UNIVERSITY OF CAPE TOWN

ENERGY RESEARCH CENTRE

RONDEBOSCH, CAPE TOWN, SOUTH AFRICA

MEC5061Z

MScEng Sustainable Energy Dissertation

THE POTENTIAL OF SOLAR PROCESS HEAT FOR SOUTH AFRICAN INDUSTRY

AUTHOR : DU PLESSIS, PIETER
DPLPIE003

DATE Submission : JUNE 2011

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ABSTRACT

This study explores the potential of using concentrated solar thermal technologies for high temperature industrial processes in South Africa. South Africa makes a significant contribution to global Greenhouse Gas (GHG) emissions and its electricity supply is currently under pressure. It is therefore required to explore reliable technologies that can provide low-carbon renewable energy at competitive costs.

Heat contributes a significant amount of final energy used in the industrial sector of South Africa and the use of solar heat for industrial processes is currently underexplored. It is argued that it is a market with enormous potential. Few studies have been conducted to date to investigate the economic and other benefits from using solar-generated heat for large-scale industrial process heat applications to replace or to support conventional heating methods. This fact is the main driver for undertaking this study.

Literature surveys prove that the potential for high temperature solar thermal energy applications for industrial processes in South Africa is significant. The industrial sector consumes 43% of the final energy and significant amounts of energy are used for heat generation. The vast majority of GHG emissions come from energy supply activities where fossil fuel is combusted for heat generation.

A range of concentrated solar technologies is currently available or in development. Parabolic trough collectors are currently the most mature technology that can be used for both power and process heat, or steam generation. Linear Fresnel collectors could become an attractive alternative in terms of cost in the not too distant future. Literature surveys show that due to the intermittency of available radiation and the cost of thermal storage, one of the most promising utilizations of concentrated solar technologies is to integrate it with existing heating systems for large-scale heat generation.

The energy outputs and costs of solar thermal systems for industrial use are modelled for a 100MW reference CSP trough plant. Energy output from the reference plant is modelled using the Solar Advisory Model (SAM) that was developed by NREL. Cost analysis is used to calculate the Levelised Cost of Electricity (LCOE) and Levelised Cost of Thermal Energy (LCOTE). The energy output and costs are compared for power and thermal generation. The performance of the concentrated solar power plant is calculated as 15.2% while the solar thermal energy plant has a performance of 48.9%. This is mainly due to the low efficiency of the power plant.

The current Levelised Cost of Electricity (LCOE) (real) for the concentrated solar power plant is calculated as ZAR 2.65/kWh and is projected to decrease to ZAR 1.54/kWh by 2050 as a result of technology learning. The current Levelised Cost of Thermal Energy (LCOTE) (real) for the concentrated solar thermal plant is calculated as ZAR 0.68/kWh and is projected to decrease to ZAR 0.36/kWh by 2050. Even though the LCOE for concentrated solar power is projected to decrease significantly, it will still be higher than fossil fuel generated electricity at their current prices. The LCOTE is currently higher than the cost of burning coal for heat, but it is projected to become cheaper than burning coal by around 2020 if the cost of coal increases marginally and the proposed carbon tax is implemented.

Apart from the potential economic benefit that solar thermal technologies have over coal, there are also other benefits such as significant savings in water consumption, GHG emissions and waste products such as ash.

It is recommended that the current underexplored high temperature solar thermal applications for large-scale industrial process heat or steam in South Africa should be given more attention as an alternative to provide low-cost and low-carbon energy.

ACKNOWLEDGEMENTS

I would never have been able to finish my dissertation without the guidance of my supervisor, help from friends, and support from my family. I would like to express my deepest gratitude to my supervisor, Dr. Brett Cohen, for his guidance and support.

Another special thanks to the Centre of Renewable and Sustainable Energy Studies (CRSES) based at the University of Stellenbosch for providing me with the funding that made my postgraduate studies possible. I would also like to thank the academic staff of the Energy Research Centre for providing excellent research material that made this study possible.

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LIST OF ACRONYMS AND ABBREVIATIONS

ALCC	Annualised Life Cycle Cost
ALCS	Annualised Life Cycle Savings
CAC	Command and Control
CIA	Central Intelligence Agency
CLFR	Concentrated Linear Fresnel Reflector
CSP	Concentrated Solar Power
DC	Direct Cost
DEAT	Department of Environmental Affairs and Tourism
DME	Department of Minerals and Energy
DNI	Direct Normal Irradiance
DOE	Department of Energy
EI	Energy Intensity
EPCM	Engineer-Procure-Construction-Management
EPRI	Electric Power Research Institute
ESCO	Energy Service Company
ESTIF	European Solar Thermal Industry Federation
GDP	Gross Domestic Product
GHG	Greenhouse Gas
HCE	Heat Collection Element
HTE	Heat Transfer Element
HTF	Heat Transfer Fluid
IFC	International Finance Cooperation
IPCC	Intergovernmental Panel on Climate Change
LCC	Life Cycle Cost
LCOE	Levelised Cost of Electricity
LCOTE	Levelised Cost of Thermal Energy
LCS	Life Cycle Savings
NASA	National Aeronautics and Space Administration
NERSA	National Energy Regulator of South Africa
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
OECD	Organisation for Economic Cooperation
O&M	Operation and Maintenance
PB	Power Block
PCM	Phase Change Materials

PPP	Purchasing Power Parity
PR	Progress Ratio
ROI	Return on Investment
TFE	Total Final Energy
SAM	Solar Advisor Model
SANEA	South African National Energy Association
SCA	Solar Collector Assemblies
SF	Solar Field
TES	Thermal Energy Storage
TPES	Total Primary Energy Supply
TPC	Total Plant Cost
USA	United States of America
USD	United States Dollar
ZAR	South African Rand

CHAPTER 1: INTRODUCTION

1.1 BACKGROUND TO PROBLEM

Climate change is currently considered one of the biggest problems the world is facing and the Fourth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC) gives compelling evidence that human activity is to blame for it (Winkler, 2007). The conclusion of the IPCC report was summarised as: "*Warming of the climate system is unequivocal, as is now evident from observations of increases in global average and ocean temperatures, widespread melting of snow and ice and a rising global mean sea level*" (IPCC in Winkler, 2007).

Current global trends in energy supply and demand are considered economically, environmentally and socially unsustainable. It is estimated that without drastic change, CO_2 emissions related to energy will more than double by 2050 (IEA, 2010). Moreover, increased demand for oil and coal will cast a shadow over the security of supplies.

South Africa makes a significant contribution to global greenhouse gas (GHG) emissions. In 2005 the average CO_2 emissions per capita of 8.8 tonnes per person were well above the global average of 6.7 tonnes per capita (Pegels, 2006). The United Nations considers Africa as the continent most vulnerable to climate change, with strong negative impacts predicted on water resources, agriculture and forestry, health etc. As active participants in the international process to help combat climate change and regulating GHG emissions, South Africa has a role to play in reducing its own high GHG emission intensity.

Apart from climate change, another issue South Africa is facing is **energy security**. Historically, energy intensive industries were established in South Africa as a result of the country's wealth of mineral deposits and relative abundance of cheap low-grade coal. From the 1950s to 1970s the South African government initiated large-scale synthetic fuel and power generation projects that resulted in excess capacity and low electricity prices. These low electricity prices put South Africa in a competitive position to attract energy intensive industries including mining, minerals processing and manufacturing.

Relatively low electricity prices continue to drive new investment in industry, although excess capacity is now virtually exhausted and electricity deficits are predicted from 2011 to 2013. Medupi and Kusile are two new coal-fired plants currently under construction and should be commissioned during 2012 and 2014 respectively. This should bring some relief to the predicted supply deficit in the short to medium term, however long term supply remains under pressure

(Eskom, 2009). Coal is the primary source of energy in South Africa and contributes 92% to the total primary source of electricity production. Nuclear provides 5% while other sources such as hydro makes up the difference (DEAT, 2009).

1.2 RATIONALE FOR CONSIDERING CONCENTRATED SOLAR ENERGY

Concentrated solar technologies can provide low-carbon renewable energy in countries with a high direct normal irradiance (DNI). South Africa has some of the best DNI available globally, making this technology an attractive option. Apart from power production, concentrated solar technologies can also produce high-temperature heat or steam for industrial processes.

Concentrated solar technologies are destined to grow in the future. Currently there are just over 500MW of installed Concentrated Solar Power (CSP) capacity globally, mainly in the United States and in Spain. About 15GW are currently in development or under construction in a number of countries. It is expected that CSP could provide 11.3% of the global electricity demand by 2050. (IEA, 2010). The installed capacity time line for CSP plants is given in Figure 1-1. From this figure it can be noted that parabolic troughs account for the largest share of the CSP market. It is considered a **proven technology.**

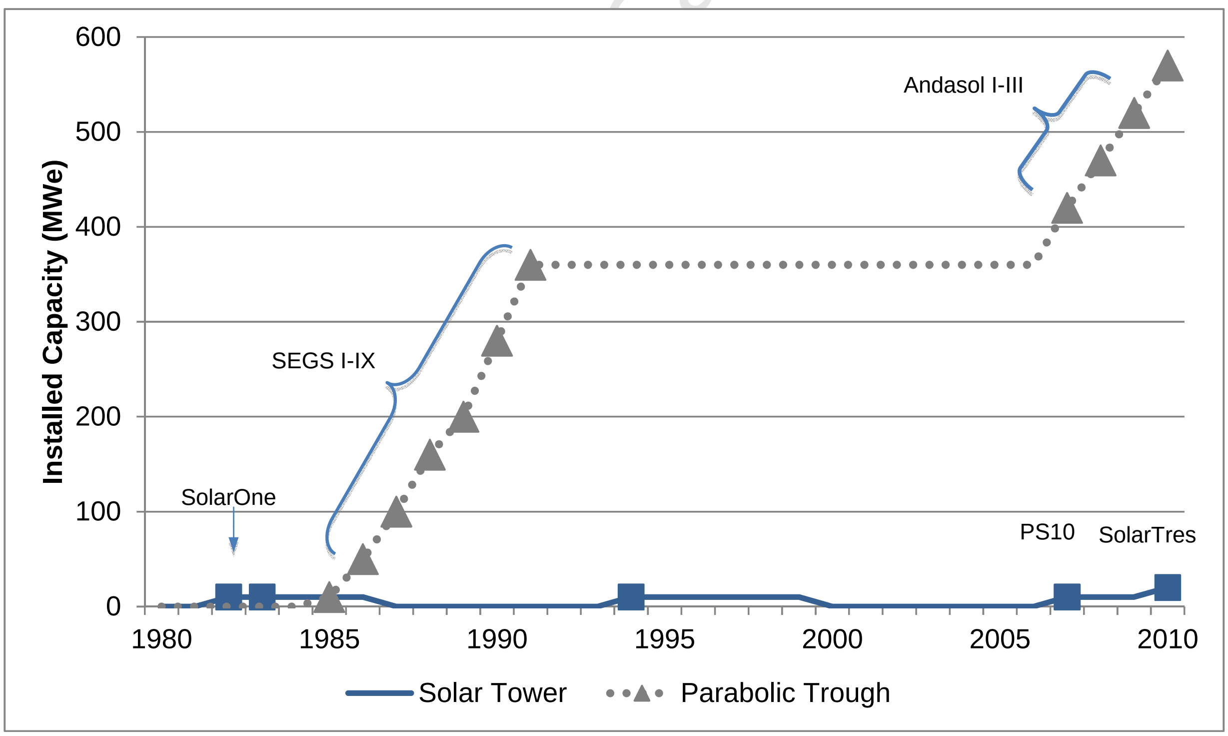


Figure 1-1: Historic global installed CSP capacity.

Source: (IEA, 2010)

CSP technologies have the advantage that energy can be stored in the form of heat for short periods (a number of hours). Heat can therefore still be extracted from the system after sunset or when it is cloudy. **Apart from power generation, concentrated solar plants can provide high temperature process heat or steam for industrial application that can be used for heating as well as for cooling**.

1.3 PROBLEM STATEMENT

In 2004, 43% of the total final energy in South Africa was consumed by the industrial sector (DME, 2004). Heat contributes 67% of the final energy used in the European Union's industrial sector, while electricity makes up the balance (ESTIF, 2006). In South Africa, the contribution of heat to the total final energy is not disaggregated and no value can be quoted, although it is expected to be high. ESTIF (2006) argues that solar heat for industrial processes is underexplored and that it is a market with enormous potential. Especially high temperature applications (>80°C) are of interest as it can also be used for power generation. ESTIF (2006) further argues that solar thermal technologies can supply a large portion of total energy demand in Europe. In South Africa with its good solar resource and strong demand for industrial process heat, the potential for such a market must also be significant. For a comprehensive analysis of the energy sector of South Africa, please refer to Appendix A.

There are many reasons why solar heat for industrial processes is still in its infancy, including lack of awareness and confidence in the technology, however process economics are considered to be one of the main barriers. When the cost of CSP and other energy technologies are compared, CSP is still seen as relatively expensive. However, **few studies have been conducted to date to investigate the savings (if any) when solar thermal energy systems are used to replace or to support conventional heating methods for generating high temperature process heat**. Furthermore, most studies only investigate the cost of generating power only from concentrated solar technologies. It is therefore worthwhile to investigate the cost of a system that only generates high temperature process heat/steam. Many big operations such as power and petrochemical plants and base metal refineries exist in South Africa and they could benefit from solar thermal energy in a country that is committed to reducing carbon emissions and that is in need of additional power supply.

1.4 OBJECTIVES OF THE STUDY

The objectives of this study are:

- To conduct a high level exploration of the opportunities within the most energy intensive industries in South Africa for **high temperature solar thermal applications**;

- To compare and understand the principles of different concentrated solar technologies and to identify the most suitable technology for technical and cost studies;
- To investigate the integration of solar thermal systems with existing operating facilities;
- To model the energy output for a preferred reference CSP plant located around the largest industrial area of South Africa;
- To use the energy output generated and to do cost and financial modelling;
- To research relevant financial mechanisms available and the effect they could have on concentrated solar thermal projects;
- To compare costs with other technologies (conventional and new);
- To compute the potential GHG emission reductions; and
- To make recommendations for further work that can be carried out under this topic of study.

1.5 RESEARCH METHODOLOGY

To meet the objectives outlined in Section 1.4, a research methodology shown in Figure 1-2 is followed in this report.

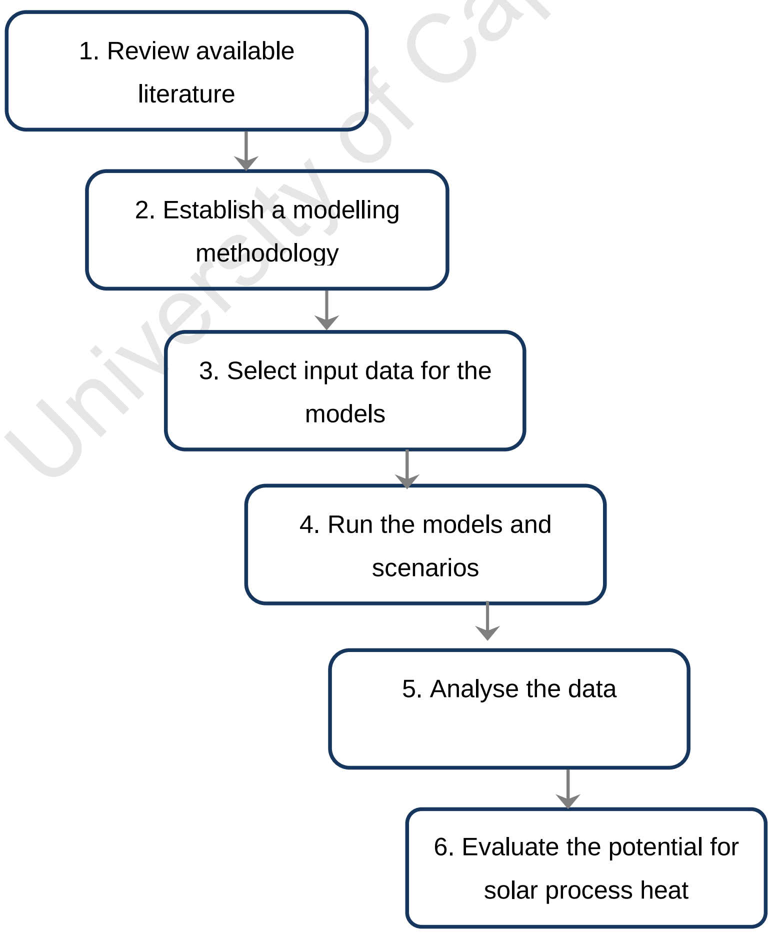


Figure 1-2: Research methodology

The **first step** is to research all the latest available literature on the topics of solar energy, policy instruments and financing mechanisms relevant to concentrated solar power and the potential for solar thermal energy in industry. **Secondly** the modelling methodology is derived and suitable models selected for energy and financial modelling. The **third step** is to research and to select the most up to date modelling inputs for both energy and financial modelling. **Fourthly** the models and scenarios are run and the required results extracted. **Fifthly** the results are analysed. **Lastly** the potential for solar process heat is tested by evaluating both the outputs of the energy and financial models against the objectives of this study.

1.6 CHAPTER OUTLINE

In **Chapter 2** a literature survey on solar energy is given. It discusses the technical aspects of solar radiation as well as the solar resource available in South Africa. This chapter further gives the technical aspects of solar thermal engineering and its application to concentrated solar technologies. Solar thermal storage and power production as well as solar process economics are topics covered in this chapter.

Chapter 3 is also a literature survey and international policy instruments and financing mechanisms available to address climate change are researched.

Chapter 4 investigates the market potential for the application of Solar Thermal Energy in South African industries. The integration of solar heat into industrial processes is researched and a case study on an integrated solar thermal plant and power station is given. Challenges and potential ways to overcome these barriers are also discussed.

Chapter 5 outlines the modelling approach used in this study. Both the approaches to model the technical energy/power output from a reference CSP plant and the costs are discussed. **Chapter 6** is concerned with the inputs used for the technical and cost modelling of the reference CSP trough plant.

In **chapter 7** analyses of the technical and cost modelling of the reference CSP trough system are performed and discussed. A number of scenarios for different operating conditions and financial situations are addressed.

In **chapters 8 and 9** conclusions and recommendations are made respectively.

CHAPTER 2: LITERATURE SURVEY: SOLAR ENERGY

The sun is the primary source of energy on earth. It is therefore important to understand the nature of solar radiation in terms of extraterrestrial radiation, the effects of orientation of a receiving surface and the theoretically possible radiation at the earth's surface when analysing solar radiation data for solar thermal engineering calculations.

2.1 INTRODUCTION TO THE UTILIZATION OF SOLAR RADIATION

In this section, the solar energy outside of the earth's atmosphere will be discussed in terms of intensity and its spectral distribution. Secondly the solar geometry (i.e. the position of the sun in the sky relative to the position on the earth's surface) will be covered. Lastly, extraterrestrial radiation on a horizontal surface will be looked into as this represents the theoretical upper limit of solar radiation that is available on the earth's surface (Duffie & Beckman, 1991).

2.1.1 Solar Constant

The solar constant, G_{sc}, is defined as "*the energy from the sun, per unit time that is received on a unit area of surface perpendicular to the direction of the propagation of the radiation, at mean earth-sun distance, outside the atmosphere*" (Duffie & Beckman, 1991). The sun consists of hot gaseous matter that has an effective blackbody temperature of 5777K (Duffie & Beckman, 1991) and produces energy through the process of fusion. The most important fusion reaction, taking place in the sun is when hydrogen (with four protons) combines to form helium (with one nucleus). The mass of the helium nucleus is less than the four protons and the mass that has been lost in the reaction is converted to energy (Duffie & Beckman, 1991). The energy produced in the inner sphere is then transferred out to the surface of the sun and radiated into space. The radiation emitted by the sun reaches the earth's surface at a nearly constant intensity that is known as the solar constant. The value used for the solar constant by Duffie and Beckman (1991) is 1367 W/m^2, as adopted by the World Radiation Center. This value has an uncertainty of 1% (Duffie & Beckman, 1991).

2.1.2 Spectral distribution of radiation

Apart from the total amount of energy that is received at the surface of the earth's atmosphere, it is also useful to know the spectral distribution of this radiation. Figure 2-1 (NTNU, 2010) shows a standard solar radiation spectrum curve at the top of the atmosphere and at sea level. The solar irradiation received at the surface of the earth is less than that received at the top of the atmosphere, as radiation at the surface is subject to atmospheric scattering and adsorption.

Scattering of radiation is caused by interactions with air molecules, water and dust and the extent of scattering is therefore dependent on the number and the size of the particles it must pass (Duffie & Beckman, 1991).

Adsorption is mainly as a result of absorption by O_3, H_2O and CO_2 in the atmosphere. Ozone almost completely absorbs short-wave radiation of wavelengths below 0.29 µm. Water absorbs strongly in the infrared band of the spectrum at wavelengths of 1.0, 1.4 and 1.8 µm, while CO_2 and H_2O will absorb most of the radiation at wavelengths above 2.5 µm (Duffie & Beckman, 1991).

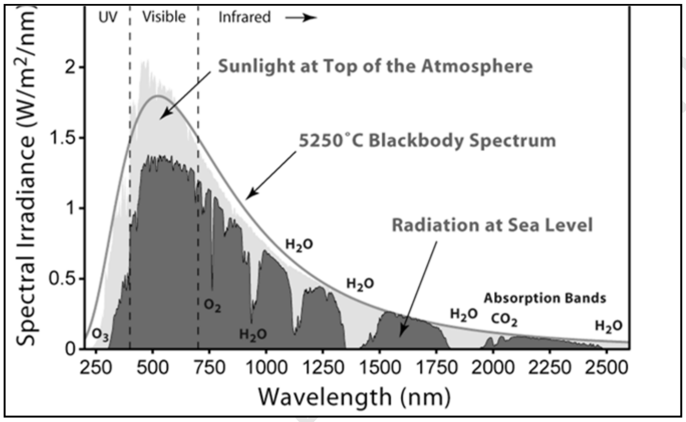


Figure 2-1: Solar Radiation Spectrum.

Source: (NTNU, 2010)

2.1.3 Definitions

Several terms will be used further in this study and the following definitions from Duffie and Beckman (1991) will be useful.

Air mass (m): *"The ratio of the mass of atmosphere through which beam radiation passes to the mass it would pass through if the sun were at the zenith (i.e. directly overhead). Thus at sea level m = 1 when the sun is at the zenith. For zenith angles from 0° to 70° at sea level, to a close approximation."*

$m = 1/\cos\theta_z$ **Equation 2-1**

In Equation 2-1, θ_z is the zenith angle.

Beam/Direct Radiation: *"The solar radiation received from the sun without having been scattered by the atmosphere. (Beam radiation is often referred to as direct solar radiation)."*

Diffuse Radiation: *"The solar radiation received from the sun after its direction has been changed through scattering by the atmosphere."*

Total Solar Radiation: *"The sum of the beam/direct and the diffuse solar radiation on a surface. (The most common measurements of solar radiation are total radiation on a horizontal surface, often referred to as the global radiation on the surface.)"*

Irradiance (W/m^2): *"The rate at which radiant energy is incident on a surface, per unit area of surface. The symbol G is used for solar irradiance with appropriate subscripts for beam, diffuse and spectral radiation."*

Emissive Power (W/m^2): *"The rate at which radiant energy leaves a surface per unit area by emission only."*

Solar Time: "*Time based on the apparent angular motion of the sun across the sky, with solar noon the time the sun crosses the meridian of the observer. Solar time does not coincide with local clock time and it is necessary to convert standard time to solar."*

2.1.4 Solar radiation data

Solar radiation data is available in many forms and it is important to understand whether data is instantaneous measurements (irradiance) or integrated over a period of time (irradiation) for example days or hours. Furthermore the time or time period of the measurements, the type of radiation (i.e. beam, diffuse or total radiation) and the receiving surface orientation (normally horizontal) are important characteristics of solar radiation data (Duffie & Beckman, 1991).

When designing concentrating collectors, it is important that the fractions of the total horizontal radiation that are diffuse and beam are known. Estimates of the long-time performance of concentrating collectors are required to be based on beam radiation and for this reason Direct Normal Irradiance (DNI) data is normally used when conducting concentrating collector calculations (Duffie & Beckman, 1991).

2.2 AVAILABILITY OF SOLAR ENERGY IN SOUTH AFRICA

Figure 2-2 (EPRI, 2010) shows the solar radiation for the world and it is clear that South Africa has an above average solar resource with most parts of the country receiving solar radiation above 3000 kWh per m^2 per year (DME, 2003). This high solar radiation provides significant scope for solar water heating applications and electricity production from Concentrating Solar Power (CSP) and solar photovoltaics (PV).

South Africa experiences some of the highest levels of solar radiation in the world with the average daily solar radiation in South Africa between 4.5 and 6.5 kWh/m^2/day. This compares to about 3.6 kWh/m^2/day for parts of the United States and about 2.5 kWh/m^2/day for Europe and the United Kingdom.

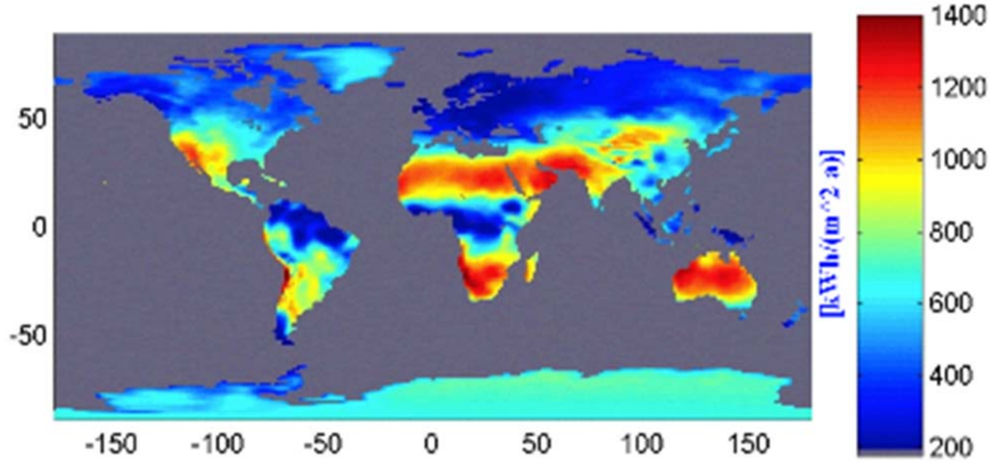


Figure 2-2: Global DNI.

Source: (EPRI, 2010)

Fluri (2009) derived solar radiation data from satellite imagery by the National Renewable Energy Laboratory (NREL) and the United States National Aeronautics and Space Administration (NASA) and produced the maps shown in Figure 2-3. These maps show the Direct Normal Irradiance (DNI) for the whole year and for the months of March, June, September and December. Five provinces of South Africa (Northern Cape, North West, Free State, Eastern Cape and the Western Cape) have an annual DNI higher than 7.0 KWh per m^2 per day. Fluri (2009) concluded that there is huge potential for CSP in South Africa and after taking potential sites into consideration in close proximity to transmission lines and with the least threatened vegetation, the potential CSP generation capacity was calculated to be 547.6 GW (Fluri, 2009).

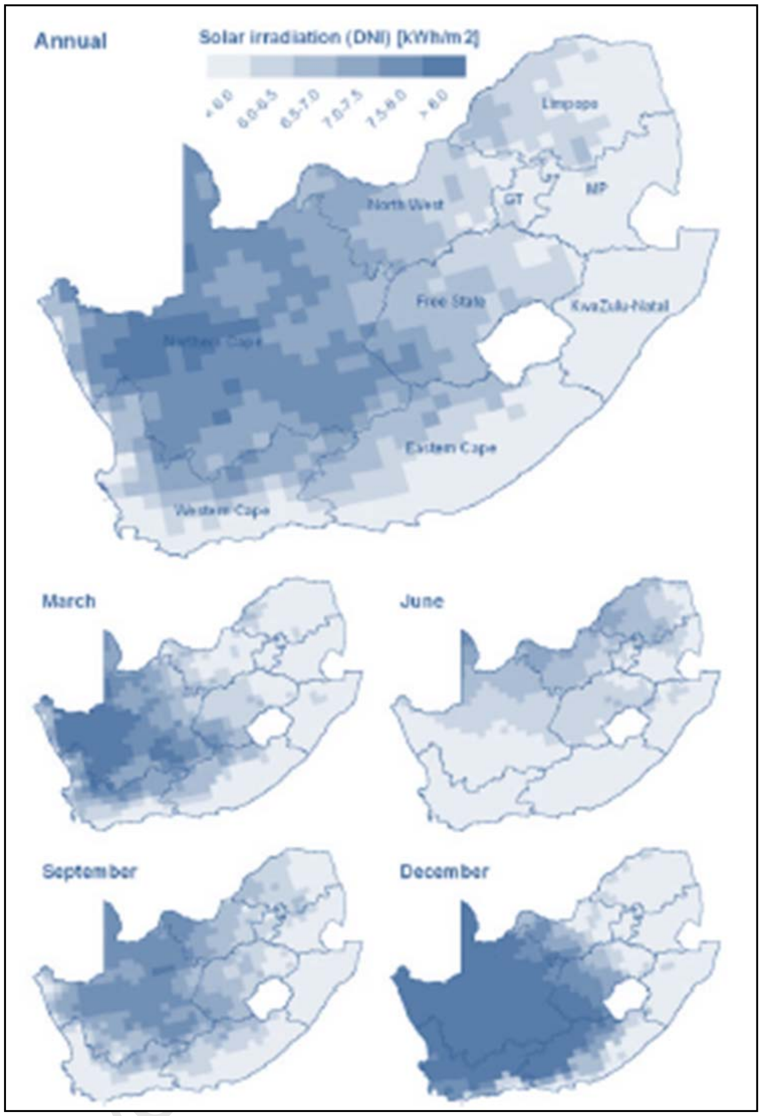


Figure 2-3: Maps derived from NREL data showing the average DNI for South Africa for the whole year and for the months of March, June, September and December.

Source: Fluri (2009)

2.3 SOLAR ENGINEERING OF CONCENTRATING COLLECTORS

Concentrating collectors can be used for applications where it is desirable to reach temperatures higher than those possible with flat-plat collectors (i.e. >80°C). Where high temperature process heat or steam for power generation is needed, concentrating collectors are required. It is possible to increase the temperature by decreasing the area from which heat losses will occur. To make this possible, an optical device is placed between the source of radiation and the energy-absorbing surface. The small absorber will have a smaller surface area and therefore smaller heat losses will occur compared to that or a flat-plate collector.

There are many designs available for concentrating collectors with varying collecting surfaces, receivers and modes of tracking. When considering different concentrating collectors, the following terminology is important and is used for all different types of concentrating collectors. The **collector** refers to the total system including the receiver and the concentrator. The **receiver** refers to the element of the system that absorbs radiation and that converts it into another form (mainly heat). The collector also includes the **absorber**, the **concentrator** (the part that directs the direct beam radiation onto the receiver) and the **aperture** that is the opening through which radiation enters the concentrator. (Duffie & Beckman, 1991).

The following sections will look into optical and heat transfer principles that are relevant to concentrating collectors. Concentrating configurations, concentration ratio and the thermal optical performance of concentrating collectors are addressed in detail. Different types of the concentrating collectors considered in this study (i.e. parabolic trough) will also be discussed.

