DECLARATION

I, Kinyanjui K. B, hereby declare that this thesis is my original work and has not been presented for a degree in any other university.

15/07/08

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DEDICATION

To

my

beloved family

and

dear parents

ACKNOWLEDGEMENTS

I feel greatly obliged to all the people who contributed to the fulfilment of my vision through accomplishment of this study which links my past interest in forestry to my current profession and career. I pay tribute to the previous generation which strived to develop in us a culture of protecting trees in the then beautiful, scenic indigenous forests of the Great Rift Valley. These conservationists include my grandfather, a career forest guard and a recipient of Head of State Commendation in recognition of his exemplary service in the Forest Department.

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Kinyanjui K.B.

2008

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ACRONYMS

AGO	Automotive Gas Oil
AKELD	Aggreko Emergency power plant, Eldoret
AKNBI	Aggreko Emergency power plant, Nairobi
ARSP	Acres Reservoir Simulation Package
bbl	Barrel
CC	Combined Cycle Plant
CDM	Clean Development Mechanism
COGEN	Cogeneration
COx	Carbon Oxides
CRF	Cost Recovery Factor
DOE	US Department of Energy
DSM	Demand Side Management
EAC	East African Community
EAPMP	East African Power Master Plan Study
ED	Economic Dispatch
EMCA	Environment Management and Coordination Act, 1999
ENS	Energy Not Served
EPC	Engineer, Procure and Construct
ERB	Electricity Regulatory Board.
ERC	Energy Regulatory Commission
EUE	Expected Unserved Energy
EWI	Institute for Energy Economics at the University of Cologne
FOR	Forced Outage Rate
FY	Fiscal Year from 1st July to 30th June
GDC	Geothermal Development Company
GDF	Geothermal Development Fund
GDP	Gross Domestic Product
GENSIM	Generation Simulation Model
GHG	greenhouse gases
GoK	Government of Kenya
GRA	Geothermal Resource Assessment
GT	Gas Turbine
GWh	Giga Watt hours
HFO	Heavy Fuel Oil
IAEA	International Atomic Energy Agency
IBA	Iberafrica Diesel power plant
IDC	Interest During Construction
IDO	Industrial Diesel Oil
IPP	Independent Power Producer
IRP.	Integrated Resource Planning
KenGen	Kenya Electricity Generating Company Limited
KGT	Kipevu Gas Turbine power plant
KPD1	Kipevu Diesel 1 power plant
KPD2	Kipevu Diesel 2 power plant
KPLC	he Kenya Power & Lighting Company Limited
kWh	Kilowatt Hours
LCP	Least Cost Plan
LCPDP	Least Cost Power Development Plan
LDC	Load Duration Curve

LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LRFO	Low Residual Fuel Oil
LSD	Low Speed Diesel
LSFO	Low Sulphur Fuel Oil
MAED	Model for Analysis of Energy Demand
MOD	Merit Order Dispatch
MSD	Medium Speed Diesel
MW	Mega Watts
MWe	Megawatts, electric
MWh	Megawatt Hours
NAR	Net As Received
NBI	Nile Basin Initiative
NCC	National Control Centre
NEMA	National Environment Management Authority
NO_x	Oxides of Nitrogen
NPV	Net Present Value
O & M	Operation and Maintenance
OPEC	Oil Producing and Exporting Countries
PPA	Power Purchase Agreement
PWC	Present Worth Cost
REF	Rural Electrification Fund
SAHP	Sondu Additional Hydro Plant, renamed Sang'oro
SAPP	Southern African Power Pool
SOx	Sulphur oxides
UETCL	Uganda Electricity Transmission Company Limited
UNECA	United Nations Economic Commission for Africa
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
US$	United States Dollar
WASP	Wien Automatic Simulation Planning Package
WEC	World Energy Council
Yr	Year

ABSTRACT

The need to study the Kenyan national power system with a view to minimising environmental emissions and energy production costs in the present and the long-term was identified. The overall objective of this research was to develop optimal generation dispatch and capacity expansion in the Kenyan power system, with the aim of minimising the environmental emissions associated with electricity supply without contravening the underlying economic objectives.

Pertinent factors that influence the level of emissions were identified through review of recent power system data and reports. A criterion was developed to assess the level of influence of identified key factors and gauge their importance to the emission problem. Modelling was then applied in the next two parts of the study. A model was developed and built for power plant dispatch with year 2006 selected as the base year, being the most recent year with a complete set of dispatch data prior to commencement of this study. Variations of the model were developed based on monthly demand data and two assumed dispatch scenarios: ideal dispatch and limited plant availability dispatch. The models used in the two scenarios were largely similar but the latter was designed to have thermal plant availabilities capped at 85%, which is the normal level expected for thermal power plants in Kenya. The optimised dispatch with limited plant availabilities resulted in 3.4% savings in generation cost compared to the actual dispatch in 2006. Emission penalties were then imposed on power plants and the annual energy generation costs and associated emissions again compared with those of 2006. The actual and Limited Plant Availability cases had close emission levels throughout the year resulting in net CO_2 emission reduction of 14,000 tonnes or 1.2% compared to the actual 2006 dispatch. The emission penalties imposed increased the total annual generation cost by US$ 2.3 million and yielded no further emission reductions since plants were penalised but no further dispatch optimization was possible in the absence of alternative non-polluting sources.

In the long-term case, the capacity expansion plan for the period 2008-2028 was remodelled with a view to replacing some of the proposed plants with renewable sources without compromising the economics of the plan. The 2007 plan, which had been determined through simulations using the Generation Simulation (GENSIM) software, was remodelled and optimised further using the Wien Automatic Simulation Planning Package (WASP). The WASP optimal solution contained geothermal power plants

between 2012 and 2016 and the Low Grand Falls hydropower project in 2020. The GENSIM model was used to further investigate the WASP output and an optimal plan was developed to simultaneously address the economic and environmental objectives of the study. The remodelled plan had a Present Worth Cost (PWC) of US$ 5,980 million compared to US$ 6,045 of the 2008-2028 least cost plan. The 1.1% or US$ 65 million difference is sufficient for development of a new 50 MW medium speed diesel power plant. The review enabled displacement of 200 MW coal and 100 MW medium speed plants with 70 MW additional geothermal, 140 MW hydro and 150 MW of imports (also assumed to be hydro). The computed potential emission reduction from the proposed plan was 23 million tonnes of CO_2 in the twenty-year period, equivalent to US$ 230 million worth of carbon credits at a conservative rate of US$ 10 per tonne. The economic and environmental benefits of avoiding the emissions, though not quantified, are considered much more than the financial value.

The three parts of the study collectively contribute towards environmental protection in the present and the future. The dispatch models developed can be used by power planners and operators for daily system dispatch operation. The capacity expansion gives an invaluable insight into the generation planning process in Kenya and forms a suitable reference point for subsequent power planning activities. The entire study is relevant to the national climate change mitigation activities. It elucidates possible areas of intervention and provides information for national reporting under global environmental conventions and possible areas for developing Clean Development Mechanism projects under the Kyoto Protocol. Ultimately, the study makes a contribution towards sustainable development.

1. INTRODUCTION

1.1. Background

Electricity supply is a major driver of economic development in every country and a key ingredient in defining the quality of life in the modern world. Supply of adequate and reliable electricity is an important objective in a power system. Methods of exploitation and harnessing of energy resources have continued to advance over the years as demand for electricity increases. Like many other forms of development in the world, production and supply of electricity can have considerable negative impacts on the environment despite the numerous accompanying benefits. For instance, electricity production from thermal or fossil fuel based generation is responsible for 15% of total global greenhouse gas (GHG) emissions in the world (WEC, 2001). Environmental damage is one of the main justifications for continued efforts to reduce energy consumption and to shift to cleaner sources (Rabl and Spadaro, 2006).

About 1.6 billion people in the world population have no access to clean energy, particularly commercial electricity (WEC, 2004) and close to a third of the people without access to electricity live in Africa. The low access to electricity is a potential business opportunity for electricity generators and power utilities. Governments of many developing countries have the responsibility of expanding electricity supply and therefore improve livelihoods of their citizens. Developed countries and multilateral funding agencies also extend financial support or partnerships to the less developed countries as grants or concession loans to accelerate access.

The main source of energy in Kenya is biomass which accounts for 70% of energy supply (Kamfor, 2000). This is mainly so in rural areas where 80% of Kenya's 34 million population reside. Firewood is used directly or indirectly in the form of charcoal to meet most of the domestic heating requirements. Due to the relatively high cost of electricity in Kenya and the low economic empowerment, most of the electrified rural homes use electricity sparingly for lighting and powering television and radio sets. Majority of the homes that have no electricity use kerosene for lighting. A significant number of rural homes have in the recent past installed solar power systems as alternative sources of energy mainly for lighting and powering entertainment systems, mainly televisions and radios. The estimated installed capacity of photovoltaic systems in Kenya in 2000 was 1.3 MW (Kamfor, 2000). Government tax policies now encourage installation of solar power systems but solar water heaters are still not affordable to many so as to enable increased use to take advantage of the abundant sunshine with the country's favourable geographical location.

Most of Kenya's electricity generation and distribution facilities were built through development assistance in the post-independence period until 1992 when donor countries pegged further financial support to prescribed reforms. The conditions imposed slackened development of hydroelectric and geothermal power projects and the general infrastructure of the country. Dominance of the hydropower in the Kenya power system has since been declining over time in favour of thermal technologies. The national installed generation capacity in 2006 was 1,159 MW comprising 677 MW hydro, 128 MW geothermal and 284 MW thermal (KPLC, 2006). During average rainfall, hydroelectric plants currently supply about 54% of the total demand, a level that portrays high dependence on the weather and therefore vulnerable to climatic change. A severe drought experienced in the 1999/2000 *La Nina* phenomena reduced the hydro capacity drastically plunging the country into serious power shortfalls. The historic power crisis led to institution of a mandatory load shedding programme which greatly curtailed economic growth and lifestyles. The government intervened through hiring of expensive emergency power plants which operated for a year before the normal rains resumed. Prior to the drought, two private thermal generators, Iberafrica Diesel and Westmont Gas Turbine, were contracted as a stop-gap measure before development of the more economic geothermal and hydropower projects which had been delayed due to lack of fiancing. Hydroelectric and geothermal potential of the country are estimated to be above 1,400 MW and 2,000 MW respectively (Acres, 1986). Feasibility and appraisal studies that have been undertaken to date present several candidate power projects.

Power plant dispatch operations are carried out by the national power transmission and distribution utility, Kenya Power and Lighting Company (KPLC). A dispatch plan is prepared beforehand to guide system operation, taking into account load demand levels and availability of power plants. System operators and planners at the National Control Centre (NCC) in Nairobi are guided by their knowledge of the system and experience. The dispatch plan is usually based on the economic merit order developed from operational data obtained in the previous month, but no computer programming is applied to optimise dispatch with more precision. The NCC has an old SCADA system that is due for replacement. It mimics the operation of the entire network and enables limited data capture and remote operations in some components of the system.

National power development plans are prepared under the oversight of the Ministry of Energy. The activity is assigned to the main corporate stakeholders in the sector, KPLC, KenGen and the Energy Regulatory Commission (ERC). The desired objective in planning is determination of a least-cost expansion plan resulting in optimal investments, low operational costs and meeting projected electricity demand. Candidate projects are evaluated over a 20-year planning horizon to establish the optimal development path to meet forecast demand. Future power generation sources considered are geothermal, hydro, thermal and expected imports through existing and planned transmission interconnections with the neighbouring countries.

1.2. Statement of Research Problem

This background information on the Kenyan power system reveals opportunities for improvements in both system operation and power development planning. Plant dispatch is seen as a contributing factor to environmental emissions from power generation. In the long term capacity expansion planning which focuses on meeting future power demand can also be carried out with due consideration of environmental impacts of the recommended plan.

Intervention measures can be instituted towards achieving optimal plant dispatch in the national power grid to enable maximisation of energy supply from renewable sources and from the cheaper thermal power plants in order to minimise overall generation costs and environmental emissions. Prudent system operation can increase efficiency and simultaneously reduce both air pollution and depletion of the non-renewable energy resources through deferment of expensive investments in power generation facilities. Potential sources of electricity of energy should be evaluated and developed optimally at a level commensurate with demand. The level of air pollution in the future is dependent on our current ability to formulate suitable long term expansion plans that contain pollution mitigation strategies.

Power system operation and national power development planning provide opportunities for safeguarding the environment. There is need to identify the key factors contributing to emissions and to study generation and power planning with a view to establishing ways of reducing environmental impacts associated with electricity generation and supply.

1.3. Justification

Energy is a key driver of industrialisation and economic development, two key areas dominating primary agendas of many developing countries. Efficient energy generation, delivery and utilization are critical to sustainable development. The optimal generation dispatch problem historically focussed more towards minimization of total generation cost of the power system. Emission control has however become one of the important operational objectives with introduction of mandatory environmental regulations (Sudhakaran *et al.*, 2004). Pollutants emitted from thermal power plants include sulphur oxides, nitrogen oxides and carbon dioxide.

Protection of the environment ranks high in the global agenda today with many countries including Kenya, having signed global Conventions and Protocols that collectively uphold the themes of protection of the environment. Many countries have developed and embraced environment protection policies for integration in socio-economic activities, having acknowledged the need to embrace sustainable development, which is defined as meeting the needs of the present without compromising the ability of the future generations to meet their needs. Kenya is a signatory to the Kyoto Protocol which places differentiated responsibilities to the signatories for regulation of anthropogenic activities that contribute to climate change. In the absence of such an effort, greenhouse gas levels are expected to gradually heat up the earth's atmosphere to the point where sea levels would begin to rise and weather patterns would be altered adversely (Simshauser and Docwra, 2004).

The Protocol has differentiated binding commitments, capping emission levels in developed countries while at the same time spearheading sustainable development in developing countries. Enactment of the Environment Management and Coordination Act (Government of Kenya[1]) in 1999 and formulation of the country's first Energy Policy (Government of Kenya[2]) released in 2004 which heralded enactment of the Energy Act 2006 (Government of Kenya[3]) show Kenya's commitment to conservation and protection of the environment.

Power system operators are usually under considerable pressure to run the power system in the most economical manner. This means producing or buying electrical energy to meet the demand at the lowest possible cost (Kirschen and Strbac, 2003). The Kenyan power system and its operation present an opportunity for research aimed at identifying intervention mechanisms for both economic dispatch and environmental protection. The system is operated through the National Control Centre in Nairobi, with focus on sources of power, costs, prevailing and forecast hydrological conditions, contractual obligations, system stability (ERB, 2004) and plant availability. Minimisation of generation costs and power system stability are key goals in system operation. Review of the power system operation is paramount for minimisation of costs, increasing efficiency and reducing negative impacts from power generation and supply such as emission of greenhouse gases (GHG). Power plant dispatch in Kenya should therefore be undertaken with due consideration of the associated environmental impacts alongside the techno-economic factors outlined. Pertinent factors that seem to influence the magnitude of impacts arising from electricity generation and supply on the environment in the short and the long term include, system operation, system expansion, cost of generation and supply, purchase contracts (UNECA and UNEP) and plant availability.

Emission factors for each type of generation need to be considered and renewable sources such as hydro and geothermal should be given priority in the dispatch process. Challenges envisaged include formulation of a balance between the technical and contractual requirements and incorporation of the environmental objectives while at the same time operating the power system with due regard to other pertinent factors. Considering the current dispatch scheme, it is necessary to research and develop a new system that continuously enables dispatch optimization to minimise both generation costs and emission of air pollutants.

The need to examine future sources of electricity supply in the same context is equally important besides the primary goal of determining a least cost power development plan for the country. Ideally, an optimal expansion plan should be sustainable and meet forecast demand at the lowest cost. In the context of environmental protection, the proposed least cost plan is expected to be environmentally acceptable. It is possible to further pursue alternatives with less environmental impacts through review of the least cost plan in a broader perspective.

1.4. Research Objectives

The overall objective of this research was to develop an optimal generation dispatch and capacity expansion in the Kenyan power system, with the aim of minimising the environmental emissions associated with electricity supply, without contravening the underlying economic objectives.

The specific objectives of the research were:

1) Identification of factors that influence the level of environmental emissions (pollution) from electricity generation and supply in the short and long term.
2) Formulation and development of an optimal power plant dispatch program through modelling.
3) Re-evaluation of the least cost power development plan and to derive an alternative capacity expansion sequence.

The first part of this study sought to establish and assess factors that influence GHG emission (CO_2) levels in the Kenyan power system. The second part was directed towards plant dispatch optimization and the third focused on the least cost power development plan for the period 2008-2028. All components of the study aim at minimising generation costs and environmental emissions from electricity generation.

2. LITERATURE REVIEW

The literature review aimed at studying the current electricity supply environment in Kenya, review of studies carried out on power plant dispatch and capacity expansion including the modelling applied. The review also focussed on the merits of various sources of electricity and the potential sources in Kenya.

2.1. Overview of Electricity Supply in Kenya

The main sources of electricity in Kenya are hydroelectric, thermal and geothermal power plants. Most of the developed hydropower resources are located in the Tana River Basin. River Turkwel in the Rift Valley Basin has a significant power plant whose location supports the voltage levels in the Western part of the grid besides helping in meeting supply demand. Rainfall forecasts and river flow data are used to predict the output from the hydropower plants. River inflow records provide a complete 48-year long term reference hydrology database covering the period April 1947 to March 1995 but no proper records are available thereafter since the gauging stations have not been effectively maintained (BKS Acres, 2004). The electricity supply mix in Kenya has been varying over time along with the country's rising demand occasioned by the expanding economic sectors. Energy purchased grew at an average of 6.2% in the last five years (KPLC, 2007). Weather variations within any given year affect plant dispatch since the system has a significant hydropower capacity supplying over half of the electrical energy demand in the power grid.

System operators at the National Control Centre (NCC) located in Nairobi monitor system parameters that determine the quality of power and the stability of the power system. These parameters include demand (loads), system frequency and voltages. Other important system data are recorded and maintained by The Kenya Power and Lighting Company (KPLC). The operators give instructions to generators to dispatch power plants from time to time as necessary. System controllers are guided by several factors in deciding the levels of generation output to request from the various suppliers connected to the grid. The forecast demand sets the expectation as seen from the demand side, prompting the operator to schedule a matching supply schedule. A global demand forecast is done for the larger system comprising of annual peak and corresponding energy demand. The annual figures are then broken down to monthly and daily requirements in what are referred to as energy and power balances.

Access to electricity in Kenya is still low at about 15% despite the existence of the Government's Rural Electrification Programme since 1972 (Tractebel, 1997). About 60% of the urban population has access to electricity and a paltry 4% in the rural areas (Kamfor, 2000). The national grid is located mainly in the Southern part of the country, panning across the large cities and densely populated agricultural lands. Most of the Northern part of the country is arid, largely undeveloped and not electrified except in the main towns which have mini power grids supplied using government-owned thermal power plants operated under highly subsidised supply tariffs. These projects are implemented under the Rural Electrification Programme to ease administration and support development in remote areas.

Power plant dispatch and grid operations are coordinated through the central command of the National Control Centre. In order to achieve and maintain a low electricity price, there is need to enhance operation of the national grid through economic generation and minimisation of operational costs. Optimal plant dispatch safeguards customer tariff levels and helps in environmental protection through reduced fossil fuel consumption in generation and energy conservation. Environmental conservation in the production and supply of various forms of energy is a challenge. Production of electricity supply which is usually done in large quantities can lead to air pollution. In the absence of electricity, biomass is widely used albeit unsustainably leading to environmental degradation.

Recent updates of national power development plans are based on a comprehensive national study undertaken in 1986 and a subsequent update in 1992 (KPLC, 2005). The studies considered most of the large potential hydro and geothermal sources available in the country. Candidate power generation projects in Kenya are usually evaluated based on their respective data mostly contained in their feasibility reports. Expansion plans contain both renewable and non-renewable sources of electricity. The projects are modelled so as to evaluate their suitability and placement within a planning period, based on their capital requirements, energy outputs and cost of operation. Combinations of both renewable and non-renewable sources are usually made and simulated using planning optimization software to determine the optimal long term power development plan for the country.

2.2. Legal and Regulatory Environment

The Kenyan power sector is governed under the Energy Act 2006 following the repeal of the Electric Power Act 1997 in December 2006 (Government of Kenya[3]). The Act was heralded by the Energy Policy developed in 2004 which is considered a milestone achievement in the entire energy sector which hitherto operated without a policy. The policy made considerable efforts to address environmental issues relating to energy supply.

The Ministry of Energy is in charge of policy development and general oversight of the energy sector. The sector comprises of the petroleum, renewable and electricity sub-sectors. The Energy Regulatory Commission (ERC) is responsible for regulation of the electricity sub-sector. The main national generator is the Kenya Electricity Generating Company (KenGen) which supplies 80% of electricity (KPLC, 2005). There are four other independent power producers (IPPs), namely, Iberafica Power, Orpower 4, Tsavo Power and Mumias Sugar Company. Emergency Power Producers (EPPs) are contracted when there are capacity shortfalls. KPLC is currently the country's sole transmission and distribution company. Kenya has over the years been importing hydropower from the neighbouring Uganda through an agreement dating back to 1957 (BKS Acres, 2004). The situation has however changed in the recent past when Uganda began experiencing power shortfalls. An interim power exchange contract prepared for the prevailing situation enables retention of the interconnection for network stability and exchange of surplus power between the two countries.

2.3. Environmental Impacts of Power Generation

A power system supplied from mixed sources of power, renewable and non-renewable is bound to have some impacts on the environment especially at the point of generation. Pollutants released from combustion of fossil oils in thermal power plants may result in both local and global impacts. Cavanagh (1999) noted the difficulty in deregulating a power generation market in a manner that encourages the appropriate economic and reliability outcomes, let alone worry about the environment. This notwithstanding, there are opportunities for intervention to meet both economic and environmental goals. In Kenya environmental factors can be addressed indirectly in dispatch through maximising use of hydro and geothermal energy for economic reasons and obtaining the balance supply from thermal power plants.

The power sector has gone through various reforms in the last decade. One of the drivers of power sector reforms is to increase generation capacity through private investment. This means allowing Independent Power Producers (IPPs) to generate electricity (UNECA and UNEP, 2007). This development has a significant environmental implication, notably: Prior to reforms, most of the electricity generation came from non-fossil fuel-based sources, mainly hydro.

In the National Control Centre, no reference or information is availed at the system controller's on environmental emission by the various power sources. Power Purchase Agreements (PPA) signed with electricity suppliers are designed to impose measures for fuel efficiency through fuel cost reimbursements at agreed consumption rates and fuel calorific values, thereby discouraging inefficiency. The cost of fuel used for electricity generation in the Kenyan system is passed on to consumers through a built in tariff component and a monthly fuel surcharge that is dependent on the fuel price, amount consumed and each plant's approved specific fuel consumption rate (Fichtner, 2006). It is computed with the assumption that the transmission and distribution efficiency is maintained at 85%. Below this efficiency level the power utility is unable to recover the additional fuel costs incurred.

A system operation plan that factors in environmental emissions is highly creditable considering the consequences of pollution being experienced worldwide, and the current efforts to address global warming and climate change. In order to investigate viability of introducing additional pollution abatement measures in the power system, it is important to consider specific plant emission factors in any power system. The next subsections provide an overview of some of the conventional sources of electricity in the environmental perspective.

2.3.1. Geothermal Resources

Geothermal energy results from enormous amounts of thermal energy continuously generated by the decay of radioactive isotopes of underground rocks and is stored in earth's interior. Deep production wells ranging from hundreds of meters to 3000 metres are drilled to extract hot fluids to the surface from underground reservoirs of porous or fractured rocks. Some reservoirs yield steam directly, while majority produce a mixture of steam and water from which steam is separated and fed to a turbine engine connected to a generator. Some steam plants include additional flashing stages. The steam tapped from the drilled wells is channelled to generator turbines through pipelines. The high pressure steam drives the turbines to produce electricity. Condensed steam goes through a cooling process before it is released back to the environment. The modern practice is to re-inject the water back into the ground. The used steam is cooled and condensed back into water, which is added to the water from the separator for re-injection as shown in Figure 2.1. Sizes of steam plant units range from 0.1 MW to 150 MW. In certain types of geothermal energy sources, heat pumps are used to extract heat directly from the ground (WEC, 2001).

Geothermal power plants have fewer and minor atmospheric emissions compared to either fossil fuel or nuclear plants. The steam from the ground usually has several types of chemicals. These include hydrogen sulphide gas which has a repugnant smell, but minor adverse impacts compared to the benefits from the energy obtained especially in comparison to the non-renewable alternatives which release carbon dioxide that leads to global warming and climate change. The smell is mainly confined in the geothermal field environs and can therefore be categorised as localised as opposed to global effects from fossil oil fired power plants.

Direct heat uses are cleaner and practically non-polluting compared to conventional heating. Another advantage which differentiates geothermal energy from other renewable energy sources is the continuous availability 24 hours a day all year round. In Kenya power plants operate with high availability of over 90% annually. Production costs are at times competitive but in other cases marginally higher than conventional energy. Capital costs for the power plants are high and not easily obtained from lenders due to high risks associated with resource exploration.

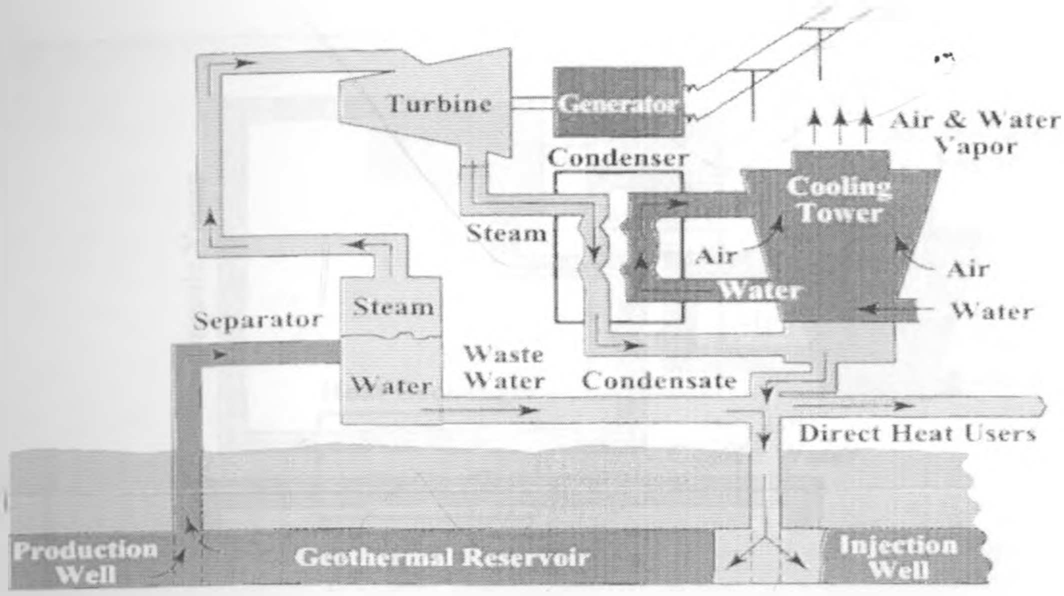

Figure 2.1: Flash Steam Power Plant
(Source: Geothermal Energy, 1998, University of Utah)

If a geothermal reservoir has temperatures between 100°C and 150°C, electricity can still be generated using binary plant technology. The produced fluid heats, through a heat exchanger, a secondary working fluid (isobutane, isopentane or ammonia), which vaporises at a lower temperature than water. The working fluid vapour turns the turbine and is condensed before being reheated by the geothermal water, allowing it to be vaporised and used again in a closed-loop circuit as illustrated in Figure 2.2.

The size of binary units range from 0.1 MW to 40 MW Commercially. However, small sizes (up to 3 MW) prevail, often used modularly, reaching a total of several tens of MW installed in a single location. The spent geothermal fluid of all types of power plants is generally injected back into the edge of the reservoir for disposal and to help maintain underground pressure. In the case of direct heat utilisation, the geothermal water produced from wells (which generally do not exceed 2000 metres) is fed to a heat exchanger before being re-injected into the ground by wells, or discharged at the surface. Water heated in the heat exchanger is then circulated within insulated pipes that reach the end-users. For other uses (greenhouses, fish farming, product drying, industrial applications) the producing wells are usually located next to the plants serviced. A horticulture farm in the

Olkaria region in Kenya is currently utilizing direct geothermal heat in flower green houses (Bw'Obuya and Mariita, 2002).

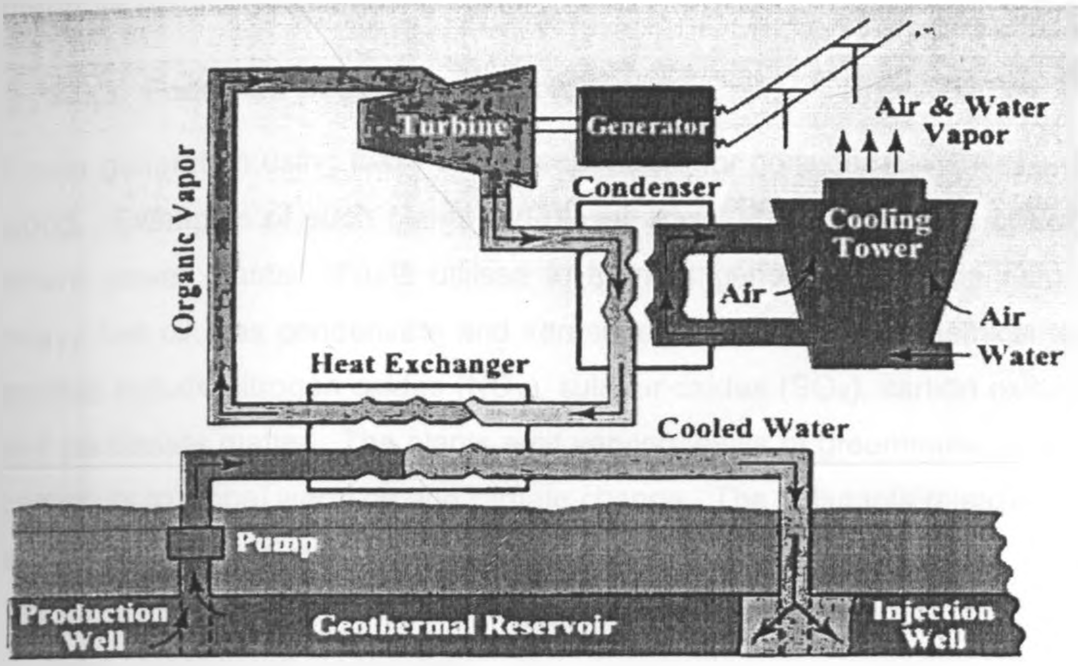

Figure 2.3.1:2Figure 2.2: Binary Cycle Power Plant
(Source: Geothermal Energy, 1998, University of Utah)

Areas with fluids above 200°C at economic depths for electricity production are concentrated in the young regional belts. They are the seats of strong tectonic activity, separating the large crystal blocks in which the earth is geologically divided. The movement of these blocks is the cause of mountain building and trench formation. The main geothermal areas of this type are located in New Zealand, Japan, Indonesia, Philippines, the western coastal Americas, the central and eastern parts of the Mediterranean, Iceland, the Azores and Eastern Africa.

2.3.2. Hydropower

Hydropower development lead to land use change in the water reservoir area and at times river diversion. Development of large scale hydropower projects can lead to ecological and hydrological disruptions, damaging local ecosystems and affecting local communities adversely (Karekezi and Timothy, 1997). This is mainly due to the requirement of a large water mass of the reservoir required to store the energy which is then regulated according to hydrological inflows and energy requirements. Depending on the size of reservoir, varying sizes of land have to be inundated thereby interfering with settlements and ecological habitats.

Generation equipment installed can affect fish population and interfere with biodiversity. Conversely, small and run-of-river hydro plants are considered more environmentally friendly since they require small regulation reservoirs and therefore result in less land inundation.

2.3.3. Fossil Oil Based Generation

Power generation using fossil oils is responsible for considerable emissions in the world. Examples of such plants are diesel, gas turbine, combined cycle and oil steam power plants. Fuels utilised in thermal generation include natural gas, heavy fuel oil, gas condensate and kerosene. Pollutants and chemical toxicants emitted include nitrogen oxides (NO_X), sulphur oxides (SO_X), carbon oxides (CO_X) and particulate matter. The plants emit varying levels of greenhouse gases which contribute to global warming and climate change. The pollutants released can also affect human health in the surrounding areas.

2.3.4. Coal Fired Generation

Coal power plants are known for high emissions. Much concern is directed to ash which is released when coal is burned. The ash from coal combustion has particulates that can affect people's respiratory systems, impact on local visibility and cause dust problems. The current trend is to shift from the traditional coal plants to clean coal technologies. Control of particulate emissions from coal-fired power plants is very important. Emissions from coal-fired power plant include mercury, selenium and arsenic, which can be harmful to human health and the environment. Other pollutants include oxides of Nitrogen (NO_x), sulphur dioxide SO_x, incombustible mineral matter and Carbon Dioxide (CO_2) which is a significant greenhouse gas (World Coal Institute, 2005).

2.4. Environmental Impacts of Electricity Transmission

Transmission lines require maintenance of corridors clear of vegetation. The width of these corridors depend on voltage level of the transmission line. This may result in land use change especially in the more populated areas. Existing structures along the line route are usually cleared to obtain adequate space for the lines. Farming activities especially those involving tall vegetation are discouraged so as to maintain suitable earth-to-ground clearance. New lines often result in displacement and resettlement of people affected. Transmission lines can affect wildlife and birds as they sometime come into contact with live equipment resulting in electrocution. These can reduce population of birds, especially the endangered species. Incidents involving electrocution of animals and birds sometime lead to costly power outages. Power lines are also known to cause interference in communication systems such as radios (LOG, 2005).

2.5. Overview of Modelling

Models can be classified as being mathematical or physical. A mathematical model uses symbolic notation and mathematical equations to represent a system. The system under study requires to be simplified such that only the key aspects of the system that are mainly affected or related to the problem are retained in the model.

Simulation entails mimicking the behaviour of a system through operation of the representation of the system (model) so as to analyse the behaviour of the system being studied. Simulation models may be classified as static or dynamic, deterministic or stochastic and discrete or continuous (Banks *et al.*, 2005). Static or Monte Carlo simulation represent a system at a particular point in time, while dynamic simulation models represent systems as they change over time. Deterministic models have a known set of inputs which results in a unique set of outputs. Stochastic models on the other hand have one or more random variables as inputs. A discrete system is one in which the state variable(s) change only at a discrete set of points in time, while a continuous system is one in which the state variable(s) change continuously over time. Few systems are wholly discrete or continuous but since one type of change predominates for most of the systems, it will usually be possible to classify a system as either discrete or continuous (Law and Kelton, 1991).

A power system is made up of different components that work together to maintain a continuously varying system. The three major components are generation, a high voltage transmission grid and distribution system (Lasseter, 2003). Random and discrete events occur in the system, for example, when customers switch on loads or when a power line trips due to system faults. These incidents introduce changes in the system's power flow and system stability dynamics. The system can therefore be modelled in different ways depending on the desired objective. Common areas of modelling of power systems include power flow, dynamic stability, operation and capacity expansion planning.

System operators maintain power system data taken at discrete points in time for reference and decision making among other reasons. In Kenya, half-hour power demand data are recorded alongside other important data. The data is suitable for discrete-event system simulation since the state variables vary at discrete set of points in time. A simulation model can be developed and analyzed using numerical methods which employ computational procedures to solve mathematical models rather than analytical methods which employ deductive reasoning of mathematics, such as application of differential calculus, to solve a model (Banks *et al.*, 2005).

Verification and validation are important aspects in modeling. The aim of verification is to ascertain if the model was built correctly by comparing the conceptual model to the computer representation that implements the conception. Validation entails establishing if the model actually performs the required task to give authentic results continuously (Law and Kelton, 1991). A model requires to be calibrated through an iterative process comparing it with the actual system behaviour and using the discrepancies between the two and additional knowledge gained from experience in the iterations done to improve the model. Necessary adjustments are done at each stage and constraints similarly adjusted to closely mimic real operations and ensure outputs are credible.

2.6. Generation Scheduling and Dispatch

Power generation and supply are increasingly being studied due to the growing needs for clean energy amidst rising energy costs and their significant environmental impacts. Operational Planning of an integrated power system involves many activities like generation scheduling and dispatch, power transmission and distribution, coordination of inter-utility transfers, appropriate tariffs mechanisms, fuel production, fuel transportation planning and several others (Chaturvedi *et al.*, 1996). Different sources and technologies are therefore compared, developed and operated based on their competing strengths. Techniques applied by researchers in plant dispatch field include mathematical algorithms such as Lagrangian relaxation (Nowak and Romisch, 2000), dynamic programming, artificial intelligence, fuzzy theorem and genetic algorithms. Mathematical models for cost optimal power scheduling in hydrothermal systems often encounter several difficulties such as a large number of mixed integer variables, non-linearities and uncertainty of problem data. Typical examples for the latter are uncertain prices in electricity trading in future electric power demand and future inflows into reservoirs of hydro plants (Gollmer *et al.*, 1998).

Modalities of operation of power systems including dispatch in different regions of the world are at different levels of development, largely influenced by supply factors, technological advancement and trading arrangements. In the developed countries power system operation is a complex task that requires optimisation and dispatch scheduling using computer programs and software, designed for predetermined objectives. Deregulation and liberalisation have led to operation of the power trade using market-based mechanisms. Generally, trade arrangements aim at minimisation of prices and operating costs so as to draw maximum benefits. Power grids generally receive supply from diverse sources, depending on location, cost of supply and reliability. Diversification of sources is important for spreading risks such as shortages, outages and total system collapse.

The important problem of minimizing the cost of producing a given amount of electrical power from a group of non-identical generators is given high priority in most systems. Power utilities face challenges in system operation due to power flow dynamics of varying system loads, machine characteristics and operations. Economic dispatch (ED) is used to determine the optimal schedule of on-line generating outputs so as to meet the load demands at the minimum operating cost (Ongsakul and Tippayachai, 1999). A Merit Order Dispatch (MOD) is therefore determined to achieve economic dispatch of available power plants. In mathematical terms MOD can be presented as an optimization problem for a system of Multivariable non-linear equations subject to a set of inequality constraints (Kalki, 2005). The non-linear constraints imposed on a system include minimum and maximum outputs for each unit and the unit ramp rate. MOD involves a decision on which units should be brought online/offline so that the system demand is met at minimum operating cost.

There are two tasks considered in power generation scheduling: unit commitment which determines the unit start up and shut down schedules in order to minimise system fuel expenditure and the economic dispatch which assigns the system load demand to the committed generating units for minimizing generating cost (Wang often encounter several difficulties such as a large number of mixed integer variables, non-linearities and uncertainty of problem data. Typical examples for the latter are uncertain prices in electricity trading in future electric power demand and future inflows into reservoirs of hydro plants (Gollmer *et al.*, 1998).

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There are two tasks considered in power generation scheduling: unit commitment which determines the unit start up and shut down schedules in order to minimise system fuel expenditure and the economic dispatch which assigns the system load demand to the committed generating units for minimizing generating cost (Wang and Shahidelpour, 1992). Generating units require to warm up in the start up process and gradually increase supply capability. When the unit is in operation, it takes a while to cool down. The two processes fall in a field that has attracted studies that aim at considering characteristics of generating units in cost minimisation. This is particularly of great interest in competitive markets where generators give commitment to supply power at specific periods, hence the need for careful scheduling to honour the commitments and at the same time factor in the economics of supply and unit characteristics.

In direct access competitive markets, generators contract freely with customers to supply electricity according to the terms of contracts, which might for example stipulate price and quantities for periods of time (Raymond *et al.*, 1996), through a transmission network controlled by an independent system operator (ISO) responsible for the security of the system. In this arrangement, the ISO runs the operations through a sophisticated computer program which ensures efficient system operation, efficient pricing and manages congestion optimally.

In the paper titled Genetic Algorithm (GA) Applications to Stochastic Thermal Power Dispatch (Selvi *et al.*, 2003), it is acknowledged that in practice optimal plans of dispatch may not be realized since information that is supposed to be known is not always deterministic, mainly due to two reasons: (i) inaccuracies in the process of measuring and forecasting of input data; and (ii) change of input performance during the period between measuring and operation. With rising fuel costs, there is growing interest to account for deviations since the effect of inaccuracies result in an increase in overall costs. Sudhakaran (2004) studied the application of GA to combined economic and environmental dispatch acknowledging that minimization of total environmental emissions alongside generation costs is an important operational objective. The paper highlights the advantages of GA, the science of natural selection and genetics to adapt to nonlinearities and discontinuities found in power systems to meet the dual objective.

Dispatch optimization of renewable energy (RE) sources in a mixed generation portfolio of renewable and non-renewable energies provides optimization in a larger scale since this can result in displacement of entire plants compared to economic dispatch which thrives on marginal cost of generation even within similar sources. In a competitive open market, small renewables can be edged out due to the fact that most have unpredictable outputs (Bhandari *et al.*, 2007) and in some cases have to participate in spot markets where advanced submission of operating levels is required. The authors propose the GA rolling window, for bidders that own both RE and non-RE sources, a technique in which the dispatch results are updated in each time period moving forward to the next period. In the Kenya power, optimisation of outputs from hydropower plants is paramount for both economic and environmental reasons, even in the absence of emission penalties for non-renewable sources. This activity is however undertaken separately being the backbone to the level of output from thermal plants.

Basu (2006) proposed interactive fuzzy satisfying method and particle swarm optimization technique for bi-objective generation scheduling for a fixed head hydrothermal power system. This technique is applied to overcome the limitations of GA and artificial intelligence based techniques which, supposedly, have no mechanism to show the vague or 'fuzzy' preference of the human decision in obtaining a compromising solution in the presence of conflicting objectives. Fuzzy goals are quantified by defining their corresponding membership functions for each of the objective functions, then the decision maker specifies the reference membership values for each of the objective functions and the corresponding best compromising solution is obtained by solving the minimax problem. Danraj and Gajendran (2004) studied economic load dispatch for plants having discontinuous equations using transformation of variables technique with directional search quadratic programming.

The United States Department of Energy (DOE, 2005) noted that many factors influence economic dispatch in practice. These include contractual, regulatory, environmental, scheduling, unit commitment, and reliability practices and procedures. Because economic dispatch requires a balance among economic efficiency, reliability and other factors, it is best thought of as a constrained cost-minimization process. Although economic dispatch will usually run higher efficiency gas-fired units before lower efficiency units, this is not always the case, for a number of possible reasons. Despite DOE's interest in ensuring the efficient use of natural gas for electricity generation and other purposes, it remains sceptical of the merits of “efficient dispatch,” for several reasons:

- short-term non-economic policy objectives should be considered only as a last resort;
- A better alternative would be to examine the practice of economic dispatch itself to determine whether modifications are needed to better achieve its traditional objectives. The fundamental purpose of economic dispatch is to reduce consumers’ electricity costs. “Efficient dispatch” would take the dispatch process off this path and increase consumers electricity costs – for benefits that may not be large enough to offset these additional costs; and
- Economic dispatch is at best a complex process, and modifications to it must be made with care in order to minimize unanticipated consequences. Modifying it to achieve

The reasons given arise from the fact that a delicate balance is required in dispatch relating to total generation cost to consumers and efficiency of energy production from the power plants dispatched.

2.6.1. Dispatch Operation in Kenya

System controllers are provided with both the balance and merit order dispatch to guide dispatch decisions. Energy balances prepared by the Planning Division of KPLC give indication of outputs expected from various sources to meet forecast demand and provide useful projections of expected energy generation/purchase and the associated fuel requirements and costs. These projections are used in preparation of the utility's financial projections and for decision making to ensure adequacy of supply capacity. Load forecasts are adopted for the purposes of determination of short term capacity reserve and medium term capacity reserve requirements and the determination of short term capacity reserves and medium term capacity reserves will be in accordance with the power system security and reliability standards (ERB, 2004). After examining the load forecast, planners confirm plant availabilities from KenGen and other generators and discuss the projections with the National Control Centre and other internal stakeholders. This enables confirmation of planned additional capacities and retirements and scheduling of power plants. Forecast hydropower and geothermal energy outputs are of great importance as they indicate the baseload energy supply level and guide planners to determine the thermal generation required for the shortfall. Planners apply the most recent energy purchase and fuel prices data in a merit order dispatch plan and project outputs from various sources aimed at providing the low total generation cost.

Dispatch scheduling aims to ensure that the continuously changing demand on the grid is met in the most economic manner (ERB, 2004). Prevailing system factors may take preference over merit order dispatch as it is prudent to keep the system running smoothly devoid of outages, blackouts and excessive voltage fluctuations. The protection system of the power grid provides automatic monitoring so as to enable fast response in under- or over-frequency to avoid system collapse. Controllers address system problems as they present before them and generally refer to the dispatch schedules during operation. Safety factors are also given due consideration as maintenance work is continuous and planned outages require coordination with responsible personnel. Communication with the maintenance crew and plant operators is done through telephones. Outputs from the operating power plants and demand levels in main substations and transmission lines in the various regions are recorded on half hourly basis. This is an important resource for system improvement, analysis and studies. Based on the data available, it is possible to induce more technology to obtain more optimal dispatch. Environmental factors are not usually considered in system dispatch. An economic merit order dispatch model that also incorporates minimisation of emissions can be formulated and implemented.

2.6.2. Dispatch Algorithm Formulation

A modelling example of a single thermal power plant is illustrated in Figure 2.3. It does not take into account the various complications that can arise due to environmental or other long-term considerations (Farr, 1995). Factors considered in plant operation include fuel, maintenance and labour costs, but it is based on the assumption that changes in output are relatively small so that fuel cost is the most significant.

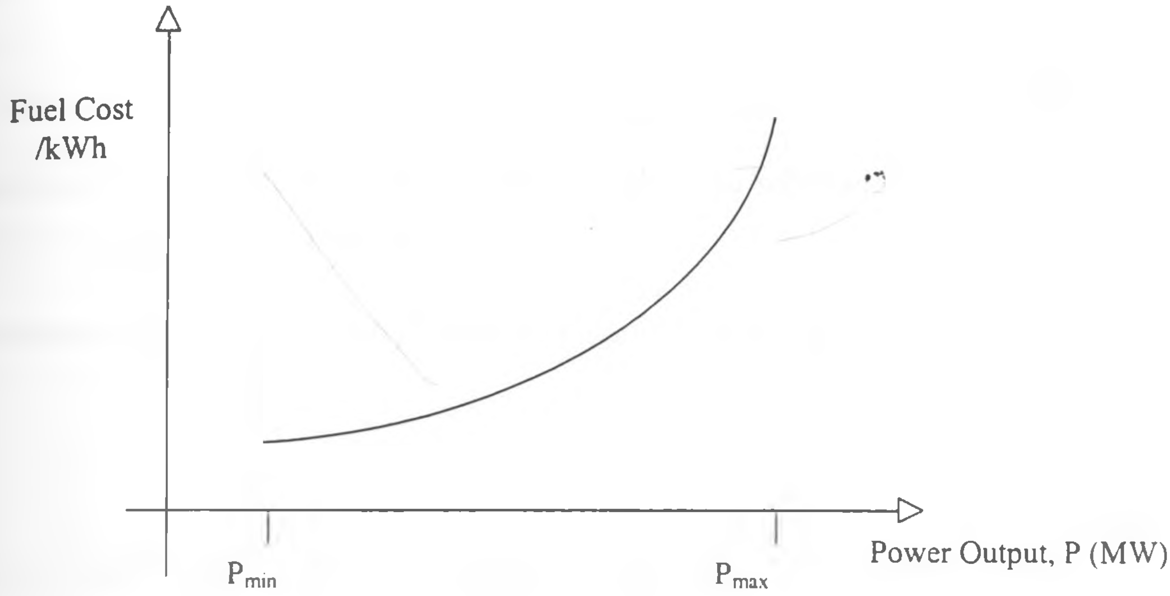

Figure 2.6.2:1Figure 2.3: Typical Fuel-Cost Curve for a Single Power Plant
(Source: Farr, 1995)

The cost curve is notably increasing exponentially. There are minimum and maximum values of P, P_{max} and P_{min}, corresponding to feasible limits of operation of the plant depending on machine characteristics. The need for an upper limit should be clear in that a given plant can not produce more power than what it is designed to generate. The lower limit usually comes from thermodynamic and/or practical considerations, for example, the fuel burning rate has to be above a certain value or the flame goes out.

In a power system comprising of a set of m power generating stations whereby for each value of i = 1,.....,m, we have a power output Pi and associated cost function Ci(Pi), corresponding to the i^{th} power generating plant. If the total power demand to be served by these power stations is represented as P_D, the economic dispatch problem to minimize the total cost (C_T) is given by (Farr, 1995):

$$C_T = \sum_{i=1}^{m} C_i(P_i) \qquad [2.1]$$

Subject to the constraints;

$$P_D = \sum_{i=1}^{m} P_i \qquad [2.2]$$

and

$$P_{mini} \le P_i \le P_{maxi}, i = 1,2,\ldots,m. \qquad [2.3]$$

Therefore one has to find values of Pi = 1, 2,.....,m satisfying the constraints such that the total cost is a minimum.

The incremental cost, ICi, of the i^{th} power station is defined by:

$$ICi = \frac{dCi}{dPi} \qquad [2.4]$$

Constraints pertinent to individual plants can be taken into account.

This problem is a simplified version of the real situation. Besides the assumptions mentioned above, the model makes the following additional assumptions.

- Line losses in transmitting power from the plants to the customers are negligible.
- Some power lines may have constraints on the amount of power they can transmit.
- The output voltages of the power stations do not vary significantly from their nominal ones as power output is changed.
- Given the upper and lower plant capacity limits for different plants which have different associated power costs, a given demand can be supplied at a minimum cost by optimisation.

Complexity of dispatch modelling increases as more constraints pertaining to individual plants are taken into account. Examples of contemplated cost type constraints are shown in Table 2.1. Thermal power plants' costs include capital costs, operation and maintenance costs (O&M), plant availability costs, fuel costs and other variable operating costs as well as start-up costs. Keeping a plant ready to operate induces operation and maintenance costs as well as a fixed capacity charge paid per MW of installed capacity. Start-up of a plant causes costs that can be divided into additional fuel costs and attrition costs. A cooling function links start-up costs and idle time of a plant.

Power generation induces fuel costs, which depend on the used fuel and the efficiency of the plant. Furthermore, other variable costs for operational supplements, production dependent attrition and variable personal costs occur. Part load operation causes additional fuel costs due to losses during energy conversion. Direct costs are induced by the dispatch of regulating and reserve power. The dispatch of incremental regulating power from plants in part load operation mode induces variable generation costs. The dispatch of incremental reserve power from a peaking plant, e.g. gas turbines, additionally induces start-up costs. For the dispatch of decrementing regulation, reserve power from non-thermal power plants result in cost reductions due to fuel savings. Both for incremental and for decremental regulation and reserve power dispatch have potential variations in efficiency considered due to changes in the part-load operation mode.

Table 2.6.2.1Table 2.1: Different cost types for thermal power plants

Cost Type	Cost Origin	Cost Period
Investment Fixed Costs	Capital recovery of power plants	Costs spread through economic life
Operation & Maintenance	Availability of installed power plants	Annual Costs
Personal Costs	Availability of installed power plants	Annual Costs
Start-up Costs	Start-up of plants	Load Period
Fuel Costs	Power generation	Load Period
Other Variable Costs e.g. environmental emissions	Power generation	Load Period
Costs related to part load operation	Power generation in part load mode	Load Period

(Source: EWI, 1995)

Available power plants can take three different modes of operation. First, they can be idle as they are not needed in the given period or because they are withheld to provide incremental reserve power. Secondly, plants can generate power on the spot market according to their net-capacity. Thirdly, plants can generate power in the part load mode when complying with the minimum load condition (EWI, 1995).

For part or full load operation the power plant capacity has to be started-up. The duration of start-up process depends on the idle time (a limitation of plant operation with regard to a minimum time of operation is not needed as this is complied with automatically due to economical reasons). Available plant capacity can be used to provide energy to the regular spot market as well as to provide incremental or decremental regulation and reserve power, whereas the application of the plant depends on its technical properties and its mode of operation. Figure 2.4 illustrates possible modes of operation and the resulting potential applications.

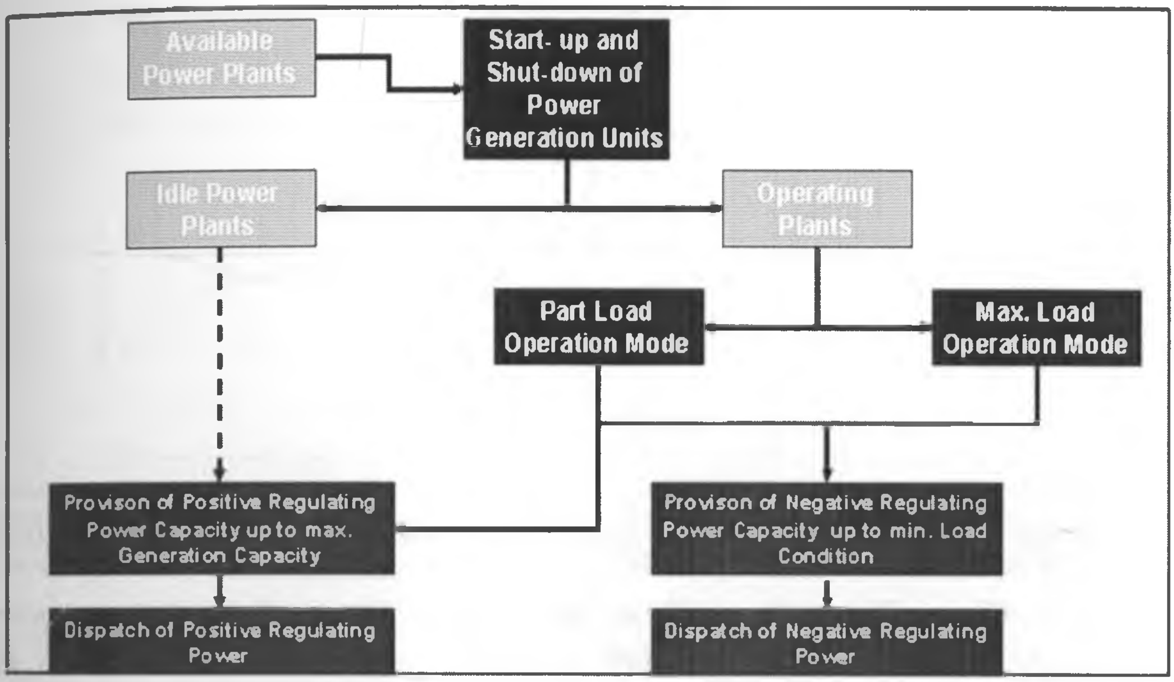

Figure 2.4: Operation Modes and Applications of Available Power Plants
(Source: EWI, 1995)

Power plants that are stand-by and do not generate power on the regular spot market can provide incremental regulating and reserve power up to their net full load capacity, if the start-up time and their technical properties comply with the transmission code qualification rules for regulating and reserve power. This incremental minute reserve can be provided by stand-by open cycle gas turbines due to the flexibility of this technology. Plants in part load operation mode can both provide incremental and decremental regulation and reserve power within the range of their minimum load and their net full load capacity. Plants that are operating with full load can provide decremental regulating and reserve power. When regulating and reserve power is needed, it can be dispatched by those capacities that are able to provide the needed type of supplementary service (Farr, 1995).

Figure 2.5 shows a typical daily load curve for the Kenyan system. The peak demand usually occurs between 19.00 and 20.00 hours followed by a gradual decline to the baseload level of about 530 MW between 24.00 hours and 05.30 hours when the domestic demand declines.

