DIPLOMARBEIT

Concentrated Solar Thermal Power for Electricity Generation: Cost and Potential Analysis for the Mediterranean Region

ausgeführt zum Zwecke der Erlangung des akademischen Grades

eines Diplom-Ingenieurs

unter der Leitung von

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Wien, im November 2008

Acknowledgements

First of all I want to thank Univ. Prof. Dr. Reinhard Haas, the referee of my thesis, and Dipl.-Ing. Dr. Gustav Resch, both of the Energy Economics Group at the Technical University in Vienna, for guiding and supporting me in writing this.

But this work would not have been possible without the support of my family and friends, so I want to take this opportunity to say thank you, especially to:

My parents, Helga and Karl, who offered me the opportunity to study at the Technical University of Vienna and for their backup (and who also always reminded me - at least weekly - to take the next examination and finish the study)

My grandmother Margareta, my brother Martin and my sister Helga for their encouragement and sponsorship

My friend Sabine Speckl for proofreading this paper (even though she had plenty to do at this time anyway)

My partner Viola Moritz, who assisted me with her patience and love in the last five years of my study; she gave me not only precious inputs for this work but also proofread it

Thank you!

Kurzfassung

Um Klimaerwärmung und ihre Folgen sowie die Abhängigkeit von importierten fossilen Rohstoffen zu verringern, ist es unerlässlich, auch in der Elektrizitätswirtschaft fossile durch erneuerbare Energien zu ersetzen. Die vorliegende Diplomarbeit beschäftigt sich mit einer erneuerbaren Technologie zur Stromerzeugung: (konzentrierenden) Solarthermischen Kraftwerken, die Sonnenenergie in Elektrizität (und Wärme) umwandeln. Um den Stand der Technologie, Kosten und Potenziale im Mittelmeerraum und im Nahen Osten zu ermitteln, wurde eine Literaturrecherche basierend auf verfügbaren Studien und Informationen zu realisierten/geplanten Projekten durchgeführt und die gefundenen Daten analysiert.

Zurzeit sind weltweit etwa 400 MW an Kapazität von solarthermischen Kraftwerken unterschiedlicher Technologien vorhanden. Die Stromerzeugungskosten liegen derzeit zwischen 14 und 24 Cents€/kWh für solaren Betrieb und zwischen 8 und 10 Cents€/kWh für hybriden Betrieb (mit etwa 20% solarem Anteil). Die Kostensenkungspotenziale bis 2020 durch Kapazitätsvergrößerung, Massenproduktion und technische Innovationen liegen bei etwa 50 - 60%. Potenziale für solarthermische Stromerzeugung sind vor allem in nordafrikanischen Ländern sehr groß (20.000 – 100.000 TWh/a), aber auch in den meisten anderen untersuchten Ländern ergeben sich Stromerzeugungspotenziale, die den Stromverbrauch des jeweiligen Landes im Jahr 2030 übersteigen. Insgesamt ergibt sich in den 24 Ländern ein Stromerzeugungspotenzial von über 600.000 TWh/a, was bei weitem den derzeitigen Weltelektrizitätsverbrauch von 17.000 TWh/a übersteigt.

Derzeit sind solarthermische Kraftwerke nur mittels finanzieller Unterstützung wirtschaftlich betreibbar, durch Massenfertigung, Kapazitätsvergrößerung der Kraftwerke und weitere technische Forschungen könnten jedoch schon bis 2020 große Kostensenkungen möglich sein, die solarthermische Systeme auch für Mittellast attraktiv machen würden. Günstigere hybride Kraftwerke könnten die Markteinführung beschleunigen, haben jedoch nur einen geringen solaren Anteil und werden derzeit nur begrenzt durch Einspeisetarife unterstützt. Aufgrund der enormen Potentiale, der Möglichkeit mit thermischen Speichern bzw. hybriden Betrieb Strom auf Abruf zu produzieren und den großen Kostensenkungspotenzialen könnte die konzentrierende solarthermische Stromerzeugung einen großen Beitrag zur Erhöhung des Anteils erneuerbaren Energien an der Stromerzeugung im Mittelmeerraum und anderen sonneneinstrahlungsreichen Gebieten leisten.

Abstract

Increasing the share of renewable energies in the electricity generation contributes to slow down climate change and decreases the dependency on fossil fuels. This master-thesis deals with one renewable technology for electricity generation: concentrating solar thermal power (CSP) plants. The objectives of this thesis are to summarize the current state of the technology and to analyse the costs and potentials of CSP in the European Union, Middle East and North Africa (EU-MENA). To reach these objectives, an in-depth desk research based on available literature and information on realised/planned projects was conducted, accompanied by an analysis of derived data.

Today CSP plants with a total capacity of about 400 MW_{el} are installed worldwide. Levelized electricity costs (LEC) range from 14 to 24 cents€/kWh for solar-only and from 8 to 10 cents€/kWh for hybrid operation (with 20% solar share) with capacity factors of 18 – 34%. Cost reduction potentials by plant upscaling, mass production and technological innovations are in the range of 50 - 60% until the year 2020. The highest CSP potentials are reached in North African countries (20,000 – 100,000 TWh/y), but also in most of the other analysed countries the CSP electricity generation potentials exceed the demand in the year 2030. In total about 600,000 TWh/y may potentially be explored in the 24 analysed countries, which is far more than the current world electricity demand of approximate 17,000 TWh/y.

To run current CSP plants economically financial support is needed. But with high cost reducing potentials until 2020, CSP systems can become attractive for mid-load. Hybrid plants can also contribute to lower the LEC, but only hybrid systems with low fossil fuel share are supported with current feed-in tariffs. With such high potentials, the ability to produce power on demand (thermal storage and/or hybrid operation) and great cost reducing potentials, CSP could become a main renewable energy technology in the future electricity mix in high insulation areas around the world.

