Addis Ababa University

Addis Ababa Institute of Technology

Center of Energy Technology

An investigation of integrated reservoir and power system operation, an optimal dispatch of the Ethiopian Electric Power System

A Thesis Submitted to Addis Ababa institute of Technology
in Partial Fulfillment of the Requirements for the Degree of Master
of Science in Energy Technology

By

Ashenafi Alemu

Advisor: Dr. Solomon Abebe

June, 2015

Addis Ababa University

Addis Ababa Institute of Technology

Center of Energy Technology

An investigation of integrated reservoir and power system operation, an optimal dispatch of the Ethiopian Electric Power System

By: **Ashenafi Alemu Demissie**

APPROVED BY BOARD OF EXAMINERS

1. Dr. Solomon Abebe ______ ___________ ___________

   Head, Energy Center- AAiT Signature Date

2. Dr. Solomon Abebe ______ ___________ ___________

   Thesis Advisor Signature Date

3. Prof. Nagandra Prasad Singh ___________ ___________

   Internal examiner Signature Date

4. Dr. Getachew Biru Worku ___ ___________ ___________

   External examiner Signature Date

DECLARATION

I, the undersigned, declare that this thesis is my original work and has not been presented for a degree in this or any other Universities, and that all source of materials used for the thesis work have been duly acknowledged.

Declared by:

Name: Ashenafi Alemu

Signature: ___________________________

Date: _______________________________

Place: Addis Ababa institute of Technology, Addis Ababa University, Addis Ababa

This thesis has been submitted for examination with my approval as a university advisor.

Confirmed by:

Advisor’s Name: Dr. Solomon Abebe

Signature: ___________________________

Date: _______________________________

Dedicated to my wife, Baby (Meraf), for her immense love, initiation, support, care, positivity and encouragement in this thesis and everything I do.

ACKNOWLEDGMENT

First and foremost, I would like to thank God and his mother Virgin Mary for keeping me healthy and safe in everything I do.

My sincere thanks go to my advisor, Dr. Solomon Abebe, for introducing me with the idea of working on the area of power system planning. In addition I would like to pass my deepest gratitude for his continuous follow-up, encouragement, insight, valuable guidance, and professional expertise during the course of this thesis work.

I would like to thank all instructors who responsibly thought me courses during my graduate study and special thanks goes to Dr.-Ing. Abebayehu Assefa who has been highly supportive, positive and encouraging during my study at the AAiT Center of Energy Technology.

My deepest gratitude goes to Aman, Daniel and Sara who are experts at LDC, corporate planning and Generation operation respectively, for providing me with majority of data together with updates on the existing electricity infrastructure construction as well as power distribution operation.

I would also like to express my appreciation and gratitude to Dr. Semu and Henock Tilahun for their kind support during the decision on the mathematics and programming to be used for solving the problem in this study, respectively.

Last but not least, I want to thank my parents, family and friends for their unconditional & continuous support and encouragement throughout the course of my study.

LIST OF ACRONYMS

EEPCo : Ethiopian Electric Power Corporation
GD III : Genale Dawa III
GDP : Gross Domestic Product
GERD : Grand Ethiopian Renaissance Dam
GGI : Gilgel Gibe I
GG II : Gilgel Gibe II
GG III : Gilgel Gibe III
GWh : Giga Watt hour
ICS : Interconnected System
IEA : International Energy Agency
KV : Kilo Volt
KW : Kilo Watt
KWh : Kilo Watt hour
LDC : Load Dispatch Center
LP : Linear Programming
USD : United States Dollar

TABLE OF CONTENTS

ACKNOWLEDGMENT v

LIST OF ACRONYMS vi

TABLE OF CONTENTS vii

LIST OF TABLES ix

LIST OF FIGURES x

ABSTRACT xii

CHAPTER 1 INTRODUCTION 1

- 1.1. Background 1
- 1.2. Problem Statement 5
- 1.3. Objective 7
  - 1.3.1. General Objective 7
  - 1.3.2. Specific objectives 7
- 1.4. Methodology 7
- 1.5. Significance of the study 8
- 1.6. Organization of the study 8

CHAPTER 2 LITERATURE REVIEW 9

- 2.1. Electrical power plant operational planning stages 9
- 2.2. Hydro dominated system problem formulation and reservoir simulation 10
- 2.3. Optimization 15
- 2.4. Hydrothermal dispatch and the case of Ethiopian power system 17

CHAPTER 3 INPUT DATA ANALYSIS 19

- 3.1. Ethiopia electricity generation potential and power system master plan 19
- 3.2. Energy and Hourly models 20
- 3.3. Energy and Hourly models optimization framework 21
- 3.4. Data acquisition and verification 23
  - 3.4.1. Power plants available for medium and short term operational plan 23
  - 3.4.2. Hydro System Diagram 26
  - 3.4.3. Hydroelectric power plants 28
  - 3.4.4. Geothermal, Co-generation, Biomass and Energy from waste plants 32
  - 3.4.5. Load (Demand) 36
  - 3.4.6. Water inflow 40

3.4.7. Evaporation and Water demand (Irrigation) 44
3.4.8. Wind power plants hourly power output 46
3.4.9. Cost and Economic parameters 53
3.4.10. Database Organization 58
CHAPTER 4 MODELING AND SIMULATION 61
4.1. Modeling 61
4.1.1. Energy Model 63
4.1.2. Hourly Model 70
4.2. Problem Formulation and Model dimensions 76
4.2.1. Problem formulation 76
4.2.2. Problem and Model dimensions 81
4.3. Solution Technique 83
4.4. Simulation with MATLAB 85
CHAPTER 5 RESULTS AND DISCUSSION 87
5.1. Reference Scenario 87
5.1.1. Year round (Energy) dispatch 87
5.1.2. Hourly dispatch 91
5.1.3. Reservoirs operation 93
5.1.4. Power plant operation 95
5.2. Sensitivity Analysis 96
5.2.1. Year round dispatch for High and Low inflow scenarios 97
5.2.2. Hourly dispatch for High and Low inflow scenarios 101
5.2.3. Comparison of Scenarios 103
CHAPTER 6 CONCLUSION AND RECOMMENDATION 113
6.1. Conclusion 113
6.2. Recommendation 115
6.3. Future works 115
REFERENCES 116
APPENDICES 120

LIST OF TABLES

Table 2.1: Publication summary on hydrothermal problems 17

Table 3.1: Ethiopian energy resources gross and economic potential for electrical power generation and energy production 19

Table 3.2: Power plants available for operational planning in the year 2017 G.C. 25

Table 3.3: Electrical characteristics of hydroelectric power plants 29

Table 3.4: Hydrological characteristics of hydroelectric power plants 31

Table 3.5: Upstream-Downstream reservoirs and power plants relationship 32

Table 3.6: Non-hydro power plants characteristics 32

Table 3.7: Seasonal availability of sugar factories Co-generation and biomass plants 35

Table 3.8: EEPCo generation expansion master plan for the year 2017 G.C. 38

Table 3.9: Energy forecast comparison 38

Table 3.10: Reservoirs monthly average total inflow for moderate inflow scenario 42

Table 3.11: Evaporation rate unit conversion for Fincha reservoir 44

Table 3.12: Monthly average water demand 45

Table 3.13: Wind farms power simulation input data summary 47

Table 3.14: Manufacturer and fitted power curve of Sany SE 7715 49

Table 3.15: Adama II simulated hourly power output on January 03, 2017 52

Table 3.16: Committed and Candidate plants annual capital cost for 2017 G.C. 56

Table 3.17: Annual capital, Operational & Maintenance and Fuel cost of all plants 57

Table 4.1: Problem dimensions 81

Table 4.2: Energy model dimensions 82

Table 4.3: Hourly model dimensions 83

Table 5.1: Amount of reservoirs water volume at the start and end of the year for reference case scenario 95

Table 5.2: Power plant operation at peak hour of the year 96

Table 5.3: List of Scenarios 97

LIST OF FIGURES

Figure 1.1: KWh per capita electricity consumption of some countries 1

Figure 1.2: Electricity production (KWh) of some countries 2

Figure 3.1: Optimization framework of Energy and hourly models...................................... 22

Figure 3.2: River basins in Ethiopia.. 26

Figure 3.3: Map of existing and potential hydroelectric developments 27

Figure 3.4: 2017 G.C. Ethiopian potential hydro system diagram [AutoCAD].................... 28

Figure 3.5: Ethiopian adjusted hourly load including exports and losses for 2017 G.C....... 37

Figure 3.6: Monthly peak demand as percent of annual peak 38

Figure 3.7: Annual load duration curve, 2013 G.C. 39

Figure 3.8: 2017 G.C. potential hydro system monthly average total inflow_moderate inflow scenario... 43

Figure 3.9: Distribution of average wind speeds [m/s] in Ethiopia (1980-2009) – 50m....... 46

Figure 3.10: Sany SE 7715 fitted curve for Adama II wind farm.. 50

Figure 3.11: Monthly average wind power distributions of selected wind farms 53

Figure 3.12: Input data Database 59

Figure 4.1: Load balance and reserve requirement.. 71

Figure 4.2: MATLAB command and workspace window.. 86

Figure 5.1: year round dispatch of the energy output (in a block of 5 consecutive days) of various technologies 88

Figure 5.2: Year round water discharge of various hydropower plants (in a block of 5 consecutive days) corresponding to the dispatch give in Figure 5.1..................................... 88

Figure 5.3: Year round energy output of each hydropower plant... 89

Figure 5.4: Year round wind energy supply (in a block of 5 consecutive days).................... 90

Figure 5.5: Year round sugar factories cogeneration supply (in a block of 5 consecutive days)... 90

Figure 5.6: Hourly dispatch for the peak demand hour duration 91

Figure 5.7: Hydropower plants hourly power dispatch for the peak demand hour duration... 91

Figure 5.8: Hydropower plants hourly water discharge for the peak demand hour duration... 92

Figure 5.9: Wind power plants hourly power dispatch for the peak demand hour duration *93*

Figure 5.10: Sugar fac. Co-gen. plants hourly power dispatch for the peak demand hour duration *93*

Figure 5.11: Year round reservoir level for largest Dams *94*

Figure 5.12: Year round reservoir level for moderate size reservoirs *94*

Figure 5.13: Year round dispatch of power plants at high inflow scenario *98*

Figure 5.14: Year round dispatch of power plants at low inflow scenario *99*

Figure 5.15: Year round Hydropower plants dispatch for high inflow scenario *99*

Figure 5.16: Year round Hydropower plants dispatch for low inflow scenario *100*

Figure 5.17: Year round water discharge trends by hydropower plants for high inflow scenario *100*

Figure 5.18: Year round water discharge trends by hydropower plants for low inflow scenario *101*

Figure 5.19: Hourly dispatch for the peak demand hour duration of the year- high inflow scenario *102*

Figure 5.20: Hourly dispatch for the peak demand hour duration of the year- low inflow scenario *102*

Figure 5.21: Annual average energy contribution percentage share for all scenarios *104*

Figure 5.22: Annual average energy contribution percentage share for hydropower plants *105*

Figure 5.23: Year round share of energy dispatch by technology for high inflow scenario *106*

Figure 5.24: Year round share of energy dispatch by technology for moderate inflow scenario *106*

Figure 5.25: Year round share of energy dispatch by technology for low inflow scenario *107*

Figure 5.26: Unserved energy for all scenarios *108*

Figure 5.27: Cost of Electricity for all scenarios *109*

Figure 5.28: Total cost of Dispatch for all scenarios *110*

Figure 5.29: Capacity factor for the three inflow scenarios *111*

An investigation of integrated reservoir and power system operation, an optimal dispatch of the Ethiopian Electric Power system

Ashenafi Alemu Demissie

ABSTRACT

Ethiopian Electric Utility (which is born from EEPCo) has been running a Load Dispatch Center (LDC), which is tasked with the responsibility of an optimal power dispatch from an operational point of view. However, to date most operational decisions (including reservoir management) are done manually. Under such circumstance, integrated reservoir management and power system dispatch become more challenging as more and more plants with different technologies are to be added in coming years. Thus, it is very important to perform high resolution system dispatch to identify short term challenges, opportunities and potential solutions. This study was performed using two parallel, linear optimization, models that have been developed using MATLAB optimization toolbox. The first one, which is termed as energy model, deals with year round reservoir operations subject to the energy requirement of the power grid. This model has 73 time steps, with each time step representing a block of successive five days. The second one uses the output of the former model to test the hourly power balance and hourly reserve needs subject to the requirements of hourly water balance in reservoir and power systems operation over the selected days. The second model has 120 time steps, with each time step representing an hour. The result for the reference scenario shows that hydropower contributes significant amount of energy (approximately 90%) to meet 2017's annual demand at least cost. It also indicates that this could be achieved while maintaining steady state reservoir level and fulfilling the power reserve requirement. However, vulnerability related to heavy reliance on hydropower puts the power grid at significant risk that would lead to high cost of electricity due to shortage of water during dry year and high demand conditions. It was also shown that 3 GW capacity of GERD power plant should be available at the beginning of 2017 in order to avoid high cost of electricity generation and unserved energy that could occur if the construction is delayed. The result shows that depending on scenarios' the increase in cost of electricity, including cost of unserved energy, was approximately 6.3 to 8.75 fold the cost at the reference scenario. The major causes of this cost increase are the direct cost related to the use of more expensive electricity generators, and the indirect cost due to unserved energy (lost GDP per kWh). In short, it is concluded that integrated reservoir and power system operation leads to efficient resource utilization (Especially water and power system infrastructure), which should be given due attention during hydropower power resources development and operation. Future mitigation of the observed vulnerability should look into the following four solutions. These are: (i) implementing an optimal integrated operation; (ii) emphasizing the use of diverse generation resources; (iii) implementing strategies that enhance water inflows to reservoirs; (iv) designing power plants with higher capacity factors.

Keywords: Power system operation; optimal reservoir operation; optimal dispatch

CHAPTER 1
INTRODUCTION

1.1. Background

Electricity is so basic to the world economy that certain electricity indices (consumption or production of electricity per capita) are used to express a country's economic growth and the standard of living (per capita electricity consumption in the domestic sector) enjoyed by the people [1]. Ethiopia's KWh (Kilo Watt hour) per capita and electricity production has grown from 39.68 to 51.96 and 3547 KWh to 5989 KWh respectively in the years 2007 to 2012 G.C [2, 3].

Consumption of electricity per capita and electricity production for different countries are given in Figures 1.1 and 1.2, respectively [2, 3]. The Figures show that Ethiopia together with other African countries lies at the bottom in terms of consumption and production.

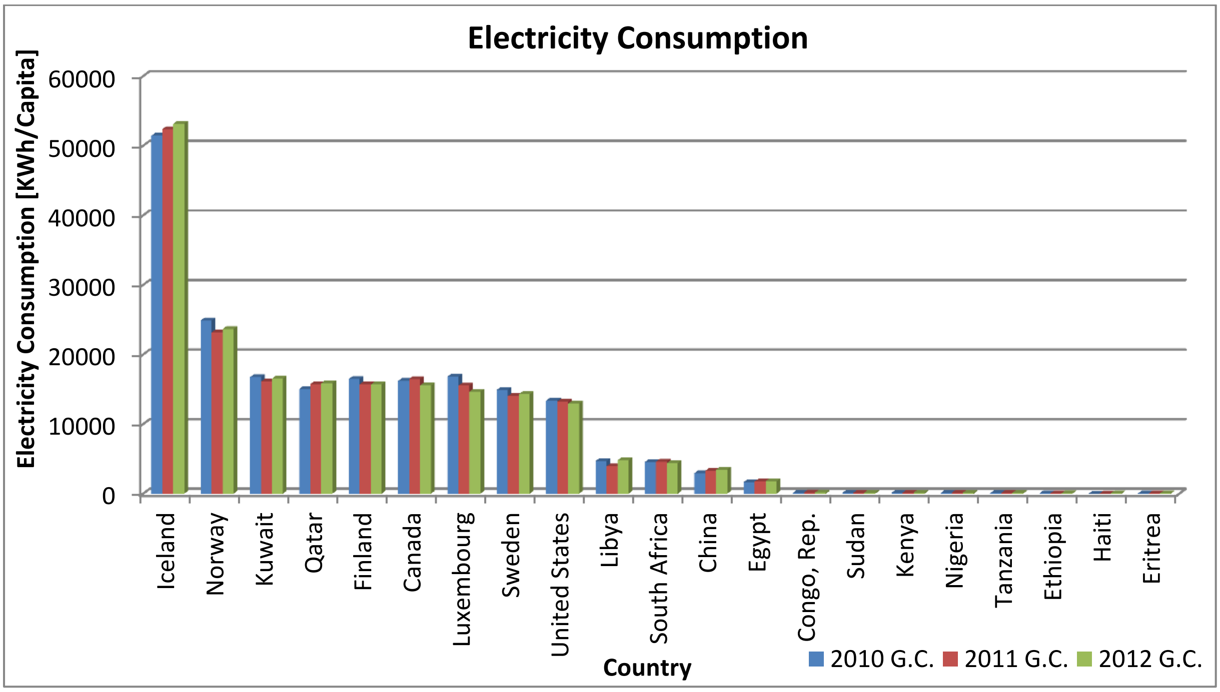


Figure 1.1: KWh per capita electricity consumption of some countries

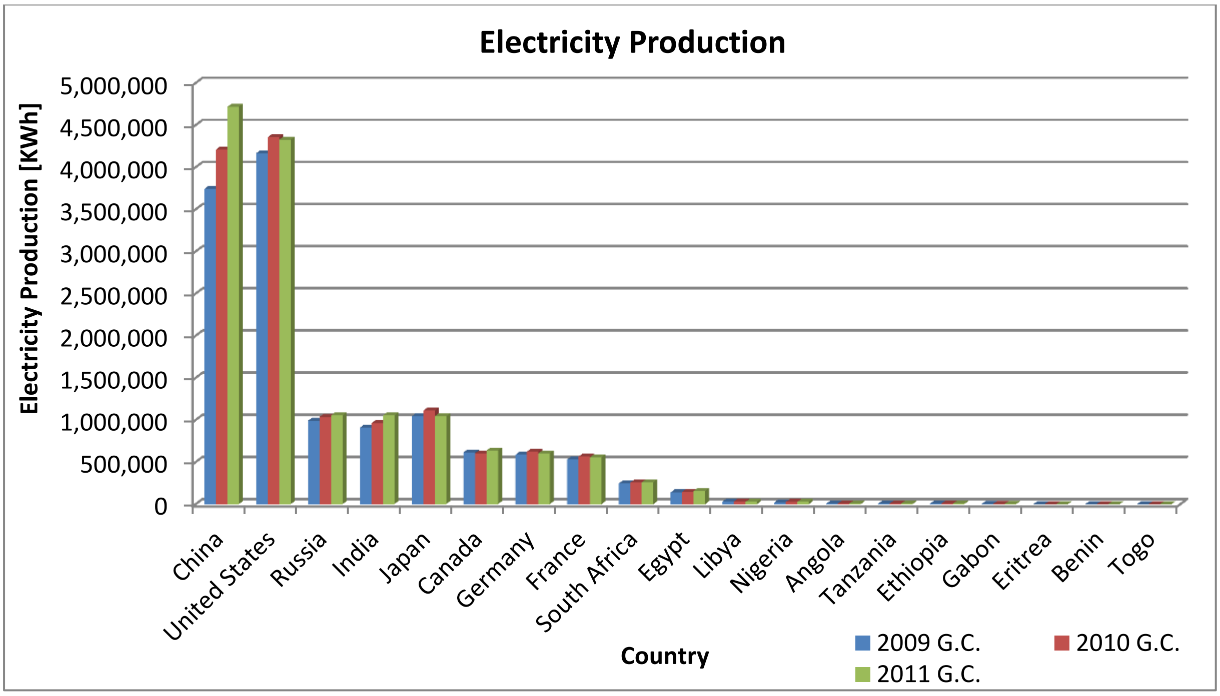


Figure 1.2: Electricity production (KWh) of some countries

Electricity supply has special characteristics that make the service unique as compared to other types of industry. The end product has to be delivered instantaneously and automatically upon the consumer's demand. In other words Electric power systems are real-time energy delivery systems in which power is generated, transported, and supplied the moment you turn on the light switch. This is because Electric power systems are not storage systems like water systems and gas systems as it cannot generally be stored at a large scale at reasonable cost [1, 4].

As a result power system operators need to make plans and take actions to keep supply and demand matched in "real-time" - from minute to minute and second to second [5]. Careful operational planning of the electric sector is therefore of great importance since the decisions to be taken involves the commitment of large resources, with potentially serious economic risks for the electrical utility and the economy as a whole [1].

The efficient and optimum economic operation and planning of electric power generation systems have always occupied an important position in the electric power industry [6]. Planning, operation and control of interconnected power system poses a variety of challenging problems, the solution of which requires extensive application of mathematical methods from various branches [7]. The electric utility industry has historically broken the process of meeting customer demands at minimal cost of generation into three stages namely resource planning, generation unit commitment and short term planning. Resource (long term) planning determines, years in advance, the requirement for new generation plants and corresponding facilities like transmission lines. Generation unit commitment (medium term planning) comes weeks or months in advance to make commitment decisions to have certain quantities of existing generation plant available to produce electricity when the need arises [5]. After completing long and medium term planning, short term planning comes in to picture.

Short term planning is operational decision of generation and transmission facilities to produce energy required to meet customer's electricity need reliably and economically subject to, any operational limits of generation and transmission facilities [8, 9].

Economic operation of power plants in Ethiopia has been an issue in the past few years as considerable potential output has been lost due to power cuts. If this problem is not addressed, potential losses from power disruption will increase in the future as the economy grows and the relative contributions of the industry and service sectors increase in the economy [10, 11].

In line with this fact, Ethiopia, having 84 million people in 18 million households (2012 G.C), has been working hard on expanding the electricity network. The corporate planning office of the former Ethiopian Electric power corporation (EEPCo) has developed a long term plan aimed at addressing these challenges [12].

Ethiopia has significant amount of water, wind, solar and geothermal energy potentials. The estimated technical potential of hydro, geothermal and wind energy resources is about 45 GW, 7 GW and 1035 GW, respectively [11, 13]. The national ground level average solar radiation is also estimated to be 5.2 kWh/m^2 per day [13].

The national grid or Interconnected System (ICS) accounts for about 99% of the electricity supply and is predominantly hydro-based (contributing 93% of the country's electricity production in normal operation) with Diesel units serving as backups during generation shortfalls [13]. The ICS consists of 13 hydro, one geothermal, two wind and 15 big & small Diesel power plants with an installed capacity of 1947.5 MW (Mega Watt), 7.3 MW, 171 MW and 110.44 MW respectively [12]. In addition, 3 hydro, 2 geothermal, 2 wind, 2 biomass, 13 Co-generation and 1 waste to energy plants with a total installed capacity of

8123.98 MW, 190 MW, 273 MW, 120 MW, 434MW and 25 MW respectively are expected to come online from 2014 to 2017 G.C - [12].

Existing transmission lines are also operated at 400 kV (Kilo Volt), 230 kV, 132 kV, 66 kV, and 45 kV with the corresponding land coverage of 686.701, 3950.332, 4457.546, 2301.591 and 295.045 Km, respectively. By the end of 2016 G.C. an additional 1240 kms of 500 kV, 2116 kms of 400 kV, 3811.2 kms of 230 kV, 2250.6 kms of 132 kV and 327 kms of 66 kV will be operational [12].

Ethiopian economy has been growing at 11% per year for the past six years and population grows by 2.6 % per annum [11, 12 and 13]. This, together with rapid rural electrification through the Universal Electricity Access Program (UEAP), has caused rapid growth in electricity demand. This demand is expected to grow as rapidly in the future due to further economic expansion and the drive for universal electrification. Electricity sales have been growing at the fastest pace ever with 13.5% growth in the past five years [11]. The annual energy consumption in 2012 rose to 5300 (Giga Watt hour)GWh against the 3593 GWh in 2009 and the annual per capita electric energy consumption has also improved to 58 kWh per capita in 2012 against 42.35 kWh per capita in 2009. Yet the electricity service remains intermittent and limited to a small part of the society [2, 3].

Thus an economic power dispatch mechanism that is capable of simulating WHAT, WHEN, and HOW MUCH power to dispatch to the network, while confirming to certain reliability and security criteria under a least cost condition, would be a useful tool for identifying the effectiveness of the short term goal of the power generation. This project is intended to study some aspect of the Ethiopian power system medium and short term operational planning during 2017 G.C by taking in to consideration the existing as well as planned plants. An extensive consideration of resources like water, wind, geothermal, biomass, sugar factories co-generation and waste to energy has been taken with their respective constraints and seasonality so as to make the plants commitment and dispatch as practical as possible. I believe that this study provides important insight about some of the risks and opportunities of the present activities in the area.

1.2. Problem Statement

As stated above, the dominant source of the Ethiopian electricity generation is hydropower, contributing more than 90%, while the remaining comes from other sources like wind, geothermal, diesel and solar energy, which shows unbalance in the power generation mix, The reliance on hydropower is further increasing since the committed and planned additions to the system are mostly hydro plants. Though hydropower plants have benefit of low economic cost and contribution to irrigation and water management, risks related to system vulnerability due to frequent climatic extremes have caused loss of considerable potential output due to water shortage in the past few years. Recent power cuts cost the Ethiopian economy 1% in Gross Domestic Product (GDP) growth [11] and the potential risks are even greater now because of very rapid demand growth and system expansion [13].

Peak demand and sales on the ICS have been growing at 5% per year prior to 2000, which increases to 8% a year over the 2000 to 2004 period before shooting up close to 14% per year from 2005 onwards. Per-capita power and energy available for Ethiopians (58 kWh per capita) is significantly lower than many African countries (average 510 KWh per capita [3]), and the population growth is projected to reach 97.1 million by 2020 [12]. Accordingly the peak power demand is projected to grow from 1,385 MW in 2012 to a maximum of nearly 7474 MW and 25,761 MW in 2020 and 2037, respectively [12]. In addition, system losses on the ICS stand at more than 20% [14].

EEPCo has been running a Load Dispatch Center (LDC) for the last seven years to optimize the power dispatch from an operational point of view though most of the operational decision is done manually without any integration between water reservoirs and power system variables. This leads to unmanageable situation as more and more plants with different technologies are to be added in coming years. This practice does not follow economic power dispatches constrained according to the peculiar characteristics of each technology and resources.

In addition Ethiopian Power System generation expansion master plan Study released by EEPCo on February 2014 mainly focuses on the long term generation expansion planning (25 years planning horizon) and gives no room for medium as well as short term optimal operational planning. It also does not optimize the generation planning together with the water resource; rather it treats the two separately. Also updates in the power sector in the past two years, like power plants major maintenance status as well as newly planned power plants, have not been incorporated in the study [12].

Another research by Girmaw Teshager plans Ethiopian power system generation expansion by 2011 G.C though most of the reservoir water management constraints are not considered in the research [15]. In general no research exists in Ethiopia that performs economic power dispatch in an hourly basis by taking in-to consideration peculiar characteristics of each technology and resource (like renewable resources). Accordingly this work is initiated to fill the gap created by the absence of hourly power dispatch, in Ethiopia, that takes in-to consideration specific characteristics of resources like water, wind, geothermal, energy from waste, sugar factories co-generation and biomass.

Thus this research focuses on developing a model that is capable of performing an optimized 1 year medium and short term operational plan for the Ethiopian power system, with the intention to simulate selected future condition (2017 G.C). The model considers renewable as well as non-renewable existing capacity and future potential, technology specific constraints (reservoir simulation, upstream downstream relationships, wind power priority to grid), transmission and distribution losses, reserve requirements, capacity limit for each plant and irrigation demand fulfillment together with satisfying a forecasted load, at any given time, in a reliable, sustainable and economic manner. It performs a detailed study of Ethiopian power grid’s reliability and operational issues which results in an optimized hourly operational planning of the power system (hourly power output, water discharge as well as reservoir level of each plant or reservoir in the study) by the year 2017 G.C. It also examines the impact of ongoing projects, reservoir operations and load variation on the power system by using updated Ethiopian power system status as input to the planning model.

1.3. Objective

1.3.1. General Objective

The major objective of the research is to develop a model that could be used to test medium and short term operational reliability of the Ethiopian power system and the effectiveness of the planned generation plants to meet the forecasted demand. I plan to build least cost optimization model, for the electric utility, by considering all sources of energy (renewable as well as non - renewable) subjected to different technological, seasonal and resource constraints as well as transmission - distribution losses and reserve margin.

1.3.2. Specific objectives

The specific objectives of this study are to:

i. Identify the objectives to be optimized and constraints to be imposed in the resource dispatch model;
ii. Develop mathematical model for the objective and constraints identified;
iii. Identify proper solution method to solve the developed model;
iv. Clarify data to be used as input (load, inflow, evaporation, irrigation, plant's capacity,..) and identify scenarios to be set for comparison and analysis (e.g. low, moderate and high inflow)
v. Develop a database, with MS Access and SQL server 2012, for the forecasted load, generating plants and hydrology data under consideration;
vi. Simulate the model, based on the database and validate the model based on the obtained result.
vii. Check for sensitivity of the model by comparing results for different levels of forecasted load (low, reference and high), water inflow to reservoirs (Low, moderate and high) and committed plants delay during construction.

1.4. Methodology

The research bases itself on EEPCo (Generation planning report, LDC and corporate planning office) and Ministry of Water, Irrigation and Energy for primary data on existing and planned generation and transmission facilities. Hourly load forecast and intermittent renewable energies (mainly wind) hourly output for available potential are used during optimization.

Identification of the objective and constraints together with the mathematical formulation of the respective functions is based on medium and short term operational planning concepts. MS Access and SQL server 2012 are used to organize the data in-to desired categories for easy manipulation during optimization. MATLAB Optimization toolbox is used for the optimization as it contains different solvers and algorithms that are capable of managing medium and large-scale optimization. It also provides compatible communication with SQL server as well as MS Access.

1.5. Significance of the study

The study shall contribute towards economic and efficient supply side management by dispatching power in an optimal way. This may promote better use of resources to meet the rising energy and peak power needs. The outcome of the model could provide more accurate generation and transmission resource requirements for reliable power system. It is also possible to identify potential vulnerabilities and potential solutions. It can also help to identify the role of intermittent renewable (like wind) and existing resources (like geothermal and hydro) in the future Ethiopian power system. In addition the findings of this study could also provide useful lessons for policy makers regarding the power sector and efficient use of its resources.

1.6. Organization of the study

This thesis consists of six chapters. The next chapter, Chapter Two, is dedicated to the theoretical and empirical literature review. Chapter Three presents the detail of methodology and the specific techniques, software tools as well as data to be used. Chapter four contains all the analysis starting from mathematical formulation of the objective and constraints to scenario formulation and finally optimization of the model. Chapter Five shows and discusses results found from the analysis as well as checks for sensitivity of variables to varying inputs. Finally, Chapter six concludes the thesis with the major findings and recommendations for future study.

CHAPTER 2
LITERATURE REVIEW

2.1. Electrical power plant operational planning stages

Every day regional electricity networks deliver hundreds of GWh of energy from generating units to consumers. Demand varies rather predictably throughout the day, but it can also fluctuate significantly in real time. In addition, Electricity is a unique commodity that can not generally be stored at a large scale at reasonable cost. Thus to ensure system security and reliability, the entities that operate the grid need to make plans and take actions to keep supply and demand matched in "real-time" - from minute to minute and second to second. The electric utility industry has historically broken the required operational planning process to meet customer demands into three stages, namely: long-term planning, Medium-term planning and Week ahead (short-term) planning. Long-term planning happens 10 to 30 years in advance with 1 to 4 weeks’ time step. At this stage, utilities plan for electric generation capacity through several mechanisms including the construction of new generation plants and supporting transmission lines [5, 16].

Medium term planning is done for months to few years horizon in a weekly time step and its main outputs include water levels of reservoirs, water discharges from reservoirs, maintenance planning and plant upgrade studies in the given time step. Load forecast and expected water flow using rainfall forecast are needed to predict the energy availability from the hydro as well as other corresponding facilities [16, 17].

Short term planning is executed Days to week in advance, with 1 or ½ hour time steps, in which utilities make "commitment" decisions to have certain quantities of existing generation plants available to produce electricity when the need arises. This step is deterministic in nature and is linked to medium term model by reservoir water level for the hydro dominated Ethiopian power system. Using results from the medium term plan and precise load and water information, a problem can be formulated where the solution yields the minimum cost of running all plants together on an hour-to-hour basis [5]. In the simplest formulation, short term planning can be defined as the problem of finding the best strategy to load each generation unit (plant) in the most economical way taking into account power balance equations and a number of technical limitations. The problem is often formulated subject to several constraints that include minimum up-time and down-time, ramp rate limits, generation constraints, load balances, must-run units, minimum and maximum energy limits, power transmission line capacity and spinning reserve [9, 18].

Based on the input from all the above steps, the real time operation or economic dispatch is done in 30 to 120 minutes horizon with 10 minute steps. Economic dispatch is the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities [9]. Economic dispatch is close to the real-time point of consumption i.e., minutes ahead of real time and actions are performed using system status (lake levels, flows, current set points) from Supervisory Control And Data Acquisition (SCADA) [5, 8 and 17].

The medium and short term planning algorithms begin by dispatching the generation source with the lowest operational cost and have that generation source increase output until all loads are supplied or the generation source hits its capacity constraint, whichever comes first. If the cheapest generation source hits its capacity constraint before all the demand is met, the second-cheapest generation source is turned on, and increases power until either it reaches its capacity constraint or all the demand is met. The process continues by successively turning on more expensive generation sources until the entire load is served. In general the algorithm plans for the best set of plants to be available to supply the forecasted load of the system over a future time period and the problem can be formulated as a non-linear, large scale linear, mixed-integer combinatorial optimization problem with continuous (unit output power or any other output) as well as binary (unit status) variables [5].

2.2. Hydro dominated system problem formulation and reservoir simulation

Optimum utilization of scarce water resources plays an important role in the sustainable development of any region. In water resources systems, reservoir operation is one of the challenging problems that involve lots of complexities that pose difficulties for water managers. The standard operating policy (SOP) is a simple and most commonly used operating policy in many reservoir systems, where the release in each time period is made to best meet its demand depending on water availability in the reservoir [19].

Hydropower plants play a key role in electric power systems due to their low operating costs and their flexibility in responding to real time change in demand. In addition, concern of sustainability and environment support their use in power systems together with other renewables, such as wind and solar energy. However the downside of hydropower plants is the uncertainty inherent in energy demand and hydrologic inflows, which subjects a purely hydro system to unacceptable levels of risk of energy deficits [20, 21].

As hydropower plants are water based, water resources management is very crucial to hydropower generation. Efficient management of hydropower reservoir can only be realized when one clearly understands the relation between reservoir variables and energy generation. Reservoir inflow, storage, reservoir elevation, turbine release, net generating head, plant use coefficient, tail race level, irrigation demand and evaporation losses are the major hydropower reservoir variables affecting the energy generation [22].

As discussed previously, the efficient scheduling of available energy resources for satisfying load demand has become an important task in modern power systems. This consists of determining the optimal operation strategy (minimizing or maximizing the objective function) for the next scheduling period, subject to a variety of constraints. Accordingly hydro dominated power system optimization problem is scheduled based on minimizing current value of costs or maximizing power output in a given time subject to many control and operational constraints [21, 23].

Objective function: is a mathematical expression that combines the variables to express our goal and may represent profit and/ or cost. In an optimal power dispatch problem it is normally required to either minimize (the current value of costs like operational, annual capital and fuel) or maximize (total hydropower generated in a given time) the objective function.

Constraints: are mathematical expressions that put limit derived from physical processes, demand requirements, capacity limitations and legal/policy impositions, on the possible solutions. Thus these constraints, presented as mathematical equations, define values of variables that are feasible [24]. Decision variables are variables whose values are not known at the start of the problem and usually represent things that can be controlled or adjusted. Generally the goal of optimization is to find values of the decision variables that provide the best value of the objective function. Accordingly the following constraints are commonly used during economic power dispatch problem of hydro dominated systems. But first description of the variables and parameters involved in the subsequent equations.

T : Total number of time steps considered;

t : is an index starting at 1 and ending at T;

J : Total number of power plants considered;

j : is an index starting at 1 and ending at J;

$P_{j,t}$: Generation of plant j during period t [MW];

Dem_t : Forecasted demand during period t including losses [Mega Watt hour (MWh)];

P_{maxj} : Maximum dependable power output of plant j [MW];

β : Percentage of power demand during period t to be used as reserve [%];

R : Total number of reservoirs considered;

r : is an index starting at 1 and ending at R;

$V_{r,t}$: Final storage volume of reservoir r at time period t [Mm^3];

$V_{r,t-1}$: Final storage volume of reservoir r at time period $\text{t} - 1$ OR Starting (Initial) storage volume of reservoir r at time period t [Mm^3];

$I_{n,r,t}$: Natural inflow of reservoir r during period t [m^3/s];

$Q_{j,t}$: Turbined flow (Discharge) from power plant j during period t [m^3/h];

$S_{r,t}$: Spilled flow from reservoir r during period t [m^3/h];

$E_{r,t}$: Evaporation loss from reservoir r during period t [mm/month];

$I_{r,r,t}$: Irrigation (Water demand) from reservoir r during period t [m^3/s];

d : Represents the time delay for water to reach from upstream reservoir/plant to downstream reservoir/plant [h];

γ_j : Productivity coefficient of power plant j [$\text{MW}/(\text{m}^3/\text{s})$];

P_{instj} : Installed capacity of plant j [MW];

CF : Capacity factor of plant j [%];

$P_{\ Wind\ sim,j,t}$: Hourly power output of wind plant j during period t [MW];

P_{minj}: Minimum power output of plant j [MW];

Q_{minj} & Q_{maxj} : Minimum and maximum water discharge of plant j respectively [m^3/h or m^3/5-days];

S_{minr} & S_{maxr} : Minimum and maximum spill of reservoir r respectively [m^3/h or m^3/5-days];

V_{minr} & V_{maxr} : Minimum and maximum storage volume of reservoir r respectively [Mm^3];

System constraints: are those that concern all the plants within the system. System load (power) balance and Spinning reserve requirement are part of system constraints.

a. **System load (power) balance**: represents the relationship between energy generation, demand and losses in the system. This constraint balances the sum of power generation from all plants with sum of power consumed and lost at any given period *t* [16, 22, 24, 25 and 26]. Mathematically it can be described as:

$$\sum_{j=1}^{J} P_{j,t} = Dem_t \qquad ------------------------ \qquad (2.1)$$

And $\quad Dem_t = Consumed\ Power_t + Loss_t$

Where: $Loss_t$: Total (technical and non-technical) loss in the power system during period t [MW].

b. **Spinning reserve requirements**: takes into consideration and covers for a possible sudden increase on power consumption, unanticipated loss of a generating unit or an interconnection which may result in unacceptable frequency drop if not corrected rapidly [23, 24]. Mathematically it can be described as:

$$\sum_{j=1}^{J} [P_{maxj} - P_{j,t}] \geq \beta * Dem_t \qquad ---------------- \qquad (2.2)$$

Unit (local) Constraints: are constraints that concern individual plants. A hydro dominated system contains the following unit constraints: hydraulic continuity, minimum total outflow limit, reservoir steady state condition, hydraulic power productivity limit, wind energy priority to grid, generation capacity limit, water storage limit and water discharge limit.

i. **Hydraulic continuity**: The mass balance principle is applied to expresses the relationship between stored volume, inflows and outflows in a reservoir. For any given time period t, the final storage in a reservoir should be equal to the difference between sum of a reservoir starting volume with inflow and sum of releases with other losses of the system. Generally mathematical expression of this constraint allows to relate a reservoir level at the end of time period t with start of time period t, inflows and hydropower output during period t [16, 20, 22, 24, 25, 26 and 27].

$$V_{r,t} = V_{r,t-1} + I_{n,r,t} - Q_{j,t} - S_{r,t} - E_{r,t} - I_{r,r,t} + \sum_{u=1}^{U} [Q_{u,t-d} + S_{u,t-d}] \quad -- \quad (2.3)$$

Where: U : Total number of upstream reservoirs to plant j;

u : is an index starting at 1 and ending at U;

ii. **Minimum total outflow limit**: This constraint guarantees the use of water resources for other activities besides electricity production, such as flood control, river navigability, irrigation, protection of downstream species and environment [19, 21 and 26]. Mathematically it can be described as:

$$Q_{j,t} + S_{r,t} \geq O_{f,t} \quad ------------------------ \quad (2.4)$$

Where: $O_{f,t}$ - Minimum total outflow from plant j during period t [m^3/s].

iii. **Reservoir Steady-state condition:** This constraint creates one of the most important operating policies of hydropower dominated power system, which is ensuring water availability inside a reservoir at any time. It does this by keeping storage volumes at the end of the last time period to be equal or greater than storage volumes at the start of the initial time period in the operation horizon [19].

$$V_{r,T} \geq V_{r,t=0} \quad -------------------------- \quad (2.5)$$

Where: $V_{r,T}$: Final storage volume of reservoir r at the last time period t [Mm^3];

$V_{r,t=0}$: Final storage volume of reservoir r before first period ($t = 0$) OR Starting (Initial) storage volume of reservoir r at first period ($t = 1$) [Mm^3].

iv. **Hydraulic productivity limit**: This constraint relates water discharge with power (energy) to be produced. It determines how much water discharge is required to produce a given amount of power or energy [19].

$$P_{j,t} = \gamma_j * Q_{j,t} \quad -------------------------- \quad (2.6)$$

v. **Wind energy priority to grid**: This constraint imposes a condition where wind power is not subject to dispatch and has priority access to the grid as wind energy can not be stored at a reasonable cost [24].

$$P_{j,t} = P_{Wind\,sim,j,t} \tag{2.7}$$

vi. **Limits on generation capacity, water storage, spillage and water discharge**: Only rarely are the decision variables in an optimization problem permitted to take on any value from minus infinity to plus infinity, instead the variables usually have bounds. Conditions restricting the values of decision variables to lie within certain closed intervals of IR are called range constraints. Range constraints can arise from the desire to keep a variable between certain upper and lower bounds or making that variable non negative [19, 21, 23, 24, 25, 26 and 27]. Mathematically it can be put as:

$$P_{minj} \leq P_{j,t} \leq P_{maxj} \tag{2.8}$$

$$Q_{minj} \leq Q_{j,t} \leq Q_{maxj} \tag{2.9}$$

$$S_{minr} \leq S_{r,t} \leq S_{maxr} \tag{2.10}$$

$$V_{minr} \leq V_{r,t} \leq V_{maxr} \tag{2.11}$$

2.3. Optimization

Optimization includes finding "best available" values of some objective function given a defined domain (or a set of constraints), including a variety of different types of objective functions and different types of domains [28]. Common optimization applications include Minimal cost, maximal profit, best approximation, optimal design, optimal management or control [27]. Accordingly in optimal power planning and dispatch, as the name tells, optimization is a basic tool in finding the least cost or maximum energy combination of plants [28].

Mathematical formulation of a power dispatch optimization problem bases itself on the objectives and constraints described in section 2.2 while adhering to some mathematical definitions as described below:

- Feasibility: All points x representing allowable choices are said to be feasible and forms the subset C of IR^n over which the maximization or minimization takes place [27]. Any point x that belongs to C, regardless of the value it gives to f_0 is a feasible solution. Optimal solution is a point x_0 furnishing the minimum value of f_0 over C, i.e., a feasible solution such that $f_0(x_0) \leq f_0(x)$ for all other feasible solutions x [27].
- Basic problem: Minimize or maximize a function f_0: IR^n _ IR, the objective function, over a specified set C _ IR^n, the feasible set [27].

- Constraints: Conditions on the decision variables that are used to specify the set of feasible points x in IR^n.
- Equality and inequality constraints: Conditions of the form $f_i(x) = ci$, $f_i(x) \leq ci$ or $f_i(x) \geq ci$ for certain functions f_i on IR^n and constants ci in IR.
- Range constraints: Conditions restricting the values of some decision variables to lie within certain closed intervals of IR.
- Linear constraints: This covers range constraints and conditions $f_i(x) = ci$, $f_i(x) \leq ci$ or $f_i(x) \geq ci$, in which the function f_i is linear.
- Data parameters: This includes constants and coefficients used in a Problem statement and are not open to manipulation when it comes to solving a particular problem.
- Decision variables: These are the unknowns that are open to manipulation in the process of maximization or minimization [27].

A wide range of optimization techniques has been applied to solve different types of problems. These techniques are principally based on the criterion of local search through the feasible region of solution. Some of the commonly used techniques include Linear programming (LP), Quadratic programming, Non-linear programming, Dynamic programming, Integer programming and Stochastic programming [28, 29]. Accordingly optimization techniques that have been applied to solve Hydro dominated power system planning can generally be classified into two main groups: deterministic methods and heuristic methods [28]. Deterministic methods include mixed-integer programming, linear programming, dynamic programming and interior-point methods whereas a heuristic method involves Genetic algorithms, particle swarm optimization and other evolutionary methods. Heuristics make few or no assumptions about the problem being optimized. Usually, heuristics do not guarantee that any optimal solution need be found. On the other hand, heuristics are used to find approximate solutions for many complicated optimization problems. Most of the methods that have been used to solve the hydropower problem are deterministic in nature [25].

Different types of algorithms have been used for different optimization techniques. Some algorithms are iterative in nature i.e. terminates in a finite number of steps while others are heuristic which may provide approximate solution to some problems. The commonly used algorithms include Simplex algorithm for linear programming, extensions of simplex algorithm for quadratic programming, interior point method for both linear and non-linear programming and many more [28].

2.4. Hydrothermal dispatch and the case of Ethiopian power system

A survey by I.A. Farhat and M.E-Hawary in 2009 (based on IEEE/IET/Elsevier databases) summarizes the number of publications and the method applied to solve a hydrothermal problem in the past two decades as indicated in Table 2.1 [25]. It is evident that these techniques can be applied to a hydro dominated system as all problem formulations in hydrothermal system contain all the hydro variables as well as constraints.

Table 2.1: Publication summary on hydrothermal problems

No	Algorithm (Method)	No. of papers
1	Lagrangian and benders decomposition	35
2	Evolutionary methods	33
3	Dynamic programming	10
4	NN and Fuzzy systems	5
5	Interior point methods	5
6	Mixed - integer programming	2
7	Optimal control and other methods	15

Other papers reviewed over hydrothermal dispatch models using interior point algorithm for both linear and non-linear programming includes multi period, multi objective as well as single period single objective optimizations. A study by Mariana Kleina [21], entitled Interior point method for hydrothermal dispatch problem, optimizes a power system by following least cost electricity generation strategy. In addition a research by Carlos Adrian Correa [17], entitled Short Term Hydrothermal Environmental/Economic Dispatch Using Interior Point Method, reveals how interior point algorithm handles a hydrothermal dispatch with environmental requirements. In both researches all the hydro variables as well as constraints, in section 2.2., are taken in to consideration and both show how interior point method (algorithm) is capable of handling such kind of optimization problems.