2.3.1 Collector configurations

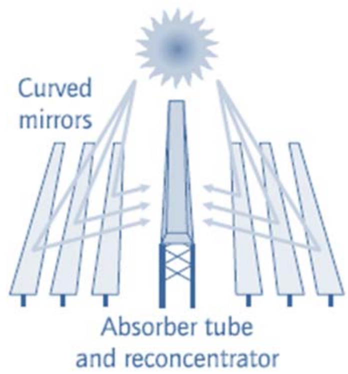
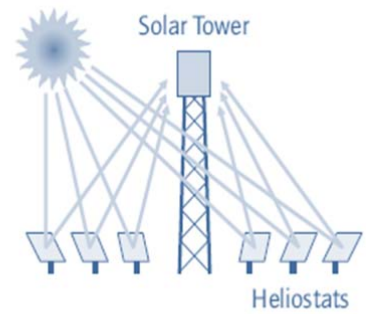
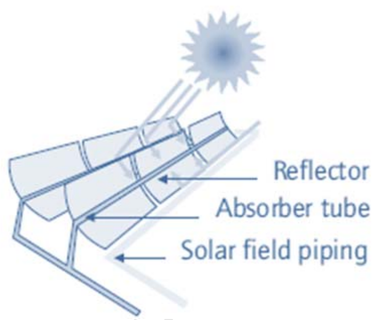
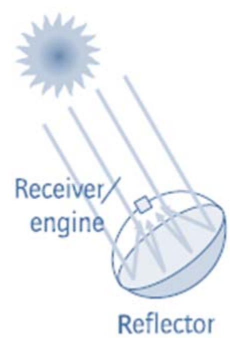
Many concentrator types are available to help increase the flux on the receivers of concentrating collectors. These configurations can mainly be grouped according to focus type and receiver type. Focus type can be either on a line or on a point while receivers can be fixed or mobile.

Line focus collectors track the sun along a single axis and focus beam radiation on a linear receiver. **Point focus** collectors track the sun along two axes and focus beam radiation on a single point receiver. This type of focus allows for higher temperatures to be reached, although tracking of the sun is more complicated. (Duffie & Beckman, 1991).

A **fixed receiver** type is stationary and does not move with the focusing device while a **mobile receiver** type moves together with the focusing device. Mobile receivers will collect more energy than fixed receivers. Table 2-1 (IEA, 2010) shows a summary of the four main concentrating collector technologies that are used and they are categorized according to focus and receiver type.

Table 2-1: Summary of the four main CSP technologies.

Source: Adapted from IEA (2010)

<table>
<tr><th>The four main technologies</th><th>Focus type:
Line Focus</th><th>Focus type:
Point Focus</th></tr>
<tr><td>Receiver type:
Fixed</td><td>Linear Fresnel Reflectors
</td><td>Central Receiver Towers
</td></tr>
<tr><td>Receiver type:
Mobile</td><td>Parabolic Troughs
</td><td>Parabolic Dishes
</td></tr>
</table>

Concentrators, where the receivers are much smaller than the aperture, are effective only on beam radiation and therefore the angle of incidence of the beam radiation on the concentrator is important and sun tracking is subsequently required. Different mechanisms have been developed to help concentrators track the sun. Line focus systems will focus beam radiation onto the receiver if the sun is in the central plane of the concentrator and therefore these systems can be rotated about a single axis of rotation. Point focus systems must be orientated so that the axis and the sun are in line and therefore two-axis tracking is normally required (horizontal and vertical). (Duffie & Beckman, 1991).

2.3.2 Concentration ratio

The area concentration ratio is the most commonly used concentration ratio and is the ratio of the area of the aperture to the area of the receiver. A flux concentration ratio can be defined as "*the ratio of the average energy flux on the receiver to that on the aperture*" (Duffie & Beckman, 1991). According to Duffie and Beckman (1991), there are substantial variations in the energy flux over the receiver's surface, making the area concentration ratio more desirable to use. The equation for the concentration ratio is given below.

$$C = \frac{A_a}{A_r} \qquad \text{Equation 2-2}$$

2.3.3 Parabolic Trough Collectors

Parabolic trough collectors are line focusing mobile receivers that concentrates sunlight before it strikes the absorber (Weiss & Rommel, 2008). The receiver is a parabolic shaped mirrored surface that is extended into a trough shape. The solar radiation is used to heat a heat transfer fluid that is pumped through the absorber tube. Parabolic trough collectors can reach temperatures of between 100 and 450°C and can maintain high collector efficiencies at these temperatures (Weiss & Rommel, 2008).

Parabolic trough collectors operate on the principle that incoming light, parallel to the axis of a parabolic mirror, is reflected to a central point called the focal point. The parabolic trough shape is extended along a straight line to form a focal line. Only beam radiation can be concentrated and these collectors need to track the sun along one axis to ensure optimum efficiency. The reflecting surfaces have to be kept clean to ensure the best performance.

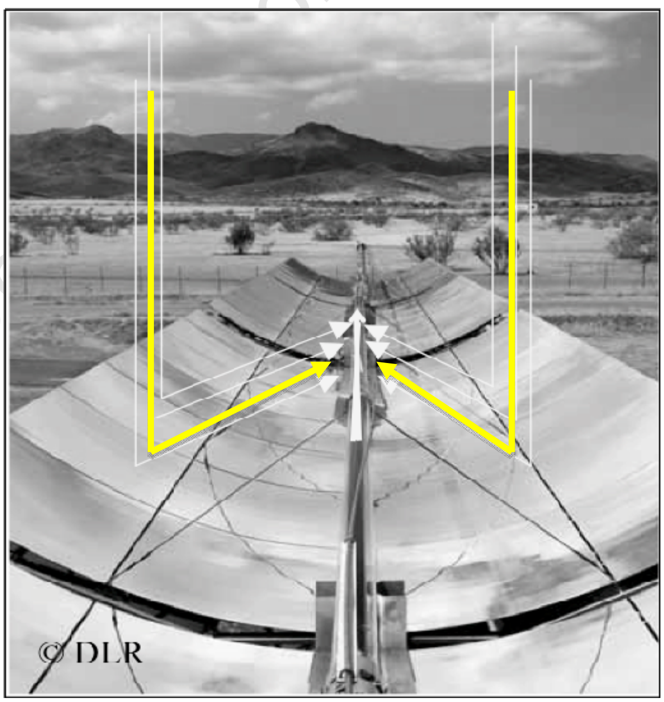


Figure 2-4: Parabolic trough collector.

Source: (IEA, 2010)

The optical efficiency refers to the efficiency if the operating temperature is equal to the ambient temperature (Weiss & Rommel, 2008). Parabolic trough collectors have optical efficiencies lower than that of flat plat collectors mainly because the shape of a parabola can never be manufactured perfectly and the mirrors also have a reflectivity of below 100% (Weiss & Rommel, 2008). Due to the small surface of the receiver, heat losses are reduced and higher temperatures can be achieved.

Construction

The shape of the reflecting surface is maintained in the shape of a parabola by a substructure consisting of metal and curved glass. The parabolic reflecting surface could be curved glass with a reflective coating applied to it, or it could be an aluminium sheet. The receiver consists of an absorber tube that is placed in the focal line of the parabolic trough. Absorbers will be painted black or with a selective coating to absorb the maximum amount of solar radiation. Often the absorber is also the metal tube that is also used to transport the heat transfer fluid. In most cases, the absorber is a glass tube with a U-shaped metal tube inside (Weiss & Rommel, 2008). The transparent glass tube reduces heat loss. The concentration ratio of parabolic trough collectors, as defined by Equation 2-2, normally ranges between 10 and 26.

Application

Parabolic trough collectors are mainly used for power generation. In these applications, thermal oil is heated to temperatures around 400°C and electricity generated by means of steam turbines. The aperture of these concentrators is around 6m and concentration ratios are at the upper end of 26 (Weiss & Rommel, 2008).

Smaller parabolic trough concentrators with concentration ratios of between 10 and 15 can achieve temperatures of between 100 and 250°C and have aperture widths of between 50 and 230cm (Weiss & Rommel, 2008). Parabolic trough collectors can use both a heat transfer medium (i.e. water or thermal oil) or they can be operated with direct steam.

2.3.4 Linear Fresnel Collectors

Linear Fresnel collectors are line focused and have a fixed receiver. It uses an array of uniaxially-tracked mirror units to reflect beam radiation onto the receiver (Weiss & Rommel, 2008). Advantages of linear Fresnel concentrators include simple construction, low wind loads and the fact that the receiver is fixed. The reflecting surface is made from flat glass that is cheaper than the reflecting material used in parabolic trough concentrators. It is common to use an absorber tube together with a secondary concentrator for the receiver.

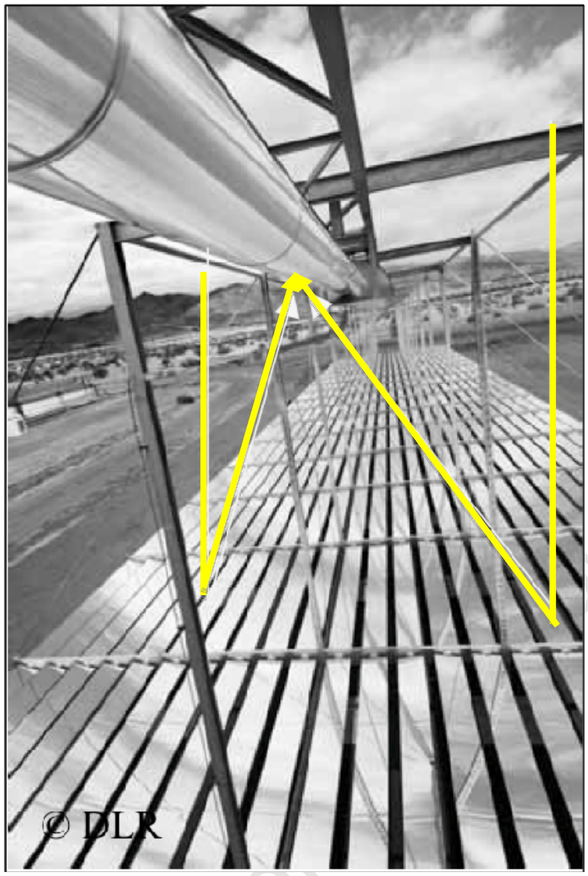


Figure 2-5: Linear Fresnel concentrator.

Source: (IEA, 2010)

The concentration ratio of Linear Fresnel collectors typically ranges between 25 and 40 (as per definition in Equation 2-2) (Weiss & Rommel, 2008). Operating temperatures as high as 400°C can be achieved, but are limited by the material constraints of the receiver. The heat carrier can be water, direct steam or thermal oil.

Application

Linear Fresnel collectors could be used for solar thermal power generation and can also be used for industrial process heat. These collectors can achieve thermal capacities of between 50 kW and up to several MW (Weiss & Rommel, 2008). Smaller systems can be mounted on top of roofs while bigger systems are placed in solar fields.

2.4 SOLAR THERMAL STORAGE

The output of solar thermal plants (and therefore solar thermal power plants) is constantly changing as a result of both predictable and unpredictable changes in weather and time. Solar thermal power plants often need some form of thermal storage that will act as a buffer to mitigate variations in solar radiation and to meet demand (NREL, 2000).

Several forms of energy storage exist and it can for example be stored as sensible heat in liquids or solids as chemical energy in reversible chemical reactions, or as heat of fusion in chemical systems (Duffie & Beckman, 1991). The most appropriate thermal storage depends on the process and in solar thermal systems energy is normally stored as sensible heat in water. Solar thermal storage is cheaper when compared to electricity storage methods (NREL, 2000). Thermal Energy Storage (TES) can be used to shift the delivery time to a later time when solar radiation is not sufficient or to ensure a smoother delivery of energy. TES systems come at a cost and the economics are important to consider. The cost mainly depends on the type of TES used and the size of these systems (length of storage required). Typical size ranges for CSP plants are 3 to 6 hours of full load operation (NREL, 2000).

2.4.1 Design criteria

The amount of energy that can be stored (i.e. thermal capacity) is one of the main design criteria for TES systems. The cost of TES systems largely depends on the storage material, the heat exchanger responsible for charging and discharging the system and the cost of space (NREL, 2000). Requirements for a good TES system design include:

- Storage material must have a high energy density;
- Good heat transfer between the storage medium and the heat transfer fluid;
- Storage material must be chemically and mechanically stable;
- Complete reversibility for numerous charging and discharging cycles;
- Minimum thermal losses; and
- Ease of control. (NREL, 2000).

2.4.2 Thermal energy storage options

TES can be categorized by storage mechanisms (i.e. sensible, latent and chemical) and storage concept (i.e. active or passive) (NREL, 2000). Next, the storage media used for the different storage mechanisms are researched.

Storage Media

Sensible, latent or heat from chemical reactions can be used for TES. Energy is stored in the form of sensible heat when the temperature of a solid or liquid is increased while latent heat refers to heat released when there is a transition from a solid to a liquid state. Properties of different storage media include the energy density, the specific heat, operational temperatures, thermal conductivity, stability and vapor pressure (NREL, 2000).

Where solid media are used for TES, the media are packed in beds and require a liquid to exchange heat with and could also be referred to as a dual storage system (NREL, 2000). One of the advantages of these systems is that inexpensive solids such as rock, sand and concrete can be used together with more expensive heat transfer fluids. Both oils and salts are feasible liquid media, however salts have a higher melting point and parasitic heating is required to keep it from solidifying at night.

Latent heat of phase change includes heat of fusion (solid-liquid transition), heat of vaporization (liquid-vapor) or heat of solid-solid crystalline phase transformation. Substances used for latent heat storage are called phase change materials (PCMs). TES systems using PCMs can be smaller in size than solid media and liquid media because the latent heat of fusion between liquid and solid states is high compared to sensible heat (NREL, 2000). Heat transfer design and media selection is more difficult than for solid and liquid TES. Table 2-2 (NREL, 2000) shows the heat capacity and the costs for different solid, liquid and latent heat storage media. From Table 2-2 it can be seen that reinforced concrete and salt have low costs and acceptable heat capacities, however the thermal conductivity is low for these materials (NREL, 2000). Cast iron has a high heat capacity at an acceptable cost. Silicone oil is rather expensive but has some environmental benefits, as it is non-toxic. Synthetic oils are cheaper, but are considered hazardous. For latent heat storage media, heat capacities are low and the cost is moderately low.

Chemical storage involves completely reversible chemical reactions. The heat from the solar collector drives an endothermic reaction and heat can be recovered from the reversible reaction. Chemical storage is not commonly used at present as it is in early stages of development.

Table 2-2: Solid, liquid and latent heat storage media (Note: costs for the year 2000).

Source: (NREL, 2000)

Storage Medium	Heat Capacity (kWh_t/m^3)	Media Cost (USD/kWh_t)
Solid Storage Media		
Reinforced concrete	100	1
NaCl (solid)	100	2
Cast Iron	160	32
Cast Steel	180	150
Silica fire bricks	60	18
Magnesia fire bricks	120	30
Liquid Storage Media		
Synthetic oil	57	43
Silicone oil	52	80
Nitrite salts	76	24
Nitrate salts	83	16
Carbonate salts	108	44
Liquid sodium	31	55
Latent Heat Storage Media		
$NaNO_3$	125	4
KNO_3	156	4
KOH	85	24

2.5 CONCENTRATED SOLAR POWER PRODUCTION

The process whereby solar energy is converted into mechanical and electrical energy is similar to other thermal processes. The process for generating electricity from solar energy is shown in Figure 2-6. Energy is collected by solar collectors (parabolic trough in this case) in a solar field and stored if appropriate. In this case oil is used for thermal energy storage. The heat from the hot oil is used to generate steam that powers a turbine. High temperature pumps are used to circulate the heat transfer fluid. The returning temperature of the heat transfer fluid for a typical parabolic trough CSP is 304°C and it is heated to 390°C in the solar field (Duffie & Beckman, 1991). A supplement fuel (natural gas in this case) is normally used to provide heat during times when the solar radiation is not sufficient to meet the demand.

The power generation cycle is a conventional Rankine cycle where the steam drives a turbine that in turn drives a generator that generates electricity. Cooling towers are used to cool the condenser cooling water.

The overall performance of a CSP plant mainly depends on the efficiency of collecting solar energy by the solar collector and the turbine-generator efficiency. The typical overall capacity factors for parabolic trough CSP systems have been in the order of 30% (Duffie & Beckman, 1991).

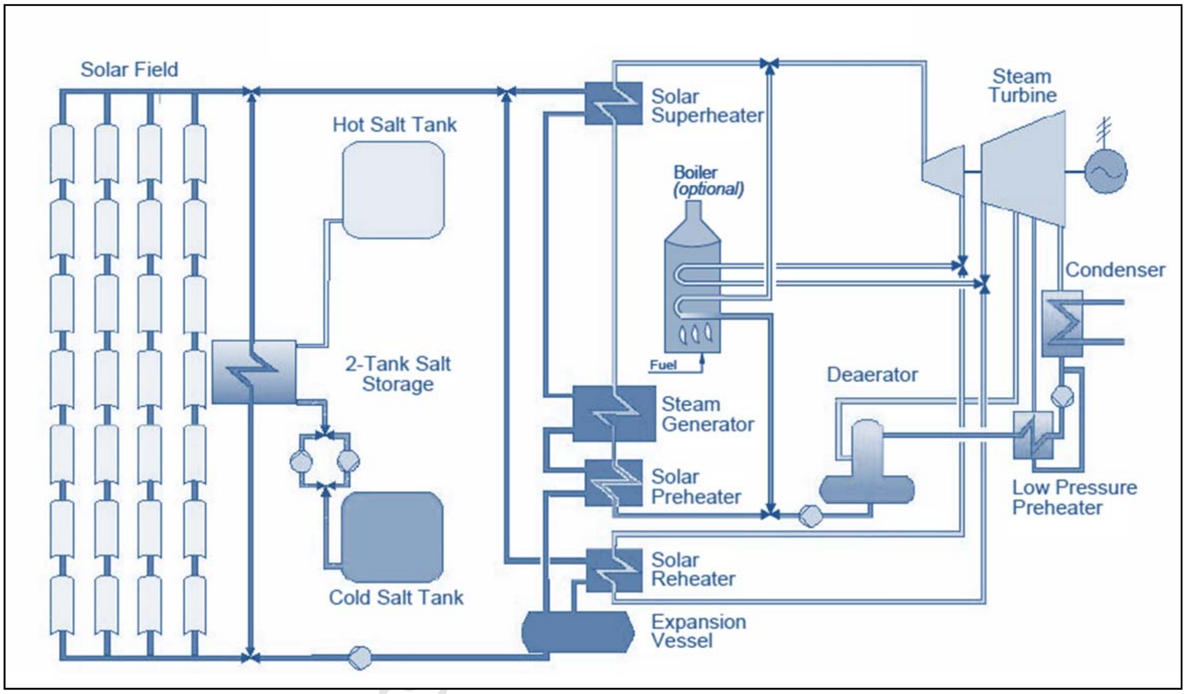


Figure 2-6: Schematic flow diagram of a CSP plant.

Source: (NREL, 2000)

2.6 SOLAR PROCESS ECONOMICS

It is necessary to evaluate solar processes in economic terms to make good investment decisions. To evaluate solar investment costs, it is necessary to take both the present investment costs and the estimated future operating costs into consideration. According to Duffie and Beckman (1991) solar processes generally have high initial investment costs and low future operating costs. Economic analysis is a process that is used to determine the least cost method of meeting the energy demand, taking both solar and alternative sources into consideration. Often solar energy processes need an auxiliary or conventional energy source and it is necessary to find the size of the solar energy system that yields the lowest cost combination of solar and auxiliary energy (Duffie & Beckman, 1991).

Initial costs mainly include the equipment, cost of land and labour. Factors that contribute to the overall cost of the system include interest on money borrowed, property and income taxes, maintenance, insurance, fuel and other operating expenses (Duffie & Beckman, 1991). The type of economic evaluation method used for this project is given in the sections to follow. The following topics are covered in this section:

- Cost of solar process systems;
- Design variables;
- Economic figures of merit;
- Discounting and inflation;
- Present worth; and
- The life cycle savings method.

2.6.1 Cost of solar process systems

The total plant cost (or total initial investment cost) of solar process systems include the delivered price of equipment as well as installation costs and costs of the support structures for the collectors. Equipment costs may include collectors, storage units, pumps and blowers, controls, pipes and ducts, heat exchangers and equipment needed for installation (Duffie & Beckman, 1991). Duffie and Beckman (1991) show the total installed costs of solar equipment as the sum of two terms namely one proportional of collector area and the other independent of collector area. Equation 2-3 (Duffie & Beckman, 1991) shows the calculation for the total installed costs of solar equipment

$$C_S = C_A A_C + C_E \qquad \textbf{Equation 2-3}$$

C_S: total cost of installed solar energy equipment (e.g. USD)
C_A: total area dependent costs (e.g. USD/m^2)
A_C: collector area (e.g. m^2)
C_E: Total costs of equipment independent of collector area (USD)

Area dependent costs include items such as the installation of the collector while area independent costs include items such as the controls that are not dependent on the area of the collector (Duffie & Beckman, 1991).

Operating costs are linked to the process itself and occur continuously while initial investment costs are a once-off investment. Examples of operating costs include auxiliary energy costs (also known as parasitic energy) to operate pumps, property and land taxes and interest charges. Income tax may also be included in operating costs (Duffie & Beckman, 1991). Income producing property and equipment can be depreciated that will in turn reduce the taxable income. The total annual cost is given by Equation 2-4 (Duffie & Beckman, 1991).

Annual cost = Fuel expense + Mortgage payment + Maintenance and insurance + Parasitic energy cost + Property taxes – Income tax savings – carbon tax savings or carbon revenues

Equation 2-4

The fuel expense refers to the cost of energy purchased for auxiliary or conventional systems while the mortgage payment include the interest and principal payment on funds that have been borrowed to pay for initial investment costs. Income tax credits refer to any credits given by the local government for investing in clean technologies or carbon emission reductions. (Duffie & Beckman, 1991).

Solar savings refer to the difference between the costs of a conventional energy system and a solar energy system. Where solar savings are negative it indicates a loss.

Solar Savings = Costs of conventional energy – Costs of solar energy

Equation 2-5

2.6.2 Design variables

Economic evaluations are concerned with finding the lowest cost solar system. Numerous variables contribute to the performance and therefore also the costs of a system. To determine the variables that are most critical to the performance and cost of a system, it is necessary to do a sensitivity analysis. The load of the solar system should also be considered when determining the optimum design (Duffie & Beckman, 1991).

2.6.3 Economic figures of merit

There are a number of economic criteria available that can be used to evaluate and optimise solar energy systems. The figures of merit discussed in Duffie and Beckman (1991) is summarised here and include:

- Least cost of solar energy;
- Life Cycle Cost (LCC);
- Life Cycle Savings (LCS) or net present worth;
- Annualised Life Cycle Cost (ALCC);
- Annualised Life Cycle Savings (ALCS)
- Payback time; and
- Return on investment.

Least cost of solar energy is suitable in situations where solar energy is the only source of energy. A system that shows least cost is defined as: *"A system showing minimum owning and operating cost over the life of the system, considering solar energy only."* (Duffie & Beckman, 1991). For systems using a combination of solar and other energy sources, the least cost of solar energy is not a suitable figure of merit to use.

The **Life Cycle Cost (LCC)** is defined by Duffy and Beckman (1991) as "*the sum of all the costs associated with an energy delivery system over its lifetime or over a selected period of analysis, in today's dollars and takes the time value of money into consideration*." The life cycle cost includes the capital expenditure of the project. Future costs are converted into present cost by discounting it and inflation is included in future expenses. This approach is considered to be the most complete approach to solar process economics. Each of the future expenses is converted into the present value by discounting it and summed over the years to calculate the LCC. Equation 2-6 shows the formula for discounting future expenses to its present value where d is the discount rate and N is the time period in years.

$$PV = \frac{1}{(1+d)^N}$$

Equation 2-6

The results of LCC economic analysis require that all expenses be predicted into the future. Recurring costs can normally be assumed to inflate or deflate at a constant rate (*i*) in the future. N is a period in the future.

$$C_N = A(1+i)^{N-1}$$

Equation 2-7

Life Cycle Savings (LCS) is the **net present value (NPV)** *of the difference between the life cycle costs of a conventional fuel-only system and the life cycle cost of the solar energy system*." (Duffie & Beckman, 1991). **Annualised Life Cycle Cost (ALCC)** is the average annual outflow of money and equals the sum of money flowing out over the period of economic analysis divided by the number of years. **Annualised Life Cycle Savings (ALCS)** follows the same principle. (Duffie & Beckman, 1991).

One definition of **payback period** is the amount of time needed before the cumulative fuel savings will equal the initial investment of the solar system or in other words how long it will take to pay back an investment by fuel savings (Duffie & Beckman, 1991).

The **Return On Investment (ROI)** refers to the discount rate that will result in zero LCS or NPV.

CHAPTER 3: LITERATURE SURVEY: POLICY INSTRUMENTS AND FINANCING MECHANISMS TO ADDRESS CLIMATE CHANGE

South Africa, being the 12th largest emitter of greenhouse gasses (Treasury, 2010), is faced with the challenge to reduce GHG emissions in line with global targets. At the Copenhagen climate change negotiations in 2009, South Africa committed to reduce GHG emissions by 34% by 2020 and 42% by 2025 below a "Business As Usual" trajectory (Treasury, 2010). Command and control (CAC) and market-based instruments are two main instruments used to address climate change. According to the Long Term Mitigation Scenarios report (2007) and the National Climate Change Response Green paper (2010), market-based instruments are considered the most effective tool for achieving GHG emission reduction targets. Market-based instruments include economic policies to encourage GHG emission reduction and the two main instruments used are carbon taxes and emissions trading. The CAC approach uses regulatory policy measures, for example the use of standards for emissions and prescribing technologies that will help reduce GHG emissions (Treasury, 2010). In Appendix G the CAC and market-based instrument approaches are discussed in more detail. In the following section, the key project risks are discussed.

3.1 KEY PROJECT RISKS

The design requirements for solar thermal heat and power projects vary considerably between different projects and applications. Some projects may be quite standard such as a standalone CSP plant whereas other projects may require months of complex detailed engineering work. Project feasibility studies will address technical design, performance planning and the economics of the projects. These studies will also have to identify all of the factors that may have an impact on the projected cost savings and the risks involved. The risks and projected cash flows of projects are critical factors that project owners and investors will evaluate. Key risks of projects typically include project performance; the project implementation plan; capacity factor; quality of inputs and technology operation; and variations in energy prices (World Bank, 2008).

a) Technical performance: The technical performance of the concentrated solar project is very important as the savings can only be achieved if the project is performing. The stakeholders need to be confident that all the technical risks have been addressed and that the equipment will perform as specified. Risks associated with equipment are most often covered by a manufacturer or supplier warranty. Underperformances of the projects are normally borne by the client, the contractor or the project designer or a combination as determined by the contractual agreement.

b) Project implementation: One of the main concerns of clients is the disruption that the implementation of integrated concentrated solar projects will bring to the facility. The project implementation could be scheduled during maintenance periods to ensure minimum losses. With projects where delays in procurement and delivery of equipment are possible, the responsibilities of each stakeholder must be sufficiently addressed.

c) Capacity factor: The number of hours of availability of equipment or processes is also a variable that needs to be taken into consideration. Weather, changing market conditions and changes in production levels are all examples of factors that could have an impact on the energy savings. This risk could be minimized through the collection of sufficient and comprehensive weather data. The end user normally carries this risk.

d) Quality of inputs and technology operation: The quality of inputs for example poor quality of sunshine, could also impact the project's performance and the end user normally carries this risk.

e) Energy price variations: Any variation in the energy price will have an impact on the projected savings and therefore the financing of the project. Energy price variations are difficult to predict and therefore the end user will normally bear this risk. (World Bank, 2008).

When evaluating a Concentrated Solar project, it is important to investigate all the potential factors that could have an impact on the technical and financial performance of the project and to allocate risk appropriately amongst the different parties.

3.2 FINANCING PROJECTS

Financing of Concentrated Solar plants differs considerably from one investment to another depending on the financing method chosen. This will have a direct impact on the levelised cost of electricity and returns of the project. Large utilities with cash can normally finance the projects directly or will have access to corporate loans. If no cash is available, utilities and investors will have to look at alternative ways to finance their project. Financing methods are numerous and should be utilised to promote the development of any renewable energy market. Mechanisms for delivery include:

a) Financing by the end user: Small or medium-sized projects are often financed internally from the enterprise's own funds.

b) Local banks: Commercial banks are often the main source of loan finance for projects.

c) <u>Leasing companies:</u> Leasing companies can be an important mechanism for commercial debt finance of projects. Partnerships of leasing companies with equipment companies can also be advantageous for promoting technologies and financing solutions.

d) <u>Multilateral development banks:</u> Institutions like the World Bank and the IFC may provide direct or indirect financing for projects. Funding is more often channeled through funds and other intermediates.

e) <u>Others:</u> Energy Service Companies (ESCOs) can also finance projects but would then also need to be financed in return. One of the above sources can be used to finance ESCOs. (World Bank, 2008).

The availability of finance is vital for successful renewable market transformation but would be worthless if no business infrastructure is in place to promote renewable energy projects. In the following section, financing support mechanisms are discussed.

3.3 FINANCING SUPPORT MECHANISMS

It is important to develop an array of financing support mechanisms and to apply the most appropriate ones according to the level of development in the credit market of a country to promote investment in renewable energy projects. The financial instruments most commonly used in other countries where successful renewable energy markets have been established include:

- Partial loan guarantees;
- Special purpose funds;
- Investment grants and subsidies; and
- Loan loss reserve and equity funds. (GEF, 2004).

Table 3-1 shows the definitions of the above and a summary of the conditions of use.

Table 3-1: Financing support-mechanisms and conditions of use.

Financial Instrument	Description	Conditions and Use
Partial Loan Guarantees	*"A legally binding agreement under which the guarantor agrees to pay a part of the amount due on a loan instrument in the event of non-payment by the borrower."* (Online: http://stats.oecd.org)	Most appropriate where banking sectors are well developed such as in South Africa. Funds can be kept in a reserve account that is used to provide partial credit guarantees for CSP projects.
Loan Loss Reserve Funds	*"Valuation reserve against a bank's total loans on the balance sheet, representing the amount thought to be adequate to cover estimated losses in the loan portfolio."* (Online: http://financial-dictionary.thefreedictionary.com)	Most appropriate for well developed banking sectors such as in South Africa. Better suited for a portfolio of small standard loans. Funds are put into an account with local bank(s) to provide full or partial coverage for a portfolio.
Special Purpose Revolving Funds	*"A fund established for a certain purpose, such as making loans, with the stipulation that repayments to the fund may be used anew for the same purpose."* (Online: http://financial-dictionary.thefreedictionary.com)	Can be used where the liquidity in the banking sector is not sufficient and where there is major risk aversion among lenders. It has the benefit of CSP projects not having to compete with more conventional projects for commercial funding.
Equity Funds	*"A stock fund or equity fund is a fund that invests in equities more commonly known as stocks."* (Online: http://financial-dictionary.thefreedictionary.com)	Funds can be used as equity to ESCOs.
Investment Grants	Grants or subsidies that can help facilitate investments on end-user side.	Can be used where the credit barrier is too high to support commercial financing and to target new and underdeveloped markets.

