CEYLON ELECTRICITY BOARD

LONG TERM GENERATION EXPANSION PLAN

2022-2041

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Transmission and Generation Planning Branch
Transmission Division
Ceylon Electricity Board
Sri Lanka
October 2021

Long Term Generation Expansion Planning Studies
2022- 2041

PUCSL approval granted with conditions in October 2021 (Refer Annex 15)

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

Long-term generation expansion planning studies are carried out every two years by the Transmission & Generation Planning Branch of the Ceylon Electricity Board, Sri Lanka and this report is a 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 2022-2041', 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 2022-2041, and replaces the Long Term Generation Expansion Plan 2018-2037.

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

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

October 2021.

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LIST OF TABLES

LIST OF FIGURES

ACRONYMS

ADB	-	Asian Development Bank
API	-	Argus/McCloskey's Coal price Index
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
CDM	-	Clean Development Mechanism
CER	-	Certified Emission Reduction
COP	-	Conference of Parties
CPC	-	Ceylon Petroleum Cooperation
DSM	-	Demand Side Management
EIA	-	Environmental Impact Assessment
ENS	-	Energy Not Served
EOI	-	Expression of Interest
ESP	-	Electrostatic Precipitator
FGD	-	Flue Gas Desulphurization
FO	-	Furnace Oil
FOB	-	Free On Board
FOR	-	Forced Outage Rate
FSRU	-	Floating Storage Regasification Unit
GCV	-	Gross Calorific Value
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
IC	-	Internal Combustion
IDC	-	Interest During Construction
IEA	-	International Energy Agency
IMF	-	International Monetary Fund
INDC	-	Intended Nationally Determined Contributions
IPCC	-	Inter-Governmental Panel on Climate Change
IPP	-	Independent Power Producer
JBIC	-	Japan Bank for International Cooperation
JCC	-	Japan Crude Oil Cocktail

JICA	-	Japan International Cooperation Agency
JKM	-	Japanese Korean Marker
LKR	-	Sri Lanka Rupees
KPS	-	Kelanithissa 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
LPG	-	Liquefied Petroleum Gas
LTGEP	-	Long Term Generation Expansion Plan
MMSCFD	-	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
NPP	-	Nuclear Power Plant
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
PRDS	-	Petroleum Resources Development Secretariat
PSPP	-	Pumped Storage Power Plant
PUCSL	-	Public Utilities Commission of Sri Lanka
PV	-	Photovoltaic
RE	-	Renewable Energy
RFP	-	Request For Proposals
SAM	-	System Advisor Model
SCR	-	Selective Catalytic Reduction
SDDP	-	Stochastic Dual Dynamic Programming
SPPA	-	Standardized Power Purchase Agreement
ST	-	Steam Turbine
TC	-	Technical Cooperation
UNFCCC	-	United Nations Framework Convention on Climate Change
USAID	-	United States Agency for International Development
US$	-	American Dollars
WB	-	World Bank
WHO	-	World Health Organization
VRE	-	Variable Renewable Energy
VSC	-	Voltage Source Converter

INTRODUCTION

This Long-Term Generation Expansion Plan (LTGEP) 2022-2041 is prepared at a time electricity systems world over are undergoing significant changes owing to the worldwide appetite to transit from the traditional fossil fuel-based generation that had dominated power systems for centuries, towards cleaner, environmentally friendly, natural forms of electricity. Considering the significant benefits and opportunities such transition could bring, not only to the Sri Lankan economy to relieve itself from imported fossil fuel dependency but also to the global environment to make economic development sustainable and go in harmony with environment, Ceylon Electricity Board (CEB) too had readily embraced such concepts as reflected in this Generation Plan.

Additionally, this plan has been prepared at a time the entire world is coming to terms with the worldwide Covid 19 pandemic, which is still ravaging and affecting world economies with no end in sight. Planning in such an environment is challenging as the final impact to economy and to the implementation of ongoing projects, are beyond even the most discerning estimates.

LTGEP 2022-2041 presents result of the generation expansion planning studies carried out by the Transmission and Generation Planning Branch of the Ceylon Electricity Board for the period 2022-2041. The report also includes information on the existing generation system, the generation planning methodology, system demand forecast and the investment requirement and implementation plans for the proposed projects. Out of different possible scenarios, the plan recommends the adoption of the most justifiable generation mix for the future (titled the "Base Case" plan). It also contains contingency analysis to prepare for possible contingency events in near term. Key actions and recommendations are separately presented at the end of this executive summary.

PLANNING THROUGH THE NEXT TWO DECADES

AT THE CROSSROAD FOR THE FUTURE

This Long-Term Generation Expansion Plan (This plan is known in the Sri Lanka Electricity Act as the Least Cost Long Term Generation Expansion Plan), a biennial publication prepared by Ceylon Electricity Board, outlines the generating capacity requirement of the power sector during the two decades ahead, to realise a secure and reliable, economical, sustainable supply of electricity, while adhering to the government policies and environmental obligations of the country. The planning window of this generation planning report extends to the fifth decade of the third millennium, and hence likely to witness the biggest changes to electricity systems since they first saw light of day in the late 19th century.

PATHWAY FOR A GRADUAL TRANSITION

Sri Lanka and the world is clearly at a crossroad, but taking their own individual pathways towards a global carbon neutral future. However, the journey towards such carbon neutral future must be made carefully, as synchronous power systems that had existed unchanged for centuries due to certain specific attributes of them, cannot be replaced hastily with asynchronous systems due to the desire to go green, no matter how noble such desire is. A country must study its own specific characteristics, capabilities and, more importantly the limitations, before devising its own strategies based on such understanding to choose the right pathway and achievable, desirable milestone targets. Prematurely abandoning the development of thermal firm generating capacity[1] is not advisable unless the foreseen Renewable Energy development to take over such conventional firm generating capacity could be practically realised, and the grid support technologies are available and economical.

MAKE THE GRID "CARBON NEUTRAL READY"

This generation plan intends to take the country progressively, but steadily towards a greener future, but via a low carbon pathway initially. If a large proportion of renewable energy (RE) based generation is forced to planning studies, a corresponding reduction will be seen to conventional firm generating capacity in the plan to make way for such high RE additions. For an instance, since RE sources such as Solar PV has very low plant factors, a very high (MW) capacity of solar PV is required to be added, compared to the capacity of a conventional thermal plant required to provide the same energy. As a result, the real time supply demand (MW) balance could be affected when large MW capacities from such non-controllable sources are integrated. It is of utmost importance to develop sufficient firm capacity in the system in parallel to high RE development, to avoid any capacity shortages.

It is noted with interest that a number of innovative and emerging technologies, which when commercially available as mature, proven technologies could assist power systems to completely abandon the development of conventional technologies in favour of renewable sources at some point in future. However, until such enabling technologies are ready, and the prices are right and affordable to countries like ours, the best option is to opt for a gradual transition, but without shutting the doors for future introduction of renewables.

Thus, this generation plan has continued with the development of re-gasified Liquified Natural Gas (LNG) based thermal capacity to give the required firm capacity and to replace coal as a fuel. Depending on the readiness of enabling grid support technologies, development of the network infrastructure and the capacity of the country’s project development machinery to develop the required RE capacities, in successive generation plans, the thermal firm capacity could be progressively reduced to pave way for the gradual transition to RE and to the greener grid of future.

PLANNING FOR THE FIRST TEN YEARS, FACILITATING FOR THE NEXT TEN

This generation plan had attempted to fulfil the traditional role of a plan of stipulating the exact generation capacity requirement that is required to be developed in to realizable projects to meet the demand for electricity in the next ten years, while presenting a visionary outlook of the last ten years of the 20-year planning window. As things are changing rapidly, and rolling generation plans would be prepared once in two years to capture such changes in future, the generation schedule during the last ten years of the planning window (2032-2041) is expected to be considerably different to what can be envisioned with today's knowledge. Thus, this generation plan attempts to declare the capacity requirement for the first half of its planning window to meet the demand and to pave the way to achieve the sustainable future envisaged.

[1] Firm generating technologies are those that can provide a firm, non-varying power output at their generating terminals at the level requested by the system operators. Storage hydro power, conventional thermal technologies fall under this category. ORE technologies such as wind and solar outputs vary depending on the resource availability and are unable to be started/stopped, power output raised/lowered on the dispatch instructions of system operators and hence termed non-firm.

RESULTS OF THE PLANNING STUDIES

THE PLANNING APPROACH

CEB's long term planning approach throughout has been to conduct studies[2] in advance to explore different technological and fuel options available to be included to plans later, and when the time is right, technologically and economically to make the choice, to include those to the long-term generation expansion plans.

Similarly, when the cost of non-conventional renewable energy sources (also termed other renewable energy sources – ORE) was very high compared to thermal sources, widescale adoption of RE at such prices for 20-year contract periods was not facilitated in generation plans. However, when ORE prices started falling rapidly due to falling costs worldwide and low prices brought in due to competitive tendering adopted, CEB plans progressively increased the share of ORE in its plans in considerable amounts.

CHANGING ROLES OF FIRM AND NON-FIRM TECHNOLOGIES

The traditional planning approach has been to plan for a sufficient firm generating capacity to meet the demand and to meet other technical requirements of the system and, after developing such firm capacity base, absorb ORE based generation to the optimum level to supplement firm capacity and thereby meet policy obligations and other planning considerations such as fuel diversity and economics. However, with the April 2019 policy guidelines of the government, CEB was given a Renewable Energy Target to aim at by the year 2030 by the policy itself. As per clause 31 under the section "Environment", it is stated that; "*Subject to favourable weather conditions, country must progress with the vision to achieve 50% of electricity generated in 2030 from renewable sources including large-scale storage hydro and Non-Conventional Renewable energy"*. As RE share by 2030 is stipulated within the policy document itself, deciding the optimum RE/thermal mix via planning studies had to be replaced by taking the mix declared in the policies directly as input. Accordingly, the 2030 RE milestone target of 50% is now forced in to the plan as input and the planning studies were conducted to decide the firm capacity and grid support interventions that are required to accommodate the policy target and to address the ensuing technical impacts instead.

FLEXIBLE GENERATION

The plan proposes natural gas fired Internal Combustion (IC) Engine based generation technology as a solution to provide operational flexibility required to integrate higher proportion of RE. Additionally, the plan had also requested all future combined cycle power plants to be "*technically, operationally and contractually capable of being operated regularly between open cycle and closed cycle operations"* to provide operational flexibility, particularly when solar generation is high.

[2] Study for Energy Diversification Enhancement by Introducing LNG Operated Power Generation Option in Sri Lanka, 2010, Energy Diversification and Enhancement Project Phase IIA- Feasibility Study for Introducing LNG to Sri Lanka 2014, Pre-Feasibility Study for High Efficiency and Eco Friendly Coal Fired Thermal Power Plant in Sri Lanka 2014, Feasibility Study on High Efficiency and Eco-friendly Coal-fired Thermal Power Plant in Sri Lanka 2015, Project on Electricity Sector Master Plan Study in Democratic Socialist Republic of Sri Lanka 2018.

RENEWABLE ENERGY DESK

The plan also had identified other grid support interventions such as the early introduction of a "Renewable Energy Desk" to the system control centre to separately manage RE capacities that are going to be integrated in large proportions. Introduction of solar and wind forecasting too is mandatory to go with the RE Desk.

FUEL DIVERSITY

Recommended Base Case scenario of this report, facilitates large-scale introduction of renewable energy sources and introduction of natural gas based generation in place of coal to lower the carbon intensity. However, with such heavy dependency now placed on natural gas, the strategic diversity in the fuel supply needs to be separately ensured to protect electricity supply against internal and external vulnerabilities in LNG supply chains. The plan recommends that " *all-Natural Gas based power plants shall also have the dual fuel capability, including suitable fuel supply/storage arrangements locally for such secondary fuel, to ensure supply security in case of disruption to LNG supply"*.

DEVELOPMENT OF THE BASE CASE PLAN

DEMAND FORECAST

Electricity demand for the period of 2022-2046 was forecasted considering a combination of medium term and long-term forecasting approaches. Five-year sales forecast of CEB Distribution Divisions and LECO and time trend approach were used to determine the medium-term forecast. Econometric approach was used for long term forecast. The impact of the ongoing Covid-19 pandemic to the economy and reduction to the future electricity demand as a result has been considered in preparing the forecast.

Table E1 - Base Demand Forecast 2022-2046

Year	Demand		Net Loss*	Net Generation		Peak Demand
	(GWh)	Growth Rate (%)	(%)	(GWh)	Growth Rate (%)	(MW)
2022	16,741	5.8%	8.03	18,203	5.7%	2,967
2023	17,705	5.8%	7.97	19,238	5.7%	3,117
2024	18,725	5.8%	7.90	20,331	5.7%	3,276
2025	19,854	6.0%	7.83	21,541	6.0%	3,452
2026**	21,036	6.0%	7.77	22,808	5.9%	3,636
2027	22,286	5.9%	7.70	24,145	5.9%	3,852
2028	23,451	5.2%	7.63	25,390	5.2%	4,069
2029	24,692	5.3%	7.57	26,714	5.2%	4,282
2030	26,035	5.4%	7.50	28,146	5.4%	4,513
2031	27,438	5.4%	7.45	29,647	5.3%	4,755
2032	28,835	5.1%	7.40	31,139	5.0%	4,996
2033	30,301	5.1%	7.35	32,705	5.0%	5,249
2034	31,826	5.0%	7.30	34,332	5.0%	5,511
2035	33,445	5.1%	7.25	36,060	5.0%	5,790
2036	35,100	4.9%	7.25	37,844	4.9%	6,078
2037	36,792	4.8%	7.25	39,668	4.8%	6,372
2038	38,506	4.7%	7.25	41,516	4.7%	6,671
2039	40,255	4.5%	7.25	43,402	4.5%	6,975
2040	42,046	4.4%	7.25	45,333	4.4%	7,287
2041	43,859	4.3%	7.25	47,288	4.3%	7,602
2042	45,705	4.2%	7.25	49,278	4.2%	7,924
2043	47,590	4.1%	7.25	51,310	4.1%	8,252
2044	49,544	4.1%	7.25	53,417	4.1%	8,592
2045	51,597	4.1%	7.25	55,630	4.1%	8,950
2046	53,703	4.1%	7.25	57,901	4.1%	9,317
5 Year Average Growth	5.9%			5.8%		5.2%
10 Year Average Growth	5.6%			5.6%		5.4%
20 Year Average Growth	5.2%			5.2%		5.1%
25 Year Average Growth	5.0%			4.9%		4.9%

* 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 depending on the hydro thermal generation mix of the future

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

Demand for electricity in the country has been growing at an average rate of about 4.4 % per annum during the last fifteen years, while peak demand has been growing at a rate of 2.6 % per annum on average. However, during year 2020 demand contracted (by 2%, 300 GWh compared to 2019) due to COVID 19 pandemic. As per past experience, electricity demand usually makes a comeback following such short-term dips and make the correction later to follow usual growth trends again. As per demand projections, the growth is expected to continue at an average rate of 5.2% in the long run. The changes in daily electricity demand pattern reveals the trend of the day time demand is becoming prominent and is anticipated to surpass the night peak and become the dominant peak beyond 2026. However, due to large addition of embedded solar PV generation, such high day peak demand may not be seen at the transmission level.

THREE POLICY BASED SCENARIOS

As stipulated in the Generation Planning code, it is mandatory to adhere to the duly approved government policy issued under section 5 of the Sri Lanka Electricity Act when conducting planning studies. The current policy for the sector is contained in the document "The General Policy Guidelines in Respect of the Electricity Industry" as issued in April 2019. In addition, it was clear from various policy indications given by the government that the intention of the government is to develop a low carbon electricity supply system and gradually take the sector towards indigenous renewable sources and ultimately towards energy independency.

Thus, planning studies were conducted under three main separate scenarios, each of which fulfil the RE absorption target given in the General Policy Guidelines while aiming to achieve the high renewable, greener grid of future.

1. **Scenario 1**: In compliance to the fuel mix as given in the existing General Policy Guidelines issued in April 2019.

   Key attributes –

   Required diversity to be maintained to the fuel mix of the installed firm capacity to maintain energy security, namely, 30% from Coal, 30% from LNG, 25% from large hydro by 2030;

   To progress with the vision to achieve 50% of electricity from RE sources by 2030 under favourable weather conditions.
2. **Scenario 2**: Achieve 70% of electricity from low carbon sources by 2030, including a minimum of 50% from RE, and **maintain** 70% low carbon share up to 2041.
3. **Scenario 3**: Achieve 70% of electricity from low carbon sources by 2030, and **increase** the share of low carbon sources beyond 2030 by restricting Coal Power development.

The Table E2 below present the comparison of the long term expansion planning scenarios considered in this LTGEP 2022-2041.

Table E2. Summary of Planning Scenarios and Present Value cost

	Total Present Value Cost (MUSD)	Difference of PV Cost compared to reference scenario (MUSD)
Reference	15,924	
Scenario 1 *Current policy on Fuel Diversification*	16,147	223
Scenario 2 *70% Low Carbon by 2030 and maintaining the same beyond 2030*	16,276	352
Scenario 3 *70% Low Carbon by 2030 with restricting Coal power Development beyond 2030*	16,280	356
Scenario 4 *Cross-border Interconnection*	16,304	380

Considering the government's intention of developing a low carbon electricity system, considering the worldwide movement to low carbon intensity energy systems, considering small difference to total present value cost (PV) between the three scenarios as given in Table E2, and considering operational flexibility that needs to be maintained in generation to absorb high proportion of RE in future, Scenario 3 as depicted in Table E3, was adopted as the Base Case scenario to facilitate long term transition towards low carbon electricity system beyond 2030.

Table E3: Proposed Base Case 2022-2041

(To be referred in conjunction with conditions stipulated by PUCSL through letter in Annex 15)

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS [h] [i]	THERMAL CAPACITY ADDITIONS [a]	THERMAL CAPACITY RETIREMENTS [c][d]
2022	Solar 340 MW Wind 20 MW Mini Hydro 15 MW Biomass 14 MW ***Uma Oya HPP 120 MW*** ***Broadlands HPP 35 MW***	**250 MW Short Term Supplementary Power** [1]	-
2023	Solar 260 MW Wind 35 MW Mini Hydro 20 MW Biomass 4 MW	***130 MW New Gas Turbines at Kelanitissa*** [2] ***200 MW Open Cycle Operation of First 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***163 MW Combined Cycle Power Plant (KPS-2)*** [3]	**4x17 MW Kelanitissa Gas Turbines** [4] **163 MW Sojitz Kelanitissa Combined Cycle Plant** [3] **100 MW Short Term Supplementary Power**
2024	Solar 270 MW Wind 40 MW [5] Mini Hydro 10 MW Biomass 5 MW ***Moragolla HPP 31 MW***	***150 MW Steam Turbine Operation of First 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***200 MW Open Cycle Operation of Second 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya***	**150 MW Short Term Supplementary Power**
2025	Solar 260 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 20 MW [9]	***150 MW Steam Turbine Operation of Second 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***300 MW Lakvijaya Coal Power Plant Extension*** [7]	**4x15.6 MW CEB Barge Power Plant** [6]
2026	Solar 195 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW	**250 MW IC Engine Power Plant (Natural Gas) – Southern Region** [7]	**115 MW Gas Turbine (GT7)** [8] **4x17 MW Sapugaskande Diesel** **8x9 MW Sapugaskande Diesel Ext.**
2027	Solar 160 MW Wind 120 MW Mini Hydro 10 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant – Western Region (Natural Gas)** [7]	-
2028	Solar 170 MW Wind 120 MW Mini Hydro 10 MW Biomass 5 MW	**300 MW New Coal Power Plant - Foul Point** [7]	-
2029	Solar 160 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 30 MW [9] **Pumped Storage HPP 200 MW**	-	-
2030	Solar 170 MW Wind 130 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 50 MW [9] **Pumped Storage HPP 200 MW**	-	-

Table E3: Proposed Base Case 2022-2041

(To be referred in conjunction with conditions stipulated by PUCSL through letter in Annex 15)

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS (h) (i)	THERMAL CAPACITY ADDITIONS (a)	THERMAL CAPACITY RETIREMENTS (c)(d)
2031	Solar 190 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW **Pumped Storage HPP 200 MW**	-	-
2032	Solar 190 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW Gas Turbine Power Plant (Natural Gas)** [7] **100 MW Gas Turbine Power Plant (Natural Gas)** [7]	-
2033	Solar 180 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas) -Western Region**[7] **200 MW IC Engine Power Plant (Natural Gas)** [7]	**165 MW Combined Cycle Plant (KPS)** **163 MW Combined Cycle Plant (KPS-2)** **3 x 8.93 MW Uthuru Janani Power Plant**
2034	Solar 200 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW IC Engine Power Plant (Natural Gas)** [7]	-
2035	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas) – Western Region**[7] **200 MW Gas Turbine Power Plant (Natural Gas)** [7]	**300 MW West Coast Combined Cycle Power Plant**
2036	Solar 250 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW Gas Turbine Power Plant (Natural Gas)** [7] **100 MW Gas Turbine Power Plant (Natural Gas)** [7]	-
2037	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas)** [7]	-
2038	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**100 MW Gas Turbine Power Plant (Natural Gas)** [7]	-
2039	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas)** [7]	-
2040	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**250 MW IC Engine Power Plant (Natural Gas)** [7]	-
2041	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas)** [7] **100 MW Gas Turbine Power Plant (Natural Gas)** [7]	**300 MW Lakvijaya Coal Power Plant Unit 1**

GENERAL NOTES

a. All plant capacities (MW) shown are the **Gross Capacities**.

b. Conventional, firm capacity power plants are shown in bold text. Committed Power Projects are shown in italic.

c. Dates of all plant additions and plant retirements, (other than retirements of existing plants on PPA) as contained in the table are the dates considered for planning studies, and considered as added/retired at the beginning (as at 1st January) of the respective year. (For example, a generating capacity retirement indicated for year 2025 implies that the plant has been considered as retired from the 1st of January 2025). However, for existing power plants that are governed by Power Purchases Agreements (PPA), the actual retirement month/date as contained in the PPA were considered for studies.

d. Retirement dates of **existing** firm capacity plants are dates considered as **inputs** to planning studies. The ACTUAL retirement of all power plants is to be made after further evaluating the actual plant condition at the time of retirement, (including the availability of useful operating hours beyond the scheduled retirement date), and the implementation progress of planned power plant additions.

e. With the development of LNG supply infrastructure, the existing 300MW West Coast power plant and 165MW Kelanithissa Combined Cycle plant are expected to be converted to natural gas in 2024.

f. Considering the heavy dependency in future on liquefied natural gas as a fuel for electricity generation, all Natural Gas based power plants shall also have the dual fuel capability, including suitable fuel supply/storage arrangements locally for such secondary fuel, to ensure supply security in case of disruption to LNG supply.

g. All new natural gas based Combined Cycle Power plants should be technically, operationally and contractually capable of being operated regularly between open cycle and closed cycle operations.

h. Mini-hydro and Biomass annual capacity additions are not restricted to the planned capacities mentioned in the table. Higher capacity additions will be evaluated case by case.

i. Thalpitigala and Gin Ganga multipurpose hydropower plants are proposed and developed by Ministry of Irrigation and both these plants are considered as candidate power plants with no specific commissioning years at present.

SPECIFIC NOTES

1. - Technology of supplementary capacity can be opened for both Gas Turbine and IC engine technology. Fuel option can be specified as appropriate at the time of procurement for suitable fuels that has established supply chains and having regulated, transparent pricing mechanisms.
   - The 50 MW CEB owned diesel based IC engine power capacity shall be considered appropriately to meet a part of the short term supplementary power capacity requirement.
   - Short-term supplementary capacity requirement under different contingency events are assessed in the contingency analysis under chapter 13 of the LCLTGEP 2022-2041 report. Such requirements too shall be appropriately considered prior to initiating procurement.
   - Extension of the contracts of existing capacities could be considered as appropriate to meet short term requirement.

2. This power plant is required to have the special capability to carry out restoration of supply in case of an island wide power failure.

3. PPA of Sojitz Kelanitissa is scheduled to be expired in 2023, and to be operated as a CEB owned power plant from 2023 to 2033 after conversion to Natural Gas in 2024. It is indicated as " KPS-2" as a capacity addition.

4. Retirement date of the 4 x 17 MW Kelanitissa Gas Turbines are to coincide with the commissioning of the new 130 MW Gas Turbine Plants at the Kelanitissa to comply with local environmental emission regulations.

5. In addition, Mannar Stage II (100 MW) could be accommodated if development is carried out on fast track basis provided plant has wind forecasting and semi-dispatchable capability.

6. Decision to extend the retirement year of 4 x 15.6 MW Barge Power Plant until the end of year 2026 will be evaluated based on the cost of any refurbishments required for such an extension and the potential benefit of extending beyond the scheduled retirement year.

7. **As per letter ref. PUC/LIC/AP21/01 dated October 5, 2021 by PUCSL (Annex 15), development of coal power-based generation will not be carried out (despite appearing in base case). Other thermal capacity additions will be reviewed and revised in the next planning cycle to comply with the new government policy sent by Secretary, Ministry of Power.**

8. Retirement year of 115 MW Kelanitissa GT7 is extended until the end of 2025 on the basis of carrying out manufacturer recommended major scheduled maintenance work, along with any other essential maintenance required to keep the plant operational.

9. Additions of planned battery energy storage capacities are mainly to provide grid level support for renewable energy integration. The additions beyond 2030 will be re-evaluated based on the exact system requirement as well as the progress of the variable renewable energy development.

MEETING ENVIRONMENTAL AND CLIMATE CHANGE OBLIGATIONS

The 20-year development plan presented in this report meets all the environmental and climate change obligations of Sri Lanka during its 20-year planning horizon. In response to the climate change challenges, Sri Lanka too has taken several initiatives by introducing national policies, strategies and actions to mitigate the impacts. Sri Lanka, being a partner to COP21 Paris agreement on mitigation of global climate change induced impacts, presented its 1st Nationally Determined Contributions (NDC) in September 2016 to strengthen global efforts, expressing a commitment of 4% unconditional and 16% conditional reduction of GHG emissions compared to the business as usual (BAU) scenario of LTGEP 2013-2032 for the electricity sector. The country is currently planning to further enhance its commitments through the 2nd NDC submission for electricity sector, by unconditionally reducing GHG emissions by 5% and conditionally by 20% as compared to the BAU. The base case plan, once fully implemented, is expected to reduce the GHG emissions beyond 25% and thus is fully capable of meeting even the enhanced target.

RENEWABLE CAPACITY ADDITIONS

The planned RE capacity as contained in this plan for the period beyond 2030 is expected to be further enhanced in successive generation plans with consideration of progress of implementation and advancement in renewable energy and storage technologies. In the event of further increase to RE capacities beyond 2030, a corresponding reduction is expected from natural gas fired generating capacities. Replacement of conventional technologies need to be made gradually, and proportionately with the development of enabling grid support technologies and hence the generation mix beyond 2030 is expected to change significantly in favour of RE though cannot be quantified at this stage. The indigenous renewable energy based generation is to dominate in both capacity and energy terms throughout the planning period with a further 3,500 MW of additions envisaged by 2030 and 9,500 MW by 2040[3].

[3] As compared with actual RE capacity as at end of 2020

- **STORAGE HYDRO**

  Development of major storage hydro capacity is expected to be limited after completing the projects that are currently in the pipeline amounting to 186 MW (120 MW Uma Oya, 35 MW Broadlands and 31 MW Moragolla hydropower plants).

- **SOLAR PV**

  Capacity of Solar PV, is planned to be increased up to 2,024 MW by end of 2025 from a capacity of 425 MW (as at end 2020) under a mix of small to large scale developments. It is planned to increase solar capacity to reach 2,874 MW by end of 2030 and is to account for the largest share in the incremental RE capacity additions. Solar PV is expected to retain its dominant share throughout the 20 year planning period.

- **WIND**

  Installed wind capacity is planned to be increased up to 1,113 MW by end of 2030 and is expected to grow beyond 2030 at the same rate. Unlike solar PV, large scale wind projects are expected to dominate the wind development.

- **MINI HYDRO, BIO MASS**

  Moderate growth is expected from Mini-hydro and biomass resources within next twenty years. The plan had not placed any restriction to the mini hydro and biomass capacities to be added. Even though mini hydro is a non-firm technology, outputs of mini hydro plants are not intermittent to the same extent as solar and wind and hence much "grid friendly" than variable renewable energy (VRE) technologies such as solar and wind. Biomass is not a conventional technology but can be considered a firm generating technology. Thus, no restriction to the development of biomass and mini hydro is placed in this plan and hence such capacities could be developed beyond year-by-year capacities mentioned in the plan subjected to any local grid restrictions, if potential exist.

The total renewable energy capacity is planned to be increased from 2,427 MW as at end 2020 to 6,240 MW by end of 2030 and to 9,600 MW by end of 2040. The year-by-year renewable energy capacities in the plan are based on the study titled "Integration of Renewable Based Generation into Sri Lankan Grid 2021-2030" conducted by the Ceylon Electricity Board to investigate the technical and economic implications of renewable energy development dictated by the policy and to study the necessary enabling measures required for the successful renewable energy development program. The scale of wind and solar development envisaged in the LTGEP 2022-2041 will elevate the country to the level of nations having high proportion of electricity generation from RE and hence along with it the expected challenges too in not only developing but also operating and maintaining such a system.

THERMAL CAPACITY ADDITIONS

The plan proposes the development of 5,130 MW of Natural Gas & 600 MW of Coal based Generation[4] to ensure reliable and economic supply of electricity for the 20-year period. They are to come in different technologies such as Gas Turbines, Combined Cycle plants, Steam Turbines and Internal Combustion Engine (IC) technologies.

[4] Refer PUCSL letter in ANNEX 15. Development of new Coal capacity will not be carried out accordingly.

- **NATURAL GAS**

  A 1,480 MW capacity from natural gas fired technologies are to be added by the end of 2030. Additions beyond 2030 are predominantly to provide system flexibility that is required when operating with higher shares of renewable sources. The existing combined cycle plants that are operating on diesel/naphtha/furnace oil at present are expected to be converted to natural gas once supply of LNG/NG is established.

- **COAL**

  No coal power development has been identified beyond 2030 to enable the low carbon transition. The plan contains the already committed 300 MW extension to Lakvijaya coal plant and another solitary 300 MW coal identified to be developed in 2028[5]. These two coal plants will add the much-needed fuel diversity in the firm conventional generating capacity mix to ensure energy supply security.

GRID SUPPORT TECHNOLOGIES

A 600 MW capacity from pumped storage hydro and a further 100 MW from battery energy storage systems are planned to be developed within the first decade of the planning horizon to enhance the flexibility of the electricity system to integrate large amount of variable renewable energy sources such as wind and solar PV.

Pumped storage hydro, that typically has lifespans of over 50 years, is considered a long term grid support solution for the country. Battery too is a very promising technology with rapidly declining price trends. However, current battery technologies need to be replaced in much shorter cycles of 10-15 years and thus, will not help to achieve energy independence to the same extent as pumped storage hydro. Thus, a mixed solution is envisaged in the plan with pumped hydro as long-term solution.

Grid storage requirements as contained in the plan beyond 2030 will be further revised in successive plans depending on the development of technology and economics.

IMMEDIATE ACTION TO BE TAKEN

Timely implementation of following is mandatory to ensure adequate, economical and reliable supply of electricity in both near and long term.

1. 35 MW Broadlands Hydropower plant, 120 MW Uma Oya Hydropower plant and 31 MW Moragolla Hydropower plant
2. 130 MW New Gas Turbines at Kelanitissa to facilitate restoration of supply in case of an island wide power failure
3. Establishing the Floating Storage Regasification Unit (FSRU) and associated natural gas supply infrastructure
4. 2x350 MW LNG fired combined cycle power plants at Kerawalapitiya in 2023 and 2024

[5] Refer PUCSL letter in ANNEX 15. Development of new Coal capacity will not be carried out accordingly.

5. Conversion of existing combined cycle power plants to natural gas by the time natural gas supply is in place
6. 300 MW Lakvijaya Coal Power Plant extension project[6]
7. Wind and solar PV development in a mix of small to large scale development having monitoring and controlling facilities enabled at National System Control Centre
8. Renewable energy resource forecasting system in intra-hour, intra-day and day-ahead timeframes
9. Critical transmission infrastructure to evacuate power from planned near term power plants such as the 2nd 220kV cable between Kerawalapitiya and Colombo

RECOMMENDATIONS

Following are the main recommendations derived from the long term planning studies and it is imperative to take necessary measures by all the stakeholders of the electricity industry to fulfil these recommendations for a secure and reliable, economical, sustainable supply of electricity.

1. Project by project development order of renewable energy resources as provided in the plan, year by year, must be prioritized primarily on economics. Development cost, levelized cost of electricity, quality of the resource and cost of additional transmission infrastructure shall be considered during prioritization. Sufficient geographical staggering also to be maintained for solar PV to minimize grid impact due to cloud movement.
2. Amendment to the Grid Code to safeguard the grid against large RE additions.
3. Strategically minimize the contractual risk of LNG fuel supplies considering fuel price volatility, weather related uncertainties and additional uncertainties caused by renewable energy generation that affect the short term, seasonal and long term LNG requirement.
4. It is highly recommended to minimize the vulnerability of the natural gas supply and delivery infrastructure system minimizing the risks of any gas supply interruptions. Also, it is recommended to ensure the dual fuel capability, including suitable fuel supply/storage arrangements locally for such secondary fuel, to ensure electricity supply security in case of disruption to LNG supply considering the degree of dependency on liquefied natural gas based generating capacity.
5. Capacity shortage is observed in during 2022 and 2023 period due to the already delayed major power projects and maintaining adequate generation capacity is important during 2022 to 2023 to alleviate short term capacity shortages. A contingency analysis is presented in this report indicating the minimum capacity requirement to maintain minimum reliability under different risk events for the first five-year period. Exact capacity requirement shall be assessed through the short term situational analysis.
6. Implementation of the planned 3 x 200 MW pumped storage hydropower plant as a long term measure to enhance the flexibility and security of the system with high shares of renewable energy technologies Implementing the planned Pumped Storage Hydropower Plant performing necessary feasibility studies to enable the development of the planned wind and solar resources.

[6] Refer PUCSL letter in ANNEX 15. Development of new Coal capacity will not be carried out accordingly.

7. Timely implementation of planned flexible thermal power plants ensuring flexible performance by both technical and contractual terms to facilitate the integration of indigenous renewable energy technology. Development of the planned flexible power plants with emphasized flexible characteristics is important to facilitate the variable renewable energy integration.
8. Due to the intermittent and variable nature of VRE, the power system needs to have sufficient flexible power sources to ensure system stability and reliability. These flexible power plants should possess the fast start up, fast ramping and deloading capabilities to support the power system to manage the daily net load fluctuations typically seen with high VRE levels.
9. Reviewing the present operating reserve policy of the system operation with dynamic, upward and downward requirements to provide additional regulation for the planned renewable energy capacities.
10. Enhancing the grid support features of variable renewable energy projects including enhanced Ride through capabilities, Frequency Ramp Rate Control functions and it is recommended to periodically review and upgrade the existing interconnection and operating codes/regulations based on detailed studies and up-to-date industry practices.
11. It is recommended to streamline renewable energy development procedures to ensure faster implementation as well as strict compliance to interconnection codes.

CHAPTER 1
INTRODUCTION

1.1 Background

Ceylon Electricity Board (CEB), established by CEB Act, No. 17 of 1969 (as amended), has a statutory obligation under section 11 of the CEB Act to "*develop and maintain an efficient, coordinated and economical system of electricity supply for the whole of Sri Lanka*." In order to fulfil this legal obligation, CEB has been preparing Long Term Generation Expansion Plans for nearly four decades. Since power sector projects, both generation and transmission, has long gestation periods, it is important to identify and commence such development activities early in order to cater to the growing demand for electricity, to cater to retirement of existing generating assets and to construct and refurbish high voltage transmission network infrastructure. As a result, Generation Plans are prepared for a 20 year period ahead. They are also updated once in two years to capture any changes to the economic and social landscape of the country since the last plan, to adopt to changes to the electricity sector requirements, and to adjust and compensate to the progress of ongoing power and network infrastructure development projects.

Once a Long-Term Generation Expansion Plan is finalized, a corresponding Long Term Transmission Development Plan too is prepared to identify and commence the developments required in the transmission network to evacuate power from the existing and future generating plants and to cater to the growing demand for electricity. As the flow of power along transmission lines is dependent both on the location of power plants and geographical spread of forecasted demand for electricity, a Long-Term Transmission Development Plan cannot be prepared unless a corresponding Long term generation Plan is prepared first. Thus, the two activities are to be treated as complimentary.

With the enactment of the Sri Lanka Electricity Act, No. 20 of 2009 in April 2009, the electricity sector was brought under the regulatory purview of the Public Utilities Commission of Sri Lanka (PUCSL), established under the Public Utilities Commission of Sri Lanka Act, No. 35 of 2002. With such change in law, CEB was issued with a generation license, a transmission license and four distribution licenses, and the duty to "*ensure that there is sufficient capacity from generation plant to meet reasonable forecast demand for electricity"* was made a responsibility of the Transmission Licensee. Subsequently, with the enactment of the Sri Lanka Electricity (Amendment) Act, No. 31 of 2013 in August 2013, CEB, as the Transmission licensee, was required to prepare the Long Term Generation Expansion Plan, (referred to in the Act as Least Cost Long Term Generation Expansion Plan), "*indicating the future electricity generating capacity requirements determined on the basis of least economic cost and meeting the technical and reliability requirements of the electricity network",* and submit the same for the approval of PUCSL [1].

Generation expansion planning studies were carried out in order to develop the Long-Term Generation Expansion Plan as contained in this report. Such studies have considered the forecasted electricity demand growth, candidate generating technologies most suitable to provide the capacity requirement, environmental and climate change considerations including obligations of the country, and declared government policies in arriving at this generation planning report.

A typical generation planning exercise strives to add a balance between three main competing objectives, as illustrated in Figure 1.1

I. The security and reliability of electricity supply
II. Sustainability
III. Economics of supply and affordability

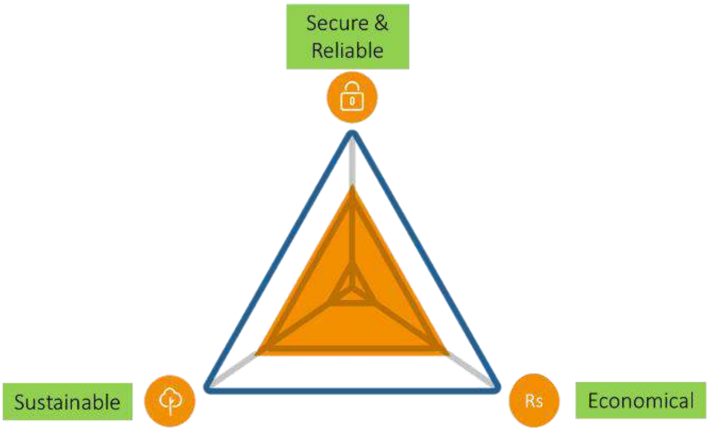


Figure 1.1 – Balance of competing objectives

Thus, this generation planning study is conducted to achieve a balance of all three as much as possible, while adhering to limits and targets specified for any of the above objectives by way of policy or by legal and regulatory requirements.

Accordingly, the planning studies carried out were based on the reliability criteria as published by the PUCSL in the Government Gazette No 2109/28 dated 2019-02-28 [2], a requirement under section 43(8) of the Electricity Act, and the electricity sector specific government policy applicable as stated under section 5 of the Sri Lanka Electricity Act titled " The General Policy Guidelines in Respect of the Electricity Industry" [3]. In addition, studies have also considered directions given in the "National Energy Policy and Strategies of Sri Lanka" as published in the Government Gazette No 2135/61 dated 2019-08-09 [4] and policy guidance given by the government.

A generation planning study typically takes about ten months to be completed. Prior to planning studies, a comprehensive analysis is carried out to determine the renewable energy capacity that could be integrated into the expanding network. To coincide with the present planning window of 2022-2041, a similar study titled "Renewable Energy Integration Study 2022-2031" was initiated in June 2020, and was conducted by a specially appointed team comprising engineers from the two planning teams (generation planning and transmission planning), the System Control and Renewable Energy Development branch. Results of such study have been considered as valuable inputs in preparing this Long Term Generation Expansion Plan 2022-2041.

The planning studies conducted to produce this Long Term Generation Plan 2022-2041 have been carried out adhering to all the government policies that are binding on the sector as stipulated under the Electricity Act and has been duly issued to CEB, and the reliability criteria published by PUCSL. Any future change to government policy and reliability criteria will be appropriately considered during the next planning cycle 2024-2043.

The planning methodology, planning criteria and policy framework is explained in detail in the chapter 6 of this report. The primary objectives of the generation planning studies conducted by CEB are,

(a) To project the national long term electricity demand forecast for next 25 years
(b) To identify the most suitable generating capacity mix and required grid support interventions to meet the forecasted demand for electricity at lowest economic cost while meeting the reliability requirements and meeting the declared sector specific policies of the government as required under law.
(c) To investigate techno economic feasibility of new alternate generating technologies to expand the generating system
(d) To prepare the capital investment program for the expansion of the generating system
(e) To investigate the robustness of the economically optimum plan by analyzing its sensitivity to changes in the key input parameters.
(f) To conduct scenario analysis to guide the government to consider different policy alternatives.

The information presented in this report has been updated to December 2020 unless otherwise stated.

1.2 Sri Lanka's Economy

The Sri Lankan economy did not exhibit a strong growth in real GDP during last six years (2015-2020). Due to the worldwide impact of Covid-19 pandemic, the economy encountered renewed challenges in 2020, further aggravating the situation. However, country's economy is expected to rebound according to the projections of the Central Bank of Sri Lanka. Nevertheless, the expected recovery and future economic growth trajectory contains a high level of uncertainty due to the still prevailing global pandemic. Thus, the same could also affect the forecasts made to electricity demand as contained in this report. Details of some demographic and economic indicators are given in Table 1.1.

Table 1.1- Demographic and Economic Indicators of Sri Lanka

	Units	2015	2016	2017	2018	2019	2020
Mid-Year Population	Millions	20.97	21.20	21.44	21.67	21.80	21.91
Population Growth Rate	%	0.9	1.1	1.1	1.1	0.6	0.5
GDP Real Growth Rate	%	5	4.5	3.6	3.3	2.3	-3.6
GDP /Capita (Market prices)	US$	3841	3886	4077	4079	3852	3682
Exchange Rate (Avg.)	LKR/US$	135.94	145.60	152.46	162.54	178.78	185.52
GDP Constant 2010 Prices	Mill LKR	8,647,833	9,035,830	9,359,147	9,665,379	9,883,350	9,530,606

Source: Annual Report 2020, Central Bank of Sri Lanka

1.2.1 Electricity and Economy

Historical electricity demand growth rate has shown to hold a direct correlation with the growth rate of the country's economy. Figure 1.2 shows the yearly growth rate of electricity demand and that of GDP from 2000 to 2020.

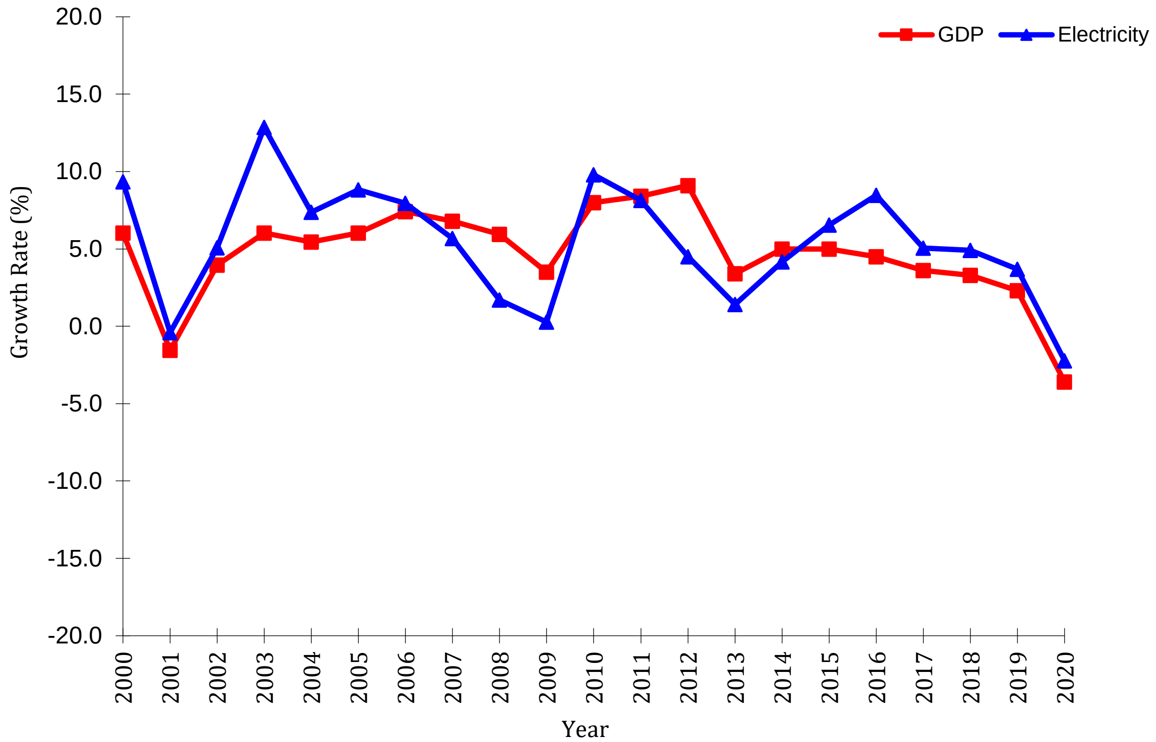


Figure 1.2 - Growth Rates of GDP and Electricity Sales

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 ahead, as published in the Annual Report 2020 [5]and Annual Report 2019 [6] as reproduced in Table 1.2.

Table 1.2 - Forecast of GDP Growth Rate in Real Terms

Year	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*
2019 Forecast	1.5	4.5	6.0	6.2	6.5	
2020 Forecast		6.0	5.2	5.8	6.5	7.0

Source: Annual Reports 2019 & 2020, Central Bank of Sri Lanka

1.3 Sri Lanka's Energy Sector

Overall energy requirements of the country are ensured directly by primary energy sources such as biomass (fuel wood) and coal, or by secondary sources such as electricity and refined petroleum products. The Energy Flow diagram as published by the Sri Lankan Sustainable Energy Authority is given in Figure 1.3. The energy flow diagram clearly shows the types of primary energy sources entered to the supply chain, their transition to secondary sources such as electricity and finished petroleum products at the middle and how they have ended up at different sectors of the economy.

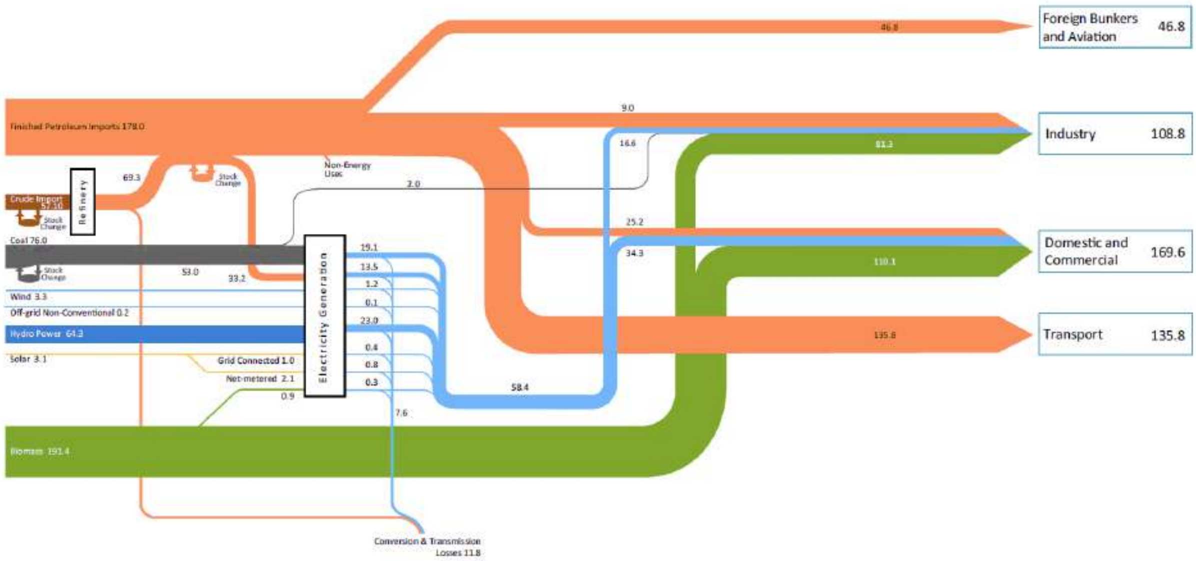


Figure 1.3 – Energy Flow Diagram (2018)

Source: Sri Lanka Sustainable Energy Authority

1.3.1 Energy Supply

The primary energy supply of Sri Lanka consists of biomass, petroleum, coal, major hydro and other renewable energy. The primary energy supply is dominated by biomass and petroleum.

By end of 2018, petroleum turns out to be the major source of energy supply, which covers a share of 40.2%. The country's petroleum supply is sourced through direct import of finished products and partly by processing imported crude oil. The only refinery in Sri Lanka, located in Sapugaskanda, converts imported crude oil to refined products to supply approximately half of the petroleum requirement of the country. There are also plans for expanding this refinery capacity.

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 Peninsula) 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.

Biomass or fuel wood, which is mainly a non-commercial fuel, provided approximately 36.2% of the country's total energy supply . Biomass is the most widely available source of energy supply in the country. Due to the abundant availability, only a limited portion of the total biomass use is channeled through a commodity market and hence the value of the energy sourced by biomass is not properly accounted.

Coal which is mainly imported for electricity generation accounted for 10.3% of the primary energy supply in year 2018.

Hydro power accounted for 9.7 % each from the total primary energy supply in year 2018. Hydropower is the main indigenous source of primary commercial energy in Sri Lanka. Estimated potential of hydro resource is about 2000 MW, of which significant resource 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.

Other renewable energy share accounted for 3.7% of total energy supply (wind, solar, biomass, small hydro) in year 2018. There is a considerable potential for wind and solar power development in the country. Steps have been initiated to harness the economical wind and solar potential in Sri Lanka in an optimal manner. The first commercial wind power plants were established in 2010 and the total capacity of wind power plants by end of 2020 was 179 MW. The first large scale wind farm was commissioned in Mannar island in 2020. The first commercial solar power plants were commissioned in year 2016 and the total capacity of commercial solar power plants by end of 2020 was 67 MW and nearly 347 MW of solar roof tops were also connected by end of 2020. 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 minor portion of the biomass supply is used for power generation thorough dendro, agricultural waste and municipal waste sources.

In 2018 the primary energy supply consisted of Biomass (4629ktoe), Petroleum (5144ktoe), Coal (1313ktoe), Hydro (1239ktoe) and other renewable sources (475ktoe). The share of these in the gross primary energy supply from 2009 to 2018 is shown in Figure 1.4.

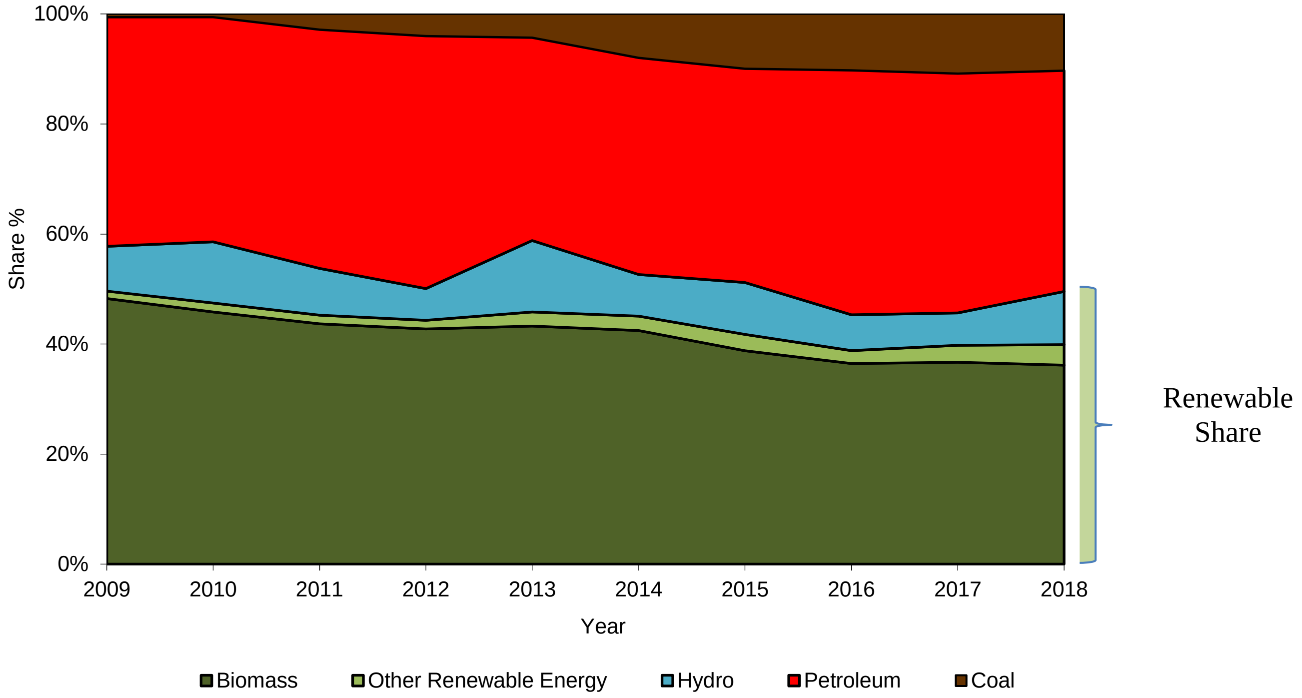


Figure 1.4 - Share of Gross Primary Energy Supply by Source

Source: Sri Lanka Sustainable Energy Authority

1.3.2 Energy Demand

The energy demand is classified based on its energy source in to four categories. These are Biomass, Petroleum, Electricity and coal. The largest use of Biomass is in the domestic sector for cooking purposes The total fossil fuel requirement of the country is for the transport, power generation, industry and other applications. In the past, the total demand for coal had been in the industries and railway transport sector. But with the commissioning of coal power plants in Norochcholai, 96% of the total coal imports have been used for electricity generation. The total energy demand by energy source over the recent past is shown in Table 1.3. The biomass, petroleum and coal demand figures presented are only in terms of final energy use and this does not include the fuels consumed in electricity generation.

Table 1.3 – Energy Demand by Energy Source

Year	Biomass		Petroleum		Electricity		Coal	
	PJ	%	PJ	%	PJ	%	PJ	%
2015	200.7	49.8	158.1	39.2	42.3	10.5	2.3	0.6
2016	194.3	45.7	183.2	43.1	45.8	10.8	2.1	0.5
2017	191.1	46.2	172.1	41.6	48.3	11.7	1.8	0.4
2018	191.4	46.2	170.0	41.0	50.8	12.3	2.0	0.5

The main sectors of energy demand can be categorized into Industry, Transport and household and commercial sector. The Sectorial energy consumption trend from 2009 to 2018 is shown in Figure 1.5. According to the above chart, household and commercial sector appears to be the largest sector in terms of energy consumption when all the traditional sources of energy are taken into account. However, it illustrates that it is moving through a decreasing trend while the Transport sector shows an increasing trend.

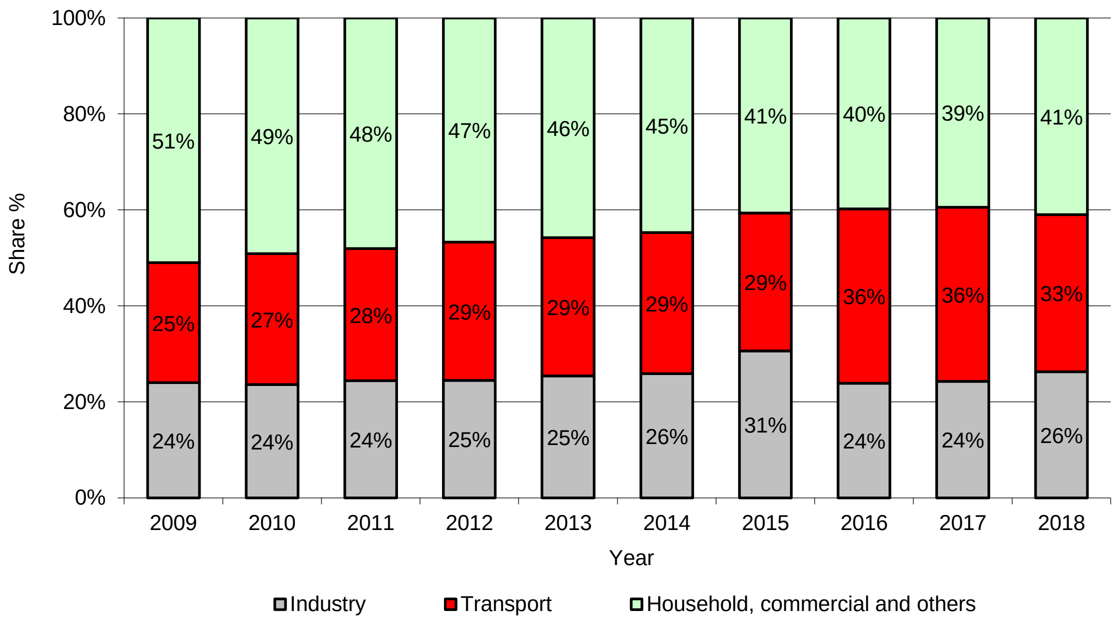


Figure 1.5 - Gross Energy Consumption by Sectors including Non-Commercial Sources

Source: Sri Lanka Sustainable Energy Authority

1.4 Electricity Sector

1.4.1 Global Electricity Sector

The global electricity demand has been growing at an average annual growth rate of approximately 3% during the last two decades. Over the past three decades, worldwide electricity demand has been predominantly supplied by fossil fuel based thermal generation. However, the contribution from indigenous renewable energy source is on the rise manly driven by the growth in solar PV and Wind resources followed by moderate growths in mini-hydro and biomass generation.

Due to the ongoing impact of the Covid-19 pandemic, global electricity demand is projected to fall by 2% and is forecasted to record its largest decline since the middle of 20th century. With the gradual recovery of the global economy, global electricity demand is expected to rebound, but starting with a modest growth in 2021.

Over the years, coal power generation remained the largest source of electricity generation, contributing to approximately 40% of electricity generated globally. There is an average annual growth of 3% in electricity generated using coal during the past two decades, which is equivalent to the global average annual growth rate for electricity. Natural gas based power generation is the second most predominant energy source at present having a share of 23% out of electricity generated. This share has been increasing from 17% (in 2000) to 23%, (in 2018), with a steady growth during past two decades. In contrast the global oil based power generation is following a steep decline and the percentage of electricity generation from oil has decreased from 8% (in 2000) to 3% (in 2018).

During the same time period the global nuclear power based generation remained at the same level. However, the nuclear energy share has declined from 17% to 10% of total electricity production as the shares of other resources increase. The total renewable energy generation worldwide, including large storage hydro power, has increased from 19%-26% during the period from 1999-2018. While the hydro energy share has roughly remained constant, the non-hydro renewable share has risen from 1.5% to 9.6%, owing to the rapid growth in solar and wind technologies. The annual electricity produced from solar has risen by 46% in past two decades while wind energy has risen by 25%.

World electricity generation during the last twenty years is summarized in Figure 1.6 and world electricity generation by source as a percentage is shown in Figure 1.7

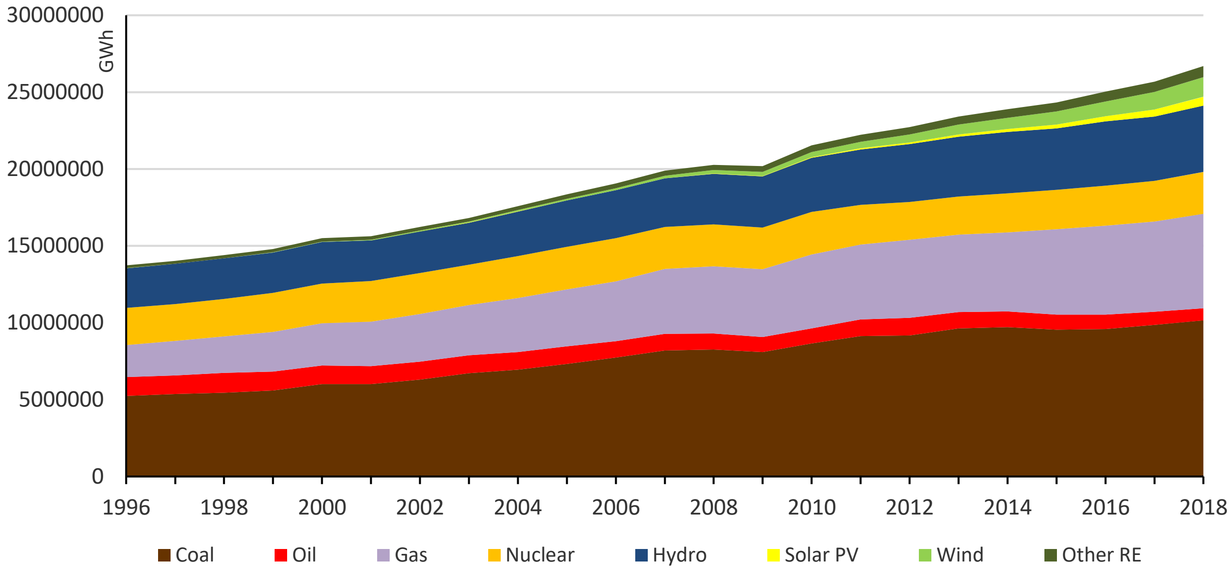


Figure 1.6 – World Electricity Generation(GWh)

Source: International Energy Agency Statistics

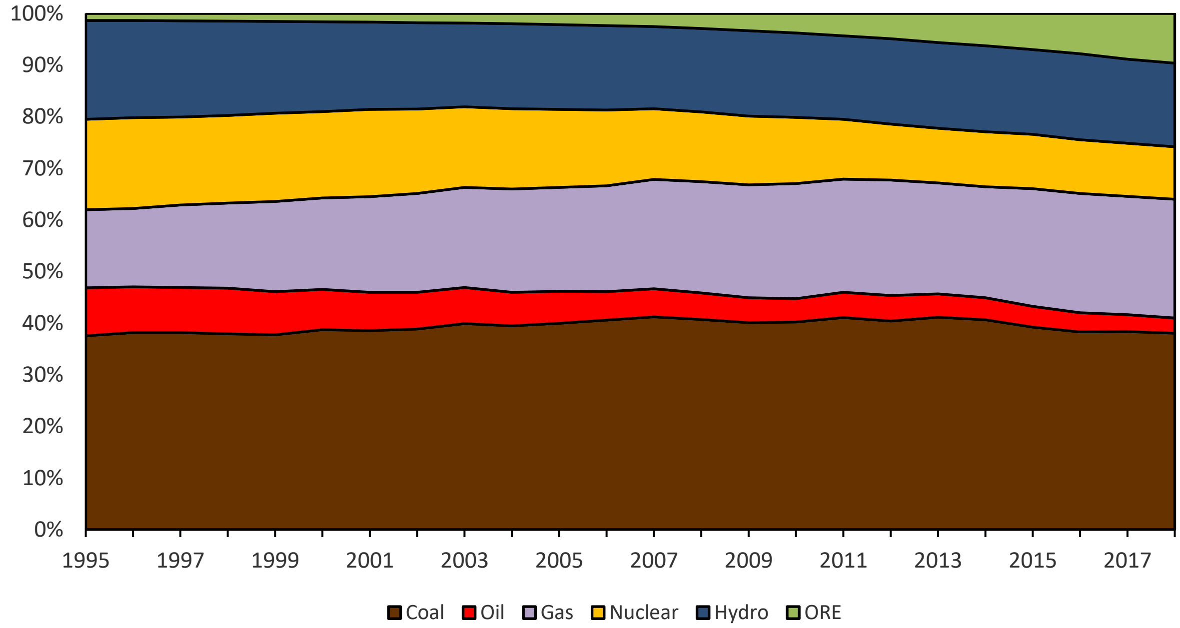


Figure 1.7 – World Electricity Generation by Source as Percentage

Source: International Energy Agency Statistics

1.4.2 Local Electricity Sector

1.4.2.1 Overview

The country's electricity demand has grown at an average rate or 5.7% during last five years. The maximum recorded peak demand to date of 2,717 MW was recorded in (month) 2020. Total net electricity generation in 2020 was 15,714 GWh. At the end of 2020, Sri Lanka had a total installed generating capacity, including rooftop solar, of (approximately) 4,615 MW. This included 2,447 MW of renewable energy based generating capacity and 2,168 MW of thermal capacity.

The renewable energy based generation capacity includes major hydro, mini hydro, solar, wind and biomass technologies and the thermal power generation fleet currently includes reciprocating engines, open cycle and combined cycle turbines and steam plants operated on imported fuel sources of coal and oil. However not all power plants have the capability of providing firm power and hence further sub categorized as dispatchable power plants and non dispatchable power plants. All thermal power plants are capable to operate as dispatchable power plants. The major hydro power plants are dispatchable but with constraints due to hydrological conditions and multipurpose usages while other renewable energy plants are inherently non dispatchable in nature. At present the total dispatchable generation capacity is 3551 MW while the balance of 1064 MW from ORE are non dispatchable.

Steps are underway to introduce natural gas to the primary fuel mix in the near future. With the introduction of natural gas, the thermal fuel mix is expected to be diversified even further. natural gas introduction is through the imported Liquefied Natural Gas (LNG) and establishing the necessary infrastructure is underway. A Floating Storage and Regasification Unit (FSRU) is planned to be established offshore at Kerawalapitiya. to provide regasified liquid natural gas to operate power plants at Kerawalapitiya and Kelanithissa.

With the introduction of a very high proportion of renewable energy based generation as included in this report, the fuel mix used for power generation is expected to be further diversified with a major shift from import dependent commercial fuels to indigenous sources.

1.4.2.2 Access to Electricity

Sri Lanka has achieved near 100% electrification by extending the transmission and distribution network throughout the country, thus providing access to electricity for every citizen. The transmission and distribution losses too were brought down gradually from 21.4 % in 2000 to 9.08 % in 2020.

However, the electricity network is required to be expanded continuously to cater to the growing demand for electricity and to relieve certain bottlenecks in the transmission network. In order to facilitate industrial growth, grid substation and transmission capacities are to be continuously enhanced and new generating capacity is to be added to facilitate the unhindered economic growth and development.

1.4.2.3 Electricity Consumption

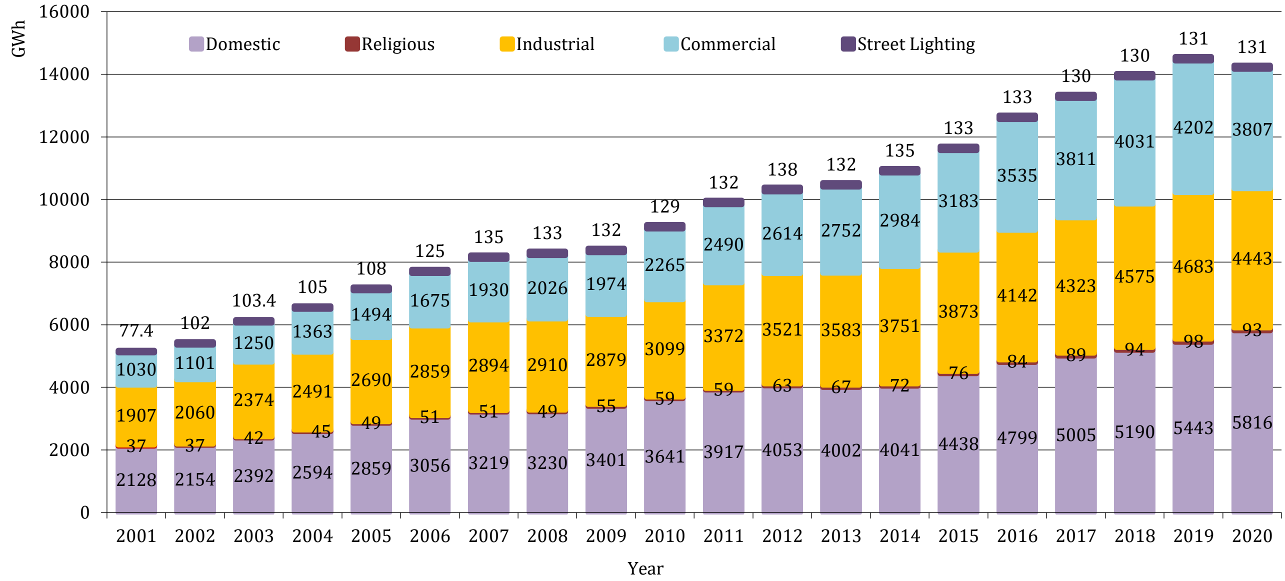


Figure 1.8 - Sectorial Consumption of Electricity (2001 - 2020)

The sectorial electricity consumption (tariff category wise) from 2001 to 2020 is shown in Figure 1.8 Figure 1.9 gives the share of sectorial electricity consumption in 2020. The combined consumption of the industrial and commercial sectors (commercial sector consist of the General Purpose, Hotel, Government tariff categories) is higher than domestic sector consumption, a favorable attribute for an economy with ambitious GDP growth projections. However due to the COVID pandemic, in year 2020 the combined electricity consumption of the industrial and commercial sectors has decreased, while the domestic sector consumption has increased.

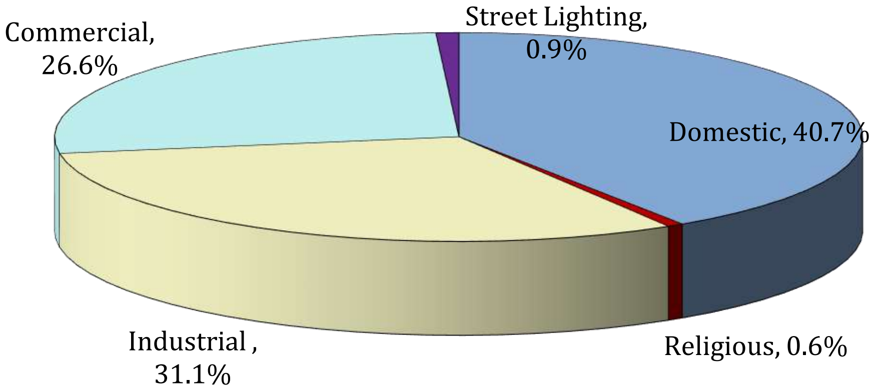


Figure 1.9 - Sectorial Consumption of Electricity (2020)

The average per capita electricity consumption in year 2020, was 652 kWh. This is a slight decrease to 670 kWh in 2019. The same has been generally rising steadily; except during the period 2007 to 2009 and during 2012 and 2013. Figure 1.10 illustrates the variation to per capita electricity consumption of Sri Lanka between 2001 to 2020.

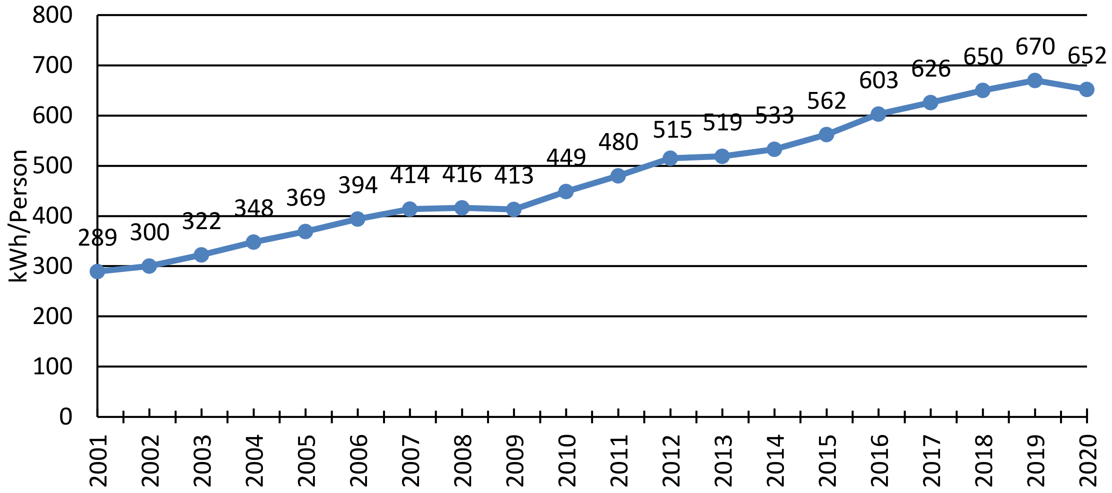


Figure 1.10 – Sri Lanka Per Capita Electricity Consumption (2001-2020)

1.4.2.4 Cost of Electricity

Low electricity price is an essential pre requisite to keep costs of production of both goods and services produced in the country low and hence be competitive in international markets. In order to keep the electricity prices low, it is mandatory to keep the electricity costs too low as artificially keeping the electricity tariffs at below costs is not sustainable and lead to wasteful use.

Both the fixed cost and the variable cost of producing and supplying a unit of electricity and losses decides the final cost of electricity supplied at end user level. The fixed cost component consists of the fixed generation cost, the costs pertaining to transmission and distribution of electricity, while the variable cost component is mainly determined by the cost of fuel used for thermal generation and variable energy charge paid to renewable sources. Due to different hydrological conditions, the cost of generating a unit of electricity could significantly vary over the years. The same also could be heavily impacted when market prices of imported fuels that are used to generate from thermal sources fluctuates. Generation planning studies are carried out to find the most economical technology mix under various hydrological conditions occurring in different probabilities.

Figure 1.11 illustrates how the actual cost of electricity (at selling point) has changed from year 2012 to 2020. It can be seen that unit cost of electricity at selling point has increased when expressed in local currency (Rs/kWh) but had remained stable when expressed in USDs (US Cts/kWh).

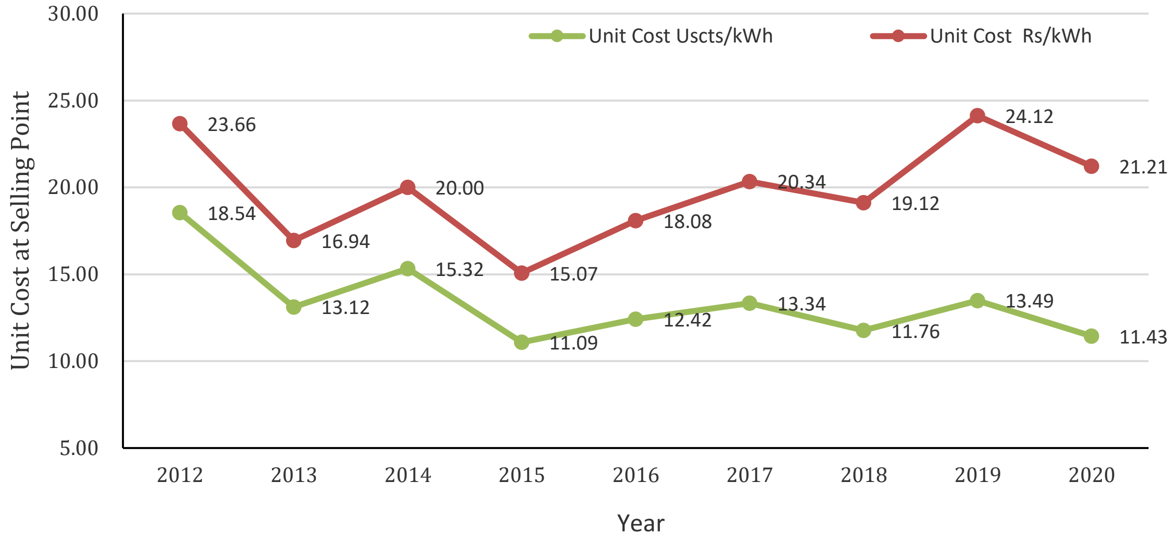


Figure 1.11 – Unit cost of Electricity (2012 -2020)

1.4.2.5 Electricity Demand and Supply

Sri Lanka's peak power demand for electricity has been growing at an average annual rate of around 3.4% during the past 20 years, and this trend is expected to continue in the foreseeable future. Country’s daily electricity demand profile has three distinguishable periods classified as the night peak, day peak and off peak. Though, the night peak records the highest electricity demand at present, the day time demand is expected to become prominent in years to come. The total installed capacity consists of both dispatchable and non dispatchable forms of generation sources. Ensuring adequate dispatchable capacity from both thermal and major hydro resources has become more important with the growing peak demand and the firm capacity shortfalls experienced in dry hydrological conditions. By the end of 2020, the total installed capacity was 4,612 MW including non dispatchable power plants (small hydro, wind, ground mounted and rooftop solar PV and biomass) of capacity

The growth of the installed capacity and peak demand over the last twenty years are given in the Table 1.4 and illustrated in Figure 1.12. (The rooftop solar installed capacity is excluded in Table 1.4 and Figure 1.12)

Table 1.4 - Installed Capacity and Peak Demand

Year	Installed Capacity (MW)	Capacity Growth (%)	Peak Demand (MW)	Peak Demand Growth (%)
2001	1,874	5.9%	1,445	2.9
2002	1,893	1.0%	1,422	-1.6
2003	2,180	13.2%	1,516	6.6
2004	2,280	5.6%	1,563	3.1
2005	2,411	4.2%	1,748	11.8
2006	2,434	0.9%	1,893	8.3
2007	2,444	0.4%	1,842	-2.7
2008	2,645	7.6%	1,922	4.3
2009	2,684	1.5%	1,868	-2.8
2010	2,818	4.8%	1,955	4.7
2011	3,141	10.3%	2,163	10.6
2012	3,312	5.2%	2,146	-0.8
2013	3,355	1.3%	2,164	0.8
2014	3,932	14.7%	2,152	-0.6
2015	3,850	-2.1%	2,283	6.1
2016	4,018	4.2%	2,453	7.4
2017	4,087	1.7%	2,523	2.9
2018	4,046	-1.0%	2,616	3.7
2019	4,217	4.1%	2,668	1.9
2020	4,265	1.1%	2,717	1.8
`Last 5 year avg. growth		2.01%		3.40%
Last 10 year avg. growth		3.93%		3.18%
Last 20 year avg. growth		4.22%		3.17%

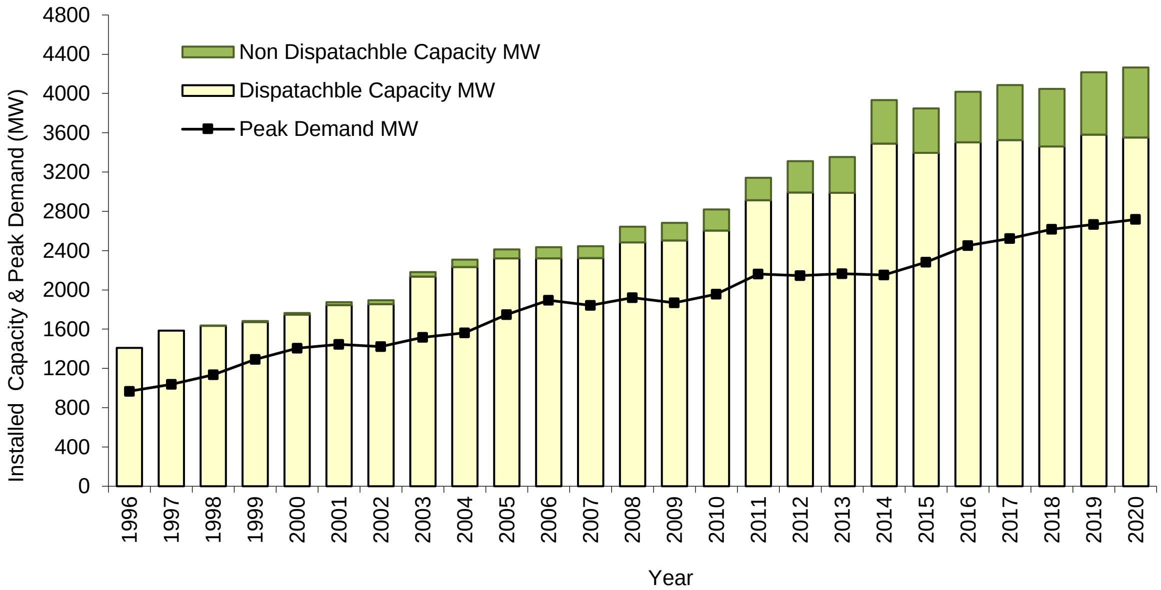


Figure 1.12 – Total Installed Capacity and Peak Demand

The Figure 1.13 below illustrates the past development of other renewable energy sources including Mini hydro, Wind, Solar PV and Biomass. Solar PV led the growth in capacity in recent years followed by wind capacities. Moderate growth recoded from Mini-hydro and Biomass Capacities

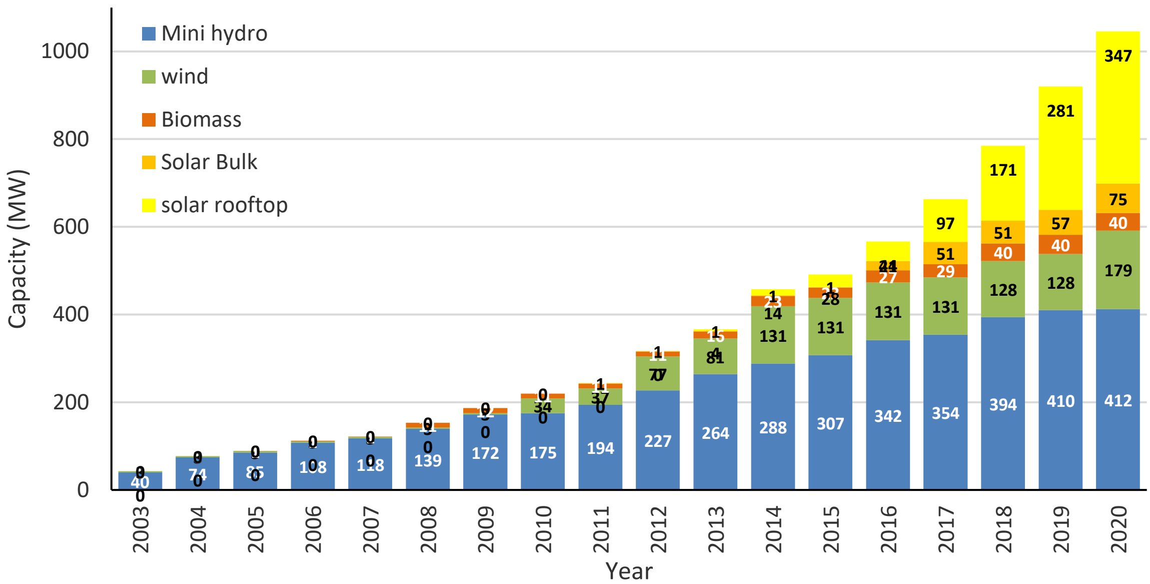


Figure 1.13 – Other Renewable Energy Capacity Development

Electricity generation of the country was predominantly 100% from hydropower until Mid-nineties. However, with the growth in electricity demand during the last 20 years and the limited potential to develop new large hydropower resources, the power generation mix in the country has shifted to a mixed hydrothermal system. Relatively high share of oil based power generation still exists in the present generation mix due to the growing demand, hydrological variations and delays in implementing other major power projects which has a significant impact on the cost of generation. In the year 2020, nearly 37% of the generation share came from coal based generation and another 37% came from renewable energy based generation. Electricity Generation during the last twenty-five years is summarized in Table 1.5 and illustrated in Figure 1.14.

