SIMULATION OF THE FUTURE ELECTRICITY DEMAND AND SUPPLY IN KENYA USING THE LONG RANGE ENERGY ALTERNATIVE PLANNING SYSTEM.

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Simulation of the future electricity demand and supply in Kenya using the long range energy alternative planning system.

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DECLARATION

This thesis is my original work and has not been presented for a degree in any other University.

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ABBREVIATIONS

ESOHK Energy Survey on Households in Kenya

EPP	Emergency Power Producer
GHG	Green House Gases
HH	Households
IPCC	Intergovernmental Panel on Climatic Change
IEA	International Energy Agency
kWh	Kilowatt hours
LCPDP	Least Cost Power Development Plan
LEAP	Long Range Energy Alternative Planning System
MAED	Model Analysis of Energy Demand
MOE	Ministry of Energy
MSD	Medium Speed Diesel
MW	Megawatts
NPV	Net Present Value
NS	Nuclear Scenario
RES	Renewable Scenario
RS	Reference Scenario
TED	Technology Database
CO_2	Carbon Dioxide
CO_2eq	Carbon Dioxide Equivalent
SO_2	Sulphur Dioxide

NO_x	Nitrogen Dioxide

NOMENCLATURE

$\overline{\mathbf{AC}_t}$	Levelised total annual costs for a specific plant [$/kWh]
CC	Capital Cost [$/kW]
$\overline{\mathbf{CC}_t}$	Levelised capital costs for a specific plant [$/kWh]
$\mathbf{C_{end}}$	Endogenous Capacity [MW]
$\mathbf{C_{ex}}$	Exogenous Capacity [MW]
CF	Capacity Factor [%]
CRF	Capital Recovery Factor [%]
$\mathbf{E_r}$	Electricity Requirements [MWhr]
FC	Fixed Costs [$/kW/year]
$\overline{\mathbf{FC}_t}$	Levelised fixed costs for a specific plant [$/kWh]
i	Discount Rate [%]
LF	Load Factor [%]
MC	Module Capacity [MW]
$\mathbf{MC_{ba}}$	Module Capacity before additions [MW]
N	Plant Lifetime [Yrs]
$\mathbf{P_{pr}}$	Peak power requirements [MW]
RM	Reserve Margin [%]
$\mathbf{RM_{ba}}$	Reserve Margin before additions [%]
$\mathbf{RM_p}$	Planning Reserve Margin [%]

t	Specific technology/plant
$\mathbf{TC}_t$	Total annual costs per plant [$/year]
$\overline{\mathbf{VC}_t}$	Variable Costs [$/kWh]

ABSTRACT

Power scenarios for Kenya are developed and simulated in this study using the Long Range Energy Alternative Planning System (LEAP) for the period 2012-2030. The scenarios represent how the sector may unfold in the future to fully satisfy the demand, mainly taking into consideration; energy security, cost of power generation and the environmental impact. They Include: Reference Scenario (RS) which represents the Least Cost Power Development Plan (LCPDP) with a supply mix of hydro, geothermal, nuclear, thermal (Medium Speed Diesel and gas turbine), wind and coal power plants. Nuclear Scenario (NS) which represents a clean technology scenario with a supply mix of hydro, geothermal, nuclear, thermal (gas turbine plants only) and wind power plants. Coal Scenario (CS) which represents a carbon intensive pathway with a supply mix of coal, geothermal, thermal (medium speed diesel and gas turbine), hydro and wind power plants. Renewable Energy Scenario (RES) with a supply mix of hydro, geothermal, wind, pumped hydro storage and small renewable plants including hydro, solar PV and biomass plants as non-dispatchable plants. The results show that the most competitive scenario in terms of cost is the coal scenario which has a Net Present Value (NPV) of $30,052.67 million but on the flip side has the most Green House Gas (GHG) emissions. On the other hand, the renewable scenario has the least GHG emissions but it’s the most expensive scenario to implement with an NPV of $ 30,733.07 million. The nuclear scenario offers a good substitute for the renewable scenario in terms of low emissions and lower costs at an NPV $30,402.57 million, but Kenya does not have known stocks of uranium so it would solely rely on importation of the fuel rods and there would be need to address the issues of the nuclear waste and public acceptance of the nuclear plants. The reference scenario which is the government’s plan has moderate costs at an NPV of $30,225.87million, but has the weight of the nuclear plants as well. These leaves the coal and renewable energy scenario as the two most suitable paths for Kenya, since they are both promising in regard to the energy security, and the coal plants can be improved to ensure that the emissions are reduced through the Carbon Capture and Storage (CCS) technology. Further research is therefore recommended to determine the

most cost effective scenario between the coal scenario with CCS and renewable energy scenario.

CHAPTER ONE

INTRODUCTION

1.1. Background

Energy has been recognized as a key element of development. High economic growth rates in many countries have been facilitated by adequate electricity supply *(*Ferguson, *et al.*, 2000). Kenya aspires to be a middle income economy by 2030 with a robust manufacturing sector which will be driven by adequate, reliable and affordable power supply. The current total installed power generation capacity is 1885MW (Kenya Power, 2014) with a supply mix comprising of hydro, thermal, geothermal, wind and cogeneration plants as shown in Table 1.1 below.

Table 1.1 Installed capacity 2013/2014

Source	**Installed (MW)**	**% Share**	**Effective**	**% Share**
Hydro	818	43%	798	44%
Thermal	624	33%	588	33%
Geothermal	363	19%	348	19%
Isolated Grid	19	1%	15	0.08%
Co-generation	26	1.3%	22	1.2%
Wind	5.3	0.03%	5.1	0.03%
EPP	30	1.5%	30	1.6%
Total	1885	100%	1805	100%

Source: (Kenya Power, 2014)

This capacity is quite limited given that the population of Kenya is estimated to be 43 million; therefore only about 24% of the population is connected to the grid (ERC, 2013). Moreover, the Kenya power supply system has been very susceptible to the weather pattern changes due to the over reliance on hydro power generating plants hence the reliability of power is greatly affected by the load shedding programs adopted during the dry season of the year. To cushion the effect of loss of power from the hydro plants; the thermal plants are run above their desirable economic plant factor thus making the cost of power to fluctuate a lot; due to the increased fuel consumption, variation of the international prices of crude oil and the foreign exchange rates.

To address these challenges in the power sector, major reforms have been undertaken in the recent past which include; liberalization of the power generation, unbundling of the state power utility company, enactment of the energy Act of 2006, development of a least cost power expansion plan incorporating a reserve margin of 25% (ERC, 2013). This expansion plan is based on the Wien Automatic System Planning Package (WASP IV) model (IAEA, 2001), whose output is the optimal Least Cost Power Development Plan (LCPDP) for various demand scenarios; low, reference and high. Through the LCPDP the government intends to diversify the current supply mix further, as shown in Figure 1.1, with the introduction of coal and nuclear plants as candidate base load plants. However, there are global concerns and public outcry in regards to the safety risks associated with the nuclear plants after the Fukushima nuclear accident in Japan as well as the requirement for long term storage of the nuclear waste (Zhang, et al., 2013). Moreover, Kenya has already implemented and reviewed the Feed-In-Tariff (FIT) policy for wind, solar, small hydro and biomass. This policy obligates the power off-taker to buy on a priority basis, the power generated from the renewable sources as per the Power Purchase Agreements (PPA) whose tenure is usually 15-20years (ERC, 2010). Several projects have been completed so far, on this tariff and are feeding into the grid, hence by the time Kenya gets its first coal plant in 2016 and nuclear plant in 2022 as per the LCPDP, there will be a substantial amount of intermittent power in the grid. Additionally, it is anticipated that a net metering policy will be adopted as the world moves to smart grids and demand side management system.

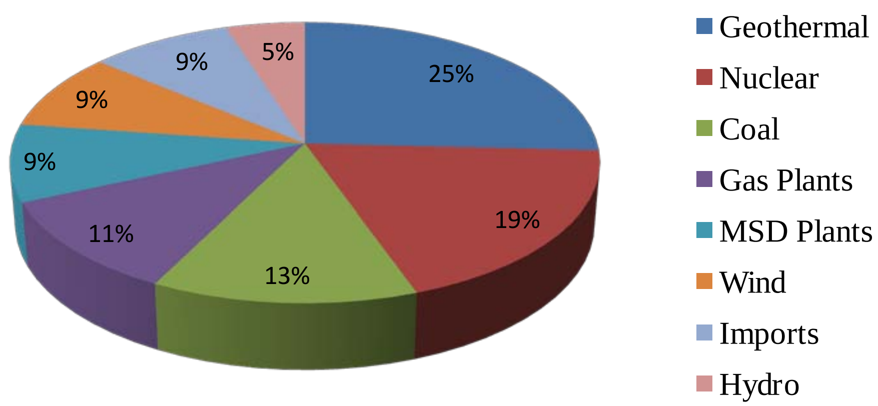

Figure 1.1 Expected power supply mix for 2030

For this reasons, there's a need to build complementary plants which are more flexible in terms of the load factor unlike the nuclear and coal plants which are designed to run at full load both from a technical and economic point of view (Gets, 2013). So as the Government prepares to make the huge capital investments in nuclear and coal plants, consideration should be made of the expected grid composition within the planning period.

In light of the concerns cited, this study analyses and simulates three possible generation pathways for Kenya and compares them to the LCPDP, which forms the Reference Scenario (RS) in terms of technological, economic and environmental impact using Long Range Energy Alternative Planning System (LEAP) software (Heap, 2011) for the period 2012-2030.

The candidate plants for the RS include; geothermal, coal, gas, thermal (MSD), wind, imports and finally nuclear plants which are introduced after 2020. The alternative scenario assessed in this study include: Coal Scenario (CS) which represents expansion of the grid capacity by enhancement of the current supply mix with addition of geothermal, coal, gas, thermal(MSD), gas wind and imports. The nuclear power is exempted from this scenario and base load requirements are expected to be met by the geothermal and coal plants. The second scenario is the Nuclear Scenario (NS), which is a clean technology scenario in that no coal and thermal (MSD) plants are built after 2013. The candidate plants include; geothermal, gas, wind, imports and the nuclear plants which are introduced after 2020. The third scenario is the Renewable Energy Scenario (RES) which is based on the exploitation of the locally available resources to enhance sustainability and energy security. The candidate plants include; geothermal, pumped hydro, imports, wind and small renewable plants; small hydro, solar, and biomass technologies.

1.2. Problem Statement

Kenya has in the recent past, faced many challenges in the power sector including; frequent load shedding regimes coupled with a high power tariff due to the limited generation capacity hence necessitating the use of the thermal power plants which have higher running costs cost compared with other plants such hydro or geothermal. This situation can be attributed to a lack of proper power planning which has a negative ripple effect on the economic growth of the country, hence the need to thoroughly scrutinize the government's power expansion plan and provide feasible alternatives.

1.3. Main Objective

To develop and model three electricity supply scenarios possible for Kenya and compare them with the Least Cost Power Development Plan (LCPDP) in terms of the technological, economical and environmental implications using the Long Range Energy Alternative Planning (LEAP) software.

1.4. Specific Objectives

1. To analyse the power demand and supply data for the year 2012.
2. To simulate the demand and supply for the four power supply scenarios from 2012-2030.
3. To carry out a cost analysis for the three scenarios.
4. To analyse the GHG emissions for the three scenarios.

CHAPTER TWO

LITERATURE REVIEW

2.1 Introduction

Scenario planning is a useful approach to design and plan for long term electricity infrastructure to cope with uncertain demand and supply for power. It allows for the construction of a repertoire of possibilities that are tied to a variety of policy and technical pathways with the aim of capturing effectively the uncertainties that lie ahead in the energy economic and environment domains (Craig, *et al*., 2002). Long term energy scenarios therefore, usually consist of different storylines that offer a set of alternative contexts for exploring different ways that the future may unfold (Ghanadan & Koomey, 2005).

This chapter therefore, reviews studies that have been undertaken in different countries on scenario analysis using LEAP and the results obtained thereof. It also reviews the study that has been carried in Kenya with an emphasis on the electricity demand analysis done using the assumption of the Model Analysis of Energy Demand (MAED). It outlines a brief description of the LEAP software which is used for this study's simulation. Finally, it reviews the natural energy resources available in Kenya so as to guide in the selection of candidate plants for the alternatives scenarios for Kenya.

Various researchers have undertaken scenario analysis for power sector in different countries. Mulugetta *et al*., (2007) did an analysis of Thailand power sector using three scenarios; the 'Business As Usual Scenario' (BAU) where fossil fuels would continue to dominate the electricity generation, the No New Coal Scenario (NNC) where dependence on coal and oil shifted towards natural gas based power generation, and finally the Green Future scenario (GF) where 35% of the capacity is derived from renewable energy sources. From the analysis, it was noted that natural gas would remain a dominant fuel in all scenarios hence the conclusion that Thailand would need to enter into mutually agreeable long term arrangement with its neighbours and suppliers to meet electricity demand. The heavy reliance on natural gas meant that the electricity generation sector would still remain an important emitter of CO_2 into the foreseeable future especially for the BAU and NNC scenarios. The GF scenario registered lower CO_2 emissions at the end of the study period 2022 compared to the base year 2002. This would be possible if the country's fuel mix was diversified to include resources that are locally available for example biomass, wind and solar. This important gain was noted to occur at a marginally higher cost than the BAU scenario without taking into account the costs associated with the CO_2 emissions.

Dagher and Ruble, (2011) simulated possible future paths for Lebanon's electricity sector and performed a fully fledged scenario analysis to examine the technical, economic and environmental implications of all scenarios, which included: the Baseline Scenario (BS) describing the business-as-usual state of affairs capturing the most likely evolution of the power sector in the absence of any climate change related or any other policy. The Renewable Energy Scenario (RES) that incorporated specific policies aimed at expanding the renewable energy's share and reducing GHG emissions. The Natural Gas Scenario (NGS), which assumed that the growth in electricity demand would be, catered for by the introduction and expansion of natural gas combined cycle generators along with an expansion of other existing technologies. The results indicated that the RES and the NGS scenarios were more superior to the baseline scenario from an economic stand point as well as from an environmental perspective. When the NGS and RES were compared, the former was superior only if the cost benefit analysis was considered but the RES scenario had lower emissions, diversified supply mix and had the potential to reduce the country's dependence on fuel imports.

Ozer *et al.*, (2013) simulated two power development scenarios for the Turkey electricity sector and they included; Business As Usual (BAU) and mitigation scenario. The results implied that the electricity demand and associated CO_2 emissions would rise in both scenarios due to economic growth until 2030. However the rise of CO_2 emissions under the BAU would be more significant than under the mitigation scenario.

Gujba *et al*.,(2011) developed four scenarios including; two fossil fuel scenarios (FF and CCGT) and two sustainable development scenario (SD1 and SD2), then compared them with the government power expansion plan in terms of cost and environmental impacts for short to medium term. The government plan which was the Business As Usual (BAU) scenario comprised of a mixture of conventional and renewable energy plants. The FF scenario was driven largely by the cheaper capital costs and readily available fuels; natural gas and coal. The CCGT scenario comprised of cleaner gas power technologies, so future conventional plants in the BAU were replaced by the Combined Cycle Gas Plants (CCGT), for this scenario the only renewable plants introduced were the hydro plants. The SD1 scenario was driven by concerns on energy security and pollution from the fossil-fuels in the Niger Delta, so there were increased renewable energy systems; wind, biomass and solar. The wind power contributed the largest share of 2976MW in this scenario while biomass and solar contributed 383MW and 510MW respectively. The SD2 scenario was based on the clean technology principle for mitigating global climate change. More renewable systems introduced as was the case of SD1 but with different capacities; biomass 1913MW, wind 1275MW and solar 3571MW. The results indicated that the FF scenario was the preferred outcome if the aim was to expand electricity access at the lowest capital costs. However the annual costs and environmental impacts increased significantly as a consequence. SD1 and SD2 scenarios showed significant increase in capital investment as compared to the government plan. The SD2 scenario had the least CO_2 emissions and therefore it was the most sustainable.

McPherson and Karney, (2014) analyzed the status of power generation in Panama and explored four possible future scenarios and their associated impacts on the marginal costs, global warming potential and resource diversity index. The Business As Usual scenario extrapolated the electricity generation trend that has been observed over the past decade with steady decrease in hydro generation as a percentage of total demand compensated with a steady increase in fossil fuel generation. Scenario 1 encouraged climate mitigation without incorporating new technologies in the generation mix. Scenario 2 maximized resource diversity and sourcing of all new electricity generation was from renewable sources. Scenario 3 minimized global warming potential by adopting renewable energy deployment and phasing out fossil fuel generation. The result of the study showed that the iteration from BAU to scenario 2 is associated with the cheaper system costs, less green house gas emissions and a higher generation resource diversity index. However, the iteration from scenario 2 to scenario 3 is associated with more expensive system costs, a lower generation resource diversity index and a lower global warming potential. Hence, the study concluded that the ideal generation mix would be achieved through optimization of scenario 2 and scenario 3.

Park, *et al*., (2013) developed the three electricity scenarios for Korea electricity sector and analyzed their energy, economic and environmental using LEAP. The scenarios included; the Baseline (BL), Government Policy (GP) and Sustainable Society (SS). The focus of the BL and GP scenarios was to increase the power supply from nuclear sources while the SS scenario focused on the demand management and increasing power supply from renewable sources. The results of the study indicated that the GHG emissions for the SS scenario reduced by 80% from the base year emissions. The discounted cumulative cost from 2009 to 2050 in the SS scenario would be 20% and 10% higher than that of the BL and GP scenarios respectively.

In Kenya however, no electricity sector scenario analysis has been done, to compare various possible generation pathways that can be brought about by the change in policies or influence policy change. The LCPDP provides optimal least cost cases for three different demand scenarios; low, reference and high. These are generated based on the WASP IV modeling software (IAEA, 2001). The demand forecasting for the LCPDP as well as for this research was carried out using the assumptions borrowed from the Model for Analysis of Energy Demand which evaluates future energy demand based on medium to long term scenarios of socio-economic, technological and demographic developments. For disaggregation of the energy demand to end use device consuming units, the analysis was carried out as per Kenya Power Tariff categories which include; domestic consumption, Street lighting, small commercial and industrial (415V), medium commercial and industrial consumption (11-33kV) and large commercial and industrial consumption (66-132kV).

2.1.1. Domestic Consumption

The demand load forecast for Kenya is carried out in two regions based on the observed specific consumption patterns as shown in the Table 2.1. The hierarchical levels that are used in the disaggregation of domestic sector electricity consumption are shown in the Figure 2.1. The households are classified into different income categories as per the Energy Survey on Households in Kenya (ESOHK) report (Jensen, *et al.*, 2012) as well as the census data for 2009 with projections to 2030 (KNBS, 2011). The consumption per household is obtained from 15 clustered appliances as shown in Appendix A.1. These clusters are derived from a total of 48 electrical appliances that are confirmed to be available in Kenyan households. With the clustered demand data the domestic demand is obtained using the equation 2.1

$$Domestic\ Demand = \Sigma(HH\ specific\ consumption\ \times No.of\ connected\ HH) \quad 2.1$$

The number of connected households was obtained from equation 2.2.

$$No.of\ connected\ HH = \frac{connection\ rate \times population}{No.of\ persons\ per\ HH} \quad 2.2$$

Where the Connection rate, population per category and number of persons per household is per ESOHK report.

