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Addis Ababa Institute of Technology
Department of Energy Technology

**The Techno-Economic Feasibility Analysis of Integrating Wind Power Pumped
Hydro-Storage System to the Existing Hydroelectric Power Plants in Ethiopia**

(Case of the Koka Hydropower Plant)

By:

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Abstract

This thesis is intended to study the Techno-economic feasibility analysis of integrating Wind Power Pumped Hydro-Storage system to the existing Hydroelectric Power plants in Ethiopia specially to enhance the volume and efficiency of the Koka Hydropower Plant Station Reservoir by pumping water from the lower reservoir to the upper reservoir in order to supply reliable and steady water to the turbine. In the analysis five tasks are carried out these are: the critical months that are mainly affected by evaporation and climate change are verified which are March, April, May, June and July, the amount of the water that evaporates from the reservoir per hour is determined by using the Evapo-transpiration calculation technique which is the Penman-Monteith equation with heat storage and it is a method with strong likelihood of correctly predicting ET_0 in a wide range of locations and climates, by using this method the average hourly evaporation for these five critical months becomes $24,112\text{m}^3/\text{hr}$, the cost of a pipeline and the various components that contribute to the economics of pipelines for the study area is carried out including designing a fluid distribution system which is sizing of pipes and ducts, determination of the pressure drop in the system, and the power needed to pump required water to the upper reservoir, Wind energy and turbine investment cost analysis using RETScreen Software, and the economic analysis which is seen from three different perspectives that are: the integration of wind power pumped hydro-system from the point view of energy security of the Koka Hydropower Plant, the profitability of the wind power used for pumping purpose from the hydroelectric power or the grid power pumping system, and the profitability of wind power used for pumping purpose from the diesel generator power pumping system.

Finally from the point view of energy security of the existing Hydropower plants in Ethiopia the integration of the wind power pumped hydro-storage system is the best solution.

Key Words: RETScreen Software, Evapotranspiration, Pumped Hydro-storage, Water Temperature

List of Acronym

IMF = International Monetary Fund	IIASA = International Institute for Applied Systems Analysis
UEAP = Universal Electricity Access Program	WatBal = Water balance model
EPCO = Ethiopian Electric Power Corporation	FAO = Food and Agricultural Organization
MW = Mega Watt	MoWR = Ministry of Water Resources
GDP = Gross Domestic Product	WWCE = Water Works Construction Enterprise
ICS = Inter-connected System	WWDSE = Water Works Design and Supervision Enterprise
SCS = Self-Contained System	ETB = Ethiopian Birr
IPP = Independent Power Producer	MAOP = Maximum Allowable Operating Pressure
EREDPC = Ethiopian Rural Energy Development Program Campaign	HP = horse power
GW = Giga Watt	BCM = Billion Metric Cubes
TWh = Tera Watt hour	ha= hectare
MCM = Million Cubic Meter	DDPP= Dire Dawa Diesel Power plant
ET ₀ = Evapotranspiration	BHP = Brake Horsepower
HOMER = Hybrid Optimization Model for Electrical Renewable	DCF = Discounted cash flow
CAES = Compressed Air Energy Storage	DPP = Diesel Power Plant
PHPS = Pumped-Hydro Power Storage	IEA = International Energy Agency
EU = European Union	LFO = Light fuel oil
WT = Wind Turbine	HFO = Heavy fuel oil
LDC's = Least Developed Countries	LHV = Lower heating value
GCM = General Circulation Models	

CHAPTER ONE

1. BACKGROUND AND STATEMENT OF THE PROBLEM

1.1. INTRODUCTION

Ethiopia is located in the eastern part of Africa between 3° to 15° north and 33° to 48° east. With a surface area of 1.1 million square kilometers, it is the third largest country in Africa. Ethiopia is one of the fastest growing developing countries in the world with the total population size estimated 84.9 million inhabitants as 2009 central statistics Agency statistical data. Among these total populations size only about 33% is estimated to have access to electricity and the per capita energy consumption is 40.59kwh, which is the lowest in the world. The Ethiopian economy has been growing at 11.7% per year for the past six years [22]. This, together with rapid electrification through the Universal Electricity Access Program (UEAP), has caused rapid growth in electricity demand. Demand is expected to grow as rapidly in the future due to further economic expansion and the drive for universal electrification.

In the past, while demand was growing slowly, the system was small and significantly over sized and the risks were minimal. In the present context where demand is growing 17% per year [11], the system is expanding fast and must be sized optimally, the risks are significantly higher. This growing percentage is due to a lot of heavy industries like metal industry, cement factories, sugar factories, textile factories, shoe and leather factories, food and beverage factories and urban small scale enterprises and industries which needs or consumes huge electric energies are constructed and also some of them are under construction. So it is not ambiguous to construct or build big power plants like Ethiopia's Grand Millennium Dam which is expected to generate 5250MW energy and wind farms like Ashegoda, Adama I and Adama II as well as it is necessary to keep the safety and the well being of these and formerly constructed power plants to have sustainable energy supply to those listed factories to keep their production stability without any power disruption.

Power disruptions have been common in the past three years. Climatic and technical problems are given as reasons for these disruptions: low water levels due to dry spells, long and delayed construction of large hydropower plants. Both of these problems are very much related to the fact that the system's overwhelming reliance on large hydropower plants. These power disruptions have serious economic impacts. One study estimates that the lost output

due to a one-day power cut to be between 10 to 15% of that days Gross Domestic Product (GDP) of the country. But what may be even more detrimental is the fact that these frequent power cuts portray infrastructure services in Ethiopia to be unreliable discouraging both local and external investment [12].

In Ethiopia electricity is provided by the state power utility EEPCO, and much smaller private, cooperative and municipal power suppliers. EEPCO runs two systems: the Interconnected System (ICS), which accounts for 98% of capacity and generation, and the Self-Contained System (SCS). Peak demand and sales on the ICS have been growing at 5% per year prior 2000 then picked up to 8% over the 2000 to 2004 period then shot up close to 14% from 2005 onwards. Available capacity is no longer able to accommodate demand and EEPCO has been forced to ration power since 2006. Transmission and distribution losses on ICS are high (20% during 2001 to 2005) [12].

The Ethiopian power sector is small even in African standards. Per-capita power and energy available for Ethiopians is significantly lower than many African countries. National electricity access (meaning the population that is within reach of low-voltage distribution lines) is 22% and actual customer connection is only about 15%; rural customer connection is less than 5% [12]. Beside the ICS and SCS systems run by EEPCO, the government is also promoting off-grid rural electrification through a separate agency (EREDPC). With this program the government provides concessionary loans to companies to develop small decentralized systems for electrification of areas outside the ICS and SCS. The off-grid electrification program is progressing at a much slower pace than the grid based program. The resources available for the program are also less than 1% that of the grid based program [12].

1.1.1. Hydro Energy in Ethiopia

Hydropower development in Ethiopia started with mini to small power plants but current and planned development is almost exclusively for large plants. Existing and committed hydropower plants use multi-purpose dams (power and irrigation). There are no pumped storage hydropower plants in Ethiopia and there appears to be none planned for the future. The hydro energy resource potential of Ethiopia is estimated to be 30 to 45GW (159TWh/year). National level resource estimates are not exhaustive or recent and there is considerable uncertainty regarding the potential. However, the fact that committed and planned additions alone add up to 14GW point to the probability that the gross potential would be at least 45GW.

Ethiopia is divided into nine river basins. Two river basins, Abay and Omo-Gibe, account for 72% of the total hydro energy potential. The Baro-Akobo and Genale-Dawa river basins contribute much of the rest. According to the 2001E.C data which is collected by EEPCO for the feasibility study for Ethiopian Adama I Wind Park the output parameters of each hydropower plant is shown in appendix A in MW units.

1.1.2. Hydro dominated power system development strategy

The Ethiopian power system is almost exclusively hydropower based. The reliance on hydropower is further increasing as committed and planned additions to the system are mostly hydro plants. There are both benefits and risks for the accelerated development of hydropower in Ethiopia. The main benefits of hydropower in the Ethiopian context are its low economic cost and its contribution to irrigation and water control. The risks are related to system vulnerability to climate and geo-hazards as well as potential social and environmental impacts.

I. Benefits of Hydropower

Hydropower is a renewable, flexible and reliable source of power and has a central role in integrated energy systems due to its energy storage and regulation capability. This energy storage and regulation capacity is in fact a prerequisite for effective use of other intermittent renewable energy sources such as wind and solar energy (which must be used where and when available) [22]. Dams built for hydropower do also serve to improve the effects seasonal and inter-annual rainfall variability thus contributing to improved water management and food security.

II. Risks of Hydropower

If Ethiopia carries out its current energy development plans, the country will soon be more than 95% dependent on hydropower. Extreme hydro dependence leaves Ethiopia's power sector vulnerable to drought, an increasingly risky scenario due to climate change. Falling reservoir levels will affect Ethiopian electricity consumers and export revenues. In 2003, Ethiopia's power supply was held hostage by severe drought, forcing sudden and severe power cuts which lasted six months. Power cuts of 15 hours twice a week were estimated to cost \$200 million in economic output. In May and September 2008, Ethiopia again experienced costly power cuts due to low water levels an experience which will likely become more frequent and pronounced in the future. The low levels were making worse by increased evaporation

rates, something that could become more worrisome across Ethiopia with climate change impacts.

If Ethiopia wants to protect its energy investments, it should do all it can to minimize risks. Energy projects which are more resilient to hydrological changes should be prioritized. Hydrological modeling of drought risks and predicted climate change impacts would help the government understand whether hydro-investments today will be cost effective 20 years from now and beyond. No analyses of drought and climate change impacts have been undertaken for the Gibe III project, nor for Ethiopia's electricity sector, become more worrisome across Ethiopia with climate change impacts. Therefore, the risks of a hydro dominated power system development strategy for Ethiopia may be divided in two: the first is the risk to the power system itself due to its almost exclusive dependence on a single resource; the second is the environment and social impacts of hydropower development can be considerable. There are significant environmental impacts on soils, waters, biodiversity and health. Hydropower projects also entail the dislocation of local populations and their consequent impoverishment and loss of cultural heritage.

1.1.3. Electricity for Export

Ethiopia predicts that power exports could bring in \$407 million annually, surpassing coffee as the country's most valuable export. By 2012, Ethiopia anticipates that it could export up to 6,159GWh/yr (almost equivalent to Gibe III's 6,500GWh/year). Foreign buyers would need to pay more than \$0.066/kWh to meet Ethiopia's revenue goals.

Ethiopia plans to export a total of 900MW to Djibouti, Sudan and Kenya, and would like to export power even further, to Egypt, Eritrea and Yemen, as well as other eastern and southern African countries via planned grid interconnections. However, no power purchase agreements have yet been signed. Investments in an \$800 million high-voltage transmission line to Kenya still need to be secured [12].

1.2. Description of the study area

The Koka reservoir has been formed as a result of the construction of the Koka dam in 1960 for developing hydroelectric power for Ethiopia. The inflow to the reservoir is supplied by the Awash and the Mojo rivers. It is located in the upper reaches of the Awash River basin with a surface area of 236 km² at an elevation of 1590.70m and approximately 81km southeast of Addis Ababa, and has been in operation for the last 45 years. The 24 m high dam originally impounded some 1750MCM of water. The dam provides a gross head of 42m for

the power plant, which has three units with 14.4MW each and total installed capacity of 43.2MW. The Awash II and III plants lie in-series, down-stream from Koka, both have installed capacities of 32 MW each, with rated heads of 59.8m. Although, the dam was initially constructed for hydropower production, eventually it becomes a multi purpose reservoir and serves as a source of water for the 30,000ha irrigation farms down stream and for flood control. It has been for long supporting lives in the surrounding community. There are about 15,000 local people who have been heavily relying on the lake as source of water for drinking, animal watering, cleaning, fishing, traditional irrigation practices, etc. Now a day, the reservoir has silted up, resulting in loss of 40% of its original capacity. The amount of water available for downstream use is severely reduced and Koka reservoir no longer has a flood-control capacity. In the previous Awash Valley master-plan study, it was proposed to raise the Koka Dam height to increase its capacity to provide water for downstream irrigation, hydropower development, and flood control. The planned Awash River study within the master-plan study will further investigate heightening of the Koka Dam from E.C. 1998 to 2000. Removal of vegetation cover through deforestation and overgrazing, repeated tilling of the soil to prepare fine seedbed and lack of adequate soil and water conservation is causing the dam to silt up. Inflow to the reservoir is heavily laden with sediments, and this has lowered the water volume from the designed live storage capacity of 1,667Mm³ to 1,186Mm³ at present (i.e., loss of 481Mm³), which is a loss of 30% of the total storage volume of the reservoir. Sedimentation in the said reservoir has been surveyed three times; in 1969 spot levels of the reservoir bed were taken and in 1973 and 1981 contour surveys were done. The total sediment deposited in the Koka reservoir in the period 1961-1981 has been estimated at 0.34km³, yielding an average of 17Mm³/year. A certain sediment prediction formula yielded 0.362km³ and 18Mm³/year, respectively [23]. This volume corresponds to a trap efficiency of 95% and to a general rise of the reservoir's initial bed by 3m. Under the current rules of operation the reservoir will not be able to function effectively after the next 16 years or so. Besides to this sediment problem like that of most Ethiopia's Hydropower plants the Koka Hydropower Plant face a reduction of water volume in its reservoir in the winter season due to most contributory rivers to the reservoir also reduces their volume, in addition to this there are also losses in the reservoir by percolation since the reservoir is found in the great east African rift valley. So it is necessary to take an action to takeover the power interruption during less water presence.



Figure 1 Lake Koka (Source: Google Maps)

1.3. Objectives

1.3.1. General objectives

The general objective of the paper is to study the Techno-Economic Feasibility Analysis of integrating Wind Power Pumped Hydro-Storage system to the existing Hydroelectric Power Plants in Ethiopia specially to enhance the volume and efficiency of the Koka Hydropower Plant Reservoir by pumping water from the lower reservoir to the upper reservoir in order to supply reliable and steady water to the turbine.

1.3.2. Specific objectives

The specific objectives of this paper are:

- Determination of critical months with small water volume and estimation loss of water in the reservoir due to evaporation.
- Estimation of loss of energy/power due to decrease in volume/level of water
- Estimation of the volume/capacity of the lower reservoir based on the above water losses in order to store water for later use.
- Estimation of cost of construction of the lower reservoir.
- Carrying out the Pipe Economic analysis for the study area.
- Wind Energy Resource and Turbine Investment Cost Analysis.
- Finally estimation of Economic/Cost Benefit analysis of integrating wind power to pump water from the lower reservoir to upper during the presence of low level of water in the upper reservoir.

1.4. Methodology

The method to be used in the thesis includes:

- **Literature review:** reviewing different books, articles, researches done before and other topics related to the title.
- **Data collection:** different input data's will be collected for the analysis of the thesis.
- **Using Software's:** different software's are used like RETScreen international, Evapotranspiration (ET₀) software version 3.1, and Mat-lab etc.
- **Analysis:** Analyzing different data's collected by using software's and by manually
- Interpretation of Result

1.5. Outline of the Report

This thesis concerns to carryout the Techno-Economic Feasibility analysis of integrating wind power pumped storage system at Koka Hydropower Plant in Ethiopia. Chapter one: is the introduction part that discusses about background and problem of the statement, description of the study area, objective of the study and the Methodology followed to carry out the analysis part. Chapter two: literature survey of Hydropower, Wind energy resource and Energy Storage system, Pumped Hydro-storage System and Determination of Evaporation from Hydroelectric Reservoir. Chapter three: Determination of the Critical Months to Pump the Water to Upper Reservoir and Determination of water volume evaporated from Koka Hydroelectric power plant reservoir. Chapter four: the Pipe Economic Analysis for the Study Area. Chapter five: Wind Energy Resource and Turbine Investment Cost Analysis Using RETScreen. Chapter six Economic Analysis. Chapter Seven: Conclusion and Recommendation.

CHAPTER TWO

2. LITERATURE REVIEW

2.1. Introduction to Hydropower

Hydroelectricity is electricity generated by the force of moving water in the penstock of a hydropower unit. Turbines are used to capture the kinetic energy of water by converting it to electricity as the falling water spins the turbine. Hydropower plants may be located below reservoirs or built in rivers (run-of-the-river units) with no water storage capacity. Hydropower is considered a renewable source of energy, as it relies on water which is continuously renewed through the natural water cycle.

Once a hydroelectric complex is constructed, the project produces no direct waste, has a considerably lower output level of the green house gas carbon dioxide (CO₂) than fossil fuel powered energy plants and ability to be dispatched quickly to meet peak electricity demand have made it one of the most valuable renewable energy sources worldwide. Worldwide, an installed capacity of 1,010GW supplied hydroelectricity in 2010. Approximately 17% of the world's electricity is renewable, with hydroelectricity account for 21% of renewable sources and 3.4% of total energy sources [24].

2.1.1. Hydropower Generating Methods

- **Conventional Method (dams):** - most hydroelectric power comes from the potential energy of dammed water driving a water turbine and generator.
- **Pumped-storage:** - method produces electricity to supply high peak demands by moving water between reservoirs at different elevations. At times of low electrical demand, excess generation capacity is used to pump water into higher reservoir. When there is higher demand, water is released back into the lower reservoir through a turbine. Pumped-storage schemes currently provide the most commercially important means of large-scale grid energy storage and improve daily capacity factor of generation system.
- **Run-of-river:** -hydroelectric stations are those with small or no reservoir capacity, so that water coming from upstream is used for generation at that moment, or allowed to bypass the dam.
- **Tide:** - a tidal power plant makes use of the daily rise and fall of ocean water due to tides; such sources are highly predictable, and if conditions permit construction of reservoirs, can also be dispatch-able to generate power during high demand periods.

2.1.2. Sizes and capacities of hydroelectric facilities

- **Large Conventional Hydropower plants:** - although no official definition exists for the capacity range of large hydroelectric power stations, facilities from over a few hundred megawatts to more than 10GW are generally considered large hydroelectric facilities.
- **Small Conventional Hydropower plants:** - the definition of a small hydro project varies but a generating capacity of up to 10MW is generally accepted as the upper limit of what can be termed small hydro. This may be stretched to 25 MW and 30MW in Canada and the United State [42].
- **Micro:** - micro hydro is a term used for hydroelectric power installations that typically produce up to 100KW of power.
- **Pico:** - hydro is a term used for hydroelectric power generation of under 5KW. It is useful in small, remote communities that require only a small amount of electricity for example, to power one or two fluorescent bulbs and TV or radio for a few homes [42].

2.1.3. Components of hydropower systems

The design of hydropower systems is an extensive field of engineering, requiring input from numerous disciplines including civil, mechanical, electrical, structural, and geotechnical. The major components of a hydropower system are:

- Dams and reservoirs to store the water required for power generation and pumping.
- Hydraulic systems, including the canals, tunnels, pipes, penstocks, valves, gates and pressure control devices used to convey the flow from the upper reservoir to either the tail-water (conventional hydropower) or to the lower reservoir (pumped-storage).
- Mechanical components of the system, including the turbine and balance of plant required for system operation.
- Electrical systems, including the generator, switchgear and transmission system.
- Powerhouse, which contains the turbines and generators.

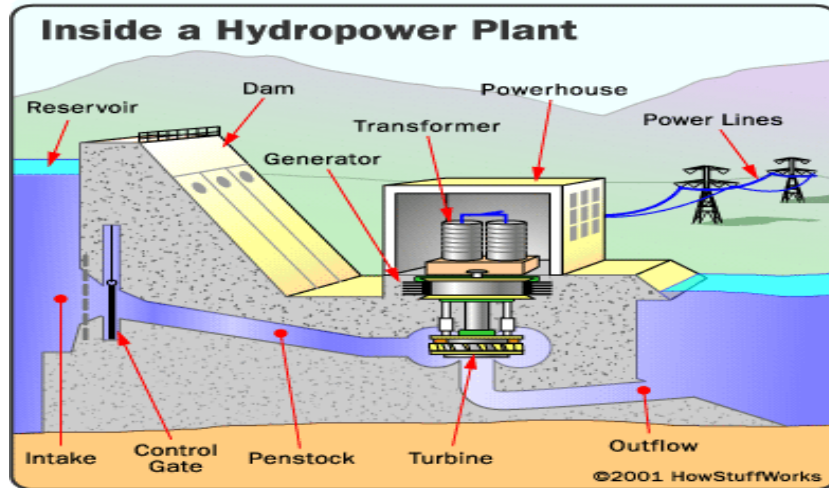


Figure 2 Components of Hydropower plant [25]

2.1.4. Electric Power Production at a Hydroelectric Plant

The amount of electricity generated by a hydropower plant mainly depends on three factors:

- The turbine generating capacity
- The turbine discharge flow (the volume of water passing through the turbine in a given amount of time), and
- The site head (the height of the water source or vertical distance between the highest point of water source and the turbine). The higher the head, the more gravitational energy the water has as it passes through the turbine.

A simple formula for approximating electric power production at a hydroelectric plant is given by [1]:

$$P = \eta \rho Q g H \quad (2.1)$$

where, P is the power output in watts,

η is the turbine efficiency ranging from 0 to 1.

ρ is the density of water ($\sim 1000 \text{ kg/m}^3$)

g is the acceleration due to gravity of 9.81 m/s^2

Q is the flow rate in cubic meters per second (m^3/s)

H is the head or height in meter (m)

The installed capacity of a hydro-plant is the maximum power which can be developed by the generators at normal head with full flow. Annual electric energy production depends on the available water supply.

Primary, or 'firm', power is the power which is always available, and which corresponds to the minimum stream flow without consideration of storage. Secondary, or surplus, power is

the remainder and is not available all the time. Secondary power is useful only if it can be absorbed by relieving some other station, thus affecting a fuel (thermal) saving or water saving (in the case of another hydro-station with storage).

2.2. Introduction Wind Energy System

The kinetic energy in the wind is a promising source of renewable energy with significant potential in many parts of the world. The energy that can be captured by wind turbines is highly dependent on the local average wind speed. Regions that normally present the most attractive potential are located near coasts, inland areas with open terrain or on the edge of bodies of water. Some mountainous areas also have good potential. Wind turbines can be used to provide power to central grids or isolated grids, or to serve as a remote power supply or for water pumping.

The stimulus for the development of wind energy in 1973 was the price of oil and concern over limited fossil-fuel resources. Now, of course, the main driver for use of wind turbines to generate electrical power is the very low CO₂ emissions (over the entire life cycle of manufacture, installation, operation and de-commissioning) and the potential of wind energy to help limit climate change.

The energy available in the wind varies as the cube of the wind speed, so understanding of the characteristics of the wind resource is critical to all aspects of wind energy exploitation, from the identification of suitable sites and predictions of the economic viability of wind farm projects through to the design of wind turbines themselves, and understanding their effect on electricity distribution networks and consumers.

2.2.1. Wind Energy distribution

The speed of the wind is continuously changing, making it desirable to describe the wind by statistical methods. The distribution of wind is expressed by Weibull distribution which is called a Raleigh distribution for K=2. The probability density function based on Rayleigh distribution can be calculated as [8, 30]:

$$f(v) = (\pi/2) \left(v/v_m^2 \right) e^{-(\pi/4)(v/v_m)^2} \quad (2.2)$$

where, V_m = mean wind speed (m/s), V =instantaneous wind speed (m/s)

and the cumulative distribute is calculated as:

$$F(V) = 1 - e^{-\frac{\pi}{4} \left(V/V_m \right)^2} \quad (2.3)$$

where, V_m = mean wind speed (m/s), V =instantaneous wind speed (m/s)

2.2.2. Calculation of wind speed at the hub height

Knowledge of wind speeds at heights of 20 to 120 m above ground is very desirable in any decision about location and type of wind turbine to be installed. Many times, these data are not available and some estimate must be made from wind speeds measured at about 10 m. This requires an equation which predicts the wind speed at one height in terms of the measured speed at another, lower, height. Such equations are developed in texts on fluid mechanics [8, 30]. The derivations are beyond the scope of this text so we shall just use the results. One possible form for the variation of wind speed $u(z)$ with height z is

$$V = V_{\text{ref}} \left[\frac{\ln(z/z_0)}{\ln(z_{\text{ref}}/z_0)} \right] \quad (2.4)$$

where: V =wind velocity at height z above ground level

V_{ref} = reference velocity, i.e., a wind velocity at height z_{ref}

Z = height above ground level for the desired velocity V

Z_0 = surface roughness length of the site

Z_{ref} = reference height, i.e., the height where the exact wind velocity

V_{ref} = is known as reference velocity

2.2.3. Wind Energy Extraction by HAWT

The energy of wind is extracted by using appropriate wind turbine. The wind energy is tapped by the wind turbine which converts the kinetic energy of the wind into mechanical shaft energy. The rotational energy is converted into electrical energy through the transmission system. The transmission system consists of the rotor shaft with bearings, brake(s), an optional gearbox, as well as a generator and optional clutches. The energy available in the wind can be expressed using equation

$$P_w = 1/2 \rho A V^3 \quad 2.5$$

where: ρ =Density of air (kg/m^3)

A =the swept area (m^2)

P_w = power in the wind (W)

V =instantaneous wind velocity (m^3)

Energy conversion from free-flowing fluid streams is limited because full energy extraction implies decrease of fluid velocity (decrease of kinetic energy of the stream), down to zero

which is impossible. Some fluid may not pass through the turbine and may simply flow around it (bypass it). This limitation is expressed in terms of Betz limit defined by the power coefficient C_p and it is defined as the ratio of actual power developed by the rotor to the theoretical power available in the wind and it is given by equation:

$$C_p = \frac{2P_T}{\rho A_T V^3} \quad 2.6$$

where, C_p = power coefficient

P_T = the actual power developed by the turbine

A_T = Area of turbine

The power coefficient, C_p , is a function of the axial induction factor. The optimum of this function (which is a maximum value for C_p) is 0.5926 (=16/27). Thus the electrical power output from the wind turbine can be expressed by equation:

$$P_{\text{wout}} = \eta_t C_p \frac{1}{2} \rho A V^3 \quad 2.7$$

where: P_{Total} = output power of wind turbine

η_t =Overall efficiency of the transmission system/power train

C_p =the power coefficient

The power coefficient and efficiency of wind turbines vary greatly from manufactures to manufacturers. As a result, the power output of wind turbines vary from turbine to turbine and is given by power curve which plots the output power of a turbine against wind speed.

The wind speed at which wind turbine starts generating electrical power is called the cut-in wind speed. The rated wind speed is the wind speed at which the turbine operates at its maximum efficiency of energy conversion. Rated power is the power output at the equal to, or above, the rated speed. The cut-out wind speed is a speed at which the turbine starts to shut down to protect the rotor and drive train machinery from damage, or high wind stalling characteristics [8, 30].

2.2.4. Wind energy equipments

The two main components for energy conversion in the wind system are turbine, and generator, and sometimes gearbox. The rotor converts the fluctuating wind energy into mechanical energy and is thus the driving component in the conversion system. The generator and possibly an electronic inverter absorb the mechanical power while converting it into electrical energy, fed into a supply grid. The main components for the grid connection of the

wind turbine are the transformer and the substation with the circuit breaker and the electricity meter inside it [8, 30].

- **Blades:** - most wind turbines have three blades, though there are some with two blades. Blades are generally 30 to 50 meters (100 to 165 feet) long, with the most common sizes around 40 meters (130 feet). Longer blades are being designed and tested.
- **Controller:** - there is a controller in the nacelle and one at the base of the turbine. The controller monitors condition of the turbine and controls the turbine movement.
- **Generators:** - the generator is the unit of the wind turbine that transforms mechanical energy into electrical energy. The blades transfer the kinetic energy from the wind into rotational energy in the transmission system, and the generator is the next step in the supply of energy from the wind turbine to the electrical grid. Generator is one of the most important components of wind energy conversion systems. In contrast to generators used in other conventional energy options, the generator of a wind turbine works under fluctuating power levels, in tune with variations in wind velocity.
- **Nacelles:** - the nacelle houses the main components of the wind turbine, such as the controller, gearbox, generator, and shafts.
- **Rotor:** - The rotor includes both blades and hub to which blades are attached
- **The Hub:** - the blades on all wind turbines are bolted to the hub. Typically, wind speeds are higher with increasing levels above ground. For that reason higher towers can exploit higher wind speeds so that the annual energy production can be increased correspondingly. The counteracting effect is the respective additional investment cost for the tower and the foundation. The tower heights for wind turbines are chosen to find a good combination of energy yield which is increasing with tower height, and costs for tower and foundation, which are increasing with tower heights.
- **The transmission system:** - this system mainly consists of Main shaft, Main bearings, The clamping unit, Control and safety systems, Tip brakes and The mechanical brake

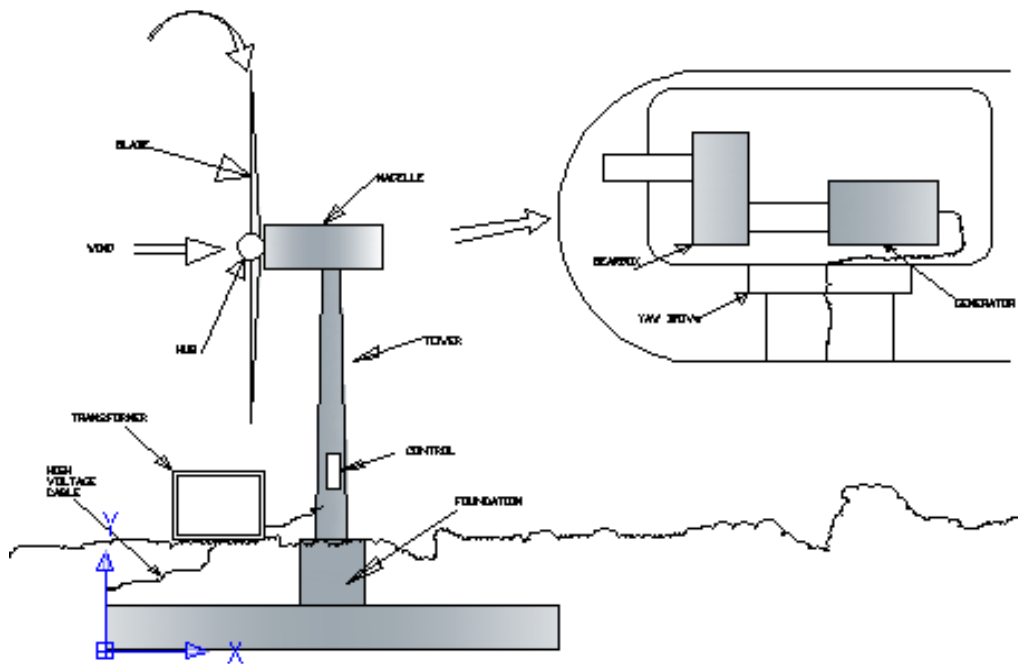


Figure 3 Components of Wind Power System [8, 30]

2.3. Energy Storage System

Electricity energy storage technologies are important for improving the efficiency of electrical energy utilization. The primary aims of developing and deploying electricity storage technologies is their potential to generate an “electricity reserve”, the benefits of which include:

- **Stabilization of the energy market:** Areas that could see improvement with wider application of energy storage are increased diversification and security of supply.
- **Stabilization of the transmission and distribution grid:** A consequence of this is that energy management can potentially reduce the need for reserve fossil fuel plants. Power quality applications can assist in smoothing out faults and other short term disruptions and perturbations, reducing the requirement for ‘spinning reserve’ in the system. Larger scale energy storage devices could also potentially provide ‘black start capacity’.
- **Optimization of intermittent renewable, particularly wind:** Linkage between intermittent sources of energy and associated storage – for example during the night or other periods of low demand – could reduce the vulnerability to supply shortages by providing a means to store excess energy, and then release it during periods of high demand. Improvements in this field will enable intermittent sources to command a higher price for the energy produced by making it more dispatch-able.

2.4. Pumped-Hydro Power Storage System

Pumped-Hydro Power Storage (PHPS) is a mature and well-developed technology ready to contribute and be a part of the call for renewable energy sources. Currently, there exists 90GW of PHPS worldwide, representing 3% of global generation capacity [27, 32]. Characterized by large capital expenditures and construction schedules measured just this side of a decade, with the capability to store thousands of megawatts of power, PHPS is still the most widespread energy storage system used to date. The first pumped hydro system was used in Italy and Switzerland beginning in 1890 and appeared much later in the U.S. when the Rocky River pumped hydro facility first opened in Connecticut in 1929 [34]. By 1933, reversible pump turbines were widely available, and as utilities discovered pumped hydro to be an effective way to manage system loads, pumped hydro peaked in construction during the 1960's through the 1980's (Baxter, 2006). In 2000 the United States had 19.5 GW of pumped storage generating capacity, accounting for about 2.5% of base load generating capacity. In 2007 the EU had 38.3 GW net capacity of pumped storage out of a total of 140GW of hydropower and representing 5% of total net electrical capacity in EU. For small islands with low installed power the pumped-storage method seems to be the most promising way to utilize the available wind potential at a high penetration level [5].