CHAPTER 4: LITERATURE SURVEY: POTENTIAL FOR SOLAR THERMAL ENERGY IN INDUSTRY

According to the European Solar Thermal Industry Federation (ESTIF, 2006), a capacity of 70 GW_{th} of solar thermal collectors with about 100 million square meters were installed by 2001 worldwide. Current uses mainly include heating for swimming pools and domestic hot water and space heating and in 2006 the use of solar thermal energy in commercial and industrial applications was insignificant when compared to residential uses (ESTIF, 2006). The industrial sector consumes about 30% of the final energy in OECD countries (ESTIF, 2006), while in South Africa this sector consumes 43% of the final energy (DME, 2004). Heat contributes 67% of the final energy used by the European Union's industrial sector, while electricity makes up the balance (ESTIF, 2006). Process heat and steam are widely used in energy intensive processes in South Africa such as in power plants, base metal refining and petrochemical plants. Therefore the potential use of solar thermal energy as a primary or supplementary energy source exists.

4.1 POTENTIAL FOR SOLAR HEAT IN INDUSTRIAL PROCESSES

Vannoni, Battisti and Drigo (2008) estimated that about 30% of the total thermal energy demand for industrial processes is below 100°C and 57% below 400°C. Temperatures below 80°C can be achieved by using non-concentrating collectors such as flat-plate and evacuated tube collectors. Industrial process heat applications often require temperatures above 80°C, which will require concentrating solar collectors. ESTIF (2006) argues that solar heat for industrial processes is underexplored and that it is a market with enormous potential. It is further argued that solar thermal technologies can supply a large portion of total energy demand in Europe. In South Africa with its good solar resource and strong demand for industrial process heat, the potential for such a market must be even bigger.

A study conducted by Vannoni, Battisti and Drigo (2008) investigated the industrial heat demand by temperature range and identified the most suitable industries and processes for solar thermal use. Figure 4-1 (Vannoni, Battisti, & Drigo, 2008) shows the share of industrial heat demand by temperature level and industrial sector.

Vannoni, Battisti and Drigo (2008) identified the industrial sectors with the most potential where solar thermal heat can be used. The sectors with the most potential are sectors with a high demand for heat and that are more or less continuous throughout the year. The temperature level of the demand must also correlate to the temperatures achievable by solar thermal collectors.

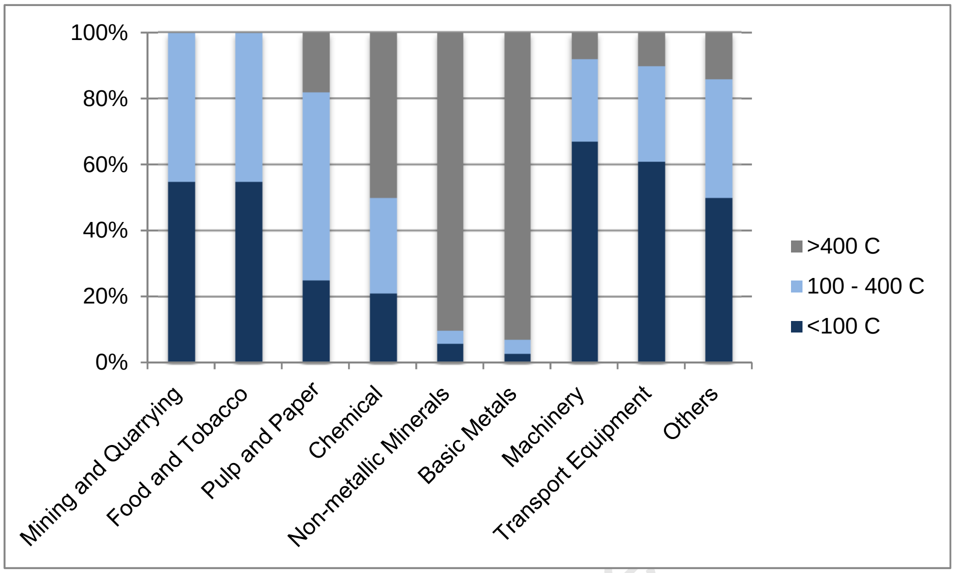


Figure 4-1: Share of industrial heat demand by sector and temperature.

Source: (Vannoni, Battisti & Drigo, 2008)

The most promising energy consuming sectors identified by Vannoni, Battisti and Drigo (2008) are food (including wine and beverage), textile, metal and plastic treatment and chemical. On the energy supply side, conventional fossil fuel plants such as coal fired power stations show promise for the use of solar thermal heat. Although the theoretical potential is high in the pulp and paper industry, the practical implementation is seen as a challenge as heat recovery systems are often used.

4.1.1 Challenges to growth

ESTIF (2006) gives the following barriers to growth in the industrial solar process heat market:

- **Awareness:** Not many solar thermal installations for industrial process heat are currently installed. Decision makers are not aware of these technologies and will most likely need reference to other installations before implementing solar thermal technologies for industrial process heat.
- **Confidence only exists in long-term and proven technologies**. Conventional and proven technologies are almost always chosen as newer technologies are seen as more risky than future prices of conventional fuels.
- **System Cost**: Solar heating systems for industrial processes typically have higher initial investment costs but save on conventional fuel costs. Uncertainties on future

conventional fuel costs for example and lack of investment decision-making skills are a key barrier to growth.

- **Lack of technology**: Industrial processes that require higher temperatures (>80°C) need unconventional designs and installations.
- **Lack of suitable planning guidelines and tools**: Skills are limited and only a few engineering companies have experience with solar thermal installations for industrial purposes.
- **Lack of education and training**: Only a few professionals currently have qualifications in solar thermal technologies. (ESTIF, 2006).

A number of recommendations were made by ESTIF (2006) to help remove these barriers. These include:

- Awareness campaigns targeted at decision makers need to be established;
- Demonstration projects need to be undertaken to boost confidence and build up experience;
- Financial incentives need to be established and made available to companies that undertake solar thermal systems;
- Funding should be made available for the research and development of new solar thermal technologies; and
- Training programmes need to be established to address the lack of expertise amongst professionals.

4.2 INTEGRATING SOLAR HEAT INTO INDUSTRIAL PROCESSES

Integrating solar heat into industrial processes is challenging. A lot of attention needs to be given to temperature levels of solar thermal systems as process facilities operate at different temperatures (IEA, 2009).

One challenge with solar thermal energy is the irregularity of supply. Big production facilities normally don't run at constant loads for 24 hours a day and the sun does not always shine. Energy should therefore be stored or alternatively solar thermal systems could only be used as supplementary to the existing system (IEA, 2009).

The location of the collectors is another factor to consider as most industrial processes use large amounts of energy in small spaces and it may be necessary to locate the collectors in a field adjacent to the processing facility, away from the buildings. The collector area may be limited to the amount of land area that is available (Duffie & Beckman, 1991).

Taking the above challenges into consideration, the best way to integrate solar thermal heat into industrial energy systems is to use it in combination with existing heating systems (IEA, 2009). Figure 4-2 (IEA, 2009) shows a process diagram for a solar thermal energy system feeding into an existing steam generation system. This configuration requires the solar collector to be

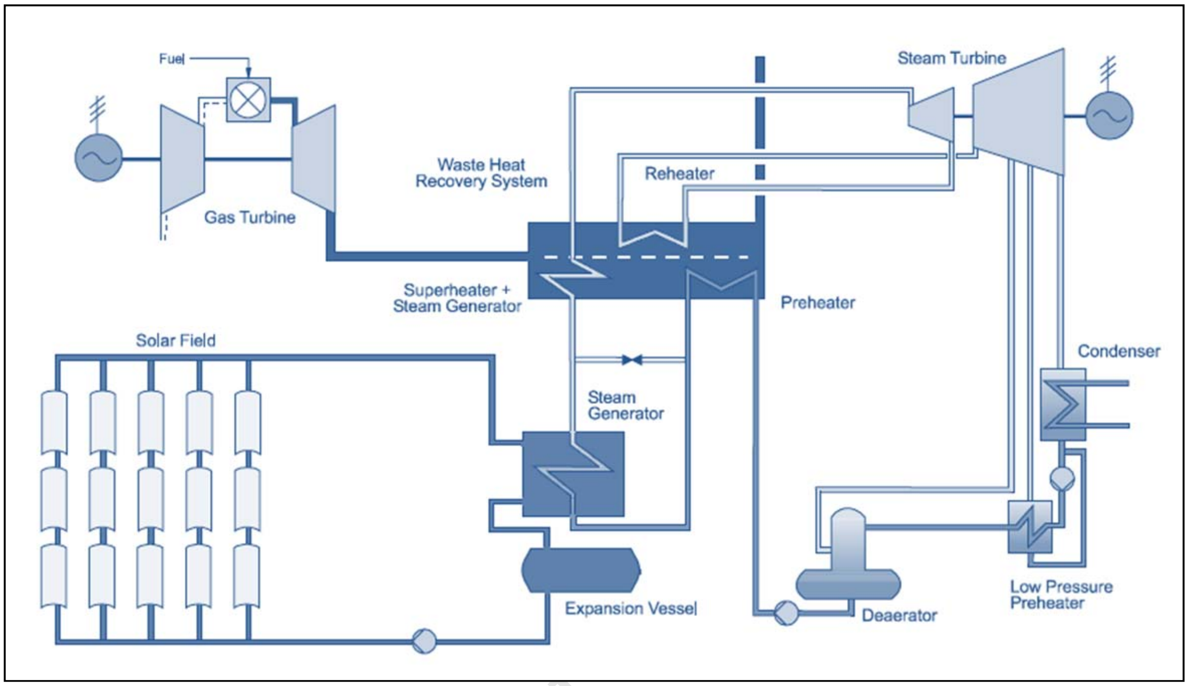


Figure 4-2: Process flow diagram for an integrated solar combined cycle power system.

Source: (IEA, 2009)

operated at the same temperature level as the existing heating system and that the heat transfer medium be water and not steam if possible. These configurations are easy to install but will have low thermal efficiencies (IEA, 2009). This integrated system is considered a viable option to retrofit existing fossil fuel powered generation systems. This configuration will be investigated in this study. In the following section, a case study is given on an integrated solar thermal system with a coal-fired power station.

Case study: Mounting a 25MWe Linear Fresnel Reflector Solar Thermal plant next to Liddell coal-fired power station

Concentrated Linear Fresnel Reflector (CLFR) technology is used to generate direct steam to preheat feed water entering the reheating circuit of the Liddell coal fired power station. The Liddell power station is a 2000MW coal fired power station located in the upper Hunter Valley in New South Wales, Australia. The integration of a coal fired power station with solar thermal technology was the first in the world. Figure 4-3 shows a picture of the CLFR installation at the Liddell power station.

A company called Solar Heat developed the project in two phases. The first phase was aimed at demonstrating that the CLFR technology can generate steam at the required temperature while the second phase was aimed at proving that this technology could be integrated with a power station through a fully automated process. The first phase commenced in 2003 and the second in 2005. A total of 18,000 square meters of mirror collectors were installed, producing steam at 285°C, an ideal temperature for this application (Clarke, 2010). The current installed capacity of the CLFR plant is about $9MW_{th}$ with an expansion planned for 2011 to double this capacity (Clarke, 2010).

The CFLR plant injected main boiler steam directly into the main boiler and reduced the amount of thermal energy that is used to produce steam on the plant side of the heat exchanger. It was estimated that over the 20-year life of the plant, 144,000 tonnes of carbon dioxide emissions will be saved.

The estimated Levelised Cost of Energy (LCOE) is 6.28 Australian Dollar cents per kWh and the project has a payback period of just less than 5 years (Mills, Morrison, & Le Lievre, 2003). The estimated LCOE is well below the long-term generation cost for trough, tower and PV systems.

The calculated efficiency (from direct beam radiation to electricity) is 15% in summer with an annual average of 12%. Although the overall efficiency is lower than that achieved by parabolic trough technology, the CLFR technology has certain features that could lead to a better system cost to performance ratio. These features include:

- Flat mirror reflectors are used instead of more costly curved glass reflectors;
- The heat transfer loop is separated from the reflector and therefore there is no need for high pressure and high temperature rotating joints; and
- The reflector structures are modest as it is near the ground, unlike parabolic trough structures. (Mills, Morrison, & Le Lievre, 2003).

Figure 4-3: CFLR installation at the Liddell power plant.

Source: (Harris, 2007)

CHAPTER 5: MODELLING METHODOLOGY

This chapter addresses the second step of the research methodology shown in Figure 1-2. To meet the objectives of this study, it was necessary to do technical modelling of the energy output of a reference CSP plant as well as cost modelling. In this chapter the modelling methodology is given. The objectives satisfied by the technical and cost modelling include (see Section 1.4 for the complete list of objectives for this study):

- To model the energy output for a preferred reference CSP plant located around the largest industrial areas of South Africa;
- To use the energy output generated and to do cost and financial modelling;
- To compare costs with other technologies (conventional and new); and
- To compute the potential GHG emission reductions.

Figure 5-1 shows a schematic illustration of the technical and cost modelling approach taken.

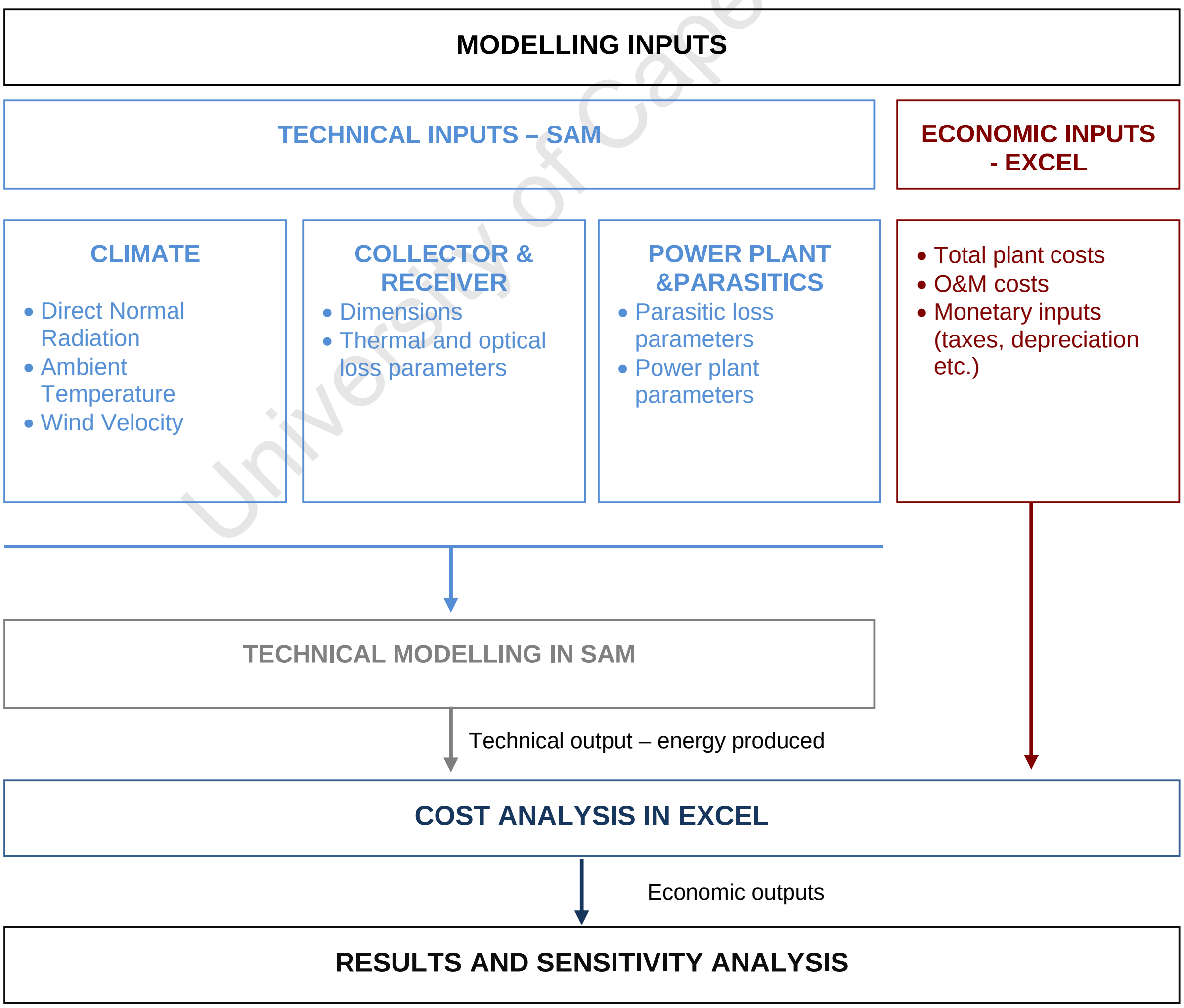


Figure 5-1: Schematic illustration of the modelling approach taken.

The Solar Advisor Model (SAM) software was used to calculate the thermal energy and/or power output from the parabolic trough plant. The SAM software was used, as it is a reliable, the most up to date and a free software package. The amount of energy produced was then used in an Excel model to estimate the cost of energy and a number of scenarios were investigated.

5.1 METHODOLOGY USED FOR TECHNICAL MODELLING

In the following section, the methodology used for the technical modelling of the energy output is discussed. The SAM software used for the modelling is discussed first.

5.1.1 Overview of the SAM

The National Renewable Energy Laboratory (NREL), in collaboration with Sandia National Laboratories in the United States, developed SAM. The development of the SAM software started in 2004 and has evolved as a reliable model that is being used worldwide for planning and evaluating research and for developing cost and performance estimates for solar projects (NREL, 2009). SAM is used to simulate a number of solar technologies including PV, however only SAM's parabolic trough performance model will be used for this study. The performance model uses TRNSYS simulation to make hourly energy calculations. These values are then passed on to the cost, incentive and financial modules to generate annual cash flows and to calculate the LCOE (NREL, 2009).

There are three main modules under the performance model and each has its own separate input page. These three modules are outlined below:

- The **solar field module** calculates the solar field thermal energy output. Weather data from weather files together with solar field parameters are used to calculate the solar thermal energy output. Thermal and optical losses, solar field warm-up energy and freeze protection energy are also taken into consideration by this section. (NREL, 2009).
- The **storage and dispatch module** calculates the energy flowing in and out of the thermal energy storage system. Parameters from SAM's storage input page are used as input to this module. In this module, the storage related thermal and parasitic losses and freeze-protection energy are also included.
- The **power block** calculates the electric output from the thermal energy coming from the storage and dispatch unit. In cases where pure solar thermal applications are considered, the power block will not be considered in the analysis.

Figure 5-2 (NREL, 2009) shows the block diagram for the SAM. The SAM is divided into three main modules: solar field, storage and dispatch and the power block. Each module is discussed in detail in Appendix B. The three modules, the flow of energy and the input parameters should be noted.

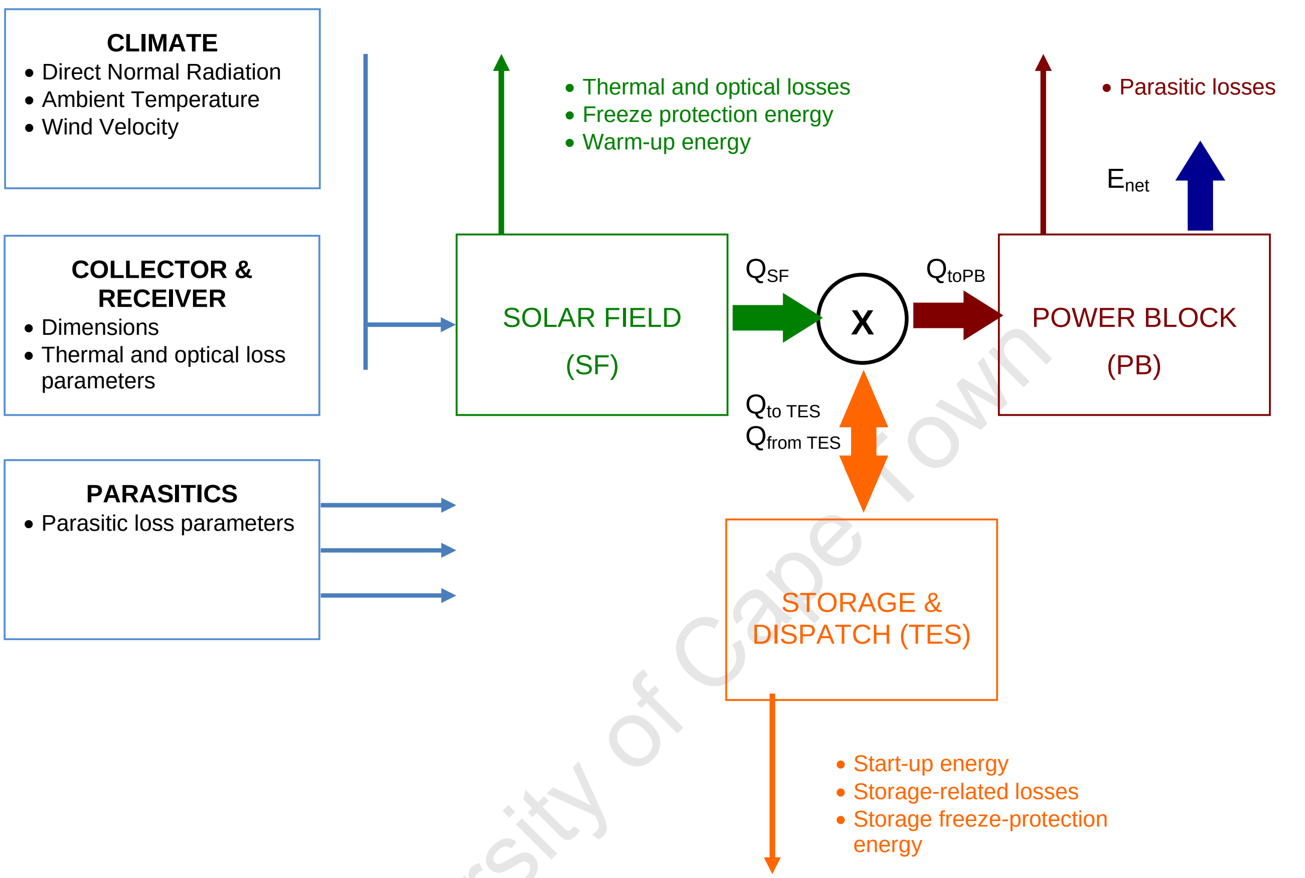


Figure 5-2: SAM block diagram.

Source: (NREL, 2009)

In the following section, the modelling results from the SAM are discussed.

5.1.2 SAM results

SAM displays various results on an hour-by-hour basis and it is possible to export these results to an Excel spreadsheet. Some of the useful variables that will be extracted from the technical analysis conducted by SAM are summarised in Table 5-1. Some of these variables were used in a separate Excel sheet to conduct cost calculations for various scenarios. Although SAM allows for comprehensive cost and financial analysis, it is geared towards United States taxes and depreciation laws and will therefore not be used for the analysis conducted here. The most important outputs from SAM are summarised in Table 5-1.

Table 5-1: Summary of the most important output variables from SAM.

Source: (NREL, 2009)

Name	Abbreviation in SAM	Description
Energy delivered by solar field	Q_{SF}	The thermal energy delivered by the solar field (MW_{th}).
Net electric output	E_{Net}	Net hourly electric output by the turbine from both solar and fossil fuel sources (MW_e).
Energy to the power block	Q_{to_PB}	The thermal energy that is delivered to the power block. This energy may include energy from the solar field and/or energy from the TES (MW_{th}).
Excess electricity	E_{Dump}	When the gross solar output is greater than the maximum design output, the difference is named the excess electricity (MW_e).

5.2 METHODOLOGY USED FOR COST MODELLING

For the cost and scenario analyses performed in this research, it was necessary to use a **reference plant** with reliable cost and performance data for a CSP plant.

A study was recently conducted by the National Renewable Energy Laboratory (NREL), in partnership with engineering consultants WorleyParsons Group Inc, to conduct a cost study for a **100MW_e parabolic trough CSP plant**. This plant, located in southwest Arizona in the United States of America (USA), has a storage capacity of six hours and both wet and dry cooling were considered (Turchi, 2010). The data used for the NREL/WorleyParsons study was also used for this study, as this is the most up to date data currently available. The costs reflect recent commodity price fluctuations as a result of the recent economic downturn. Adjustments to the NREL/WorleyParsons data were made to account for the fact that the reference plant would be located near Johannesburg in South Africa. Adjustments to the costs were made using adjustment factors that were developed by the Electric Power Research Institute (EPRI). The methodology that was used in the study, *"Power Generation Technology Data for Integrated Resource Plan of South Africa"* (EPRI, 2010), for making adjustments to the costs was also used in this study and is discussed below.

Reasons for choosing the parabolic trough technology as a high temperature solar system include that it is the most mature technology of all CSP technologies (Turchi, 2010) and that it can supply thermal heat within the required temperature ranges. Another reason is that more than 500MW of parabolic trough plants are already in operation in Spain and in the United States. Moreover, several gigawatts of parabolic trough plants are currently in the planning phase in a number of countries (Turchi, 2010). The Solar Advisor Model (SAM) is capable of doing comprehensive technical analysis of the performance of parabolic trough plants. It was not possible to create a reliable technical model for another technology (e.g. linear Fresnel) for this study.

5.2.1 Adjustments to costs

Adjustments to total plant costs

In the EPRI report on "*Power Generation Technology Data for Integrated Resource Plan of South Africa"* (EPRI, 2010) factors were used to covert construction costs for the USA to the cost of construction in South Africa. Table 5-2 presents factors for materials, labour productivity and labour rates. It should be noted that construction material costs are more or less the same as in the USA. South Africa has a lower labour productivity and therefore the number of hours required for construction is expected to be significantly more. The lower labour productivity in South Africa is offset by a lower labour rate than in the USA.

Table 5-2: Construction adjustment factors for converting USA to South African costs.

Source: (EPRI, 2010)

	Materials	Labour Productivity	Labour Rate
Value Used	1.00	2.10	0.65

In the EPRI report (2010), assumptions are made about the fraction of the equipment imported and the fraction supplied locally. For a parabolic trough plant, the following assumptions are made:

- 50% of the equipment is imported;
- 50% of the equipment is sourced locally;
- 45% of the material issourced locally; and
- 55% of the construction labour is sourced locally.

The US-based costs from the NREL study: "*Parabolic Trough Reference Plant for Cost Modelling with the Solar Advisor Model*", were converted to South African costs using the process shown in Figure 5-3. This process include the following:

- The first step involved breaking down the TPC into its local and imported portion of the costs;
- Imported costs were assumed to be from the USA and prices were kept in USD terms;
- The local portion of the costs was broken into materials and labour, and the factors from Table 5-2 were applied to these costs;

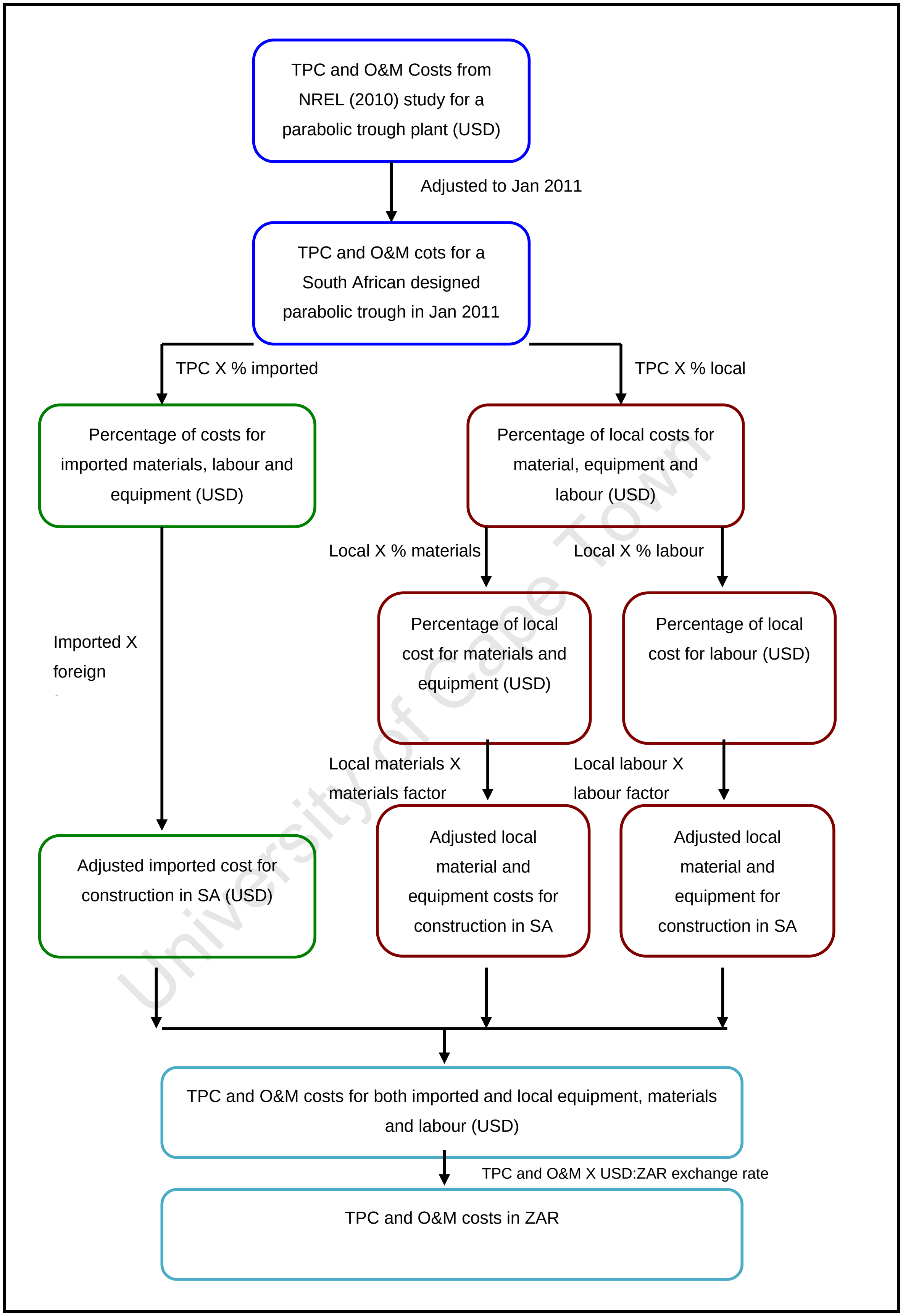


Figure 5-3: Methodology used for estimating capital costs.

Source: (EPRI, 2010)

- The local and imported costs were then combined and calculated in USD terms. In the final step, the costs in US dollars were converted to South African Rands (ZAR) using an exchange rate that equals the average for the year 2010. The exchange rate used was 7.33 ZAR/USD.

Adjustments to operations and maintenance costs

The O&M costs were also adjusted to South African currency and conditions. The US based O&M costs from the NREL study: "*Parabolic Trough Reference Plant for Cost Modelling with the Solar Advisor Model",* were used as a baseline. O&M costs are split into fixed and variable components. Fixed O&M costs were adjusted by using the same adjustment factors that were used to adjust TPC costs (Table 5-2). The O&M costs were converted to South African currency using an exchange rate of 7.33 ZAR/USD.

