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Global review of CSP Technologies

Dissertation presented for the degree of
Masters of Science in Sustainable Energy
Engineering
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I know the meaning of plagiarism and declare that all of the work in the dissertation, save for that which is properly acknowledged, is my own.

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Signed:

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Abstract

This global review of concentrating solar power (CSP) technologies is based mainly on an assessment of available international literature, up to 31 October 2011. It includes a review of major CSP projects currently operating or under development at this time; the respective CSP technologies employed; and an assessment of the present and future economics of CSP relative to other conventional and renewable energy electricity-generating technologies. Global outlook scenarios for CSP are discussed, as well as specific conditions and proposals for CSP developments in South Africa.

The economic analysis has been limited by several challenges. Since the CSP industry is new, there are few well-documented projects on which to base the analysis. Most of the projects referenced here are from the USA and Spain. As the CSP market rapidly expands, competition in the industry tends to restrict the disclosure of detailed financial/economic information for projects under development. In general, it has been difficult to compare the publicly available economic data, on a reliable basis, since the financial costing parameters used may vary from case to case. In addition, most of the economic forecasts, which have been reviewed, are based on forward modeling rather than practical proven costs. There are uncertainties and quite wide variations in such predictions.

This dissertation concludes, however, that there is great optimism for the growing employment of CSP technology in the near future and that CSP electricity-generating costs, in areas with high solar energy resources, are expected to become competitive with levelised electricity generating costs from other conventional and renewable energy technologies. The cost reduction potentials for CSP lie mainly in expected technical research and development advances, and production economies of scale, achieved by high volume deployment, supported by mid-term investment incentives from governments and other agencies. Another cost reduction potential, especially in the South African context, lies in the localization of skills and local fabrication of some plant structures and components.

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Abbreviations

€	Euro
ACS	Actividades de Construcción y Servicios
ANU	Australian National University
ar	Annual Report
CCGT	Closed Cycle Gas Turbine
CFE	Comisión Federal de Electricidad
CNRS	Centre National de la recherche scientifique
CPV	Concentrating Photovoltaic
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSP	Concentrating Solar Power
DNI	Direct Normal Irradiation
DoE	Department of Energy (USA)
DoE (SA)	Department of Energy (South Africa)
ECOSTAR	European Concentrating Solar Thermal Road Map
ENEL	Ente Nazionale per l'Energia eLettrica
EPR	Evolutionary Pressurised Reactor
EPRI	Electric Power Research Institute
ESTELA	European Solar Thermal Electricity Association
FB	Fluidised Bed
FGD	Fluidised Gas Desulphurisation
FIT	Feed-in Tariff
FOM	Fixed Operating and Maintenance Cost
GEF	Global Environmental Facility
HTF	Heat Transfer Fluid
IEA	International Energy Agency
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ISCCS	Integrated Solar Combined Cycle System
LCOE	Levelised Cost of Electricity
MW	Megawatt
NEEDS	New Energy Externalities Developments for Sustainability
NREL	National Renewable Energy Laboratory

O&M	Operation and Maintenance
OCGT	Open Cycle Gas Turbine
PF	Pulverised Fuel
PS	Planta Solar
REFIT	Renewable Energy Feed-in Tariff
SAMCA	Sociedad Anónima Minera Catalano-Aragonesa
SEGS	Solar Electricity Generating System
SolarPACES	Solar Power and Chemical Energy Systems
USA	United States of America
VOM	Variable Operating and Maintenance cost
ZAR	South African Rand

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1 Introduction

The purpose of this dissertation is to review Concentrating Solar Power (CSP) technologies and assess their current and future projected costs, performance and expected market share against other technologies, especially conventional nuclear and coal power plants.

The research questions for this dissertation are as follows:

- How do the current and future costs of CSP plants compare with those of conventional power plants, and other renewable technologies?
- What is the state of the current market for CSP, and projected future market potential?
- What are the known market barriers for CSP development, and what strategies can be used to promote the development of CSP technologies?
- What are the cost reduction potentials that can be employed to bring CSP-generation technologies to levels competitive with conventional power plants?

This review is based on an assessment of international literature, up to October 2011. The CSP projects referenced here are mainly plants in the United States of America (USA) and Spain. The South African cost data is drawn from information obtained about the proposed Eskom CSP plant in the Northern Cape, and from the Electric Power Research Institute's (EPRI, 2010) *Power Generation Technology Data for Integrated Resource Plan of South Africa* study.

CSP technologies use mirrors to concentrate solar energy to produce high temperature heat, usually used to produce steam to drive turbine-generators and produce electricity. There are four basic CSP technology types, namely; parabolic trough, solar tower (central receiver), linear Fresnel reflector and parabolic dish. They can be deployed as stand-alone units servicing small demand markets or large units that are connected to the grid, either servicing peak demands or operating as base load power stations. The demand market usually determines the plants' configurations.

The CSP technologies' main advantages are that they utilise the free, abundant and renewable solar resource to produce electricity with very little carbon emissions. The main disadvantages are that the solar resource is affected by cloudy and rainy days and their current initial capital and levelised costs are more expensive than those of the conventional and some other renewable energy technologies.

This dissertation is organised into three main sections: current CSP project developments, the CSP technologies, and an economic review of CSP technologies.

The objective of the current CSP project development review section is to assess the global status of CSP projects. The global status shows the capacity of projects operating, under construction and under development per technology and country. It also discusses the recently commissioned Torresol Gemasolar 19.9MW central receiver base load plant, with up to 15 hours of molten salt thermal storage. It also reviews the causes of growth or stagnation of the CSP industry per country.

The second section describes and reviews the four main CSP technologies namely; parabolic trough, solar tower (central receiver), linear Fresnel reflector and parabolic dish. It also describes the thermal storage options, reviews the technology most suited for South Africa and the water cooling options and cost requirements for CSP technologies.

The last section reviews the global economics of CSP projects. It reviews data and opinions on the current and future capital and levelised costs of CSP electricity, and compares these with other technologies especially conventional coal and nuclear power plants. It also reviews the cost reduction potentials that may be realised for future projects. The objective of this section is to show that despite the currently expensive nature of CSP there is optimism about opportunities for these costs to be reduced in future, to levels competitive with those conventional power plants and other renewable technologies. These cost reduction potentials and opportunities are expected to come mainly through plant scale-up factors, technical improvements, volume production and reductions in CSP financing charges.

This study is relevant at this time because of the recent global CSP growth, and the opportunities for applications in South Africa. First, Eskom is currently undertaking research to establish the feasibility of using CSP as a large-scale electricity

generation option. Second, Eskom will consider the use of solar thermal plants to form hybrid power stations with the future coal power plants after the completions of the Kusile and Medupi coal power plants. The feasibility studies on the first 100MW central receiver technology plant are underway and this plant is expected to be completed and commissioned in 2016. It is expected to be funded by the African Development Bank and the World Bank through their Clean Technology Fund (Eskom, ar2011).

By the end of October 2011, approximately 1507MW of CSP capacity was installed worldwide of which 60% is in Spain, 37% in the USA and 3% elsewhere around the world. 3257MW capacity projects were under construction worldwide, of which 43% are in Spain, 51% in the USA. About 36 457MW capacity was under development or announced worldwide, most of these (86%) are in the USA.

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2 Current Concentrating Solar Power (CSP) projects development

The following data on commercial CSP projects development is for the period up to 31 October 2011. It shows data for operational CSP plants and those under construction and development from Spain, USA and the rest of the world. The tables below were developed by using information and tables from internet sources.

2.1 Operating CSP plants

The CSP industry has been very dynamic in the past two years. The introduction of favourable CSP policies and schemes like the Feed-In Tariffs (FIT) by different governments has led to an industry growth especially in Spain where approximately 170MW CSP capacity was completed in 2011, 450MW capacity in 2010, 173MW capacity in 2009 and more than 1403MW capacity plants were under construction as of 31 October 2011. The total global installed CSP capacity is approximately 1507MW.

According to Table 2-1, Spain is presently the world leader in terms of CSP installed capacity with a total installed capacity of just above 900MW, followed by the USA, which had been the world leader before 2010 with approximately 555MW of installed capacity (Table 2-2). There is approximately 49MW of installed CSP capacity (Table 2-3) in other countries. This represents approximately 60% (Spain), 37% (USA) and 3% (rest of the world) in installed capacity share of the global CSP market.

According to the Tables 2-1, 2-2 and 2-3 below, the parabolic trough technology is presently the dominant technology used. Of the total estimated 1507MW installed CSP capacity, approximately 95% employs the parabolic trough technology, and approximately 4% solar tower technology, with Fresnel reflector and parabolic dish technologies accounting for less than 1% of the total.

The Torresol Gemasolar (formerly called Solar Tres) plant changed the CSP industry by becoming the world's first commercial scale central receiver technology plant to incorporate molten-salt storage and operate for 24hours continuous. This 19.9MW plant is equipped with molten salt thermal facilities that permit electricity generation of up to 15 hours without sunlight. According to the Torresol energy website, this

plant is equipped with 2650 heliostats on 185 hectares and has an expected net annual electrical production of 110 GWh.

It is situated in Seville, Spain and is seen as an important milestone in the history of the CSP plant because of its ability to continuous operate even at night and over short periods of inadequate DNI. This will prolong its turbine and plant life and reduce the challenges and inefficiencies resulting from the start-stop that characterise the current commercial CSP plants. The other advantage about the evolutional 15hours thermal storage capacity plant is the ability to generate electricity at a demand regulated rate rather than following the solar resource variations.

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Table 2-1 Operating CSP plants in Spain

Capacity MW	Technology type	Name	Installation year	Developer
50	Parabolic trough	Solnova 1	2010	Abengoa Solar
50	Parabolic trough	Solnova 3	2010	Abengoa Solar
50	Parabolic trough	Solnova 4	2010	Abengoa Solar
50	Parabolic trough	Andasol 1	2008	ACS/Cobra
50	Parabolic trough	Andasol 2	2009	ACS/Cobra
50	Parabolic trough	Andasol 3	2011	Solar Millennium
50	Parabolic trough	Ibersol Ciudad Real	2009	Iberdrola
50	Parabolic trough	Alvarado 1 (or La Risca 1)	2009	Acciona
50	Parabolic trough	Extresol 1	2010	ACS/Cobra
50	Parabolic trough	Extresol 2	2010	ACS/Cobra
50	Parabolic trough	La Florida	2010	SAMCA
50	Parabolic trough	La Dehesa	2010	SAMCA
50	Parabolic trough	Manchasol 1	2011	ACS/Cobra
50	Parabolic trough	Palma del Rio 1	2011	Acciona Energia
50	Parabolic trough	Palma del Rio 2	2010	Acciona Energia
50	Parabolic trough	Helioenergy 1	2011	Abengoa Solar/
50	Parabolic trough	Termoelectrica de Majadas	2010	Acciona Energia
22	Central receiver	Planta Solar (PS)20	2009	Abengoa Solar
19.9	Central Receiver	Torresol Gemasolar	2011	Torresol
11	Central receiver	PS10	2007	Abengoa Solar
1.4	Linear Fresnel reflector	Puerto Errado 1	2009	Novatec Biosol AG

Table 2-2 Operating CSP plants in the USA

Capacity MW	Technology type	Name	Installation year	Developer
354	Parabolic trough	SEGS ¹	1985 to 1991	Luz
75	Parabolic trough	Martin Next Generation Solar Energy Center	2010	Florida Power and Light Company
64	Parabolic trough	Nevada Solar One	2007	Acciona Solar
43	Parabolic trough	Sky Trough demonstration	2010	Sky Fuel
5	Linear Fresnel reflector	Kimberlina	2008	AREVA/Ausra
5	Central receiver	Sierra SunTower	2009	Esolar
4	Parabolic trough	Cameo Coal-Fired Hybrid Demonstration Project	2010	Abengoa Solar
2	Parabolic trough	Keahole Solar Power	2009	Sopogy
1.5	Parabolic dish	Maricopa Solar	2010	Tessera Solar
1	Parabolic trough	Saguaro Solar Power plant	2005	Solargenix

¹ The Solar Energy Generating Systems (SEGS) is a collection of nine parabolic solar plants found in the Mojave Desert in California with capacities ranging from 14MW to 80MW per unit. The first unit was completed in 1985 and the last in 1991.

Table 2-3 Operating CSP plants in the rest of the world

Capacity MW	Technology type	Name	Country	Installation year	Developer
20	Parabolic trough	Ain Beni Mathar	Morocco	2010	Abener Energia
17	Parabolic trough	Yazd ISCCS	Iran	2009	Parhoon Tarh company
5	Parabolic trough	Archimede solar power plant	Italy	2010	ENEL
3	Linear Fresnel reflector	Liddell Phase 2	Australia	2008	AREVA
1	Fresnel reflector	Liddell	Australia	2009	Ausra/Macquire (Solar Heat and Power Ltd)
1.5	Central Receiver	Jülich Solar Tower	Germany	2008	Kraftanlagen München (KAM)
0.5	Central receiver	National Solar Energy Centre	Australia	2011	CSIRO
0.32	Parabolic dish	Big Dish	Australia	2011	ANU
0.25	Parabolic trough	Shiraz solar power plant	Iran	2008	Iran ²

2.2 CSP projects under construction

According to Appendix 4 and Table 2-4 below, there is a total of 3257MW of CSP capacity projects under construction and 1662MW capacity of those is in the USA followed by Spain with 1403 capacity. In other parts of the world, projects under construction are mostly Integrated Solar Combined Cycle System (ISCCS) technology plants (Table 2-4) with a total of 192MW solar only capacity. Spain is already the world leader in terms of CSP installed capacity and it will continue to dominate the global CSP industry until other countries like the USA and the solar resourceful Africa start building CSP plants soon.

² This plant was developed and built by Iranian government solar experts;
http://news.tavanir.org.ir/press/press_detail.php?id=15858 accessed 17 May 2011

The CSP capacity under construction in the USA represents approximately 51% of the total projects under construction worldwide followed closely by Spain with about 43% share. The parabolic trough technology continues to be the technology of choice in the projects under construction with approximately 64% market share and the central receiver technology is approximately 34%. This is a huge step forward for the central receiver technology for the 4% of the total operating projects. 99% of these central receiver technology projects, totaling 1102MW, are in the USA and are scheduled to be operational in 2013 and 2014. These projects are the 392MW Invapah, 600MW BrightSource and the 110MW Crescent Dunes projects.

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Table 2-4 CSP plants under construction in other parts of the world

Capacity (MW)	Technology	Name	Country	Planned installation year	Developer
280	Parabolic trough	Solana	USA	2013	Abengoa Solar
280	Parabolic trough	Mojave Solar	USA	2014	Abengoa Solar
3X200	Central receiver	BrightSource	USA	2014	BrightSource Energy & PG&E
126	Central Receiver	Invapah SEGS 1	USA	2013	BrightSource Energy
133	Central Receiver	Invapah SEGS 2	USA	2013	BrightSource Energy
133	Central Receiver	Invapah SEGS 3	USA	2013	BrightSource Energy
100	Parabolic trough	Shams 1	UAE	2011	Abengoa-Total JV
110	Central Receiver	Crescent Dunes	USA	2014	Toponah Solar Energy
20	Parabolic trough	Kuraymat Plant ISCCS	Egypt	2012	Solar millennium
25	Parabolic trough	Hassi R'mel ISCCS	Algeria	2011	Iberdola/Flagsol
12	Linear Fresnel reflector	Alba Nova 1	France	2013	Corsica
12	Parabolic trough	Agua Prieta 2 project	Mexico	2013	CFE
10	Parabolic trough	Rajasthan Solar One	India	2013	Entegra
5	Parabolic trough	Archimedes prototype project	Italy	2010	ENEL
3	Central Receiver	Lake Cargelligo	Australia	2011	Graphite Energy
2.5	Linear Fresnel reflector	Himin Solar	China	Not known	Himin Solar
1.4	Central receiver	PÉGAS	France	Not known	CNRS
1	Central receiver	IIECAS	China	Not known	IECAS
0.2	Central receiver	Brayton Solar	Australia	Not known	CSIRO

2.3 CSP projects under development or announced

CSP projects under development or announced is a challenging section to study because not enough data is available on these projects and the available data is constantly changing (O’Sullivan, 2009). The Table 2-5 below shows the capacity of projects under development or announced by country and technology type. It is generated from the information obtained from the CSP Today World plant location map. The projects under development or announced do not necessarily mean they will be built and connected to the grid. Some may be delayed for several years and some may be cancelled due to different reasons, like lack of funding, change of government policies and incentives and change of priorities by interested parties.

