FEASIBILITY STUDY OF A HYBRID SOLAR/BIO-OIL THERMAL POWER GENERATION PLANT IN NORTHERN GHANA

By

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DECLARATION

I hereby declare that this submission is my own work towards the Master of science in Mechanical Engineering and that, to the best of my knowledge, it contains no material which has been accepted for the award of any other degree of the university or any other university, except where due acknowledgement has been made in the text.

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(Supervisor) Signature Date

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DEDICATION

This thesis is dedicated to my parents, Mr. and Mrs. Abu and my favourite auntie, Harriet Takyi.

ABSTRACT

Solar energy plants benefit from the use of a freely available source of energy but suffer from the intermittency of the day/night cycles and also from periods of reduced irradiation. Bio-oil power plants are comparatively less expensive to build but have to confront the higher cost associated with the continuous supply of large amounts of a seasonal and relatively expensive bio-oil for fuel. Concentrating Solar Power (CSP) with supplementary bio-oil combustion evidences the possible integration of these two technologies in the generation of electricity.

This thesis provides a preliminary technical and economic analysis of a 20MW stand-alone Power Tower at Wa, a location with daily average DNI of 4.288 kWh/m^2/day. The analysis, using RETScreen software version 4 established a capacity factor of 17.87% for Wa, with a negative NPV at a bulk supply tariff of US$ 0.08 /kWh. Three technical concepts for hybrid solar/bio-oil combustion power plants are developed and the concept of integrating flat plate collectors into a bio-oil combustion steam power plant selected because of the relatively low DNI simulated for the selected site.

At the current PURC Bulk Generation Charge of US$ 0.086 /kWh, and Jatropha oil prices of US$ 950 /Mt, a 20 MW hybrid solar/bio-oil thermal power plant at a capital cost of US$ 1,748 /kW would yield a negative NPV. The financial viability of the plant is confirmed at a tariff of US$ 0.34 /kWh, at the prevailing Jatropha oil prices. A 40% drop in the Jatropha oil prices will however yield a positive NPV and a payback period of 3.2 years at tariffs of US$ 0.26 /kWh.

This study concludes that a combination of low bio-oil prices and relatively low feed-in-tariffs is the way to improve the financial viability of bio-oil combustion power plants in Ghana.

ACKNOWLEDGEMENT

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I also wish to thank Mr Stephen Doku, Technical Director of VRA, and the entire management and staff of VRA-Tema for a one week industrial attachment to familiarise myself with operations in the plant.

I am highly indebted to the following people and institutions for their assistance provided: Alhaji Sulemana (TRAGRIMACS), Mawufemo Modjinou (Energy Commission), Khalil Abdulai (VRA-Akuse), Benjamin Osei Owusu Sarpong (Anglogold Ashanti-Obuasi), Joseph Abbey and Kassim Abubakar (all of GRIDCo). Thank you for every piece of information I received from your offices for the purpose on this thesis.

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Finally and most importantly, my sincere thanks to my dear mum and dad for their immense support during my postgraduate studies.

Majeed Koranteng Osman

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LIST OF ACRONYMS

CLFRs	Compact Linear Fresnel Reflectors
CRS	Central Receiver System
CSP	Concentrating Solar Power
DNI	Direct Normal Irradiance
DOE	Department Of Energy
DSG	Direct Steam Generation
DST	Distributed Solar Thermal
GHG	Greenhouse Gas
GHI	Global Horizontal Irradiance
GW	Gigawatt
HRSG	Heat Recovery Steam Generator
HTF	Heat Transfer Fluid
IEA	International Energy Agency
IPP	Independent Power Producer
ISCC	Integrated Solar Combined Cycle
LFRs	Linear Fresnel Reflectors
MW	Megawatt
NPV	Net Present Value
PURC	Public Utilities Regulatory Commission
SEGS	Solar Energy Generating Systems
SVO	Straight Vegetable Oil
TES	Thermal Energy Storage
TMY	Typical Meteorological Year
TRAGRIMACS	Tropical Agricultural Marketing and Consultancy Services
T&D	Transmission and Distribution
UNEP	United Nations Environment Programme
WEO	World Energy Outlook

CHAPTER ONE

INTRODUCTION

1.1 Background

The earth's climate has continually been damaged since the industrial revolution by the use of fossil fuels (oil, coal and gas) to provide energy and for transportation as well. Aringhoff et al. (2005) affirm that there has already been a global mean temperature rise of 0.6°C during the last century, significantly due to the greenhouse gases that have been discharged into the atmosphere. This trend, if it continues would be a threat to the stability of our climate and eco-system. Rising concerns about energy security and acceptance of global warming impacts have sparked worldwide efforts to replace fossil fuels rapidly with clean alternative energy sources due to a projection of 50% increment in the global demand for oil by 2030 (IEA, 2008). The quest for energy however continues to grow with many countries trying to achieve a balanced energy mix and energy security. Renewable energy therefore is not only seen as an option but a mandate to curb the projected soaring crude oil prices in the near future and also to contribute immensely to the development of Africa.

The oil crises of 1973 and 1979 however sparked interests in renewable energy technologies including Concentrating Solar Power (CSP). This led to the development of the Solar Energy Generating Systems (SEGS) in California and other smaller projects around the world. Recently, technological progress has revealed interesting prospects for advanced concepts such as the addition of thermal storage systems or the use of fossil backups to boost up power supply and also to guarantee a more reliable power source, unlike the standalone CSP plants which work on during some periods of the day.

Currently, in Africa, there is a 140MWe Integrated Solar Combined Cycle (ISCC) System in Kuraymat, Egypt, which operates on natural gas as the fuel for the conventional fossil fuel cycle of 120MWe, with the solar cycle contributing 20MWe. The system however does not have a standalone solar solution, rendering the solar field incapable to operate when the gas turbine is down.

Bio-liquids, a renewable energy derived from biomass has much potential as a sustainable alternative energy supply of liquid fuels. Von Matiz et al (2000) does not only describe it as an alternative energy supply within the developing world, but also as a potential mechanism to stimulate agricultural development, create jobs and save foreign exchange. In 2009, a UNEP report on biofuel prospects revealed that biofuels provided about 1.8% of the world's transportation fuel in 2008. It is projected that the use of biofuels as fuel for transportation will increase by 200% from 2005 to 2015.

1.2 Justification

Africa has immense potential of solar energy radiation which could be harnessed for electricity generation yet the IEA World Energy Outlook (2009) states that 589 million Africans do not have access to electricity. The continent's total installed generating capacity as at 2011 is about at 117 GW while the real demand to satisfy the needs of over one billion population is estimated to be about 335 GW. This demand is however projected to jump to 584 GW by 2030 and to 984 GW by 2050, with growth rate of 2.8 % annually (AFREC, 2011).

Even with this low rate, electricity supplies are mostly unreliable due to recurrent load shedding and blackouts, as well as transmission and distribution problems. Like most African countries, Ghana is richly endowment in energy resources but still caught up in energy poverty.

A study conducted by Opoku (2010), on the prospects of CSP in northern Ghana established that Wa is the best area for siting CSP plant, with an average DNI of 4.5-5 kWh/m^2/day. The capacity factor for the Central Receiver System (CRS) was estimated to be 15.76%, with a project payback period of 71.9 years. There is therefore the need to explore other hybrid technologies like using thermal storage, auxiliary boilers or integrating with a gas turbine to achieve greater operating flexibility and dispatchability. This will improve the solar-to-electric conversion efficiency and also reduce risks to investors.

1.3 Objectives

The main objective is to conduct a techno-economic feasibility study of a hybrid solar/bio-oil combustion thermal power generation plant in northern Ghana.

The specific objectives are to:

- Generate Typical Meteorological Year (TMY) data with Meteonorm software and determine areas in northern Ghana best suitable for mid-scale CSP
- Design an appropriate hybrid technology for the selected site and undertake a technical performance assessment of the plant.
- Perform financial and sensitivity analysis to determine the economic viability of the project.

1.4 Methodology

The project will start with a pre-feasibility study, which would include an extensive literature review of existing and relevant material to the subject matter. Solar resource assessment will then be analysed based on data availability and computer simulation with the Meteonorm Software version 6.1.0.23, to generate TMY data.

Simulation will be done with priority to locations that have been established in literature to have higher solar radiation levels with respect to Ghana.

A number of conceptual designs would be developed based on the effective integration of a solar field into a bio-oil combustion thermal power plant. For the purpose of this analysis, a turbine steam-consumption calculator will be used to calculate the steam consumption, and the quantity of bio-oil determined afterwards.

RETScreen software will be used to perform part of the technical analysis dealing with GHG emissions and financial analysis of the plant, where the NPV and its corresponding simple payback period will be determined. NPV has been chosen as the main financial indicator because it determines whether or not the project would generally be a financially acceptable investment. A positive NPV would be an indicator of a potentially feasible project. Results obtained for Payback period will be compared with the results reported in Opoku (2010). Sensitivity analysis would then be performed, graphs drawn and interpretations made to ascertain the financial viability of the project.

1.5 Scope of Work

The main idea of the thesis is to focus on the possible integration of a solar field into a bio-oil fired Rankine cycle. The most appropriate technology would be recommended based on its adaptation to the current situation in Ghana. RETScreen analysis would be conducted for the selected site to perform emission and financial analysis on the project.

1.6 Thesis Organisation

This is a five chapter report, with the first chapter giving a brief overview of the study. The review of extensive literature on relevant subject matter is captured in chapter two. Figure 1.1 shows the structure of the thesis.

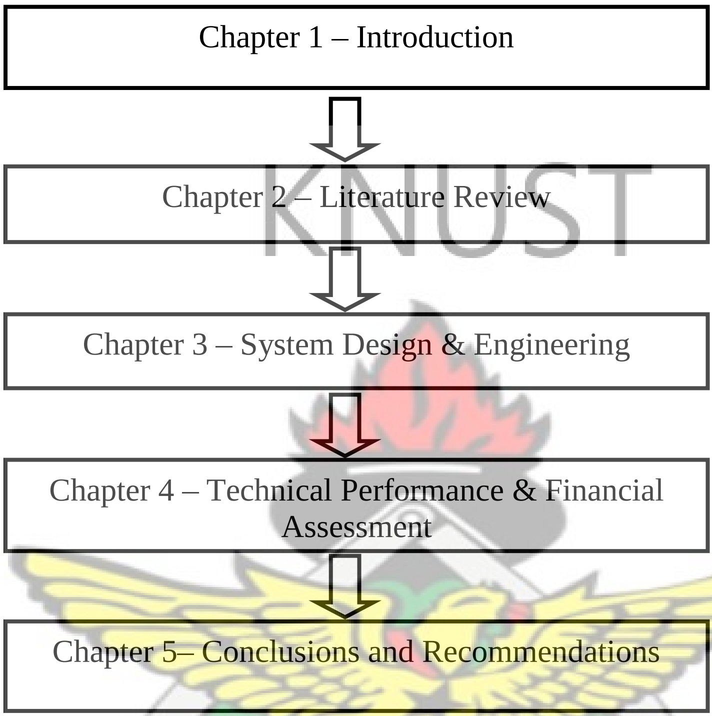

Figure 1.1: Thesis Organization

In the third chapter, a number of technical concepts are presented and the most appropriate concept for the site is selected. The GHI and DNI solar radiation are also generated in this chapter.

Chapter four presents the comprehensive performance assessment of the selected concept to determine the technical and financial viability of the project. This chapter also sought to discuss the findings of the study in relation to previous work done by Opoku (2010) at the same site. Chapter five draws conclusions on the study and presents recommendations for the various stakeholders.

CHAPTER TWO

OVERVIEW OF SOLAR THERMAL POWER GENERATION

2.1 Introduction

In Concentrating Solar Power (CSP) plants, solar radiation is used to heat a fluid to high temperatures for electricity generation. Concentrating mirrors or lenses are used to generate this heat. The concentrating collector absorbs the DNI to heat up the working fluid in the receiver unit to the required temperatures and pressures for use in a power conversion cycle. Different technologies have been developed to concentrate the solar radiation, depending on the working fluid temperature, the power conversion cycle, the plant size and its capacity.

2.2 Concentrating Solar Power Technologies

There are four main types of commercial CSP technologies: Parabolic Troughs and Linear Fresnel Systems, which are line-concentrating and central receivers and parabolic dishes, which are point-concentrating. Central Receiver Systems are also called solar towers. The four main technologies are discussed below.

2.2.1 Parabolic Troughs (Line Focus, Mobile Receiver)

Parabolic trough-shaped mirror reflectors are used to concentrate sunlight on to thermally efficient receiver tubes placed in the trough's focal line as shown in Figure 2.1. The troughs are usually designed to track the Sun along one axis, predominantly north–south. A thermal transfer fluid, such as synthetic thermal oil, is circulated in these tubes. The fluid is heated to approximately 400°C by the sun's concentrated rays and then pumped through a series of heat exchangers to produce superheated steam. The steam is converted to electrical energy in a conventional steam turbine generator, which can either be part of a conventional steam cycle or integrated into a combined steam and gas turbine cycle. (CSP Outlook, 2009)

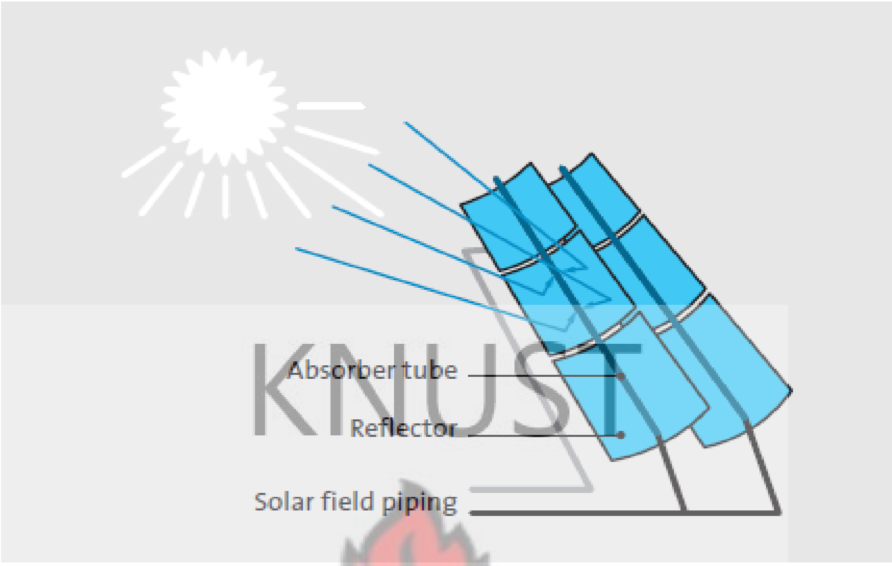

Figure 2.1: Parabolic Trough (IEA, 2010)

2.2.2 Linear Fresnel reflectors (line focus, fixed receiver)

Linear Fresnel reflectors (LFRs) approximate the parabolic shape of trough systems but by using long rows of flat or slightly curved mirrors to reflect the sun's rays onto a downward-facing linear, fixed receiver. A more recent design, known as compact linear Fresnel reflectors (CLFRs), uses two parallel receivers for each row of mirrors and thus needs less land than parabolic troughs to produce a given output. The main advantage of LFR systems is that their flexibly bent mirrors and fixed receivers require lower investment costs and facilitates direct steam generation (DSG), thereby eliminating the need for – and cost of – heat transfer fluids and heat exchangers. They are however, less efficient than the parabolic troughs. (IEA 2010)

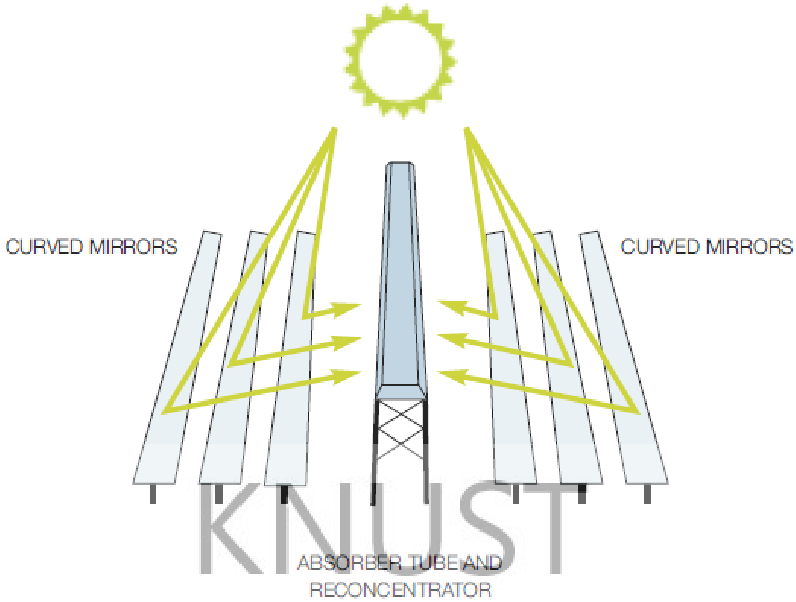

Figure 2.2: Compact Linear Fresnel Reflectors (CSP Outlook, 2009)

2.2.3 Central Receiver Systems (point focus, fixed receiver)

A circular array of heliostats (large mirrors with sun tracking motion) concentrates sunlight on to a central receiver mounted at the top of a tower. A heat-transfer medium in this central receiver absorbs the highly concentrated radiation reflected by the heliostats and converts it into thermal energy, which is used to generate superheated steam for the turbine. To date, the heat transfer media demonstrated include water/steam, molten salts and air. If pressurised gas or air is used at very high temperatures of about 1,000°C or more as the heat transfer medium, it can even be used to directly replace natural gas in a gas turbine, making use of the excellent cycle (60% and more) of modern gas and steam combined cycles. Fig 2.3 shows how the mirrors reflect sunlight into a central receiver.

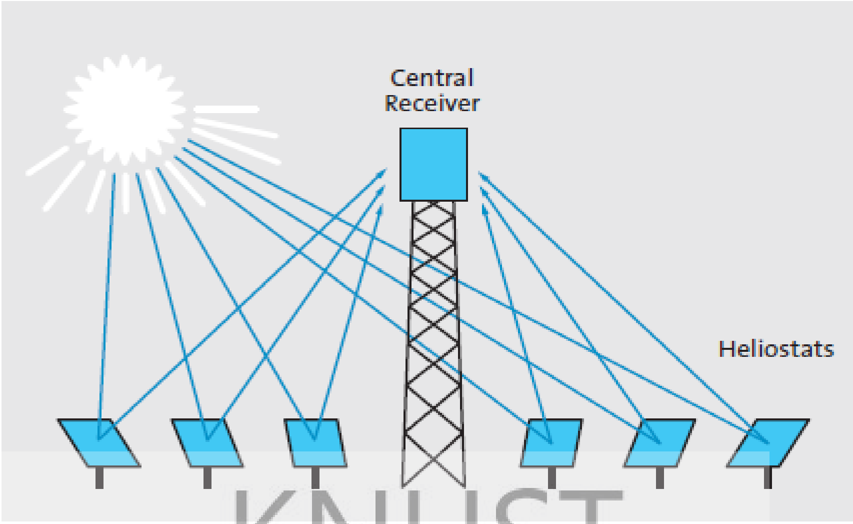

Figure 2.3: Central Receiver System (IEA, 2010)

2.2.4 Parabolic dishes (point focus, mobile receiver)

A parabolic dish-shaped reflector concentrates sunlight on to a receiver located at the focal point of the dish. They are generally designed to track the Sun along one axis, predominantly north to south. The concentrated beam radiation is absorbed into a receiver to heat a working fluid to approximately 750°C (Opoku, 2010). This working fluid is then used to generate electricity in a Stirling engine or a micro turbine, attached to the receiver.