As far as researches in Ethiopia are concerned, Ethiopian Power System generation expansion master plan study released by EEPCo on February 2014 mainly uses software, named AQUARIS, which optimizes the hydro resources using linear programming (LP) [12]. It has been reviewed and found to be an effective way to optimize the hydro dominated

Ethiopian power system though the resolution is on monthly basis. In addition a research by Girmaw Teshager plans Ethiopian power system generation expansion by the year 2011 G.C using LP [15].

Thus this study uses an optimization technique that combines large-scale linear programming with interior point algorithm as both are proved to be fit for hydro dominated power systems according to the literature review discussed above.

CHAPTER 3
INPUT DATA ANALYSIS

As discussed in Chapter one section 1.3.2 and 1.4 data collection, analysis, modeling and simulation are the methods adopted for this research. Accordingly this Section discusses, in detail, how the various input data required for the model has been collected, organized, refined, analyzed and verified to make the model complete.

3.1. Ethiopia electricity generation potential and power system master plan

Ethiopia, located in the horn of Africa, is a country endowed with huge amount of hydro, wind, geothermal and solar power potentials. However, only a small portion of these resources have been utilized so far and less than a quarter of the nation's population (23.3%) has access to electricity [3].

Table 3.1 indicates estimates of the respective resources potential, gross as well as economic (exploitable), for power generation in Ethiopia based on different studies as indicated along with the data. The average capacity factor is estimated by averaging capacity factors for existing, committed and candidate plants from Ethiopian power system master plan.

Table 3.1: Ethiopian energy resources gross and economic potential for electrical power generation and energy production

No.	Energy Resource	Exploitable Potential[MW]	Average Capacity Factor[%] [1]	Estimated Energy [GWh/year]	Gross potential
1	Hydro	45,000 [2]	50.55	199,268	650,000 GWh/year [2]
2	Wind	10,000 [3]	30.91	27,077	1035 GW [2]
3	Solar	NA	20	526	5.2KWh/m^2 [2]
4	Geothermal	7,000 [2]	90	55,188	NA
5	Biomass	530 [4]	89.38	4,150	50 million tons/year [2]
6	NG	600 [4]	84.85	4,459	112 billion m^3
7	Coal	100	68	596	320 million tons
Total		**63,530**		**291,264**	

---

[1] EEPCO power system expansion master plan study, 2014 [12]

[2] Ministry of water and energy, 2013 [13]

[3] Afribiz, 2013 [30]

[4] Ethiopian resource group – 2009 [11]

As it stands at 2011, the energy share of resources shows biomass fuels such as wood, charcoal, agricultural residue and animal waste, taking a lion's share (i.e. 92% of the annual demand) but petroleum and electricity only contributes 7% and 1% to the total energy demand of the country [31]. Within the same year the total electricity consumption was 4645 GWh, which implies that the total energy consumed in the country to be 4645 GWh / 0.01 = 464,500GWh. Thus it can clearly be seen that the energy resource available for electricity generation in the country (291,264 GWh) could have supplied significant percentage i.e. 62.7% (291,264GWh*100 / 464,500GWh) of the total energy demand. Therefore use of such a significant resource to make electricity accessible to the vast non-electrified majority (76.7%) demands careful expansion planning.

Accordingly, EEPCo produced a draft report on February 2014 that contains load forecast, generation expansion planning, Transmission expansion planning as well as financial assessments. According to this study online times of new power plants were identified [12]. This thesis builds on this expansion plan to perform a detailed study of Ethiopian power grid's reliability and operational issues by the year 2017 G.C. It will examine the impact of ongoing projects, reservoir operations and load variation on the power system using short and medium term models that are constructed for this study. Section 3.4.1 of this study discusses plants chosen for 2017 G.C and how they are chosen, based on the expansion planning mentioned above.

For easy understanding of the optimization process as well as input data organization, the next two sections briefly explain models developed (with the corresponding simulation time steps) as well as the optimization framework used to process models under this study.

3.2. Energy and Hourly models

This study developed two parallel models that have been used to represent the reference year (2017 G.C) Ethiopian power system. The first one, which is termed as "energy model", deals with year round reservoir operations subject to the energy requirement of the power grid. This model has 73 time steps, with each time step representing a block of successive five days or it uses 5 daily time step. It plays the role of medium term models (discussed in previous chapters) that are used to reach at medium term optimal operational planning. The main outputs of this model are expected to be energy dispatch, water discharge, spillage and reservoir level for all the time steps (5 days) in the year.

The second one, called “hourly model”, uses the output of the former model (Energy model) to test the hourly power balance (check that hourly reserve needs are met) subject to the requirements of hourly reservoir level, water discharge and power systems operation over the selected days. This model has 120 time steps with hourly resolution. This model also plays the role of short term models (discussed in previous chapters) that are used to reach at short term optimal operational planning. The first model was developed because of the lack of proper computational resources to perform the optimization on hourly bases using the second model. The output is an hourly expected power dispatch with the corresponding water discharge, spillage and reservoir volume. Detailed explanation of each model, with the corresponding modeling and simulation concept behind, is put in chapter 4 of this study.

3.3. Energy and Hourly models optimization framework

In an optimization exercise it is important to understand the process, organization of the input data, details of the optimization exercise and the corresponding expected results. Accordingly Figure 3.1 summarizes the input data required as well as the expected outputs for both energy and hourly models using an optimization framework.

The input data has been organized in to 8 broad divisions namely: power plants expected to be available by the year 2017 G.C, forecasted load, water inflow, hydraulic parameters, electrical parameters, initial conditions, wind power plants hourly output and economic parameters. These divisions in turn explain the input required for both models in greater depth. Data acquisition and verification section of this chapter discusses each input data parameter in detail.

The objective and constraints linked with each model are put in the framework together with the relationship between the energy and hourly models. It can be seen that the output of the energy model is used as input to hourly model and is discussed in depth in chapter 4 of this study. Outputs from each model are presented briefly on the framework and discussed further in chapter 5 of this study.

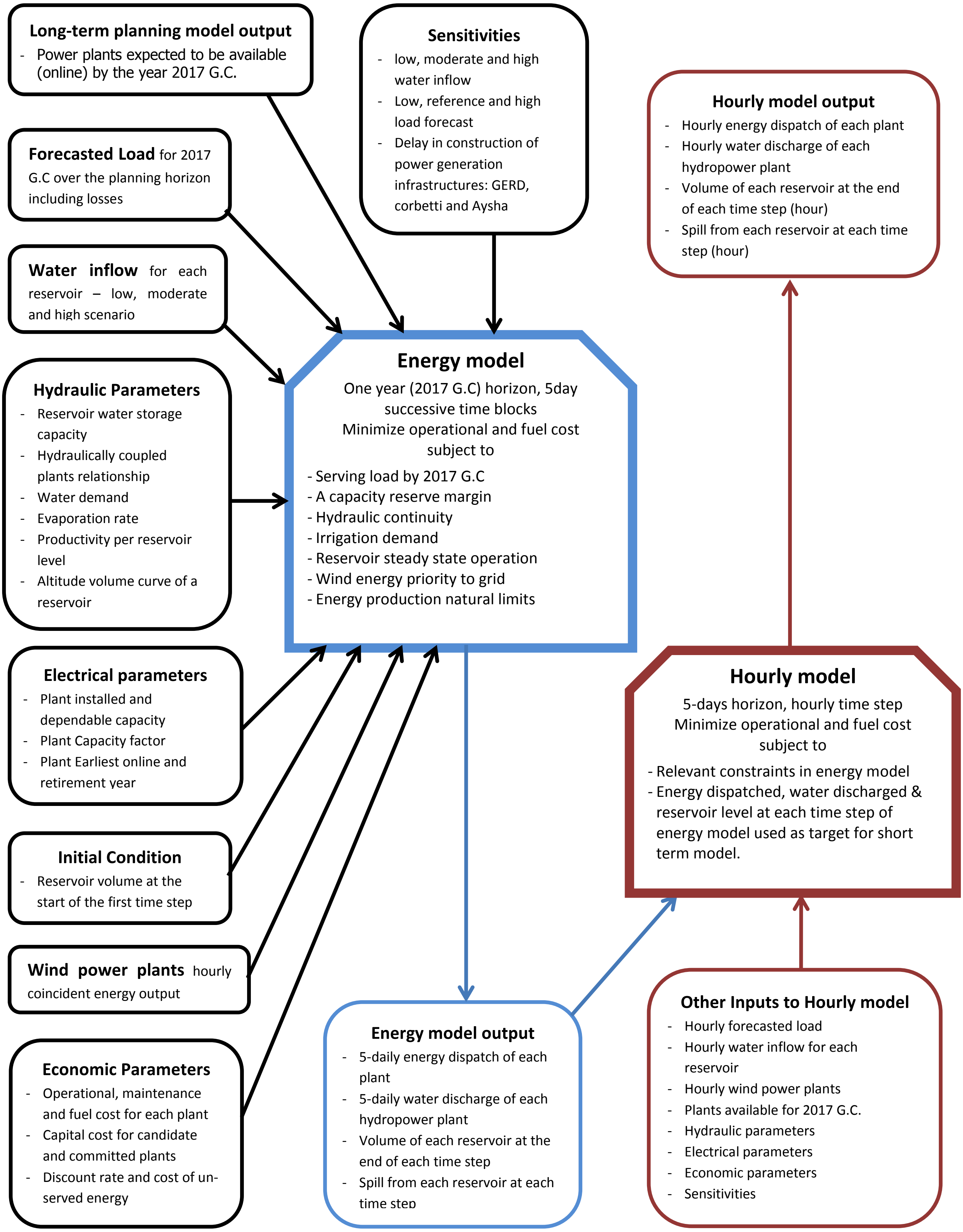


Figure 3.1: Optimization framework of Energy and hourly models

3.4. Data acquisition and verification

The requested data has mainly been sourced from EEPCo (Generation operation, LDC and corporate planning) and Ministry of Water and Energy. The time required for data acquisition and verification was considerably longer than had been planned. Among the factors which contributed to this situation were:

- Lack of readily available information.
- Lack of up dated information for power plants being studied or under construction. This demanded contacting the respective project offices, Aysha wind farm, Gilgel gibe III (GG III), Genale dawa III (GD III) and Corbetti Geothermal, to get updated information.
- The necessity to make requests to various departments within EEPCO, as well as other Ethiopian institutions like the Ministry of Water, Irrigation and Energy, instead of one source.
- EEPCo was going through major administrative structural change while the data has been collected and it results in requesting a similar set of data for up to three times as responsible personnel were changing.

Each set of data will be discussed, in the following sub-sections, starting from analysis year and plants selection to assumptions and adjustments made to provide the model with more accurate data.

3.4.1. Power plants available for medium and short term operational plan

As explained in Section 2.1, medium term planning is based on a one-year plan, which implies the need to select that specific year. 2017 G.C has been identified as a year where a number of high capacity committed plants (including Grand Ethiopian Renaissance Dam (GERD) and GG III) become practically operational. Thus operational planning of 2017 can show the opportunities and challenges that lie ahead in meeting the power and energy needs of the nation with due consideration for potential power plants. Identifying Power plants that would be available on a specific year is also basic requirement in working towards medium and short term planning for that year. As can be seen in Table 3.2 different sources have been used to properly identify plants that would be available in the year 2017 G.C.

In the operational planning of hydro-dominated power systems like Ethiopia, where electric power supply from hydropower sources takes 98.99% of the total electricity supply [3], planning is usually achieved by hierarchical chains of long, medium and short-term models. Medium term planning mainly depends on the output of a long term power expansion plan [16, 17]. Accordingly Ethiopian Power System Expansion master plan study overall installed generation plan until 2037(Appendix A) has been a good resource to start looking for plants that would be available for 2017 G.C. The parameters used to select 2017 plants, from a list of 77 plants on Table A.0.1 given in Appendix A, are plant type, earliest online (commissioning) year and retirement year.

Plant type identifies if a plant is already existing (labeled as existing), under construction (labeled as committed) or study completed and ready for construction (labeled as candidate). Existing plants are automatically taken in to consideration unless the retirement year has already passed. Committed and candidate plants are also taken in to consideration unless the commissioning year is after 2017 G.C. As a result power plants selected for medium and short term planning, for the year 2017 G.C, are listed in Table 3.2.

Based on feedback from EEPCo planning, Generation operation and respective project offices the following practical considerations are made:

- Aysha wind farm is exceptionally included as the only candidate plant since the project office confirmed 120MW capacity will be available by start of 2017 G.C.
- Melkawakena one unit and Aluto langano I maintenance has taken more than planned on the expansion plan, thus appropriate adjustments are made by consulting with EEPCo planning.
- Corbetti never existed in the master plan but included in this study since the project is actively developing and 120MW will be expected by 2017.
- Thermal back up (Virtual diesel plant) has been included to account for unserved energy.

A life of 75 years has been assumed for Hydro plants, though hydro plants have long lives of up to hundred years assuming proper refurbishment has been done at a reasonable time, to keep consistency with EEPCo planning experience. Other technologies like wind, sugar factories co-generation and biomass have taken a life of 25 years. Energy from waste is exception with a life of 30 years.

Table 3.2: Power plants available for operational planning in the year 2017 G.C.

No	Technology	Plant	Plant type	Earliest Online Year		Retirement Year	Data Source
1	Hydro	Fincha	Existing	Nov	1973	2048	EEPCo Generation Expansion master plan
2	Hydro	Melkawakena	Existing	April	1988	2063	
		Melkawakena (refurb)		Jan	2016	2091	EEPCo planning and Generation operation
3	Hydro	Tana beles	Existing	May	2010	2085	EEPCo Generation Expansion master plan
4	Hydro	GG II	Existing	Jan	2010	2085	
5	Hydro	Tekeze	Existing	Nov	2009	2084	
6	Hydro	GG I	Existing	Feb	2004	2079	
7	Hydro	Amerti neshe	Existing	July	2013	2088	
8	Hydro	Tis Abay I	Existing	Jan	1964	2039	
9	Hydro	Tis Abay II	Existing	March	2001	2076	
10	Hydro	Koka	Existing	May	1960	2035	EEPCo planning
11	Hydro	Awash I	Existing	Nov	1966	2041	
12	Hydro	Awash II	Existing	Nov	1971	2046	
13	Hydro	Sor 1	Existing	Jan	2014	2089	
14	Hydro	GG III	Committed	Dec	2014	2089	Project office
				Sept	2015	2090	
15	Hydro	GD III	Committed	Jan	2016	2092	Project Consultants
16	Hydro	GERD	Committed	March	2015	2090	Project office
				Jan	2017	2092	EEPCo Generation Expansion master plan
17	Geothermal	Aluto Langano I	Existing	Jan	2016	2041	EEPCo generation operation
18	Geothermal	Corbetti	Committed	Dec	2015	2040	Rekjavic COO (Chief Operations Officer)
				Dec	2016	2041	
19	Wind	Adama I	Existing	Jan	2012	2037	EEPCo Generation Expansion master plan
20	Wind	Ashegoda I	Existing	Jan	2012	2037	
21	Wind	Ashegoda II	Existing	Jan	2014	2039	
22	Wind	Adama II	Committed	Jan	2015	2040	
23	Wind	Aysha	Candidate	Jan	2017	2042	Project Office
24	Sugar Factories Co. gen.	Tendaho	Committed	Jan	2015	2040	EEPCo Generation Expansion master plan
25	Sugar Factories Co. gen.	Wonji	Committed	Jan	2013	2038	
26	Sugar Factories Co. gen.	Fincha	Committed	Jan	2013	2038	
27	Sugar Factories Co. gen.	Beles I	Committed	Jan	2015	2040	
28	Sugar Factories Co. gen.	Beles II	Committed	Jan	2015	2040	
29	Sugar Factories Co. gen.	Beles III	Committed	Jan	2016	2041	
30	Sugar Factories Co. gen.	Wolkayit	Committed	Jan	2015	2040	
31	Sugar Factories Co. gen.	Omo kuraz 1	Committed	Jan	2015	2040	
32	Sugar Factories Co. gen.	Omo kuraz 2	Committed	Jan	2016	2041	
33	Sugar Factories Co. gen.	Omo kuraz 3	Committed	Jan	2016	2041	
34	Sugar Factories Co. gen.	Omo kuraz 4	Committed	Jan	2017	2042	
35	Sugar Factories Co. gen.	Omo kuraz 5	Committed	Jan	2017	2042	

36	Sugar Factories Co. gen.	Kesem	Committed	Jan	2015	2040	
37	biomass	Bamza	Committed	Jan	2015	2040	
38	biomass	meikasedi	Committed	Jan	2015	2040	
39	Energy from waste	EFW-Addis Ababa	Committed	Jan	2015	2045	
40	Thermal_backup (Unserved energy)	Diesel HFO/gas	Backup	Jan	2015	2100	

3.4.2. Hydro System Diagram

Ethiopia is a country with a very high hydropower potential and fulfills 98.99% of the total electricity supply from Hydro power [3], though only a fraction of the existing potential have been harnessed. This huge hydropower potential is mainly due to eight large river basins in the country namely Abay (Blue Nile), Awash, Genale, Wabi Shebele, Baro Akobo, Tekeze, Omo Gibe and Rift Valley [12]. Figure 3.2 shows the eight river basins in Ethiopia. The dominance of hydropower in Ethiopia electric generation will even get higher with the completion of two high capacity dams, GG III and GERD, in the near future. Accordingly this section discusses the hydro system under consideration, for the year 2017G.C, based on Hydropower plants given in section 3.4.1. The location of all the existing, committed and candidate hydro plants and river systems are shown in Figure 3.3 [12].

The Hydro system for 2017 G.C. contains different size hydropower plants, reservoirs and all other relevant dimensions. Sixteen hydropower plants, eleven reservoirs and 4 water demands for irrigation are considered in the model. Figure 3.4 shows 2017 potential hydro system model diagram in which the different relationships between reservoirs as well as Hydropower plants are indicated.

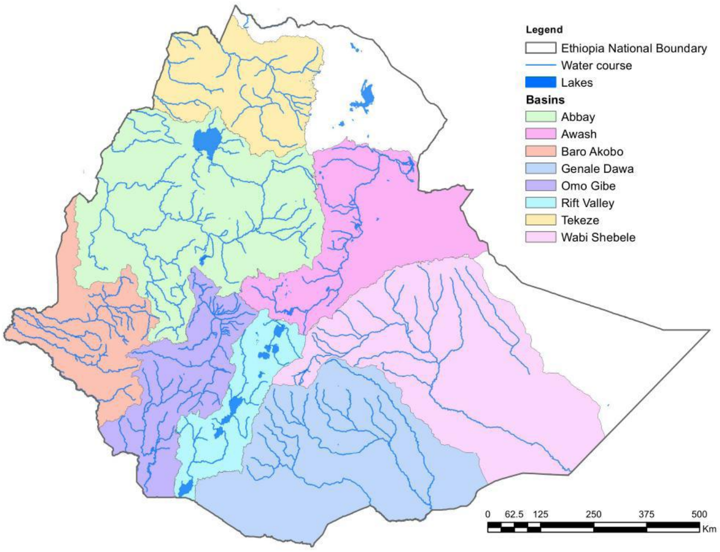


Figure 3.2: River basins in Ethiopia

From the Hydro system model diagram the following relationships between plants and reservoirs are observed:

- Hydropower plants with reservoir and having no upstream reservoir: This category includes hydropower plants namely Fincha, Melkawakena, Tekeze, GG I, Amerti neshe, Koka, Sor 1, GG III, GD III and GERD.
- Hydropower plants sharing a reservoir: Tana Beles, Tis Abay I and Tis Abay II share lake tana.
- Hydropower plants with no reservoir and having upstream reservoir: GG II and Awash I with their respective upstreams being GG I and Koka.
- Hydropower plants with no reservoir and having upstream plant with no reservoir: Awash II with its respective upstream Awash I belongs to this group.

Detail data related to each Hydropower plant will be discussed in coming sections.

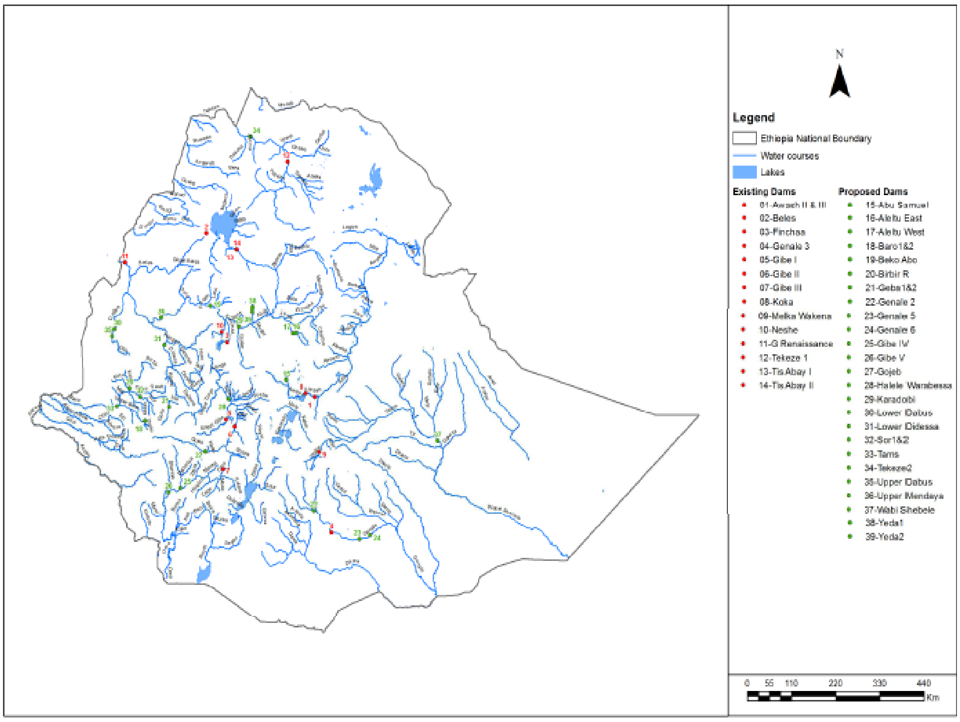


Figure 3.3: Map of existing and potential hydroelectric developments

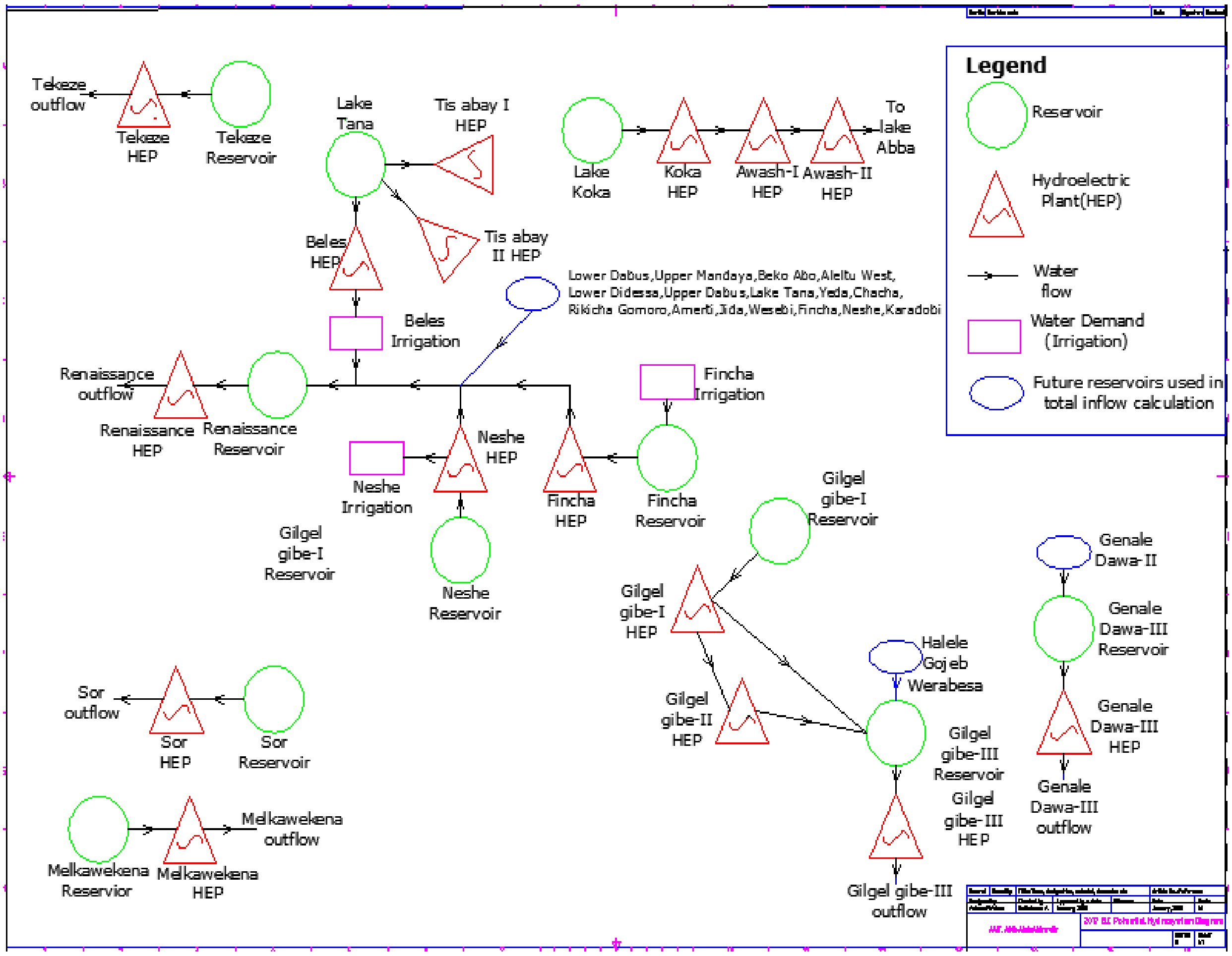


Figure 3.4: 2017 G.C. Ethiopian potential hydro system diagram [AutoCAD]

3.4.3. Hydroelectric power plants

Hydroelectric plants data is categorized in-to power related and hydrology related data as shown in Tables 3.3 and 3.4, respectively. Installed capacity is the actual installed capacity whereas dependable capacity is the portion of the installed capacity that is available for use on the year 2017. For existing plants it is due to plants efficiency reduction with time but for committed plants it is the value adopted from the long term least cost EEPCO generation expansion master plan where resource availability is considered. According to personal communication with EEPCo generation operation office, one unit of Melkawakena (34MW) is under maintenance but will be available for use by January 2016 thus considered in this study.

The extent of use of a generating plant is measured by the plant capacity factor or plant factor. If during a given period a plant is kept fully loaded, it is evident that it is used to the maximum extent, or operated at 100% capacity factor [6]. Mathematically it can be put as:

$$Capacity\ Factor = \frac{Generated\ energy\ per\ year}{Installed\ Capacity * No.of\ hours\ in\ a\ year} \quad --- \quad (3.1)$$

Table 3.3: Electrical characteristics of hydroelectric power plants

No	Hydropower Plant	Plant type	Installed[5] Capacity [MW]	Dependable[5] Capacity [MW]	Capacity[6] factor [%]	Firm energy[5] [GWh/Year]	Average[6] energy [GWh/Year]
1	Fincha	Existing	134.00	128.00	54.97	421.97	624.67
2	Melkawakena	Existing	153.00	152.00	41.56	324.60	555.49
3	Tana beles	Existing	460.00	444.00	68.35	1,357.18	2,748.74
4	GG II	Existing	420.00	420.00	55.33	1,399.92	2,030.17
5	Tekeze	Existing	300.00	297.00	53.41	781.84	1,399.48
6	GG I	Existing	184.00	184.00	48.08	609.61	882.13
7	Amerti neshe	Existing	98.00	98.00	28.69	130.86	244.98
8	Tis Abay I	Existing	11.00	11.00	26.72	NA*	25.75
9	Tis Abay II	Existing	73.00	68.00	26.73	NA*	10.07
10	Koka	Existing	43.00[6]	38.40	35.58	93.87	133.47
11	Awash I	Existing	32.00[6]	28.00	65.60	149.14	183.48
12	Awash II	Existing	32.00[6]	28.00	65.86	149.95	184.22
13	Sor 1	Existing	5.00	5.00	68.30	25.37	29.89
14	GG III	Committed	1,870.00	1,067.00	32.77	3,284.90	5,348.27
15	GD III	Committed	254.00	250.00	76.12	1,123.76	1,690.56
16	GERD	Committed	6,000.00	4,957.00	28.07	10,322.48	14,684.17

Seasonal effects as well as forced outages, operation and maintenance outages are taken care of using capacity factor. Capacity factor of all hydropower plants in this study is put in Table 3.3.

According to personal visit at GG III project office, 748MW (4units) are expected to be commissioned by September 2015 whereas another 1122MW (6units) is expected to be operational by end 2015. GERD also has two stages of commissioning in which 500MW is expected to be operational by September 2015 and the remaining 5500MW by the start of 2017.

Tis Abay I and II are only used during June, July, August and September (rainy season) to prevent Chara Chara (Upstream reservoir for Tana beles, Tis Abay I and II) from spillage[7]. Accordingly Capacity factor for Tis Abay I and II is set to zero for the months of January,

---

[5] EEPCO power system expansion master plan study, 2014 [12]

[6] EEPCo Corporate planning office

*Data not available

[7] EEPCo LDC and EEPCo Generation operation office

February, March, April, May, October, November and December whereas for months of June to September it is calculated by using generated energy of the plants within the year, installed capacity and the number of hours within the four months (2927 hrs) since both plants are only operational within these four months.

$$Tis\ Abay\ I\ adjusted\ C.Factor = \frac{Generated\ energy\ per\ year}{Installed\ Capacity * 2927\ h} = \frac{25.75 * (10^9)}{11 * (10^6) * 2927} * 100\ =\ 80\%$$

$$Tis\ Abay\ II\ adjusted\ C.Factor = \frac{Generated\ energy\ per\ year}{Installed\ Capacity * 2927\ h} = \frac{170.94 * (10^9)}{73 * (10^6) * 2927} * 100 = 80\%$$

Peak load and base load plants are mainly differentiated based on capacity factor. Plants having larger capacity factors, like GD III, Sor1, Awash I, Awash II and Tana beles, serve as base load plants as such plants can provide power with their full capacity for majority of the time (greater than 65% as shown in Table 3.3) whereas plants having smaller capacity factor, like GERD, GG III, Koka and Amerti neshi, are regarded as peak load plants since these plants are only available for small portion of time (less than 35%) with their full capacity. The firm and average energy are collected from the respective sources as mentioned in Table 3.3.

The Hydrology related data are given in Table 3.4. Productivity measures the amount of power that could be produced using a unit of water discharge. Productivity values for all power plants, averaged from productivity values at different water levels of respective reservoirs, are shown in Table 3.4. Table B.0.1 given in Appendix B shows productivity of all 11 reservoirs at different water levels.

Minimum (dead) reservoir volume gives minimum volume of water required in the reservoir to produce power while maximum reservoir volume refers to the volume of water above which the reservoir starts to spill. Active storage volume is the volume of water that can actually be used for power production thus found by subtracting minimum reservoir volume from maximum reservoir volume. Minimum, maximum and active volumes of the reservoirs, as collected from EEPCo planning office (in person) and verified from data collected at LDC and generation operation (in person), are put in Table 3.4. Initial Volume is the volume of water available on December 31st of the previous year for use by the first day of the year under study. As 2017 is the year under study, the water level at December 31st 2016 is estimated by averaging the water level of respective reservoirs on December 31st for the years 2006/2007 until 2012/2013. Altitude volume curve is used to get the corresponding volume from the averaged water level (altitude). In cases where a volume amount can not be directly found for a specific water level, interpolation technique is used based on immediate upper and lower water levels. Tables C.0.1 and C.0.2 given in Appendix C show water level and altitude-volume curve of reservoirs. Note that for committed and candidate plants average value of starting volume for existing plants (65% of maximum reservoir volume) is used since no reservoir water level data can be available.

Table 3.4: Hydrological characteristics of hydroelectric power plants

No	**Hydropower Plant**	**Plant type**	**Productivity[8] [MW per m^3/s]**	**Min[8] Volume [Mm^3]**	**Max[8] Volume [Mm^3]**	**Active[8] Volume [Mm^3]**	**Initial[10] Volume [Mm^3]**	**Name of[10] associated reservoir**	**Upstream[9] reservoir**	**Upstream plant**
1	Fincha	Existing	4.8225	332	1120	788	681	Fincha		
2	Melkawakena	Existing	2.6737	160	760	600	473.125	Melkawakena		
3	Tana beles	Existing	2.8868	22958	32088	9,130	27741.8	Lake Tana (Chara chara)		
4	GG II	Existing	4.2857						GG I	
5	Tekeze	Existing	1.2739	4004	10958	6,954	6540.64	Tekeze		
6	GG I	Existing	1.9366	89	807	718	686.54	GG I		
7	Amerti neshe	Existing	5.0250	85 [10]	524 [10]	439	265.57	Amerti neshe		
8	Tis Abay I	Existing	0.4202						Lake Tana (Chara chara)	
9	Tis Abay II	Existing	0.4087						Lake Tana (Chara chara)	
10	Koka	Existing	0.3239	17	1185	1,168	697.506	Koka		
11	Awash I	Existing	0.5349						Koka	
12	Awash II	Existing	0.5381							Awash I
13	Sor 1	Existing	0.3195	59	323	264	209.95	Sor 1		
14	GG III	Committed	1.3878	2467	13300	10,833	8645	GG III		
15	GD III	Committed	2.2250	800	2000	1,200	1300	GD III		
16	GERD	Committed	1.0556	11750	63350	51,600	41177.5	GERD		

Reservoir, upstream reservoir or upstream plant associated with respective power plant is identified using the hydro system diagram shown in Figure 3.4. As explained in section 3.4.2,

---

[8] EEPCo Corporate planning office

[9] EEPCo LDC

[10] EEPCo Generation operation office

the different relationships between reservoirs and hydropower plants can clearly be seen with this data arrangement.

There exists a time delay for a unit water volume to reach from an upstream reservoir/plant to a downstream reservoir/plant which is mainly dependent on the water course. Time delays used between reservoirs/plants in this study, for hourly model, is summarized in Table 3.5.

Table 3.5: Upstream-Downstream reservoirs and power plants relationship

Upstream reservoir/plant	**Downstream reservoir/plant**	**Time_Delay [h]**
GG I	GG II	1 [10]
Lake Tana	Tis Ababy I	8
Lake Tana	Tis Ababy II	8
Koka	Awash I	8
Awash I	Awash II	1

3.4.4. Geothermal, Co-generation, Biomass and Energy from waste plants

As explained in section 3.1, Ethiopia has a considerable potential of non-Hydro resources for electricity generation. Wind and geothermal resources are already contributing their share to the ICS. A number of non-hydro new technologies, like Sugar factories co-generation and energy from waste, are also expected to join the national grid in the near future. Accordingly some important parameters of the non-hydro technologies and plants, expected to be operational by 2017 G.C, are listed in Table 3.6.

Table 3.6: Non-hydro power plants characteristics

No	**Technology**	**Plant**	**Plant type**	**Installed[11] capacity [MW]**	**Dependable[12] Capacity [MW]**	**Capacity factor [%]**	**Average[11] energy [GWh/Year]**
1	Geothermal	Aluto Langano I	Existing	7	5[13]	90 [14]	37
2	Geothermal	Corbetti	Committed	20 [14]	20 [14]	90 [14]	158
				100[14]	100 [14]	90 [14]	788
3	Sugar Factories Co-gen.	Tendaho	Committed	120	70	-	337
4	Sugar Factories Co-gen.	Wonji	Committed	30	16	-	77

---

[11] EEPCo corporate planning office

[12] EEPCO power system expansion master plan study, 2014 [12]

[13] Aluto Langano I Geothermal plant manager

[14] Corbetti Geothermal Reykjavik COO (Chief operations officer)

*Data not available

5	Sugar Factories Co-gen.	Fincha	Committed	31	10	-	48
6	Sugar Factories Co-gen.	Beles I	Committed	30	20	-	96
7	Sugar Factories Co-gen.	Beles II	Committed	30	20	-	96
8	Sugar Factories Co-gen.	Beles III	Committed	30	20	-	96
9	Sugar Factories Co-gen.	Wolkayit	Committed	133	82	-	395
10	Sugar Factories Co-gen.	Omo kuraz 1	Committed	60	20	-	96
11	Sugar Factories Co-gen.	Omo kuraz 2	Committed	60	40	-	193
12	Sugar Factories Co-gen.	Omo kuraz 3	Committed	60	40	-	193
13	Sugar Factories Co-gen.	Omo kuraz 4	Committed	60	40	-	193
14	Sugar Factories Co-gen.	Omo kuraz 5	Committed	60	40	-	193
15	Sugar Factories Co-gen.	Kesem	Committed	26	16	-	77
16	Biomass	Bamza	Committed	120	60	-	289
17	Biomass	meikasedi	Committed	138	60	-	289
18	Energy from waste	EFW-A.A.	Committed	25	25	85.42	186
19	Thermal_backup (Unserved energy)	Diesel HFO/gas	Backup	8,175	8,175	83.84	NA*

Corbetti Geothermal development was not included in EEPCo Generation master plan since the project was not under consideration during the master plan development. According to Presentation by the project Chief operations officer, 20MW is expected to be commissioned by end of 2015 whereas another 100MW is expected by end of 2016. Aluto Langano I, the existing geothermal plant, is under maintenance but considered for this study as it is expected to be operational by January 2016 according to personal communication with EEPCo generation operation and plant manager. A plant (capacity) factor of 90% is set for geothermal plants by considering an annual forced outage rate of 6% and scheduled maintenance of 4%[15].

The Ethiopian Sugar Corporation has a committed program for sugar factories Co-generation. Bagasse burning co-generation plants produce steam and electricity from October to June, the only crop timing within a year, and the electricity is used for factory, villages around the factory as well as irrigation. During the off-crop season, June till September, the village loads are supplied from the grid, and have been included in the load considered at that time. The surplus generation is exported to grid and this supply of electricity has been included in the medium term planning for 2017, as dependable capacity in Table 3.6. In other words, the difference between the installed capacity and dependable capacity goes for factory and factory facilities like irrigation and villages around.

---

[15] Corbetti Geothermal Reykjavik COO (Chief operations officer)

As mentioned above, co-generation plants produce electricity from October to May. This seasonality together with forced as well as operation and maintenance outages was addressed by setting proper capacity (plant) factor, i.e. zero for the duration from June to September and 80% otherwise as shown in Table 3.7.

The grand renaissance Thermal Power Plant (Bamza) and the Kesem Thermal Power Plant (Meikasedi) are two of the recently committed biomass plants[16]. Bamza will initially burn the wood cut down in the deluge area of the GERD hydro power reservoir. After about eight years, will burn bagasse from local sugar plantations while Meikasedi will burn bagasse from the adjacent sugar mill in the crop season, and at other times will burn prosopsis (Proliferation of the Prosopisjuliflora plant in the Afar region of Ethiopia), and possibly other residues such as crop residue from cotton farms.

Bamza and Meikasedi have a rated plant capacity of 120 and 138 MW, respectively. But considering the fuel resource available in both areas 60 MW has been taken as a feasible plant size, for both plants, by EEPCo for planning purposes. Thus to keep consistency this study also adopts a plant size of 60MW for both Bamza and Meikasedi. To take account of the seasonal availability of bagasse, the plants are unavailable for four months during the off-crop season, June to September, similar to sugar factories co-generation. Accordingly capacity factor of biomass plants includes a forced outage of 3% together with a scheduled maintenance in those four months and is set to zero from June to September and 89.38 percent in the remaining 8 months as shown in Table 3.7.

As stated above, co-generation and biomass plants produce electricity from October to May which gives these plants a generation pattern that has complementary to hydro generation as both technologies operate during the relatively dry and consequently low power generation season for hydroelectric power plants.

Ethiopian cities have a large potential for waste to energy plants with their rapidly expanding population. The population of Addis Ababa is expected to reach 6 million within the next 20 years where the daily waste generation of the city is 0.252 kg per capita per day, which will

---

[16] EEPCO power system expansion master plan study, 2014 [12]

equate to a total daily waste generation of about 1,500 tons per day in 2033 G.C., based on population projections.[17]

Table 3.7: Seasonal availability of sugar factories Co-generation and biomass plants

No	**Technology**	**Plant**	**Plant Type**	**Seasonal Availability [%] [16]**											
				1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
1	Sugar Fact. Co-gen.	Tendaho	Committed	79.97	80.06	79.97	80.00	79.97	0.00	0.00	0.00	0.00	79.97	80.00	79.97
2	Sugar Fact. Co-gen.	Wonji	Committed	79.97	80.06	79.97	80.00	79.97	0.00	0.00	0.00	0.00	79.97	80.00	79.97
3	Sugar Fact. Co-gen.	Fincha	Committed	79.97	80.06	79.97	80.00	79.97	0.00	0.00	0.00	0.00	79.97	80.00	79.97
4	Sugar Fact. Co-gen.	Beles I	Committed	79.97	80.06	79.97	80.00	79.97	0.00	0.00	0.00	0.00	79.97	80.00	79.97
5	Sugar Fact. Co-gen.	Beles II	Committed	79.97	80.06	79.97	80.00	79.97	0.00	0.00	0.00	0.00	79.97	80.00	79.97
6	Sugar Fact. Co-gen.	Beles III	Committed	79.97	80.06	79.97	80.00	79.97	0.00	0.00	0.00	0.00	79.97	80.00	79.97
7	Sugar Fact. Co-gen.	Wolkayit	Committed	79.97	80.06	79.97	80.00	79.97	0.00	0.00	0.00	0.00	79.97	80.00	79.97
8	Sugar Fact. Co-gen.	Omo kuraz	Committed	79.97	80.06	79.97	80.00	79.97	0.00	0.00	0.00	0.00	79.97	80.00	79.97
9	Sugar Fact. Co-gen.	Omo kuraz	Committed	79.97	80.06	79.97	80.00	79.97	0.00	0.00	0.00	0.00	79.97	80.00	79.97
10	Sugar Fact. Co-gen.	Omo kuraz	Committed	79.97	80.06	79.97	80.00	79.97	0.00	0.00	0.00	0.00	79.97	80.00	79.97
11	Sugar Fact. Co-gen.	Omo kuraz	Committed	79.97	80.06	79.97	80.00	79.97	0.00	0.00	0.00	0.00	79.97	80.00	79.97
12	Sugar Fact. Co-gen.	Omo kuraz	Committed	79.97	80.06	79.97	80.00	79.97	0.00	0.00	0.00	0.00	79.97	80.00	79.97
13	Sugar Fact. Co-gen.	Kesem	Committed	79.97	80.06	79.97	80.00	79.97	0.00	0.00	0.00	0.00	79.97	80.00	79.97
14	Biomass	Bamza	Committed	89.38	89.38	89.38	90.40	89.38	0.00	0.00	0.00	0.00	89.38	89.40	89.38
15	Biomass	meikasedi	Committed	89.38	89.38	89.38	90.40	89.38	0.00	0.00	0.00	0.00	89.38	89.40	89.38

There is currently only one committed waste to energy plant for Ethiopia, the Addis Ababa waste to energy Plant, being developed by Cambridge Industries Limited. The proposed site for the plant, Repi, has previously been used for open, unmonitored incineration of waste and has a compact area of 7 hectares. Repi is the largest landfill site in Addis, covering an area of 37 hectares, with waste estimated to be as deep as 40 m. EEPCo finalized a turnkey contract with Cambridge Industries Limited on 4 January 2013 to design and construct a 50 MW Waste to Energy plant in the Repi (Koshe) area of the city[17].

Due to the nature of municipal solid waste, the calorific value of the waste to be used is variable. The waste of developing countries contains high levels of organic matter with a relatively low calorific value, approximately around 6.3 MJ/kg. But in order to generate 50 MW of electricity at base load, a calorific value of around 9-10 MJ/kg from 350,000 tons per annum is required. Accordingly, the Repi plant, with expected Calorific value of 6 MJ/kg, is

---

[17] EEPCO power system expansion master plan study, 2014 [12]

only expected to be able to generate 20 to25 MW of electricity at base load[11]. Being a base load plant, capacity factor for Repi waste to energy plant is expected to be 85.42%[16].

Finally traditional approaches to medium-term power system operational planning only uses reserve margin as a measure of system reliability. But modern approaches include unserved energy as additional criteria of reliability to be considered during the optimization process [1]. This study uses a pseudo thermal backup plant, with a capacity that equals dependable capacity of all hydro plants, to serve as a measure of unserved energy during the optimization.

3.4.5. Load (Demand)

Accurate Load (Demand) data is one of the critical input based on which the amount of power to be dispatched is determined. For this study, data collected through personal communication with EEPCo generation operation has been used and it contains detailed power plant generation data (including exports to Sudan and Djibouti) from December 10, 2010 to July 07, 2011 G.C and July 08, 2012 to April 08, 2014. Thus it has been possible to get a full year data only for 2013 G.C, which is taken as a base year for hourly load forecast of 2017 G.C.

The detailed power plant generation data consisted of hourly readings of sent-out generating capacity, of most existing plants, for the hours of 01:00 to 09:00, 12:00 to 18:00 and 22:00 to 00:00 East Africa Time (EAT) inclusive each day and quarter-hourly data for the periods 09:15 to 11:45 and 18:15 to 21:45 EAT each day.

The hourly and quarter-hourly power plant generation data was adjusted to remove the effect of system events, i.e. trip incidents or more usually data recording errors, by a process of interpolation based on comparisons with same hour data on the days either side of the incident or the same day in the weeks either side of the incident in order to account for variation associated with the day of the week.

Quarter-hourly records have been averaged to give the associated hourly readings, except for the peak demand hour where the absolute peak represents that hour load. This helps in rationalizing the mixed hourly and quarter-hourly power plant generation data to get consistent hourly data.

As stated above 2013 has been used as a base year for hourly load forecast of 2017 G.C, which is found by multiplying the respective hourly demand of 2013 by the ratio of the annual peak demands of 2017 over 2013 [18]. Mathematically it can be put as:

$$2017\ hourly\ load\ forecast\ = 2013\ hourly\ load\ * \frac{Forecasted\ Annual\ peak\ demand\ for\ 2017}{Annual\ peak\ demand\ for\ 2013} \quad - \quad (3.2)$$

Annual peak demand for 2013 has been found as 1417.84MW, including losses and export, from the collected data. Forecasted annual peak demand for 2017, including losses and export, has been adopted from EEPCo generation expansion master plan whose values are shown in Table 3.8 for low, reference and high load scenarios. Low, reference and high forecast scenarios have been used for further sensitivity studies in Chapter 5 of this study. In addition the respective energy forecast is also provided. Table D.0.1, given in Appendix D, shows EEPCo generation expansion load forecast until 2037 G.C and hourly forecasted load for 2017 is shown in the load curve in Figure 3.5.