Table 1.5 - Electricity Generation 1996-2020

Year	Hydro Generation		Other Renewable		Thermal Generation		Self-Generation & Small Islands		Total
	GWh	%	GWh	%	GWh	%	GWh	%	GWh
1996	3,233	72.0	3	0.1	1,102	24.5	152	3.4	4,490
1997	3,426	67.1	4	0.1	1,441	28.2	235	4.6	5,107
1998	3,892	69.1	6	0.1	1,620	28.8	114	2.0	5,632
1999	4,135	67.5	21	0.3	1,871	30.6	97	1.6	6,125
2000	3,138	46.3	46	0.7	3,437	50.7	158	2.3	6,780
2001	3,030	46.2	68	1	3,361	51.2	105	1.6	6,564
2002	2,575	37.4	107	1.6	4,074	59.1	136	2	6,892
2003	3,175	42	124	1.6	4,263	56.4	0	0	7,562
2004	2,739	33.8	208	2.6	5,051	62.3	115	1.4	8,113
2005	3,158	36.3	282	3.2	5,269	60.5	0	0	8,709
2006	4,272	45.9	349	3.7	4,694	50.4	0	0	9,314
2007	3,585	36.8	347	3.6	5,800	59.6	0	0	9,733
2008	3,683	37.5	438	4.5	5,697	58	0	0	9,819
2009	3,338	34	552	5.6	5,914	60.3	0	0	9,803
2010	4,969	46.7	731	6.9	4,948	46.5	0	0	10,649
2011	3,999	35.2	725	6.4	6,629	58.4	2.9	0	11,356
2012	2,710	23.1	736	6.3	8,280	70.6	1.4	0	11,727
2013	5,990	50.3	1,179	9.9	4,729	39.7	0	0	11,898
2014	3,632	29.5	1,217	9.9	7,466	60.6	0	0	12,316
2015	4,904	37.5	1,467	11.2	6,718	51.3	0	0	13,090
2016	3,481	24.6	1,160	8.2	9,507	67.2	0	0	14,148
2017	3,059	20.8	1,464	10	10,148	69.2	0	0	14,671
2018	5,149	33.8	1,715	11.2	8,390	55	2.4	0	15,257
2019	3,784	23.8	1,761	11.1	10,373	65.1	18.7	0.1	15,937
2020	3,911	24.9	1,866	11.9	9,933	63.2	4.2	0	15,714
Last 5 year av. Growth			6.2 %		10.1%				3.8%
Last 10 year av. Growth			11.6%		11.4%				4.0%
Last 20 year av. Growth			16.2%		7.9%				4.3%

Note: Rooftop solar self-consumption is excluded and rooftop solar (export) only included from year 2019 onwards.

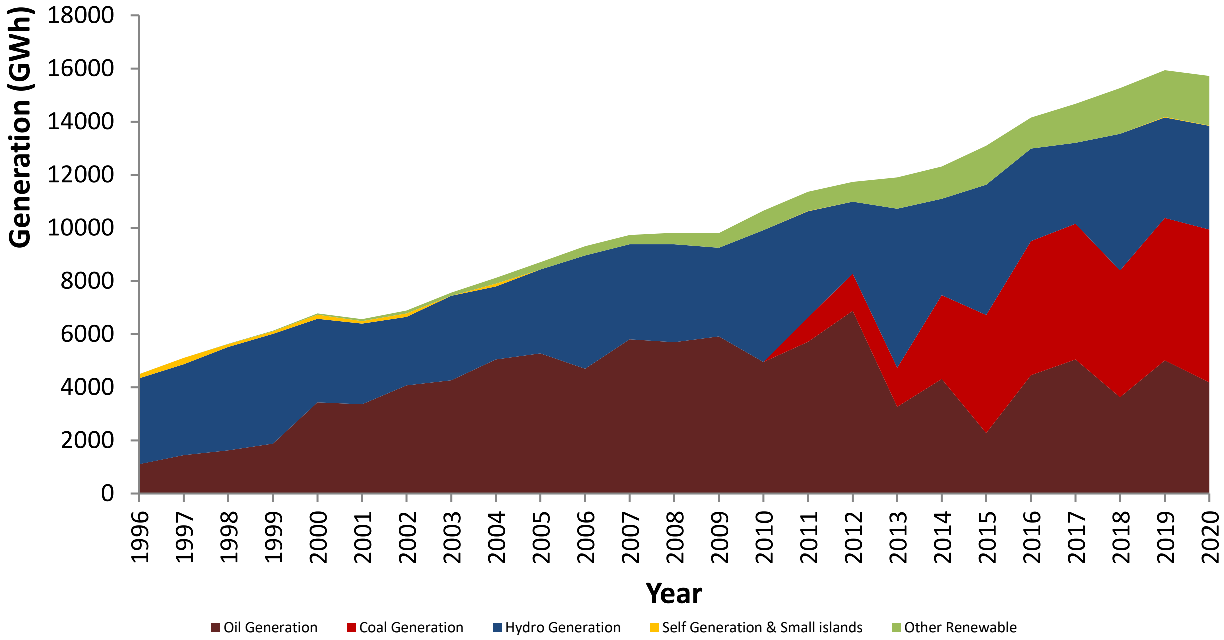


Figure 1.14 - Generation Share in the Recent Past

Sri Lankan electricity system has been able to maintain the total renewable energy share between 30%-60% during recent past. Major Hydro contribution has varied notably depending on the hydrological conditional and the other renewable energy share has been increasing steadily. The total renewable energy share varied over the past fifteen years are shown in Figure 1.15. This clean energy share is expected to increase further in the future with the planned renewable energy development.

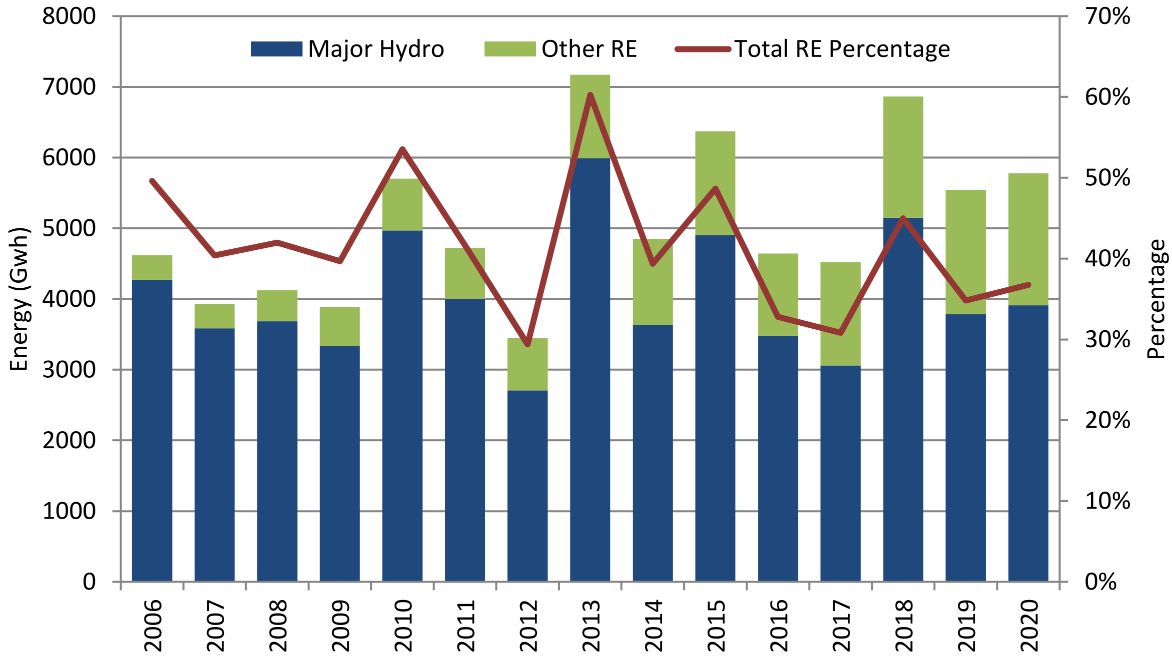


Figure 1.15 – Renewable Share in the Recent Past

1.5 Emissions

The total CO_2 emission of Sri Lanka in 2018 was 20.6million tons, which is only 0.06% of the total world CO_2 emissions. The absolute emission levels as well as the per capita emission levels of Sri Lanka remains low compared to the overall global average and when compared to many regional countries, countries having similar economies and with the developed world as tabulated in Table 1.6.

Table 1.6 - Comparison of CO_2 Emissions from Fuel Combustion

Country	kg CO_2/2015US$ of GDP	kg CO_2/2015US$ of GDP Adjusted to PPP	Tons of CO_2 per Capita	Total CO_2 Emissions (Million tons)
Sri Lanka	**0.23**	**0.07**	**0.95**	**20.6**
Pakistan	0.61	0.17	0.92	194.1
India	0.89	0.23	1.71	2,307.8
Bangladesh	0.34	0.12	0.51	82.0
Indonesia	0.54	0.16	2.03	542.9
Malaysia	0.65	0.24	7.23	228.0
Thailand	0.54	0.19	3.47	241.0
China	0.71	0.40	6.84	9,528.2
Japan	0.23	0.20	8.55	1,080.7
France	0.12	0.11	4.51	303.5
Denmark	0.09	0.11	5.53	32.0
Germany	0.20	0.17	8.40	696.1
Switzerland	0.05	0.06	4.20	35.7
United Kingdom	0.11	0.12	5.30	352.4
Russia	1.12	0.43	10.99	1,587.0
USA	0.25	0.25	15.03	4,921.1
Canada	0.34	0.33	15.25	565.2
Australia	0.29	0.32	15.32	382.9
South Africa	1.31	0.57	7.41	428.0
Qatar	0.51	0.26	30.95	87.0
Egypt	0.59	0.19	2.27	223.6
Brazil	0.23	0.13	1.94	406.3
World	0.41	0.26	4.42	33,513

Source: IEA CO_2 Emissions from Fuel Combustion (2020 Edition) [7] -2018 Data

Globally, electricity sector is the major contributor of CO_2 emissions out of total energy use or fuel combustion. However, in Sri Lanka, the transport sector is the largest contributor to emissions whereas electricity sector comes second. The sector wise contributions to emissions of Sri Lanka in the recent past is tabulated in Table 1.7 and sector wise comparison of CO_2 emissions of Sri Lanka and the world in 2018 is shown graphically in Figure 1.16.

Table 1.7 – Sri Lanka CO_2 Emissions in the Recent Past

Year	Overall CO_2 Emissions (Million tons)	Electricity Sector CO_2 Emissions (Million tons)
2013	13.74	4.04
2014	16.74	6.79
2015	19.5	6.8
2016	20.9	8.7
2017	23.1	9.9
2018	20.6	8.1

Source: IEA CO_2 Emissions from Fuel Combustion (2020 Edition) [7] -2018 Data

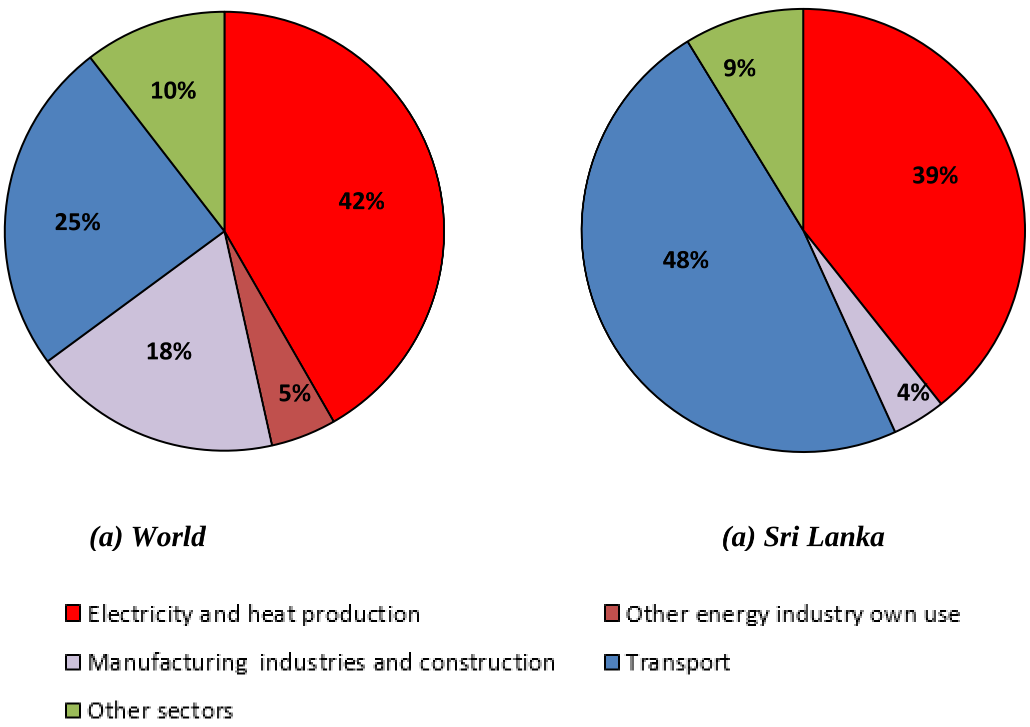


Figure 1.16 - CO_2 Emissions from Fuel Combustion 2020

Source: IEA CO_2 Emissions from Fuel Combustion (2020 Edition) [7] -2018 Data

1.6 Implementation of the Expansion Plan

After a long term generation expansion plan is prepared and approval is received, a corresponding long term transmission development plan is prepared for facilitating the transmission infrastructure for the anticipated generation expansion. The last generation plan that received the approval of the PUCSL was the LTGEP 2018-2037. Thus, the last transmission development plan that is available is the 'Long Term Transmission Development Plan 2018-2027', which was prepared in correspondence to the LTGEP 2018-2037. As no transmission development plan is available to commence transmission development beyond 2027, obtaining the approval to the generation plan 2022-2041, without delay, is critically important.

Since 2013, when the approval of PUCSL was made mandatory to Long Term Generation Expansion Plans, the three generation plans submitted for PUCSL approval had taken over 13 months for approval, due to varying reasons. The last LTGEP 2020-2039 could not obtain the approval even after 20 months, before it was completely abandoned and preparation of this new plan was commenced. As generation plans are prepared once in two years, and as preparation of a plan itself takes more than ten months, securing the approval within a reasonable time frame is important.

As per the Sri Lanka Electricity Act, a power plant cannot be added to the system unless the same is identified first in an approved LTGEP. As a result, if a power plant that is identified in an approved generation plan is cancelled due to some reason, another power plant cannot be brought to replace it unless it is included in a generation plan and approval is obtained. Further, as the grace period of large power projects is longer than their construction period, timely implementation of power plants as identified in LTGEPs is very important without canceling them.

Non implementation of expansion plans creates the risk of having non desirable levels of unserved energy as well as procurement of high cost supplementary power. Therefore, it is imperative to implement the low cost major power plants in time as planned to overcome capacity and energy shortfalls and to avoid detrimental impacts on the sector and on the economy.

1.7 Structure of the Report

The Long Term Generation Expansion Plan 2022-2041 consists of the following chapters as indicated in the Grid Code.

Chapter 2 Existing and committed generation system of Sri Lanka.
Chapter 3 The past and forecasted electricity demand and the forecasting methodology.
Chapter 4 Thermal Generating options for the future.
Chapter 5 Renewable Generating options for the future.
Chapter 6 Generation expansion planning guidelines, methodology and the parameters.
Chapter 7 Development of the Reference Case.
Chapter 8 Development of the Base Case and Sensitivity Analysis.
Chapter 9 Policy and Scenario Analysis.
Chapter 10 Environmental implications of the expansion plan.

Chapter 11 Recommendations of the Base Case Plan.
Chapter 12 Implementation schedule and investments for the generation projects.
Chapter 13 Contingency analysis.
Chapter 14 Comparison of this year plan with the previous plan.

CHAPTER 2
THE EXISTING AND COMMITTED GENERATING SYSTEM

This chapter presents an overview of the existing generating system of the country and the committed generation plants which would be connected to the system in the near future.

The existing generating system in the country is mainly owned and operated by CEB with a considerable share of recent additions 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 4,265 MW of installed capacity by December 2020 excluding rooftop solar PV installations which amounts to approximately 350 MW. A breakdown of the total installed capacity figure is presented in Table 2.1.

Table 2.1 –Composition of Total Installed Capacity of the System by December 2020

Ownership	Plant Type	Capacity (MW)
CEB	Hydro	1,383
	Thermal	1,554
	Renewables	31
Independent Power Producers (IPP)	Thermal	614
	Renewables	683

2.1 Hydro and Other Renewable Power Generation

Hydropower is the main firm renewable source of generation in the Sri Lankan 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, majority of 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 10 MW (termed mini hydro), are allowed to be developed by private sector as run-of-the-river plants and larger hydro plants are to be developed by the CEB. Since these run-of-the-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 12.80 US$/kW per annum.

(a) Existing System

The existing CEB generating system has a substantial share based on hydropower (i.e., 1,383 MW hydro out of 2,968 MW of total CEB installed capacity). Approximately 47% of the total existing CEB system capacity is installed in 17 hydro power stations and approximately 26% of the total energy demand was met by the major hydro plants in 2020. Details of the existing and committed hydro system are given in Table 2.2 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 353.8 MW (26% of the total hydropower capacity) have been built in Laxapana Complex where two cascaded systems are associated with the two main tributaries of Kelani River, Kehelgamu Oya and Maskeli Oya. 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 Maussakelle are the major storage reservoirs in the Laxapana hydropower complex located at main tributaries Kehelgamu Oya and Maskeli Oya respectively. Castlereigh reservoir with active storage of 52 MCM feeds the Wimalasurendra Power Station of capacity 2 x 25 MW at Norton-bridge, while Canyon 2 x 30 MW is fed from the Maussakelle reservoir of storage 108 MCM.

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 814 MW (59% of the total hydropower capacity). Three major reservoirs*, Kotmale, Victoria and Randenigala*, which were built under the accelerated Mahaweli development program, feed their respective power stations. The latest major power station in this system is 150 MW 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 (38 MW). After generating electricity at Ukuwela power station the water is discharged to Sudu Ganga, upstream of Amban Ganga, which carries water to Bowatenna reservoir. It then feeds both Bowatenna power station (40 MW) and mainly Mahaweli System-H by means of separate waterways. Water discharged through Bowatenna power station goes to Elahera Ela and is available for diversion to Mahaweli systems D and G.

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

Samanalawewa hydro power plant of capacity 120 MW was commissioned in 1992. Samanalawewa reservoir, which is on Walawe River and with active storage of 218 MCM, 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 70 MW in capacity and provides an average of 300 GWh of energy per year under average hydro conditions.

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

Mannar Wind Park is the first large scale wind power project developed in Sri Lanka. During the 1st stage, 103.5 MW of wind power was developed by CEB in the southern coast of the Mannar island which is expected to provide average 337 GWh of energy per year under average wind conditions.

(b) Committed Plants

The 35 MW Broadlands hydropower plant is the downmost Power plant in the Laxapana Complex and is located near the town Kithulagala. The dam site of the plant is located near Polpitiya power house and in addition to the main dam, there will be a diversion weir across Kehelgamu oya which diverts water to the main pond. The pond that feeds the plant has 0.198 MCM active storage and the plant is expected to generate 126 GWh energy per annum. It will be added to the system in 2021.

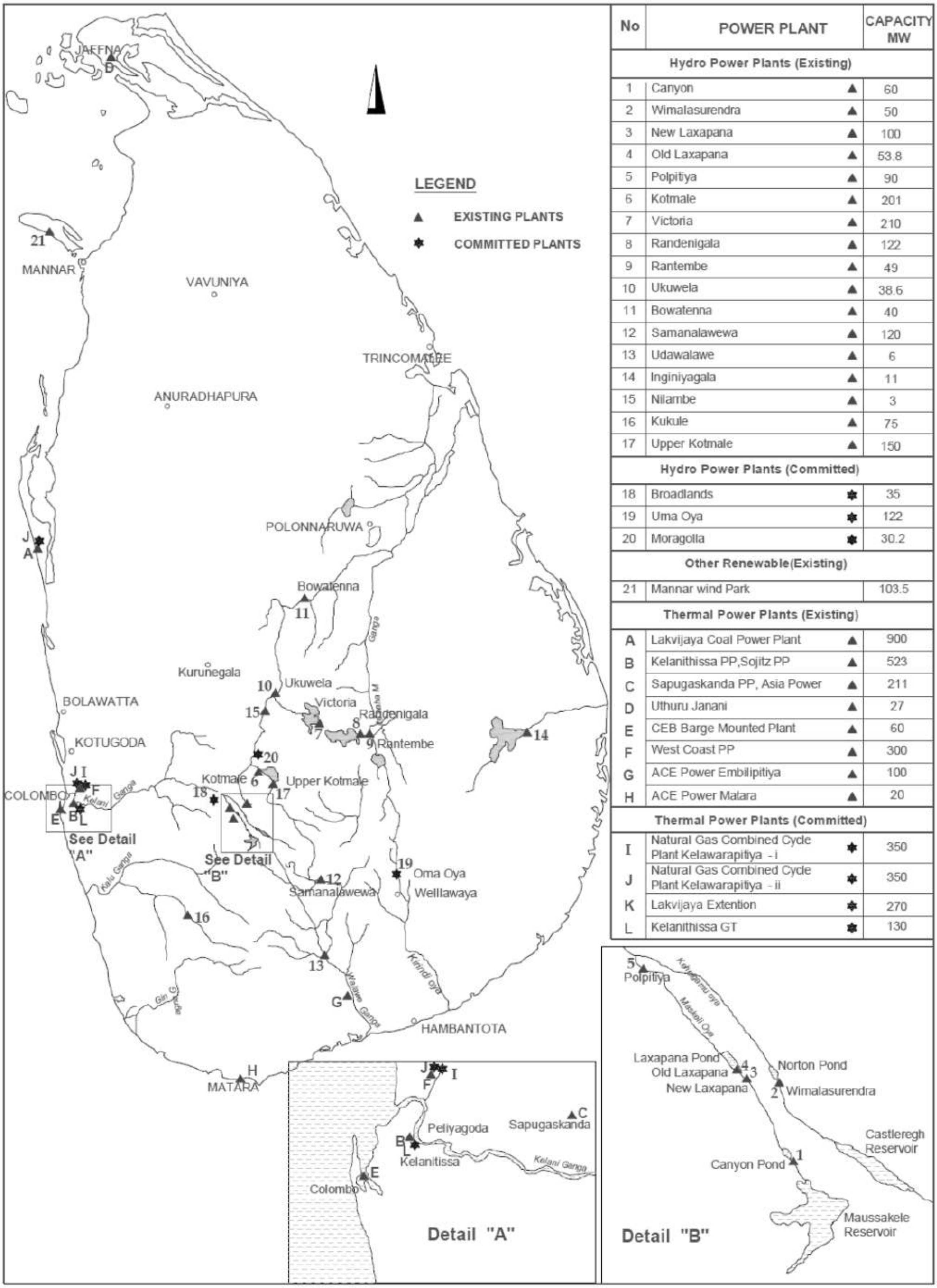
122 MW Uma Oya hydro power plant is to be operated as a part of the Uma Oya multipurpose hydro power project. Two small reservoirs are built close to Welimada where the water from these two reservoirs will be diverted through a tunnel to the underground power house located at Randeniya, near Wellawaya. This Power Plant is expected to generate 290 GWh of annual energy and the plant will be operational in 2021. This project is implemented by the Ministry of Mahaweli Development and Environment.

Moragolla Hydro Power project with a reservoir of 1.98 MCM active storage 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 30.2 MW and 97.6 GWh of mean annual energy. This plant will be added to the system in December 2023.

Table 2.2 - 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 (Maussakelle)	207.2	1983 - Unit 1 1989 - Unit 2
Wimalasurendra	2 x 25	50	112	47.93 (Castlereigh)	227.4	1965
Old Laxapana	3x 9.6+ 2x12.5	53.8	286	0.245 (Norton)	472.4	1950 1958
New Laxapana	2 x 50	100	552	0.629 (Canyon)	541	Unit 1 1974 Unit 2 1974
Polpitiya	2 x 45	90	453	0.113 (Laxapana)	259	1969
Laxapana Total		**353.8**	**1,563**			
Upper Kotmale	2 x 75	150	409	0.8	473	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 19.3	40	154	2.1	75.1	Unit 1&2–'76
Bowatenna	1 x 40	40	48	23.5	50.9	1981
Rantambe	2 x 24.5	50	239	3.4	32.7	1990
Nilambe	2 x 1.61	3.22	-	0.005	110	1988
Mahaweli Total		**816.22**	**2,667**			
Samanalawewa	2 x 60	120	344	218	320	1992
Kukule	2 x 37.5	75	300	1.67	186.4	2003
Small hydro		17.25				
Samanala Total		**212.25**	**644**			
Existing Major Hydro Total		**1,383**	**4,874**			
Committed Other Renewable						
Mannar Wind Park		103.5	337			2021
Other Renewable Total		**103.5**	**337**			
Committed Hydro						
Broadlands	2x17.5	35	126	0.198	56.9	2021
Moragolla	2x15.1	30.2	97.6	1.98	69	2024
Uma Oya (Multi-Purpose)	2x61	122	290	0.7	722	2021
Total		**290.7**	**850.6***			

Note: *According to feasibility studies



No	POWER PLANT		CAPACITY MW
	Hydro Power Plants (Existing)		
1	Canyon	▲	60
2	Wimalasurendra	▲	50
3	New Laxapana	▲	100
4	Old Laxapana	▲	53.8
5	Polpitiya	▲	90
6	Kotmale	▲	201
7	Victoria	▲	210
8	Randenigala	▲	122
9	Rantembe	▲	49
10	Ukuwela	▲	38.6
11	Bowatenna	▲	40
12	Samanalawewa	▲	120
13	Udawalawe	▲	6
14	Inginiyagala	▲	11
15	Nilambe	▲	3
16	Kukule	▲	75
17	Upper Kotmale	▲	150
	Hydro Power Plants (Committed)		
18	Broadlands	✸	35
19	Uma Oya	✸	122
20	Moragolla	✸	30.2
	Other Renewable(Existing)		
21	Mannar wind Park		103.5
	Thermal Power Plants (Existing)		
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	ACE Power Embilipitiya	▲	100
H	ACE Power Matara	▲	20
	Thermal Power Plants (Committed)		
I	Natural Gas Combined Cycle Plant Kelawarapitiya - i	✸	350
J	Natural Gas Combined Cycle Plant Kelawarapitiya - ii	✸	350
K	Lakvijaya Extention	✸	270
L	Kelanithissa GT	✸	130

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

2.1.2 Other Renewable Power Plants Owned by IPPs

Initially, Government of Sri Lanka has taken a policy decision to develop hydropower plants below 10 MW capacities through private sector participation. Many small hydro plants and other renewable power plants have been connected to the system since 1996. Apart from mini hydro power plants, during recent years, there has been a substantial increase in Wind and Solar additions to the system.

Total capacity of these plants is approximately 683 MW as at 31st December 2020. These plants are mainly connected to 33 kV distribution lines. The capacity contributions from other renewable sources are tabulated in Table 2.3.

Table 2.3: Existing Other Renewable Energy (ORE) Capacities

Project Type	Number of Projects	Capacity (MW)
Mini Hydro Power	210	409.5
Wind Power	17	148.45
Biomass	14	50.09
Solar Power	32	75.36

In this planning exercise, capacity and energy contributions from mini hydro plants and other non-conventional renewable energy plants are considered for analysis. The capacity additions were projected considering anticipated development of plants according to the current project pipeline records. The projected committed development used in this study is given and further explained in chapter 5.

In addition, total Rooftop Solar capacity of approximately 350 MW (both CEB and LECO) has been integrated to the system by 31st December 2020.

2.1.3 Capability of Hydropower Plants

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 are 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.

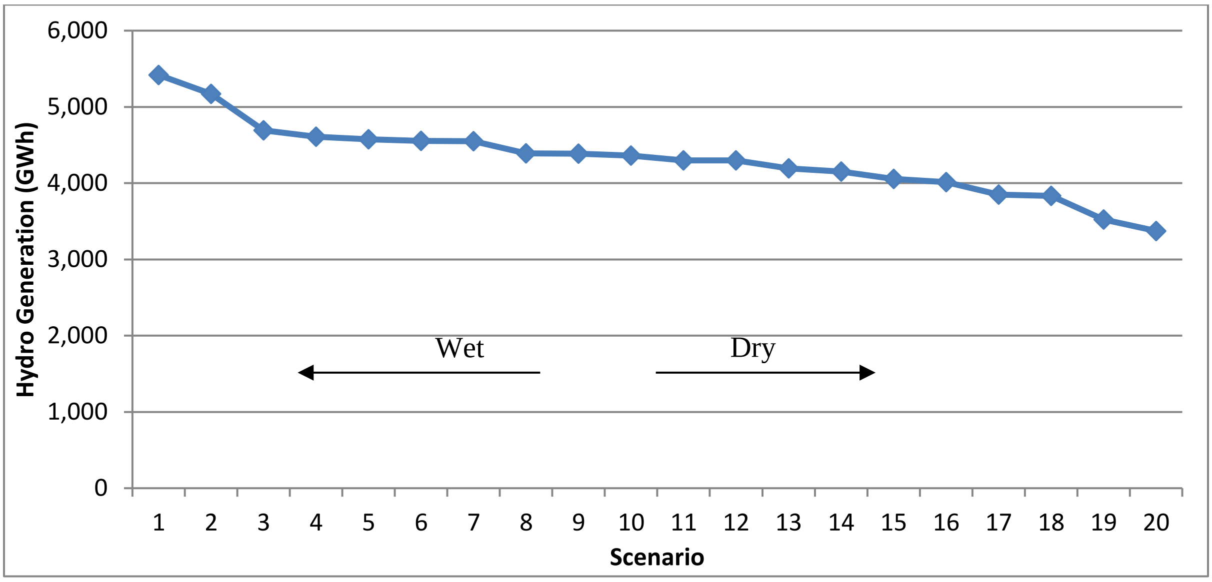


Figure 2.2 - Potential of Hydropower System from Past 20years Hydrological Data

The annual energy variation of the hydro system was evaluated using the Stochastic Dual Dynamic Programming (SDDP) model which is a hydrothermal dispatch model used for short, medium and long term operation studies. As inputs for the model, inflow data for past 20 years and the operational details of hydro plants were entered and the model allows a more detailed representation of the uncertainty of future inflows through the use of multiple scenarios in the time-coupled optimization. Based on SDDP simulation outputs, hydro generation figures for the existing plus new hydro plants are obtained and average annual hydro generation figures for 20 scenarios is shown in Figure 2.2. This shows that the capability of the major hydro system (Mahaweli, Laxapana and Samanala) together with new hydro power plants could vary as much as from around 3,100 GWh to 5,500 GWh. Long term planning exercise has been carried out using 20 scenarios while for short term operational studies up to 100 hydro scenarios have been simulated.

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 1,504 MW. It is made up of Lakvijaya Coal power plant of 900 MW, Kelanitissa Gas Turbines of 195 MW, Kelanitissa Combined Cycle plant of 165 MW, Sapugaskanda Diesel power plants of 160 MW, Uthuru Janani diesel power plant of 27 MW and Barge Mounted Plant of 64 MW. The Lakvijaya Coal plant 900 MW was commissioned in 2011 (Phase I) and 2014 (Phase II).

(b) Plant Retirements

For planning purposes, retirement dates of CEB owned existing thermal power plants are considered as indicated in Table 2.4. Plants' retirement is considered as at the beginning of the specified year. For instance, a generating capacity retirement in year 2025 indicates that the plant capacity will not be available after December 2024.

Table 2.4: Plant Retirement Schedule

CEB Power Plants	Year
1. KPS Frame5 GTs all units	2023
2. KPS GT7	2026
3. Sapugaskanda PS A (4 units)	2026
4. Sapugaskanda PS B (8 Units)	2026
5. Barge Mounted Power Plant*	2025
6. Kelanithissa Combined Cycle Plants	2033

* Provision of further extension beyond 2025 will be further studied.

Capacity and energy details of the existing and committed thermal plants are shown in Table 2.5.

Technical parameters and cost details of the existing thermal generation plants as input to the 2020 Expansion Planning Studies are summarized in Table 2.6.

Table 2.5 - Details of CEB Owned Existing 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	3x300	3x270	5355	2011& 2014
Puttalam Coal Total	**900**	**810**	**5,355**	
Kelanitissa Power Station				
Gas turbine (Small GTs)	4 x 20	4 x 17	382	Dec 81, Mar 82, Apr 82,
Gas turbine (GT 7)	1x 115	1 x 115	703	Aug 97
Combined Cycle	1x 165	1 x 161	1196	Aug 2002
Kelanitissa Total	**360**	**344**	**2,281**	
Sapugaskanda Power Station				
Diesel	4 x 20	4 x 17	493	May 84, May 84, Sep 84, Oct 84
Diesel (Ext.)	8 x 10	8 x 9	481	4 Units Sept 97 4 Units Oct 99
Sapugaskanda Total	**160**	**140**	**974**	
Other Thermal Power Plants				
Uthuru Janani	3 x 8.9	3 x 8.9	184	Jan 2013
Barge Mounted Plant	4 x 15.6	4 x 15.6	515	Acquired in
Containerized Emergency Power Plant	50 x 1	50 x 1		2019
Existing Total Thermal	**1,559.1**	**1,433.1**	**9,309**	

Table 2.6 - Characteristics of Existing 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
					Input Parameters for Studies				
Number of Units		4	1	1	4	8	3	3	4
Unit Capacity	MW	17	115	161	3 x 18 + 16	9	270	8.93	15.6
Minimum operating level	MW	17	80	100	11	7	162	8.93	15.6
Calorific Value of the fuel	kCal/kg	10,500	10,500	10,880	10,300	10,300	6,300	10,300	10,300
Heat Rate at Min. Load	kCal/kWh	4,200	3,620	2,127	2,276	2,136	Unit 1-2,767 Unit 2-2,691 Unit 3-2,615	2,164	2,132
Incremental Heat Rate	kCal/kWh	0	2,337	1,359	2,204	1,889	Unit 1-2,172 Unit 2-2,331 Unit 3-2,330	0	0
Heat Rate at Full Load	kCal/kWh	4,200	3,230	1,837	2,248	2,081	Unit 1-2,529 Unit 2-2,547 Unit 3-2,501	2,164	2,132
Fuel Cost	USCts/GCal	5,259	5,259	5,295	3,885	3,885	1,680	3,885	3,885
Full Load Efficiency	%	20	27	47	38	41	Unit 1-31 Unit 2-32 Unit 3-33	40	40
Forced Outage Rate	%	29	19	8	14.7	14.5	12	15	2
Fixed O&M Cost	$/kWmonth	3.14	0.18	1.93	2.70	2.70	1.13	1.81	0.95
Variable O&M Cost	$/MWh	0.81	0.75	2.22	2.50	1.41	3.35	3.48	5.13

Note: All costs are in January 2021US$ border prices. Fuel prices are based on Table 4.3 and 4.4 of Chapter 4. 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, other thermal Power Plants owned by Independent Power Producers that are connected to the national grid are given in Table 2.6.

Table 2.6 - Details of Existing and Committed IPP Thermal Power Plants

Plant Name	**Name Plate Capacity (MW)**	**Capacity used for Studies (MW)**	**Min. Guaranteed Annual Energy (GWh)**	**Commissioning**	**Contract Period (Yrs.)**
Independent Power Producers	163	163	-	GT- 2003March	20
Sojitz Kelanitissa (Pvt.) Ltd				ST –2003October	
	100	99.5	697	2005 April	10
ACE Power Embilipitiya Ltd*	24.8	20	167	2002 March	
ACE Power Matara Ltd*	51	50.8	330	1998 June	20
Asia Power Ltd*	300	270	-	2010 May	25
West Coast (Pvt)Ltd.					
Existing Total IPP	**638.8**	**603.3**			
Committed+	-	-	-		
NG fired Combined Cycle Power Plant 1 at Kerawalapitiya	350	350		2024	
135MW Gas Turbine Power Plants at Kelanitissa	135	135		2023	
NG fired Combined Cycle Power Plant 2 at Kerawalapitiya	350	350			
Lakvijaya Power Plant Extension	300	270			
Committed Total IPP	**1,135**	**1,105**	**-**		

Note:

+ Committed power plants are considered as the plants for which the project development phase has been initiated.

* Contracts of these power plants are scheduled to be terminated in April 2021.

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 4.4% per annum while peak demand has been growing at a rate of 2.6% per annum as shown in Table 3.1. The peak demand has grown at a rate of 2.6% during the last 5 years and energy demand has been growing at a rate of 2.8% per annum.

Electricity consumption of Sri Lanka has declined strongly after the national lockdown was enacted in March 2020 due to the COVID-19 pandemic situation. After relaxing of the restrictions in May 2020, electricity consumption showed positive and negative growth rates over the months compared to monthly consumptions of 2019. However, it is observed the decrease in total electricity demand in 2020 compared to 2019 with the growth rate of -2.2%. In 2020, net electricity generated to meet the demand amounted to 15,714 GWh (including rooftop solar energy contribution), which had been 15,922 GWh in 2019 with -1.3% growth rate and 11,353 GWh ten years ago. The recorded maximum demand within the year 2020 was 2,717 MW, which was 2,669 MW in year 2019 with 1.8% growth rate and 2,163 MW ten years ago.

Table 3.1 - Electricity Demand in Sri Lanka, 2006– 2020

Year	Demand* (GWh)	Avg. Growth (%)	Trans. & Distri. Losses (%)	Net Generation (GWh)	Avg. Growth (%)	Load Factor ** (%)	Peak (MW)	Avg. Growth (%)
2006	7,832	8.0	15.9	9,314	6.9	56.2	1,893	8.3
2007	8,276	5.7	15.0	9,733	4.5	60.3	1,842	-2.7
2008	8,417	1.7	14.3	9,819	0.9	58.3	1,922	4.3
2009	8,441	0.3	13.9	9,803	-0.2	59.9	1,868	-2.8
2010	9,268	9.8	13.0	10,649	8.6	62.2	1,955	4.7
2011	10,024	8.2	11.7	11,353	6.6	59.9	2,163	10.6
2012	10,474	4.5	10.7	11,725	3.3	62.4	2,146	-0.8
2013	10,624	1.4	10.7	11,898	1.5	62.8	2,164	0.8
2014	11,063	4.1	10.2	12,316	3.5	65.3	2,152	-0.6
2015	11,786	6.5	10.0	13,090	6.3	65.4	2,283	6.1
2016	12,785	8.5	9.6	14,148	8.1	65.8	2,453	7.4
2017	13,431	5.1	8.5	14,671	3.7	66.4	2,523	2.9
2018	14,091	4.9	8.3	15,374+	4.8	67.1	2,616	3.7
2019	14,611	3.7	8.2	15,922+	3.6	68.1	2,669	2.0
2020	14,286	-2.2	9.1 (a)	15,714+	-1.3	65.8	2,717	1.8
Last 5 year		2.8%			2.7%			2.6%
Last 10 year		4.0%			3.7%			2.6%
Last 15 year		4.4%			3.8%			2.6%

Note: *Gross units sold, **Load factor calculated on net Generation
+Including Rooftop Solar energy contribution, (a) Provisional
Based on the statistical data from CEB Statistical Digests & System Control Centre Annual Reports

Figure 3.1 shows a considerable decrease in percentage of system losses during 2000-2019. The major contribution towards this decrement is the decrease in Transmission & Distribution Losses. Figure 3.2 shows the System Load Factor variation over last 15 years. This was calculated based on net generation according the system data availability without calculating on load/demand side. After 2015, adjustment was done for the peak demand by adding respective mini hydro contribution and beyond 2018, net generation adjusted including rooftop solar contribution. All the above changes reflected in system load factor and overall improvement can be observed with 68.1% for year 2019 based on the Statistical Digest 2019 data.

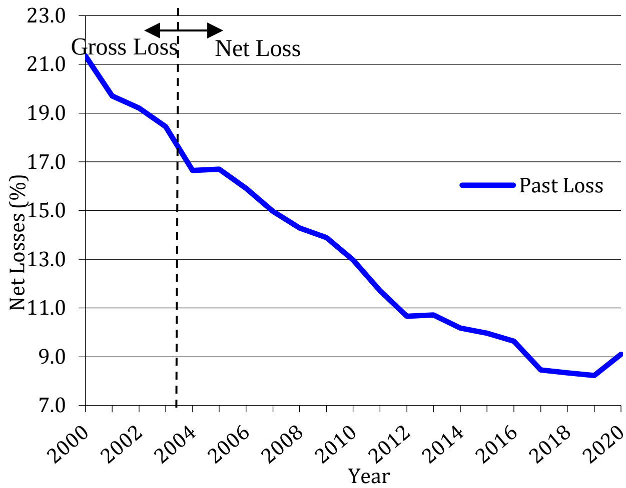


Figure 3.1 - Past System Loss

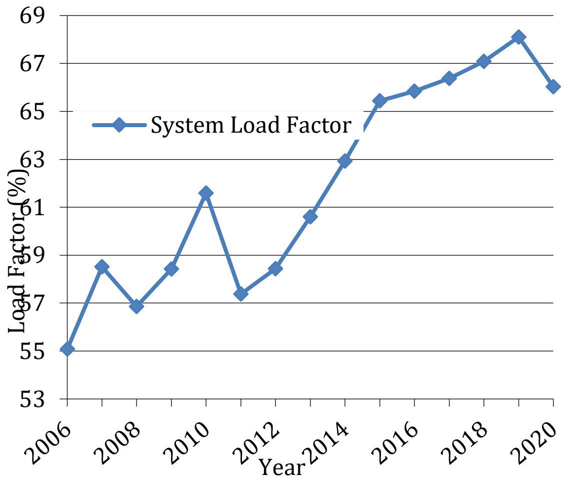


Figure 3.2 – Past Trend in the Load Factor

Figure 3.3 shows the country's daily load curve recorded on the day of annual peak for previous eight years. It could be observed that the shape of the load curve follows almost a similar pattern. However, significant growth in the day peak could be seen in last five years (2016, 2017, 2018, 2019 and 2020) compared to previous years. The system peak demand occurs generally from about 18.30 to 22.30 hours daily. The recorded maximum system peak is 2,669 MW in year 2019, while in year 2020 the peak is 2,717 MW.

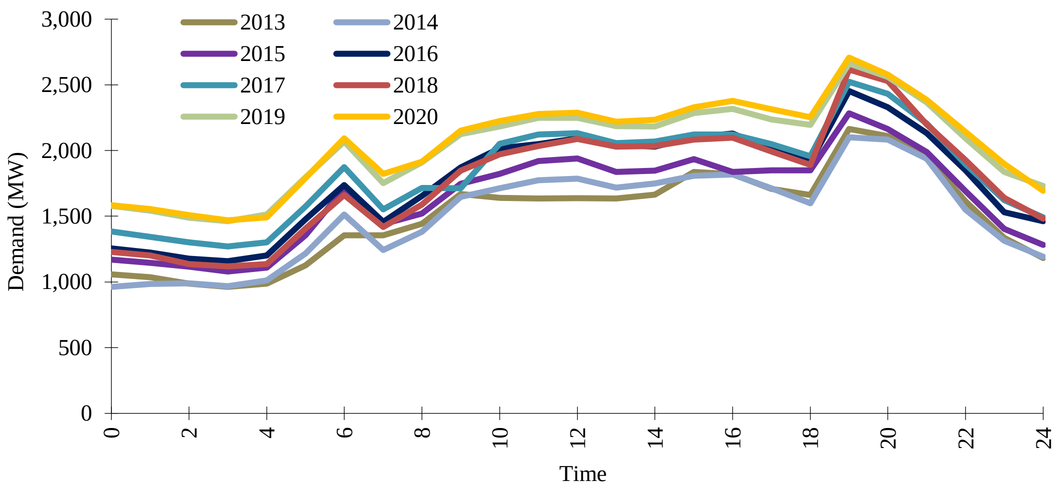


Figure 3.3 - Change in Daily Load Curve over Last Eight Years

Figure 3.4 shows the percentage consumption shares among different consumer categories from 1980 to 2019.In 2019, share of domestic consumption in the total demand was 37% while that of industrial and commercial sectors were 32% and 29% respectively. Religious purpose consumers and street lighting, which is referred as the other category, together accounted only for 2%. Similarly in 2010 (10 years ago), share of domestic, industrial, commercial and religious purpose & street lighting consumptions in the total demand, were 40%, 34%, 25% and 2% respectively.

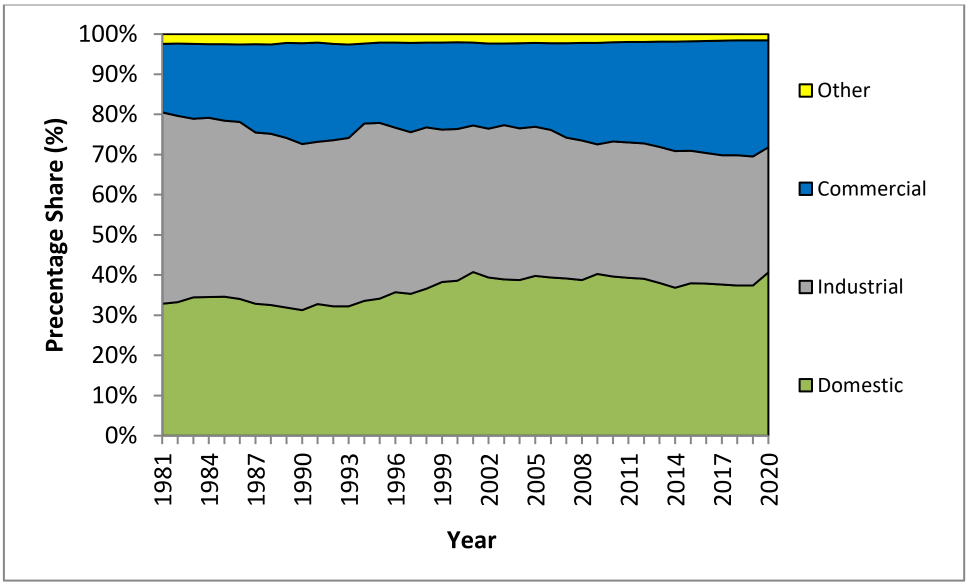


Figure 3.4 - Consumption Share among Different Consumer Categories

3.2 Policies, Guidelines and Information on Future Major Development Projects for Electricity Demand Forecast

3.2.1 Policies and Guidelines

The Electricity Demand Forecast 2022-2046 is prepared complying with the following policies and guidelines.

- Draft National Energy Policy and Strategies of Sri Lanka, August 2019
- General Policy Guidelines on the Electricity Industry for the Public Utilities Commission of Sri Lanka, June 2009 amended in March 2019
- Draft Generation Planning Code in the Draft Grid Code issued by the Transmission Division, Ceylon Electricity Board, August 2015

3.2.2 Information on Future Major Development Projects for Electricity Demand Forecast

The Government has proposed and planned for large scale developments which will lead to increase of electricity demand in the future. The major development plans are identified by Ministry of Urban Development, Water Supply and Housing Facilities. Currently, these developments are under different stages including feasibility study, planning and construction.

Some of the major development projects identified under Ministry of Urban Development, Water Supply and Housing Facilities can be listed as follows.

- Colombo Port City Development
- Western Region Light Rail Transit Project
- Solid Waste Management Project
- Metro Colombo Urban Development Project etc.

The Colombo Port City Development Project is a major development project in the load centre and cumulative electricity demand requirement is given as 75MW by 2022, 177MW by 2025, 313MW by 2030 and 393MW by 2040 with phase developments. For the Western Region Light Rail Transit Project, cumulative electricity demand requirement is given as 122MW by 2022, 131MW by 2030 and 139MW by 2035 and beyond.

According to the Ministry of Urban Development, Water Supply and Housing Facilities information, some of the planned projects were cancelled and some will implement with scope changes. Cumulative electricity demand requirement of other main development projects are indicatively estimated as 118MW by 2022, 260MW by 2030 and 290MW by 2040. In addition, Hambantota port development identified approximate power requirement of 500MW by 2040 and BOI zones with 105MW by 2025.

The Electricity Demand Forecast 2022-2046 was prepared considering the phase development of the above large scale projects. During the detail planning stages, it is required to identify the time based load requirement to determine the load pattern which would impact on actual electricity demand.

3.3 Demand Forecasting Methodology

A combination of medium term and long term forecast approaches has been adopted for the preparation of base demand forecast 2022-2046. Distribution Divisions five year sales forecast and time trend approach has been considered to determine the medium term forecast. For the long term, econometric approach has been adopted by analysing past electricity demand figures with significant independent variables.

For the medium term and long term analysis, past annual electricity demand was considered by adjusting annual electricity sales with power cuts (energy not served) and estimated rooftop solar self consumption.

In addition to the above, a number of demand forecast scenarios and sensitivities were prepared for the planning horizon. Accordingly, the End User Approach was adopted separately through MAED model as described in section 3.5. Analysis of end user energy demand is considered by identifying technological, social and economic driving factors in different sectors. In addition, other demand forecast scenarios and sensitivities are described in section 3.6.

3.3.1 Medium Term Demand Forecast (2022-2024)

Five year demand forecasts from the CEB Distribution Divisions and LECO were collected and considered for the medium term demand forecast. Additionally, sales forecast prepared for the period of 2020-2025 for the tariff filling also considered which adjusted with 2020 electricity sales reduction.

Time trend modelling based on the past five year electricity demand figures (2015-2019) has been developed and trend with 1 year lag was compared with all the forecasts as mentioned above.

Separate analysis was carried out with the historical electricity sales and growth rates and it was observed that electricity demand bounces back with higher growth rate after the years having unexpected demand drop. Accordingly, medium term demand forecast was developed with trend analysis reflect this bounce back phenomenon with average growth rate of 5.7% beyond 2022.

Accordingly, time trend forecast with 1 year lag was adopted for the medium term demand forecast by capturing recent reduced electricity demand caused due to the prevailing pandemic situation of the country [8].

3.3.2 Long Term Demand Forecast (2025-2046)

Econometric modelling was used for the long term demand forecasting from 2025-2046, giving due consideration to the electricity consumer tariff categories (multisector) and economic growth of sectors [8]. Separate models and forecasts were prepared for three main sectors Domestic, Industry and Commercial to comply with multi sector approach.

In the models, annual electricity demand (sales figures adjusted with energy not served and estimated rooftop solar self consumption) figures of the past were analysed against several independent variables as given in Table 3.2 using multiple 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	Gross Domestic Product	Gross Domestic Product	Gross Domestic Product	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 Gross Value Added	Agriculture Sector Gross Value Added	
	Previous year Domestic Consumer Accounts	Industrial Sector Gross Value Added	Industrial Sector Gross Value Added	
		Service Sector Gross Value Added	Service Sector Gross Value Added	
		Industrial Consumer Accounts	Commercial Consumer Accounts	
		Previous year Industrial Consumer Accounts	Previous year Commercial Consumer Accounts	

According to the Central Bank of Sri Lanka Annual Report 2019 and previous publications, sector wise gross value added and its percentage share to the total GDP were analysed for the period from 1978 to 2019. Base year was taken as 2019 and the percentage share for Industry, Services and Agriculture are 26.4%, 57.4% and 7.0% 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 three 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 three significant variables. Gross Domestic Product Per Capita, Domestic Consumer Accounts and Previous year Electricity Demand in Domestic consumer category were significant independent variables for the domestic sector demand growth. The econometric model is as follows, where t indicates years:

Ddom (t) = 32.4 + 0.58 GDPPC (t) + 0.16 CAdom (t) + 0.8 Ddom (t-1)

Where,

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

GDPPC (t) - Gross Domestic Product Per Capita (’000s LKR)
CAdom (t) - Domestic Consumer Accounts (’000s)
Ddom (t-1) - Previous year Electricity Demand in Domestic consumer category (GWh)

Industrial Sector

The significant variables for electricity demand growth in this sector are Industrial sector Gross Value Added (GVA), Industrial consumer accounts and previous year Electricity demand in Industrial consumer category. The econometric model is as follows, where t indicates years:

Di (t) = 57.86 + 0.26 GVAi (t) + 13.1 CAi (t) + 0.67 Di (t-1)
Where,
Di (t) - Electricity demand in Industrial consumer categories (GWh)
GVAi (t) - Industrial Sector Gross Value Added (’000 LKR)
CAi (t) - Industrial Consumer Accounts (’000s)
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 Gross Value Added and previous year Electricity demand in Commercial consumer category. 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 GVA was selected as the most significant variable in regression analysis. The econometric model is as follows, where t indicates years:

Dcom (t) = -76.55 + 0.11 GVAser (t) + 0.93 Dcom (t-1)
Where,
Dcom (t) - Electricity demand in Commercial consumer categories (GWh)
GVAser - Service Sector Gross Value Added (’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 using logarithm approach was performed to predict the demand in this sector.

ln (Dos (t)) = -97.25 + 0.051t
Where,
Dos (t) - Electricity demand in other sector consumer category (GWh)
t - Year

Trend Analysis for Long Term Electricity Demand Forecast

Post-model adjustments were made to account for potential impacts that were not captured in the long term models. Accordingly, to capture the recent trend variation of Domestic, Industrial and Commercial (General Purpose, Hotel and Government) sector demands, each sector has been separately analysed based on past electricity demand data and reflected in long term forecast. For the domestic sector past data is considered from 2012 to 2019 and for other two sectors past data considered from 2015 to 2019.

3.3.3 Cumulative Electricity Demand Forecast

Once the electricity demand forecast was derived based on the econometric approach adjusting with trend analysis for the main three sectors separately, forecasts of four sectors were added together to derive the demand forecast from 2025 to 2046. Cumulative electricity demand forecast 2022-2046 is the combination of medium term and long term approaches as described in section 3.3.

Net Loss Forecast

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.

Expected Transmission and Distribution loss of 7.50% in year 2030 and 7.25% in year 2035 was used in the planning 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. However, the actual losses would be vary depending on the generation combination of each year. 2019 system net loss was analysed considering energy contribution from Rooftop Solar PV connections, Self-Generation, Small Island Generation etc. and approximate value of 8.23% was taken as the base year value.

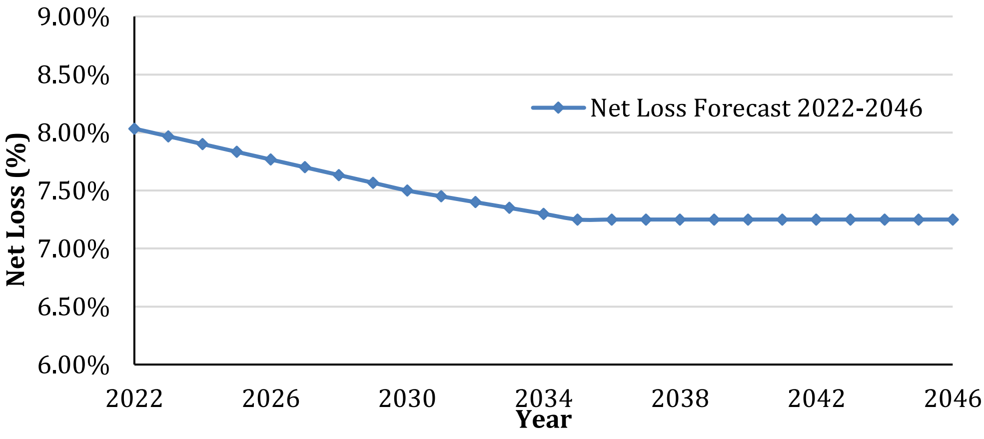


Figure 3.5–Net Loss Forecast 2022-2046

System Load Factor and Peak Demand Forecast

The System Load Factor which is illustrated in Figure 3.2 is calculated by including Other Renewable Energy (Mini hydro, Wind & Solar) in the past fifteen years and in 2019 it was 68.1% on net generation.

According to the analysis carried out by considering actual monthly records of the night peak, day peak and off peak from 2011 to 2019 for the whole country, it was observed that the night peak, day peak and off peak remains its increasing trends as shown in Figure 3.6 (a). It could be observed that the growth of day peak is higher than the growth of night peak specially in the recent five years by 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 daytime 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. In addition, growth of the off peak based on the past growth and trend with assumptions is considered for the future.

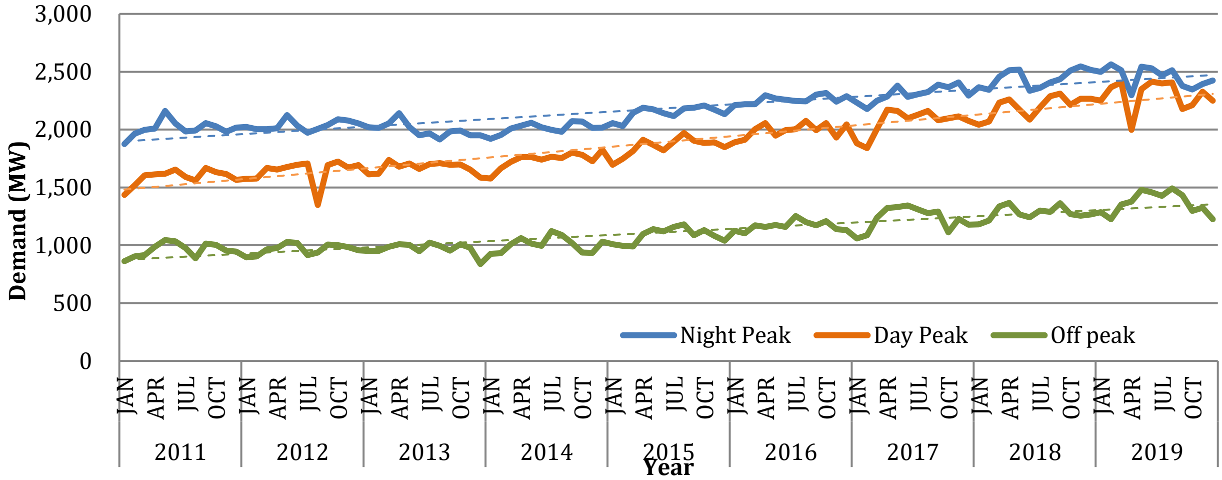


Figure 3.6 (a) – Analysis of Night peak, Day peak and Off peak Trends 2011-2019

According to the peak growth analysis, it was predicted that the crossover of the load profile shape would occur in 2026. Annual load profiles were determined for each year considering the ratios between peak to off peak, morning peak and night peak. Accordingly, the resultant normalised load profiles are shown in Figure 3.6 (b).

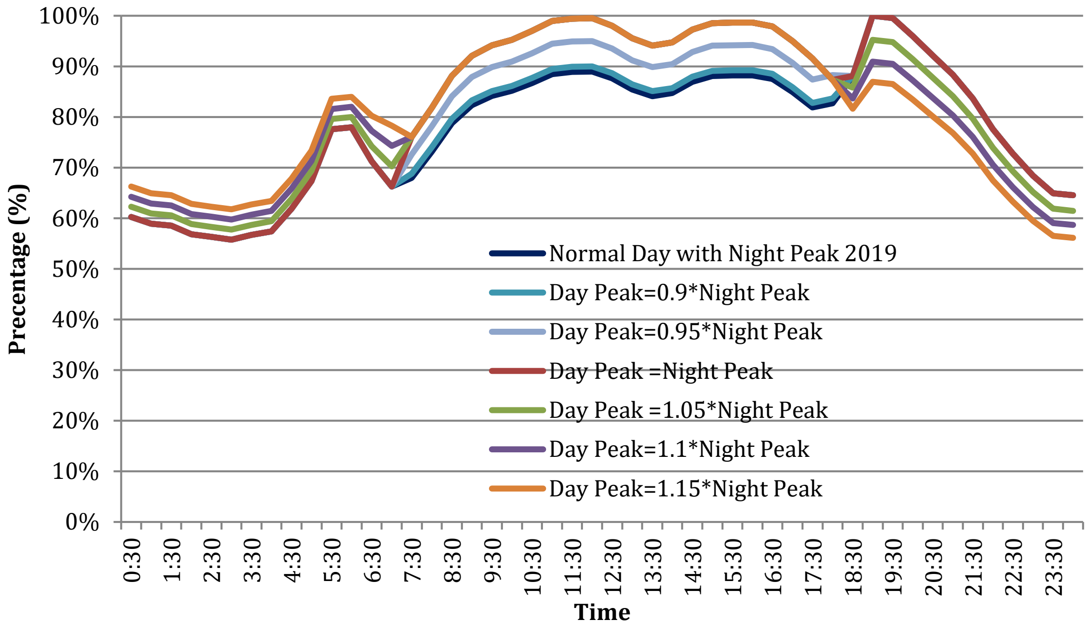


Figure 3.6 (b) – Load Profile Shape Forecast

It is assumed that the load factor becomes maximum in 2026. The forecast of annual load factor up to 2046 was done based on the analysis conducted with normalized load profiles considering the relationship between the ratio of the day and night peak demands and the load factor. However, demand 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 71.6% by 2026 and Figure 3.7 shows the system load factor forecast for the planning horizon.

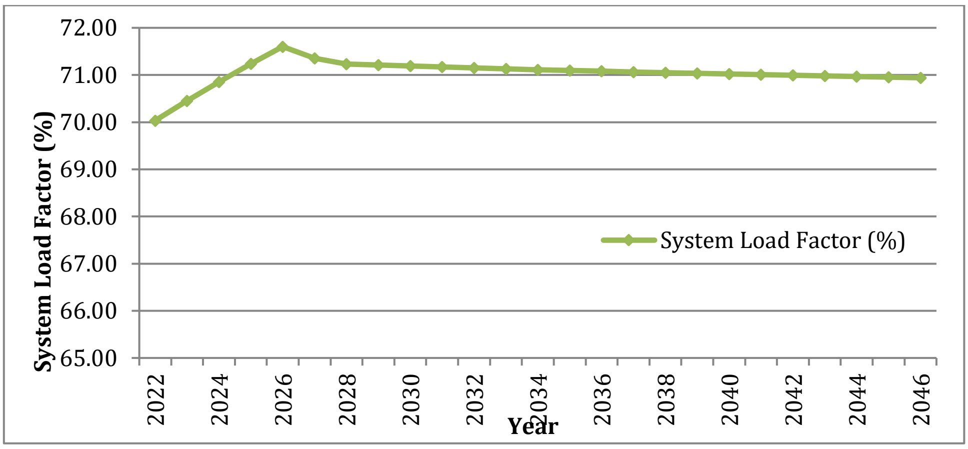


Figure 3.7 – System Load Factor Forecast 2022-2046

Finally, the peak demand forecast was derived using the annual electricity generation forecast and load factor forecast.

3.4 Base Demand Forecast 2022-2046

Base demand forecast 2022-2046 was prepared as per the methodology described in Section 3.3 for the planning horizon. Table 3.3 shows the 'Base Demand Forecast 2022-2046'.

Table 3.3 - Base Demand Forecast 2022-2046

Year	Demand		Net Loss*	Net Generation		Peak Demand
	(GWh)	Growth Rate (%)	(%)	(GWh)	Growth Rate (%)	(MW)
2022	16,741	5.8%	8.03	18,203	5.7%	2,967
2023	17,705	5.8%	7.97	19,238	5.7%	3,117
2024	18,725	5.8%	7.90	20,331	5.7%	3,276
2025	19,854	6.0%	7.83	21,541	6.0%	3,452
2026**	21,036	6.0%	7.77	22,808	5.9%	3,636
2027	22,286	5.9%	7.70	24,145	5.9%	3,852
2028	23,451	5.2%	7.63	25,390	5.2%	4,069
2029	24,692	5.3%	7.57	26,714	5.2%	4,282
2030	26,035	5.4%	7.50	28,146	5.4%	4,513
2031	27,438	5.4%	7.45	29,647	5.3%	4,755
2032	28,835	5.1%	7.40	31,139	5.0%	4,996
2033	30,301	5.1%	7.35	32,705	5.0%	5,249
2034	31,826	5.0%	7.30	34,332	5.0%	5,511
2035	33,445	5.1%	7.25	36,060	5.0%	5,790
2036	35,100	4.9%	7.25	37,844	4.9%	6,078
2037	36,792	4.8%	7.25	39,668	4.8%	6,372
2038	38,506	4.7%	7.25	41,516	4.7%	6,671
2039	40,255	4.5%	7.25	43,402	4.5%	6,975
2040	42,046	4.4%	7.25	45,333	4.4%	7,287
2041	43,859	4.3%	7.25	47,288	4.3%	7,602
2042	45,705	4.2%	7.25	49,278	4.2%	7,924
2043	47,590	4.1%	7.25	51,310	4.1%	8,252
2044	49,544	4.1%	7.25	53,417	4.1%	8,592
2045	51,597	4.1%	7.25	55,630	4.1%	8,950
2046	53,703	4.1%	7.25	57,901	4.1%	9,317
5 Year Average Growth	5.9%			5.8%		5.2%
10 Year Average Growth	5.6%			5.6%		5.4%
20 Year Average Growth	5.2%			5.2%		5.1%
25 Year Average Growth	5.0%			4.9%		4.9%

*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 depending 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 Load Projection Scenario based on MAED Model

Model for Analysis of Energy Demand (MAED) was developed by International Atomic Energy Agency (IAEA) for load projection with Bottom-Up (End User) approach. Energy demand calculation module utilize extensive analysis of end use energy demand data and evaluates future energy demand based on socio-economic, technological and demographic developments of the country.

The model identifies social, economic and technological driving factors and their relations to the identified energy consumer sectors that affect to the final energy demand of each sector.

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

Model was developed and revised based on the socio-economic data up to 2019. Planning years from 2022 to 2046 adjusted considering the present situation and future of the economy, demography, sector changes 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. In addition, peak electricity demand is calculated considering seasonal, daily and hourly variation of the profiles.

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="2">Household</td><td colspan="2">Urban</td></tr>
<tr><td colspan="2">Rural</td></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>Transport</td><td colspan="2">Domestic Electric Vehicle Charging pattern</td></tr>
</table>

Three scenarios were developed to analyse the 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 assumptions that demand 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 2022-2046 planning horizon for each scenario.

Table 3.5 – Annual Average Growth Rate 2022-2046

Scenario	Total Net Generation Growth Rate %	Electricity Demand Growth Rate %
Reference	4.8	4.7
Low Economic Growth	4.3	4.1
High Electricity Penetration	5.1	5.0

Table 3.6, shows the summary of total secondary electricity demand (net generation) and peak demand for the Reference scenario over the planning horizon.

Table 3.6 – MAED Reference Scenario

	Unit	2022	2027	2032	2037	2042
Net Generation	GWh	18,455	23,954	31,162	39,624	48,771
Peak Demand	MW	3,067	3,907	5,059	6,424	7,852

Total electricity demand of the MAED reference scenario and Base Demand Forecast 2022-2046 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.

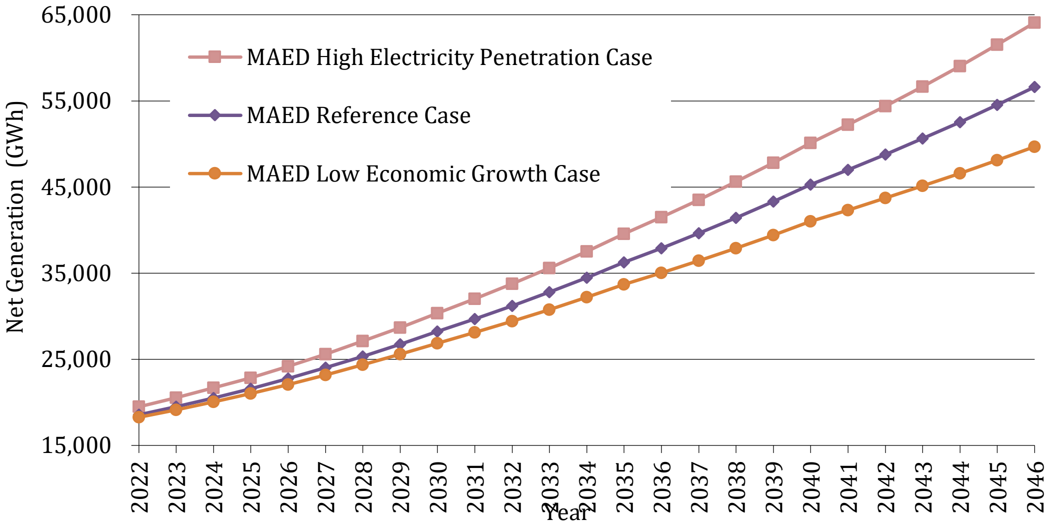


Figure 3.8 - Generation Forecast Comparison

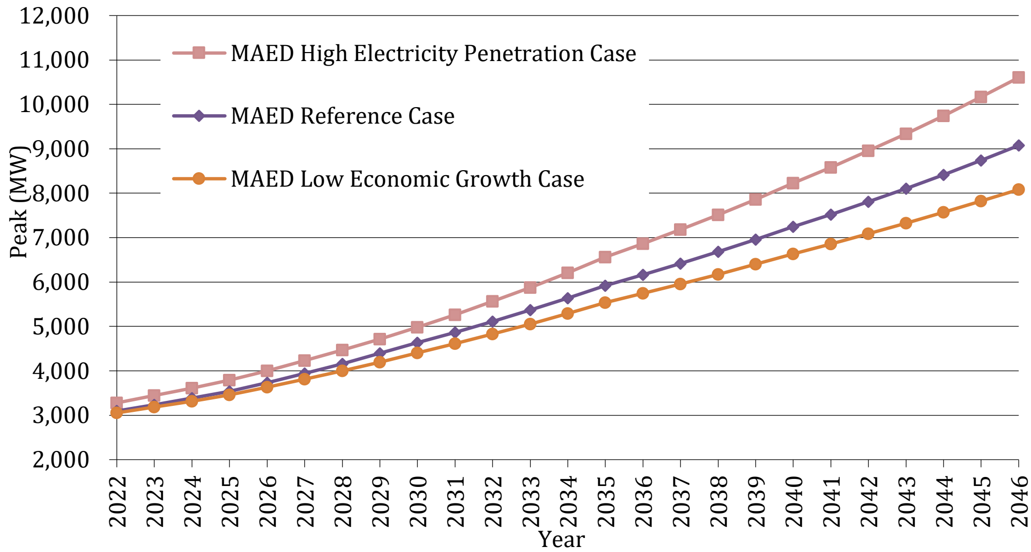


Figure 3.9 – Peak Demand Forecast Comparison

3.6 Demand Forecast Scenarios and Sensitivities

Different demand forecast scenarios and sensitivities were prepared considering variations to the base demand forecast, using long term time trend approach, considering end user approach with MAED model and those are listed below. The effects of the load variation (High and Low load forecast) on the base case generation expansion plan are described in Chapter 8.

1. **High Load Forecast** - The forecast developed considering higher economic growth of the country beyond 2022 and economic sector change based on higher growth in Industrial and Service sector in future

2. **Low Load Forecast** - The forecast developed considering economic growth rate reduction

compared with annual growth rate considered for the base load forecast (slow recovery of the economy considered for the initial years) and also reduction of other driving factors

3. **Long Term Time Trend Forecast** - The forecast developed purely based on the time trend approach using the past 25 year electricity demand figures starting from 1995

4. **MAED Load Projection –** The projection 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

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

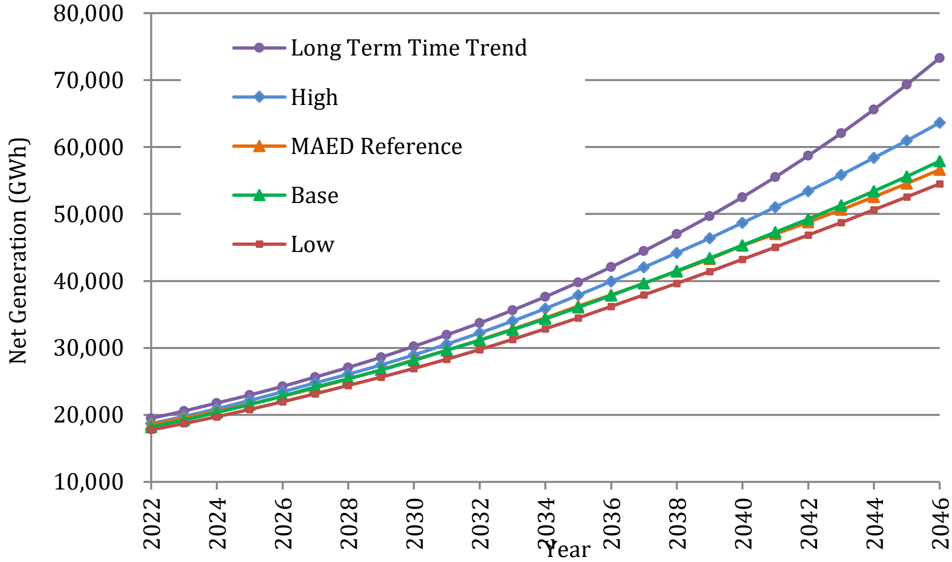


Figure 3.10 - Generation Forecast of Low, High, Long Term Time Trend and MAED with Base

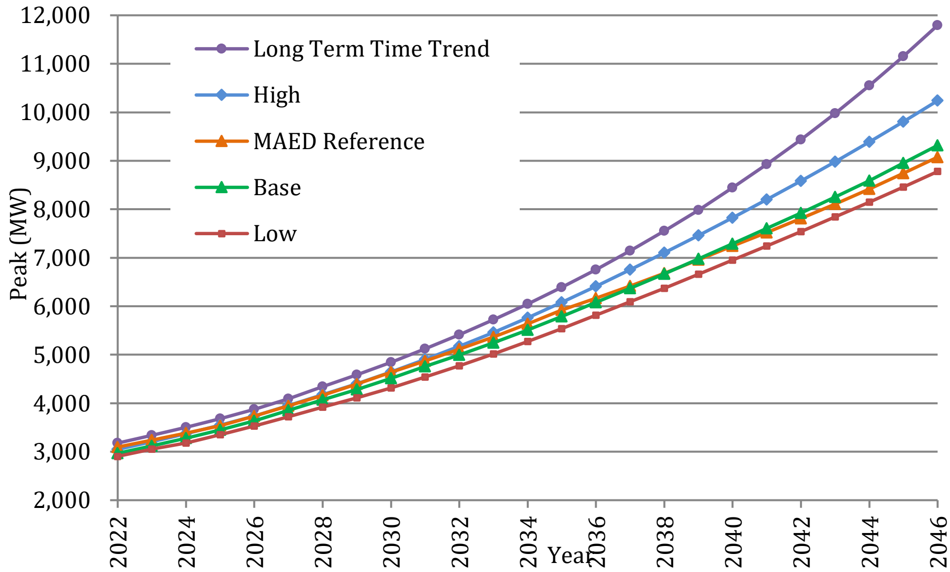


Figure 3.11–Peak Demand Forecast of Low, High, Long Term Time Trend and MAED with Base

3.7 Comparison with Past Forecasts

Electricity 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 factors. Table 3.7 shows the comparison of past demand forecasts used in the previous expansion plans and their percentage variation against the gross energy sold in respective years. 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 Gross Energy Sold (in GWh)

Year	LTGEP 2011 - 2025	LTGEP 2013 - 2032	LTGEP 2015 - 2034	LTGEP 2018-2037	LTGEP 2020-2039 (Draft)	Gross Energy Sold (GWh)
2011	10,036 (+0.1%)					10,026
2012	10,698 (+2.1%)	10,675 (+1.9%)				10,475
2013	11,402 (+7.3%)	11,104 (+4.5%)				10,624
2014	12,149 (+9.8%)	12,072 (+9.1%)				11,063
2015	12,941 (+9.8%)	12,834 (+8.9%)	11,516 (-2.3%)			11,786
2016	13,773 (+7.7%)	13,618 (+6.5%)	12,015 (-6.0%)			12,785
2017	14,630 (+8.9%)	14,420 (+7.4%)	12,842 (-4.4%)			13,431
2018	15,530 (+10.2%)	15,240 (+8.2%)	13,726 (-2.6%)	14,588 (+3.5%)		14,091
2019	16,481 (+12.8%)	16,075 (+10.0%)	14,671 (+0.4%)	15,583 (+6.7%)		14,611
2020	17,489 (+22.4%)	16,937 (+18.6%)	15,681 (+9.8%)	16,646 (+16.5%)	16,914 (+18.4%)	14,286

Note:

1. Within bracket figures indicate the percentage deviation of demand forecast with reference to gross energy sold
2. Demand forecast represent actual electricity energy demand of the country considering rooftop solar self consumption

3.8 Electricity Demand Reduction and Demand Side Management

Energy demand reduction is taken as a key alternative in the design of energy supply schemes, as it is another way of balancing the energy demand with available supply, as opposed to building new facilities to cater to increasing demand. 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 expensive base load generation. Ultimately, these initiatives will avoid peak demand burden on the network by supporting efficient utilization of available generating options.

Improving Energy Efficiency and Conservation is identified as one of the ten pillars of the National Energy Policy & Strategies (NEPS) of Sri Lanka, 2019. 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 foreseeable 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.

The NEPS identified several strategies on energy demand reduction impacting many sectors in the demand side. Accordingly, identified main strategies which are directly and indirectly related to the power sector are as follows:

- Further strengthening of the national energy efficiency improvement and conservation programme engaging all stakeholders in household, industrial and commercial sectors.
- Energy efficiency improvement and conservation will be promoted through minimum energy performance standards and labelling of appliances, and by introducing green procurement processes in state and private sector organisations.
- Taxation and other incentives and disincentives to support the market for efficient technologies will be introduced.
- Expert energy advisory services will be offered through state and private sector service providers to promote energy efficiency, conservation and energy cost reduction across all end use sectors.
- Water resources will be recognized as a valuable indigenous energy resource. Efficient use of water by competing users at places where there is a high opportunity cost to water will be enhanced.
- Conversion efficiency of power generation facilities will be enhanced.
- A strategic plan for street lighting will be formulated to ensure proper management of street lighting.

- Automated demand response technologies will be considered as a main demand-side management strategy.

- Losses in energy delivery networks will be reduced to optimum levels.

- Virtual offices and video/teleconferencing will be promoted by making necessary changes to organisational working culture as a strategy to minimize physical movement.

- Energy efficiency will be a primary concern in retrofits, and new building designs will be evaluated for their energy performance on a mandatory basis.

- Smart technologies, including smart buildings and complete conversion to smart metering will be ensured to convey price signals to customers, altering the demand profile to reduce the overall cost of supply.

Sustainable Energy Authority (SEA) which carries the responsibility of designing and implementing the energy efficiency improvement & conservation programme, attempted to implement a national programme named Operation Demand Side Management (Operation DSM) under the guidance of a Presidential Task Force on Energy Demand Side Management (PTF on EDSM) with modest success. The programme, launched in 2017 could not amass the financial and human resources as anticipated in the programme design. Nevertheless, the programme was implemented under severe constraints.

SEA has identified possible candidates for reducing energy demand as the ten thrust areas including efficient lighting, efficient refrigerators, efficient chillers, efficient air conditioning, efficient motors & variable speed drives, eliminating incandescent lamps, efficient fans, green buildings, smart homes and power factor improvement. A brief summary of the status of the some initiatives are given below:

- **Efficient Lighting**: A study of 100 commercial buildings completed, uncovering a potential to save 515GWh of electrical energy per year, with lighting retrofits.

- **Efficient Refrigerators**: Implementation of the Minimum Energy Performance Standard nearing completion, after adoption of the standard by the Council of the Sri Lanka Standards Institute. Pilot project on replacing 10,000 old refrigerators is being developed, and is awaiting utility response on inclusion of hire purchase instalment payments in the electricity bill.

- **Eliminating Incandescent Lamps**: First phase of the programme, targeting families which use less than 30kWh per month was implemented. The programme achieved modest success and analysis of pre and post implementation energy use in progress.