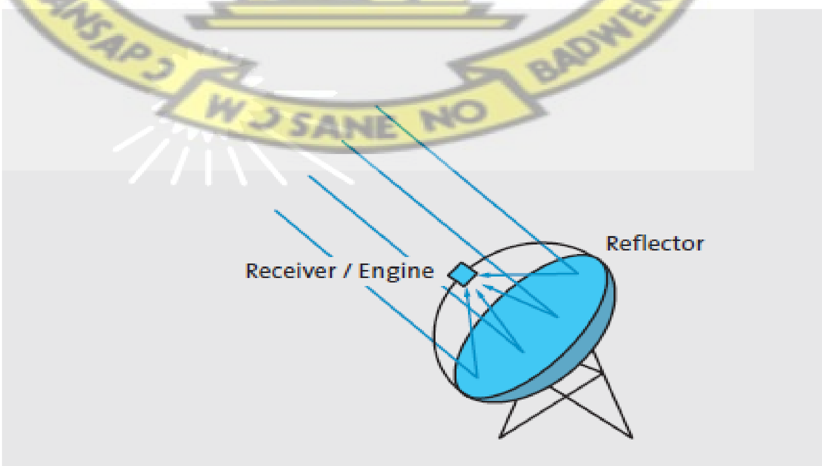

Figure 2.4: Parabolic Dish Technology (IEA, 2010)

2.3 Backup and hybridisation

Virtually all CSP plants, with or without storage, are equipped with fuel-powered backup systems that help to regulate production and guarantee capacity, especially in peak and mid-peak periods. Thermal Storage and fuel backup increase the value of the plant by providing guaranteed capacities. Storage can be used to extend the electricity generation after sunset, when electricity loads remain high (IEA-SolarPACES, 2007). Figure 2.5 shows a Round–the-Clock operation of a CSP plant with storage and fuel back-up.

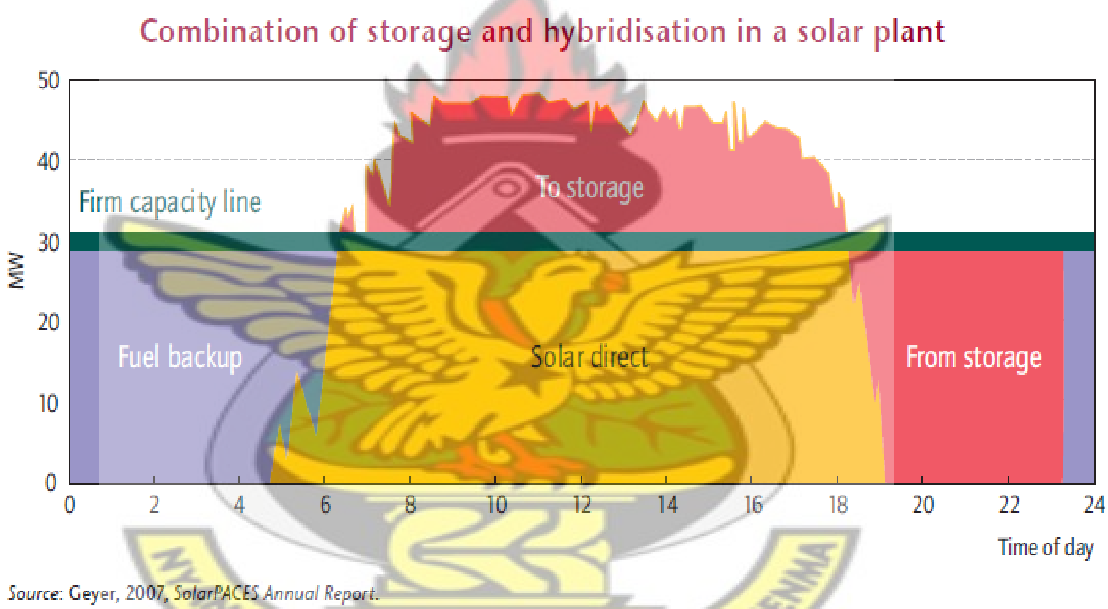

Figure 2.5: Round-the-clock operation of a CSP plant with Storage and Back-up

Providing 100% firm capacity with only thermal storage would require significantly more investment in reserve solar field and storage capacity, which would produce little energy over the year. This means that incorporating thermal storage and fossil backup serve as a boost to the plant and ensures smooth power generation at a reduced capital cost as compared to a standalone solar system with thermal storage.

2.4 Thermal Energy Storage

Although Thermal Energy Storage (TES) has not been used in most solar thermal power plants built to date, it does offer four important benefits according to US Department of Energy (2011)

- A unique and very important characteristic of trough and power tower CSP plants is their ability to dispatch electricity beyond daylight hours by utilizing thermal energy storage systems (Parabolic dish-engine technology currently cannot utilize TES).
- In TES systems, about 98% of the thermal energy placed in storage can be recovered, and the plant running hours may be extended up to 16 hours per day, which allows for greater dispatch capability.
- Moreover, storage increases the technology's marketability, as utilities can dispatch the electricity to meet peak and non-peak demand.
- Furthermore, thermal storage increases the solar capacity factor of the plant. In systems without storage, the annual solar capacity factor is limited to approximately 25%, where as it can increase to 50% with thermal storage.

2.4.1 How Thermal Storage Works

TES systems often utilize molten salt as the storage medium since they neither decompose nor are they volatile at the high temperatures of about 565°C needed in a CSP plant. In a typical molten-salt CSP plant, the salts are stored in two tanks, one much hotter than the other. Figure 2.2 shows the layout of a central receiver system with thermal storage.

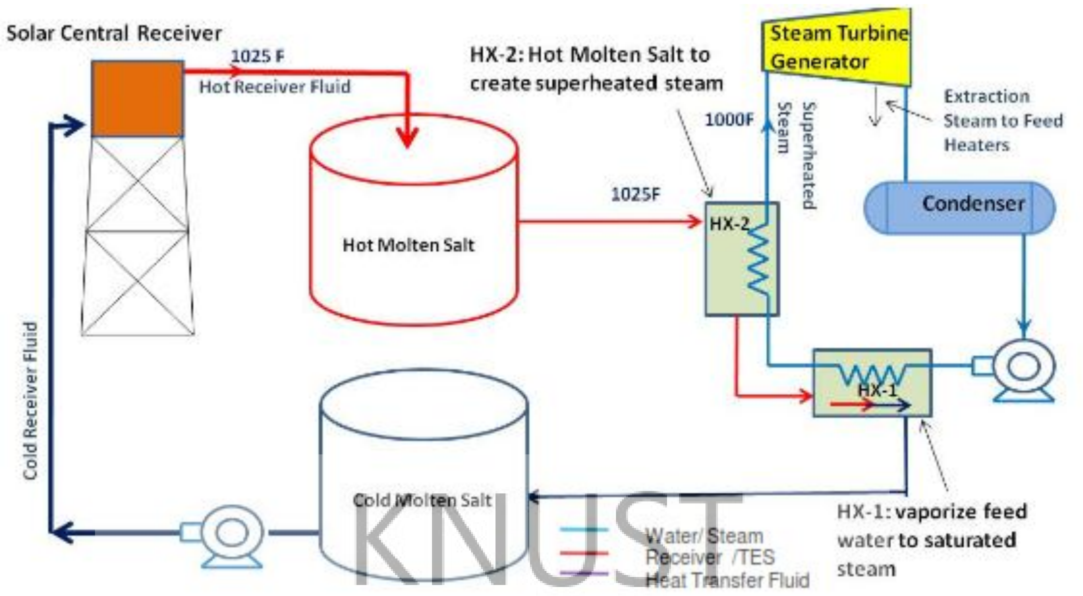

Figure 2.6: Central Receiver System with Thermal Storage (Mathur, 2009)

The lower-temperature tank has a temperature of about 293°C, while the higher-temperature tank is at about 552°C. The salt is pumped from the cold tank to the power tower, where it collects the solar energy that is focused on the receiver, raising its average temperature. The salts then descend into the hot tank, where they can maintain this very hot temperature for several days, though typically they are used within hours. The salt in the hot tank is then sent to a heat exchanger that generates steam at about 537°C to run the turbine to generate electricity. As they exit the steam generator, the salts cool, and by the time they return to the cold tank, they measure about 293°C (Mathur, 2009).

An example of a CSP plant with TES system is the 50-MW Andasol 1 plant in Spain, which utilizes a molten salt mixture of 60% sodium nitrate and 40% potassium nitrate as the storage medium, to enable 6 hours of additional electricity production after the DNI is no longer available. The Nevada Solar One plant incorporates roughly half an hour of storage via its HTF inventory, but no additional investments were made in storage tanks (DOE, 2009). The 17MW Solar Tres project in Sevilla, Spain will be the first commercial molten-salt central receiver plant in the world. With a 15hr molten-salt storage system, it will be able to supply electricity almost constantly. (Bosschem & Debacker, 2009)

2.5 Fossil Backup

In most all CSP plants, fuel burners are used to boost the conversion efficiency of solar heat to electricity during start-ups and transient conditions such as cloudy conditions. In such plants, the backup fuel is either used to heat the thermal fluid to the required temperatures or be used in a superheater where necessary.

The SEGS CSP plants built in California between 1984 and 1991 use natural gas to boost production year-round. In the summer, SEGS operators use backup in the late afternoon and run the turbine alone after sunset, corresponding to the time period (up to 10:00pm.) when mid-peak pricing applies. During the winter mid-peak pricing time (12:00 noon to 6:00pm.), SEGS uses natural gas to achieve rated capacity by supplementing low solar irradiance. By law, the plant is limited to using gas to produce only 25% of primary energy (IEA, 2010).

2.6 Hybrid Solar Thermal Systems

Many solar-fossil hybrid options are possible with natural gas combined-cycle and coal-fired or oil-fired Rankine plants, and may accelerate near-term deployment of projects due to improved economics and reduced overall project risk. There are currently three known hybrid solar thermal power concepts in operation. These are discussed below:

2.6.1 Auxiliary Boiler Integration

Auxiliary boiler integration (fuel backup) makes it possible to almost completely guarantee a solar plant's production capacity at a lower cost as compared to the plant being solely dependent on the solar field. This can be run continuously to serve as a solar boost to increase annual energy output or as a backup system to give solar system more reliability, especially in the absence of thermal energy storage. Figure 2.7 below shows the proposed 250 megawatt Solar Dawn power plant expected to generate clean and safe energy with AREVA's standalone CLFR power plant hybridised with a natural gas fired boiler to ensure smooth power supply irrespective of the solar radiation and time of the day. The proposed project, to be built near Chinchilla, South West Queensland, Australia, is expected to commence operation early 2015, following a three-year construction timeframe (SolarDawn, n.d).

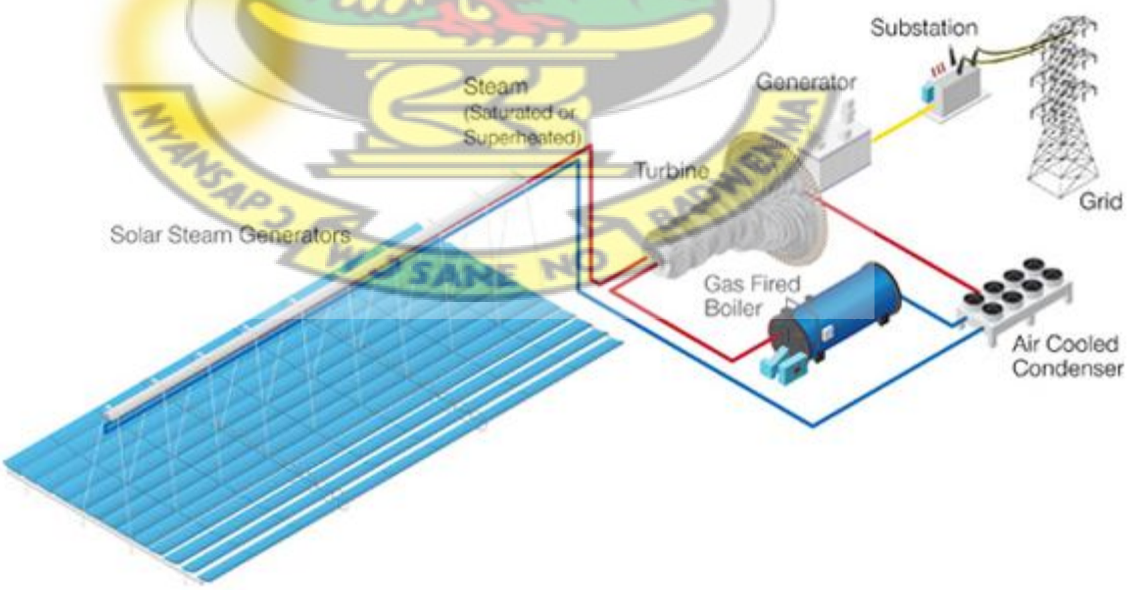

Figure 2.7: Proposed Hybrid CLFR Solar Plant (Source: AREVA, n.d, a)

2.6.1.1 Kogan Creek Power Boost

CS Energy, a Queensland Government owned electricity generator, has partnered with solar thermal technology provider AREVA on a 44 MW solar thermal addition to the existing 750 MW Kogan Creek Power Station. The project will augment Kogan Creek Power Station's feedwater system by using solar technology to heat feedwater entering the boiler, supplementing the conventional coal-fired feedwater heating process. This means that steam that was previously diverted from the turbine to the feedwater system can instead be used to generate extra electricity. The solar addition will enable Kogan Creek Power Station to produce more electricity with the same amount of coal, making the coal-fired plant more fuel efficient and reducing its greenhouse intensity. The project commenced in 2010 and is expected to be operational in 2013. Figure 2.8 is an inset of the Kogan Creek project.

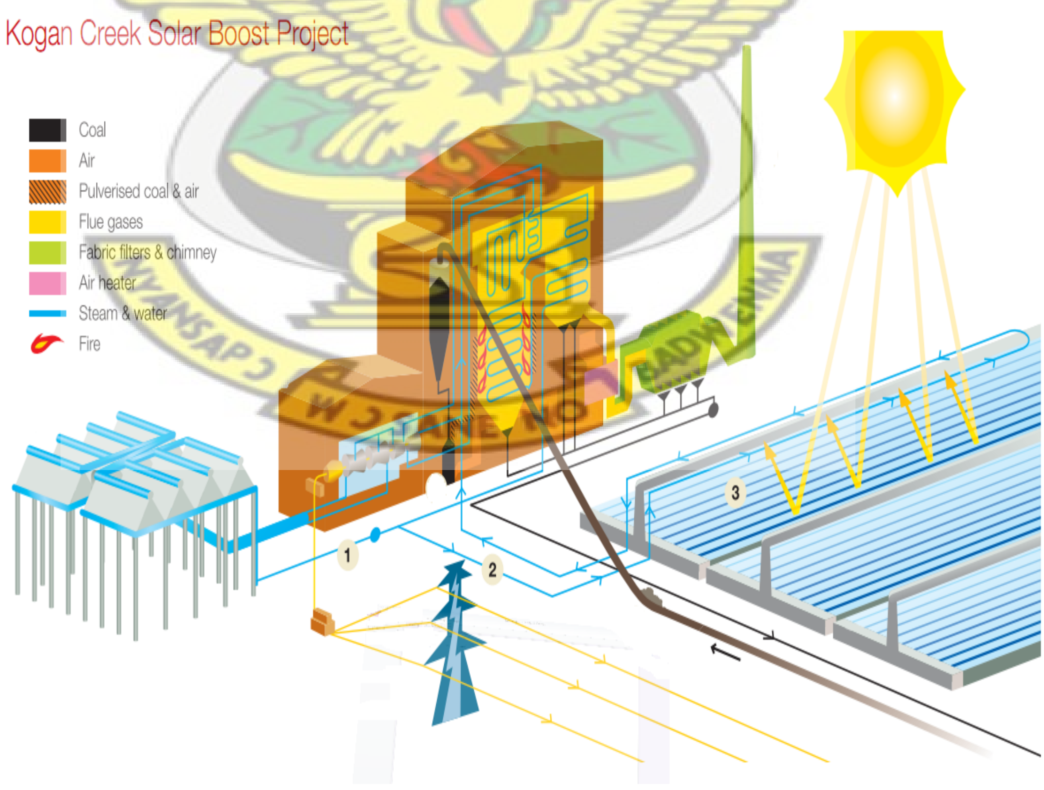

Figure 2.8: Kogan Creek Solar Boost Project (Source: AREVA, n.d, b)

Cold water from the air-cooled condenser is piped to the boiler feed pump as shown in stage 1 in Figure 2.8. The water is then diverted to the solar field at stage 2, whenever the solar resource is available. The solar field then heats up the water in the elevated water pipes to generate low pressure steam at stage 3. Steam from the solar field is further heated in the coal boiler to meet the operating conditions of the steam turbine to generate electricity.

2.6.2 Integrating Solar Field into Combined Cycle Systems

Conventional gas turbine units feature rapid start-up and load-following capabilities. The units have a modest capital cost and run at high efficiency. Their high exhaust gas temperatures are essential features for integration with parabolic troughs and linear Fresnel Reflector systems. In an Integrated Solar Combined Cycle Systems (ISCCS) additional steam is produced by the solar field to boost up the energy generated during the day. Figure 2.9 shows the integration of a parabolic trough field into a combined cycle power plant.

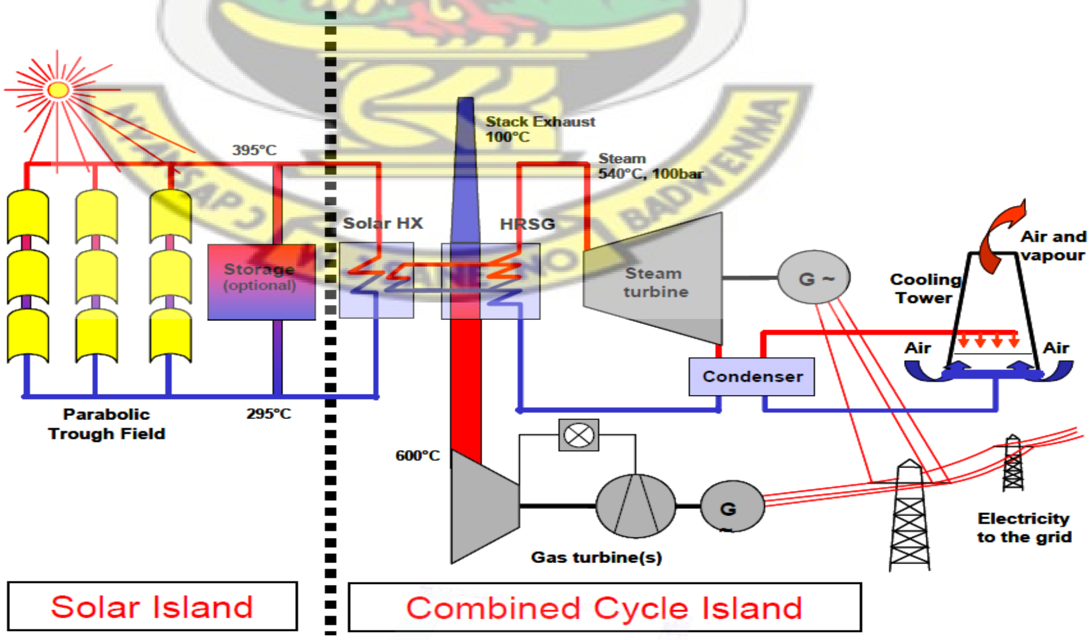

Figure 2. 9: Integrated Solar Combined Cycle System (Brakmann et al, 2006)

The gas turbine exhaust is used for superheating the steam generated in the solar field, thereby increasing the power of the steam turbine. Both high temperature and medium temperature CSP technologies are well suited for ISCC, although all ISCC plants in operation and under construction use parabolic trough technology. Currently, in Africa, there is a 140MWe Integrated Solar Combined Cycle (ISCC) System in Kuraymat, Egypt, which operates on natural gas as the fuel for the conventional fossil fuel cycle of 120MWe, with the solar cycle contributing 20MWe.

2.6.2.1 Limitation of ISCC Systems

Nonetheless, the integrated concept suffers from a distinct disadvantage. When the gas turbine is running on full load on high solar irradiation days, the heat from the HRSG plus the heat from the solar field can be larger than what can be accommodated by the steam turbine. Due to this reason, the steam turbine has to be oversized to accommodate any extra steam on high solar radiation days. Oversizing the steam turbine would result in higher costs, larger part load losses and subsequently lower efficiency whenever the solar field operates without maximum solar heat input (Turchi & Ma, 2011).

2.6.3 Distributed Solar Thermal (DST) Technology

AORA's unique modular Distributed Solar Thermal (DST) technology works on the principle of the central receiver system, where the heliostat field reflects solar radiation to a receiver unit to heat up air, which is used to power a microturbine to generate electricity. The microturbines require just 8% of the amount of water required by central receiver system for cooling purposes. They are configured in compact base units (100kWe each) that are connectable, offering scalable utilitygrade power for both on-grid and stand-alone applications. Figure 2.10 is a schematic of AORA's first hybrid solar plant that is able to run for 24 hours.