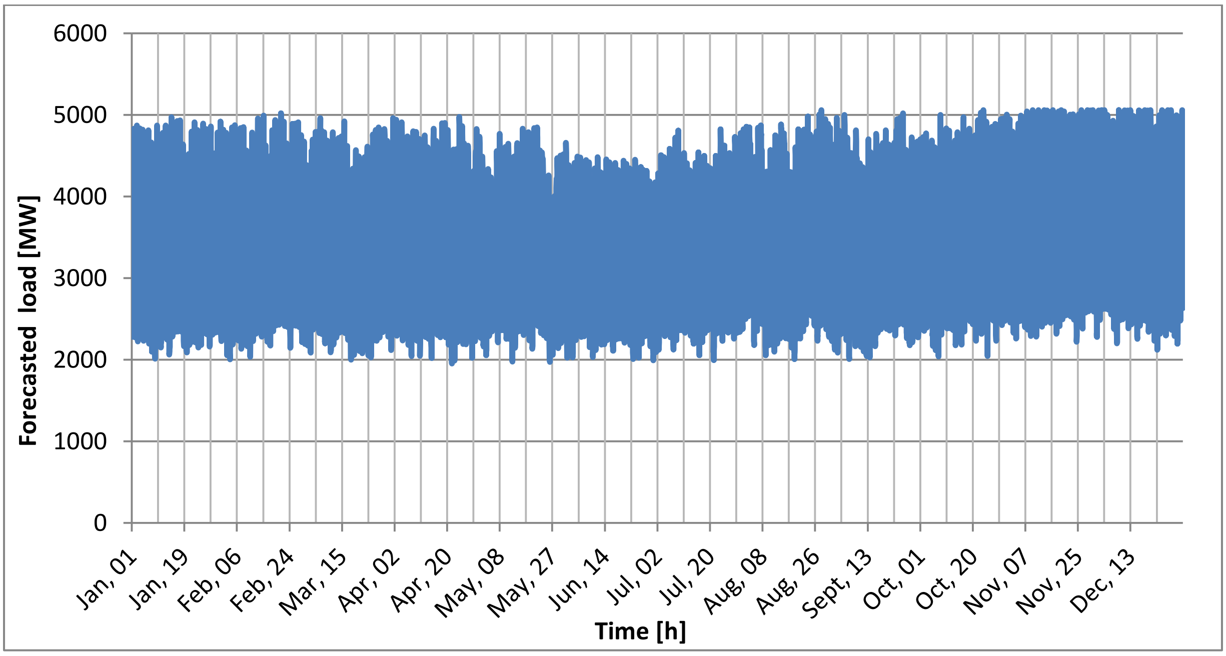


Figure 3.5: Ethiopian adjusted hourly load including exports and losses for 2017 G.C.

For all the three scenarios the hourly load has been forecasted, added and compared with the energy forecast for verification. The comparison has shown the energy forecast by EEPCo master plan to match reasonably with energy forecast by the above method as shown in Table 3.9.

---

[18] EEPCO power system expansion master plan study, 2014 [12]

Table 3.8: EEPCo generation expansion master plan for the year 2017 G.C.

2017 Peak Load forecast [MW]			**2017 Energy forecast [GWh]**		
Low	**Reference**	**High**	**Low**	**Reference**	**High**
3,938	5,062	6,037	23,700	31,729	38,469

Table 3.9: Energy forecast comparison

2017 Energy forecast _ This study [GWh]			**2017 Energy forecast _EEPCo master plan [GWh]**		
Low	**Reference**	**High**	**Low**	**Reference**	**High**
23,291	31,122	37,968	23,700	31,729	38,469

As the simulation time step is on 5-days and hourly basis the load data is also organized in to 5-days duration, by adding hourly data of every 5 days, which ultimately organizes in to a 73 row data for one year (2017). Load curve for 2017 takes on the same pattern as that of 2013 shown in Figure 3.5.

As shown in Figure 3.6 the ratio of the monthly peak demand to the annual peak demand stays the same for both 2013 and 2017, for the reference scenario, as the hourly forecast for 2017 is done based on hourly load of 2013. The annual peak is observed to be in November 2013 and other month's peak demand falls between 84.5% and 99.68% of the annual peak.

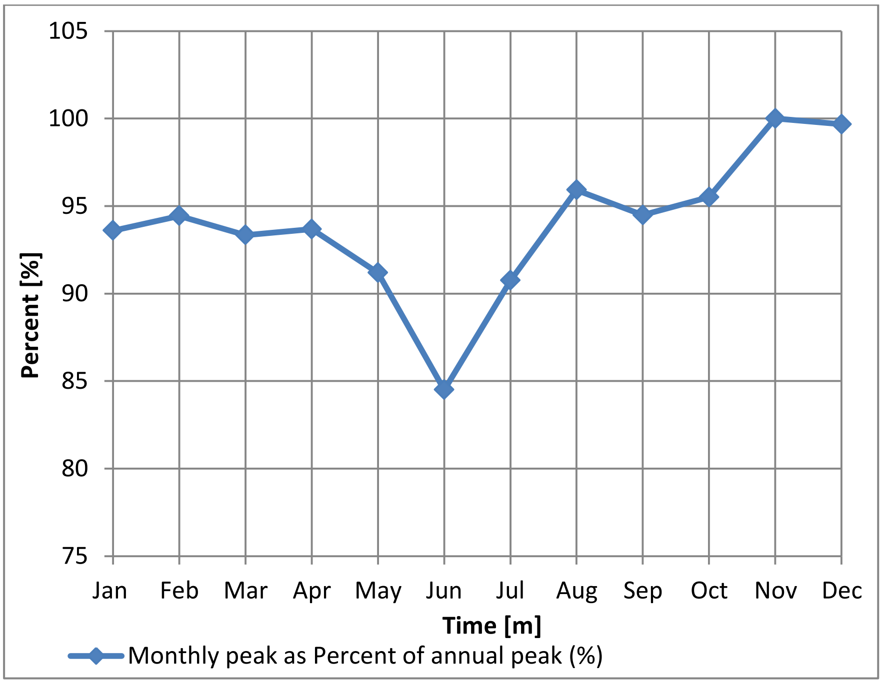


Figure 3.6: Monthly peak demand as percent of annual peak

Load Duration Curve (LDC)

The degree of variation of a load over a period of time is measured by the load factor which is defined as average load, average of total load within the study period, divided by peak load within a given time range. Mathematically it can be defined as:

$$Load\ Factor\ (L.F) = \frac{Average\ load}{Peak\ load} \qquad ---------- \qquad (3.3)$$

Accordingly, the load factor for 2013 and 2017 is 66.85%. It measures variation from the peak load but does not give any indication of the precise shape of the load-duration curve. As the load factor approaches zero, the duration curve will approach a narrow L shape, indicating a peak load of very short duration with very low or no load during the major portion of the time but as the load factor approaches unity, the duration curve will be somewhat rectangular in appearance, indicating high sustained loads. Accordingly load factor above 50% for 2013 and 2017 indicates a sustained load.

To get a clear picture of the load variation over time, load duration curve is important. Load duration curve shows the relation between demands and lengths (percent) of time during which that specific demand is equaled or exceeded [32]. Annual load duration curve for the year 2013 G.C, which has similar shape as that of 2017 G.C, is done using a rank ordered technique and shown in Figure 3.7.

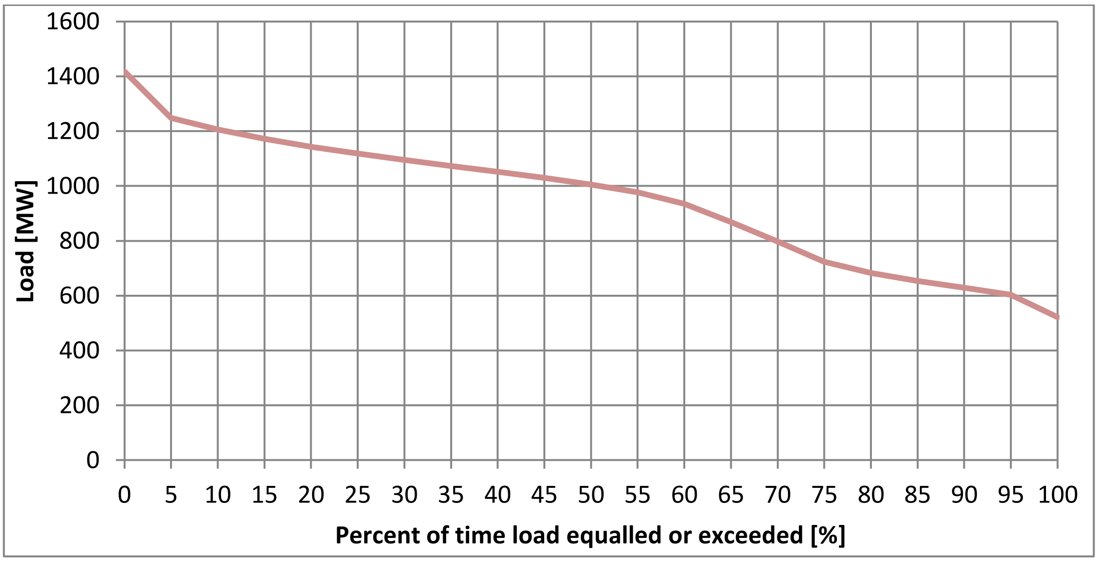


Figure 3.7: Annual load duration curve, 2013 G.C.

3.4.6. Water inflow

Efficient management of hydropower reservoir can only be realized when there is sufficient understanding of the interactions existing between reservoir variables, and energy generation. Reservoir inflow, storage, reservoir elevation, turbine release, net generating head, tail race level and evaporation losses are the major hydropower reservoir variables affecting the energy generation [22]. To model the behavior of existing and committed hydropower plants, flow time series for inflow to various reservoirs and hydropower plants, evaporation and rainfall data at the reservoirs and Irrigation (water demand) from the reservoirs are the major inputs taken in to consideration.

Adjusted and coincident monthly average Inflow data, from January 1961 to December 2005 G.C, for the eleven reservoirs and their respective upstream reservoirs, if any, has been collected through personal communication with EEPCo planning. Daily average non-coincident data was found from Ministry of Water, Irrigation and Energy but only contains few reservoirs thus taken as incomplete data and not used in this study. Two types of inflow data has been found namely total inflow and incremental inflow.

Total inflow is used for reservoirs and hydropower plants that have no upstream reservoirs/ hydropower plants thus this time series data is the only inflow source to the hydropower plant or reservoir.

Incremental inflow is for reservoirs and hydropower plants that have upstream reservoirs/ hydropower plants indicating the existence of upstream inflows to these reservoirs or hydropower plants in addition to this incremental inflow. Incremental inflow only accounts for the natural rainfall runoff collected by the local catchment between the reservoirs/hydropower plants immediate upstream and the reservoir/hydropower plant to which this incremental flow applies. Thus incremental inflow is helpful in avoiding double count of flow when upstream downstream relationship exists.

According to personal communication with EEPCo planning office, most of the incremental inflows were estimated by subtracting the total flow arriving at the reservoir/hydropower plant from the total flow arriving at the immediate upstream reservoir/hydropower plant. This study adopts this concept to generate total flow of a reservoir from the same reservoir incremental flow and upstream reservoir total flow.

The collected monthly average Inflow data for 45 years , in m^3/s, is for hydropower plants having reservoirs namely Fincha, Melkawakena, Lake Tana, Tekeze, GG I, Neshe, Koka, Sor, GG III, GD III, GERD and their respective up-streams, if any. All existing reservoirs, Fincha, Melkawakena, Lake Tana, Tekeze, GG I, Neshe, Sor and Koka do not have upstream reservoir thus the collected total inflow data was directly used to create different inflow scenarios, low , moderate and high inflow. GG III, GD III and GERD have gone through a calculation where each reservoir’s total inflow is calculated from sum of own incremental inflow and total/incremental inflow of respective upstream reservoirs. The relationship between the above three reservoirs and their respective up-streams are shown in Figure E.0.1 given in Appendix E.

GD III, though on construction at this time, is expected to have Genale dawa II in future. Thus GD III total inflow is found by adding Genale dawa II total flow with GD III incremental flow for each month of the collected data period i.e. January 1961 to December 2005 G.C. Only total inflow is used for GG III as its respective upstreams Gojeb, Halele and werabesa will not be available by 2017 G.C and time delay from GG I can not be known. Accordingly GG III total inflow is calculated by adding own incremental inflow with total inflows from GG I, halele and Gojeb as well as incremental inflow from werabesa for each month of the collected data period.

With the exception of Fincha, Neshe and Tana all other upstream of GERD are yet to be built after 2020 G.C. Thus total inflow for GERD is calculated by adding own incremental inflow to inflow of upstream plants including 4 incremental inflows of candidate hydropower plants and 13 total inflows of existing and candidate plants for each month of the collected data period. The upstreams contributing to the incremental inflow includes Lower Dabus, Upper Mandaya, Beko Abo & Aleltu West whereas the ones providing total inflow are Lower Didessa, Upper Dabus, Tana, Yeda, Chacha, Chemoga, Rikicha Gomoro, Amerti, Jida, Wesebi, Fincha, Neshe & Karadobi.

Once the monthly total inflow for 45 years (January 1961 to December 2005 G.C.) is determined the next step was creating the three inflow scenarios (Low, Moderate and High) for each of the eleven reservoirs based on flow duration of each month. As explained in section 3.4.6 the rank ordered technique is used to create the flow duration for each month which is further used to determine the high, moderate and low inflows for that month based on the percentage happening(weight) of the inflow. The steps followed to identify Low, Moderate and High inflow scenarios are explained below.

i. The monthly average inflow 45 years data is arranged in decreasing order.
ii. These rank-ordered values are assigned individual order numbers, the largest beginning with order 1.
iii. If individual order numbers are labeled *m* and the total number in the record labeled *n*, Gringorten formula, among the many formulas, is used to calculate the percent of time that the inflow has been equaled or exceeded during the period of record being considered (45 years). Gringorten formula, as shown below, is chosen as it is a method well known and used for many years in Ethiopia [32].

$$Exceedence\ percentage = \frac{(m - 0.44)}{(n + 0.12)} * 100 \qquad -------- \qquad (3.4)$$

iv. The inflow value that relates with 80% exceedence percentage is taken as low inflow value as 80 percent of the time that low inflow value or more happens.
v. The inflow value that relates with 20% exceedence percentage (80% in reverse order) is taken as high inflow value as 20 percent of the time that high inflow value or more happens.
vi. Moderate inflow is calculated either by taking average of the 45 years flow or 50% exceedence percentage. Only minor insignificant variation is observed between the two results.
vii. Steps I to vi are repeated for all 12 months creating the respective low, moderate and high inflows for the specific reservoir.
viii. Step Vii is repeated for all the 11 reservoirs and the result is summarized in Table 3.10 for the moderate scenario.

Table 3.10: Reservoirs monthly average total inflow for moderate inflow scenario

Month	**Monthly Average Total Inflow [m^3/s] _moderate scenario**											
	Fincha	**Melka Wakena**	**Lake Tana**	**Tekeze**	**GG I**	**Neshe**	**Koka**	**Sor**	**GG III**	**GD III**	**GERD**	**Total**
Jan	4.1	7.1	65.2	12.7	9.2	0.7	11.4	7.5	92.5	30.1	353.4	593.8
Feb	3.0	9.0	73.7	11.4	7.8	0.5	12.9	5.2	83.7	27.4	260.1	494.9
Mar	2.5	11.8	70.2	16.9	8.0	0.4	13.7	3.9	76.0	31.0	198.5	432.9
Apr	2.8	19.5	38.5	16.7	10.4	0.4	14.9	4.9	101.4	67.2	165.7	442.3
May	3.0	18.2	63.8	21.5	18.3	0.6	13.6	14.3	161.3	107.2	287.1	709.1
Jun	5.3	14.2	80.4	45.4	52.0	2.2	20.8	48.1	374.8	98.0	732.3	1,473.6

Jul	17.0	36.9	200.5	377.3	126.2	12.2	109.9	94.5	1,024.9	117.3	2,651.2	4,767.8
Aug	37.8	74.9	750.2	617.3	201.5	23.0	237.6	141.8	1,658.9	160.8	3,805.4	7,709.2
Sept	40.7	52.0	721.7	248.6	161.6	18.5	139.3	158.7	1,210.7	169.5	4,367.1	7,288.4
Oct	27.5	29.1	279.5	68.6	85.2	8.6	37.0	90.4	667.2	186.3	2,442.9	3,922.4
Nov	15.0	13.1	117.9	32.1	37.8	2.1	18.6	28.4	254.9	101.1	970.2	1,591.3
Dec	7.7	6.7	70.8	19.2	17.3	1.0	12.1	12.9	133.2	50.9	520.1	852.0

The added monthly average total inflow of all eleven reservoirs shows inflow seasonal variation in the country. Figure 3.8 shows the pattern of inflow for moderate scenario. It can clearly be seen that months from June to October are high inflow months which agrees with existing Ethiopian rainfall seasonality. As can be seen in Table 3.10, all reservoirs follow this trend except GD III which tends to have high inflow from May to November, for a period of seven months. The respective monthly average total inflow for low and high inflow scenarios are shown in Tables E.0.1 and E.2 given in Appendix E.

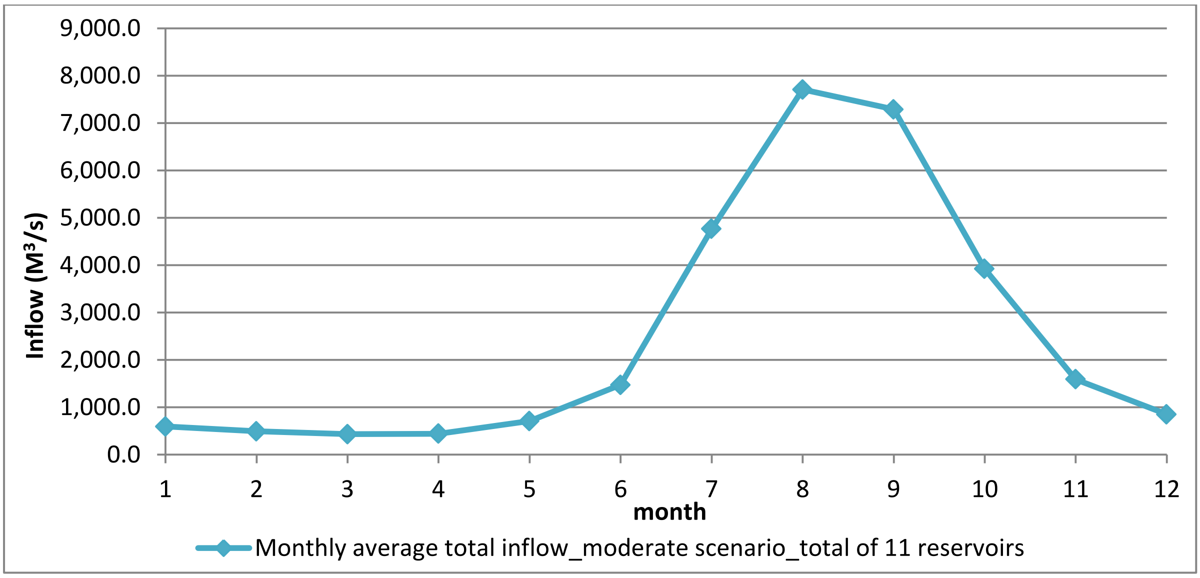


Figure 3.8: 2017 G.C. potential hydro system monthly average total inflow_moderate inflow scenario

The monthly average total inflow data in m^3/s is converted to m^3/h for the hourly simulation step. And by adding the hourly data of every 5 consecutive days, the data is also organized in to 5 days duration (a 73 row data for one year). This is done for all scenarios and power plants.

3.4.7. Evaporation and Water demand (Irrigation)

Evaporation

Evaporation data estimates the water loss in reservoirs due to evaporation and the data for reservoirs under study has been collected from EEPCo planning in person. The data collected has a calendar monthly resolution and the monthly average evaporation rate is expressed in mm/month. Mathematically it can be put as:

$$Evaporation\ rate\ \left(\frac{mm}{month}\right) = \frac{Total\ evaporation\ (mm)}{Duration\ of\ evaporation\ (month)} \qquad -- \qquad (3.5)$$

Total amount of evaporation, expressed in mm, can be easily expressed using a container with 1 m wide and 1 m long. For this container the corresponding evaporation volume is calculated by multiplying 1m^2 by the amount of evaporation in mm, to find it in m^3, and the evaporation rate is subsequently calculated by dividing the respective volume, in m^3, by the duration of evaporation, in hours.

Accordingly the mm/month and reservoir area data found through personal communication with EEPCo planning office has been used to generate the evaporation rate in m^3/sec and is converted to m^3/h which is useful for the hourly simulation. The 5 days simulation time step uses evaporation data by summing the hourly evaporation data for 5 days. Maximum area of each reservoir has been used, for respective evaporation rate calculation, as evaporation happens from the surface and also to be conservative. Note that evaporation variation with time of the day (day and night) can not be accounted as monthly average value is used.

Evaporation rate for Fincha reservoir is shown as an example in Table 3.11 and 10 other reservoirs have been addressed in a similar fashion, together with 5 days evaporation sum.

Table 3.11: Evaporation rate unit conversion for Fincha reservoir

Month	**Evaporation rate**			
	Area [m^2]	**[mm/ month]**	**[m^3/sec]**	**[m^3/h]**
Jan	470,000,000	105.0	18.4	66,330.6
Feb	470,000,000	107.0	20.8	74,836.3
Mar	470,000,000	70.0	12.3	44,220.4
Apr	470,000,000	88.0	16.0	57,444.4
May	470,000,000	-39.0	-6.8	-24,637.1

Jun	470,000,000	-68.0	-12.3	-44,388.9
Jul	470,000,000	-176.0	-30.9	-111,182.8
Aug	470,000,000	-174.0	-30.5	-109,919.4
Sept	470,000,000	-90.0	-16.3	-58,750.0
Oct	470,000,000	128.0	22.5	80,860.2
Nov	470,000,000	188.0	34.1	122,722.2
Dec	470,000,000	150.0	26.3	94,758.1

It can be noted that for some months there are negative evaporation rate values which indicates rainfall over the surface area, of lakes or reservoirs, will more than exceed losses due to evaporation.

Water demand (Irrigation)

Irrigation (Water demand) data allows the model to consider the amount of water needed for irrigation from the respective reservoirs or hydropower plant. Fixed seasonally varying monthly average irrigation data was obtained from EEPCo planning.

Only four water demand areas have been observed to exist for the hydro system under this study. Tana irrigation and Fincha irrigation have water demands directly from lake tana and Fincha reservoir whereas Beles irrigation and Neshe irrigation satisfy water demands after electricity generation by respective power plants. These two conditions are treated differently in the model which is discussed in section 4.1.1.2.2 and 4.1.2.2.2.

Table 3.12 shows the monthly average water demand, for the four water demand areas, in both m^3/s and m^3/h. The data in m^3/s is directly collected from EEPCo planning (in person) and converted to m^3/h to make it ready for hourly simulation. The hourly data is further adjusted in to 5 days duration, by adding 5 days hourly data, which makes it suitable for 5 days simulation step.

Table 3.12: Monthly average water demand

Month	**Monthly average Irrigation (water demand)**							
	Fincha [m^3/s]	**Fincha [m^3/h]**	**Beles [m^3/s]**	**Beles [m^3/h]**	**Lake Tana [m^3/s]**	**Lake Tana [m^3/h]**	**Neshe [m^3/s]**	**Neshe [m^3/h]**
Jan	0.58	2075.76	9.67	34798.32	0.33	1185.12	1.00	3600.00
Feb	0.85	3044.88	14.18	51037.20	0.48	1738.08	1.00	3600.00
Mar	0.58	2075.76	9.67	34798.32	0.33	1185.12	1.00	3600.00
Apr	0.17	622.80	2.90	10439.64	0.10	355.68	1.00	3600.00

May	0.14	511.92	2.42	8699.98	0.08	296.28	1.00	3600.00
Jun	0.16	588.24	2.38	8563.68	0.09	335.88	1.00	3600.00
Jul	0.00	0.00	0.00	0.00	0.00	0.00	1.00	3600.00
Aug	0.00	0.00	0.00	0.00	0.00	0.00	1.00	3600.00
Sept	0.21	761.04	3.54	12759.48	0.12	434.52	1.00	3600.00
Oct	0.19	687.96	3.20	11531.16	0.11	392.76	1.00	3600.00
Nov	0.04	138.24	0.64	2319.84	0.02	78.84	1.00	3600.00
Dec	0.19	695.88	3.24	11667.60	0.00	0.00	1.00	3600.00

3.4.8. Wind power plants hourly power output

Based on report from Hydrochina, 51 candidate wind plant potential sites have been identified based on average wind speed. These are principally located on a central north-south axis corresponding to high terrain. However, some candidates are located in lower but windy areas to the east, and also on high ground to the west of the axis. The Ogaden region (south-eastern Ethiopia) and far south areas are seen to have high average wind-speeds (> 9m/s at 50 m height) but can not be selected as a potential site due to lack of transmission facilities and population density. A map of the distribution of average wind speeds together with the identified sites is shown in Figure 3.9 [12].

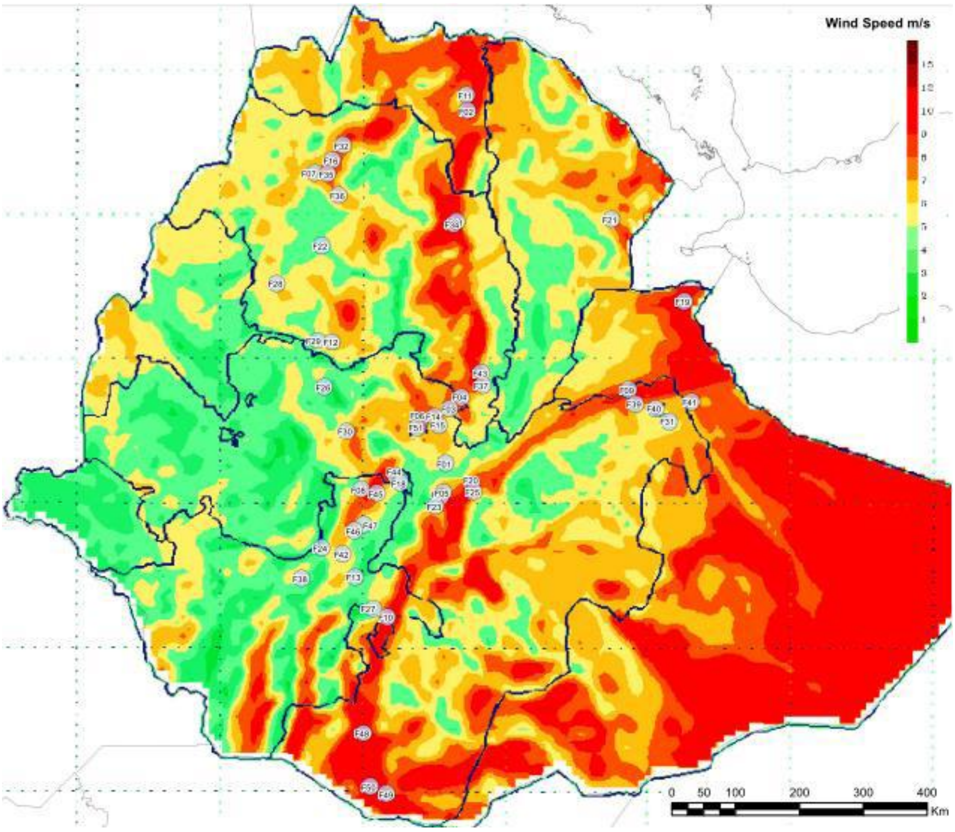


Figure 3.9: Distribution of average wind speeds [m/s] in Ethiopia (1980-2009) – 50m

As discussed in section 3.4.1, five wind farms has been identified to be available for the operational planning of the year 2017. Adama I, Ashegoda I and Ashegoda II are existing sites whereas Adama II is a committed plant which is partly operational. Aysha is a candidate plant and at bidding stage. As wind is intermittent renewable energy, hourly power output of each plant is required for good representation in the optimization exercise. Accordingly hourly power output of each of 5 wind farms has been simulated based on the hourly wind speed at hub height (for that specific wind farm) and power curve of the turbine used on a specific farm. Summary of input data, including respective sources, has been explained in Table 3.13.

Table 3.13: Wind farms power simulation input data summary

Wind farm	**Hourly wind speed mast location**	**Shear coefficient [α]**	**Source**	**Turbine**
Adama I	40 m Wind mast location: North Latitude – 945054mN, East Longitude – 525580mE	0.1854	Hydrochina Corporation, November 2009. Feasibility study for Ethiopian Adama (Nazreth) wind park	Gold Wind_1.5MW _ hub height - 65m
Adama II				SANY SE7715_1.5MW _ hub height - 70m
Ashegoda I	40m wind mast_Exact Location: unknown_ on a hill around Ashegoda	0.118	GTZ, August 2005. Wind energy programme TERNA-Ethiopia.	VERGNET GEV-HP_1MW_hub height-70m
Ashegoda II				Alstom Eco 74_ 1.67MW [Power curve can not be found thus AAER 1.5MW turbine is used for simulation] _hub height - 80m
Aysha	10 m wind mast location: North Latitude - 1191632mN, East Longitude - 235162.2mE	0.1	DongFang Electric Corporation (DEC), 2011. Technical Description: Design, Supply, Construction, Installation and Commissioning of Aysha Wind Power Project	GAMESA_2MW_ hub height - 67m

Once these data has been collected three steps has been used to reach at a wind farm hourly power output as explained below.

- Determine wind speed at hub height for each wind farm.

- Represent respective power curves with three degree polynomial equation, with almost no error, using curve fitting technique.
- Determine hourly power output of the wind farm based on the fitted power curve and hourly wind speed data at hub height.

These steps have been applied on each of the above wind farms to produce the respective hourly power outputs. Adama II wind farm has been selected to show the above steps in detail.

Wind speed at hub height

The wind speed at a certain height above ground level is determined from the expression:

$$\frac{V_2}{V_1} = \left(\frac{h_2}{h_1}\right)^{\alpha} \qquad ------------------------ \qquad (3.6)$$

Where: V_2 = wind speed at height h_2 (hub height) above ground level,

V_1 = reference speed, i.e. a wind velocity at height h_1(wind mast height),

h_2 = wind turbine hub height,

h_1 = reference height, i.e. the height where the exact wind speed V_1 is known or wind mast height,

α = shear coefficient of the site.

From the Table 3.13 it can be seen that $V_1, h_2, h_1 and\ \alpha$ are already given thus using the formula in equation 3.6 V_2(Wind speed at hub height) can easily be calculated. For instance Adama II has the following values: h_1 = 40m, h_2 = 70m, α = 0.1854 and V_1= hourly wind speed data found from data logger on the mast. Accordingly all farms hourly wind speed at hub height has been calculated using respective input data.

Power curve approximation

Power curves for turbines put in Tables F.0.1and F.0.2, given in Appendix F, have been collected from manufacturer’s data sheet, except Alstom which can not be found, and approximated using scatter plot and curve fitting technique of MS. Excel. One power curve has been approximated using three or four different curves with almost zero error percentage.

Adama II power curve has been sectioned in to four different curves, based on four wind speed ranges, as shown in Table 3.14. Different approximation is implemented for wind speeds of 4 to 7m/s, 7 to 10m/s, 10 to 13m/s and 13 to 15m/s for accurate representation of the power curve. The x value represents the wind speed in m/s whereas the corresponding y value represents power output of the turbine. For speed values between 15 and 25m/s (cut-off speed) power output is the turbine rated power, thus constant. Figure 3.10 shows one of the four approximated curves for wind speeds in the range 4 to 7 m/s. These four equations has been used, to determine power output at that speed, using concatenated if statement on Ms. Excel given as:

```
y=IF(x<4,0,IF(x<7,1.0567*(x^3)-4.815*(x^2)+46.218*(B3)-
156.77,IF(x<10,0.625*(x^3)+9.14*(x^2)-80.625*(x)+195.4,IF(x<13,-
5.8083*(x^3)+138.74*(x^2)-697.3*(x)-164.05,IF(x<15,8.635*(x^2)-
219.8*(x)+2854.4,IF(x<25.001,1500.37,0))))))
```

Table 3.14 shows the manufacturer and approximated power curve, for Adama II, with corresponding percentage error which is almost 0%. Similar steps have been implemented to approximate all other power curves and the approximated power curves with corresponding concatenated if statements are given in Appendix F.

Table 3.14: Manufacturer and fitted power curve of Sany SE 7715

Power curve of Sany SE 7715			
V [m/s]	**Manufacturer Power curve [kW]**	**Fitted power [KW]**	**Percent error [%]**
4	18.69	18.691	0.004
5	86.03	86.033	0.003
6	175.44	175.445	0.003
7	293.26	293.269	0.003
8	455.36	455.360	0.000
9	665.74	665.740	0.000
10	928.15	928.150	0.000
11	1221.73	1222.343	0.050
12	1409.43	1410.168	0.052
13	1456.4	1457.275	0.060

14	1469.75	1469.660	-0.006
15	1500.37	1500.370	0.000
16	1500.37	1500.370	0.000
17	1500.37	1500.370	0.000
18	1500.37	1500.370	0.000
19	1500.37	1500.370	0.000
20	1500.37	1500.370	0.000
21	1500.37	1500.370	0.000
22	1500.37	1500.370	0.000
23	1500.37	1500.370	0.000
24	1500.37	1500.370	0.000
25	1500.37	1500.370	0.000

Hourly power output of a wind farm

Once the hourly wind speed at turbine hub height and the corresponding turbine power curve equation is determined, using concatenated if statement, hourly power output of one turbine at any hour can be calculated by inserting the corresponding wind speed value at that hour in to the x value of the if statement. Multiplying power output of one turbine at a specific hour by the number of turbines on the farm gives that hour gross power output of the farm.

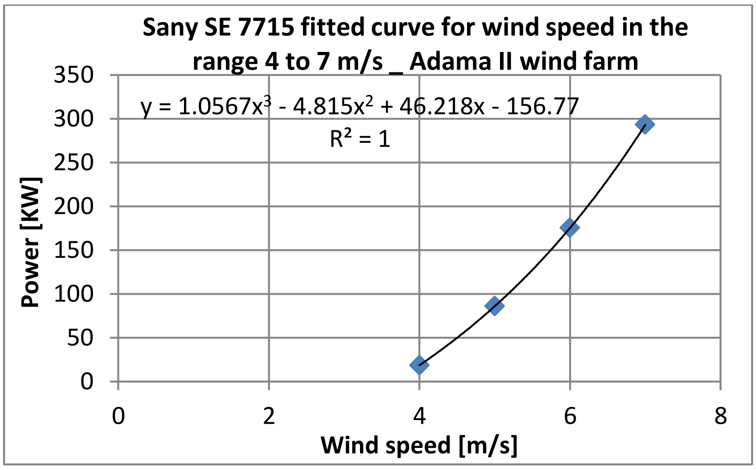


Figure 3.10: Sany SE 7715 fitted curve for Adama II wind farm

Gross power output of a farm is subject to different technical and environmental losses to give net power output of the farm. Losses associated with wind farms include:

Wake losses: Interactions between wind turbines gives rise to losses called wake losses. These losses are estimated at 5% [33].

Power curve air density correction reduction: Manufacturer power curves are done using air density at sea level i.e. 1.225 kg/m^3. But in actual conditions, for majority of wind farms, air density is smaller than the one at sea level which implies a reduction in power output of a farm. Thus a correction factor of 5% is applied in order to obtain more accurate power output estimation of a farm [34].

Utilization of wind turbines: wind turbines availability factor is taken as 95% considering failure and maintenance of wind turbines, power grid failure, and arrangement of routine maintenance in low wind energy month, wind turbine overhaul and accident. In other words a 5% unavailability factor is assumed for wind farms [33, 35].

Reliability of the power curve: Manufacturer's Guarantee for the reliability of power curve is 95% as power curve is developed in wind tunnels inside a laboratory and not in real site conditions, thus a reduction of 5% in the farm power output [35].

Power loss due to components in the wind farm: Energy losses of auxiliary power system and transmission lines, transformer and substation within the wind farm takes about 7% of the total gross power output [33, 35].

Meteorological data reduction: Inaccuracy of the meteorological data collected at the mast together with the inaccuracy associated while converting mast height wind speed to hub height wind speed, a 5% loss is considered on the gross wind farm power output [33, 35].

Turbulence reduction: Taking in to consideration the local climate of the mentioned wind farms the turbulence intensity is generally moderate thus Control and turbulence reduction factor of 5% is taken for this study [33, 35].

In general the total loss factor is found by multiplying all the above factors and it gives us:

Total loss factor = $(1-0.05)^6 *(1-0.07) = 0.684$

This reveals that only 68.4% of the gross wind farm power is converted to useful power. Table 3.15 illustrates a one day (January 03, 2017) hourly power output of Adama II wind farm with 102 turbines, shear coefficient of 0.1854 and total loss factor of 0.684. Similar procedure has been applied to all wind farms to reach at estimation of the corresponding wind farm every hour net power output.

Table 3.15: Adama II simulated hourly power output on January 03, 2017

Date	Time [h]	V[m/s] _40m	V[m/s] _70m	Wind Turbine Fitted Power [MW]	Wind Farm Gross power [MW]	Wind Farm Net power [MW]
3-Jan	1:00	13.13	14.56	1.48	151.44	103.53
3-Jan	2:00	12.90	14.31	1.48	150.69	103.01
3-Jan	3:00	11.83	13.12	1.46	148.61	101.60
3-Jan	4:00	10.48	11.62	1.35	138.06	94.38
3-Jan	5:00	11.10	12.31	1.44	147.06	100.53
3-Jan	6:00	12.03	13.34	1.46	148.81	101.73
3-Jan	7:00	9.78	10.84	1.18	120.62	82.46
3-Jan	8:00	9.35	10.37	1.05	106.91	73.09
3-Jan	9:00	8.65	9.60	0.82	83.19	56.87
3-Jan	10:00	8.63	9.57	0.81	82.43	56.35
3-Jan	11:00	9.53	10.57	1.11	112.81	77.12
3-Jan	12:00	9.25	10.26	1.01	103.39	70.68
3-Jan	13:00	9.55	10.59	1.11	113.62	77.67
3-Jan	14:00	9.40	10.43	1.06	108.63	74.26
3-Jan	15:00	9.85	10.93	1.20	122.81	83.96
3-Jan	16:00	11.20	12.42	1.45	147.84	101.07
3-Jan	17:00	12.35	13.70	1.46	149.31	102.08
3-Jan	18:00	13.18	14.62	1.49	151.62	103.65
3-Jan	19:00	13.53	15.00	1.50	153.04	104.62
3-Jan	20:00	13.60	15.09	1.50	153.04	104.62
3-Jan	21:00	14.53	16.11	1.50	153.04	104.62
3-Jan	22:00	14.83	16.45	1.50	153.04	104.62
3-Jan	23:00	15.50	17.19	1.50	153.04	104.62
3-Jan	0:00	15.28	16.94	1.50	153.04	104.62

Adding the hourly power output of a specific wind farm for every 5 days interval gives the energy output useful for 5 daily simulation time step optimization problem.

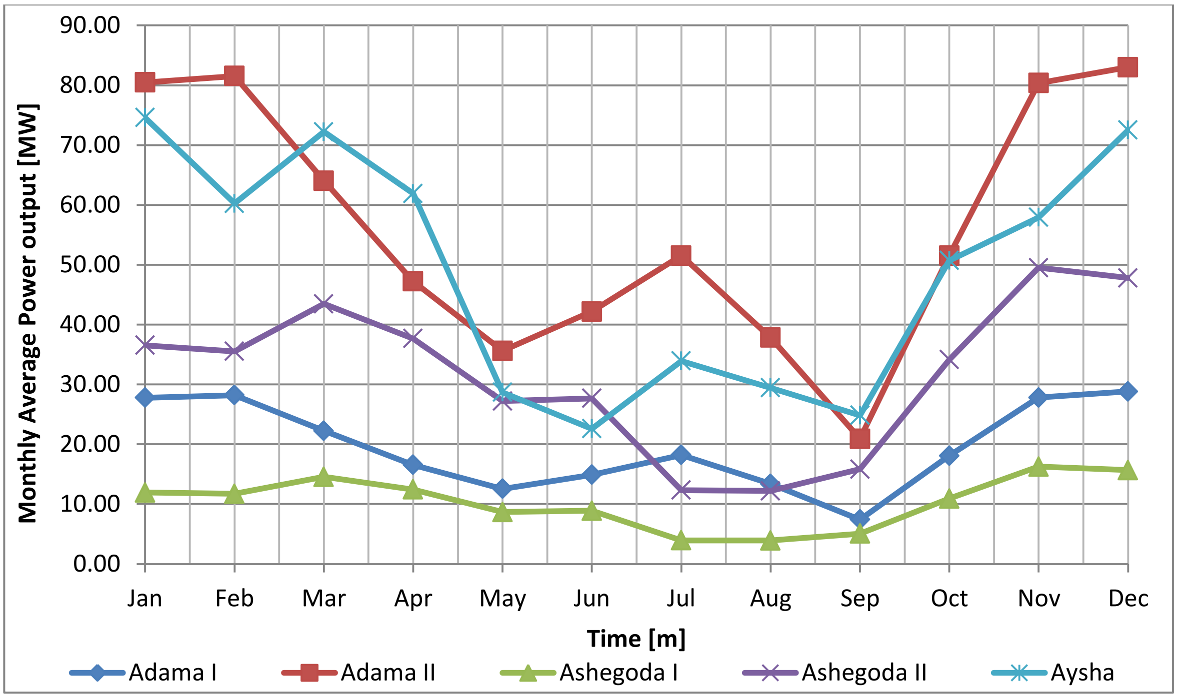


Figure 3.11: Monthly average wind power distributions of selected wind farms

Figure 3.11 shows trend of monthly average wind power production for the 5 wind farms under this study. It can be observed that wind farms has low power outputs between months of June and October and high power outputs for the rest of the months, unlike hydropower which has high inflow (and high power output) between months of June and October and low power outputs for the remaining months as shown in Figure 3.8. Therefore an advantage of complementarity is observed between hydro and wind technologies for electric power production in Ethiopia.

3.4.9. Cost and Economic parameters

As explained in section 1.3.1, the major objective of this research is to develop a model that creates the least cost optimal medium and short term plan to test whether the planned generation plants meet the forecasted demand by year 2017. Thus it is clear that cost and economic parameters play an important role in determining power plants dispatch sequence. This section explains the different types of costs related to each power plant and start by explaining types of costs and the associated economic parameters as well as time value of money.

Types of costs useful in this study include capital and Generation costs. Generation cost is in turn divided in to operation & maintenance and fuel costs. The capital cost is due to total cost for building the power plant, which includes the cost of items purchase (turbines, machines), balance of plant (civil work and labor costs during construction) and costs for grid connectivity. It is approximately proportional to MW generated [10]. Capital costs included in this study include interest during construction which varies depending on the duration of construction and the cost of money.

Generation cost is the total annual cost incurred in power generation and has three parts namely fixed cost, semi-fixed cost and running cost. Fixed cost is due to cost of central organization, interest on the capital cost of land and salaries of higher officials and management thus independent of the capacity. Semi-fixed cost is due to cost of interest and depreciation on the capital cost of generating unit and transmission network, insurance and compensation. Running cost is due to annual cost of fuel, lubricating oil, water, maintenance and repairing cost of equipment, and wages and salaries of operation, maintenance and supervisory staff. This cost is approximately proportional to energy generated (MWh) [1, 10]. Fuel cost is treated differently as it differs significantly based on technology but all the other generation costs are treated together as operation & maintenance cost.

Therefore, Capital (investment) and generation cost (Operation & maintenance + fuel cost) can be formulated by adding the capital cost of committed and candidate plants and generating cost of existing, committed and candidate plants. To keep unit consistency capital cost is put into $/MWh form by using suitable conversion factors. Table 3.17 shows the capital, operation & maintenance as well as fuel costs used in the model for optimal planning.

Cost data has been collected from different sources implying different times of money which demands converting costs to same time (base year). This is because the basic idea for economic equivalency calculations is to convert the value of benefits or costs that occur at different times to equivalent monetary amounts, recognizing the time value of money, for easy comparison and use in the optimization process. Accordingly different economic parameters and concepts are employed among which the most important ones are explained below.

- Present worth (P):-the value of an investment at the present, or the value of money expended in the future discounted back to the present.
- Future worth (F):-the value of a future investment, or the value of an expenditure at present discounted out to that future time.

- Discount rate (i):-the price paid for borrowing money expressed as a percentage of the amount borrowed or is the rate used to discount future worth in order to obtain the present worth.
- Equivalent annual payment (A):- a discounted uniform annual amount expended or paid that is equal to a present invested amount to cover some given activity over a fixed period of time.

The process of mathematically obtaining the present worth of benefits or costs is called discounting and it recognizes the time value of money in the form of the willingness to pay interest for the use of money. Single-payment compound-amount factor is used to calculate how much an initially invested amount P will accumulate after n interest periods [36]. If the accumulated amount is labeled as F:

$$F = P * (1 + i)^n \qquad ---------------------- \qquad (3.7)$$

Where the term $(1 + i)^n$ is known as the single-payment compound amount factor (SPCAF)

Uniform annual series factors are useful to determine benefits or costs in the form of equivalent annual payments which provides a means of calculating a series of equal annual payments that is equal to a present-worth (P) or a future-worth value (F) based on a defined interest rate (i) for discounting. Among the many uniform annual series factors is capital recovery factor (CRF) which is concerned with the capital recovery amount that is the value of uniform payments that are made and discounted at the rate i from a present worth and is mathematically described as [36]:

$$A = P * \frac{(1 + i)^n * i}{(1 + i)^n - 1} \qquad ------------------ \qquad (3.8)$$

Annual capital cost has been calculated, for all committed and candidate plants in the year 2017 G.C., from total capital cost using the Capital recovery factor explained above. This is done to only use the amount of capital cost to be recovered by the generation capacity during that year. Adama II wind farm is the only exception, from committed plants, not to have capital cost as it is almost fully functional. In addition, Single payment compound amount factor (SPCAF) is also used to convert all money to 2012 money as most of the cost data found is that of 2012 G.C. The detail of annual cost calculation with respective data source is shown in Table 3.16.