Table 2.1 Specific Consumption for households 2012

Region	Global Consumption (kWh)	Households	Specific Consumption (kWh)
Nairobi, Western Kenya and Mount Kenya	2,355.9	1,797,470	1,311
Coast	420.3	221,320	1,899
Kenya	2,776.2	2,018,790	1,375

Source: (Jensen, *et al*., 2012)

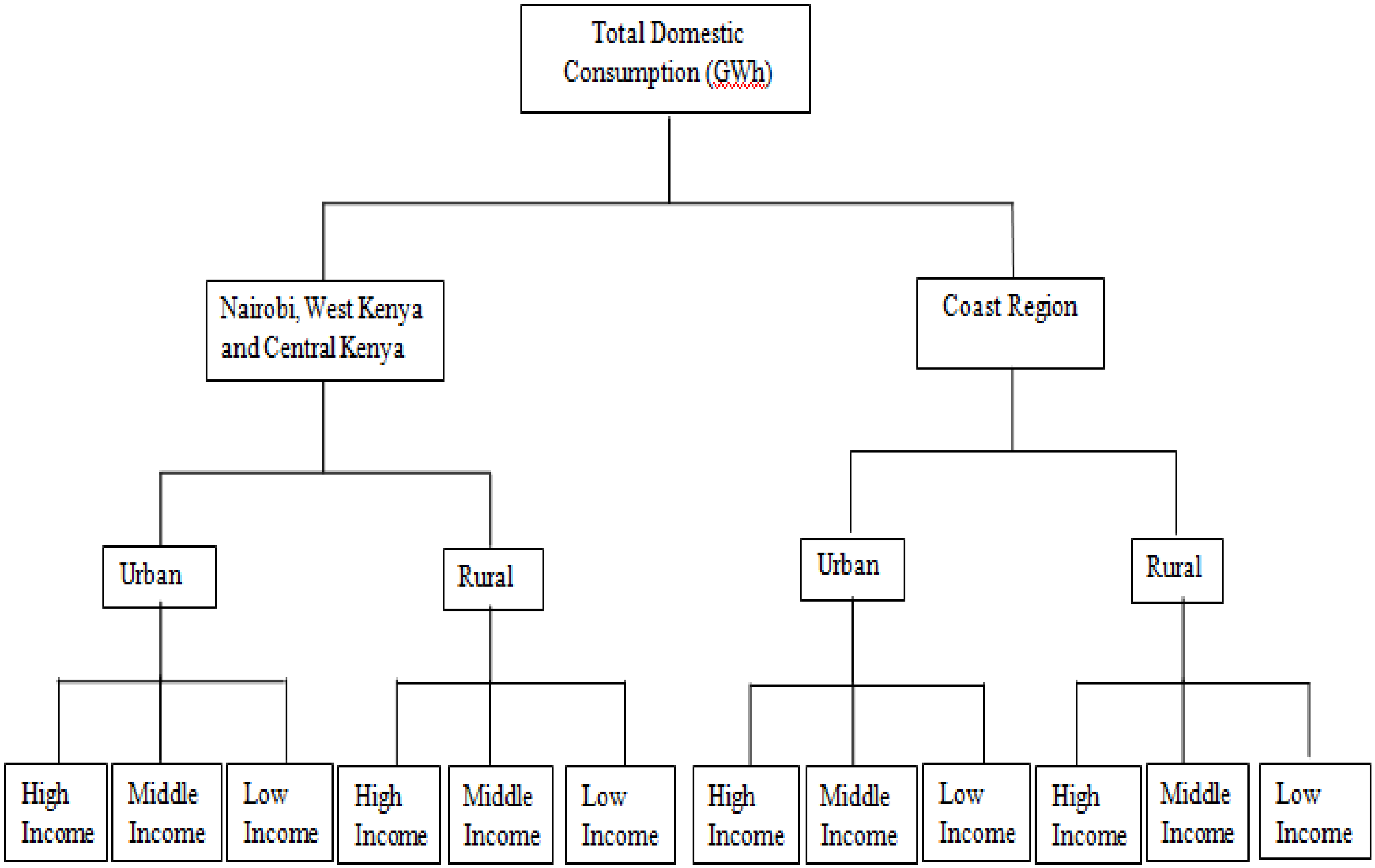

Figure 2.1 Hierarchical levels for domestic sector

2.1.2. Street Lighting Consumption

The street lighting demand projection for the load forecasting report is carried out using the number of poles installed and the specific consumption of the poles (kWh/pole). The demand for the year 2012 was 16GWh as per the annual publication by the Kenya Power Company. (Power, 2012).

2.1.3. Commercial and Industrial Consumption

The demand projection for the load forecasting report was done using an elasticity factor obtained by relating the power consumption growth rate for the years 2009-2011 to the Gross Domestic Product (GDP) of the respective years obtained from the Kenya Economic Survey Report (KNBS, 2012). The commercial and industrial consumption for the year 2012 was 3419GWh and projection was done using the equation 2.3 (Jensen, et al., 2012).

$$D_t = D_{t-1}\left(\varepsilon\frac{\Delta \mathrm{GDP}}{\mathrm{GDP}} + 1\right) + \Delta \mathrm{M_t} \qquad 2.3$$

Where:

- D is the 2012 commercial and industrial electricity demand
- ε is the elasticity index that reflects the proportion of growth in electricity consumption to economic growth.
- t is the year.
- $\Delta \mathrm{M_t}$ is the additional demand from new large demand points e.g. from the natural resources extraction sector in year t.

2.2. LEAP Model

The LEAP model was developed by Stockholm Environment Institute (SEI). It’s used to evaluate energy development policies (Heap, 2011). The concept of LEAP is an end use driven scenario analysis. The LEAP structure is shown in Figure 2.2.

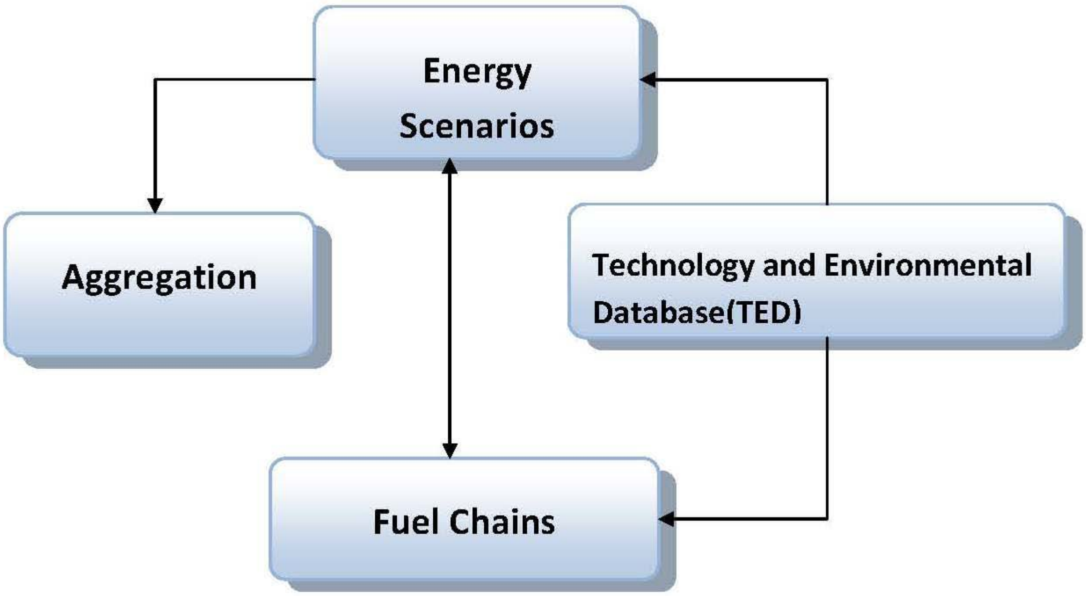

Figure 2.2 LEAP structure

The energy scenario is at the heart of LEAP and shows how future energy systems might evolve over time under particular set of policies. The Technology and Environment Database (TED) is a compilation of technical characteristics, costs, and environmental data for a range of energy technologies from sources including the Intergovernmental Panel on Climate Change (IPCC), Department of Energy (DoE) and International Energy Agency (IEA). The aggregation program is used to display multi area results from analyses carried out in different modules of the program. The fuel chain is used to compare total energy and environmental impacts of specific fuels and technology choices per unit of energy, for service delivered.

The LEAP framework is disaggregated into hierarchical tree structure of four levels: sector, subsector, end-use and device. Its accounting platform matches demand with supply side energy technology outputs, while the scenario manager facilitates the comparison of alternative electricity generation systems over the medium to long term duration to enable technical, economical and environmental impact analysis. As such LEAP enables top-down macro-economic modeling simulation of the electricity sector and capacity expansion planning. In order to facilitate simulation of different electricity generation profiles, the model incorporates two main modules which form the basis of the hour to hour simulation, within the rules defined: Energy demand module and transformation modules as shown in the Figure 2.3.

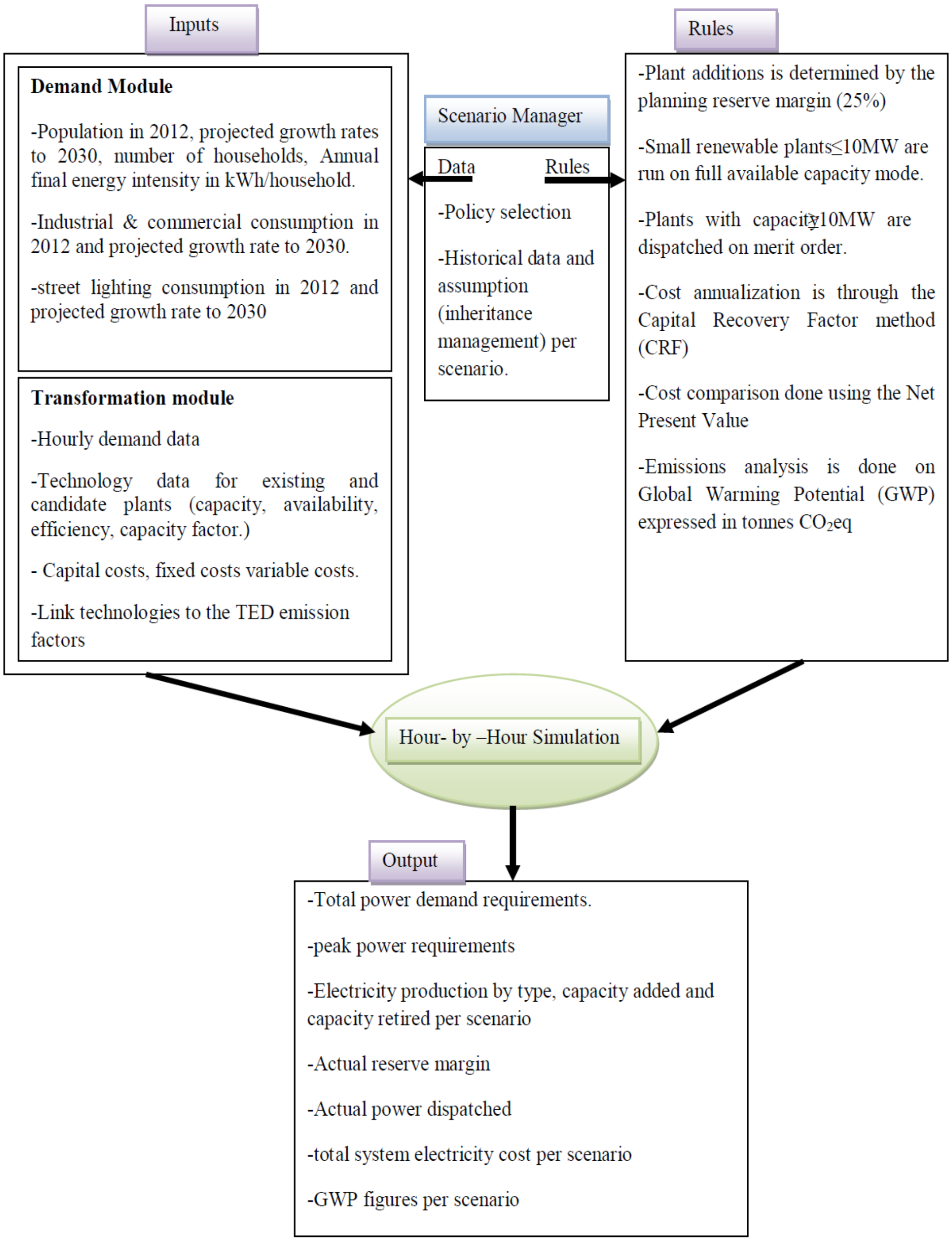

Figure 2.3 Summary of LEAP model inputs and outputs

2.3 Natural Energy Resources

Kenya unique physical terrain and climate makes it possess immense potential for renewable energy. Its strategic location along the equator and in the East Africa, favours a tropical climate with temperatures averaging 22^{o}C with plenty of sunshine and cool nights for most parts of the country. The average insolation levels are approximately 4-6kWh/m^2/day as can be seen in Appendix B.1.

The Great Rift Valley runs from the North to the South of the country and it possesses huge geothermal potential estimated to be approximately 5,000-10,000MW with only 363MW harness so far. Appendix B.2 shows the map of geothermal prospect locations.

Kenya possesses substantial unexploited potential for large and small hydros. With five major drainage basins and many small rivers the overall hydro power potential is estimated to be approximately 3000-6000MW; with only 818MW being harnessed so far. Appendix B.3 shows the map of major rivers and a summary of the hydro potential for each river basin. Appendix B.4 depicts the potential for small hydro power.

There's considerable wind energy potential in Kenya as depicted in the map of simulated wind power density (W/m^2) at 50m height; Appendix B.5. Some of the major wind hot spots identified record wind speed between 8-14 m/s. These include; Marsabit, Turkana, Ngong and the coastal areas as noted by (Kamau, et al., 2010); (Kiplagat, et al., 2011).

Biomass potential from cogeneration project is estimated to be 360MW, with the potential in the sugar sector alone being 192.8MW as depicted in Appendix B.6.

Fossil fuel deposits have also been discovered in Kenya. Coal deposits have been confirmed to be in the Mui basin between Mwingi and Kitui counties as shown in Appendix B.7. Crude oil deposits with commercial viability have been confirmed in Turkana County Ngamia 1 well and further exploration is still ongoing in the country's oil blocks, both on shore and off shore. (World Oil, 2012).

CHAPTER THREE

METHODOLOGY

This chapter outlines the methodology used for the simulation of the electricity sector for the year 2012 to 2030. The main areas of study include: electricity demand and supply analysis for the year 2012, design of scenarios, simulation of the electricity sector using LEAP from 2012 to 2030 and the comparative analysis of the scenarios in terms of capacity added, costs and emissions.

3.1. 2012 Electricity Demand and Supply Analysis

An important parameter for the simulation of the electricity load and supply is generation of time slices which are the seasonal as well as time of day divisions into which annual electricity loads can be divided. To obtain the time slices for the base year, the 2012 electricity load data obtained from Kenya Power was used. The hourly data was analysed and the chronological system load curve plotted so as to depict the load variation throughout the year. The daily load curves were used to ascertain the variation of load within 24hrs for various days of the year. Using the daily load curves, the monthly variations were also assessed. The daily and monthly; peak maximum and off peak minimum consumption figures were determined and also the days of occurrence noted, that is weekdays or weekend, so as to determine the predominant pattern in Kenya.

The Load Duration Curve (LDC) was then obtained by arranging the chronological system of load, into a decreasing order of magnitude after which the normalization was carried out in percentage terms against the annual peak value to produce a standard LDC. The Standard LDC formed the basis of dispatch of the power plants under the merit order dispatch category.

In regards to the supply side, all the plants were classified into categories on the basis of fuel type; hydro, geothermal and thermal. The daily average capacity factor for each plant was obtained using equation 3.1, to establish plants which formed the baseload, intermediate and peak power plants in Kenya.

$$Capacity\ Factor = \frac{Total\ daily\ output\ (kWh/day)}{Maximum\ plant\ capacity\ kW \times 24hrs/day} \qquad 3.1$$

The daily and monthly generation patterns of the power plants were assessed and supply curves plotted to determine how the generation varied for different seasons because the variation in the generation of one plant had a significant impact on the production of other plants.

3.2 Scenario Design

To carry out the modeling in LEAP three scenarios were developed with different candidate plants for additions to the system to maintain a reserve margin of 25%. These scenarios included CS, NS and RES. They had similar demand characteristics and base year supply data. The overview of the scenarios is given in the Table 3.1.

3.3 Simulation

To carry out the simulation of the electricity sector the demand data for the domestic, street lighting, industrial and commercial sectors was input into LEAP. For the domestic sector the equation 3.2 was used to obtain the overall demand for all the households in Kenya.

$$D_{b,s,t} = TA_{b,s,t} \times EI_{b,s,t} \qquad 3.2$$

Where: D is energy demand, TA is total activity (demographic data), EI is energy intensity of a particular device, b is the branch or categories, s is scenario, t is year.

Table 3.1a Overview of the alternative scenarios

	Reference Scenario	Nuclear Scenario	Coal Scenario	Renewable Scenario
Driving philosophy	Represents the least cost power development plan	Represents a clean technology scenario with no coal and MSD plants after 2013.	Represents a carbon intensive pathway, which anticipates blocking of nuclear plants due to safety issues.	Represents the utilization of local renewable resources for energy security.
Demand	Growth of demand in Domestic, Small Commercial, Street lighting, and Commercial and Industrial sector follows Load Forecast Report 2012 Number of households is determined from the population data with projection done using KNBS growth rates of 2.5% up to 2020 then 2.2% thereafter. The share of urban population is expected to be 61% by 2030 Final Energy Intensity Urban household: The average annual growth rate of energy consumption per household is 1.00% from 2012 to 2030 Rural household: The average annual growth rate of energy consumption per household is 1.01% from 2012 t0 2030 Commercial & Industrial: The average annual growth rate of energy consumption is 2% from 2012 to 2030 Street lighting: The average annual growth rate of energy consumption is 1.2% from 2012 to 2030			
Supply side	System load factor = 68% **Committed Project(Exogenous Capacity)** Upgrading of Hydro plant (Kindaruma) to gain 32MW Upgrading of Geothermal plants in 2014, 316MW, 2015, 140MW. Well head generator 35MW New Coal plants 2015 20MW New MSD plants 2013, 332MW			

Table 3.1b Overview of the alternative Scenarios

	Reference Scenario	Nuclear Scenario	Coal Scenario	Renewable Scenario
Supply side				
	Retirements			
	Decommission Thermal MSD plants 2019, 56MW, 2021, 74MW, 2023, 75MW			
	Decommission Gas Turbine plants 2014, 60MW			
	Decommission Geothermal plants 2028, 52MW, 2029, 70MW			
	Decommission Cogeneration plant 2019, 26MW			
	Endogenous Capacity (Candidate Plants)			
	Geothermal plants 140MW	Geothermal plants 140MW	Geothermal plants 140MW	Geothermal plants 140MW
	Coal plants 300MW	Nuclear 1000MW	Coal plants 300MW	Wind 100MW
	Hydro Imports 200MW	Hydro Imports 200MW	Hydro Imports 200MW	Hydro Imports 200MW
	MSD plants 160MW	Wind 100MW	MSD plants 160MW	Pumped Hydro 100MW
	Wind 100MW	Natural Gas 180MW	Wind 100MW	Small Hydro 10MW
	Natural Gas 180MW		Natural Gas 180MW	Solar 10MW
	Nuclear 1000MW			Biomass 10MW

The total activity level for a technology is the product of the activity levels in all branches from the technology branch back up to the original demand branch as shown in Figure. 3.1 and equation 3.3.

