ECONOMICS OF REACHING YEAR 2015 NON-CONVENTIONAL RENEWABLE ELECTRICITY GENERATION TARGET

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degree of Master of Science

by

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DECLARATION

The work submitted in this dissertation is the result of my own investigation, except where otherwise stated.

It has not already been accepted for any degree, and is also not being concurrently submitted for any other degree.

UOM Verified Signature

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21-09-2010

I endorse the declaration by the candidate.

UOM Verified Signature

Professor.H.Y.R. Perera

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Abstract

As per 2008 National Energy Policy, it is envisaged to reach 10% of electricity energy generation by end of year 2015 from Non-Conventional Renewable Electricity (NCRE) generation sources. As per generation data, NCRE projects have generated around 525 GWh of electric energy during 2009. To reach this envisaged amount by end of year 2015, total annual NCRE contribution has to be increased to 1700 GWh as per year 2005 and 2008 Long-Term Generation Expansion Plan (LTGEP) demand predictions.

To encourage more private investments on NCRE resources for grid connected power generation, Sustainable Energy Authority (SEA) has introduced cost based and source specific tariff system. However, when implementing this new tariff structure, SEA has to subsidize this new tariff system since its tariff is higher than present CEB avoided cost tariff especially during initial years of operation.

In this study, present CEB avoided cost calculation methodology has been reviewed to reflect more realistic avoided cost as per Small Power Purchase Agreement (SPPA) guidelines. With proposed modifications to the present methodology of avoided cost calculation, avoided cost of CEB has been forecasted for until year 2020 based on data available in LTGEPs. Also based on the identified potential NCRE sources, tariff commitments of SEA has been calculated under constant terms for each year when reaching year 2015 NCRE generation endeavor. Here, analysis has been done under different scenarios to analyze the return on overall investment with varying fossil fuel prices.

Net revenue of SEA will largely depend on fuel prices, plants implementation and retiring schedules as well as combination of NCRE power plants in operation. As per the considered scenarios, to breakeven the NCRE tariff investment, average crude oil prices should at least reach 100 – 120 US $ per barrel.

List of Abbreviations

CEB	Ceylon Electricity Board
SEA	Sustainable Energy Authority
CCY	Combined Cycle
NCRE	Non-Conventional Renewable Electricity
CPC	Ceylon Petroleum Corporation
SPP	Small Power Producer (or Small Power Plant)
CDM	Clean Development Mechanism
WASP	Wien Automatic System Planning (model)
METRO	Medium Term Reservoir Optimisation (model)
IPP	Independent Power Producer
LTGEP	Long-term Generation Expansion Plan
SPPA	Small Power Purchase Agreement (of CEB)
GWh	Gigawatthour
kWh	kilowatthour
MW	Megawatt
ENS	Energy not Served
NPV	Net Present Value
FOR	Forced Outage Rate
LDC	Load-duration Curve
GHG	Green house gasses
HV	High Voltage
MV	Medium Voltage
CCPI	Colombo Consumer Price Index
SRC	Short Rotational Coppicing
UNFCCC	United Nations Framework Convention on Climate Change
EU ETS	European Union Emission Trading Scheme
CCX	Chicago Climate Exchange

Chapter 1

Introduction

With the advancement of technology, a lot of successful techniques have been developed over the years to utilize renewable resources for electricity generation. This has lead to remarkable growth in non- conventional renewable electricity generation all over the world with the policy measures introduced to promote the sector.

As a tropical country, Sri Lanka is blessed with various renewable energy sources. In the present context, utility scale electricity generation is mostly limited to conventional types of power plants, such as large scale hydro power stations and thermal power stations and a small number of scattered renewable plants. As it stands, most of the small scale renewable plants are small hydro power plants, which were implemented by private investors. Around 5.5 % of electrical energy served through the national grid is provided from these non conventional renewable energy sources [1].

Most of these small scale grid connected power plants are presently selling energy to national grid under SPPA, signed by respective developers with CEB. Here, these plants are directly connected to the distribution network and the capacities should be below 10 MW [2]. Since these plants are connected to the distribution network, these generators are identified as embedded generators. CEB view these embedded generators as unpredictable negative loads in localized level [3].

1.1 Present power system

Power system consists of Generation, Transmission and Distribution network of electric power. In Sri Lanka, CEB is the statutory body with the responsibility of transmission and most of the generation and distribution of electricity.

Since 1996, CEB allows addition of private power plants to the national grid. These power plants are twofold; one is dispatchable thermal power plants, which connects to the system under different power purchase agreements between CEB and respective private power producers. Other one is renewable power plants, which are not dispatchable power plants and the capacities are less than 10MW. These renewable power plants have a Standard Power Purchase Agreement with CEB. As far as transmission and distribution networks are concerned, all the operations are under the control of CEB except small a section of distribution. which is given to a another subsidiary of CEB.

Sri Lankan electricity requirement was growing at an average rate of 6 - 8% annually [4], a trend which is expected to continue in the future, even though a slowdown in demand growth has occurred in last few quarters [5].

1.2 Generation facilities

Before 1990, CEB had access to low cost hydro power due to implementation of large hydropower stations under various schemes. After completion of most of the main hydro power stations, CEB had to install thermal power plants to cater the ever rising electricity demand. Due to non implementation of remaining large scale hydropower plants already planned and the relatively cheap coal-fired power plants, CEB had to depend on high cost oil power plants. Presently all our petroleum products being imported for all the thermal power plants, which accounts for around 40% of county's annual fuel bill [6]. In this context, as a nation we are heavily dependent on highly fluctuating and highly polluting thermal power plants for our electricity requirements.

Table 1-1: Summary of Electricity generating sources of year 2009

Source of Energy	Capacity (MW)	Average Annual Energy (GWh)	Energy Contribution (%)
CEB Hydro	1185	3845	40%
CEB Thermal	492	1923	20%
IPP - Thermal	805	3312	34.5%
Renewable	194	525	5.5%

Table 1-1, shows the summary of present generation mix in Sri Lanka [3]. Available electricity generation sources can be categorized into four types, such as CEB hydro, CEB thermal, private thermal plants and Renewable plants. As per available maximum energy capacities of each sector, average thermal power contribution is high as 55% out of the total available generation capacity, as against 40% in CEB hydro. Due to the limited availability of sites for hydro electric power plants, CEB Hydro electric contribution is not increasing significantly and expected to drop to 15% of annual requirement by year 2020.

Apart from CEB Thermal power plants, several independent power producers, such as Lakdanavi (pvt) Ltd, Asia Power (pvt) Ltd, ACE Power Matara, ACE Power Horana, Heladanavi, AES Kelanitissa and Kerawalapitiya CCY are in operation. Presently these private thermal power plants have the capacity to contribute around 30% of total electricity requirement. Except AES Kalanitissa and Kerawalapitiya CCY, which have combined cycle plants, all other IPP plants are diesel engines.

1.3 Transmission & Distribution facilities

CEB Transmission facilities consist of all the 132 / 220 kV transmission network and their grid substations. High tension 220kV system is mainly used to transmit power from Mahaveli hydropower generating stations to main load centers. High tension 132 kV transmission network is used to inter connect most of the grid substations and to transfer power from other power stations [7].

The distribution voltage levels used in Sri Lanka are 33 kV, 11 kV and 400 V. Medium voltage distribution lines originate from grid substations, where the 132 kV / 220 kV lines terminates. All the power plants that come under SPPA are connected to these distribution lines.

1.4 Current status of Non conventional renewable power generation

Non conventional renewable sources include Mini Hydro, Wind, Biomass, Municipal Waste heat energy, Solar .etc. As it stands Mini Hydro power plants dominate in NCRE sector.

Due to the favorable topographical and hydrological conditions that prevail, especially in Western slopes of hill country, a lot of mini hydro power projects have been developed to harness this potential. By middle of year 2010, it single handedly contributes 172 MW cumulative capacity and around 505 GWh of electric energy per year to the national grid [23].

In March 2010, Sri Lanka's first ever commercial scale Wind power plant was commissioned in Mampuri of the Puttalam District, with the installed capacity of 10MW. In addition to that there is a 3 MW of Wind power plant done by CEB, however that is considered as a pilot Wind power project. In addition to that, there is 1 MW Dendro power plant done by Lanka Transformers Ltd in Walapane area [8] and another 10 MW Biomass project has been commissioned by Tokyo Cement Company in year 2009.

1.5 Savings on Foreign Exchange

High level of thermal energy generation, which needs imported fossil fuels, has contributed to drain out country's precious foreign exchange reserves to a larger extent during past few years. Therefore, there is an urgent need to minimize the outflow of foreign exchange. The main advantage lies in the fact that there is no recurrent foreign exchange commitment after installation of renewable sources, compared to available thermal power plants. In the case of coal and thermal units, coal and oil have to be imported, incurring valuable foreign exchange, which has to be borrowed at high interest. The cost in foreign exchange also escalates due to the fall in the values of the local currency at around 6% per year in countries like Sri Lanka [6]. As per SEA's estimates, addition of each MW of non conventional renewable sources for electricity generation can save around Rs. 25 million of foreign exchange by means of reducing thermal power generation in each year [11].

1.6 Energy Security

There are a few commodities which a country should be less dependent on other countries. Energy is one such important item. Since our electricity mix is very much depending on imported fossil fuels, our energy future is uncertain. As energy demand increases, dependency on imported fuel sources will increase. We would be both literally and metaphorically near the end of the line for fossil fuels and any interruption in that supply could leave us without power. The Non conventional renewable sources are free energy sources, widely available and will never run out. Electricity generated from these indigenous sources will be vital in building a secure and sustainable energy future that will help keep the lights on.

1.7 Jobs and the Economy

Renewable energy sources generate more than just electricity. It also generates more jobs per unit of energy produced than most other forms of energy. In gas (and oil) fired plants fuel costs account for much of the operating expenses. However, with renewable sources, the majority of the operating expenses will remain within the country, in the form of wages.

Moreover much of the employment occurs in economically disadvantaged rural areas where employment opportunities are both scarce and low paying [11].

The government spends large sums of money to keep people in employment. Different energy options offer different levels of employment opportunities. Out of feasible non conventional renewable sources, Dendro power plants offer most number of employment opportunities, due to its dependency on fuel food supply. Therefore, construction of the Non-conventional renewable energy power plants will enable employment avenues in many remote rural areas.

The final cost of energy could be divided into two distinct components, namely local and foreign. As per present policies followed by CEB, composite cost has been compared with various energy generation options, when selecting power plants as per least cost principle. From the macroeconomic prospective of the country, this local cost component would help to stimulate other economic activities within the country. Since, these non conventional electricity generation options have fairly large portion of local cost components compared to thermal power plants, implementation of these power plants will help to improve the other sectors of the economy as well.

1.8 Renewable Energy Development Policy

World crude oil and coal prices had reached to all time record levels in mid 2008, then prices started to reduce dramatically during later part of 2008 and early part of year 2009 fueled by world economic recession. With the recovery of world main economies, fossil fuel prices start rising since mid 2009 and now crude oil prices are fluctuating from 70 – 80 US $ / Barrel. Therefore a high dependence on an energy source with highly fluctuating prices for power generation is questionable. From energy security point of view, it is advisable to strike a balance between thermal power generation and promoting of non conventional renewable energy generation by considering macroeconomic benefits and sustainable development of the economy.

By taking all those aspects into account, the government has decided to accelerate the utilization of non conventional renewable sources for utility scale power generation. As a result of it, government has declared their ambitious target for renewable sources in 2008 through national energy policy.

As per national energy policy, published by Ministry of Power and Energy in 2008, Sri Lanka will endeavor to generate at least 10 % of electricity generation from non conventional renewable energy sources by end of 2015.

1.9 Role of Sustainable Energy Authority in NCRE Generation

The non conventional renewable energy sources, by definition, do not include large hydro power plants but includes Small Hydro, Wind, Dendro, Municipal waste plants and others [12]. Earlier development of renewable sources was entrusted to CEB. Since CEB has its own interests as a commercial entity, which may not always match with the interest of development of utility scale renewable sources has hampered the development in this sector. Therefore, the government has decided to entrust this responsibility to a separate entity to fast-track the utilization of renewable sources. That was, one of the main motive to establish Sri Lanka Sustainable Energy Authority (SEA) in 2007, under the Ministry of Power and Energy.

Presently, SEA has introduced a new cost-based tariff system by replacing the earlier avoided cost tariff system, which was offered by CEB. Up to now CEB pays all the renewable sources the same avoided cost of CEB, irrespective of the renewable energy source used for power generation. However, this avoided cost tariff was not attractive for private investors to invest on renewable sources other than mini hydro. Under the new system, difference between cost based tariff & avoided cost will be financed by SEA. Therefore introduction of new tariff system will not be an undue burden on CEB or the electricity consumers due to effort in renewable energy development.

1.10 Present Status of NCRE Generation

Table 1-2: Present Status of NCRE –May 2010

Project Type	**Capacity (MW)**
Mini Hydro	174
Dendro and Biomass	11
Wind	10
Waste Heat Recovery	0.1
Solar Power	0.018
Total - Commissioned	195

With the establishment of necessary regulations and frame works to install NCRE plants, NCRE generating plants have been feeding to the national electricity grid since 1997. Table 1-2 shows the present status of these plants as at May 2010 [23].

Since 1996 up to year 2010, CEB had published their seasonal tariff for NCRE projects based on avoided cost principle. Figure 1-1 illustrates the historical variation in CEB avoided cost tariff for NCRE projects [23].

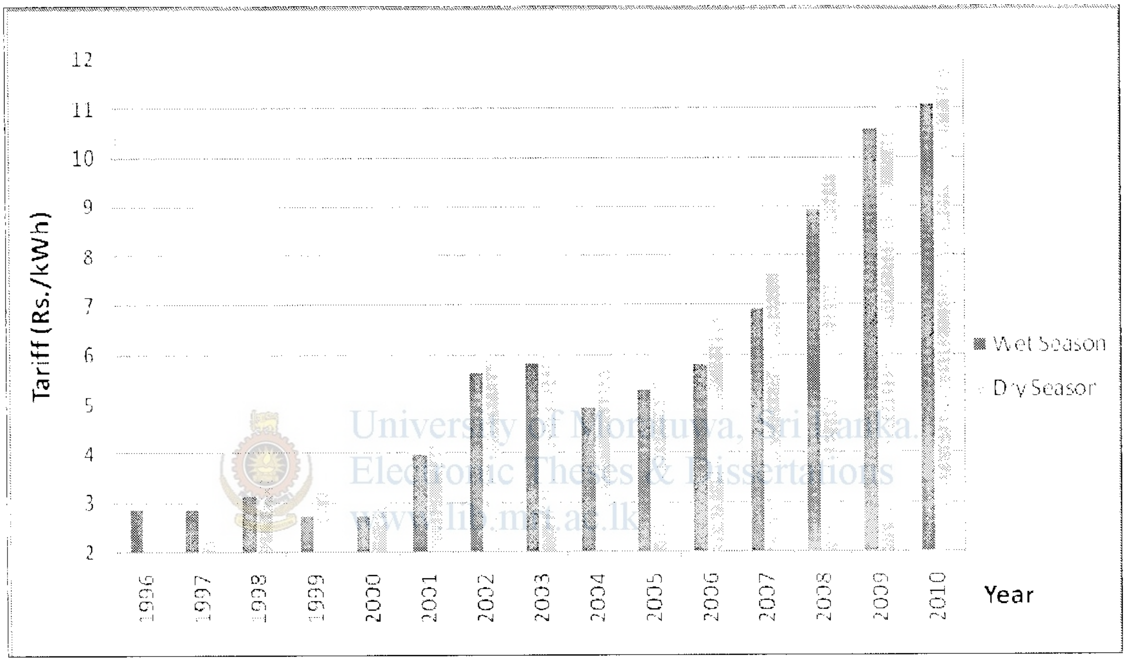

Figure 1-1: SPP Tariff from 1996 to 2010

1.11 The Problem Statement

When reaching renewable electricity generation target, SEA has to subsidize the present avoided cost tariff offered by CEB, since SEA cost based tariff is more than present avoided cost of CEB. Therefore SEA has to invest on renewable tariff especially during initial phase of development. The amount of investment will largely depend on expected avoided cost of CEB as well as renewable energy generation mix in each year. This information is very much important to decision makers to arrange necessary funds to subsidize NCRE tariff in timely manner. Here, it is questionable whether present CEB avoided cost calculation does reflect the correct avoided cost of CEB as per SPPA. Also it is necessary to find out the overall economics of this investment under different scenarios to see whether overall cost when reaching this NCRE electricity generation target.

1.12 Manifestation of the Problem

The absence of economic analysis on NCRE tariff investment will make it difficult for policy makers to arrange necessary funds to meet NCRE tariff commitments in timely manner. Since, these funds are required to be arranged from international donor agencies, negotiations must commence in advance to secure soft loans. However, it will be difficult to start negotiations for loans due to lack of information on the expected investment on NCRE tariff. On the other hand, SEA has to negotiate with CEB in advance to correct present avoided cost calculation methodology to reflect true avoided cost of CEB due to NCRE plants. Otherwise, SEA tariff commitments will be more than legitimate value due to present underestimation of avoided cost.

1.13 Objectives of the Dissertation/Research

The main objective of this study is to analyze the economics of this expected upfront investment on NCRE tariff when reaching the projected renewable energy generation target by end of year 2015. Since, investment on tariff will largely depend on CEB avoided cost, present CEB avoided cost calculation methodology will be scrutinized to identify possible modifications to reflect actual avoided cost as per SPPA guidelines. Here, scenario study will be carried out to see the economics of the investment under different circumstances.