- **Efficient Fans**: Mandatory labelling scheme fully implemented and import of inefficient fans to the country is now prohibited.

- **Green Buildings**: The Energy Efficiency Building Code 2020 was finalised and the regulations were drafted. It will be implemented on mandatory basis shortly, targeting buildings with more than 5,000m^2 of serviced space. A supportive legislation titled Energy Usage Benchmark Regulations was cleared by the Legal Draftsman.

- **Smart Homes**: A guideline for families embarking on house construction projects was launched, encouraging the use of sustainable energy technologies.

- **Power Factor Improvement**: A limited study on the optimal location of power factor correction equipment undertaken.

An approximate estimation of energy savings (kWh) and demand savings (MW) realizable indicates that the programme can save 1,104 GWh by 2025 and differ a 417 MW capacity in generation expansion. Similarly, the Smart Home initiative focusing on solar PV roof top systems which expected to avoid 139.2GWh of central generation by 2020 and differ a 100 MW capacity in day time grid generation surpassed the targets and now delivers 362 GWh from a distributed generation capacity of 262 MW on rooftops.

The Operation DSM programme, with the support of the Department of Census & Statistics conducted an island wide survey of homes involving a representative sample of 6,430 residences. The survey titled 'Household Domestic Electrical Equipment Survey (HDEES)' was conducted in late 2019 and generated a vast array of data on all electrical appliance types, age, penetration and time of use, information on cooking energy and other household expenses on energy and non-energy commodities. The data analysis is expected to be completed shortly, and provide valuable load research data for estimation of demand from the residential sector.

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

Power generation options are broadly categorized into 'renewable energy based power generation' and 'thermal energy based power generation'. Thermal energy based power generation technology types are of internal combustion engines, gas turbines, steam turbines and combined cycles utilizing fuel combinations from oil, natural gas and coal. Nuclear power generation also falls into thermal power generation where nuclear fuel is used to operate a steam turbine.

Thermal power generation has its benefits as well as distinct drawbacks compared to its alternative, renewable power generation. Each technology has its specific operational characteristics as well as economics. A large number of factors including cost of development, O&M costs and operational constraints have to be evaluated while adhering to environmental limitations in order to consider the suitability of these primary generation options. The costs of associated environmental mitigation measures of respective generation options are included in the cost figures given in this report.

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

a) Study for Energy Diversification Enhancement by Introducing LNG Operated Power generation Option in Sri Lanka, 2010 [9].

b) Energy Diversification and Enhancement Project Phase IIA- Feasibility Study for Introducing LNG to Sri Lanka, 2014 [10]

c) Pre-Feasibility Study for High Efficiency and Eco Friendly Coal Fired Thermal Power Plant in Sri Lanka, 2014. [11]

d) Feasibility Study on High Efficiency and Eco-friendly Coal-fired Thermal Power Plant in Sri Lanka, 2015 [12]

e) Project on Electricity Sector Master Plan Study in Democratic Socialist Republic of Sri Lanka, 2018. [13]

4.1. Thermal Power Candidate Technologies

4.1.1 Thermal Power Technologies

The main categories for thermal power development technologies are based on Internal combustion engines, gas turbines, steam turbines and combined cycles.

Internal combustion Engines

Internal combustion engines are typically categorized by speed and fuel type. They come in fuel forms of gaseous fuel, liquid fuel, and dual fuel. Due to the possibility of adopting modular sizes of these engine technologies, higher degree of flexibility is seen in operation. In addition, it provides favorable fuel efficiency merits in part load operations with fast start up times. However, the inertia support from internal combustion engines is low.

Open Cycle Gas Turbines

Gas turbine can operate from both gaseous fuel and liquid fuels. They are classified into two main categories of aero derivative gas turbines and industrial gas turbines. Both of these find application in the power generation industry, for peaking and fast load balancing applications. Open cycle gas turbines have faster start up times and quick ramping capabilities while aero-derivatives have additional advantages of higher efficiency and no additional cost on O&M for the startup. Gas turbines provide high rotating inertia which shall be essential for future power system stability.

Combined Cycle Gas Turbine

Combined cycle gas turbine plants are a merge of gas turbine and steam turbine technologies coupled through Heat Recovery Steam Generators (HRSG). They come in 1-on-1 configuration or 2-on-1 configurations. Combined cycle plants are often characterized with very high efficiencies designed for baseload and intermediate load operations.

Steam Turbines

Steam turbines are one of the most conventional technologies to produce electricity. Steam is produced by firing boilers, with the help of using fuels such as coal, nuclear and biomass. Steam turbines do not easily adapt to excessive load variations, therefore, are better suited for base load operation. However advanced designs in once through boiler technologies, enable certain level of flexibility for operation of coal power plants.

4.1.2 Candidate Thermal Plants for Initial Screening

Power generation technologies with different fuel configurations were considered in the initial screening of generation options. These were based on prevailing models in the market and previously conducted feasibility studies. Following are the thermal power generation technologies considered for the initial screening process:

(i) Natural gas, Internal combustion engines
(ii) Diesel, Internal combustion engines
(iii) FO, Internal combustion engines
(iv) LPG, Internal combustion engines
(v) Natural gas, industrial gas turbine power plant
(vi) Natural gas, aero derivative gas turbine power plant
(vii) Diesel, industrial gas turbine power plant
(viii) Natural gas, combined cycle power plant
(ix) Diesel, combined cycle power plants
(x) High efficient coal thermal power plant
(xi) Super critical coal thermal power plant
(xii) Nuclear power plant

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 analysis which is based on Specific Generation cost is employed in the initial screening which is described in the Section 6.4.

After the initial screening, fourteen alternative expansion options, which are described in Section 4.1.2, were considered for the detailed planning studies. The results of the screening curve analysis are given in Annex 8.1.

4.1.3 Candidate Thermal Plant Specifications

Capital costs of projects are shown in two components: The foreign cost and the local cost. During the prefeasibility 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 2021 values. 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 - Cost Details of Thermal Expansion Candidates

Plant	Net Capacity (MW)	Pure unit cost (US$/ kW)	Const: Period (Years)	Total unit cost with IDC at 10% (net) (US$/kW)	Economic life (Years)	Fixed O&M cost (US$/kW Month)	Variable O&M cost (US$/ MWh)
15 MW NG IC Engine	16.62	1,044	1.5	1,112	20	2.93	5.69
15 MW FO IC Engine	16.62	1,044	1.5	1,112	20	2.93	5.69
15 MW Diesel IC Engine	17.1	1,044	1.5	1,112	20	2.93	5.69
200 MW NG IC Engine Plant	208	634	1.5	720	20	2.93	5.69
250 MW NG IC Engine Plant	256	634	1.5	720	20	2.93	5.69
40 MW NG Gas Turbine	40.2	568.3	1.5	605	20	0.58	4.50
40 MW NG Gas Turbine (Aero Derivative)	41.1	740	1.5	788.2	20	1.33	4.70
100 MW NG Gas Turbine	106.4	398.3	1.5	423.9	20	0.58	4.50
200 MW NG Gas Turbine	191.8	345	1.5	367.5	20	0.58	4.50
300 MW NG Combined Cycle	288.5	922.5	3	1,047.4	30	1.02	2.55
400 MW NG Combined Cycle	419	872.5	3	972.2	30	1.02	2.55
300 MW High Efficient Coal Plant	270	1,864	4	2,209	30	3.38	4.50
600 MW Super Critical Coal Plant	564	2,005	4	2,376	30	3.38	4.50
600 MW Nuclear Power Plant	552	4,799	5	5,940	60	10.08	2.37

All costs are in December 2020 border prices., IDC = Interest during Construction

Table 4.2 – Characteristics of Candidate Thermal Plants

Plant	Net Capacity (MW)	Min Load (MW)	Heat Rate (kcal/kWh)		Full Load Efficiency (Net,HHV) %	FOR
			Full. Load	Avg. Incr.		
15 MW NG IC Engine	16.62	1.6	2,021	1,797	42.6	10
15 MW FO IC Engine	16.62	1.6	2,074	1,844	41.5	10
15 MW Diesel IC Engine	17.1	1.7	1,943	1,727	44	10
200 MW NG IC Engine	208	1.6	2,021	1,797	42.6	10
250 MW NG IC Engine	256	1.6	2,021	1,797	42.6	10
40 MW NG Gas Turbine	40.2	20.1	2,911	2,038	29.6	8
40 MW NG Gas Turbine (Aero Derivative)	41.1	20.5	2,315	1,621	37.2	8
100 MW NG Gas Turbine	106.4	53.2	2,548	1,784	33.8	8
200 MW NG Gas Turbine	191.8	95.9	2,568	1,798	33.5	8
300 MW NG Combined Cycle	288.5	112.5	1,919	1,428	44.9	8
400 MW NG Combined Cycle	419	167.6	1,757	1,288	49	8
300 MW High Efficient Coal Plant	270	135	2,241	1,935	38.4	3
600 MW Super Critical Coal Plant	564	338.4	2,082	1,833	41.4	3
600 MW Nuclear Power Plant	552	496.8	2,685	2,343	32.1	0.5

Heat values of petroleum fuel and coal based plants are in HHV ;FOR = Forced Outage Rate

4. 2 Fuel Types

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 in World Energy Outlook – 2020, World Bank Commodity Price Forecast and IMF Commodity Price Forecast. All fuel prices considered are in economic terms, exclusive of taxes.

(i) Liquid Petroleum Products (Auto Diesel, Fuel 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 ongoing in the Mannar basin). Ceylon Petroleum Corporation (CPC) presently provides all petroleum products required for thermal power stations.

Weighted average of Brent crude oil price from year 2017 to 2020 is 61.46 US$/bbl. It is in same range of weighted average crude oil CIF price to Sri Lanka for the same period at 61.33 US$/bbl which has been used for the study.

The World Bank and International Monetary Fund (IMF) also publish a forecast on crude oil price variations. The comparison of the price used for the study with international price forecasts is shown in Figure 4.1. A fuel price sensitivity scenario is modelled in Section 8.6 to capture the implications of long term international price forecasts.

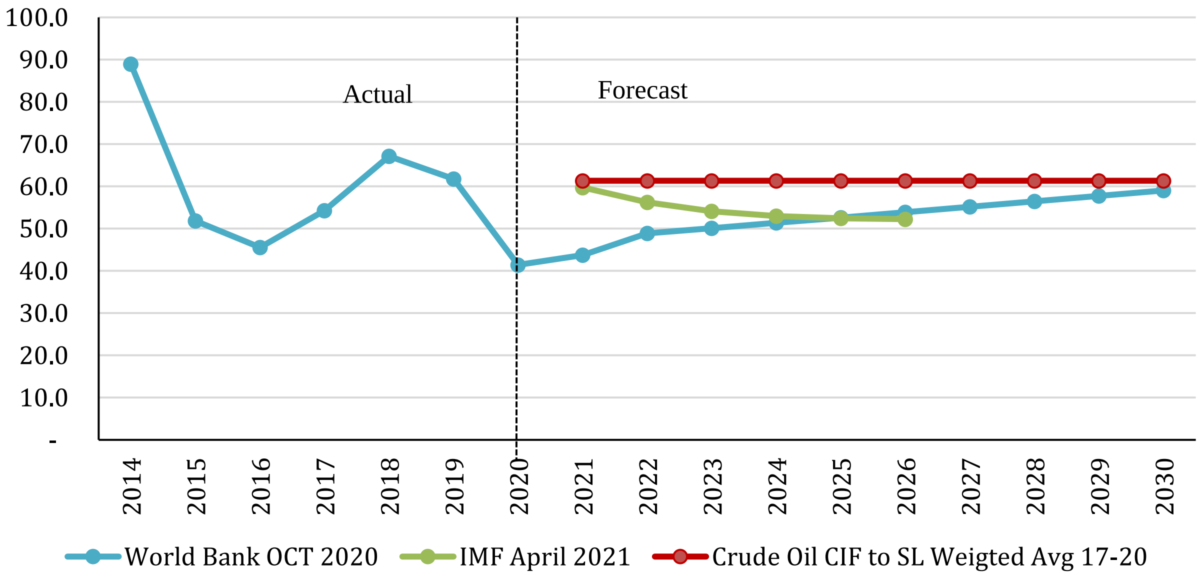


Figure 4.1 –Crude Oil Price Comparison

The fuel prices for diesel, fuel oil and naphtha are based on the weighted average value of the economic prices provided by the CPC. The CIF prices are shown in Table 4.3 with the fuel characteristics and the fuel prices used in the analyses. For each fuel type the applicable local cost were separately added. 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	CIF Price	
			($/bbl)	Rs/l
Auto Diesel	10,500	0.84	73.75	86.83
Fuel oil	10,300	0.94	59.81	70.41
Naphtha	10,880	0.76	56.56	66.59

Source: Oil prices based on Ceylon Petroleum Cooperation at 1 US$ = LKR 187.18

(ii) Coal

Coal is a commonly used fuel option for electricity generation in the world. In 1980's CEB identified coal as an economically attractive fuel option for electricity generation. Coal prices vary with the specific calorific value of coal and other specific parameters of the coal quality such as Ash content, Sulphur amount and volatility. Coal procured to Sri Lanka at present is based on the API 4 index from Argus which is correlated to the coal of net heat value of 6,000 kcal/kg on FOB basis from Richards Bay, South Africa. Shipping cost may vary depending on shipping distance and typical values range from 12-13 US$/ton.

Weighted average of API 4 index from year 2017 to 2020 is considered with applicable handling charges in deriving coal prices for LTGEP 2022-2041. The comparison with World Bank fuel price forecast which is based on coal from New castle, Australia and IMF fuel price forecast based on South African Coal is shown in Figure 4.2. A fuel price sensitivity scenario is modelled in Section 8.6 to capture the implications of long term international price forecasts.

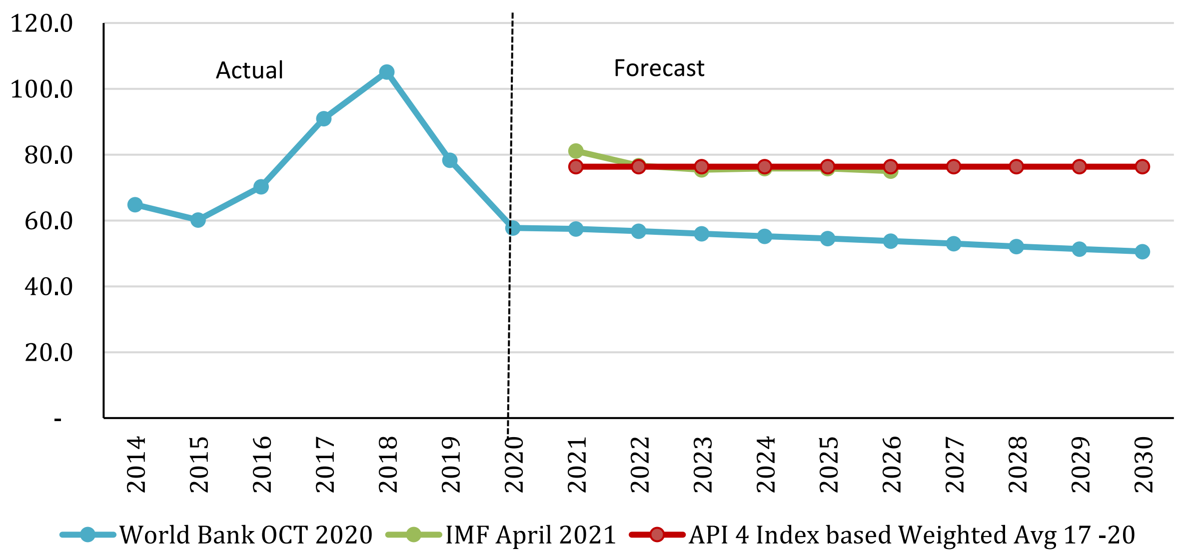


Figure 4.2 –Coal Price Forecast Comparison

Two coal types are used in planning studies considering the based on different handling cost associated with potential locations. The values are shown in Table 4.4.

Table 4.4 – Coal Prices and Characteristics for Analysis

Fuel Type	Net Heat Content (kcal/kg)	Market Price ($/MTon)	Remarks
Coal type 1	6,000	91.5	Coal Power Plants at Norochcholai
Coal type 2	6,000	88.5	High Efficiency Coal Power Plants and Super Critical Coal Power Plants at East Coast

Source: Coal prices based on API 4 Index

(iii) Natural Gas

Natural gas would add diversification to the country's fuel mix. There is no commercially developed gas field in Sri Lanka though discoverable gas reserves have been identified. Natural Gas as a fuel for Gas Engines, Gas Turbine and Combined Cycle plants is an attractive option from environmental perspective.

(a) Regasified-Liquefied Natural Gas

Feasibility study for introducing LNG to Sri Lanka conducted in year 2014, identified that the Colombo North Port as the best site for development of a LNG terminal out of 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 NG fired power plants by considering the technical, economic, social and environmental aspects. As identified therein, LNG facility suitable for Sri Lanka would consist of an LNG import facility (via tanker ships), domestic storage, regasification unit and necessary piping for supplying to the power plants.

However, a recent development of the Floating Storage and Regasification Unit (FSRU) which can be moored in the sea has a faster implementation possibility. Considering the initial requirements identified in previous planning studies, CEB has advertised for the deployment of a FSRU, offshore of Kerawalapitiya with a regasification capacity of 380 MMSCFD and LNG storage capacity of minimum 156,000 m^3. The terminal is expected to operate for a period of 10 years on BOO basis with compatible Mooring System on BOOT basis. Pipeline infrastructure up to the boundaries of the power plants will be established by Ceylon Petroleum Corporation on BOOT basis.

LNG prices are categorized based on Long term contracts, Medium term contracts and short term spot prices. There are different LNG pricing mechanisms adopted in different regions of the world. The long term contracts are often linked with oil price and in the Asian market, Japanese Crude Oil Cocktail (JCC) and Brent Crude Oil Index is used for this purpose. 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. Even though typical LNG contracts had

11%-17%proportional linkage to oil indexes in the past, recent trends reveal even at low order quantities a lower proportional linkage is achievable through good negotiations.

Weighted average value for12.5% proportional linkage to Brent Crude Oil Index from year 2017 to 2020 is considered in deriving LNG prices for LTGEP 2022-2041. Thus, LNG price of 7.68 US$/MMBtu is considered based on Brent Crude oil price of 61.46 US$/bbl projected in section 4.2(i). The comparison with World Bank and IMF fuel price forecast which is based LNG import price in Japan is shown in Figure 4.3. A fuel price sensitivity scenario is modelled in Section 8.6 to capture the implications of long term international price forecasts.

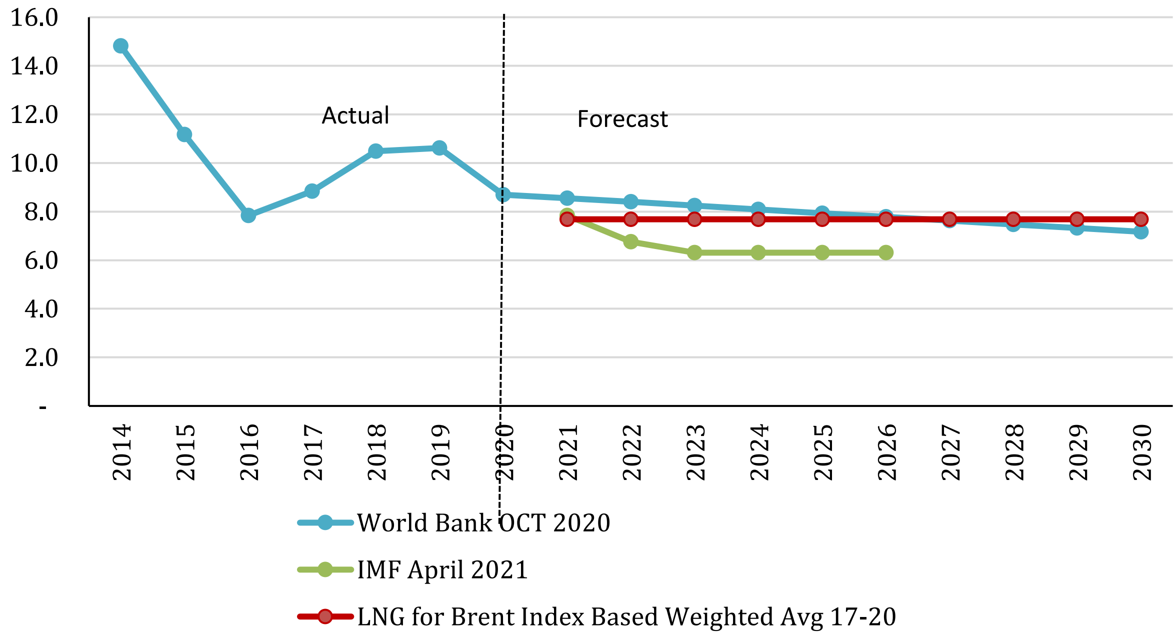


Figure 4.3 –Natural Gas Price Comparison

In addition to the CIF price, the price of fuel delivered to the power plant is calculated which includes the handling charge estimated to be 2US$/MMBtu consisting of regasification and transportation of fuel through pipeline network. Hence price of regasified LNG delivered to power plant is projected as 9.68US$/ MMBtu for LTGEP 2022-2041.

(b) Local Natural Gas

The Petroleum Resources Development Secretariat (PRDS) which was established under the Petroleum Resources Act, N0 26 of 2003, launched its first licensing round for exploration of oil and gas in the Mannar Basin off the north-west coast in 2007, and exploration activities initiated with the awarding of one exploration block (3,000 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 MMSCFD. 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 1,000MW 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. PRDS is currently engaged in joint studies with international oil companies to explore additional oil and gas prospectively.

The price of local natural gas depends on factors such as commercially exploitable quantity, contractual fiscal terms, government tax policy, off take options, delivery options for locations, socio-economic concerns, exploration risk capital, development and operating & maintenance costs, etc. Most of these factors are market sensitive. Hence, it is difficult to make accurate predictions on the gas price and the estimated values based on assumptions could be volatile. The PRDS estimate on local gas price excluding the tax components, is in the range of 6 – 10 US$/MMBtu.

(iv) Liquefied Petroleum Gas

LPG based power generation has only emerged recently, mainly as an environmentally friendly alternative to oil based power generation. Countries which have plans to develop natural gas power plants in the future have developed LPG based power plants in the short term, with the longer term plan to convert to natural gas once the gas is available. Although LPG is primarily used for residential applications, the fuel quality used for power generation has to have high propane content in contrast to the residential applications.

(v) Nuclear

Nuclear power has been considered to be explored as an alternative thermal generation option to avoid excessive dependence on the other imported fossil fuels for power sector in Sri Lanka. A cabinet approval has been received on 8th September 2010 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.

Accordingly, Sri Lankan government requested and subsequently received International Atomic Energy agency (IAEA) assistance through the technical cooperation programs as follows;

- IAEA TC Project SRL/2/008 (2012/2013 period): Supporting Energy Planning and Pre-Feasibility Study for Nuclear Power and Human Resources Development in Nuclear Power Engineering

- IAEA TC Project SRL/2/010 (2018/2020 Period): Establishing a Roadmap for Nuclear Power Program in Sri Lanka

Under the purview of Ministry of Power, Ceylon Electricity Board (CEB), Sri Lanka Atomic Energy Board (SLAEB) and Sri Lanka Atomic Energy Regulatory Council (SLAERC) contributed as the leading institutions for the project "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. Project Management Unit "To Study the Nuclear Power Option in Sri Lanka" under Ministry of Power acted as the Nuclear Energy Programme Implementing Organization (NEPIO). The main task of the project was to prepare a comprehensive report addressing the 19 milestones, according to Phase 1 of the IAEA milestones approach. IAEA assistance was obtained on nine major areas to prepare the comprehensive report covering the 19 milestones for Nuclear Power Development. The nine major areas are as follows.

- Legal and regulatory
- Communications and Human Resource
- Policy
- Electricity market and generation mix
- Nuclear Power Technology
- Siting of NPPs/Nuclear facilities
- Economics and Finance
- Localization Assessment
- Safety and Security

During the project period, a Steering Committee, Program Management Unit and Working Groups have been formed and several IAEA expert missions have been conducted with the participation of stakeholder organizations.

Presently draft working group reports on nine major areas and the draft comprehensive report have been prepared which are review. The comprehensive report is scheduled to be submitted to the Government of Sri Lanka within year 2021.

From a long-term generation planning perspective, accommodating a relatively large nuclear power unit to the Sri Lankan grid is the most significant technical challenge as capacity of the proven and widely adopted nuclear power plants designs are in the range of 600 MW to 1,650 MW. In future scenarios where the development of cross-border interconnection with India and the planned pumped storage hydro units, the system's capability will change in favour of accommodating a larger unit.

4.3. Thermal Plant Specific Cost Comparison

The specific costs of the selected candidate plants for different plant factors are tabulated in the Table 4.5. 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. It reveals how different technologies perform at different plant factors. Full load heat rates are considered in deriving the specific costs. Accordingly, peak load power plants are cost effective at low plant factor operation whereas base load plants such as coal power plants and nuclear powerplants are attractive options for higher plant factor operations. However, in actual simulations, the size of the generation units is taken into account and it would make a significant effect in the final plant selection.

Table 4.5 - Specific Cost of Candidate Thermal Plants in USCts/kWh (LKR/kWh)

Power Plant	Plant Factor							
	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8
15 MW NG IC Engine	26.34 (49.30)	17.33 (32.44)	14.33 (26.83)	12.83 (24.02	11.93 (22.33)	11.33 (21.21)	10.90 (20.40)	10.58 (19.80)
15 MW FO IC Engine	26.71 (50.00)	17.71 (33.14)	14.70 (27.52)	13.20 (24.71)	12.30 (23.03)	11.70 (21.90)	11.27 (21.10)	10.95 (20.50)
15 MW Diesel IC Engine	28.87 (54.04)	19.86 (37.18)	16.86 (31.56)	15.36 (28.75)	14.46 (27.07)	13.86 (25.94)	13.43 (25.14)	13.11 (24.54)
200 MW NG IC Engine	22.96 (42.98)	15.65 (29.28)	13.21 (24.72)	11.99 (22.44)	11.26 (21.07)	10.77 (20.15)	10.42 (19.50)	10.16 (19.01)
250 MW NG IC Engine	22.78 (42.64)	15.56 (29.11)	13.15 (24.61)	11.94 (22.35)	11.22 (21.00)	10.74 (20.10)	10.39 (19.45)	10.14 (18.97)
40 MW NG Gas Turbine	20.04 (37.52)	15.83 (29.64)	14.43 (27.01)	13.73 (25.70)	13.31 (24.91)	13.03 (24.38)	12.83 (24.01)	12.68 (23.73)
40 MW NG Gas Turbine (Aero Derivative)	21.11 (39.50)	15.23 (28.51)	13.27 (24.84)	12.29 (23.01)	11.71 (21.91)	11.31 (21.18)	11.04 (20.65)	10.83 (20.26)
100 MW NG Gas Turbine	16.37 (30.64)	13.30 (24.90)	12.28 (22.98)	11.77 (22.02)	11.46 (21.45)	11.25 (21.07)	11.11 (20.79)	11.00 (20.59)
200 MW NG Gas Turbine	15.73 (29.45)	13.02 (24.37)	12.12 (22.68)	11.66 (21.83)	11.39 (21.32)	11.21 (20.99)	11.08 (20.74)	10.99 (20.56)
300 MW NG Combined Cycle	20.81 (38.96)	14.22 (26.61)	12.02 (22.50)	10.92 (20.44)	10.26 (19.20)	9.82 (18.38)	9.51 (17.79)	9.27 (17.35)
400 MW NG Combined Cycle	19.39 (36.30)	13.20 (24.70)	11.12 (20.81)	10.10 (18.90)	9.48 (17.74)	9.07 (16.97)	8.77 (16.41)	8.55 (16.00)
300 MW High Efficient Coal Plant	31.58 (59.11)	17.64 (33.02)	13.00 (24.33)	10.67 (19.98)	9.28 (17.37)	8.35 (15.63)	7.69 (14.39)	7.19 (13.46)
600 MW Super Critical Coal Plant	32.39 (60.63)	17.93 (33.56)	13.11 (24.54)	10.70 (20.03)	9.26 (17.33)	8.29 (15.52)	7.61 (14.24)	7.09 (13.27)
600 MW Nuclear Power Plant	69.47 (130.02)	35.08 (65.65)	23.61 (44.20)	17.88 (33.47)	14.44 (27.03)	12.15 (22.74)	10.51 (19.68)	9.28 (17.38)

Note: 1 US$ = LKR 187.18

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. 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 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 [23], indicating 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. Under the above study, candidate sites were studied and Trincomalee area was selected as the most suitable sites for future coal power development. Basic thermal plant design has been prepared for 1,200 MW (either 300 MW High efficient advanced subcritical power plants or 600 MW 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 alternative land at Foul Point area has been identified and process of acquisition is initiated. Necessary feasibility studies for the alternative land are to recommence once the land acquisition is finalized.

(c) **Natural Gas Power Plants in the West Coast – Kerawalapitiya**

Ceylon Electricity Board intends to develop natural gas based power plants in Western region, near to the main load centre of the country. In addition to the conversion of existing combined cycle power plants to natural gas, 2x350 MW dual fuel (natural gas and auto diesel) combined cycle plants are at their project development phases. These two dual fuel combined cycle plants are expected to be constructed at the land adjacent to the West Coast Plant in Kerawalapitiya. Furthermore, 100-acre land in Muthurajawela has been identified for the development of further natural gas based power generation in the Western region. Cabinet approval has been granted for this development and EIA is in progress by the Sri Lanka Land Development Corporation (SLLDC) for land reclamation.

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 out jointly by CEB and Power Grid Corporation Indian Limited (POWERGRID) with the main objective to provide the necessary recommendations for implementation of 1,000MW HVDC interconnection project.

In 2002, NEXANT with the assistance of United States Agency for International Development (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. Technical, economical, legal, regulatory and commercial aspects in trading electricity between India and Sri Lanka have also been considered. Consequently, the route option was selected for the initial feasibility study consisting of 130 km 400 kV HVDC overhead line segment from Madurai to Indian sea coast, 120 km of 400 kV Under-Sea cable from Indian sea coast to Sri

Lankan Sea coast, 110 km Overhead line segment of 400 kV from Sri Lankan sea coast to Anuradhapura and two converter stations at Madurai and Anuradhapura.

During latest working group discussions between countries initiated in year 2017, it was proposed to shift the HVDC station in Sri Lankan side from Anuradhapura to New Habarana. Both HVDC technologies, Conventional Line Commuted Conversion (LCC) and Voltage Source Conversion (VSC) are to be considered in future studies. The interconnection has been envisaged to be implemented with 2x500MW HVDC blocks in two phases, where phase I would be 1 x 500 MW (monopole)and phase IIwould be 2 x 500 MW (bipole).

The cost of each alternative for combined stage I and II development has been estimated and power flow studies have been conducted from Indian and Sri Lankan side during the latest studies. The feasibility study is yet to be initiated once the option if finalized.

CHAPTER 5
RENEWABLE GENERATION OPTIONS FOR FUTURE EXPANSION

5.1 Introduction

Sri Lanka being a tropical country is blessed with indigenous renewable energy resources and these indigenous resources have underpinned the economic growth for decades. Country's electricity energy needs were predominantly met by renewable energy sources in nineties, with prime contribution from the major hydro power resources. That has enabled the country to maintain green credential with per capita low carbon emissions level in electricity generation throughout the past years. The rising economic growth and the energy demand led the expansion of other renewable energy sector as well as thermal based resources. Though the large hydro resources played a major role in renewable energy share in the past, variable forms renewable resources such as wind and solar are becoming dominant contributors in the future. In line with the global efforts to mitigate climate change implications, Sri Lanka has progressively enhanced its ambitious targets and development activities on renewable energy development. Accordingly, a substantial growth the indigenous wind and solar resource development is envisaged as the country is moving forward on a low carbon pathway in meeting its future electricity requirement.

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. Sri Lanka has harnessed major renewable resources (large hydro) to almost its maximum economical potential. 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 progressing at present.

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

Hydro power and biomass power generation are not intermittent whereas wind and solar Photovoltaic sources are highly intermittent and seasonal in nature. These inherent physical characteristics of the resources cause challenges in grid integration and different power systems has different capability for grid integration based system characteristics as well as resource characteristics. Prior to the preparation of Long Term Generation Expansion Plan, a comprehensive Renewable Energy Grid Integration Study is conducted to investigate the grid integration challenges and to explore necessary interventions to facilitate higher levels of intermittent renewable energy penetration.

5.2 Major Renewable Energy Development

Sri Lanka was a Hydro Power dependent nation till the late 1990s 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 remains in the pipeline. Several prospective candidate hydro projects have been identified in the Master Plan Study [14], 1989. These include 27 sites capable of generating electricity at a long-term average cost of less than 15 UScts/kWh (in 1988 prices) and having a total capacity of approximately 870 MW. 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 [15]. 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 [16 and 17] 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 [18] 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. In December 2018, the Technical Feasibility Study of the project has been completed by Central Engineering Consultancy Bureau (CECB) of Sri Lanka.

(f) "Development Planning on Optimal Power Generation for Peak Power Demand in Sri Lanka" carried out by JICA funds [19] 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.

(g) "Electricity Sector Master Plan Study in Democratic Socialist Republic of Sri Lanka" carried out by JICA Funds in March 2018 [13] proposed an alternative location for a Pumped Storage Power Plant considering the existing Victoria reservoir being used for the lower pond and an existing irrigation pond located on the eastern side of Victoria Lake being used for the upper pond by expanding the pond.

5.2.2 Committed Hydro Power Projects

Some major hydro projects identified in the Master Plan Study as Broadlands (35 MW) and Moragolla (30.2 MW) 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 122 MW 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 126 GWh 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 final stages of construction work and electro mechanical work are in Progress in parallel at Main Dam, Main tunnel, Penstock & Surge Chamber, Diversion Weir, Diversion tunnel, Power House & Switchyard and Transmission Line. The project is scheduled to be completed in June 2021.

ii. Moragolla Hydro Power Project

The 30.2 MW 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 expected 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 site preparatory works are being carried out and detailed designs are developed. The power plant is expected to be operational by December 2023.

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 122 MW 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 September 2021.

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 15 MW were not considered as candidates in order to give priority for the large projects.

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

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

However, almost all projects within these criteria have been developed by CEB, as well as by the private sector sometimes with reduced energy/capacity benefits.

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 on the Seethawaka Ganga which is an upper tributary of the Kelani River and was initially identified as a 30 MW capacity producing 123 GWh per year. However, due to Social and Environmental considerations, the project is scaled down to a lower capacity hydro power plant. 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 was appointed in CEB to implement the project and the detailed feasibility study has been completed in December 2018 in addition to the EIA which was completed in May 2020. As per the feasibility study, a reservoir with a 3.51 MCM capacity is to be impounded to facilitate regulation of flow mainly for generating hydro energy during daily peak demand of electricity. Installed capacity of the power house is 24 MW with an expected annual power generation about 54 GWh. The Project had received the EIA approval from the CEA. However due to high investment cost and the failure of securing funding for the project as a CEB implemented project; alternative development models are being explored at present.

ii. Other Hydro Power Projects

Multipurpose hydro projects such as Thalpitigala and Gin Gaga and 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. As per the feasibility studies, the power plant is 15 MW (2 x 7.5 MW) with an estimated annual energy contribution of 52.4GWh. However due to difficulties in securing project finances, the project is on hold at present.

The preliminary feasibility studies for Gin Ganga hydro project are in progress and the parameters of the hydro power plant is yet to be finalized.

5.2.4 Details of the Candidate Hydro Power Projects

The basic technical data of the selected projects are summarized in Table 5.1 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	24	54(@ 27% PF)	3.51
Thalpitigala	Uma Oya	15	52.4(@39% PF)	17.96

Table 5.2 - Capital Cost Details of Hydro Expansion Candidates

Plant	Capacity (MW)	Total Cost (US$ millions)	Const Period (Years)	Economic Life (Years)
Seethawaka[1]	24	85.94	4	50
Thalpitigala[2]	15	174	3.5	50

1. Estimated Project cost is extracted from the Seethawaka Ganga Hydropower Project Feasibility Study, December 2018 [20]
2. The total cost of the project is shown as a detailed cost breakdown is not feasible as hydro power is a secondary benefit and developed by Ministry of Irrigation and Water Resource Management.

5.3 Hydro Power Capacity Extensions

As the share of other renewable energy sources increase in the system, the role of firm hydro power shall become pivotal to provide low cost intermediate and peak power operation. The capability of providing peak power support from hydro power 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" [15].

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 [21] 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 pumped storage power plant (pumped 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 114 MW each will be added. This expansion could double the capacity of Victoria while the energy benefits are as follows.

Table 5.3 – 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 70 MW 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.

According to the ongoing study by "Mahaweli Water Security Investment Program "under the Ministry of Mahaweli Development and Environment, it has been proposed to transfer water from the Randenigala reservoir to Kaluganga reservoir to meet the water demand requirements of North Central Province. This will impact the water availability and operation of the reservoirs of the Mahaweli complex. Therefore, the feasibility of Victoria expansion and upgradation should be further reviewed based on the study outcome of Mahaweli Water Security Investment Program before incorporating into the Long Term Generation Expansion Plan.

(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 39 GWh. For the implementation of above project, Operation of Upper Kothmale Hydro Power Plant needs to be interrupted for 6 months resulting reduction of 150 MW capacity and 200 GWh 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 67 MW generators are installed in the Kotmale Power Station with an annual average energy output of 455 GWh. The amount of energy could be increased by about 20% by raising the dam crest from elevation 706.5m to 735.0 masl.

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 60 MW each. In addition to these, studies have indicated that further two units of 60 MW 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 60 MW units have been made to extend the capacity of the power plant to 240 MW. The extension comprises of construction of Diyawini Oya reservoir.

However, the Stage II Feasibility Study report done by CECB in April 2002 has considered it as infeasible to construct the Diyawini Oya reservoir and recommends installation of one additional 60 MW 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 5.4. However, further studies are required to be carried out to revise the findings in the original study as per the present conditions.

Table 5.4 – 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 [22], 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 100 MW to 116 MW. Planned replacement of generator, turbine governor excitation & controls of the old Laxapana Project were completed increasing the plant capacity and efficiency.

Expansion of Polpitiya Power Station has been implemented and the plant capacity has been increased to 90 MW from 75 MW from 2019 onwards.

5.4 Other Renewable Energy Development

As the large hydro resource and of the country have been largely developed over the past decades, the other renewable energy sources, mainly small hydro, wind, biomass and solar resources remain as the main potential indigenous resources for future development. The tropical climate of the country influenced by Asian monsoon winds characterizes these resources and distinct seasonality exists in hydro and wind resources.

The grid connected small renewable energy resource development was first initiated in 1997 through the regularization of small renewable energy power producers by Ceylon Electricity Board with the publication of standardized power purchase agreement (SPPA). The growth of other renewable energy sources in Sri Lanka in commercial scale commenced with the development of mini-hydro resources in 1997 and its continued growth under feed-in tariff system. The introduction of cost reflective, technology specific feed-in tariff in 2007 paved the way for the development of wind resources and considerable growth was achieved in local wind resource development. With the introduction of the solar net metering facility in the country in 2009 followed by the rapid technology cost decline and rapid growth in the global solar PV industry after 2010, solar resource development gained steep growth over the past years. With the introduction of Net metering, Net accounting and Net plus schemes stimulated the growth of rooftop solar applications and grid scale solar PV developments are also growing at different scales. The other renewable energy project development was led largely by the private sector with the facilitation of Ceylon Electricity Board and the Sri Lanka Sustainable Energy Authority and the first large scale renewable energy project of the country, the 100 MW wind farm in Mannar island is developed by the Ceylon Electricity Board. The renewable energy projects have been successful in attracting investment and the renewable energy industry has been growing continuously over the years. The figure 5.1 bellow illustrates the growth of other renewable energy capacity over the last two decades.

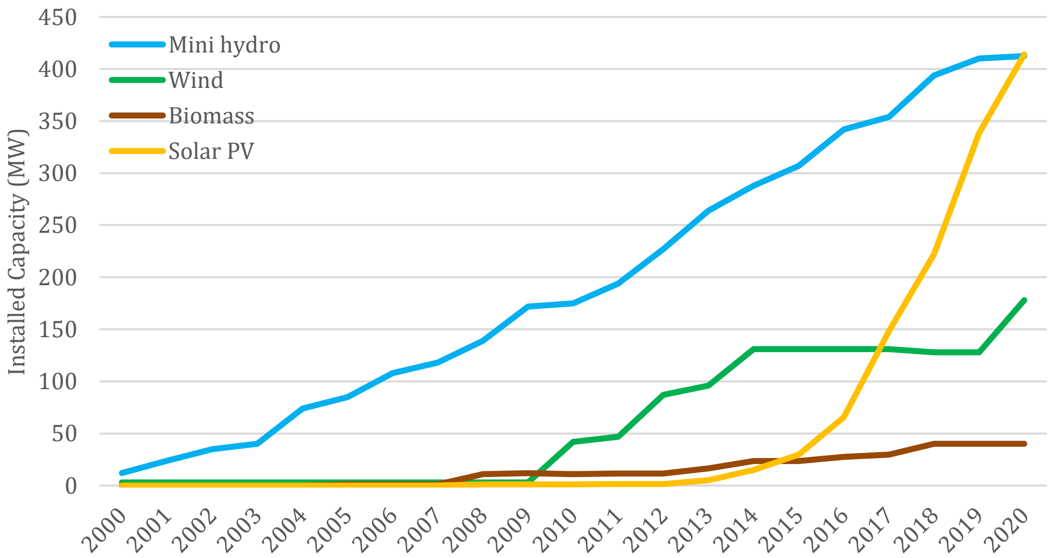


Figure 5.1: Other Renewable Installed Capacity by source 2000-2020

Share of Other Renewable Energy based generation at present is 12% of total energy generation in the country and its contribution is expected to increase in the future. At the end of 2020, 683 MW of other renewable energy power plants have been connected to the national grid and the total comprises 409.5 MW of mini-hydro, 148.5 MW of wind, 75.36 MW of Solar PV and 50.09 MW of biomass based generation capacities. The rooftop solar PV capacity with a total of approximately 350 MW embedded at the consumer end is growing steadily.

Other renewable energy sources have been under the cost reflective technology specific tariff scheme since 2012 and with the falling technology costs and rising competition in the industry, competitive bidding process is increasingly being followed at present for the development of new renewable energy projects. Table 5.5 shows the growth of the renewable energy capacity and energy contribution compared to the overall capacity and generation for past 15 years in the country. Rooftop Solar PV installed capacity and the energy exported to the grid by rooftop Solar (export) included from year 2019 onwards.

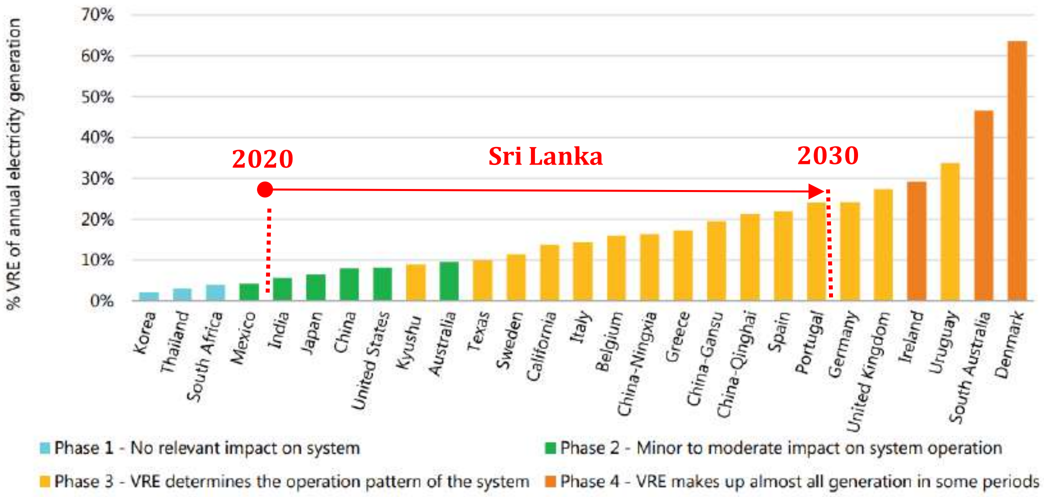
Table 5.5 – Energy and Demand Contribution from Other Renewable Sources

Year	Energy Generation (GWh)		Capacity (MW)	
	Other Renewable	System Total	Other Renewable	Total System Installed Capacity
2006	346	9,389	112	2,434
2007	344	9,814	119	2,444
2008	433	9,901	161	2,645
2009	546	9,882	181	2,684
2010	724	10,714	212	2,818
2011	722	11,528	227	3,141
2012	730	11,801	320	3,312
2013	1,178	11,962	367	3,355
2014	1,215	12,418	442	3,932
2015	1,466	13,154	455	3,850
2016	1,160	14,148	516	4,018
2017	1,464	14,671	562	4,087
2018	1,714	15,914	573	4,048
2019	1,761	15,922	915	4,214
2020	1,866	15,714	1,060	4,265

5.4.1 Projected Future Development

As the country is moving forward with an ambitious program for developing indigenous renewable energy resources towards enhancing its energy security in a low carbon future, substantial grown in indigenous renewable energy development is expected. The "General Policy Guidelines in Respect of the Electricity Industry'' which provides the specific government policy guidelines applicable to the Electricity Industry issued in April 2019, stipulates the vision of achieving a total renewable energy share of 50% in 2030. With the massive scale of wind and solar resource development required to achieve that target, Sri Lanka is expected to move to challenging phases of renewable energy integration. Moderate growth is expected from the Mini-hydro resources considering the remaining economical resource potentials. However, the addition of Mini-hydro and biomass resource is not strictly limited and will be assessed case by case for future projects. Both wind and solar resources being variable renewable energy sources (VRE) with inherent characteristics introduce range of challenges in reliable and economic operation of power system as well as transmission network expansion. In order to identify and address these challenges, the Ceylon Electricity Board conducts a comprehensive Renewable Energy Grid Integration Study during planning cycles and the study considers the available technical potential, resource quality, system stability and reliability, system operational implications, transmission infrastructure development and other techno economic considerations. The future development of the other renewable energy resources included in the Base Case of this LTGEP 2022-2041 are based on the study 'Integration of Renewable Based Generation into Sri Lankan Grid 2020-2030 [23].

According to the classification defined by International Energy Agency (IEA) based on key characteristics and challenges experienced by different systems of different countries with their present wind and solar penetration levels (Annual share of VRE generation), six different phases have been defined ranging from no impact to from VRE to severe impact from VRE. The 4th phase is the highest phase reached by countries at present as shown in the Figure 5.2 below and Sri Lanka with its wind and solar development currently envisaged is expected to move all the way from the beginning of phase 2 to the end of phase 3 within 10 years. This signifies the planned transition of the country as well as the scale of challenges the country should address in this pathway.



Source: International Energy Agency

Figure 5.2: Classification of phases based on variable renewable integration challenges

Planned development of other renewable energy, as incorporated in the long term generation expansion plan for the period of 2022-2041, is given in the Table 5.6 below. Projected capacity additions have been assumed as committed and modelled accordingly. Hence the timely implementation is important to capture the intended benefits.

Table 5.6 – 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 %
2022	464	268	81	1,039	1,852	4,581	25%
2023	484	303	85	1,299	2,171	5,239	27%
2024	494	343	90	1,569	2,496	5,893	29%
2025	504	443	95	1,829	2,871	6,743	31%
2026	514	543	100	2,024	3,181	7,471	33%
2027	524	663	105	2,184	3,476	8,196	34%
2028	534	783	110	2,354	3,781	8,920	35%
2029	544	883	115	2,514	4,056	9,547	36%
2030	554	1,013	120	2,684	4,371	10,276	36%
2031	559	1,113	125	2,874	4,671	10,969	37%
2032	564	1,213	130	3,064	4,971	11,680	37%
2033	569	1,313	135	3,244	5,261	12,402	38%
2034	574	1,413	140	3,444	5,571	13,181	38%
2035	579	1,513	145	3,684	5,921	14,015	39%
2036	584	1,613	150	3,934	6,281	14,829	39%
2037	589	1,713	155	4,174	6,631	15,664	39%
2038	594	1,813	160	4,414	6,981	16,520	40%
2039	599	1,913	165	4,654	7,331	17,356	40%
2040	604	2,013	170	4,894	7,681	18,168	40%
2041	609	2,113	175	5,134	8,031	18,980	40%

Note: Further addition of Mini-hydro and Biomass capacities are not limited to above planned values and will be considered case by case depending on the technical feasibility

At the end of year 2020, the total renewable energy capacity has reached 2,447 MW which includes 1,383 MW of Major Hydro and 1,064 MW of other renewable energy capacity. Other renewable energy capacity includes 425 MW of Solar PV with both rooftop and ground mounted applications, 410 MW of mini-hydro capacity, 179 MW of wind capacity and 50 MW of biomass capacity.

Solar PV, being the leading form of renewable energy technology, is facilitated to be increased up to 1,829 MW by 2025 under several schemes of implementation and expected to reach 2,684 MW by 2030 together with large scale solar PV projects. Present wind capacity is planned to grow up to 1,013 MW by 2030 and continue to grow beyond the same pace with large scale wind resource development. Mini-hydro and biomass resources are expected to grow moderately within next twenty years.

The total exploitable wind and solar PV resource locations are based on the resource potentials identified by Sri Lanka Sustainable Energy Authority, assessed considering multiple factors such as the resource potential, local climate, land use and reservations, coastal reservations, access to resource locations, housing density, local climate and distance to transmission infrastructure, etc. The identified resources potentials for each type are planned to be developed following an economic order based on the resources quality (energy yield, geographical staggering due to variability etc.) and infrastructure requirement (land, transmission infrastructure, access roads etc).

Development of renewable energy resources introduces range of challenges for the planning and reliable operation of the power system. Despite the level of renewable energy development envisaged, it is utmost important to ensure that the power system reliability is maintained and all the necessary grid integration measures are properly implemented. Therefore, the development of the planned intermittent renewable energy resources is conditional to the proper implementation of grid integration measures recommended by the grid integration study. Figure 5.3 below illustrates the ORE development over past two decades and planned ORE capacity addition for next 20-year period until 2041. The total ORE capacity added during the past twenty years is planned to grow nearly by eight times over the next twenty years, presenting an enormous development challenge as a country to achieve and maintain 50% renewable energy share target by 2030 and beyond.

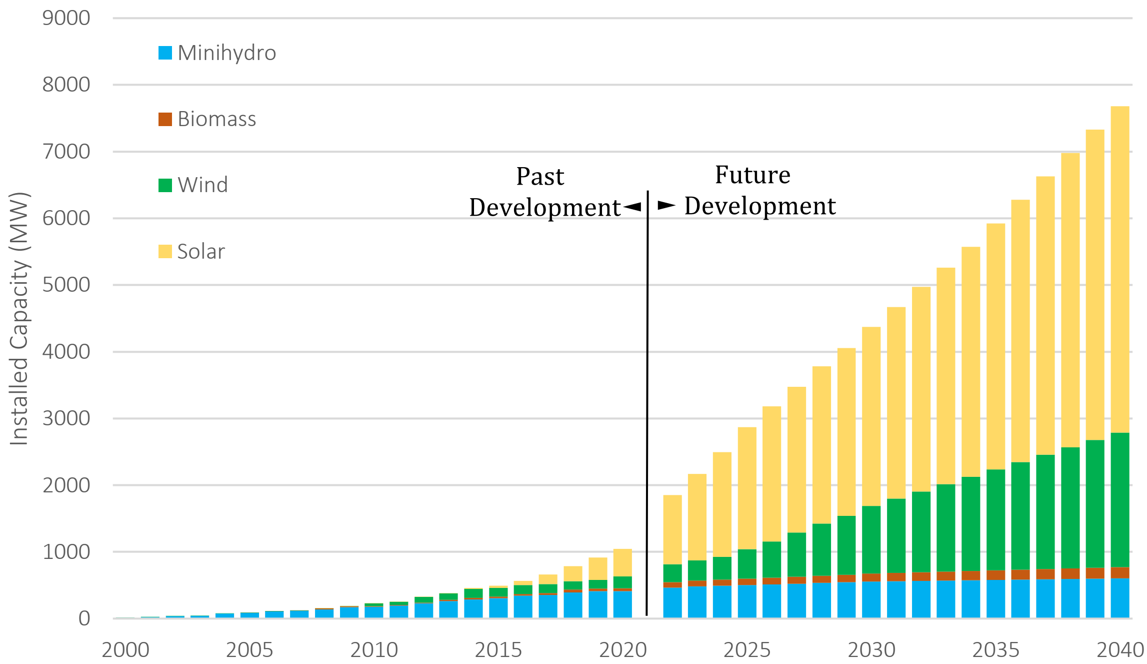


Figure 5.3: Past and Future Other Renewable Energy (ORE) Capacity Development

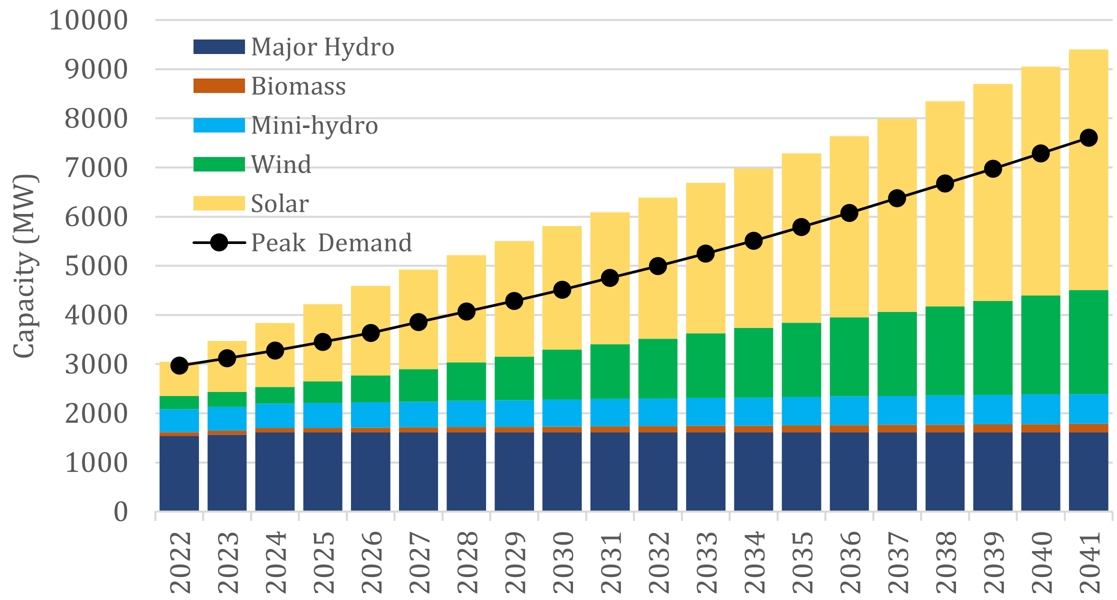


Figure 5.4: Total Renewable Energy Capacity Development

In long term, the total other renewable energy (ORE) capacity is planned to increase from 2,447 MW in 2020 to 5,903 MW by 2030 and to 9,563 MW by 2041 as show in the figure 5.4 above. Total capacity of major hydro resources is expected to increase first five years by 186 MW with the completion of ongoing hydro power projects and will remain at the same level afterwards. The total planned Other Renewable Energy (ORE) capacity will increase from 1,064 MW to 4,371 MW by 2030. Wind and Solar capacity is the significant contributor to the ORE capacity increase whereas a moderate growth is expected in Mini-hydro and Biomass technologies. Beyond 2024, the major share of the total renewable capacity is held by the solar PV capacity followed by major hydro capacity.

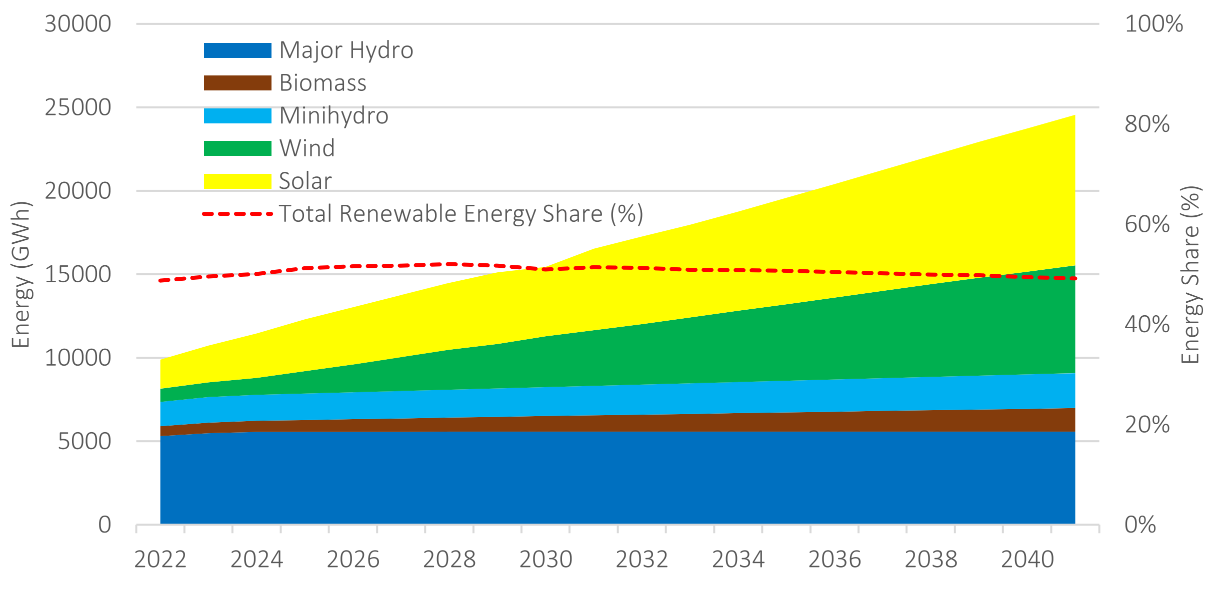


Figure 5.5: Energy Contribution of Renewable Energy Sources and Energy Share for next 20 Years

Figure 5.5 above illustrates the contribution of renewable energy sources and the percentage energy share variation over the next 20-year period. The total renewable energy share continues to be significant over the next 20-year period mainly due to scaling up other renewable energy resources. ORE contribution increases progressively surpassing the major hydro energy share mainly with the growth of wind and solar resources. It is envisaged that the solar PV will dominate other forms of renewable energy by capacity and its energy share will also be significant beyond 2030. The total renewable energy share will be significant and stands above 50% in average and wet conditions throughout the twenty-year period and the same can reach up to 57% in very wet hydrological conditions. The Variable renewable energy share reaches 27% by 2030 which indicates the increasing levels of grid integration challenges.

The total renewable energy capacity as shown in the figure 5.6 below will be 60% of the installed capacity and will be higher than the peak demand of the country. The planned scale of renewable energy resources development presents paradigm change aimed towards low carbon power system for future and it is well in compliance to environmental obligations of the country expressed though the Nationally Determined Contribution (NDCs) to the United Nations Framework Convention on Climate Change (UNFCC). The country's future plan to scale up indigenous renewable energy sources lowering the carbon emissions as well as dependence on import fossil fuels, signifies the national efforts to enable the transition to a cleaner and secure electricity system.

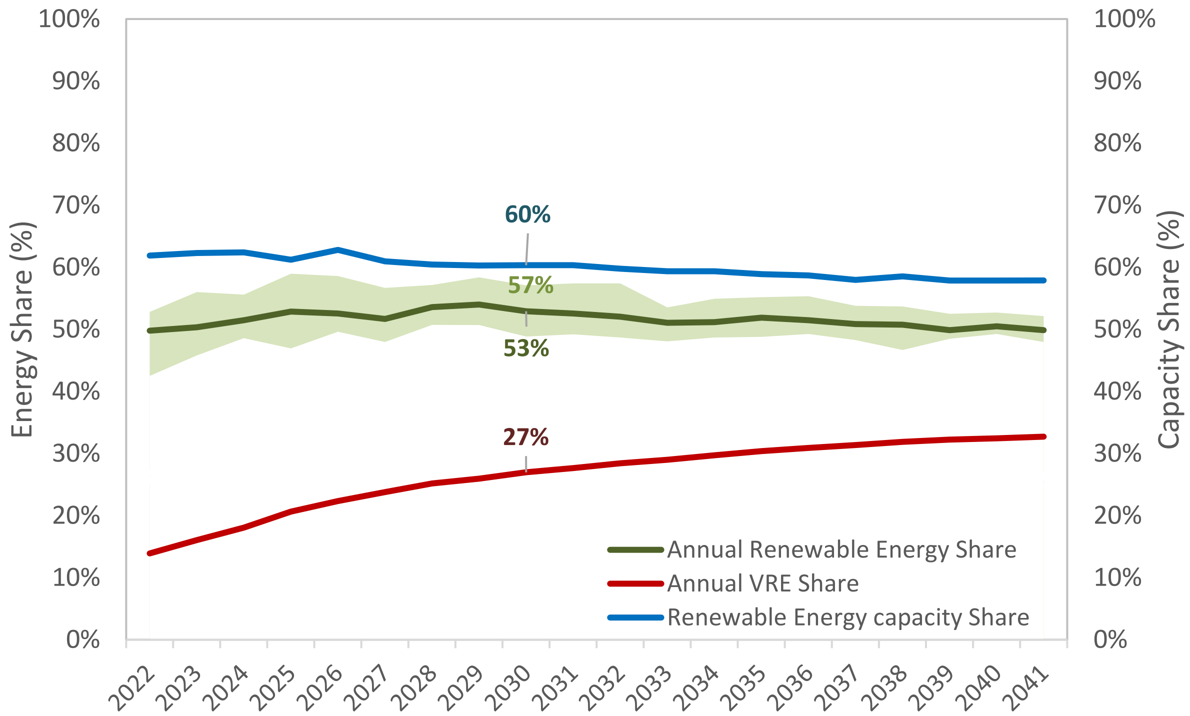


Figure 5.6. Energy Contribution of Renewable Energy Sources and Energy Share for Next 20 Years

5.4.2 Renewable Energy Grid Integration Study 2020 - 2030

Developing indigenous renewable energy resources including intermittent resources such as wind and solar at large scale creates growing concerns of their impact on the planning and operating the power system. Ceylon Electricity Board (CEB) as the Transmission Licensee having a statutory duty to develop and maintain an efficient, coordinated and economical system of Electricity Supply, conducts a comprehensive Renewable Energy Grid Integration Study specifically designed to identify and address the grid integration challenges related to introducing large amount of renewable energy sources. Assessment of technical, operational, economic aspects and identifying necessary integration measures is the key for enabling the effective utilization of renewable energy sources while maintaining a quality and reliable supply of electricity. Supplementing the long term generation expansion planning studies, the grid integration study serves as a comprehensive examination of the challenges and necessary interventions associated with integrating higher levels of intermittent renewable energy generation in the electricity grid covering the period of 2020 to 2030. The "General Policy Guidelines in Respect of the Electricity Industry'' which provides the specific government policy guidelines applicable to the Electricity Industry issued in April 2019, stipulates the vision of achieving a total renewable energy share of 50% in 2030. With the scale of wind and solar resource development required to achieve that target, Sri Lanka is expected to move to challenging phases of renewable energy integrations. The objective of the study is to provide the most effective and efficient pathway with effective grid integration measures for Sri Lankan Power system for the goal of achieving a total renewable energy share of 50% from the total electricity generation in 2030 while maintaining reliable supply of electricity.

The scale of wind and solar resource development currently being envisaged with recent policies will move the country's power system to phases where the integration challenges become much more significant requiring special operational, policy and investment based interventions to ensure reliable operation of the power system. These common challenges can be present in many systems, but their severity and importance often depend on the characteristics of each system. According to the classification defined by International Energy Agency (IEA) based key characteristics and challenges experienced by different countries with their present wind and solar penetration levels (Annual share of VRE generation), six different phases have been defined ranging from no impact to severe impact of VRE. The 4th phase is the highest phase reached by countries at present and Sri Lanka with its wind and solar development currently envisaged is expected to move all the way from the beginning of phase 2 to the end of phase 3 as illustrated in the section 5.4.1 of this chapter.

As the major portion of the potential renewable additions is comprised of VRE, this study evaluates implications of VRE in different time frames covering capacity adequacy, transmission infrastructure development, system operational flexibility and system stability aspects of the power system. Therefore, this study is designed with an integrated approach combining resource assessment, capacity expansion planning, system operation analysis and transmission network analysis study components. Then the study recommends the key integration measures to be implemented at the grid level and at plant level (both dispatchable and non dispatchable). An outline of the study methodology is shown in the annex 5.1.

Assessing resource potential for future development is a key step in the study process. Remaining major hydro and mini-hydro resource potential were considered in the study and the total wind and solar PV resource locations are based on the exploitable resource potentials identified by Sri Lanka Sustainable Energy Authority through the resource assessment based on GIS information covering the entire country. Large scale development of wind and solar resource development for the next twenty years requires prioritizing the resource sites and associated transmission infrastructure development. Therefore, all wind and solar resources were classified in to seven renewable energy zones where each zone has a specific topographical and resource characteristic. All seven renewable energy zones have substantial potential for solar power, but the wind power is limited to renewable energy zones in Northern and North-western area. The classification of zones considered in this study is shown in annex 5.1.

Sri Lankan power system, being a small isolated power system, its ability to integrate more variable renewable energy that are variable and uncertain significantly depends on the stability and operational flexibility of the system. A system operation study was performed under the renewable energy grid integration study to investigate the implication on system operation to identify challenging operating conditions and potential solutions to mitigate the implications of renewable generation. Dispatchable power plants (both Storage Hydro and Thermal plants) have complement the non-dispatchbale generation in meeting the electricity demand while maintaining the balance between supply and demand. Under high penetration levels of variable renewable energy, the dispatchable power plants are required to follow more cyclic operation and to provide fast ramping more regularly. Therefore, the technical constraints of the dispatchable plants as well as the system flexibility level governs the ability of the system to operate under higher penetration levels reliably.

Operation constraints are prominent specially during low load period such as weekends with large amount of wind, mini-hydro and solar PV generation. During such constrained periods the large thermal units have to lower their output to a minimum or consider shutting down depending on network requirement and the start-up costs etc. Beyond such levels a surplus generation exists in renewable which has to be either curtailed or stored to maintain the supply demand balance of the system. According to the study results, the curtailment magnitude is likely to increase year by year to significant levels with the addition of the planned renewable energy capacities. The most severe constraints on operation is observed during periods where both wind and hydro generation peaks. Therefore, it is crucial that the system operator has adequate measures such as flexible generation, VRE curtailment and energy storage to maintain the supply demand balance throughout the year. The study has recommended adopting improved flexibility performance in both technical and contractual terms for thermal plants, introducing plants with the capability of fast ramping and frequent cycling and the introduction of pumped storage hydro power plant as a long term energy storage measure to enhance system flexibility.

High shares of inverter based non-synchronous renewable energy generation challenges the stable operation of the power system. As the inverter based generation does not actively contribute to the synchronous inertia or to the system strength, high instantaneous penetration levels of inverter based generation lowers the system's ability to withstand sudden imbalances and disturbances that can potentially lead to system failures. The grid integration study evaluates the transmission infrastructure development and the impacts of VRE integration on the stability and security of the transmission network under different operating conditions. The study has proposed the required Transmission system development and strengthening measures for large scale renewable energy development. Further the introduction of 100 MW of battery energy storage system is proposed by 2030 to provide fast responses required to manage the frequency under high penetration levels of variable renewable energy sources.

Key technical recommendation of the grid integration study that are essential to progress with the planned renewable energy development program is outlined below.

- Establishing Renewable Energy Forecasting system to manage the uncertainty in maintaining supply and demand balance under in intra-hour, intra-day and day-ahead timeframes.
- Establishing monitoring and supervisory control facility for new renewable energy projects to provide the visibility and controllability to the system control centre to manage both normal and contingency operating conditions.
- Enhancing the flexibility of the firm capacity mix to facilitate the long term transition towards indigenous renewable energy technology. Appropriately adopting flexible generation thermal power technologies with the capability of fast ramping and frequent cycling features ensured by both technical and contractual terms.
- Development of the planned pumped storage hydro plant as a long term measure to enhance the flexibility and security of the system.
- Implementing 100 MW battery energy storage systems starting from pilot scale to provide the fast frequency response requirement of the system.
- Integration of solar PV with Battery energy storages is encouraged to provide the capacity requirements and its potential to displace the peak capacity economically and really will be evaluated with the future progress and competitiveness with other alternatives.
- Establishing downward dispatchability for new variable renewable energy projects (Wind and Solar PV) as a mandatory requirement by regulation to curtail the output as and when necessary for secure and economic system operation.
- Enhancing the grid support features of variable renewable energy projects including enhanced Ride through capabilities, Frequency Ramp Rate Control functions and it is recommended to periodically review and upgrade the existing interconnection and operating codes/regulations based on detailed studies and up-to-date industry practices.
- Reviewing the present operating reserve policy of the system operation to provide the additional regulating reserve to integrate the planned renewable energy capacities by preferably adopting a dynamic reserve policy in both up and down directions.
- Maximizing the flexibility performance of future thermal Power fleet by ensuring the design features are properly specified to match the increasing flexibility requirement in terms of lower minimum output, higher ramp rates, short start-up times as well as present industry practices.
- Minimizing the risk of possible take or pay Liquid Natural Gas (LNG) contracts that could hinder the flexible operation of the planned natural gas based thermal fleet.
- Conduct further studies to investigate the necessity of a non-synchronous penetration limit for the system

5.4.3 Wind Resource Development

Sri Lanka is blessed with quality wind resources mainly located in the North-western coastal area, Northern area and central highland area. The wind resource patterns are mainly characterized by the Asian monsoon wind system and mainly the richest wind power potential of the island (Class 4 and above) is available in the areas that are exposed to southwest monsoon. Only a portion of the total available potential is economically exploitable due to reasons such as competing land uses, accessibility and environmentally sensitive concerns. Ceylon Electricity Board has identified these exploitable wind resource potentials and prioritized their development activities together with the expansion of transmission infrastructure. Annex 5.2 illustrates the prominent seasonality characteristics of different wind regimes of the island.

The economically exploitable wind power potential identified in the preliminary resource potential assessment is mainly concentrated on Northern and North western coastal line of the country. The north eastern coast and the central hills also hold certain amount of wind resources but not prioritized for the immediate development in large scale due to development constraints. The Mannar area, Northern area and Puttalam area are priority resource area to develop wind power compared to other regions of the country. Nearly 2060 MW exploitable potential is identified for the development in these three regions span on 16 divisional secretariat divisions of 6 districts. Both public and private sector participation developing these resources is taking place and at present competitive mechanisms are being followed in developing projects.

The first ever largest wind farm of the country, the 100 MW Thambapavani Wind Farm has been developed by Ceylon Electricity Board with financial assistance from Asian Development Bank (ADB) in the Southern coast of the Mannar island and further extension to the farm is being considered. Sri Lanka Sustainable Energy Authority had identified another 200 MW to be developed in the Mannar island in which land area have been earmarked and gazetted.

Ministry of Power together with Sri Lanka Sustainable Energy Authority and Ceylon Electricity board have taken the new initiative to develop a large scale renewable energy park at the Pooneryn site located in the northern province. Preliminary studies are currently in progress both for the renewable energy park and associated transmission infrastructure. According to the initial assessments, the park will produce 250 MW wind power and 150 MW of solar PV generation.

5.4.4 Solar Power Development

Sri Lanka, being located within the equatorial belt, has substantial potential in solar resource. Solar resource maps of the country indicate the existence of higher solar resource potentials in the Northern half, Eastern and Southern parts of the country. Resource potential in other areas including mountainous regions is mainly characterized by climatic and geographical features. The cost of solar PV technology is becoming increasingly competitive and a steady and strong growth is expected to continue for both rooftop and ground mounted applications in commercial scale. The local solar power industry gained significant momentum over the past years due to number of support schemes and development initiatives of the Ministry of Power, State Ministry of Solar, Wind and Hydro Power Generation Projects Development, Ceylon Electricity Board and the Sri Lanka Sustainable Energy Authority.

Similar to the wind resource, the technical potential of integrating solar PV resources into the power system is assessed by the renewable energy grid integration study conducted by Ceylon Electricity Board. Both large scale and small scale development is planned for the next twenty years as solar PV is the main form of renewable energy source that indicates the highest growth for long term.

The Solar potential identified in the country can be classified in to following categories of development and are implemented through several configurations appropriately.

1. Ground Mounted Solar
   a. Large and Medium scale solar parks (10-100 MW)
   b. Scattered small scale solar parks (1-10 MW)
   c. Scattered small scale solar parks in LV Network
2. Rooftop Solar (Net Metering, Net Accounting, Net Plus)
3. Floating Solar

5.4.4.1 Development of large and Medium Scale Solar PV Parks

Large scale solar PV part development has its own advantages in economies of scale and also the technical challenges in grid integration. Large scale solar PV parks in the scale of 100 MW are planned for future development in Northern, Southern and Eastern areas. The Sri Lanka Sustainable Energy Authority has identified potential resource locations for large scale development in Trincomalee, Ampara, Monaragala, Batticaloa, Hambantota, Kurunegala, Puttalam and Anuradhapura areas to support a longer term large scale development plan. Potential resource locations for the development of medium scale ground mounted PV capacities above 10 MW and below 100 MW have also been identified around the island. Prioritizing the development of large scale resources depending on the resource quality and associated development cost is important for achieving the economic efficiency of the long term renewable energy development program.

5.4.4.2 Development of Small Scale Distributed Solar PV Projects

One strategy to minimize the inherent variability challenge of solar PV resources is geographical distribution of solar PV installations as there is a greater diversity in variability characteristics in smallest time scales. Studies conducted by Ceylon Electricity Board have identified that the geographical distribution of solar PV projects can reduce the overall variability levels experienced by the system notably. In line with the second phase of the accelerated solar development program of the government, Ceylon Electricity Board initiated the development of 60 MW with 1 MW Solar PV projects at 20 selected Grid substations through international competitive bidding process under BOO basis. Subsequently several phases of the same scheme were launched to develop 1 MW x 90, 1 MW x150 solar PV plants with improved contractual terms to provide more facilitation and flexibility to developers. It is planned to develop further 150 MW and another 140 MW in near term under the same scheme.

5.4.4.3 Development of Small Scale Distributed Solar PV schemes in Low Voltage Network

A new initiative was taken to develop ground mounted solar PV plants in the distribution system in small scale distributed manner to facilitate rapid uptake of solar PV utilizing the existing network infrastructure. Accordingly, Ceylon Electricity Board (CEB) has invited proposals from prospective developers through National Competitive Bidding (NCB) for development of ground mounted, low voltage connected solar PV power plants each with 75 kW capacity, on Build, Own & Operate (BOO) basis. These schemes are planned to be developed within 500 m radius of pre-identified distribution substations, mainly in rural locations and in areas that have less potential for rooftop solar installations. Over 7000 distribution substations have been identified for phased development under this programme. It is crucial to implement suitable mechanism to provide adequate visibility and controllability of these schemes to the system operator, so that supply demand balance could be maintained during constrained operation periods.

5.4.4.4 Development of Rooftop Solar PV Installations

Roof top solar systems are starting to play a prominent role in providing energy needs of the electricity consumers and it is an effective form of embedded generation located at the end user. Since these solar PV installations utilize the available rooftop spaces, those have less impact to the environment caused by land use. 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 through the power utilities 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.

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. 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. The total installed capacity of rooftop solar PV under three has reached 374 MW by the end of 2020 surpassing the program's goal of reaching an installed roof top solar PV capacity of 200 MW by 2020.

These three schemes change the role of the traditional electricity consumer to a consumer and producer. Roof top capacity is expected to grow further in the forthcoming years under the projected solar capacity additions stipulated in Table 5.6. With the planned growth of rooftop solar PV capacity for future, it is essential to address the main technical challenges encountered at the distribution level to streamline the roof top solar PV program and to maintain the quality of the electricity supply to the consumers.

3.4.4.5 Potential to develop Floating Solar PV Plants

Floating solar technology alternative has the potential to resolve the land limitation issues for developing solar power plants. In this, solar panels are usually mounted upon a floating structure and to keep its location fixed, floating structure is anchored and moored. Direct advantages of floating solar technologies are

- Higher gains in energy production due to lower PV array temperature
- Minimal Land requirement compared to ground-mounted solar PV
- Reduction in water evaporation of reservoirs
- Possibility of sharing existing electrical infrastructure

A Floating solar power plant with a capacity of 42 kW was installed at the University of Jaffna in 2020 marking the country's first such project as a pilot project. Moreover, the Sri Lanka Sustainable Energy Authority has identified multiple potential reservoir locations to develop large scale floating solar projects and detailed techno-economic assessments for each resource sites are required for long term investment decisions.

5.4.4 Mini-hydro Development

History of small hydro power generation in Sri Lanka spans over a century and it is mainly associated with the power generation for the large scale tea plantations in the colonial era. Since then, the small hydro capacity grew gradually until 1960s when the electricity grid was extended to provide supply of electricity. In 1990s, CEB's assistance was provided for the development of the Mini hydropower sector with the required assistance to the private sector, which includes training & capacity building, pre-feasibility studies and resource assessments. The procedure for electricity purchases from Small Power Producers (SPPs) by the CEB was regularized beginning in 1997 with the publication of a standardized power purchase agreement (SPPA) which included a scheme for calculating the purchase price based on the avoided cost principle. Further, National Energy Policy in 2006 has identified fuel diversify and energy security in electricity generation as a strategic objective and development of renewable energy projects was identified as a part of this strategy. In view of above, action was taken to introduce a three-tier tariff instead of avoided cost based tariff with effect from year 2008. All large-scale hydropower generation facilities are to be remained under Government control for the foreseeable future and development of small hydro power plants is done through the Private sector. Currently the technology specific cost reflective tariff introduced in 2012 is in force.

The geo-climatic condition in Sri Lanka is favourable for the mini hydro development and several past studies have assessed the potential for the development of mini-hydro resources. A comprehensive study has been carried out as part of the Dam Safety and Water Resources Planning project (DSWRP) of the Ministry of Irrigation and Water Resources, focusing on 13 river basins of the country, and the study has concluded that the total Mini-hydro potential in the country as 873 MW. As at the end of 2020, the total grid connected Mini hydro capacity is 412 MW which comprises 387 MW developed by the private sector and 25 MW under the Moragahakanda Kaluganga Development multi-purpose development project by the Ministry of Mahaweli Development and Environment with the Mahaweli Authority of Sri Lanka. In this long term generation expansion plan, the Mini-hydro capacity is expected to grow moderately within next twenty years as most of the attractive resources and sites have been already developed. The projection of future Mini-hydro capacity additions as per the table 5.6 and further capacity additions shall be considered case by case, depending on the feasibility of implementation. Annex 5.3 illustrates the characteristics of annual mini-hydro production pattern.

5.4.5 Biomass Power Development

Biomass is a renewable resource that is primarily based on organic matter as a fuel related to plants, vegetation and waste that generates from agricultural and industrial process as a by-product or residue. Growing biomass as a fuel for Dendro power generation gained attention in the recent past and at the end of 2020 total biomass based capacity was 40 MW including both dendro and agricultural waste based power generation. Evidently, the growth of the biomass capacity in the past has not achieved the expected progress primarily due to the factors associated with biomass fuel supply mechanisms and only a moderate growth is expected in future. However, being a non-intermittent form of generation, the capacity additions are not strictly limited to the planned capacities and further capacity additions shall be considered depending on the feasibility and success of implementation.

5.4.6 Municipal Solid Waste Based Power Generation

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

Sri Lanka's first Waste-to-Energy Power project was developed and commissioned in Kerawalapitiya area. The 10 MW project is able to convert 700 tons of solid waste, nearly 20% of the household waste to electricity each day. The project was developed with private sector investment with the facilitation of Ceylon Electricity Board and Sustainable Energy Authority. Further, CEB has already signed SPPA to develop 2x10 MW Municipal solid waste power plants at Muthurajawela and Karadiyana.

5.4.7 Other Forms of Renewable Energy Technologies

CEB has provided opportunity for the development of other forms of new renewable energy sources with the recent initiative by requesting international proposals to develop new renewable technology applications such as Geothermal Energy conversion, Compressed Air based power generation, Ocean Thermal Energy Conversion (OTEC), Ocean Energy (Wave) conversion, Biogas power generation and other storage applications such as grid scale battery storages for energy shifting and hybrid systems consisting wind, solar PV and energy storage. The objective of this scheme was to pave way for potential green technologies that had reached their commercial capability beyond research level.

5.4.9 Development of Grid Scale Energy Storages

Integrating variable energy supply while providing reliable supply of electricity as well as efforts to integrate renewables into the end-use sectors has brought much significance to the potential energy storage applications. Storage technologies are diverse and their applications are rapidly expanding globally. Their applications in power systems are growing and can range from energy shifting, frequency controlling, and renewable energy fluctuation controlling. The economic value of different technologies varies depending on the type of application, amount of energy required, amount of power required and the location of the application.

High Energy density storage systems are suitable for performing energy shifting function in system operation whereas high power density storage technologies are suitable to provide fast power to manage instantaneous and momentary supply demand unbalances. Battery energy storages and pumped hydro energy storages are two major storage technologies applicable to power systems today and Ceylon Electricity Board has identified the requirement of developing the pumped hydro power project as a long term solution to increase power system flexibility and also CEB is currently embarking upon developing grid scale battery energy storages to enhance the quality of the supply of electricity.