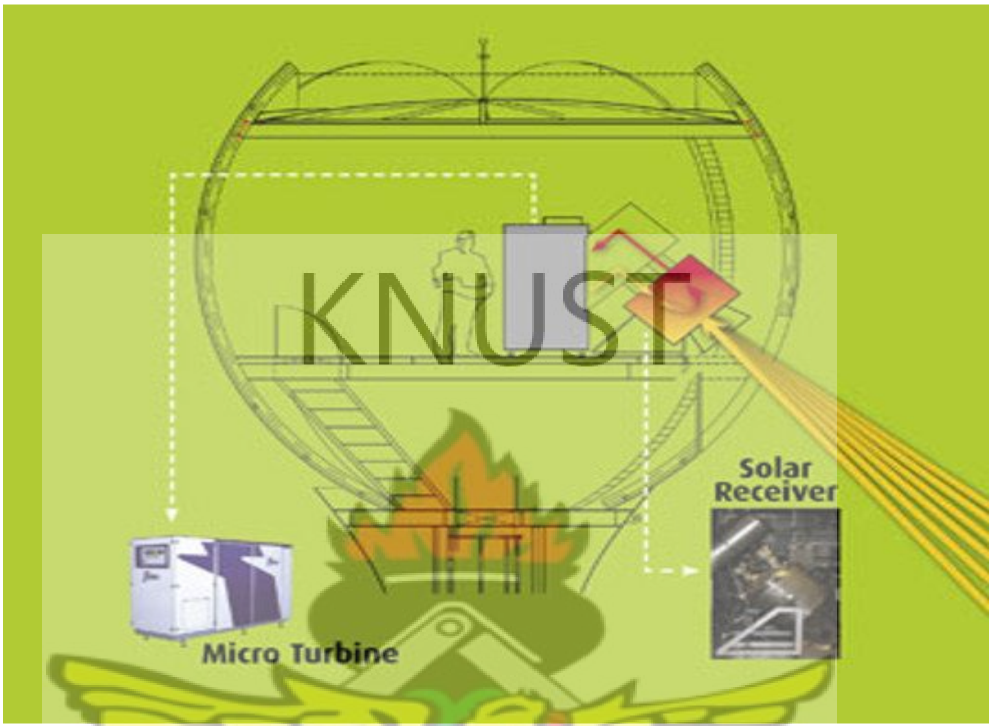

Figure 2.10: DST Technology (Source: AORA-SOLAR)

AORA's first CSP prototype module has been in operation in Israel since 2009. The plant consists of 30 heliostats that track the sun and direct its rays up to the 30-meter tall tower, where all the sunlight from the heliostats is concentrated.

The hybrid system is capable of working at night and in heavy cloud coverage, using alternative fuels to continue powering the micro turbine. The modularity of the system enables a constant supply of electricity, even while individual units are undergoing repairs or routine maintenance.

2.7 Plant Cooling and Water Requirements

As in other thermal power generation plants, CSP requires water for cooling and condensation processes, as well as cleaning the collectors. Water requirements are relatively high: about 800-1000 gallons/MWh for parabolic trough and Linear Fresnel Reflectors, compared to about 400-750 gallons/MWh for a coal plant and only 200 gallons/MWh for combined-cycle natural gas plants. Parabolic dishes are cooled by the surrounding air, and need no cooling water. Table 2.1 summarizes the amount of water presently consumed by power plants throughout the U.S. and the options available to CSP for reducing water consumption.

Table 2.1: Water Requirements for Power Plant Technologies (DOE, 2009)

Technology	Cooling	Gallons MWhr	Perform. Penalty
Coal / Nuclear	Once-Through	23,000 – 27,000	
	Recirculating	400 - 750	
	Air Cooling	50 - 65	
Natural Gas			
	Recirculating	200	
Power Tower	Recirculating	500 - 750	
	Combination Hybrid Parallel	90-250	1-3%
	Air Cooling	90	1.3%
Parabolic Trough	Recirculating	800	
	Combination Hybrid Parallel	100-450	1-4%
	Air Cooling	78	4.5-5%
Dish / Engine			
	Mirror Washing	20	
Fresnel	Recirculating	1000	

Dry cooling (with air) is one effective alternative used on the ISCC plants under construction in North Africa. However, it is more costly and can reduce annual electricity production by 5%, whilst generation cost can go as high as 9% (DOE, 2009). Wet cooling is more effective but costly, and therefore operators of hybrid systems tend to use only dry cooling in the winter when cooling needs are lower, then switch to combined wet and dry cooling during the summer. For a parabolic trough CSP plant, this approach could reduce water consumption by 50% with only a 1% drop in annual electrical energy production (IEA, 2010).

2.8 Solar Thermal Electric Generation in Ghana

Recent studies conducted by Opoku (2010), on the prospects of a 20MWe CSP plant in northern Ghana established Wa as the best area for siting a CSP plant in Ghana, with an average DNI of 3.75 kWh/m^2/day. The study considered a Central Receiver System without storage and backup. The capacity factor was estimated to be 15.76%, annual energy production of the plant to be 27.6 GWh and the annual GHG savings as 13,503.4 tCO2, equivalent to 2,473 cars and light trucks not used in a year. The financial viability of the study is shown in Figure 2.11 below.

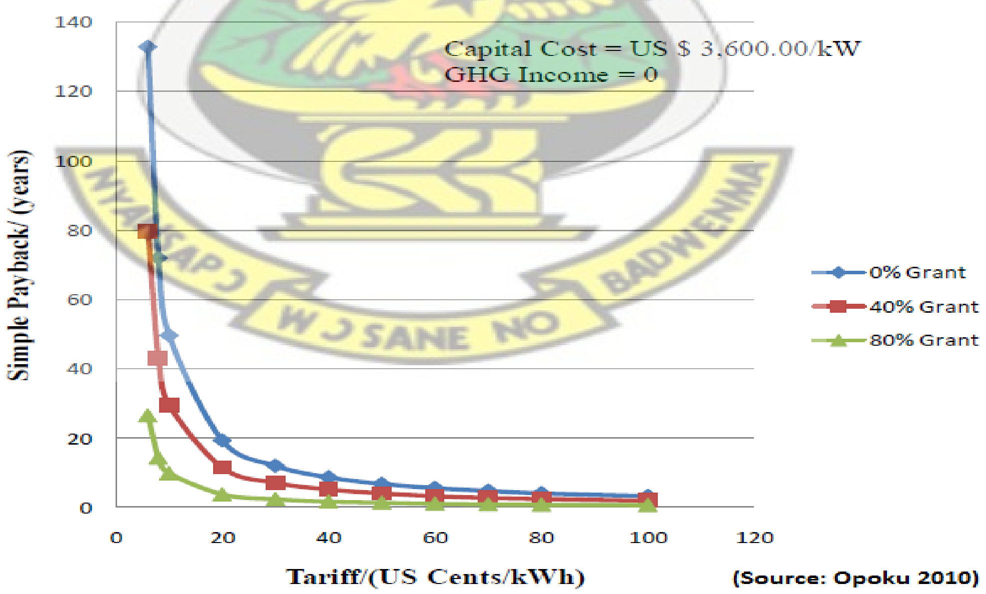

Figure 2.11: Effect of Grants/Capital subsidies on Payback Period for a Hypothetical Solar Thermal Plant in Wa

Figure 2.11 also shows that a judicious mix of capital subsidy with the right tariff is needed to bring the payback period below 10 years, which is what a private investor would look out for, since most private investors are interested in project with simple payback period of 10 years or below.

CHAPTER THREE

SYSTEM DESIGN & ENGINEERING

3.1 Introduction

This chapter addresses the solar resource in areas in Ghana that have been established to have the highest beam radiation based on existing literature. It further looks at the grid potential and cooling water availability within the said regions. Finally, the solar/bio-oil integration that best suits the selected site is selected out of a number of technical concepts developed.

3.2 Solar Resource Assessment

The annual average DNI Map of Ghana shown in Figure 3.1 shows that areas within latitude 10º N to 11º N, and longitude -1.5º E to -3º E in the Upper West region, as well as areas within latitude 10.7º N to 11.1º N, and longitude -0.3º E to -0.9º E in the Upper East region has an average DNI range of (4.0 – 4.5) $kWh/m^2/day$. The Solar map of Ghana prepared by the Ghana Ministry of Mines and Energy in 1998, figure 3.2, also revealed that areas within latitude 10º N to 11º N have very low diffuse radiation of about 32% of total radiation (Opoku, 2010). This justifies the selection of some sections of the upper east and upper west regions of Ghana as potential areas with the best DNI in Ghana.

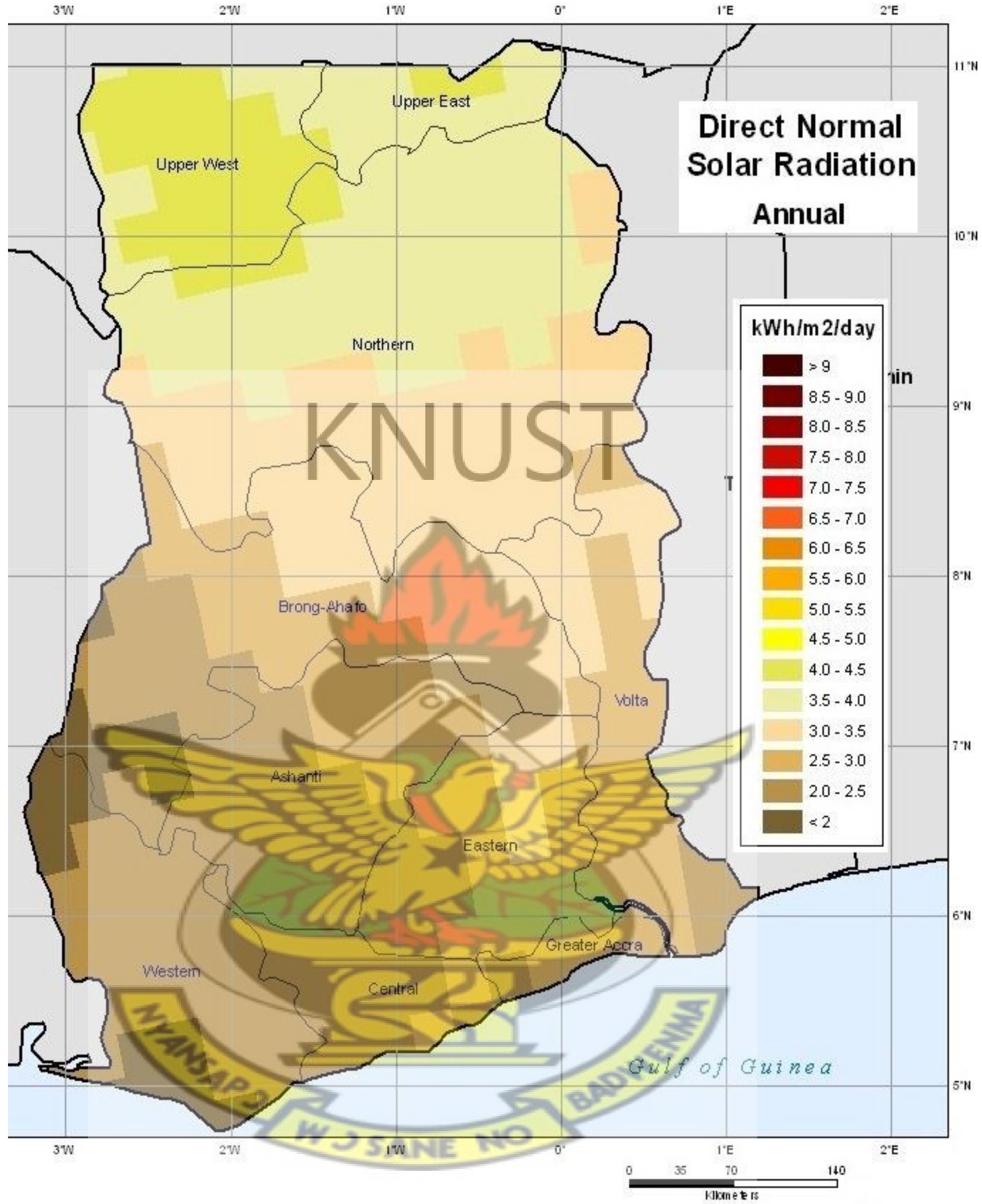

Figure 3. 1: Annual average DNI map at 40km resolution (Source: NREL)

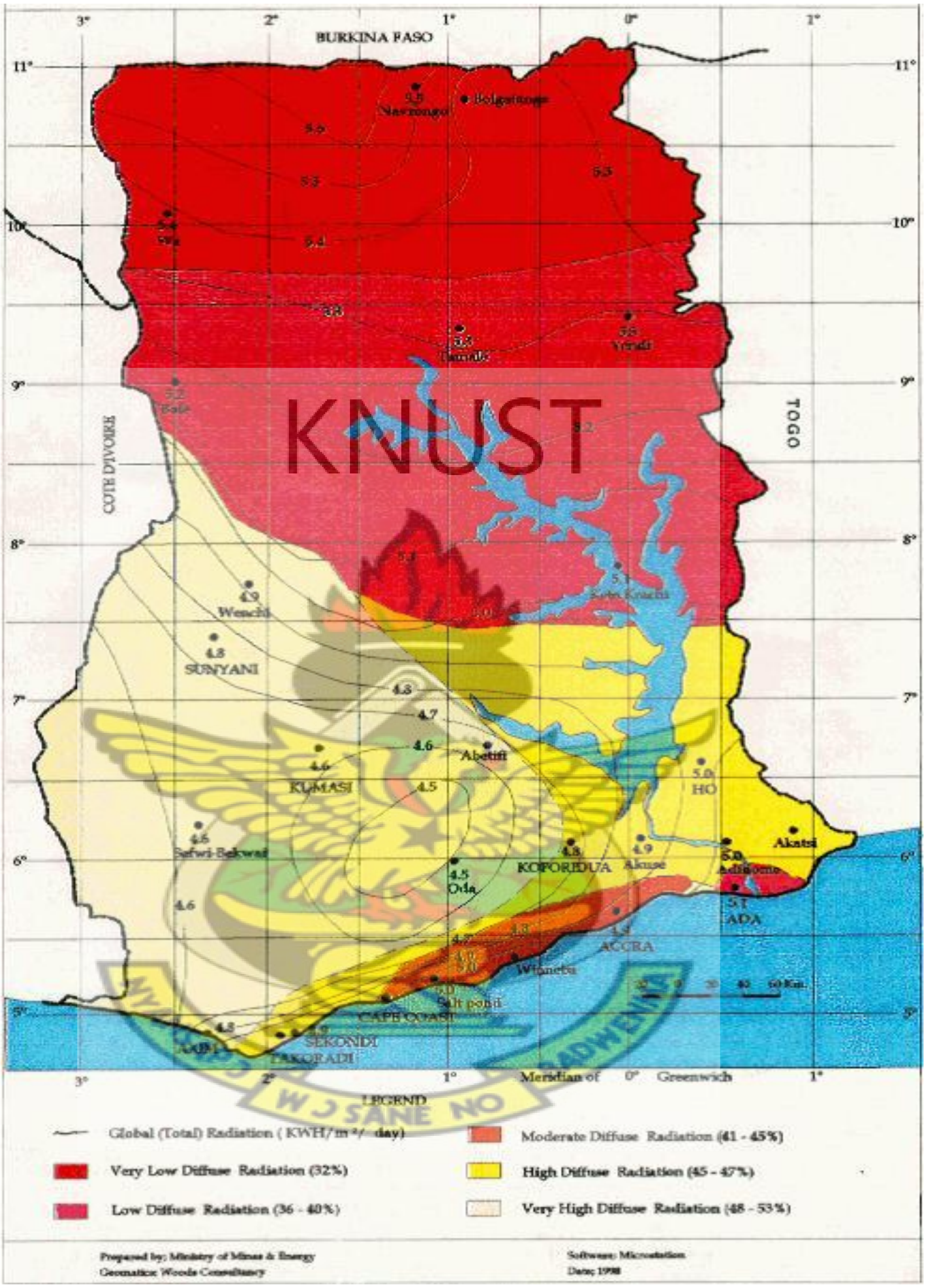

Figure 3. 2: Solar Map of Ghana (Source: MoME, 1998)

3.2.1 Irradiation Data

The annual average solar radiation for six virtual stations obtained from Meteonorm software is discussed in the graphs below. A brief overview of the inputs and output of the Meteonorm software is discussed in Appendix A. Figure 3.3 below is a graph showing the annual average GHI and DNI for the six virtual stations. Out of the sites explored, Wa has the lowest GHI of 5.588 kWh/m^2/day, whereas Navrongo recorded the highest GHI of 5.775 kWh/m^2/day. Annual average DNI for the six stations ranges between 4.288 kWh/m^2/day in Wa to 4.828kWh/m^2/day at Bongo.

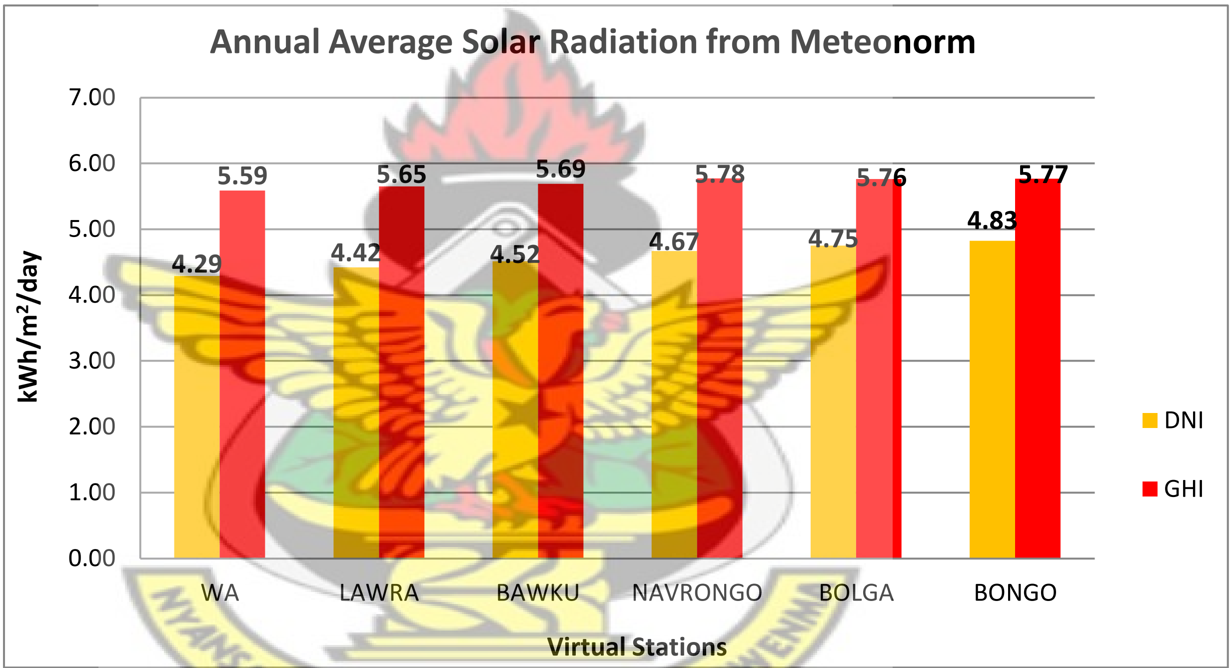

Figure 3. 3: Annual Average Solar Radiation for Six Virtual Stations

Due to the unavailability of reliable observations of DNI in northern Ghana, the monthly average DNI for the six virtual stations was again estimated from the mean GHI generated from meteonorm, assuming a constant beam fraction of 0.68 throughout the year as reported by Opoku and Brew-Hammond (2011). The results are presented in the graphs shown in Figure 3.4.

