

Research Article

Technoeconomic Evaluation of Electricity Generation from Concentrated Solar Power Technologies in Ghana

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This work estimates the annual energy that could be generated from a concentrated solar power (CSP) plant. The optimal location used for this analysis was selected based on a set of multicriteria decision-making (MCDM) methods employed in an earlier research. The paper also determines the financial viability of implementing a CSP plant within the selected location. A 100 MW CSP plant for the said location was modelled and simulated using the System Advisor Model (SAM) software with data from the online database of the National Renewable Energy Lab (NREL) available from the SAM software. Using a solar multiple of 2.0 with a TES of 6 hours, the plant generated an estimated annual energy of 306.850 GWh with a capacity factor of 35.10% and gross-to-net conversion of 89.10%. The months with the highest generation were from November to March while July to September had the least generation. Generation begins from 8 am, rising to a peak around 12 pm to 4 pm and gradually declines into the night. Results from the financial analysis produced a net present value (NPV) of USD 156,287,433.72 after the plant life of 25 years, indicating profitability of the project. Results from the sensitivity analysis showed that the project NPV became negative only when the base case capital cost, electricity price, and revenue were, respectively, increased by 15%, reduced by 10%, and reduced by 13%.

1. Introduction

The increase in energy demand, increase in fossil fuel prices, and environmental pollution and energy security issues have caused countries to move into the usage of renewable energy sources to satisfy energy demand and decrease the overdependence on the conventional power generation plants [1–4]. Fossil and gas-fired thermal power plants have impacted the environment negatively through the emission of greenhouse gases such as CO_2 , methane, sulphur oxides (SO_x) , and nitrogen oxides (NO_x) from their combustion into the atmosphere [5–7]. According to Zheng [8], the respective CO_2 emissions from natural gas, oil, and coal combustion are $400 \text{ gCO}_2/\text{kWh}$, $675 \text{ gCO}_2/\text{kWh}$, and $825 \text{ gCO}_2/\text{kWh} - 1,035 \text{ gCO}_2/\text{kWh}$ while about 1,220 gCO₂/

kWh is emitted from nonrenewable municipal waste combustion. Hirbodi et al. [9] also indicated that CSP plants save about 399 kilotons of CO_2 emissions and 190 million cubic meters of fossil annually.

Electricity generation from concentrated solar power (CSP) plants is a very good replacement for the conventional fossil fuel and gas-fired thermal power plants, thereby saving fuel costs. According to Sheina et al. and Răboacă et al., a 1 m^2 mirror of the solar field produces 400 kWh of energy per year, reduces CO₂ emissions by 12 tonnes, and leads to fossil fuel savings of 2.5 tonnes over a 25-year lifetime [10, 11].

Considering the challenges in Ghana's energy sector coupled with the increasing nature of fossil fuel prices as well as concerns about climate change [12–14], renewable energy has attracted much attention in recent years. This has resulted in the development of policies to ensure the development of renewable energy and its integration into the national grid. The major sources of electric power generation in Ghana are hydro and thermal power [15]. According to the Ghana Renewable Energy Act, 2011 (Act 832), renewable energy (RE) technologies in Ghana are expected to achieve a 10% share of the total grid electricity generation [16, 17]. This, however, has not been possible as the current grid-connected RE sources are less than 2% as presented in Table 1 [18]. Table 1 also shows the available installed capacity for the power generation plants for Volta River Authorities (VRA) and the Independent Power Producers (IPPs). Another observation from Table 1 is that Ghana highly relies on thermal power generation followed by hydro. Renewable energy power plants, most of which is solar PV, in Ghana comprise less than 2% of the total installed grid capacity. However, there are several other standalone (off-grid) PV systems installed by various establishments and institutions within the country [18, 19].

In spite of the abundant solar resource available for the country, this has not been fully utilised for the generation of electricity. This partly leads to the 10% share of RE technologies not being realised to date. It is, therefore, necessary to carry out this research to evaluate the technical and economic prospects of generating electricity using CSP technologies in Ghana. A parabolic trough CSP plant would be modelled using the System Advisor Model, and hence, the economic viability would be evaluated.

In the design of a CSP plant, the most important parameter that affects its performance is the DNI [20, 21]. The most economical values of DNI for CSP plants are above 1,800 kWh/m²/year (\geq 5 kWh/m²/day) [22–25]. However, Ramdé et al. [26] conducted a study for the West African subregion and showed that locations with DNI values greater than 5 kWh/m²/day, between 4 and 5 kWh/m²/day, and between 3 and 4 kWh/m²/day, respectively, indicate high potential, medium potential, and low potential zones for the implementation of CSP plants. R. Bhattacharjee and S. Bhattacharjee [27] researched into the viability of CSP in lower DNI regions (3–4 kWh/m²/ day). Their results indicated that the performance of CSP in such regions is much comparable with that in higher DNI regions.

Other parameters, such as the ambient temperature, relative humidity, cloud cover, wind speed, and the availability of a water source, also invariably affect the performance of CSP plants [28]. Sites that were within the acceptable range of values from the meteorological data were selected for further analysis.

Nyasapoh et al. [15] reviewed the energy resources and the generation mix for Ghana's electricity. It was recommended that Ghana and other developing countries should invest in modern energy options, which are more environmentally friendly.

Abd-ur-Rehman and Ahmad [22] evaluated the thermal performance of a 100 MW PTC CSP plant located in Quetta, Pakistan. The said location was able to generate 277,542,912 kWh of electricity with a capacity factor of 31.7%, which indicates that the location can support the development of CSP for power generation.