5.4.9.1 Grid Scale Battery Energy Storage Development

Battery energy storage applications in power systems are expanding globally and the technology costs are declining notably. Even though the scale of battery energy storages applications in power systems are small compared to pumped hydro storages, battery energy storages have a wide array of applications in all generation, transmission distribution and consumer end points. Given the range of applications, battery energy storages are employed to enhance the quality and reliability of supply of electricity.

The battery storage systems provide services in different time frames ranging from fast frequency support to energy arbitrage with economic dispatch. Also it provides various support services for renewable energy grid integration. Lithium-ion type of batteries in power system applications are growing at present than the other forms of chemical batteries such as Flow batteries, Lead-based batteries and Sodium Sulphur batteries. Techno-economic assessment of the type of battery storage application and the type of battery technology is essential to identify effective storage solutions. Ceylon Electricity Board in its latest renewable energy grid integration study has assessed the requirement of grid side application of battery energy storages with the introduction of large amount of intermittent and non-synchronous generation in to the power system. Accordingly, it is planned to deploy a 20 MW of Battery Energy Storage capacity by 2025 as a gird level application primarily to provide frequency support services. It is expected to increase that to 100 MW by 2030 depending on the system requirement and the progress of wind and solar PV integration.

5.4.9.1 Pumped Storage Hydro Power Development

Being a matured technology, pumped hydro storage currently accounts for nearly 97% of the storage applications in power systems worldwide. Primary function of pumped hydro storage was to provide peaking capacity releasing the stored energy. However, the technology has now evolved to provide enhanced services to enable flexible grid operation specially with renewable energy integration.

CEB conducted the study in 2014 on exploring peak power generation options including pumped storage hydro power plant. The study titled “Development Planning on Optimal Power Generation for Peak Power Demand in Sri Lanka” was done with the technical assistance from JICA. During the study, all the possible peaking options were evaluated and following options were identified as feasible options.

- Hydro Power Plant Capacity Extension
- Pumped 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 Pumped 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 pumped storage power plant.

Pumped storage hydro power plant as a large scale storage medium that is able to serve several important secondary purposes other than providing the peaking power. Pumping operation of off-peak period enables the storage of surplus renewable energy that otherwise would have curtailed due to power system operational limitations. The new adjustable speed technology enables greater flexibility for pumping operation and it enables the frequency regulation functions and stability improvement by fast reaction to system supply and demand fluctuations. Moreover, the pumping operation during low load periods enables the operation of base load power plants in the system at their most efficient loads. The renewable energy grid integration study identifies significant renewable energy curtailment requirement with planned renewable energy capacities. The curtailments are mainly due to the demand pattern of the country and seasonality and variability of variable renewable energy sources. A large scale pumped hydro storage will enable greater utilization of renewable energy resources while alleviating system operational challenges. Therefore, this long term generation expansion plan proposes the development of a pumped hydro storage project having variable speed type technology to achieve required flexibility to the Sri Lankan island power system.

At the initial stage, the study conducted by JICA and CEB identified 11 potential sites for the development of 600 MW Pumped 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. According to the ranking, Halgran Oya, Maha Oya and Loggal Oya which were located in Nuwara Eliya, 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 Pumped Storage power plant should be 600 MW considering the peaking requirement beyond 2025. The unit capacity of the power plant was determined considering the system limitations in terms of frequency deviations and manufacturing limitations of high head turbines. The study considered 200 MW unit size for the baseline case and the final unit size will be decided after further assessments.

Another new site location for the PSPP plant was proposed by the Electricity Sector Master Plan Study completed in 2018 with the assistance of JICA. The proposed site is located in the Kandy district adjacent to the Victoria reservoir. This scheme will utilize the existing Victoria reservoir as the lower pond and an existing irrigation pond located at Wewathenna (on the eastern side of Victoria reservoir) as the upper pond, after expansion. The site has the potential to develop a pumped hydro storage power plant with a total capacity of 1,400 MW and staged development is proposed in the study. Figure 5.7 below illustrates the proposed site under two studies mentioned above and the table 5.7 shows the estimated capital cost of development for proposed sites locations under two studies. It is planned to conduct the detailed feasibility studies for the most promising site.

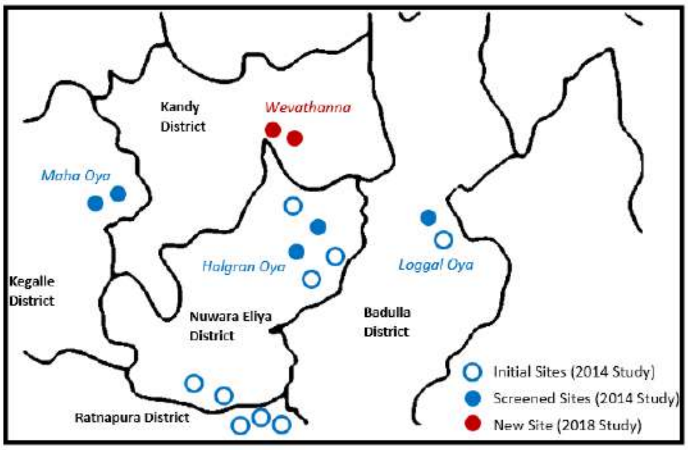


Figure 5.7: Three Selected Sites for PSPP after Preliminary Screening

Table 5.7 – Solar resource regimes and average capacity factors

Proposed Project	*Capacity (MW)*	*Capital Cost Pure ($/kW)*	*Capital Cost with IDC ($/kW)*	*Construction Period (Years)*	*Economic Plant Life (Years)*
Proposed site (2014 study)[1]	***600***	***1055.8***	***1306.9***	***5.0***	***50***
Proposed site (2018 study)[2]	***1400***	***649.0***	***803.33***	***5.0***	***50***

1. Development Planning on Optimal Power Generation for Peak Power Demand in Sri Lanka" carried out by JICA funds in December 2014 [19]
2. Electricity Sector Master Plan Study in Democratic Socialist Republic of Sri Lanka" carried out by JICA in March 2018 [13]

CHAPTER 6
GENERATION EXPANSION PLANNING METHODOLOGY AND PARAMETERS

The long term generation planning exercise investigates avenues to develop the electricity generation system to meet the future electricity demand by considering the all potential and proven sources of thermal and renewable energy generation. Several factors are taken in to account in this process of evaluating and selecting the most suitable power generation alternatives. Technical and economic characteristics of each generating technology, requirement of the system in terms of system security and system operation, technically exploitable resource potentials, global and local environmental obligations as well as future transition are among several factors considered in this selection process.

Together with these factors, the guidelines and study reports such as “Draft Grid Code of CEB Transmission Licensee” [24], “The National Energy Policy and Strategies of Sri Lanka” [4] and “General Policy Guidelines on the Electricity Industry for the Public Utilities Commission of Sri Lanka” [3] are taken into consideration in the planning process stipulated in the policy framework and the planning criteria.

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

The Least Cost Generation Expansion Planning Code was published in April 2011, to act as basis for conducting generation planning activities. The code represents objectives, planning period, frequency of update, planning boundaries, planning criteria, establishment of economic parameters, the development of base case with sensitivity analysis and other policy and scenario analysis to be considered when preparation of the Least Cost Generation Expansion Plan.

All elements of the Least Cost Generation Expansion Planning Code are considered in the Draft Generation Planning Code under the Grid Code issued by the Transmission Licensee in August 2015, which has been updated from the Grid Code issued by PUCSL in March 2014.

6.2. National Energy Policy and Strategies

Ministry of Power and Energy updated the National Energy Policy & Strategies of Sri Lanka in the Gazette Extraordinary No. 2135/61 dated 2019-08-19 after reviewing and revising the National Energy Policy and Strategies of Sri Lanka published in 2008. The main objective of the National Energy Policy and Strategies declared is to ensure convenient and affordable energy services are available for equitable development of Sri Lanka using clean, safe, sustainable, reliable and economically feasible energy supply. This Policy is formulated in alignment with the future goals of Sri Lanka, current global trends in energy and the Goal 7 of the Sustainable Development Goals of the United Nations.

The “National Energy Policy and Strategies of Sri Lanka” is elaborated in three sections in this policy document as follows:

- **The National Energy Policy** ; stating the ten pillars of the policy framework
- **Implementing Strategies** ;describing the specific strategies to implement the policy
- **The Results Delivery Framework** ; elaborating the specific actions, milestones and the institutions responsible

The National energy policy is founded on the following ten pillars, rooted in the broad areas to counter balance the forces through enhanced equity, security and sustainability.

- Assuring Energy Security
- Providing Access to Energy Services
- Providing Energy Services at the Optimum Cost to the National Economy
- Improving Energy Efficiency and Conservation
- Enhancing Self Reliance
- Caring for the Environment
- Enhancing the Share of Renewable Energy
- Strengthening the Governance in the Energy Sector
- Securing Future Energy Infrastructure
- Providing Opportunities for Innovation and Entrepreneurship

During the Preparation of Long Term Generation Expansion Plan 2022-2041, due consideration is given to salient features of National Energy Policy pillars considering the Implementing Strategies and specific milestones as follows .

Assuring Energy Security

1. Diversity in energy resources used in electricity generation to be ensured, with natural gas to be the next fossil fuel to be utilized to broaden diversity.
2. A liquefied natural gas (LNG) terminal of optimum size and technology would be established at the most suitable location. Considering the impact to the country’s energy security, operation of the first terminal and LNG procurement shall be kept under state control.
3. Percentage installed power generation capacity from a single imported fuel shall not exceed 50% of the total installed firm capacity to safeguard against geopolitical uncertainties and fuel price shocks.
4. National requirements of electricity will be met with proven generation technologies and fuel sources.

Enhancing Self Reliance

1. Oil and natural gas resources of the country will be explored. Commercial scale exploitation will be strategically phased, giving due consideration to higher future value and possible use in the future as a locally available fuel source to derive cleaner futuristic energy sources such as hydrogen.

2. Renewable energy resources will be exploited based on a priority order arrived at, considering economics, technology and quality of each resource.

3. Wind is identified as the second most promising renewable energy resource after hydropower and highest priority is given to develop wind to realize a minimum 20% share of electricity generated from renewable energy sources excluding major hydro, by 2022.

Caring for the Environment

1. Energy supply from cleaner sources and technologies will be encouraged to minimize harm to the local and global environment, while taking into consideration both the impacts on the National economy and the long-term environmental benefits.

2. Nationally Determined Contributions (NDCs) to global emission reduction goals will be made to meet the National emission reduction obligations as agreed.

Enhancing the Share of Renewable Energy

1. Energy supply from renewable energy resources in the country's energy mix will be increased to reduce pressure on foreign exchange, as a means of engaging the local community in the energy industry and to attain sustainability.

2. Renewable energy investments for electricity generation will be realized through a competitive scheme to reduce the costs and to facilitate wider investor participation.

3. Research will be conducted to overcome adverse impacts of renewable energy absorption to the power system from intermittent sources such as wind and solar energy.

4. Effective forecasting technologies for wind, solar and rainfall will be introduced so that optimum use of renewable resources could be realised.

5. Energy storage solutions will be encouraged for firming intermittent renewable sources, voltage and frequency regulation, local grid support, peak shaving and improving grid resilience.

Securing Land for Future Energy Infrastructure

1. Suitable sites to locate future energy infrastructure such as coal, natural gas and nuclear power plants, refineries and terminals will be strategically earmarked in advance following preliminary feasibility studies, so that the public can avoid using such sites, resulting in minimal relocation and social impacts at the time of actual development.

2. Best sites to locate large scale renewable energy infrastructure such as wind and solar farms would be identified in advance and marked on a master plan so that they can be developed as large concentrated facilities in phases.

6.3 General Policy Guidelines on the Electricity Industry for the PUCSL

Section 5 of Sri Lanka Electricity Act, No 20 of 2009 defines Minister of Power and Renewable Energy has the power to formulate the General Policy Guidelines on Electricity sector for the Public Utilities commission. The General Policy Guidelines on the Electricity Industry issued on 2009 was amended with the new 'General Policy Guidelines on the Electricity Industry for the Public Utilities Commission', issued in April 2019.

Long Term Generation Expansion Plan 2022-2041 has incorporated the instructions given in the General Policy Guidelines on the Electricity Industry, in the planning studies with emphasis given on following clauses.

Clause 9

To ensure security, availability and reliability of supply, there shall be installed firm power capacity (based on firm energy sources such as fossil fuels and storage hydro) at all time to provide at least 2/3rd of the demand for power.

Clause 10

In order maintain a practical and balanced fuel mix in the installed firm power capacity, by the year 2030, 30% of the installed firm capacity must be on Liquefied Natural Gas or indigenous Natural gas, 30% on high efficient coal, 25% based on large storage hydro, and 15% utilizing furnace oil produced during local refinery process as a by-product and NCRE capacity based on firm energy sources.

Clause 20

Adequate generation should be added to fully meet the growing demand for base and peak loads in accordance with the Least Cost Long Term Generation Expansion Plan (LCLTGEP). Reliability of supply should be maintained at a level determined by the PUCSL from time to time in consultation with the relevant licensees.

Clause 30

Non-conventional Renewable Energy based generation shall be optimally developed to provide 1/3rd of the power demand by 2030.

Clause 31

Subject to favourable weather conditions, country must progress with the vision to achieve 50% of electricity generated in 2030 from renewable sources including large scale storage hydro and Non conventional renewable energy.

6.4 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 proven power generation technologies are considered in the initial screening of generation options to select the technologies and prime source of energy to be utilized for planning studies. Details of the screening curve methodology are given in Annex 6.1. The results of the screening curve analysis are explained in section 8.1 in Chapter 8.

6.5. 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), NCP and OPTGEN software tools developed by PSR (Brazil) were extensively used in conducting the system expansion planning studies to determine optimal Long Term Generation Expansion Plan. Model for Analysis of Energy Demand (MAED) developed by International Atomic Energy Agency (IAEA) was used to develop a demand forecast scenario by end user approach.

6.5.1 Stochastic Dual Dynamic Programming (SDDP)

Stochastic Dual Dynamic Programming (SDDP) model is an operation planning tool developed by PSR (Brazil) which simulates the hydro and thermal generation system to optimize the operation of hydro system. 20 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 modelling and reservoir level detail modelling has been done to accurately represent the actual operation. Maximum of hundred scenario simulations could be considered in the model to represent the stochastic nature of hydrological conditions. To observe the operational patterns of the future generation system and to identify any operational issues, SDDP was used to simulate the hourly operation considering the least-cost stochastic operating policy of the hydrothermal system of the country, taking into account the following main inputs:

1. Operational details of hydro plants (water balance, limits on storage and turbine outflow, spillage etc.)
2. Detailed thermal plant modelling (unit commitment, fuel contracts, efficiency curves, fuel consumption constraints, multiple fuels, etc.)
3. Renewable resource profiles and associated renewable generation plant modelling
4. Modelling of energy storage devices connected to the grid considering hourly time steps
5. Operational constraints of the system
6. Hourly Load variation levels

The modelling and simulation is performed to identify the operating patterns of the conventional power plants, system flexibility issues and the implications of variable renewable energy on the operation of conventional plants including energy storage solutions such as pumped hydro and battery storages in hourly resolution.

6.5.2 OPTGEN/SDDP Software

OPTGEN/SDDP, software developed by PSR (Brazil) is a long term expansion planning model which is used to determine the least cost sizing and timing decisions for construction and reinforcement of generation capacities and transmission network. OPTGEN optimizes the trade-off between investment costs to build new projects and the expected value of operative costs obtained from SDDP, the stochastic dispatch model. The Software is capable of modelling Other Renewable Energy Sources and is considered for optimization. In order to solve the expansion problem, OPTGEN model uses advanced optimization techniques of mixed-integer programming.

6.5.3 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.

6.6 Modelling of Hydropower Development

Hydro resource is one of the main indigenous sources of energy and lifetime of a hydropower plant is longer compared to the other alternative sources. Sri Lanka has already developed almost all of the economically feasible hydro power projects in the country and few minor projects remain at their initial feasibility study level due to the inability to justify economically. 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. At present only Broadlands hydropower project, Uma Oya hydropower project and the Moragolla hydropower project are considered as committed.

6.7 Modelling of Other Renewable Energy

The LTGEP 2022-2041 includes a significant amount of renewable energy resource development including wind and solar resources. Therefore, accurate representation of the important characteristics of each renewable energy resources is very important in the planning process. The OPTGEN and SDDP Software packages used in this planning exercise are developed to capture the characteristics of renewable energy resources in the capacity expansion planning exercise in a more effective manner.

The main ORE technologies of mini-hydro, wind, solar and dendro were modelled based on actual resource characteristics as applicable for the generation planning exercise. As the major portion of the future renewable additions is comprised of variable renewable energy such as wind and solar PV, the modelling work has captured the variability, uncertainty and seasonality characteristics. Moreover, as explained in the Chapter 5 of this report, a comprehensive renewable energy grid integration study is conducted by CEB parallel to the generation expansion planning exercise which includes detailed analysis using resource modelling.

6.8 Assessment of System Operational Capability

It is essential that the proposed development plan provides operational capability to the System Control Centre, to operate the power system in a secure and economical manner, in both normal and contingency situations. As the system is transitioning towards higher shares of non-dispatchable intermittent variable renewable energy sources with higher degree of variability and uncertainty, ensuring the adequate operational flexibility is essential for the normal system operation to meet the dynamically varying demand of the system. The conventional generation technologies are increasingly required to provide more cyclic operation with faster ramping and frequent start-ups. Therefore, the generation planning exercise has decided the firm capacity mix in each year to facilitate the necessary flexibility requirements. Designing and developing a stable and a resilient power system is essential to withstand both internal and external disturbances to the operation. Important attributes such as adequate synchronous inertia, frequency/voltage control capabilities and power failure restoration capabilities have been considered in preparing the development plan.

6.9 Assessment of Environmental Implications

The environmental effects of each thermal options are considered in the initial selection of a candidate power plant in the planning process. All thermal power plants are required to adhere to the approved 'National Environmental (Ambient Air Quality) Regulations published in 2008 and the National Environmental (Stationary Sources Emission Control) Regulations published in 2019. Any additional costs to comply with the environmental regulations are considered in the capital cost of the respective power project. During project preconstruction phase, a detailed EIA shall be conducted to address and explore methods to mitigate all localised adverse environmental impacts.

The greenhouse gas emissions that impact the global environment is assessed for each planning scenario as presented in the Chapter 10. The GHG emission levels are analysed to ensure that the climate obligations of Sri Lanka to the UNFCC under the Nationally Determined Commitments (NDCs) are compiled as well as to explore further opportunities to reduce greenhouse gas emissions.

6.10 Assessment of Implementation Time and Financial Scheduling

The implementation and financing of the planned power projects are two important aspects in planning and developing a electricity supply system. In fact, the total period of implementation of a project including feasibility studies varies depending on the type, technology and the location of the power project. Typical duration required for generation projects, including the period taken for preplanning activities, is shown below.

1. Internal Combustion Engine 4 years
2. Gas Turbine 4 years
3. Combined Cycle Plant 6 years
4. Coal Plant 7- 8 years
5. Nuclear Plant 12- 15 years
6. Hydropower Plant 7 - 8 years

Similarly, implementation period of a large to medium scale solar and wind parks is in the range of 3 to 4 years. Developing the electricity generation system is often a highly capital intensive activity in the economy, hence funding and financing power sector projects remains as a critical challenge affecting the timely implementation of projects. An investment schedule of the Base Case scenario is presented to identify the necessary funding and financing requirement as well as for preparing future projections on electricity tariff system.

6.11 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 Generation Planning Software. Parameters and constraints given in Grid Code were used in the studies and those are described in detail.

6.11.1 Study Period

Generation Expansion Panning studies are conducted for a period of 25 years (2022-2046) and the results of Base Case and all sensitivity studies are presented in the report for a period of 20 years (2022-2041). The consideration of additional years in the planning exercise is to enhance the accuracy of the solution to the optimization problem.

6.11.2 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 187.18 LKR/USD. This is the average value of December 2020 exchange rates. All costs are based on 1st of January 2021.

6.11.3 Plant Commissioning and Retirements

It is assumed that the power plants are commissioned or retired at the beginning of each year. Such limitations are common in the long term planning tools. However, in actual terms, CEB owned power plants are expected to be retired considering their remaining operable hours and actual implementation progress of new power projects. IPP power plants are to be retired according to the expiry dates of Power Purchase Agreements.

6.11.4 Cost of Energy Not Served (ENS)

The average loss to the economy due to electrical energy not supplied has been estimated as 0.782 USD/kWh (in 2021 prices). This value has been derived by escalating the ENS figure given by PUCSL as 0.5 USD/kWh in 2011.

6.11.5 Reliability Criteria

As per the provisions stipulated in Sri Lanka Electricity Act Section 43(8) and Clause 20 of The General Policy Guidelines on the Electricity Industry issued on 2019, the PUCSL has to publish the reliability criteria for electricity network in consultation with the relevant licensees. "The technical and reliability requirements of electricity network of Sri Lanka" was published in Gazette Extraordinary No. 2109/28 dated 2019-02-08 by the PUCSL [2].

Reserve Margin

Reserve margin is the measure of firm generation capacity available over and above the amount required to meet the system load requirements. When preparing the LTGEP, reserve margin values are maintained between 2.5% (minimum) and 20% (maximum) as published in Gazette Extraordinary No. 2109/28 dated 2019-02-08. The Reserve Margin level is maintained between stipulated limits and necessary reserve margins, in each year, is maintained considering factors such as largest unit sizes, optimum usage of earmarked lands and stability of the network.

Loss of Load Probability (LOLP)

LOLP is another 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.

The association between Reserve Margin and LOLP indices are interrelated and the exact values depend on the approach and the complexity of the adopted methodology. The LTGEP 2022-2041 is prepared maintaining the LOLP values within the stipulated maximum limit of 1.5% as stipulated in the Grid Code and published in Gazette Extraordinary No. 2109/28 dated 2019-02-08.

Transmission License shall prepare the Plan maintaining LOLP values at optimum levels with the mandate on flexibility to adjust the values providing sufficient justification, considering the aforementioned restrictions.

6.11.6 Discount Rate

The discount rate is used in order to analyse 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 analysed by applying lower and higher discount rates.

6.11.7 Plant Capital Cost Distribution among Construction Years

The distribution of plant capital cost during the construction period is carried out by adopting "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 Annex 12.1 and Annex 12.2 in Chapter 12.

6.11.8 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 fuel prices assumed to remain constant as of the reference date, and expressed in economic terms (border prices) as stipulated in the Grid code.

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

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

e) Committed Power Plants are shown in the Table 6.1 below.

Table 6.1 Committed Power Plants

Power Plant	Capacity (MW)	Year of Operation
Thermal		
Kelanithissa Gas Turbines	130	2023
Natural Gas Combined Cycle Power Plant I	350	2023 – Open Cycle 2024 – Combined Cycle
Natural Gas Combined Cycle Power Plant II	350	2024 – Open Cycle 2025 – Combined Cycle
Lakvijaya Coal Plant Extension	300	2025
Hydro		
Uma Oya Hydropower Plant	122	2022 (to be commissioned within 2021)
Broadlands Hydropower Plant	35	2022 (to be commissioned within 2021)
Moragolla Hydropower Plant	30.2	2024

f) The Candidate Power Plants with earliest possible commissioning year are depicted in the Table 6.2 below.

Table 6.2 Candidate Power Plants

Power Plant	**Capacity (MW)**	**Year of Operation**
Thermal		
IC Engines (Diesel / FO / NG)	15 /200 /250	2025
Gas Turbine (NG)	40 /100 /200	2025
Combined Cycle Power Plant (NG)	300 / 400	2027
Coal Plant (High Efficient /Supercritical)	300 / 600	2028
Nuclear Power Plant	600	2035
Storage		
Battery Storage		2025
Pumped Storage	3x200	2029

g) The integration capacity of bio mass and mini hydro power plants is not limited but could be considered on project by project basis depending on the feasibility.

h) Future large scale wind parks are to be developed as Semi-dispatchable power plants.

i) All new wind and solar PV plants are capable to curtail the generation when necessary.

j) The development of required LNG infrastructure will be available by 2024 for importing natural gas.

k) Plant retirements of CEB owned plants and IPP plants are given in Table 6.3. The power plant retirements are assumed to be at the beginning of each year. However, the actual retirement of all power plants are to be made after further evaluating the actual plant condition at the time of retirement, (including the availability of useful operating hours beyond the scheduled retirement date), and the implementation progress of planned power plant additions.

Table 6.3 Plant Retirement Schedule

CEB Power Plants	**Year**	**IPP Power Plants**	**Year**
1. Kelanithissa Frame5 GTs	2023	1. Sojitz Combined Cycle plant	2023
2. Barge mounted power plant	2025	2. Westcoast Combined Cycle plant	2035
3. Sapugaskanda PS A (4 units)	2026		
4. Sapugaskanda PS B (8 Units)	2026		
5. Kelanithissa GT7	2026		
6. Kelanithissa Combined Cycle plant	2033		
7. Uthuru Janani power plant	2033		
8. Lakvijaya coal plant unit 1	2041		

- The contract of 163 MW Sojitz Combined Cycle plant at Kelanithissa will expire in October, 2023 and it will be operated as a CEB plant until 2033.

- Retirement year of Kelanithissa Frame 5 GTs shall be reviewed with the actual implementation year of Kelanithissa New Gas Turbines as constrained by local environmental emission regulations.

- Retirement year of 115 MW Kelanithissa GT7 is extended until beginning of 2026 on the basis of carrying out manufacturer recommended major scheduled maintenance work, along with any other essential maintenance required to keep the plant operational.

CHAPTER 7
GENERATION EXPANSION PLANNING STUDY DEVELOPMENT OF THE REFERENCE CASE

This chapter presents the analysis results of the reference case for 2022-2041 planning horizon in detail including capacity additions, system energy share, dispatch and annual CO2 emissions. The reference case plan is the unconstrained least cost plan and the total cost of reference case demonstrates the total present value cost of generation expansion for the planning horizon unconstrained by policies. This case indicates the least cost development pathway as well as provides a basis for comparison to other scenarios that are constrained by policies.

7.1 Introduction

To develop the reference case 2022-2041, the Draft Generation Planning Code in the Draft Grid Code [24] issued by the Transmission Licensee was used as a guideline. As per the grid code, the reference case should be developed with exclusion of any policy guidelines on generation technology options that would cause the plan to deviate from least cost. In addition, candidate non-dispatchable power plants required to be included owing to policy guidelines issued by the commission or any of the Transmission Licensee's own policies, are not included in the reference case, unless the Transmission Licensee can demonstrate that such power plant costs shall not violate the least-cost objective of developing the reference case.

Accordingly, as the first step of developing the reference case, a case with ORE power plants already in operation as at 1st January 2021 and the committed renewable energy plants was considered. When the case was analysed, it was observed that further cost reductions could be expected by incorporating candidate ORE additions to the plan to a certain extent. Several scenarios were evaluated with varying candidate ORE additions throughout the planning horizon which do not require substantial investments in network or operational reinforcements. Through this evaluation, it was established that with the existing ORE plants, committed ORE additions up to 2024 and annual candidate ORE additions identified beyond 2025 in the base case of the draft LTGEP 2020-2039 would result in the least cost reference case.

7.2 Reference Case Plan

The reference case plan is given in Table 7.1 and the total present value (PV) cost of the Reference Case Plan for the period 2022-2041 is USD 15,924 million (LKR 2,980.63 billion) in January 2021 values based on the discount rate of 10%).

Table 7.1: Generation Expansion Planning Study – Reference Case (2022-2041)

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS	THERMAL CAPACITY ADDITIONS	THERMAL CAPACITY RETIREMENTS
2022	Solar 340 MW Wind 20 MW Mini Hydro 15 MW Biomass 14 MW ***Uma Oya HPP 120 MW*** ***Broadlands HPP 35 MW***	**250 MW Short Term Supplementary Power**	-
2023	Solar 260 MW Wind 35 MW Mini Hydro 15 MW Biomass 5 MW	***130 MW New Gas Turbines at Kelanitissa*** ***200 MW Open Cycle Operation of First 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***163 MW Combined Cycle Power Plant (KPS–2)***	**4x17 MW Kelanitissa Gas Turbines** **163 MW Sojitz Kelanitissa Combined Cycle Plant** **100 MW Short Term Supplementary Power**
2024	Solar 270 MW Wind 40 MW Mini Hydro 10 MW Biomass 4 MW ***Moragolla HPP 31 MW***	***150 MW Steam Turbine Operation of First 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***200 MW Open Cycle Operation of Second 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya***	**150 MW Short Term Supplementary Power**
2025	Solar 260 MW Wind 40 MW Mini Hydro 10 MW Biomass 5 MW	***150 MW Steam Turbine Operation of Second 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***300 MW Lakvijaya Coal Power Plant Extension***	**4x15.6 MW CEB Barge Power Plant**
2026	Solar 90 MW Wind 35 MW Mini Hydro 10 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant – (Natural Gas)**	**115 MW Gas Turbine (GT7)** **4x17 MW Sapugaskanda Diesel** **8x9 MW Sapugaskanda Diesel Ext.**
2027	Solar 90 MW Wind 50 MW Mini Hydro 10 MW Biomass 5 MW	-	-
2028	Solar 100 MW Wind 40 MW Mini Hydro 10 MW Biomass 5 MW	**300 MW New Coal Power Plant** **300 MW New Coal Power Plant**	-
2029	Solar 100 MW Wind 40 MW Mini Hydro 10 MW Biomass 5 MW	-	-
2030	Solar 90 MW Wind 20 MW Mini Hydro 10 MW Biomass 5 MW	**200 MW Gas Turbine Power Plant (Natural Gas)**	-
2031	Solar 100 MW Wind 60 MW Mini Hydro 10 MW Biomass 5 MW	**200 MW Gas Turbine Power Plant (Natural Gas)**	-
2032	Solar 110 MW Wind 50 MW Mini Hydro 10 MW Biomass 5 MW	**200 MW Gas Turbine Power Plant (Natural Gas)** **100 MW Gas Turbine Power Plant (Natural Gas)**	-

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS	THERMAL CAPACITY ADDITIONS	THERMAL CAPACITY RETIREMENTS
2033	Solar 110 MW Wind 35 MW Mini Hydro 10 MW Biomass 5 MW	**300 MW New Coal Power Plant** **300 MW New Coal Power Plant** **100 MW Gas Turbine Power Plant (Natural Gas)**	**165 MW Combined Cycle Plant (KPS)** **163 MW Combined Cycle Plant (KPS- 2)** **3 x 8.93 MW Uthuru Janani Power Plant**
2034	Solar 120 MW Wind 70 MW Mini Hydro 10 MW Biomass 5 MW	**300 MW New Coal Power Plant**	**-**
2035	Solar 120 MW Wind 45 MW Mini Hydro 10 MW Biomass 5 MW **Pumped Storage HPP 200 MW**	**300 MW New Coal Power Plant**	**300 MW West Coast Combined Cycle Power Plant**
2036	Solar 110 MW Wind 50 MW Mini Hydro 10 MW Biomass 5 MW	**300 MW New Coal Power Plant** **100 MW Gas Turbine Power Plant (Natural Gas)**	-
2037	Solar 110 MW Wind 50 MW Mini Hydro 10 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas)**	-
2038	Solar 110 MW Wind 70 MW Mini Hydro 10 MW Biomass 5 MW	**300 MW New Coal Power Plant** **100 MW Gas Turbine Power Plant (Natural Gas)**	-
2039	Solar 110 MW Wind 70 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas)** **200 MW Gas Turbine Power Plant (Natural Gas)**	-
2040	Solar 110 MW Wind 70 MW Mini Hydro 5 MW Biomass 5 MW	**-**	-
2041	Solar 110 MW Wind 70 MW Mini Hydro 5 MW Biomass 5 MW **Pumped Storage HPP 200 MW** **Pumped Storage HPP 200 MW**	**-**	**300 MW Lakvijaya Coal Power Plant Unit 1**

7.2.1 System Capacity Distribution

Reference case capacity additions by plant type are summarised in five year periods in the Table 7.2 and graphically represents in Figure 7.1. The supply mix heavily depends on the thermal based generation system with limited contribution from the renewable based energy.

Table 7.2: Capacity Additions by Plant Type – Reference Case (2022-2041)

Type of Plant	2022-2026 (MW)	2027-2031 (MW)	2032-2036 (MW)	2037-2041 (MW)	Total capacity addition	
					(MW)	%
Major Hydro	186	-	-	-	186	2%
Pumped Hydro	-	-	200	400	600	5%
Gas Turbines	130	400	500	300	1,330	12%
Coal	300	600	1500	300	2,700	25%
Combined Cycle	1,100	-	-	800	1,900	18%
ORE	1,483	765	895	940	4,083	38%
Total	**3,199**	**1,765**	**3,095**	**2,740**	**10,799**	**100%**

According to the above, reference case plan is comprised of a mix of thermal and renewable power plants. Major hydro and ORE additions amount to 40% of the total capacity additions in the planning horizon while thermal capacity additions include 25% of coal based power plants 30% of natural gas based combined cycles/gas turbines. 5% capacity addition of pumped hydro power plant is also included in the reference case. When compared with the base case plan, the reference case contains 2,385 MW less capacity additions mainly due the reduction in ORE capacities in the planning horizon. Future capacity mix of the reference case is graphically represented in Figure 7.2

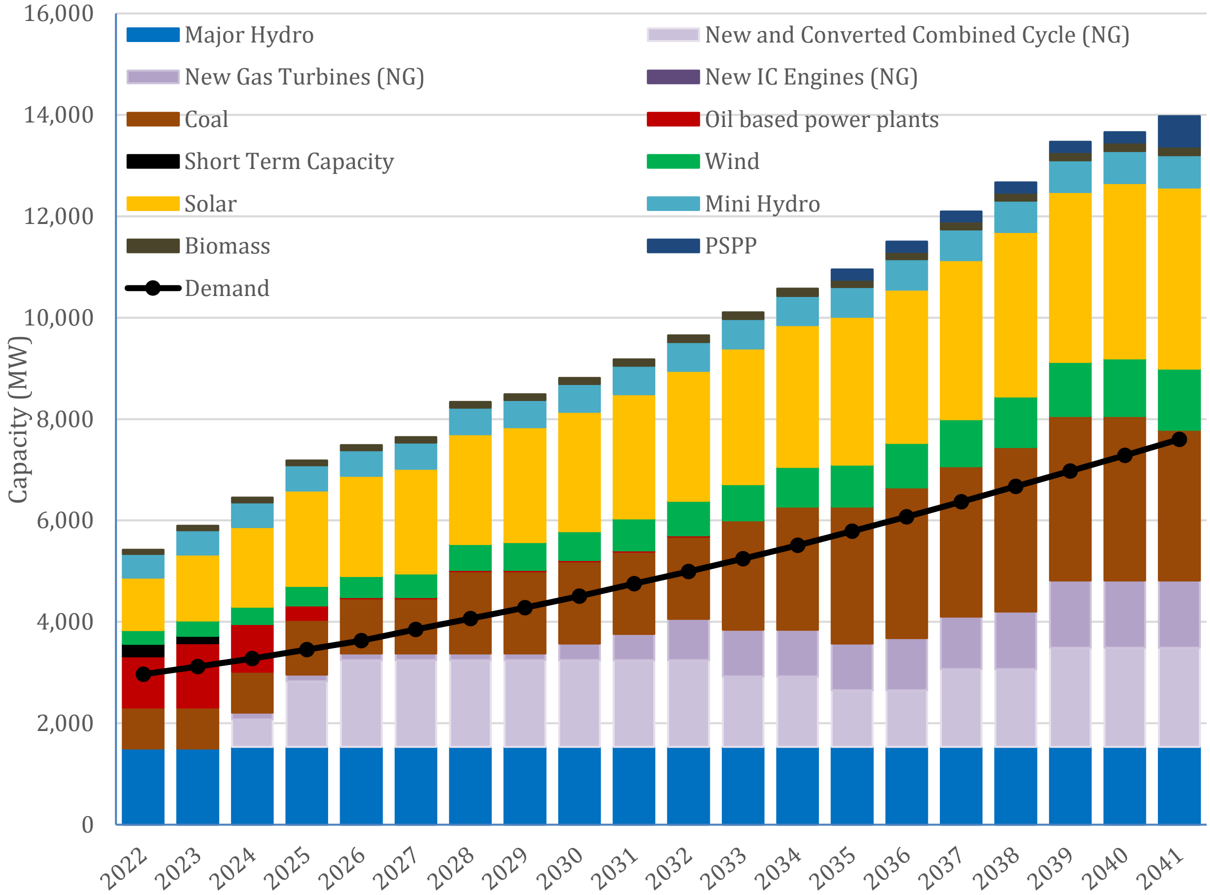


Figure 7.1 - Cumulative Capacity by Plant Type in Reference Case

7.2.2 System Energy Share

Future energy supply mix of the reference case is graphically represented in Figure 7.2.

As for renewables, the hydro generation share gradually decreases throughout the planning horizon starting from 25% in 2022 to 10% in 2041. Energy contribution from ORE reaches 30% in 2025 and continues at the same level throughout the horizon.

As for thermal power plants, during initial 3 years of the planning horizon major energy contribution comes from oil and coal based thermal generation, and beyond 2025, coal based power plants become the major thermal energy contributor of the system and the energy share gradually increases with the addition of new coal power plants. Coal energy share is 30% in 2022 and will gradually increase up to 50% by the latter parts of the planning horizon. The energy contribution from other oil-fired power plants reduces from 20% in 2022 to 2% by 2025 with the gradual retirement of oil plants and thereafter becomes negligible. As shown in the Figure 7.2, energy share of natural gas based power plants varies throughout the planning horizon, ranging from 8% to 21%.

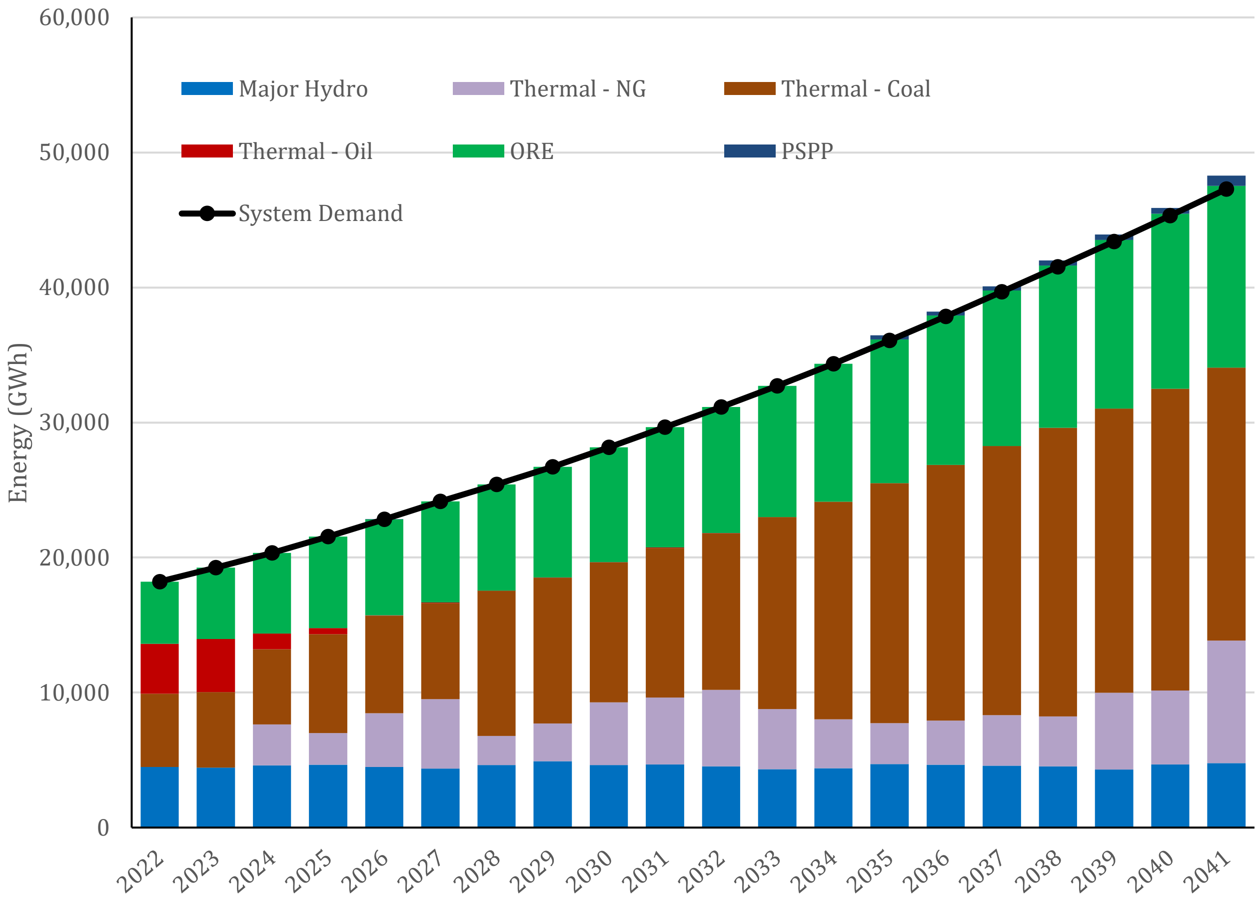


Figure 7.2 – Energy Mix over next 20 years in Reference Case

Compared with the base case plan, reference case shows the USD 356 million PV cost decrement over the planning horizon.

7.2.3 Environmental Emissions and Implications

Reference case contains higher amount of coal based generation share in comparison to ORE and natural gas based generation share. As a result, a large amount of environmental emissions are observed limiting the ability of the country to maintain a low carbon footprint. In contrast, the development of the base case considers much higher contribution from renewable energy sources and natural gas based generation so that the transition to a low carbon future is enabled significantly reducing the carbon intensity of the sector. The environmental emissions of the reference case in specific years are presented in Table 7.3 and detailed results on the environmental implications of the Reference Case are presented in the Chapter 10.

Table 7.3: Annual environmental emissions of the Reference Case

Year/Emission type	2025	2030	2040
CO_2 Emissions (million tons)	9.0	12.9	24.6
SO_2 Emissions (1000 tons)	21.7	5.3	9.0
NO_x Emissions (1000 tons)	23.4	20.0	23.6
PM Emissions (1000 tons)	5.5	7.0	10.6

CHAPTER 8
RESULTS OF GENERATION EXPANSION PLANNING STUDY – BASE CASE PLAN

This chapter presents the results of the Base Case analysis for 2022-2041 planning horizon in detail. Results on Environmental Impacts of Base Case analysis are discussed in the Chapter 10.

8.1 Results of the Preliminary Screening of Generation Options

For the preliminary screening of alternative thermal options, two coal fired steam plant technologies, four natural gas fired gas turbines, two diesel fired gas turbines, two oil fired reciprocating engine power plant, two natural gas fired combined cycle plants, two diesel fired combined cycle plants, three natural gas fired reciprocating engines and a nuclear power plant were considered. For comparing and evaluating alternative generation technologies with varying capital investments, operational costs, maintenance costs and life time, it is necessary to develop a common indicator for all plants. Specific generation cost expressed in US Cents/ kWh calculated at different plant factors for each plant was used as the indicator 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 10% discount rate is shown in Annex 8.1.

From the screening curve analysis, two diesel fired gas turbines (100 MW and 40 MW) and two diesel fired combined cycle plants (300 MW and 150 MW) were eliminated from planning studies due to the comparatively high specific cost at full plant factor range. The following thermal candidate technologies were selected as suitable options for detailed generation expansion planning studies. It should be noted that all natural gas based candidates have the duel fuel capability and 15 MW NG Reciprocating Engine option has the dual fuel capability. However, for screening analysis, operation of these candidates with natural gas as primary fuel was considered.

- 15 MW NG Reciprocating Engine
- 15 MW Fuel Oil Reciprocating Engine
- 15 MW Diesel Reciprocating Engine
- 200 MW NG Reciprocating Engine Plant
- 250 MW NG Reciprocating Engine Plant
- 40 MW NG Gas Turbine
- 40 MW NG Gas Turbine (Aero Derivative)
- 100 MW NG Gas Turbine
- 200 MW NG Gas Turbine
- 300 MW NG Combined Cycle
- 400 MW NG Combined Cycle
- 300 MW High Efficient Coal Plant
- 600 MW Super Critical Coal Plant
- 600 MW Nuclear Power Plant

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

In addition to the above thermal alternatives derived from the screening analysis, candidate renewable options were also considered in the expansion studies. As for major hydro candidate options, Seethawaka, Thalpitigala and Gin Ganga were considered. However due to issues in funding arrangements, the projects are on hold at the moment.

3 x 200 MW Pumped Storage Power Plant (PSPP) was introduced to the system as an energy storage option. Introduction of PSPP was based on the results of two studies, "Development Planning on Optimal Power generation for Peak Demand in Sri Lanka" [19] and "Integration of Renewable Based Generation into Sri Lankan Grid" [23]. In the Base Case plan, PSPP is proposed to be added to the system primarily to provide system flexibility with a range of grid support functionalities as well as to store the surplus of renewable energy that would have curtailed due to power system operational limitations. This will also enable relaxing of operational constraints and efficient operation of the low cost thermal power plants in the system during low load periods. The adjustable speed type technology in PSPP is specifically proposed, so that system operational requirements for absorbing variable renewable energy can be supplied even during pumping mode operations.

In addition to PSPP, grid scale battery storage has also been introduced to the system primarily to provide frequency support services. It is planned to deploy a 20 MW of Battery Energy Storage capacity by 2025 to gradually increase that to 100 MW by 2030 depending on the system requirement and the progress of wind and solar PV integration program.

8.2 Government Policy on Composition of Electricity Generation

When developing the Base Case Plan, special consideration was given to the "General Policy Guidelines in Respect of the Electricity Industry'' as stipulated in the Sri Lanka Electricity Act no 20 of 2009 (as amended) and the Public Utilities Commission of Sri Lanka (PUCSL) Act no 35 of 2002. This policy guideline was issued in April 2019 and still in effect up to date. The government policy directive based on the above policy guidelines contains 05 clauses directly related to the future electricity mix of the country proposed through LTGEP. The energy mix proposed through the Base Case Plan of LTGEP 2022-2041 has considered these clauses and aligned the Base Case along with the salient points included in the 05 specific clauses as indicated below.

1. To ensure security, availability and reliability of supply, there shall be installed firm power capacity (based on firm energy sources such as fossil fuels and storage hydro) at all time to provide at least 2/3rd of the demand for power.

2. In order to maintain a practical and balanced fuel mix in the installed firm power capacity, by the year 2030, 30% of the installed firm capacity must be on Liquefied Natural Gas or indigenous Natural gas, 30% on high efficient coal, 25% based on large storage hydro, and 15% utilizing furnace oil produced during local refinery process as a by-product and NCRE capacity based on firm energy sources.

3. Adequate generation should be added to fully meet the growing demand for base and peak loads in accordance with the Least Cost Long Term Generation Expansion Plan (LCLTGEP). Reliability of supply should be maintained at a level determined by the PUCSL from time to time in consultation with the relevant licensees.

4. Non conventional Renewable Energy based generation shall be optimally developed to provide 1/3rd of the power demand by 2030.

5. Subject to favourable weather conditions, country must progress with the vision to achieve 50% of electricity generated in 2030 from renewable sources including large scale storage hydro and Non conventional renewable energy.

The Base Case plan proposes a diversified energy mix with several firm energy sources such as coal, natural gas, large hydro, furnace oil and other renewable energy (pumped storage, ORE with battery etc.). Development of these different types of sources were optimized and the above diverse firm energy mix consisting of both imported and indigenous resources paves way to ensuring the energy security of the country.

In accordance with "The technical and reliability requirements of electricity network of Sri Lanka" which was published in Gazette Extraordinary No. 2109/28 dated 2019-02-08 by the PUCSL, the Base Case plan has maintained minimum firm capacity amounting to 2.5% over the peak demand throughout the planning horizon. This also synonymously conforms with the clause in the policy guideline which requires installed firm power capacity to provide minimum 2/3 of peak demand at all times.

Priority was given to developing the maximum feasible renewable energy sources which is explained in detail in Chapter 5. The RE capacity in the system by 2030 is 6,303 MW (64% of total installed capacity) and this capacity share is maintained around 60% throughout the planning horizon. Energy storage options such as pumped storage power plant and battery storage systems are included in the Base Case to ensure the maximum utilization of ORE. As for energy contribution from renewable energy sources, all key scenarios contained 50% energy contributed from renewable sources in average hydro condition and maintained 50% share beyond 2030. By 2030, anticipated renewable energy contribution amounts to 14,925 GWh (~ 53% of total energy) in average hydro condition and to 16,115 GWh (~ 57% of total energy) in wet hydro condition.

During planning studies for LTGEP 2022-2041, the following key policy scenarios were analysed and all of which are targeted to achieve 50% Renewable energy share by 2030 and beyond.

- Current Policy on Fuel Diversification
- 70% Low Carbon by 2030 and maintaining the same beyond 2030
- 70% Low Carbon by 2030 with restricting Coal power development beyond 2030

Out of which the scenario with current policy indicated a comparatively lower PV cost. Second scenario considers achieving and retaining the 70% low carbon share after 2030 and the third scenario considers the same as well and restrictions on new coal power development beyond

2030. Considering the government's policy directions on developing a low carbon electricity system, the global trends on low carbon energy systems, operational flexibility requirements to absorb high proportion of renewable resources and the minimum cost differences between the scenarios, the third scenario "*70% Low Carbon by 2030 with restricting Coal power development beyond 2030"* was adopted as the Base Case scenario. However, as the selected scenario does not adhere with the existing policy guideline on firm capacity mix, it is anticipated that a new policy directive would be duly issued as an amendment to the existing General Policy Guidelines. Detailed discussion on determining the Base Case plan is presented in Section 9.6 in Chapter 9.

8.3 Base Case Plan

The Base Case Plan is given in Table 8.1 and corresponding annual capacity additions are given in the Table 8.2. In this study, committed power plants have been fixed according to the present implementation schedules.

The total present value (PV) cost of the Base Case Plan including the cost of development of ORE for the period 2022-2041 is USD 16,280 million (LKR 3,047.3 billion) in January 2021 values based on the discount rate of 10%.

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 cost of the system (PV) which is the optimized result of expansion studies. Furthermore, the cost to be incurred for developing corresponding transmission infrastructure which is essential for the development of each project would be considered in the transmission planning studies related to this generation expansion plan.

Table 8.1– Generation Expansion Planning Study - Base Case (2022 – 2041)

(To be referred in conjunction with conditions stipulated by PUCSL through letter in Annex 15)

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS (h) (i)	THERMAL CAPACITY ADDITIONS (a)	THERMAL CAPACITY RETIREMENTS (c)(d)
2022	Solar 340 MW Wind 20 MW Mini Hydro 15 MW Biomass 14 MW ***Uma Oya HPP 120 MW*** ***Broadlands HPP 35 MW***	**250 MW Short Term Supplementary Power** [1]	-
2023	Solar 260 MW Wind 35 MW Mini Hydro 20 MW Biomass 4 MW	***130 MW New Gas Turbines at Kelanitissa*** [2] ***200 MW Open Cycle Operation of First 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***163 MW Combined Cycle Power Plant (KPS-2)*** [3]	**4x17 MW Kelanitissa Gas Turbines** [4] **163 MW Sojitz Kelanitissa Combined Cycle Plant** [3] **100 MW Short Term Supplementary Power**
2024	Solar 270 MW Wind 40 MW [5] Mini Hydro 10 MW Biomass 5 MW ***Moragolla HPP 31 MW***	***150 MW Steam Turbine Operation of First 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***200 MW Open Cycle Operation of Second 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya***	**150 MW Short Term Supplementary Power**
2025	Solar 260 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 20 MW [9]	***150 MW Steam Turbine Operation of Second 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***300 MW Lakvijaya Coal Power Plant Extension*** [7]	**4x15.6 MW CEB Barge Power Plant** [6]
2026	Solar 195 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW	**250 MW IC Engine Power Plant (Natural Gas) – Southern Region** [7]	**115 MW Gas Turbine (GT7)** [8] **4x17 MW Sapugaskande Diesel** **8x9 MW Sapugaskande Diesel Ext.**
2027	Solar 160 MW Wind 120 MW Mini Hydro 10 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant – Western Region (Natural Gas)** [7]	-
2028	Solar 170 MW Wind 120 MW Mini Hydro 10 MW Biomass 5 MW	**300 MW New Coal Power Plant - Foul Point** [7]	-
2029	Solar 160 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 30 MW [9] **Pumped Storage HPP 200 MW**	-	-
2030	Solar 170 MW Wind 130 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 50 MW [9] **Pumped Storage HPP 200 MW**	-	-

(To be referred in conjunction with conditions stipulated by PUCSL through letter in Annex 15)

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS [h] [i]	THERMAL CAPACITY ADDITIONS [a]	THERMAL CAPACITY RETIREMENTS [c][d]
2031	Solar 190 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW **Pumped Storage HPP 200 MW**	-	-
2032	Solar 190 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW Gas Turbine Power Plant (Natural Gas)** [7] **100 MW Gas Turbine Power Plant (Natural Gas)** [7]	-
2033	Solar 180 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas) -Western Region**[7] **200 MW IC Engine Power Plant (Natural Gas)** [7]	**165 MW Combined Cycle Plant (KPS)** **163 MW Combined Cycle Plant (KPS-2)** **3 x 8.93 MW Uthuru Janani Power Plant**
2034	Solar 200 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW IC Engine Power Plant (Natural Gas)** [7]	-
2035	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas) – Western Region**[7] **200 MW Gas Turbine Power Plant (Natural Gas)** [7]	**300 MW West Coast Combined Cycle Power Plant**
2036	Solar 250 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW Gas Turbine Power Plant (Natural Gas)** [7] **100 MW Gas Turbine Power Plant (Natural Gas)** [7]	-
2037	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas)** [7]	-
2038	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**100 MW Gas Turbine Power Plant (Natural Gas)** [7]	-
2039	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas)** [7]	-
2040	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**250 MW IC Engine Power Plant (Natural Gas)** [7]	-
2041	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas)** [7] **100 MW Gas Turbine Power Plant (Natural Gas)** [7]	**300 MW Lakvijaya Coal Power Plant Unit 1**

GENERAL NOTES

a. All plant capacities (MW) shown are the **Gross Capacities**.

b. Conventional, firm capacity power plants are shown in bold text. Committed Power Projects are shown in italic.

c. Dates of all plant additions and plant retirements, (other than retirements of existing plants on PPA) as contained in the table are the dates <u>considered for planning studies</u>, and considered as added/retired at the beginning (as at 1st January) of the respective year. (For example, a generating capacity retirement indicated for year 2025 implies that the plant has been considered as retired from the 1st of January 2025). However, for existing power plants that are governed by Power Purchases Agreements (PPA), the actual retirement month/date as contained in the PPA were considered for studies.

d. Retirement dates of **existing** firm capacity plants are dates considered as **inputs** to planning studies. The ACTUAL retirement of all power plants is to be made after further evaluating the actual plant condition at the time of retirement, (including the availability of useful operating hours beyond the scheduled retirement date), and the implementation progress of planned power plant additions.

e. With the development of LNG supply infrastructure, the existing 300MW West Coast power plant and 165MW Kelanithissa Combined Cycle plant are expected to be converted to natural gas in 2024.

f. Considering the heavy dependency in future on liquefied natural gas as a fuel for electricity generation, all Natural Gas based power plants shall also have the dual fuel capability, including suitable fuel supply/storage arrangements locally for such secondary fuel, to ensure supply security in case of disruption to LNG supply.

g. All new natural gas based Combined Cycle Power plants should be technically, operationally and contractually capable of being operated regularly between open cycle and closed cycle operations.

h. Mini-hydro and Biomass annual capacity additions are not restricted to the planned capacities mentioned in the table. Higher capacity additions will be evaluated case by case.

i. Thalpitigala and Gin Ganga multipurpose hydropower plants are proposed and developed by Ministry of Irrigation and both these plants are considered as candidate power plants with no specific commissioning years at present.

SPECIFIC NOTES

1. - Technology of supplementary capacity can be opened for both Gas Turbine and IC engine technology. Fuel option can be specified as appropriate at the time of procurement for suitable fuels that has established supply chains and having regulated, transparent pricing mechanisms.
   - The 50 MW CEB owned diesel based IC engine power capacity shall be considered appropriately to meet a part of the short term supplementary power capacity requirement.
   - Short-term supplementary capacity requirement under different contingency events are assessed in the contingency analysis under chapter 13 of the LCLTGEP 2022-2041 report. Such requirements too shall be appropriately considered prior to initiating procurement.
   - Extension of the contracts of existing capacities could be considered as appropriate to meet short term requirement.

2. This power plant is required to have the special capability to carry out restoration of supply in case of an island wide power failure.

3. PPA of Sojitz Kelanitissa is scheduled to be expired in 2023, and to be operated as a CEB owned power plant from 2023 to 2033 after conversion to Natural Gas in 2024. It is indicated as " KPS-2" as a capacity addition.

4. Retirement date of the 4 x 17 MW Kelanitissa Gas Turbines are to coincide with the commissioning of the new 130 MW Gas Turbine Plants at the Kelanitissa to comply with local environmental emission regulations.

5. In addition, Mannar Stage II (100 MW) could be accommodated if development is carried out on fast track basis provided plant has wind forecasting and semi-dispatchable capability.

6. Decision to extend the retirement year of 4 x 15.6 MW Barge Power Plant until the end of year 2026 will be evaluated based on the cost of any refurbishments required for such an extension and the potential benefit of extending beyond the scheduled retirement year.

7. **As per letter ref. PUC/LIC/AP21/01 dated October 5, 2021 by PUCSL (Annex 15), development of coal power-based generation will not be carried out (despite appearing in base case). Other thermal capacity additions will be reviewed and revised in the next planning cycle to comply with the new government policy sent by Secretary, Ministry of Power.**

8. Retirement year of 115 MW Kelanitissa GT7 is extended until the end of 2025 on the basis of carrying out manufacturer recommended major scheduled maintenance work, along with any other essential maintenance required to keep the plant operational.

9. Additions of planned battery energy storage capacities are mainly to provide grid level support for renewable energy integration. The additions beyond 2030 will be re-evaluated based on the exact system requirement as well as the progress of the variable renewable energy development.

Table 8.2: Generation Expansion Planning Study - Base Case Capacity Additions (2022 – 2041)

Year	Peak Demand (MW)	Gross Capacity Addition (MW)									Existing Plant Retirements	Annual LOLP* (%)
		Gas Turbines	IC Engines	Coal	Combined Cycle	Major Hydro	Pumped Hydro/ Battery Storage	Short Term	ORE	Total		
2022	2,967					155		250	389	794		1.35%
2023	3,117	130			200			(100)	319	549	(68)	0.70%
2024	3,276				350	31		(150)	325	556		0.14%
2025	3,452			300	150		20		375	845	(62)	0.03%
2026	3,633		250						310	560	(255)	0.01%
2027	3,848				400				295	695		0.09%
2028	4,065			300					305	605		0.00%
2029	4,279						230		275	505		0.00%
2030	4,509						250		315	565		0.01%
2031	4,751						200		300	500		0.00%
2032	4,992	300							300	600		0.00%
2033	5,245		200		400				290	890	(355)	0.02%
2034	5,509		200						310	510		0.00%
2035	5,789	200			400				350	950	(300)	0.00%
2036	6,075	300							360	660		0.00%
2037	6,372				400				350	750		0.00%
2038	6,670	100							350	450		0.00%
2039	6,974				400				350	750		0.01%
2040	7,286		250						350	600		0.00%
2041	7,601	100			400				350	850	(300)	0.00%
Total		**1,130**	**900**	**600**	**3,100**	**186**	**700**	**0**	**6,568**	**13,184**		

* Loss of Load Probability (LOLP) is the yearly average value considering all the hydro conditions.

8.3.1 System Capacity Distribution

The supply mix of the power sector is moving towards increased share in thermal and ORE based generation system to satisfy the rising demand, with the total hydro capacity remaining 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

8.1. In the year 2025, the share of coal based generation capacity is 15% and it gradually decreases to 6% by the end of planning horizon due to no new coal based power generation plants been added to the system beyond 2030. Current Major Hydro capacity contribution is 28% whereas it will be 16% and 9% in the years 2030 and 2041 respectively. Current share of oil based capacity is 23% and it gradually decreases with the introduction of natural gas and coal based thermal power plants in the first half of the planning period and then the capacity share becomes negligible reaching zero by 2033.

Present total installed capacity is 4265 MW and out of that 3551 MW is dispatchable power plants. Chapter 2 includes the detailed information of the existing generation system. 1340 MW of existing thermal capacity is due to retire during the 20 year planning period. Future addition of hydro capacity is 186 MW including committed plants as shown in the Table 8.1. 600 MW of coal power plants and 3100 MW of natural gas based combined cycle power plants are added during the planning period of 2022-2041. In addition, 900 MW of natural gas based IC engines and 1,130 MW natural gas based gas turbines are introduced to the system to serve the operational requirements of the system, due to high integration of variable renewable energy sources.

As shown in the Table 5.6, 6,568 MW of ORE capacity additions over the 20-year period is expected which is a 126% increase from the total ORE additions envisaged in the latest approved plan LTGEP 2018-2037.

Energy storage solutions such as, pumped storage hydro and grid scale battery storage have been proposed. The first 200 MW Pumped Storage Hydro power plant unit is added in 2029 followed by another two units of same capacity in 2030 and 2031. Grid scale battery storage systems are added in phase development with 20 MW in 2025, 30 MW in 2029 and 50 MW in 2030. Battery storage requirement beyond 2030 is to be revaluated based on the exact system requirement as well as the progress of the variable renewable energy development.

Capacity additions by plant type are summarised in five year periods in Table 8.3 and graphically represented in Figure 8.1. Capacity balance of the system is presented in Annex 8.2.

Table 8.3: Capacity Additions by Plant Type

Type of Plant	2022-2026 (MW)	2027-2031 (MW)	2032-2036 (MW)	2037-2041 (MW)	Total capacity addition	
					(MW)	%
Major Hydro	186	-	-	-	186	1%
Pumped Hydro/ Battery Storage	20	680	-	-	700	5%
Gas Turbines	130	-	800	200	1,130	9%
Coal	300	300	-	-	600	5%
Combined Cycle	700	400	800	1200	3,100	23%
IC Engines	250	-	400	250	900	7%
Short Term Capacity	0*	-	-	-	-	-
ORE	1,718	1,490	1,610	1,750	6,568	50%
Total	**3,304**	**2,870**	**3,610**	**3,400**	**13,184**	**100%**

Above figures represent net capacity additions

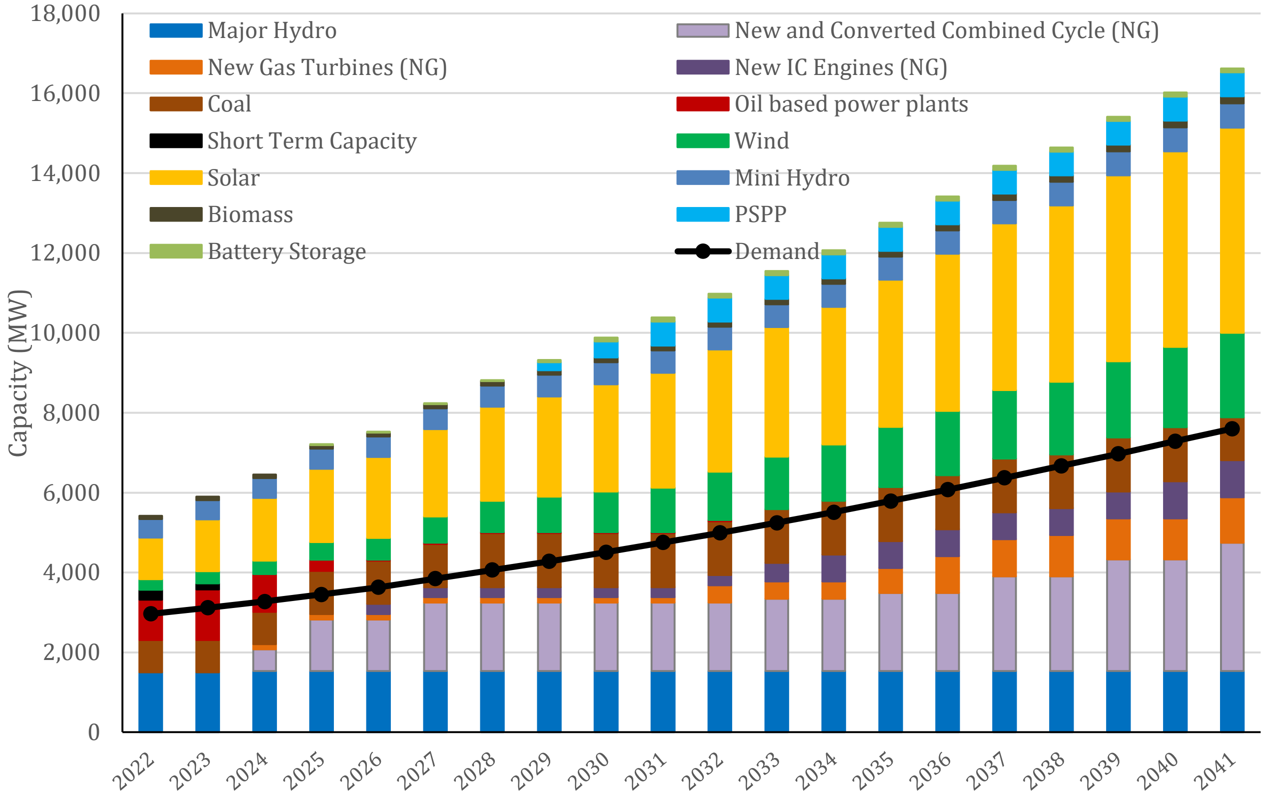


Figure 8.1 –Cumulative Capacity by Plant Type in Base Case

Information on the capacity share is illustrated in the Figure 8.2 and the variation of the total renewable capacity contribution over the years is shown in the Figure 8.3. It is observed that 60% of capacity share is maintained by renewable sources throughout the planning horizon complying with development of renewable energy as a prime policy of the government.

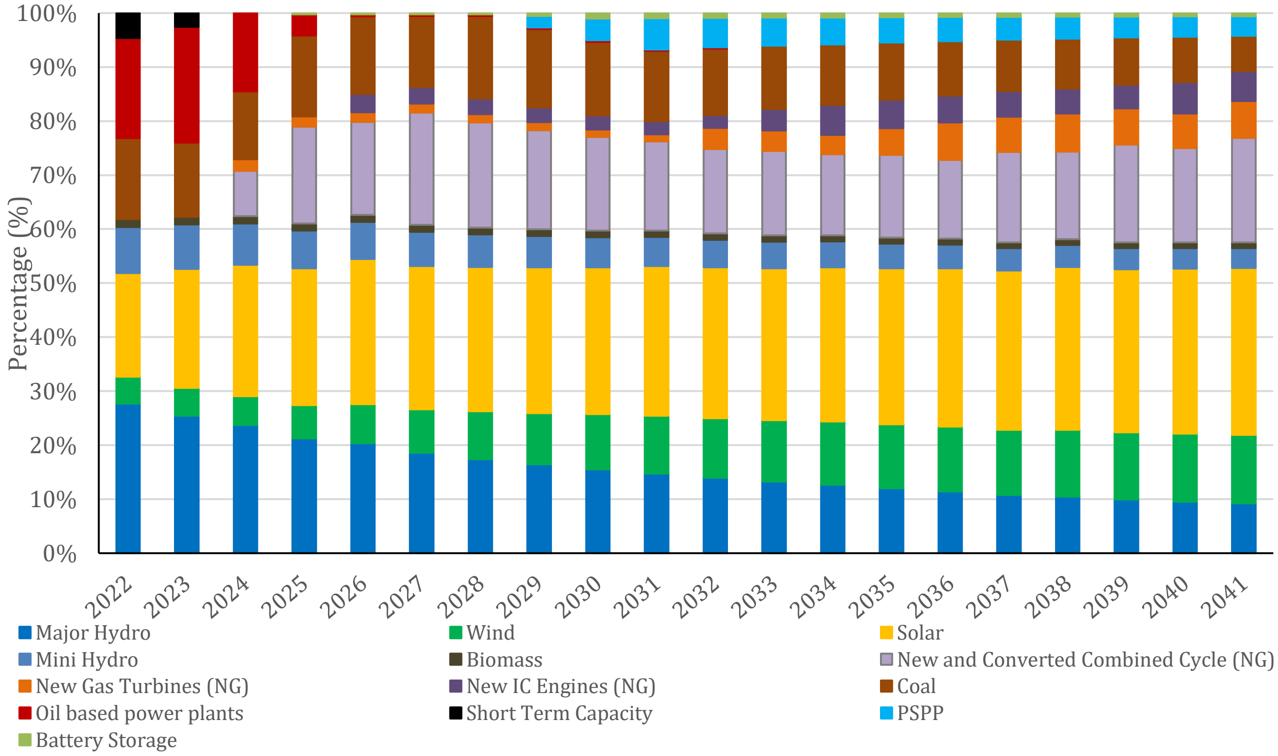


Figure 8.2 – Capacity Mix over next 20 years in Base Case

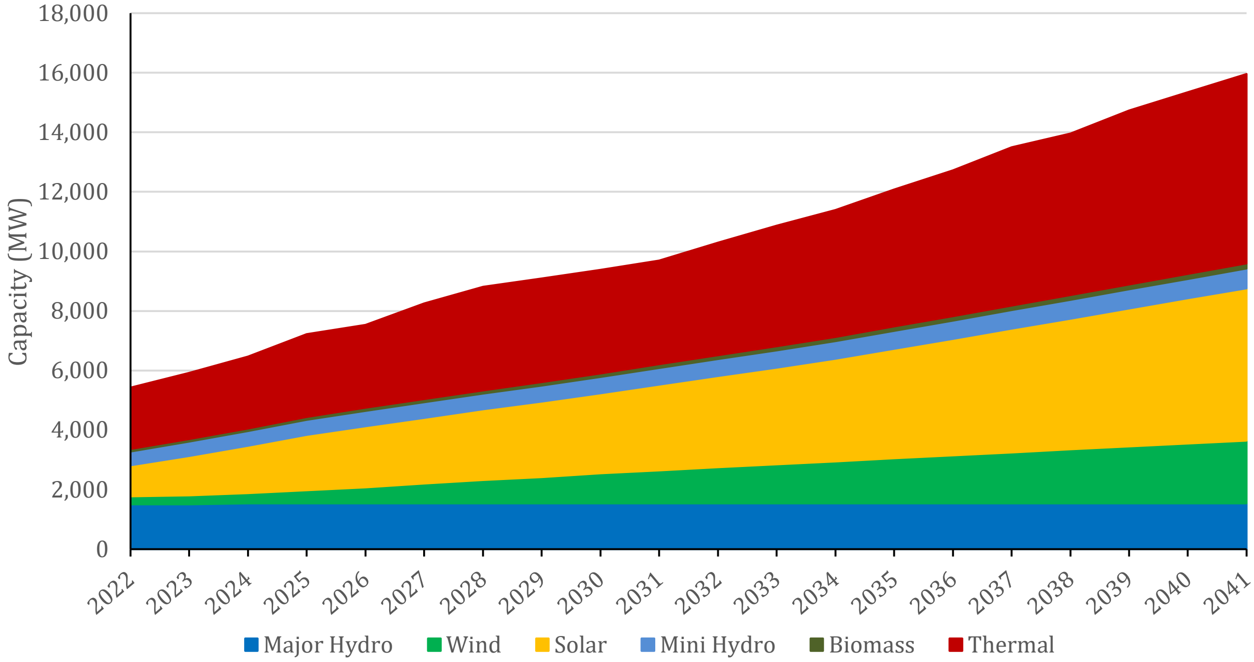


Figure 8.3 – Capacity wise Renewable Contribution over next 20 years

Variation of the firm capacity share over the planning horizon is shown in the figure 8.4. By year 2030, firm capacity share is comprised of 38% Natural Gas, 24% high efficient coal power, 27% large hydro, and 11% other sources. For the whole planning horizon and especially beyond 2030, with a high firm capacity share Natural Gas based thermal power plants dominate the capacity share as the major firm thermal energy source.

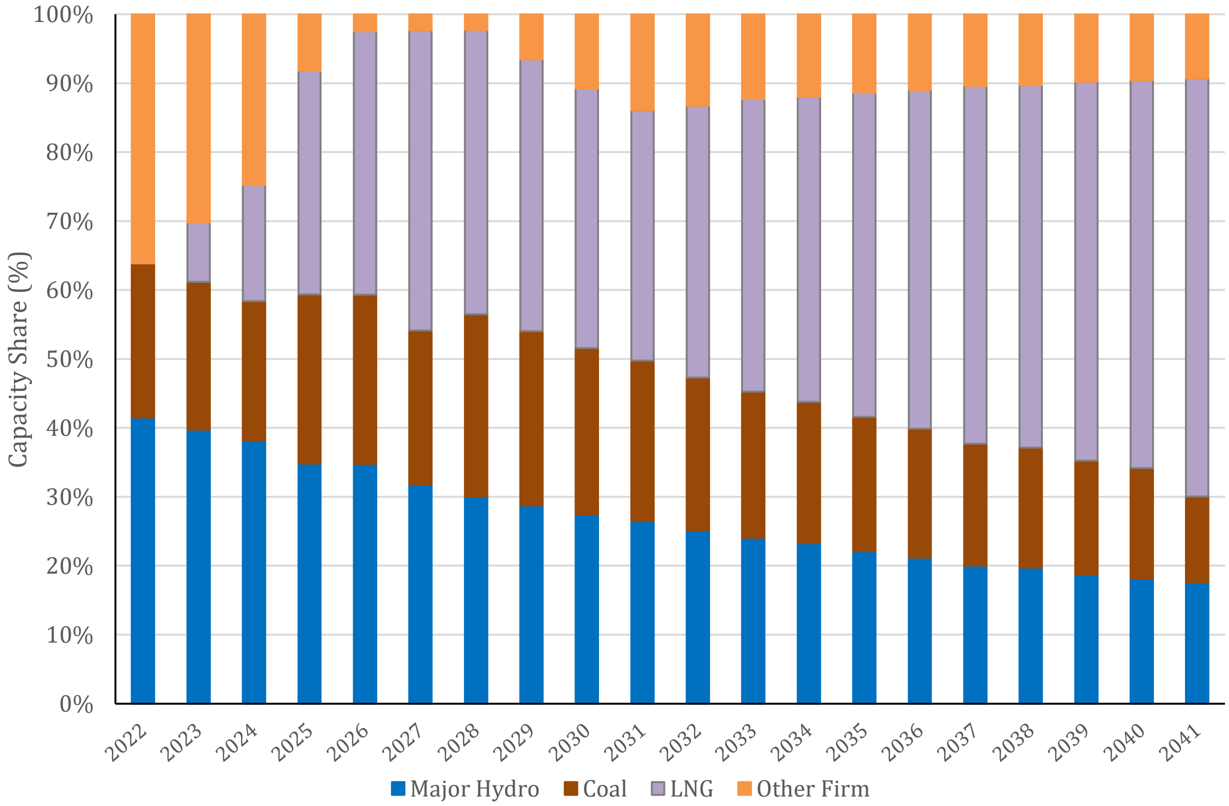


Figure 8.4 – Firm Capacity Share over next 20 years in Base Case

Table 8.4 shows total installed capacity, firm capacity, renewable energy capacity and the peak demand for the years 2025, 2030 and 2039. It is observed that the firm capacity share and the renewable energy share with regard to the total installed capacity and peak demand comply with the government policy on future electricity generation mix.

Table 8.4: Capacity Distribution for Selected Years in Base Case

Year	2030	2035	2041
Total Installed Capacity (MW)	**9,784**	**12,657**	**16,521**
Total Firm Installed Capacity (MW)	5,589	6,925	8,694
Major Hydro Installed Capacity (MW)	1,533	1,533	1,533
ORE Installed Capacity (MW)	4,371	5,921	8,031
Total Renewable Installed Capacity (MW)	**5,904**	**7,454**	**9,564**
Peak Demand (MW)	**4,509**	**5,789**	**7,601**

8.3.2 System Energy Share

In 2020, on average 37% of the total energy demand is met by renewable energy sources (25% major hydro and 12% ORE) whereas 63% is met by thermal generation. Future energy supply scenario of the Base Case Plan from 2022 onwards is graphically represented in Figure 8.5.

As for renewables, the hydro generation share gradually decreases throughout the planning horizon starting from 25% in 2022 to 10% in 2041. Energy contribution from ORE gradually increases throughout the planning horizon from 25% in 2022 to 40% by 2041 which is the optimum ORE penetration level to the system.

As for thermal power plants, during initial 3 years of the planning horizon major energy contribution comes from oil and coal based thermal generation, but Beyond 2024, NG become the major thermal energy contributors of the system and the energy share gradually increases with the addition of new NG power plants to cater the increasing national demand and improve system operational capabilities. Coal energy share is 30% in 2022 and will gradually decrease up to 16% by 2041. The energy contribution from other oil-fired power plants decreases from 20% in 2022 to 3% by 2025 with the gradual retirement of oil plants and thereafter becomes negligible. As shown in the Figure 8.5, energy share of natural gas based power plants gradually increases in the planning horizon, staring from 15% in 2024 to 34% in 2041. Percentage energy share of each plant type is given in Figure 8.6 and Energy Balance of the system is given in Annex 8.3. The Annual expected generation and plant factors under different hydro conditions for the Base Case Plan are given in Annex 8.4.

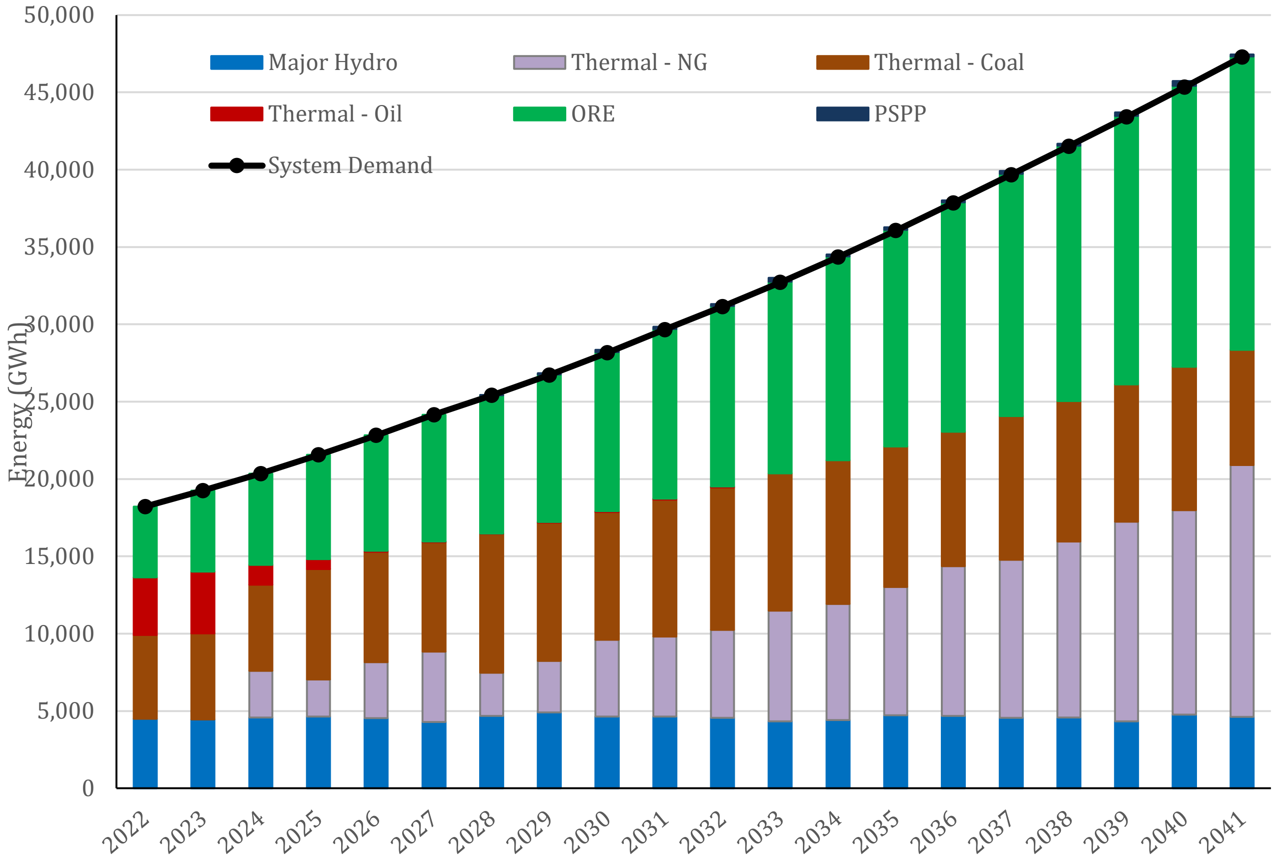


Figure 8.5 – Energy Mix over next 20 years in Base Case

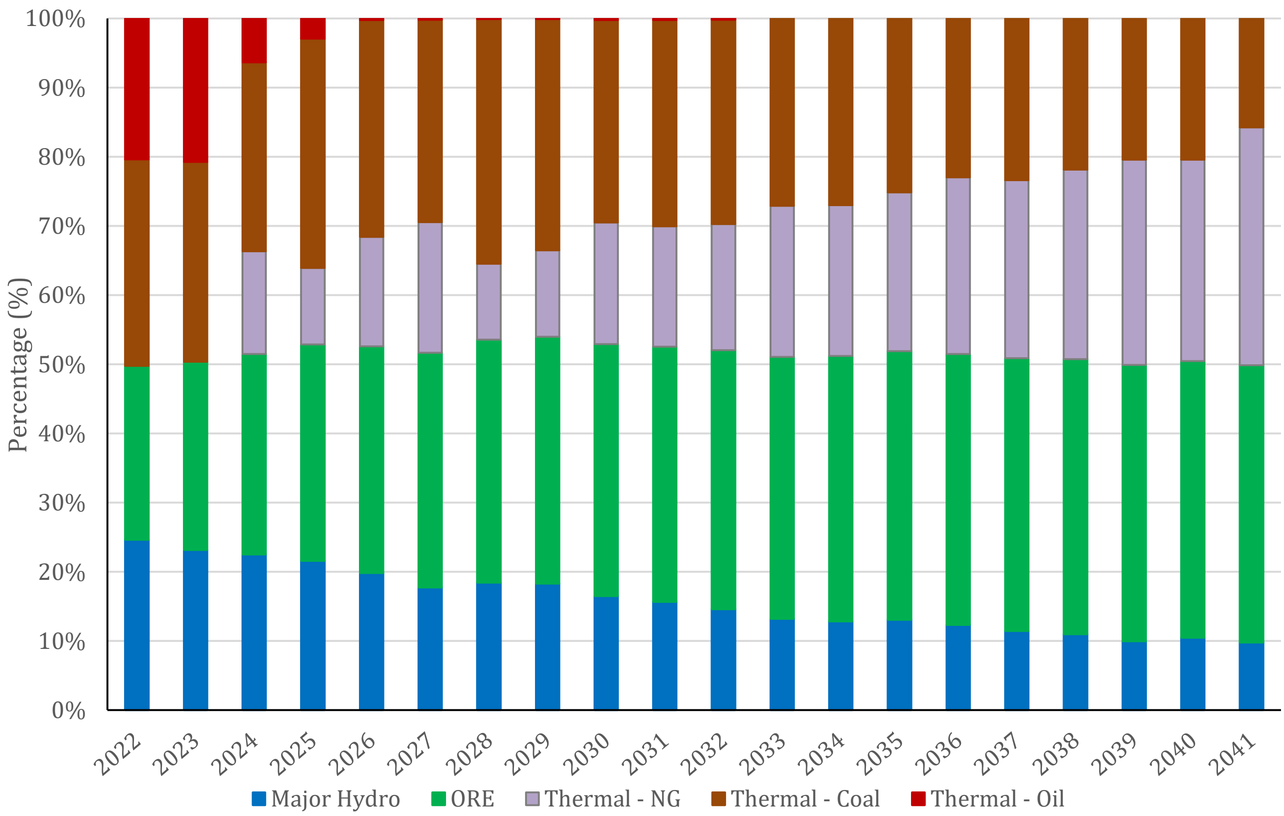


Figure 8.6 – Percentage Share of Energy Mix over next 20 years in Base Case

Contribution from ORE based generation is shown in Figure 8.7 and the Figure 8.8 illustrates the variation of low carbon-based energy share in the total system for the 20-year study period. To integrate the optimum amount of ORE based generation, the implementation of proposed thermal power plants and pumped storage power plants as scheduled is imperative in order to maintain the reliability criterion of the power system and to minimize the ORE curtailments during off peak and seasonal resource variations.