An estimate of the Capital recovery period has been adopted from RET Screen international, a reputed excel based software for renewable energy technologies and the discount rate is taken as 10% based on information from Ethiopian Economic Association and EEPCo generation expansion master plan study. Capital Costs for GG III, GD III, GERD and all sugar factories co-generation has been converted from 2009 money to 2012 money using SPCAF.

Table 3.16: Committed and Candidate plants annual capital cost for 2017 G.C.

No	**Plant**	**Capital Cost [$/KW]**	**Years of capital recovery[n]**[19]	**Discount rate [i]**[20]	**Cost recovery factor [CRF]**	**Annual capital cost [$/KW]***
1	GG III	1,527.99 [21]	35	0.10	0.1102	168.34
2	GD III	1,876.71 [21]	35	0.10	0.1102	206.75
3	GERD	1,331.00 [22]	35	0.10	0.1102	146.63
4	Corbetti	4,825.00 [22]	10	0.10	0.1627	785.25
5	Ayisha	2,334.30 [22]	8	0.10	0.1874	437.55
6	Tendaho	2,092.33 [23]	7	0.10	0.2054	429.78
7	Wonji	2,092.33	7	0.10	0.2054	429.78
8	Fincha	2,092.33	7	0.10	0.2054	429.78
9	Beles I	2,092.33	7	0.10	0.2054	429.78
10	Beles II	2,092.33	7	0.10	0.2054	429.78
11	Beles III	2,092.33	7	0.10	0.2054	429.78
12	Wolkayit	2,092.33	7	0.10	0.2054	429.78
13	Omo kuraz 1	2,092.33	7	0.10	0.2054	429.78
14	Omo kuraz 2	2,092.33	7	0.10	0.2054	429.78
15	Omo kuraz 3	2,092.33	7	0.10	0.2054	429.78
16	Omo kuraz 4	2,092.33	7	0.10	0.2054	429.78
17	Omo kuraz 5	2,092.33	7	0.10	0.2054	429.78
18	Kesem	2,092.33	7	0.10	0.2054	429.78
19	Bamza	1,530.52 [22]	9	0.10	0.1736	265.76
20	meikasedi	1,473.97 [22]	9	0.10	0.1736	255.94
21	EFW-Addis Ababa	2,880.00 [22]	10	0.10	0.1627	468.71
22	Thermal backup (Unserved energy)	10,000.00 [22]	20	0.10	0.1175	1,174.60

Operational and maintenance costs have been sourced from many offices inside EEPCo as information can not be found at one point. EEPCo planning, EEPCo generation expansion

---

[19] RET Screen International, Small hydro project model 2004 [37]

[20] EEPCO power system expansion master plan study, 2014 [12]

[21] East African Power pool and East African community, 2011[38]

[22] EEPCo corporate planning office

[23] Ethiopian Sugar Development Agency, 2009 [39]

* All 2012 money

master plan and East African power pool have been used as main sources as can be seen on Table 3.17. Data from EEPCo planning as well as EAPP have been converted from 2006 & 2009 money to 2012 money. It can easily be observed that most hydropower plants have small operational and maintenance cost as compared to other technologies which makes hydro prior for dispatch given other constraints like water availability is fulfilled.

Fuel cost is only considered for biomass and thermal back-up plant as other technologies have almost zero fuel cost since resources are available freely. The thermal backup plant only serves to include the unserved energy in the optimization process. Accordingly cost of unserved energy i.e. $1/KWh or $1000/MWh calculated based on lost GDP due to one KWh is used to set the respective fuel cost [12, 38]. Therefore fuel cost for the pseudo thermal backup plant is found by subtracting $15.849/MWh (O & M cost of thermal backup plants) from $1000/MWh which equals 984.15 $/MWh.

Table 3.17: Annual capital, Operational & Maintenance and Fuel cost of all plants

No	**Technology**	**Plant**	**Plant type**	**Annual Capital Cost [$/KW]**	**Operational [24] * Maintenance cost [$/MWh]**	**Fuel [24] * cost [$/MWh]**
1	Hydro	Fincha	Existing	-	2.0512 [25]	0.00
2	Hydro	Melkawakena	Existing	-	2.0512 [25]	0.00
3	Hydro	Tana beles	Existing	-	4.7000 [26]	0.00
4	Hydro	GG II	Existing	-	3.6300 [11]	0.00
5	Hydro	Tekeze	Existing	-	5.9300 [11]	0.00
6	Hydro	GG I	Existing	-	3.4600 [11]	0.00
7	Hydro	Amerti neshe	Existing	-	10.5900 [11]	0.00
8	Hydro	Tis Abay I	Existing	-	2.0512 [25]	0.00
9	Hydro	Tis Abay II	Existing	-	2.0512 [25]	0.00
10	Hydro	Koka	Existing	-	2.0512 [25]	0.00
11	Hydro	Awash I	Existing	-	2.0512 [25]	0.00
12	Hydro	Awash II	Existing	-	2.0512 [25]	0.00
13	Hydro	Sor 1	Existing	-	2.0512 [25]	0.00
14	Hydro	GG III	Committed	168.34	5.6900 [11]	0.00
15	Hydro	GD III	Committed	206.75	5.9600 [11]	0.00
16	Hydro	GERD	Committed	146.63	6.9700 [11]	0.00
17	Geothermal	Aluto Langano I	Existing	-	16.1900	0.00
18	Geothermal	Corbetti	Committed	785.25	18.4900	0.00

---

[24] EEPCO power system expansion master plan study, 2014 [12]

[25] East African Power pool and East African community, 2011[38]

* All 2012 money

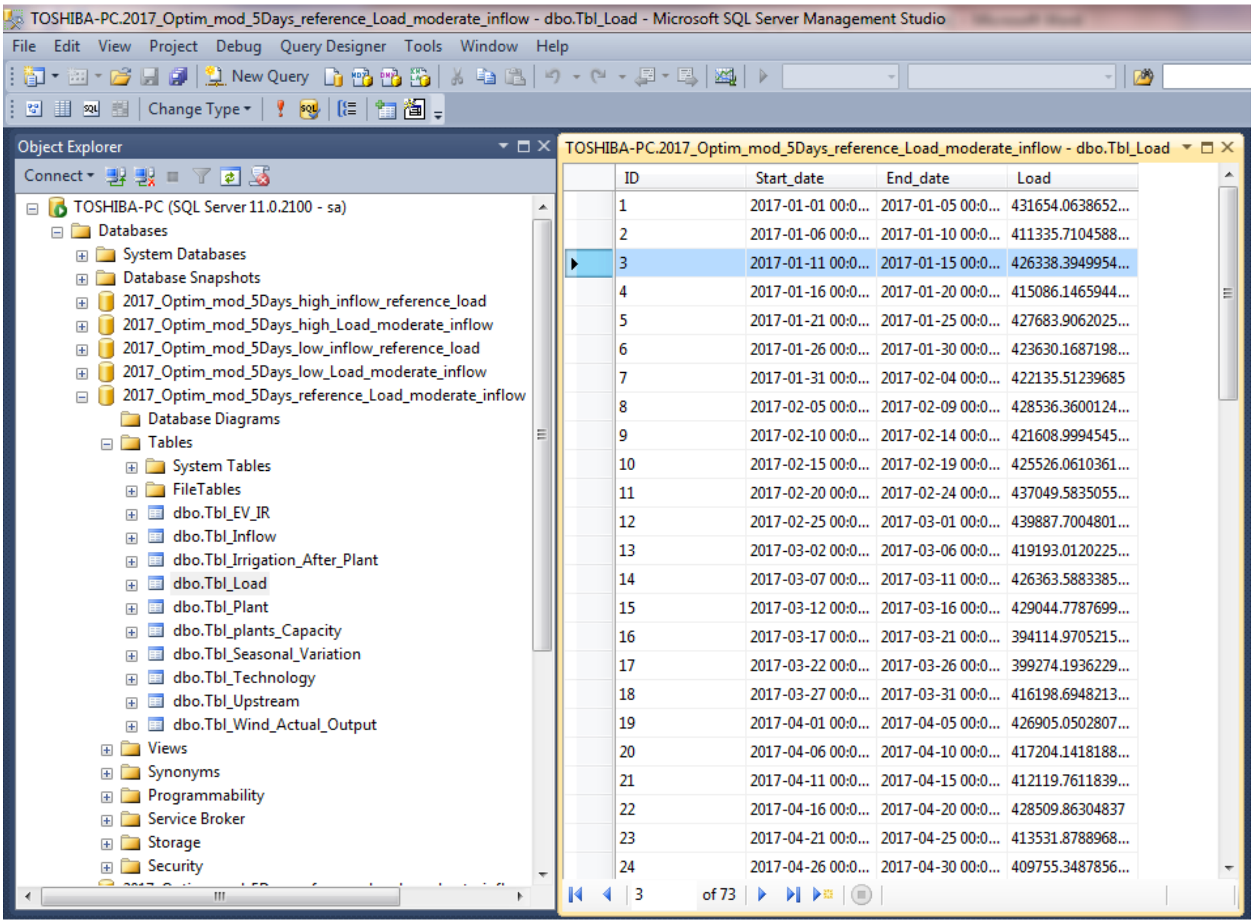
[26] EEPCo corporate planning office

19	Wind	Adama I	Existing	-	15.5000	0.00
20	Wind	Ashegoda I	Existing	-	17.6300	0.00
21	Wind	Ashegoda II		-	17.6300	0.00
22	Wind	Adama II	Committed	-	15.8000	0.00
23	Wind	Ayisha	Candidate	437.55	12.9000	0.00
24	Sugar Fac. Co.Gen.	Tendaho	Committed	429.78	7.1330	0.00
25	Sugar Fac. Co.Gen.	Wonji	Committed	429.78	7.1330	0.00
26	Sugar Fac. Co.Gen.	Fincha	Committed	429.78	7.1330	0.00
27	Sugar Fac. Co.Gen.	Beles I	Committed	429.78	7.1330	0.00
28	Sugar Fac. Co.Gen.	Beles II	Committed	429.78	7.1330	0.00
29	Sugar Fac. Co.Gen.	Beles III	Committed	429.78	7.1330	0.00
30	Sugar Fac. Co.Gen.	Wolkayit	Committed	429.78	7.1330	0.00
31	Sugar Fac. Co.Gen.	Omo kuraz 1	Committed	429.78	7.1330	0.00
32	Sugar Fac. Co.Gen.	Omo kuraz 2	Committed	429.78	7.1330	0.00
33	Sugar Fac. Co.Gen.	Omo kuraz 3	Committed	429.78	7.1330	0.00
34	Sugar Fac. Co.Gen.	Omo kuraz 4	Committed	429.78	7.1330	0.00
35	Sugar Fac. Co.Gen.	Omo kuraz 5	Committed	429.78	7.1330	0.00
36	Sugar Fac. Co.Gen.	Kesem	Committed	429.78	7.1330	0.00
37	Biomass	Bamza	Committed	265.76	15.7500	62.24
38	Biomass	meikasedi	Committed	255.94	15.7500	62.24
39	Energy from waste	EFW-A.A.	Committed	468.71	147.5600	0.00
40	Thermal_backup (Unserved energy)	Diesel HFO/gas	Backup	1,174.60	15.8490	984.15

3.4.10. Database Organization

Microsoft SQL(Structured Query Language) Server 2012 management studio, one of the most known Database Management System has been applied in this study to structure and format all the data, explained in previous sections, for easy use by the program developed for optimization.

Different databases have been created based on load conditions and inflow scenarios as well as simulation time steps discussed above. Each database Data has in turn been organized in to different tables according to the type of data (water, wind…) and resolution (hourly/5-daily, seasonally or fixed) and uses plant ID as primary key. Thus 10 tables has been used for both the 5daily and hourly simulation time step, only the data resolution being different as the simulation time step suggests. One more table has been added for the hourly simulation time step to accommodate the water discharge, power output and reservoir level targets found from the 5-daily simulation time step. The resulting database organization in Microsoft SQL is shown in Figure 3.12 and details of each table are described afterwards.



ID	Start_date	End_date	Load
1	2017-01-01 00:0...	2017-01-05 00:0...	431654.0638652...
2	2017-01-06 00:0...	2017-01-10 00:0...	411335.7104588...
3	2017-01-11 00:0...	2017-01-15 00:0...	426338.3949954...
4	2017-01-16 00:0...	2017-01-20 00:0...	415086.1465944...
5	2017-01-21 00:0...	2017-01-25 00:0...	427683.9062025...
6	2017-01-26 00:0...	2017-01-30 00:0...	423630.1687198...
7	2017-01-31 00:0...	2017-02-04 00:0...	422135.51239685
8	2017-02-05 00:0...	2017-02-09 00:0...	428536.3600124...
9	2017-02-10 00:0...	2017-02-14 00:0...	421608.9994545...
10	2017-02-15 00:0...	2017-02-19 00:0...	425526.0610361...
11	2017-02-20 00:0...	2017-02-24 00:0...	437049.5835055...
12	2017-02-25 00:0...	2017-03-01 00:0...	439887.7004801...
13	2017-03-02 00:0...	2017-03-06 00:0...	419193.0120225...
14	2017-03-07 00:0...	2017-03-11 00:0...	426363.5883385...
15	2017-03-12 00:0...	2017-03-16 00:0...	429044.7787699...
16	2017-03-17 00:0...	2017-03-21 00:0...	394114.9705215...
17	2017-03-22 00:0...	2017-03-26 00:0...	399274.1936229...
18	2017-03-27 00:0...	2017-03-31 00:0...	416198.6948213...
19	2017-04-01 00:0...	2017-04-05 00:0...	426905.0502807...
20	2017-04-06 00:0...	2017-04-10 00:0...	417204.1418188...
21	2017-04-11 00:0...	2017-04-15 00:0...	412119.7611839...
22	2017-04-16 00:0...	2017-04-20 00:0...	428509.86304837
23	2017-04-21 00:0...	2017-04-25 00:0...	413531.8788968...
24	2017-04-26 00:0...	2017-04-30 00:0...	409755.3487856...

Figure 3.12: Input data Database

a. Tbl_Technology: have Tech_Id and Tech-type as attributes to identify plants in to respective technologies namely Hydro, Wind, Geothermal, Biomass, Energy from waste, Sugar factories Co-generation and Thermal backup.

b. Tbl_Plant: Uses Plant_ID and Tech_ID as attributes to give unique ID to each plant and relate each plant to corresponding technology respectively. It also assigns capital, operational and fuel cost to every plant through Op_cost, Cap_cost and Fuel_cost identifications. Existing and committed/candidate plants as well as hydro plants with or without reservoirs are identified in this table. Hydro specific data like initial volume, minimum volume, maximum volume and productivity are assigned to each hydro plant using this table. Yearly_CF contains capacity factor values to plants (technologies) not varying significantly with season.

c. Tbl_Plants_Capacity: This table provides installed and dependable capacity of every plant together with the commissioning & retirement time useful to limit plants availability as well as capacity.

d. Tbl_Load: For the 5 daily simulation start & end days date together with the respective load in that day and for the hourly simulation date, time and load on that specific time are provided for the optimization program from this table.
e. Tbl_Inflow: Reservoirs total inflow based on start & end dates for both 5 daily and hourly simulation time steps are stored in this table.
f. Tbl_EV_IR: Similar to Tbl_Inflow with the exception that the data in this table is evaporation and irrigation of respective reservoirs.
g. Tbl_Irrigation_after_plant: Irrigation (water demand) that happens after generating electricity, like Fincha and Neshe, is available in this table.
h. Tbl_Seasonal_Variation: Plants with varying seasonal availability, like Tis Abay I & II, all sugar factories Co-generation and biomass plants, is addressed in this table with the attribute Monthly_CF. Start and end date are used to specify the period in which that monthly_CF value is applied.
i. Tbl_Upstream: Specifies relationship between upstream and downstream reservoirs/plants with respective time delays.
j. Tbl_wind_actual_output: Wind plants actual hourly as well as 5 daily output, for the respective hourly and 5 daily simulation time steps, is registered in this table.
k. Tbl_finvol_energy limit: This table is only applied for hourly simulation time step in which outputs of 5 daily simulation time step (energy, water discharge and reservoir level targets) are provided as input for the hourly simulation. Outputs from 5 daily simulations are mapped in to the hourly simulation using start and end date as well as respective plant_ID.

CHAPTER 4
MODELING AND SIMULATION

4.1. Modeling

As discussed in section 3.2, this study developed two parallel models, namely Energy and Hourly models, which have been used to represent the reference year (2017 G.C) Ethiopian power system. These optimization models run based on cost minimizing objectives subjected to technology specific constraints (reservoir simulation, upstream/downstream relationships and wind power priority to grid), transmission and distribution losses, reserve for reliability while satisfying electricity demand, capacity limit for each plant and irrigation demand at any given time. The following general assumptions and scope limitation are made during model formulation:

- Only power plants within the ICS (Inter connected power system) are considered in this study, thus SCS (Self-contained system) is excluded.
- Load (Demand) is assumed constant during the smallest time step (interval).
- Head is assumed constant (not varying with time) for each hydropower plant.
- All committed and candidate plants are assumed to be available according to earliest online year.

In the following, mathematical formulations of the objective function as well as constraints together with respective operational policies are explained. In this section, we focus on description of variables and parameters involved in the model formulation.

T : Total number of time steps in the energy model i.e. 73;

t : is an index starting at 1 and ending at T;

H : Total number of time steps in the hourly model i.e. 120;

h : is an index starting at 1 and ending at H;

J : Total number of power plants considered i.e. 40;

j : is an index starting at 1 and ending at J;

c_{Cj} : Capital unit cost of a committed or candidate plant j [\$/KW/Year];

o_{cj} : Operational and maintenance unit cost of existing or committed or candidate plant j [\$/MWh];

f_{cj} : Fuel unit cost of existing or committed or candidate plant j [\$/MWh];

$\mathbf{E_{ccj,t}}$: Generation of committed or candidate plant j during period t [MWh];

$\mathbf{E_{ej,t}}$: Generation of existing plant j during period t [MWh];

$\mathbf{P_{ccj,t}}$: Generation of committed or candidate plant j during period t [MW];

$\mathbf{P_{ej,t}}$: Generation of existing plant j during period t [MW];

dem_t : Forecasted demand during period t including losses [MWh];

p_{minj} & p_{maxj} : Minimum and Maximum dependable power output of plant j, respectively [MW];

e_{minj} & e_{maxj}: Minimum and maximum dependable energy output of plant j, respectively [MWh].

β : Percentage of power demand during period t to be used as reserve [%];

R : Total Number of reservoirs considered i.e. 11;

r : is an index starting at 1 and ending at R;

$\mathbf{V_{r,t}}$: Final storage volume of reservoir r at time period t [Mm^3];

$\mathbf{V_{r,t-1}}$: Final storage volume of reservoir r at time period $\mathrm{t}-1$ OR Starting (Initial) storage Volume of reservoir r at time period t [Mm^3];

$i_{n,r,t}$: Natural inflow of reservoir r during period t [m^3/s];

$\mathbf{Q_{j,t}}$: Turbined flow (Discharge) from power plant j during period t [m^3/h];

$\mathbf{S_{r,t}}$: Spilled flow from reservoir r during period t [m^3/h];

$e_{r,t}$: Evaporation loss from reservoir r during period t [mm/month];

$i_{r,r,t}$: Irrigation (Water demand) from reservoir r during period t [m^3/s];

d : Represents the time delay for water to reach from upstream reservoir/plant to downstream reservoir/ plant [h];

γ_j : Productivity coefficient of power plant j [MW/(m^3/s)];

p_{instj} : Installed capacity of plant j [MW];

cf : Capacity factor of plant j [%];

$e_{\,Wind\,sim,j,t}$: Simulated energy output of wind plant j during period t [MWh];

$p_{Wind\,sim,j,t}$: Hourly power output of wind plant j during period t [MW];

q_{minj} & q_{maxj} : Minimum and maximum water discharge of plant j respectively [m^3/h or m^3/5-days];

s_{minr} & s_{maxr} : Minimum and maximum spill of reservoir r respectively [m^3/h or m^3/5-days];

v_{minr} & v_{maxr} : Minimum and maximum storage volume of reservoir r respectively [Mm^3];

4.1.1. Energy Model

The energy model is made of objective function and constraints that define the Ethiopian power system for a year horizon (2017G.C) on a consecutive 5 day time step basis. This model produces optimized energy dispatch for all time steps in 2017G.C. The decision variables are $\mathbf{E_{ccj,t}}$ (Generation of committed or candidate plant j during period t [MWh]), $\mathbf{E_{ej,t}}$ (Generation of existing plant j during period t [MWh]), $\mathbf{V_{r,t}}$ (Final storage volume of reservoir r at time period t [m^3]), $\mathbf{Q_{j,t}}$ (Turbined flow (Discharge) from power plant j during period t [m^3/5-days]) and $\mathbf{S_{r,t}}$ (Spilled flow from reservoir r during period t [m^3/5-days]).

4.1.1.1. Objective function

The objective function to be minimized comprises operation and maintenance, fuel and annual capital costs of all power plants considered for the year 2017 G.C. Annual capital costs are only considered for committed and candidate plants whereas fuel and O & M costs are applied to all plants. Annual capital cost is given in $/KW/year but as O & M costs are given in $/MWh a need arises for unit consistency. Accordingly the conversion to $/MWh is done by dividing the value in $/MW with the total number of hours in a year as it is annual cost. This is done inside the developed MATLAB program. Details of each cost component are discussed in section 3.4.9. The objective function can be described as:

$$\begin{aligned} \mathrm{F} = (&\mathrm{Annual\ cap}ital\ cost\ of\ committed\ and\ candidate\ plants) \\ &+ (Annual\ Operational\ and\ maintenance\ cost\ of\ all\ plants) \\ &+ (Annual\ fuel\ cost\ of\ all\ plants) \end{aligned}$$

$$\mathrm{F} = \left(\text{Capital unit cost } \left(\frac{\$}{\text{MWh}}\right) * \text{Generation from committed and candidate plants (MWh)}\right) + \left(\left(\text{O \& M unit cost}\left(\frac{\$}{\text{MWh}}\right) + \text{fuel unit cost } \left(\frac{\$}{\text{MWh}}\right)\right) * \text{Generation from all plants (MWh)}\right)$$

Thus the objective function can be put as:

$$F = \sum_{t=1}^{T} \left[\sum_{j=1}^{J} \left[c_{cj} * \mathbf{E_{ccj,t}} \right] + \sum_{j=1}^{J} \left[\left(o_{cj} + f_{cj} \right) * \left(\mathbf{E_{ej,t}} + \mathbf{E_{ccj,t}} \right) \right] \right] \qquad --- \qquad (4.1)$$

$$F = \sum_{t=1}^{T} \left[\sum_{j=1}^{J} \left[\left(c_{cj} + o_{cj} + f_{cj} \right) * \mathbf{E_{ccj,t}} \right] + \sum_{j=1}^{J} \left[\left(o_{cj} + f_{cj} \right) * \left(\mathbf{E_{ej,t}} \right) \right] \right] \qquad --- \qquad (4.2)$$

And the objective of the problem is minimizing F which can mathematically be defined as:

$$\begin{aligned} \text{Minimize } F = \min \sum_{t=1}^{T} \Bigg[& \sum_{j=1}^{J} \left[\left(c_{cj} + o_{cj} + f_{cj} \right) * \mathbf{E_{ccj,t}} \right] + \sum_{j=1}^{J} \left[\left(o_{cj} + f_{cj} \right) * \left(\mathbf{E_{ej,t}} \right) \right] \\ & + \sum_{hy=1}^{HY} \left[(zero) * \left(\mathbf{Q_{j,t}} \right) \right] + \sum_{r=1}^{R} \left[(zero) * \left(\mathbf{S_{r,t}} + \mathbf{V_{r,t}} \right) \right] \Bigg] \qquad ---- \qquad (4.3) \end{aligned}$$

Where: HY : Total number of hydropower plants considered i.e., 16;

hy : Is an index starting at 1 and ending at HY;

This objective seeks the possible minimization of capital, operational & maintenance and fuel costs for power generation activities. Note that variables $\mathbf{Q_{j,t}}$, $\mathbf{S_{r,t}}$ and $\mathbf{V_{r,t}}$ are included in equation 4.3 with zero coefficients so as to make variables available in both constraint and objective functions.

4.1.1.2. Constraints

As classified in section 2.2 this study consists of system and unit constraints. This section customizes and describes both types in great depth.

4.1.1.2.1. System Constraints

Load balance: This constraint has been adopted from the one in equation 2.1.

$$\sum_{j=1}^{J} \left[\mathbf{E_{ccj,t}} + \mathbf{E_{ej,t}} \right] = dem_t \qquad ------------------ \qquad (4.4)$$

And $dem_t = consumed\ power_t + loss_t$

As explained in section 3.4.5., the load (demand) forecast adopted from EEPCo generation expansion master plan includes losses. Loss at some period t is taken as percentage of power dispatched during that period. Energy losses for 2007,2008,2009,2010, 2011 and 2012 G.C. have been 22%, 20%, 21%, 18%, 18% and 17% respectively out of which transmission losses make up 4%, distribution losses 10-12% and non-technical losses the remainder. Considering EEPCo loss reduction programs the generation expansion master adopted technical loss (transmission and distribution losses) of 12 – 14% and non-technical loss of 1% which comes to a total loss in the range of 13 to 15% [3,12].

Reserve requirements (Demand satisfaction): This constraint has been adopted from the one in equation 2.2. For the 5-daily simulation time step, though not very important, average power is used to assure reserve capacity and the above equation is modified as follows.

$$\sum_{j=1}^{J}[\mathrm{p}_{\mathrm{max}j} - \frac{\mathbf{E}_{\mathbf{ccj,t}} + \mathbf{E}_{\mathbf{ej,t}}}{\text{No. of hrs in one time step}}] \geq \beta * \frac{\mathrm{dem}_t}{\text{No. of hrs in one time step}} \qquad ---- \qquad (4.5)$$

Where: $No.of\ hrs\ in\ one\ time\ step = 5 * 24 = 120hrs$

Generally it is recommended to take a 15 - 25% reserve for thermal dominant power systems whereas only 15% is recommended for hybrid systems [15]. As Ethiopia has a hydro dominated power system and choosing the conservative figure, 15% is taken as a reasonable reserve percentage for this study.

4.1.1.2.2. Unit Constraints

Hydraulic continuity: As discussed in section 3.4.2 and shown on Hydro system model diagram (Figure 3.4) four distinct types of hydraulic relationships exist between plants and reservoirs with own mathematical expressions as explained below. Mathematical expression of this category of constraint is derived from equation 2.3.

I. **Hydropower plants with reservoir and having no upstream reservoir**: This category of hydropower plants have no upstream downstream relationship and includes Fincha, Melkawakena, Tekeze, GG I, Amerti neshe, Koka, Sor 1, GG III, GD III and GERD. The Hydraulic continuity equation for such type of reservoirs/plants can be put as follows.

$$\mathbf{V}_{\mathbf{r,t}} = \mathrm{V}_{\mathrm{r,t-1}} + \mathrm{i}_{\mathrm{n,r,t}} - \mathbf{Q}_{\mathbf{j,t}} - \mathbf{S}_{\mathbf{r,t}} - \mathrm{e}_{\mathrm{r,t}} - \mathrm{i}_{\mathrm{r,r,t}} \qquad ---------- \qquad (4.6)$$

$\mathbf{V_{r,t}}$, $\mathbf{Q_{j,t}}$ and $\mathbf{S_{r,t}}$ are decision variables whose values are to be determined after optimizing the problem while the remaining are parameters whose definition and respective values are discussed in chapter three. $i_{r,r,t}$ represents water demands (Irrigation) directly addressed from a reservoir. Fincha reservoir is the only, from 10 reservoirs under this category, having such a demand. To keep unit consistency Mm^3, m^3/s and mm/month are all converted to m^3 as per the explanation in sections 3.4.6 and 3.4.7.

II. **Hydropower plants sharing a reservoir**: Here Tana Beles, Tis Abay I and Tis Abay II share Lake Tana. The hydraulic continuity equation is very similar to equation 4.6 with the only difference that sum of the discharge from all three power plants is deducted from Lake Tana whereas all other parameters are only properties of Lake Tana. Thus the equation becomes:

$$\mathbf{V_{r,t}} = \mathrm{V_{r,t-1}} + \mathrm{i_{n,r,t}} - \sum_{i=1}^{I} \mathbf{Q_{i,t}} - \mathbf{S_{r,t}} - \mathrm{e_{r,t}} - \mathrm{i_{r,r,t}} \qquad --------- \qquad (4.7)$$

Where: I : Number of total power plants to be fed from reservoir r;

i : Is an index starting at 1 and ending at I;

Lake Tana has similar water demand for irrigation, directly from reservoir, like Fincha reservoir in the previous condition.

III. **Hydropower plants with no reservoir and having upstream reservoir**: GG II and Awash I with their respective up-streams GG I and Koka belong to this group. The hydraulic continuity can mathematically be given as:

$$\mathbf{Q_{j,t}} \leq \sum_{u=1}^{U} [\mathbf{Q_{u,t}} + \mathbf{S_{u,t}}] \qquad ------------------ \qquad (4.8)$$

Where: j : Downstream hydropower plant relating to set of upstream reservoirs U;

U : Total number of upstream reservoirs to plant j;

u : is an index starting at 1 and ending at U;

IV. **Hydropower plants with no reservoir and having upstream plant with no reservoir**: Awash II with its respective upstream Awash I belongs to this group. This condition has no reservoir and only discharges between the upstream and downstream plants need to balance.

$$\mathbf{Q_{j,t}} \leq \sum_{u_p=1}^{U_p} [\mathbf{Q_{u_p,t}}] \qquad ---------------------- \qquad (4.9)$$

Where: j : Downstream hydropower plant relating to set of upstream plants U_p;

U_p : Total number of upstream plants to plant j;

u_p : is an index starting at 1 and ending at U_p;

Minimum total outflow limit: In this study irrigation is the only water demand considered and water demands that happen after electricity generation, which determine the minimum outflow of the power plant, are categorized under this constraint. Neshe irrigation and Beles irrigation are grouped here as both depend on water discharge from Amerti neshe and Tana beles power plants respectively. Mathematical expression similar to equation 2.4 is used for this constraint.

$$\mathbf{Q_{j,t}} + \mathbf{S_{r,t}} \geq o_{f,t} \qquad ---------------------- \qquad (4.10)$$

Where: $o_{f,t}$: Minimum total outflow from plant j during period t [m^3/s].

Reservoir Steady-state condition: Under this constraint reservoir volume at the end of the last time step should be equal or greater than reservoir volume at the start of the first time step (initial volume). Mathematical expression similar to the one used in equation 2.5 is given as:

$$\mathbf{V_{r,T}} \geq v_{r,t=0} \qquad ------------------------ \qquad (4.11)$$

Where: $\mathbf{V_{r,T}}$: Final storage volume of reservoir r at the last time period t [Mm^3];

$v_{r,t=0}$: Final storage volume of reservoir r before first period $(t = 0)$ OR Starting (Initial) storage volume of reservoir r at first period $(t = 1)$ [Mm^3].

Hydraulic productivity limit: This constraint uses the basic formulation shown in equation 2.6. The same equation is used with only few modifications for unit consistency as shown below.

$$\frac{\mathbf{E_{ccj,t}} \text{ or } \mathbf{E_{ej,t}}}{\text{No of hours in one time step}} = \gamma_j * \frac{\mathbf{Q_{j,t}}}{\text{No of seconds in one time step}} \quad - \quad (4.12)$$

Where: $\text{No of hours in one time step} = 5 * 24 = 120 \text{ hs}$

$$No.\,of\ seconds\ in\ one\ time\ step = 60 * 60 * 120 = 432{,}000\ seconds$$

Energy production limit: This constraint puts resource limitation, like water and wind, as well as forced outages, seasonality and scheduled maintenance in to the optimization exercise. As discussed in sections 3.4.3 and 3.4.4 all hydro plants (except Tis abay I and II), Aluto langano I and Corbetti geothermal, Addis Ababa energy from waste and Thermal backup plants have a yearly capacity factor which determines the amount of energy that can possibly be harnessed from each technology. It can be expressed as:

$$\sum_{t=1}^{T}[\mathbf{E_{ccj,t}} + \mathbf{E_{ej,t}}] \leq \text{cf} * \text{p}_{\text{instj}} * \text{No of hrs in full time horizon} \quad --- \quad (4.13)$$

Where: $No.\,of\ hours\ in\ the\ full\ time\ horizon = 73 * 5 * 24 = 8760\ hrs$

All Sugar factories co-generation power plants, Tis Abay I and II hydropower plants as well as biomass plants (Bamza and Meikasedi) exhibit seasonal properties as discussed in section 3.4.4. Sugar factories co-generation and biomass plants are unavailable from June to September during off crop season while Tis Abay I and II are available during the same period to avoid Tana lake spillage. Accordingly the equations are divided into three seasons: January to May, June to September and October to December respectively.

$$\sum_{t=1}^{T_1}[\mathbf{E_{ccj,t}} + \mathbf{E_{ej,t}}] \leq \text{cf}_1 * \text{p}_{\text{instj}} * \text{No of hrs in full time horizon}_1 \quad --- \quad (4.14)$$

$$\sum_{t=T_1+1}^{T_2}[\mathbf{E_{ccj,t}} + \mathbf{E_{ej,t}}] \leq \text{cf}_2 * \text{p}_{\text{instj}} * \text{No of hrs in full time horizon}_2 \quad -- \quad (4.15)$$

$$\sum_{t=T_2+1}^{T}[\mathbf{E_{ccj,t}} + \mathbf{E_{ej,t}}] \leq \text{cf}_3 * \text{p}_{\text{instj}} * \text{No of hrs in full time horizon}_3 \quad -- \quad (4.16)$$

Where: T_1 : Number of total time steps considered from January to May (30);

T_2 : Number of total time steps considered from June to September (24);

T : Number of total time steps considered from October to December (19);

cf_1, cf_2, cf_3 : Capacity factor of plant j during period 1, 2 and 3 [%];

$$No\ of\ hrs\ in\ full\ time\ horizon_1 = T_1 * 120 = 3600\ hrs$$

$$No\ of\ hrs\ in\ full\ time\ horizon_2 = (T_2 - T_1) * 120 = 2880\ hrs$$

$$No\ of\ hrs\ in\ full\ time\ horizon_3 = (T - T_2) * 120 = 2280\ hrs$$

Wind plants priority to Grid: This constraint makes sure the simulated wind energy output (explained in section 3.4.8) equals the wind energy dispatched for a given wind power plant in similar 5 days interval. Mathematical formulation of this constraint is similar to the one shown in equation 2.7and is given as:

$$\mathbf{E}_{\mathbf{ccj,t}} \text{ or } \mathbf{E}_{\mathbf{ej,t}} = \mathrm{e}_{\mathrm{Wind\ sim,j,t}} \qquad -------------- \qquad (4.17)$$

Generation capacity, water discharge, spill and storage limits: In this study the decision variables, $\mathbf{E}_{\mathbf{ccj,t}}, \mathbf{E}_{\mathbf{ej,t}}, \mathbf{Q}_{\mathbf{j,t}}, \mathbf{S}_{\mathbf{r,t}}$ and $\mathbf{V}_{\mathbf{r,t}}$, are all bounded using lower and upper bounds. Generation capacity limits, $e_{\mathrm{minj}}\ and\ e_{\mathrm{maxj}}$, fix the minimum and maximum energy production of plant j depending on the power plant capacity and reliability. $q_{minj} and\ q_{maxj}$, water discharge bounds, limits the minimum and maximum discharge a plant can make taking in to consideration turbine physical limits while $s_{minr}\ and\ s_{maxr}$ limit the minimum and maximum spill a reservoir can make. In addition a reservoir is allowed to operate between minimum and maximum operating volumes labeled $v_{minr}\ and\ v_{maxr}$ respectively.

e_{minj} is set to zero for all plants while e_{maxj} is the maximum dependable energy from Table 3.3. q_{minj} is zero for all hydro plants while q_{maxj} is calculated from p_{maxj} and respective productivity coefficient. s_{minr} is also zero but s_{maxr} is more than 65% of v_{maxr} to use the active volume as maximum spill target. v_{minr} and v_{maxr} are provided in Table 3.4. Mathematical expressions of these constraints are similar to those explained in equation 2.8, 2.9, 2.10 and 2.11.

$$\mathrm{e}_{\mathrm{minj}} \le \mathbf{E}_{\mathbf{ccj,t}} \le \mathrm{e}_{\mathrm{maxj}} \qquad ---------------- \qquad (4.18)$$

$$\mathrm{e}_{\mathrm{minj}} \le \mathbf{E}_{\mathbf{ej,t}} \le \mathrm{e}_{\mathrm{maxj}} \qquad ---------------- \qquad (4.19)$$

$$\mathrm{q_{minj}} \leq \mathbf{Q_{j,t}} \leq \mathrm{q_{maxj}} \qquad ----------------- \qquad (4.20)$$

$$\mathrm{s_{minr}} \leq \mathbf{S_{r,t}} \leq \mathrm{s_{maxr}} \qquad ----------------- \qquad (4.21)$$

$$\mathrm{v_{minr}} \leq \mathbf{V_{r,t}} \leq \mathrm{v_{maxr}} \qquad ----------------- \qquad (4.22)$$

Overflow (Spill) estimation: The overflow occurs when the final storage exceeds the reservoir capacity and can be estimated using the following equation as constraint:

$$\mathbf{S_{r,t}} = \max\left[\left(\mathbf{V_{r,t}} - \mathrm{v_{maxr}}\right), 0\right] \qquad --------------- \qquad (4.23)$$

$$\mathbf{V_{r,t}} = \mathrm{v_{maxr}} \quad \text{if } \mathbf{S_{r,t}} \geq 0 \qquad --------------- \qquad (4.24)$$

This constraint shows the conditional relationship between reservoir maximum storage capacity and spill amount. Spill occurs only when reservoir volume passes the maximum set storage volume otherwise spill is set to zero.

4.1.2. Hourly Model

The hourly model bases on the result of the energy model to assure optimized power dispatch for every 5 days simulation horizon. It contains objective function and constraints that define the problem on hourly time step basis. The decision variables are $\mathbf{P_{ccj,h}}$ (Generation of committed or candidate plant j during period h [MW]), $\mathbf{P_{ej,h}}$ (Generation of existing plant j during period h [MW]), $\mathbf{V_{r,h}}$ (Final storage volume of reservoir r at time period h [m^3]), $\mathbf{Q_{j,h}}$ (Turbined flow (Discharge) from power plant j during period h [m^3/h]) and $\mathbf{S_{r,t}}$ (Spilled flow from reservoir r during period h [m^3/h]).

4.1.2.1. Objective function

The objective function minimizes operation and maintenance, fuel and annual capital costs of all power plants for all 5 day simulation horizons. The number of hourly time steps for a 5 day optimization horizon is 120. Similar objective function formulation to the energy model has been applied and the resulting equation is given as:

$$
\begin{aligned}
Minimize\ F = min \sum_{h=1}^{H}\Bigg[\sum_{j=1}^{J}\big[(c_{cj} + o_{cj} + f_{cj}) * \mathbf{P_{ccj,h}}\big] + \sum_{j=1}^{J}\big[(o_{cj} + f_{cj}) * (\mathbf{P_{ej,h}})\big] \\
+ \sum_{hy=1}^{HY}\big[(zero) * (\mathbf{Q_{j,h}})\big] + \sum_{r=1}^{R}\big[(zero) * (\mathbf{S_{r,h}} + \mathbf{V_{r,h}})\big]\Bigg] \quad ---- \quad (4.25)
\end{aligned}
$$

4.1.2.2. Constraints

4.1.2.2.1. System Constraints

Load balance: Equation formulation as well as parameters used has been identical to the ones in the energy model but $\mathbf{P_{ccj,t}}$ and $\mathbf{P_{ej,t}}$ have been used in the hourly model load balance constraint as shown in equation 4.26.

$$
\sum_{j=1}^{J}[\mathbf{P_{ccj,h}} + \mathbf{P_{ej,h}}] = \mathrm{dem_h} \qquad ----------------- \qquad (4.26)
$$

Reserve requirements (Demand satisfaction): Considering similar reserve percentage as the one used in the energy model, the hourly model reserve requirement constraint is used to check if the reserve percentage can be maintained during peak load hours.

$$
\sum_{j=1}^{J}[\mathrm{p_{maxj}} - [\mathbf{P_{ccj,h}} + \mathbf{P_{ej,h}}]] \geq \beta * \mathrm{dem_h} \qquad ---------- \qquad (4.27)
$$

For easy understanding the two system constraints can graphically be described as shown in Figure 4.1. It can clearly be seen that the loss and reserve amounts keep the balance between consumed power during period h and maximum power output capacity by all power plants.

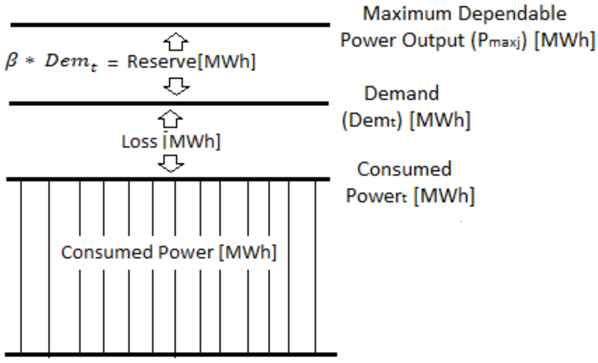


Figure 4.1: Load balance and reserve requirement

Note that p_{maxj} is the dependable maximum power output that can possibly be generated by power plant j.

4.1.2.2.2. Unit Constraints

Hydraulic continuity: The Hydro system model diagram shown in Figure 3.4 governs hydraulic relationship between reservoirs and hydropower plants. Types of hydraulic relationships that exist between plants and reservoirs take the same form as used for the Energy model. The Hourly model takes in to consideration the time delay that takes the water to reach from upstream to downstream reservoir as given in Table 3.5. Mathematical expression of each relationship category is described below:

I. **Hydropower plants with reservoir and having no upstream reservoir**:

$$\mathbf{V_{r,h}} = V_{r,h-1} + i_{n,r,h} - \mathbf{Q_{j,h}} - \mathbf{S_{r,h}} - e_{r,h} - i_{r,r,h} \qquad --------- \qquad (4.28)$$

II. **Hydropower plants sharing a reservoir**:

$$\mathbf{V_{r,h}} = V_{r,h-1} + i_{n,r,h} - \sum_{i=1}^{I} \mathbf{Q_{i,h-d}} - \mathbf{S_{r,h}} - e_{r,h} - i_{r,r,h} \qquad ------ \qquad (4.29)$$

Where: I : Number of total power plants to be fed from reservoir r;

i : Is an index starting at 1 and ending at I;

Time delays for Tis Abay I and Tis Abay II power plants are given in Table 3.5 but Tana beles power has no time delay as the power plant is close to Lake Tana.

III. **Hydropower plants with no reservoir and having upstream reservoir**: Corresponding time delays are given in Table 3.5 for the hourly model.

$$\mathbf{Q_{j,h}} \leq \sum_{u=1}^{U} [\mathbf{Q_{u,h-d}} + \mathbf{S_{u,h-d}}] \qquad ----------------- \qquad (4.30)$$

Where: j : Downstream hydropower plant relating to set of upstream reservoirs U;

U : Total number of upstream reservoirs to plant j;

u : is an index starting at 1 and ending at U;

IV. **Hydropower plants with no reservoir and having upstream plant with no reservoir**: The time delay between Awash I and II is given in Table 3.5.

$$\mathbf{Q_{j,h}} \leq \sum_{\mathrm{u_p}=1}^{\mathrm{U_p}} [\mathbf{Q_{u_p,h-d}}] \qquad ------------------ \qquad (4.31)$$

Where: j : Downstream hydropower plant relating to set of upstream plants U_p;

$\mathrm{U_p}$: Total number of upstream plants to plant j;

u_p : is an index starting at 1 and ending at U_p;

Minimum total outflow limit: Amerti neshe and Tana beles are linked with this constraint like the Energy model. Mathematical expression is given as follows:

$$\mathbf{Q_{j,h}} + \mathbf{S_{r,h}} \geq \mathrm{o_{f,h}} \qquad ------------------- \qquad (4.32)$$

Where: $o_{f,h}$: Minimum total outflow from plant j during period h [m^3/s].

Reservoir Steady-state condition: Optimized reservoir storage volumes found from the energy model, for each 5 days simulation time step, are used as targets for the respective Hourly model. In other words reservoir volume at the end of the last hour, in the Hourly model, should be equal or greater than the respective reservoir volume found in the energy model, for those similar 5days. For example consider Energy model for 2017G.C with 5 days resolution. In addition consider January 01, 2017 till January 05, 2017 to be the horizon for Hourly model. Thus the reservoir volume at the end hour of January 05, 2017 should be equal or greater than the volume found for the Energy model at the end of the period between January 01 and January 05. Accordingly for the hourly simulation time step the mathematical expression can be put as:

$$\mathbf{V_{r,H}} \geq \mathrm{v_{rtarget}} \qquad --------------------- \qquad (4.33)$$

Where: $\mathbf{V_{r,H}}$: Final storage volume of reservoir r at the last time period H [m^3];

$v_{r\mathrm{target}}$: Target storage volume of reservoir r at the end hour of 5 days optimization horizon, found from result of same period time step in a year optimization horizon [m^3].

Hydraulic productivity limit: For the hourly model this constraint can mathematically be given as:

$$\mathbf{P_{ccj,h}} \text{ or } \mathbf{P_{ej,h}} = \gamma_j * \frac{\mathbf{Q_{j,h}}}{\text{No of seconds in one time step}} \qquad ------ \qquad (4.34)$$

Where: $No.of\ seconds\ in\ one\ time\ step = 60 * 60 = 3600\ seconds$

Energy production limit: This constraint puts resource limitation, like water and wind, as well as forced outages, seasonality and scheduled maintenance in to the optimization exercise. Optimized energy output of a given time step in the energy model is used as a target to limit the energy production of the corresponding 5 day optimization horizon in the Hourly model and is given as:

$$\sum_{t=1}^{T} [\mathbf{P_{ccj,h}} + \mathbf{P_{ej,h}}] \leq \mathrm{en}_{\mathrm{tar,j}} \qquad ----------------- \qquad (4.35)$$

Where: $en_{tar,j}$: Optimized energy output of a one 5 daily time step, from a year horizon, of plant j [MWh].

Optimized water discharge output of a given time step in the energy model is used as a target to limit the water discharge of the corresponding 5 day optimization horizon in the Hourly model and is given as:

$$\sum_{t=1}^{T} \mathbf{Q_{j,h}} \leq \mathrm{dis}_{\mathrm{tar,j}} \qquad ------------------- \qquad (4.36)$$

Where: $dis_{tar,j}$: Optimized water discharge output of a one 5 daily time step, from a year horizon, of plant j [MWh].