Table 2-5 Global projects under development or announced

Country	Technology				Total capacity per country
	Parabolic trough (MW)	Central receiver (MW)	Dish (MW)	Linear Fresnel reflector (MW)	
USA	20 817	8458	3105	400	32 780
Spain	1000	120	65		1185
India	590		10		600
Israel	440				440
Australia	350	4		423	777
China	281	100			381
Algeria	215				215
Morocco	645				645
Tunisia	200				200
Egypt	100				100
South Africa	450	200			650
Jordan				100	100
Iran	67				67
Brazil	50				50
France			50		50
Portugal				13	13
Total capacity per technology	25 205	8882	3230	936	38 253

From Table 2-5 above, the USA has the highest capacity of the total announced projects worldwide with approximately 86% share. While the current CSP development world leader, Spain, has only 1185MW of announced capacity,

(approximately 3% of the global capacity announced). The USA looks set to become the world CSP development leader in the near future. The future rate of growth of the CSP industry in Spain seems to be hampered by the current European economic crisis. This has slowed down the solar market due to increased premium rates on lending and stricter requirements from the financiers.

The parabolic trough technology is the preferred CSP technology choice for the announced projects with approximately 66% share. Judging from Table 2-5 above, 23% of the total projects announced are planned to employ the central receiver technology.

2.4 Causes of growth or stagnation of CSP by country

The CSP technology industry is a new electricity power industry that is dominated by the USA and Spain. Since the last of the SEGS plants was brought on line in 1991 the CSP technology industry was dormant until 2007 when Nevada Solar One and PS10 solar plants started commercial operation in the USA and Spain respectively. This has been credited to the favourable solar incentives and policies introduced by different governments. These incentives include the Feed-in-Tariffs, power purchase agreements and tax incentives.

Besides the economic and policy incentives, the success of CSP technologies is also based on the solar resource and site latitude of the specific location. According to the solar potential Table 2-6 below, Spain has the least Direct Normal Irradiation (DNI) potential for the locations shown, while South Africa has the best DNI. Judging from these DNI values alone it is expected that South Africa should be world leader in terms of CSP development and generate the cheapest solar electricity.

Table 2-6 Solar potential for selected world places

Location	Site Latitude	Annual DNI (kWh/m ²)
South Africa		
Upington, Northern Cape	28°S	2955
United States		
Barstow, California	35°N	2725
Las Vegas, Nevada	36°N	2573
Albuquerque, New Mexico	35°N	2443
International		
Northern Mexico	26-30°N	2835
Wadi Rum, Jordan	30°N	2500
Ouarzazate, Morocco	31°N	2364
Crete	35°N	2293
Jodhpur, India	26°N	2200
Spain	34°N	2100

Source: Bohlweki Environmental (2006)

2.4.1 Spain

Currently Spain is the world leader in CSP development because of its feed-in tariff scheme, introduced in 2007, good solar resources for CSP – DNI levels of about 2100 kWh/m² annually – and with large areas of flat barren land suitable for CSP development.

In 2007, the Spanish government introduced a FIT of 26.94 €cents/kWh for CSP electricity, valid for 25 years according to the royal decree 661/2007, in order to achieve a target of 500 MW of installed CSP capacity by the end of 2010. This FIT increases annually with inflation minus 1% for plant sizes up to 50MW capacity and is meant for combined new installations. After 25 years, this FIT price reduces to 21.5 €cents/kWh (SolarPACES, 2010).

In the middle of 2010, The Spanish government trimmed down the renewable energy subsidies through FIT cutbacks and delayed incentives implementation because of the financial losses realised through their support³. The effect of these cuts, together with the current European economic crisis, can be seen in the reduced number of

³ <http://www.ecoseed.org/politics/feed-in-tariff/article/32-feed-in-tariff/7543-spain-slashes-incentives-for-wind-and-c-s-pv-could-be-next> accessed 19 August 2011

CSP projects announced (Table 2-5) compared to those under construction (Appendix 4).

As of the end of October 2011, Spain had a total of 900MW of installed CSP capacity making it the world leader in terms of CSP growth and installed capacity. Many more projects are under construction or in development stages.

2.4.2 USA

The USA was the first country to operate a CSP technology plant commercially. The SEGS plants operated profitably in the 1980s and early 1990s because of high oil prices. This advantage was coupled with solar power state and federal support in terms of tax incentives, favourable regulation support and guarantees from the US Department of Energy (Squire et al, 2005).

The Luz International Company was planning to build more CSP plants before it became bankrupt and the subsequent drop and stabilisation of the world energy prices stalled the development of the CSP industry. Also at that time, the USA government preferred the larger, low priced conventional power plants to the small expensive CSP plants (Squire et al, 2005).

The USA government could no longer support the high CSP electricity prices and later withdrew their tax provisions (SolarPACES, 2010). In the USA and worldwide there were no financial and political support systems, leading to a stalling of the CSP industry after the last SEGS plant was built in 1991.

More recently, the USA has introduced a range of incentives to stimulate the growth of CSP technologies. At the end of 2008, they introduced a 30% Federal Investment Tax Credit (ITC) and Department of Energy (DoE) loan guarantee program, additional to the existing Renewable Portfolio standards, which require utilities to generate 20% of their electricity from renewable sources⁴.

2.4.3 South Africa

Currently South Africa does not have a commercial operating CSP plant. Its electricity is currently generated mostly from relatively cheap and dependable coal.

⁴ http://www.digtheheat.com/Solar/concentrating_solar.html accessed 28 April 2011

This utilisation of coal resources allows for one of the cheapest electricity generation costs in the world (Eskom, 2009). Eskom's average short term marginal generating cost was estimated to be approximately 16 cents/kWh (South African cents) in 2010⁵. This low generating cost from conventional technologies and the lack of government support for CSP technologies meant that the CSP industry could not be established in South Africa.

One of the drivers for the South African CSP industry development is its excellent solar resource in the world with a potential nominal CSP capacity of 547GW over the whole country⁶. The recently published South African Integrated Resource Plan (IRP) for the period from 2010 to 2030 includes a committed build plan of 1200MW of CSP capacity.

In 2009, the South African government first introduced a FIT of ZAR2.10/kWh for CSP plants with 6hours of storage per day (NERSA, 2009) and a proposed reduction to ZAR1.836/kWh in 2011. This REFIT program was recently abandoned for the Renewable Energy Independent Power Producer Procurement Program or 'Rebid' process, which has a heavy emphasis on job creation and using local supplies. The bidding process for the first 200MW of CSP, amongst the 3750MW for renewable projects announced by DoE (SA), by IPPs was from 3 August to 4 November 2011 and the second bidding will open on November 25 with bids due in by 5 March 2012. The biggest challenge for this first 200MW allocated to CSP is that it might not be enough to entice CSP developers.

This program allows IPPs to bid on selling price rather than the guaranteed REFIT. This part of the bid makes up 70% of the whole bid process whilst the remaining 30% is for meeting the requirements for economic development criteria, which include elements such as localization for economic development, local manufacturing, job creation, community socio-economic development and black economic empowerment. The IPPs are charged R15000 for the bidding

⁵ This value is calculated by dividing the operating expenditure by the electricity sales as stated in the Multi Year Price Determination 2010/11 to 2012/13 (MYPD 2) <http://www.ner.org.za/> accessed 8 July 2011

⁶ <http://www.csptoday.com/southafrica/documents/CSPreportchapter.pdf> accessed 19 August 2011

documentation. In addition, the bidders are required to deposit a bond of R100 000 for each MW they intend to install and the bidding price is capped at R2.85/kWh.

Eskom, the sole buyer under the 'Rebid' program is excluded from the Rebid process, is anticipating the growth of renewable energy electricity generation from the Northern Cape and is planning to build additional transmission lines and transformers to cater for additional 1500MW of electricity generation by 2017 in their Power Execution Plan.

The South African DoE is also currently undertaking a feasibility study to assess the potential for developing a 5000MW solar park and identify opportunities for localization and economic development of the Northern Cape. The initial feasibility study undertaken by the DoE (SA) and presented in October 2010 makes provision for the first 1000MW to be installed as from 2017. This solar park would potentially contain plants with several different solar thermal and photovoltaic technologies.

The benefits of the proposed solar park will be on the economies-of-scale principle, where IPPs benefit by sharing infrastructure and single environmental impact assessment covering the entire project.

Eskom is in the process of developing a 100MW CSP plant in the Northern Cape for completion in 2015. Other companies that are involved with CSP planning and development in the Northern Cape include the Siemens 100MW parabolic trough, Group Five 500MW Kalahari Park, Solafrica 75MW CSP plant, Exxaro and Spanish Abengoa 100MW project near Upington.

One of the biggest challenges faced by the CSP and energy industry in general is the lack of funding. Fortunately, in South Africa there have been funding programs available. For example the World Bank approved a US\$3.75 billion loan to Eskom, out of this, US\$200 million is for the their proposed CSP plant. Other state institutions like the Industrial Development Corp (IDC) and the Development Bank of Southern Africa are supporting private CSP ventures bidding under the Rebid program.

2.4.4 Other countries

Besides the USA, South Africa and Spain, other countries like France, Italy, Portugal, Israel, Greece and North African countries like Morocco and Egypt have introduced economic and policy incentives to boost their CSP industry. France in 2006 introduced a FIT of 30 €cents/kWh (40 €cents/kWh for overseas) with an additional 25 €cents/kWh if integrated into buildings (15 €cents/kWh for overseas) limited to solar-only installations with capacities up to 12MW and less than 1500hours of operation annually (SolarPACES, 2010).

Italy introduced a FIT of between 22 and 28 €cents/kWh for the solar proportion of ISCCS plants, depending on percent solar proportion of the whole ISCCS plant. This tariff applies to plants that will come on line as from 31 December 2012 and is fixed for 25 years. The highest FIT price will apply to ISCCS plants with more than 85% solar operation (SolarPACES, ESTELA & GreenPeace, 2009).

In 2007, Portugal introduced a FIT of 27 €cents/kWh for plants up to 10MW of installed capacity and 16 €cents/kWh for any plants with capacity above 10MW. In 2006, Greece introduced a FIT of 25 €cents/kWh for plants on the mainland and 27 €cents/kWh for those in non-interconnected islands. In 2006, Israel introduced a FIT of 20.4 US cents/kWh for plant capacities of up to 20MW and 16.3 UScents/kWh for those larger than 20MW. This FIT is valid for 20 years from 2006 (SolarPACES, ESTELA & GreenPeace, 2009).

Despite such lucrative FIT policies, most of those European countries do not have suitable solar resources to support CSP growth, while the Middle East and North African countries may lack the political will and necessary internal funding resources (compared with Spain and the USA) to realise the growth of the CSP industry. In recent years, some European countries have shown interest in these regions where they plan to set up CSP plants and transmit the generated electricity over long distances on land and under oceans to supply European networks (German Aerospace Centre, 2006).

3 CSP technologies

Most thermal electricity generating technologies require a heat source to produce steam or hot gas to drive a turbine generator and produce electricity. Nuclear plants use nuclear fission energy as the heat source, coal plants use burning coal to supply the heat and CSP plants use the concept of concentrating solar radiation onto a solar receiver carrying a heat transfer fluid. There are four main ways of concentrating solar radiation. These are parabolic trough, central receiver or solar tower, parabolic dish and linear Fresnel reflector technologies. The parabolic trough and linear Fresnel are linear focusers because they focus the solar irradiation onto linear solar receivers. The solar tower and the parabolic dish technologies are called the point focusers because solar irradiation is concentrated onto a receiver that carries a heat transfer fluid. The parabolic trough is the maturest of these technologies because of the experience of the USA SEGS plants since 1985. The Solar One and Two plants in the USA and recently by the PS10, PS20 and Gemasolar plants in Spain have demonstrated the solar tower technology for commercial operation. The other technologies are still in the research and development stages.

Currently all operating CSP plants are hybridised with fossil plants to guarantee a firm, smooth electricity supply during periods of low solar irradiation. Hybridisation also reduces the levelised cost of electricity produced because fossils fuel plants are cheaper than CSP technologies and they offer higher availability factors. The Renewable Energy Feed-in Tariffs (REFIT) laws from different countries provide provision for the CSP designs to incorporate hybridisation, like in Spain where up to 12-15% non-solar generation is allowed (SolarPACES, 2010).

Hybridisation can be achieved in different ways. It can be used to superheat steam as in the SEGS 1 plant, or to generate extra steam as in the SEGS 2-7 plants or it can be used to heat the same Heat Transfer Fluid (HTF) as in the solar field and supplied directly to the boiler as in the SEGS 8 & 9 plants. South Africa's state

owned Eskom utility could consider the use of hybrid power plants after the completion of the coal-fired Kusile and Medupi power stations⁷.

The solar plants mainly consist of the solar field with its heat transfer circuits, the power block with its turbine generator and auxiliaries and a storage system for some plants.

3.1 Parabolic trough

This is currently the most proven CSP technology with more than 1500MW of installed capacity globally. The parabolic trough technology uses parabolic shaped mirrors to concentrate solar irradiation onto a receiver tube containing a heat transfer fluid. A typical parabolic trough CSP plant is represented by the Figure 3-1 below.

⁷ <http://www.engineeringnews.co.za/article/sa-could-see-its-first-hybrid-power-station-after-kusile-2011-07-27> accessed 19 August 2010

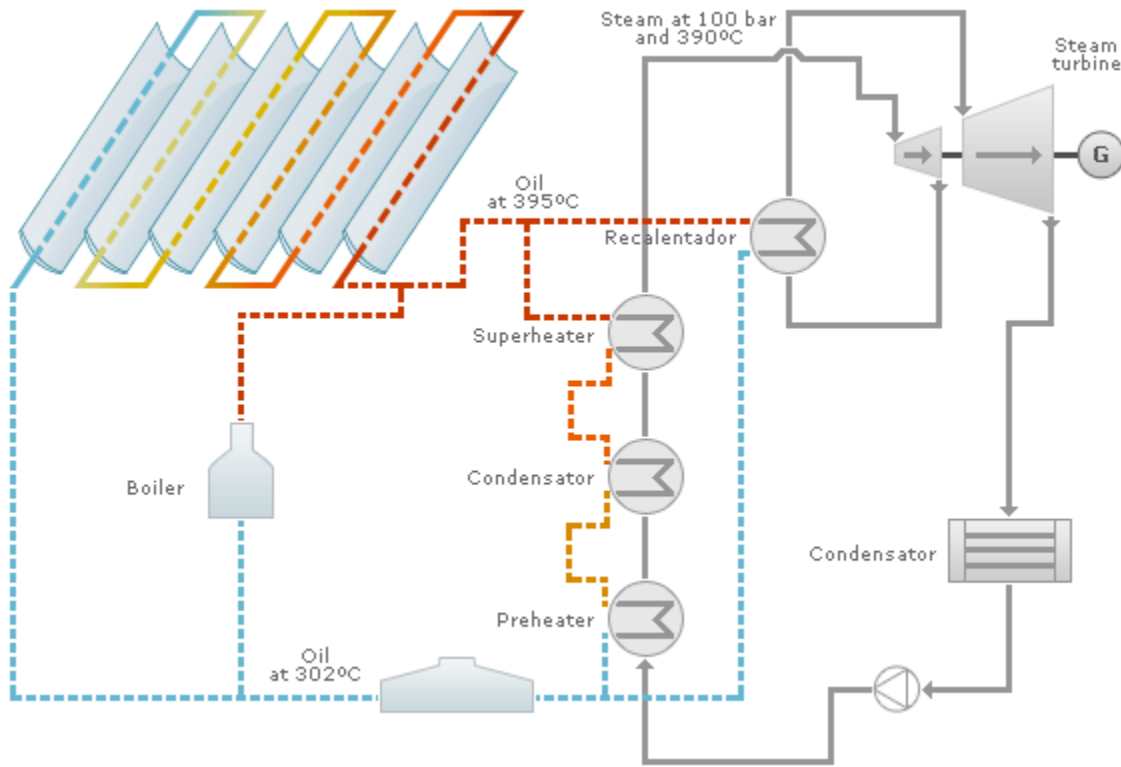


Figure 3-1 Typical layout of a parabolic trough plant (50MW Solnova 1 plant)

Source:

http://www.abengosolar.com/corp/web/en/our_projects/solucar/solnova/index.html

accessed 18 September 2010

Figure 3-1 above shows a typical parabolic plant consisting of a solar field, power block and heat transfer fluid. The earlier SEGS plants and most of the recently completed parabolic plants did not incorporate thermal energy storage facilities in their designs. This may be due to their customer electricity demand curve. In Spain and the USA, most of these plants are built to satisfy the summer day peak loads due to air-conditioners⁸.

