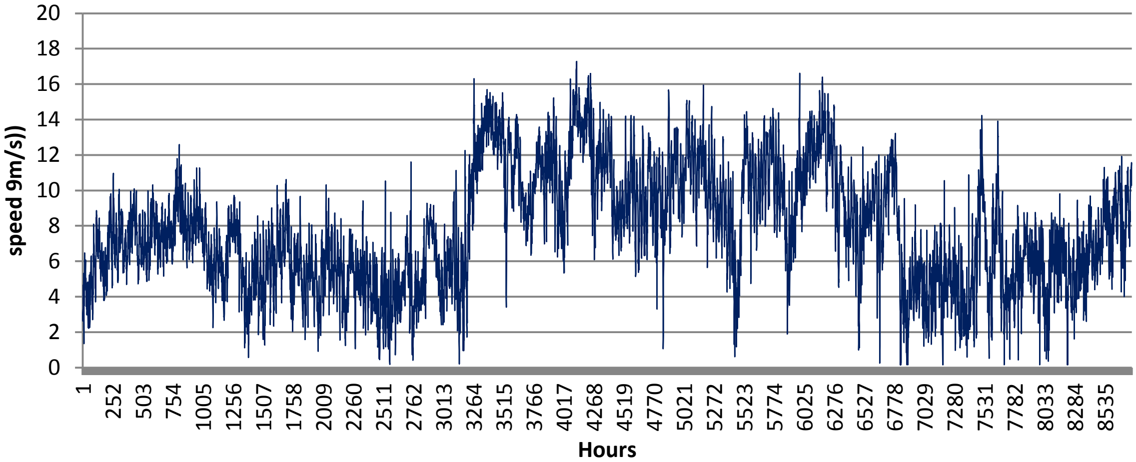


Fig. A5.2: Wind speed variation

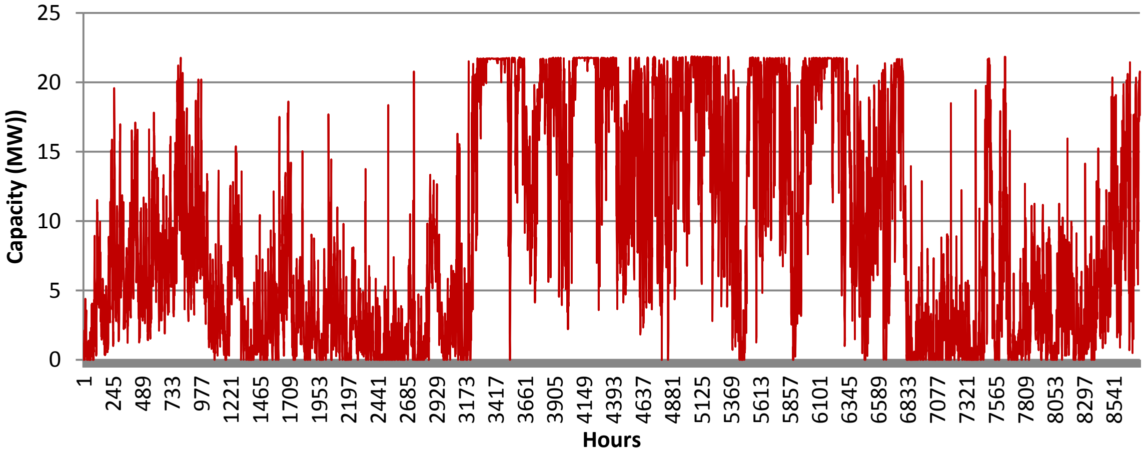


Fig. A5.3: Wind Plant Power output

2. Puttalam 20MW Wind Power Plant - Power Output

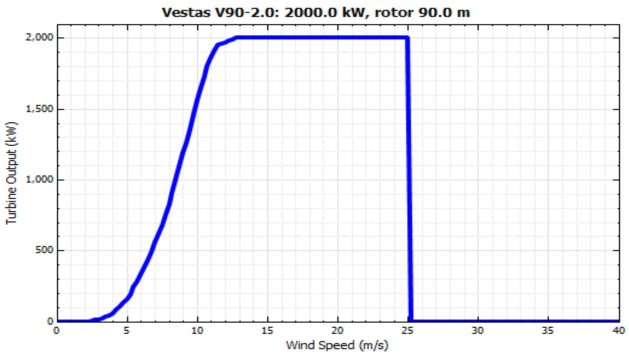


Fig. A5.4: Power curve of the modelled wind turbine

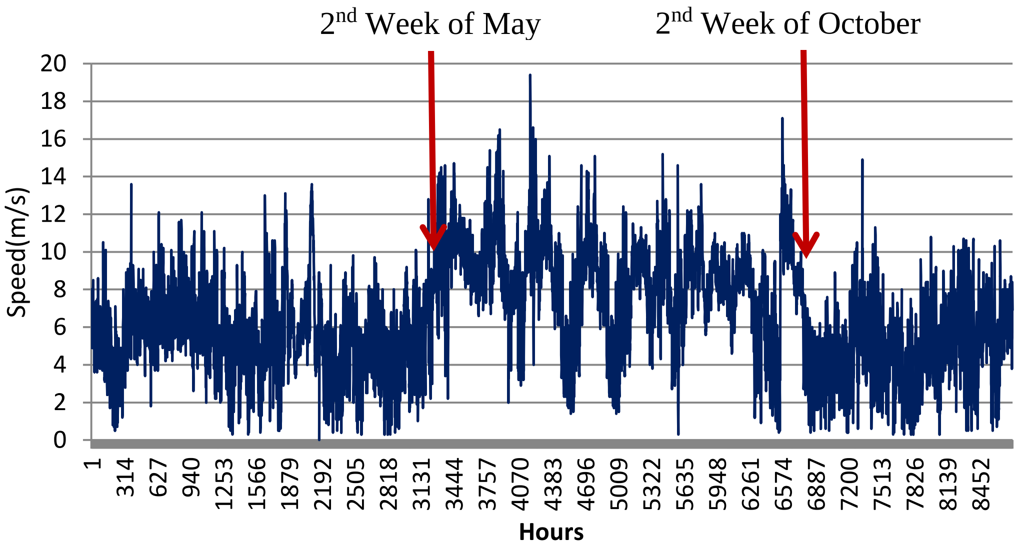


Fig. A5.5: Wind speed variation of modelled wind turbine

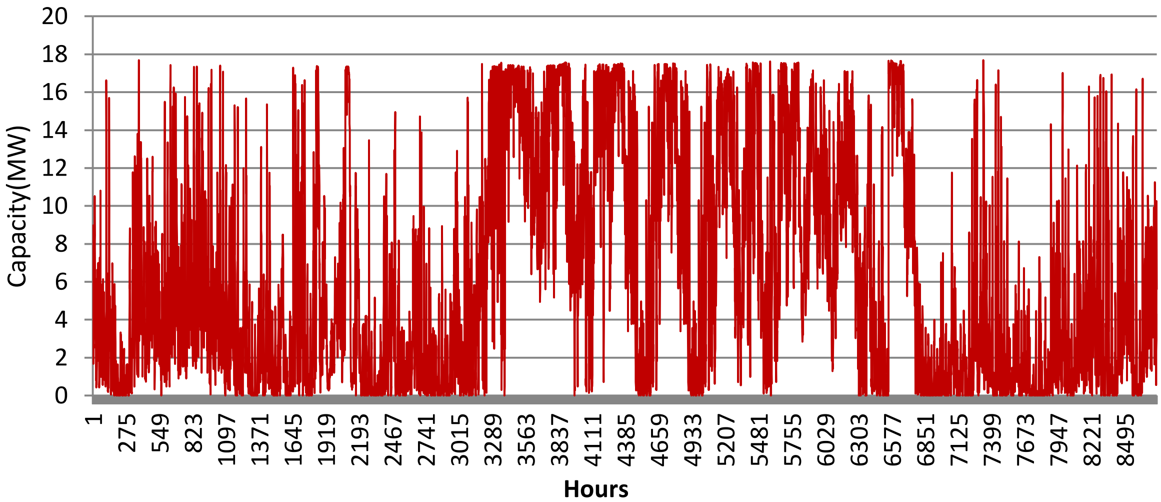


Fig. A5.6: Wind Plant Power output

3. Northern 20MW Wind Power Plant - Power Output

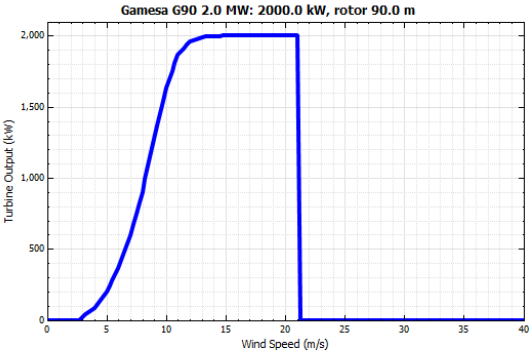


Fig. A5.7: Power curve of the modelled wind turbine

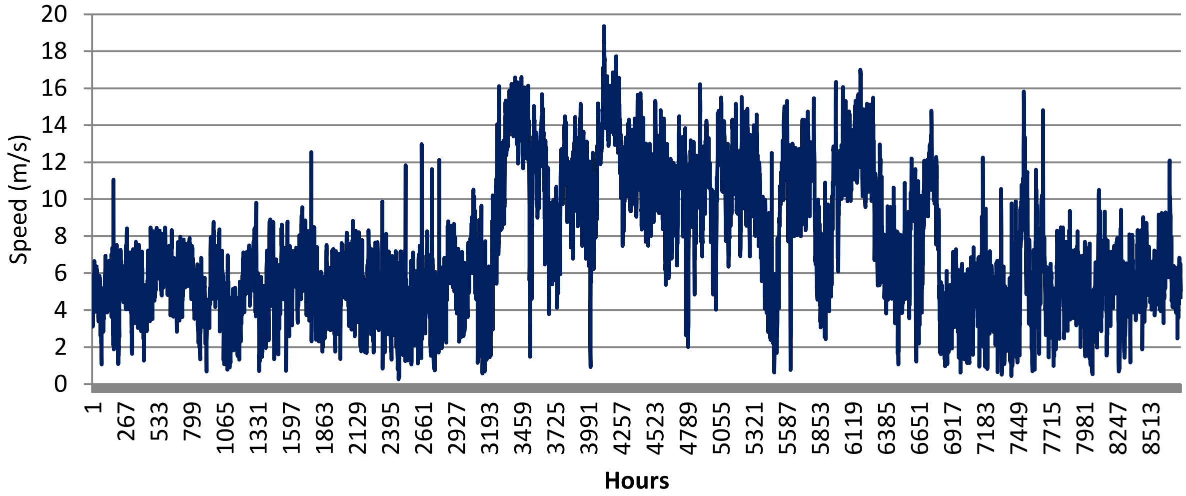


Fig. A5.8: Wind speed variation

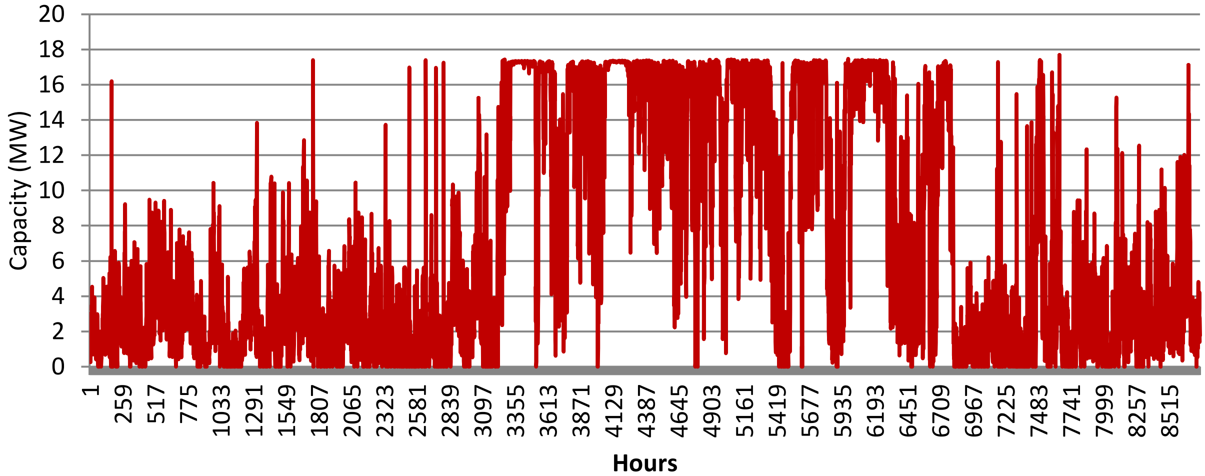


Fig. A5.9: Wind Plant Power output

4. Eastern 20MW Wind Power Plant - Power Output

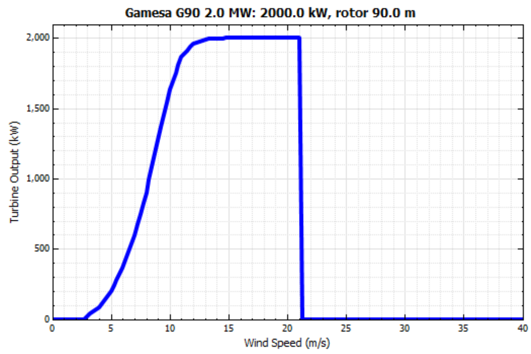


Fig. A5.10: Power curve of the modelled wind turbine

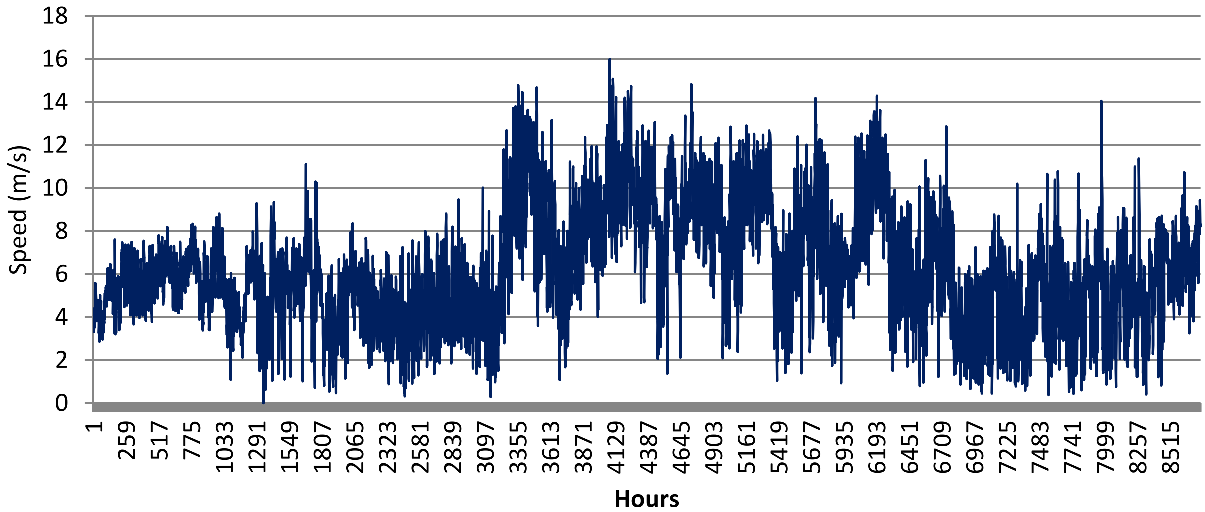


Fig. A5.11: Wind speed variation

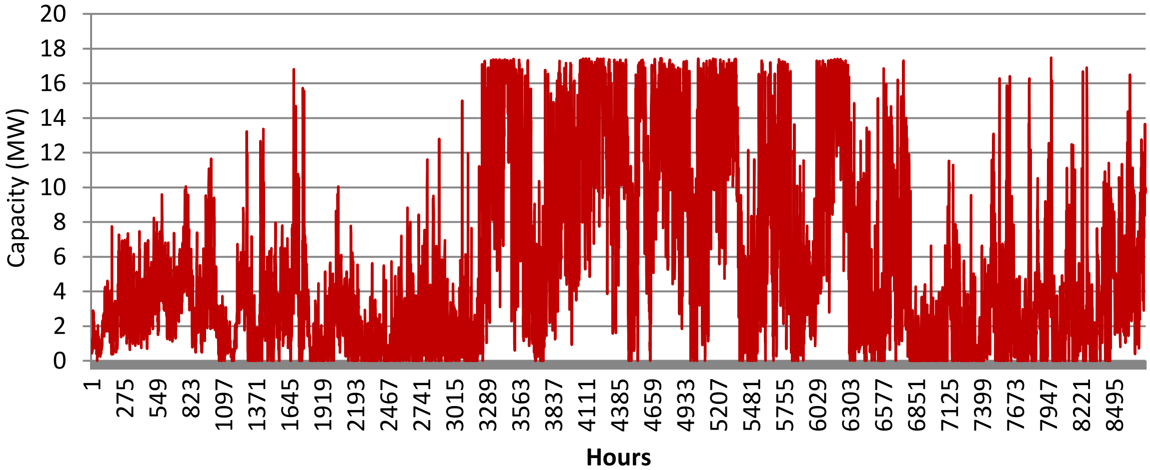


Fig. A5.12: Wind Plant Power output

5. Hill Country 10.45 MW Wind Power Plant - Power Output

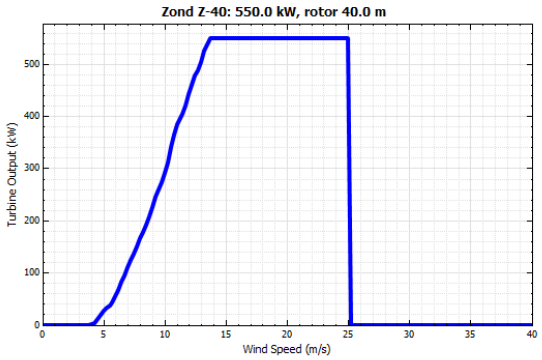


Figure A5.13: Power curve of the modelled wind turbine

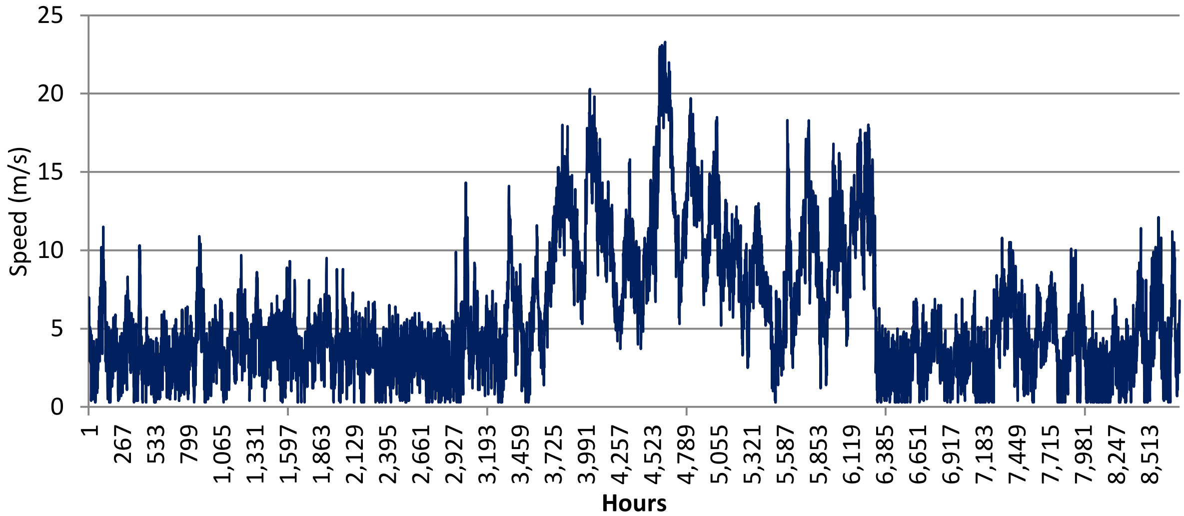


Fig. A5.14: Wind speed variation

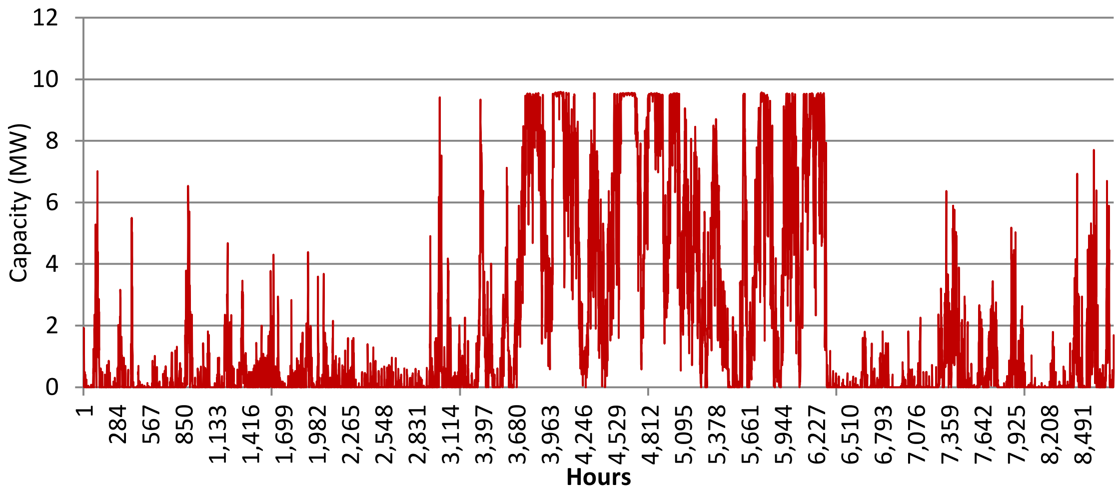
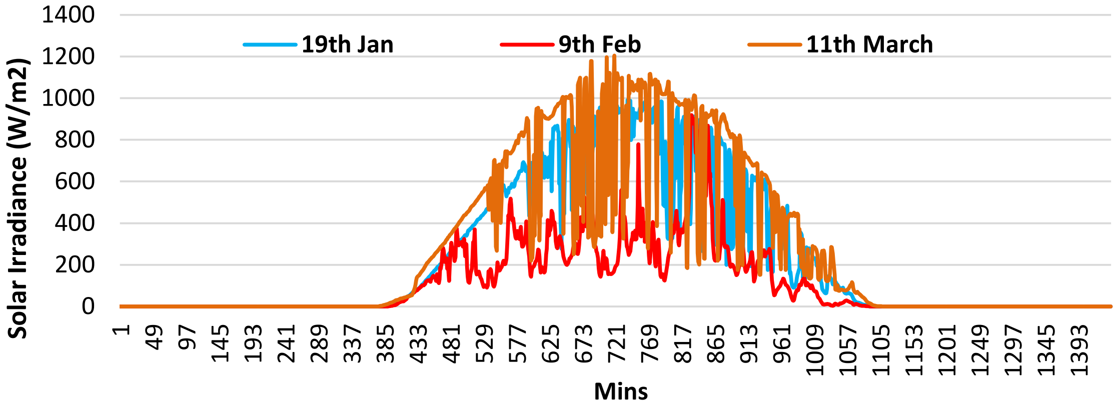
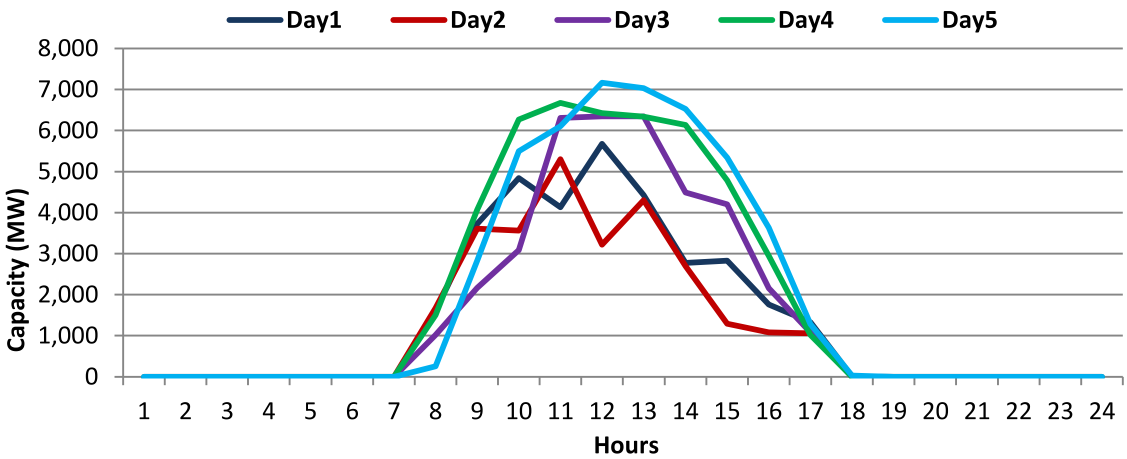


Fig. A5.15: Wind Plant Power output

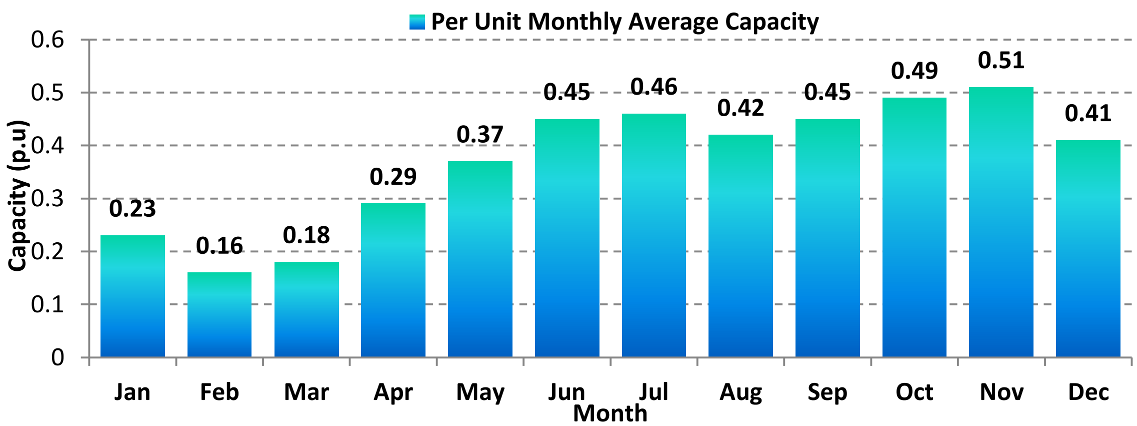
Solar and Mini-Hydro Plant Production Profiles