1.14 Studies done on this topic

Several studies have been done on SPP tariff related issues, since the inception of grid connected SPP. Out of them, following studies are found relevant to this topic.

- Study on Grid Connect Small Power Tariff, in Sri Lanka by Resource Management Associates (Pvt.) Ltd, 2001 [14] – In this study, concerns of SPP developers about calculation methodology of SPP tariff was extensively discussed with possible modifications for the calculations as well.
- Implication of Carbon Credit on Sri Lankan Power Sector by Final year students of University of Moratuwa, 2007 [21] – In this study it mainly focuses possibility of CDM funds to promote NCRE projects.
- Pricing of Embedded Generation: Incorporation of externalities and avoided network losses by Asanka S. Rodrigo, Priyantha D.C. Wijayatunga, 2007 [15] – In this study it had mainly studied on variation in avoided network losses in the system.

Chapter 2

Avoided Cost Calculation Methodology

Presently most of the renewable energy plants, which are connected to national grid, are governed by SPPA signed between CEB and private renewable developers. This standard agreement includes, all the requirements to be fulfilled by independent power producers or the CEB, including tariff commitments. As per SPPA, CEB agrees to pay their avoided cost to renewable electricity developers after deducting their agreed overhead cost, irrespective of the source of renewable generation. Here, CEB has to announce renewable energy tariff at the end of each year valid for the following year. Tariff announced by CEB is seasonal, which consist of dry and wet periods, dry tariff is applied for month of February, March and April and wet tariff is applied for remaining months in the year.

In SPPA, guidelines are given to calculate renewable energy tariff. As per guidelines, avoided cost of generation is the cost of fuel and other variable O & M costs of the generation avoided, when a power purchase is made from renewable sources. Assuming merit order running, the generation displaced would be from the most expensive plant running at that time, in other words a marginal unit. The marginal cost of generating this unit is the cost of fuel and other variable operational and maintenance cost of the marginal plant [2].

2.1 Principles behind Avoided Cost Calculation

When dispatching power plants to meet the demand, System Control Center dispatches power plants based on merit order. Thus, most expensive thermal power plant is to dispatch as the last option to meet the demand by keeping hydro generation capacities at optimum level. So, theoretically renewable energy at any given instant expected to replace equivalent amount of energy from most expensive power plant at that time.

Dispatching and backing off power plants to meet the demand is a complex real time exercise done by System Control engineers. On the other hand, all the renewable generators are non-dispatchable generators and System Control Center doesn't know the exact contribution from those plants at a given moment, since there is no mode of online data transferring facility between System Control Center and those power plants. Due to these complexities in the system controlling process, the replacement of most expensive source of energy from renewable sources can't be expected to happen all the time. Therefore, practically it is very difficult to predict exact energy generation reduction from each thermal power plant due to renewable contribution.

In practice, System Control Center can reduce the generation from CEB hydro sources if renewable energy is available, even though it is difficult to reduce it from most expensive energy source at a given moment. Then later, excess hydro energy saved due to renewable sources can be used to reduce the most expensive form of energy at a different period. but at that time most expensive source of energy may not be same as at the earlier occasion.

2.1.1 Assumptions in Avoided Cost Calculation Methodology

When estimating the cost saving on CEB due to renewable energy. calculation has to be done to find out the possible net generation reduction expected from each thermal power plant. due to renewable energy inclusion to the system. Here, owing to above mentioned complexities involved in real time plant dispatch arrangements, certain assumptions have to be made to estimate avoided energy cost to justify the methodology stated in SPPA. Out of that, main assumptions can be described as follows,

1. Here, it is assumed that all the dispatched plants operate at its full capacity. For example, if the plant factor of a thermal plant is 20%, it means that the plant is to run at full load for 20 % of the time, but not any other combinations, like running at its half load for 40% of the time which is also equivalent to same plant factor. If marginal power plants operate at partial loads, then it gives higher avoided cost. Therefore, this assumption is more favorable to CEB. Due to this assumption, it is possible to use plant factor of each power plant to estimate expected reduction from each thermal power plant due to renewable energy.

2. To reduce the complexity in estimates, it has been assumed that constant power supply from all the renewable sources combined together for period concerned. So that, known amount of renewable capacity can be used to replace most expensive thermal source at a given time. The assumed constant capacity can be decided based on the projected renewable energy for that particular period. However, in reality available renewable

capacities vary seasonally. Since there are several types of renewable sources are available and their seasons of maximum availability also do vary from place to place, extensive study has to be done to estimate available capacities in each period concerned. If the renewable energy contribution is more than the estimated average amount, then the actual generation reduction fraction from the most expensive source in the system for avoided cost would be low, on contrary, contribution from most expensive plants would be more if the renewable generation is below the expected average. Therefore it is justifiable to assume average renewable capacity in avoided cost calculation.

3. After calculating the plant factors, expected reduction of energy due to renewable energy has to be calculated. This is being done by stacking power plants based on their individual avoided cost. As per present methodology used for avoided cost calculation, it is assumed that power plants are stacked in on top of the other by keeping least cost plants at the bottom, so that renewable sources are always expected to replace most expensive source of thermal energy at any given moment.

2.1.2 Stacking of Power Plants to Meet the Demand

Figure 2-1 shows the load duration curve, on a typical day (June 2008).

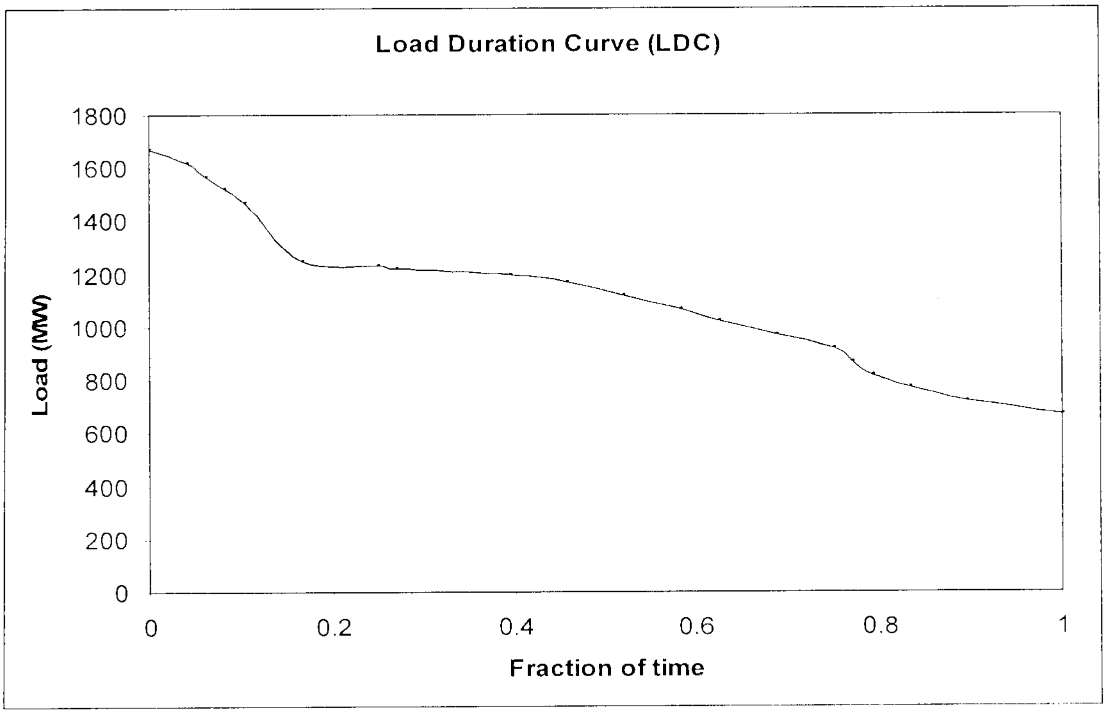

Figure 2-1: Load Duration Curve

To meet the required demand, plants are to be dispatched to fit into load duration curve. Table 2-1 shows, some of the thermal plants with their characteristics. For convenience of explanation, only the selected thermal power plants are being listed. Here, thermal plants are sorted in descending order based on their avoided cost per kWh.

Table 2-1: Characteristics of thermal Power plants

Plant	P,F	Capacity (MW)	Avoided cost (Rs./kWh)
GT 7	0.05	115	25.61
ACE Embilipitiya	0.56	100	13.90
Asia Power	0.72	49	13.10
Heladanavi	0.85	100	12.60
KPS-JBIC	0.77	163	11.82
Sapugaskanda Ext	1.00	72	11.63

Figure 2-2 further illustrates the possible dispatching sequence of selected thermal power plants to meet the demand based on their merit order of dispatch. Here, it is assumed that plants are stack one after the other based on their merit order. In addition to the above mentioned power plants, there are several other thermal power plants and CEB hydro power plants in the system to meet the demand.

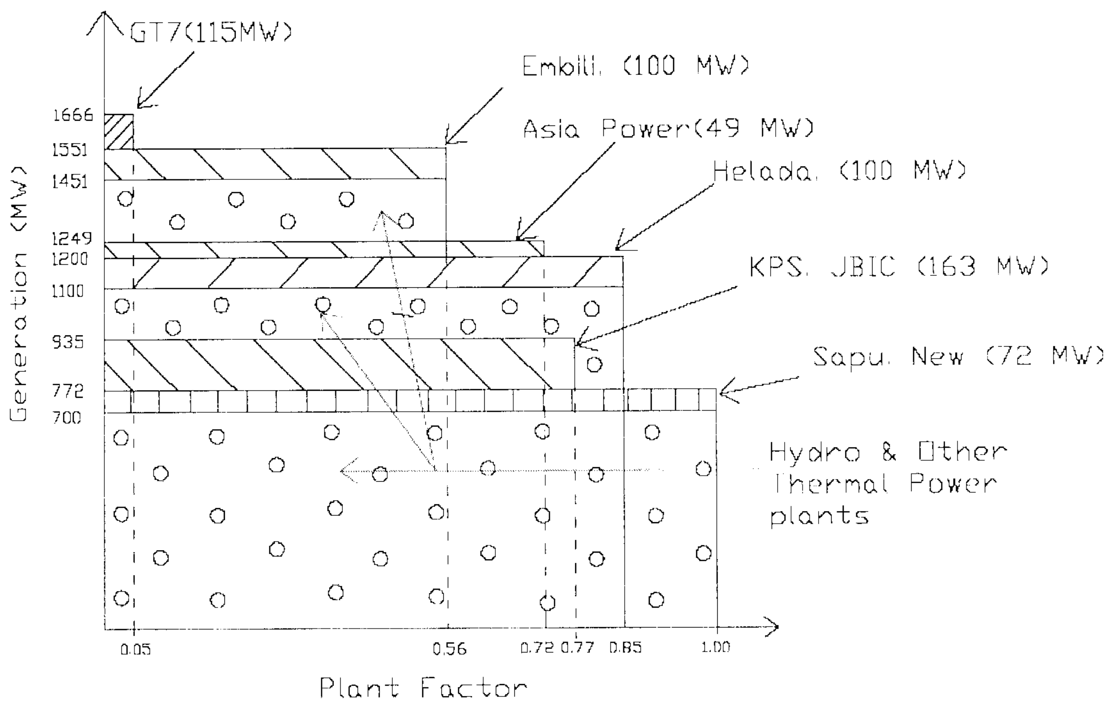

Figure 2-2: Plant Dispatch Schedule

2.1.3 Marginal Thermal Power Plants

In avoided cost calculation, only the marginal thermal power plants are being considered. These are the plants to reduce their generation due to renewable generation. As shown in figure 2-2 GT 7, ACE Embilipitiya, Asia Power, Heladanavi and Sapugaskanda New are the marginal power plants, which can partially back off when the energy from renewable sources are available. And KPS – JBIC power plant doesn't act as a marginal plant, since its plant factor is less than the maximum plant factor of the plants, with higher avoided cost.

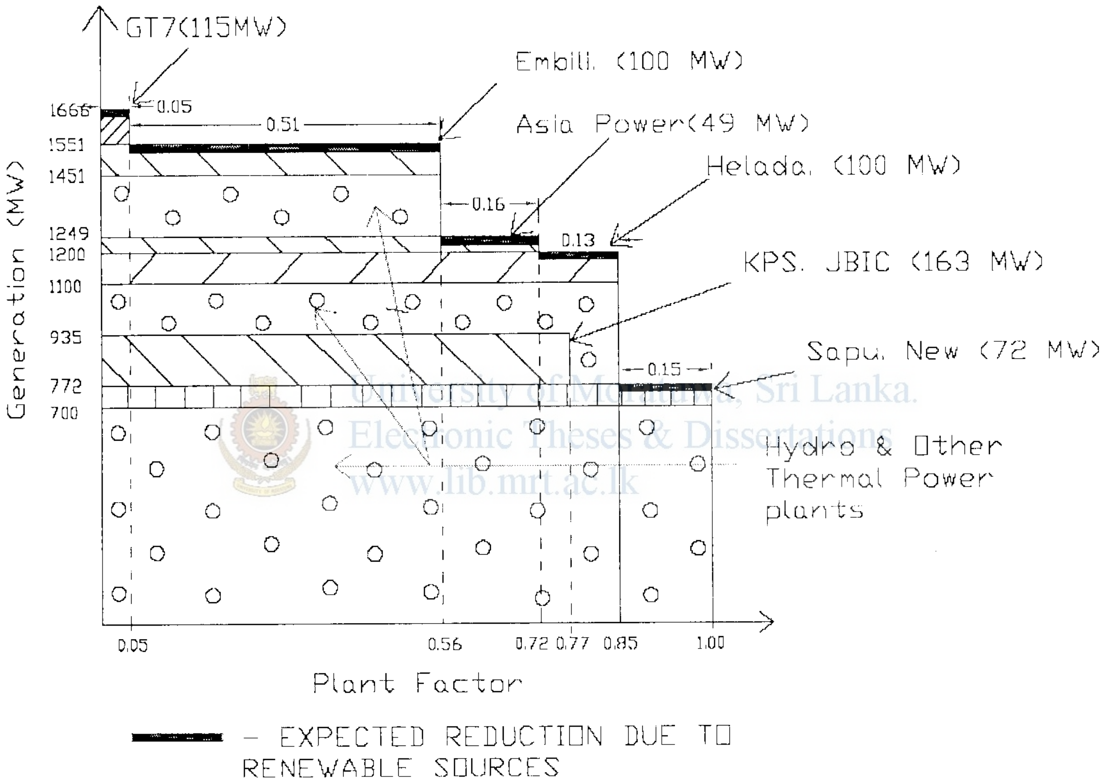

Figure 2-3: Reduction of Generation from Marginal Power Plants

After plotting the plant dispatch graph, expected reduction of capacity from each marginal plant, due to renewable sources, can be calculated as illustrated in figure 2-3. Here, for explanation purposes, it is assumed that the average contribution from renewable sources as 25 MW (correspond to 220 GWh per year). Based on this, expected use of renewable energy to replace marginal plants can be calculated as below.

Table 2-2: Fraction of Time in Margin

Marginal Plant	GT – 7 (115MW)	Embilipitiya (100MW)	Asia Power (49MW)	Heladanavi (100MW)	Sapu. Ext. (72MW)
Plant factor	0.05	0.56	0.72	0.85	1
Expected Fraction of Renewable Energy usage	0.05	0.56 – 0.05 = 0.51	0.72 – 0.56 = 0.16	0.85 – 0.72 = 0.13	1.00 – 0.85 = 0.15

This expected fraction of renewable energy usage by each thermal power plant is defined as fraction of time in margin in avoided cost calculation.

2.1.4 Average Avoided Cost Calculation

As per above fractions of time each thermal power plant in margin, 05% (11 GWh), 51% (112 GWh), 16% (35 GWh), 13% (28 GWh) and 15% (33 GWh) of renewable energy would be used to reduce the generation from GT -7, Embilipitiya, Asia Power, Heladanavi & Sapugaskanda Ext. respectively. Thus, the contribution for overall avoided cost from each marginal plant should be proportional to the fraction of time each power plant is in margin. Individual contribution for avoided cost can be calculated by multiplying, fraction of time in margin by individual respective avoided cost. Summation of these individual contributions for avoided cost gives average CEB's cost saving per unit of renewable generation as shown in table 2-3.

Table 2-3: Sample Avoided Cost Calculation

Marginal Plant	GT – 7 (115MW)	Embilipitiya (100MW)	Asia Power (49MW)	Heladanavi (100MW)	Sapu. Ext. (72MW)
Plant factor	0.05	0.56	0.72	0.85	1
Fraction of time in margin	0.05	0.51	0.16	0.13	0.15
Avoided cost (Rs./kWh)	25.61	13.90	13.10	12.60	11.63
Avoided cost contribution from each plant (Rs.)	25.61X0.05 = 1.28	13.90X0.51 = 7.09	13.10X0.16 = 2.10	12.60X0.13 = 1.64	11.63X0.15 = 1.74
Average Avoided Cost (Rs.)	13.85				

2.2 CEB's Avoided Cost Calculation Steps

CEB is to prepare avoided cost tariff for each year at the end of the preceding year. considering the dispatch schedules prepared by System Control Center. These dispatch schedules are prepared on monthly basis, based on expected fuel prices, availability of hydro capacities, machine maintenance schedules, expected system demand, etc in coming operational year. Present CEB methodology of calculating renewable energy tariff is described below.

Stage A

First of all avoided cost per kWh of each thermal plant in operation has to be calculated with applicable fuel costs and other plant data, such as average fuel usage for each kWh. Here, the applicable fuel cost will be determined on the basis of the fuel price calculated by the Ceylon Petroleum Corporation in its fuel sales to CEB in the following year. In this exercise, CEB assumes that there is a station loss of 3% in each thermal plant and another avoided transmission loss of 3.2 %. Even though actual station and transmission losses do vary with the type of plant, capacity and the location, to simplify the calculation CEB uses constant percentages for all the thermal plants.