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List of Abbreviations

CC .... combined cycle
CLFR .... compact linear Fresnel reflector
CRS .... central receiver system
CSP................. concentrated solar thermal power
DLR................. German Aerospace Centre
DNI .... direct normal irradiance
DSG .... direct steam generation
E_{net}.................. annual net electricity
EU .... European Union
EU-MENA .... European Union, Middle East and North Africa
GT .... gas turbine
HTF .... heat transfer fluid
IEA .... International Energy Agency
ISCCS .... integrated solar combined cycle system
k_d .... real debt interest rate
K_{fuel} .... annual fuel costs
$k_{insurance}$ .... annual insurance rate
K_{invest} .... total investment of the plant
$K_{O\&M}$ .... annual operation and maintenance costs
LEC .... levelized electricity costs
LFR .... linear Fresnel reflector
n .... depreciation period in years
O&M................ ordinance and maintenance
PCM .... phase change media
PT................... parabolic trough
PV................... photovoltaic
RES-E.............. electricity from renewable energy sources *or* renewable energy source for electricity generation
S&L................. Sargent & Lundy
SEGS............... solar electric generating system
ST................... steam turbine
TESS .... thermal energy storage system
UAE................. United Arabian Emirates

1 Introduction

To slow down the dramatic effects of global warming and reduce the dependency on fossil fuels, which are limited and get more and more expensive, renewable energy sources are needed to be explored, especially for the electricity generation.

In the year 2006 the electricity consumption in the EU-25 was about 3080 TWh, with a share of renewable energy source for electricity generation (RES-E) in size of about 14.65% (451.5 TWh). Nowadays hydropower plays the greatest role of the RES-E with 63.3% (see Figure 1.1), followed by wind (18.1%) and biomass (16.8%). The suns direct energy in form of the sunlight was only used for 0.5% of the renewable electricity generation (Solar PV) in the year 2006.

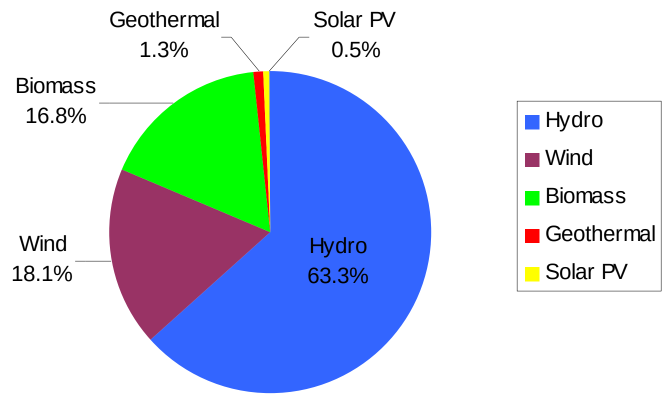


Figure 1.1 Share of each RES in the EU-25 renewable electricity generation in the year 2006
Source: EurObserv'ER, 2007

In this master thesis another technology for electricity and heat generation that uses the suns energy, the Concentrated Solar Thermal Power (CSP), is assessed. CSP systems work similar to normal solar thermal systems (which are commonly used to heat water), but concentrate the solar radiation with mirrors to reach higher temperatures (for details see chapter 2). CSP is not very new at all; the first 45 kW solar power plant was built in 1912 at Meadi, near Cairo, Egypt, by the American engineer Frank Shuman, but not well known in central Europe, because only Southern Europe’s Mediterranean countries like Spain or Greece meet the requirements of CSP: high direct normal irradiation (DNI).

In regions with high DNI CSP systems offer some great benefits compared to other power plants:

- Little adverse environmental impact: hardly any polluting emissions, exhaust fumes or noise during operation, decommissioning a system is not problematic
- High potential capacity in EU-MENA
- Grid connection on a high voltage level just like conventional power plants
- Power on demand via thermal energy storage or hybrid operation

The first commercial solar thermal power plants were the parabolic trough SEGS (Solar Electric Generating System). The first SEGS began operation in the year 1985. In total nine SEGS plants were built in the California Mojave desert with a total capacity of 354 MW. The last and biggest plant SEGS IX began operation in 1991. All plants use gas-fired back-up burners for hybrid operation and are still in commercial operation. (Aringhoff et al., 2005) p16

Table 1.1 shows the characteristics of the SEGS plants.

Table 1.1 Characteristics of SEGS plant I to IX
Source: Based on Pitz-Paal et al., 2005 p35

SEGS Plant	First Year of Operation	Net Output [MW_{el}]	Solar Field Outlet Temp. [°C]	Solar Field Area [m^2]	Solar/Fossil Turbine Efficiency [%]	Annual Output [MWh]	Dispatch ability provided by
I	1985	13.8	307	82,960	31.5/NA	30,100	3h thermal storage, gas-fired superheater
II	1986	30	316	190,338	29.4/37.3	80,500	gas-fired boiler
III/IV	1987	30	349	230,300	30.6/37.4	92,780	gas-fired boiler
V	1988	30	349	250,500	30.6/37.4	91,820	gas-fired boiler
VI	1989	30	390	188,000	37.5/39.5	90,850	gas-fired boiler
VII	1989	30	390	194,280	37.5/39.5	92,646	gas-fired boiler
VIII	1990	80	390	464,340	37.6/37.6	252,750	gas-fired HTF heater
IX	1991	80	390	483,960	37.6/37.6	256,125	gas-fired HTF heater

Today only about 400 MW of capacity are installed worldwide, the greatest part of this represent the SEGS plants in California, USA. Since 1991 only a few commercial plants were built because of the high investment costs of the systems compared to conventional power plants.