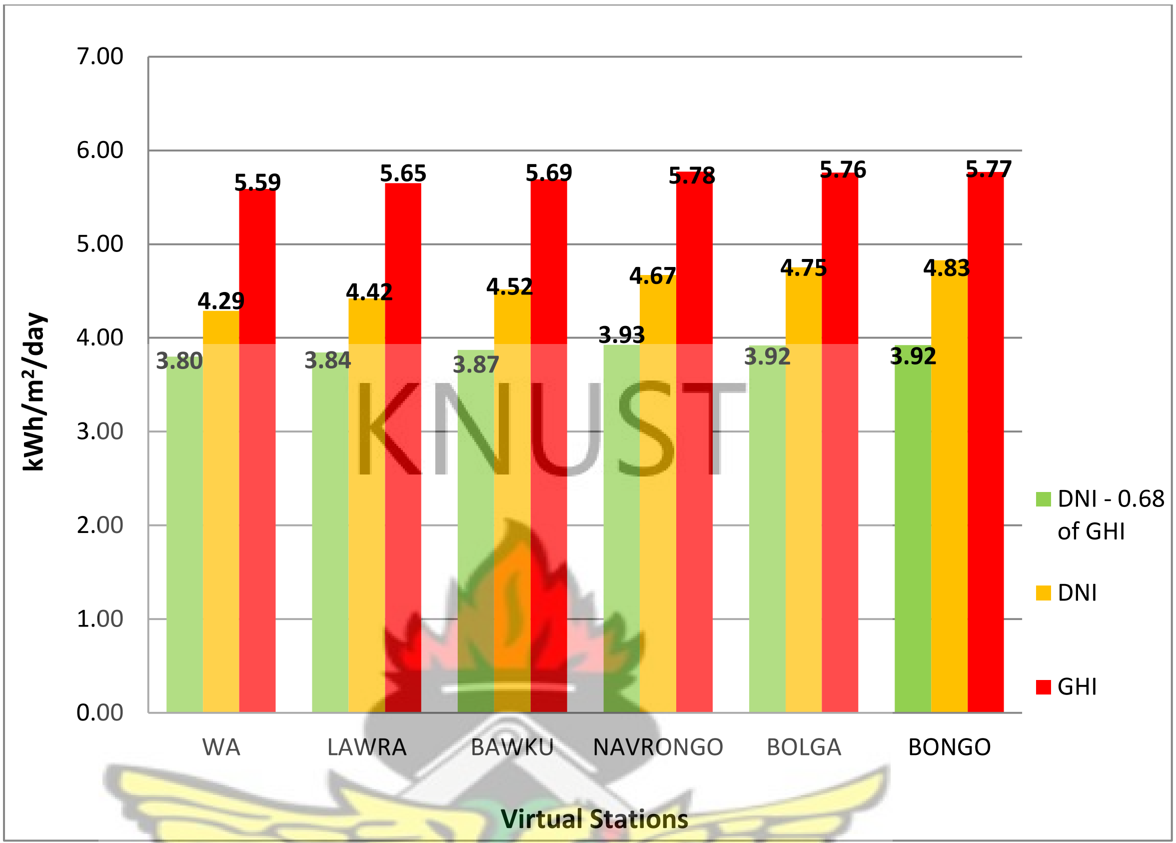

Figure 3. 4: Summary of Simulation Results

Comparing the results from the simulations, as shown in Figure 3.4 above, there are differences between the DNI generated by Meteonorm and that generated from assuming a constant beam fraction of 0.68. Whereas the annual average DNI generated from meteonorm ranges between 4.288 kWh/m^2/day in Wa to 4.828kWh/m^2/day at Bongo, that generated on assumption of a constant beam fraction with reference to Opoku & Brew-Hammond (2011) estimates DNI ranging from 3.800 kWh/m^2/day in Wa, to 3.927 kWh/m^2/day at Navrongo. Although data generated indicates that Bolga, Bongo and Navrongo are promising sites for CSP applications in Ghana, the solar map in Figure 3.1 places Navrongo and Bolga in a

DNI region of 3.5 – 4.0 kWh/m^2/day. Ideally, Bongo becomes the best site with maximum DNI for CSP applications in Ghana. Wa on the other side recorded the lowest DNI in both cases. This contradicts to the fact that Wa is the best site to be considered for CSP applications in Ghana, as reported in Opoku (2010). It is therefore necessary for ground measurements to be taken to establish the actual radiation levels of the area, since Meteonorm has an error margin of +/- 9%.

That notwithstanding, economically viable minimum DNI for CSP applications has been suggested in the literature to be 5kWh/m^2/day (Azoumah et al, 2010). This however implies that CSP in northern Ghana would not be economically viable, confirming the findings of Opoku and Brew-Hammond, (2011).

3.3 Cooling Water Availability

The physical layout of the Volta River Basin in West Africa shows that the Upper East region is characterized by shallow and accessible groundwater resources compared to other northern regions. Due to the easy accessibility of ground water resources in the region, the solar plant can be operated using either the wet or hybrid cooling method. Detailed information on the rainfall pattern and ground water resources in the upper east region can be found in Appendix B.

3.4 Grid Infrastructure

Referring to the current grid map of the Upper East and West regions of Ghana in Figures 3.5a & b, the region has existing 161 kV power lines operating at full voltage, running from southern Ghana to Zebilla, and 161 kV power lines that operate at 34.5 kV, transporting power to Burkina Faso, Togo and Cote d'Ivoire. The region has proposed 330 kV power lines from Southern Ghana and 225 kV lines to Ouagadougou. Upper West region on the other hand has existing 161 kV power lines operating at 34.5 kV and proposed 161 kV lines. The grid infrastructure in the upper east region is therefore more developed as compared to the upper west region.

Though the Upper East Region has been proven to have better DNI and grid infrastructure, this thesis is being limited to the viability of a hybrid solar/bio-oil thermal power generation in Wa, in upper west region of Ghana, to build upon the previous study conducted in Wa by Opoku, (2010). It is therefore recommended that feasibility studies be conducted in the promising sites to establish the technical and financial viability of solar thermal applications in the upper east region.

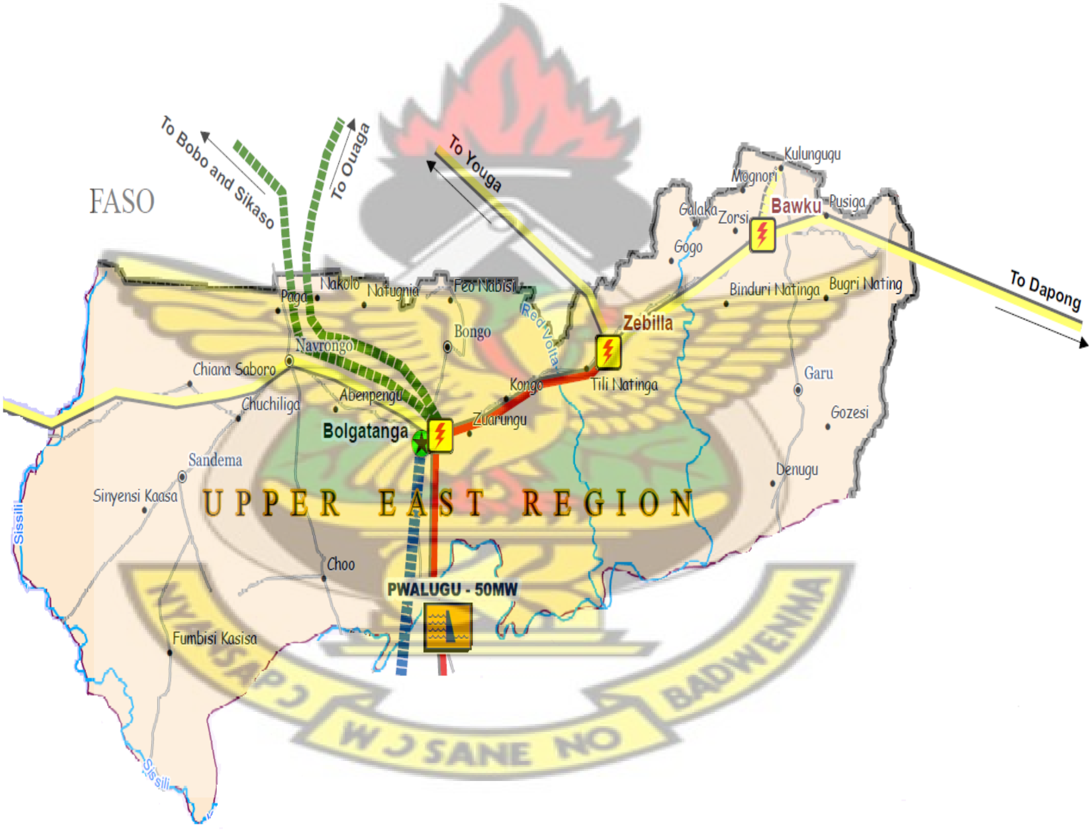

Figure 3.5a: Upper East Grid Infrastructure

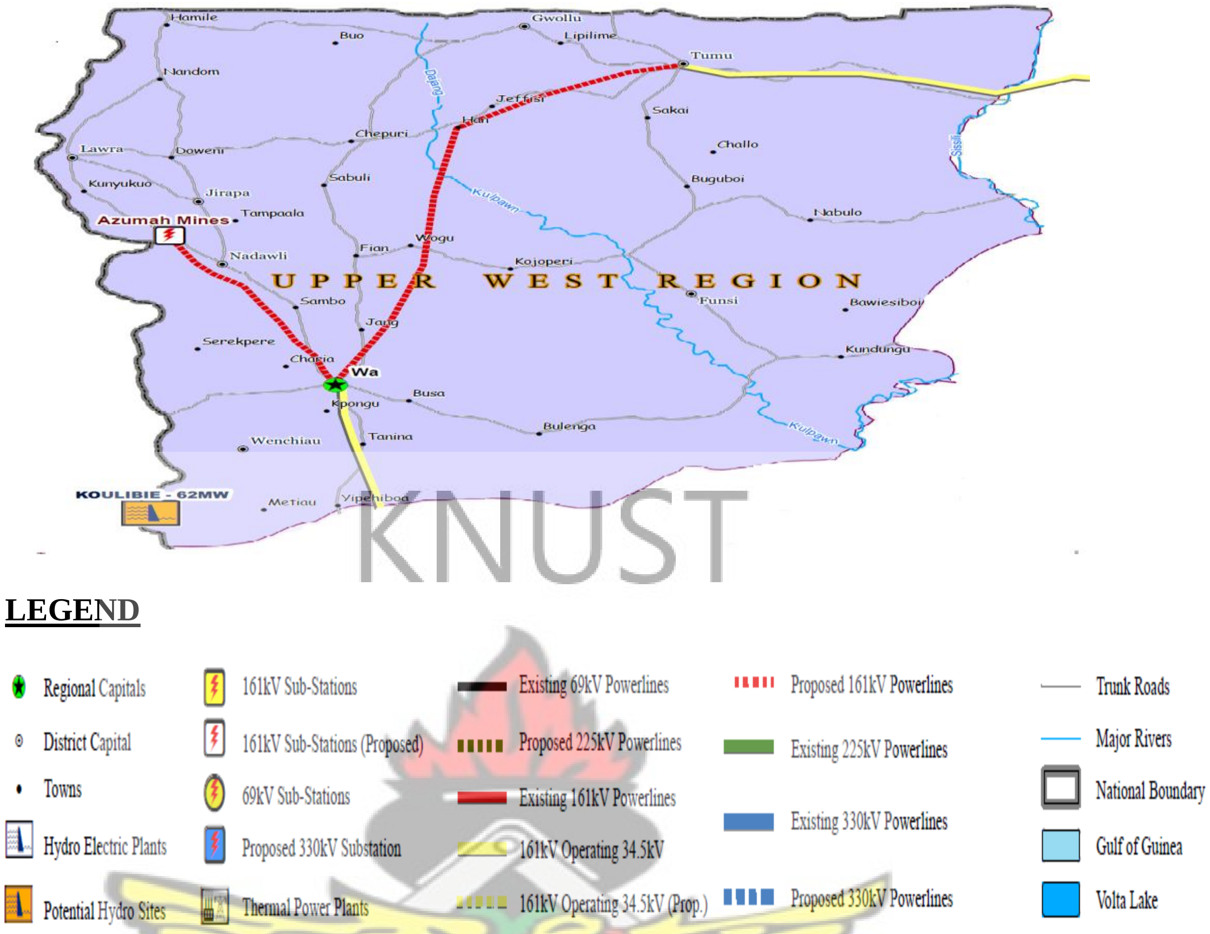

Figure 3.5b: Upper West Grid Infrastructure (Source: GRIDCO, 2010)

3.5 Technical Concepts

This thesis presents three major conceptual designs of hybridizing solar thermal power plants using bio-oil as the backup fuel. The conceptual designs would rely on the effective integration of a central receiver system and flat plate collectors into a bio-oil fired thermal power plant. Central receiver system was considered on the basis of a recommendation by Opoku (2010) to explore the viability of hybrid central receiver systems in Wa. Flat plate collectors were also considered due to its ability to absorb both global and diffuse radiations, and therefore could be used for pre-heating. The conceptual designs are discussed in the following sections.

3.5.1 Concept A: Hybrid CRS with Backup Boiler

This concept proposes the integration of an auxiliary boiler into a central receiver system, to serve as a backup to the solar resource. During hours of the day when the solar resource is available, the mirrors in the heliostat field reflects beam radiation to a receiver to heat up the cold HTF, as shown in Figure 3.6. The hot HTF goes through a solar heat exchanger, where it heats up water to produce high pressure steam to run the steam turbine. The other half of the plant is a complete bio-oil combustion steam power plant which backs up the solar resource. The system is designed such that the working fluid can further be heated in the bio-oil boiler if the operating conditions of the turbine are not met in the solar heat exchanger.

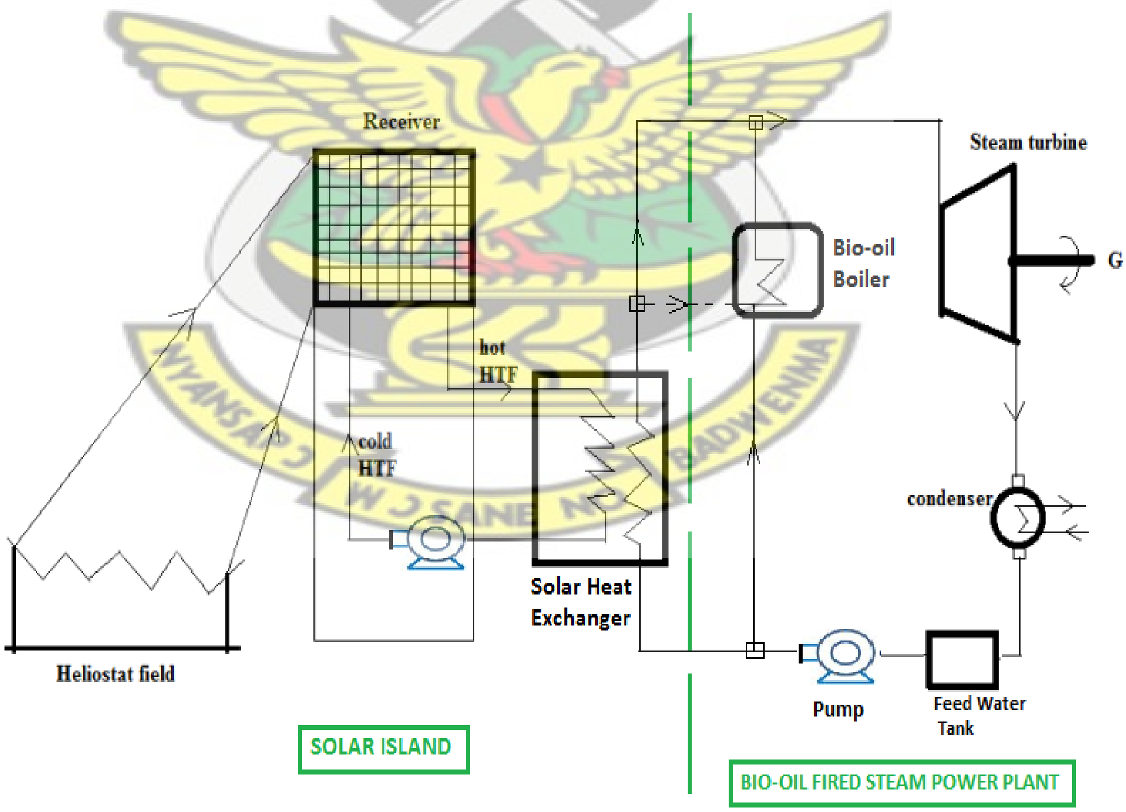

Figure 3. 6: Hybrid CRS with Backup Boiler

The integration of the backup boiler ensures round-the-clock operation of the power plant, such that there is smooth supply of energy during short transients and also when the solar resource is unavailable. This is illustrated in the graph in Figure 3.7. The plant runs on full bio-oil during the hours of 17:00 GMT and 7:00 GMT until the solar resource starts coming in.

Generally, the taking over of the solar resource reduces the quantity of fuel required for operation on full load.

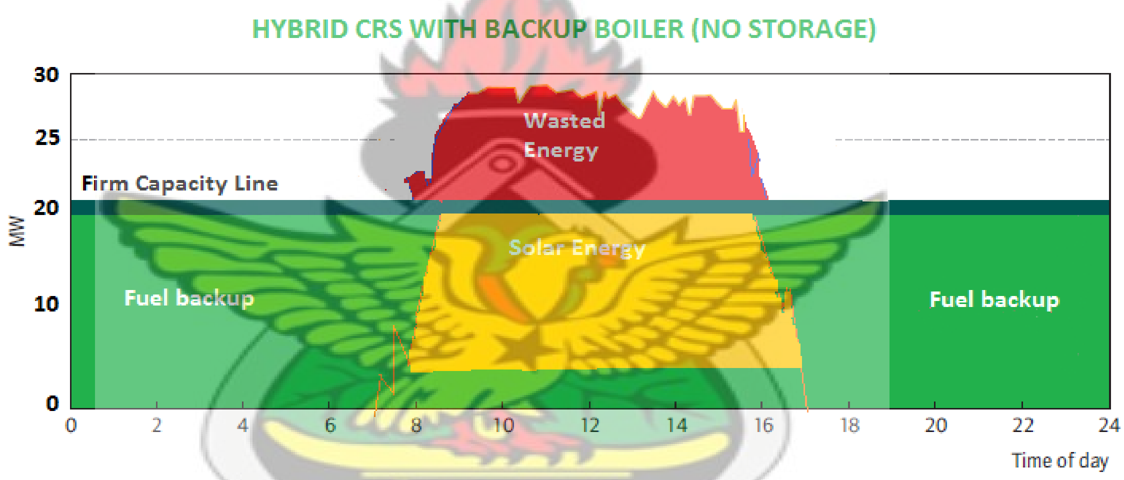

Figure 3. 7: Round–The-Clock Operation of Hybrid CRS with Backup Boiler

3.5.2 Concept B: Rankine Cycle with Solar Preheater

Concept B shows a rankine cycle integration with flat plate collectors used to preheat the boiler feed water. From a conceptual standpoint, the flat plate collector technology will be used to preheat feedwater entering the boiler, supplementing the conventional bio-oil fired feedwater heating process. This is illustrated in Figure 3.8. Steam that was previously diverted from the turbine to the feedwater system for preheating can therefore be used to generate extra electricity. The quantity of fuel required is varied depending on the intensity of solar irradiation.

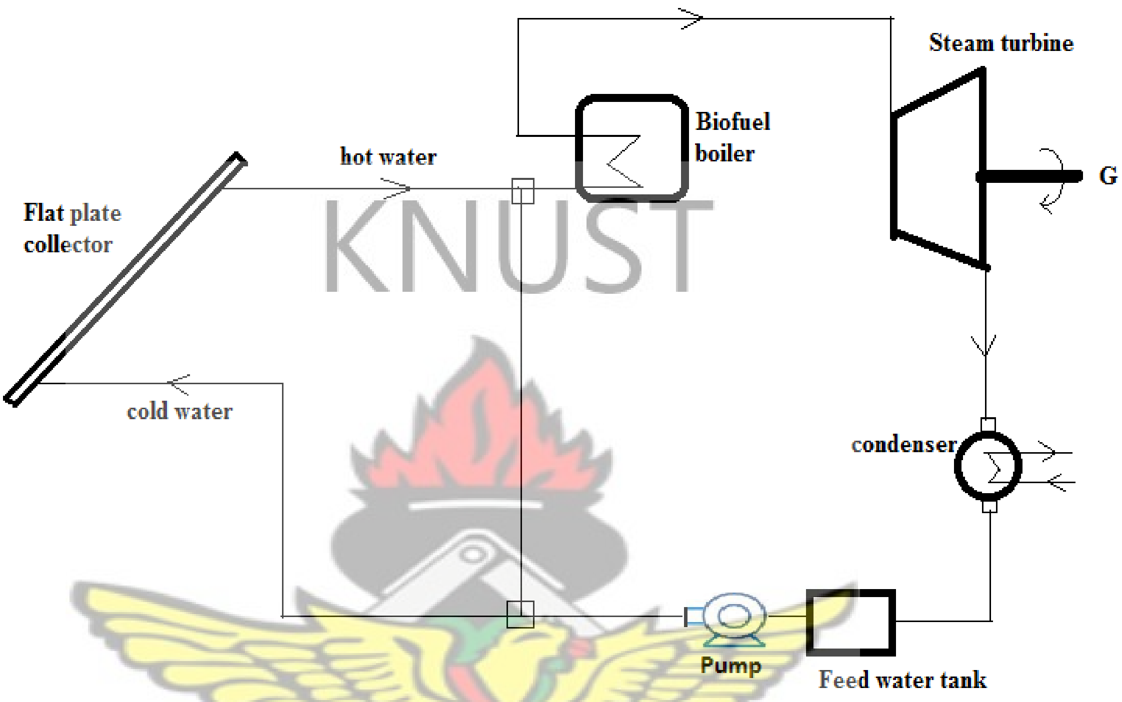

Figure 3. 8: Flat Plate Collectors Integrated with Rankine Cycle

Figure 3.9 is a graph that presents the round-the-clock operation in Concept B. The solar resource is used only for preheating, and therefore a significant quantity of fuel is still required to run the plant during its normal operations. The excess energy generated by the sun goes to waste since thermal storage was not included in the design.