Stage B

After calculating the overall avoided cost of each thermal plant in the system, thermal plants would be sorted in descending order based on their average avoided cost.

Stage C

Then expected plant factor of each thermal power plant for each month would be calculated as per the dispatch schedule prepared by System Control Center with METRO software. Here, this dispatch schedule is prepared, based on available hydro capacity, predicted system load and maintenance schedules of power plants. Due to these variables, these dispatch schedules don't always tally with predicted yearly dispatch schedules in the LTGEPs, prepared based on WASP software.

Stage D

After calculating the expected plant factor for each month, fraction of time that each plant operates in the margin during a given month has to be calculated. This fraction of time in margin gives the expected fraction of contribution from each thermal power plant for avoided cost.

There are several methods of estimating fraction of time, of the i^{th} plant is in margin (f_i). Like "WASP III+" or "METRO" software models can be used to estimate it. These two software models provide estimates of the energy expected to be delivered from each power plant during each month within the period of analysis.

Theoretically for any particular month, summation of these fractions of margins should be equal to 1 ($\sum f_i = 1$)

f_i means fraction of i^{th} power plant at the margin.

Stage E

After calculating the fraction of time each power plant operates in margin, individual avoided cost contribution from each plant can be calculated by multiplying avoided cost and the respective monthly fraction of time each plant in margin. Summation of those individual contributions from thermal power plants, gives the total avoided cost for the period concerned.

Avoided cost = $\sum C_i.f_i$; C_i is the marginal cost of i^{th} power plant.

After calculating the avoided cost of respective months, dry season tariff can be calculated by averaging the avoided costs in months of February, March and April. And the average of the remaining months gives the wet season tariff.

CEB retains 1.5% of calculated avoided cost as their overhead cost to recover their additional expenses incurred due to embedded generators. This charge should cover,

a. Costs of reading the meter and processing the payments to SPPs

b. Maintenance of the meters and the metering transformers.

c. Maintenance of transmission line extension and clearing of way leaves between the grid and the SPP.

After excluding CEB's overhead cost from avoided cost, tariff would be announced by taking the three year moving average.

2.3 Comments on CEB Avoided Cost Calculation

As per the definition of avoided cost calculation, CEB is to calculate their cost saving by means of estimated reduction in thermal energy generation due to availability of renewable energy. So, avoided cost calculation should reflect the true cost saving due to reduction in thermal energy generation. In this section, identified concerns areas in CEB avoided cost calculation methodology has been discussed.

2.3.1 Summation of Fractions of Time in margins

As explained in tariff calculation procedure of CEB, avoided cost contribution from each thermal power generation plant would be estimated based on their individual avoided cost and their fraction of time in margin during period concerned.

Here, if all the renewable energy generated is used to replace thermal power generation, then summation of this fraction of time in margin should be equal to 1 during that period. This value may be less than 1, only if CEB has to reduce their net hydro generation to absorb energy from renewable energy sources. In this scenario, it has to be assumed that avoided cost of CEB hydro plants as zero. However, as per the present power generation mix in Sri Lanka, it is very unlikely that renewable energy would cause to net reduction in CEB hydro generation. Because, even as per dispatch schedule of year 2008, most of the thermal power plants, such as Sapugaskanda old and new diesel sets and some of the IPP thermal power plants are being used as base load power plants.

Figure 2-4 shows the sample daily generation curve, for 31st July 2008. Here, generation has been basically broken into several segments, such as CEB hydro, Sapugaskanda CEB, Kelanithissa CEB and IPP thermal to illustrate the typical contribution from each sector during a typical day. As per the figure, total generation is varying between maximum generation of 1660 MW at peak load and minimum generation of 696 MW during night off peak. So the ratio between maximum to minimum generation is 2.39.

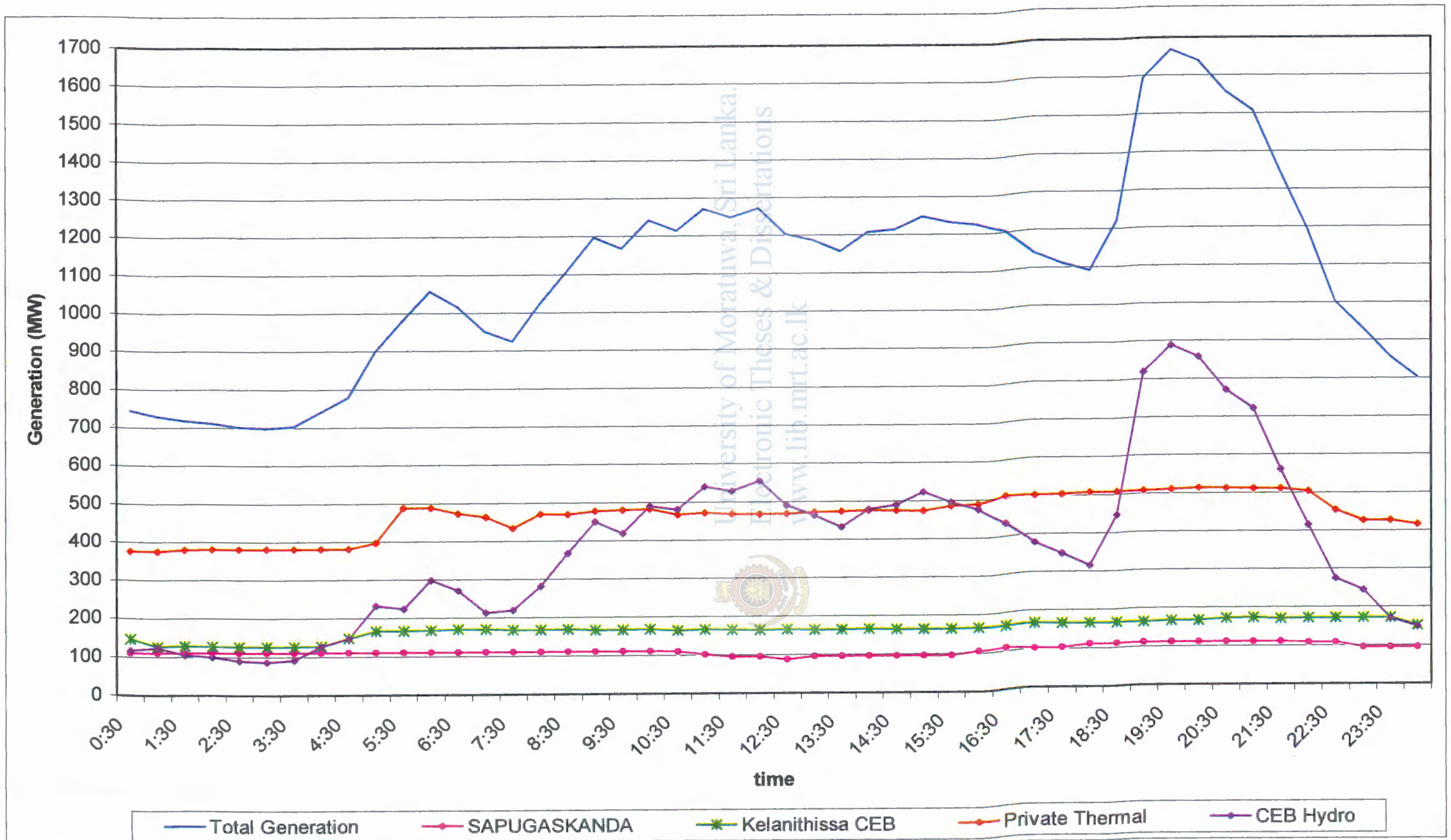

Figure 2-4: Daily Generation Curve on 31st July 2008

Table 2-4: Plant Maximum to Minimum Ratios during a Typical Day (31st July 2008)

Plant Segment	Minimum Gen. (MW)	Maximum Gen. (MW)	Max. / Min. Ratio
Sapugaskanda	84	109	1.29
Private Thermal	373	510	1.37
Kelanithissa CEB	125	171	1.37
CEB Hydro	84	886	10.53
Total Generation	696	1667	2.39

Table 2-4 shows the maximum to minimum generation ratios of each plant category on a typical day. This shows that thermal generation from various sources combined together don't vary as much as the daily total generation and CEB hydro generation do. From above table it is also conclusive that most of the thermal power plants act as base load power plants, fluctuations in demand are mainly accommodated by varying the generation from CEB hydro power plants by keeping their total energy generation at a maximum level. This makes it clear that, almost 100 % of renewable energy can be used to partially back off the most expensive power plants in the system at any given time.

As it stands (2010), capacity of total CEB hydro is 1185 MW. Since present generation is varying from 1750 MW to 750MW, theoretically there is a possibility of meeting the total demand in certain times of the day only with CEB hydro power plants. However, System Control Center dispatches CEB hydro power plants to optimize the available CEB hydro generation. Therefore, under normal circumstances System Control Center dispatches CEB hydro for its full capacity to meet peak load and keep the hydro generation at low level during off peak hours to preserve water in the reservoirs for peak operation. Therefore, net reduction in CEB hydro electric energy generation is only possible due to renewable energy at a time when CEB hydro reservoirs are spilling and unable to load it to maximum potential due to the availability of renewable energy generation in the system after removing all the thermal power plants. However this is a very unlikely situation, occurrence of this kind of situation is extremely rare as per past generation records. In addition, the CEB hydro component as a percentage in the system is expected to reduce significantly in coming years, since the expected CEB hydro power expansion is very limited, compared to the demand growth.

In order to reflect the true avoided cost of generation from renewable energy sources, summation of fractions of time in margin should be decided for each year separately. For current generation mix, this value should be very much close to 1.

As per avoided cost calculation of CEB, summations of fractions of time in margins of thermal power plants are very much less than 1. In year 2008 CEB tariff calculation, summation of fractions of margins varies from 0.78 to 0.91. This means around 9 to 22% of renewable energy is being estimated to reduce zero cost CEB hydro generation. Therefore, it is questionable whether this calculation reflects the true avoided cost as per the definition.

As explained above CEB's avoided cost calculation methodology, summation of fraction of time in margin is always equal to the maximum plant factor of the thermal power plant in operation. Since, CEB uses, apparent plant factors instead of actual plant factor of those plants, it gives summation of marginal factors very much less than 1 [14]. Difference between actual and apparent plant factors can be explained from sample calculation given below:

As per dispatch schedule prepared by System Control Center, maximum plant factor expected in January 2008 is from Sapugaskanda Ext.

Expected energy generation from Sap. Ext in January 2008 = 48 GWh

Capacity of Sap. Ext = 72 MW

Plant factor without taking actual availability into account $= \frac{48 \times 1000}{72 \times 24 \times 31}$

$= 0.89$

Thus $\sum f_i$ during January 2008 as per CEB calculations $= 0.89$

But, Expected availability factor during month of January of Sapu. Ext is $= 0.9$

Effective plant factor with availability factor $= \frac{48 \times 1000}{72 \times 24 \times 31 \times 0.9}$

$= 0.98$

Thus, Actual $\sum f_i$ during January 2008 $= 0.98$

Likewise, plant factors have been calculated in CEB methodology, without taking availability factors into account. Therefore, plant factors used in CEB calculation are less than the actual plant factors of those thermal power plants with more accurate running times.

On the other hand, CEB uses these actual plant factors in their short term and long dispatch schedule preparation with METRO & WASP software models, where the plant factors are higher than the plant factors which were used in avoided cost calculations for same period. Thus, summation of fraction of time in margin shows a lower value than the actual and causes to give lesser overall avoided cost than actual.

Following approach has been followed to minimize the error involved in fraction of time in margin calculation,

A) First of all, to correct the plant factor error in the calculation, estimated schedule maintenance days and forced outage rates of each type of plant, available in LGEP [4] and Study On Grid Connected Small Power Tariff, Sri Lanka [14] have been used to calculate availability factors for each type of plant.

Availability factor = (Total days – Scheduled main. days) × (1- Forced outage rate)

Based on above data, average availability factors of each type of thermal power plants can be calculated as follows,

Table 2-5: Average Availability factors of each plant

Plant	FOR	Expected Maintenance Days per year	Availability Factor
GT Old	0.15	40	0.76
GT NW	0.10	30	0.83
Lakdanavi	0.05	30	0.87
Asia Power	0.05	30	0.87
BARGE	0.05	30	0.87
ACE Matara / Horana / Embi.	0.05	30	0.87
Sapugaskanda New	0.05	30	0.87
Sapugaskanda Old	0.07	30	0.85
AES Combined Cycle Plant	0.10	30	0.83
Kera. Combined Cycle Plant	0.10	30	0.83
CEB Combined Cycle plant	0.10	30	0.83
Coal power plant	0.03	40	0.87

Thus, Effective Plant Factor = Apparent plant factor / Availability Factor

This will help to reduce the error involved in effective plant factor calculation. Still availability factor of a plant does vary, based on several other conditions, including its age. In this calculation variation of availability factors other than type of plant is not being taken into account to simplify the calculation.

B) Even with effective plant factors, (which still is an approximate value) summation of the fractions of time in margins, doesn't always come to 1. However, as explained above, theoretically this value should be equal to 1, unless there is a net reduction in CEB hydro energy due to renewable energy. To minimize this error, avoided cost will be adjusted. Here, minimum plant factor of the least cost marginal plant in the system will be considered as 0.98. Thus, it is assumed that, at least 98% of renewable energy would be able to replace thermal power generation.

Summary of expected thermal energy generation and total required generation forecast as per 2005 LGEP is shown in table 2-6.

Table 2-6: Projected Thermal Energy Generation

Year	Predicted Total Energy Generation (GWh)	Predicted Thermal Energy Generation (GWh)	Predicted Thermal Energy Contribution (%)
2010	12168	7388	63%
2011	13115	8018	62%
2012	14126	9109	65%
2013	15214	10212	67%
2014	16389	11326	70%
2015	17684	12632	72%
2016	19067	14080	74%
2017	20552	15505	76%
2018	22140	17145	77%
2019	23832	18845	84%
2020	25653	20660	81%

As per table 2-6, present thermal energy contribution will continue to increase in coming years as per forecasted energy dispatch schedules. So, addition of renewable energy sources for main grid will most probably substitute the thermal energy generation.

2.3.2 Dispatch Schedules to Calculate Avoided Cost

The objective of the avoided cost calculation is to estimate the saving on CEB due to the availability of renewable sources in the system. To obtain this saving, calculation has to be done with dispatch schedules prepared without expected renewable energy, by following the above explained avoided cost calculation methodology. Otherwise, fraction of time in margin calculation would not be correct.

In year 2008 CEB avoided cost calculations, CEB uses dispatch schedules with renewable energy. Therefore, it doesn't correctly represent the true saving due to renewable sources.

The whole idea behind this avoided cost calculation is that the renewable energy can substitute the most expensive form of thermal energy at a given moment. Based on this philosophy, it calculates the fraction of time each thermal plant is in margin, and thereby calculates the amount of reduction that can be expected from each of the thermal power plant due to inclusion of renewable energy. However, if dispatch schedules with renewable sources are used, where expected thermal power reduction is already taken into account, then it only gives the amount of avoided cost for additional renewable energy in addition to what was predicted. This means, relatively low contribution for avoided cost from most expensive plants in the system, since reduction of most expensive thermal energy have already taken place. Thus, dispatch schedules prepared with renewable energy causes an underestimate of the avoided cost.

To explain above scenario further, the comparison between avoided cost calculations done, based on dispatch schedule with and without renewable contributions, are shown in table 2-7. The calculation done, with dispatch schedule including renewable resources show smaller marginal factors for most expensive power plants, causing a reduction in the overall avoided cost.

Therefore dispatch schedule prepared without renewable resources has to be used to obtain more accurate results.

Table 2-7: Comparison of Avoided Cost with and without Renewable Dispatch Schedules (June 2008)

Plant	Without Renewable			With Renewable		
	Plant Factor	Fraction of time in margin	Avoided cost (Rs.)	Plant Factor	Fraction of time in margin	Avoided cost (Rs.)
GT 7	0.05	0.05	1.28	0.04	0.04	1.00
ACE Embilipitiya	0.56	0.51	7.09	0.43	0.39	5.47
Asia power	0.72	0.16	2.10	0.64	0.21	2.70
Heladanavi	0.85	0.13	1.64	0.82	0.18	2.26
KPS-JBIC	0.77	0	0.00	0.77	0.00	0.00
Sapugaskanda Ext	1	0.15	1.74	0.95	0.13	1.52
		1	13.85		0.95	12.94

2.3.3 Dependence of Avoided Cost on Expected Renewable Generation

The avoided cost calculation methodology explained in above sections doesn't take into account the amount of energy expected from renewable sources for a particular period when calculating marginal factors. This can cause to overestimate the avoided cost, if the marginal plant at a given time becomes more than one plant. This happens when the total operational renewable sources capacity exceeds the predicted capacity of the marginal power plant. In this scenario, in addition to predicted marginal power plant, power plant (or plants) with lower avoided cost will also act as marginal plants. Thus, actual average avoided cost will become less than with the predicted single marginal power plant.

This can be further explained with following example, where it assumes average renewable contribution as 70 MW.