Pumped-Hydro Power Storage utilizes two reservoirs at varying elevations to convert stored gravitational potential energy into electrical energy. A pumped storage system operates by using excess energy output during periods of low demand to pump water from the lower reservoir to the upper reservoir to be stored as gravitational potential energy or uses Wind Energy for pumping the water from the lower reservoir to the upper reservoir. During times of heavy demand load, the water in the upper reservoir is released through turbines generating electricity to supply the grid [32]. The pumped-hydro system is capable of daily and seasonal load balancing. The water used to “fuel” a facility is clean, renewable, and free, providing wind energy with an equally renewable storage partner. An entire cycle of the pumped-hydro system results in a satisfactory efficiency between 70-85%, competitive if not superior than many storage devices.

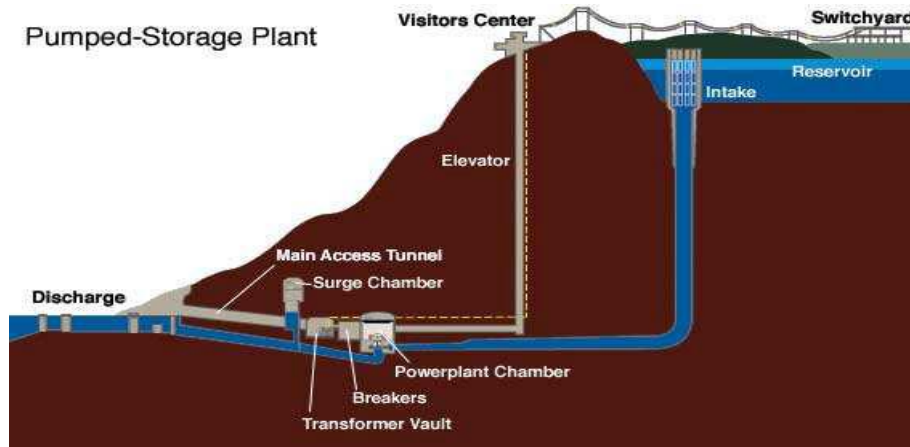


Figure 4 Diagram of Pumped Hydro Facility [32]

According to study of group of researchers for Ikaria Island near Greece due to the high load fluctuations internal combustion engines usually work with low efficiency and in order to increase maximum penetration level of renewable energy system especially of wind energy they redesigned the system from scratch so that wind energy will be the main energy source for the island community and the conventional diesel units will be in the only additional and backup role. The aim of their study was to find the optimum size of each subsystem: i) the capacity of the installed WP, ii) the capacity of the pump-station and iii) the capacity of the reservoirs. After the optimum sizing they found that the hybrid system should compose of: i) Wind Energy Subsystem with total capacity of 5400kW with the existing capacity of 385kW, ii) Mid term storage system with nominal power of 1600kW and iii) Conventional power station with capacity of 6900kW. After simulation they found that the suitable reservoir size is 60000m³. The pumping unit should be composed of ten 160kW pumps. The simulation results are presented and the optimization procedure is analyzed in. At the end of their study they found that the Hybrid System of Ikaria would be a highly profitable investment [6].

According to Bueno and Carta study on a wind powered pumped hydro storage system installation on Gran Canaria Island (Canarian Archipelago), the results obtained from the application of an optimum-sized economic model of such a system indicate that penetration of renewable sourced energy can be increased by 1.93% at a competitive cost for the unit energy supplied. The total thermal electrical power installed in Gran Canaria on 31 December 2002 was 715.36 MW. Total electricity production from the power stations during 2002 was 2,725,570.55MWh, with a fossil fuel consumption of 681,175 metric tons. Wind sourced power connected to the island grid at the end of 2002 was 74,535kW, entailing 10.42% of conventional power, with total electricity production in 2002 of 128,588,336kWh; this means an overall annual penetration of 4.72% of renewable sourced energy fed into the grid. For the

proposed system to operate correctly they propose a control algorithm which will make a balance between the total electrical power P_{total} fed into the grid by the three types of power subsystems (diesel power system, pumped hydro storage system, and wind farm) involved and the total demand D_{total} required by the various loads. The iterative method was considered for finding out the optimum combination for their proposed hybrid system. In their result they found that the renewable system which provides the minimum cost of the unit energy supplied (0.084euros/kWh) consists of 24 WT with a rated output of 850kW, 89 pumps with a rated output of 200kW and six hydraulic turbines with a rated output of 10MW. These results are obtained on the hypothesis that two of the largest existing reservoirs on the island (with a difference in height between the two of 281m and a capacity of some 5,000,000m³ in each) are employed as storage deposits [9].

According to another research conducted for Ramea which is a small island in southern Newfoundland, since 2004, Ramea has a wind-diesel hybrid power system to provide power for approximately 600 inhabitants. The average wind energy contribution to the total supplied load is less than 10%. Newfoundland and Labrador Hydro has upgraded the Ramea hybrid power system. They have added three more 100kW wind turbines and a hydrogen energy storage system. The current hybrid power system in Ramea consists of a diesel plant, wind turbines, and a hydrogen based energy storage system. Their analysis indicates that yearly contribution from the hydrogen storage to the system will be less than 1%. They propose a pumped hydro based energy storage system for Ramea. Their study shows that a 4000m³ water reservoir could be built on the Man of War hill in Ramea for excess wind energy storage. This reservoir will have a head of 63m and can use sea water. A 150kW pumping and turbine station could be built near the base of Man of War hill next to the available water and already existing transmission line. Their analysis indicates that such a pumped hydro energy storage system will lead to 37% renewable energy fraction and result in an acceptable electrical transient in the system. By using a synchronous machine based turbine unit and an induction motor based pumping unit a pumped hydro energy system can be directly connected to the system. A variable speed system is also a possibility. They believe that such an energy storage system can be built and maintained using locally available technology and manpower. Therefore, they recommend a full feasibility study of such an energy storage system for Ramea, Newfoundland. They also believe that pumped hydro energy storage is the best energy storage option for many diesel communities in Newfoundland and Labrador [2].

2.5. Impact of Climate Change on Hydropower Potential

Increased global precipitation would appear to suggest more water available for hydroelectric power production. However, higher temperatures will lead to increased evaporation of the water levels of the reservoirs and as a result it brings lower hydroelectric power production. In the past, feasibility studies have relied on historical rainfall and river flow data for the assessment of hydroelectric potential at a proposed site, but now it is serious to study the climatic conditions of the site because of a climate change has a great impact on hydropower production by reducing or affecting the amount rainfall and river flows rates. Therefore, the resource potential for hydropower is mainly based on historical data for the present climatic conditions [39]. Generally, with a changing climate; the hydropower potential could change due to:

- Changes in river flow (runoff) related to changes in local climate, particularly on precipitation and temperature in the catchment area.
- Changes in extreme events (floods and droughts) may increase the cost and risk for the hydropower projects.
- Hydropower potential depends on topography and volume, variability and seasonal distribution of runoff. An increase in climate variability, even with no change in average runoff, can lead to reduced hydropower production unless more reservoir capacity is built. Generally, the regions with increasing precipitation and runoff will have increasing potential for hydropower production, while regions with decreasing precipitation and runoff will face a reduction in hydropower potential.

Consequently, Changes in the quantity and timing of river runoff, together with increased reservoir evaporation will have a number of effects on the production of hydroelectric power. These include impacts upon system operation, financial effects and impacts on other energy sectors:

- Changes in the availability of existing hydroelectric plant, together with system constraints will affect the ability of electricity supply system to meet average and peak demands. In longer term, as demand levels increase, system planning may have to address any predicted shortfall in hydro output by constructing additional generating plant [40]. The likelihood is that fossil fuels will be used; further enhancing radiative forcing [39].
- Hydroelectric stations are characterized by low operational costs but high capital costs. Generally, revenue from electricity sales is the only way of servicing the capital debt. Thus reductions in electricity sales will affect the return on investment and hence the

viability of the plant [39]. The loss of hydroelectric generating capacity will require additional plant to be constructed to meet demand, requiring additional capital and thus reducing overall system returns. Many large hydropower developments in Least Developed Countries (LDC's) are built with the intention of stimulating economic development. Generally, this requires international financing with a requirement for the loan repayments to be in hard currency. Reductions in revenue may affect the ability to repay the hard currency debt and this may severely stress a weak economy.

2.5.1. Impact of Climate Change on Ethiopian Hydropower Reservoirs

Ethiopia's 'white oil'—water—translates into abundant hydropower potential, yet less than 10 percent has been harnessed due to numerous challenges, including financial, political, socio-economic, and climate. Effectively, this translates into 83 percent of Ethiopia's population lacking access to electricity, and 94 percent still relying on fuel wood for daily cooking and heating [31, 37].

Implications of climate variability and emerging climate change within Ethiopia are less well understood, further complicating the landscape. This motivates analysis to understand how and to what extent climate change may impact the energy sector through hydropower, given the current development strategy. Alternative development strategies to mitigate climate risks may ultimately be warranted [31].

A new approach to the determination of lake evaporation is being tested on Lake Tana Ethiopia which is a high altitude lake in the source area of the Blue Nile at altitude 1786m, and average area of 3000km². A ground survey in the Lake Tana catchment area was carried out in August 2007 in co-operation with the Ethiopian Ministry of Water Resources, Bahir Dar University and Lake Tana Research Center. Additional information with regard to lake temperatures and synoptic meteorological data was collected since the start of 2008. According to the investigation on determination of Lake Tana Evaporation the annual evaporation of the Lake Tana lays between 0 to 600mm/year [3].

The Awash River starts in the highlands of central Ethiopia, at an altitude of about 3000m above sea level. After flowing to the southeast for about 250km, the river enters the Great Rift Valley at an altitude of 1500m, and then follows the valley for the rest of its course to Lake Abe on the border with the Djibouti Republic, at an altitude of about 250m. The total length of the river is about 1200km and its catchment area is 113,700km². The Awash River drains the northerly part of the Rift Valley in Ethiopia from approximately 8.5° N to 12° N.



Figure 5 Awash River Flow Map

The Koka Reservoir, about 75km from Addis Ababa, has been in use since 1961 with a net available capacity of 1660km² and a concrete dam that is 42 m high. The maximum rate of outflow through its turbines is 360m³/s, and the normal annual outflow is about 120,000m³. Losses by evaporation are about 31,500m³/yr, and by percolation about 38,000m³/yr. The climate of the Awash River Basin varies from humid subtropical over central Ethiopia to arid over Afar lowlands [14].

An attempt was made to investigate the sensitivity of water resources to climate change in the Awash River Basin in Ethiopia. The climate of the basin varies from humid subtropical to arid. The basin was divided into 3 sub-catchments for better resolution in calibration and simulation.

Different sets of temperature and rainfall scenarios were developed using General Circulation Models (GCMs) both in transient and CO₂ doubling and incremental scenarios. The International Institute for Applied Systems Analysis (IIASA) integrated water balance model (WatBal) was used to estimate runoff under a changed climate. The model represents the water balance among surface outflow, sub-surface outflow, and Evapo-transpiration. The model was calibrated using a 10 yr period (1971 to 1980), validated with the next 6 yr period (1981 to 1986), and then applied for different climate scenarios. Results of the impact assessment over the basin showed a projected decrease in runoff, which ranged from -10 to -34%, with doubling of CO₂ and transient scenarios of CO₂ increase Geo-Physical Fluid Dynamic Model3, Canadian Climate Center Model, Geophysical Fluid Dynamics01 (GFD3,

CCCM, GF01). Sensitivity analysis based on incremental scenarios showed that a drier and warmer climate change scenario results in reduced runoff [26].

Another investigation that was carried out is the annual Potential Evapo-transpiration Upper Wabe River Catchment, South Eastern Central Ethiopia and it is calculated by using Penman formula and it is more than 1093.08mm/yr [16].

One way of improving water management is increasing the efficiency of utilization of dam reservoirs. Even small improvement in reservoir operation can lead to large benefits. Melka Wakana Plant is that it is sometimes idle due to shortage of water in the reservoir. The reservoir has never touched its full reservoir level (FRL) since its commissioning except in the year 1998 when the spillway spilled for only two months in the rainy season [6, 35].

Powersim Simulation software tool was used to determine optimal reservoir operation guides for Melka Wakana Hydropower Plant in Ethiopia Mean monthly data of reservoir inflow, evaporation rate, recorded energy production; recorded discharge (turbine flow) and recorded reservoir elevation were used as time series input data. Different variables and relationships between variables were defined along with the constraints. After developing and calibrating the model successfully, detailed simulation analysis has been carried out by controlling reservoir releases for energy production, taking into consideration; increasing yearly energy production and improving the uniformity of monthly energy production. The results of the simulation analyses indicated that the yearly energy production was increased by 5.67% while evaporation loss was reduced by 38.33%. But this power plant still produces below its design capacity by 12.21% [6, 35].

2.6. Determination of Evaporation from Hydroelectric Reservoir

The total volume of evaporated water (WE , m^3/yr) from the hydropower reservoir over the year is:

$$WE = \left(10 \times \sum_{t=1}^{365} E \right) \times A \quad (2.8)$$

where E is the daily evaporation (mm/day) and A the area of the reservoir (ha)

There are a number of methods for the measurement or estimation of evaporation. These methods can be grouped into several categories including [29]:

- **The Empirical methods:** is related to pan evaporation, actual lake evaporation or lysimeter measurements to meteorological factors using regression analyses. The weakness of these empirical methods is that they have a limited range of applicability.

- **The water budget methods:** are simple and can potentially provide a more reliable estimate of evaporation, as long as each water budget component is accurately measured. However, owing to difficulties in measuring some of variables such as the seepage rate in a water system water budget methods rarely produce reliable results in practice [2, 29].
- **The energy budget method:** the evaporation from a water body is estimated as the difference between energy inputs and outputs measured at a site. Energy budget methods are considered to be the most reliable in theory [2, 29], but require costly instrumentation and a large commitment of personnel for field work and data processing [33].
- **The mass-transfer (aerodynamic) based methods:** utilize the concept of eddy motion transfer of water vapor from an evaporating surface to the atmosphere. The mass-transfer methods normally use easily measurable variables and give satisfactory results in many cases. However, measurement of wind speed and air temperature at inconsistent heights, have resulted in a large number of equations with similar or identical structure [2, 29].
- **The combination methods:** combine the mass transfer and energy budget principles in a single equation. Two of the most commonly known combination methods are the Penman equation and the Penman-Monteith equation.
- Owing to its limited empirical basis, the Penman-Monteith equation is more readily applicable to a variety of water bodies. In addition, the model takes into account heat storage within water bodies. Therefore, for the purpose of the current study the Penman-Monteith equation with heat storage is considered suitable for the estimation of evaporation from the selected hydropower reservoirs. Therefore, among this the Method used to determine the amount of water evaporated from the Koka Hydroelectric power plant reservoir is Evapo-transpiration (ET₀) software version 3.1 which is developed by the Food and Agriculture Organization of the United Nations (FAO), Land and Water division in Rome, Italy January 2009 that is developed based on combination method that combines mass transfer and energy budget principles in a single equation and becomes the Penman-Monteith equation.

The evaporation from the water surface (E , mm/day) is estimated using the Penman-Monteith equation with an inclusion of water body heat storage. This equation is written as [2, 29]:

$$E = \frac{1}{\lambda} \times \left(\frac{\Delta_w \times (R_n - G) + \gamma \times f(u) \times (e_w - e_a)}{\Delta_w + \gamma} \right) \quad (2.9)$$

where, E is open water evaporation (mm/day);

λ the latent heat of vaporization (MJ/kg);

Δ_w slope of temperature saturation water vapor curve at water temperature (kPa/°C);

R_n net radiation (MJ /m²/day);

G the change in heat storage in the water body (MJ/m²/day);

$f(u)$ the wind function (MJ/m²/day/kPa);

e_w the saturated vapor pressure at water temperature (kPa);

e_a the vapor pressure at air temperature (kPa); and

γ = the psychrometric constant (kPa/°C).

➤ **Atmospheric parameters:** - several relationships are available to express climatic parameters. The effect of the principal weather parameters on evaporation can be assessed with the help of these equations. Some of the relationships require parameters which express a specific characteristic of the atmosphere. Before studying the four principal weather parameters, some atmospheric parameters will be discussed under here.

➤ **Atmospheric pressure (P):** - the atmospheric pressure, P, is the pressure exerted by the weight of the earth's atmosphere. Evaporation at high altitudes is promoted due to low atmospheric pressure as expressed in the psychrometric constant. The effect is, however, small and in the calculation procedures, the average value for a location is sufficient. A simplification of the ideal gas law, assuming 20°C for a standard atmosphere, can be employed to calculate P [2, 29]:

$$P = 101.3 \times \left(\frac{293 - 0.0065z}{293} \right)^{5.26} \quad (2.10)$$

where, P atmospheric pressure [kPa], z elevation above sea level [m]

➤ **Latent heat of vaporization (λ):** - the latent heat of vaporization, λ , expresses the energy required to change a unit mass of water from liquid to water vapor in a constant pressure and constant temperature process. The value of the latent heat varies as a function of temperature. At a high temperature, less energy will be required than at lower temperatures. The latent heat of vaporization, λ , is calculated as [2, 29]:

$$\lambda = 2.501 - 2.361 \times 10^{-3} T_a \quad (2.11)$$

where, λ = the latent heat of vaporization [MJ/kg], T_a = air temperature [°C]

➤ **Psychrometric constant (γ):** - the psychrometric constant, γ , [2, 29]: is given by:

$$\gamma = \frac{C_p \times P}{\epsilon \times \lambda} = \frac{1 \cdot 63 \times 10^{-3} P}{\lambda} \quad (2.12)$$

where γ Psychrometric constant [kPa /°C],

P Atmospheric pressure [kPa],

λ Latent heat of vaporization [MJ /kg],

C_p Specific heat of air at constant pressure, 1.013×10^{-3} [MJ /kg/°C],

ϵ Ratio molecular weight of water vapour/dry air = 0.622 which is dimensionless

The specific heat at constant pressure is the amount of energy required to increase the temperature of a unit mass of air by one degree at constant pressure. Its value depends on the composition of the air, i.e., on its humidity. For average atmospheric conditions a value $c_p = 1.013 \times 10^{-3}$ MJ/kg/°C can be used. As an average atmospheric pressure is used for each location, the psychrometric constant is kept constant for each location.

- **The Wind Function $f(u)$:** wind function $f(u)$ (MJ/m²/day/kPa) is calculated from wind speed at 10 m (u_{10} , m/s) and the so-called equivalent area (A_r , km²) [2, 29]:

$$f(u) = \left(\frac{5}{A_r}\right)^{0.05} \times (3.80 + 1.57 \times u_{10}) \quad (2.13)$$

The equivalent area (A_r , km²) is equal to the total surface area for regularly shaped reservoirs, but for irregularly shaped reservoirs, it can be taken equal to the square of the mean width.

- **Air Temperature:** air temperature is measured inside shelters (Stevenson screens or ventilated radiation shields) placed in line with World Meteorological Organization (WMO) standards at 2m above the ground. For standardization, the mean temperature (T_{mean}) for 24-hour periods is defined as the mean of the daily maximum (T_{max}) and minimum temperatures (T_{min}) rather than as the average of hourly temperature measurements.

$$T_{\text{mean}} = \frac{T_{\text{max}} + T_{\text{min}}}{2} \quad (2.14)$$

The temperature is given in degrees Celsius (°C) or Fahrenheit°F. In some calculation procedures, temperature is required in Kelvin (K), which can be obtained by adding 273.16 to the temperature expressed in degrees Celsius (in practice $K = ^\circ\text{C} + 273.16$). The Kelvin and Celsius scale have the same scale interval.

- **Air humidity:** the water content of the air can be expressed in several ways. In agro-meteorology, vapor pressure, dew-point temperature and relative humidity are common expressions to indicate air humidity.
- **Vapour pressure:** water vapor is a gas and its pressure contributes to the total atmospheric pressure. The amount of water in the air is related directly to the partial pressure exerted by the water vapor in the air and is therefore a direct measure of the air water content.
- **Dew point temperature:** the dew point temperature is the temperature to which the air needs to be cooled to make the air saturated. The actual vapor pressure of the air is the saturation

vapor pressure at the dew point temperature, the drier the air, the larger the difference between the air temperature and dew point temperature.

- **Relative humidity:** the relative humidity (RH) expresses the degree of saturation of the air as a ratio of the actual (e_a) to the saturation ($e^o(T)$) vapor pressure at the same temperature (T):

$$RH = 100 \times \frac{e_a}{e^o(T)} \quad (2.15)$$

Relative humidity is the ratio between the amount of water the ambient air actually holds and the amount it could hold at the same temperature. It is dimensionless and is commonly given as a percentage.

- **Mean saturation vapor pressure (e_s):** as saturation vapor pressure is related to air temperature, it can be calculated from the air temperature. The relationship is expressed by:

$$e^o(T_a) = 0.6108 \exp\left(\frac{17.27T_a}{T_a + 237.3}\right) \quad (2.16)$$

where $e^o(T_a)$ = Saturation vapor pressure at the air temperature T_a [kPa],

T_a = air temperature [°C],

Exp [...] = 2.7183 (base of natural logarithm) raised to the power [...],

$T_a=22.4^\circ\text{C}$

Due to the non-linearity of the above equation, the mean saturation vapor pressure for a day, week, decade or month should be computed as the mean between the saturation vapor pressure at the mean daily maximum and minimum air temperatures for that period:

$$e_s = \frac{e^o(T_{\max}) + e^o(T_{\min})}{2} \quad (2.17)$$

2.6.1. Net Solar Radiation

Net radiation (R_n , MJ/m²/day) is the difference between the net incoming short-wave radiations (R_{ns} , MJ/m²/d) and the net outgoing long-wave radiation (R_{nl} , MJ/m²/day) [2, 29]:

$$R_n = R_{ns} - R_{nl} \quad (2.18)$$

The net incoming short-wave radiation (R_{ns} , MJ/m²/day) resulting from the balance between incoming and reflected solar radiation is given by [2, 29]:

$$R_{ns} = (1 - \alpha) \times R_s \quad (2.19)$$

where

α = the albedo coefficient for open water (dimensionless), which has a value of 0.07 [47], and R_s the incoming solar radiation (MJ/m²/day).

Solar radiation (R_s , MJ/m²/day) can be calculated with the Angstrom formula, which relates solar radiation to extraterrestrial radiation and relative sunshine duration:

$$R_s = \left(a_s + b_s \times \frac{n}{N} \right) \times R_a \quad (2.20)$$

where n = the actual duration of sunshine (hours);

N = the maximum possible duration of sunshine or daylight hours (hours);

n/N = the relative sunshine duration (which is equal to one minus the cloud cover fraction, dimensionless);

R_a = extraterrestrial radiation ($\text{MJ}/\text{m}^2/\text{day}$);

a_s = a regression constant, expressing the fraction of extraterrestrial radiation reaching the earth on overcast days ($n = 0$) and $a_s + b_s$ = fraction of extraterrestrial radiation reaching earth on clear days (when $n = N$)

Depending on atmospheric conditions (humidity, dust) and solar declination (latitude and month), the Angstrom values a_s and b_s will vary. Where no actual solar radiation data are available and no calibration has been carried out for improved a_s and b_s parameters, the values $a_s = 0.25$ and $b_s = 0.50$ are taken as recommended by [54].

2.6.2. The extraterrestrial radiation R_a

It is the solar radiation outside the earth's atmosphere. The intensity of the extraterrestrial radiation outside a planet varies inversely to the square of the distance of the planet from the sun. If the intensity of the radiation at a point is and the distance from the sun is known then the intensity at another point can be calculated from the knowledge of its distance from the sun.

Extraterrestrial radiation R_a , for each day of the year and for different latitudes, can be estimated from the solar constant, the solar declination and the time of the year as follows:

$$R_a = \frac{24 \times 3600}{\pi} G_{sc} \times d_r \times \left[\frac{\pi}{180} \times \omega_s \times \sin(\varphi) \times \sin(\delta) + \cos(\varphi) \times \cos(\delta) \times \sin(\omega_s) \right] \quad (2.21)$$

where G_{sc} = the solar constant (which is equal to $1367 \text{w}/\text{m}^2$);

d_r = the inverse relative distance Earth-Sun; ω_s the sunset hour angle (*radian*);

φ = the latitude (*radian*) and it is positive for the northern hemisphere and negative for the southern hemisphere.

2.6.3. Change in the Heat Storage in the Water Body (G)

Change in heat storage in the water body (G , $\text{MJ}/\text{m}^2/\text{day}$) is calculated from [2, 29]:

$$G = \rho_w \times c_w \times h \times (T_{w,i} - T_{w,i-1}) \quad (2.38)$$

ρ_w = is the density of water (= 1000 kg/m³); c_w = the specific heat of water (0.0042 MJ/kg/K); and h = the depth of water (m), estimated from reservoir volume capacity and area (= 8.3m), and $T_{w,i}$ = the water temperature at i month.

2.6.4. Saturated Vapour Pressure at Water Temperature (e_w)

Saturated vapour pressure at water temperature (e_w , kPa) is calculated from:

$$e_w = 0.6108 \times \exp\left(\frac{17.27T_w}{(T_w + 273.3)}\right) \quad (2.39)$$

where T_w = water surface temperature

2.6.5. Slope of Temperature Saturation Water Vapour Curve T_a Water Temperature (Δ_w)

Finally, the slope of the temperature saturation water vapour curve at water surface temperature (Δ_w , kPa/°C) is:

$$\Delta_w = \frac{4098 \times \left[0.6108 \times \exp\left(\frac{17.27T_w}{(T_w + 273.3)}\right)\right]}{(T_w + 273.3)^2} \quad (3.40)$$

CHAPTER THREE

3. DETERMINATION OF CRITICAL MONTHS TO PUMP THE WATER TO UPPER RESERVOIR AND ESTIMATION OF EVAPORATION FROM HYDROELECTRIC RESERVOIR

3.1. Determination of water amount in Koka Dam plant Reservoir

For this data analysis the data is taken from the five representative years starting from 2000-2004E.C for Koka hydropower plant reservoir and the basic data like total area of the reservoir 236km², Maximum Depth of the reservoir 13m, Average depth of the reservoir 9.14m, total storage capacity of the reservoir at 1590.7m (asl) 1958.8Mm³, usable storage capacity of the reservoir 1680.32Mm³, volume of dead storage 57Mm³, Spillway level of the dam 110.3m, dead storage water level 102.0m, water level at the beginning and end of each month is obtained from Ethiopian Electric Power Corporation (EEPCO) Koka hydropower plant Operation and Generation team.

Table 1 Basic data for Koka Hydropower Plant

Description	Value
Total area of the Reservoir	236km ²
Maximum depth of the reservoir	13m
Average depth of the reservoir	9.14m
Total storage capacity of the reservoir	1958.8Mm ³
Usable storage capacity of the reservoir	1680.32Mm ³
Volume of the dead storage	57.33Mm ³
Spillway level of the dam	110.3m
Dead storage water level	102.0m



Figure 6 Part of the Lake, upstream, where the power plant is located

The usable water height of the Koka water reservoir is calculated as follows:

$$USC = A_{TR} \times UWHR \quad (3.1)$$

Where, USC=Usable storage capacity

A_{TR} =total area of reservoir

UWHR=usable water height of reservoir

$$1680.32 \text{Mm}^3 = 236 \text{km}^2 \times H_{\text{usable}}$$

$$H_{\text{usable}} = (1680.32 \times 10^6 \text{m}^3) / (236 \times 10^6 \text{m}^2) = 7.12 \text{m}$$

When the Koka Hydropower Reservoir is seen according to it's the water level it will be as follows:

- i. According to its water Level of the reservoir in the year 2000E.C. The water level of the Koka hydropower Reservoir is given in appendix B. The difference between the usable storage water level and water level at the beginning of the month is calculated as follows:

$$\text{Difference [m]} = \text{usable storage water level} - \text{water level at the beginning of month}$$

Now the difference is summarized in the table 3.1 as follows:

Table 2 Water levels of the usable storage and at the beginning of the month of the reservoir in the year 2000E.C source EEPCO

Month	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	Ma	Jun	July	Aug	Pag
Usable water level[m]	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12
Water level at beginning of month[m]	110.26	110.04	109.44	108.7	107.96	107.2	106.34	105.45	105.63	105.14	105.39	107.48	110.23
Difference[m]	-1.1	-0.9	-0.3	0.4	1.2	1.9	2.8	3.7	3.5	4.0	3.7	1.6	-1.1

From this table the negative height indicates that the water level at the beginning of the month is above the usable storage water level and the positive height indicates that the water level is below the usable storage water level. Therefore, the Koka water reservoir level is much less in months March, April, May, June, and July at the beginning of the month.

The difference between the usable storage water level and water level at the end of the month for the year 2000E.C is calculated as follows:

$$\text{Difference [m]} = \text{usable storage water level} - \text{water level at the end of the month}$$

Now the difference is summarized in the table 3.2 as follows:

Table 3 Water levels of the usable storage and at the end of the month of the reservoir in the year 2000E.C source EEPCO

Month	Sep	Oct	No	De	Jan	Feb	Ma	Apr	Ma	Jun	July	Au	Pag
Usable water level[m]	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12
Water level at the end of the month[m]	110.05	109.46	108.72	107.99	107.22	106.37	105.48	104.53	105.16	105.34	107.34	110.15	110.29
Difference[m]	-0.9	-0.3	0.4	1.1	1.9	2.8	3.6	4.6	4.0	3.8	1.8	-1.0	-1.1

In the months February, March, April, May and June at the end of the month shows the water level highly reduced below the usable water storage level.

When usable water storage level, the water level at the beginning of the month, water level at the end of the month and the dead storage water level is shown graphically as follows for 2000E.C:

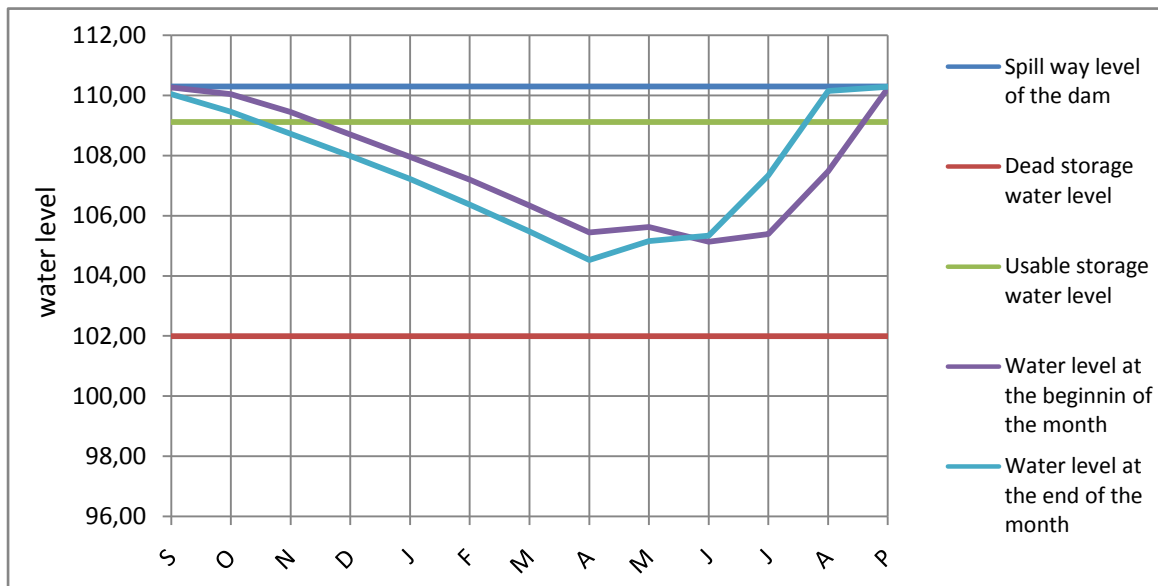


Figure 7 Usable and dead storage water level and Water level at the beginning, and end of the month for 2000E.C

From this graph what can be concluded is that a minimum of 0.4m water level in November and a maximum of 4.59m water level in April both at the end of the month are needed to reach the usable storage water level.

ii. According to its water Level of the reservoir in the year 2001E.C

The difference between the usable storage water level and water level at the beginning of the month is calculated as follows:

$$\text{Difference [m]} = \text{usable storage water level} - \text{water level at the beginning of month}$$

Now the difference is summarized in the table 3.3 as follows:

Table 4 Water levels of the usable storage and at the beginning of the month of the reservoir in the year 2001E.C source EEPCO

Month	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	Ma	Jun	July	Aug	Pag
Usable water level[m]	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12
Water level at the beginning of the month[m]	110.33	109.85	109.53	108.91	108.1	107.29	106.38	105.54	104.37	103.03	103.02	106.48	110.14
Difference[m]	-1.2	-0.7	-0.4	0.2	1.0	1.8	2.7	3.6	4.8	6.1	6.1	2.6	-1.0

From this the negative heights indicates that the water level at the beginning of the month is above the usable storage water level that meant there is excess water in the reservoir and the positive heights indicates that the water level is below the usable storage water level that means minimum water is found in the reservoir. Therefore, the Koka water reservoir level is much less in months March, April, May, June, July and August at the beginning of the month.