With a new feed-in tariff for CSP plants in Spain in the year 2002 (with the latest tariff increase in 2007 to about 0.27 €/kWh, which is granted for CSP plants up to 50 MW for 25 years; (SolarPACES, 2008)), CSP plants were made attractive for investors in Europe. Today Spain is one of the hottest spots for CSP plants worldwide.

1.1 Objective and Methodology

The core objective of this thesis is to analyse the costs and the potential of CSP systems for electricity generation in the European Union, Middle East and North African (EU-MENA) region.

Derived objectives are:

- To give an overview about the CSP technology: concentration technologies, thermal storage systems, thermal cycles and performance of CSP systems
- To compare the costs of current realised CSP projects with data on reference systems found in the literature

- To make a sensitivity analysis for key input parameters (of the levelized electricity cost of some CSP systems)
- To give an outlook to cost reduction potentials for CSP systems in the future
- To estimate the electricity generation potential of CSP systems in the EU-MENA region until the year 2030

To reach these objectives, an in-depth desk research based on available literature and information on realised/planned projects was conducted, accompanied by an analysis of derived data.

1.2 Main Literature

The literature was mainly taken from the internet. The following two reports/documents of the German Aerospace Centre (DLR) were used as basis for the potential and the cost analysis of CSP systems:

- "Concentrating Solar Power for the Mediterranean Region (MED-CSP)", final report (2005): contains potential estimations for CSP systems for each individual country in the EU-MENA region, which were used for the potential analysis
- "ECOSTAR – European Concentrated Solar Thermal Road-Mapping", roadmap document (2004): contains cost calculations for different CSP systems, which were used for the cost analysis

Also very helpful data of existing or CSP power plants which are currently under construction in Europe were found in:

- "Concentrating Solar Power from research to implementation", European Commission (2007): contains data of various CSP systems and components which are funded by the EU

Generally useful information was found on the following internet sites:

- www.solarpaces.org: Homepage of the IEA implementing agreement for the establishment of a project on solar power and chemical energy systems (SolarPACES) with useful documents to download and a worldwide overview of current CSP project developments
- www.trec-uk.org.uk: Homepage of the Trans-Mediterranean Renewable Energy Cooperation (initiative of the Club of Rome), gives information about current projects as well as the history of CSP and reports to download

1.3 Structure of this Thesis

In the second chapter of this thesis the CSP technology is introduced, including a description of the different concentration technologies, thermal heat storages, used thermal cycles and performance data.

Chapter 3 deals with the cost assessment, where for various CSP systems cost components and levelized electricity cost are compared with each other. Thereby, data about reference (virtual) and actual plants were taken from the literature. Also the sensitivity analysis and cost reduction potentials are described in this chapter.

Chapter 4 describes the method used for the CSP potential analysis in the EU-MENA region followed by individual country data.

The main aspects and conclusions are summarized in chapter 5.

2 Concentrated Solar Thermal Power

2.1 Basics

Concentrated Solar thermal Power (CSP) plants concentrate solar radiation to produce high-temperature heat. This heat is used to generate electricity within conventional power cycles using steam turbines, gas turbines or Stirling engines.

The concentration of the solar radiation is necessary because the sunlight reaches the Earth’s surface only with a low density (kW/m^2), which is adequate for heating systems (for instance water heaters) but not high enough to produce electricity in an efficient thermodynamic cycle.

The concentration is done with glass parabolic or flat mirrors/reflectors that continuously track the position of the sun and focus the sunlight onto/into a receiver. In the receiver a fluid (the Heat Transfer Fluid, HTF) is flowing through, which takes the heat towards the thermal power cycle.

Figure 2.1 shows the principle of a CSP-system: The solar heat is transported with a HTF from the concentrating solar collector field to the power block and to an optionally integrated thermal energy storage system. In the power block the solar heat is used to produce electricity and/or process heat. In times with less or no solar radiation (fossil) fuel can be used to run the power block (=> hybrid operation).

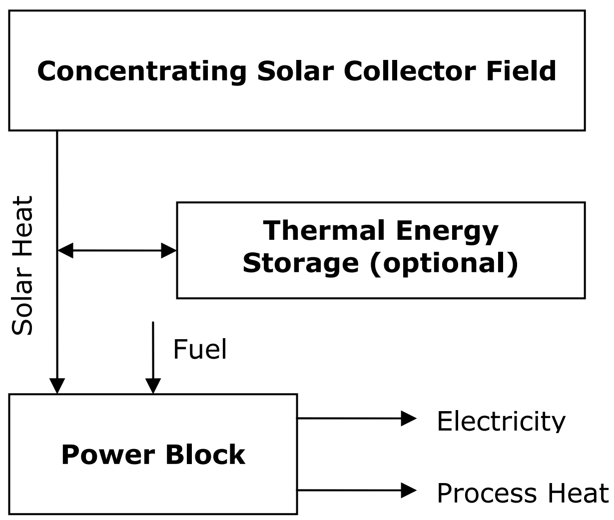


Figure 2.1 Principle of a CSP power plant with optional thermal energy storage and the possibility to generate electricity and/or process heat
Source: Based on DLR, 2003 p3

A very important fact is that “solar thermal power can only use direct sunlight, called `beam radiation` or Direct Normal Irradiance (DNI), i.e. that fraction of sunlight which is not deviated by clouds, fumes or dust in the atmosphere and that reaches the earth’s surface in parallel beams for concentration”. (Aringhoff et al., 2005) p8

In the desert regions of MENA and also in some Southern European areas the annual sum of DNI on a surface tracking the sun is usually higher than the global (diffuse and direct) irradiance on a fixed surface (horizontal or tilted South), which is generally used by PV-arrays (Figure 2.2). (DLR, 2007) p23

