PREFEASIBILITY STUDY FOR THE DEVELOPMENT OF THE FULLER FALLS FOR SMALL HYDROPOWER GENERATION

BY

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DECLARATION

I hereby declare that this submission is my own work towards the Msc and that, to the best of my knowledge, it contains no material previously published by another person nor material which has been accepted for the award of any other degree of the University, except where due acknowledgement has been made in the text.

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ABSTRACT

Since the early 1980s a lot of effort and resources have been invested in numerous studies on potential small scale hydropower sites in Ghana, however, none of these potential sites has been developed. The country has gone through more than a decade of uncertainties in power generation and has now resorted to the development of thermal power to supplement the traditional hydropower sources. This report is a preliminary assessment into the technical, financial and economic feasibility of developing a mini hydro power plant on the Yoko River at Fuller Falls in the Brong Ahafo Region of Ghana.

The methodology employed in the research work includes actual site measurements and hydrological assessment which was based on the catchment area, precipitation and evaporation of the project site. The financial viability of the project was assessed by the use of the RETScreen software. According to the site survey conducted in this research work, the best scheme type is a run-off-river and central grid connectivity because the nearest village Yabraso which is about 1 km from the proposed site is already connected to the national grid. With a gross head of 18.46m and design discharge of 1.95m^3/s, the possible installed capacity and annual energy generation are estimated to be in the region of 235kW and 1.626 GWh respectively. Using the RETScreen software, the total initial cost of the project is estimated at $1.06 million translating into approximately $4,500 per proposed installed kW. Assuming a 25 year project life, cost of energy of $100/MWh and annual electricity escalation export rate of 0.2%; the Benefit-Cost Ratio (B-C), the Net Present Value (NPV) and the Internal Rate of Return (IRR) is estimated at 1.54, $142,519 and 13.5% respectively. This prefeasibility study therefore indicates that the project is technically and financially feasible.

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LIST OF ABBREVIATIONS

kW	Kilowatt
kWh	Kilowatt Hour
MW	Megawatt
MWh	Megawatt Hour
GW	Gigawatt
GWh	Gigawatt Hour
BHA	British Hydropower Association
MDGs	Millennium Development Goals
FDC	Flow Duration Curve
IRR	Internal Rate of Return
B-C	Benefit-Cost Ration
IRR	Internal Rate of Return
CND	Canadian Dollars ($)
USD	United States Dollars ($)
tCO2	Tones of Carbon Dioxide
US-DoI	United States Department of Interior
DoE	Department of Energy
O & M	Operation and Maintenance
VRA	Volta River Authority
SHP	Small Hydropower Plant

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CHAPTER ONE

INTRODUCTION

1.1 BACKGROUND

As the price of electricity rises, more people are looking for alternative sources of energy and renewable energy is the alternative that the world is turning to. Ghana has an installed capacity of about 2,170MW made up of hydro and thermal generation stations as shown in table 1.1. Electricity demand which is currently about 1,500MW is growing at about 10% per annum (Energy Commission, 2012). It is estimated that Ghana requires capacity additions of about 200MW to catch up with increasing demand in the medium to long term (MoE-NEP, 2010). The average electricity consumption of Ghana over the past ten years was about 5,884GWh (Energy Commission, 2010). In Ghana most of the electricity consumed comes from hydropower plants in Akosombo and Kpong. As the population keeps growing, the demand for energy also increases.

Table 1.1: Installed Capacity in Ghana (End of Dec 2011) (Source; Energy Commission, 2012)

Plant	Fuel Type	Installed Capacity (MW)
Hydro Generation		
Akosombo	Water	1,020
Kpong	Water	160
Sub-Total		*1,180*
Thermal Generation		
Takoradi Power Company (TAPCO)	LCO/Natural Gas	330
Takoradi International Company (TICO)	LCO/Natural Gas	220
SunonAsogli Power (Ghana) Limited	Natural Gas	200
Tema Thermal 1 Power Plant (TT1PP)	LCO/Natural Gas	110
Mines Reserve Plant (MRP)	Diesel	80
Tema Thermal 2 Power Plant (TT2PP)	Natural Gas	49.5
Sub - Total		*989.5*
Total		2,169.5

Most renewable sources of energy including hydroelectricity generation are capital intensive but have lower operational costs than thermal and nuclear options. This initial cost is a serious barrier to rapid growth in energy use in developing countries where most of the untapped economic potential is located (Kalitsi, 2003). With the ever increasing demand of electricity and the high cost of generating power from thermal plants, it would be prudent for government and private developers to invest in harnessing the power potentials of some of these mini-hydro sites to supplement the country's energy needs. A pre-feasibility assessment is the first step in developing a SHP project. This projects aims at accessing the technical and economic feasibility of developing the Fuller Falls for hydropower generation.

1.2 PROBLEM STATEMENT

There is an increasing need in many developing countries for power supplies to rural areas, partly to support industries, and partly to provide illumination at night. Government authorities are usually faced with the very high costs of extending electricity grids. Renewable energy sources such as small hydropower schemes often provide an economic alternative to the grid. This is because independent small hydropower schemes save on the cost of grid transmission lines, and because grid extension schemes often have very expensive equipment and staff costs. In contrast, small scale-hydropower schemes can be designed and built by local staff and smaller organizations following less strict regulations and using 'off-the-shelf' components or locally made machinery.

Ghana is said to have a total of 85 potential hydropower sites of up to 30 MW, with a total potential capacity of 110 MW. 69 sites (< 2MW) with a total potential of about 15.18 MW and 12 sites (<1 MW) with a total potential of 2.24 MW ***(UNIDO, 2013).*** Although a lot of resources have been invested in numerous studies on some of these potential small scale hydropower sites none has been developed.

1.3 JUSTIFICATION

Electricity is essential for the provision of basic social services, including education and health, and also for powering machines that support income generating activities which tends to reduce poverty. Harnessing hydropower to generate electricity has the potential for ensuring energy security which can be an effective way of reducing poverty in Africa (Ministerial Conference on water for Agriculture and Energy in Africa, 2008).

Large-scale dam hydropower projects are often criticized for their impacts on wildlife habitat, fish migration, and water flow and quality. However, small, run-of-the- river projects are free from many of the environmental problems associated with their large-scale relatives because they use the natural flow of the river, and thus produce relatively little change in the stream channel and flow. The dams built for some run-of-the-river projects are very small and impound little water and many projects do not require a dam at all. Thus, effects such as oxygen depletion, increased temperature, decreased flow, and rejection of upstream migration aids like fish ladders are not problems for many run-of-the-river projects (DoE-USA, 2001). Small-scale hydropower is one of the most cost-effective and reliable energy technologies to be considered for providing clean electricity generation.

1.4 OBJECTIVES

The main objective of this research work is to conduct a prefeasibility study for the development of Fuller Falls for hydropower generation.

1.4.1 Specific Objectives

1. To determine the available head, discharge and type of turbine.
2. To assess the best site development method.
3. To determine the potential installed capacity and annual energy to be generated.
4. To determine the estimated total cost of the project and the cost per installed capacity
5. To determine the return on investment of the project

CHAPTER TWO

LITERATURE REVIEW

2.1 ENERGY FORMS

Energy can be defined as the ability to do work. Energy cannot be destroyed nor created but transformed from one form to the other. Nearly all the activities of human life nowadays, are dependent on some form of energy or another (Wagner and Mathur, 2001). Different forms of energy exist in nature, potential energy, kinetic energy, thermal energy, electrical energy; chemical energy etc. kinetic energy is the energy possessed by virtue of its movement whist potential energy is the energy possessed by a body by the virtue of its position. When compared to thermal energy; mechanical and electrical energy, also known as 'high grade energy', are preferred, since they can be converted into all other forms of energy with no major losses. Electricity is the most preferred since it can be easily transported over large distances through transmission lines, which becomes difficult for mechanical power (Wagner and Mathur, 2001). Today, a majority of the world's energy requirements is met by energy sources which are burned and produced as heat or thermal energy

Solar, wind, geothermal, and tidal energy, synthetic fuels, and conservation are all currently active alternative energy programs (Christensen and Emerson, 1981). Solar energy is the mother of all these other forms of energy; wind, geothermal, and tidal energy. Winds can be defined as large-scale movements of air masses in the atmosphere. These movements of air are formed as a result on a global scale primarily by differential solar heating of the Earth's atmosphere. Therefore, wind power can be thought of as an indirect form of solar energy (Nkrumah, 2002). Geothermal energy is also another form of solar energy as a result of the storage of solar energy in the earth's crust. The same story could be told for tidal energy which also comes about as a result the radiations of the sun.

2.2 WATER CYCLE

The water cycle or the hydrological cycle can be described as the continuous movement of water on, above and below the surface of the Earth. The constant movement of water in its three states, solid, liquid, and gas, through the biosphere is known as the hydrology or water cycle (Micklin, 1996). The global water cycle is central to the Earth's climate system. It transcends conventional disciplinary boundaries and is a pervasive aspect of the physical, biological, and chemical processes and interactions of the coupled climate system (NRC, 2002). The various stages of the water are shown on figure 2.1. The hydrologic cycle begins with the evaporation of water from the surface of the ocean and other parts of the earth's surface. As moist air is lifted above the surface the earth and the oceans, it cools and water vapour condenses to form clouds. Moisture is then transported around the globe until it returns to the surface as precipitation.

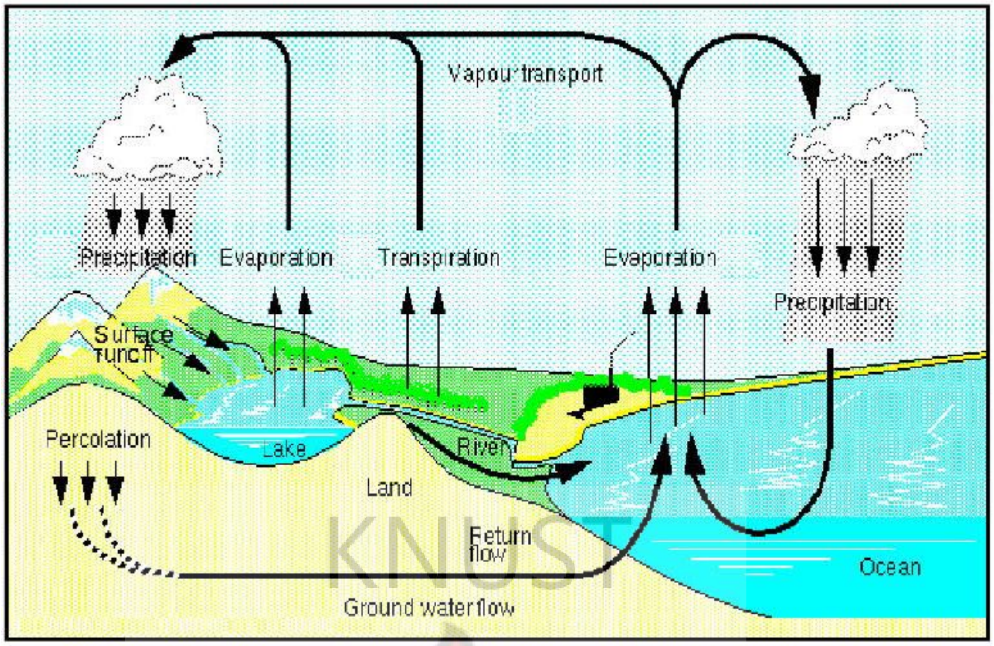

Figure 2.1 The stages of water cycle (Erich Rockner, Max Plank Institute of Meteorology)

Every year, the turnover of water on Earth involves 577,000 km^3 of water. This is water that evaporates from the ocean surface (502,800 km^3) and from land (74,200 km^3). The same amount of water falls as atmospheric precipitation, 458,000 km^3 on the ocean and 119,000 km^3 on land. The difference between precipitation and evaporation from the land surface 44,800 km^3/year) represents the total run-off of the Earth's rivers (42,700 km^3/year) and direct groundwater run-off (Shiklomanov, 1993).

2.3 HYDROPOWER

Hydropower is a renewable source of energy of which ecological benefits include very low average greenhouse gas (Truffer et al., 2001). Hydropower plants produce electricity without burning fossil fuels and producing air pollution and are sometimes thought of as environmentally benign (Harpman, 1999). Hydropower (from *hydro,* meaning water) is energy that is obtained from the force of moving water. Hydro power as the name suggests could be defined as energy derived from water bodies as a result from movement of water from one point to the other due to gravity. Hydropower production that began with waterwheels on small rivers has expanded to include the run-of-river type, conduit type, dam and conduit type, and dam type (JCLD, 2009). There are other forms of solar energy. Just as hydropower is a form of solar energy, so too is wind power. In effect, the sun causes the wind to blow by heating air masses that rise, cool, and sink to earth again. Solar energy in some form is always at work -- in rays of sunlight, in air currents, and in the water cycle (US-DoIBR, 2005)

Kumar et. 2011 reported that the total worldwide technical potential for hydropower generation is 14,576 TWh/yr (52.47 EJ/yr) with a corresponding installed capacity of 3,721 GW roughly four times the current installed capacity. The worldwide total installed hydropower capacity in 2009 was 926 GW, producing annual generation of 3,551 TWh/y (12.8 EJ/y), and representing a global average capacity factor of 44%. Of the total technical potential for hydropower, undeveloped capacity ranges from about 47% in Europe and North America to 92% in Africa, which indicates large opportunities for continued hydropower development worldwide, with the largest growth potential in Africa, Asia and Latin America. Additionally, possible renovation, modernization and upgrading of old power stations are often less costly than developing a new power plant, have relatively smaller environment and social impacts, and require less time for implementation. They also reported that significant potential also exists to rework existing infrastructure that currently lacks generating units (e.g., existing barrages, weirs, dams, canal fall structures, water supply schemes) by adding new hydropower facilities. Only 25% of the existing 45,000 large dams are used for hydropower, while the other 75% are used exclusively for other purposes (e.g., irrigation, flood control, navigation and urban water supply schemes). It was also cited that climate change is expected to increase overall average precipitation and runoff, but regional patterns will vary: the impacts on hydropower generation are likely to be small on a global basis, but significant regional changes in river flow volumes and timing may pose challenges for planning.

Power generated from water has been in existence since the beginning of civilization. Along with the burning of wood for light and heating, water power was used as the main source for generating mechanical driving power. The water streaming down from higher to lower levels consists of potential energy in itself because of its altitude which is converted into kinetic energy while flowing downhill. Jointly these energy forms contribute to what we call water power. It is a renewable source of energy because it is renewed continuously in a natural way. (Wagner and Mathur, 2001)

Of the total 20.3 GW of hydropower currently installed in Africa, about 23% is located in North Africa, 25% in West Africa and the remaining 51% located in South/Central/Eastern Africa (Kalitsi, 2003).

The Volta River Authority (VRA) is the main body which operates and manages the two hydroelectric power plants in Ghana. The plants at Akosombo and Kpong were commissioned in 1965 and 1982, respectively and they provide the majority of Ghana's electricity. The two stations account for 1,180 megawatts (MW) of the total national power-generating capacity of with Akosombo providing 1020MW while Kpong provides 160MW. The plants are located on the Volta River with Akosombo at the upstream of Kpong.

2.3.1 Classification of Hydropower Plants

Hydropower plants can be classified in many ways but only two will be discussed here. These are (1) Based on the total head of water available at the hydroelectric power plants and (2) the capacity of the installed plants.

2.3.1.1 Head Based Classification

According to Khemani, (2009), "hydropower plants grouped according to the head can be classified in three ways; low head hydroelectric power plants, medium head hydroelectric power plants, and high head hydroelectric power plants".

Table 2.1 Classification of hydropower plants based on head

Classification	Range
Low Head	Less than 30m
Medium Head	Greater than 30m but less than 300m
High Head	300m and above

Low head hydroelectric power plants

According to Khemani, 2009, the "low head hydroelectric power plants are plants in which the available water head is less than 30 meters. This dam type of power plants is of very small head and may be even of few meters only. In certain cases a weir is used and in other cases there is no dam at all and water flowing in the river is used for generation of electricity. The low head types of hydroelectric power plants cannot store water and electricity is produced only when sufficient flow of water is available in the river. They only produce electricity during particular seasons when abundant flow of water is available. Since the head of water is very small in these hydroelectric power plants, they have lesser power producing capacity."

Medium head hydroelectric power plants

Medium head hydroelectric power plants are hydroelectric power plants in which the working head of water is more than 30 meters but less than 300 meters. These hydroelectric power plant are usually located in the mountainous regions where the rivers flows at high heights, thus obtaining the high head of the water in dam becomes possible. In medium head hydroelectric plants dams are constructed behind which there can be large reservoir of water for power generation. Water from the reservoir can be taken to the power generation system where electricity is generated (Khemani, 2009).

Large, high-head dams can produce more power at lower costs than low-head dams, but construction of large dams may be limited by lack of suitable sites, by environmental considerations, or by economic conditions (US-DoIBR, 2005).

Most of the technologies for high and medium head sites are fairly mature, but low head sites could benefit from innovation and optimization to develop technology that is suitable for the remaining low head resource (Campbell, 2010).

High head hydroelectric power plants

In the high head hydroelectric power plants the head of water available for electricity production is more than 300 meters. These are the most commonly constructed hydroelectric power plants. In the high head hydroelectric power plants huge dams are constructed across the rivers. There is large reservoir of water in the dams that can store water at very high heads. Water is mainly stored during the rainy seasons and it can be used throughout the year. Thus the high head hydroelectric power plants can generate electricity throughout the year. The high head hydroelectric power plants are very important in the national grid because they can be adjusted easily to produce the power as per the required loads (Khemani, 2009).

2.3.1.2 Capacity Based Classification

Hydropower plants can also be classified on the basis of their total power output. In 1993, an assessment of studies performed by recognized institutions such as the United Nations and the World Energy Council, as well as statistical material provided by pertinent hydropower magazine s, indicated a worldwide hydroelectric potential of about 2,360 GW (Kaygusuz, 1999). Based on installed capacity of hydropower projects, classification of hydropower varies differently in various countries. A general classification may be taken as:

Table 2.2 Classification of hydropower plants based on Capacity (Saxena and Kumar, 2010)

Hydro Classification	Capacity
Pico	5Kw and below
Micro	< 5Kw but > 100kW
Mini	<100kw but > 2000kW
Small	<2000kw but > 2500kW
Medium	<2500kw but > 100,000kW
Large	>100,000kW

2.3.2 Types of Hydropower Schemes

There are three main types of hydroelectric schemes, these are:

- Run of the River
- Dam Based (Storage Scheme)
- Pumped Storage

2.3.2.1 Run of the River

A run-of-the-river scheme does not stop the river flow, but instead diverts part of the flow into a channel and pipe and then through a turbine. Micro-hydro schemes are almost always run-of-the-river. The disadvantage of this approach is that water is not carried over from rainy to dry seasons of the year. The advantage is that the scheme can be built locally at low cost, and its simplicity gives rise to better long term reliability. Run-of-the-river schemes are preferable from the point of view of environmental damage since seasonal river flow patterns downstream of the installation are not affected and there is no need for flooding of the valleys upstream of the installation.

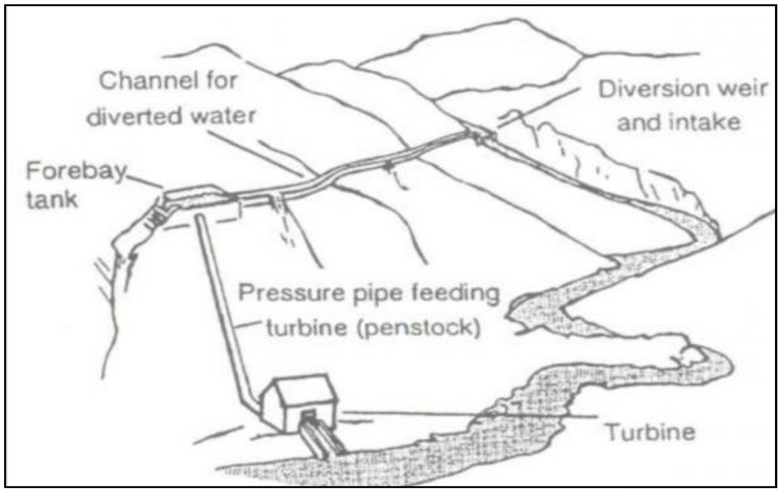

Figure 2.1 Run of the River hydropower scheme

2.3.2.2 Dam Based (Storage Scheme)

A storage scheme makes use of a dam to stop river flow, building up a reservoir of water behind the dam to store water and to provide sufficient head for the turbine. The water is then released through turbines when power is needed. The advantage of this approach is that rainfall can accumulate during the wet season of the year and then release power during some or all of the drier periods of the year. Storage schemes with dams have the disadvantage of being more complex and expensive.

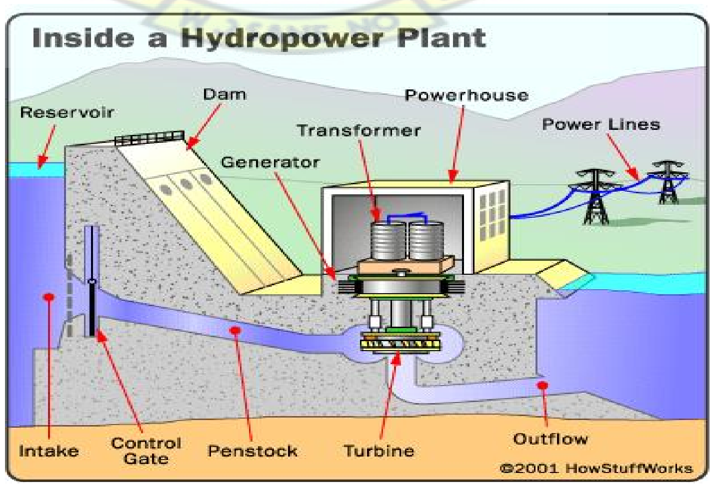

Figure 2.2 Dam Based hydropower scheme (ESD Bulgaria, 2005)

2.3.2.3 Pumped Storage

Pumped storage is a scheme that incorporates two reservoirs. It utilises a reversible pumping turbine to store hydro energy during off-peak electricity hours by pumping water from a lower reservoir to an upper reservoir, at times of low demand, generally when electricity is cheap like at night, electricity is bought to pump water from the lower to the upper basin. This stored energy is then used to generate electricity during peak hours, when demand is high and prices high. This means that the company make money on their investment of electricity for pumping. This enables the scheme to perform with greater efficiency when matching supply and demand. This type of scheme is also similar to pumping for tidal barrages to increase supply and income.