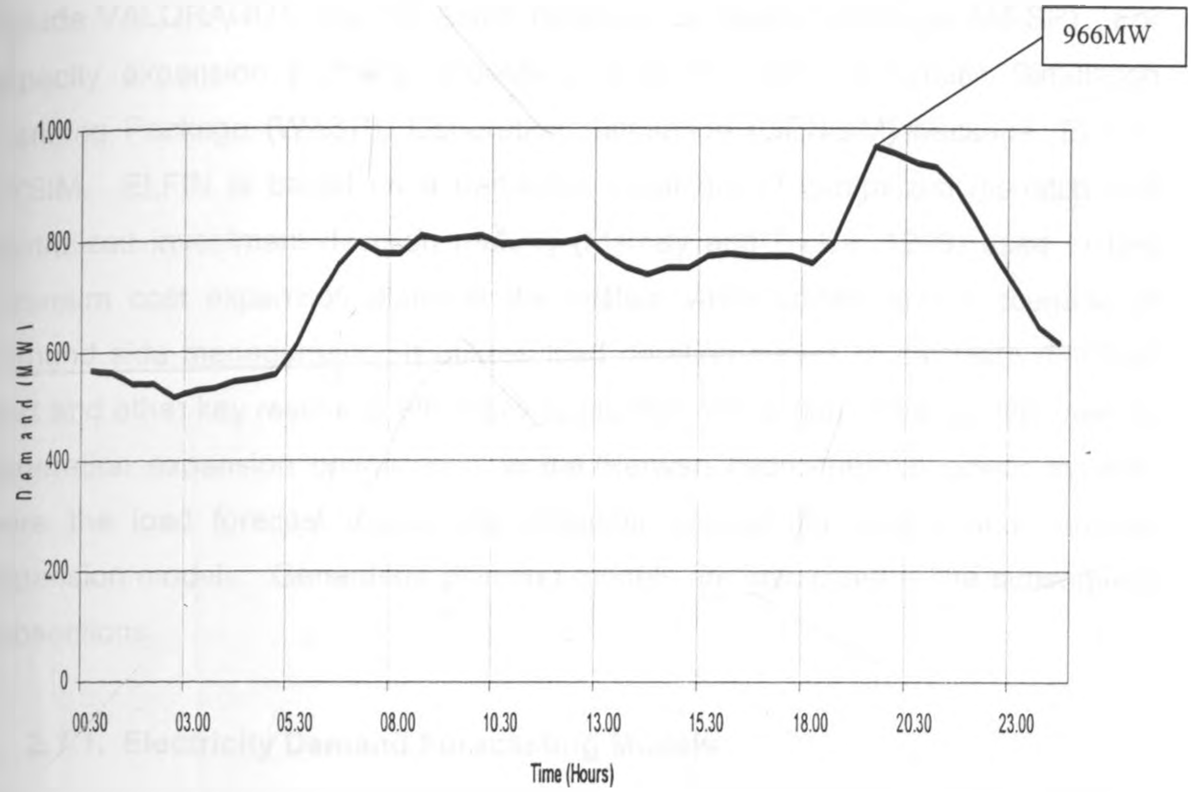

Figure 2.6.2:3Figure 2.5: Typical Daily Load Demand Curve
(Source: KPLC Daily Analysis Statistics, 2006)

2.7. Generation Expansion Planning

Generation expansion planning has historically addressed the problem of identifying ideal technology, expansion size, siting and timing of construction of new plant capacity in an economic fashion and manner that ensures installed capacity adequately meets projected demand (Chuang et al., 2001). Power system expansion planning can be divided into generation and transmission expansion planning. In generation expansion, the aim is to determine the most appropriate new power plants to be added to the power system and the timing of implementation so as to meet forecast demand of the system at the least cost. Planning therefore involves determination of an optimal path for development. Various computer based software have been developed for optimisation of the generation candidates.

Three types of models are usually used in capacity expansion planning: load forecasting models, hydro-system optimization models and capacity optimization models. A number of models have been developed for respective applications worldwide. Load forecasting models include the Model for Analysis of Energy Demand (MAED) and Time Series Econometric models. Hydro-optization models include VALORAGUA and the Acres Resovoir Simulation Package (ARSP). For capacity expansion planning, models include the Wien Automatic Simulation Planning Package (WASP), Generation Simulation (GENSIM) package, ELFIN, SYSIM. ELFIN is based on a traditional paradigm of centralized dispatch and centralized investment decision making (Marnay and Pickle, 1998) used to find minimum cost expansion plans in the system while considering a scenario of demand side management. It utilizes load duration curves to calculate marginal cost and other key results of electricity production simulation. The models used in generation expansion optimization in the Kenyan hydro-thermal power system, were the load forecast model, the reservoir optimization model and capacity expansion models. Generation planning models are discussed in the subsequent subsections.

2.7.1. Electricity Demand Forecasting Models

The accuracy of electricity demand forecast in capacity expansion planning is very important as it relates to the level of investments required over a given period. Econometric methods of forecasting, in the context of energy demand forecasting, can be described as 'the science and art of specification, estimation, testing and evaluation of models of economic processes that drive the demand for fuels (Bharadwaj and Mehra, 2001). Underestimates usually lead to the need for emergency measures to avoid shortfalls while, on the other hand, overestimates can result in unnecessary expensive investments that are underutilized. In the modern world, the new electricity market will have two segments: "captive consumers" and "free consumers". This segmentation makes the demand forecasting task a tough one, since it will involve not only the determination of the overall demand in the franchise area, but will require also the evaluation of the "free consumers" share (Filho and Schuch, 1998). Bharadwaj and Mehra (2001) reviewed the several demand forecasting approaches and models in use, namely;

- Trend method,

- End-use method,
- Econometric approach,
- Time series methods, and
- Hybrid approaches.

The Trend method is placed under the category of the non-causal models of demand forecasting that do not explain how the values of the variable being projected are determined. The variable to be predicted purely as a function of time, rather than by relating it to other economic, demographic, policy and technological variables. This function of time is obtained as the function that best explains the available data and is observed to be most suitable for short-term projections. The trend method has the advantage of its simplicity and ease of use. However, the main disadvantage of this approach lies in the fact that it ignores possible interaction of the variable under study with other economic factors. The end-use approach attempts to capture the impact of energy usage patterns of various devices and systems. The end-use models for electricity demand focus on its various uses in the residential, commercial, agriculture and industrial sectors of the economy. For example, in the residential sector electricity is used for cooking, air conditioning, refrigeration and lighting, while in agriculture it is used for irrigation. The end-use method is based on the premise that energy is required for the service that it delivers and not as a final good. The following relation defines the end use methodology for a sector:

$$E = S \times N \times P \times H \qquad [2.5]$$

Where,

E = Energy consumption of an appliance in kWh

S = Penetration level in terms of number of such appliances per customer

N = Number of customers

P = Power required by the appliance in kW

H = Hours of appliance use.

This, when summed over different end-uses in a sector, gives the aggregate energy demand. The method takes into account improvements in efficiency of energy use, utilization rates and inter-fuel substitution among other factors in a sector as these are related to the power required by an appliance P. In the process, the approach implicitly captures the price, income and other economic and policy effects as well.

The Econometric approach combines economic theory with statistical methods to produce a system of equations for forecasting energy demand. Taking time-series or cross-sectional/pooled data, causal relationships are established between electricity demand and other economic variables. Demand for electricity being the dependent variable, is expressed as a function of various economic factors. These variables could be population, income per capita or value added or output (in industry or commercial sectors), price of power, price(s) of alternative fuels (that could be used as substitutes) or proxies for penetration of appliances/equipment (capture technology effect in case of industries). The relationship can be defined as:

$$E_D = f(Y, P_i, P_j, P_{OP}, T) \qquad [2.6]$$

Where,

E_D = Electricity demand

Y = Output or income

P_i = Own price

P_j = Price of related fuels

P_{OP} = Population

T = Technology

Several functional forms and combinations of these and other variables may have to be tried till the basic assumptions of the model are met and the relationship is found statistically significant. The econometric methods require a consistent set of information over a reasonably long duration. This requirement forms a pre-requisite for establishing both short-term and long-term relationships between the variables involved.

A Time Series is defined to be an ordered set of data values of a certain variable.

Time series models are, essentially, econometric models where the only explanatory variables used are lagged values of the variable to be explained and predicted. The intuition underlying time-series processes is that the future behavior of variables is related to its past values, both actual and predicted, with some adaptation/adjustment built-in to take care of how past realizations deviated from those expected. Thus, the essential prerequisite for a time series forecasting technique is data for the last 20 to 30 time periods. The difference between econometric models based on time series data and time series models lies in the explanatory variables used. It is worthwhile to highlight here that in an econometric model, the explanatory variables (such as incomes, prices, population etc.) are used as causal factors while in the case of time series models only lagged (or previous) values of the same variable are used in the prediction.

Hybrid approaches entails the use of a combination of econometric and time series models to achieve greater precision in the forecasts. This has the advantage of establishing causal relationships as in an econometric model along with the dependency relationship. Various functional forms such as linear, quadratic, log-linear, and translog, are used to capture the possible trends that may be evident in the data. The functional form of the model is arrived at after a trial and error process. A model is built using the available data, truncating the last few observations. The procedure for testing the model entails making predictions for the last few time periods for which actual data are available and were truncated. The models available in KPLC are MAED and the Time Series Econometric model.

The MAED Model

MAED analyses available sources of energy to determine the likely demand for electricity based on competing factors. Accuracy of the input data to any model is paramount and therefore the need to use the most realistic load forecast is necessary so as to generate a plan that closely meets system requirements. The model projects energy demand for all sectors of the economy for medium and long-term periods. It considers the demand by sector and captures the effects of the various sources of energy that may compete with electricity, in a bottom-up approach or end use method. Figure 2.6 shows some historical and forecast one-day demand levels. MAED considers possible development patterns and relevant determining factors, namely:

- Economic activity level
- Lifestyle of population
- Technological development
- Socio-economic policies
- Energy policies
- Favorable global economic performance

Environment policies aimed at encouraging use of alternative energy in place of biomass is one of the considerations in forecasting since the availability and accessibility of one resource may have direct correlation with the use of another. Electricity demand projections and consumption patterns are derived from the total energy demand.

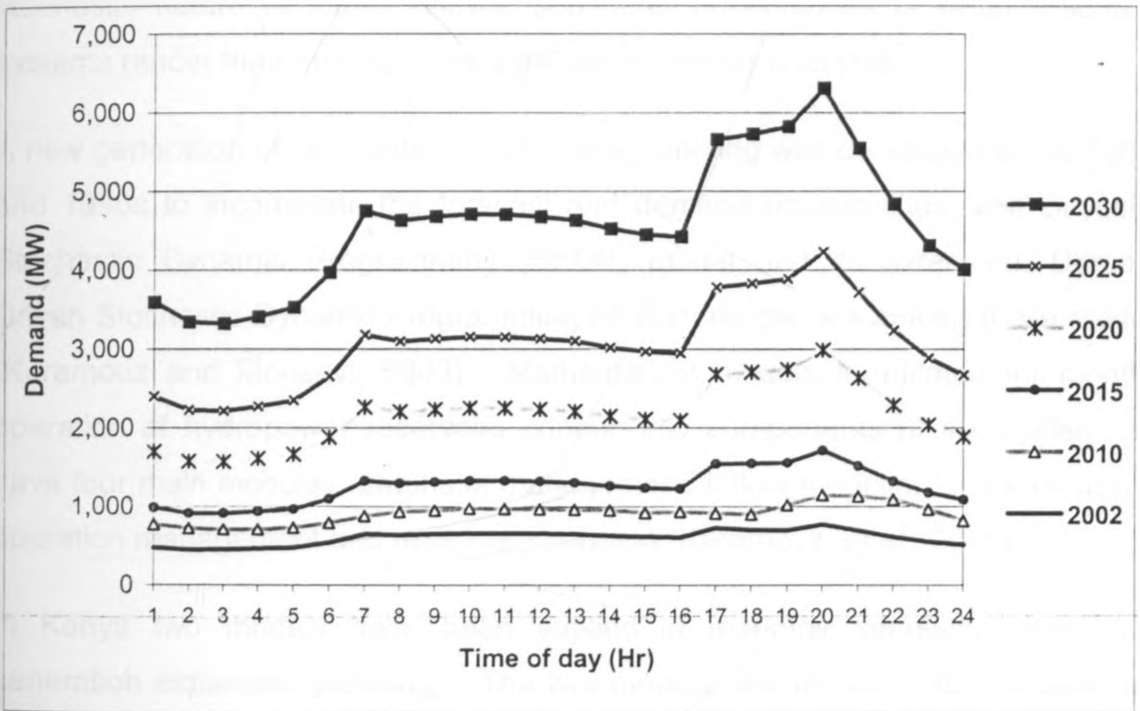

Figure 2.7.1:1Figure 2.6: One Day Levels Electricity Demand Forecast
(Source; LCPDP Training, 2005)

2.7.2. Reservoir Simulation Models

The problem of planning and managing multipurpose reservoir systems, most often stated as optimal control problem, has been and continues to be a subject of extensive research work (Koutsoyiannis *et al.*, 2002). Computer modeling is necessary in reservoir simulation to optimize and efficiently manage operations in reservoirs subject to complex interrelations that exist within and across basins. The key components of surface water systems include reservoirs and their associated inflow and abstraction components, spillways and hydropower units. The pertinent multiple factors considered in a reservoir include demands for power, environmental mandates, increasing demands, recreational needs, irrigation and climate change. River and reservoir systems are usually operated according to policies dictated by various laws, decrees, agreements and other formally recognized laws (Zagona *et al.*, 2001). The basic underlying concept in all reservoir models is the principle of conservation of mass. Thus at any given time the reservoir storage, S_t, can be stated as:

$$S_t = S_{t-1} + (\text{Total inflows - total outflows})] \qquad [2.7]$$

The large number of variables involved, the nonlinearity of dynamics, the stochastic nature of future inflows, and other uncertainties of water resources systems render their management a difficult but imperative task.

A new generation of stochastic dynamic programming was developed in the 1980s and 1990s to incorporate the forecast and demand uncertainties. The Bayesian Stochastic Dynamic Programming (BSDP) model and its extension, Demand Driven Stochastic Dynamic Programming (DDSP) model, are among those models (Karamouz and Mousavi, 2003). Mathematical models formulated for monthly operation of hydropower reservoirs contain key components of the system and have four main modules: database management, inflow modeling and forecasting, operation management and real-time operation (Karamouz, *et al.*, 2005).

In Kenya two models have been applied in reservoir simulation for power generation expansion planning. The two models, ARSP and VALORAGUA, are discussed respectively in the remaining part of this section.

The ARSP Model

The Acres Reservoir Simulation Package (ARSP) is a software model for simulating the operation of water resource systems, capable of simulating complex systems containing multiple reservoirs and multiple water usage. It is more suitable for medium to long-term operational planning with resource systems having conflicting demands. Rule curves are used to develop a strategy for operation of a reservoir or a group of reservoirs.

Hydroelectric power and energy production can be viewed under varying operating rules and water use constraints with two key parameters used to measure the effects of the policy:

- Minimum energy production- least generation in all the time periods simulated
- Average energy production –long term average generation in all the time periods simulated

The objective of analysis in simulations for specified system energy demands is to find the firm energy capability of a particular system configuration in all simulation runs. Energy production is measured in terms of the average power output over the time period. It uses network algorithm which solves a subset of generalised linear programming problems. The aim of this network programming formulation is to minimise a cost function which reflects benefits derived from a particular operating policy, while satisfying all flow constraints and continuity of mass within the water resource system (Acres, 1998). Mathematically, the network programming formulation is stated as;

$$\text{Min } Z = \sum_{ij} C_{ij} \qquad \text{for all } i \text{ and } j \qquad [2.8]$$

Subject to the following constraints:

$$\sum q_j - \sum q_j = 0 \qquad \text{for all i and j}$$

$$L_{ij} < q_{ij} \leq U_{ij} \qquad \text{for all i and j}$$

Where,

Z = Objective function to be minimized, the sum of the cost of flow in all arcs of the network in this case

C_{ij} = Total cost of flow in the arc from node i to node j = $c_{ij}q_{ij}$

c_{ij} = Cost of each unit of flow in the arc from node i to node j

q_{ij} = Total flow in the arc from node i to node j

L_{ij} = Lower flow bound in the arc connecting node i to node j

U_{ij} = Upper flow bound in the arc connecting node i to node j

The first set of constraints ensures that the overall continuity in the network is satisfied. The second set guarantees, for a feasible solution to exist, the flow in all the arcs to fall between a minimum and maximum limits.

The VALORAGUA Model

The VALORAGUA model can be used to enable optimization of operation of a hydro-thermal electric system. The name VALORAGUA is adopted from the Portuguese language, meaning "Value of Water". It involves modelling of the hydro according to seasonal variations and optimizing the system operation maximising the hydro output. Its objective is to minimize power system plant operation costs over 1 year, month-by-month or week-by-week. VALORAGUA is microcomputer package software, developed in FORTRAN, composed of several modules, implemented to perform the management of a hydrothermal electric power system, at a national level or with interconnections with other countries (or areas). It establishes the optimal strategy of operation for a given power system by the use of the "value of water" concept (in energy terms) in each power station, for each time interval (i.e. month/week) and for each hydrological condition. For hydro power plants, the model takes into account that the water may have other utilizations rather than the energy generation (REN, 2001).

The detailed analysis performed by the model, particularly for hydro power plants, enables the determination of operational characteristic in order to reach the minimum operation costs. The model supplies detailed information about technical, economic and environmental behaviour of the system and of each generation centre, taking into consideration the randomness of hydrology. It also supplies a careful calculation of the economic dual variables, the marginal generation costs and the marginal value of water for each hydroelectric plant. The model considers other uses of water besides energy generation such as public water supply (PWS) and mandatory environmental releases for the river downstream eco-system sustenance and computes short-run marginal generation cost and marginal value of water. Figure 2.7 shows graphical representation of the Tana and Turkwel cascades in Kenya modelled in VALORAGUA.

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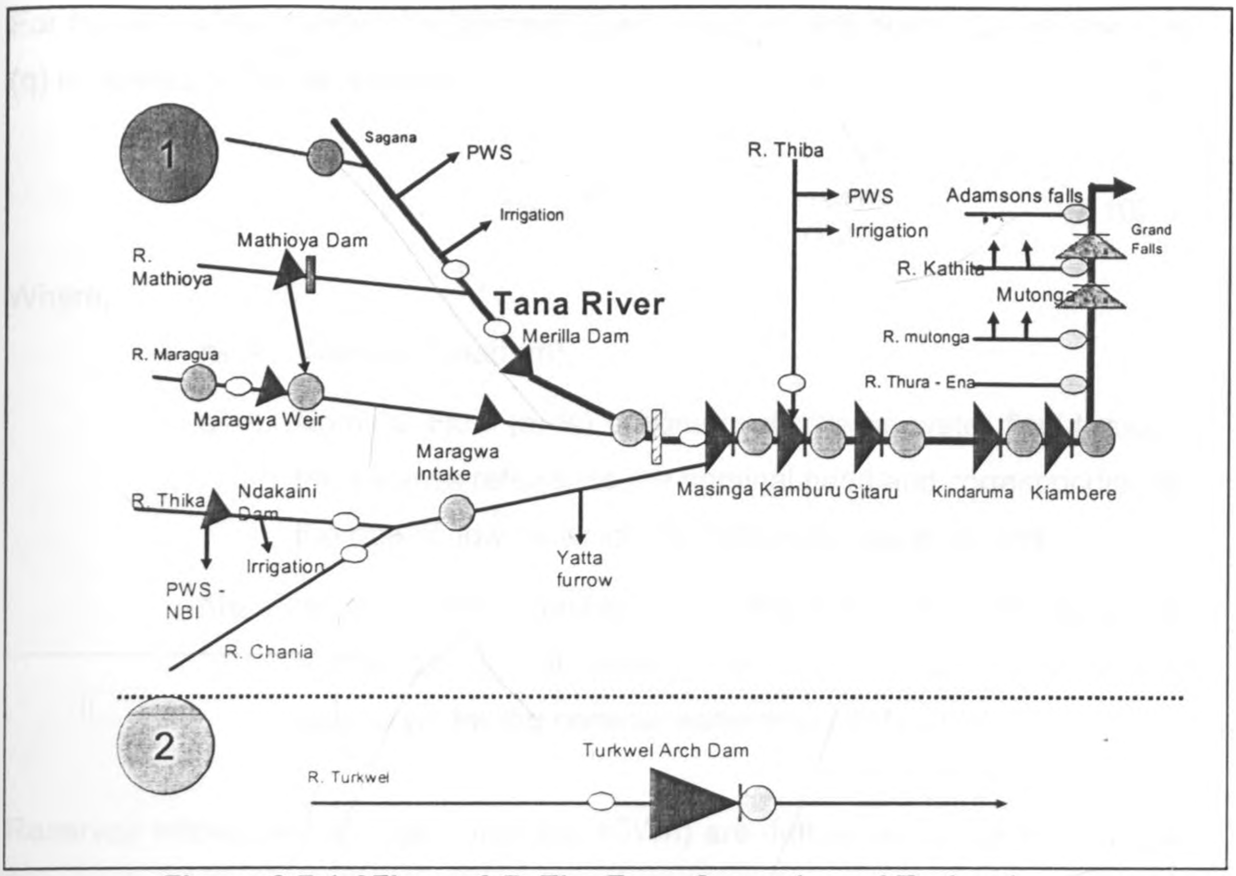

Figure 2.7.1:2Figure 2.7: The Tana Cascade and Turkwel
(LCPDP Training, 2005)

Technical data requirements for the model include:

- Reservoir storage Capacity (Millions of cubic meters) - the greatest value used to define the maximum quantity of water that can be stocked in the reservoir;
- Dead volume (Millions of cubic meters) - the water volume that cannot be used for energy generation because it is below the water intake level;
- Level/volume function - represents the one-to-one relationship between the stored volume (V) and the water level (z) in the reservoir and is represented by the following equation (REN, 2001):

$$Z = Z_o + \alpha \times (V - V_o)^{\beta} \qquad [2.9]$$

Where α and β are characteristic parameters associated to the reservoir "shape" and (Z_0, V_0) corresponds to the first point of the level/volume function: for the level Z_0 (meters) corresponds to the volume V_0 (Millions of cubic meters).

For hydro turbines, under the Nominal Operation point the head loss for any flow (q) is defined by the expression:

$$\Delta h = \frac{\Delta h_o}{q_o^2} xq \qquad [2.10]$$

Where,

h_o = Nominal Head (m);

q_o = Nominal Flow (m^3/s) maximum discharge water flow through the turbines referred to the nominal head and corresponding to the rate of flow for which the turbine is designed; and

Δh_o = Head loss (m) - corresponds to the head reduction, equivalent to the amount of energy lost, due to the friction in the waterways for the nominal water flow (REN, 2001).

Reservoir inflows and storage capacities (GWh) are defined in energy (GWh) and the maximum energy that can be stored in the reservoir recorded. Average operation cost, that is, the average cost of the first unit generated if monthly/weekly average costs are used. Other important parameters in optimization are reliability, maintenance schedules and variable costs. Optimal maintenance schedules require to be made for specific hydrological conditions.

2.7.3. Capacity Expansion Models

The Capacity expansion problem can be stated as a problem of selection, sequencing and timing of capacity projects (Smith and Villegas, 1997). Generation expansion planning models are important tools that have continued to evolve over time in line with the needs of the industry for capacity expansion optimization. The objective in the optimization is meeting the long term electricity demand forecast while minimizing the sum of operational costs and expected investment for each year of the planning period considering the reliability and environmental constraints (Liik, *et al.*, 2004). The models are required to be able to capture the continually varying demand as seen in a daily load profile and match it with the supply available in the varying seasons of the year, especially when there are hydropower plants in the system. Load duration curves (LDC) are used for long term (year) planning. LDC curves are generated by sorting chronological load from highest to lowest thereby creating a curve representing system loads typically for a year, season, or month. The area under this curve is the total energy requirement and individual generator contributions may be solved very quickly using simple integration (Meier, 2005). The curves enable visualization of the duration when demand lies above a given level within a period as shown in Figure 2.8 with the units is per unit (p.u), where the demand in the entire planning period was above 47% of the peak demand.

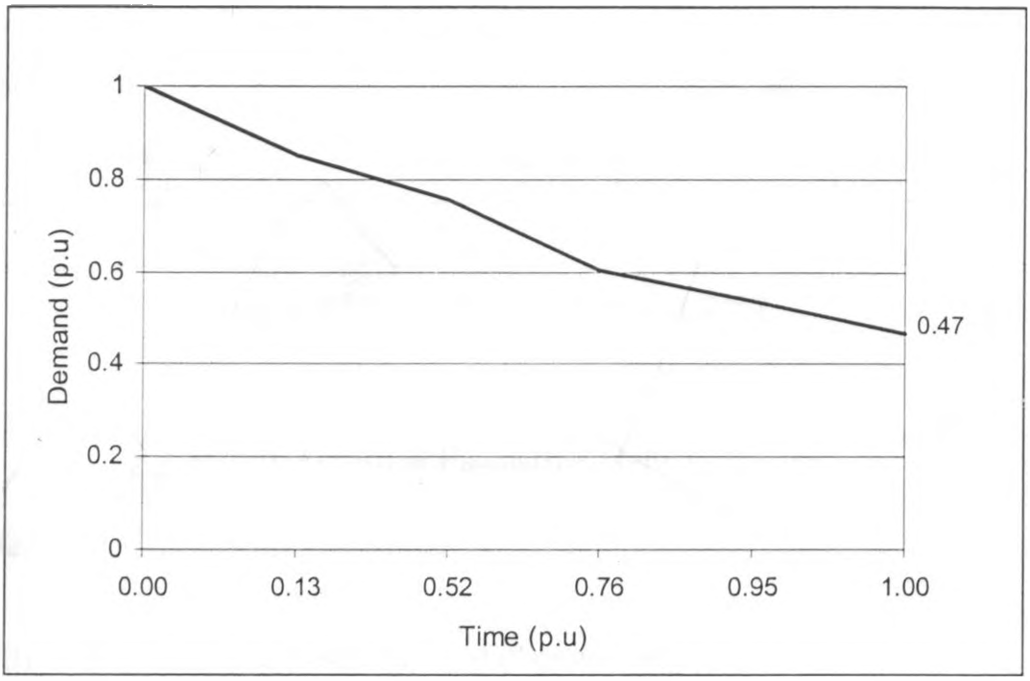

Figure 2.7.3:1Figure 2.8: A Load Duration Curve
(Source: LCP 2007 Planning Data)

A significant change in planning processes which traditionally focused on optimization of an economic indicator as the sole objective function is the gradual shift towards integrated resource planning (IRP). In this approach, costs considered in a broad sense account not just for the utility's perspective but also for the society's perspective by including, for example, environmental issues in the assessment of planning alternatives (Martins *et al.*, 1996).

Liik *et al.*, (2004) describes the optimization problem for load demand duration $P_D(t)$ and total costs C_i (P_i), with the total for existing and possible new generation plants as follows:

$$C_i (P_i) = C_{if} + C_v(P_i) \qquad [2.11]$$

Where;

C_{if} = fixed costs

$C_v(P_i)$ = variable costs

Then;

$$\int_{T=0}^{T\max} \sum_{i=1}^{N} Ci(Pi(t)dt \qquad [2.12]$$

Subject to;

$$(P_D(t) - \sum_{i=1}^{N} Pi(t)dt = 0 \qquad t=[0,T^{max}] \qquad [2.13$$

$$P_i^{min} \le P_i(t) \le P_i^{max}, \ I = 1,\ldots.N \qquad t=[0,T^{max}] \qquad [2.14]$$

$$\sum_{I=1}^{N} P_i^{max}(t) - (P_D(t) \ge P_{reserve}(t) \qquad t=[0,T^{max}] \qquad [2.15]$$

Where,

$P_i(t)$ = Load duration curve of i^{th} generating unit

N = Total number of generating units possible to use for optimization

$P_{reserve}(t)$ = Duration of needed reserve capacity

T = Length of planning period

The problems described in the equations above include the unit commitment and economic dispatch problems, while equation 2.15 considers also capacity charges and lifetimes of units.

Smith and Villegas (1997) compared several optimization models, namely, Dynamic Programming (DP), Heuristic Procedures and Mixed Integer Linear Programming (MILP). The research showed the superiority of DP and therefore the importance of interdependence considerations in capacity expansion problem when hydropower projects are included. The study indicated that the other two models have limitations in simulating the interference but are capable of giving better results if more constraints are added.

The GENSIM Model

Generation Simulation (GENSIM) package developed by Acres International of Canada has been in use for sometime in Kenya for determination of the least cost plan. The package analyses possible expansion plans using three modules, namely, GSPlan for capacity planning, GSOper for operation of plants and GSEcon for economic analyses of the alternative plans (LCPDP, 2005). The operation of the package using the three modules operates as illustrated in the flow diagram in Figure 2.9. Planning data for modelling a power system include system demand, investment costs and plant operational data.

The Planning module analyses possible expansion plans under the set criteria of Loss of Load Expectation (LOLE) and maximum expected unserved energy (EUE). The output of the GSPlan is a feasible generation expansion plan and its associated plant maintenance schedule under critical drought conditions. The GSOper module uses the output of GSPlan to calculate net energy output and fuel consumption per plant. The Economic module, GSEcon, calculates the present worth cost (PWC) of each sequence based on capital cost, operational cost and the cost of EUE. The sequence with the lowest PWC is the least cost plan.

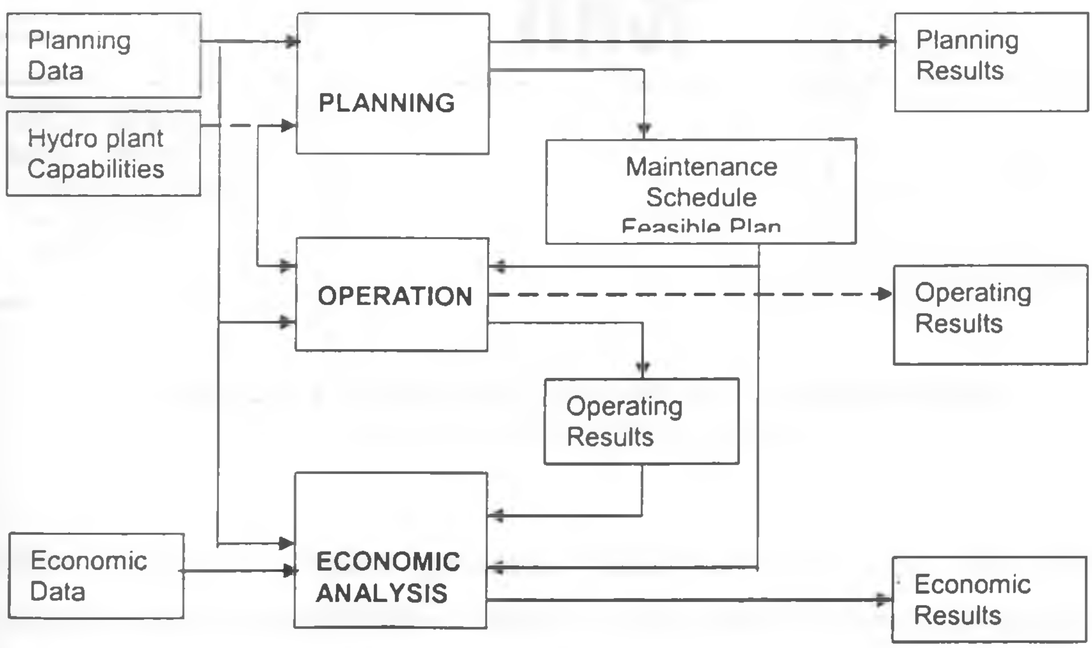

Figure 2.7.3:2Figure 2.9: Structure of the GENSIM Model
(Source: LCPDP, 2005)

The WASP Model

The load forecast and outputs of VALORAGUA are utilised by the Wien Automatic Simulation Planning Package (WASP). The model is an optimization program that determines the generation expansion plan to meet projected demand at minimum cost subject to input constraints. Its inputs also include outputs from MAED and VALORAGUA models. WASP evaluates many combinations of candidate generation projects to obtain a least-cost expansion plan (optimal solution) for a given period. Outputs of WASP include:

- Alternative expansion plans and their Net Present Value (NPV) costs;
- Annual Financing requirements; and
- Summary reports.

Figure 2.10 illustrates the relationships between WASP, MAED and VALORAGUA.

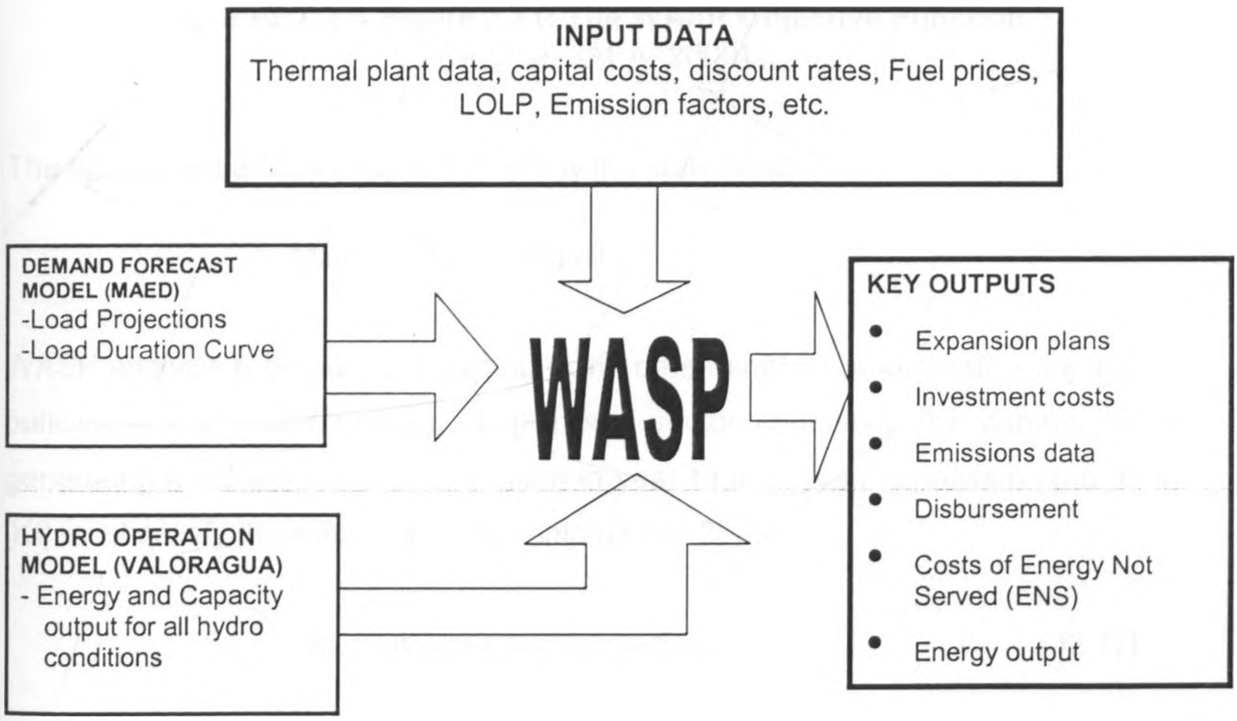

Figure 2.7.3:3Figure 2.10: Operations in the WASP Model
(Source: LCPDP Training, 2005)

WASP configures possible generation expansion plans and uses dynamic programming to evaluate them. It allows consideration of various constraints such as reliability, fuel usage, generation and emissions. Figure 2.11 of equation 2.16

shows the objective function of the WASP simulation software, utilised in determining the optimal plan from presented candidate generation sources.

$$B_j = \sum_{t=1}^{T} I_{j,t} + S_{j,t} + F_{j,t} + M_{j,t} + O_{j,t} \qquad [2.16]$$

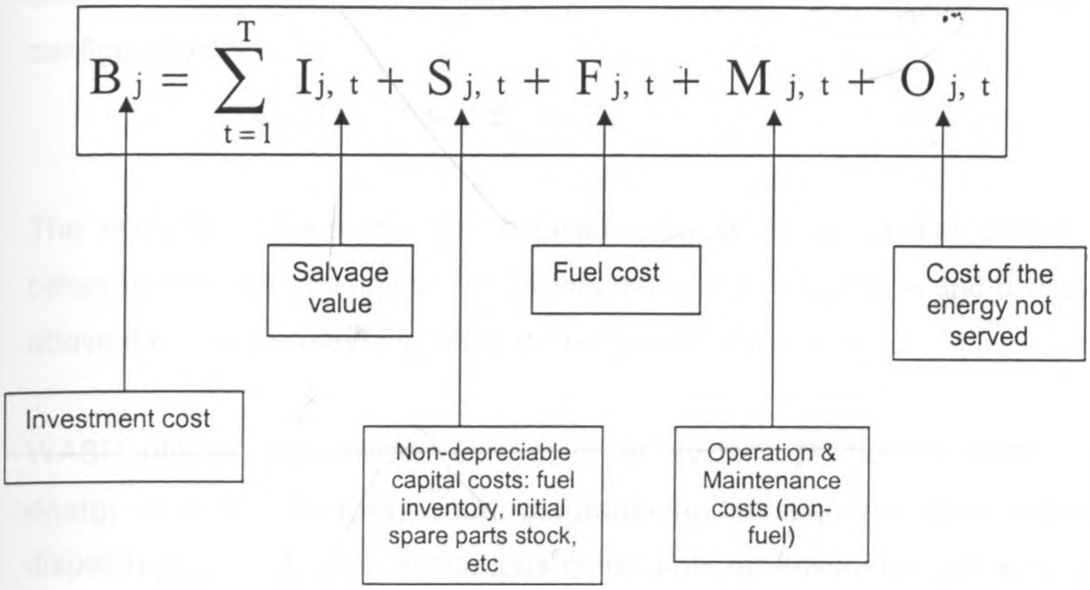

Figure 2.7.3:4 Figure 2.11: The WASP Objective Function
(Source: IAEA, 2000)

The optimal expansion plan is defined by the statement:

Minimum Bj among all j

WASP analysis requires as a starting point, determination of alternative expansion policies in the power system. If [Kt] is a vector containing the number of all generating units which are in operation in year t for a given expansion plan, then [Kt] must satisfy the following relationship (IAEA, 2000):

$$[\,K] = [\,K_{t-1}] + [\,A_t\,] - [\,R_t + [\,U_t\,] \qquad [2.17]$$

Where,

$[A_t]$ = vector of committed additions of units in year t,

$[R_t\,]$ = vector of committed retirements of units in year t,

$[U_t]$ = vector of candidate generating units added to the system in year t.

$[A_t]$ and $[R_t\,]$ are given data and $[U_t]$ is the unknown variable to be determined; the latter is called the system configuration vector or, simply, the system configuration.

Defining the critical period (p) as the period of the year for which the difference between the corresponding available generating capacity and the peak demand has the smallest value and if $P(K_{tp})$ is the installed capacity of the system in the critical period of year t, the following constraints should be met by every acceptable configuration:

$$(1+a_t)\,D \geq P(K_{tp}) \geq (1+b_t)\,D_{tp} \qquad [2.19]$$

The equation implies that the installed capacity in the critical period must lie between the given maximum and minimum reserve margins, a_t and b_t respectively, above the peak demand D_{tp} in the critical period of the year.

WASP utilizes probabilistic estimation of system production costs, unserved energy costs and reliability, linear programming technique for determining optimal dispatch policy satisfying exogenous constraints on environmental emissions, fuel availability and electricity generation by some plants and the dynamic programming method for optimizing the cost of alternative system expansion policies.

The WASP-IV model can be utilised to find an optimal solution for a power generating system over a period of up to thirty years within constraints given by the planner. The optimum plan is evaluated in terms of minimum discounted total costs. Each possible sequence of power units added to the system expansion plan meeting the constraints is evaluated by means of a cost function or the objective function presented in equation 2.16. The optimal expansion plan is the one that returns minimum Bj among all j. Generation by each plant for each period of the year is estimated based on an optimal dispatch policy which is, in turn, dependent on availability of plants/units, maintenance requirements, spinning reserve requirements and any other exogenous constraints imposed by the user (IAEA, 2000).

The WASP model comprises of several modules through which several functions are executed. The first module is the LOADSY which processes information describing peak loads and load duration curves for the power system over the study period. Module 2 is the FIXSYS which processes information describing the existing (fixed) generation system and any predetermined additions or retirements as well as information on constraints imposed by the user such as environmental, fuel availability or electricity generation by some plants.

Module 3 is the variable system, VARSYS, which processes information describing various generating plants which are to be considered as candidates for expanding the generation system. Next is the configure generators, COGEN, module which calculates all possible year-to-year combinations with the fixed system satisfying the loads. COGEN also calculates the basic economic loading order of the combined list of FIXSYS and VARSYS plants. Module 5 called MERSIM (merge and simulate) considers all the configurations put forward by COGEN and uses probabilistic simulation of system operation to calculate the associated production costs, energy not served and system reliability for each configuration, while taking into account any limitations imposed on some group of plant. Dispatching of plants is determined in such a way that the imposed requirements are satisfied at minimum cost. The module makes use of previously simulated configurations and can also be used to simulate the system operation of the best solution provided by the current DYNPRO in a mode of operation called REMERSIM, that is remerge and simulate.

Module 6 is the Dynamic Programming Optimization module (DYNPRO) which determines the optimum expansion plan based on previously derived operating costs along with input information on the capital costs, energy not served cost and economic parameters and reliability criteria. The last module is the report writer of WASP in a batched environment, REPROBAT. It writes a report summarising the total or partial results for the optimum or near optimum power system expansion plan and for fixed expansion schedules (IAEA, 2000).

2.8. The 2008-2028 Power Development Plan

The least cost plan prepared in 2007 and the models used in the process were reviewed in this part of the study to provide the background of the problem in the perspective of the third specific objective of this study.

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2.8.1. Demand Forecast

Econometric-Times series hybrid demand forecast forecasting models were used by KPLC in 2007 in preparation of LCPCP 2007. The models were updated using regression analysis on the available historical data. The regression relationships tested in the models grouped into the following categories: Sales versus;

(a.) Income (GDP) variable

(b.) Price of electricity

(c.) Time (time trend)

(d.) Combination of the above variables.

The objective of regression analysis is to determine the overall long-term growth trend for a variety of consumption categories using available historical data. The equation models for four distinct customer categories take the linear or log-linear form. Historical data up to the year 2005/06 were used in the regression analysis to determine the coefficients of the four customer forecast categories. The customer categories were:

i) Domestic Forecast Model

ii) Commercial/Industrial Forecast Model

iii) Off-Peak Forecast Model

iv) Rural Electrification Forecast Model

Domestic Forecast Model

The domestic forecast model used historical domestic sales, a moving average tariff for domestic customers and non-agricultural GDP data. A log-linear regression analysis was carried out to obtain parameters and coefficients for the model. The domestic moving average tariff coefficient of elasticity was taken to be -0.20 as derived in the 1986 and the regression output results for the domestic model gave an underlying growth rate of 4.1 per cent and a non-agricultural GDP growth elasticity of 0.53 (LCPDP, 2007). The model equation for the domestic sales forecast was:

$$\text{Sales (MWh)} = A \times B^{t} \times GDP_{na}^{\;0.53} \times Tar^{-0.2} \qquad [2.20]$$

Where,

A and B = Coefficients

t = Forecast year 1971 to 2006

GDP_{na} = Non Agricultural Gross Domestic Product

Tar = Moving Average Domestic Tariff

Commercial/Industrial Forecast Model

The regression analysis was performed using manufacturing sector GDP and services sector GDP as parameters, with a tariff coefficient of –0.1. The resultant new commercial/industrial model derived was:

$$\text{Sales (MWh)} = ((-C + (D \times GDP_{man}) + (E \times GDP_{ser})) \times Tar^{-0.1} \qquad [2.21]$$

Where,

C, D and E = Coefficients

GDP_{man} = Manufacturing Sector GDP

GDP_{ser} = Service Sector GDP

Tar = Moving Average Commercial/industrial Tariff

Off-Peak Forecast Model

The off–peak model was developed using the relationship between the number of off-peak customers and time, as the two variables were found to have a close correlation. The coefficient produced in the regression analysis is indicative of the underlying growth rate in the number of off-peak customers over time. A tariff coefficient of –0.2 was assumed and used to adjust sales per customer downwards annually as the moving average off-peak tariff rises. The off-peak sales forecast model derived by KPLC (LCPDP, 2007) was:

$$\text{Sales (kWh)} = F \times G^{t} \times Tar^{-0.2} \qquad [2.22]$$

Where,

F and G = Coefficients,

t = Forecast year and

Tar = Moving Average off-peak tariff.

Rural Electrification Forecast Model

The purpose of Kenya's Rural Electrification Program (REP) is to promote rural development by providing affordable electrical energy to more people living in the rural areas. The design of the model used is based on regression of REP sales against past cumulative REP investment and current year investment, where all expenditure is deflated to 1982 prices by the GDP deflator. A tariff parameter is included based on the moving average overall tariff. The following model derived and used in the 2007 LCPDP was:

$$\text{REF Sales} = (H \times INV_t^{\,0.7689t}) \times \text{Log}\,(NI+CI) \times Tar^{-0.2} \qquad [2.23]$$

Where,

H = Coefficient,

INV = Cumulative Capital expenditure up to year t-1 + annual capital expenditure in year t,

t = Year of forecast-2006 and

Tar = Moving Average Tariff.

A summary of the load forecast used in the least cost plan is shown in Table A6-1 in Appendix A6.

2.8.2. Reservoir Simulation

The ARSP reservoir simulation model described in section 2.7.2 was used in the least cost plan under review in this study, to generate the hydropower plants files which contain the data used in capacity expansion optimization in the GENSIM software. The files generated contain projected monthly capacity and energy outputs for both existing and candidate hydropower plants. The outputs are categorized into firm and probable amounts for appropriate use in the planning and operation modules of GENSIM.

2.8.3. Candidate Generation Resources

Kenya is endowed with sizeable hydroelectric resources which can be prioritized in development to meet demand and enable displacement or delay of installation of more thermal plants. The 1986 Least Cost Power Development Plan cites over 1,400 MW of identified potential hydropower capacity capable of providing 6,000 GWh/yr. The sites are located in the five drainage basins in Kenya, which are

Tana, Lake Victoria, Ewaso Ngiro North, Rift Valley and Athi. Selection of hydroelectric candidate projects is based on available data in respective feasibility studies. This limits the candidates to be evaluated particularly small projects which have no firm data. Table 2.2 shows the installed capacity and hydropower potential in some of the country's identified sites, based on the findings of the Kenya National Power Development Plan, 1986-2006 (Acres, 1986).

Table 2.8.3.1Table 2.2: Candidate Hydropower Projects

River Basin	Installed Capacity (MW)	Potential Capacity (MW)
Tana	569	570
Lake Victoria	2	355
Rift Valley	106	345
Ewaso Ngiro North	0	155
Athi Basin	0	38
Total	**677**	**1,463**

(Source: Acres, 986).

The Lake Victoria Basin is located in the Western part of the country. The region is known for frequent floods which result in loss of lives and property. Hydropower development could introduce river flow regulation and abatement of floods. Rivers with significant hydropower potential flowing from the Western slopes of Kenyan highlands draining into Lake Victoria are Nzoia, Yala, Nyando, Sondu, Migori and Kuja. The Magwagwa site which lies in the junction of Kipsonoi and Yurith rivers is ideal for regulation of the highly seasonal flows estimated to have a potential for 95 MW capacity. This site is however densely populated and therefore development would involve expensive displacement of people. Another site in the Victoria basin is the Nandi Forest adjacent to the Kano plains, which is capable of supporting a 50 MW power plant with a firm energy output of 248 GWh/yr.

Economic evaluation on the sites in the Lake Victoria basin were in favour of the Sondu Miriu power project which has been implemented, despite facing financial and environmental challenges. Sondu Miriu Hydropower project has a capacity of 60 MW. A further 20 MW will be installed downstream of the current project in the short term (KPLC, 2006). Sondu project is a run of river and therefore requires only a regulating reservoir as opposed to large storage reservoirs. The additional capacity will greatly improve reliability and quality (voltage stability) of power supply in the Western region of the country.

The Tana basin in the central part of the country is the main source of hydropower in Kenya. Six projects have been developed in the most economic sections of the Tana River while six future projects could be developed in the relatively flat middle reach of Tana. The most promising potential lies in Mutonga and the Low Grand Falls sites, which are capable of producing 60 MW and 140 MW respectively. Both projects have feasibility study reports carried out a decade ago but are expected to be updated soon.

The Athi Basin has small potential schemes that have not been developed, but some agricultural development projects have been implemented in the Kibwezi area. Two sites that have been identified are the Munyu (8 MW) Dam and Fourteen Falls cascade (30 MW). These small hydro projects are likely to generate more interest in the future as alternatives to the expensive sources with the escalating cost of fossil fuels.

The Arror River in the Rift Valley Basin is capable of supporting a 60 MW hydroelectric power plant at Sererwa site, according to the 1986 LCPDP. The study however indicated that the costs of developing this hydro site was comparatively higher that the candidates in the Tana Basin.

The Ewaso Ngiro South hydro project is located along the Ewaso Ngiro South River in Narok District which drains into Lake Natron on the Kenya-Tanzania border, in the Rift Valley Basin. The economic capacity recommended for future development from three sites is a total of 220 MW (Acres, 1992) from three sites. A key environmental concern in this project is the recommended inter-basin transfer of water from a river draining into the Lake Victoria Basin which could cause a rise in the level of Lake Natron and reduced inflow to Lake Victoria. The predicted impacts and comparatively rising project costs curtailed efforts for implementation of the project which had been included in the least cost plan. The sensitive nature of cross-border impacts requires proper consultations and agreements to avert conflicts. A planned mitigation measure in the Natron side was to implement an irrigation project to utilize diverted waters after release from the power generation plants.

In the Ewaso Ngiro North Basin, identified projects are Crocodile Jaws (40 MW), Muridjo (25 MW) and Karimun (90 MW). Detailed studies for these proposed projects have not been carried out (Acres, 1986).

Geothermal potential in Kenya is estimated to surpass 2000 MW capacity (Acres, 1986). The high potential sites are located along the Rift Valley. The current developed capacity of 128 MW is the highest in Africa, with the first 45 MW geothermal plant having been in operation for over 25 years. The risks in exploration to confirm adequacy of the resource underground is one factor that contributes to slow development and increased investment costs in geothermal projects. Expensive exploratory wells have to be sunk in order to assess resource levels in identified potential blocks. Specific sites mapped out in recent exploration activities lie between Olkaria and Lake Bogoria. The newly enacted Energy Act 2006 will enable creation of Geothermal Development Company (GDC) to carry out the initial exploration and expedite development and investments in this sector.

Coal exploration in Kenya has continued to raise hopes of striking substantial deposits, which could displace expensive imported oil used for electricity generation and other industrial energy requirements. Exploratory activities in Mui Basin in Kitui and Mwingi Districts and Taru Basin in Kwale and Kilifi districts have yielded positive indications. However, more work needs to be done in order to establish the feasibility of mining and power generation. Current power expansion plans consider the possibility of construction of coal plants in Mombasa running on imported coal. The viability of this proposal assumption will be determined once an ongoing study on the feasibility of building a 300 MW coal plant in Mombasa is completed (LCPDP, 2007). The East African Power Master Plan (BKS Acres, 2004) indicated that coal deposits discovered in Tanzania can be used for internal generation leaving no hope for any exports to neighbouring countries.

Thermal power plant data is used in analyses to determine suitability of candidate fossil oil-fired plants in the least cost expansion plan. The data can be broadly classified as technical and financial. Cost-based screening of candidate thermal, imports, geothermal and coal-fired power plants which is undertaken to select the best candidate projects, is discussed in section 2.8.4. Plant emission penalties are factored into planning to disadvantage the polluters (LCPDP, 2005) over the renewable resources, although the law currently imposes no penalties for emissions arising from power generation. This also creates competition within and between different technologies by discouraging high emitters through increasing their per unit generation costs.

Kenya has historically been importing power from Uganda through a 30 MW contract signed in 1954. Uganda's increasing demand has however diminished surpluses for export culminating in the review of the 30 MW non-firm supply contract to a power exchange contract, currently with net exports to Uganda. Three East African countries (Kenya, Uganda and Tanzania) commissioned a study for regional integrated development to maximise on the most economic resource development and utilization. The study recommended considerable power imports from Tanzania in the future to displace fossil thermal generation in Kenya. More imports are also expected from the Southern African Power Pool (SAPP) through Tanzania if proposed interconnectors are built between Zambia, Tanzania and Kenya. Zambia could then transmit power through a proposed 1,200 km line with a back up from possible surpluses from the SAPP countries.

Nine riparian countries of River Nile are also carrying out projects under the Nile Basin Initiative (NBI) supported through funding from the World Bank. The initiative aims at pooling resources of the Nile and developing a shared sustainable resource exploitation arrangement for the member countries. Cooperation in development activities related to the Nile waters is essential to avoid conflicts and to foster economic development in the region in an agreeable approach. The principal of mutual benefits envisaged in the regional initiatives include creation of a regional trading power pool, displacement of expensive thermal generation, hydro complementarities, optimum investment programs, system planning and operation.

2.8.4. Selection of Candidate Generation projects

Power supply capacity expansion planning involves taking into account objective envisaged and consideration of pertinent factors that influence the process and the implications of the results. The aim of planning is to meet power demand through the most optimal development path. Factors influencing demand for electricity need to be considered in energy planning so as to derive the likely level of supply requirements over the planning period. Options for meeting electricity demand are evaluated based on technology, cost, implementation period, capacity, fuel supply, environmental impacts, location and level of security, among other factors.

Table 2.3 shows three hydropower projects identified as feasible for development. However Ewaso Ngiro South project which has environmental concerns from the proposed inter-basin water transfer and may not be implemented without adequate mitigation measures. Capital cost data for the hydro projects were obtained from the East African Power Master Plan study but increased by 20% to account for increased material, construction and mitigation costs since the studies were carried out (LCPDP, 2007). The increased capital costs disadvantage the hydro plants' by raising the unit energy costs. The projected unit costs of energy for the three plants are above 11 US cents/kWh and have low plant factors, highly dependent on weather conditions.

Table 2.8.4.1Table 2.3: Candidate Hydropower Projects

	Ewaso Ng'iro South	Mutonga	Low Grand Falls
Configuration (n x MW)	**220**	**2 x 30**	**1 x70**
Total Capacity (MW)	220	60	140
Lead Time (Yrs)	7	7	9
Earliest commissioning year	2015	2015	2017
Fixed Cost			
Capital ($ x 10^6)	404.3	235.7	439.8
Transmission ($ x 10^6)	8.25	7.22	14.43
Total ($ x 10^6)	412.6	242.9	454.2
Unit Cost ($/kW)	1,875	4,049	3,244
IDC Factor	1.3644	1.2391	1.2998
C.R.F.	0.1204	0.1204	0.1204
Interim Replacement	0.0040	0.0040	0.0040
Fixed Annual Capital ($/kW/yr)	318.3	624.2	524.7
Fixed O & M ($/kW/yr)	22.3	10.0	7.0
Total Fixed Cost ($/kW/yr)	341	634	532
Total Outage Rate	0.0969	0.0969	0.0969
Outage Adjustment	1.11	1.11	1.11
Adj. Fixed Cost ($/kW/yr)	**377**	**702**	**589**
Annual Average Energy (GWh/yr)	598	337	715
Energy at 100% Plant Factor (GWh/yr)	1927.2	525.6	1226.4
Operating Plant Factor	31%	64%	58%
Adj. Fixed Cost (USCts/kWh)	**13.9**	**12.5**	**11.5**

(Source: LCPDP, 2007)

Geothermal resource assessment by KenGen has been in progress through funding from Government and development partners. Drilling of the appraisal wells for the next power plant is in progress, where six directional geothermal appraisal wells will initially be drilled and about sixteen more production wells sunk later depending on the outcome of this appraisal drilling. The aim is to establish the optimal resource capacity and the timing of the proposed Olkaria IV 70 MW geothermal power plant planned for commissioning by year 2010. The Geothermal Development Company (GDC) is expected to carry out geothermal resource exploration and steam production and therefore accelerate progress in geothermal development. Operational arrangements of the GDC relative to other sector players are currently being formulated. These may be designed to have the GDC selling steam for power generation to KenGen and IPPs.