A5.16 Actual Measured Solar Irradiance variation for 3 days in 2015 (1 minute resolution)



A5.17 Modelled Plant output variation of 10MW at kilinochchi area for consecutive 5 days



A5.18 Per unit Monthly average capacity of Mini Hydro plant model

Other Renewable Energy Cost Details

The Capital Costs of ORE technologies are considered as follows in the generation expansion studies:

- Solar: USD 1400/kW at the present context and would gradually decline to USD 900/kW in 2025 and stabilize at that point.
- Wind: USD 1525/kW
- Biomass: USD 2067/kW
- Mini Hydro: USD 1729/kW

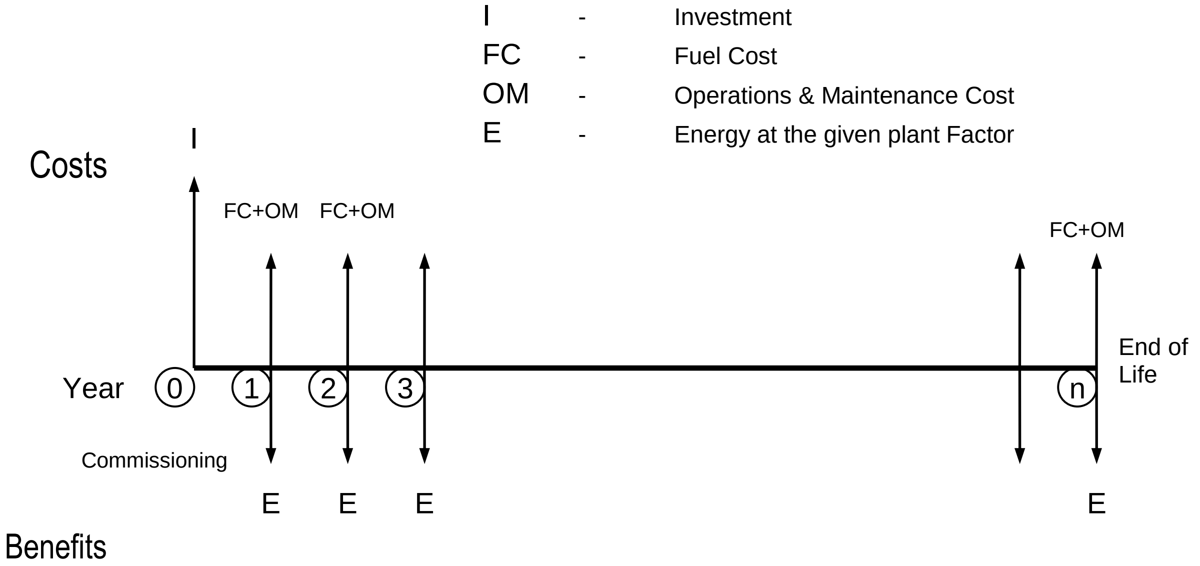
The O & M Costs of these technologies are considered as a percentage of the capital costs and the percentages are as follows:

Fixed O&M Cost	%
Mini Hydro	3
Wind	1.5
Solar	0.7
Biomass	4

Annex 6.1

Methodology of the Screening of Curve

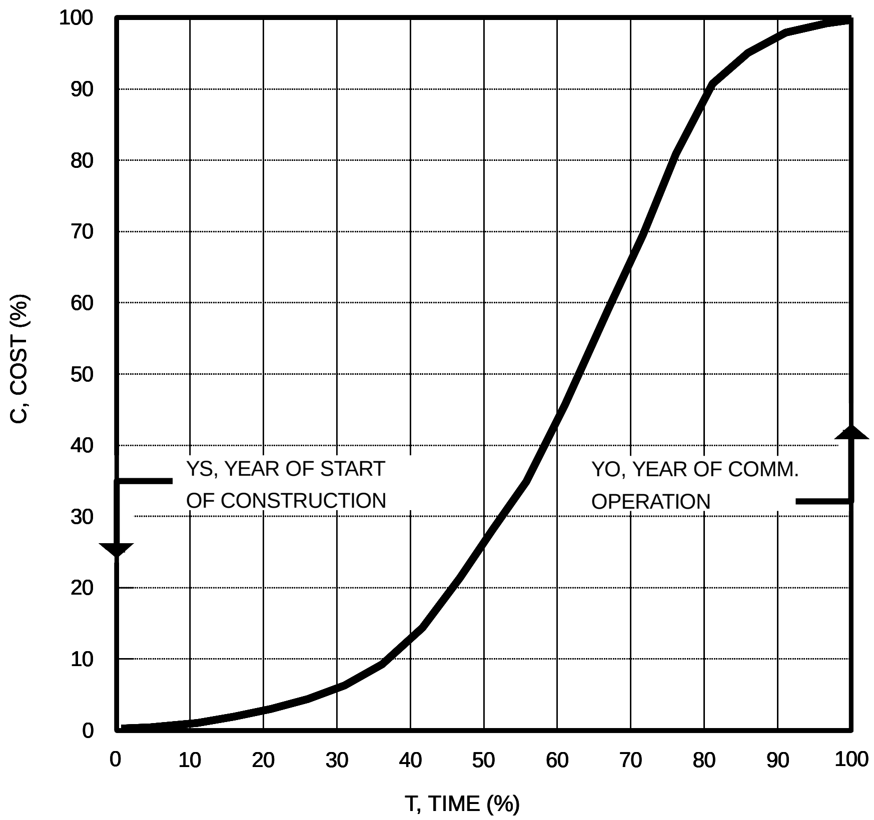
Present value of specific energy cost of thermal plants is calculated for a range of plant factors, in order to mimic the procedure adopted in the WASP planning package used for the expansion studies.



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

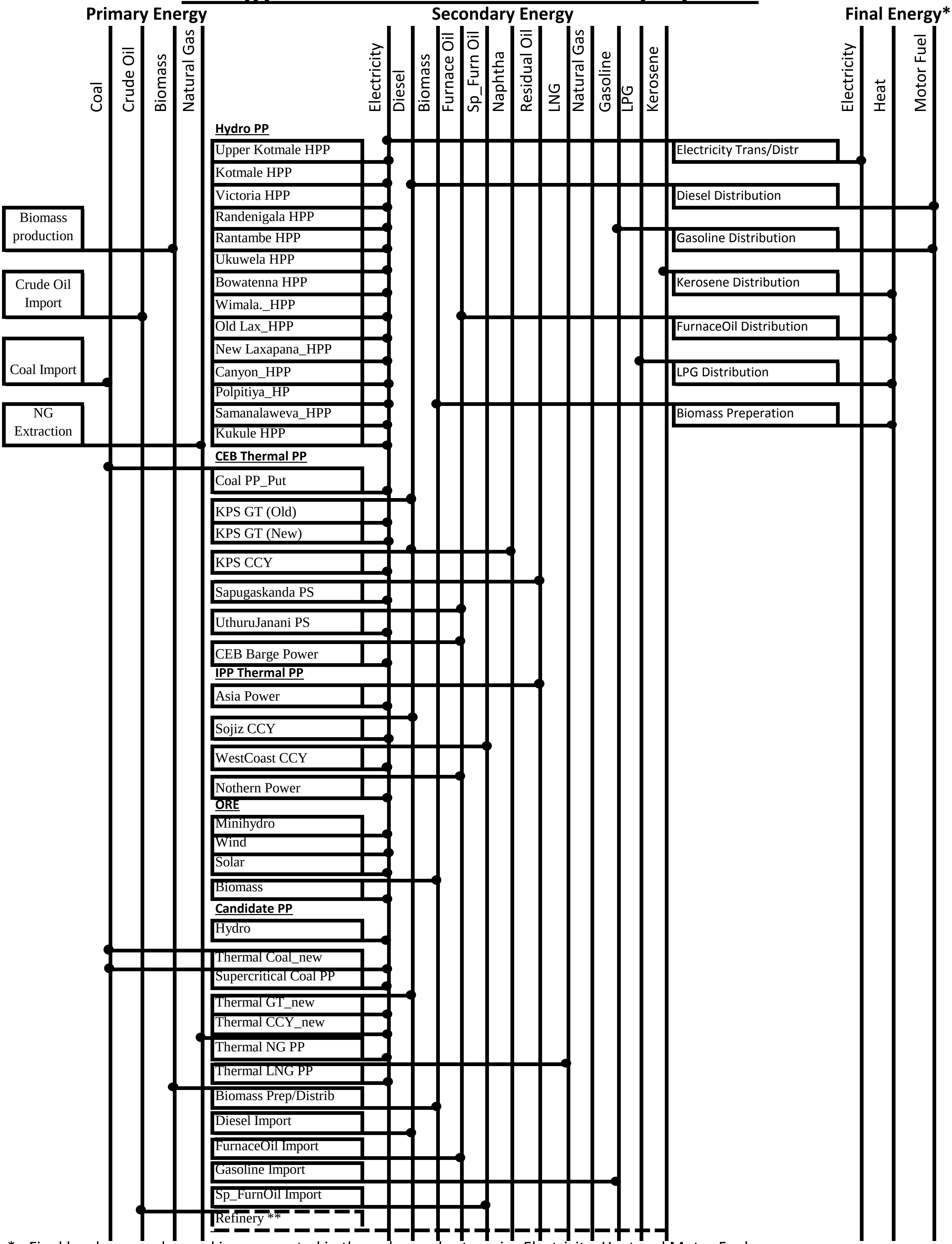
Interest during construction (IDC) is calculated assuming “S” curve shape cost distribution during the construction period which is shown in the figure below.



Plant capital cost distribution against time

Source: Wien Automatic System Planning Package (WASP), Version WASP-IV, User Mannual, 2000

Energy Flow Chart of the Electricity System



* - Final level energy demand is represented in three demand categories Electricity, Heat and Motor Fuel.