The difference between the usable storage water level and water level at the end of the month for the year 2001E.C is calculated as follows:

$$\text{Difference [m]} = \text{usable storage water level} - \text{water level at the end of the month}$$

Now the difference is summarized in the table 3.4 as follows:

Table 5 Water levels of the usable storage and at the end of the month of the reservoir in the year 2001E.C source EEPCO

Month	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	Ma	Jun	July	Aug	Pag
Usable water level[m]	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12
Water level at the end of the month[m]	109.87	109.55	108.94	108.13	107.32	106.41	105.56	104.43	103.07	102.45	106.32	110.08	110.31
Difference[m]	-0.8	-0.4	0.18	0.99	1.8	2.7	3.6	4.7	6.1	6.7	2.8	-1.0	-1.2

In the months February, March, April, May and June shows the water level highly reduced below the usable water storage level at the end of the month small amount of water level is found above the usable water storage level in months August, Pagume, September and October.

When usable water storage level, the water level at the beginning of the month, water level at the end of the month and the dead storage water level is shown graphically as follows for 2001E.C:

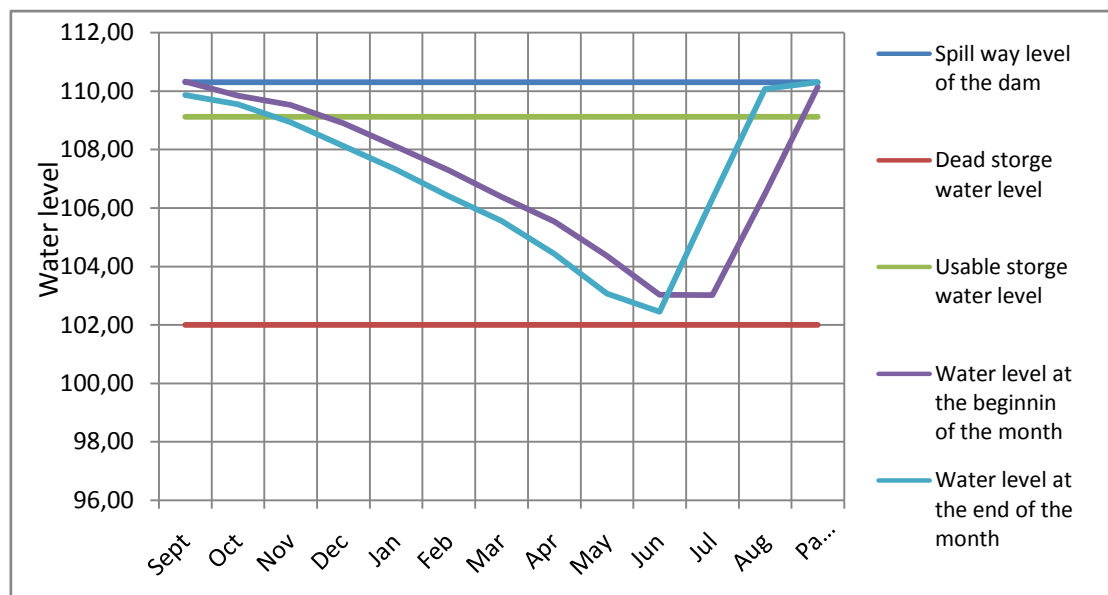


Figure 8 Usable and dead storage water level and Water level at the beginning, and end of the month for 2001E.C

From this graph what can be concluded is that a minimum of 0.18m in November and a maximum of 6.67m water level in June at the end of the month are needed to reach the usable storage water level.

iii. According to its water Level of the reservoir in the year 2002E.C

The difference between the usable storage water level and water level at the beginning of the month is calculated as follows:

$$\text{Difference [m]} = \text{usable storage water level} - \text{water level at the beginning of month}$$

Now the difference is summarized in the table 3.5 as follows:

Table 6 Water levels of the usable storage and at the beginning of the month of the reservoir in the year 2002E.C source EEPCO

Month	Sep	Oct	No	Dec	Jan	Feb	Mar	Apr	Ma	Jun	July	Au	Pag
Usable water level[m]	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12
Water level at the beginning of the month[m]	108.7	108.67	108.2	107.49	106.8	106.11	105.78	105.26	104.91	104.26	102.5	104.34	108.14
Difference[m]	0.4	0.4	0.9	1.6	2.3	3.0	3.3	3.9	4.2	4.9	6.6	4.8	1.0

In this year there is no negative height this indicates that water level at the beginning of month is below usable storage water level. Therefore, Koka water reservoir level is much less in months January, February, March, April, May, June, July and August at the beginning of the month. The difference between the usable storage water level and water level at the end of the month for the year 2002E.C is calculated as follows:

Difference [m] = usable storage water level – water level at the end of the month

Now the difference is summarized in the table 3.6 as follows:

Table 7 water levels of the usable storage and at the end of the month of the reservoir in the year 2002E.C source EEPCCO

Month	Sep	Oct	No	De	Jan	Feb	Ma	Apr	Ma	Jun	Jul	Aug	Pag
Usable water level[m]	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12
Water level at the end of the month[m]	108.65	108.22	107.49	106.83	106.12	105.79	105.28	104.9	104.29	104.37	104.24	108.03	108.6
Difference[m]	0.47	0.90	1.63	2.29	3.00	3.33	3.84	4.22	4.83	4.75	4.88	1.09	0.52

In the months December, January, February, March, April, May, June and July shows the water level highly reduced below the usable water storage level at the end of the month.

When usable water storage level, the water level at the beginning of the month, water level at the end of the month and the dead storage water level is shown graphically as follows for 2002E.C:

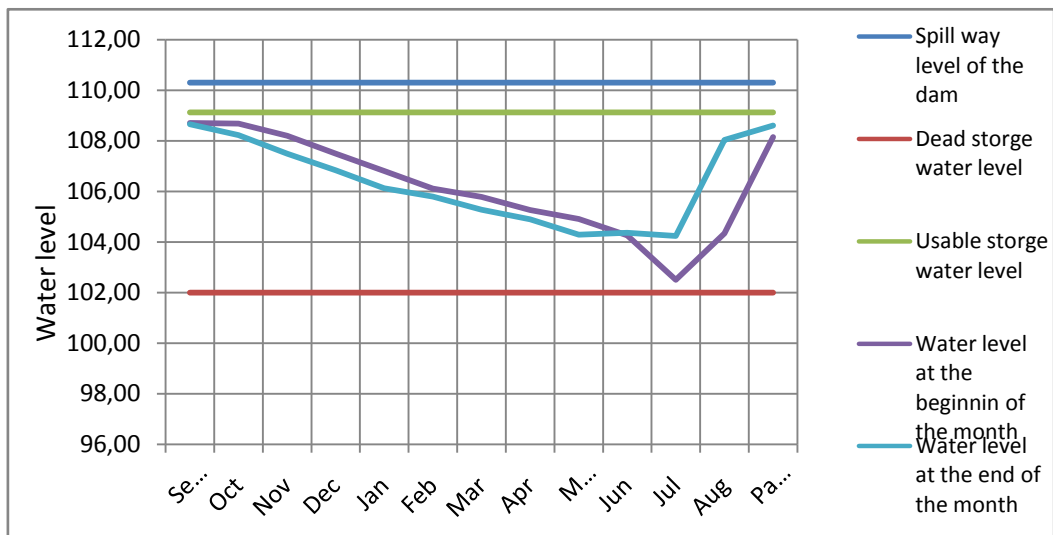


Figure 9 usable and dead storage water level and Water level at the beginning, and end of the month for 2002E.C

From this graph what can be concluded is that a minimum of 0.42m in September and a maximum of 6.62m water level in July both at the beginning of the month are needed to reach the usable storage water level.

iv. According to its water Level of the reservoir in the year 2003E.C

The difference between the usable storage water level and water level at the beginning of the month is calculated as follows:

Difference [m] = usable storage water level – water level at the beginning of month

Now the difference is summarized in the table 3.7 as follows:

Table 8 Water levels of the usable storage and at the beginning of the month of the reservoir in the year 2003E.C source EEPCO

Month	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	Ma	Jun	July	Aug	Pag
Usable water level[m]	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12
Water level at the beginning of the month[m]	109.82	110.02	109.4	108.66	107.88	107.17	106.39	105.63	104.73	103.49	104.38	107.32	109.63
Difference[m]	-0.7	-0.9	-0.3	0.5	1.2	2.0	2.7	3.5	4.4	5.6	4.7	1.8	-0.5

From this the negative heights indicates that the water level at the beginning of the month is above the usable storage water level and the positive heights indicates that the water level is below the usable storage water level. Therefore, water reservoir level is much less in months March, April, May, June, and July at the beginning of the month. The difference between the usable storage water level and water level at the end of the month for the year 2003E.C is calculated as follows:

$$\text{Difference [m]} = \text{usable storage water level} - \text{water level at the end of the month}$$

Now the difference is summarized in the table 3.8 as follows:

Table 9 water levels of the usable storage and at the end of the month of the reservoir in the year 2003E.C source EEPCO

Month	Sep	Oct	No	De	Jan	Feb	Mar	Apr	Ma	Jun	Jul	Au	Pag
Usable water level[m]	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12
Water level at end of month[m]	110.03	109.42	108.69	107.9	107.2	106.41	105.66	104.77	103.53	103.21	107.3	109.54	109.8
Difference[m]	-0.2	0.6	0.7	0.8	0.7	0.8	0.7	0.9	1.2	0.3	-2.9	-2	-0.7

In the months November, December, January, February, March, April and May shows the water level slightly reduced below the usable water storage level at the end of the month and on the contrary side the water level is much greater at the end of the months in July and August.

When usable water storage level, the water level at the beginning of the month, water level at the end of the month and the dead storage water level is shown graphically as follows for 2003E.C:

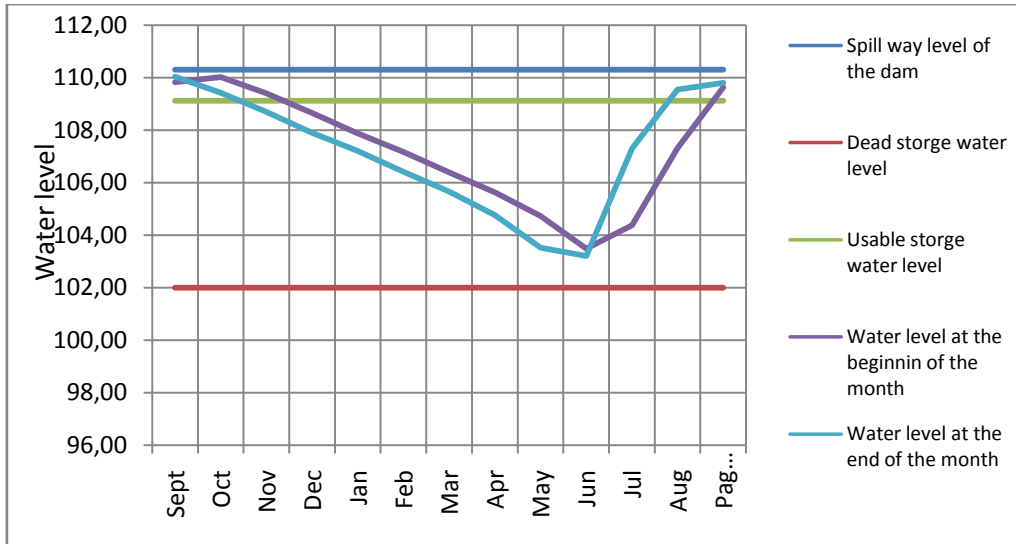


Figure 10 usable and dead storage water level and Water level at the beginning, and end of the month for 2003E.C

From this graph what can be concluded is that minimum of 0.46m in December and maximum of 5.63m June both at the beginning of the month water level are needed to reach the usable storage water level.

- v. According to its water Level of the reservoir in the year 2004E.C.The difference between the usable storage water level and water level at the beginning of the month is calculated as follows:

$$\text{Difference [m]} = \text{usable storage water level} - \text{water level at the beginning of month}$$

Now the difference is summarized in the table 3.9 as follows:

Table 10 water levels of the usable storage and at the beginning of the month of the reservoir in the year 2004E.C source EEPCO

Month	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Pag
Usable water level[m]	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12
Water level at the beginning of the month[m]	109.22	109.73	109.24	108.64	107.96	107.29	106.45	105.76	105.25	103.33	103.24	104.77	108.66
Difference[m]	-0.1	-0.6	-0.1	0.5	1.2	1.8	2.7	3.4	3.9	5.8	5.9	4.4	0.5

From this the negative heights indicates that the water level at the beginning of the month is above the usable storage water level and the positive heights indicates that the water level is below the usable storage water level. Therefore, the Koka water reservoir level is much less in months February, March, April, May, June, July and August at the beginning of the month .The difference between the usable storage water level and water level at the end of the month for the year 2004E.C is calculated as follows:

$$\text{Difference [m]} = \text{usable storage water level} - \text{water level at the end of the month}$$

Now the difference is summarized in the table 3.10 as follows:

Table 11 water levels of the usable storage and at the end of the month of the reservoir in the year 2004E.C source EEPKO

Month	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	Ma	Jun	July	Aug	Pag
Usable water level[m]	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12
Water level at the end of the month[m]	109.74	109.25	108.66	107.99	107.32	106.48	105.78	105.27	104.53	104.21	104.68	108.55	109.02
Difference[m]	-0.6	-0.1	0.5	1.1	1.8	2.6	3.3	3.9	4.6	4.9	4.4	0.6	0.1

In the months January, February, March, April, May, June and July shows the water level highly reduced below the usable water storage level at the end of the month.

When usable water storage level, the water level at the beginning of the month, water level at the end of the month and the dead storage water level is shown graphically as follows for 2004E.C:

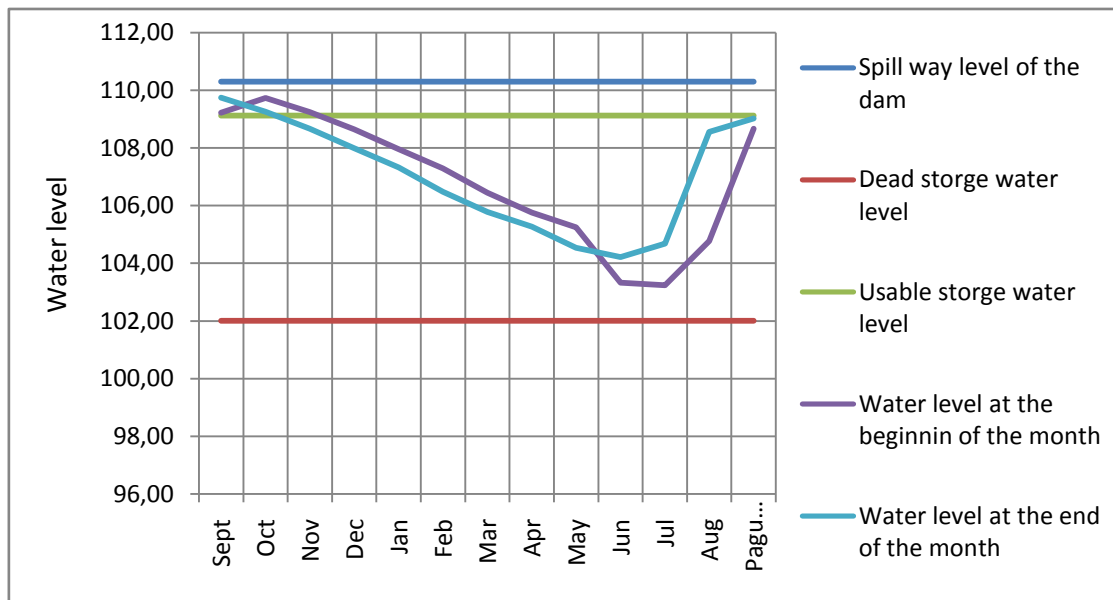


Figure 11 Usable and dead storage water level and Water level at the beginning, and end of the month for 2004E.C

From this graph what can be concluded is that a minimum of 0.1m in Pagume at the end of the month and a maximum of 5.88m water level in July at the beginning of the month are needed to reach the usable storage water level.

Finally from this analysis what we can conclude is that the most critical months that needs water to be pumped are March, April, May, June and July. Although, these months are the most ones, there are other months that need more water in the reservoir for turbine operation like months of February and August. Among the above critical ones April, June and July especially needs more to be pumped since they are months that suffer from water shortage in

the above taken representative years for this thesis. The most important situation that makes these Months lucky is that there is enough Wind Energy Resource around the selected site for water pumping purpose.

3.2. Determination of Evaporation from Hydroelectric Reservoir

3.2.1. Determination of evaporation from Koka Hydroelectric power plant reservoir

The amount of water evaporated from the Koka Hydroelectric power plant reservoir is determined by using the Penman-Monteith equation with an inclusion of water body heat storage. This equation is written as [2, 29]:

$$E = \frac{1}{\lambda} \times \left(\frac{\Delta_w \times (R_n - G) + \gamma \times f(u) \times (e_w - e_a)}{\Delta_w + \gamma} \right) \quad (3.2)$$

Where, E is open water evaporation (mm/day);

λ the latent heat of vaporization (MJ/kg);

Δ_w slope of temperature saturation water vapour curve at water temperature (kPa/°C);

R_n net radiation (MJ /m²/day);

G the change in heat storage in the water body (MJ/m²/day);

f(u) the wind function (MJ/m²/day/kPa);

e_w the saturated vapour pressure at water temperature (kPa);

e_a the vapour pressure at air temperature (kPa); and

γ the psychometric constant (kPa/°C);

3.2.1.1. Atmospheric pressure (P)

Assuming 20°C for a standard atmosphere the value of P for the selected site can be calculate as follows by [2, 29]:

$$P = 101.3 \times \left(\frac{293 - 0.0065z}{293} \right)^{5.26} \quad (3.3)$$

where, P atmospheric pressure [kPa], z elevation above sea level [m], Z=1590.7m

$$P = 83.85kPa$$

3.2.1.2. Latent heat of vaporization (λ)

The latent heat of vaporization, λ , for the site is calculated [2, 29] by using the site near by Adama monthly Average Temperature [°c] from 1997 to 2007 year as follows:

Table 12 Adama monthly Average temperatures [°C]

Average of 1997-2007 Year	Jan	Feb	M	Ap	Ma	Ju	Jul	Au	Sep	Oc	No	De	Av
monthly maximum T (°C)	26.8	28.9	29	30	31	30	28	27	27	28	27	26	28.9
monthly minimum T(°C)	12.9	14.4	15	16	16	17	18	16	15	14	13	13	14
Average	19.9	22.7	22	24	24	24	21	22	21	21	20	19	22.4

$$\lambda = 2.501 - 2.361 \times 10^{-3}T_a \quad (3.4)$$

where, λ = the latent heat of vaporization [MJ/kg], T_a = air temperature [°C], $T_a = 22.4^\circ\text{C}$,

$$\lambda = 2.501 - 2.361 \times 10^{-3} \times 22.4^\circ\text{C} = 2.45\text{MJ/kg}$$

3.2.1.3. Psychrometric constant (γ)

The psychrometric constant, γ , from [2, 29]: is given by:

$$\gamma = \frac{C_p \times P}{\varepsilon \times \lambda} = \frac{1.63 \times 10^{-3} \times P}{\lambda} \quad (3.5)$$

where, γ = Psychrometric constant [kPa /°C], P = Atmospheric pressure [kPa],

λ =Latent heat of vaporization [MJ /kg], C_p =Specific heat of air at constant pressure, 1.013 10^{-3} [MJ /kg/°C], ε = Ratio molecular weight of water vapor/dry air = 0.622 which is dimensionless

$$\gamma = \frac{1.63 \times 10^{-3} \times 83.86\text{kPa}}{2.45^\circ\text{C}} = 0.056\text{kPa}/^\circ\text{C}$$

3.2.1.4. The Wind Function $f(u)$

The wind function $f(u)$ (MJ/m²/day/kPa) for the site is calculated from wind speed at 10 m (u_{10} , m/s) and the so-called equivalent area (A_r , km²) [2, 29]: as follows:

$$f(u) = \left(\frac{5}{A_r}\right)^{0.05} \times (3.8 + 1.57 \times u_{10}) \quad (3.6)$$

$$A_r = 236\text{km}^2 \quad u_{10} = 8.43 \text{ m/s}$$

$$f(u) = \left(\frac{5}{236}\right)^{0.05} \times (3.8 + 1.57 \times 8.43) = 13.88\text{MJ}/\text{m}^2/\text{day}/\text{kPa}$$

3.2.1.5. Air Temperature

Air temperature for the site calculated as follows:

$$T_{max} = 28.4^{\circ}\text{C} \quad T_{min} = 16.4^{\circ}\text{C}, \quad T_{mean} = \frac{28.4+16.4}{2} = 22.4^{\circ}\text{C}$$

$$K = ^{\circ}\text{C} + 273.16 = 22.4 + 273.16 = 295.56\text{K}$$

3.2.1.6. Dew point temperature

The dew point temperature of the study area or Koka hydropower plant is given from NASA as follows:

Table 13 Dew/Frost Point Temperature at 10 m ($^{\circ}\text{C}$) source NASA

Dew/Frost Point Temperature At 10 m ($^{\circ}\text{C}$)													
Lat 8.468	Jan	Feb	Ma	Apr	Ma	Jun	Jul	Au	Sep	Oct	No	De	Ave
Lon 39.159													
Daily Ave	4.78	4.11	6.1	9.1	10.3	12.4	12.4	12.4	11.4	8.25	5.45	5.47	8.51

3.2.1.7. Mean saturation vapour pressure (e_s)

The air temperature that is taken from the Ethiopian National Meteorological agency from the near by Adama Meteorological station the average air temperature is 22.4°C . The relationship is expressed by:

$$e^{\circ}(T_a) = 0.6108 \exp\left(\frac{17.27T_a}{T_a + 237.3}\right) \quad (3.7)$$

Where, $e^{\circ}(T_a)$ = Saturation vapour pressure at the air temperature T_a [kPa], T_a = air temperature [$^{\circ}\text{C}$], $\text{Exp}[\dots] = 2.7183$ (base of natural logarithm) raised to the power [...], $T_a=22.4^{\circ}\text{C}$ $e^{\circ}(T_a) = 2.71\text{kPa}$
 Due to the non-linearity of the above equation, the mean saturation vapour pressure for the Koka hydropower plant is calculated as:

$$e_s = \frac{e^{\circ}(T_{max}) + e^{\circ}(T_{min})}{2} \quad (3.8)$$

$$e^{\circ}(T_{max}) = 3.87\text{kPa}, \quad e^{\circ}(T_{min}) = 1.84\text{kPa} \quad e_s = 2.85\text{kPa}$$

Using mean air temperature instead of daily minimum and maximum temperatures results in lower estimates for the mean saturation vapour pressure. The corresponding vapour pressure deficit (a parameter expressing the evaporating power of the atmosphere) will also be smaller and the result will be some underestimation of the evaporation. Therefore, the mean saturation vapour pressure should be calculated as the mean between the saturation vapour pressure at both the daily maximum and minimum air temperature.

3.2.1.8. Net Solar Radiation

Net radiation (R_n , MJ/m²/day) is the difference between the net incoming short-wave radiations (R_{ns} , MJ/m²/d) and the net outgoing long-wave radiation (R_{nl} , MJ/m²/day) [2, 29]:

$$R_n = R_{ns} - R_{nl} \quad (3.9)$$

The net incoming short-wave radiation (R_{ns} , MJ/m²/day) resulting from the balance between incoming and reflected solar radiation given by [2, 29]:

$$R_{ns} = (1 - \alpha) \times R_s \quad (3.10)$$

where, α = the albedo coefficient for open water (dimensionless), which has a value of 0.07 [47] and R_s the incoming solar radiation (MJ/m²/day).

Solar radiation (R_s , MJ/m²/day) can be calculated with the Angstrom formula, which relates solar radiation to extraterrestrial radiation and relative sunshine duration:

$$R_s = \left(a_s + b_s \times \frac{n}{N} \right) \times R_a \quad (3.11)$$

where, n = the actual duration of sunshine (hours);

N = the maximum possible duration of sunshine or daylight hours (hours);

n/N = the relative sunshine duration (which is equal to one minus the cloud cover fraction, dimensionless);

R_a = extraterrestrial radiation (MJ/m² /day);

a_s = a regression constant, expressing the fraction of extraterrestrial radiation reaching the earth on overcast days ($n = 0$) and $a_s + b_s$ = fraction of extraterrestrial radiation reaching earth on clear days (when $n = N$)

Depending on atmospheric conditions (humidity, dust) and solar declination (latitude and month), the Angstrom values a_s and b_s will vary. Where no actual solar radiation data are available and no calibration has been carried out for improved a_s and b_s parameters, values $a_s = 0.25$ and $b_s = 0.50$ are taken as recommended by [2, 29].

3.2.1.9. The extraterrestrial radiation R_a

Extraterrestrial radiation R_a , for each day of the year and for different latitudes, can be estimated from the solar constant, the solar declination and the time of the year as follows:

$$R_a = \frac{24 \times 3600}{\pi} G_{sc} \times d_r \times \left[\frac{\pi}{180} \times \omega_s \times \sin(\varphi) \times \sin(\delta) + \cos(\varphi) \times \cos(\delta) \times \sin(\omega_s) \right] \quad (3.12)$$

where

G_{sc} the solar constant (which is equal to 1367w/m²);

d_r the inverse relative distance Earth-Sun;

ω_s the sunset hour angle(*radian*);

φ the latitude (*radian*) and it is positive for the northern hemisphere and negative for the southern hemisphere. The latitude of a location is the angle made by the radial line, joining the given location to the center of the earth, with its projection on the equatorial plane. Note: the latitudinal and longitudinal location of the Koka Hydropower Plant is 8.5° and 39.5° respectively in the northern hemisphere.

δ the solar declination (radian)

3.2.1.10. Mean Day of the Month

The recommended average days for each month and values of N by months are given in appendix C and the day of the months for March, April, May, June and July are 75, 105, 135, 162, and 198 respectively [9].

3.2.1.11. Earth–Sun Distance (d_r)

The inverse relative distance Earth-Sun, d_r is calculated as [9]:

$$d_r = 1 + 0.033 \cos\left(\frac{360}{365} \times N\right) \quad (3.13)$$

where, N is number of the day in the year between 1 (1 January) and 365 or 366 (31 December)

The inverse Relative distance Earth-Sun, d_r March, April, May, June, and July is calculated as:

For March $N=75$ $d_r = 1.01$, For April $N=105$, $d_r = 0.99$, For May $N=135$ $d_r = 0.977$,
For June $N=162$ $d_r = 0.969$ For July $N=198$ $d_r = 0.968$

3.2.1.12. The solar declination(δ)

The solar declination δ is given by [9]:

$$\delta = 23.45 \sin\left[\frac{360}{365}(N + 284)\right] \quad (3.14)$$

Where, N is number of the day in the year between 1 (1 January) and 365 or 366 (31 December)

For March $N=75$ $\delta = -2.42^\circ$, For April $N=105$ $\delta = 9.4^\circ$

For May $N=135$ $\delta = 18.8^\circ$, For June $N=162$ $\delta = 23.1^\circ$

For July $N=198$ $\delta = 21.2^\circ$

3.2.1.13. Sun rise and Sunset Hour Angle (ω_s)

It is the hour angle at the time of sun rise (or sunset). Or it is the hour angle when the latitude angle is zero. The sunset hour angle(ω_s) is given by [9]:

$$\omega_s = \cos^{-1}[-\tan(\varphi) \times \tan(\delta)] \quad (3.15)$$

Latitude(φ) = 8.5°

For March, $\omega_s = 89.6^\circ$, For April, $\omega_s = 91.4^\circ$, For May, $\omega_s = 92.9^\circ$

For June, $\omega_s = 93.6^\circ$, For July, $\omega_s = 93.3^\circ$

From Equation [3.12] the extraterrestrial solar radiation for those critical months can be calculated as [9]:

$$R_a = \frac{24 \times 3600}{\pi} G_{sc} \times d_r \times \left[\frac{\pi}{180} \times \omega_s \times \sin(\varphi) \times \sin(\delta) + \cos(\varphi) \times \cos(\delta) \times \sin(\omega_s) \right]$$

For March, $R_a = 37.15 \text{MJ}/\text{m}^2/\text{day}$, For April, $R_a = 37.74 \text{MJ}/\text{m}^2/\text{day}$

For May, $R_a = 37.18 \text{MJ}/\text{m}^2/\text{day}$, For June, $R_a = 36.45 \text{MJ}/\text{m}^2/\text{day}$

For July, $R_a = 36.69 \text{MJ}/\text{m}^2/\text{day}$

3.2.1.14. Daylight hours (N)

The daylight hours, N, are given by [2, 9]:

$$N = \frac{24}{\pi} \times \omega_s \quad (3.16)$$

$\pi = 180^\circ$, therefore, Daylight Hours, N, for the critical months can be calculated as follows:

For Mar, $\omega_s = 89.6^\circ$, $N = 11.95$, For April, $\omega_s = 91.4^\circ$ $N = 12.2$

For May, $\omega_s = 92.9^\circ$, $N = 12.4$, For June, $\omega_s = 93.6^\circ$ $N = 12.5$

For July, $\omega_s = 93.3^\circ$ $N = 12.44$

The value of n or sunshine for the critical months is taken from Appendix D and that is 8.07 for March, 8.06 for April, 9.00 for May, 8.27 for June and 6.46 for July. Then the value of n/N for the critical month becomes:

March, $n/N = 8.07/11.95 = 0.68$, April, $n/N = \frac{8.06}{12.2} = 0.66$, May, $n/N = 9/12.4 = 0.73$,

June, $n/N = 8.27/12.5 = 0.66$, July, $n/N = 6.46/12.44 = 0.52$

From equation [3.11] the solar radiation for the critical months can be calculated as follows and for no actual solar radiation data are available and no calibration has been carried out for improved a_s and b_s parameters, the values $a_s = 0.25$ and $b_s = 0.50$ are taken.

$$R_s = \left(a_s + b_s \times \frac{n}{N} \right) \times R_a$$

For March, $R_s = 21.92 \text{MJ}/\text{m}^2/\text{day}$, For April, $R_s = 21.90 \text{MJ}/\text{m}^2/\text{day}$

For May, $R_s = 22.87 \text{MJ}/\text{m}^2/\text{day}$, For June, $R_s = 21.14 \text{MJ}/\text{m}^2/\text{day}$

For July, $R_s = 18.71\text{MJ}/\text{m}^2/\text{day}$

Then, from equation [3.10] the net incoming short-wave radiation (R_{ns} , $\text{MJ}/\text{m}^2/\text{day}$) is calculated as follows for the albedo coefficient (α) of open water (dimensionless), with a value of 0.19 [2, 9, and 29]:

$$R_{ns} = (1 - \alpha) \times R_s$$

For March, $R_{ns} = 17.76\text{MJ}/\text{m}^2/\text{day}$, For April, $R_{ns} = 17.74\text{MJ}/\text{m}^2/\text{day}$

For May, $R_{ns} = 18.52\text{MJ}/\text{m}^2/\text{day}$, For June, $R_{ns} = 17.12\text{MJ}/\text{m}^2/\text{day}$

For July, $R_{ns} = 15.15\text{MJ}/\text{m}^2/\text{day}$

3.2.1.15. The Net Outgoing Long-Wave Radiation (R_{nl})

The net outgoing long-wave radiation (R_{nl} , $\text{MJ}/\text{m}^2/\text{day}$) is the difference between the outgoing long-wave radiation ($R_l\uparrow$, $\text{MJ}/\text{m}^2/\text{day}$) and the incoming long-wave radiation ($R_l\downarrow$, $\text{MJ}/\text{m}^2/\text{day}$):

$$R_{nl} = R_l\uparrow - R_l\downarrow \quad (3.17)$$

3.2.1.16. The Incoming Long-Wave Radiation ($R_l\downarrow$)

The incoming long-wave radiation ($R_l\downarrow$, $\text{MJ}/\text{m}^2/\text{day}$) is calculated from [2, 9, and 29]:

$$R_l\downarrow = \varepsilon_a \times \sigma \times (T_a + 273.15)^4 \times (1 + 0.17C_f^2) \times (1 - r_{lw}) \quad (3.18)$$

where, ε_a = emissivity of air (dimensionless); σ = Stefan-Boltzmann constant ($4.903 \times 10^{-9} \text{MJ}/\text{K}^4/\text{m}^2/\text{day}$); C_f = the fractional cloud cover (dimensionless); and r_{lw} = total reflectivity of water surface for long wave radiation, taken as a constant with a value of 0.03:

The emissivity of air is calculated as [2, 29]:

$$\varepsilon_a = C_\varepsilon \times (T_a + 273.15)^2 \quad (3.19)$$

Where, $C_\varepsilon = 9.37 \times 10^{-6} \text{K}^{-2}$, $T_a = 22.4$

$$\varepsilon_a = 0.82$$

The fractional cloud cover C_f can be calculated as:

$$n/N = 1 - C_f \quad (3.20)$$

For March, $n/N = 0.68$, $C_f = 0.32$, For April, $n/N = 0.66$, $C_f = 0.34$

For May, $n/N = 0.73$, $C_f = 0.27$, For June, $n/N = 0.66$, $C_f = 0.34$

For July, $n/N = 0.52$, $C_f = 0.48$

From equation [3.18] incoming long-wave radiation ($R_l\downarrow$, $\text{MJ}/\text{m}^2/\text{day}$) for the critical months can be calculated as follows for, $\varepsilon_a = 0.82$, $\sigma = 4.903 \times 10^{-9} \text{MJ}/\text{K}^4/\text{m}^2/\text{day}$, and $r_{lw} = 0.03$,

$$R_l\downarrow = \varepsilon_a \times \sigma \times (T_a + 273.15)^4 \times (1 + 0.17C_f^2) \times (1 - r_{lw})$$

For March, $T_a = 22^\circ\text{C}$, $R_1 \downarrow = 30.11\text{MJ/m}^2 /\text{day}$,

For April, $T_a = 24^\circ\text{C}$, $R_1 \downarrow = 31.00\text{MJ/m}^2 /\text{day}$

For May, $T_a = 24^\circ\text{C}$, $R_1 \downarrow = 30.78\text{MJ/m}^2 /\text{day}$,

For June, $T_a = 24^\circ\text{C}$, $R_1 \downarrow = 31.00\text{MJ/m}^2 /\text{day}$

For July, $T_a = 21^\circ\text{C}$, $R_1 \downarrow = 30.34\text{MJ/m}^2 /\text{day}$

3.2.1.17. The Outgoing Long-Wave Radiation ($R_1 \uparrow$)

The outgoing long-wave radiation at water temperature ($R_1 \uparrow$, $\text{MJ/m}^2/\text{day}$) is calculated as [2, 29]:

$$R_1 \uparrow = \epsilon_w \times \sigma \times (T_w + 273.15)^4 \quad (3.21)$$

Where, σ = is the Stefan-Boltzmann constant ($\text{MJ/m}^2/\text{K}^4/\text{day}$);

T_w = the water surface temperature ($^\circ\text{C}$); and

ϵ_w = the emissivity of water, equal to 0.97.