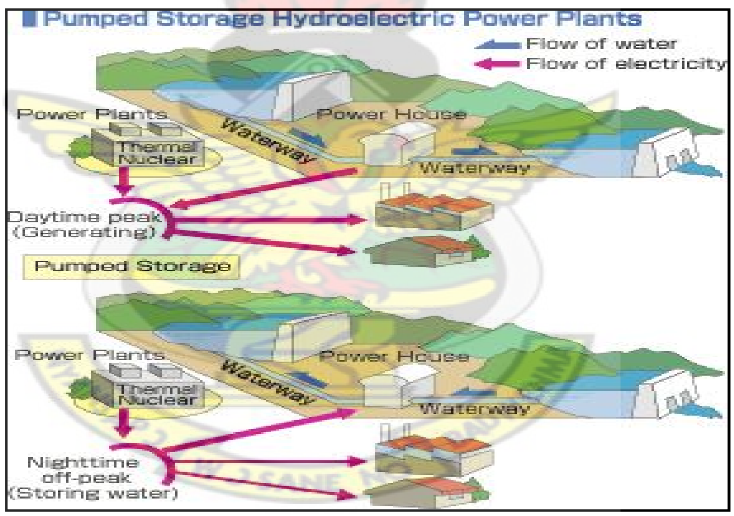

Figure 2.3 Pumped Storage Hydropower Scheme (Tokyo Electric Power Company, 2013)

2.4 SMALL HYDROPOWER (SHP) DEVELOPEMNT

Small-scale hydropower is one of the most cost-effective and reliable energy technologies to be considered for providing clean electricity generation. It is also environmentally benign. Small hydro is in most cases "run-of-river"; in other words any dam or barrage is quite small, usually just a weir, and little or no water is stored. Therefore run-of-river installations do not have the same kinds of adverse effect on the local environment as large-scale hydro. (BHA, 2005)

Small hydropower plays a dominant role in rural renewable energy markets. SHP plays a great role in remote off-grid communities with typical applications in areas such as rural residential community lighting, TV, radio and telephony, rural small industry (agriculture and other uses) as well as grid based power generation. SHP can serve two main purposes: social and commercial. The social SHP supplies electricity in standalone mode characterised by small capacity and poor load factor. Often used in distribution and normally government supported. Overheads and maintenance costs are recovered through user charges collection. Commercial SHP on the other hand have larger capacities, sells power to power distribution or trading companies, are grid connected and have higher load factor.

2.4.1 Advantages of Small Hydropower

A paper published by British Hydropower Association, in 2005 gives the following as advantages of small hydropower plants;

- A high efficiency (70 - 90%), by far the best of all energy technologies.
- A high capacity factor (typically >50%), compared with 10% for solar and 30% for wind

- A high level of predictability, varying with annual rainfall patterns
- Slow rate of change; the output power varies only gradually from day to day (not from minute to minute).
- A good correlation with demand i.e. output is maximum in winter
- It is a long-lasting and robust technology; systems can readily be engineered to last for 50 years or more

2.4.2 Barriers to SHP Development

The key barriers hindering the development of SHP in Africa as summarised by the Ministerial Conference on water for Agriculture and Energy in Africa in 2008 are as follows:

- Lack of infrastructure in the design, manufacturing of turbines, installation and operation.
- Lack of access to appropriate technologies
- Lack of local capacity (local skills and know how) in developing SHP projects. There is the need for technical assistance in the planning, development and implementation.
- Lack of information about potential sites (hydrological data).
- Lack of SHP awareness, incentives and motivation.
- Lack of private sector participation in SHP development.
- Lack of joint venture (public and private sector partnership).

2.4.3 Components of SHP Scheme

Main Elements of a Small Hydro Power Scheme as illustrated in Figure 2.5 are as follows:

- Intake
- Forebay /Settling Tank
- Canal or Leat
- Spillway
- Penstock
- Powerhouse
- Tailrace

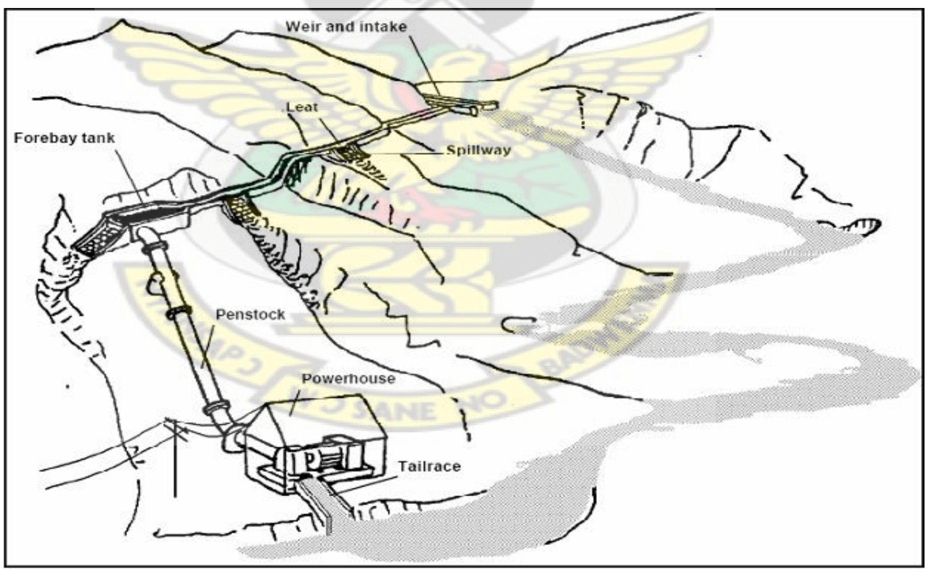

Figure 2.4 Main components of SHP Scheme (BHA, 2005)

Water is taken from the river by diverting it through an intake at a weir. In medium or high-head installations water may first be carried horizontally to the forebay tank by a small canal or 'leat'. Before descending to the turbine, the water passes through a settling tank or 'forebay' in which the water is slowed down sufficiently for suspended particles to settle out. Forebay is usually protected by a rack of metal bars (a trash rack) which filters out waterborne debris. A pressure pipe, or ‘penstock’, conveys the water from the forebay to the turbine, which is enclosed in the powerhouse together with the generator and control equipment. After leaving the turbine, the water discharges down a ‘tailrace’ canal back into the river. (BHA, 2005).

2.5 ELECTRICITY PRODUCTION IN GHANA.

Ghana is a water-rich country. Construction of dams for hydropower, water supply and irrigation is a reality (GDDN, 2009). One of the major challenges facing Ghana in her developmental efforts is the generation of adequate and affordable electricity to meet increasing demand. With a customer base of approximately 1.4 million, it has been estimated that 45-47% of Ghanaians, including 15-17% of the rural population, have access to grid electricity with a per capita electricity consumption of 358Kwh (RCECR, 2005). The total electricity generated in 2011 was 11,200 GWh; as against that of 10,167 GWh (10,232 GWh) in 2010. The 2011 generation comprised 7,561 GWh (67.5 %) hydropower and 3,134 GWh (32.5%) of thermal power. Even though, hydropower generation share decreased by about 0.8 percentage points over 2010, energy produced increased by about 566 GWh due to significant water inflows into the Akosombo reservoir in 2011. Net power exported decreased by about 64% over 2010. Total power transmission losses in 2011 was 4.9% net of gross electricity transmitted (Ghana Energy Commission, 2012).

2.6 SMALL HYDROPOWER DEVELOPMENT IN GHANA

Studies and research initiatives, aimed at harnessing the power generation potential of small rivers in Ghana to supplement the large Akosombo and Kpong power plants have been undertaken in Ghana for over two decades. At the peak of such studies, mini hydro power plants were regarded not only as supplementary sources of power but also as alternatives for grid extension to rural areas which were far from the national grid. (Dernedde and Ofori-Ahenkorah, 2002) A total of about 85 potential sites have been estimated for small-scale hydropower in Ghana, with an overall hydropower potential of 110MW (UNIDO, 2012).

Although a lot of effort and resources have been expended on numerous such studies, not a single mini-hydro plant has been developed in the country, although Ghana has gone through several years of uncertainties in power generation and has now resorted to thermal power generation as a supplement to the traditional hydropower sources (Dernedde and Ofori-Ahenkorah, 2002). Some of the potential small hydropower sites are indicated in table 2.3.

Table 2.3 Potential mini-hydropower sites in Ghana (Dernedde and Ofori-Ahenkorah, 2002)

No.	Region	Location	River	Possible Installed capacity (kW)	Energy Generation
1	Volta	Wli Falls Afegame	Nuboi	1000 kW	3,500,000 kWh
2		Alavanyo-Abehensi Tsatsadu Falls	Tsatsuda	320kW	1,200,000kWh
3		Likpe Kukurantumi	Dayi	100-150kW	400,000-500,000kWh
4		Dzolo	Dayi	no information	
5		New Ayoma	Dayi	no information	
6		Menusu	Menu	500 kW (AESC)	4,380,000 kWh
7		Ahamansu	Wawa	125 kW (ACRES)	403,000 kWh
8		Dodi Papase	Wawa	500 kW (AESC)	4,380,000 kWh
9		Asuboe	Wawa	100 kW (ACRES)	322,000 kWh
10		Dodo Tamale	Asuakawkaw	unknown	
11		Dodo Amanfron	Jelem	unknown	
12	Brong Ahafo	Nkoranza	Fia	60 kW	525,000 kWh
13		KokumaFalls	Edam	75kW	375,000 kWh
14		Fuller Falls	Oyoko	380kW	1,900,000kWh
15		Randall Falls, "Kintampo Falls", Kintampo	Pumpum	160kW	810,000kWh
16	Ashanti	Boumfum Falls Kumawu	Ongwam	225 kW	1,970,000 kWh
17		Barekese water works		400kW	n/a
18		Maabang	Kwasu	200 kW	1,75,000 kWh
19	Western Region	Sanwu Falls, Sefwi Boinzah	Sanwu	60 kW	525,000 kWh
20		Nworannae Falls, Asampanaye	Nworannae	40 kW	350,000 kWh
21		Sefwi Asanwinso	Benchema	45 kW	394,000 kWh
22	Eastern	Wurudu Falls Moseaaso	Wurudu	25kW	219,000kWh
23	Central	Kwanyaku water works	-	130kW	-

2.7 TECHNICAL PARAMETERS FOR HYDROPOWER

2.7.1 Head and Flow

The power generation potential of a stream is dictated by two main factors: the hydraulic head (H) and the flow or discharge (Q). Head is how far the water drops. It is the height difference between the inlet to the hydro turbine and its outlet (Fig 2.5).

Hydraulic power can be captured wherever a flow of water falls from a higher level to a lower level. This usually occurs where a river runs down a hillside, or passes over a waterfall or man-made weir, or where a reservoir discharges water back into the main river.

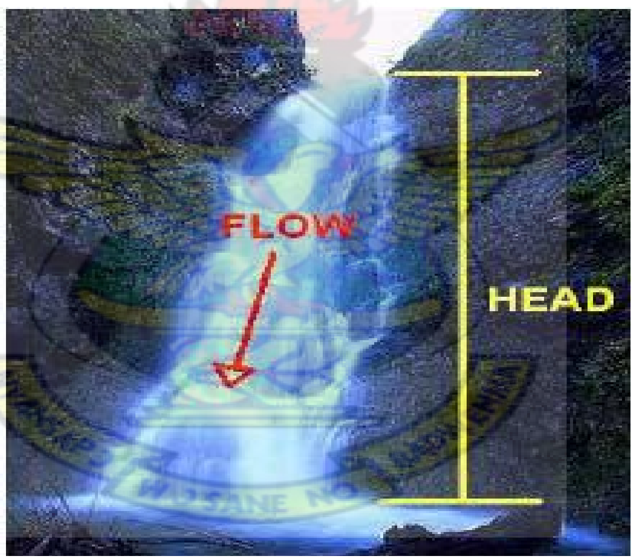

Figure 2.5 Head and Flow Illustrated (BHA, 2005)

The head H is very essential for hydropower generation; fast-flowing water on its own does not contain sufficient energy for useful power production except on a very large scale, such as offshore marine currents. Hence two quantities are required: a Flow Rate of water Q, and a Head H. It is generally better to have more head than more flow, since this keeps the equipment smaller. (BHA, 2005)

Flow/ Discharge Q, is how much water moves through the system—the more water that flows through a system, the higher the discharge. To estimate the power generation of a hydroelectric power plant, the hydraulic head and flow of the stream need to be measured.

2.8.2 Power and Energy

Energy is the ability to do work and its measures in Joules (J). Energy is usually divided by time to get power. Power is measured in Watts of Joules per second i.e. W or J/s.

In a hydropower plant, the potential energy is converted into kinetic energy. The head of the water is very critical in the calculation of the potential energy which is then converted into the kinetic energy for the turbines to rotate with to produce energy.

- $Potential\ Energy(Ep) = m \times g \times h$ .... (1)
- $Kinetic\ Energy(Ek) = \frac{1}{2}mv^2$ ....(2)

Where *m*= the mass of the water in kg,

g= acceleration due to gravity in m/s^2,

h=the effective pressure head of water across the turbine (m).

v= the velocity of water at the intake of the turbine blade (m/s).

$Where, velocity\ v\ = c\sqrt{2gH}$ … … … … … … … … … … … … … … … … (3)

The mechanical energy delivered by the turbine is mainly due to the height difference of the hydro system. Hydro-turbines convert water force into mechanical shaft power, which can be used to drive an electricity generator, or other machinery. The power available is proportional to the product of the *head* and *flow rate*.

The general formula for a hydropower system power output is stated as;

$P = \eta \times \rho \times g \times Q \times H$ .... (4)

Where,

P =is the mechanical power produced at the turbine shaft (Watts),

η= is the hydraulic efficiency of the turbine,

ρ = the density of water (1000 kg/m^3)

g= is the acceleration due to gravity (9.81 m/s^2),

Q =is the volume flow rate passing through the turbine (m^3/s),

H =is the effective pressure head of water across the turbine (m).

2.9 HYDRAULIC TURBINES; TYPES AND OPERATIONAL ASPECTS

Hydraulic Turbines are machines which transfer energy from a flowing fluid to a rotating shaft and turbine means an object which rotates or spins (Naveenagrawal, 2009). Hydraulic turbines mostly extract energy from water which has a high head. Hydraulic turbines extract energy from the gravitational potential of water sources or from the kinetic energy of flowing water or from a combination of the two (Finermore et al., 2002). The specific type of turbine to be used in a power plant is not selected until all operational studies and cost estimates are complete. The turbine selected depends largely on the site conditions (US-DoIBR, 2005).

2.9.1 Classification of Turbines

Turbines can be classified based on the head of water under which they operate i.e. High Head, Medium Head and Low head turbines, and based on the principle of operation i.e. Impulse or reaction turbines. Reaction turbines are further classified as radial and mixed-flow (Francis) turbines or as axial-flow or propeller turbines Table 2.4.

Table 2.4 Classification of Hydropower Turbines (BHA (January 2005))

Turbine Type	**Head Classification**		
	High head (>50m)	**Medium head (10-50m)**	**Low head (<10m)**
Impulse turbines	Pelton Turgo Multi-jet Pelton	Cross-flow Turgo Multi-jet Pelton	Cross-flow
Reaction turbines		Francis (spiral case)	Francis (open-flume) Propeller Kaplan

2.9.1.1 Reaction Turbines

According to the US-DoIBRA, 2005, "reaction turbine is a horizontal or vertical wheel which operates with the wheel completely submerged a feature which reduces turbulence. In theory, the reaction turbine works like a rotating lawn sprinkler whereby water at a central point is under pressure and escapes from the ends of the blades, causing rotation. Reaction turbines are the type most widely used. Reaction turbines include Francis, Propeller and Kaplan Turbines.

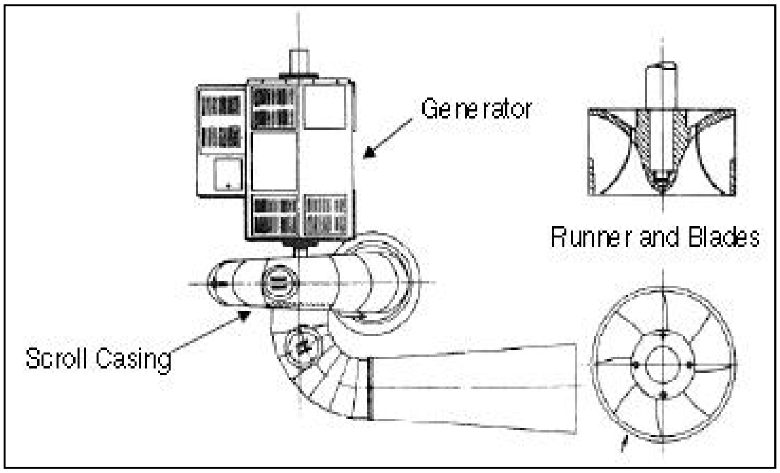

Figure 2.6 Francis Turbine (Holland 1983)

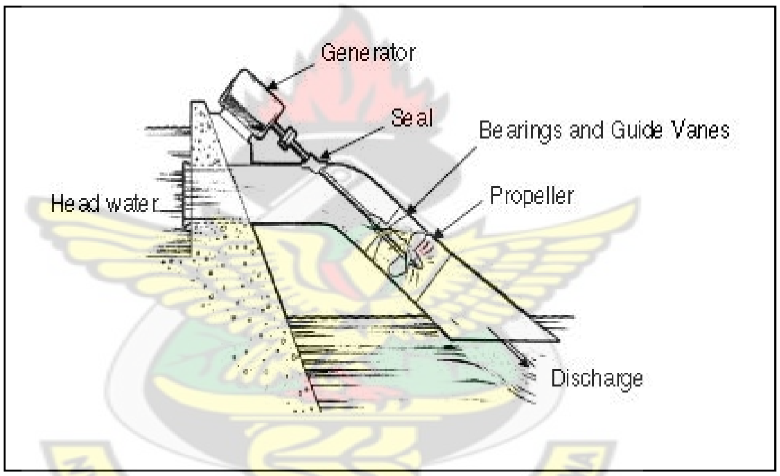

Figure 2.7 Propeller Turbine (Mckinney, 1986)

2.9.1.2 Impulse Turbines

An impulse turbine is a horizontal or vertical wheel that uses the kinetic energy of water striking its buckets or blades to cause rotation. The wheel is covered by a housing and the buckets or blades are shaped so they turn the flow of water about 170 degrees inside the housing. After turning the blades or buckets, the water falls to the bottom of the wheel housing and flows out". Impulse turbines usually operate under relatively high heads and low flow rates. One or more nozzles convert available energy into kinetic energy, most of which is transferred to buckets attached to a rotating wheel (runner). The resulting shaft torque drives a generator or other machinery. Windage, fluid friction, turbulence, separation and leakage cause the principal losses (Finermore et al., 2002). Examples of impulse turbines are the Pelton, Turgo and the Cross flow turbines.

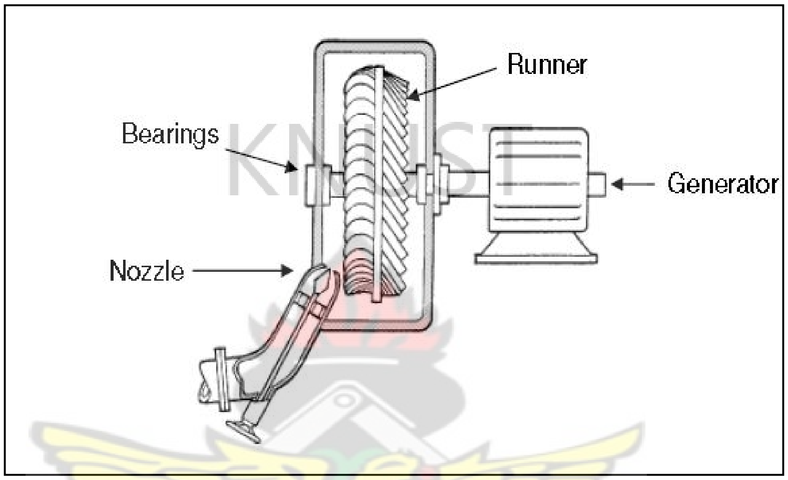

Figure 2.8 Turgo Turbine (BHA, 2005)

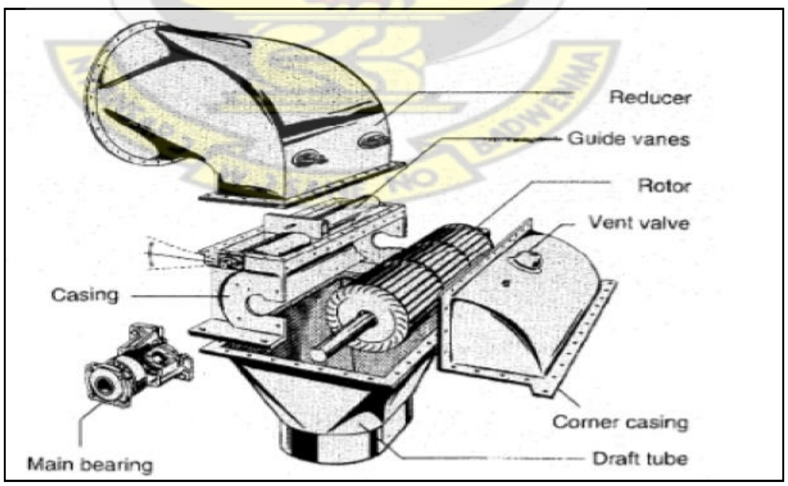

Figure 2.9 Arrangement of a Crossflow Turbine (© Ossberger)

2.9.2 Turbine Selection

The role of all turbines is to convert the energy stored in the falling water into the rotating shaft power. This is one of the most efficient ways of getting energy from water. The selection of a turbine for a particular hydro site is a great challenge as it directly affects the total power that can be generated from the scheme. Turbine selection is commonly based on the available head and flow rate. In general, impulse turbines are used for high head sites, and reaction turbines are used for low head sites.