CHAPTER 6: MODELLING INPUTS FOR THE CSP TROUGH SIMULATION

In this Chapter, the inputs used for modelling the energy/power outputs and costs are discussed. This chapter addresses the third step of the research approach shown in Figure 1-2. The following sections are covered in this chapter:

- Technical inputs;
- Economic and cost inputs; and
- The scenarios investigated.

6.1 TECHNICAL INPUTS

The reference plant for this model was a parabolic trough plant with a 100MW capacity and six hours of storage in southwest Arizona in the United States. For this study, however, the plant (with the same design) would be located near Johannesburg in South Africa as this study investigates the opportunity for high temperature process heat/steam for industrial processes. Johannesburg is located in the most concentrated industrial area of South Africa as shown in this section. In this section weather data, baseline trough plant specifications, as well as collector and receiver, power plant and parasitic inputs are given and discussed.

6.1.1 Weather data

This study investigates concentrated solar thermal technologies that can be used to generate industrial process heat and therefore a location near the most important industrial area in South Africa was chosen. Figure 6-1 shows a map of South Africa's most important industrial areas and mines. The area around Gauteng is the most concentrated industrial area in South Africa with many industries, including the petrochemical giant, Sasol, a base metal refinery (Rustenburg Base Metal Refinery) and numerous power stations in close proximity. For this reason the weather data for Johannesburg was chosen as input into SAM. As a rule of thumb, weather data are more or less consistent within a 50km radius from the reference point. The hourly weather data for Johannesburg is also freely available from the EnergyPlus weather data website (online: www.eere.energy/gov/buildings/energyplus/cfm/weather_data.cfm).

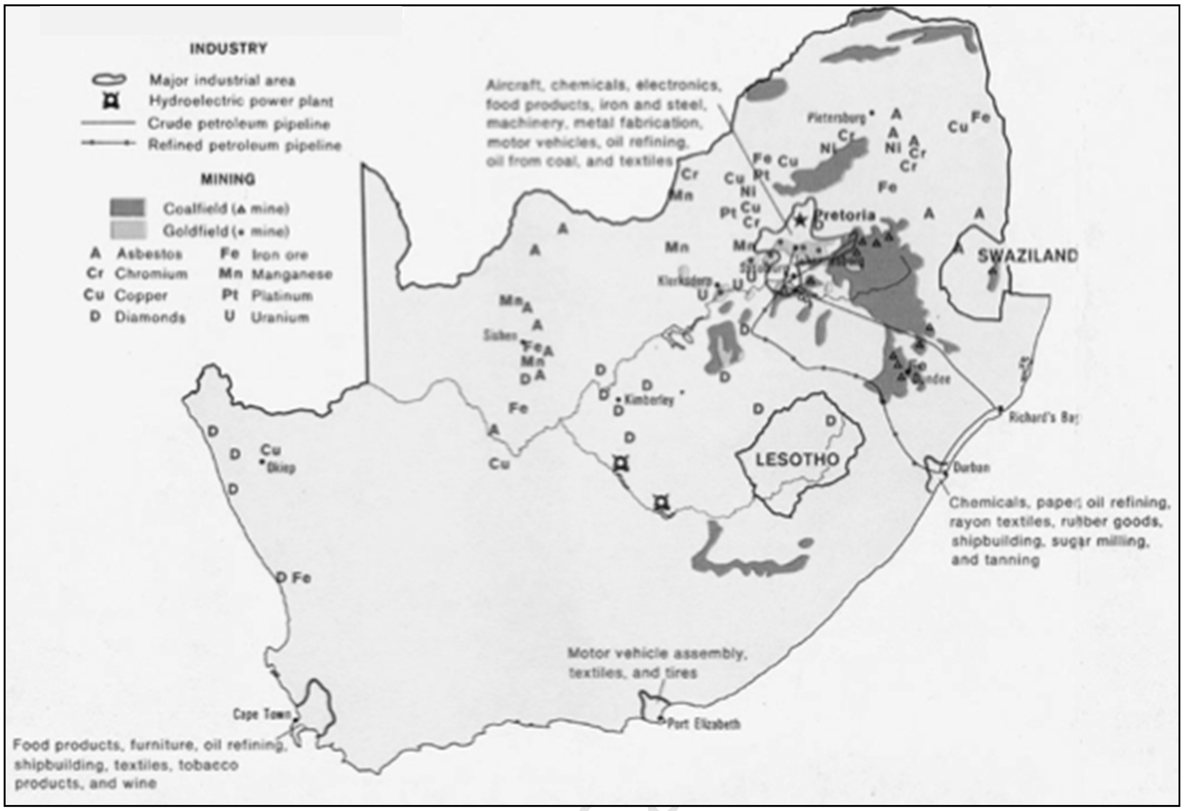


Figure 6-1: Map of South Africa's main industrial and mining locations.

Table 6-1 shows information for the location and annual weather data for Johannesburg. The annual weather data was computed by SAM from hourly weather data imported from the EnergyPlus weather data website.

Table 6-1: Summary of weather data for Johannesburg as computed by SAM.

Location details	
City	Johannesburg
Timezone	GMT + 2
Elevation	1700 m
Latitude	26.13 ° South
Longitude	28.23 ° East
Annual weather data Information	
Direct Normal Irradiance (DNI)	1781.7 kWh/m^2
Global Horizontal Irradiance	1975.0 kWh/m^2
Dry-bulb temperature	15.8 °C
Wind Speed	3.2 m/s

6.1.2 Baseline trough plant specifications

The reference parabolic trough plant specifications are given in Table 6-2. WorleyParsons conceptually designed the solar trough plant for NREL in 2009. The same technical input parameters were used in this study.

Table 6-2: Reference parabolic trough plant specifications.

Source: (Turchi, 2010)

Parameter	Value
Nameplate capacity	$100MW_e$
Thermal storage (operating time possible at the nameplate capacity)	6 hours
Solar Multiple	2
Heat Transfer Fluid	Synthetic oil
Storage Fluid	Binary Na/K nitrate salt
Thermal Storage system	Indirect 2-tank system
Power cycle	Superheated steam Rankine cycle with wet cooling
Location	Johannesburg, South Africa

6.1.3 Solar field specifications

In the solar field section of SAM's user interface, variables and options are used to characterize the size and the properties of the solar field and the heat transfer fluid used. For the reference plant, a solar multiple of 2 was specified. This multiple is used to calculate the solar field area required to drive the power cycle at its design capacity and design conditions. The mirror washing variables are used to determine the quantity of water required. Table 6-3 shows the solar field specifications used for the reference CSP trough plant.

Table 6-3: Solar field specifications

Input	Value	Reference/Comment
Layout mode	Solar Multiple	(NREL, 2009)
Row Spacing	15 m	(WorleyParsons Group, 2009)
Stow Angle	170 °	(NREL, 2009)
Deploy angle	10 °	(NREL, 2009)
Solar Field	H layout	(NREL, 2009)
Header pipe roughness	4.57e-05 m	(NREL, 2009)
HTF pump efficiency	0.85	(NREL, 2009)
Freeze protection temperature	37.8 °C	(WorleyParsons Group, 2009)
Irradiation at design	950 W/m^2	(NREL, 2009)
Field Heat Transfer Fluid	Therminol VP-1	(NREL, 2009)
Design loop inlet temperature	293 °C	(WorleyParsons Group, 2009)
Design loop outlet temp.	393 °C	(WorleyParsons Group, 2009)
Min single loop flow rate	1 kg/s	(NREL, 2009)
Max single loop flow rate	12 kg/s	(NREL, 2009)
Header design min flow velocity	2 m/s	(NREL, 2009)
Header design max flow velocity	3 m/s	(NREL, 2009)
Initial field temperature	25 °C	Room temperature
Water used per wash	0.7 liter/m^2 of aperture	(NREL, 2009)
Washes per year	63	(NREL, 2009)

6.1.4 Solar collector assembly specifications

The Solar Collector Assembly (SCA) of the trough plant includes the mirrors, supporting structures and the receivers. The same collector type, used in the WorleyParsons study to compile the cost of the CSP trough plant for NREL, was used as the basis for the reference design. The input variables used are given in Table 6-4. SAM assumes that the field consists of identical loops.

Table 6-4: SCA specifications

Input	Value	Reference
Reflective aperture area	817.5 m^2	(WorleyParsons Group, 2009)
Aperture width, total structure	5.75 m	(WorleyParsons Group, 2009)
Length of collector assembly	150 m	(WorleyParsons Group, 2009)
Number of modules per assembly	12	SAM library
Average surface-to-focus path length	2.11	SAM library
Piping distance between assemblies	1	SAM library

6.1.5 Heat collection element (HCE) specifications

The Heat Collection Element (HCE)/receiver is made of a metal pipe contained within a vacuum that runs through the focal line of the collector. On the Receiver input page in SAM, the option exists to choose from four different receiver types. The Schott PTR70 2008 receiver type was chosen for the baseline design. Data from the SAM database is used to populate the input variables used for heat transfer and thermodynamic calculations. The most important input variables used are summarised in Table 6-5.

Table 6-5: HCE/Receiver specifications.

Input	Value	Reference
Configuration name	Schott PTR70 2008	SAM library
Absorber tube inner diameter	0.066 m	SAM library
Absorber tube outer diameter	0.07 m	SAM library
Glass envelope inner diameter	0.115 m	SAM library
Glass envelope outer diameter	0.12 m	SAM library

6.1.6 Power cycle specifications

In the power block, thermal energy is converted into electricity using a steam Rankine power plant. In SAM the option exists to use either an evaporative cooling system for wet cooling or an air-cooled system for dry cooling. As South Africa is a water scarce country it was decided to use an air-cooled system for the baseline study. The study used a design gross output of $110MW_e$ for the baseline scenario. The design gross output does not account for parasitic losses and SAM uses this value to size system components such as the solar field (NREL, 2009). Table 6-6 shows the input variables used for the reference CSP trough plant.

Table 6-6: Power cycle input variable.

Input	Value	Reference
Design gross output	110 MW_e	(NREL, 2009)
Estimated gross to net conversion factor	0.9	(NREL, 2009)
Rated cycle conversion efficiency	0.3548	SAM library
Boiler operating pressure	100 bar	SAM library
Heat capacity of balance of plant	5 $kWh_t/K\text{-}MWh_e$	SAM library
Cooling system	Air cooled	Input choice
Ambient temperature at design	25 °C	Average temperature of Johannesburg

6.1.7 Thermal energy storage specifications

The Thermal Energy Storage (TES) system of the plant is used to store heat from the solar field in a liquid medium for times when the energy from the solar field is no longer available or not sufficient. The hot liquid is stored in tanks. For the reference plant, 6 hours of full load TES have been specified and binary Na/K nitrate salt (or solar salt) was specified as the storage heat transfer fluid. The properties of the solar salt are stored in SAM's database and are used for thermodynamics and heat transfer calculations. The input variables used for thermal energy storage are shown in Table 6-7.

Table 6-7: Thermal energy storage input variables.

Input	Value	Reference
Full load hours of TES	6 hr	(WorleyParsons Group, 2009)
Storage heat transfer fluid	Binary Na/K nitrate salt	(NREL, 2009)
Parallel tank pairs	2	(NREL, 2009)
Tank height	20 m	(NREL, 2009)
Tank loss coefficient	0.4 $W/m^2\text{-}K$	(NREL, 2009)
Initial TES fluid temperature	300 °C	(NREL, 2009)

6.1.8 Parasitics specifications

Parasitics refer to electrical loads in the system that reduces the electrical output of the system. Piping thermal losses, power used for tracking and pumping are all examples of parasitics.

Table 6-8 shows the input variables for the parasitics specified.

Table 6-8: Input variables for parasitics.

Input	Value	Reference
Piping thermal loss coefficient	0.45 W/m^2-K	SAM
Tracking power	125 W/SCA	SAM
Required pumping power for HTF through power block	0.55 kJ/kg	SAM
Fraction of rated gross power consumed at all times	0.15 kJ/kg	SAM

6.2 COST INPUTS

The costs used in this study are from the WorleyParsons report for the NREL study: "*Parabolic Trough Reference Plant for Cost Modelling with the Solar Advisor Model*" and are based on an Engineer-Procure-Construction-Management (EPCM) approach. Costs are considered to be ±30% accurate (WorleyParsons Group, 2009). All the costs are expressed in January 2010 costs and in United States Dollars (USD). These costs were then adjusted to reflect the cost of construction in South Africa and the cost in local South African currency (ZAR). Total Plant Cost (TPC) (also called total capital costs) and Operation and Maintenance (O&M) costs are given as overnight costs. Overnight costs do not include interest on financing costs as it is assumed that the plant is built overnight. The TPC for the plant include:

- Equipment;
- Materials;
- Labour (direct and indirect);
- EPCM; and
- Contingencies. (EPRI, 2010).

The TPC estimates do not include owner's costs or government tariffs that may be incurred for imported equipment, material or labour. The cost of shipping was included in the cost of equipment. The methodology for adjusting the costs is given in Section 5.2.1.

6.2.1 Costs before and after adjustments

A summary of the TPC and O&M costs are given in Table 6-9 and Table 6-10 respectively. The values for the USA (second column) are from the NREL study: "*Parabolic Trough Reference Plant for Cost Modelling with the Solar Advisor Model*". The values for South Africa (fourth column) were calculated using the methodology given in Section 5.2.1 and were inflated to reflect prices for January 2011. The units presented in these tables are in line with the units required for input into SAM.

Table 6-9: Total Plant Costs in the USA and adjusted for South African construction and currency.

DIRECT COSTS (DC)	VALUE (USA) (Turchi, 2010)	UNITS – USA	VALUE (RSA) (Calculated)	UNITS – RSA
Site Improvements	28	USD/m^2	237	ZAR/m^2
Solar Field	295	USD/m^2	2560	ZAR/m^2
HTF System	90	USD/m^2	780	ZAR/m^2
Storage	81	USD/kWh_t	672	ZAR/kW_t
Fossil Backup	0	USD/kW	0	ZAR/kW
Power Plant (dry-cooled)	1160	USD/kW	7388	ZAR/kW
Contingency	10	% of DC	10	% of DC
INDIRECT COSTS (IC)				
Engineer-Procure-Construct	14.8	% of DC	14.8	% of DC
Project, Land, Management	3.9	% of DC	3.9	% of DC
Sales Tax/VAT	6.5	%	6.5	%

Table 6-10: Operations and Maintenance costs in the USA and adjusted for South African construction and currency.

O&M COSTS	VALUE (USA) (Turchi, 2010)	UNITS – USA	VALUE (RSA) (Calculated)	UNITS – RSA
Fixed Annual Cost	0	USD/yr	0	ZAR/yr
Fixed Cost by Capacity	69	USD/kW-yr	583	ZAR/kW-yr
Variable Cost by Generation	2.5	USD/MWh	19	ZAR/MWh
Fuel Cost	0	USD/MMBTU	0	ZAR/MMBTU

6.3 ECONOMIC INPUTS

In this section, an overview of the economic inputs is given where after the method used for calculating the cost of energy is discussed.

6.3.1 Economic inputs

The parameters shown in Table 6-11 were used for the economic analyses.

Table 6-11: Economic Inputs.

Parameter	Value	Reference
Percentage of Debt	60%	(EPRI, 2010)
Cost of Debt (real terms)	7.3%	(EPRI, 2010)
Common Stock (Equity)	40%	(EPRI, 2010)
Cost of Equity (real terms)	10.6%	(EPRI, 2010)
Inflation Rate	4.5%	(Winkler, 2007)
Income tax rate		
Discount Rate	8%	(Winkler, 2007)
Book Life	30 years	(EPRI, 2010)
Plant availability	96%	(Turchi, 2010)
Project schedule	4 years	(EPRI, 2010)
Expense schedule, % of TPC per year	10%, 25%, 45%, 20%	(EPRI, 2010)

According to Winkler (2007) the inflation rate of South Africa is expected to remain between 4 and 5% and therefore a value of 4.5% was used in this study. The discount rate is an important parameter that will greatly influence the economic outcome of a project. The discount rate reflects the preference of money (i.e. money today is preferred to money in the future) (Winkler, 2007). For this study it was decided to use a discount rate of 8% for all scenarios. EPRI (2010) uses a book life of 30 years for solar thermal trough plants and this was also used for this study together with a straight-line depreciation of 3.33% per annum. There are two types of depreciation. Book depreciation is the first type and is a measure of the extent to which the value of the plant declines. The second type is tax depreciation and is used for income tax calculations.

Return on Equity

For this study it is assumed that issuing equity in the project will finance 40% (EPRI, 2010) of the project. Equity comes at a cost as equity holders earn a return on their investment in the project. 10.6%, in real terms, was used in the Integrated Resource Plan for South Africa (EPRI, 2010). This value was also used for this study.

Cost of Debt

For this study it was assumed that debt financing would cover 60% of the TPC. Numerous financing instruments can be used for debt financing including loans, bonds etc. and interest is payable on all of the outstanding amounts of the debt. 7.3% (real terms) (EPRI, 2010) was used for the cost of debt.

Income Taxes

The income taxes paid depend on the tax rate and the taxable income. Income taxes will therefore only be payable where the utility is sold to another party, for example when electricity is sold. Where electricity and/or thermal heat are generated for own consumption, no income taxes will be applicable. The income tax rate used for this study was 28% (EPRI, 2010).

Property taxes and insurance

Insurance and property taxes are calculated as the product of the insurance and property tax rates and the total capital required.

6.3.2 Cost of energy calculation

The capital and O&M costs and the performance of a plant is combined in a cost of energy calculation to yield a cost per megawatt-hour basis. This calculation makes it possible to compare different technologies across a number of sizes and operating conditions. The cost of energy consists of three cost components, namely the capital cost, the O&M cost and the fuel costs. To calculate the cost of energy, the costs must be combined to yield the cost of energy that is normally quoted as ZAR/MWh in South Africa (EPRI, 2010). The following all contribute to the cost of energy calculation.

Annual Megawatt-hours produced

The amount of energy produced by a plant during a given year is a key component of the levelized cost of energy. The capacity factor of a plant is the ratio of the actual amount of energy produced over the maximum of energy that could be produced if the plant was to operate at full load for every hour there is in a year (i.e. 8760 hours). SAM calculates the amount of energy that is produced in the form of thermal energy or electricity. This value was then used for cost of energy calculations.

Real vs. nominal value of money

The cost of energy is often presented on a levelised basis. The levelised cost of energy is the cost of energy required annually to achieve that same present value as the actual capital (TPC) and O&M costs of the plant. Levelised cost of energy can be quoted as either real or nominal values. Real values do not take the effect of inflation into consideration, while nominal values do take the effect of inflation into consideration. Nominal values are always higher than real values as the costs are inflated on a year-by-year basis under the nominal method. Both methods are used in industry, but it is important to compare costs where the same method has been applied.

Capital contribution to Cost of Energy

The capital costs or the Total Plant Costs (TPC) are broken down in Table 6-9 and are presented in ZAR/m^2 or ZAR/kW. These costs can be multiplied by the overall size of the plant (in m^2 and kW where applicable) to determine the cost on a South African Rand (ZAR) basis. This value is then divided by the amount of megawatt-hours produced and the capital costs or TPC are presented on a ZAR/MWh basis.

O&M Contribution to Cost of Energy

Fixed O&M costs are presented in Table 6-10 on a Rand per kilowatt-year basis. The fixed O&M costs can be converted to a rand basis by multiplying by the kilowatts generated per year. The fixed O&M cost of energy is then calculated by dividing by the annual MWh output of the plant.

The variable O&M costs are presented in Table 6-10 in ZAR/MWh and therefore do not need to be converted.

Fuel contribution to Cost of Energy

Where fuel is used in certain technologies, the annual cost of fuel is calculated by multiplying the fuel in Rand per gigajoule by the heat rate of the plant.

Cost of greenhouse gas emissions

To help reduce GHG emissions, economic policy instruments such as carbon tax and emissions trading schemes can be introduced. Carbon taxes encourage behavioural change that in turn encourages lower emissions. Numerous countries around the world have recognized the importance of these two instruments, and South Africa is currently investigating the option to introduce a carbon tax (Department of National Treasury, 2010) The purpose of carbon tax is to reduce emissions through a price mechanism directly. Some of the scenarios investigate the impact that carbon tax has on the cost of energy for conventional energies used to generate thermal heat and steam (i.e. electricity and coal-fired boiler plants). To calculate the effect that carbon tax has on the cost of carbon intensive technologies, the emissions per unit of energy generated were first calculated. The formula for calculating the cost is shown in Equation 6-1.

Cost Per Annum = [Energy Produced Per Annum] X [Emission Factor] X [Cost of CO_2]

Equation 6-1

For electricity generation, the average emissions from coal-fired plants in South Africa are 0.993 kg CO_2 – equivalent per kWh of electricity produced (Eskom, 2009).

Industrial coal-fired boilers, used for process heat and steam generation, have average operating efficiencies ranging between 80 to 90% (Fang, Zeng, Yang, Oye, Sarofim, & Beer, 2008). A value of 85% was used in this study to calculate emissions. An emission factor used by Eskom for South African coal is 25.8 tonnes CO_2/TJ of heat produced by coal (Eskom, 2009).

Figure 6-2 shows the carbon emissions tax proposed for South Africa by the Department of Energy (DOE) that was used for this study.

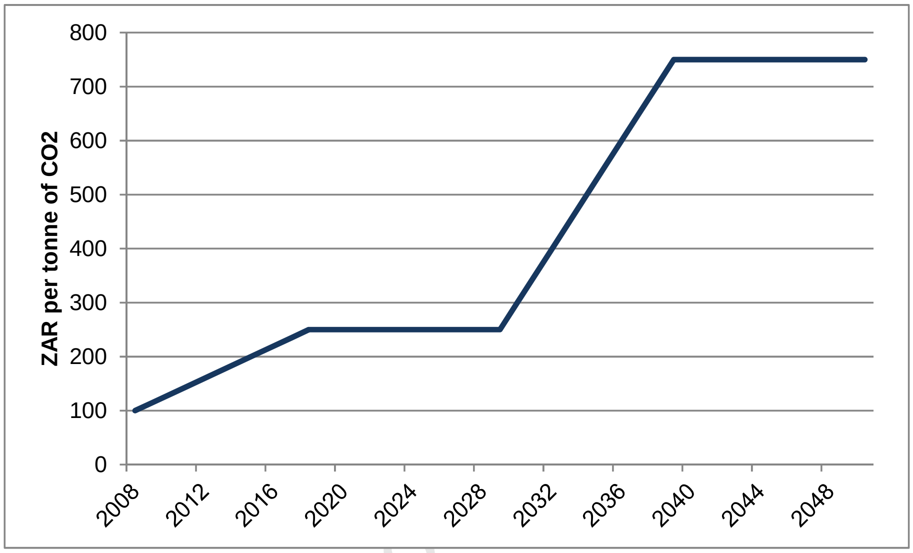


Figure 6-2: Estimated carbon emissions tax for South Africa.

Source: (DOE, 2010)

Technology learning

The cost of technology change over time and often, new technologies get cheaper as the total installed capacity increases. Two reasons for new technologies getting cheaper over time include learning by doing and economies of scale (Winkler, 2007). The cost of technology will not decline indefinitely and will slow as technologies reach their maximum global capacities. The learning in mature technologies will normally slow and will tend to zero. For this study the learning rate for coal generated electricity was assumed to be zero while the learning rates for the different components of CSP plants were adopted from Trieb et. al. (2009). The learning curves for the different components are shown in Figure 6-3.

The learning curve is the ratio of the cost in year x (c_x) to the cost in year 0 (c_0). The cost as a function of time was calculated from the total installed capacity (P) as a function of time (x) and from the progress ratio (PR). The equation used for calculating the ratio of c_x:c_o is shown in

Equation 6-2 (Trieb et. al., 2009). P_0 is the installed capacity at the starting year (2005) where P_x is the predicted installed capacity in year x.

$$\frac{C_x}{C_o} = \left(\frac{P_x}{P_o}\right)^{\log\left(\frac{PR}{2}\right)} \qquad \text{Equation 6-2}$$

The progress ratio (PR) is used to calculate the amount by which the specific investment is reduced by each time the global installed capacity doubles. For example a 90% PR means that the specific investment cost will reduce by 10% each time the global installed capacity doubles.

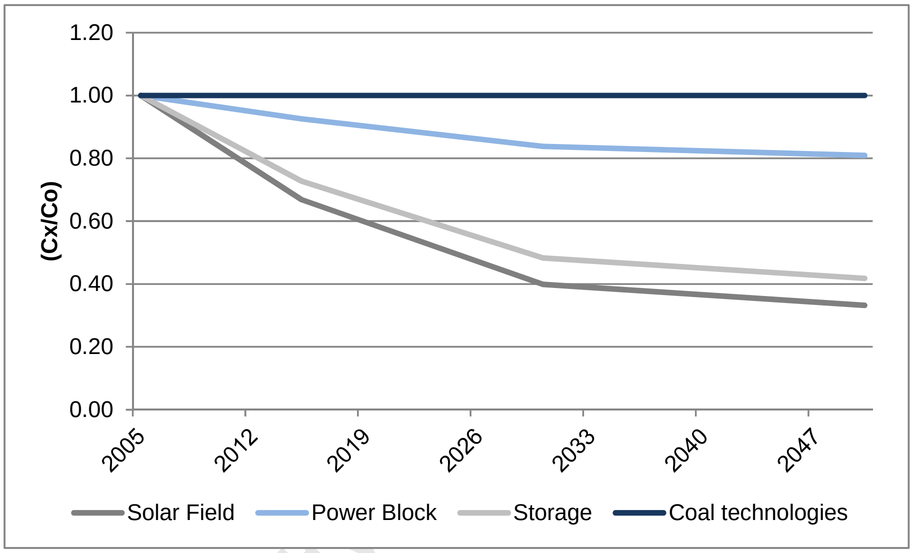


Figure 6-3: Learning rates for the components of CSP plants and for coal technologies.

Source: (EPRI, 2010)

The PR values and estimates for installed capacity, used for calculating the learning rate are given in Table 6-12. Current parabolic trough technology, molten salt storage and steam cycle power block with dry cooling tower are taken as reference.

Table 6-12: Start value C_0 (2005), progress ratio (PR) and future costs for CSP plant components.

Source: (EPRI, 2010)

Year	PR	2005	2015	2030	2050	Unit
World CSP Capacity		354	5000	150000	500000	MW
Solar Field	90%	360	241	144	120	€/m^2
Power Block	98%	1200	1111	1006	971	€/kW
Storage	92%	60	44	29	25	€/kWh

6.3.3 Cost of coal in South Africa

Coal is the primary energy source in South Africa and it is important to understand the cost thereof as well as to investigate cost projections for coal in South Africa. The projection for the cost of coal is used in the next chapter to make comparisons to the cost of concentrated solar technologies. The cost of coal for power production in South Africa used in this study was ZAR 15/GJ and the energy content was estimated to be 19,220 kJ/kg. This cost was estimated by EPRI in their report called *"Power Generation Technology Data for Integrated Resource Plan of South Africa"* (EPRI, 2010) and it was assumed that it would not increase beyond general inflation.

For the scenario analysis, it was important to consider the impact that an increase in the cost of coal would have should it increase beyond general inflation. Forecasting the price of coal in South Africa is not straightforward and it is dependent on the category of contract (short, medium or long term). Eskom, the main purchaser of coal for power in South Africa, does not disclose the price of coal, as this is commercially sensitive information. About 80% of the volume of coal purchased by Eskom comes from long-term contracts, while the difference comes from medium and short-term contracts. Coal purchased in terms of medium- or short-term contracts is market-related and therefore more expensive. The price of coal purchased from cost-plus contracts is dependent on operational cost and is dependent on certain cost drivers including labour prices and O&M costs. Eskom is therefore at risk in terms of variations in cost. The prices for coal purchased from existing long-term contracts are dependent on the fixed-priced/indexed-based and escalation indices specified in contracts. Prices are projected for long-term contracts by considering forecasted price indices or specified indices as specified in the contracts 20 years ago (Eskom, 2009). These long-term contracts are partly the factor that enables Eskom to procure coal at prices well below export market prices. This could become a problem for Eskom in the future as coal producers could seek to export coal instead of supplying Eskom as long-term contracts come to an end.

No transparent projections for the cost of coal is available, however certain data were extracted from the *Multi-year Price Determination 2010/2011 to 2012/2012* report from Eskom (Eskom, 2009) that gives an indication of coal price escalations expected for the coming years. Table 6-13 gives a projection of the cost related to coal burning over the next few years. The cost of coal per tonne is expected to increase significantly, above inflation in the coming years.

Table 6-13: Primary energy cost projections from burning coal.

Source: (Eskom, 2009)

Primary Energy Costs R(m)	FY09/10	FY10/11	FY11/12	FY12/13	FY13/14	FY14/15
Coal Burn	20,569	25,120	29,030	33,600	38,733	44,253
Coal Handling	618	657	692	728	771	818
Fuel Procurement	643	670	650	660	780	770
Water Costs	1262	1550	2060	2310	2650	2990
Water treatment	225	232	233	246	249	263
Sorbent	0	0	0	40	190	434
Total coal related costs	24,485	29,500	34,004	38,984	44,917	51,134
Average Cost (c/kWh)	**11**	**13**	**15**	**17**	**19**	**20**

6.4 SCENARIO ANALYSIS

For this study, two scenarios are investigated. The first one is called the Base Case scenario and the second is the Solar Thermal Energy scenario. These two scenarios were performed to enable comparative analysis of both performance and cost. Results for technical and financial performance are given in the next chapter. A sensitivity analysis is also performed to investigate the impact that the cost of coal and the proposed carbon tax for South Africa will have on these two scenarios.

6.4.1 Base Case Scenario

The Base Case scenario is for a 100MW_e CSP parabolic trough plant located near Johannesburg in South Africa. Technical and financial inputs are given in previous sections in this chapter. Table 6-14 gives the main inputs for the Base Case scenario.

Table 6-14: Main inputs for the Base Case scenario.

	Value	Units
Nameplate capacity	100	MW_e
Thermal storage (operating time at nameplate capacity)	6	Hours
Solar Multiple	2	

6.4.2 Solar Thermal Energy Scenario

The Solar Thermal Energy scenario was used to determine the energy output, performance and costs for a plant with the same technical specifications as the Base Case plant, but without the Power Block. Therefore the specifications for the solar field and the capacity for the TES were the same. The main specifications for the Solar Thermal Energy scenario are given in Table 6-15 below.

Table 6-15: Main plant specifications for the Solar Thermal Energy scenario.

	Value	Units
Thermal storage (operating time at nameplate capacity)	6	Hours
Solar Multiple	2	
Annual Thermal Energy	812,000	MWh
Solar Field outlet temperature	393	°C

6.5 SENSITIVITY ANALYSIS

Two sensitivity analyses were performed on the financial results of the two scenarios discussed in Section 6.4. Firstly the impact of an increase in the coal price beyond general inflation was investigated and secondly, the impact of the proposed carbon tax was investigated.