Solar field

The solar field consists of a large array of modular solar collectors. The solar collector consists of a parabolic mirror and absorber tube situated at the focus of the mirrors. The mirrors, also known as reflectors, concentrate sun's direct irradiation onto a linear receiver. The solar collectors are usually aligned in a north-south

⁸ http://www.solarmillennium.de/english/press/press-releases/2011_03_21-foundation-stone-ibersol.html accessed 28August 2010

direction and they track the solar irradiation throughout the day from the east to the west direction to make sure that it is continually focused on the solar receivers.

Besides the parabolic mirrors and the linear receivers, the solar collector modules include supporting structures and drive systems. The supporting structures, usually made from metal, support the parabolic reflectors and the solar receivers at the same time, allowing the whole module to optically follow the solar irradiation throughout the sunny days. The drive mechanism with its associated controls, normally located at the centre of the solar collector, measures the solar rays' angle of incidence and optically adjusts the solar collector module to harvest the maximum solar energy.

The solar modules operate independently and the linear solar receivers are interconnected by either flexible hoses or ball joint assemblies. The SEGS plants have used flexible hose connections while the new plants have moved to ball joint assemblies due to the high failure rates that have been experienced with flexible hoses (SolarPACES, 2010).



Figure 3-2 Typical parabolic-trough solar field

Source: <http://www.renewbl.com/wp-content/uploads/2009/10/Solel-Solar-Systems-panels-example.jpg> accessed 19 May 2010

3.2 Central receiver (Solar Tower)

The central receiver systems use numerous individual mounted mirrors to concentrate sunlight (DNI) onto a solar receiver usually mounted on a tall tower. As in the parabolic trough system, the central receiver design consists of a solar field, receiver and working fluid and the power block.

The solar field consists of numerous individual sun tracking mirrors called heliostats, which are individually operated to continuously track and concentrate the sunrays to a focal receiver system mounted on a tower. The concentration ratio⁹ of about 600 to 1000 can achieve a central receiver temperature of about 800°C to well over 1000°C (SolarPACES, ESTELA & GreenPeace, 2009) making the central receiver more thermodynamically efficient for electricity generation than the parabolic trough systems. The higher operating temperatures also allow for larger amounts of useful thermal storage compared to the parabolic trough technology (Turchi et al, 2010).

The central receiver is cooled by a working fluid, which can be steam, molten salt or gas. The working-fluid heat is used to produce steam to drive the turbine generator and produce electricity. The most commonly used working and thermal storage fluid is the molten salt because of its high operating temperatures and lower costs compared with the synthetic oils mostly used in the parabolic trough technologies (Blake et al, 2002).

Currently the central receiver system is not as matured as the parabolic troughs. The 11MW PS10, 22MW PS20 and more recently the 19.9MW Gemasolar solar plants were the first plants to employ the central receiver system commercially. Before then this technology was mostly implemented in demonstration plants. These include the 10MW each Solar One and Solar Two plants in the USA that demonstrated the use of steam and molten salt as working fluids respectively.

3.3 Parabolic Dish

The parabolic dish technology systems comprise of a parabolic dish that reflects and concentrates sunlight (DNI) onto a receiver mounted centrally above the dish at a focal point. The dish systems track the sun throughout the day using a two-axis

⁹ Collector aperture divided by the receiver diameter

system to maximise solar irradiation. They usually come with a motor mounted on the receiver to directly utilise the collected energy to drive it and produce electricity. They have the highest thermoelectric efficiency of all CSP technologies (Szczygielski & Wagner, 2009).

Parabolic dish systems are the smallest of the CSP systems in terms of unit size and are considered most suitable for stand-alone off grid systems to power small electric demands. Their unit sizes can go up to 50kW_e and the plants can be up to 5MW (SolarPACES, 2010). There is currently a 1.5MW capacity commercially operating parabolic dish plant in the USA, a 1MW plant under construction in Spain and a couple of demonstration plants in South Africa, Australia, USA, Mexico and other countries. Since the dish systems are point focusers they can operate at high temperatures of about 750°C (SolarPACES, ESTELA & GreenPeace, 2009).

3.4 Linear Fresnel

The linear Fresnel reflector technology is a line concentrator like the parabolic trough technology. It uses slightly curved mirrors to reflect and focus sunlight onto a receiver tube located at a height above the mirrors. It is a cheaper technology than the parabolic trough because it uses cheap flat mirrors mounted on a simple sun tracking system and its receiver is stationary thus reducing the tracking device cost encountered in the parabolic trough systems. It is perceived to be less efficient than the parabolic trough because of lower concentration ratio and lower operating temperatures (SolarPACES, ESTELA & GreenPeace, 2009).

This technology is still in the development and demonstration stages. Although there are demonstration plants around the world, the first commercial plants are the 5MW capacity Kimberlina plant in the USA that was installed in 2008 and the 1MW Fresnel plant that was connected to an existing coal fired Liddell Power Station in Australia in 2009 (SolarPACES, ESTELA & GreenPeace, 2009).

3.5 Power block

The power block comprises of the steam generator, turbine, condenser and other auxiliaries like pre-heaters, super-heaters, re-heaters and de-aerators. The heated

HTF from the solar field is used to generate high-pressure superheated steam in the steam generators.

The superheated or saturated steam is force-fed into the steam turbine that is coupled to a generator. The steam does work by expanding through the turbine blades and rotating them. At certain stages of the turbine, steam is bled and reheated to increase its energy and avoid its condensation in the turbine, which might damage the turbine blades. The generator produces electricity that is either sent to the grid or used locally.

The exhaust steam from the turbine is condensed in a condenser and sent back to the steam generator. The condenser is cooled by either river, sea or cooling towers and the condensate is reheated and pressurised before it is sent back to the steam generators. This is done to increase the thermodynamic cycle efficiency and reduce the amount of energy required to produce steam.

3.6 Thermal storage

Thermal energy storage facilities in the CSP plants are used to store excess solar energy, in insulated reservoirs, collected during the sunny periods and used when needed during periods of inadequate or no solar energy. Different energy storage technology options are used in storing the excess energy. The direct steam and the molten salt technologies are those widely used in the existing CSP plants. Future CSP plants may use alternative options such as ceramic material, concrete structures, and phase change materials, among others. However, for large-scale applications, these are still in research and development stages.

Thermal storage offers better utilisation of the turbine because the excess stored heat increases the turbine run time and hence this improves the plant capacity factor. According to research by the CSP Today organisation¹⁰, thermal energy storage allows CSP plants to achieve considerably higher annual capacity factors — from 25% without thermal storage up to 70% or more with it.

The addition of a thermal energy storage facility to a plant requires additions to the solar field, for optimisation. This increases the cost of the solar field and the total

¹⁰ <http://social.csptoday.com/industry-insight/down-earth-ceramic-based-solar-theothermal-storage> accessed 28 November 2010

cost of the plant. According to an International Energy Agency (IEA) (2010) study, a 7-hour molten salt storage facility for a 50MW parabolic trough plant would cost about 9% of the total capital cost but lower the overall levelised electricity cost.

Thermal storage technologies differ with different CSP configurations. These technologies can be used directly or indirectly to store heat. In the direct thermal storage arrangement, one working fluid is used as both the heat transfer and thermal energy storage medium. The PS10 plant in Spain uses direct heat storage by compressing steam during operation¹¹. During periods of low steam supply, this steam is expanded and can run the turbine for an additional 30 minutes. Other plants with similar heat storage technologies include the SEGS 1 plants. This technology is more costly than the indirect method because of the expensive pressure vessels and storage facilities for the large steam volumes (SolarPACES, ESTELA & GreenPeace, 2009). It is designed to protect the plant against very short periods of inadequate sunlight energy.

The indirect thermal storage technology normally utilises two different working fluids for thermal energy storage and heat transfer. During normal operation of the plant, the heat transfer fluid is used to generate steam for the turbine generator; at the same time, it is used to heat the thermal energy storage fluid from the cold tank to the hot tank through a series of heat exchangers. During periods of insufficient sunlight or at night, the heat from the thermal energy storage is extracted by reversing the flow of both fluids. The thermal energy storage fluid is used to heat the heat transfer fluid to produce steam for the turbine generator. Most of the existing plants and plants under development in Spain using thermal energy storage techniques use the indirect thermal energy storage technology concept¹².

3.7 Integrated Solar Combined Cycle Systems (ISCCS)

The ISCCS design combines a CSP plant and a gas turbine plant together. The ISCCS design reduces the levelised cost of electricity produced because gas turbines are cheaper than the CSP technologies.

¹¹ http://ec.europa.eu/energy/res/sectors/doc/csp/ps10_final_report.pdf accessed 28 November 2010

¹² http://www.nrel.gov/csp/troughnet/thermal_energy_storage.html accessed 17 May 2010

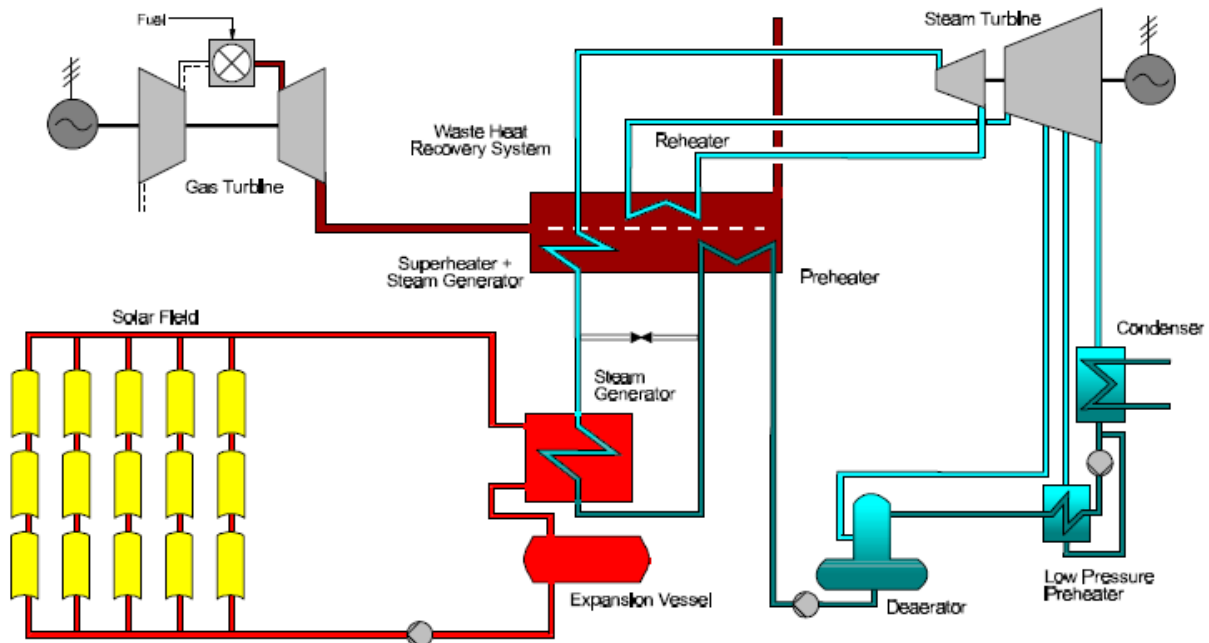


Figure 3-3 Typical ISCCS plant layout

Source: National Renewable Energy Laboratory (NREL), 2001

Figure 3-3 above shows a typical ISCCS plant layout with the exhaust/waste heat from the gas turbine plant supplementing the solar heat to raise the steam temperature (superheat) before it enters the steam turbine. The gas turbine exhaust heat can also be used to do the following:

- Re-heat high-pressure turbine exhaust steam before it enters the low-pressure turbine. This is done to improve the steam quality and energy so that it does not prematurely condense in the low-pressure turbine and damage the turbine blades.
- Preheat the feed water before it enters the steam generator. The steam from the turbine is condensed and cooled in the condenser to low temperature. This condensate is preheated and pressurised before it enters the steam generator to improve the thermal cycle efficiency and reduce the amount of energy needed to turn it to steam.

The World Bank Global Environmental Fund (GEF) project provides funds to developing countries to develop ISCCS plants. These plants varying from 50 to 310 MW capacities are located mostly in sunny developing countries like India, Morocco, Egypt and Algeria (SolarPACES, 2010). The following are some of the plants that

have integrated parabolic trough technology into ISCCS systems, including those financed by GEF:

- India: proposed 140MW ISCCS plant including 35MW parabolic trough
- Egypt, Kuraymat: 135MW including 20MW parabolic trough, currently under construction
- Mexico: proposed El Fresnal 560MW plant, including 25-40MW parabolic trough
- Morocco Ain Beni Mathar: 240MW including 25MW parabolic trough currently under construction
- Morocco: proposed 150 MW natural-gas-fired ISCCS plant project including 30 to 50 MW parabolic trough
- Algeria: proposed 400MW ISCCS including 70MW parabolic trough

3.8 Water cooling options and cost requirements for CSP technologies

Water is used in a CSP plant to clean the mirrors, produce steam and for cooling processes. The cost of water consumed in a power plant depends on its source. Just like all steam cycle plants, CSP plants using a steam cycle require cooling and condensing the steam in the condenser for re-use in the cycle. Cooling can be provided by air or water. The smaller Dish engines are mostly air-cooled and in this case, water is mostly used for washing the mirrors. However, air-cooled plants using steam cycles operate at a lower efficiency than water-cooled ones due to better cooling properties of water compared to air.

Cooling of such CSP plant thermal cycles can be achieved by using different cooling methods namely; wet cooling (evaporative water or once-through cooling), dry cooling, and hybrid wet/dry cooling. In wet cooling and hybrid wet/dry, condensers, cooling water and cooling towers are used while dry cooling can be achieved with or without these. Cooling methods that utilise the least amount of water are often favoured for CSP plants because most of them are built in dry, remote places with good solar resources but scarce water resources.

Once-through cooling

The once-through cooling technique draws water from a cold source and returns all of it back to that source at an elevated temperature. This technique requires water sources like perennial river sources, large dams, lakes or seas. According to Table 3-1 below, this is the most water-intensive cooling technique in terms of volumes of water required – although not in terms of water losses to the atmosphere. Since most CSP plants are located in dry, remote places where there are no large water bodies, this cooling technique is usually limited to conventional coal and nuclear power plant technologies. Eskom Koeberg power station utilises the once-through cooling technique by drawing and returning water from the sea.

Wet cooling (with evaporation and recirculation of cooling water)

In evaporative wet cooling methods, the cooling water runs through the condenser tubing, where the working steam cools and condenses on the outside of these tubes. The cooling water is circulated between the condenser and the cooling tower. In the cooling towers, the cooling water is pumped to some height and sprinkled down where an upward movement of air evaporates some of the water forming a white plume seen on top of most cooling towers. This is the most common cooling technique used in many of the Eskom coal power stations and the existing parabolic trough plants because it is the most efficient and cheapest cooling technique available(SEIA, 2010).

CSP plants using this cooling method consume approximately the same amount of water per kWh of electricity produced as conventional coal and nuclear power technologies (Table 3-1). This is the most water-intensive cooling technique after the once-through technique, in terms of water volumes required, and has higher rates of water lost to the atmosphere.

Dry cooling

The dry cooling technique can be achieved *directly* where steam from the turbines is channeled into heat exchangers cooled by fans. Most of these do not employ a cooling tower. In *indirect* dry cooling systems, a closed cooling water circuit is used to remove heat from the condenser and dump it to the upward rising cold air in the cooling towers. Such dry cooling techniques use the least amount of water, but are more expensive to construct. The huge cooling fans produce a lot of noise, and the reduced heat transfer capabilities lead to reduced thermodynamic efficiencies in the power cycle, by a few percent (see Table 3-1). Matimba and Kendal power stations in South Africa are the largest direct and indirect dry-cooled power plants in the world respectively¹³. Despite the disadvantages of these dry-cooling techniques, they are probably the most suitable for CSP plants located in places with severely limited water resources.