The selection of turbines depends upon following factors

- Site characteristics
- Head of the hydro scheme
- Flow rate available in the scheme
- Desired runner speed of the generator
- The probability of operating the turbine at reduced flow rates

The Turbine Application Chart presented in Figure 2.10 illustrates the applicability of specific turbine types depending on head and flow.

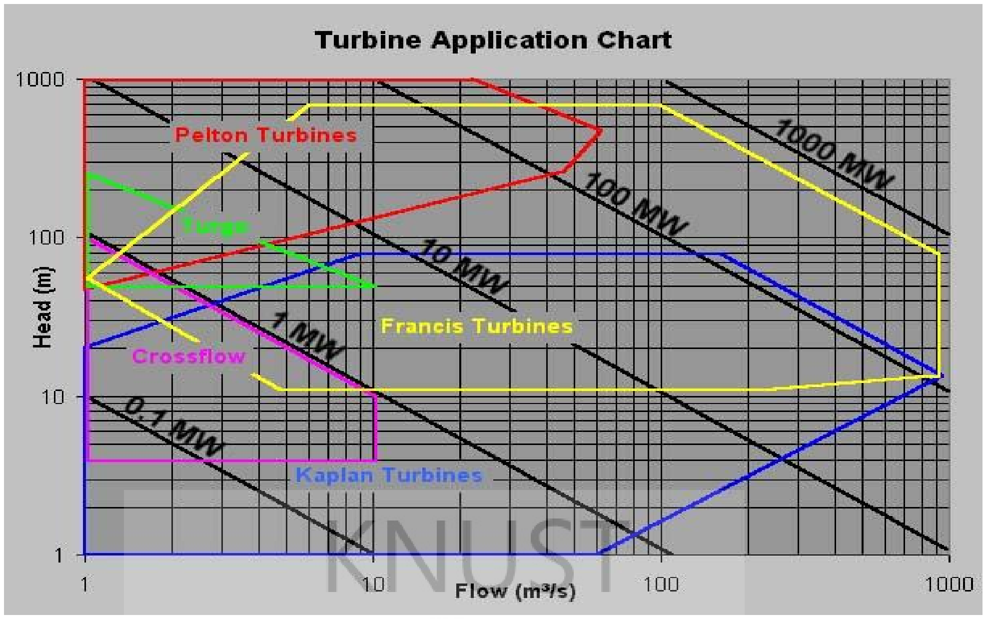

Figure 2.10 The Turbine Application Chart ((c) Wikipedia)

2.10 COMPUTER SOFTWARE FOR SMALL HYDROPOWER DEVELOPMENT

Development of a small hydropower scheme is a challenging process which requires great amount of time and money in addition to expertise in various disciplines. The first stages of the development require quick estimations of the energy output of the project. Several computer software programs such as RETScreen, HES, Hydra are developed to make initial economic analysis for a new SHP project. Utilization of such software shortens the time and money spent for conducting the initial economical assessments for the projects (Aydin, 2010).

CHAPTER THREE

MATERIALS AND METHODS

This chapter seeks to undertake a preliminary assessment into the technical and financial viability of developing the Fuller Falls for small hydropower generation. In order to achieve this, the under listed methodology was employed. The study was conducted in five stages namely;

- Desk study and Review of available literature
- Information from stakeholders through interview
- Field work/Data collection
- Technical assessment of collected data
- Financial analysis of the proposed project

3.1 DESK STUDY AND REVIEW OF AVAILABLE LITERATURE

The first stage was through desk study and literature review. Initial site visit and site assessments were made to obtain first hand information regarding the site topography, geology, available structures and land use. Available literature was also reviewed to obtain information and relevant data pertaining to the site understudy, the under listed materials amongst others were used;

- Topographical map of Ghana (1/50,000) from the Geological Survey Department of Ghana and was used to estimate the total catchment/drainage area of the project site.
- Temperature and rainfall data from the Meteorological Services of Ghana

- Geological map of Ghana from the Ghana Geological Service Department
- Information from studies that have been conducted on the proposed site.

3.2 INFORMATION FROM STAKEHOLDERS THROUGH INTERVIEW

The caretaker of the site was interviewed to gather information concerning;

- History of the Falls
- Land ownership
- Land use

3.3 FIELD WORK /DATA COLLECTION

The field work forms a core of this project. Some measurements and field surveys were made on the project site to determine the under listed parameters

- The available head H (m)
- Discharge available Q (m3/s)

The available head and discharge are very essential parameters in any hydropower assessment. The US-BOIRB, 2005 reported that "Before a hydroelectric power site is developed, engineers compute how much power can be produced when the facility is complete. The actual output of energy at a hydropower plant is determined by the volume of water released (discharge) and the vertical distance the water falls (head)".

3.3.1 Head Measurement

There are a number of methods for head measurement. Some methods are more suitable on low head sites, but are inaccurate on high heads; some are only suitable on high head sites. It is recommended that the most accurate method be chosen given the equipment available. Some of the methods used for head measurements are:

• Water-filled tube (with rods or person)

• Water-filled tube and pressure gauge

• Spirit level and plank (or string)

• Altimeter

• Sighting meters

• Sighting with spirit level

• Builder's levels

• Map

For the purpose of this study the services of a professional surveyor was employed, and with the use of a Total Station instrument and a Staff, the available head was accurately measured.

3.3.2 Flow or Discharge Measurement

A flow measurement is a single record and is therefore of less use. However, it acts as a check that the hydrological analysis is not misleading as a result of mistakes or changes to the catchment or abstraction from the river. Because of the limited time available for the submission of this thesis only one flow measurement for a single day in July 2013 was taken. The result obtained was used only for the purposes of control of the results obtained from the hydrograph which was developed from the hydrological analysis.

The Following are some of the flow measuring techniques that are normally used for site flow measurement:

- The salt gulp method
- The bucket method
- The float method
- Propeller devices
- Stage/control methods, including weir methods.

It is necessary to study the distinctive features of each of these methods in order to find a suitable method for any particular site. For the purposes of this study the float method was adopted.

The Float Method

The float method is the easiest way to measure the flow of a stream because it requires the least equipment and less time hence it was considered for this experiment. The average cross sectional area of the stream will be multiplied by the average velocity of the stream to calculate the flow. This is represented by the equation

$Q = A \times v$ .... (3.1)

Where; Q =the flow of the stream in m^3/s,

A =the cross-sectional area of the stream in m^2, and

v =is the average velocity of the stream in m/s.

Tools and materials needed

1. Steel tape
2. Measuring rod
3. Light object
4. Clothed tape
5. Poles
6. Stop watch

Measuring procedure

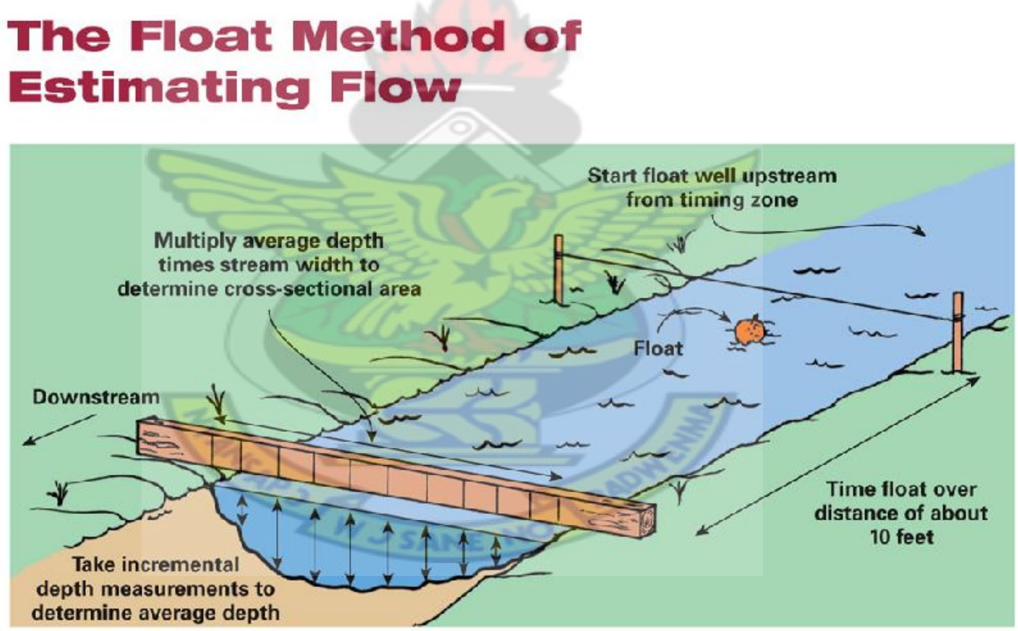

Figure 3.1 Float method of estimation stream flow (Home Power Inc, 2013)

1. Measurement was made at the place where the axis of streambed is straight and the cross section of the river is almost uniform.
2. Transverse lines were set at the upstream and downstream perpendicular to the axis of streambed at least 3m apart

3. String a rope across each end of the 3m length.
4. Depths of the river at 0.5m interval were taken at the two end
5. By using the trapezoidal area method, the cross-sectional areas of the stream at both ends were estimated. And the average area found as indicated below;

   $A_n = \frac{1}{2} \times (h_1 + h_2) \times 0.5\ (m^2\ )$............................ *(3.2)*

   $A_{average} = \frac{1}{2}(A_1 + A_2\ )\ (\ m^2\ )$...............................*(3.3)*

6. Release the float at the upstream site. Using a stopwatch, record the time it takes to reach the downstream tape. Repeat the measurement two more times for a total of three measurements.
7. Calculate the velocity as distance travelled divided by the average amount of time it took the float to travel the distance.

   Distance Travelled (m) / Average Time (s) =Average Velocity (m/s)

8. Correct for the surface versus mid-depth velocity by multiplying the surface velocity by 0.85.

   Stream Velocity V = 0.85 x Average Velocity ....(3.4)

9. Calculate the discharge in cubic meters per second (m3/s) by multiplying velocity (m/s) by the average cross-sectional area (m2) of the stream.

   Stream Discharge Q = Stream Velocity V x Average Cross sectional Area A

   Q= V x A....................................... (3.5)

3.4 TECHNICAL ASSESSMENT OF COLLECTED DATA

Technical assessment of the data collected was undertaken in order to establish:

1. Possible Scheme type i.e. Dam based, canal bases or run-off-river

2. The minimum discharge available for power generation
3. Possible installed capacity
4. Annual Energy Output
5. Turbine Option

3.4.1 Possible Scheme type

The site specific geology and topography of the project site was assessed in order to choose the best site development scheme.

3.4.2 The discharge available for power generation

In order to obtain the discharge variation throughout the year, hydrological analysis of the site was undertaken. The purpose of the hydrology study was to predict flow, as it varies throughout the year. The results of the hydrology study will always be the proper record of flow at the site. The hydrology study should be based on many years of daily records. However there is no gauged station anywhere in the vicinity of the site, therefore for the purposes of this study, a 16 year rainfall and temperature data (1992 to 2007) for the area was obtained from the Meteorological Service Department of Ghana. The water balance method was then used to estimate the mean monthly discharges and the corresponding hydrographs and flow duration curves were deduced.

3.4.2.1 Water Balance Method

Water Balance of the Drainage Area

This type of hydrological assessment makes use of rainfall and temperature data within a specific catchment area in the determination of discharges. Annual Precipitation or rainfall (P) is equal to annual runoff plus annual evaporation; the equations and tables used for this analysis were obtained from the DoE (2009), Philippines, Manuals and Guidelines for Micro-hydropower Development in Rural Electrification, Vol. 1.

$P = R + Et$ …………………………… (3.6)

$P = Rd + Rb + Et$ …………………… (3.7)

where,

P : Annual rainfall (mm)

R : Annual runoff (mm)

Rd : Annual direct runoff (mm)

Rb : Annual base runoff (mm)

Et : Annual evaporation (mm)

The relation of rainfall, runoff (direct runoff, base runoff), and evaporation is indicated by the viewpoint of annual water balance as shown in equation 3.6 and 3.7. In this case, pooling of drainage area, inflow and runoff from/to other drainage area are not necessary.

Runoff (R) is obtained from calculated evaporation (Et) by the presumption formula and observed rainfall (P).

The runoff is provided from sub-surface water, and it contained base runoff with less seasonal fluctuation and direct runoff wherein the rainfall immediately becomes the runoff. The ratio of subsoil water (Rg) to annual runoff (R) is shown in Table 3-

1. For Africa Rg / R = 0.35 is a constant. This means the sub-surface water (Rb) or the subsoil water (Rg) is 35% of the annual runoff.

Table 3.1 World water balance model (Lvovich 1973)

Area	Asia	Africa	North America	South America	Europe	Australia	Japan
Rainfall (P)	726	686	670	1648	734	736	1788
Runoff (R)	293	139	287	583	319	226	1197
Direct runoff (Rd)	217	91	203	373	210	172	-
Subsoil water	76	48	84	210	109	54	-
Evaporation (Et)	433	547	383	1065	415	510	597
Rg / R (%)	26	35	32	36	34	24	-

Calculation of possible evaporation

Three formulas namely, Blaney-Criddle formula, Penman formula, and Thornthwaite formula, can be used in the determination of possible evaporation, For the purpose of this study, the Blaney-Criddle formula was adopted. This is because the formula adopts the use of the latitude and temperature of the selected site.

Blaney-Criddle formula;

$U = K.P.((45.7t + 813))/100$ .... (3.8)

where,

u = Monthly evaporation (mm)

K = Monthly coefficient of vegetation; K value is a constant which depends on the vegetation condition, a constant value of 0.6 will be adopted for this study.

P =Monthly rate of annual sunshine (%); this is obtained by the latitude at the drainage area of selected site as indicated in Table A.1 in Appendix A,

t = Monthly average temperature (°C); using temperature records at the drainage area of the selected site

The Monthly Real Evaporation and Monthly Mean Discharges were derived by inputting the various parameters indicated in Table 3.1.

Table 3.1 Sample Evaporation and Monthly mean discharge calculations table

Calculation of possible evaporation and real evaporation						**Derivation of monthly mean discharge**				
	(1)	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**	**(8)**	**(9)**	**(10)**
Month	Tempt, t (□)	Monthly Rate of Annual Sunshine, p (%)	Possible Evapo-ration (mm)	Rainfall (mm)	Real Evapo-ration (mm)	Runoff (mm)	Direct runoff (mm)	Base runoff (mm)	Monthly runoff (mm)	Monthly mean discharge (m3/s)
Jan.										
Feb.										
Mar.										
Nov.										
Dec.										
Total										

- **(1) Monthly average temperature (t □);** observed data of the site was obtained from meteorological services department
- **(2) Monthly rate of annual sunshine (P %)** obtained from table A-1 and A-2 in Appendix A, knowing the latitude of the drainage area, since the site is

located in the northern hemisphere (latitude 8° 4' 60" North and longitude 1° 46' 60" West) table A-1 was used.

- **(3) Possible evaporation** was calculated from the Blaney-Criddle formula as indicated above
- **(4) Rainfall;** using rainfall records at the drainage area of the selected site of the site, data will be obtained from meteorological services department
- **(5) Real Evaporation;** is equal to the smallest of (3) possible evaporation and (4) Rainfall
- **(6) Runoff** is equal to **(4)-(5)** i.e. Rainfall – Real evaporation
- **(7) Direct runoff =** 0.65x(6) Runoff, from table 3-1, direct runoff for Africa is 65% of Runoff
- **(8) Base runoff** = (0.35x Total of runoff /365)x no. day in the month
- **(9) Monthly runoff** = (7) + (8) , (direct runoff + base runoff)
- **(10) Monthly mean discharge** is derived using the formula stated below

$$Q_i = \frac{\text{Monthly Runoff}\left((9)\text{of table } 3-1\right)}{1000} \times CA \times 10^6 \times \frac{1}{86{,}400 \times n} \quad \text{.........................} \ (3.9)$$

Where,

Q_i: Monthly mean discharge at the selected site in 'i (month)' (m^3/s)

CA: Drainage area (km2), which will be derived from 1:50,000 topographical maps obtained from the Geological Survey Department.

n: Number of days in the month

3.4.3 Possible installed capacity

The maximum power output (capacity), P_{max} of a hydropower plant can be determined according to the equation below;

$P_{max} = Q \times H \times g \times \rho \times \eta_{total}$ (kW) .... (3.10)

Where

Q = the discharge m3/s

H= Head m (difference in height between the inlet and outlet surfaces)

g = acceleration due to gravity (m2/s)

ρ = density of water (kg/m3)

η_{total} = efficiency of hydroelectric plant (%) = $\eta_{Tur} \times \eta_{GU} \times \eta_{Gen}$

η_{Tur} = turbine efficiency

η_{GU} = gear unit efficiency

η_{Gen} = generator efficiency

3.4.4 Determination of annual energy output

The annual energy output of the proposed minihydro power plant can be estimated by multiplying the power output of the turbine by the total number of hours the plant will work i.e. 8760 hours. The equation then becomes

$E_{annual} = KW \times 8760$.. (3.11)

The power factor or capacity factor of the generator has to be considered in the annual power out of the hydropower plant. Hence if the power factor (pf) is considered in the design, the real annual power output of the turbine becomes

$$E_{annual} = KW \times 8760 \times pf \text{ .... } (3.12)$$

Where, pf is the power output of the proposed generator.

3.4.5 Turbine Selection

For the purposes of this study an initial indication of appropriate turbine technology suitable for the proposed site will be given.

Turbine selection is commonly based on the available head and flow rate. In general, impulse Turbines are used for high head sites and reaction turbines are used for low head sites. The Turbine Application Chart shown in Figure 2-11, Chapter 2, illustrates the applicability of specific turbine types depending on head and flow. The type of turbine will therefore be selected after the design flow and head have been determined.

3.5 FINANCIAL ANALYSIS OF THE PROPOSED PROJECT

The final stage of the study will be to undertake financial analysis which involves the estimated total cost and the Internal Rate of Return (IRR) of the project. The RET-Screen would be used to undertake the financial analyses of this study.

CHAPTER FOUR

SITE CHARACTERISTICS AND TECHNICAL ANALYSIS

4.1 SITE CHARACTERISTICS

4.1.1 Project location

The Fuller Falls is one of the potential mini-hydro sites identified in the Brong Ahafo Region of Ghana (Figure 4.1). The site falls approximately within latitude 8° 4’ 60” North and longitude 1° 46’ 60” West in a village know as Yabraso located in the Kintampo North district about 7km from Kintampo.

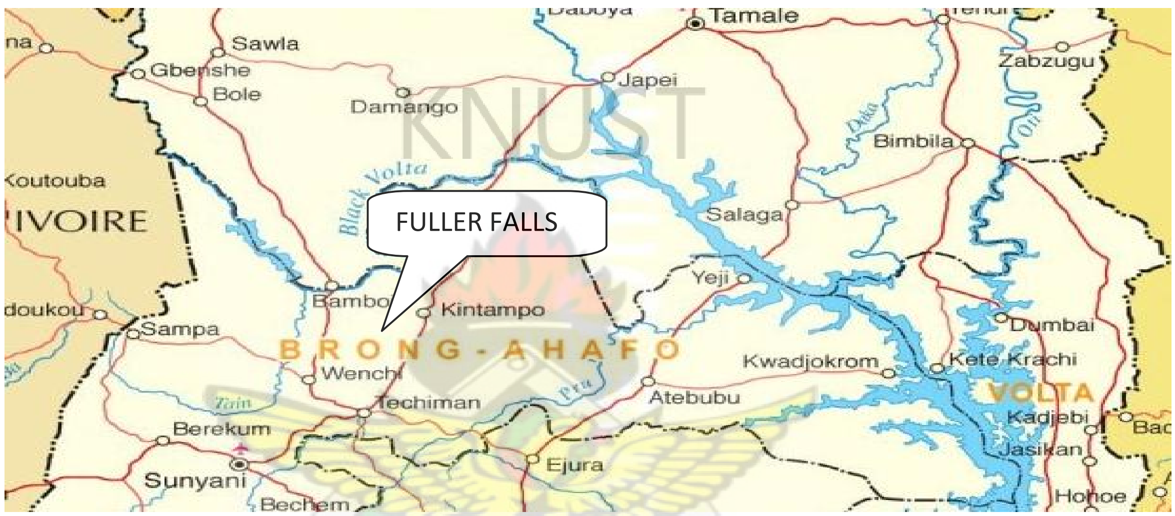

Figure 4- 1 Project location

Figure 4.2 View from Downstream of Fuller Falls

Figure 4.3 View from upstream of Fuller Falls

With a catchment area of about 465km^2 (Figure A.1 Appendix A), the Fuller falls flow gently over a series of cascades along the Yoko River (Figure 4.2 and Figure 4.3) at about 1km off Yabraso Village while continuing its journey into the Black Volta River.

The village is already connected to the national grid which is just about 1km away from the falls; therefore the site should be developed as a central grid system to serve the national grid system.

4.1.2 Land Ownership and Land Use

The Fuller Falls was discovered in the 1988 by Rev. Fr. Joseph Panabang a Pilipino Missionary of the Society of Divine Word. He arrived in Ghana in 1986 and moved to Kintampo in 1987. Whiles working as Assistant Parish of the St. Joseph Catholic Church in Kintampo, he worked tirelessly with his own earnings to develop the place into a prayer centre (Figure 4.4).