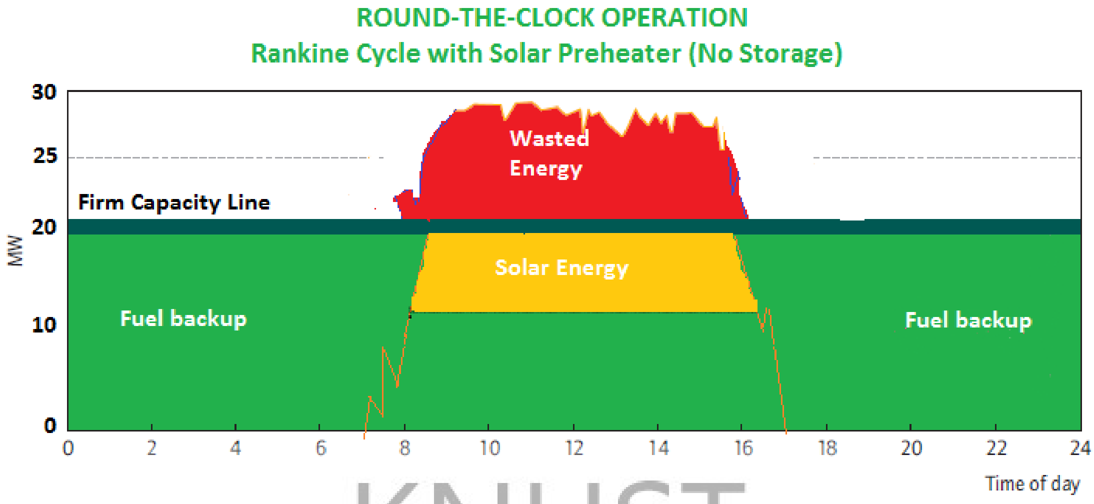

Figure 3. 9: Round–The-Clock Operation: Rankine Cycle with Solar Preheater

3.5.3 Concept C: Combined Cycle Gas Turbine with Solar Preheater

This configuration consists of the integration of flat plate collectors into a combined cycle thermal power plant with biodiesel as the main fuel to be used in the gas turbine cycle. With this design configuration (Figure 3.10), the primary aim of the solar field is to preheat feed water before in enters the Heat Recovery Steam Generator (HRSG). The exhaust gases of the gas turbine are used in the HRSG to generate high pressure steam to run a steam turbine, coupled to a generator to produce electrical power. When the solar resource is down, the feedwater goes straight to the HRSG without going through the solar field.

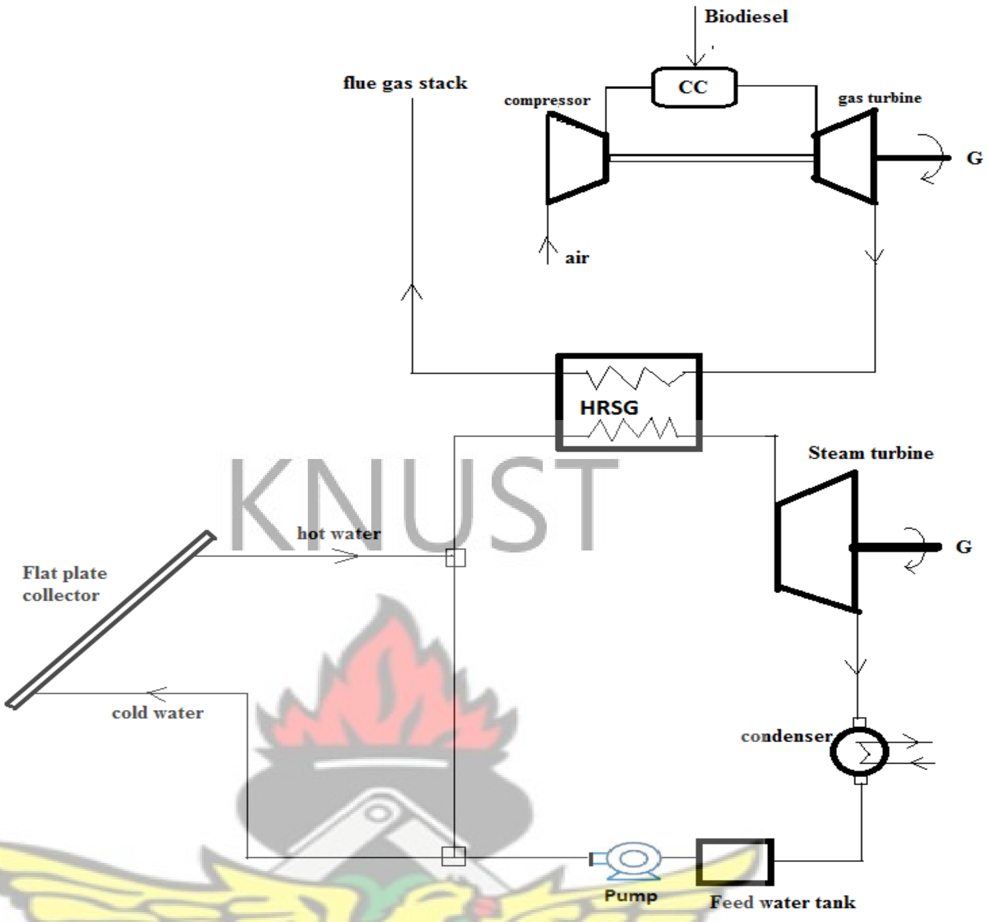

Figure 3.10: Flat Plate Collector Integration with Combined Cycle Power Plant

That notwithstanding, when the gas turbine is running on full load on high solar irradiation days, the heat from the HRSG plus the heat from the solar field can be larger than what can be accommodated by the steam turbine. Due to this reason, the steam turbine has to be oversized to accommodate any extra steam on high solar radiation days. Oversizing the steam turbine would result in higher costs, larger part load losses and subsequently lower efficiency whenever the solar field operates without maximum solar heat input.

3.6 Criteria for Selection of Technical Concepts

Though the three concepts above are practically feasible, some key factors are generally considered in siting a hybrid solar plant. The solar resource, backup fuel availability and the capital cost are the criteria to be used for the selection of the appropriate technical concepts. These factors would help determine the technology best suitable for the chosen location.

3.6.1 Fuel Availability

A comprehensive review of Ghana's biomass resources and biofuels potential and the recent energy situation analysis by the Energy Commission of Ghana (2012 a), and Duku et al, (2011), revealed that though there is the potential to develop biomass and biofuels in the country, there is no commercial production of biodiesel in the country. The unavailability of commercial biodiesel rules out the option of Concept C, since the focus is to run the gas turbine unit fully on biodiesel. Table 3.1 shows the major bio-oil availability in Northern Ghana (Brong Ahafo and Northern Regions).

Table 3.1: Bio-Oil Potential in Northern Ghana

Region	Town and/or District	Plantation owner and location	Current size (ha)	Seed yield (tones)	Oil yield (tones)	Remarks
Northern	Yendi (Jatropha)	*Solar Harvest	400	1,800	~ 594	seeds exported
Northern	Mamprusi (Jatropha)	*New Energy led EU project	360	1,620	~ 535	seeds exported
Northern	Buipe (Jatropha)	*Jatropha Africa	150	675	~ 223	seeds exported
Northern	Yeji (Jatropha)	*Agroils	25	113	~ 37	seeds exported
Brong Ahafo	Bredie (Jatropha)	*Kimminic Ghana	10,000	45,000	~ 14,850	seeds exported
Brong Ahafo	Kintampo (Jatropha)	*Savannah Black Farms	200	900	~297	seeds exported
Brong Ahafo	Techiman (Soya Oil)	^Ghana Nuts Ltd	-	-	15,512.50	Oil consumed locally, cake exported
Brong Ahafo	Techiman (Shear Butter Oil)	^ Ghana Nuts Ltd	-	-	19,545.75	Oil consumed locally, cake exported
Northern	Daboya (sunflower)	^ TRAGRIMACS	300	8,604	~ 2,581	Oil and cake consumed locally

*Kemausour F. (2012) – Independent Site Survey as part of PhD Thesis

^ Personal Conversation, ~ Potential Oil yields

Though the Jatropha seeds are exported, current farm sizes have potentials to yield 16,536 tonnes of Jatropha oil. Shea butter oil has the highest production levels of 19,545.75 tonnes per annum, with sunflower oil the least, with 13,500 tonnes of annual production. TRAGRIMACS however transports all the sunflower seeds to Accra for oil extraction. Soya and Shea butter oils are consumed locally due to the insatiable demand for them for food and other uses. Jatropha oil therefore becomes the only option for fuel capabilities due to food security, and also the fact that most biofuel investors in Northern Ghana are cultivating Jatropha oil seed crop.

3.6.2 DNI

The design point DNI for Wa is 4.288 kWh/m^2/day, less than 5.0 kWh/m^2/day, which is the minimum DNI for economically viable commercial CSP applications, as said by Azoumah et al (2010). Commercial CSP, not only in Wa, but in Ghana would not therefore not be advised, since the highest simulated annual average DNI is 4.828 kWh/m^2/day, which is less than the minimum required DNI. The use of Flat Plate Collectors will however be suitable for low temperature thermal applications.

3.6.3 Capital Cost

CSP plants are highly capital intensive. The World Bank Group in 2006 projected the capital cost for oil fired steam power plants to be $920 /kW, and that of Combined Cycle power plants as $650 /kW. George, (2010), quoted the capital costs for power tower systems without storage as $5,200 /kW, with the solar field contributing to 44% of the capital costs. The average price for flat plate collectors is about $540 /m^2 (RETScreen, 2012). Details of the cost/ kW for the concepts can be found in Appendix E

3.7 Concept Selection

Considering the criteria analysed above, the unavailability of commercial biodiesel production in the country would be a limitation for the implementation of Concept C, since the gas turbine unit is designed to run fully on biodiesel. Table 3.2 is the simulation results for the monthly average DNI from Meteonorm. Considering the location Wa, the average monthly DNI values for November, January and February are higher than 5.0 kWh/m^2/day. On the basis of DNI, commercial CSP at Wa would be viable for only these three months in the year.

Table 3.2: Monthly Average DNI for Wa (kWh/m²/day)

MONTH	DNI (kWh/m²/day)
JANUARY	5.323
FEBRUARY	5.571
MARCH	4.613
APRIL	4.233
MAY	4.742
JUNE	3.567
JULY	2.806
AUGUST	2.645
SEPTEMBER	3.50
OCTOBER	4.355
NOVEMBER	5.20
DECEMBER	4.903
AVERAGE	**4.288**

Though the possibility of a CSP plant can be confirmed for three months, the low annual average DNI would require a greater percentage of backup fuel since the DNI conditions are met only for about 25% of the entire year. Thus, from the above discussed limitations, and with the huge investments costs associated with CSP plants, Concept B best suits the current conditions at the selected site. Table 3.3 summarises the evaluation criteria used for the concept selection. Further details are provided in Appendix E.

Table 3.3: Summary of Concept Selection

CONCEPT	ANNUAL SOLAR RADIATION	FUEL AVAILABILITY	CAPITAL COST
A	Low DNI 4.288 kWh/m²/day	Jatropha seeds and other SVOs available	$ 5,200 /kW
B	Good GHI 5.588 kWh/m²/day	Jatropha seeds and other SVOs available	$ 1,748 /kW
C	Good GHI 5.588 kWh/m²/day	No Biodiesel Production	$ 1,478 /kW

CHAPTER FOUR

PERFORMANCE ASSESSMENT AND FINANCIAL EVALUATION

4.1 Introduction

This Chapter begins with a comparative assessment of simulation results from Opoku (2010) and results from DNI data generated with Meteonorm. It further outlines a methodology and runs a comprehensive technical performance assessment for the concept selected in chapter three. Finally, it looks at the total initial cost of the hybrid plant and performs a financial analysis to determine NPV and Payback Period plus the effect of tariffs and grants/capital subsidies on the viability of the project.

4.2 Power Tower Performance Results

Table 4.1 shows a summary of results for performance of a 20MW Stand-alone Power Tower system, comparing DNI generated from Meteonorm to previous studies carried out in Wa by Opoku (2010). In his work, he assumed a constant beam fraction of 0.68 and estimated the DNI from the ground measured GHI.

Table 4. 1: Power Tower Performance

PARAMETER	UNIT	DNI = 0.68 of GHI	DNI from METEONORM
Annual Average DNI	kWh/m²/year	1371.06	1565.12
Capacity Factor	%	15.76	17.87
Electrical Output	MWe	20	20
Annual Energy	MWh	27604	31308
Capital Cost	$/kW	3600	3600
Electricity Tariff	¢/kWh	8	8
NPV	$	Negative	Negative
Simple Payback	Years	71.9	57.7

All input parameters, with exception of the solar radiation data used in the study were held constant. A performance and economic assessment was then run on the power towel model using RETScreen. The simulation results indicated that an increase in the DNI results in an increase in capacity factor of the plant, and subsequently an increase in the annual energy generated by the plant. The project would still not be financially acceptable for an independent power producer who has no capital subsidy or grants available due to a negative Net Present Value (NPV).

4.3 Technology Assessment of Concept B

For the purpose of this analysis, a 20MW Rankine cycle power plant with superheat has been selected as an optimum balance between performance and bio-oil supply, (see Chapter 3). Based on the bio-oil statistics in Ghana (Table 3.1), straight Jatropha oil was selected as boiler fuel, there is the potential to extract the oil from the available seeds. A turbine-steam consumption calculator was used to calculate the steam consumption, given the steam inlet and exhausts conditions, and the turbine power generated. The quantity of Jatropha oil required by the oil combustion boiler for a steady generation was calculated for a 20MWe plant.

4.3.1 Modelling and Methodology

Total heat energy transferred to the water by the collector modules is expressed as

$$Q_{SF} = \dot{m}_w C_P (T_O - T_I) \qquad (1)$$

where Q_{SF} = Rate of thermal energy leaving the collector

$\dot{m}_w$ = water flow rate through collector modules

T_o = water temperature at collector outlet

T_i = water temperature at collector Inlet

Efficiency of collector modules is given by the relation

$$\eta_{col} = \frac{Q_{SF}}{I_A \times A_A} \qquad (2)$$

where, η_{col} = collector efficiency

I_A = Global Irradiance at collector surface

A_A = collector total aperture area

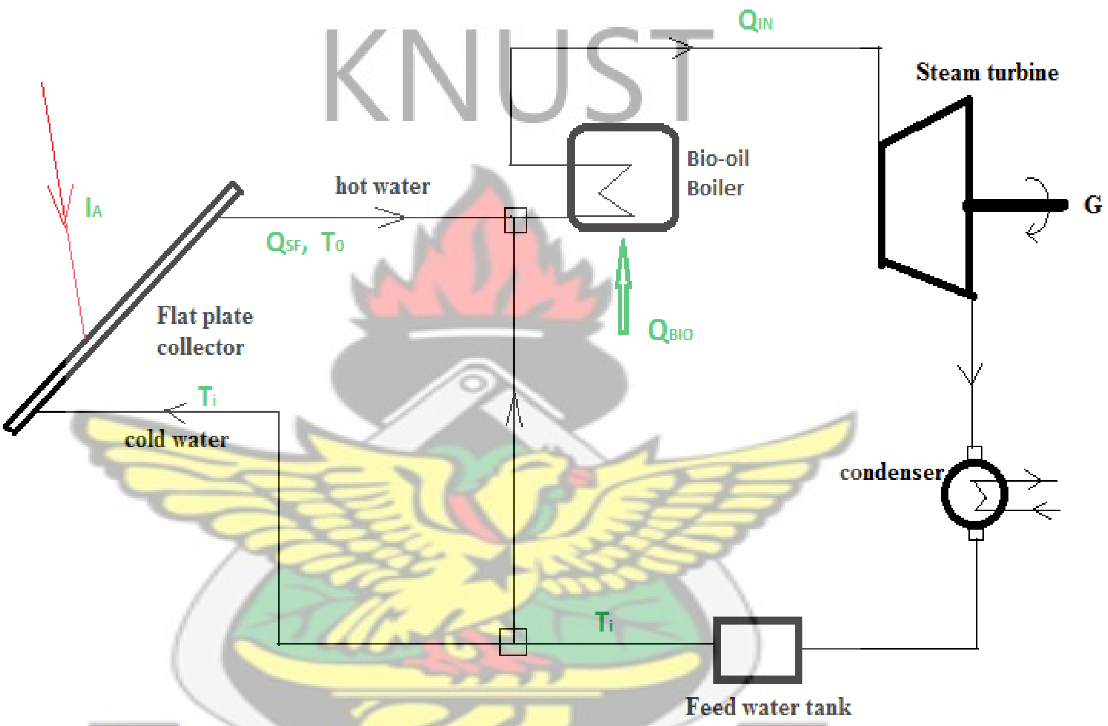

Figure 4. 1: Energy Flow Diagram for Concept B

Energy balance across boiler is expressed as a relation between the energy generated by bio-oil combustion and the energy generated by the solar field as shown below.

$$Q_{IN} = (\eta_B Q_{BIO} + Q_{SF}) \qquad (3)$$

such that Q_{IN} = Total energy input

Q_{BIO} = Total Energy content of bio-oil

η_B = Bio-oil combustion boiler efficiency

$\eta_B Q_{BIO}$ = Total energy added in the boiler

Energy generated from the bio-oil can further be expressed as a relation between the fuel flow rate and the calorific value of the fuel as shown below.

$$Q_{BIO} = \dot{m}_{BIO} \times CV \quad (4)$$

$\dot{m}_{BIO}$ = fuel flow rate

CV = Calorific Value of fuel

Substituting equation (2) and (4) into equation (3) rearranging,

$$\eta_B(\dot{m}_{BIO} \times CV) = Q_{IN} - Q_{SF} \quad (5)$$

$$\dot{m}_{BIO} \times CV = \frac{Q_{IN} - (\eta_{col} \times I_A \times A_A)}{\eta_B} \quad (6)$$

Thus

$$\dot{m}_{BIO} = \frac{Q_{IN} - (\eta_{col} \times I_A \times A_A)}{\eta_B \times CV} \quad (7)$$

Equation (7) therefore estimates the quantity of bio-oil required by the boiler for operation. An increase in the global insolation, I_A, will lead to a subsequent decrease in the quantity of fuel required by the boiler and vice versa.

Table 4.2 shows the design inputs used. Although San Miguel et al (2011) gave the optimum working pressure for a 50MW plant to be in the order of 90 to 100 bar, 60 bar was chosen for this 20MW power plant to minimize expenses and technical difficulties. Key design input for solar field is set to preheat working fluid from 35 °C to 80 °C.

Table 4. 2: Key Design Inputs

Meteorological Data	
GHI (I_A)	2041 kWh/m^2/year
Solar Field	
Collector Efficiency	70% *
Collector Inlet Temperature (T_i)	35 °C
Collector exit temperature (T_o)	80 °C*
Oil Boiler	
Combustion Efficiency	89.6 % #
Calorific Value (Jatropha oil)	42.048 MJ/Kg ^
Turbine Input Data	
Inlet Temperature	400 °C
Inlet Pressure	60 bar
Turbine Efficiency	85%
Turbine Power	21.05 MW
Exit Pressure	0.07 bar

Sources: *Stine & Geyer (2001), # IEA ETSAP (2010), ^Forson et al (2004)

Table 4. 3: Summary of Results

Inlet Steam Properties		
Saturation Temperature	°C	275.4
Enthalpy	kJ/kg	3178.7
Steam Consumption		
Specific	kg/kWh	3.697
Actual ($\dot{m}_s$)	kg/s	21.62

Table 4.3 presents the output results from the turbine steam-consumption calculator. The actual steam consumption of the boiler is 21.62 kg/s. Details of the steam consumption calculator output can be found in Appendix C (Figure C-2).