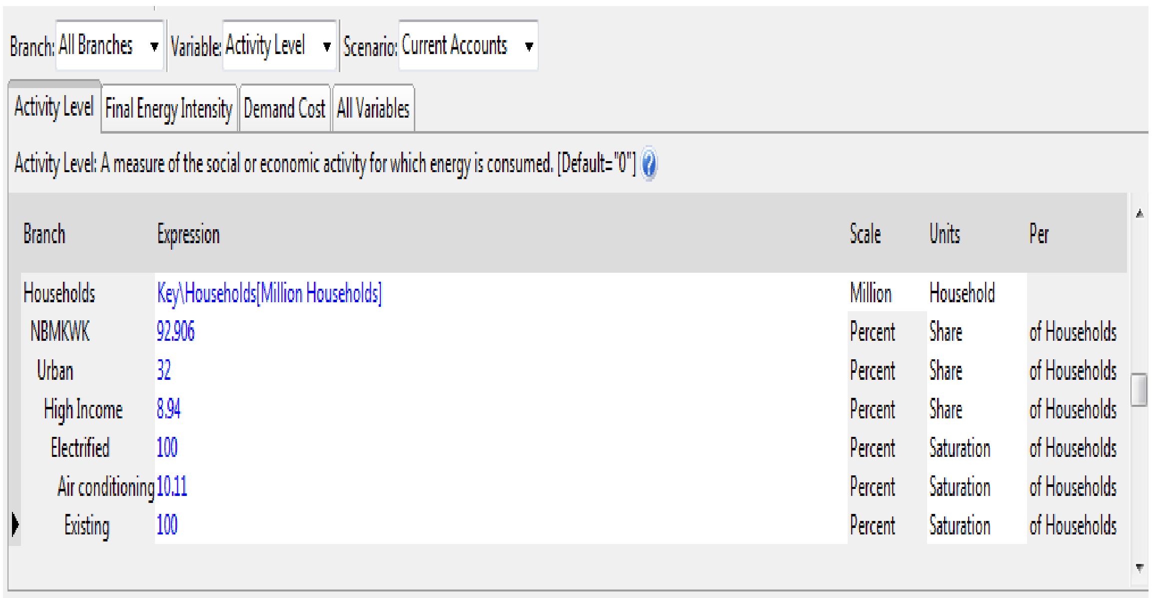

Figure 3.1 Activity Levels for domestic sector

$$TA_{b,s,t} = A_{b's,t} \times A_{b''s,t} \times A_{b'''s,t} \qquad 3.3$$

Where

- A_b is the activity level in a particular branch b.
- b’ is the parent of branch b and b” is the grandparent.

The energy intensity for each activity was calculated on the basis of the specific electricity consumption (kWh) for each device as provided for in the 2012 load forecasting report (Jensen, et al., 2012).

The disaggregated end-use based approach was not used for the street lighting, commercial and industrial sector due to data constraints. However, the total annual demand data as used in the 2012 load forecasting report was available and this is what was adopted for this study.

3.3.1. Supply Process Data and Model Assumptions

- Capacity data for existing plants, committed plants and plant retirement programs was specified under the exogenous capacity.
- Candidate plants data which would be used to maintain a minimum reserve margin as well as meet the demand after retirements was specified under the endogenous capacity. The endogenous capacity provides a list of processes that are available for addition with a specified addition size and order for each scenario.
- The transmission and distribution losses were specified as 14.50% for the year 2012 after which they reduced to 14% in 2015 (ERC, 2013).
- The planning reserve margin for the period 2012-2030 was 25% (ERC, 2013). This margin is used by the system to determine when to automatically add additional endogenous capacity to maintain it on or above the value set in the system.
- The process efficiency which is defined as the percentage ratio of energy output to feedstock energy input was set in the system as follows; for the renewable plants, since the feedstock is a natural resource with no cost the efficiency was defined to be 100% while that of MSD plants was taken to be 35%, natural gas 40%, coal 40% and nuclear 80% (Heap, 2011).
- The Maximum availability which is normally described by planned and forced outages and is expressed as a ratio of the maximum energy produced to what would have been produced if the process ran at full capacity for a given period was defined in the system as follows; for KenGen plants maximum availability data was obtained from KenGen report (KenGen, 2012), on the other hand the data for IPP was not readily available and therefore data for similar plants was obtained from the LEAP TED.
- The merit order which indicates the order in which processes are to be dispatched was set to 1 for baseload plants, 2 for intermediate plants and 3 for peak plants. For hydro and thermal plants whose output was variable throughout the year, the

merit order was defined for each time slice. This allowed for hydro plants to be dispatched as baseload plants during the wet season and as peak load plants during the dry season. The processes with the lowest merit order were dispatched first and processes with the highest merit order were dispatched last. Processes with equal merit order were dispatched together in proportion to the available capacity.

  - The dispatch rule which determines how the power plants are dispatched to meet the demand requirement on and after the first simulation year was set to run on ascending merit order for most plants apart from wind, solar and small hydro plants which were set to run in proportion to their full capacity.

- The capacity credit which is defined as the fraction of the rated capacity considered firm for the purpose of calculating the module reserve margin, was obtained from KenGen report for KenGen plants and LEAP TED for the IPP plants and new additions. The capacity credit for hydro imports was set to be zero.
- The lifetime of the endogenous plants was specified as a variable used for calculation of annualized capital costs as well as setting the retirement period.
- Cost data considered for simulation was only for the committed and candidate plants. The existing plants cost data was not readily available.
- A discount rate of 10% was used for annualization of the capital costs using the Capital Recovery Factor method (CRF).
- Sensitivity analysis was performed using 8% and 12% discount rates.
- For the calculation of the GHG emissions the fuels used for the various processes were specified and linked to the TED library that provides the default emission factors as given by the intergovernmental Panel on Climate Change (IPCC).

3.3.2. Plants Dispatch Simulation

The base year data was first input in to the system for the process dispatch to be undertaken. Twelve time slices were created for the base year 2012 to correspond to 12 months in a year. The total annual demand was then mapped on the time slices. Various parameters for the different plants like the merit order and availability that varied with respect to the time slices were specified on yearly profiles. To dispatch the processes to meet the demand requirements, different algorithms were used for the different dispatch rules, the summary in form of a flow chart is given in the Figure 3.2. For Plants dispatched to run on full capacity, the formulae used to calculate the process share is as depicted by equation 3.4. To obtain the actual available output for each process dispatched on full available capacity, equation 3.5 (Heap, 2011) is used.

$$Process\ share_t = \frac{Capacity_t \times MCF_t}{\sum_t^n (Capacity_t \times MCF_t)} \qquad 3.4$$

Where:

- MCF is Maximum Capacity Factor.
- t is a specific plant
- n represent the total number of plants dispatched on run on full available capacity

$$Actual\ Output\ _t = Capacity_t \times Availability_t \qquad 3.5$$

Where:

- t is the specific plant/technology dispatched on run on full available capacity.

Finally a total for all plants being dispatched on full available capacity is obtained after which the plants being dispatched on merit order are incorporated to supply the deficit.

For the plants dispatched to run on ascending merit order rule, dispatch is simulated on a cumulative annual load curve. First, a list of the processes is made; sorted by merit order for existing plants as shown in Appendix C.1 and Appendix C.2 for new additions. The load duration curve is then defined in the model as a percentage of the peak load, as shown in the Figure 3.3 after which, it is divided into vertical strips as defined by the information specified in the yearly shapes screen. The height of the strips is determined by the average percentage of peak load for two adjacent points on the specified curve multiplied by the overall system peak load requirement given by equation 3.6.

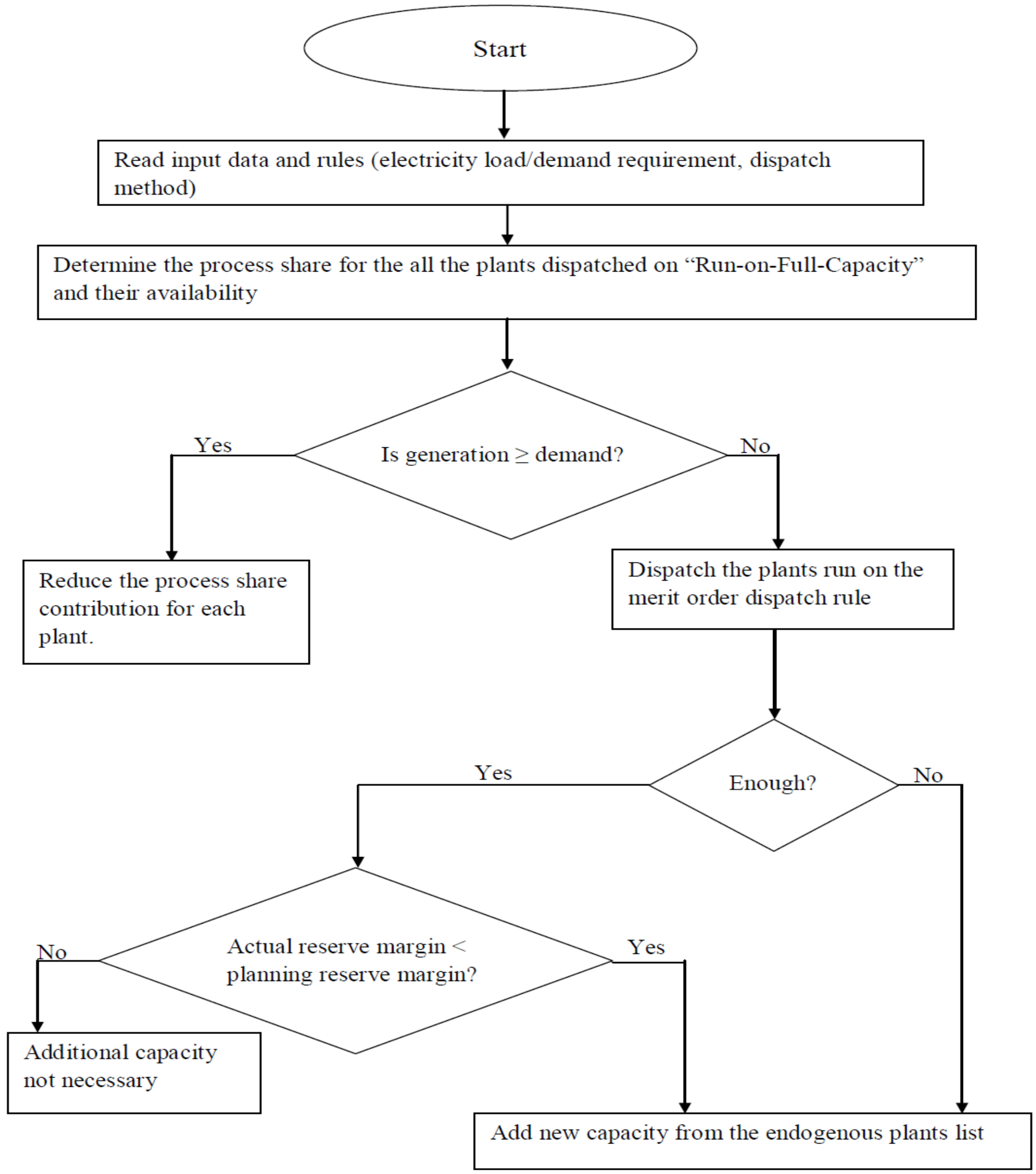

Figure 3.2 Concept flow chart of the algorithm used to dispatch plants

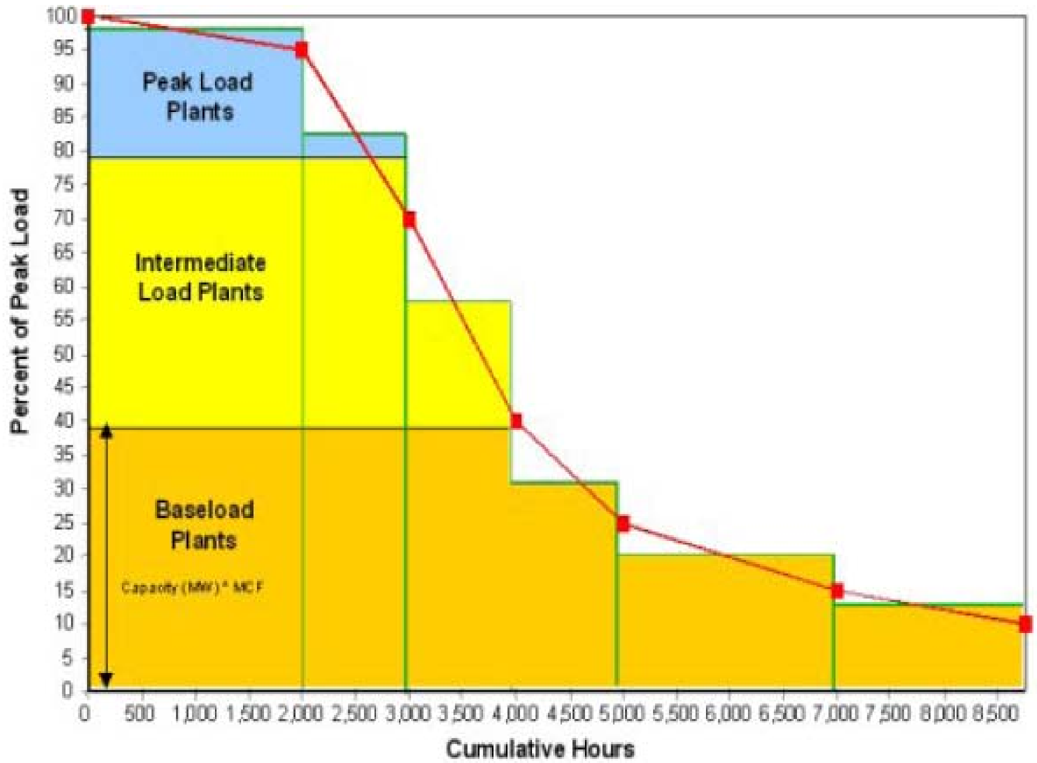

Figure 3.3 Annual load duration curve as a percentage of peak load (Heap, 2011)

$$P_{pr} = \frac{E_r}{LF \times 8760hrs} \tag{3.6}$$

Where:

The Load Factor (LF) was taken as the mean height of the load curve.

Each group of the processes is then dispatched in vertical strips to fill the area under the load curve. Baseload plants are dispatched first at the bottom, followed by the intermediate and finally the peak plants. The maximum Height (H_m) of the each strip is obtained by equation 3.7.

$$H_m = \sum(Capacity_t \times MCF_t) \tag{3.7}$$

To maintain sufficient capacity to meet the increasing demand, the Reserve Margin (RM), given by equation 3.8 is applied as the check and maintained it on or above 25%.

$$RM_{BA}\,(\%) = 100\ \times (MC_{BA} - \ P_{pr})/P_{pr}) \qquad 3.8$$

The Module Capacity before addition MC_{BA} is obtained by using equation 3.9 for all processes available.

$$MC_{BA} = \ \sum(\ C\ \times CF) \qquad 3.9$$

The module capacity C is given by the sum of the exogenous capacity which were explicitly specified and the endogenous capacity that had been added previously as given by equation 3.10.

$$C\ = (C_{ex} + \ C_{end}) \qquad 3.10$$

To calculate the endogenous capacity to be added after confirmation that the reserve margin is below the planning margin of 25% equation 3.11 is used.

$$C_{end}\ = \left(RM_p - RM_{BA}\right) \times \ P_{pr} \qquad 3.11$$

3.4. Emission Analysis

The GHG emissions for the various processes of power generation were estimated using equation 3.12.

$$Emission\ _{t,y,p} = \ Energy\ consumption_{t,y}\ \times \ Emission\ factor_{t,y,p} \qquad 3.12$$

Where:

- t is the type of technology
- y is the year
- p is the plant

The emissions for each scenario were aggregated together, then assigned a global warming potential relative to CO_2 so as to compare their effects on a scenario basis. Appendix C.3 outlines the emission factors used in this study.

3.5. Cost Analysis

The cost analysis boundary for this study was restricted to the additional generation capacity for each scenario due to data constraints of the existing plants. The cost data for the candidate plants is indicated in the Appendix C.4.

The annualization of the capital costs over the lifetime of the plant was done using the Capital Recovery Factor (CRF) as per the equation 3.13.

$$Capital\ costs_{annual} = capital\ cost\ \left(\frac{i\ (1+i)^n}{(1+i)^n - 1}\right) \tag{3.13}$$

Where:

- i is the discount rate
- n is the lifetime of the plant in years.

The levelised annual capital costs in \$/kWh for each plant was obtained by using equation 3.14.

$$\overline{CC_t} = \frac{CC_t\ \times\ CRF}{8760\ hours\ \times CF_t} \tag{3.14}$$

The levelised annual fixed O&M costs in \$/kWh for each plant was obtained by using equation 3.15.

$$\overline{FC} = \frac{FC_t}{8760\ hours\ \times\ CF_t} \tag{3.15}$$

The total levelised total annual costs \$/kWh for each plant was obtained by using equation 3.16.

$$\overline{AC_t} = \overline{CC_t} + \overline{FC_t} + \overline{VC_t} \qquad 3.16$$

The total annual costs in $/year for each plant was obtained by using equation 3.17.

$$TC_t = \overline{AC_t} \times CF_t \times 8760 \times Capacity_t \qquad 3.17$$

To carry out a comparison of costs per scenario the Net Present Value (NPV) for each plant was obtained using equation 3.18.

$$NPV_t = TC_t \left(\frac{(1+i)^n \pm 1}{i(1+i)^n} \right) \qquad 3.18$$

Finally the total sum for all the plants NPV per scenario was obtained.

$$NPV_S = \sum_{t=1}^{n} NPV_t \qquad 3.19$$

CHAPTER FOUR

RESULTS AND DISCUSSION

This chapter outlines the results of the base year demand and supply analysis, the simulation results for the four scenarios, the cost as well as the emission results and comparisons for the four scenarios.

4.1. Base Year Data Analysis

The total overall electricity demand for the year 2012 was 6299GWh. The greatest share of the power was consumed by the commercial and industrial sector at 55% as shown by Figure 4.1.

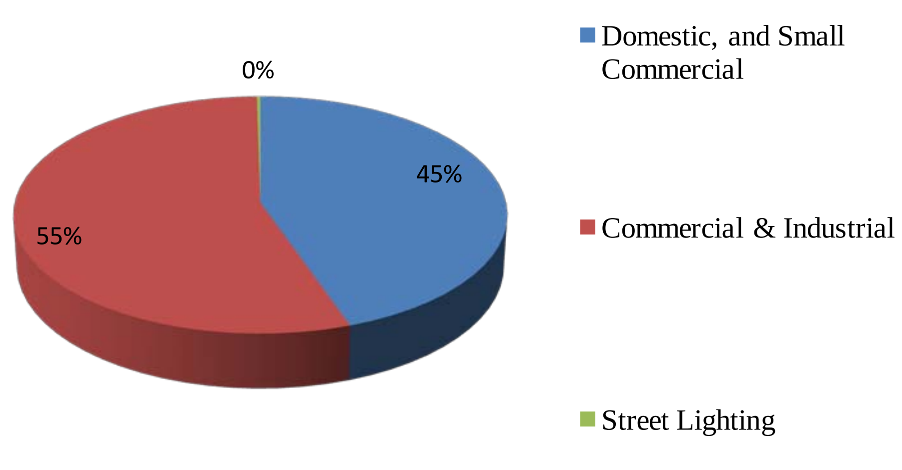

Figure 4.1 Breakdown of power demand by sectors

The power demand pattern for the year was fairly constant as shown by the annual load duration curve on Figure 4.2, as well as the daily load duration curves on Figure 4.3. The daily peak demand occurred between 1800hrs to 2200hrs throughout the year because of the increase in consumption from the domestic sector. The peak demand was also fairly constant around 1180MW and so was the off peak demand at 600MW as shown in Figure 4.4. These results were useful in the mapping of time slices.