The current development in geothermal technology favours larger units, which have savings due to economies of scale. Therefore development of the identified resource prospects is likely to be in nominal 70 MW single units. There will be need to match the unit size to the available resource and characteristics. Thus future units may be of various sizes as determined during resource exploration and appraisal. A combination of vertical and directional wells will be drilled, with some production wells being drilled in pads used for exploration and appraisal.

Reconnaissance studies (LCPDP, 2007) indicate that future geothermal plants, after Olkaria IV, will be located further from Olkaria. Distances of the proposed development sites relative to the existing transmission lines are used to estimate the costs of interconnection facilities required. The estimated average capital cost for a 70 MW geothermal plant was US$ 171.3 million.

Selection of thermal power plants require analysis of both technology and fuel consumption. In the LCPDP 2007, the base crude oil price projections were adopted from the World Bank's 2006 Global Commodity Price Projections. The Bank forecast an average crude oil price of US$ 61.3/bbl in 2007 declining to US$ 57/bbl in 2008 and further to US$ 35/bbl by 2015. A high price projection of US$ 59/bbl in 2008 was derived from the assumption that the rate of price decline would be lower than the average projected by the World Bank, to reach US$ 47/bbl by 2015. The low forecast was based on the 2007 World Bank Prospects for the Global Economy report which projects US$ 53/bbl in 2008. The results of the modified forecast are shown in Table 2.4.

The most likely source of imported coal identified was South Africa which exports mainly to the European market, Far East and Asia. In the least cost plan, a price of US$ 50/ton FOB of 6000 kcal/kg coal was assumed for imports from South Africa delivered to Mombasa based on the 2006 price levels reported in South African Coal Statistics 2006 report published by Barlow Jonker (LCPDP, 2007). The price levels are indicated by the South African Steam Coal (SASC) Index, a monthly index of the price for spot thermal coal exported from Richards Bay Coal

Terminal in South Africa for customers in the European Market. The index which is determined by Barlow Jonker relates to a base 100.00 in January 1986 when the price was US$ 30/ton FOB. It offers time series data for South African 6,000 kcal/kg NAR coal, with a maximum of 15.0% and 0.80% ash and sulphur content, respectively. The SASC Index averaged US$ 50/t during the first half of 2006 compared with US$ 47.65/t in the corresponding period in 2005.

Both crude oil and coal projections were based on the World Bank data and are now low compared to the actual situation experienced in 2007 when prices escalated to above US$100 per barrel and per tonne, respectively. The prices were however retained in this review so as to enable comparison at par in the review of the 2007 LCPDP.

Table 2.8.4.2Table 2.4: World Average Crude Oil Price Projections

	2007	2008	2010	2015
Average Forecast US$/bbl	61.3	57	50	35
Escalation for Low and Reference Forecast		-6.70%	-13.10%	-29.60%
Escalation for High Forecast		-3.35%	-6.55%	-14.80%
High Forecast	61.3	59	55	47
Low Forecast	57	53	46	33

(Source: LCPDP, 2007)

2.8.5. Screening of Candidate Projects

Technical and financial data for candidate thermal power plants are used to screen candidate projects' suitability for inclusion in expansion plans. In addition emission penalties are applied to disadvantage the non-renewable sources, although the law imposes no penalties on emissions from power plants. The penalties therefore create competition between technologies through variable unit generation costs. All thermal plant candidates were subjected to an environmental of tax of US$ 10/tonne of carbon dioxide emitted, which was added to the variable operational and maintenance costs of each plant to penalize emissions (LCPDP, 2007). Table 2.5 shows the cost data for the various thermal plants, geothermal and imports and their respective computed unit generation costs. Average cost of a generating plan is equal to its capital cost per unit of energy production plus its operating cost (Chuang *et al.*,2001). This can be expressed as follows:

$$\text{Average cost} = \text{operating cost} + \frac{\text{capital cost}}{\text{annual.energy}} \qquad [2.24]$$

The costs are used to generate the screening curves for the candidate thermal and geothermal plants and anticipated power imports from neighboring countries shown in Figure 2.12. The curves indicate the cost per MW per year for the different sources at varying utilization levels with Crude Oil price at US$59/bbl and Coal at US$70/tonne. From the curves gas turbines are seen to be cheaper to run at low utilization levels making them suitable for operation at peak. Imports are cheapest for the intermediate to high utilization levels. The next cheapest sources are coal plants, while geothermal plants are best utilised as baseload units since their cost per unit remains relatively uniform with utilization because they have low variable costs. Combined cycle plants lie between the gas turbines and geothermal power plants.

Table 2.8.5.1Table 2.5: Screening of Candidate Sources

Configuration (n x MW)		Geothermal	Coal	G.T.	CC	LSD	MSD	Import
Configuration (n x MW)		**1 x 70**	**1 x 100**	**2 x 90**	**3 x 90**	**2 x 50**	**4 x 20**	**100**
Total Capacity (MW)		70	100	180	270	**100**	80	100
Fixed Cost								
Capital ($ x 106)		171.3	195.6	98.0	205.7	199.5	92.4	48
Capital ($/kW)		2447	1956	544	762	1995	1155	476
Fixed Annual Capital ($/kW/yr)		420.7	307.6	83.0	117.4	279.1	174.3	71.8
Fixed O&M Costs ($/kW/yr)		33.55	50	7.0	3.5	15	40	0.544
Total Fixed Annual Cost ($/kW/yr)		454	358	90	121	294	214	72
Total Outage Rate		0.039	0.156	0.078	0.078	0.098	0.098	0.050
Outage Adjustment		1.040	1.185	1.085	1.085	1.108	1.108	1.053
Annual Fixed Cost ($/kW.yr)		**472**	**424**	**98**	**131**	**326**	**238**	**76**
Variable Cost								
Fuel Price ($/GJ)		0	2.388	12.5020	12.5020	6.8944	6.8944	
Heat Rate (kJ/kWh)		0	11300	11,440	7,810	8,140	8,470	
Fuel Cost ($/kWh)		0	0.0270	0.1430	0.0976	0.0561	0.0584	
CO2 Tax ($/kWh)		0	0.0115	0.0089	0.0061	0.0067	0.0069	
Variable O&M ($/kWh)		0.0020	0.0067	0.0045	0.0032	0.0100	0.0140	0.0590
Total Variable ($/kWh)		**0.00204**	**0.0452**	**0.1565**	**0.1069**	**0.0728**	**0.0793**	**0.0590**
Unit Cost ($/kW.yr)								
Plant Factor............	10%	474	463	235	225	390	307	128
Plant Factor............	20%	476	503	372	318	453	376	180
Plant Factor............	30%	478	543	509	412	517	446	231
Plant Factor............	40%	480	582	646	506	581	515	283
Plant Factor............	50%	481	622	783	599	645	585	335
Plant Factor............	60%	483	661	920	693	708	654	386
Plant Factor............	70%	485	701	1057	787	772	724	438
Plant Factor............	80%	487	740	1194	880	836	793	490
Plant Factor............	90%	489	780	1331	974	900	863	541
Plant Factor............	100%	490	820	1468	1068	963	932	593
Unit Cost ($/kWh)								
Plant Factor............	10%	0.5414	0.529	0.268	0.257	0.445	0.350	0.146
Plant Factor............	20%	0.2717	0.287	0.212	0.182	0.259	0.215	0.102
Plant Factor............	30%	0.1818	0.206	0.194	0.157	0.197	0.170	0.088
Plant Factor............	40%	0.1369	0.166	0.184	0.144	0.166	0.147	0.081
Plant Factor............	50%	0.1099	0.142	0.179	0.137	0.147	0.134	0.076
Plant Factor............	60%	0.0919	0.126	0.175	0.132	0.135	0.125	0.073
Plant Factor............	70%	0.0791	0.114	0.172	0.128	0.126	0.118	0.071
Plant Factor............	80%	0.0695	0.106	0.170	0.126	0.119	0.113	0.070
Plant Factor............	90%	0.0620	0.099	0.169	0.124	0.114	0.109	0.069
Plant Factor............	100%	0.0560	0.094	0.168	0.122	0.110	0.106	0.068

(Source: LCPDP, 2007)

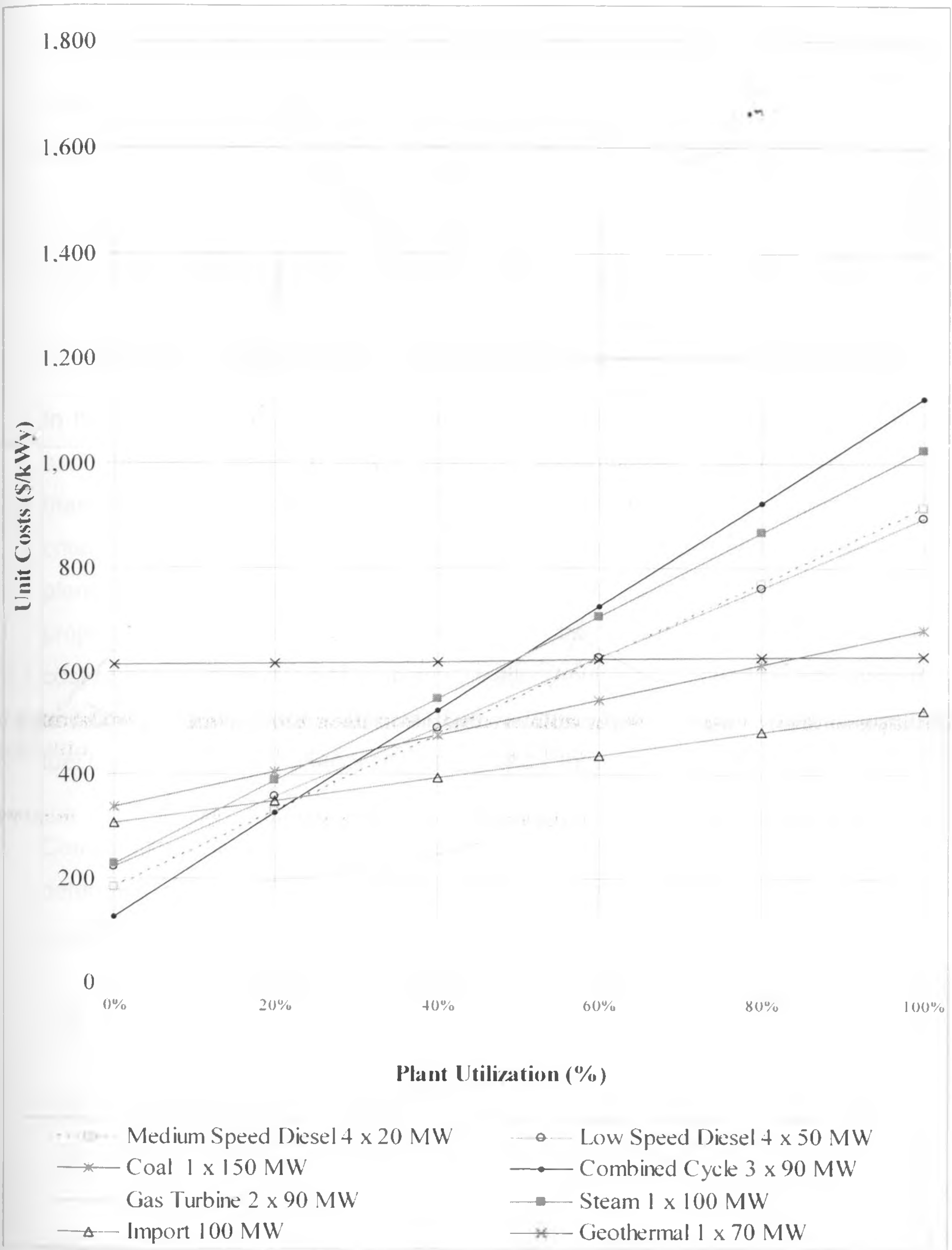

Figure 2.12: Cost-based Screening Curves for Candidate Projects
(Source: LCPDP, 2007)

2.8.6. Planning Criteria and Assumptions

In the 2007 least cost plan, the following criteria and assumptions were made for the simulations undertaken to determine the least cost expansion plan. A discount rate of 12% was used in this development plan, as is the case with many other economic analyses and studies in Kenya. The generation system reliability criteria under critical drought were set at 10 days per year loss of load expectation (LOLE) and annual maximum expected unserved energy EUE of 0.1% of system energy demand. The expected unserved energy (EUE) was priced at 0.84 US$/kWh.

2.8.7. Capacity Expansion Optimization in LCPDP 2007

In the 2007 LCPDP, the existing system (power plants) and committed additions and retirements were common in all sequences simulated. Candidate plants were then added to meet the increasing demand in order to meet the system reliability criteria. Various sequences consisting of different combinations of candidate plants were analyzed. Screening is the process of comparing possible candidate projects to determine the best choices for addition to meet demand based on the cost of energy generated at a given utilization level. The costs that add up to the unit cost (US$/kWh) are fixed costs and variable costs. Variable costs include the fuel costs and per unit energy charges for the various sources.

Combinations of the sequences found to be more economic for evaluation to determine the least cost plan based on the screening results and preliminary simulations were:

(i) Geothermal + Coal + Import + Medium Speed Diesel + Combined Cycle + Gas Turbines'

(ii) Geothermal + Coal + Import + Medium Speed Diesel + Gas Turbines, and

(iii) Geothermal + Coal + Import + Medium Speed Diesel + Combined Cycle

Geothermal plants formed the base of every sequence since they ranked favourably in the screening curves and are more likely to be implemented faster compared to imports which require long lead times and negotiations. Combinations were then made using Coal, Gas Turbines, Combined Cycle and Power Imports. The sequences that were analyzed and the results obtained are as listed in Table 4.6 in ascending order. The present worth costs of the sequences analyzed were compared to determine the least cost plan.

The existing system and committed additions and retirements were common in all sequences simulated. Candidate plants presented in Tables 2.3 and 2.4 were then added to meet the increasing demand in order to meet the system reliability criteria. Various sequences consisting of different combinations of candidate plants were analyzed. Choices of the combinations of candidate plants were made based on the screening curves in Figure 2.12. Geothermal plants and imports formed the base sequence to which combinations of Coal, Medium Speed Diesel, Gas Turbine and Combined Cycle plants were added in varying amounts at different commissioning dates as required to meet forecast demand.

The competitiveness of Medium Speed Diesel, Gas Turbines and Combined Cycle plants were initially performed. Simulation results indicated that cases containing all the three types of plants in varying capacities were more competitive that those with only one or two of these types. More analysis enabled elimination of the less competitive cases leading to convergence to sequences with capacity levels. These sequences were analyzed further by varying the timing of addition of each type of these plants through a process of advancing, delaying and swapping. The results obtained sorted in ascending order of their Present Worth Costs are shown in Table 2.6.

Table 2.8.7.1 Table 2.6: The LCP 2007 Simulation Results

		Key Additions Excluding Committed Projects (MW)						**PWC to 2058** (million USD)
	Case Code	GEOT	IMPORT	COAL	MSDs	GTs	CCs	
1	GCGTDL8a	490	900	1,000	630	170	540	6,045
2	GCGTDL8	490	900	1,000	700	80	540	6,054
3	GCGTDL7	490	900	1,100	620	80	540	6,181
4	GCGTDLa	490	1,100	1,100	360	80	540	6,184
5	GCGTDL6	490	900	1,100	620	80	540	6,188
6	GCGTDL5	490	900	1,100	700	260	270	6,195
7	GCGTDL4	490	1,000	1,100	600	260	270	6,216
8	GCGTDL0	490	900	1,100	600	80	540	6,232
9	GCGTDL9	490	800	1,200	620	80	540	6,233
10	GCGTDL1	490	900	1,100	680	80	540	6,237

(Source: LCPDP 2007)

Key:

GEOT:	Geothermal Power
MSD	Medium Speed Diesel
GT	Gas Turbine
CC	Combined Cycle Power
IMPORT	Power Imports
Coal	Coal Power Plant
HYDRO	Hydropower

The sequence coded GCGTDL8a had the lowest PWC. The main features of this sequence are addition of 100 MW coal in 2015 and 100 MW MSD in 2016 and an extra 90 MW GT above most of the other sequences coming in earlier. It also has moderate levels of medium speed diesel and combined cycle capacities. Sensitivity analyses to variation in crude oil and coal prices were performed on the top five cases to establish if there would be a shift in the economic ranking and the output presented in Table 2.7. The results indicate that with crude oil prices of the reference forecast, ranking of the sequences does not change for both low and high coal price scenarios. Thus the sequence with the lowest PWC under reference scenario still returns the lowest PWC for both low and high crude oil prices irrespective of changes in the price of coal.

Table 2.8.7.2 Table 2.7: LCP 2007 Sensitivity Analyses

Case Code	PWC (million USD)				
	R_OL_C	R_OH_C	L_OR_C	H_OR_C	H_OH_C
GCGTDL8a	6,018	6,098	5,974	6,283	6,336
GCGTDL8	6,029	6,105	5,982	6,299	6,350
GCGTDL7	6,150	6,243	6,111	6,399	6,461
GCGTDLa	6,155	6,242	6,114	6,399	6,457
GCGTDL6	6,157	6,250	6,118	6,406	6,468

(Source: LCPDP, 2007)

Key:

R_OL_C:	Reference Crude Oil, Low Coal
R_OH_C:	Reference Crude Oil, High Coal
L_OR_C:	Low Crude Oil, Reference Coal
H_OR_C:	High Crude Oil, Reference Coal
H_OH_C:	High Crude Oil, High Coal

Table 2.8 shows the least cost power development plan prepared in 2007 covering the period 2008-2028. More details on the composition of the least cost plan are shown in Table A6-2 in Appendix A6.

Table 2.8.7.3Table 2.8: The 2008-2028 Least Cost Power Development Plan

Year ending 30th June	Configuration	Description	Capital Cost (Mln US$)	Type	Added Capacity MW	Total Capacity MW	System Peak MW	Reserve Margin MW	Reserve Margin as % of Total Capacity
Existing 2007						1,045	1,082	-37	-4%
2008	2 x 30	Sondu Miriu			60				
	1 x 80	Gas Turbine		GT	80	1,185	1,153	32	3%
2009	6 x 15	Medium Speed Diesel		MSD	90				
		Olkaria III		GEO	35				
	-1 x 10	Fiat GT Retirement		GT	-10				
		Kiambere		HYDRO	20				
		Mumias Cogeneration		COGEN	25				
	1 x 35	Olkaria II 3rd Unit		GEO	35				
		Kipevu Combined		CC	30	1,410	1,206	204	14%
2010		Raising Masinga Dam		HYDRO	0				
		Tana Rehabilitation		HYDRO	19.6				
	2 x 330kV	Mombasa -Nbi	209.9	Line					
	1 x 20	Kindaruma 3rd Unit		HYDRO	20				-
	2 x 10.3	Sangoro		HYDRO	20.6	1,457	1,294	163	11%
2011	6 x 20	Medium Speed Diesel	139	MSD	120	1,577	1,398	179	11%
2012	1 x 70	Geothermal	171.3	GEO	70	1,647	1,508	139	8%
2013	1 x 100	Import		IMPORT	100	1,747	1,625	122	7%
2014	2 x 100	Import		IMPORT	200	1,947	1,749	198	10%
2015	-3 x 15	Olkaria I Retirement		GEO	-45				
	1 x 25	Olkaria I Replacement		GEO	25				
	1 x 100	Coal	195.6	COAL	100	2,027	1,881	146	7%
2016	1 x 70	Geothermal	171.3	GEO	70				
	5 x 20	Medium Speed Diesel	119	MSD	100				
	2 x 220kV	Olkaria-Nairobi	34	Line		2,197	2,021	176	8%
2017	4 x 20	Medium Speed Diesel	92.4	MSD	80				
	1 x 90	Gas Turbine		GT	90	2,367	2,171	196	8%
2018	1 x 100	Import		IMPORT	100	2,467	2,330	137	6%
2019	-6 x 12.5	Kipevu I Retirement		MSD	-75				
	4 x 20	Medium Speed Diesel	92.4	MSD	80				
	1 x 100	Coal	195.6	COAL	100				
	1 x 90	Gas Turbine		GT	90				
	2 x 330kV	Mombasa -Nbi	209.9	Line		2,662	2,499	163	6%
2020	-10 x 5.66	Iberafrica Diesel		MSD	-56.6				
	4 x 20	Medium Speed Diesel	92.4	MSD	80				
	1 x 70	Geothermal	171.3	GEO	70				
	1 x 100	Import		IMPORT	100	2,855	2,679	176	6%
2021	2 x 100	Coal	391.2	COAL	200	3,055	2,871	184	6%
2022	-7 x 10.57	Tsavo Diesel		MSD	-74.0				
	-1 x 90	Gas Turbine		GT	-90				
	3 x 90	Combined Cycle	156.7	CC	270				
	1 x 100	Import		IMPORT	100	3,261	3,076	185	6%
2023	2 x 100	Coal	391.2	COAL	200				
	2 x 330kV	Mombasa -Nbi	209.9	Line		3,461	3,294	167	5%
2024	1 x 70	Geothermal	171.3	GEO	70				
	4 x 20	Medium Speed Diesel	92.4	MSD	80				
	1 x 100	Import		IMPORT	100	3,711	3,527	184	5%
2025	2 x 100	Coal	391.2	COAL	200				
	1 x 90	Gas Turbine	49	GT	90				
	2 x 330kV	Mombasa -Nbi	209.9	Line		4,001	3,774	227	6%
2026	1 x 70	Geothermal	171.3	GEO	70				
	2 x 100	Import		IMPORT	200	4,271	4,038	233	5%
2027	-1 x 90	Gas Turbine		GT	-90				
	3 x 90	Combined Cycle	156.7	CC	270				
	4 x 20	Medium Speed Diesel	92.4	MSD	80	4,531	4,320	211	5%
2028	2 x 100	Coal	391.2	COAL	200				
	2 x 70	Geothermal	342.6	GEO	140	4,871	4,620	251	5%

(Source: LCPDP, 2007)

The summary of the approach used in preparation of the 2007 least cost plan and the results obtained provide an indication of the opportunities for improvement of the approach in view of the environmental objectives of the study and the optimization of the expansion plan. The more pertinent areas include the level of renewable sources in the plan and the capacity expansion planning process itself. The review also shows how the level of capacity of thermal power was arrived at in planning, this being pertinent to control of environmental emissions in the long term.

2.9. Summary of Literature Review

The literature review identified, in the context of the objective of the study, several factors that have influence on the level of environmental emissions in the Kenyan power system. In the short term, the generation mix arising from plant dispatch is one key emission determinant factor. The second factor is the amount of available hydro and geothermal energy that meets varying baseload demand. This determines the outputs from thermal power plants which supply the shortfall not met through the renewable sources. The review indicates that the thermal plants in the system are different and therefore have different characteristics including emission factors and generation costs at varying operation modes. Thus plant dispatch order also relates to emission levels at any given time.

The research papers studied elucidated various approaches used in the plant dispatch problem. Fuzzy theorem, genetic algorithms and dynamic programming techniques are key approaches in unit scheduling and plant dispatch with multi-objective criteria. A different approach was chosen for this research in which historical plant dispatch data and respective generation costs and emission factors were used.

The review also covered capacity expansion models and methodologies studied in order to project the objectives of the study to the long term. Three key areas of capacity expansion planning were reviewed: load forecasting, reservoir simulation and capacity optimization. The significance of each of these areas in relation to the planning process in Kenya is evident in the review.

Several options for supplying electricity to the expanding demand in Kenya were noted from the foregoing literature. Hydropower and geothermal potential resources can contribute significant capacity towards meeting the increasing electricity demand. Power imports from neighbouring countries can also play a major role in meeting future power needs of the country.

3. METHODOLOGY

This methodology applies to the three components of the study, sequenced to begin with identification of factors that influence the levels of emission in power supply, followed by modelling power plant dispatch and finally capacity expansion planning.

3.1. Identification of Factors Influencing Environmental Emissions

Review of relevant literature and power system data was necessary for identification of pertinent factors prior to the subsequent modelling studies. The generation mix of the country and thermal plants' emission factors for the various non-renewable electricity sources were leading factors. The level of output from thermal plants was studied based on data recorded by KPLC. This was undertaken in the perspective of dependability on the available renewable power from hydro and geothermal. Other important factors considered were the level of power generation demand and system losses over recent years as reported in KPLC's 2007 Annual Report. Environmental impacts associated with transmission of power were studied with reference to an Environmental Audit carried out on KPLC facilities in 2005 which provided relevant information on impacts from the lines. The various factors influencing emission levels were classified under direct or indirect and the influence level categorised further as low, medium or high level based on a criteria developed in this study for this purpose.

3.2. Plant Dispatch Study

The main activities in the dispatch study can be outlined as follows:

(i) Analysis of historical monthly power system dispatch operation and hydrological conditions in the year of study 2006;

(ii) Separation of the actual thermal generation component/requirement in the system;

(iii) Computation of average weekly demand requirements for each month of the year, for every half-hour for each typical day of the month, based on the half-hour data recorded by KPLC at the National Control Centre;

(iv) Modelling and simulation of alternative operation dispatch schedules to obtain optimal generation costs for each month of the year, considering an ideal dispatch and constrained plant capacity dispatch scenarios;

(v) Introduction of emission penalties in the models described in (iv) and simulation of new dispatch schedules aimed at reduced emissions from thermal power plants in the system;

(vi) Computation of energy outputs and associated costs for the actual and model dispatch cases;

(vii) Computation of environmental emissions for the actual and model dispatch cases;

(viii) Comparison of the outputs from the models with the computed outputs in (vi) and (vii); and

(ix) Developing discussions and drawing conclusions and recommendations from the findings of the study.

The dispatch data for year 2006 was selected for the study to represent a typical year being the most recent year before this study commenced with adequate electricity data and, based on the electricity outputs from hydropower plants, it had average reservoir inflows or normal rainfall. The year was also considered suitable since the level of the available capacity was close to the prevailing system demand and therefore suitable to avoid mismatch of capacity and demand skewed results. Ideally the baseload demand is first met using the cheapest sources of power, in this case hydro and geothermal. Additional demand is met through thermal sources which are called upon progressively beginning with the cheapest in a merit order dispatch. Other technical system requirements such as voltage and frequency levels are also of great importance in actual system operation. System operational data relating to generation and demand required for dispatch optimization were obtained from the National Control Centre and KPLC's Energy Purchase and Power System Planning Sections.

3.2.1. Plant Dispatch Data Analysis

The data required in this research was obtained from KPLC's databases in the Power System Development Department. The database contains daily operational data provided by the National Control Centre. Power system dispatch data is monitored and recorded every half hour and stored in Microsoft Excel. The components of the daily operation levels categorized into the baseload, day peak and the evening peak

Table A3-1 in Appendix A3 shows daily averages of power demand for each month of 2006 and illustrates the half-hourly records maintained by the NCC. Averages were calculated to enable manipulation of the bulky data in the modelling. Daily dispatch data provides the actual operation within a 24 hour period. This means that at any given time, one can determine the outputs from different power plants and therefore overall contributions from hydro, geothermal and thermal sources.

Historical output levels from thermal power plants were used to compute the required average thermal generation level in different months of the year. The thermal component of the 2006 demand data shown in Table A3-2 in Appendix 3 was removed from the overall daily half-hourly demand data. It was assumed that the output of the other sources were optimised leaving the balance to be supplied from thermal sources. Power imports from Uganda were treated as thermal in accordance with treatment given to the current power exchanges between the two countries. Averages were computed for every weekday in a month so as to obtain weekly representative demand for each typical day in a month. For example, to obtain typical weekday data for the Sundays in a month, the average half hourly demand data for all the Sundays in the month was obtained. A month was then represented by one week data to reduce the volume of data input and number of simulations required to be undertaken in the annual study.

Modelling was simplified for representative days for each month of the year through averaging values derived from actual daily dispatch data for 2006. The number of weekdays in each month was obtained from the calendar to enable the outputs from the simplified monthly models to be used to establish the generation per month and therefore the associated data. Table 3.1 shows the weekdays in each month of year 2006.

Table 3.2.1.1Table 3.1: Weekdays in Each Month of 2006

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Sundays	5	4	4	5	4	4	5	4	4	5	4	5
Mondays	5	4	4	4	5	4	5	5	4	5	4	4
Tuesdays	5	4	4	4	5	4	4	5	4	5	4	4
Wednesdays	4	4	5	4	5	4	4	5	4	4	5	4
Thursdays	4	4	5	4	4	5	4	4	4	4	5	4
Fridays	4	4	5	4	4	5	4	4	5	4	4	5
Saturdays	4	4	4	5	4	4	5	4	5	4	4	5

This approach enabled monthly data to be reduced to seven representative weekdays for each month. The results obtained after simulating a weekly dispatch operation were then extrapolated to cover a month. The underlying assumption in this case was that the demand levels for every similar weekday of a month were identical.

3.2.2. Dispatch Model Formulation

The choice of the next thermal plant to be dispatched depends on its availability and position in economic merit order hierarchy ranked by cost of generation and the level of demand. The geographical location of a generation plant relative to load distribution was considered important in dispatch. The general layout of the system was classified into five main generation centres, based on the actual distribution of the power plants:

- Tana cascade -hydropower plants,
- Olkaria -geothermal ,
- Mombasa -thermal ,
- Nairobi -thermal , and
- Western generation –Turkwel hydro, Eldoret emergency plant and imports.

Figure 3.1 illustrates the layout of the system's main generation centres across the country as visualised in this study based on the known geographical locations of the existing plants.

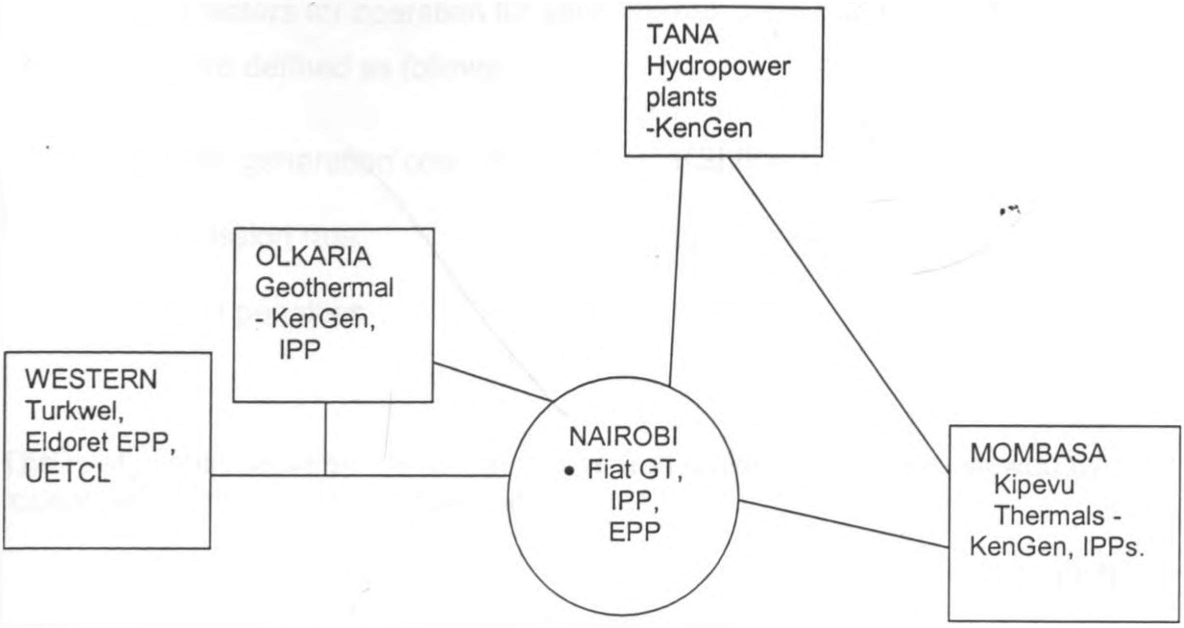

Figure 3.2.2:1:Figure 3.1: Simplified System Layout showing the Main Power Generation Centres in Kenya

It was necessary to obtain the desired thermal capacity output for given forecast demand at any given point in time. The thermal power requirement was determined by subtracting the hydro, geothermal and import capacity available. Depending on the geographical location of a given power plant, a certain minimum thermal supply required for voltage support and general system stability were derived from the half hourly generation data of year 2006 since the model was not analytical so as to deal with the complexity of power flow dynamics. The actual data was used to deduce and develop the operational criteria suitable for the system and therefore formed a basis for dispatch of thermal power plants. Constraints were introduced each half-hour to ensure some generation occurred in three main geographical load centers, Mombasa, Nairobi and Western (represented by Eldoret) for voltage support. The central part of the country was assumed to be supported adequately from the Tana cascade power plants. The regional demand constraints were estimated by studying the daily half-hour data and deriving the averages in Tables A3-3 through to A3-5. Minimum outputs from the plants located in the selected regions were set such that even when demand was low, some local generation had to be availed as necessary. The operating limits for both plants and regional demand requirements were factored in the model as constraints to ensure that they were regarded alongside dispatch optimization of cost of generation and the associated emissions.

The pertinent factors for operation for each thermal plant with environmental constraints were defined as follows:

Unit plant generation cost	=	C_i	KSh/Kwh
CO_2 emission rate	=	R_i	tonnes/Kwh
Emission penalties	=	T_i	KSh/tonne

The relationship between the factors above and emissions, S, were viewed by the researcher as defined by the function:

$$S = f(C_i, R_i, T_i) \qquad [3.1]$$

At any given time, the total thermal output (F) in MW required in the system was derived as:

$$F = D - (H + G + I) \qquad [3.2]$$

Where,

D = System energy demand in MW

H = Hydro output, MW

G = Geothermal output, MW

I = Imports, MW

To determine the total cost of generation from thermal power plants based on the equation [2.1], for each half hour period the cost of generation, C_e, in KSh from all n thermal plants can be estimated by:

$$C_e = \sum_{i=1}^{n} C_i \times F_i \times 1000 \times 0.5 \qquad [3.3]$$

Where,

F_i is the output form thermal i, where i = 1, 2, ….n.

The incremental pollution penalty in KSh/kWh for a given plant producing F_i MW costs in a half hour was computed as follows:

$$T = F_i \times 1000 \times 0.5 \times R_i \times T_i \qquad [3.4]$$

The economic objective function therefore, aimed to;

$$\text{Minimise } \left(\sum_{i=1}^{n} C_i \times F_i \times 1000 \times 0.5\right) \qquad [3.5]$$

Introducing the environmental penalties, the objective function becomes;

$$\text{Minimise } \left\{\left(\sum_{i=1}^{n} C_i \times F_i \times 1000 \times 0.5\right) + \left(\sum_{i=1}^{n} F_i \times 1000 \times 0.5 \times R_i \times T_i\right)\right\} \qquad [3.6]$$

To be able to effectively simulate the twelve months of the year, four sets of models were built. This was necessary because some emergency capacity was introduced in June 2006 to avoid foreseen power shortfalls. A part of that emergency capacity was later moved to Eldoret to help address voltage stability in the western region. The first model covered January to May and the second one June to cater for the emergency plant introduced in Nairobi. The third model was designed for October while the fourth covered July, September, November and December. October had rather high thermal generation and had to be treated separately. This categorization enabled the constraints of the system to be modeled so as to closely replicate the actual situation in the year.

Two sets of data were assembled: An ideal case where the outputs from individual plants were not limited to a given level such that the maximum output was always available and more realistic case where capacity constraints imposed on the thermal plants to limit plant availabilities to a maximum of 85%. This was found necessary so as to first have an ideal situation where the most economic plants could be dispatched regardless of the region. The ideal case was thereafter modified to factor in environmental penalties imposed on thermal plants in accordance with the emission factors. The emission factors for the thermal plants were calculated based on data from the year 2000 Least Cost Power development plan. The factor for the EPP plant was estimated to be the same as that of Iberafrica power plant since it has comparatively smaller units and utilizes low sulphur fuel.

The generation costs associated with the two dispatch models were computed within the simulation of the model and recorded half-hourly for the typical week in a month. The demand computation shown in equation [3.2] was based on the assumption that each demand level was sustained for each half hour. The same assumption and formula was used in calculating the cost of the actual dispatch in 2006. All candidate thermal plants were subjected to an environmental tax of US$ 10 per tonne of Carbon Dioxide released, the rate applied in least cost power planning (LCPDP, 2007) in Kenya. This was added to the variable operation and maintenance cost of a plant. Emissions from each plant were obtained using the plant emission factors multiplied by the energy output from each plant and summed up for the entire week in a month. Accruing emissions penalties were then computed based on plant heat rates and US$10/tonne of CO2 and then converted to Kenya shillings at an exchange rate of Sh 67 per Dollar match the currency used in computing generation costs in this study. This is the penalty imposed on thermal power plants in Kenya's capacity expansion planning so as to give advantage to candidate renewable energy resources. The total cost of thermal based generation was therefore a summation of costs incurred by all thermal plants operating within the half-hour periods, as given in equation [3.10]. Below is a sample calculation to determine the emission penalty for 75 MW Diesel power plant, using the data from LCPDP, 2007:

Emission penalty for the plant is given by:

$$P = H \times C \times T_c \times 67 \qquad \text{Sh/kWh} \qquad [3.7]$$

Where,

H Plant Heat Rate in kJ/kWh

T_c = CO_2 Tax, $/tonne

C = Plant's Emission Factor in ton/kJ

For the Diesel Plant,

H = 8,800 kJ/kWh

C = 0.075 ton/GJ

T_c = 10 $/tonne

Emission per kWh generated,

$$E_f = 0.075 \times 8{,}800/1000{,}000 \text{ Tonne/kWh} \quad [3.8]$$
$$= 0.00066 \text{ tonne/kWh}$$

Therefore,

$$P = (0.00066 \text{ tonne/kWh}) \times (10 \text{ \$/tonne}) \times 67 \quad [3.9]$$
$$= 0.44 \text{ Sh/kWh}$$

The computed per unit emission penalties were added to each plant's generation cost in the various models. Simulations were then carried out as done in the economic dispatch cases and the results obtained analyzed in terms of costs and emissions.

3.2.3. The Dispatch Model

The conceptualised model to realize the objectives was expected to first compute the cost function developed for the dispatch to result in minimum generation costs for a given set of conditions. The model was then modified to include penalties on environmental emissions. Other pertinent system requirements were expected to provide a set of constraints for the program.

The Solver tool in Microsoft Excel was initially used to study the feasibility of building the optimization model minimizing the total generation cost with a given set of generation capacity limits imposed on power plants with regional demand requirements modelled as constraints. Solver had limitations in that it could only handle one value of data at a time and could not be linked to a database for either input or output data manipulation. The search for a more suitable tool led to identification of logical programming language (LPL), a structured mathematical program which allows one to build, maintain, modify and document large linear, non-linear and other mathematical models (Hurlimann, 2003). It allows one to automatically create different input files for linear models or some evaluation code for an optimization software package. LPL also contains an innovative input and report generator, which allows the user to input data from different files and database tables and to write the results to files, databases or reports.

Based on the objectives of the dispatch optimization part of this research, the model was initially considered adequate for writing a program to solve the first two objectives:

(i.) Economic dispatch optimization and

(ii.) Minimization of CO_2 emissions through penalties

Reduction of CO_2 emission was considered as adequate illustration of air pollution abatement in general, representing other forms of similar emissions since the respective emission factors can be varied accordingly. The LPL model was able to make the necessary computations for one set of data covering one half-hour period out of the targeted one day operation. The program was configured to write some of the desired outputs at the end of the operation. The initial Economic Dispatch Model in the LPL program prepared is shown in Appendix A1.

The LPL program downloaded from the Internet however, had limitations pertaining to proprietary rights on duration of free usage. The model objective was transferred into a Mixed Integer Linear Programming (MILP) program, Lp_solve, for continuation. Lp_solve is a free linear (integer) programming solver based on the simplex method and the Branch-and-Bound method for the integers. It contains full source codes, examples and manuals. The program solves pure linear, (mixed) integer/binary, semi-continuous and special ordered sets (SOS) models and has no limit on model size. It is basically, a library, with a set of routines called the API that can be called from almost any programming language to solve MILP problems. The library can be called from different languages like C, Visual Basic, NET, Delphi, Excel and Java. The solver was used to develop the new model to carry out simulations for a whole set of daily demand data for every day of the week, each day representing a typical weekday in the month.

The dispatch model was formulated for every half-hour based in the following cost objective function:

$$\mathrm{Min}(7.95X_1 + 5.6X_2 + 19.84X_3 + 19.84X_4 + 29.2X_5 + 9.01X_6 + 13.84X_7 + 15.6X_8 + 18.98X_9) \times 0.5 \qquad [3.10]$$

where the coefficients represent respective costs of generation (Sh/kWh) and X_1 - X_9 represent outputs (MW) from the dispatchable power plants in the syetm, namely, Kipevu Diesel, Tsavo, Iberafrica, Kipevu GT1 Kipevu GT2, Nairobi South Fiat Gt, Aggreko Embakasi, Aggreko Eldoret and Uganda Imports, respectively, subject to the constraints given in Appendix A2. To use this model in the user interface developed for LP_Solve Dynamic Link Library (DLL), the model was represented in a matrix form.

3.2.4. Verification and Validation of the Dispatch Model

The models built and their operations and outputs were studied so as to verify if they operated correctly as conceptualized and sufficiently represented the real system. The outputs expected from each run included daily machine outputs in MW for each week representing a given month of the year. The models were modified, ran and readjusted again after observation of outputs and comparison with the expected results from the actual data. New model constraints and month-specific models were made as required and applied to ensure each model performed as intended. Comparisons of model outputs with the actual 2006 dispatch eased the verification and validation process. The ideal and the limited availability cases were compared with the actual dispatch outputs in terms of electricity generation, unit costs and total CO_2 emissions. The results were analysed graphically to ease visualization and interpretation. Interpretations were done and conclusions and recommendations drawn based on the results obtained and comparisons made.

3.3. Capacity Expansion Study

This part of the study had the objective of reviewing the national power development plan, establishing the expected environmental emissions from the recommended plan and remodelling it to reduce emissions levels through determination of an alternative plan. The key activities in this section included:

(i) General review of previous least cost power development plans and other relevant studies;

(ii) Identification of environmental concerns from various sources of electricity;

(iii) Researching on opportunities to factor in environmental considerations in capacity expansion planning;

(iv) Remodelling the current development plan to develop a greener economic alternative least cost plan;

(v) Analyzing alternative plans and selection of an optimal least cost plan with lower emissions than the current least cost plan;

(vi) Comparison of emission levels and economic costs of alternative development plans;

(vii) Developing discussions, conclusions and recommendations from the findings of the study.

The main reference studies in this research were the power development plans for the periods 1986-2006, 1991-2011 and the recommended plan in the 2008-2028 update prepared in 2007. Models and data files in the 2007 update were used as the basis for the study. In order to enable simulation of the plan in the WASP optimization model, the load forecast data was converted to a format allowing establishment of the annual load duration curve. Hydrological data and files developed in 2005 were reviewed for this application. Power plants were modelled and coded into the WASP software.

3.3.1. Planning Criteria and Assumptions

The following criteria and assumptions were made in the simulations undertaken to determine the least cost plan: The generation system reliability criteria under critical drought were set at 10 days per year loss of load expectation (LOLE); and the annual maximum expected 'unserved' energy EUE of 0.1% of system energy demand. LOLE indicates that the capacity available in any given year was adequate to meet demand in all other days of the year except ten days. The energy not served (EUE) in the ten days was equivalent to 0.1% of the total annual energy required by the system. The expected unserved energy was priced at 0.84 US$ per kWh, which can be interpreted as the cost to the economy due to the shortage in supply of the required energy. A discount rate of 12% was used in this development plan, as is the case with many other economic analyses and studies in Kenya.

3.3.2. Re-valuation of the 2008-2028 Least Cost Plan

The 2007 least cost expansion plan previously obtained through simulations with the GENSIM model, was used as the base case in remodelling with the WASP optimization software. The candidate projects identified from the screening curves to have comparatively lower generation costs were availed to the model to enable selection of the optimal plan from the possible combinations. Two hydropower candidates were also considered in the re-evaluation. The WASP model was ran to investigate the cheapest way to develop the system without imposing limitations on emission levels.

The results obtained from simulations in WASP were examined against the practicable development least cost plan obtained using the GENSIM model in order to gauge the feasibility of the alternative plan while considering the environmental objectives of reducing emissions through introduction of more renewable sources such as geothermal and hydropower plants. The optimal plan was remodelled to accommodate desirable features of the WASP output. The existing system and committed additions and retirements were common in subsequent sequences developed in the analysis. Adjustments were made to accommodate the good features of the WASP optimal solution. A geothermal plant was first successfully advanced from year 2016 to 2015 and some 50 MW import added in the same year to displace the first coal plant proposed for installation in the 2007 plan. The next step was introduction of the 140 MW Low Grand Falls in the location pointed out by the WASP model. The sequence was refined further downstream in line with the study's objective. Several sequences were analyzed in varying capacity levels and staggered within the planning horizon as necessary. Simulation results were studied to identify the most competitive cases based on types of plants in varying capacities. More analysis enabled elimination of the less competitive cases leading to fewer sequences. These sequences were analyzed further by varying the timing of addition of each type of plant through a keen process of advancing, delaying and swapping candidates.

The most optimal plans were subjected to sensitivity runs in GENSIM to determine the variation of the Present Worth Costs (PWC) with fluctuations in coal and crude oil prices so as to determine the economic robustness of the greenest plan. The alternative development plan with fewer impacts was then determined. A comparative analysis on the two plans was done and discussed in the context of the objective of the study, that is, determination of an optimum economic expansion plan with lower environmental emissions.

3.3.3. Verification and Validation of the Capacity Expansion Model

Existing capacity expansion models were utilised in simulations, but new cases or expansion sequences were assembled and analysed to meet the objective of the study. Output files from simulations carried out provided a basis for validating.

The ability of a case to undergo the successful simulation and to satisfy forecast demand verified correct model operation. The decision to utilize WASP outputs in GENSIM was another measure that enabled comparison of results alternative sequences on a common benchmark. The range of the PWC of the recommended plan was compared with that of the least cost plan to establish the validity of the model outputs. The energy outputs from the various existing and candidate power plants as given by the model outputs were studied and compared with the expected levels and the least cost plan outputs to enable validation of the model operations and results.

3.4. Summary of Methodology

The pertinent factors that influence the level of environmental emissions were identified in the context of the power plant dispatch operation and power development planning. The basis of dispatch model was the objective function in equation 3.10 formulated for minimising the total thermal generation costs and emission penalties. Dispatch modelling was carried out using the Mixed Integer Linear Programming Model (MILP). The model was designed to enable simulation of a weekly dispatch every half hour. Constraints in demand and plant outputs were introduced to guide the dispatch operation to closely match real time operations. An ideal scenario was conceived and studied in which power plant availabilities were not restrained from reaching full capacity. A second scenario had the thermal plants maximum capacities capped at 85%. The models were adjusted to accommodate different unit generation factors for each plant corresponding to emission penalties imposed so as to disadvantage the highest polluters. The outputs from the model were compared with the actual dispatch in 2006.

The 2007 least cost power development plan was reviewed and remodelled in WASP to tackle the capacity optimization part of the study. The output from WASP was remodelled in GENSIM to develop an expansion plan with lower emissions. The reviewed plan was compared with the LCPDP 2007 in terms of PWC and the associated projected emission levels.

4. RESULTS AND DISCUSSIONS

Results from the three parts of the research, namely, identification of factors influencing environmental emission levels in power generation and supply, optimal plant dispatch and capacity expansion, are presented and discussed in this chapter.

4.1. Factors Influencing to Environmental Pollution

The varying levels of annual outputs by the various power plants indicated the levels and mix of generation outputs as shown in Figure 4.1.

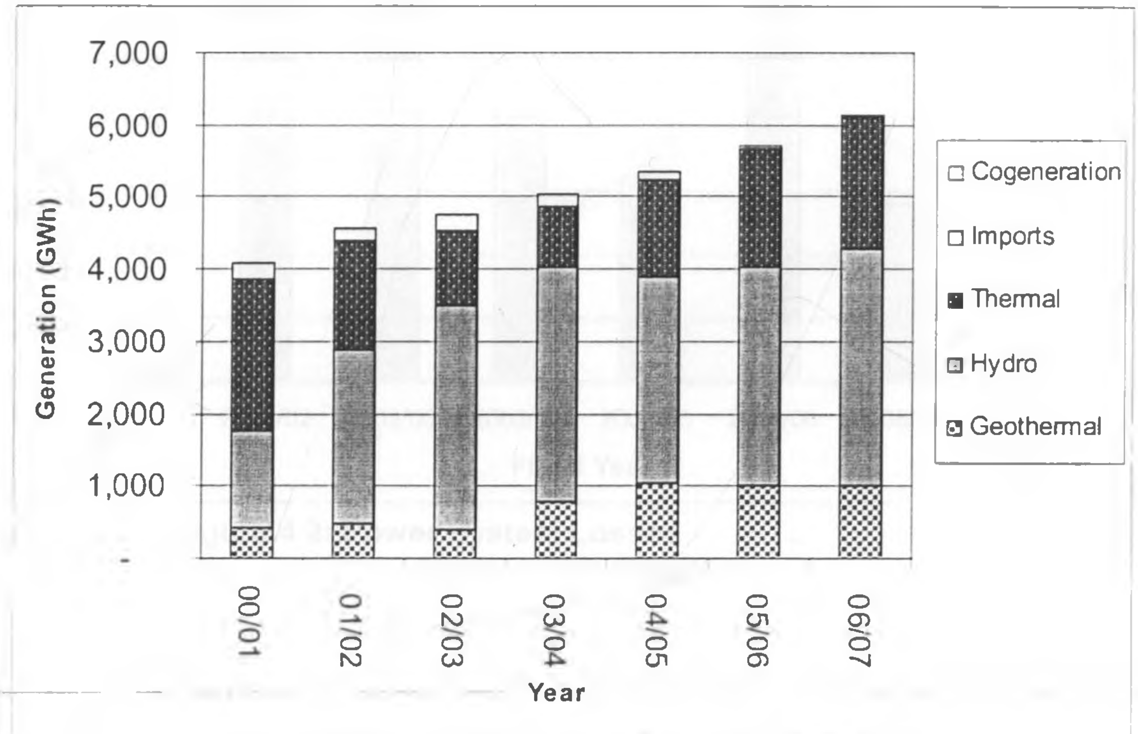

Figure 4.1:1Figure 4.1: Historical Generation by Type
(Source: KPLC 2007)

The graph shows that the available hydro and geothermal outputs influence the magnitude of output from thermal plants. The hydro output in 2000/01 was seen to have been very low but stable in subsequent years. Output from thermal plants was found to be increasing with growing electricity demand, while the geothermal and hydro outputs varied only slightly in the more recent years. This implies that the level of CO_2 emission is increasing annually. Growth in demand by was also seen as a factor that leads to additional generation which could be met from any of the sources depending on the prevailing circumstances.

Power system losses constitute a significant part of electricity generated in Kenya. Figure 4.2 shows that the loss level has improved from 20.5% in 2001/2 to 17.9% in 2006/07. Considering that thermal power provides the peaking component of energy which is not met by the renewable baseload power plants, loss levels contribute to the total environmental impacts and the cost of energy supplied.

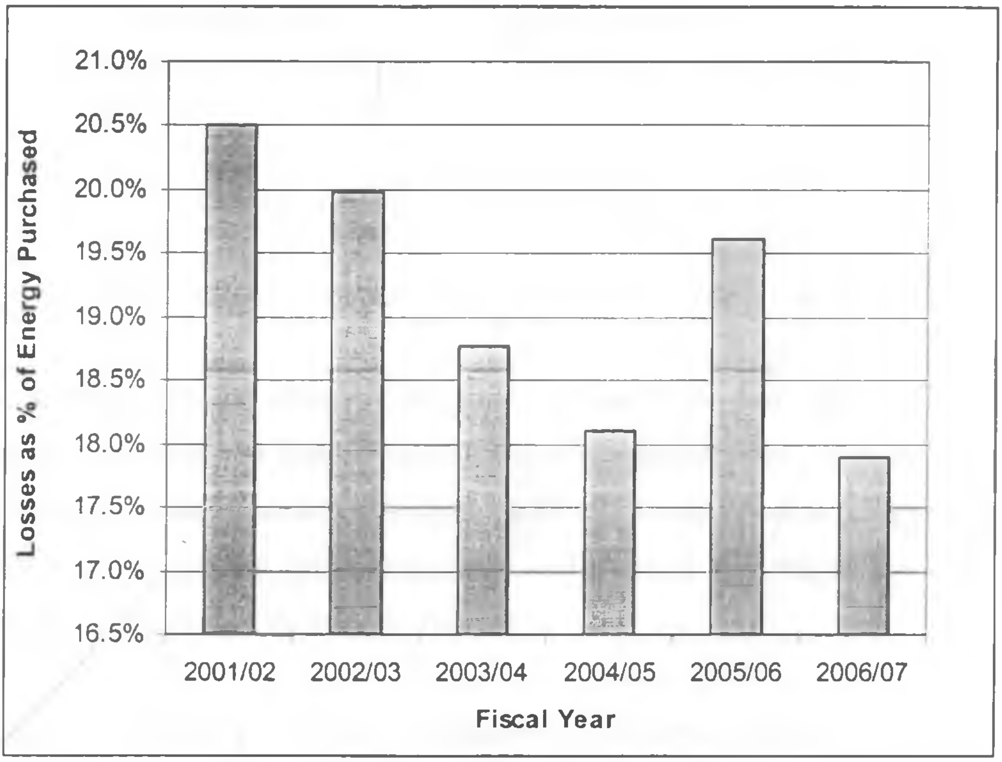

Figure 4.1:2:Figure 4.2: Power System Losses
(Source: KPLC 2007)

Power transmission and distribution lines mainly cross through unsettled areas along forests. The immediate physical environment of the transmission line paths consist of trees, valleys and some human settlements in a few sections. However, distribution lines are closer to consumption points, cross through populated residential areas, industrial areas and business centres. Trees and other vegetation that lie along the line routes are usually trimmed to maintain safe clearance from live conductors. Reduction of the vegetation cover is known to be equivalent to reducing the carbon sink since trees absorb carbon dioxide. Since vegetation cover regenerates between the trimming cycles, the impact is partly mitigate, which is in agreement with the KPLC Environmental Audit Report (LOG, 2005).

The level of significance influence on the level of emissions for the various sources of generation, growth in demand and the power losses were assessed and categorised as either low, medium or high under the criteria developed shown in Table 4.1.

Table 4.1.1Table 4.1: Categorization of and Rating Factors

Direct Influence		Indirect Influence	
% of total Generation	Influence Rating	% of total Generation	Influence Rating
≤5%	Low	≤10%	Low
5%≤10%	Medium	10%≤20%	Medium
>10%	High	>20%	High

The average composition of electricity generation and losses over the total generation for the last three financial years were analysed. The factors identified to influence emission levels associated with electricity generation and supply in the Kenyan power system are summarised in the table 4.2, based on their levels of influence and whether directly or indirectly.