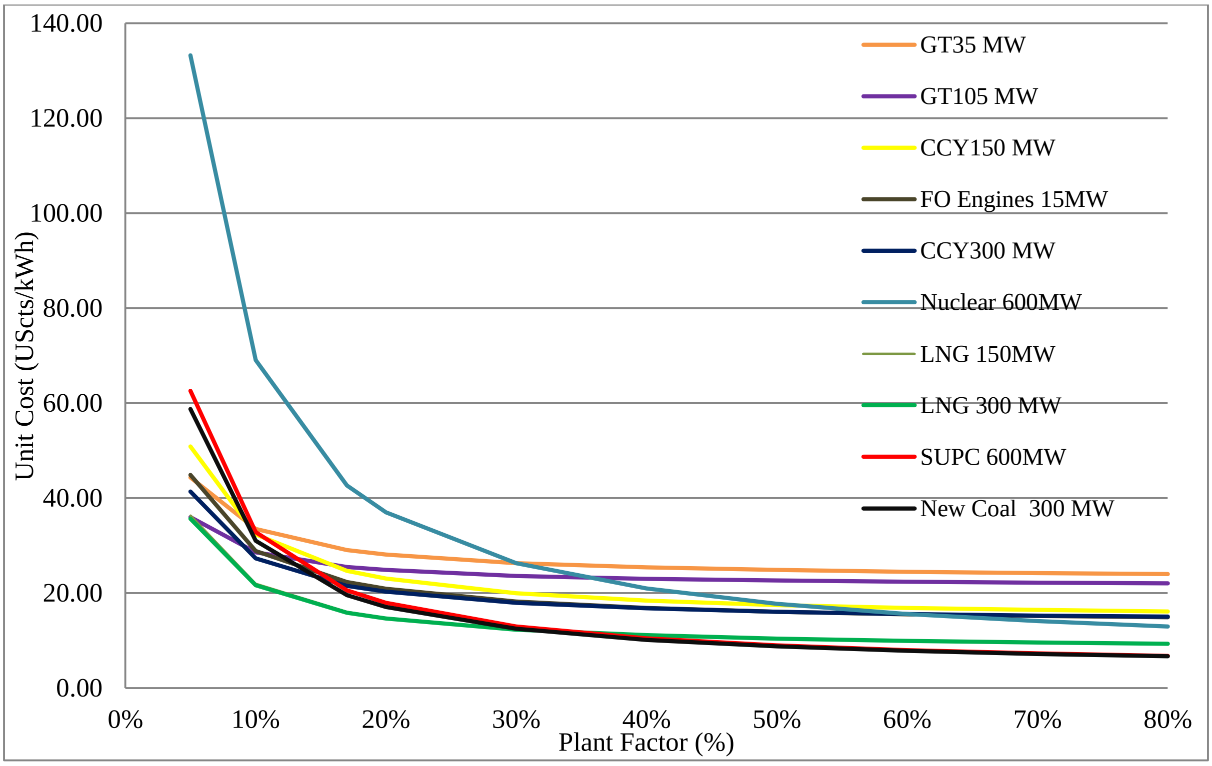
** - Refinery which has secondary level Oil outputs is shown indicatively

Screening of Generation Options

The screening curves were developed for the following Thermal Generation Alternatives

1. GT 35MW - 35MW Auto Diesel fired gas turbine
2. GT 105MW - 105MW Auto Diesel fired gas turbine
3. CCY 150MW - 150MW Auto Diesel fired combined cycle power plant
4. CCY 300MW - 300MW Auto Diesel fired combined cycle power plant
5. New Coal 300MW - 300MW Coal fired thermal power plant
6. SUPC 600MW - 600MW Super Critical Coal power plant
7. LNG 150MW - 150MW NG fired combined cycle power plant
8. LNG 300MW - 300MW NG fired combined cycle power plant
9. Nuclear 600MW - 600MW Nuclear Power plant
10. FO 15MW - 15MW Furnace oil Reciprocating Engine

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



7.1.2 Specific Cost of Screened Candidate Thermal Plants (in LKR)

Plant \ Plant Factor	*0.1*	*0.2*	*0.3*	*0.4*	*0.5*	*0.6*	*0.7*	*0.8*
35MW Diesel fired gas turbine+	49.94	41.87	39.18	37.83	37.02	36.49	36.10	35.81
105MW Diesel fired gas turbine+	42.58	37.04	35.19	34.27	33.71	33.34	33.08	32.88
150MW Diesel fired combined cycle power plant+	48.15	34.35	29.75	27.45	26.07	25.15	24.49	24.00
300MW Diesel fired combined cycle power plant+	40.69	30.22	26.73	24.99	23.94	23.25	22.75	22.37
300MW Coal fired thermal power plant	46.13	25.47	18.59	15.14	13.08	11.70	10.72	9.98
600MW Super Critical Coal power plant	48.86	26.70	19.31	15.61	13.40	11.92	10.87	10.07
150MW NG fired combined cycle power plant	32.69	22.00	18.44	16.66	15.59	14.88	14.37	13.99
300MW NG fired combined cycle power plant	32.21	21.77	18.29	16.55	15.51	14.81	14.32	13.94
600MW Nuclear Power plant	102.84	55.08	39.16	31.20	26.43	23.24	20.97	19.26
15MW Furnace oil Reciprocating Engine+	43.02	31.11	27.14	25.15	23.96	23.17	22.60	22.17

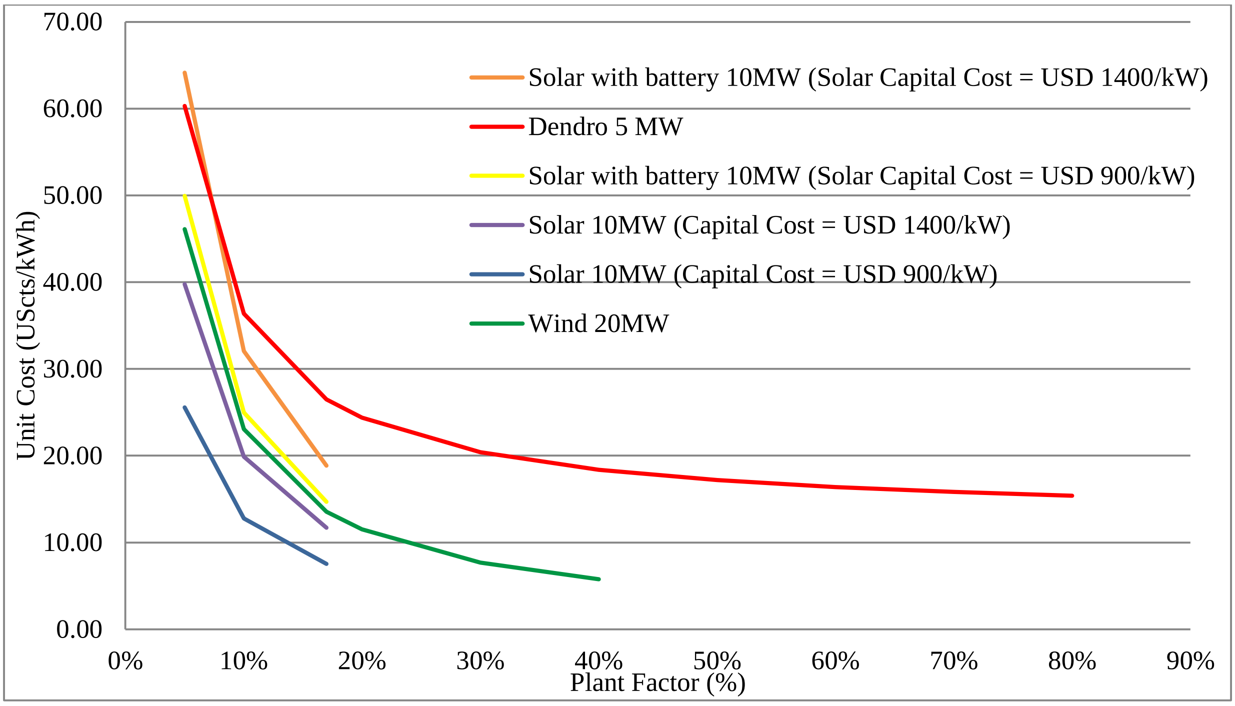
Note: 1 US$ = LKR 148.88

*LNG terminal cost and coal jetty cost is not included in the plant capital cost

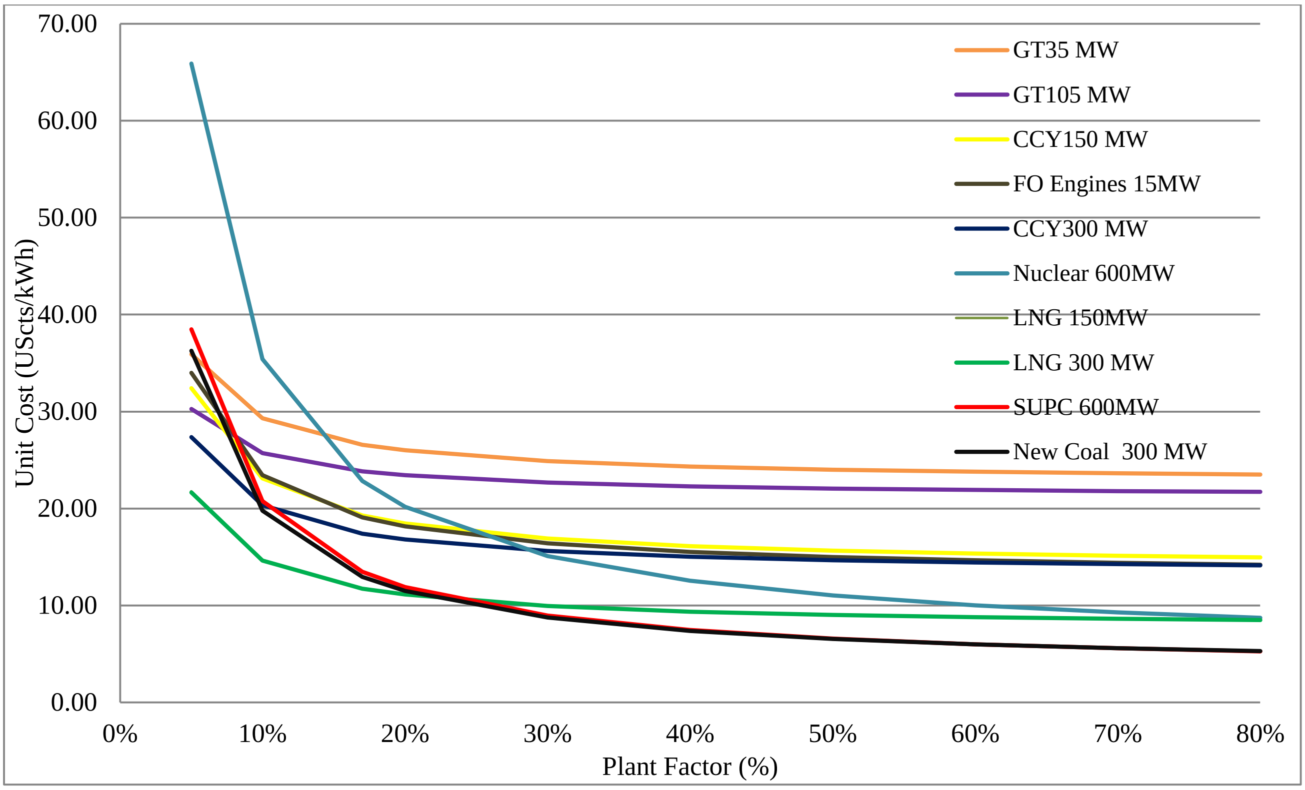
+Figures are based on the market prices of oil.

The screening curves were developed for the following renewable energy options also.

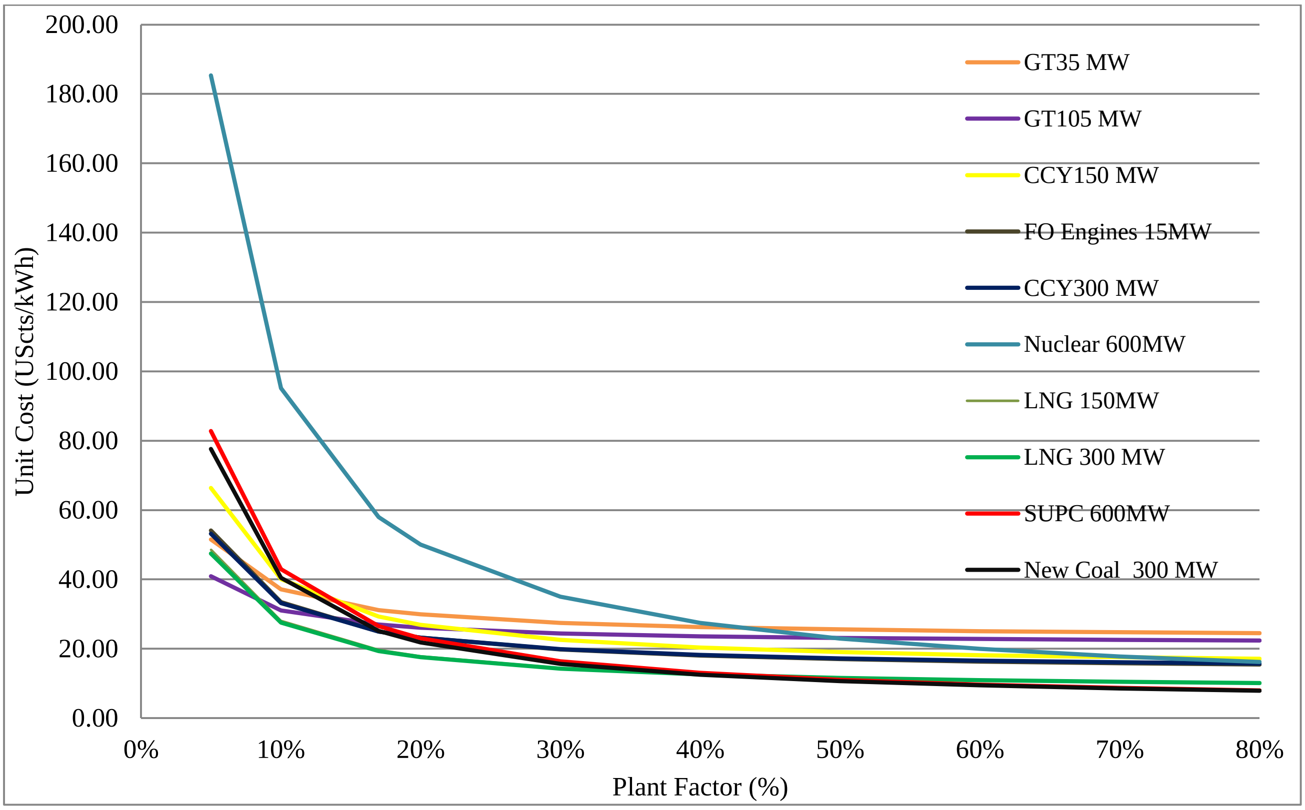
1. Dendro 5MW - 5MW Biomass power plant
2. Wind 25MW - 25MW Wind power plant
3. Solar 10MW - 10MW Solar power plant
4. Solar with Battery 10MW - 10MW Solar power plant with Battery Storage



A7.1.3 Screening Curves of the Generation Options at 3% Discount Rate



A7.1.4 Screening Curves of the Generation Options at 15% Discount Rate



Capacity Balance for the Base Case 2018 - 2037

Plant Name	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Hydro																				
Existing Major Hydro	1370	1370	1370	1370	1370	1370	1370	1370	1370	1370	1370	1370	1370	1370	1370	1370	1370	1370	1370	1370
New Major Hydro	0	120	170	170	241	241	241	241	241	241	241	241	241	241	241	241	241	241	241	241
Pumped Hydro	0	0	0	0	0	0	0	200	400	600	600	600	600	600	600	600	600	600	600	600
Sub Total	**1370**	**1490**	**1540**	**1540**	**1611**	**1611**	**1611**	**1811**	**2011**	**2211**	**2211**	**2211**	**2211**	**2211**	**2211**	**2211**	**2211**	**2211**	**2211**	**2211**
Thermal Existing and Committed																				
Small Gas Turbines	65	65	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Sapugaskanda	70	70	70	70	70	70	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesl Ext.Sapugaskanda	70	70	70	70	70	35	35	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Turbine No7	113	113	113	113	113	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Asia Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kelanitissa Combined Cycle	161	161	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sojitz Combined Cycle	163	163	163	163	163	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kerawalapitiya CCY	270	270	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakvijaya Coal	825	825	825	825	825	825	825	825	825	825	825	825	825	825	825	825	825	825	825	825
Northern Power	30	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Uthurujanani	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
CEB Barge Power	60	60	60	60	60	60	60	0	0	0	0	0	0	0	0	0	0	0	0	0
Furnace Oil fired Power Plant 150 MW	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Furnace Oil fired Power Plant 170 MW	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170
NG Converted Sojitz Combined Cycle	0	0	0	0	0	163	163	163	163	163	163	163	163	163	163	0	0	0	0	0
NG Converted Kelanitissa Combined Cycle	0	0	161	161	161	161	161	161	161	161	161	161	161	161	161	0	0	0	0	0
NG Converted Kerawalapitiya CCY	0	0	270	270	270	270	270	270	270	270	270	270	270	270	270	270	270	0	0	0
Sub Total	**2,172**	**2,172**	**2,142**	**2,077**	**2,077**	**1,929**	**1,860**	**1,765**	**1,765**	**1,765**	**1,765**	**1,765**	**1,765**	**1,765**	**1,765**	**1,441**	**1,441**	**1,171**	**1,171**	**1,171**
New Thermal Plants																				
New Coal	0	0	0	0	0	270	540	810	810	810	1,374	1,374	1,374	1,938	1,938	1,938	1,938	2,502	2,502	2,502
Gas Turbine 35 MW	0	70	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105
New NG Combined Cyle	0	200	287	574	574	574	574	574	574	574	574	574	574	574	574	1148	1148	1148	1435	1435
Sub Total	**0**	**270**	**392**	**679**	**679**	**949**	**1219**	**1489**	**1489**	**1489**	**2053**	**2053**	**2053**	**2617**	**2617**	**3191**	**3191**	**3755**	**4042**	**4042**
Other Renewable Energy																				
ORE (Minihydro, Wind & Solar)	698	858	1198	1338	1404	1529	1639	1838	1903	1993	2153	2242	2377	2477	2587	2721	2857	2991	3151	3335
ORE (Biomass - Existing)	24	24	24	24	24	24	24	24	24	24	24	11	11	11	11	11	11	11	11	11
ORE (Biomass - New)	5	10	15	20	25	30	35	40	45	50	55	60	65	70	70	75	75	80	80	85
Sub Total	**727**	**892**	**1237**	**1382**	**1453**	**1583**	**1698**	**1902**	**1972**	**2067**	**2232**	**2313**	**2453**	**2558**	**2668**	**2807**	**2943**	**3082**	**3242**	**3431**
Total Installed Capacity (A)	**4269**	**4824**	**5311**	**5678**	**5820**	**6072**	**6387**	**6966**	**7236**	**7531**	**8260**	**8341**	**8481**	**9150**	**9260**	**9649**	**9785**	**10218**	**10665**	**10854**
Installed Capacity without ORE (B)	**3542**	**3932**	**4074**	**4296**	**4367**	**4489**	**4690**	**5065**	**5265**	**5465**	**6029**	**6029**	**6029**	**6593**	**6593**	**6843**	**6843**	**7137**	**7424**	**7424**
Peak Demand (C)	**2738**	**2903**	**3077**	**3208**	**3346**	**3491**	**3643**	**3804**	**3972**	**4149**	**4335**	**4527**	**4726**	**4939**	**5157**	**5381**	**5612**	**5854**	**6107**	**6372**
Difference without ORE (B-C)	**804**	**1029**	**997**	**1088**	**1021**	**998**	**1047**	**1261**	**1293**	**1316**	**1694**	**1502**	**1303**	**1654**	**1436**	**1462**	**1231**	**1283**	**1317**	**1052**
Difference (%)	**29.4**	**35.5**	**32.4**	**33.9**	**30.5**	**28.6**	**28.7**	**33.1**	**32.5**	**31.7**	**39.1**	**33.2**	**27.6**	**33.5**	**27.8**	**27.2**	**21.9**	**21.9**	**21.6**	**16.5**