3.2.1.18. The water surface temperature T_w

The water surface temperature is the same as with the earth skin temperature and it is not available from the Ethiopian National Meteorological Agency. So for this specific thesis the water surface temperature is taken from NASA.

Table 14 Monthly Averaged Earth Skin Temperature ($^\circ\text{C}$) Source NASA

Monthly Averaged Earth Skin Temperature ($^\circ\text{C}$)													
Lat 8.468 Lon 39.159	Jan	Feb	Mar	Apr	Ma	Jun	Jul	Au	Sep	Oct	No	Dec	Annual Ave
22-year ave	22.7	24.9	26.7	26.3	25.3	21.8	19.6	19.3	20.2	21.3	21.5	21.4	22.6

Then from Equation [3.21] the outgoing long-wave radiation at water temperature ($R_1 \uparrow$, $\text{MJ/m}^2/\text{day}$) for $\epsilon_w = 0.97$ and $\sigma = 4.903 \times 10^{-9} \text{MJ/K}^4/\text{m}^2/\text{day}$ is calculated as:

$$R_1 \uparrow = \epsilon_w \times \sigma \times (T_w + 273.15)^4$$

For March, $T_w = 26.7^\circ\text{C}$, $R_1 \uparrow = 38.45\text{MJ/m}^2/\text{day}$,

For April, $T_w = 26.3^\circ\text{C}$, $R_1 \uparrow = 38.24\text{MJ/m}^2/\text{day}$

For May, $T_w = 25.3^\circ\text{C}$, $R_1 \uparrow = 37.73\text{MJ/m}^2/\text{day}$

For June, $T_w = 21.8^\circ\text{C}$, $R_1 \uparrow = 36.00\text{MJ/m}^2/\text{day}$

For March, $T_w = 19.6^\circ\text{C}$, $R_1 \uparrow = 34.93\text{MJ/m}^2/\text{day}$

Therefore, the net outgoing long-wave radiation (R_{nl} , $\text{MJ/m}^2/\text{day}$) is the difference between the outgoing long-wave radiation ($R_1 \uparrow$, $\text{MJ/m}^2/\text{day}$) and the incoming long-wave radiation ($R_1 \downarrow$, $\text{MJ/m}^2/\text{day}$). Then the net outgoing long-wave radiation (R_{nl} , $\text{MJ/m}^2/\text{day}$) becomes:

$$R_{nl} = R_l \uparrow - R_l \downarrow$$

For March, $R_{nl} = 8.34 \text{ MJ/m}^2/\text{day}$, For April, $R_{nl} = 7.24 \text{ MJ/m}^2/\text{day}$

For May, $R_{nl} = 6.95 \text{ MJ/m}^2/\text{day}$, For June, $R_{nl} = 5.00 \text{ MJ/m}^2/\text{day}$

For July, $R_{nl} = 4.59 \text{ MJ/m}^2/\text{day}$

Finally from equation [3.9] the Net radiation (R_n , $\text{MJ/m}^2/\text{day}$) is the difference between the net incoming short-wave radiations (R_{ns} , $\text{MJ/m}^2/\text{d}$) and the net outgoing long-wave radiation (R_{nl} , $\text{MJ/m}^2/\text{day}$) for the five critical months it becomes:

$$R_n = R_{ns} - R_{nl}$$

For March, $R_n = 9.42 \text{ MJ/m}^2/\text{day}$, For April, $R_n = 10.5 \text{ MJ/m}^2/\text{day}$

For May, $R_n = 11.25 \text{ MJ/m}^2/\text{day}$, For June, $R_n = 12.12 \text{ MJ/m}^2/\text{day}$

For July, $R_n = 10.56 \text{ MJ/m}^2/\text{day}$

Therefore, the net radiation (R_n , $\text{MJ/m}^2/\text{day}$) for the five critical Months March, April, May, June and July becomes $9.42 \text{ MJ/m}^2/\text{day}$, $10.5 \text{ MJ/m}^2/\text{day}$, $11.25 \text{ MJ/m}^2/\text{day}$, $12.12 \text{ MJ/m}^2/\text{day}$ and $10.56 \text{ MJ/m}^2/\text{day}$ respectively.

3.2.1.19. The Water Temperature (T_{wi})

The water temperature at day i (T_{wi} , $^\circ\text{C}$) is calculated from the following equation [2, 29]:

$$T_{w,i} = T_e + (T_{w,i-1} - T_e) \times \exp\left(\frac{-1}{\tau}\right) \quad (3.22)$$

Where, $T_{w,i-1}$ is the water temperature at day $i-1$ ($^\circ\text{C}$);

T_e = the equilibrium temperature ($^\circ\text{C}$); and τ = the time constant (day)

3.2.1.20. The Equilibrium Temperature (T_e)

The equilibrium temperature (T_e , $^\circ\text{C}$) is calculated as follows [2, 29]:

$$T_e = T_n + \frac{R_n^*}{4\sigma \times (T_n + 273.15)^3 + f(u) \times (\Delta_n + \gamma)} \quad (3.23)$$

Where, $f(u)$ = the wind function at 10 m (u_{10} , m/s) = $13.88 \text{ MJ/m}^2/\text{day/kPa}$,

$$\sigma = 4.903 \times 10^{-9} \text{ MJ/K}^4/\text{m}^2/\text{day}$$

3.2.1.21. Wet-Bulb Temperature (T_n , $^\circ\text{C}$)

Wet-bulb temperature (T_n , $^\circ\text{C}$) is calculated using vapour pressure (e_a , kPa) and dew point temperature (T_d , $^\circ\text{C}$) as follows [77]:

The Wet-bulb temperature (T_n , $^\circ\text{C}$) for the critical months March, April, May, June and July with the value of air temperature of 22, 24, 24, 24 and 21 respectively, the dew temperature

of 6.09, 9.08, 10.3, 12.4 and 12.4 respectively from table 12 and 13 respectively and $e_a = 2.75kPa$ can be calculated as follows:

$$T_n = \frac{0.00066 \times 100T_a + \left(\frac{4098e_a}{(T_d + 273.15)^2} \right) \times T_d}{0.00066 \times 100 + \left(\frac{4098e_a}{(T_d + 273.15)^2} \right)} \quad (3.24)$$

For March, $T_n = 11.10^\circ C$, For April, $T_n = 13.83^\circ C$, For May, $T_n = 14.71^\circ C$, For June, $T_n = 16.18^\circ C$ For July, $T_n = 15.20^\circ C$

3.2.1.22. Slope of Temperature Saturation Water Vapour Curve at Wet Bulb Temperature (Δ_n)

The slope of the temperature saturation water vapour curve at wet bulb temperature (Δ_n , kPa/K) is given by:

$$\Delta_n = \frac{4098 \times \left[0.6108 \times \exp\left(\frac{17.27T_n}{(T_n + 237.3)}\right) \right]}{(T_n + 273.3)^2} \quad (3.25)$$

The slope of the temperature saturation water vapour at wet bulb temperature T_n for the selected month becomes:

For March, $\Delta_n = 0.0877kPa/K$, For April, $\Delta_n = 0.103kPa/K$, For May, $\Delta_n = 0.108kPa/K$, For June, $\Delta_n = 0.117kPa/K$, For July, $\Delta_n = 0.111kPa/K$

3.2.1.23. Net Radiation at Wet-Bulb Temperature (R_n^*)

Net radiation at wet-bulb temperature (R_n^* , MJ/m²/day) is calculated using albedo (α) as follows: $R_n^* = (1 - \alpha) \times R_s + (R_l \downarrow - R_{ln} \uparrow)$ (3.26)

3.2.1.24. Outgoing Long-Wave Radiation at Wet-Bulb Temperature ($R_l \uparrow_n$)

Outgoing long-wave radiation at wet-bulb temperature ($R_l \uparrow_n$, MJ/m²/day) is calculated, based on [2, 29]:

$$R_l \uparrow_n = C_f \times (\sigma \times (T_a + 273.15)^4 + 4\sigma \times (T_a + 273.15)^3 \times (T_n - T_a)) \quad (3.27)$$

Where, T_a is the air temperature for the selected months March, April, May, June and July are 22°C, 24°C, 24°C, 24°C and 21°C respectively from table 12 and the value of T_n for those months as calculated above are 11.1°C, 13.83°C, 14.71°C, 16.18°C 15.20°C respectively, $\sigma = 4.903 \times 10^{-9}$ MJ/K⁴/m²/day, $C_f =$ is fractional cloud cover for the selected months March, April, May, June and July becomes 0.32, 0.34, 0.27, 0.34 and 0.48

respectively. Then outgoing long-wave radiation at wet-bulb temperature ($R_l \uparrow_n$, MJ/m²/day) for the selected months March, April, May, June and July becomes:

$$R_l \uparrow_n = C_f \times (\sigma \times (T_a + 273.15)^4 + 4\sigma \times (T_a + 273.15)^3 \times (T_n - T_a))$$

For March, $R_l \uparrow_n = 6.41 \text{ MJ/m}^2/\text{day}$, For April, $R_l \uparrow_n = 7.76 \text{ MJ/m}^2/\text{day}$

For May, $R_l \uparrow_n = 5.54 \text{ MJ/m}^2/\text{day}$, For June, $R_l \uparrow_n = 8.97 \text{ MJ/m}^2/\text{day}$

For July, $R_l \uparrow_n = 14.72 \text{ MJ/m}^2/\text{day}$

As calculated before the incoming long-wave radiation ($R_l \downarrow$, MJ/m²/day) for the selected months March, April, May, June and July is $30.11 \text{ MJ/m}^2/\text{day}$, $31.00 \text{ MJ/m}^2/\text{day}$, $30.78 \text{ MJ/m}^2/\text{day}$, $31.00 \text{ MJ/m}^2/\text{day}$ and $30.34 \text{ MJ/m}^2/\text{day}$ respectively. Therefore, the net long wave solar radiation at wet bulb temperature for the selected months can be calculated as follows:

$$R_{ln}^* = R_l \downarrow - R_{ln} \uparrow$$

For March, $R_{ln}^* = 23.7 \text{ MJ/m}^2/\text{day}$, For April, $R_{ln}^* = 23.24 \text{ MJ/m}^2/\text{day}$

For May, $R_{ln}^* = 25.24 \text{ MJ/m}^2/\text{day}$, For June, $R_{ln}^* = 22.03 \text{ MJ/m}^2/\text{day}$

For July, $R_{ln}^* = 15.62 \text{ MJ/m}^2/\text{day}$

The net incoming short-wave radiation (R_{ns}) values for the critical months March, April, May, June and July is $17.76 \text{ MJ/m}^2/\text{day}$, $17.74 \text{ MJ/m}^2/\text{day}$, $18.52 \text{ MJ/m}^2/\text{day}$, $17.12 \text{ MJ/m}^2/\text{day}$ and $15.15 \text{ MJ/m}^2/\text{day}$ respectively. Now Net radiation at wet-bulb temperature (R_n^* , MJ/m²/day) for the selected months is calculated as follows:

$$R_n^* = R_{ns} + R_{ln}^*$$

For March, $R_n^* = 41.46 \text{ MJ/m}^2/\text{day}$, For April, $R_n^* = 40.98 \text{ MJ/m}^2/\text{day}$

For May, $R_n^* = 43.76 \text{ MJ/m}^2/\text{day}$, For June, $R_n^* = 39.15 \text{ MJ/m}^2/\text{day}$

For July, $R_n^* = 30.78 \text{ MJ/m}^2/\text{day}$

Then equilibrium temperature (T_e , °C) for the selected months March, April, May, June, and July is calculated as follows for the values, $\sigma = 4.903 \times 10^{-9} \text{ MJ/K}^4/\text{m}^2/\text{day}$, $f(u) = 13.88 \text{ MJ/m}^2/\text{day/kPa}$, $\gamma = 0.056 \text{ kPa/}^\circ\text{C}$, the value of T_n for those months as calculated above are 11.1°C , 13.83°C , 14.71°C , 16.18°C 15.20°C respectively and as calculated above the slope of the temperature saturation water vapor curve at wet bulb temperature (Δ_n , kPa/K) for the selected months above becomes: 0.0877 kPa/K , 0.103 kPa/K , 0.108 kPa/K , 0.117 kPa/K , and 0.111 kPa/K respectively and then equilibrium temperature (T_e , °C) becomes:

$$T_e = T_n + \frac{R_n^*}{4\sigma \times (T_n + 273.15)^3 + f(u) \times (\Delta_n + \gamma)}$$

For March, $T_e = 28.06^\circ\text{C}$, For April, $T_e = 29.18^\circ\text{C}$, For May, $T_e = 30.65^\circ\text{C}$

For June, $T_e = 29.79^\circ\text{C}$, For July, $T_e = 26.24^\circ\text{C}$

3.2.1.25. The Time Constant (τ , day)

The time constant (τ , day) is given as [2, 29]:

$$\tau = \frac{\rho_w \times c_w \times h}{4\sigma \times (T_n + 273.15)^3 + f(u) \times (\Delta_n + \gamma)} \quad (3.28)$$

where, ρ_w = is the density of water (= 1000 kg/m³); c_w = the specific heat of water (= 0.0042 MJ/kg/K); h =the depth of water (m), estimated from reservoir volume capacity and area (= 8.3m); $\sigma = 4.903 \times 10^{-9}$ MJ/K⁴/m²/day, $f(u) = 13.88 \text{ MJ/m}^2/\text{day/kPa}$, $\gamma = 0.056 \text{ kPa}/^\circ\text{C}$, the value of T_n for those selected months as calculated above are 11.1°C, 13.83°C, 14.71°C, 16.18°C 15.20°C respectively and the slope of the temperature saturation water vapor curve at wet bulb temperature (Δ_n , kPa/K) for the selected months above becomes: 0.0877kPa/K, 0.103kPa/K, 0.108kPa/K, 0.117kPa/K, and 0.111kPa/K respectively. Then the time constant (τ , day) for the selected month March, April, May, June, and July is calculated as follows:

$$\tau = \frac{\rho_w \times c_w \times h}{4\sigma \times (T_n + 273.15)^3 + f(u) \times (\Delta_n + \gamma)}$$

For March, $\tau = 14.25 \text{ day}$, For April, $\tau = 13.05 \text{ day}$, For May, $\tau = 12.7 \text{ day}$

For June, $\tau = 12.12 \text{ day}$, For July, $\tau = 12.50 \text{ day}$

From equation [3.22] The water temperature at day i (T_{wi} , °C) is calculated as

$$T_{w,i} = T_e + (T_{w,i-1} - T_e) \times \exp\left(\frac{-1}{\tau}\right)$$

Where, $T_{w,i-1}$ = is the water temperature at day $i-1$ (°C);

For the purpose of initialization $T_{w,0} = T_w = 26.7^\circ\text{C}$ of March is taken as a reference. Then the water temperature at a month i (T_{wi} , °C) for the selected months March, April, May, June and July can be calculated as follows:

$$\text{For March } T_{w,1} = T_e + (T_{w,0} - T_e) \times \exp\left(\frac{-1}{\tau}\right)$$

$$T_{w,1} = 28.06 + (26.7 - 28.06) \times \exp\left(\frac{-1}{14.25}\right) = 26.79^\circ\text{C}$$

$$\text{For April } T_{w,2} = T_e + (T_{w,1} - T_e) \times \exp\left(\frac{-1}{\tau}\right)$$

$$T_{w,2} = 29.18 + (26.79 - 29.18) \times \exp\left(\frac{-1}{13.05}\right) = 26.96^\circ\text{C}$$

$$\text{For May } T_{w,3} = T_e + (T_{w,2} - T_e) \times \exp\left(\frac{-1}{\tau}\right)$$

$$T_{w,3} = 30.65 + (26.96 - 30.65) \times \exp\left(\frac{-1}{12.7}\right) = 27.24^\circ\text{C}$$

For June $T_{w,4} = T_e + (T_{w,3} - T_e) \times \exp\left(\frac{-1}{\tau}\right)$

$$T_{w,4} = 29.79 + (27.24 - 29.79) \times \exp\left(\frac{-1}{12.12}\right) = 27.44^\circ\text{C}$$

For July $T_{w,5} = T_e + (T_{w,4} - T_e) \times \exp\left(\frac{-1}{\tau}\right)$

$$T_{w,5} = 26.24 + (27.44 - 26.24) \times \exp\left(\frac{-1}{12.5}\right) = 27.35^\circ\text{C}$$

Then the water temperature at a month i ($T_{w,i}$, °C) for the selected months March, April, May, June and July becomes 26.79°C, 26.96°C, 27.24°C, 27.44°C, and 27.35°C respectively.

3.2.1.26. Change in the Heat Storage in the Water Body (G)

Change in heat storage in the water body (G , MJ/m²/day) is calculated from [2, 29]:

$$G = \rho_w \times c_w \times h \times (T_{w,i} - T_{w,i-1}) \quad (3.29)$$

ρ_w = is the density of water (= 1000 kg/m³); c_w = the specific heat of water (= 0.0042 MJ/kg/K); and h = the depth of water (m), estimated from reservoir volume capacity and area (8.3m)

Change in the heat storage in the water body (G , MJ/m²/day) for the selected months March, April, May, June, and July can be calculated as follows:

For March, $G_{\text{month } 1} = \rho_w \times c_w \times h \times (T_{w,1} - T_{w,0})$, $T_{w,0} = T_w = 26.7^\circ\text{C}$

$$G_{\text{month } 1} = 1000 \times 0.0042 \times 8.3 \times (26.79 - 26.70) = 3.14\text{MJ/m}^2/\text{day}$$

For April, $G_{\text{month } 2} = \rho_w \times c_w \times h \times (T_{w,2} - T_{w,1})$

$$G_{\text{month } 1} = 1000 \times 0.0042 \times 8.3 \times (26.96 - 26.79) = 5.93\text{MJ/m}^2/\text{day}$$

For May, $G_{\text{month } 3} = \rho_w \times c_w \times h \times (T_{w,3} - T_{w,2})$

$$G_{\text{month } 1} = 1000 \times 0.0042 \times 8.3 \times (27.24 - 26.96) = 9.76\text{MJ/m}^2/\text{day}$$

For June, $G_{\text{month } 4} = \rho_w \times c_w \times h \times (T_{w,4} - T_{w,3})$

$$G_{\text{month } 1} = 1000 \times 0.0042 \times 8.3 \times (27.44 - 27.24) = 6.97\text{MJ/m}^2/\text{day}$$

For May, $G_{\text{month } 5} = \rho_w \times c_w \times h \times (T_{w,5} - T_{w,4})$

$$G_{\text{month } 1} = 1000 \times 0.0042 \times 8.3 \times (27.35 - 27.44) = -3.14\text{MJ/m}^2/\text{day}$$

Finally change in the heat storage in the water body ($G_{\text{month } i}$, MJ/m²/day) for the selected months March, April, May, June, and July becomes 3.14MJ/m²/day, 5.93MJ/m²/day, 9.76MJ/m²/day, 6.97MJ/m²/day, and -3.14MJ/m²/day respectively.

3.2.1.27. Saturated Vapour Pressure at Water Temperature (e_w)

Saturated vapour pressure at water temperature (e_w , kPa) is calculated from:

$$e_w = 0.6108 \times \exp\left(\frac{17.27T_w}{(T_w + 273.3)}\right) \quad (3.30)$$

3.2.1.28. The water surface temperature T_w

The water surface temperature is the same as with the earth skin temperature and it is not available from the Ethiopian National Meteorological Agency. So for this specific thesis the water surface temperature is taken from NASA and it is shown in table: 14

Then water surface temperature T_w for the selected months March, April, May June and July becomes 26.7, 26.3, 25.3, 21.8, and 19.6 respectively and then the saturated vapour pressure at water temperature (e_w , kPa) for those selected months can be calculated as follows:

$$e_w = 0.6108 \times \exp\left(\frac{17.27T_w}{(T_w + 273.3)}\right)$$

For March, $e_w = 3.50\text{kPa}$, For April, $e_w = 3.42\text{kPa}$, For May, $e_w = 3.22\text{kPa}$

For June, $e_w = 2.61\text{kPa}$, For July, $e_w = 2.28\text{kPa}$

3.2.1.29. Slope of Temperature Saturation Water Vapour Curve T_a Water Temperature (Δ_w)

Finally, the slope of the temperature saturation water vapour at water surface temperature (Δ_w , kPa/°C) is:

$$\Delta_w = \frac{4098 \times \left[0.6108 \times \exp\left(\frac{17.27T_w}{(T_w + 273.3)}\right)\right]}{(T_w + 273.3)^2} \quad (3.31)$$

Δ_w Can be rewritten as:

$$\Delta_w = \frac{4098 \times e_w}{(T_w + 273.3)^2} \quad (3.32)$$

Then the slope of the temperature saturation water vapour at water surface temperature (Δ_w , kPa/°C) for the selected months that is for March, April, May June and July becomes 26.7, 26.3, 25.3, 21.8, and 19.6 respectively and the saturated vapour pressure at water temperature (e_w , kPa) for those selected months March, April, May, June and July becomes 3.50kPa , 3.42kPa , 3.22kPa , 2.61kPa and 2.28kPa respectively can be calculated as:

$$\Delta_w = \frac{4098 \times e_w}{(T_w + 273.3)^2}$$

For March, $\Delta_w = 0.206\text{kPa}/^\circ\text{C}$, For April, $\Delta_w = 0.202\text{kPa}/^\circ\text{C}$, For May,

$\Delta_w = 0.191\text{kPa}/^\circ\text{C}$

For June, $\Delta_w = 0.159\text{kPa}/^\circ\text{C}$, For April $\Delta_w = 0.142\text{kPa}/^\circ\text{C}$

Finally after calculating and obtaining the necessary parameters by the above procedure it is possible to obtain the Koka Hydropower Plant Reservoir evaporation for the critical months March, April, May, June and July. From equation (3.2) evaporation from the water surface (E , mm/day) is estimated using the Penman-Monteith equation for critical months with an inclusion of water body heat storage becomes:

$$E = \frac{1}{\lambda} \times \left(\frac{\Delta_w \times (R_n - G) + \gamma \times f(u) \times (e_w - e_a)}{\Delta_w + \gamma} \right)$$

The evaporation from the water surface (E , mm/day) of the Koka Hydropower Plant Reservoir for the critical months March, April, May, June and July can be calculated as follows:

$$\text{For March } E = \frac{1}{2.45} \times \left(\frac{0.206 \times (9.42 - 3.14) + 0.056 \times 13.88 \times (3.5 - 2.75)}{0.206 + 0.056} \right) = 2.92 \text{ mm/day}$$

$$\text{For April } E = \frac{1}{2.45} \times \left(\frac{0.202 \times (10.5 - 5.93) + 0.056 \times 13.88 \times (3.42 - 2.75)}{0.202 + 0.056} \right) = 2.28 \text{ mm/day}$$

$$\text{For May } E = \frac{1}{2.45} \times \left(\frac{0.191 \times (12.2 - 9.76) + 0.056 \times 13.88 \times (3.22 - 2.75)}{0.191 + 0.056} \right) = 1.5 \text{ mm/day}$$

$$\text{For June } E = \frac{1}{2.45} \times \left(\frac{0.159 \times (12.6 - 6.97) + 0.056 \times 13.88 \times (2.61 - 2.75)}{0.159 + 0.056} \right) = 2.30 \text{ mm/day}$$

$$\text{For July } E = \frac{1}{2.45} \times \left(\frac{0.142 \times (10.56 - (-3.14)) + 0.056 \times 13.88 \times (2.28 - 2.75)}{0.142 + 0.056} \right) = 3.26 \text{ mm/day}$$

Finally the evaporation from the open water surface (E , mm/day) of the Koka Hydropower Plant Reservoir for the critical months March, April, May, June and July becomes 2.92mm/day, 2.28mm/day, 1.5mm/day, 2.30mm/day, and 3.26mm/day respectively.

From this calculated evaporation rate for the selected critical months we can also calculate the Volume of water Evaporated from the reservoir in the day time by using the total reservoir area for the selected months as follows:

$$\text{Area of the reservoir } (A_r) = 236 \text{ km}^2$$

Volume of Evaporated water in March

$$V_e = A_r \times E_{\text{March}}, \quad V_e = 236 \times 10^6 \text{ m}^2 \times 2.92 \times 10^{-3} \text{ m} = 689,120 \text{ m}^3$$

$$Q = \frac{689,120 \text{ m}^3}{\text{day}} = \frac{689,120 \text{ m}^3}{(12)} = 57,427 \text{ m}^3/\text{hr} = 16 \text{ m}^3/\text{s}$$

$$\text{For April } V_e = A_r \times E_{\text{April}} \quad V_e = 236 \times 10^6 \text{ m}^2 \times 2.28 \times 10^{-3} \text{ m} = 538,080 \text{ m}^3$$

$$Q = \frac{538,080 \text{ m}^3}{\text{day}} = \frac{538,080 \text{ m}^3}{(12)} = 44,840 \text{ m}^3/\text{hr} = 12.45 \text{ m}^3/\text{s}$$

$$\text{For May } V_e = A_r \times E_{\text{May}} \quad V_e = 236 \times 10^6 \text{ m}^2 \times 1.5 \times 10^{-3} \text{ m} = 354,000 \text{ m}^3$$

$$Q = \frac{354,000 \text{ m}^3}{\text{day}} = \frac{354,000 \text{ m}^3}{(12)} = 29,500 \text{ m}^3/\text{hr} = 8.2 \text{ m}^3/\text{s}$$

$$\text{For June } V_e = A_r \times E_{\text{June}} \quad V_e = 236 \times 10^6 \text{ m}^2 \times 2.3 \times 10^{-3} \text{ m} = 542,800 \text{ m}^3$$

$$Q = \frac{542,800\text{m}^3}{\text{day}} = \frac{542,000\text{m}^3}{(12)} = 45,167\text{m}^3/\text{hr} = 12.55\text{m}^3/\text{s}$$

$$\text{For July } V_e = A_r \times E_{\text{July}} \quad V_e = 236 \times 10^6\text{m}^2 \times 3.26 \times 10^{-3}\text{m} = 769,360\text{m}^3$$

$$Q = \frac{769,360\text{m}^3}{\text{day}} = \frac{769,360\text{m}^3}{(12)} = 64,113\text{m}^3/\text{hr} = 17.81\text{m}^3/\text{s}$$

After calculating the amount of water that evaporates from the hydroelectric reservoir in the five selected critical months March, April, May, June and July from the five representative years starting from 2000E.C up to 2004E.C we can determine the minimum volume of the lower reservoir capacity to store water for pumping during the time of water shortage in the upper reservoir mainly during the dry months like January, March, April, May, June and July. So, the amount of water that evaporates from the upper reservoir during the five selected critical months March, April, May, June, and July is 689,120m³/day, 538,080m³/day, 354,000m³/day, 542,800m³/day, 769,360m³/day respectively. From this value the maximum water that evaporates from the reservoir will be taken as the minimum water capacity that should be stored in the lower reservoir that is 769,360m³ approximately it is about 1Mm³. Even though this volume of water is taken as representative water that is to be stored in the lower reservoir per day the capacity of the lower reservoir will be on the basis of annual so it is taken as 360Mm³ (1Mm³x 30day x 12month=360Mm³/year), then total amount of water that should be stored in the lower reservoir is 360Mm³/year.

CHAPTER FOUR

4. THE PIPE ECONOMIC ANALYSIS FOR THE STUDY AREA

4.1. Introduction

In this chapter we discuss the cost of a pipeline and the various components that contribute to the economics of pipelines. These include the major components of the initial capital costs and the recurring annual costs.

In any pipeline investment project we must perform an economic analysis of the pipeline system to ensure that we have the right equipment and materials at the right cost to perform the necessary service and provide a profitable income for the venture. Besides to this, in this chapter we analyze the cost implications and how to decide on the economic pipe size and pumping equipment required to provide the optimum rate of return on investment.

The major capital Cost components of a pipeline system consist of the pipe, pump stations, storage reservoirs, valves, fittings, and meter stations. Once this capital is expended, and the pipeline has been installed and the pump station and other facilities built, annual operating and maintenance costs for these facilities will be incurred. Annual costs will also include general and administrative (G&A) costs including payroll costs, rental and lease costs, and other recurring costs necessary for the safe and efficient operation of the pipeline system.

As stated above the Koka Hydropower Plant Reservoir is located at 1590.7m (a.s.l) maximum level and 1580.7m (a.s.l) minimum level and the total storage capacity at the maximum level (1590.7m a.s.l) is $1850 \times 10^6 m^3$, the usable storage capacity is $1680 \times 10^6 m^3$, the total reservoir area at 1590.7 is $236 m^2$ and the total head of the reservoir is around 45 meters. The dam type is concrete gravity dam; its crest elevation is at 1593.20 meter (a.s.l), crest length 458m, maximum dam height 23.8m and Maximum spillway discharge (4×250) with total discharge of $1000 m^3/s$. The water conductors; the pressure tunnel length 71.50m with diameter of 5.50m and the concrete pipe length 145.37m with diameter of 5.50m. Its surge tank is 18m diameter with height of 20m and three penstocks in number with diameter of 3.5m and length of 50.7m, 55.4m and 61.4m respectively.