Ezeanya et al. [29] used the SAM software to model and simulate a 50 kW CSP plant in order to characterize its performance and to help in analysing and evaluating the performance of the plant. Their results showed that an optimal combination of SM and TES hours could reduce electricity cost by about 70%. Soomro et al. [30] used the SAM software to present a performance improvement of cost-reduction analysis for a 50 MWe PT CSP plant for Abu Dhabi. It was concluded that an appropriate selection of the technology could reduce the cost, improve the system performance, and effectively meet energy demands.

Yang et al. [31] investigated into the cost-benefit analysis for a CSP plant in China. Their research employed the static payback period, net present value (NPV), net present value rate (NPVR), and internal rate of return (IRR) to analyse the cost and benefit of CSP. It was found that annual electricity production, operation and maintenance costs, loans, and their respective interests have some level of impact on the CSP system performance.

In terms of financing renewable energy projects in sub-Saharan Africa, Ref. [32] identified three main challenges, namely, longer payback periods, limited track record, and a high initial investment cost, which need to be critically considered to determine the attractiveness of the investment.

The rest of the paper is organised as follows. Section 2 discusses the methodology used, while Sections 3 and 4 present the results and discussions and conclusions and recommendations, respectively.

2. Methodology

Meteorological and solar radiation data were collected from several locations across the country, out of which locations whose parameters are within acceptable limits were selected for further analysis, as reported in [33].

2.1. Main Components of the Plant. The main components of a concentrated solar power plant, i.e., the solar field, power block, TES, and the heat transfer fluid, are described in this section with the various individual component specifications given. They have been selected based on maturity of the technology, availability of material, cost, and efficiency.

These components work together to generate the thermal energy required by the power block to generate electricity. The solar field consists of one or more solar collector loops whose size is determined by the amount of thermal energy required to generate a certain amount of electric energy. Each loop further consists of a series of solar collectors together with receivers, which are used to increase the temperature of the HTF to the design outlet temperature. Figure 1 shows a typical representation of a parabolic trough solar field while Figure 2 shows a single loop in the solar collector field, which features a parabolic trough collector (PTC) [34].

The parabolic trough collector is designed to rotate on only one axis [35] and therefore uses a single-axis tracking system to concentrate solar radiation onto its focal line to

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Dlant	Fuel	Installed conscitu	Dopondoble conscitu	Dercentage of installed canacity	
	Fuel	Installed capacity		Percentage of installed capacity	
Thermal					
ТАРСО-ТТ	GAS/LCO	330	300		
TICO-T2	GAS/LCO	340	320		
Amandi	LCO/gas	190	190		
TT1PP	Gas/LCO	110	100		
TT2PP	Gas	87	70		
Genser	Gas	95	18		
KTPP	Gas/DFO	220	200		
Ameri Power Plant	Gas	250	230	67.89%	
Kar Power Badge	HFO	470	450		
Sunon Asogli Ph1	Gas	200	180		
Sunon Asogli Ph2 St1	Gas/LCO	360	340		
Trojan	DFO/gas	44	39.6		
Cenit Power Plant	LCO	110	100		
Cen Power	LCO/gas	360	340		
AKSA	HFO	370	350		
Subtotal		3,456.00			
Hydro					
Akosombo	Water	1020	900		
Kpong	Water	160	140	30.41%	
Bui	Water	404	360		
Subtotal		1,584.00			
Solar					
Navrongo Solar Power Plant	Solar	2.5	1.75		
Bxc	Solar	20	14		
Meinergy	Solar	20	14	a .coo/	
Nadowli Kaleo District	Solar	17		1.69%	
Bui Power	Solar	22.25			
Lawra Solar Power Plant	Solar	6.5			
Subtotal		88.25			
Total capacity		5,208.25		100%	

TABLE 1: Current installed generation capacity for VRA and IPPs in Ghana [18].

generate large amounts of power. As illustrated in Figure 3, the parabolic trough solar field is aligned on a North-South (N-S) axis to enable the collectors to track the sun in an East-West (E-W) direction [35–37].

2.1.1. Solar Energy Collectors. The collectors are responsible for the collection and reflection or concentration of the solar rays onto the absorber tubes, which contains the HTF. Collectors are made of different shapes and designs. The parabolic trough collector is the most mature CSP technology available and has the largest share of total CSP installations worldwide [38–40]. Among the parabolic trough collector types, the EuroTrough ET150 has been considered in this work because this is the most advanced and sustainable technology used in most parabolic trough solar power plants worldwide [34, 41]. The technical specifications for the EuroTrough ET150 collector are shown in Table 2 [42]. The concentration ratio of the collector is a very important parameter to consider as it affects the operating temperature of the plant. The mirror material should have a very high reflectivity, as it is an indicator of the fraction of the incident radiation that is reflected by the mirror surface [43, 44].

2.1.2. Receiver/Absorber Tubes. The receiver tubes are responsible for carrying the HTF within the solar field. Special coatings and thermal insulations measures are employed to convert most of the radiation into heat, thereby minimising to a greater extent, the optical and thermal losses [45].

The Schott PTR® 70 2008 absorber tube has been selected as it provides the best optical and thermal performances and has been installed in over 50 CSP projects worldwide and suitable for usage in plants operating with oil-based HTFs at temperatures up to 400°C. This receiver consists of a metallic inner tube, which is also the absorber, surrounded by glass outer cover. In between the metal tube and glass cover, a vacuum is created, which helps to



FIGURE 1: Parabolic trough solar field configuration [34].