4.4 System Performance Assessment

The technical performance of the plant is analysed, taking into consideration the annual energy generated, solar field capacity and the fuel requirements of the power plant. It further estimates the boiler capacity and the annual GHG emission analysis of the plant. These are further discussed as follows:

i. Rate of Solar Heat Output

$Q_{SF} = 4066.722$ kW

ii. Total Collector Aperture Area

$A_A = 24934.9 \text{ m}^2$

iii. Total Energy generated by boiler

$Q_{IN} = 68723.49$ kW

iv. Quantity of Jatropha Oil Required

$$\dot{m}_{BIO} = \frac{Q_{IN} - (\eta_{col} \times I_A \times A_A)}{\eta_B \times CV} \quad (7)$$

Substituting the results into the equation (7) and simplifying,

$$\dot{m}_{BIO} = 1.824 - 0.4633\ I_A \qquad \left({kg}/{s}\right) \quad (8)$$

Equation (8) estimates the actual quantity of Jatropha oil required to fuel the boiler at the design input parameters in Table 4.2. This is however relative to the global solar radiation recorded at the collector surface and tends to increase as the radiation levels decreases and vice versa.

4.4.1 Annual Fuel Consumption

A recent technology brief document on industrial combustion boilers by IEA (2010) estimated plant availability including planned down time hours as 94.4%. Annual operating hours was therefore calculated based on the plant availability. With the operational hours, the annual fuel consumption was estimated in two scenarios. Scenario one estimates the quantity requirement to run the plant fully on Jatropha oil, while scenario two estimates the fuel requirement for running the plant in dual mode.

Annual Operating hours = Total hours in a year × Plant Availability

= 8234.4 hours

4.4.1.1 Scenario 1 (Biofuel only)

In this case, the plant is assumed to run fully on biofuels (Jatropha oil) at all times of the year. From equation (8), when the solar resource is available,

$\dot{m}_{BIO} = 1.824 - 0.4633\ I_A$, where $I_A = 0$

$\dot{m}_{BIO} = 1.824\ {}^{kg}/_{s}$

Hourly fuel required = $1.824\ {}^{kg}/_{s} \times 3600 = 6566.81\ {}^{kg}/_{h}$

Annual Fuel Requirement $= 54073.73\ {}^{MT}/_{yr}$

4.3.1.2 Scenario 2 (Solar and Biofuel mode)

In scenario two, the plant will make use of the solar resource whenever it is available for preheating, and run fully on biofuels when the solar resource in not available.

From equation (8),

$\dot{m}_{BIO} = 1.824 - 0.4633\ I_A$, where $I_A = 232.99\ {}^{W}/_{m^2}$

$\dot{m}_{BIO}$= 1.716 ${}^{kg}/_{s}$

Hourly fuel required (day) = 1.716 ${}^{kg}/_{s}$ × 3600 = 6177.6 ${}^{kg}/_{h}$

Hours of Solar Operation = sunshine duration per day × number of days

Daily sunshine duration for Wa = 7.7 hours (Energy Commission, 2012 a)

Hours of sunshine per year = 7.7 × 365 = 2810.5 hours

Hours of biofuel operation = annual operating hours - sunshine operation hours

Hours of Bio-oil operation = 5423.9 hours

Fuel required during solar operation = 6177.6 × 2810.5 = 17362.14 ${}^{Mt}/_{yr}$

Fuel required during bio-oil operation = 6566.809 × 5423.9 = 35617.72 ${}^{Mt}/_{yr}$

Annual Fuel Requirement = 52797.86 ${}^{MT}/_{yr}$

4.4.2 Annual Energy Generated

Rated Power = 20MW

Annual Operating hours = 8234.4 hours

Annual Energy Generated = 164688 MWh

Plant Capacity Factor $= \frac{\text{Actual Energy}}{\text{Rated Energy}} = 94\%$

4.4.3 GHG Emission Analysis

The GHG Emission Analysis is performed by RETScreen software, which compares annual GHG emission reduction of the proposed technology to the existing technology (base case). Fuel distribution mix in Ghana for the year 2010 (Table 4.4) is taken as the base case with an assumption of 20% T&D losses.

Table 4. 4: Base Case

2010 FUEL DISTRIBUTION	
Generation Type	**%**
HYDRO	69
LCO	1.77
NG	29.19
DIESEL	0.04
Total	100

(Ghana Energy Commission, 2012 b)

Annual GHG emission reduction = 23423.7 tCO_2.

This is equivalent to 54,474 barrels of crude oil not consumed. See Appendix D (Figure D-2) for details.

4.5 Financial Assessment

In all cases, the NPV and Payback Period will be the evaluation criteria for analysing the hybrid solar/bio-oil thermal power plant to ascertain its financial viability. A project will be commercially viable if the present value of the discounted cash flows is greater than zero. If it is less than zero, the project would not be commercially viable.

4.5.1 Total Investment Costs

Cost-reduction potential of oil-fired steam power plants over the next 10 years will result in a capital cost of about US$ 920 /kW. Annual O&M cost is set to $ 65 /kW and 10% is set as miscellaneous expenses to cater for any unforeseen shocks (The World Bank Group, 2006). Flat plate collector costs are obtained when the total collector aperture area is entered into the RETScreen software. Table 4.5 shows the breakdown of the initial investment of the project. The total investment cost is analysed in the Cost Analysis page of the RETScreen software in Appendix D (Figure D-1)

Table 4. 5: Total Investment and Operating Costs for a 20MW Hybrid Solar/Bio-oil Power Plant

ITEM	**COST (US $)**
Oil Power Plant Capital Costs	18,400,000.00
Flat Plate Collector Costs	13,375,440.00
Miscellaneous	3,177,544.00
Total Initial Costs	**34,952,984.00**
OPERATING COSTS	
O&M Costs	1,300,000.00
Annual Fuel Costs (Jatropha Oil)	50,440,250.00
Total Annual Costs	**51,740,250.00**

Considering the uncertainties associated with the cost estimates, the capital and generation costs quoted in the report may vary mainly due to site-specific considerations.

4.5.2 Cash Flow Analysis

Tariff for Asogli Power Plant, an IPP shown in Appendix D (Figure D-3) was used as the reference tariff for the RETScreen analysis. For a Bulk Supply Tariff of US ¢8.6 /kWh, RETScreen analysis calculates the yearly revenue generated by the plant, and further calculates the total revenue generated over the plant’s life time of 20 years.

A reference case was established using the following data set for the analysis:

Power Capacity- 20 MWe

Total Initial Costs - US $ 34,952,984.00

Jatropha Oil Price - $ 950 /MT (BPF International, 2012)

Electricity Export rate- US¢ 8.6 /kWh

Grant/Capital Subsidy - 0%

Inflation - 0%

Discount Rate - 10%

4.5.2.1 Summary of Results

Summary of analysis results from the RETscreen is provided in Table 4.6 and Figure 4.2 respectively.

Table 4. 6: Annual Revenue Generated and Required Feed-In-Tariff

ITEM	AMOUNT (US $)
Bulk Supply Tariff	¢ 8.6 /kWh
Annual Revenue Generated	$14,135,171.00
Annual O&M Costs	$ 51,740,250.00
Annual Deficit	**$ 37,605,079.00**
Required Feed-In-Tariff	¢ 35 /kWh

The annual revenue generated in Table 4.6 shows that it is not possible to operate a hybrid solar/bio-oil steam power plant in Wa under reference conditions indicated. A feed-in-tariff of ¢ 35 /kWh would be required to yield a positive NPV of $15,281,724 .00, with a Payback Period of 5.9 years.

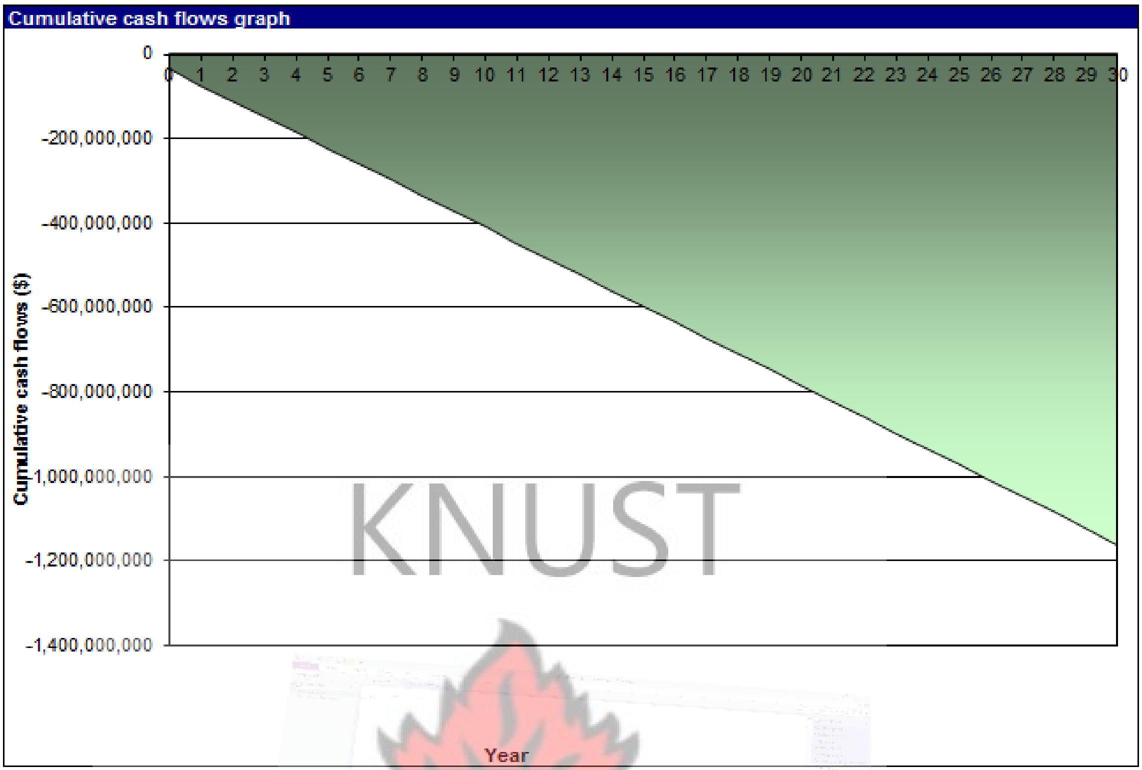

Figure 4. 2: Cumulative cash flow graph generated from RETScreen software

The prevailing bulk supply tariffs from PURC and the high cost of Jatropha oil amounts to an annual pre-tax deficit of $ 37,605,079.00 without inflation. This can clearly be seen in the cumulative cash flow graph (Fig 4.2), where right from year one, the cost deficit begins to increase to about $ 1,200,000,000.00 by end of the entire project life of 30 years. This clearly makes the project financially unattractive under the reference scenario conditions.

4.6 Sensitivity Analysis

Sensitivity analysis was performed to determine factors that can be adjusted to make the project financially viable for a profit minded investor. Two scenarios were considered during the sensitivity analysis to determine effects of Tariff changes on simple payback period and NPV.

4.6.1 Effects of Tariff Changes on Simple Payback Period and NPV for Reference Case

In this scenario, the bulk supply tariff of 8.6 US¢ /kWh is varied until a positive NPV is achieved. From Figures 4.3 and 4.4, the project does not look attractive at the prevailing tariffs until an increase of 300% is reached. The financial viability of the project is then confirmed for tariffs above 34 US ¢ /kWh since it yields a positive NPV, and a simple payback period 7.4 years. (Appendix E, Table E-2)

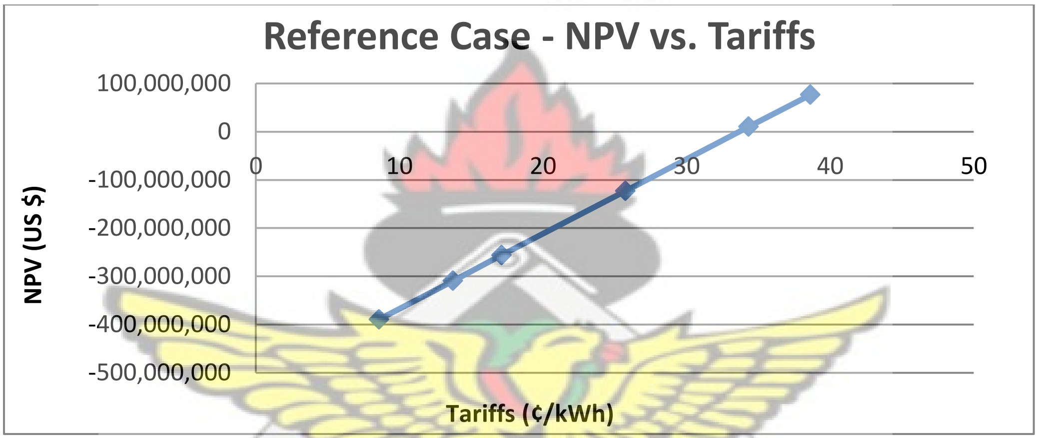

Figure 4. 3: Graph of NPV vs. Tariffs

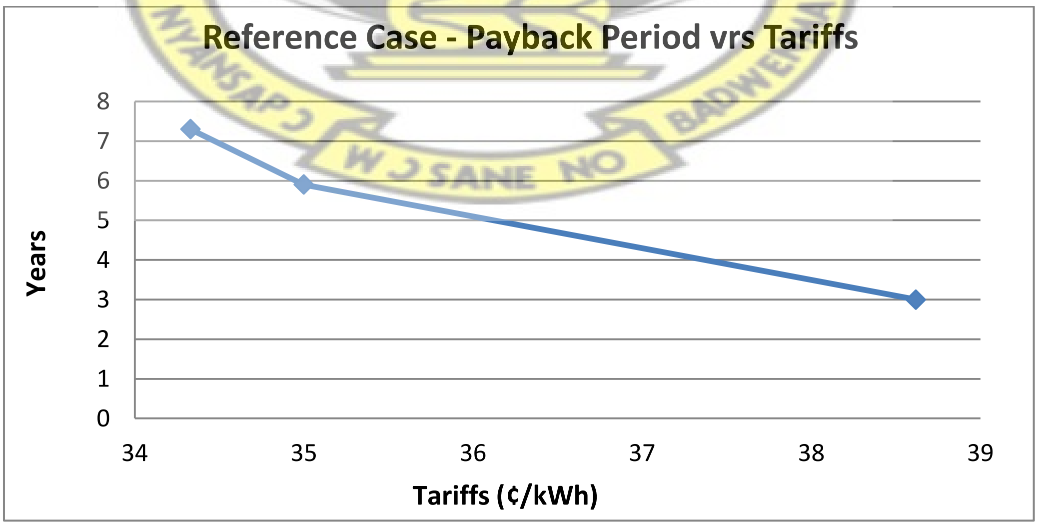

Figure 4. 4: Graph of Payback Period vs. Tariffs

4.6.2 Effects of Oil price drop on Simple Payback and NPV at different Tariffs.

This scenario analyses the effects of Jatropha oil price reduction with increasing tariffs on NPV and Simple Payback Period. The graphs in Fig 4.5 clearly spell out that there is viability in the project for increasing tariffs and oil price drops. For all scenarios considered, a positive NPV is achieved at tariffs of US cents 34 /kWh. This drops with subsequent Jatropha oil drops, with the NPV increasing accordingly. The graph indicates that for a tariff range of US cents 15 /kWh to US cents 25 /kWh, the prevailing Jatropha oil prices would have to drop 20% to 40% in order to yield a positive NPV.

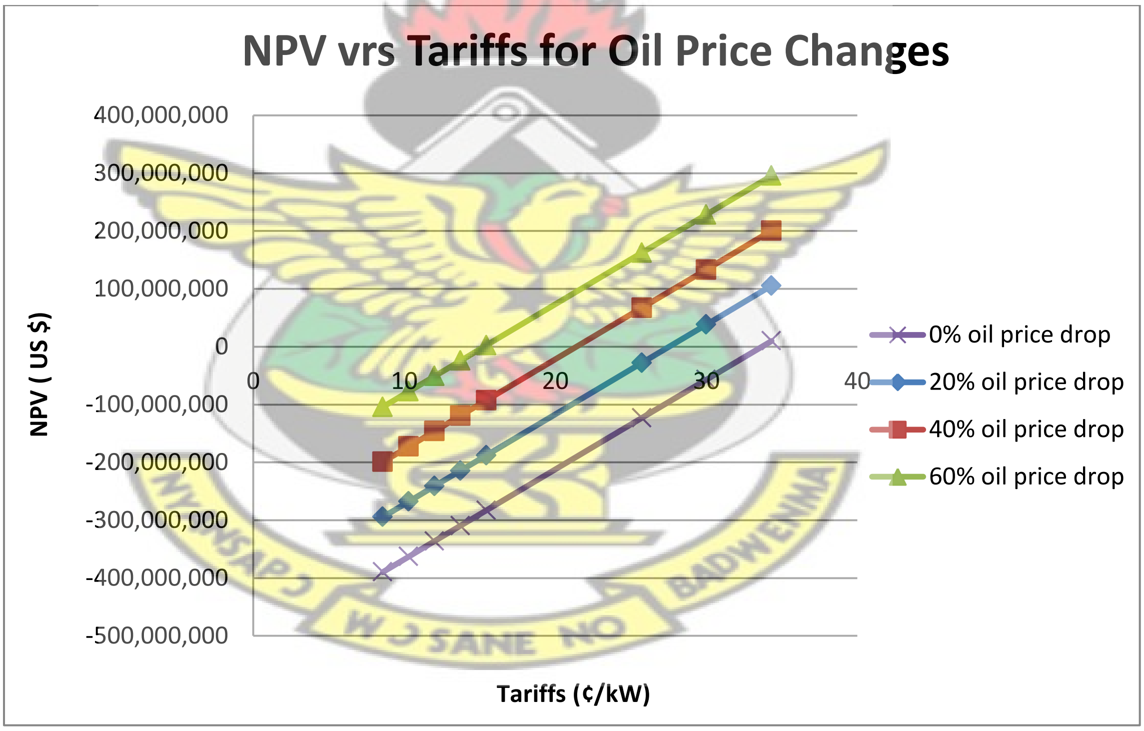

Figure 4. 5: Graph of NPV against Increasing Tariffs for Different Oil Prices

For a project lifetime of 30 years, emphasis was placed on tariffs within the range of 28 to 35 (US cents /kWh) since it yielded payback periods under 10 years. This is presented in Figure 4.6. For the reference case, the project is not financially attractive at low tariffs (Figure 4.3), and as such a tariff of 34 cents/kWh is required to achieve a payback period of 8years. For all other scenarios analysed, tariffs at 28 cents /kWh will yield payback periods under 10 years, thereby making the project financially attractive to private investors.

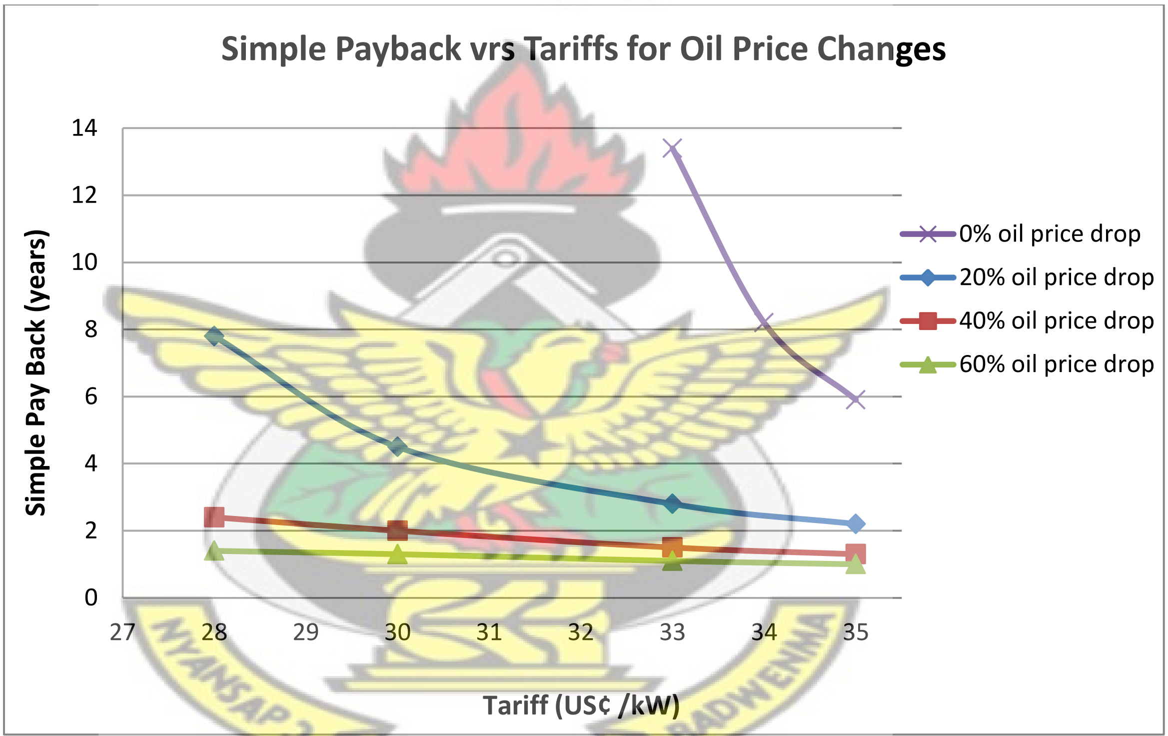

Figure 4. 6: Graph of Payback Period against Increasing Tariffs and Oil Price Drops

CHAPTER 5

CONCLUSION AND RECOMMENDATION

5.1 Conclusion

One major objective of this thesis was to establish the DNI levels in the upper east and upper west regions with the Meteonorm software, and determine areas best suitable for CSP applications.