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

Energy Balance for the Base Case 2018 - 2037

Plant Name	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Hydro																				
Existing Major Hydro	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050
New Major Hydro	0	249	415	408	616	609	601	593	586	579	571	563	557	549	541	533	526	519	511	504
PSPP Generation	0	0	0	0	0	0	0	199	396	593	580	595	599	596	598	595	595	599	596	595
Sub Total	4,050	4,299	4,465	4,458	4,666	4,659	4,651	4,842	5,032	5,222	5,201	5,208	5,206	5,195	5,189	5,178	5,171	5,168	5,157	5,149
Thermal Existing and Committed																				
Small Gas Turbines	10	2	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Sapugaskanda	390	405	317	327	347	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesl Ext.Sapugaskanda	487	487	450	447	450	54	30	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Turbine No7	220	299	241	246	274	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Asia Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kelanitissa Combined Cycle	745	768	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sojitz Combined Cycle	408	439	354	332	369	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kerawalapitiya CCY	708	792	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakvijaya Coal	4,642	4,580	4,643	4,590	4,713	5,213	5,154	5,170	5,298	5,395	5,045	5,162	5,229	4,881	5,022	5,099	5,172	4,981	4,998	5,100
Northern Power	104	142	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Uthurujanani	165	165	150	149	150	33	13	4	13	22	1	4	23	0	4	4	17	8	4	1
CEB Barge Power	333	347	270	277	296	6	4	0	0	0	0	0	0	0	0	0	0	0	0	0
Furnace Oil fired Power Plant 150MW	970	983	783	804	832	41	19	3	6	18	0	0	13	0	2	2	13	3	2	19
Furnace Oil fired Power Plant 170MW	1,218	1,223	1,068	1,066	1,087	159	54	20	46	104	1	12	87	2	13	14	81	26	12	81
NG Converted Sojitz Combined Cycle	0	0	0	0	0	809	686	553	637	744	540	611	716	534	594	0	0	0	0	0
NG Converted Kelanitissa Combined Cycle	0	0	765	713	735	874	808	738	815	864	728	785	837	728	777	0	0	0	0	0
NG Converted Kerawalapitiya CCY	0	0	936	823	857	919	788	645	745	893	572	857	969	806	854	868	940	0	0	0
Sub Total	10,399	10,632	9,978	9,773	10,111	8,116	7,557	7,133	7,558	8,039	6,886	7,432	7,874	6,951	7,266	5,986	6,224	5,019	5,016	5,202
New Thermal Plants																				
New Coal	0	0	0	0	0	1,807	3,520	5,200	5,544	5,787	9,005	9,319	9,591	12,556	12,961	13,219	13,505	16,794	16,905	17,238
Gas Turbine 35 MW	0	5	8	3	7	6	3	0	0	2	0	0	1	0	0	0	3	1	1	4
New NG Combined Cyle	0	292	1,057	1,848	2,053	3,050	2,735	2,275	2,651	3,056	2,001	2,375	2,765	1,877	2,293	4,415	5,025	4,157	5,250	5,989
Sub Total	0	296	1,065	1,851	2,060	4,863	6,258	7,475	8,195	8,845	11,006	11,694	12,358	14,433	15,253	17,634	18,532	20,953	22,156	23,231
Other Renewable Energy																				
ORE (Minihydro, Wind & Solar)	1,573	1,906	2,801	3,149	3,351	3,632	3,879	4,308	4,418	4,601	4,915	5,098	5,413	5,615	5,858	6,172	6,487	6,803	7,195	7,579
ORE (Biomass)	270	305	340	375	410	445	480	515	550	585	620	655	690	725	725	760	760	795	795	830
Sub Total	1,842	2,211	3,141	3,523	3,761	4,077	4,359	4,823	4,968	5,186	5,535	5,753	6,104	6,340	6,583	6,932	7,248	7,599	7,991	8,409
Total Generation (Excluding New Biomass)	**16,182**	**17,294**	**18,460**	**19,381**	**20,337**	**21,354**	**22,413**	**23,821**	**25,274**	**26,790**	**28,065**	**29,434**	**30,862**	**32,193**	**33,568**	**34,971**	**36,423**	**37,945**	**39,527**	**41,168**
System Demand	16,188	17,285	18,456	19,370	20,331	21,342	22,404	23,522	24,697	25,933	27,225	28,570	29,990	31,328	32,692	34,099	35,546	37,063	38,642	40,302
PSPP Demand	0	0	0	0	0	0	0	284	566	847	829	850	856	851	854	850	850	856	851	850
Unserved Energy	**6**	**-9**	**-4**	**-11**	**-6**	**-12**	**-9**	**-15**	**-11**	**-10**	**-11**	**-14**	**-16**	**-14**	**-22**	**-22**	**-27**	**-27**	**-33**	**-16**

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

Base Case: 2018 to 2037

Year / Plant	Annual Energy (GWh) Hydrology condition 1	2	3	4	5	Avg.	Annual Plant Factor (%) Hydrology condition 1	2	3	4	5	Avg.
2018												
4x17 MW Kelanitissa Gas Turbines	1	1	9	23	39	10	0.1	0.2	1.5	4.0	6.7	1.7
4x18 MW Sapugaskanda Diesel Plant	307	360	401	430	445	390	50.4	59.0	65.7	70.5	73.0	63.9
8x9 MW Sapugaskanda Diesel Ext.	471	486	489	489	489	487	77.2	79.7	80.2	80.3	80.3	79.8
115 MW Kelanitissa Gas Turbine	114	166	227	303	333	220	11.5	16.8	23.0	30.6	33.7	22.3
160 MW Kelanitissa CCY Plant	560	640	762	885	943	745	39.7	45.4	54.1	62.8	66.9	52.9
300 MW Lakvijaya Coal PS (Unit 1)	1,312	1,394	1,450	1,511	1,587	1,441	54.5	57.9	60.2	62.7	65.9	59.8
3x8.6 MW Uthuru Janani PS	157	164	166	166	166	165	68.8	71.8	72.9	73.0	73.0	72.3
163MW Sojitz CCY Plant	200	333	416	565	578	408	14.0	23.3	29.1	39.6	40.5	28.6
30 MW Northern Power Plant	54	80	109	139	145	104	20.5	30.6	41.4	52.7	55.2	39.6
300 MW West Coast CCY Plant	421	566	707	983	1,041	708	17.8	23.9	29.9	41.5	44.0	29.9
60 MW CEB Barge Power Plant	240	304	345	375	390	333	45.6	57.9	65.6	71.4	74.3	63.3
300 MW Lakvijaya Coal PS (Unit 2)	1,492	1,565	1,714	1,750	1,769	1,670	61.9	64.9	71.1	72.6	73.4	69.3
300 MW Lakvijaya Coal PS (Unit 3)	1,376	1,451	1,561	1,599	1,664	1,532	57.1	60.2	64.8	66.4	69.1	63.6
150 MW FO Reciprocating Engines	847	923	990	1,025	1,031	970	64.5	70.2	75.3	78.0	78.5	73.8
170 MW FO Reciprocating Engines	1,124	1,194	1,235	1,247	1,248	1,218	71.3	75.8	78.3	79.1	79.1	77.3
Total hydro	6,658	5,703	4,744	3,799	3,397	4,918						
Total thermal	8,676	9,627	10,579	11,490	11,869	10,399						
Total generation	15,334	15,329	15,323	15,288	15,266	15,317						
Total demand	15,335	15,335	15,335	15,335	15,335	15,335						
Deficit	1	6	12	47	69	18						
2019												
4x17 MW Kelanitissa Gas Turbines	0	0	1	9	8	2	0.0	0.0	0.1	1.5	1.3	0.3
4x18 MW Sapugaskanda Diesel Plant	330	372	417	445	452	405	54.1	61.0	68.4	73.0	74.1	66.4
8x9 MW Sapugaskanda Diesel Ext.	471	485	489	489	489	487	77.3	79.6	80.2	80.3	80.3	79.8
115 MW Kelanitissa Gas Turbine	148	257	316	369	395	299	15.0	26.0	31.9	37.3	39.9	30.2
160 MW Kelanitissa CCY Plant	576	674	788	895	941	768	40.9	47.9	55.9	63.5	66.8	54.5
300 MW Lakvijaya Coal PS (Unit 1)	1,307	1,386	1,439	1,507	1,594	1,433	54.3	57.5	59.7	62.6	66.2	59.5
3x8.6 MW Uthuru Janani PS	157	164	166	166	166	165	69.1	71.9	72.9	73.0	73.0	72.3
163MW Sojitz CCY Plant	255	353	438	615	632	439	17.9	24.8	30.7	43.1	44.3	30.8
30 MW Northern Power Plant	81	115	153	171	179	142	30.9	43.6	58.4	64.9	68.2	54.1
300 MW West Coast CCY Plant	465	596	824	1,054	1,128	792	19.7	25.2	34.8	44.6	47.7	33.5
60 MW CEB Barge Power Plant	245	318	361	388	399	347	46.6	60.5	68.7	73.9	75.9	66.0
300 MW Lakvijaya Coal PS (Unit 2)	1,483	1,541	1,655	1,726	1,768	1,631	61.6	64.0	68.7	71.6	73.4	67.7
300 MW Lakvijaya Coal PS (Unit 3)	1,386	1,457	1,530	1,586	1,665	1,516	57.5	60.5	63.5	65.8	69.1	62.9
150 MW FO Reciprocating Engines	866	941	1,003	1,032	1,036	983	65.9	71.6	76.3	78.5	78.8	74.8
300 MW LNG CCY Plant (Simple Cycle)	106	208	304	423	478	292	6.0	11.9	17.4	24.2	27.3	16.7
35 MW Gas Turbine (2 Units)	0	1	1	20	14	4	0.0	0.1	0.2	3.3	2.2	0.7
170 MW FO Reciprocating Engines	1,133	1,201	1,239	1,248	1,248	1,223	71.9	76.2	78.6	79.2	79.2	77.5
Total hydro	7,142	6,077	5,020	3,997	3,542	5,216						
Total thermal	9,010	10,069	11,125	12,144	12,590	10,929						
Total generation	16,152	16,146	16,145	16,141	16,132	16,145						
Total demand	16,153	16,153	16,153	16,153	16,153	16,153						
Deficit	1	7	8	12	21	8						

-Total generation figure excludes generation from Wind, Solar and Biomass Power Plants.

Year	Annual Energy (GWh)						Annual Plant Factor (%)					
	Hydrology condition						Hydrology condition					
Plant	1	2	3	4	5	Avg.	1	2	3	4	5	Avg.
2020												
4x17 MW Kelanitissa Gas Turbines	0	0	1	12	9	3	0.0	0.0	0.1	2.1	1.5	0.4
4x18 MW Sapugaskanda Diesel Plant	189	291	319	400	407	317	31.0	47.8	52.3	65.5	66.7	52.0
8x9 MW Sapugaskanda Diesel Ext.	394	430	457	480	473	450	64.6	70.5	74.9	78.7	77.6	73.7
115 MW Kelanitissa Gas Turbine	107	174	255	335	343	240	10.8	17.6	25.8	33.9	34.7	24.3
300 MW Lakvijaya Coal PS (Unit 1)	1,321	1,404	1,464	1,504	1,610	1,451	54.8	58.3	60.8	62.4	66.8	60.2
3x8.6 MW Uthuru Janani PS	129	142	153	162	159	150	56.8	62.4	67.1	71.0	70.0	65.8
163MW Sojitz CCY Plant	185	241	378	487	499	354	13.0	16.9	26.5	34.1	34.9	24.8
60 MW CEB Barge Power Plant	150	230	282	340	351	270	28.5	43.7	53.6	64.6	66.9	51.4
165 MW Kelanitissa CCY Plant (LNG)	686	739	765	826	847	765	51.3	55.3	57.2	61.7	63.3	57.2
270 MW Kerawalapitiya CCY (LNG)	741	817	969	1,052	1,120	936	33.0	36.4	43.1	46.8	49.8	41.6
300 MW Lakvijaya Coal PS (Unit 2)	1,516	1,555	1,682	1,748	1,777	1,655	63.0	64.6	69.8	72.6	73.8	68.7
300 MW Lakvijaya Coal PS (Unit 3)	1,421	1,468	1,549	1,616	1,677	1,536	59.0	60.9	64.3	67.1	69.6	63.8
150 MW FO Reciprocating Engines	570	719	793	924	949	783	43.3	54.7	60.4	70.3	72.2	59.6
300 MW LNG CCY Plant	802	943	1,082	1,206	1,318	1,056	33.6	39.5	45.3	50.5	55.2	44.2
35 MW Gas Turbine (3 Units)	0	1	2	28	48	8	0.1	0.1	0.2	3.0	5.2	0.9
170 MW FO Reciprocating Engines	840	1,002	1,094	1,181	1,186	1,068	53.3	63.6	69.4	74.9	75.2	67.7
Total hydro	7,440	6,326	5,226	4,163	3,686	5,431						
Total thermal	9,051	10,156	11,245	12,299	12,773	11,043						
Total generation	16,491	16,482	16,471	16,462	16,459	16,474						
Total demand	16,491	16,491	16,491	16,491	16,491	16,491						
Deficit	0	9	20	29	32	17						
2021												
4x18 MW Sapugaskanda Diesel Plant	184	275	356	377	383	327	30.2	45.2	58.4	61.9	62.9	53.7
8x9 MW Sapugaskanda Diesel Ext.	391	424	457	474	465	447	64.1	69.6	75.0	77.7	76.3	73.3
115 MW Kelanitissa Gas Turbine	127	192	263	317	314	246	12.9	19.4	26.6	32.1	31.7	24.8
300 MW Lakvijaya Coal PS (Unit 1)	1,292	1,386	1,427	1,499	1,602	1,425	53.6	57.5	59.2	62.2	66.5	59.2
3x8.6 MW Uthuru Janani PS	128	140	153	159	157	149	56.2	61.4	67.0	69.9	68.9	65.3
163MW Sojitz CCY Plant	169	218	367	436	456	332	11.8	15.3	25.7	30.5	31.9	23.3
60 MW CEB Barge Power Plant	163	224	299	330	335	277	31.0	42.5	57.0	62.8	63.8	52.7
165 MW Kelanitissa CCY Plant (LNG)	649	685	711	777	789	713	48.5	51.2	53.2	58.1	59.0	53.3
270 MW Kerawalapitiya CCY (LNG)	731	784	823	916	886	823	32.5	34.9	36.6	40.8	39.5	36.6
300 MW Lakvijaya Coal PS (Unit 2)	1,526	1,575	1,669	1,738	1,763	1,651	63.4	65.4	69.3	72.1	73.2	68.5
300 MW Lakvijaya Coal PS (Unit 3)	1,396	1,448	1,528	1,582	1,663	1,514	57.9	60.1	63.4	65.7	69.0	62.8
150 MW FO Reciprocating Engines	575	735	836	903	913	804	43.7	55.9	63.6	68.7	69.5	61.2
300 MW LNG CCY Plant (2 Units)	1,406	1,652	1,840	2,220	2,489	1,848	29.4	34.6	38.5	46.5	52.1	38.7
35 MW Gas Turbine (3 Units)	0	0	1	12	10	3	0.0	0.0	0.1	1.3	1.1	0.3
170 MW FO Reciprocating Engines	869	987	1,099	1,159	1,156	1,065	55.1	62.6	69.7	73.5	73.3	67.6
Total hydro	7,493	6,362	5,249	4,172	3,690	5,457						
Total thermal	9,606	10,725	11,828	12,900	13,381	11,623						
Total generation	17,099	17,087	17,077	17,072	17,071	17,080						
Total demand	17,099	17,099	17,099	17,099	17,099	17,099						
Deficit	0	12	22	27	28	19						

-Total generation figure excludes generation from Wind, Solar and Biomass Power Plants.