FIGURE 2: A single loop in the PTC solar field [34].



FIGURE 3: Diagrammatic representation of PTC sun tracking direction.

minimise heat losses. The technical specifications for the Schott PTR[®] 70 2008 absorber tubes are provided in Table 3 [46, 47].

2.1.3. Heat Transfer Fluids. The HTF is the carrier of the thermal energy generated in the solar field [48]. The HTF is heated to temperatures required to turn water into steam and is sent to the power block, from where electricity is generated from the generator coupled to a steam turbine. The fluid should not evaporate under the high temperatures reached by the solar field and therefore should have high evaporation temperatures. The fluid should also possess sufficient thermal stability to be able to withstand the high operating temperatures reached. In order to reduce the energy required for pumping the HTF, the fluid should have low viscosity.

The HTF used in this research is the Therminol VP-1, which is an eutectic mixture of biphenyl ($C_{12}H_{10}$) and diphenyl oxide ($C_{12}H_{10}O$; DPO). It is miscible and interchangeable with other similarly constituted DPO or biphenyl fluids. Its choice is due to its popular usage in most parabolic trough plants worldwide and its performance benefits, such as superb heat transfer properties, a wide temperature performance range from 12°C to 400°C. This fluid has high thermal stability so long as the maximum temperature is not exceeded. Table 4 shows the technical properties of the Therminol VP-1.

2.2. The Simulation Software: System Advisor Model. The System Advisor Model (SAM) comprises performance and financial models, which represent the various parts of the system and the financial structure of the project, respectively. The models require input data to describe the performance characteristics of physical equipment in the system

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TABLE 2: Technical specifications for the solar collector [42].

Property (unit)	Value
Focal length (m)	1.71
Length per collector element (m)	12.00
Total length of a single collector assembly	150
Aperture width (m)	5.77
Reflectivity	0.94
Geometric concentration	82:1
Peak optical efficiency (%)	80

TABLE 3: Technical specifications for the absorber tube [46, 47].

Property (unit)	Value
Tube length (m)	4.060
Outer diameter (m)	0.070
Inner diameter (m)	0.066
Glass envelope outer diameter	0.125
Absorptance, α	0.960
Thermal emittance, ϵ	0.095
Transmittance, $ au$	0.965
Absorber tube weight (kg/m)	3.390
Active aperture area (%)	96.700
Operating pressure (bar)	≤41

TABLE 4: Technical specifications for Therminol VP-1.

Property	Value
Inlet temperature (°C)	293
Outlet temperature (°C)	391
Minimum use temperature (°C)	12
Normal boiling point temperature (°C)	257
Maximum use temperature (°C)	400
Density at 340°C (kg/m ³)	773
Heat capacity at 340°C (kJ/kg/K)	2.425

and the cost of the project. The user interface of SAM makes it possible for users to build a model of a renewable energy project and to make cost and performance projections based on model results. SAM requires a weather data Typical Meteorological Year (TMY) file to describe the renewable energy resource and weather conditions at a project location.

For this research, the physical trough model of the parabolic trough concentrated solar power plant is used because the empirical model is used for systems whose designs are like the solar energy generation system (SEGS) plants in the USA. Data from the SAM software provided by the National Renewable Energy Lab–National Solar Radiation Database (NREL NSRDB), which includes direct normal (beam) irradiation, diffuse horizontal irradiance, dry-bulb and dew-point temperatures, relative humidity, and atmospheric pressure, can be used for simulations and further analysis [29, 49]. This data could be used to estimate the solar radiation that has been available historically at a given location and could also be used to predict the future availability of solar energy.

The SAM software has functional pages for modelling, simulation, and analysing power plants [29, 49]. This also includes the major components needed to be able to harness the heat from the sun to generate electricity.

2.2.1. Location and Resource. This page provides access to the solar resource library. This is a collection of default weather files and those which are downloaded from the NREL NSRDB and stored on the computer. There is a download weather file option that allows users to download up-to-date data from the NSRDB.

2.2.2. System Design. The System Design page of the SAM shows inputs for design point parameters that determine the nameplate capacity of the system.

2.2.3. Solar Field. This page provides variables and options that describe the size and properties of the solar field including that of the HTF.

Equations (1) and (2) describe the solar field thermal output and total conversion efficiency, respectively [50].

$$P_{\rm th_{SF}} = \frac{\rm DNI_{DP} \times \eta_{\rm TLC} \times A_a}{1 \times 10^6}, \qquad (1)$$

$$\eta_{\rm TLC} = \eta_{\rm optloop} \times \eta_{\rm RHL},\tag{2}$$

where $P_{\rm thSF}$ is the solar field thermal output, DNI_{DP} is the design point DNI, $\eta_{\rm TLC}$ is the total loop conversion efficiency, A_a is the total aperture area, $\eta_{\rm optloop}$ is the loop optical efficiency, and $\eta_{\rm RHL}$ is the receiver heat loss efficiency.

2.2.4. Collectors. The characteristics of the collector types used are defined on the solar collector assembly (SCA) page. The aperture area of a single loop represents the sum of the aperture areas of each SCA in the loop.

2.2.5. Receivers. This is the heat collection element (HCE) page where the receivers to be used are described and defined. There are a set of collector parameters for commercially available collectors, which are within the software.

2.2.6. Power Cycle. The power cycle parameters describe the parts of the system that converts thermal energy from the solar field or TES system into electricity. It depends on a steam turbine that runs on a conventional Rankine power cycle and may or may not include fossil fuel backup.