Hybrid dry/wet cooling

This is a combination of dry and wet cooling techniques. Such hybrid designs are mostly built to reduce the plume produced by wet cooling towers and/or reduce water consumption in a thermal power plant. Since most CSP plants are located in dry, remote places this technique would mostly be used to reduce water consumption. The dry cooling part of the hybrid arrangement could be used most of the time, with the wet cooling part used on very hot days to improve the overall thermal cycle efficiency. According to Parsons (2008), this cooling technique is cheaper than plain dry-cooling methods, but more expensive to construct than conventional wet-cooling methods.

¹³ <http://www.eskom.co.za/c/article/240/water-management/> accessed 28 July 2011

Table 3-1 Comparison of the consumptive water use of various power plant technologies using various cooling methods

Technology	Cooling Method	Gallons/MWh	Litres/MWh ^d	Performance Penalty ^a
Coal/Nuclear	Once through	23 000-27000 ^b	87064-102206	
	Recirculating	400-750	1518-2839	
	Air cooling	50-65	189-246	
Natural gas	Recirculating	200	757	
Power Tower	Recirculating	500-750	1893-2839	
	Hybrid	90-250	340-946	1-3%
	Air cooling	90	340	1.3%
Parabolic Trough	Recirculating	800 ^c	3028	
	Hybrid	100-450	379-1703	1-4%
	Air cooling	78	295	4.5-5%
Dish/engine	Mirror washing	20	75	
Fresnel	Recirculating	1000	3785	

Source :(DOE, d.u.)

Note:

- a Annual energy output loss is relative to the most efficient cooling technique
- b Most of the water is returned to the source but at an elevated temperature. Some is lost through evaporation
- c 2% of this amount is used for washing the parabolic reflector mirrors
- d converted from Gallons/MWh by the author (rounded off)

CSP plants using air-cooling have lower overall plant performance, which can lead to higher levelised costs of electricity produced, depending on water costs and the economic value of water savings. The cooling efficiency, and hence overall plant performance impact, is relative to the operating temperature and ambient temperature difference, in air-cooled systems. The performance penalties (compared with wet evaporative cooling) are therefore greater for trough plants than for power tower technologies because towers operate at higher temperatures. The penalties, especially for troughs, are most severe over periods when ambient temperatures are very high. Part of the rationale for hybrid wet/dry cooling is to employ more effective wet cooling to supplement the basic dry cooling facilities, on very hot days, while at the same time conserving annual water consumption by relying on air-cooling at other times.

In Table 3-1 above, the USA data compares very well with the South African coal power plants using wet cooling techniques. According to the Eskom (2009) annual report, the coal power plants consumed on average 1350l of water/MWh and the dry-cooled coal power plants used 93% less water.

3.9 Technology most suited for South Africa

The technologies and plant configurations used in different regions and countries normally depend on the electricity demand of those places. For example, in Spain and in hot parts of the USA, there is higher afternoon electricity demand during summer months than at other times of day, due to the use of air-conditioners (Figures 3-4 and 3-5). In such regions, to help cover peak daytime electricity demands, especially in summer months – when the available solar energy is also highest – the use of cheaper parabolic trough technologies with no thermal energy storage would be the most appropriate CSP choice, with conventional plants (e.g. coal, gas, nuclear and hydro, where available) covering the base load electricity demand.

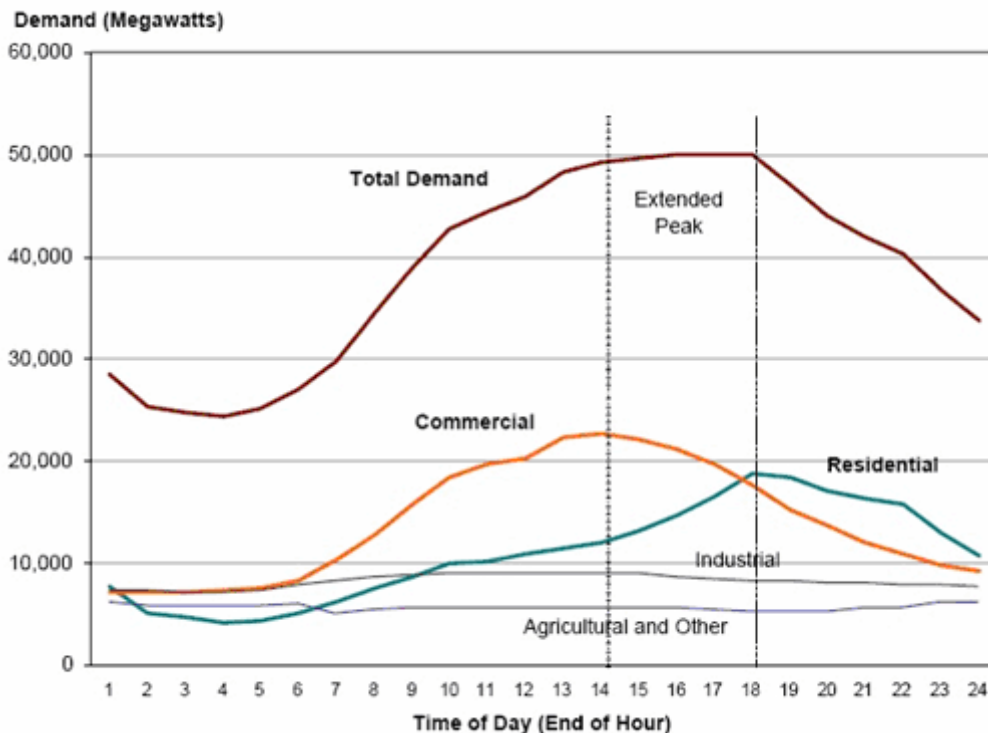


Figure 3-4 Typical total California load profile for a hot day in 1999

Source: http://www.mpoweruk.com/electricity_demand.htm accessed 19 May 2011

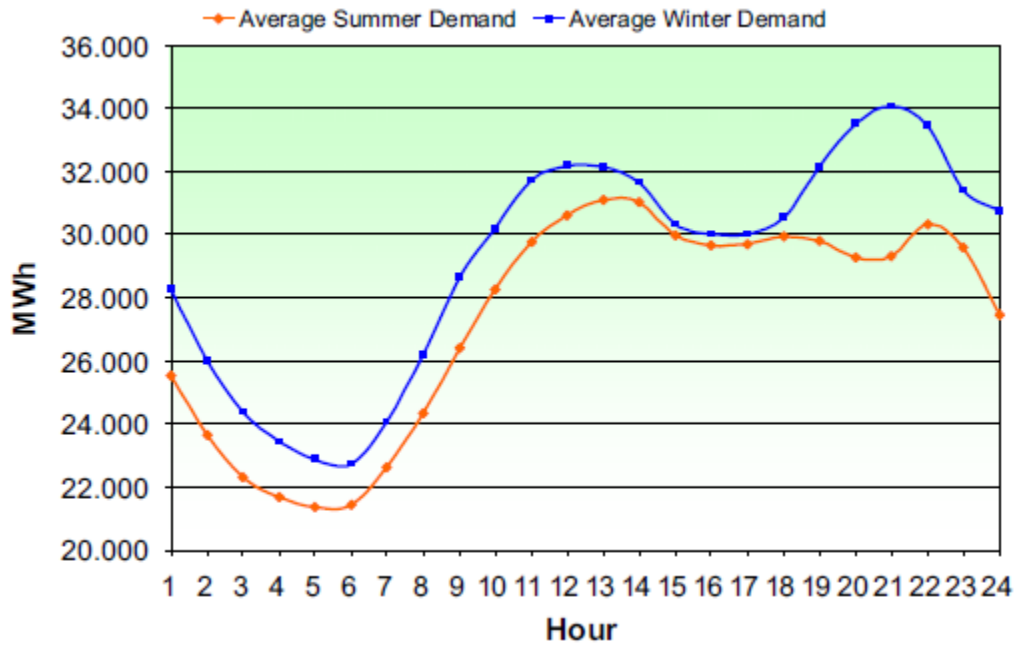


Figure 3-5 Average hourly electricity demand curve for a typical winter and summer day in Spain

Source: García-Ascanio and Maté, 2009

South Africa is a developing country and its national electricity demand curves differ from those of Spain and the USA due to different electricity use patterns. Some typical South African national electricity demand curves are shown in Figure 3-6 below, for periods in 2007, as published by Eskom. South Africa has a morning and evening peak demand and a flat afternoon demand.

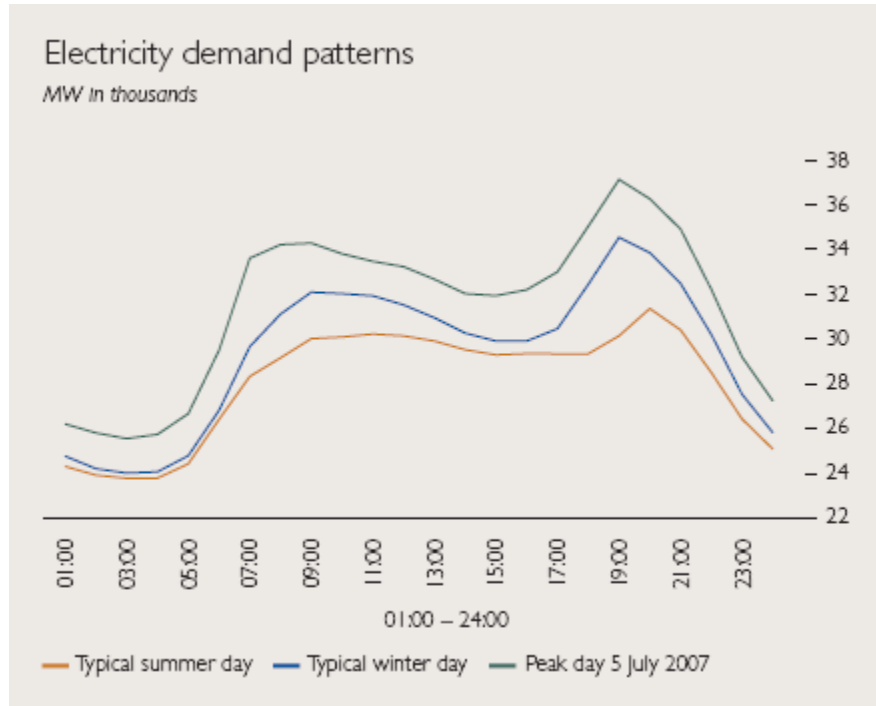


Figure 3-6 Typical South Africa electricity demand patterns

Source: Eskom Annual Report (2008)

Note:

Figure 3-6 shows the average national hourly electricity demand, as recorded by Eskom. The typical summer day profile consists of data from 1 February 2007 to 15 April 2007 and 1 October 2007 to 15 December 2007. It is flat with high air-conditioner load during the day. Morning peak is usually at 12:00hrs and evening peak at 20:00hrs. The typical winter day profile consists of data from 15 May 2007 to 15 August 2007. The demand is highest and peaky in winter with high demand in the morning between 07:00 to 09:00 and evening at about 19:00hrs due to heating requirements (Eskom, ar2008).

In South Africa the coal-fired generation, which is cheap, plus a nuclear contribution dominate base load electricity supply. To cover peak electricity demands, especially in winter months, additional gas turbines are operated, which are very expensive to

run, and sensitive to petroleum fuel costs and supplies (Eskom, ar2008). In light of these circumstances, the CSP technologies with thermal energy storage could be best used to replace some of the expensive gas turbines supplying intermediate and peak electricity demand. In order to do this, CSP plants would need thermal energy storage capacity so that CSP-generated energy is dispatchable during evening intermediate and peak demand periods. According to the DNI data measured by Eskom in Uppington, the optimal DNI for CSP plant operation is from 8-9am to 5-6pm depending on the season¹⁴. The evening peak is at 7-8pm with an evening intermediate peak lasting 1-2hours before and after the evening peak (Figure 3-6). Therefore, a CSP plant with a 6-hour thermal energy storage capacity would be ideal.

The data for the calculation below is derived from the recent EPRI (2010) study and the discount rate used 10% (Table 4-6, for developing countries). The calculation shows that the LCOE for both 148MW OCGT and 125MW central receiver technologies is similar and hence CSP may be used to replace OCGT. The Excel spreadsheet for this calculation is in Appendix 5.

Table 3-2 Central Receiver and OCGT technology costs and performance

Technology	Central Receiver	OCGT
Rated capacity, MW	125	148
Overnight capital cost, ZAR/kW	32190	3955
Lead times, Years	4	2
Fixed O&M	546	70
Variable O&M	0	0
Efficiency, kCal/kWh	1590	3481
Fuel Costs, ZAR/10 ⁶ kCal	0	175.72
Capacity or load factor %	36.7	10
Discount rate, dr	10%	10%

¹⁴ <http://www.eskom.co.za/content/EskomSolarMeasurementdata.doc> accessed 06 November 2011

1. LCOE calculation for the proposed 125MW central receiver plant in Upington

2. OCGT fuel cost per kCal calculation

(EPRI, 2010)

Unit conversion ratio

3. LCOE calculation for the 148MW Ankerlig OCGT

The best location for these plants would be around Upington, in the Northern Cape, where there is one the best solar resources (Table 2-6). This design does not cater for the morning peak, but will be used in the afternoon and the thermal storage capacity will cover the evening peak loads. The morning peaks will be covered by the backup fuel.

University of Cape Town

4 Economic review

This chapter looks at a global economic review of CSP technologies, focusing on present and expected future CSP cost trends in South Africa, Spain and the USA. These cost data are compared to other electricity generating technologies like wind, nuclear and fossils. It will also discuss the potential for future CSP cost reductions.

Currently South Africa does not have any commercially operating CSP plants, but Eskom is actively investigating the feasibility of using CSP technology for large-scale electricity generation in South Africa (Eskom, ar2009). At present, they propose to install a 100MW plant with 14hours of storage and commercial demonstration of central receiver technology. This plant is planned to be situated in the Northern Cape, location Farm 450, Olyfenhoutsdrift, Upington.

This Eskom data will be used for review purposes in this chapter. Another source of cost estimates for CSP in South Africa comes from the recent electricity generating technologies cost estimate study by EPRI (2010) for the forthcoming South African government IRP. The cost data and economic analyses for CSP projects in other countries are drawn mainly from internet sources.

The approximate exchange rates of 1 US\$ = 7.6 South African Rand (ZAR) and 1 € = ZAR 10.8 used for this dissertation were calculated from daily average exchange rate data obtained from the Standard Bank (2010), covering the period from 14 May 2009 to 14 May 2010 (see Appendix 2).

There is very little documented CSP commercial experience to provide economic benchmarks, and this makes it more difficult to evaluate economic data or forecasts for CSP technologies. Much of the information available at this stage comes from assumptions and estimates made by researchers. Currently there are few commercial CSP plants in operation, as described in previous chapters and included in section 4.2 below.

4.1 Costing methods and definitions of costing parameters

Collecting and comparing the economic data for CSP technologies is challenging, because in most instances the values provided are not fully explained in terms of financial parameters such as assumed project lifetimes, discount rates and investment interest rates. Also in most cases where capital costs are evaluated, it is not specified whether these are real, overnight or discounted amounts.

The following are definitions and brief discussions of the type of costs and other financial terms used in this Chapter.

4.1.1 Capital cost

The capital cost is the amount of money required to complete a project, usually expressed in monetary amount per kW of installed capacity. The capital cost can be given as an overnight cost or real project cost. The “overnight cost” assumes that the plant is built overnight, with no added costs in the form of interest charges during the construction period and associated financial costs of borrowing the money. However, CSP plants are built over a couple of years and hence accumulate additional finance charges. The “real project cost” is the amount of money actually required to complete a CSP plant, including accumulated finance charges, and allowances for insurance, depreciation, changes in plan, etc. Before a project commences the real project cost can only be estimated, using expected interest and discount rates, and other relevant forecasts parameters.

4.1.2 Operating and maintenance (O&M) costs

Operating and maintenance plant costs are the costs incurred once the plant has been built and commissioned. In electricity generating power plants, operating and maintenance costs are usually separated into fixed and variable costs. Fixed O&M costs are usually the constant costs that are independent of the plant production status. These include personnel remuneration and fixed financial charges. They are normally dependent on the plant size and hence expressed in monetary amount per kW of installed capacity.