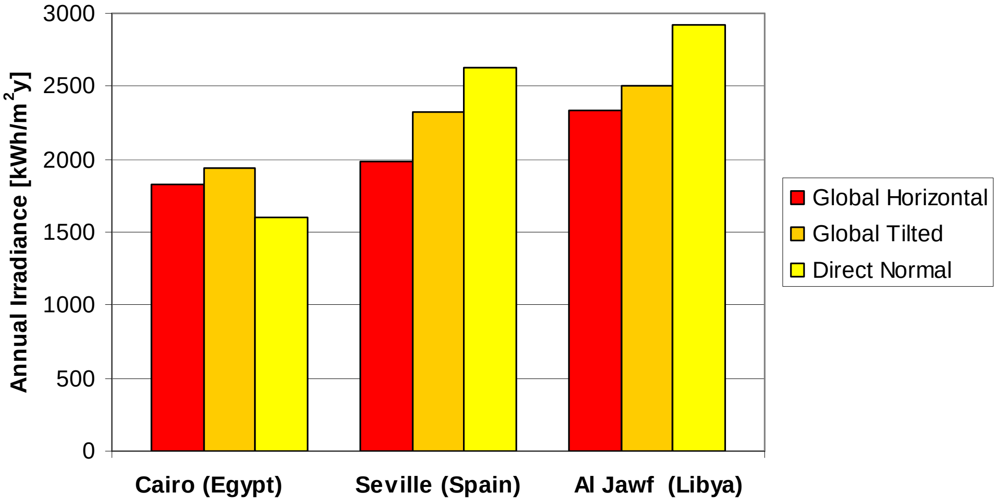


Figure 2.2 *Examples for the annual sum of global horizontal, global tilted and direct normal irradiance (data of the year 2005)*
Source: SoDa, 2008

In the following chapters the different CSP technologies, the thermal energy storage systems and power cycles are described.

2.2 CSP Technologies

Currently there are four common CSP technologies:

- Parabolic trough
- Linear Fresnel Reflector (LFR)
- Central Receiver Systems (CRS) or Solar Tower
- Parabolic Dish

Figure 2.3 *The four common CSP-technologies: parabolic trough (upper left), linear Fresnel (bottom left), solar tower (upper right) and parabolic dish (bottom right)*
Source: DLR, 2007 p24

These four technologies can be divided into line focusing systems, which are the parabolic trough and the linear Fresnel systems, and point focusing systems, which are the central receiver and the parabolic dish systems.

Due to higher concentration rates, point focusing systems achieve higher temperatures.

2.2.1 Parabolic Trough

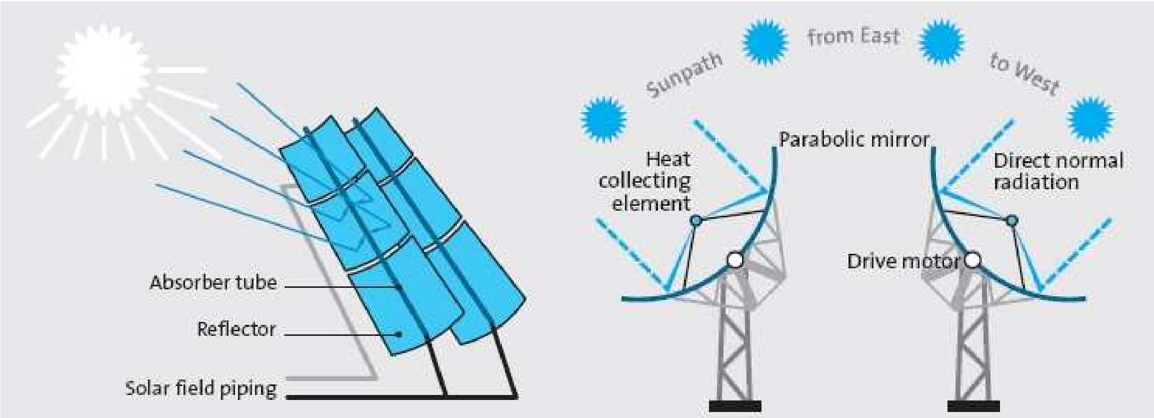


Figure 2.4 left: principle of a parabolic trough solar collector
right: operation and daily tracking of a parabolic trough collector
Source: Aringhoff et al., 2005 p12, p14

A parabolic trough power plant consists of many parallel rows of single-axis-tracking parabolic trough collectors. These modular collectors are normally aligned on a North/South horizontal axis to track the sun from East to West during the day (Figure 2.4).

The parabolic-shaped reflector of the collector focuses the sun's direct normal radiation on an absorber tube, which is located at the focus of the parabola. In this receiver/absorber tube a heat transfer fluid circulates, is heated up by the focused radiation and flows to the power block.

2.2.2 Linear Fresnel Systems

Like the parabolic troughs the linear Fresnel systems focus the sun's radiation on an elevated inverted linear absorber. But instead of the parabolic shape of the mirrors in the trough system, "Fresnel technology (…) uses flat reflectors, simulating a curved mirror by varying the adjustable angle of the individual rows of mirrors in relation to the absorber pipe". (Reinhardt, 2008)

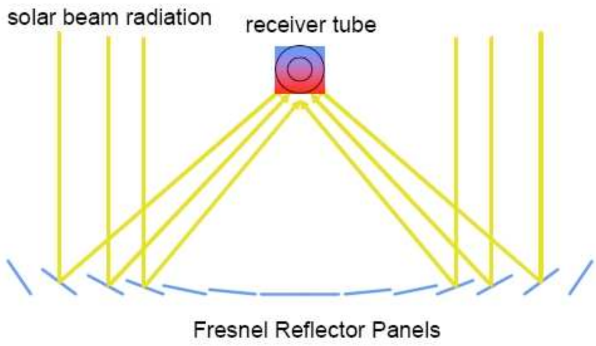


Figure 2.5 Principle of a linear Fresnel reflector
Source: DLR, 2007 p29

While the parabolic troughs are more efficient (~15% (Reinhardt, 2008), 1/3 (DLR, 2007) p31), the Fresnel technology reduces costs because the reflectors can be made of standard flat glass and all mirrors are kept close to the ground, which lowers wind loads and steel usage. (Ausra, 2007) p5

Also the Fresnel structure leads to a weight reduction of 80% per square metre because of its very light design. The better land use, because of the smaller distances between the mirrors, is another advantage. While with a Fresnel system 80 – 90% of required land is covered by mirrors, parabolic trough plants only reach 30%. (DLR, 2007) p31

Furthermore the LFR can provide a semi-shaded space below, which may be especially useful in desert climates.