2.2.7. Dispatch Optimisation. When dispatch optimisation is enabled, SAM automatically determines the following scenarios:

- (i) When the system should defocus the troughs in the solar field during high flux conditions;
- (ii) When to store thermal energy from the solar field; and
- (iii) When it dispatches thermal energy from the TES system to the power cycle.

TABLE 5: Design point DNI value.

(1) Assumptions Made in Using the Software. The following assumptions were made when using the software [51]:

- (i) First principles of heat transfer and thermodynamics are used to characterize the system components;
- (ii) Mathematical models that represent component geometry and energy transfer properties are incorporated. This allows for specifying characteristics of the system components;
- (iii) The parabolic troughs in the solar field have a single-axis tracking system to track the sun; and
- (iv) The software has been validated against empirical data from the solar electric generating stations.

(2) Justification for Choice of Software. Most of the available software are usually used for solar PV simulations as well as for other renewable energy technologies, which mostly excludes options for CSP simulations. The SAM, however, has options for CSP modelling and simulations, hence the choice of this software in the modelling and simulation of the proposed CSP plant for the specified location. The data used is obtained from the NREL NSRDB because that is the data available and used by the SAM for its simulations.

Weather data was extracted from the NREL database and used to evaluate the performance of the CSP plant in the said locations. The data include hourly, daily, and monthly DNI, ambient temperature, wind speed, atmospheric pressure, sun angle, and solar azimuth angle for the complete year (8,760 hours).

2.3. Methodology for the Design and Sizing of the Plant. The thermal power generated by the solar block is a function which depends on the ambient temperature, the available DNI, and the design configuration of the solar field as shown by the expression in Equation (3) [52]. The electrical power generated by the power block depends on the thermal power generated from the solar field, the ambient temperature, and the design configuration of the plant as represented by Equation (4) [52]. The power block is usually made of a steam Rankine cycle coupled to an electric generator.

$$P_{\text{therm}} = f_{\text{solar}}(t_{\text{amb}}, \text{DNI}, \text{design}),$$
 (3)

$$P_{\rm el} = f_{\rm power}(P_{\rm therm}, t_{\rm amb}, {\rm design}).$$
(4)

2.3.1. Determining the Design Point DNI. The design point DNI is used to calculate the aperture area required to drive the power cycle at its design capacity, and it is the DNI value which when multiplied by the solar field area will give the nameplate capacity of the plant. Higher design point DNI values contribute to an undersized solar field, which results in a lower capacity factor of the plant. Lower design point DNI leads to an oversized solar field, which results in the excessive wastage of energy and high solar field costs.

Date, time	System power generated (kW)	er Beam normal irradiance N) (W/m ²)	
Jun 21, 12:00 am	-1,865.57	0	
Jun 21, 01:00 am	-1,865.49	0	
Jun 21, 02:00 am	-1,865.41	0	
Jun 21, 03:00 am	-1,865.34	0	
Jun 21, 04:00 am	-1,865.27	0	
Jun 21, 05:00 am	-1,865.21	0	
Jun 21, 06:00 am	-1,972.19	193	
Jun 21, 07:00 am	-2,795.04	451	
Jun 21, 08:00 am	64,306.00	591	
Jun 21, 09:00 am	107,776.00	669	
Jun 21, 10:00 am	108,417.00	350	
Jun 21, 11:00 am	106,642.00	732	
Jun 21, 12:00 pm	109,679.00	760	
Jun 21, 01:00 pm	110,033.00	745	
Jun 21, 02:00 pm	110,851.00	707	
Jun 21, 03:00 pm	112,319.00	625	
Jun 21, 04:00 pm	113,925.00	489	
Jun 21, 05:00 pm	103,477.00	235	
Jun 21, 06:00 pm	98,317.90	0	

The design point DNI is fixed at the solar noon on 21st June, and this value corresponds to 760 W/m^2 as shown in Table 5.

2.3.2. Determining the Power Output of the Plant. The annual net electrical output of the power plant, measured in GWhe, is the sum of all the net power generated by the plant throughout one year of its operation (8,760 hours). The capacity factor is the ratio of the annual net electricity output and the theoretical output the plant will produce if it were to operate at its full nameplate capacity for the given period.

Solar multiple and hours of TES are very useful parameters that need to be considered, where the solar multiple is the ratio between the thermal power produced by the solar field at the design point DNI and the thermal power required by the power block at nominal conditions. A solar multiple of 1 represents the solar field area that when exposed to solar radiation of design point value will generate the thermal energy required to drive the power block at its rated nameplate capacity while accounting for optical and thermal losses [53]. Hours of storage of TES are the number of continuous uninterrupted hours that a fully charged TES system can be fully discharged [54, 55]. An adequate TES is provided to ensure dispatchability of the CSP plant and to increase the capacity factor [56, 57].

The useful heat gain (thermal power) obtained from a single concentrating collector is calculated using Equation (7) [58, 59]. To determine the useful heat gain, the absorbed radiation per unit area, *S*, of the collector-tube arrangement is calculated using Equation (6), which is a product of the optical efficiency and the beam radiation [58]. The DNI is also given by [60] as shown in

$$DNI = \int_{year} I_b(t) dt,$$
 (5)

$$S = I_b \rho \gamma \tau \alpha \text{IAM} = I_b \eta_o, \tag{6}$$

$$Q_u = F_R A_a \left[S - \frac{A_r}{A_a} U_L (T_{\rm in} - T_a) \right], \tag{7}$$

where Q_u is the useful heat gain, F_R is the collector heat removal factor, A_a is the concentrator aperture area, S is the absorbed solar radiation, A_r is the receiver area, U_L is the heat loss coefficient, $T_{\rm in}$ is the fluid inlet temperature, T_a is the ambient temperature, I_b is the DNI or beam radiation, ρ is the reflectance of the collector, γ is the intercept factor, τ is the transmittance of the absorber, α is the absorptance of the absorber, IAM is the incident angle modifier, and η_o is the optical efficiency.