Figure 4- 4 Rev. Fr. Joseph Panabang and Associates at work at the site

The place has now been turned into a tourist site and is under the management of the Kintampo North District Assembly and the Yabraso Community. Information obtained from the caretaker of the place indicated that a minimum of 200 people visit the place on typical weekends during the dry seasons whiles the number reduces to just ten or sometimes zero during the rainy seasons.

About 6 acres of land around the falls have been bought by a private developer for the construction of hotels. Construction works is said to have commenced in the year 2002, however works are being carried out rather on a very slow pace as a results of lack of funds. When works are completed, in the event that the private developer is interested he can develop the site to provide power for his hotel and the excess power generated could be supplied to the national grid through "net metering".

Figure 4.5 Construction of hotels around the Falls

4.1.3 Geology

Current published geological information shows that the study area is underlain by rocks belonging to the Upper Voltaian System of Lower Palaeozoic age. The Voltaian System is made up of a near horizontally – bedded sequence of sedimentary rocks which include **sandstones** (micaceous, ferruginous and quartzitic), **mudrocks** (mudstones, shales and siltstones), **conglomerates**, **limestones** and **tillites**. The entire project site overlies sandstones belonging to the Molasse deposits with outcrops visible in and around the site.

Residual soils formed over rocks of the Voltaian System consist mainly of clayey and silty sands which are generally free-draining and perform reasonably well when used as subgrades. Sources of winning good quality quartzitic gravels for civil works are, however difficult to find in areas underlain by rocks of the Voltaian System. However sand and natural gravel pits which are available in large quantities in the area will be very useful for concrete and road subbase and base purposes.

4.1.4 Topography

The Kintampo North Municipal which falls within the Voltain Basin and the Southern Plateau physiographic regions is a plain with rolling and undulating land surface with a general elevation between 60-150m above sea level. The southern Voltain plateau occupying the southern part of the district is characterized by series of escarpments. (Ministry of Local Government and Rural Development , 2006)

The upper part of the falls is relatively flat, with a lot of rock out-crops which might cause a little difficulty during excavation works for the construction of headrace channel.

4.1.5 Rainfall and Temperature

A 16-year mean monthly rainfall and temperature data were obtained from the Meteorological Service Department for the purpose of this study as shown in tables B-1 and B-2 of Appendix B. The gauged station is located at Kintampo about 7km from the project site. As can be seen from the Figure 4-6, there are five dry months (November to March) and seven wet months which start from April and end in October. The coldest and hottest months are August and March with a monthly mean temperature of 24.90°C and 29.45°C respectively as presented in table 4.1.

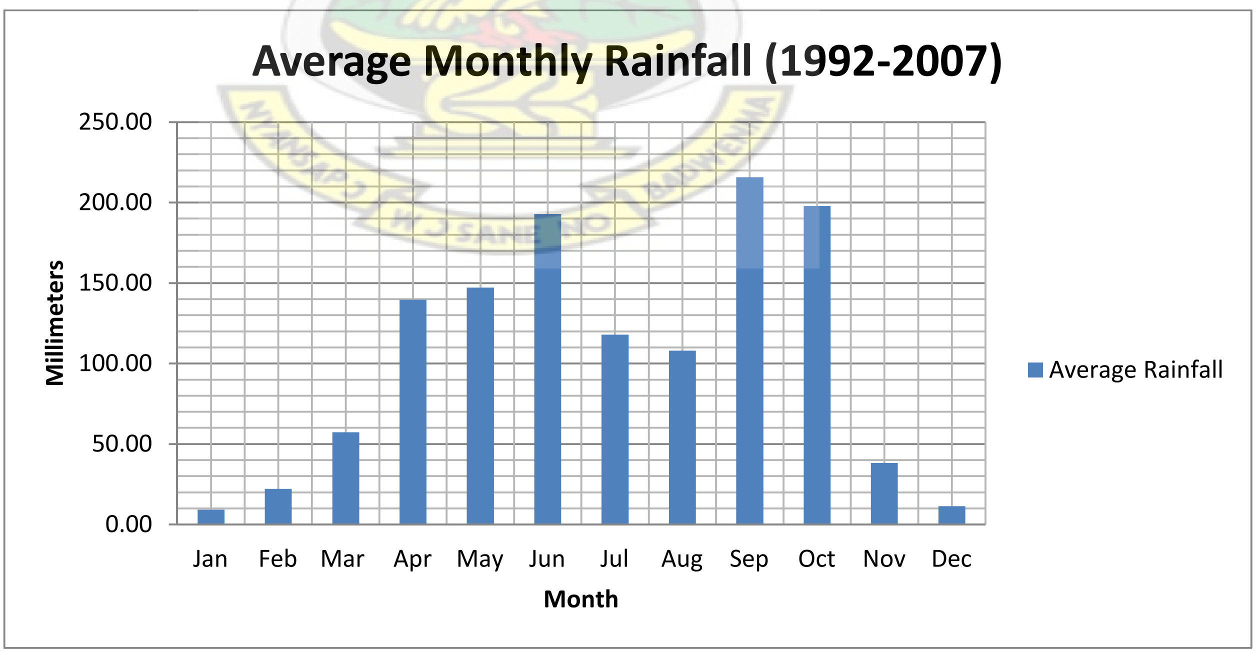

Figure 4.6 Average Monthly Rainfall (mm) for the project site

Table 4.1 Average Monthly Temperatures (°C) for Kintampo (1992-2007)

Months	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Max	33.73	35.44	35.41	33.41	31.75	30.09	28.74	28.56	29.27	30.84	32.49	32.56
Min	20.20	22.30	23.56	23.18	22.89	22.19	21.58	21.23	21.43	21.48	21.69	19.91
Mean	26.97	28.87	29.48	28.29	27.32	26.14	25.16	24.90	25.35	26.16	27.09	26.23

4.1.6 Head Measurement

Water located at a height represents stored energy. Thus, if the available head at the site is maximised the power output from the turbine will be increased. With the help of a professional surveyor, a Total Station instrument and a Surveyor's Staff were used to measure the available head. The following measurements were made:

- The vertical height difference between the proposed intake and the forebay is 1.0m
- The vertical height difference between the proposed forebay and the possible tailrace is 18.46m

Figure 4.7 Survey of head with total station

4.1.7 Flow Measurement

Because of time constraints only one flow measurement for a single day in the last week of July 2013 was taken. As can be seen in Figure 4.8, the float method as described in methodology was employed in the determination of the site discharge; the field results and calculations are presented in table A-2, Appendix A. The summary of the results obtained are presented in Table 4.2.

Figure 4.8 site flow measurement upstream of the Fuller Falls

Table 4.2 Results site flow measurement taken in July 2013

Average stream cross sectional Area (m2)	Average stream velocity (m/s)	Stream bed correction factor	Average Measured flow (m3/s)
2.00	0.66	0.85	1.12

4.2 TECHNICAL ANALYSIS

4.2.1 Site selection and Scheme Type

The proposed scheme type is run-of-river. The proposed locations of intake weir, diversion channel, forebay tank, penstock path and power house are indicated in figures 4.9 and 4.10. The Weir is located at a distance of about 100m upstream of the fall where the river width is very narrow. The diverted water is conveyed through a 100m long diversion channel along the left bank of the river to the forebay tank which will be located at a distance of about 50m from the edge of the falls. A 145m penstock is laid from forebay tank down to power house which is located about 10m away from the flood zone of the tail end of the falls. The tail race channel directly diverted to the river itself, by so doing there will be no effect on the present water flow cycle.

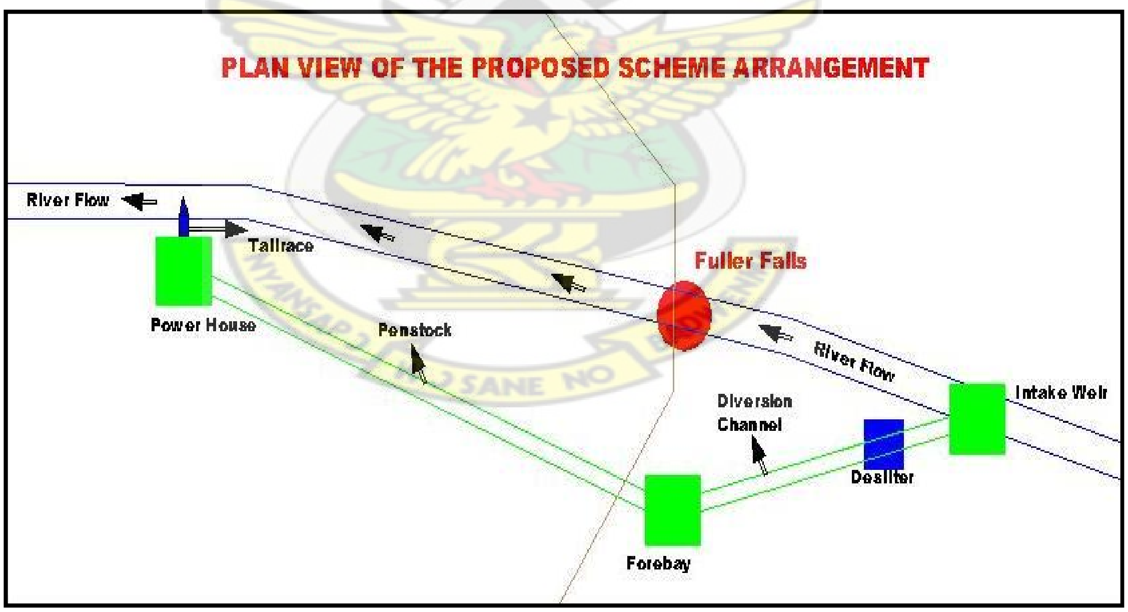

Figure 4.9 Plan view of proposed scheme arrangement

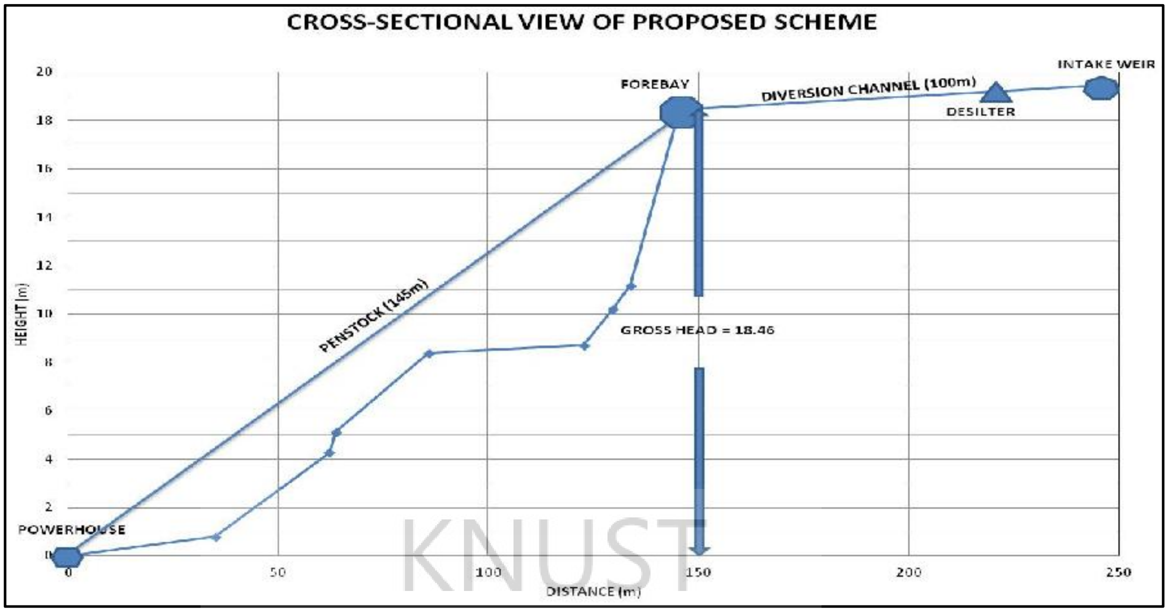

Figure 4.10 Cross sectional view of proposed scheme arrangement

4.2.2 Hydrological Analysis

Hydrology study was done based on the 16 year rainfall and temperature (1992 to 2007) measured at Kintampo, collected from the Meteorological Service Department. The catchment area was calculated using the 1:50000 topographical maps obtained from the Geological Survey department.

Parameters considered for the hydrology are;

- Catchment area of 465km2 (Figure A.1 Appendix A)
- Monthly mean temperatures (Table B.1 Appendix B)
- Monthly average rainfall (Table B.2 Appendix B)
- Monthly rate of annual sunshine p (%) (Table A.1 Appendix A)

Detailed calculations of the hydrology analysis and the summary of the monthly average discharges are presented in Table C.1 and C.2 respectively at Appendix C. The calculated discharges are illustrated in the hydrograph shown in Figure 4.11.

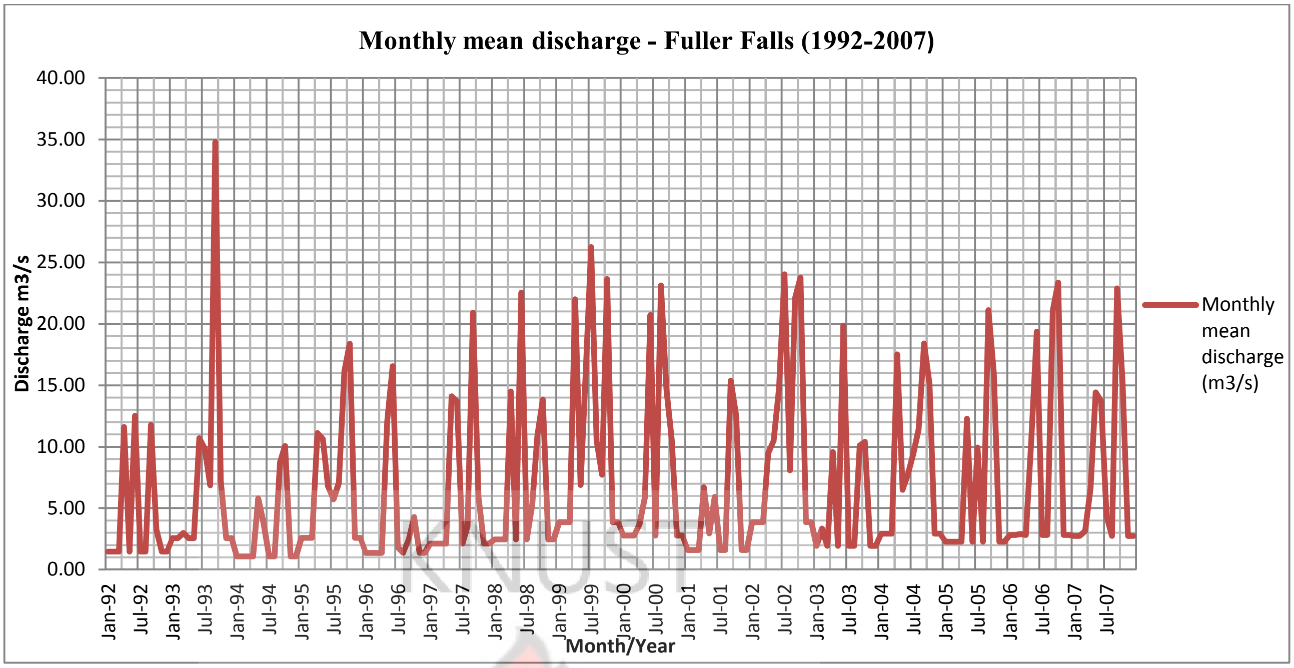

Figure 4.11 Hydrograph of monthly average discharge

There was a wide difference between the field discharge of 1.12m3/s measured in July 2013 and the calculated average monthly discharge of 6.73m3/s for July in the hydrological analysis, this could be attributed to several factors, amongst which is the possibility of delay in rainfall in June 2013. As can be observed from Figure 4.12, there has been similar low flows in July 1992, 1994 and 2001 which are comparable to the field flow of 1.12m3/s obtained in July 2013.

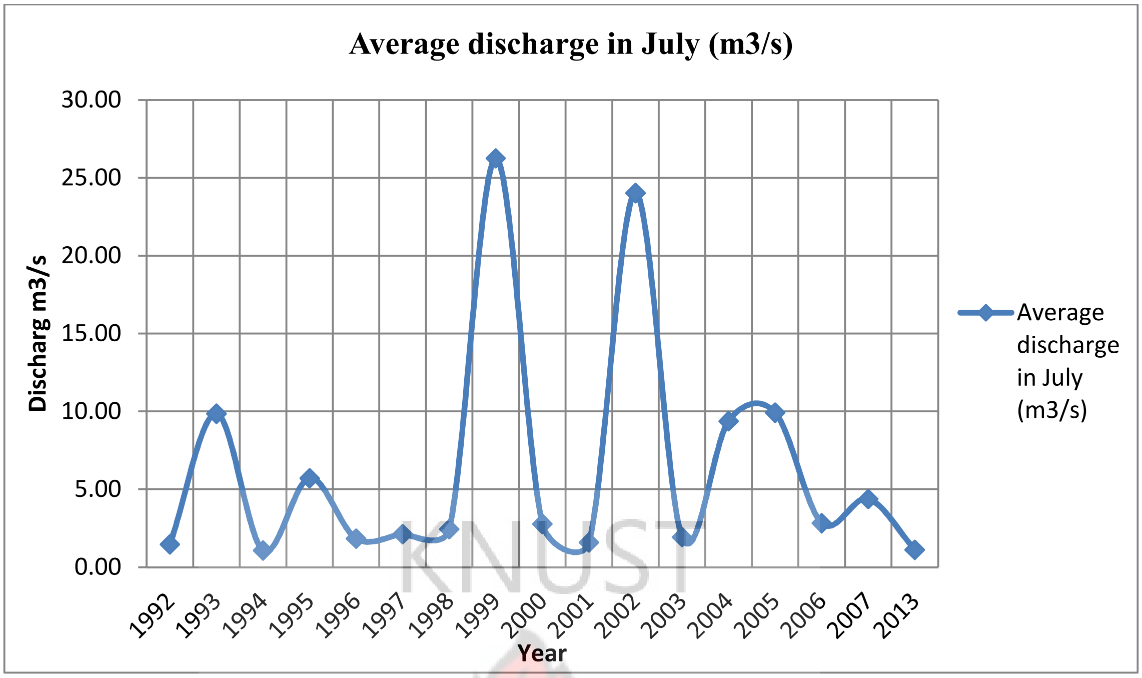

Figure 4.12 Average discharges in July

4.2.2.1 Analysis of flow record

The hydrograph shown in Figure 4.11 assess the quantitative availability of water for power generation from the proposed project site, using the above discharges a flow duration curve (Figure 4.13) was developed to illustrate the flow distribution and number of times a particular flow is attained or exceeded. The table 4.3 is a summary of the analysis of the flow record as derived from the flow duration curve;

Table 4.3 Summary of flow records

Discharges m3/s	Min ($Q_{100\%}$)	Max	$Q_{50\%}$	$Q_{70\%}$
Values	1.1	34.8	3.0	2.45

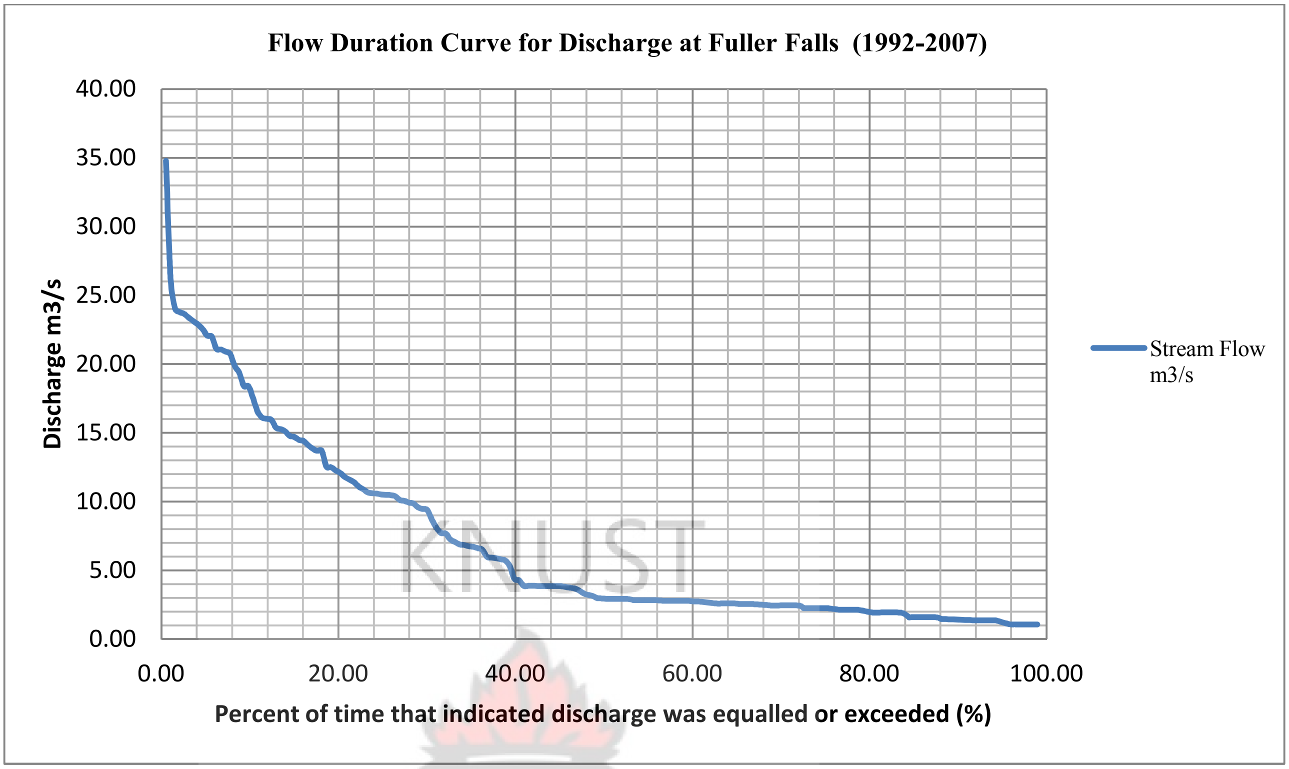

Figure 4.13 Flow Duration Curve

4.2.2.2 Design Flow

Because the site in question is a tourist site, a minimum discharge of 0.5m3/s would be allowed to remain in the waterfalls during the dry season. The new flow available for power generation is presented in figure 4.14. For the purpose of this study $Q_{70\%}$ representing flow that is available or exceeded 70% of the time would be adopted for power generation.