Variable costs are usually the expenses that are incurred over a short period from the actual operation of the plant. These may be for services or goods purchased to

run the plant and they are often dependent on the electricity generated hence expressed in monetary amount per kWh of electricity produced. Variable costs include variable fuel costs, working fluid make-up and other plant consumables.

4.1.3 Levelised cost of electricity (LCOE)

The LCOE is the net present value of total life cycle costs of the project divided by the quantity of energy produced over the system life. It is the evaluation of the life-cycle energy cost and life-cycle energy production and its unit of measurement is monetary amount per kWh.

The total life cycle cost includes the capital investment cost, annual operating and maintenance costs and overhead costs, taking account of interest rates and any other finance charges, depreciation, tax rates, and discount rates used to convert expenditures in future periods to “present value”. The total lifetime energy production is the actual electricity energy sent out to customers measured in kWh. The ratio of the actual electricity energy sent out to the rated power is the system capacity factor (CF).

The LCOE calculation can be used to compare different technologies in terms of the cost of generating electricity and different financial and technical parameters. Larger conventional coal and nuclear plants normally have high capital costs (although not as high, per kW, as CSP) but lower levelised costs due to their higher capacity factors and lower interest rates compared to CSP technologies, and lower operating costs compared with OCGT plants.

4.1.4 The discount rate

The discount rate is a factor used to convert future costs to present-value costs. It reflects the time value of money at any given time. Unlike the interest rates, which are the rental price of money, the discount rate discounts future sums of money to present worth. Theoretically, it is a reflection of the opportunity cost of money to a particular investor (IAEA, 1984). Table 4-6 shows some typical discount rates used by different investors.

4.2 Selected operating CSP plants

4.2.1 Solar Electricity Generating Station (SEGS) plants

The SEGS were the first commercially operated CSP plants in the world. They were built from 1985 when the first SEGS 14MW capacity plant was installed to 1991 when the last two, 80MW capacity, of the nine SEGS plants were installed. The SEGS plants use parabolic trough receivers to convert solar irradiation to electricity.

These SEGS plants which were built by an Israeli company called Luz Industries at a total capital cost of \$1.2 billion (2006 US\$ value) are located in the Mojave desert of California, are still commercially operating today and doing so well that their plant availability is averaging 99% annually (World Bank, 2006). They have no storage facilities and are backed by up to 25% electricity generation by gas turbines. Most of the recent parabolic troughs, including the Andasol plants in Spain, are built on the experience of the SEGS plants. Figure 4-1 below shows an aerial view of some of the SEGS plants.



Figure 4-1 SEGS plants

Source: <http://indiavisions.files.wordpress.com/2008/08/kjc.jpg?w=403&h=609>
accessed 12 May 2011

4.2.2 Andasol 1

The Andasol 1 solar thermal power plant is the first parabolic trough plant to be installed in Europe and has an installed capacity of 50MW and a peak molten salt thermal storage of up to 7.5hours. Andasol 1 is the first of three identical Andasol plants (the others are Andasol 2 and 3) and is located in Granada Province in southern Spain with an average DNI of 2 136 kWh/m²/yr (NREL, 2011). This plant was developed by Solar Millennium AG at an estimated capital cost of €300 million (2008 value) (POWER-technology, 2010). It is estimated to generate about 50GWh

of electricity annually supplying over 500 000 people especially in the summer months when the daytime demand is highest¹⁵. Andasol 2 is commercially in operation and Andasol 3 is under construction and scheduled to be operating by 2011. Figure 4-2 below shows the aerial view of the Andasol 1 solar plant's power block surrounded by numerous rows of parabolic troughs in the foreground.



Figure 4-2 Andasol 1 parabolic trough technology plant

Source:

http://www.solarmillennium.de/english/technology/references_and_projects/andasol-spain/index.html accessed 12 May 2011

4.2.3 Planta Solar (PS) 10

The PS10 is an 11 MW solar thermal power plant in Casaquemada, 20 km from Seville in Southern Spain. It is the first solar power tower completed in Europe and its construction started in 2001 and was finally completed at the end of 2005 at a total cost of € 35 million (2005 value) (Power-technology, 2010).

The PS10 power tower/heliostat field technology has a solar field composed of 624 120m² heliostats with a mobile curved reflective surface that concentrate solar radiation on a receiver at the top of a 100 m tower. The receiver, which produces saturated steam at 40 bars and 250°C from thermal energy supplied by the

¹⁵ http://www.solarmillennium.de/index_lang2.html accessed 2 September 2010

concentrated solar radiation flux, has a cavity design to reduce radiation and convection losses¹⁶.

The PS10, which uses saturated steam as its heat transfer fluid has a 30-minute storage facility, which stores steam under pressure that can be used when there is insufficient solar resource. Additionally it can be backed by gas turbines, which can generate up to 15% of the electricity produced. The PS10 currently generates about 24 GWh of electricity annually. The PS20 plant, which was connected to the grid in 2009, is sited adjacent to PS10. It uses the same technology but its capacity is twice that of PS10. Figure 4-3 below shows an aerial view of the PS10 (foreground) and PS20 solar plants.



Figure 4-3 Aerial view of PS 10 and PS 20 solar tower technology plants

Source: <http://www.switchoffhazelwood.org/resources/400px-PS20andPS10.jpg>
accessed 23 May 2011

¹⁶ <http://www.solarpaces.org/Tasks/Task1/ps10.htm> accessed on 23 September 2010

4.2.4 Alvarado 1

The Alvarado 1 parabolic trough power plant is one of the recent CSP plants to be commissioned and connected to the grid in Spain. According to an Acciona media release, this 50MW rated capacity plant was built at an investment cost of €236 million and was connected to the grid in July 2009 (ESTELA, 2010). It became the first Acciona CSP plant to be connected to the grid in Spain after they had built and commissioned the 64MW Nevada 1 parabolic trough power plant in the USA.

The Alvarado I CSP plant, which is expected to generate over 100MWh of electricity annually, was built on more than 130 hectares with 184,320 mirrors aligned in rows and 768 solar collectors. It is expected to employ about 31 operating and maintenance staff (ESTELA, 2010).



Figure 4-4 Aerial view of Alvarado 1 solar plant

Source: http://i.bnet.com/blogs/samca_laflorida_01.jpg accessed 23 May 2011

4.2.5 Nevada Solar One

The 64MW Nevada Solar One parabolic trough technology plant situated in the Nevada desert was developed by Solargenix Energy Company and started operating

in June 2007. The estimated total project cost is US \$262 million (Power-technology, 2010).

This plant utilises 140 hectares of land and about 184 000 parabolic mirrors to concentrate solar irradiation onto a receiver. According to Power Technology website (Power-technology, 2010), this plant supplies about 40 000 households with electricity at a generating cost of 9-13 UScents/kWh (2007 value).



Figure 4-5 Aerial view of 64MW Nevada Solar One plant

Source: <http://www.travelfreehi.com/wp-content/uploads/2011/05/nevada.solar-one-Krafwerk-Foto-Schott.jpg> accessed 23 May 2011

4.3 Current cost data review

The current cost data presented here are derived mainly from literature on existing plants in the USA and Spain. The cost projections for South Africa are from Eskom CSP feasibility studies and from the EPRI electricity generation cost estimates produced for South African IRP purposes.

The comparison amongst different technologies is to show the relative cost of CSP. Currently CSP technologies are capital expensive, and generate expensive electricity (in terms of LCOE), as shown above. However, it is believed that with mass equipment production and increases in unit capacities, the economic market will have more confidence in CSP technology. This will probably lead to decreasing CSP costs in the future and make them more competitive to conventional electricity generating technologies.

This future competitiveness has been projected to occur in about 2026 with nuclear and 2045 with coal in South Africa (Marquard et al, 2008) and from 2025 to 2030 for the USA markets (IEA, 2010).

The cost of CSP depends on the availability of the DNI solar resource. The economic feasibility of a CSP power plant is first determined by the solar resource of the chosen sites. Economic operation of solar thermal power plants, on present estimates, requires direct normal solar irradiation of at least 1900 kWh/m² per year (Solar PACES, 2007). According to the IEA (2007), the levelised cost of CSP electricity, in places with higher DNI values like the South Western USA, can be 30% cheaper than those with lower DNI values like Spain, for similar plants with similar financing conditions.

CSP generation is even cheaper in locations like Upington, South Africa, with DNI values of almost 3000 kWh/m²/yr (Bohlweki Environmental, 2006). This is because of the higher amount of solar energy harnessed, which equates to higher thermal efficiencies.

World places like Southern Africa, Northern Africa, Southern Europe, South Western USA and the Middle East, with high DNI regimes, are potentially cheaper for CSP generation than those with lower DNI levels. Other factors that affect CSP generating costs are the size of plant and storage, the technology used, sources of funding, and associated financial terms.

All CSP technologies require very high capital cost per MW of electricity installed. This dominates in the LCOE such that the lifetime cost of the installation is about 80% capital expenditure and associated interest, and the rest is operating expenditure (Lazard, 2009). The solar field represents the largest share of the cost of

any CSP plant. Depending on the technology, this cost could vary from around 43% for Tower and Fresnel technology, to almost 60% for Parabolic Trough and Parabolic Dish technology plants (CSP industry report for 2010-2011¹⁷). However, recent studies by the IEA (2010) estimate that lower values are possible, e.g. as low as 30% for state-of-the-art parabolic trough plants.

It is believed that once the plant is paid off the operating costs would be in the range of 3 UScents/kWh of energy produced and that CSP production will in future become competitive with conventional electricity generating power plants (Greenpeace, 2009).

Since the current CSP levelised cost of electricity is not economically viable, governments have introduced FIT to promote CSP capacity growth. In Spain, the current CSP expansion program is mainly a result of the 27 €cents/kWh tariff introduced in 2007. The literature review earlier showed that currently Spain has over 900MW capacity of CSP operating, over 1403MW capacity projects in construction (as of October 2011) and over 1185MW in development or proposal stage.

The South African government through NERSA introduced a FIT of ZAR2.10/kWh for CSP plants with six hours of storage to entice Independent Power Producers (IPPs) to invest in CSPs. Eskom is in the process of doing feasibility studies to construct a 100MW solar power tower in the Northern Cape (Eskom, ar2011).

4.3.1 South Africa current cost data estimates

South Africa does not yet have a CSP plant, and the cost reviews in this chapter for CSP in South Africa will use Eskom and EPRI projected cost estimates.

The Eskom cost and performance estimates referenced below are for Eskom's proposed power tower system in the Northern Cape, with the following specifications (email from Eskom CSP Engineer; see appendix 1) which are subject to verification:

- Thermal rating - 540MWth
- Electrical - 100MW

¹⁷ <http://www.slideshare.net/Newsolar/global-concentrated-solar-power-industry-report-2010-2011> accessed on 2 September 2010

- Capacity factor¹⁸ – 64-70%
- Storage: 14 hours
- House load - 10MW
- Gross production per annum - 560GWh
- Net production per annum - 516GWh
- Location - Farm 450, Olyfenhoutsdrift, Upington
- Overnight Capex - ZAR5 351 Million
- Total Nominal (excl FC(financial charges) & IDC (interests during construction)) - ZAR5 873 Million
- Total Nominal (incl FC & IDC) - ZAR7 642 Million
- The calculated LCOE is ZAR 1.30 /kWh

This proposed plant will utilise a two tank storage system, with molten salt, designed for optimised levelised energy costs, and will be dry cooled or hybrid cooled – designed to optimise water usage. The plant is expected to be completed and commissioned in 2016 and is expected to be funded by the African Development Bank and the World Bank through their Clean Technology Fund (Eskom, ar2011).

Table 4-1 below shows the estimated costs for CSP and other generating technologies in South Africa as done by EPRI for the forthcoming South African IRP. All costs are expressed in January 2010 ZAR value. The CSP technologies are assumed to be fitted with a 6-hour thermal salt storage facility and are located in Upington where the solar DNI average annual value is close to 3000 kWh/m² per annum. This is one of the world's best places in terms of solar resources.

¹⁸Ratio of actual power output to the maximum output that can be produced over a period of time.

Table 4-1 South Africa technology cost estimates

Technology	Rated capacity, MW net	Overnight Capital cost ZAR/kW	Fuel cost ZAR/MWh	VOM ZAR/MWh	FOM ZAR/kW/yr	LCOE ZAR/MWh
Landfill gas	5	17 540	17.1	111.1	497	493.6
CPV	10	37 225	0	0	502	2299.8
Central Receiver	125	32 190	0	0	546	151570.3
Parabolic Trough	125	50 910	0	0	635	2025
Wind	20	16 930	0	0	312	836.7
OCGT	114.7	3 955	502.1	0	70	1397
CCGT	711.3	5 780	315.2	0	148	460.1
Nuclear EPR	4800	27 605	67.3	97.3	included in VOM	721.3
Coal: FB with FGD	1500	14 840	151.2	99.1	365	585.9
Coal: PF with FGD	4500	17 785	146.5	44.4	455	590.9

Source: EPRI, 2010

Key:

CCGT	Closed Cycle Gas Turbine
CPV	Concentrating Photovoltaic
EPR	European Pressurised Reactor
FB	Fluidised Bed
FGD	Flue-Gas Desulfurisation
FOM	Fixed Operating Cost
kW	kiloWatt
MWh	Megawatt hour
OCGT	Open Cycle Gas Turbine
PF	Pulverised Fuel
VOM	Variable Operating Cost

Table 4-1 above shows that CSP costs are higher than other renewable technologies (except CPV) and conventional technologies like fossils and nuclear. This is because of the very high capital cost, which in most cases is not totally offset by lower operating and maintenance costs during the life of the plant. It is estimated that the overnight capital cost of parabolic trough and power towers would be ZAR43 385/kW

and ZAR32 190/kW of installed capacity. Their levelised cost of electricity generation is estimated here to be ZAR 2.08/kWh and ZAR1.57/kWh respectively.

For the proposed 100MW Eskom power tower, with 14hours of storage, the estimated capital cost is ZAR 5.873 billion (excluding finance charges and interest during construction) or ZAR 58 730/kW, with the levelised cost of electricity generation estimated at about ZAR 1.30 /kWh (Eskom CSP senior Engineer, see appendix 1). The difference in the Eskom and EPRI estimates for central receiver technologies stems from the different assumptions used in their costing methods. Besides the different financial parameters, the EPRI study assumes a 125MW capacity plant with 6hours of molten salt storage and air-cooled condensers while the Eskom study assumes a 100MW plant with 14hours of molten salt storage and either dry cooling or hybrid cooling. For comparison purposes, the 4800MW Kusile coal plant is estimated to cost over ZAR100billion (Eskom, ar2009) or ZAR20 833/kW. This value seems higher than the one from the EPRI estimates of ZAR 14 840/kW and ZAR 17 785/kW for FB with FGD and PF with FGD coal plants respectively.

Both the EPRI and Eskom estimates for CSPs are about 3 times the average overnight capital cost of coal plants and about twice that of nuclear. This investment disincentive may be overcome by government support mechanisms like tax rebates and FIT policies that favour the generation and sale of CSP electricity.

According to the EPRI estimates, the central receiver CSP option is cheaper than parabolic trough technology in South Africa. The cost estimate values are assumed for plants that would come online from 2014 (DoE (SA), 2011). It is assumed that by this time, the power tower technology would be more mature and the current estimated costs would have come down to lower than the parabolic trough options due to learning and technology advancement (Turchi et al, 2010). The central receiver technology considered here is assumed to use direct thermal energy storage, which reduces costs, as one HTF is used for heating and storage purposes therefore reducing the HTF piping requirements.

The current capital estimates do not seem to include the cost of building new high voltage transmission lines and infrastructure for the CSP plant. The best place for the installation of CSP plants in South Africa is the Northern Cape, which is not

currently linked to the current Eskom high-voltage grid system (Eskom, ar2009). The estimated cost of building a 400kV transmission line is about ZAR 1 million per km¹⁹. This would increase the capital expenditure of the CSP projects.

There are future CSP cost reduction potentials in South Africa. Since the bulk of the capital cost is from the solar field, it is believed that capital cost can be reduced by local manufacturing of CSP components rather than importing (Holm et al, 2008).