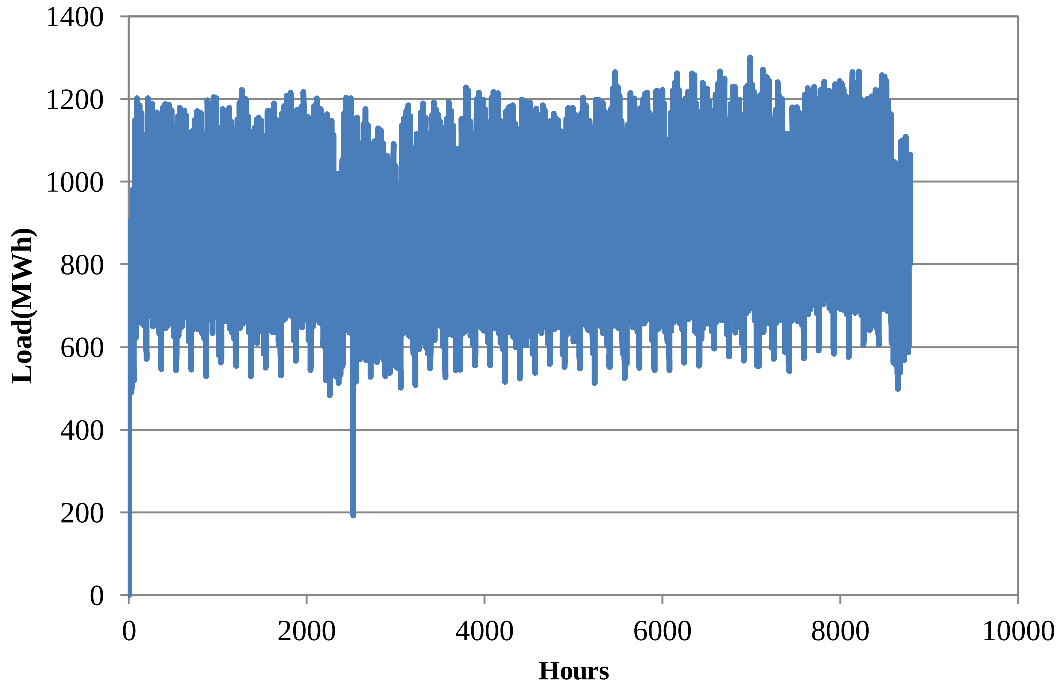

Figure 4.2 2012 Annual load duration curve

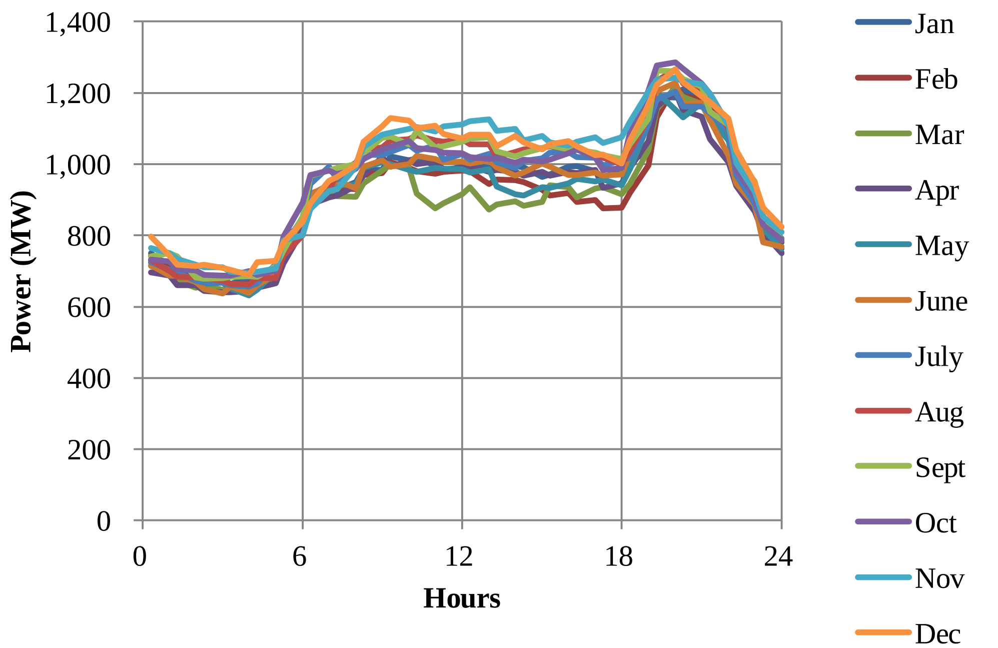

Figure 4.3 Sampled daily load duration curves

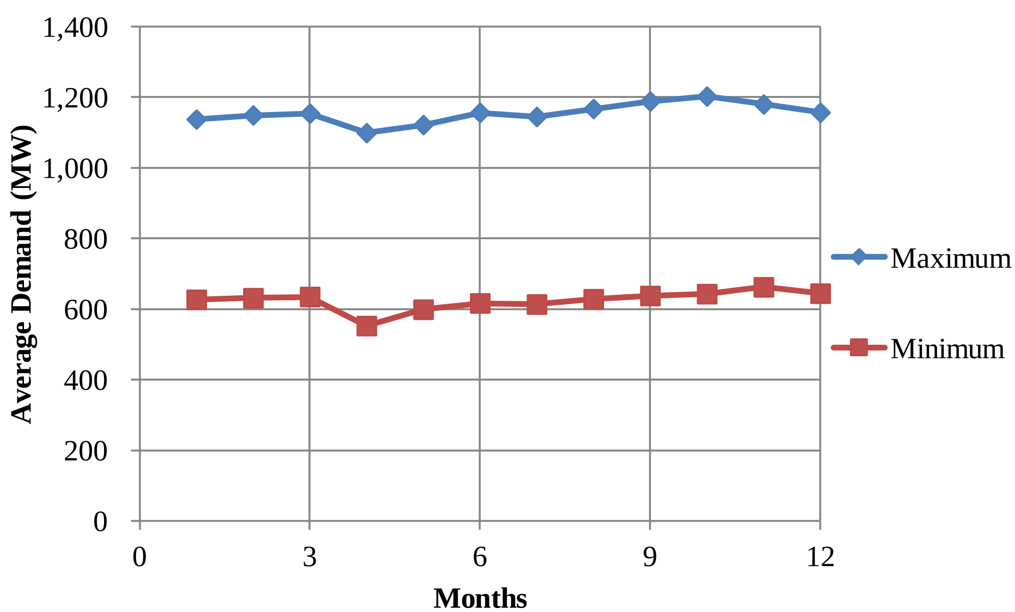

Figure 4.4 A graph of average maximum and minimum demand

The annual average load factor was 68% and it was obtained as the mean height of the annual standard LDC shown in Figure 4.5. This load factor was used in calculating the power requirement when dispatching the plants on ascending merit order rule and it's an important indicator of the utilization of installed capacity. The higher the load factor the better the utilization of the capacity whereas a low load factor indicates that there's a lot of idle capacity during the off-peak hours.

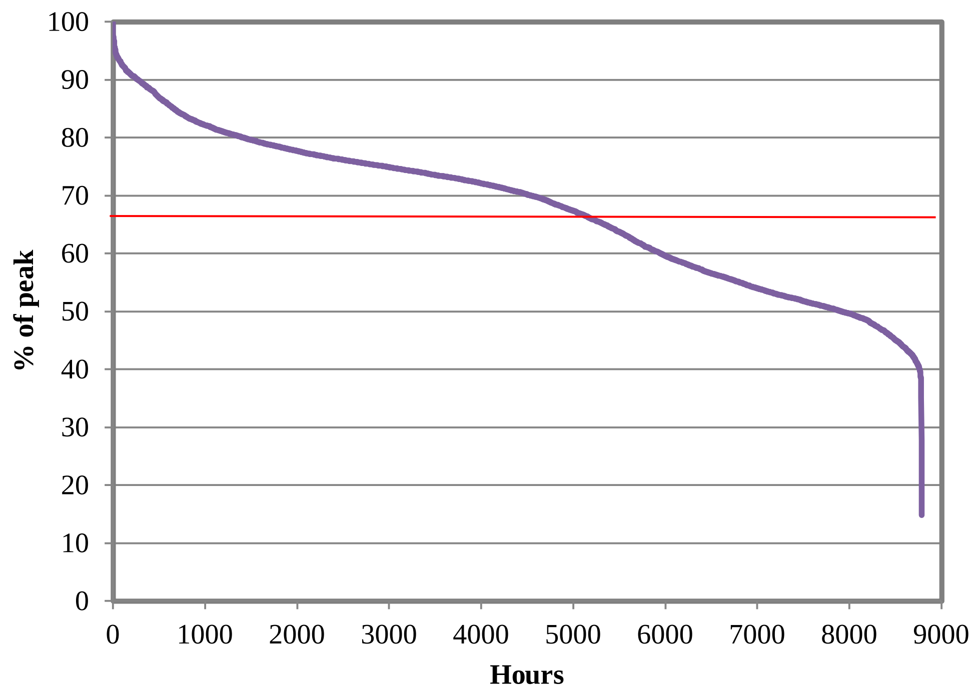

Figure 4.5 Standard load duration curve

From the generation side, the contribution of the various power plants to the grid was assessed by determining the daily average capacity factor for the different groups of power plants as shown in Figure 4.6.

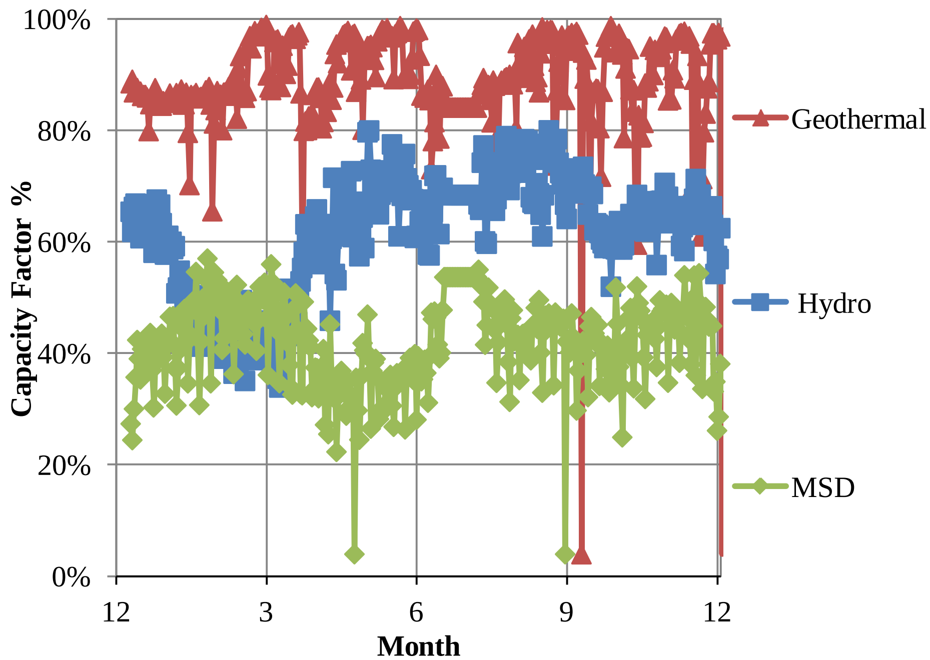

Figure 4.6 Variation of capacity factor for power plants

This variation was useful in the assignment of merit order for the power plants, as per the time slices, hence generating yearly merit order profiles which were used in guiding of power plants dispatch. The capacity factor for geothermal plants was constantly above 80% hence, it was classified as a baseload plant but the capacity factors for hydro and MSD plants were variable depending on the season. For the dry period around February to April the power production of Hydro plants was at the lowest but the MSD plants somewhat compensated for this loss. For the wet season in April-June and October-November, the hydro plants generated optimally thus reducing the share of MSD plants. Figure 4.7 and 4.8 clearly show the power production variation in a typical day, for the different classes of power plants during the dry and wet season respectively. Geothermal plants production remains constant while that of MSD and hydro plants varies.

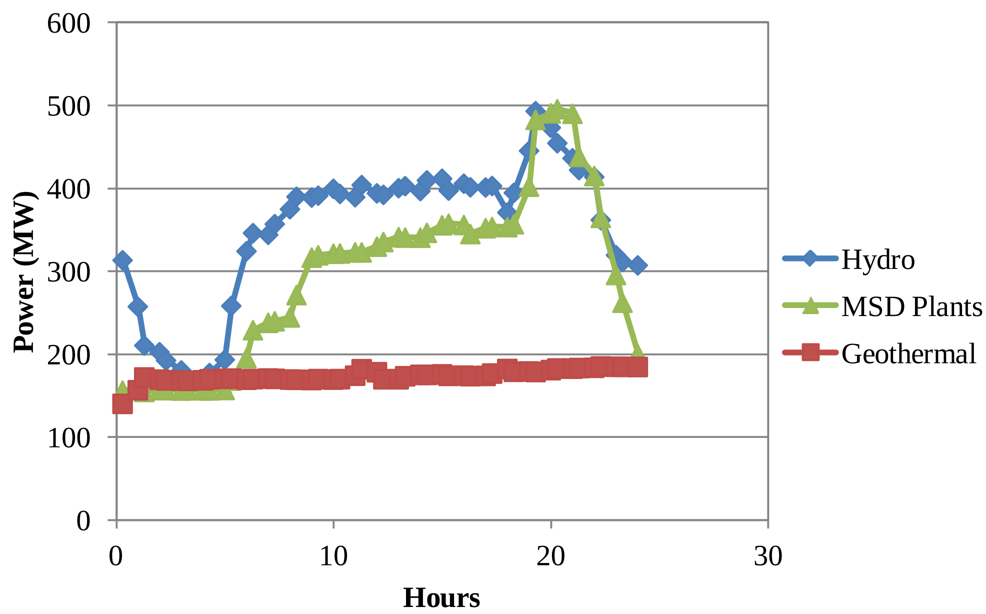

Figure 4.7 Typical dry season supply curve

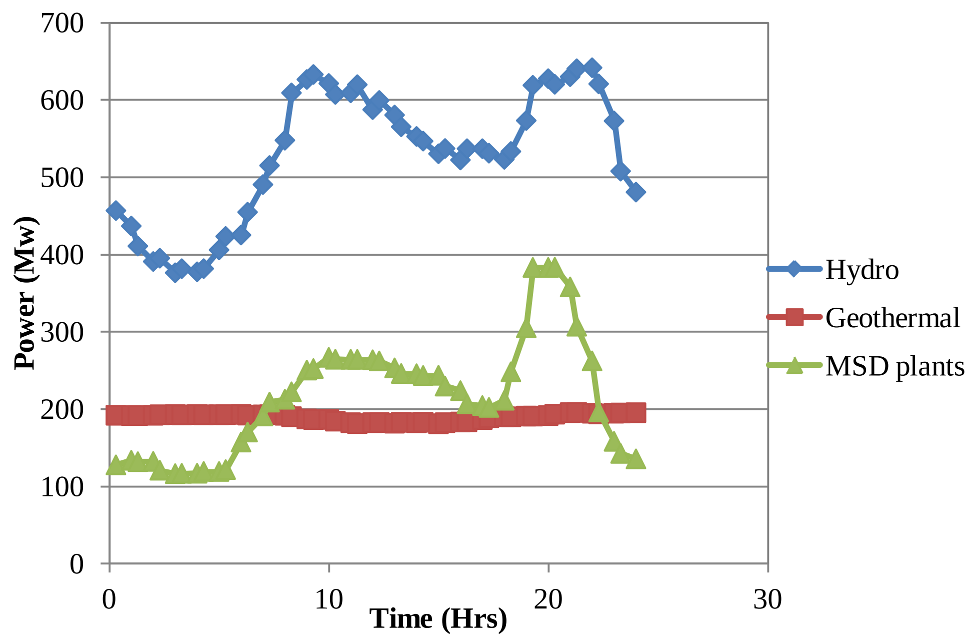

Figure 4.8 Typical wet season supply curve

4.2 Simulation

The power demand for all scenarios increased from 6299GWh to 38500GWh as shown by Figure 4.9. The peak demand increased from 1286MW to 7500MW as shown in Figure 4.10. The industrial demand remained above 50% throughout the study period, with the street lighting consumption growing marginally because it is expected that they will be powered off grid.

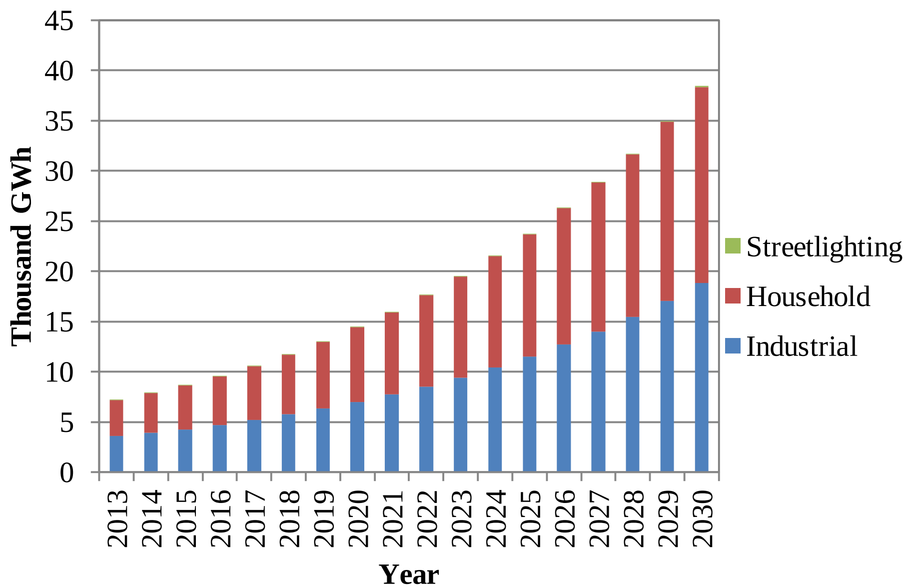

Figure 4.9 Electricity demand as modeled from 2012 -2030

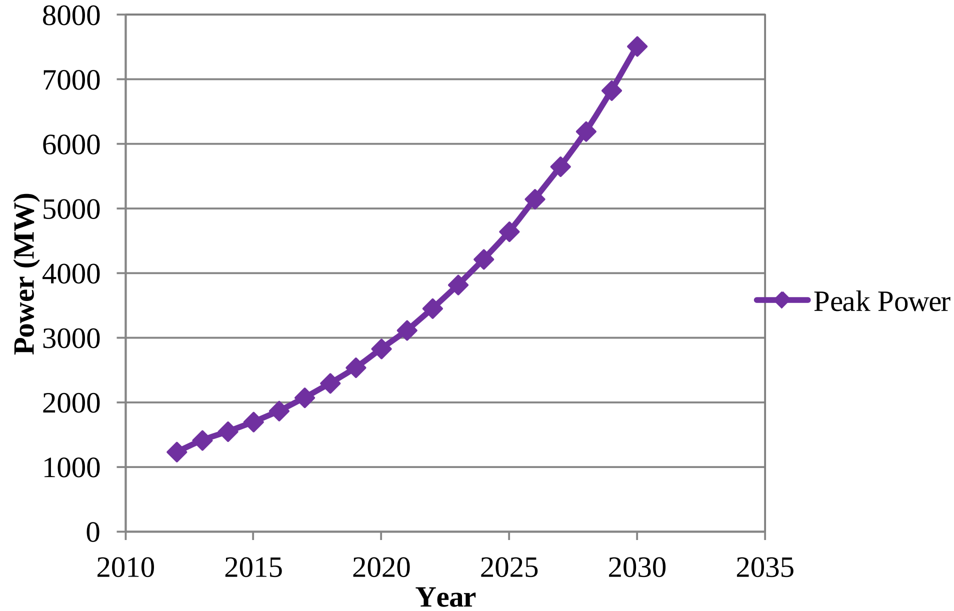

Figure 4.10 Projected peak power requirements 2012 – 2030

Figure 4.11 shows the projected growth of the power supply for the RS scenario. At the initial stages of simulation there's an over design in terms of capacity but this is gradually reduced as the demand increases. In this scenario the geothermal capacity increases to contribute 29% of the total power supply. Nuclear plants contribute 15% while coal plants contribute 14%. The hydro power plants contribution is greatly reduced to 8%. For the peak power plants; the MSD plants contribute 12% and the gas plants contribute 8%. Wind power in this scenario contributes 6% and imports contribute 9%. The total generation capacity in this scenario is increased to 13,192MW in 2030.