From this data we can assume that the total pipe line length from the lower reservoir to the upper reservoir will be the sum of the length of the water conductors, the pressure tunnel length and the concrete pipe length and the penstock with maximum length is taken as are a representative of the three penstocks and as an allowance 121.73m is added on the total

length for the pipe by considering the geographical land feature. Then the total pipe line length will be:

$$\begin{aligned}
 \text{Pipe Line Length(PLL)} &= \text{Pressure Tunnel length(PTL)} + \text{Concrete pipe Line length(CPLL)} \\
 &+ \text{length of Penstock(LP)} + \text{Allowance Length(AL)} \\
 \text{PLL} &= \text{PTL} + \text{CPLL} + \text{LP} + \text{AL} \\
 &= 71.5\text{m} + 145.37\text{m} + 61.4\text{m} + 121.73\text{m} \\
 \text{PLL} &= 400\text{m}
 \end{aligned}$$

The amount of water that evaporates from the upper reservoir during the five selected critical months March, April, May, June, and July $57,427\text{m}^3/\text{hr}$, $44,840\text{m}^3/\text{hr}$, $29,500\text{m}^3/\text{hr}$, $45,167\text{m}^3/\text{hr}$, $64,113\text{m}^3/\text{hr}$, respectively.

Now we can determine the amount of water that is to be pumped per hour to the upper reservoir will be the average of the five selected month values:

$$Q_{\text{hr}} = \frac{57,427 + 44,840 + 29,500 + 45,167 + 64,113}{5} = 48,210\text{m}^3/\text{hr}$$

In order to pump $48,210\text{m}^3/\text{hr}$ amount of water we used 6 pumps with a pumping capacity of $8040\text{m}^3/\text{hr}$ up to a total head of 45m which is a small head to pump so we can pump large volume of water to the upper reservoir. The number of the pump here can be adjusted according to the user based on the pumping capacity and commercial availability of the pumps with the capacity of $8040\text{m}^3/\text{hr}$ [10].

The next step is to calculate the pipe diameter to transport water to the upper reservoir and the amount electric power needed to drive electric motors to pump the water up to the required head that is 45m and the total economic analysis of the pipe line and pumping station. The amount of water to be pumped in an hour is 8040m^3 .

When designing a fluid distribution system, three distinct steps are required:

- Establish the design and objectives,
- Sizing of pipes and ducts, and
- The calculation or determination of the pressure drop in the system

Now, the number of pumps is already fixed that is 6 then what is expected from the analysis is to decide on the economic pipe size and pumping equipment required to provide the optimum rate of return on investment.

The main tasks are:

- i. To Determine the optimum pipe diameter and
- ii. Determine the HP required for pumping the required volume on a continuous basis
- iii. To calculate the capital cost of facilities

- iv. To determine the labor cost for installing the pipe
- v. To determine the installed cost for pump stations
- vi. To determine the total annual operating cost of the system
- vii. Finally selecting the best pipe line system with the best pumping station design

4.2. Determining the optimum pipe diameter

In this step, first we have to set or bracket the pipe diameter range. For this case let us assume the three diameters, the first with the value of 30in. or 762mm outer diameter with thickness of 1.2in., or 30mm, the second with the value of 32in. or 813mm outer diameter with thickness of 1.2in., or 30mm, and the third one with the value of 34in. or 864mm outer diameter with thickness of 1.2in., or 30mm. Later we will calculate the actual required wall thickness for the given MAOP. Assume A minimum delivery pressure of 50 psi (345kPa) is required at the pipeline terminus and the pipeline operating pressure must be limited to 500 psi (3450kPa) using steel pipe with yield strength of 52,000 psi (358800kPa). The internal diameter of the assumed pipe diameter is obtained by subtraction twice of the thickness from the outer diameter [10].

$$D_{\text{inner}} = D_{\text{outer}} - 2 \times T \quad (4.1)$$

where, T= Wall thickness, D_{inner} = inner diameter, D_{out} = outer diameter

For 762mm diameter the inner diameter is: $D_{\text{inner}} = 762 - 2 \times 30 = 702\text{mm}$

For 813mm diameter the inner diameter is: $D_{\text{inner}} = 813 - 2 \times 30 = 753\text{mm}$

For 864mm diameter the inner diameter is: $D_{\text{inner}} = 864 - 2 \times 30 = 804\text{mm}$

4.3. Determining the average velocity in the pipe line

Velocity of flow in a pipeline is the average velocity based on the pipe diameter and liquid flow rate. Depending on the type of flow (laminar and turbulent), the liquid velocity in a pipeline at a particular pipe cross-section will vary along the pipe radius. The liquid molecules at the pipe wall are at rest and therefore have zero velocity. As we approach the centerline of the pipe, the liquid molecules are increasingly free and therefore have increasing velocity. In SI units, the velocity is calculated as follows [10].

$$V = \frac{353.6777 \times Q(\text{m}^3/\text{hr})}{D^2} \quad (4.2)$$

where, V=Velocity [m/s], D=Pipe internal diameter [mm], $Q = 8040\text{m}^3/\text{hr}$

For 762mm diameter the velocity becomes: $V = \frac{353.6777 \times 8040\text{m}^3/\text{hr}}{(702)^2} = 5.77 \text{ m/s}$

For 813mm diameter the velocity becomes: $V = \frac{353.6777 \times 8040 \text{ m}^3/\text{hr}}{(753)^2} = 5.02 \text{ m/s}$

For 864mm diameter the velocity becomes: $V = \frac{353.6777 \times 8040 \text{ m}^3/\text{hr}}{(804)^2} = 4.4 \text{ m/s}$

The selected pipe size of 762mm, 813mm and 864mm will result in a water velocity 5.77m/s, 5.02m/s and 4.4m/s respectively.

Next we need to calculate a suitable wall thickness for each pipe size to limit the operating pressure to 500 psi (3450kPa). Using the internal design pressure Equation or Barlow's equation, we calculate the pipe wall thickness required as follows [10].

$$T = \frac{D_{\text{out}} \times P}{2 \times \sigma \times E \times F} \quad (4.3)$$

where, P=Pipe internal design pressure, kPa take (=3450kPa)

D=Nominal pipe outside diameter, mm

T=Nominal pipe wall thickness, mm (= ? mm)

S=Specified minimum yield strength (SMYS) of pipe material, kPa take (52000psi = 358800kPa), E=Seam joint factor, 1.0 for seamless

F=Design factor, usually 0.72 for liquid pipelines, except that a design factor of 0.60 is used for pipe, including risers, on a platform located off shore or on a platform in inland navigable waters, and 0.54 is used for pipe that has been subjected to cold expansion to meet the SMYS and subsequently heated, other than by welding or stress-relieving as a part of the welding, to a temperature higher than 900°F (482°C) for any period of time or to over 600°F (316°C) for more than 1 hour.

The strength of pipe material designated as specified minimum yield strength (SMYS) depends on pipe material and grade. In the United States, steel pipeline material used in the oil and gas industry is manufactured in accordance with American Petroleum Institute (API) standards 5L and 5LX. For example, grades 5LX-42, 5LX-52, 5LX-60, 5LX-65, 5LX-70, and 5LX-80 are used commonly in pipeline applications. The numbers after 5LX above indicate the SMYS values in thousands of psi. Thus, 5LX-52 pipe has minimum yield strength of 52,000 psi. The lowest grade of pipe material used is 5L Grade B, which has an SMYS of 35,000 psi. In addition, seamless steel pipe designated as ASTM A106 and Grade B pipe are also used for liquid pipeline systems. These have an SMYS value of 35,000 psi.

For 762mm diameter the wall thickness $T = \frac{762 \times 3450}{2 \times 358800 \times 1 \times 0.72} = 5.1 \text{ mm} = 0.20 \text{ in.}$

For 813mm diameter the wall thickness $T = \frac{813 \times 3450}{2 \times 358800 \times 1 \times 0.72} = 5.43 \text{ mm} = 0.22 \text{ in.}$

For 864mm diameter the wall thickness $T = \frac{864 \times 3450}{2 \times 358800 \times 1 \times 0.72} = 5.77 \text{ mm} = 0.23 \text{ in.}$

Next using the closest commercially available pipe wall thicknesses, we choose the following three sizes [4]:

Table 15 Commercially available pipe wall thicknesses

In inch			psi	In mm			kPa
D _{out}	T	D _{in}	P _{MAOP}	D _{out}	T	D _{in}	P _{MAOP}
30	0.25	29.5	433	762	6.4	750	2,987.7
32	0.25	31.5	406	813	6.4	802	2,801.4
34	0.25	33.5	382	864	6.4	851	2,635.8

The revised MAOP (Maximum Allowable Operating Pressure) values for each pipe size, with the slightly higher than required minimum wall thickness, were calculated as shown above table 14. With the revised pipe wall thickness, the velocity calculated earlier will be corrected to:

$$V = \frac{353.6777 \times Q(\text{m}^3/\text{hr})}{D^2}$$

Where, V=Velocity [m/s], D=Pipe internal diameter [mm], Q = 8040m³/hr

For 762mm diameter the velocity becomes: $V = \frac{353.6777 \times 8040 \text{m}^3/\text{hr}}{(750)^2} = 5.05 \text{ m/s}$

For 813mm diameter the velocity becomes: $V = \frac{353.6777 \times 8040 \text{m}^3/\text{hr}}{(802)^2} = 4.4 \text{ m/s}$

For 864mm diameter the velocity becomes: $V = \frac{353.6777 \times 8040 \text{m}^3/\text{hr}}{(851)^2} = 3.9 \text{ m/s}$

The selected pipe size of 762mm, 813mm and 864mm will result in a water velocity 5.05m/s, 4.4m/s and 3.9m/s respectively which are acceptable range of velocities in pipes.

Next, we calculate the pressure drop due to friction in each pipe size at the given flow rate of 8040m³/hr, using the Hazen-Williams equation [10] with a C-factor of 100.

i. **Hazen-Williams Equation**

$$h = \frac{4.73 \times L \times \left(\frac{Q}{C}\right)^{1.852}}{D^{4.87}}$$

$$Q = 9.0379 \times 10^{-8} \times C \times D^{2.63} \times (P_{\text{km}}/\text{sg})^{0.54} \quad (4.4)$$

where, L=pipe length, h=head loss due to friction (m), Q=Flow rate, (m³/hr)

D=Pipe internal diameter, (mm), P_{km}=Frictional pressure drop, (kPa/km)

Sg=Liquid specific gravity=1 for water, C=Hazen-Williams C-factor

Rearranging and solving for the pressure drop P_m we get:

$$P_{km} = \left(\frac{Q}{9.0379 \times 10^{-8} \times C \times D^{2.63}} \right)^{\frac{100}{54}} \times sg \quad (4.5)$$

For 762mm diameter, Q=8040m³/hr, C-factor=100 and Sg= 1

$$P_{km} = \left(\frac{8040 \text{ m}^3/\text{hr}}{9.0379 \times 10^{-8} \times 100 \times (750)^{2.63}} \right)^{\frac{100}{54}} \times 1.0 = 291 \text{ kPa/km} = 0.291 \text{ kPa/m}$$

For 813mm diameter, Q=8040m³/hr, C-factor=100 and Sg= 1

$$P_{km} = \left(\frac{8040 \text{ m}^3/\text{hr}}{9.0379 \times 10^{-8} \times 100 \times (802)^{2.63}} \right)^{\frac{100}{54}} \times 1.0 = 209 \text{ kPa/km} = 0.209 \text{ kPa/m}$$

For 864mm diameter, Q=8040m³/hr, C-factor=100 and Sg= 1

$$P_{km} = \left(\frac{8040 \text{ m}^3/\text{hr}}{9.0379 \times 10^{-8} \times 100 \times (851)^{2.63}} \right)^{\frac{100}{54}} \times 1.0 = 156.4 \text{ kPa/km} = 0.1564 \text{ kPa/m}$$

ii. Pressure and Head

$$\text{In SI units Head}(H) = \frac{0.102(\text{kPa})}{S_{pg}} \times H(\text{m}) \quad (4.6)$$

Where Spgr=Liquid specific gravity=1.0 for water, H=head in [m] =45m

$$\text{Head} = \frac{0.102(\text{kPa})}{1\text{m}} \times 45\text{m} = 4.6\text{kPa}$$

We can now calculate the total pressure required for each pipe size, taking into account the friction drop in the 400m (0.4km) pipeline and the elevation head of 45m along with a minimum delivery pressure of 50 psi (345kPa) at the pipeline terminus.

Therefore, the Total Pressure Required at the origin pump station is:

Total Pressure Required (TPR)

$$\begin{aligned} &= \text{Pressure Drop Due to Friction (PDF)} + \text{Head Pressure (HP)} \\ &+ \text{minimum delivery pressure at the pipeline terminus (MDPPT)} \end{aligned}$$

$$\text{For 762mm, TPR} = 291 \left(\frac{\text{kPa}}{\text{km}} \right) \times 0.4\text{km} + 4.6\text{kPa} + 345\text{kPa} = 466\text{kPa}$$

$$\text{For 813mm, TPR} = 209 \left(\frac{\text{kPa}}{\text{km}} \right) \times 0.4\text{km} + 4.6\text{kPa} + 345\text{kPa} = 433.2\text{kPa}$$

$$\text{For 864mm, TPR} = 156.4 \left(\frac{\text{kPa}}{\text{km}} \right) \times 0.4\text{km} + 4.6\text{kPa} + 345\text{kPa} = 412.2\text{kPa}$$

Since the MAOP of the pipeline is limited to 3450kPa, and the total pressure required at the origin pump station is lower than the MAOP it is clear that we would need one pump station each pipeline cases or scenarios. We assume that the pumps require a minimum suction pressure of the pipe 345kPa.

The brake horsepower takes into account the pump efficiency. Then the brake horsepower (BHP) can be calculated as follows [10]:

$$\text{Brake horsepower} = \frac{\text{Hydraulic horsepower}}{\text{Pump efficiency}} \quad (4.7)$$

The total BHP (Brake Horsepower) required for each case will be calculated from the above total pressure and the flow rate of 8040m³/hr using Equation:

$$\text{BHP(kW)} = \frac{Q \times P_T}{3600 \times \eta} \quad (4.8)$$

where BHP=Brake Horsepower [kW], Q= flow rate [m³/hr],

P_T=Total pressure, [kPa], η=efficiency [%]

Assuming a pump efficiency of 80%=0.80

For 762mm diameter, P_T=466kPa, Q=8040m³/hr, and η=80%=0.8; BHP (kW): BHP(kW) = $\frac{8040 \times 466}{3600 \times 0.8} = 1301\text{kW}$ Or BHP(HP) = $\frac{1301\text{kW}}{0.746\text{kW}} \times 1\text{HP} = 1744\text{HP}$

For 813mm diameter, P_T=433.2kPa, Q=8040m³/hr, and η=80%=0.8: BHP (kW): BHP(kW) = $\frac{8040 \times 433.2}{3600 \times 0.8} = 1209.4\text{kW}$ Or BHP(HP) = $\frac{1209.4\text{kW}}{0.746\text{kW}} \times 1\text{HP} = 1622\text{HP}$

For 864mm diameter, P_T=412.2kPa, Q=8040m³/hr and η=80%=0.8: BHP (kW): BHP(kW) = $\frac{8040 \times 412.2}{3600 \times 0.8} = 1151\text{kW}$ Or BHP(HP) = $\frac{1151\text{kW}}{0.746\text{kW}} \times 1\text{HP} = 1543\text{HP}$

If an electric motor is used to drive the above pump, the actual Motor Horsepower (MHP) required would be calculated as [10]:

$$\text{MHP} = \frac{\text{BHP}}{\eta_m} \quad (4.9)$$

4.3.1. Standard Horsepower Ratings

Standard horsepower ratings of electrical motors - 1 to 4000 hp are indicated below:

1, 1 1/2, 2, 3, 5, 7 1/2, 10, 15, 20, 25, 30, 40, 50, 60, 75, 100, 125, 150, 200, 250, 300, 350, 400, 450, 500, 600, 700, 800, 900, 1000, 1250, 1500, 1750, 2000, 2250, 2500, 3000, 3500, 4000 [19].

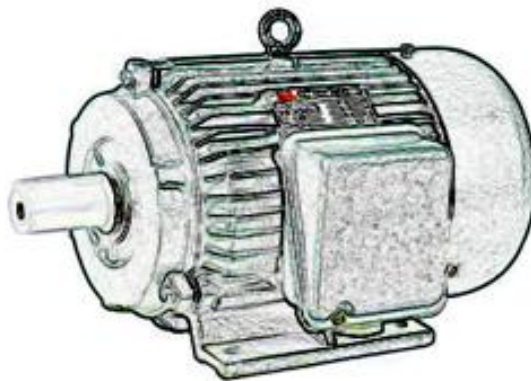


Figure 12 Induction Electrical Motor

Generally induction motors used for driving pumps have fairly high efficiencies, ranging from 95% to 98%. Using 95% motor efficiency, we can calculate the motor HP required as follows:

For 762mm diameter, BHP=1301kW, $\eta=95\%=0.95$:

$$\text{MHP(kW)} = \frac{1301\text{KW}}{0.95} = 1369.5\text{kW} \quad \text{Or} \quad \text{MHP(HP)} = \frac{1369.5\text{kW}}{0.746\text{kW}} \times 1\text{HP} = 1836\text{HP}$$

For 813mm diameter, BHP=1209.4kW, $\eta=95\%=0.95$:

$$\text{MHP(kW)} = \frac{1209.4\text{KW}}{0.95} = 1273.1\text{kW} \quad \text{Or} \quad \text{MHP(HP)} = \frac{1273.1\text{kW}}{0.746\text{kW}} \times 1\text{HP} = 1707\text{HP}$$

For 864mm diameter, BHP=1151kW, $\eta=95\%=0.95$:

$$\text{MHP(kW)} = \frac{1151\text{KW}}{0.95} = 1211.6\text{kW} \quad \text{Or} \quad \text{MHP(HP)} = \frac{1211.6\text{kW}}{0.746\text{kW}} \times 1\text{HP} = 1625\text{HP}$$

Choosing the nearest motor size, we will use 2000 HP for the 762mm diameter pipeline system, and 1750HP for the 813mm and 864mm diameter system.

4.4. Calculating the capital cost of facilities

The major capital components of a pipeline system consist of the pipe, pump stations, storage dams or reservoir, valves, fittings, and meter stations.

4.4.1. Pipeline Costs

The capital cost of a pipeline consists of material and labor for installation.

- i. **Material cost:** - to estimate the material cost we will use the following method [10]

$$\text{PMC} = 0.02463 \times L \times (D - t) \times t \times (C_{pt}) \quad (10)$$

Where, PMC=Pipe material cost [\$], L=Pipe length [km], D=Pipe outside diameter [mm], t=Pipe wall thickness [mm], C_{pt} =Pipe cost [\$/metric ton]

Since the pipe will be coated, wrapped, and delivered to the site, we will have to increase the material cost by some factor to account for these items or add the actual cost of these items to the pipe material cost.

To calculate the pipeline material cost, we will use prices ranging from \$500/ton-\$1100/ton for steel pipe from well known steel pipe producing company Liaocheng Mill Company in China. It is a producer of large diameter thick wall ASTM A53 ERW Black Steel Pipes for Water Transmission with length ranging from 6m to 12m, wall thickness ranging from 2.5mm to 80mm and outer diameter of ranging from 12.7mm to 690mm pipes, delivered to the construction site. But since the plastic pipes can be manufactured in Ethiopia it can be replaced by the steel pipes and the price of the pipe can be reduced [20].

From the point of view of the manufacturer data the total number of pipe lines needed in this thesis case will be:

$$\text{Total Pipeline Length (TPLL)} = 12\text{m} \times \text{Number of the pipes (n)}$$

Then, $n = \frac{\text{TPLL}}{12\text{m}}$, $n = 400\text{m}/12\text{m} = 34$ and therefore, the pipe material cost will be:

For $L=400\text{m}=0.4\text{km}$, $D_{\text{out}}=762\text{mm}$, $t=6.4\text{mm}$ and $C_{\text{pt}}=\$500/\text{ton}=\$454/\text{metric ton}$

$$\text{PMC} = 0.02463 \times 0.4 \times (762 - 6.4) \times 6.4 \times 454 = \$21,630$$

For $L=400\text{m}=0.4\text{km}$, $D_{\text{out}}=813\text{mm}$, $t=6.4\text{mm}$ and $C_{\text{pt}}=\$500/\text{ton}=\$454/\text{metric ton}$

$$\text{PMC} = 0.02463 \times 0.4 \times (813 - 6.4) \times 6.4 \times 454 = \$23,090$$

For $L=400\text{m}=0.4\text{km}$, $D_{\text{out}}=864\text{mm}$, $t=6.4\text{mm}$ and $C_{\text{pt}}=\$500/\text{ton}=\$454/\text{metric ton}$

$$\text{PMC} = 0.02463 \times 0.4 \times (864 - 6.4) \times 6.4 \times 454 = \$24,550$$

Pipe installation cost or labor cost is generally stated in \$/ft or \$/mile of pipe. It may also be stated based on an inch-diameter-mile of pipe. Construction contractors will estimate the labor cost of installing a given pipeline based on a detailed analysis of the terrain, construction conditions, difficulty of access, and other factors. Historical data is available for estimating labor costs of various-size pipelines. In this thesis we will use approximate methods; these should be verified with contractors taking into account current labor rates, geographic and terrain issues and level of construction difficulty. A good approach is to express the labor cost in terms of \$/inch-diameter per mile of pipe. In Appendix F shows a summary of typical labor costs. In addition to labor costs for installing straight pipe, there may be other construction costs such as road crossings, railroad crossings, river crossings, etc. These are generally estimated as a lump sum for each item and added to the total pipe installation costs.

- ii. **Labor cost:** - assume labor cost for installing the pipe will be based on \$600 per inch-diameter-mile [10] because of labor cost is cheap in Ethiopia and the summarized approximate pipeline construction labor cost in table is based on developed countries.

For $L=400\text{m}=0.4\text{km}=0.2486\text{mile}$, pipe length and diameter (D) = $762\text{mm}=30\text{in}$.

$$\text{Labor Cost (LC)} = \left(\frac{\$600}{\text{inch}} - \text{diameter} - \text{mile} \right) \times 0.2486\text{mile} \times 30\text{inch} = \$4,475$$

For $L=400\text{m}=0.4\text{km}=0.2486\text{mile}$, pipe length and diameter (D) = $813\text{mm}=32\text{in}$.

$$\text{Labor Cost (LC)} = \left(\frac{\$600}{\text{inch}} - \text{diameter} - \text{mile} \right) \times 0.2486\text{mile} \times 32\text{inch} = \$4,774$$

For $L=400\text{m}=0.4\text{km}=0.2486\text{mile}$, pipe length and diameter (D) = $864\text{mm}=34\text{in}$.

$$\text{Labor Cost (LC)} = \left(\frac{\$600}{\text{inch}} - \text{diameter} - \text{mile} \right) \times 0.2486\text{mile} \times 34\text{inch} = \$5,072$$

Now the total pipeline capital cost will be the sum of the pipeline material cost and the labor cost. Then it will be:

$$\begin{aligned} \text{PipeLine Capital Cost (PLCC)} &= \text{PipeLine Material Cost(PMC)} + \text{Labor Cost(LC)} \\ \text{PLCC} &= \text{PMC} + \text{LC} \end{aligned} \quad (4.11)$$

For diameter of 762mm PLCC will be: $\text{PLCC} = \$21,630 + \$4,475 = \$26,105$

For diameter of 813mm PLCC will be: $\text{PLCC} = \$23,090 + \$4,772 = \$27,864$

For diameter of 864mm PLCC will be: $\text{PLCC} = \$24,550 + \$5,072 = \$29,622$

- iii. **Pump Station:** - to estimate the pump station cost a detailed analysis would consist of preparing a material take-off from the pump station drawings and getting vendor quotes on major equipment such as pumps, drivers, switchgear, valves, instrumentation, etc., and estimating the station labor costs. An approximate cost for pump stations can be estimated using a value for cost in dollars per installed horsepower. This is an all-inclusive number considering all facilities associated with the pump station. This analysis takes into account all material and equipment cost and construction labor. Such values of installed cost per HP can be obtained from historical data on recently constructed pump stations. Larger HP pump stations will have smaller \$/HP costs while smaller pump stations with less HP will have a higher \$/HP cost, reflecting economies of scale [10]. In this thesis case it used an installed cost of \$150/HP and the pump station cost (PSC) for the three scenarios with the horsepower of, 2,000HP, 1,1750HP and 1,750HP becomes:

$$\text{Pump Station Cost (PSC)} = \text{Horsepower (HP)} \times \$/(\text{HP})$$

$$\text{PSC} = \text{HP} \times \frac{\$}{\text{HP}} \quad (4.12)$$

For 762mm diameter with the Horsepower of 2,000HP becomes:

$$\text{PSC} = 2,000\text{HP} \times \$150/(\text{HP}) = \$300,000$$

For 813mm diameter with the Horsepower of 1,750HP becomes:

$$\text{PSC} = 1,750\text{HP} \times \$150/(\text{HP}) = \$262,500$$

For 864mm diameter with the Horsepower of 1,750HP becomes:

$$\text{PSC} = 1,750\text{HP} \times \$150/(\text{HP}) = \$262,500$$

- iv. **Reservoir cost:** - the Reservoir or the dam cost cannot be easily estimated or determined or it has no any standard guide line for its cost estimation, so the cost of the reservoir for this thesis is taken from the past historical data on recently constructed dams or reservoir costs in Ethiopia. For example, the Tendaho Dam and Irrigation project is a water resources development program that is constructed on the downstream of the Awash

River Basin planned to increase agricultural productivity, with further focus on sugar cane production on 60,000 ha. The Tendaho Dam and Irrigation project is found in Afar region 650 km. from Addis Ababa to Samara road and it is financed by the Government of Ethiopia. The project is involved in the construction of a dam height of 53m, crest length 412m, reservoir area of close to 17,000 ha and water reservoir capacity of 1.86 billion meter cube. The components of the structures are saddle (weighed down) dam, spillway, intake tower, diversion tunnel, approach channel and canals to develop the irrigable land. The MoWR (Ministry of Water Resources) appointed WWCE (Water Works Construction Enterprise) to construct the dam and irrigation system structures and WWDSE (Water Works Design and Supervision Enterprise) to Design and supervise the work at a contract price amounting ETB840, 254,274.70 and ETB24, 327,057.00 respectively. From the project cost breakdown sheet the cost of the preparatory and temporary facility costs, ETB5, 680,000, and its dam body costs about ETB30, 245,000 the sum total of the dam body construction and the preparatory and temporary cost is around ETB36, 000,000=\$2M and it is taken as a cost reference for this thesis case that is a dam or a reservoir with the total volume of 360Mm³ on the downstream of the Koka Hydropower plant reservoir [13]. Another cost reference taken for this thesis is the Koga Irrigation and Watershed Management Project is located within the Koga Basin in Mecha Woreda of Amhara Regional State. It will harness the water resources of the Koga River to irrigate 6,000ha of the command area, as well as improve rain fed agriculture, forestry, livestock, soil conservation, water and sanitation on some 22,000ha catchment area. It is around 77Mm³ of water reservoir created on the Koga River, capable of delivering 9,400m³/ha per annum and at a rate of 0.98 l/s ha during peak demand, and the dam has a 16.7km concrete-lined main canal, 78km of lined secondary canals, 120km unlined tertiary canals, 310km of quaternary canals, and 11 night storage reservoirs. Then the cost for the Development or construction of only the dam part of Koga dam accounts ETB111, 158,400 = \$6M in US Dollars [13, 28].

From the two dam costs examples the Tendaho dam and irrigation project dam cost is more specific to the reservoir or dam cost and the Koga Irrigation and Watershed Management Project it is wider than the dam cost means it may include irrigation system construction costs, so its cost is much higher than the Tendaho project. Therefore, the Tendaho project dam cost is taken as a reference and we take \$2million for the thesis dam cost. As with installed HP costs, the cost for dams decreases with reservoir size that is why we take \$2

million for the thesis with the reservoir capacity of 360Mm³ than Tendaho dam with the volume of 1.8BCM (Billion Metric Cube) and costs \$2million.

- v. **Valves and Fittings:** - valves and fittings may also be estimated as a percentage of the total pipe cost. However, if there are several mainline block valve locations that can be estimated as a lump sum cost, we can estimate the total cost of valves and fittings as follows: A typical 16 in. mainline block valve installation may cost \$100,000 per site including material and labor costs. If there are 10 such installations spaced 10 miles apart on a pipeline, we would estimate cost of valves and fittings to be \$1.0 million. Therefore, it taken \$1,000 per site for 30 in.-34 in. diameter pipe line size for installation including material and labor cost for this specific thesis because the thesis is proposed for 300m pipe line length so it is too short and it needs only one pump station site [10].
- vi. **Meter Stations:** - meter stations may be estimated as a lump sum fixed price for a complete site. For example, a 10 in. meter station with meter, valves, and piping instrumentation may be priced at \$250,000 per site including material and labor cost. If there are two such meter stations on the pipeline, we would estimate total meter costs at \$500,000. Therefore, for this specific project we take \$50,000 per site for diameters ranging from 30 in.-34 in. pipeline size meter station installation including material and labor cost since the case is the same as the valves and fittings that is why we take \$2,000 for the meter station [10].
- vii. **SCADA and Telecommunication System:** - this category covers costs associated with Supervisory Control and Data Acquisition (SCADA), telephone, microwave, etc. SCADA system costs include the facilities for remote monitoring, operation, and control of the pipeline from a central control center. Depending upon the length of the pipeline, number of pump stations, valve stations, etc., the cost of these facilities may range from \$2 million to \$5 million or more. An estimate based on the total project costs of pipeline may range from 2% to 5%. Assume for SCADA and Telecommunication System cost is 2% of the pipeline capital cost (PLCC) for three scenarios [10].

$$SCADA \& TC = PLCC \times 0.02 \quad (4.13)$$

For diameter of 762mm with PLCC=\$26,105 will be:

$$SCADA \& TC = \$26,105 \times 0.02 = \$523$$

For diameter of 813mm with PLCC=\$27,864 will be:

$$SCADA \& TC = \$27,864 \times 0.02 = \$558$$

For diameter of 864mm with PLCC=\$29,622 will be:

$$SCADA \& TC = \$29,622 \times 0.02 = \$593$$

- viii. **Engineering and Construction Management (ECM):** - engineering and construction management consists of preliminary and detailed engineering design costs and personnel costs associated with management and inspection of the construction effort for pipelines pump stations, and other facilities. This category usually ranges from 15% to 20% of total pipeline project costs of pipeline. Assume Engineering and construction management cost (ECMC) of the system is 3% of the pipeline capital cost (PLCC) for the three scenarios in Ethiopian case [10].

$$ECMC = PLCC \times 0.03 \tag{4.14}$$

For 762mm with PLCC=\$26,105 will be: $ECMC = \$26,105 \times 0.03 = \784

For 813mm with PLCC=\$27,864 will be: $ECMC = \$27,864 \times 0.03 = \836

For 864mm with PLCC=\$29,622 will be: $ECMC = \$29,622 \times 0.03 = \889

- ix. **Environmental and Permitting (EP):** -Permitting costs would include pipeline construction permits such as road crossings, railroad crossings, river and stream crossings, and permitting for antipollution devices for pump stations. Environmental and permitting costs may be as high as 10% to 15% of the total project costs of pipeline. Assume Environmental and Permitting cost (EPC) 0.5% for the three scenarios. This percent is taken in relative to Adama wind farm Environmental and permitting percentage [10].

$$EPC = PLCC \times 0.005 \tag{4.15}$$

For 762mm with PLCC=\$26,105 will be: $EPC = \$26,105 \times 0.005 = \131

For 813mm with PLCC=\$27,864 will be: $EPC = \$27,864 \times 0.005 = \140

For 864mm with PLCC=\$29,622 will be: $EPC = \$29,622 \times 0.005 = \149

- x. **Right-of-Way Acquisitions:** - right of way (ROW) acquisition must be acquired for building a pipeline along private lands, farms, public roads, and railroads. The annual ROW costs would be considered an expense and would be included in the operating costs of the pipeline. Historically, ROW costs have been in the range of 6% to 8% of total project costs for pipelines. Assume Right-of-way Acquisition cost (ROWAC) is 0.5% for the three scenarios [10].

$$ROWAC = PLCC \times 0.005 \tag{4.16}$$

For 762mm with PLCC=\$26,105 will be: $ROWAC = \$26,105 \times 0.005 = \131

For 813mm with PLCC=\$27,864 will be: $ROWAC = \$27,864 \times 0.005 = \140

For 864mm with PLCC=\$29,622 will be: $ROWAC = \$29,622 \times 0.005 = \149

- xi. **Other Project Costs:** - other project costs would include allowance for funds used during construction (AFUDC), legal and regulatory costs, and contingency costs. Contingency costs cover unforeseen circumstances and design changes including pipeline rerouting to bypass sensitive areas, pump stations and facilities modifications not originally anticipated at the start of the project. AFUDC and contingency costs will range between 15% and 20% of the total project costs of pipeline. Assume an AFUDC and contingency cost (AFDC&CC) is 2% for the three scenarios [10].

$$AFDCCC = PLCC \times 0.02 \quad (4.17)$$

For 762mm with PLCC=\$26,105 will be: $AFDCCC = \$26,105 \times 0.02 = \523

For 813mm with PLCC=\$27,864 will be: $AFDCCC = \$27,864 \times 0.02 = \558

For 864mm with PLCC=\$29,622 will be: $AFDCCC = \$29,622 \times 0.02 = \593

The estimated capital cost for the three pipe sizes are summarized in table: 16 below:

Table 16 the summarized estimated capital cost for the three pipe sizes

No	Capital Cost (\$)	Pipeline Diameter or size (mm)		
		762	813	864
1	Pipeline	26,105	27,864	29,622
2	Pump station	300,000	262,500	262,500
3	Reservoir	2,000,000	2,000,000	2,000,000
4	Valves and Fittings	1,000	1,000	1,000
5	Meter Station	2,000	2,000	2,000
6	SCADA and Telecommunication	523	558	593
7	Engineering and construction management	784	836	889
8	Environmental and Permitting	131	140	149
9	Right-of-way (ROW) Acquisition	131	140	149
10	AFUDC and contingency	523	558	593
11	Total	2,331,197	2,295,596	2,297,495

From this what we can conclude is that, based on total capital costs alone, it can be seen that the 813mm (32in.) with the total capital cost of **\$2,295,596** system is the best. However, we will have to look at the operating costs as well, before making a decision on the optimum pipe size. Next, we calculate operating cost for each scenario, using electrical energy costs for pumping.