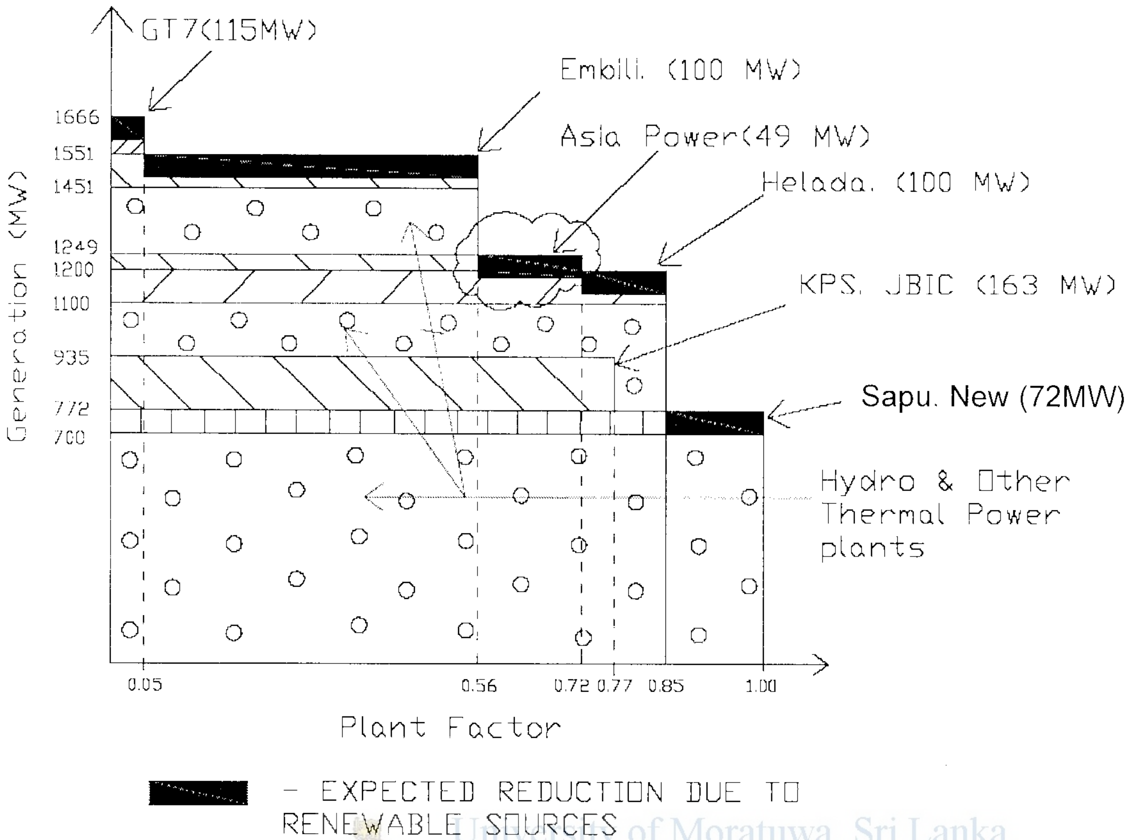

Figure 2-5: Reduction of Thermal Generation due to Renewable Energy at Average Capacity of 70 MW

Here, out of 5 marginal power plants, Asia Power plant's capacity is less than the predicted average cumulative renewable capacity. Thus, at the time when Asia Power plant becomes marginal power plant, renewable energy provides more than the capacity of the Asia Power plant. Thus, it cut into next power plant in line for remaining capacity as shown in figure 2-5. This means, out of average 70 MW renewable capacity, 49 MW would be used to offset the Asia Power plant and remaining 21 MW would be used to offset Heladanavi power plant, which is the next plant in line. Then the effective avoided cost in this period has to be estimated as follows.

Avoided cost in this period = (49 x 13.10 + 21 x 12.60) / 70

= Rs. 12.95

At this instant avoided cost of Asia Power plant has to be taken as Rs. 12.95 instead of Rs. 13.10. Therefore, when the average renewable plant capacity is more than the capacity of marginal power plant, weighted avoided cost has to be used to calculate overall avoided cost. With the projected rise in contribution from renewable energy portion in the system, where it is envisaged to rise from present 525 GWh to 1700 GWh of renewable energy by year 2015, expected renewable generation has to be taken into account when calculating avoided cost, to avoid overestimation of avoided cost.

2.3.4 HV Transmission Loss estimate

In CEB avoided cost calculations, it is assumed that thermal power plants have additional 3.2% of energy loss in the HV transmission network [13]. The actual energy saving owing to reduction of HV transmission losses caused by renewable energy would vary based on factors, such as changes in dispatch schedules, commissioning and decommissioning of thermal power plants, addition of embedded generators, distribution of embedded generators, etc.

According to a study done in 2007, estimated HV transmission loss reduction due to embedded generators is supposed to be around 4.5 %, which is higher than present 3.2% used in CEB calculations [15]. However, if the concentration of embedded generators is increased of a particular substation more than its local load, then excess energy in substation will have to be fed to HV grid through substation's MV / HV transformers. This leads reduce expected energy saving due to HV transmission losses. This scenario is most likely to occur with the increase of renewable energy penetration.

Due to above mentioned complex variables involved in HV transmission loss saving due to renewable energy, an extensive study has to be done in each year to estimate possible HV transmission loss saving. Owing to this difficulty, in this study present CEB's 3.2% HV transmission loss saving have been used.

2.3.5 Fuel cost estimate

When calculating annual avoided cost as per guidelines specified in SPPA, fuel price projections provided by World Bank and adjusted by the Asian Development Bank for the regional market during period concerned have to be used. In practice, CEB uses Fuel prices at the end of the year to calculate the avoided cost for following year. This methodology is acceptable when the fuel prices are stable, but when the prices are fluctuating it doesn't reflect the actual avoided cost. Especially during year 2008 - 2010 world crude oil prices have fluctuated from 150 US $ per barrel to 35 US $ per barrel. On the other hand, it is also very difficult to accurately predict the fuel prices in coming operational year. Therefore, to minimize the inaccuracies involved in avoided cost estimate, it is advisable to use average fuel price during previous year to predict avoided cost in coming operational year.

Since this study is to be done on constant terms, no fuel price fluctuations are being considered during the study period.

2.3.6 Calculation of avoided cost of individual thermal power plants

When calculating avoided cost of each thermal power plant, actual parameters of each thermal power plant has to be used to reflect correct avoided cost of individual power plant. Average avoided cost per unit (kWh) of thermal generation mainly consist of following variables [14],

A) Cost of fuel

B) Variable O & M cost

C) Cost of station losses

D) Fuel transportation cost

E) Cost of transmission losses

Out of above variables, fuel cost is the most dominant component in avoided cost. And cost of fuel per unit (kWh) does vary depending on the type of fuel, generation method, capacity of the plant and the efficiency of the plant.

Table 2-8: Comparison of CEB, Individual Avoided Cost with Estimated Values

Power plant	Avoided Cost		
	CEB (Rs./kWh)	Estimate (Rs./kWh)	Variation (%)
GTs Old (4X17 MW)	38.67	38.42	-0.64%
Colombo Power (60MW)	13.36	13.32	-0.33%
ACE - Matara (20MW)	13.67	13.65	-0.13%
CEB Sapugaskanda old (72MW)	12.63	12.62	-0.04%
ACE - Embilipitiya (100MW)	13.93	13.93	-0.03%
Lakdhanavi (22.5MW)	13.73	13.73	0.01%
ACE - Horana (20MW)	13.55	13.56	0.05%
Asia Power (49MW)	13.13	13.14	0.07%
Heladhanavi (100MW)	12.61	12.62	0.09%
CEB CCY (165MW)	11.81	12.09	2.37%
CEB Sapugaskanda (72MW)	11.37	12.06	6.02%
AES Kelanitissa (165MW)	11.98	14.71	22.77%
GT 7 (115MW)	14.60	26.36	80.53%

Here, individual avoided cost of thermal power plants used in CEB avoided cost calculation is being studied with estimated values. Table 2-8 shows the summary of comparison between CEB avoided cost calculation of individual thermal power plants with values estimated in this study.

As per table 2-8, except AES Kelanithissa and GT 7 power plants, individual avoided cost of all other power plants do not show significant difference between CEB calculation and estimated results. Table 2-9 gives the detailed comparison between CEB and estimated avoided cost calculation for AES Kelanithissa and GT 7.

As per table 2-9, in CEB calculations, GT7 fuel usage rate has been taken as 0.18 liter/kWh, but actually this is as high as 0.32 liter/kWh as per LGEP data sheets for proposed similar type of gas turbines. This has caused to underestimate the avoided cost of GT7 from Rs.26.36 to 14.60. Also in case of avoided cost of AES Kalenithissa power plant, it indicates only Rs. 11.98 as per CEB calculation for year 2008 as against estimated cost of Rs. 14.71. Here, what is give as the fuel cost for AES Kelanithissa, as per CEB calculation is only Rs. 11.61, but this value is also not a realistic value as per data available in LGEP for similar kind of combined cycle projects. Since this plant uses Auto Diesel and it's estimated fuel usage is around 0.18 liters/kWh, actual fuel cost alone come to about Rs. 13.75 as against Rs. 11.61 as per CEB calculation for year 2008.

Table 2-9: Comparison of Avoided Cost Calculation Methodology for AES and GT7 Plants

Description	AES Kelanitissa (165MW)		GT 7 (115MW)	
Calculation category	CEB	Estimate	CEB	Estimate
Fuel Used	Auto Diesel		Auto Diesel	
Fuel Price (Rs/liter)	76.42		76.42	
Fuel Usage (l/kWh)	0.15	0.18	0.18	0.32
Fuel Cost (Rs/kWh)	11.61	13.76	13.44	24.45
Total Fuel cost (Rs/kWh)	11.61	13.76	13.44	24.45
Total variable O&M cost		0.10	0.31	0.37
Station losses (%)		0.03	0.03	0.03
Tx Losses (%)	0.03	0.03	0.03	0.03
Marginal Cost @ 33kV level	**11.98**	**14.71**	**14.60**	**26.36**

The above mentioned avoided cost calculation procedure uses same methodology to calculate avoided cost for both CEB thermal power plants and IPP power plants alike. However, in case of IPP power plants, amount of actual saving on CEB would be more than the estimated avoided cost, because actual selling price per kWh in those IPP plants would be more than their avoided cost, since it includes their profit margins as well. On the other hand, amount of variation between avoided cost and actual selling price of those IPP power plants would vary from plant to plant depending on their agreement with CEB. Since exact difference between estimated avoided cost and actual selling price data is not available, this study will be based on the estimated avoided cost of IPP power plant like in CEB thermal power plants, even though it is more favorable for CEB.

2.4 Comparison of Avoided Cost Calculation for year 2008

CEB has published their 2008 avoided cost tariff, based on dispatch schedule prepared by System Control Center with METRO model, at the beginning of 2008. CEB has published two different tariffs for dry and wet periods by averaging the monthly avoided costs for respective periods. Here, they have taken fuel prices of November 2007, for their calculations.

Dry period avoided cost – Rs. 12.82
Wet period avoided cost – Rs. 12.16
Since avoided cost calculation forecast can only be done in yearly basis, year 2008 avoided cost calculation has been done in yearly basis to compare with CEB avoided calculation results, which was done in monthly basis. Here, both WASP and METRO generated dispatch schedules were used to calculate avoided cost for year 2008.
Fuel prices in table 2-10, which were used by CEB for year 2008 calculation, have been used for this study as well.

Table 2-10: **Fuel Prices for year 2008 Calculations (CEB fuel purchasing rate from CPC on November 2007)**

Fuel	Rs. / Liter
Auto Diesel	76.42
Residual Oil (3000 S)	46.65
Furnace Oil (1500 S)	51.70
Naptha	58.03

Stage A:

Table 2-11 shows the estimated avoided cost calculation for each thermal power plant in year 2008 based on methodology described in section 2.3.

Table 2-11: Avoided Cost of Thermal Unit from Each Thermal Plant for year 2008

Description	CEB Sapugaskanda old	CEB Sapugaskanda	Heladhanavi	Asia Power	Colombo Power	ACE - Horana	ACE - Embilipitiya	ACE - Matara	Lakdhanavi	CEB CCY	AES Kelanitissa	GT 7	GTs Old	Kerawalapitiya GT
Capacity (MW)	72	72	100.0	49	60	20	100	20	22.5	165	165	115	68	200
Fuel Used	HFO 3500s	HFO 3500s	HFO 1500s	HFO 3500s	HFO 1500s	HFO 1500s	HFO 1500s	HFO 1500s	HFO 1500s	Naptha	Auto Diesel	Auto Diesel	Auto Diesel	Low S HFO
Fuel Price (Rs/liter)	46.65	46.65	51.7	46.65	51.7	51.7	51.7	51.7	51.7	58.03	76.42	76.42	76 42	70.86
Fuel Usage (l/kWh)	0.23	0.23	0.22	0.25	0.24	0.24	0.24	0.24	0.23	0.19	0.18	0.32	0.47	0.30
l/kWh	0.23	0.23	0.22	0.25	0.24	0.24	0.24	0.24	0.23	0.19	0.18	0.32	0.47	0.30
Fuel Cost (Rs/kWh)	10.85	10.64	11.17	11.66	12.41	12.25	12.61	12.25	11.63	11.08	13.76	24.45	35.92	21.26
Fuel Transportation cost (Rs/kWh)			0.08			0.03	0.05	0.12						
Total Fuel cost (Rs/kWh)	10.85	10.64	11.25	11.66	12.41	12.28	12.66	12.37	11.63	11.08	13.76	24.45	35.92	21.26
Total variable O&M cost	1.00	0.72	0.64	0.71	0.13	0.48	0.45	0.48	1.30	0.30	0.10	0.37	0.26	0.73
Station losses (%)	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
Tx Losses (%)	3.20%	3.20%	3.20%	3.20%	3.20%	3.20%	3.20%	3.20%	3.20%	3.20%	3.20%	3.20%	3.20%	3.20%
Marginal Cost @ 33kV level	**12.59**	**12.06**	**12.62**	**13.14**	**13.32**	**13.56**	**13.93**	**13.65**	**13.73**	**12.09**	**14.71**	**26.36**	**38.42**	**23.35**

Stage B:

After calculating the avoided cost of each thermal power plant, plants can be sorted based on its avoided costs for further calculations as follows,

Table 2-12: Avoided Cost of Thermal Power Plants for year 2008

Plant	Avoided Cost (Rs./kWh)
GTs Old	38.42
GT 7	26.36
Kerawalapitiya Gas Turbine	23.35
AES Kelanitissa	14.71
ACE - Embilipitiya	13.93
Lakdhanavi	13.73
ACE - Matara	13.65
ACE - Horana	13.56
Colombo Power	13.32
Asia Power	13.14
Heladhanavi	12.62
CEB Sapugaskanda old	12.59
CEB CCY	12.09
CEB Sapugaskanda	12.06

Stage C:

After calculating avoided cost of individual power plants, table 2-13 and 2-14 shows the average avoided cost calculation for year 2008 with both METRO and WASP dispatch schedules. Here, METRO expected annual energy generation is obtained from 2008 predicted energy balance, and WASP energy balances were obtained from LGEPs (2005 report and 2008 report).

Table 2-13: Summary of Avoided Cost Calculated for 2008 with METRO Energy Balance

Plant	Avoided Cost (Rs. / kWh)	Annual Energy (GWh)	Plant Factor	Fraction of the Time in the Margin	Avoided cost contribution from each plant (Rs.)
GT Old	38.42	3	0.004	0.004	0.155
GT7	26.36	25	0.025	0.021	0.548
Kerawalapitiya	23.35	160	0.107	0.083	1.929
AES Kelanitissa	14.71	925	0.640	0.533	7.833
ACE - Embilipitiya	13.93	602	0.687	0.047	0.658
ACE - Horana	13.56	157	0.747	0.014	0.194
Colombo Power	13.32	408	0.776	0.039	0.519
Asia Power	13.14	333	0.776	0.000	0.000
Heladhanavi	12.62	722	0.824	0.048	0.605
CEB Sapugaskanda Old	12.59	381	0.604	0.000	0.000
CEB CCY	11.81	1087	0.752	0.000	0.000
CEB Sapugaskanda	12.06	504	0.799	0.000	0.000
		5584		0.788	12.442

Table 2-13 shows the results of avoided cost calculation done with METRO annual energy balance used by CEB for year 2008 without applying the recommendations made to the calculation in section 2.3. As per CEB avoided cost calculation, average yearly avoided cost is Rs. 12.143 as against above Rs. 12.442. Difference is there, since this calculation has been done with annual energy balance instead of monthly energy balances like in CEB calculation.

Same avoided cost calculation methodology has been followed with WASP energy balances (with 2005 and 2008 LGEP) in place of METRO energy balance for year 2008. Table 2-14 shows the summary of that calculation.

Table 2-14: Summary of Avoided Cost Calculated for 2008 with WASP Energy Balance (with 2005 and 2008 LGEP)

Plant	Avoided Cost (Rs. / kWh)	Annual Energy (GWh)		Plant Factor		Fraction of the Time in the Margin		Avoided cost contribution from each plant (Rs.)	
		2005 LGEP	2008 LGEP	2005 LGEP	2008 LGEP	2005 LGEP	2008 LGEP	2005 LGEP	2008 LGEP
GT old	38.42	15	49	0.020	0.066	0.020	0.066	0.774	2.528
GT7	26.36	491	319	0.487	0.317	0.467	0.251	12.317	6.613
Kerawalapitiya	23.35	345	190	0.232	0.128	0.000	0.000	0.000	0.000
AES Kelanitissa	14.71	599	550	0.414	0.381	0.000	0.064	0.000	0.939
ACE - Embilipitiya	13.93	695	692	0.793	0.790	0.306	0.409	4.262	5.702
Lakdanavi	13.73	155	146	0.786	0.741	0.000	0.000	0.000	0.000
ACE - Matara	13.65	167	162	0.794	0.771	0.001	0.000	0.008	0.000
ACE - Horana	13.56	167	163	0.794	0.775	0.000	0.000	0.003	0.000
Colombo Power	13.32	419	419	0.797	0.797	0.003	0.007	0.040	0.096
Asia Power	13.14	329	329	0.766	0.766	0.000	0.000	0.000	0.000
Heladhanavi	12.62	682	697	0.779	0.796	0.000	0.000	0.000	0.000
CEB Sapugaskanda X	12.59	478	457	0.758	0.725	0.000	0.000	0.000	0.000
CEB CCY	12.09	1007	902	0.697	0.624	0.000	0.000	0.000	0.000
CEB Sapugaskanda	12.06	451	492	0.715	0.780	0.000	0.000	0.000	0.000
		6000	5567			0.797	0.797	17.404	15.879

As per above calculations, results can be summarized as below.