Table 4.1.2Table 4.2: Factors Influencing Environmental Emissions

Factor	3-Year Average Level	Mode of Impact	Influence on Emissions Level	Remarks
Thermal generation	28%	Direct	High	Contributes 28% of total electricity supplied
Hydropower generation	53%	Indirect	High	Absence would lead to high thermal generation
Geothermal generation	18%	Indirect	Medium	Absence would lead to high thermal generation
Imports and cogeneration sources	1%	Indirect	Low	Imports and cogeneration
Electricity Demand	7%	Indirect	Low	Growth could be met from a mixture of the sources
Power transmission and distribution efficiency	18.5%	Direct	High	Inefficiency would results in high thermal generation

The level thermal generation and the available hydro were both seen as key determinants of cost of generation and the level of emissions. Power system losses also have considerable influence on both cost and emission levels. However transmission loss formulations are involving and time consuming (Nanda *et al.*, 1992) and could not be fully covered under this study. Growth in demand and the level of imports were seen to have low influence in the assessment based on historical data as they provide room for intervention based on their percentage rating, while geothermal influence rating as medium due to the current contribution to the system. The study was therefore directed towards plant dispatch and capacity expansion for the long term which also addresses demand growth and renewable sources.

4.2. Plant Dispatch Study

The model developed is represented in a matrix format in Table 4.3. The data on the right hand side (RH) represent MW and was subject to change depending on specific demand levels, plant capacity and constraints (abbreviated contr) stored in data files outside the model and corresponding to the months of the year as shown in Table 4.4 and Appendix A3-2. The models made for the specific periods of the year to match prevailing system conditions are presented in Appendix A4.

Table 4.2.1Table 4.3: The Optimal Dispatch Model

	KPD1	KPD2	KGT1	KGT2	FIAT	IBA	AKNBI	AKELD	UETCL	INQ	RH
Obj:Min	3.98	2.8	9.92	9.92	14.1	4.5	6.92	7.8	9.49		
Contr1	1	1	1	1	1	1	1	1	1	=	145
Contr2	1	1	1	1	0	0	0	0	0	>=	44
Contr3	1	1	1	1	0	0	0	0	0	<=	197
Contr4	0	0	0	0	0	0	0	1	0	>=	10
Contr5	0	0	0	0	0	0	0	1	0	<=	36
Contr6	0	0	0	0	1	1	0	0	0	>=	18
Contr7	0	0	0	0	1	1	0	0	0	<=	66
Contr8	1	0	0	0	0	0	0	0	0	<=	63
Contr9	0	1	0	0	0	0	0	0	0	<=	72
Contr10	0	0	1	0	0	0	0	0	0	<=	30
Contr11	0	0	0	1	0	0	0	0	0	<=	30
Contr12	0	0	0	0	1	0	0	0	0	<=	10
Contr13	0	0	0	0	0	1	0	0	0	<=	56
Contr14	0	0	0	0	0	0	1	0	0	=	0
Contr15	0	0	0	0	0	0	0	1	0	=	0
Contr16	0	0	0	0	0	0	0	0	1	<=	2
Contr17	1	1	0	0	0	0	0	0	0	<=	125
Contr18	0	0	0	0	1	1	0	0	0	<=	66

Table 4.1Table 4.4: Sample One Week Model Input Data (MW) and Model Constraints

Time	0.30	1.00	1.30	2.00	2.30	3.00	3.30	4.00	4.30	5.00	5.30	6.00	6.30	7.00	7.30	8.00	8.30	9.00	9.30	10.00	10.30	11.00	11.30
Sunday	201	206	204	202	196	193	191	189	188	199	200	202	201	201	204	207	208	195	192	192	197	194	192
Monday	200	200	191	186	174	173	172	173	176	182	186	188	188	188	192	195	195	185	184	187	186	185	181
Tuesday	186	182	180	176	175	176	175	173	175	179	184	187	190	188	192	192	193	187	184	187	187	191	190
Wednesday	206	208	207	206	207	208	202	201	202	205	209	209	209	207	207	198	201	198	198	198	198	201	193
Thursday	199	197	195	194	195	194	190	192	192	189	186	189	188	190	199	198	199	194	194	192	194	198	200
Friday	202	200	201	201	197	201	199	201	201	205	208	207	208	202	201	202	206	196	196	199	197	193	193
Saturday	203	202	204	204	203	200	197	197	200	199	204	201	205	200	202	206	207	200	196	196	199	197	197
CoastGenMin	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
CoastGenMax	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177
EldoretGenMin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EldoretGenMax	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NairobiGenMin	17	17	17	17	15	14	14	14	15	16	24	32	41	47	47	47	49	50	50	50	50	50	48
NairobiGenMax	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66

Time	12.30	13.00	13.00	13.30	14.00	14.30	15.00	15.30	16.00	16.30	17.00	17.30	18.00	18.30	19.00	19.30	20.00	20.30	21.00	21.30	22.00	22.30	23.00	23.30
Sunday	191	197	197	195	198	196	196	190	193	193	190	193	196	204	210	209	209	209	211	211	205	211	212	208
Monday	182	184	184	190	190	188	187	184	182	185	187	192	193	201	200	202	202	205	207	207	207	197	199	195
Tuesday	192	193	193	192	184	194	197	193	190	197	198	198	199	204	205	203	203	209	207	211	213	210	212	210
Wednesday	192	195	195	200	198	196	195	196	198	199	201	200	205	202	206	209	212	213	213	213	210	206	206	203
Thursday	202	200	200	200	198	198	199	200	198	198	201	204	203	205	210	200	199	203	203	206	206	207	207	205
Friday	198	197	197	194	194	193	190	189	193	193	195	197	201	205	206	205	208	209	211	211	209	211	213	210
Saturday	198	199	199	202	204	204	179	189	194	192	193	194	197	202	204	202	205	203	203	206	204	207	203	204
CoastGenMin	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
CoastGenMax	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177
EldoretGenMin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EldoretGenMax	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NairobiGenMin	48	48	48	48	48	48	48	48	48	48	48	48	49	49	49	49	49	49	49	49	47	46	45	38
NairobiGenMax	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66

(Source: KPLC

The Ideal Dispatch and the Limited Plant Availability dispatch models developed were simulated on the basis of the dispatch objective presented in equation 3.10 and the following two conditions:

- Optimised economic dispatch
- Optimised economic environmental dispatch

Electricity generation costs were derived on the view that they mainly comprise of energy charges, fuel costs and capacity charges, where energy costs are paid for every unit purchased from a plant, while fuel costs are incurred on fuel used to generate one unit of electricity. Capacity charges which form the third component of the energy price costs, enable recovery of investments made and are usually in \$/kW/yr which is convertible to \$/KWh at given plant utilization factors. Capacity charges were omitted in determination of the merit order of dispatch since they must be paid as long as the plant is available to enable recovery of investment costs regardless of whether the power plant is dispatched or not. KenGen and three Independent Power Producers contribute to the national grid. IPPs have capacity charges which enable recovery of investment costs but the current contract between KPLC and KenGen does not contain a capacity charge component although this may be introduced if recommendations from a recent tariff study are implemented (Fichtner, 2006).

4.2.1. The Ideal Dispatch Model

Economic dispatch runs performed on the ideal model gave average daily electricity generation for each week in a year, which were then used to calculate the monthly generation costs. Figure 4.3 shows average generation costs incurred in each typical weekday in respective months of the year, as computed from the outputs of the models. The weekly outputs were then used to derive the monthly generation costs for the various power plants in the system.

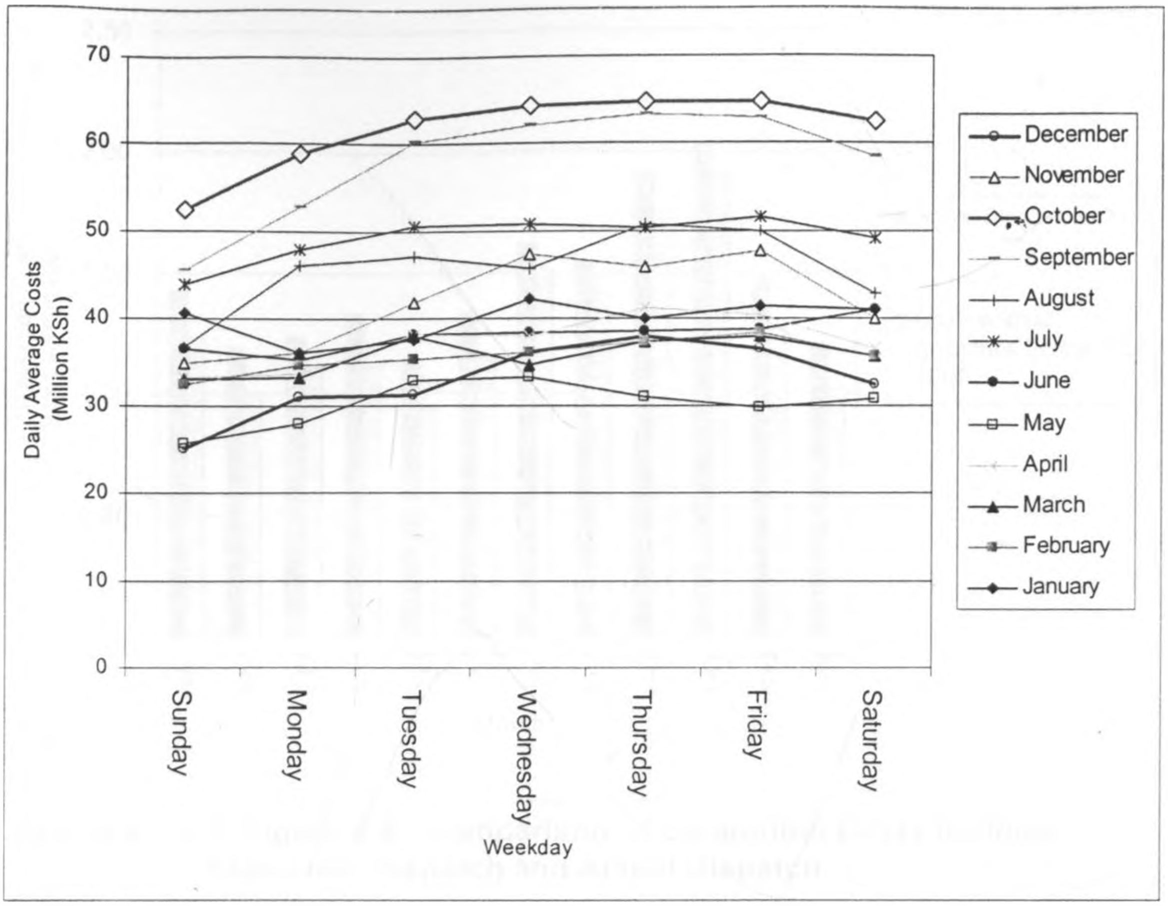

Figure 4.2.1:1::Figure 4.3: Daily Average Generation Costs for Ideal Optimised Economic Dispatch

Figure 4.4 gives a comparison of the actual 2006 monthly generation costs and those computed from the results of the ideal optimal dispatch model. The results indicate that the output from the ideal model followed the actual dispatch consistently throughout the year. It shows that under the ideal dispatch situation, the model maximises on the cheapest plants, running little or none of the expensive plants throughout the year. This is in agreement with the desired operation in an actual hydro-thermal power system, albeit optimistic. Considering that the problem of finding the optimal solution, as described by Meier (2005), is a balancing act between accurately simulating the real world, and providing enough simplification and constraints to allow a mathematical solution in a reasonable time, the model output is acceptable.

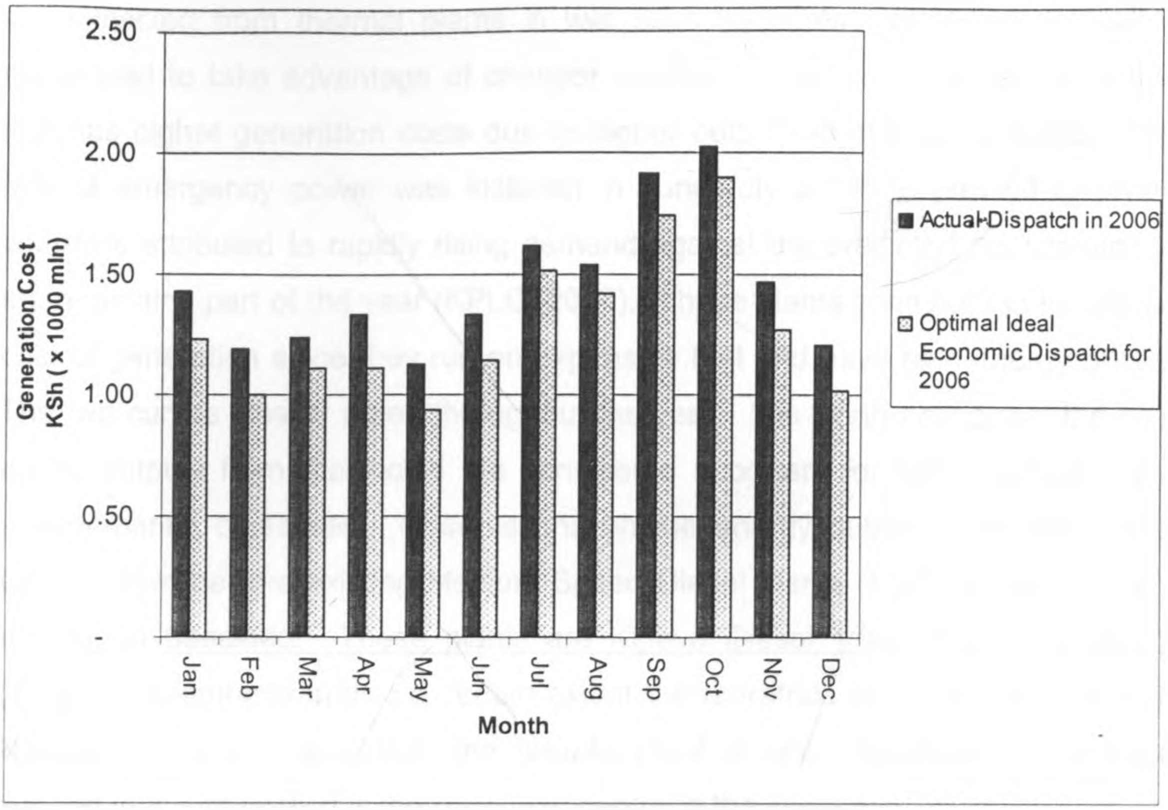

Figure 4.2.1:2::Figure 4.4: Comparison of Generation Costs for Ideal Economic Dispatch and Actual Dispatch

The computed cost of actual energy generated in 2006 for the ideal optimal case was KSh 17,332 millions or US$ 258.7 millions when converted at an exchange rate of KSh 67 per US Dollar, compared to KSh 15,389 millions or US$ 229.7, equivalent to a savings of US$ 29 million. This saving is appears high but this was not surprising because the simulations could not take into consideration all other prevailing factors that influence the choice of plant in an actual operating environment such as plant outages and voltage support needs. The results therefore present an ideal operation situation desired by any operator. The case forms a benchmark for subsequent modelling and analysis work and validates the model design and operation in view of desired optimal dispatch modelling.

Power demand variations in the two situations are seen to be varying in a similar manner throughout the year, therefore reaffirming consistence in model operations. The dispatch indicates that the actual operation varied as expected with requirement for thermal generation in different months. The annual pattern of operation of power plants is consistent with the average annual rainfall pattern in the Kenyan system. In a normal year short rains are experienced around November while the long rains are revived between March and May. Low outputs are expected from thermal plants in wet seasons when hydropower output is maximised to take advantage of cheaper energy. June to October is the period that has higher generation costs due to higher outputs from thermal plants. 100 MW of emergency power was installed in June-July 2006, to prevent foreseen shortfalls attributed to rapidly rising demand against the predicted poor rainfall in the remaining part of the year (KPLC, 2007). These plants contribute to increased cost of generation since they run on expensive fuel and have high energy prices. The two curves closely agree throughout the year. It is worth noting that the cost based outputs from the model are considered important for both economic and environmental objectives. Observations on the energy outputs from the power plants show that the existing Medium Speed Diesel plants (MSD) should be kept running at baseload. These plants are Kipevu Diesel 1 and Kipevu Diesel 2 (Tsavo) in Mombasa and to a certain extent the Iberafrica Power Plant located in Nairobi. In actual operation, the Nairobi plant is also dispatched for voltage support in the city which is the main load centre in the system.

The results show that the installed capacity in 2006 was sufficient to meet demand most of the time without the two 30 MW gas turbine in Mombasa (Kipevu GT1 and GT2) and the 10 MW Fiat GT located in Nairobi. Practically this is not the case because a power system is operated with consideration of other underlying pertinent factors that enable the power system to remain stable and maintain the quality of supply. In brief, these are dynamics of voltage and frequency in the power system. The desired frequency in Kenya is 50 Hz with a plus or minus 2%. Under-frequency loadshed measures are designed to be instituted automatically should the frequency drop below 50 Hz. These are in three stages with the first load shedding occurring at 49.0 Hz, 48.5 Hz and 48.0 Hz respectively. In order to maintain voltage and frequency at desired levels, the dispatch operation has to be carried diligently. A plant in Mombasa can therefore be dispatched despite its high unit cost so as to support voltages and frequency in the region. On the other hand, over-frequency is controlled by reducing outputs from machines in the system. This can lead to reduction of the output from a cheaper unit in a given region flouting the economic merit order dispatch.

In order to accomplish the environmental objective in the ideal case, the model's parameters were set as in the ideal economic model discussed above but higher unit costs were introduced to penalise emissions. The emission penalty of US$10/tonne of CO_2 applied in national power development planning in Kenya (LCPDP, 2007) was used in determination of plant specific penalty rates per tonne of CO_2 emitted per kWh generated by the plant were calculated based on the heat rate and specific fuel consumption of each plant, resulting in equation 4.1.

$$\text{Min}(8.39X_1 + 6.04X_2 + 20.57X_3 + 20.57X_4 + 30.21X_5 + 9.37X_6 + 14.2X_7 + 15.96X_8 + 19.34X_9) \times 0.5 \quad [4.1]$$

The economic model was expected to follow a merit order dependent on the resultant unit generation cost. In this scenario, most of the expensive plants were increasingly more polluting and therefore plants did not swap positions so as to affect the merit order dispatch. Figure 4.5 shows the results from the ideal model with environmental penalties incorporated in all thermal plants to discourage operation of the more polluting plants. The graphs show the incremental costs due to the penalties imposed raise the daily generation costs for all the months in the year, the highest being incurred in October when thermal generation was highest.

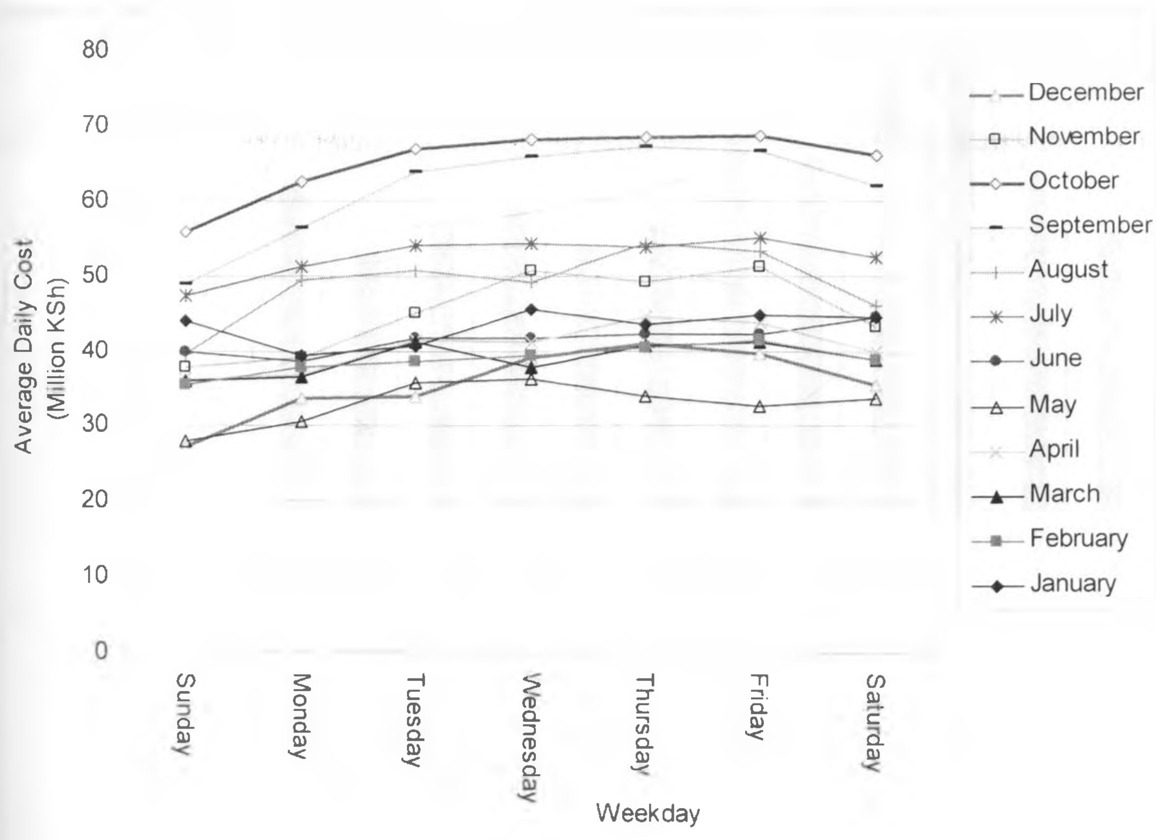

Figure 4.5: Daily Generation Costs for Ideal Environmental Dispatch

Figure 4.6 compares the actual 2006 generation costs with those returned by the ideal environmental dispatch output. This simulation followed the pattern of the ideal case with a nearly uniform shift throughout the period equivalent to the impact of the penalty. The incremental costs however led to additional generation cost. The total generation costs was equivalent to US$ 247.5 million, which is US$ 11.2 million or 4.3% less than the actual 2006 costs. This level of savings realized was comparatively high and can again be attributed to the fact that plant dispatch could not factor in all other technical variable constraints existing in normal operation such as voltage support needs, but nonetheless signifies success in optimal dispatch modelling. Regional constraints imposed to ensure the level of generation from the three main regions, Mombasa, Nairobi and Eldoret were set so as to make the model closely follow the actual dispatch. The arising difference from the actual situation can mainly be attributed to plant availabilities and other dynamic factors such as transmission network constraints that require some plants to be dispatched due to other system constraints such as power flow.

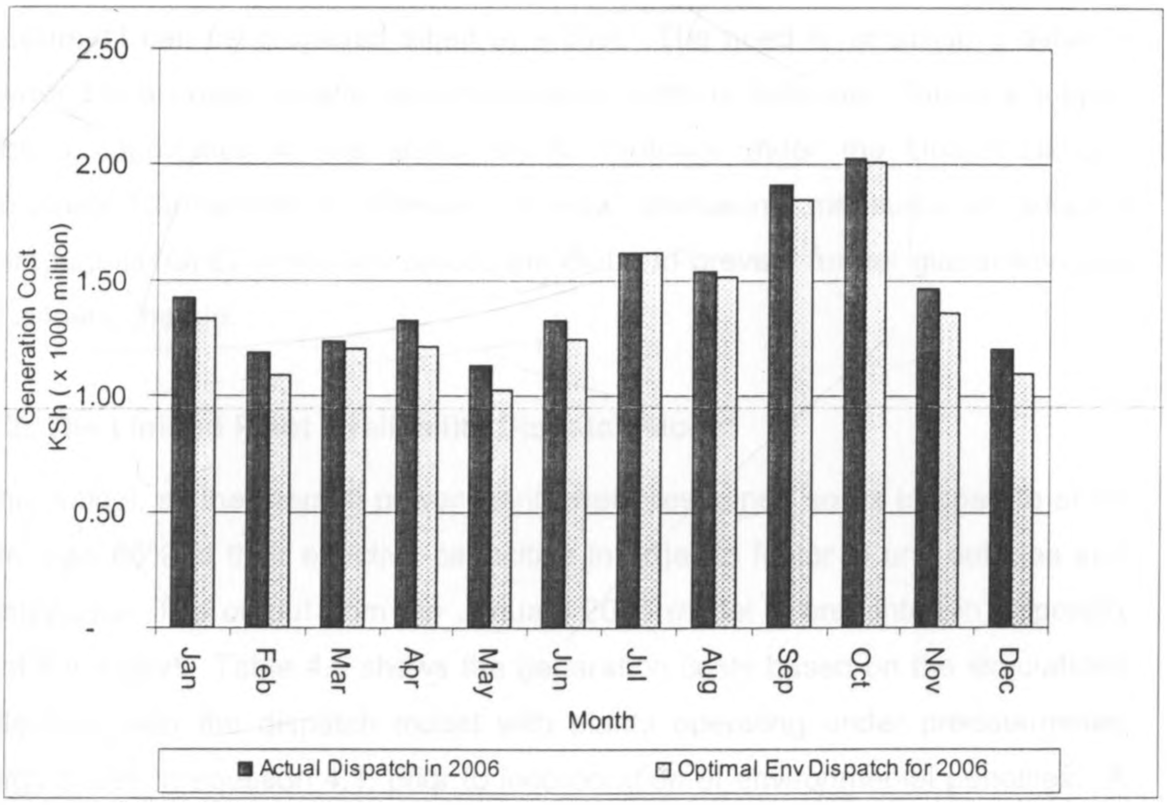

Figure 4.2.1:4::Figure 4.6: Generation Costs for Ideal Optimised Environmental Dispatch

Results from this simulation indicate that the cost of generation from the dispatch model were slightly above the actual in July 2006. This was attributed to the inclusion of incremental costs from the emission penalties imposed on the thermal plants. The total annual savings amounted to US$ 17.8 million. The savings margin dropped drastically due to the incremental costs from the penalties on the base load plants, Tsavo Diesel, Kipevu Diesel 1 and Iberafrica which varied by 8%, 6% and 4% respectively above normal rates. The three plants dominate supply in the ideal model, meaning that they operated at maximum or near maximum output levels throughout the simulation period. In general costs went up 8% above the ideal dispatch scenario, which is within the expected margin based on the incremental unit charges. The variations in costs in the environmental dispatch cases were largely uniform throughout the period, lying between 6% and 9% per month. The results support the validity of the economic-environmental dispatch model.

Reduced financial benefits due to imposed environmental penalties imply that the environment can be protected albeit at a cost. The need to establish a balance between the accrued benefits and incremental costs is deduced. This is a subject of great importance in the global Kyoto Protocol under the United Nations Framework Convention on Climate Change, containing measures to address anthropogenic GHG emissions across the globe to prevent further global warming and climate change.

4.2.2. The Limited Plant Availability Dispatch Model

In this model, all the thermal power plants were restrained so as to operate at no more than 85% of their effective capacities in order to factor in unit outages and maintenance. The output from the January 2006 model is presented in Appendix A5 of this report. Table 4.5 shows the generation costs based on the simulations carried out with the dispatch model with plants operating under predetermined energy prices in equation 4.1, prior to incorporation of environmental penalties. A comparison of the total generation costs obtained and the actual costs is presented in Figure 4.7.

Table 4.2.2.1Table 4.5: Daily Costs for Optimised Environmental Plant Dispatch

	Costs (Million KSh)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Sundays	46	37	38	38	27	40	46	38	48	54	36	26
Mondays	41	40	38	38	30	39	51	49	57	62	38	32
Tuesdays	42	40	43	43	37	42	54	50	66	66	44	32
Wednesdays	47	41	40	43	37	42	55	48	68	68	50	38
Thursdays	45	42	42	46	34	43	54	54	70	68	49	40
Fridays	46	43	43	45	32	43	56	53	69	68	51	39
Saturdays	46	41	41	42	33	45	52	45	63	66	42	34

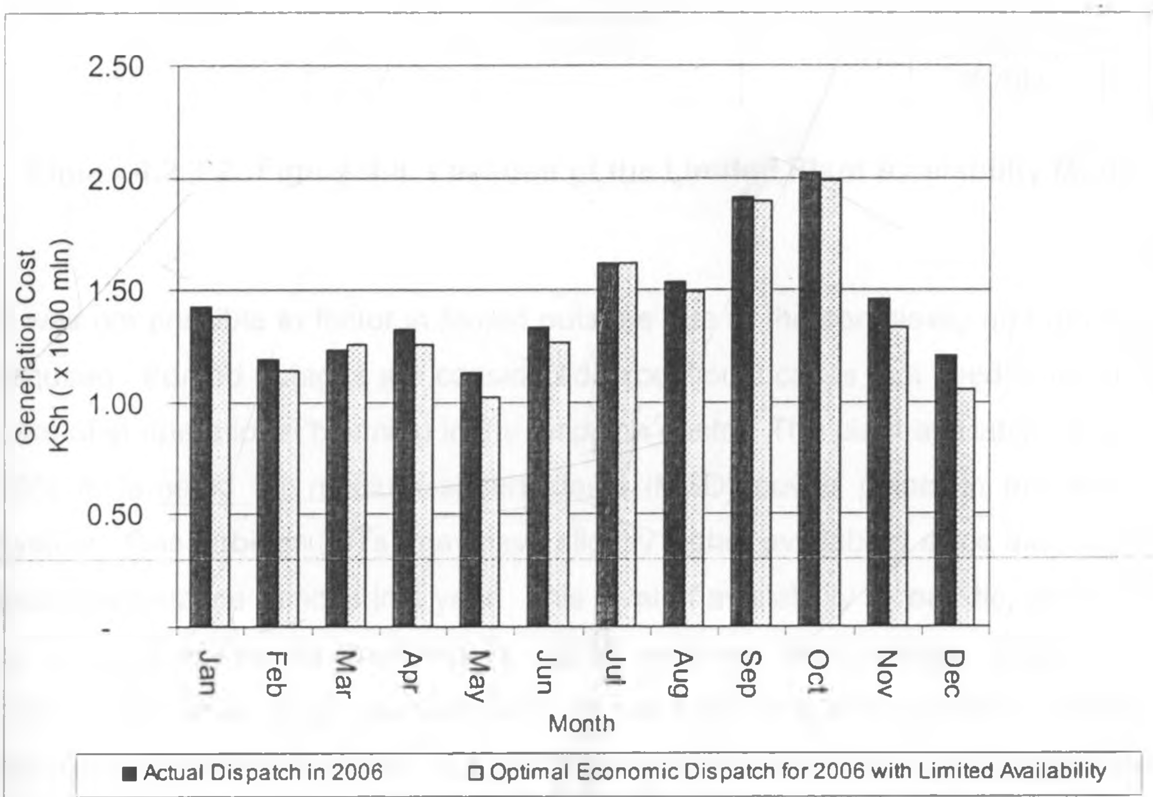

Figure 4.2.2:1::Figure 4.7: Comparison of Costs for Actual and Optimised Limited Availability Dispatch

The Limited Plant Availability economic dispatch output provided savings equivalent to US$ 8.8 million compared to the actual costs incurred in 2006. The savings accrued from all the months except Mar and July when the actual costs were lower than the outputs of the model. The cost curve followed the trend of the actual dispatch throughout the year, though with comparatively saving margin averaging an impressive 3.4%. This appears achievable despite the need to factor in other technical operational constraints in the power system as mentioned in the previous section. Introduction of capacity limitations seemed to incline this moderate case to depict a worst-case scenario. The economic design of the model ensured that simulations returned the least cost dispatch under the prevailing demands and constraints. Figure 4.8 illustrates the positioning of this model relative to the ideal and the extreme cases, a location that bolsters the validity of design fundamentals of the model thereby authenticating model operation. The results from this simulation were therefore expected to largely agree with the actual 2006 costs data.

Figure 4.2.2:2::Figure 4.8: Location of the Limited Plant Availability Model

It was not possible to factor in forced outages due to the complexity and the effort required. Forced outages are considered exceptional cases that need to be taken care of in operational planning in the dispatch centre. The plant availability level of 85% is targeted for medium speed diesel (MSD) power plants in the Kenyan system. Gas turbines (GTs) may have slightly higher availability since they require less maintenance periods in a year. This level of availability is realistic, although it is disadvantageous in modelling in that it assumes that cheaper power plants cannot operate at their maximum even at peak and therefore force the model to call in more expensive plants. This is however not entirely disadvantageous since it enables the GTs to be operated similarly to the practical situation. Economic dispatch in the ideal model indicated that depending on the requirements, the GTs can operate marginally throughout the year, only complementing the other baseload plants. This to an extent reflects opportunities in application of optimal dispatch and also shows the complexity of intertwining real dispatch with the optimization goals.

The final dispatch model was obtained through upward adjustment of the unit generation costs in the Limited Plant Availability model as applied in equation 4.1 to penalise emissions. In essence, as pointed out previously, this could rearrange the economic merit order dispatch depending on the polluting capabilities of the plants in the model. The incremental costs were similar to those in the ideal model, ranging between 2% (for UETCL) and 8% (for Tsavo). The degree of variation depended on the initial per unit charge comprising of energy and fuel charges. Simulations were carried out as previously done to investigate the changes in generation and costs throughout the year. The weekly costs obtained are shown in Figure 4.8, while a comparison of the actual monthly costs and those from the model is shown in Figure 4.9.

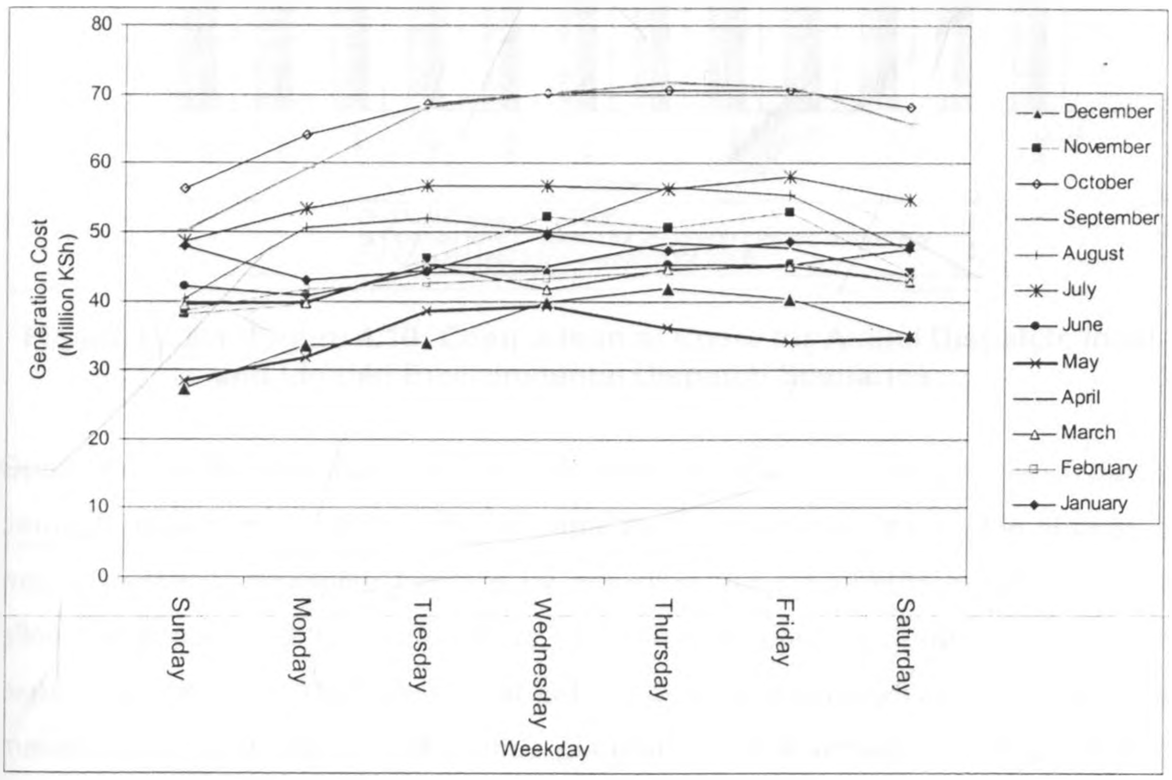

Figure 4.2.2:3::Figure 4.9: Daily Costs for Optimised Dispatch with Limited Availability

The results indicate that generation costs fluctuated between -2% and 8% from the actual costs along the economic dispatch curve in Figure 4.10. The overall total costs were equivalent to US$ 2.3 million above the actual 2006 costs, or 0.9% and 4.3% above the actual and the economic dispatch costs, respectively. This can be defined as the financial cost of protecting the environment. The narrow margin implies that the dispatch was close to the actual operation which again validates the design and operations of the models.

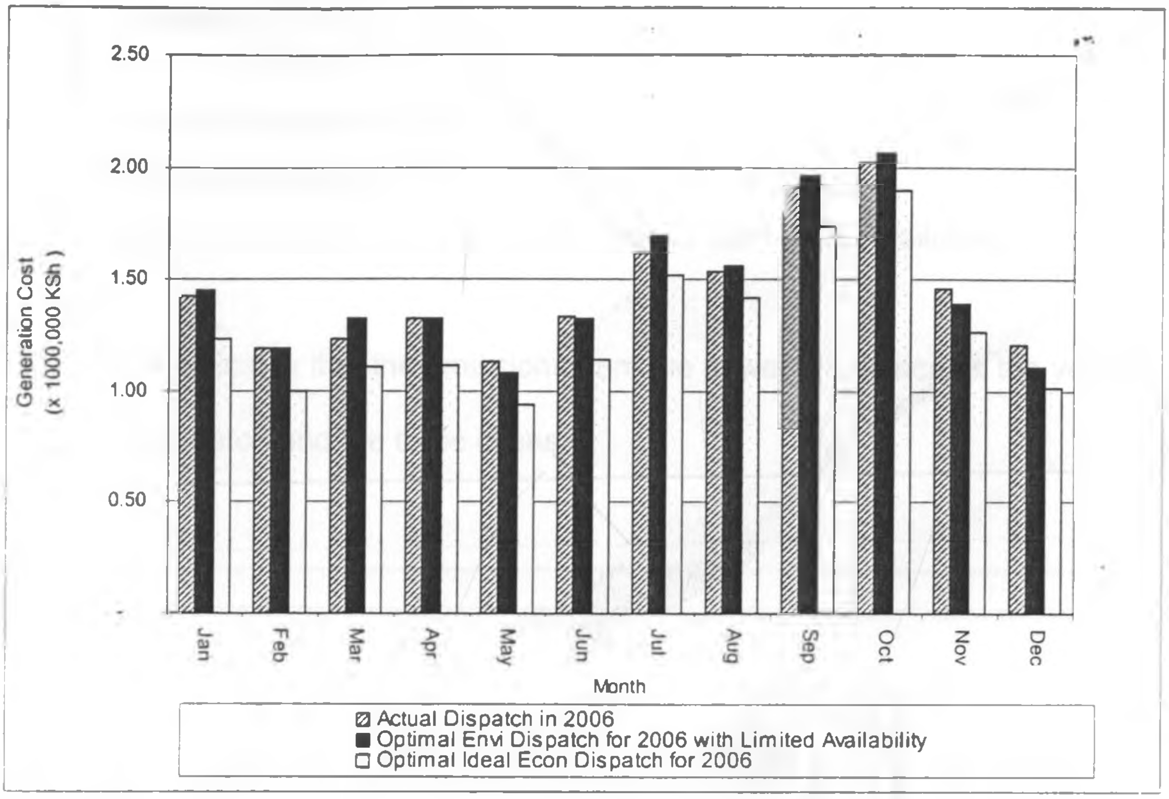

Figure 4.2.2:4::Figure 4.10: Comparison of Costs for Actual Dispatch, Ideal and Limited Environmental Dispatch Scenarios

Operation of the thermal units closely matched the prevailing system power demand requirements. When the full capacity of a plant was achievable at peak, it was possible to maximise benefits by adjusting the constraints in the model to allow full dispatch for that period, thus enabling reduction in outputs from the more expensive sources. This can be carried out through incorporation of the planned maintenance schedule for the various generators. The actual cost of generation may however vary as influenced by other factors such as generator start up costs incurred when a unit is required to shut down and start up again (Wang and Shahidelpour, 1992). This notwithstanding, the models operations in the several scenarios demonstrated realization of economic dispatch.

4.2.3. Comparison of Generation Costs and Emissions

It was imperative to compute the subsequently avoided emissions and assess if the benefits obtained justified the effort and price. Three sets of output data were selected for comparison of emissions associated with the optimised dispatch with those computed from the actual dispatch data in 2006 using the same emission factors applied in the models. The sets of output were derived from the three models, namely:

i) Ideal Optimised Environmental Dispatch
ii) Optimised Dispatch with Limited Plant Availability and
iii) Optimised Environmental Dispatch with Limited Plant Availability

Figure 4.11 indicates that the emissions from the power plants across the year for the actual dispatch and the three cases.

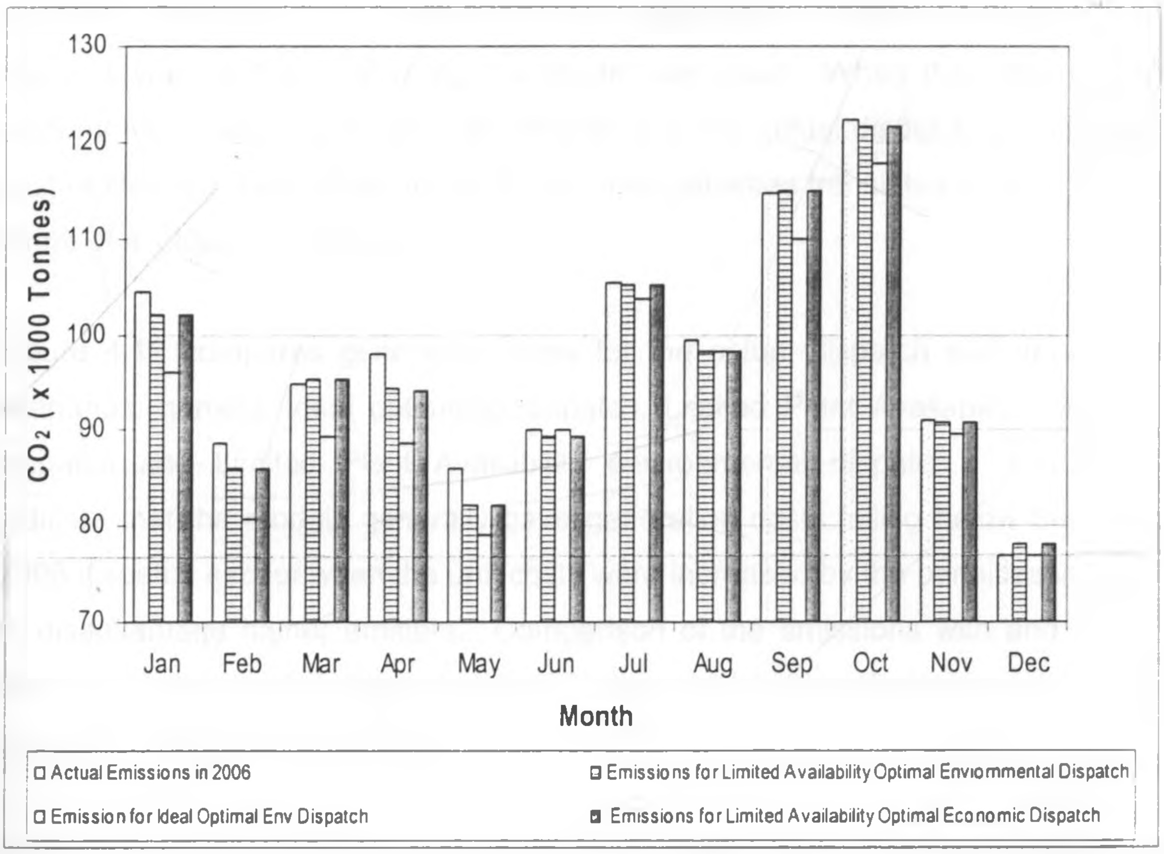

Figure 4.2.3:1::Figure 4.11: Comparison of Monthly CO_2 Emissions for Different Models

The ideal case resulted in comparatively low emission levels in the early months of the year than the rest of the cases. The levels then rose steeply to the range of the other two outputs in the later parts of the year except in September and October where the gap was sustained shortly. The high emissions were as a result of the high thermal generation in the July-October period to meet rising demand. The actual and the Limited Plant Availability outputs had very close emission levels throughout the year, with the variation oscillating between -1% and 4% compared to the actual case. The model recorded higher emissions in March and December implying that the actual dispatch was more environmentally friendly in these months than the model output. Simulations from the Limited Plant Availability environmental model returned a net emission reduction of 1.2% compared to the actual dispatch. The total emission reduction achieved was 14,000 tonnes of CO_2. Cumulative environmental penalties amounted to US$ 11.2 million, equivalent to a 4.5% increase in generation costs from the output of the ideal optimal environmental dispatch model. This, however, would be a rather high price to pay compared to the emissions reduction. The high cost is of course due to the assumptions made in the design of the ideal model as discussed in the previous sections. It translated to a price of US$ 821 per tonne of avoided emissions. This was not unexpected considering the model was ideal. When the more realistic environmental dispatch model was compared to the actual dispatch the additional cost of US$ 2.3 million from the environmental penalties translated to US$ 172 per tonne of avoided CO_2 emissions.

Figure 4.12 compares generation costs for the actual dispatch and three other scenarios, namely, ideal optimised dispatch, Limited Plant Availability optimised dispatch and Limited Plant Availability environmental dispatch. The curves indicate that the models generally gave generation costs falling below the actual 2006 dispatch except when the unit costs were increased by the penalties imposed to disadvantage higher emitters. Comparison of the emissions with and without penalties in the limited dispatch model indicated that no emissions were avoided through introduction of penalties.

These results imply that all the plants were penalised yet they had to operate in the absence of alternative non-polluting sources to meet power demand. It also confirms that the expensive sources, according to the available data were progressively more polluting thereby retaining the economic merit dispatch order. The US$ 10 per tonne of CO_2 imposed all the generators did not abate pollution any further since the plants had to operate to satisfy demand. This interpretation is supported by the fact that the surplus capacity in the system was low leading to procurement of emergency power plants. Therefore achievement of economic dispatch prior to introduction of penalties was adequate in this case since there were limited options in with regard to the power plants available since all had to be operated despite the penalties imposed. Rabl and Spadaro (2006) point out that there are no natural criterion for deciding how far to reduce emissions of pollutants and therefore there is a serious risk of spending too much on he fight against air pollution. A comparison of costs and benefits is needed for rational policy making.

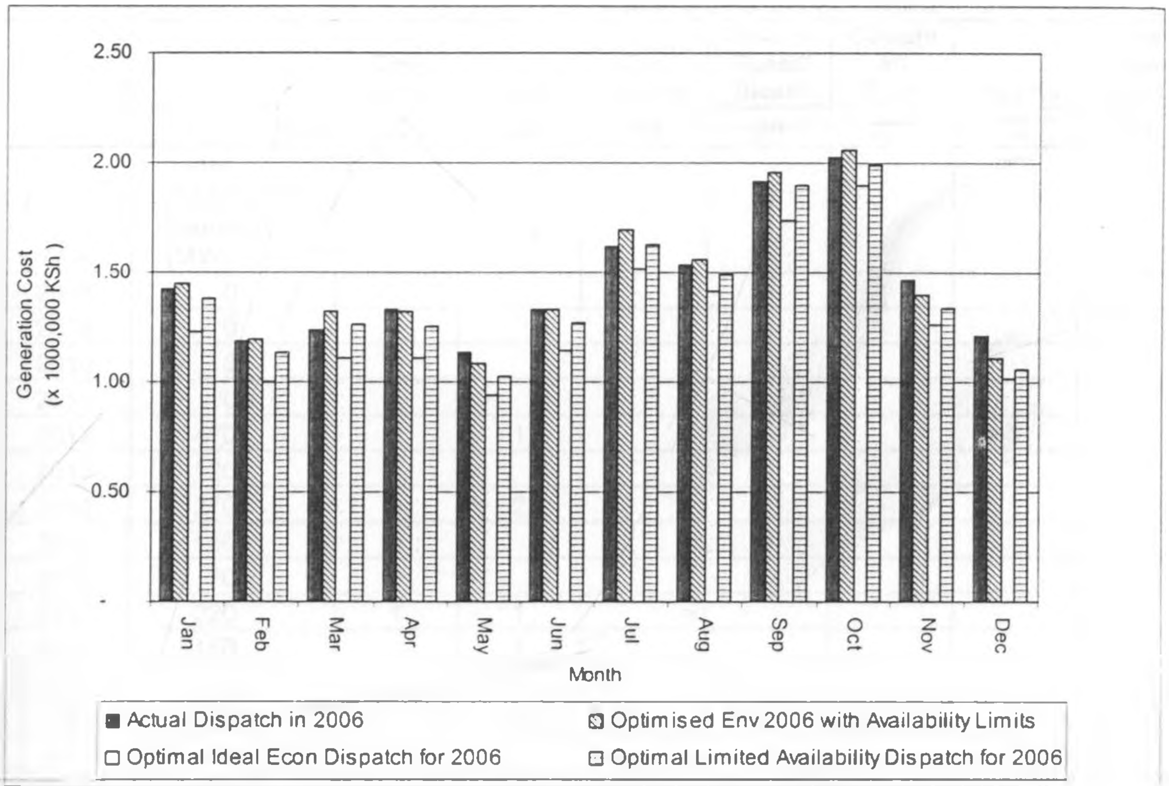

Figure 4.2.3:2::Figure 4.12: Comparison of Monthly Generation Costs for Different Models

4.3. Capacity Expansion Study

The 2008-2028 least cost expansion plan hat was obtained through simulation with the GENSIM software was used as the base case in the remodelling study using the WASP optimization software. The candidates were availed to the model to enable selection of the optimal plan from feasible combinations. The WASP model was ran to determine a cheaper sequence for adding capacity in the planning horizon without incorporating environmental emission constraints other than the penalties applied in the 2008-2028 least cost plan, so as to determine a more economic but comparable plan. The results from the WASP simulations are presented in Table 4.6. The output was examined against the development plan (least cost plan) obtained from the GENSIM model, with a view to assessing the feasibility of a new plan in the perspective of the environmental objective of the study. The WASP optimal solution included additional geothermal power plants every year between 2012 and 2016 and one hydropower project, the Low Grand Falls, in the year 2020.

Table 4.3.1Table 4.6: The WASP Optimal Solution for Kenya

		Name and No. of Units added						
		Geo-thermal	Coal	Gas Turbine	Medium Speed Diesel	Combined Cycle	Imports	Low Grand Falls
	MW	70	150	90	20	270	50	140
Year	Total Additional Capacity (MW)							
2008	0							
2009	0							
2010	0							
2011	0							
2012	470	1	1				5	
2013	120	1					1	
2014	370	1	2					
2015	150	1			4			
2016	70	1						
2017	220	1	1					
2018	150		1					
2019	150		1					
2020	360	1	1					1
2021	130				4		1	
2022	300		2					
2023	310	1	1	1				
2024	240		1	1				
2025	210	1		1			1	
2026	340		2		2			
2027	40				2	1		
2028	710		2	1			1	
TOTAL	**4,340**	**9**	**15**	**4**	**12**	**1**	**9**	**1**

Examination of the optimal solution revealed that it included too many geothermal plants which could not be achieved easily as it would require mobilisation of huge resources. The plan also included many coal power plants, which are not desirable in pollution abatement. The plan was therefore not adopted as obtained. Adjustments were made on the actual least cost plan to accommodate the desirable features in the WASP output and simulations then carried out again in GENSIM. The sequence was refined, giving rise to several alternatives. Sensitivity runs were done to investigate the changes in Present Worth Costs (PWC) of the alternatives with fluctuations in coal and crude prices.

The results shown in Table 4.7 indicate that the new plan was more economic compared to the least cost plan in all the sensitivity simulations carried out. The findings indicate that the new plan is consistently better than its rivals for the various combinations of coal and crude prices. This confirmed the robustness of the resultant remodelled expansion plan presented in Table 4.8 compared to the least cost plan in Table 2.8.

Table 4.3.2 Table 4.7: Sensitivity of PWC to Fuel Prices

	PWC to year 2058 (Million USD)					
Case Code	$L_O R_C$	$R_O L_C$	$R_O R_C$	$R_O H_C$	$H_O R_C$	$H_O H_C$
GCGTDL8a LCP 2007	6,001	6,045	6,072	6,125	6,309	6,362
GCGTDL8R Advanced Geothermal	5,928	5,978	5,999	6,039	6,223	6,264
GCGTDL8F Advance Geothermal with LGF Hydro	5,910	5,963	5,980	6,015	6,199	6,234

Key:

$R_O R_C$ Reference Crude Oil, Reference Coal
$R_C L_C$ Reference Crude Oil, Low Coal
$R_C H_C$ Reference Crude Oil, High Coal
$L_O R_C$ Low Crude Oil, Reference Coal
$H_O R_C$ High Crude Oil, Reference Coal
$H_O H_C$ High Crude Oil, High Coal

Table 4.3.3Table 4.8: The Remodelled Least Cost power Development Plan for 2008-2028

Year Ending 30th June	Configuration MW			Description	Capital Cost (Mln US$)	Type	Added Capacity MW	Total Capacity MW	System Peak MW	Reserve Margin MW	Reserve Margin %
Existing 2007								1,045	1,082	-37	-4%
2008	2	x	30	Sondu Miriu			60				
	1	x	80	Gas Turbine		GT	80	1,185	1,153	32	3%
2009	6	x	15	Medium Speed		MSD	90				
				Olkaria III		GEO	35				
	-1	x	10	Fiat GT		GT	-10				
				Kiambere		HYDRO	20				
				Mumias		COGEN	25				
	1	x	35	Olkaria II 3rd Unit		GEO	35				
				Kipevu Combined Cycle		CC	30	1,410	1,206	204	14%
2010				Raising Masinga		HYDRO	0				
				Tana		HYDRO	19.6				
	2	x	330kV	Mombasa -Nbi	209.9	Line					
	1	x	20	Kindaruma 3rd		HYDRO	20				
	2	x	10.3	Sangoro		HYDRO	20.6	1,470	1,294	176	12%
2011	6	x	20	Medium Speed	139	MSD	120	1,590	1,398	192	12%
2012	1	x	70	Geothermal	171.3	GEO	70	1,660	1,508	152	9%
2013	1	x	100	Import		IMPORT	100	1,760	1,625	135	8%
2014	2	x	100	Import		IMPORT	200	1,960	1,749	211	11%
2015	-3	x	15	Olkaria I		GEO	-45				
	1	x	25	Olkaria I		GEO	25				
	1	x	50	Import		IMPORT	50				
	1	x	70	Geothermal	171.3	GEO	70	2,060	1881	179.2	9%
2016	1	x	70	Geothermal	171.3	GEO	70				
	4	x	20	Medium Speed	92.4	MSD	80				
	2	x	220kV	Olkaria-Nairobi	34	Line		2,210	2,021	189	9%
2017	1	x	100	Import		IMPORT	100				
	1	x	90	Gas Turbine		GT	90	2,400	2,171	229	10%
2018	4	x	20	Medium Speed	92.4	MSD	80	2,480	2,330	150	6%
2019	-6	x	12.5	Kipevu I		MSD	-75				
	4	x	20	Medium Speed	92.4	MSD	80				
	1	x	100	Coal	195.6	COAL	100				
	1	x	90	Gas Turbine		GT	90				
	2	x	330kV	Mombasa -Nbi	209.9	Line		2,675	2,499	176	7%
2020	-10	x	5.66	Iberafrica Diesel		MSD	-56.6				
	2	x	70	Low Grand Falls	439.8	HYDRO	140				
	1	x	70	Geothermal	171.3	GEO	70				
	1	x	100	Import		IMPORT	100	2,929	2,679	250	9%
2021	1	x	100	Coal	195.6	COAL	100	3,029	2,871	158	5%
2022	-7	x	10.57	Tsavo Diesel		MSD	-74				
	-1	x	90	Gas Turbine		GT	-90				
	3	x	90	Combined Cycle	156.7	CC	270				
	1	x	100	Import		IMPORT	100	3,135	3,076	59	2%
2023	2	x	100	Coal	391.2	COAL	200				
	2	x	330kV	Mombasa -Nbi	209.9	Line		3,335	3,294	41	1%
2024	1	x	70	Geothermal	171.3	GEO	70				
	4	x	20	Medium Speed	92.4	MSD	80				
	1	x	100	Import		IMPORT	100	3,585	3,527	58	2%
2025	2	x	100	Coal	391.2	COAL	200				
	1	x	90	Gas Turbine	49	GT	90				
	2	x	330kV	Mombasa -Nbi	209.9	Line		3,875	3,774	101	3%
2026	1	x	70	Geothermal	171.3	GEO	70				
	2	x	100	Import		IMPORT	200	4,145	4,038	107	3%
2027	-1	x	90	Gas Turbine		GT	-90				
	3	x	90	Combined Cycle	156.7	CC	270				
	4	x	20	Medium Speed	92.4	MSD	80	4,405	4,320	85	2%
2028	2	x	100	Coal	391.2	COAL	200				
	2	x	70	Geothermal	342.6	GEO	140	4,745	4,620	125	3%

The capacity expansion study indicated that it was still possible to develop an alternative least cost plan with a lower PWC than the latest cost plan and more renewable energy sources. Table 4.9 shows the composition of the additional capacities by type in the various cases evaluated given in code names. The least cost plan had a PWC of US$ 6,045 while the new plan had US$ 5,080 million, a difference of 1.1%. or US$ 65 million. This is a savings is sufficient for development of a 50 MW medium speed diesel power plant based on the costs applied in the 2007 LCPDP. The study suggested replacement of 200 MW coal and 100 MW medium speed plants in the plan with 70 MW additional geothermal, 140 MW hydro and 150 MW of imports which are also assumed to be hydro-based.