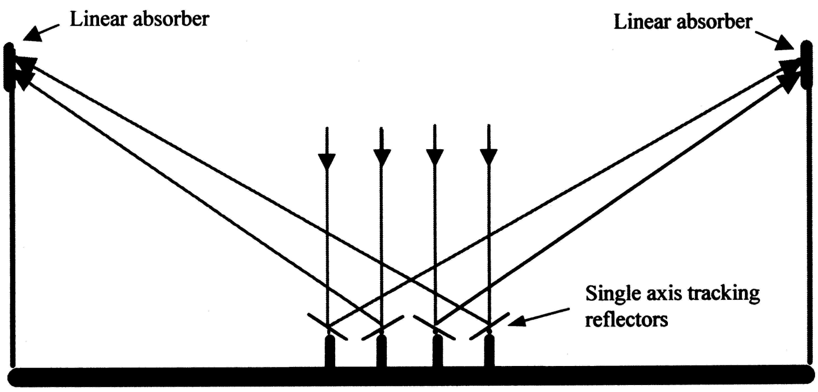


Figure 2.6 Principle of a compact linear Fresnel reflector with two receivers
Source: Mills and Morrison, 2000 p3

In Figure 2.6 a second type of LFR system is shown: the Compact Linear Fresnel Reflector (CLFR). In CLFR systems a single field of reflectors is used for multiple (at least two) receivers, if they are close enough. So the reflectors can change their focal point from one receiver to another during the day. This additional option in orientation allows the reflectors to be more closely together without shading or blocking each other. Also the height of the receiver tower can be lowered, which is an additional cost save. (Mills and Morrison, 2000) p2-3

2.2.3 Central Receiver Systems

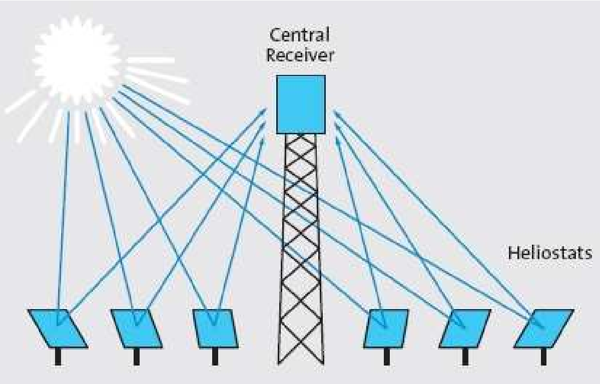


Figure 2.7 Principle of a central receiver system
Source: Aringhoff et al., 2005 p12

Central receiver or solar (power) tower systems use a centralized receiver as the collector. The solar radiation is concentrated by a field of sun-tracking mirrors called heliostats onto the centralized receiver, which is located on top of/in a tower. In the centralized receiver solar radiation energy is transferred to a working fluid which can be used to run a conventional power cycle. Abengoa Solar, 2007 p8

The heliostats are tracking the sun in two axes.

2.2.4 Parabolic Dish

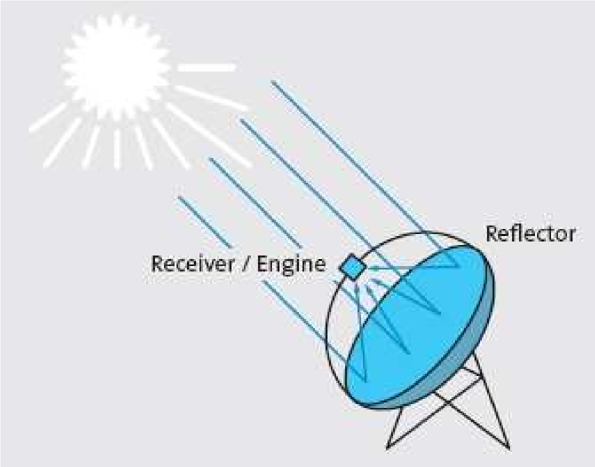


Figure 2.8 Principle of a parabolic dish
Source: Aringhoff et al., 2005 p12

Parabolic dish systems are relatively small units (usually 8 – 10 m in diameter) of a single structure with a parabolic dish. The dish, which is covered with mirrors, reflects the radiation to a solar receiver located at the focal point of the dish. The receiver is combined with an energy producing thermal engine, such as a Stirling engine or a Brayton cycle turbine. (Pitz-Paal et al., 2005) p9

The parabolic dish also tracks the sun in two axes.

2.3 Thermal Storage

Thermal energy storage systems are used to store the thermal heat collected by the solar field for later use.

Figure 2.9 shows a typical load curve of a solar thermal power plant with a two hour thermal storage system and a backup burner. It can be seen, that, when the firm capacity of the plant is reached, the thermal output of the solar field goes directly to the storage system. This stored thermal energy can be used later, in times without or with too less direct sunlight to increase the period of the solar-only operation of the plant. When the stored thermal energy is used up, a parallel (fossil) burner guarantees the thermal output of the CSP system.