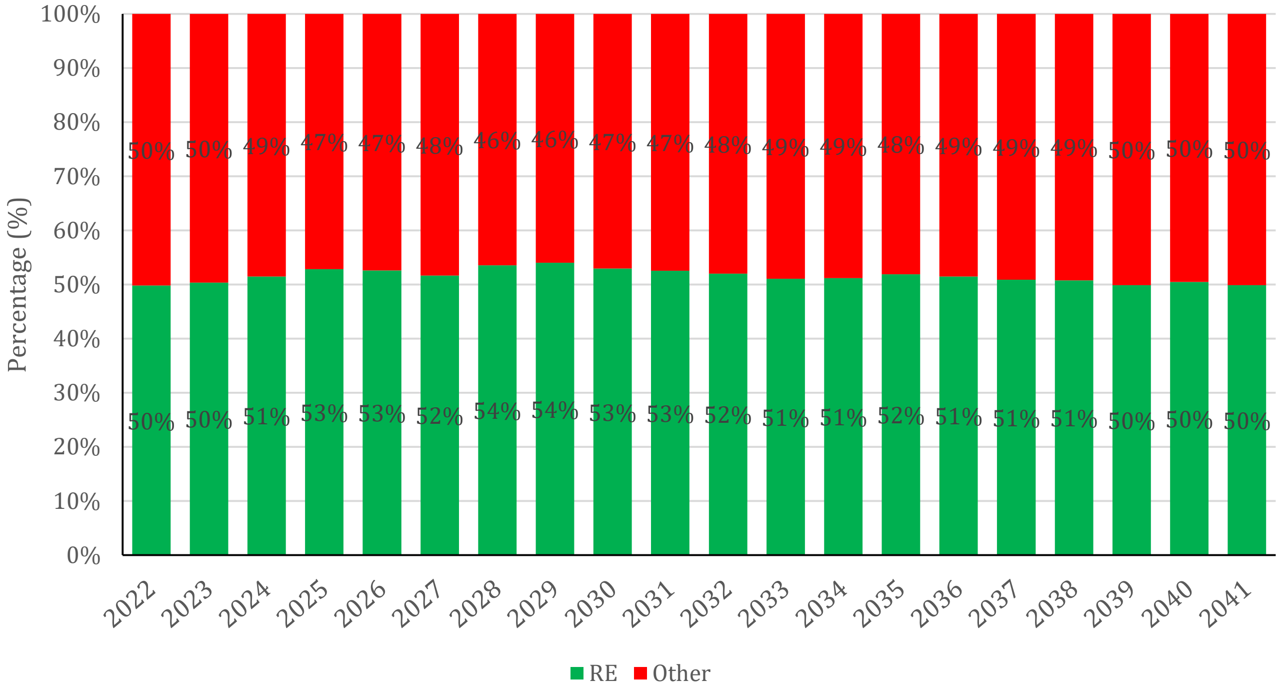


Figure 8.7 – Percentage Share of Renewables over next 20 years in Base Case

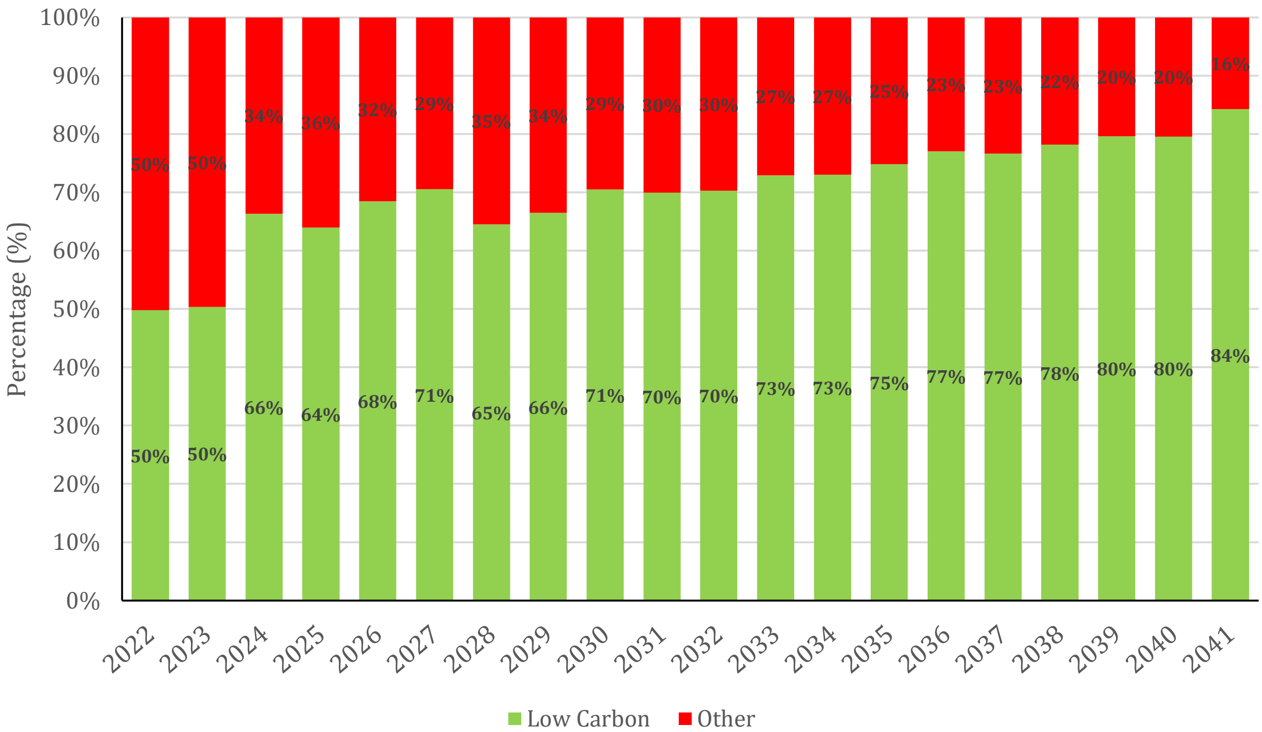


Figure 8.8 - Percentage Share of low carbon based generation over next 20 years in Base Case

8.3.3 Fuel, Operation and Maintenance Cost

Expected expenditure on fuel, operation and maintenance (O&M) of the Generation System from 2022 to 2041 is summarized in Table 8.5 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 8.5. Expected fuel quantities and associated costs of fuel in the Base Case are graphically represented in Figure 8.9 and Figure 8.10 based on the fuel prices indicated in Section 4.2 of Chapter 4.

Table 8.5: Cost of Fuel, Operation and Maintenance of Base Case

Units: million US$

Year	Operation and Maintenance					Fuel
	Hydro	Pumped Hydro	Thermal	ORE	Total	
2022-2026	97	-	374	264	735	2,881
2027-2031	98	15	407	379	899	3,384
2032-2036	98	38	472	493	1,101	5,049
2037-2041	98	38	565	615	1,316	7,050
Total	**392**	**92**	**1,818**	**1,750**	**4,051**	**18,364**

Total fixed and variable O&M cost over next 20 years is in the order of about 4,051 million USD and total fuel cost is about 18,364 million USD in constant terms.

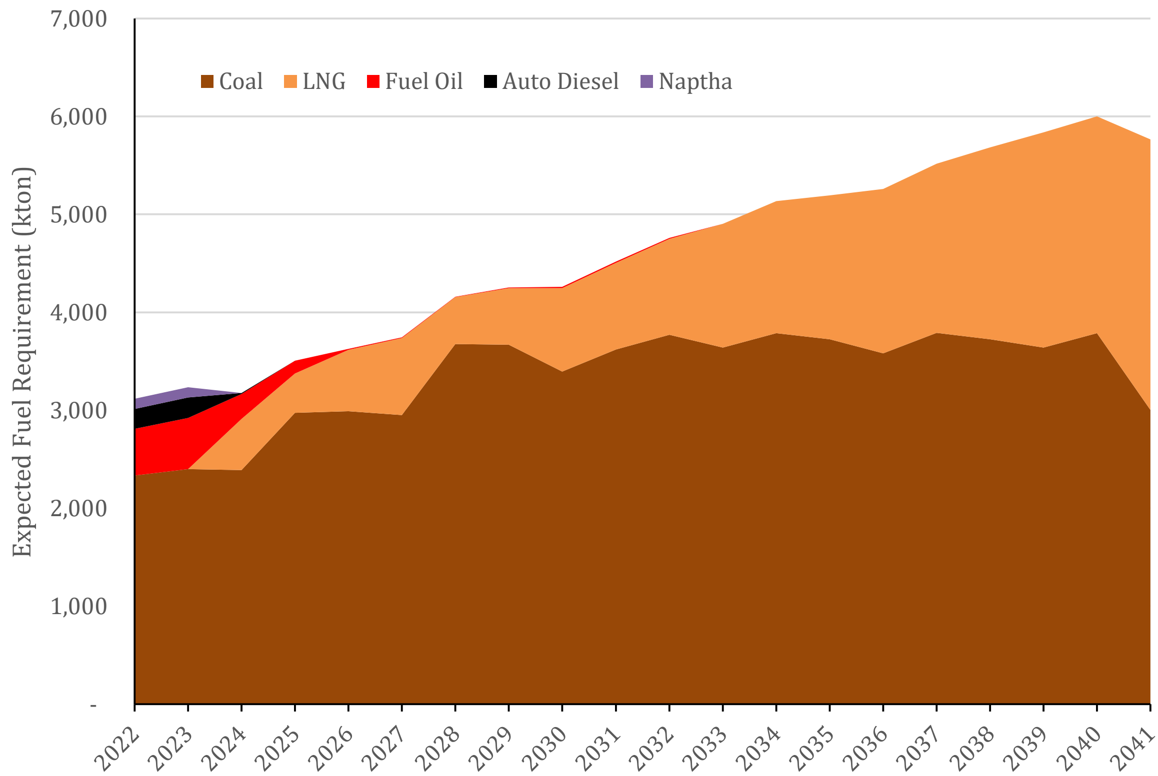


Figure 8.9 - Fuel Requirement of Base Case

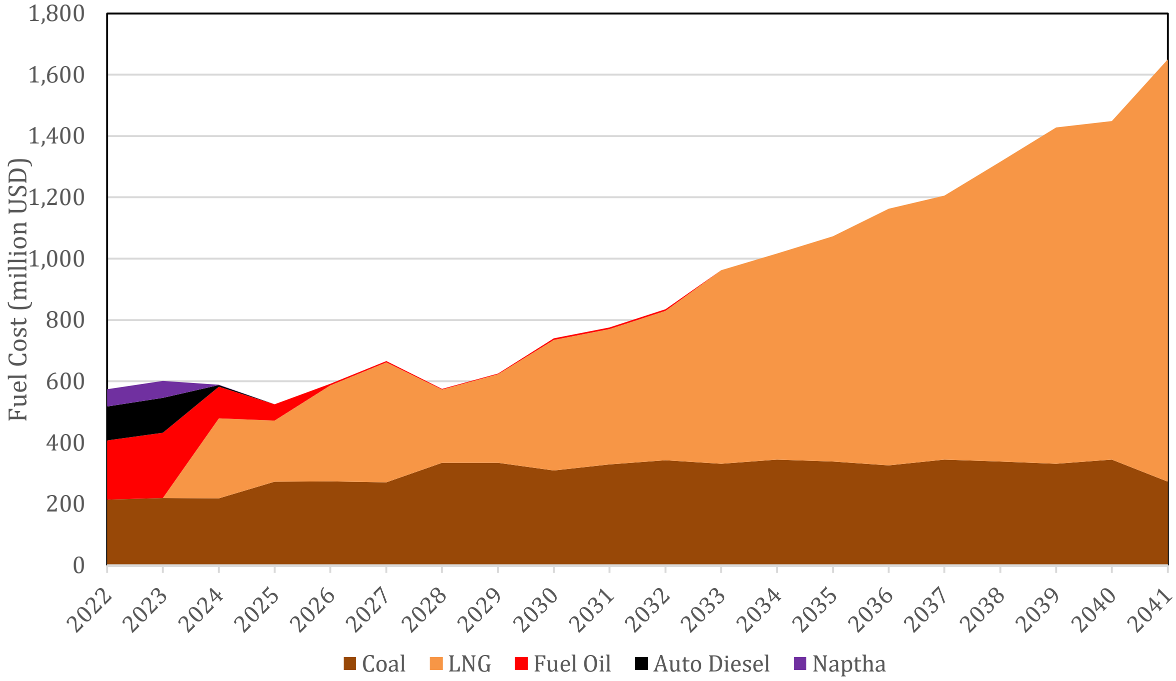


Figure 8.10 - Expected Variation of Fuel Cost of Base Case

In the initial years of the planning period, the oil requirement is relatively high due to short term capacity requirements and the coal remains constant while LNG requirement is increasing gradually. After 2025, the oil quantity requirement becomes negligible with the retirement of existing oil based power plants and the minimal dispatch of the oil based thermal power plants, while the NG requirement increases gradually with the introduction of new natural gas based plants. A coal power plant of capacity 300 MW typically consumes approximately 0.8 million tons per annum and a NG Combined Cycle power plant of capacity 400MW typically consumes approximately 0.3 million tonnes per annum at 60% plant factor, however it can vary depending on energy generated, plant characteristics and fuel characteristics.

In the year 2022, nearly 0.8 million tons of fuel oil, diesel and naphtha will be burnt in oil power stations and this consumption will decrease significantly to 0.011 million tons in 2026 and will completely be phased out by 2033. 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 natural gas based power plants including the conversion of existing oil power plants to natural gas.

As natural gas becomes the dominant fuel in the planning horizon, the expected annual fuel requirement for the future development of natural gas based power plants in average, dry and wet hydro scenarios as per the Base Case Plan, is shown in the Figure 8.11 and details are given in Annex 8.5

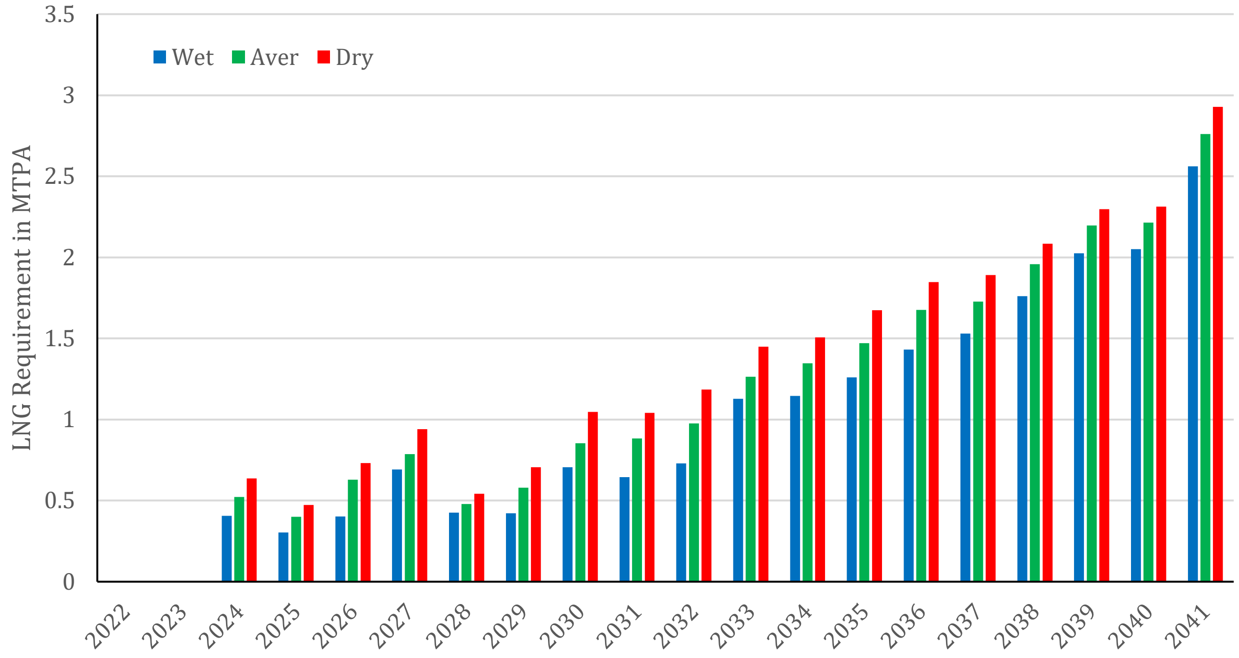


Figure 8.11 - Expected Annual Natural Gas Requirement of the Base Case in Different Hydro Scenarios

8.3.4 Reserve Margin and LOLP

The Base Case plan complies with the stipulated values for Loss of Load Probability and Reserve Margin, for all the hydro conditions in accordance with "The technical and reliability requirements of electricity network of Sri Lanka" which was published in Gazette Extraordinary No. 2109/28 dated 2019-02-08 by the PUCSL.

The Base Case plan maintains available firm capacity share within the minimum Reserve Margin of 2.5% and maximum Reserve Margin of 20% at the critical period for each year (Generally the month with the driest hydro condition). Reserve Capacity in the worst hydro condition is maintained within the stipulated limits even during the initial years of the planning period despite the retirement of several thermal power plants in this period. Reserve Margin variation during the driest period throughout the 20-year period, considering the available firm capacity during the critical period of each year is shown in the Figure 8.12. It should be noted that the total installed capacity of the system including VRE sources is maintained at 100% - 130% over the peak demand throughout the horizon due to the high capacity of VRE resources integrated to the system.

Base Case plan maintains the annual LOLP value below the Maximum LOLP value of 1.5%, which should be complied during all conditions including the driest hydro conditions as shown in Table 8.2.

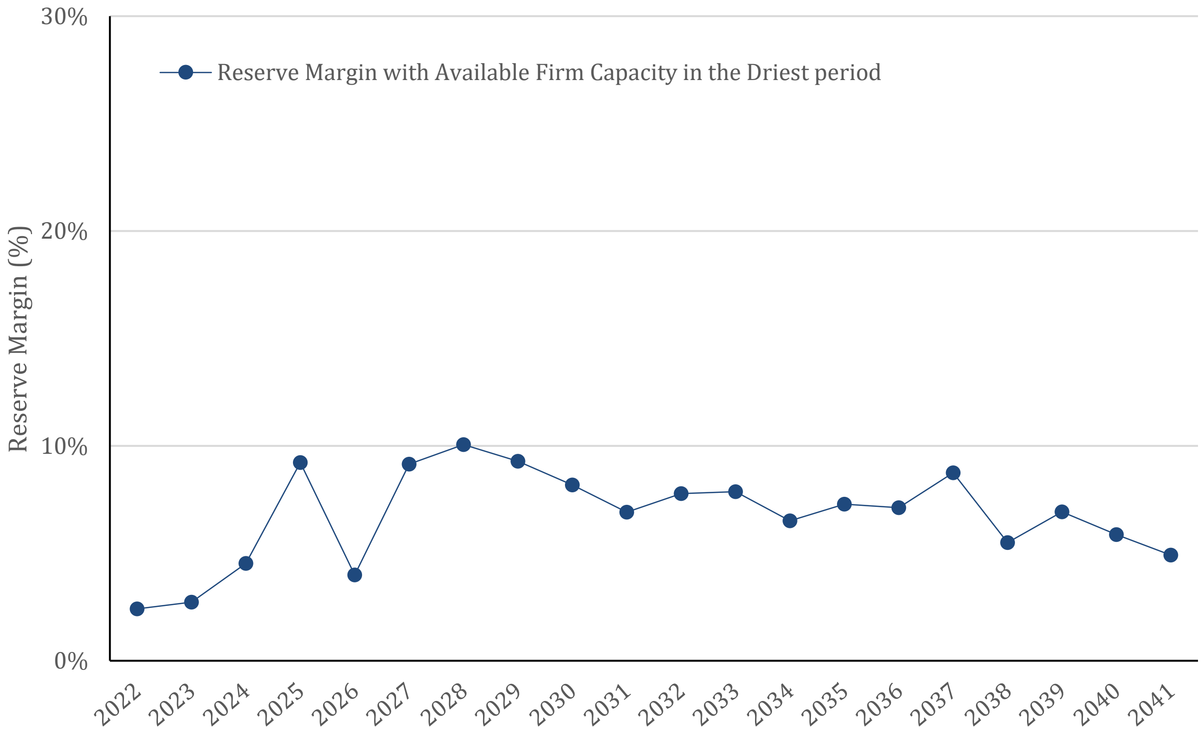


Figure 8.12 – Variation of Reserve Margin in Base Case

8.3.5 Operational Analysis of the Base Case Plan

Traditionally long-term planning of power systems was mainly based on meeting the projected demand at minimum cost. Sri Lanka also being a country having a large hydro and thermal based power system has been carrying out long term generation planning based on conventional long term planning concepts. During the last decade, increasing amounts of wind and solar power (termed as Variable Renewable Energy – VRE) has been integrated to the system. The present trend is to aggressively add VRE to the system to meet the government's policy targets set to reduce dependency on fossil fuels and to promote indigenous resources, resulting in reduced environment impacts and reduced expenditure on fossil fuel. Furthermore, diminishing capital cost of VRE technologies has encouraged this. These developments together with other various advancements in power systems such as increased reliability requirements, increased use of novel technologies etc., have prompted to incorporate operational planning aspects to long term planning to evaluate the flexibility and resilience of the power system.

The addition of VRE sources to the system and the increase in share of VRE throughout the planning horizon is illustrated in Figure 8.13. It is observed that VRE share which is currently at less than 10%, increases rapidly during the planning period reaching 27% by 2030 and 33% by 2041. As shown in Figure 5.2 of Chapter 5, Sri Lanka moves from Phase 1 to Phase 3 on the classification defined by International Energy Agency (IEA) based wind and solar penetration levels which results in VRE share in the system determining the operating pattern of the system.

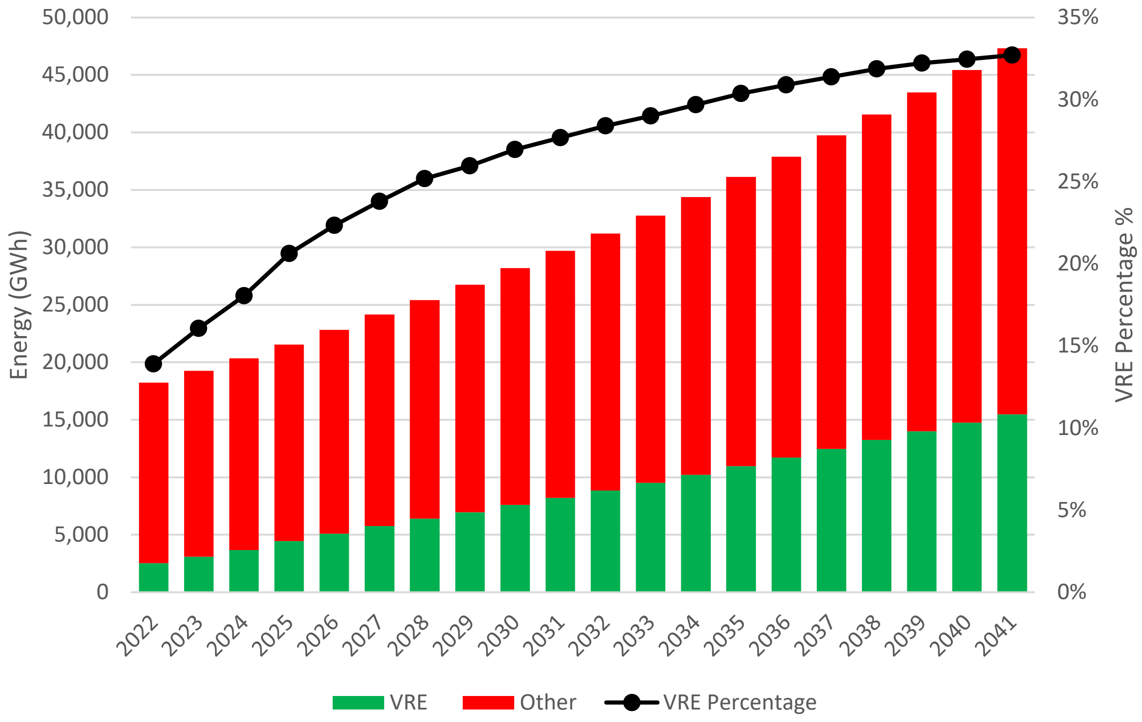


Figure 8.13 – VRE Capacity and the Energy Share in the Base Case

Some of the notable drawbacks in VRE are intermittency of the resource and low inertial support to the system. To overcome these system-wide impacts of VRE, sufficient system inertia and high ramping requirements of conventional power plants is demanded. The intermittency of VRE would cause the conventional power plants having comparatively higher unit costs to start up and ramp up more frequently. Different forms of energy storage and mechanisms such as demand response will become increasingly relevant to aid in the shaping of supply and demand to match one another at all time points of the load curve.

With the above operational considerations, long term generation planning evolves steadily. In the past, many operational constraints were simplified, to keep the planning models computationally small. However, with the ever-increasing demand for operational flexibility of power systems, it is vital to evaluate the projected operational aspects of the system such as power system stability, sufficient ramping capability, sufficient reserve availability, behaviour of energy storage in the system, etc.

The long-term generation planning tools used by CEB offer the capability to carry out hourly simulations of the generation system which enables to capture some of the operational characteristics of the projected power system. This section summarizes the results of the operational analysis carried out for milestone years of the planning horizon in the long-term generation planning exercise. The operational features which were checked using the SDDP hourly simulations are listed below:

1. The worst anticipated hourly and daily ramping event originated from VRE sources.
2. Sufficient generation capacity to provide required operating reserves and the designated power plants providing primary and secondary reserve requirement.

The primary reserve responds to varying frequency signals, stabilizing the system frequency by compensating imbalances. The purpose of the secondary reserve is to restore power balance and relieve the primary reserve.

3. Sufficient Power plants with fast ramp up and ramp down capability.

4. Standby generation capacity reserve requirement for releasing a major power plant for planned maintenance or forced outages.

5. Sufficient generating capacity (having black start/line charging) capability to restore island wide supply in case of a total system failure, under the standard total failure restoration.

The results of the operational analysis carried out are summarized in Table 8.6 and the results are presented for the milestone years of the planning horizon which are 2025, 2030, 2035 and 2041. Figure 8.14 and Figure 8.15 illustrates the anticipated magnitude of daily and hourly ramps of the Net load caused by VRE generation for a particular week of the year 2030.

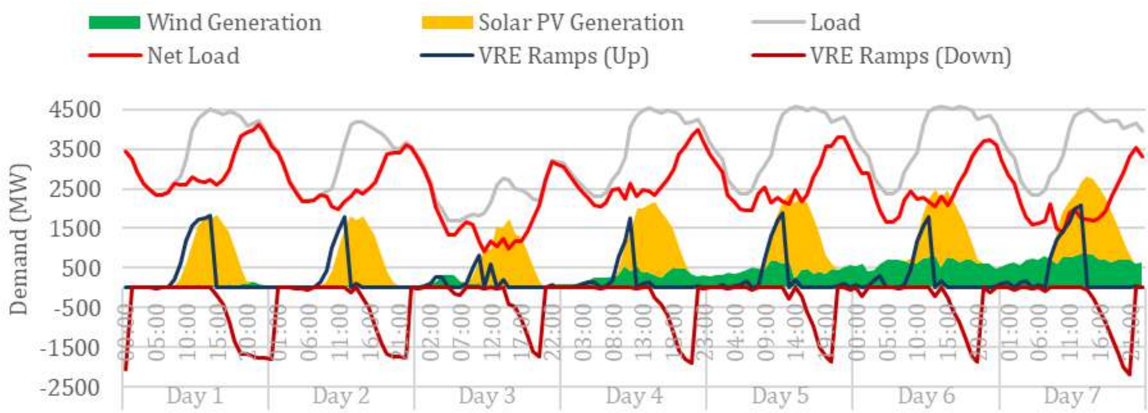


Figure 8.14 – Daily Ramping events from VRE- 20th Week of Year 2030

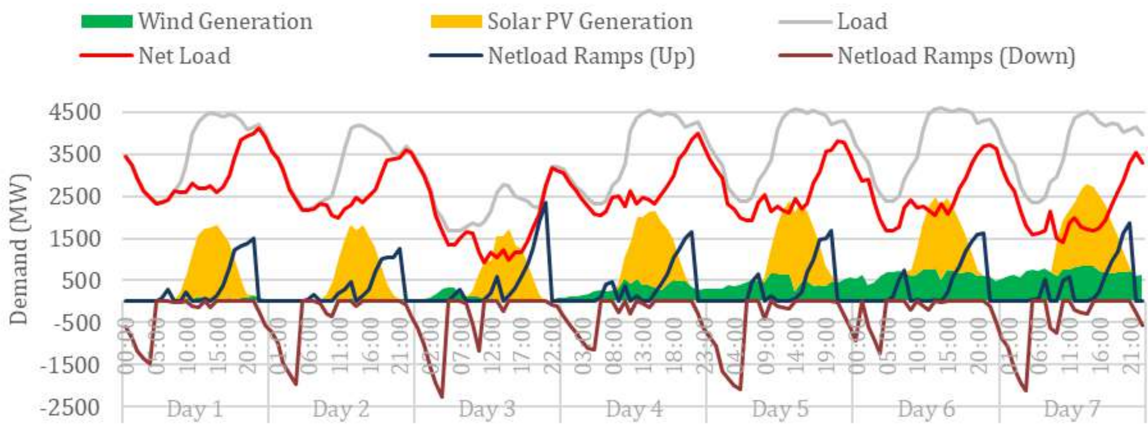


Figure 8.15 – Daily Ramping events of the Net Load- 20th Week of Year 2030

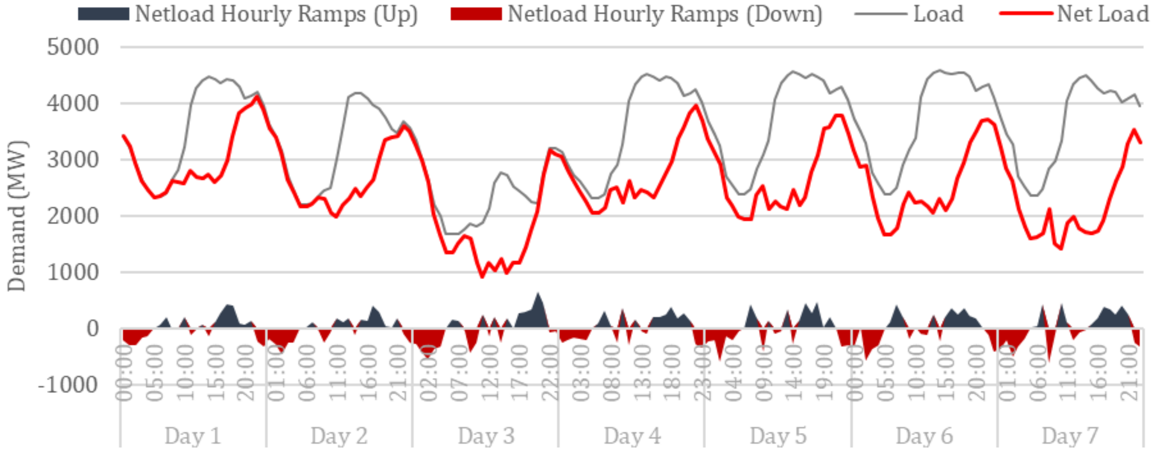


Figure 8.16 - Hourly Ramps of the Net Load - 20th Week of Year 2030

Figure 8.14 illustrates the largest ramp events caused by the VRE generation in the 20th week of year 2030. The daily ramp up events of large magnitude of generation is mainly caused by the rise in solar PV generation in the morning half of the day and ramp down events at the evening portion. Such VRE generation ramp events have the possibility of exceeding 2000 MW in the year 2030. Figure 8.15 illustrates the large daily ramping up events taking place in the net load due to changes in both VRE generation and the load. These large changes take place in the evening reflecting the "Duck Curve" effect requiring the ramping up of flexible generation to meet the sharp evening peak appearing in the net load. This sharp peak in the net load that reaches up to 2600 MW in the year 2030 requires the operation of peaking capacities.

The figure 8.16 illustrates the hourly changes in the net load due to the variabilities in the VRE generation and the demand. The flexible capacity is required to adjust the output to maintain the supply demand balance in the hour-to-hour basis and the requirement can reach 1100 MW by 2030. Geographical staggering of wind and solar PV resource will be able to lower this hour-to-hour requirement. The flexibility requirement due to the planned renewable energy development and the availability of the adequate flexible generation is examined in this operational analysis.

Table 8.6: Results of the Operational Analysis

No.	Operational Feature	Unit	Results			
			2025	**2030**	**2035**	**2041**
1	Largest anticipated hourly ramp event from total VRE Generation	MW	560	830	1,130	1,420
2	largest anticipated daily ramp event from total VRE Generation	MW	1,400	2,130	2,980	3,760
3	Largest anticipated hourly ramp of the net load	MW	750	1,100	1,530	1,920
4	Largest anticipated daily ramp of the net load	MW	1,770	2,600	3,520	3,860
5	Power Plants with the capability to provide primary operating reserves[1]		• 130 MW New GTs • 2 x 350 MW CCY (Open Cycle Mode)	• 130 MW New GTs • 2 x 350 MW CCY (Open Cycle Mode) • 250 MW Gas Engines • 400 MW CCY (Open Cycle Mode) • 400 MW PSPP	• 130 MW New GTs • 2 x 350 MW CCY (Open Cycle Mode) • 250 + 2 x 200 MW MW Gas Engines • 2 x 200 MW + 100 MW GTs • 3 x 400 MW CCY (Open Cycle Mode) • 600 MW PSPP	• 130 MW New GTs • 2 x 350 MW CCY (Open Cycle Mode) • 2 x 250 MW + 2 x 200 MW Gas Engines • 3 x 200 MW + 4 x 100 MW GTs • 6 x 400 MW CCY (Open Cycle Mode) • 600 MW PSPP

6	Power Plants with the capability to provide secondary operating reserves[1]		• 130 MW New GTs • 2 x 350 MW CCY (Open Cycle Mode)	• 130 MW New GTs • 2 x 350 MW CCY (Open Cycle Mode) • 250 MW Gas Engines • 400 MW CCY (Open Cycle Mode) • 400 MW PSPP	• 130 MW New GTs • 2 x 350 MW CCY (Open Cycle Mode) • 250 + 2 x 200 MW MW Gas Engines • 2 x 200 MW + 100 MW GTs • 3 x 400 MW CCY (Open Cycle Mode) • 600 MW PSPP	• 130 MW New GTs • 2 x 350 MW CCY (Open Cycle Mode) • 2 x 250 + 2 x 200 MW MW Gas Engines • 3 x 200 MW + 4 x 100 MW GTs • 6 x 400 MW CCY (Open Cycle Mode) • 600 MW PSPP
7	Power plant with fastest ramp up and down capability and the ramp rate	Power Plant	130 MW New GTs	250 MW Gas Engines	250 MW Gas Engines	250 MW Gas Engines
		%/min	Approx. 20	Approx. 100	Approx. 100	Approx. 100
8	Standby generation capacity reserve requirement to release a major power plant for maintenance	MW	Reserve firm capacity has been maintained in each year throughout the planning horizon to compensate for the outage of the largest unit of the system.			
9	Power plants with the capability to restore island wide supply in case of a total system failure under the standard total failure restoration and total capacity	Power Plants	130 MW New GTs	130 MW New GTs[2]	130 MW New GTs[2]	130 MW New GTs[2]
		MW	130 MW	130 MW	130 MW	130 MW

1. Only indicates the power plant additions proposed in the base case. Power Plants in the existing system with the capability to provide reserves is not included.
2. In addition to this plant, if further capacity is required to have the capability to restore the grid after a system failure, it would be assessed in future with further transmission related studies and added to the specifications of the new plant additions accordingly.

8.4 Impact of Demand Variation on Base Case Plan

High Demand and Low Demand cases were analysed in order to identify the impact of the demand variation on the Base Case Plan 2022-2041. The demand forecasts used for these two cases are shown in Annex 3.1.

High demand forecast average electricity demand growth rate for twenty-year planning horizon is 5.5% while Base Demand forecast shows 5.2% average growth rate. This demand increase results an increase of short term and long term power plant capacity additions than identified in the Base Case Plan 2022-2041. In addition, High demand case shows 6% increment in the total present worth cost compared to the Base Case over the planning horizon. Capacity additions for High Demand Case by plant type are summarised in five year periods in Table 8.7.

Table 8.7: Capacity Additions by Plant Type – High Demand Case

Type of Plant	2022-2026 (MW)	2027-2031 (MW)	2032-2036 (MW)	2037-2041 (MW)	Total capacity addition (MW)	Total capacity addition %
Major Hydro	186	-	-	-	186	1%
Pumped Hydro/Battery Storage	20	680	-	-	700	5%
Gas Turbines	130	100	800	200	1230	9%
Coal	300	-	300	-	600	5%
Combined Cycle	700	800	800	1600	3900	28%
IC Engines	250	-	250	200	700	5%
ORE	1,718	1,490	1,610	1,750	6568	47%
Total	3304	3070	3760	3750	13884	**100%**

Above figures represent net capacity additions

Twenty-year average electricity demand growth in low demand forecast is 5.1% which is 0.1% lower than the growth in Base Demand forecast. This demand reduction results to the reduction of short term and long term power plant capacity additions than identified in Base Case Plan 2022-2041. Low demand case shows 5.5% total present worth cost decrement compared to the Base Case Plan 2022-2041. Capacity additions for Low Demand Case by plant type are summarised in five year periods in Table 8.8.

Table 8.8: Capacity Additions by Plant Type – Low Demand Case

Type of Plant	2022-2026 (MW)	2027-2031 (MW)	2032-2036 (MW)	2037-2041 (MW)	Total capacity addition (MW)	%
Major Hydro	186	-	-	-	186	1%
Pumped Hydro/Battery Storage	20	680	-	-	700	5%
Gas Turbines	130	-	700	500	1330	10%
Coal	300	300	-	-	600	5%
Combined Cycle	700	400	800	800	2700	21%
IC Engines	250	-	200	450	900	7%
ORE	1,718	1,490	1,610	1,750	6568	51%
Total	3304	2870	3310	3500	12984	**100%**

Above figures represent net capacity additions

Overall annual capacity additions of Thermal power plants and their corresponding fuel requirement vary over the planning horizon for High and Low Demand cases. The resulting plans for the two cases are given in Annex 8.6 and Annex 8.7 respectively.

8.5 Impact of Discount Rate Variation on Base Case Plan

The discount rate is a crucial component of a discounted cash flow valuation. The discount rate can have a considerable impact on the valuation and hence the selection of power plants in the expansion plan. To study the effect of discount rate on Base Case Plan, analysis was carried out for high and low discount rates compared to 10% used in the Base Case Plan. For low discount rate analysis 3% was used and 15% used for high discount rate.

Low discount rate scenario was carried out to investigate whether high capital cost plants are selected at lower discount rate. In this scenario power plants with comparatively high capital cost were advanced. In the high discount rate analysis, it was observed that the selection of high capital cost power plants was delayed. Therefore, it should be noted that when financing high capital cost power plants, it is required to attract low interest finances in order to be comparatively viable.

Nevertheless, the government policy directive regarding the future electricity mix of the country should be complied in both above scenarios. Therefore, the real impact on cost due to variation of discount rate cannot be analysed.

8.6 Impact of Fuel Price Sensitivity on Base Case Plan

Preparation of the Base Case Plan considers the constant fuel prices throughout the planning horizon and the impact of the fuel price volatility and variation is separately investigated as a sensitivity analysis in the planning process. The impact of long term global fuel price escalations and short term fuel price volatility are important considerations in terms of electricity system security. The main policy scenario studies in the LTGEP aiming to achieve 50% Renewable energy share by 2030 and beyond, has different firm capacity mixes having different degree of impact from potential fuel price escalation and fluctuations. Therefore, the impact of the projected fuel price escalation on the Base Case and the impact of the fuel price sensitivity on the operating cost of the three main policy scenarios including the Base Case was tested.

The LTGEP 2022-2041 analyses three main policy scenarios having different capacity composition based on considerations such as capacity diversification, enhancing system flexibility and enhancing low carbon share. The World Energy Outlook 2020 published by International Energy Agency (IEA) announces the latest indicative long term price variations of coal, oil and gas up to 2040. The IEA's methodology considers the impact of supply demand balance, current and future energy policies, global economic activities and demographic trends for projecting future fuel prices trajectories. Following fuel prices escalations given in Table 8.9 have been projected by the International Energy Agency under the current policies scenario. In contrast to previous years' projections of IEA projection have been revised down due to the dampening effect of the crisis on global demand, changes in policies and strategies as well as cost structures on the supply side. However, IEA further states that although the price projections are lower, the possibility of price volatility and new price cycles has increased. Therefore, both the long term behavior of the fuel price as well as price volatilities are important for securing the electricity system.

Table 8.9: Fuel Price Projections - Current Policy Scenario of World Energy Outlook 2020

Fuel	2025	2030	2035	2040
Crude oil ($/barrel)	71	76	81	85
Natural Gas ($/MMBtu)	9.2	8.9	8.9	9.0
Coal ($/MT)	77	79	78	77

Note: Oil price is the IEA Crude oil price which is the weighted average import price of IEA member countries. The above natural Gas price is solely the LNG import prices of Japan. Coal price is solely the import price of coal for Japan. The above specific price projections have been considered for the purpose of this analysis to reflect the prices for importing nations.

Source- International Energy Agency

IEA based on projected supply demand dynamics anticipates that the oil prices to flatten after next five years where as natural gas prices to slightly increase in different regions. Coal prices have been revised downwards reflecting the low demand in overall. Application of above price trends to the Base case scenario yields an 8.4% increase to the total PV cost. The 1,372 million USD increase in operational cost compared to Base fuel prices, results in a Total PV cost of 17,652 million USD for the period of 2022-2041. This increase is mainly due to the impact on the rise in imported natural gas fuel prices due to the impact of rise of the natural gas prices. The recent ten-year fuel price forecast made by the world bank described in the chapter 4 follows the similar trajectory whereas the 5 year forecast made by IMF anticipate an early decline in oil and natural gas prices in initial years.

Variation in the fuel prices was applied to the key policy scenarios to assess the degree of impact on the operation cost of each policy scenario. The results provide an indication of the robustness of each policy scenario against fuel price variations. The fuel price sensitivity is applied to imported LNG and coal prices and the oil prices was not considered as the oil based generation is phased out within the initial years leading t minimal impact in all the scenarios.

Historical fuel price variations show that high volatility in global LNG prices and relatively low level of volatility in international coal prices. Considering both the extent of volatility and the likelihood of volatility of LNG and coal prices, it is important to examine the potential impact on key policy scenarios. According to the results it was observed that the current policy on fuel diversification exhibit the lowest level of impact due to the balance mix of resources. In contrast the reference case shows a high level of impact for coal price variation whereas the Base Case shows a high level of impact for LNG price variations. Even though the Base Case has lowered the import dependence by indigenous resource renewable development, reliance on the natural gas based capacities can lead to higher impact of gas prices fluctuations. It is important to adopt available measures to minimize the risk of imported natural gas price fluctuations. In the event where the local natural gas is available in future, country will have the opportunity to lower the dependency on imported liquid natural gas.

Table 8.10: Sensitivity of Operational Cost due to fuel price variations

Scenario	**Operating Cost (million USD)**		**Degree of impact**
	Coal Price 50% High	**LNG Prices 50% High**	
Reference Case	19%	5%	High
Current Policy on Fuel Diversification	4%	8%	Moderate
70% Low Carbon by 2030 and maintaining the same beyond 2030	2%	13%	High
Base Case- 70% Low Carbon by 2030 with restricted Coal power development beyond 2030	2%	15%	High

8.7 Summary

The total present value of cost over the planning horizon for Base Case and Sensitivities studied are summarized in Table 8.11.

Table 8.11: Comparison of the Sensitivities of the Base Case Plan

	Present Value of costs during the planning horizon	Deviation of PV Cost from Base Case	
	(Million USD)	(Million USD)	%
Base Case	16,280	-	-
Sensitivities on Base Case			
Demand Variation			
High Demand	17,296	1,016	6
Low Demand	15,384	(896)	(5.5)
Fuel Price Escalation	17,652	1,372	8.4

CHAPTER 9

RESULTS OF GENERATION EXPANSION PLANNING STUDY – SCENARIO ANALYSIS AND DETERMINATION OF BASE CASE

This chapter presents the analysis of the different scenarios considered in the generation expansion planning studies in addition to the Reference Case and selection of the Base Case out of the scenarios studied.

The current policy for the sector is stipulated through General Policy Guidelines in Respect of The Electricity Industry as issued in April 2019. However, various policy indications given by the government at present highlights the intention of the government to develop a low carbon electricity supply system and gradually take the sector towards high share of indigenous sources. Thus, planning studies were conducted under three separate scenarios with respect to policy guidelines, each of which fulfil the RE absorption target given in the General Policy Guidelines while aiming to achieve the high renewable share in the future. The three scenarios are as follows:

1. **Scenario 1**: Strictly in compliance to existing General Policy Guidelines.
2. **Scenario 2**: Achieve 70% of electricity from low carbon sources by 2030, including a minimum of 50% from RE, and **maintain** 70% low carbon share up to 2041.
3. **Scenario 3**: Achieve 70% of electricity from low carbon sources by 2030, and **increase** the share of low carbon sources beyond 2030 by restricting Coal Power development.

In addition to the above scenarios, considering the energy policy element of diversifying the energy mix to the maximum feasible level, adopting nuclear technology as a potential energy source, Energy Mix with Nuclear Power Development Scenario was discussed.

Also, HVDC interconnection with India was studied as a separate scenario to study the impact of the interconnection on the economics and operation of the Sri Lankan power system and how the scenario compares with the other cases studied.

9.1 Scenario 1:Current Policy Scenario

This scenario was formulated by complying to the current policy guidelines stipulated in the General Policy Guidelines in Respect of The Electricity Industry as issued in April 2019. Regarding the future electricity mix of the country, the following key policy elements from the guidelines were complied through this scenario.

- Required diversity to be maintained to the fuel mix of the installed firm capacity to maintain energy security, namely, 30% from Coal, 30% from LNG, 25% from large hydro by 2030;
- To progress with the vision to achieve 50% of electricity from RE sources by 2030 under favourable weather conditions.

The scenario was developed for the demand forecast as described in Table 3.3. The Other Renewable (ORE)integration levels were also kept as same as described in Table 5.6 after verifying with operational and transmission network constraints.

The total PV cost of this scenario is USD 16,147 million and shows the lowest PV cost among all the other scenarios studied except for the reference case.

The capacity additions by plant type which are summarised in five-year periods are shown in Table 9.1and the plant schedule is presented in Annex 9.1.

Table 9.1: Capacity Additions by Plant Type of Scenario 1: Current Policy Scenario

Type of Plant	2022-2026 (MW)	2027-2031 (MW)	2032-2036 (MW)	2037-2041 (MW)	Total capacity addition	
					(MW)	%
Major Hydro	186	-	-	-	186	1%
Pumped Hydro/Battery Storage	20	680	-	-	700	5%
Gas Turbines	130	-	800	300	1,230	9%
Coal	300	600	600	900	2,400	18%
Combined Cycle	700	400	-	400	1,500	11%
IC Engines	250	-	400	250	900	7%
Short Term Capacity	0*	-	-	-	0	0%
ORE	1,718	1,490	1,610	1,750	6,568	49%
Total	**3,304**	**3,170**	**3,410**	**3,600**	**13,484**	**100%**

Above figures represent net capacity additions

9.2 Scenario 2: 70% Low Carbon by 2030 and maintaining the samebeyond 2030

This scenario was developed complying with the perceived policy of the government, which is to maximize generation from renewable sources and, as an interim milestone, a minimum of 70% of electricity should be generated by 2030 from low carbon sources, out of which not less than 50% should be from renewable sources.

This case was formulated using the same demand forecast and the ORE integration schedule used in Scenario 1 but incorporating constraints to achieve 70% of electricity from low carbon sources by 2030, including a minimum of 50% from RE, and maintaining 70% low carbon share up to 2041.

The total PV cost of this scenario is USD 16,276 million and showed an increment of USD 129 million from the PV cost of Scenario 1.

The capacity additions by plant type which are summarised in five-year periods are shown in Table 9.2 and the plant schedule is presented in Annex 9.2.

Table 9.2: Capacity Additions by Plant Type of Scenario 2: 70% Low Carbon by 2030 and maintaining the same beyond 2030

Type of Plant	2022-2026 (MW)	2027-2031 (MW)	2032-2036 (MW)	2037-2041 (MW)	Total capacity addition	
					(MW)	%
Major Hydro	186	-	-	-	186	1%
Pumped Hydro/Battery Storage	20	680	-	-	700	5%
Gas Turbines	130	-	500	300	930	7%
Coal	300	300	300	600	1,500	11%
Combined Cycle	700	400	800	800	2,700	20%
IC Engines	250	-	400	250	900	7%
Short Term Capacity	0*	-	-	-	0	0%
ORE	1,718	1,490	1,610	1,750	6,568	49%
Total	**3,304**	**2,870**	**3,610**	**3,700**	**13,484**	**100%**

Above figures represent net capacity additions

9.3 Scenario 3: 70% Low Carbon by 2030 and increasing the same beyond 2030 by restricting coal power development

This scenario was also developed complying with the perceived policy of the government, which was used as the basis for Scenario 2. However, considering the worldwide trend of gradually opting for a low/zero carbon energy mix in future and the required operational flexibility in the installed generating capacity to absorb high proportion of renewable resources, Scenario 2 was amended by restricting coal power development beyond 2030 to arrive at Scenario 3.

This case was formulated using the same demand forecast and the ORE integration schedule used in Scenario 2 but incorporating constraints to achieve 70% of electricity from low carbon sources by 2030, including a minimum of 50% from RE, and maintaining 70% low carbon share up to 2041 with restriction on coal power development beyond 2030.

The total PV cost of this scenario is USD 16,280 million and showed an increment of USD 133 million from the PV cost of Scenario 1 and a minor increment of USD 4 million from Scenario 2.

The capacity additions by plant type which are summarised in five-year periods are shown in Table 9.3 and the plant schedule is presented in Annex 9.3.

Table 9.3: Capacity Additions by Plant Type of Scenario 3: Low Carbon by 2030 and increasing the same beyond 2030 by restricting coal power development

Type of Plant	2022-2026 (MW)	2027-2031 (MW)	2032-2036 (MW)	2037-2041 (MW)	Total capacity addition	
					(MW)	%
Major Hydro	186	-	-	-	186	1%
Pumped Hydro/Battery Storage	20	680	-	-	700	5%
Gas Turbines	130	-	800	200	1,130	9%
Coal	300	300	-	-	600	5%
Combined Cycle	700	400	800	1200	3,100	23%
IC Engines	250	-	400	250	900	7%
Short Term Capacity	0*	-	-	-	-	-
ORE	1,718	1,490	1,610	1,750	6,568	50%
Total	**3,304**	**2,870**	**3,610**	**3,400**	**13,184**	**100%**

Above figures represent net capacity additions

9.4 India-Sri Lanka HVDC Interconnection Scenario

Importance of regional integration is increasingly being recognized due to its economic and reliability benefits. Cross border interconnections in South Asian region offers new opportunities to greater use of cheaper and cleaner resources as there is a diversity in natural resources, daily and seasonal electricity demand patterns between countries. Interconnection between India-Sri Lanka is being studied with the support of two governments.

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 India 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. According to the initial proposals on feasibility study and also with the economic & financial analysis, the project is not economically or financially viable [25]. Major items which are affecting the project cost are submarine cable and HVDC Technology (Conventional HVDC or VSC based HVDC) selection.

In Sri Lanka, the very ambitious renewable energy development program, changing electricity demand pattern, future requirement of ancillary services are the important factors when considering HVDC interconnection. In the Long Term Generation Expansion Planning studies for the period of 2022-2041, a scenario was developed considering the implementation of 500 MW HVDC in the year 2032. Estimated investment cost of 651 USD million was used for evaluation purpose considering the project alternative mentioned in Chapter 4. Further, landed cost of 9.49 US Cents/kWh is considered based on a previous study [26] which includes marginal cost of Indian system, interconnection transmission charges, reliability support charges, O&M charges etc. and the same is used in the analysis. Given the uncertainty of the transfer price at this initial stage, a sensitivity analysis was performed for the study purpose to examine its impact on the utilization of the interconnection.

Following assumptions were made regarding the HVDC Interconnection Scenario

(a) 1 × 500MW HVDC Interconnection is schedule for operation by 2032.

(b) Transfer price of 9.49 US Cents/kWh is considered. (A ± 20% variation of the transfer price was evaluated separately as a sensitivity).

(c) ORE implementation will remain same as Base Case plan and the 600 MW Pumped Storage Power Plant (PSPP) is also considered as planned in this scenario.

(d) Thermal power plants addition will remain as same as Base Case plan up to 2031.

The Indian and Sri Lankan systems were considered as integrated systems in the simulation and the energy exchanged opportunity was assessed for the 500 MW HVDC link. The HVDC interconnection scenario developed based on the above assumptions has a total PV cost of 16,304 million USD and it is expensive than the Base Case of the LTGEP 2022- 2041 with a marginal difference of 24 Million USD. It was observed that the average utilization of the interconnection for the transfer price of 9.49 US Cents/kWh is around 25% beyond 2032. The utilization rate is highly sensitive to the applied transfer price and a ± 20% change in the transfer price can vary the utilization from 15% to 80% as shown in the table 9.4 below. The hydrological variation also causes changes in the plant factor of the interconnection.

Table 9.4 – Sensitivity analysis for the transfer price of the HVDC interconnection

Scenario/Sensitivity	**Total PV Cost 2022-2041 (mill USD)**	**Average utilization of the interconnection beyond 2032**
500 MW HVDC Interconnection (9.4 Uscts/kWh)	16,304	25%
500 MW HVDC Interconnection (7.5 Uscts/kWh)	16,178	80%
500 MW HVDC Interconnection (11.3 Uscts/kWh)	16,371	15%

The capacity additions by plant type are summarised in the Table 9.5 below. Power plant sequence of the scenario is given in Annex 9.4.

Table 9.5: Capacity Additions by Plant Type of HVDC Interconnection Scenario

Type of Plant	2022-2026 (MW)	2027-2031 (MW)	2032-2036 (MW)	2037-2041 (MW)	Total capacity addition	
					(MW)	%
Major Hydro	186	-	-	-	186	1%
Pumped Hydro/Battery Storage	20	680	-	-	700	5%
Gas Turbines	130	-	800	200	1130	9%
Coal	300	300	-	-	600	5%
Combined Cycle	700	400	400	1200	2700	20%
HVDC Interconnection			500		500	4%
IC Engines	250	-	400	250	900	7%
Short Term Capacity	0*	-	-	-	0	0%
ORE	1,718	1,490	1,610	1,750	6568	49%
Total	**3,304**	**2,870**	**3,710**	**3,400**	13284	100%

Above figures represent net capacity additions

It is observed that the integrated operation of two systems primarily provides import opportunities for Sri Lanka with minimal or no export opportunities in the studied scenario. Importantly the plant factor of the interconnection can vary significantly depending on the transfer price in an integrated operation. The total PV cost of the alternative can vary depending on the exact investment cost, pricing and trading arrangements possible between India and Sri Lanka. Further the presence of the Indian power exchange provides an expanded market space allowing the energy exchanges to be based on the requirements of the producers and buyers.

It should be reviewed in detail whether the design and terms of operation of 500 MW HVDC interconnection has the potential to enhance the system flexibility to integrate a large amount of renewable energy in long term. In addition to that the development policies of power sectors both in India and Sri Lanka will have a significant impact on applicability of the HVDC interconnection alternative between two countries.

Considering these factors, it is important to conduct detailed feasibility studies reviewing technical and economic parameters to further investigate the exchange opportunities between India and Sri Lanka and to establish the techno economic viability of the cross border interconnection.

9.5 Energy Mix with Nuclear Power Development Scenario

Nuclear power is the second-largest source of low-carbon electricity today and it is regarded as one of the technologies having large potential to combat climate change. Despite the declining investment on nuclear power on advanced countries, several new comer countries are exploring the possibility of introducing nuclear power mainly driven by energy security concerns.

Energy Mix with Nuclear Power Development scenario was carried out to study the impact of further diversification of electricity generation mix in addition to the use of fossil fuel based generation. The general policy guidelines on future electricity mix also stresses on diversifying the energy mix to the maximum feasible level adopting sophisticated technologies in the world, to accept in principle the necessity of strategically developing all the practically developable energy sources including Nuclear Power.

Nuclear power is widely regarded as a generation option which requires special consideration when introduced and operated in a power system. Unlike other conventional thermal generation alternatives, Nuclear power facility and the electric grid have a tight inter-dependency that is very important for the safe and economic operation of the nuclear power plant. The electric grid expects the nuclear power facility to provide reliable power similar to any other large thermal power plant but unlike other power plants the nuclear unit requires the grid to support the nuclear facility in normal operation and during start-up, shut down and outage periods for safe operation. In addition to that it is important that the electric grid to provide voltage, frequency and supply continuity at safer and standard level for safe and economic operation of the nuclear facility. In this background, IAEA highlights the importance of considering aspects such as overall Grid Studies, Grid reliability and performance, Unit Size, NPP Operating characteristics, Site Assessment and grid connection, Power system standards, Grid control and communication, Interface between Nuclear power plant and the system operator when evaluating the nuclear power option. The electric grid infrastructure was assessed under the study "Establishing a Roadmap for Nuclear Power Program in Sri Lanka" with the assistance of International Atomic Energy agency (IAEA) developing a comprehensive report 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. The main findings and the conclusion made under the study is outlined below and they are intended to support the decision making on the nuclear power program of the country.

1. The upfront investment cost of nuclear power is very high compared to other alternatives even without considering additional investments required for transmission network reinforcements. Therefore, the nuclear power can possibly come in to the mix when the development of other cheaper thermal sources is restricted or strictly decided based on policy to enhance energy security through fuel diversification or to meet long term carbon emission reduction targets rather than for pure economic reasons.

2. Evaluation of the performance of the grid at present reveals that the improvements are required in frequency and voltage performance to match the industry criteria/guidelines for integrating a nuclear power unit to the Grid, safely and reliably.

3. The relatively large unit size of NPP continues to be the biggest technical challenge for the Sri Lankan system. The maximum unit size of a nuclear power unit with current grid characteristics is calculated to be in the range of 440 MW - 490 MW by 2040 and calculation based on an industry thumb rule, the possible size of a nuclear power unit turns out to be 372 MW for the year 2040 and 541 MW for the year 2050. This indicates the limited capability of the Sri Lankan power system to integrate a large nuclear power unit as an isolated system.

4. The development of cross-border interconnection and pumped storage hydro units in future aremost likely change the system characteristics drastically allowing large units to be connected to the system. The HVDC interconnection between India and Sri Lanka which is being studied at present for feasibility can well be a prerequisite to integrate a large nuclear power unit to the system in future provided that the terms of operation of the interconnection are set in favour of the NPP operation. Therefore, introduction of the interconnection as well as the pumped storage hydro plant will create significant milestone in making the Sri Lanka system capable to integrate a Large Nuclear power unit and that should be studied in detail.

5. The previous and recent policies of the electricity sector tend to focus more in the direction of enhancing the contribution of variable renewable energy resources which will lead to more decentralized power system. Given the system wide implications caused by variable renewable energy (VRE) technologies such as wind and solar, it is important to recognize the challenges it creates in terms of system stability, security and operation flexibility for the safe and economic operation of a nuclear power unit. Therefore, the future design of the power system is a major factor which will determine the country's ability to accommodate a nuclear power unit in safe and economic manner. It is important to establish and prioritize the long term energy strategy of the country and then to design and develop the power system for the future needs. Such considerations are necessary if the country is to decide on pursuing a nuclear power development program.

Based on the aforementioned findings, it was concluded that integrating a conventional nuclear plant to the system is a severe challenge during this planning horizon. However, developments in small scale modular nuclear power plants (SMRs) in commercial scale in future and the advancements of grid enhancement technologies will provide future prospects for Sri Lankan system to integrate a nuclear power unit which will be considered in future planning cycles.

9.6 Determination of Base Case

"Base Case" refers to the recommended schedule of generating plants for the 20-year period as contained in a Least Cost Long Term Generation Expansion Planning studies. It needs to be the most economical generation scenario out of all considered. However, Generation Planning Code authorizes Transmission Licensee to present an alternate generation scenario as the Base Case considering operational requirements of the system with clear justification.

Out of the scenarios discussed above, it could be observed that both Scenarios 4 and 5 need further studies to establish a clear pathway for implementation, hence the HVDC interconnection and the Nuclear power developments scenarios were not selected as the base case.

A comparison of PV costs of the first three scenarios evaluated is presented in Table 9.6.

Table 9.6: Summary of PV cost of the scenarios

Scenario	Incremental Capacity Additions between 2022-2041		Total Present Value Cost (MUSD)	Difference of PV Cost compared to scenario 1 (MUSD)
Scenario 1 (Current Policy Scenario)	Natural Gas	3,630 MW	16,147	-
	Coal	2,100 MW		
	Pumped Storage	600 MW		
	Renewables	6,754 MW		
Scenario 2 (70% Low Carbon by 2030 and maintaining the same beyond 2030)	Natural Gas	4,530 MW	16,276	129
	Coal	1,500 MW		
	Pumped Storage	600 MW		
	Renewables	6,754 MW		
Scenario 3 (70% Low Carbon by 2030 and increasing the same beyond 2030 by restricting Coal power development)	Natural Gas	5,130MW	16,280	133
	Coal	600 MW		
	Pumped Storage	600 MW		
	Renewables	6,754 MW		

Among the first three scenarios, Scenario 1 indicates the lowest PV cost. However, after considering the following key points, Scenario 3 has been recommended as the base case for LTGEP 2022-2041.

1. The perceived policy of the government, as contained in the National Policy Framework "Vistas of Prosperity and Splendour", is to maximize generation from renewable sources. During a meeting held on 2020-09-14 under the chairmanship of His Excellency thePresident and with the participation of all stakeholders and officials of electricity sector to obtain newpolicy guidelines for the sector, it was clarified that the policy of the government is tomaximize generation from renewable sources and, as an interim milestone, a minimum of 70%of electricity should be generated by 2030 from low carbon sources, out of which notless than 50% should be from renewable sources. Only Scenario 2 and 3 complies with this policy directive.

2. Electricity generation based on Clean and low carbon resources hasincreased in recent years worldwide, largely driven byrapid deploymentof renewable energy sources especially includingwind and solar. Additionally, many power systems are switching fuels from coal based generation to natural gas based generation due to relatively low carbon emissions of natural gas as well as higher degree of flexibility. The projected energy mixes shown in Table 9.7 reflect the global trend towards gradually shifting to low carbon energy mixes.

3. Many power systems dominated byfossil fuel capacities have also modernized their assetsand improved their resource efficiency and flexibility to suit the demands of large scale VRE integration. Future power systems will be characterized by large shares of variable renewable sources. This will require existing and new power capacities to be operated more flexibly. They will be complemented by cross border interconnections,demand-sidemanagement and energystorage solutions. Therefore, ensuring operational flexibility is required in the installed generating capacity to absorb high proportion of renewable resources and operation of coal power plants which would be deployed as low-cost base load power plants would be increasingly challenging in future VRE dominated power systems.

9.7 Comparison of Energy Supply alternatives in 2041

9.7.1 Global Context

Table 9.7 shows the present and projected energy mix in a number of different countries. It could be observed that majority of the countries and regions as whole are projecting a balanced generation mix with considerable contributions from Natural Gas, Coal, Nuclear and Renewables. Another important observation is that most of the countries and regions are thriving to increase the renewable share in the energy mix by projecting higher renewable shares while reducing the coal share significantly.

Especially, 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 68% in 2040.

Table 9.7: Present & Projected Power Generation Mix in Other Countries and Regions

		NG	Coal	Nuclear	Renewable	Other	Source
USA	2019	38%	25%	19%	18%	1%	IEA-World Energy Outlook 2020
	2040	39%	6%	12%	43%	0%	
China	2019	3%	65%	5%	27%	0%	
	2040	6%	42%	8%	44%	0%	
EU	2019	20%	17%	27%	35%	2%	
	2040	14%	1%	16%	68%	0%	
Japan	2019	34%	32%	8%	20%	3%	
	2040	23%	20%	21%	33%	1%	
Russia	2019	49%	15%	18%	17%	1%	
	2040	45%	10%	19%	26%	0%	
India	2019	4%	72%	3%	21%	0%	
	2040	4%	34%	6%	56%	0%	
Middle East	2019	71%	0%	1%	2%	26%	
	2040	63%	1%	4%	20%	12%	
Asia Pacific	2019	12%	58%	5%	24%	1%	
	2040	11%	37%	7%	44%	0%	
Sri Lanka	**2020**	**0%**	**36%**	**0%**	**37%**	**27%**	Draft LTGEP 2022-2041
	2041	**34%**	**16%**	**0%**	**50%**	**0%**	

9.7.2 Sri Lankan Context

The Figure 9.1 illustrates the projected energy mix in 2041 forthe scenarios considered in planning studies. The Base Case Scenario is complied with the perceived government policy of achieving 70% low carbon energy mix by 2030 and improving upon it beyond 2030.In the HVDC interconnection scenario, impact from the interconnection on the operation of the system was identified. As a detailed expansion study has not been carried out for Energy Mix with Nuclear Power Development Scenario, the capacity and energy mixes are not presented here.

Figure 9.2 illustrates the corresponding capacity mix in 2041 for the scenarios considered.

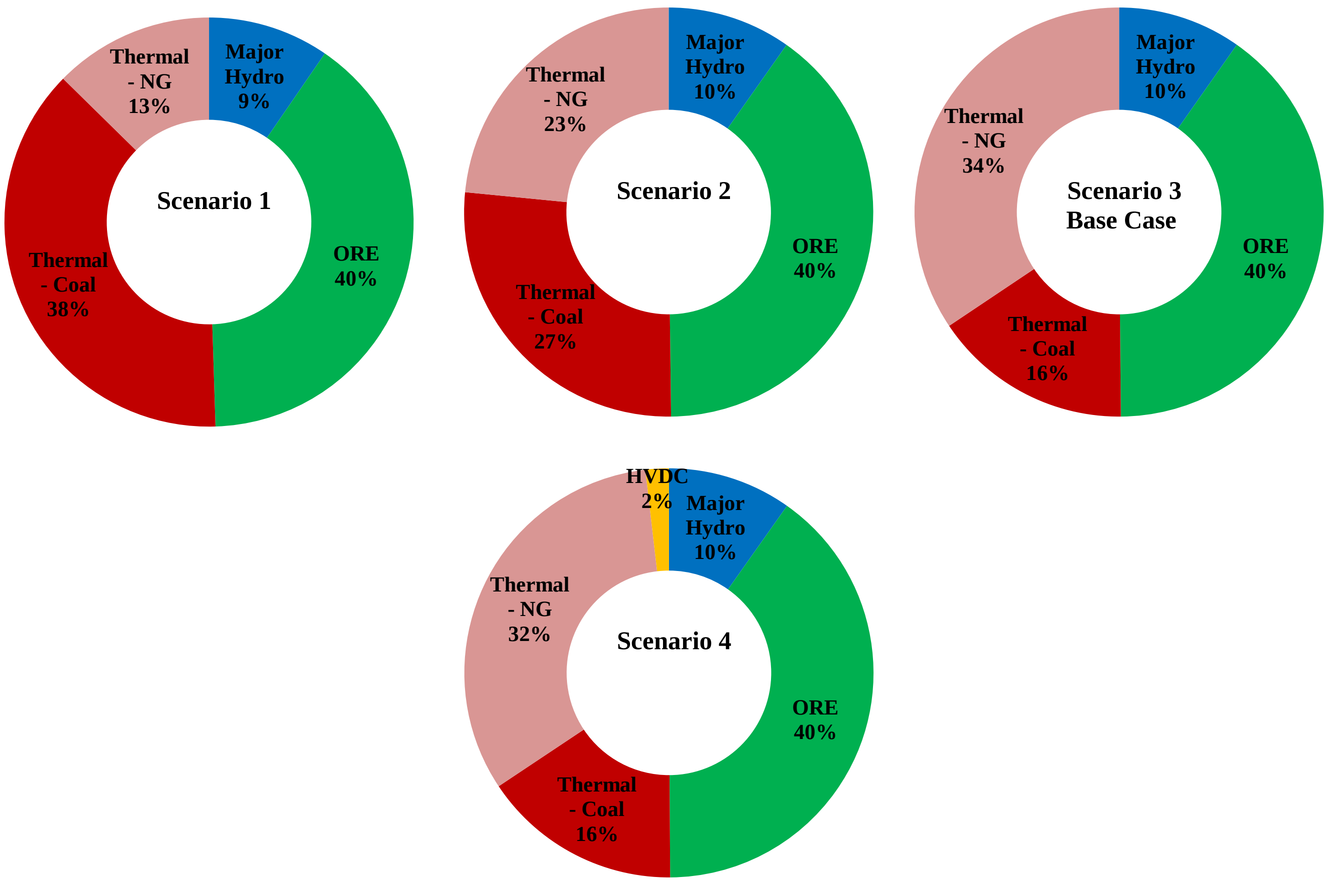


Figure 9.1 –Energy Share Comparison in 2041

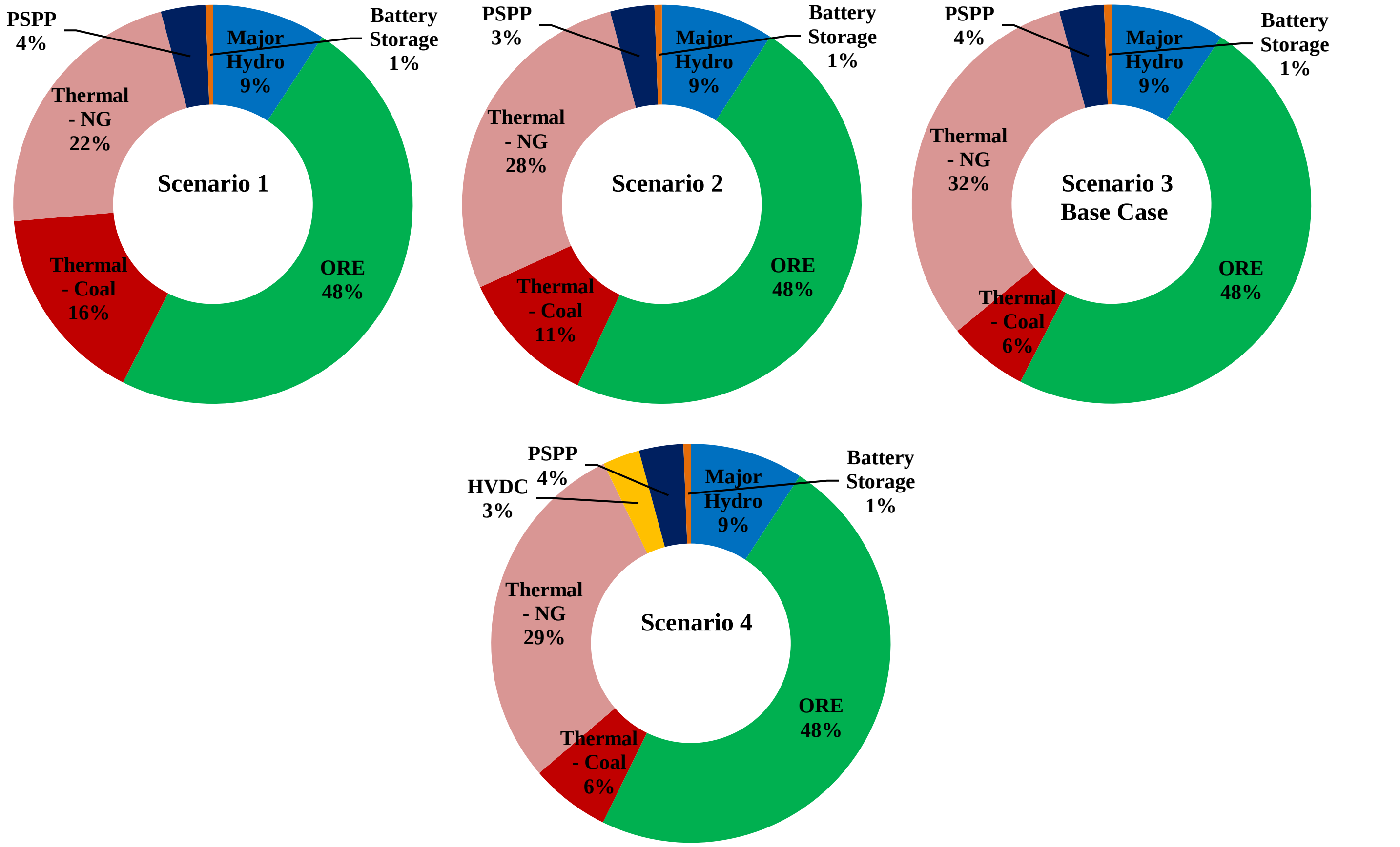


Figure 9.2 – Installed Capacity Share Comparison in 2041

CHAPTER 10
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 fossil fuel thermal generation was increased only during the drought period; hence the power sector had only a minor impact on the environment. However, after exploiting most of the major hydro potential, fossil fuel based power plants were introduced into the power system to cater the growing electricity demand.

Presently, around 50% of the power generation in Sri Lanka, is based on renewable energy sources including major hydro. The balance is generated from fossil fuel power plants. In many instances, electricity generation causes environmental drawbacks. The impact of electricity generation on the environment could be due to one or several factors including particulate emissions, gaseous emissions (CO_2, SO_2, NO_X etc.), warm water discharges into water bodies, liquid and solid waste (sludge, ash), inundation (in the case of large reservoirs), noise pollution 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. Further, when developing renewable power plants such as wind and solar, due consideration should be given to localised issues such as conflicts with bird migration routes, bird habitats, water habitats (in case of floating solar), unique land features such as sand dunes, vegetation, changes in land use, inhabitants and noise pollution.

This chapter describes an overview of environmental commitments related to the electricity sector and the impacts due to particulate and gaseous emissions, by the implementation of Base Case Generation Expansion Plan and other selected scenarios.

10.1 Climate Change

10.1.1 Greenhouse Gases

Greenhouse gases are gases that 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). For each greenhouse gas, a Global Warming Potential (GWP) has been calculated to reflect how long it remains in the atmosphere and how strongly it absorbs energy.

Table 10.1 – Global Warming Potential of Greenhouse Gases

Greenhouse Gas	GWP values for 100 year time horizon
Carbon Dioxide	1
Methane	25
Nitrous Oxide	298
Hydrofluorocarbons	14,800
Perfluorocarbons	22,800

Source: The Fourth Assessment Report of the United Nations Intergovernmental Panel on Climate Change

10.1.2 GHG Emission Reduction Protocols

The effects of global warming have directly caused concern for the adoption of proper management in climate change. Due to the increasing global concern on climate change, the United Nations Environment Programme and the World Meteorological Organisation jointly established the Intergovernmental Panel on Climate Change (IPCC) in 1988 with a directive to assess the best scientific options on climate change, its potential impacts, and possible response strategies. 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. Major events and decisions by Conference of Parties are summarized in Table 10.2.

(a) The Kyoto Protocol

During the COP3 meeting in 1997 at Kyoto, Japan, the Kyoto Protocol was accepted. It sets binding targets for 37 industrialised counties and the European Community for reducing GHG emissions. It will amount to an average of 5% against 1990 levels over the five-year period 2008-2012. 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 entered in to force on 16th February 2005. Under the Kyoto Protocol, Annex I countries must meet their targets primarily through national measures with support from additional market based mechanisms.

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

Under the Protocol, country's 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.

During COP 18 at Doha, Qatar in 2012, developed country parties agreed for a second commitment period up to 31.12.2020, with 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 significant 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.

(b) The Paris Agreement

In 2015, the COP21 meeting was held in Paris, where the Paris agreement was introduced in which 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. Under the Paris Agreement both developed and developing countries must determine, plan, and regularly report on the contribution that it undertakes to mitigate global warming.

No mechanism forces a country to set a specific emissions target by a specific date, but each target should go beyond previously set targets. Many countries submitted comprehensive national climate action plans as Intended Nationally Determined Contributions (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. Sri Lanka ratified its Nationally Determined Contributions (NDC) in September 2016 [27]. On 5 October 2016, the threshold for entry into force of the Paris Agreement was achieved and was entered into force on November 2016.

Table 10.2– 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 adopted. 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.

COP	Events and Decisions
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 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	Paris Agreement was introduced. Before and during the Paris conference, countries submitted comprehensive national climate action plans (INDCs).
COP22/CMP12/CMA1-1 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.
COP24/CMP14/CMA1-3 Katowice, Poland 2018	"Paris Agreement Rule Book" has been taken up for negotiation and participants from Ministry of Mahaweli Development & Environment have participated from Sri Lanka.

10.1.3 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.

10. 2 Country Context

10.2.1 Overview of Emissions in Sri Lanka

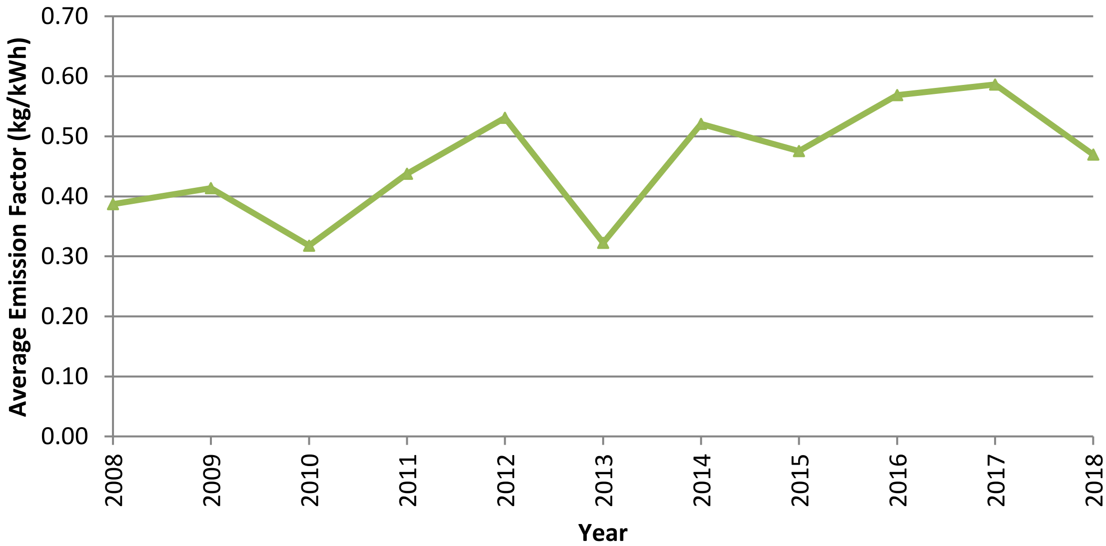
When considering the greenhouse gases, CO_2 is one of the primary gases which contribute towards warming of earth's atmosphere. Table 10.3 indicates Sri Lanka's CO_2 emissions from fuel combustion in each sector for the year 2018. It could be observed that approximately 39% of CO_2 emission is from the electricity sector while major contributor for CO_2 emission is the transport sector which accounts for approximately 48%.