Table 2-15: Summary of Avoided Cost Calculation Results for Year 2008

	CEB calculation	With METRO Energy Balance	With WASP Energy Balance - 2008 LGEP	With WASP Energy Balance - 2005 LGEP
Average Annual avoided cost (Rs.)	12.325	12.442	15.879	17.404
Annual Thermal generation (GWh)	5584	5584	5567	6000
Summation of Fractions of time in margin	0.824	0.788	0.797	0.797

As per table 2-15, WASP generated dispatch schedule gives higher avoided cost than METRO generated dispatch schedules in year 2008. This is mainly due to high expected generation from expensive GT7 gas turbine (491 & 316 GWh as against 25 GWh) in WASP dispatch schedules than in METRO schedule. In calculation based on WASP dispatch schedules in 2005 and 2008 LGEPs, out of Rs.17.40 & 15.88 of total avoided cost, Rs.12.32 & 6.61 have contributed from GT 7 respectively. In METRO based avoided cost calculation, GT7 has only contributed Rs.0.55 out of total avoided cost of Rs.12.44.

As shown in table 2-15, expected annual thermal generation is very much higher in year 2005 LGEP with compared 2008 LGEP and METRO dispatch schedules. This has further cause to increase the estimated avoided cost with 2005 LGEP dispatch schedule, since plant factors of high cost thermal power plants increases when the thermal generation is more. On the other hand, except 2005 LGEP dispatch schedule other two dispatch schedules have been prepared by taking renewable contribution also taking into account, thus it has cause to underestimate those avoided cost estimates as explained in section 2.3.

As per summary of results presented in table 2-16 for year 2008, summation of fraction of time in margins varies from 0.788 to 0.824 for different dispatch schedules. This means avoided cost due to renewable is being considered at zero cost for 21 % to 18 % of renewable energy. Thus, around 70 to 75 GWh (18% to 21% of 350 GWh) of renewable energy is not being taken into account in avoided cost calculation.

This much high zero avoided cost portion shows mainly due to using of apparent plant factor instead of effective plant factor. Above avoided calculations have been done with effective plant factor to reduce the margin of error involved in this avoided cost calculation as explained in section 2.3.

Based on above estimated (table 2-5) average availability factors of thermal power plants, effective plant factor can be calculated. Table 2-16 displays the comparison of avoided cost calculation results with apparent and effective plant factors for year 2008.

Table 2-16: Comparison of Avoided Cost Calculation Results with Apparent and Effective Plant Factors for 2008

	With Apparent Plant Factor				With Effective Plant Factor		
	CEB calculation	Avoided cost calculation			Avoided cost calculation		
		METRO Energy Balance	WASP E. B with 2005 LGEP	WASP E. B with 2008 LGEP	METRO Energy Balance	WASP E. B with 2005 LGEP	WASP E. B with 2008 LGEP
Average Annual avoided cost (Rs.)	12.32	12.44	17.40	15.88	15.52	20.56	16.50
Summation of Fractions of time in margin	0.79	0.79	0.80	0.80	1.00	0.93	0.93

Based on above avoided cost calculation results, it is clear that with effective plant factor it gives higher avoided cost than with apparent plant factor, since it minimize the zero cost renewable contribution. Also it is evident that avoided cost has changed from Rs. 15.52 to Rs. 20.56 with effective plant factors due to variation in dispatch schedules. This clearly indicates the dependency of the avoided cost on dispatch schedule as well.

After estimating avoided cost for a particular year, 1.5% would be reduced to recover additional expenses incurred by CEB due to embedded generators. After that, avoided cost tariff would be announced by taking moving average for 3 years. Table 2-17, illustrate possible annual average tariff under different conditions discussed in detail above.

Table 2-17: Comparison of Avoided Cost Tariff with Apparent and Effective Plant Factors for 2008

	With Apparent Plant Factor				With Effective Plant Factor		
	CEB calculation	Avoided cost calculation			Avoided cost calculation		
		METRO Energy Balance	WASP E. B with 2005 LGEP	WASP E. B with 2008 LGEP	METRO Energy Balance	WASP E. B with 2005 LGEP	WASP E. B with 2008 LGEP
Average Annual avoided cost Tariff (Rs.)	9.12	9.31	10.78	10.28	10.16	11.82	10.49
Summation of Fractions of time in margin	0.79	0.79	0.80	0.80	1.00	0.93	0.93

As per above summary of avoided cost tariff calculation results for 2008, it shows varying results between Rs. 9.12 to Rs. 11.82 under various conditions as explained above sections with constant fuel prices. It is clear from above results, avoided cost tariff does depend on various other factors in addition to fuel prices. Here, above variation of avoided cost tariff occurs due to differences in expected dispatch schedule, fuel usage rate of each thermal power plant and calculation methodology of fraction of time each power plant in margin.

2.5 Avoided Cost Forecast

By keeping in line with avoided cost calculation methodology specified in SPPA, following modifications have been done for avoided cost calculation to maximize the accuracy of avoided cost calculation as explained in section 2.3.

A) Corrected fuel usage rates have been used.
B) Calculated availability factors have been used to calculate effective plant factor.
C) Expected total Renewable energy contributions have taken into account when calculating fraction of time in margin for each plant to avoid overestimation of avoided cost.
D) Summation of fractions of time in margins adjusted to at least 0.98, by increasing the fraction of margin of least cost thermal generation source.

CEB avoided cost tariff calculation methodology with above modifications has been used to forecast respective average avoided tariff up to year 2020 with LGEP dispatch schedules.

During past 2 years, global fuel prices have fluctuated drastically, for instant crude oil price went up to US $ 147 / barrel in August 2008 and then went down to US $ 35 / barrel in February 2009, therefore it is not practical impossible to predict future fuel prices [16]. Due to this reason, avoided cost calculation forecasting has been done with below three scenarios [24].

- September 2008, fuel prices of CEB - (Corr. crude oil price 137 US $/barrel)
- March 2009, fuel prices of CEB - (Corr. crude oil price 37 US $/barrel)
- September 2010, fuel prices of CEB - (Corr. crude oil price 75 US $/barrel)

Table 2-18: Corresponding Fuel Prices for three Scenarios

Fuel	Unit	Fuel Prices		
		Sep. 2008	Mar.2009	Sep. 2010
Auto Diesel	Rs. / liter	110	65	73
Fuel Oil (HFO 3000 s)	Rs. / liter	66	32	34
Fuel Oil (HFO 1500 s)	Rs. / liter	72	25	40
Naptha	Rs. / liter	83	34	46
Low Sulphur Heavy fuel	Rs. / liter	81	31	42
Coal*	US $ / Ton	200	91	110

* Bituminous coal prices were obtained from NEWC index, after that freight chargers were added to calculate the actual cost for each scenario [17].

2.5.1 Basis of Avoided Cost Forecast

This avoided cost forecasting exercise involves a lot of variables. which are difficult to predict in the long run. Therefore, to minimize the effect of those variables on avoided cost calculations. this study has been done under constant terms. Thus, the basis of this study can be summarized as below.

A) All the proposed power plants / old thermal plants will be implemented / retired as scheduled in LGEPs. Here since two different plans (2005 and 2008 LGEP) are being used. study will be done for both scenarios.

B) HV transmission loss saving will remain at 3.2 % and station losses also keep it at 3%.

C) Oil and Coal prices will remain as it is during study period for each scenario.

D) Individual avoided cost of CEB & Private thermal power plants have been calculated with modifications proposed in section 2.3.

E) No change in foreign exchange rates during study period.

F) Yearly dispatch schedules available in LGEP have been used.

G) Data available in LGEP have been used to calculate plant availability factors.

H) Minimum summation of fraction of time in margin has kept at 0.98 by taking the effective plant factor of the least cost thermal plant as 0.98.

2.5.2 Dispatch Schedules for Avoided Cost Forecast

CEB generally use METRO or WASP models to prepare plant dispatch schedules. Out of that, METRO model is mainly used to prepare short to medium term dispatch schedules and WASP model is used to prepare long term dispatch schedules [3]. However, in the context of calculating of generation from each thermal power plant, the facilities offered by METRO are more convenient than those offered by WASP. In particular, the following are attractive.

(a) WASP can't model the addition of new power plants or retirement of existing power plants in the middle of a year. METRO can model such mid-year changes, at the beginning of a month.

(b) WASP cannot consider the opening storage of water available in the CEB reservoirs, to which METRO gives full consideration.

Due to above mentioned advantages in METRO model as against WASP model, CEB uses monthly dispatch schedules prepared by System Control Center from METRO model for avoided cost calculations. Since these monthly dispatch schedules are prepared at the beginning of each year, METRO developed dispatch schedules aren't available for long term forecasting of avoided cost. Thus, this study uses the yearly dispatch schedules available in LGEPs, which were prepared from 'WASP' model.

LGEP is a publication of CEB's Generation Planning Branch and available latest publication was issued in year 2008 for year 2009 to 2022. In addition to that, dispatch schedules in, year 2005 LGEP report also being used in this study. Even though the predicted total generation doesn't show much of a difference, there are considerable differences between dispatch schedules in these two LGEP reports. This includes differences in plant commissioning schedules as well as type of plants to be implemented. As per 2005 LGEP, 105 MW Gas Turbine was to be added to the system in year 2010, however this addition was not included in 2008 LGEP. Even though 2008 LGEP does seem to give more up to date dispatch schedules than year 2005 report, there is a major constraint in 2008 dispatch schedules for this study. Unlike in year 2005 report, 2008 report dispatch schedules are being prepared by taking renewable energy contribution also into account, therefore as explained in section 2.3.2, this cause to underestimate avoided cost.

In the absence of monthly dispatch schedules for long term avoided cost forecast, only average yearly avoided cost can be forecasted. Therefore unlike in CEB avoided cost calculation, there will not be two different tariffs for dry and wet periods.

2.5.3 Renewable Energy forecast

As per National Energy policy, it is endeavored to supply 10% of electricity energy generation from non conventional renewable sources by end of year 2015. To reach this target by year 2015, SEA has set some intermediate mile stones by considering present penetration of renewable sources. In year 2008 non conventional renewable sources have contributed around 4.2 % of the electricity energy demand. Reach the target of 10% by 2015, SEA expects to reach at least 5% by year 2010. This means present (2009) 525 GWh of renewable contribution has to be increased to 600 GWh in 2010. To reach the target of 10% renewable energy supply out of total electricity generation by year 2015. total renewable energy contribution has to be increased by more than 1700 GWh.

Table 2-19 summarizes the one possible non conventional renewable energy additions in each year to reach renewable electricity generation endeavors specified in National Energy Policy.

Table 2-19: Possible NCRE additions in each year to reach the Target

Year	Total Predicted Generation (GWh)	NCRE Generation (GWh)	NCRE Contribution (%)
2010	12168	608	5.00%
2011	13115	850	6.48%
2012	14126	1100	7.79%
2013	15214	1300	8.54%
2014	16389	1520	9.27%
2015	17684	1768	10.00%

National Energy Policy prescribes only NCRE generation ambitions to be achieved by year 2015. And it doesn't illustrate the amount of contribution expected from NCRE sources from each year. Since, the main objective of this study is to study the economics of reaching NCRE generation endeavor. This study has focused on the new NCRE additions up to year 2015 to reach the policy endeavors and completion of their allotted operational period.

2.5.4 Avoided cost Tariff forecast

Avoided cost tariff forecast has been done by taking forecasted WASP generated dispatch schedules available in 2005 LGEP and expected non conventional renewable energy contribution to reach the NCRE electricity generation target.

Table 2-20 shows the avoided cost calculation has done for year 2020 with Sep 2010 fuel prices, as a sample avoided cost forecast.

Table 2-20: Summary of Avoided Cost Calculation for 2020 with September 2010 Fuel Prices

Plant	Avoided Cost (Rs. / kWh)	Annual Energy (GWh)	Plant Factor	Fraction of the Time in Margin	Avoided cost contribution from each plant (Rs.)
GT 35 MW	26.75	2	0.008	0.001	0.02
GT 75 MW	26.75	18	0.033	0.007	0.18
GT 105 MW	25.20	170	0.224	0.064	1.61
AES Kelanitissa (165 MW)	15.61	109	0.086	0.007	0.11
Kerawalapitiya CCY (270 MW)	12.71	155	0.076	0	0
CEB CCY (165 MW)	12.68	163	0.132	0.026	0.32
CEB Sapugaskanda (72 MW)	9.00	98	0.194	0.018	0.16
West and South Coal (3655 MW)	4.94	19945	0.980	0.858	4.24
				0.980	6.65

Here, when forecasting avoided cost, all the proposed modifications proposed in section 2.3 have been followed to improve the accuracy of the tariff calculation.

After forecasting average avoided cost, excluding CEB overhead charges for respective years concerned, SPP avoided cost tariff for each year has been calculated by taking moving average of 3 years.

Table 2-21 shows the results of the avoided cost tariff forecast until year 2020 with Sep. 2008, Mar. 2009 and Sep. 2010 fuel prices.

Table 2-21: Projected Avoided Cost Tariff with Sep 2008, Mar 2009 and Sep 2010 fuel prices

Year	Average avoided cost Tariff with Sep. 2008 fuel prices (Rs./kWh)	Average avoided cost Tariff with Mar. 2009 fuel prices (Rs./kWh)	Average avoided cost Tariff with Sep. 2010 fuel prices (Rs./kWh)	Sum of Marginal factors ($\sum$ fi)
2011	14.23	10.33	11.37	0.98
2012	16.02	8.78	10.64	0.99
2013	18.17	7.94	10.47	0.98
2014	15.75	7.07	9.04	0.98
2015	14.07	6.58	8.11	0.98
2016	12.46	6.03	7.20	0.98
2017	11.71	5.80	6.81	0.98
2018	11.15	5.53	6.50	0.98
2019	10.98	5.46	6.43	0.98
2020	11.03	5.51	6.48	0.98

Table 2-21 shows the projected avoided cost tariff under three different fuel prices. Here, it also shows summation of marginal factors are very much close to unity. This means only around 1 to 2% of renewable energy are not being taken into account when calculating avoided cost tariff as against 17% as per CEB SPP tariff calculations for year 2008. This value has basically reduced due to use of effective plant factors rather than apparent plant factors in avoided cost calculation.

These avoided cost tariff forecast prepared for different fuel prices can be plotted as shown in figure 2-6. Here sep. 08' plot peeks in year 2013 and other plots shows gradual decline. This has happened due to taking of 3 year moving average when calculating avoided cost tariff. In year by year basis all the 3 avoided cost figures peek in year 2010.

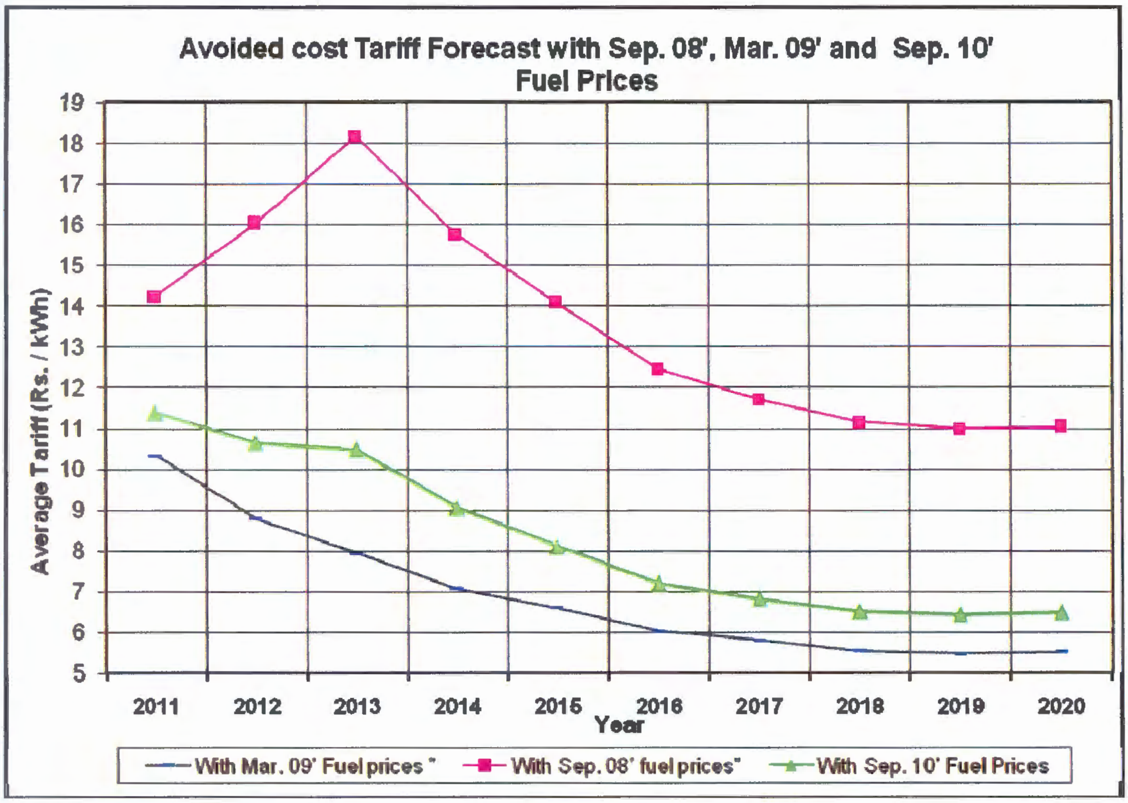

Figure 2-6: Projected SPP Tariff with 2005 LGEP

Due to inclusion of coal power plants to the National Grid from year 2011 onwards, avoided cost tariff starts to decline drastically from 2011 and it will stabilize around 2018 after saturation of coal power plant's energy contribution to the maximum level. At this time coal power plants will contribute around 75% of electricity generation as per LGEPs.