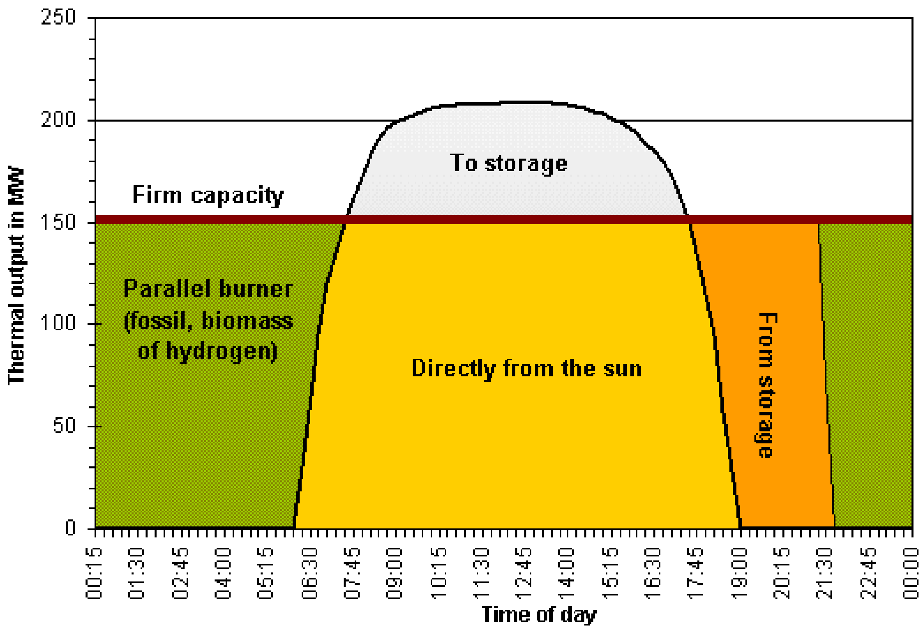


Figure 2.9 Typical daily load curve of a solar thermal power plant with backup burner and thermal storage
Source: Quaschning, 2003

"A typical storage concept consists of two storage tanks filled with a liquid storage medium which are on a different temperature level. When charging the storage, the medium is pumped from the 'cold' to the 'hot' tank being heated up (directly or indirectly) using the collected solar heat. When discharging the storage the medium is pumped from the 'hot' to the 'cold' tank extracting the heat in a steam generator that drives the power cycle.

The capacity of the storage is normally designed for some full-load hours of the plant." (DLR, 2005) p25-26

With heat and exergetic losses below 5% of the thermal throughput, Storage systems can help to let the plant always run under full-load conditions. So compared to other renewable energies like wind or photovoltaic (PV), a CSP system with thermal storage does not need short-term control energy back-up from the grid. Wind turbines or PV generators need this short-term energy, because a wind gust or cloud may cut off the actual energy supplied by them in seconds. (DLR, 2005) p26

Heat storage, compared to the storage of electricity, offers some significant benefits:

- Attractive specific costs and efficiencies (specific investment costs of 10 – 30 €/kWh$_{th}$ / 25 - 75 €/kWh$_{el}$ of storage capacity and efficiencies of >95%)
- Thermal energy storage cost does not necessarily increase the specific electricity generation cost of the plant

Unlike any electrical energy storage, which increases the specific cost of the electricity of the system, a CSP using a thermal storage system can reduce the specific electricity generation costs. This is because the power conversion unit in a CSP system with thermal storage can be reduced in its nominal power capacity (which saves costs) and its full-load operation hours are extended. So if the investment in the storage is less than the cost saving in the smaller power block, electricity generation costs can be reduced. (DLR, 2005) p26

Thermal energy storage systems are used to shift energy for some hours (e.g. from day time to evening) but can not compensate the seasonal difference of the solar input (summer/winter). So the capacity factor of the plant varies over the year, which can be seen in Figure 2.10 for a parabolic trough plant with seven hours of equivalent full-load capacity. (Pitz-Paal et al., 2005) p26

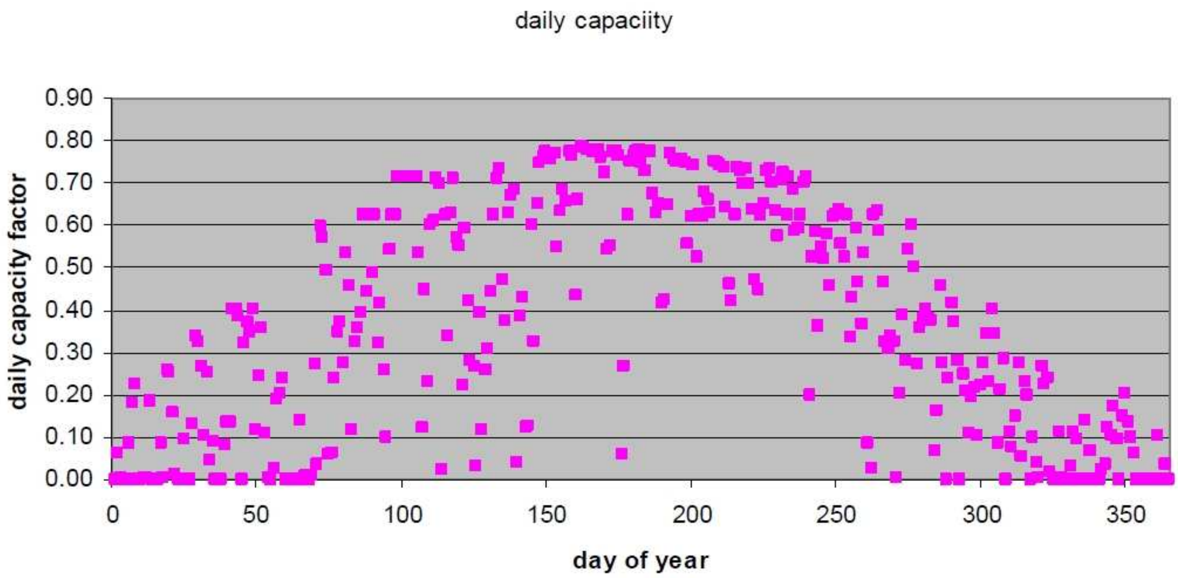


Figure 2.10 Variation of the daily capacity factor over the year of a parabolic trough plant with seven hour full-load capacity
Source: Pitz-Paal et al., 2005 p27