On comparing the results from the simulations, the annual average DNI generated from meteonorm ranged between 4.288 kWh/m^2/day in Wa to 4.828kWh/m^2/day at Bongo, whereas DNI generated on assumption of a constant beam fraction with reference to Opoku & Brew-Hammond (2011) estimated a DNI range of 3.800 kWh/m^2/day in Wa, to 3.927 kWh/m^2/day at Navrongo. Ideally, the best site with the highest DNI is Bongo, with a DNI of 4.828kWh/m^2/day. This clearly disputes the reports of Opoku (2010), that Wa is the site with the highest DNI in Ghana. That notwithstanding, CSP in Wa would still not be economically viable since the minimum DNI of 5.0 kWh/m^2/day required for CSP applications is recorded only 25% of the entire year.

The thesis further presented a preliminary technical and economic analysis of a 20MW stand-alone Power Tower assessment at Wa, and a second option of preheating feed water of a 20MW bio-oil combustion thermal power plant with flat plate collectors. The Power Tower assessment at Wa, established a capacity factor of 17.87%, with a negative NPV at a bulk supply tariff of US$ 0.08 /kWh.

Integrating flat plate collectors into a bio-oil combustion power plant (Rankine cycle with superheat) however yields a positive NPV at 25 US cents/kWh, and a simple payback period close to 3 years when the prevailing Jatropha oil price drops by 40%.

The study finally concludes that bio-oil price drops with increasing tariffs as the major way of improving the financial viability of a bio-oil combustion power plant in Ghana, since the price of bio-oil costs approximately 2.66 times higher than the plant revenue generated for the reference case.

5.2 Recommendations

The following recommendations are made based on the findings and conclusions that were drawn from this study:

i. Large scale CSP is theoretically not feasible due to relatively low annual average DNI values recorded. Further studies should therefore be conducted into the technical viability of low temperature solar thermal applications in the northern sector of Ghana.

ii. Ground measurement of the solar irradiance for the promising sites considered in this thesis has to be conducted to establish the actual radiation levels of the area. This will help determine the best technology type suitable for solar thermal applications.

iii. Research should be conducted to establish the financial viability of using other sources of clean energy fuels such as biomass and biogas as a substitute to bio-oil.

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APPENDICES

APPENDIX A

METEONORM SOFTWARE OVERVIEW

Meteonorm software is primarily used for calculation of solar radiation on arbitrarily orientated surfaces at any desired location in the world. It supplies meteorological data at any desired location in the world as monthly, daily, hourly or minute values in a range of alternate output formats by interpolating and extrapolating between ground measured and satellite data available within the specified location.

To calculate meteorological data for any desired location in the world, the software applies an interpolation procedure. For global radiation, this is done with a 3-D inverse distance model (Shepard’s gravity interpolation), based on the introduction by Zelenka et al. (1992) (IEA Task 9), with additional North-South distance penalty (Wald and Lefèvre, 2001), where:

$$G_h(x) = \sum w_i \cdot \left[G_h(x_i) + (z_i - z_x) \cdot g_v\right]$$
$$w_i = \left[(1-\delta_i)/\delta_i^2\right] \Big/ \sum w_k \text{ with}$$
$$\delta_i = d_i/R \text{ for } d_i < R$$
$$w_i = 0 \text{ otherwise}$$
$$d_i^2 = f_{NS}^2 \cdot \left\{s^2 + \left[v \cdot (z_i - z_x)\right]^2\right\}$$
$$f_{NS} = 1 + 0.3 \cdot \left|\Phi_i - \Phi_x\right| \cdot \left[1 + (\sin\Phi_i + \sin\Phi_x)/2\right]$$

w_i :	weight i	w_k :	sum of over all weights
R :	search radius (max. 2000 km)	v :	vertical scale factor
s :	horizontal (geodetic) distance [m]	z_x, z_i :	altitudes of the sites [m]
i:	Number of sites (maximum 6)	Φ_i , Φ_x:	latitudes of the points
g_v:	vertical gradient		

Comparisons with longer term measurements show that the discrepancy in average total radiation due to choice of time period is less than 2% for all weather stations. The radiation data was subjected to extensive tests. The error in interpolating the monthly radiation values is 9%, and 1.5°C for temperature.

It commences with the user specifying a particular location for which meteorological data are required, and terminates with the delivery of data of the desired structure and in the required format. Figure A-1 shows the interface of the meteonorm software

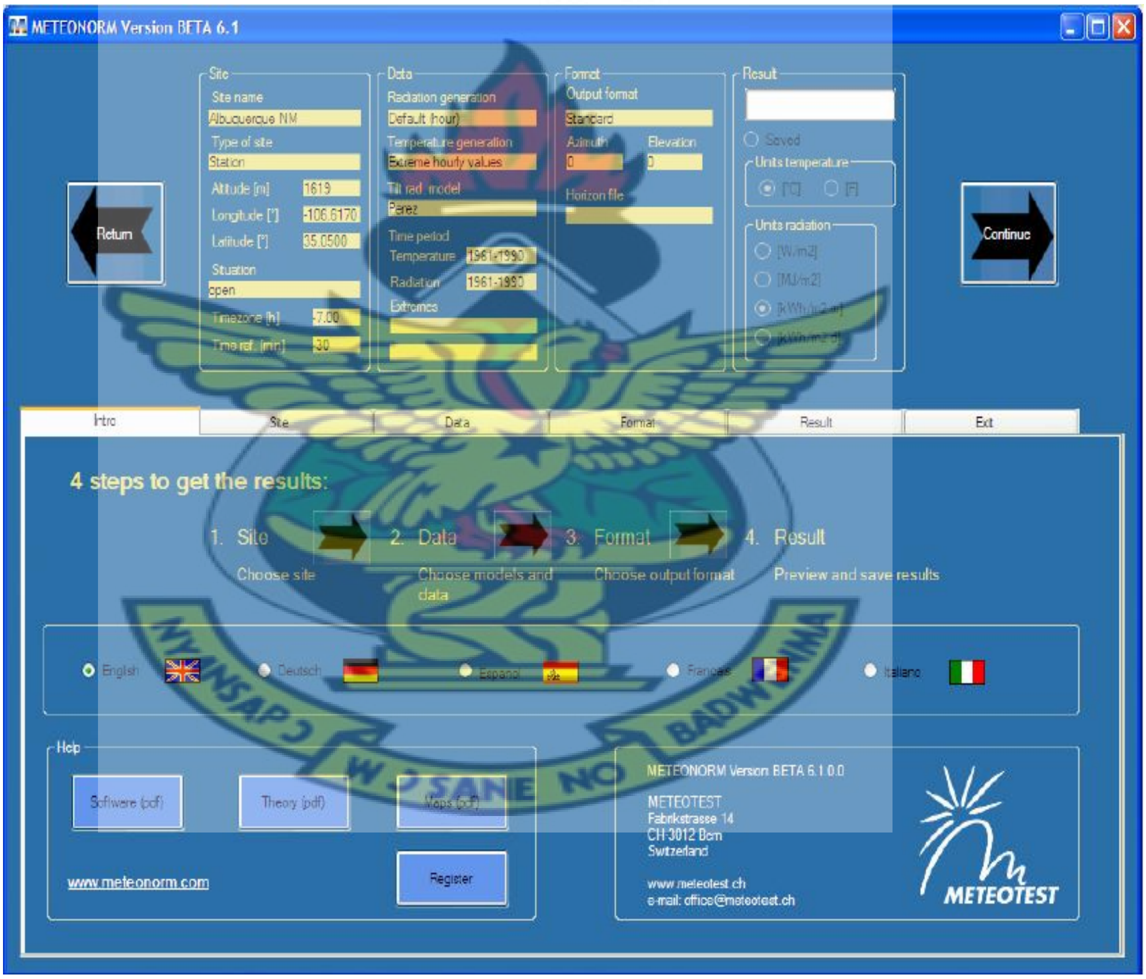

Figure A- 1: Interface of The Meteonorm Software

The Meteonorm software presents TMY output files for Global, Diffuse and Beam radiations. The nearest weather stations which are considered in the interpolation are also displayed in the output file. Figures A2 - A6 shows sample typical output files of meteonorm.

METEONORM Version 6.1.0.23

Name of site = Bolga

Latitude [°] = 10.799, Longitude [°] = -0.858, Altitude [m] = 175, Climatic zone = V, 3

Radiation model = Default (hour); Temperature model = Default (hour)

Tilt radiation model = Perez

Temperature: Old period = 1961-1990

Radiation: New period = 1981-2000

RR: Only 4 station(s) for interpolation

FF: Only 4 station(s) for interpolation

SD: Only 3 station(s) for interpolation

RD: Only 4 station(s) for interpolation

Nearest 3 stations: Gh: Navrongo (26 km), Tamale (154 km), Yendi (176 km)

Nearest 3 stations: Ta: Navrongo (26 km), Mango/Sansanne (153 km), Tamale (154 km)

Month	H_Gh	H_Dh	H_Bn	Ta
	[kWh/m2]	[kWh/m2]	[kWh/m2]	[C]
Jan	190	46	214	27.6
Feb	181	55	179	29.8
Mar	196	78	159	31.7
Apr	186	85	135	32.0
May	184	85	136	30.6
Jun	173	86	120	28.1
Jul	169	86	118	26.5
Aug	149	84	91	25.9
Sep	161	80	113	26.2
Oct	173	81	129	27.6
Nov	167	64	154	28.1
Dec	173	54	184	26.8
Year	2105	884	1734	28.4

\-

Legend:

H_Gh: Irradiation of global radiation horizontal

H_Dh: Irradiation of diffuse radiation horizontal

H_Bn: Irradiation of beam

Ta: Air temperature

Page 1 of 2

Figure A- 2: Bolga Solar Data

Name of site = Bongo
Latitude [°] = 10.918, Longitude [°] = -0.814, Altitude [m] = 244, Climatic zone = V, 3
Radiation model = Default (hour); Temperature model = Default (hour)
Tilt radiation model = Perez
Temperature: Old period = 1961-1990
Radiation: New period = 1981-2000
RR: Only 4 station(s) for interpolation
FF: Only 4 station(s) for interpolation
SD: Only 3 station(s) for interpolation
RD: Only 4 station(s) for interpolation
Nearest 3 stations: Gh: Navrongo (30 km), Fada Ngourma (180 km), Tamale (167 km)
Nearest 3 stations: Ta: Navrongo (30 km), Mango/Sansanne (153 km), Fada Ngourma (180 km)

Month	H_Gh	H_Dh	H_Bn	Ta
	[kWh/m2]	[kWh/m2]	[kWh/m2]	[C]
Jan	189	45	217	27.5
Feb	181	55	180	29.7
Mar	196	79	159	31.6
Apr	186	86	135	31.9
May	185	85	136	30.5
Jun	174	85	123	28.0
Jul	170	84	120	26.5
Aug	150	79	101	25.9
Sep	161	81	114	26.2
Oct	173	78	132	27.6
Nov	167	63	155	28.0
Dec	172	53	187	26.7
Year	2105	872	1759	28.3

-
Legend:
H_Gh: Irradiation of global radiation horizontal
H_Dh: Irradiation of diffuse radiation horizontal
H_Bn: Irradiation of beam
Ta: Air temperature

Figure A- 3: Bongo Solar Data

Name of site = Bawku

Latitude [°] = 11.058, Longitude [°] = -0.239, Altitude [m] = 244, Climatic zone = V, 3

Radiation model = Default (hour); Temperature model = Default (hour)

Tilt radiation model = Perez

Temperature: Old period = 1961-1990

Radiation: New period = 1981-2000

Ta: Only 4 station(s) for interpolation

RR: Only 4 station(s) for interpolation

FF: Only 4 station(s) for interpolation

SD: Only 4 station(s) for interpolation

RD: Only 4 station(s) for interpolation

Nearest 3 stations: Gh: Navrongo (94 km), Fada Ngourma (129 km), Yendi (181 km)

Nearest 3 stations: Ta: Navrongo (94 km), Mango/Sansanne (109 km), Fada Ngourma (129 km)

Month	H_Gh	H_Dh	H_Bn	Ta
	[kWh/m2]	[kWh/m2]	[kWh/m2]	[C]
Jan	179	56	185	27.2
Feb	176	59	167	29.5
Mar	193	86	146	31.6
Apr	185	83	136	31.9
May	186	82	143	30.4
Jun	173	87	116	28.0
Jul	167	91	103	26.5
Aug	153	84	96	25.9
Sep	161	81	108	26.3
Oct	173	81	129	27.7
Nov	165	63	153	28.0
Dec	165	60	163	26.7
Year	2078	915	1643	28.3

-

Legend:
H_Gh: Irradiation of global radiation horizontal
H_Dh: Irradiation of diffuse radiation horizontal
H_Bn: Irradiation of beam
Ta: Air temperature

Figure A- 4: Bawku Solar Data

Name of site = WA

Latitude [°] = 10.097, Longitude [°] = -2.495, Altitude [m] = 329, Climatic zone = V, 3

Radiation model = Default (hour); Temperature model = Default (hour)

Tilt radiation model = Perez

Temperature: Old period = 1961-1990

Radiation: New period = 1981-2000

FF: Only 3 station(s) for interpolation

SD: Only 3 station(s) for interpolation

Nearest 3 stations: Gh: Gaoua (80 km), Bole (121 km), Navrongo (178 km)

Nearest 3 stations: Ta: Gaoua (80 km), Navrongo (178 km), Tamale (192 km)

Month	H_Gh	H_Dh	H_Bn	Ta
	[kWh/m2]	[kWh/m2]	[kWh/m2]	[C]
Jan	171	63	165	27.1
Feb	171	63	156	29.1
Mar	190	84	143	30.5
Apr	181	86	127	30.3
May	188	83	146	28.7
Jun	171	91	107	27.0
Jul	156	92	87	25.8
Aug	146	85	82	25.4
Sep	158	81	105	25.7
Oct	178	79	135	27.4
Nov	168	62	156	28.1
Dec	160	62	152	26.7
Year	2041	931	1562	27.7

-

Legend:
H_Gh: Irradiation of global radiation horizontal
H_Dh: Irradiation of diffuse radiation horizontal
H_Bn: Irradiation of beam
Ta: Air temperature

Figure A- 5: Wa Solar Data

Tables A1- A3 presents a summary of the monthly and annual averages of GHI and DNI for the six virtual stations considered in the thesis.

Table A- 1: Monthly Average Global Horizontal Radiation (kWh/m^2/day)

	VIRTUAL STATIONS					
MONTH	**WA**	**LAWRA**	**BAWKU**	**BONGO**	**BOLGA**	**NAVRONGO**
January	5.516	5.613	5.774	6.097	6.129	6.129
February	6.107	6.179	6.286	6.464	6.464	6.464
March	6.129	6.194	6.226	6.323	6.323	6.323
April	6.033	6.10	6.167	6.20	6.20	6.20
May	6.065	6.097	6.0	5.968	5.935	5.968
June	5.70	5.733	5.767	5.8	5.767	5.80
July	5.032	5.065	5.387	5.484	5.452	5.484
August	4.710	4.774	4.935	4.839	4.806	4.839
September	5.267	5.333	5.367	5.367	5.367	5.367
October	5.742	5.806	5.581	5.581	5.581	5.581
November	5.60	5.667	5.50	5.567	5.567	5.567
December	5.161	5.258	5.323	5.548	5.581	5.581
AVERAGE	5.588	5.652	5.693	5.770	5.764	5.775

Table A- 2: Monthly Average Direct Normal Irradiation (kWh/m^2/day)

	VIRTUAL STATIONS					
MONTH	**WA**	**LAWRA**	**BAWKU**	**NAVRONGO**	**BOLGA**	**BONGO**
JANUARY	5.323	5.548	5.968	6.710	6.903	7.000
FEBRUARY	5.571	5.714	5.964	6.357	6.393	6.429
MARCH	4.613	4.774	4.710	5.097	5.129	5.129
APRIL	4.233	4.167	4.533	4.333	4.50	4.50
MAY	4.742	4.677	4.613	4.516	4.387	4.387
JUNE	3.567	3.933	3.867	3.867	4.0	4.10
JULY	2.806	2.968	3.323	3.742	3.806	3.871
AUGUST	2.645	2.516	3.097	2.613	2.935	3.258
SEPTEMBER	3.50	3.733	3.60	3.567	3.767	3.80
OCTOBER	4.355	4.677	4.161	4.161	4.161	4.258
NOVEMBER	5.20	5.233	5.10	5.10	5.133	5.167
DECEMBER	4.903	5.097	5.258	5.968	5.935	6.032
AVERAGE	4.288	4.420	4.516	4.669	4.754	4.828

Table A- 3: Monthly Average DNI (Beam Fraction = 0.68, kWh/m^2/day)

	VIRTUAL STATIONS					
MONTH	**WA**	**LAWRA**	**BAWKU**	**BOLGA**	**BONGO**	**NAVRONGO**
JANUARY	3.751	3.817	3.926	4.168	4.146	4.168
FEBRUARY	4.153	4.201	4.274	4.396	4.396	4.396
MARCH	4.168	4.212	4.234	4.299	4.299	4.299
APRIL	4.103	4.148	4.193	4.216	4.216	4.216
MAY	4.124	4.146	4.080	4.036	4.058	4.058
JUNE	3.876	3.899	3.921	3.921	3.944	3.944
JULY	3.422	3.444	3.663	3.707	3.729	3.729
AUGUST	3.203	3.246	3.356	3.268	3.290	3.290
SEPTEMBER	3.581	3.627	3.649	3.649	3.649	3.649
OCTOBER	3.905	3.948	3.795	3.795	3.795	3.795
NOVEMBER	3.808	3.853	3.740	3.785	3.785	3.785
DECEMBER	3.510	3.575	3.619	3.795	3.773	3.795
AVERAGE	3.800	3.843	3.871	3.920	3.923	3.927

APPENDIX B

WATER AVAILABILITY IN UPPER EAST REGION

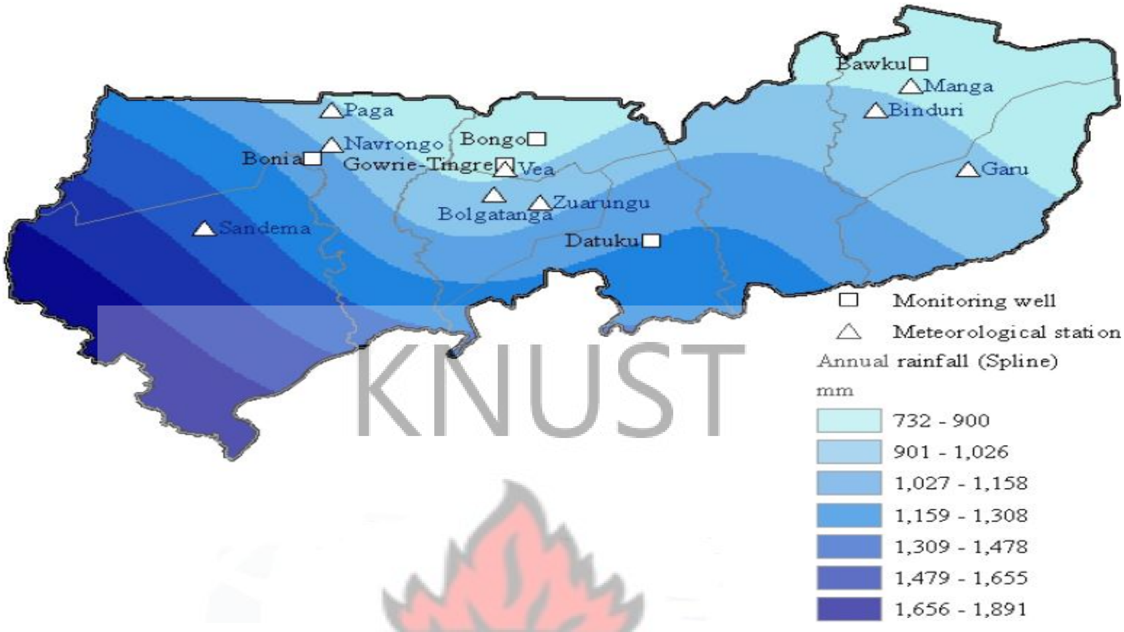

Figure B- 1: Water availability in Upper East Region

Table B-1: Details of monitoring wells in the UER [data from William Agyekum, Groundwater Division, WRI]