Table 10.3 - CO_2 Emissions from fuel combustion

	CO_2 emissions *Million tons of CO_2*	
Total	**20.60**	**100.0%**
Electricity and heat production	8.1	39%
Manuf. industries and construction	0.80	4%
Transport	9.9	48%
Other sectors	1.8	9%

Source: IEA CO_2 Emissions from Fuel Combustion (2020 Edition) -2018 Data [28]

Further the average CO_2 emission factor from electricity generation in the past is shown in Figure 10.1



Source: Sustainable Energy Authority

Figure 10.1 – Average CO_2 Emission Factor

Until large thermal plants were introduced to Sri Lankan power system, the power sector 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 in reducing GHG emissions and promoted through Government policies. With the focus on increasing renewable energy, more complicated analysis is required to overcome the uncertainties and intermittency which is inherent to renewable energy generation.

10.2.2 Role of Sri Lanka on Climate Change Mitigation

Responding to climate change involves two possible approaches: reducing and stabilizing the levels of heat-trapping greenhouse gases in the atmosphere ("mitigation") and adjustment to consequences of climate change that cannot be avoided ("adaptation").

Sri Lanka 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 CO_2 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 formed under the Ministry of Mahaweli Development and Environment, in 2008. National Adaptation Plan for Climate Change Impacts in Sri Lanka 2016-2025 (NCCAS) was developed in 2016. Further, 'The National Climate Change Policy of Sri Lanka' has been developed by the Climate Change Secretariat of Sri Lanka under the Ministry of Mahaweli Development and Environment. Sri Lanka ratified its Nationally Determined Contributions (NDC) in September 2016 in accordance to the Paris agreement through the Climate Change Secretariat of Sri Lanka.

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. Further, CEB is an active member of the National Expert Committee on Climate Change Mitigation which provides consultation on various activities related to mitigation.

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

(a) Amendment of National Energy Policy and New Energy Mix

Government of Sri Lanka has given priority in the power sector which is presently dependent on imported fossil fuel, to reduce the present trend by enforcing sustainable energy policies for absorbing more renewable energy into the system.

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. The subsequent

National Energy Policy and Strategies of Sri Lanka (2019) [ ] has increased the milestone to realize a minimum 20% share of electricity generated from renewable energy sources excluding major hydro, by 2022.

The General Policy Guidelines in Respect of the Electricity Industry (2019) [ ] has given guideline to progress with the vision to achieve 50% of electricity generation from renewable energy sources by 2030 under favourable weather conditions.

(b) 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. 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.

(c) Partnership for Market Readiness (PMR)

The Partnership for Market Readiness (PMR) is a grant-based, multilateral trust fund administered by the World Bank which provides support to countries to prepare and implement climate change mitigation policies, including carbon pricing instruments (CPI), to scale up greenhouse gas (GHG) emission reductions. The PMR brings together developed and developing countries, as well as other key experts and stakeholders, in order to provide a platform for technical discussions on CPIs, collective innovation for pilot efforts and the implementation and scale up of financial flows. Basic elements in implementing CPI is to build market readiness capacity, such as measurement, reporting and verification (MRV) systems, data collection, baseline setting, and establishing regulatory institutions etc. Climate Change Secretariat under the purview of Ministry of Mahaweli Development and Environment is the implementing entity and CEB as a major stakeholder has been involved in providing necessary input and feedback to the work carried out under PMR program. Major activities performed during the project period are as follows.

Implemented by World Bank

1. Assessment of mitigation potential in different sectors and identification of suitable CPI(s) for potential sectors
2. Needs Assessment and MRV and Registry Design
3. Deployment of the MRV and Registry system for Customization in Sri Lankan context
4. Sri Lanka Carbon Crediting Scheme (SLCCS) strategy and design study (assessment of the supply and demand and the existing institutional, legal and technical framework for implementation of an enhanced SLCCS)

Implemented by Ministry of Environment

1. Evaluation of overall policy coherence and recommendation on designing and implementing policy package for MRV, registry and SLCCS implementation
2. Deployment of IT infrastructure for MRV and registry
3. Development and implementation of a national climate change data sharing network
4. Road map for new Carbon Pricing Instruments (CPIs)
5. Communication, Capacity Building, Stakeholder Consultation and General Outreach

(d) 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.

(e) 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 2020 it has been reduced to approximately 9.08%.

(f) 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.

(g) Tree Planting Program

The General Policy Guidelines in Respect of the Electricity Industry (2019), givens directives to introduce counter balancing interventions such as carbon sequestration plantations to reduce carbon footprint of electricity due to power generation.

Ceylon Electricity Board has identified this as a social responsibility and has carried out numerous tree planting campaigns within last five years. Since 2015, CEB has planted over 34,044 trees consisting of tree types of Kaluwara, Kumbuk, Kohomba Bamboo, Mango, etc. Additionally, CEB has planned to plant another 16,250 trees in year 2021 in power plant locations, catchment areas and public places.

10.2.3 Nationally Determined Contributions (NDCs) of Sri Lanka

Sri Lanka submitted its first Nationally Determined Contributions in September 2016, in accordance with Decision of COP 21 of the UNFCCC. Base year 2010 is considered as per Business-As-Usual scenario and Target period of emission reduction is 2021-2030. The scope of NDC comprise of four areas on mitigation, adaptation, loss and damage and means of implementation. Under the scope of mitigation, reducing GHG emissions are focused on five sectors as follows.

1. Energy sector has a 20% GHG emission reduction target in the NDCs, which amounts to 39,383Gg of the total GHG emissions (196,915Gg for the period 2020-2030 as per the BAU scenario of the Long Term Generation Expansion Plan 2013-2032 published in October 2013). The reduction of emissions includes 4% unconditional and 16% conditional reduction.

2. The sectors of transport, waste, industry and forestry aims to reduce 10% of its GHG emissions from the BAU scenarios by 2030. This will be 3% unconditional and 7% conditional. However, at the time of submission, BAU emission scenarios were to be estimated in details and detailed emission reduction plans for these sectors were yet to be developed.

All countries were expected to revise and submit stronger, more ambitious national climate action plans in 2021 to achieve the Paris Agreement goal. In Sri Lanka, the second submission of NDC commitments is at preparation stage and is expected to be submitted to the UNFCC in 2021.

The revised more ambitious targets for NDC in Electricity sector are as follows.

Target:

A GHG reduction of 25% in the electricity sector is envisaged (5% unconditionally and 20% conditionally) equivalent to an estimated mitigation level of 9,819,000 MT unconditionally and 39,274,000 MT conditionally (total of 49,093,000 MT) of carbon dioxide equivalent during the period of 2021-2030. (Compared to the BAU scenario of the Long-Term Generation Expansion Plan 2013-2032 of Ceylon Electricity Board published in October 2013).

Actions:

1. Enhance renewable energy contribution to the national electricity generation mix by increasing Solar PV, Wind, Hydro and Sustainable Biomass based electricity generations (Target: Develop an additional capacity of 3,867 MW renewable energy over the RE capacity considered in Business-As-Usual scenario, out of which approximately 950 MW are on an unconditional basis and 2,917 MW on a conditional basis)

2. Implement Demand Side Management (DSM) measures by promoting energy-efficient equipment, technologies, and system improvements in a national energy efficiency improvement and conservation(EEI&C) programme

3. Conversion of existing fuel oil-based combined cycle power plants to Natural Gas (NG) and establishment of new NG plants as conditional measures (once the necessary infrastructure is available)

4. Transmission and distribution network efficiency improvements (Loss reduction of 0.5% compared with BAU by 2030) as an unconditional measure (Target: Approximately 1,848 GWh energy savings)

5. Conduct R&D activities to implement pilot scale projects for NCRE sources that have not yet reached commercial maturity and develop other grid supporting infrastructures as conditional measures

Compatibility to Base Case Plan

The Base Case plan of LTGEP 2022-2041 complies with the NDC commitment, with more than 25% reduction in GHG emissions for the period from 2021-2030, compared to the BAU scenario of LTGEP 2013-2032. Since the demand forecast of LTGEP 2013-2032 was higher than the demand forecast in LTGEP 2022-2041, a separate scenario with the plant schedule of BAU scenario of LTGEP 2013-2032 is worked out using the demand forecast of LTGEP 2022-2041 to see even with the reduced demand, still the Base Case plan of LTGEP 2022-2041 complies with the NDC commitment. It has more than 25% reduction in GHG emissions for the period from 2021-2030. Figure 10.2 illustrates the compatibility of Base Case Plan to Sri Lanka's NDC commitments in electricity sector.

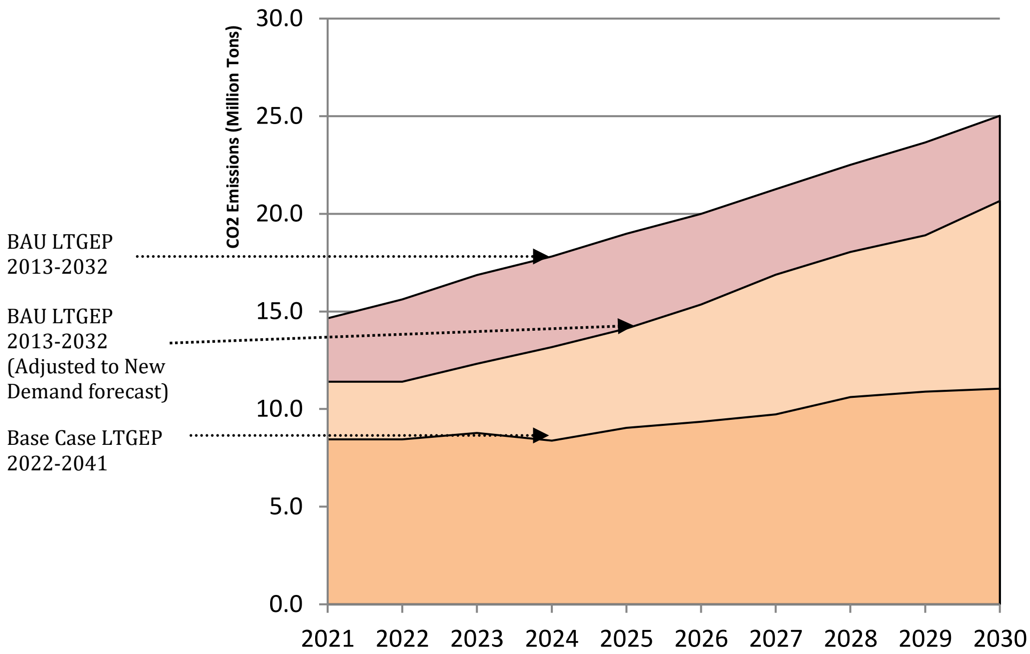


Figure 10.2 – Expected Emission reduction of Base Case compared to NDC - BAU

When achieving the NDC activities, the unconditional targets have been declared based on the financial and technical capability already available in the country. Targets that require external financial and technical support to supplement the domestic capacity are declared as conditional targets.

Conditional development includes the technical and financial support for development of 2,917 MW of renewable energy, for conversion of generators to NG, establishment of natural gas power plants and for development of other grid supporting infrastructures such as storage.

However it should be noted that non implementation of these conditional targets on time will significantly impact on the level of emission reductions stipulated in the above. Hence, actual emission reductions achievable should be tracked with the implementation progress of the power projects.

10.2.4 Ambient Air Quality & Stack Emission Standards

In 1994, Government of Sri Lanka has approved The National Environmental (Ambient Air Quality) Regulations which was amended through extraordinary gazette No. 1562/22 in August 2008 [29]. The National Environmental (Stationary Sources Emission Control) Regulations, No. 01 of 2019 was published through extraordinary gazette No. 2126/36 in June 2019 which stipulates the stack emission standards for stationary sources [30]. The regulation enforces minimum stack height as well as stack emission limits for thermal power plants.

All thermal power plants are required to comply with the standards of these regulations, as shown in Table 10.4 and Table 10.5.

Table 10.4 - Ambient Air Quality Standards of Sri Lanka

Pollutant Type	Annual Level (μg/m³)	24 hour level (μg/m³)	8 hour Level (μg/m³)	1 hour Level (μg/m³)
Nitrogen Dioxides (NO_2)	-	100	150	250
Sulphur Dioxides (SO_2)	-	80	120	200
PM10	50	100	-	-
PM2.5	25	50	-	-

Source: Central Environmental Authority

Table 10.5 - Stack Emission Standards of Sri Lanka

Pollutant Type	Oil > 100 MW	Natural Gas >100 MW	Coal > 50 MW
Nitrogen Dioxides (NO_2) (mg/Nm^3)	500 (Steam Turbine) 450 (Gas Turbine / CCY) 650 (IC Reciprocating Engine)	300 (Steam Turbine) 200 (Gas Turbine / CCY) 350 (IC Reciprocating Engine)	650
Sulphur Dioxides (SO_2) (mg/Nm^3)	850	75	850
PM10 (mg/Nm^3)	150	75	150
Smoke (Opacity)	20%	-	15%

Source: Central Environmental Authority

In 2006, World Health Organization (WHO) released a set of guidelines that would address all regions of the world and provide uniform targets for air quality known as the Air Quality Guidelines (AQG), with the purpose of directing national policymakers to create acceptable air quality standards. WHO also created the WHO-Interim Targets to provide flexibility for developing countries to move towards more stringent standards at their own pace. Sri Lankan ambient air quality standards are mostly in line with the WHO interim targets. Most Asian countries based their standards on the WHO AQG and United States Environment Protection Agency (US EPA) National Ambient Air Quality Standards (NAAQS). Table 10.6 shows a comparison of air quality standards adopted by various countries.

Table 10.6 - Comparison of Ambient Air Quality Standards of Different Countries & Organisation

(All values in mg/m3)

Pollutant	Averaging time	WHO Guideline (Interim target-1, Interim target-2)	US EPA NAAQS	India	Indonesia	Thailand	Pakistan	**Sri Lanka**
Nitrogen Dioxide (NO_2)	Annual	0.04	0.1	0.04	0.1	0.057	0.04	**-**
	24 hours	-		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	-		0.05	0.06	0.1	0.08	**-**
	24 hours	0.02(0.125, 0.05)		0.08	0.365	0.3	0.12	**0.08**
	8 hour						-	**0.12**
	1 hour				0.9	0.78	-	**0.2**
	3 hour		1.3					
	10 minute	0.5		-			-	**-**
PM 10	Annual	0.02 (0.07, 0.05)		0.06		0.05	0.12	**0.05**
	24 hours	0.05 (0.15,0.1)	0.15	0.1	0.15	0.12	0.15	**0.1**
PM 2.5	Annual	0.01 (0.035, 0.025)	0.015	0.04		0.025	0.015	**0.025**
	24 hours	0.025 (0.075, 0.05)	0.035	0.06		0.05	0.035	**0.05**
Suspended Particulate	Annual	-		-	0.09	0.1	0.36	**-**
	24 hours	-		-	0.23	0.33	0.5	**-**

Source: World Wide Web, Central Environmental Authority

10.3 Emission Factors

10.3.1 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 10.7 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 10.7 - 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)
Internal Combustion Engine	Fuel Oil	10,300	43,124	2-3.5	13.0	76.3	1.709	1.2
	Residual FO	10,300	43,124	2-3.5	13.0	77.4	1.639	1.2
	Auto Diesel	10,500	43,961	1.0	5.0	74.1	0.453	1.2
Gas Turbine	Auto Diesel	10,500	43,961	1.0	5.0	74.1	0.453	0.28
	Natural Gas	13,000	54,428	0	0.0	56.1	0.0	0.1
Comb. Cycle	Auto Diesel	10,500	43,961	1.0	5.0	74.1	0.453	0.28
	Naphtha	10,880	45,552	0	0.0	73.3	0	0.28
	Natural Gas	13,000	54,428	0	0.0	56.1	0.0	0.1
Coal Steam	Coal	6,300	26,377	0.6	40.0	94.6	0.455	0.3
Dendro	Dendro	3,224	13,498	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 NO_x 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.

10.3.2 Emission Control Technologies

According to the expansion sequence of Base Case Plan 2022-2041 mentioned in Chapter 8 (Table 8.1), 6,754 MW of Renewable energy power plants, 5,130 MW Natural Gas fired power plants and 600 MW of Coal fired power plants along with short term supplementary power plants are to be added to the Sri Lankan power system during the planning horizon. The impact on the environment due to particulate and air-emissions from the thermal power plants out of above additions with that of existing power plants and the effectiveness of using control devices to mitigate those impacts are analysed here. Particulate matter (PM) and gaseous emissions of SO_2, NO_x and CO_2 were considered in the analysis.

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_2 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 SO_2 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 SO_2 and low NO_x burners and two stage combustion for the control of NO_x. 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 NO_x. Indoor coal storages or silos will be proposed in new coal power plants in order to curb pollution due to coal dust. The Low-NO_x burners are an integrated part of most of the commercially available combined cycle plants, which are capable of reducing NO_x emissions to 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 deposits 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 10.8 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 Long Term Generation Expansion Plan which is also a part of the environmental damage mitigation cost.

Table 10.8 - Abatement Factors of Typical Control Devices

(Factors in %)

Device	SO_2	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 – GT/ CCY *		80					

Sources: Decades Manual & Coal feasibility Study Reports

TSP - Total Suspended Particles

NMVOC - Non Methane Volatile Organic Compounds

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

Further, CEB has taken 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 by 12%-16% comparatively with subcritical technologies.

10.3.3 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 10.9 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 10.5 it is clear that the performance of the coal power plants in Sri Lanka is much satisfactory.

Table 10.9 - Emission Factors of the coal power plants

Plant Type	GCV of coal (kcal/kg)	Sulphur Content (%)	Emission Factor			
			Particulate (mg/MJ)	CO_2 (g/MJ)	SO2 (g/MJ)	NO_x (g/MJ)
High efficient coal power plant	6,300	0.65	7.00	94.6	0.035	0.035
Super critical coal power plant	6,300	0.65	7.00	94.6	0.035	0.035
Lakvijaya coal power station	6,300	0.7	15.00	94.6	0.056	0.260

Taking into consideration the emission factors mentioned in Table 10.7, Table 10.9 and the characteristics of the power plants, emissions per unit of electricity generated from candidate power plants are calculated as shown in Table 10.10

Table 10.10 Emission Factors of Candidate Power Plants

Plant Type	Fuel Type	Full Load Heat Rate kcal/kWh	Emission Factor			
			Particulate tons/GWh	CO_2 tons/GWh	SO_2 tons/GWh	NOx tons/GWh
15 MW IC Engines	Furnace Oil	2,210	0.1	706.0	15.8	11.1
15 MW IC Engines	Auto Diesel	1,943	0.04	602.8	3.7	9.8
15 MW IC Engines	Natural Gas	2,021	0.0	474.7	0.0	2.0
200 MW IC Engines	Natural Gas	2,021	0.0	474.7	0.0	2.0
250 MW IC Engines	Natural Gas	2,021	0.0	474.7	0.0	2.0
40 MW Gas Turbine	Natural Gas	2,911	0.0	683.7	0.0	0.2
40 MW Gas Turbine (AERO)	Natural Gas	2,315	0.0	543.7	0.0	0.2
100 MW Gas Turbine	Natural Gas	2,548	0.0	598.5	0.0	0.2
200 MW Gas Turbine	Natural Gas	2,568	0.0	603.2	0.0	0.2
300 MW Combined Cycle	Natural Gas	1,919	0.0	450.7	0.0	0.2
400 MW Combined Cycle	Natural Gas	1,757	0.0	412.7	0.0	0.1
300 MW High Efficient Coal	Coal	2,241	0.1	887.6	0.3	0.3
600 MW Supercritical Coal	Coal	2,082	0.1	824.6	0.3	0.3
600 MW Nuclear Power	Nuclear	2,685	0.0	0.0	0.0	0.0
5 MW Dendro Plant	Dendro	5,694	6.1	0.0	0.0	4.8

10.4 Environmental Implications – Base Case

Presented below is a quantitative analysis of the emissions associated with the Base Case generation expansion plan described in Chapter 8. The total particulate and gaseous emissions (controlled) under the Base Case plan are shown in Table 10.11 and Figure 10.3.

Table 10.11 – Air Emissions of Base Case

1000 tons/year

Year	PM	SO_2	NO_x	CO_2
2022	4.9	59.3	40.2	8,446
2023	5.1	61.9	38.1	8,773
2024	5.2	40.0	35.4	8,387
2025	5.5	27.7	28.2	9,046
2026	5.7	4.5	22.5	9,359
2027	5.9	4.3	22.7	9,723
2028	6.3	4.6	22.0	10,619
2029	6.6	4.8	23.2	10,901
2030	6.8	5.0	23.8	11,045
2031	7.1	5.2	23.9	11,702
2032	7.4	5.3	25.0	12,350
2033	7.7	4.3	25.9	12,825
2034	8.0	4.4	27.2	13,439
2035	8.2	4.4	27.5	13,648
2036	8.5	4.3	26.3	13,898
2037	8.8	4.4	25.4	14,563
2038	9.0	4.4	27.4	15,085
2039	9.3	4.3	27.4	15,581
2040	9.5	4.4	26.0	15,997
2041	9.5	3.3	23.4	15,649

With the development of coal and natural gas power based generation to meet the increasing demand, emission levels of CO_2 shows a continuous increasing trend. However, the introduction of natural gas based power plants as an alternative to coal power plants reduces the increasing rate of CO_2 emissions. The higher level of particulate, SO_2 and NO_x emissions in the initial years is due to dispatch of oil fired power plants which are added to the system on short term basis due to delays in implementation of the power plants identified in previous plans. The SO_2 and NO_x levels are maintained at a steady level after the oil fired plants are retired and major plants are commissioned. Although the energy contribution is low from biomass plants, it is the major contributor to the increasing trend of the PM emissions during the planning horizon.

According to Figure 10.4, SO_2 and NO_x emissions per kWh shows a levelised trend while per unit CO_2 emissions has slightly an increasing trend. The higher energy dispatch of furnace oil fired power plants with heavy SO2 and NO_x pollutants has led to much higher per unit emission levels in the initial years.

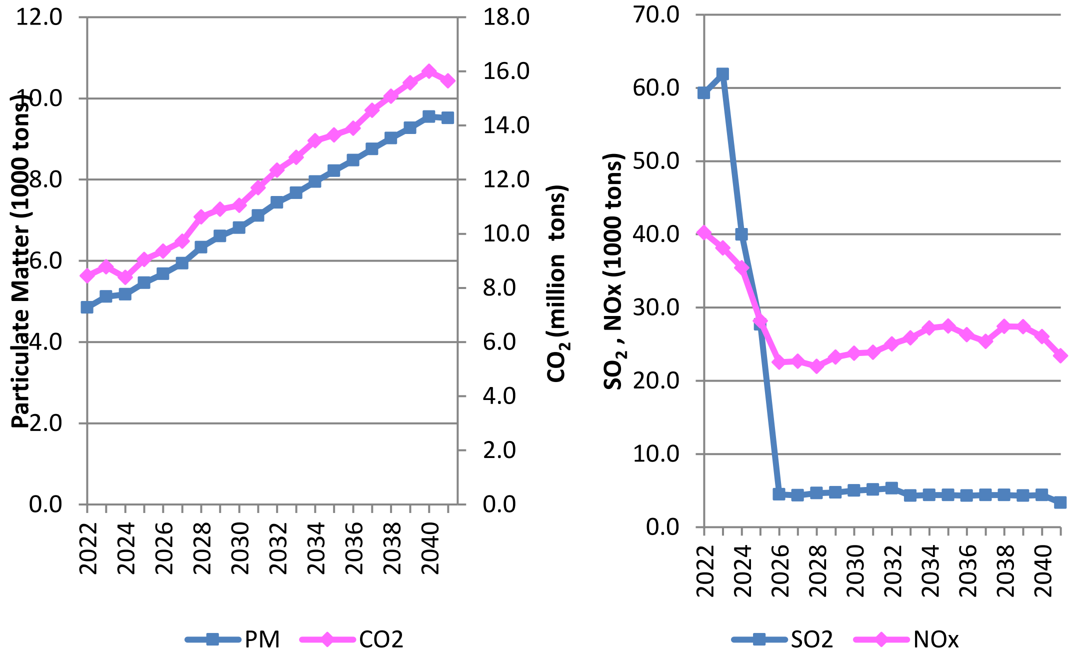


Figure 10.3 – CO_2, PM, SO_2 and NO_x emissions of Base Scenario

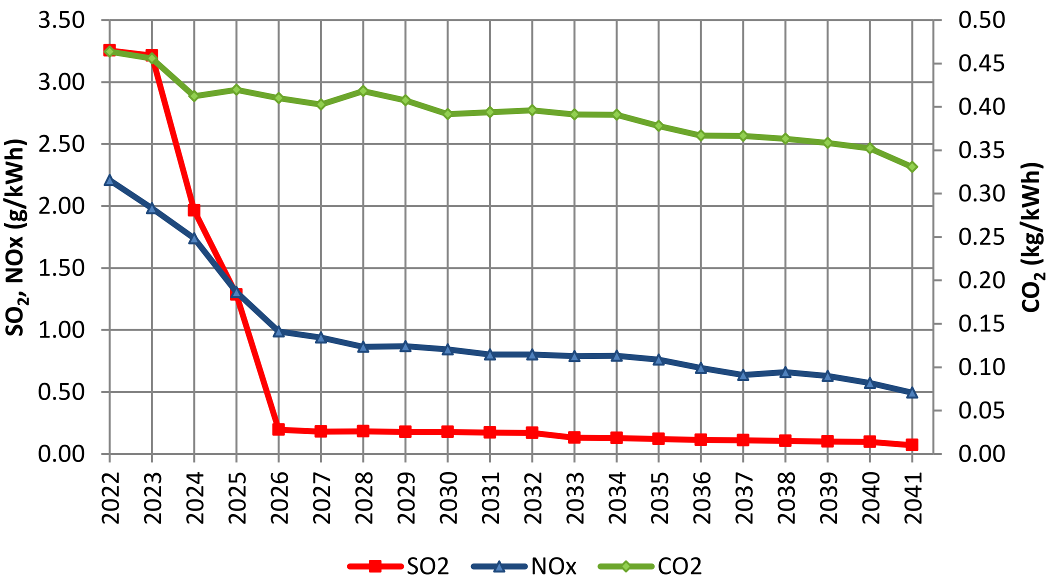


Figure 10.4 – SO_2, NO_x and CO_2 emissions per kWh generated

Figure 10.5 shows the past actual and forecast values of Average CO_2 emission factors for the Base Case. Average CO_2 emission factor of the Base Case scenario shows a decreasing trend in the long term.

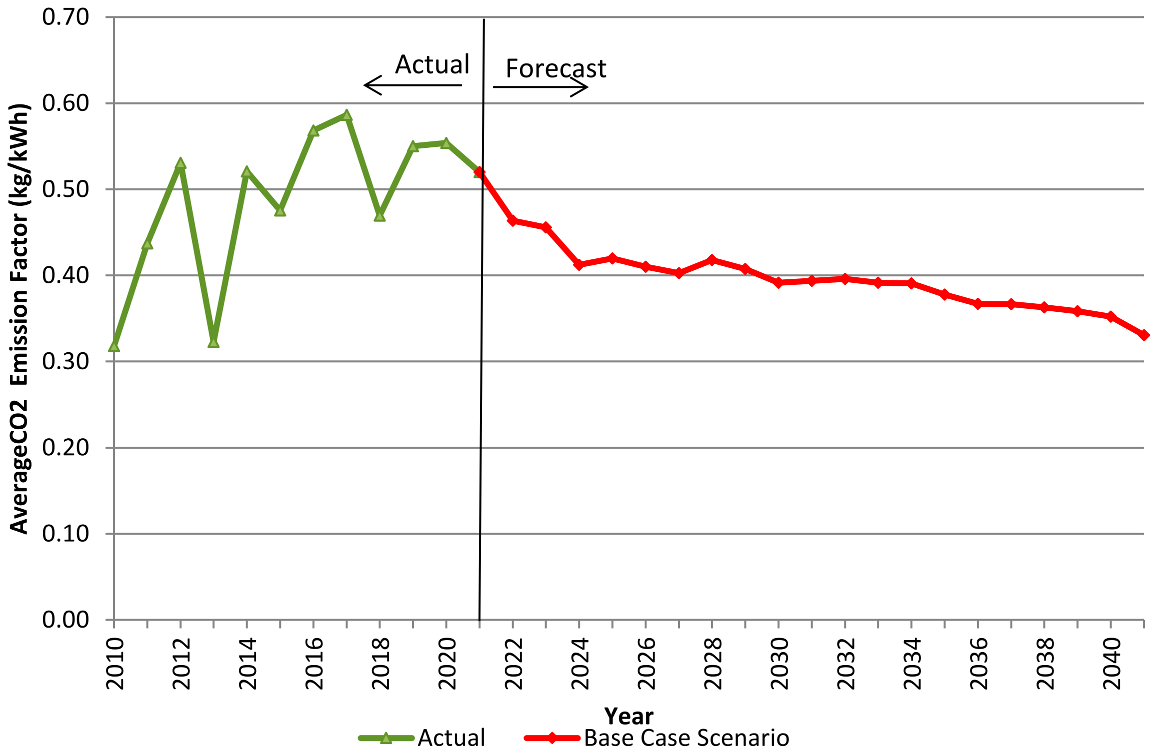


Figure 10.5 – Average CO_2 Emission Factor Comparison

10.5 Environmental Implications – Other Scenarios

10.5.1 Comparison of Emissions

The effects on emissions under following scenarios were analysed and evaluated against the Base Case emission quantities.

1. Reference Scenario
2. Current Policy Scenario
3. Low Carbon Share (70%) Scenario
4. HVDC Scenario

In the HVDC scenario emissions of the electricity imported will not be accounted and hence this scenario has lowest emissions (Energy export also not considered for analysis)

The Figure 10.6 depicts the SO_2 emissions for the planning horizon for all scenarios. It can be seen that the SO_2 are higher during the initial years due to the dispatch of oil power plants. After 2026 the SO_2 emissions have drastically reduced and thereafter the rate of increase is also very low.

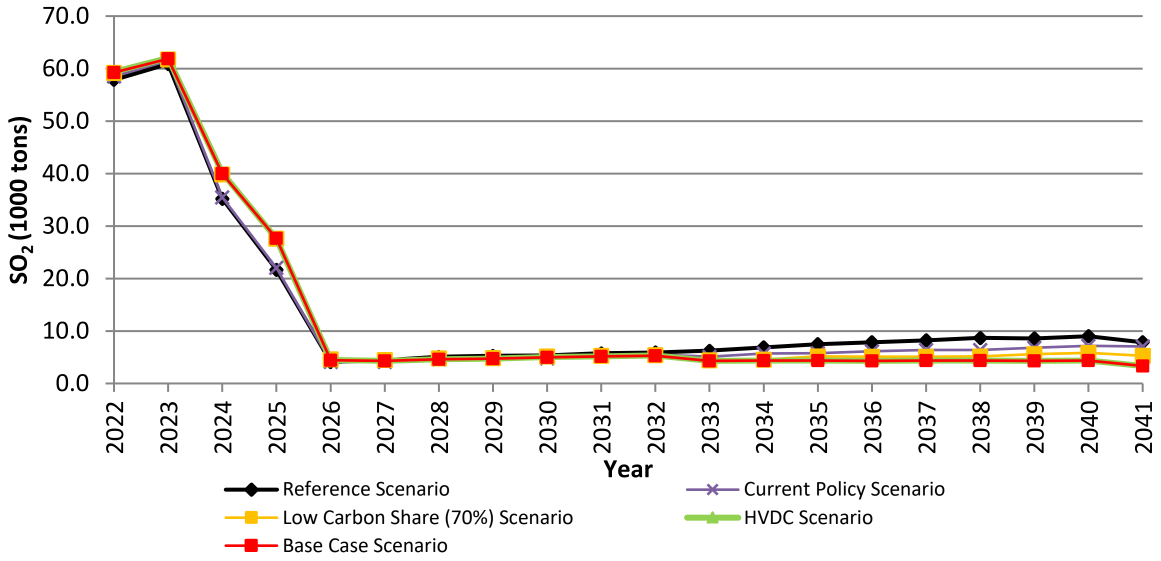


Figure 10.6 – SO_2 Emissions

The Figure 10.7 illustrates the NO_x emissions during planning horizon for all scenarios. The higher amount of NO_x emissions would be reduced with the retirement of oil power plants but would gradually increase during the horizon in all scenarios.

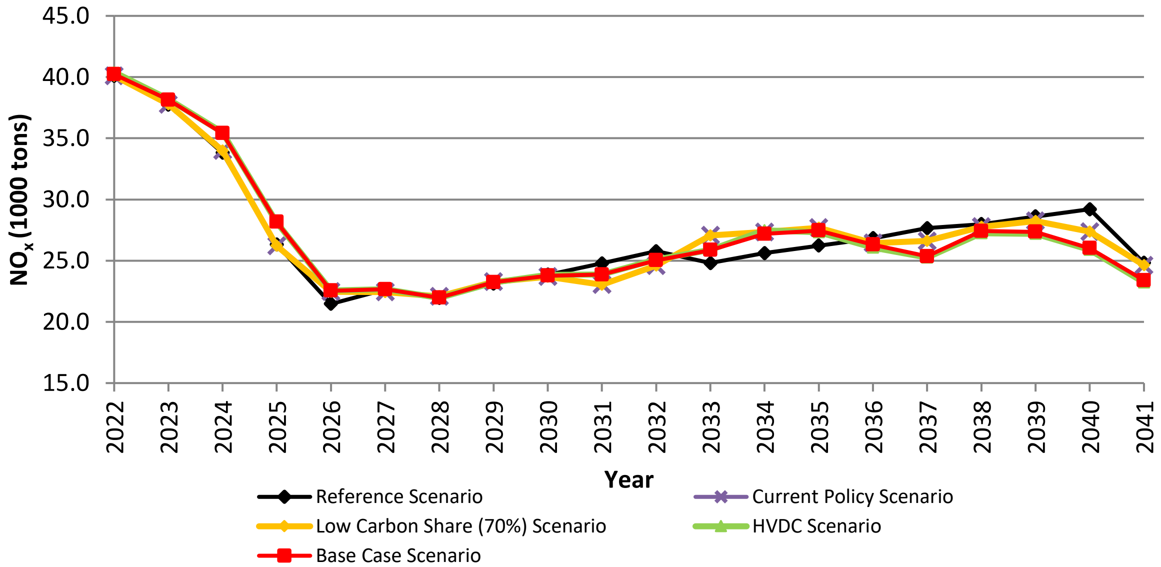


Figure 10.7 – NO_x Emissions

Figure 10.8 shows the CO_2 emissions of the scenarios. Reference Scenario has higher CO_2 emissions compared to Base Case Scenario due to lower share of new renewable energy power plants. The CO_2 emission factors of Natural gas fired combined cycle plants are about 50% less than that of coal fired power plants. Therefore the increased number of Natural gas fired power plants in the Base Case scenario is also contributing towards the reduction of CO_2 emissions.

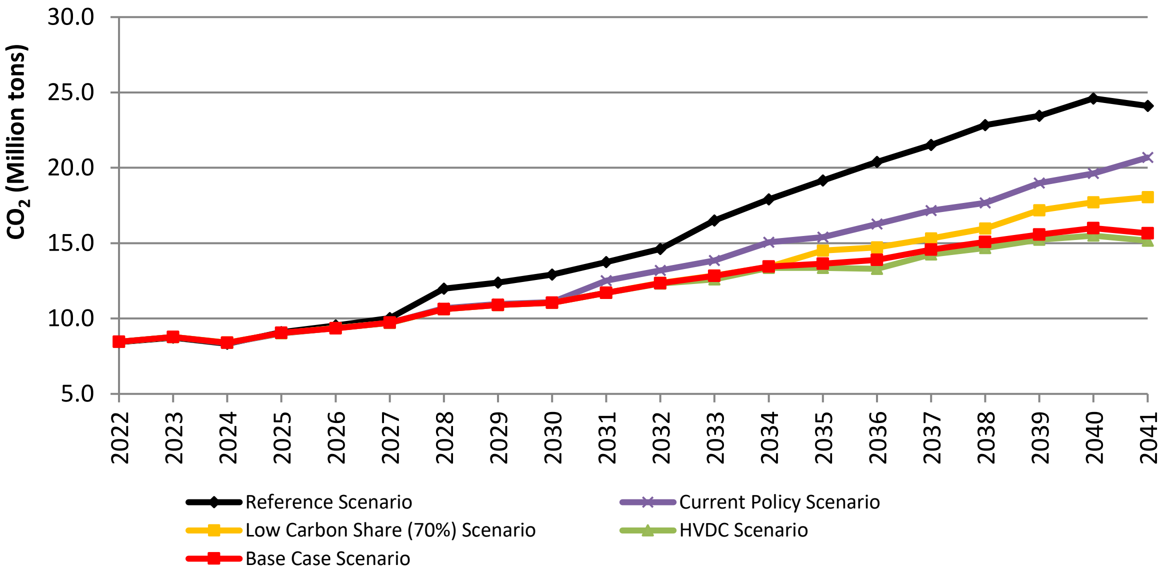


Figure 10.8 – CO_2 Emissions

Similarly particulate emission factors of NG fired combined cycle plants are negligible. Future biomass power plants have contributed mainly towards the increase, in addition to the coal power plants. Figure 10.9 shows the comparison of PM emission related to various scenarios.

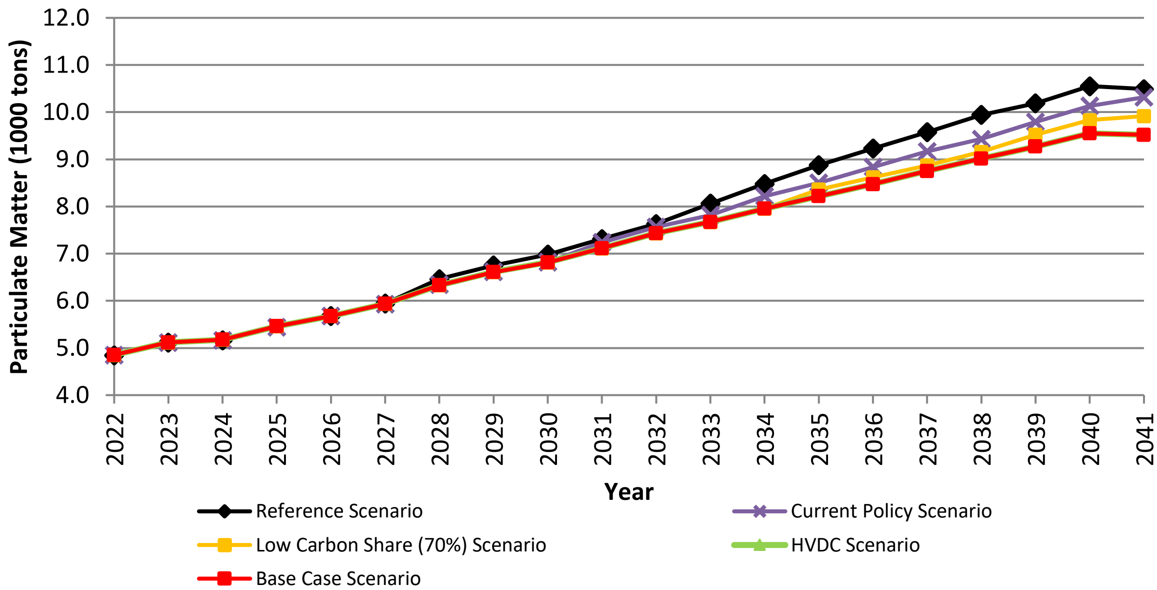


Figure 10.9 – Particulate Matter Emissions

10.5.2 Cost Impacts of CO_2 Emission 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. Therefore, it can be a useful analytical tool in defining a cost-effective, low carbon investment program for Sri Lanka.

Comparison of total CO_2 emission with total system cost is shown in Figure 10.10.

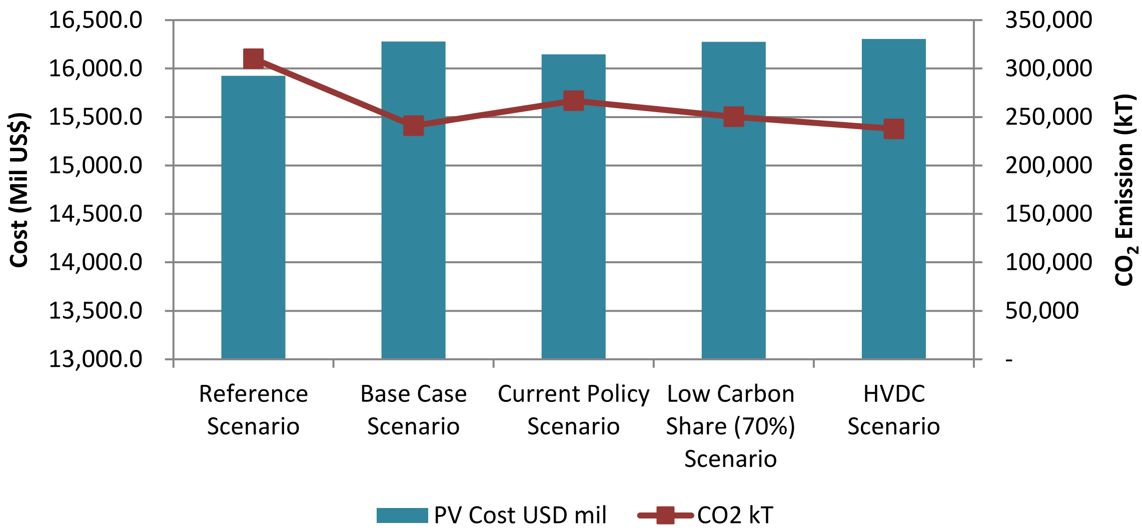


Figure 10.10 – Comparison of System Cost with CO_2 Emissions

Further, the incremental cost of each case is shown in Figure 10.11 by comparing the cost differences and the reduction of CO_2 emissions in each case compared to Reference Case and

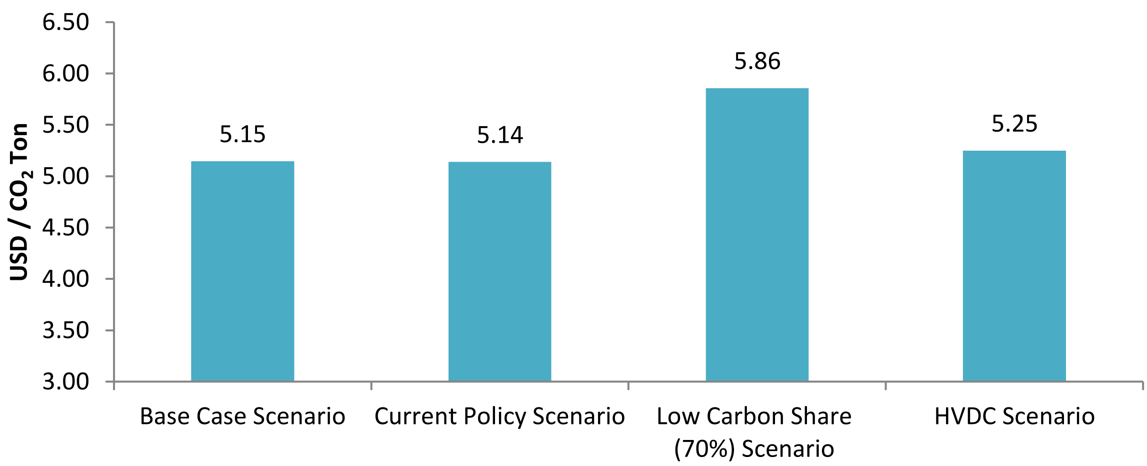


Figure 10.11 – Comparison of Incremental Cost for CO_2 reduction

10.6 Externalities

Externalities as discussed in generation planning are the consequences of a generation activity which indirectly affects other parties without being reflected in market prices. Externalities can be either a positive benefit or negative cost with relation to power generation.

Like any other heavy industry, power industry too causes negative impacts on the social and natural environment in varying degrees. The negative impacts at local level include, releasing of pollutants to local environment, release of waste heat, noise pollution, inundation of lands due to construction of hydro reservoirs, disruption of bird routes by wind plants, etc. The global level impacts are mainly caused with releasing of Green House Gases (GHG). These negative externalities could have non quantifiable impacts to climate change, health, society, agriculture and even bio diversity.

As for the positive impacts, technologies that are capable of generating low cost electricity shall increase the domestic production capabilities contributing to increase the country's GDP. Furthermore, power generation can produce by-products that could be used in manufacturing industries. For example, power generation through coal produces by-products that are used in cement industry and brick manufacturing industry.

Such impacts, when expressed in monetary terms, are called externalities. Estimates of such externalities of different power generating technologies give policy makers a valuable input to decide countries energy policy, generating/fuel mix, future power sector strategies, etc.

As the environmental impacts are a combined effect of all industries, estimating externality costs of specific power generating technology/fuel is a challenge and can be highly subjective due to the difficulty in isolating the contribution of power industry from the impacts from all other industries. Further, as electricity accounts for a less than 12% share of the total energy usage in the country, isolating the impacts of power industry from the balance 88% is very difficult. Thus, expressing the externality costs in monetary terms is a highly subjective exercise as seen from results of studies done in other countries.

Environmental and social impacts of development projects cannot be completely eliminated but can only be contained within ''acceptable limits". Such limits are stipulated in the environmental laws, regulations and standards of a country. This Long-Term Generation Expansion Plan is prepared meeting all such laws and standards. When it comes to reducing GHG emissions, Sri Lanka has obligations under Nationally Determined Contributions (NDC) to reduce emissions unconditionally as well as conditionally, depending on availability of carbon finance as discussed in section 10.1.3. This LTGEP is prepared complying with all such the international commitments related to climate change mitigation.

10.6.1 Local Environmental Damage Issues

Local impacts to social and natural environment can arise due to many causes such as,

1. Local Air pollution as a result of fuel combustion.
2. Pollutants released including waste heat and effluents.
3. Disposal of residual waste products such as ash.
4. Noise emanating from thermal power plants and wind turbines.
5. Effects due to hydro reservoirs.
6. Effects on bird migratory routes and other eco systems

Such localized impacts can have adverse social, environmental and health related issues. However, externality costs of such local impacts cannot be generalised by power generating technology and be adopted to Sri Lanka using studies done in other countries.

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 power plant. Sri Lanka being an island, the localized effects would be entirely different to that of other countries where plants are located inland and therefore health damage issues associated with air pollutants and thermal discharges need to be evaluated in Sri Lanka specific studies. Studies done in other countries for certain generating technologies such as coal power plants cannot be straightaway adopted to Sri Lanka as coal plants operated in such countries are of much older technologies compared with the existing and future coal plants of Sri Lanka. Therefore, country and location specific studies are required to be done to reasonably estimate the damage costs even though that too can be highly subjective.

10.6.2 Global Damage Issues of GHG Emissions

Global impacts of power generation are primarily due to release of CO_2 during combustion process. However, such global impacts of power generation are not only limited to the impacts due to conversion of fuels to electricity at the point of power generation, but also includes the impacts during the total supply chain of the fuel from the mine to the plant. When the total life-cycle emissions of LNG, which include emissions at the point of mining/extraction, liquefaction, transportation, regasification and combustion are considered, the results are totally contrast to the emission of GHGs during combustion only. Global studies have been conducted to prove that when life cycle emissions of natural gas, liquid fuel oils and coal are considered, the equivalent GHG emission of natural gas (which consists of methane having a GHG effect 28 times than CO_2) is more than that of other liquid fuel oils and are somewhat in the same range of coal. Such indirect emissions are present not only in thermal power generating sources but are common to any other type of generating source including hydro, wind and solar PV. Disposal of solar PV panels after de-commissioning has raised a huge global environment concern and re-cycling technologies are yet emerging. Thus, estimating the global impact of GHGs as a part of externalities is highly subjective and is beyond the scope of economic planning.

However, CEB had enhanced the operational specifications of future candidate power generating technologies to further reduce the environmental impacts of such technologies over and above what is stipulated under law. Additional costs to do so have already been considered and factored in to the capital costs of candidate thermal power plants in this planning study. Thus, CEB has already considered additional costs to bring down externality costs of power generating technologies, to be well below the threshold values of environmental regulations and hence the costs of externalities have been internalized in to the planning studies in the form of additional capital investment.

CHAPTER 11
RECOMMENDATIONS OF THE BASE CASE PLAN

This chapter elaborates the recommendations for the Base Case Plan by emphasizing the importance of implementation of proposed power projects identified in the planning horizon.

11.1 Introduction

As discussed in Chapter 8, Base Case Plan is a mix of thermal and renewable energy generation technologies and storage options. Timely implementation of proposed power plants is crucial to avoid capacity shortages, energy shortages and high cost alternative generation in the future.

Economies of renewable energy and advancement in renewable and storage technologies are evolving rapidly around the world. The rolling generation expansion plans prepared by CEB once in two years are intended to capture such changes in subsequent planning cycles. The generation expansion envisioned for the last ten years in the planning window is relied on the present up-to-date information whereas such can undergo changes in the future.

Accordingly, the recommendations for the Base Case Plan, pertaining particularly to the first ten years of the planning horizon are given below with special emphasis on the importance of timely implementation to secure, affordable and reliable supply of electricity.

11.2 Recommendations for the Base Case Plan

Major recommendations for the Base Case Plan are as follows.

1. Completion of committed Major Hydro power plants on time

   Base Case Plan 2022-2041 has identified committed Hydro power plants of 35 MW Broadlands and 122 MW Uma Oya to be made available by 2022 and 31 MW Moragolla to be made available by 2024. Timely implementation of all these committed Hydro power plants is important to avoid power shortages in future.

2. Commissioning of Natural gas based Combined Cycle power plants on time.

   The first two 350 MW Natural gas based Combined Cycle power plants which are at the project development phase, should be commissioned to operate on combined cycle mode by the years 2024 and 2025 respectively. Availability for open cycle operation of these power plants is important and that has to be ensured well prior to their combined cycle mode operation.

   The 3rd Natural gas based Combined Cycle power plant of 400 MW capacity is expected to be constructed by 2027 in western region. The land reservation process is required to be completed and procurement activities are required to be initiated for the plant to be commissioned on time.

All new natural gas based Combined Cycle power plants should be technically, operationally and contractually capable of being operated regularly between open cycle and combined cycle operations. For this purpose, inclusion of an IPP tariff structure for simple cycle operation would be an associated requirement for the power plants developed through IPP structure.

As per the long term operational studies, it is expected that future LNG Combined Cycle Plants would undergo daily cycling and frequent deloading mainly due to high variability and intermittency of renewable energy. In such situation, running of the GTs alone (open cycle mode) is a decision that would likely to be taken during dispatch. Thus, having a diverter damper in the combined cycle plant for facilitating quick changeover to simple cycle operation would be advantageous.

In addition to above, GT, HRSG, ST configuration of 1+1+1 or 2+1+1 is also an important factor to be decided at the initiation of procurement. This decision has to be taken in consultation with the National System Control Centre, considering above mentioned varying nature of the demand caused by high renewable integration and the reliability/flexibility of operation.

3. As future combined cycle plants are required to perform more flexible operation, ensuring the plant's operational/technical capability of providing cyclic operation, lower minimum load level, higher ramp rates and shorter start up time in par with present industry performance levels is also important.

4. Conversion of fuel capability to Natural gas of Kelanithissa Combined Cycle Power Plant, Sojitz Kelanithissa and West Coast Power Plant

   The existing 270 MW West Coast power plant, 165 MW Kelanithissa Combined Cycle power plant and 163 MW Sojitz Kelanithissa Combined Cycle power plant are expected to be converted to operate on natural gas by 2024. Hence all activities that are required to enable the conversion of fuel on time should be initiated immediately.

5. Availability of Liquefied Natural Gas (LNG)/Natural Gas (NG) and Infrastructure

   Natural gas based power plants operation is expected from year 2024 onwards with the basis of natural gas delivered to power plants through necessary infrastructure. Therefore, required LNG infrastructure with associated natural gas distribution network should be developed in line with this time target considering it as a national priority project.

   The LNG procurements contracts should be negotiated to minimize the 'Take or Pay' risks in order not to commit the minimum plant factors. Otherwise, this would lead to curtailment of more ORE sources in order to dispatch the LNG operated power plants.

6. Commissioning of New Kelanithissa Gas Turbine

   The 130 MW New Kelanithissa Gas Turbines, are expected to be commissioned in year 2023. To facilitate quick supply restoration in case of an island wide power failure, it is critical to have this power plant commissioned. In addition, the power plant shall provide necessary peak power requirement of the system.

7. Development of Flexible Firm Generation to Complement High VRE Integration

Due to the intermittent and variable nature of VRE, the power system needs to have sufficient flexible power sources to ensure system stability and reliability. These flexible power plants should possess the fast startup, fast ramping and deloading capabilities to support the power system to manage the daily net load fluctuations typically seen with high VRE levels.

IC Engine power plant proposed for year 2026 and all the Gas Turbine and IC Engine power plants proposed beyond 2030 have been included in the base case plan to fulfil this specific flexibility requirement of the system. Therefore, these proposed power plants should have superior operational flexibility with capability of several start-ups and stops per day without causing wear and tear and efficient provision of spinning and non-spinning reserves. These power plants should also have high part load efficiencies and should have minimum start up and shut down times (comparable with latest industry standard for IC Engine and Gas Turbine power plants).

8. Development of Coal Power Plants[1]

It is necessary to expedite the pre-construction activities of 300 MW Lakvijaya coal plant extension, and ensure the plant is commissioned in year 2025. The coal power plant will ensure least cost firm power supply to the system.

Another 300 MW coal power plant is identified to be developed at Foul point in 2028 considering its significant economic benefit and to add the important fuel diversity in the firm conventional generating capacity mix to ensure energy supply security. The Foul Point coal power plant shall be developed with high efficient low emission technologies and operationally flexible characteristics.

9. Development of Pumped Storage Power Plant

Implementation of the planned 3 x 200 MW pumped storage hydro plant is critical as a long term measure to enhance the flexibility and security of the system with high shares of renewable energy technologies. This energy storage technology shall facilitate projected variable renewable energy (wind & solar) absorption by reducing the curtailments of energy generation. In addition, this will operate as a peaking power plant by minimizing high cost thermal generation. The first unit of the PSPP is expected to be commissioned in 2029. It is necessary to complete the detailed feasibility and secure funding and finance for the project such that it could be commissioned on time.

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[1] Refer PUCSL letter in ANNEX 15. Development of new Coal capacity will not be carried out accordingly.

10. Supplementary power for capacity shortages

    Capacity shortage of 250 MW and 150 MW is observed in during 2022 and 2023 respectively due to the already delayed implementation of major power projects. Technology for procurement of supplementary capacity can be opened for both Gas turbine and IC engine technology primarily to ensure the most economic terms for the short term requirement from the available alternatives in the market. The fuel option can be specified as appropriate at the time of procurement from suitable fuels that has established supply chains and having regulated, transparent pricing mechanisms. Part of the supplementary capacity requirement could be catered from the 50 MW CEB owned diesel based IC engine power capacity (standby plants). Further, the possibility of utilizing the operational generating capacities with lapsed contracts as well as other short term alternatives shall be considered as appropriately to meet short term requirement in most economically advantageous terms for the country.

11. Development of Other Renewable Energy

    Base Case Plan 2022-2041 has identified a cumulative capacity of 3,508 MW of ORE to be developed within the first ten years of the planning horizon. This includes development of 2,365 MW of solar and 965 MW of wind power capacities in the first ten years. Timely implementation of projects to achieve these ORE capacities as per the schedule is important to achieve policy targets and climate change obligations. The locations of ORE power plants should be prioritized based on the plant factors, land availability and cost of transmission network. Formalities and procedures related to land acquisition, environment clearance, etc. have to be reviewed in order to facilitate fast track implementation of ORE projects.

    It is recommended to streamline renewable energy development procedures to ensure faster implementation as well as strict compliance to interconnection codes. All new medium to large scale ORE power plants should have the operational, technical and contractual capability for curtailment when necessary.

12. Establishment of Renewable Energy Desk with Resource Forecasting System

    The early introduction of a "Renewable Energy Desk" to the National System Control Centre is essential to separately manage renewable energy capacities that are going to be integrated in large proportions. Establishing renewable energy forecasting system at the "Renewable Energy Desk" in intra-hour, intra-day and day-ahead timeframes is vital to manage the uncertainty in maintaining supply and demand balance.

    The monitoring and controlling facilities of renewable energy plants are to be provided to National System Control Centre.

13. Development of Battery Energy Storage System

    Battery energy storage capacities are introduced mainly to provide grid level support for renewable energy integration. As first step, a 20 MW capacity is planned to be commissioned by year 2025, to support frequency regulation services. The capacity is planned to be gradually increased to 100 MW by 2030 to provide grid support services for renewable integration.

14. Development of Transmission Infrastructure

It is mandatory to have critical transmission infrastructure identified for each project to be implemented in parallel, to ensure evacuation of power from the power plants with the expected reliability. Securing funding for these critical transmission infrastructure projects is essential for timely implementation.

15. Securing of Land and Transmission Line Corridors

In the power sector, identification and securing of the lands for future power plants and associated infrastructure is crucial. Therefore, locations for establishing power generation facilities and related transmission corridors which interconnect such facilities to the national grid should be identified in advance and secured considering this as a national priority.

Potential locations identified at present for future power generation projects are given in Table 11.1.

Table 11.1 – Potential Locations for Future Power Generation Projects

Power Project	**Identified Location**
Natural Gas Power Projects	Kerawalapitiya , Hambantota
Coal Power Projects	Norachcholai in Puttalam, Foul Point in Trincomalee
Pumped Storage Power Projects	Maha Oya -Aranayaka in Kegalle, Victoria-Wewathenna in Kandy
Wind Park Developments	Mannar, Pooneryn, Puttalam, Vadamaradchi (Northern & North Western Regions)
Solar Park Developments (Ground Mounted / Floating)	Siymbalanduwa, Hambantota, Trincomalee, Pooneryn, (Northern, North Central, Southern & Eastern regions)

16. Dual Fuel Capability for Power Plants

Considering the heavy dependency in future on imported LNG as a fuel for electricity generation, all natural gas based power plants shall also have the dual fuel capability, including suitable fuel supply/storage arrangements locally for such secondary fuel, to ensure supply security in case of disruption to LNG supply. The choice of secondary fuel shall be decided at procurement stage from suitable fuels that has established supply chains and having regulated, transparent pricing mechanisms.

17. Review of Interconnection and operating codes, policies and regulations

    It is recommended to periodically review and upgrade the existing interconnection and operating codes/regulations based on detailed studies and up-to-date industry practices.

    Reviewing the present operating reserve policy of system operation, with dynamic upward and downward requirements that provide additional regulation for the planned renewable energy capacities is required.

    Enhancing the grid support features of variable renewable energy projects including enhanced Ride through capabilities, Ramp Rate Control functions, active power control, etc. through codes and regulations is mandatory to proceed with the planned renewable energy development program.

CHAPTER 12
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 2022-2041.

12.1 Present Status Power Plants in the Base Case Plan

12.1.1 Present Status of the Committed Plants

A brief description of the current status of power projects that were considered as committed projects in the present study are given below.

Renewable Energy Power Projects:

(i) 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 final phase of construction work and electro mechanical work is in progress and the project is scheduled to be completed within year 2021.

(ii) Uma Oya Multipurpose Project

This 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. The financial assistance for the project is provided by the Government of Iran and currently the project is under final stages of construction and expected to be completed within year 2021.

(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. The power plant is expected to be in operation by December 2023.

(iv) Solar Power Development

CEB initiated the procurement of small scale scattered solar power projects from private sector under the second phase of the accelerated solar development program of the government. Solar power projects of 1 MW x 60, 1 MW x 90 and 1 MW x150 were tendered through international competitive bidding process for selected grid substations. By 31st December 2020, 24 MW capacity have been developed and the remaining capacity is expected to be commissioned through the period from 2021-2024. It is planned to develop further 150 MW and another 140 MW in near term under the same scheme. In addition to this, Solar PV systems of 75 kW capacities are planned within 500 m of identified distribution substations where there is less potential for rooftop solar installations. A total of 7000 distribution substations have been identified for phased development under this programme to contribute a cumulative capacity of 525 MW to be developed within the period from 2021-2025.

(v) Wind Power Development

The extension of Mannar Wind Plant by 20 MW is being implemented by CEB. The capacity enhancement with six additional wind turbine generator units would increase the total capacity of the power plant to 123 MW. Funds from ADB were obtained for implementation of this project and CEB has called for bids for procurement of the plant.

Furthermore, CEB had called for bids of 60 MW wind power development from private sector, in which 3 projects has been committed to be developed in Trincomalee (10 MW), Madampe (10 MW) and Mannar (15 MW).

Thermal Power Projects:

(i) Kelanithissa New Gas Turbines (130 MW)

CEB has called for bids under the international competitive bidding scheme to design, manufacture, supply, installation and commissioning of 130 MW Gas Turbines at the Kelanithissa Power Station. This power plant is required to have the special capability to carry out restoration of supply in case of an island wide power failure. The power plant is expected to be operational by 2023.

(ii) 1st Natural gas fired Combined Cycle Power Plant (350 MW)

The LOI has been issued for the development of 350 MW Natural Gas fired Combined Cycle Power Plant with dual fuel capability on BOOT basis at Kerawalapitiya. The project preconstruction work has commenced and final negotiations on PPA are under progress. The Power plant is expected to be commissioned in 2023 in open cycle operation and in 2024 as combined cycle operation.

(iii) 2nd Natural gas fired Combined Cycle Power Plant (350 MW)

CEB has issued the RFP document for development of 350 MW Natural Gas fired Combined Cycle Power Plant with dual fuel capability on BOOT basis at Kerawalapitiya. The project is to be advertised for procurement in 2021, and expected to be commissioned in 2024 in open cycle operation and in 2025 as combined cycle operation.

(iv) Lakvijaya Coal Plant Extension (300 MW)[1]

The Cabinet approval has been granted to develop additional 300 MW capacity within the premises of Lakvijaya Coal Power Station. The Project Management Unit appointed within CEB has conducted the feasibility study and the EIA for the extension of Lakvijaya coal power plant.

[1] Refer PUCSL letter in ANNEX 15. Development of new Coal capacity will not be carried out accordingly.

The project is expected to be developed as a joint venture between CEB and CMEC (China Machinery Engineering Corporation) and is expected to be commissioned in 2025.

12.1.2 Present Status of the Candidate Power Plants

A brief description of the current status of the candidate power projects on which the initial project activities were commenced are given below.

Renewable Energy Power Projects:

(i) Other Multipurpose Hydro Power 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 approved. However due to difficulties in securing project finances, the project is on hold at present.

(ii) Solar Power Development

The SEA and CEB has conducted initial studies to identify potential locations to develop large scale solar parks in the country. These include 100 MW ground mounted solar parks and floating solar power plants. As first phase, large scale solar power parks are planned to be developed in Siyambalanduwa, Hambantota and Trincomalee. The land acquisition and initial prefeasibility studies for these projects are to be done.

(iii) Wind Power Development

The resources identification for wind power projects has recognized high potential wind power capacity in North western and Northern region of the country. As first phase, large scale on-shore wind power parks are planned to be established in Mannar and Pooneryn. Furthermore, new wind power development projects are focused on Vadamaradchi and Puttalam areas.

Thermal Power Projects:

(i) Natural Gas based Power Plant – West Coast, Muthurajawela

It has been identified that locating major power plants near the load centres of the country has significant economic benefits. Thus, with the establishment of FSRU facilities off-shore near Kerawalapitiya, next natural gas power plant is identified to be developed in Muthurajawela. The EIA for land reclamation is complete, and once approved, shall be considered for implementation of next natural gas power project.

(ii) New Coal fired Power Plant – Foul Point, Trincomalee[2]

Pre-feasibility study on High Efficient Coal Fired Thermal Power Plant was initiated in 2013 by the financial assistance from New Energy and Industrial Technology Development Organization (NEDO), Japan. CEB and Japanese experts identified a land area in Sampur, Trincomalee which is suitable for 1200 MW coal power development (either 300 MW High efficient advanced subcritical power plants or 600 MW Super critical power plants). However, 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 land acquisition is initiated. Necessary feasibility studies and EIA for the alternate land are to recommence once the land acquisition process is finalized.

Energy Storage Projects:

(i) Pumped Storage Power Project

Pumped Storage Power Plants are to be used as a grid level energy storage and frequency controlling option in future. The JICA assisted study, 'Development Planning on Optimal Power Generation for Peak Power Demand in Sri Lanka' (2015) identified a site at Aranayaka in the Maha Oya basin as the most suitable site to locate the first pumped storage hydropower project in Sri Lanka. A prefeasibility level study has been completed for this location. Subsequently, 'Electricity Sector Master Plan Study' (2018) identified Victoria-Wewathenna as an alternative location for pumped storage option.

The Cabinet approval has been granted to conduct the feasibility study for the first pumped storage power plant in Sri Lanka. The first phase of this study is to conduct a pre-feasibility on Wewathenna-Victoria site and evaluate the best site to construct the first pumped storage power plant in Sri Lanka. The second phase of the study shall conduct a detailed feasibility study for the identified most promising location in the first phase. The feasibility study is financed through the Asian Development Bank (ADB).

[2] Refer PUCSL letter in ANNEX 15. Development of new Coal capacity will not be carried out accordingly.

12.2 Power Plants Identified in the Base Case Plan from 2022 to 2031

The proposed major hydro, thermal and other renewable energy plants up to 2032 according to the Base Case Plan are given below.

Thermal Power Plants:

(i) Kelanithissa New Gas Turbines (130 MW) in 2023
(ii) 1st Natural gas fired Combined Cycle Power Plant (350 MW) in 2023/2024
(iii) 2nd Natural gas fired Combined Cycle Power Plant (350 MW) in 2024/2025
(iv) Lakvijaya Coal Plant Extension (300 MW) in 2025[3]
(v) Natural gas fired Gas Engines (250 MW) in 2026
(vi) 3rd Natural gas fired Combined Cycle Power Plant (400 MW) in 2027
(vii) High Efficient Coal Power Plant (300 MW) in 2028[3]

Renewable Energy Power Plants

(i) Broadlands Hydro Power Plant (35 MW) in 2022
(ii) Uma Oya Hydro Power Plant (122 MW) in 2022
(iii) Moragolla Hydro Power Plant (31 MW) in 2024
(iv) Other Renewable Energy additions (2022-2031)
  - Solar (2,175 MW)
  - Wind (865 MW)
  - Mini Hydro (110 MW)
  - Biomass (58 MW)

Energy Storage Power Plants:

(i) Battery Storage (100 MW) phased development from 2025-2030
(ii) Pumped Storage Power Plant (200 MW) in 2029
(iii) Pumped Storage Power Plant (200 MW) in 2030
(iv) Pumped Storage Power Plant (200 MW) in 2031

12.3 Implementation Schedule

The implementation of power projects consists of three phases; feasibility, pre construction and construction phase. Some sub activities during these phases include land identification and allocation, obtaining environmental approvals, procurement procedures and securing of funding and finances. In order to implement a project on time, it is necessary to have support from all relevant government institutions and other involved public stakeholders.

It is mandatory to have critical transmission infrastructure identified for each project to be implemented in parallel, to ensure evacuation of power from the power plant and reliability during operation and maintenance. The implementation schedule for both committed and proposed major thermal power plants and committed and proposed major renewable energy and storage projects in the Base Case 2022-2041 is shown in Figure 12.1 and Figure 12.2 respectively.

[3] Refer PUCSL letter in ANNEX 15. Development of new Coal capacity will not be carried out accordingly.

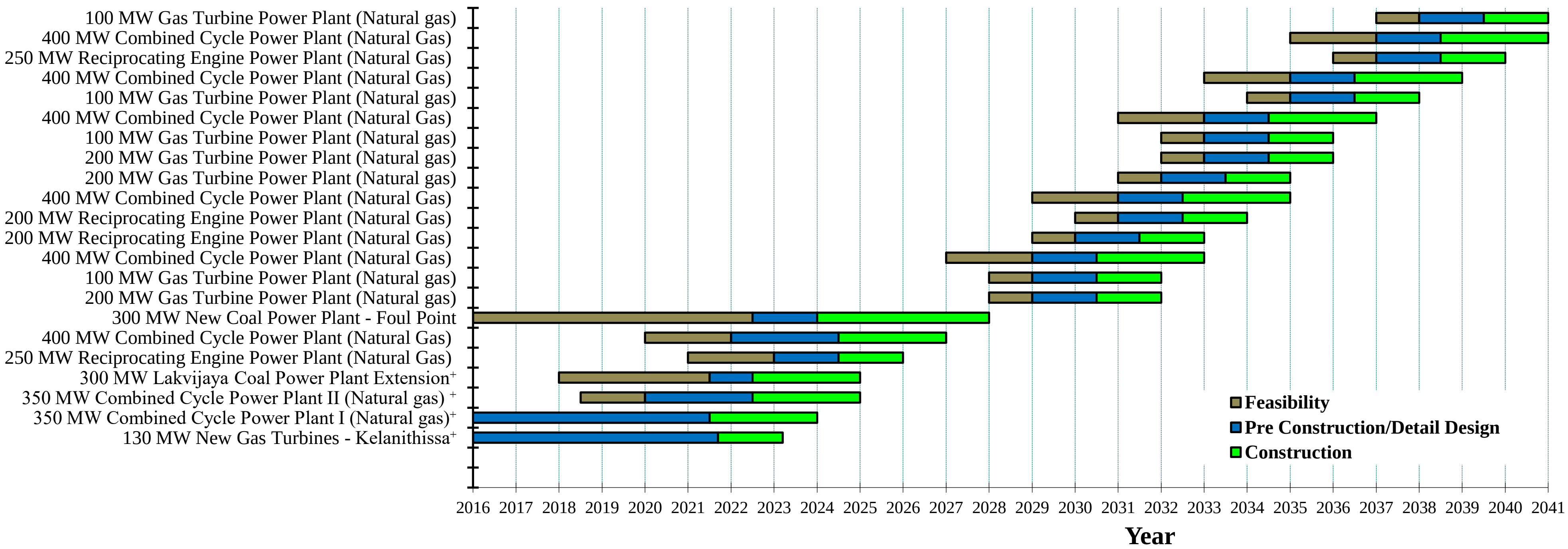

Figure 12.1 - Implementation Plan of Thermal Power Projects 2022-2041

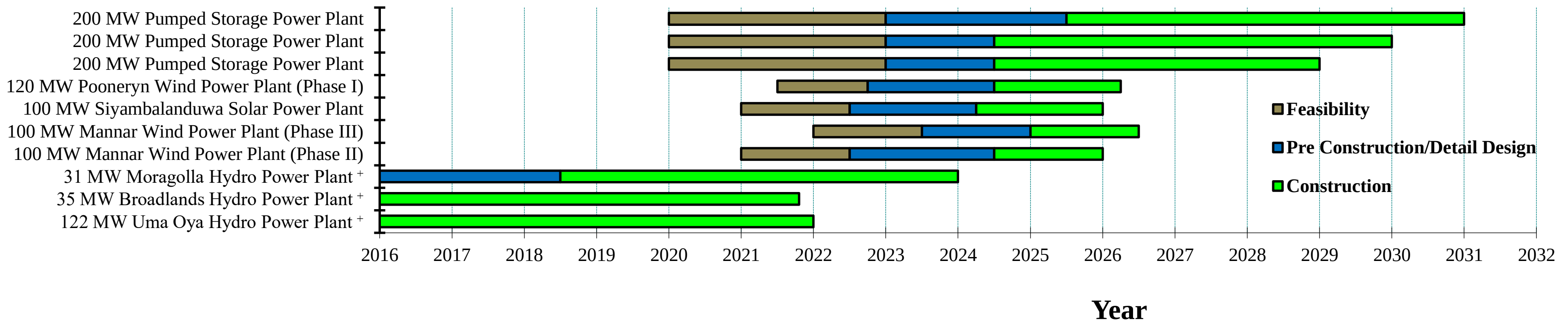

Figure 12.2 - Implementation Plan of Major Renewable Energy and Storage Projects 2022-2031

+ Committed Plants

12.4 Investment Plan for Base Case 2022-2041 and Financial Options

12.4.1 Investment Plan for Base Case Plan 2022-2041

Annual investment requirement for the Base Case Plan 2022-2041 is graphically shown in Figure 12.3. The cost details of the investment plan for major hydro & thermal power projects and major wind & solar power developments are given in Annex 12.1 and 12.2 respectively. Tabulated annual investment costs include only the plant-by-plant pure construction cost and excludes the construction cost for associated other infrastructures (eg: coal jetty, LNG terminal & pipelines, etc.).

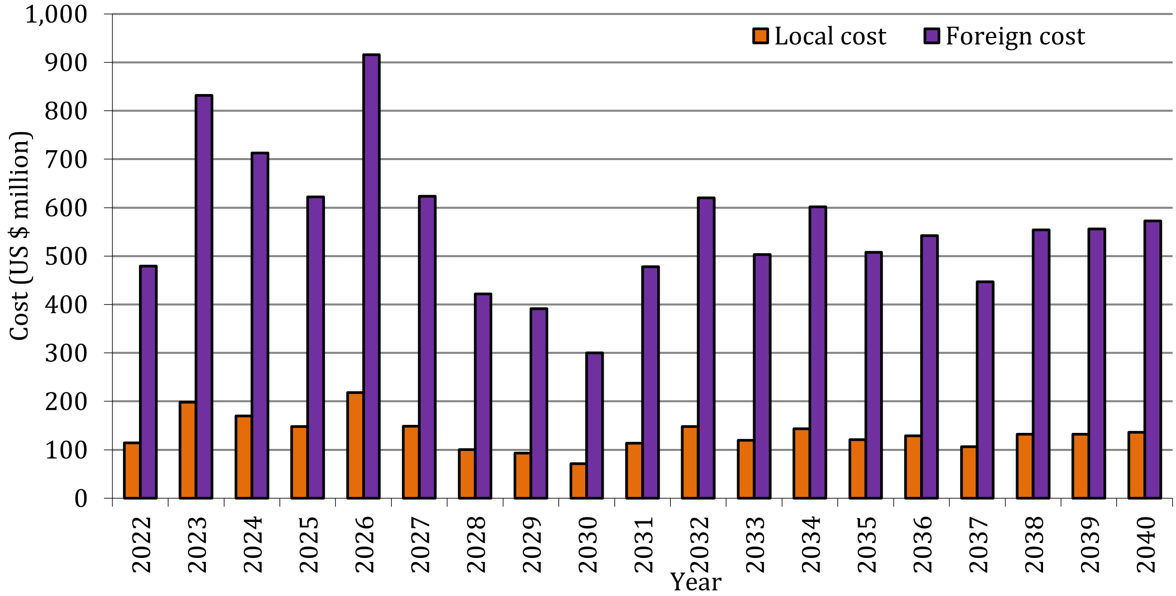

Figure 12.3 - Investment Plan for Base Case 2022 – 2041

12.4.2 Financial Options

Timely investment on the power generation projects is highly important to be in line with the commissioning years of the planned power plant developments.

Capital investment required for the new power generation facilities could be considered 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, issuance of Green Bonds, Grants by other countries and Government to Government facilities.

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
- Government to Government Concessions, etc.

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

Financial evaluation aims at evaluating the return on investment from a viewpoint of an implementing agency. Financial evaluation of individual projects shall be performed considering financial indicators, which determine the viability of individual project. The financial indicators include,

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

The WACC is an estimation of the expected costs of a projects' all financing sources. This indicates the rate that a project/company is expected to pay on average to all its capital sources including required rate of return demanded by equity holders (cost of equity financing) and debt obligations (cost of debt financing).

LCOE is a useful indicator to determine whether to invest for a power generation project. This will vary depending on the type of 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.

CHAPTER 13
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 the immediate future years from 2022 to 2026 in the Base Case. The Contingency Analysis focus to identify the main risk events, which are given below:

1. Variation in hydrology
2. Variation in demand
3. Delays in implementation of power plants
4. Long outage period of a major power plant

13.1 Risk Events

13.1.1 Variation in Hydrology

Hydrology is one of the significant risk event that could lead to energy supply shortage. Table 13.1 depicts the annual expected energy output of hydro system for the five hydro conditions, and the difference of energy with respect to the average hydro condition. Availability of adequate capacity and energy supply to meet the demand in the driest hydrological condition is important.

Table 13.1 – Expected Annual Energy Output of Five Hydro Conditions and the Difference Compared with Annual Average Hydro Energy

Hydro Condition	Expected Annual Energy (GWh)	Difference of Energy (GWh)
Very dry	3,269	-1,273
Dry	4,139	-403
Average	4,542	0
Wet	4,920	378
Very wet	5,967	1,425

13.1.2 Variation in Demand

Variation in demand from the base demand projection is considered as an uncertainty. Difference of annual energy and peak demand from 2022 to 2026, for both high demand and low demand scenarios compared to the base demand forecast is shown in figure 13.1 and figure 13.2. Assessment of the adequacy of capacity and energy supply to cater the high demand scenario is an important consideration.

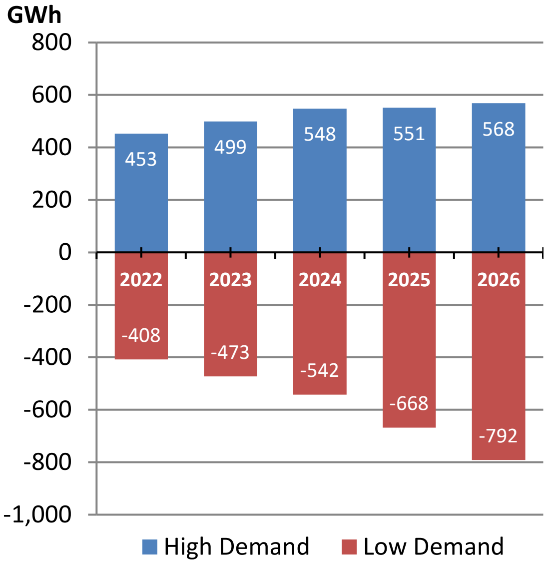

Figure 13.1 – Comparison of Annual energy demand differences of high and low demand projections with the base demand forecast

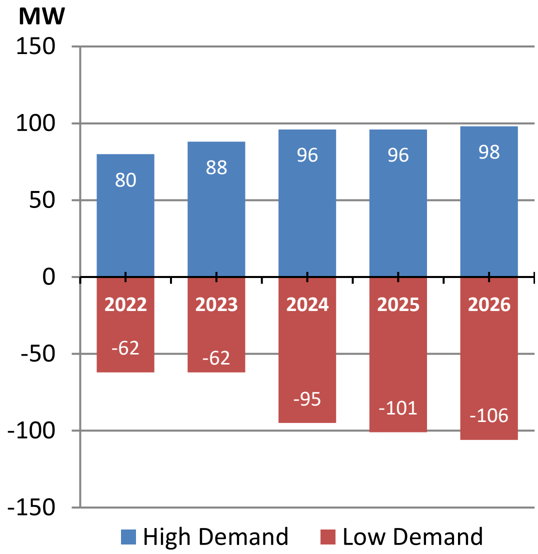

Figure 13.1 – Comparison of Annual energy demand differences of high and low demand projections with the base demand forecast

13.1.3 Delays in Implementing Power Plants

Timely implementation of committed power plants on schedule is critical to avoid capacity and energy shortfalls in short term. However, unexpected deviations can occur in power project implementation phase and the consequences of such implementation delays on the capacity deficit have been considered in this analysis. A possibility of a one year delay has been considered for each major pipeline project under five different implementation delay cases as show in the Table 13.2 below.

As described in chapter 6, the retirement year of the 4 x 17 MW Kelanitissa Gas Turbines, is to be considered with the actual implementation of Kelanithissa New Gas Turbines. Hence during the contingency analysis it is assumed the 4 x 17 MW Kelanitissa Gas Turbines are available until the New Gas Turbines are commissioned at the Kelanithissa power station.

For evaluation of contingencies under five implementation delay cases as depicted in table 13.3 are considered, with one year implementation delay considered for each of the committed thermal power projects in the pipeline.

Table 13.2 – Implementation Delay Cases for Major Pipeline Projects

Implementation delay Case	Major Pipeline Project					
	130 MW New gas turbines at Kelanitissa	Open Cycle of 1st 350 MW NG CCY	Combined Cycle of 1st 350 MW NG CCY	Open Cycle of 2nd 350 MW NG CCY	Combined Cycle of 2nd 350 MW NG CCY	300 MW Lakvijaya coal power plant extension
Base Case	**2023**	**2023**	**2024**	**2024**	**2025**	**2025**
Case 1	2024	2023	2024	2024	2025	2025
Case 2	2023	2024	2025	2024	2025	2025
Case 3	2023	2024	2025	2025	2026	2025
Case 4	2023	2024	2025	2025	2026	2026
Case 5	2024	2024	2025	2025	2026	2026

13.1.4 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 13.3.

Table 13.3 – 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) in each year
Loss of Capacity	275 MW
Loss of Energy	560 GWh per year

13.2 Evaluation of Contingencies

In this contingeny analysis, initially the single occurrence of above mentioned four risk events were considered at first and thereafter, simultatious occurrence of several events were analysed to identify the short term energy and capacity shortage. The capacity requiremnt identified in this contingency analysis is in addtion to the short term supplementary power capacity identified in Base Case plan shown in Table 8.1 of Chapter 8 unless otherwise stated.