6.5.1 Coal price sensitivity

As mentioned in Section 6.3.3, the cost of coal for power production in South Africa used in this study was ZAR 15/GJ and the energy content of coal was estimated to be 19,220 kJ/kg. The Base Case scenario assumed that this price would not increase beyond the average inflation of South Africa. It is evident from Table 6-14 that Eskom estimated that the price of coal would increase significantly in the future, so it is worth investigating the impact that an increase above inflation will have on the cost of electricity and thermal energy production in South Africa. Three scenarios were investigated:

- The cost of coal will increase on average 2% above inflation every year;
- The cost of coal will increase on average 5% above inflation every year; and
- The cost of coal will increase in line with Eskom projection until 2015. This assumes a real increase in the cost of coal as follows: 2011: 8.8%; 2012: 7.3%; 2013: 5.9% and 2014: 3.9% and thereafter at 2% per year.

The analysis was done by assuming that the escalation beyond inflation is only applicable to the contribution of the cost of coal (i.e. fuel cost) to the total cost of electricity from a coal-fired power station. The other variable costs and capital costs were kept constant. To determine the effect on the thermal energy, only the cost of coal (i.e. fuel cost) was escalated. The breakdown of the LCOE for the year 2010 was taken from the EPRI report and is given in Table 6-16.

Table 6-16: Breakdown of the LCOE generated from coal power.

Source (EPRI, 2010)

Breakdown of LCOE	ZAR per kWh
Fuel cost (i.e.) cost of coal	0.144
Variable Operating and Maintenance cost	0.036
Fixed Operating and Maintenance cost	0.051
Capital	0.322
LCOE	**0.553**

6.5.2 Carbon price sensitivity

To determine the contribution and sensitivity of the cost of electricity and thermal energy to the carbon price, the change in the LCOE was determined for both scenarios. The carbon emission prices given in Figure 6-2 together with the calculated carbon emissions savings from generating power from a CSP plant or from generating thermal energy from concentrated solar technologies instead of using coal could be used to calculate a levelised cost saving. The emissions factors for electricity generation and from sub-bituminous coal published by Eskom were used for these calculations. For electricity, a value of 0.963 kg of CO_2 per kWh was used and for sub-bituminous coal, 96,250 kg CO_2 per TJ of energy was used.

CHAPTER 7: RESULTS AND DISCUSSION

In this chapter the results are given for the technical and financial analysis outlined in the previous chapter. This section addresses both steps 4 and 5 of the research methodology shown in Figure 1-2. The models and are run and the outputs generated and the data is analysed. It can be assumed that the inputs of the models are the same as given in Chapter 6.

In the first section of this chapter, the weather and solar radiation results are given. These results will be the same for both case studies and sensitivity analyses, as the location for this study is fixed. In the following section, the results from the Base Case scenario are given. The Base Case scenario represents a Concentrated Solar Power plant. The second case study is for a Concentrated Solar Thermal plant with no power generation. For both these cases, results are given and discussed for the energy output, financials, emissions and water consumption.

As part of the financial analysis, the projected Levelised Cost of Electricity (LCOE) and Levelised cost of Thermal Energy (LCOTE) are given based on the learning rates. The final section presents sensitivity analyses related to carbon emissions tax and the price of coal.

7.1 WEATHER AND SOLAR RADIATION RESULTS

The weather results for Johannesburg are shown in Figure 7-1 and Figure 7-2. The details of the exact location are given in Table 6-1. The hourly monthly averages of the direct normal irradiance (DNI), the ambient temperature (°C) and the wind speed (m/s) are discussed in this section.

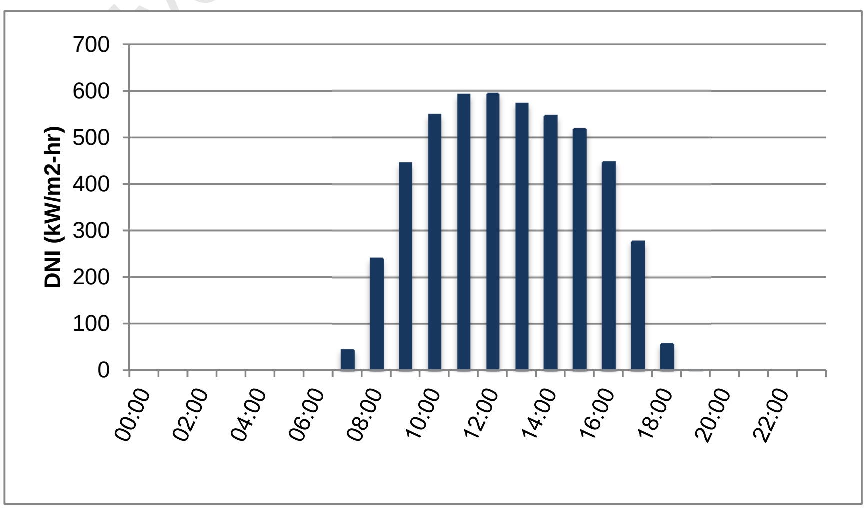


Figure 7-1: Hourly annual average DNI (kW/m^2-hr).

From Figure 7-1 it can be seen that the DNI for an average day increases sharply from 07:00 until it reaches a peak of 590 kW/m^2-hr between 11:00 to 12:00. After 12:00 it drops gradually until it reaches 450 kW/m^2-hr at 16:00 and then it drops to zero after 19:00.

The annual DNI of Johannesburg is relatively low when compared to locations with the highest DNI in South Africa. To put this into perspective, Johannesburg has an annual DNI of 1781.7 kWh/m^2 while Upington has an annual DNI of 2818.2 kWh/m^2 (source: SAM weather files).

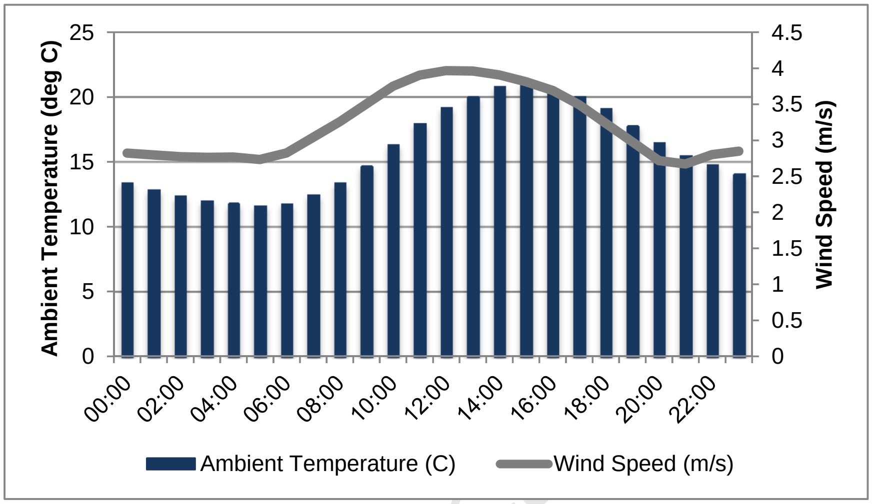


Figure 7-2: Hourly annual average ambient temperatures and wind speeds.

From Figure 7-2 a typical ambient temperature profile can be noted. The average temperatures reach a peak of 21°C at 15:00 and then it drops to 11.6°C at 05:00. Johannesburg experiences temperatures below 0°C at certain times of the year. This means that freeze protection in the solar plants is required. From Figure 7-2 it can also be noted that the average wind speed increases as the temperature and DNI increases. The wind speed has an adverse impact on the performance of solar plants as it decreases the amount of heat transferred to the receiver.

7.2 FLOW OF ENERGY FROM INCIDENT SOLAR TO NET ELECTRICITY

Figure 7-3 shows the energy flow from the incident solar radiation (or DNI) to the net electricity output for each month of the year. This graph shows the performance of the various sections of the plant for each month. Looking firstly at the DNI, it is evident that higher DNI is experienced over the summer months (October to January).

December is the month that receives the highest incident solar radiation with a total incident solar radiation of 1.80E+08 kWh. The total thermal energy captured by the solar field is 8.46E+07 kWh. The loss of energy in the solar field is mainly as a result of optical losses, thermal losses in the heat collector element (or receiver) and heat losses from the pipes and the heat transfer fluid. The total thermal energy entering the power block is 7.15E+07 kWh. The decline in thermal energy from the solar field to the thermal energy entering the power block is mainly as a result of losses from the thermal energy storage tanks and the energy that gets dumped or used for start-up energy in the power block. The amount of energy declines further to 2.53E+07 kWh of gross electric output from the power block. This reduction is mainly due to the low efficiency of the power cycle. The net electric output for December was 2.25E+07 kWh. The difference between the gross electric output and the net electric output is as a result of parasitics in the plant such as the power used for pumping.

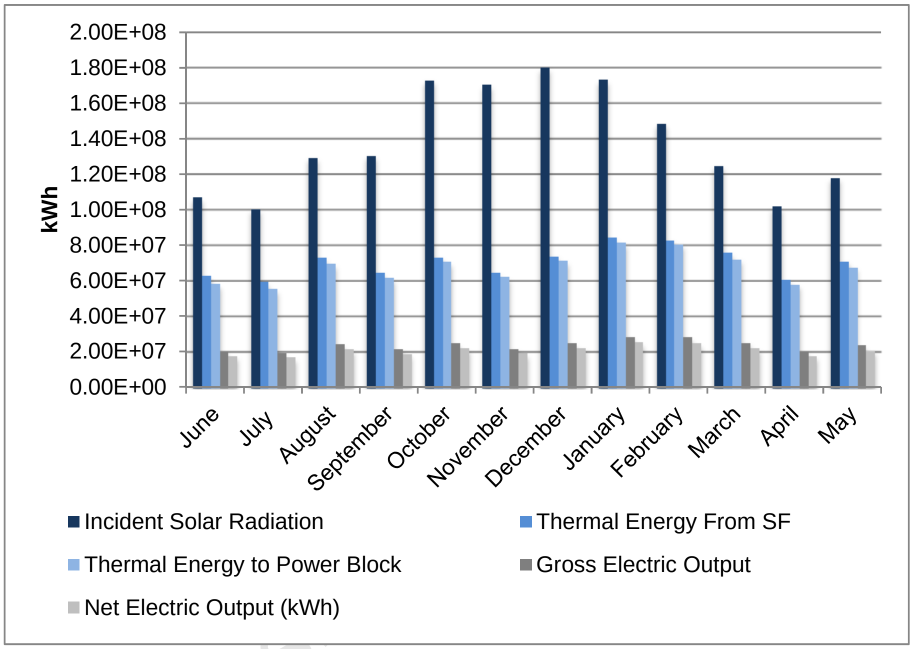


Figure 7-3: Monthly energy flow from incident solar radiation to net electric output for the base case scenario.

In Table 7-1 the annual performance of the solar plant is given with respect to the amount of energy reaching the plant in the form of incident solar radiation. From this table it can be seen that the solar field has an efficiency of 51.2% with respect to the incident solar radiation. This amount is in line with another study that achieved a 50.1% performance from its parabolic trough solar field (Haberle, et al., 2002). Only 15.2% of the annual incident solar radiation is converted into net electricity, mainly as a result of the low efficiency of the power cycle and losses from the solar field.

In the next section the results from the Base Case scenario are discussed.

Table 7-1: Performance of the different sections of the solar plant with respect to the incident solar radiation.

Incident Solar Radiation	Thermal Energy From SF	Thermal Energy to Power Block	Gross Electric Output	Net Electric Output (kWh)
100.0%	51.2%	48.9%	17.2%	15.2%

7.3 BASE CASE SCENARIO

In this section, the results for the Base Case scenario are given and discussed (see section 6.4 for the inputs). The Base Case scenario can be defined as a Concentrated Solar Power plant that delivers electricity only. Table 7-2 shows a summary of the Base Case plant specifications.

Table 7-2: Base Case plant specifications.

	Value	Units
Nameplate capacity	100	MW_e
Thermal storage (operating time at nameplate capacity)	6	Hours
Solar Multiple	2	
Solar Field Area	931,950	m^2
Annual Energy	243,365	MWh
Total Land Area	340.03	Hectares
TES Thermal Capacity	1877.10	MWh_t

In the following section, the energy output from the Base Case plant is analysed.

7.3.1 Energy Output and Performance Results

Firstly, the flow of energy from incident solar radiation to net electricity output is discussed. Figure 7-4 shows the net monthly electricity output from the power block. The results seem to be in line with the annual incident solar radiation pattern and more electricity is generated during the summer months. From Table 7-1 it can be seen that the overall performance of the Base Case is 15.2%, mainly as a result of the low efficiency of the power plant. The net electricity output has a direct impact on the Levelised Cost of Electricity (LCOE) and this will become evident in subsequent sections.

Figure 7-5 shows a stacked area graph for the Base Case scenario. The total area represents the incident solar radiation and this is broken down into the net electric output and the various losses occurring throughout the plant for each month of the year. As shown in Table 7-1, on average only 15.2% of the incident solar radiation is converted into net electricity output. It can be noted from this graph that significant losses occur in the Solar Collector Assembly (SCA) and in the Power Block (PB).

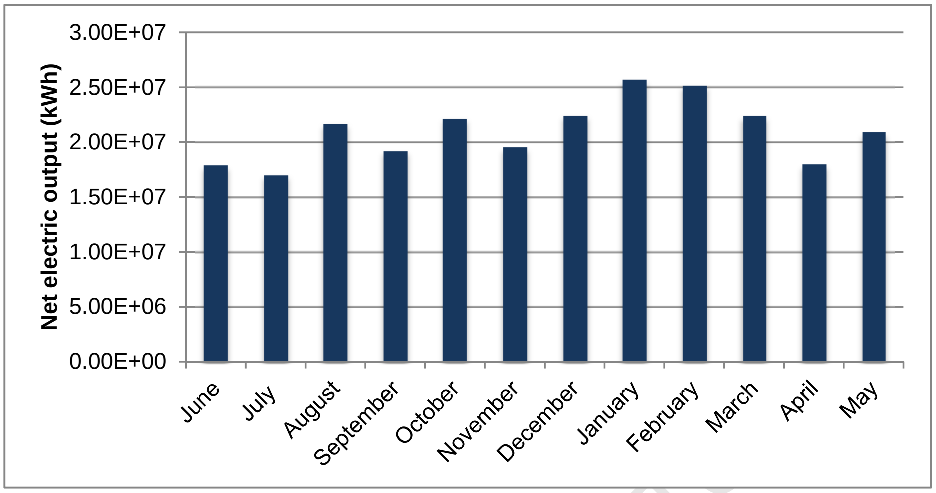


Figure 7-4: Monthly net electricity output from the power plant.

The losses occurring in the SCA is in particular significant during the summer months. Losses in the SCA occur mainly as a result of optical losses due to reflected light at the end of each SCA, mirror condition and shading from adjacent units. A smaller amount of energy is also lost in the Heat Collector Element (HCE) in the form of heat loss. The wind speed, ambient temperature, insulation and the collector angle are all factors having an impact on HCE losses (NREL, 2009). Other small losses include piping thermal, Thermal Energy Storage (TES) and parasitic losses. A small amount of energy is also lost as a result of energy being dumped when it is insufficient to power the turbine or when the TES is full and the power block is operating at full capacity.

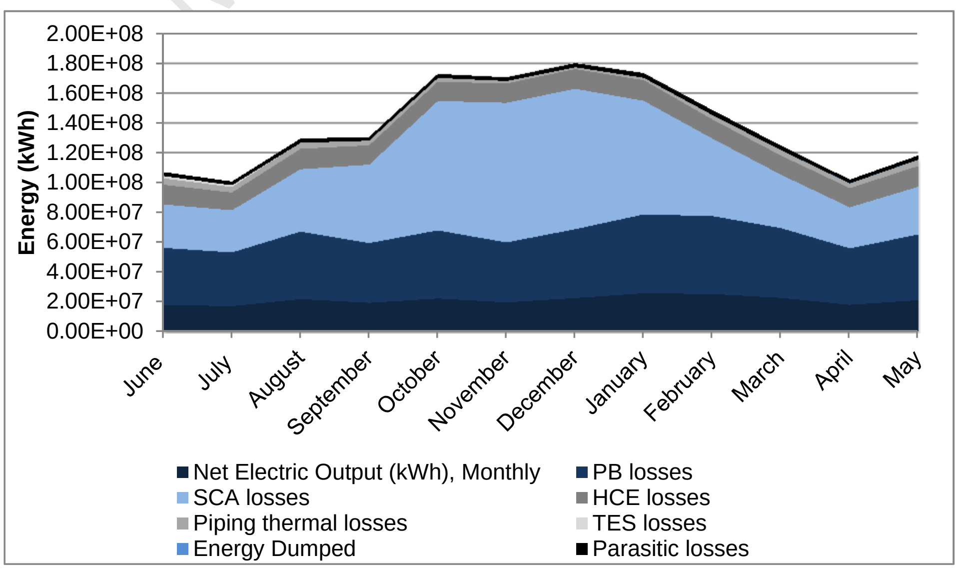


Figure 7-5: Detailed analysis of the losses in the Concentrated Solar Power plant.

7.3.2 Financial Results

In this section, the results from the financial analysis are given and discussed. Table 7-3 gives a summary of the metrics for the Base Case scenario. The annual net electricity produced and LCOE are given. The LCOE is given in both nominal and real terms. The real LCOE does not take inflation into account, while the nominal LCOE does. Including inflation complicates the analysis and makes comparison with other studies unreliable.

Table 7-3: Summary of the metrics for the Base Case financials.

Metric	Value	Units
Annual Net Electricity	253,506	MWh
LCOE Nominal	3.94	ZAR/kWh
LCOE Real	2.65	ZAR/kWh

The LCOE given in this table is related to the costs in the year 2011, when this study was conducted. As noted before, the Total Plant Cost (TPC) of a CSP plant contributes most to the overall cost of the plant. O&M costs normally contribute much less. In the following section the costs of the CSP plant are discussed.

Capital expenditure of the CSP plant

A breakdown of the capital expenditure is given in Figure 7-6. Totals are also given in Table 7-4 below to make comparison easier. The solar field makes out the bulk of the capital expenditure, contributing 30% to the total, while Thermal Energy Storage contributes 17%. The power block contributes 11% to the overall capital expenditure.

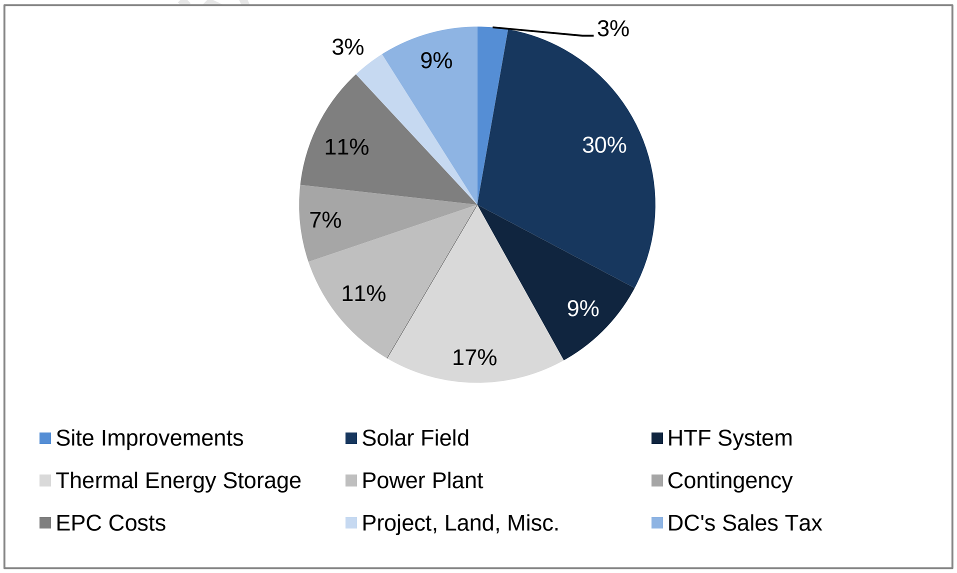


Figure 7-6: Base Case scenario capital cost breakdown.

Table 7-4: Summary of the Direct and Indirect Capital Expenditures.

DIRECT CAPITAL EXPENDITURES	Unit Cost	Unit Size (Calculated by SAM)	Cost – Million ZAR
Site improvements	ZAR 237/m^2	931,950 m^2	220.9
Solar Field	ZAR 2560/m^2	931,950 m^2	2,385.8
HTF System	ZAR 780/m^2	931,950 m^2	726.9
Thermal Energy Storage	ZAR 672/kWh_t	1877.11 MWh_t	1,262.4
Fossil Fuel Backup	ZAR 0/kW_e	111 MW_e	-
Power Plant	ZAR 7388/kW_e	111 MW_e	820.1
Contingency	10%	-	541.5
INDIRECT CAPITAL EXPENDITURES			
EPC Costs	14.8% of Direct Capital		881.6
Project, Land, Miscellaneous	3.9% of Direct Capital		232.3
Direct Capital VAT	14% (Applies to 50% of DC)		416.9
TOTAL CAPITAL EXPENDITURES			**7,487.4**

Operations and Maintenance Expenditure

In Table 7-5 a summary of the Operations and Maintenance costs are given. The fixed cost is given by capacity, while the variable cost is given by generation. There is no fuel cost for the Base Case as the plant was designed without any fossil fuel back-up.

Table 7-5: Summary of the Operations and Maintenance Costs.

OPERATIONS & MAINTENANCE COSTS	Unit Cost	Units
Fixed Cost by Capacity	583	ZAR/kW-yr
Variable Cost by Generation	19	ZAR/MWh
Fossil Fuel Cost	0	ZAR/MMBTU

Levelised Cost of Electricity

As noted in Section 6.3, the cost of technology changes over time and often, new technologies get cheaper as the total installed capacity increases. Two reasons for new technologies getting cheaper over time include learning by doing and economies of scale. For this study the learning rate for coal generated electricity was assumed zero while the learning rates for the different components of CSP plants were adopted from Trieb et. al. (2009). The Solar Field, Power Block and Thermal Energy Storage each have a different learning rate. The learning rates were used to generate the graph in Figure 7-7.

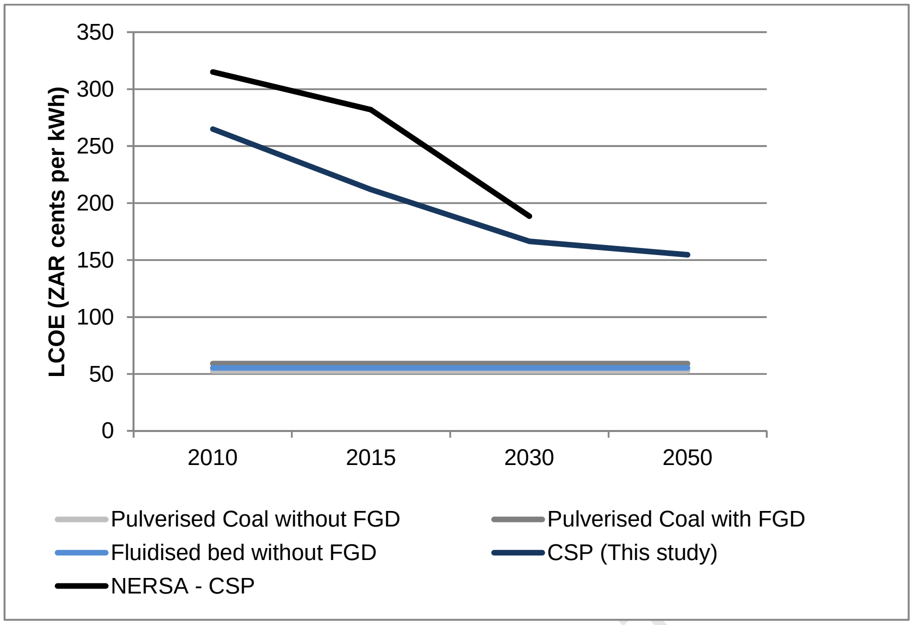


Figure 7-7: Projected LCOE (real) for CSP and coal technologies in South Africa.

In Figure 7-7 and Table 7-6 the 2010 LCOE values used in the *"Power Generation Technology Data for Integrated Resource Plan of South Africa"* (EPRI, 2010) for different coal technologies are used as a reference. It is assumed that coal power generation technologies are mature and that no future technology learning is possible. It is also assumed that the price of coal will remain constant. All LCOE values given in this graph are in real terms, meaning that the impact of inflation is not taken into account.

Table 7-6: Projected LCOE (real) for coal and CSP technologies in South Africa.

Technology / Study (ZAR cents /kWh)	2010	2015	2030	2050
Pulverised Coal without FGD	52.6	52.6	52.6	52.6
Pulverised Coal with FGD	59.1	59.1	59.1	59.1
Fluidised bed without FGD	55.3	55.3	55.3	55.3
Fluidised bed with FGD	58.6	58.6	58.6	58.6
CSP (This study)	265	211.9	166.4	154.6
CSP (NERSA)	315	281.9	188.4	-

CSP technologies are compared to coal-fired power generation technologies in South Africa, as coal is by far the most common and cheapest way of generating electricity. From Figure 7-7 it is evident that electricity generation from CSP technologies is expensive. The LCOE for CSP in 2010 was calculated to be ZAR 2.65/kWh. This compares to a LCOE for coal technologies ranging between ZAR 0.52 to 0.59 per kWh. It should be noted that the location chosen for this research is aimed at industrial applications (in the Johannesburg area) and therefore if the plant was located in the Northern Cape (with better DNI) the LCOE would have been lower.

The results of this study were compared to two other sources. Figure 7-7 also shows the LCOE for CSP in South Africa up to the year 2030 as determined by the National Energy Regulator of South Africa (NERSA) (NERSA, 2009). NERSA used these values to determine the renewable energy feed-in tariff. The estimate for the cost of CSP by NERSA is higher than that calculated by this study and in 2010 they estimated the LCOE of CSP as ZAR 3.15/kWh dropping to ZAR 1.88/kWh by 2030. This compares to a LCOE of ZAR 1.66/kWh as calculated in this study. The *"Power Generation Technology Data for Integrated Resource Plan of South Africa"* (EPRI, 2010) estimated the LCOE for CSP with six hours of storage as ZAR 2.08/kWh in 2010 for a plant located near Upington. These two comparisons prove that the results obtained from this study are in line with other results although it should be noted that results are dependent on many factors of which the location of the plant has the biggest impact.

7.3.3 Emissions and water consumption

At the moment, emissions and water are two pressing issues, not only in South Africa but also in the rest of the world. In this section, the emissions and water savings from using CSP technology are investigated. The amount of savings in emissions and water are given with respect to the emissions and water consumption from an average coal fired power plant in South Africa. Environmental indicators, published by Eskom (DEAT, 2009), were used for the calculations. The amount of water used in a CSP plant was calculated and compared to the water used in a coal fired power plant. Water is mainly used for cleaning the mirrors of a CSP plant. In Table 7-7 the annual savings in emissions and water for the Base Case CSP plant are given.

Table 7-7: Annual emissions and water consumption savings for the Base Case CSP plant.

Indicator	**Annual Net electricity produced from CSP**	**Fossil fuel** (DEAT, 2009) **(per kWh generated)**	**CSP (per kWh generated)**	**Annual Savings**
CO_2	2.53E+08 kWh	0.963 kilograms	0	243,257 tonne
SO_2	2.53E+08 kWh	8.793 gras	0	2,221 tonne
NO_x	2.53E+08 kWh	3.872 grams	0	978 tonne
Water	2.53E+08 kWh	1.26 litres	0.084 liters	296,870,106 liters

Emissions can also be monetised, and the potential savings from not having to pay carbon taxes or gains from trading carbon are also investigated here. The carbon emission prices given in Figure 6-2 were used for this calculation. In Figure 7-8, annual savings from not having to pay carbon taxes or gains from emissions trading are given for each year of the project. The cumulative carbon emissions savings is shown on the secondary y-axis over the 30-year lifetime of the project.

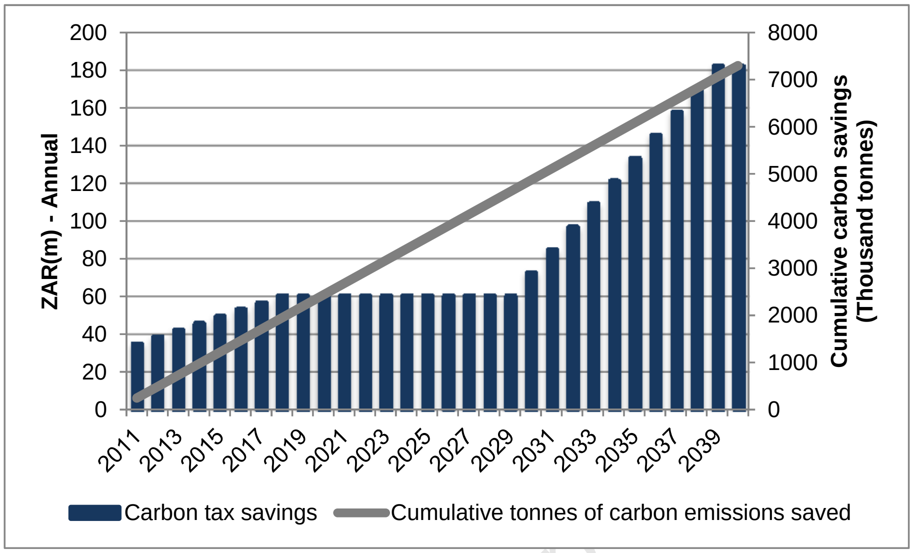


Figure 7-8: Emissions savings for the Base Case scenario over the lifetime of the project.

From Figure 7-8 it is evident that savings in carbon taxes or gains from carbon emissions trading are significant.

7.4 SOLAR THERMAL ENERGY SCENARIO

In this section the results for the plant generating Solar Thermal energy only are given and discussed. Table 7-8 shows a summary of the Solar Thermal plant specifications. To be able to compare the results of the Base Case plant to the Solar Thermal plant, it was necessary to keep the specifications for the solar field and the capacity for the TES the same. The Thermal Energy delivered from the Solar Thermal plant is steam at 393°C.

The Power Block was excluded for the Solar Thermal Energy scenario. The Annual Thermal Energy given in the table below is the same amount of energy that fed the Power Block in the Base Case scenario. It is assumed that the Thermal Energy will be fed directly into the process plant or power plant as shown in Figure 4-2. **Based on the analysis so far, the most promising use for solar thermal energy for industrial applications is when it is used as a supplementary energy source and used in combination with an existing/fossil fuel heating system**. This is mainly due to the intermittency of the incident solar radiation.

Table 7-8: Plant specifications for the Solar Thermal plant.

	Value	Units
Thermal storage (operating time at nameplate capacity)	6	Hours
Solar Multiple	2	
Solar Field Area	931,950	m^2
Annual Thermal Energy	812,000	MWh
Total Land Area	340	Hectares
TES Thermal Capacity	1877.10	MWh_t
Outlet steam temperate	393	°C

In the following section, the monthly thermal energy output from the Solar Thermal plant is analysed.

7.4.1 Energy Output and Performance Results

Firstly, the flow of energy from incident solar radiation to net thermal energy output is discussed. Figure 7-9 shows the net monthly thermal energy output from the TES unit. The results seem to be in line with the annual incident solar radiation pattern and more thermal energy is generated during the summer months. From Table 7-1 it is clear that the overall performance of the Solar Thermal scenario is 48.9%, significantly higher than the Base Case scenario's overall performance of 15.2%.