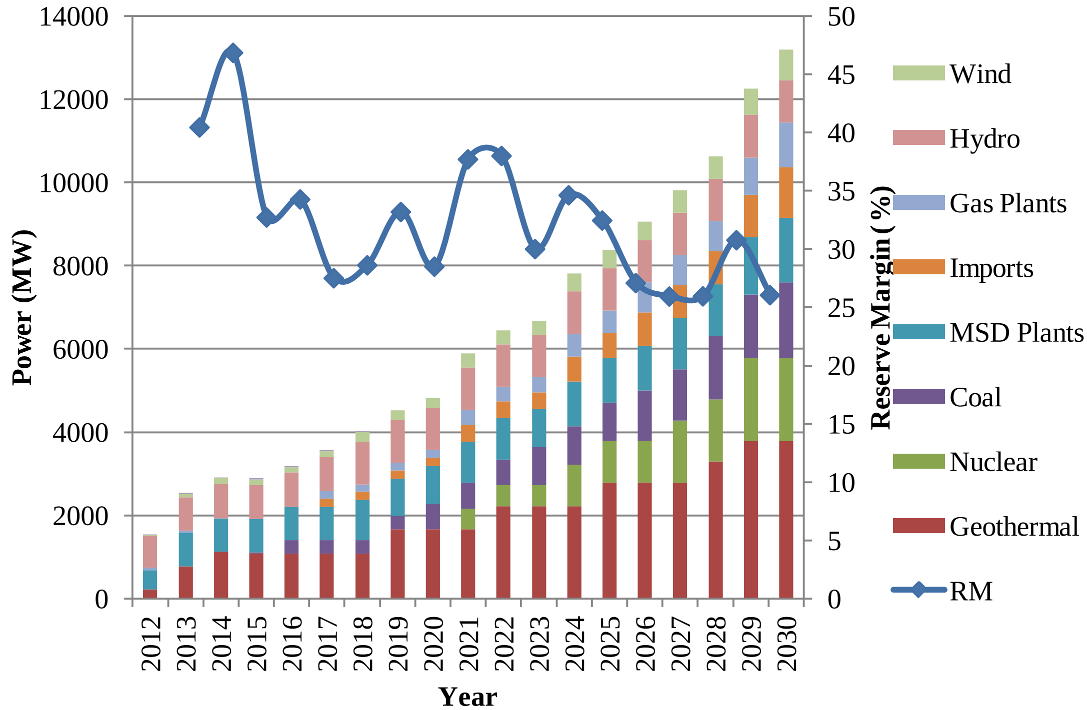

Figure 4.11 Projected electricity supply growth in RS scenario

Figure 4.12 show the projected growth of power supply in the NS scenario. The total generation capacity increases to 14,072MW. Geothermal plants contribute 38% of total power generated. Nuclear plants contribute 21%, imports 11%, gas plants 10%, hydro and wind contribute 7% each and finally MSD plants contribute 5%. In this scenario there's still an over design in terms of capacity by 2030 since the reserve margin is 30%. This is undesirable because of the costs implications of the excess capacity.

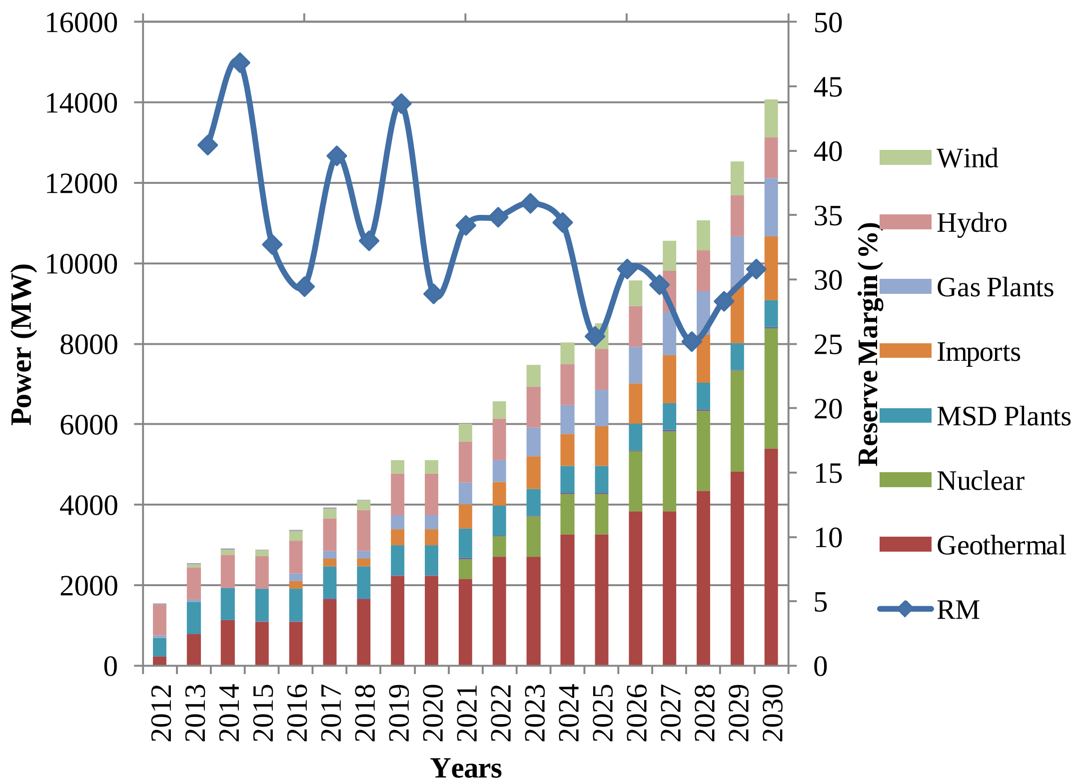

Figure 4.12 Projected electricity supply growth in the NS scenario

Figure 4.13 shows the projected growth of power supply in the CS scenario. Geothermal plants contribute 36% of the generation capacity. Coal plants contribute 18%, MSD plants contribute 13%, imports 10%, gas plants 9%, Hydro 8% and wind 6%. The reserve margin for this scenario starts to stabilize by the year 2020 at 26%. The total generation capacity is 13,552MW which compares well with the reference scenario.

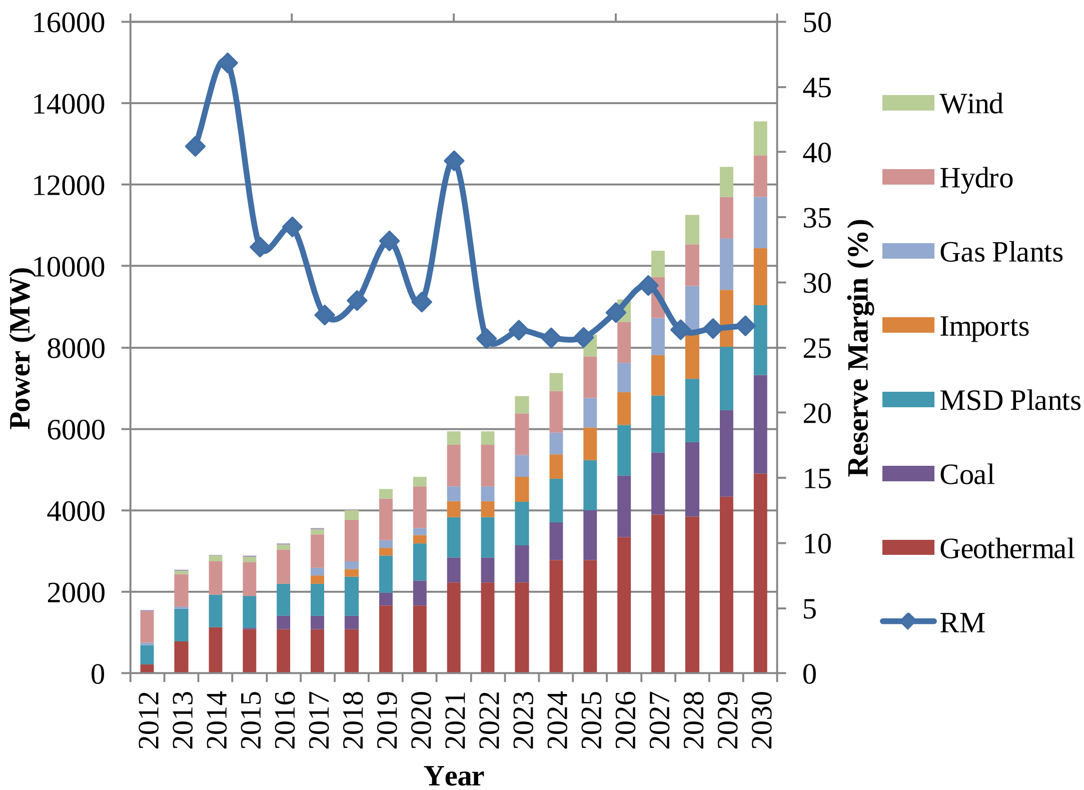

Figure 4.13 Projected electricity supply growth in CS scenario

Figure 4.14 shows the projected power supply growth for the RES scenario. Geothermal plants contribute 48% of the total generation capacity. Hydro capacity is reduced to 17%; out of which 1020MW is hydro plants capacity with storage, pumped hydro contribute 1000MW and small hydro plants 650MW. Imports contribute 15%, wind 9%, solar plants 4%, biomass 2% and MSD plants 4%. The total generation capacity for this scenario is 15897MW. The reserve margin stabilizes at around 26% from the year 2023. The installed capacity in this scenario is the greatest among all the scenarios because imports are not included in the reserve margin calculation and also the firm capacity for the wind and solar plants is quite low. Therefore to compensate for this limitation, the geothermal plants capacity is increased.

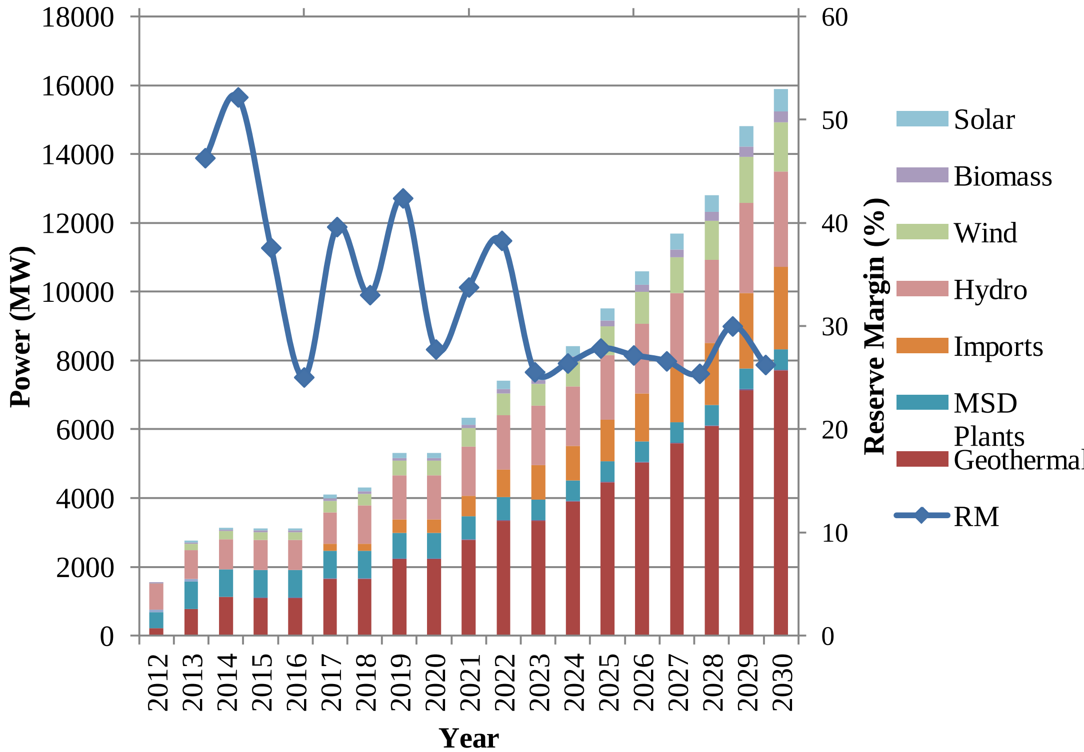

Figure 4.14 Projected power supply growth in the RES scenario

Comparing the results of the coal scenario, nuclear scenario and the renewable energy scenario to the reference scenario in terms of capacity; only the coal scenario compares wells because the size of the plants being added are moderate, with the highest capacity addition being 300MW. Secondly, all the plants added have a high capacity credit rating, so they contribute to the reserve margin. In regards to the nuclear scenario, the addition capacity of one nuclear plant is 1000MW, so at any one time the nuclear plants are added, there’s excess capacity and hence the high reserve margin. In the case of the renewable energy scenario the actual reserve margin is optimum but due to the fact that solar and wind plants do not contribute to the reserve margin, which is the basis of plant addition in this study, then the other plants compensate for that, leading to a very high figure of the generation capacity.

4.3. Cost Analysis

Figure 4.15 shows how the capital costs were spread across the study period for all the scenarios. The RES was the most expensive scenario, while the least expensive scenario was the CS. The high costs of the RES scenario were attributed to the greater capacity installed at 15,897MW in comparison with the other scenarios as well as the slightly higher capital costs of the renewable technologies.

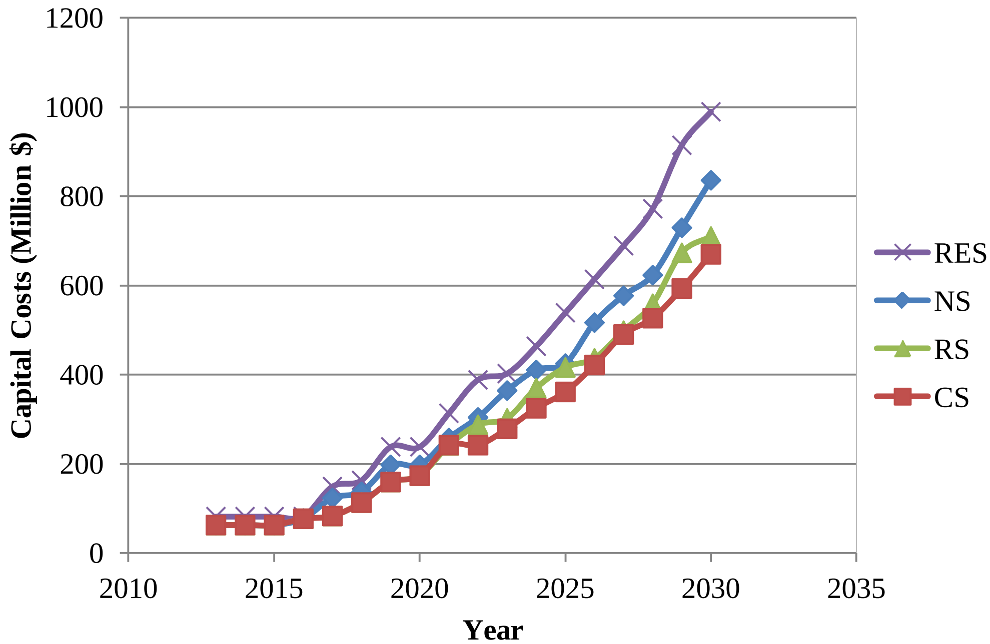

Figure 4.15 Capital costs comparison of the scenarios

When the annual fixed costs were compared as shown in Figure 4.16, there were no major variations for the RES, NS and RS scenarios. The annual cost pattern showed a stable trend across the study period. The CS scenario had the least annual fixed cost because the additional plant capacity were below 300MW, so when the cost were spread over the lifetime of 30-40years, the figures were more favourable than for the nuclear plants in the RS and NS. In the case of renewable scenario the capacity additions were the most as compared to other scenarios hence high annual costs. When the variable costs were compared, the RES scenario was characterized by lower costs vis a vis the other scenarios as shown in Figure 4.17. Renewable energy plants incurs the least variable costs since they utilize the naturally available energy resources that are available free of charge.