The reflective aperture area of the solar field is calculated using Equation (8), where SM is the solar multiple, N_{SCA} is the number of collectors, and A_{SCA} is the reflective area per collector [61].

$$A_r = \mathrm{SM} \times N_{\mathrm{SCA}} \times A_{\mathrm{SCA}}.$$
 (8)

The input thermal energy needed by the power block to deliver the gross output of the turbine is described by [61] in Equation (9), where Q_{des} is the design cycle thermal input, E_{gross} is the design gross output, and $\eta_{turbine}$ is the turbine efficiency.

$$Q_{\rm des} = \frac{E_{\rm gross}}{\eta_{\rm turbine}}.$$
 (9)

(1) Thermal Power Required. The thermal power required from the solar field is estimated using Equation (10). This is obtained by dividing the total electric load power by the

combined efficiencies of the boiler, turbine, and generator.

$$P_{\text{thermal}} = \frac{P_{\text{net load}} + P_{\text{parasitic}}}{\eta_{\text{boiler}} \times \eta_{\text{turbine}} \times \eta_{\text{generator}}},$$
(10)

where $P_{\text{parasitic}}$ is the parasitic load, P_{netload} is the net load, η_{boiler} is the boiler efficiency, η_{turbine} is the turbine efficiency, and $\eta_{\text{generator}}$ is the generator efficiency.

The total number of collector loops needed to provide the required thermal energy is given by [23, 52]

$$n_{\text{loops}} = \frac{\left(P_{\text{th}}/P_{\text{out per collector}}\right)}{\text{collectors per loop}},$$
(11)

where P_{th} is the thermal power and $P_{\text{outper collector}}$ is the output power per collector Q_u .

(2) Outlet Temperature. The output temperature, T_{out} , of the HTF flowing out of the absorber tubes is calculated using Equation (12), where *c* is the specific heat capacity of the HTF [29, 58]. It is seen from the equation that T_{out} increases as the mass flow rate of the HTF, *m*, reduces and vice versa. Larger *m* values imply shorter time for the fluid to pass through the absorber tubes [62]. According to Vergura and Di Fronzo [63], for a fixed value of *m*, T_{out} always has a positive correlation with I_b (or DNI) and, therefore, the thermal performance increases as I_b (or DNI) increases.

$$T_{\rm out} = T_{\rm in} + \frac{Q_u}{\dot{m}c}.$$
 (12)

The maximum thermal energy that can be stored is also described by Equation (13) [61, 64], where $Q_{\text{max,tes}}$ is the maximum TES, TES_{hours} is the hours of TES, and Q_{des} is the design cycle thermal input.

$$Q_{\text{max,tes}} = \text{TES}_{\text{hours}} \times Q_{\text{des}}.$$
 (13)

2.3.3. Efficiency of the Power Plant and Its Main Components. The instantaneous efficiency of a parabolic trough collector is defined as the rate at which useful energy is delivered to the working fluid per unit aperture area (Q_u) divided by the DNI (I_b) at the collector aperture plane. This is represented by Equation (14) [65]. The knowledge of heat loss from the receiver is important for predicting the performance and, hence, designing PTCs.

$$\eta_{i} = \frac{Q_{u}}{I_{b}} = F_{R}A_{a}\eta_{o} - \frac{F_{R}A_{r}U_{L}(T_{i} - T_{a})}{I_{b}}.$$
 (14)

The thermal efficiency of the solar field is given as the ratio of the useful heat gain by the solar field to the total heat energy available to the solar field. This is represented by [64]

$$\eta_{\rm SF} = \frac{Q_u}{Q_{\rm abs}} = \frac{Q_u}{I_b \times A_a}.$$
 (15)

The overall efficiency, also known as the solar-to-electric efficiency represented by Equations (16) and (17), is the ratio of the electric power output to the irradiance incident on the collector surface area, where $P_{\rm el}$ is the electrical power, A_a is the aperture area, I_b is the DNI, $\eta_{\rm SF}$ is the solar field efficiency, and $\eta_{\rm PB}$ is the power block efficiency [34, 66].

$$\eta = \frac{P_{\rm use}}{P_{\rm in}} = \frac{P_{\rm el}}{A_a \times I_b},\tag{16}$$

$$\eta = \eta_{\rm SF} \times \eta_{\rm PB}.\tag{17}$$

2.3.4. Modelling and Simulation of a CSP Plant Using System Advisor Model. Figure 4 shows a physical layout of a CSP plant consisting of a solar field, TES system, and a power block. Using a design point DNI of 760 W/m^2 , as shown in Table 5, simulations were run for different range of values of solar multiple and hours of TES.

 E_{net} is obtained using Equation (18) and the capacity factor is represented by Equation (19) [34, 67].

$$E_{\rm net} = \sum_{i}^{8760} E_{i},$$
 (18)

$$CF = \frac{E_{\text{net}}}{P_{\text{out}} \times 8,760},$$
 (19)

where E_i is the hourly energy generated by the plant. E_{net} is the annual energy production, and P_{out} is the nameplate capacity of the power plant.