13.2.1 Single Occurrence of Risk Events

The four risk events are potential to cause challenges in adequate supply capability of the system. Variation of hydrology is significant but by default the planning is performed for the driest hydro contition. Therefore impact of the hydrology variation is already taken in to accounted in the Base Case preparation. Secondly the variation in demand is also performed as a sensitivity. Thirdly the event of power plant implemnetation delays has a major impact on the Base Case and likelihood of occuring the implemnetation delay risk event is also high. Finally, the outage of a largest unit during critical periods of the year can further aggravate the situation. The base case has already identified the short term capacity requirement of 250 MW and 150 MW for the year 2022 and 2023 respectively under the driest hydro condition. The Table 13.4 below shows the additional capacity deficit required for the minimum relaibility level under implementation delay cases as well as the differed energy due to the delayed power projects that are planned in the base case.

Table 13.4 –Additional short term capacity requirement and the differed energy under implementation delay cases compared to the Base Case (drirest hydro condition)

Case		2022	2023	2024	2025
Base Case	Capacity Deficit (Differed Energy)	-	-	-	-
Case 1	Capacity Deficit (Differed Energy)	-	50 MW (28 GWh)	-	-
Case 2	Capacity Deficit (Differed Energy)	-	175 MW (173 GWh)	85 MW (1,880 GWh)	-
Case 3	Capacity Deficit (Differed Energy)	-	175 MW (173 GWh)	275 MW (1964 GWh)	- (766 GWh)
Case 4	Capacity Deficit (Differed Energy)	-	175 MW (173 GWh)	275 MW (1,964 GWh)	190 MW (766 GWh)
Case 5	Capacity Deficit (Differed Energy)	-	240 MW (201 GWh)	275 MW (1,964 GWh)	190 MW (2,671GWh)

The summary of impact of other single occurance of risk events is shown in Table 13.5 below. Capacity Deficit risk is the possibility of firm capacity shortage to meet the peak demand in the critical period and the energy deficit risk is the possibility that the exsisting plants will not be able to provide the total energy requirement.

Table 13.5 – Impact of Single Occurrence of Risk Events

Risk Event	Capacity Deficit Risk	Energy Deficit Risk	Remarks
Hydrology Reduction (Very Dry)	No	No	No capacity deficit with the planned capacity addition of the Base Case. Energy requirement in the very dry hydrological condition can be catered with the planned capacities in the Base Case. (Table E.3)
High Demand	Yes	No	65 MW, 60 MW and 50 MW of additional capacities are required in 2022, 2023, and 2024 respectively for the Base Case to maintain the minimum capacity requirment in the case of high demand (Annex 8.6)
Plant Implementation Delay	Yes	Yes	Refer Table 13.5.
Outage of a Major Power Plant	Yes	Yes	Outage of largest unit can lead to capacity deficit in the driest month of each year during period of 2022 to 2026. Energy deficit can be expected in the year 2022.

13.2.2 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. The available firm capacity during the critical month of each year in the Base Case shown in the table 13.6 is taken as the reference for the following contingency events.

Table 13.6 – Available Firm Capacities in Critical Period in the Base Case (MW)

Available Capacity	2022	2023	2024	2025
Existing Firm Capacity	2,613	2,545	2,545	2,483
New Major Hydro	93	93	111	111
Supplementary Power	250	150	0	0
New Gas Turbine	0	130	130	130
LNG CCY Plants	0	200	550	700
Coal fired Plant	0	0	0	270
ORE	50	52	54	56
Available Firm Capacity (Critical Period)	**3,006**	**3,170**	**3,390**	**3,749**
Peak Demand (Critical Period)	**2,935**	**3,083**	**3,240**	**3,437**

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

The both events of worst hydro condition and the power plant implementation delays were taken as the first contingency event. The parameter variations given in sectoin 13.1.1 and 13.1.3 were taken as the basis for the analysis. In terms of mitigating this risk, possibility of providing the energy deficit from avalilable power plants was studied relative to the Base case. The additional capacity deficit and the risk of energy deficit compared to the Base case is indicated in the Table 13.7 below.

Table 13.7 – Assessment of the additional capacity deficit and the risk of energy deficit compared to the Base Case under Contingency event 1 due to Risk event 1 and Risk event 3

		2022	2023	2024	2025
Risk 1 :Dry Hydro Condition					
Hydro Energy Reduction		**(1,273)**	**(1,273)**	**(1,273)**	**(1,273)**
Risk 3:Delay in Plant Implementation					
Case 1	Capacity Deficit (Risk of Energy Deficit)	- (No)	50 MW (No)	- (No)	- (No)
Case 2	Capacity Deficit (Risk of Energy Deficit)	- (No)	175 MW (No)	85 MW (No)	- (No)
Case 3	Capacity Deficit (Risk of Energy Deficit)	- (No)	175 MW (No)	275 MW (Yes)	- (No)
Case 4	Capacity Deficit (Risk of Energy Deficit)	- (No)	175 MW (No)	275 MW (Yes)	190 MW (No)
Case 5	Capacity Deficit (Risk of Energy Deficit)	- (No)	240 MW (No)	275 MW (Yes)	190 MW (No)

This contingency event has a very large impact on the adequate supply capacity of the system as well as the likelihood of the contingency event 1 is also high. Additional capacity is required to meet the electricity demand adequately while maintaining the minimum relaibility level. Therefore, timely implementation of the pipeline major projects is crucial to avoid additional capacity and energy deficit. Additional capacity of 50 MW to 240 MW would be necessary for the year 2023 depeding on the implementation delay case, to meet the projected demand in the driest hydro condition at the minimum relaibility level while mitigating this contingency event.

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 other two risk events of section (a) above is considered for the analysis. The unit outage is assumed to occur in the dry season during first four months of the year. It was observed that both energy and capacity deficit can occur for a short period in this contingency event. Additional capacity deficit of 260 MW for the year 2022 and a maximum deficit of 510 MW for the year 2023 is necessary to meet the projected demand in the driest hydro condition at the minimum relaibility level when a largest unit outage takes place for a short period of time.

Table 13.8 – Assessment of the additional capacity deficit and the risk of energy deficit compared to the Base Case under Contingency event 1 due to Risk event 1,3 and 4

		2022	**2023**	**2024**	**2025**
Risk 1 :Dry Hydro Condition					
Hydro Energy Reduction		**(1,273)**	**(1,273)**	**(1,273)**	**(1,273)**
Risk 4 : Major Unit Outage (Outage of one unit of Lakvijaya Power Plant in Jan- April)					
Capacity Reduction Energy Reduction		270 MW 560 GWh	270 MW 560 GWh	270 MW 560 GWh	270 MW 560 GWh
Risk 3: Delay in Plant Implementation					
Case 1	Capacity Deficit (Risk of Energy Deficit)	260 MW (Yes)	320 MW (No)	190 MW (No)	30 MW (No)
Case 2	Capacity Deficit (Risk of Energy Deficit)	260 MW (Yes)	440 MW (Yes)	350 MW (No)	30 MW (No)
Case 3	Capacity Deficit (Risk of Energy Deficit)	260 MW (Yes)	445 MW (Yes)	545 MW (Yes)	190 MW (No)
Case 4	Capacity Deficit (Risk of Energy Deficit)	260 MW (Yes)	445 MW (Yes)	545 MW (Yes)	460 MW (No)
Case 5	Capacity Deficit (Risk of Energy Deficit)	260 MW (Yes)	510 MW (Yes)	545 MW (Yes)	460 MW (No)

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

The risk event considers the possibility of a demand increase beyond the base demand projection under worst hydro condition with delays in power plant implementation. The demand increase beyond the base demand projection has a relatively low likelihood due to the reduced national demand under present circumstances but the level of uncertainty related to the demand is very high.

Table 13.9 – Assessment of the additional capacity deficit and the risk of energy deficit compared to the Base Case under Contingency event 1 due to Risk event 1,2 and 3

		2022	2023	2024	2025
Risk 1 :Dry Hydro Condition					
Hydro Energy Reduction		**(1,273)**	**(1,273)**	**(1,273)**	**(1,273)**
Risk 2 : High Demand					
Increase in Peak Demand(Critical period) Increase in Energy Demand		65 MW 453 GWh	72 MW 499 GWh	79 MW 548 GWh	85 MW 551 GWh
Risk 3:Delay in Plant Implementation					
Case 1	Capacity Deficit (Risk of Energy Deficit)	330 MW (Yes)	395 MW (No)	275 MW (No)	115 MW (No)
Case 2	Capacity Deficit (Risk of Energy Deficit)	330 MW (Yes)	515 MW (Yes)	435 MW (No)	115 MW (No)
Case 3	Capacity Deficit (Risk of Energy Deficit)	330 MW (Yes)	520 MW (Yes)	625 MW (Yes)	275 MW (No)
Case 4	Capacity Deficit (Risk of Energy Deficit)	330 MW (Yes)	520 MW (Yes)	625 MW (Yes)	545 MW (No)
Case 5	Capacity Deficit (Risk of Energy Deficit)	330 MW (Yes)	585MW (Yes)	625 MW (Yes)	545 MW (No)

13.3 Conclusion

(1) The individual risk event has a varying impact on the base case and the driest hydrology condition has already been captured in the preparation of the Base Case in the planning studies. The variation in demand is also performed as a sensitivity. The demand increase beyond the base demand projection has a relatively low likelihood due to the reduced national demand under present circumstances, but the level of uncertainty related to the demand is very high. Thirdly, the event of power plant implemnetation delays presents the major risk for the Base case as both the impacts and the likelihood of occuring of the implemnetation delay risk event is high. Finally, an outage of a largest unit during critical periods of the year can further aggravate the situation.

(2) In the case of simultaneous occurrence of contingency events, the likelihood of contingency event 1 is high and its impact on the base case is also high. Implementation delays in the planned 130 MW Gas Turbine and 2 x 350 MW Natural gas combined cycle plants and the extention to the Lakvijya coal power plant can lead to capacity and energy deficit durung 2022 to 2025 period.

(3) The likelihood of contingency event 2 is moderate but the impact can be severe if a major unit outage takes place during the driest period when the pipeline project implementation is delayed. Therefore, it is important to ensure the timely implementtaion of the planned projects as well as the availability of the major thermal power plants in operation

(4) The likelihood of contingency event 3 is relatively low as likelihood of a demand increase beyond the base demand projection in the initial years is low. But in the event of demand

increase takes place with implementation delays, severe capacity deficits can be experienced during 2022 to 2025 period.

(5) The implementation delays of planned renewable energy projects have not been considered in this contingency analysis and it is important to ensure the timely implementation of wind and solar projects to obtain the expected energy contribution.

(6) The short term capacity requirements identified in the table 13.8, 13.9 and 13.10 are based on inputs used for the preparation of the Base Case 2022-2041 and the exact capacity requirement and the period of its requirement shall be determined at the time of procurement through detailed short term studies and situational analysis of the system.

(7) It should be noted that, in the occurrence of a risk event, the part of the supplementary capacity requirement could be catered from the 50 MW CEB owned diesel based IC engine power capacity (standby plants). Further, the possibility of utilizing the operational generating capacities with lapsed contracts as well as other short term alternatives shall be considered as appropriately to meet short term requirement in most economically advantageous terms for the country.

(8) The impact of the above contingency events on the cost of generation as well as on the economy as a whole is high as the short term capacity deficits are avoided using expensive short term generation alternatives that are often expensive. Therefore, it is a nationally important task to implement the planned pipeline projects as well as the planned transmission development on time to ensure reliable and economic supply of electricity.

CHAPTER 14
REVISIONS TO PREVIOUS PLAN

This chapter examines the deviations of the results of the present study from the previous generation expansion plan, and analyses the factors for such deviations. Due to non receiving of approval for the draft LTGEP 2020-2039, this chapter focuses on the differences between the current study; LTGEP 2022-2041(submitted in 2021) and last PUCSL approved LTGEP 2018-2037 (submitted in 2017).

This chapter focuses on the main differences from the previous plan under following areas.

- Government Policies
- Base Demand Forecast
    - Variation in daily load profile shape with the maximum demand shifting from night peak to day peak was advanced to an earlier year considering the recent trends.
    - Load factor variation with load profile change and demand growth trends of each tariff category.
- Fuel price variations
- Higher capacity integration of Other Renewable Energy (ORE) based on the results of the study "Integration of Renewable Based Generation in to Sri Lankan Grid 2021-2030"
- Introduction of Battery Storage as an Energy Storage System.
- Capacity share and Energy share
- Environmental emissions

14.1 Government Policies

The General Policy Guidelines on the Electricity Industry issued in 2009 was amended with the new 'General Policy Guidelines on the Electricity Industry for the Public Utilities Commission', issued in April 2019.

The policy focuses the country's progression with the vision to achieve 50% of electricity generated in 2030 from renewable sources under favourable weather conditions. Hence, LTGEP 2022-2041 is optimised with the enforcement of 50% renewable energy target.

Furthermore, the perceived policy of the government is to maximize generation from renewable sources and, as an interim milestone, a 70% of electricity to be generated from low carbon sources by 2030, in which not less than 50% are to be met from renewable sources.

14.2 Demand Forecast

As identified in LTGEP 2018-2037, the night peak, day peak and off peak shows an increasing trend but in particular, the growth of the day peak was higher than the growth of night peak. It was anticipated that the day peak would surpass the night peak by 2030. After incorporating the trend of recent years, it is now estimated that the day peak would exceed the night peak as early as 2026. The shape of the daily load profile also undergoes gradually changes.

Base Demand Forecast of LTGEP is a combination of Time Trend modelling and Econometric approach as described in Chapter 3. Twenty-five-year average growth rates of Energy demand and Peak forecasts of LTGEP 2022-2041 are respectively 5.0% and 4.9% while Energy demand and Peak forecast of LTGEP 2018-2037 was 4.8% and 4.4% respectively. Figure 14.1 & 14.2 shows the Energy demand and Peak forecast comparison of two LTGEPs.

As illustrated in figure 14.1 & 14.2, both the annual energy demand and annual peak demand of LTGEP 2022-2041 are lower than the LTGEP 2018-2037 in initial years, but gradually overlap during the end of the planning horizon.

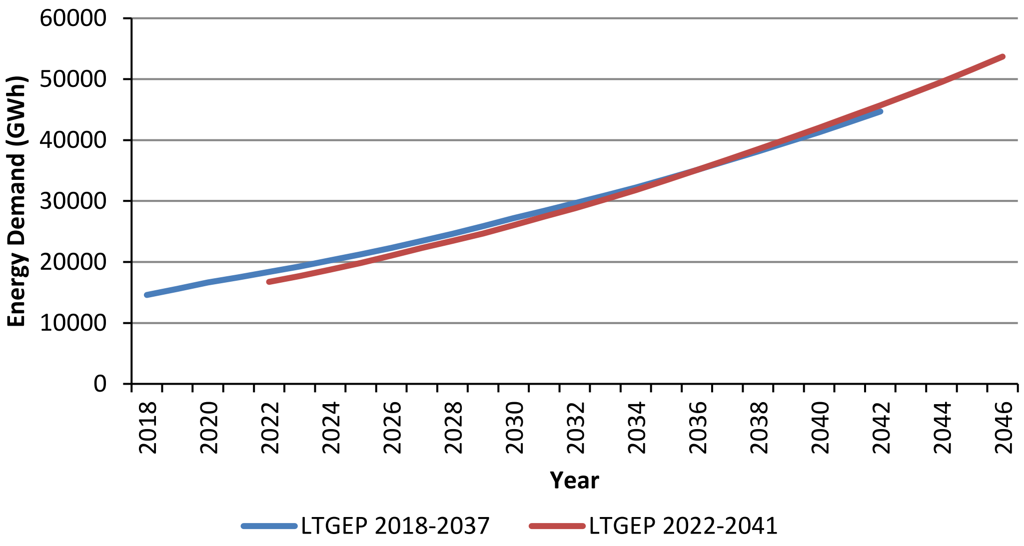

Figure 14.1 - Comparison of LTGEP 2018-2037 and LTGEP 2022-2041 Energy Demand Forecasts

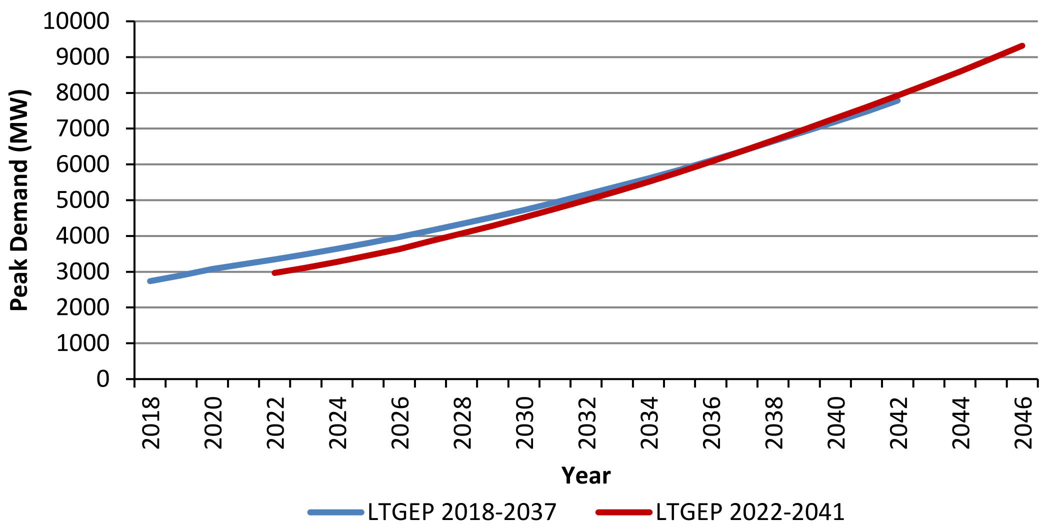

Figure 14.2 - Comparison of LTGEP 2018-2037 and LTGEP 2022-2041 Peak Demand Forecasts

14.3 Fuel Prices Variation

Fuel Prices of Coal, Natural Gas and Oil for the present study (LTGEP 2022-2041) were based on historical data of past four year weighted average. It should be noted that in the present study, all fuel prices are considered as the price delivered at the power plant exclusive of tax. Fuel prices used in the LTGEP 2022-2041 and LTGEP 2018-2037 are shown in Figure 14.3.

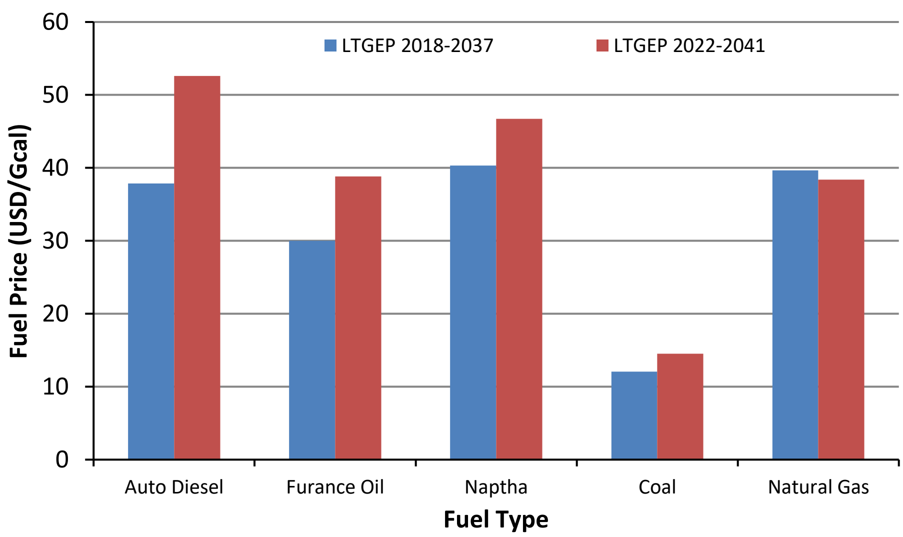

Figure 14.3 – Fuel price variation of LTGEP 2018-2037 and LTGEP 2022-2041

* Prices indicated for Diesel, Furnace Oil and Naphtha in LTGEP 2018-2037 are market prices.

14.4 Integration of Other Renewable Energy (ORE)

Figure 14.4 shows the variation of cumulative Other Renewable Energy (ORE) capacity contribution in the selected years of 2025, 2020 and 2035 for both LTGEP 2018-2037 and the LTGEP 2022-2041. The total ORE capacity increases to 6,631 MW by 2037 in LTGEP 2022-2041 which is 92% higher than LTGEP 2018-2037 total ORE capacity.

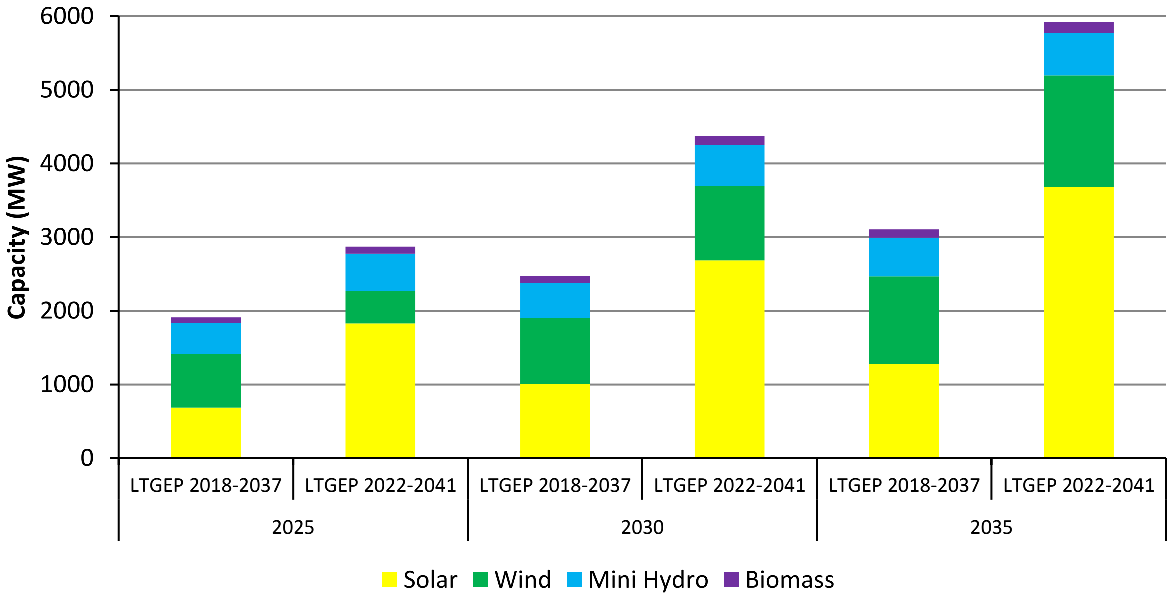

Figure 14.4 – Comparison of ORE Capacity between LTGEP 2018-2037 & LTGEP 2022-2041

14.5 Introduction of Battery Storage

Battery storage is proposed to be added to the system in phase development. A cumulative capacity of 20 MW by 2025 and 100 MW by 2030 is expected to be incorporated to the system. Capacities beyond 2030 to be re-evaluated based on the exact system requirement as well as the progress of the variable renewable energy development.

14.6 Capacity Share and Energy Share

In LTGEP 2022-2041, the capacity shares in 2030 of renewable energy based power plants and natural gas based power plants have increased by 12.3 % and 6.5 % respectively compared to LTGEP 2018-2037. However, the capacity shares of coal based power plants and oil based power plants have decreased by 12.1% and 3.8 % respectively in year 2030. A summary of change in capacity shares between LTGEP 2022-2041 and LTGEP 2018-2037 is illustrated in Figure 14.5

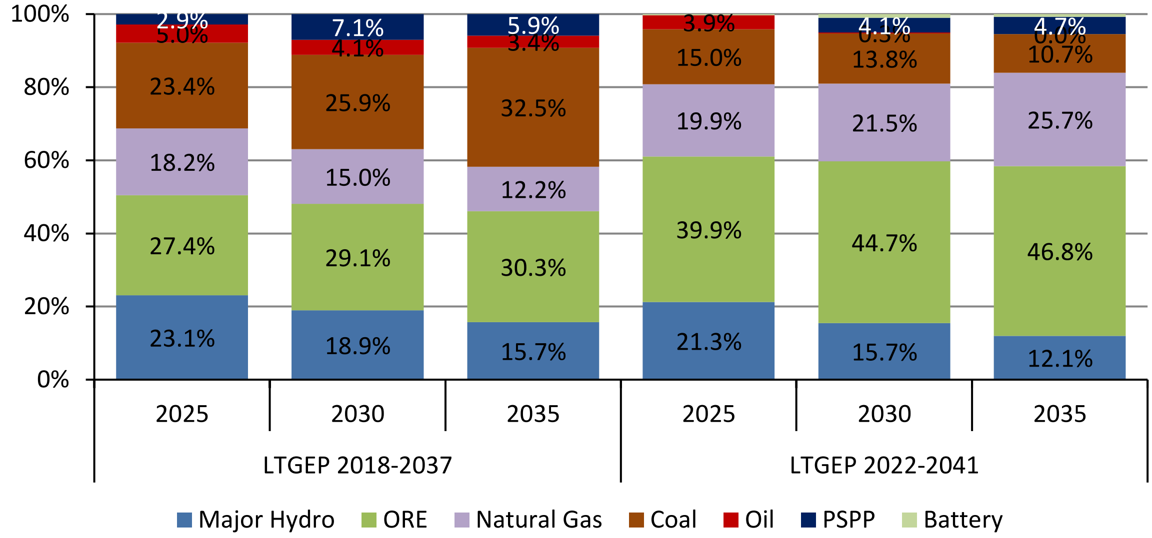

Figure 14.5 – Comparison of Capacity Share between LTGEP 2018-2037 & LTGEP 2022-2041

Correspondingly in LTGEP 2022-2041, the energy share of renewable energy based power plants in year 2030 has increased by 18.3% compared to LTGEP 2018-2037. The main decrease in energy share is from coal based power plants with a reduction of 18.6%. The energy share from natural gas and oil based power plants remain marginally same, although their operational pattern has changed drastically. A summary of change in energy shares between LTGEP 2022-2041 and LTGEP 2018-2037 is illustrated in Figure 14.6

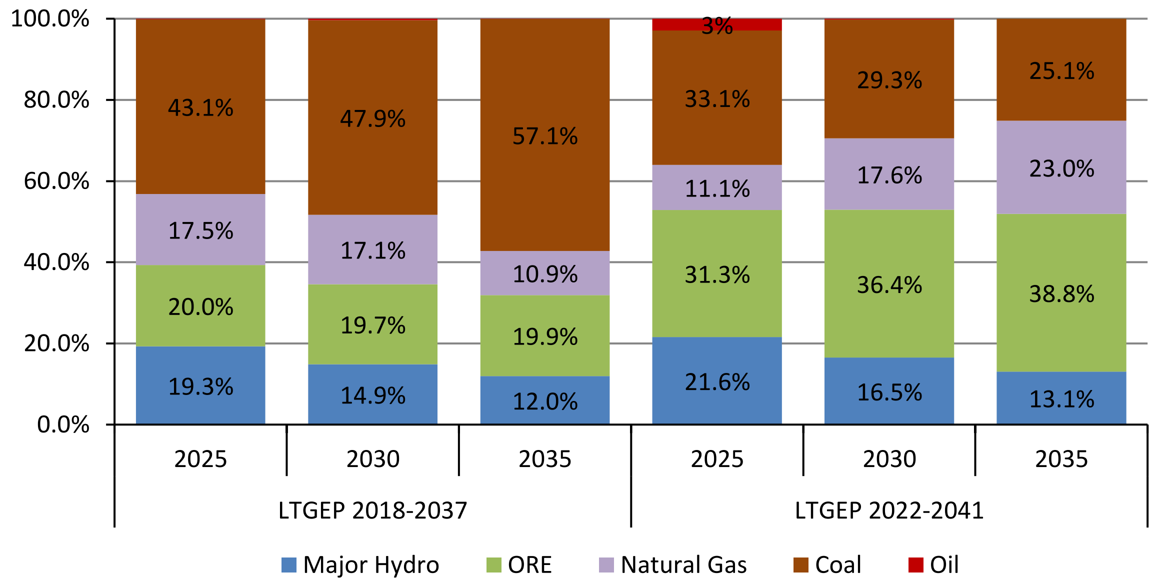

Figure 14.6 – Comparison of Energy Share between LTGEP 2018-2037 & LTGEP 2022-2041

14.7 Environmental Emissions

CO_2 emissions are lower in LTGEP 2022-2041 than the CO_2 emissions level in the LTGEP 2018-2037. An increasing trend of PM emissions is observed in LTGEP 2022-2041 due to the anticipated higher implementation of biomass plants. Also, SO_2 emissions have increased in the initial years, due to dependency on thermal oil plants caused by non-implementation of natural gas projects on time. However, increase of NO_x could be observed with adoption of higher share of reciprocating engines to allow operational flexibility to the system. This could be reduced with adoption other mitigation technologies such as selective catalytic reduction (SCR). Comparisons of these environmental emissions are shown in Figure 14.7 and Figure 14.8.

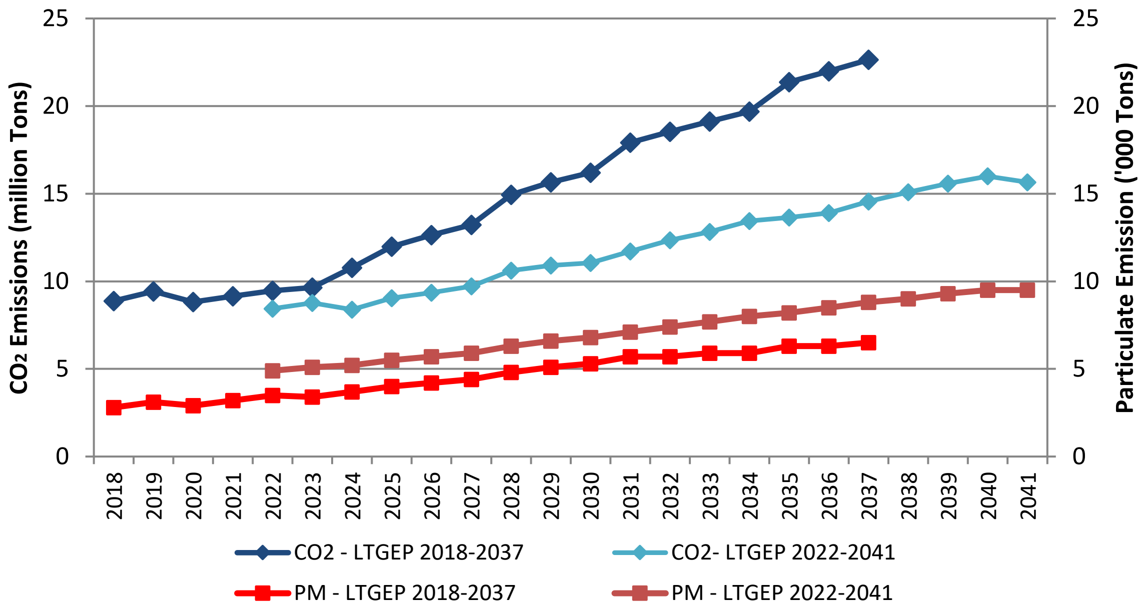

Figure 14.7 - CO_2 and PM Emissions between LTGEP 2018-2037 & LTGEP 2022-2041

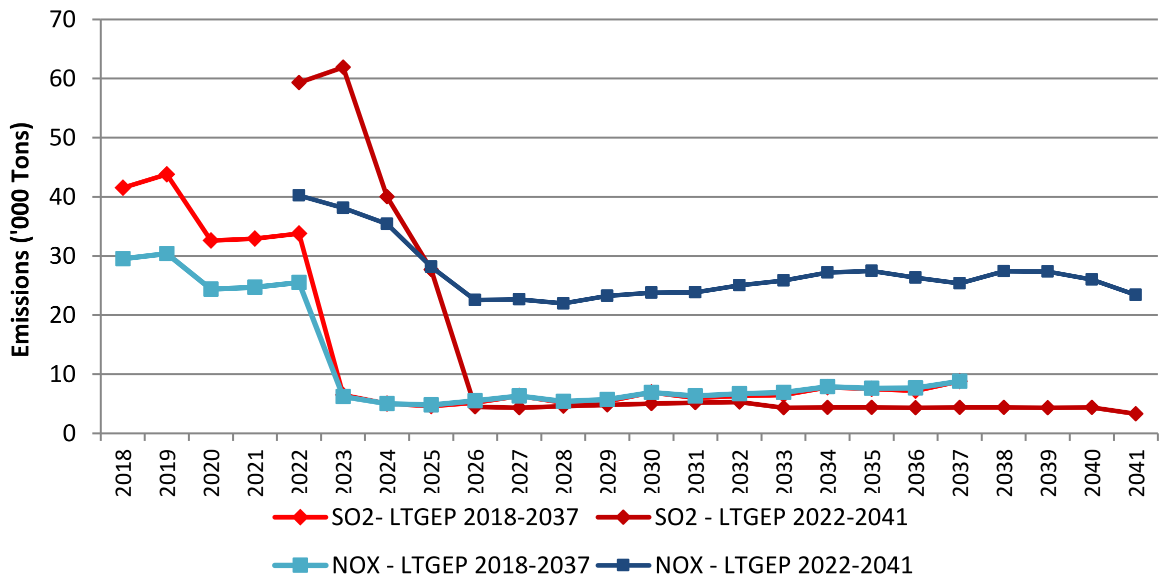

Figure 14.8 – SO_2 and NO_x Emissions between LTGEP 2018-2037 & LTGEP 2022-2041

14.8 Overall Comparison

The overall comparison of generation expansions proposed by plans for last 20 years and actual implementation is shown in Annex 14.1

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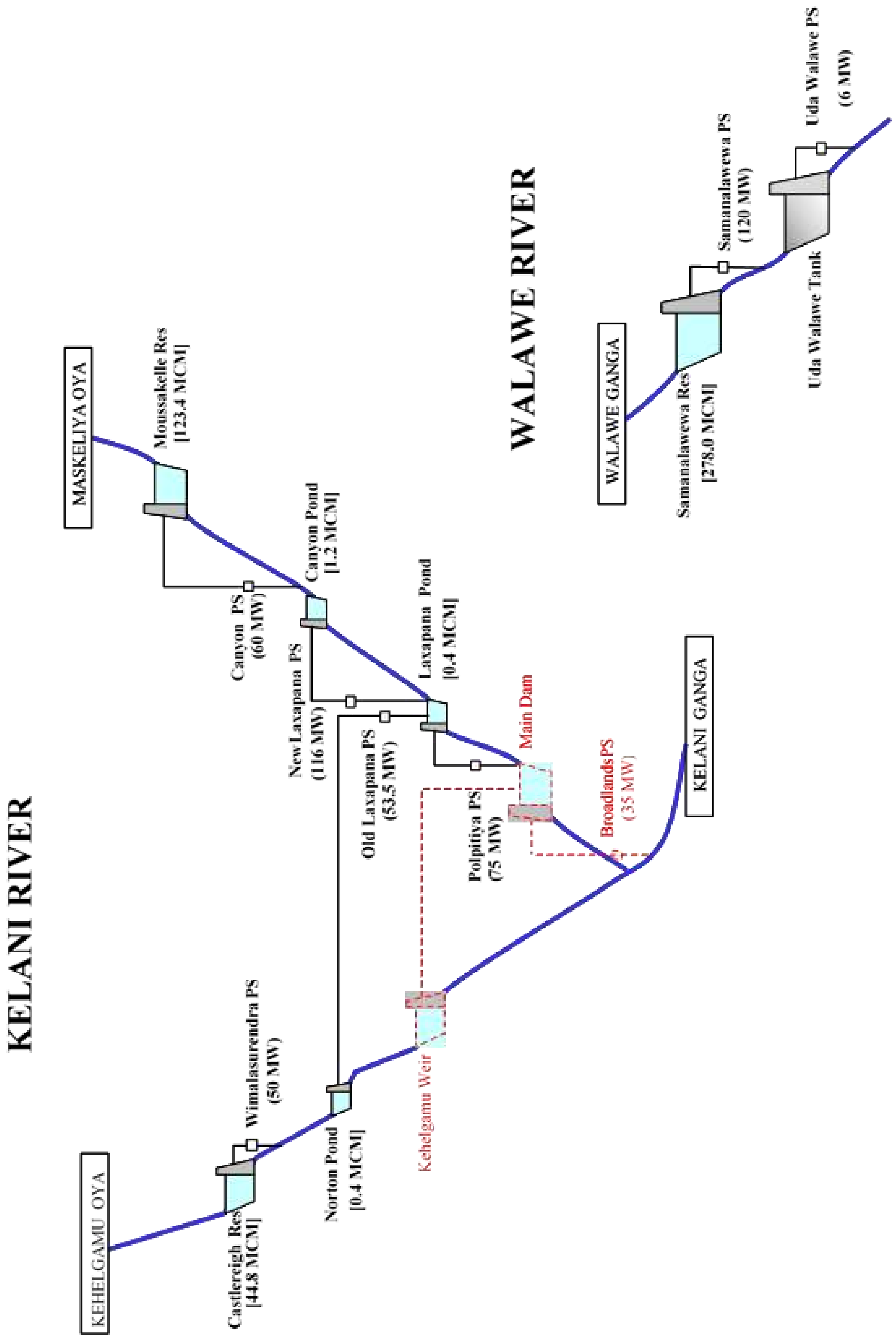
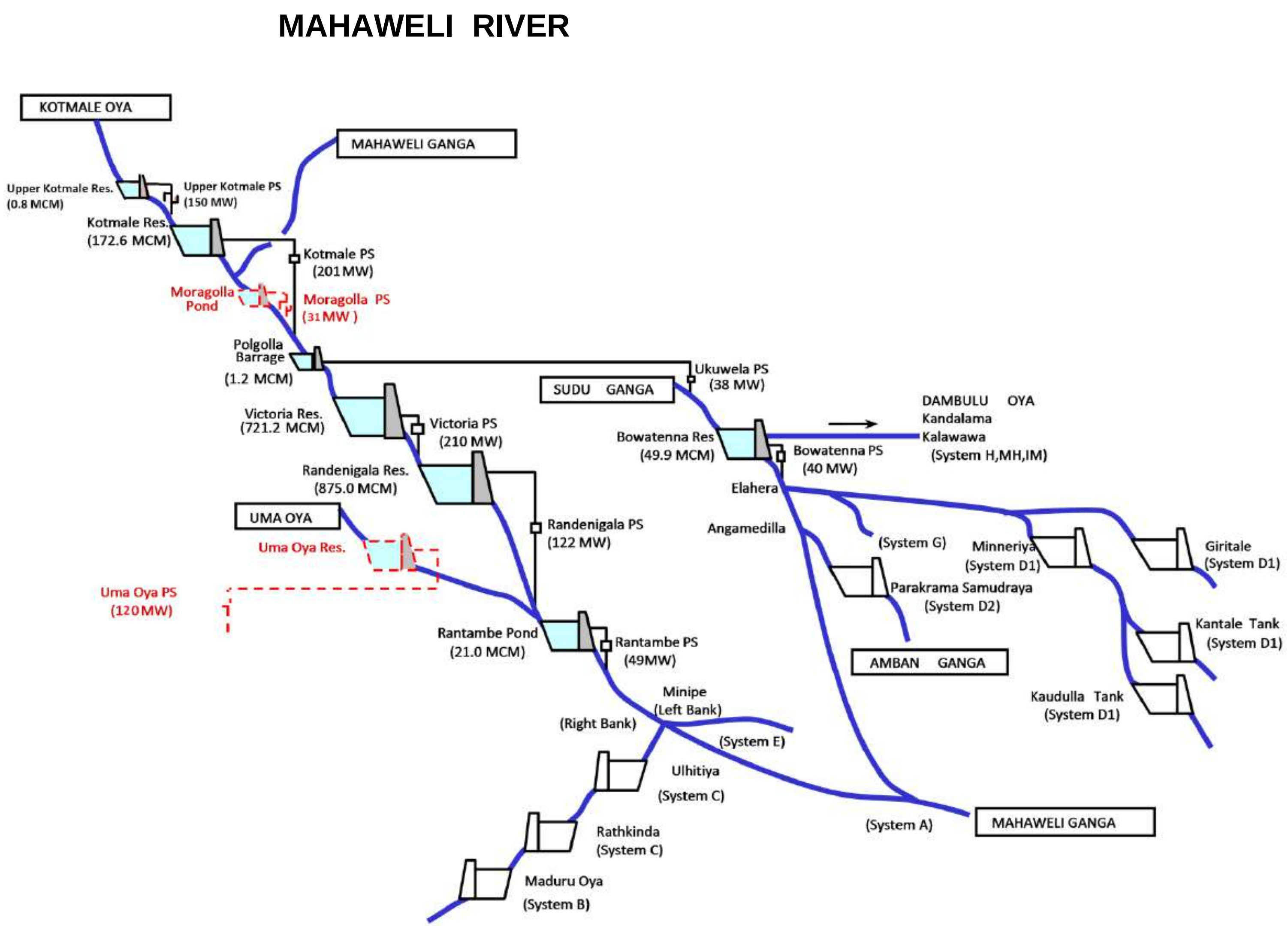
Reservoir Systems in Mahaweli, Kelani and Walawe River Basins

A2.1.1 Reservoir Systems in Kelani and Walawe River Basins



A2.1.2 Reservoir System in Mahaweli River Basin



Annex 3.1
Scenarios and Sensitivities of the Demand Forecast

Table A3.1 – High Demand Forecast

Year	Demand (GWh)	Net Losses* (%)	Generation (GWh)	Peak (MW)
2022	17194	8.03	18696	3047
2023	18204	7.97	19780	3205
2024	19273	7.90	20926	3372
2025	20405	7.83	22139	3548
2026**	21604	7.77	23423	3734
2027	22872	7.70	24781	3953
2028	24077	7.63	26067	4178
2029	25375	7.57	27452	4401
2030	26789	7.50	28961	4644
2031	28281	7.45	30557	4901
2032	29860	7.40	32246	5174
2033	31526	7.35	34027	5461
2034	33270	7.30	35890	5761
2035	35123	7.25	37868	6080
2036	37028	7.25	39923	6412
2037	38989	7.25	42036	6753
2038	40990	7.25	44194	7101
2039	43044	7.25	46408	7458
2040	45160	7.25	48690	7826
2041	47317	7.25	51016	8202
2042	49526	7.25	53397	8586
2043	51795	7.25	55843	8981
2044	54130	7.25	58361	9388
2045	56536	7.25	60956	9807
2046	59020	7.25	63633	10239
5 Year Average Growth	5.9%		5.8%	5.2%
10 Year Average Growth	5.7%		5.6%	5.4%
20 Year Average Growth	5.5%		5.4%	5.3%
25 Year Average Growth	5.3%		5.2%	5.2%

*****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* (%)	Generation (GWh)	Peak (MW)
2022	16333	8.03	17760	2905
2023	17232	7.97	18723	3055
2024	18183	7.90	19742	3181
2025	19186	7.83	20817	3351
2026	20244	7.77	21949	3530
2027	21362	7.70	23144	3718
2028	22540	7.63	24403	3917
2029	23684	7.57	25623	4109
2030**	24924	7.50	26945	4316
2031	26217	7.45	28328	4539
2032	27573	7.40	29776	4773
2033	28989	7.35	31288	5018
2034	30455	7.30	32853	5271
2035	32003	7.25	34504	5538
2036	33577	7.25	36201	5812
2037	35177	7.25	37926	6091
2038	36790	7.25	39666	6373
2039	38427	7.25	41430	6659
2040	40093	7.25	43227	6950
2041	41771	7.25	45036	7243
2042	43469	7.25	46867	7539
2043	45194	7.25	48726	7840
2044	46948	7.25	50618	8147
2045	48736	7.25	52546	8460
2046	50562	7.25	54514	8779
5 Year Average Growth	5.5%		5.4%	5.0%
10 Year Average Growth	5.4%		5.3%	5.1%
20 Year Average Growth	5.1%		5.0%	4.9%
25 Year Average Growth	4.8%		4.8%	4.7%

*****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* (%)	Generation (GWh)	Peak (MW)
2022	17929	8.03	19495	3178
2023	18953	7.97	20594	3337
2024	20035	7.90	21754	3505
2025	21179	7.83	22979	3682
2026	22389	7.77	24274	3870
2027	23667	7.70	25642	4091
2028	25019	7.63	27086	4341
2029	26447	7.57	28612	4587
2030	27958	7.50	30225	4847
2031	29554	7.45	31933	5122
2032	31242	7.40	33739	5413
2033	33026	7.35	35646	5721
2034	34912	7.30	37661	6046
2035	36905	7.25	39790	6389
2036	39013	7.25	42062	6755
2037	41241	7.25	44464	7143
2038	43596	7.25	47003	7552
2039	46085	7.25	49688	7985
2040	48717	7.25	52525	8443
2041	51499	7.25	55524	8927
2042	54440	7.25	58695	9438
2043	57548	7.25	62047	9979
2044	60835	7.25	65590	10551
2045	64308	7.25	69335	11155
2046	67981	7.25	73295	11794
5 Year Average Growth	5.7%		5.6%	5.1%
10 Year Average Growth	5.7%		5.6%	5.4%
20 Year Average Growth	5.7%		5.7%	5.6%
25 Year Average Growth	5.7%		5.7%	5.6%

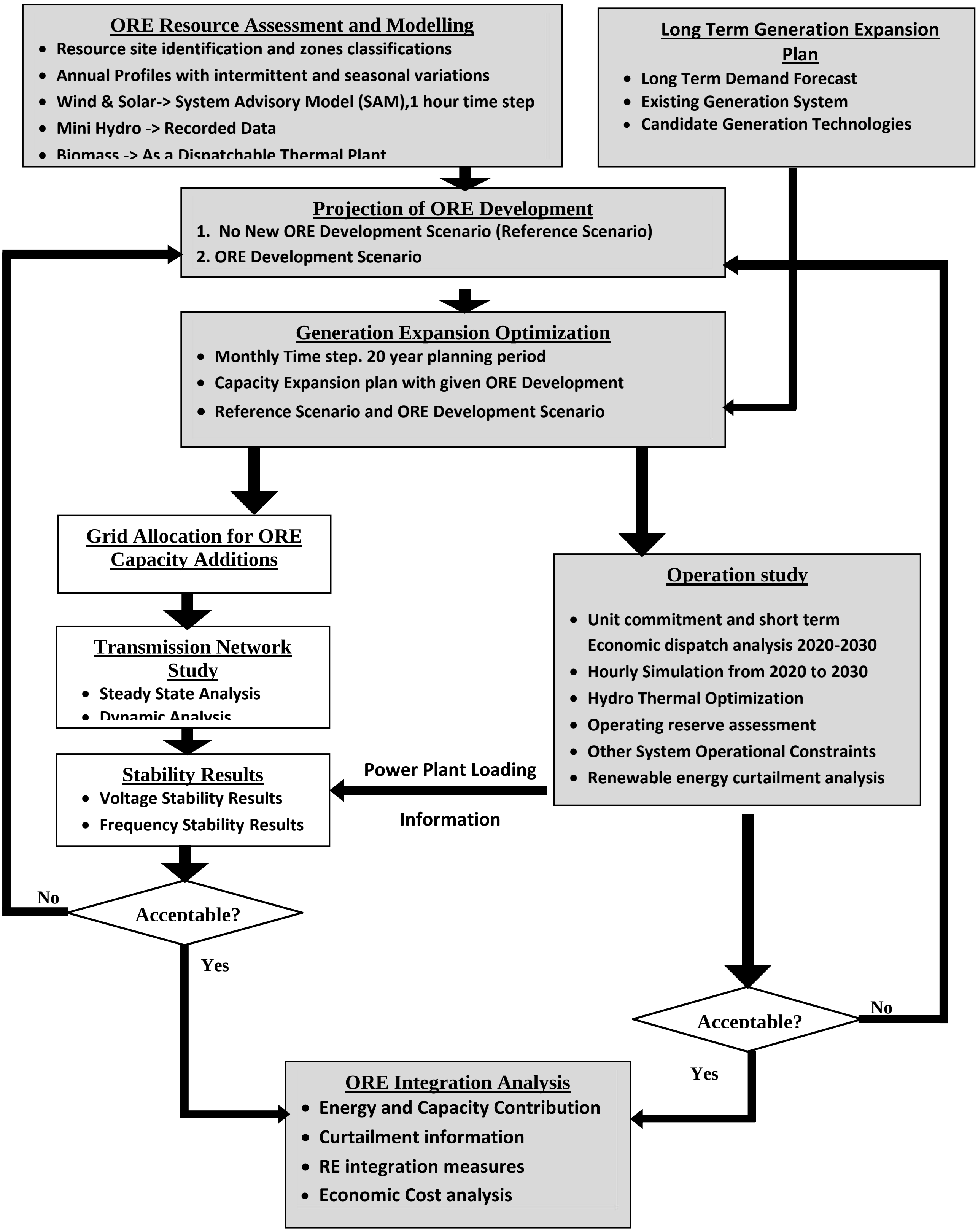
*****Net losses include losses at the Transmission & Distribution levels and any non-technical losses, Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depend on the hydro thermal generation mix of the future.

Table A3.4 – MAED Load Projection

Year	Demand (GWh)	Net Losses* (%)	Generation (GWh)	Peak (MW)
2022	16902	8.42	18455	3067
2023	17811	8.28	19419	3213
2024	18768	8.15	20433	3365
2025	19777	8.01	21501	3525
2026	20887	7.96	22694	3711
2027	22059	7.91	23954	3907
2028	23296	7.86	25284	4114
2029	24603	7.81	26688	4331
2030	25983	7.76	28169	4560
2031	27331	7.75	29628	4803
2032	28750	7.74	31162	5059
2033	30241	7.73	32776	5329
2034	31811	7.72	34474	5613
2035	33461	7.72	36259	5912
2036	34983	7.71	37904	6163
2037	36574	7.70	39624	6424
2038	38237	7.69	41423	6697
2039	39975	7.68	43302	6981
2040	41793	7.68	45267	7277
2041	43405	7.62	46987	7559
2042	45080	7.57	48771	7852
2043	46819	7.52	50623	8156
2044	48625	7.46	52546	8473
2045	50501	7.41	54542	8801
2046	52449	7.36	56613	9142
5 Year Average Growth	5.4%		5.3%	4.9%
10 Year Average Growth	5.5%		5.4%	5.1%
20 Year Average Growth	5.1%		5.0%	4.9%
25 Year Average Growth	4.8%		4.8%	4.7%

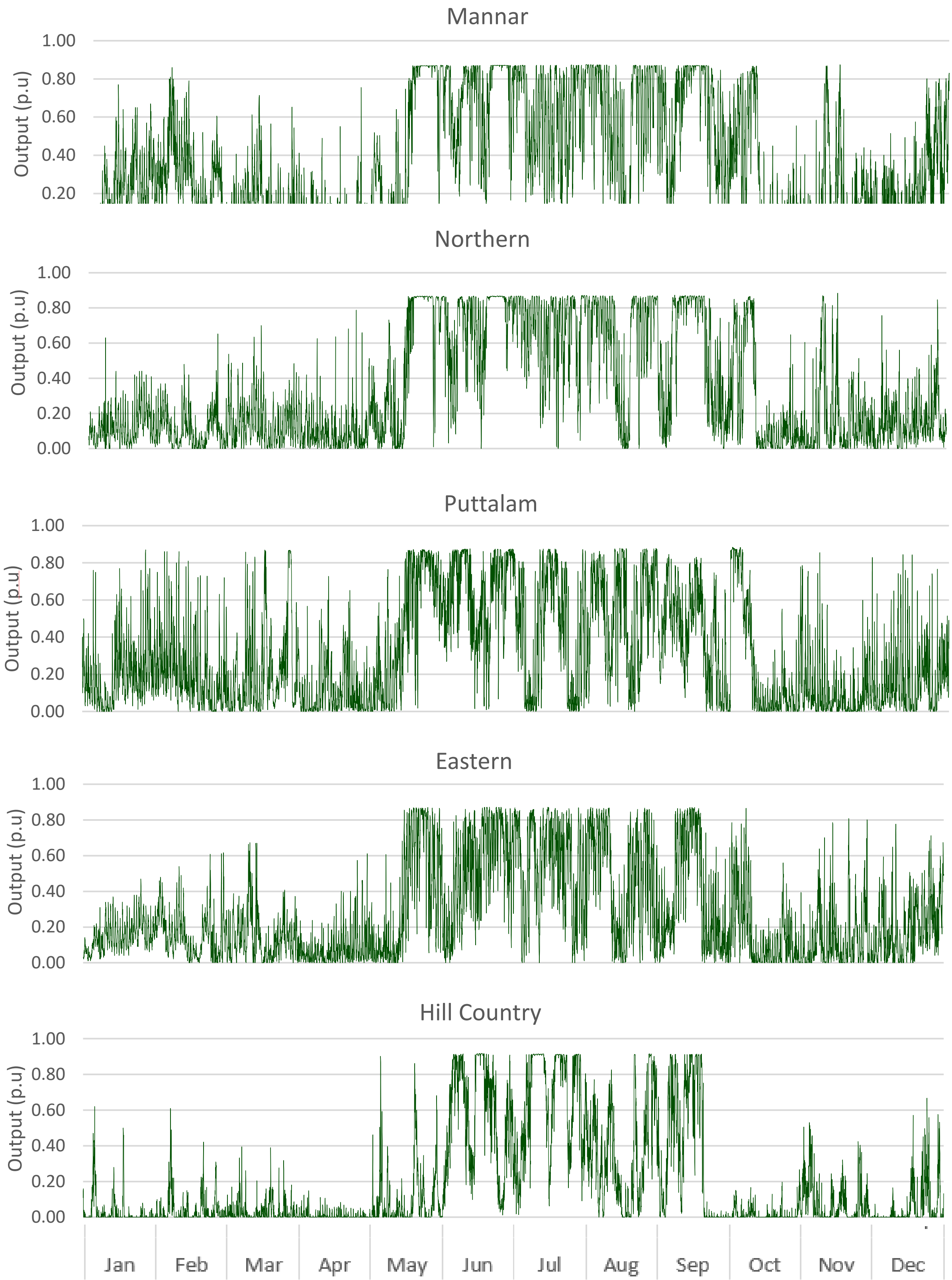
*****Net losses include losses at the Transmission & Distribution levels and any non-technical losses, Generation (Including auxiliary consumption) losses are excluded. This forecast will vary depend on the hydro thermal generation mix of the future.

Methodology of the Renewable Energy Integration Study 2020-2030



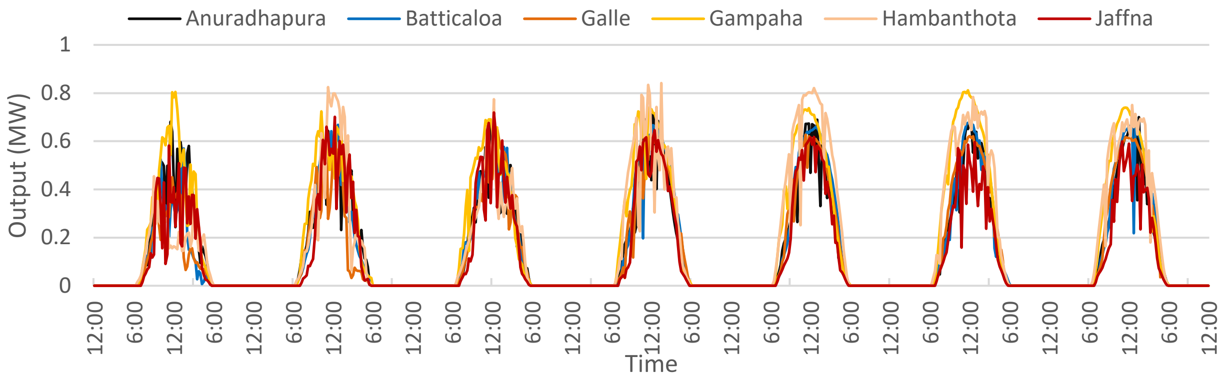
A5.1 Outline of the study methodology of renewable energy integration study 2020-2030

Modelled Wind Turbine Characteristics and Power Plant Output

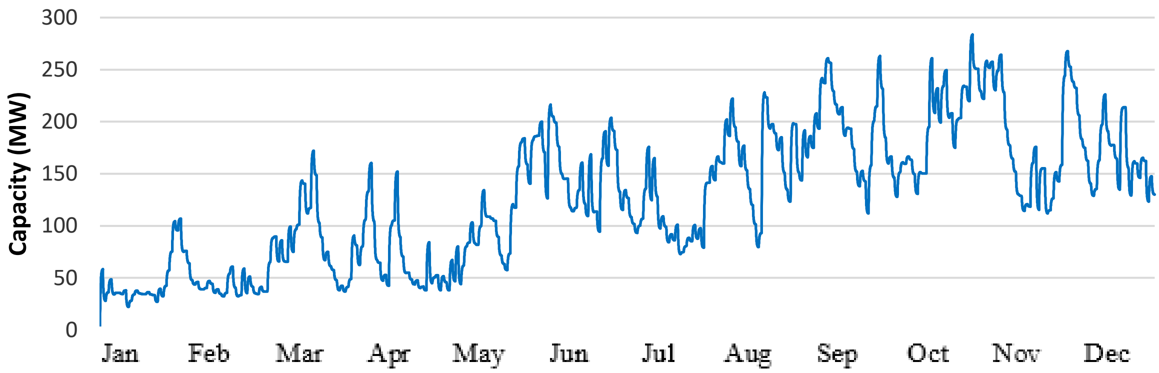


A5.2 Annual variation of wind power production in five wind regimes (Based on 10 min Actual data)

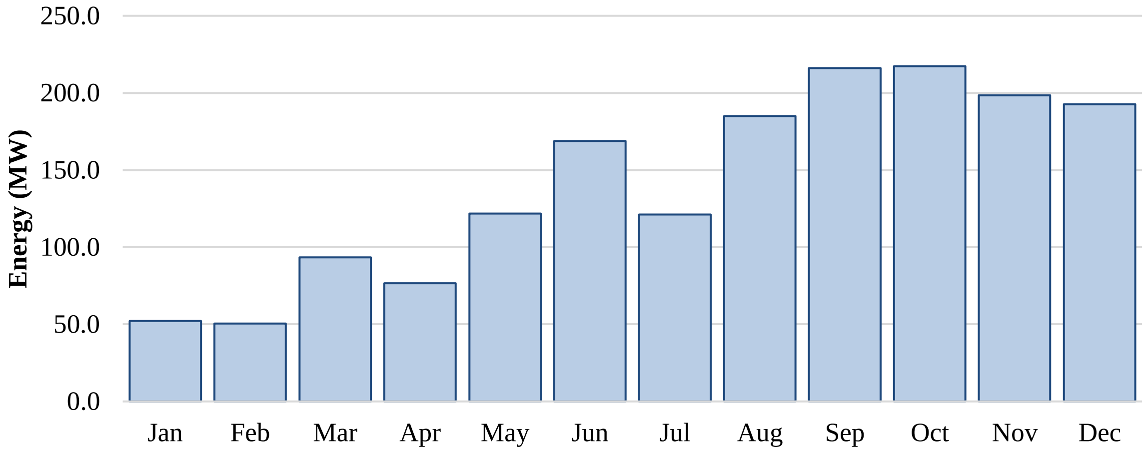
Solar and Mini-Hydro Plant Production Profiles



A5.3 Extract of Solar PV Production based on actual measurement data (15 minute)



A5.4 Modelled production profile of Mini-hydro resource based on 2017 data



A5.5 Monthly energy production of Mini-hydro resource based on 2017 data

Annex 5.4

Cost Details Other Renewable Energy

The Capital Costs of ORE technologies are considered as follows in the generation expansion studies:

- Solar: 900 USD/kW
- Wind: 1400 USD/kW
- Biomass: 1782 USD/kW
- Mini Hydro: 1749 USD/kW

The O & M Costs of these technologies are considered as a percentage of the capital costs and the percentages are as follows:

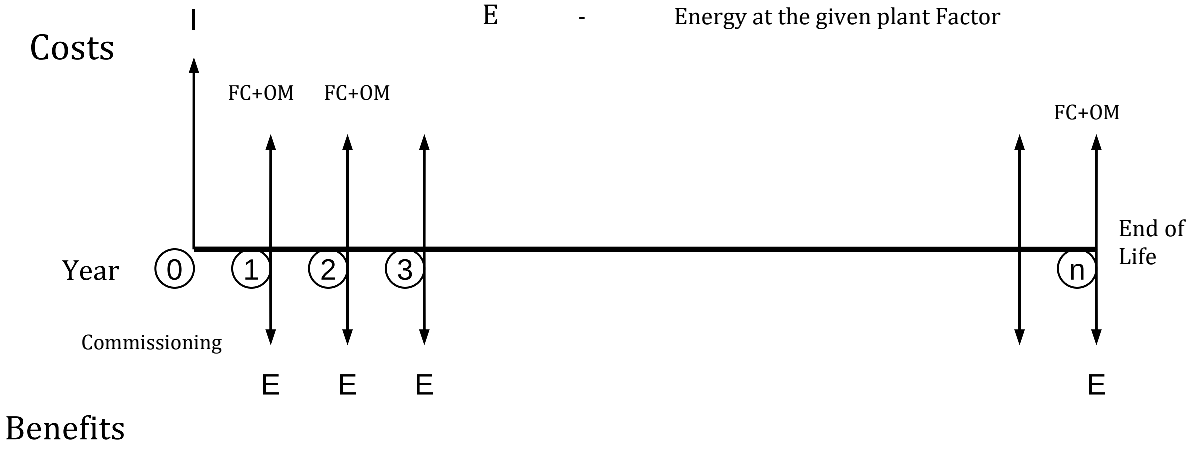
Fixed O&M Cost	%
Mini Hydro	3
Wind	1.5
Solar	0.9
Biomass	4

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 planning software's used for the expansion studies.

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



Investment cost assumed as an overnight cost 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

Annex 8.1

Screening of Generation Options

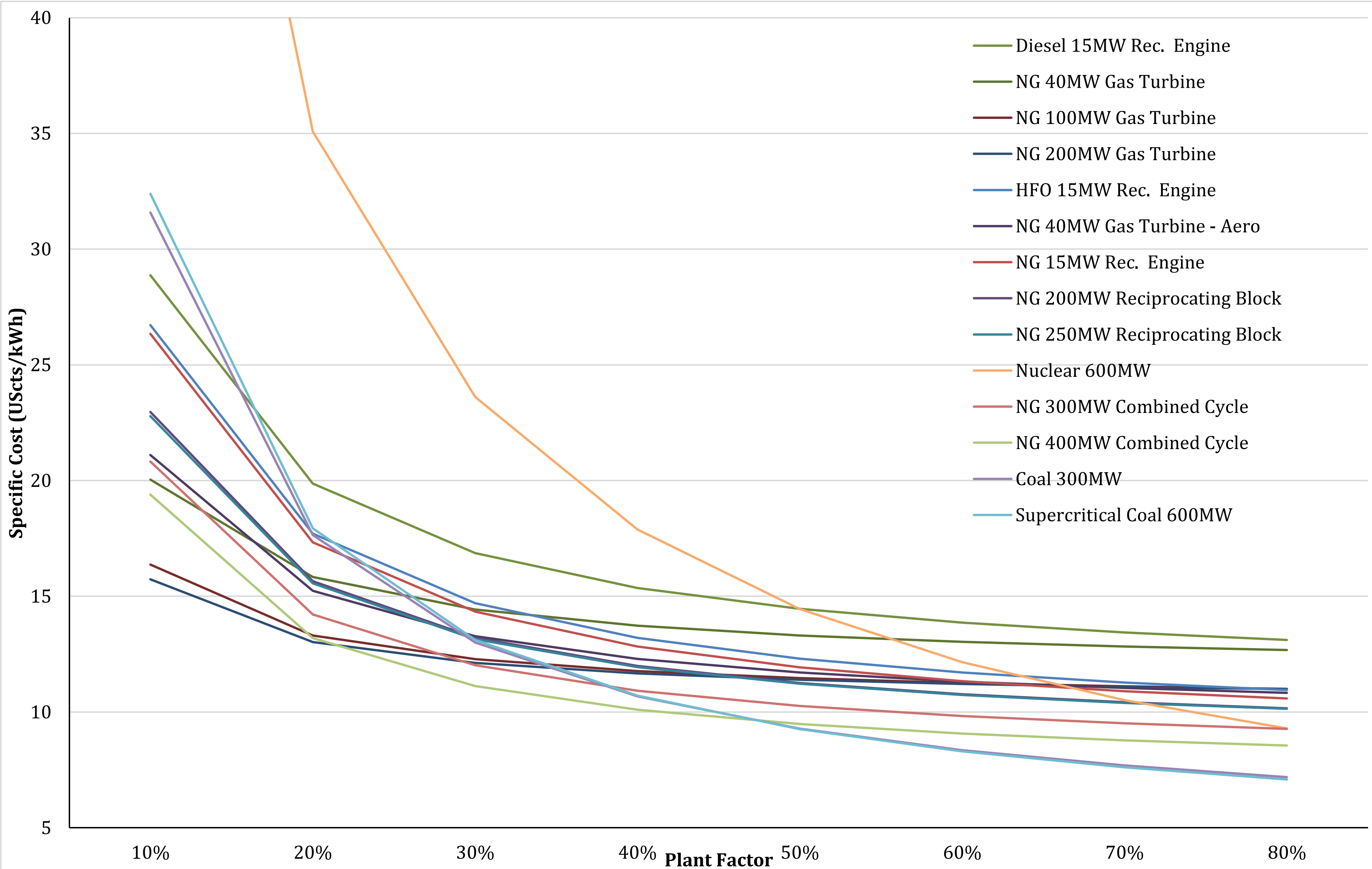
The screening curves were developed for the selected thermal generation options and the specific cost calculated for these options and the resultant screening curves are mentioned below.

A8.1 Specific Cost of Screened Candidate Thermal Plants in US cents/kWh (in LKR/kWh)

Power Plant	Plant Factor							
	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8
15 MW NG IC Engine	26.34 (49.30)	17.33 (32.44)	14.33 (26.83)	12.83 (24.02	11.93 (22.33)	11.33 (21.21)	10.90 (20.40)	10.58 (19.80)
15 MW FO IC Engine	26.71 (50.00)	17.71 (33.14)	14.70 (27.52)	13.20 (24.71)	12.30 (23.03)	11.70 (21.90)	11.27 (21.10)	10.95 (20.50)
15 MW Diesel IC Engine	28.87 (54.04)	19.86 (37.18)	16.86 (31.56)	15.36 (28.75)	14.46 (27.07)	13.86 (25.94)	13.43 (25.14)	13.11 (24.54)
200 MW NG IC Engine	22.96 (42.98)	15.65 (29.28)	13.21 (24.72)	11.99 (22.44)	11.26 (21.07)	10.77 (20.15)	10.42 (19.50)	10.16 (19.01)
250 MW NG IC Engine	22.78 (42.64)	15.56 (29.11)	13.15 (24.61)	11.94 (22.35)	11.22 (21.00)	10.74 (20.10)	10.39 (19.45)	10.14 (18.97)
40 MW NG Gas Turbine	20.04 (37.52)	15.83 (29.64)	14.43 (27.01)	13.73 (25.70)	13.31 (24.91)	13.03 (24.38)	12.83 (24.01)	12.68 (23.73)
40 MW NG Gas Turbine (Aero Derivative)	21.11 (39.50)	15.23 (28.51)	13.27 (24.84)	12.29 (23.01)	11.71 (21.91)	11.31 (21.18)	11.04 (20.65)	10.83 (20.26)
100 MW NG Gas Turbine	16.37 (30.64)	13.30 (24.90)	12.28 (22.98)	11.77 (22.02)	11.46 (21.45)	11.25 (21.07)	11.11 (20.79)	11.00 (20.59)
200 MW NG Gas Turbine	15.73 (29.45)	13.02 (24.37)	12.12 (22.68)	11.66 (21.83)	11.39 (21.32)	11.21 (20.99)	11.08 (20.74)	10.99 (20.56)
300 MW NG Combined Cycle	20.81 (38.96)	14.22 (26.61)	12.02 (22.50)	10.92 (20.44)	10.26 (19.20)	9.82 (18.38)	9.51 (17.79)	9.27 (17.35)
400 MW NG Combined Cycle	19.39 (36.30)	13.20 (24.70)	11.12 (20.81)	10.10 (18.90)	9.48 (17.74)	9.07 (16.97)	8.77 (16.41)	8.55 (16.00)
300 MW High Efficient Coal Plant	31.58 (59.11)	17.64 (33.02)	13.00 (24.33)	10.67 (19.98)	9.28 (17.37)	8.35 (15.63)	7.69 (14.39)	7.19 (13.46)
600 MW Super Critical Coal Plant	32.39 (60.63)	17.93 (33.56)	13.11 (24.54)	10.70 (20.03)	9.26 (17.33)	8.29 (15.52)	7.61 (14.24)	7.09 (13.27)
600 MW Nuclear Power Plant	69.47 (130.02)	35.08 (65.65)	23.61 (44.20)	17.88 (33.47)	14.44 (27.03)	12.15 (22.74)	10.51 (19.68)	9.28 (17.38)

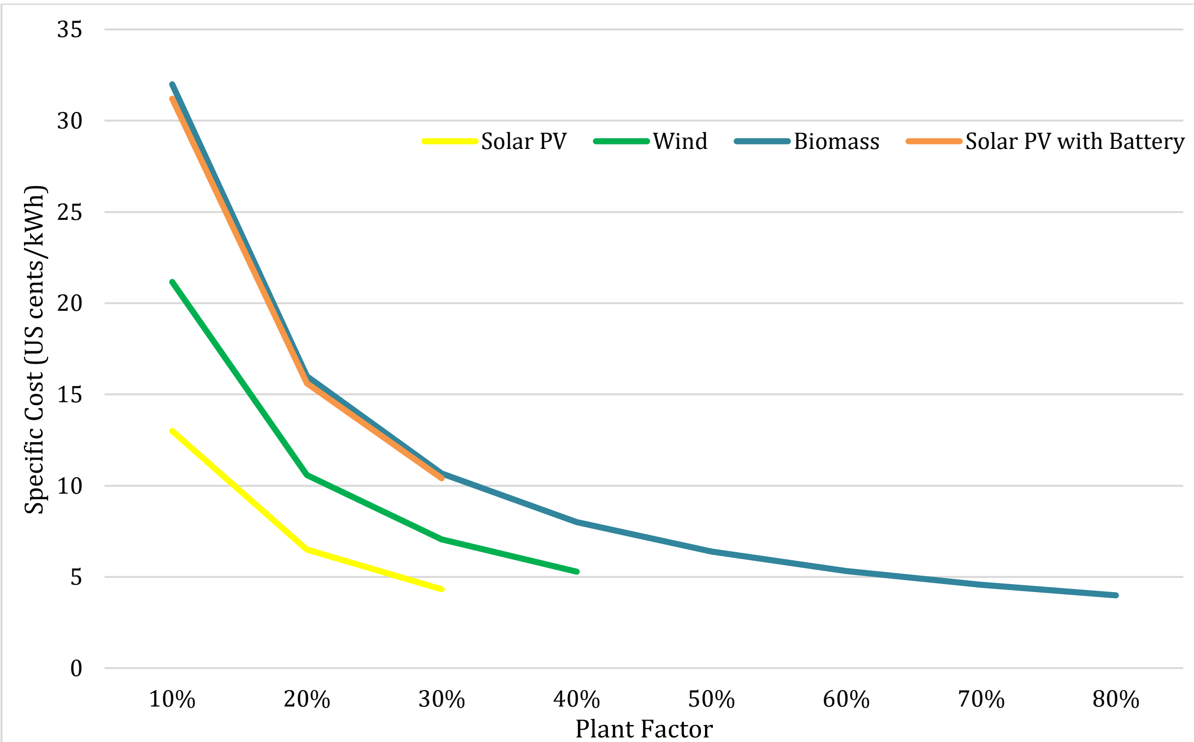
Note:1 US$ = LKR 187.17

A8.1.1 Screening Curves of the Generation Options at 10% Discount Rate



The screening curves were developed for the following renewable energy options also.

1. Biomass 10 MW
2. Wind 10 MW
3. Solar PV 10 MW
4. Solar PV 10 MW with 10MW/20MWh Battery



Capacity Balance for Base Case Plan of LTGEP 2022-2041

Plant Name	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Hydro																				
Major Hydro	1538	1538	1568	1568	1568	1568	1568	1568	1568	1568	1568	1568	1568	1568	1568	1568	1568	1568	1568	1568
PSPP Generation	0	0	0	0	0	0	0	200	400	600	600	600	600	600	600	600	600	600	600	600
Sub Total	1,538	1,538	1,568	1,568	1,568	1,568	1,568	1,768	1,968	2,168	2,168	2,168	2,168	2,168	2,168	2,168	2,168	2,168	2,168	2,168
Thermal Existing and Committed																				
Small Gas Turbines	68	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Sapugaskanda	68	68	68	68	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesl Ext.Sapugaskanda	72	72	72	72	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Turbine No7	115	115	115	115	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kelanitissa Combined Cycle	161	161	161	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sojitz Combined Cycle	163	163	163	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kerawalapitiya CCY	270	270	270	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakvijaya Coal	810	810	810	810	810	810	810	810	810	810	810	810	810	810	810	810	810	810	810	540
Uthurujanani	27	27	27	27	27	27	27	27	27	27	27	0	0	0	0	0	0	0	0	0
CEB Barge Power	62	62	62	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short Term Supplimentary Power Plants	250	150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NG Converted Sojitz Combined Cycle	0	0	163	163	163	163	163	163	163	163	163	0	0	0	0	0	0	0	0	0
NG Converted Kelanitissa Combined Cycle	0	0	161	161	161	161	161	161	161	161	161	0	0	0	0	0	0	0	0	0
NG Converted Kerawalapitiya CCY	0	0	270	270	270	270	270	270	270	270	270	270	270	0	0	0	0	0	0	0
Sub Total	2,066	1,898	2,342	1,685	1,430	1,430	1,430	1,430	1,430	1,430	1,430	1,080	1,080	810	810	810	810	810	810	540
New Thermal Plants																				
New Coal	0	0	0	270	270	270	540	540	540	540	540	540	540	540	540	540	540	540	540	540
Kelanitissa New Gas Turbines	0	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
New Gas Engines	0	0	0	0	256	256	256	256	256	256	256	464	672	672	672	672	672	672	928	928
New Gas Turbines	0	0	0	0	0	0	0	0	0	0	298	298	298	490	788	788	895	895	895	1,001
New NG Combined Cyle	0	192	542	700	700	1,119	1,119	1,119	1,119	1,119	1,119	1,538	1,538	1,957	1,957	2,376	2,376	2,795	2,795	3,214
Sub Total	0	327	677	1,105	1,361	1,780	2,050	2,050	2,050	2,050	2,348	2,975	3,183	3,794	4,092	4,511	4,618	5,037	5,293	5,818
Other Renewable Energy																				
Mini Hydro	464	484	494	504	514	524	534	544	554	559	564	569	574	579	584	589	594	599	604	609
Biomass	81	85	90	95	100	105	110	115	120	125	130	135	140	145	150	155	160	165	170	175
Wind	268	303	343	443	543	663	783	883	1,013	1,113	1,213	1,313	1,413	1,513	1,613	1,713	1,813	1,913	2,013	2,113
Solar	1,039	1,299	1,569	1,829	2,024	2,184	2,354	2,514	2,684	2,874	3,064	3,244	3,444	3,684	3,934	4,174	4,414	4,654	4,894	5,134
Sub Total	1,852	2,171	2,496	2,871	3,181	3,476	3,781	4,056	4,371	4,671	4,971	5,261	5,571	5,921	6,281	6,631	6,981	7,331	7,681	8,031

Installed Capacity	**5,455**	**5,933**	**7,082**	**7,229**	**7,540**	**8,254**	**8,829**	**9,304**	**9,819**	**10,319**	**10,917**	**11,484**	**12,002**	**12,692**	**13,351**	**14,120**	**14,576**	**15,345**	**15,951**	**16,556**
System Demand	**2,967**	**3,117**	**3,276**	**3,452**	**3,633**	**3,848**	**4,065**	**4,279**	**4,509**	**4,751**	**4,992**	**5,245**	**5,509**	**5,789**	**6,075**	**6,372**	**6,670**	**6,974**	**7,286**	**7,601**

Notes : All the Capacities are in MW (net)
Maintenance and forced outages are not considered.

Energy Balance of the Base Case for LTGEP 2022-2041

Plant Name	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Hydro																				
Major Hydro	4489	4456	4582	4650	4528	4282	4687	4902	4649	4645	4548	4334	4418	4727	4679	4550	4573	4333	4760	4619
PSPP Generation	0	0	0	0	0	0	0	59	109	88	90	164	88	114	100	125	91	158	214	89
Sub Total	4,489	4,456	4,582	4,650	4,528	4,282	4,687	4,961	4,759	4,733	4,638	4,498	4,506	4,842	4,778	4,675	4,665	4,491	4,974	4,708
Thermal Existing and Committed																				
Small Gas Turbines	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesel Sapugaskanda	366	364	309	222	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Diesl Ext.Sapugaskanda	453	454	431	365	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Turbine No7	76	14	4	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kelanitissa Combined Cycle	484	492	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sojitz Combined Cycle	753	841	51	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kerawalapitiya CCY	842	1,065	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakvijaya Coal	5,432	5,568	5,559	5,223	5,325	5,362	5,187	5,344	5,216	5,084	5,358	5,418	5,241	5,385	5,595	5,242	5,360	5,418	5,235	3,644
Uthurujanani	153	138	97	41	52	45	24	30	64	65	61	0	0	0	0	0	0	0	0	0
CEB Barge Power	419	420	366	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short Term Supplimentary Power Plants	165	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NG Converted Sojitz Combined Cycle	0	0	320	96	187	135	52	114	269	245	275	0	0	0	0	0	0	0	0	0
NG Converted Kelanitissa Combined Cycle	0	0	379	104	215	151	67	122	237	258	268	0	0	0	0	0	0	0	0	0
NG Converted Kerawalapitiya CCY	0	0	341	48	152	169	22	77	314	193	212	370	252	0	0	0	0	0	0	0
Sub Total	9,147	9,364	7,888	6,102	5,931	5,862	5,352	5,687	6,101	5,845	6,174	5,788	5,492	5,385	5,595	5,242	5,360	5,418	5,235	3,644
New Thermal Plants																				
New Coal	0	0	0	1,915	1,824	1,703	3,800	3,596	3,034	3,778	3,848	3,451	4,040	3,697	3,102	4,042	3,718	3,456	4,048	3,808
Kelanitissa New Gas Turbines	0	25	2	0	2	4	0	0	3	0	3	8	1	1	9	0	0	11	1	1
New Gas Engines	0	0	0	0	256	235	106	215	185	186	178	757	1,267	1,132	425	241	737	533	72	618
New Gas Turbines	0	0	0	0	0	0	0	0	0	0	100	239	94	232	714	256	400	408	386	506
New NG Combined Cyle	0	169	1,980	2,145	2,811	3,870	2,537	2,811	3,955	4,284	4,658	5,790	5,892	6,929	8,534	9,738	10,246	11,951	12,757	15,151
Sub Total	0	194	1,983	4,060	4,892	5,812	6,443	6,622	7,176	8,248	8,787	10,245	11,293	11,991	12,785	14,278	15,102	16,360	17,264	20,084
Other Renewable Energy																				
Mini Hydro	1,456	1,519	1,551	1,582	1,613	1,645	1,676	1,707	1,739	1,770	1,802	1,833	1,864	1,896	1,927	1,959	1,990	2,021	2,053	2,084
Biomass	592	627	671	715	759	802	846	890	934	978	1,021	1,065	1,109	1,153	1,197	1,240	1,284	1,328	1,372	1,416
Wind	798	897	1,021	1,343	1,665	2,023	2,381	2,656	3,044	3,323	3,621	3,943	4,265	4,586	4,908	5,229	5,551	5,861	6,159	6,458
Solar	1,735	2,195	2,651	3,104	3,434	3,726	4,017	4,294	4,560	4,898	5,236	5,561	5,943	6,381	6,798	7,236	7,695	8,145	8,584	9,023
Sub Total	4,581	5,239	5,893	6,743	7,471	8,196	8,920	9,547	10,276	10,969	11,680	12,402	13,181	14,015	14,829	15,664	16,520	17,356	18,168	18,980

Total Generation	**18,218**	**19,253**	**20,346**	**21,556**	**22,822**	**24,152**	**25,404**	**26,817**	**28,312**	**29,795**	**31,279**	**32,933**	**34,473**	**36,233**	**37,988**	**39,860**	**41,647**	**43,625**	**45,641**	**47,416**
System Demand	**18,220**	**19,254**	**20,346**	**21,556**	**22,822**	**24,159**	**25,404**	**26,727**	**28,160**	**29,659**	**31,151**	**32,716**	**34,342**	**36,069**	**37,852**	**39,675**	**41,521**	**43,405**	**45,334**	**47,287**
PSPP	0	0	0	0	0	0	0	89	154	136	128	231	131	164	135	185	126	228	307	129
Unserved Energy	**2**	**1**	**0**	**0**	**0**	**7**	**0**	**0**	**1**	**0**	**0**	**13**	**0**	**0**	**0**	**0**	**0**	**8**	**0**	**0**

Notes - Numbers may not add exactly due to rounding off and net generation figures have slight deviation from demand forecast figures as energy balance is developed based on simulation results.
Aggregation of hydro dispatches for individual plant is not possible owing to integrated operation and dispatch of hydro energy
All energy figures are shown for weighted average hydrological condition in GWh.