Note that wind power plants energy limit is not considered in this constraint as simulated hourly energy output is used to best harness the available wind resource.

Wind plants priority to Grid: This constraint makes sure the simulated hourly wind power output (explained in section 3.4.8) equals the wind power dispatched for a given wind power plant in similar hour interval. Mathematical formulation of this constraint is given as:

$$\mathbf{P_{ccj,h}} \text{ or } \mathbf{P_{ej,h}} = \mathrm{p_{Wind\ sim,j,h}} \qquad -------------- \qquad (4.38)$$

Generation capacity, water discharge, spill and storage limits: The decision variables, $\mathbf{P_{ccj,h}}, \mathbf{P_{ej,h}}, \mathbf{Q_{j,h}}, \mathbf{S_{r,h}}$ and $\mathbf{V_{r,h}}$, are all bounded using lower and upper bounds. Generation capacity limits, p_{minj} and p_{maxj} fix the minimum and maximum power production of plant j depending on the power plant capacity and reliability. $q_{minj} and\ q_{maxj}$, water discharge bounds, limits the minimum and maximum discharge a plant can make taking in to consideration turbine physical limits while $s_{minr}\ and\ s_{maxr}$ limit the minimum and maximum spill a reservoir can make. In addition a reservoir is allowed to operate between minimum and maximum operating volumes labeled $v_{minr}\ and\ v_{maxr}$ respectively.

p_{minj} is set to zero for all plants while p_{maxj} is the maximum dependable power from Table 3.4. q_{minj} is zero for all hydro plants while q_{maxj} is calculated from p_{maxj} and respective productivity coefficient. s_{minr} is also zero but s_{maxr} is more than 65% of v_{maxr} to use the active volume as maximum spill target. v_{minr} and v_{maxr} are provided in Table 3.4. Mathematical expressions of these constraints are given below.

$$\mathrm{p_{minj}} \le \mathbf{P_{ccj,h}} \le \mathrm{p_{maxj}} \qquad ------------------- \qquad (4.39)$$

$$\mathrm{p_{minj}} \le \mathbf{P_{ej,h}} \le \mathrm{p_{maxj}} \qquad ------------------- \qquad (4.40)$$

$$\mathrm{q_{minj}} \le \mathbf{Q_{j,h}} \le \mathrm{q_{maxj}} \qquad ------------------- \qquad (4.41)$$

$$\mathrm{s_{minr}} \le \mathbf{S_{r,h}} \le \mathrm{s_{maxr}} \qquad ------------------- \qquad (4.42)$$

$$\mathrm{v_{minr}} \le \mathbf{V_{r,h}} \le \mathrm{v_{maxr}} \qquad ------------------- \qquad (4.43)$$

Overflow (Spill) estimation: This constraint takes the same form as that of the Energy model.

$$\mathbf{S_{r,h}} = \max\left[(\mathbf{V_{r,h}} - \mathrm{v_{maxr}}), 0\right] \qquad ------------- \qquad (4.44)$$

$$\mathbf{V_{r,h}} = \mathrm{v_{maxr}} \quad \text{if } \mathbf{S_{r,h}} \ge 0 \qquad ------------- \qquad (4.45)$$

4.2. Problem Formulation and Model dimensions

4.2.1. Problem formulation

As can be seen in sections 4.1.1 and 4.1.2 both the objective function as well as constraints are only linear equations thus the whole problem is based on a linear formulation. Linear problem can be defined as the problem of finding a vector x that minimizes a linear function $f^T x$ subject to linear constraints or expressed as:

$$\min_{x} f^{T}x \text{ such that } \begin{cases} A.x \leq b, \\ A_{eq}.x = b_{eq}, \\ lb \leq x \leq ub. \end{cases} \qquad -------------- \qquad (4.46)$$

Where: Problem f : Linear objective function vector f

$(.)^T$: Matrix transpose of the objective function known coefficients

x : Vector length of decision variables

A : Matrix of linear inequality constraints

b : Vector of linear inequality constraints

A_{eq} : Matrix of linear equality constraints

b_{eq} : Vector of linear equality constraints

lb : Vector of lower bounds

ub : Vector of upper bounds

As can be seen above in sections 4.1.1 & 4.1.2, constraint equations are many in numbers and not organized. Accordingly, for easy understanding, constraints are categorized in to equality, inequality and lower & upper bound constraints and the formulated problem is summarized as below, for both energy and hourly models. Note that values of parameters used in these models are all discussed in chapter three.

i. **Energy model**: Minimization of cost subjected to operational constraints for a year horizon with 5 days simulation time step is formulated as shown below.

$$Minimize\ F = min \sum_{t=1}^{T} \left[\sum_{j=1}^{J} \left[(c_{cj} + o_{cj} + f_{cj}) * \mathbf{E_{ccj,t}} \right] + \sum_{j=1}^{J} \left[(o_{cj} + f_{cj}) * (\mathbf{E_{ej,t}}) \right] + \sum_{hy=1}^{HY} \left[(zero) * (\mathbf{Q_{j,t}}) \right] + \sum_{r=1}^{R} \left[(zero) * (\mathbf{S_{r,t}} + \mathbf{V_{r,t}}) \right] \right] \quad ---- \quad (4.47)$$

Subject to:

Equality Constraints are summarized below.

Load balance

$$\sum_{j=1}^{J} [\mathbf{E_{ccj,t}} + \mathbf{E_{ej,t}}] = \mathrm{dem_t}, \qquad \text{for all power plants} \qquad ---- \quad (4.48)$$

Hydropower plants with reservoir and having no upstream reservoir

$$\mathbf{V_{r,t}} - \mathrm{V_{r,t-1}} + \mathbf{Q_{j,t}} + \mathbf{S_{r,t}} = \mathrm{i_{n,r,t}} - \mathrm{e_{r,t}} - \mathrm{i_{r,r,t}}, \ \text{for all hydropower plants in this category} \quad -- \quad (4.49)$$

Hydropower plants sharing a reservoir

$$\mathbf{V_{r,t}} - \mathrm{V_{r,t-1}} + \sum_{i=1}^{I} \mathbf{Q_{i,t-d}} + \mathbf{S_{r,t}} = \mathrm{i_{n,r,t}} - \mathrm{e_{r,t}} - \mathrm{i_{r,r,t}}, \text{for all hydro plants in this category} \quad ---- \quad (4.50)$$

Hydraulic productivity limit

$$\frac{\mathbf{E_{ccj,t}}}{No\ of\ hours\ in\ one\ time\ step} - \left(\gamma_j * \frac{\mathbf{Q_{j,t}}}{No\ of\ seconds\ in\ one\ time\ step} \right) = 0, for\ comm. \&\ cand. hydro \quad - \quad (4.51)$$

$$\frac{\mathbf{E_{ej,t}}}{No\ of\ hours\ in\ one\ time\ step} - \left(\gamma_j * \frac{\mathbf{Q_{j,t}}}{No\ of\ seconds\ in\ one\ time\ step} \right) = 0, for\ existing\ hydro \quad -- \quad (4.52)$$

$[No\ of\ hours\ in\ one\ time\ step = 5 * 24 = 120\ \ and\ \ No. of\ seconds\ in\ one\ time\ step = 60 * 60 * 120 = 432{,}000]$

Wind power plants priority to grid

$$\mathbf{E_{ccj,t}} = \mathrm{e}_{\mathrm{Wind\ sim},j,t}, \text{for committed and candidate wind power plants} \quad --- \quad (4.53)$$

$$\mathbf{E_{ej,t}} = \mathrm{e}_{\mathrm{Wind\ sim},j,t}, \quad \text{for existing wind power plants} \quad ------ \quad (4.54)$$

Inequality Constraints are summarized below.

Reserve requirements

$$\sum_{j=1}^{J} \frac{\mathbf{E_{ccj,t}}+\mathbf{E_{ej,t}}}{No.of\ hrs\ in\ one\ time\ step} \leq \sum_{j=1}^{J}\left[p_{maxj} - \left(\beta * \frac{dem_t}{No.of\ hrs\ in\ one\ time\ step}\right)\right], for\ all\ plants -- (4.55)$$

$[No.of\ hrs\ in\ one\ time\ step = 5 * 24 = 120hrs]$

Energy production limit

$$\sum_{t=1}^{T}[\mathbf{E_{ccj,t}} + \mathbf{E_{ej,t}}] \leq \mathrm{cf} * \mathrm{p_{instj}} * \text{No of hrs in full time horizon} \quad ---- \quad (4.56)$$

$for\ all\ geothermal\ EFW, thermal\ and\ most\ hydro\ power\ plants$

$[No.\ of\ hours\ in\ the\ full\ time\ horizon = 73 * 5 * 24 = 8760]$

$$\sum_{t=1}^{T_1}[\mathbf{E_{ccj,t}} + \mathbf{E_{ej,t}}] \leq \mathrm{cf_1} * \mathrm{p_{instj}} * \text{No of hrs in full time horizon}_1, \quad --- \quad (4.57)$$

$for\ all\ biomass, Sugar\ factories\ co - generation\ and\ two\ hydro\ power\ plants$

$$\sum_{t=T_1+1}^{T_2}[\mathbf{E_{ccj,t}} + \mathbf{E_{ej,t}}] \leq \mathrm{cf_2} * \mathrm{p_{instj}} * \text{No of hrs in full time horizon}_2 \quad --- (4.58)$$

$$\sum_{t=T_2+1}^{T}[\mathbf{E_{ccj,t}} + \mathbf{E_{ej,t}}] \leq \mathrm{cf_3} * \mathrm{p_{instj}} * \text{No of hrs in full time horizon}_3 \quad --- (4.59)$$

$[No\ of\ hrs\ in\ time\ horizon_1 = 3600,\ No\ of\ hrs\ in\ time\ horizon_2 = 2880,\ No\ of\ hrs\ in\ time\ horizon_3 = 2280]$

Hydropower plants with no reservoir and having upstream reservoir

$$\mathbf{Q_{j,t}} - \sum_{u=1}^{U}[\mathbf{Q_{u,t-d}} + \mathbf{S_{u,t-d}}] \leq 0, \text{for all hydropower plants in this category} \quad -- \quad (4.60)$$

Hydropower plants with no reservoir and having upstream plant with no reservoir

$$\mathbf{Q_{j,t}} - \sum_{u_p=1}^{U_p}[\mathbf{Q_{u_p,t-d}}] \leq 0, \text{ for all hydropower plants in this category} \quad --- \quad (4.61)$$

Minimum total outflow limit

$$-\mathbf{Q_{j,t}} - \mathbf{S_{r,t}} \leq -\mathrm{o_{f,t}}, \text{ for all hydropower plants in this category} \quad --- \quad (4.62)$$

Reservoir Steady-state condition

$$-\mathbf{V_{r,T}} \leq -\mathrm{v_{r,t=0}}\ , \text{ for all hydropower plants} \quad --------- \quad (4.63)$$

Lower and upper bound Constraints are summarized below.

Generation capacity, water discharge, spill and storage limits, $for\ all\ hydropower\ plants$

$$\mathrm{e_{minj}} \le \mathbf{E_{ccj,t}} \le \mathrm{e_{maxj}} \qquad ------------------ \qquad (4.64)$$

$$\mathrm{e_{minj}} \le \mathbf{E_{ej,t}} \le \mathrm{e_{maxj}} \qquad ------------------ \qquad (4.65)$$

$$\mathrm{q_{minj}} \le \mathbf{Q_{j,t}} \le \mathrm{q_{maxj}} \qquad ------------------ \qquad (4.66)$$

$$\mathrm{s_{minr}} \le \mathbf{S_{r,t}} \le \mathrm{s_{maxr}} \qquad ------------------ \qquad (4.67)$$

$$\mathrm{v_{minr}} \le \mathbf{V_{r,t}} \le \mathrm{v_{maxr}} \qquad ------------------ \qquad (4.68)$$

ii. **Hourly model**: Minimization of cost subjected to operational constraints for 5 days horizon with hourly simulation time step is formulated as follows.

$$Minimize\ F = min \sum_{h=1}^{H} \left[\sum_{j=1}^{J} \left[(c_{cj} + o_{cj} + f_{cj}) * \mathbf{P_{ccj,h}} \right] + \sum_{j=1}^{J} \left[\left(o_{cj} + f_{cj} \right) * (\mathbf{P_{ej,h}}) \right] + \sum_{hy=1}^{HY} \left[(zero) * (\mathbf{Q_{j,h}}) \right] + \sum_{r=1}^{R} \left[(zero) * (\mathbf{S_{r,h}} + \mathbf{V_{r,h}}) \right] \right] \quad --- \quad (4.69)$$

Subject to:

Equality Constraints are summarized below.

Load balance

$$\sum_{\mathrm{j=1}}^{\mathrm{J}} [\mathbf{P_{ccj,h}} + \mathbf{P_{ej,h}}] = \mathrm{dem_h}, \qquad \text{for all power plants} \qquad ----- \qquad (4.70)$$

Hydropower plants with reservoir and having no upstream reservoir

$$\mathbf{V_{r,h}} - \mathrm{V_{r,h-1}} + \mathbf{Q_{j,h}} + \mathbf{S_{r,h}} = i_{n,r,h} - e_{r,h} - i_{r,r,h}\ , for\ all\ hydro\ plants\ in\ this\ category \quad - \quad (4.71)$$

Hydropower plants sharing a reservoir

$$\mathbf{V_{r,h}} - \mathrm{V_{r,h-1}} + \sum_{\mathbf{i=1}}^{\mathbf{I}} \mathbf{Q_{i,h-d}} + \mathbf{S_{r,h}} = \mathrm{i_{n,r,h}} - \mathrm{e_{r,h}} - \mathrm{i_{r,r,h}}\ , \textbf{for all hydro plants in this category} \quad - \quad (\mathbf{4.72})$$

Hydraulic productivity limit

$$\mathbf{P_{ccj,h}} - \left(\gamma_j * \frac{\mathbf{Q_{j,h}}}{No\ of\ seconds\ in\ one\ time\ step}\right) = 0, for\ comm.and\ cand.hydro \quad --- \quad (4.73)$$

$$\mathbf{P_{ej,h}} - \left(\gamma_j * \frac{\mathbf{Q_{j,h}}}{No\ of\ seconds\ in\ one\ time\ step}\right) = 0, \quad for\ existing\ hydropower\ plants \quad -- \quad (4.74)$$

$[No. of\ seconds\ in\ one\ time\ step = 60 * 60 = 3{,}600]$

Wind power plants priority to grid

$$\mathbf{P_{ccj,h}} = \mathrm{p}_{\mathrm{Wind\ sim,j,h}}, \quad \text{for committed and candidate wind power plants} \quad -- \quad (4.75)$$

$$\mathbf{P_{ej,h}} = \mathrm{p}_{\mathrm{Wind\ sim,j,h}}, \quad \text{for existing wind power plants} \quad --------- \quad (4.76)$$

Inequality Constraints are summarized below.

Reserve requirements

$$\sum_{\mathrm{j}=1}^{\mathrm{J}} \mathbf{P_{ccj,h}} + \mathbf{P_{ej,h}} \leq \sum_{\mathrm{j}=1}^{\mathrm{J}} \mathrm{p_{maxj}} - (\beta * \mathrm{dem_h}), \quad \text{for all power plants} \quad -- \quad (4.77)$$

Energy production limit

$$\sum_{\mathrm{t}=1}^{\mathrm{H}} [\mathbf{P_{ccj,h}} + \mathbf{P_{ej,h}}] \leq \mathrm{en}_{\mathrm{tar,j}}, \quad \text{for all power plants} \quad ------ \quad (4.78)$$

$$\sum_{\mathrm{t}=1}^{\mathrm{H}} \mathbf{Q_{j,h}} \leq \mathrm{dis}_{\mathrm{tar,j}} \quad --------------------- \quad (4.79)$$

Hydropower plants with no reservoir and having upstream reservoir

$$\mathbf{Q_{j,h}} - \sum_{\mathrm{u}=1}^{\mathrm{U}} [\mathbf{Q_{u,h-d}} + \mathbf{S_{u,h-d}}] \leq 0, \text{for all hydropower plants in this category} \quad -- \quad (4.80)$$

Hydropower plants with no reservoir and having upstream plant with no reservoir

$$\mathbf{Q_{j,h}} - \sum_{\mathrm{u_p}=1}^{\mathrm{U_p}} [\mathbf{Q_{u_p,h-d}}] \leq 0, \text{for all hydropower plants in this category} \quad -- \quad (4.81)$$

Minimum total outflow limit

$$-\mathbf{Q_{j,h}} - \mathbf{S_{r,h}} \leq -\mathrm{o_{f,h}}, \quad \text{for all hydropower plants in this category} \quad --- \quad (4.82)$$

Reservoir Steady-state condition

$$-\mathbf{V}_{\mathbf{r,H}} \leq -\mathrm{v}_{\mathrm{rtarget}}, \quad \text{for all hydropower plants} \quad --------- \quad (4.83)$$

Lower and upper bound Constraints are summarized below.

Generation capacity, water discharge, spill and storage limits, $for\ all\ hydropower\ plants$

$$\mathrm{p}_{\mathrm{minj}} \leq \mathbf{P}_{\mathbf{ccj,h}} \leq \mathrm{p}_{\mathrm{maxj}} \quad ------------------------ \quad (4.84)$$

$$\mathrm{p}_{\mathrm{minj}} \leq \mathbf{P}_{\mathbf{ej,h}} \leq \mathrm{p}_{\mathrm{maxj}} \quad ------------------------ \quad (4.85)$$

$$\mathrm{q}_{\mathrm{minj}} \leq \mathbf{Q}_{\mathbf{j,h}} \leq \mathrm{q}_{\mathrm{maxj}} \quad ------------------------ \quad (4.86)$$

$$\mathrm{s}_{\mathrm{minr}} \leq \mathbf{S}_{\mathbf{r,h}} \leq \mathrm{s}_{\mathrm{maxr}} \quad ------------------------ \quad (4.87)$$

$$\mathrm{v}_{\mathrm{minr}} \leq \mathbf{V}_{\mathbf{r,h}} \leq \mathrm{v}_{\mathrm{maxr}} \quad ------------------------ \quad (4.88)$$

4.2.2. Problem and Model dimensions

The problem is generally observed to contain the set of physical quantities shown in Table 4.1 which indicates the dimension of problem addressed in this study.

Table 4.1: Problem dimensions

Description	Quantity
All Power plants	40
Hydropower plants	16
Reservoirs	11
Water demands (Irrigation)	4
Hydro plants with reservoir and having no upstream reservoir	10
Hydro plants sharing a reservoir	3
Hydro plants with no reservoir and having upstream reservoir	2
Hydro plants with no reservoir and having upstream plant with no reservoir	1
Wind power plants	5
Geothermal power plants	2
Sugar factories Co-generation plants	13
Biomass plants	2
EFW plants	1
Thermal backup plants (unserved energy)	1
Committed and candidate plants	22
Existing plants	18

As can be seen in equations 4.50, 4.60, 4.61, 4.72, 4.80 and 4.81 reservoir simulation relates the previous time reservoir storage volume with next time storage volume. This relationship between variables in different time steps demands discretizing the problem based on the time step used. Thus both energy and hourly model problems are treated as discrete linear problems. Accordingly the number of constraint equations, matrix & vector sizes for both models are shown in Tables 4.2 and 4.3.

Table 4.2: Energy model dimensions

Constraint	**No of time steps**	**No of constraint equations**	**Matrix size [Aeq, A]**		**Vector Size [beq, b]**
			No of rows	**Number of columns**	
Equality Constraints					
Load Balance	73	73	73	5694	73
Hydropower plants with a reservoir and having no upstream reservoir	73	730	730	5694	730
Hydropower plants sharing a reservoir	73	73	73	5694	73
Hydraulic productivity limit	73	1168	1168	5694	1168
Wind Power priority to grid	73	365	365	5694	365
Total		**2409**	**2409**	**5694**	**2409**
Inequality Constraints					
Reserve requirement	73	73	73	5694	73
Energy limit _ yearly	1	18	18	5694	18
Enery limit _ Seasonal	3	51	51	5694	51
Hydropower plants with no reservoir and having upstream reservoir	73	146	146	5694	146
Hydropower plants with no reservoir and having upstream plant with no reservoir	73	73	73	5694	73
Minimum total outflow limit	73	146	146	5694	146
Reservoir steady state condition	1	11	11	5694	11
Total		**518**	**518**	**5694**	**518**

Table 4.3: Hourly model dimensions

Constraint	**No of time steps**	**No of constraint equations**	**Matrix size[Aeq, A]**		**Vector size [beq, b]**
			No of rows	**Number of columns**	
Equality Constraints					
Load Balance	120	120	120	9360	120
Hydropower plants with a reservoir and having no upstream reservoir	120	1200	1200	9360	1200
Hydropower plants sharing a reservoir	120	120	120	9360	120
Hydraulic productivity limit	120	1920	1920	9360	1920
Wind Power priority to grid	120	600	600	9360	600
Total		**3960**	**3960**	**9360**	**3960**
Inequality Constraints					
Reserve requirement	120	120	120	9360	120
Energy limit _ yearly	1	40	40	9360	40
Enery limit _ Seasonal	1	16	16	9360	16
Hydropower plants with no reservoir and having upstream reservoir	120	240	240	9360	240
Hydropower plants with no reservoir and having upstream plant with no reservoir	120	120	120	9360	120
Minimum total outflow limit	120	240	240	9360	240
Reservoir steady state condition	1	11	11	9360	11
Total		**787**	**787**	**9360**	**787**

In addition to the above dimensions each vectors of lower and upper bounds $(lb\ and\ ub)$ have 5694 X 1 dimensions for the energy model whereas 9360 X 1 for the hourly model.

4.3. Solution Technique

Mathematical optimization includes finding "best available" values of some objective function given a defined domain (or a set of constraints), including a variety of different types of objective functions and different types of domains [28]. Optimization techniques that have been applied to solve Hydro dominated power system planning are deterministic in nature and include linear programming (LP), nonlinear programming (NLP) and Dynamic programming. Looking at the nature of equations that define the objective function as well as constraints the following facts are observed:

- All functions are linear.
- Values of all parameters/ variables are deterministic and not probabilistic.
- No piecewise nature of equations.
- All matrices are sparse.

Wide application of LP in optimizing hydro dominated systems, as discussed in literature review, together with the above observations led this study to choose LP for optimizing the stated problem.

LP problem can be defined as the problem of allocating a number m of resources among 1, 2… n activities in such a way as to maximize the worth from all the activities. In such a problem, all constraints and relationships between decision variables and activities are linear [15]. Simplex and interior point algorithms are the most commonly used algorithms for LP problems. MATLAB, software platform used for this study, uses large scale linear programming, active set medium scale and medium scale simplex algorithms based on simplex and interior point algorithms.

An optimization algorithm is large scale when it uses linear algebra that does not need to store, nor operates on, full matrices. This may be done internally by storing sparse matrices, and by using sparse linear algebra for computations whenever possible. As the nature of the problem defined in this study has sparse matrices, large scale linear programming algorithm has been used and is observed to save iteration time thirty times.

MATLAB built in function (solver) for such type of problems named LINPROG has been used in this study. Linprog solves large scale linear programming problems based on LIPSOL (Linear Interior Point Solver within the MATLAB environment) which uses a primal-dual interior-point method. LINPROG finds the minimum of a problem given in equation 4.46 by transforming the problem in to primal and dual parts. The optimality conditions for this primal-dual linear program are:

$$F(x, y, z, s, w) = \begin{bmatrix} A.x - b \\ x + s - u \\ A^T.\mathrm{y} - w + z - f \\ x_i z_i \\ s_i w_i \end{bmatrix} = 0 \qquad -------------- \qquad (4.89)$$

$x \geq 0, z \geq 0, s \geq 0, w \geq 0$

s consists of primal slack variables, y and w consist of the dual variables and z consists of the dual slacks. The quadratic equations $x_i z_i = 0$ and $s_i w_i = 0$ are called the complementarity conditions for the linear program whereas the other (linear) equations are called the feasibility conditions. The algorithm is a primal-dual algorithm, meaning that both the primal and the dual programs are solved simultaneously.

The iterative part of the algorithm works with the following stopping criteria:

$$\frac{\|A.x-b\|}{max(1,\|b\|)}+\frac{\|A^T.\mathrm{y}-w+z-f\|}{max(1,\|f\|)}+\frac{\|x+s-u\|}{max(1,\|u\|)}+\frac{|f^T.\mathrm{x}-b^T.\mathrm{y}+u^T.\mathrm{w}|}{max(1,|f^T.\mathrm{x}|,|b^T.\mathrm{y}-u^T.\mathrm{w}|)}\le tol-(4.90)$$

Where $A.x-b$, $A^T.\mathrm{y}-w+z-f$ and $x+s-u$ are the primal residual, dual residual and upper-bound feasibility respectively, and $f^T.\mathrm{x}-b^T.\mathrm{y}+u^T.\mathrm{w}$ is the difference between the primal and dual objective values. The sum in the stopping criteria measures the total relative errors of the optimality conditions shown in equation 4.90 and *tol* is termination tolerance on the function value (default value is 1e-08 for large-scale algorithm)[27].

4.4. Simulation with MATLAB

As mentioned previously MATLAB programming platform has been used to simulate both the Energy and Hourly models discussed in sections 4.1.1 and 4.1.2. The following steps have been followed to develop a MATLAB programming code that simulates both models.

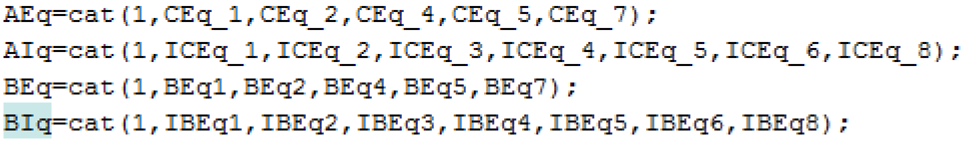
i. Variables and parameters have been defined.

ii. Objective function matrix *f* has been developed, according to matrix sizes given in section 4.2.2, for both models.

iii. Each equality constraint matrix (five for each model) has been developed separately for both models according to matrix sizes shown in Tables 4.2 and 4.3.

iv. Each inequality constraint matrix (seven for each model) has been developed separately for both models according to matrix sizes shown in Tables 4.2 and 4.3.

v. For each model, the already formed five equality constraints are concatenated using a function *cat* to create the respective input argument for linprog i.e., A_{eq} and b_{eq}. MATLAB code using cat is shown below:



```
AEq=cat(1,CEq_1,CEq_2,CEq_4,CEq_5,CEq_7);
AIq=cat(1,ICEq_1,ICEq_2,ICEq_3,ICEq_4,ICEq_5,ICEq_6,ICEq_8);
BEq=cat(1,BEq1,BEq2,BEq4,BEq5,BEq7);
BIq=cat(1,IBEq1,IBEq2,IBEq3,IBEq4,IBEq5,IBEq6,IBEq8);
```

vi. Step v has been repeated for inequality constraints to create additional input arguments for linprog known as *A* and *b*.

---

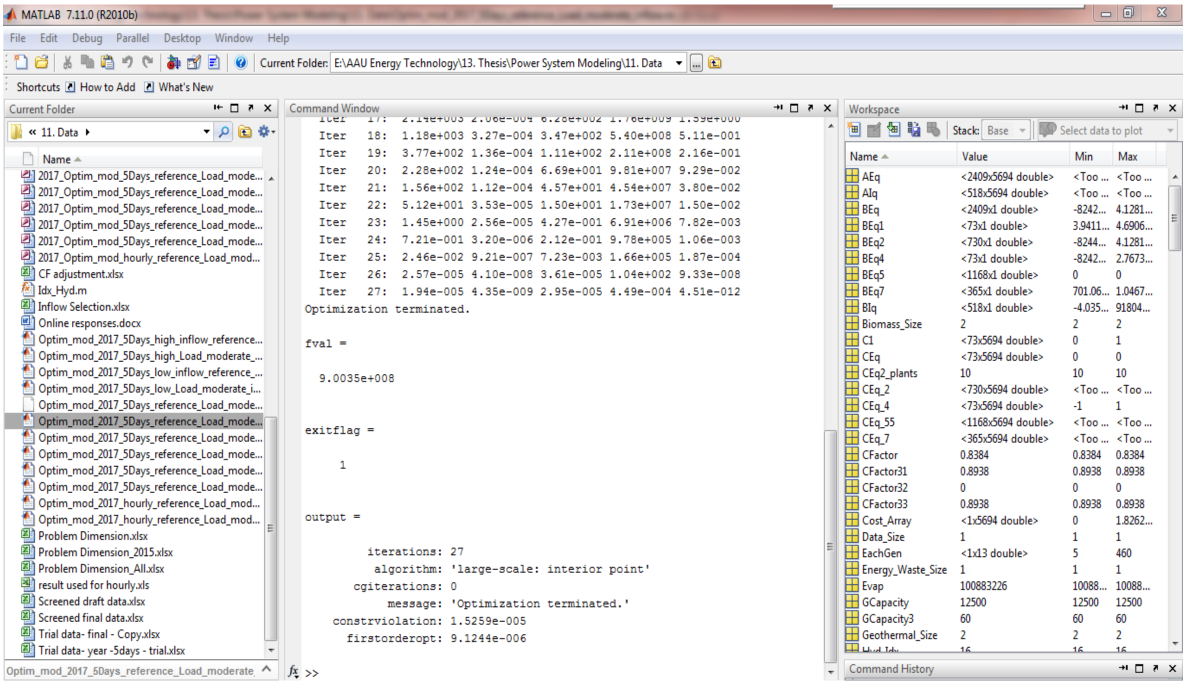
[27] Matlab, 2010 [40]

vii. Lower and upper bound vectors, for each model, have been developed based on vector sizes given in sections 4.2.2.

viii. The call function *[x,fval,exitflag,output] = linprog(f,A,b,Aeq,beq,lb,ub,x0,options);* has been used to solve the optimization problem.

ix. Finally output has been exported to respective excel sheets for analysis.

Figure 4.2 shows a snap shot of MATLAB interface that contains the current folder directory, command window with output arguments and iteration steps as well as a workspace showing model dimensions (sizes of matrices and vectors).



```
  Iter   18:  1.18e+003 3.27e-004 3.47e+002 5.40e+008 5.11e-001
  Iter   19:  3.77e+002 1.36e-004 1.11e+002 2.11e+008 2.16e-001
  Iter   20:  2.28e+002 1.24e-004 6.69e+001 9.81e+007 9.29e-002
  Iter   21:  1.56e+002 1.12e-004 4.57e+001 4.54e+007 3.80e-002
  Iter   22:  5.12e+001 3.53e-005 1.50e+001 1.73e+007 1.50e-002
  Iter   23:  1.45e+000 2.56e-005 4.27e-001 6.91e+006 7.82e-003
  Iter   24:  7.21e-001 3.20e-006 2.12e-001 9.78e+005 1.06e-003
  Iter   25:  2.46e-002 9.21e-007 7.23e-003 1.66e+005 1.87e-004
  Iter   26:  2.57e-005 4.10e-008 3.61e-005 1.04e+002 9.33e-008
  Iter   27:  1.94e-005 4.35e-009 2.95e-005 4.49e-004 4.51e-012
Optimization terminated.

fval =

  9.0035e+008


exitflag =

     1


output =

         iterations: 27
          algorithm: 'large-scale: interior point'
       cgiterations: 0
            message: 'Optimization terminated.'
    constrviolation: 1.5259e-005
       firstorderopt: 9.1244e-006

>>
```

Name	Value	Min	Max
AEq	<2409x5694 double>	<Too ...	<Too ...
AIq	<518x5694 double>	<Too ...	<Too ...
BEq	<2409x1 double>	-8242...	4.1281...
BEq1	<73x1 double>	3.9411...	4.6906...
BEq2	<730x1 double>	-8244...	4.1281...
BEq4	<73x1 double>	-8242...	2.7673...
BEq5	<1168x1 double>	0	0
BEq7	<365x1 double>	701.06...	1.0467...
BIq	<518x1 double>	-4.035...	91804...
Biomass_Size	2	2	2
C1	<73x5694 double>	0	1
CEq	<73x5694 double>	0	0
CEq2_plants	10	10	10
CEq_2	<730x5694 double>	<Too ...	<Too ...
CEq_4	<73x5694 double>	-1	1
CEq_55	<1168x5694 double>	<Too ...	<Too ...
CEq_7	<365x5694 double>	<Too ...	<Too ...
CFactor	0.8384	0.8384	0.8384
CFactor31	0.8938	0.8938	0.8938
CFactor32	0	0	0
CFactor33	0.8938	0.8938	0.8938
Cost_Array	<1x5694 double>	0	1.8262...
Data_Size	1	1	1
EachGen	<1x13 double>	5	460
Energy_Waste_Size	1	1	1
Evap	100883226	10088...	10088...
GCapacity	12500	12500	12500
GCapacity3	60	60	60
Geothermal_Size	2	2	2

Figure 4.2: MATLAB command and workspace window

CHAPTER 5
RESULTS AND DISCUSSION

In this chapter, the study findings are presented in two broad categories. The first category presents a result of the reference scenario (Moderate inflow at reference forecasted load) based on year round and hourly dispatches. The year round dispatch result was based on the 73 consecutive blocks of 5 days used in Energy model while the hourly dispatch presents an hourly resolution for the five days consisting the peak demand hour of the year. The second category explores sensitivities of results to different scenarios based on varying conditions like water inflow to reservoirs, load forecast errors and power plants construction completion time delays.

5.1. Reference Scenario

5.1.1. Year round (Energy) dispatch

Let's first study the dispatch trend obtained from the energy model for the reference forecasted load and moderate hydrological inflow condition. Figure 5.1 presents the year round dispatch of the energy output of various technologies summed over 5 consecutive days. The figure shows that hydropower contributes the largest share of the energy need. When looking at seasonal behavior of energy generation by technology, hydro appears to have a constant output throughout the year though with a minor peak during the month of August to September. The year round uniform generation of hydropower is because of the corresponding reservoir operation given in Figure 5.2. Figure 5.2 presents the corresponding water discharge from various hydropower plants. As can be seen from the figure, the water discharge relatively peaks from June through September, which is Ethiopia's rainy season. As discussed in Chapter 3, the flow rate in other seasons is significantly low, especially during the winter (which is the hottest and driest season of Ethiopia).

It can easily be seen that hydropower technology fulfills most of the energy demand as most existing hydro plants has small operational costs, with no annual capital and fuel cost, as compared to other technologies (see Table 3.18). Figure 5.3 presents the annual dispatch schedule of each hydropower plants and their overall role. The dispatch smoothly follows the water discharge trend given in Figure 5.2. This model dispatches each hydropower plant almost uniformly throughout the year except Tana beles, whose output appears to decrease during summer. The decrease might be due to both Tis Abay power plants, which shares the same reservoir and becomes operational only during this period. Figure 5.3 also shows that GERD, GG III, Tana beles and GG II are major energy contributors of all hydropower plants, in the range of 20 to 180 GWh per 5 days.

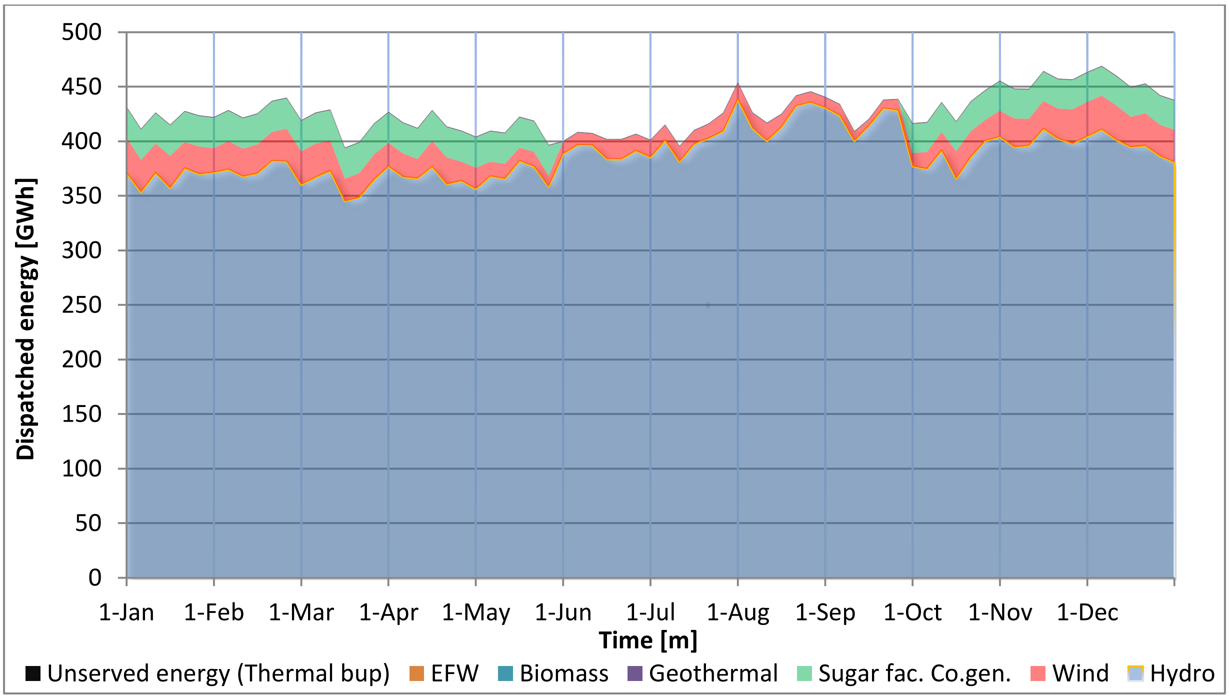


Figure 5.1: year round dispatch of the energy output (in a block of 5 consecutive days) of various technologies

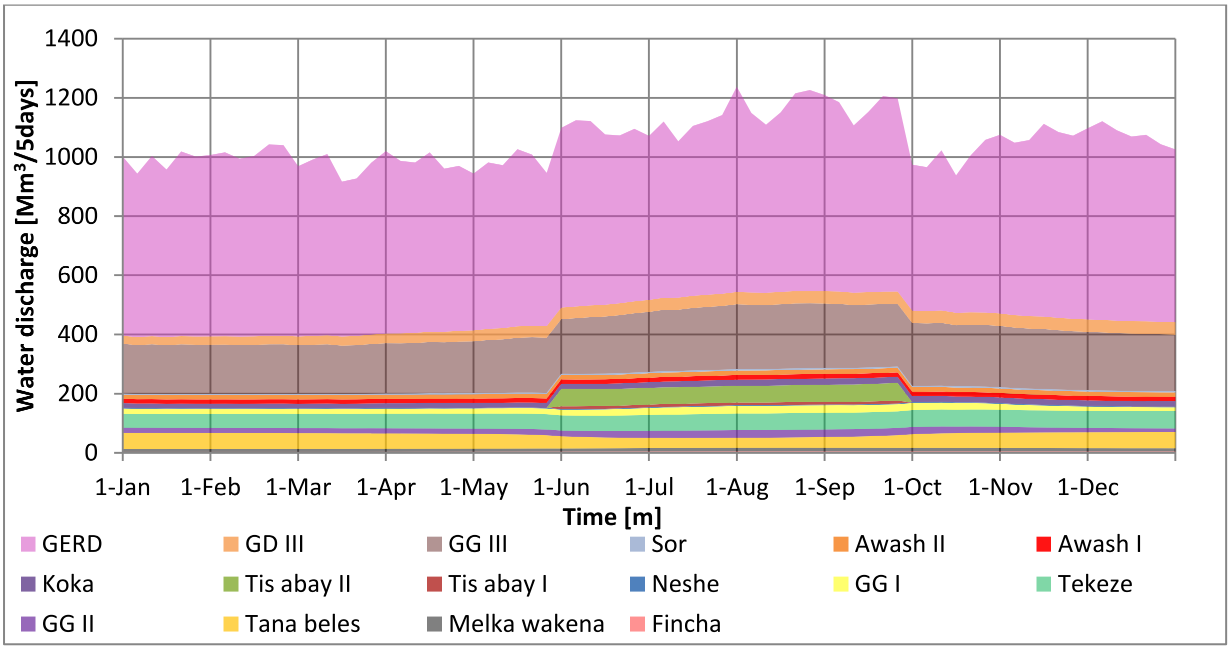


Figure 5.2: Year round water discharge of various hydropower plants (in a block of 5 consecutive days) corresponding to the dispatch give in Figure 5.1

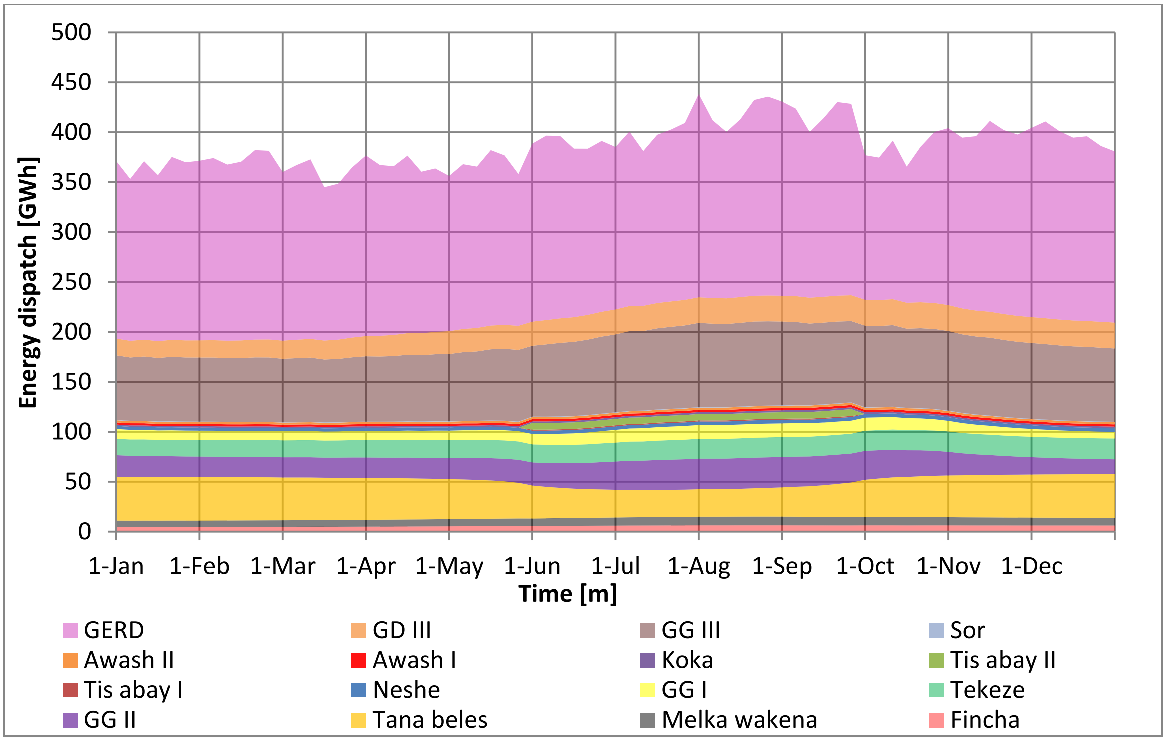


Figure 5.3: Year round energy output of each hydropower plant

Coming back to Figure 5.1, it is found that wind and other technologies, such as sugar factories Co-generations and biomass; provide their highest contributions during winter. Figure 5.4 and Figure 5.5 presents Wind and sugar factory co-generation plants year round dispatch. Depending on Ethiopia's wind resource profile, wind energy output was the highest during winter time and low during summer. At the same time, due to the impact of cropping season the sugar factory co-generation and biomass plants produce energy only from October to June. Overall, these technologies appear to be in a good complementarity with hydropower. Their overall contribution is lowered only due to the low available capacity. However, because of the dispatch priority given to wind and relatively cheaper generation cost of sugar factories co-generation plants, they are found to contribute more energy as compared to other non-hydro sources such as Biomass, EFW and some geothermal plants.