Table 6 shows the number of loops corresponding to the different solar multiples based on the design point DNI selected. Increasing the solar multiple increases the number of loops, which indicates an increase in the solar field with a corresponding increase in component costs.

2.4. Methodology for Economic Evaluation. The economic evaluation is performed to determine how profitable or feasible a project would be. There are a number of methods for performing economic evaluation of projects which include the simple payback period, net present value, internal rate of return, and the levelised cost of energy. In order to determine the profitability of the project, the cash flow which consists of cash inflow and cash outflow should be determined. In this thesis, the cash inflow component is the generated revenue while the cash outflow components include investment cost, operation and maintenance costs, interests on the capital, and taxes paid. Factors such as the total plant capacity and annual energy generation among other relevant parameters are needed to perform a good economic analysis for a project.

2.4.1. Economic Parameters

(1) Capital Cost of the CSP System. The capital cost of the power plant, also known as the capital expenditure (CAPEX) or the total investment cost, represents the source of funds

used in funding the plant installation, purchase of components for the project, and other auxiliary costs. It is obtained from debt and equity sources. The debt ratio (loan) refers to the percentage of money borrowed and is payable with an interest, while the equity ratio refers to amount obtained by selling stocks of the company to the market. Because CSP projects require large investments, loans are usually obtained from promising sources which are paid later with or without interest, depending on where the loan was obtained from.

This CAPEX includes the initial investment cost of the plant and includes the equipment cost and mechanical systems [68]. This also includes the total component costs from solar collector field, HTF, thermal storage system, the power block, the piping and insulation systems, and support structures. It also includes cost of construction and workmanship and other miscellaneous costs.

The capital cost used in this paper was obtained from a reference parabolic trough CSP plant located in China [69]. The CSNP Urat is 100 MW which generates about 350 GWh of electricity annually.

The capital or initial investment cost is incurred only in the Zeroth year of the plant.

(2) Operating and Maintenance Cost. The operating and maintenance (O&M) cost also known as the operational expenditure (OPEX) refers to all the costs incurred during the operational life of the power plant. The operating and maintenance cost of CSP plants is lower than that of conventional power plants because fuel consumption is not accounted for in CSP plants.

The annual operating and maintenance cost is taken as 2% of the total investment cost of the system [70].

The operating and maintenance cost begins to be incurred only when the plant begins operation, i.e., from the end of year one to the end of the plant life. It is, therefore, measured per kWh of energy produced.

(3) Discount Rate. The discount rate is the rate of return used to discount future cash flows back to their present value [71, 72]. It is used to account for the time value of money and is, therefore, a very essential factor in the calculation of the NPV [73]. A discount rate of 0.86% [74] which is the central bank discount rate of US in dollars has been used in this work because all amounts are in US dollars. The discounted factor, DF, is obtained using

$$\mathrm{DF} = \frac{1}{\left(1+r\right)^n}.\tag{20}$$

(4) Estimated Revenue. This is the amount of money that is expected to be generated from the plant after the energy generated has been sold. It is obtained by multiplying the feedin-tariff rate of energy sold from solar by the amount of energy generated.



FIGURE 4: A physical layout of CSP plant.

TABLE 6: Number of loops required for varying solar multiples with design point DNI.

Solar multiple	Number of loops	Total aperture area (m ²)
1.0	173	565,710
1.5	259	846,930
2.0	346	1,131,420
2.5	432	1,412,640
3.0	518	1,693,860

TABLE 7: Technical and economic parameters.

Parameter	Value
Total plant capacity (kW)	100,000.00
Annual net energy generation (kWhe)	306,850,336.00
Plant life/economic life (years)	25
Production start time (year)	1
Fuel consumption (L)	0
Working hours of plant (h)	8,760
Sales price per kWh (USD/kWh)	0.151
Cost per kW of installed power (USD)	4,219.80
CO ₂ saved per kWh of energy (tonnes)	0.00002
Total CO ₂ saved (tonnes)	6,137.01
Unit price of electricity (USD)	0.151
Annual electricity escalation rate	1%
Carbon credit (CO ₂ savings) (\$/ton)	15
Interest rate on debt (%/year)	1%
Discount rate	0.86%

A feed-in-tariff of 59.7750 Ghana Pesewas per kWh equivalent to USD 0.151/kWh (exchange rate of 31 August 2016: $1 = GH \notin 3.9476$) was obtained from the 2016 PURC

feed-in-tariff rates applicable to renewable energy projects [75]. There is also a carbon credit of \$15/tonne [76], which when incorporated by policymakers would save the country a lot of cost.

Table 7 presents the economic parameters and other economic considerations that were used for the various calculations.

2.4.2. Economic and Cost Indicators. The economic indices that determine how profitable the project would be were determined using the following.

(1) Net Present Value. The net present value (NPV) is the difference between the present value of cash inflows and the present value of cash outflows over a period and is used to determine the profitability of a project, considering the time value of money. A positive NPV value shows that a project is commercially viable, while a negative value shows the nonviability of a project. Therefore, a project with a higher NPV value is always preferred. A major drawback of NPV analysis, however, is that it makes assumptions about future events which may not be reliable. The NPV is mathematically presented using Equation (21), where N is the project lifetime, C_0 is the initial investment, C_n is the cash flow at the end of year n, and r is the minimum rate of return.