Chapter 3

SEA's investment on NCRE tariff

One of the main objectives of setting up of SEA is to increase the utilization of available renewable resources for grid connected electricity generation. As a result, SEA came up with new cost based, technology specific tariff structure to attract more private investors to invest on these projects, which was mainly restricted to mini hydro development under previous CEB's avoided cost tariff. Since, CEB's avoided cost tariff is source neutral tariff system all the renewable sources are given the same tariff. This makes only the mini hydro plants economically feasible for private investors. Due to this reason, since the opening of opportunities for private investors to implement small-scale renewable power plants, development had been limited to mini hydro power plants.

This new SEA's cost based tariff scheme is very much different to CEB's avoided cost tariff. Also SEA's 3-tier tariff scheme offer higher tariff rates during initial years, which is more than the present avoided cost tariff. On the other hand, as a separate commercial entity, CEB is only willing to pay their avoided cost for renewable energy. Therefore, to implement this new tariff scheme SEA has to invest on NCRE tariff. Amount of investment, SEA has to be made will largely depend on available renewable mix and the CEB's avoided cost.

3.1 New Cost based Tariff Structure

SEA's new cost based tariff structure has designed to encourage private investors to invest on renewable resources, especially sources likes Wind, Biomass and Municipal waste. In this new tariff structure, investors have two options; either they can go for 3-tier tariff structure or flat tariff option.

In 3 –tier tariff system, escalable amounts will be calculated based on five –year average of Colombo Consumer Price Index (CCPI) and the average LKR / USD rates of change. Therefore, tariff will be adjusted every year depending on this escalable percentage. Table 3-1 shows the basis of 3-tier tariff calculation for different sources [25].

Table 3-1: SEA, 3 – Tier SPP Tariff Option (April 2009)

Technology	Escalable Base O&M Rate (Rs.)	Escalable Base Fuel Rate (Rs.)	Non-escalable Fixed Rate (Rs.)		Escalable Year 16+ Base Rate (Rs.)	Royalty to Govt. paid direct by the power purchaser Year 16+
			Year 1 - 8	Year 9 - 15		
Mini - Hydro	1.55	none	14.18	5.16	1.62	10% of total tariff
Wind	2.46	none	22.53	8.19	1.62	10% of total tariff
Biomass (Dendro)	1.24 (1 -15 Years) 1.55 (16th year onwards)	7.14	8.50	3.09	1.62	No Loyalty
Agricultural & Industrial Waste	1.24 (1 -15 Years) 1.55 (16th year onwards)	3.56	8.50	3.09	1.62	No Loyalty
Municipal waste	3.13	none	12.26	4.46	1.62	No Loyalty
Waste Heat Recovery	0.49	none	10.15	3.69	1.62	No Loyalty
Wave Energy	1.01	none	6.58	2.48	1.3	10% of total tariff

Table 3-2 shows the flat tariff rates for different renewable sources. In flat tariff option, there is no escalable part in the tariff. Hence, same tariff will be paid without change for 20 years of operational period [25].

Table 3-2: SEA, Flat Tariff option (April 2009)

Technology	All inclusive Rate (Rs./kWh) for Years 1 - 20
Mini - Hydro	14.58
Wind	23.07
Biomass	18.56
Agricultural & Industrial Waste	13.88
Municipal waste	15.31
Waste Heat Recovery	9.55

Since avoided cost tariff was calculated based on constant terms (0% escalation) only 3 – tier tariff option can be used for this analysis. Because in flat tariff option, tariff is calculated by taking estimated escalation into account, therefore flat tariff option can't be compared with projected CEB avoided cost tariff, which was calculated under constant terms.

Table 3-3: SEA, 3 – Tier SPP Tariff under Constant Terms (0% escalation)

Year	Mini Hydro Rate (Rs. / kWh)	Biomass Rate (Rs. / kWh)	Wind Rate (Rs. / kWh)
1 to 8	15.73	16.88	24.99
9 to 15	6.71	11.47	10.65
16 to 20	2.85	10.31	3.67
>20	2.85	10.31	3.67
Avg. Rate for 20 years	9.02	13.16	14.10

Under constant terms, 3 – tier tariff can be presented as shown in table 3-3 for different renewable sources. Here, only Mini hydro, Biomass and Wind power plants are considered, since implementations of other forms of renewable sources are not expected to be significant during this study period.

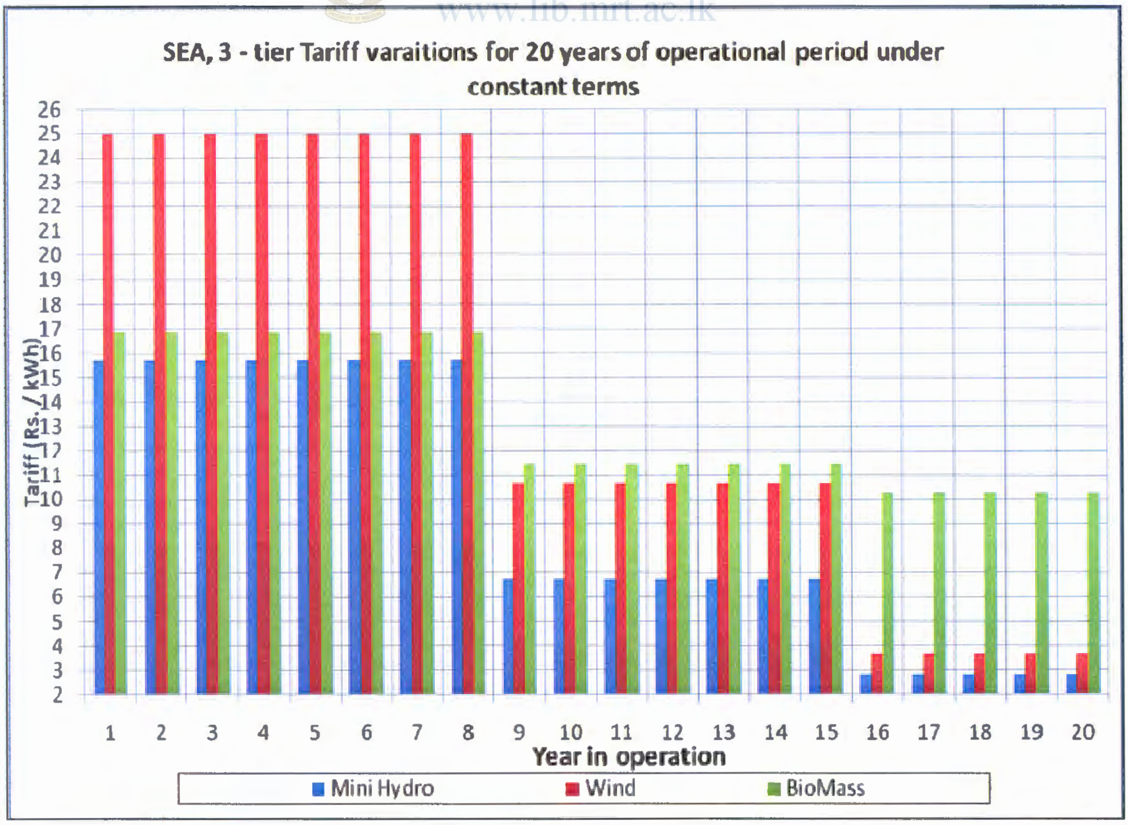

Figure 3-1: Tariff projection as per SEA, 3 – tier option under constant terms

Figure 3-1, further illustrate the projected variation in Mini hydro, Biomass and Wind energy plant's 3 –tier tariff under constant terms. As per figure 3-1, it is clear that Wind and Biomass plants will cost more for SEA than Mini hydro power plants. Also, all the sources are expecting to get higher tariff during their initial years to ease the burden on developer's cash flow, and will get lesser tariff during 2nd and 3rd tiers. Therefore, SEA is basically expecting to recover their investment on tariff during 2nd and 3rd tiers.

At the moment almost all of mini hydro power plants in operation have signed SPPA with CEB for 15 years. Therefore, until it lapses tariff for those power plants will be purely based on CEB avoided cost tariff principle. After completion of contract period of those SPPAs all the plants will have to operate under new SEA, 3 –tier tariff structure under 3rd category (from 16 +).

3.2 Non Conventional Renewable Energy Sources

Over the years, Sri Lanka has exploited large conventional hydro power resources to almost its maximum economical potential. Non conventional renewable energy has become a prime potential source of energy for the future due to the low impact on environment compared with conventional power plants. As far as Non conventional renewable energy sources, which can be utilized for grid integration, following proven options are available in Sri Lanka,

A) Mini Hydro power plants,
B) Wind power plants
C) Biomass power plants
D) Waste heat power plants
E) Others like Solar, Wave energy and ocean thermal power plants

However, this category doesn't include conventional renewable energy sources, such as large scale hydro power plants. Under the present CEB SPP regulations, capacities of these power plants have to be limited to a maximum of 10 MW. Therefore, these non conventional power plants are connected to medium voltage distribution system of the CEB to integrate with national grid as embedded generators.

As of May 2010 around 195 MW of embedded renewable power plants are being connected to the national grid. Out of this, most are mini hydro power plants and there are few other power plants, including recently commissioned 10MW Wind power plant in Puttalam under SEA's tariff scheme. Apart from these grid connected power plants, there are several off grid micro hydro power plants, wind plants, Dendro plants and Solar PV plants available to fulfill basic electricity needs at village level.

As far as Grid connected NCRE power plants are being concerned, all the developments are being done through private investments except CEB wind power plant in Hambanthota and one mini hydro power plant in Nilambe.

3.2.1 Mini Hydro Power Potential

At the moment, Mini hydro power plants are the dominant non conventional renewable form of energy source used for utility scale power production. Presently it accounts for more than 170 MW grid connected capacity. This development of grid connected mini hydro power plants have been started since 1996 after CEB allows private small scale power plants to connect to national grid. Also, mini hydro power is the only source out of renewable, identified as economically and technologically feasible under CEB's avoided cost principle. Topographical nature and relatively high rainfall in Sri Lanka, especially in hill country provide ideal opportunities to develop small scale hydro power plants without much disturbance to the Nature. In addition to that, this is the oldest form of renewable power generating method in Sri Lanka, going back to colonial era as well; therefore there is enough local expertise in this sector.

In addition to already implemented projects, there are considerable untapped potential in the country which can be used for utility scale projects. This includes,

A) Untapped hydro Potential available specially in eastern slopes of hill country.
B) Harnessing the head from irrigation canals, tanks and reservoirs
C) low head projects

As per present SEA statistics, in addition to already commissioned mini hydro power plants initial approval has been given for another 210 MW capacity. These statistics are based on the applications received by SEA for mini hydro power developments. However, study has to be done to identify the actual, economically viable potential available in mini hydro sector for future development.

Development of all those sites will largely depend on availability of infrastructure, mainly availability of grid, economic feasibility and investor's interest.

3.2.2 Wind Electric Potential

Several studies are being done regarding the wind power potential in our island nation by various organizations and individuals. Out of that, studies conducted by Ceylon Electricity Board and National Energy Laboratory of USA are paramount. CEB took the initiative to carry out a detailed wind-monitoring program in the south-eastern part of the country in 1988. The study revealed that the total potential of wind power generation in the South-eastern part of the country to be 200 MW. This excludes the land area for wild life reserves and agriculture.

There are several locations in Sri Lanka that show near-term potential for cost-effective utility scale wind power development given the current economic climate and infrastructure status [18]. The most promising sites identified, in order of potential feasibility, are

- Kalpitiya Peninsula
- National Livestock Board cattle farm near Ambewela
- Southeast coastal areas from Hambantota to Buthawa.
- Several other locations such as Mannar Island

And Jaffna District has favorable wind resource potential. However, the lacks of infrastructure pose significant barriers to near-term development.

Until commissioning of 10MW Wind plant in Puttalam in March 2010, only CEB developed 3 MW wind plant connected to the national grid located in Hambantota on the south-eastern coast. It was planned as a pilot plant for CEB to get hands-on experience and also to study the implications of integrating wind power into the grid system. Compared to mini hydro development, utility scale wind plants are still in its early stages of development. But several private parties have already taken initiatives to harness wind potential in Sri Lanka. With the advancements in technology in wind power plants, wind power has now become the world's fastest growing renewable form of energy.

SEA has already issued initial clearance to develop around 95 MW of wind capacity. Even though there is a huge un-tapped wind potential in Sri Lanka, implementation of these projects are hindered due to network and other infrastructure bottle necks.

3.2.3 Biomass potential

Biomass energy had always been the major source of primary energy in Sri Lanka. At present it accounts for nearly 50% of the total primary energy requirements [19]. For the past many decades, a substantial part of the biomass came from agricultural residues such as rubber plantations, cinnamon crop, coconut plantations, homesteads, fuel wood plantations established by the Forest Departments and some of the tea plantations. A significant quantity also came from unsustainable forest clearings.

There is great potential in Sri Lanka to utilize biomass for utility scale power production. Use of firewood from Short Rotational Coppicing (SRC), sugar cain residue and municipal waste are the most prominent sources of biomass, which can be use for utility scale energy generation. Out of above biomass options, use of firewood from short rotational crops considers to be the most potential source of biomass for electricity generation.

Several studied are being done by the Ministry of Science & Technology with many partner organizations including Coconut Research Institute, many tree species have been tested to be used in Dendro power production. Among them, *Gliricidia sepium, Acacia auriculiformis, Calliandra calothrysus, Leucaena leucocephala* have proven to be successful. The assessment was primarily based on the wood yield, ease of establishment and the ability to withstand frequent coppicing. Further, additional benefits such as rate of leaf decomposition, which leads to the improved nutrient status of the soil, were noted. Based on these results, *Gliricidia sepium* was selected as the best for a major proportion of the country [20].

As per present estimates, SRC can produce around 15 - 20 ton / year. The total extent of degraded marginal lands suitable for energy plantation in Sri Lanka is estimated at 1.6 million hectares. Hence the national potential for Dendro power in Sri Lanka is estimated as 4000 MW annually generating over 24 TWh [20]. This is more than total hydropower potential in this country. As per above statistics, Dendro potential in our country is adequate to meet our electrical energy demand for many decades.

Dendro power provides a significant potential to contribute to national economic growth and employment generation in rural areas, as well as local and global environmental management. With modern technologies, wood and other biomass can provide a competitive and sustainable fuel for processing and conversion into electricity in many situations. This position is expected to develop considerably when more expertise is gained with using biomass as a modern energy carrier.

Even though there is massive potential in sector to develop, only two plants has commissioned in commercial scale up to now. Unlike other renewable sources like mini hydro & Wind power plants, source of energy is not freely available, so maintaining proper supply of firewood is the biggest challenge in this sector.

3.3 Possible Technological Options to Reach the Target

Mini Hydro, Wind and Biomass are the main feasible non-conventional renewable energy generation potentials available for near term utility scale renewable energy developments. As per table 2-19, up to now only around 525 GWh of electric energy is being contributed from these non-conventional forms of energy per annum. To reach the envisaged NCRE contribution by year 2015, this value has to be increased to more than 1700 GWh. That means nearly 3 times the present contribution from the sector.

This is definitely a daunting task to be achieved. Even though there are enough renewable resources to reach this target; successful implementation of these projects will depend on several factors. Here government is only expected to play the facilitation role, such as providing the infrastructure facilities and policy frame work to fast track the implementation of renewable projects through private investments.

Since private investors are involved in development in renewable sector, it is difficult to pin point the exact amount and combination of renewable sources in operation in a particular year. It will largely depend on their interest and opportunities to develop these projects.

There can be several technological options to reach the year 2015 renewable target. Following table shows one possible combination of renewable sources to reach the target by taking into account feasible potential available from each source as per present studies.

Table 3-4: Possible addition of NCRE plants to reach envisaged generation by 2015

Year	Mini Hydro (MW)	Biomass (MW)	Wind (MW)
2010	24	3	10
2011	49	6	11
2012	49	11	9
2013	16	12	10
2014	16	16	18
2015	25	17	14

As shown in table 3-4, envisaged 2015 NCRE generation can be met with above combination. This means another 179 MW of Mini hydro, 65 MW of biomass and 62 MW of wind plants have to be added to the national grid by end of year 2015.

3.3.1 Required Energy contribution from each sector

Table 3-5 shows the possible additional contribution expected from each of these sectors in each year, if plants are implemented according to schedule mentioned in table 3-4. Here, it is assumed that, plant factors of mini hydro, biomass and wind power plants as 42%, 80% and 32% respectively [12].