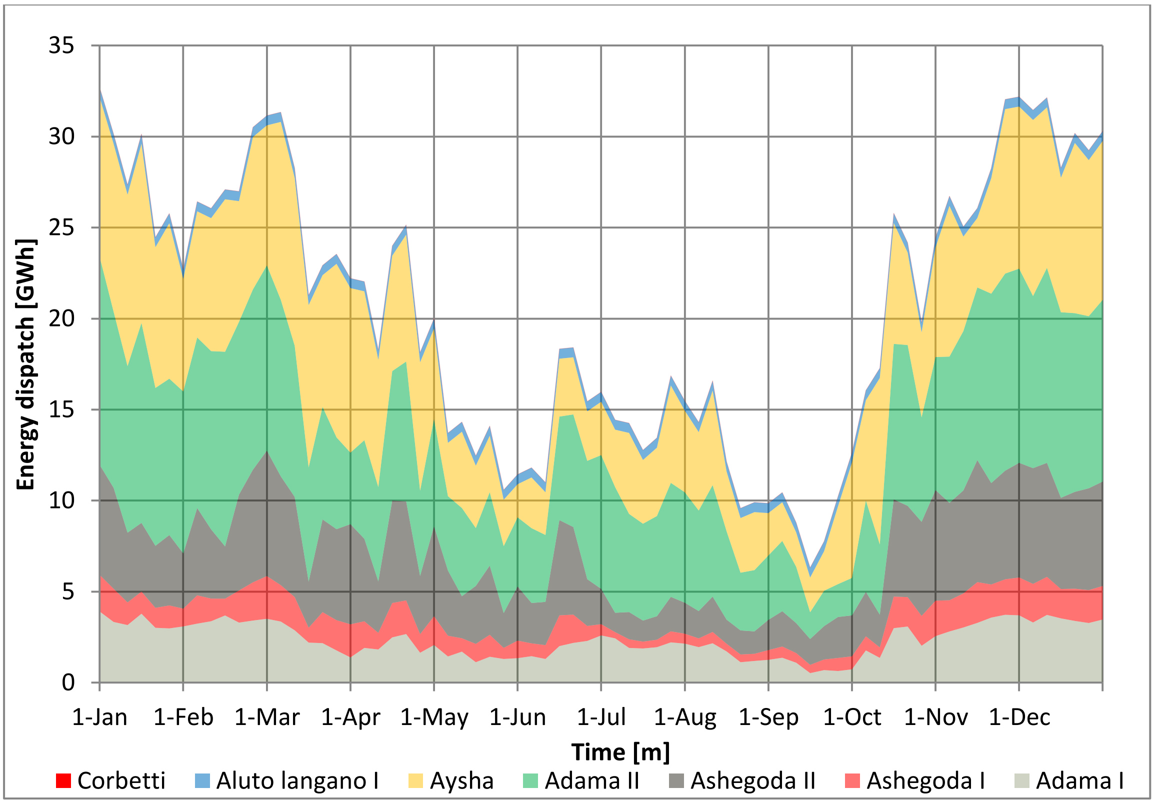


Figure 5.4: Year round wind energy supply (in a block of 5 consecutive days)

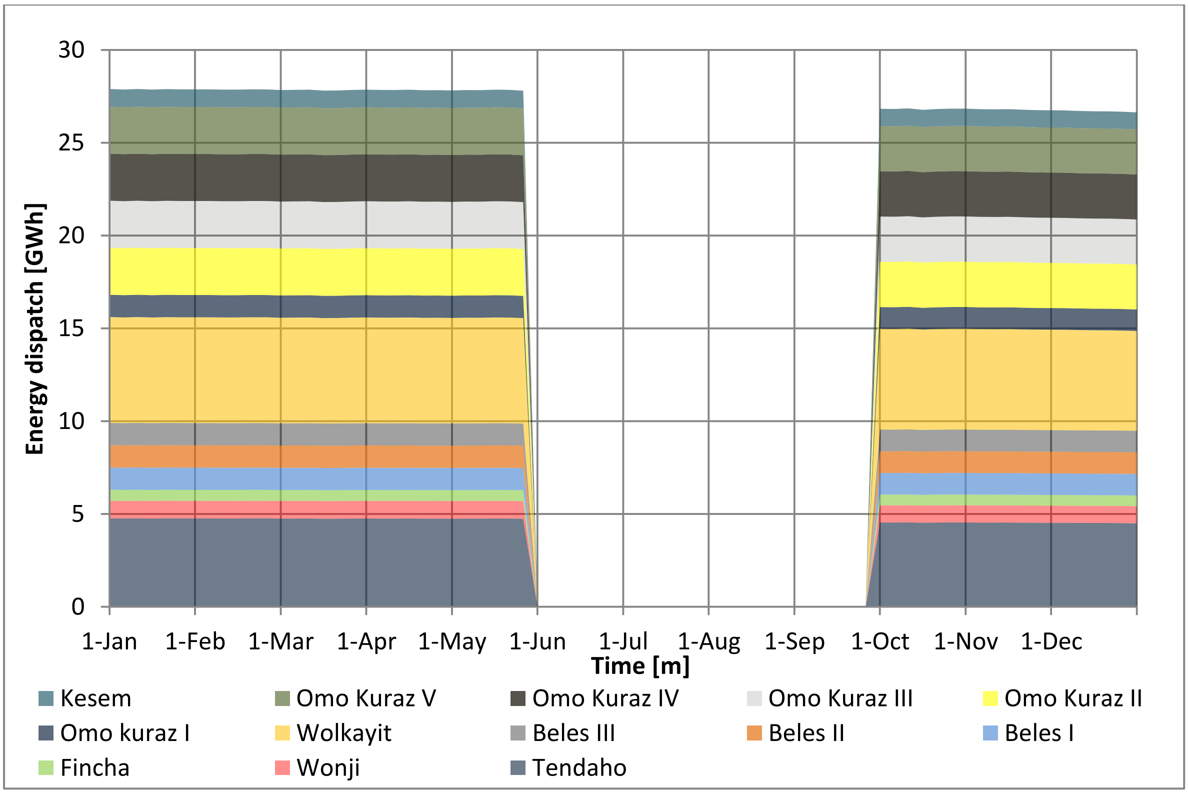


Figure 5.5: Year round sugar factories cogeneration supply (in a block of 5 consecutive days)

5.1.2. Hourly dispatch

In this section, the hourly dispatch profile is studied to test the presence of enough reserve requirements. While the hourly dispatch test was also done for other weeks, the result for the 5-days containing the peak demand hour of the year (November 11, 2017 – 19:00hrs) is presented here. To perform this study, the required initial conditions for reservoirs were set to the corresponding condition at the end of the preceding time block.

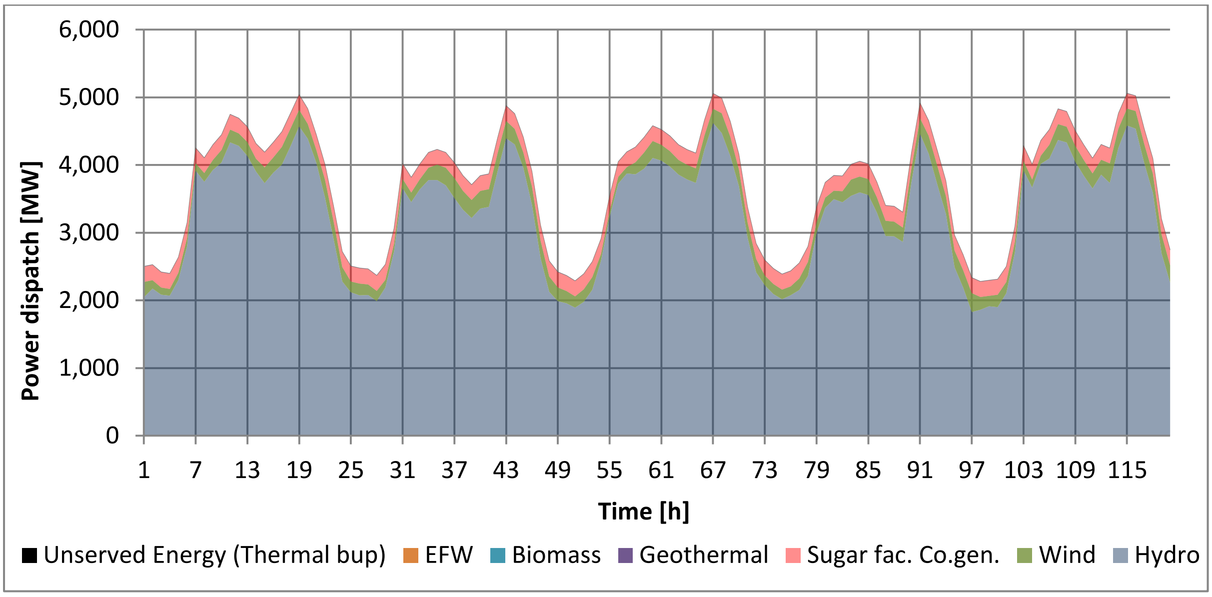


Figure 5.6: Hourly dispatch for the peak demand hour duration

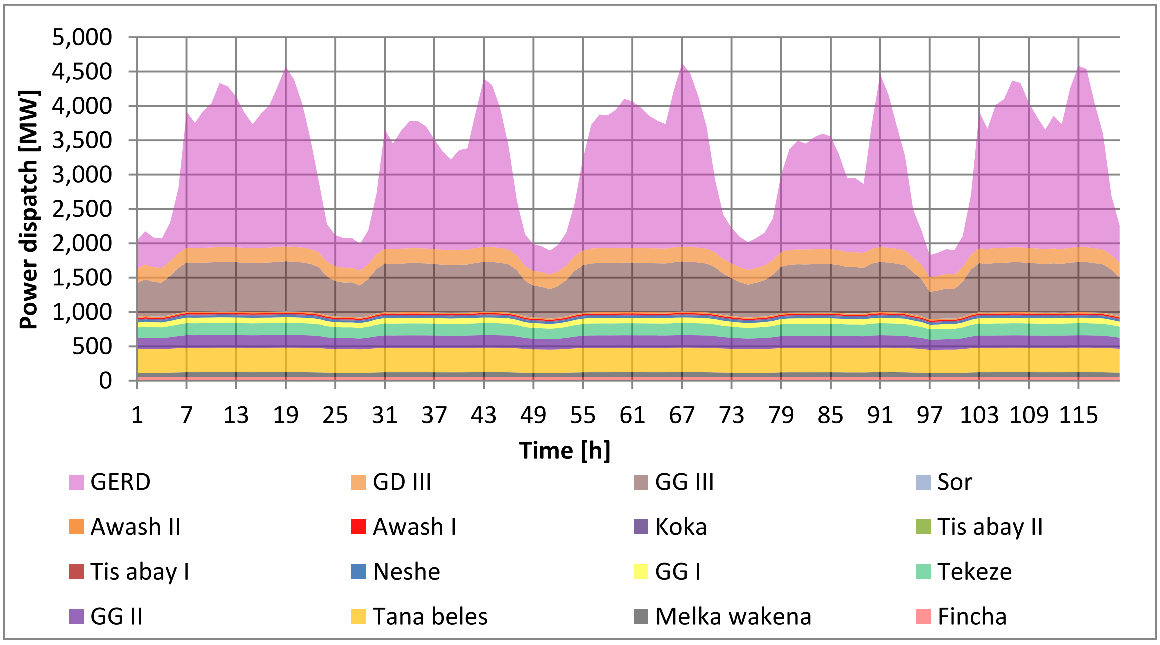


Figure 5.7: Hydropower plants hourly power dispatch for the peak demand hour duration

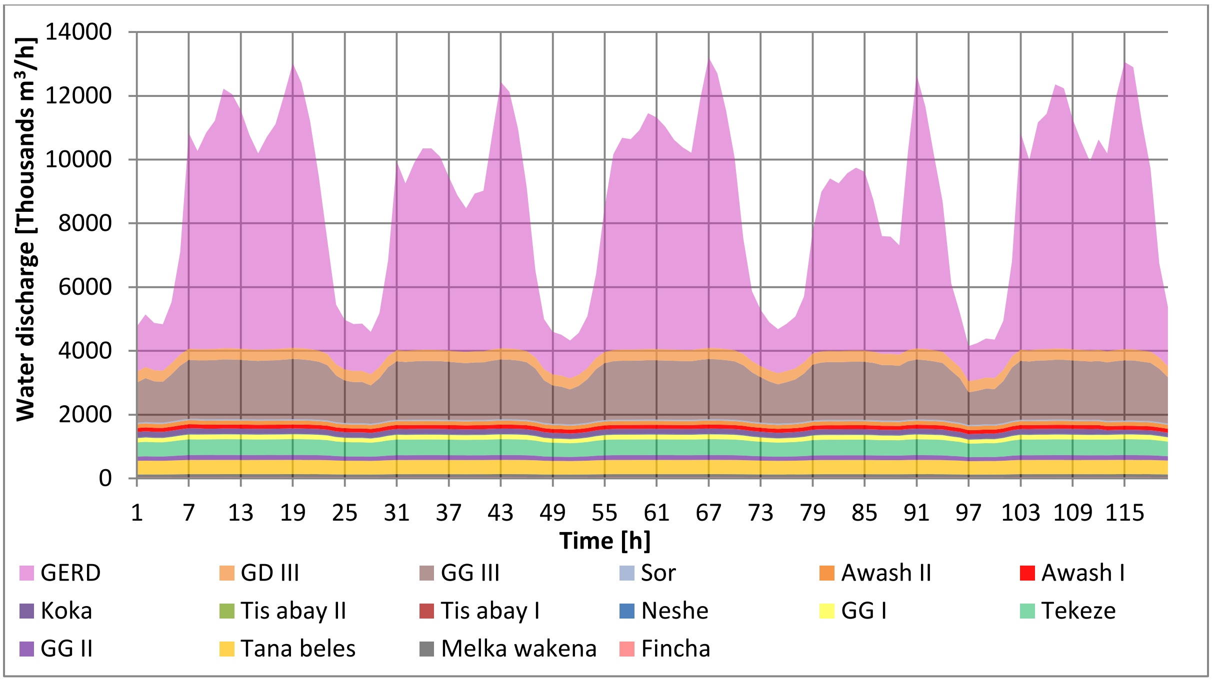


Figure 5.8: Hydropower plants hourly water discharge for the peak demand hour duration

Figure 5.6 shows that power plants in 2017 G.C will effectively meet the hourly demand including the peak demand hour plus 15% reserve margin. The figure reveals that hydropower dispatch effectively follows the load variation i.e., the hourly power dispatch takes on similar shape as that of hourly load curve, hitting high values at 19:00 hours for all the 5days under this simulation, which suggests how the water discharge rate changes with times of a day.

Figure 5.7 presents the hourly contribution of each hydropower generators while Figure 5.8 presents the corresponding water discharge. Both figures show that GERD performs the majority of the load requirement and supplies the largest amount of energy to customer. However, for the year 2017 G.C a capacity higher that 3GW will not be required from this power plant. Note that the water discharge does not follow the inflow trend, which could probably be constant throughout most of the days.

Figure 5.6 also shows that the hourly wind energy contribution varies with time of the day. Figure 5.9 present a magnified version of the wind energy output. The figure shows that wind output peaks between 18:00 and 20:00 hrs, which coincides with peak demand time of the day i.e., 19 hrs. In addition to the seasonal complementarities of wind and hydro, it is observed that wind appears to reduce the required generation from hydro at peak demand hour of the day. On the other, as shown in Figure 5.10, the hourly output of all cogeneration power plants supplied a constant amount of power throughout the week.

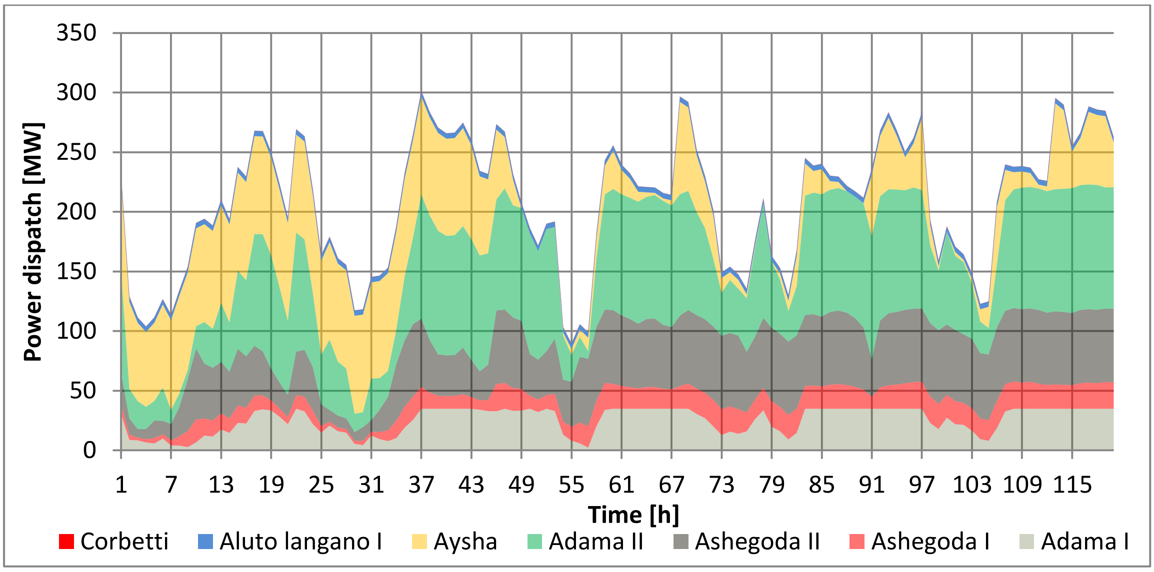


Figure 5.9: Wind power plants hourly power dispatch for the peak demand hour duration

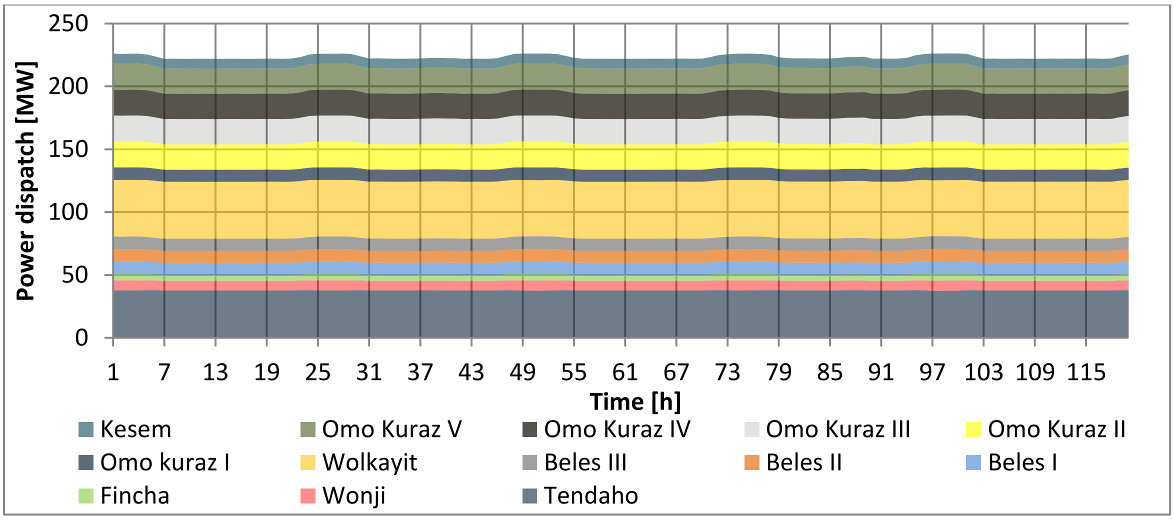


Figure 5.10: Sugar fac. Co-gen. plants hourly power dispatch for the peak demand hour duration

5.1.3. Reservoirs operation

In the foregoing discussion, the nature of integrated reservoirs and power systems dispatch has been looked in to. This section explores the nature of water use, reservoir volume dynamics and power system operation under the given circumstance. This study shows that the water resource was consumed effectively to generate electricity by all power plants, which should be clear from the absence of spillage in both the year round and the hourly dispatch.

On the other hand, as shown in Figure 5.11 and Figure 5.12, reservoir level was found to change in some fashion. Except in the cases of GD III, Fincha and Sor whose reservoir bottoms out earlier, all other reservoirs reach their minimum in the month of June. However, the reservoir level reaches the maximum level in the month of October or November, around the end of the rainy season, depending on reservoir location.

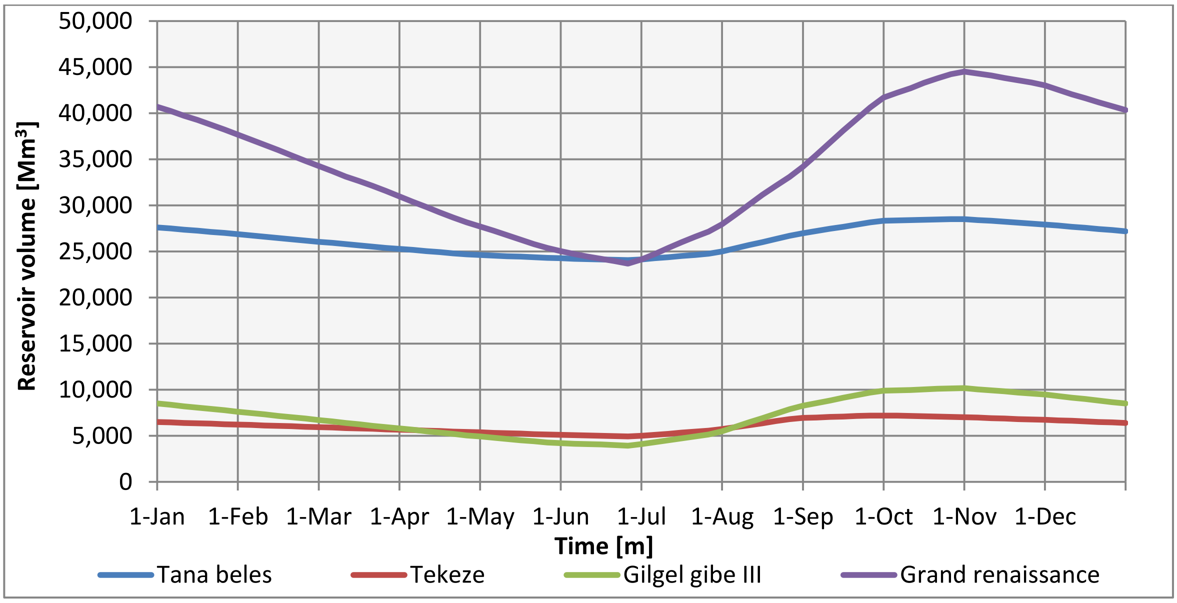


Figure 5.11: Year round reservoir level for largest Dams

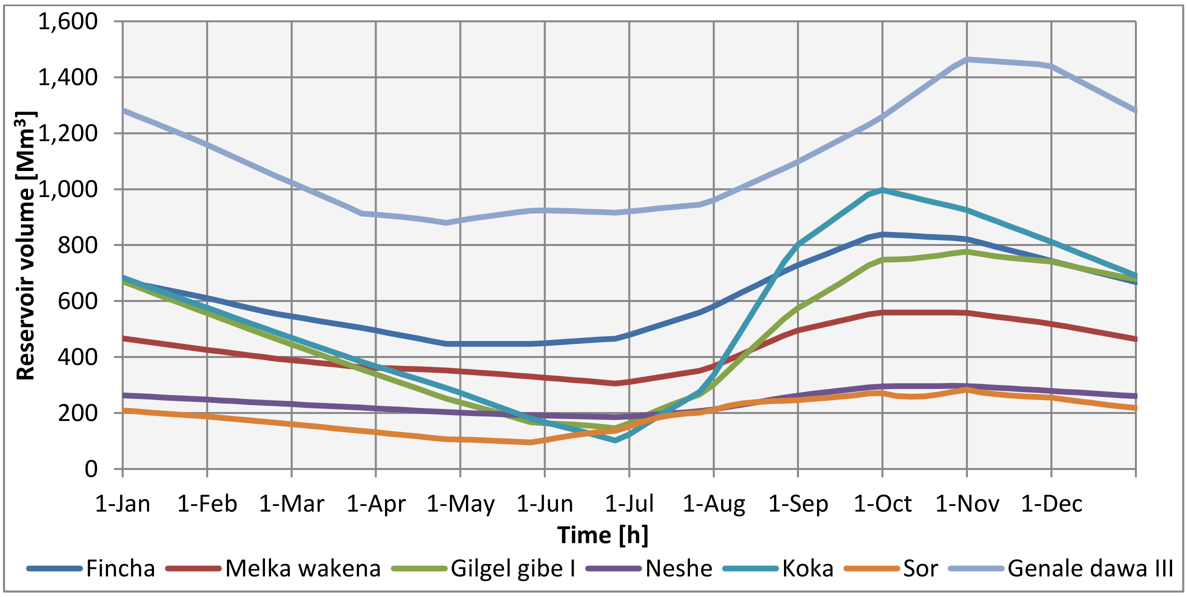


Figure 5.12: Year round reservoir level for moderate size reservoirs

From Figure 5.11 and Figure 5.12, one can also see that the reservoir volume remains almost the same during the beginning and the end of the year. Table 5.1 presents the amount of water volume at the start and end of simulation for each reservoir. It can be seen that every reservoir water level is maintained between 98 and 103 percent of the starting volume, thus all reservoirs can be made ready for 2018 dispatch with proper water levels. The above result shows that approximately all the total annual inflows of water were discharged from all reservoirs.

Table 5.1: Amount of reservoirs water volume at the start and end of the year for reference case scenario

No	Reservoir	Initial volume at start of Jan 01, 2017 01:00 [Mm^3]	Final volume at the end of Dec 31, 2017 00:00 [Mm^3]	Final volume as percent of initial volume[%]
1	Fincha	681.00	667.38	98.00
2	Melkawakena	473.13	464.79	98.24
3	Tana beles	27741.89	27187.07	98.00
4	Tekeze	6540.64	6409.83	98.00
5	GG I	686.54	678.31	98.80
6	Amerti neshe	265.57	260.39	98.05
7	Koka	697.51	690.70	99.02
8	Sor 1	209.95	217.93	103.80
9	GG III	8645.00	8512.08	98.46
10	GD III	1300.00	1280.90	98.53
11	GRED	41177.50	40353.95	98.00

5.1.4. Power plant operation

Based on Table 5.2 some power plants, such as GERD and GG-III, possesses significantly larger capacity than the capacity required by 2017 G.C. It is clear that these two power plants are designed for peak power service. However, given that the expected annual inflow has already been effectively used to generate electricity, its economic performance depends on the cost of power service at peak demand hours. It is, therefore, very important to assess the impact of the market on its economic value under different ways of operation. Under the present scenario, the power plant dispatch is basically based on the cost of electrical energy it produces. The observation in this study suggests that the economic value of the entire power plant depends both on water resources and cost of power in the future market.

Table 5.2: Power plant operation at peak hour of the year

No	plant	Reference load moderate inflow					
		Maximum Hourly dispatched power for peak hour duration - Nov 07 - 11, 2017 [MW]	**Unit Nominal Capacity [MW]**	**Available units [Pcs]**	**Used units [Pcs]**	**Standby units [Pcs]**	**Standby capacity [MW]**
1	Fincha	52.95	32.00	4	2	2	64.00
2	Melkawakena	68.98	38.25	4	2	2	76.50
3	Tana beles	358.08	115.00	4	4	0	0.00
4	GG II	179.34	105.00	4	2	2	210.00
5	Tekeze	176.12	75.00	4	3	1	75.00
6	GG I	81.04	61.33	3	2	1	61.33
7	Amerti neshe	30.83	49.00	2	1	1	49.00
8	Tis Abay I	0.00	6.00	2	0	2	12.00
9	Tis Abay II	0.00	34.00	2	0	2	68.00
10	Koka	11.24	12.67	3	1	2	25.33
11	Awash I	18.64	9.33	3	2	1	9.33
12	Awash II	18.72	14.00	2	2	0	0.00
13	Sor 1	3.54	3.00	2	2	0	0.00
14	GG III	727.35	187.00	6	4	2	374.00
15	GD III	217.22	84.67	3	3	0	0.00
16	GERD	2640.75	375.00	14	8	6	2250.00

5.2. Sensitivity Analysis

In order to do a thorough analysis regarding the Ethiopian power systems opportunity and challenges by 2017, the impact of various changes needs to be assessed. The typical sensitivity includes load forecast errors, hydrological variations and delay in power plants construction completion time. List of all scenarios and their descriptions are summarized in Table 5.3.

Table 5.3: List of Scenarios

No	Scenario Name	Description
1	High Inflow	Details of each scenario are explained in section 3.4.6. [All three scenarios only correspond to a reference forecasted load]
2	Moderate Inflow	
3	Low Inflow	
4	High Load	It is certain that the actual outcome in future (2017) will almost invariably be different from the reference load forecast. The low as well as high load forecasts help in containing those inaccuracies. The high and low scenarios used in this study are adopted from Ethiopian power system generation expansion master plan study, February 2014, based on realistic consideration of the future economically, socially and from end user point of view. - refer section 3.4.5. [All three scenarios only correspond to a moderate inflow]
5	Reference Load	
6	Low Load	
7	GERD+COR+AYS delay	**GERD** - Considering bulky power plant construction and its huge water and time requirement to fill up the reservoir, completion in construction of 840MW (2 to 3 units) capacity for use in 2017 is set as one delay scenario. **CORBETTI** - According to a presentation by chief operations officer of Reykjavik, 20MW is expected to be operational by December 2015 and additional 100 MW by December 2016. As geothermal power plants development (including financing) majorly depends on the output of the actual drilling, the 100 MW to be delivered by end of 2016 may not be delivered as expected. Thus 50% delay in delivery of the 100MW is assumed or total capacity of Corbetti, at 2017, is reduced to 70MW from 120MW. **AYSHA** - According to personal communications with Aysha wind power project manager at EEPCo this project is expected to kick off in September 2015 and expected to deliver a capacity of 120MW by start of 2017 though there is an outstanding issue over financing that needs to be resolved. In consideration of this fact Aysha is assumed to be delayed until 2018 or no contribution to the grid in 2017. [All three scenarios only assume a reference forecasted load and moderate inflow] **Note:** Only power plants that are planned to be completed by the end of 2016 or start of 2017 are considered to have potential for delay.
8	GERD delay	
9	COR+AYS delay	

5.2.1. Year round dispatch for High and Low inflow scenarios

To reduce the space and time required to present each detail of all scenarios, we will focus on the year round dispatch of two scenarios, specifically high inflow and low inflow scenarios, for a reference load. Figure 5.13 presents the dispatch for high inflow scenario while Figure 5.14 presents the same for the low inflow scenario. As can be seen from Figure 5.13, under high inflow scenario the dominance of hydropower becomes higher than moderate inflow condition. In the contrary Figure 5.14 shows that hydro power still dominates the dispatch but its contribution significantly diminishes due to low water inflow. As a result, under the high inflow condition the model dispatches hydropower, wind and a very small amount of geothermal power to fulfill the demand throughout the year. Sugar factories co-generation, biomass and EFW plants are not dispatched because of their total costs being higher than hydro plants. And during the low inflow scenario there exists an unserved energy of 4277.27 GWh (13.74% of total energy supplied) which stands next to hydropower plants implying a significant amount of unserved energy. This unserved energy is modeled as a thermal backup system with a cost of electricity generation of 1.1 United States Dollar/KWh or USD/KWh.

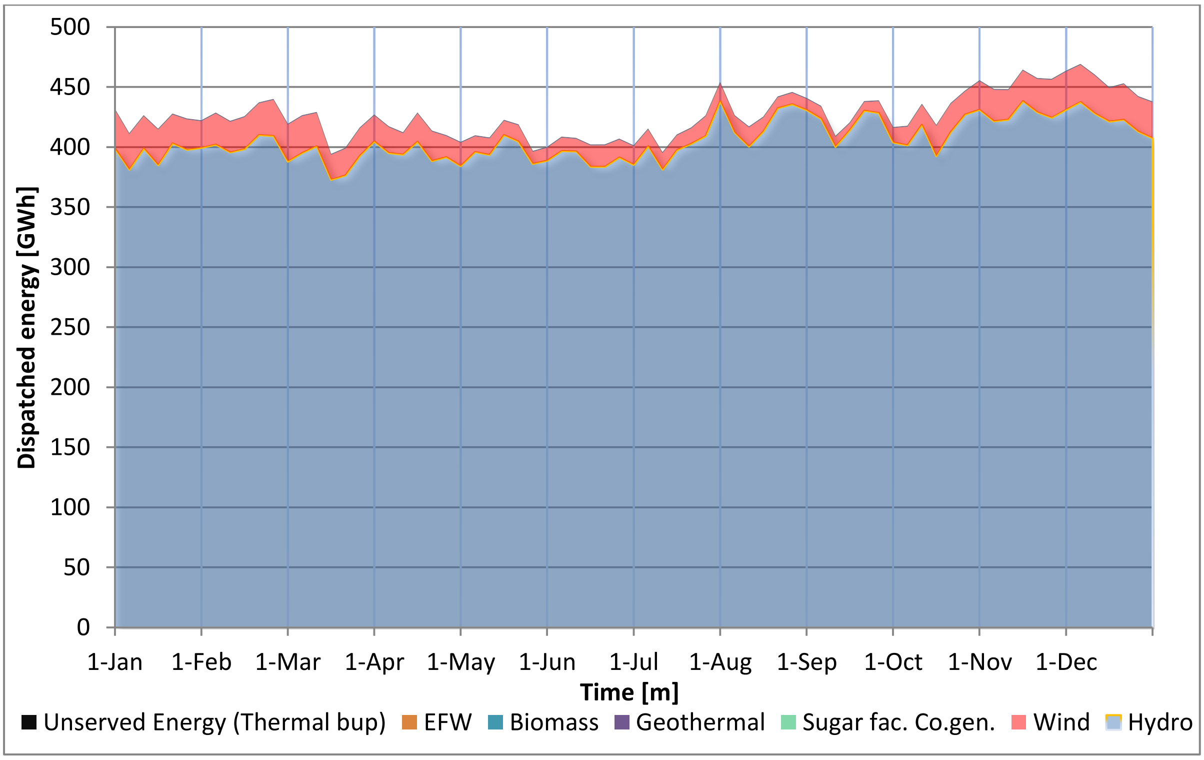


Figure 5.13: Year round dispatch of power plants at high inflow scenario

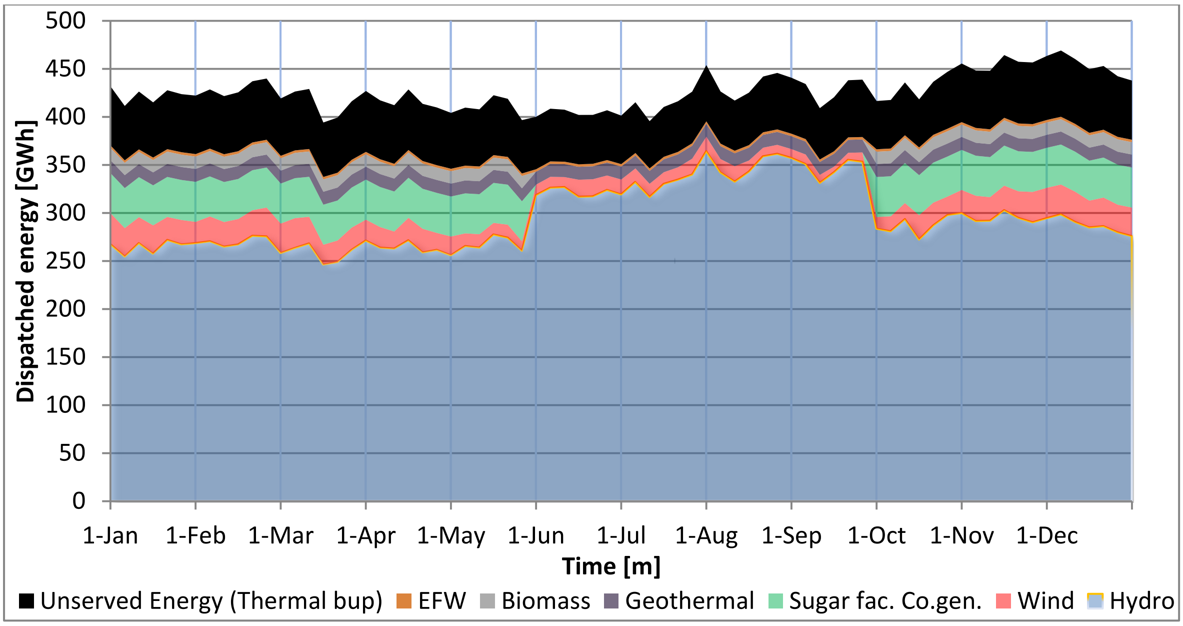


Figure 5.14: Year round dispatch of power plants at low inflow scenario

As shown in Figures 5.14 and 5.16 the summer time peak dispatch was very pronounced in the case of low inflow scenario. This is because of the significant reduction of hydropower generation at other seasons due to reduced water inflow. Overall, this reduced hydropower generation is complemented by wind, EFW and sugar factories cogeneration technologies. But the model anticipates significant unserved energy almost throughout the year. Similarly, energy from geothermal power plants must also be available almost throughout the year.

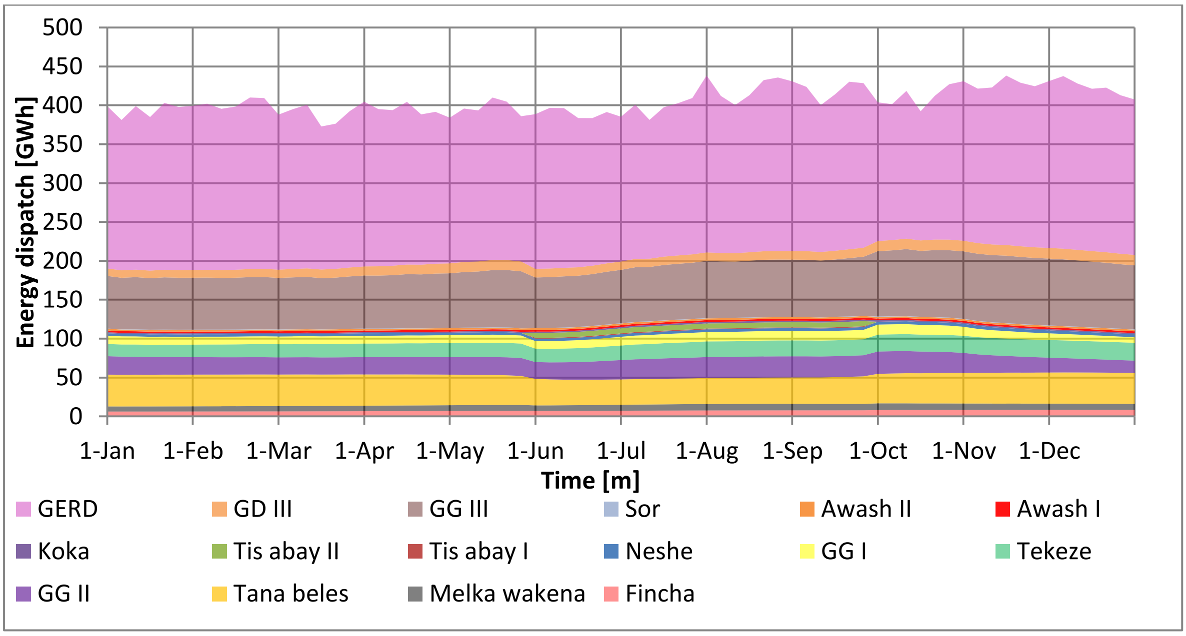


Figure 5.15: Year round Hydropower plants dispatch for high inflow scenario

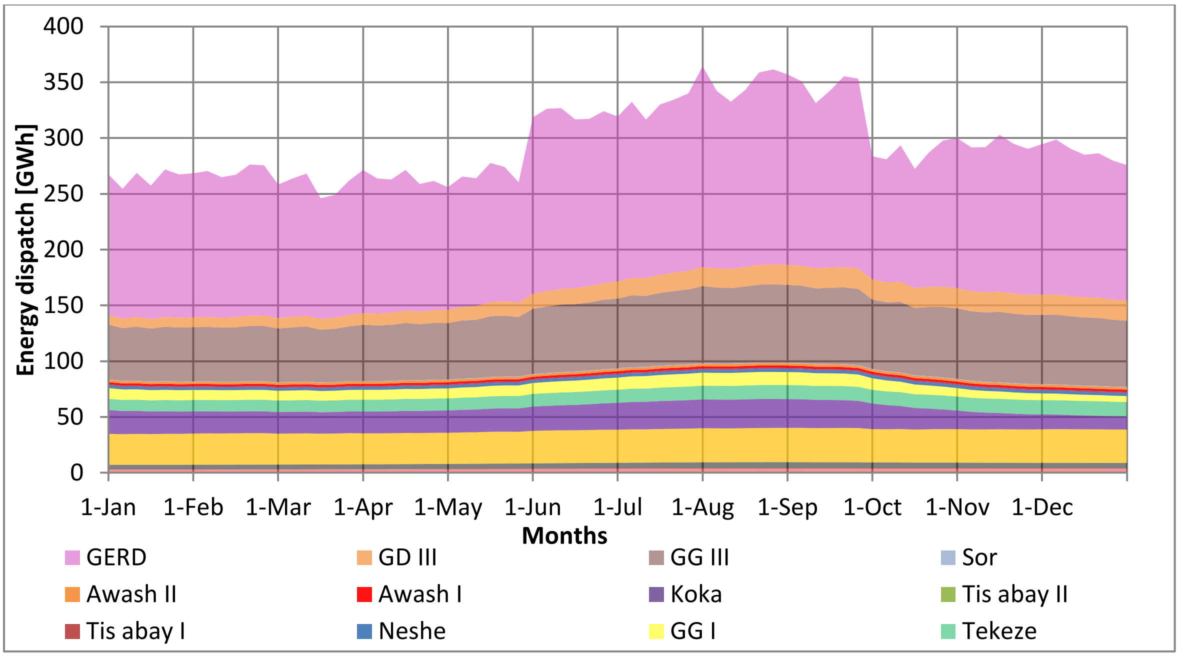


Figure 5.16: Year round Hydropower plants dispatch for low inflow scenario

Figure 5.15 and Figure 5.16 presents the hydropower year round dispatch for high inflow and low inflow scenarios, respectively. Comparing the two Figures and Figure 5.2, one can easily see that the impact of dry year on hydropower generation potential of Ethiopia is very significant. The corresponding water discharges for both scenarios are given in Figure 5.17 and Figure 5.18.

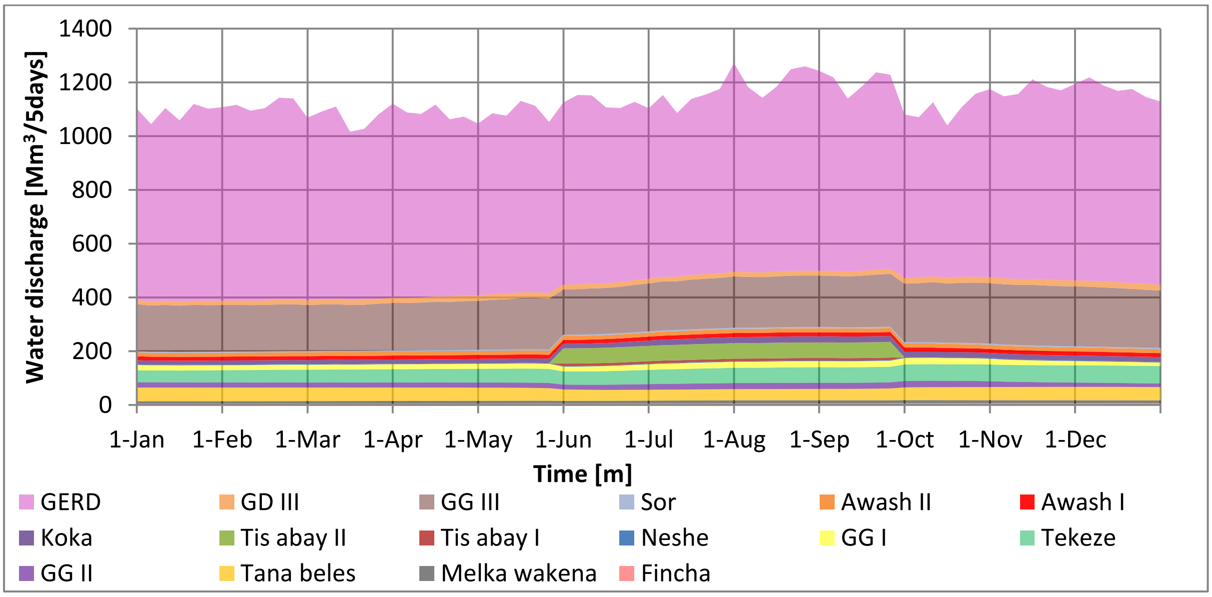


Figure 5.17: Year round water discharge trends by hydropower plants for high inflow scenario

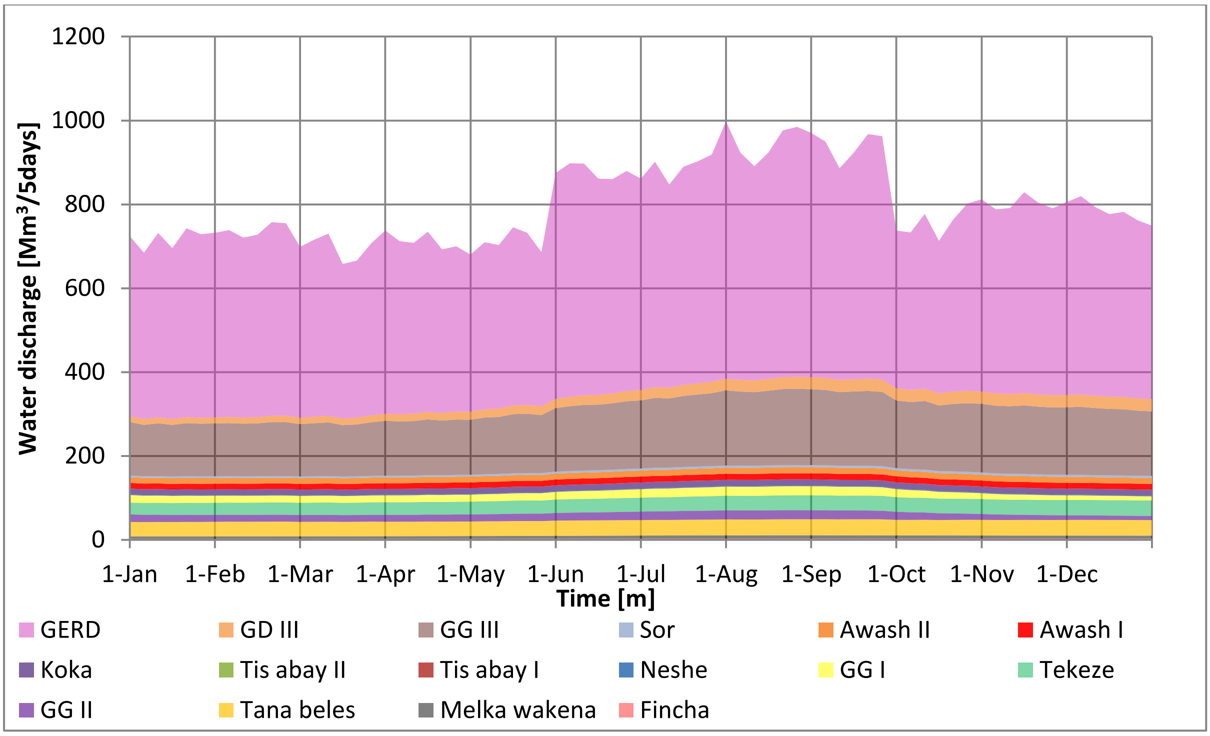


Figure 5.18: Year round water discharge trends by hydropower plants for low inflow scenario

The year round reservoir level trend does not show significant change from what was observed for the moderate inflow scenario. The reservoir volume at the end of the year was also between 98% and 105% of the initial volume of the reservoir, with Sor1 (104.7%) and GD III (104.6%) having slightly more water than their initial volume.

5.2.2. Hourly dispatch for High and Low inflow scenarios

Figure 5.19 shows that peak demand is fulfilled using hydropower, wind and very small amounts of geothermal technologies. Comparing it with Figure 5.6, sugar factories cogeneration plants do not participate in the high inflow scenario. This is because hydropower plants cover most of the energy that was supplied by sugar factories cogeneration plants in the moderate inflow scenario. This is due to hydropower plants low operating cost and additional water inflow to hydropower reservoirs that exists in the high inflow scenario.