Table 4.3.4Table 4.9: Capacity of Generation Sources in Alternatives Plans

		KEY ADDITIONS EXCLUDING COMMITTED PROJECTS (MW)							**PWC to 2058** (million US$)
	CASE CODE	GEOT	IMPORT	COAL	MSDs	GTs	CCs	HYDRO	
1	GCGTDL8F	560	1,050	800	530	170	540	140	5,980
2	GCGTDL8a (LCPDP 2007)	490	900	1,000	630	170	540	-	6,045
3	GCGTDL8	490	900	1,000	700	80	540	-	6,054
4	GCGTDL7	490	900	1,100	620	80	540	-	6,181
5	GCGTDLa	490	1,100	1,100	360	80	540	-	6,184

Key:

GEOT	Geothermal Power
MSD	Medium Speed Diesel
GT	Gas Turbine
CC	Combined Cycle Power
IMPORT	Power Imports
Coal	Coal Power Plant
HYDRO	Hydropower

The present worth cost of the new plan was US$ 5,980 million compared to US$ 6,072 million in the 2007 least cost plan. Figure 4.13 and Figure 4.14 present the expected generation outputs from the LCP and the remodelled LCP over the planning horizon. Inclusion of a hydropower plant and additional imports and geothermal capacity in the new plan coupled with the rearrangement of the development sequence resulted in less thermal generation from 2015. The remodelled plan shows the imports contributed the highest supply, a position previously held by thermal plants in the least cost plan. The resultant total thermal generation in the remodelled plan was 28% lower. Hydropower and geothermal generation went up by 14% each while imports increased by 10%. The contribution by the Low Grand Falls is evident from 2020 breaking the hitherto constant supply of firm hydro energy in the least cost plan. The increased level of imports may raise concerns on national power security and self reliance, but the study assumes the power imports as emanating from more than one country through regional power interconnector lines, and therefore mitigating the risk of total loss. Kenya's 40 years experience in power trade with Uganda strengthens justification of regional power trading, without underrating the need for development of national power projects concurrently.

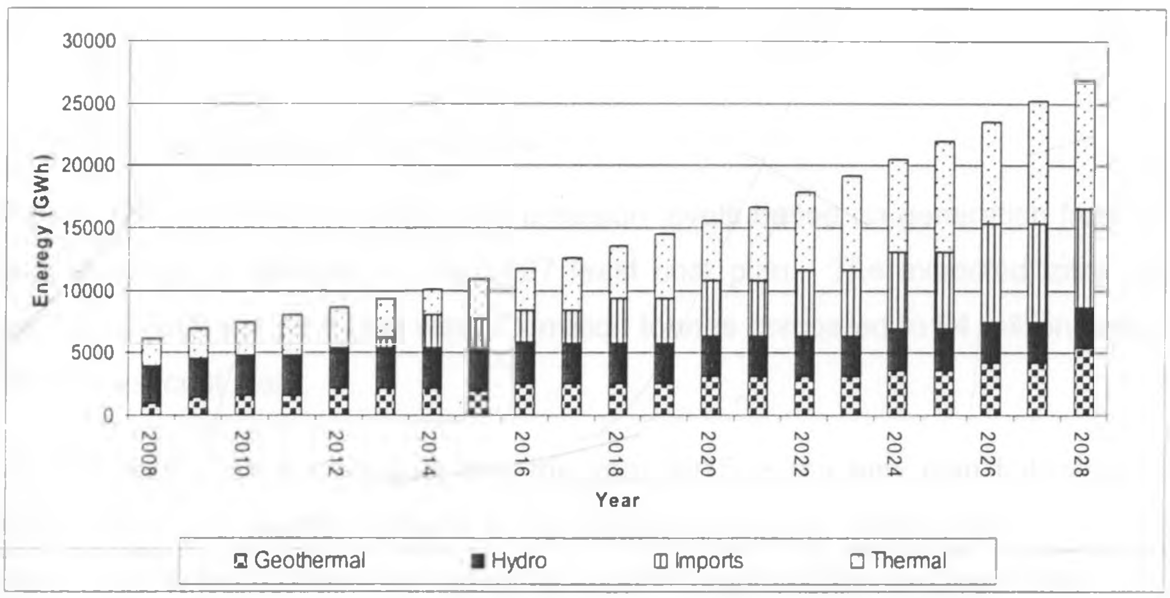

Figure 4.3:1::Figure 4.13: Comparison of Generation Outputs -LCP 2007

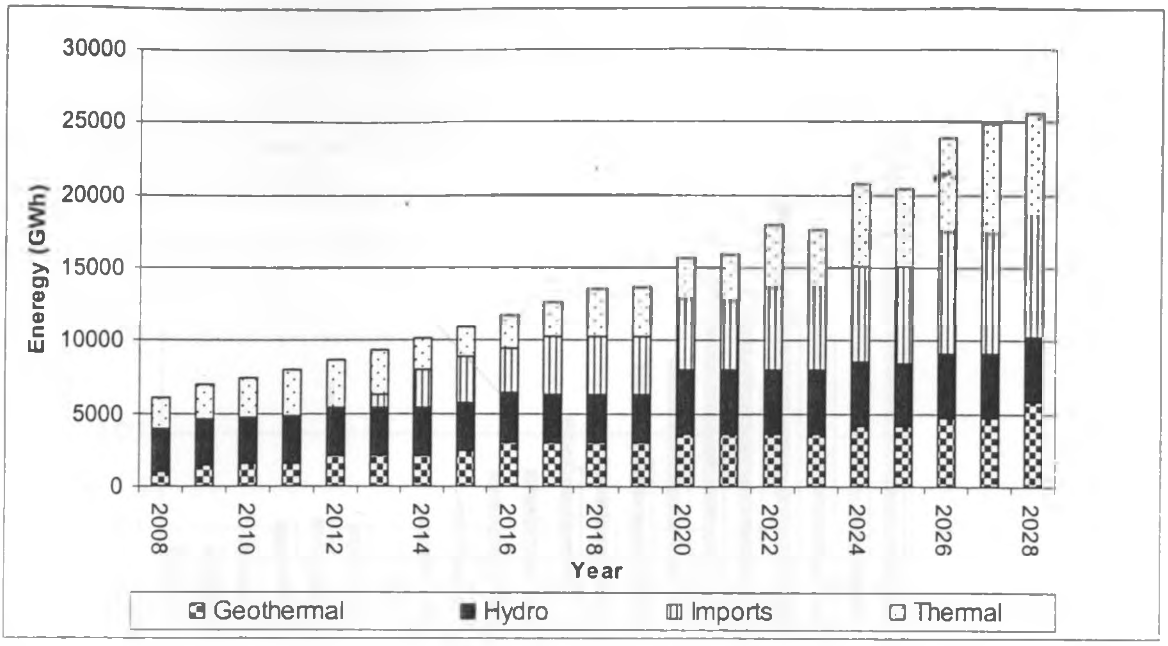

Figure 4.3:2::Figure 4.14: Comparison of Generation Outputs -Remodelled LCP 2007

4.3.1. Comparison of Emissions

Figure 4.15 presents the calculated emission levels based on generation from the proposed plan compared to the 2007 least cost plan. The expected total CO_2 emissions with the new plan were 71 million tonnes compared to 94 million tonnes in the least cost plan.

The emission levels decrease from the year 2015 in the new plan following the introduction of a geothermal and some additional imports in the plan. The gains were augmented further with additional imports proposed but reduced when more thermal plants were added and the coal plant that had been delayed. Introduction of the Low Grand Falls hydro in 2020 reduced the emissions further. This gap was sustained following reduction by half of the capacity of a proposed 200 MW coal plant in 2021. The savings were thereafter generally sustained except for slight variations noted in 2022 where a large combined cycle plant was added and in 2026 when some more imports were added resulting in less emissions.

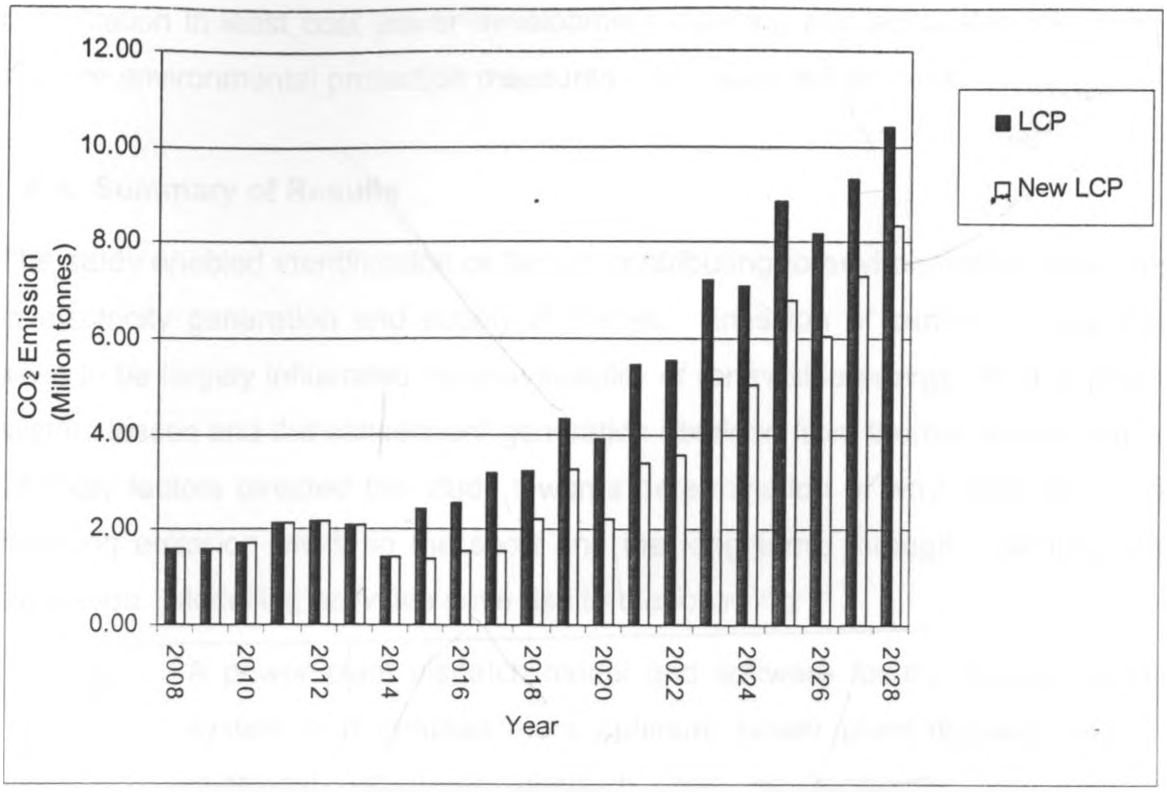

Figure 4.3.1:1: Figure 4.15: Comparison of CO_2 Emissions

The new plan has potential to avoid 23 million tonnes of CO_2 between 2014 and 2028. If carbon credits from the avoided emissions were sold to developed countries, they would generate US$ 230 million at a selling price of US$ 10 per tonne. The economic and environmental value of avoiding the emissions is much higher but cannot be quantified in this study. These avoided environmental damages include global warming, human health impacts, mortality, crop losses and damage to materials (Rabl and Spadaro, 2006) The two plans were purposely left the same until the year 2014 after which the sequencing of the candidates was reviewed. This cushioned the plan against proposing unachievable gains given the short duration between the time of this study and the year 2014. The gap provides space for suggestions and also adequate time for decision making should the new proposal be considered for adoption.

The research anticipated the emission reduction measures to raise the overall cost of the plan and therefore require a cost benefit analysis. The reviewed plan however resulted in a lower PWC compared to the 2007 LCPDP. It was therefore not possible to price the emission reductions since the resultant expansion plan emerged cheaper than the official plan. The study identified more scope for optimization in least cost power development planning and advocates integration of more environmental protection measures in the planning process.

4.4. Summary of Results

The study enabled identification of factors contributing to environmental emissions in electricity generation and supply in Kenya. Emission of carbon dioxide was seen to be largely influenced by unavailability of renewable energy, level of power system losses and the consequent generation obtained from thermal power plants. The key factors directed the study towards determination of ways and means of reducing emission levels in the short and the long term, through modelling and simulation. Modelling activities gave rise to the following:

(i) A power plant dispatch model and software for the Kenyan power system that enabled more optimum power plant dispatch and for improved economic dispatch and environmental management through reduction of emissions.

(ii) A remodelled national power development plan for Kenya which emerged less expensive in the long run than the recommended 2007 least cost plan. The new plan includes more renewable generation and less thermal plants. It is therefore more environmentally friendly.

5. CONCLUSIONS AND RECOMMENDATIONS

The study identified several factors that influence environmental emissions both in the immediate under power plant dispatch and the long term under capacity expansion planning. Emission factors for the existing thermal power plants and their generation outputs as dictated by dispatch, determine the influence of the level of environmental emissions. Generation output from thermal power plants was found to be dependent on system demand and the amount of available hydropower and geothermal generation both in the short and long term. The next two sections present other conclusions drawn from the findings of the study.

5.1. Factors Influencing Environmental Emissions

The level of CO_2 emission from electricity generation and supply is dependent the output from fossil oil fired thermal plants, power system losses and the amount of renewable energy available against the national power demand at any given time. Power system losses were seen to be generally reducing while thermal generation was increased at an average rate of 33% in the last three years, while both hydropower and geothermal which on average grew at below 1% in the same period. Thermal generation was therefore confirmed to be a key factor influencing the level of air pollution in Kenya. The absence of additional hydro and geothermal energy against the increasing national electricity consumption was also seen to significantly influence the level of thermal power generation and therefore the emission levels. The growth in electricity demand, which on average grew at 7% in the last three years (KPLC, 2007), can gradually be met through a balance of the renewable and non-renewable and therefore this was seen to have low impact on emission levels based on the scale developed in this study.

5.2. Power Plant Dispatch

The MILP Optimal dispatch model developed and used in this study derived results that indicated that modelling and analysis enabled a more economic dispatch and with reduced cost of electricity generation. The variable used in the dispatch model played a key role in making plant dispatch to closely follow the actual system operation and also enabled prediction of the outcome of the dispatch simulation more precisely. The models with limited plant capacities returned lower operational cost compared to the actual 2006 dispatch signifying that there is scope for improvement in plant dispatch through application of computerized optimization to complement the current approach that is highly dependent on human judgement.

The environmental dispatch scenarios revealed that the prevailing level of emissions from power plants could not be reduced further by imposing penalties in the circumstances prevailing then, where system demand was high and required most of the available capacity, leading to a high proportion of thermal generation. The impact of penalties would have been more if they resulted in a shift in the economic merit order for the existing power plants. As new thermal power plants continue to be introduced in the system to meet the growing electricity demand, there is likelihood of rearrangement in the merit order such that some emission factors cross in a utilization curve. This could happen, for example, when a more polluting coal plant competes with a medium speed diesel plant for baseload operation so as to change the merit order in favour of the lower polluter. Comparison of generation costs for the actual dispatch and three other scenarios, namely, ideal optimised dispatch, Limited Plant Availability optimised dispatch and Limited Plant Availability environmental dispatch, indicated that the models generally gave generation costs falling below the actual dispatch except when the unit costs were increased by the penalties imposed to disadvantage higher emitters.

Comparison of emissions resulting from the actual dispatch and those from the economic dispatch models indicated that optimal economic dispatch of power plants and optimal operation of the available renewable sources (hydropower and geothermal) can sufficiently lead to reduction of emissions in the Kenyan system. This is the case since the expensive plants are progressively more polluting, therefore attracting higher penalties. The constraints applied in the model required that the system demand be supplied from the available capacity in addition to minimising the overall cost given by the objective function. Achievement of reduced emissions with the limited plant outputs implies that in reality more emissions can be avoided by always taking advantage of the available full capacity from the cheaper and less polluting sources. This proves that the model and the findings of the study are valid. From the dispatch modelling study, it was demonstrated that plant dispatch can be optimized to result in less overall generation cost and reduced pollution from thermal plants.

5.3. Generation Capacity Expansion

The 2007 least cost plan was re-evaluated through modelling in WASP and GENSIM software, giving rise to a cheaper development plan containing less coal and diesel plants. The WASP model The present worth cost of the new plan was found to be 1.5% cheaper than the 2008-2028 was used to determine a more economic least cost plan that contained a hydropower plant which had been declared uneconomic in recent expansion plans. The expected total CO_2 emissions for the remodelled plan were 24% less than those from the 2007 least cost plan over the entire planning horizon, implying that there is room for environmental protection in power system expansion planning.

The study indicated that detailed analysis during the planning process could lead to inclusion of more renewable power generation sources in the least cost plan as desired for environmental safeguard. Inclusion of a hydro power plant in the least cost plan based on analyses carried out during the study implies that planners and decision makers should continue evaluating undeveloped hydropower sites in Kenya alongside other alternative sources. The renewable energy projects can be supported further through the Clean Development Mechanism (CDM) under the Kyoto Protocol to improve their revenue streams to make them more competitive than thermal plants. The results also support inclusion of more imports in the least cost plan at the assumed level of cost with the assumption that all future imports will be hydro. The risk of heavy dependence on imported power against national security can be mitigated by sourcing the imports from more than once source so. The study also provides an informative insight into the generation planning process in Kenya, revealing its strengths and opportunities for improvement.

5.4. Recommendations

The study gave rise to the following recommendations:

i) The need to re-evaluate hydropower plants' dispatch regime as a key area of a study aimed to develop a concrete hydro dispatch policy that would result in optimal reservoir drawdown regime to avoid water spillage and excessive drawdown. Such a study would enhance emission control measures through maximisation of the renewable hydropower output and therefore reduced dispatch of the expensive and polluting thermal plants. KenGen, which is in charge of hydropower reservoir systems, should explore this recommendation.

ii) The dispatch model developed can be improved further through multi-objective programming to ensure that generating units run above the minimum stable generation levels except at start-up, and allow dispatch of other available units including hydropower plants to provide small supply deficits. KPLC, which is in charge of system dispatch, should explore this possibility.

iii) The study indicated that introduction of emission penalties in the Kenyan system may not result in further emission reductions currently compared to economic dispatch. Penalties on emitters should however continue to be imposed in national power development planning to enhance competitiveness of candidate renewable generation projects.

iv) The stakeholders involved in preparation of Kenya's long term capacity expansion plan should incorporate more environmental protection goals with careful analysis of the potential power supply sources for inclusion in the least cost power development plan. Further research should be undertaken to confirm viability and practicality of developing the proposed power generation projects with more emphasis on renewable resources. The study calls for deferment of some of the non-renewable sources in favour of friendlier, attractive alternatives, and determination the most suitable balance between imported power and local generation in view of security of supply.

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7. APPENDICES

APPENDIX A1

THE BASE ECONOMIC DISPATCH MODEL

Table A1-1: The Base Economic Dispatch Model

```
MODEL Power "Half-hourly Plant Dispatch problem";
 (*First the variables are declared*)
 (*The variables are MW output from each power plant*)
 VARIABLE   KipevuD1 ALIAS D;
         KipevuD2 ALIAS V;
         KipevuGT1 ALIAS A;
         KipevuGT2 ALIAS B;
         FiatGT ALIAS F;
         IberafricaDiesel ALIAS I;
         AgrekkoNbi ALIAS K;
         AgrekkoEld ALIAS E;
         UgandaImp ALIAS U;
         ThermalGeneration ALIAS T;
         L "cost/kwh for KipevuD1";
         M "cost/kwh for KipevuD2";
         N "cost/kwh for GT1";
         P "cost/kwh for GT2";
         Q "cost/kwh for FiatGT";
         R "cost/kwh for IberafricaDiesel";
         S "cost/kwh for AgrekkoNbi";
         W "cost/kwh for AgrekkoEld";
         X "cost/kwh for UgandaImp";
         Generationcost ALIAS GC;

(*The objective is to minimise generation costs*)

MINIMIZE cost:
D*L+V*M+A*N+B*P+F*Q+I*R+K*S+E*W+U*X;
 (*Insert the constraints*)
  CONSTRAINTS
   gene: D+V+A+B+F+I+K+E+U =145;
    CoastGen: D+V+A+B >=0.4*100;
    Nairobigen: I+K >=0.2*200;
    Eldoretgen:   E >=0.2*100;
    D1maxcapacity:  0 >=D>=70;
    D2maxcapacity:  0 >=V>=74;
    GT1maxcapacity: 0 >=A>=30;
    GT2maxcapacity: 0 >=B>=30;
    Ftmaxcapacity:  0 >=F>=10;
    Ibmaxcapacity:  0 >=I>=56;
    AKnmaxcapacity: 0 >=K>=40;
    AKemaxcapacity: 0 >=E>=60;
    Uimaxcapacity:  0 >=U>=30;
     D1perunitcost:  L=7.95  "Sh/k
     D2perunitcost:  M=5.60  "Sh/k
     GT1perunitcost: N=19.84 "Sh/kwh";
     GT2perunitcost: P=19.84 "Sh/kwh";
     Ftperunitcost:  Q=29.20 "Sh/kwh";
     Ibperunitcost:  R=9.01 "Sh/kwh";
     AKnperunitcost: S=13.84 "Sh/kwh";
     AKeperunitcost: W=15.60 "Sh/kwh";
     Uiperunitcost:  X=18.98 "Sh/kwh";
      ReqThermalgene:
    D*L+V*M+A*N+B*P+F*Q+I*R+K*S+E*W+U*X;
(*Record the total generation cost and the MW outputs
from all the thermal plants*)
WRITE D, V,A, B, F, I, K, E, U,T;
END
```

APPENDIX A2

THE MIXED INTEGER LINEAR PROGRAMMING MODEL

Table A2-1: THE MILP MODEL

The dispatch model was formulated for every half-hour based on the following cost objective function:

min: $(7.95X_1 + 5.6 X_2 + 19.84X_3 + 19.84X_4 + 28.2X_5 + 9X_6 + 13.84X_7 + 15.6 X_8 + 18.98X_9) \times 0.5$,

subject to the constraints in MW:

contr1: $+X_1 + X_2 + X_3 + X_4 + X_5 + X_6 + X_7 + X_8 + X_9 = 145$;
contr2: $+X_1 + X_2 + X_3 + X_4 >= 127$;
contr3: $+X_1 + X_2 + X_3 + X_4 <= 44$;
contr4: $+X_8 >= 197$;
contr5: $+X_8 <= 12.7$;
contr6: $+X_5 + X_6 + X_7 >= 36$;
contr7: $+X_5 + X_6 + X_7 <= 19.3$;
contr8: $+X_1 <= 63$;
contr9: $+X_2 <= 74$;
contr10: $+X_3 <= 30$;
contr11: $+X_4 <= 30$;
contr12: $+X_5 <= 10$;
contr13: $+X_6 <= 56$;
contr14: $+X_7 <= 60$;
contr15: $+X_8 <= 36$;
contr16: $+X_9 <= 30$;

Where X_1 to X_9 are the respective outputs from the thermal plants Kipevu Diesel 1, Tsavo, Gas Turbine 1, Gas Turbine 2, Fiat, Iberafrica, Agrekko Nairobi, Agrekko Eldoret and UETCL imports.

APPENDIX A3

SYSTEM GROSS AND COMPUTED DEMAND DATA

Table A3-1: Average 2006 Half-Hourly System Gross Demand (MW)

Time	00.30	01.00	01.30	02.00	02.30	03.00	03.30	04.00	04.30	05.00	05.30	06.00	06.30	07.00	07.30	08.00	08.30	09.00	09.30	10.00	10.30	11.00	11.30	12.00
January																								
Sunday	541.7	529.6	517.5	505.9	492.9	491.2	487.2	485.7	487.0	494.5	502.5	517.7	528.7	547.0	565.9	585.2	599.3	600.3	593.9	588.5	580.5	572.7	555.7	556.3
Monday	471.2	461.5	449.7	441.6	435.6	434.6	435.2	437.0	439.6	445.8	487.9	536.7	583.1	612.4	606.0	624.9	645.8	673.7	675.4	685.0	677.7	683.4	686.2	690.9
Tuesday	526.8	513.9	502.3	495.1	492.6	490.0	489.4	486.7	491.5	504.7	538.5	616.9	662.2	685.3	676.3	690.0	709.3	732.2	741.4	742.0	736.8	738.8	741.6	750.9
Wednesday	543.3	536.6	526.2	516.8	515.6	516.0	507.0	508.9	519.3	533.0	562.9	630.7	682.5	705.9	708.0	708.0	749.4	762.1	770.5	764.0	758.9	752.0	751.5	753.2
Thursday	562.4	544.8	536.5	530.0	532.7	526.5	522.4	524.4	526.2	532.1	577.6	638.0	684.2	709.0	718.9	722.2	744.0	776.1	773.3	761.9	750.5	753.1	738.4	735.6
Friday	554.7	532.8	526.4	518.5	513.8	512.7	514.5	514.6	516.4	537.3	577.1	638.6	683.1	712.7	703.8	710.0	738.1	763.9	772.2	771.3	757.7	756.1	755.1	751.8
Saturday	571.8	542.7	539.1	533.8	524.6	522.0	521.3	516.6	522.1	530.9	546.4	571.0	593.2	619.3	655.2	678.4	713.5	731.7	753.9	748.8	745.6	737.7	737.8	734.4
February																								
Sunday	550.1	530.6	515.6	506.1	501.1	495.6	492.4	491.8	491.7	497.8	507.0	526.1	542.4	567.2	589.6	604.6	602.6	623.1	604.0	599.6	592.4	573.5	569.6	567.7
Monday	476.4	466.4	453.8	452.1	450.5	446.4	449.2	447.1	450.8	462.2	518.8	576.8	629.9	656.0	648.2	643.3	680.4	702.2	716.8	719.3	710.2	711.3	718.4	723.2
Tuesday	554.8	543.4	524.0	522.1	522.4	516.0	516.2	513.7	518.1	535.6	589.6	654.2	709.6	733.6	712.7	711.0	730.2	757.6	752.1	753.3	740.0	740.8	739.7	737.5
Wednesday	560.2	544.4	534.7	523.0	518.3	520.5	520.4	521.4	527.2	539.6	596.1	661.9	716.9	729.6	720.8	715.4	727.2	754.5	747.2	755.4	742.6	743.7	740.4	742.1
Thursday	556.7	549.8	526.0	522.1	516.8	524.1	514.3	511.5	511.9	531.3	579.3	649.9	693.4	723.0	710.9	699.2	720.4	738.5	746.0	740.4	736.4	735.0	743.7	736.3
Friday	563.6	540.0	533.2	523.9	519.8	518.5	516.2	518.2	521.4	528.7	580.8	635.9	699.6	722.1	714.2	708.6	725.8	745.3	756.2	746.8	744.5	738.3	739.5	742.1
Saturday	567.5	551.6	541.0	535.2	525.0	520.7	521.2	522.4	520.0	528.7	544.2	571.1	598.3	636.8	653.8	670.8	692.5	726.3	734.4	720.5	726.5	727.0	725.2	719.8
March																								
Sunday	531.9	510.4	498.6	495.9	483.8	485.7	483.8	479.1	484.2	485.5	495.7	513.1	534.9	561.2	580.3	596.9	608.6	615.7	606.8	601.7	586.8	561.5	558.4	553.1
Monday	468.0	457.8	448.6	439.3	434.6	432.1	431.3	434.1	439.2	458.6	509.9	574.8	632.2	655.3	641.1	635.7	675.6	696.4	700.4	701.5	701.9	702.9	701.2	706.8
Tuesday	541.9	521.2	514.2	501.2	495.6	494.5	498.0	501.7	505.4	525.2	573.2	644.9	703.3	728.2	716.0	707.3	723.6	757.6	754.6	757.2	749.0	746.8	742.7	752.5
Wednesday	559.8	549.0	527.1	517.9	508.6	507.9	504.7	506.9	511.6	528.1	575.8	646.1	701.5	724.1	697.8	700.1	718.6	732.7	743.4	730.6	737.0	725.8	732.2	735.6
Thursday	554.6	541.3	521.7	515.2	507.5	506.8	505.5	508.9	513.3	532.6	581.9	639.5	696.4	723.9	713.2	708.7	725.9	750.8	767.7	748.3	737.4	737.7	736.4	737.2
Friday	554.8	535.6	521.9	521.9	516.6	512.5	515.5	517.3	517.8	532.9	577.8	646.1	704.6	717.4	703.1	703.2	728.9	752.0	753.4	751.6	742.4	745.2	737.7	741.0
Saturday	566.8	549.1	534.5	523.6	524.9	512.7	512.0	508.6	504.4	519.8	540.3	567.0	599.1	633.7	658.9	675.5	699.2	731.9	729.9	724.2	723.2	713.9	713.8	710.6
April																								
Sunday	563.6	513.6	505.4	496.2	491.8	488.4	486.5	486.3	488.7	491.2	491.6	520.8	530.6	551.5	580.1	598.5	611.4	621.2	621.6	616.4	601.2	587.1	569.8	569.0
Monday	539.5	458.8	449.4	447.4	446.4	447.1	438.4	441.0	446.0	465.0	484.6	532.2	573.9	602.5	618.9	623.8	653.0	673.9	679.0	680.7	670.1	667.3	663.7	672.2
Tuesday	541.7	514.8	505.7	500.0	506.5	500.5	501.4	499.4	503.4	514.5	553.1	603.3	653.0	687.9	690.3	702.8	729.9	757.9	757.6	755.3	748.0	744.7	745.1	750.7
Wednesday	470.5	543.1	539.8	522.9	517.1	516.4	513.2	513.1	519.2	529.1	580.8	628.5	682.5	706.6	709.4	718.1	735.5	762.5	772.1	764.8	759.9	759.9	738.4	748.9
Thursday	536.1	542.5	523.4	525.3	520.9	514.8	515.6	516.2	518.2	531.9	564.7	616.6	667.6	699.2	711.8	719.4	741.2	780.1	776.7	770.0	765.4	755.6	752.2	756.1
Friday	561.3	536.9	528.8	524.8	522.8	514.4	513.5	514.6	521.1	530.7	552.1	595.2	633.6	651.1	654.5	654.2	671.5	694.4	692.9	693.0	681.3	686.7	684.1	680.3
Saturday	573.5	523.2	503.5	495.6	489.7	485.6	486.1	489.2	493.9	498.0	509.7	543.1	569.2	600.0	628.0	653.8	679.6	704.2	707.3	705.2	693.8	695.2	684.5	690.0
May																								
Sunday	545.0	523.4	507.9	497.3	488.8	483.7	478.7	479.9	473.9	478.8	485.3	515.2	535.7	567.0	589.8	609.6	622.6	618.4	611.2	602.4	594.3	575.2	564.6	563.4

Time	00.30	01.00	01.30	02.00	02.30	03.00	03.30	04.00	04.30	05.00	05.30	06.00	06.30	07.00	07.30	08.00	08.30	09.00	09.30	10.00	10.30	11.00	11.30	12.00
Monday	458.8	442.2	429.5	426.4	426.6	425.4	422.8	420.3	426.9	435.2	480.5	549.4	592.6	612.7	617.8	623.8	640.5	669.2	673.3	674.5	671.6	671.2	672.2	671.8
Tuesday	519.5	499.8	489.1	489.8	483.1	481.7	477.5	477.4	477.4	494.1	550.0	620.6	672.6	690.8	694.0	696.3	720.6	746.4	753.3	749.0	741.0	736.1	740.1	736.7
Wednesday	540.4	527.5	511.3	505.1	493.9	496.5	499.0	497.4	505.0	524.7	579.4	646.6	708.0	715.8	713.0	712.2	729.2	766.3	754.5	744.1	737.0	733.6	728.6	729.1
Thursday	540.9	512.7	502.7	499.7	503.2	503.3	500.3	501.0	502.6	532.6	573.2	626.2	684.6	723.3	714.4	720.0	743.3	759.3	760.6	763.4	746.2	738.6	738.6	739.1
Friday	549.1	523.8	515.4	506.4	506.4	508.8	506.4	504.6	514.2	528.7	575.0	640.4	699.0	719.4	716.1	713.5	746.4	771.5	771.5	767.2	764.8	758.6	758.9	749.2
Saturday	552.1	534.2	521.1	511.7	506.2	500.9	502.6	506.3	508.0	517.0	533.4	566.1	603.4	637.0	663.8	678.5	707.0	734.7	731.8	735.5	739.7	729.0	721.7	719.0
June																								
Sunday	543.7	525.7	511.8	495.9	491.7	489.1	485.3	482.8	487.0	495.7	504.9	534.1	547.9	576.6	603.6	617.9	636.9	638.8	626.5	622.0	621.1	596.5	593.8	579.5
Monday	468.0	448.3	436.4	433.1	425.9	423.9	422.9	423.4	433.8	451.6	505.5	567.0	636.0	649.6	648.9	655.9	681.5	717.2	721.7	718.7	717.0	725.7	722.0	720.8
Tuesday	555.1	541.7	518.4	516.7	507.1	513.4	506.7	507.0	516.2	542.3	598.8	661.8	719.9	744.7	735.3	728.5	751.3	770.3	774.2	768.5	756.8	757.1	759.1	751.2
Wednesday	555.0	530.2	523.7	516.4	515.5	510.3	509.5	514.3	514.9	542.9	605.4	657.9	728.8	757.0	746.3	742.9	758.6	770.5	778.0	769.3	762.0	758.4	758.0	767.3
Thursday	549.0	543.5	531.1	528.1	520.0	514.6	516.1	517.2	522.2	538.7	589.5	642.0	691.8	705.4	701.4	710.5	722.0	741.4	741.9	744.6	732.0	730.1	717.6	721.4
Friday	544.3	525.8	510.7	510.3	504.9	502.1	499.1	499.1	505.8	531.8	584.9	634.1	684.8	694.4	704.5	712.6	740.3	761.4	770.4	767.1	764.8	757.7	751.3	751.7
Saturday	565.4	544.3	529.6	524.1	519.1	516.3	517.4	519.3	517.2	519.7	555.0	587.5	621.0	652.3	685.3	702.4	723.0	743.8	753.1	746.8	734.6	734.7	730.8	722.1
July																								
Sunday	583.0	560.9	542.9	535.9	525.6	516.1	512.0	512.5	515.4	520.9	538.0	552.1	572.0	602.4	628.0	665.9	685.8	686.6	682.1	679.5	647.6	625.4	639.3	638.7
Monday	509.0	494.1	477.5	465.9	461.3	456.9	456.6	457.2	464.4	481.0	552.0	593.2	659.6	690.2	690.9	697.7	729.6	764.4	777.2	785.6	773.6	775.1	774.0	775.3
Tuesday	563.1	543.0	542.1	536.6	527.6	528.6	527.7	535.7	537.9	547.6	619.8	670.2	742.5	782.0	773.7	759.4	773.2	803.4	827.1	814.3	812.1	806.9	797.7	799.4
Wednesday	590.6	570.5	549.1	545.8	543.4	536.9	532.5	537.9	543.4	548.1	620.2	685.5	743.0	778.6	770.0	775.6	801.7	822.7	827.2	827.2	817.5	808.8	803.9	802.0
Thursday	594.7	570.6	559.7	551.3	550.3	550.0	549.1	545.6	559.4	571.2	619.2	684.8	759.9	780.3	786.8	786.5	792.9	826.2	814.2	807.4	796.1	787.7	791.8	805.6
Friday	583.5	579.8	562.8	553.2	548.0	543.3	541.7	538.2	550.0	566.0	626.3	693.2	753.2	782.6	781.2	779.9	801.7	834.9	837.9	837.7	830.7	819.1	827.8	820.2
Saturday	599.3	576.2	557.6	556.2	544.8	546.7	543.3	543.1	544.4	547.2	581.2	605.5	639.5	679.3	713.8	741.6	782.3	810.7	808.1	813.5	798.5	798.3	792.7	790.3
Saturday	583.0	560.9	542.9	535.9	525.6	516.1	512.0	512.5	515.4	520.9	538.0	552.1	572.0	602.4	628.0	665.9	685.8	686.6	682.1	679.5	647.6	625.4	639.3	638.7
August																								
Sunday	553.3	526.0	498.6	494.3	489.9	483.0	480.6	476.4	477.6	480.5	497.8	530.1	549.3	577.6	613.3	645.4	656.3	670.5	668.2	658.3	629.1	605.9	596.0	599.4
Monday	511.7	500.6	491.2	477.7	468.5	463.5	458.8	462.9	466.0	473.2	514.5	560.8	610.8	655.4	682.6	706.6	734.5	769.5	771.7	772.1	760.2	767.3	751.3	748.8
Tuesday	569.9	560.4	552.4	544.7	535.0	532.4	531.6	536.1	546.4	546.9	597.5	632.1	711.6	756.3	778.3	778.1	801.9	830.9	840.4	835.7	816.8	813.2	808.2	811.4
Wednesday	560.4	542.8	529.9	522.7	509.0	503.3	503.5	504.2	506.5	516.7	576.9	613.2	684.4	728.0	748.7	764.7	791.2	813.7	812.3	811.1	793.7	793.8	788.0	792.2
Thursday	574.3	564.3	560.3	545.6	537.1	536.3	535.2	531.8	532.4	532.6	577.1	638.6	704.8	738.8	761.6	765.9	792.1	819.1	809.9	796.1	801.5	803.5	793.0	793.6
Friday	582.8	566.8	559.8	551.5	548.1	550.9	542.7	535.4	544.9	552.4	604.5	640.3	704.4	737.2	765.8	778.5	804.6	829.2	844.7	836.5	819.4	820.0	818.5	820.0
Saturday	586.2	569.7	544.6	530.6	515.5	513.3	508.7	510.1	515.5	514.7	544.6	575.7	647.6	669.7	698.8	727.3	746.0	755.4	760.6	763.3	772.0	764.7	755.4	754.5
September																								
Sunday	563.0	544.8	527.5	522.5	517.3	510.1	504.7	505.5	503.6	506.5	516.5	545.9	577.9	601.0	629.3	649.7	647.2	651.5	647.7	620.1	603.7	583.8	572.4	552.1
Monday	469.8	465.4	459.4	459.0	448.3	447.6	443.0	447.5	452.7	464.0	516.0	596.6	665.1	687.1	678.3	685.9	707.4	739.0	747.0	750.1	735.6	736.6	731.7	739.1
Tuesday	564.9	565.6	553.3	553.6	552.6	549.4	541.0	542.7	546.1	563.2	615.8	699.7	768.2	784.7	768.8	771.3	775.1	795.0	801.8	789.1	787.2	783.7	785.0	784.5
Wednesday	585.4	578.6	566.3	561.0	551.5	549.2	545.5	550.2	552.6	564.9	617.6	695.6	774.9	802.7	790.7	777.8	779.9	792.5	807.2	799.8	783.6	781.3	777.5	780.8

Time	00.30	01.00	01.30	02.00	02.30	03.00	03.30	04.00	04.30	05.00	05.30	06.00	06.30	07.00	07.30	08.00	08.30	09.00	09.30	10.00	10.30	11.00	11.30	12.00
Thursday	589.5	591.2	572.0	566.9	560.2	552.8	552.0	549.9	554.2	561.7	611.0	709.9	784.5	806.7	788.7	761.8	772.6	800.2	791.6	792.1	784.1	769.0	769.9	770.9
Friday	575.0	574.5	565.6	555.7	550.1	538.8	535.9	540.3	544.9	566.7	617.6	687.3	758.5	790.6	787.3	788.2	786.1	812.5	817.5	808.7	802.0	796.6	797.3	793.1
Saturday	593.4	579.7	570.1	571.6	566.6	551.8	549.0	547.2	545.9	554.8	576.5	612.2	645.4	690.3	727.6	738.7	759.0	779.4	788.7	792.2	768.1	766.0	763.6	764.9
October																								
Sunday	583.1	566.1	562.9	545.6	536.3	530.7	530.8	525.3	527.7	534.4	549.0	563.1	592.6	623.9	634.2	662.1	654.5	657.5	648.9	640.4	624.9	606.6	599.2	598.0
Monday	508.8	502.9	488.6	491.4	483.5	479.2	478.2	476.6	479.5	490.9	543.0	617.0	678.3	701.5	691.2	696.5	707.0	720.6	738.2	742.0	744.2	737.5	735.4	740.8
Tuesday	576.5	579.3	576.0	567.5	559.6	556.2	555.0	555.2	558.0	570.0	606.5	660.2	736.7	744.8	735.0	725.5	733.0	743.5	752.3	753.0	749.8	745.6	739.0	735.8
Wednesday	567.8	570.0	569.9	546.1	534.0	532.6	529.8	535.1	542.2	556.0	614.1	696.6	753.8	772.7	759.6	762.3	766.6	789.6	796.6	791.8	781.6	777.4	777.3	768.4
Thursday	595.2	594.9	588.4	587.5	574.8	562.8	563.3	560.9	564.3	590.6	638.5	717.5	792.0	793.9	777.6	781.7	793.9	806.6	809.1	799.6	791.1	789.2	792.0	787.9
Friday	609.6	607.2	593.1	579.2	571.1	565.4	563.3	559.3	566.1	585.3	621.2	690.4	739.2	752.2	746.6	745.4	734.4	744.9	756.9	756.9	754.1	755.2	753.2	755.0
Saturday	589.9	581.4	574.5	562.6	549.4	544.9	541.6	537.0	532.0	543.4	562.7	613.9	654.1	682.9	706.0	724.9	741.2	767.0	790.9	779.8	770.5	761.6	758.0	757.1
November																								
Sunday	601.6	587.7	574.6	561.6	545.3	538.1	540.0	533.0	533.4	537.1	543.8	567.5	602.5	617.8	638.4	654.3	660.8	652.4	646.9	637.2	625.0	617.0	606.3	602.0
Monday	505.7	491.9	485.9	475.4	477.2	470.1	467.5	467.4	467.1	488.7	534.0	592.1	641.6	679.6	694.0	710.2	730.1	753.5	770.4	781.3	774.5	764.6	766.0	761.9
Tuesday	567.3	571.9	578.7	577.8	566.6	565.2	560.1	559.5	563.4	582.2	627.4	680.9	751.4	767.0	775.9	779.3	789.9	810.0	816.6	808.9	809.2	810.7	801.2	802.3
Wednesday	588.5	579.1	566.4	557.3	548.8	544.4	543.7	544.6	549.3	562.5	617.7	691.7	746.8	767.1	773.7	777.6	788.0	813.8	819.6	808.4	795.2	790.5	789.3	789.8
Thursday	608.6	591.1	575.0	562.1	551.3	545.0	543.6	543.9	546.2	557.1	609.4	671.6	736.9	775.5	766.3	770.4	785.4	819.1	816.6	812.6	804.6	797.7	792.1	785.6
Friday	594.8	586.6	573.8	567.2	552.5	548.0	546.7	544.5	547.2	562.1	615.6	689.9	747.3	767.3	761.3	776.5	782.5	814.3	800.6	808.6	793.2	806.1	785.1	796.1
Saturday	609.5	595.1	592.5	580.2	568.4	563.9	557.6	560.3	558.7	561.5	592.7	613.3	655.4	690.4	714.9	739.0	755.6	781.0	789.4	783.5	783.1	770.8	772.0	761.0
December																								
Sunday	562.7	548.7	541.3	523.2	508.7	508.2	509.0	505.1	505.0	508.0	522.3	544.6	565.7	579.6	607.1	628.3	640.5	651.4	668.0	641.9	633.0	625.1	609.9	602.5
Monday	507.7	496.3	480.6	468.0	468.4	468.7	465.5	465.5	461.3	463.9	499.9	539.5	576.6	613.3	634.7	665.2	683.7	709.8	716.0	721.1	718.4	704.8	708.0	708.6
Tuesday	565.7	552.5	546.6	522.6	518.7	515.6	513.4	513.0	514.0	521.9	543.6	577.7	606.3	618.2	642.7	662.0	687.0	715.8	726.7	724.5	721.1	717.7	715.6	718.1
Wednesday	555.9	546.0	536.0	518.0	513.2	505.0	499.2	495.1	496.6	511.9	533.8	584.3	613.0	654.3	684.5	724.7	740.0	782.3	791.1	797.5	783.3	768.5	766.9	751.8
Thursday	579.1	577.9	556.3	557.1	554.1	549.2	536.7	538.3	539.6	551.4	571.6	620.7	641.7	693.2	722.0	753.2	774.7	799.1	806.2	796.9	763.7	758.9	756.8	760.1
Friday	585.1	579.3	565.9	553.5	542.9	537.4	536.7	532.0	534.0	545.5	574.2	618.0	651.0	691.3	723.0	757.9	770.0	794.2	810.7	804.3	789.3	785.9	776.9	781.5
Saturday	588.0	572.2	568.7	556.8	544.1	541.7	536.9	533.6	535.0	540.8	558.0	604.4	622.4	657.0	689.3	708.0	727.0	750.6	777.5	780.3	770.5	760.0	754.4	751.1

Time	12.30	13.00	13.30	14.00	14.30	15.00	15.30	16.00	16.30	17.00	17.30	18.00	18.30	19.00	19.30	20.00	20.30	21.00	21.30	22.00	22.30	23.00	23.30	24.00
January																								
Sunday	553.7	556.3	556.1	545.6	540.9	519.0	519.2	520.6	518.6	513.8	519.1	531.3	547.8	606.5	741.9	778.7	765.8	752.7	731.4	687.3	632.0	578.8	528.8	494.7
Monday	689.5	687.1	675.1	660.4	665.3	671.6	674.4	679.8	680.9	681.8	666.5	656.8	667.3	727.9	830.4	853.3	849.9	838.9	807.9	756.8	695.2	646.5	583.2	554.2

Time	12.30	13.00	13.30	14.00	14.30	15.00	15.30	16.00	16.30	17.00	17.30	18.00	18.30	19.00	19.30	20.00	20.30	21.00	21.30	22.00	22.30	23.00	23.30	24.00
Tuesday	741.2	738.3	716.8	702.5	705.5	708.3	709.1	713.4	721.2	716.6	697.9	694.0	704.0	763.7	857.8	880.8	879.0	859.3	835.2	792.3	723.6	676.3	608.5	583.4
Wednesday	738.7	739.6	719.4	708.7	717.2	721.7	712.6	718.9	724.6	721.4	710.6	697.9	685.1	760.3	864.9	893.0	886.6	860.0	839.5	786.6	737.5	678.0	617.7	583.3
Thursday	738.7	731.1	712.2	696.8	705.4	713.4	717.2	707.9	715.4	713.4	699.5	681.4	697.0	751.1	843.9	865.5	856.2	853.0	815.7	768.9	726.5	667.2	605.4	569.5
Friday	742.9	733.9	703.7	699.1	701.4	707.3	710.5	710.8	715.2	712.8	690.7	688.6	698.1	747.6	856.3	882.9	879.6	851.0	820.6	776.8	724.2	681.9	621.9	585.4
Saturday	729.0	713.3	689.7	671.0	664.1	642.9	645.8	642.3	644.3	643.9	641.1	639.1	653.6	709.0	821.3	850.3	839.9	823.4	791.0	752.1	703.6	650.1	608.5	565.4
February																								
Sunday	573.0	573.3	570.9	558.2	545.6	533.3	529.1	527.7	533.9	532.6	539.6	546.6	564.7	628.2	748.1	774.4	766.8	757.3	739.3	693.0	635.4	583.7	532.6	494.9
Monday	717.0	713.2	697.4	688.7	693.7	693.9	699.5	709.6	706.0	705.2	696.2	695.4	701.3	752.9	844.9	847.2	842.7	832.5	828.4	778.7	719.4	653.4	608.5	569.0
Tuesday	743.2	735.4	712.3	703.2	707.0	707.0	718.8	717.0	713.5	713.6	693.3	683.8	699.7	747.2	851.0	860.7	850.6	835.0	817.5	771.1	713.7	653.5	600.0	571.6
Wednesday	748.1	743.7	724.1	706.4	711.4	729.8	727.3	730.0	719.2	710.9	697.2	688.0	703.1	754.6	860.9	863.6	857.7	846.7	829.5	793.1	722.6	671.4	615.4	584.4
Thursday	729.6	716.2	697.7	686.6	700.1	702.5	707.0	712.8	713.3	712.2	702.3	693.7	707.0	756.9	849.0	868.4	864.8	859.4	834.1	785.8	733.1	675.7	617.8	582.8
Friday	738.2	729.7	702.7	700.5	703.9	701.9	712.0	706.4	719.3	717.4	698.5	691.1	693.0	748.5	850.4	869.8	862.9	846.9	811.8	778.3	723.3	680.0	633.6	591.2
Saturday	713.4	702.8	671.9	648.5	642.1	630.2	623.7	621.1	624.4	625.5	627.4	626.0	640.0	696.6	812.5	838.8	827.6	811.7	789.3	750.1	699.3	651.4	606.6	564.4
March																								
Sunday	557.5	558.5	545.5	543.4	534.9	530.1	530.1	535.9	530.7	528.1	536.2	551.1	592.9	654.7	764.1	788.2	776.0	758.3	734.9	683.4	625.7	572.5	513.4	487.9
Monday	706.6	697.0	676.3	673.4	690.0	695.5	693.0	702.4	708.0	709.6	694.2	689.3	709.4	793.2	872.0	873.3	860.8	849.7	822.6	778.1	701.9	642.1	587.9	552.8
Tuesday	743.4	736.3	708.3	709.5	709.2	716.4	717.3	725.8	722.7	720.0	713.7	705.1	702.5	784.2	870.1	889.3	865.0	873.7	835.3	799.5	720.1	680.8	621.6	588.5
Wednesday	723.8	727.8	707.0	700.4	704.8	714.5	717.7	724.1	716.4	721.8	704.4	691.1	715.1	791.2	862.9	881.2	864.2	845.3	819.9	762.3	707.6	655.7	599.5	571.8
Thursday	738.7	730.0	708.8	701.7	702.2	711.7	714.9	717.3	720.3	716.7	704.4	700.2	710.5	784.4	867.4	879.5	872.9	862.1	828.0	773.8	728.4	664.7	614.8	573.3
Friday	737.6	730.1	707.3	699.0	709.3	716.0	717.0	718.2	715.4	713.0	697.0	695.0	702.5	777.7	852.8	870.4	856.2	845.4	812.5	768.7	716.7	668.0	618.3	585.1
Saturday	708.0	704.6	681.3	660.3	655.5	655.0	631.5	643.9	642.4	638.1	626.0	630.1	638.8	705.2	810.8	826.2	814.2	794.8	773.0	734.6	685.6	630.9	587.8	562.8
April																								
Sunday	571.0	562.4	563.8	553.7	546.4	544.8	547.8	543.5	541.4	549.7	555.4	560.7	603.7	691.8	775.4	775.4	755.4	734.0	705.3	663.9	608.8	561.3	514.5	491.0
Monday	675.2	674.5	661.6	655.7	653.4	655.8	662.2	664.9	665.7	657.4	649.8	651.2	680.6	760.9	825.7	829.7	819.3	809.6	777.4	747.5	683.5	637.8	582.2	552.7
Tuesday	748.4	753.5	720.8	712.8	718.0	729.7	734.7	734.1	734.2	734.5	720.8	726.8	744.3	820.6	859.3	853.7	832.2	822.4	804.3	761.9	706.7	664.8	624.5	580.9
Wednesday	753.2	758.6	731.0	712.9	719.8	725.6	717.2	727.0	727.0	737.0	715.0	702.7	721.7	811.6	866.2	872.4	853.6	835.8	777.4	756.9	697.5	655.9	624.3	593.6
Thursday	751.1	749.1	731.9	731.7	721.9	731.9	734.4	734.8	735.6	731.0	723.2	711.6	728.5	812.1	869.5	864.4	834.8	837.0	798.3	757.7	709.5	664.3	606.1	578.6
Friday	684.7	682.8	659.5	649.4	652.2	654.0	646.9	655.3	660.4	653.5	647.3	642.4	670.7	755.8	822.3	817.4	805.3	784.4	766.1	727.4	674.3	628.0	581.5	557.7
Saturday	687.5	684.2	669.7	647.0	632.1	627.9	628.5	627.1	630.0	623.5	625.4	628.7	651.9	742.2	819.9	822.7	802.3	785.2	751.2	731.7	690.0	642.4	597.0	563.9
May																								
Sunday	564.4	568.6	559.8	551.4	550.4	538.6	526.7	537.6	540.2	545.6	551.9	560.7	600.9	707.7	773.1	775.8	769.2	743.3	722.7	680.3	615.1	558.6	515.7	473.6
Monday	675.8	676.8	643.0	644.7	639.8	648.2	651.1	661.5	663.4	663.5	659.9	660.6	704.4	789.9	832.7	829.1	814.4	797.7	774.0	728.9	674.7	619.1	572.2	540.5
Tuesday	732.1	732.8	710.8	697.8	704.1	714.8	717.0	716.5	718.4	723.6	707.6	713.5	744.5	823.6	871.7	845.6	824.8	836.8	798.6	755.7	692.4	641.2	592.1	561.0
Wednesday	730.8	726.5	704.3	692.1	693.7	706.0	709.1	720.6	720.0	716.9	708.1	706.8	728.3	823.9	877.0	868.3	858.4	844.4	800.1	759.9	708.0	654.3	604.1	566.7
Thursday	540.9	512.7	502.7	499.7	503.2	503.3	500.3	501.0	502.6	532.6	573.2	626.2	684.6	723.3	714.4	720.0	743.3	759.3	760.6	763.4	746.2	738.6	738.6	739.1
Friday	549.1	523.8	515.4	506.4	506.4	508.8	506.4	504.6	514.2	528.7	575.0	640.4	699.0	719.4	716.1	713.5	746.4	771.5	771.5	767.2	764.8	758.6	758.9	749.2