Year / Plant	Annual Energy (GWh) Hydrology condition						Annual Plant Factor (%) Hydrology condition					
	1	2	3	4	5	Avg.	1	2	3	4	5	Avg.
2022												
4x18 MW Sapugaskanda Diesel Plant	197	316	371	390	409	347	32.3	51.8	60.8	64.0	67.2	56.9
8x9 MW Sapugaskanda Diesel Ext.	395	430	459	475	479	450	64.8	70.6	75.3	77.9	78.5	73.9
115 MW Kelanitissa Gas Turbine	141	215	296	341	359	274	14.3	21.7	29.9	34.4	36.3	27.7
300 MW Lakvijaya Coal PS (Unit 1)	1,330	1,394	1,472	1,570	1,609	1,464	55.2	57.9	61.1	65.2	66.8	60.8
3x8.6 MW Uthuru Janani PS	130	143	154	160	162	150	57.2	62.6	67.4	70.2	71.0	66.0
163MW Sojitz CCY Plant	200	301	386	477	489	369	14.0	21.1	27.0	33.4	34.3	25.9
60 MW CEB Barge Power Plant	174	262	313	343	360	296	33.1	49.8	59.6	65.2	68.4	56.3
165 MW Kelanitissa CCY Plant (LNG)	654	700	738	796	835	735	48.9	52.3	55.2	59.5	62.4	55.0
270 MW Kerawalapitiya CCY (LNG)	742	804	845	995	1,007	857	33.0	35.8	37.6	44.3	44.8	38.1
300 MW Lakvijaya Coal PS (Unit 2)	1,671	1,627	1,701	1,757	1,767	1,695	69.4	67.6	70.6	72.9	73.4	70.4
300 MW Lakvijaya Coal PS (Unit 3)	1,418	1,488	1,567	1,655	1,669	1,554	58.9	61.8	65.0	68.7	69.3	64.5
150 MW FO Reciprocating Engines	607	770	860	924	960	831	46.2	58.6	65.5	70.3	73.1	63.3
300 MW LNG CCY Plant (2 Units)	1,492	1,763	2,108	2,420	2,680	2,053	31.2	36.9	44.1	50.7	56.1	43.0
35 MW Gas Turbine (3 Units)	0	1	2	32	28	7	0.0	0.1	0.2	3.5	3.1	0.8
170 MW FO Reciprocating Engines	908	1,019	1,114	1,171	1,198	1,087	57.6	64.6	70.6	74.3	76.0	68.9
Total hydro	7,827	6,645	5,481	4,353	3,839	5,697						
Total thermal	10,059	11,230	12,385	13,507	14,011	12,171						
Total generation	17,886	17,875	17,866	17,860	17,850	17,868						
Total demand	17,887	17,887	17,887	17,887	17,887	17,887						
Deficit	1	12	21	27	37	19						
2023												
4x18 MW Sapugaskanda Diesel Plant	1	1	2	40	39	9	0.1	0.2	0.4	6.6	6.4	1.5
8x9 MW Sapugaskanda Diesel Ext.	15	20	58	93	100	54	5.0	6.5	19.1	30.6	32.8	17.6
300 MW Lakvijaya Coal PS (Unit 1)	1,479	1,593	1,644	1,695	1,709	1,628	61.4	66.1	68.2	70.4	70.9	67.6
3x8.6 MW Uthuru Janani PS	10	12	37	52	63	33	4.2	5.5	16.4	22.8	27.7	14.5
60 MW CEB Barge Power Plant	0	1	1	23	29	6	0.1	0.1	0.3	4.3	5.5	1.1
163 MW CEB KCCP 2 CCY Plant	551	713	834	964	992	809	40.7	52.6	61.5	71.1	73.2	59.7
165 MW Kelanitissa CCY Plant (LNG)	685	802	900	970	989	874	51.2	60.0	67.3	72.5	73.9	65.3
270 MW Kerawalapitiya CCY (LNG)	689	773	946	1,068	1,245	919	30.7	34.4	42.1	47.5	55.4	40.9
300 MW Lakvijaya Coal PS (Unit 2)	1,798	1,820	1,850	1,871	1,885	1,844	74.6	75.5	76.8	77.7	78.2	76.5
300 MW Lakvijaya Coal PS (Unit 3)	1,670	1,711	1,751	1,779	1,792	1,741	69.3	71.0	72.7	73.8	74.4	72.3
150 MW FO Reciprocating Engines	3	16	15	146	162	41	0.2	1.2	1.2	11.1	12.3	3.1
300 MW LNG CCY Plant (2 Units)	2,298	2,748	3,177	3,394	3,469	3,050	48.1	57.5	66.5	71.1	72.6	63.9
35 MW Gas Turbine (3 Units)	0	1	2	26	20	6	0.0	0.1	0.2	2.8	2.2	0.6
170 MW FO Reciprocating Engines	12	79	151	311	390	159	0.8	5.0	9.6	19.7	24.8	10.1
300 MW High Efficient Coal Plant (1 Unit)	1,634	1,750	1,824	1,895	1,942	1,807	69.1	74.0	77.1	80.1	82.1	76.4
Total hydro	7,880	6,681	5,504	4,362	3,843	5,723						
Total thermal	10,845	12,041	13,193	14,327	14,829	12,980						
Total generation	18,725	18,722	18,697	18,689	18,672	18,703						
Total demand	18,725	18,725	18,725	18,725	18,725	18,725						
Deficit	0	3	28	36	53	22						

-Total generation figure excludes generation from Wind, Solar and Biomass Power Plants.

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.	2	15	29	60	69	30	0.6	4.9	9.7	19.7	22.6	9.9
300 MW Lakvijaya Coal PS (Unit 1)	1,383	1,521	1,599	1,654	1,666	1,573	57.4	63.1	66.4	68.7	69.2	65.3
3x8.6 MW Uthuru Janani PS	1	9	8	38	37	13	0.4	4.1	3.4	16.6	16.3	5.9
60 MW CEB Barge Power Plant	0	1	1	18	13	4	0.1	0.1	0.2	3.4	2.5	0.8
163 MW CEB KCCP 2 CCY Plant	445	593	712	821	867	686	32.8	43.8	52.5	60.6	63.9	50.6
165 MW Kelanitissa CCY Plant (LNG)	637	722	838	894	938	808	47.6	54.0	62.7	66.9	70.2	60.4
270 MW Kerawalapitiya CCY (LNG)	516	658	809	974	1,094	788	23.0	29.3	36.0	43.3	48.7	35.1
300 MW Lakvijaya Coal PS (Unit 2)	1,810	1,834	1,852	1,868	1,874	1,848	75.2	76.2	76.9	77.5	77.8	76.7
300 MW Lakvijaya Coal PS (Unit 3)	1,676	1,707	1,738	1,768	1,780	1,732	69.6	70.8	72.2	73.4	73.9	71.9
150 MW FO Reciprocating Engines	1	3	5	75	95	19	0.1	0.2	0.4	5.7	7.2	1.5
300 MW LNG CCY Plant (2 Units)	2,042	2,383	2,858	3,088	3,242	2,735	42.8	49.9	59.8	64.7	67.9	57.3
35 MW Gas Turbine (3 Units)	0	1	1	8	17	3	0.0	0.1	0.1	0.9	1.9	0.3
170 MW FO Reciprocating Engines	4	27	16	196	224	54	0.3	1.7	1.0	12.4	14.2	3.5
300 MW High Efficient Coal Plant (2 Units)	3,132	3,382	3,571	3,711	3,769	3,520	66.2	71.5	75.5	78.4	79.7	74.4
Total hydro	7,933	6,716	5,527	4,371	3,847	5,748						
Total thermal	11,650	12,855	14,038	15,173	15,686	13,815						
Total generation	19,583	19,571	19,565	19,544	19,533	19,563						
Total demand	19,583	19,583	19,583	19,583	19,583	19,583						
Deficit	0	12	18	39	50	20						
2025												
300 MW Lakvijaya Coal PS (Unit 1)	1,346	1,451	1,558	1,629	1,632	1,529	55.9	60.2	64.7	67.6	67.8	63.5
3x8.6 MW Uthuru Janani PS	0	0	1	19	23	4	0.1	0.1	0.2	8.3	10.1	1.9
163 MW CEB KCCP 2 CCY Plant	382	485	544	727	729	553	28.2	35.7	40.1	53.6	53.8	40.8
165 MW Kelanitissa CCY Plant (LNG)	572	678	752	840	860	738	42.7	50.7	56.2	62.8	64.3	55.2
270 MW Kerawalapitiya CCY (LNG)	424	519	685	760	847	645	18.9	23.1	30.5	33.8	37.7	28.7
300 MW Lakvijaya Coal PS (Unit 2)	1,836	1,869	1,880	1,886	1,890	1,875	76.2	77.6	78.1	78.3	78.4	77.8
300 MW Lakvijaya Coal PS (Unit 3)	1,718	1,754	1,770	1,787	1,790	1,765	71.3	72.8	73.5	74.2	74.3	73.3
150 MW FO Reciprocating Engines	0	0	1	14	14	3	0.0	0.0	0.1	1.1	1.1	0.2
300 MW LNG CCY Plant (2 Units)	1,553	1,897	2,371	2,704	2,977	2,275	32.5	39.7	49.6	56.6	62.3	47.6
35 MW Gas Turbine (3 Units)	0	0	0	0	1	0	0.0	0.0	0.0	0.1	0.1	0.0
170 MW FO Reciprocating Engines	0	1	2	87	101	20	0.0	0.1	0.2	5.6	6.4	1.2
300 MW High Efficient Coal Plant (3 Units)	4,577	4,983	5,267	5,530	5,654	5,200	64.5	70.2	74.2	77.9	79.7	73.3
Total hydro	8,186	6,952	5,749	4,575	4,050	5,972						
Total thermal	12,409	13,637	14,832	15,985	16,518	14,608						
Total generation	20,595	20,589	20,581	20,560	20,568	20,580						
Total demand	20,309	20,309	20,309	20,309	20,309	20,309						
Deficit*	-286	-280	-272	-251	-259	-271						
2026												
300 MW Lakvijaya Coal PS (Unit 1)	1,452	1,550	1,629	1,679	1,699	1,606	60.3	64.3	67.6	69.7	70.5	66.7
3x8.6 MW Uthuru Janani PS	0	0	11	39	38	13	0.0	0.1	4.7	17.0	16.8	5.8
163 MW CEB KCCP 2 CCY Plant	466	545	635	802	862	637	34.4	40.2	46.8	59.1	63.6	46.9
165 MW Kelanitissa CCY Plant (LNG)	680	757	828	894	936	814	50.8	56.6	61.9	66.9	70.0	60.9
270 MW Kerawalapitiya CCY (LNG)	465	654	732	1,002	1,033	745	20.7	29.1	32.6	44.6	46.0	33.2
300 MW Lakvijaya Coal PS (Unit 2)	1,881	1,892	1,898	1,900	1,901	1,896	78.1	78.5	78.8	78.9	78.9	78.7
300 MW Lakvijaya Coal PS (Unit 3)	1,767	1,795	1,799	1,802	1,808	1,796	73.3	74.5	74.7	74.8	75.1	74.5
150 MW FO Reciprocating Engines	0	0	0	21	49	6	0.0	0.0	0.0	1.6	3.7	0.4
300 MW LNG CCY Plant (2 Units)	1,832	2,281	2,788	3,031	3,261	2,651	38.4	47.8	58.4	63.5	68.3	55.5
35 MW Gas Turbine (3 Units)	0	0	0	0	4	0	0.0	0.0	0.0	0.0	0.5	0.0
170 MW FO Reciprocating Engines	0	1	20	174	185	45	0.0	0.1	1.3	11.0	11.7	2.9
300 MW High Efficient Coal Plant (3 Units)	4,990	5,293	5,644	5,796	5,897	5,544	70.3	74.6	79.5	81.7	83.1	78.1
Total hydro	8,439	7,183	5,972	4,770	4,250	6,195						
Total thermal	13,533	14,768	15,984	17,140	17,674	15,753						
Total generation	21,972	21,951	21,956	21,910	21,924	21,948						
Total demand	21,401	21,401	21,401	21,401	21,401	21,401						
Deficit*	-571	-550	-555	-509	-523	-547						

* The deficit figure shows a negative value from 2025 onwards due to the PSPP operation.

-Total generation figure excludes generation from Wind, Solar and Biomass Power Plants.

Year	Annual Energy (GWh)						Annual Plant Factor (%)					
	Hydrology condition						Hydrology condition					
Plant	1	2	3	4	5	Avg.	1	2	3	4	5	Avg.
2027												
300 MW Lakvijaya Coal PS (Unit 1)	1,519	1,630	1,708	1,737	1,750	1,680	63.0	67.7	70.9	72.1	72.6	69.7
3x8.6 MW Uthuru Janani PS	0	4	21	53	55	22	0.0	2.0	9.1	23.3	24.0	9.6
163 MW CEB KCCP 2 CCY Plant	534	628	776	861	950	744	39.4	46.3	57.2	63.5	70.1	54.8
165 MW Kelanitissa CCY Plant (LNG)	710	831	875	930	997	864	53.1	62.1	65.4	69.5	74.6	64.6
270 MW Kerawalapitiya CCY (LNG)	616	754	883	1,164	1,293	893	27.4	33.5	39.3	51.8	57.5	39.8
300 MW Lakvijaya Coal PS (Unit 2)	1,899	1,902	1,902	1,902	1,902	1,901	78.8	78.9	78.9	79.0	79.0	78.9
300 MW Lakvijaya Coal PS (Unit 3)	1,798	1,814	1,814	1,817	1,817	1,813	74.6	75.3	75.3	75.4	75.4	75.3
150 MW FO Reciprocating Engines	0	0	0	81	110	18	0.0	0.0	0.0	6.2	8.4	1.4
300 MW LNG CCY Plant (2 Units)	2,207	2,643	3,194	3,520	3,628	3,056	46.2	55.3	66.9	73.7	76.0	64.0
35 MW Gas Turbine (3 Units)	0	0	0	4	26	2	0.0	0.0	0.0	0.5	2.9	0.2
170 MW FO Reciprocating Engines	0	19	83	288	307	104	0.0	1.2	5.3	18.3	19.5	6.6
300 MW High Efficient Coal Plant (3 Units)	5,353	5,681	5,855	5,923	5,987	5,787	75.4	80.1	82.5	83.5	84.4	81.6
Total hydro	8,686	7,423	6,189	4,978	4,446	6,417						
Total thermal	14,637	15,906	17,111	18,281	18,823	16,883						
Total generation	23,323	23,329	23,300	23,259	23,269	23,300						
Total demand	22,475	22,475	22,475	22,475	22,475	22,475						
Deficit*	-848	-854	-825	-784	-794	-825						
2028												
300 MW Lakvijaya Coal PS (Unit 1)	1,347	1,411	1,482	1,577	1,601	1,475	55.9	58.6	61.5	65.5	66.4	61.2
3x8.6 MW Uthuru Janani PS	0	0	0	5	0	1	0.0	0.0	0.0	2.3	0.1	0.4
163 MW CEB KCCP 2 CCY Plant	473	515	524	628	658	540	34.8	38.0	38.7	46.3	48.5	39.8
165 MW Kelanitissa CCY Plant (LNG)	663	700	723	792	834	728	49.6	52.3	54.0	59.2	62.3	54.4
270 MW Kerawalapitiya CCY (LNG)	499	543	560	676	642	572	22.2	24.1	24.9	30.1	28.6	25.5
300 MW Lakvijaya Coal PS (Unit 2)	1,724	1,804	1,854	1,866	1,865	1,833	71.6	74.9	77.0	77.5	77.4	76.1
300 MW Lakvijaya Coal PS (Unit 3)	1,598	1,698	1,765	1,771	1,777	1,736	66.3	70.5	73.3	73.5	73.8	72.1
150 MW FO Reciprocating Engines	0	0	0	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0
300 MW LNG CCY Plant (2 Units)	1,427	1,639	2,057	2,387	2,876	2,001	29.9	34.3	43.1	50.0	60.2	41.9
35 MW Gas Turbine (3 Units)	0	0	0	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0
170 MW FO Reciprocating Engines	0	0	0	3	1	1	0.0	0.0	0.0	0.2	0.1	0.0
600 MW Supercritical Coal Plant (1 Unit)	3,787	3,973	4,071	4,132	4,130	4,035	76.7	80.4	82.4	83.6	83.6	81.7
300 MW High Efficient Coal Plant (3 Units)	4,092	4,609	5,089	5,467	5,491	4,970	57.7	64.9	71.7	77.1	77.4	70.1
Total hydro	8,740	7,458	6,194	4,964	4,448	6,429						
Total thermal	15,610	16,892	18,126	19,305	19,874	17,892						
Total generation	24,350	24,350	24,320	24,269	24,322	24,321						
Total demand	23,501	23,501	23,501	23,501	23,501	23,501						
Deficit*	-849	-849	-819	-768	-821	-820						
2029												
300 MW Lakvijaya Coal PS (Unit 1)	1,432	1,494	1,562	1,627	1,648	1,550	59.5	62.0	64.8	67.5	68.4	64.3
3x8.6 MW Uthuru Janani PS	0	0	0	19	28	4	0.0	0.0	0.1	8.5	12.1	1.9
163 MW CEB KCCP 2 CCY Plant	502	541	609	718	816	611	37.0	39.9	44.9	53.0	60.1	45.1
165 MW Kelanitissa CCY Plant (LNG)	713	735	790	842	910	785	53.3	55.0	59.1	62.9	68.1	58.7
270 MW Kerawalapitiya CCY (LNG)	750	809	839	1,006	999	857	33.4	36.0	37.4	44.8	44.5	38.2
300 MW Lakvijaya Coal PS (Unit 2)	1,781	1,835	1,861	1,881	1,882	1,852	73.9	76.2	77.3	78.1	78.1	76.9
300 MW Lakvijaya Coal PS (Unit 3)	1,674	1,738	1,774	1,793	1,791	1,760	69.5	72.1	73.6	74.4	74.3	73.1
150 MW FO Reciprocating Engines	0	0	0	1	1	0	0.0	0.0	0.0	0.1	0.1	0.0
300 MW LNG CCY Plant (2 Units)	1,563	2,073	2,444	2,846	3,103	2,375	32.7	43.4	51.2	59.6	65.0	49.7
35 MW Gas Turbine (3 Units)	0	0	0	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0
170 MW FO Reciprocating Engines	0	0	1	51	70	12	0.0	0.0	0.0	3.3	4.4	0.7
600 MW Supercritical Coal Plant (1 Unit)	3,906	4,027	4,100	4,166	4,169	4,079	79.1	81.5	83.0	84.3	84.4	82.6
300 MW High Efficient Coal Plant (3 Units)	4,484	4,859	5,383	5,614	5,714	5,239	63.2	68.5	75.9	79.1	80.5	73.8
Total hydro	8,798	7,494	6,240	4,984	4,466	6,470						
Total thermal	16,806	18,110	19,364	20,564	21,130	19,126						
Total generation	25,604	25,604	25,604	25,548	25,596	25,596						
Total demand	24,739	24,739	24,739	24,739	24,739	24,739						
Deficit*	-865	-865	-865	-809	-857	-857						

-Total generation figure excludes generation from Wind, Solar and Biomass Power Plants.