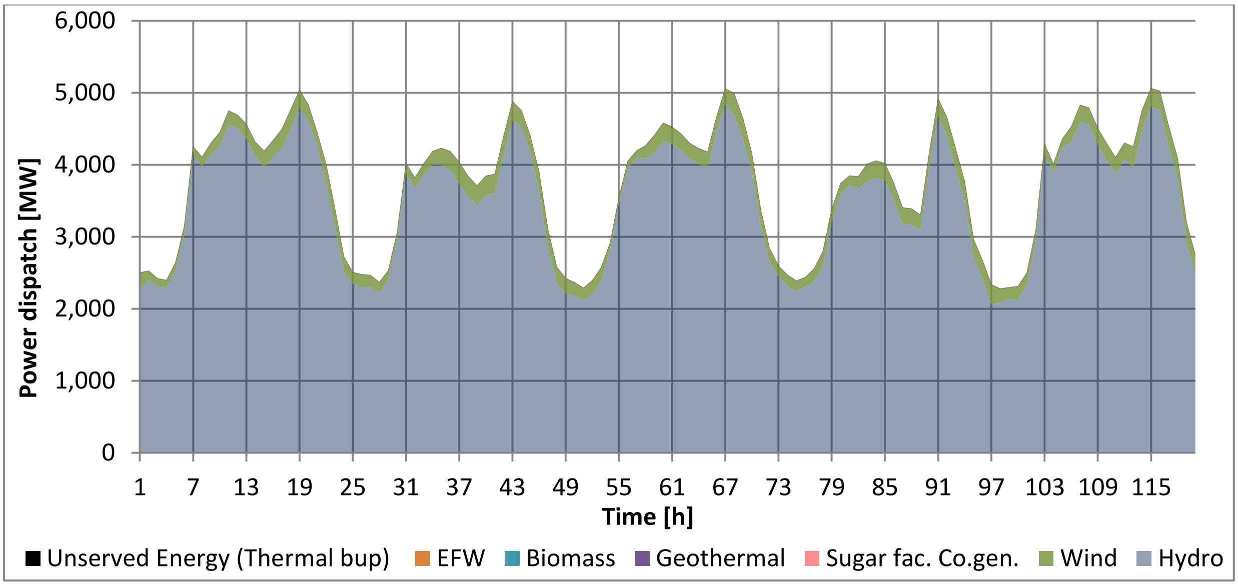


Figure 5.19: Hourly dispatch for the peak demand hour duration of the year- high inflow scenario

During the low inflow scenario, as shown in Figure 5.20, hydropower still takes major share of the energy supply but all technologies participate on the dispatch unlike the moderate and high inflow scenarios. There even exists an unserved energy, in the range of 7.8% - 15.7% of the total energy supplied in that hour, due to the low water inflow to hydropower reservoirs. This shows that high reliance of Ethiopian power system on hydropower plants carries a significant risk for its sustainable energy supply. Thus during the low inflow scenario, unlike the moderate and high inflow scenarios, peak hour demand can not be fulfilled.

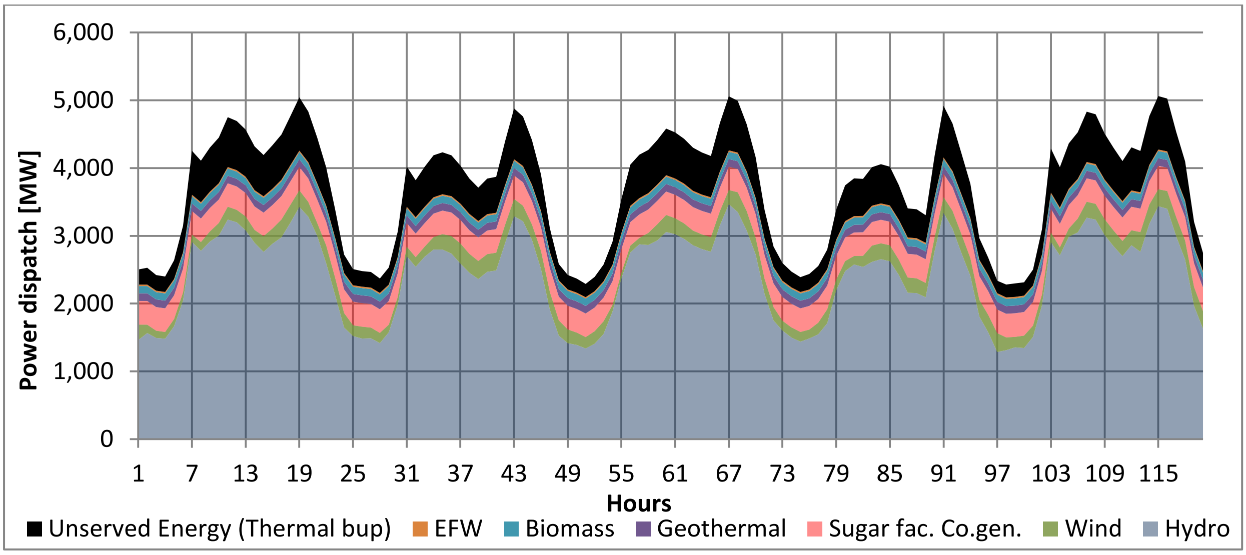


Figure 5.20: Hourly dispatch for the peak demand hour duration of the year- low inflow scenario

5.2.3. Comparison of Scenarios

Sub-sections 5.2.1 and 5.2.2 discussed dispatch results based on High and low inflow scenarios. This sub-section focuses on comparing all scenarios, stated in table 5.3, based on unserved energy, cost of electricity, total cost of power dispatch, plant's capacity usage and energy dispatch percentage composition. Comparisons of scenarios are done based on results of the year round (energy) dispatch.

5.2.3.1. Energy dispatch percentage composition

This section shows percentage share of energy contribution by each technology or plant for the scenarios explained in Table 5.3. Annual average energy contribution percentage share for all technologies based on scenarios in Table 5.3 are given in Figure 5.21. Heavy reliance on hydro technology in all scenarios is noted which accounts from 69.2% up to 95.17% of the total energy supply depending on scenarios.

Regarding the three inflow scenarios, hydropower technology annual average energy contributions are 69.2%, 90.86% and 95.17 % for low, moderate and high inflow scenarios. The percentage share increases with increase in inflow as hydropower receives dispatch priority based on the cheap electricity it produces. Accordingly percentage share of hydropower technology has a significant impact on the amount of energy that will be served by other technologies. During moderate and high inflow scenarios all biomass and EFW plants will not be used due to high total costs. Sugar factories co-generation plants are useful in the moderate and low inflow scenarios. Wind is given prior access to grid, thus same dispatch in all scenarios. In the low inflow scenario despite the fact that all technologies take part in the dispatch, the demand can not be fulfilled and 13.74% of the total energy need (4277GWh) remains unserved.

During reference and low load scenarios, hydro, wind, sugar factories co-generation and very small geothermal technologies are used to satisfy demand and no un-served energy exists. But during high load scenario, though all technologies are dispatched, there exists an unserved energy of 4384.84GWh or 11.55% of the total energy demand. In all the three load scenarios hydropower still stands as the major energy supplier, providing in the range of 74.7% to 93.55% of annual demand. The percentage share of hydropower decreases as the load increases because the load tends to exhaust the existing hydropower potential.

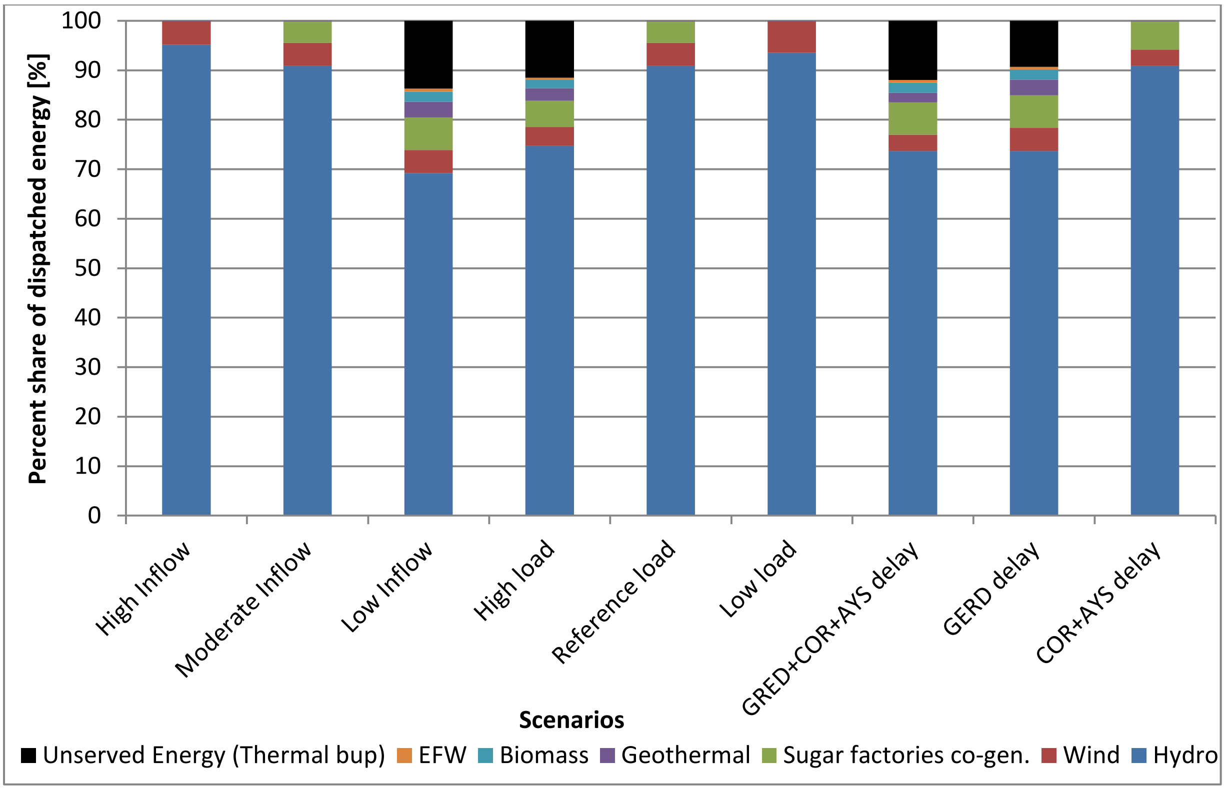


Figure 5.21: Annual average energy contribution percentage share for all scenarios

As far as delay in construction is concerned, GERD+COR+AYS delay and GERD delay scenarios lead to an increased use of other technologies, with hydropower still taking the major share of about 73.66%, but there exists an unserved energy of 3716.261GWh and 2891.777GWh, respectively. COR+AYS delay scenario alone do not bring any significant change on dispatch (as compared to moderate inflow or reference load scenario) except interchanging the dispatch between wind and sugar factories cogeneration plants.

Hydropower being major energy contributor, energy percent share of each hydropower plant, from the total dispatched energy in the year 2017, for all scenarios in Table 5.3 is shown in Figure 5.22. It can clearly be seen that GERD and GG III takes major share of the energy supply in all scenarios. GERD share ranges from 23.7% to 54.66% whereas GG III takes 13.63% to 17.25% of the dispatch. Thus these two plants together contribute significant portion of the demand, from 40.95% to 64.66%, depending on inflow scenarios. GERD hits the lowest percent share during its delay in construction and low inflow scenarios because both contain low water supply to reservoirs.

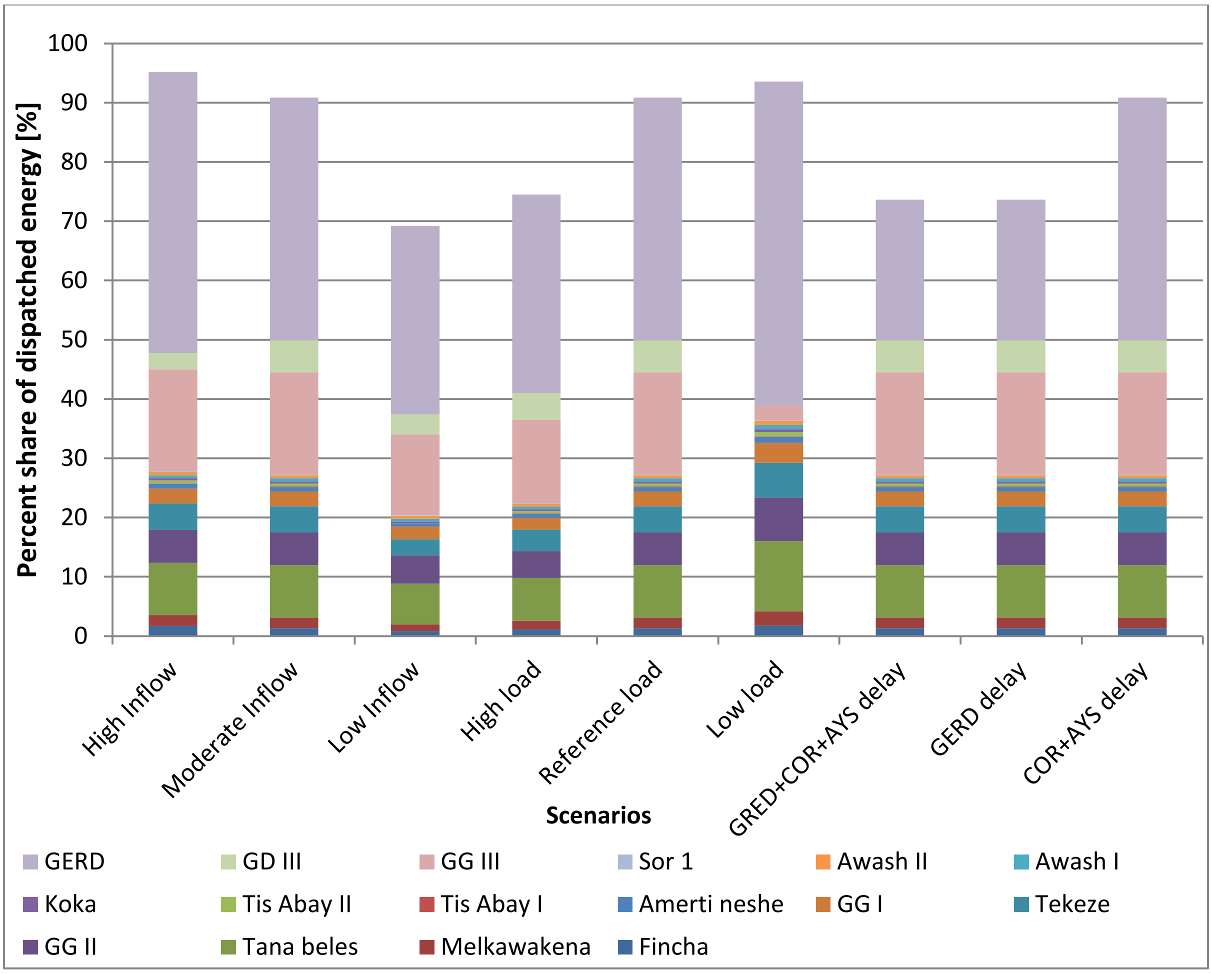


Figure 5.22: Annual average energy contribution percentage share for hydropower plants

Percentage share of energy dispatch by each technology (hydro being major contributor) is shown in Figures 5.23, 5.24 and 5.25 for the three inflow scenarios. These figures illustrate variation of the percentage share throughout the year. It can be seen that hydropower technology percentage contribution increases from June to October, for all inflow scenarios, as it is a rainy season in Ethiopia.

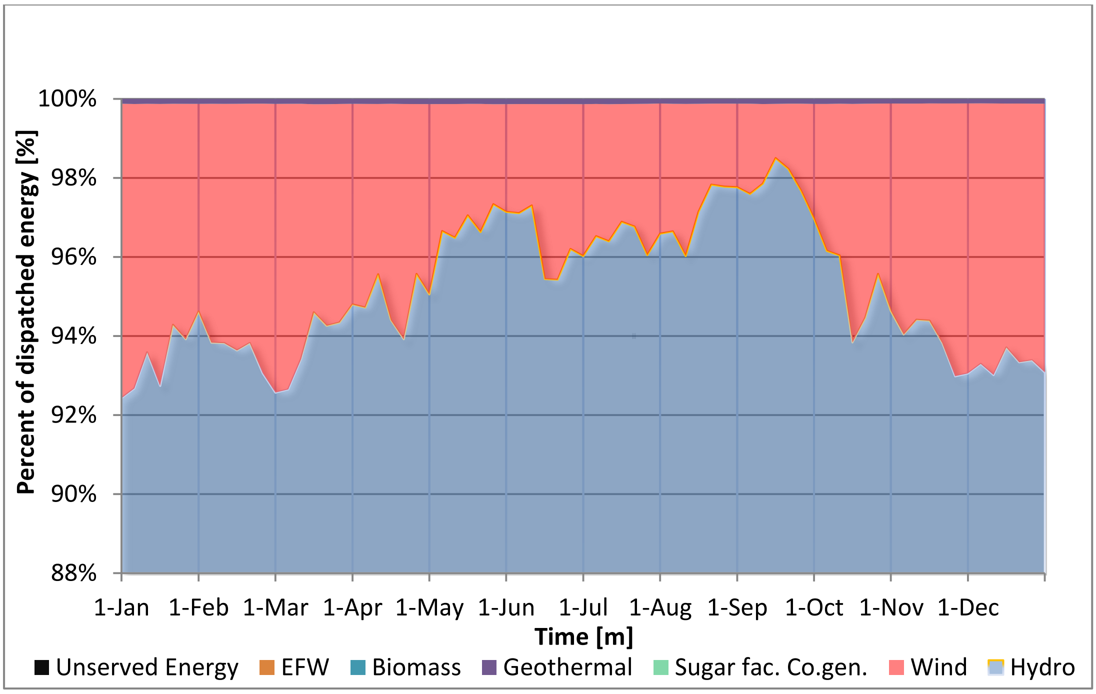


Figure 5.23: Year round share of energy dispatch by technology for high inflow scenario

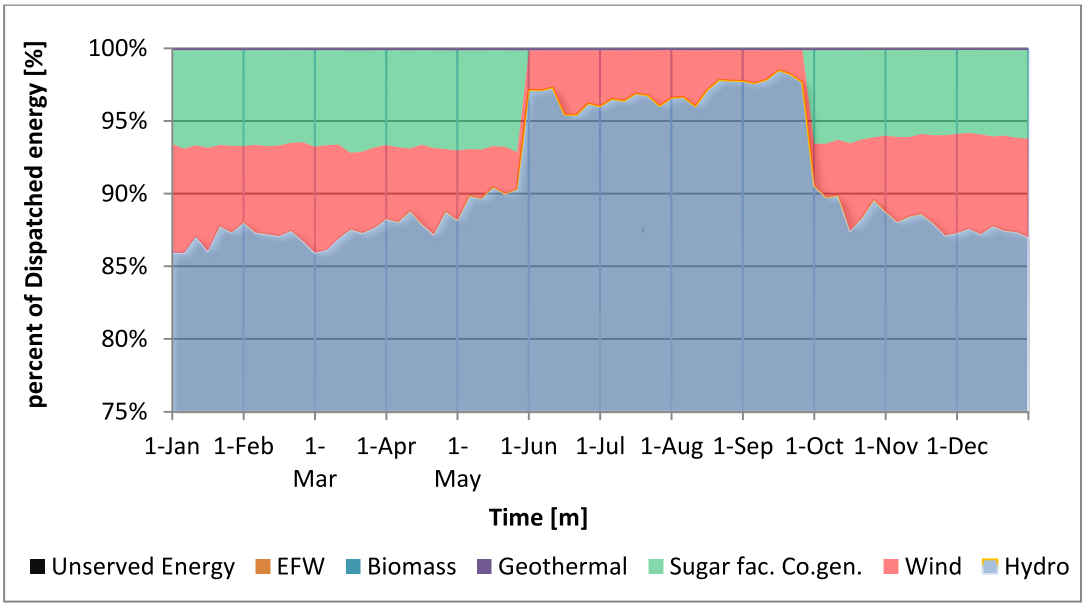


Figure 5.24: Year round share of energy dispatch by technology for moderate inflow scenario

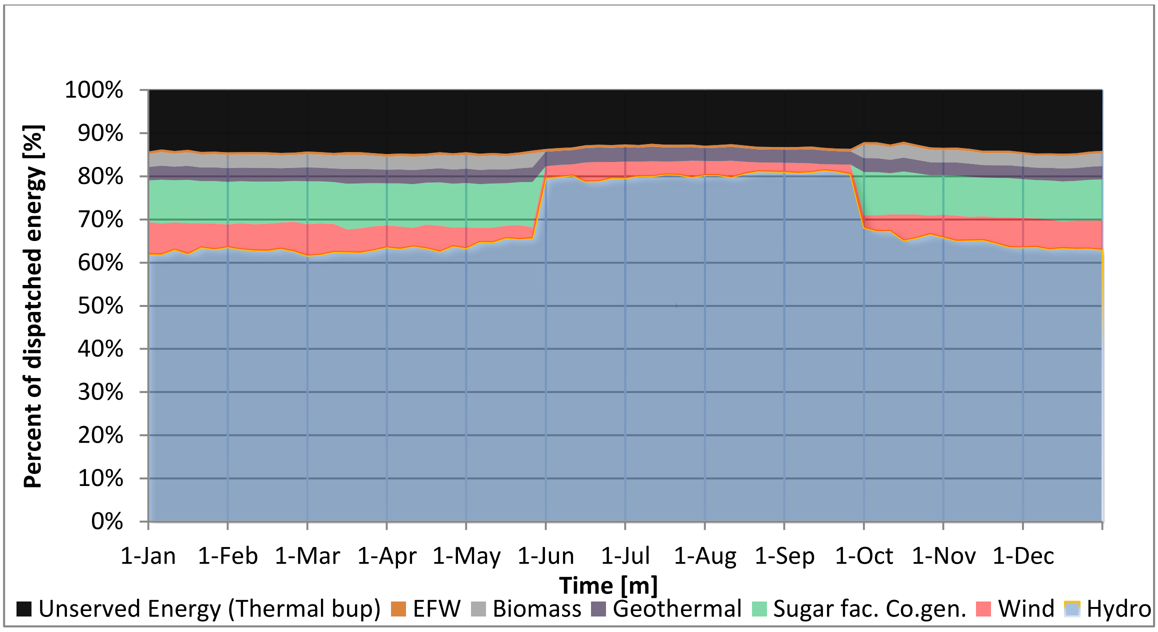


Figure 5.25: Year round share of energy dispatch by technology for low inflow scenario

5.2.3.2. Unserved Energy

Unserved energy represents the amount of energy that can not be served in a specified duration (in this study 2017 G.C.) and thus tells how well a dispatch serves the energy demanded. Figure 5.26 shows the amount of unserved energy that results in different scenarios discussed previously. It can be seen that high and moderate inflow as well as reference and low load scenarios have served all the energy demanded without any unserved energy. In the contrary, low inflow and high load scenarios results in unserved energy of 4277.27 and 4384.84 GWh, respectively. These numbers correspond to 13.74% and 11.55% of the respective total energy demands. This implies an inverse relationship between the amount of water input to reservoirs and the resulting unserved energy and a direct relationship between load growth and unserved energy.

A delay in all three plants (GERD, Corbetti and Aysha) results in unserved energy of 3716.261 GWh which corresponds to 11.94% of the total energy demand. Among the three a delay in GERD alone gives an unserved energy of 2891.777 GWh or 9.29% of the total energy demand. Thus delay in construction of GERD contributes significant portion of the total un-served energy that comes due to delay of all three plants. On the contrary, delay of Corbetti and Aysha alone do not result in any unserved energy. Therefore un-served energy is observed to increase significantly due to delay in construction of GERD but it did not occur in the delay of Corbetti or Aysha. In general unserved energy takes the highest percentage of the demand for low inflow scenario followed by GERD+COR+AYS delay and high load scenarios.

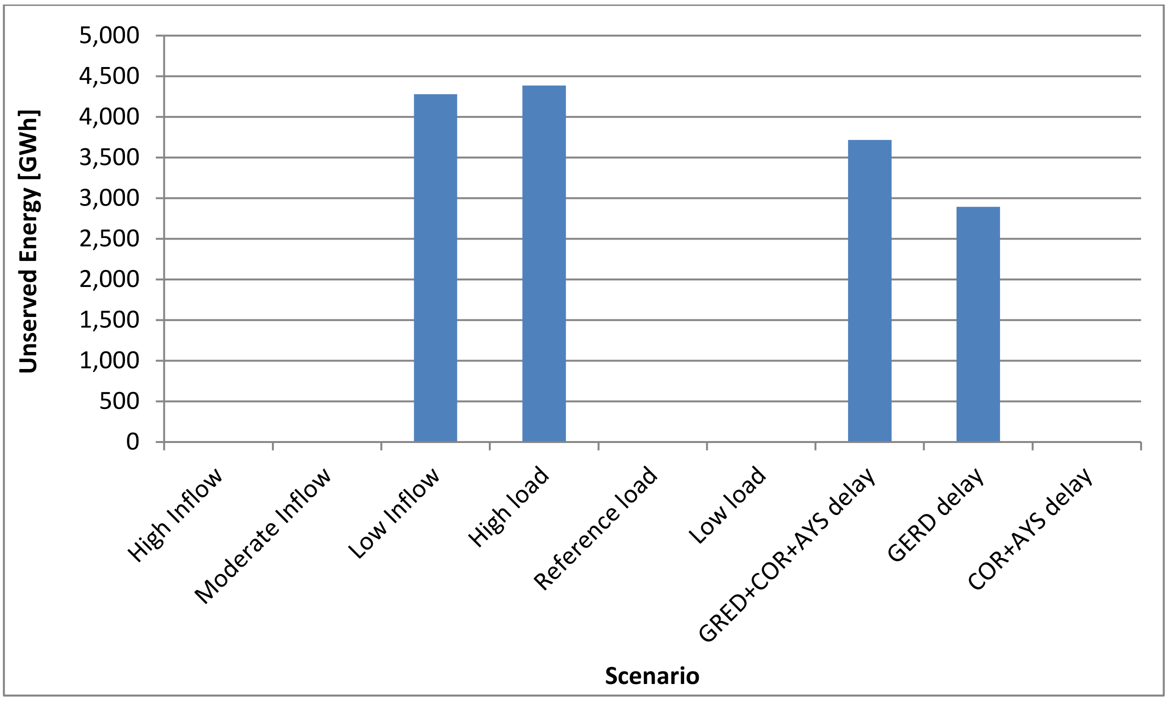


Figure 5.26: Unserved energy for all scenarios

5.2.3.3. Cost of Electricity

Cost of electricity measures the amount of money required to generate one MWh of energy whereas total cost of dispatch gives the total energy generation cost through the dispatch horizon (2017 G.C). Figure 5.27 and 5.28 provides a comparison of cost of electricity and total cost of dispatch for scenarios stated in Table 5.3.

Cost of electricity for high inflow condition is 8% cheaper than the moderate inflow because cheap hydropower plants fulfill the demand due to water abundance. In contrary the low inflow scenario presents a situation where cost of electricity is 8.75 times higher than the moderate inflow scenario. This is mainly because of two reasons:

- Water availability being small, non-hydro expensive technologies like biomass, EFW and Sugar factories co-generation take part in the dispatch making its cost higher than the moderate scenario.

- As stated in section 5.2.3.2 an unserved energy of 4277 GWh results during the low inflow scenario. Levelized cost of unserved energy being $1/KWh[28] for Ethiopia, total cost of un-served energy contributes significant percentage (53.63%) to the total cost of dispatch as shown in Figure 5.28.

Thus, among the inflow scenarios, the high inflow scenario is the most economical one with the least cost of electricity and no un-served energy.

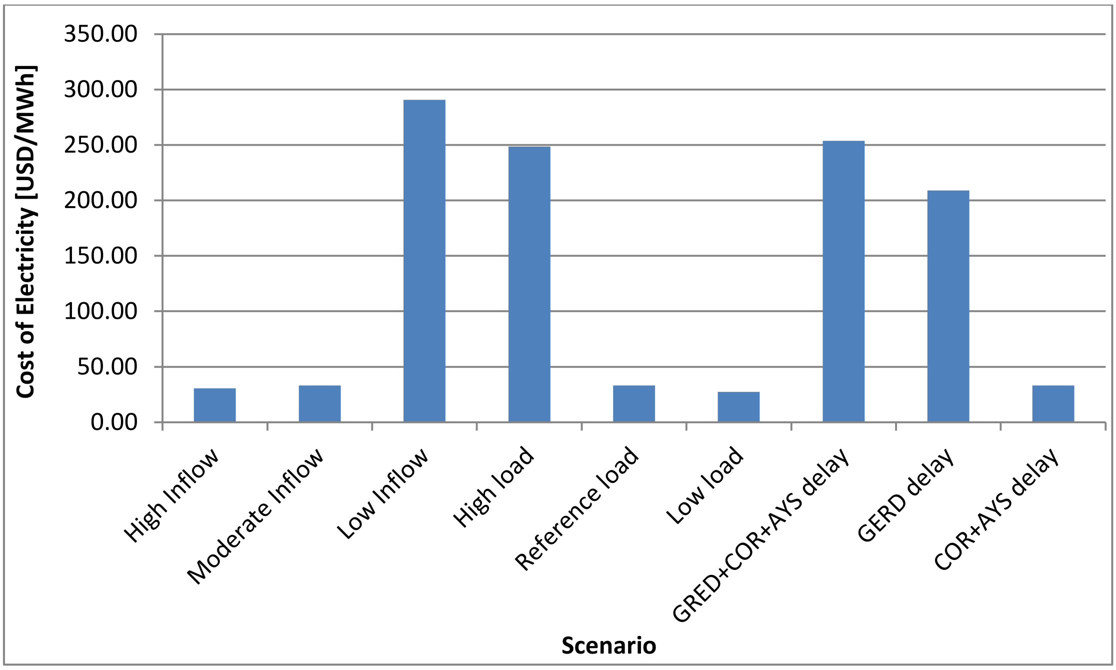


Figure 5.27: Cost of Electricity for all scenarios

Regarding the three load forecast scenarios, the low load scenario is 17.35% cheaper than the reference load scenario owing to the use of only cheap hydropower plants to fulfill the relatively low demand. Unlike the low load scenario, the high load scenario results in a cost of electricity which is 7.49 times higher than the reference load forecast scenario. This is mainly because of two reasons:

- Forecasted load being high, non-hydro expensive technologies like biomass, EFW and Sugar factories co-generation take part in the dispatch making dispatch cost higher than the reference load scenario.
- The unserved energy during the high load scenario, 4385 GWh, contributes significant percentage, 52.68%, to the total cost of dispatch as shown in Figure 5.28.

---

[28] EEPCO power system expansion master plan study, 2014 [12] and East African Power pool and East African community, 2011[38]

Thus, among the three load forecast scenarios, low load scenario is the most economical one with the least cost of electricity and no un-served energy.

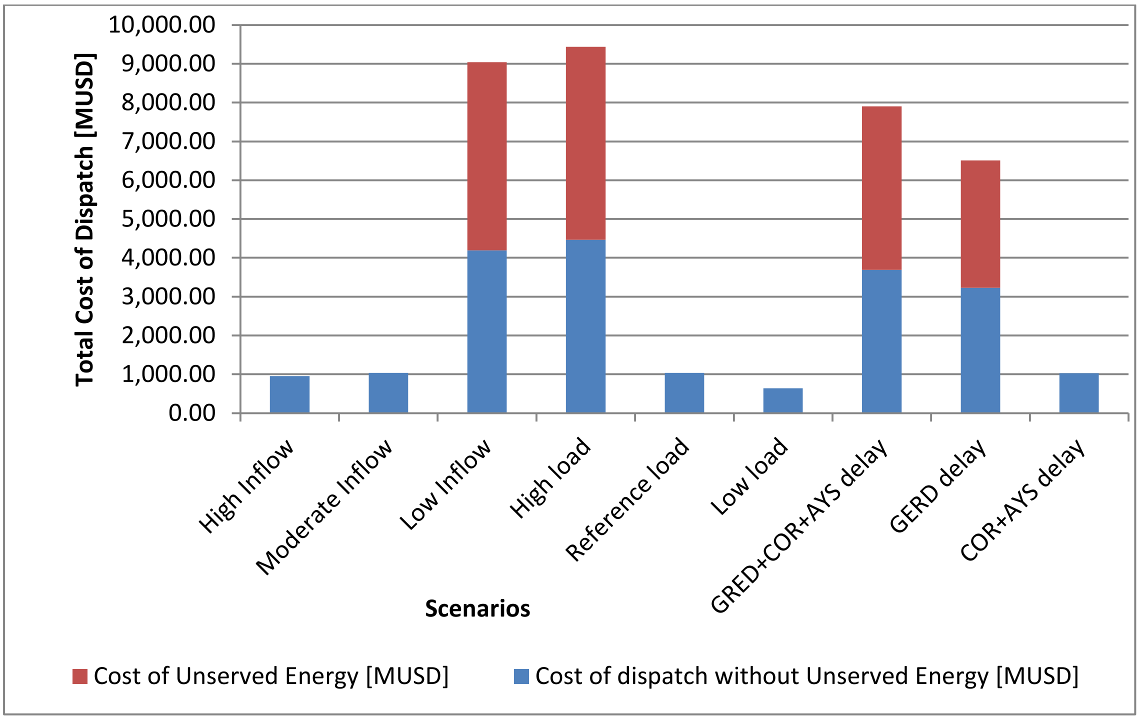


Figure 5.28: Total cost of Dispatch for all scenarios

As far as delay in construction is concerned, delay in Corbetti and Aysha will not affect the cost of electricity as sugar factory co-generation plants, which are dispatched in place of Aysha, are cheaper than Aysha. As shown in Figure 5.27, GERD+COR+AYS delay and GERD delay scenarios bring 7.65 and 6.3 times expensive dispatch than the moderate inflow or reference load scenario, respectively. This is because GERD is major energy contributor and delay in construction causes part of the energy to be unserved. Note that the unserved energy takes more than 46% of the total dispatch cost as shown in Figure 5.28.

Comparing cost of electricity in Figures 5.27 and 5.28, least cost results during low load and high inflow scenarios which are 82.64% and 91.96% of the reference scenario, respectively. In addition highest cost of electricity results during low inflow, GERD+COR+AYS delay and high load scenarios which are 8.75, 7.65 and 7.49 folds the reference scenario, respectively.

5.2.3.4. Power plants capacity usage

As discussed in section 3.4.3 the extent of use of a generating plant is measured by the plant capacity factor. Figure 5.29 compares capacity factor of all hydropower plants resulting from 2017 optimized dispatch (for high, moderate and low inflow scenarios) with respective design capacity factors.

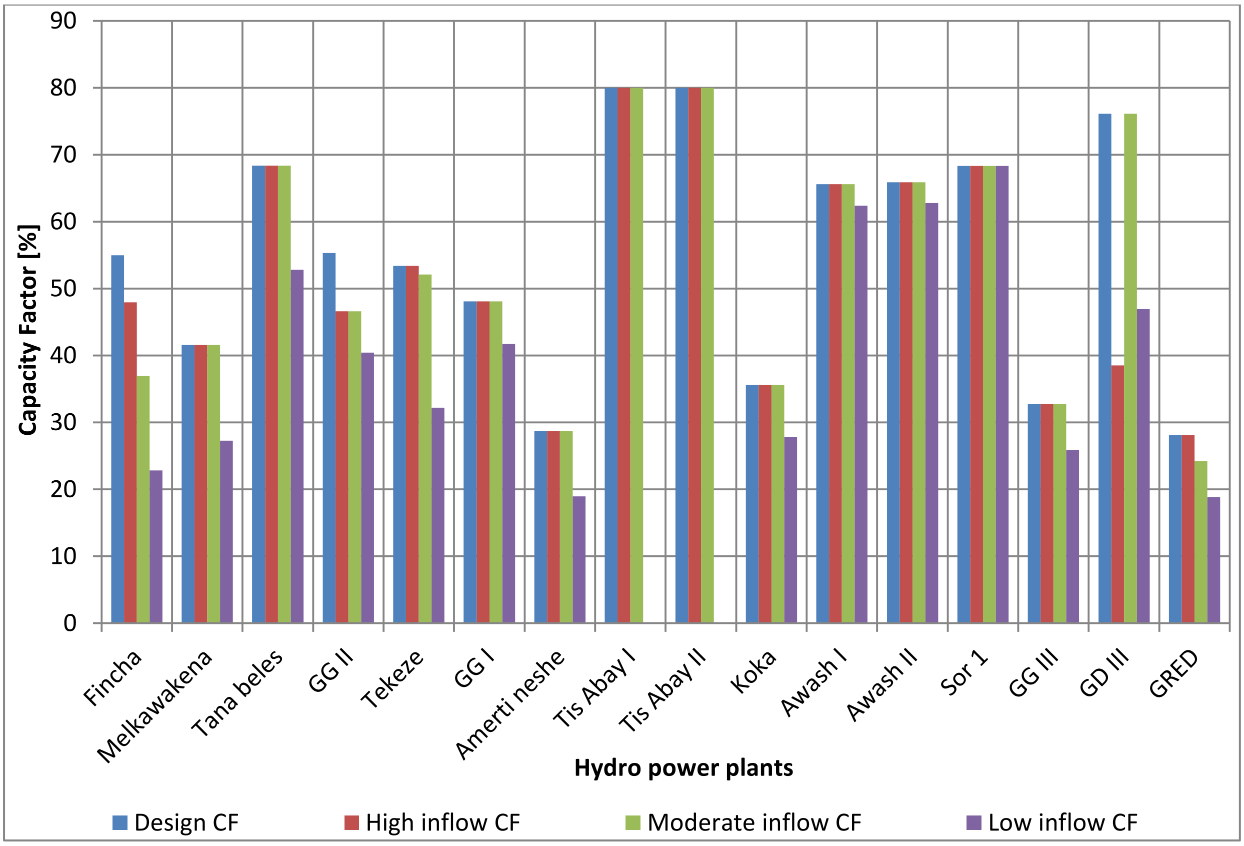


Figure 5.29: Capacity factor for the three inflow scenarios

The following points have been observed regarding each hydropower plant:

- **Fincha**: Despite the fact that Fincha uses all its available water resource and is given dispatch priority than other technologies (like sugar factories co-generation, biomass, EFW), the actual capacity factor is behind the design capacity factor for all inflow scenarios. Thus it can not provide the energy amount it is expected to provide in a year. This is mainly because enough water is not available in the reservoir to reach the designed capacity factor.
- **GG II:** Similar to Fincha, GG II actual capacity factor is less than it's designed capacity factor for all inflow scenarios though it is given dispatch priority than other technologies (like sugar factories co-generation, biomass, EFW). This is because GG II only source of

water is discharge and /or spill of GG I. And since no spill occurs in 2017 the discharge of GG I can not be enough for GG II to use its full capacity.

- **Tekeze and GERD:** Though these power plants are given dispatch priority than other technologies (like sugar factories co-generation, biomass, EFW) and use all the water resource available the actual capacity factor is behind the design capacity factor for moderate and low inflow scenarios. But for high inflow scenario both plants are able to reach the designed capacity factor. Thus it can easily be observed that implying that enough water is not available in respective reservoirs to reach the designed capacity factor during moderate and low inflow scenarios. It is also important to note that GERD dispatches lower capacity than available.
- **GD III:** During high inflow GD III was only needed to provide only half of the energy expected in a year since all other relatively cheaper hydropower plants were able to supply the demand. But it uses all its potential during the moderate inflow scenario. The low inflow scenario is similar to all other hydropower plants where only limited amount of water is available to use which makes the actual capacity factor to fall behind the designed capacity factor.
- **All other hydro power plants** can provide the expected yearly energy with the amount of water available in respective reservoirs. Only during the low inflow scenario all hydropower plants can not provide the expected yearly energy which results in unserved energy as discussed previously.

Non-hydro plants, except wind, are only partly used or not used except for the low inflow scenario. Note that wind plants are given prior access to grid and any potential available will directly be sent to grid regardless of cost to harness the wind energy that can not be stored otherwise.

CHAPTER 6
CONCLUSION AND RECOMMENDATION

6.1. Conclusion

This study works on the case of integrated reservoir and power system operation using two parallel optimization models that are developed. The first model focuses on year round system operation while the second one assesses hourly dispatch for 5 days. The result shows that for a reference load, hydropower contributes 69.2%, 90.86% and 95.17 % of the total demand per year when hydro water inflow is low, moderate and high, respectively. The corresponding share of wind was approximately 4.7% of the annual demand. But the contribution of sugar factory co-generation plants depends on water availability. Specifically, sugar factories co-generation plants contribute 6.56%, 4.32% and 0% for low, moderate and high inflow conditions, respectively. At the same time, Biomass, EFW and Geothermal plants contributes 2.03%, 0.6% and 3.17%, respectively, during low inflow scenario, when unserved energy also shares 13.74% of the energy demand. Geothermal contribution during high and moderate inflow scenarios appears negligible due to its low installed capacity. The result also shows that the cost of electricity generation depends on the nature of the water resource during the study year, i.e. 2017. Hydropower could be credited for low cost electricity services. However, its variability could be a source of significant vulnerability to the Ethiopian power system.

Among hydropower plants, GERD takes major share of the energy contribution with 31.82%, 40.90% and 47.41% of the total demand for low, moderate and high inflow scenarios, respectively. Whereas, GG III and Tana beles together provide 20.47%, 26.1% and 26.1% of the demand in the three inflow conditions. The corresponding share of all other hydro and non-hydro plants are 33.97%, 33% and 26.94% of the total demand in low, moderate and high inflow conditions, respectively. In addition, the hourly dispatch indicates that except for the low inflow scenario, under the remaining two inflow cases the power balance and the reserve requirement were properly satisfied. To fulfill this requirement, dispatching 3 GW and 748 MW of GERD and GG III, respectively, was adequate. Thus, it is concluded that the Ethiopia power grid mainly depends on three hydro power plants, namely GERD, GG_II and Tana beles, for 2017 energy supply.

Examination of reservoirs dispatch shows that during the study year all reservoirs' final volume at the end of period (i.e., Dec 31, 2017) was between 98 and 104 percent of the starting volume in all the three inflow conditions. In addition no spill results in any of the reservoirs at any specific simulation period. This indicates that the significant differences in hydropower contribution under the three scenarios are mainly attributable to water inflow variability. This is of significant policy importance to the Ethiopian power system which heavily relies on hydropower.

Further analyses of various sensitivities were examined by evaluating the impact of other uncertainties related to new power plant construction timeline and load forecast error. Uncertainties of power plant construction delay relates to GERD, Corbetti, and Aysha. The load forecast error was tested by introducing the high and low load scenarios. These additional consideration lead to a total of 9 scenarios including the three inflow scenarios discussed above.

Over all comparison between these scenarios indicate that under four cases the energy need was not satisfied. These scenarios are low inflow, high load, GERD delay and GERD+COR+AYS delay. The corresponding unserved energy as percentage of the total demand was 13.74, 11.55, 9.29 and 11.94, respectively. In addition, the remaining electricity need was supplied at a significantly higher cost as compared to the reference scenario, which becomes 4.7, 4, 3.45 and 4.05 folds the reference case, respectively. Moreover, including the indirect cost of unserved energy (which is a cost to the economy), the cost of electricity becomes 8.75, 7.49, 6.3 and 7.65 folds the reference scenario, respectively. The cost of electricity was found to be cheaper during the low load and high inflow scenarios, which was 82.64% and 91.96% of the cost during the reference scenario. Depending on scenarios the observed increase in cost of electricity could be attributed to the dispatch of more expensive plants and the corresponding cost of unserved energy.

Finally, this study shows that for low inflow scenario, all hydropower plants were operated at a capacity factor significantly lower than their designed capacity factor. Moreover, some power plants such as Fincha, GG II, GERD and Tekeze have been observed to generate lower than their respective designed capacity factors by 18.01%, 8.72%, 3.85% and 1.3%, respectively, even under moderate inflow scenario. The major source for this underperformance appears to result due to water inflow shortage to the respective reservoirs.

This indicates that designing and development of hydropower should focus on efficient utilization of these resources.

6.2. Recommendation

The following recommendations are forwarded towards mitigating vulnerabilities observed in this study.

- **Implementing an optimal integrated operation:** Medium and short term operational planning which provides reliable energy supply with sustainable reservoir management need to be consistently practiced in future.
- **Implementing strategies that enhance inflows to reservoirs:** Water inflow to reservoirs needs to increase, especially for Fincha, Tekeze and GERD, as the high inflow scenario is the most chosen scenario interms of reducing dispatch cost as well as avoiding unserved energy.
- **Emphasizing the use of diverse generation resources:** Increasing percent share of other technologies than hydro could help in avoiding uncertainties that may arise due to water inflow variability.
- GERD supplies more than 40% of the demand in reference scenario and if delayed more than 9% of the total demand will not be served, thus **timely completion of GERD** is recommended.
- **Designing power plants with higher capacity factors**: As hydro dominated system is challenged by energy shortage (due to water inflow variability) than capacity, plants with high capacity factor need to be encouraged.
- This model can be used as a significant input for policy and decision making regarding medium and short term operational planning.

6.3. Future works

The following future works can be performed for better accuracy of this study:

- The model can be modified to incorporate different load areas which take in to account transmission system capacity as well as load flow between load areas for better accuracy of the operational planning.
- A non-linear model can be used to define power productivities for hydropower plants as a function of both head and discharge for more accurate power output estimation.

REFERENCES

1. **A.J. Covarrubias**, Expansion planning for Electric Power Systems, IAEA Bulletin – Vol. 21, No. 213, 1979.
2. **International Energy Agency**, Key World Energy statistics, Accessed from: http://www.iea.org, Accessed on January 10, 2015.
3. **The World Bank**, World Development Indicators, Accessed from: http://databank.worldbank.org/data/views/variableselection/selectvariables.aspx?source=world-development-indicators, Accessed on January10, 2015.
4. **Steven W. Blume**, Electric power system basics, IEEE Press series on power engineering, USA, 2007.
5. **Seth Blumsack**, Economic Dispatch and Operations of Electric Utilities, Department of Energy and Mineral Engineering - The Pennsylvania State University, USA, Pennsylvania, 2014.
6. **Allen J. Wood, Bruce F. Wollenberg**, Power Generation, Operation and Control, A Wiley Interscience publication, USA, 1996.
7. **Prof. P.S.R. Murty**, Power system analysis, BS publications, India, Hyderabad, 2007.
8. **FERC Staff**, Economic Dispatch: Concepts, Practices and Issues, USA, California, November, 2005.
9. **Office of Electricity delivery and Energy reliability**, The value of Economic dispatch, US Department of Energy, USA, November, 2005.
10. **J.B. Gupta**, Power Systems, India, New Delhi, 2004.
11. **Ethio Resource Group**, Diversity and Security for the Ethiopian Power System - A Preliminary Assessment of Risks and Opportunities for the Power Sector, August 2009.
12. **PARSONS BRINCKERHOFF**, Ethiopian Power Systems Expansion Master Plan Study – Draft final report, Ethiopian Electric Power Corporation, Ethiopia, Addis Ababa, February, 2014.
13. **Ministry of Water and Energy**, Ethiopian National Energy Policy (2nd draft), Ethiopia, Addis Ababa, February 2013.
14. **Ministry of Water and Energy**, Scaling-up Renewable Energy Program – Ethiopia Investment Plan (Final draft), Ethiopia, Addis Ababa, January 2012.