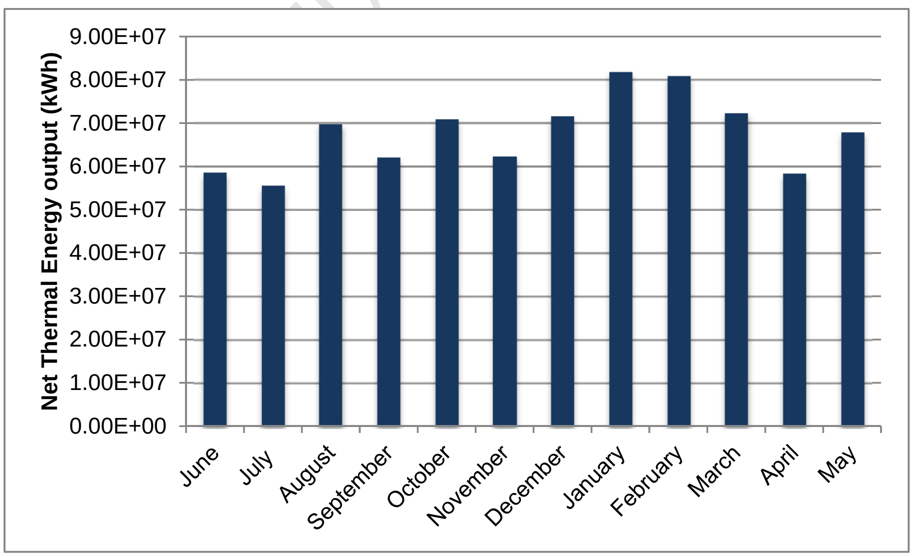


Figure 7-9: Net monthly thermal energy output from the Solar Thermal plant.

Figure 7-10 shows a stacked area graph for the Solar Thermal plant. The total area represents the incident solar radiation and this is broken down into net thermal energy and the various losses occurring throughout the plant for each month of the year. As shown in Table 7-1, on average 48.9% of the incident solar radiation is converted into net thermal energy. It should be noted from this graph that significant losses occur in the Solar Collector Assembly (SCA), especially during the summer months.

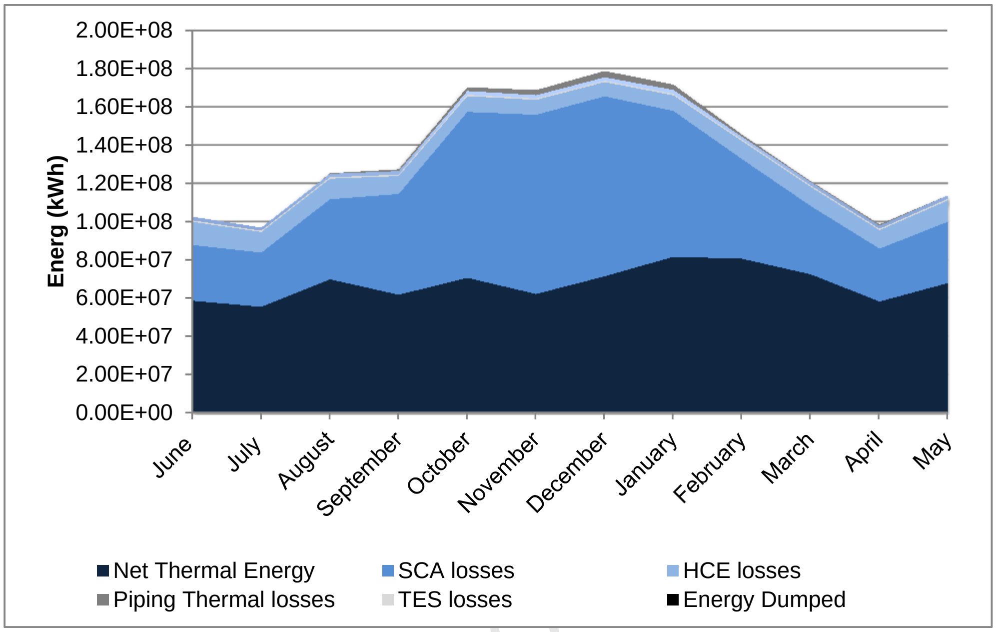


Figure 7-10: Detailed analysis of the losses in the Solar Thermal plant.

7.4.2 Financial Results

In this section, the results from the financial analysis are given and discussed for the Solar Thermal plant. Table 7-9 gives a summary of the metrics for the Solar Thermal plant. The annual net thermal energy produced and the Levelised Cost of Thermal Energy (LCOTE) are given. The LCOTE is given in both nominal and real terms. The real LCOTE does not take inflation into account, while the nominal LCOTE does.

Table 7-9: Summary of the metrics for the Solar Thermal plant.

Metric	Value	Units
Annual Thermal Energy	812,000	MWh
LCOTE Nominal	1.01	ZAR/kWh
LCOTE Real	0.68	ZAR/kWh

The LCOTE given in this table relates to the costs of 2011, when this study was conducted. The LCOTE for the Solar Thermal Energy plant is significantly lower than the LCOE of the CSP plant. The reasons for this include less capital expenditure and the higher overall performance of the plant. O&M costs normally contribute much less to the total costs for Concentrated Solar Plants. In the following section, the costs for the Solar Thermal plant are given.

Capital costs for the Solar Thermal plant

A breakdown of the capital expenditure is given for the Solar Thermal plant in Figure 7-11. The solar field makes out the bulk of the capital expenditure, contributing 36% to the total, while thermal energy storage contributes 20%. There is no power block in the Solar Thermal plant.

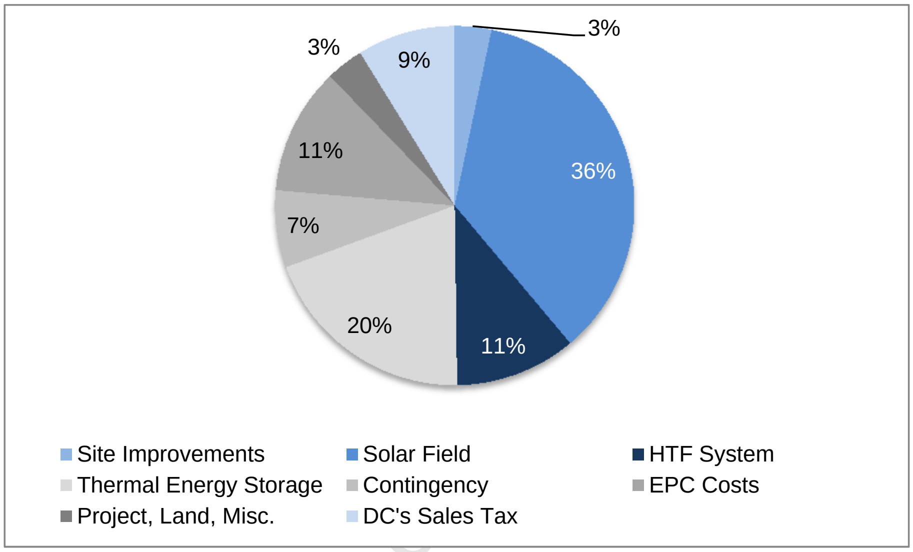


Figure 7-11: Breakdown of the capital expenditure of the Solar Thermal plant.

Totals are also given in Table 7-10 below to make comparison easier.

Operations and Maintenance Expenditure

In Table 7-11 a summary of the O&M costs are given for the Solar Thermal plant. The fixed cost is given by capacity. For the Solar Thermal plant there is no fuel cost or variable cost by generation. The overall O&M costs for the Solar Thermal plant are lower than the O&M costs for the Base Case plant. Some labour and administrative expenses, related to the power block, were removed for the calculation of the total O&M costs of the Solar Thermal plant.

Table 7-10: Summary of the Direct and Indirect Capital costs for the Solar Thermal plant.

DIRECT CAPITAL EXPENDITURES	Unit Cost	Unit Size (Calculated by SAM)	Cost – Million ZAR
Site improvements	ZAR 237/m^2	931,950 m^2	220.9
Solar Field	ZAR 2560/m^2	931,950 m^2	2,385.8
HTF System	ZAR 780/m^2	931,950 m^2	726.9
Thermal Energy Storage	ZAR 672/kWh_t	1877.11 MWh_t	1,262.4
Fossil Fuel Backup	ZAR 0/kW_e	-	-
Power Plant	ZAR 0/kW_e	-	-
Contingency	10%	-	459.5
INDIRECT CAPITAL EXPENDITURES			
EPC Costs	14.8% of Direct Capital		748.0
Project, Land, Miscellaneous	3.9% of Direct Capital		197.1
Direct Capital VAT	14% (Applies to 50% of DC)		353.8
TOTAL CAPITAL EXPENDITURES			**6,353.5**

Table 7-11: Summary of the Operations and Maintenance costs for the Solar Thermal plant.

OPERATIONS & MAINTENANCE COSTS	Unit Cost	Units
Fixed Cost by Capacity	395	ZAR/kW-yr
Variable Cost by Generation	0	ZAR/MWh
Fossil Fuel Cost	0	ZAR/MMBTU

Levelised cost of Thermal Energy

As noted in Section 6.3, the cost of technology changes over time and often, new technologies get cheaper as the total installed capacity increases. For this study the learning rates for the different components of the Solar Thermal Energy plant, shown in Table 6-13, were used to make a projection of the LCOTE for a Solar Thermal Energy plant up to 2050. This projection is shown in Figure 7-12.

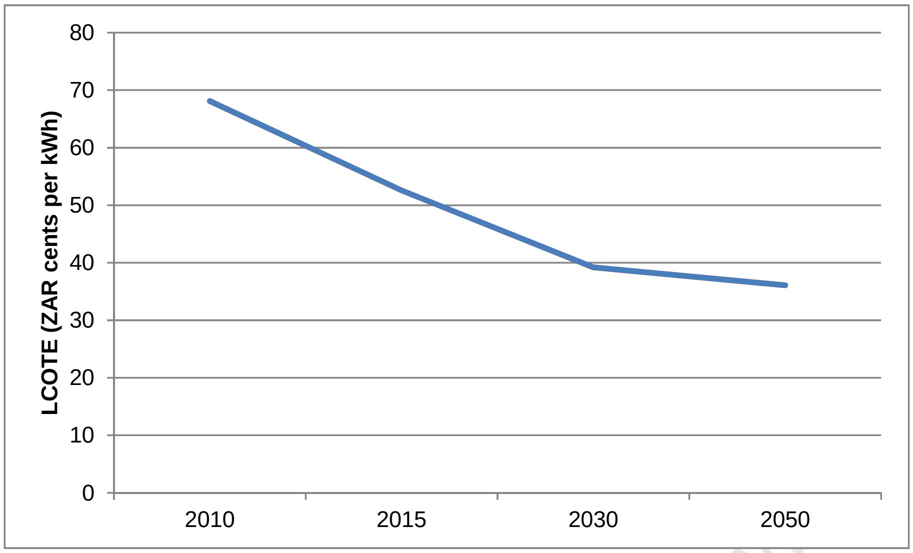


Figure 7-12: LCOTE (real) for Solar Thermal Energy.

From Figure 7-12 it can be seen that the LCOTE (real) of Solar Thermal Energy is projected to decrease significantly from ZAR 0.68 per kWh in 2010 to ZAR 0.36 in 2050 as a result of technology learning. The LCOTE for thermal heat from fossil fuel (e.g. thermal coal) in industrial boilers was not calculated in this study, as it was not part of the objectives. It is therefore not possible to directly compare the LCOTE of Solar Thermal Energy to the LCOTE of Thermal Energy from fossil fuel directly.

Figures for industrial thermal heat in South Africa are also not available in literature. To get an idea of the fuel cost of coal fired power stations, the breakdown of the LCOE of electricity for the year 2010 was used from the EPRI report (2010) and is given in Table 6-17. From this table it is evident that the contribution of the fuel cost or the cost of coal to the LCOE at Eskom power stations is currently ZAR 0.14 per kWh generated. Although this figure does not include the capital expenditure (e.g. the boiler) or O&M costs related to the generation of coal-generated thermal energy, it can be used as a rough indication of the cost.

7.4.3 Emissions savings

The amount of savings in emissions can be calculated using the emissions indicators published for sub-bituminous coal for South Africa. Environmental indicators, published by Eskom (DEAT, 2009), were used for the calculations. Sub-bituminous coal has an emissions factor of 96,250 kg or CO_2 per TJ of energy generated. The efficiency of the boiler mentioned previously was used to calculate the savings in emissions that could be achieved from the thermal energy generated by the Solar Thermal Energy scenario. Potential savings from carbon taxes or gains from trading carbon are also investigated here. The carbon emission prices given in Figure 6-2 were used for this calculation. In Figure 7-13, annual savings from carbon taxes or gains from emissions trading are given for each year of the project. The cumulative savings in carbon emissions are given on the secondary y-axis over the 30-year lifetime of the project.

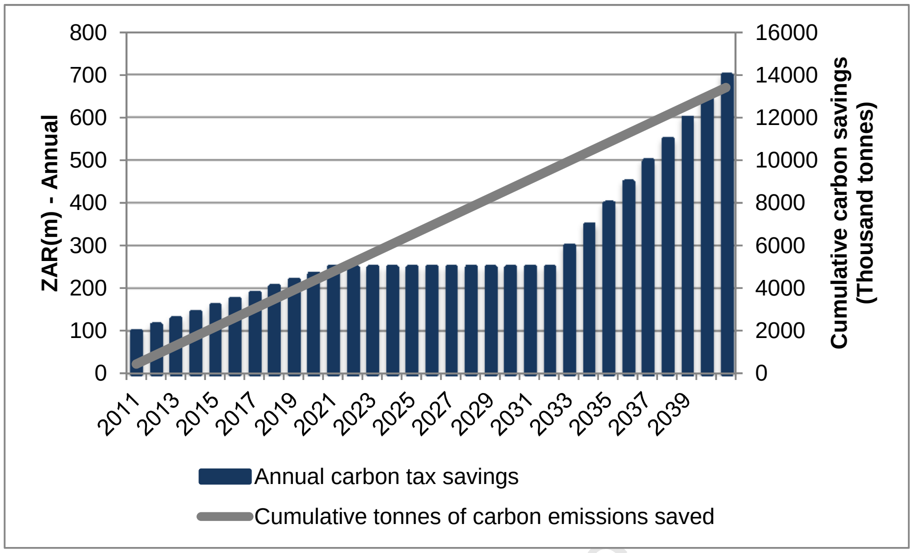


Figure 7-13: Carbon savings for the Solar Thermal Energy scenario over the lifetime of the project.

7.5 SENSITIVITY ANALYSIS

Two sensitivity analyses were performed on the financial results of the two scenarios discussed in previous section. Firstly the impact of an increase in the coal price beyond general inflation was investigated and secondly, the impact of the proposed carbon tax was investigated.

7.5.1 Coal price sensitivity

As mentioned in Section 6.3.3, the cost of coal for power production in South Africa used in this study was ZAR 15/GJ and the energy content of coal was estimated to be 19,220 kJ/kg. The Base Case scenario assumed that this price would not increase beyond the average inflation of South Africa. It is evident from Table 6-14 that Eskom estimated that the price of coal would increase significantly in the future, so it is worth investigating the impact that an increase above inflation will have on the cost of electricity and thermal energy production in South Africa. Three scenarios were investigated:

- The cost of coal will increase on average 2% above inflation every year;
- The cost of coal will increase on average 5% above inflation every year; and
- The cost of coal will increase in line with Eskom projection until 2015. This assumes a real increase in the cost of coal as follows: 2011: 8.8%; 2012: 7.3%; 2013: 5.9% and 2014: 3.9% and thereafter at 2% per year.

In Figure 7-14, the sensitivity of the projected Levelised Cost of Electricity (LCOE) to the cost of coal is shown from 2010 to 2050. On this graph, the projected LCOE from CSP is also shown. It is evident that even with a 5% real annual increase in the cost of coal, the LCOE from CSP is still higher than that of electricity generated from coal in South Africa. It should be noted that the gap between the LCOE for CSP and that of coal-fired power generation would become significantly smaller by the year 2050.

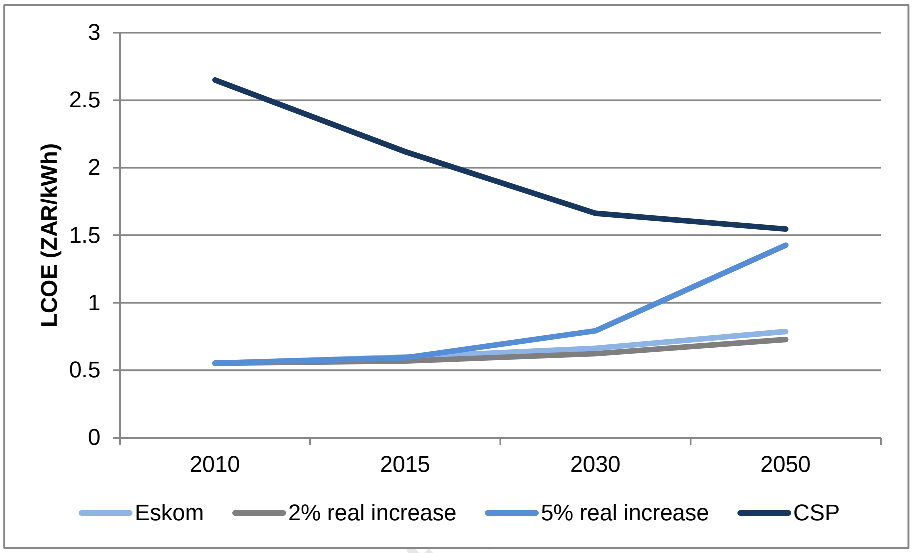


Figure 7-14: Sensitivity of Levelised Cost of Electricity to the cost of coal-fired power generation.

Figure 7-15, shows the sensitivity of the projected Levelised Cost of Thermal Energy (LCOTE) to the levelised cost of coal from 2010 to 2050. On this graph, the projected levelised cost of coal for the three scenarios is also given. It is evident that the LCOTE for solar generation will be less than the levelised cost of coal by 2030 if the cost of coal increases by 5% in real terms annually. The LCOTE for solar generation will also be more or less the same by 2050 if the cost of coal increases by just 2% in real terms annually. **It should be noted that the levelised cost of coal only includes the fuel cost and excludes initial capital and O&M costs. A separate calculation needs to be done to determine the capital and O&M costs for coal-fired boilers and to determine the LCOTE for coal-fired thermal generation.**

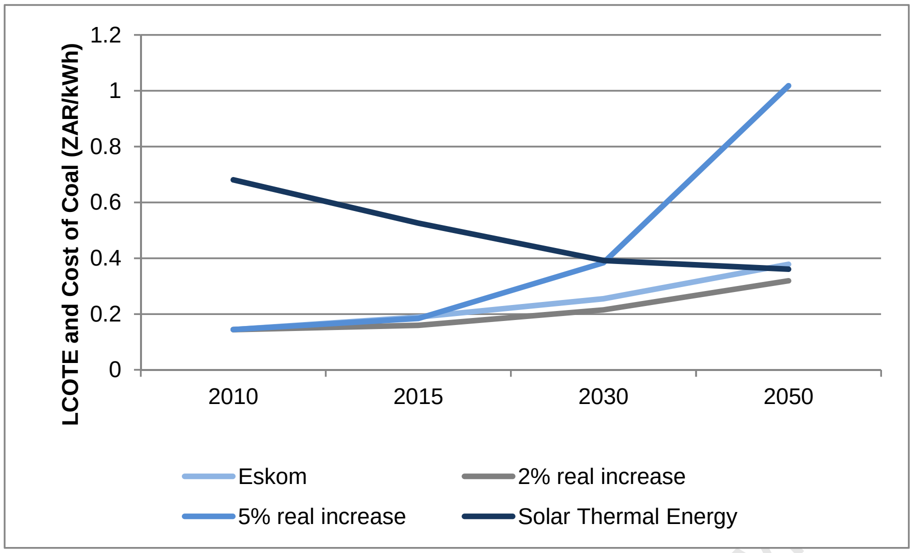


Figure 7-15: Sensitivity of the Levelised cost of Thermal Energy to the levelised cost of coal.

7.5.2 Carbon price sensitivity

To determine the contribution and sensitivity of the cost of electricity and thermal energy to the carbon price, the change in the LCOE and LCOTE was calculated for both scenarios. The carbon emission prices given in Figure 6-4 together with the emissions factors for electricity generation and for sub-bituminous coal published by Eskom were used for these calculations. For electricity, a value of 0.963 kg of CO_2 per kWh was used and for sub-bituminous coal 96,250 kg CO_2 per TJ of energy was used.

The levelised cost related to carbon emissions was calculated as ZAR 0.097/kWh for electricity and ZAR 0.054/kWh for thermal energy. The levelised cost is higher for electricity generation as the process takes the efficiency of the power block into account.

Figure 7-16 shows the sensitivity of the projected LCOE to the cost of coal and it takes the levelised cost of carbon emissions into account. The LCOE for CSP reduces as carbon emissions are reduced, while the LCOE for power generated from coal increases as carbon emissions are taxed or has to be paid for. It can be seen from this graph that although the LCOE for CSP is still higher than for coal generated power, the gap reduces significantly.

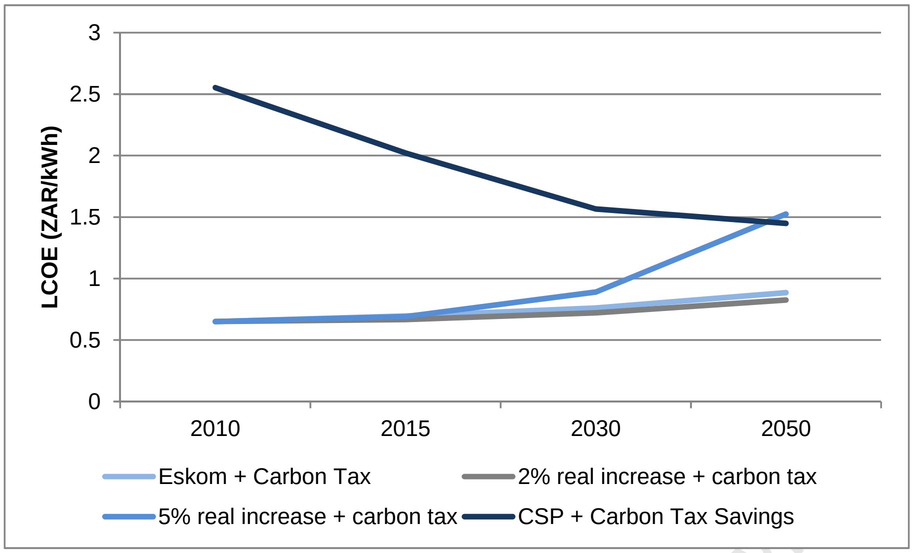


Figure 7-16: Sensitivity of the LCOE to the cost of coal and carbon emissions.

Figure 7-17 shows the sensitivity of the Levelised Cost of Thermal Energy (LCOTE) to the levelised cost coal and it takes the levelised cost of carbon emissions into account. From this figure it is evident that the LCOTE of solar-generated thermal energy reduces significantly and reduces to below the levelised cost of coal by 2030 for all the scenarios. By 2050 the LCOTE for solar-generated thermal energy reduces to ZAR 0.26/kWh. **It should be noted that the levelised cost of coal only includes the fuel cost and excludes initial capital and O&M costs.**

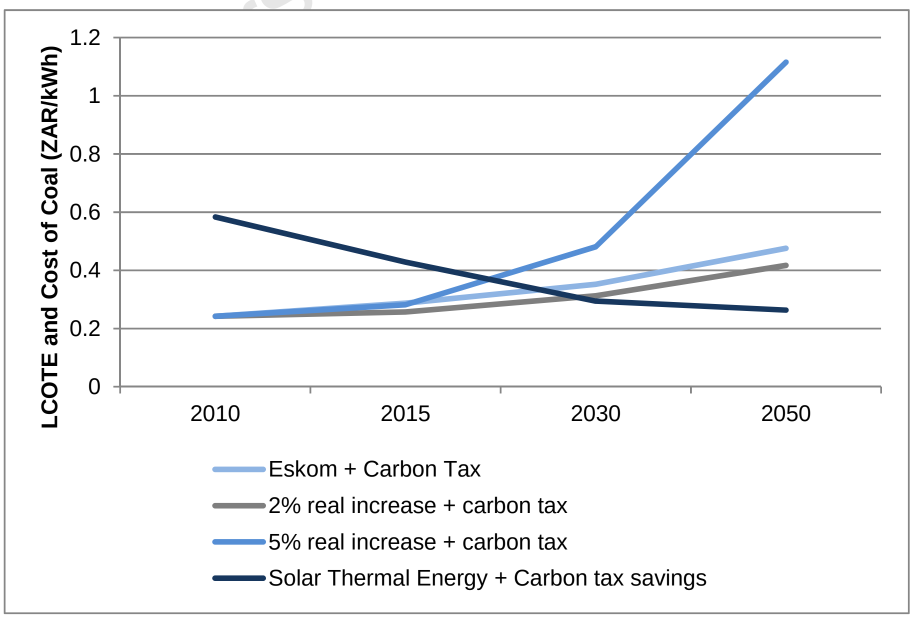


Figure 7-17: Sensitivity of the LCOTE to the cost of coal and carbon emissions.

7.6 DISCUSSION OF RESULTS

This section forms part of the last step of the research methodology shown in Figure 1-2. The results in this chapter are discussed and the potential for solar process heat in South Africa is evaluated from a performance and cost perspective.

The **performance** of a solar thermal plant with specifications shown in Table 7-8 compares favourably to that of a CSP plant with specifications shown in Table 7-2. From the results in Section 7-2, it can be seen that the solar thermal plant has a much higher overall efficiency of 48.9% w.r.t incident solar radiation relative to the overall efficiency of 15.2% for the CSP plant. Significant losses in the power blocks are the main reason for the lower efficiency of the CSP plant.

Currently the **cost** of generating CSP is much higher than the cost of generating electricity from conventional coal power generation technologies. The LCOE of ZAR 2.65/kWh calculated for the CSP plant in 2010 is about five times the current LCOE of coal power generation technologies. Compared to the cost of CSP, the calculated cost of energy from the solar thermal energy plant is much lower at ZAR 0.68/kWh in 2010. This is mainly as a result of better performance and the high cost of the power block in the CSP plant. Where electricity is used to generate process heat and steam, solar thermal energy could be considered as an alternative in the not too distant future as the cost of solar thermal energy is projected to decline to about ZAR 0.4/kWh by 2030, less than the cost of electricity today.

Where process heat and steam are generated by means of coal boilers, the cost of solar thermal energy still seems to be higher. Without a proper analysis of the LCOTE of coal fired boilers, no concise evaluation can be made.

Emissions and water savings for both the CSP and solar thermal plants are significant when compared to conventional coal fired power generation technologies and therefore it should be factored in when evaluating these technologies. Annual savings above 200,000 tonne of carbon and about 300 million liters of water are significant and relevant in an emission intensive and water scarce country such as South Africa.

The **sensitivity analyses** show that slight increases in the cost of coal will make both CSP and solar thermal technologies more competitive, however solar thermal technologies will be the first to become less expensive than energy generated from coal technologies given that a carbon tax is imposed and the cost of coal increases marginally above inflation.

CHAPTER 8: CONCLUSIONS

Based on the objectives (see Section 1.4), literature reviews and the technical and financial analyses, the following conclusions could be drawn:

- **The potential for high temperature solar thermal energy applications for industrial processes in South Africa is significant and largely underexplored**. The industrial sector of South Africa consumes 43% of the final energy, with significant amounts of energy used for heat generation at temperatures between the 100°C and 400°C range.
- Energy supply and consumption contribute 79% to the total **GHG emissions in South Africa**. Of this percentage, public electricity and heat production contribute most. Coal constitutes 92% of the fuel used for electricity generation as a result of the low price and relative abundance thereof.
- South Africa has some of the best DNI available globally, making **Concentrated Solar technologies an attractive option that can provide low-carbon renewable energy**. Concentrated Solar technologies are currently a proven technology and are destined to grow in the future and according to the IEA (2010), it is expected to provide 11.3% of the global electricity demand by 2050. Apart from power generation, Concentrated Solar plants can also provide high temperature process heat for industrial application, co-generation for heating as well as for cooling. Parabolic trough collectors are currently the most mature of the Concentrated Solar technologies, although linear Fresnel collectors are currently in the early phases of commercialisation and could in the future be an attractive alternative in terms of cost.
- Due to the intermittency of available radiation, **one of the most promising utilizations of Concentrated Solar Thermal technologies is to integrate it with existing heating systems for large-scale heat generation.** An example of such an integrated system is a linear Fresnel Solar Thermal plant that is used in combination with the coal-fired power station at Liddell in Australia. The main challenge is to fully automate the process. The integrated systems are currently not common and according to ESTIF (2006) the following **barriers to growth in this market** include: Awareness; confidence only exists in long-term and proven technologies; system cost; lack of technology; lack of suitable planning guidelines and tools and a lack of education and training.
- **Command-and-control and market-based instruments are the two main instruments that can be used to address climate change in a country.**
- A variety of financing methods are available to finance Concentrated Solar plants and these include: financing by the end user; local banks; leasing companies; multilateral development banks and ESCOs.

- Using the Solar Advisor Model (SAM) developed by the National Renewable Energy Laboratory (NREL), the thermal energy output could be modeled for a 100MW$_e$ solar parabolic trough reference plant with six hours of storage near Johannesburg, the main industrial area of South Africa. **For the Base Case scenario, the overall performance of the plant was 15.2% and for the Solar Thermal Energy plant 48.9%.** The reasons for the low performance of the CSP plant include the low efficiency of the power cycle and losses from the solar field. Annually, the Base Case plant generates 243,365 MWh of electricity, while the Solar Thermal plant generates 812,000 MWh of thermal steam at 393°C.
- The LCOE for the Base Case plant is predicted to decline significantly over the next few decades as a result of technology learning. The LCOE was calculated as ZAR 2.65/kWh in 2010 and projected to decrease to ZAR 1.54/kWh in 2050 (real terms). Compared to coal-fired power generation, CSP generation is still expensive. It was noted that a CSP plant in Johannesburg is not the optimum location for this plant, although this location was chosen as it is in close proximity to the largest industrial area in South Africa. The Total Plant Cost contributes most to the LCOE. O&M costs are small in comparison.
- **The LCOTE for the Solar Thermal Energy plant is significantly lower than the LCOE for the CSP plant mainly as a result that no power block is required and that the overall efficiency of the plant is higher.** The LCOTE in 2010 was calculated as ZAR 0.68/kWh and it is predicted to decrease to ZAR 0.36/kWh in 2050 (real terms).
- **The savings in GHG emissions when solar technologies are used instead of coal technologies are significant** and the annual savings for the Base Case Plant was calculated as 243,250 tonnes of CO_2 and 432,800 tonnes of CO_2 for the Solar Thermal plant. Annual water savings for the Base Case CSP plant was calculated to be 296 million litres with reference to the water consumption of an average coal-fired power station in South Africa.
- **Both the LCOE and LCOTE for concentrated solar technologies prove to be sensitive to an increase in the coal price.** It is projected that with an annual increase of 5% in the cost of coal, the LCOTE for solar thermal energy will be lower than the levelised cost of coal by 2030 and more or less the same by 2050 with a 2% annual increase in the cost of coal. It was noted that the LCOTE for coal-generated thermal energy was not calculated, as it was not part of the scope to determine capital and O&M costs for boilers in South Africa. The levelised cost of coal is merely used to compare the LCOTE for solar thermal energy.
- **The impact of carbon taxes or emissions trading on the LCOE and LCOTE for concentrated solar technologies is significant.** A combination of an increase in the

cost of coal and the introduction of the proposed carbon tax for South Africa still does not make CSP an economically attractive alternative to coal-generated power until 2050. A combination of increases in the cost of coal and the introduction of a carbon tax in South Africa will result in the LCOTE being lower than the levelised cost of coal from 2020 onwards. Apart from the economic benefit that solar thermal technologies has over coal, there are also other benefits such as significant savings in water consumption, GHG emissions and waste products such as ash.