Year Plant	Annual Energy (GWh) Hydrology condition 1	2	3	4	5	Avg.	Annual Plant Factor (%) Hydrology condition 1	2	3	4	5	Avg.
2030												
300 MW Lakvijaya Coal PS (Unit 1)	1,488	1,541	1,616	1,675	1,698	1,601	61.8	64.0	67.1	69.5	70.5	66.5
3x8.6 MW Uthuru Janani PS	0	7	21	53	63	23	0.0	3.1	9.2	23.4	27.5	10.1
163 MW CEB KCCP 2 CCY Plant	514	615	748	812	910	716	37.9	45.4	55.2	59.9	67.1	52.8
165 MW Kelanitissa CCY Plant (LNG)	712	774	856	899	973	837	53.2	57.8	64.0	67.2	72.8	62.6
270 MW Kerawalapitiya CCY (LNG)	810	886	969	1,107	1,212	969	36.0	39.4	43.1	49.3	54.0	43.1
300 MW Lakvijaya Coal PS (Unit 2)	1,802	1,839	1,869	1,882	1,889	1,859	74.8	76.3	77.6	78.1	78.4	77.2
300 MW Lakvijaya Coal PS (Unit 3)	1,700	1,751	1,779	1,795	1,799	1,769	70.6	72.7	73.8	74.5	74.7	73.4
150 MW FO Reciprocating Engines	0	0	1	65	65	13	0.0	0.0	0.0	4.9	5.0	1.0
300 MW LNG CCY Plant (2 Units)	2,161	2,422	2,843	3,178	3,334	2,765	45.3	50.7	59.5	66.6	69.8	57.9
35 MW Gas Turbine (3 Units)	0	0	0	4	9	1	0.0	0.0	0.0	0.4	0.9	0.1
170 MW FO Reciprocating Engines	0	29	47	291	283	87	0.0	1.8	3.0	18.5	17.9	5.5
600 MW Supercritical Coal Plant (1 Unit)	3,983	4,073	4,131	4,165	4,182	4,113	80.6	82.4	83.6	84.3	84.7	83.2
300 MW High Efficient Coal Plant (3 Units)	4,721	5,273	5,591	5,765	5,831	5,479	66.5	74.3	78.8	81.3	82.2	77.2
Total hydro	8,851	7,529	6,263	5,015	4,470	6,498						
Total thermal	17,892	19,211	20,470	21,692	22,247	20,232						
Total generation	26,743	26,740	26,733	26,707	26,717	26,730						
Total demand	25,883	25,883	25,883	25,883	25,883	25,883						
Deficit*	-860	-857	-850	-824	-834	-847						
2031												
300 MW Lakvijaya Coal PS (Unit 1)	1,298	1,413	1,497	1,506	1,558	1,465	53.9	58.7	62.1	62.5	64.7	60.8
3x8.6 MW Uthuru Janani PS	0	0	0	0	6	0	0.0	0.0	0.0	0.1	2.7	0.2
163 MW CEB KCCP 2 CCY Plant	481	512	526	608	590	534	35.4	37.8	38.8	44.8	43.5	39.4
165 MW Kelanitissa CCY Plant (LNG)	684	694	721	804	781	728	51.2	51.9	53.9	60.1	58.4	54.4
270 MW Kerawalapitiya CCY (LNG)	722	782	813	851	861	806	32.1	34.8	36.2	37.9	38.3	35.8
300 MW Lakvijaya Coal PS (Unit 2)	1,632	1,717	1,786	1,818	1,841	1,765	67.7	71.3	74.2	75.4	76.4	73.3
300 MW Lakvijaya Coal PS (Unit 3)	1,549	1,602	1,662	1,724	1,741	1,652	64.3	66.5	69.0	71.6	72.3	68.6
150 MW FO Reciprocating Engines	0	0	0	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0
300 MW LNG CCY Plant (2 Units)	1,391	1,582	1,877	2,359	2,580	1,877	29.1	33.1	39.3	49.4	54.0	39.3
35 MW Gas Turbine (3 Units)	0	0	0	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0
170 MW FO Reciprocating Engines	0	0	0	1	30	2	0.0	0.0	0.0	0.1	1.9	0.1
600 MW Supercritical Coal Plant (2 Units)	7,340	7,735	8,011	8,164	8,195	7,921	74.3	78.3	81.1	82.6	82.9	80.2
300 MW High Efficient Coal Plant (3 Units)	3,908	4,308	4,732	5,030	5,246	4,635	55.1	60.7	66.7	70.9	73.9	65.3
Total hydro	8,904	7,565	6,286	5,008	4,468	6,521						
Total thermal	19,006	20,346	21,624	22,865	23,431	21,383						
Total generation	27,910	27,911	27,910	27,873	27,899	27,904						
Total demand	27,050	27,050	27,050	27,050	27,050	27,050						
Deficit*	-860	-861	-860	-823	-849	-854						
2032												
300 MW Lakvijaya Coal PS (Unit 1)	1,417	1,472	1,540	1,607	1,603	1,527	58.8	61.1	63.9	66.7	66.6	63.4
3x8.6 MW Uthuru Janani PS	0	1	0	17	21	4	0.0	0.3	0.1	7.4	9.3	1.7
163 MW CEB KCCP 2 CCY Plant	500	541	587	695	762	594	36.9	39.9	43.3	51.3	56.2	43.8
165 MW Kelanitissa CCY Plant (LNG)	683	721	787	845	883	777	51.0	53.9	58.8	63.2	66.0	58.1
270 MW Kerawalapitiya CCY (LNG)	750	796	848	985	956	854	33.4	35.5	37.7	43.8	42.5	38.0
300 MW Lakvijaya Coal PS (Unit 2)	1,702	1,761	1,812	1,846	1,859	1,799	70.7	73.1	75.2	76.6	77.2	74.7
300 MW Lakvijaya Coal PS (Unit 3)	1,590	1,658	1,712	1,743	1,769	1,697	66.0	68.8	71.1	72.4	73.4	70.4
150 MW FO Reciprocating Engines	0	0	0	1	28	2	0.0	0.0	0.0	0.1	2.1	0.1
300 MW LNG CCY Plant (2 Units)	1,577	1,974	2,384	2,690	2,890	2,293	33.0	41.3	49.9	56.3	60.5	48.0
35 MW Gas Turbine (3 Units)	0	0	0	0	1	0	0.0	0.0	0.0	0.0	0.1	0.0
170 MW FO Reciprocating Engines	0	1	1	54	83	13	0.0	0.0	0.1	3.4	5.3	0.8
600 MW Supercritical Coal Plant (2 Units)	7,575	7,914	8,133	8,192	8,246	8,048	76.7	80.1	82.3	82.9	83.4	81.4
300 MW High Efficient Coal Plant (3 Units)	4,321	4,632	4,959	5,338	5,486	4,913	60.9	65.3	69.9	75.2	77.3	69.2
Total hydro	8,957	7,600	6,308	5,029	4,477	6,548						
Total thermal	20,115	21,472	22,764	24,013	24,587	22,519						
Total generation	29,072	29,072	29,072	29,042	29,064	29,067						
Total demand	28,208	28,208	28,208	28,208	28,208	28,208						
Deficit*	-864	-864	-864	-834	-856	-859						

-Total generation figure excludes generation from Wind, Solar and Biomass Power Plants.

Year / Plant	Annual Energy (GWh) Hydrology condition 1	2	3	4	5	Avg.	Annual Plant Factor (%) Hydrology condition 1	2	3	4	5	Avg.
2033												
300 MW Lakvijaya Coal PS (Unit 1)	1,442	1,507	1,564	1,622	1,638	1,553	59.9	62.6	64.9	67.3	68.0	64.5
3x8.6 MW Uthuru Janani PS	0	0	0	16	18	4	0.0	0.1	0.1	7.1	7.9	1.5
270 MW Kerawalapitiya CCY (LNG)	773	837	868	955	928	868	34.4	37.3	38.6	42.5	41.3	38.6
300 MW Lakvijaya Coal PS (Unit 2)	1,728	1,786	1,836	1,858	1,864	1,820	71.7	74.1	76.2	77.1	77.4	75.6
300 MW Lakvijaya Coal PS (Unit 3)	1,641	1,687	1,741	1,767	1,776	1,726	68.1	70.0	72.3	73.4	73.7	71.7
150 MW FO Reciprocating Engines	0	0	0	1	29	2	0.0	0.0	0.0	0.1	2.2	0.1
300 MW LNG CCY Plant (4 Units)	3,346	3,869	4,529	5,112	5,493	4,415	35.0	40.5	47.4	53.5	57.5	46.2
35 MW Gas Turbine (3 Units)	0	0	0	0	1	0	0.0	0.0	0.0	0.0	0.1	0.0
170 MW FO Reciprocating Engines	0	1	1	62	72	14	0.0	0.0	0.1	3.9	4.6	0.9
600 MW Supercritical Coal Plant (2 Units)	7,735	8,008	8,171	8,259	8,278	8,113	78.3	81.0	82.7	83.6	83.8	82.1
300 MW High Efficient Coal Plant (3 Units)	4,522	4,869	5,156	5,478	5,604	5,106	63.7	68.6	72.7	77.2	79.0	72.0
Total hydro	9,010	7,636	6,331	5,025	4,462	6,571						
Total thermal	21,189	22,564	23,868	25,131	25,701	23,621						
Total generation	30,199	30,200	30,199	30,156	30,163	30,192						
Total demand	29,341	29,341	29,341	29,341	29,341	29,341						
Deficit*	-858	-859	-858	-815	-822	-851						
2034												
300 MW Lakvijaya Coal PS (Unit 1)	1,487	1,550	1,592	1,662	1,665	1,587	61.7	64.3	66.1	69.0	69.1	65.9
3x8.6 MW Uthuru Janani PS	0	7	18	36	32	17	0.1	3.0	7.7	15.8	14.1	7.5
270 MW Kerawalapitiya CCY (LNG)	819	858	932	1,093	1,131	940	36.4	38.2	41.5	48.7	50.3	41.8
300 MW Lakvijaya Coal PS (Unit 2)	1,771	1,818	1,850	1,865	1,875	1,839	73.5	75.5	76.8	77.4	77.8	76.3
300 MW Lakvijaya Coal PS (Unit 3)	1,674	1,717	1,759	1,777	1,781	1,746	69.5	71.3	73.0	73.8	73.9	72.5
150 MW FO Reciprocating Engines	0	1	1	61	64	13	0.0	0.1	0.1	4.7	4.9	1.0
300 MW LNG CCY Plant (4 Units)	3,891	4,506	5,171	5,628	6,097	5,025	40.7	47.2	54.1	58.9	63.8	52.6
35 MW Gas Turbine (3 Units)	0	0	1	6	29	3	0.0	0.0	0.1	0.6	3.1	0.3
170 MW FO Reciprocating Engines	1	36	62	224	176	81	0.1	2.3	3.9	14.2	11.2	5.1
600 MW Supercritical Coal Plant (2 Units)	7,915	8,113	8,227	8,300	8,308	8,188	80.1	82.1	83.3	84.0	84.1	82.9
300 MW High Efficient Coal Plant (3 Units)	4,747	5,089	5,391	5,623	5,698	5,317	66.9	71.7	76.0	79.3	80.3	74.9
Total hydro	9,063	7,671	6,354	5,030	4,485	6,596						
Total thermal	22,305	23,695	25,004	26,276	26,856	24,756						
Total generation	31,368	31,366	31,358	31,306	31,341	31,352						
Total demand	30,509	30,509	30,509	30,509	30,509	30,509						
Deficit*	-859	-857	-849	-797	-832	-843						
2035												
300 MW Lakvijaya Coal PS (Unit 1)	1,395	1,475	1,530	1,598	1,608	1,519	57.9	61.2	63.5	66.3	66.8	63.1
3x8.6 MW Uthuru Janani PS	0	0	5	30	26	8	0.1	0.1	2.0	13.0	11.4	3.6
300 MW Lakvijaya Coal PS (Unit 2)	1,674	1,738	1,797	1,822	1,841	1,779	69.5	72.1	74.6	75.6	76.4	73.8
300 MW Lakvijaya Coal PS (Unit 3)	1,584	1,646	1,700	1,724	1,746	1,683	65.7	68.3	70.6	71.6	72.5	69.9
150 MW FO Reciprocating Engines	0	1	1	2	40	3	0.0	0.0	0.1	0.2	3.0	0.2
300 MW LNG CCY Plant (4 Units)	3,164	3,677	4,259	4,802	5,115	4,157	33.1	38.5	44.6	50.3	53.5	43.5
35 MW Gas Turbine (3 Units)	0	0	0	1	13	1	0.0	0.0	0.0	0.1	1.4	0.1
170 MW FO Reciprocating Engines	1	1	3	113	155	26	0.0	0.1	0.2	7.2	9.8	1.7
600 MW Supercritical Coal Plant (3 Units)	11,384	11,774	12,080	12,253	12,305	11,987	76.8	79.4	81.5	82.7	83.0	80.9
300 MW High Efficient Coal Plant (3 Units)	4,284	4,582	4,850	5,170	5,246	4,808	60.4	64.6	68.4	72.9	73.9	67.8
Total hydro	9,116	7,707	6,377	5,068	4,476	6,625						
Total thermal	23,485	24,893	26,225	27,514	28,095	25,972						
Total generation	32,601	32,600	32,602	32,582	32,571	32,597						
Total demand	31,743	31,743	31,743	31,743	31,743	31,743						
Deficit*	-858	-857	-859	-839	-828	-854						

-Total generation figure excludes generation from Wind, Solar and Biomass Power Plants.

Year / Plant	Annual Energy (GWh) Hydrology condition 1	2	3	4	5	Avg.	Annual Plant Factor (%) Hydrology condition 1	2	3	4	5	Avg.
2036												
300 MW Lakvijaya Coal PS (Unit 1)	1,428	1,495	1,537	1,602	1,614	1,532	59.3	62.1	63.8	66.5	67.0	63.6
3x8.6 MW Uthuru Janani PS	0	0	0	20	17	4	0.1	0.1	0.2	8.9	7.4	1.8
300 MW Lakvijaya Coal PS (Unit 2)	1,682	1,755	1,797	1,819	1,847	1,783	69.8	72.8	74.6	75.5	76.7	74.0
300 MW Lakvijaya Coal PS (Unit 3)	1,594	1,650	1,694	1,727	1,749	1,683	66.2	68.5	70.3	71.7	72.6	69.9
150 MW FO Reciprocating Engines	0	0	1	2	25	2	0.0	0.0	0.1	0.2	1.9	0.2
300 MW LNG CCY Plant (5 Units)	4,038	4,715	5,347	6,075	6,377	5,250	33.8	39.5	44.8	50.9	53.4	44.0
35 MW Gas Turbine (3 Units)	0	0	0	1	3	1	0.0	0.0	0.0	0.1	0.4	0.1
170 MW FO Reciprocating Engines	1	1	3	42	91	12	0.1	0.1	0.2	2.6	5.8	0.8
600 MW Supercritical Coal Plant (3 Units)	11,494	11,813	12,117	12,246	12,312	12,023	77.5	79.7	81.8	82.6	83.1	81.1
300 MW High Efficient Coal Plant (3 Units)	4,421	4,655	4,931	5,199	5,282	4,882	62.3	65.6	69.5	73.3	74.4	68.8
Total hydro	9,169	7,742	6,399	5,058	4,473	6,647						
Total thermal	24,658	26,085	27,428	28,732	29,317	27,172						
Total generation	33,827	33,827	33,827	33,790	33,790	33,819						
Total demand	32,968	32,968	32,968	32,968	32,968	32,968						
Deficit*	-859	-859	-859	-822	-822	-851						
2037												
300 MW Lakvijaya Coal PS (Unit 1)	1,489	1,517	1,571	1,620	1,635	1,562	61.8	63.0	65.2	67.3	67.9	64.8
3x8.6 MW Uthuru Janani PS	1	5	13	42	52	16	0.2	2.0	5.6	18.5	22.8	7.2
300 MW Lakvijaya Coal PS (Unit 2)	1,734	1,783	1,832	1,848	1,856	1,816	72.0	74.0	76.1	76.7	77.0	75.4
300 MW Lakvijaya Coal PS (Unit 3)	1,636	1,689	1,737	1,756	1,768	1,722	67.9	70.1	72.1	72.9	73.4	71.5
150 MW FO Reciprocating Engines	1	2	8	65	104	19	0.1	0.1	0.6	4.9	7.9	1.5
300 MW LNG CCY Plant (5 Units)	4,698	5,426	6,119	6,801	7,079	5,989	39.3	45.4	51.3	57.0	59.3	50.2
35 MW Gas Turbine (3 Units)	0	1	4	6	31	4	0.0	0.1	0.4	0.7	3.3	0.5
170 MW FO Reciprocating Engines	2	30	53	235	256	81	0.2	1.9	3.4	14.9	16.2	5.1
600 MW Supercritical Coal Plant (3 Units)	11,753	12,034	12,225	12,322	12,369	12,161	79.3	81.2	82.5	83.1	83.4	82.1
300 MW High Efficient Coal Plant (3 Units)	4,600	4,870	5,144	5,322	5,449	5,077	64.8	68.6	72.5	75.0	76.8	71.6
Total hydro	9,222	7,778	6,418	5,069	4,492	6,672						
Total thermal	25,915	27,356	28,706	30,019	30,598	28,449						
Total generation	35,137	35,134	35,124	35,088	35,090	35,121						
Total demand	34,277	34,277	34,277	34,277	34,277	34,277						
Deficit*	-860	-857	-847	-811	-813	-844						

-Total generation figure excludes generation from Wind, Solar and Biomass Power Plants.