15. **Girmaw Teshager**, OPTIMAL POWER GENERATION EXPANSION PLANNING FOR ETHIOPIAN ELECTRIC POWER SYSTEM, M.Sc. Thesis -AAU, Ethiopia, Addis Ababa, July, 2011.
16. **S. Soares, T. ohishi**, Hydro-dominated short-term hydrothermal scheduling via a hybrid simulation-optimisation approach: a case study, IEE Proc-Gener. Transm. Distrib., Vol. 142, No. 6, Brazil, November, 1995.
17. **Carlos Adrian Correa, Ricardo Bolanos, Alejandro Garces**, Short Term Hydrothermal Environmental/ Economic Dispatch Using Interior Point Method, revista épsilon, nº 18 • enero-junio 2012 • pp. 45-58 • ISSN 1692-1259, Colombia, March, 2012.
18. **Nadia Zendehdel, Ali Karimpour, Majid Oloomi**, Optimal Unit Commitment Using Equivalent Linear Minimum Up and Down Time Constraints, 2nd IEEE International Conference on Power and Energy (PECon 08), Malaysia, Johor Baharu, December, 2008.
19. **Bhola N.S. Ghimire, M.Janga Reddy**, Optimal Reservoir Operation for Hydropower Production Using Particle Swarm Optimization and Sustainability Analysis of Hydropower, ISH Journal of Hydraulic Engineering, United Kingdom, London, March, 2014.
20. **Alejandro Perea, Jesús M Latorre, Andrés Ramos, Santiago Cerisola, Rafael Bellido**, Simulation Applications to Hydropower Systems Management and Design, Instituto de Investigación Tecnológica ICAI – Universidad Pontifica Comillas de Madrid, Spain.
21. **Mariana Kleina, Luiz C. Matioli, Débora C. Marcilio, Ana P. Oening, Claudio A. V. Vallejos, Marcelo R. Bessa, Márcio L. Bloot**, Interior-Point Method for Hydrothermal Dispatch Problem, National Agency of Electrical Energy (ANEEL) through- the Strategic Project of Research and Development - ANEEL PE-6491-0108/2009, Brazil, February, 2012.
22. **ABDULKADIR T. S., SALAMI A. W., ANWAR A. R. and KAREEM A. G.**, MODELLING OF HYDROPOWER RESERVOIR VARIABLES FOR ENERGY GENERATION: NEURAL NETWORK APPROACH, Ethiopian Journal of Environmental Studies and Management Vol. 6 No.3 2013, Ethiopia, April, 2013.
23. **Esteban Gil, Julian Bustos, Hugh Rudnick**, Short-Term Hydrothermal Generation Scheduling Model Using a Genetic Algorithm, IEEE TRANSACTIONS ON POWER SYSTEMS, VOL. 18, NO. 4, Chile, November, 2013.

24. **Sergio Pereira, Paula Ferreira, A. Ismael F. Vaz**, Short-term scheduling model for a wind-hydro-thermal electricity system, PROCEEDINGS OF ECOS 2012 - THE 25TH INTERNATIONAL CONFERENCE ON EFFICIENCY, COST, OPTIMIZATION, SIMULATION AND ENVIRONMENTAL IMPACT OF ENERGY SYSTEMS, Italy, PERUGIA, June, 2012.
25. **I.A. Farhat, M.E. El-Hawary**, Optimization methods applied for solving the short-term hydrothermal coordination problem, Electric Power Systems Research 79 (2009) 1308–1320 - Published by Elsevier, Canada, April, 2009.
26. **R. Arunkumar, V. Jothiprakash**, Optimal Reservoir Operation for Hydropower Generation using Non-linear Programming Model, The Institution of Engineers, India, Mumbai, September, 2012.
27. **R. T. Rockafellar**, FUNDAMENTALS OF OPTIMIZATION, Dept. of Mathematics- University of Washington, Seattle, 2007.
28. **WIKIPEDIA - The Free Encyclopedia**, Mathematical optimization, Accessed from http://en.wikipedia.org/wiki/Mathematical_optimization, Accessed on January 12, 2015.
29. **WIKIPEDIA - The Free Encyclopedia**, Linear programming, Accessed from http://en.wikipedia.org/wiki/Linear_programming, Accessed on January 12, 2015.
30. **Afribiz 2013, June 30**, Renewable Energy Potential in Ethiopia**,** Accessed from http://www.afribiz.info/content/renewable energy potential in Ethiopia**,** Accessed on December 25, 2013.
31. **Energypedia**, Ethiopia Energy Situation, Accessed from https://energypedia.info/wiki/Ethiopia_Energy_Situation, Accessed on January 20, 2015.
32. **K.C.Patra**, Hydrology and water resource engineering, Narosa publishing house, India, New delhi, 2008.
33. **Natural Resources Canada**, Wind Energy project model, RETScreen International Clean Energy Decision Support Center, Canada, Quebec, November, 2012.
34. **Lasse Svenningsen**, Power Curve Air Density Correction and Other Power Curve Options In WindPRO, EMD International A/S, Denmark, January, 2010.
35. **Dong Fang Electric Corporation**, Design, Supply, Construction, Installation and Commissioning of Aysha Wind Power Project, December, 2011.
36. **Prasanna Chandra**, Projects planning, analysis, selection, financing, implementation and review, CFM-TMH, Professional series in finance, Tata Mc Graw Hill Education Private Limited, India, New delhi, 2012.

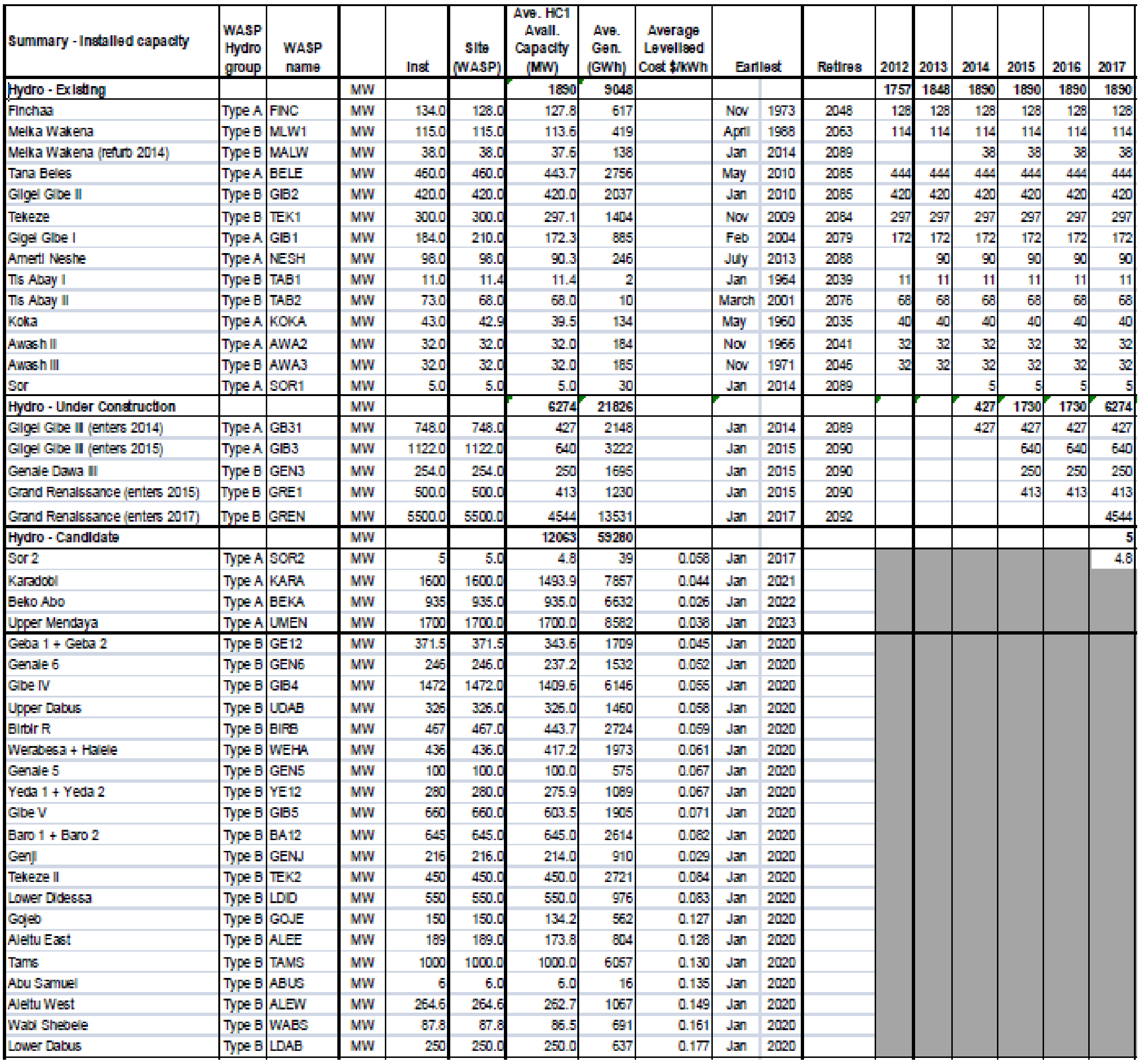
37. **Natural Resources Canada**, Small Hydro project model, RETScreen International Clean Energy Decision Support Center, Canada, Quebec, November, 2012.
38. **SNC LAVALIN INTERNATIONAL INC. and PARSONS BRINCKERHOFF**, Regional Power System Master Plan and Power code study, EAST African Power Pool (EAPP) and East African Community (EAC), Ethiopia, May, 2011.
39. **Belay Dechassa**, Challenges and prospects of Cogeneration and Energy Efficiency Improvement in Ethiopian Sugar Industry, Proc. Ethiop. Sugar. Ind. Bienn. Conf., 1:137-147 (2009) - Published by Ethiopian Sugar Development Agency Research Directorate, Ethiopia, Addis Ababa, 2009.
40. **The MathWorks Inc.**, Large Scale Linear Programming, MATLAB help, USA, 2010.

APPENDICES

Appendix A

The recommended Reference Case of the overall installed generation plan within Ethiopian Power System Expansion Master Plan Study draft final report Prepared for EEPCO, dated February 2014, is shown below in two parts. Table A.0.1 shows part of the generation expansion plan until 2017 G.C [12].

Table A.0.1: Generation expansion plan until 2017 G.C.



Summary - Installed capacity	WASP Hydro group	WASP name		Inst	Site (WASP)	Ave. HC1 Avail. Capacity (MW)	Ave. Gen. (GWh)	Average Levellised Cost $/kWh	Earliest		Retires	2012	2013	2014	2015	2016	2017
Hydro - Existing			MW			1890	9048					1757	1848	1890	1890	1890	1890
Finchaa	Type A	FINC	MW	134.0	128.0	127.8	617		Nov	1973	2048	128	128	128	128	128	128
Melka Wakena	Type B	MLW1	MW	115.0	115.0	113.6	419		April	1988	2063	114	114	114	114	114	114
Melka Wakena (refurb 2014)	Type B	MALW	MW	38.0	38.0	37.6	138		Jan	2014	2089			38	38	38	38
Tana Beles	Type A	BELE	MW	460.0	460.0	443.7	2756		May	2010	2085	444	444	444	444	444	444
Gilgel Gibe II	Type B	GIB2	MW	420.0	420.0	420.0	2037		Jan	2010	2085	420	420	420	420	420	420
Tekeze	Type B	TEK1	MW	300.0	300.0	297.1	1404		Nov	2009	2084	297	297	297	297	297	297
Gigel Gibe I	Type A	GIB1	MW	184.0	210.0	172.3	885		Feb	2004	2079	172	172	172	172	172	172
Amerti Neshe	Type A	NESH	MW	98.0	98.0	90.3	246		July	2013	2088		90	90	90	90	90
Tis Abay I	Type B	TAB1	MW	11.0	11.4	11.4	2		Jan	1964	2039	11	11	11	11	11	11
Tis Abay II	Type B	TAB2	MW	73.0	68.0	68.0	10		March	2001	2076	68	68	68	68	68	68
Koka	Type A	KOKA	MW	43.0	42.9	39.5	134		May	1960	2035	40	40	40	40	40	40
Awash II	Type A	AWA2	MW	32.0	32.0	32.0	184		Nov	1966	2041	32	32	32	32	32	32
Awash III	Type B	AWA3	MW	32.0	32.0	32.0	165		Nov	1971	2046	32	32	32	32	32	32
Sor	Type A	SOR1	MW	5.0	5.0	5.0	30		Jan	2014	2089			5	5	5	5
Hydro - Under Construction			MW			6274	21826							427	1730	1730	6274
Gilgel Gibe III (enters 2014)	Type A	GB31	MW	748.0	748.0	427	2148		Jan	2014	2089			427	427	427	427
Gilgel Gibe III (enters 2015)	Type A	GIB3	MW	1122.0	1122.0	640	3222		Jan	2015	2090				640	640	640
Genale Dawa III	Type B	GEN3	MW	254.0	254.0	250	1695		Jan	2015	2090				250	250	250
Grand Renaissance (enters 2015)	Type B	GRE1	MW	500.0	500.0	413	1230		Jan	2015	2090				413	413	413
Grand Renaissance (enters 2017)	Type B	GREN	MW	5500.0	5500.0	4544	13531		Jan	2017	2092						4544
Hydro - Candidate			MW			12063	59280										5
Sor 2	Type A	SOR2	MW	5	5.0	4.8	39	0.058	Jan	2017							4.8
Karadobi	Type A	KARA	MW	1600	1600.0	1493.9	7857	0.044	Jan	2021							
Beko Abo	Type A	BEKA	MW	935	935.0	935.0	6632	0.026	Jan	2022							
Upper Mendaya	Type A	UMEN	MW	1700	1700.0	1700.0	8582	0.038	Jan	2023							
Geba 1 + Geba 2	Type B	GE12	MW	371.5	371.5	343.6	1709	0.045	Jan	2020							
Genale 6	Type B	GEN6	MW	246	246.0	237.2	1532	0.052	Jan	2020							
Gibe IV	Type B	GIB4	MW	1472	1472.0	1409.6	6146	0.055	Jan	2020							
Upper Dabus	Type B	UDAB	MW	326	326.0	326.0	1460	0.058	Jan	2020							
Birbir R	Type B	BIRB	MW	467	467.0	443.7	2724	0.059	Jan	2020							
Werabesa + Halele	Type B	WEHA	MW	436	436.0	417.2	1973	0.061	Jan	2020							
Genale 5	Type B	GEN5	MW	100	100.0	100.0	575	0.067	Jan	2020							
Yeda 1 + Yeda 2	Type B	YE12	MW	280	280.0	275.9	1089	0.067	Jan	2020							
Gibe V	Type B	GIB5	MW	660	660.0	603.5	1905	0.071	Jan	2020							
Baro 1 + Baro 2	Type B	BA12	MW	645	645.0	645.0	2614	0.082	Jan	2020							
Genji	Type B	GENJ	MW	216	216.0	214.0	910	0.029	Jan	2020							
Tekeze II	Type B	TEK2	MW	450	450.0	450.0	2721	0.084	Jan	2020							
Lower Didessa	Type B	LDID	MW	550	550.0	550.0	976	0.083	Jan	2020							
Gojeb	Type B	GOJE	MW	150	150.0	134.2	562	0.127	Jan	2020							
Aleltu East	Type B	ALEE	MW	189	189.0	173.8	804	0.128	Jan	2020							
Tams	Type B	TAMS	MW	1000	1000.0	1000.0	6057	0.130	Jan	2020							
Abu Samuel	Type B	ABUS	MW	6	6.0	6.0	16	0.135	Jan	2020							
Aleltu West	Type B	ALEW	MW	264.6	264.6	262.7	1067	0.149	Jan	2020							
Wabi Shebele	Type B	WABS	MW	87.8	87.8	86.5	691	0.161	Jan	2020							
Lower Dabus	Type B	LDAB	MW	250	250.0	250.0	637	0.177	Jan	2020							

Geothermal - Existing			MW			5	37					5	5	5	5	5	5
Aluto Langano		GAL1	MW	7	5	5	37		Jan	2007	2032	5	5	5	5	5	5
Geothermal - Committed			MW			75	558										
Aluto Langano II		GAL2	MW	75	75	75	558		Jan	2018	2043						
Geothermal - Candidate			MW			100	745										
Geo - candidate - 100MW		G100	MW	100	100	100.0	745		Jan	2018		▨	▨	▨	▨	▨	▨
Wind - Existing			MW			171	428					81	81	171	171	171	171
Adama		ADA1	MW	51	51	51	150		Jan	2012	2027	51	51	51	51	51	51
Ashegoda (enters 2012)		ASH1	MW	30	30	30	70		Jan	2012	2027	30	30	30	30	30	30
Ashegoda (enters 2014)		ASH2	MW	90	90	90	208		Jan	2014	2029			90	90	90	90
Wind - Committed			MW			153	424								153	153	153
Adama II		ADA2	MW	153	153	153	424		Jan	2015	2030				153	153	153
Wind			MW			300	953									300	600
Wind - candidate - 300MW		WIND	MW	300.0	300.0	300.0	953		Jan	2016		▨	▨	▨	▨	300	600
Solar - Candidate			MW			300	526									300	300
Solar - candidate - equiv. 300MW		SO10	MW	300.0	300.0	300.0	526		Jan	2016		▨	▨	▨	▨	300	300
Energy From Waste - Committed			MW			25	186								25	25	25
Addis Ababa EFW		EFWA	MW	25	25	25	186		Jan	2015	2045				25	25	25
Sugar Factories - Exist., U/C & Comm.			MW		Export	474	2284						26	26	254	354	434
Tendaue / Ende		STEN	MW	120	70	70	337		Jan	2015	2040				70	70	70
Wenji		SWEN	MW	30	16	16	77		Jan	2013	2038		16	16	16	16	16
Finchaa		SFIN	MW	31	10	10	48		Jan	2013	2038		10	10	10	10	10
Beles 1		SBE1	MW	30	20	20	96		Jan	2015	2040				20	20	20
Beles 2		SBE2	MW	30	20	20	96		Jan	2015	2040				20	20	20
Beles 3		SBE3	MW	30	20	20	96		Jan	2016	2041					20	20
Wolkayit		SWOL	MW	133	82	82	395		Jan	2015	2040				82	82	82
Omo Kuraz 1		SOK1	MW	60	20	20	96		Jan	2015	2040				20	20	20
Omo Kuraz 2		SOK2	MW	60	40	40	193		Jan	2016	2041					40	40
Omo Kuraz 3		SOK3	MW	60	40	40	193		Jan	2016	2041					40	40
Omo Kuraz 4		SOK4	MW	60	40	40	193		Jan	2017	2042						40
Omo Kuraz 5		SOK5	MW	60	40	40	193		Jan	2017	2042						40
Omo Kuraz 6		SOK6	MW	60	40	40	193		Jan	2019	2044						
Kessem		SKES	MW	26	16	16	77		Jan	2015	2040				16	16	16
Biomass - Committed			MW			120	578								120	120	120
Bio - committed - "120MW"		B120	MW		60	60	289		Jan	2015	2040				60	60	60
Bio - committed - "137.5MW"		B137	MW		60	60	289		Jan	2015	2040				60	60	60
Diesels - Existing			MW		Site	79	554							78	78	78	78
Dire Dawa		DDDA	MW	40	38	38	266			2014	2023			38	38	38	38
Awash 7 Kilo		DAWK	MW	35	30	30	210			2014	2020			30	30	30	30
Kality		DKAL	MW	12	10	10	70			2014	2020			10	10	10	10
Gas turbines - Candidate			MW			280	2208										
GT - candidate - diesel		GTDO	MW	180	140	140.0	1104		Jan	2016		▨	▨	▨	▨		
GT - candidate - gas		GTNG	MW	180	140	140.0	1104		Jan	2025		▨	▨	▨	▨	▨	▨
CCGTs - Candidate			MW			420	3219										
CCGT - candidate - gas		CCGT	MW	420	420	420.0	3219		Jan	2025		▨	▨	▨	▨	▨	▨
Diesel - Candidate			MW			70	515										
Diesel candidate - HFO/gas		DIHF	MW	70	70	70.0	515		Jan	2016		▨	▨	▨	▨		

Appendix B

Table B.0.1: Productivities of all hydropower plants at different reservoir water levels

Hydro plant	**Parameter**	**Unit/ index**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
Fincha	Water level	masl	2219	2218.7	2218.4	2218.1	2217.8	2217.5	2217.2	2216.9	2216.6	2216.3	2216
	Productivity	MW/(m^3/s)	4.8338	4.8315	4.8292	4.827	4.8247	4.8225	4.8202	4.818	4.8157	4.8135	4.8112
Melka wakena	Water level	masl	2521	2519.7	2518.4	2517.1	2515.8	2514.5	2513.2	2511.9	2510.6	2509.3	2508
	Productivity	MW/(m^3/s)	2.7109	2.7046	2.697	2.6893	2.6817	2.674	2.6663	2.6585	2.6508	2.643	2.635
Tana beles	Water level	masl	1787	1786.7	1786.4	1786.1	1785.8	1785.5	1785.2	1784.9	1784.6	1784.3	1784
	Productivity	MW/(m^3/s)	2.8971	2.8951	2.893	2.8909	2.8889	2.8868	2.8847	2.8827	2.8806	2.8785	2.8765
GG II	Water level	masl	100										
	Productivity	MW/(m^3/s)	4.2857										
Tekeze	Water level	masl	1140	1135.6	1131.2	1126.8	1122.4	1118	1113.6	1109.2	1104.8	1100.4	1096
	Productivity	MW/(m^3/s)	1.45	1.425	1.395	1.36	1.32	1.28	1.24	1.2	1.1575	1.115	1.07
GG I	Water level	masl	1671	1669.2	1667.4	1665.6	1663.8	1662	1660.2	1658.4	1656.6	1654.8	1653
	Productivity	MW/(m^3/s)	2.0158	2.0002	1.9846	1.9688	1.953	1.937	1.921	1.9049	1.8887	1.8725	1.8563
Amerti neshe	Water level	masl	2230	2228.4	2226.8	2225.2	2223.6	2222	2220.4	2218.8	2217.2	2215.6	2214
	Productivity	MW/(m^3/s)	5.0927	5.0791	5.0656	5.0521	5.0386	5.025	5.0115	4.998	4.9844	4.9709	4.9573
Tis abay I	Water level	masl	1622.9	1622.6	1622.3	1622	1621.7	1621.4	1621.1	1620.8	1620.5	1620.2	1619.9
	Productivity	MW/(m^3/s)	0.4328	0.4304	0.4281	0.4257	0.4232	0.4205	0.4178	0.4151	0.4124	0.4097	0.407
Tis abay II	Water level	masl	1622.9	1622.6	1622.3	1622	1621.7	1621.4	1621.1	1620.8	1620.5	1620.2	1619.9
	Productivity	MW/(m^3/s)	0.4224	0.4197	0.417	0.4142	0.4115	0.4088	0.406	0.4032	0.4005	0.3977	0.3949
Koka	Water level	masl	1590.7	1590	1589.3	1588.6	1587.9	1587.2	1586.5	1585.8	1585.1	1584.4	1583.7
	Productivity	MW/(m^3/s)	0.356	0.3497	0.3433	0.337	0.3306	0.3242	0.3177	0.3112	0.3046	0.2979	0.2912
Awash I	Water level	masl	1535.5	1535.4	1535.3	1535.2	1535.1	1535	1534.9	1534.8	1534.7	1534.6	1534.5
	Productivity	MW/(m^3/s)	0.5383	0.5376	0.5369	0.5363	0.5356	0.5349	0.5343	0.5336	0.5329	0.5323	0.5316
Awash II	Water level	masl	1471.8	1471.8	1471.8	1471.8	1471.8	1471.8	1471.8	1471.8	1471.8	1471.8	1471.8
	Productivity	MW/(m^3/s)	0.5415	0.5408	0.5401	0.5395	0.5388	0.5381	0.5375	0.5368	0.5361	0.5355	0.5348
Sor	Water level	masl	100										
	Productivity	MW/(m^3/s)	0.3195										
GG III	Water level	masl	892	882.8	873.6	864.4	855.2	846	836.8	827.6	818.4	809.2	800
	Productivity	MW/(m^3/s)	1.8135	1.7354	1.654	1.5711	1.4874	1.4025	1.3154	1.2245	1.1279	1.0238	0.9107
GD III	Water level	masl	1120	1116	1112	1108	1104	1100	1096	1092	1088	1084	1080
	Productivity	MW/(m^3/s)	2.4039	2.3689	2.3335	2.2987	2.2618	2.2257	2.1895	2.1531	2.1167	2.0801	2.0435
GERD	Water level	masl	640	636.4	632.8	629.2	625.6	622	618.4	614.8	611.2	607.6	604
	Productivity	MW/(m^3/s)	1.22	1.1878	1.1567	1.1233	1.09	1.0567	1.0256	0.986	0.9578	0.92	0.8878

Appendix C

Table C.0.1: Water level of reservoirs on December 31st for years from 2006/7 to 2012/13

Plant/ Year	**2006/7**	**2007/8**	**2008/9**	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**Average**
Fincha	2217.49	2217.77		2216.64	2216.54	2217.14	2217.47	2217.18
Melka wakena	2516.70	2517.10		2515.10	2515.68	2517.27	2515.65	2516.25
Tana	1786.70	1786.37		1785.78	1786.89	1786.91	1787.01	1786.61
Tekeze		1085.60	1102.59	0.00	1134.03	1131.79	1131.57	1117.12
GG I	1668.86	1666.12		1668.03	1665.32	1669.91	1667.80	1667.67
Neshe							2223.07	2223.07
Koka	107.81	108.19		107.02	108.08	108.20	108.46	107.96

Table C.0.2: Altitude volume relationship of reservoirs

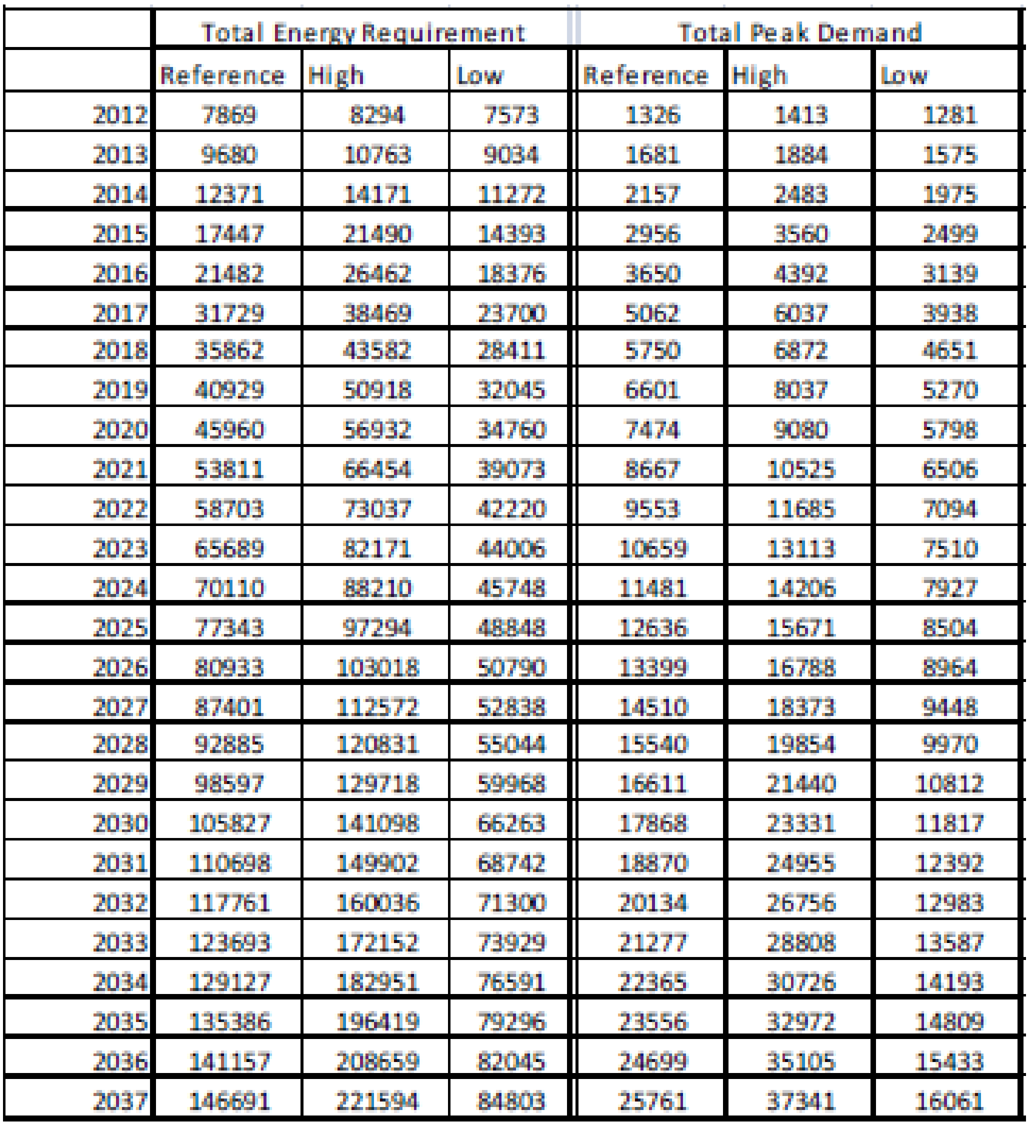
Fincha		**Melka wakena**		**Tana**		**GG I**		**Amerti neshe**		**Koka**	
level - masl	**Volume [Mm^3]**	**level - masl**	**Volume [Mm^3]**	**level - masl**	**Volume [Mm^3]**	**level - masl**	**Volume [Mm^3]**	**level - masl**	**Volume [Mm^3]**	**level - masl**	**Volume [Mm^3]**
2212	0	2508	157	1784	0	1638	0	71.1	2213	97	0.015
2213	50	2509	187.5	1785	2984	1646	42	85	2214	98	0.09
2214	100	2510	212.5	1786	6026	1648	84	101.1	2215	99	0.76
2215	200	2511	250	1787	9127	1651	127	117.2	2216	100	4.35
2215.5	300	2512	282.5	1788	12298	1653	170	135.8	2217	101	18.67
2216	400	2513	320	1789	15540	1656.5	250	175	2219	102	57.33
2217	630	2514	362.5	1790	18855	1658	333	217.9	2221	103	125.38
2217.6	800	2515	410	-	-	1661	417	263.9	2223	104	218.94
2218	850	2516	460	-	-	1664	500	312.9	2225	105	331.7
2219	1200	2517	512.5	-	-	1665.5	583	365	2227	106	460.08
2220	1600	2518	575	-	-	1667.5	667	420.1	2229	107	604.54
2221	2200	2519	640	-	-	1669	750	480.25	2231	108	701.38
2222	2800	2520	702.5	-	-	1671	842	606	2235	109	930.2
2223	3300	2521	745	-	-	1674	1000	673.5	2237	110	1127.16
2224	3800	2522	-	-	-	1675	1080	747	2239	111	1328.31

Tekeze		**Sor**		**GGIII**		**GDIII**		**GERD**	
level - masl	**Volume [Mm^3]**	**level - masl**	**Volume [Mm^3]**	**level - masl**	**Volume [Mm^3]**	**level - masl**	**Volume [Mm^3]**	**level - masl**	**Volume [Mm^3]**
1150	10958	1544	323	893	13300	1125	3330	660	103000
1140	9293	1540	275	890	12700	1100	1250	650	82500
1100	4354	1530	164	805	2500	1075	290	640	62500
1096	4000	1520	93	654	0	1050	45	630	48000
1090	3480	1510	48			1020	20	620	35000
1050	1023	1500	20			1005	0	610	25000

975	0	1490	5					600	17500
		1480	1					590	11000
		1470	0						

Appendix D

Table D.0.1: Electricity generated and maximum demand forecasts including exports



	Total Energy Requirement			Total Peak Demand		
	Reference	High	Low	Reference	High	Low
2012	7869	8294	7573	1326	1413	1281
2013	9680	10763	9034	1681	1884	1575
2014	12371	14171	11272	2157	2483	1975
2015	17447	21490	14393	2956	3560	2499
2016	21482	26462	18376	3650	4392	3139
2017	31729	38469	23700	5062	6037	3938
2018	35862	43582	28411	5750	6872	4651
2019	40929	50918	32045	6601	8037	5270
2020	45960	56932	34760	7474	9080	5798
2021	53811	66454	39073	8667	10525	6506
2022	58703	73037	42220	9553	11685	7094
2023	65689	82171	44006	10659	13113	7510
2024	70110	88210	45748	11481	14206	7927
2025	77343	97294	48848	12636	15671	8504
2026	80933	103018	50790	13399	16788	8964
2027	87401	112572	52838	14510	18373	9448
2028	92885	120831	55044	15540	19854	9970
2029	98597	129718	59968	16611	21440	10812
2030	105827	141098	66263	17868	23331	11817
2031	110698	149902	68742	18870	24955	12392
2032	117761	160036	71300	20134	26756	12983
2033	123693	172152	73929	21277	28808	13587
2034	129127	182951	76591	22365	30726	14193
2035	135386	196419	79296	23556	32972	14809
2036	141157	208659	82045	24699	35105	15433
2037	146691	221594	84803	25761	37341	16061

Appendix E

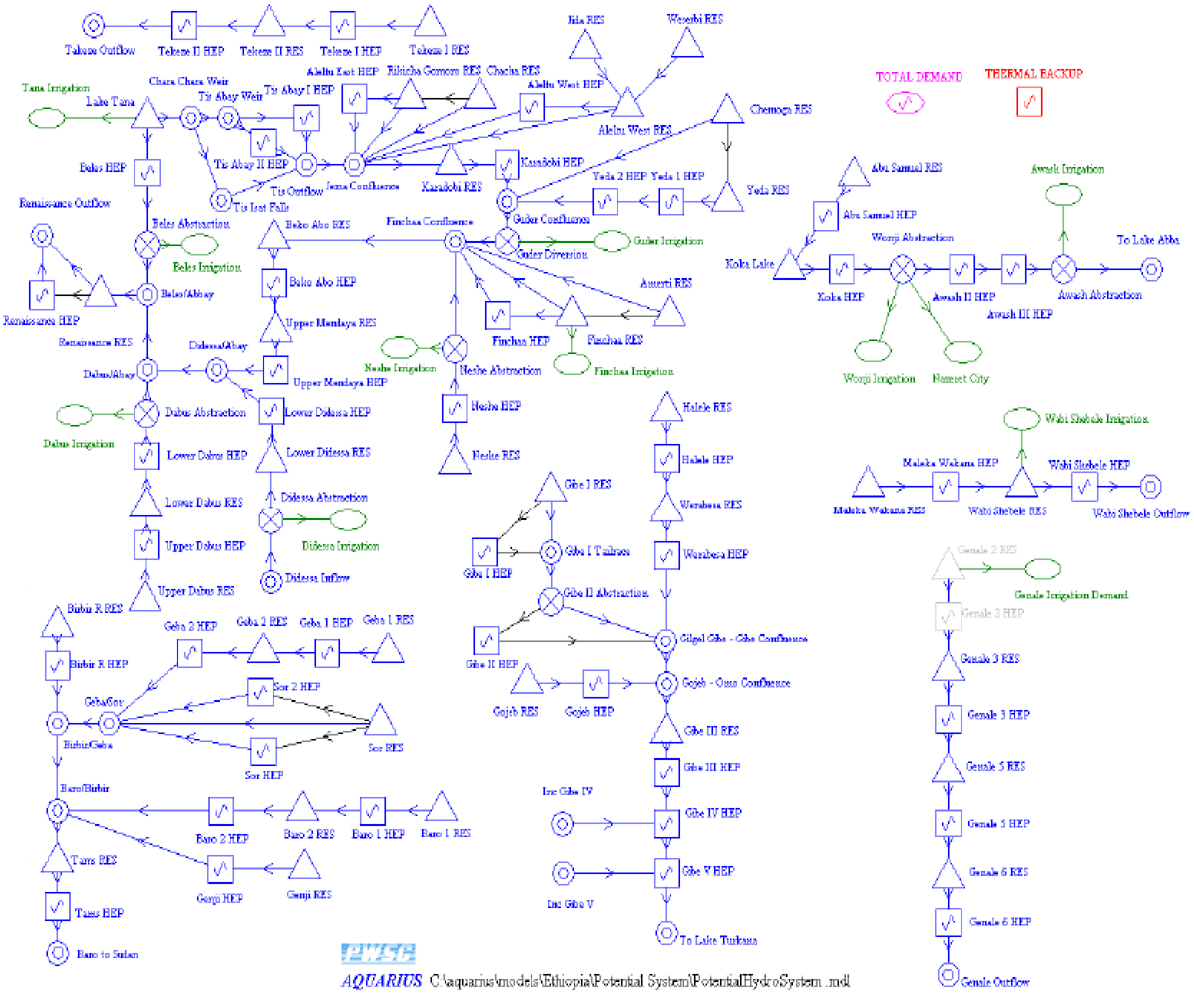


Figure E.0.1: Aquarius ‘Potential Hydro System’ model schematic

Table E.0.1: Reservoirs monthly average total inflow for low inflow scenario

Month	**Monthly Average Total Inflow [m^3/s] _Low scenario**											
	Fincha	**Melka Wakena**	**Lake Tana**	**Tekeze**	**GG I**	**Neshe**	**Koka**	**Sor**	**GG III**	**GD III**	**GERD**	**Total**
Jan	3.0	3.8	45.2	3.4	6.0	0.4	4.9	3.7	56.6	9.4	234.8	371.1
Feb	1.7	3.8	57.9	2.4	3.7	0.3	4.8	2.9	52.7	8.0	164.2	302.4
Mar	1.3	3.7	50.0	3.4	3.4	0.3	4.5	2.6	48.2	7.5	131.1	255.9
Apr	1.5	8.8	11.6	5.0	5.4	0.2	6.9	2.3	65.8	35.4	99.1	242.0
May	1.6	9.0	27.6	8.2	8.2	0.4	5.6	5.6	97.8	48.9	186.5	399.3
Jun	2.2	7.6	54.9	22.8	31.6	0.9	9.7	26.2	283.1	44.0	482.5	965.4
Jul	10.4	26.9	63.7	247.9	96.1	6.5	69.4	64.4	770.4	90.4	1862.7	3308.9
Aug	30.8	52.8	580.6	434.2	134.0	16.6	173.5	106.8	1300.6	122.7	2955.9	5908.5
Sept	33.0	38.4	471.8	149.7	125.8	14.5	98.8	118.1	924.4	119.6	4382.4	6476.5
Oct	20.0	14.0	176.2	34.7	40.0	4.3	20.5	61.6	356.4	119.7	1622.8	2470.2
Nov	10.1	6.6	50.5	12.0	15.8	1.0	6.9	16.2	152.3	43.7	661.8	976.9
Dec	6.2	3.4	40.7	6.7	9.0	0.6	5.6	8.2	80.5	21.4	341.0	523.3

Table E.0.2: Reservoirs monthly average total inflow for high inflow scenario

Month	**Monthly Average Total Inflow [m^3/s] _High scenario**											
	Fincha	**Melka Wakena**	**Lake Tana**	**Tekeze**	**GG I**	**Neshe**	**Koka**	**Sor**	**GG III**	**GG III**	**GERD**	**Total**
Jan	6.1	9.5	80.7	17.2	11.2	0.9	17.2	10.5	110.6	45.9	449.5	759.1
Feb	4.4	13.5	88.9	18.0	8.8	0.8	19.6	7.4	104.5	48.4	308.5	622.7
Mar	2.7	17.0	87.0	20.0	12.0	0.6	24.6	4.9	89.4	47.0	242.1	547.3
Apr	3.3	30.8	65.2	27.4	12.7	0.7	24.3	6.6	120.8	98.2	229.2	619.2
May	4.4	21.6	96.3	23.5	21.7	0.9	19.4	23.2	226.4	167.0	351.1	955.5
Jun	7.6	20.3	130.4	55.2	62.9	2.9	29.7	61.3	396.8	142.4	979.9	1889.4
Jul	21.4	45.6	517.9	476.0	143.4	17.3	138.9	116.9	1248.4	139.7	3283.6	6149.0
Aug	45.0	90.2	952.8	821.4	243.4	28.5	286.0	163.9	1891.6	190.4	4533.3	9246.6
Sept	46.5	67.5	905.9	314.8	204.5	20.4	180.9	184.4	1517.5	214.8	5145.7	8802.8
Oct	33.0	38.6	377.5	83.8	113.7	10.8	46.7	120.2	912.7	263.0	2790.8	4790.7
Nov	18.2	18.1	150.1	49.4	41.7	3.0	24.7	37.1	337.4	137.9	1187.0	2004.5
Dec	8.9	7.4	103.1	31.4	18.4	1.3	14.6	15.7	168.7	79.0	663.1	1111.5

Appendix F

Adama I concatenated if statement after fitting the Power curve of Gold wind 1.5MW wind turbine:

Y = IF(x<4,0,IF(x<7,0*(x^6)+2.1667*(x^3)-18*(x^2)+94.833*(x)-196, IF(x<10,0.6667 *(x^3)+43*(x^2)-354.33*(x)+931,IF(x<12,-73.5*(x^2)+1856.5*(x)-10194,IF(x<25,1500,0)))))

Aysha concatenated if statement after fitting the Power curve of Gamesa 2MW wind turbine:

Y=IF(x<4,0,IF(x<7,4.8333*(x^3)-48.5*(x^2)+203.67*(x)-305,IF(x<10,-3.3333*(x^3)+106.5 *(x^2)-776.17*(x)+1760,IF(x<14,-10.167*(x^3)+337.5*(x^2)-3521.3*(x)+13046, IF(x<25,2000,0)))))

Table F.0.1: Manufacturer and fitted power curve of Gold wind 1.5MW and Gamesa 2 MW

Power curve of Gold wind 1.5MW using 1.225kg/m^3_ Adama I wind farm				**Power curve of Gamesa 2 MW using 1.225kg/m^3_Aysha wind farm**			
V [m/s]	**Manufacturer Power curve [kW]**	**Fitted power [KW]**	**Percent error [%]**	**V [m/s]**	**Manufacturer Power curve [kW]**	**Fitted power[KW]**	**Percent error [%]**
4	34	34.001	0.002	4	43	43.011	0.026
5	99	99.003	0.003	5	105	105.013	0.012
6	193	193.005	0.003	6	215	215.013	0.006
7	329	329.009	0.003	7	402	402.012	0.003
8	507	507.010	0.002	8	660	659.990	-0.001
9	739	739.006	0.001	9	971	970.994	-0.001
10	1021	1021.000	0.000	10	1315	1315.000	0.000
11	1334	1334.000	0.000	11	1617	1616.923	-0.005
12	1500	1500.000	0.000	12	1822	1821.824	-0.010
13	1500	1500.000	0.000	13	1970	1969.701	-0.015
14	1500	1500.000	0.000	14	2000	2000.000	0.000
15	1500	1500.000	0.000	15	2000	2000.000	0.000
16	1500	1500.000	0.000	16	2000	2000.000	0.000
17	1500	1500.000	0.000	17	2000	2000.000	0.000
18	1500	1500.000	0.000	18	2000	2000.000	0.000
19	1500	1500.000	0.000	19	2000	2000.000	0.000
20	1500	1500.000	0.000	20	2000	2000.000	0.000
21	1500	1500.000	0.000	21	2000	2000.000	0.000
22	1500	1500.000	0.000	22	2000	2000.000	0.000
23	1500	1500.000	0.000	23	2000	2000.000	0.000
24	1500	1500.000	0.000	24	2000	2000.000	0.000
25	1500	1500.000	0.000	25	2000	2000.000	0.000

Ashegoda I concatenated if statement after fitting the Power curve of Vergnet 1MW wind turbine:

Y=IF(x<4,0,IF(x<7,-0.5*(x^3)+19.5*(x^2)-102*(x)+158,IF(x<10,2.1667*(x^3)-42.5*(x^2) +405.33*(x)-1270,IF(x<13,4.8333*(x^3)-194.5*(x^2)+2634.7*(x)-11030,IF(x<15,-5.5*(x^2)+169.5*(x)-305, IF(x<25,1000,0))))))

Ashegoda II concatenated if statement after fitting the Power curve of AAER 1.5MW wind turbine:

Y=IF(x<4,0,IF(x<7,2.1667*(x^3)-14.5*(x^2)+76.333*(x)-172,IF(x<10,-1.1667*(x^3)+61*(x^2)-504.83 *(x) +1340,IF(x<12,-87.5*(x^2)+2062.5*(x)-10650,IF(x<25,1500,0)))))

Table F.0.2: Manufacturer and fitted power curve of Vergnet 1 MW and AAER 1.5 MW

Power curve of Vergnet 1MW using 1.225kg/m^3_ Ashegoda I wind farm				**Power curve of AAER 1.5 MW using 1.225kg/m^3_Ashegoda II wind farm**			
V [m/s]	**Manufacturer Power curve [kW]**	**Fitted power [KW]**	**Percent error [%]**	**V [m/s]**	**Manufacturer Power curve [kW]**	**Fitted power [KW]**	**Percent error [%]**
4	30	30.000	0.000	4	40	40.001	0.002
5	73	73.000	0.000	5	118	118.003	0.002
6	140	140.000	0.000	6	232	232.005	0.002
7	228	228.000	0.000	7	395	395.009	0.002
8	362	361.990	-0.003	8	608	608.010	0.002
9	515	514.994	-0.001	9	887	887.006	0.001
10	700	700.000	0.000	10	1225	1225.000	0.000
11	850	850.322	0.038	11	1450	1450.000	0.000
12	930	930.342	0.037	12	1500	1500.000	0.000
13	969	969.360	0.037	13	1500	1500.000	0.000
14	990	990.000	0.000	14	1500	1500.000	0.000
15	1000	1000.000	0.000	15	1500	1500.000	0.000
16	1000	1000.000	0.000	16	1500	1500.000	0.000
17	1000	1000.000	0.000	17	1500	1500.000	0.000
18	1000	1000.000	0.000	18	1500	1500.000	0.000
19	1000	1000.000	0.000	19	1500	1500.000	0.000
20	1000	1000.000	0.000	20	1500	1500.000	0.000
21	1000	1000.000	0.000	21	1500	1500.000	0.000
22	1000	1000.000	0.000	22	1500	1500.000	0.000
23	1000	1000.000	0.000	23	1500	1500.000	0.000
24	1000	1000.000	0.000	24	1500	1500.000	0.000
25	1000	1000.000	0.000	25	1500	1500.000	0.000