CHAPTER 9: RECOMMENDATIONS

Based on the conclusions drawn, the following recommendations are made:

- High temperature solar thermal applications for large-scale industrial process heat in South Africa should be given more attention as an alternative to provide low-cost and low-carbon energy. In particular the integration of existing/fossil fuel heating systems with solar thermal systems should be explored.
- A detailed study should be done to investigate the heat demand by sector and temperature range in South Africa. The energy sources (e.g. coal or electricity) used to meet the demand should also be investigated.
- The barriers to growth in the industrial solar process heat market should be addressed in South Africa. It is recommended that:
    - Awareness campaigns should be targeted at decision makers;
    - Demonstration projects be undertaken to boost confidence and to build experience;
    - Financial incentives be developed and made available to companies that undertake solar thermal systems;
    - Funding be made available for the research and development of new solar thermal technologies; and
    - Training programmes be established to address the lack of expertise and to raise the level of awareness.
- Further detailed research should be undertaken to investigate the technical challenges to the integration of solar process heat into industrial processes and how to fully automate such processes.
- A study should be conducted to calculate the LCOTE for an integrated existing/fossil fuel heating system with a Concentrated Solar Thermal system.

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APPENDIX A: OVERVIEW OF THE SOUTH AFRICAN ENERGY SECTOR AND GREENHOUSE GAS EMISSIONS

Historically, energy demand in South Africa has been driven by energy intensive industries, mainly related to mining activities and minerals processing. Energy intensive industries were established in South Africa as a result of the country's wealth of mineral deposits and historically low energy costs. Compared to other countries, South Africa's energy intensity is high i.e. it has a high energy input per unit of Gross Domestic Product (GDP). According to Simmonds and Clark (in Winkler 2006) there is significant scope to reduce the energy intensity of the country through energy efficiency and the use of new and renewable energy technologies. At the same time a reduction in greenhouse gases (GHG) can be achieved through the deployment of energy efficiency and new and renewable energy technologies (Trikam et al. 2002).

To help contextualise energy intensity, energy demand in South Africa is analysed first. This section is followed by an overview of energy supply in South Africa.

A.1 ENERGY DEMAND

Looking at the history of the supply and demand for energy in South Africa, it is evident that the mining and minerals processing industries in the early twentieth century largely shaped South Africa's economy and energy structures. From the 1950s to 1970s the apartheid government of South Africa initiated large-scale synthetic fuels and power generation projects to promote the energy security of the country. This resulted in large excess capacity and also low electricity prices in the 1980s and 1990s.

As a result of historically low electricity prices and the country's wealth of natural resources, South Africa was in a competitive position to develop energy intensive industries such as mining, minerals processing and manufacturing. Relatively low electricity prices continue to drive new investment in industry, although excess capacity is now practically exhausted according to Eskom (in Winkler, 2006) and as a result, blackouts were experienced in 2006. According to Winkler (2006) a low energy price promotes inefficient energy use while at the same time it accelerates the depletion of natural reserves and causes pollution.

Figure A-1 (DME, 2004) shows the share of Total Final Energy (TFE) consumption by sector for South Africa in 2004. It is evident from this figure that the industrial and transport sectors consume the largest amount of the TFE. Focusing on the industrial sector, Figure A-2 (DME, 2004) shows the energy consumption of the major sub-sectors of industry and it is clear from this figure that the iron and steel and the chemical and petroleum sectors in particular are major energy consuming industries.

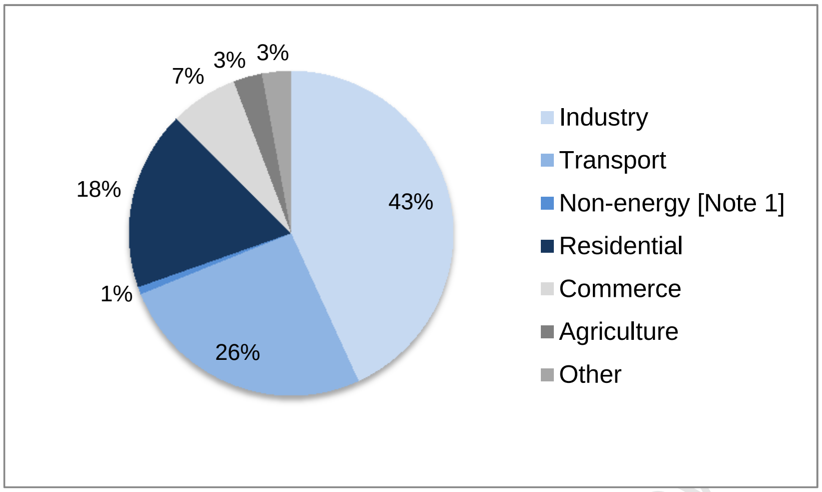


Figure A-1: Total Final Energy demand in South Africa by sector, 2004.

Source: (DME, 2004)

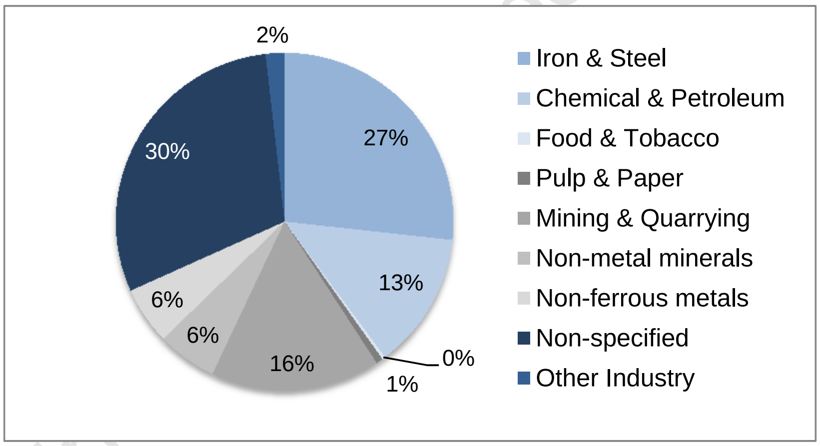


Figure A-2: Industrial sub-sector final energy consumption, 2004.

Source: (DME, 2004)

Note 1: "'Non – energy' in Figure A-1 relates to resources such as coal, oil, gas and wood, which could be used for energy, but instead used for products like chemicals and paper". (Winkler, 2006).

It is worth noting that in the industrial sector, the largest TFE-consuming sector in South Africa, 50% of energy comes from coal, 33% from electricity, 12% from petroleum and 3% from gas (DME, 2004). Compared to the energy intensities of Organisation for Economic Cooperation and Development (OECD) countries, energy intensities in South Africa are high with some industries consuming twice as much energy per ton of output (Winkler, 2006).

Transport, the second largest TFE-consuming sector in South Africa, consumes energy mainly in the form of liquid fuels (petrol and diesel). Consumption in the transport sector is heavily skewed towards land passenger and land freight transport (SANEA, (South African National Energy Association), 2003). Rail and air transport consumes much less energy relative to road transport (DME, 2004). The energy demand of the transport sector is high in South Africa as a result of an array of problems such as a lack of public transport and geographic layouts of cities mainly caused by apartheid.

Other sectors consuming significant amounts of TFE in South Africa include the commercial sector and the residential sector. The commercial sector consumes 7% of the national TFE and the residential sector 18% of TFE (DME, 2004). Both sectors use electricity as a main energy source. In the following section, the supply of energy in South Africa is investigated.

A.2 ENERGY SUPPLY

Figure A-3 shows the share of primary energy sources for South Africa (DME, 2004). Coal is the dominant primary energy supply, contributing 66% of the total primary energy supply. Coal is plentiful in South Africa and inexpensive by international standards.

Crude oil contributed 22% to the total primary energy supply in 2004 (DME, 2004). All crude oil is imported to meet most of the liquid fuel requirements of the country while about 30% of South Africa's liquid fuel demand is produced from coal via Sasol. A smaller percentage of 8% of the liquid fuel demand is met from natural gas production (DME, 2004). Nuclear currently supplies 3% of the total primary energy supply while biomass and hydroelectric power are the main contributors to the 8% share of energy produced from renewables and waste.

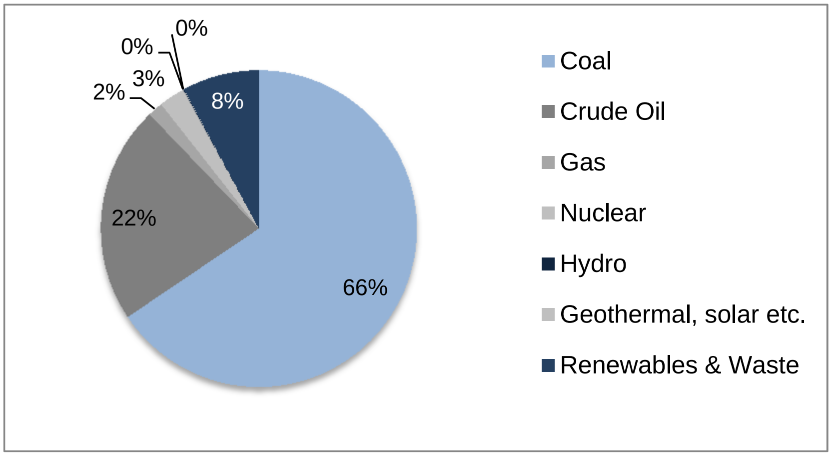


Figure A-3: Share of primary energy supply in South Africa, 2004.

Source: (DME, 2004)

In the following section, the Energy Intensity (EI) of the industrial sector of South Africa is investigated.

A.3 ENERGY INTENSITY

The most commonly used measure for EI is the amount of total primary energy supply (TPES) per unit of Gross Domestic Product (GDP), GDP (Purchasing Power Parity, PPP), and energy consumption per person. "*A country's GDP at PPP exchange rates is the sum value of all goods and services produced in the country valued at prices prevailing in the United States*" Most economists prefer using GDP (PPP) when looking at the use of resources across countries (CIA (Central Intelligence Agency), 2010).

Table A-1 (IEA in Winkler, 2006) compares the TPES per GDP, GDP (PPP) and per capita, to that of other countries.

Table A-1: Energy Intensity and energy consumption, 2000.

Source: (Winkler, 2006)

	TPES/capita (Toe/capita)	TPES/GDP (Toe/000 1995 USD)	TPES/GDP (Toe/000 PPP 1995 USD)	Electricity consumption per capita (national average) (kWh/capita)
South Africa	**2.51**	**0.63**	**0.29**	**4533**
Africa	0.64	0.86	0.32	501
South Korea	4.10	0.31	0.30	5901
Indonesia	0.69	0.70	0.25	390
Non-OECD	0.96	0.74	0.28	1028
OECD	4.78	0.19	0.22	8090
World	1.67	0.30	0.24	2343

Notes: TPES: Total Primary Energy Supply; toe: tons of oil equivalent.

From Table A-1, it should be noted that South Africa has higher EI in terms of GDP than an industrialising country such as South Korea and significantly higher EI than OECD countries. EI relating to GDP, after adjusting for PPP, is similar to that of South Korea, close to Indonesia and higher than OECD countries and the world average. EI measured in terms of per capita consumption is relatively lower than OECD countries as a result of lower income per capita in South Africa (DME 2002).

To get a better understanding of the EI of South Africa, it is necessary to investigate the contributions to GDP by the various economic sectors and sub-sectors. It should be noted that the GDP contribution by sector is reported differently than for energy consumption by sector. Nonetheless, from Figure A-4 (South African Statistics, 2009) it can be seen that mining and quarrying contributes 5.8% to the total GDP of South Africa while manufacturing contributes 16.6%. In retrospect, this is a relatively small contribution when looking at the sectoral energy consumption in South Africa, however it should be noted that these sectors are also significantly supporting other sectors such as finance and business services.

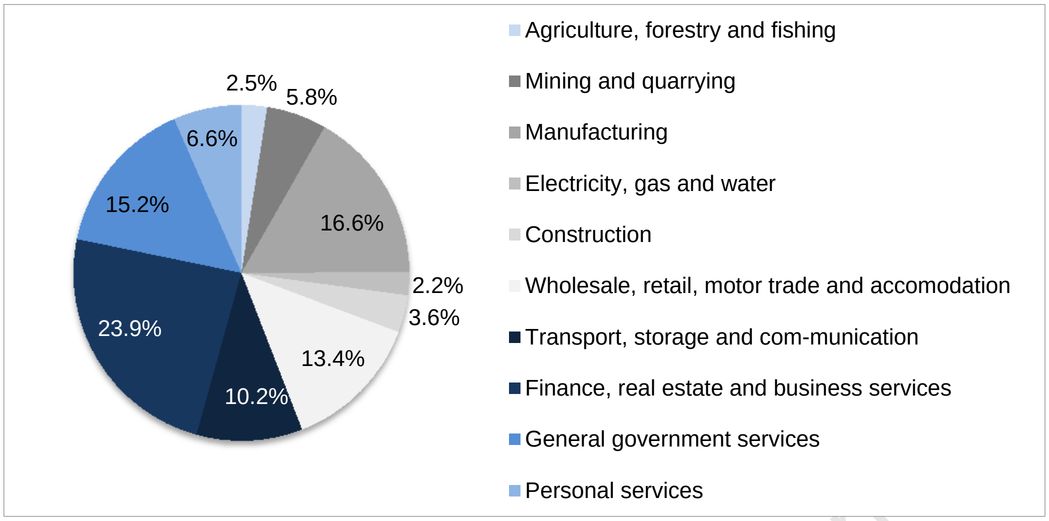


Figure A-4: GDP contributions by sector, 2009.

Source: (South African Statistics, 2009)

The South African industrial sector is still dominated by processes that require a high input of energy per value added of output. To date there has been a limited drive to move from heavy and energy intensive industries to less energy intensive industries that use light manufacturing and advanced technologies.

In the following section the Greenhouse Gas (GHG) emissions of South Africa are investigated.

A.4 KEY GREENHOUSE GAS EMISSION SOURCES IN SOUTH AFRICA

A study commissioned by the Department of Environmental Affairs and Tourism (DEAT) in 2009 investigated the national inventory of greenhouse gases (GHGs) for South Africa in the year 2000. In this study the most significant sources that contribute to South Africa's emissions were identified and are presented in Figure 2-5. The five sources that together contributed 62.5% of South Africa's GHG emissions include:

- Public electricity and heat production;
- Road transport;
- Iron and steel energy consumption;
- Iron and steel production (through process emissions); and
- Enteric fermentation. (DEAT, 2009).

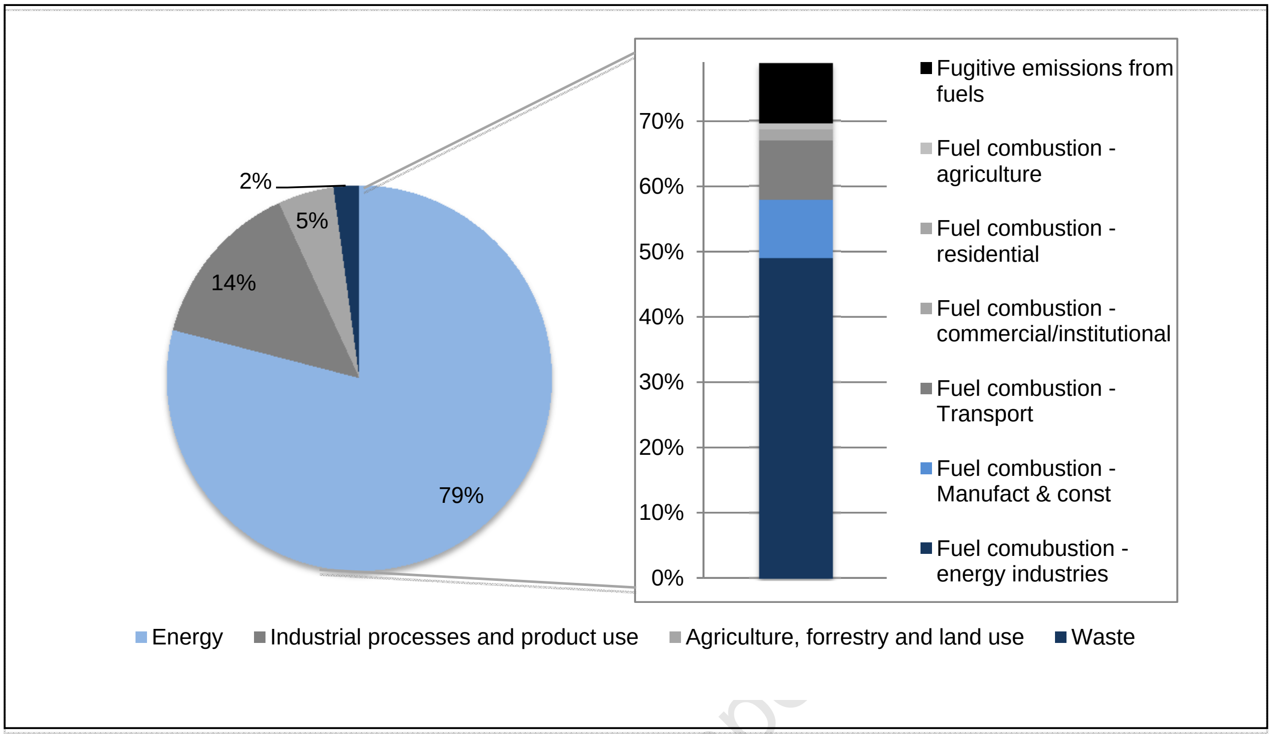


Figure A-5: Analysis of GHG emission sources in South Africa in 2000.

Source: (DEAT, 2009)

According to the DEAT report (2009), the total emissions for South Africa were 437.3 million tonnes of CO_2 equivalent in 2000. From Figure A-5 it can be noted that 79% of these emissions were associated with energy supply and consumption, 14% came from industrial processes, 5% from agricultural activities and 2% was contributed by waste. In the following sections the sources that contribute most to GHG emissions in South Africa are investigated in more detail.

A.4.1 Combustion of fossil fuels by the energy sector

The energy sector is the largest contributor to GHG emissions with the largest source of emissions coming from the combustion of fossil fuels. According to DEAT (2009) the energy sector emissions sources include:

- The development of primary energy sources, for example coal mining;
- The process of converting primary energy sources into more sophisticated forms of energy, for example refineries and power plants;
- The use of fuels in stationary applications for example in manufacturing; and
- The use of fuels in mobile applications for example in transport.

The 2000 GHG inventory for South Africa estimated that the energy sector contributed 79% of the total GHG emissions (DEAT, 2009). Of this percentage, the combustion of fuel in refineries and power plants accounted for about 69%. Fugitive emissions from fuels through coal, oil and gas activities accounted for 12% while emissions associated with transport accounted for 12% and manufacturing and construction 11% of the energy sector emissions (DEAT, 2009).

It is worth investigating the fossil fuel emission factors from the energy industry in South Africa, as this sector is by far the largest source of GHG emissions. Fossil fuel emissions from the energy industry are mainly as a result of the combustion of fuels by large fuel extraction and energy producing industries. Table A-2 (DEAT, 2009) shows the activity and the emission factors for the energy industry.

Table A-2: Activity and emission factors in the energy industry.

Source: (DEAT, 2009)

Energy Transformation	Total Amount (TJ)	Emission factors (kg CO_2/TJ)
Sub bituminous coal for public electricity	1,773,676	96,250
Auto-producers	81,232	96,250
Refinery fuel oil	27,804	77,400
Refinery fuel gas	30,175	57,600
Refinery FFC coke use	5,883	97,500
Refinery coal	301,928	94,600
Refinery others	9,060	73,300
Other solid biomass	47,000	No information
Gas works gas	27	73,300
Total	**2,276,787**	

Bituminous coal is mainly used in public electricity plants that feed electricity into the public grid and are mainly owned by Eskom. Coal is relatively abundant and cheap in South Africa and constitutes 92% of the fuel used for electricity generation. It is also the main source of GHG emissions. *Auto-producers* mean industrial companies that operate their own power stations (DEAT, 2009).

As the largest emitter of GHG, emission factors were calculated for electricity generation. Eskom published environmental indicators for its operations as shown in Table A-3 below.

Table A-3: Activity and emissions factors for electricity generation in South Africa.

Source: (DEAT, 2009)

Indicator	Factor	Units per kWh generated
Coal use	0.53	Kilogram
Water use	1.26	Litre
Ash produced	157	Gram
Particulate emissions	0.28	Gram
CO_2 emissions	0.963	Kilogram
SO_2 emissions	8.793	Gram
NO_x emissions	3.872	Gram

Another significant source of GHG emissions in South Africa is petroleum refining. The refining of crude oil and the production of synthetic fuels from coal are carbon intensive processes. Refining of fuels contributed 7% to the total GHG emissions in South Africa in 2000 (DEAT, 2009).

A.4.2 Combustion of fossil fuels by manufacturing industries and construction

The DEAT (2009) report categorises several fuel combustion sources in the industry sector, such as the production of cement, iron and steel and metal production under *Manufacturing industries and construction*. This category also includes the combustion of fossil fuels by the construction industry (DEAT, 2009). From Figure A-5 it can be noted that Manufacturing industries and construction contribute 9% to the total GHG emissions in South Africa. GHG emissions captured by this category only account for the combustion of fossil fuels and not the processes itself.

The combustion of bituminous coal accounted for about 62% (DEAT, 2009) of the fossil fuels combusted, mainly for the generation of process heat.

A.4.3 GHG emissions from industrial processes and other product use

The *Industrial Processes and Other Products* category was second to the energy sector the largest source of GHG emissions in South Africa in 2000 and contributed 14% (DEAT, 2009) to the total emissions. Emissions sources mainly include the manufacturing of minerals products such as cement, the manufacture of chemical products and metal product production (e.g. iron and steel) (DEAT, 2009). In the year 2000, the chemical industry contributed 50% of the GHG emissions of this category, while metal production contributed 39% and mineral products 11% (DEAT, 2009).

APPENDIX B: DETAILED OVERVIEW OF THE SAM SOFTWARE

There are three main modules under the performance model and each has its own separate input page in the SAM software. These three modules are outlined below:

- The **solar field module** calculates the solar field thermal energy output. Weather data from weather files together with solar field parameters are used to calculate the solar thermal energy output. Thermal and optical losses, solar field warm-up energy and freeze protection energy are also taken into consideration by this section. (NREL, 2009).
- The **storage and dispatch module** calculates the energy flowing in and out of the thermal energy storage system. Parameters from SAM's storage input page are used as input to this module. In this module, the storage related thermal and parasitic losses and freeze-protection energy are also included.
- The **power block** calculates the electric output from the thermal energy coming from the storage and dispatch unit. In cases where pure solar thermal applications are considered, the power block will not be considered in the analysis.

B.1 SOLAR FIELD

The solar field mainly includes the collectors and the receivers. In this module SAM calculates the amount of thermal energy (Q_{SF}) that is generated by the solar field. The main inputs into this module are related to the climate, Solar Collector Assemblies (SCA) and Heat Transfer Element (HTE) or receiver and the parasitics (NREL, 2009).

When the sun is shining, energy is delivered to the solar field through solar radiation. The amount of energy delivered by the solar field (Q_{SF}) will equal the amount of solar energy absorbed by the SCA minus heat losses from the solar field. The quantity of energy absorbed by the SCA depends on:

- The solar position and SCA orientation;
- The size of the solar field;
- The size and quantity of the SCA;
- Thermal and optical losses; and
- The Heat Transfer Fluid (HTF). (NREL, 2009).

Heat losses from the solar field will mainly occur as a result of ambient temperature and wind speed as well as differences between the inlet and outlet temperatures of the HTF. When the sun is not shining, SAM takes energy required for freeze protection and warm-up energy into account (NREL, 2009).

B.1.1 Solar field area and solar multiple

In the solar multiple mode, SAM uses the reference weather conditions together with the equipment design parameters and thermal losses under reference conditions to calculate the solar field size. The **solar multiple** is the ratio of solar energy collected at the design point to the amount of solar energy required to generate the rated gross power. A solar multiple of one indicates that the energy delivered by the solar field will exactly equal the amount of energy required to run the plant at its design output under design point conditions. The reference set of conditions used for designing a solar system is known as the **design point** (NREL, 2009)**.**

Under the solar multiple mode, SAM calculates the area of the solar field (A_{Solar_field}) based on the solar multiple ($F_{Solar\_multiple}$), the aperture area per SCA ($A_{SCA\_aperture}$) and the number of SCAs (N_{SCA_exact}). Equation B-1 shows the formula used by SAM to calculate the area of the solar field.

$$A_{Solar\_Field} = N_{SCA} \times A_{SCA\_Aperture} \times F_{Solar\_Multiple}$$

Equation B-1

The dimensions of the solar field are determined by the layout variables specified. Appendix C contains a summary of the definitions and symbols used by SAM as defined in their user manual. The solar field layout design parameters used by SAM include the distance between the SCAs in row, the row spacing (center-to-centre), the number of SCAs per row, the deploy angle and the stow angle.

SAM uses the design point variables to calculate the solar field size. These variables include reference weather conditions, equipment design parameters and thermal losses under reference conditions. Appendix C presents all the design point input variables used by SAM as well as their definition and symbols.

B.1.2 Solar multiple reference conditions

The three reference conditions for the solar field include the **ambient temperature**, **the direct normal radiation** and the **wind velocity** (NREL, 2009). Under reference conditions the output of the thermal field equals the power block's output times by the solar multiple. The reference ambient temperature and wind velocity are used to determine the design heat losses while the reference direct normal radiation makes a significant contribution to the solar field size calculations. The direct normal radiation is mainly influenced by the location of the plant, the storage capacity and the variability of the solar resource over the year (NREL, 2009). One way to determine the direct normal radiation value is to set it to the actual direct normal radiation value that has a 95% cumulative annual frequency value (NREL, 2009). SAM then optimizes the solar multiple and storage capacity to minimize the system's levelised cost of energy.

B.1.3 Delivered thermal energy

The energy delivered by the solar field (Q_{SF}) is calculated hourly and depends on the solar energy absorbed by the solar collector ($Q_{absorbed}$), the solar field inlet, outlet and average temperatures (T_{SFin}, T_{SFout} and T_{SFavg}) and the solar field heat losses (Q_{Heat_loss}).

The total solar field energy (Q_{SF}) is the product of the energy per SCA (Q_{SCA}) and the solar field area (A_{Solar_field}). This is given in Equation B-2.

$$Q_{SF} = Q_{SCA} \times A_{Solar\_Field}$$ **Equation B-2**

The energy produced by the SCAs, in W/m^2, is the amount of energy absorbed less the heat loss.

$$Q_{SCA} = Q_{Absorbed} - Q_{Heat\_loss}$$ **Equation B-3**

The amount of thermal energy absorbed by the SCAs depends on the solar field optical efficiency ($F_{SF\_Optical\_Eff}$), the incident solar radiation (Q_{NIP}), the solar field availability factor ($F_{Availability}$) and the solar incidence angle ($\theta_{Solar\_incidence}$) (NREL, 2009).

$$Q_{Absorbed} = \cos(\theta_{Solar\_incidence}) \times Q_{NIP} \times F_{SF\_Optical\_Eff} \times F_{Availability}$$ **Equation B-4**

The total amount of heat loss (Q_{Heat_Loss}) is the sum of the heat loss in the solar field pipes and the HCE thermal losses (NREL, 2009).

$$Q_{Heat\_loss} = Q_{HCE\_loss} + Q_{SF\_pipe\_loss}$$ **Equation B-5**

A.2 SOLAR COLLECTOR ASSEMBLY AND HEAT COLLECTION ELEMENT

As part of the solar field module, SAM uses input parameters from the Solar Collector Assembly (SCA) or collector and the Heat Collection Element (HCE) or receiver to calculate the:

- Optical efficiency of the solar field ($F_{SF\_Optical\_efficiency}$);
- Total heat loss (Q_{Heat_loss}); and

- The total SCA absorbed energy (Q_{SCA}). (NREL, 2009).

SCA input variables are used to describe the optical characteristics and dimensions of the SCA/collector and include for example the collector type, aperture area, mirror reflectivity, concentrator factor etc. (NREL, 2009). Detailed descriptions of all the SCA input variables are given in Appendix E. Values for the input variables are stored in libraries in the SAM software.

B.2.1. Mirror reflectivity

The reflectivity of a mirror depends mainly on the thickness, the iron content (Fe_2O_3) and the thickness of the reflective coating of the mirror (NREL, 2009). The reflectivity of glass will increase the thinner the glass is, however thinner glass is more susceptible to breaking during transfer and installation. Glass of 5 mm thickness is usually considered suitable for parabolic trough plants (NREL, 2009). Lower iron content will yield a better mirror reflectivity and should generally be below 0.02% (NREL, 2009). Silver is normally used for mirror coating and a thickness of between 800 and 1200Å is normally considered the optimum thickness. Thicknesses above these thicknesses, will not improve the reflectivity of the mirrors (NREL, 2009). SAM suggests the values given in Table B-1 for reflectivity for different types of commercially available glass.

Table B-1: Suggested reflectivity values for different types of glass.

Source: (NREL, 2006)

Glass Thickness (mm)	Iron Content	Mirror Reflectivity
4	Low	0.93±0.002
1	Low	0.96±0.002
4	Low	0.948±0.003
4	Very low	0.946±0.001
3	Very low	0.956±0.001

B.2.2 HCE/Receiver

The Heat Collector Element (HCE) or receiver has different properties depending on the type of receiver. SAM allows the choice of four receivers.

B.2.3 Solar field optical efficiency

The total solar field optical efficiency ($F_{SF\_Opt\_eff}$) depends on the SCA/collector efficiency, the row-shadowing losses, the end losses and the incident angle related losses. The formula for calculating the solar field optical efficiency is given in Equation B-6.

$$F_{SF\_OptEff} = F_{SCA\_OptEff} \times F_{Row\_Shadow} \times F_{End\_loss} \times F_{IAM}$$ **Equation B-6**

In the above equation, the following definitions should be noted:

- The SCA/collector optical efficiency ($F_{SCA\_Opt\_eff}$) is the product of the SCA field error (a function of the tracking error and twist, mirror reflectivity, mirror cleanliness and the concentrator factor) and the HCE/receiver field error (a function of bellows shadowing, envelope transmissivity and absorber absorption) (NREL, 2009);
- Row shadowing losses (F_{Row_Shadow}) result from row-to-row shadowing that occurs for a period after the sun rises and before it sets (NREL, 2009);
- End losses (F_{End_Loss}) occur as a result of light that reflects off the end of the collector rows;
- F_{IAM} is the incident angle modifier coefficient.