Time	12.30	13.00	13.30	14.00	14.30	15.00	15.30	16.00	16.30	17.00	17.30	18.00	18.30	19.00	19.30	20.00	20.30	21.00	21.30	22.00	22.30	23.00	23.30	24.00
Saturday	552.1	534.2	521.1	511.7	506.2	500.9	502.6	506.3	508.0	517.0	533.4	566.1	603.4	637.0	663.8	678.5	707.0	734.7	731.8	735.5	739.7	729.0	721.7	719.0
June																								
Sunday	543.7	525.7	511.8	495.9	491.7	489.1	485.3	482.8	487.0	495.7	504.9	534.1	547.9	576.6	603.6	617.9	636.9	638.8	626.5	622.0	621.1	596.5	593.8	579.5
Monday	468.0	448.3	436.4	433.1	425.9	423.9	422.9	423.4	433.8	451.6	505.5	567.0	636.0	649.6	648.9	655.9	681.5	717.2	721.7	718.7	717.0	725.7	722.0	720.8
Tuesday	555.1	541.7	518.4	516.7	507.1	513.4	506.7	507.0	516.2	542.3	598.8	661.8	719.9	744.7	735.3	728.5	751.3	770.3	774.2	768.5	756.8	757.1	759.1	751.2
Wednesday	555.0	530.2	523.7	516.4	515.5	510.3	509.5	514.3	514.9	542.9	605.4	657.9	728.8	757.0	746.3	742.9	758.6	770.5	778.0	769.3	762.0	758.4	758.0	767.3
Thursday	549.0	543.5	531.1	528.1	520.0	514.6	516.1	517.2	522.2	538.7	589.5	642.0	691.8	705.4	701.4	710.5	722.0	741.4	741.9	744.6	732.0	730.1	717.6	721.4
Friday	544.3	525.8	510.7	510.3	504.9	502.1	499.1	499.1	505.8	531.8	584.9	634.1	684.8	694.4	704.5	712.6	740.3	761.4	770.4	767.1	764.8	757.7	751.3	751.7
Saturday	565.4	544.3	529.6	524.1	519.1	516.3	517.4	519.3	517.2	519.7	555.0	587.5	621.0	652.3	685.3	702.4	723.0	743.8	753.1	746.8	734.6	734.7	730.8	722.1
July																								
Sunday	583.0	560.9	542.9	535.9	525.6	516.1	512.0	512.5	515.4	520.9	538.0	552.1	572.0	602.4	628.0	665.9	685.8	686.6	682.1	679.5	647.6	625.4	639.3	638.7
Monday	509.0	494.1	477.5	465.9	461.3	456.9	456.6	457.2	464.4	481.0	552.0	593.2	659.6	690.2	690.9	697.7	729.6	764.4	777.2	785.6	773.6	775.1	774.0	775.3
Tuesday	563.1	543.0	542.1	536.6	527.6	528.6	527.7	535.7	537.9	547.6	619.8	670.2	742.5	782.0	773.7	759.4	773.2	803.4	827.1	814.3	812.1	806.9	797.7	799.4
Wednesday	590.6	570.5	549.1	545.8	543.4	536.9	532.5	537.9	543.4	548.1	620.2	685.5	743.0	778.6	770.0	775.6	801.7	822.7	827.2	827.2	817.5	808.8	803.9	802.0
Thursday	594.7	570.6	559.7	551.3	550.3	550.0	549.1	545.6	559.4	571.2	619.2	684.8	759.9	780.3	786.8	786.5	792.9	826.2	814.2	807.4	796.1	787.7	791.8	805.6
Friday	583.5	579.8	562.8	553.2	548.0	543.3	541.7	538.2	550.0	566.0	626.3	693.2	753.2	782.6	781.2	779.9	801.7	834.9	837.9	837.7	830.7	819.1	827.8	820.2
Saturday	599.3	576.2	557.6	556.2	544.8	546.7	543.3	543.1	544.4	547.2	581.2	605.5	639.5	679.3	713.8	741.6	782.3	810.7	808.1	813.5	798.5	798.3	792.7	790.3
August																								
Sunday	553.3	526.0	498.6	494.3	489.9	483.0	480.6	476.4	477.6	480.5	497.8	530.1	549.3	577.6	613.3	645.4	656.3	670.5	668.2	658.3	629.1	605.9	596.0	599.4
Monday	511.7	500.6	491.2	477.7	468.5	463.5	458.8	462.9	466.0	473.2	514.5	560.8	610.8	655.4	682.6	706.6	734.5	769.5	771.7	772.1	760.2	767.3	751.3	748.8
Tuesday	569.9	560.4	552.4	544.7	535.0	532.4	531.6	536.1	546.4	546.9	597.5	632.1	711.6	756.3	778.3	778.1	801.9	830.9	840.4	835.7	816.8	813.2	808.2	811.4
Wednesday	560.4	542.8	529.9	522.7	509.0	503.3	503.5	504.2	506.5	516.7	576.9	613.2	684.4	728.0	748.7	764.7	791.2	813.7	812.3	811.1	793.7	793.8	788.0	792.2
Thursday	574.3	564.3	560.3	545.6	537.1	536.3	535.2	531.8	532.4	532.6	577.1	638.6	704.8	738.8	761.6	765.9	792.1	819.1	809.9	796.1	801.5	803.5	793.0	793.6
Friday	582.8	566.8	559.8	551.5	548.1	550.9	542.7	535.4	544.9	552.4	604.5	640.3	704.4	737.2	765.8	778.5	804.6	829.2	844.7	836.5	819.4	820.0	818.5	820.0
Saturday	586.2 0	569.7 5	544.5 6	530.5 8	515.4 7	513.2 9	508.7 0	510.0 8	515.4 8	514.7 5	544.5 9	575.6 5	647.5 6	669.6 9	698.8 2	727.3 0	746.0 4	755.4 1	760.5 5	763.2 5	771.9 6	764.7 1	755.4 4	754.5 2
September																								
Sunday	563.0	544.8	527.5	522.5	517.3	510.1	504.7	505.5	503.6	506.5	516.5	545.9	577.9	601.0	629.3	649.7	647.2	651.5	647.7	620.1	603.7	585.8	572.4	552.1
Monday	469.8	465.4	459.4	459.0	448.3	447.6	443.0	447.5	452.7	464.0	516.0	596.6	665.1	687.1	678.3	685.9	707.4	739.0	747.0	750.1	735.6	736.6	731.7	739.1
Tuesday	564.9	565.6	553.3	553.6	552.6	549.4	541.0	542.7	546.1	563.2	615.8	699.7	768.2	784.7	768.8	771.3	775.1	795.0	801.8	789.1	787.2	783.7	785.0	784.5
Wednesday	585.4	578.6	566.3	561.0	551.5	549.2	545.5	550.2	552.6	564.9	617.6	695.6	774.9	802.7	790.7	777.8	779.9	792.5	807.2	799.8	783.6	781.3	777.5	780.8
Thursday	589.5	591.2	572.0	566.9	560.2	552.8	552.0	549.9	554.2	561.7	611.0	709.9	784.5	806.7	788.7	761.8	772.6	800.2	791.6	792.1	784.1	769.0	769.9	770.9
Friday	575.0	574.5	565.6	555.7	550.1	538.8	535.9	540.3	544.9	566.7	617.6	687.3	758.5	790.6	[illegible]	788.2	786.1	812.5	817.5	808.7	802.0	796.6	797.3	793.1
Saturday	593.4 0	579.7 2	570.0 8	571.5 6	566.6 2	551.8 2	548.9 7	547.1 6	545.9 5	554.8 3	576.4 7	612.2 0	645.1 1	690.3 0	727.6 0	738.7 4	759.0 2	779.4 2	788.6 7	792.1 9	768.0 6	765.9 5	763.6 5	764.9 1
October																								
Sunday	583.1	566.1	562.9	545.6	536.3	530.7	530.8	525.3	527.7	534.4	549.0	563.1	592.6	623.9	634.2	662.1	654.5	657.5	648.9	640.4	624.9	606.6	599.2	598.0

Time	12.30	13.00	13.30	14.00	14.30	15.00	15.30	16.00	16.30	17.00	17.30	18.00	18.30	19.00	19.30	20.00	20.30	21.00	21.30	22.00	22.30	23.00	23.30	24.00
Monday	508.8	502.9	488.6	491.4	483.5	479.2	478.2	476.6	479.5	490.9	543.0	617.0	678.3	701.5	691.2	696.5	707.0	720.6	738.2	742.0	744.2	737.5	735.4	740.8
Tuesday	576.5	579.3	576.0	567.5	559.6	556.2	555.0	555.2	558.0	570.0	606.5	660.2	736.7	744.8	735.0	725.5	733.0	743.5	752.3	753.0	749.8	745.6	739.0	735.8
Wednesday	567.8	570.0	569.9	546.1	534.0	532.6	529.8	535.1	542.2	556.0	614.1	696.6	753.8	772.7	759.6	762.3	766.6	789.6	796.6	791.8	781.6	777.4	777.3	768.4
Thursday	595.2	594.9	588.4	587.5	574.8	562.8	563.3	560.9	564.3	590.6	638.5	717.5	792.0	793.9	777.6	781.7	793.9	806.6	809.1	799.6	791.1	789.2	792.0	787.9
Friday	609.6	607.2	593.1	579.2	571.1	565.4	563.3	559.3	566.1	585.3	621.2	690.4	739.2	752.2	746.6	745.4	734.4	744.9	756.9	756.9	754.1	755.2	753.2	755.0
Saturday	589.86	581.45	574.54	562.62	549.40	544.85	541.61	537.02	532.00	543.39	562.69	613.89	654.10	682.86	706.03	724.92	741.16	767.03	790.91	779.75	770.47	761.61	758.02	757.11
November																								
Sunday	601.6	587.7	574.6	561.6	545.3	538.1	540.0	533.0	533.4	537.1	543.8	567.5	602.5	617.8	638.4	654.3	660.8	652.4	646.9	637.2	625.0	617.0	606.3	602.0
Monday	505.7	491.9	485.9	475.4	477.2	470.1	467.5	467.4	467.1	488.7	534.0	592.1	641.6	679.6	694.0	710.2	730.1	753.5	770.4	781.3	774.5	764.6	766.0	761.9
Tuesday	567.3	571.9	578.7	577.8	566.6	565.2	560.1	559.5	563.4	582.2	627.4	680.9	751.4	767.0	775.9	779.3	789.9	810.0	816.6	808.9	809.2	810.7	801.2	802.3
Wednesday	588.5	579.1	566.4	557.3	548.8	544.4	543.7	544.6	549.3	562.5	617.7	691.7	746.8	767.1	773.7	777.6	788.0	813.8	819.6	808.4	795.2	790.5	789.3	789.8
Thursday	608.6	591.1	575.0	562.1	551.3	545.0	543.6	543.9	546.2	557.1	609.4	671.6	736.9	775.5	766.3	770.4	785.4	819.1	816.6	812.6	804.6	797.7	792.1	785.6
Friday	594.8	586.6	573.8	567.2	552.5	548.0	546.7	544.5	547.2	562.1	615.6	689.9	747.3	767.3	761.3	776.5	782.5	814.3	800.6	808.6	793.2	806.1	785.1	796.1
Saturday	609.46	595.09	592.50	580.20	568.40	563.88	557.55	560.27	558.73	561.52	592.71	613.26	655.41	690.41	714.90	738.98	755.62	781.05	789.42	783.53	783.14	770.81	772.02	761.02
December																								
Sunday	562.7	548.7	541.3	523.2	508.7	508.2	509.0	505.1	505.0	508.0	522.3	544.6	565.7	579.6	607.1	628.3	640.5	651.4	668.0	641.9	633.0	625.1	609.9	602.5
Monday	507.7	496.3	480.6	468.0	468.4	468.7	465.5	465.5	461.3	463.9	499.9	539.5	576.6	613.3	634.7	665.2	683.7	709.8	716.0	721.1	718.4	704.8	708.0	708.6
Tuesday	565.7	552.5	546.6	522.6	518.7	515.6	513.4	513.0	514.0	521.9	543.6	577.7	606.3	618.2	642.7	662.0	687.0	715.8	726.7	724.5	721.1	717.7	715.6	718.1
Wednesday	555.9	546.0	536.0	518.0	513.2	505.0	499.2	495.1	496.6	511.9	533.8	584.3	613.0	654.3	684.5	724.7	740.0	782.3	791.1	797.5	783.3	768.5	766.9	751.8
Thursday	579.1	577.9	556.3	557.1	554.1	549.2	536.7	538.3	539.6	551.4	571.6	620.7	641.7	693.2	722.0	753.2	774.7	799.1	806.2	796.9	763.7	758.9	756.8	760.1
Friday	585.1	579.3	565.9	553.5	542.9	537.4	536.7	532.0	534.0	545.5	574.2	618.0	651.0	691.3	723.0	757.9	770.0	794.2	810.7	804.3	789.3	785.9	776.9	781.5
Saturday	588.05	572.21	568.74	556.76	544.07	541.70	536.94	533.56	535.00	540.76	557.96	604.38	622.36	656.96	689.34	707.99	727.00	750.57	777.48	780.31	770.54	759.98	754.41	751.09

Table A3-2: Average Thermal 2006 Half-Hourly Demand (MW)

Time	00.30	01.00	01.30	02.00	02.30	03.00	03.30	04.00	04.30	05.00	05.30	06.00	06.30	07.00	07.30	08.00	08.30	09.00	09.30	10.00	10.30	11.00	11.30	12.00
January																								
Sunday	201	206	204	202	196	193	191	189	188	199	200	202	201	201	204	207	208	195	192	192	197	194	192	191
Monday	200	200	191	186	174	173	172	173	176	182	186	188	188	188	192	195	195	185	184	187	186	185	181	182
Tuesday	186	182	180	176	175	176	175	173	175	179	184	187	190	188	192	192	193	187	184	187	187	191	190	192
Wednesday	206	208	207	206	207	208	202	201	202	205	209	209	209	207	207	198	201	198	198	198	198	201	193	194
Thursday	199	197	195	194	195	194	190	192	192	189	186	189	188	190	199	198	199	194	194	192	194	198	200	200
Friday	202	200	201	201	197	201	199	201	201	205	208	207	208	202	201	202	206	196	196	199	197	193	193	197
Saturday	203	202	204	204	203	200	197	197	200	199	204	201	205	200	202	206	207	200	196	196	199	197	197	202
February																								
Sunday	186	183	182	187	184	181	182	184	183	185	191	191	195	190	191	191	175	175	171	172	176	178	171	172
Monday	177	179	176	176	178	182	187	185	189	189	188	189	190	186	188	185	191	194	183	182	179	179	179	181
Tuesday	187	193	190	187	187	186	188	186	188	187	186	189	191	190	189	188	193	193	191	183	181	181	184	184
Wednesday	187	188	189	186	183	184	182	182	184	184	185	189	187	187	189	191	191	191	188	190	189	190	187	187
Thursday	188	191	188	185	184	185	182	183	181	182	184	186	186	186	185	183	191	182	183	185	187	191	190	190
Friday	190	190	191	191	190	190	188	190	193	195	194	191	194	192	194	204	206	201	200	198	194	195	194	195
Saturday	190	189	188	187	190	187	188	188	184	184	182	182	186	184	181	189	186	188	190	188	190	190	188	185
March																								
Sunday	187	184	187	186	183	183	184	181	181	182	184	183	183	178	179	180	178	163	163	171	176	173	174	175
Monday	180	180	174	168	166	165	163	168	166	169	178	186	190	188	188	181	187	189	186	184	182	176	175	176
Tuesday	194	194	195	195	193	191	194	192	192	193	194	193	197	195	196	198	198	194	191	193	190	188	188	187
Wednesday	195	195	193	186	185	184	185	184	189	195	197	198	197	195	191	193	185	184	184	180	183	182	178	183
Thursday	191	190	188	189	188	187	186	186	187	190	191	193	195	191	194	194	194	189	186	179	180	179	179	181
Friday	196	193	196	195	195	197	197	198	198	195	196	195	195	193	196	197	195	188	188	189	192	189	187	188
Saturday	199	200	200	195	199	197	196	193	191	194	192	193	192	191	192	191	190	187	189	188	185	188	184	181
April																								
Sunday	203	179	179	175	170	168	167	169	170	173	172	182	182	183	187	189	184	180	175	174	179	178	181	183
Monday	196	166	163	160	161	163	158	159	162	164	168	180	187	187	190	191	191	184	178	179	179	182	184	181
Tuesday	186	195	192	191	192	190	189	189	189	190	192	198	198	199	199	196	193	195	192	191	189	186	192	187
Wednesday	171	193	192	192	187	186	182	181	184	188	191	200	201	197	200	198	197	195	195	192	194	188	185	183
Thursday	193	193	188	194	195	194	191	193	194	195	195	201	206	207	207	207	208	205	206	201	205	200	201	200
Friday	197	197	197	197	196	192	190	191	191	193	202	199	202	200	202	202	201	201	201	202	201	203	200	199
Saturday	200	194	190	184	184	180	178	181	182	185	183	193	204	196	199	194	195	194	195	194	186	185	188	187
May																								
Sunday	179	161	155	149	142	141	142	142	141	141	142	154	159	153	154	155	155	143	134	140	140	142	139	140

Time	00.30	01.00	01.30	02.00	02.30	03.00	03.30	04.00	04.30	05.00	05.30	06.00	06.30	07.00	07.30	08.00	08.30	09.00	09.30	10.00	10.30	11.00	11.30	12.00
Monday	133	126	125	121	121	118	115	115	118	119	119	133	148	155	168	169	167	162	160	158	160	159	159	156
Tuesday	171	159	156	155	153	148	145	145	144	147	161	180	188	185	187	187	189	185	183	180	179	178	178	178
Wednesday	175	168	161	156	148	150	151	150	155	158	177	187	194	189	191	191	188	184	183	183	181	182	180	182
Thursday	163	158	159	155	157	156	154	155	154	158	162	169	167	173	178	179	184	184	182	178	177	175	177	176
Friday	167	157	154	153	152	151	151	153	153	156	162	169	179	176	178	175	172	171	170	168	168	169	170	171
Saturday	161	159	156	157	158	157	156	156	157	157	158	159	166	164	168	166	167	170	168	169	169	166	171	173
June																								
Sunday	199	189	183	176	174	174	172	171	173	176	183	191	199	197	208	205	200	189	186	200	205	203	208	206
Monday	163	147	137	132	127	124	123	123	129	137	170	185	206	209	211	211	207	205	206	206	206	207	205	205
Tuesday	197	194	181	175	167	170	168	166	171	178	194	198	206	204	207	210	206	203	205	203	201	200	201	201
Wednesday	198	195	190	188	181	175	174	174	174	178	196	199	212	212	212	213	214	210	200	196	200	199	200	199
Thursday	191	190	188	191	187	186	185	184	184	185	203	207	205	187	193	207	202	202	201	200	201	199	193	195
Friday	206	192	185	182	180	178	174	172	175	185	201	204	207	205	203	204	206	206	210	210	209	207	204	201
Saturday	199	198	185	183	184	182	182	183	179	179	201	211	221	221	224	223	214	212	219	220	218	216	217	216
July																								
Sunday	222	222	207	204	198	195	192	190	191	195	211	216	226	222	228	232	234	227	222	229	220	214	220	224
Monday	198	188	184	177	173	171	169	170	174	182	210	217	234	242	246	246	244	243	245	244	241	241	239	238
Tuesday	214	210	208	204	198	194	194	195	199	201	228	236	249	245	245	245	242	242	248	244	245	251	247	246
Wednesday	225	224	210	208	203	204	197	199	200	198	225	226	234	242	240	240	241	245	244	241	240	238	237	240
Thursday	214	215	203	200	200	198	196	195	200	201	222	230	235	242	245	242	240	253	252	251	252	252	247	247
Friday	208	208	200	201	197	197	195	196	207	209	227	228	238	237	251	251	247	256	257	253	254	253	252	251
Saturday	216	214	207	204	195	195	194	193	194	195	215	225	242	238	243	244	245	243	242	243	243	242	244	244
August																								
Sunday	193	181	171	162	159	154	154	153	153	153	161	168	180	194	209	215	216	211	203	203	200	194	190	190
Monday	188	185	178	172	168	168	164	164	174	178	197	207	224	226	232	235	242	237	239	239	233	231	217	217
Tuesday	197	195	192	189	186	182	179	181	190	191	216	216	228	229	239	237	242	242	246	246	245	245	246	244
Wednesday	190	186	178	172	164	157	159	161	161	166	193	197	219	226	236	232	240	244	243	242	239	238	234	235
Thursday	189	189	188	186	180	179	177	174	176	176	196	201	233	233	251	255	257	255	249	248	261	265	262	260
Friday	204	200	194	193	193	194	190	188	189	190	209	216	241	251	258	258	259	257	255	251	250	258	257	257
Saturday	202	196	191	182	174	175	171	174	174	173	183	195	216	215	228	231	236	221	218	222	227	227	221	220
September																								
Sunday	229	216	201	192	193	190	189	188	188	189	194	204	220	228	231	245	244	228	221	204	202	205	212	218
Monday	182	177	178	178	167	168	164	166	168	172	195	227	236	239	239	242	248	250	252	255	261	263	260	262
Tuesday	221	221	220	220	221	221	222	221	222	229	236	240	264	276	276	278	282	284	282	278	277	276	274	274
Wednesday	247	240	236	235	234	235	234	235	236	236	239	252	264	284	286	288	287	285	279	280	276	274	266	268
Thursday	248	249	246	243	237	230	230	228	229	220	227	257	264	278	270	272	273	277	276	278	279	285	284	285

Time	00.30	01.00	01.30	02.00	02.30	03.00	03.30	04.00	04.30	05.00	05.30	06.00	06.30	07.00	07.30	08.00	08.30	09.00	09.30	10.00	10.30	11.00	11.30	12.00
Friday	239	235	234	231	230	225	221	222	223	225	235	247	264	284	289	292	291	289	286	282	282	283	285	281
Saturday	250	244	242	245	244	233	230	228	225	227	234	247	250	259	262	261	264	262	260	264	262	261	265	263
October																								
Sunday	231	226	227	223	217	217	215	212	210	214	215	220	228	237	240	243	238	238	242	243	251	250	247	244
Monday	210	202	197	198	195	191	189	188	189	189	200	231	250	259	261	260	262	264	264	263	273	274	273	273
Tuesday	251	250	251	251	250	252	249	249	250	252	255	257	267	282	282	273	271	267	272	275	276	278	275	276
Wednesday	248	250	247	241	228	225	224	225	231	234	240	263	275	281	281	286	286	295	295	288	280	281	279	274
Thursday	244	241	238	241	241	234	232	231	231	236	242	273	282	284	287	285	286	282	282	280	283	281	279	279
Friday	247	248	247	242	240	242	241	236	233	241	246	264	268	275	285	289	286	282	282	280	281	281	278	279
Saturday	229	229	225	218	214	215	214	212	210	213	219	243	252	269	274	284	286	287	294	292	287	286	285	286
November																								
Sunday	184	176	172	166	155	150	152	147	146	147	148	168	184	187	188	187	189	190	196	195	201	198	192	186
Monday	138	133	131	126	123	119	119	120	122	132	141	149	158	173	175	183	191	185	184	183	176	177	176	174
Tuesday	139	142	146	156	152	152	153	151	154	153	161	174	184	192	201	209	209	207	210	209	214	218	217	214
Wednesday	183	178	169	166	164	162	162	161	161	163	169	197	208	215	219	222	223	234	241	232	230	232	231	234
Thursday	180	178	178	175	168	165	164	163	164	166	178	189	202	217	216	225	225	229	232	235	234	233	229	226
Friday	193	184	178	172	171	170	169	166	168	172	181	209	220	227	227	240	236	233	233	232	232	239	233	234
Saturday	195	192	192	186	177	171	169	170	169	168	178	185	181	188	193	194	199	197	203	204	205	204	203	208
December																								
Sunday	125	115	111	100	100	101	101	100	101	102	104	110	121	121	121	123	127	124	140	144	146	146	145	145
Monday	119	114	104	104	104	105	104	104	102	103	110	124	146	149	144	152	163	165	163	170	174	171	171	169
Tuesday	147	138	135	110	108	108	106	103	105	107	114	126	140	143	144	152	156	157	165	170	167	166	166	167
Wednesday	142	140	133	133	130	127	127	128	128	134	143	159	165	167	171	188	200	206	204	203	205	198	202	192
Thursday	155	152	143	140	127	129	126	128	129	135	141	165	172	174	184	196	200	201	208	214	207	205	202	210
Friday	135	133	132	126	123	121	119	117	116	119	124	133	142	153	169	182	181	185	189	190	191	192	196	192
Saturday	157	151	148	145	142	142	140	138	133	132	133	147	149	161	171	178	181	179	186	190	187	185	182	184

Table A3-3: Nairobi Minimum Generation (MW)

Time	00.30	01.00	01.30	02.00	02.30	03.00	03.30	04.00	04.30	05.00	05.30	06.00	06.30	07.00	07.30	08.00	08.30	09.00	09.30	10.00	10.30	11.00	11.30	12.00
January																								
Sunday	34.6	29.5	27.8	25.6	24.2	23.4	23.4	23.4	24.6	27.2	33.2	41.8	47.6	49.0	49.2	49.8	49.8	49.7	49.7	50.2	49.8	49.7	49.8	49.8
Monday	32.2	29.8	28.3	27.7	27.8	27.8	27.8	27.9	27.7	27.8	30.3	34.3	44.8	48.9	51.3	52.0	52.1	52.0	52.1	52.1	52.0	52.1	52.1	52.0
Tuesday	36.4	32.3	28.4	27.4	26.8	26.2	25.7	25.6	25.5	25.6	26.8	33.5	40.8	46.8	47.4	47.3	48.8	50.1	50.3	49.8	49.9	49.9	49.8	49.9
Wednesday	16.7	16.7	16.7	16.7	15.0	13.9	13.9	13.9	14.6	16.5	24.4	31.9	41.9	49.8	52.7	52.6	51.8	51.3	51.3	51.3	51.4	51.2	51.3	51.3
Thursday	36.0	32.0	30.2	29.2	29.2	29.2	29.2	29.2	28.9	35.2	40.2	47.2	50.4	51.4	51.4	51.4	51.4	51.4	51.4	51.5	51.4	51.3	50.4	50.2
Friday	35.2	29.7	26.5	26.4	26.6	26.5	26.6	26.6	26.6	30.3	38.1	46.7	51.3	51.4	51.5	51.4	51.4	51.5	50.5	50.0	50.1	50.0	50.6	51.5
Saturday	35.9	32.9	28.4	27.7	26.4	25.4	24.9	24.9	25.7	27.9	33.8	44.8	49.4	49.7	50.0	49.8	49.8	50.5	51.2	50.2	49.9	49.6	48.4	48.3
February																								
Sunday	34.3	29.3	29.2	29.3	29.3	29.2	29.3	29.3	29.3	31.2	38.3	44.8	50.9	55.9	54.9	54.6	54.4	54.5	54.5	54.6	54.5	54.5	54.5	54.4
Monday	34.9	27.9	27.9	27.7	27.7	27.9	27.8	27.8	27.9	29.2	33.0	40.7	45.4	52.0	53.7	54.9	54.4	53.4	51.8	51.5	50.4	50.1	50.2	49.4
Tuesday	41.2	37.7	33.8	31.8	29.2	27.8	27.7	27.6	27.8	29.1	32.5	38.8	45.4	46.6	49.2	53.0	53.1	51.6	51.6	49.2	41.1	41.0	43.3	46.5
Wednesday	22.7	19.3	18.3	18.2	18.2	18.2	18.2	18.2	18.5	22.3	32.3	46.7	48.1	49.1	50.2	51.8	51.7	51.7	51.7	51.7	51.7	51.7	51.8	51.7
Thursday	25.4	22.2	22.3	22.2	22.3	22.3	22.3	22.2	22.2	28.1	32.5	41.3	45.9	49.6	53.1	53.0	53.1	53.1	53.1	52.2	51.6	50.1	48.9	52.0
Friday	27.4	25.0	25.0	24.9	25.0	25.0	25.0	25.0	24.8	28.4	35.4	42.0	45.7	50.0	51.6	50.5	50.2	50.2	50.3	50.3	50.2	50.2	50.3	50.2
Saturday	32.7	28.3	27.4	26.4	26.5	26.5	26.5	26.5	27.4	28.7	32.1	42.6	47.6	52.9	53.1	53.0	53.0	53.0	53.0	53.0	53.1	52.9	53.0	53.1
March																								
Sunday	37.6	37.3	32.4	30.5	30.5	30.5	30.4	30.5	30.4	30.4	35.5	42.9	47.7	50.4	51.7	51.7	52.1	52.6	52.4	52.4	52.6	52.5	52.4	52.4
Monday	38.0	35.4	34.7	34.6	34.5	34.7	34.7	34.5	34.7	35.4	36.8	39.1	44.8	51.0	51.7	51.8	51.3	50.4	50.5	50.4	50.4	50.4	50.4	50.4
Tuesday	37.8	35.9	34.7	34.7	34.8	34.7	34.7	34.6	35.6	36.3	37.7	44.3	46.2	51.9	53.2	52.9	51.6	50.6	50.3	50.2	50.2	50.2	50.3	50.3
Wednesday	26.6	25.8	24.5	24.5	23.9	23.4	23.4	23.4	24.1	26.6	35.9	43.0	47.0	49.5	50.2	51.4	51.4	51.5	51.4	51.4	51.4	51.5	51.5	51.4
Thursday	42.7	35.9	34.3	34.4	34.4	34.4	34.4	34.4	35.2	36.7	37.2	45.5	47.6	50.7	52.6	52.4	51.3	51.4	51.4	50.2	50.3	50.2	50.2	50.3
Friday	33.3	29.8	28.8	26.7	26.6	26.6	26.5	26.5	27.3	33.7	40.1	48.2	52.4	53.6	53.7	53.6	53.7	52.8	52.5	51.7	51.5	46.6	45.1	48.2
Saturday	33.1	30.5	30.5	30.4	30.4	30.4	30.5	29.7	29.4	29.2	32.2	41.2	46.3	53.1	52.1	51.7	51.8	50.8	50.3	50.3	50.4	50.4	50.4	50.3
April																								
Sunday	47.8	43.2	42.5	41.8	41.3	41.4	41.4	41.8	44.0	48.2	51.5	51.5	51.4	51.4	51.5	51.5	51.4	50.6	50.5	50.4	50.4	50.0	49.4	49.4
Monday	45.8	38.6	34.8	34.8	35.2	36.2	36.2	36.2	37.9	43.0	48.7	50.3	51.0	50.5	50.3	50.2	50.1	50.3	50.2	50.2	50.2	50.2	50.2	50.6
Tuesday	44.4	44.6	43.0	41.9	41.8	41.8	42.0	41.9	42.7	44.5	45.2	49.3	53.0	51.9	52.0	53.0	50.7	50.1	50.0	50.1	50.2	50.1	50.1	50.0
Wednesday	42.4	23.7	23.7	23.7	23.7	23.6	23.7	26.5	28.5	36.2	41.0	43.3	46.6	49.6	50.2	50.4	50.8	51.9	51.8	51.8	51.9	51.8	51.8	51.8
Thursday	49.4	38.2	31.4	29.3	29.2	29.2	29.3	29.9	37.1	46.1	53.1	54.5	54.5	52.3	51.7	51.7	51.7	51.6	51.7	52.2	53.1	53.1	53.2	53.2
Friday	25.5	47.0	39.2	36.5	36.3	36.3	36.4	36.4	37.6	44.6	51.7	52.3	53.1	53.0	53.2	53.1	53.0	53.1	53.0	53.2	53.1	53.1	53.1	50.6
Saturday	44.1	43.2	42.4	42.4	42.4	42.5	42.4	42.5	44.0	48.1	50.6	50.3	50.4	50.4	50.4	50.4	50.4	50.4	50.3	50.4	50.4	50.4	50.3	50.3
May																								
Sunday	39.8	38.0	37.5	35.7	35.1	35.0	34.9	35.0	39.3	44.3	48.1	51.7	51.9	52.0	52.1	52.0	49.4	49.2	49.2	49.3	49.3	49.3	49.2	49.3
Monday	39.5	33.4	32.3	32.3	32.2	32.2	32.2	32.2	34.0	37.5	40.5	42.8	47.2	49.5	52.4	52.7	52.7	52.8	52.7	52.7	52.7	52.7	51.8	51.7
Tuesday	42.7	38.2	39.6	37.5	35.6	35.6	35.6	35.6	35.7	37.2	40.1	42.8	48.3	50.7	51.6	51.8	51.7	51.6	51.7	51.8	51.6	51.7	51.6	51.8
Wednesday	28.5	26.5	25.7	25.6	25.7	25.7	25.6	27.0	30.6	36.4	41.0	45.5	47.1	47.1	47.5	49.4	48.8	50.0	49.6	49.4	49.4	48.6	48.2	48.3
Thursday	38.1	34.8	32.0	31.9	30.5	30.2	26.7	26.4	28.3	34.4	39.2	43.1	46.7	48.9	48.9	49.0	47.6	47.9	49.0	49.1	49.2	49.1	49.1	49.1
Friday	48.9	42.4	37.1	35.0	33.0	29.4	29.2	29.3	31.4	38.7	46.2	49.8	50.5	50.4	49.1	49.1	47.8	48.1	49.9	50.5	50.4	50.6	50.5	50.5
Saturday	40.1	35.5	34.9	34.9	35.1	35.0	34.9	35.0	38.6	42.6	47.5	50.9	50.8	50.5	50.5	50.5	50.5	50.5	50.6	50.5	50.5	50.5	50.5	50.5

Time	00.30	01.00	01.30	02.00	02.30	03.00	03.30	04.00	04.30	05.00	05.30	06.00	06.30	07.00	07.30	08.00	08.30	09.00	09.30	10.00	10.30	11.00	11.30	12.00
June																								
Sunday	47.6	47.6	44.2	40.7	40.1	39.4	39.4	39.5	39.4	42.0	46.5	49.1	49.0	48.9	49.1	49.0	49.0	48.9	49.1	49.1	49.0	49.0	49.2	49.1
Monday	47.6	45.4	40.8	39.2	39.2	39.2	39.3	39.3	40.0	41.8	45.4	49.0	49.1	49.1	47.5	47.5	47.6	47.7	47.5	47.5	47.5	47.7	48.5	48.9
Tuesday	37.3	36.2	36.2	34.2	33.5	33.5	33.4	33.5	33.4	33.4	33.4	37.3	42.7	43.6	46.4	47.4	47.4	47.5	45.3	44.3	46.0	45.9	46.1	46.1
Wednesday	36.5	34.8	34.9	34.9	35.0	34.9	34.8	34.9	34.9	35.0	40.7	49.6	50.2	50.3	50.3	49.2	48.4	47.5	47.4	47.5	47.6	47.6	47.6	47.6
Thursday	38.2	37.5	37.0	37.0	37.0	37.0	36.9	37.0	37.0	38.3	45.3	47.3	48.9	50.4	50.3	50.3	50.4	48.9	48.0	48.1	47.5	47.1	46.1	46.5
Friday	41.5	41.3	41.4	40.4	40.9	41.4	41.6	41.6	41.6	42.2	46.0	48.9	45.6	46.9	46.8	46.9	46.8	45.9	45.7	45.7	45.8	45.7	45.7	45.8
Saturday	36.8	36.3	36.4	36.3	33.1	29.1	33.6	36.3	36.9	39.7	43.1	47.5	49.0	49.0	49.1	49.0	49.0	49.0	49.1	49.1	49.0	49.0	49.1	49.1
July																								
Sunday	52.5	52.5	52.6	52.6	52.5	52.5	52.5	52.5	52.6	52.6	52.5	52.6	52.6	51.0	50.3	50.3	50.3	50.4	50.8	51.5	45.6	43.6	42.3	41.7
Monday	51.9	51.8	51.9	51.8	48.4	47.7	47.6	47.6	47.7	47.8	47.6	49.1	53.2	53.3	51.9	51.6	51.8	51.7	50.9	50.3	50.4	50.3	50.4	49.8
Tuesday	48.4	48.7	48.9	45.6	44.5	44.5	44.5	45.1	45.9	47.9	50.1	50.1	50.3	50.2	50.2	50.1	50.2	50.2	50.2	50.1	50.3	49.3	48.7	48.0
Wednesday	53.2	53.2	48.7	47.6	47.5	47.5	47.5	47.5	47.5	46.2	50.2	51.8	51.7	51.8	51.7	51.5	51.4	50.7	50.3	50.4	49.3	48.8	48.9	50.0
Thursday	51.9	51.8	51.8	51.9	51.8	51.9	51.9	51.8	51.8	52.3	53.2	53.2	53.2	53.3	53.2	53.2	53.1	53.3	51.5	50.4	50.5	51.0	50.6	50.5
Friday	50.5	49.6	49.0	49.0	49.0	49.0	49.3	50.6	52.0	53.3	53.2	53.2	53.2	53.3	53.2	53.1	53.2	53.2	52.5	52.1	53.3	52.7	51.7	51.6
Saturday	50.2	50.2	50.7	51.5	50.9	50.3	48.6	48.1	48.1	48.1	49.7	51.5	51.5	50.0	48.5	49.2	49.3	49.3	49.3	49.3	49.3	48.2	48.1	48.1
August																								
Sunday	44.2	36.5	32.4	29.3	28.3	28.2	28.1	28.0	28.1	28.1	28.1	28.3	32.0	37.9	45.4	48.8	49.3	48.4	47.8	47.9	47.7	44.7	40.8	40.8
Monday	29.7	26.3	26.6	26.7	26.2	26.5	26.6	26.5	27.7	28.3	34.1	41.1	45.1	48.1	49.2	49.2	49.2	49.1	49.1	49.1	49.2	49.2	48.6	49.0
Tuesday	48.3	47.8	44.8	44.9	44.8	44.8	44.8	44.8	44.9	44.9	45.3	47.2	48.8	50.5	50.5	50.4	50.5	49.9	49.0	48.2	48.2	48.2	48.3	47.4
Wednesday	47.2	44.9	41.6	37.0	33.6	33.3	34.8	37.1	37.2	40.0	44.3	48.0	48.8	49.3	49.5	49.3	48.8	48.2	48.2	48.2	48.2	48.3	48.2	48.3
Thursday	46.1	45.4	44.9	42.3	39.4	39.2	39.3	39.4	39.3	39.3	41.5	45.6	46.0	46.1	46.0	46.0	46.0	45.2	44.9	44.9	44.9	45.0	44.3	44.1
Friday	46.8	46.3	46.1	46.1	46.1	46.2	42.8	40.5	40.6	40.6	41.6	44.8	46.8	47.8	49.0	49.1	49.1	49.0	49.1	49.1	49.1	49.1	49.0	49.1
Saturday	43.1	40.2	38.2	34.7	30.9	30.7	30.8	30.8	30.7	30.7	37.0	43.7	46.0	47.7	47.5	47.7	46.2	44.7	44.7	44.6	45.3	45.6	46.5	47.7
September																								
Sunday	24.5	17.6	12.8	11.1	11.1	11.1	11.2	11.2	11.1	11.2	16.2	22.5	29.1	29.5	32.3	36.7	37.8	37.9	37.8	37.8	37.9	37.8	37.9	37.8
Monday	11.1	11.1	11.2	11.2	11.1	11.1	11.1	11.2	11.2	11.1	13.3	24.2	34.2	36.5	37.8	38.4	40.7	40.5	38.1	37.6	37.8	39.0	39.0	39.0
Tuesday	25.3	25.0	24.8	24.9	25.1	25.0	25.0	25.1	24.8	26.6	28.4	33.4	39.7	41.7	43.3	44.3	43.6	43.4	43.5	43.4	43.4	43.4	43.4	43.4
Wednesday	36.5	29.7	27.5	27.6	27.7	27.7	27.8	27.8	27.7	27.6	31.6	38.1	40.7	44.8	44.9	44.9	44.8	44.8	44.8	44.9	44.9	44.4	43.3	43.3
Thursday	34.6	32.1	32.1	32.0	30.7	27.7	27.7	27.8	27.8	27.9	30.6	42.9	44.5	44.9	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.7
Friday	33.8	32.6	32.4	26.5	25.9	24.4	23.4	23.4	23.4	25.7	29.4	34.7	39.9	44.5	45.0	44.8	43.8	43.8	43.8	43.8	43.9	43.8	43.8	43.4
Saturday	35.4	32.6	32.2	32.3	30.8	29.3	28.1	26.8	24.6	24.7	29.2	34.7	36.0	39.3	41.8	41.6	38.8	38.0	37.8	37.9	37.9	37.8	37.9	37.9
October																								
Sunday	30.2	24.7	24.7	24.6	21.1	21.1	21.2	21.1	21.2	22.0	23.4	23.1	24.4	28.1	31.5	32.5	33.4	37.4	41.4	41.4	41.5	39.6	38.5	36.4
Monday	16.5	13.6	13.4	13.4	13.3	13.4	13.4	13.4	13.4	13.4	19.1	35.2	42.3	44.7	44.8	44.8	45.7	47.5	49.6	50.6	52.1	52.6	52.7	51.5
Tuesday	37.0	35.9	35.2	32.5	31.2	30.2	30.2	32.2	34.5	36.0	39.7	43.0	48.0	50.3	51.4	44.7	42.5	42.8	46.4	51.3	51.4	51.5	51.4	51.3
Wednesday	34.9	34.9	35.0	33.9	28.0	26.5	26.4	26.5	26.3	26.4	30.4	40.3	47.2	51.1	53.2	54.4	55.7	55.0	54.7	54.6	49.6	47.7	47.6	40.6
Thursday	33.4	33.5	33.5	33.5	32.1	27.5	26.5	26.4	26.4	27.4	30.9	41.3	44.7	48.0	50.5	50.4	50.5	50.5	50.5	50.5	50.5	50.5	50.6	50.6
Friday	32.1	32.0	31.7	28.2	25.0	23.4	21.3	19.5	19.6	23.3	30.5	40.6	42.1	43.4	50.6	50.6	50.6	50.4	50.5	50.4	50.4	50.5	50.5	50.6
Saturday	32.4	32.3	32.4	29.5	25.3	25.2	24.3	23.0	19.5	20.5	23.5	37.7	47.0	49.1	49.2	50.3	50.5	51.4	51.9	52.0	52.0	51.9	51.8	51.9
November																								

Time	00.30	01.00	01.30	02.00	02.30	03.00	03.30	04.00	04.30	05.00	05.30	06.00	06.30	07.00	07.30	08.00	08.30	09.00	09.30	10.00	10.30	11.00	11.30	12.00
Sunday	11.2	11.1	11.2	11.2	11.3	11.2	11.1	11.2	11.1	11.3	12.0	17.2	22.6	24.8	24.8	25.0	25.0	24.9	20.6	20.7	22.1	22.1	20.6	19.4
Monday	13.9	12.7	11.3	11.2	11.2	11.1	11.2	11.1	12.0	15.5	20.1	23.0	25.0	25.0	25.0	25.3	26.7	27.6	27.9	27.7	27.9	27.7	26.8	26.4
Tuesday	13.9	13.8	13.8	13.9	13.9	14.0	13.9	13.9	14.0	14.1	19.6	30.3	34.6	36.4	36.4	36.5	37.0	39.4	44.3	47.2	49.1	49.2	46.4	45.0
Wednesday	20.0	18.7	14.8	13.3	13.4	13.4	13.4	13.4	13.2	15.9	20.5	34.3	41.8	46.0	46.0	46.0	46.2	46.2	47.0	41.4	40.8	40.1	41.0	46.3
Thursday	19.6	18.0	17.9	17.9	17.8	16.4	15.6	15.6	15.6	17.5	25.5	31.5	37.8	42.3	43.7	43.6	42.8	45.6	48.0	49.3	48.2	48.3	46.9	45.0
Friday	19.5	17.6	16.7	16.8	16.9	16.9	16.8	16.7	16.9	20.9	25.3	36.3	44.0	47.7	47.6	48.6	46.1	43.9	46.3	51.1	51.9	51.3	50.5	50.5
Saturday	23.2	20.1	19.4	19.3	17.5	16.6	16.7	16.8	16.7	16.9	22.1	27.9	28.9	30.9	30.7	30.9	32.1	34.8	37.8	44.9	45.0	44.9	44.9	44.3
December																								
Sunday	4.5	4.5	4.4	4.5	4.4	4.4	4.5	4.4	4.4	4.5	4.4	9.6	12.8	12.8	12.9	12.9	12.9	12.7	22.5	26.5	30.0	30.0	30.0	30.3
Monday	11.1	11.1	9.9	8.4	8.4	8.4	8.4	8.3	8.4	8.4	10.2	14.8	25.1	29.8	29.8	29.9	30.4	32.8	32.9	32.6	32.9	32.9	32.7	32.8
Tuesday	16.7	16.8	13.4	11.1	11.1	11.1	11.2	11.1	11.0	11.1	17.0	18.1	20.5	19.8	24.2	28.9	38.3	38.3	38.2	38.3	38.3	37.3	37.0	37.0
Wednesday	18.2	17.1	15.3	15.4	14.6	12.0	9.8	9.8	9.9	10.4	17.3	32.8	34.4	35.9	39.1	41.2	46.7	51.0	50.2	50.2	50.1	50.0	44.3	37.4
Thursday	23.7	21.1	19.4	16.9	13.9	13.9	13.8	13.9	13.9	13.8	18.2	33.9	39.3	41.2	42.2	42.5	42.4	42.4	42.4	49.9	50.2	50.2	50.4	50.4
Friday	11.0	11.1	8.9	6.7	6.6	6.6	5.7	4.5	4.5	4.5	5.1	8.9	8.9	20.0	31.3	34.8	35.6	37.9	36.0	35.6	35.6	35.6	35.6	35.6
Saturday	8.9	8.0	6.7	5.8	4.6	4.5	4.4	4.4	4.4	4.5	6.0	15.1	17.8	22.2	27.1	30.6	32.4	32.4	36.4	38.6	38.6	38.6	38.6	38.6

Time	12.30	13.00	13.30	14.00	14.30	15.00	15.30	16.00	16.30	17.00	17.30	18.00	18.30	19.00	19.30	20.00	20.30	21.00	21.30	22.00	22.30	23.00	23.30	24.00
January																								
Sunday	49.7	49.8	49.8	49.9	50.4	50.9	51.0	51.0	50.9	51.0	50.9	51.0	51.0	51.0	51.0	51.0	51.4	52.0	52.1	52.1	52.0	52.1	44.9	37.6
Monday	51.8	51.0	51.0	51.0	51.0	50.4	50.0	50.0	50.0	50.0	50.0	50.4	51.1	51.6	52.1	52.1	52.0	52.1	52.1	52.1	52.0	52.1	44.9	39.5
Tuesday	49.1	48.8	48.7	48.8	49.6	48.9	48.7	48.6	48.7	48.6	48.6	49.1	49.9	48.8	48.8	48.8	48.8	48.8	48.8	46.7	46.1	44.6	38.4	22.1
Wednesday	51.3	51.4	51.3	51.2	51.4	51.3	51.3	51.3	51.3	51.3	51.3	51.4	51.3	51.3	51.4	51.5	52.1	52.7	52.7	52.7	52.7	50.7	46.3	42.3
Thursday	50.1	50.0	50.0	49.9	50.1	50.0	50.0	50.0	50.0	50.1	50.0	50.0	50.0	50.5	51.4	51.4	51.4	51.4	51.4	51.5	51.4	51.4	46.9	44.9
Friday	51.5	51.5	51.4	51.4	51.5	51.4	51.4	51.5	51.4	51.5	51.4	51.5	51.4	51.4	51.4	52.0	52.6	52.7	52.7	52.8	52.7	52.7	52.7	48.6
Saturday	48.3	48.3	48.4	48.3	48.3	48.4	48.4	48.4	48.4	48.3	48.4	48.6	49.0	49.1	49.9	50.3	51.2	51.2	51.2	51.2	51.2	51.2	48.1	42.5
February																								
Sunday	54.5	54.6	54.5	54.5	54.5	54.4	54.5	54.6	54.5	54.4	55.8	55.9	56.0	55.8	56.0	55.9	55.9	56.0	55.9	56.0	55.9	55.9	52.3	49.3
Monday	48.8	48.7	48.9	48.8	48.8	49.0	50.1	50.1	50.1	50.1	50.4	51.6	51.5	51.6	51.6	51.5	51.6	51.7	51.7	51.6	51.5	49.6	47.3	42.0
Tuesday	48.6	48.7	48.6	48.6	48.6	49.0	50.2	50.0	50.1	50.2	50.1	50.8	51.6	52.1	53.2	53.0	53.2	53.1	53.1	53.0	51.1	44.2	37.0	32.0
Wednesday	51.6	51.7	52.2	53.1	53.1	53.1	53.1	53.1	51.6	51.7	51.6	51.5	51.6	51.6	51.7	51.6	51.6	51.7	51.5	51.8	53.1	53.1	43.0	35.5
Thursday	52.5	53.1	53.1	53.1	53.1	53.2	53.1	53.0	53.1	53.2	53.1	53.0	53.2	53.1	53.0	53.1	53.2	53.0	53.1	53.1	53.1	52.9	43.4	36.5
Friday	50.1	50.2	50.3	50.2	50.2	50.2	50.2	50.2	50.2	50.2	50.2	50.3	50.2	50.1	50.2	50.2	50.3	50.2	50.6	51.5	51.6	51.1	47.3	40.3
Saturday	53.0	53.2	53.3	53.7	54.4	54.4	54.4	54.4	54.4	54.4	54.5	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	54.4	52.7	46.9
March																								
Sunday	52.6	52.6	52.5	52.4	52.5	52.5	52.6	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	50.1	45.0
Monday	50.4	50.5	50.4	50.3	50.4	50.4	50.4	50.4	50.3	51.4	51.8	51.8	51.7	51.9	51.8	51.7	51.7	51.8	51.8	51.7	51.8	51.8	51.2	43.1
Tuesday	50.1	50.2	50.3	49.3	48.8	48.8	48.9	48.9	48.9	48.9	48.8	48.9	48.9	48.8	49.4	50.3	50.4	50.3	50.4	51.3	51.8	51.8	39.2	28.3
Wednesday	51.4	51.4	51.5	51.4	51.5	51.4	51.5	51.4	51.4	51.5	51.5	51.4	51.4	51.4	51.5	51.5	51.5	51.4	51.4	51.4	51.5	51.4	48.9	44.6
Thursday	50.2	50.2	50.2	50.3	50.3	50.2	50.2	50.3	50.3	50.3	50.2	50.3	50.3	50.3	50.3	50.5	51.4	51.4	51.9	52.8	53.7	53.7	53.4	43.2
Friday	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.3	51.4	51.5	51.3	51.4	51.5	51.4	51.4	51.4	51.4	51.9	52.5	52.5	52.6	52.6	48.0	37.7
Saturday	50.4	50.4	50.4	50.4	50.3	50.4	50.4	50.3	47.3	47.5	48.5	50.1	50.4	50.9	51.8	51.7	51.8	51.8	51.7	51.7	51.7	51.7	51.0	39.5

[illegible]	[illegible]	13.00	13.30	14.00	14.30	15.00	15.30	16.00	16.30	17.00	17.30	18.00	18.30	19.00	19.30	20.00	20.30	21.00	21.30	22.00	22.30	23.00	23.30	24.00
April																								
Sunday	49.3	49.3	49.4	49.2	49.3	49.3	49.3	49.4	49.4	48.5	48.2	48.2	48.2	48.2	48.2	49.1	49.3	49.3	49.3	49.3	49.3	49.3	48.4	45.1
Monday	51.6	51.6	51.6	51.9	52.7	53.0	53.0	53.0	53.1	52.9	53.0	53.0	53.0	53.1	52.9	53.0	53.1	53.0	52.9	53.0	53.1	53.0	53.1	53.0
Tuesday	50.2	50.1	50.1	50.0	50.2	51.0	51.5	51.5	51.4	51.6	51.5	51.5	51.5	51.5	51.5	51.6	51.5	52.1	53.0	53.0	53.6	54.5	52.0	39.7
Wednesday	51.8	51.8	50,6	50.4	50.4	50.5	50.4	50.4	50.4	50.5	36.4	36.8	39.6	41.9	42.4	48.9	53.2	53.1	53.1	53.1	53.1	53.2	53.2	53.1
Thursday	53.2	53.2	53.1	53.1	53.2	53.1	53.1	53.0	52.2	51.8	51.7	51.8	51.7	50.7	50.4	50.4	50.4	50.5	50.5	50.5	49.8	49.2	49.0	49.0
Friday	50.3	50.9	53.1	53.1	53.2	51.8	51.7	51.8	51.9	51.8	51.7	51.8	51.8	51.9	51.8	51.8	51.8	51.9	51.8	51.9	51.8	51.8	51.8	51.8
Saturday	50.4	50.4	50.4	50.3	50.3	50.3	50.5	50.4	50.0	49.3	49.2	49.3	49.3	49.3	49.2	49.3	49.4	49.3	49.2	49.2	49.3	49.4	49.3	48.6
May																								
Sunday	49.3	49.2	49.3	49.3	49.3	49.4	50.2	50.6	50.7	51.2	50.6	50.7	50.6	50.7	50.7	50.7	49.5	49.3	49.3	49.3	49.4	48.3	45.0	43.8
Monday	51.6	51.7	51.6	51.7	51.5	50.4	50.5	50.5	50.4	50.4	50.5	50.6	50.4	50.4	50.5	50.5	50.5	50.8	51.5	51.6	51.6	52.1	50.4	48.9
Tuesday	50.8	50.6	49.5	49.4	47.8	47.2	47.2	47.2	47.1	47.2	47.2	47.1	47.2	47.2	47.2	47.2	48.3	49.3	50.6	50.8	51.7	49.9	43.3	34.7
Wednesday	47.6	47.1	47.1	47.1	47.1	47.2	45.8	44.9	45.0	45.0	44.8	45.8	47.0	49.8	50.5	50.6	50.6	50.6	50.6	50.6	49.8	49.5	50.0	46.8
Thursday	49.1	49.1	49.9	50.4	50.4	50.5	50.6	48.5	47.2	46.1	46.3	46.4	49.1	51.8	51.8	51.2	50.6	50.5	50.4	50.5	50.5	48.3	47.5	48.1
Friday	50.5	50.4	49.7	49.1	49.1	49.1	49.1	49.1	49.2	49.1	49.1	49.1	49.2	49.0	49.1	49.1	49.1	49.2	49.0	49.1	49.2	49.1	46.1	43.2
Saturday	50.5	50.4	49.6	49.0	48.9	49.0	49.1	49.1	50.3	50.4	50.4	49.6	49.0	49.0	49.1	49.2	50.8	52.0	52.1	52.0	52.0	52.0	52.1	48.4
June																								
Sunday	49.1	49.3	48.6	49.1	48.1	47.6	47.6	47.6	47.5	47.5	48.6	49.1	49.0	49.0	49.1	49.1	49.0	48.9	49.1	49.0	48.1	47.7	47.6	47.7
Monday	48.9	48.9	49.0	48.9	48.9	48.9	49.0	49.0	48.8	48.9	48.9	49.0	48.8	48.8	49.0	48.9	48.8	49.0	48.9	48.9	48.9	48.9	49.0	47.5
Tuesday	45.9	46.0	46.1	46.0	46.0	45.9	42.0	42.2	41.6	41.6	39.1	41.9	44.0	44.4	46.2	47.6	47.7	47.5	47.5	46.7	46.0	45.9	46.0	46.0
Wednesday	47.6	47.7	47.9	49.0	48.9	48.9	49.0	48.9	48.9	48.9	48.9	49.0	48.9	49.4	50.5	51.2	51.8	51.8	51.8	51.7	49.7	47.6	45.6	36.7
Thursday	47.1	47.1	48.1	48.1	48.2	48.2	48.0	48.1	48.2	48.1	48.1	48.1	48.2	48.2	48.2	48.2	48.1	48.1	48.1	48.2	48.4	49.2	47.7	44.4
Friday	45.8	45.0	45.2	45.8	46.2	45.8	45.9	45.9	45.8	45.8	45.9	46.8	47.6	48.0	47.9	48.0	48.1	48.0	48.0	48.0	48.1	48.0	48.0	45.0
Saturday	49.0	49.1	49.0	49.0	48.6	47.8	47.6	47.9	49.1	49.0	49.0	49.0	49.0	49.0	48.0	47.6	47.6	47.6	47.6	47.5	47.5	47.6	47.4	47.4
July																								
Sunday	41.9	43.4	44.7	45.3	47.4	48.8	49.8	50.4	49.2	48.2	48.2	48.1	48.2	49.9	50.4	50.4	50.7	51.7	52.5	52.6	52.6	52.0	50.6	50.4
Monday	48.9	49.0	49.0	49.0	48.9	49.0	48.9	48.2	47.4	48.1	47.6	47.6	47.6	47.5	47.7	47.6	48.0	48.7	48.9	48.9	48.9	49.0	48.9	48.5
Tuesday	47.4	47.3	47.4	47.4	48.4	48.9	48.9	48.9	48.8	49.0	49.0	48.9	49.1	49.6	50.6	51.8	51.7	52.2	53.3	53.2	53.3	53.3	53.2	53.2
Wednesday	50.4	50.3	50.3	50.4	50.3	49.2	49.0	49.1	48.0	47.7	47.6	47.7	47.7	48.4	50.1	50.7	51.8	51.1	50.2	50.7	50.6	51.9	51.9	51.8
Thursday	50.4	50.5	50.4	49.6	49.2	49.1	48.3	47.7	47.7	47.7	48.1	48.9	49.9	50.4	50.4	50.6	50.6	50.4	50.4	50.5	50.5	50.4	50.5	50.5
Friday	51.0	50.4	50.4	51.1	50.4	50.5	51.1	50.9	50.3	50.4	50.3	50.3	50.4	50.3	50.3	50.4	50.4	50.2	50.3	50.4	50.4	50.2	50.3	50.5
Saturday	48.2	49.3	49.2	49.2	49.4	49.3	49.3	49.3	48.8	48.2	48.2	48.9	49.3	49.3	49.3	49.2	49.2	49.3	49.3	49.2	48.4	48.8	50.2	52.0
August																								
Sunday	40.3	40.0	40.9	40.8	41.3	42.1	42.2	42.3	42.2	42.2	42.2	42.2	42.2	42.7	43.6	43.5	43.4	43.5	43.5	43.5	43.3	42.2	40.8	38.5
Monday	47.8	46.4	46.3	45.6	45.1	46.1	46.2	46.2	46.3	46.2	44.9	44.8	45.2	46.0	46.6	47.1	47.2	47.5	47.5	47.6	46.5	46.3	46.4	47.4
Tuesday	46.7	46.1	46.0	46.5	46.7	46.2	46.2	45.8	45.6	46.2	46.2	46.1	39.8	39.7	41.5	42.7	47.0	47.4	47.3	47.2	47.2	47.2	47.2	47.2
Wednesday	47.8	47.2	47.3	46.6	46.2	46.2	46.1	46.1	46.2	46.1	46.1	46.1	46.1	45.8	45.0	45.0	44.9	45.0	45.0	44.8	44.9	43.9	44.0	46.0
Thursday	45.3	46.0	46.2	46.0	47.5	48.9	49.3	49.4	49.4	42.3	43.0	44.3	46.8	47.3	47.2	47.2	47.2	47.0	46.0	45.9	46.0	46.5	45.0	44.1
Friday	48.2	46.9	46.2	44.8	44.7	44.9	32.0	29.6	30.7	32.6	34.3	36.0	39.5	40.7	43.0	45.5	44.8	44.7	44.7	45.4	45.7	44.8	44.8	44.9
Saturday	47.4	46.3	46.3	46.4	46.2	46.4	45.5	44.8	44.8	44.8	44.9	44.8	44.9	45.7	46.1	46.5	45.8	46.3	46.3	45.6	45.0	44.9	44.9	46.1
September																								
Sunday	37.8	37.9	37.8	37.1	31.6	26.6	26.6	26.5	26.5	26.6	26.7	26.5	26.5	26.6	27.3	28.7	33.3	35.0	35.8	37.7	32.4	24.0	16.1	11.1
Monday	39.2	39.1	39.1	39.0	39.0	39.2	39.1	39.0	39.1	39.1	39.2	40.1	41.0	42.0	42.0	42.0	42.1	42.1	42.0	42.0	42.0	42.1	38.4	27.8
Tuesday	43.5	43.4	43.4	43.4	42.4	29.5	29.8	30.5	34.7	37.4	40.1	42.1	42.1	42.7	43.5	43.4	43.6	43.5	43.4	43.5	43.6	43.5	43.4	39.6
Wednesday	43.3	43.2	43.2	43.3	43.3	43.3	43.3	43.4	43.5	44.8	44.8	44.8	44.7	44.8	44.8	44.8	44.7	44.8	44.8	44.8	44.7	44.8	44.8	42.0
Thursday	44.7	44.8	44.8	44.8	44.7	44.8	44.9	44.7	44.1	43.4	44.2	44.8	44.8	44.7	44.8	44.7	44.8	44.9	44.7	44.7	44.8	44.8	42.6	38.0