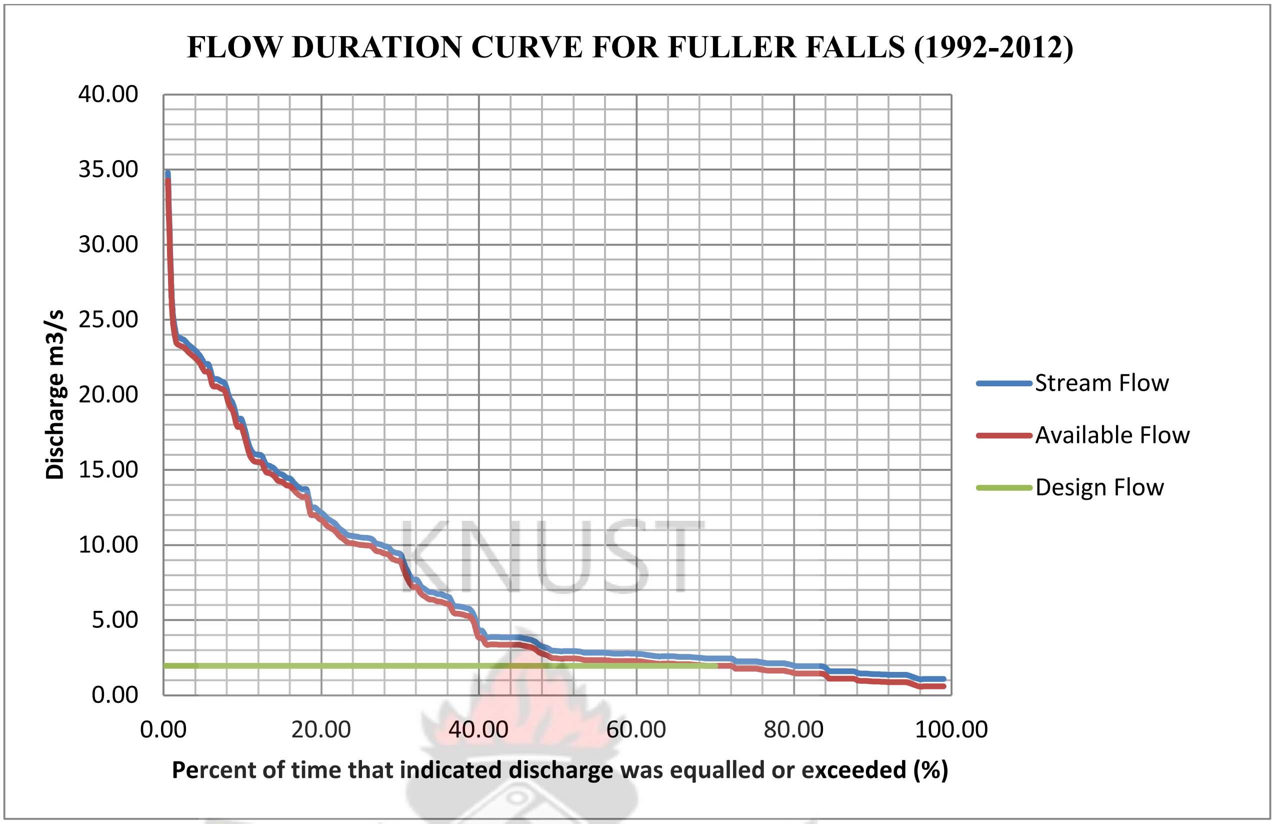

Figure 4.14 Available discharges for power generation

Table 4.4 Summary of available flow

Discharges	Min ($Q_{100\%}$)	Max	$Q_{50\%}$	Design Discharge $Q_{70\%}$
Values m3/s	0.6	34.3	2.4	1.95

4.2.3 Turbine Selection

The selection of appropriate turbine, mechanical and electrical equipment typically forms part of a feasibility study and initial design. However, for the purposes of this study which is just a prefeasibility study an initial indication of appropriate turbine technology will be given. As stated in section 3.4.5, turbine selection is commonly based on the available head and flow rate. With a head of 18.46m and discharge of

1.95m3/s, the desirable turbine is the cross flow turbine as indicated in Figure 4.15. A look at the turbine efficiency curve at Figure 4.16 indicates that between 60% and 100% of design discharge, the cross flow turbine has efficiency equal or greater than 80%.

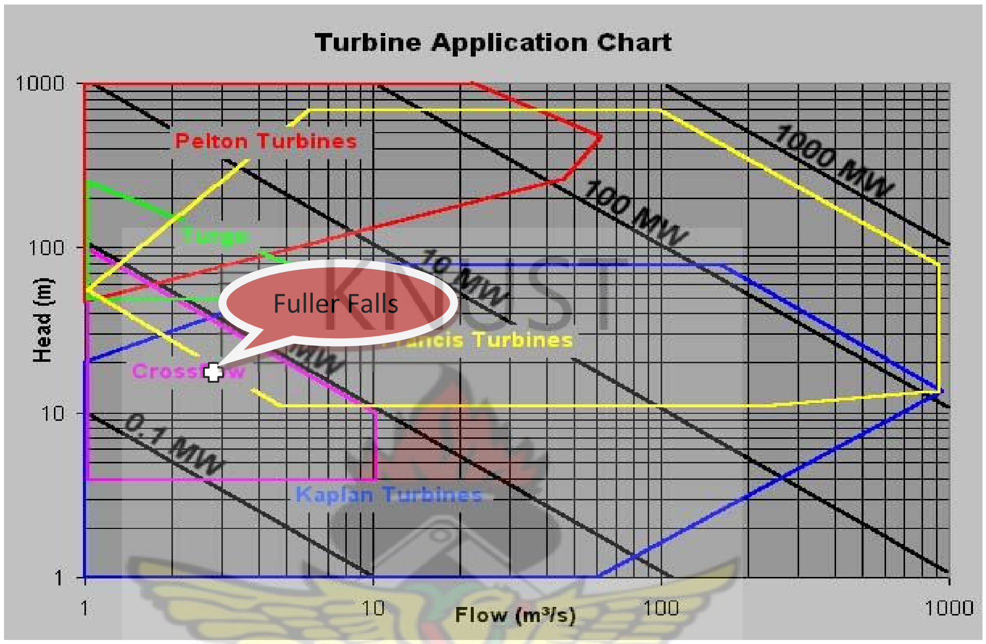

Figure 4.15 Turbine Application Chart indicating selected turbine

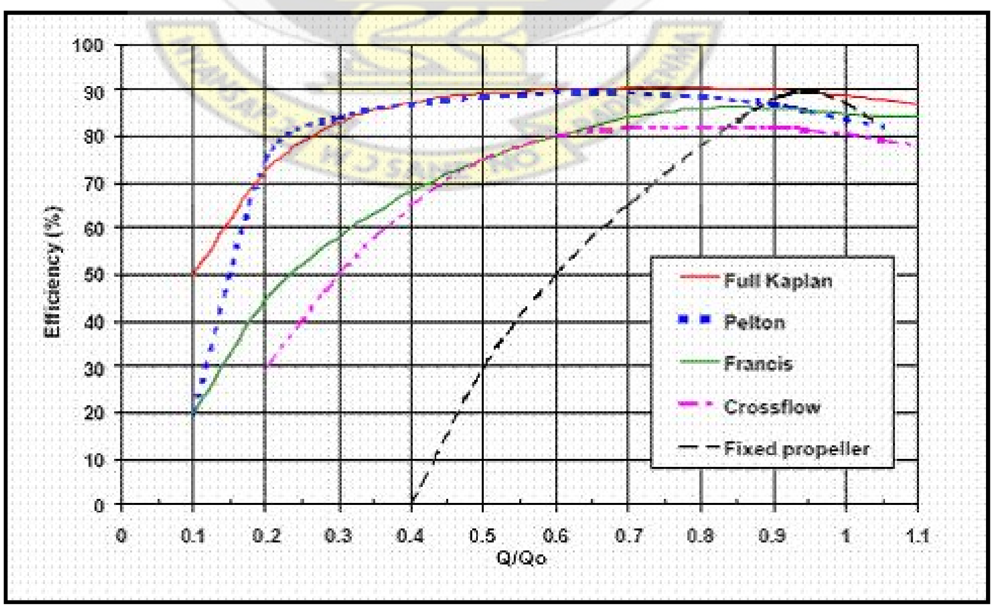

Figure 4.16 Turbine Efficiency Curve ((c) Wikipedia)

4.2.4 Potential Plant Capacity

With the under listed parameters

Q = 1.95 m3/s

H= 18.46 m (gross), H_{net} = 16.61 (assuming a head loss of 10%)

g = 9.8(m^2/s), ρ = 1000 (kg/m^3)

$\eta_{total} = \eta_{Tur} \times \eta_{GU} \times \eta_{Gen}$

η_{Tur} = 80% turbine efficiency is assumed

η_{GU} = 95% gear unit efficiency is assumed

η_{Gen} = 96% generator efficiency is assumed

η_{total} = 0.8 x 0.95 x 0.96 =0.73

$$\mathbf{P_{max} = 1.95 \times 16.61 \times 9.81 \times 1000 \times 0.73 \quad (W)}$$

P_{max} = 232kW

4.2.5 Potential Energy to be generated per Annum

The total annual energy output is the summation of all the daily generations throughout the year. The maximum output can seldom be achieved continuously over an entire year, since the plant would not work through the whole year; there will be down time for maintenance and system failure. A plant factor of 80% will be adopted based on the following analysis;

- 70% of the time the plant will run on the design discharge
- 10% of the time that the plant is not in operation (downtime), will be used for repairs and maintenance

- 20% of the time the plant will run on less than 100% but not less than 50% of the design flow at turbine efficiency of 0.75. Hence minimum power (P_{min}) when flow is less than the design flow is computed as follows

$$\mathbf{P_{min} = Q_{min} \times H \times g \times \rho \times \eta \quad (W)}$$

Minimum discharge, $Q_{min} = 1.1\ (m^3/s)$

Net Head, $H_{net} = 16.61$, $g = 9.8 (m^2/s)$

$\rho = 1000\ (kg/m3)$

Total Efficiency, $\eta_{total} = \eta_{Tur} \times \eta_{GU} \times \eta_{Gen} = 0.75 \times 0.95 \times 0.96$

$\eta_{total} = 0.68$

$$P_{min} = 1.1 \times 16.61 \times 9.81 \times 1000 \times 0.68 \quad (W)$$

$$\mathbf{P_{min} = 122kW}$$

$$Plant\ Factor\ (pf) = \frac{Possible\ Annual\ energy\ generation}{P_{max} \times 365 \times 24} (\%)$$

$$\boldsymbol{Plant\ Factor\ (pf)} = \frac{\mathbf{(232 \times 365 \times 24 \times 0.7) + (122 \times 365 \times 24 \times 0.2)}}{\mathbf{(232 \times 365 \times 24)}} = \mathbf{80\%}$$

4.2.5.1 Annual Energy Computation

The potential annual energy is computed as follows;

$$\boldsymbol{E_{annual} = P(kW) \times 8760 \times pf}$$

Firm Capacity (P_{max}) =232kW

Plant Factor (Pf) =80%

$$E_{annual} = 232 \times 8760 \times 80/100$$

$$\boldsymbol{E_{annual} = 1,625,856\ kWh = 1.626\ GWh\ \ per\ Annum}$$

CHAPTER FIVE

PROJECT COSTING AND FINANCIAL ANALYSIS USING RETScreen SOFTWARE

5.1 RETScreen SOFTWARE

The project costing and financial analysis were done using the RETScreen4 software program (Figure 5.1). The RETScreen software is a clean energy project analysis software which is provided free of charge by Natural Resources Canada (Natural Resources Canada, 2010). All financial and economic equations and algorithms were created by *Natural Resources Canada* and used through the RETScreen4 interface. The project information derived from the technical analysis was entered into the software at various stages and the out puts added to this report.

Figure 5.1 The RETScreen software

5.1.1 Start Sheet

The start sheet of the RETScreen for the Fuller Falls minihydro project is presented in Figure 5.2. The following information were entered:

- **Project Information**: The project information was inputted as shown in table 5.2. **Project type** is power and the **technology** is hydro turbine.
- **Grid type:** This can either be central grid, isolated grid or off-grid. Electricity produced at the proposed site will be connected to the national grid, thus central grid is selected

- **Analysis type:** The software makes provision for two types of analysis depending on the extent of information available. Method 2 requires more detailed information than Method 1 and it is preferable to use Method 2 if sufficient amount of information is available. If not, Method 1 can be selected but in this case cost analysis, emission analysis, financial and risk analyses become unavailable. Method 2 is selected for the analysis of the Fuller Falls Minihydro Project, however due to the limited information available at this stage of the study no emission analysis, and risk analyses will be undertaken.

- **Heating value** For hydropower projects, this value is important only if emission analysis will be carried out. It is a measure of energy released when fuel is burned completely. No emission analysis is carried out in this study.
- **Site reference conditions:** the user enters the climatic data (such as air temperature, relative humidity, wind speed, etc.) of the project area or copy them from the RETScreen's climate database. For this project it is Kintampo.

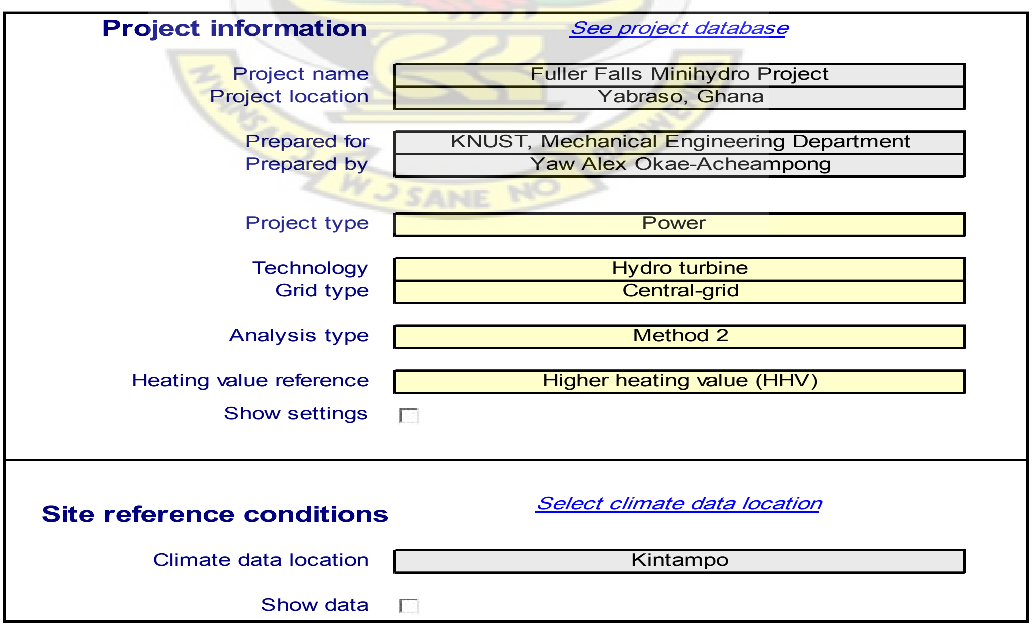

Figure 5.2 Start Sheet of RETScreen

5.1.2 Energy Model

The following parameters were the inputs for the analysis; the energy model sheet 1 and 2 depict the inputs and outputs are shown in Figures 5.3 and 5.4.

Table 5.1 Input parameters for Energy model sheet

Resource assessment	**User Inputs**
Proposed project	Run-off-river
Hydrology method	flow duration curve for the proposed site
Gross head	18.46
Maximum tail water effect	0
Residual flow	0
Percent time firm flow available	90%
Hydro turbine	**User Inputs**
Design flow	1.95
Type	Crossflow
Number of turbines	1
Efficiency adjustment	0
Maximum hydraulic losses	10% is assumed
Miscellaneous losses	1.5% is assumed
Generator efficiency	95% is assumed
Availability	plant is assumed to be available 90% of the time
Summary	**User Inputs**
Available flow adjustment factor	1 is assumed meaning no adjustment
Electricity exported to grid	$100/MWh current average hydro rate in Ghana

Proposed case power system

Technology		Hydro turbine
Analysis type		○ Method 1 ⦿ Method 2
Resource assessment		
Proposed project		Run-of-river
Hydrology method		User-defined
Gross head	m	18.5
Maximum tailwater effect	m	0.00
Residual flow	m³/s	0.000
Percent time firm flow available	%	90.0%
Firm flow	m³/s	0.86
Hydro turbine		
Design flow	m³/s	1.950
Type		Cross-flow
Turbine efficiency		Standard
Number of turbines		1
Manufacturer		Ossberger
Model		Cross-flow
Efficiency adjustment	%	0.0%
Turbine peak efficiency	%	0.0%
Flow at peak efficiency	m³/s	0.0
Turbine efficiency at design flow	%	79.0%

Figure 5.3 Energy Model Sheet 1, Project formulation

%	Flow m³/s	Turbine efficiency	Number of turbines	Combined efficiency
0%	35.00	0.00	0	0.00
5%	22.00	0.00	1	0.00
10%	17.50	0.34	1	0.34
15%	14.00	0.52	1	0.52
20%	11.50	0.61	1	0.61
25%	10.00	0.65	1	0.65
30%	9.00	0.68	1	0.68
35%	6.20	0.69	1	0.69
40%	3.80	0.70	1	0.70
45%	3.37	0.71	1	0.71
50%	2.43	0.71	1	0.71
55%	2.33	0.72	1	0.72
60%	2.25	0.73	1	0.73
65%	2.06	0.74	1	0.74
70%	1.95	0.74	1	0.74
75%	1.77	0.75	1	0.75
80%	1.44	0.76	1	0.76
85%	1.09	0.77	1	0.77
90%	0.86	0.77	1	0.77
95%	0.58	0.78	1	0.78
100%	0.58	0.79	1	0.79

Maximum hydraulic losses	%	10.0%	
Miscellaneous losses	%	1.5%	
Generator efficiency	%	95.0%	
Availability	%	90.0%	
Summary			Firm
Power capacity	kW	235	101
Available flow adjustment factor		1.00	
Capacity factor	%	79.0%	
Electricity exported to grid	MWh	1,626	
Electricity export rate	$/MWh	100.00	

Figure 5.4 Energy Model Sheet 2, Project formulation

The following are the outputs from the energy model analysis; the value of "electricity exported to the grid" is automatically carried to the financial analysis sheet and used during the financial and economic analysis.

- Turbine efficiency at design flow – 79%
- Firm flow –0.86m^3/s
- Power Capacity – 235kW
- Firm Capacity - 101kW
- Capacity Factor – 79%
- Electricity exported to grid – 1,626 MWh

5.2 PROJECT COSTING

5.2.1 Cost Analysis using Hydro Formula Costing Method

The "hydro formula costing method" offered by RETScreen will be used for the initial costing of this project. This method is available in the "tools sheet". The hydro formula costing method tool estimates the project costs using the empirical formulae derived from the costs of numerous completed small hydro projects. Since costs associated with various construction items, engineering and development works are beyond the scope of this study, the hydro formula costing method was used to estimate total initial cost of the project. The following project parameters were inputted into the software to calculate the total initial cost of the project.