B.3 POWER BLOCK

SAM calculates the steam turbine's performance by using the parameters of a reference steam turbine. The main output of the power block module in SAM is the hourly net electric output (E_{Net}) and is dependent on the amount of energy supplied to this module (Q_{To_PB}) from the Dispatch and Storage module. SAM first calculates the design point gross electric output ($E_{Gross\_Solar\_Design}$) and applies a number of correction factors to finally calculate the net electric output (E_{net}). The following steps are followed:

- The **design point gross output electricity** ($E_{Gross\_Solar\_Design}$) is calculated. This correlates to the amount of electricity produced by the power block under the design thermal input and is dependent on the efficiency conversion of thermal energy to electricity.
- The cooling tower and thermal energy storage system losses are taken into consideration and the **corrected gross electricity output** ($E_{Gross\_solar\_corrected}$) is calculated accordingly.
- The **gross solar electricity output** (E_{Gross_Solar}) is calculated.
- Energy from the **fossil backup fuel** (E_{Gross_Backup}) is added.
- Parasitic losses are subtracted and the **net electric output** calculated accordingly. (NREL, 2009).

B.3.1 Input Variables

Two sets of input variables are used for the power block module: turbine ratings group and the power cycle group. The turbine ratings are used to determine the capacity of the power block while the power cycle variables are used to determine the performance parameters for the reference turbine used by SAM (NREL, 2009). The turbine rating input variables include: rated turbine net capacity, design turbine gross output, power plant availability and the annual degradation.

The variables of the power cycle group are used to describe the steam turbine. SAM calculates the real turbine output using reference steam turbine specifications.

B.3.2 Design turbine thermal input

SAM calculates the design turbine thermal input (Q_{PB_Design}) from the design turbine gross output (E_{Design}) and design gross turbine efficiency ($F_{Gross\_TurbineEff\_D}$) using Equation B-7.

$$Q_{PB\_Design} = \frac{E_{Design}}{F_{Gross\_TurbineEff\_D}} \qquad \text{Equation B-7}$$

B.3.3 Design point gross output

SAM calculates the design point gross electric output from solar ($E_{Gross\_Solar\_Design}$) by normalizing the thermal energy delivered to the block Q_{To_PB} to the design turbine thermal input (Q_{PB_Design}). This normalized value is then used in the power block's thermal-to-electricity conversion efficiency equation, a polynomial of the fourth order (NREL, 2009).

B.3.4 Corrected gross output

Temperature and thermal energy storage (TES) correction factors are applied to the design point gross electric output from solar ($E_{Gross\_Solar\_Design}$) to account for losses occurring in the cooling tower and during TES. The corrected gross electric output from solar ($E_{Gross\_Solar\_Corr}$) is calculated by multiplying the design point gross electric output from solar by a temperature correction factor and a TES correction factor (NREL, 2009).

B.3.5 Gross solar output

SAM calculates the gross solar output (E_{Gross_Solar}) after calculating the corrected gross electric output from solar. It tests whether this value falls within the range of design limits for the power block. These limits are the minimum load ($E_{Gross\_Solar\_Minium}$) and the maximum load ($E_{Gross\_Solar\_Maximum}$) and are functions of the design turbine gross output (E_{Design}) and the minimum and maximum load factors (F_{PB_min} and F_{PB_max}).

$$E_{Gross\_Solar\_\min} = E_{Design} \times F_{PB\_\min} \qquad \text{Equation B-8}$$

$$E_{Gros\_Solar\_\max} = E_{Design} \times F_{PB\_\max}$$ **Equation B-9**

For hours when gross solar output is insufficient to drive the power block the gross solar output is set to zero. Similarly, for hours when the gross solar output exceeds the maximum design output rating of the power block, excess energy is generated and labeled E_{Dump}. (NREL, 2009).

B.3.6 Annual delivered output

The amount of electricity delivered per year is calculated by multiplying the delivered annual output ($E_{Net\_Year\_one}$) by the availability of the power plant ($F_{Availability}$). The annual delivered output is calculated by summing the hourly net output values for the whole year.

$$E_{Net\_Year\_one} = \sum_{h=1}^{8760} E_{Net,h}$$ **Equation B-10**

$$E_{Delivered\_Year\_One} = E_{Net\_Year\_One} \times F_{Availability}$$ **Equation B-11**

B.4 DISPATCH AND STORAGE

The dispatch and storage module of SAM firstly determines how the energy is distributed from the solar field to and from thermal energy storage (TES) and the power block. Secondly it models the TES for solar systems with storage (NREL, 2009). The dispatch mode depends on the operating mode of the power block (not operating, starting up or operating), the energy available from the solar field and TES and the energy required by the power block (NREL, 2009). Simulations are done on an hourly basis. At times when the energy from the solar field exceeds the energy needed by the power block, excess solar energy will be sent to the TES, however when TES is full, it will be dumped (NREL, 2009).

B.4.1 Dispatch parameters

The limits of the TES and the power block are defined under the dispatch parameters and include:

- The maximum TES storage capacity;
- The storage dispatch levels;
- The power block minimum and maximum input limits;
- The power block load requirement;
- The maximum TES charge and discharge rate limits;
- The start-up energy requirements; and
- The heat exchanger duty. (NREL, 2009).

B.4.2 TES maximum storage

The maximum TES ($Q_{in\_TES\_Max}$) is calculated as the product of the equivalent full load hours of TES ($N_{Hours\_of\_storage}$) and the design turbine thermal energy input (Q_{PB_Design}).

$$Q_{in\_TES\_\max} = N_{Hours\_of\_storage} \times Q_{PB\_Design} \quad \textbf{Equation B-12}$$

B.4.3 Direct and indirect systems

An **indirect solar system** is one with a heat exchanger while a direct system has no heat exchanger. A TES system will only have a heat exchanger when the solar heat transfer fluid and storage fluid are not the same (NREL, 2009). When a heat exchanger is present, thermal energy is transferred from the solar field to the TES and from the TES to the power block. The heat exchanger duty must be sufficient to meet the power block's input requirements and is dependent on the solar multiple.

When the solar field heat transfer fluid and the storage fluid are the same, the system will have no heat exchanger and is termed a **direct solar system.**

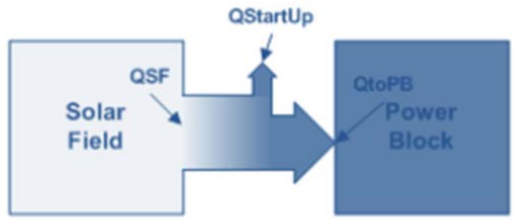
B.4.4 Start-up energy requirement

The start-up energy required ($Q_{Start\_up\_required}$) is the energy needed to bring the power block to its operating temperature after a period when it was not operating. This energy is the product of the design turbine thermal input and the turbine start-up energy fraction (F_{Start_up}) (NREL, 2009).

$$Q_{Start\_Up\_Required} = F_{Start\_up} \times Q_{PB\_Design} \quad \textbf{Equation B-13}$$

B.4.5 Dispatch system without TES

For systems without any TES, the amount of energy generated by the solar field must be bigger than the required start-up energy for the power block (Q_{Start_up}). A number of scenarios are possible when no TES are present. When start-up energy is required for the power block and the energy from the solar field exceeds the required start-up energy, the energy balance will be as shown in Figure B-1.



$$Q_{toPB} = Q_{SF} - Q_{Start\_up\_required}$$

Figure B-1: Energy from solar field exceeds the start-up energy requirement. Scenario only when start-up energy to the power block is required.

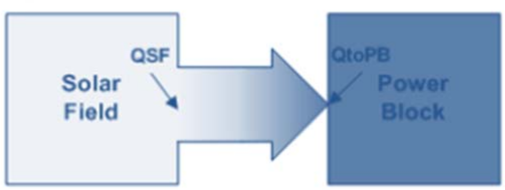
Source: (NREL, 2009)

When the power block did not operate in the previous hour, no start-up energy is required and the energy balance from the solar field to the power is as shown in Table B-2. Table B-2 (a) shows the energy balance for the scenario when the energy from the solar field is greater than zero and Table B-2 (b) shows the scenario when there is no energy generated by the solar field.

Table B-2: Scenarios showing different modes of energy flow from the solar field to the power block.

Source: (NREL, 2009)

(a)



$$Q_{toPB} = Q_{SF}$$

(b)

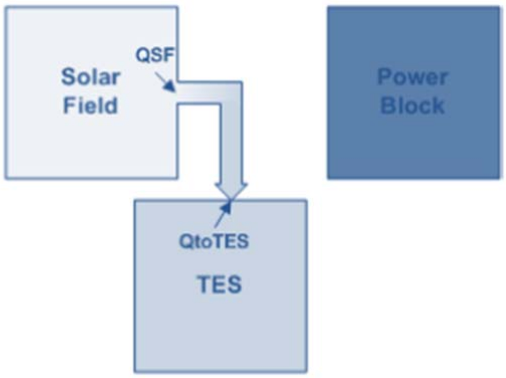
$$Q_{toPB} = 0$$

B.4.6 Dispatch system with TES

Systems with TES dispatch energy is based on whether the power block is operating; the amount of energy in storage in current hour; the energy available from the solar field; the time of day and the storage dispatch fraction (NREL, 2009). There are several different modes available for a system with TES. Table B-3 shows a summary of the different modes possible for a system that is starting up while Table B-4 shows the modes for a system that is operating.

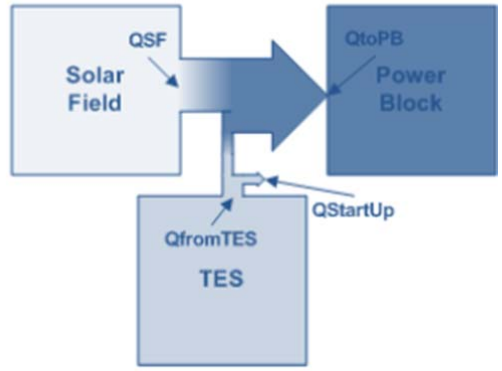
Table B-3: Different modes during start-up.
Source: (NREL, 2009)

Dispatch with insufficient start-up energy



$$Q_{to\_PB} = 0$$
$$Q_{from\_TES} = 0$$
$$Q_{to\_TES} = Q_{SF}$$

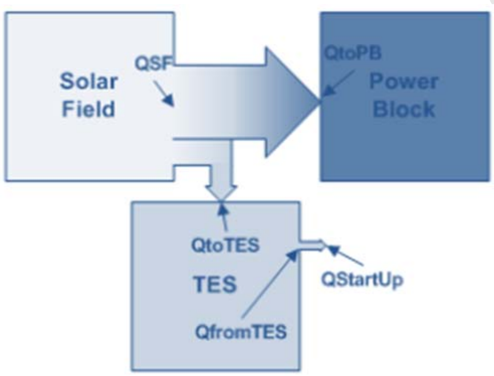
Solar field energy is less or equal to load requirement



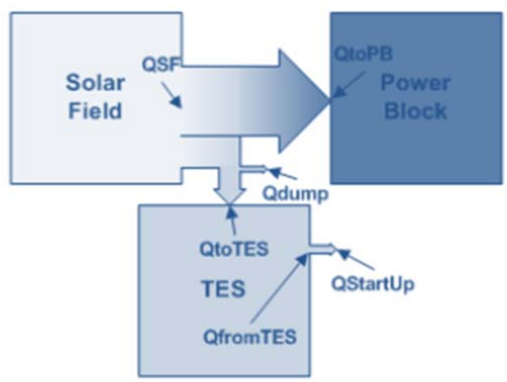
$$Q_{to\_PB} = Q_{PB\_Load}$$
$$Q_{to\_TES} = Q_{to\_TES\_\max}$$
$$Q_{from\_TES} = 0$$
$$Q_{Dump} = Q_{to\_TES} - Q_{to\_TES\_\max}$$

SOLAR FIELD ENERGY IS GREATER THAN THE LOAD REQUIREMENT

Energy to TES does not exceed maximum charge rate

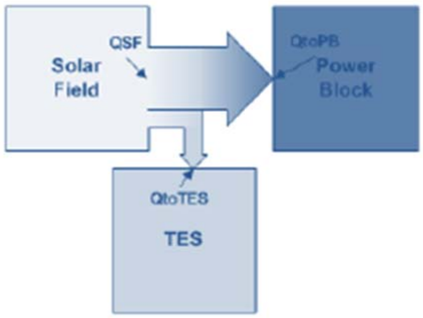


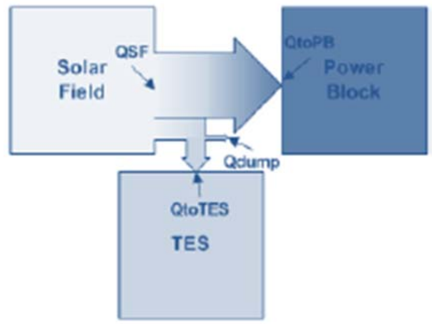
Energy to TES exceeds maximum charge rate

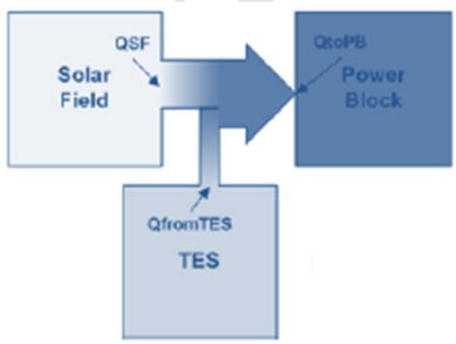


$$Q_{to\_PB} = Q_{PB\_Load}$$
$$Q_{to\_TES} = Q_{to\_TES\_\max}$$
$$Q_{Dump} = Q_{to\_TES} - Q_{to\_TES\_\max}$$
$$Q_{from\_TES} = Q_{StartUp}$$

Table B-4: Different operating modes during operation.
Source: (NREL, 2006)

<table>
<tr><th colspan="2">SUFFICIENT ENERGY TO DRIVE POWER BLOCK AT DESIGN POINT</th></tr>
<tr>
<td>Solar field energy exceeds power block load requirement


$$Q_{to\_PB} = Q_{PB\_Load}$$
$$Q_{to\_TES} = Q_{SF} - Q_{to\_PB}$$
$$Q_{from\_TES} = 0$$</td>
<td>Energy from solar field is greater that the power block input and TES maximum charge rate


$$Q_{to\_PB} = Q_{PB\_Load}$$
$$Q_{to\_TES} = Q_{to\_TES\_max}$$
$$Q_{from\_TES} = 0$$
$$Q_{Dump} = Q_{to\_TES} - Q_{to\_TES\_max}$$</td>
</tr>
<tr><td colspan="2">Energy from solar field is less or equal to the power block requirement


$$Q_{to\_PB} = Q_{from\_TES} + Q_{SF}$$
$$Q_{to\_TES} = 0$$
$$Q_{from\_TES} = Q_{Start\_Up} + \frac{Q_{from\_TES\_max}}{Q_{PB\_Load}} \times \left(Q_{PB\_Load} - Q_{SF}\right)$$</td></tr>
</table>

B.4.7 TES losses and freeze protection

SAM adjusts the amount of energy in storage by taking heat loss and energy supplied for freeze protection into account. It also uses the heat transfer fluid pump's load factor to calculate the TES related parasitic electric losses.

APPENDIX C: SOLAR FIELD LAYOUT VARIABLES

Source: Taken directly from NREL (2009)

Name	Description	Units	Symbol
Solar Multiple and Solar Field Areas	In Solar Multiple mode, SAM calculates the solar field area and displays it in "Solar Field Area (calculated).* In Solar Field Area mode, SAM calculates the solar multiple and displays it in "Solar Multiple (calculated). *Note that SAM does not use the value that appears dimmed for the inactive option.	-	-
Distance Between SCAs in Row	The end-to-end distance in meters between SCAs (Solar Collection Elements, or collectors, in a single row, assuming that SCAs are laid out uniformly in all rows of the solar field. SAM uses this value to calculate the end loss. This value is not part of the SCA library, and should be verified manually to ensure that it is appropriate for the SCA type that appears on the SCA / HCE page	m	D_{SCA}
Row spacing centre-to-centre	The centerline-to-centerline distance in meters between rows of SCAs, assuming that rows are laid out uniformly throughout the solar field. SAM uses this value to calculate the row-to-row shadowing loss factor. This value is not part of the SCA library, and should be verified manually to ensure that it is appropriate for the SCA type that appears on the SCA / HCE page.	m	D_{SCARow}
Number of SCAs per Row	The number of SCAs in each row, assuming that each row in the solar field has the same number of SCAs. SAM uses this value in the SCA and loss calculation	-	$N_{SCAPerRow}$
Deploy Angle	The SCA angle during the hour of deployment. A deploy angle of zero for a northern latitude is vertical facing due east. SAM uses this value along with sun angle values to determine whether the current hour of simulation is the hour of deployment, which is the hour before the first hour of operation in the morning. SAM assumes that this angle applies to all SCAs in the solar field.	Degrees	θ_{Deploy}
Stow Angle	The SCA angle during the hour of stow. A stow angle of zero for a northern latitude is vertical facing east, and 180 degrees is vertical facing west. SAM uses this value along with the sun angle values to determine whether the current hour of simulation is the hour of stow, which is the hour after the final hour of operation in the evening	Degrees	θ_{Stow}

APPENDIX D: DESIGN POINT VARIABLES

Source: Taken directly from NREL (2009)

Name	Description	Units	Symbol
Solar Multiple (calculated	The solar field area expressed as a multiple of the exact area (see “Exact Area” below). SAM uses the calculated solar multiple value to calculate the design solar field thermal energy and the maximum thermal energy storage charge rate	-	$F_{SolarMultiple}$
Solar Field Area (calculated)	The solar field area expressed in square meters. SAM uses this value in the delivered thermal energy calculations	m^2	$A_{SolarFiled}$
Ambient Temperature	Reference ambient temperature in degrees Celsius. Used to calculate the design solar field pipe heat losses	°C	$T_{AmbientRef}$
Direct Normal Radiation	Reference direct normal radiation in Watts per square meter. Used to calculate the solar field area that would be required at this insolation level to generate enough thermal energy to drive the power block at the design turbine thermal input level. SAM also uses this value to calculate the design HOE heat losses displayed on the SCA / HCE page	W/m^2	Q_{NIRef}
Wind Velocity	Reference wind velocity in meters per second. SAM uses this value to calculate the design HCE heat losses displayed on the SCA / HCE page	m/s	$V_{WindRef}$
Exact Area	The solar field area required to deliver sufficient solar energy to drive the power block at the design turbine gross output level under reference weather conditions. It is equivalent to a solar multiple of one, and used to calculate the solar field area when the Layout mode is Solar Multiple	m^2	A_{Exact}
Exact Number of SCAs	The exact area divided by the SCA aperture area. SAM uses the nearest integer greater than or equal to this value in the solar field size equations to calculate value of the Solar Field Area (calculated) variable described above. The exact number of SCAs represents the number of SCAs in a solar field for a solar multiple of one.	-	$N_{SCAExact}$
Aperture Area per SCA	SCA aperture area variable from SCA / HCE page. SAM uses this value in the solar field size equations to calculate the value of the Solar Field Area (calculated) variable described above.	m^2	$A_{Aperture}$
HCE Thermal Losses	Design HCE thermal losses based on the heat loss parameters on SCA / HCE page. SAM uses this value only in the solar field size equations. This design value is different from the hourly HCE thermal losses calculated during simulation.	W/m^2	$Q_{HCELossD}$
Optical Efficiency	Weighted optical efficiency variable from SCA / HCE page. SAM uses this design value only in the solar field size equations. This design value is different form SCA efficiency factor calculated during simulations.	-	$F_{SFOpticalEffD}$
Design Turbine Thermal Input	Design turbine thermal input variable from Power Block page. Used to calculate the exact area described above.	MWt	$Q_{PBDesign}$
Solar Field Piping Heat Losses	Design solar field piping heat losses This value is used only in the solar field size equations. This design value is different from the hourly solar field pipe heat losses calculated during simulation.	W/m^2	$Q_{SFPipeLossD}$

APPENDIX E: HEAT TRANSFER FLUID

Source: Taken directly from NREL (2009)

Name	Description	Units	Symbol
Solar Field HTF	Name of the heat transfer fluid type. The Minimum HTF Temperature value depends on the HTF type. The available fluid types are limited to those described in the HTF Properties section.	-	-
Solar Field inlet Temperatures	Design temperature of the solar field inlet in degrees Celsius used to calculate design solar field average temperature, and design HTF enthalpy at the solar field inlet. SAM also limits the solar field inlet temperature to this value to calculate the actual inlet temperature when the solar field energy is insufficient for warm-up.	°C	T_{SfinD}
Solar Field Outlet Temperature	Design temperature of the solar field outlet in degrees Celsius, used to calculate design solar field average temperature. It is also used to calculate the design HTF enthalpy at the solar field outlet, which SAM uses to determine whether solar field is operating or warming up. SAM also uses this value to calculate the actual inlet temperature when the solar field energy is insufficient for warm-up.	°C	T_{SFoutD}
Solar Field Initial Temperature	Initial solar field inlet temperature. The solar field inlet temperature is set to this value for hour one of the simulation.	°C	$T_{SFinlet}$
Solar Field Piping Losses @ Design Temperature	Solar field piping heat loss in Watts per square meter of solar field calculated based on design variables. Used in solar field heat loss calculation.	W/m^2	Q_{PHLD}
Piping Heat Loss coefficients (3)	These three values are used with the solar field piping heat loss at design temperature to calculate solar field piping heat loss.	$-°C^{-1}$; $-°C^{-2}$; $-°C^{-3}$	F_{PHL}
Minimum HTF Temperature	Minimum heat transfer fluid temperature in degrees Celsius. SAM automatically populates the value based on the properties of the solar field HTF type, i.e., changing the HTF type changes the minimum protection energy is required, is used to calculate HTF enthalpies for the freeze protection energy calculation and is the lower limit of the average solar field temperature.	°C	T_{HTFMin}
HTF Gallons Per Area	Volume of HTF per square meter of solar field area used to calculate the total mass of HTF in the solar field, which is used to calculate solar field temperatures and energies during hourly simulations. The volume includes fluid in the entire system including the power block and storage system if applicable. Example values are: SEGS VI: 115,000 gal VP-1 for a 188,000 m^2 solar field is 0.612 gal/m^2, SEGS VIII 340,500 gal VP-1 and 464340 m^2 solar field is 0.733 gal/m^2	Gal/m^2	V_{HTF}

APPENDIX F: SCA VARIABLES

Source: Taken directly from NREL (2009)

Name	Description	Units	Symbol
Collector Type	The name of the collector in the SCA library.	-	-
SCA Length	Length of a single SCA. Used n SCA end loss calculation	m	$D_{SCALength}$
SCA Aperture	Mirror aperture of a single. Used in the row-to-row shadowing loss factor and HCE thermal loss calculations	m	$D_{SCAAperture}$
SCA Aperture Area	Area of aperture of single SCA. Used in the solar field size calculation	m^2	$A_{SCAAperture}$
Average Focal Length	Average through focal length. Used in end gain and end loss factor calculations	m	$D_{AveFocalLenght}$
Incident Angle Modifier	Incident angle modifier coefficient. Used to calculate the incident angle modifier factor, which is used to calculate the HCE absorbed energy and the solar field optical efficiency	-	F_{IAM}
Tracking Error and Twist	Accounts for errors in the SCA's ability to track the sun. Sources of error may include poor alignment or sun sensor, tracking algorithm error, errors caused by the tracker drive update rate, and twisting of the SCA and at the sun sensor mounting location relative to the tracking unit end. A typical value is 0.985. Used to calculate SCA field error factor	-	$F_{TrackTwist}$
Geometric Accuracy	Accounts for SCA optical errors caused by misaligned mirrors, mirror contour distortion caused by the support structure, mirror shape errors compared to an ideal parabola, and misaligned or distorted HCE. A typical range of values is between 0.97 and 0.98. Used to calculate SCA field error factor	-	$F_{GeomAccuracy}$
Mirror Reflectivity	The solar-weighted hemispherical reflectance of the mirror. For 4 mm low iron, pristine, second surface tempered glass mirrors, a reasonable value would be 0.95. Used to calculate SCA field error factor	-	$F_{MirrorRefl}$
Mirror Cleanliness Factor (field average)	Accounts for dirt and dust on the mirrors that reduce their effective reflectivity. Typically, mirrors are continuously cleaned but a single mirror may be cleaned once each one or two weeks. The expected overall effect on the total solar field would be an average loss of between one and two percent. A typical value would be 0.985. Used to calculate SCA field error factor	-	$F_{MirrorClean}$
Dust on Envelope (field average)	Accounts for dust on the HCE envelope that affects light transmission. A typical value would be 0.99. Used to calculate HCE heat loss.	-	$F_{DustEnvelope}$
Concentrator Factor	An additional error factor to make it possible to adjust the SCE performance without modifying the other error factors. Useful for modelling an improved or degraded SCE. The default value is 1. Used to calculate SCA field error factor.	-	$F_{Concentration}$
Solar Field Availability	Accounts for solar field down time for maintenance and repairs. Used to calculate absorbed energy.	-	$F_{SFAvailability}$

APPENDIX G: MARKET-BASED INSTRUMENTS VERSUS COMMAND AND CONTROL

G.1 MARKET-BASED INSTRUMENTS

Market-based instruments make use of pricing mechanisms to encourage GHG emissions reduction. In comparison to CAC measures, market-based instruments offer a more flexible approach in the way and quantity in which GHG emissions are reduced. The abatement cost of GHG emissions varies for different industries and firms and market-based instruments offer flexibility in the amount of carbon reduced. In comparison, CAC measures are less flexible and require compliance with certain regulation, with no consideration of the abatement costs.

Market-based instruments provide an incentive to polluters to undertake research and development that will abate emissions. Emissions are taxed per unit of emission and therefore an on-going incentive exists for technological innovations that will help reduce the tax liability. In contrast to this, CAC regulatory measures will discourage innovation, as polluters have no incentive to go beyond regulatory compliance. Innovation might also lead to stricter standards in the future, resulting in polluters to be strategically discouraging innovation (Treasury, 2010).

Another advantage to market-based instruments is that it creates the opportunity to increase revenue. Using either or both market-based instruments and CAC approaches will lower the emissions of heavy polluters. Firms that take a pro-active approach through reducing emissions will be able to reduce output prices below that of the competition and realise additional profits. Taxes have the highest potential to increase the revenue of firms that pro-actively reduce emissions (Treasury, 2010).

Based on the arguments above, market-based instruments are considered more advantageous and in particular environmental taxes are favoured. In the following section market-based instruments are discussed in more detail.

G.2 MARKET-BASED INSTRUMENTS

In this section, environmental related Pigouvian taxation is discussed first where after carbon pricing options are discussed in greater detail.

G.2.1 Environmental related Pigouvian taxation

The OECD defines Pigouvian tax as *"a tax that is levied on an agent causing an environmental externality (environmental damage) as an incentive to avert or mitigate such damage."* (Online: www.stats.oecd.org/glossary). In essence, external costs are included in production and consumption costs of environmentally damaging goods, thereby creating incentives for behavioural change. Pigouvian taxes work in a dual way; it encourages a reduction in the consumption of a product or service while it also provides an incentive to implement technology that reduces emissions (Treasury, 2010).

The appropriate tax rate is estimated as the external cost of carbon, i.e. the cost of the damages that will result from emitting an additional unit of carbon (in the case of carbon tax) into the atmosphere. The estimation of this rate is not straightforward as there are many variables involved.

In the following section the two main market-based instruments used, carbon taxes and emissions trading schemes are explored.

G.2.2 Carbon taxes and emissions trading schemes

One way to reduce the levels of carbon dioxide emissions in a country is to introduce a tax on carbon dioxide emissions and thereby giving a monetary value to clean energy processes (Winkler, 2007). Emission trading on the other hand is a market-based instrument to combat emissions through economic incentives. An emissions trading scheme works in the way that permits companies to emit a certain amount of GHGs as set by a central authority. The permits are also referred to as carbon credits and are equivalent to their baseline emissions. An increase in emissions by the firm will result in the firm having to buy carbon credits (or permits), while a firm with fewer emissions can sell its credits. The result is that the firm with excessive emissions has to pay, while the firm with reduced emissions gains.

The main difference between carbon taxes and emissions trading is that the former aims to reduce emissions through pricing directly, while the latter aims to achieve a reduction through trading in allowances. Under emissions trading, the carbon price is set by the market, while carbon tax rates are set by the Government (Treasury, 2010). Table G-1 (Treasury, 2010) gives a comparison of emissions trading schemes and carbon taxes.

Table G-1: Comparison of emission trading schemes and carbon taxes.

Source: (Treasury, 2010)

	Emissions trading schemes	**Carbon taxes**
Design	Takes the extent and exposure of the trading scheme, cap of carbon credits (permits) into consideration.	Takes the tax base, collection of taxes, price level and mitigation actions into consideration.
Visibility	Carbon prices of trading scheme are hidden.	Carbon tax rates are explicit.
Effectiveness of reduction	Capped emissions give a reasonable certainty of reduction.	Uncertainty of the emission reductions that will be achieved.
Price	Uncertain and dependent on the amount of initial credit allocation.	Certain prices, as it is fixed for a specific time period.

G.2.3 Carbon pricing

Carbon is priced by quantifying the damage costs of climate change in monetary terms when an additional ton of CO_2 is released into the atmosphere. According to the *Discussion Paper for Reducing Greenhouse Gas Emissions: The Carbon Tax Option (2010)*, two main approaches are taken to put a price on carbon. It includes:

- Marginal damage estimates that involve a direct valuation of the expected cost of damage that will result from climate change; and
- Cost effectiveness approaches that are an indirect valuation that estimate the investment that is needed to achieve climate stabilization at least cost.

Various studies have been undertaken to determine the external cost of carbon and a summary of the estimated price of carbon and suggested reduction paths is given for a number of studies in Table G-2 (Treasury, 2010).

Table G-2: Carbon price estimates and reduction path suggestions.

Source: (Treasury, 2010)

Study	Suggested Carbon Price (per tonne of carbon)	Suggested emissions reduction path
Stern Review (2007)	USD 30	CO_2 concentration stabilized at 550pm
	USD 85	Long-term stabilization target
Nordhaus (2008)	USD 8	CO_2 concentration stabilized at 550pm
Metcalf (2008)	USD 15	Increased over time
IPCC Summary	USD 80 by 2030; USD 155 by 2050	CO_2 concentration stabilized at 550pm by 2100
	USD 65 by 2030; USD 130 by 2050	CO_2 concentration stabilized at 550pm by 2100 with induced changes in technology
Long Term Mitigation Scenarios for South Africa (2007)	ZAR 100 (2008 - 2019)	Reduction of carbon emissions targeted at 30 – 40% by 2050 from 2003 levels
	ZAR 250 (2020 – 2040)	
	ZAR 750 (2040 – 2050)	

In the following section key project risks are discussed. These risks will be taken into account when the projects are considered for financing. The severity of the risks will also determine the financing support mechanisms used to finance projects.