Well	Latitude °	Longitude °	Elevation (m)	Depth (m)	Yield (L/min)	Data availability	
Bawku	11.06	-0.26	224	3.97	300	Aug-06	Nov-08
Bongo	10.91	-0.81	224	5.72	45	Nov-05	Nov-08
Bonia	10.87	-1.13	179	4.92	175	Nov-05	Nov-08
Datuku	10.71	-0.64	194	2.60	20	Nov-05	Nov-08
Gowrie-Tingre	10.86	-0.85	181	1.50	200	Nov-05	Nov-08

(Source: Anyah and Kaluarachchi, 2009)

APPENDIX C

BOILER & STEAM TURBINE SPECIFICATIONS

Technical Performance	
Energy input	Gas, Coal, Oil, Wood and other fuels
Output	Steam
Benchmark combustion efficiency, %	Coal 90.3%, Oil residual 89.6%, Oil distillate 88.7%, Natural Gas 85.7%,
Actual efficiency, full load, %	Coal 85%, Oil 80%, Natural Gas 75%, Biomass 70%
Actual efficiency, low load, %	Coal 75%, Oil 72%, Natural Gas 70%, Biomass 60%
Construction time, months	22 months – 48 months (large industrial boilers)
Technical lifetime, yr	25 years – 40+ years
Max. (boiler) availability, %	86.6% - 94.2%
Typical (capacity) size, GJ/hr	Small < 11 GJ, large 11 – 264 GJ, very large > 264 GJ
Environmental Impact	**Air pollution**
total selected metals (TSM), kg/GJ	0.00003
HCl, kg/GJ	0.00019-0.0069
Hg, kg/GJ	0.0000011
CO, kg/GJ	0.14-0.25 (200 ppm)
SO_2, Mg/Nm^3	5 – 850
NO_X, Mg/Nm^3	100 – 400
Dust, Mg/Nm^3	5 – 50
CO2	Input fuel dependent
Costs	
Capital cost, overnight	3% of the life-time cost The typical cost of a gas- or oil–fired packaged fire-tube boiler that generates some 4,695 kg/hr steam at 1,034 kPa may be approximately around $ 60,000 (US $ 2008). Incremental mass flow rate of 1,565 kg/hr may result in cost increase of some $5,500.
O&M cost (fixed and variable)	1% of the life-time cost
Energy/fuel cost	Dependent on fuel type, market price of fuel type and utilization, constitutes up to 96% of life time cost
Economic lifetime, yr	25 – 40
Interest rate	Sector dependent

Figure C-1: Key Data and Figures for Boiler [Source: IEA ETSAP (2010)]

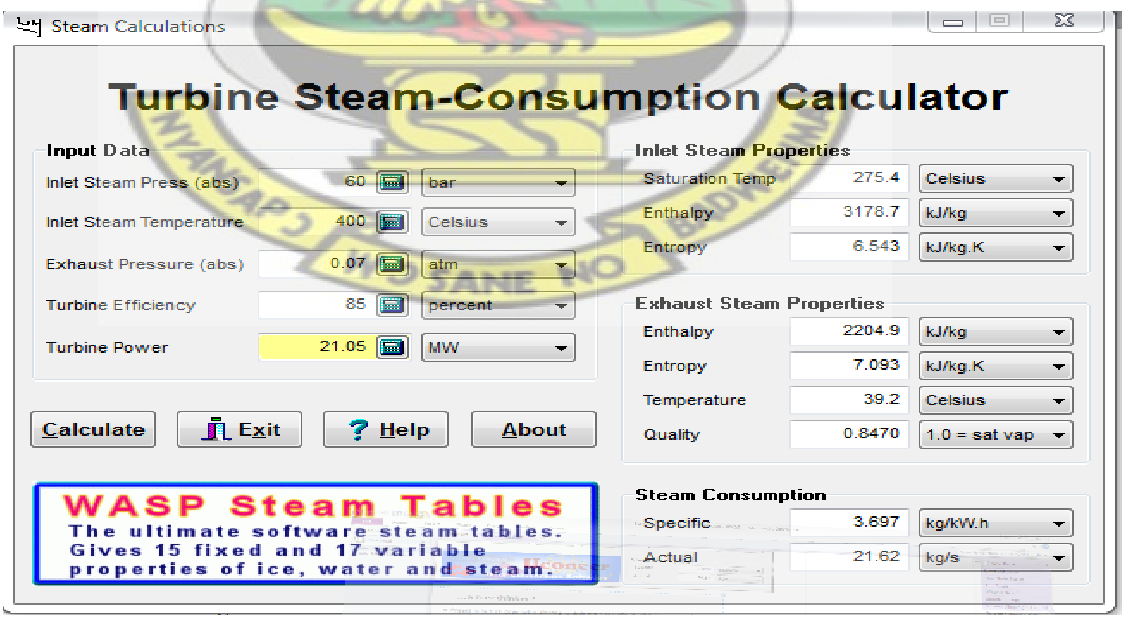

Figure C-2: Turbine Steam-Consumption Calculator

APPENDIX D

RETSCREEN ANALYSIS

RET Screen Cost Analysis - Power project

Settings				
Method 1	Notes/Range			
Method 2	Second currency	Notes/Range	None	
	Cost allocation			

Initial costs (credits)	Unit	Quantity	Unit cost	Amount	Relative costs
Feasibility study					
Solar Field	cost			$ -	
Sub-total:				$ -	0.0%
Development					
Solar Receiver	cost			$ -	
Sub-total:				$ -	0.0%
Engineering					
Steam Generation	cost			$ -	
Sub-total:				$ -	0.0%
Power system					
Solar thermal power	kW	20,000.00	$ 920	$ 18,400,000	
Road construction	km			$ -	
Transmission line	km			$ -	
Substation	project			$ -	
Energy efficiency measures	project			$ -	
Solar Field	cost	1	$ 13,375,440	$ 13,375,440	
Engineering				$ -	
Sub-total:				$ 31,775,440	90.9%
Balance of system & miscellaneous					
Spare parts	%			$ -	
Transportation	project			$ -	
Training & commissioning	p-d			$ -	
User-defined	cost			$ -	
Contingencies	%	10.0%	$ 31,775,440	$ 3,177,544	
Interest during construction			$ 34,952,984	$ -	
Sub-total:		Enter number of months		$ 3,177,544	9.1%
Total initial costs				$ 34,952,984	100.0%

Annual costs (credits)	Unit	Quantity	Unit cost	Amount
O&M				
Parts & labour	project	20,000	$ 65	$ 1,300,000
Fuel Costs	cost	53,095	$ 950	$ 50,440,250
Contingencies	%		$ 51,740,250	$ -
Sub-total:				$ 51,740,250

Periodic costs (credits)	Unit	Year	Unit cost	Amount
	cost			$ -
				$ -
End of project life	cost			$ -

Go to Emission Analysis sheet

Figure D-1: Cost Analysis

RETScreen Emission Reduction Analysis - Power project

Emission Analysis

○ Method 1
◉ Method 2
○ Method 3

Global warming potential of GHG
25 tonnes CO_2 = 1 tonne CH_4 (IPCC 2007)
298 tonnes CO_2 = 1 tonne N_2O (IPCC 2007)

Base case electricity system (Baseline)

Fuel type	Fuel mix %	CO2 emission factor kg/GJ	CH4 emission factor kg/GJ	N2O emission factor kg/GJ	Electricity generation efficiency %	T&D losses %	GHG emission factor tCO2/MWh
Hydro	69.0%	0.0	0.0000	0.0000	100.0%	20.0%	0.000
Natural gas	29.2%	54.6	0.0040	0.0010	45.0%	20.0%	0.549
Diesel (#2 oil)	0.0%	73.3	0.0020	0.0020	30.0%	20.0%	1.110
Oil (#6)	1.8%	77.8	0.0030	0.0020	30.0%	20.0%	1.178
Electricity mix	100.0%	50.0	0.0035	0.0010		20.0%	0.181

☐ Baseline changes during project life

Base case system GHG summary (Baseline)

Fuel type	Fuel mix %	CO2 emission factor kg/GJ	CH4 emission factor kg/GJ	N2O emission factor kg/GJ	Fuel consumption MWh	GHG emission factor tCO2/MWh	GHG emission tCO2
Electricity	100.0%	50.0	0.0035	0.0010	164,688	0.181	29,877.1
Total	100.0%	50.0	0.0035	0.0010	164,688	0.181	29,877.1

Proposed case system GHG summary (Power project)

Fuel type	Fuel mix %	CO2 emission factor kg/GJ	CH4 emission factor kg/GJ	N2O emission factor kg/GJ	Fuel consumption MWh	GHG emission factor tCO2/MWh	GHG emission tCO2
Solar	100.0%	0.0	0.0000	0.0000	164,688	0.000	0.0
Total	100.0%	0.0	0.0000	0.0000	164,688	0.000	0.0
				T&D losses			
Electricity exported to grid	MWh	164,688		20.0%	32,938	0.181	5,975.4
						Total	5,975.4

GHG emission reduction summary

	Base case GHG emission tCO2	Proposed case GHG emission tCO2	Gross annual GHG emission reduction tCO2	GHG credits transaction fee %	Net annual GHG emission reduction tCO2
Power project	29,877.1	5,975.4	23,901.7	2%	23,423.7

Net annual GHG emission reduction 23,424 tCO2 is equivalent to 54,474 Barrels of crude oil not consumed

Figure D-2: Emission Analysis

RETScreen Financial Analysis - Power project

Financial parameters

General		
Fuel cost escalation rate	%	
Inflation rate	%	
Discount rate	%	10.0%
Project life	yr	30
Finance		
Incentives and grants	$	
Debt ratio	%	
Income tax analysis		☑
Effective income tax rate	%	
Loss carryforward?		No
Depreciation method		Declining balance
Half-year rule - year 1	yes/no	Yes
Depreciation tax basis	%	
Depreciation rate	%	
Tax holiday available?	yes/no	No

Annual income

Electricity export income		
Electricity exported to grid	MWh	164,688
Electricity export rate	$/MWh	85.83
Electricity export income	$	14,135,171
Electricity export escalation rate	%	
GHG reduction income		☐
Net GHG reduction	tCO2/yr	23,424
Net GHG reduction - 30 yrs	tCO2	702,710
Customer premium income (rebate)		☐
Other income (cost)		☐
Clean Energy (CE) production income		☐

Project costs and savings/income summary

Initial costs			
Power system	90.9%	$	31,775,440
Balance of system & misc.	9.1%	$	3,177,544
Total initial costs	100.0%	$	34,952,984
Annual costs and debt payments			
O&M		$	51,740,250
Fuel cost - proposed case		$	0
Total annual costs		$	51,740,260
Periodic costs (credits)			
Annual savings and income			
Fuel cost - base case		$	0
Electricity export income		$	14,135,171
Total annual savings and income		$	14,135,171

Financial viability

Pre-tax IRR - equity	%	negative
Pre-tax IRR - assets	%	negative
After-tax IRR - equity	%	negative
After-tax IRR - assets	%	negative
Simple payback	yr	-0.9
Equity payback	yr	> project
Net Present Value (NPV)	$	-389,452,847
Annual life cycle savings	$/yr	-41,312,865
Benefit-Cost (B-C) ratio		-10.14
Energy production cost	$/MWh	336.69
GHG reduction cost	$/tCO2	1,764

Yearly cash flows

Year	Pre-tax	After-tax	Cumulative
#	$	$	$
0	-34,952,984	-34,952,984	-34,952,984
1	-37,605,079	-37,605,079	-72,558,063
2	-37,605,079	-37,605,079	-110,163,142
3	-37,605,079	-37,605,079	-147,768,221
4	-37,605,079	-37,605,079	-185,373,300
5	-37,605,079	-37,605,079	-222,978,379
6	-37,605,079	-37,605,079	-260,583,458
7	-37,605,079	-37,605,079	-298,188,537
8	-37,605,079	-37,605,079	-335,793,616
9	-37,605,079	-37,605,079	-373,398,695
10	-37,605,079	-37,605,079	-411,003,774
11	-37,605,079	-37,605,079	-448,608,853
12	-37,605,079	-37,605,079	-486,213,932
13	-37,605,079	-37,605,079	-523,819,010
14	-37,605,079	-37,605,079	-561,424,089
15	-37,605,079	-37,605,079	-599,029,168
16	-37,605,079	-37,605,079	-636,634,247
17	-37,605,079	-37,605,079	-674,239,326
18	-37,605,079	-37,605,079	-711,844,405
19	-37,605,079	-37,605,079	-749,449,484
20	-37,605,079	-37,605,079	-787,054,563
21	-37,605,079	-37,605,079	-824,659,642
22	-37,605,079	-37,605,079	-862,264,721
23	-37,605,079	-37,605,079	-899,869,800
24	-37,605,079	-37,605,079	-937,474,879
25	-37,605,079	-37,605,079	-975,079,958
26	-37,605,079	-37,605,079	-1,012,685,037
27	-37,605,079	-37,605,079	-1,050,290,116
28	-37,605,079	-37,605,079	-1,087,895,195
29	-37,605,079	-37,605,079	-1,125,500,274
30	-37,605,079	-37,605,079	-1,163,105,353

Cumulative cash flows graph

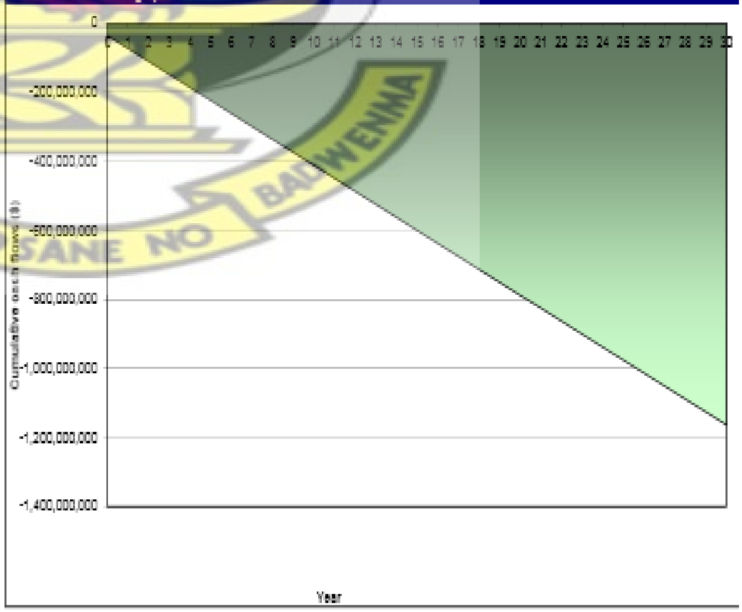

Figure D-3: Financial Analysis

APPENDIX E

FINANCIAL ANALYSIS

Table E-1: Power Plant Projected Costs [The World Bank Group, 2006]

	2005			2010			2015		
	Min	Probable	Max	Min	Probable	Max	Min	Probable	Max
Capital cost ($/kW)	780	880	980	700	810	920	670	800	920
Generating cost (cent/kWh)	6.21	7.24	9.00	5.50	6.70	9.08	5.49	6.78	9.63

DETAILED Cost /kW FOR CONCEPT B

Plant Capacity = 20MW

Oil fired steam power plant cost = $920 /kW

= 920 x 20,000 = $18,400,000. 00

Flat plate collectors is about = $540 /$m^2$

Total area of flat plate collectors required = 24,934.9 m^2 (page 44)

Total collector cost = $ 13,375,440

Misc [10% of (collector + power plant costs] = $ 3,177,544.

Total Initial costs =$ 34,952,984.00

Cost/ kW = **$ 1,748 /kW**

DETAILED Cost /kW FOR CONCEPT C

Plant Capacity	= 20MW
CC Power plant cost	= $650 /kW
	= 650 x 20,000 = $13,000,000. 00
Total collector cost	= $ 13,375,440
Misc [10% of (collector +cc plant costs]	=$ 2,637,544.00
Total Initial costs	=$ 29,012,984.00
Cost/ kW	= **$ 1,478 /kW**

Table E-2: Effects of Tariff changes on payback period and NPV

Tariff (¢/kW)	**Payback (yrs)**	**NPV ($)**
8.58	-	-389,452,847
13.73	-	-309,502,218
17.12	-	-256,201,799
25.75	-	-122,950,750
34.33	7.3	10,455,548
38.62	3	76,560,985

Table E- 3: Effect of Oil Price Drop on NPV

NPV (US $)			
Tariff	**20% oil price drop**	**40% oil price drop**	**60% oil price drop**
8.58	-294,353,662	-199,254,478	-104,155,293
10.3	-267,697,243	-172,598,058	-77,498,874
12	-241,056,348	-145,957,164	-50,857,979
13.73	-214,399,928	-119,300,744	-24,201,559
15.4	-187,759,034	-92,644,324	2,454,860
25.7	-27,851,566	67,247,619	162,346,803
30	38,145,196	133,244,381	228,343,565
34.3	105,399,483	200,498,667	295,597,852

Table E- 4: Effect of Oil Price Drop on Simple Payback at Different Tariffs

	SIMPLE PAYBACK PERIOD (YEARS)			
Tariff	**0% oil price drop**	**20% oil price drop**	**40% oil price drop**	**60% oil price drop**
28	36.4	7.8	2.4	1.4
30	13.4	4.5	2	1.3
33	8.2	2.8	1.5	1.1
35	5.9	2.2	1.3	1

Table E-5: PURC Tariffs [PURC, Ghana]

GHANA GAZETTE, 9TH SEPTEMBER, 2011 1347

FIRST SCHEDULE

Tariff Category	Effective 1st September, 2011
BGC VRA (GHp/KWH)	7.9145
GC ASOGLI (GHp/KWH)	16.3084
Composite BGC-VRA & Asogli (GHp/KWH)	9.6402

SECOND SCHEDULE

Tariff Category	Effective 1st September, 2011
TSC (GHp/KWH)*	2.4827

THIRD SCHEDULE

Tariff Category	Effective 1st September, 2011
DSC (GHp/KWH)	9.6863

FOURTH SCHEDULE

Tariff Category	Effective 1st September, 2011 Billing Cycle
Residential	
0–50 (Exclusive) (GHp/KWH)**	9.50
51–300 (GHp/KWH)	17.07
301–600 (GHp/KWH)	22.15
601+ (GHp/KWH)	24.61
Service Charge (GHp/Month)	160.50
Non-Residential	
0–300 (GHp/KWH)	24.54
301–600 (GHp/KWH)	26.11
601+ (GHp/KWH)	41.20
Service Charge (GHp/Month)	267.50

Tariff Category	Effective 1st September, 2011 Billing Cycle
SLT-LV	
Max. Demand (GHp/KVA/Month)	1498.00
Energy Charge (GHp/KWH)	25.57
Service Charge (GHp/Month)	1070.00
SLT-MV	
Max. Demand (GHp/KVA/Month)	1284.00
Energy Charge (GHp/KVH)	19.80
Service Charge (GHp/Month)	1498.00
SLT-HV	
Max. Demand (GHp/KVA/Month)	1284.00
Energy Charge (GHp/KWH)	18.19
Service Charge (GHp/Month)	1498.00
SLT-HV Mines	
Max. Demand (GHp/KVA/Month)	1498.00
Energy Charge (GHp/KWH)	28.89
Service Charge (GHp/Month)	1498.00

*The TSC of GHp 2.4827/KWH includes a regulator levy of GHp¢0.2174/KWH of electricity transmitted which is payable to the Public Utilities Regulatory Commission

** Residential Consumption between 0-50 units per month will attract a service charge of GHp¢100.00

SIGNED
DR.. EMMANUEL K. ANNAN
Chairman, Public Utilities Regulatory Commission