4.4.2. Annual Operating Costs

The annual operating cost of a pipeline consists mainly of; Pump station energy cost (electricity or natural gas), Pump station equipment maintenance costs (equipment overhaul, repairs, etc.), Pipeline maintenance cost including line rider, aerial patrol, pipe replacements, relocations, etc, SCADA and telecommunication costs, Valve and meter station maintenance, Reservoir operation and maintenance, Utility costs: water, natural gas, etc, Ongoing environmental and permitting costs, Right-of-way lease costs, Rentals and lease costs, General and administrative costs including payroll. Among these major costs pump station costs include electrical energy, equipment maintenance costs General and Administration costs which can be substantial [10]. For simplicity, we will increase electrical cost of the pump stations by a factor which is 10% to account for all other operating costs. This percentage share trend is taken from feasibility study of Wind Park at Ashegoda site that it takes a Dire Dawa Diesel Power plant as economic comparison bench mark and it says the fuel cost represents more than 80% of the total operating costs of the diesel power plant and the remaining 20% accounts for all other costs. The reason why we take 10% as a factor than taking 20 % is the size of the project is smaller than the DDPP and select the electrical energy as a benchmark the electrical cost of the pump station exists throughout the year and all other costs comes once or twice a year, that is why we select an electrical cost pumping station is needed to be multiplied by a factor which is 10% to account for all other operating costs and add it on actual electrical cost of pump station.

Using the Brake Horsepower (BHP) calculated at each pump station for the three cases and \$0.066/kWh for electricity cost which is based on (EEPCO) that agreed to sale electricity for the neighboring countries like Djibouti, Kenya, and Sudan. We assume that the annual operating cost for 24 hr operation per day, 15 days shut down for maintenance and 350 days per year and the annual operating costs for the three scenarios become:

Then the electrical cost of pump station (ECPS) of the three scenarios becomes [10]:

$$ECPS = BHP(kW) \times 24hr \times 350day \times \$/kWhr \quad (4.18)$$

For the Pump Station with the BHP (kW) of 1301kW and diameter of 762mm:

$$ECPS = 1301kW \times 24hr \times 350day \times \$0.066/kWhr = \$721,274.4/year$$

For the Pump Station with the BHP (kW) of 1209kW and diameter of 813mm:

$$ECPS = 1209kW \times 24hr \times 350day \times \$0.066/kWhr = \$670,270/year$$

For the Pump Station with the BHP (kW) of 1202kW and diameter of 864mm:

$$ECPS = 1151kW \times 24hr \times 350day \times \$0.066/kWhr = \$638,115/year$$

Strictly speaking, the above costs will have to be increased to account for the demand charge for starting and stopping electric motors. The utility company may charge based on the kW rating of the motor or Motor Horsepower (MHP) (kW). This will range from \$4 to \$6 per kW/month. Using demand charge of \$0.05/kW/ month for Ethiopian case, we get the following demand charges for the pump station in a 12 month period. Then the demand charge (DC) for starting and stopping electric motors for three scenarios become:

$$DC = MHP(kW) \times \$0.05/kW/month \times 12month \quad (4.19)$$

The demand charge (DC) for 762mm diameter, and MHP=1369.5kW:

$$DC = 1369.5kW \times \$0.05/kW/month \times 12month = \$821.7/year$$

The demand charge (DC) for 813mm diameter, and MHP=1273.1kW:

$$DC = 1273.1kW \times \$0.05/kW/month \times 12month = \$763.86/year$$

The demand charge (DC) for 864mm diameter, and MHP=1211.6kW:

$$DC = 1211.6kW \times \$0.05/kW/month \times 12month = \$726.96/year$$

Adding the demand charges to the previously calculated electric power cost, we get the total annual electricity costs (AEC) as follows:

$$AEC = DC + ECPS \quad (4.20)$$

For 762mm: $AEC = \$821.7/year + \$721,274.4/year = \$722,096.1/year$

For 813mm: $AEC = \$763.86/year + \$670,270/year = \$671,034/year$

For 864mm: $AEC = \$726.96/year + \$638,115/year = \$638,842/year$

Since the annual operating cost excludes the annual electrical cost because the electricity cost is included in the wind energy project cost analysis and what here calculated is used to determine other operating costs. By multiplying the above calculated annual electrical cost by a 10% factor to account for other operating costs such as O&M, G&A, etc., of pumping station we get the following for annual operating costs (AOC) other than annual electrical cost for each scenario [10]:

$$AOC = 0.1 \times AEC \quad (4.21)$$

For diameter of 762mm: $AOC = 0.1 \times \$722,096/year = \$72,209.6/year$

For diameter of 813mm: $AOC = 0.1 \times \$671,034/year = \$67,103.4/year$

For diameter of 864mm: $AOC = 0.1 \times \$638,842/year = \$63,884.2/year$

Next, we use a project life of 20 years and interest rate of 10% to perform a discounted cash flow (DCF) analysis, to obtain the present value of these annual operating costs. Then the total capital cost calculated earlier and listed in the table 16 above will be added to the present values of the annual operating costs other than annual electrical cost. The present

value of annual operating cost (PVAOC) will then be obtained for each of the three scenarios by using the annual operating cost formula. The present value of these annual operating costs can be calculated as follows [10]:

$$P = A \times \left[\frac{(1+i)^N - 1}{i \times (1+i)^N} \right] \quad (4.22)$$

P=present Value (PV), A=Annual Operating Cost (AOC), i=interest rate, N=number of years

For 762mm and i=10%=0.1: $P = \$72,209.6 \times \left[\frac{(1+0.1)^{20} - 1}{0.1 \times (1+0.1)^{20}} \right] = \$614,761.031$

For 813mm and i=10%=0.1: $P = \$67,103.4 \times \left[\frac{(1+0.1)^{20} - 1}{0.1 \times (1+0.1)^{20}} \right] = \$571,289.072$

For 864mm and i=10%=0.1: $P = \$63,884 \times \left[\frac{(1+0.1)^{20} - 1}{0.1 \times (1+0.1)^{20}} \right] = \$543,880.5$

Now the total present value cost (TPVC) of the three scenarios including total capital cost (TCC) of the project and the present value of annual operating cost (P) other than the annual electrical cost of the project becomes:

$$TPVC = TCC + P \quad (4.23)$$

For 762mm will be: $TPVC = 2,338,446 + 614,761.031 = \$2,993,895.4$

For 813mm will be: $TPVC = 2,310,828 + 571,289.072 = \$2,919,928.2$

For 864mm will be: $TPVC = 2,313,210 + 543,880.5 = \$2,893,088.0$

When the total present value cost (TPVC) of the pipe line system other than the annual electrical cost is summarized in table: 17 below as follows:

Table 17 Summarized total present value cost (TPVC) of the pipe line system other than annual electrical cost

No	Capital Cost (\$)	Pipeline Diameter or size (mm)		
		762	813	864
1	Pipeline	26,105	27,864	29,622
2	Pump station	300,000	262,500	262,500
3	Reservoir	2,000,000	2,000,000	2,000,000
4	Valves and Fittings	1,000	1,000	1,000
5	Meter Station	2,000	2,000	2,000
6	SCADA and Telecommunication	523	558	593
7	Engineering and construction management	784	836	889
8	Environmental and Permitting	131	140	149
9	Right-of-way (ROW) Acquisition	131	140	149
10	AFUDC and contingency	523	558	593

11	Capital cost of the pipeline system	2,331,197	2,295,596	2,297,495
12	Present value of Annual Operating cost other than annual electrical cost of pipeline	614,761.03	571,289.07	543,880.05
13	Total cost for one pump system	2,945,958	2,866,885	2,841,375

Thus, based on the net present value of investment, we can conclude that the 864mm (34in.) diameter pipeline system with one 1750 HP pump station is the preferred choice which cost **\$2,841,375**.

Finally this total present value cost is to install a pipe line system with a capacity to pump 8040m³/hr, but the hourly water requirement is 48,210m³/hr so it is needed 7 similar capacity pumps connected in parallel pump connection system one as a reserve pump or standby in order to perform the required work or pump the hourly water requirement on a continuous base. Therefore, the total present value cost for the 6 pumps will be the product of the value of one system by 7 pumps then the pipeline system total cost (PLSTC) for the pump station becomes:

$$PTC = 7 \times TPVCOPLS \quad (4.24)$$

where, PTC=Total Cost, TPVCOPLS= Total Present Value Cost for one Pipeline system

$$PTC = 7 \times \$2,841,375 = \$19,889,625$$

Based on its pumping capacity of 9000m³/hr water in a wide range of head that is up to 125m and the commercial availability the Gould's 3180 Model Pump [41] was selected as pumping equipment.

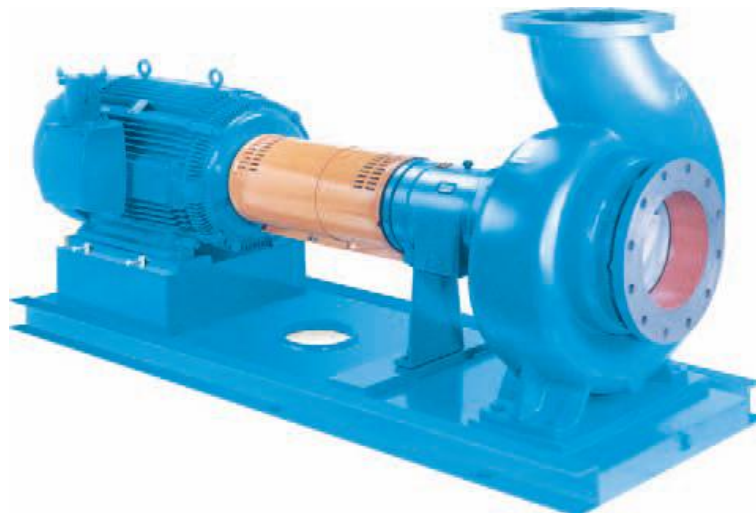


Figure 13 Gould's 3180 Model pump [41]

The specification of Gould's 3180 Model pump is pumping capacity to 9000m³/hr, Pumping head up to 125m, Temperature 230°C and Pressure 16bar.

The Next step is to calculate the total power needed to run the pump station and determine the number of the wind turbine and select the appropriate type of the wind turbine that fulfills the power requirement of the pump station.

From the Pipeline system analysis we selected induction electric motor with the Horsepower of 1750HP. Therefore, if 1342.8kW is for one pump motor then the power requirement for the 6 pumps is 6 times 1342.8kW. Thus, the total power required to run the pump station is 8056.8kW or approximately, around 8.5MW power is needed in an hour including allowance.

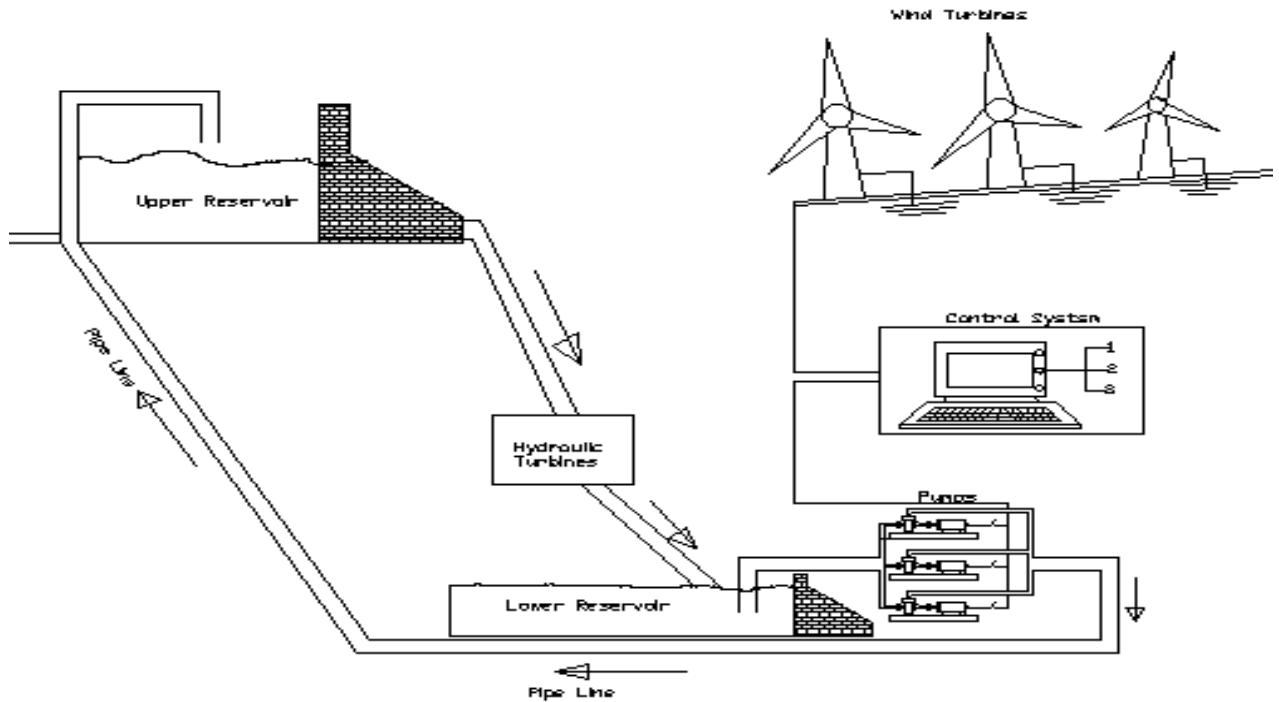


Figure 14 Schematic Diagram of the wind power pumped hydro-storage

CHAPTER FIVE

5. WIND ENERGY RESOURCE AND TURBINE INVESTMENT COST ANALYSIS USING RETSCREEN

5.1. Wind Energy Distribution

The average wind speed obtained from the Ethiopia National Meteorological Agency which is taken from Adama meteorological station which is the nearby meteorological station to the Koka Hydropower Plant is given in table 18 below.

Table 18 the average wind speed of the study area

Months	Jan	Feb	Mar	Apr	Ma	Jun	Jul	Au	Sep	Oct	Nov	Dec	Aver
Wind speed at 10m (2006-2008)	9.2	9.6	7.8	7.5	7.3	7.5	8.2	6.6	7.5	8.1	9.9	10.2	8.43

- **Mean:** the average wind speed at Koka Hydropower Plant is specific wind site is can also be calculated as follows [8, 30]:

$$\bar{u} = \left[\frac{1}{(n-1)} \sum_{i=1}^n u_i^3 \right]^{1/3} \quad (5.1)$$

$$\bar{u} = \left(\frac{(9.2^3 + 9.6^3 + 7.8^3 + 7.5^3 + 7.3^3 + 7.5^3 + 8.2^3 + 6.6^3 + 7.5^3 + 8.1^3 + 9.9^3 + 10.2^3)}{11} \right)^{(1/3)} = 8.43 \text{ m/s}$$

- **Wind speed at the hub height:** the annual average wind speed at $z_{ref} = 10\text{m}$ of Koka Hydropower is calculated above, i.e., $V_{ref} = 8.43\text{m/s}$ and the average wind speed at the hub height $z = 65\text{m}$ with the wind shear exponent of $\alpha = 0.12$ is calculated as follows

[8, 30]:
$$V = V_{ref} \left[\frac{\ln(z/z_0)}{\ln(z_{ref}/z_0)} \right] \quad (5.2)$$

$$V = 11.57 \text{ m/s}$$

5.1.1. Probability distribution of wind site's energy

Wind speed distribution is calculated as a Weibull probability density function (the Rayleigh wind speed distribution). For the precise calculation of k and c , adequate wind data, collected over shorter time intervals are essential. In many cases, such information may not be readily available. The existing data may be in the form of the mean wind velocity over a given time period. Under such situations, a simplified case of the Weibull model can be derived; by

approximating k as 2. This is known as the Rayleigh distribution. Therefore, the data obtained from the national Meteorological agency is monthly average wind speed Rayleigh distribution is used to calculate the site probability distribution of the site. The Rayleigh distribution is given as [8, 30]:

$$f(v) = \left(\frac{\pi}{2}\right) \left(\frac{v}{v_m^2}\right) e^{-\left(\frac{\pi}{4}\right)\left(\frac{v}{v_m}\right)^2} \quad (5.3)$$

Table 19 the probability density function of the Koka Hydropower Plant wind site

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
V(m/s)	9.2	9.6	7.8	7.5	7.3	7.5	8.2	6.6	7.5	8.1	9.9	10.2
f(V)	0.08	0.077	0.088	0.089	0.09	0.089	0.086	0.09	0.089	0.087	0.074	0.07

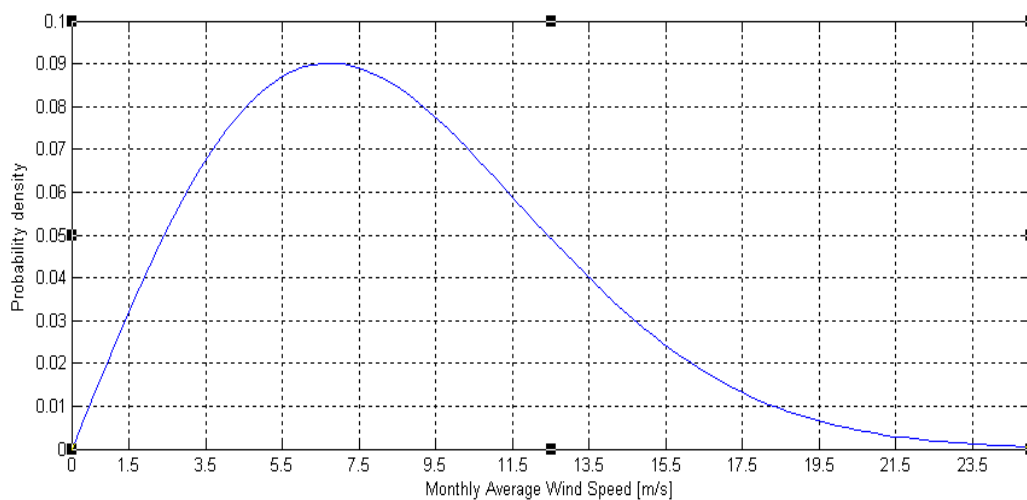


Figure 15 the probability density functions of Koka Hydropower Plant wind system Similarly cumulative distribution function of a wind system is given by [8, 30]: $F(v) =$

$$1 - e^{-\left(\frac{\pi}{4}\right)\left(\frac{v}{v_m}\right)^2} \quad (5.4)$$

Table 20 Cumulative distribution functions Koka Hydropower Plant wind system

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
V(m/s)	9.2	9.6	7.8	7.5	7.3	7.5	8.2	6.6	7.5	8.1	9.9	10.2
F(V)	0.61	0.64	0.49	0.46	0.44	0.46	0.52	0.38	0.46	0.52	0.66	0.68

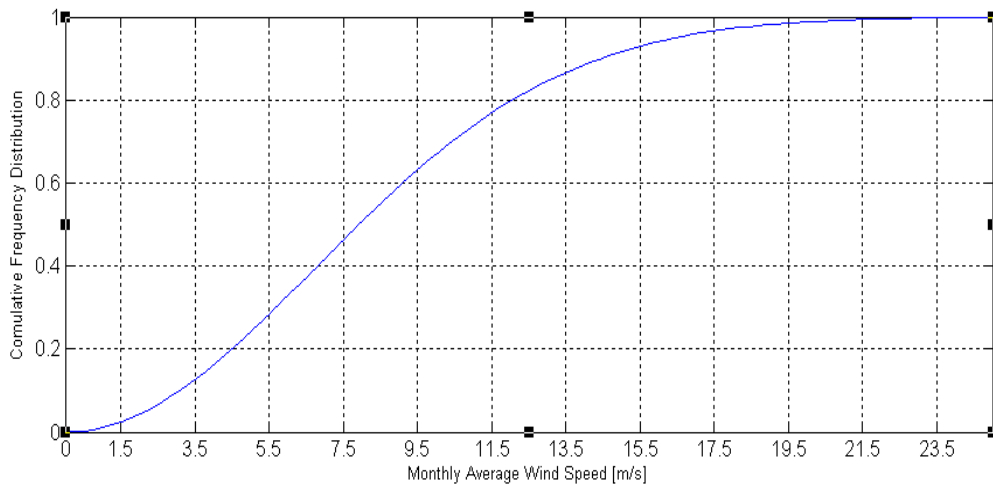


Figure 16 the cumulative distribution functions of Koka Hydropower Plant wind system

5.2. Wind energy investment cost

The investment cost for this project is analyzed by using RETScreen International Wind Energy Project Model which consists of a standardized and integrated clean energy Project analysis software that can be used world-wide to evaluate the Energy production, life-cycle costs and greenhouse gas emission reductions for central-grid, isolated-grid, and off-grid wind energy projects, ranging in size from large-scale multi-turbine wind farms to small-scale single turbine and wind-diesel hybrid systems. In order to calculate the wind power investments cost needed to fulfill the power requirement by the pump station in order to perform the required work it is necessary to make assumptions based on the RETScreen Software online user manual and the current condition regarding the cost or price of labor and home made materials that are necessary for the project. To estimate investment cost of wind energy three main costs are evaluated first and the rest associated costs followed immediately [43].

5.2.1. The Site Condition

The Wind Power Pumped Hydro-storage Integrated Koka Hydropower Plant project site is found in Oromia region around 16km far apart from Adama town, and the meteorological data are taken from the ENMA and the data used is taken from the Adama meteorological station because the meteorological station found from the specific site is not functional for many years and the data used for the this specific project is annual average wind speed of 8.43m/s which is measured at a 10m height, average atmospheric pressure of 83.84kPa, and annual average temperature of 22.4°C and these data are used in the RETScreen energy model part.

5.2.2. System Characteristics

The system characteristic of the project is used to describe the type of the grid, the peak load, number of wind turbines, energy absorption rate, array losses, airfoil soiling and icing losses, other downtime losses, and miscellaneous losses at the project site. The type of the grid is off-grid type used for water pumping purpose for Koka Hydropower Plant energy security.

5.2.3. The Renewable Equipment Data

For this specific project the wind turbines used for the scenario analysis are the product of Gamesa Eolica wind turbine manufacturer with G80-1.5 MW model, 1500kW power rate, 3.98m/s cut in speed and 24.98m/s cut out speed, product of Vestas wind turbine manufacturer with V80-1800IEC class I model, 1800kW power rate, 3.98m/s cut in speed and 24.98m/s cut out speed and product of Gamesa Eolica wind turbine manufacturer with G80-2.0MW model, 2000kW power rate, and 3.98m/s cut in speed and 24.99m/s cut out speed.

5.2.4. Wind Turbine Characteristics

The wind turbine characteristics is the total performance characteristics of a particular wind turbine provided by the manufacturer of the equipment and also it includes energy curve data source which is used to determine how the energy curve data will be calculated for the wind turbine specified [43].

5.2.5. Wind Turbine Production Data

The wind turbine production data are calculated by the RETScreen model and if it is given from wind turbine manufacturer the user can enter it into the software [43].

5.2.6. Wind Turbine Power and Energy Curves

This graph provides a representation of the power in (KW) and energy in (MWh/yr) delivered by the wind turbine measured over a range of the wind speed. The graph is based on values from the power curve data and energy curve data columns above [43].

5.2.7. Annual Energy Production

Based on the site condition, the system characteristics, the plant capacity and the selected wind turbine equipment data annual energy production of the project site for 3 wind turbine is clearly calculated by using the RETScreen software in table 21 [43].

Table 21 Annual Energy Production

Annual Energy Production	G80-1.5 MW	V80-1800 IEC class II	G80- 2.0MW
Wind plant capacity [MW]	10.50	10.80	10.00
Unadjusted energy production [MWh]	58,441	57,379	50,720
Gross energy production [MWh]	45,245	44,423	39,268
Wind plant capacity factor [%]	34	33	31%
Renewable energy collected [MWh]	31,596	31,022	27,422
Renewable energy delivered [MWh]	30,964	30,401	26,873
Excess RE available [MWh]	632	620	548

5.2.8. Costs Analysis of the Project

The RETScreen Clean Energy Project Analysis Software is used to help the user to estimate costs associated with a wind energy project. These costs are addressed from the initial, or investment, cost standpoint and from the annual, or recurring, cost standpoint [43].

In order to provide the guide lines for the estimation of the costs associated with the implementation of a wind energy project, the following classification has been adopted. Categories of wind energy projects were created based on the number of wind turbines comprising the wind farm and the size of the turbine, according to appendix E.

The initial costs associated with the implementation of the Koka wind power pumped hydroelectric storage wind farm include costs for preparing a feasibility study, performing the project development functions, completing the necessary engineering work, purchasing and installing the energy equipment, construction of the balance of plant and costs for any other miscellaneous items. The energy equipment and balance of plant are the two cost categories showing the strongest dependence on the number of wind turbines that make up the wind farm. Hence, the larger the wind farm, the more relative weight these two categories represent.

From the suggested typical ranges of relative costs, for the main cost categories, according to RET Screen® International user manual in appendix E by taking the costs for each category as reference and taking into account the current country situation that means cheap labor force, inland made accessories like transmission cable, road construction, and civil work materials like cement, stones, and metal products the initial project costs for 3 wind turbine are analyzed using the software and shown in table 22.

Table 22 Project costs

Project costs	G80-1.5 MW	V80-1800 IEC	G80-2.0MW
Initial Costs		class II	
Feasibility study	25,325	25,325	25,325
Development	11,455	11,455	11,455
Engineering	2,480	2,480	2,480
Energy equipment	16,137,800	15,998,880	14,536,000
Balance of plant	76,000	73,000	70,000
Miscellaneous	989,907	981,264	891,992
Initial costs- total	17,242,967	17,242,967	15,537,252

5.2.9. Annual costs and savings

There will be a number of annual costs associated with the operation of a wind energy project. These will include land lease, property taxes, insurance premium, transmission line maintenance, parts and labor, GHG monitoring and verification, community benefits, travel and accommodation and general and administrative expenses. In addition, costs for contingencies will also be incurred. According to the analysis of the software the annual cost and savings for the 3 wind turbine is shown in table 23 [43].

Table 23 Annual costs (credits) and savings

Annual costs and savings	G80-1.5 MW	V80-1800 IEC class II	G80-2.0MW
Annual Costs and Debt – Total (O & M)	436,484	429,031	382,329
Annual Savings or Income total	2,941,590	2,888,103	2,552,961

When the annual operation and Maintenance cost are converted to the present value for 20 years service life by the internal rate of return of (10%) it becomes:

$$P = A \times \left[\frac{(1+i)^N - 1}{i \times (1+i)^N} \right] \quad (5.5)$$

$$P = \$382,329 \times \left[\frac{(1+0.1)^{20} - 1}{0.1 \times (1+0.1)^{20}} \right]$$

$$P = \$3,254,983.303$$

5.2.10. Periodic costs

A periodic cost represents recurrent costs that must be incurred at regular intervals to maintain the project in working condition. The project may also be credited for periodic costs that would have been incurred over the project life of the base case, or conventional, energy system. Therefore the total periodic cost (TPC) of the project in the RETScreen analysis is the sum of the periodic costs of the drive train and blades cost and for the 3 wind turbine type it is shown in table 24 [43].

Table 24 Periodic Costs

Periodic Costs (Credits)	G80-1.5 MW	V80-1800 IEC class II	G80-2.0MW
Drive train	500,000	500,000	500,000
Blades	500,000	500,000	500,000
Total periodic costs	1,000,000	1,000,000	1,000,000

5.2.11. The GHG Analysis Part

This part in the RETScreen software analysis represents the analysis of the proposed case electricity system, in this case the wind energy system and the GHG emission reduction summery. According to the analysis the proposed project has the net annual GHG emission reduction for the 3 wind turbine types shown in table 25 [43].

Table 25 The Net GHG reduction

GHG Analysis	G80-1.5 MW	V80-1800 IEC class II	G80-2.0MW
The Net GHG reduction [tCO ₂]	13,890	13,637	12,055

5.2.12. Financial analysis

The results of the financial feasibility analysis provide the decision maker with various financial indicators for the proposed project. This financial analysis part of the RETScreen worksheet of the specific project contains five sections: Annual Energy Balance, financial parameters, project costs and savings, financial feasibility and yearly cash flows. The Annual Energy Balance and the project costs and savings section provide a summary of the Energy model, Cost analysis, and GHG analysis associated with each project studied. The financial feasibility section provides financial indicators of the project analyzed based on the financial

parameters. The yearly cash flows section allows the users visualize the stream of pre-tax, after-tax and cumulative cash flows over the project life [43].

5.2.12. Financial feasibility

The results of this part provide the decision maker with various financial indicators for the proposed project. Therefore, the internal rate of return (IRR), the simple payback period, year to positive cash flow the net present value (NPV), annual life cycle savings and the benefit-cost (B-C) ratio of the three wind turbine type are given in table 26 below. The IRR is greater than the Minimum Attractive Rate of Return (MARR) set by the Ministry of Economic and Finance Development that is 10%, the NPV is positive and the B-C ratio is greater than one therefore, from this what we can conclude is that the project is feasible for the given parameters [43].

Table 26 Financial feasibility

Financial feasibility	G80-1.5 MW	V80-1800 IEC class II	G80-2.0MW
Pre-tax IRR and ROI [%]	15.9	15	15.2
After-tax IRR and ROI [%]	15.9	15	15.2
Simple Payback [year]	6.9	7.0	7.2
Year-to-positive cash flow [year]	6.4	6.5	6.7
Net Present Value – NPV [\$]	9,096,752	6,620,328	7,211,209
Annual Life Cycle Savings [\$]	1,002,172	777,621	794,445
Benefit-Cost (B-C) ratio	1.53	1.39	1.46
Project equity [\$]	17,242,967	17,242,967	15,537,252

5.2.13. The cumulative cash flows graph

The cumulative cash flows are plotted versus time in the cash flows graph. These cash flows over the project life are calculated and reported in the yearly cash flow analysis. Then the graph and the full financial and sensitivity analysis of this project is given in appendix E [43].

5.2.14. Turbine selection

The selection of wind machine size depends on the existing worldwide standard sizes, commercial availability, high energy yield and capacity factor, local adaptability, ease of transportation to the installation site, etc.

The choice of manufacturer will include the interest of the manufacturer for providing services in Ethiopia, competitive cost, technical support during installation phase, training of

the operation and maintenance staff, terms and conditions for maintenance of the wind machines and the supply of spare parts during project life time, re-powering provision of the plant after the expiry of designed life, etc. The placement of a right turbine at the right place is very important and critical from optimal energy production point of view. Other important aspects are rated power, cut-in-speed, transportability, life span, capital cost, corrosion resistivity, harsh weather resistance, etc.

For the scenario analysis the wind turbine taken are the three wind turbines that are G80-1.5 MW, V80-1800 IEC class II and G80-2.0MW.

When we compare these three wind turbine types based on the annual energy production, the project initial cost, GHG Emission reduction, and financial feasibility parameter, and the G80-2.0MW wind Turbine is the best to fulfill the requirement of the pumping station.

Finally, the total cost of the wind farm with the G80-2.0MW wind turbine for the life of the project is the sum of the initial cost and the annual operating cost for the life of the project of the wind farm, which is **\$15,537,252**.