Following thermal energy storage systems (TESS) are currently used or planned:

- Two-tank direct TESS (mineral oil storage): The first commercial trough plant, SEGS 1 in California, had a direct two-tank thermal energy storage system with 3 hours of full-load storage capacity. In this system the mineral oil (Caloria) heat transfer fluid (HTF) was also used to store energy for later use.
- Two-tank indirect TESS: These systems use a second media to store the thermal energy. The thermal energy of HTF is given to the cold storage media by heat exchanger, where both media run through. An example for a storage

media is molten salt, which is used in the two-tank TESS of the parabolic trough AndaSol 1 plant in Spain.

- Two-tank direct TESS (molten salt storage): In these systems both the HTF and the storage media are molten salt, so there is no need for expensive heat exchangers. Also higher HTF temperatures can be reached (which are not allowed by other HTF such as mineral oil). The Solar Tres CRS in Spain for example is being built with such a system.

- Single-tank thermocline TESS: "A single tank for storing both the hot and cold fluid provides one possibility for further reducing the cost of a direct two-tank storage system. This thermocline storage system features the hot fluid on top and the cold fluid on the bottom. The zone between the hot and cold fluids is called the thermocline". (NREL, 2008)

- Solid media TESS: These systems use a standard HTF in the solar field, which "passes through an array of pipes imbedded in the solid medium to transfer the thermal energy to and from the media during plant operation". As solid storage medium high temperature concrete or castable ceramic can be used. "The high-temperature concrete is favoured because of lower costs, higher material strength, and easier handling". (NREL, 2008)

  These systems are currently tested by DLR.

- Phase-change media TESS (latent heat storage): "Phase-change materials (PCMs) allow large amounts of energy to be stored in relatively small volumes, resulting in some of the lowest storage media costs of any storage concepts". (NREL, 2008) These systems are currently under development.

Which kind of storage system is used depends on the chosen CSP technology and HTF fluid.

2.4 Thermal Cycles

In the following chapters the various thermal power cycles which are used within CSP systems are described.

2.4.1 Rankine Cycle

The Rankine cycle is a steam-based thermal cycle. The hot heat transfer fluid which comes from the solar receiver transfers its heat in the heat exchanger to the water/steam of the steam turbine. The steam then drives the turbine to produce electricity. A condenser turns the used steam into water, which is reheated in the heat exchanger and the cycle repeats.

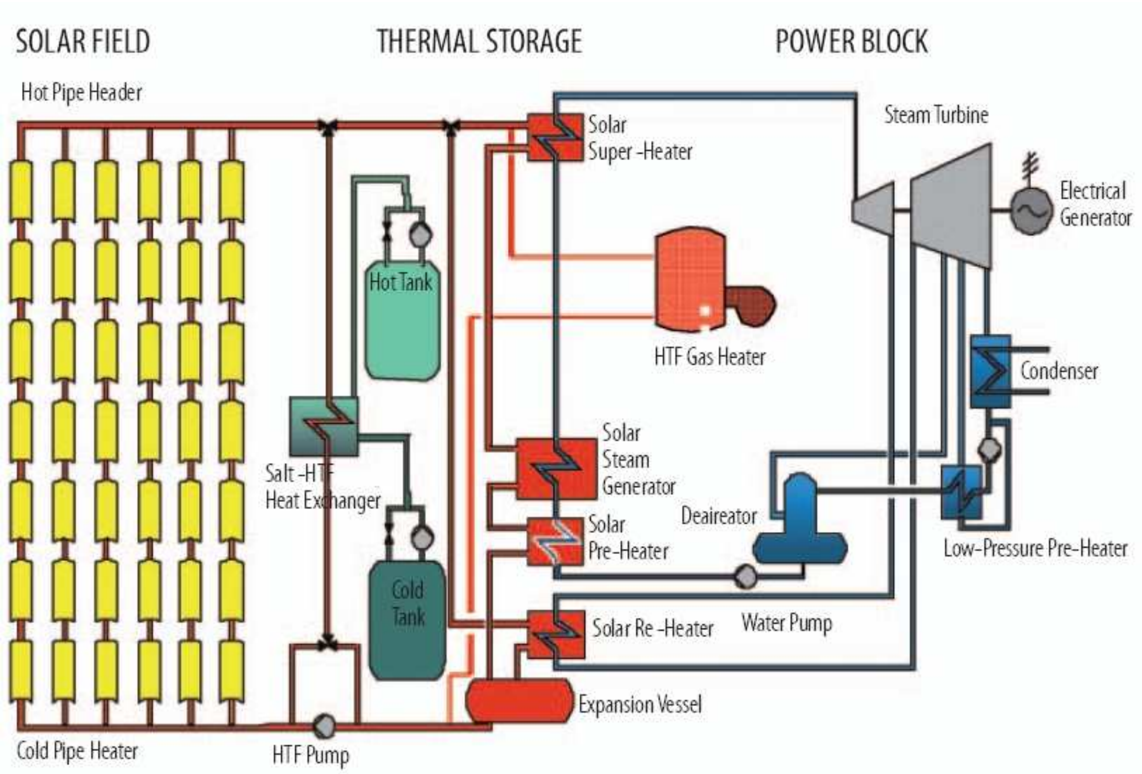


Figure 2.11 Schematic of a parabolic trough power plant with two-tank salt storage and gas heater (Rankine Cycle)
Source: European Commission, 2007 p16

Figure 2.11 shows a typical parabolic trough power plant with a two-tank thermal storage system which uses a Rankine cycle to generate electricity. The solar heat is used to pre-heat the fluid, generate the steam and super-heat the steam for the turbine. A gas heater can also be used to heat up the HTF.