Table 3-5: Required Additional Energy Contribution from each Sector

Year	Mini Hydro (GWh)	Biomass (GWh)	Wind (GWh)
2010	83	22	30
2011	171	40	28
2012	171	80	25
2013	57	83	28
2014	57	113	50
2015	89	120	40

3.4 Forecasting of SEA Investment on Non-conventional Renewable Sources to meet the Targeted Contribution

SEA cost-based tariff structure has been designed to alleviate the problems of negative cash flow experienced by many SPPs during the period of loan repayment, when the tariff was technology neutral and based on avoided costs to CEB. This means during initial period SEA has to make additional contribution to pay for SPPs with the available CEB's avoided cost tariff.

Amount of investment, SEA has to make on renewable energy tariff when reaching year 2015 non-conventional renewable electricity generation target will depend on several variables. These variables can be mainly categorized into two categories, such as actual combination of renewable energy sources and CEB avoided cost.

Table 3-6 shows one possible combination of non-conventional renewable sources expect to implement under new SEA tariff structure to meet envisaged renewable energy generation. Here, the only difference with table 3-5, which gives the overall plant implementation schedule, is that the part of the mini hydro contribution is not being included for year 2010 in case of table 3-6, since these plants are expected to be commissioned in year 2010 under CEB SPP agreements.

Table 3-6: Possible NCRE Combination comes under SEA's Tariff Structure

Year	Mini Hydro (GWh)	Biomass (GWh)	Wind (GWh)
2010	23	22	30
2011	171	40	28
2012	171	80	25
2013	57	83	28
2014	57	113	50
2015	89	120	40
Total contribution (GWh)	566	458	201
Percentage contribution (%)	46%	37%	17%

As per table 3-6, 46%, 37% and 17% of new renewable energy to be contributed from mini hydro sector, biomass and wind power sources respectively. If the above contribution changes, it will affect net revenue of SEA, since SEA's tariff is source-based. For instance, if the contribution from wind and biomass increases, then overall cost on SEA will increase since average tariff of those plants are higher than mini hydro tariff.

Table 3-7: Comparison of Average Source based Tariff and Forecasted Avoided Cost Tariff

SEA long Term Average Tariff (Rs./kWh)			Average CEB Tariff (Rs./kWh)		
Mini Hydro	Biomass	Wind	With Sep. 08' fuel prices	With Mar. 09' fuel prices	With Sep. 10' fuel prices
9.02	13.16	14.1	12.32	6.50	7.63

Table 3-7 shows the average 3-tier tariff for each main renewable source during their operational period and respective average avoided cost calculated with different fuel prices based on 2005 LGEP. This indicates, average SEA cost based tariff for mini hydro, biomass and wind power plants are more than the average CEB's avoided cost tariff calculated with September 2010 and March 2009 fuel prices. However, avoided cost average tariff calculated with September 2008 fuel prices is higher than the cost based SEA's tariff for mini hydro. Therefore, depending on fuel prices there is a possibility to SEA to cross subsidize wind and biomass projects with mini hydro plants.

SEA's net revenue for each year has been calculated based on estimated CEB's avoided cost tariff and SEA's 3-tier tariff commitments to reach year 2015, envisaged electricity generation from renewable sources. Since, this study concentrate on reaching year 2015 renewable electricity generation target, expected new renewable plants after year 2015 has not been taken into consideration.

Even though non conventional renewable addition is considered only up to year 2015, SEA's net revenue has been estimated until all those renewable plants complete their allotted period. Thus, it will help to evaluate net revenue of SEA, if those renewable plants implemented to meet specified renewable electricity generation target. Since, SEA offer higher tariff at the initial years and expect to recover during 2nd and 3rd tiers, it is very much important to continue this evaluation until all those plants complete their allotted period. Therefore SEA's net revenue from these new NCRE additions up to 2015 has been calculated until year 2034, where the plants implemented in year 2015 will complete their contract period.

Since, latest published LGEP (2008) contains data only up to year 2022, avoided cost for year 2023 to 2034 are assumed as the average avoided cost of last 3 years (2020 – 2022).

In addition to new renewable plants, which are expecting come up under SEA's cost based tariff system, all the present mini hydro plants, which presently operate under CEB's avoided cost tariff, will come under SEA's purview after completion of their allotted 15 years. Absorption of these old mini hydro power plants will commence from year 2012 onwards. Those existing mini hydro power plants will get 3rd tier tariff for another 15 years after expiring of their present SPPA with CEB.

Table 3-8 shows, sector vise and overall SEA's expected net income, when implementing their cost based 3-tier tariff scheme to meet National Energy Policy targets. As per the figures, SEA will need to subsidize, especially until 2026 to meet their tariff commitments. From year 2026 onwards they will have a surplus of income, since most of the implemented plants (up to 2015) are in 2nd or 3rd tier at that time.

Table 3-8: Net Income Calculation Summary of SEA with Sep. 2010 Fuel Prices and 2005 LGEP

Year	Expected New Energy addition from each sector under SEA tariff system (GWh)			Required total allocation to meet SEA 3 - tier Tariff (Rs. Millions)				Net Revenue From each sectors (Rs. Millions)			Net Revenue for SEA (Rs. Millions)
	Mini Hydro	Biomass	Wind	Mini Hydro Energy cost	Biomass Energy cost	Wind Energy cost	Energy cost of old plants	Mini Hydro	Biomass	Wind	
2010	23	22	30	362	371	750	0	(97)	(118)	(404)	(619)
2011	171	40	28	3,052	1,047	1,449	0	(846)	(342)	(790)	(1,978)
2012	171	80	25	5,741	2,397	2,074	20	(1,857)	(886)	(1,191)	(3,880)
2013	57	83	28	6,638	3,798	2,774	60	(2,218)	(1,441)	(1,611)	(5,110)
2014	57	113	50	7,535	5,705	4,023	110	(3,203)	(2,649)	(2,568)	(8,181)
2015	89	120	40	8,935	7,731	5,023	190	(4,330)	(4,018)	(3,393)	(11,391)
2016	0	0	0	8,935	7,731	5,023	270	(4,842)	(4,431)	(3,575)	(12,437)
2017	0	0	0	8,935	7,731	5,023	370	(5,066)	(4,612)	(3,654)	(12,818)
2018	0	0	0	8,727	7,612	4,593	490	(5,033)	(4,633)	(3,286)	(12,325)
2019	0	0	0	7,185	7,396	4,191	630	(3,535)	(4,453)	(2,900)	(10,099)
2020	0	0	0	5,642	6,963	3,833	780	(1,962)	(3,995)	(2,530)	(7,496)
2021	0	0	0	5,128	6,514	3,431	950	(1,453)	(3,551)	(2,131)	(5,931)
2022	0	0	0	4,614	5,902	2,714	1,150	(946)	(2,944)	(1,416)	(3,853)
2023	0	0	0	3,811	5,253	2,141	1,250	(137)	(2,290)	(840)	(1,683)
2024	0	0	0	3,811	5,253	2,141	1,480	(139)	(2,292)	(841)	(1,398)
2025	0	0	0	3,723	5,228	1,931	1,629	(51)	(2,267)	(632)	(887)
2026	0	0	0	3,063	5,181	1,736	1,629	610	(2,220)	(436)	18
2027	0	0	0	2,403	5,089	1,561	1,610	1,269	(2,127)	(262)	918
2028	0	0	0	2,184	4,992	1,366	1,570	1,489	(2,031)	(67)	1,379
2029	0	0	0	1,964	4,861	1,017	1,520	1,709	(1,900)	282	2,016
2030	0	0	0	1,621	4,722	738	1,440	2,052	(1,761)	562	2,676
2031	0	0	0	1,621	4,722	738	1,360	2,052	(1,761)	562	2,575
2032	0	0	0	1,621	4,722	738	1,260	2,052	(1,761)	562	2,448
2033	0	0	0	1,621	4,722	738	1,140	2,052	(1,761)	562	2,296
2034	0	0	0	1,621	4,722	738	1,000	2,052	(1,761)	562	2,119

3.4.1 Scenario Study of SEA's Financial Performances

SEA's net revenue of each year will basically depend on their tariff commitments and CEB's avoided cost. Here, their tariff commitments can vary each year depending on total renewable electricity generation as well as available renewable electricity generation mix. On the other hand, CEB's avoided cost can basically vary, with expected generation mix and fuel price.

A scenario study will be carried out to examine the variation of net revenue of the SEA under different circumstances. As per both, 2005 LGEP and 2008 LGEP, expected electricity generation is around 17500 GWh by year 2015. Therefore, expected electricity generation from NCRE can be kept as it is irrespective of LGEP when reaching NCRE generation endeavor by year 2015. Still, NCRE mix can vary to meet the same targeted renewable energy generation, which can change the tariff commitments of the SEA. As explained in section 3.3 optimum combination of NCRE addition is considered for initial study by considering identified NCRE sources, thus variation in NCRE energy mix has not been taken into account in this scenario study.

On the other hand SEA's main income, which is CEB's avoided cost, can drastically vary based on fuel prices as well as CEB generation mix, which also differs from 2005 LGEP to 2008 LGEP. Therefore, scenario study will be done under following different conditions to examine the net income of the SEA by keeping SEA's tariff commitments as it is.

A) Sep. 2008 fuel prices (with 2005 LGEP & 2008 LGEP)
B) Mar. 2009 fuel prices (with 2005 LGEP & 2008 LGEP)
C) Sep. 2010 fuel prices (with 2005 LGEP & 2008 LGEP)

Table 3-9 shows the net revenue of SEA in each of those scenarios, which involve 3 different fuel prices (Sep. 2008, Mar. 2009 & Sep. 2010) and 2 LGEPs (2005 LGEP and 2008 LGEP). As per the figures in the table, it is clear that a subsidy need to be provided by SEA with 2008 LGEP is more than 2005 LGEP due to its low avoided cost.

Table 3-9 : Summary of Net Revenue of SEA, without Carbon Credit in Different Scenarios

Year	Net Revenue of SEA (Rs. Millions)					
	Sep. 2010 fuel prices		Mar. 2009 fuel prices		Sep. 2008 fuel prices	
	With 2008 LGEP	With 2005 LGEP	With 2008 LGEP	With 2005 LGEP	With 2008 LGEP	With 2005 LGEP
2010	(619)	(619)	(619)	(619)	(619)	(619)
2011	(1,872)	(1,978)	(2,107)	(2,305)	(929)	(1,078)
2012	(3,091)	(3,880)	(3,989)	(4,991)	519	(667)
2013	(4,888)	(5,110)	(6,374)	(7,087)	1,134	882
2014	(8,952)	(8,181)	(10,466)	(10,191)	(2,683)	(1,360)
2015	(14,662)	(11,391)	(15,976)	(13,363)	(8,924)	(3,672)
2016	(14,891)	(12,437)	(16,138)	(13,992)	(9,328)	(5,490)
2017	(14,885)	(12,818)	(16,134)	(14,192)	(9,263)	(6,168)
2018	(13,983)	(12,325)	(15,282)	(13,686)	(8,153)	(5,824)
2019	(11,664)	(10,099)	(13,013)	(11,497)	(5,617)	(3,504)
2020	(9,092)	(7,496)	(10,515)	(8,955)	(2,755)	(668)
2021	(7,663)	(5,931)	(9,123)	(7,445)	(1,127)	1,221
2022	(5,622)	(3,853)	(7,153)	(5,434)	1,101	3,585
2023	(3,492)	(1,683)	(5,059)	(3,300)	3,341	5,920
2024	(3,308)	(1,398)	(4,946)	(3,092)	3,665	6,582
2025	(2,844)	(887)	(4,534)	(2,632)	4,000	7,326
2026	(1,941)	18	(3,631)	(1,727)	4,904	8,233
2027	(1,036)	918	(2,718)	(820)	5,778	9,102
2028	(558)	1,379	(2,228)	(346)	6,198	9,497
2029	98	2,016	(1,556)	308	6,780	10,055
2030	788	2,676	(839)	995	7,352	10,587
2031	718	2,575	(883)	921	7,164	10,357
2032	629	2,448	(938)	829	6,929	10,071
2033	523	2,296	(1,005)	718	6,646	9,727
2034	400	2,119	(1,083)	588	6,316	9,325

3.4.2 Carbon credit for SEA NCRE Projects

Electricity generated from grid connected non-conventional renewable energy sources, replaces the generation from conventional thermal power stations, thus preventing the emissions of greenhouse gases, including carbon and Sulphur dioxides.

Sri Lanka is a United Nations Framework Convention on Climate Change (UNFCCC) member, has signed the agreement and the ratification was given on the 3rd September 2002. The Clean Development Mechanism (CDM) is a win-win proposition: it allows industrialized countries or their authorized private entities to earn emission credits at a cheaper price through projects that contribute to the sustainable development of developing countries [20].

According to the Kyoto Protocol, gas emission reductions generated by CDM project activities must be additional to those that otherwise would occur. Additionality test checks whether the CDM project would have happened anyway or whether it needed the CDM to go ahead. Credits for GHG emission reduction were only be granted for the projects which are additional, that is credits were only granted for the projects which would not have taken place in the absence of the crediting procedure or Implication of Carbon Credits. So in order to obtain credits for a CDM project one must show that the project is impossible without the credits for GHG emission reduction.

Since SEA is offering higher Tariff to promote implementation of renewable energy sources for power generation, there is a strong argument for SEA to claim Carbon credit for energy generation from renewable sources, which are implemented under new SEA Tariff structure. Therefore, in addition to expected revenue from renewable energy income from CEB, SEA is expecting to generate some revenue through CDM as well. Since, NCRE energy to substitute fossil fuel energy generation and in line with all other criteria's of CDM, these plants are eligible to claim for CDM funds. These funds defiantly help to reduce the burden on SEA due to their tariff commitments, especially during initial periods.

Like any other market, purchasing price rate of carbon credit is very much volatile; also it varies from place to place as well. In year 2006 it went even up to 50 US $ per ton of carbon, now it is trading around 20 US $ [21]. Presently, European Union Emission

Trading Scheme (EU ETS) is the largest market for CDM projects. In addition to that, there are several other trading floors, likes of Chicago Climate Exchange (CCX), New South Wales Greenhouse Gas Abatement Scheme (NSW GGAS) and some voluntarily trading schemes.

3.4.3 Scenario study with carbon credit income

Scenario study can be continued with possible carbon credit income for SEA. Table 3-10; illustrate net income of the SEA in each year from renewable electricity sales with carbon credit. As per studies, each kWh of renewable electricity generation can reduce 0.75 kg of carbon emission [21]. Since SEA has large volume of carbon credit, it will be in a better position to get an attractive rate for its carbon credit. However, in this study, it is assumed that rate of carbon credit sales at 20 US$ per ton of carbon (present market price of EU ETS). This means around Rs. 1.68 / kWh additional income can be generated from carbon credit sales for SEA in addition to CEB avoided cost tariff.

Table 3-10: Summary of Net Revenue of SEA, with Carbon Credit in Different Scenarios

Year	Net Revenue of SEA with Carbon Credit (Rs. Millions)					
	Sep. 2010 fuel prices		Mar. 2009 fuel prices		Sep. 2008 fuel prices	
	With 2008 LGEP	With 2005 LGEP	With 2008 LGEP	With 2005 LGEP	With 2008 LGEP	With 2005 LGEP
2010	(493)	(493)	(493)	(493)	(493)	(493)
2011	(1,345)	(1,450)	(1,579)	(1,778)	(401)	(551)
2012	(2,088)	(2,877)	(2,986)	(3,988)	1,522	335
2013	(3,579)	(3,801)	(5,066)	(5,778)	2,443	2,191
2014	(7,245)	(6,473)	(8,758)	(8,483)	(976)	347
2015	(12,488)	(9,218)	(13,803)	(11,190)	(6,751)	(1,499)
2016	(12,671)	(10,216)	(13,918)	(11,772)	(7,108)	(3,270)
2017	(12,605)	(10,539)	(13,855)	(11,912)	(6,984)	(3,889)
2018	(11,634)	(9,975)	(12,932)	(11,336)	(5,803)	(3,474)
2019	(9,231)	(7,667)	(10,581)	(9,065)	(3,185)	(1,072)
2020	(6,572)	(4,975)	(7,995)	(6,435)	(234)	1,853
2021	(5,042)	(3,310)	(6,503)	(4,824)	1,493	3,841
2022	(2,884)	(1,115)	(4,414)	(2,696)	3,957	6,323
2023	(695)	1,114	(2,262)	(503)	6,304	8,717
2024	(375)	1,535	(2,014)	(159)	6,951	9,515
2025	177	2,134	(1,513)	389	7,727	10,347
2026	1,080	3,039	(610)	1,294	8,631	11,254
2027	1,973	3,927	291	2,189	9,493	12,111
2028	2,428	4,364	758	2,640	9,890	12,483
2029	3,054	4,972	1,401	3,264	10,443	13,011
2030	3,697	5,585	2,070	3,905	10,968	13,496
2031	3,580	5,437	1,979	3,784	10,733	13,220
2032	3,432	5,251	1,865	3,632	10,438	12,874
2033	3,256	5,029	1,727	3,450	10,085	12,459
2034	3,050	4,769	1,567	3,238	9,673	11,976

3.4.4 Additional Funds need to Fulfill Tariff Commitments

As per table 3-9 and table 3-10, it is clear that in all considered scenarios, SEA will need external funds to fulfill its tariff commitments, if NCRE plants implemented to reach year 2015 envisaged electricity generation. As per those tables, SEA will mainly need those funds from year 2013 to 2023.

Since SEA is a government authority and trying to promote renewable electricity generation by providing higher tariff in initial years, they will be able to secure soft loan schemes from international donor agencies to subsidize renewable energy tariff. Since, it is expected to be a soft loan, in this study it is assumed that the rate of interest as 4 %. By assuming those conditions net present value of SEA`s overall income during concern period has been calculated for all the considered scenarios.