4.3.2 Global CSP costs

This section looks at the cost of existing CSP plants in USA and Europe. Most of the relevant cost data currently available is based on plants in the USA and Spain. The cost of CSP plants in other parts of the world like Egypt, Algeria, Morocco and Asia was not reviewed here because of the scarcity of data. Most of the latter are either small demonstration plants or still under development.

Globally, the CSP industry has recently restarted with the construction of CSP plants after a break since the last SEGS plant in 1991. According to current CSP project development described in Chapter 2, by October 2011 there is about 1507MW of installed capacity worldwide, more than 3257 MW capacity under construction and more than 38 GW under development. As of October 2011, Spain was the world leader in installed capacity with about 60% market share followed by USA with about 37% and the rest of the world with about 3% share. The parabolic trough is the dominating CSP technology with 95% of the total installed CSP capacity share and about 64% of the projects under construction. Judging from the above statistics, the CSP technology seems to be taking off again after project constructions went into hibernation after 1991.

Of recent the Desertec Initiative (DLR, 2006) seeks to export CSP power from the Middle East and North African (MENA) countries to European countries with limited solar resources. Studies have shown that in these desert areas, the solar potential far exceeds their energy demand hence European countries like Germany with virtually no CSP potential are seriously considering importing electricity through sea

¹⁹ <http://www.eskom.co.za/content/ES%200004ElectrCostBenefRev4.doc> accessed 10 September 2010

bed high voltage transmission lines to meet their energy sustainability goals (Greenpeace 2009).

4.3.2.1 Cost of CSP in USA

The USA was the first country to operate a CSP plant commercially. Judging from the CSP plants under development in the USA the parabolic trough technology will continue to be preferred one amongst other CSP technologies.

Though the parabolic trough technology has been operating on a full commercial scale, the same cannot be said of solar power tower technology. The largest solar power tower plant built is the 10MW Solar One, which operated from 1982 to 1988 and was later retrofitted with molten salt technology to demonstrate molten salt use as both HTF and TES medium. The retrofitted plant was later called Solar Two and operated from 1998 to 1999.

The cost of CSP, capital and LCOE, has in the past shown signs of going down in the USA. The SEGS plants capital expenditure fell from US\$ 4 500/kWe for the first SEGS 1 30MW plant to US\$2 875 for the bigger and later 80MW plant. According to Squire et al (2005), this has been due to the economies of scale, the learning experience from increased production and because the technology used after the SEGS 4 is different and more efficient than that of SEGS 1-3. It is believed that the cost of CSPs will fall in future due to the above-mentioned reasons. Many research studies (Sargent and Lundy, 2003; Greenpeace, 2009; World Bank, 2006; Lazard, 2009; UBS, 2009) forecast a similar trend in the USA and worldwide if the above-mentioned developments are successfully implemented.

Table 4-2: USA cost estimates for different electricity generating technologies

Technology	Tower	Trough	PV	Wind	Nuclear	Coal	IGCC	CCGT
Unit size, MW	100	200	10	100	1100	600	580	550
LCOE, \$/MWh	129-169	150-206	131-196	57-113	107-138	78-144	110-141	74-102
Capital Costs, \$/kW	5000-6300	4500-5800	3250-5000	1900-2500	6325-8375	2800-5925	4075-5550	950-1175

Source: Lazard, 2009

Table 4-2 above lists the estimated capital costs and LCOE for different electricity generating systems. The levelised cost of generating electricity from CSP technologies is estimated here to be between 12.9 UScents/kWh and 16.9 UScents/kWh for solar tower systems and between 15 UScents/kWh to 20.6 UScents/kWh for parabolic trough systems, depending on different technology arrangements, DNI values and financing conditions. According to Table 4-2 above, the power tower technology is currently estimated to be more expensive than the parabolic trough because of the higher financial and technical risk associated with first of its kind technology. Investors put higher finance charges on solar tower technology compared with the more proven parabolic trough systems.

Studies on CSP (Sargent & Landry 2003, Greenpeace 2009, IEA, 2010; DoE, 2010) cost estimates show that the CSP costs are higher than for conventional coal and nuclear generation. The 2005 study by Sargent and Lundy estimated a LCOE of about 11 UScents/kWh (2005 value) for parabolic trough systems. The 2009 study by Greenpeace estimated the LCOE to be around 15 UScents/kWh (2009 value).

Currently these levelised cost estimates are more expensive than other main generating technologies in the USA. Within the renewable energy field, CSP has to compete with wind generation, which can achieve LCOEs in the region of 5 to 6 UScents/kWh. The levelised cost of conventional technologies like coal and nuclear is US\$78-144/MWh and US\$107-138/MWh respectively.

According to Lazard (2009), the current capital cost estimates are US\$5000-6300/kW and US\$ 4500-5800/kW for solar tower and parabolic troughs respectively depending on the technology, DNI and financing parameters. In 2010, the USA DoE estimates that the current typical 100MW CSP plant capital cost is US\$4798/kW. The most recently installed 64MW Nevada Solar One parabolic trough plant was reported to have a total project capital cost of \$262 million (Power-technology, 2010) or US \$ 4094/kW.

Studies on CSP in the USA forecast future cost reduction for CSPs. There is optimism that CSP will be able to compete with other electricity generating technologies in future. The IEA CSP road map (2010) study forecast that by 2025 to 2030 CSP-generated electricity would be competitive with conventional electricity generating technologies. These potential future cost reductions are based on

technical improvements, large-scale deployment and scaling up of CSP plants (Sargent and Lundy, 2005).

4.3.2.2 Cost of CSP in Spain

Spain became the first country to introduce a FIT in Europe and it set a 2010 CSP target of 500MW installed capacity. The first FIT was introduced in 2002, which granted 12 €cents/kWh for 100kW to 50MW plants. This was later revised in 2004 to 18 €cents/kWh, due to projects' unbankability. In 2007, this tariff was further increased to 27 €cents/kWh for 25 years increasing yearly with inflation minus 1 percent point then dropping to 80% of the price at that time (Solar Millennium, 2008).

The introduction of the later tariff of 27 €cent/kWh for 25 years stimulated the CSP growth in Spain. Abengoa's Plataforma Solar de Sanlucar la Mayor (PSSM) plants could be the world's largest solar platform, with a total CSP capacity of 300 MW, including the 10MW PS10, 20MW PS20 central receiver plants, and 50-MW each Solnova 1, 3 and 4 parabolic trough plants (IEA, 2007). The other two 50MW each Solnova 2 and 5 plants, are still in the development stage.

Table 4-3 below shows some of the completed CSP plants and their estimated capital costs in Spain. The average DNI for Spain is 2100kWh/m²/yr (Bohlweki Environmental, 2006; IEA Solar PACES, 2007).

Table 4-3: Cost estimates for currently operating CSP plants in Spain

Capacity, MW	Technology type	Thermal Energy Storage	Name	Cost, € million	Cost, € /kW	Year of Completion
50	Parabolic Trough	No storage	Solnova 1	292.5	5840	May 2010
50	Parabolic Trough	No storage	Solnova 3	292.5	5840	May 2010
50	Parabolic Trough	7.5hrs molten salt	Andasol 1	300	6000	April 2008
50	Parabolic Trough	7.5hrs molten salt	Andasol 2	300	6000	2009
50	Parabolic Trough	No storage	Ibersol Ciudad Real	200	4000	May 2009
50	Parabolic Trough	No storage	Alvarado I	236	4720	July 2009
50	Parabolic Trough	7.5hrs, molten salt	Extresol 1	300	6000	February 2010
11	Solar Tower	1 hour steam	PS10	35	3182	2006

The Table 4-3 above shows capital costs of CSP plants in Spain ranging from €3182/kW (2006 value) to €6000/kW (2010 value) of installed capacity. Using Spain's recent consumer price index (CPI) of 3.5% (see Appendix 3) to adjust to 2010 values, these capital costs range from €3651/kW to €6000/kW. The average capital cost for parabolic troughs with no storage is €4982/kW and that of parabolic troughs with storage of 7.5hours of molten salt is €6000/kW.

The capital cost values of Spain CSP plants show that plants with storage facilities are more expensive than those without, per kW of rated capacity. The extra costs come from the storage facility itself and the extended solar field to supply both the solar generating unit and the thermal solar storage facility with heat. However, the storage facilities can enable such plants to operate at higher capacity factors and with improved ability to meet utility load profile demands, potentially decreasing LCOEs, and increasing the value of dispatched electricity.

4.3.2.3 Costs in other European countries

There is not much development of CSP technologies to date in other European countries. According to the EPRI Solar Resource map study (2010) and Greenpeace, SolarPACES and ESTELA (2009), there is limited solar insolation to operate CSP plants in most of these countries. European countries with limited solar resources like Germany introduced feed in tariffs of 28.43 €cents/kWh (Germany blog, 2010). In December 2008, they completed the construction of a 1.5 MW Solar Tower in Jülich to demonstrate a volumetric air receiver technology (Kraftanlagen München, 2010)²⁰.

In 2008, the Italian government introduced a feed in tariff of 22-28 eurocents per kWh depending on the solar proportion of the plant electricity output i.e. 28€cent/kWh for net power output of 85% and above; 25€cent/kWh for 50-85% and 22€cent/kWh for less than 50%²¹. In July 2010²², the first Italian CSP plant was a project where a 5 MW parabolic trough solar field, called Archimede, was coupled to an existing gas-fired power station to form an ISCCS plant with thermal heat storage. This CSP plant incorporates 8 hours of molten salt storage facility (NREL, 2011).

According to Greenpeace, ESTELA and SolarPACES (2009), France introduced a FIT of 30 €cents/kWh (40 €cents/kWh overseas) in 2006 plus an extra 25 €cents/kWh if integrated in buildings (plus 15 €cents/kWh overseas) and have a target of installing at least one CSP plant in every province. So far one 2MW hybrid gas-solar plant is under development for construction in the near future.

Other European countries like Greece and Denmark have shown interest in CSP. A European block of countries has also shown interest in importing CSP electricity from Middle East and North African (MENA) countries. The capital cost of constructing a CSP plant in the MENA region is estimated to be about \$3320/kW and the levelised cost of electricity is estimated to be 15.8 - 16.7 UScents/kWh for technologies with no thermal storage and 12.8 - 13.6 UScents/kWh for those with thermal storage facilities. These plants will be situated in remote areas with no

²⁰ <http://www.ka-muenchen.de/253+M52087573ab0.0.html> accessed 13 September 2010

²¹ <http://www.csptoday.com/csp/pdf/CSPFITGUIDE.pdf> accessed 18 July 2011

²² <http://www.guardian.co.uk/environment/2010/jul/22/first-molten-salt-solar-power> accessed 24 September 2010

infrastructure. The cost to construct high-voltage alternating current transmission lines and substations from MENA to Europe is estimated at US\$200 000/km and about \$10 million for each substation at either end (2008 US\$ value). The costs of high voltage direct current transmission lines are estimated to be more expensive than the HVAC option but these would have lower electricity transmission losses. Transmission lines running through the sea would incur additional costs (Ummel and Wheeler, 2008).

4.4 Cost reduction potential for CSP Technologies

Most of the CSP technologies are still in the research and demonstration phases. The recent IEA (2010) study concludes that the biggest cost reduction technique is to increase the unit size. An increase from 50MW to 100MW per unit would bring the capital costs down by 12%, and by 20% if increased to 200MW per unit, with the power block contributing about 20 to 25% decrease. Most of the future cost projections are based on the potential for technology R&D progress, economies of scale, and learning curve economies associated with increased deployment and experience to reduce CSP costs. In the recent (15 July 2010) European Solar Thermal Electricity Association (ESTELA) CSP workshop²³ held in Brussels, their analysis concluded that major reduction potential is seen in engineering and planning cost, thermal generation and storage system cost.

Various studies have shown that current CSP costs are more expensive than other technologies in electricity generation like coal, nuclear and oil but that there is a great potential to reduce the cost of solar technologies in the future. Sergeant and Lundy (2005) forecast that there is a likelihood that the estimated LCOE would fall from US15cents/kWh to US5.7cents/kWh and from US11cents/kWh to US6.5cents/kWh (2005 US\$ values) for power towers and parabolic troughs respectively from year 2005 to 2020.

Sargent and Lundy (2003) concluded that the cost of CSP energy could be reduced by means of improved technology, increased deployment, scaling up of individual unit capacities, use of thermal storage and providing favourable cost financing and investment incentives. These could reduce the LCOE by 15 to 28% depending on

²³ <http://www.estelasolar.eu/> accessed on 10 September 2010

the technology. They advised that a technically aggressive approach would help to achieve such cost reductions.

4.4.1 Plant scale-up

Production costs are often reduced by scaling up quantities. For CSP, production costs are expected to reduce by increasing the unit size of the plants (Sargent and Lundy, 2003).

Table 4-4: SEGS cost history

Name	Unit size, MW	Capital cost, US\$/kW	LCOE, UScents/kWh
SEGS 1	13.8	4500	24
SEGS 2	30	4500	24
SEGS 3-7	30 each	3400	12
SEGS 8 & 9	80	2875	8 to 10

Source: Sanders and Dempsey (2005)

Table 4-4 above shows the cost reduction from the 13.8MW SEGS 1 to the 80MW SEGS 9 plants in the USA. The capital cost of these plants reduced from US\$4500/kW for the first 13.8MW capacity SEGS 1 to US\$2875/kW for the last 80MW capacity SEGS 9 plant. The LCOE also reduced from 24 UScents/kWh to 8-10 UScents/kWh respectively. These cost reductions are largely credited to scaling up the unit sizes, although technology and production advances also played a part.

According to an NREL (2003) study, a 63% reduction in levelised cost of generating electricity is achievable for parabolic troughs when unit sizes are increased from 10MW to 400MW, for solar-only plant with no thermal storage facilities. In addition to economies of scale in initial costs, the operating and maintenance costs are also likely to decrease with plant scale-up because increasing the size of the unit does not necessarily lead to significant increases in personnel working in the unit.

A World Bank (2006) study estimates that a doubling of unit capacity can lead to a 15% cost reduction due to economies of scale (up to 200 MW).

There may be other reasons, however, which challenge the extent of unit scale-up. For example, the CSP development world leader, Spain, has put a cap of 50MW maximum capacity for plants to be eligible for their FIT policy. This restriction is said to be an encouragement for competition in the CSP industry.

4.4.2 Thermal storage

Thermal storage is used in CSP technologies to improve the plant capacity factor, dispatchability and firm supply. It can reduce the levelised unit O&M and levelised capital costs because of the higher annual energy output, and also allow dispatch of CSP-generated electricity at times of peak demand, which may not coincide with peak solar generation periods (e.g. if there is an evening peak load demand). The ability to offer firm supply at periods of peak demand may attract higher payback tariffs, or be of greater value to a utility, which includes CSP plants in its generation mix.

While plant capacity factors can be increased through thermal storage capacity, to a certain extent (Sargent and Lundy, 2003), the installation of thermal storage facilities does increase the capital cost of a CSP plant. The increased capital costs include additional solar field and solar storage equipment. These additional costs tend to be higher for parabolic trough technologies than for solar tower technologies (Sargent and Lundy, 2003) because of extra piping and working fluid requirements in the former case.

In places like Spain and the USA, most of the currently operating plants do not have thermal storage facilities because their peak demand is mostly in the afternoons for air-conditioning when the solar resource is at its maximum. Some of the recently completed CSP plants in Spain like the Andasol parabolic trough plants have incorporated 7.5hours molten salt thermal storage capacities, which will be used to cover the late afternoon to evening medium peaks.

The proposed 100MW capacity Eskom central receiver plant and the 19.9MW capacity Gemasolar central receiver plant in Spain under construction will incorporate a 14-hour and 16-hour solar thermal storage facility respectively with no combustive fuel back up. They will be used as base load plants (GreenPeace, ESTELA and SolarPACES, 2005) with the extra hours used in the morning before

the sun resource is high enough to run the plant. CSP technology plants with such high thermal storage capacities can operate at about 75% capacity factor (IEA, 2010). An associated advantage of incorporating prolonged hours of energy storage is that it reduces the thermal losses due to turbine stop-starts (periods when the turbine working fluid is heated or cooled with no electricity generated).

The optimal thermal storage capacity depends on the intended use of the CSP technology, feed-in-tariff structures and conditions, etc. Broadly, however, studies by Sargent and Lundy (2003) and the World Bank (2006) have advised that CSP technology plants with capacities up to 12 hours of thermal storage can be cheaper in terms of LCOE than those without or with higher than 12 hours. Another study by NREL (2003) concluded that thermal storage capacity of between 6 and 16 hours could improve the CSP plants' capacity factors and reduce their levelised costs.