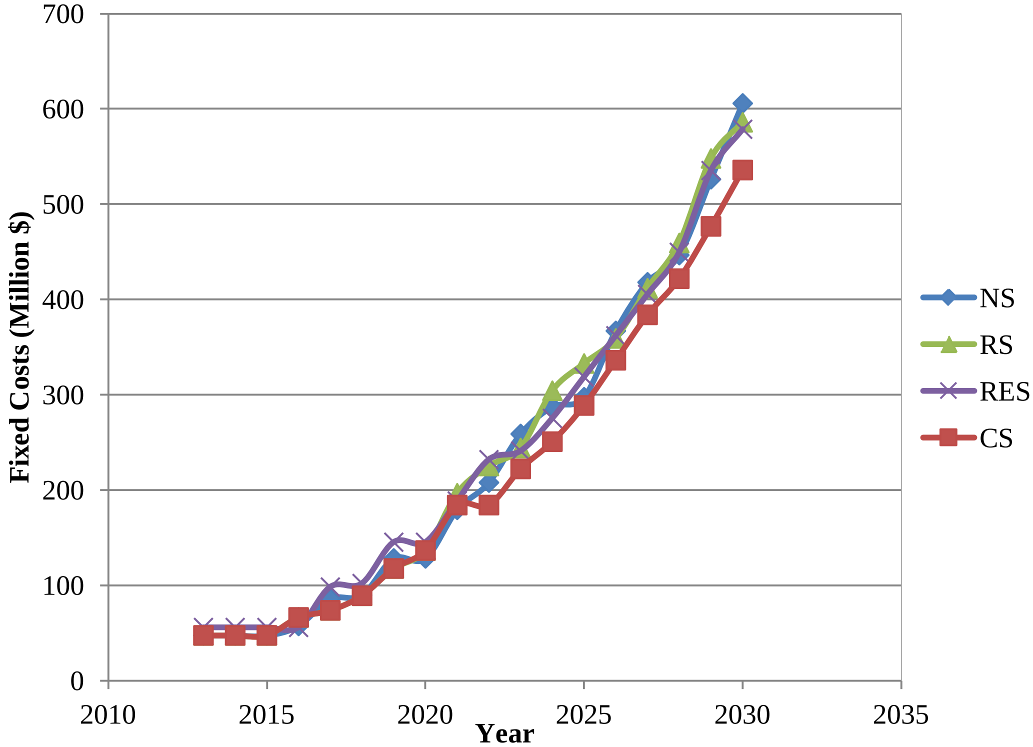

Figure 4.16 Fixed costs comparisons of the scenarios

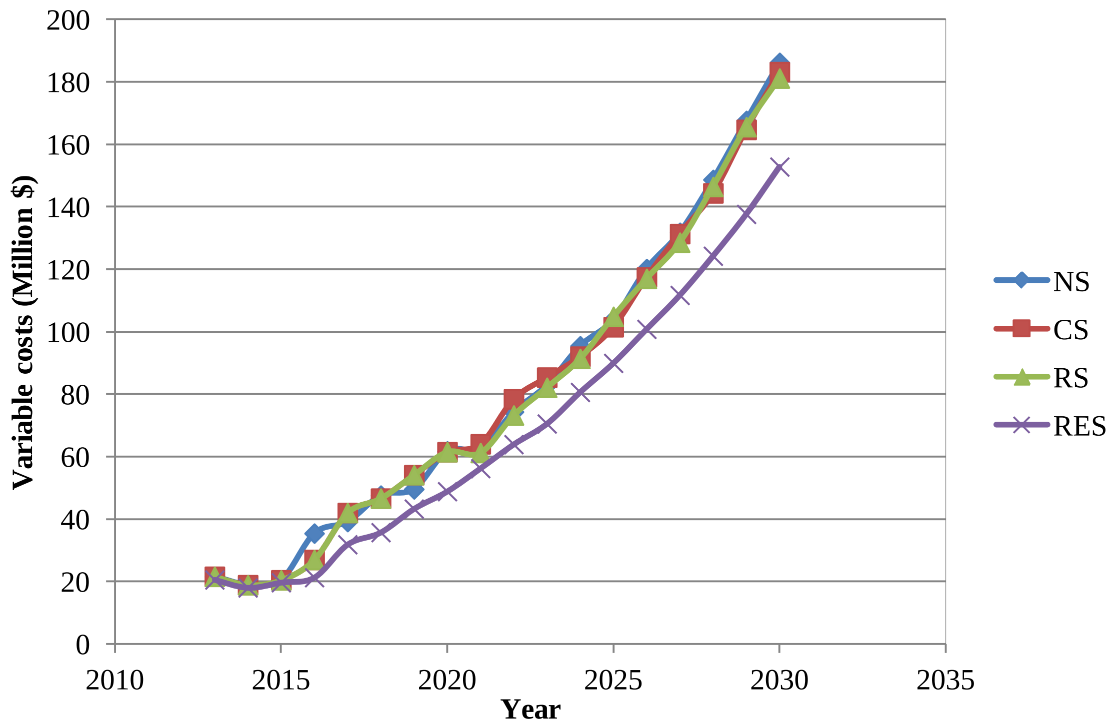

Figure 4.17 Variable costs comparison for the scenarios

On discounting all the costs to the base year first at 10%, then at 8% and 12% discount rate the CS scenario had the least cost at all the discount rates and the most expensive scenario was the RES as shown in Figure 4.18. The RS scenario was the second most attractive option followed by the NS.

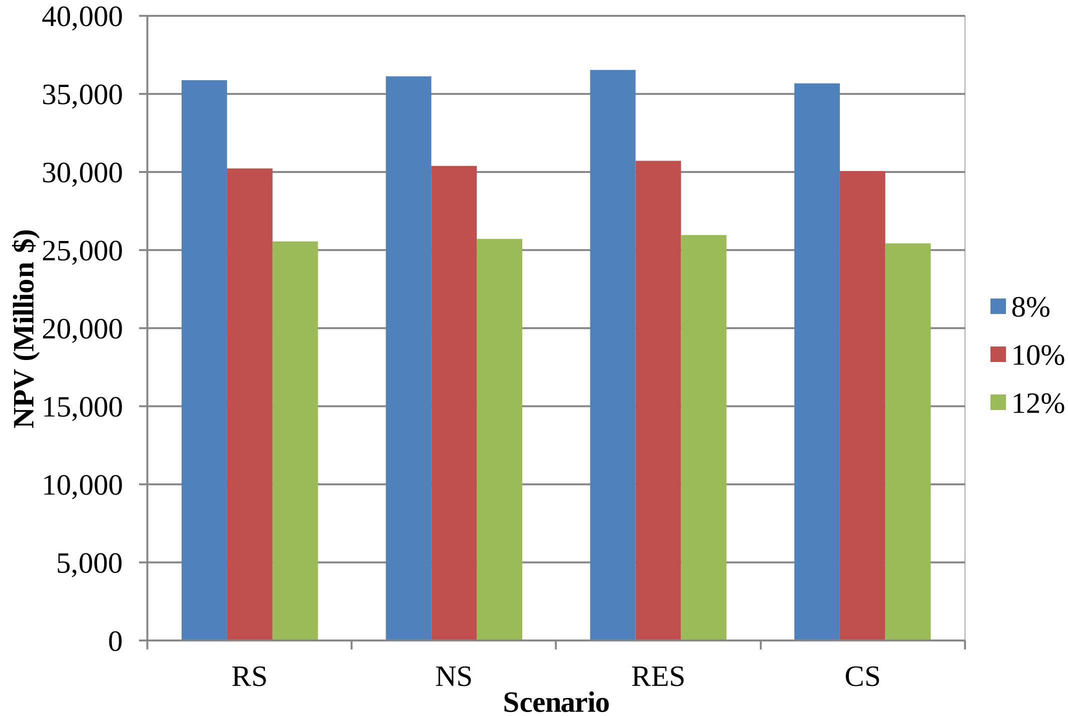

Figure 4.18 Net present generation costs for all scenarios

From the cost analysis it is worth noting that since the dispatch mode for the power plants was merit order, the fuel costs were not included in the variable costs hence some undue advantage was given to the RS, NS and CS scenario over the RES on the variable costs component of power generation. The merit order dispatch mode was chosen due to the inaccessibility of the costs data for the existing plants. The most suitable dispatch method is based on the running costs of the plants, since it incorporates the cost of fuels for the existing plants and for the newly added plants, in addition to the fixed costs of the plants, unlike the merit order rule that can override the costs incurred by the existing plants.

4.4. Emission Analysis

The projected GHG emissions for the various scenarios across the study period are depicted in Figure 4.19, measured in million metric tonnes of CO_2 equivalent. The CS scenario had the most emissions as the coal and MSD plants were added to meet the power demand throughout the study period. The RS scenario had slightly lower emission levels compared to the CS scenario starting from the year 2022 due to the introduction of nuclear plants into the generation mix, hence the contribution of the coal plants was somewhat reduced as the demand for power increased. The RES and NS scenario had very low emission levels but this would be achieved at a cost as shown in Table 4.1. The cost of reducing GHG emissions in the RES scenario was \$8.6/tCO_2eq while that of NS scenario was \$3/tCO_2eq.

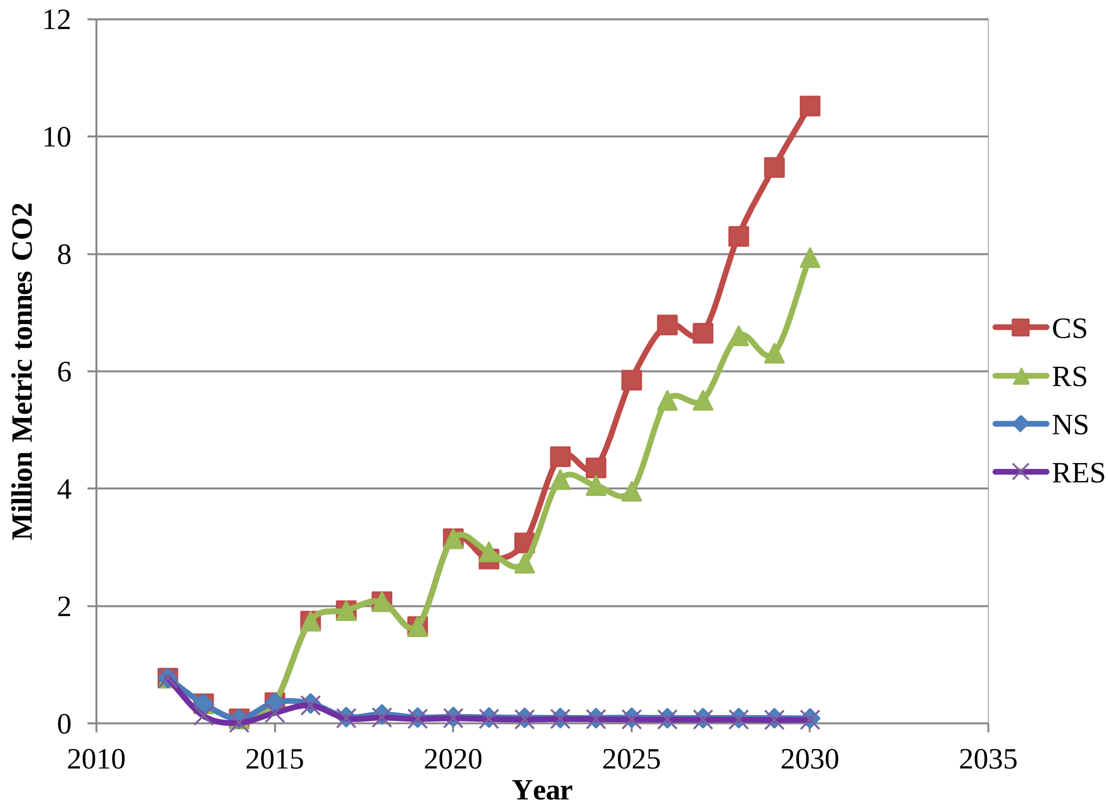

Figure 4.19 Projected emission levels for all scenarios

Table 4.1 Cumulative cost and benefit analysis 2012-2030; compared to Reference Scenario

Discount rate	10%		
Scenario	RES	NS	CS
Net Present Value (NPV) million $	507.2	176.7	-173.2
GHG Savings (Million tCO_2eq.)	59.3	58.5	-12.7
Cost of Avoided CO_2 (U.S. Dollar/tCO_2eq.)	8.6	3	n/a

Hence from this study's emissions analysis results, in the absence of a policy intervention, the RES and NS scenarios remain unattractive from the cost point of view in comparison to the reference scenario.

CONCLUSIONS AND RECOMMENDATIONS

5.1. Conclusions

The coal scenario is the most economically viable scenario at a net present value of \$30,052.67 million, using a 10% discount rate but on the flip side has the most emissions. The reference scenario which represented the government's LCPDP comes second at a NPV of \$30,225.87 million with 12.7million tCO_2eq lower emissions than the coal scenario.

The most sustainable scenario with the least emissions is the renewable scenario but it has the highest NPV of \$30,733.07 million. If this scenario is implemented it would lead to a GHG saving of 59.3 million tCO_2eq with reference to the RS scenario. The nuclear scenario being a clean technology scenario has low emissions as well, if implemented it would lead to a GHG saving of 58.5million tCO_2eq with reference to the RS scenario, but nevertheless it has a higher NPV at \$30,402.57 million.

From the energy security point of view, the renewable energy scenario utilizes the locally available resources only. So it would be the least susceptible scenario to any external instability and price fluctuations. Coal scenario also fares well in that, the only technology that would require fuel importation is the gas turbine plants and these are also built to run on dual fuels such that incase the gas is unavailable; Kerosene can be used as a substitute. The reference scenario and nuclear scenario both have nuclear plants and gas plants so their susceptibility factor in regards to external conditions is higher.

From this study's objective of modeling other possible scenarios for Kenya, and comparing them to the LCPDP in regards to the energy security, cost and environmental sustainability; the renewable energy scenario and coal scenario seem to be the most suitable paths for Kenya to adopt, but further analysis would be necessary especially from the cost point of view, since this research did not take into account the running costs of the existing plants. Furthermore, to improve on the environmental sustainability of the coal scenario the carbon capture and storage technology should be introduced in place of the conventional coal plants which were used in this study.

5.2. Recommendations

This study has shown that Kenya has a range of opportunities that it can use for power generation expansion, but more research is required to determine the most suitable path that can meet the demand requirements with the locally available resources at the most optimal cost.

Other areas identified for further research work include:

- Simulation of the scenarios based on a different dispatch rule; for example dispatching plants by running costs so as to include the costs of fuels in the overall calculation of the net present value of the scenarios. This dispatch rule requires one to input all the costs of the plant in the model including the existing exogenous capacity.
- Optimization of the scenarios to obtain the least cost options, this can be done using the merit order rule but the annual fixed and variable costs for all plants including existing exogenous capacity need to be captured.
- Coal scenario to be simulated as two scenarios; one with the conventional technology and the other with the Carbon Capture and Storage (CCS) technology, so that the environmental impact and costs of the two scenarios are compared.
- Simulation of scenarios for Off-grid areas e.g. Kirinyaga and Murang’a, which have potential for small hydro power that can be used to replace use of fossil fuels in the households and the small medium enterprises.

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APPENDICES

Appendix A: Specific household consumption per region for each income category.

A.1 Specific consumption for the 15cluster appliances used in Nairobi, Western and Central Kenya Region. Urban (High income) category.

		2012			2030		
Cluster	Cluster Name	Spec Con (KWh)	Penetration Probability	Final Spec Con (KWh)	Spec Con (KWh)	Penetration Probability	Final Spec Con (KWh)
CLU 1	Air Conditioning	7223	10.11%	730	3889	20.00%	778
CLU 2	Cloth Cleaning	218	38.46%	84	137	50.00%	69
CLU 3	Cooking	471	40.94%	193	297	50.00%	149
CLU 4	Dishwasher	613	15.38%	94	320	20.00%	64
CLU 5	Entertainment &ICT	1603	59.63%	956	824	80.00%	659
CLU 6	Fitness	297	2.56%	8	151	10.00%	15
CLU 7	Grooming	38	30.77%	12	21	50.00%	10
CLU 8	House Cleaning	126	41.03%	52	69	60.00%	41
CLU 9	Space Heating	113	10.26%	12	69	15.00%	10
CLU 10	Ironing	273	97.44%	266	160	100.00%	160
CLU 11	Lighting	756	98.96%	748	275	100.00%	275
CLU 12	Refrigeration	2624	26.02%	683	1281	50.00%	641
CLU 13	Sanitary water	2485	34.74%	864	1144	80.00%	915
CLU 14	Small Kitchen Apps	1035	44.18%	457	549	80.00%	439
CLU 15	Water Supply	128	33.33%	43	64	60.00%	38
CLU 16	Electric Car	0	0.00%	0	2745	5.00%	137
	Total			**5,200**			**4,400**

Source (Jensen, *et al*., 2012)

A.2 Specific consumption for the 15cluster appliances used in Nairobi, Western and Central Kenya Region. Urban (Middle income) category.

		2012			2030		
Cluster	Cluster Name	Spec Con (KWh)	Penetration Probability	Final Spec Con (KWh)	Spec Con (KWh)	Penetration Probability	Final Spec Cons (KWh)
CLU 1	Air Conditioning	4246	1.31%	55	2351	5.00%	118
CLU 2	Cloth Cleaning	128	11.11%	14	77	20.00%	15
CLU 3	Cooking	250	17.85%	45	128	25.00%	32
CLU 4	Dishwasher	360	8.64%	31	178	10.00%	18
CLU 5	Entertainmen t &ICT	942	43.92%	414	406	60.00%	244
CLU 6	Fitness	174	1.86%	3	86	1.86%	2
CLU 7	Grooming	22	13.53%	3	11	20.00%	2
CLU 8	House Cleaning	74	7.41%	5	37	30.00%	11
CLU 9	Space Heating	67	6.17%	4	33	10.00%	3
CLU 10	Ironing	160	96.30%	155	79	100.00%	79
CLU 11	Lighting	42	83.77%	35	19	100.00%	19
CLU 12	Refrigeration	1617	15.44%	250	800	40.00%	320
CLU 13	Sanitary water	1461	16.49%	241	598	17.00%	102
CLU 14	Small Kitchen Apps	609	22.25%	135	321	40.00%	128
CLU 15	Water Supply	75	12.35%	9	34	20.00%	7
	Total			**1,400**			**1,100**

Source (Jensen, *et al.*, 2012)

A.3 Specific consumption for the 15cluster appliances used in Nairobi, Western and Central Kenya Region. Urban (low income) category.

		2012			2030		
Cluster	Cluster Name	Spec Cons (KWh)	Penetration Probability	Final Spec Cons (KWh)	Spec Cons (KWh)	Penetration Probability	Final Spec Cons (KWh)
CLU 1	Air Conditioning	1829	1.49%	27	1736	2.00%	35
CLU 2	Cloth Cleaning	55	3.62%	2	52	3.62%	2
CLU 3	Cooking	108	8.36%	9	102	8.36%	9
CLU 4	Dishwasher	155	6.52%	10	147	6.52%	10
CLU 5	Entertainment &ICT	406	34.68%	141	385	45.00%	173
CLU 6	Fitness	75	1.45%	1	71	1.45%	1
CLU 7	Grooming	10	4.43%	0	9	4.43%	0
CLU 8	House Cleaning	32	1.45%	0	30	3.00%	1
CLU 9	Space Heating	0	0.00%	0	0	0.00%	0
CLU 10	Ironing	69	92.03%	64	66	99.00%	65
CLU 11	Lighting	75	94.80%	71	67	95.00%	64
CLU 12	Refrigeration	696	7.31%	51	661	8.00%	53
CLU 13	Sanitary water	629	9.57%	60	597	10.00%	60
CLU 14	Small Kitchen Apps	262	9.36%	25	249	10.00%	25
CLU 15	Water Supply	32	7.25%	2	31	10.00%	3
	Total			**464**			**500**

Source (Jensen, *et al*., 2012)

A.4 Specific consumption for the 15cluster appliances used in Nairobi, Western and Central Kenya Region. Rural (High income) category.

Cluster	Cluster Name	Spec Cons (KWh)	Penetration Probability	Final Spec Cons (KWh)	Spec Cons (KWh)	Penetration Probability	Final Spec Cons (KWh)
CLU 1	Air Conditioning	5223	6.45%	337	4335	10.00%	433
CLU 2	Cloth Cleaning	0	0.00%	0	138	5.00%	7
CLU 3	Cooking	235	10.21%	24	197	15.00%	30
CLU 4	Dishwasher	0	0.00%	0	345	2.00%	7
CLU 5	Entertainment &ICT	892	39.45%	352	740	50.00%	370
CLU 6	Fitness	0	0.00%	0	0	0.00%	0
CLU 7	Grooming	27	14.81%	4	23	14.81%	3
CLU 8	House Cleaning	0	0.00%	0	69	5.00%	3
CLU 9	Space Heating	0	0.00%	0	0	0.00%	0
CLU 10	Ironing	197	60.00%	118	164	70.00%	114
CLU 11	Lighting	547	98.51%	539	414	100.00%	414
CLU 12	Refrigeration	1255	18.31%	230	1380	30.00%	414
CLU 13	Sanitary water	785	5.00%	39	690	15.00%	104
CLU 14	Small Kitchen Apps	748	7.56%	57	621	15.00%	93
CLU 15	Water Supply	0	0.00%	0	69	10.00%	7
	Total			**1700**			**2000**

Source (Jensen, *et al*., 2012)

A.5. Specific consumption for the 15cluster appliances used in Nairobi, Western and Central Kenya Region. Rural (Middle income) category.