Table 3-11: Summary of SEA's NPV of Income for Different Scenarios

Fuel price (crude oil – US $ / Barrel)	LGEP	NPV of cumulative income with 4% Discount rate (Rs. Millions)	
		Without carbon credit	With carbon credit
Sep. 2010 - 75	2005	(66,395)	(32,749)
	2008	(88,005)	(54,359)
Mar. 2009 - 37	2005	(88,954)	(55,307)
	2008	(108,154)	(74,508)
Sep. 2008- 137	2005	31,087	64,734
	2008	(2,967)	34,224

As per table 3-11, except with September 2008 fuel prices in all the other considered scenarios, SEA's net overall income is in negative terrain. This means, in all those other considered scenarios, government of Sri Lanka need to subsidize renewable energy sector, when reaching the 2015 envisaged renewable electricity generation.

This scenario study data has been used to analyze the NPV of SEA's net income with variation in crude oil prices. Figure 3-2 shows the variation of NPV of SEA's net income due to their tariff commitments against crude oil prices.

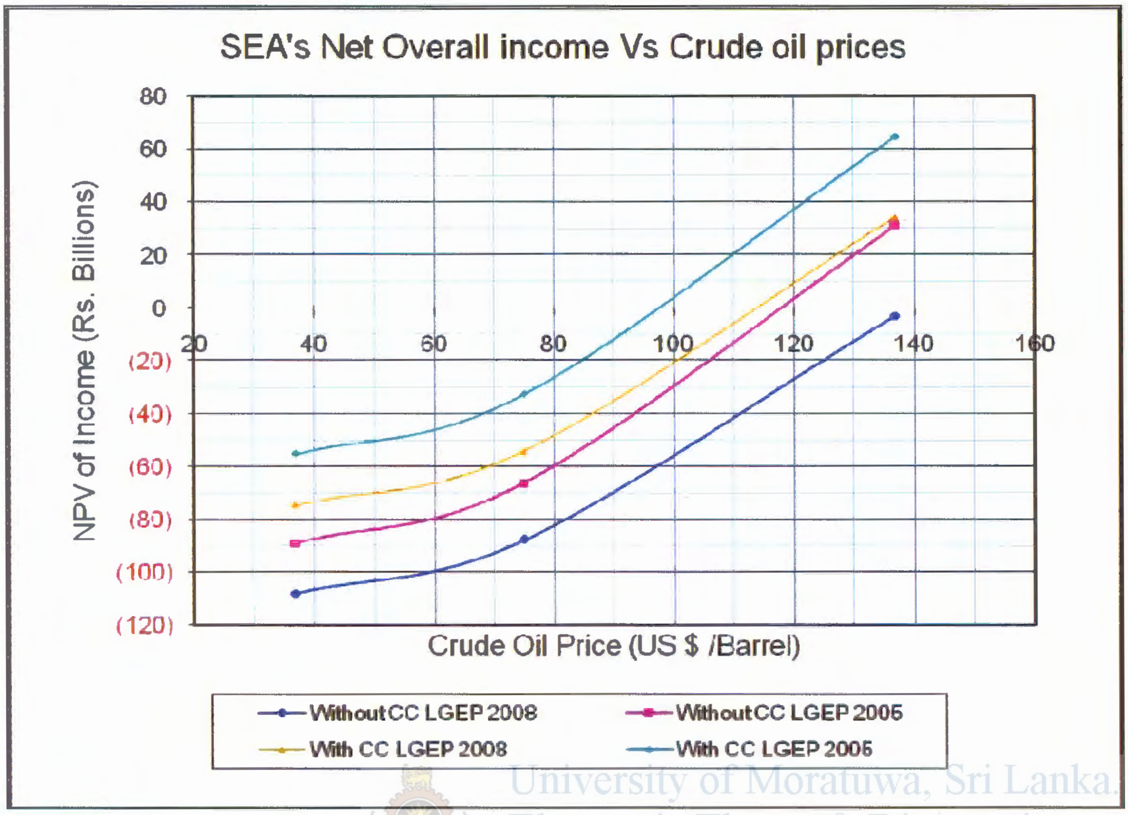

Figure 3-2: SEA's NPV of net income variation with crude oil prices in different scenarios

As per figure 3-2, SEA's investment on NCRE tariff will become breakeven, if the average crude oil prices stabilize within 100 – 120 $ per barrel. And if the price of crude oil goes below that range, government has to subsidize SEA to meet its tariff commitments. On the other hand if the average crude oil prices increases more than 100 – 120 $/ barrel then SEA will be able to make a profit out of their investment.

Chapter 4

Conclusion

The attempt by the researcher to study economics of SEA when reaching for 2015 Renewable Electricity Generation endeavor, has been materialized in this dissertation. The researcher did extensive literature review, including past research reports and interviewing with stake holders in the industry on the topic. In a nutshell, this study include scrutinizing of present avoid cost tariff calculation methodology for renewable electricity generation, forecasting possible combination of renewable resources to reach National Energy Policy endeavor on renewable electricity generation based on available LGEPs, forecasting of avoided cost tariff based on LGEP's generator plant's dispatching schedules after improving present tariff calculation methodology on constant terms, forecasting additional funding requirements for new SEA tariff on constant terms and scenario study with different fuel prices and LGEPs.

Due to a lot of unpredictable variable in the tariff calculation, this study was done under constant terms. Therefore, during study period it is considered fixed exchange rate, 0% inflation rate and fixed fuel prices. However, scenario studies have been conducted under different dispatching schedules and fuel prices to get a better understand on those variables on final result.

As per the scrutinizing of present CEB avoided cost calculation methodology, it has been found several modifications has to be done to the calculation to reflect the more realistic avoided cost of CEB as per SPPA guidelines. When forecasting avoided cost, modified avoided cost calculation methodology has been used to reduce the inaccuracies involve in present calculations.

This study can be used as a tool to further improve the present avoided cost tariff calculations to reflect more accurate avoided cost and thereby reduce SEA's tariff commitments, can use for policy makers to get an understanding of SEA's cash flow requirements to meet tariff commitments as per new SEA's tariff when reaching year 2015 renewable generation endeavor and to identify the correlation between SEA's return on tariff investment and oil prices.

4.1 Recommendations for Future

Overall the researcher feels he has delivered a reasonable research out come to study the economics of SEA's investment on tariff to reach renewable target. However this study can be improved in following areas.

This study is basically based on the dispatch schedules and demand forecasts available in 2005 and 2008 LGEPs. However as per the recent past actual data, it is evident that the present actual demand is fairly less than the demand predicted in the forecast, thus this directly affect the required renewable contribution to reach the envisaged value and overall SEA's tariff commitments. Also when calculating avoided cost due to renewable, dispatch schedules need to be prepared without taking renewable contribution into account to avoid underestimating of avoided cost as discussed in chapter 2. However in 2008 LGEP, dispatch schedules are prepared by taking renewable contribution into account. Therefore, overall result will be more accurate by using more up to date forecasts and dispatch schedules without renewable.

Also more scenario studies can be done for different possible combinations of renewable sources to reach the target to have better view of SEA's tariff investment under different circumstances.

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APPENDIX – A: Summary of Published CEB Avoided Calculation for 2008

Dispatch Schedule used for CEB calculations

1	Total Generation	[illegible]	[illegible]	804	734	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2	Total Generation/day	27	[illegible]	29	28	29	27	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
3	Generation Red. due to Mini Hydro	20	[illegible]	17	25	32	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
4	Northern Generation	12	11	12	12	12	12	13	12	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
6	No of Days	31	29	31	30	31	30	31	31	30	[illegible]	[illegible]	[illegible]	[illegible]
7	Generation (Centrally Dispatched)	759	751	776	679	653	837	847	843	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
8	Reqd Generation/day	25	26	25	23	27	28	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
9	Laxapana Sepu. - 22.5 MW	11	11	11	10	10	10	11	11	[illegible]	[illegible]	[illegible]	10	[illegible]
10	Heladhanavi - Put - 100MW	61	62	66	64	66	64	66	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
11	Barge - 60MW	31	28	40	35	30	33	37	37	35	[illegible]	[illegible]	[illegible]	408
12	Asia Power - 49MW	27	25	31	27	27	27	28	26	[illegible]	[illegible]	[illegible]	[illegible]	333
13	ACE - Matara - 24MW	14	13	14	13	13	13	12	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
14	ACE - Horana - 24 MW	14	13	14	13	13	13	13	13	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
15	ACE - Embilipitiya - 100MW	51	48	50	49	51	49	50	[illegible]	[illegible]	[illegible]	[illegible]	51	[illegible]
16	Kerawalapitiya_IPP	0	0	0	0	0	0	0	0	0	54	52	53	160
17	AES Kelanitissa - 163 MW	86	79	86	83	86	83	79	79	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
18	TOTAL_IPP	293	[illegible]	313	295	298	292	298	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
19	Demand on CEB	505	463	564	514	565	575	547	544	[illegible]	480	475	453	6249
20	Sapu Extn 8 x 9 MW	43	[illegible]	42	41	42	41	42	42	[illegible]	[illegible]	41	[illegible]	[illegible]
21	Sapu Old 4 x 18 MW	34	[illegible]	30	33	30	33	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	381
22	KPS Combined - 165 MW	94	94	102	94	102	[illegible]	[illegible]	102	[illegible]	54	[illegible]	[illegible]	[illegible]
23	KPS GT 1 x 115 MW	4	4	4	2	3	[illegible]	0	1	4	[illegible]	[illegible]	[illegible]	[illegible]
24	Kerawalapitiya_CEB	0	[illegible]	0	0	0	[illegible]	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
25	KPS GT 5 x 17 MW	1	1	1	1	0	[illegible]	0	0	[illegible]	[illegible]	[illegible]	0	[illegible]
26	CEB Thermal Generation	181	[illegible]	179	111	176	174	174	[illegible]	[illegible]	134	[illegible]	176	[illegible]
28	Prospective Gen / Energy Shortfall	0	0	0	0	0	0	0	0	[illegible]	0	[illegible]	0	[illegible]
29	Total Thermal Generation	475	[illegible]	491	406	474	436	472	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
30	Hydro Gen Reqd	324	[illegible]	395	403	339	400	373	[illegible]	300	[illegible]	[illegible]	[illegible]	4259
31	Actual Hydro reqd	324	[illegible]	365	403	339	400	373	[illegible]	[illegible]	[illegible]	[illegible]	227	[illegible]
32	Average Inflow	270	[illegible]	163	272	376	427	422	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
33	Drawdown from reservoirs	53	[illegible]	[illegible]	129	10	[illegible]	-52	[illegible]	[illegible]	[illegible]	[illegible]	-201	
34	STARTING STORAGE	900	[illegible]	[illegible]	512	384	374	403	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
35	Month End Storage	849	[illegible]	[illegible]	384	374	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
36	% Storage	[illegible]	[illegible]	[illegible]	30%	30%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	

CEB Avoided cost calculations for individual thermal plants

Small Power Purchase Tariff -2008

Exchange rate: 1 US $ = Rs. 110.94
Auto Diesel Price (Rs/litre) 76.42

	GT OLD	GTNEW	KPS-JBIC	Lakdhanavi	Asia Power	BARGE	Sapu Old	Sapu Ext.	Matara	Horana	Heladhanavi	AES CCP	Embilipitiya
Fuel used	Auto Diesel	Auto Diesel	Naphtha				Heavy Fuel	Heavy Fuel					
Fuel Price (Rs/litre)	76.42	76.42	54.13				46.05	46.66					
Heat Content (kCal/litre)	8,892	8,892	7,413				9,661	9,622					
Heat Rate (kCal/kWh)	4,192	1,355	1,104				2,202	2,073					
Fuel Usage (litres/kWh)	0.47	0.18	0.19				0.23	0.21					
Fuel Cost (Rs/kWh)	36.15	13.44	10.46		12.72	12.95	10.93	9.99			12.22	11.51	11.50
Variable O&M cost													
US Cts/kWh	0.213	0.281	0.158				0.941	0.6525					
Rs/kWh	0.23	0.31	0.17				1.04	0.72					
Station Losses (%)	3%	3%	2%				3%	3%					
Rs/kWh	1.09	0.41	0.20				0.35	0.32					
Transmission Losses (%)	3.2%	3.2%	3.2%		3.2%	3.2%	3.2%	3.2%			3.2%	3.2%	3.2%
Rs/kWh	1.20	0.45	1.17		0.41	0.41	0.39	0.35			0.39	0.37	0.43
Avoided Cost at 33 kV level (Rs/kWh)	38.70	14.61	11.02	13.73	13.13	13.36	12.64	11.39	13.67	13.55	12.61	11.90	13.93

Variable costs at 33kV level (Rs/kWh) for each plant

GT OLD	38.70
Kerawalapitiya	16.16
GTNEW	14.61
Embilipitiya	13.93
Lakdhanavi	13.73
Matara	13.67
Horana	13.55
BARGE	13.36
Asia Power	13.13
Sapu Old	12.64
Heladhanavi	12.61
AES CCP	11.88
KPS JBIC	11.82
Sapu Ext.	11.09

1	35	GT OLD	38.70
2	120	Kerawalapitiya	16.16
3	115	GTNEW	14.61
4	100	Embilipitiya	13.93
5	22.5	Lakdhanavi	13.73
6	24	Matara	13.67
7	24	Horana	13.55
8	60	BARGE	13.36
9	49	Asia Power	13.13
10	72	Sapu Old	12.64
11	100	Heladhanavi	12.61
12	165	AES CCP	11.88
13	165	KPS-JBIC	11.82
14	[illegible]	Sapu Ext	11.09

CEB avoided cost calculation

System Control Centre Dispatch Schedule 2008 - GWh

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total GWh	Capacity MW	Cost Rs/kWh
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[illegible] Plant factors

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Capacity MW	
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[illegible] of Unit in the margin

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	Cost
G.T.G.T.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
GTNEW	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Embilipitiya	0.04	0.04	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Matara	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Horana	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
BARGE	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Asia Power	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Heladhanavi	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	0.93	0.91	0.91	[illegible]	[illegible]	0.80	[illegible]	[illegible]	0.85	0.78	0.82	0.83	[illegible]	[illegible]

[illegible]	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
	[illegible]	13.02	[illegible]	12.63	[illegible]	12.21	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

	Cost	price (excluding CEB o/m)
Off Season (Rs./kWh)	12.16	11.98
Dry Season (Rs./kWh)	[illegible]	12.63

Avoided [illegible]

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Published Tariff

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

APPENDIX – B: SEA's Cost Based Tariff Announcement on April 2009

Non Conventional Renewable Energy Tariff Announcement

Purchase of Electricity to the National Grid under Small Power Purchase Agreements (SPPA)

Sri Lanka Sustainable Energy Authority (SLSEA) of the Ministry of Power and Energy is pleased to announce the new rates for electricity purchased by the Ceylon Electricity Board (CEB) from Non conventional Renewable Energy (NCRE) Sources under (SPPAs) signed from today onwards. The tariffs and the SPPA will continue to be standardised and non-negotiable. The tariff will be cost-based and technology-specific, and the developers have the option of selecting either a three tier tariff or a flat tariff. The SPPAs will continue to be applicable to projects with a rated generating capacity up to 10 MW, and will be valid for a period of 20 years and extendable by mutual consent.

This tariff will remain unchanged until further notice and the tariff review process is initiated strictly on necessity.

The tariff for electricity produced using Non-conventional Renewable Energy (NCRE) sources based on Small Power Purchase Agreements (SPPAs) signed from today onwards would be as follows:
All prices are in Sri Lanka Rupees per kilowatt hour (LKR/kWh).

Option 1: Three-tier Tariff

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

Technology	Escalable Base O&M Rate	Escalable Base Fuel rate	Non-escalable fixed rate Year 1-8	Non-escalable fixed rate Year 9-15	Escalable Year 16+ Base rate	Royalty to Govt. paid direct by the power purchaser Year 16+
Mini-hydro	1.55	None	14.18	5.16	1.62	10% of total tariff
Wind	2.46	None	22.53	8.19	1.62	10% of total tariff
Biomass (Dendro)	1.24 (1-15 years) 1.55 (16th year onwards)	7.14	8.50	3.09	1.62	No royalty
Agricultural & Industrial Waste	1.24 (1-15 years) 1.55 (16th year onwards)	3.56	8.50	3.09	1.62	No royalty
Municipal Waste	3.13	None	12.26	4.46	1.62	No royalty
Waste Heat Recovery	0.49	None	10.15	3.69	1.62	No royalty
Escalation rate for year 2009	8.06%	5.37%	None	None	5.37%	

Note 1: Escalation of O&M rate and fuel rate shall commence from the 1st day of the month of January immediately after the commercial operation date.
Note 2: The applicable escalation rate for each subsequent year shall be the rate announced for that particular year.
Note 3: To compensate for the higher tariffs in tier 1, developers will be required to deliver in tier 2, an average amount of energy at least equal to that delivered in tier 1. This obligation will be stipulated in the agreement, with corresponding penalties for non-delivery in tier 2.
Note 4: Biomass (Dendro) means sustainably grown firewood.

Option 2: Flat Tariff

Technology	All inclusive rate (LKR/kWh) for years 1-20
Mini-hydro	14.58
Wind	23.07
Biomass (Dendro)	18.56
Agricultural & Industrial Waste	13.88
Municipal Waste	15.31
Waste Heat Recovery	9.55

Note 1: The flat tariff will not be escalated for any reason over the entire 20-year period.
Note 2: Extensions after the 20th year will be at the same rate as for an option 1 project.

The selection between options 1 and 2 would be at the discretion of the developer, at the time of signing the SPPA.

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