Table 5.2 Input parameters for hydro formula costing method sheet

Descriptions	**Inputs**
Cold climate	No
Design flow	1.95m3/s
Gross head	18.46m
Number of turbines	1
Type	Crossflow
Facility type	Mini
Existing dam	no
New dam crest length	0
Rock at dam site	yes
Maximum hydraulic losses	10%
Miscellaneous losses	5%
Road construction	
Length	1.2km
Tote road only	yes
Difficulty of terrain	1
Canal	
Length in rock	100m
Terrain side slope in rock (average)	0
Length in impervious soil	0
Terrain side slope in soil (average)	0
Penstock	
Length	145m
Number	1
Allowable penstock headloss factor	1%
Distance to borrow pits	10km
Transmission line	
Grid type	Central-grid
Length	1.5km
Difficulty of terrain	1
Voltage	33kV

Hydro formula costing method uses the projects completed in Canada as the source for empirical formulae. Therefore, the cost estimations are applicable for Canada. However, RETScreen software makes provision for the user to enter the local conditions through cost ratios. These ratios should carefully be calculated since the cost estimations could vary greatly with different cost ratios. The under listed assumptions are made as inputs for the various ratios;

- **Local vs. Canadian equipment cost ratio** is taken as 1.0, equipment cost is assumed to be unchanged
- **Local vs. Canadian fuel cost ratio** is taken as 0.77, the average pump price for diesel in Ghana and Canada were 0.95cents/litre and 1.23cents /litre respectively (2008-2012) (The World Bank Group, 2013)
- **Local vs. Canadian labour cost ratio** is taken as 0.15, Ghana labour rate is assumed to be 15% of Canada, this however is on a higher side compared to the prevailing 2013 minimum wage of the two countries which are $757 per annum and $20,280 per annum minimum wage for Ghana and Canada respectively (Wikipedia). Thus bringing the ratio to 0.037.
- **Equipment manufacture cost coefficient is taken as** 1.0; equipment cost is assumed to be unchanged
- **Exchange rate is taken as** 0.95; all amounts are expressed in US dollars for this analysis. An exchange rate of 0.95 US$/CDN$ was assumed (Bank of Canada, 2013)

Hydro formula costing method

Country		Ghana	
Local vs. Canadian equipment cost ratio		1.00	
Local vs. Canadian fuel cost ratio		0.77	
Local vs. Canadian labour cost ratio		0.15	
Equipment manufacture cost coefficient		1.00	
Exchange rate	$/CAD	0.95	
Cold climate	yes/no	No	
Design flow	m³/s	1.95	1.95
Gross head	m	18.46	18.46
Number of turbines	turbine	1	1
Type		Cross-flow	Cross-flow
Flow per turbine	m³/s	1.95	
Turbine runner diameter per unit	m	0.65	
Facility type		Mini	Mini
Existing dam	yes/no	No	
New dam crest length	m	0	
Rock at dam site	yes/no	Yes	
Maximum hydraulic losses	%	10.0%	10.0%
Miscellaneous losses	%	5.0%	
☑ **Road construction**			
Length	km	1.2	
Tote road only	yes/no	Yes	
Difficulty of terrain		1.0	
☐ **Tunnel**			
☑ **Canal**			
Length in rock	m	100	
Terrain side slope in rock (average)	°	0	
Length in impervious soil	m	0	
Terrain side slope in soil (average)	°	0	
Total canal headloss	m	0.1	
☑ **Penstock**			
Length	m	145.0	
Number	penstock	1	
Allowable penstock headloss factor	%	1.0%	
Diameter	m	1.30	
Average pipe wall thickness	mm	7.41	
Distance to borrow pits	km	10.0	
Transmission line			
Grid type		Central-grid	Central-grid
Length	km	1.5	
Difficulty of terrain		1.0	
Voltage	kV	33.0	

Initial costs (credits)	**Amount $**	**Adjustment factor**	**Amount $**	**Relative costs**
Feasibility study	33,000	1.00	33,000	3.1%
Development	39,000	1.00	39,000	3.7%
Engineering	132,000	1.00	132,000	12.5%
Power system				
Hydro turbine	350,000	1.00	350,000	33.0%
Road construction	3,000	1.00	3,000	0.3%
Transmission line	32,000	1.00	32,000	3.0%
Substation	7,000	1.00	7,000	0.7%
Balance of system & miscellaneous				
Penstock	225,000	1.00	225,000	21.2%
Canal	7,000	1.00	7,000	0.7%
Tunnel	0	1.00	0	0.0%
Other	232,000	1.00	232,000	21.9%
Sub-total:	464,000		464,000	
Total initial costs	**1,060,000**		**1,060,000**	**100.0%**

Figure 5.5 Hydro costing Formula method with initial project cost

As indicated in Figure 5.5, the total initial cost of the proposed project which is made up of feasibility studies, development and engineering, as well as civil works and electromechanical works amounts to $1,060,000. This amount translates into approximately $4,500/kW of installed capacity. This is within the average investment cost for minihydro projects in 2008 which ranged between $2,000/kW and $5,000/kW, rural regions is said to require a greater investment cost of around $6,000/kW. (Whiticar, 2012)

In addition to the initial costing, the Hydro costing formula method sheet also automatically calculates the following technical project parameters,

- turbine runner diameter = 0.65m
- penstock diameter = 1.3m
- average pipe thickness of penstock =7.41mm

5.3 FINANCIAL ANALYSIS

5.3.1 Financial Analysis Sheet

The financial parameters indicated in Figure 5-5 were inputted into the software for the financial analysis. The following information was assumed for the purposes of the analysis;

- **Fuel cost escalation rate** is taken as 0 % since hydropower plants do not generate electricity using fuel. Fuel is used only in the construction period to run the construction machinery. Therefore the effect of this rate can be assumed to be negligible.
- **Inflation rate** was assumed to be 2 %

- **Discount rate** was assumed to be 10 %
- **Project life** was assumed 25 years.
- 75 % of the total cost is assumed to be paid from the loans taken from the banks with an interest rate of 10 %. This is to be paid back in 10 years.
- **Effective income tax rate** is taken as 20 %
- **Depreciation method** is selected as straight line. The depreciation period is taken as 25 years which is equal to the project life time. The percentage of total costs to be depreciated (depreciated tax basis) is 95 %. The remaining 5 % accounts for the cost items that cannot be depreciated
- **Annual electricity escalation export rate** is assumed to be 0.2%
- **O & M** cost is taken as 1% of initial cost
- **Recurring/periodic cost** is taken as 5% of initial cost every 5years

Financial parameters		
General		
Fuel cost escalation rate	%	0.0%
Inflation rate	%	2.0%
Discount rate	%	10.0%
Project life	yr	25
Finance		
Incentives and grants	$	
Debt ratio	%	75.0%
Debt	$	795,000
Equity	$	265,000
Debt interest rate	%	10.00%
Debt term	yr	10
Debt payments	$/yr	129,383
Income tax analysis		☑
Effective income tax rate	%	20.0%
Loss carryforward?		Yes
Depreciation method		Straight-line
Depreciation tax basis	%	95.0%
Depreciation period	yr	25
Tax holiday available?	yes/no	No
Annual income		
Electricity export income		
Electricity exported to grid	MWh	1,626
Electricity export rate	$/MWh	100.00
Electricity export income	$	162,590
Electricity export escalation rate	%	0.2%

Figure 5.5 Project financial parameters

The financial analysis outputs include summary of project costs and saving/income, financial viability parameters, cumulative cash flow graph and yearly cash flow table. These results are shown in Figures 5.6 – 5.9.

Project costs and savings/income summary			
Initial costs			
Power system	100.0%	$	1,060,000
Balance of system & misc.	0.0%	$	0
Total initial costs	**100.0%**	**$**	**1,060,000**
Annual costs and debt payments			
O&M		$	10,600
Fuel cost - proposed case		$	0
Debt payments - 10 yrs		$	129,383
Total annual costs		**$**	**139,983**
Periodic costs (credits)			
User-defined - 5 yrs		$	53,000
Annual savings and income			
Fuel cost - base case		$	0
Electricity export income		$	162,590
Total annual savings and income		**$**	**162,590**

Figure 5.6 Summary of project cost and saving/income

Financial viability		
Pre-tax IRR - equity	%	15.4%
Pre-tax IRR - assets	%	4.5%
After-tax IRR - equity	%	13.0%
After-tax IRR - assets	%	3.1%
Simple payback	yr	7.0
Equity payback	yr	11.9
Net Present Value (NPV)	$	121,389
Annual life cycle savings	$/yr	13,373
Benefit-Cost (B-C) ratio		1.46
Debt service coverage		0.68
Energy production cost	$/MWh	89.95
GHG reduction cost	$/tCO2	(42)

Figure 5.7 Project financial viability parameters

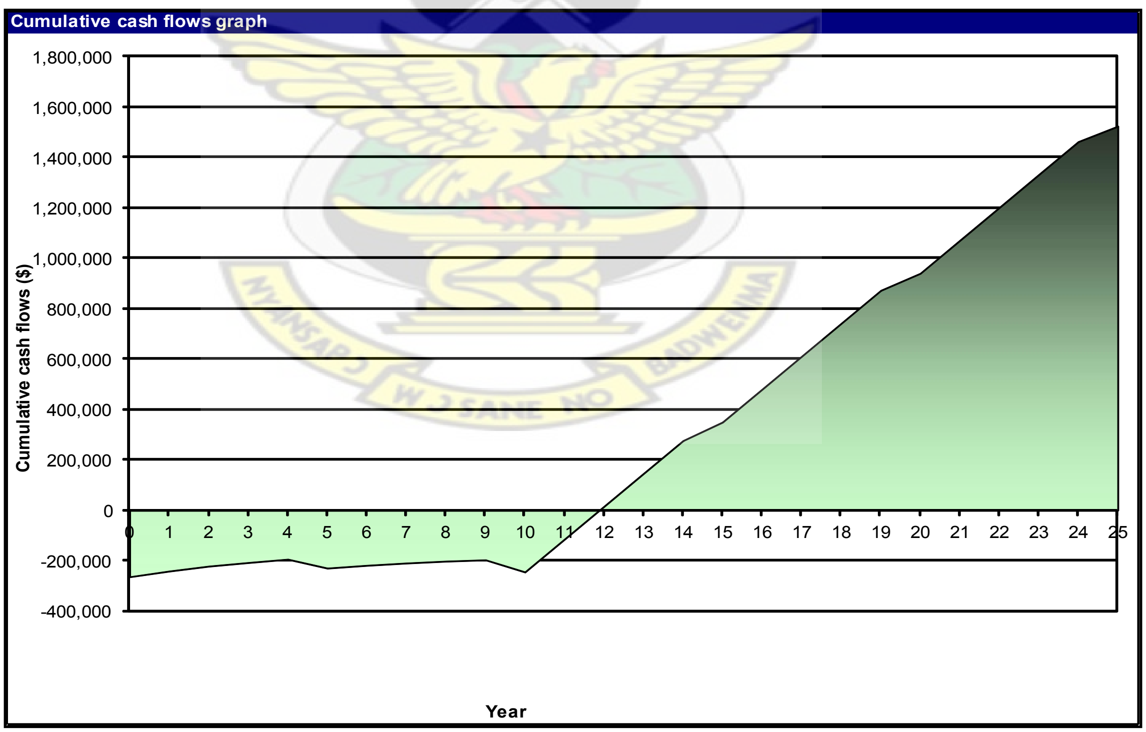

Figure 5.8 Project cumulative cash flow graph

Yearly cash flows			
Year	Pre-tax	After-tax	Cumulative
#	$	$	$
0	-265,000	-265,000	-265,000
1	22,720	22,720	-242,280
2	22,830	19,481	-222,799
3	22,936	14,333	-208,466
4	23,038	13,208	-195,258
5	-35,380	-35,380	-230,638
6	23,231	11,099	-219,540
7	23,321	9,039	-210,501
8	23,407	7,340	-203,161
9	23,489	5,462	-197,699
10	-41,040	-48,300	-245,999
11	153,023	130,474	-115,525
12	153,092	130,529	15,004
13	153,156	130,581	145,585
14	153,215	130,628	276,213
15	81,939	73,607	349,820
16	153,320	130,712	480,532
17	153,364	130,748	611,280
18	153,404	130,779	742,059
19	153,438	130,807	872,865
20	74,712	67,826	940,691
21	153,491	130,848	1,071,539
22	153,508	130,863	1,202,402
23	153,520	130,872	1,333,274
24	153,527	130,877	1,464,152
25	66,575	61,316	1,525,467

Figure 5.9 Project yearly cash flow table

5.3.2 Discussion of financial analysis

A hydropower project is said to be economically viable and financially sound when the following criteria are met;

- If the internal Rate of Return (IRR) is greater or equal to the discount rate
- If the Net Present Value (NPV) is greater or equal to zero (0)
- If the Benefit-Cost ratio (B-C) is greater than one (1)

As can be seen in Figure 5.8 and Figure 5.9, the cumulative cash flow is negative until the 11th year. It turns positive as it approaches the 12th year, meaning that the investor starts making profit.

Figure 5.7 also demonstrates clearly that the project is viable, benefit-cost ratio is greater than 1, IRR is greater than the discount rate of 10% and NPV is greater than zero.

When all the financial variables remain constant with changing interest rates, it can be observed from table 5.3 that the project will not be financially viable with interest rate above 14.27% since NPV turns negative.

Table 5.3 Effect of interest rate on economic and financial indicators

Interest Rate (%)	**IRR- Equity after tax (%)**	**Equity payback (years)**	**NPV ($)**	**Benefit -Cost ratio**	**Energy production cost ($/MWh)**
8.00%	14.5	11.2	173,979	1.66	85.56
10.00%	13.0	11.9	121,389	1.46	89.95
12.00%	11.5	12.0	66,366	1.25	94.53
14.00%	10.2	13.0	8,342	1.03	99.33
14.27%	10.0	13.4	63	1	99.99
14.28%	10.0	13.4	-244	1	100.02

CHAPTER SIX

6.0 CONCLUSIONS AND RECOMENDATIONS

6.1 CONCLUSIONS

This prefeasibility study has established that developing the Fuller Falls for hydropower generation is technically, economically and financially viable. The major conclusions from this work can be summarised as follows;

6.1.2 Technical

Due to the relatively flat topography of the upper part of the falls, the best site development method is the run-off-river and the central grid connectivity since the nearest village Yabraso is already connected to the national grid. The maximum gross head available for energy generation as determined from the fieldwork using the Total Station Instrument was 18.46 m. The hydrological analyses which based on the water balance method generated an optimum design discharge of 1.95 m^3/s being the discharge available 70% of the year. A provision was made for a minimum flow of 0.5 m^3/s to be kept in the fall during the dry season since the place is a tourist site.

With such low head and discharge the Cross Flow turbine technology was found to be most appropriate. It has the advantage of simplicity and ease of maintenance and repairs. With an efficiency of 75% to 80% cross flow turbines have a good response to a wide range of variable flow.

Using a design discharge of 1.95 m^3/s and a gross head of 18.46 m, the maximum plant capacity was found to be 232 kW. The plant is projected to generate an annual energy in the region of 1.626 GWh with a plant capacity factor of 80%.

6.1.2 Financial

The following are the summary of the financial parameters and economic indicators which are the inputs and outputs from the RETScreen Software financial analysis; they show that the project is economically viable and financially sound.

Table 6.2 Summary of Financial parameters and economic indicators

Life Span of Project	25years
Total Initial Project Cost	$1,060,000
Operation and maintenance	$10,060
Periodic Cost (every 5years)	$53,000
Electricity Export Rate	10 cents/kWh
IRR Equity after tax (assets)	13% (3.1%)
NPV	$121,389
Benefit-Cost Ratio	1.46

6.2 RECOMENDATIONS

Though this prefeasibility study concludes that the project technically, economically and financially viable, it is recommended that a more detailed assessment be made to determine the overall feasibility of the proposed project, since this is just a preliminary study and a lot of assumptions have been made.

The following detailed assessment is therefore recommended;

6.2.1 Detailed Hydrological Studies

For the feasibility study, hydrological parameters must be firmly established; the average river flows used in this study were deduced from rainfall and temperature data.

A more reliable flow data will be required to establish the actual variation of the river flow. A gauging station should be set up near the project site to collect flow data.

6.2.2 Detailed Geological Studies

Visual inspection of the site in the cause of this study gives the indication that the geological condition of the site is good. However there will be the need to undertake further field investigations during the feasibility study to determine the soundness of the foundation for the various civil structures, the penstock and the powerhouse. The foundations of the powerhouse for instance must be strong enough to withstand the heavy electromechanical equipments that will be installed. Trail pitting, percussion drilling or rotary drilling can be undertaken at the locations for the various structures to assess the subsurface profile and rock properties.

6.2.3 Environmental and Social Impact Assessment

There will be the need to undertake some environment and social impact assessment to establish the actual impact that the project if implemented would have on the environment and the tourism potential of the site. There will be the need to make a detailed assessment on the minimum volume of water that should be left for the falls during the dry season since the $0.5m^3/s$ used for this study was just an assumption.

6.2.4 Detailed Economic and Financial Analysis

Even though this preliminary study establishes the economic and financial viability of the project, it is recommended that further analysis be undertaken based on actual measured quantities extracted from detailed designs of a feasibility study.

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APPENDIX A

- Table A.1 Monthly rate of annual sunshine (Northern Hemisphere)
- Table A.2 Site stream flow measure taken on 3rd of July 2013, upstream of Fuller Falls
- Figure A.1 Catchment Area of Fuller Falls

Table A.1 Monthly rate of annual sunshine (Northern Hemisphere) (%)   (DoE, Philippines, 2009)

North Latitude	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
65	3.52	5.13	7.96	9.97	12.72	14.15	13.59	11.18	8.55	6.53	4.08	2.62
64	3.81	5.27	8.00	9.92	12.50	13.63	13.26	11.08	8.56	6.63	4.32	3.02
63	4.07	5.39	8.04	9.86	12.29	13.24	12.97	10.97	8.56	6.73	4.52	3.36
62	4.31	5.49	8.07	9.80	12.11	12.92	12.73	10.87	8.55	6.80	4.70	3.65
61	4.51	5.58	8.09	9.74	11.94	12.66	12.51	10.77	8.55	6.88	4.86	3.91
60	4.70	5.67	8.11	9.69	11.78	12.41	12.31	10.68	8.54	6.95	5.02	4.14
59	4.86	5.76	8.13	9.64	11.64	12.19	12.13	10.60	8.53	7.00	5.17	4.35
58	5.02	5.84	8.14	9.59	11.50	12.00	11.96	10.52	8.53	7.06	5.30	4.54
57	5.17	5.91	8.15	9.53	11.38	11.83	11.81	10.44	8.52	7.13	5.42	4.71
56	5.31	5.98	8.17	9.48	11.26	11.68	11.67	10.36	8.52	7.18	5.52	4.87
55	5.44	6.04	8.18	9.44	11.15	11.53	11.54	10.29	8.51	7.23	5.63	5.02
54	5.56	6.10	8.19	9.40	11.04	11.39	11.42	10.22	8.50	7.28	5.74	5.16
53	5.68	6.16	8.20	9.36	10.94	11.26	11.30	10.16	8.49	7.32	5.83	5.30
52	5.79	6.22	8.21	9.32	10.85	11.14	11.19	10.10	8.48	7.36	5.92	5.42
51	5.89	6.27	8.23	9.28	10.76	11.02	11.09	10.05	8.47	7.40	6.00	5.54
50	5.99	6.32	8.24	9.24	10.68	10.92	10.99	9.99	8.46	7.44	6.08	5.65
48	6.17	6.41	8.26	9.17	10.52	10.72	10.81	9.89	8.45	7.51	6.24	5.85
46	6.33	6.50	8.28	9.11	10.38	10.53	10.65	9.79	8.43	7.58	6.37	6.05
44	6.48	6.57	8.29	9.05	10.25	10.39	10.49	9.71	8.41	7.64	6.50	6.22
42	6.61	6.65	8.30	8.99	10.13	10.24	10.35	9.62	8.40	7.70	6.62	6.39
40	6.75	6.72	8.32	8.93	10.01	10.09	10.22	9.55	8.39	7.75	6.73	6.54
38	6.87	6.79	8.33	8.89	9.90	9.96	10.11	9.47	8.37	7.80	6.83	6.68
36	6.98	6.85	8.35	8.85	9.80	9.82	9.99	9.41	8.36	7.85	6.93	6.81
34	7.10	6.91	8.35	8.80	9.71	9.71	9.88	9.34	8.35	7.90	7.02	6.93
32	7.20	6.97	8.36	8.75	9.62	9.60	9.77	9.28	8.34	7.95	7.11	7.05
30	7.31	7.02	8.37	8.71	9.54	9.49	9.67	9.21	8.33	7.99	7.20	7.16
28	7.40	7.07	8.37	8.67	9.46	9.39	9.58	9.17	8.32	8.02	7.28	7.27
26	7.49	7.12	8.38	8.64	9.37	9.29	9.49	9.11	8.32	8.06	7.36	7.37
24	7.58	7.16	8.39	8.60	9.30	9.19	9.40	9.06	8.31	8.10	7.44	7.47
22	7.67	7.21	8.40	8.56	9.22	9.11	9.32	9.01	8.30	8.13	7.51	7.56
20	7.75	7.26	8.41	8.53	9.15	9.02	9.24	8.95	8.29	8.17	7.58	7.65
18	7.83	7.31	8.41	8.50	9.08	8.93	9.16	8.90	8.29	8.20	7.65	7.74
16	7.91	7.35	8.42	8.47	9.01	8.85	9.08	8.85	8.28	8.23	7.72	7.83
14	7.98	7.39	8.43	8.43	8.94	8.77	9.00	8.80	8.27	8.27	7.79	7.93
12	8.06	7.43	8.44	8.40	8.87	8.69	8.92	8.76	8.26	8.31	7.85	8.01
10	8.14	7.47	8.45	8.37	8.81	8.61	8.85	8.71	8.25	8.34	7.91	8.09
8	8.21	7.51	8.45	8.34	8.74	8.53	8.78	8.66	8.25	8.37	7.98	8.18
6	8.28	7.55	8.46	8.31	8.68	8.45	8.71	8.62	8.24	8.40	8.04	8.26
4	8.36	7.59	8.47	8.28	8.62	8.37	8.64	8.58	8.23	8.43	8.10	8.34
2	8.43	7.63	8.49	8.25	8.55	8.29	8.57	8.53	8.22	8.46	8.16	8.42
0	8.50	7.67	8.49	8.22	8.49	8.22	8.50	8.49	8.21	8.49	8.22	8.50

Table A.2 Site stream flow measure taken on 3rd of July 2013, upstream of Fuller Falls

Determination of Stream Cross Sectional Area								
Location 1					Location 2			
Points	Depth (m)	Position (m)	Area (m2)		Points	Depth (m)	Position (m)	Area (m2)
L 1	0.00	0.00	0.00		L 1	0.00	0.00	0.00
L 2	0.08	0.50	0.02		L 2	0.04	0.50	0.01
L 3	0.17	1.00	0.06		L 3	0.14	1.00	0.05
L 4	0.28	1.50	0.11		L 4	0.25	1.50	0.10
L 5	0.32	2.00	0.15		L 5	0.29	2.00	0.14
L 6	0.37	2.50	0.17		L 6	0.30	2.50	0.15
L 7	0.40	3.00	0.19		L 7	0.31	3.00	0.15
L 8	0.40	3.50	0.20		L 8	0.32	3.50	0.16
L 9	0.60	4.00	0.25		L 9	0.33	4.00	0.16
L 10	0.54	4.50	0.28		L 10	0.39	4.50	0.18
L 11	0.47	5.00	0.25		L 11	0.48	5.00	0.22
L 12	0.30	5.50	0.19		L 12	0.59	5.50	0.27
L 13	0.04	6.00	0.09		L 13	0.48	6.00	0.27
L 14	0.00	6.50	0.01		L 14	0.14	6.50	0.16
					L 15	0.00	7.00	0.04
Total	Area 1 =		1.98		Total	Area 2 =		2.03
Average Cross sectional area of stream A =0.5 x (Area1+ Area2) =								2.00