Cluster	Cluster Name	Spec Cons (KWh)	Penetration Probability	Final Spec Cons (KWh)	Spec Cons (KWh)	Penetration Probability	Final Spec Cons (KWh)
CLU 1	Air Conditioning	281	20.59%	58	223	20.59%	46
CLU 2	Cloth Cleaning	0	0.00%	0	141	2.00%	3
CLU 3	Cooking	197	4.73%	9	176	6.00%	11
CLU 4	Dishwasher	0	0.00%	0	352	1.00%	4
CLU 5	Entertainmen t &ICT	1064	28.69%	305	844	45.00%	380
CLU 6	Fitness	0	0.00%	0	0	0.00%	0
CLU 7	Grooming	26	3.16%	1	20	3.16%	1
CLU 8	House Cleaning	0	0.00%	0	70	3.00%	2
CLU 9	Space Heating	0	0.00%	0	0	0.00%	0
CLU 10	Ironing	183	61.76%	113	145	80.00%	116
CLU 11	Lighting	48	80.67%	39	35	100.00%	35
CLU 12	Refrigeration	1281	9.25%	119	1015	15.00%	152
CLU 13	Sanitary water	1666	5.36%	89	1126	10.00%	113
CLU 14	Small Kitchen Apps	401	3.03%	12	318	10.00%	32
CLU 15	Water Supply	85	5.88%	5	70	10.00%	7
	Total			**750**			**900**

Source (Jensen, *et al.*, 2012)

A.6. Specific consumption for the 15cluster appliances used in Nairobi, Western and Central Kenya Region. Rural (low income) category.

		2012			2030		
Cluster	Cluster Name	Spec Cons (KWh)	Penetration Probability	Final Spec Cons (KWh)	Spec Cons (KWh)	Penetration Probability	Final Spec Cons (KWh)
CLU 1	Air Conditioning	1451	3.88%	56	1434	3.88%	56
CLU 2	Cloth Cleaning	44	1.89%	1	43	2.00%	1
CLU 3	Cooking	14	3.77%	1	14	5.00%	1
CLU 4	Dishwasher	0	0.00%	0	0	0.00%	0
CLU 5	Entertainment &ICT	279	21.79%	61	276	30.00%	83
CLU 6	Fitness	0	0.00%	0	0	0.00%	0
CLU 7	Grooming	7	1.89%	0	7	1.89%	0
CLU 8	House Cleaning	0	0.00%	0	100	2.00%	2
CLU 9	Space Heating	0	0.00%	0	0	0.00%	0
CLU 10	Ironing	55	39.62%	22	54	45.00%	24
CLU 11	Lighting	60	95.58%	57	59	100.00%	59
CLU 12	Refrigeration	349	2.92%	10	345	4.00%	14
CLU 13	Sanitary water	320	2.34%	7	350	5.00%	18
CLU 14	Small Kitchen Apps	47	1.89%	1	46	3.00%	1
CLU 15	Water Supply	25	1.89%	0	50	5.00%	3
	Total			**216**			**261**

Source (Jensen, *et al.*, 2012)

A.7. Specific consumption for the 15cluster appliances used in Coast Region. Urban (High income) category.

		2012			2030		
Cluster	Cluster Name	Spec Con (KWh)	Penetration Probability	Final Spec Cons (KWh)	Spec Cons (KWh)	Penetration Probability	Final Spec Cons (KWh)
CLU 1	Air Conditioning	7024	97.72%	6864	7054	99.00%	6984
CLU 2	Cloth Cleaning	212	38.46%	82	235	50.00%	118
CLU 3	Cooking	458	40.94%	188	509	50.00%	255
CLU 4	Dishwasher	596	15.38%	92	549	20.00%	110
CLU 5	Entertainment &ICT	1559	59.63%	929	1411	80.00%	1129
CLU 6	Fitness	289	2.56%	7	259	10.00%	26
CLU 7	Grooming	37	30.77%	11	35	50.00%	18
CLU 8	House Cleaning	123	41.03%	50	118	60.00%	71
CLU 9	Space Heating	110	10.26%	11	118	15.00%	18
CLU 10	Ironing	265	97.44%	259	274	100.00%	274
CLU 11	Lighting	735	98.96%	728	470	100.00%	470
CLU 12	Refrigeration	2552	26.02%	664	2195	50.00%	1097
CLU 13	Sanitary water	2417	34.74%	840	1959	80.00%	1568
CLU 14	Small Kitchen Apps	1007	44.18%	445	941	80.00%	752
CLU 15	Water Supply	124	33.33%	41	110	60.00%	66
CLU 16	Electric car	0	0.00%	0	6000	5.00%	235
	Total			**11,211**			**13,189**

Source (Jensen, *et al*., 2012)

A.8. Specific consumption for the 15cluster appliances used in Coast Region. Urban (middle income) category.

		2012			2030		
Cluster	Cluster Name	Spec Con (KWh)	Penetration Probability	Final Spec Con (kWh)	Spec Cons (kWh)	Penetration Probability	Final Specs Cons (kWh)
CLU 1	Air Conditioning	4246	18.50%	785	5533	25.00%	1383
CLU 2	Cloth Cleaning	128	11.11%	14	142	20.00%	28
CLU 3	Cooking	250	17.85%	45	237	25.00%	59
CLU 4	Dishwasher	360	8.64%	31	330	10.00%	33
CLU 5	Entertainmen t &ICT	942	43.92%	414	751	60.00%	451
CLU 6	Fitness	174	1.86%	3	160	1.86%	3
CLU 7	Grooming	22	13.53%	3	20	20.00%	4
CLU 8	House Cleaning	74	7.41%	5	68	30.00%	20
CLU 9	Space Heating	67	6.17%	4	61	10.00%	6
CLU 10	Ironing	160	96.30%	155	147	100.00%	147
CLU 11	Lighting	42	83.77%	35	36	100.00%	36
CLU 12	Refrigeration	1617	15.44%	250	1479	40.00%	592
CLU 13	Sanitary water	1461	16.49%	241	1107	17.00%	188
CLU 14	Small Kitchen Apps	609	22.25%	135	593	40.00%	237
CLU 15	Water Supply	75	12.35%	9	63	20.00%	13
	Total			**2,130**			**3,200**

Source (Jensen, *et al*., 2012)

A.9. Specific consumption for the 15cluster appliances used in Coast Region. Urban (low income) category.

		2012			2030		
Cluster	Cluster Name	Spec Cons (kWh)	Penetration Probability	Final Spec Cons (kWh)	Spec Cons (kWh)	Penetration probability	Final spec Cons (kWh)
CLU 1	Air Conditioning	1829	1.49%	27	1807	2.00%	36
CLU 2	Cloth Cleaning	55	3.62%	2	55	3.62%	2
CLU 3	Cooking	108	8.36%	9	106	8.36%	9
CLU 4	Dishwasher	155	6.52%	10	153	6.52%	10
CLU 5	Entertainment &ICT	406	34.68%	141	401	45.00%	180
CLU 6	Fitness	75	1.45%	1	74	1.45%	1
CLU 7	Grooming	10	4.43%	0	9	4.43%	0
CLU 8	House Cleaning	32	1.45%	0	32	3.00%	1
CLU 9	Space Heating	0	0.00%	0	0	0.00%	0
CLU 10	Ironing	69	92.03%	64	68	99.00%	68
CLU 11	Lighting	75	94.80%	71	70	95.00%	67
CLU 12	Refrigeration	696	7.31%	51	688	8.00%	55
CLU 13	Sanitary water	629	9.57%	60	622	10.00%	62
CLU 14	Small Kitchen Apps	262	9.36%	25	259	10.00%	26
CLU 15	Water Supply	32	7.25%	2	32	10.00%	3
	Total			**464**			**520**

Source (Jensen, *et al.*, 2012)

A.10. Specific consumption for the 15cluster appliances used in Coast Region. Rural (high income) category.

		2012			2030		
Cluster	Cluster Name	Spec Con (kWh)	Penetration Probability	Final Spec Con (kWh)	Spec Cons (kWh)	Penetration Probability	Final Spec Cons (kWh)
CLU 1	Air Conditioning	5223	31.46%	1643	5051	40.00%	2020
CLU 2	Cloth Cleaning	0	0.00%	0	144	5.00%	7
CLU 3	Cooking	235	10.21%	24	206	15.00%	31
CLU 4	Dishwasher	0	0.00%	0	361	2.00%	7
CLU 5	Entertainment &ICT	892	39.45%	352	774	50.00%	387
CLU 6	Fitness	0	0.00%	0	0	0.00%	0
CLU 7	Grooming	27	14.81%	4	24	14.81%	4
CLU 8	House Cleaning	0	0.00%	0	72	5.00%	4
CLU 9	Space Heating	0	0.00%	0	0	0.00%	0
CLU 10	Ironing	197	60.00%	118	171	70.00%	120
CLU 11	Lighting	547	98.51%	539	433	100.00%	433
CLU 12	Refrigeration	1255	18.31%	230	1443	30.00%	433
CLU 13	Sanitary water	785	5.00%	39	722	15.00%	108
CLU 14	Small Kitchen Apps	748	7.56%	57	649	15.00%	97
CLU 15	Water Supply	0	0.00%	0	72	10.00%	7
	Total			**3,006**			**3,659**

Source (Jensen, *et al.*, 2012)

A.11. Specific consumption for the 15cluster appliances used in Coast Region. Rural (middle income) category.

		2012			2030		
Cluster	Cluster Name	Spec Con (kWh)	Penetration Probability	Final Spec Cons (kWh)	Spec Cons (kWh)	Penetration Probability	Final Spec Cons (kWh)
CLU 1	Air Conditioning	281	20.59%	58	317	20.59%	65
CLU 2	Cloth Cleaning	0	0.00%	0	200	2.00%	4
CLU 3	Cooking	197	4.73%	9	250	6.00%	15
CLU 4	Dishwasher	0	0.00%	0	500	1.00%	5
CLU 5	Entertainment &ICT	1064	28.69%	305	1199	45.00%	540
CLU 6	Fitness	0	0.00%	0	0	0.00%	0
CLU 7	Grooming	26	3.16%	1	29	3.16%	1
CLU 8	House Cleaning	0	0.00%	0	100	3.00%	3
CLU 9	Space Heating	0	0.00%	0	0	0.00%	0
CLU 10	Ironing	183	61.76%	113	206	80.00%	165
CLU 11	Lighting	48	80.67%	39	50	100.00%	50
CLU 12	Refrigeration	1281	9.25%	119	1443	15.00%	216
CLU 13	Sanitary water	1661	5.36%	89	1600	10.00%	160
CLU 14	Small Kitchen Apps	401	3.03%	12	452	10.00%	45
CLU 15	Water Supply	85	5.88%	5	100	10.00%	10
	Total			**750**			**1,279**

Source (Jensen, *et al.*, 2012)

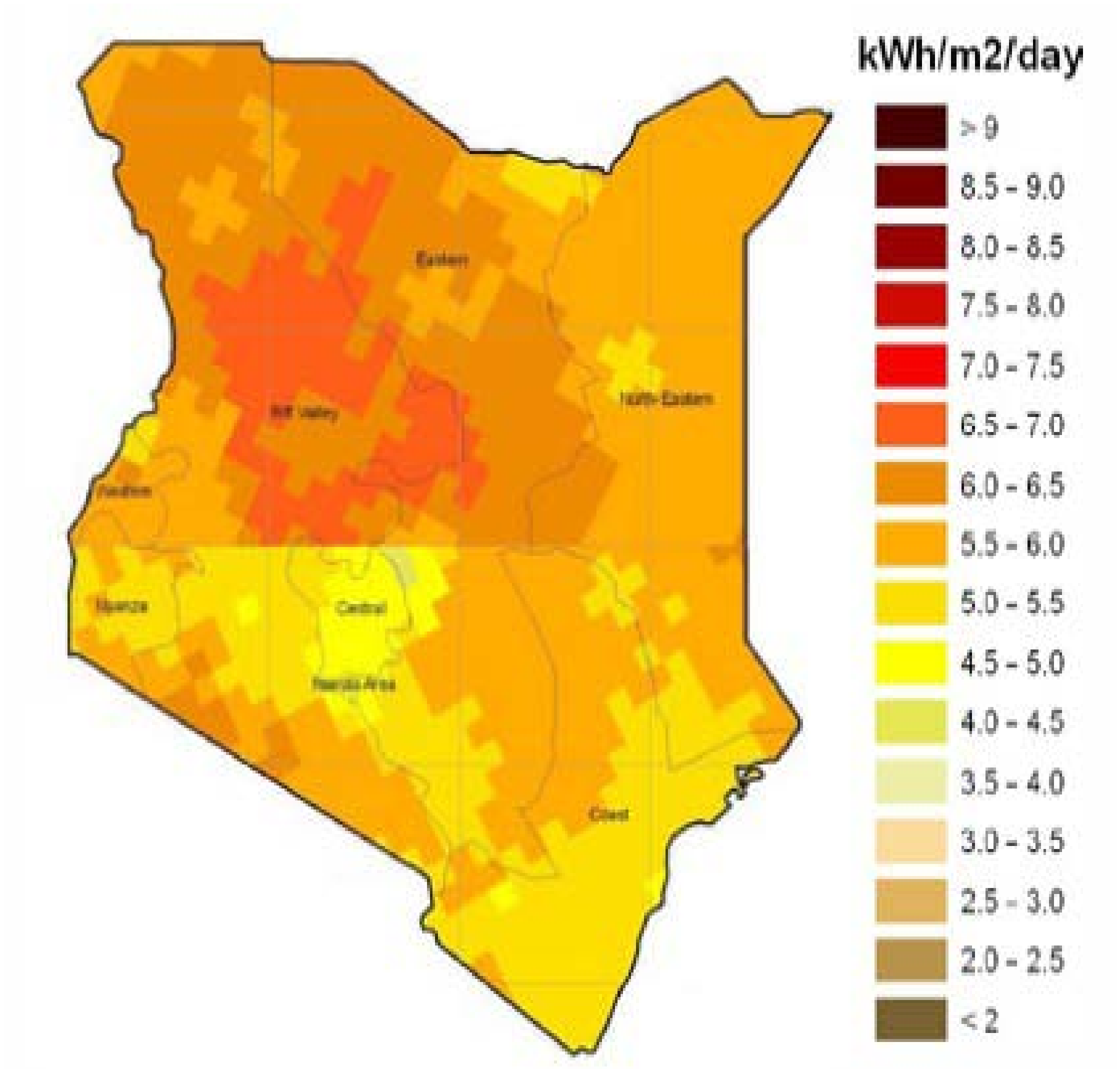
A.12. Specific consumption for the 15cluster appliances used in Coast Region. Rural (low income) category.

		2012			2030		
Cluster	Cluster Name	Spec Con (kWh)	Penetration Probability	Final Spec Cons (kWh)	Spec Cons (kWh)	Penetration Probability	Final Spec Cons (kWh)
CLU 1	Air Conditioning	1451	3.88%	57	1434	3.88%	56
CLU 2	Cloth Cleaning	44	1.89%	1	43	2.00%	1
CLU 3	Cooking	14	3.77%	1	14	5.00%	1
CLU 4	Dishwasher	0	0.00%	0	0	0.00%	0
CLU 5	Entertainment &ICT	279	21.79%	61	276	30.00%	83
CLU 6	Fitness	0	0.00%	0	0	0.00%	0
CLU 7	Grooming	7	1.89%	0	7	1.89%	0
CLU 8	House Cleaning	0	0.00%	0	100	2.00%	2
CLU 9	Space Heating	0	0.00%	0	0	0.00%	0
CLU 10	Ironing	55	39.62%	22	54	45.00%	24
CLU 11	Lighting	60	95.58%	57	59	100.00%	59
CLU 12	Refrigeration	349	2.92%	10	345	4.00%	14
CLU 13	Sanitary water	320	2.34%	7	350	5.00%	18
CLU 14	Small Kitchen Apps	47	1.89%	1	46	3.00%	1
CLU 15	Water Supply	25	1.89%	0	50	5.00%	3
	Total			**217**			**261**

Source (Jensen, *et al.*, 2012)

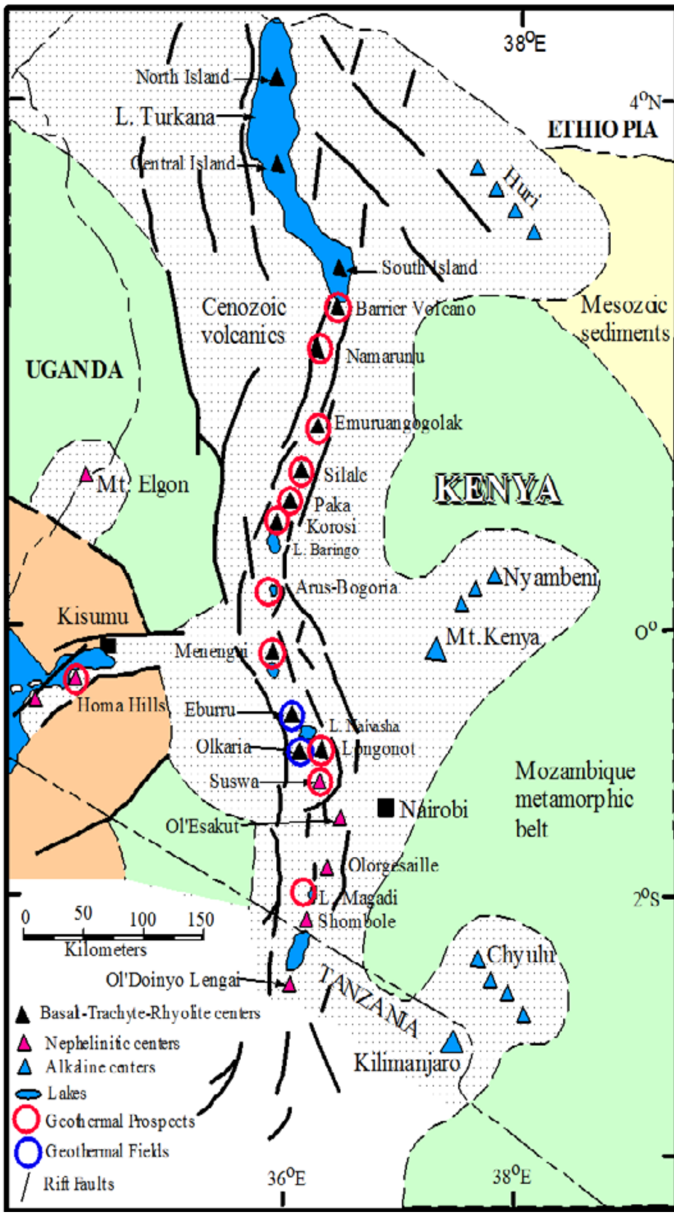
Appendix B: Natural energy resource maps for Kenya

B.1 Solar Radiation Map for Kenya



Source: (Hille, 2011)