Fuel Requirement and Expenditure on Fuel

Base Case 2018 - 2037

Year	Auto Diesel		Furnace Oil (LSFO 180)		Furnace Oil (HSFO 180)		Residual Oil (HSFO 380)		Naphtha		Coal (6300 kcal/kg)		Coal (5900 kcal/kg)		LNG		Dendro	
	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD
2018	137.8	128.1	154.5	109.3	597.3	341.4	182.3	104.2	126.6	104.8	1777.5	141.4					476.5	21.4
2019	243.3	234.2	172.8	119.6	612.5	350.1	185.6	106.1	130.6	107.7	1754.0	140.0					538.4	24.2
2020	132.9	124.4			486.3	278.0	159.0	90.9			1777.8	141.2			421.4	254.6	600.3	27.0
2021	127.9	120.5			491.3	280.9	160.7	91.8			1757.3	140.1			504.5	316.4	662.2	29.8
2022	143.6	134.5			506.3	289.4	165.7	94.7			1804.7	142.7			542.1	332.1	724.1	32.6
2023	1.7	1.3			51.0	29.1	12.8	7.3			1996.1	153.4	686.2	48.5	832.1	463.5	785.9	35.3
2024	0.8	0.6			19.4	11.1	6.1	3.5			1972.8	152.1	1337.1	95.0	737.5	422.3	847.8	38.1
2025	-	-			5.8	3.3					1978.3	152.6	1975.2	140.7	618.4	375.7	909.7	40.9
2026	0.1	0.1			13.7	7.8					2027.7	155.5	2105.7	148.6	711.9	419.0	971.6	43.7
2027	0.6	0.4			30.7	17.5					2065.7	157.6	2198.0	154.1	817.2	465.2	1033.5	46.5
2028	-	-			0.3	0.2					1930.0	150.0	3311.7	235.2	564.1	356.4	1095.4	49.2
2029	-	-			3.5	2.0					1975.6	152.6	3429.6	242.3	685.0	417.3	1157.3	52.0
2030	0.3	0.3			26.3	15.1					2001.7	154.0	3532.2	248.5	782.1	456.4	1219.1	54.8
2031	-	-			0.5	0.3					1868.0	146.5	4555.5	324.1	586.9	375.4	1281.0	57.6
2032	-	-			4.0	2.3					1922.5	149.5	4706.0	333.2	669.3	409.9	1281.0	57.6
2033	-	-			4.1	2.3					1951.9	151.2	4802.3	339.0	766.9	464.2	1342.9	60.4
2034	0.8	0.6			23.8	13.6					1980.1	152.8	4908.8	345.5	864.5	505.2	1342.9	60.4
2035	0.3	0.2			8.0	4.6					1906.9	148.6	6056.0	428.4	578.9	350.3	1404.8	63.2
2036	0.2	0.1			4.0	2.3					1913.3	148.9	6097.1	430.9	731.1	441.0	1404.8	63.2
2037	1.3	1.0			24.9	14.2					1952.6	151.2	6219.8	438.4	834.0	484.7	1466.7	65.9

Results of Generation Expansion Planning Studies 2018-2037

Reference Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2018		*100 MW Furnace Oil fired Power Plant ** *70 MW Furnace Oil fired Power Plant ** *150 MW Furnace Oil fired Power Plant **	8x6.13 MW Asia Power	1.490
2019	Major Hydro *122 MW* *(Uma Oya HPP)*	*2x35 MW Gas Turbine* *1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region+*	-	0.412
2020	Major Hydro *35 MW* *(Broadlands HPP)* **15 MW** **(Thalpitigala HPP)**	*1x35 MW Gas Turbine*	6x5 MW Northern Power	0.896
2021	-	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**	4x17 MW Kelanitissa Gas Turbines	0.633
2022	Major Hydro *30 MW* *(Moragolla HPP)* **20 MW** **(Seethawaka HPP)** **20 MW** **(Gin Ganga HPP)**	**2x35 MW Gas Turbine**		0.850
2023	-	**2x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** *163 MW Combined Cycle Power Plant (KPS–2)* •	115 MW Gas Turbine** 4x9 MW Sapugaskanda Diesel Ext.** 163 MW Sojitz Kelanitissa Combined Cycle Plant •	0.078
2024	-	-	4x18 MW Sapugaskanda Diesel	0.766
2025	Major Hydro 200 MW (Pumped Storage Power Plant)	**1x600 MW New Supercritical Coal Power Plant**	4x9 MW Sapugaskanda Diesel Ext. 4x15 MW CEB Barge Power Plant	0.033
2026	Major Hydro 200 MW (Pumped Storage Power Plant)	-	-	0.030
2027	Major Hydro 200 MW (Pumped Storage Power Plant)	-	-	0.084
2028	-	-	-	0.783
2029	-	**1x600 MW New Supercritical Coal Power Plant**	-	0.020
2030	-	-	-	0.151
2031	-	**1x600 MW New Supercritical Coal Power Plant**	-	0.019
2032	-	-	-	0.090
2033	-	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region** **1x600 MW New Supercritical Coal Power Plant**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS- 2)	0.029
2034	-	-	-	0.115
2035	-	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**	300MW West Coast Combined Cycle Power Plant	0.662
2036	-	**1x600 MW New Supercritical Coal Power Plant**	-	0.133
2037	-	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**	-	0.170
Total PV Cost up to year 2037, **USD 14,414.55 million** (LKR 2,146.04 billion)				

Please refer Page A7-23 for General Notes

Results of Generation Expansion Planning Studies 2018-2037

Future coal power development limited to 1800 MW

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2018	Mini Hydro 15 MW Solar 160 MW Biomass 5 MW	*100 MW Furnace Oil fired Power Plant ** *70 MW Furnace Oil fired Power Plant ** *150 MW Furnace Oil fired Power Plant **	8x6.13 MW Asia Power	1.245
2019	Major Hydro *120 MW* *(Uma Oya HPP)* Mini Hydro 15 MW Wind 50 MW Solar 95 MW Biomass 5 MW	*2x35 MW Gas Turbine* *1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region*+	-	0.220
2020	Major Hydro *35 MW* *(Broadlands HPP)* **15 MW** **(Thalpitigala HPP)** *Wind 100 MW (Mannar Wind Park)* Mini Hydro 15 MW Wind 120 MW Solar 105 MW Biomass 5 MW	*1x35 MW Gas Turbine*	6x5 MW Northern Power	0.237
2021	Mini Hydro 10 MW Wind 75 MW Solar 55 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**	4x17 MW Kelanitissa Gas Turbines	0.107
2022	Major Hydro *31 MW* *(Moragolla HPP)* **20 MW** **(Seethawaka HPP)** **20 MW** **(Gin Ganga HPP)** Mini Hydro 10 MW Wind 50 MW Solar 6 MW Biomass 5 MW			0.237
2023	Mini Hydro 10 MW Wind 60 MW Solar 55 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** *163 MW Combined Cycle Power Plant (KPS–2)* •	115 MW Gas Turbine** 4x9 MW Sapugaskanda Diesel Ext.** 163 MW Sojitz Kelanitissa Combined Cycle Plant •	0.205
2024	Mini Hydro 10 MW Wind 45 MW Solar 55 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)**	4x18 MW Sapugaskanda Diesel	0.145
2025	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 85 MW Solar 104 MW Biomass 5 MW	-	4x9 MW Sapugaskanda Diesel Ext. 4x15 MW CEB Barge Power Plant	0.192
2026	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Solar 55 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Southern Region**	-	0.022
2027	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 25 MW Solar 54 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Southern Region**	-	0.002
2028	Mini Hydro 10 MW Wind 45 MW Solar 105 MW Biomass 5 MW	-	-	0.009
2029	Mini Hydro 10 MW Wind 25 MW Solar 54 MW Biomass 5 MW	**1x600 MW New Supercritical Coal Power Plant**	-	0.002
2030	Mini Hydro 10 MW Wind 70 MW Solar 55 MW Biomass 5 MW	-	-	0.006
2031	Mini Hydro 10 MW Wind 35 MW Solar 54 MW Biomass 5 MW	-	-	0.025
2032	Mini Hydro 10 MW Wind 45 MW Solar 55 MW	**1x600 MW New Supercritical Coal Power Plant**	-	0.005
2033	Mini Hydro 10 MW Wind 70 MW Solar 54 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS-2)	0.025
2034	Mini Hydro 10 MW Wind 70 MW Solar 55 MW	-	-	0.113
2035	Mini Hydro 10 MW Wind 70 MW Solar 54 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant -Western Region** **1x300 MW Natural Gas fired Combined Cycle Power Plant - Southern Region**	300MW West Coast Combined Cycle Power Plant	0.067
2036	Mini Hydro 10 MW Wind 95 MW Solar 55 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant -Southern Region**	-	0.066
2037	Mini Hydro 10 MW Wind 70 MW Solar 104 MW Biomass 5 MW	-	-	0.259
Total PV Cost up to year 2037, **USD 14,894.64 million** (LKR 2,217.51 billion)++				

Please refer Page A7-23 for General Notes

Results of Generation Expansion Planning Studies 2018-2037

No future coal power development

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2018	Mini Hydro 15 MW Solar 160 MW Biomass 5 MW	*100 MW Furnace Oil fired Power Plant ** *70 MW Furnace Oil fired Power Plant ** *150 MW Furnace Oil fired Power Plant **	8x6.13 MW Asia Power	1.245
2019	Major Hydro *120 MW* *(Uma Oya HPP)* Mini Hydro 15 MW Wind 50 MW Solar 95 MW Biomass 5 MW	*2x35 MW Gas Turbine* *1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region+*	-	0.220
2020	Major Hydro *35 MW* *(Broadlands HPP)* **15 MW** **(Thalpitigala HPP)** *Wind 100 MW (Mannar Wind Park)* Mini Hydro 15 MW Wind 120 MW Solar 105 MW Biomass 5 MW	*1x35 MW Gas Turbine*	6x5 MW Northern Power	0.237
2021	Mini Hydro 10 MW Wind 75 MW Solar 55 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**	4x17 MW Kelanitissa Gas Turbines	0.107
2022	Major Hydro *30 MW* *(Moragolla HPP)* **20 MW** **(Seethawaka HPP)** **20 MW** **(Gin Ganga HPP)** Mini Hydro 10 MW Wind 50 MW Solar 6 MW Biomass 5 MW			0.237
2023	Mini Hydro 10 MW Wind 60 MW Solar 55 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Southern Region** *163 MW Combined Cycle Power Plant (KPS–2)* •	115 MW Gas Turbine** 4x9 MW Sapugaskanda Diesel Ext.** 163 MW Sojitz Kelanitissa Combined Cycle Plant •	0.231
2024	Mini Hydro 10 MW Wind 25 MW Solar 55 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Southern Region**	4x18 MW Sapugaskanda Diesel	0.193
2025	Mini Hydro 10 MW Wind 25 MW Solar 54 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	4x9 MW Sapugaskanda Diesel Ext. 4x15 MW CEB Barge Power Plant	0.220
2026	Mini Hydro 10 MW Solar 55 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	-	0.157
2027	Mini Hydro 10 MW Wind 25 MW Solar 54 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	-	0.101
2028	Mini Hydro 10 MW Wind 45 MW Solar 105 MW Biomass 5 MW	-	-	0.277
2029	Mini Hydro 10 MW Wind 25 MW Solar 54 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	-	0.208
2030	Mini Hydro 10 MW Wind 70 MW Solar 55 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Southern Region**	-	0.147
2031	Mini Hydro 10 MW Wind 35 MW Solar 54 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Southern Region**	-	0.118
2032	Mini Hydro 10 MW Wind 45 MW Solar 55 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant–Southern Region**	-	0.098
2033	Mini Hydro 10 MW Wind 70 MW Solar 54 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant - Western Region** **1x300 MW Natural Gas fired Combined Cycle Power Plant**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS- 2)	0.111
2034	Mini Hydro 10 MW Wind 70 MW Solar 55 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant - Western Region**	-	0.097
2035	Mini Hydro 10 MW Wind 70 MW Solar 54 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant -Western Region**	300MW West Coast Combined Cycle Power Plant	0.263
2036	Mini Hydro 10 MW Wind 95 MW Solar 55 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant**	-	0.251
2037	Mini Hydro 10 MW Wind 70 MW Solar 104 MW Biomass 5 MW	-	-	0.740
Total PV Cost up to year 2037, **USD 15,607.70 million** (LKR 2,323.67 billion)				

Please refer Page A7-23 for General Notes

Annex 7.9

Results of Generation Expansion Planning Studies 2018-2037

High Demand Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2018	Mini Hydro 15 MW, Solar 160 MW Biomass 5 MW	*100 MW Furnace Oil fired Power Plant ** *70 MW Furnace Oil fired Power Plant ** *270 MW Furnace Oil fired Power Plant ◦*	8x6.13 MW Asia Power	0.826
2019	Major Hydro *122 MW (Uma Oya HPP)* Mini Hydro 15 MW, Wind 50 MW Solar 95 MW, Biomass 5 MW	*2x35 MW Gas Turbine* *1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region⁺*	-	0.138
2020	Major Hydro *35 MW (Broadlands HPP)* **15 MW (Thalpitigala HPP)** *Wind 100 MW (Mannar Wind Park)* Mini Hydro 15 MW, Wind 120 MW Solar 105 MW, Biomass 5 MW	*1x35 MW Gas Turbine*	6x5 MW Northern Power	0.207
2021	Mini Hydro 10 MW, Wind 75 MW Solar 55 MW, Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**	4x17 MW Kelanitissa Gas Turbines	0.100
2022	Major Hydro *30 MW (Moragolla HPP)* **20 MW (Seethawaka HPP)** **20 MW (Gin Ganga HPP)** Mini Hydro 10 MW, Wind 50 MW Solar 6 MW, Biomass 5 MW	-	-	0.221
2023	Mini Hydro 10 MW, Wind 60 MW Solar 55 MW, Biomass 5 MW	**2x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** *163 MW Combined Cycle Power Plant (KPS–2) •*	115 MW Gas Turbine** 4x9 MW Sapugaskanda Diesel Ext.** 163 MW Sojitz Kelanitissa Combined Cycle Plant •	0.034
2024	Mini Hydro 10 MW, Wind 45 MW Solar 55 MW, Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**	4x18 MW Sapugaskanda Diesel	0.035
2025	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW, Wind 85 MW Solar 104 MW, Biomass 5 MW	-	4x9 MW Sapugaskanda Diesel Ext. 4x15 MW CEB Barge Power Plant	0.043
2026	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW, Solar 55 MW Biomass 5 MW	-	-	0.064
2027	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW, Wind 25 MW Solar 54 MW, Biomass 5 MW	**1x600 MW New Supercritical Coal Power Plant**	-	0.001
2028	Mini Hydro 10 MW, Wind 45 MW Solar 105 MW, Biomass 5 MW	-	-	0.005
2029	Mini Hydro 10 MW, Wind 25 MW Solar 54 MW, Biomass 5 MW	-	-	0.088
2030	Mini Hydro 10 MW, Wind 70 MW Solar 55 MW, Biomass 5 MW	**1x600 MW New Supercritical Coal Power Plant**	-	0.010
2031	Mini Hydro 10 MW, Wind 35 MW Solar 54 MW, Biomass 5 MW	-	-	0.110
2032	Mini Hydro 10 MW, Wind 45 MW Solar 55 MW	**1x600 MW New Supercritical Coal Power Plant**	-	0.016
2033	Mini Hydro 10 MW, Wind 70 MW Solar 54 MW, Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants -Western Region**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS- 2)	0.158
2034	Mini Hydro 10 MW, Wind 70 MW Solar 55 MW	**1x600 MW New Supercritical Coal Power Plant**	-	0.039
2035	Mini Hydro 10 MW, Wind 70 MW Solar 54 MW, Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants -Western Region**	300MW West Coast Combined Cycle Power Plant	0.212
2036	Mini Hydro 10 MW, Wind 95 MW Solar 55 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant -Western Region**	-	0.333
2037	Mini Hydro 10 MW, Wind 70 MW Solar 104 MW, Biomass 5 MW	**1x600 MW New Supercritical Coal Power Plant**	-	0.143
Total PV Cost up to year 2037, **USD 16,603.88 million** (LKR 2,471.99 billion)⁺⁺				

Please refer Page A7-23 for General Notes

Results of Generation Expansion Planning Studies 2018-2037

Low Demand Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2018	Mini Hydro 15 MW Solar 160 MW Biomass 5 MW	*100 MW Furnace Oil fired Power Plant ** *70 MW Furnace Oil fired Power Plant ** *150 MW Furnace Oil fired Power Plant **	8x6.13 MW Asia Power	0.932
2019	Major Hydro *122 MW* *(Uma Oya HPP)* Mini Hydro 15 MW Wind 50 MW Solar 95 MW Biomass 5 MW	*2x35 MW Gas Turbine* *1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region+*	-	0.114
2020	Major Hydro *35 MW* *(Broadlands HPP)* **15 MW** **(Thalpitigala HPP)** *Wind* *100 MW* *(Mannar Wind Park)* Mini Hydro 15 MW Wind 120 MW Solar 105 MW Biomass 5 MW	*1x35 MW Gas Turbine*	6x5 MW Northern Power	0.087
2021	Mini Hydro 10 MW Wind 75 MW Solar 55 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**	4x17 MW Kelanitissa Gas Turbines	0.040
2022	Major Hydro *30 MW* *(Moragolla HPP)* **20 MW** **(Seethawaka HPP)** **20 MW** **(Gin Ganga HPP)** Mini Hydro 10 MW Wind 50 MW Solar 6 MW Biomass 5 MW	-	-	0.055
2023	Mini Hydro 10 MW Wind 45 MW Solar 30 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** *163 MW Combined Cycle Power Plant (KPS–2)* •	115 MW Gas Turbine** 4x9 MW Sapugaskanda Diesel Ext.** 163 MW Sojitz Kelanitissa Combined Cycle Plant •	0.042
2024	Mini Hydro 10 MW Wind 25 MW Solar 30 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)**	4x18 MW Sapugaskanda Diesel	0.025
2025	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 40 MW Solar 29 MW	-	4x9 MW Sapugaskanda Diesel Ext. 4x15 MW CEB Barge Power Plant	0.022
2026	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Solar 55 MW Biomass 5 MW	-	-	0.010
2027	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 25 MW Solar 54 MW Biomass 5 MW	-	-	0.004
2028	Mini Hydro 10 MW Wind 20 MW Solar 105 MW	-	-	0.034
2029	Mini Hydro 10 MW Wind 25 MW Solar 54 MW Biomass 5 MW	**1x600 MW New Supercritical Coal Power Plant**	-	0.001
2030	Mini Hydro 10 MW Wind 45 MW Solar 55 MW Biomass 5 MW	-	-	0.004
2031	Mini Hydro 10 MW Wind 10 MW Solar 29 MW Biomass 5 MW	-	-	0.012
2032	Mini Hydro 10 MW Wind 45 MW Solar 55 MW	**1x600 MW New Supercritical Coal Power Plant**	-	0.001
2033	Mini Hydro 10 MW Wind 45 MW Solar 29 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants -Western Region**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS- 2)	0.005
2034	Mini Hydro 10 MW Wind 45 MW Solar 30 MW	-	-	0.012
2035	Mini Hydro 10 MW Wind 45 MW Solar 29 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants -Western Region**	300MW West Coast Combined Cycle Power Plant	0.022
2036	Mini Hydro 10 MW Wind 45 MW Solar 30 MW	-	-	0.054
2037	Mini Hydro 10 MW Wind 45 MW Solar 54 MW Biomass 5 MW	-	-	0.194
Total PV Cost up to year 2037, **USD 13,055.31 million** (LKR 1,943.67 billion)++				