NPV =
$$C_0 + \sum_{n=1}^{N} \frac{C_n}{(1+r)^n}$$
. (21)

(2) Simple Payback Period. The simple payback period represents the time in years, required for the cash inflow to equal the total invested capital, and is mathematically represented in Equation (22) by [77, 78]. This is the time that it takes for the cumulative cash flow to switch from negative to positive. A limitation of this method is that it does not properly account for the time value of money and other important

TES hours		Solar multiple				
		1.0	1.5	2.0	2.5	3.0
	E _{net} (kWh-e)	144,919,232	201,970,064	233,365,472	245,537,216	
0	CF (%)	16.600	23.100	26.700	28.10	
	LCOE (¢/kWh)	38.50	27.74	24.06	22.89	
	E _{net} (kWh-e)	143,306,400	226,005,248	288,797,856	322,499,744	342,452,256
3	CF (%)	16.400	25.800	33.000	36.90	39.10
	LCOE (¢/kWh)	38.93	24.83	19.52	17.52	16.52
	E _{net} (kWh-e)	141,200,080	224,700,352	306,850,336	365,934,400	400,525,984
6	CF (%)	16.100	25.700	35.100	41.80	45.80
	LCOE (¢/kWh)	39.50	24.97	18.39	15.49	14.18
	E _{net} (kWh-e)	139,186,912	223,235,776	306,254,976	384,359,968	439,292,960
9	CF (%)	15.900	25.600	35.000	43.90	50.20
	LCOE (¢/kWh)	40.07	25.13	18.43	14.76	12.97
	E _{net} (kWh-e)	137,312,112	221,675,456	304,905,504	385,637,472	457,337,056
12	CF (%)	15.700	25.300	34.800	44.10	52.30
	LCOE (¢/kWh)	40.61	25.31	18.51	14.72	12.47

TABLE 8: Energy generation and capacity factor for varying SMs and TES hours.

"-" indicates that the software could not run simulation for that combination.



FIGURE 5: Annual energy generation for varying SM and hours of TES.

economic considerations. Shorter payback periods are preferable to longer periods.

$$Payback Period = \frac{Investment Capital}{Annual Cash Inflow}.$$
 (22)

(3) Internal Rate of Return. This is the discount rate that makes the NPV of a project zero and is represented by

[77–79] in Equation (23). A project with a higher IRR value is more desirable than one with a lower IRR value. If the IRR of the project is lower than the interest rate on the project, it is considered not economically viable [79].

NPV(r) =
$$\sum_{n=0}^{N} \frac{\text{Cash flow at end of year } n}{(1 + \text{IRR})^n} = 0.$$
 (23)



FIGURE 6: Capacity factor for varying SM and hours of TES.



FIGURE 7: Monthly energy generation for Bawku.

(4) Levelised Cost of Energy. The LCOE can also be regarded as the minimum cost at which electricity must be sold in order to break-even over the lifetime of the project. It is used to calculate the cost of electricity during the lifetime and takes into account the time value of money and the associated risks.

Using TES of 6 hours and $\rm DNI_{dp}$ of 760 W/m², $E_{\rm net},$ CF, and the corresponding LCOE have been obtained as shown

in Table 8.

$$LCOE = \frac{\sum_{n=0}^{N} C_n / (1+d)^n}{\sum_{n=1}^{N} Q_n / (1+d)^n},$$
 (24)

where C_n is the project cost in period n, Q_n is the system annual generated quantity of electricity in period n, and d is the annual discount rate.



FIGURE 8: Net electricity to the grid in year 1.

3. Results and Discussions

3.1. Effects of Solar Multiple and Hours of Thermal Energy Storage. Figure 5 shows the annual energy generation obtained for the different combinations of TES hours and SM. It could be seen from the graph that the amount of energy generated increases for increasing hours of TES and increasing SM. However, increasing both SM and hours of TES leads to an increase in component costs because larger solar multiples require larger areas of solar field and its components while larger TES also requires larger storage tank capacities. It is observed that for generation with no storage, E_{net} showed the lowest values for all the indicated SMs, followed by 3 hours of TES, 6 hours of TES, 9 hours of TES, and finally the highest generation obtained with the 12 hours of TES. The corresponding increase in the energy generation is due to the corresponding increase in the hours of the storage.

The effects of varying different combinations of hours of TES and SM on the CF were also analysed. As shown in Figure 6, the graphs obtained have similar characteristics as those obtained for the energy generation. This is because the CF is directly proportional to the energy generation. The higher the energy generation from the system, the higher the capacity factor.

From Figures 5 and 6, obtained from the simulation results, the lowest energy generation was produced by the system with no storage. For the system with no storage, E_{net} increased gradually until it reached its highest value of 245.537 GWhe at SM of 2.5. The 3 hours, 6 hours, 9 hours, and 12 hours of thermal storage produced close results from SM 1.0 to 2.0. This implies that the cost of TES for a plant with SM of 1.0 to 2.0 is almost the same for 3, 6, 9, and 12 hours. However, from above 2.0 SM, there are significant changes in E_{net} as the TES is varied from 0 to 12. Observing

 $\rm E_{net}$ against the various SM and TES hours, a good trade-off has been made to select SM of 2 and TES of 6 hours. This is because $\rm E_{net}$ for larger SM does not increase the energy significantly but comes with extra cost due to the large solar field. Therefore, SM of 2 which has a relatively low cost is better to be chosen.

3.2. Results for the System Power Generated and Annual Energy Generation. In an earlier research, Amoah et al. [33] used the analytical hierarchy process (AHP) and a set of MCDM techniques to select Bawku, a town in the Upper West of Ghana, as the most optimal location for the implementation of a CSP plant. This location is used for the analysis in this paper.