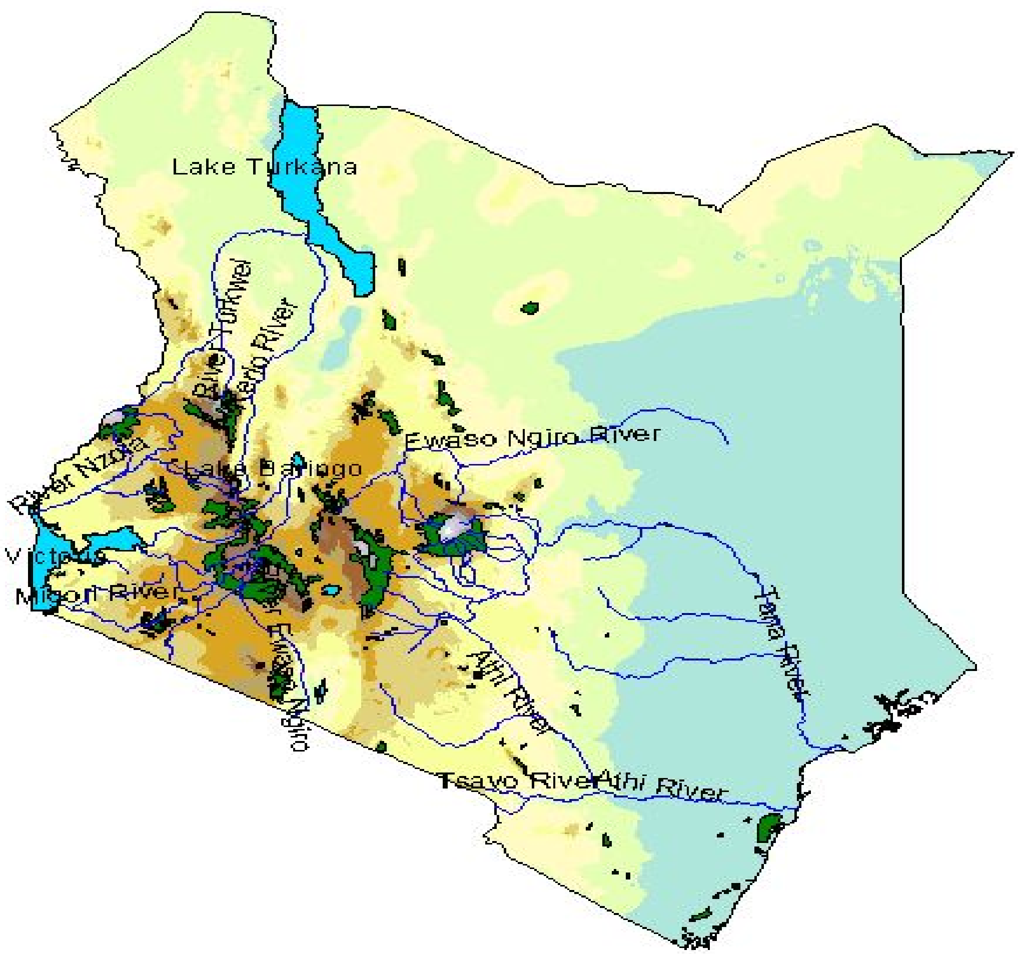
B.2 Geothermal Prospects within Kenya



Rift Region (MW)	Potential
Central Rift	
• Menengai	1,600MW
• Eburru	250MW
• Arus Bogoria	400MW
	2,250MW
South Rift	
• Olkaria	2,000MW
• Longonot	750MW
• Suswa	600MW
• Lake Magadi	100MW
	3,450MW
North Rift	
• Lake Baringo	200MW
• Korosi	450MW
• Paka	500MW
• Silali	1,200MW
• Emuruangogolak	650MW
• Namarunu	400MW
• Barrier	450MW
	3,850MW
Nyanza	
Homa hills	100MV
Akira	350MW
	450MW
Total Potential	10,000MW

Source (ERC, 2013)

B.3 Major Rivers in Kenya

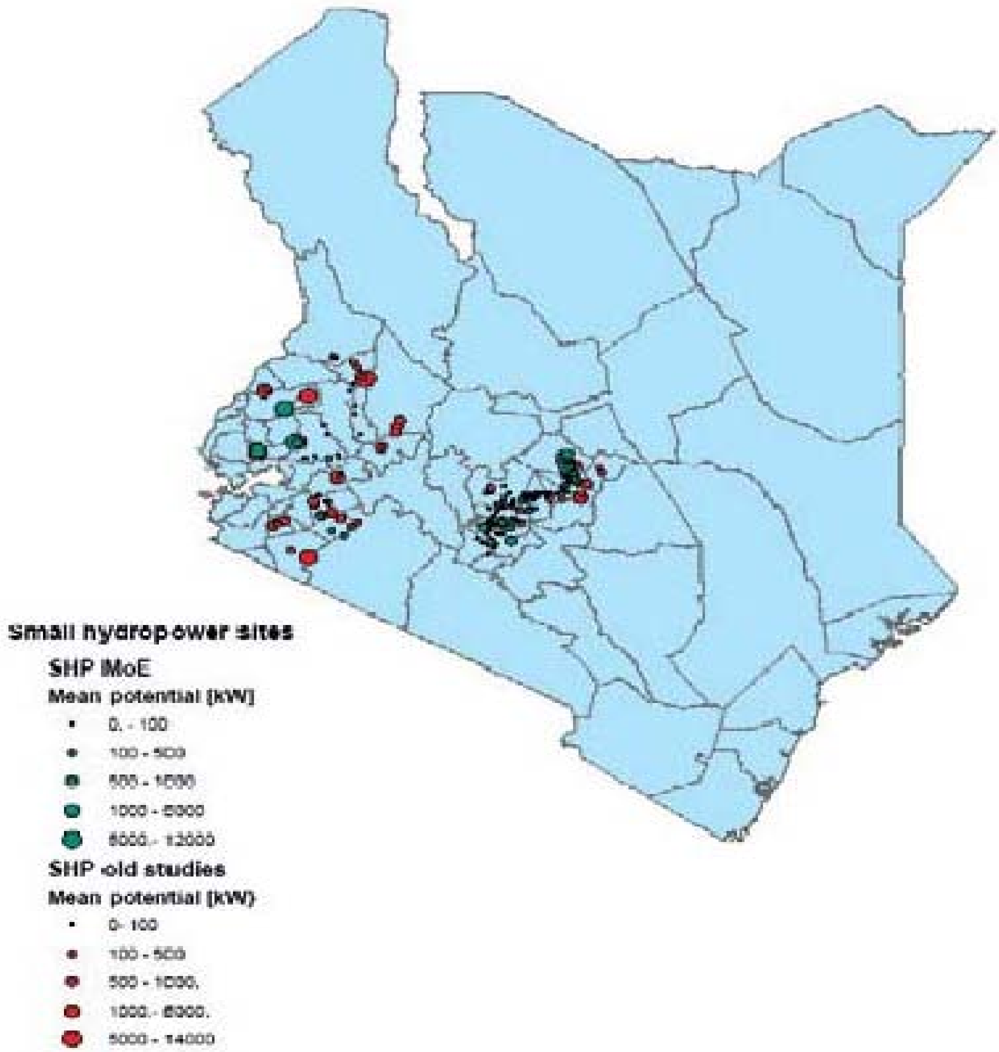


Source: (ERC, 2013)

River Basin	Potential Capacity (MW)	Average Energy (GWh/yr)	Firm Energy (GWH/yr)
Tana	570	2,490	1,650
Lake Victoria	295	1,680	1,450
Ewaso Ngiro North	155	675	250*
Rift Valley	345	630	300
Athi Basin	84	460	290

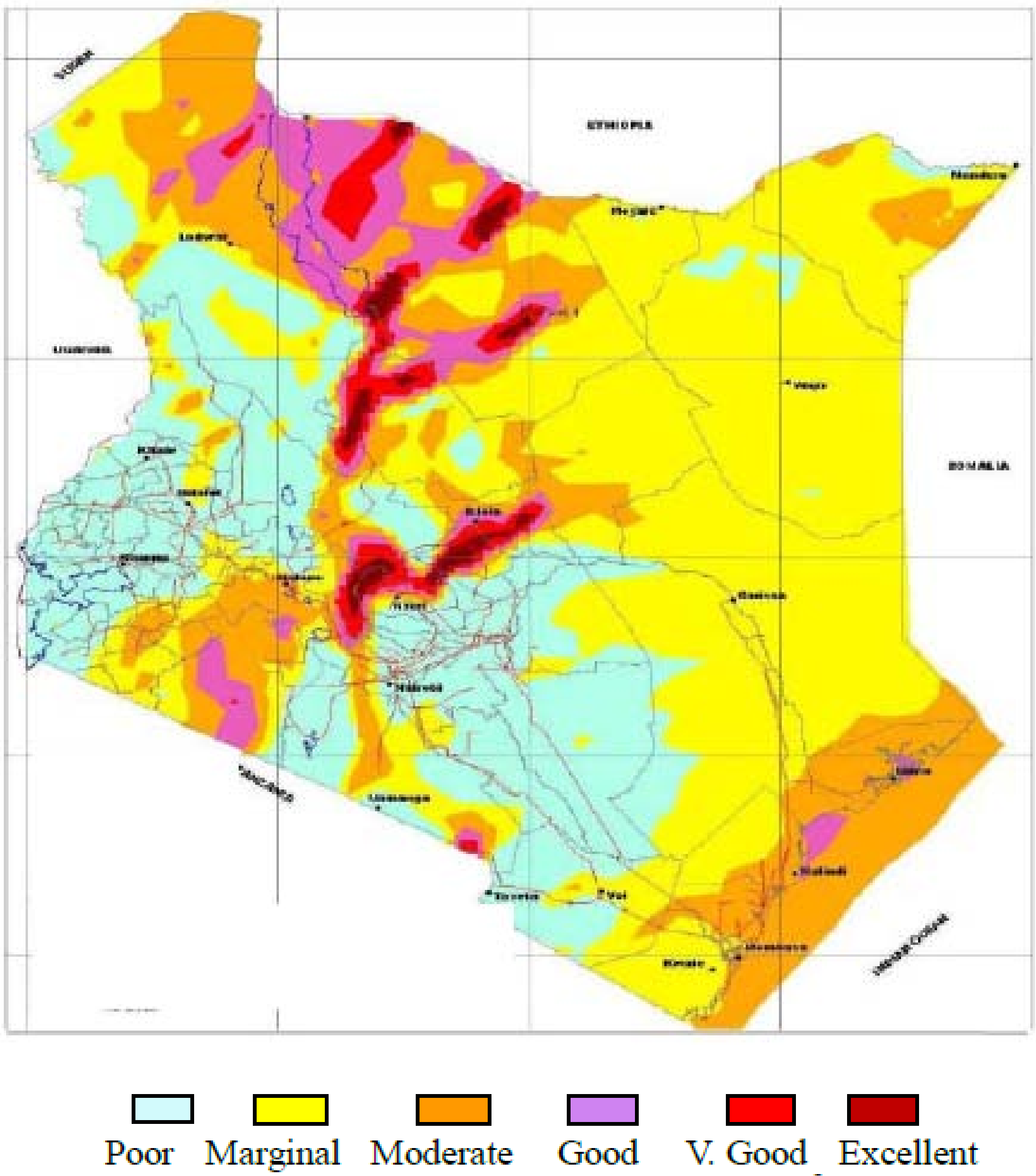
*Estimate

B.4 Small Hydro Potential in Kenya



Source: (ERC, 2013)

B.5 Wind Power Density Map



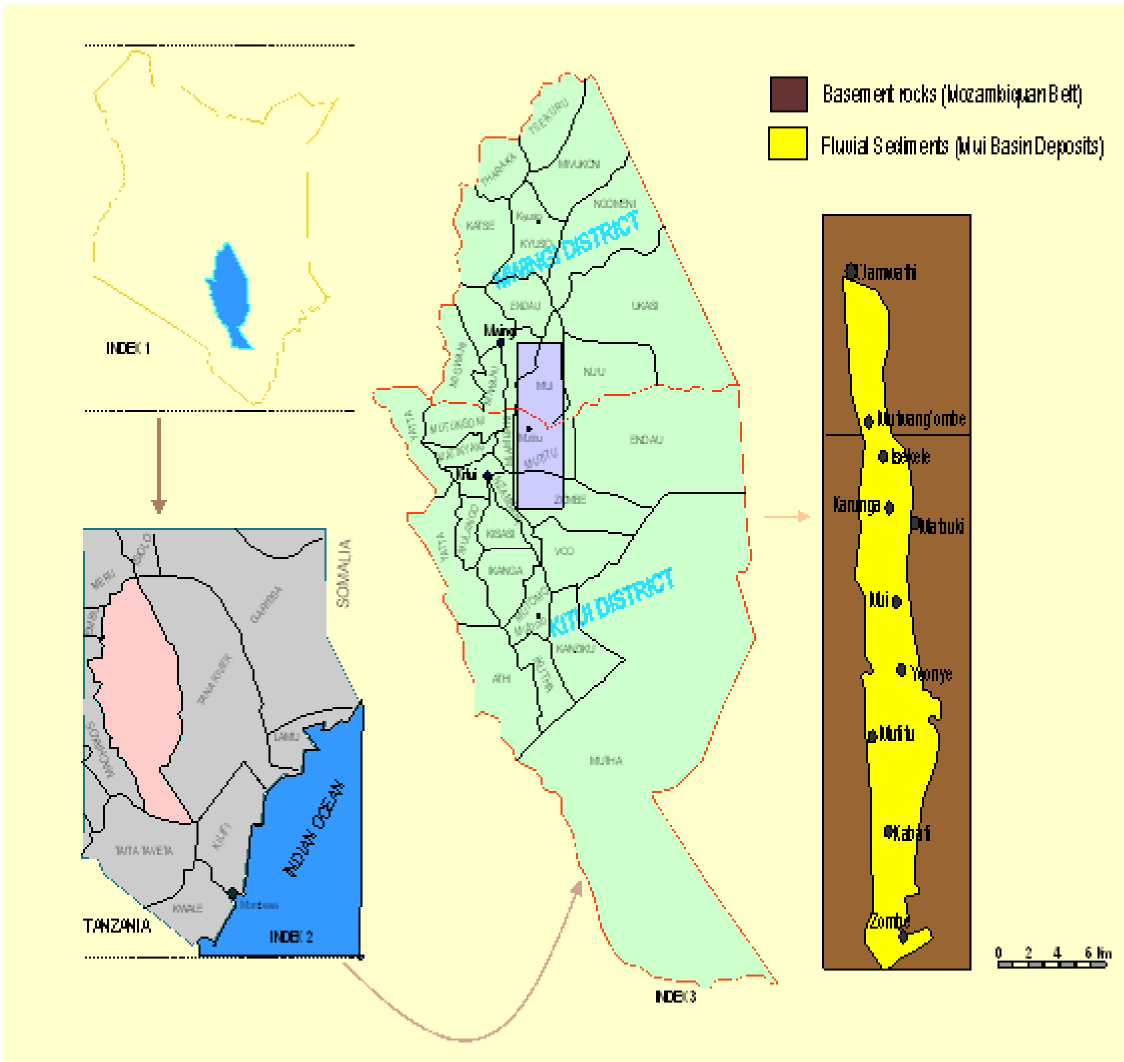
Source: (ERC, 2013)

B.6 Biomass Power Potential from Bagasse

	Bagasse Available (Tonnes/day)		Power Generation (MW)		Electrical Energy (GWh/year)		Internal Usage (GWh/year)		Export (GWh/year)	
Factory	current	potential	current	potential	current	potential	current	potential	current	potential
Chemelil	950	2660	10	29	48	156	14	47	34	108
Muhoroni	800	1720	9.8	19.8	35	134	7	27	28	108
Mumias	2850	3650	32	47	214	236	52	57	162	179
Nzoia	1090	2940	14	40	52	221	11	47	41	174
Sony	1110	2405	15	37	74	231	16	50	58	181
West Kenya	488	1295	5	20	25	109	5	29	20	80
Total	7288	14670	85.5	192.8	448	1087	105	257	343	830

Source (ERC, 2013)

B.7 Location of the Coal Deposits in Mui Basin



Source: (ERC, 2013)

Appendix C: LEAP Transformation module data

C.1 Existing Power Plants

Plant	Cap (MW)	Type	Process Efficiency (%)	Max Availability (%)	Merit Order	Cap Credit (%)
Wanjii	7.4	Reservoir	100	89.52	Variable(1,2,3)	80
Tana	20	Reservoir	100	71.31	Variable(1,2,3)	80
Masinga	40	Reservoir	100	98.77	Variable(1,2,3)	80
Kamburu	94	Reservoir	100	96.62	Variable(1,2,3)	80
Gitaru	225	Reservoir	100	84.98	Variable(1,2,3)	80
Kindaruma	40	Reservoir	100	85.18	Variable(1,2,3)	80
Kiambere	168	Reservoir	100	96.74	Variable(1,2,3)	80
Turkwel	106	Reservoir	100	90.59	Variable(1,2,3)	80
Sondu	60	Run-of-River	100	95.61	Variable(1,2,3)	80
Sagana	1.5	Run-of-River	100	96.25	Variable(1,2,3)	70
Gogo	1.6	Run-of-River	100	77.96	Variable(1,2,3)	70
Sosiani	0.4	Run-of-River	100	91.25	Variable(1,2,3)	70
Kipevu I	75	Fuel Oil	35	66.18	Variable(1,2,3)	75
Kipevu III	120	Fuel Oil	35	92.92	Variable(1,2,3)	75
Tsavo	74	Fuel Oil	35	75	Variable(1,2,3)	75
Kipevu GT 1 & 2	60	Kerosene	35	42	Variable(1,2,3)	75
IberAfrica 1 & 2	108.5	Fuel Oil	35	75	Variable(1,2,3)	75
Rabai	98	Fuel Oil	35	75	Variable(1,2,3)	75
Olkaria I	45	Steam	100	73.11	1	85
Olkaria II	70	Steam	100	85.5	1	85
Olkaria III	48	Steam	100	85.5	1	85
Orpower	52	Steam	100	85	1	85
Eburru Well Head	2.3	Steam	100	68.62	1	75
Ngong Wind	5.1	Wind	100	69.3	Run to Full available capacity	30

C.2 Endogenous Capacity

Plant Type	Dispatch Rule	Cap [MW]	Merit Order	Process Efficiency [%]	Maximum Availability [%]	Cap Credit [%]	Lifetime [Yrs]
Geothermal	Merit Order	140	1	100	85	85	40
Nuclear	Merit Order	1000	1	80	80	85	40
Coal	Merit Order	300	1	40	85	85	40
Natural Gas	Merit Order	180	2,3	40	75	85	30
MSD	Merit Order	160	2,3	35	85	85	25
Hydro Imports	Merit Order	200	2	100	80	0	40
Wind	Run to Full available capacity	100	-	100	45	30	25
Small Hydro	Run to Full available capacity	10	-	100	80	50	30
Biomass	Run to Full available capacity	10	-	100	80	50	30
Solar	Run to Full available capacity	10	-	100	25	30	25

C.3 Emission Factors

Fuel Type	**Coal**	**Residual Fuel Oil (FO)**	**Kerosene**	**Natural Gas**
Emission Type	**Emission Factor (Kg/TJ)**	**Emission Factor (Kg/TJ)**	**Emission Factor (Kg/TJ)**	**Emission Factor (Kg/TJ)**
CO_2	92,644.15	72,550.00	69,944.13	55,781.05
CO	20.00	15.00	241.34	20.00
Methane	1.00	3.00	132.51	1.00
NMVOC	5.00	5.00	66.15	5.00
No_x	300.00	200.00	18.64	150.00
SO_2	13.59	1.99	5.30	-

C.4 Technology Costs

Technology	Overnight Costs ($2012/kW)	Fixed Costs ($2012/kW)	Variable costs ($2012/kWh)
MSD Plants (160MW)	1232	56.4	0.008
Geothermal Plants (140MW)	3296	50.6	0.0050
Nuclear Plant (1000MW)	3661	81.3	0.0044
Coal Plant (300MW)	1900	62.3	0.0039
Gas Turbine (Natural Gas 180MW)	677	10.7	0.01084
Import (1000MW)	411	27.1	0.045
Mutonga (60MW)	3895	19.2	0.0048
LG Falls (140MW)	3270	17.9	0.0048
Wind (300MW)	2077	25.4	0.00090
Small Hydro (1-10MW)	2500	53	0
Biomass (1-10MW)	2000	58	0.009
Solar PV (1-10MW)	2500	34	0
Pumped Hydro	2335	9.114	0