Annex 8.4

Annual Energy Generation and Plant Factors

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2022	Major Hydro	1538 MW	3162	4489	5045			
	ORE	1852 MW	4581	4581	4581			
	Kelanitissa Small GTs	4 x 17 MW	20	4	1	3%	1%	0%
	Sapugaskanda A	4 x 17 MW	400	366	332	67%	61%	56%
	Sapugaskanda B	8 x 9 MW	472	453	454	75%	72%	72%
	Kelanitissa GT7	1 x 115 MW	133	76	64	13%	8%	6%
	Kelanitissa Combined Cycle	1 x 161 MW	619	484	438	44%	34%	31%
	Sojitz Combined Cycle	1 x 163 MW	1044	753	579	73%	53%	41%
	West Coast Combined Cycle	1 x 270 MW	1277	842	714	54%	36%	30%
	Lakvijaya Unit 1	300 MW	1451	1444	1447	61%	61%	61%
	Lakvijaya Unit 2	300 MW	1910	1910	1910	81%	81%	81%
	Lakvijaya Unit 3	300 MW	2081	2078	2081	88%	88%	88%
	Uthuru Janani	3 x 9 MW	179	153	125	76%	65%	54%
	Barge Power Plant	4 x 16 MW	442	419	420	81%	77%	77%
	Short Term Supplimentary Power Plants	250 MW	447	165	26	20%	8%	1%
	Total Renewable Generation		**7743**	**9071**	**9627**			
	Total Thermal Generation		**10475**	**9147**	**8592**			
	Total Generation		**18218**	**18218**	**18219**			
2023	Major Hydro	1538 MW	3575	4456	5542			
	ORE	2171 MW	5239	5239	5239			
	Sapugaskanda A	4 x 17 MW	404	364	308	68%	61%	52%
	Sapugaskanda B	8 x 9 MW	472	454	413	75%	72%	66%
	Kelanitissa GT7	1 x 115 MW	1	14	3	0%	1%	0%
	Kelanitissa Combined Cycle	1 x 161 MW	580	492	422	41%	35%	30%
	Sojitz Combined Cycle	1 x 163 MW	1110	841	570	78%	59%	40%
	West Coast Combined Cycle	1 x 270 MW	1486	1065	605	63%	45%	26%
	Lakvijaya Unit 1	300 MW	1930	1930	1914	82%	82%	81%
	Lakvijaya Unit 2	300 MW	1734	1733	1726	73%	73%	73%
	Lakvijaya Unit 3	300 MW	1910	1906	1891	81%	81%	80%
	Uthuru Janani	3 x 9 MW	142	138	115	61%	59%	49%
	Barge Power Plant	4 x 16 MW	442	420	354	81%	77%	65%
	Short Term Supplimentary Power Plants	150 MW	2	9	2	0%	1%	0%
	Kelanitissa New Gas Turbines	130 MW	5	25	10	0%	2%	1%
	New NG Combined Cycles (Open Cycle)	200 MW	222	169	142	13%	10%	8%
	Total Renewable Generation		**8813**	**9695**	**10781**			
	Total Thermal Generation		**10440**	**9558**	**8471**			
	Total Generation		**19253**	**19253**	**19252**			
2024	Major Hydro	1568 MW	3988	4582	5417			
	ORE	2496 MW	5893	5893	5893			
	Sapugaskanda A	4 x 17 MW	351	309	238	59%	52%	40%
	Sapugaskanda B	8 x 9 MW	425	431	376	67%	68%	60%
	Kelanitissa GT7	1 x 115 MW	1	4	7	0%	0%	1%
	Kelanitissa Combined Cycle	1 x 161 MW	3	5	0	0%	0%	0%
	Sojitz Combined Cycle	1 x 163 MW	67	51	86	5%	4%	6%
	West Coast Combined Cycle	1 x 270 MW	61	25	45	3%	1%	2%
	Lakvijaya Unit 1	300 MW	1780	1766	1764	75%	75%	75%
	Lakvijaya Unit 2	300 MW	1905	2062	2077	81%	87%	88%
	Lakvijaya Unit 3	300 MW	1734	1731	1734	73%	73%	73%
	Uthuru Janani	3 x 9 MW	120	97	73	51%	42%	31%
	Barge Power Plant	4 x 16 MW	351	366	289	64%	67%	53%
	NG Converted Sojitz Combined Cycle	1 x 163 MW	469	320	221	33%	22%	15%
	NG Converted Kelanitissa Combined Cycle	1 x 161 MW	479	379	309	34%	27%	22%
	NG Converted West Coast Combined Cycle	1 x 270 MW	456	341	240	19%	14%	10%
	Kelanitissa New Gas Turbines	130 MW	0	2	0	0%	0%	0%
	New NG Combined Cycles	1 x 350 MW + 200 MW	2265	1980	1577	48%	42%	33%
	Total Renewable Generation		**9881**	**10476**	**11310**			
	Total Thermal Generation		**10465**	**9870**	**9036**			
	Total Generation		**20346**	**20346**	**20346**			

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	**Average**	**Wet**	**Dry**	**Average**	**Wet**
2025	Major Hydro	1568 MW	3377	4650	5967			
	ORE	2871 MW	6743	6743	6743			
	Sapugaskanda A	4 x 17 MW	305	222	176	51%	37%	30%
	Sapugaskanda B	8 x 9 MW	405	365	278	64%	58%	44%
	Kelanitissa GT7	1 x 115 MW	0	2	2	0%	0%	0%
	Lakvijaya Unit 1	300 MW	1451	1480	1531	61%	63%	65%
	Lakvijaya Unit 2	300 MW	1889	1859	1699	80%	79%	72%
	Lakvijaya Unit 3	300 MW	1905	1884	1678	81%	80%	71%
	Uthuru Janani	3 x 9 MW	72	41	15	31%	18%	6%
	NG Converted Sojitz Combined Cycle	1 x 163 MW	233	96	72	16%	7%	5%
	NG Converted Kelanitissa Combined Cycle	1 x 161 MW	183	104	47	13%	7%	3%
	NG Converted West Coast Combined Cycle	1 x 270 MW	174	48	34	7%	2%	1%
	New Coal	300 MW	1966	1915	1663	83%	81%	70%
	Kelanitissa New Gas Turbines	130 MW	0	0	0	0%	0%	0%
	New NG Combined Cycles	2 x 350 MW	2854	2145	1649	47%	35%	27%
	Total Renewable Generation		**10120**	**11393**	**12710**			
	Total Thermal Generation		**11436**	**10162**	**8845**			
	Total Generation		**21556**	**21556**	**21556**			
2026	Major Hydro	1568 MW	3858	4528	5901			
	ORE	3181 MW	7471	7471	7471			
	Lakvijaya Unit 1	300 MW	1902	1884	1912	80%	80%	81%
	Lakvijaya Unit 2	300 MW	1557	1546	1545	66%	65%	65%
	Lakvijaya Unit 3	300 MW	1892	1895	1885	80%	80%	80%
	Uthuru Janani	3 x 9 MW	55	52	18	23%	22%	8%
	NG Converted Sojitz Combined Cycle	1 x 163 MW	308	187	99	22%	13%	7%
	NG Converted Kelanitissa Combined Cycle	1 x 161 MW	420	215	145	30%	15%	10%
	NG Converted West Coast Combined Cycle	1 x 270 MW	163	152	62	7%	6%	3%
	New Coal	300 MW	1826	1824	1769	77%	77%	75%
	Kelanitissa New Gas Turbines	130 MW	0	2	2	0%	0%	0%
	New Gas Engines	250 MW	144	256	142	6%	11%	6%
	New NG Combined Cycles	2 x 350 MW	3227	2811	1872	53%	46%	31%
	Total Renewable Generation		**11329**	**11999**	**13371**			
	Total Thermal Generation		**11493**	**10823**	**9450**			
	Total Generation		**22822**	**22822**	**22822**			
2027	Major Hydro	1568 MW	3392	4282	5502			
	ORE	3476 MW	8196	8196	8196			
	Lakvijaya Unit 1	300 MW	1621	1749	1767	69%	74%	75%
	Lakvijaya Unit 2	300 MW	2081	2063	1905	88%	87%	81%
	Lakvijaya Unit 3	300 MW	1557	1551	1543	66%	66%	65%
	Uthuru Janani	3 x 9 MW	81	45	17	34%	19%	7%
	NG Converted Sojitz Combined Cycle	1 x 163 MW	234	135	112	16%	9%	8%
	NG Converted Kelanitissa Combined Cycle	1 x 161 MW	205	151	129	15%	11%	9%
	NG Converted West Coast Combined Cycle	1 x 270 MW	185	169	224	8%	7%	9%
	New Coal	300 MW	1728	1703	1636	73%	72%	69%
	Kelanitissa New Gas Turbines	130 MW	1	4	24	0%	0%	2%
	New Gas Engines	250 MW	179	235	265	8%	10%	12%
	New NG Combined Cycles	2 x 350 MW + 1 x 400 MW	4697	3870	2837	48%	39%	29%
	Total Renewable Generation		**11588**	**12478**	**13698**			
	Total Thermal Generation		**12568**	**11674**	**10458**			
	Total Generation		**24156**	**24152**	**24155**			

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2028	Major Hydro	1568 MW	3964	4687	5601			
	ORE	3781 MW	8920	8920	8920			
	Lakvijaya Unit 1	300 MW	1433	1391	1352	61%	59%	57%
	Lakvijaya Unit 2	300 MW	1732	1782	1699	73%	75%	72%
	Lakvijaya Unit 3	300 MW	2069	2014	1996	87%	85%	84%
	Uthuru Janani	3 x 9 MW	45	24	11	19%	10%	5%
	NG Converted Sojitz Combined Cycle	1 x 163 MW	100	52	30	7%	4%	2%
	NG Converted Kelanitissa Combined Cycle	1 x 161 MW	119	67	20	8%	5%	1%
	NG Converted West Coast Combined Cycle	1 x 270 MW	14	22	52	1%	1%	2%
	New Coal	2 x 300 MW	4045	3800	3378	86%	80%	71%
	Kelanitissa New Gas Turbines	130 MW	0	0	1	0%	0%	0%
	New Gas Engines	250 MW	52	106	86	2%	5%	4%
	New NG Combined Cycles	2 x 350 MW + 1 x 400 MW	2910	2537	2258	30%	26%	23%
	Total Renewable Generation		**12885**	**13608**	**14521**			
	Total Thermal Generation		**12519**	**11796**	**10882**			
	Total Generation		**25404**	**25404**	**25404**			
2029	Major Hydro	1568 MW	4011	4902	6086			
	ORE	4056 MW	9547	9547	9547			
	Lakvijaya Unit 1	300 MW	1902	1827	1928	80%	77%	82%
	Lakvijaya Unit 2	300 MW	1557	1648	1557	66%	70%	66%
	Lakvijaya Unit 3	300 MW	1895	1868	1900	80%	79%	80%
	Uthuru Janani	3 x 9 MW	52	30	12	22%	13%	5%
	NG Converted Sojitz Combined Cycle	1 x 163 MW	117	114	114	8%	8%	8%
	NG Converted Kelanitissa Combined Cycle	1 x 161 MW	132	122	124	9%	9%	9%
	NG Converted West Coast Combined Cycle	1 x 270 MW	27	77	65	1%	3%	3%
	New Coal	2 x 300 MW	3674	3596	3373	78%	76%	71%
	Kelanitissa New Gas Turbines	130 MW	0	0	0	0%	0%	0%
	New Gas Engines	250 MW	218	215	140	10%	10%	6%
	New NG Combined Cycles	2 x 350 MW + 1 x 400 MW	3614	2811	1922	37%	29%	20%
	Total Renewable Generation		**13558**	**14449**	**15633**			
	Total Thermal Generation		**13187**	**12309**	**11134**			
	Total Generation		**26745**	**26758**	**26767**			
2030	Major Hydro	1568 MW	3519	4649	5838			
	ORE	4371 MW	10276	10276	10276			
	Lakvijaya Unit 1	300 MW	1615	1602	1579	68%	68%	67%
	Lakvijaya Unit 2	300 MW	1910	1892	1730	81%	80%	73%
	Lakvijaya Unit 3	300 MW	1734	1722	1719	73%	73%	73%
	Uthuru Janani	3 x 9 MW	88	64	43	38%	28%	19%
	NG Converted Sojitz Combined Cycle	1 x 163 MW	394	269	233	28%	19%	16%
	NG Converted Kelanitissa Combined Cycle	1 x 161 MW	342	237	214	24%	17%	15%
	NG Converted West Coast Combined Cycle	1 x 270 MW	487	314	269	21%	13%	11%
	New Coal	2 x 300 MW	3068	3034	2942	65%	64%	62%
	Kelanitissa New Gas Turbines	130 MW	1	3	6	0%	0%	0%
	New Gas Engines	250 MW	372	185	115	17%	8%	5%
	New NG Combined Cycles	2 x 350 MW + 1 x 400 MW	4437	3955	3264	45%	40%	33%
	Total Renewable Generation		**13795**	**14925**	**16115**			
	Total Thermal Generation		**14448**	**13277**	**12114**			
	Total Generation		**28244**	**28203**	**28229**			

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2031	Major Hydro	1568 MW	3639	4645	6101			
	ORE	4671 MW	10969	10969	10969			
	Lakvijaya Unit 1	300 MW	1451	1448	1451	61%	61%	61%
	Lakvijaya Unit 2	300 MW	1734	1733	1734	73%	73%	73%
	Lakvijaya Unit 3	300 MW	1905	1903	1905	81%	80%	81%
	Uthuru Janani	3 x 9 MW	77	65	48	33%	28%	21%
	NG Converted Sojitz Combined Cycle	1 x 163 MW	349	245	189	24%	17%	13%
	NG Converted Kelanitissa Combined Cycle	1 x 161 MW	394	258	147	28%	18%	10%
	NG Converted West Coast Combined Cycle	1 x 270 MW	337	193	128	14%	8%	5%
	New Coal	2 x 300 MW	3806	3778	3770	80%	80%	80%
	Kelanitissa New Gas Turbines	130 MW	0	0	0	0%	0%	0%
	New Gas Engines	250 MW	316	186	112	14%	8%	5%
	New NG Combined Cycles	2 x 350 MW + 1 x 400 MW	4708	4284	3183	48%	44%	32%
	Total Renewable Generation		**14608**	**15614**	**17070**			
	Total Thermal Generation		**15077**	**14093**	**12666**			
	Total Generation		**29685**	**29707**	**29736**			
2032	Major Hydro	1568 MW	3506	4548	6264			
	ORE	4971 MW	11680	11680	11680			
	Lakvijaya Unit 1	300 MW	1940	1913	1921	82%	81%	81%
	Lakvijaya Unit 2	300 MW	1557	1556	1557	66%	66%	66%
	Lakvijaya Unit 3	300 MW	1734	1889	1896	73%	80%	80%
	Uthuru Janani	3 x 9 MW	74	61	48	32%	26%	21%
	NG Converted Sojitz Combined Cycle	1 x 163 MW	309	275	207	22%	19%	15%
	NG Converted Kelanitissa Combined Cycle	1 x 161 MW	287	268	188	20%	19%	13%
	NG Converted West Coast Combined Cycle	1 x 270 MW	261	212	144	11%	9%	6%
	New Coal	2 x 300 MW	3975	3848	3655	84%	81%	77%
	Kelanitissa New Gas Turbines	130 MW	34	3	0	3%	0%	0%
	New Gas Engines	250 MW	269	178	57	12%	8%	3%
	New Gas Turbines	1 x 100 MW + 1 x 200 MW	157	100	134	6%	4%	5%
	New NG Combined Cycles	2 x 350 MW + 1 x 400 MW	5397	4658	3497	55%	48%	36%
	Total Renewable Generation		**15186**	**16228**	**17944**			
	Total Thermal Generation		**15994**	**14961**	**13303**			
	Total Generation		**31180**	**31189**	**31247**			

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2033	Major Hydro	1568 MW	3336	4334	5167			
	ORE	5261 MW	12402	12402	12402			
	Lakvijaya Unit 1	300 MW	1780	1780	1780	75%	75%	75%
	Lakvijaya Unit 2	300 MW	2081	2081	2081	88%	88%	88%
	Lakvijaya Unit 3	300 MW	1557	1557	1557	66%	66%	66%
	NG Converted West Coast Combined Cycle	1 x 270 MW	342	370	285	14%	16%	12%
	New Coal	2 x 300 MW	3454	3451	3405	73%	73%	72%
	Kelanitissa New Gas Turbines	130 MW	12	8	8	1%	1%	1%
	New Gas Engines	1 x 250 MW + 1 x 200 MW	1014	757	642	25%	19%	16%
	New Gas Turbines	1 x 100 MW + 1 x 200 MW	308	239	197	12%	9%	8%
	New NG Combined Cycles	2 x 350 MW +2 x 400 MW	6457	5790	5278	48%	43%	39%
	Total Renewable Generation		**15738**	**16736**	**17569**			
	Total Thermal Generation		**17004**	**16033**	**15234**			
	Total Generation		**32742**	**32769**	**32804**			
2034	Major Hydro	1568 MW	3556	4418	5747			
	ORE	5571 MW	13181	13181	13181			
	Lakvijaya Unit 1	300 MW	1451	1449	1411	61%	61%	60%
	Lakvijaya Unit 2	300 MW	1890	1889	1902	80%	80%	80%
	Lakvijaya Unit 3	300 MW	1905	1904	1885	81%	80%	80%
	NG Converted West Coast Combined Cycle	1 x 270 MW	371	252	337	16%	11%	14%
	New Coal	2 x 300 MW	4040	4040	4028	85%	85%	85%
	Kelanitissa New Gas Turbines	130 MW	0	1	1	0%	0%	0%
	New Gas Engines	1 x 250 MW + 2 x 200 MW	1445	1267	1110	25%	22%	19%
	New Gas Turbines	1 x 100 MW + 1 x 200 MW	89	94	130	3%	4%	5%
	New NG Combined Cycles	2 x 350 MW + 2 x 400 MW	6465	5892	4737	48%	44%	35%
	Total Renewable Generation		**16738**	**17599**	**18929**			
	Total Thermal Generation		**17655**	**16786**	**15540**			
	Total Generation		**34392**	**34385**	**34469**			
2035	Major Hydro	1568 MW	3604	4727	5952			
	ORE	5921 MW	14015	14015	14015			
	Lakvijaya Unit 1	300 MW	1775	1788	1775	75%	76%	75%
	Lakvijaya Unit 2	300 MW	1710	1717	1719	72%	73%	73%
	Lakvijaya Unit 3	300 MW	1872	1880	1894	79%	79%	80%
	New Coal	2 x 300 MW	3728	3697	3695	79%	78%	78%
	Kelanitissa New Gas Turbines	130 MW	0	1	2	0%	0%	0%
	New Gas Engines	1 x 250 MW + 2 x 200 MW	1340	1132	945	23%	19%	16%
	New Gas Turbines	1 x 100 MW + 2 x 200 MW	336	232	122	8%	5%	3%
	New NG Combined Cycles	2 x 350 MW + 3 x 400 MW	7717	6929	6061	45%	40%	35%
	Total Renewable Generation		**17620**	**18743**	**19968**			
	Total Thermal Generation		**18478**	**17376**	**16213**			
	Total Generation		**36097**	**36119**	**36180**			
2036	Major Hydro	1568 MW	3837	4679	6173			
	ORE	6281 MW	14829	14829	14829			
	Lakvijaya Unit 1	300 MW	1780	1780	1780	75%	75%	75%
	Lakvijaya Unit 2	300 MW	2081	2081	2081	88%	88%	88%
	Lakvijaya Unit 3	300 MW	1734	1734	1734	73%	73%	73%
	New Coal	2 x 300 MW	3104	3102	3087	66%	66%	65%
	Kelanitissa New Gas Turbines	130 MW	0	9	0	0%	1%	0%
	New Gas Engines	1 x 250 MW + 2 x 200 MW	626	425	450	11%	7%	8%
	New Gas Turbines	2 x 100 MW + 3 x 200 MW	1056	714	416	15%	10%	6%
	New NG Combined Cycles	2 x 350 MW + 3 x 400 MW	8843	8534	7406	52%	50%	43%
	Total Renewable Generation		**18666**	**19508**	**21003**			
	Total Thermal Generation		**19224**	**18380**	**16953**			
	Total Generation		**37890**	**37888**	**37956**			

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2037	Major Hydro	1568 MW	3513	4550	5760			
	ORE	6631 MW	15664	15664	15664			
	Lakvijaya Unit 1	300 MW	1451	1451	1451	61%	61%	61%
	Lakvijaya Unit 2	300 MW	1886	1887	1884	80%	80%	80%
	Lakvijaya Unit 3	300 MW	1905	1905	1905	81%	81%	81%
	New Coal	2 x 300 MW	4043	4042	4045	85%	85%	86%
	Kelanitissa New Gas Turbines	130 MW	0	0	0	0%	0%	0%
	New Gas Engines	1 x 250 MW + 2 x 200 MW	294	241	123	5%	4%	2%
	New Gas Turbines	2 x 100 MW + 3 x 200 MW	388	256	219	6%	4%	3%
	New NG Combined Cycles	2 x 350 MW + 4 x 400 MW	10581	9738	8766	51%	47%	42%
	Total Renewable Generation		**19177**	**20214**	**21424**			
	Total Thermal Generation		**20548**	**19520**	**18393**			
	Total Generation		**39725**	**39735**	**39817**			
2038	Major Hydro	1568 MW	2886	4573	5857			
	ORE	6981 MW	16520	16520	16520			
	Lakvijaya Unit 1	300 MW	1897	1912	1906	80%	81%	81%
	Lakvijaya Unit 2	300 MW	1557	1557	1557	66%	66%	66%
	Lakvijaya Unit 3	300 MW	1884	1892	1894	80%	80%	80%
	New Coal	2 x 300 MW	3743	3718	3724	79%	79%	79%
	Kelanitissa New Gas Turbines	130 MW	0	0	0	0%	0%	0%
	New Gas Engines	1 x 250 MW + 2 x 200 MW	651	737	638	11%	13%	11%
	New Gas Turbines	3 x 100 MW + 3 x 200 MW	713	400	331	9%	5%	4%
	New NG Combined Cycles	2 x 350 MW + 4 x 400 MW	11717	10246	9247	56%	49%	44%
	Total Renewable Generation		**19406**	**21094**	**22377**			
	Total Thermal Generation		**22163**	**20462**	**19297**			
	Total Generation		**41569**	**41556**	**41675**			
2039	Major Hydro	1568 MW	3723	4333	5456			
	ORE	7331 MW	17356	17356	17356			
	Lakvijaya Unit 1	300 MW	1780	1780	1780	75%	75%	75%
	Lakvijaya Unit 2	300 MW	2081	2081	2081	88%	88%	88%
	Lakvijaya Unit 3	300 MW	1557	1557	1557	66%	66%	66%
	New Coal	2 x 300 MW	3458	3456	3456	73%	73%	73%
	Kelanitissa New Gas Turbines	130 MW	2	11	17	0%	1%	1%
	New Gas Engines	1 x 250 MW + 2 x 200 MW	470	533	570	8%	9%	10%
	New Gas Turbines	3 x 100 MW + 3 x 200 MW	450	408	336	6%	5%	4%
	New NG Combined Cycles	2 x 350 MW + 5 x 400 MW	12610	11951	10858	52%	49%	44%
	Total Renewable Generation		**21079**	**21689**	**22811**			
	Total Thermal Generation		**22408**	**21778**	**20656**			
	Total Generation		**43487**	**43467**	**43467**			
2040	Major Hydro	1568 MW	4190	4760	5790			
	ORE	7681 MW	18168	18168	18168			
	Lakvijaya Unit 1	300 MW	1451	1449	1447	61%	61%	61%
	Lakvijaya Unit 2	300 MW	1883	1882	1881	80%	80%	80%
	Lakvijaya Unit 3	300 MW	1905	1904	1901	81%	80%	80%
	New Coal	2 x 300 MW	4047	4048	3985	86%	86%	84%
	Kelanitissa New Gas Turbines	130 MW	0	1	0	0%	0%	0%
	New Gas Engines	2 x 250 MW + 2 x 200 MW	122	72	49	2%	1%	1%
	New Gas Turbines	3 x 100 MW + 3 x 200 MW	493	386	287	6%	5%	4%
	New NG Combined Cycles	2 x 350 MW + 5 x 400 MW	13149	12757	11932	54%	52%	49%
	Total Renewable Generation		**22358**	**22929**	**23958**			
	Total Thermal Generation		**23050**	**22498**	**21482**			
	Total Generation		**45408**	**45427**	**45440**			

Year	Power Plant	Capacity	Annual Energy (GWh)			Annual Plant Factor (%)		
			Dry	Average	Wet	Dry	Average	Wet
2041	Major Hydro	1568 MW	3727	4619	5685			
	ORE	8031 MW	18980	18980	18980			
	Lakvijaya Unit 2	300 MW	1734	1734	1734	73%	73%	73%
	Lakvijaya Unit 3	300 MW	1910	1910	1910	81%	81%	81%
	New Coal	2 x 300 MW	3811	3808	3810	81%	81%	81%
	Kelanitissa New Gas Turbines	130 MW	9	1	0	1%	0%	0%
	New Gas Engines	2 x 250 MW + 2 x 200 MW	587	618	465	7%	8%	6%
	New Gas Turbines	4 x 100 MW + 3 x 200 MW	863	506	267	10%	6%	3%
	New NG Combined Cycles	2 x 350 MW + 6 x 400 MW	15708	15151	14473	56%	54%	51%
	Total Renewable Generation		**22707**	**23600**	**24665**			
	Total Thermal Generation		**24623**	**23728**	**22658**			
	Total Generation		**47329**	**47327**	**47324**			

NOTES:
1. Annual total generation figure does not include operation of PSPP
2. Annual total renewable generation figure includes the generation from new biomass power plants.

Annex 8.5

Fuel Requirement and Expenditure on Fuel

Base Case 2022-2041

Year	Auto Diesel		Fuel Oil		Naphtha		Coal		LNG	
	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD	1000 MT	mn USD
2022	201.7	110.5	477.5	194.1	105.5	55.8	2333.9	213.6		
2023	207.1	83.4	524.2	212.9	104.3	55.2	2397.7	219.4		
2024	9.9	5.4	254.5	103.5	1.1	0.6	2388.3	218.5	522.6	260.8
2025	0.7	0.4	130.7	53.1			2972.9	272.0	400.5	199.8
2026			10.8	4.7			2988.5	273.5	628.1	313.4
2027			9.2	4.0			2950.1	269.9	785.9	392.1
2028			5.0	2.2			3675.6	334.1	479.5	239.2
2029			6.2	2.7			3668.5	333.6	579.8	289.3
2030			13.3	5.8			3394.3	308.8	853.0	425.6
2031			13.5	5.9			3621.1	329.2	883.6	440.9
2032			12.6	5.5			3771.6	342.8	976.5	487.3
2033							3638.1	330.9	1264.9	631.1
2034							3786.8	344.1	1347.3	672.2
2035							3723.2	338.5	1472.1	734.5
2036							3582.3	326.0	1676.4	836.5
2037							3788.2	344.3	1727.3	861.9
2038							3723.6	338.5	1959.2	977.6
2039							3640.1	331.1	2197.8	1096.7
2040							3787.3	344.2	2214.3	1104.9
2041							3002.1	272.5	2762.0	1378.2

Results of Generation Expansion Planning Studies 2022-2041

High Demand Case

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS	THERMAL CAPACITY ADDITIONS	THERMAL CAPACITY RETIREMENTS
2022	Solar 340 MW Wind 20 MW Mini Hydro 15 MW Biomass 14 MW ***Uma Oya HPP 120 MW*** ***Broadlands HPP 35 MW***	**315 MW Short Term Supplementary Power**	-
2023	Solar 260 MW Wind 35 MW Mini Hydro 20 MW Biomass 4 MW	***130 MW New Gas Turbines at Kelanitissa*** ***200 MW Open Cycle Operation of First 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***163 MW Combined Cycle Power Plant (KPS–2)***	**4x17 MW Kelanitissa Gas Turbines** **163 MW Sojitz Kelanitissa Combined Cycle Plant** **105 MW Short Term Supplementary Power**
2024	Solar 270 MW Wind 40 MW Mini Hydro 10 MW Biomass 5 MW ***Moragolla HPP 31 MW***	***150 MW Steam Turbine Operation of First 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***200 MW Open Cycle Operation of Second 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya***	**160 MW Short Term Supplementary Power**
2025	Solar 260 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 20 MW	***150 MW Steam Turbine Operation of Second 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***300 MW Lakvijaya Coal Power Plant Extension***	**50 MW Short Term Supplementary Power** **4x15.6 MW CEB Barge Power Plant**
2026	Solar 195 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW	**250 MW IC Engine Power Plant (Natural Gas) – Southern Region**	**115 MW Gas Turbine (GT7)** **4x17 MW Sapugaskanda Diesel** **8x9 MW Sapugaskanda Diesel Ext.**
2027	Solar 160 MW Wind 120 MW Mini Hydro 10 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant – Western Region (Natural Gas)** **400 MW Combined Cycle Power Plant (Natural Gas)**	-
2028	Solar 170 MW Wind 120 MW Mini Hydro 10 MW Biomass 5 MW	-	-
2029	Solar 160 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 30 MW **Pumped Storage HPP 200 MW**	-	-
2030	Solar 170 MW Wind 130 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 50 MW **Pumped Storage HPP 200 MW**	-	-
2031	Solar 190 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW **Pumped Storage HPP 200 MW**	**100 MW Gas Turbine Power Plant (Natural Gas)**	-

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS	THERMAL CAPACITY ADDITIONS	THERMAL CAPACITY RETIREMENTS
2032	Solar 190 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**300 MW New Coal Power Plant (Foul Point)**	-
2033	Solar 180 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas) -Western Region** **200 MW Gas Turbine Power Plant (Natural Gas)**	**165 MW Combined Cycle Plant (KPS)** **163 MW Combined Cycle Plant (KPS-2)** **3 x 8.93 MW Uthuru Janani Power Plant**
2034	Solar 200 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**250 MW IC Engine Power Plant (Natural Gas)**	**-**
2035	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas) – Western Region** **200 MW Gas Turbine Power Plant (Natural Gas)** **100 MW Gas Turbine Power Plant (Natural Gas)**	**300 MW West Coast Combined Cycle Power Plant**
2036	Solar 250 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW Gas Turbine Power Plant (Natural Gas)** **100 MW Gas Turbine Power Plant (Natural Gas)**	-
2037	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant(Natural Gas)**	-
2038	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW IC Engine Power Plant (Natural Gas)**	-
2039	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas)**	-
2040	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas)**	-
2041	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas)** **200 MW Gas Turbine Power Plant (Natural Gas)**	**300 MW Lakvijaya Coal Power Plant Unit 1**

Results of Generation Expansion Planning Studies 2022-2041

Low Demand Case

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS	THERMAL CAPACITY ADDITIONS	THERMAL CAPACITY RETIREMENTS
2022	Solar 340 MW Wind 20 MW Mini Hydro 15 MW Biomass 14 MW ***Uma Oya HPP 120 MW*** ***Broadlands HPP 35 MW***	**165 MW Short Term Supplementary Power**	-
2023	Solar 260 MW Wind 35 MW Mini Hydro 20 MW Biomass 4 MW	***130 MW New Gas Turbines at Kelanitissa*** ***200 MW Open Cycle Operation of First 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***163 MW Combined Cycle Power Plant (KPS–2)***	**4x17 MW Kelanitissa Gas Turbines** **163 MW Sojitz Kelanitissa Combined Cycle Plant** **105 MW Short Term Supplementary Power**
2024	Solar 270 MW Wind 40 MW Mini Hydro 10 MW Biomass 5 MW ***Moragolla HPP 31 MW***	***150 MW Steam Turbine Operation of First 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***200 MW Open Cycle Operation of Second 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya***	**60 MW Short Term Supplementary Power**
2025	Solar 260 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 20 MW	***150 MW Steam Turbine Operation of Second 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***300 MW Lakvijaya Coal Power Plant Extension***	**4x15.6 MW CEB Barge Power Plant**
2026	Solar 195 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW	**250 MW IC Engine Power Plant (Natural Gas) – Southern Region**	**115 MW Gas Turbine (GT7)** **4x17 MW Sapugaskanda Diesel** **8x9 MW Sapugaskanda Diesel Ext.**
2027	Solar 160 MW Wind 120 MW Mini Hydro 10 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant – Western Region (Natural Gas)**	-
2028	Solar 170 MW Wind 120 MW Mini Hydro 10 MW Biomass 5 MW	**300 MW New Coal Power Plant (Foul Point)**	-
2029	Solar 160 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 30 MW **Pumped Storage HPP 200 MW**	-	-
2030	Solar 170 MW Wind 130 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 50 MW **Pumped Storage HPP 200 MW**	-	-
2031	Solar 190 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW **Pumped Storage HPP 200 MW**	-	-

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS	THERMAL CAPACITY ADDITIONS	THERMAL CAPACITY RETIREMENTS
2032	Solar 190 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**100 MW Gas Turbine Power Plant (Natural Gas)**	-
2033	Solar 180 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas) -Western Region** **200 MW Gas Turbine Power Plant (Natural Gas)**	**165 MW Combined Cycle Plant (KPS)** **163 MW Combined Cycle Plant (KPS-2)** **3 x 8.93 MW Uthuru Janani Power Plant**
2034	Solar 200 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW IC Engine Power Plant (Natural Gas)**	**-**
2035	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas) – Western Region** **100 MW Gas Turbine Power Plant (Natural Gas)**	**300 MW West Coast Combined Cycle Power Plant**
2036	Solar 250 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW Gas Turbine Power Plant (Natural Gas)** **100 MW Gas Turbine Power Plant (Natural Gas)**	-
2037	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**250 MW IC Engine Power Plant (Natural Gas)**	-
2038	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW IC Engine Power Plant (Natural Gas)**	-
2039	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas)**	-
2040	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW Gas Turbine Power Plant (Natural Gas)**	-
2041	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas)** **200 MW Gas Turbine Power Plant (Natural Gas)** **100 MW Gas Turbine Power Plant (Natural Gas)**	**300 MW Lakvijaya Coal Power Plant Unit 1**

Results of Generation Expansion Planning Studies 2022-2041

Scenario 1: Current Policy Scenario

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS	THERMAL CAPACITY ADDITIONS	THERMAL CAPACITY RETIREMENTS
2022	Solar 340 MW Wind 20 MW Mini Hydro 15 MW Biomass 14 MW ***Uma Oya HPP 120 MW*** ***Broadlands HPP 35 MW***	**250 MW Short Term Supplementary Power**	-
2023	Solar 260 MW Wind 35 MW Mini Hydro 20 MW Biomass 4 MW	***130 MW New Gas Turbines at Kelanitissa*** ***200 MW Open Cycle Operation of First 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***163 MW Combined Cycle Power Plant (KPS–2)***	**4x17 MW Kelanitissa Gas Turbines** **163 MW Sojitz Kelanitissa Combined Cycle Plant** **100 MW Short Term Supplementary Power**
2024	Solar 270 MW Wind 40 MW Mini Hydro 10 MW Biomass 5 MW ***Moragolla HPP 31 MW***	***150 MW Steam Turbine Operation of First 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***200 MW Open Cycle Operation of Second 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya***	**150 MW Short Term Supplementary Power**
2025	Solar 260 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 20 MW	***150 MW Steam Turbine Operation of Second 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***300 MW Lakvijaya Coal Power Plant Extension***	**4x15.6 MW CEB Barge Power Plant**
2026	Solar 195 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW	**250 MW IC Engine Power Plant (Natural Gas) – Southern Region**	**115 MW Gas Turbine (GT7)** **4x17 MW Sapugaskanda Diesel** **8x9 MW Sapugaskanda Diesel Ext.**
2027	Solar 160 MW Wind 120 MW Mini Hydro 10 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant – Western Region (Natural Gas)**	-
2028	Solar 170 MW Wind 120 MW Mini Hydro 10 MW Biomass 5 MW	**300 MW New Coal Power Plant - Foul Point**	-
2029	Solar 160 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 30 MW **Pumped Storage HPP 200 MW**	-	-
2030	Solar 170 MW Wind 130 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 50 MW **Pumped Storage HPP 200 MW**	-	-

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS	THERMAL CAPACITY ADDITIONS	THERMAL CAPACITY RETIREMENTS
2031	Solar 190 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW **Pumped Storage HPP 200 MW**	**300 MW New Coal Power Plant**	**-**
2032	Solar 190 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**-**	-
2033	Solar 180 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW Gas Turbine Power Plant (Natural Gas)** **100 MW Gas Turbine Power Plant (Natural Gas)** **2 x 200 MW IC Engine Power Plant (Natural Gas)**	**165 MW Combined Cycle Plant (KPS)** **163 MW Combined Cycle Plant (KPS-2)** **3 x 8.93 MW Uthuru Janani Power Plant**
2034	Solar 200 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**300 MW New Coal Power Plant**	**-**
2035	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW Gas Turbine Power Plant (Natural Gas)** **100 MW Gas Turbine Power Plant (Natural Gas)** **200 MW Gas Turbine Power Plant (Natural Gas)**	**300 MW West Coast Combined Cycle Power Plant**
2036	Solar 250 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**300 MW New Coal Power Plant**	-
2037	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW Gas Turbine Power Plant (Natural Gas)** **100 MW Gas Turbine Power Plant (Natural Gas)**	-
2038	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas)**	-
2039	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**300 MW New Coal Power Plant**	-
2040	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**250 MW IC Engine Power Plant (Natural Gas)**	-
2041	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**2 x 300 MW New Coal Power Plant**	**300 MW Lakvijaya Coal Power Plant Unit 1**

Results of Generation Expansion Planning Studies 2022-2041

Scenario 2: 70% Low Carbon by 2030 and maintaining the same beyond 2030

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS	THERMAL CAPACITY ADDITIONS	THERMAL CAPACITY RETIREMENTS
2022	Solar 340 MW Wind 20 MW Mini Hydro 15 MW Biomass 14 MW ***Uma Oya HPP 120 MW*** ***Broadlands HPP 35 MW***	**250 MW Short Term Supplementary Power**	-
2023	Solar 260 MW Wind 35 MW Mini Hydro 20 MW Biomass 4 MW	***130 MW New Gas Turbines at Kelanitissa*** ***200 MW Open Cycle Operation of First 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***163 MW Combined Cycle Power Plant (KPS–2)***	**4x17 MW Kelanitissa Gas Turbines** **163 MW Sojitz Kelanitissa Combined Cycle Plant** **100 MW Short Term Supplementary Power**
2024	Solar 270 MW Wind 40 MW Mini Hydro 10 MW Biomass 5 MW ***Moragolla HPP 31 MW***	***150 MW Steam Turbine Operation of First 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***200 MW Open Cycle Operation of Second 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya***	**150 MW Short Term Supplementary Power**
2025	Solar 260 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 20 MW	***150 MW Steam Turbine Operation of Second 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***300 MW Lakvijaya Coal Power Plant Extension***	**4x15.6 MW CEB Barge Power Plant**
2026	Solar 195 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW	**250 MW IC Engine Power Plant (Natural Gas) – Southern Region**	**115 MW Gas Turbine (GT7)** **4x17 MW Sapugaskanda Diesel** **8x9 MW Sapugaskanda Diesel Ext.**
2027	Solar 160 MW Wind 120 MW Mini Hydro 10 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant – Western Region (Natural Gas)**	-
2028	Solar 170 MW Wind 120 MW Mini Hydro 10 MW Biomass 5 MW	**300 MW New Coal Power Plant - Foul Point**	-
2029	Solar 160 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 30 MW **Pumped Storage HPP 200 MW**	-	-
2030	Solar 170 MW Wind 130 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 50 MW **Pumped Storage HPP 200 MW**	-	-
2031	Solar 190 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW **Pumped Storage HPP 200 MW**	-	-

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS	THERMAL CAPACITY ADDITIONS	THERMAL CAPACITY RETIREMENTS
2032	Solar 190 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW Gas Turbine Power Plant (Natural Gas)** **100 MW Gas Turbine Power Plant (Natural Gas)**	-
2033	Solar 180 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas) -Western Region** **200 MW IC Engine Power Plant (Natural Gas)**	**165 MW Combined Cycle Plant (KPS)** **163 MW Combined Cycle Plant (KPS-2)** **3 x 8.93 MW Uthuru Janani Power Plant**
2034	Solar 200 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW IC Engine Power Plant (Natural Gas)**	**-**
2035	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas) -Western Region** **300 MW New Coal Power Plant**	**300 MW West Coast Combined Cycle Power Plant**
2036	Solar 250 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW Gas Turbine Power Plant (Natural Gas)**	-
2037	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW Gas Turbine Power Plant (Natural Gas)** **100 MW Gas Turbine Power Plant (Natural Gas)**	-
2038	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**250 MW IC Engine Power Plant (Natural Gas)**	-
2039	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas)** **300 MW New Coal Power Plant**	-
2040	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**-**	-
2041	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas)** **300 MW New Coal Power Plant**	**300 MW Lakvijaya Coal Power Plant Unit 1**

Results of Generation Expansion Planning Studies 2022-2041

Scenario 3: 70% Low Carbon by 2030 and increasing the same beyond 2030 by restricting coal power development

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS	THERMAL CAPACITY ADDITIONS	THERMAL CAPACITY RETIREMENTS
2022	Solar 340 MW Wind 20 MW Mini Hydro 15 MW Biomass 14 MW ***Uma Oya HPP 120 MW*** ***Broadlands HPP 35 MW***	**250 MW Short Term Supplementary Power**	-
2023	Solar 260 MW Wind 35 MW Mini Hydro 20 MW Biomass 4 MW	***130 MW New Gas Turbines at Kelanitissa*** ***200 MW Open Cycle Operation of First 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***163 MW Combined Cycle Power Plant (KPS–2)***	**4x17 MW Kelanitissa Gas Turbines** **163 MW Sojitz Kelanitissa Combined Cycle Plant** **100 MW Short Term Supplementary Power**
2024	Solar 270 MW Wind 40 MW Mini Hydro 10 MW Biomass 5 MW ***Moragolla HPP 31 MW***	***150 MW Steam Turbine Operation of First 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***200 MW Open Cycle Operation of Second 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya***	**150 MW Short Term Supplementary Power**
2025	Solar 260 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 20 MW	***150 MW Steam Turbine Operation of Second 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***300 MW Lakvijaya Coal Power Plant Extension***	**4x15.6 MW CEB Barge Power Plant**
2026	Solar 195 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW	**250 MW IC Engine Power Plant (Natural Gas) – Southern Region**	**115 MW Gas Turbine (GT7)** **4x17 MW Sapugaskanda Diesel** **8x9 MW Sapugaskanda Diesel Ext.**
2027	Solar 160 MW Wind 120 MW Mini Hydro 10 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant – Western Region (Natural Gas)**	-
2028	Solar 170 MW Wind 120 MW Mini Hydro 10 MW Biomass 5 MW	**300 MW New Coal Power Plant - Foul Point**	-
2029	Solar 160 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 30 MW **Pumped Storage HPP 200 MW**	-	-
2030	Solar 170 MW Wind 130 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 50 MW **Pumped Storage HPP 200 MW**	-	-
2031	Solar 190 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW **Pumped Storage HPP 200 MW**	-	-

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS	THERMAL CAPACITY ADDITIONS	THERMAL CAPACITY RETIREMENTS
2032	Solar 190 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW Gas Turbine Power Plant (Natural Gas) 100 MW Gas Turbine Power Plant (Natural Gas)**	-
2033	Solar 180 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas) -Western Region 200 MW IC Engine Power Plant (Natural Gas)**	**165 MW Combined Cycle Plant (KPS) 163 MW Combined Cycle Plant (KPS-2) 3 x 8.93 MW Uthuru Janani Power Plant**
2034	Solar 200 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW IC Engine Power Plant (Natural Gas)**	**-**
2035	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas) – Western Region 200 MW Gas Turbine Power Plant (Natural Gas)**	**300 MW West Coast Combined Cycle Power Plant**
2036	Solar 250 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW Gas Turbine Power Plant (Natural Gas) 100 MW Gas Turbine Power Plant (Natural Gas)**	-
2037	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant(Natural Gas)**	-
2038	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**100 MW Gas Turbine Power Plant (Natural Gas)**	-
2039	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas)**	-
2040	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**250 MW IC Engine Power Plant (Natural Gas)**	-
2041	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas) 100 MW Gas Turbine Power Plant (Natural Gas)**	**300 MW Lakvijaya Coal Power Plant Unit 1**

Results of Generation Expansion Planning Studies 2022-2041

Scenario 4: India-Sri Lanka Cross Border HVDC Interconnection Scenario

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS	THERMAL CAPACITY ADDITIONS	THERMAL CAPACITY RETIREMENTS
2022	Solar 340 MW Wind 20 MW Mini Hydro 15 MW Biomass 14 MW ***Uma Oya HPP 120 MW*** ***Broadlands HPP 35 MW***	**250 MW Short Term Supplementary Power**	-
2023	Solar 260 MW Wind 35 MW Mini Hydro 20 MW Biomass 4 MW	***130 MW New Gas Turbines at Kelanitissa*** ***200 MW Open Cycle Operation of First 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***163 MW Combined Cycle Power Plant (KPS–2)***	**4x17 MW Kelanitissa Gas Turbines** **163 MW Sojitz Kelanitissa Combined Cycle Plant** **100 MW Short Term Supplementary Power**
2024	Solar 270 MW Wind 40 MW Mini Hydro 10 MW Biomass 5 MW ***Moragolla HPP 31 MW***	***150 MW Steam Turbine Operation of First 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***200 MW Open Cycle Operation of Second 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya***	**150 MW Short Term Supplementary Power**
2025	Solar 260 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 20 MW	***150 MW Steam Turbine Operation of Second 350 MW Natural Gas Combined Cycle Power Plant – Kerawalapitiya*** ***300 MW Lakvijaya Coal Power Plant Extension***	**4x15.6 MW CEB Barge Power Plant**
2026	Solar 195 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW	**250 MW IC Engine Power Plant (Natural Gas) – Southern Region**	**115 MW Gas Turbine (GT7)** **4x17 MW Sapugaskanda Diesel** **8x9 MW Sapugaskanda Diesel Ext.**
2027	Solar 160 MW Wind 120 MW Mini Hydro 10 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant – Western Region (Natural Gas)**	-
2028	Solar 170 MW Wind 120 MW Mini Hydro 10 MW Biomass 5 MW	**300 MW New Coal Power Plant - Foul Point**	-
2029	Solar 160 MW Wind 100 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 30 MW **Pumped Storage HPP 200 MW**	-	-
2030	Solar 170 MW Wind 130 MW Mini Hydro 10 MW Biomass 5 MW Battery Energy Storage 50 MW **Pumped Storage HPP 200 MW**	-	-
2031	Solar 190 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW **Pumped Storage HPP 200 MW**	-	-

YEAR	RENEWABLE CAPACITY & GRID SCALE ENERGY STORAGE CAPACITY ADDITIONS	THERMAL CAPACITY ADDITIONS	THERMAL CAPACITY RETIREMENTS
2032	Solar 190 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW Gas Turbine Power Plant (Natural Gas)** **100 MW Gas Turbine Power Plant (Natural Gas)** **500MW India-Sri Lanka HVDC Interconnection**	-
2033	Solar 180 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas) -Western Region** **200 MW IC Engine Power Plant (Natural Gas)**	**165 MW Combined Cycle Plant (KPS)** **163 MW Combined Cycle Plant (KPS-2)** **3 x 8.93 MW Uthuru Janani Power Plant**
2034	Solar 200 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW IC Engine Power Plant (Natural Gas)**	**-**
2035	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas) – Western Region** **200 MW Gas Turbine Power Plant (Natural Gas)**	**300 MW West Coast Combined Cycle Power Plant**
2036	Solar 250 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**200 MW Gas Turbine Power Plant (Natural Gas)** **100 MW Gas Turbine Power Plant (Natural Gas)**	-
2037	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant(Natural Gas)**	-
2038	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**100 MW Gas Turbine Power Plant (Natural Gas)**	-
2039	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas)**	-
2040	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**250 MW IC Engine Power Plant (Natural Gas)**	-
2041	Solar 240 MW Wind 100 MW Mini Hydro 5 MW Biomass 5 MW	**400 MW Combined Cycle Power Plant (Natural Gas)** **100 MW Gas Turbine Power Plant (Natural Gas)**	**300 MW Lakvijaya Coal Power Plant Unit 1**

Investment Plan for Major Hydro & Thermal Projects (Base Case), 2022-2041

(Costs in million US$, Exch. Rate:187.2 LKR/US$)

YEAR & PLANT	2022		2023		2024		2025		2026		2027		2028		2029		2030		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- 130 MW Gas Turbine - 3/4 units																					
Base Cost	16.0	64.2																	**16.0**	**64.2**	**80.2**
Contingencies	1.6	6.4																	**1.6**	**6.4**	**8.0**
Port Handling & other charges (5%)		3.5																	**0.0**	**3.5**	**3.5**
Total	17.6	74.1																	**17.6**	**74.1**	**91.7**
2024 - 350 MW Natural Gas Fired Combined Cycle Power Plant - Kerawalapitiya																					
Base Cost	19.8	79.2	42.1	168.3															**61.9**	**247.5**	**309.3**
Contingencies	2.0	7.9	4.2	16.8															**6.2**	**24.7**	**30.9**
Port Handling & other charges (5%)		4.4		9.3															**0.0**	**13.6**	**13.6**
Total	21.8	91.5	46.3	194.4															**68.1**	**285.8**	**353.9**
2025 - 350 MW Natural Gas Fired Combined Cycle Power Plant - Kerawalapitiya																					
Base Cost			19.8	79.2	42.1	168.3													**61.9**	**247.5**	**309.3**
Contingencies			2.0	7.9	4.2	16.8													**6.2**	**24.7**	**30.9**
Port Handling & other charges (5%)			0.0	4.4	0.0	9.3													**0.0**	**13.6**	**13.6**
Total			21.8	91.5	46.3	194.4													**68.1**	**285.8**	**353.9**
2025- 300 MW Lakvijaya Extension																					
Base Cost	10.0	40.1	58.1	232.3	32.0	128.2													**100.1**	**400.6**	**500.7**
Contingencies	1.0	4.0	5.8	23.2	3.2	12.8													**10.0**	**40.1**	**50.1**
Port Handling & other charges (5%)		2.2		12.8		7.0													**0.0**	**22.0**	**22.0**
Total	11.0	46.3	63.9	268.3	35.2	148.0													**110.2**	**462.6**	**572.8**
2026 - 250 MW IC Engine Power Plant (Natural Gas) – Southern Region																					
Base Cost					3.4	13.5	30.1	120.6											**33.5**	**134.1**	**167.6**
Contingencies					0.3	1.3	3.0	12.1											**3.4**	**13.4**	**16.8**
Port Handling & other charges (5%)						0.7		6.6											**0.0**	**7.4**	**7.4**
Total					3.7	15.5	33.2	139.3											**36.9**	**154.8**	**191.7**
2027 - 400 MW Combined Cycle Power Plant – Western Region (Natural Gas)																					
Base Cost							24.1	96.6	51.3	205.3									**75.5**	**301.9**	**377.3**
Contingencies							2.4	9.7	5.1	20.5									**7.5**	**30.2**	**37.7**
Port Handling & other charges (5%)								5.3		11.3									**0.0**	**16.6**	**16.6**
Total							26.6	111.6	56.4	237.1									**83.0**	**348.7**	**431.7**
2028 - 300 MW New Coal Power Plant (Foul Point)																					
Base Cost							10.8	43.4	62.9	251.6	34.7	138.8							**108.4**	**433.8**	**542.2**
Contingencies							1.1	4.3	6.3	25.2	3.5	13.9							**10.8**	**43.4**	**54.2**
Port Handling & other charges (5%)								2.4		13.8		7.6							**0.0**	**23.9**	**23.9**
Total							11.9	50.1	69.2	290.6	38.2	160.3							**119.3**	**501.0**	**620.3**
2029 - Pumped Storage HPP 200 MW - Unit 1																					
Base Cost					2.4	9.5	7.1	28.5	16.2	64.6	16.6	66.5	5.2	20.9					**47.5**	**190.1**	**237.6**
Contingencies					0.2	1.0	0.7	2.9	1.6	6.5	1.7	6.7	0.5	2.1					**4.8**	**19.0**	**23.8**
Port Handling & other charges (5%)						0.5		1.6		3.6		3.7		1.2					**0.0**	**10.5**	**10.5**
Total					2.6	11.0	7.8	32.9	17.8	74.7	18.3	76.9	5.8	24.2					**52.3**	**219.6**	**271.9**
2030 - Pumped Storage HPP 200 MW - Unit 2																					
Base Cost							2.4	9.5	7.1	28.5	16.2	64.6	16.6	66.5	5.2	20.9			**47.5**	**190.1**	**237.6**
Contingencies							0.2	1.0	0.7	2.9	1.6	6.5	1.7	6.7	0.5	2.1			**4.8**	**19.0**	**23.8**
Port Handling & other charges (5%)							0.0	0.5	0.0	1.6	0.0	3.6	0.0	3.7	0.0	1.2			**0.0**	**10.5**	**10.5**
Total							2.6	11.0	7.8	32.9	17.8	74.7	18.3	76.9	5.8	24.2			**52.3**	**219.6**	**271.9**
Annual Total	**50.4**	**211.8**	**131.9**	**554.2**	**87.8**	**368.9**	**82.1**	**344.9**													

Continued in the next page

Investment Plan for Major Hydro & Thermal Projects (Base Case), 2022-2041

(Costs in million US$, Exch. Rate:187.2 LKR/US$)

YEAR & PLANT	2026		2027		2028		2029		2030		2031		2032		2033		2034		2035		Total		Grand
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	Total
2031 - Pumped Storage HPP 200 MW - Unit 3																							
Base Cost	2.4	9.5	7.1	28.5	16.2	64.6	16.6	66.5	5.2	20.9											**47.5**	**190.1**	**237.6**
Contingencies	0.2	1.0	0.7	2.9	1.6	6.5	1.7	6.7	0.5	2.1											**4.8**	**19.0**	**23.8**
Port Handling & other charges (5%)	0.0	0.5	0.0	1.6	0.0	3.6	0.0	3.7	0.0	1.2											**0.0**	**10.5**	**10.5**
Total	2.6	11.0	7.8	32.9	17.8	74.7	18.3	76.9	5.8	24.2											**52.3**	**219.6**	**271.9**
2032 - 200 MW Gas Turbine Power Plant (Natural Gas)																							
Base Cost									1.3	5.1	11.5	46.1									**12.8**	**51.2**	**64.0**
Contingencies									0.1	0.5	1.2	4.6									**1.3**	**5.1**	**6.4**
Port Handling & other charges (5%)										0.3		2.5									**0.0**	**2.8**	**2.8**
Total									1.4	5.9	12.7	53.2									**14.1**	**59.1**	**73.2**
2032 - 100 MW Gas Turbine Power Plant (Natural Gas)																							
Base Cost									0.8	3.3	7.4	29.4									**8.2**	**32.7**	**40.9**
Contingencies									0.1	0.3	0.7	2.9									**0.8**	**3.3**	**4.1**
Port Handling & other charges (5%)										0.2		1.6									**0.0**	**1.8**	**1.8**
Total									0.9	3.8	8.1	34.0									**9.0**	**37.8**	**46.8**
2033 - 400 MW Combined Cycle Power Plant (Natural Gas) -Western Region																							
Base Cost											24.1	96.6	51.3	205.3							**75.5**	**301.9**	**377.3**
Contingencies											2.4	9.7	5.1	20.5							**7.5**	**30.2**	**37.7**
Port Handling & other charges (5%)											0.0	5.3	0.0	11.3							**0.0**	**16.6**	**16.6**
Total											26.6	111.6	56.4	237.1							**83.0**	**348.7**	**431.7**
2033 - 200 MW IC Engine Power Plant (Natural Gas)																							
Base Cost											2.7	10.9	24.5	98.0							**27.2**	**108.9**	**136.1**
Contingencies											0.3	1.1	2.4	9.8							**2.7**	**10.9**	**13.6**
Port Handling & other charges (5%)												0.6		5.4							**0.0**	**6.0**	**6.0**
Total											3.0	12.6	26.9	113.2							**30.0**	**125.8**	**155.8**
2034 - 200 MW IC Engine Power Plant (Natural Gas)																							
Base Cost													2.7	10.9	24.5	98.0					**27.2**	**108.9**	**136.1**
Contingencies													0.3	1.1	2.4	9.8					**2.7**	**10.9**	**13.6**
Port Handling & other charges (5%)													0.0	0.6	0.0	5.4					**0.0**	**6.0**	**6.0**
Total													3.0	12.6	26.9	113.2					**30.0**	**125.8**	**155.8**
2035 - 400 MW Combined Cycle Power Plant (Natural Gas)– Western Region																							
Base Cost															24.1	96.6	51.3	205.3			**75.5**	**301.9**	**377.3**
Contingencies															2.4	9.7	5.1	20.5			**7.5**	**30.2**	**37.7**
Port Handling & other charges (5%)															0.0	5.3	0.0	11.3			**0.0**	**16.6**	**16.6**
Total															26.6	111.6	56.4	237.1			**83.0**	**348.7**	**431.7**
2035 - 200 MW Gas Turbine Power Plant (Natural Gas)																							
Base Cost															1.3	5.1	11.5	46.1			**12.8**	**51.2**	**64.0**
Contingencies															0.1	0.5	1.2	4.6			**1.3**	**5.1**	**6.4**
Port Handling & other charges (5%)															0.0	0.3	0.0	2.5			**0.0**	**2.8**	**2.8**
Total															1.4	5.9	12.7	53.2			**14.1**	**59.1**	**73.2**
2036 - 200 MW Gas Turbine Power Plant (Natural Gas)																							
Base Cost																	1.3	5.1	11.5	46.1	**12.8**	**51.2**	**64.0**
Contingencies																	0.1	0.5	1.2	4.6	**1.3**	**5.1**	**6.4**
Port Handling & other charges (5%)																	0.0	0.3	0.0	2.5	**0.0**	**2.8**	**2.8**
Total																	1.4	5.9	12.7	53.2	**14.1**	**59.1**	**73.2**
Annual Total	**153.9**	**646.2**	**82.1**	**344.8**	**41.8**	**175.7**	**24.0**	**101.0**	**8.1**	**33.9**	**50.3**	**211.4**	**86.4**	**362.9**	**54.9**	**230.7**							

Continued in the next page

Investment Plan for Major Hydro & Thermal Projects (Base Case), 2022-2041

(Costs in million US$, Exch. Rate:187.2 LKR/US$)

YEAR & PLANT	2034		2035		2036		2037		2038		2039		2040		2041		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**
2036 - 100 MW Gas Turbine Power Plant (Natural Gas)																			
Base Cost	0.8	3.3	7.4	29.4													**8.2**	**32.7**	**40.9**
Contingencies	0.1	0.3	0.7	2.9													**0.8**	**3.3**	**4.1**
Port Handling & other charges (5%)	0.0	0.2	0.0	1.6													**0.0**	**1.8**	**1.8**
Total	0.9	3.8	8.1	34.0													**9.0**	**37.8**	**46.8**
2037 - 400 MW Combined Cycle Power Plant (Natural Gas)																			
Base Cost			24.1	96.6	51.3	205.3											**75.5**	**301.9**	**377.3**
Contingencies			2.4	9.7	5.1	20.5											**7.5**	**30.2**	**37.7**
Port Handling & other charges (5%)			0.0	5.3	0.0	11.3											**0.0**	**16.6**	**16.6**
Total			26.6	111.6	56.4	237.1											**83.0**	**348.7**	**431.7**
2038 - 100 MW Gas Turbine Power Plant (Natural Gas)																			
Base Cost					0.8	3.3	7.4	29.4									**8.2**	**32.7**	**40.9**
Contingencies					0.1	0.3	0.7	2.9									**0.8**	**3.3**	**4.1**
Port Handling & other charges (5%)					0.0	0.2	0.0	1.6									**0.0**	**1.8**	**1.8**
Total					0.9	3.8	8.1	34.0									**9.0**	**37.8**	**46.8**
2039 - 400 MW Combined Cycle Power Plant (Natural Gas)																			
Base Cost							24.1	96.6	51.3	205.3							**75.5**	**301.9**	**377.3**
Contingencies							2.4	9.7	5.1	20.5							**7.5**	**30.2**	**37.7**
Port Handling & other charges (5%)							0.0	5.3	0.0	11.3							**0.0**	**16.6**	**16.6**
Total							26.6	111.6	56.4	237.1							**83.0**	**348.7**	**431.7**
2040 - 250 MW IC Engine Power Plant (Natural Gas)																			
Base Cost									3.4	13.5	30.1	120.6					**33.5**	**134.1**	**167.6**
Contingencies									0.3	1.3	3.0	12.1					**3.4**	**13.4**	**16.8**
Port Handling & other charges (5%)									0.0	0.7	0.0	6.6					**0.0**	**7.4**	**7.4**
Total									3.7	15.5	33.2	139.3					**36.9**	**154.8**	**191.7**
2041 - 400 MW Combined Cycle Power Plant (Natural Gas)																			
Base Cost											24.1	96.6	51.3	205.3			**75.5**	**301.9**	**377.3**
Contingencies											2.4	9.7	5.1	20.5			**7.5**	**30.2**	**37.7**
Port Handling & other charges (5%)											0.0	5.3	0.0	11.3			**0.0**	**16.6**	**16.6**
Total											26.6	111.6	56.4	237.1			**83.0**	**348.7**	**431.7**
2041 - 100 MW Gas Turbine Power Plant (Natural Gas)																			
Base Cost											0.8	3.3	7.4	29.4			**8.2**	**32.7**	**40.9**
Contingencies											0.1	0.3	0.7	2.9			**0.8**	**3.3**	**4.1**
Port Handling & other charges (5%)											0.0	0.2	0.0	1.6			**0.0**	**1.8**	**1.8**
Total											0.9	3.8	8.1	34.0			**9.0**	**37.8**	**46.8**
Annual Total	**71.4**	**300.0**	**47.3**	**198.8**	**57.4**	**240.9**	**34.7**	**145.6**	**60.1**	**252.6**	**60.6**	**254.6**	**64.5**	**271.1**					

Note:

(i) Disbursement start from year 2022 onwards.

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

Investment Plan for Major Wind & Solar Developments (Base Case), 2022-2041

(Costs in million US$, Exch. Rate:187.2 LKR/US$)

YEAR & PLANT	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	Total
2023 - 260 MW Solar Power Development											
Base Cost	49.0	195.9							**49.0**	**195.9**	**244.9**
Contingencies	4.9	19.6							**4.9**	**19.6**	**24.5**
Port Handling & other charges (5%)		10.8							**0.0**	**10.8**	**10.8**
Total	53.9	226.3							**53.9**	**226.3**	**280.1**
2023 - 35 MW Wind Power Development											
Base Cost	8.9	35.6							**8.9**	**35.6**	**44.5**
Contingencies	0.9	3.6							**0.9**	**3.6**	**4.5**
Port Handling & other charges (5%)		2.0							**0.0**	**2.0**	**2.0**
Total	9.8	41.2							**9.8**	**41.2**	**51.0**
2024 - 270 MW Solar Power Development											
Base Cost			49.9	199.7					**49.9**	**199.7**	**249.7**
Contingencies			5.0	20.0					**5.0**	**20.0**	**25.0**
Port Handling & other charges (5%)				11.0					**0.0**	**11.0**	**11.0**
Total			54.9	230.7					**54.9**	**230.7**	**285.6**
2024 - 40 MW Wind Power Development											
Base Cost			10.2	40.7					**10.2**	**40.7**	**50.9**
Contingencies			1.0	4.1					**1.0**	**4.1**	**5.1**
Port Handling & other charges (5%)				2.2					**0.0**	**2.2**	**2.2**
Total			11.2	47.0					**11.2**	**47.0**	**58.2**
2025 - 260 MW Solar Power Development											
Base Cost					49.0	195.9			**49.0**	**195.9**	**244.9**
Contingencies					4.9	19.6			**4.9**	**19.6**	**24.5**
Port Handling & other charges (5%)					0.0	10.8			**0.0**	**10.8**	**10.8**
Total					53.9	226.3			**53.9**	**226.3**	**280.1**
2025 - 100 MW Wind Power Development											
Base Cost					25.5	101.8			**25.5**	**101.8**	**127.3**
Contingencies					2.5	10.2			**2.5**	**10.2**	**12.7**
Port Handling & other charges (5%)						5.6			**0.0**	**5.6**	**5.6**
Total					28.0	117.6			**28.0**	**117.6**	**145.6**
2026 - 195 MW Solar Power Development											
Base Cost							34.6	138.3	**34.6**	**138.3**	**172.9**
Contingencies							3.5	13.8	**3.5**	**13.8**	**17.3**
Port Handling & other charges (5%)								7.6	**0.0**	**7.6**	**7.6**
Total							38.0	159.8	**38.0**	**159.8**	**197.8**
2026 - 100 MW Wind Power Development											
Base Cost							25.5	101.8	**25.5**	**101.8**	**127.3**
Contingencies							2.5	10.2	**2.5**	**10.2**	**12.7**
Port Handling & other charges (5%)								5.6	**0.0**	**5.6**	**5.6**
Total							28.0	117.6	**28.0**	**117.6**	**145.6**
Annual Total	**63.7**	**267.4**	**66.1**	**277.7**	**81.9**	**343.9**	**66.0**	**277.4**			

Continued in the next page

Investment Plan for Major Wind & Solar Developments (Base Case), 2022-2041

(Costs in million US$, Exch. Rate:187.2 LKR/US$)

YEAR & PLANT	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	
2027 - 160 MW Solar Power Development											
Base Cost	27.9	111.5							**27.9**	**111.5**	**139.4**
Contingencies	2.8	11.1							**2.8**	**11.1**	**13.9**
Port Handling & other charges (5%)		6.1							**0.0**	**6.1**	**6.1**
Total	30.7	128.8							**30.7**	**128.8**	**159.4**
2027 - 120 MW Wind Power Development											
Base Cost	30.5	122.2							**30.5**	**122.2**	**152.7**
Contingencies	3.1	12.2							**3.1**	**12.2**	**15.3**
Port Handling & other charges (5%)		6.7							**0.0**	**6.7**	**6.7**
Total	33.6	141.1							**33.6**	**141.1**	**174.7**
2028 - 170 MW Solar Power Development											
Base Cost			29.8	119.2					**29.8**	**119.2**	**149.0**
Contingencies			3.0	11.9					**3.0**	**11.9**	**14.9**
Port Handling & other charges (5%)				6.6					**0.0**	**6.6**	**6.6**
Total			32.8	137.6					**32.8**	**137.6**	**170.4**
2028 - 120 MW Wind Power Development											
Base Cost			30.5	122.2					**30.5**	**122.2**	**152.7**
Contingencies			3.1	12.2					**3.1**	**12.2**	**15.3**
Port Handling & other charges (5%)				6.7					**0.0**	**6.7**	**6.7**
Total			33.6	141.1					**33.6**	**141.1**	**174.7**
2029 - 160 MW Solar Power Development											
Base Cost					27.9	111.5			**27.9**	**111.5**	**139.4**
Contingencies					2.8	11.1			**2.8**	**11.1**	**13.9**
Port Handling & other charges (5%)						6.1			**0.0**	**6.1**	**6.1**
Total					30.7	128.8			**30.7**	**128.8**	**159.4**
2029 - 100 MW Wind Power Development											
Base Cost					25.5	101.8			**25.5**	**101.8**	**127.3**
Contingencies					2.5	10.2			**2.5**	**10.2**	**12.7**
Port Handling & other charges (5%)						5.6			**0.0**	**5.6**	**5.6**
Total					28.0	117.6			**28.0**	**117.6**	**145.6**
2030 - 170 MW Solar Power Development											
Base Cost							29.8	119.2	**29.8**	**119.2**	**149.0**
Contingencies							3.0	11.9	**3.0**	**11.9**	**14.9**
Port Handling & other charges (5%)								6.6	**0.0**	**6.6**	**6.6**
Total							32.8	137.6	**32.8**	**137.6**	**170.4**
Annual Total	**64.3**	**269.9**	**66.4**	**278.8**	**58.7**	**246.4**					

Continued in the next page

Investment Plan for Major Wind & Solar Developments (Base Case), 2022-2041

(Costs in million US$, Exch. Rate:187.2 LKR/US$)

YEAR & PLANT	2029		2030		2031		2032		2033		2034		2035		2036		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
2030 - 130 MW Wind Power Development																			
Base Cost	33.1	132.4															**33.1**	**132.4**	**165.5**
Contingencies	3.3	13.2															**3.3**	**13.2**	**16.5**
Port Handling & other charges (5%)		7.3															**0.0**	**7.3**	**7.3**
Total	36.4	152.9															**36.4**	**152.9**	**189.3**
2031 - 190 MW Solar Power Development																			
Base Cost			32.2	128.9													**32.2**	**128.9**	**161.1**
Contingencies			3.2	12.9													**3.2**	**12.9**	**16.1**
Port Handling & other charges (5%)				7.1													**0.0**	**7.1**	**7.1**
Total			35.4	148.8													**35.4**	**148.8**	**184.3**
2031 - 100 MW Wind Power Development																			
Base Cost			25.5	101.8													**25.5**	**101.8**	**127.3**
Contingencies			2.5	10.2													**2.5**	**10.2**	**12.7**
Port Handling & other charges (5%)				5.6													**0.0**	**5.6**	**5.6**
Total			28.0	117.6													**28.0**	**117.6**	**145.6**
2032 - 190 MW Solar Power Development																			
Base Cost					32.2	128.9											**32.2**	**128.9**	**161.1**
Contingencies					3.2	12.9											**3.2**	**12.9**	**16.1**
Port Handling & other charges (5%)						7.1											**0.0**	**7.1**	**7.1**
Total					35.4	148.8											**35.4**	**148.8**	**184.3**
2032 - 100 MW Wind Power Development																			
Base Cost					25.5	101.8											**25.5**	**101.8**	**127.3**
Contingencies					2.5	10.2											**2.5**	**10.2**	**12.7**
Port Handling & other charges (5%)						5.6											**0.0**	**5.6**	**5.6**
Total					28.0	117.6											28.0	**117.6**	**145.6**
2033 - 180 MW Solar Power Development																			
Base Cost							30.3	121.2									**30.3**	**121.2**	**151.5**
Contingencies							3.0	12.1									**3.0**	**12.1**	**15.2**
Port Handling & other charges (5%)								6.7									**0.0**	**6.7**	**6.7**
Total							33.3	140.0									**33.3**	**140.0**	**173.3**
2033 - 100 MW Wind Power Development																			
Base Cost							25.5	101.8									**25.5**	**101.8**	**127.3**
Contingencies							2.5	10.2									**2.5**	**10.2**	**12.7**
Port Handling & other charges (5%)								5.6									**0.0**	**5.6**	**5.6**
Total							28.0	117.6									**28.0**	**117.6**	**145.6**
2034 - 200 MW Solar Power Development																			
Base Cost									33.6	134.3							**33.6**	**134.3**	**167.9**
Contingencies									3.4	13.4							**3.4**	**13.4**	**16.8**
Port Handling & other charges (5%)										7.4							**0.0**	**7.4**	**7.4**
Total									36.9	155.1							**36.9**	**155.1**	**192.0**
Annual Total	**69.2**	**290.5**	**63.4**	**266.4**	**63.4**	**266.4**	**61.3**	**257.6**											

Continued in the next page

Investment Plan for Major Wind & Solar Developments (Base Case), 2022-2041

(Costs in million US$, Exch. Rate:187.2 LKR/US$)

YEAR & PLANT	2033		2034		2035		2036		2037		2038		2039		2040		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	
2034 - 100 MW Wind Power Development																			
Base Cost	25.5	101.8															**25.5**	**101.8**	**127.3**
Contingencies	2.5	10.2															**2.5**	**10.2**	**12.7**
Port Handling & other charges (5%)		5.6															**0.0**	**5.6**	**5.6**
Total	28.0	117.6															**28.0**	**117.6**	**145.6**
2035 - 240 MW Solar Power Development																			
Base Cost			39.8	159.3													**39.8**	**159.3**	**199.2**
Contingencies			4.0	15.9													**4.0**	**15.9**	**19.9**
Port Handling & other charges (5%)				8.8													**0.0**	**8.8**	**8.8**
Total			43.8	184.0													**43.8**	**184.0**	**227.9**
2035 - 100 MW Wind Power Development																			
Base Cost			25.5	101.8													**25.5**	**101.8**	**127.3**
Contingencies			2.5	10.2													**2.5**	**10.2**	**12.7**
Port Handling & other charges (5%)				5.6													**0.0**	**5.6**	**5.6**
Total			28.0	117.6													**28.0**	**117.6**	**145.6**
2036 - 250 MW Solar Power Development																			
Base Cost					41.5	165.9											**41.5**	**165.9**	**207.4**
Contingencies					4.1	16.6											**4.1**	**16.6**	**20.7**
Port Handling & other charges (5%)						9.1											**0.0**	**9.1**	**9.1**
Total					45.6	191.6											**45.6**	**191.6**	**237.2**
2036 - 100 MW Wind Power Development																			
Base Cost					25.5	101.8											**25.5**	**101.8**	**127.3**
Contingencies					2.5	10.2											**2.5**	**10.2**	**12.7**
Port Handling & other charges (5%)						5.6											**0.0**	**5.6**	**5.6**
Total					28.0	117.6											28.0	**117.6**	**145.6**
2037 - 240 MW Solar Power Development																			
Base Cost							39.8	159.3									**39.8**	**159.3**	**199.2**
Contingencies							4.0	15.9									**4.0**	**15.9**	**19.9**
Port Handling & other charges (5%)								8.8									**0.0**	**8.8**	**8.8**
Total							43.8	184.0									**43.8**	**184.0**	**227.9**
2037 - 100 MW Wind Power Development																			
Base Cost							25.5	101.8									**25.5**	**101.8**	**127.3**
Contingencies							2.5	10.2									**2.5**	**10.2**	**12.7**
Port Handling & other charges (5%)								5.6									**0.0**	**5.6**	**5.6**
Total							28.0	117.6									**28.0**	**117.6**	**145.6**
2038 - 240 MW Solar Power Development																			
Base Cost									39.8	159.3							**39.8**	**159.3**	**199.2**
Contingencies									4.0	15.9							**4.0**	**15.9**	**19.9**
Port Handling & other charges (5%)										8.8							**0.0**	**8.8**	**8.8**
Total									43.8	184.0							**43.8**	**184.0**	**227.9**
Annual Total	**64.9**	**272.7**	**71.8**	**301.6**	**73.6**	**309.2**	**71.8**	**301.6**											

Continued in the next page

Investment Plan for Major Wind & Solar Developments (Base Case), 2022-2041

(Costs in million US$, Exch. Rate:187.2 LKR/US$)

YEAR & PLANT	2037		2038		2039		2040		Total		Grand
	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	L.C	F.C	Total
2038 - 100 MW Wind Power Development											
Base Cost	25.5	101.8							**25.5**	**101.8**	**127.3**
Contingencies	2.5	10.2							**2.5**	**10.2**	**12.7**
Port Handling & other charges (5%)		5.6							**0.0**	**5.6**	**5.6**
Total	28.0	117.6							**28.0**	**117.6**	**145.6**
2039 - 240 MW Solar Power Development											
Base Cost			39.8	159.3					**39.8**	**159.3**	**199.2**
Contingencies			4.0	15.9					**4.0**	**15.9**	**19.9**
Port Handling & other charges (5%)				8.8					**0.0**	**8.8**	**8.8**
Total			43.8	184.0					**43.8**	**184.0**	**227.9**
2039 - 100 MW Wind Power Development											
Base Cost			25.5	101.8					**25.5**	**101.8**	**127.3**
Contingencies			2.5	10.2					**2.5**	**10.2**	**12.7**
Port Handling & other charges (5%)				5.6					**0.0**	**5.6**	**5.6**
Total			28.0	117.6					**28.0**	**117.6**	**145.6**
2040 - 240 MW Solar Power Development											
Base Cost					39.8	159.3			**39.8**	**159.3**	**199.2**
Contingencies					4.0	15.9			**4.0**	**15.9**	**19.9**
Port Handling & other charges (5%)						8.8			**0.0**	**8.8**	**8.8**
Total					43.8	184.0			**43.8**	**184.0**	**227.9**
2040 - 100 MW Wind Power Development											
Base Cost					25.5	101.8			**25.5**	**101.8**	**127.3**
Contingencies					2.5	10.2			**2.5**	**10.2**	**12.7**
Port Handling & other charges (5%)						5.6			**0.0**	**5.6**	**5.6**
Total					28.0	117.6			28.0	**117.6**	**145.6**
2041 - 240 MW Solar Power Development											
Base Cost							39.8	159.3	**39.8**	**159.3**	**199.2**
Contingencies							4.0	15.9	**4.0**	**15.9**	**19.9**
Port Handling & other charges (5%)								8.8	**0.0**	**8.8**	**8.8**
Total							43.8	184.0	43.8	**184.0**	**227.9**
2041 - 100 MW Wind Power Development											
Base Cost							25.5	101.8	**25.5**	**101.8**	**127.3**
Contingencies							2.5	10.2	**2.5**	**10.2**	**12.7**
Port Handling & other charges (5%)								5.6	**0.0**	**5.6**	**5.6**
Total							28.0	117.6	**28.0**	**117.6**	**145.6**
Annual Total	**71.8**	**301.6**	**71.8**	**301.6**	**71.8**	**301.6**	**71.8**	**301.6**			

Note:

(i) Disbursement start from year 2022 onwards.

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

Actual Generation Expansions and the Plans from 1993-2022

Year	Actual Expansions	Long Term Generation Expansion Plan (LTGEP)																
		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	2018-2037	2022-2041
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	00-ST PAR 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	285-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*285-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	320-FO	-
2019	–	–	–	–	–	–	–	–	–	–	420-GT	300-CO	–	250-TPCL	2*300-CO	35-GT 300-LNG	300-LNG 120-Uma Oya 2*35-GT	-
2020	–	–	–	–	–	–	–	–	–	–	–	105-GT 300-CO	300-CO	–	–	15-THAL	35-BDL 15-THAL 35-GT	-
2021	–	–	–	–	–	–	–	–	–	–	–	–	300-CO	2*300-CO	300-CO	250-TPCL**	300-LNG	-
2022	–	–	–	–	–	–	–	–	–	–	–	–	300-CO	300-CO	300-CO 49-GIN	31-Moragolla 20-SEETHA 20-GIN 250-TPCL**	31-Moragolla 20-SEETHA 20-GIN	35-BDL 120-Uma Oya
2023	–	–	–	–	–	–	–	–	–	–	–	–	–	300-CO	2*300-CO	163-AES CCY(LNG) 300-ASC CO	163-AES CCY(LNG) 300-ASC CO	130 GT
2024	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	300-ASC CO	300-ASC CO	31-Moragolla 350-CCY LNG
2025	–	–	–	–	–	–	–	–	–	–	–	–	–	2*300-CO	300-CO	200 PSPP	300-ASC CO 200 PSPP	350-CCY LNG 300 Coal LVPS**
2026	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	200 PSPP	200 PSPP	250 Gas Engine LNG

Note: ORE Plants are not indicated ** Approval was not granted by PUCSL +PPA has extended and procurement of power plants by CEB is under consideration

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, PSPP - Pumped storage power plant

ශ්‍රී ලංකා මහජන උපයෝගිතා කොමිෂන් සභාව
இலங்கைப் பொதுப் பயன்பாடுகள் ஆணைக்குழு
PUBLIC UTILITIES COMMISSION OF SRI LANKA

ඔබේ අංකය / உமது இல. / Your No. }

අපේ අංකය / எமது இல. / Our No. } PUC/LIC/AP21/01

දිනය / திகதி / Date } 5th October 2021

Authorized officer for Licensees: EL/T/09-001
General Manager
Ceylon Electricity Board
3rd Floor, No 50, Sir Chittampalam A Gardiner Mawatha
Colombo 02.

Dear Mr. Ranathunga,

Least Cost Long Term Generation Expansion Plan 2022-2041

Reference is made to your letter ref. GP/CE/EXPAN/F-101 dated September 16, 2021, regarding the above subject.

The draft of LTGEP 2022 – 2041 was submitted to the Commission in July 2021 and the Government policy in respect of electricity industry approved by the Cabinet of Ministers was conveyed to the Commission by the Secretary, Ministry of Power as per section 5 of Sri Lanka Electricity Act on 04th August 2021 stating the following commitments from Sri Lanka.

- To achieve 70% renewable energy in electricity generation by 2030
- To achieve Carbon Neutrality by 2050 in electricity generation
- No capacity addition of Coal power plants

Also, the same was communicated to the Chairman and General Manager of CEB by the Secretary. Hence, the Commission decided to grant a period of 09 months to prepare and submit a draft LTGEP in alignment with the Government Policy. However, considering your request the Commission in terms of section 43 of the Sri Lanka Electricity Act grants approval to following developments identified in the draft LTGEP 2022- 2041 as there would be no hindrance to meet the commitments made by the said policy to the power sector due to those developments.

- All renewable energy power plants identified in the Base Case Plan of the LCLTGEP 2022-41
- Thermal power plants which comply with the government policy sent by the Secretary, Ministry of Power by the letter PE/TECH/D/42/03 dated 04/08/2021 (copy attached) in respect of the section 5 of Sri Lanka Electricity Act

The Commission requires you to submit the Least Cost Long Term Generation Expansion Plan prepared in compliance with the government policy on or before 30th June 2022.

Thank you,
Yours Sincerely,

Public Utilities Commission of Sri Lanka

Janaka Ratnayake
Chairman

06.වන මහල, ලංකා බැංකු වෙළඳ කුළුණ, 28. ශාන්ත මයිකල් පාර, කොළඹ 03.
06 ஆவது மாடி, இலங்கை வங்கி வர்த்தகக் கோபுரம், 28, செண் மைக்கல் வீதி, கொழும்பு 03.
Level 06, BOC Merchant Tower, 28, St. Michael's Road, Colombo 03, Sri Lanka.

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