Such guidelines will be sensitive to any major changes in the relative costs of direct CSP generation, and CSP energy storage, in particular circumstances.

4.4.3 Technical improvements

Technical improvements through continued research and development can reduce the cost of CSPs by improving overall plant efficiencies or reducing the component costs. Equipment and processes can be replaced with better and more efficient ones to bring down capital costs and LCOE.

Recent studies by aluminium manufacturer Alcoa, partnering with NREL, have reported tests on the use of highly reflective aluminium mirrors in place of the conventional glass mirrors in parabolic trough systems. They estimate that this could reduce the CSP costs, in such systems, by up to 20% due to lower installation costs and because aluminium mirrors have the advantage of sustainability, mass production and recyclability (CSPtoday, 2011).

Other initiatives include the development of improved absorber coating for CSP receivers, by NREL, and using better thermal storage materials like calcium hydride instead of molten salt, by the HeliFocus Company in Israel. These could help lower CSP costs in the future.

The combination of solar and gas plants to form an ISCCS plant would also reduce the cost of solar generated electricity (NREL, 2003). The planned ISCC plants by the World Bank in Morocco, Egypt and Mexico would combine 20–30 MW CSP technologies with a gas-fired power plant so that during sunny days the exhaust gases from the gas turbines would be used to preheat and superheat steam generated by the solar plant (World Bank, 2007).

4.4.4 Volume production and “learning curves”

It is believed that volume increases in installed CSP capacities will lead to cost reductions, through economies of scale, lessons learned, experience gained, and improved production techniques. Industry “learning curves” are an estimation of how their costs will decline (or have declined) with each doubling of installed capacity, e.g. as a result of plant scaling effects, process innovations and learning from doing (Neij, 1997).

Although it is complex to extrapolate results from former periods of industry development into the future, the SEGS experience has been used together with assessments of other innovative ideas to forecast future cost trends for CSP technologies. For example, extrapolation of the SEGS experience curve was deemed to show probable cost reductions in the future as long as CSP deployment and research and development continue (NEEDS, 2006).

According to Hughes et al (2007), the CSP technology learning ratios from literature are between 5 and 32%. A recent IEA study (2010) indicates that the expected solar thermal learning ratios for new plant assumed to be commissioned in 2012 is 20%. This means that the cost of CSP technology is expected to reduce to 80% of the original finance cost by each doubling of the installed capacity. However, these ratios would decrease as more plants are constructed and installed because the room for economic and technical improvements gets limited.

4.4.5 Localisation

Indigenisation and local manufacturing are seen as very important tools for bringing down the costs of the CSP industry in South Africa. It has the potential to reduce the costs associated with importing prefabricated materials because no additional costs are incurred from transportation, duty and foreign currency exchange charges. The

other benefit of localisation is the realisation of government socio-economic and industrial policies for growth. The socioeconomic benefits are in job creation and skills development for manufacturing, installation, operation, maintenance and refurbishment of the CSP projects. Each MW of generation constructed will result in 5.9 jobs created (Edkins et al, 2009) and the industry is forecasted to create 125 000 new jobs in CSP local manufacturing and installation alone by 2020 (DoE (SA), 2009).

The recently adapted Rebid program places a lot of emphasis on these policies. In order for localisation to be effective and reduce technology costs through local experience and learning, at least 500MW of large scale CSP projects must be local manufactured and (DoE (SA), 2009). This will give the local suppliers the needed economies of scale to justify investing in a meaningful manufacturing capacity.

A number of CSP components and parts can be local manufactured in South Africa. The Table 4-5 below shows the CSP components and their potential to be sourced locally (DoE (SA), 2009). The local supply will depend greatly on their production volumes.

Table 4-5 CSP components with local supply potential

Component	Local supply potential	
	Yes	No
Collector tubes		Collector tubes are specialised components that will need to be imported. Very few companies manufacture these.
Frames	Frames or Support structures include mirror support, pylons, central stem and support arms can be manufactured local from the local steel and aluminum industry	
Mirrors	There are local companies that can produce float glass to the desired specification for CSPs	
Drives		Helio-stat drives are not standard products and will need to be imported
HTF- oil	South Africa oil industry has the capacity to produce the needed quality and specification for oil used as HTF	
HTF- salt		Molten salt for international CSP plants is currently only sourced from Chile and Israel
Receiver		Receivers represent critical and proprietary technology
Storage system	There is a lot of on-going research in South Africa on storage systems and a potential to be local supplied	
Turbine/generator		South Africa does not currently manufacture power generating components
Steam generator		Those presently used in South Africa are imported but there is a potential for local fabrication
Cooling system	Cooling systems are heat exchangers which are locally manufactured	
Other Balance of Plant	Auxiliary systems for existing power plants are mostly locally supplied	

4.4.6 Financial incentives and funding

Financial parameters have a huge influence on the monthly premiums when paying back a debt. CSP technologies are high capital cost projects, with low operating and maintenance costs. Most of the CSP projects are financed through debt, which attracts high finance charges due to the higher uncertainties and risks related to their under-developed and less mature status, compared with conventional power generation technologies. The parabolic trough technology has demonstrated its commercial operation since 1983 unlike other technologies which are still in the research, development and demonstration phases, hence qualifying for finance at somewhat lower interest rates.

Access to low cost capital finance would significantly reduce the cost of CSPs (Kistner and Price, 1999). The NREL (2003) study analysed the effect of interest and internal rates of returns, and showed how lower rates allow less expensive monthly premium repayments on an investment, and hence lower LCOEs. The proposed Eskom CSP plant may be financed by the World Bank Clean Technology Fund at low interest rates of between 0.25 and 0.75% per annum and guaranteed by the government (Eskom, ar2011).

When financiers and investors make investment decisions, they typically make use of estimated discount rates, to compare the value of expected future costs or income streams with present values. Such discount rates can differ for various agencies, reflecting factors such as access to capital, ability to cover risks, and the opportunity costs of investing the capital in a particular way, versus alternatives. Table 4-6 below shows some of the typical discount rates used by different financiers/investors. The values suggested below are in “real” terms, i.e. adjusted for any inflation.

Table 4-6: Examples of discount rates used in investment decisions by various agencies in energy projects

Investor	Discount Rate %
Governments	4-12
World Bank	10
Public Utility (USA, Sweden)	6-8
Public Utility (Brazil, Thailand)	10-12
Industry	15-20
Residential Household	35-70 ²⁴

Source: Swisher et al (IRP manual), 1997

In the Table 4-6 above, USA and Sweden represent developed nations while Brazil and Thailand represent developing nations. Governments and larger utilities tend to use lower discount rates in financial planning, compared with smaller industries, because they often have access to lower cost capital finance, can afford longer-term investments, have longer payback periods and their risks are spread over a broad range of investments (Swisher et al, 1997). In the case of residential households, the supposed household discount rates are very high and variable, reflecting factors such as limited or expensive access to loan finance, greater uncertainty about the ability to pay back loans and, especially for lower-income households, a preference for preserving current income and expenditures versus committing resources to longer-term investments.

Financial incentives such as subsidised feed-in-tariffs, tax exemptions and financial measures to encourage greenhouse gas reduction, can be used to compensate for the higher risks and costs of CSP investments, helping to achieve access to lower-cost capital finance.

²⁴ Unlike utilities, governments, financing institutions and industrial/commercial financial planners, household discount rates are normally informal, very uncertain and merely estimated indicators of "aversion" to the risks of capital expenditures. Lower-income households in particular are more likely to spend their uncertain income on short-term needs rather than put it into longer-term investments.

4.5 Future CSP cost projections

Currently CSP technologies contribute a negligible component of overall world electricity supply. According to a REN21 (2010) report, the global installed electricity generating capacity from renewable energy sources was about 1230GW in 2009 – this includes large hydro schemes, which contributed about 925GW – while total global electricity generation capacity was around 4800GW. Currently CSP installed capacity is about 1GW. At this level, CSP contributes an electricity share of only 0.021% of the installed global electricity capacity, and 0.08% of current installed renewable energy electricity capacity including large hydro.

Since 2007, there have been positive developments in the CSP industry. Many countries introduced CSP growth incentives and strategies.

CSP technologies are near the beginning of their learning curve and with technology improvements, scale-up of units and mass production, their cost is set to come down in the near future. The parabolic trough technology is the most mature of the CSP technologies because of the SEGS operating history, hence it is currently cheaper than the power tower technology, but the latter has seen some important recent growth with the installation of the PS10, PS20 plants and Torresol's Gemasolar in Spain. Currently central-receiver CSP plants are more costly than parabolic trough systems but are expected in future to be cheaper because of their higher operating temperatures and concentrating ratios (increasing the efficiency of thermal cycle) and reduced piping requirements.

One of the recent solar studies, by Greenpeace (2009), forecast an 800% growth of installed capacity from the current 1000MW to 830GW by 2050. In this forecast, they believe that the LCOE generated should fall from the current 15 €cents/kWh for high DNI places and 23 €cents/kWh for lower DNI site locations to between 10 and 14 €cents/kWh respectively by 2050. They predict investment costs to fall from the current €4000/kW to €2280/kW.

According to Sargent and Lundy (2005), LCOE of 10.9-15 UScents/kWh will come down to 6.5-5.7 UScents/kWh by 2020 depending on the total capacity of various technologies deployed and the extent of research and development program success.

The following extract from the SolarPACES 2007 annual report also commented on the potential for future CSP cost reductions, “Plants operating in California have already achieved impressive cost reductions, with generating costs of 18 to 35 UScents/kWh, depending on the solar resource available, plant type and size, and forecasts are for less than 15 UScents/kWh. Advanced technologies, mass production, economies of scale and improved operation will all contribute to cost reduction, making solar electricity competitive with other power resources within the next 10 to 15 years. The CSP industry expects solar electricity generation to be fully competitive with fossil-based, grid-connected power starting from a global 5,000 MW installed of CSP solar capacity”.

A recent study by UBS (2009) concluded that future cost reductions for CSP technologies are possible, and that CSP competitiveness with other technologies is projected to be achieved by 2020-2030. Table 4-7 below, extracted from this study, shows that the CSP technology generating cost is expected to fall to between 4 and 10 UScents/kWh. The values in the brackets are for the technologies that will include Carbon Capture and Storage.

Table 4-7: Technology Generating Costs from Literature

Technology	2009 UScents/kWh	2020-2030 UScents/kWh
CSP	15 - 40	4 -10
Wind	4 - 15	3 - 8
PV	25 - 80	6 - 25
Coal	3.5 - 6.0	4.5 - 8.5 (6.0 - 8.5)
Gas	4 - 7	5 - 8 (7 - 10)

Source: UBS, 2009

4.5.1 Parabolic troughs

The history of the SEGS plants has been used for cost development purposes on other plants. The recently commissioned 64 MW Nevada Solar One plant began operating in 2007 and is a SEGS plant prototype. According to Squire et al (2005), the SEGS plants’ capital costs fell from US\$4500/kW to US\$2875/kW between 1985

and 1991 for the first 13.8MW and last two 80MW plants respectively. This was credited to the scale-up and technology advancements of the units.

A recent IEA (2010) study estimates that the current investment cost for large state of the art parabolic trough plant is from US\$4200/kW to US\$8400/kW and the levelised cost of electricity is estimated to range from 20 UScents/kWh to 30 UScents/kWh for large trough plants. This range of values seem higher than those given for the SEGS plants above because of changes in dollar values over the years, inclusion of storage facilities and different assumptions used. The levelised cost is projected to reduce to between 4 UScents/kWh and 5 UScents/kWh for places with DNI values of 2600 kWh/m²/yr and 2100kWh/m²/yr respectively. The cost will depend on the DNI values, operating and maintenance cost, technologies, amount of storage and size of the solar field.

Table 4-4, from Sanders & Dempsey (2005), shows capital cost and levelised cost of energy for each SEGS plant since 1985. These costs have gradually decreased, which has been used as evidence that the costs of CSP will fall in the future and it will become more competitive with other electricity generating technologies. The capital cost has decreased from US\$4500/kW for the first two SEGS plants to US\$3400/kW for the 30MW units and to US \$2875/kW for the latter and bigger 80MW units. Similarly, the LCOE has decreased from 24 UScents/kWh for the first two units to 12 UScents/kWh for the 30MW units and to 8-10 UScents/kWh for the latter and bigger 80MW units. These costs are estimated at the year of installation for each unit.

Many studies (ECOSTAR, 2005; Sargent and Lundy, 2003; Black & Veatch, 2006; Greenpeace, 2009; Winkler 2007; IEA, 2010) discuss the future cost trends of parabolic trough plants and predict that the future costs will fall and become competitive with other electricity generating technologies like wind, coal and nuclear because of the reasons discussed in the earlier section. The extent of decrease is however uncertain due to the uncertainty of financial, political and technological situations.

According to Acciona Solar (2010), the recently built 50MW parabolic trough in Spain was constructed at a total cost of €236 million (July 2009 value). A similar 50MW Majaradas plant under construction and planned to be on line at the end of the year,

is estimated to cost €241million. This translates to €4720/kW (ZAR50 882/kW) investment cost. This remains significantly higher than the capital cost of new coal power stations in South Africa. In South Africa, coal-fired power stations dominate electricity generation and this will continue for a long time due to abundant coal reserves and very low electricity generating costs. The capital cost of the planned 4800MW Kusile power station in Mpumalanga is projected to be ZAR100billion (2009 value) or ZAR20 990/kW (Eskom, ar2009). From these two 2009 technology costs, the capital cost of CSPs is more than two times that of pulverised coal and is currently not competitive. From recent studies by Edkins et al (2009), the cost of CSP is projected to be competitive to that of coal by 2045.

To realise the projected 2045 CSP cost-competitiveness between CSP and coal-fired generation, CSP costs must reduce accordingly. According to Sargent and Lundy (2003) the bulk contributors to the costs of parabolic trough solar plants with thermal storage are the solar collector field (53%), thermal storage system (23%), and power block (14%).

Their analysis of the potential for future electricity cost reductions concluded that in a “technically aggressive” scenario for parabolic trough technology, future cost reductions were due to volume production (26% reduction), plant scale-up (20% reduction) and technological advancements (54%). The percentages in brackets show the proportions of the overall forecast cost reduction.

4.5.2 Solar towers

The solar tower central receiver technology is the second most advanced CSP technology after parabolic trough systems. It is a new technology at a commercial level in CSP electricity generation, and hence it is difficult to find reliable cost data at present from commercial-scale applications.

Recent global estimations of the costs of solar tower options are higher than for trough systems, (e.g. Lazard, 2009); but in future these costs are expected to decrease below those of parabolic troughs mainly because of the greater scope for plant scale-up, shorter HTF piping requirements, higher operating temperatures and the potential for higher power-cycle and energy storage cycle efficiencies.

In 2007, the 10MW PS10 plant in Spain became the first commercially operated solar tower technology to be connected to the grid. Before then, there was the Solar One steam demonstration plant, which was later transformed into the Solar Two molten salt demonstration plant in the USA. To date there is about 56MW of power tower capacity connected to the grid globally. There are a few projects under construction and many under development.

According to Sargent and Lundy (2003), the capital cost, operating and maintenance costs and levelised costs of electricity will come down in the longer term for solar tower systems. They forecast that the capital cost component of the LCOE might be reduced by around 57%, from US\$97.1/MWh in 2004 to US\$46.1/MWh in 2020. The O&M cost component may reduce by 72% from US\$46.1/MWh to US\$12.9/MWh in 2020; and the levelised cost of electricity could come down by 62% from US\$143.1/MWh to US\$57/MWh (2004 USD values). These electricity cost reduction forecasts were due to volume production (28%), plant scale-up (48%), and technological advance (24%), in 2020.

4.6 Global outlook scenarios review

The amount of future deployment of CSP could determine their future costs. A large-scale roll out of CSP globally has the potential to reduce the future cost of CSP, as the industry will learn from experience and improve.

Globally CSP technologies installed capacity is about 11507MW compared to 280GW (including large hydro) of total installed renewable and 4700GW of total world electricity installed capacity (REN21, 2009). These values show that CSP technology still has a long way to catch up with other electricity generating capacities. However, there are good signs that CSP will become a major player in world electricity generation judging from the recent increase in the number of completed projects, projects under construction and those that are still in the development stage. Recently the USA president, Barack Obama announced his government support to the CSP industry by guaranteeing US1.45billion²⁵ towards the construction of the largest concentrating solar plant in the world.