Determination of Velocity & Discharge					
Time	Seconds (s)	Distance L between Location 1 & 2 =		3.5	m
T1	5.65	Mean Velocity =	L / Tmean	0.657	m/s
T2	5.30	Discharge Q=	VxA =	1.31	m3/s
T3	5.03	Correction factor		0.85	
T_{mean}	5.33	Actual Discharge Qactual	0.85 xQ=	**1.12**	**m3/s**

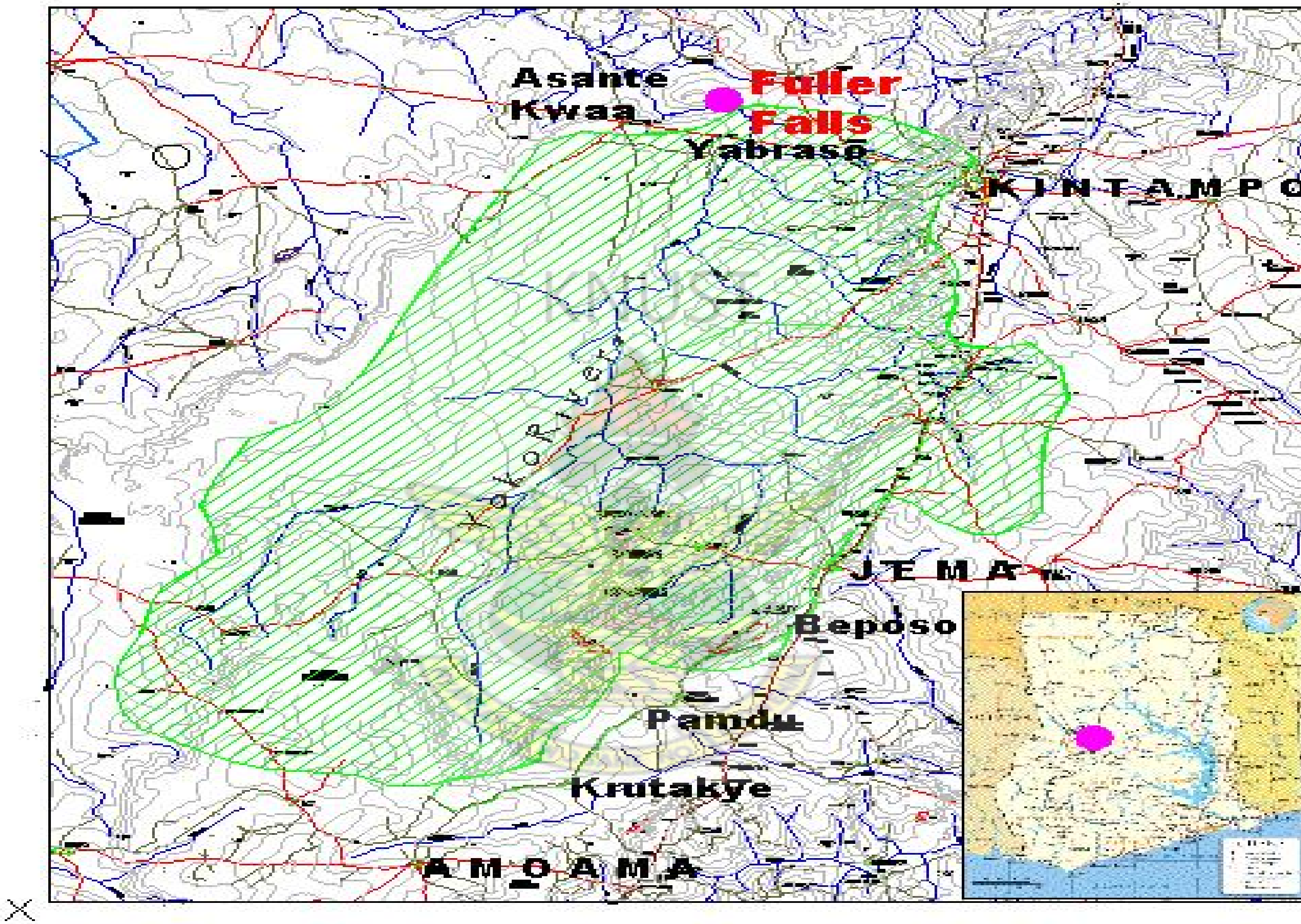

Figure A.1 Catchment Area of Fuller Falls

APPENDIX B

- Table B.1 Monthly mean Temperatures (°C) (1992 to 2007)
- Table B- 2 Average Monthly Rainfall (mm) (1992-2007)

Table B.1 Monthly mean Temperatures (°C) (1992 to 2007)

Year	Jan			Feb			Mar			Apr			May			Jun		
	Max.	Min.	mean	Max.	Min.	mean	Max.	Min.	mean	Max.	Min.	mean	Max.	Min.	mean	Max.	Min.	mean
1992	32.9	19.4	26.15	35.8	22.6	29.2	34.6	24.1	29.35	32.7	23.1	27.9	31.4	22.7	27.05	29.20	21.40	25.30
1993	33.7	17.2	25.45	35.7	22.2	28.95	33.9	20.7	27.3	34.1	21.1	27.6	32.3	23	27.65	30.10	21.80	25.95
1994	34.2	20.1	27.15	36.5	22.9	29.7	36.5	23.7	30.1	33.8	23.8	28.8	30.1	23	26.55	29.60	21.90	25.75
1995	34.4	20.2	27.3	36.6	22	29.3	36.1	23.7	29.9	33.5	24	28.75	31.8	22.7	27.25	30.10	22.00	26.05
1996	34.4	21.2	27.8	35.4	21.4	28.4	35	23.4	29.2	33	23.2	28.1	31.7	22.9	27.30	29.60	21.90	25.75
1997	34.3	21.6	27.95	35.8	21.3	28.55	35.7	23.9	29.8	32.8	23.2	28	30.8	22.7	26.75	29.20	21.80	25.50
1998	34.3	19.3	26.8	36.2	22	29.1	37.8	26	31.9	34.3	24.1	29.2	33	23.7	28.35	30.40	22.20	26.30
1999	34.6	19.6	27.1	34.7	21.5	28.1	34.6	23.3	28.95	32.8	22.8	27.8	32.1	22.3	27.20	31.20	22.10	26.65
2000	33.5	20.7	27.1	35	20.8	27.9	36.5	23	29.75	34.6	23.2	28.9	32.6	22.6	27.60	29.90	21.70	25.80
2001	34.6	14.8	24.7	36.5	21.4	28.95	36.6	22.7	29.65	33.9	22.5	28.2	32.3	22.7	27.50	32.90	26.10	29.50
2002	33.7	21.9	27.8	36.1	23.4	29.75	35	24.1	29.55	32.8	22.8	27.8	31.5	23	27.25	30.00	21.80	25.90
2003	33.9	22.1	28	34.8	23.3	29.05	35.3	23.8	29.55	32.6	23.2	27.9	32.1	23.3	27.70	29.20	21.70	25.45
2004	33.3	21.9	27.6	34.5	23.2	28.85	34.5	23.7	29.1	32.9	23.1	28	31.1	23.1	27.10	29.90	21.90	25.90
2005	32	20.6	26.3	33.8	22.4	28.1	34.6	23.9	29.25	34.2	23.9	29.05	31.9	22.8	27.35	29.30	22.30	25.80
2006	33.7	21.6	27.65	35.1	23.1	29.1	34.2	23.2	28.7	33.7	23.8	28.75	31.5	22.7	27.10	30.40	22.30	26.35
2007	32.2	21	26.6	34.6	23.3	28.95	35.6	23.8	29.7	32.8	23	27.9	31.8	23.1	27.45	30.40	22.10	26.25
Mean	33.7	20.2	26.97	35.4	22.3	28.87	35.4	23.6	29.48	33.4	23.2	28.29	31.8	22.9	27.32	30.09	22.19	26.14
Avg	26.97			28.87			29.48			28.29			27.32			26.14		

Table B.1 Monthly mean Temperatures (°C) (1992 to 2007) continued

Year	Jul			Aug			Sep			Oct			Nov			Dec		
	Max.	Min.	mean	Max.	Min.	mean	Max.	Min.	mean	Max.	Min.	mean	Max.	Min.	mean	Max.	Min.	mean
1992	27.50	21.00	24.25	28.10	20.60	24.35	29.20	20.10	24.65	30.60	20.90	25.75	31.70	20.10	25.90	32.50	17.40	24.95
1993	28.10	21.40	24.75	28.50	21.00	24.75	29.10	21.10	25.10	31.50	22.00	26.75	32.50	22.60	27.55	32.20	19.80	26.00
1994	29.30	21.80	25.55	29.60	21.30	25.45	29.20	21.40	25.30	30.10	21.80	25.95	33.00	20.50	26.75	33.50	18.90	26.20
1995	28.80	21.70	25.25	28.00	21.80	24.90	29.80	21.30	25.55	30.40	21.30	25.85	32.90	20.40	26.65	32.40	20.90	26.65
1996	28.70	21.40	25.05	28.50	21.60	25.05	28.60	21.70	25.15	30.60	21.20	25.90	33.40	20.50	26.95	32.80	21.90	27.35
1997	28.70	21.40	25.05	28.80	21.60	25.20	29.40	22.10	25.75	31.10	22.40	26.75	32.60	22.00	27.30	32.80	18.10	25.45
1998	28.90	22.00	25.45	28.80	21.60	25.20	29.60	21.50	25.55	31.00	21.5*	26.25	33.60	22.00	27.80	33.10	20.30	26.70
1999	29.40	21.40	25.40	29.20	21.00	25.10	29.00	21.00	25.00	30.40	18.30	24.35	32.70	21.70	27.20	32.80	19.00	25.90
2000	28.60	21.30	24.95	28.40	20.80	24.60	28.70	21.60	25.15	32.30	21.20	26.75	32.70	21.60	27.15	32.70	17.30	25.00
2001	29.40	21.40	25.40	28.40	21.30	24.85	29.3*	21.0*	25.35	30.8*	21.5*	26.15	32.5*	21.7*	27.10	32.6*	19.9*	26.25
2002	28.30	21.80	25.05	27.70	21.60	24.65	28.80	21.50	25.15	30.20	21.90	26.05	31.40	22.50	26.95	32.00	21.40	26.70
2003	28.30	21.60	24.95	28.40	21.50	24.95	29.40	21.90	25.65	30.80	22.40	26.60	31.50	22.50	27.00	32.6*	19.9*	26.25
2004	29.10	21.60	25.35	28.50	21.60	25.05	29.40	21.40	25.40	31.20	21.80	26.50	32.20	22.80	27.50	32.40	22.50	27.45
2005	28.90	21.50	25.20	28.00	21.30	24.65	29.20	21.60	25.40	31.10	21.70	26.40	32.60	22.30	27.45	32.20	19.80	26.00
2006	29.10	22.30	25.70	28.80	21.90	25.35	29.80	21.80	25.80	30.60	22.20	26.40	32.20	21.80	27.00	32.40	20.80	26.60
2007	28.7*	21.6*	25.15	29.30	19.20	24.25	29.80	21.40	25.60	30.80	21.50	26.15	32.30	22.00	27.15	32.00	20.60	26.30
Mean	28.74	21.58	25.16	28.56	21.23	24.90	29.27	21.43	25.35	30.84	21.48	26.16	32.49	21.69	27.09	32.56	19.91	26.23
Avg	25.16			24.90			25.35			26.16			27.09			26.23		

* Values missing, monthly average values used

Table B- 2 Average Monthly Rainfall (mm) (1992-2007)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
1992	0	9.3	80.3	191.4	91.6	195.4	46.1	9.2	184.6	115.5	52.7	0
1993	0	13	108.3	55.6	108	172	167.2	139.1	373.4	143.9	24.7	3.4
1994	0	0	32.9	74.8	148.1	124.7	32	88	162.7	179.9	11.3	0
1995	0	1.1	13.8	179.4	179	138.2	131.3	141	213.9	240.1	9.8	20.3
1996	8.1	32	72.2	99.2	203.1	232	107.4	76.4	106.7	126.2	0	0
1997	11.1	0	66	73.6	212.9	200.3	52.2	114.7	259.5	136.4	89.7	0
1998	0	29.6	0	210.7	71.3	275.4	42.5	127.3	170.5	202.1	73.4	32.8
1999	0	41.9	71.4	259.7	134.5	208.1	302.3	160.3	129.7	271.9	70.3	0
2000	41.90	0.00	7.30	114.60	136.30	255.90	31.30	280.90	199.40	170.80	10.40	0.00
2001	0.00	0.00	31.10	149.10	120.70	147.80	101.40	53.20	215.82*	197.86*	38.23*	11.35*
2002	0.00	0.00	64.80	152.30	166.60	195.80	281.80	138.20	253.20	277.10	34.80	15.90
2003	9.30	107.70	28.50	170.00	56.90	254.80	75.90	85.40	168.40	176.80	92.40	0.00
2004	70.80	44.10	48.80	229.70	139.20	142.90	161.00	176.90	230.30	209.50	47.40	24.40
2005	4.40	27.40	68.20	66.60	196.80	99.70	171.40	84.90	259.30	222.60	33.50	59.20
2006	2.10	18.60	108.40	69.00	176.20	245.00	64.60	22.00	254.90	283.30	0.00	0.00
2007	0	28.3	113.6	137.6	211.8	196.9	117.89*	30.8	270.8	211.8	23	14.2
Average Rainfall	**9.23**	**22.06**	**57.23**	**139.58**	**147.06**	**192.81**	**117.89**	**108.02**	**215.82**	**197.86**	**38.23**	**11.35**
* Values missing , monthly average values used												

APPENDIX C

- Table C.1 Discharge Calculations using the Water Balance Method
- Table C-2 Average Monthly Discharge (m^3/s)

Table C.1 Discharge Calculations using the Water Balance Method 1 of 8

Year	Tempt, t ( )	Monthly Rate of Annual Sunshine, p (%)	Possible Evaporation (mm)	Rainfall (mm)	Real Evaporation (mm)	Runoff (mm)	Direct runoff (mm)	Base runoff (mm)	Monthly runoff (mm)	No. Days in Month	Monthly mean discharge (m3/s)
Jan-92	26.15	8.21	98.92	0	0.00	0.00	0.00	8.47	8.47	31.00	1.47
Feb-92	29.20	7.51	96.76	9.3	9.30	0.00	0.00	7.92	7.92	29.00	1.47
Mar-92	29.35	8.45	109.22	80.3	80.30	0.00	0.00	8.47	8.47	31.00	1.47
Apr-92	27.90	8.34	104.49	191.4	104.49	86.91	56.49	8.19	64.69	30.00	11.60
May-92	27.10	8.74	107.58	91.6	91.60	0.00	0.00	8.47	8.47	31.00	1.47
Jun-92	25.30	8.53	100.78	195.4	100.78	94.62	61.50	8.19	69.69	30.00	12.50
Jul-92	24.25	8.78	101.21	46.1	46.10	0.00	0.00	8.47	8.47	31.00	1.47
Aug-92	24.35	8.66	100.06	9.2	9.20	0.00	0.00	8.47	8.47	31.00	1.47
Sep-92	24.70	8.25	96.12	184.6	96.12	88.48	57.51	8.19	65.71	30.00	11.79
Oct-92	25.75	8.37	99.93	115.5	99.93	15.57	10.12	8.47	18.59	31.00	3.23
Nov-92	25.90	7.98	95.60	52.7	52.70	0.00	0.00	8.19	8.19	30.00	1.47
Dec-92	24.95	8.18	95.86	0	0.00	0.00	0.00	8.47	8.47	31.00	1.47
total			**0.00**	**976.10**		**285.59**	**185.63**	**99.95**	**285.59**		
			0.00								
Jan-93	25.45	8.21	97.34	0	0.00	0.00	0.00	14.70	14.70	31.00	2.55
Feb-93	28.95	7.51	96.25	13	13.00	0.00	0.00	13.28	13.28	28.00	2.55
Mar-93	27.30	8.45	104.47	108.3	104.47	3.83	2.49	14.70	17.19	31.00	2.98
Apr-93	27.60	8.34	103.80	55.6	55.60	0.00	0.00	14.22	14.22	30.00	2.55
May-93	27.65	8.74	108.90	108	108.00	0.00	0.00	14.70	14.70	31.00	2.55
Jun-93	25.95	8.53	102.30	172	102.30	69.70	45.30	14.22	59.53	30.00	10.68
Jul-93	24.75	8.78	102.41	167.2	102.41	64.79	42.11	14.70	56.81	31.00	9.86
Aug-93	24.75	8.66	101.01	139.1	101.01	38.09	24.76	14.70	39.45	31.00	6.85
Sep-93	25.10	8.25	97.02	373.4	97.02	276.38	179.64	14.22	193.87	30.00	34.78
Oct-93	26.75	8.37	102.22	143.9	102.22	41.68	27.09	14.70	41.79	31.00	7.26
Nov-93	27.55	7.98	99.21	24.7	24.70	0.00	0.00	14.22	14.22	30.00	2.55
Dec-93	26.00	8.18	98.22	3.4	3.40	0.00	0.00	14.70	14.70	31.00	2.55
total				1308.60		494.45	321.39	173.06	494.45		

Table C.1 Discharge Calculations using the Water Balance Method

Year	Tempt, t ( )	Monthly Rate of Annual Sunshine, p (%)	Possible Evaporation (mm)	Rainfall (mm)	Real Evaporation (mm)	Runoff (mm)	Direct runoff (mm)	Base runoff (mm)	Monthly runoff (mm)	No. Days in Month	Monthly mean discharge (m3/s)
Jan-94	27.15	8.21	101.17	0	0.00	0.00	0.00	6.23	6.23	31.00	1.08
Feb-94	29.70	7.51	97.79	0	0.00	0.00	0.00	5.62	5.62	28.00	1.08
Mar-94	30.10	8.45	110.96	32.9	32.90	0.00	0.00	6.23	6.23	31.00	1.08
Apr-94	28.80	8.34	106.54	74.8	74.80	0.00	0.00	6.03	6.03	30.00	1.08
May-94	26.55	8.74	106.26	148.1	106.26	41.84	27.20	6.23	33.42	31.00	5.80
Jun-94	25.75	8.53	101.84	124.7	101.84	22.86	14.86	6.03	20.89	30.00	3.75
Jul-94	25.55	8.78	104.34	32	32.00	0.00	0.00	6.23	6.23	31.00	1.08
Aug-94	25.45	8.66	102.68	88	88.00	0.00	0.00	6.23	6.23	31.00	1.08
Sep-94	25.30	8.25	97.48	162.7	97.48	65.22	42.40	6.03	48.42	30.00	8.69
Oct-94	25.95	8.37	100.39	179.9	100.39	79.51	51.68	6.23	57.91	31.00	10.05
Nov-94	26.75	7.98	97.46	11.3	11.30	0.00	0.00	6.03	6.03	30.00	1.08
Dec-94	26.20	8.18	98.67	0	0.00	0.00	0.00	6.23	6.23	31.00	1.08
total						209.44	136.14	73.30	209.44		
Jan-95	27.30	8.21	101.51	0	0.00	0.00	0.00	14.95	14.95	31.00	2.59
Feb-95	29.30	7.51	96.97	1.1	1.10	0.00	0.00	13.50	13.50	28.00	2.59
Mar-95	29.90	8.45	110.50	13.8	13.80	0.00	0.00	14.95	14.95	31.00	2.59
Apr-95	28.75	8.34	106.43	179.4	106.43	72.97	47.43	14.46	61.90	30.00	11.10
May-95	27.25	8.74	107.94	179	107.94	71.06	46.19	14.95	61.14	31.00	10.61
Jun-95	26.05	8.53	102.54	138.2	102.54	35.66	23.18	14.46	37.64	30.00	6.75
Jul-95	25.25	8.78	103.62	131.3	103.62	27.68	17.99	14.95	32.94	31.00	5.72
Aug-95	24.90	8.66	101.37	141	101.37	39.63	25.76	14.95	40.71	31.00	7.07
Sep-95	25.55	8.25	98.04	213.9	98.04	115.86	75.31	14.46	89.77	30.00	16.11
Oct-95	25.85	8.37	100.16	240.1	100.16	139.94	90.96	14.95	105.91	31.00	18.39
Nov-95	26.65	7.98	97.24	9.8	9.80	0.00	0.00	14.46	14.46	30.00	2.59
Dec-95	26.65	8.18	99.68	20.3	20.30	0.00	0.00	14.95	14.95	31.00	2.59
total						502.81	326.83	175.98	502.81		