Time	12.30	13.00	13.30	14.00	14.30	15.00	15.30	16.00	16.30	17.00	17.30	18.00	18.30	19.00	19.30	20.00	20.30	21.00	21.30	22.00	22.30	23.00	23.30	24.00
Friday	42.0	41.6	38.6	38.0	38.1	39.2	39.3	39.6	41.5	42.7	42.7	42.7	42.7	42.7	42.7	42.9	43.4	43.5	43.6	43.6	43.5	43.5	41.6	39.0
Saturday	37.9	37.9	37.8	37.9	37.9	37.9	37.9	37.9	36.9	36.7	36.7	36.7	36.4	37.4	39.2	41.7	42.2	42.5	43.2	43.3	43.0	41.2	39.0	34.5
October																								
Sunday	36.9	37.6	38.0	38.0	38.1	38.2	38.2	38.2	38.2	38.1	38.2	38.1	38.6	41.8	44.8	44.8	44.8	44.8	42.2	41.4	41.3	40.8	29.0	18.5
Monday	50.3	50.3	52.6	56.0	56.0	56.0	56.1	56.0	55.9	55.9	55.9	56.0	56.0	55.5	54.9	54.9	54.8	54.8	55.0	54.8	54.8	53.4	49.6	41.3
Tuesday	51.6	52.5	52.5	52.6	52.5	49.0	47.7	49.4	50.8	51.8	52.6	52.7	53.1	55.9	55.9	56.0	55.9	55.9	56.0	55.4	51.9	44.1	41.3	36.6
Wednesday	43.2	46.7	47.5	47.6	47.5	47.6	47.6	47.4	47.6	47.6	47.6	47.5	47.4	48.0	50.5	50.4	50.6	50.6	50.5	50.5	50.4	45.9	40.6	33.4
Thursday	50.6	50.5	50.5	50.6	50.5	50.4	50.5	50.5	50.5	50.5	48.3	47.5	49.7	50.0	50.6	50.5	50.5	50.6	50.5	50.4	50.6	50.6	47.3	40.6
Friday	50.6	50.5	50.6	50.5	50.4	50.6	50.4	50.5	50.5	50.5	50.6	50.5	50.4	50.5	50.4	50.5	50.6	50.6	50.5	50.6	50.6	49.8	37.8	32.5
Saturday	52.0	52.0	51.8	51.9	52.0	51.9	51.9	51.8	52.0	50.3	49.0	49.0	48.8	48.9	48.8	48.9	50.1	51.0	51.9	51.9	51.8	51.8	47.1	43.5
November																								
Sunday	19.4	19.3	19.5	19.5	19.5	19.6	19.7	19.5	19.5	19.4	19.6	23.0	30.7	40.3	43.5	44.8	44.9	45.0	40.9	36.0	21.9	14.1	13.9	13.9
Monday	26.6	26.7	26.4	26.6	26.5	26.6	26.6	27.1	28.9	29.3	29.3	29.3	29.4	32.5	43.3	47.5	47.8	47.1	40.7	37.9	37.9	33.4	18.5	14.8
Tuesday	45.1	45.1	45.2	44.0	43.8	42.9	42.3	42.4	42.3	42.3	42.4	42.4	43.4	46.3	50.5	50.5	51.6	51.9	46.9	44.9	38.6	35.0	28.5	17.9
Wednesday	46.4	46.0	46.0	46.1	45.9	45.9	46.0	46.0	45.9	46.0	46.0	46.0	46.6	48.0	51.6	51.7	51.6	51.6	50.9	46.4	40.3	37.0	29.1	22.8
Thursday	47.0	47.0	45.2	44.8	44.8	44.8	44.7	44.9	44.9	44.8	44.8	45.8	48.8	50.6	50.7	51.1	51.2	50.5	48.9	41.6	33.7	27.6	24.9	23.0
Friday	45.6	44.9	40.0	37.5	37.5	37.6	37.5	37.6	37.6	37.6	37.8	41.1	42.8	47.0	49.0	50.9	53.6	54.0	53.3	51.0	48.9	43.0	35.9	27.0
Saturday	43.5	43.6	43.6	43.5	37.9	33.7	33.6	33.6	33.5	31.0	31.0	31.0	31.1	37.4	48.2	51.9	52.0	52.0	51.9	52.1	46.1	40.6	28.6	13.2
December																								
Sunday	30.1	32.2	31.8	32.3	27.4	22.2	21.6	21.6	21.6	21.8	21.8	21.8	23.4	36.8	47.8	52.6	51.8	44.3	41.3	31.6	27.4	14.2	6.9	6.6
Monday	32.9	33.0	32.9	32.8	32.8	32.9	32.8	32.9	32.9	32.9	32.9	32.9	33.9	47.0	49.1	52.8	54.3	53.9	53.7	52.4	38.1	24.7	17.8	16.8
Tuesday	37.0	36.8	36.8	37.3	39.5	38.8	38.4	38.4	38.1	38.1	38.3	38.6	43.0	48.8	49.7	50.3	50.3	50.4	50.5	50.4	52.1	47.6	29.9	18.2
Wednesday	37.3	37.3	37.8	38.2	38.6	39.7	39.9	39.7	39.7	39.9	40.0	39.6	39.9	47.1	50.4	50.4	50.4	49.9	40.1	35.4	29.4	29.1	24.8	23.7
Thursday	50.1	46.5	36.5	34.2	34.0	33.9	34.0	34.0	34.0	34.2	33.9	34.0	32.8	40.9	47.9	55.5	58.4	54.9	42.4	39.0	30.7	29.0	23.8	23.6
Friday	39.6	44.4	43.2	42.8	42.4	42.8	42.8	42.8	42.8	42.8	43.2	44.5	46.6	57.4	67.1	67.7	67.0	67.5	59.1	40.4	29.6	20.2	15.4	10.8
Saturday	38.8	38.6	38.0	30.2	30.2	30.0	30.0	30.2	30.2	30.2	30.2	31.4	34.7	42.7	58.3	61.7	57.2	55.6	48.6	44.4	31.7	22.0	17.3	6.2

Table A3-4: Mombasa Minimum Generation (MW)

Time	00.30	01.00	01.30	02.00	02.30	03.00	03.30	04.00	04.30	05.00	05.30	06.00	06.30	07.00	07.30	08.00	08.30	09.00	09.30	10.00	10.30	11.00	11.30	12.00
January																								
Sunday	120.9	122.6	122.5	121.8	119.1	116.8	117.4	117.1	117.0	120.1	122.3	121.9	121.6	122.7	122.0	122.3	119.8	110.2	106.8	109.6	116.4	114.6	114.6	113.8
Monday	124.3	122.1	122.2	121.7	117.4	118.3	118.2	117.8	118.2	117.4	117.8	119.8	115.9	116.2	118.6	121.1	116.3	108.8	108.7	109.3	109.6	107.7	102.2	104.9
Tuesday	121.8	117.6	116.4	111.8	106.2	105.5	106.4	103.9	104.4	107.7	108.8	110.2	109.4	111.1	112.1	114.1	112.8	102.5	98.0	99.6	100.4	104.2	101.8	103.1
Wednesday	124.4	126.2	126.1	125.7	125.5	126.6	126.5	126.5	127.5	127.1	127.2	126.6	126.8	127.7	126.1	124.5	123.8	116.7	113.3	113.6	114.2	113.7	114.9	114.6
Thursday	122.7	122.1	121.7	122.8	124.6	123.4	118.9	120.0	118.1	115.3	112.7	111.5	109.0	111.3	118.0	115.9	116.7	112.8	111.2	109.0	110.0	106.6	108.4	108.3
Friday	119.8	115.4	118.0	120.6	119.0	120.9	120.1	121.5	120.9	122.1	123.2	121.0	122.4	119.5	119.4	117.7	116.1	107.6	108.7	110.4	109.9	105.4	106.3	109.8
Saturday	119.4	119.7	122.7	121.5	123.0	121.9	120.3	121.3	123.0	120.0	123.9	120.4	120.8	122.3	121.8	121.7	119.6	112.5	108.9	110.8	113.7	111.8	112.0	117.2
February																								
Sunday	118.1	114.2	114.2	117.0	117.1	114.9	116.1	116.2	116.3	116.4	116.9	115.0	117.3	115.1	116.9	116.6	111.4	104.6	100.7	101.3	105.2	111.7	111.9	113.1
Monday	117.0	115.7	113.9	114.1	114.8	112.1	117.5	116.5	118.4	119.1	118.0	119.1	119.0	118.3	118.0	118.7	117.9	116.5	107.2	105.8	104.8	103.9	104.1	104.7
Tuesday	117.9	121.2	119.6	120.3	120.2	119.9	121.6	119.2	121.0	120.1	119.1	117.8	120.0	120.4	118.4	117.7	115.9	113.9	110.8	108.0	109.3	107.5	108.7	107.9
Wednesday	111.9	113.4	113.0	113.0	112.7	113.0	110.1	109.9	111.5	111.0	109.4	113.1	112.5	113.8	113.2	111.2	109.2	107.9	106.8	109.5	108.8	109.1	107.0	105.2
Thursday	112.9	114.1	114.6	114.9	114.3	115.8	113.3	113.0	112.5	112.7	115.5	116.0	115.1	116.1	115.7	111.5	111.7	103.0	102.5	102.7	106.7	110.3	109.4	110.9
Friday	117.2	117.3	117.8	118.6	120.7	119.4	119.5	121.0	121.3	120.9	121.1	120.3	120.5	120.6	119.6	121.6	120.1	117.2	115.8	112.6	109.0	111.2	109.1	110.5
Saturday	120.2	121.0	117.8	117.1	118.7	120.0	121.8	120.8	119.6	119.2	116.7	117.1	122.5	120.2	118.6	119.9	114.7	114.3	116.4	111.7	112.9	112.3	110.8	107.9
March																								
Sunday	121.5	121.0	121.6	120.6	119.6	120.1	120.0	115.5	116.1	117.4	119.4	116.2	116.1	114.1	115.6	116.0	112.7	99.6	99.8	106.9	110.8	108.8	111.1	112.0
Monday	112.3	111.1	109.5	106.1	104.6	104.2	103.1	105.4	104.2	106.7	113.6	115.2	117.1	115.3	118.0	116.3	117.9	116.9	112.8	114.7	113.2	107.3	104.0	105.6
Tuesday	122.8	123.4	123.8	122.2	120.4	119.2	121.8	120.8	121.1	121.8	124.1	122.9	123.8	123.8	123.4	123.0	121.9	119.1	116.3	114.1	114.9	113.6	114.3	113.7
Wednesday	121.6	121.3	121.4	121.2	120.0	120.0	120.5	119.0	119.7	121.2	122.1	122.2	120.4	121.2	119.9	121.2	119.6	120.8	118.8	116.7	117.6	115.2	111.9	115.1
Thursday	122.3	122.3	122.6	123.6	121.6	121.7	121.0	120.9	120.9	121.0	122.1	121.8	123.6	122.6	124.0	122.0	122.7	121.3	118.8	112.5	114.3	112.4	110.0	110.1
Friday	123.0	118.8	121.3	121.4	122.2	122.6	121.8	121.8	122.1	119.2	121.5	120.1	119.5	119.4	121.7	120.8	119.9	114.0	110.8	111.2	113.4	112.7	111.9	113.0
Saturday	122.6	122.5	123.7	119.3	124.0	121.8	122.1	119.3	119.2	121.3	120.7	121.2	118.3	121.3	121.9	119.0	120.7	117.8	117.8	118.0	115.8	117.1	114.4	111.3
April																								
Sunday	113.3	110.6	109.5	107.7	105.8	105.0	105.4	106.6	108.2	110.2	109.8	112.9	112.8	114.4	115.6	114.5	109.6	104.9	100.5	101.5	105.3	107.4	109.6	111.6
Monday	116.4	109.2	108.0	105.9	107.1	105.2	104.2	104.9	107.6	106.7	109.1	113.2	111.9	113.2	112.8	112.4	114.8	112.6	108.9	106.9	106.3	106.7	109.1	106.9
Tuesday	114.9	111.9	112.2	112.6	113.9	112.3	111.2	112.2	111.6	110.8	110.3	111.1	109.9	111.1	110.3	108.7	105.7	108.3	105.3	104.1	100.5	98.3	103.5	101.5
Wednesday	109.8	114.1	113.9	114.5	112.0	110.5	107.5	106.2	109.4	109.7	109.7	110.4	109.6	109.6	110.2	108.4	107.6	109.6	109.2	107.2	106.4	102.8	99.6	99.3
Thursday	111.9	112.2	110.1	112.2	113.7	112.5	111.5	111.6	113.0	113.8	111.1	113.1	113.0	115.7	115.3	114.9	115.3	112.9	112.8	109.3	112.3	109.7	110.0	111.0
Friday	114.1	113.4	117.4	118.5	119.1	116.7	116.8	117.5	118.2	119.1	119.1	118.0	117.0	116.9	118.1	117.8	116.3	115.1	115.7	115.1	115.0	114.8	113.6	112.4
Saturday	114.1	116.0	114.8	114.8	113.6	111.6	109.4	110.3	110.9	110.0	105.9	108.7	115.4	112.1	114.7	111.1	110.7	109.8	111.8	110.9	110.5	108.8	111.7	108.8
May																								
Sunday	113.7	103.7	99.0	98.7	95.9	95.4	96.0	96.2	94.9	95.0	95.7	99.7	100.7	100.7	101.1	100.8	100.8	87.9	80.7	87.2	88.4	88.1	84.2	84.3
Monday	88.3	83.4	80.8	80.3	80.2	75.8	73.4	73.8	75.4	75.8	73.8	79.2	86.6	97.3	105.2	105.5	107.2	106.4	103.8	101.4	103.6	101.8	103.4	102.0
Tuesday	107.9	99.1	95.7	97.2	94.4	93.2	91.0	89.7	88.6	90.0	99.5	109.3	112.4	112.1	113.5	113.3	113.5	109.6	107.1	104.4	102.6	103.6	103.5	103.9
Wednesday	106.4	99.0	94.2	91.7	85.6	86.4	86.5	87.2	89.3	90.3	104.2	109.0	111.0	109.3	109.8	109.4	109.0	107.6	107.6	108.6	107.0	107.0	106.9	108.5
Thursday	100.6	97.5	96.3	95.2	96.3	94.7	94.7	94.4	95.6	95.7	94.9	97.7	98.9	108.0	111.5	112.6	114.4	114.9	112.2	108.7	108.4	107.3	107.7	108.6
Friday	105.3	101.9	101.0	98.6	98.4	98.0	97.7	98.9	99.3	97.9	102.6	104.4	102.1	103.3	103.7	101.7	101.5	101.1	100.6	97.9	98.8	98.2	97.6	98.1
Saturday	101.8	97.8	98.0	101.1	101.2	101.0	100.6	101.6	100.6	101.4	102.9	100.2	103.4	105.0	107.1	103.0	103.4	107.3	104.5	105.8	105.4	103.1	107.1	108.7
June																								
Sunday	105.1	98.3	98.0	97.1	94.5	94.7	93.7	92.1	94.0	95.9	95.5	97.3	97.7	98.8	103.2	99.8	101.0	90.8	86.7	100.1	106.1	104.1	107.3	106.2

Time	00.30	01.00	01.30	02.00	02.30	03.00	03.30	04.00	04.30	05.00	05.30	06.00	06.30	07.00	07.30	08.00	08.30	09.00	09.30	10.00	10.30	11.00	11.30	12.00
Monday	98.5	93.2	92.3	87.7	87.3	83.6	81.5	81.5	82.0	88.8	95.7	97.2	107.2	112.4	111.0	111.4	111.0	110.9	110.5	110.9	110.9	111.8	107.8	108.3
Tuesday	111.3	111.0	109.1	104.7	103.3	104.5	102.2	100.2	100.8	102.6	108.4	108.1	108.1	107.8	108.2	109.3	106.4	104.6	106.3	104.4	103.1	103.1	103.9	104.6
Wednesday	112.5	112.8	114.0	112.4	111.8	106.4	106.0	106.4	106.3	109.5	112.3	108.6	111.9	113.5	113.4	114.3	113.9	112.0	107.1	105.7	108.6	108.2	110.3	111.7
Thursday	109.5	109.3	109.6	110.7	111.0	111.0	111.4	111.2	111.8	111.8	111.4	111.2	109.0	93.6	97.6	109.8	108.9	110.5	108.0	104.7	106.8	105.7	102.3	105.5
Friday	110.5	102.8	102.8	99.2	98.8	96.7	93.5	92.5	92.2	96.0	99.6	107.1	111.2	110.9	111.6	109.3	110.5	105.5	103.3	105.1	105.9	104.7	106.4	103.9
Saturday	108.7	107.6	108.6	108.6	107.4	105.5	107.6	107.6	105.0	104.4	111.7	113.9	112.9	113.4	113.5	114.0	114.4	112.9	114.4	114.6	113.9	113.2	113.4	112.4
July																								
Sunday	120.2	120.3	120.3	117.6	114.2	109.9	107.8	105.0	106.7	109.5	114.6	119.1	118.3	119.1	118.3	119.6	116.0	107.7	104.8	110.7	106.7	101.4	109.9	116.2
Monday	113.8	103.7	102.9	96.2	96.1	94.1	92.2	93.5	92.1	98.2	103.9	108.6	112.4	119.5	123.2	122.3	122.0	116.2	118.1	117.4	116.4	116.1	113.0	112.0
Tuesday	121.4	116.8	117.4	116.5	117.3	114.0	113.9	114.0	113.8	114.3	114.0	119.1	120.1	120.4	119.6	119.8	117.8	116.6	112.6	110.0	110.2	110.2	108.9	109.5
Wednesday	114.6	113.4	114.0	113.8	112.9	113.5	112.5	114.5	115.0	112.4	115.7	115.3	116.1	117.2	114.7	115.0	115.1	112.7	110.5	108.3	106.7	105.7	107.3	108.2
Thursday	112.3	114.3	114.6	110.8	112.5	110.4	109.1	106.1	106.9	107.4	102.4	108.8	110.4	110.9	112.9	110.3	108.6	108.0	106.4	106.7	106.3	107.0	105.2	107.0
Friday	113.7	113.7	114.1	114.1	114.0	113.6	114.1	113.7	114.7	114.0	114.0	114.1	115.1	112.6	114.1	114.2	111.0	111.5	109.6	106.9	106.2	105.7	106.3	105.7
Saturday	118.7	117.4	113.1	109.3	109.2	110.4	109.6	110.1	109.6	109.2	109.7	116.3	117.8	118.4	118.8	118.8	118.7	116.6	116.8	117.4	118.0	118.3	118.6	119.0
August	120.2	120.3	120.3	117.6	114.2	109.9	107.8	105.0	106.7	109.5	114.6	119.1	118.3	119.1	118.3	119.6	116.0	107.7	104.8	110.7	106.7	101.4	109.9	116.2
Sunday																								
Monday	107.9	103.4	95.9	90.3	89.6	84.9	85.9	84.5	84.0	83.0	89.6	94.9	98.3	106.3	115.3	117.1	117.0	113.7	109.2	109.2	112.8	109.1	108.6	109.0
Tuesday	117.4	114.1	107.0	103.8	99.6	99.7	97.9	97.7	99.8	102.9	110.5	113.9	114.4	113.4	114.7	116.2	119.1	117.0	115.1	114.5	112.1	111.4	109.6	109.0
Wednesday	114.1	112.6	112.8	109.4	106.3	103.0	101.5	102.4	102.7	104.7	112.9	111.8	111.1	110.2	110.6	108.2	109.6	107.8	109.4	110.5	109.4	109.4	110.8	108.9
Thursday	108.2	106.4	103.4	100.0	95.9	90.9	90.8	89.7	89.0	92.6	99.1	100.0	96.9	103.9	109.7	105.6	111.4	110.3	109.9	108.7	106.3	105.5	104.4	105.6
Friday	109.4	108.9	109.0	109.6	107.3	106.3	103.8	99.7	98.7	99.8	101.7	103.0	114.4	114.6	117.8	117.4	116.6	114.7	114.0	108.4	107.2	107.5	110.6	109.2
Saturday	115.7	111.3	111.7	110.3	109.2	110.6	110.7	110.8	111.4	111.0	113.9	117.2	117.1	119.4	119.5	120.4	119.9	118.9	117.1	113.4	111.1	113.2	113.1	112.3
September	117.3	114.9	110.9	104.3	102.0	103.7	99.8	100.9	101.8	99.9	101.8	106.9	117.3	115.3	115.2	117.2	115.0	104.3	102.8	106.3	114.1	113.3	110.9	108.7
Sunday																								
Monday	107.0	101.1	91.9	85.2	85.5	82.1	81.3	81.1	81.5	81.7	81.1	84.8	93.9	101.5	105.0	109.3	107.1	94.5	91.1	74.2	72.1	74.3	75.3	80.4
Tuesday	87.5	82.6	82.2	82.5	73.8	75.1	71.7	74.2	73.6	77.6	87.1	108.4	110.2	111.1	110.6	113.3	112.3	108.0	106.0	102.7	105.8	105.5	105.9	106.6
Wednesday	102.2	102.7	102.6	102.8	103.7	103.1	104.2	102.7	103.3	108.5	114.3	113.4	115.5	115.9	116.1	117.1	117.5	117.0	114.4	111.7	110.1	109.0	107.9	108.8
Thursday	116.9	116.1	115.4	114.0	114.3	115.0	112.9	113.9	114.3	114.5	113.9	115.9	116.0	117.2	117.1	118.1	117.2	115.2	111.4	110.9	108.4	108.4	104.6	105.6
Friday	116.9	120.6	118.0	115.4	111.0	107.1	104.7	102.2	104.6	95.8	97.8	103.1	106.6	107.1	105.7	106.6	107.1	111.9	112.4	112.2	114.1	112.5	112.1	113.8
Saturday	112.8	110.5	110.0	112.9	110.7	106.4	104.4	105.3	105.2	104.9	108.8	111.9	118.4	120.3	120.0	120.6	118.4	118.8	114.4	111.7	112.2	113.8	113.3	111.8
October	120.9	118.0	116.7	119.9	119.8	110.8	107.3	107.3	106.2	107.7	111.0	118.3	119.8	120.5	121.1	119.2	119.9	118.0	118.7	120.9	118.7	118.3	120.0	120.4
Sunday																								
Monday	109.8	110.0	109.5	106.2	103.7	103.4	101.0	98.2	95.8	98.6	98.2	104.0	110.8	116.4	116.2	117.0	107.8	103.1	101.1	102.2	103.4	106.8	105.4	105.4
Tuesday	101.0	95.6	91.1	92.8	88.9	84.9	83.0	81.9	82.7	82.4	87.7	103.2	115.4	122.0	122.7	121.2	121.8	117.7	116.8	113.7	116.2	117.0	117.1	118.4
Wednesday	112.2	112.7	113.6	115.9	116.1	119.6	116.8	115.4	112.6	113.2	108.0	106.0	110.5	119.0	118.6	115.4	114.7	113.8	114.3	113.3	113.9	113.2	112.6	115.7
Thursday	120.9	122.5	118.6	113.5	107.4	105.5	104.0	105.1	110.6	112.9	114.5	119.8	118.2	119.9	119.1	121.3	120.9	121.9	118.6	113.3	112.8	114.1	113.4	114.5
Friday	118.4	115.3	112.4	114.6	115.0	113.1	112.7	111.4	110.6	114.2	117.0	121.0	119.5	118.4	119.2	117.8	119.4	116.0	116.5	113.6	114.8	113.8	113.5	113.3
Saturday	120.9	121.4	121.0	119.7	121.4	125.0	125.0	121.9	118.8	123.1	120.8	122.0	121.2	121.6	122.5	122.2	118.6	118.8	118.7	116.9	118.3	118.0	114.5	113.8
November	105.8	105.4	101.4	96.9	97.4	98.1	97.6	97.6	98.1	100.3	104.2	113.6	113.6	119.8	125.1	126.1	124.2	126.0	123.6	121.3	121.8	121.0	121.7	121.5
Sunday																								
Monday	117.5	110.0	105.6	99.4	87.0	82.6	85.8	81.2	79.4	78.4	78.4	88.6	99.5	101.1	102.0	100.7	99.8	99.3	101.4	106.6	111.1	108.1	103.3	97.3
Tuesday	71.5	70.6	70.0	71.6	68.4	65.3	64.9	65.9	66.7	65.8	69.9	74.5	82.3	94.8	97.0	98.3	101.1	99.0	99.4	99.0	92.3	91.9	92.3	89.9
Wednesday	69.5	71.0	76.2	81.9	83.5	82.9	83.9	81.9	84.6	84.0	85.9	88.4	94.8	99.3	108.3	108.7	108.0	104.3	106.5	102.8	104.3	101.9	103.9	104.3
Thursday	96.9	92.7	87.5	86.6	86.4	84.8	84.9	84.2	84.6	83.6	85.3	95.6	98.3	98.4	98.6	96.3	98.0	103.7	107.6	104.6	103.1	104.1	105.2	103.9

Time	00.30	01.00	01.30	02.00	02.30	03.00	03.30	04.00	04.30	05.00	05.30	06.00	06.30	07.00	07.30	08.00	08.30	09.00	09.30	10.00	10.30	11.00	11.30	12.00
Friday	98.1	97.8	98.1	96.8	91.0	89.6	90.3	89.2	90.4	90.0	91.9	98.9	105.7	109.0	106.5	109.6	110.1	110.4	111.2	113.1	112.0	113.6	111.0	111.5
Saturday	104.5	96.8	91.2	85.8	84.2	83.6	82.4	79.4	81.5	81.1	85.5	102.2	106.2	106.2	105.7	108.9	109.7	110.4	106.2	104.2	101.3	103.3	99.2	100.1
December	104.7	104.1	105.2	101.7	94.6	89.1	87.1	88.3	86.7	85.7	90.2	91.4	90.7	96.1	100.7	99.8	100.8	101.3	102.7	98.9	97.6	96.7	95.6	96.7
Sunday																								
Monday	85.2	77.2	76.6	71.5	70.0	70.8	69.6	68.6	69.9	70.2	70.6	69.2	72.4	72.9	72.2	72.4	70.8	69.3	73.5	72.8	79.7	80.9	80.1	79.5
Tuesday	81.2	76.1	70.7	72.1	71.7	72.1	71.7	71.7	69.7	69.6	69.7	68.2	74.7	74.8	72.8	77.5	79.2	82.8	85.4	87.5	90.8	86.0	86.9	86.0
Wednesday	75.1	67.8	66.8	64.3	62.4	61.8	61.5	59.1	59.1	59.3	59.9	64.0	74.5	77.3	76.4	74.4	74.1	74.1	83.3	85.0	85.0	84.7	84.8	86.8
Thursday	85.9	85.9	86.2	85.2	82.7	82.7	82.8	83.2	83.2	82.8	83.8	89.2	90.5	94.4	94.6	95.1	97.4	95.9	94.5	94.3	93.7	93.9	94.7	95.3
Friday	80.7	81.1	80.8	79.3	72.7	73.3	72.1	73.3	73.7	73.1	73.3	75.4	74.6	78.8	87.0	88.8	91.2	90.5	95.4	97.0	95.3	92.8	90.1	89.7
Saturday	81.0	79.5	81.6	80.3	78.8	77.6	75.3	74.5	74.4	73.5	75.8	78.8	84.2	87.4	91.0	91.9	93.4	95.3	97.0	95.9	95.6	95.1	98.2	97.2
January	93.4	90.8	89.7	88.5	87.2	86.5	85.3	84.0	82.8	81.1	81.3	82.1	83.8	89.1	93.0	94.0	94.8	94.1	94.9	97.8	97.3	94.5	93.5	95.4

Time	12.30	13.00	13.30	14.00	14.30	15.00	15.30	16.00	16.30	17.00	17.30	18.00	18.30	19.00	19.30	20.00	20.30	21.00	21.30	22.00	22.30	23.00	23.30	24.00
January																								
Sunday	113.3	113.8	111.2	114.0	112.9	113.1	108.6	112.0	112.3	113.7	115.0	116.8	117.4	121.8	121.5	123.4	122.5	122.8	122.9	120.2	122.1	122.8	123.5	122.8
Monday	105.4	105.2	107.2	105.5	106.4	107.4	106.5	103.7	106.3	109.4	111.7	112.2	117.0	116.1	120.2	121.5	120.8	121.2	121.2	119.6	119.2	120.2	120.0	121.1
Tuesday	102.5	103.8	99.2	93.7	101.4	104.0	107.2	105.3	107.3	108.7	107.7	108.5	115.0	114.8	115.3	116.0	119.0	119.4	120.5	122.0	118.8	120.5	121.4	121.2
Wednesday	113.3	116.5	117.7	115.0	115.7	117.8	116.1	118.6	119.9	121.6	121.5	123.2	118.7	122.3	124.2	125.5	125.4	124.7	124.8	124.4	125.5	126.1	124.6	122.6
Thursday	109.7	111.2	108.9	104.9	104.3	106.7	108.3	107.5	108.9	110.2	113.1	114.8	118.0	118.2	118.3	117.1	120.4	118.0	121.9	121.6	120.2	121.2	120.1	119.7
Friday	111.3	110.6	108.6	107.7	104.7	104.3	103.8	106.6	108.9	110.1	111.9	115.7	116.2	118.7	119.6	120.2	120.1	120.4	120.5	119.8	121.0	122.2	118.5	119.7
Saturday	113.7	114.2	115.5	117.1	113.4	95.3	107.0	112.5	112.8	115.4	115.3	116.2	116.3	115.0	114.8	118.1	118.2	118.5	120.9	119.2	121.5	121.1	120.8	120.7
February																								
Sunday	110.7	109.7	109.4	110.5	109.5	109.3	108.8	106.1	106.4	107.0	107.0	112.6	114.0	112.8	116.2	116.0	117.2	118.6	117.8	116.9	116.1	117.3	114.3	114.9
Monday	104.0	105.0	105.3	105.3	104.0	104.4	103.9	105.3	104.1	108.0	107.8	110.3	112.8	115.2	118.1	118.1	119.6	117.8	119.5	118.8	118.7	118.6	118.5	119.7
Tuesday	107.5	107.5	106.5	106.1	106.4	105.5	106.5	106.4	106.2	108.1	107.7	110.3	114.8	115.8	115.9	115.4	115.5	116.6	117.5	113.9	113.8	116.7	118.7	116.1
Wednesday	108.0	107.6	105.4	106.5	108.0	106.4	106.5	108.8	106.7	107.4	110.3	109.8	111.1	112.5	115.8	113.7	115.4	114.4	115.2	112.7	114.4	115.2	115.2	114.8
Thursday	110.7	108.1	109.5	108.2	108.2	108.0	109.6	112.4	114.1	114.4	118.6	114.5	117.8	118.1	120.3	119.9	120.5	120.0	120.1	121.2	119.7	119.7	120.9	119.8
Friday	102.7	103.3	103.5	105.0	104.4	104.6	105.3	103.9	107.6	110.5	110.6	111.5	114.7	115.3	120.3	118.6	119.7	118.2	119.8	119.4	117.6	120.0	119.2	118.0
Saturday	111.4	111.0	110.7	113.1	113.0	109.1	106.5	107.7	109.8	109.0	109.2	112.9	114.5	116.1	117.3	116.9	119.8	117.4	119.6	119.8	119.3	119.1	118.8	117.3
March																								
Sunday	113.6	112.5	116.0	118.7	118.1	118.3	116.9	119.1	119.8	116.2	117.1	120.1	116.6	117.6	117.5	114.8	114.7	116.6	117.3	116.7	117.8	117.9	116.2	118.5
Monday	107.9	110.4	111.0	112.5	113.1	110.6	111.6	114.2	113.2	117.7	119.8	119.4	118.2	121.6	123.7	123.5	123.0	123.0	123.6	123.1	120.8	122.7	122.4	123.2
Tuesday	114.0	112.2	111.5	113.0	113.3	113.9	114.3	111.8	116.4	114.7	117.5	116.5	117.6	116.6	117.4	120.2	120.8	122.2	120.3	119.8	118.4	121.5	120.2	122.2
Wednesday	113.4	117.1	114.2	111.6	114.3	117.8	117.0	115.3	117.8	118.4	118.2	117.8	119.0	121.4	122.3	122.6	122.9	122.0	123.7	122.9	120.5	122.2	122.0	124.3
Thursday	*111.1*	*110.6*	*113.3*	*111.6*	*111.0*	*110.4*	*110.6*	*115.0*	*112.4*	*113.9*	*116.6*	*118.8*	*116.4*	*118.9*	*119.9*	*120.7*	*121.5*	*122.6*	*123.1*	*122.7*	*121.7*	*121.0*	*122.0*	*122.4*
Friday	113.4	111.6	110.8	111.6	113.2	116.9	114.8	113.6	110.9	112.0	116.7	116.9	118.5	119.0	120.8	119.9	118.6	121.0	119.6	120.5	119.5	122.5	121.5	122.8
Saturday	114.6	112.3	116.4	118.1	118.1	119.5	113.7	116.7	116.2	113.0	114.1	115.1	116.5	115.0	115.4	117.9	119.3	120.0	120.3	120.4	120.5	119.8	119.4	120.2
April																								
Sunday	111.9	112.0	112.6	112.9	109.5	110.4	110.0	112.3	111.1	110.3	114.1	115.1	118.0	118.2	117.8	115.4	114.3	113.7	115.8	115.2	114.8	114.4	110.4	106.6

Time	12.30	13.00	13.30	14.00	14.30	15.00	15.30	16.00	16.30	17.00	17.30	18.00	18.30	19.00	19.30	20.00	20.30	21.00	21.30	22.00	22.30	23.00	23.30	24.00
Monday	110.1	107.9	106.9	107.3	106.3	108.6	106.6	106.3	107.5	105.7	106.8	110.7	111.7	109.3	112.9	112.4	112.0	112.6	112.6	112.4	111.0	113.5	111.0	113.3
Tuesday	100.2	102.3	101.7	103.5	102.7	105.8	106.4	108.7	108.5	107.8	111.8	113.9	115.5	115.8	114.0	115.1	115.8	114.3	113.0	112.5	113.5	113.9	112.9	113.3
Wednesday	101.0	103.1	101.0	100.9	102.1	101.1	99.7	100.3	100.7	103.1	104.9	106.8	107.6	107.0	110.2	115.0	116.2	114.2	115.9	114.7	114.4	112.7	113.0	111.4
Thursday	111.9	111.8	109.0	109.3	107.4	110.4	108.9	109.8	110.5	109.8	111.6	113.5	110.8	114.4	115.9	116.3	117.1	115.9	117.5	118.0	119.0	116.0	114.3	115.7
Friday	114.2	114.9	113.4	112.4	108.4	115.3	113.2	113.6	115.8	114.9	111.8	110.7	113.8	115.3	116.3	115.5	116.0	114.9	117.5	118.5	115.4	114.7	114.0	115.9
Saturday	110.3	110.2	108.1	108.0	110.8	110.2	110.3	111.6	110.3	109.4	112.3	112.9	112.4	112.1	116.2	114.8	114.9	113.2	113.1	114.5	115.4	114.6	113.5	113.6
May																								
Sunday	84.8	84.0	83.4	83.0	85.0	83.8	83.9	85.0	81.9	85.2	89.1	91.0	103.4	109.3	111.3	115.1	114.4	113.5	114.0	113.6	114.0	108.8	103.3	96.6
Monday	103.0	101.9	99.6	100.4	102.4	101.8	103.8	103.6	104.6	106.0	108.0	108.8	112.7	113.0	114.6	114.0	114.6	114.9	115.5	116.1	113.7	115.8	115.0	112.6
Tuesday	103.3	105.0	104.6	104.8	104.8	104.7	107.5	106.7	105.4	107.1	107.9	108.6	110.0	107.8	111.9	109.8	109.0	112.0	113.8	113.0	114.2	112.9	113.8	110.8
Wednesday	108.2	108.3	109.0	108.4	106.6	107.2	106.0	107.2	107.4	108.6	109.7	110.7	109.6	111.0	112.6	111.9	110.5	112.2	112.7	112.9	113.6	113.6	109.4	101.0
Thursday	107.9	107.9	106.6	107.6	108.2	109.0	107.5	108.2	108.7	108.7	108.3	110.6	112.7	112.8	115.4	113.4	113.0	114.0	113.5	113.8	114.0	113.0	111.9	107.8
Friday	96.5	95.4	94.8	96.2	97.5	96.4	97.7	100.6	98.6	102.3	108.6	108.3	108.5	113.3	113.4	111.5	111.8	112.3	111.7	111.0	112.1	110.0	110.7	103.8
Saturday	107.7	108.1	106.5	105.1	105.1	106.9	103.8	100.7	99.6	100.3	100.3	101.3	110.1	113.7	114.1	113.9	114.5	113.7	114.6	114.0	114.0	113.0	114.7	114.5
June																								
Sunday	108.9	107.9	110.7	110.5	109.2	109.6	104.6	106.0	105.6	108.6	107.8	108.8	109.1	110.5	111.9	111.5	111.5	110.9	111.0	112.0	111.0	111.7	100.5	97.8
Monday	108.1	108.2	108.2	107.7	109.1	109.3	107.6	107.8	108.3	108.0	110.1	110.8	111.0	110.2	110.3	110.8	110.7	110.2	110.9	111.4	111.2	111.3	110.3	110.3
Tuesday	103.0	101.4	106.0	108.7	108.0	108.0	107.9	107.7	110.4	111.0	112.1	110.9	112.4	112.7	111.8	113.0	112.6	111.7	113.5	112.3	110.7	113.5	112.8	114.0
Wednesday	111.2	110.8	85.1	96.7	106.1	108.3	109.5	110.9	111.3	112.5	113.0	113.8	111.9	112.8	112.4	113.5	113.9	112.5	113.9	113.8	112.2	109.8	111.1	109.9
Thursday	106.4	106.6	105.2	104.8	103.3	107.1	107.9	108.4	108.7	109.9	111.7	111.9	112.4	114.3	112.7	114.3	113.2	113.5	113.1	113.8	112.8	113.5	113.9	113.0
Friday	106.6	102.7	104.0	105.8	106.6	104.2	104.9	105.0	91.0	93.4	101.2	102.3	107.9	109.8	113.7	114.0	112.5	113.2	115.1	113.0	116.3	114.2	114.8	115.4
Saturday	113.2	112.7	113.1	113.4	114.3	112.8	113.9	111.4	109.6	111.2	111.3	113.9	112.4	114.0	113.5	114.0	114.4	112.4	113.4	113.9	114.5	114.4	112.9	113.0
July																								
Sunday	116.2	116.3	117.9	116.6	116.8	118.8	118.4	118.2	117.4	117.9	117.5	119.1	120.4	120.8	120.7	121.5	120.6	118.9	119.8	121.4	120.7	119.4	118.0	119.2
Monday	111.5	112.9	114.4	112.9	116.1	116.6	118.0	114.0	111.1	113.6	116.5	119.4	119.4	120.1	120.6	118.4	118.2	118.9	119.3	118.8	119.3	119.2	119.4	119.1
Tuesday	107.9	109.4	108.9	108.9	108.9	110.4	111.8	112.1	110.6	108.9	112.0	110.8	109.9	113.5	115.6	113.5	114.1	114.1	113.2	113.9	115.3	115.7	115.6	117.5
Wednesday	106.5	104.5	104.1	106.7	106.7	105.8	107.2	106.4	105.8	106.8	107.7	109.2	111.6	111.7	114.6	114.4	113.6	116.1	113.0	113.2	111.9	112.9	113.1	115.1
Thursday	109.8	108.5	109.9	108.3	108.5	111.8	113.3	112.5	111.0	108.8	110.0	111.2	113.5	113.6	113.6	114.5	112.4	111.6	111.0	115.2	114.5	112.2	114.0	114.5
Friday	106.9	103.0	104.2	103.1	104.6	104.0	104.5	104.1	105.5	107.6	106.6	110.5	113.9	113.2	117.5	117.5	117.7	116.6	116.1	120.3	119.8	118.4	119.7	119.3
Saturday	118.2	117.8	117.6	116.4	116.3	116.5	116.1	116.8	118.3	118.7	120.2	119.4	118.3	118.5	121.1	120.7	119.9	118.6	118.3	120.4	121.2	121.4	120.3	119.6
August	116.2	116.3	117.9	116.6	116.8	118.8	118.4	118.2	117.4	117.9	117.5	119.1	120.4	120.8	120.7	121.5	120.6	118.9	119.8	121.4	120.7	119.4	118.0	119.2
Sunday																								
Monday	109.7	110.7	108.0	106.3	104.2	102.4	102.6	104.2	106.3	107.0	113.5	114.0	113.3	114.8	117.1	117.6	115.9	116.6	116.6	118.3	120.2	118.7	119.3	119.3
Tuesday	113.2	113.9	112.8	113.7	114.2	112.7	113.9	114.2	116.6	116.4	117.8	118.8	118.7	119.3	119.2	119.3	114.1	112.5	113.9	114.4	114.3	115.3	117.2	116.8
Wednesday	110.5	109.3	108.8	107.3	106.2	105.8	105.9	105.6	106.3	105.8	106.5	105.6	111.5	115.4	116.5	117.1	115.8	116.1	116.2	116.2	115.3	115.4	113.7	112.9
Thursday	104.9	105.4	106.6	108.3	107.8	107.8	107.6	107.4	106.6	108.4	110.4	111.1	112.1	115.2	116.2	112.6	113.5	116.1	115.8	117.0	116.2	116.2	112.5	107.6
Friday	109.8	109.6	109.6	109.7	108.4	108.6	107.9	111.0	111.9	113.6	116.3	117.8	117.9	118.0	119.4	117.7	118.1	120.7	119.1	118.7	118.3	118.3	118.3	116.0
Saturday	109.0	109.1	109.0	109.5	109.0	109.0	109.5	110.4	111.6	111.0	112.6	114.6	116.2	116.3	116.3	116.7	116.7	117.8	118.4	116.2	115.9	117.0	117.3	118.2
September	108.7	108.8	108.9	107.3	108.1	106.5	102.4	105.1	109.4	114.9	114.5	111.7	111.3	111.2	111.2	109.3	111.1	111.8	110.2	110.6	111.7	111.3	111.9	108.0

Time	12.30	13.00	13.30	14.00	14.30	15.00	15.30	16.00	16.30	17.00	17.30	18.00	18.30	19.00	19.30	20.00	20.30	21.00	21.30	22.00	22.30	23.00	23.30	24.00
Sunday																								
Monday	87.7	100.2	100.3	97.1	95.2	97.6	98.8	102.5	101.3	102.1	99.9	99.9	105.3	104.3	109.7	116.5	118.0	117.7	117.1	115.4	118.8	110.3	104.8	97.4
Tuesday	104.7	105.9	105.7	106.8	105.9	109.2	108.9	108.4	108.0	108.5	113.6	114.4	112.9	116.4	117.1	114.5	115.1	116.1	117.1	117.0	116.6	116.6	115.7	114.8
Wednesday	109.9	110.8	111.4	111.2	109.4	109.2	110.0	111.6	112.6	115.0	113.7	112.6	108.6	108.1	114.3	111.1	111.9	111.8	115.6	117.0	116.5	116.7	116.0	117.6
Thursday	107.0	103.7	101.6	105.3	106.3	109.7	110.4	111.8	109.9	108.2	109.3	113.1	118.1	118.6	118.6	119.1	117.4	118.6	119.5	119.2	120.0	119.1	119.2	119.6
Friday	113.2	114.2	114.2	114.0	112.8	113.2	112.6	113.8	112.4	111.8	114.6	116.9	114.4	114.9	115.6	115.3	115.8	116.3	118.3	117.2	116.6	117.1	117.2	115.4
Saturday	113.8	114.2	111.9	112.9	113.8	112.2	111.8	113.7	113.2	113.0	115.7	118.8	119.7	119.8	117.6	118.8	119.1	120.0	118.8	119.0	120.6	120.2	119.7	120.2
October	120.0	120.0	117.0	119.2	117.9	117.5	117.2	118.4	117.1	117.6	117.1	117.1	118.0	117.9	118.5	117.1	117.9	118.0	118.2	120.9	120.1	117.8	115.6	115.8
Sunday																								
Monday	106.7	105.7	105.2	105.2	104.8	104.9	102.5	102.7	105.1	104.9	110.2	113.8	115.9	121.2	122.6	123.8	124.2	124.8	125.0	123.2	123.9	120.9	114.7	105.8
Tuesday	116.6	117.4	117.5	115.9	116.1	115.7	116.6	115.2	116.3	118.5	121.4	121.8	120.0	121.6	120.8	120.0	121.6	121.5	121.0	119.4	121.4	118.8	113.2	109.9
Wednesday	113.4	112.0	114.8	114.7	115.1	114.4	115.0	113.0	114.2	112.9	117.6	120.7	123.2	121.2	122.4	121.1	122.5	122.0	122.4	120.9	122.0	121.3	122.8	122.4
Thursday	115.0	116.9	115.0	115.0	116.5	115.8	115.0	116.3	117.3	118.6	120.2	119.6	121.9	121.9	121.0	121.9	121.5	121.9	121.5	122.3	120.5	122.5	121.9	120.1
Friday	112.9	112.0	110.3	110.3	112.7	112.9	113.8	109.8	111.9	111.6	115.9	115.5	116.2	117.4	121.9	123.7	121.9	121.3	121.5	121.2	124.0	121.8	121.5	122.0
Saturday	114.6	117.5	119.0	118.4	116.4	114.4	115.9	113.6	112.7	117.6	118.8	119.9	121.3	122.5	122.0	121.2	120.4	116.5	118.6	120.1	117.1	116.8	119.2	112.7
November	121.1	121.2	116.8	113.4	116.6	117.5	118.2	119.4	118.4	118.4	118.6	121.0	124.5	122.6	121.6	121.2	119.8	118.9	120.5	121.3	122.1	122.8	122.0	119.4
Sunday																								
Monday	97.1	94.0	89.2	85.2	84.4	84.1	82.8	79.5	79.3	79.5	80.7	93.7	105.3	109.6	116.5	113.9	114.7	115.4	116.7	112.8	100.1	92.1	80.5	74.9
Tuesday	95.6	96.2	95.7	98.6	95.1	98.1	99.2	101.2	105.6	107.9	109.1	111.2	111.7	111.7	115.6	114.8	114.6	116.2	115.3	114.9	109.1	105.9	100.2	73.0
Wednesday	103.9	104.7	104.8	105.6	104.3	103.7	105.0	101.8	100.2	98.7	102.4	104.3	106.0	105.5	109.0	110.7	109.8	110.3	110.9	110.8	110.0	103.5	92.1	89.5
Thursday	104.1	102.4	104.4	105.6	105.3	107.7	107.1	105.8	105.5	107.8	111.5	109.8	113.0	112.4	117.4	117.5	117.9	116.6	117.2	117.2	111.8	109.1	104.8	98.1
Friday	112.3	111.6	108.6	107.8	107.9	110.9	107.2	107.9	109.0	108.8	108.4	113.1	116.3	116.9	119.4	119.4	117.7	119.9	117.8	114.6	112.0	109.0	101.4	98.9
Saturday	99.1	100.5	102.2	102.7	102.2	102.7	102.4	105.0	103.7	105.5	107.2	108.5	110.7	110.6	114.8	115.8	116.9	117.1	119.4	118.5	118.1	115.1	108.3	105.8
December	98.5	105.5	106.9	104.7	98.1	94.8	93.3	92.6	94.6	95.8	94.8	93.5	92.5	105.9	115.6	117.0	116.5	115.7	116.8	113.3	116.4	114.6	115.1	115.3
Sunday																								
Monday	79.3	78.6	78.0	78.5	77.2	77.7	74.5	74.5	75.2	75.4	76.4	81.0	84.0	96.4	99.6	102.5	101.6	98.0	98.0	97.5	96.1	88.7	81.5	77.8
Tuesday	82.6	83.2	84.6	84.7	85.5	85.2	84.9	82.4	86.5	84.9	84.7	85.5	86.2	94.5	98.2	100.5	103.5	101.9	101.9	99.4	95.0	90.0	83.7	75.5
Wednesday	90.4	90.6	88.0	86.2	86.8	87.2	87.7	87.5	88.2	88.3	87.5	88.3	92.1	93.8	98.1	101.7	102.3	102.7	102.4	100.7	102.2	101.0	93.9	85.3
Thursday	95.3	95.4	97.3	98.8	97.9	99.3	97.5	97.8	97.5	101.3	103.7	104.1	104.0	104.7	104.1	92.8	90.0	88.6	85.6	87.6	91.1	90.5	85.6	80.8
Friday	89.0	89.3	84.5	84.4	87.8	85.7	86.8	87.4	85.5	87.0	88.7	89.5	95.6	98.5	104.5	105.9	106.6	107.4	107.1	108.1	107.6	103.6	92.3	84.7
Saturday	96.4	96.6	97.0	96.2	95.4	93.6	95.4	98.5	99.8	98.5	98.6	98.2	101.7	108.6	111.8	112.4	113.4	114.6	116.8	114.6	116.3	110.6	99.4	94.8
January	94.9	94.7	96.4	92.2	87.3	86.8	87.7	86.9	86.6	87.2	88.5	88.4	92.4	95.9	101.5	108.7	108.6	109.0	109.7	109.2	109.2	98.0	91.1	89.6

Table A3-5: Eldoret Minimum Generation (MW)