CHAPTER SIX

6. ECONOMIC ANALYSIS AND DISCUSSION

6.1. Introduction

The main purpose of an economic analysis is to help to design and select projects that contribute to the welfare of a country. Whereas the financial analysis evaluates the project from the point of view of the operating company or Independent Power Producer (IPP), the economic analysis evaluates the project from the point of view of the whole economy of the country. Therefore, the purpose of this investigation is to compare the benefits of integrating of the wind power pumped Hydro-storage systems in the existing Hydropower plants in Ethiopia especially on Koka Hydropower plant from the economic standpoint of view with the costs it incurs. The calculations are made for the years 2013 through 2035, i.e., the year in which the wind turbines and the pipeline systems are expected to be commissioned plus 20 years of operation.

6.2. The Economic Analysis

The economic analysis conducted for this thesis is seen from three angles that are:

1. From the point view of energy security of the Koka Hydropower Plant
2. The profitability of the wind power used for pumping purpose from the hydroelectric power or the grid power pumping system
3. The profitability of wind power used for pumping purpose from the diesel generator power pumping system.

6.2.1. From the Point View of Energy Security

A pumped storage station is needed for a hydropower plant station where water shortage can occur or generation and consumption of electricity is not absolutely synchronous. In all electricity networks there is a surplus or lack of electricity. But in the case of most of Ethiopian hydropower plants it is lack of electricity due to shortage of water in the reservoir during the winter season. A pumped storage power station can control and guarantee a safe operation in the electricity grid.

In a conventional pumped storage power station design, the turbines and the pumps are separate units. This has many advantages, like better efficiency of the pumps when operated at full capacity using low cost power from wind turbines. The total amount of water pumped

by the wind power system and the 6 pumps is 13.5m³/s and the power produced by this calculated flow rate is calculated as follows:

Given

$$Q = 13.5\text{m}^3/\text{s} = \text{the flow rate}$$

$$H = 43\text{m} = \text{head of the koka hydropower plant}$$

$$\rho = 1000\text{Kg}/\text{m}^3 = \text{density of water}$$

$$g = 9.81\text{m}^2/\text{s} = \text{acceleration due gravity}$$

$$\eta = 0.88 = \text{the efficiency of the Koka Hdropower Plant turbines}$$

Now the power produced by the pumped water will be [1]:

$$P = \rho \times g \times H \times Q \times \eta \quad (\text{KW}) \quad (6.1)$$

$$P = 1000 \times 9.81 \times 43 \times 13.5 \times 0.88 \text{ kW}$$

$$P = 5.1\text{MW}$$

From this we can conclude is that the power produced by the pumped water is smaller than the power used to drive pump station which is 8.056MW this is because the power production of the Hydropower plant are mainly depend on the head of the plant (H), the flow rate used to run the hydraulic turbines (Qm³/s) and the efficiency of the Hydraulic turbines (η), therefore, the Koka Hydropower Plant is a low head hydropower plant and it uses larger flow rate in the three hydraulic turbines.

The installed capacity, the firm capacity, the actual average output power, the combined out power of the actual average output power, the wind power pumped water output power produced throughout the year of the Koka hydropower plant is given in table 27 and from appendix A. The pumped water output power is 5.1MW.

Table 27: Power Production table of Koka Hydropower Plant

Months	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Projected output	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2
Firm output	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5
Actual Average output	12	11	11	13	15	10	8	6	25	15	12	13
Actual average output power + wind power Pumped water Power	17.1	16.1	16.1	18.1	20.1	15.1	13.1	11.1	30.1	20.1	17.1	18.1

From the point view of energy security we will see following main points depending on table 27 as follows:

From table 27 the sum of Actual average output power and Wind Power Pumped water Power indicates that it is the sum of the Actual average output before integrating the wind power pumped storage and Wind Power Pumped water Power, the power produced by the Wind Power pumped water is 5.1MW.

Someone may consider directly to generate power from wind and integrate to the grid system without using for pumping purpose throughout the year but here what we need to know is the number of the turbine and the power that can be generated by these wind turbine is small and at the time of wind power integration system into the existing power system it is must be analyzed in detail by using specialized computer programs that analyzes power system dynamics, so this is an additional cost for wind power integration.

It is important to be aware that the integration of wind farms has an influence on the transmission system in a variety of ways. The intermittent and uncontrollable energy production that characterizes wind farms needs to be dealt with in the power system they connect to and it becomes even more important with increasing amount of integrated wind power. Because of the intermittent nature of wind power a larger reserve is needed in case the wind doesn't blow to maintain system capacity. In addition to its uncontrollable energy production characteristics power quality problem is taken in account. The main problem areas these are related to power peaks, the absorption of reactive power, flicker problems, the causation of harmonics and switching operations. Power peaks occur with sudden changes in the turbines output, this could happen during a sudden increase in wind speed. Therefore, better control over the power output of the inverter system using advanced control mechanisms like stall, pitch or combined system and building a wind farm with many turbines adds a smoothing effect to this phenomenon as the occurrence of a sudden increase in wind generally does not happen at exactly the same time at all turbines and also increasing the number of wind turbine is another expenditure. Therefore, it is better to integrate the actual average output power and the wind power pumped water power system with small number of wind turbine than integrating the actual average output power and directly these small number of wind turbines for power producing purpose and integrate to the existing power system. Generally direct integration of the wind turbine strike at the foundations of the existing stable power system or destabilize the whole power system.

Without considering other benefits that are added to the system a 5.1MW power produce throughout the year by the pumped water covers the overall investment cost of the project that is the cost incurred on the wind power system and the pipeline system which is **\$35,426,877** as follows and the price of the electricity used for calculation is taken from the EEPCO electric sales tariff for the neighboring countries that is \$0.066/KWh and it becomes:

SP (price) = \$0.066/kWh= selling price of electricity

P = 5.1MW = power produced throughout the year by considering pumped water

H=24hr=hours in a day

D=350days= number of day in the year and 15 days shut down or maintenance

A =? [\$]= annual amount of money obtained selling of the power

Therefore,

$$A = SP \left[\frac{\$}{\text{kWh}} \right] \times P[\text{KW}] \times H[\text{hr}] \times D[\text{days}] \quad (6.2)$$

$$A = \$0.066 \times 5100 \text{ kW} \times 24 \times 350$$

$$A = \$2,827,440$$

The \$2,827,440 amount of money is obtained from integrating the wind power pumped hydro-storage system to the Koka Hydropower plant annually and when it is converted to its future value by taking the internal rate of return 10% it will be [15]:

$$F = A \times \left[\frac{(1+i)^n - 1}{i} \right] \quad (6.3)$$

$$F = 2,827,440 \times \left[\frac{(1+0.1)^{20} - 1}{0.1} \right]$$

$$F = \$161,941,624.6$$

From this what we conclude is that power produce throughout the year by the pumped water covers the overall investment cost of the project that is the cost incurred on the wind power system and the pipeline system which is **\$35,426,877**. Therefore, it is beneficial to integrate the wind power pumped hydro-storage system to the Koka Hydropower Plant from the point view of energy security.

6.2.2. The profitability of the wind power used pumping system from the hydroelectric power or the grid power pumping system

In order to compare the profitability of wind power used pumping system with the hydroelectric power or the grid power pumping system we need to look in to the investment cost of the wind turbine power system with the hydroelectric power or the grid power pumping system cost. This comparison is based on the energy or fuel that is used to run the pipeline system to pump the water to the upper reservoir. Therefore, as obtained from the wind energy investment cost analysis part the investment cost for the wind turbine system for running the pipeline system is **\$15,537,252**. This cost includes all the costs that are needed throughout the life of the project. As obtained from the pipeline system analysis part the total power (P_t) needed to run the pipe line system is 8.5MW and when we calculate the cost of energy or fuel used from the Hydroelectric power system to run the pipeline system on annual base and we use the EEPKO tariff for selling electricity or electricity price (E_p) for the neighboring country that is \$0.066/KWh as a bench mark for this analysis but this selling

price hopefully increase for the future due to the need for energy will also increase because of fast economic growth. As the pipeline system is proposed for 20 years and the electric price is \$0.066/KWh then the cost of the Hydroelectric or the Grid power system (HEPS/GPS) for running the pipeline system will be calculated as follows:

$P_t = 8.5\text{MW}$ = total power needed by the pipeline system

$E_p = \$0.066/\text{KWh}$ = electricity price

$H = 24\text{h}$ = number of hours in a day

$D = 350\text{days}$ = number of days in the year and 15 days shut down for maintenance

Therefore, the hydroelectric or the grid power system cost for the life time becomes,

$$\text{HEPS/GPS} = P_t \times E_p \times H \times D \quad (6.4)$$

$$\text{HEPS/GPS} = 8500\text{KW} \times \$0.066/\text{KWh} \times 24\text{h} \times 350$$

$$\text{HEPS/GPS} = \$4,712,400$$

When Present Value (PV) of a Series of Payments for the annual cost (A) hydroelectric pumping energy is calculated at a discount rate 10% for the project life for 20 years it becomes [15]:

$$PV = \$4,712,400 \times \left[\frac{(1 + 0.1)^{20} - 1}{0.1 \times (1 + 0.1)^{20}} \right] = \$$$

Therefore, when we compare the cost of installation of the wind power pumping system that is **\$15,537,252** and the cost of the hydroelectric or the grid power system for pumping the water from the lower reservoir to the upper reservoir that is \$4,712,400 amount of money is annually needed for the project life and the difference is \$24,582,065.67 more than the total investment cost of the wind power pumping system. From this result what we can conclude is that using the power from the hydroelectric or the grid power system is too expensive than installing the wind turbines for pumping system. Therefore, it is much profitable installing the wind turbine for the pumping purpose.

6.2.3. The profitability of wind power used pumping system with the diesel generator power pumping system

The profitability or the economic analysis of comparing the wind power used pumping system with the diesel generator power pumping system is conducted in the form of equalizing the value of wind farm used for pumping system to the induced savings in the pumping system in terms of avoided costs of diesel generator power generation. The incremental economic cost of the wind farm output is defined as the difference between the economic costs of the wind farm and the avoided economic cost of a diesel power plant. The

economic costs of power generation with a diesel power plant comprise: capital costs of the plant; fuel costs; variable and fixed operating costs; and external costs of diesel power generation.

The economic costs for power generation with alternative project (wind power) are accounted for: capital costs of the wind park, fixed operating costs of the wind power installation, and external costs of wind power generation.

From an economic point of view, the project is profitable, if during the period of time in question the cost of generating electricity with the wind park is lower than the cost of generating electricity with the diesel power plant. In other words: the costs incurred for building and operating the discussed wind farm must be lower than the diesel power plant, which it provides. The economic benefits are measured here in terms of avoided costs (savings). If the wind park is built, the operating costs, and the external costs, of diesel-based power generation will be avoided.

6.2.3.1. Economic Benefits Diesel Power Plant

In the economic analysis the identified benefits are:

- i. the avoided capital costs
- ii. the avoided fuel costs
- iii. avoided O&M costs and
- iv. the avoided emissions

6.2.3.2. Basic Diesel Power Plant Data

The basic data for this study was based on similar brand diesel power plant but different power production state with the existing diesel power plant located in the northern part of Ethiopia and it has approximately similar power production of the wind farm for the pumping purpose. The power plant is a heavy fuel oil operated diesel power plant and it consists of 12 cylinders, V-type, 4-stroke, medium speed Wartsila diesel engine type 32 coupled to ABB AMG 0900MK08 alternator and the genset is rated 4318KW (site capacity at alternator terminal). The net plant capacity at full load is 4.2MW.

The engine speed of the type 32 is 750 rpm. This diesel power plant is taken from Chinese Electrical supplier and Manufacturer called CFAS Enterprise Inc. web site that is [17, 18].



Figure 17 4.2MW Wartsila HFO Power Plant

The technical data of reference DPP considered in economic analysis are presented in table:
28.

Table 28 Technical data of the reference DPP

Engine Data	Value
Engine Model	GTG_1518NEP_Wart12V32LN
Engine type	12V32NL
Number of cylinder	12
Specification number	173310
Date of manufacturing	10/2000
Engine speed for 50Hz	750rpm
Alternator Data	Value
Alternator Model	ABB AMG 0900MK08
Alternator type	AMG 0900MK08
Insulation class	F
Protection class	IP21
Frequency	50Hz
Power factor	0.8
Output voltage	11kV
Efficiency	97.5 at 0.8 P.F. at 100% load
Ambient Temperature	+50°C
Genset Data	Value

ISO Capacity at alternators terminal	5208kVA
Site Capacity at alternators terminal	4318kW
Net Plant Capacity	4200kW
Capacity De-rating Factor	17.1%
Life time	20-25 year

6.2.3.4. Avoided Capital Costs

Economic feasibility is determined by comparing the wind park with an equivalent diesel power plant and wind-park relative to the equivalent diesel based generation has been considered in terms of its energy production. If Wind Park would not be installed, additional energy would have to be provided by new diesel generators at higher costs.

The chosen DPP is especially suited for the analysis, since its annual generation is similar to the estimated energy production of the wind park. The capacities of the diesel unit at this power plant are de-rated because of the prevailing site conditions. Due to the importance of this fact, for the correct interpretation of the calculated capital costs and operation costs, the influence of the site conditions on the engine's capacity will be further analyzed. The ISO capacity at alternator terminals of each Wartsila unit is 5208 kW. The site capacity is 4318kW. This comparison shows that each diesel genset is de-rated by 17.1% that is $(1 - (4318/5208) = 0.171)$ due to the site conditions. This comparison is important for the interpretation of the study's results, since the de-rated capacity of the plant increases the specific costs of the plant compared to a non-de-rated plant by approximately 10-20%. The gross plant capacity (at alternator terminal) is 4318 kW, Net plant capacity is 4200 kW and the difference between both values $(4318-4200 = 118 \text{ kW})$, that is $(1 - (4318/4200) = 2.73\%)$ is the auxiliary power consumption of the plant. The economic data of the reference DPP considered in economic analysis are presented in table: 29.

Table 29 Economic data of the reference DPP

Economic Data	Value in USA Dollar
DPP Investment Requirements	1,255,000 USD
Capital Cost of DPP at ISO electrical gross capacity of 5208kW	$\$1,255,000/5208\text{kW}=\$241/\text{kW}$
Adjusted cost for de-rating (17.1%)	$\$241 + (0.171 * \$241) = \$282.2/\text{kW}$
Capital Cost of DPP at Site electrical net plant capacity of 4318 kW	$\$1,255,000/4318\text{W}=\$290.64/\text{kW}$

The avoided capital costs refer to the investment costs that would occur when installing a DPP like the investigated 4.2MW plant. The avoided capital costs were calculated at \$290.644/kW. This value is much lower than the capital costs for a wind turbine that is \$2000/kW which is used for the wind energy cost analysis in the above part. Even though this happens for the fuel cost, the variable O&M costs and the Net GHG Emission reduction Cost will be checked a gain for the project profitability analysis.

6.2.3.5. Avoided Fuel Costs

Fuel is not required to produce wind power. When wind energy is produced, it saves significant amounts of fuel costs in the form of coal, gas and oil that would otherwise have been needed for power production. In addition to these avoided costs, the production of wind energy reduces demand for imported fuel (and thereby the cost of fuel), while reducing the rate of depletion of remaining fossil fuel reserves. Naturally, the avoided fuel costs of wind energy depend on the assumptions made about future fuel prices. Oil and gas prices are very closely linked, and coal also follows, to a lesser extent, the price of oil. Both the International Energy Agency (IEA) and the European Commission have for many years made predictions on future coal, gas and oil prices, and most governments base their energy policies on the IEA's fuel price scenarios. A barrel of oil cost US\$100 at the start of 2008, and reached a record \$147 in July. Appendix F shows the latest oil price estimates from [24]. Nobody can predict oil prices, but it should be a minimum requirement that the IEA include fuel price sensitivity analysis in their scenarios for the future development of the energy markets.

6.2.3.6. Fuel Consumption calculator

The fuel consumption calculator approximates the fuel consumption of a diesel generator based on its size and operating load. These results are intended to estimate how much fuel a generator uses during operation. Note that the results are not exact metric due to various factors that can affect the amount of fuel consumed [21]. In this project case the selected diesel generator size is 4200kW working at the full load and according to the fuel consumption calculator the diesel generator at its full load consumes 298.9gal/hr to generate the required power.

$$4200\text{kW} = 298.9\text{gal/hr(gallon per hour)}, 4200\text{kwhr} = 298.9\text{gal}$$

$$1\text{liter} = 0.264\text{gal}, 1\text{gal} = 3.788\text{liter}$$

$$4200\text{kwhr} = 1132.2\text{liter}, 1\text{hr} = 0.27\text{liter/kW}$$

In the current economic analysis, avoided fuel costs are determined by the fuel prices and the fuel consumption of the diesel gensets. The considered DPP is laid out for continuous operation on cheap heavy fuel oil (HFO). Expensive light fuel oil (LFO) is only needed as back-up fuel: used during start-up and shut down of the diesel engines, and when HFO is not available due to technical problems of the transfer and/or fuel treatment systems. The annual fuel consumption considered is:

- HFO consumption: 82%
- LFO consumption: 18%

The stated HFO to LFO consumption ratio are values of the 38MW Dire Dawa diesel power plants (DPP) having similar property and Brand with the DPP selected for this study for comparison. For the economic analysis a fuel consumption of 0.27liter/kWh at the alternator's terminals was considered. According to the current fuel price in Ethiopia, HFO: 16ETB/liter and LFO: 17ETB/liter and the current rate of exchange in Ethiopia is 1USD= ETB17.8 (1:17.8), then, the current fuel price in dollar is:

$$\text{HFO price per metric tons} = \text{Birr}16/\text{liter} = \text{USD } 0.899/\text{liter}$$

$$\text{LFO price per metric tons} = \text{Birr}17/\text{liter} = \text{USD } 0.955/\text{liter}$$

For HOF: the cost to producing a kWh will be:

$$\text{Cost (HFO)} = 0.27\text{liter}/\text{Kwh} \times \text{USD } 0.899/\text{liter} = \text{USD}0.243/\text{kwh}$$

For LOF: the cost of producing a kWh will be:

$$\text{Cost(LFO)} = 0.27\text{liter}/\text{Kwh} \times \text{USD } 0.955/\text{liter} = \text{USD}0.258/\text{Kwh}$$

Net annual plant energy production (NAPEP) at a plant capacity (PC) of 4200kW and the load factor (LF) of 0.8 will be calculated as follows:

$$\text{NAPEP} = \text{PC} \times \text{LF} \times \text{H} \times \text{ND} \tag{6.4}$$

Where NAPEP =? = Net annual plant energy production

$$\text{PC} = 4200\text{kW} = \text{plant capacity}$$

$$\text{LF} = 0.8 = \text{load factor}$$

$$\text{H} = 24\text{h} = \text{hours in a day}$$

$$\text{ND} = 365 = \text{number of days in a year}$$

$$\text{NAPEP} = 4200\text{kW} \times 0.8 \times 24 \times 365$$

$$\text{NAPEP} = 29,433.6\text{MWh}$$

Therefore, the annual price of HFO (APHFO) for the production of 29,433.6MWh with the unit price of \$0.243/kWh of HFO will be:

$$\text{APHFO} = \text{NAPEP} \times \$0.243/\text{kWh} \tag{6.5}$$

$$\text{APHFO} = 29,433.6 \times 10^3 \text{kWh} \times \$0.243/\text{kWh}$$

$$\text{APHFO} = \$7,152,365$$

The annual price of LFO (APLFO) for the production of 29,433.6MWh with the unit price of \$0.206/kWh of LFO becomes:

$$\text{APLFO} = \text{NAPEP} \times \$0.258/\text{kWh} \quad (6.6)$$

$$\text{APLFO} = 29,433.6 \times 10^3 \text{kWh} \times \$0.258/\text{kWh}$$

$$\text{APLFO} = \$7,593,869$$

Therefore, the annual avoided fuel cost due to the installation of the wind park is the sum total of the expenditure incurred for HFO and LFO and it becomes **\$14,746,234**

6.2.3.6. Avoided non-Fuel O&M Costs

Depending on the plant load factor, operating hours and fuel price, the fuel costs represents more than 80% of the total operation costs of a DPP. The remaining costs, the (non-) fuel O&M costs consist of fixed and variable costs. The fixed O&M costs include all those cost items which will be incurred irrespective of an operation of the plants operation status. These fixed costs include costs for personnel, insurance, management and administration, as well as general maintenance costs. The general maintenance cost component includes costs of administration for services, consumables, materials, supplies procured, costs of postage, telephone, facsimile, reproductions and travel expenses. The variable O&M costs include such cost components which are only incurred if the plant is operating. These costs comprise of lubrication oil and other consumables like chemicals, etc. Variable costs for the power plant also include the cost for overhauls including spare parts. Each diesel engine has to undergo service and maintenance every 1500/3000/6000/12000/24000 and 36000/48000 operation hours. After 12000/24000 and 36000/48000 operation hours the diesel engines undergo major maintenance works, which are very cost intensive. The specific variable O&M costs from similar standard plant considered to be 6 USD/MWh (source Evaluation of Institution of Diesel and Gas Turbine Engineers (IDGTE) Working Cost and Operational Report 1997) for HFO operated DPP's of similar design and configuration is an average value calculated within one whole operation cycle until major overhaul at 36000/48000 operation hours. Moderate international standard cost estimates settled at 100,000 USD for fix non-fuel O&M costs per year are assumed to apply in economic analysis.

The estimation of avoided non-fuel variable O&M costs per year for the Diesel Power Plant has been considered according to the Consultants experience from similar African Diesel Power Plants and according the following data:

Table 30 Non-fuel variable O&M for a DPP

Net Plant Capacity	4200kW
Assumed Plant load factor, DPP as base load plant	0.8
Net plant energy production at HV side of step-up transformers	4.2MW X 0.8 X 24 X 365/year = 24,433.6MWh/year
Specific variable O&M costs for HFO operated DPP's of similar design and configuration all over the world (source evaluation of institution of diesel and Gas Turbine Engineers (IDGTE) working cost and operational report 1997	6 USD/MWh
Estimated annual expenditure for variable O&M costs	USD 146,601.6

When the present worth of the annual estimated expenditure for variable O&M costs of the diesel power plant is calculated for the entire life of the project it becomes [15]:

$$P = A \times \left[\frac{(1 + i) - 1}{i \times (1 + i)} \right]$$

where $i=10\%$, $A=146,602$, $P=?$

$$P = 146,602 \times \left[\frac{(1 + 0.1) - 1}{0.1 \times (1 + 0.1)} \right] = \$1,248,103$$

6.2.3.7. Avoided Emissions

The avoided CO₂ emissions are calculated considering that a DPP with an efficiency of 43 % emits 670 gr. of CO₂ per kWh. The system calculates as shown in table 31 below.

Table 31 avoided CO₂ emission

Net GHG reduction	<i>tCO₂/yr</i>	5,176
Net GHG emission reduction - 10 yrs	<i>t/CO₂</i>	5176*10 = 51,760
Net GHG emission reduction - 20 yrs	<i>t/CO₂</i>	51,760+10*5176 = 103,520

In the economic analysis the wind park is compared with a diesel power plant. Thus, the avoided emissions in the wind park analysis refer to the DPP. The economic monetary quantification of the avoided emissions has been based on the Mitigation Cost Approach. In the Mitigation Cost Approach, the use of USD20/CO₂ tones is considered as a reasonable estimate for the shadow price of carbon emissions and it is consistent with the existing work by many experts:

- The Federation of American Scientists arrived at a shadow price of USD10-20/CO₂ tones based on a Delphi-type assessment;

- And simulations of the global carbon offset market performed by the Norwegian research group, ECON, indicate a future market price for carbon of USD10-30/tCO₂

Therefore, that a price of 20 USD/ CO₂ tones has been applied in the economic analysis of this specific project (In the financial analysis, current Certified Emission Reduction (CER) credit prices for Clean Development Mechanism (CDM)).

When the Net GHG Emission Reduction Cost (NGHGERC) for 20years or for the project life is converted in to monetary value by using the mitigation cost approach it becomes:

$$\text{NGHGERC} = 20 \text{ USD/tCO}_2 \times 103,520, \text{ NGHGERC} = \$2,070,400/\text{tCO}_2$$

The total sum of the investment costs that will be incurred on the life time of the diesel power plant is the sum of all costs involved in the DPP that is the sum of costs of capital, fuel costs and emission costs and it becomes **\$19,319,737**, but the total sum of investment cots that will be incurred on the proposed wind park life time is **\$15,537,252**. From this what we can conclude is that the use of wind power for pumping the water from lower reservoir is profitable than using the diesel power plant.

CHAPTER SEVEN

7. CONCLUSION AND RECOMMENDATION

7.1. CONCLUSION

- From the taken representative years that are from 2000 to 2004E.C the analysis shows the most critical months that need water to be pumped are March, April, May, June and July. Among these critical ones April, June and July especially needs more water since they are months that suffer from water shortage. The most important situation that makes these Months lucky is that there is enough Wind Energy Resource around the selected site for water pumping purpose.
- The reservoir evaporation analysis part shows the amount of water that evaporates from the reservoir in a day in each critical months March, April, May, June, and July is $689,120m^3/day$, $538,080m^3/day$, $354,000m^3/day$, $542,800m^3/day$, and $769,360m^3/day$ respectively.
- The maximum water that evaporates from the reservoir will be taken as the minimum water capacity that should be stored in the lower reservoir that is $769,360m^3$ approximately it is about $1Mm^3$. Even though this volume of water is taken as representative water that is to be stored in the lower reservoir per day the capacity of the lower reservoir will be on the annual basis so it is $360Mm^3(1Mm^3 \times 30day \times 12month=360Mm^3/year)$, then total amount of water that should be stored in the lower reservoir is $360Mm^3/year$.
- The amount of water that is to be pumped per hour to the upper reservoir is the average of the five selected month values that is $48,210m^3/hr$. Based on the commercial availability of the pumps with the capacity of pumping $9000m^3/hr$ 6 Gould's 3180 pumps were selected.
- From the pipeline economic analysis, based on the net present value of investment of the bracketed pipe diameter range the 864mm (34in.) diameter pipeline system with 1750 HP pump station is selected. $9000m^3/hr$
- In order to pump the hourly water requirement $48,210m^3/hr$ it needs 7 similar capacity pumps connected in parallel pump connection system one as a reserve pump or standby in order to perform the required work or pump the hourly water requirement on a continuous base.

- The total present value cost for the four pumps is **\$19,889,625**. The total power required to run the pump station is 8,500kW power is needed in an hour including allowance.
- The total cost of the wind farm with the G80-2.0MW wind turbine for the life of the project is the sum of the initial cost and the annual operating cost for the life of the project of the wind farm, which is **\$15,537,252**.
- For the reason that the number of the selected wind turbine for the site is small and the intermittent and uncontrollable energy production of the wind turbine limits the direct integration of this selected wind turbines to the existing power system instead it is preferable to use for pumping the water from the lower reservoir to upper reservoir to enhance the volume of the upper reservoir.
- From the angle of investment cost only the 5.1MW power generated by the pumped water will cover its expended cost throughout the project life time.
- From the analysis part when it is compared the profitability of wind power used for pumping system with the hydroelectric power or the grid power pumping system it is better to use the wind power pumping system.
- When it is compared the profitability of wind power used pumping system with the diesel generator power pumping system it is the best option to use the wind power pumping system than the diesel generator because the diesel generator costs are consists of different costs even if we take only the fuel cost of the diesel generator throughout the project life time it exceeds the total cost that will be incurred to the wind farm up to the project life time.

7.2. RECOMMENDATION FUTURE WORKS

- This thesis mainly concerns on the Koka hydropower plant for further study it is possible to investigate its feasibility study to use the wind-solar hybrid power for water pumping system to increase the efficiency of Koka hydropower reservoir.
- The scope of this thesis is limited on the Koka hydropower plant and because of most of the hydropower plants in Ethiopia faces the same problem it is possible to extend the study to the other hydropower plants like Melka Wakana, Tekeze, and other hydropower plants.
- Investigation of the feasibility study of integrating other renewable energy pumped hydro-system to the existing hydro-powers plants in Ethiopia.