Table C.1 Discharge Calculations using the Water Balance Method

Year	Tempt, t ( ) ¤	Monthly Rate of Annual Sunshine, p (%)	Possible Evaporation (mm)	Rainfall (mm)	Real Evaporation (mm)	Runoff (mm)	Direct runoff (mm)	Base runoff (mm)	Monthly runoff (mm)	No. Days in Month	Monthly mean discharge (m3/s)
Jan-96	27.80	8.21	102.63	8.1	8.10	0.00	0.00	7.85	7.85	31.00	1.36
Feb-96	28.40	7.51	95.12	32	32.00	0.00	0.00	7.35	7.35	29.00	1.36
Mar-96	29.20	8.45	108.88	72.2	72.20	0.00	0.00	7.85	7.85	31.00	1.36
Apr-96	28.10	8.34	104.94	99.2	99.20	0.00	0.00	7.60	7.60	30.00	1.36
May-96	27.30	8.74	108.06	203.1	108.06	95.04	61.78	7.85	69.63	31.00	12.09
Jun-96	25.75	8.53	101.84	232	101.84	130.16	84.61	7.60	92.21	30.00	16.54
Jul-96	25.05	8.78	103.14	107.4	103.14	4.26	2.77	7.85	10.63	31.00	1.84
Aug-96	25.05	8.66	101.73	76.4	76.40	0.00	0.00	7.85	7.85	31.00	1.36
Sep-96	25.15	8.25	97.14	106.7	97.14	9.56	6.22	7.60	13.82	30.00	2.48
Oct-96	25.90	8.37	100.27	126.2	100.27	25.93	16.85	7.85	24.71	31.00	4.29
Nov-96	26.95	7.98	97.90	0	0.00	0.00	0.00	7.60	7.60	30.00	1.36
Dec-96	27.35	8.18	101.25	0	0.00	0.00	0.00	7.85	7.85	31.00	1.36
total						264.96	172.22	92.74	264.96		
			0.00								
Jan-97	27.95	8.21	102.97	11.1	11.10	0.00	0.00	12.28	12.28	31.00	2.13
Feb-97	28.55	7.51	95.43	0	0.00	0.00	0.00	11.09	11.09	28.00	2.13
Mar-97	29.80	8.45	110.27	66	66.00	0.00	0.00	12.28	12.28	31.00	2.13
Apr-97	28.00	8.34	104.71	73.6	73.60	0.00	0.00	11.88	11.88	30.00	2.13
May-97	26.75	8.74	106.74	212.9	106.74	106.16	69.00	12.28	81.28	31.00	14.11
Jun-97	25.50	8.53	101.25	200.3	101.25	99.05	64.38	11.88	76.26	30.00	13.68
Jul-97	25.05	8.78	103.14	52.2	52.20	0.00	0.00	12.28	12.28	31.00	2.13
Aug-97	25.20	8.66	102.08	114.7	102.08	12.62	8.20	12.28	20.48	31.00	3.56
Sep-97	25.75	8.25	98.49	259.5	98.49	161.01	104.65	11.88	116.54	30.00	20.91
Oct-97	26.75	8.37	102.22	136.4	102.22	34.18	22.22	12.28	34.49	31.00	5.99
Nov-97	27.30	7.98	98.66	89.7	89.70	0.00	0.00	11.88	11.88	30.00	2.13
Dec-97	25.45	8.18	96.99	0	0.00	0.00	0.00	12.28	12.28	31.00	2.13
total						413.01	268.46	144.55	413.01		

Table C.1 Discharge Calculations using the Water Balance Method 4 of 8

Year	Tempt, t ( )	Monthly Rate of Annual Sunshine, p (%)	Possible Evaporation (mm)	Rainfall (mm)	Real Evaporation (mm)	Runoff (mm)	Direct runoff (mm)	Base runoff (mm)	Monthly runoff (mm)	No. Days in Month	Monthly mean discharge (m3/s)
Jan-98	26.80	8.21	100.38	0	0.00	0.00	0.00	14.10	14.10	31.00	2.45
Feb-98	29.10	7.51	96.56	29.6	29.60	0.00	0.00	12.73	12.73	28.00	2.45
Mar-98	31.90	8.45	115.13	0	0.00	0.00	0.00	14.10	14.10	31.00	2.45
Apr-98	29.20	8.34	107.46	210.7	107.46	103.24	67.11	13.64	80.75	30.00	14.49
May-98	28.35	8.74	110.57	71.3	71.30	0.00	0.00	14.10	14.10	31.00	2.45
Jun-98	26.30	8.53	103.12	275.4	103.12	172.28	111.98	13.64	125.62	30.00	22.54
Jul-98	25.45	8.78	104.10	42.5	42.50	0.00	0.00	14.10	14.10	31.00	2.45
Aug-98	25.20	8.66	102.08	127.3	102.08	25.22	16.39	14.10	30.49	31.00	5.29
Sep-98	25.55	8.25	98.04	170.5	98.04	72.46	47.10	13.64	60.74	30.00	10.90
Oct-98	26.25	8.37	101.07	202.1	101.07	101.03	65.67	14.10	79.76	31.00	13.85
Nov-98	27.80	7.98	99.76	73.4	73.40	0.00	0.00	13.64	13.64	30.00	2.45
Dec-98	26.70	8.18	99.79	32.8	32.80	0.00	0.00	14.10	14.10	31.00	2.45
total						474.22	308.24	165.98	474.22		
			0.00								
Jan-99	27.10	8.21	101.06	0	0.00	0.00	0.00	22.33	22.33	31.00	3.88
Feb-99	28.10	7.51	94.50	41.9	41.90	0.00	0.00	20.17	20.17	28.00	3.88
Mar-99	28.95	8.45	108.30	71.4	71.40	0.00	0.00	22.33	22.33	31.00	3.88
Apr-99	27.80	8.34	104.26	259.7	104.26	155.44	101.04	21.61	122.65	30.00	22.00
May-99	27.20	8.74	107.82	134.5	107.82	26.68	17.34	22.33	39.67	31.00	6.89
Jun-99	26.65	8.53	103.94	208.1	103.94	104.16	67.70	21.61	89.31	30.00	16.02
Jul-99	25.40	8.78	103.98	302.3	103.98	198.32	128.91	22.33	151.24	31.00	26.26
Aug-99	25.10	8.66	101.85	160.3	101.85	58.45	38.00	22.33	60.32	31.00	10.47
Sep-99	25.00	8.25	96.80	129.7	96.80	32.90	21.39	21.61	43.00	30.00	7.71
Oct-99	24.35	8.37	96.71	271.9	96.71	175.19	113.87	22.33	136.20	31.00	23.65
Nov-99	27.20	7.98	98.44	70.3	70.30	0.00	0.00	21.61	21.61	30.00	3.88
Dec-99	25.90	8.18	97.99	0	0.00	0.00	0.00	22.33	22.33	31.00	3.88
total						751.15	488.25	262.90	751.15		

Table C.1 Discharge Calculations using the Water Balance Method 5 of 8

Year	Tempt, t ( )	Monthly Rate of Annual Sunshine, p (%)	Possible Evaporation (mm)	Rainfall (mm)	Real Evaporation (mm)	Runoff (mm)	Direct runoff (mm)	Base runoff (mm)	Monthly runoff (mm)	No. Days in Month	Monthly mean discharge (m3/s)
Jan-00	27.10	8.21	101.06	41.90	41.90	0.00	0.00	16.02	16.02	31.00	2.78
Feb-00	27.90	7.51	94.09	0.00	0.00	0.00	0.00	14.99	14.99	29.00	2.78
Mar-00	29.75	8.45	110.15	7.30	7.30	0.00	0.00	16.02	16.02	31.00	2.78
Apr-00	28.90	8.34	106.77	114.60	106.77	7.83	5.09	15.50	20.59	30.00	3.69
May-00	27.60	8.74	108.78	136.30	108.78	27.52	17.89	16.02	33.91	31.00	5.89
Jun-00	25.80	8.53	101.95	255.90	101.95	153.95	100.07	15.50	115.57	30.00	20.73
Jul-00	24.95	8.78	102.90	31.30	31.30	0.00	0.00	16.02	16.02	31.00	2.78
Aug-00	24.60	8.66	100.66	280.90	100.66	180.24	117.16	16.02	133.18	31.00	23.12
Sep-00	25.15	8.25	97.14	199.40	97.14	102.26	66.47	15.50	81.97	30.00	14.71
Oct-00	26.75	8.37	102.22	170.80	102.22	68.58	44.58	16.02	60.60	31.00	10.52
Nov-00	27.15	7.98	98.33	10.40	10.40	0.00	0.00	15.50	15.50	30.00	2.78
Dec-00	25.00	8.18	95.98	0.00	0.00	0.00	0.00	16.02	16.02	31.00	2.78
total						540.38	351.25	189.13	540.38		
			0.00								
Jan-01	24.70	8.21	95.65	0.00	0.00	0.00	0.00	9.17	9.17	31.00	1.59
Feb-01	28.95	7.51	96.25	0.00	0.00	0.00	0.00	8.28	8.28	28.00	1.59
Mar-01	29.65	8.45	109.92	31.10	31.10	0.00	0.00	9.17	9.17	31.00	1.59
Apr-01	28.20	8.34	105.17	149.10	105.17	43.93	28.55	8.88	37.43	30.00	6.71
May-01	27.50	8.74	108.54	120.70	108.54	12.16	7.91	9.17	17.08	31.00	2.96
Jun-01	29.50	8.53	110.61	147.80	110.61	37.19	24.18	8.88	33.05	30.00	5.93
Jul-01	25.40	8.78	103.98	101.40	101.40	0.00	0.00	9.17	9.17	31.00	1.59
Aug-01	24.85	8.66	101.25	53.20	53.20	0.00	0.00	9.17	9.17	31.00	1.59
Sep-01	25.35	8.25	97.59	215.82	97.59	118.23	76.85	8.88	85.73	30.00	15.38
Oct-01	26.15	8.37	100.84	197.86	100.84	97.02	63.06	9.17	72.23	31.00	12.54
Nov-01	27.10	7.98	98.22	38.23	38.23	0.00	0.00	8.88	8.88	30.00	1.59
Dec-01	26.25	8.18	98.78	11.35	11.35	0.00	0.00	9.17	9.17	31.00	1.59
total			0.00			308.53	200.54	107.99	308.53		

Table C.1 Discharge Calculations using the Water Balance Method

Year	Tempt, t ( )	Monthly Rate of Annual Sunshine, p (%)	Possible Evaporation (mm)	Rainfall (mm)	Real Evaporation (mm)	Runoff (mm)	Direct runoff (mm)	Base runoff (mm)	Monthly runoff (mm)	No. Days in Month	Monthly mean discharge (m3/s)
Jan-02	27.80	8.21	102.63	0.00	0.00	0.00	0.00	22.26	22.26	31.00	3.87
Feb-02	29.75	7.51	97.90	0.00	0.00	0.00	0.00	20.11	20.11	28.00	3.87
Mar-02	29.55	8.45	109.69	64.80	64.80	0.00	0.00	22.26	22.26	31.00	3.87
Apr-02	27.80	8.34	104.26	152.30	104.26	48.04	31.23	21.55	52.77	30.00	9.47
May-02	27.25	8.74	107.94	166.60	107.94	58.66	38.13	22.26	60.39	31.00	10.48
Jun-02	25.90	8.53	102.19	195.80	102.19	93.61	60.85	21.55	82.39	30.00	14.78
Jul-02	25.05	8.78	103.14	281.80	103.14	178.66	116.13	22.26	138.39	31.00	24.03
Aug-02	24.65	8.66	100.78	138.20	100.78	37.42	24.33	22.26	46.59	31.00	8.09
Sep-02	25.15	8.25	97.14	253.20	97.14	156.06	101.44	21.55	122.99	30.00	22.06
Oct-02	26.05	8.37	100.62	277.10	100.62	176.48	114.72	22.26	136.98	31.00	23.78
Nov-02	26.95	7.98	97.90	34.80	34.80	0.00	0.00	21.55	21.55	30.00	3.87
Dec-02	26.70	8.18	99.79	15.90	15.90	0.00	0.00	22.26	22.26	31.00	3.87
total					831.55	748.95	486.82	262.13			
Jan-03	28.00	8.21	103.08	9.30	9.30	0.00	0.00	11.16	11.16	31.00	1.94
Feb-03	29.05	7.51	96.45	107.70	96.45	11.25	7.31	10.08	17.39	28.00	3.34
Mar-03	29.55	8.45	109.69	28.50	28.50	0.00	0.00	11.16	11.16	31.00	1.94
Apr-03	27.90	8.34	104.49	170.00	104.49	65.51	42.58	10.80	53.39	30.00	9.58
May-03	27.70	8.74	109.02	56.90	56.90	0.00	0.00	11.16	11.16	31.00	1.94
Jun-03	25.45	8.53	101.14	254.80	101.14	153.66	99.88	10.80	110.68	30.00	19.86
Jul-03	24.95	8.78	102.90	75.90	75.90	0.00	0.00	11.16	11.16	31.00	1.94
Aug-03	24.95	8.66	101.49	85.40	85.40	0.00	0.00	11.16	11.16	31.00	1.94
Sep-03	25.65	8.25	98.27	168.40	98.27	70.13	45.59	10.80	56.39	30.00	10.12
Oct-03	26.60	8.37	101.88	176.80	101.88	74.92	48.70	11.16	59.86	31.00	10.39
Nov-03	27.00	7.98	98.01	92.40	92.40	0.00	0.00	10.80	10.80	30.00	1.94
Dec-03	26.25	8.18	98.78	0.00	0.00	0.00	0.00	11.16	11.16	31.00	1.94
total						375.48	244.06	131.42	375.48		

Table C.1 Discharge Calculations using the Water Balance Method

Year	Tempt, t ( ) ▫	Monthly Rate of Annual Sunshine, p (%)	Possible Evaporation (mm)	Rainfall (mm)	Real Evaporation (mm)	Runoff (mm)	Direct runoff (mm)	Base runoff (mm)	Monthly runoff (mm)	No. Days in Month	Monthly mean discharge (m3/s)
Jan-04	27.60	8.21	102.18	70.80	70.80	0.00	0.00	16.90	16.90	31.00	2.93
Feb-04	28.85	7.51	96.04	44.10	44.10	0.00	0.00	15.81	15.81	29.00	2.93
Mar-04	29.10	8.45	108.64	48.80	48.80	0.00	0.00	16.90	16.90	31.00	2.93
Apr-04	28.00	8.34	104.71	229.70	104.71	124.99	81.24	16.35	97.60	30.00	17.51
May-04	27.10	8.74	107.58	139.20	107.58	31.62	20.55	16.90	37.45	31.00	6.50
Jun-04	25.90	8.53	102.19	142.90	102.19	40.71	26.46	16.35	42.82	30.00	7.68
Jul-04	25.35	8.78	103.86	161.00	103.86	57.14	37.14	16.90	54.04	31.00	9.38
Aug-04	25.05	8.66	101.73	176.90	101.73	75.17	48.86	16.90	65.76	31.00	11.42
Sep-04	25.40	8.25	97.70	230.30	97.70	132.60	86.19	16.35	102.54	30.00	18.40
Oct-04	26.50	8.37	101.65	209.50	101.65	107.85	70.10	16.90	87.00	31.00	15.10
Nov-04	27.50	7.98	99.10	47.40	47.40	0.00	0.00	16.35	16.35	30.00	2.93
Dec-04	27.45	8.18	101.47	24.40	24.40	0.00	0.00	16.90	16.90	31.00	2.93
total						570.08	370.56	199.53	570.08		
			0.00								
Jan-05	26.30	8.21	99.25	4.40	4.40	0.00	0.00	13.06	13.06	31.00	2.27
Feb-05	28.10	7.51	94.50	27.40	27.40	0.00	0.00	11.80	11.80	28.00	2.27
Mar-05	29.25	8.45	108.99	68.20	68.20	0.00	0.00	13.06	13.06	31.00	2.27
Apr-05	29.05	8.34	107.11	66.60	66.60	0.00	0.00	12.64	12.64	30.00	2.27
May-05	27.35	8.74	108.18	196.80	108.18	88.62	57.60	13.06	70.66	31.00	12.27
Jun-05	25.80	8.53	101.95	99.70	99.70	0.00	0.00	12.64	12.64	30.00	2.27
Jul-05	25.20	8.78	103.50	171.40	103.50	67.90	44.14	13.06	57.20	31.00	9.93
Aug-05	24.65	8.66	100.78	84.90	84.90	0.00	0.00	13.06	13.06	31.00	2.27
Sep-05	25.40	8.25	97.70	259.30	97.70	161.60	105.04	12.64	117.68	30.00	21.11
Oct-05	26.40	8.37	101.42	222.60	101.42	121.18	78.77	13.06	91.83	31.00	15.94
Nov-05	27.45	7.98	98.99	33.50	33.50	0.00	0.00	12.64	12.64	30.00	2.27
Dec-05	26.00	8.18	98.22	59.20	59.20	0.00	0.00	13.06	13.06	31.00	2.27
total						439.30	285.55	153.76	439.30		

Table C.1 Discharge Calculations using the Water Balance Method 8 of 8

Year	Tempt, t ( )	Monthly Rate of Annual Sunshine, p (%)	Possible Evaporation (mm)	Rainfall (mm)	Real Evaporation (mm)	Runoff (mm)	Direct runoff (mm)	Base runoff (mm)	Monthly runoff (mm)	No. Days in Month	Monthly mean discharge (m3/s)
Jan-06	27.65	8.21	102.29	2.10	2.10	0.00	0.00	16.33	16.33	31.00	2.83
Feb-06	29.10	7.51	96.56	18.60	18.60	0.00	0.00	14.75	14.75	28.00	2.83
Mar-06	28.70	8.45	107.72	108.40	107.72	0.68	0.44	16.33	16.77	31.00	2.91
Apr-06	28.75	8.34	106.43	69.00	69.00	0.00	0.00	15.80	15.80	30.00	2.83
May-06	27.10	8.74	107.58	176.20	107.58	68.62	44.60	16.33	60.93	31.00	10.58
Jun-06	26.35	8.53	103.24	245.00	103.24	141.76	92.14	15.80	107.94	30.00	19.36
Jul-06	25.70	8.78	104.70	64.60	64.60	0.00	0.00	16.33	16.33	31.00	2.83
Aug-06	25.35	8.66	102.44	22.00	22.00	0.00	0.00	16.33	16.33	31.00	2.83
Sep-06	25.80	8.25	98.61	254.90	98.61	156.29	101.59	15.80	117.39	30.00	21.06
Oct-06	26.40	8.37	101.42	283.30	101.42	181.88	118.22	16.33	134.55	31.00	23.36
Nov-06	27.00	7.98	98.01	0.00	0.00	0.00	0.00	15.80	15.80	30.00	2.83
Dec-06	26.60	8.18	99.56	0.00	0.00	0.00	0.00	16.33	16.33	31.00	2.83
total						549.24	357.01	192.23	549.24		
Jan-07	26.60	8.21	99.93	0.00	0.00	0.00	0.00	15.82	15.82	31.00	2.75
Feb-07	28.95	7.51	96.25	28.30	28.30	0.00	0.00	14.29	14.29	28.00	2.75
Mar-07	29.70	8.45	110.03	113.60	110.03	3.57	2.32	15.82	18.13	31.00	3.15
Apr-07	27.90	8.34	104.49	137.60	104.49	33.11	21.52	15.31	36.83	30.00	6.61
May-07	27.45	8.74	108.42	211.80	108.42	103.38	67.20	15.82	83.01	31.00	14.41
Jun-07	26.25	8.53	103.01	196.90	103.01	93.89	61.03	15.31	76.34	30.00	13.69
Jul-07	25.15	8.78	103.38	117.89	103.38	14.51	9.43	15.82	25.25	31.00	4.38
Aug-07	24.25	8.66	99.83	30.80	30.80	0.00	0.00	15.82	15.82	31.00	2.75
Sep-07	25.60	8.25	98.15	270.80	98.15	172.65	112.22	15.31	127.53	30.00	22.88
Oct-07	26.15	8.37	100.84	211.80	100.84	110.96	72.12	15.82	87.94	31.00	15.27
Nov-07	27.15	7.98	98.33	23.00	23.00	0.00	0.00	15.31	15.31	30.00	2.75
Dec-07	26.30	8.18	98.89	14.20	14.20	0.00	0.00	15.82	15.82	31.00	2.75
total						532.07	345.85	186.22	532.07		

Table C.2 Average Monthly Discharge (m3/s)													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Average**
1992	1.47	1.47	1.47	11.60	1.47	12.50	1.47	1.47	11.79	3.23	1.47	1.47	4.24
1993	2.55	2.55	2.98	2.55	2.55	10.68	9.86	6.85	34.78	7.26	2.55	2.55	7.31
1994	1.08	1.08	1.08	1.08	5.80	3.75	1.08	1.08	8.69	10.05	1.08	1.08	3.08
1995	2.59	2.59	2.59	11.10	10.61	6.75	5.72	7.07	16.11	18.39	2.59	2.59	7.39
1996	1.36	1.36	1.36	1.36	12.09	16.54	1.84	1.36	2.48	4.29	1.36	1.36	3.90
1997	2.13	2.13	2.13	2.13	14.11	13.68	2.13	3.56	20.91	5.99	2.13	2.13	6.10
1998	2.45	2.45	2.45	14.49	2.45	22.54	2.45	5.29	10.90	13.85	2.45	2.45	7.02
1999	3.88	3.88	3.88	22.00	6.89	16.02	26.26	10.47	7.71	23.65	3.88	3.88	11.03
2000	2.78	2.78	2.78	3.69	5.89	20.73	2.78	23.12	14.71	10.52	2.78	2.78	7.95
2001	1.59	1.59	1.59	6.71	2.96	5.93	1.59	1.59	15.38	12.54	1.59	1.59	4.56
2002	3.87	3.87	3.87	9.47	10.48	14.78	24.03	8.09	22.06	23.78	3.87	3.87	11.00
2003	1.94	3.34	1.94	9.58	1.94	19.86	1.94	1.94	10.12	10.39	1.94	1.94	5.57
2004	2.93	2.93	2.93	17.51	6.50	7.68	9.38	11.42	18.40	15.10	2.93	2.93	8.39
2005	2.27	2.27	2.27	2.27	12.27	2.27	9.93	2.27	21.11	15.94	2.27	2.27	6.45
2006	2.83	2.83	2.91	2.83	10.58	19.36	2.83	2.83	21.06	23.36	2.83	2.83	8.09
2007	2.75	2.75	3.15	6.61	14.41	13.69	4.38	2.75	22.88	15.27	2.75	2.75	7.84
Average	**2.40**	**2.49**	**2.46**	**7.81**	**7.56**	**12.92**	**6.73**	**5.70**	**16.19**	**13.35**	**2.40**	**2.40**	**6.87**