Please refer Page A7-23 for General Notes

Results of Generation Expansion Planning Studies 2018-2037

High Discount Rate (15%) Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2018	Mini Hydro 15 MW Solar 160 MW Biomass 5 MW	*100 MW Furnace Oil fired Power Plant ** *70 MW Furnace Oil fired Power Plant ** *150 MW Furnace Oil fired Power Plant **	8x6.13 MW Asia Power	1.245
2019	Major Hydro *122 MW* *(Uma Oya HPP)* Mini Hydro 15 MW Wind 50 MW Solar 95 MW Biomass 5 MW	*2x35 MW Gas Turbine* *1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region⁺*	-	0.220
2020	Major Hydro *35 MW* *(Broadlands HPP)* **15 MW** **(Thalpitigala HPP)** *Wind* *100 MW* *(Mannar Wind Park)* Mini Hydro 15 MW Wind 120 MW Solar 105 MW Biomass 5 MW	*1x35 MW Gas Turbine*	6x5 MW Northern Power	0.237
2021	Mini Hydro 10 MW Wind 75 MW Solar 55 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**	4x17 MW Kelanitissa Gas Turbines	0.107
2022	Major Hydro *30 MW* *(Moragolla HPP)* **20 MW** **(Seethawaka HPP)** **20 MW** **(Gin Ganga HPP)** Mini Hydro 10 MW Wind 50 MW Solar 6 MW Biomass 5 MW			0.237
2023	Mini Hydro 10 MW Wind 60 MW Solar 55 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** *163 MW Combined Cycle Power Plant (KPS–2)* •	115 MW Gas Turbine** 4x9 MW Sapugaskanda Diesel Ext.** 163 MW Sojitz Kelanitissa Combined Cycle Plant •	0.205
2024	Mini Hydro 10 MW Wind 45 MW Solar 55 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)**	4x18 MW Sapugaskanda Diesel	0.145
2025	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 85 MW Solar 104 MW Biomass 5 MW		4x9 MW Sapugaskanda Diesel Ext. 4x15 MW CEB Barge Power Plant	0.192
2026	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Solar 55 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)**	-	0.019
2027	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 25 MW Solar 54 MW Biomass 5 MW	-	-	0.012
2028	Mini Hydro 10 MW Wind 45 MW Solar 105 MW Biomass 5 MW	**1x600 MW New Supercritical Coal Power Plant**	-	0.002
2029	Mini Hydro 10 MW Wind 25 MW Solar 54 MW Biomass 5 MW	-	-	0.008
2030	Mini Hydro 10 MW Wind 70 MW Solar 55 MW Biomass 5 MW		-	0.027
2031	Mini Hydro 10 MW Wind 35 MW Solar 54 MW Biomass 5 MW	**1x600 MW New Supercritical Coal Power Plant**	-	0.005
2032	Mini Hydro 10 MW Wind 45 MW Solar 55 MW	-	-	0.019
2033	Mini Hydro 10 MW Wind 70 MW Solar 54 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants -Western Region**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS- 2)	0.148
2034	Mini Hydro 10 MW Wind 70 MW Solar 55 MW	**1x600 MW New Supercritical Coal Power Plant**	-	0.019
2035	Mini Hydro 10 MW Wind 70 MW Solar 54 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants -Western Region**	300MW West Coast Combined Cycle Power Plant	0.058
2036	Mini Hydro 10 MW Wind 95 MW Solar 55 MW		-	0.254
2037	Mini Hydro 10 MW Wind 70 MW Solar 104 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant -Western Region**	-	0.230
Total PV Cost up to year 2037, **USD 10,915 million** (LKR 1,625.07 billion)⁺⁺				

Please refer Page A7-23 for General Notes

Results of Generation Expansion Planning Studies 2018-2037

Low Discount Rate (3%) Case

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2018	Mini Hydro 15 MW Solar 160 MW Biomass 5 MW	*100 MW Furnace Oil fired Power Plant ** *70 MW Furnace Oil fired Power Plant ** *150 MW Furnace Oil fired Power Plant **	8x6.13 MW Asia Power	1.245
2019	Major Hydro *122 MW (Uma Oya HPP)* Mini Hydro 15 MW Wind 50 MW Solar 95 MW Biomass 5 MW	*2x35 MW Gas Turbine* *1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region*[+]	-	0.220
2020	Major Hydro *35 MW (Broadlands HPP)* **15 MW (Thalpitigala HPP)** *Wind 100 MW (Mannar Wind Park)* Mini Hydro 15 MW Wind 120 MW Solar 105 MW Biomass 5 MW	*1x35 MW Gas Turbine*	6x5 MW Northern Power	0.237
2021	Mini Hydro 10 MW Wind 75 MW Solar 55 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**	4x17 MW Kelanitissa Gas Turbines	0.107
2022	Major Hydro *30 MW (Moragolla HPP)* **20 MW (Seethawaka HPP)** **20 MW (Gin Ganga HPP)** Mini Hydro 10 MW Wind 50 MW Solar 6 MW Biomass 5 MW			0.237
2023	Mini Hydro 10 MW Wind 60 MW Solar 55 MW Biomass 5 MW	**2x300 MW New Coal Power Plant (Change to Super critical will be evaluated)** *163 MW Combined Cycle Power Plant (KPS–2)* •	115 MW Gas Turbine** 4x9 MW Sapugaskanda Diesel Ext.** 163 MW Sojitz Kelanitissa Combined Cycle Plant •	0.031
2024	Mini Hydro 10 MW Wind 45 MW Solar 55 MW Biomass 5 MW	**1x300 MW New Coal Power Plant (Change to Super critical will be evaluated)**	4x18 MW Sapugaskanda Diesel	0.024
2025	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 85 MW Solar 104 MW Biomass 5 MW		4x9 MW Sapugaskanda Diesel Ext. 4x15 MW CEB Barge Power Plant	0.026
2026	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Solar 55 MW Biomass 5 MW	-	-	0.019
2027	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 25 MW Solar 54 MW Biomass 5 MW	-	-	0.012
2028	Mini Hydro 10 MW Wind 45 MW Solar 105 MW Biomass 5 MW	**1x600 MW New Supercritical Coal Power Plant**	-	0.002
2029	Mini Hydro 10 MW Wind 25 MW Solar 54 MW Biomass 5 MW	-	-	0.008
2030	Mini Hydro 10 MW Wind 70 MW Solar 55 MW Biomass 5 MW		-	0.027
2031	Mini Hydro 10 MW Wind 35 MW Solar 54 MW Biomass 5 MW	**1x600 MW New Supercritical Coal Power Plant**	-	0.005
2032	Mini Hydro 10 MW Wind 45 MW Solar 55 MW	-	-	0.019
2033	Mini Hydro 10 MW Wind 70 MW Solar 54 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants -Western Region**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS- 2)	0.148
2034	Mini Hydro 10 MW Wind 70 MW Solar 55 MW	**1x600 MW New Supercritical Coal Power Plant**	-	0.019
2035	Mini Hydro 10 MW Wind 70 MW Solar 54 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plants -Western Region**	300MW West Coast Combined Cycle Power Plant	0.058
2036	Mini Hydro 10 MW Wind 95 MW Solar 55 MW	-	-	0.254
2037	Mini Hydro 10 MW Wind 70 MW Solar 104 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant -Western Region**	-	0.230
Total PV Cost up to year 2037, **USD 24,064.96 million** (LKR 3,582.79 billion)[++]				

Please refer Page A7-23 for General Notes

Results of Generation Expansion Planning Studies 2018-2037

Energy Mix with Nuclear Power Development

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2018	Mini Hydro 15 MW Solar 160 MW Biomass 5 MW	*100 MW Furnace Oil fired Power Plant ** *70 MW Furnace Oil fired Power Plant ** *150 MW Furnace Oil fired Power Plant **	8x6.13 MW Asia Power	1.245
2019	Major Hydro *122 MW* *(Uma Oya HPP)* Mini Hydro 15 MW Wind 50 MW Solar 95 MW Biomass 5 MW	*2x35 MW Gas Turbine* *1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region*[+]	-	0.220
2020	Major Hydro *35 MW* *(Broadlands HPP)* **15 MW** **(Thalpitigala HPP)** *Wind* *100 MW* *(Mannar Wind Park)* Mini Hydro 15 MW Wind 120 MW Solar 105 MW Biomass 5 MW	*1x35 MW Gas Turbine*	6x5 MW Northern Power	0.237
2021	Mini Hydro 10 MW Wind 75 MW Solar 55 MW Biomass 5 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant – Western Region**	4x17 MW Kelanitissa Gas Turbines	0.107
2022	Major Hydro *30 MW* *(Moragolla HPP)* **20 MW** **(Seethawaka HPP)** **20 MW** **(Gin Ganga HPP)** Mini Hydro 10 MW Wind 50 MW Solar 6 MW Biomass 5 MW			0.237
2023	Mini Hydro 10 MW Wind 60 MW Solar 55 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)** *163 MW Combined Cycle Power Plant (KPS–2)* •	115 MW Gas Turbine** 4x9 MW Sapugaskanda Diesel Ext.** 163 MW Sojitz Kelanitissa Combined Cycle Plant •	0.205
2024	Mini Hydro 10 MW Wind 45 MW Solar 55 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)**	4x18 MW Sapugaskanda Diesel	0.145
2025	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 85 MW Solar 104 MW Biomass 5 MW	**1x300 MW New Coal Power Plant** **(Change to Super critical will be evaluated)**	4x9 MW Sapugaskanda Diesel Ext. 4x15 MW CEB Barge Power Plant	0.026
2026	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Solar 55 MW Biomass 5 MW	-	-	0.019
2027	Major Hydro 200 MW (Pumped Storage Power Plant) Mini Hydro 10 MW Wind 25 MW Solar 54 MW Biomass 5 MW	-	-	0.012
2028	Mini Hydro 10 MW Wind 45 MW Solar 105 MW Biomass 5 MW	**1x600 MW New Supercritical Coal Power Plant**	-	0.002
2029	Mini Hydro 10 MW Wind 25 MW Solar 54 MW Biomass 5 MW	-	-	0.008
2030	Mini Hydro 10 MW Wind 70 MW Solar 55 MW Biomass 5 MW	-	-	0.027
2031	Mini Hydro 10 MW Wind 35 MW Solar 54 MW Biomass 5 MW	-	-	0.327
2032	Mini Hydro 10 MW Wind 45 MW Solar 55 MW	**1x600 MW Nuclear Power Plant**	-	0.012
2033	Mini Hydro 10 MW Wind 70 MW Solar 54 MW Biomass 5 MW	**2x300 MW Natural Gas fired Combined Cycle Power Plants -Western Region**	165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS- 2)	0.015
2034	Mini Hydro 10 MW Wind 70 MW Solar 55 MW	-	-	0.081
2035	Mini Hydro 10 MW Wind 70 MW Solar 54 MW Biomass 5 MW	**1x600 MW Nuclear Power Plant**	300MW West Coast Combined Cycle Power Plant	0.033
2036	Mini Hydro 10 MW Wind 95 MW Solar 55 MW	**1x300 MW Natural Gas fired Combined Cycle Power Plant -Western Region**	-	0.034
2037	Mini Hydro 10 MW Wind 70 MW Solar 104 MW Biomass 5 MW	-	-	0.155
Total PV Cost up to year 2037, **USD 15,125.87 million** (LKR 2,251.94 billion)[++]				

Please refer Page A7-23 for General Notes

GENERAL NOTES:

∗ To meet the demand from year 2018 until major power plants are implemented, 70 MW, 100MW and 150MW power plants are proposed with operation by FO.

o For high demand case, additional 120MW of FO based power plants are proposed for year 2018.

\+ Grid integration of 1x300 MW Natural Gas fired Combined Cycle Power Plant would be possible once the Kerawalapitiya- Port 220kV cable is available in June 2018. Gas Turbine operation of the Combined Cycle Power Plant is expected to commence in 2019 and the combined cycle operation is expected in 2020.

** Retirement of these plants would be evaluated based on the plant conditions.

++ PV Cost includes the cost of projected ORE, USD 2004.6 million based on economic cost (excluding the future Dendro power development) and an additional spinning reserve capacity is kept to compensate for the intermittency of ORE.

- For reference case the cost of projected ORE is USD 242.2 million
- For no future coal power development case the cost of projected ORE is USD 1917.2 million
- For low demand case the cost of projected ORE is USD 1764.7 million

• Sojitz Kelanitissa is scheduled to be retired in 2023 will be operated as a CEB Natural Gas fired power plant from 2023 to 2033 with the conversion. West Coast and Kelanithissa Combined Cycle plant are converted to Natural Gas in 2020 with the development of LNG based infrastructure.

✓ Committed plants are shown in Italics. All plant capacities are given in gross values.

✓ Thalpitigala and Gin Ganga multipurpose hydro power plants proposed by Ministry of Irrigation are forced considering secured Cabinet approval for the implementation of the Projects.

✓ Seethawaka HPP and PSPP units are forced in 2022, 2025, 2026 and 2027 respectively.

✓ Moragahakanda HPP will be added in to the system by 2017, 2020 and 2022 with capacities of 10 MW, 7.5 MW and 7.5 MW respectively.

Actual Generation Expansions and the Plans from 1990-2015

Year	Actual Expansions	Long Term Generation Expansion Plan (LTGEP)																
		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	2009-2022	2011-2025	2013-2032	2015-2034
2003	20-ACE 165-CCY	150-CO	60-GT (Refurbish)	60-GT (Refurbish)	60-GT (Refurbish)	150-CO 60-GT (Refurbish)	150-CO 60-GT (Refurbish)	-	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 (Refurbish)	300-CO 60-GT (Refurbish)	300-CO 60-GT (Refurbish)	60-GT (Refurbish)	300-CO 60-GT (Refurbish)	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	180-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	270-CCY	-	-	-
2011	300-PUT	-	-	-	-	-	-	300-TRNC	-	300-TRNC	-	300-CO	300-CO	2*300-CO 150-UPK	285-PUT	315-PUT	-	-
2012	150-UPK	-	-	-	-	-	-	210-GT	300-TRNC	105-GT	300-CO	300-CO	300-CO	300-CO	150-UPK	150-UPK	-	-
2013	-	-	-	-	-	-	-	-	105-GT 10-DS	300-TRNC	300-TRNC	105-GT	300-CO	300-CO	2*285-PUT(ST2) 250-TPCL	-	-	-
2014	2*300-PUT 20-Northern 24-CPE	_	_	_	_	_	_	_	_	210-GT	_	300-CO	300-CO	300-CO	250-TPCL	20-Northern 24-CPE 75-GT 2*315-PUT	20-Northern 24-CPE 300-PUT	-
2015	60-Col(CEB)	_	_	_	_	_	_	_	_	_	300-TRNC	300-CO 210-GT	285-GT	300-CO	300-CO	2*35-GT	300-PUT 3*75-GT	60-Col(CEB)
2016	_	_	_	_	_	_	_	_	_	_	175-GT	300-CO	300-CO	300-CO	_	35-BDL 120-Uma Oya	35-BDL 120-Uma Oya	-
2017	100-ACE^{+} 20-ACE^{+}	_	_	_	_	_	_	_	_		_	210-GT	300-CO	300-CO	300-CO	2*250-TPCL	105-GT	170-FO
2018	_	_	_	_	_	_	_	_	_	_	_	_	300-CO 180-GT	300-CO	300-CO	49-GIN 250-TPCL	27-Moragolla 2*250-TPCL	35-BDL 120-Uma Oya 2*35-GT
2019	_	_	_	_	_	_	_	_	_	_	_	_	420-GT	300-CO	_	250-TPCL	2*300-CO	35-GT 300-LNG
2020	_	_	_	_	_	_	_	_	_	_	_	_	_	105-GT 300-CO	300-CO	_	_	15-THAL
2021	_	_	_	_	_	_	_	_	_	_	_	_	_	_	300-CO	2*300-CO	300-CO	250-TPCL**
2022	_	_	_	_	_	_	_	_	_	_	_	_	_	_	300-CO	300-CO	300-CO 49-GIN	31-Moragolla 20-SEETHA 20-GIN 250-TPCL**
2023	_	_	_	_	_	_	_	_	_	_	_	_	_	_	_	300-CO	2*300-CO	163-AES CCY(LNG) 300-ASC CO

Note: ORE 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, THAL - Thalpitigala, SEETHA - Seethawaka

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, PUT-Puttalam Coal Power Plant, TPCL-Trincomalee Power Company Coal Power Plant, FO-Furnace Oil power plant, LNG - Natural Gas fired Combined Cycle Power Plant (Western Region), ASC CO-Advanced Sub Critical Coal Power Plant, AES CCY(LNG)-AES Kelanitissa Convertion to LNG, Col(CEB)-CEB Colombo Power Plant

** Approval was not granted by PUCSL

$^{+}$PPA has extended for the one year and procurment of power plants by CEB is under consideration