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Appendix A: The output power of each Hydropower Plants of Ethiopia [MW]

Plant	Month	Jan	Feb	Mar	Apr	Ma	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Wakana	Projected output	153	153	153	153	153	153	153	153	153	153	153	153
	Average output	101	104	90	46	26	22	35	27	53	64	83	92
Koka	Projected output	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2
	Average output	12	11	11	13	15	10	8	6	25	15	12	13
Finchaa	Projected output	134	134	134	134	134	134	134	134	134	134	134	134
	Average output	92	90	89	94	95	87	76	44	90	94	96	94
Awash I and II	Projected output	64	64	64	64	64	64	64	64	64	64	64	64
	Average output	45	44	42	47	50	36	35	22	40	45	47	45
Tis I	Projected output	12	12	12	12	12	12	12	12	12	12	12	12
	Average output	2	3	3	4	2	4	5	3	4	6	6	3
Tis II	Projected output	73	73	73	73	73	73	73	73	73	73	73	73
	Average output	46	45	44	45	46	33	30	24	46	39	49	45
G.G I	Projected output	184	184	184	184	184	184	184	184	184	184	184	184
	Average output	75	69	64	54	38	91	146	73	82	93	101	103
G.G II	Projected output	420	420	420	420	420	420	420	420	420	420	420	420
	Average output	197	183	169	141	101	241	384	192	217	245	265	270
Tekeze	Projected output	300	300	300	300	300	300	300	300	300	300	300	300
	Average output	111	103	95	79	57	135	216	108	122	138	149	152
Beles	Projected output	420	420	420	420	420	420	420	420	420	420	420	420
	Average output	191	177	163	137	98	233	372	186	210	237	257	262

No	Year 2003E.C	Months																	
	Description	Unit	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Pag	Min	Ave	Max	
1	Spill way level of the dam	mts	110.30	110.30	110.30	110.30	110.30	110.30	110.30	110.30	110.30	110.30	110.30	110.30	110.30	110.30	110.30	110.30	110.30
2	Dead storage water level	mts	102.00	102.00	102.00	102.00	102.00	102.00	102.00	102.00	102.00	102.00	102.00	102.00	102.00	102.00	102.00	102.00	102.00
3	Usable storage water level	mts	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12
4	Water level at the beginning of the month	mts	109.82	110.02	109.04	108.66	107.88	107.17	106.39	105.63	104.73	103.49	104.38	107.32	109.63	103.49	107.27	109.00	110.00
5	Water level at the end of the month	mts	110.03	109.42	108.69	107.9	107.2	106.41	105.66	104.77	103.53	103.21	107.3	109.54	109.8	103.21	107.19	109.00	110.00
6	Difference	mts	0.21	0.6	0.71	0.76	0.68	0.76	0.73	0.86	1.2	0.28	2.92	2.22	0.17	2.92	0.08	1.20	
7	Difference of usable storage water level and water level at the beginning of month	mts	0.70	0.90	0.28	0.46	1.24	1.95	2.73	3.49	4.39	5.63	4.74	1.80	0.51	0.90	1.85	5.63	
8	Difference of usable storage water level and water level at the end of the month	mts	0.21	0.6	0.71	0.76	0.68	0.76	0.73	0.86	1.2	0.28	2.92	2.22	0.17	2.92	0.08	1.20	
9	Area of the Water Reservoir	Mm ²	236.00	236.00	236.00	236.00	236.00	236.00	236.00	236.00	236.00	236.00	236.00	236.00	236.00	236.00	236.00	236.00	236.00
10	Max. Depth of Reservoir	mts	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
11	Av. Depth of the Reservoir	ms	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14
12	Usable water height	mts	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12
13	Total storage capacity of the Reservoir at 1590.7m (asl)	Mm ³	195.88	195.88	195.88	195.88	195.88	195.88	195.88	195.88	195.88	195.88	195.88	195.88	195.88	195.88	195.88	195.88	1958.80
14	Usable Storage Capacity of the reservoir	Mm ³	168.032	168.032	168.032	168.032	168.032	168.032	168.032	168.032	168.032	168.032	168.032	168.032	168.032	168.032	168.032	168.032	1680.32
15	Volume of Dead storage	Mm ³	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.33

No	Year 2004E.C	Months																	
	Description	Unit	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Pag	Min	Ave	Max	
1	Spill way level of the dam	mts	110.30	110.30	110.30	110.30	110.30	110.30	110.30	110.30	110.30	110.30	110.30	110.30	110.30	110.30	110.30	110.30	110.30
2	Dead storage water level	mts	102.00	102.00	102.00	102.00	102.00	102.00	102.00	102.00	102.00	102.00	102.00	102.00	102.00	102.00	102.00	102.00	102.00
3	Usable storage water level	mts	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12	109.12
4	Water level at the beginning of the month	mts	109.22	109.73	109.24	108.64	107.96	107.29	106.45	105.76	105.25	103.33	103.24	104.77	108.66	103.24	106.89	109.00	109.70
5	Water level at the end of the month	mts	109.74	109.25	108.66	107.99	107.32	106.48	105.78	105.27	104.53	104.21	104.68	108.55	109.02	104.21	107.04	109.00	109.70
6	Difference	mts	0.52	0.48	0.58	0.65	0.64	0.81	0.67	0.49	0.72	0.88	1.44	3.78	0.36	3.78	0.15	0.81	
7	Difference of usable storage water level and water level at the beginning of month	mts	0.10	0.61	0.12	0.48	1.16	1.83	2.67	3.36	3.87	5.79	5.88	4.35	0.46	0.61	2.23	5.88	
8	Difference of usable storage water level and water level at the end of the month	mts	0.62	0.13	0.46	1.13	1.80	2.64	3.34	3.85	4.59	4.91	4.44	0.57	0.10	0.62	2.08	4.91	
9	Area of the Water Reservoir	Mm ²	236.00	236.00	236.00	236.00	236.00	236.00	236.00	236.00	236.00	236.00	236.00	236.00	236.00	236.00	236.00	236.00	236.00
10	Max. Depth of Reservoir	mts	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
11	Av. Depth of Reservoir	ms	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14	9.14
12	Usable water height	mts	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12	7.12
13	Total storage capacity of the Reservoir at 1590.7m (asl)	Mm ³	195.88	195.88	195.88	195.88	195.88	195.88	195.88	195.88	195.88	195.88	195.88	195.88	195.88	195.88	195.88	195.88	1958.80
14	Usable Storage Capacity of the reservoir	Mm ³	168.032	168.032	168.032	168.032	168.032	168.032	168.032	168.032	168.032	168.032	168.032	168.032	168.032	168.032	168.032	168.032	1680.32
15	Volume of Dead storage	Mm ³	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.33

Appendix C: Recommended Average Days for Months and Values of N by Months

Month	N for i th Day of Month	For the Average Day of the Month		
		Date	Day of the Year N	Declination Angle δ
January	i	17	17	-20.9
February	31+i	16	47	-13.0
March	59+i	16	75	-2.4
April	90+i	15	105	9.4
May	120+i	15	135	18.8
June	151+i	11	162	23.1
July	181+i	17	198	21.2
August	212+i	16	228	13.5
September	243+i	15	258	2.2
October	273+i	15	288	-9.6
November	304+i	14	318	-18.9
December	334+i	10	344	-23.0

Appendix D: The overall Meteorological data of Koka hydropower plant

The actual duration of sunshine hours of Adam meteorological station

Year	1998	1999	2000	2001	2002	2003	2004	1998-2004 Average
Jan	8.9	9.4	10.4	10.4	8.9	9.8	9.1	9.56
Feb	9	5.2	10.3	9.9	10.1	9.5	9.4	9.06
Mar	8.2	4	9.7	7.7	9.3	7.7	9.9	8.07
Apr	9.4	5.2	8.7	8.4	8.5	7.9	8.3	8.06
May	9	9.1	8.9	10.1	7.5	9.4	9	9.00
Jun	9.1	9.3	8.3	8	7.7	7.8	7.7	8.27
Jul	6.7	6.5	6.4	7.2	6.1	6.8	5.5	6.46
Aug	6.8	7.9	6.9	7.6	8.8	5.9	6.6	7.21
Sep	7.6	8.6	5.7	8.2	7.5	7.5	6.5	7.37
Oct	7.1	7.9	7.1	8.8	9.8	8.2	9.3	8.31
Nov	10.1	9.9	9	10.1	9.4	10	9.3	9.69
Dec	10.6	10.3	8.7	8.8	10.7	8.8	10.5	9.77

Monthly Averaged Daylight Hours Source: NASA

Monthly Averaged Daylight Hours (h)												
Latitude 8.5 Longitude 39.5	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec
Hours	11.7	11.8	12.0	12.3	12.5	12.6	12.5	12.4	12.1	11.9	11.7	11.6

Adama monthly Average temperature (°c)

Average of 1997-2007 Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Aver
monthly minimum temperature (°c)	26.8	28.9	29.4	29.6	30.8	29.6	28.1	26.7	27.1	27.6	26.9	26	28.9
monthly maximum temperature (°c)	12.9	14.4	15.2	15.8	16.3	17.3	18.2	15.9	15.2	13.7	13.1	12.7	15.9
Average	19.9	22.7	22.3	23.7	23.6	23.5	21.2	21.8	21.2	20.7	20.0	19.4	22.4

Adama wind speed at different height (m/s)

at 2, 10 and 40 meters Month	2 meters (2003 -2007)	10 meters (2006-2008)	40 meters (2007)	Power generated at 10 m (kwh)
January	2.4	9.2	10.5	351.0
February	2.5	9.6	9.5	435.2
March	2.0	7.8	10.8	300.4
April	2.0	7.5	7.0	271.1
May	1.9	7.3	7.7	178.6
June	2.0	7.5	7.8	216.2
July	2.2	8.2	7.1	290.4
August	1.7	6.6	6.0	257.3
September	2.0	7.5	7.9	216.7
October	2.1	8.1	10.4	296.1
November	2.6	9.9	11.1	309.9
December	2.7	10.2	11.0	393.8
Average	2.2	8.3	8.9	293

Appendix E: Wind Turbine Data and Costs

Classification of wind farms

Wind Farm Classes	Number of Turbines
Single turbine	1
Small wind farm	2 to 5
Large wind farm	More than 5

Classification of Wind Turbine Sizes

Wind Turbine Size	Rated Output (KW)	Rotor Diameter (m)	Swept area (m ²)
Micro	0 to 1.5	Less than 3	Less than 7
Small	1.5 to 20	3 to 25	7 to 80
Medium	20 to 200	10 to 25	80 to 500
Large	200 to 2,000	More than 25	More than 500

Turbine size and specific cost

Wind turbine size (kW)	Specific cost of turbine (\$/kW)
10 to 20	2,200 to 2,900
20 to 200	1,500 to 2,300
More than 200	1,000 to 1,600

Relative Initial Costs for Wind Energy Projects

Main cost category	Large Wind Power (recommended) (%)
Feasibility study	Less than 2
Development	1 to 8
Engineering	1 to 8
RE equipments	67 to 80
Balance of plant	17 to 26
Miscellaneous	1 to 4

Weight of wind turbine component

Wind turbine size (kW)	Typical weight (Kg)		
	Nacelle	Tower	Blades Set
1.5	70	175	6
5.0	250	300	25
10.0	400	500	60
40.0	2,000	2,500	450
200.0	8,000	18,000	2,000
600.0	25,000	50,000	6,000
1,500.0	60,000	120,000	15,000

Appendix F: approximate pipeline construction labor cost and oil price

The summarized approximate pipeline construction labor cost

Pipe diameter (in.)	Average Cost (\$/in.-diameter/mile)
8	18,000
10	20,000
12	22,000
16	14,900
20	20,100
24	33,950
30	34,600
36	40,750

The latest oil price estimates from IEA (2009)

Year	2009	2010	2011	2012	Percent Change		
					09-10	10-11	11-12
Crude(\$/barrel)	61.65	79.40	93.26	97.50	28.8	17.5	4.5


Appendix G: Wind Energy and Turbine Investment cost of Koka Hydropower Plant

RETScreen® Energy Model - Wind Energy Project

[Training & Support](#)

Units:

Site Conditions		Estimate	Notes/Range
Project name		koka wind Pump	See Online Manual
Project location		Ethiopia	
Wind data source		Wind speed	
Nearest location for weather data		Adama	See Weather Database
Annual average wind speed	m/s	8.3	
Height of wind measurement	m	10.0	3.0 to 100.0 m
Wind shear exponent	-	0.14	0.10 to 0.40
Wind speed at 10 m	m/s	8.3	
Average atmospheric pressure	kPa	80.4	60.0 to 103.0 kPa
Annual average temperature	°C	22	-20 to 30 °C

System Characteristics		Estimate	Notes/Range
Grid type	-	Off-grid	
Peak load	kW	12,000	
Wind turbine rated power	kW	2,000	 Complete Equipment Data sheet
Number of turbines	-	5	
Wind plant capacity	kW	10,000	
Hub height	m	70.0	6.0 to 100.0 m
Wind speed at hub height	m/s	10.9	
Wind power density at hub height	W/m ²	1,469	
Wind penetration level	%	83.3%	
Suggested wind energy absorption rate	%	See manual	
Wind energy absorption rate	%	98%	
Array losses	%	15%	0% to 20%
Airfoil soiling and/or icing losses	%	8%	1% to 10%
Other downtime losses	%	6%	2% to 7%
Miscellaneous losses	%	5%	2% to 6%

Annual Energy Production		Estimate Per Turbine	Estimate Total	Notes/Range
Wind plant capacity	kW	2,000	10,000	
	MW	2.000	10.000	
Unadjusted energy production	MWh	10,144	50,720	
Pressure adjustment coefficient	-	0.79	0.79	0.59 to 1.02
Temperature adjustment coefficient	-	0.98	0.98	0.98 to 1.15
Gross energy production	MWh	7,854	39,268	
Losses coefficient	-	0.70	0.70	0.75 to 1.00
Specific yield	kWh/m ²	1,091	1,091	150 to 1,500 kWh/m ²
Wind plant capacity factor	%	31%	31%	20% to 40%
Renewable energy collected	MWh	5,484	27,422	
Renewable energy delivered	MWh	5,375	26,873	
	GJ	19,349	96,744	
Excess RE available	MWh	110	548	

[Complete Cost Analysis sheet](#)

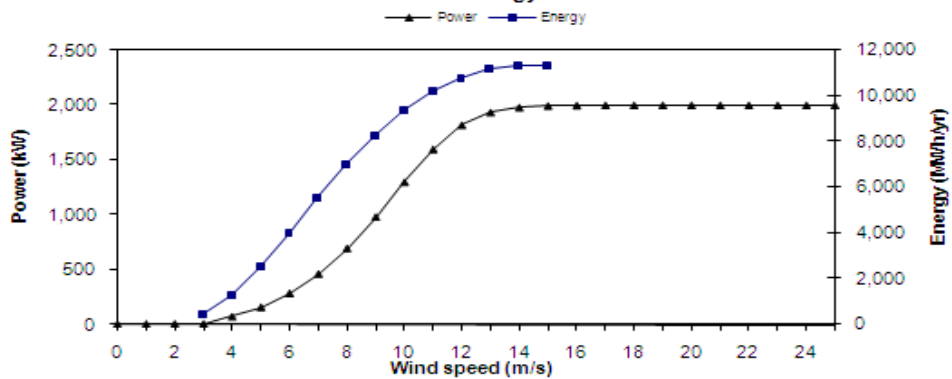
RETScreen® Equipment Data - Wind Energy Project

Wind Turbine Characteristics		Estimate	Notes/Range
Wind turbine rated power	kW	2,000	See Product Database
Hub height	m	70.0	6.0 to 100.0 m
Rotor diameter	m	80	7 to 80 m
Swept area	m ²	5,027	35 to 5,027 m ²
Wind turbine manufacturer		Gamesa Eolica	
Wind turbine model		G80-2.0 MW	
Energy curve data source	-	Standard	Rayleigh wind distribution
Shape factor	-	2.0	

Wind Turbine Production Data

Wind speed (m/s)	Power curve data (kW)	Energy curve data (MWh/yr)
0	0	-
1	0	-
2	0	-
3	0	467.4
4	66.3	1,295.2
5	152	2,532.3
6	280	4,021.6
7	457	5,567.8
8	690	7,028.2
9	978	8,319.2
10	1296	9,393.5
11	1598	10,228.3
12	1818	10,821.4
13	1935	11,188.6
14	1980	11,357.7
15	1995	11,362.4
16	1999	-
17	2000	-
18	2000	-
19	2000	-
20	2000	-
21	2000	-
22	2000	-
23	2000	-
24	2000	-
25	2000	-

Power and Energy Curves



[Return to](#)

RETScreen® Cost Analysis - Wind Energy Project

Type of analysis:

Currency:

Cost references:

Initial Costs (Credits)	Unit	Quantity	Unit Cost	Amount	Relative Costs	Quantity Range	Unit Cost Range
Feasibility Study							
Site investigation	p-d	3.0	\$ 15	\$ 45		2.0 - 8.0	\$200 - \$800
Wind resource assessment	met tower	1	\$ 10,000	\$ 10,000			\$10K - \$25K
Environmental assessment	p-d	3.0	\$ 15	\$ 45		1.0 - 8.0	\$200 - \$800
Preliminary design	p-d	4.0	\$ 15	\$ 60		2.0 - 20.0	\$200 - \$800
Detailed cost estimate	p-d	3.0	\$ 15	\$ 45		3.0 - 20.0	\$200 - \$800
GHG baseline study and MP	project	1	\$ 15,000	\$ 15,000			\$40K - \$60K
Report preparation	p-d	3.0	\$ 15	\$ 45		2.0 - 15.0	\$200 - \$800
Project management	p-d	3.0	\$ 15	\$ 45		2.0 - 11.0	\$300 - \$800
Travel and accommodation	p-trip	2	\$ 20	\$ 40			
Other - Feasibility study	Cost	0	\$ -	\$ -			
Sub-total:				\$ 25,325	0.2%		
Development							
PPA negotiation	p-d	10.0	\$ -	\$ -		0.0 - 30.0	\$300 - \$1,500
Permits and approvals	p-d	10.0	\$ 15	\$ 150		0.0 - 400.0	\$200 - \$800
Land rights	project	1	\$ 15	\$ 15			
Land survey	p-d	6.0	\$ 15	\$ 90		0.0 - 100.0	\$400 - \$600
GHG validation and registration	project	1	\$ 5,000	\$ 5,000			\$40K - \$100K
Project financing	p-d	4.0	\$ 15	\$ 60		3.0 - 100.0	\$500 - \$1,500
Legal and accounting	p-d	4.0	\$ 15	\$ 60		3.0 - 100.0	\$300 - \$1,500
Project management	p-yr	1.00	\$ 6,000	\$ 6,000		0.20 - 4.00	\$130K - \$180K
Travel and accommodation	p-trip	4	\$ 20	\$ 80			
Other - Development	Cost	0	\$ -	\$ -			
Sub-total:				\$ 11,455	0.1%		
Engineering							
Wind turbine(s) micro-siting	p-d	7.0	\$ 20	\$ 140		0.0 - 300.0	\$200 - \$800
Mechanical design	p-d	3.0	\$ 20	\$ 60		2.0 - 150.0	\$200 - \$800
Electrical design	p-d	3.0	\$ 20	\$ 60		3.0 - 300.0	\$200 - \$800
Civil design	p-d	3.0	\$ 20	\$ 60		3.0 - 300.0	\$200 - \$800
Tenders and contracting	p-d	8.0	\$ 20	\$ 160		4.0 - 300.0	\$200 - \$800
Construction supervision	p-yr	1.00	\$ 2,000	\$ 2,000		0.00 - 2.00	\$130K - \$180K
Other - Engineering	Cost	0	\$ -	\$ -			
Sub-total:				\$ 2,480	0.0%		
Energy Equipment							
Wind turbine(s)	kW	10,000	\$ 1,200	\$ 12,000,000			\$1,000 - 3,000
Spare parts	%	0.3%	\$ 12,000,000	\$ 36,000		0.0% - 30.0%	
Transportation	turbine	5	\$ 500,000	\$ 2,500,000			
Other - Energy equipment	Cost	0	\$ -	\$ -			
Sub-total:				\$ 14,536,000	93.6%		
Balance of Plant							
Wind turbine(s) foundation(s)	turbine	5	\$ 1,500	\$ 7,500			
Wind turbine(s) erection	turbine	5	\$ 1,500	\$ 7,500			
Road construction	km	16.00	\$ 2,000	\$ 32,000			\$0K - \$80K/km
Transmission line	km	0.50	\$ 8,000	\$ 4,000			
Substation	project	1	\$ 10,000	\$ 10,000			
Control and O&M building(s)	building	1	\$ 4,000	\$ 4,000		0 - 2	
Transportation	project	1	\$ 5,000	\$ 5,000			
Other - Balance of plant	Cost	0	\$ -	\$ -			
Sub-total:				\$ 70,000	0.5%		
Miscellaneous							
Training	p-d	3.0	\$ 15	\$ 45			\$200 - \$800
Commissioning	p-d	3.0	\$ 15	\$ 45			\$200 - \$800
Contingencies	%	3%	\$ 14,645,350	\$ 439,361		5% - 40%	
Interest during construction	6.0%	12 month(s)	\$ 15,084,711	\$ 452,541		3.0% - 15.0%	
Sub-total:				\$ 891,992	5.7%		
Initial Costs - Total				\$ 15,537,252	100.0%		

Annual Costs (Credits)	Unit	Quantity	Unit Cost	Amount	Relative Costs	Quantity Range	Unit Cost Range
O&M							
Land lease	project	1	\$ -	\$ -			
Property taxes	project	0	\$ -	\$ -			
Insurance premium	project	1	\$ 76,589	\$ 76,589			
Transmission line maintenance	%	3.0%	\$ 14,000	\$ 420		3.0% - 6.0%	
Parts and labour	kWh	26,873,272	\$ 0.010	\$ 268,733			\$0.007 - \$0.024
GHG monitoring and verification	project	1	\$ 200	\$ 200			
Community benefits	-	1	\$ 25,000	\$ 25,000			
Travel and accommodation	p-trip	3	\$ 60	\$ 180			
General and administrative	%	1%	\$ 371,122	\$ 3,711		1% - 20%	
Other - O&M	Cost	0	\$ -	\$ -			
Contingencies	%	2%	\$ 374,833	\$ 7,497		10% - 20%	
Annual Costs - Total				\$ 382,329	100.0%		

Periodic Costs (Credits)	Unit	Quantity	Unit Cost	Amount	Interval Range	Unit Cost Range
Drive train	Cost	10 yr	\$ 500,000	\$ 500,000		
Blades	Cost	15 yr	\$ 500,000	\$ 500,000		
End of project life	Credit	-	\$ -	\$ -		

[Go to GHG Analysis sheet](#)

RETScreen® Greenhouse Gas (GHG) Emission Reduction Analysis - Wind Energy Project

Use GHG analysis sheet?
 Potential CDM project?

Type of analysis:

Background Information

Project Information

Project name: koka wind Pump
 Project location: Ethiopia

Project capacity: 10.00 MW
 Grid type: Off-grid

Global Warming Potential of GHG

21 tonnes CO₂ = 1 tonne CH₄ (IPCC 1996)
 310 tonnes CO₂ = 1 tonne N₂O (IPCC 1996)

Base Case Electricity System (Baseline)

Fuel type	Fuel mix (%)	CO ₂ emission factor (kg/GJ)	CH ₄ emission factor (kg/GJ)	N ₂ O emission factor (kg/GJ)	Fuel conversion efficiency (%)	T & D losses (%)	GHG emission factor (tCO ₂ /MWh)
Diesel (#2 oil)	50.0%	74.1	0.0020	0.0020	30.0%	12.0%	1.019
Small hydro	50.0%	0.0	0.0000	0.0000	100.0%	12.0%	0.000
Electricity mix	100%	140.3	0.0038	0.0038		12.0%	0.510

Does baseline change during project life?

Proposed Case Electricity System (Wind Energy Project)

Fuel type	Fuel mix (%)	CO ₂ emission factor (kg/GJ)	CH ₄ emission factor (kg/GJ)	N ₂ O emission factor (kg/GJ)	Fuel conversion efficiency (%)	T & D losses (%)	GHG emission factor (tCO ₂ /MWh)
Electricity system							
Wind	100.0%	0.0	0.0000	0.0000	100.0%	12.0%	0.000

GHG Emission Reduction Summary

Electricity system	Base case GHG emission factor (tCO ₂ /MWh)	Proposed case GHG emission factor (tCO ₂ /MWh)	End-use annual energy delivered (MWh)	Gross annual GHG emission reduction (tCO ₂)	GHG credits transaction fee (%)	Net annual GHG emission reduction (tCO ₂)
Electricity system	0.510	0.000	23,648	12,055	0.0%	12,055

[Complete Financial Summary sheet](#)

RETScreen® Financial Summary - Wind Energy Project

Annual Energy Balance					Yearly Cash Flows				
Project name		koka wind Pump	Peak load	kW	12,000	Year #	Pre-tax \$	After-tax \$	Cumulative \$
Project location		Ethiopia				0	(15,537,252)	(15,537,252)	(15,537,252)
Renewable energy delivered	MWh	26,873	Net GHG reduction	t-co ₂ /yr	12,055	1	2,212,132	2,212,132	(13,325,119)
Excess RE available	MWh	548				2	2,254,416	2,254,416	(11,070,704)
Firm RE capacity	kW	-				3	2,297,495	2,297,495	(8,773,208)
Grid type		Off-grid	Net GHG emission reduction - 25 yrs	t-co ₂	301,365	4	2,341,387	2,341,387	(6,431,822)
						5	2,386,104	2,386,104	(4,045,717)
						6	2,431,664	2,431,664	(1,614,054)
						7	2,478,080	2,478,080	864,026
						8	2,525,369	2,525,369	3,389,396
						9	2,573,547	2,573,547	5,962,943
						10	1,982,589	1,982,589	7,945,532
						11	2,672,637	2,672,637	10,618,168
						12	2,723,581	2,723,581	13,341,750
						13	2,775,482	2,775,482	16,117,231
						14	2,828,356	2,828,356	18,945,587
						15	2,158,073	2,158,073	21,103,660
						16	2,937,098	2,937,098	24,040,758
						17	2,993,002	2,993,002	27,033,760
						18	3,049,953	3,049,953	30,083,714
						19	3,107,971	3,107,971	33,191,685
						20	2,347,766	2,347,766	35,539,451
						21	3,227,283	3,227,283	38,766,734
						22	3,288,618	3,288,618	42,055,352
						23	3,351,099	3,351,099	45,406,452
						24	3,414,748	3,414,748	48,821,200
						25	3,479,585	3,479,585	52,300,785

Financial Parameters					
Avoided cost of energy	\$/kWh	0.0950	Debt ratio	%	0.0%
RE production credit	\$/kWh	-			
GHG emission reduction credit	\$/t-co ₂	-	Income tax analysis?	yes/no	No
Avoided cost of excess energy	\$/kWh	-			
Energy cost escalation rate	%	2.0%			
Inflation	%	2.5%			
Discount rate	%	10.0%			
Project life	yr	25			

Project Costs and Savings				
Initial Costs			Annual Costs and Debt	
Feasibility study	0.2%	\$ 25,325	O&M	\$ 382,329
Development	0.1%	\$ 11,455		
Engineering	0.0%	\$ 2,480		
Energy equipment	93.6%	\$ 14,536,000	Annual Costs and Debt - Total	\$ 382,329
Balance of plant	0.5%	\$ 70,000		
Miscellaneous	5.7%	\$ 891,992	Annual Savings or Income	
Initial Costs - Total	100.0%	\$ 15,537,252	Energy savings/income	\$ 2,552,961
Incentives/Grants	\$	-	Capacity savings/income	\$ -
			Annual Savings - Total	\$ 2,552,961
Periodic Costs (Credits)			Schedule yr # 10,20	
Drive train	\$	500,000	Schedule yr # 15	
Blades	\$	500,000		
	\$	-		
End of project life - Credit	\$	-		

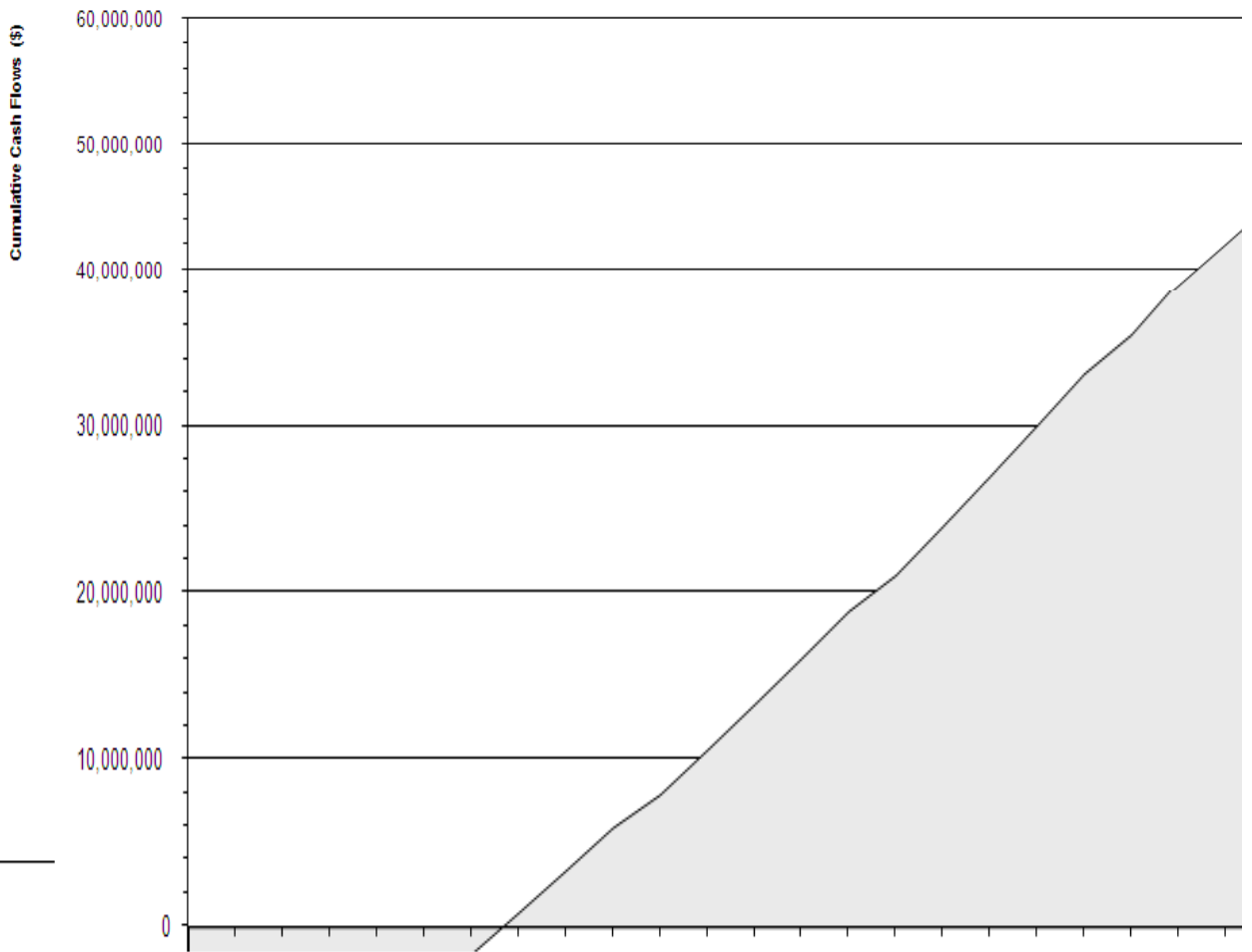
Financial Feasibility					
Pre-tax IRR and ROI	%	15.2%	Calculate energy production cost?	yes/no	No
After-tax IRR and ROI	%	15.2%	Calculate GHG reduction cost?	yes/no	No
Simple Payback	yr	7.2			
Year-to-positive cash flow	yr	6.7	Project equity	\$	15,537,252
Net Present Value - NPV	\$	7,211,209			
Annual Life Cycle Savings	\$	794,445			
Benefit-Cost (B-C) ratio	-	1.46			

Wind Energy Project Cumulative Cash Flows koka wind Pump, Ethiopia

Renewable energy delivered (MWh/yr): 26,873

Total Initial Costs: \$ 15,537,252

Net average GHG reduction (t_{CO2}/yr): 12,055



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RETScreen® Sensitivity and Risk Analysis - Wind Energy Project

Use sensitivity analysis sheet?

Yes

Perform risk analysis too?

Yes

Project name

koka wind Pump

Project location

Ethiopia

Perform analysis on

After-tax IRR and ROI

Sensitivity range

15%

Threshold

10.0

%

[Click here to Calculate Sensitivity Analysis](#)

Sensitivity Analysis for After-tax IRR and ROI

RE delivered (MWh)		Avoided cost of energy (\$/kWh)				
		0.0808 -15%	0.0879 -8%	0.0950 0%	0.1021 8%	0.1093 15%
22,842	-15%	13.0%	14.6%	16.1%	17.6%	19.1%
24,858	-8%	14.6%	16.2%	17.9%	19.5%	21.0%
26,873	0%	16.1%	17.9%	19.6%	21.3%	22.9%
28,889	8%	17.6%	19.5%	21.3%	23.1%	24.8%
30,904	15%	19.1%	21.0%	22.9%	24.8%	26.7%

Initial costs (\$)		Avoided cost of energy (\$/kWh)				
		0.0808 -15%	0.0879 -8%	0.0950 0%	0.1021 8%	0.1093 15%
13,206,664	-15%	19.0%	21.0%	23.0%	24.9%	26.9%
14,371,958	-8%	17.4%	19.3%	21.1%	23.0%	24.7%
15,537,252	0%	16.1%	17.9%	19.6%	21.3%	22.9%
16,702,546	8%	14.9%	16.6%	18.2%	19.8%	21.4%
17,867,840	15%	13.9%	15.5%	17.0%	18.5%	20.0%

Annual costs (\$)		Avoided cost of energy (\$/kWh)				
		0.0808 -15%	0.0879 -8%	0.0950 0%	0.1021 8%	0.1093 15%
324,980	-15%	16.7%	18.4%	20.1%	21.8%	23.5%
353,655	-8%	16.4%	18.1%	19.9%	21.6%	23.2%
382,329	0%	16.1%	17.9%	19.6%	21.3%	22.9%
411,004	8%	15.8%	17.6%	19.3%	21.0%	22.7%
439,679	15%	15.5%	17.3%	19.0%	20.7%	22.4%

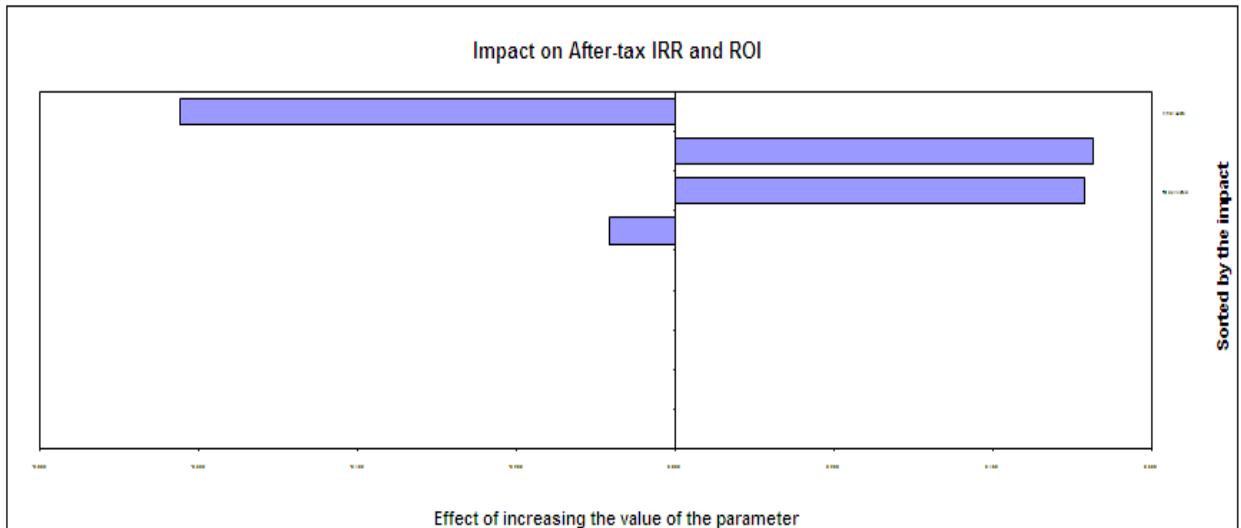
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Risk Analysis for After-tax IRR and ROI

Parameter	Unit	Value	Range (+/-)	Minimum	Maximum
Avoided cost of energy	\$/kWh	0.0950	15%	0.0808	0.1093
RE delivered	MWh	26,873	15%	22,842	30,904
Initial costs	\$	15,537,252	20%	12,429,801	18,644,702
Annual costs	\$	382,329	15%	324,980	439,679



Median	%	15.2%
Level of risk	%	10%
Minimum within level of confidence	%	12.3%
Maximum within level of confidence	%	18.0%