²⁵ <http://www.greentechmedia.com/articles/read/abengoa/> accessed 09 September 2010

Financial institutions like the World Bank are providing support for the CSP technology through their GEF projects in some developing countries (e.g. the Egypt Solar Thermal Hybrid Project in Kuraymat; India Solar Thermal Project in Mathania; the Mexico Hybrid Solar Thermal Power Plant Project in Agua Prieta; and the Morocco Integrated Solar Combined Cycle Power Project in Ain Beni Mathar). This will also help in the growth of CSPs (World Bank, 2006).

There has been a positive change in the last few years by several governments in introducing supportive policies and strategies in the CSP industry to help stimulate the deployment of CSP electricity. Spain's REFIT strategies have stimulated the growth of CSP plants. Some US states have introduced mandatory inclusion of CSP power in the generating institutions' portfolios. South Africa has set a target of 200MW of CSP capacity by 2015 in their recent IRP plan and Eskom is in the development stage for a 100MW power tower plant. Other companies that have announced plans to develop CSP are Abengoa's 100MW CSP plant Solafrica's 75MW parabolic, Group Five's 150MW parabolic trough facility in the Kalahari Solar Park and Emvello's 125MW CSP plant.

The future looks bright for CSP technologies, judging by different studies and projections, such as those of Sargent and Lundy (2003), ECOSTAR (2005), the World Bank (2006), UBS (2009), Greenpeace (2009), and the IEA (2010). From the earlier to later CSP studies, there has been growing optimism on the future of CSP deployment capacities. As long as there is deployment, research and development, and financial and political will, the CSP capacity will increase.

In 2003, Sargent and Lundy projected that by 2020, the global CSP capacity would be 2.6GW and the Sunlab projected it to grow to 8.7GW globally by 2020. Later studies by World Bank in 2006 projected that the global capacity would reach 20GW by 2015. The IEA Energy Technology Perspectives (2008) study projected that by 2050 the global CSP capacity would be 630GW and in 2009 IEA (SolarPACES, ESTELA & Greenpeace, 2009) projected that the global CSP installed capacity would reach 1500GW.

The recent IEA (2010) study projects that the global installed capacity would reach 1089GW or 11.3% (1.7% from back up fuels) of estimated global electricity production in 2050. This estimate assumes that the average capacity factor of CSP

plants will reach about 50% and that they will be cost-competitive with conventional electricity generating technologies like nuclear and coal. By 2050, this study predicts that North America (USA and Mexico) would be the world leader in CSP electricity generation followed by Africa, India and the Middle East. Most of the CSP-electricity to be generated in North Africa is projected to be exported to Europe.

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5 Conclusions

According to the literature review used for this dissertation, the LCOE ranges from 10.9-15 UScents/kWh (Sargent and Lundy, 2005) to 18-35 UScents/kWh (SolarPACES, 2007). Most of the other estimates from other studies lie between these two estimates.

The majority of the earlier years' studies showed that the parabolic trough technology is estimated to be cheaper than central receiver technology, but the latter has a greater potential for future cost reductions. The recent studies like the EPRI (2010) and Lazard (2009) estimate that the central receiver is less expensive than the parabolic trough because their cost estimates are based on the recently completed central receiver plants rather than the risk-inflated cost parameters used in earlier years' estimates.

Besides the wide variation in the LCOE estimates from different studies, there is optimism that the CSP technology costs will be reduced in the near future and will become competitive to those of conventional and other renewable energy technologies. Their LCOE is expected to fall by up to 85% by 2050 whilst on the other hand, the LCOE of conventional power plants is expected to increase in future making the CSP technologies competitive or even cheaper.

The LCOE from CSP plants is expected to fall to around 6.5-5.7 UScents/kWh (Sargent and Lundy, 2005) by 2020, 4-10 UScents/kWh (UBS, 2005) by 2030 and 3-6 UScents/kWh (IEA, 2010) by 2050.

Most of the studies estimate that central receiver CSP technology will become cheaper than parabolic trough designs, due to the greater potential for economies of scale and higher operating temperatures. These cost reductions and growing cost competitiveness can be realised by an aggressive approach in increasing unit sizes, mass production and deployment, research and development and increased prices of other technologies. Financiers like the World Bank GEF can also play a major role in cost reduction by financing projects at lower interest rates. Because of the current high cost associated with the CSP projects, it is necessary to provide incentives and feed in tariffs to grow the industry to such a level that their LCOE will reduce through volume production (learning curve).

Judging from the recent number of completed plants in Spain and the USA and those that are under development in the rest of the world (especially in the USA) it can be seen that there is optimism on the future growth of the CSP industry. This growth can be accelerated and sustained by concerted efforts from concerned participants like governments, researchers, developers and financiers. It is projected that CSP could account for 8% to 25% of the global electricity by 2050 if financial, political and technology barriers are overcome (GreenPeace, ESTELA & SolarPACES, 2009). The recent IEA (2010) study projects that the global installed capacity would reach 1089GW or 11.3% (1.7% from back up fuels) of estimated global electricity production in 2050. This estimate assumes that the average capacity factor of CSP plants will reach about 50% and that they will be cost-competitive with conventional electricity generating technologies like nuclear and coal.

Judging from the current CSP technology project developments, the parabolic trough technology will continue to be the dominant technology of choice in the near future and the solar tower will increase slightly. The parabolic dish and the linear Fresnel reflector technologies are still to enter the pilot stage of development.

The global market for CSP projects is very large. The suitable regions for CSP plants are the very sunny regions, specially the arid and semi-arid places like Southern Europe, Southern Africa, North Africa and Middle East countries, south western USA, Australia and parts of Brazil, India and Mexico. Most of these suitable regions are in the developing countries hence can take advantage of the low interest rate World Bank/GEF funding. The proposed Eskom CSP plant in Upington, South Africa will be funded through the World Bank GEF.

The Middle East and North African regions may lack the economic power and political will to take advantage of the abundance of their solar resource for CSP generation. The development of the CSP industry in these regions lies in the interest shown by the European group of countries that plan to set up CSP plants and transmit the generated electricity over long distances on land and under seas to supply European networks.

Although the CSP industry is set to grow in future, recent announcements by the Spanish and South African governments to reduce the existing FIT will lower this

rate of growth. The recent economic crisis dented the CSP growth rate especially in Europe where the Spanish finance institutions have become stricter when lending money for renewable energy projects. This effect can be seen in the reduced number of announced future CSP projects in Spain compared to those under construction.

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7 Appendices

7.1 Appendix 1: Email from Eskom CSP Engineer

The CSP100 project, comprising a 1 x 100MW unit, aims to use the molten salt-type, CR technology in a first pilot to prove the technology in the South African context and in full-scale commercial operation.

Thermal rating - 540MWth

Electrical - 100MWe

Load factor – 64-70%

Storage: 14 hours

House load - 10MW

Gross production per annum - 560GWh

Net production per annum - 516GWh

Location - Farm 450, Olyfenhoutsdrift, Upington

Overnight Capex - R5.351 Million

Total Nominal (excl FC & IDC) - R5.873 Million

Total Nominal (incl FC & IDC) - R7.642 Million

LEC - R1.30/kWh

Qedile Sikhosana - Re: CSP technical and economic data

From: Terence Govender
To: Qedile Sikhosana
Date: 2010/03/18 04:00 PM
Subject: Re: CSP technical and economic data
Attachments: plant details.doc; plant details.doc

Hi,

I cannot give u detailed info as we are in the process of verifying these numbers. see attached for info as a start.

Best Regards

.....
Terence Govender (PrEng)
MSc. Electrical Engineering, SAIEE(MEM)
CSD- S&I
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Eskom Research and Innovation Centre (ERIC Building)

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emailto: terence.govender@eskom.co.za
God Bless

The perusal, use, dissemination, copying or storing of this message or it's attachments and the opening of attachments is subject to Eskom standard email disclaimer available at internet address: www.eskom.co.za/disclaimer.htm or on request from the sender.

>>> On 2010/03/18 at 03:23 PM, in message <4BA2456A.F66E.0080.0@eskom.co.za>, Qedile Sikhosana <SikhosQ@eskom.co.za> wrote:

Good day

I have been referred to you by Raahsaan Arscott. I am an engineer at Koeberg Nuclear Power Station and currently doing Post Grad studies in Sustainable Energy Engineering at University of Cape Town. My thesis involves the global review of CSP technologies. I am looking for Eskom CSP technical and economic data on the planned CSP project. I am kindly asking for your assistance in this regard.

Kind regards

Qedile Sikhosana
Tel: 021 522 1147
Cell: 082 062 4888
Fax: 8944 1147

7.2 Appendix 2 :Exchange Rates

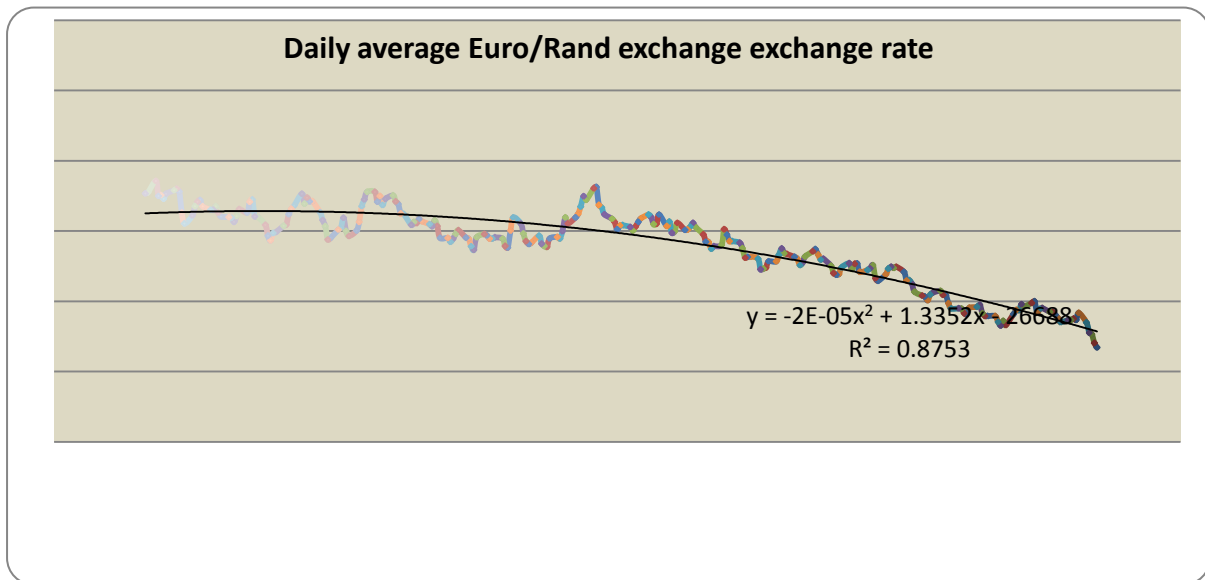


Figure 7-1 Average Euro/ZAR exchange rate

Average is 10.78

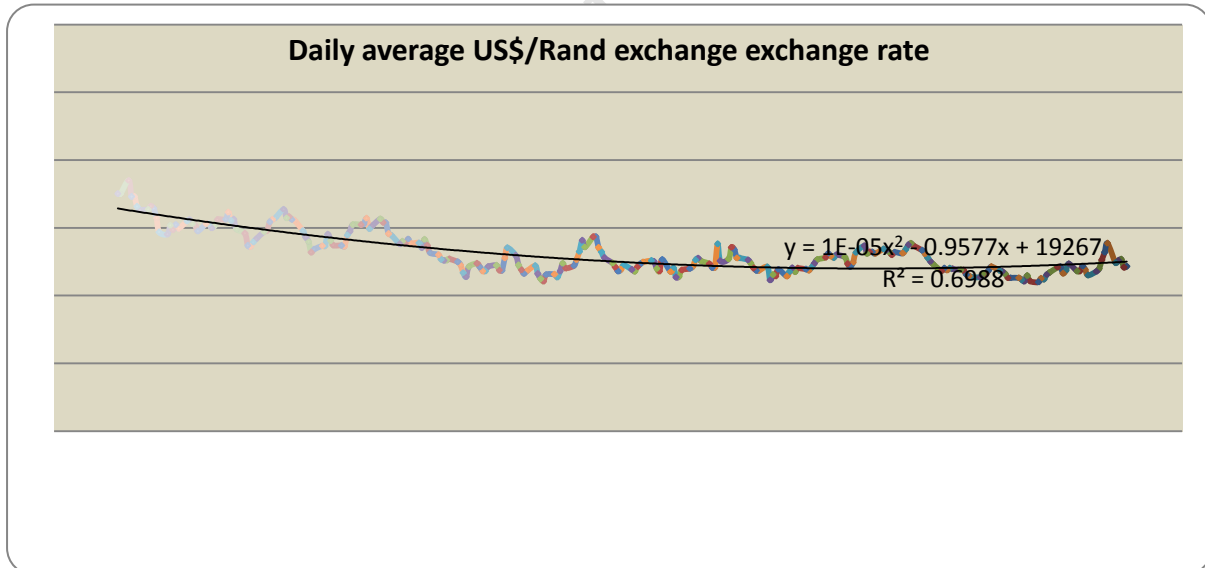


Figure 7-2 Average US\$/ZAR exchange rate

Average is 7.63

7.3 Appendix 3: Average Yearly inflation in Spain

Year	Average inflation	Year	Average inflation
2008	4.09 %	1999	2.31 %
2007	2.78 %	1998	1.84 %
2006	3.52 %	1997	1.97 %
2005	3.37 %	1996	3.56 %
2004	3.04 %	1995	4.68 %
2003	3.04 %	1994	4.72 %
2002	3.06 %	1993	4.57 %
2001	3.59 %	1992	5.93 %
2000	3.43 %		

Average inflation for the period 1992 to 2008 is 3.5%

Source: <http://www.inflation.eu/inflation-rates/spain/historic-inflation/cpi-inflation-spain.aspx> accessed 25 May 2011

7.4 Appendix 4: CSP plants under construction in Spain

Capacity (MW)	Technology	Name	Planned installation year	Developer
50	Parabolic trough	Extresol 3	2010	ACS/Cobra
50	Parabolic trough	Ibersol	2013	Solar Millennium
50	Parabolic trough	Helioenergy 2	2011	Abengoa Solar
2X50	Parabolic trough	Valle 1 and 2	2011	Torresol energy
2X50	Parabolic trough	Termosol 1 and 2	2011	Torresol Energy
50	Parabolic trough	Solar Termoelectrica (ASTE ²⁶ 1A)	2011	Dioxipe Solar ²⁷
50	Parabolic trough	Solar Termoelectrica (ASTE 1B)	2012	Dioxipe Solar
50	Parabolic trough	Solar Termoelectrica (Astexol 2)	Not known	Dioxipe Solar
2X50	Parabolic trough	Helios 1 and 2	Not known	Hyperion Energy
50	Parabolic trough	Lebrija-1	2010	Sacyr/Solel
50	Parabolic trough	Arenales PS	2013	Arenalis Solar PS
50	Parabolic trough	El Reboso 2	2011	Bogaris
50	Parabolic trough	El Reboso 3	2011	Bogaris
50	Parabolic trough	Orellana (Bajadoz)	2012	Acciona
50	Parabolic trough	Termosolar Soluz Guzmán	2012	Sener
50	Parabolic trough	Consol-Orellana	2012	Sener
2X50	Parabolic trough	Solarcor 1 and 2	2012	Acciona

²⁶ Aries Solar Termoelectrica (ASTE)

²⁷ consists of Elecnor, Aries and EISER companies

3X50	Parabolic trough	Solarben 1, 2 and 3	Not known	Solarben Electricidad
2X50	Parabolic trough	Solarcor 1 and 2	Not known	Solacar Electricidad
50	Parabolic trough	Lebrija 1	2011	
30	Linear Fresnel reflector	Puerto Errado 2 Thermosolar Power Plant	2012	Novatec Biosol AG
22	Parabolic trough	Termosolar Borges		Abantia
1	Parabolic dish	Renovalia	2011	Renovalia Energy

University of Cape Town