Table 8 presents the annual energy generation, E_{net} , capacity factor (CF), and LCOE obtained from the different combinations of SM and TES hours, using data for the selected location. The SM ranges from 1 to 3 at 0.5 intervals while the hours of TES range from 0 to 12 at intervals of 3 hours.

Figure 7 shows the monthly energy generation from the simulation using Bawku as the location [33]. The months with the highest energy outputs were from November to March, with November having the highest generation of 37.49 GWhe. These months are found within the dry season, an indication that CSP plants are more efficient during the dry season. The months with the least generation were July, August, and September, which are all within the rainy season, with the least generation of 13.33 GWhe obtained in July. This is because the rainy season is characterized by longer periods of rainfall, lower temperatures, and higher percentages of cloud cover.

This is an indication that the rainy seasons adversely affect the performance of CSP systems. An alternative source of heat would, therefore, be required during these periods to



FIGURE 9: System generated power output and DNI.



Solar multiple

FIGURE 10: LCOE for different SM and hours of TES.



FIGURE 11: NPV for various discount rates with base case values.



FIGURE 12: Relationship between relative changes in capital cost, electricity price, and revenue with the NPV.

be able to provide heat to ensure the continuous generation of steam (generation).

Figure 8 also illustrates the net electricity generated throughout the year with the area of concentration being

from around 9 am to 6 pm. It can be seen that at certain periods, generation takes place due to the presence of TES.

Figure 9 shows the monthly system power generated from the power plant as well as the DNI for the location.

For all the months, generation begins from around 8 am to 9 am and attains its maximum generated power from 11 am to 4 pm. The highest peaks usually occur from November to April while the lowest peaks occur from July to September. It could be deduced from the graphs that the shape of the power generation is similar to that of the DNI indicating that the two are directly proportional to each other.

3.3. Results for the Financial Analysis of the CSP Plant

3.3.1. Levelised Cost of Energy. From Figure 10, the following observations were made:

- (i) At a solar multiple of 1, the system with no storage had the lowest LCOE of 37.06 c/kWh while the 12 hours of storage had the highest LCOE of 38.87 c/ kWh;
- (ii) At a solar multiple of 1.5, the 3-hour TES had the lowest LCOE of 23.91 c/kWh while the system with no storage gave the largest LCOE of 26.70 c/kWh;
- (iii) At a solar multiple of 2, the 9-hour TES had the lowest LCOE of 17.72 c/kWh while the system with no storage had the highest LCOE of 23.17 c/kWh;
- (iv) At a solar multiple of 2.5, the 12-hour TES had the lowest LCOE of 14.17 c/kWh while the system with no storage had 22.04 c/kWh; and
- (v) At a solar multiple of 3, the 12-hour TES had the lowest LCOE of 12.12 c/kWh.

The results from this research show that the selection of the best solar multiple for a solar thermal system with TES is dependent on the system requirements. Therefore, for a 1.5 solar multiple, a 3-hour TES is optimum. Moreover, for a solar multiple of 2.5 and above, the higher the hours of TES, the lower the LCOE. The results also show that incorporating a TES to the system increases the hours of generation even when the sun is no longer available.

3.3.2. Effects of Changes in Various Cost Indicators with NPV and IRR. The total investment cost of USD 421,980,000.00 [69] and an annual operating and maintenance cost of USD 8,439,600.00 yielded an annual revenue of USD 46,459,733.97 and could as well save the country an estimated amount of USD 92,055.10 in CO₂ savings per annum.

Performing a detailed cash flow analysis using Microsoft Excel, the NPV at the end of the plant life (25 years) with a discount rate of 0.86% [74] was USD 156,287,433.72. This is an indication that the project is financially feasible because the NPV is positive. As seen in Figure 11, the minimum rate of return, which is the IRR of the project, is 3.34%. Since the discount rate for the project is below the IRR, it implies that the project would be profitable. A discount rate greater than the IRR of 3.34% will render the project not profitable.

Sensitivity analysis was performed to determine the effects of the relative changes in the cost indicators with the NPV, and the graph in Figure 12 was obtained. The following could be deduced:

- (ii) The electricity price produced a negative NPV when its base case value was reduced by more than 10%, which also renders the project not profitable; and
- (iii) When the generated revenue reduces by more than 13%, the project becomes unprofitable because the NPV becomes negative at that point.

4. Conclusions and Recommendations

Incorporating a TES system provides great improvement on the efficiency and the cost-effectiveness of a solar thermal power plant.

The choice of the hours of storage of TES and the SM is dependent on the system requirements. The larger the size of the solar field, the larger the storage facility needed to increase the generation to ensure more energy generated and sold to offset the high costs involved.

The system with no storage has high LCOE because the energy generated would have to be sold at a higher cost to be able pay off the total cost of installation.

The following recommendations have been made:

- (i) Boilers should be integrated into the system to ensure continuity of heat supply and hence continuous generation of steam for the power plant to operate; and
- (ii) A higher solar multiple is really essential in improving the efficiency and cost-effectiveness of a solar thermal collector system. The higher solar multiple also implies a higher cost of the entire plant. Therefore, an accurate trade-off must be ensured between the solar multiple and the hours of TES.

Data Availability

The data used to support the findings of this study were obtained from the National Solar Radiation Database of the National Renewable Energy Laboratory available within the System Advisor Model software as downloadable weather files.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

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