DATE	00.30	01.00	01.30	02.00	02.30	03.00	03.30	04.00	04.30	05.00	05.30	06.00	06.30	07.00	07.30	08.00	08.30	09.00	09.30	10.00	10.30	11.00	11.30	12.00
16-Nov-06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17-Nov-06	12.7	12.7	12.8	12.8	13.0	13.0	13.0	13.0	13.4	13.4	13.5	13.5	13.7	13.7	13.9	13.9	13.5	13.5	13.3	13.3	13.4	13.4	13.1	13.1
18-Nov-06	13.6	13.6	12.8	12.8	12.7	12.7	13.4	13.4	13.6	13.6	13.2	13.2	0.2	0.2	0.0	0.0	0.0	0.0	5.5	5.5	13.0	13.0	13.1	13.1
19-Nov-06	14.0	14.0	13.9	13.9	14.0	14.0	13.7	13.7	14.1	14.1	13.3	13.3	13.9	13.9	13.8	13.8	13.4	13.4	14.1	14.1	13.4	13.4	14.1	14.1
20-Nov-06	13.7	13.7	13.4	13.4	13.5	13.5	12.9	12.9	12.9	12.9	13.0	13.0	12.9	12.9	12.3	12.3	12.4	12.4	12.8	12.8	13.7	13.7	13.7	13.7
21-Nov-06	13.9	13.9	14.3	14.3	11.9	11.9	13.6	13.6	13.7	13.7	14.6	14.6	12.9	12.9	13.7	13.7	13.7	13.7	14.0	14.0	14.1	14.1	13.8	13.8
22-Nov-06	14.1	14.1	13.9	13.9	13.8	13.8	14.2	14.2	14.3	14.3	13.7	13.7	13.5	13.5	13.6	13.6	13.4	13.4	13.4	13.4	13.6	13.6	13.6	13.6
23-Nov-06	13.6	13.6	14.1	14.1	14.0	14.0	14.1	14.1	13.9	13.9	13.9	13.9	13.9	13.9	13.8	13.8	13.8	13.8	13.8	13.8	13.0	-13.0	13.8	13.8
24-Nov-06	13.5	13.5	14.0	14.0	13.9	13.9	14.0	14.0	13.6	13.6	14.2	14.2	13.1	13.1	13.6	13.6	13.7	13.7	13.7	13.7	13.6	13.6	13.8	13.8
25-Nov-06	13.2	13.2	13.9	13.9	13.9	13.9	13.6	13.6	13.9	13.9	14.1	14.1	13.8	13.8	13.8	13.8	13.2	13.2	13.6	13.6	13.4	13.4	13.2	13.2
26-Nov-06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.2	5.2	13.2	13.2	13.2	13.2	13.7	13.7
27-Nov-06	13.6	13.6	13.4	13.4	13.9	13.9	14.1	14.1	13.7	13.7	14.0	14.0	14.0	14.0	14.0	14.0	13.3	13.3	13.5	13.5	13.6	13.6	13.7	13.7
28-Nov-06	13.8	13.8	13.9	13.9	13.8	13.8	14.0	14.0	14.1	14.1	14.1	14.1	14.1	14.1	13.8	13.8	13.8	13.8	13.1	13.1	13.0	13.0	13.4	13.4
29-Nov-06	14.0	14.0	13.4	13.4	13.7	13.7	14.0	14.0	13.6	13.6	13.8	13.8	13.9	13.9	14.0	14.0	13.2	13.2	13.7	13.7	13.6	13.6	13.8	13.8
30-Nov-06	13.8	13.8	13.5	13.5	13.7	13.7	13.7	13.7	13.8	13.8	13.9	13.9	13.7	13.7	13.9	13.9	13.9	13.9	13.9	13.9	13.8	13.8	13.5	13.5
1-Dec-06	13.9	13.9	12.9	12.9	13.1	13.1	12.6	12.6	12.7	12.7	12.7	12.7	12.8	12.8	13.7	13.7	13.7	13.7	13.6	13.6	13.8	13.8	13.7	13.7
2-Dec-06	13.2	13.2	13.5	13.5	13.1	13.1	13.4	13.4	13.6	13.6	13.3	13.3	13.4	13.4	13.7	13.7	13.6	13.6	13.4	13.4	13.5	13.5	13.7	13.7
3-Dec-06	13.8	13.8	13.7	13.7	14.0	14.0	13.9	13.9	14.0	14.0	13.9	13.9	14.0	14.0	13.8	13.8	13.6	13.6	13.7	13.7	14.1	14.1	14.0	14.0
4-Dec-06	13.8	13.8	13.3	13.3	13.6	13.6	13.6	13.6	13.8	13.8	13.6	13.6	13.5	13.5	13.4	13.4	11.2	11.2	9.4	9.4	13.8	13.8	14.0	14.0
5-Dec-06	13.1	13.1	13.5	13.5	13.8	13.8	13.4	13.4	13.7	13.7	13.8	13.8	13.6	13.6	13.9	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6-Dec-06	13.3	13.3	13.6	13.6	13.5	13.5	13.4	13.4	13.6	13.6	13.7	13.7	13.9	13.9	13.2	13.2	14.5	14.5	12.5	12.5	26.1	26.1	32.8	32.8
7-Dec-06	35.9	35.9	35.1	35.1	35.2	35.2	32.5	32.5	34.1	34.1	34.5	34.5	35.0	35.0	36.2	36.2	36.6	36.6	35.8	35.8	36.5	36.5	36.1	36.1
8-Dec-06	35.7	35.7	36.2	36.2	34.7	34.7	36.4	36.4	36.1	36.1	35.7	35.7	34.6	34.6	34.8	34.8	31.9	31.9	33.6	33.6	35.9	35.9	32.6	32.6
9-Dec-06	33.2	33.2	32.9	32.9	33.6	33.6	34.3	34.3	34.3	34.3	34.5	34.5	26.1	26.1	28.6	28.6	20.9	20.9	32.8	32.8	21.3	21.3	31.5	31.5
10-Dec-06	7.0	7.0	19.6	19.6	26.2	26.2	31.7	31.7	33.5	33.5	33.8	33.8	34.1	34.1	35.3	35.3	33.8	33.8	34.3	34.3	34.4	34.4	34.1	34.1
11-Dec-06	36.1	36.1	35.8	35.8	35.9	35.9	36.3	36.3	34.3	34.3	35.1	35.1	35.5	35.5	33.1	33.1	36.0	36.0	35.6	35.6	34.9	34.9	36.4	36.4
12-Dec-06	35.3	35.3	35.9	35.9	36.0	36.0	31.7	31.7	35.6	35.6	35.8	35.8	35.3	35.3	35.3	35.3	35.0	35.0	35.2	35.2	35.9	35.9	36.2	36.2
13-Dec-06	35.0	35.0	34.6	34.6	34.8	34.8	34.9	34.9	34.9	34.9	34.7	34.7	34.8	34.8	35.3	35.3	35.0	35.0	36.1	36.1	35.4	0.0	36.4	36.4
14-Dec-06	35.9	35.9	36.1	36.1	36.3	36.3	36.4	36.4	36.7	36.7	36.6	36.6	36.6	36.6	36.0	36.0	36.1	36.1	36.9	36.9	34.9	34.9	36.1	36.1
15-Dec-06	36.0	36.0	36.0	36.0	35.7	35.7	36.6	36.6	36.5	36.5	36.2	36.2	36.2	36.2	36.4	36.4	35.8	35.8	35.5	35.5	35.9	35.9	36.3	36.3
16-Dec-06	36.6	36.6	36.1	36.1	36.0	36.0	36.2	36.2	35.5	35.5	36.8	36.8	37.1	37.1	38.3	38.3	36.5	36.5	36.1	36.1	36.2	36.2	35.4	35.4
17-Dec-06	33.5	33.5	10.2	10.2	10.6	10.6	10.4	10.4	10.4	10.4	11.2	11.2	13.6	13.6	19.5	19.5	33.4	33.4	35.1	35.1	13.2	13.2	10.4	10.4
18-Dec-06	16.9	16.9	5.2	5.2	5.3	5.3	5.2	5.2	5.3	5.3	25.4	25.4	36.9	36.9	34.9	34.9	35.4	35.4	35.8	35.8	36.2	36.2	35.6	35.6
19-Dec-06	35.5	35.5	36.9	36.9	36.2	36.2	35.6	35.6	36.5	36.5	36.2	36.2	36.5	36.5	34.3	34.3	35.7	35.7	36.5	36.5	35.6	35.6	35.3	35.3
20-Dec-06	19.8	19.8	27.6	27.6	28.3	28.3	37.1	37.1	36.5	36.5	36.3	36.3	36.5	36.5	35.6	35.6	36.6	36.6	35.3	35.3	35.3	35.3	35.1	35.1
21-Dec-06	36.2	36.2	17.8	17.8	7.9	7.9	8.6	8.6	10.3	10.3	10.4	10.4	10.5	10.5	15.0	15.0	28.7	28.7	29.5	29.5	29.7	29.7	30.5	30.5
22-Dec-06	36.1	36.1	29.6	29.6	20.7	20.7	20.5	20.5	20.3	20.3	20.2	20.2	20.8	20.8	20.9	20.9	21.9	21.9	36.8	36.8	36.2	36.2	35.8	35.8
23-Dec-06	36.1	36.1	36.1	36.1	36.9	36.9	36.6	36.6	36.3	36.3	35.4	35.4	34.3	34.3	35.0	35.0	35.8	35.8	36.3	36.3	36.0	36.0	23.5	23.5

DATE	00.30	01.00	01.30	02.00	02.30	03.00	03.30	04.00	04.30	05.00	05.30	06.00	06.30	07.00	07.30	08.00	08.30	09.00	09.30	10.00	10.30	11.00	11.30	12.00
24-Dec-06	10.4	10.4	5.2	5.2	5.1	5.1	5.2	5.2	5.2	5.2	12.5	12.5	20.3	20.3	19.0	19.0	27.6	27.6	33.3	33.3	19.9	19.9	20.4	20.4
25-Dec-06	5.2	5.2	3.7	3.7	5.1	5.1	5.1	5.1	5.0	5.0	4.9	4.9	4.7	4.7	5.3	5.3	5.0	5.0	5.1	5.1	5.2	5.2	5.0	5.0
26-Dec-06	4.9	4.9	5.1	5.1	5.1	5.1	5.2	5.2	5.1	5.1	5.1	5.1	5.1	5.1	5.2	5.2	4.4	4.4	4.8	4.8	5.0	5.0	6.3	6.3
27-Dec-06	5.3	5.3	5.3	5.3	5.6	5.6	5.0	5.0	5.3	5.3	5.4	5.4	5.3	5.3	9.0	9.0	19.4	19.4	20.2	20.2	20.1	20.1	19.7	19.7
28-Dec-06	10.1	10.1	5.0	5.0	5.1	5.1	5.2	5.2	5.1	5.1	16.1	16.1	20.6	20.6	20.2	20.2	20.0	20.0	20.5	20.5	21.0	21.0	19.8	19.8
29-Dec-06	5.0	5.0	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	19.7	19.7	20.3	20.3	19.4	19.4	28.1	28.1	35.6	35.6	36.1	36.1	35.8	35.8
30-Dec-06	36.4	36.4	36.4	36.4	36.4	36.4	31.7	31.7	12.7	12.7	10.6	10.6	9.4	9.4	10.4	10.4	10.5	10.5	10.2	10.2	10.9	10.9	10.3	10.3
31-Dec-06	10.2	10.2	10.2	10.2	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.0	10.0	10.3	10.3	10.3	10.3	10.1	10.1	10.2	10.2
AVERAGE																								
Sunday	**12.7**	**12.7**	**10.4**	**10.4**	**11.5**	**11.5**	**12.2**	**12.2**	**12.5**	**12.5**	**13.6**	**13.6**	**15.2**	**15.2**	**15.9**	**15.9**	**19.6**	**19.6**	**22.0**	**22.0**	**16.9**	**16.9**	**16.7**	**16.7**
Monday	**16.6**	**16.6**	**14.1**	**14.1**	**14.5**	**14.5**	**14.5**	**14.5**	**14.2**	**14.2**	**17.7**	**17.7**	**19.6**	**19.6**	**18.8**	**18.8**	**18.9**	**18.9**	**18.7**	**18.7**	**19.6**	**19.6**	**19.7**	**19.7**
Tuesday	**19.4**	**19.4**	**19.9**	**19.9**	**19.5**	**19.5**	**18.9**	**18.9**	**19.8**	**19.8**	**19.9**	**19.9**	**19.6**	**19.6**	**19.4**	**19.4**	**17.1**	**17.1**	**17.3**	**17.3**	**17.3**	**17.3**	**17.5**	**17.5**
Wednesday	**16.3**	**16.3**	**17.0**	**17.0**	**17.3**	**17.3**	**18.7**	**18.7**	**18.7**	**18.7**	**18.7**	**18.7**	**19.0**	**19.0**	**19.5**	**19.5**	**21.7**	**21.7**	**21.9**	**21.9**	**23.0**	**17.9**	**24.0**	**24.0**
Thursday	**23.1**	**23.1**	**19.4**	**19.4**	**18.1**	**18.1**	**17.8**	**17.8**	**18.3**	**18.3**	**20.4**	**20.4**	**21.4**	**21.4**	**22.0**	**22.0**	**24.0**	**24.0**	**24.1**	**24.1**	**24.1**	**24.1**	**24.2**	**24.2**
Friday	**21.5**	**21.5**	**20.8**	**20.8**	**19.5**	**19.5**	**19.6**	**19.6**	**19.7**	**19.7**	**21.5**	**21.5**	**21.4**	**21.4**	**21.5**	**21.5**	**22.0**	**22.0**	**24.9**	**24.9**	**25.3**	**25.3**	**24.8**	**24.8**
Saturday	**24.8**	**24.8**	**24.8**	**24.8**	**25.0**	**25.0**	**24.7**	**24.7**	**22.3**	**22.3**	**22.1**	**22.1**	**19.2**	**19.2**	**19.9**	**19.9**	**19.0**	**19.0**	**21.2**	**21.2**	**20.9**	**20.3**	**20.6**	**20.6**

DATE	12.30	13.00	13.30	14.00	14.30	15.00	15.30	16.00	16.30	17.00	17.30	18.00	18.30	19.00	19.30	20.00	20.30	21.00	21.30	22.00	22.30	23.00	23.30	24.00
16-Nov-06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	13.2	13.2	13.0	13.0	12.5	12.5
17-Nov-06	13.9	13.9	12.7	12.7	13.7	13.7	13.2	13.2	13.0	13.0	12.9	12.9	13.7	13.7	13.9	13.9	13.7	13.7	13.3	13.3	13.6	13.6	13.1	13.1
18-Nov-06	13.9	13.9	13.4	13.4	13.9	13.9	13.8	13.8	13.6	13.6	13.2	13.2	13.9	13.9	14.0	14.0	13.9	13.9	13.3	13.3	13.5	13.5	13.6	13.6
19-Nov-06	13.5	13.5	13.5	13.5	13.6	13.6	13.7	13.7	13.8	13.8	14.0	14.0	13.7	13.7	13.8	13.8	13.7	13.7	13.6	13.6	13.5	13.5	13.3	13.3
20-Nov-06	13.8	13.8	12.3	12.3	13.9	13.9	13.8	13.8	13.9	13.9	14.0	14.0	14.2	14.2	13.4	13.4	13.1	13.1	13.2	13.2	13.1	13.1	13.6	13.6
21-Nov-06	13.6	13.6	13.3	13.3	13.5	13.5	13.6	13.6	13.8	13.8	14.0	14.0	14.0	14.0	13.6	13.6	13.2	13.2	13.8	13.8	13.6	13.6	13.7	13.7
22-Nov-06	13.5	13.5	13.6	13.6	13.7	13.7	13.8	13.8	14.0	14.0	14.1	14.1	14.2	14.2	13.5	13.5	13.4	13.4	14.1	14.1	13.7	13.7	13.1	13.1
23-Nov-06	13.5	13.5	13.6	13.6	13.8	13.8	14.0	14.0	13.9	13.9	13.6	13.6	13.7	13.7	13.4	13.4	14.1	14.1	13.8	13.8	13.6	13.6	13.1	13.1
24-Nov-06	13.6	13.6	13.6	13.6	13.8	13.8	14.0	14.0	14.0	14.0	13.8	13.8	13.8	13.8	13.8	13.8	13.6	13.6	13.7	13.7	6.5	6.5	11.0	11.0
25-Nov-06	12.9	12.9	14.3	14.3	13.8	13.8	13.7	13.7	13.8	13.8	14.0	14.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26-Nov-06	13.9	13.9	14.1	14.1	14.0	14.0	14.0	14.0	14.0	14.0	13.9	13.9	14.0	14.0	13.5	13.5	13.4	13.4	13.5	13.5	13.9	13.9	13.7	13.7
27-Nov-06	13.6	13.6	13.8	13.8	14.0	14.0	13.9	13.9	13.8	13.8	13.6	13.6	13.9	13.9	13.8	13.8	13.7	13.7	13.6	13.6	13.6	13.6	13.6	13.6
28-Nov-06	12.7	12.7	13.8	13.8	13.2	13.2	13.5	13.5	13.7	13.7	13.6	13.6	13.9	13.9	13.4	13.4	13.3	13.3	13.3	13.3	13.7	13.7	13.8	13.8
29-Nov-06	14.7	14.7	12.7	12.7	13.8	13.8	13.9	13.9	14.0	14.0	13.7	13.7	14.1	14.1	13.7	13.7	13.0	13.0	13.1	13.1	13.1	13.1	13.6	13.6
30-Nov-06	13.3	13.3	13.4	13.4	13.7	13.7	13.6	13.6	14.2	14.2	13.2	13.2	13.8	13.8	13.2	13.2	13.4	13.4	13.4	13.4	13.5	13.5	13.4	13.4
1-Dec-06	13.9	13.9	13.8	13.8	13.9	13.9	13.8	13.8	13.9	13.9	13.7	13.7	13.6	13.6	13.4	13.4	13.3	13.3	13.7	13.7	13.8	13.8	13.6	13.6
2-Dec-06	13.7	13.7	13.6	13.6	13.7	13.7	13.8	13.8	13.8	13.8	13.8	13.8	13.7	13.7	8.4	8.4	13.4	13.4	13.5	13.5	12.8	12.8	13.5	13.5
3-Dec-06	13.4	13.4	13.5	13.5	13.3	13.3	12.7	12.7	13.5	13.5	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.8	13.8	13.8	13.8	13.7	13.7

DATE	12.30	13.00	13.30	14.00	14.30	15.00	15.30	16.00	16.30	17.00	17.30	18.00	18.30	19.00	19.30	20.00	20.30	21.00	21.30	22.00	22.30	23.00	23.30	24.00
4-Dec-06	12.8	12.8	13.8	13.8	13.2	13.2	13.4	13.4	13.6	13.6	13.3	13.3	13.7	13.7	14.0	14.0	13.9	13.9	13.8	13.8	13.8	13.8	13.1	13.1
5-Dec-06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.2	12.8	12.8	13.0	13.0
6-Dec-06	33.7	33.7	34.1	34.1	34.1	34.1	36.2	36.2	35.5	35.5	35.5	35.5	35.5	35.5	34.6	34.6	33.5	33.5	33.9	33.9	34.4	34.4	33.4	33.4
7-Dec-06	37.9	37.9	34.7	34.7	34.0	34.0	33.7	33.7	36.0	36.0	33.2	33.2	35.4	35.4	34.6	34.6	35.0	35.0	35.7	35.7	34.7	34.7	35.4	35.4
8-Dec-06	11.2	11.2	26.4	26.4	34.0	34.0	34.0	34.0	33.9	33.9	34.1	34.1	34.7	34.7	35.4	35.4	34.1	34.1	34.1	34.1	33.3	33.3	33.1	33.1
9-Dec-06	32.0	32.0	34.9	34.9	33.4	33.4	35.6	35.6	33.2	33.2	32.9	32.9	21.1	21.1	13.8	13.8	4.3	4.3	0.0	0.0	0.0	0.0	0.6	0.6
10-Dec-06	34.9	34.9	35.3	35.3	35.8	35.8	34.0	34.0	35.4	35.4	34.4	34.4	35.2	35.2	37.1	37.1	34.6	34.6	33.9	33.9	34.4	34.4	35.2	35.2
11-Dec-06	32.9	32.9	36.0	36.0	34.7	34.7	34.5	34.5	35.1	35.1	36.7	36.7	34.9	34.9	35.6	35.6	36.6	36.6	34.5	34.5	36.1	36.1	36.6	36.6
12-Dec-06	34.1	34.1	34.9	34.9	34.7	34.7	36.8	36.8	36.9	36.9	36.5	36.5	35.8	35.8	33.6	33.6	24.1	24.1	14.6	14.6	24.7	24.7	35.5	35.5
13-Dec-06	33.8	33.8	35.0	35.0	35.5	35.5	36.5	36.5	36.8	36.8	36.3	36.3	36.0	36.0	36.7	36.7	35.7	35.7	35.8	35.8	35.7	35.7	35.9	35.9
14-Dec-06	36.3	36.3	35.4	35.4	36.0	36.0	34.9	34.9	35.2	35.2	36.0	36.0	36.7	36.7	29.5	29.5	35.9	35.9	36.3	36.3	36.1	36.1	35.9	35.9
15-Dec-06	34.5	34.5	34.9	34.9	35.6	35.6	36.3	36.3	35.9	35.9	36.1	36.1	35.3	35.3	35.3	35.3	33.0	33.0	36.5	36.5	35.3	35.3	36.0	36.0
16-Dec-06	35.7	35.7	36.1	36.1	35.9	35.9	36.5	36.5	35.8	35.8	36.2	36.2	36.4	36.4	35.9	35.9	35.3	35.3	33.5	33.5	36.0	36.0	35.7	35.7
17-Dec-06	10.4	10.4	10.3	10.3	10.4	10.4	10.3	10.3	10.3	10.3	10.3	10.3	33.8	33.8	36.5	36.5	34.7	34.7	36.2	36.2	35.0	35.0	34.1	34.1
18-Dec-06	35.8	35.8	35.2	35.2	36.1	36.1	35.7	35.7	35.9	35.9	35.3	35.3	35.7	35.7	35.9	35.9	36.7	36.7	25.9	25.9	34.9	34.9	34.5	34.5
19-Dec-06	36.9	36.9	35.9	35.9	34.8	34.8	35.2	35.2	36.3	36.3	35.9	35.9	35.7	35.7	35.6	35.6	36.8	36.8	33.9	33.9	32.5	32.5	32.1	32.1
20-Dec-06	36.1	36.1	35.8	35.8	36.1	36.1	36.2	36.2	36.2	36.2	35.5	35.5	36.3	36.3	36.4	36.4	35.6	35.6	36.5	36.5	36.6	36.6	36.3	36.3
21-Dec-06	29.2	29.2	32.7	32.7	30.3	30.3	29.6	29.6	31.4	31.4	30.2	30.2	31.9	31.9	37.1	37.1	36.2	36.2	35.9	35.9	36.4	36.4	32.8	32.8
22-Dec-06	36.0	36.0	35.9	35.9	36.0	36.0	35.9	35.9	36.1	36.1	35.6	35.6	36.4	36.4	36.7	36.7	36.1	36.1	36.6	36.6	36.5	36.5	36.2	36.2
23-Dec-06	20.3	20.3	19.9	19.9	19.6	19.6	19.9	19.9	20.6	20.6	20.8	20.8	20.0	20.0	31.7	31.7	36.8	36.8	36.5	36.5	31.4	31.4	20.9	20.9
24-Dec-06	21.6	21.6	20.7	20.7	20.7	20.7	20.1	20.1	20.6	20.6	21.2	21.2	20.4	20.4	20.5	20.5	20.1	20.1	20.5	20.5	11.0	11.0	7.4	7.4
25-Dec-06	5.2	5.2	5.0	5.0	5.3	5.3	5.1	5.1	5.0	5.0	5.0	5.0	5.2	5.2	5.1	5.1	3.9	3.9	5.2	5.2	5.2	5.2	5.2	5.2
26-Dec-06	5.1	5.1	5.3	5.3	5.3	5.3	5.2	5.2	5.1	5.1	5.2	5.2	5.3	5.3	4.6	4.6	5.2	5.2	5.1	5.1	5.2	5.2	5.3	5.3
27-Dec-06	20.1	20.1	20.5	20.5	20.1	20.1	26.5	26.5	31.8	31.8	36.4	36.4	36.4	36.4	36.3	36.3	35.2	35.2	35.9	35.9	16.8	16.8	5.1	5.1
28-Dec-06	20.3	20.3	21.2	21.2	20.2	20.2	20.1	20.1	27.7	27.7	39.8	39.8	36.5	36.5	36.8	36.8	36.3	36.3	35.5	35.5	29.9	29.9	8.4	8.4
29-Dec-06	36.5	36.5	35.1	35.1	36.3	36.3	36.9	36.9	35.9	35.9	36.5	36.5	35.7	35.7	36.4	36.4	35.5	35.5	36.2	36.2	36.2	36.2	36.4	36.4
30-Dec-06	10.4	10.4	10.3	10.3	10.8	10.8	10.9	10.9	10.1	10.1	11.0	11.0	10.3	10.3	10.9	10.9	10.4	10.4	4.2	4.2	10.3	10.3	10.3	10.3
31-Dec-06	10.4	10.4	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	8.9	8.9	14.2	14.2	31.8	31.8	36.5	36.5	36.3	36.3	36.1	36.1	36.6	36.6
AVERAGE																								
Sunday	**16.9**	**16.9**	**16.8**	**16.8**	**16.9**	**16.9**	**16.4**	**16.4**	**16.8**	**16.8**	**16.6**	**16.6**	**20.7**	**20.7**	**23.9**	**23.9**	**23.8**	**23.8**	**24.0**	**24.0**	**22.5**	**22.5**	**22.0**	**22.0**
Monday	**19.0**	**19.0**	**19.4**	**19.4**	**19.5**	**19.5**	**19.4**	**19.4**	**19.5**	**19.5**	**19.7**	**19.7**	**19.6**	**19.6**	**19.6**	**19.6**	**19.6**	**19.6**	**17.7**	**17.7**	**19.5**	**19.5**	**19.4**	**19.4**
Tuesday	**17.1**	**17.1**	**17.2**	**17.2**	**16.9**	**16.9**	**17.4**	**17.4**	**17.6**	**17.6**	**17.5**	**17.5**	**17.5**	**17.5**	**16.8**	**16.8**	**15.4**	**15.4**	**13.5**	**14.3**	**17.1**	**17.1**	**18.9**	**18.9**
Wednesday	**24.1**	**24.1**	**24.1**	**24.1**	**24.3**	**24.3**	**25.7**	**25.7**	**26.4**	**26.4**	**26.9**	**26.9**	**27.6**	**27.6**	**27.9**	**27.9**	**27.2**	**27.2**	**27.6**	**27.6**	**24.7**	**24.7**	**22.8**	**22.8**
Thursday	**24.2**	**24.2**	**24.3**	**24.3**	**23.9**	**23.9**	**23.6**	**23.6**	**25.4**	**25.4**	**26.5**	**26.5**	**26.8**	**26.8**	**26.3**	**26.3**	**27.2**	**27.2**	**26.9**	**26.9**	**26.2**	**26.2**	**22.6**	**22.6**
Friday	**22.1**	**22.1**	**23.7**	**23.7**	**25.0**	**25.0**	**25.2**	**25.2**	**25.0**	**25.0**	**25.0**	**25.0**	**25.1**	**25.1**	**25.2**	**25.2**	**24.4**	**24.4**	**24.7**	**24.8**	**24.0**	**24.0**	**24.8**	**24.8**
Saturday	**20.4**	**20.4**	**20.8**	**20.8**	**20.7**	**20.7**	**21.2**	**21.2**	**20.9**	**20.9**	**21.1**	**21.1**	**17.9**	**17.9**	**17.8**	**17.8**	**17.7**	**17.7**	**16.1**	**16.1**	**16.1**	**16.1**	**14.7**	**14.7**

APPENDIX A4

OPTIMAL DISPATCH MODELS

able A4-1: Limited Availability Model-Jan-May 2006

arame er	KPD1	KPD2	KGT1	KGT2	FIAT	IBA	AKNBI	AKELD	UETCL	INQ	RH
j:Min	3.98	2.8	9.92	9.92	14.1	4.5	6.92	7.8	9.49		
ontr1	1	1	1	1	1	1	1	1	1	=	71
ontr2	1	1	1	1	0	0	0	0	0	>=	44
ontr3	1	1	1	1	0	0	0	0	0	<=	167
ontr4	0	0	0	0	0	0	0	1	0	=	0
ontr5	0	0	0	0	0	0	0	1	0	<=	36
ontr6	0	0	0	0	1	1	0	0	0	>=	10
ontr7	0	0	0	0	1	1	0	0	0	<=	57
ontr8	1	0	0	0	0	0	0	0	0	<=	54
ontr9	0	1	0	0	0	0	0	0	0	<=	63
ontr10	0	0	1	0	0	0	0	0	0	<=	26
ontr11	0	0	0	1	0	0	0	0	0	<=	26
ontr12	0	0	0	0	1	0	0	0	0	<=	9
ontr13	0	0	0	0	0	1	0	0	0	<=	48
ntr14	0	0	0	0	0	0	1	0	0	=	0
ontr15	0	0	0	0	0	0	0	1	0	=	0
ontr16	0	0	0	0	0	0	0	0	1	<=	2
ontr17	1	1	0	0	0	0	0	0	0	<=	117
ontr18	0	0	0	0	1	1	0	0	0	<=	57
bo	inf	inf	inf	inf	inf	inf	inf	inf	inf		
owbo	0	0	0	0	0	0	0	0	0		
ype	Real	Real	Real	Real	Real	Real	Real	Real	Real		

able A4-2: Limited Availability Model -June 2006

arame er	KPD1	KPD2	KGT1	KGT2	FIAT	IBA	AKNBI	AKELD	UETCL	INQ	RH
j:Min	3.98	2.8	9.92	9.92	14.1	4.5	6.92	7.8	9.49		
ntr1	1	1	1	1	1	1	1	1	1	=	71
ntr2	1	1	1	1	0	0	0	0	0	>=	44
ntr3	1	1	1	1	0	0	0	0	0	<=	167
ontr4	0	0	0	0	0	0	0	1	0	=	0
ontr5	0	0	0	0	0	0	0	1	0	=	0
ntr6	0	0	0	0	0	1	1	0	0	>=	11
ntr7	0	0	0	0	0	1	1	0	0	<=	99
ontr8	1	0	0	0	0	0	0	0	0	<=	54
ntr9	0	1	0	0	0	0	0	0	0	<=	63
ntr10	0	0	1	0	0	0	0	0	0	<=	26
ntr11	0	0	0	1	0	0	0	0	0	<=	26
ntr12	0	0	0	0	1	0	0	0	0	<=	9
ntr13	0	0	0	0	0	1	0	0	0	<=	48
tr14	0	0	0	0	0	0	1	0	0	<=	51
ntr15	0	0	0	0	0	0	0	1	0	=	0
tr16	0	0	0	0	0	0	0	0	1	<=	2
ntr17	1	1	0	0	0	0	0	0	0	<=	117
ntr18	0	0	0	0	1	1	1	0	0	<=	107
bo	inf	inf	inf	inf	inf	inf	inf	inf	inf		
bo	0	0	0	0	0	0	0	0	0		
e	Real	Real	Real	Real	Real	Real	Real	Real	Real		

able A4-3: Limited Availability Model-July 2006

arame er	KPD1	KPD2	KGT1	KGT2	FIAT	IBA	AKNBI	AKELD	UETCL	INQ	RH
bj:Min	3.98	2.8	9.92	14.1	14.1	4.5	6.92	7.8	9.49		
ontr1	1	1	1	1	1	1	1	1	1	=	71
ontr2	1	1	1	1	0	0	0	0	0	>=	44
ontr3	1	1	1	1	0	0	0	0	0	<=	167
ontr4	0	0	0	0	0	0	0	1	0	=	0
ontr5	0	0	0	0	0	0	0	1	0	=	0
ontr6	0	0	0	0	0	1	1	0	0	>=	18
ontr7	0	0	0	0	0	1	1	0	0	<=	119
ontr8	1	0	0	0	0	0	0	0	0	<=	54
ontr9	0	1	0	0	0	0	0	0	0	<=	63
ontr10	0	0	1	0	0	0	0	0	0	<=	26
ontr11	0	0	0	1	0	0	0	0	0	<=	26
ontr12	0	0	0	0	1	0	0	0	0	<=	9
ontr13	0	0	0	0	0	1	0	0	0	<=	48
ontr14	0	0	0	0	0	0	1	0	0	<=	71
ontr15	0	0	0	0	0	0	0	1	0	=	0
ontr16	0	0	0	0	0	0	0	0	1	<=	2
ntr17	1	1	0	0	0	0	0	0	0	<=	117
ontr18	0	0	0	0	1	1	1	0	0	<=	127
bo	inf	inf	inf	inf	inf	inf	inf	inf	inf		
wbo	0	0	0	0	0	0	0	0	0		
ype	Real	Real	Real	Real	Real	Real	Real	Real	Real		

ble A4-4: Limited Availability Model -Aug, September, November, December 2006

rame r	KPD1	KPD2	KGT1	KGT2	FIAT	IBA	AKNBI	AKELD	UETCL	INQ	RH
bj:Min	3.98	2.8	9.92	14.1	14.1	4.5	6.92	7.8	9.49		
ntr1	1	1	1	1	1	1	1	1	1	=	71
ntr2	1	1	1	1	0	0	0	0	0	>=	44
ntr3	1	1	1	1	0	0	0	0	0	<=	167
ntr4	0	0	0	0	0	0	0	1	0	>=	10
ntr5	0	0	0	0	0	0	0	1	0	<=	31
ntr6	0	0	0	0	0	1	1	0	0	>=	18
ntr7	0	0	0	0	0	1	1	0	0	<=	99
ntr8	1	0	0	0	0	0	0	0	0	<=	54
ntr9	0	1	0	0	0	0	0	0	0	<=	63
r10	0	0	1	0	0	0	0	0	0	<=	26
tr11	0	0	0	1	0	0	0	0	0	<=	26
tr12	0	0	0	0	1	0	0	0	0	<=	9
tr13	0	0	0	0	0	1	0	0	0	<=	48
r14	0	0	0	0	0	0	1	0	0	<=	51
r15	0	0	0	0	0	0	0	1	0	<=	31
r16	0	0	0	0	0	0	0	0	1	<=	2
r17	1	1	0	0	0	0	0	0	0	<=	117
r18	0	0	0	0	1	1	1	0	0	<=	107
[illegible]	inf	inf	inf	inf	inf	inf	inf	inf	inf		
[illegible]	0	0	0	0	0	0	0	0	0		
[illegible]	Real	Real	Real	Real	Real	Real	Real	Real	Real		

Table A4-5: Limited Availability Model-October 2006

Parameter	KPD1	KPD2	KGT1	KGT2	FIAT	IBA	AKNBI	AKELD	UETCL	INQ	RH
Obj:Min	3.98	2.8	9.92	14.1	14.1	4.5	6.92	7.8	9.49		
contr1	1	1	1	1	1	1	1	1	1	=	71
contr2	1	1	1	1	0	0	0	0	0	>=	44
contr3	1	1	1	1	0	0	0	0	0	<=	172
contr4	0	0	0	0	0	0	0	1	0	>=	10
contr5	0	0	0	0	0	0	0	1	0	<=	31
contr6	0	0	0	0	0	1	1	0	0	>=	18
contr7	0	0	0	0	0	1	1	0	0	<=	99
contr8	1	0	0	0	0	0	0	0	0	<=	54
contr9	0	1	0	0	0	0	0	0	0	<=	68
contr10	0	0	1	0	0	0	0	0	0	<=	26
contr11	0	0	0	1	0	0	0	0	0	<=	26
contr12	0	0	0	0	1	0	0	0	0	<=	9
contr13	0	0	0	0	0	1	0	0	0	<=	51
contr14	0	0	0	0	0	0	1	0	0	<=	53
contr15	0	0	0	0	0	0	0	1	0	<=	32
contr16	0	0	0	0	0	0	0	0	1	<=	2
contr17	1	1	0	0	0	0	0	0	0	<=	122
contr18	0	0	0	0	1	1	1	0	0	<=	112
upbo	inf	inf	inf	inf	inf	inf	inf	inf	inf		
lowbo	0	0	0	0	0	0	0	0	0		
Type	Real	Real	Real	Real	Real	Real	Real	Real	Real		

APPENDIX A5

TYPICAL OPTIMIZED DISPATCH OUTPUT

Table A5-1: Limited Availability Dispatch Model Simulation Output -January 2006

DATE	00.30	01.00	01.30	02.00	02.30	03.00	03.30	04.00	04.30	05.00	05.30	06.00	06.30	07.00	07.30	08.00	08.30	09.00	09.30	10.00	10.30	11.00	11.30	12.00	12.30
Sunday	201	206	204	202	196	193	191	189	188	199	200	202	201	201	204	207	208	195	192	192	197	194	192	191	191
Monday	200	200	191	186	174	173	172	173	176	182	186	188	188	188	192	195	195	185	184	187	186	185	181	182	182
Tuesday	186	182	180	176	175	176	175	173	175	179	184	187	190	188	192	192	193	187	184	187	187	191	190	192	192
Wednesday	206	208	207	206	207	208	202	201	202	205	209	209	209	207	207	198	201	198	198	198	198	201	193	194	192
Thursday	199	197	195	194	195	194	190	192	192	189	186	189	188	190	199	198	199	194	194	192	194	198	200	200	202
Friday	202	200	201	201	197	201	199	201	201	205	208	207	208	202	201	202	206	196	196	199	197	193	193	197	198
Saturday	203	202	204	204	203	200	197	197	200	199	204	201	205	200	202	206	207	200	196	196	199	197	197	202	198
CoastGenMin	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
CoastGenMax	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167
EldoretGenMin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EldoretGenMax	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NairobiGenMin	17	17	17	17	15	14	14	14	15	16	24	32	41	47	47	47	49	50	50	50	50	50	48	48	48
NairobiGenMax	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57
Sunday																									
Stat / Time	0.3	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	8	9	9	10	10	11	11	12	12
KPD1 (MW)	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
KPD2 (MW)	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
KGT1 (MW)	26	26	26	26	26	26	24	22	21	26	26	26	26	26	26	26	26	26	23	24	26	26	25	24	24
KGT2 (MW)	9	13	11	9	3	0	0	0	0	6	7	9	8	8	11	14	14	1	0	0	2	0	0	0	0
FIAT (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	2	2	2	2	0	0	0
IBA (MW)	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
AKNBI (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AKELD (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UETCL (MW)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Generation Cost('000'KSh)	968	1015	998	969	916	883	866	843	832	941	953	974	966	963	990	1022	1035	916	880	887	930	905	880	868	865
Monday																									
Stat / Time	0	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	8	9	9	10	10	11	11	12	12
KPD1 (MW)	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
KPD2 (MW)	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
KGT1 (MW)	26	26	24	19	8	6	5	6	9	15	19	21	21	21	25	26	26	16	15	19	17	17	14	15	15
KGT2 (MW)	7	7	0	0	0	0	0	0	0	0	0	0	0	0	0	2	1	0	0	0	0	0	0	0	0
FIAT (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	2	2	2	2	0	0	0
IBA (MW)	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
AKNBI (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AKELD (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UETCL (MW)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Generation Cost('000'KSh)	958	955	867	812	701	685	673	683	711	771	812	831	830	837	871	907	909	811	799	835	823	815	771	778	775

DATE	00.30	01.00	01.30	02.00	02.30	03.00	03.30	04.00	04.30	05.00	05.30	06.00	06.30	07.00	07.30	08.00	08.30	09.00	09.30	10.00	10.30	11.00	11.30	12.00	12.30
Tuesday																									
Stat / Time	0	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	8	9	9	10	10	11	11	12	12
KPD1 (MW)	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
KPD2 (MW)	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
KGT1 (MW)	19	15	13	9	8	9	8	7	8	12	17	20	23	21	25	25	26	18	15	18	18	23	23	24	24
KGT2 (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FIAT (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	2	2	2	2	0	0	0
IBA (MW)	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
AKNBI (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AKELD (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UETCL (MW)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Generation Cost('000'KSh)	811	771	759	712	704	711	703	690	703	748	794	827	853	833	871	878	891	832	803	832	835	875	855	871	871
Wednesday																									
Stat / Time	0	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	8	9	9	10	10	11	11	12	12
KPD1 (MW)	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
KPD2 (MW)	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
KGT1 (MW)	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	25
KGT2 (MW)	13	15	14	13	14	15	9	8	9	12	16	16	16	14	14	5	7	3	3	3	3	6	0	1	0
FIAT (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	2	2	2	2	0	0	0
IBA (MW)	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
AKNBI (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AKELD (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UETCL (MW)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Generation Cost('000'KSh)	1011	1035	1022	1017	1019	1034	977	963	974	999	1045	1040	1047	1023	1018	938	963	941	936	940	937	966	885	895	874
Thursday																									
Stat / Time	0	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	8	9	9	10	10	11	11	12	12
KPD1 (MW)	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
KPD2 (MW)	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
KGT1 (MW)	26	26	26	26	26	26	23	25	25	22	19	22	21	23	26	26	26	26	25	23	25	26	26	26	26
KGT2 (MW)	6	5	2	1	2	1	0	0	0	0	0	0	0	0	6	5	5	0	0	0	0	3	7	6	8
FIAT (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	2	2	2	2	0	0	0
IBA (MW)	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
AKNBI (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AKELD (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UETCL (MW)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Generation Cost('000'KSh)	944	929	908	896	907	896	851	878	870	847	812	842	832	855	943	931	946	906	902	882	898	936	954	952	972

DATE	00.30	01.00	01.30	02.00	02.30	03.00	03.30	04.00	04.30	05.00	05.30	06.00	06.30	07.00	07.30	08.00	08.30	09.00	09.30	10.00	10.30	11.00	11.30	12.00	12.30
Friday																									
Stat / Time	0	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	8	9	9	10	10	11	11	12	12
KPD1 (MW)	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
KPD2 (MW)	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
KGT1 (MW)	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	24	26	26	26
KGT2 (MW)	10	7	8	8	4	8	6	8	8	12	15	14	15	9	8	9	12	1	1	4	2	0	0	4	5
FIAT (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	2	2	2	2	0	0	0
IBA (MW)	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
AKNBI (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AKELD (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UETCL (MW)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Generation Cost('000'KSh)	978	952	966	966	928	965	942	965	966	1007	1029	1019	1029	972	964	974	1014	920	919	949	927	886	888	925	933
Saturday																									
Stat / Time	0	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	8	9	9	10	10	11	11	12	12
KPD1 (MW)	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
KPD2 (MW)	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
KGT1 (MW)	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
KGT2 (MW)	11	9	11	11	10	7	4	4	7	6	11	8	12	7	9	13	13	5	2	1	4	3	4	9	5
FIAT (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	2	2	2	2	0	0	0
IBA (MW)	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
AKNBI (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
AKELD (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
UETCL (MW)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Generation Cost('000'KSh)	988	975	990	990	984	949	927	926	951	941	992	968	1001	957	971	1009	1023	961	923	923	950	934	925	976	934

DATE	13.00	13.30	14.00	14.30	15.00	15.30	16.00	16.30	17.00	17.30	18.00	18.30	19.00	19.30	20.00	20.30	21.00	21.30	22.00	22.30	23.00	23.30	24.00		
Sunday	197	195	198	196	196	190	193	193	190	193	196	204	210	209	209	209	211	211	205	211	212	208	203		
Monday	184	190	190	188	187	184	182	185	187	192	193	201	200	202	202	205	207	207	207	197	199	195	190		
Tuesday	193	192	184	194	197	193	190	197	198	198	199	204	205	203	203	209	207	211	213	210	212	210	207		
Wednesday	195	200	198	196	195	196	198	199	201	200	205	202	206	209	212	213	213	213	210	206	206	203	198		
Thursday	200	200	198	198	199	200	198	198	201	204	203	205	210	200	199	203	203	206	206	207	207	205	205		
Friday	197	194	194	193	190	189	193	193	195	197	201	205	206	205	208	209	211	211	209	211	213	210	208		
Saturday	199	202	204	204	179	189	194	192	193	194	197	202	204	202	205	203	203	206	204	207	203	204	203		
CoastGenMin	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44		
CoastGenMax	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167	167		
EldoretGenMin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
EldoretGenMax	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		

DATE	13.00	13.30	14.00	14.30	15.00	15.30	16.00	16.30	17.00	17.30	18.00	18.30	19.00	19.30	20.00	20.30	21.00	21.30	22.00	22.30	23.00	23.30	24.00		
NairobiGenMin	48	48	48	48	48	48	48	48	48	48	49	49	49	49	49	49	49	49	47	46	45	38	22		
NairobiGenMax	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57		
Sunday																								TOTAL GWH	Sunday
Stat / Time	13	13	14	14	15	15	16	16	17	17	18	18	19	19	20	20	21	21	22	22	23	23	24		
KPD1 (MW)	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	2,592	
KPD2 (MW)	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	3,024	
KGT1 (MW)	26	26	26	26	26	22	25	25	23	26	26	26	26	26	26	26	26	26	26	26	26	26	26	1,218	
KGT2 (MW)	4	2	5	3	2	0	0	0	0	0	3	10	16	16	15	15	18	17	12	18	19	15	10	322	
FIAT (MW)	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	0	0	0	0	0	20	
IBA (MW)	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	2,304	
AKNBI (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
AKELD (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
UETCL (MW)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	96	
Generation Cost('000'KSh)	924	905	938	913	914	851	883	882	860	885	918	995	1052	1050	1048	1046	1071	1061	1008	1065	1069	1028	987	Total (000 KSH)=	45,616
Monday																								TOTAL GWH	Monday
Stat / Time	13	13	14	14	15	15	16	16	17	17	18	18	19	19	20	20	21	21	22	22	23	23	24		
KPD1 (MW)	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	2,218	
KPD2 (MW)	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	3,456	
KGT1 (MW)	16	22	23	21	19	17	15	18	20	25	26	26	26	26	26	26	26	26	26	26	26	26	23	171	
KGT2 (MW)	0	0	0	0	0	0	0	0	0	0	0	8	6	8	8	11	13	14	14	4	6	2	0	0	
FIAT (MW)	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	0	0	0	0	0	0	
IBA (MW)	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	2,079	
AKNBI (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
AKELD (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
UETCL (MW)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	34	
Generation Cost('000'KSh)	792	854	857	835	825	796	775	810	824	878	892	972	953	977	973	1008	1022	1030	1023	923	940	905	854		40,933
Tuesday																								TOTAL GWH	Tuesday
Stat / Time	13	13	14	14	15	15	16	16	17	17	18	18	19	19	20	20	21	21	22	22	23	23	24		
KPD1 (MW)	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	1,732	
KPD2 (MW)	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	3,456	
KGT1 (MW)	26	25	17	26	26	26	22	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	0	
KGT2 (MW)	0	0	0	0	4	0	0	4	4	4	5	10	11	9	10	15	14	17	20	17	19	17	14	0	
FIAT (MW)	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	0	0	0	0	0	0	
IBA (MW)	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	1,919	

DATE	13 00	13 30	14 00	14 30	15 00	15 30	16 00	16 30	17 00	17 30	18 00	18 30	19 00	19 30	20 00	20 30	21 00	21.30	22 00	22.30	23.00	23.30	24.00		
AKNBI (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
AKELD (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
UETCL (MW)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0	
Generation Cost('000'KSh)	886	880	800	891	925	888	853	924	933	931	946	1000	1008	983	991	1045	1029	1064	1078	1049	1071	1052	1021		42,280
Wednesday																								TOTAL GWH	Wednesday
Stat / Time	13	13	14	14	15	15	16	16	17	17	18	18	19	19	20	20	21	21	22	22	23	23	24		
KPD1 (MW)	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	1,859	
KPD2 (MW)	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	3,449	
KGT1 (MW)	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	240	
KGT2 (MW)	1	6	4	3	2	3	5	6	8	7	12	8	12	16	19	19	20	19	17	13	13	10	5	0	
FIAT (MW)	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	0	0	0	0	0	0	
IBA (MW)	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	2,086	
AKNBI (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
AKELD (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
UETCL (MW)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	32	
Generation Cost('000'KSh)	903	953	932	916	908	915	936	947	965	959	1007	977	1014	1050	1080	1087	1088	1082	1055	1018	1014	982	938		47,225
Thursday																								TOTAL GWH	Thursday
Stat / Time	13	13	14	14	15	15	16	16	17	17	18	18	19	19	20	20	21	21	22	22	23	23	24		
KPD1 (MW)	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	2,393	
KPD2 (MW)	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	3,456	
KGT1 (MW)	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	453	
KGT2 (MW)	7	7	5	5	5	6	4	5	8	10	9	11	17	6	6	10	9	13	13	14	14	12	13	35	
FIAT (MW)	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	0	0	0	0	0	0	
IBA (MW)	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	2,172	
AKNBI (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
AKELD (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
UETCL (MW)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	60	
Generation Cost('000'KSh)	956	956	933	932	942	951	931	937	966	990	986	1009	1059	954	952	990	983	1021	1014	1024	1027	1004	1008		45,013
Friday																								TOTAL GWH	Friday
Stat / Time	13	13	14	14	15	15	16	16	17	17	18	18	19	19	20	20	21	21	22	22	23	23	24		
KPD1 (MW)	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	2,351	
KPD2 (MW)	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	3,456	
KGT1 (MW)	26	26	26	26	23	22	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	561	
KGT2 (MW)	4	1	1	0	0	0	0	0	2	3	7	11	13	11	14	15	17	17	16	18	20	17	15	3	
FIAT (MW)	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	0	0	0	0	0	0	

DATE	13 00	13.30	14.00	14.30	15 00	15.30	16 00	16 30	17.00	17.30	18 00	18.30	19 00	19.30	20 00	20.30	21.00	21.30	22.00	22.30	23.00	23.30	24.00		
IBA (MW)	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	2,176	
AKNBI (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
AKELD (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
UETCL (MW)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	64	
Generation Cost('000'KSh)	925	899	899	887	860	850	884	885	908	922	965	1004	1020	1008	1037	1043	1061	1066	1046	1060	1082	1051	1029		46,370
Saturday																								TOTAL GWH	Saturday
Stat / Time	13	13	14	14	15	15	16	16	17	17	18	18	19	19	20	20	21	21	22	22	23	23	24		
KPD1 (MW)	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	2,339	
KPD2 (MW)	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	3,456	
KGT1 (MW)	26	26	26	26	11	21	26	25	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	306	
KGT2 (MW)	5	9	11	11	0	0	1	0	0	1	4	9	10	9	12	9	10	12	11	14	10	11	10	0	
FIAT (MW)	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	0	0	0	0	0	0	
IBA (MW)	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	2,157	
AKNBI (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
AKELD (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
UETCL (MW)	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	52	
Generation Cost('000'KSh)	941	973	997	995	744	842	896	881	889	899	929	982	993	981	1011	983	990	1014	994	1023	983	997	988		45,990

APPENDIX A6

THE 2007 LOAD FORECAST AND LEAST COST DEVELOPMENT PLAN

Table A6-1: Summary of the Load Forecast Results

Fiscal Year	LOW Net Energy (GWh)	LOW Net System Peak (MW)	REFERENCE Net Energy (GWh)	REFERENCE Net System Peak (MW)	HIGH Net Energy (GWh)	HIGH Net System Peak (MW)
2006/07	6,161	1,043	6,203	1,082	6,246	1,057
2007/08	6,534	1,106	6,607	1,153	6,672	1,130
2008/09	7,011	1,187	7,119	1,206	7,209	1,221
2009/10	7,493	1,269	7,638	1,294	7,790	1,320
2010/11	8,061	1,366	8,251	1,398	8,498	1,441
2011/12	8.656	1,467	8,895	1,508	9,251	1,569
2012/13	9.285	1,574	9,580	1,625	10,060	1,707
2013/14	9.952	1,688	10,308	1,749	10,929	1,855
2014/15	10.657	1.808	11,082	1,881	11,862	2,014
2015/16	11.403	1.935	11,905	2,021	12,865	2,186
2016/17	12.194	2,070	12,781	2,171	13,943	2,370
2017/18	13,032	2,213	13,713	2,330	15,102	2,567
2018/19	13,921	2,364	14,705	2,499	16,349	2,780
2019/20	14,862	2,525	15,762	2,679	17,690	3,009
2020/21	15,861	2,696	16,887	2,871	19,133	3,256
2021/22	16,920	2,876	18,085	3,076	20,687	3,522
2022/23	18.044	3,068	19,362	3,294	22,359	3,807
2023/24	19,236	3.272	20,723	3,527	24,160	4,115
2024/25	20.502	3,488	22,174	3,774	26,099	4,447
2025/26	21.845	3,717	23,720	4,038	28,188	4,804
2026/27	23,270	3,961	25,368	4,320	30,438	5,188
2027/28	24.784	4.219	27,126	4,620	32,862	5,603

Table A6-2: 2008-2028 Least Cost Plan Generation by Type (GWh)

Year	Forecast	Import	Hydro	Geot	Diesel	Coal	Comb Cycle	Cogen	Gas Turbine	Total
2008	6,607	0	3,011	979	1,557	0	0	0	597	**6,144**
2009	7,119	0	3,170	1,437	2,072	0	0	138	299	**7,115**
2010	7,638	0	3,236	1,548	2,162	0	0	192	488	**7,625**
2011	8,251	0	3,296	1,548	2,981	0	0	192	232	**8,249**
2012	8,895	0	3,283	2,130	2,987	0	0	192	295	**8,888**
2013	9,580	876	3,281	2,108	2,875	0	0	192	240	**9,571**
2014	10,308	2,628	3,298	2,108	2,055	0	0	192	27	**10,307**
2015	11,082	2,628	3,282	1,948	2,150	820	0	192	59	**11,078**
2016	11,905	2,628	3,298	2,530	2,476	741	0	192	36	**11,902**
2017	12,781	2,628	3,293	2,508	3,339	744	0	192	75	**12,779**
2018	13,713	3,503	3,302	2,508	3,353	743	0	192	104	**13,705**
2019	14,705	3,503	3,291	2,508	3,492	1,566	0	192	148	**14,700**
2020	15,762	4,379	3,292	3,090	3,193	1,485	0	192	126	**15,757**
2021	16,887	4,379	3,296	3,068	2,710	3,116	0	192	119	**16,881**
2022	18,085	5,255	3,289	3,068	3,005	2,959	163	192	147	**18,078**
2023	19,362	5,255	3,293	3,068	2,668	4,578	158	192	138	**19,350**
2024	20,723	6,131	3,279	3,650	2,798	4,405	142	192	114	**20,711**
2025	22,174	6,131	3,276	3,628	2,646	5,996	155	192	142	**22,165**
2026	23,720	7,882	3,281	4,211	2,195	5,672	147	192	131	**23,710**
2027	25,368	7,882	3,289	4,188	3,456	5,864	337	192	147	**25,355**
2028	27,126	7,882	3,291	5,353	2,721	7,272	290	192	113	**27,115**

LIST OF DEFINITIONS

1. **Baseload plants** –Power plants that are operated to meet the baseload demand of a system, usually due to their lower generation costs.
2. **Baseload** –The average lower level of demand in a power system's daily load profile.
3. **Blackout** –Total outage of an entire power system (system collapse).
4. **Candidate plants** –Power generation projects for possible development in future.
5. **Carbon Trading** –Trading of certified carbon (or equivalent) emission reduction credits between developed and developing countries.
6. **Cogeneration** –Generation of power from by-products of a main process, e.g use of bagasse from sugar factories for power generation.
7. **Dispatch** –Ordering a power generation plant connected in a system to supply power.
8. **Emissions** –Air pollutants released from power generating plants, in this case CO_2 emitted by thermal power plants.
9. **Energy balance** –Schedule of energy output from available sources against forecast demand.
10. **Expected Unserved Energy (EUE)** –Electricty demand required by a power system but is no met due to capacity deficiency. EUE is assigned a price to indicate the cost of not supplying the economy with energy so as to cost the lost productivity.
11. **Firm energy capability** –The maximum of the minimum energy production by a power plant in simulation runs or actual operation.
12. **Least cost plan or Least Cost Power Development Plan** –The national power expansion plan for Kenya
13. **Load Duration Curve** –A recording of chronological load in which the x-axis shows how many hours the load was equal to, or greater than, the power level which is shown on the y-axis.
14. **Load forecast** –Electricity demand forecast

15. **Load shedding** –Opening of power distribution lines to isolate loads from the systems

16. **Loss of Load Expectation (LOLE)** –The probability of not meeting load demand in a given period.

17. **Merit order dispatch** –Dispatch schedule ranked by cost of generation for each plant, usually from the cheapest to the most expensive

18. **Model** –A representation of a system for the purpose of studying the system

19. **Outage** –When power source or transmission system is out of operation due to a malfunction or system fault.

20. **Power System Planning** –Planning activities related to expansion of power transmission and generation capacities.

21. **Present Worth Cost** –The cost of an investment plan over a given period discounted to the present.

22. **Ramp down** –Rate of percentage decrease in the output of power generator turbine.

23. **Ramp up** –Rate of percentage increase in the output of power generator turbine.

24. **Run-of-river** –A power plant that is driven by water diverted from a river through a channel with a small or no regulating water reservoir.

25. **System collapse** –An event where a power system losses stability and all interconnected power sources and networks are disconnect electrically interrupting supply to all loads supplied from the system.

26. **Validation** –Process of evaluating a model to confirm if it is an accurate representation of the real system.

27. **Verification** –to ascertain if the model is built correctly by comparing the conceptual model to the computer representation that implements the conception.