Rankine-cycle systems have relatively low conversion efficiencies of 30 – 40%. Conventional steam turbines are usually combined with line focusing systems or CRS. For hybrid operation a fuel burner (boiler) can be added to the system.

2.4.2 Brayton Cycle

The Brayton engine, also called the jet engine, combustion turbine or gas turbine, is an internal combustion engine which produces power by the controlled burning of a mixture of compressed air and fuel.

Solar heat can replace or supplement the fuel. With a continuous burning process in the gas turbine, the rapidly expanding gas turns a turbine and alternator to produce power.

As in the other engines, waste heat is used to preheat air from the compressor to achieve a higher efficiency.

Because of high turbine inlet temperatures gas turbines are usually used with point focusing systems or in integrated solar combined cycles with parabolic troughs.

2.4.3 Integrated Solar Combined Cycle

A **combined cycle (CC)** system couples a Brayton Cycle (gas turbine) and a Rankine Cycle (steam turbine), which leads to the highest efficiency of power generation from fossil fuel of over 50%. The gas turbine is driven by fuel-heated hot, pressurized gas. The still relatively hot residual gas which is leaving the gas turbine can be used to generate high pressure steam to drive a steam turbine for power generation with approximately half the capacity of the gas turbine. While the gas turbine provides 65 - 70%, the steam turbine powers about 30 - 35% of the total capacity of the CC plant. (DLR, 2007) pA-7

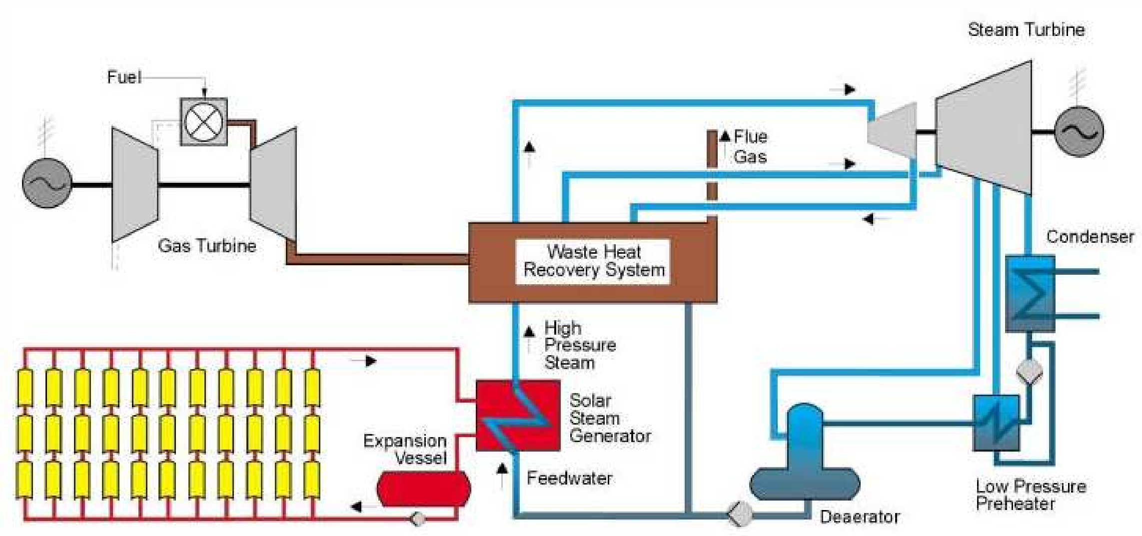


Figure 2.12 Schematic of an ISCC power plant
Source: FLAGSOL, 2008

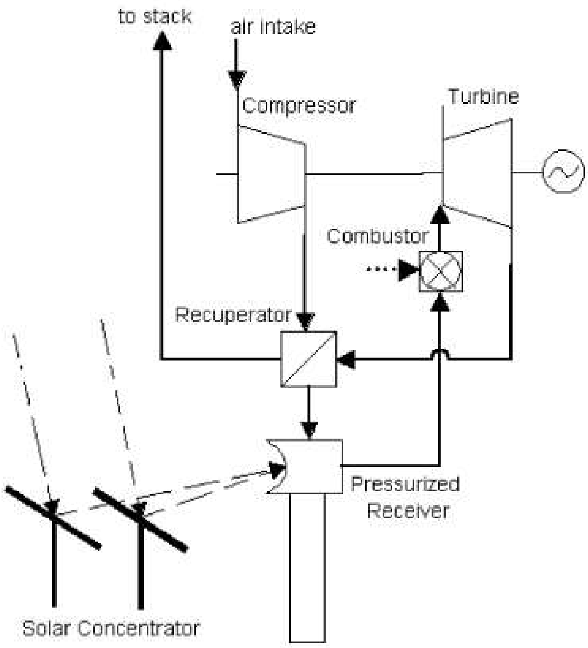
An **integrated solar combined cycle systems (ISCCS)** uses a parabolic trough solar field to provide additional steam for the Rankine cycle of a combined cycle system (see Figure 2.12).

"The steam turbine must be oversized to about 50% of total capacity, because during daytime it will have to take both, the fuel gas from the gas turbine and additional solar heat, while it will be partially idle at night when no solar heat is available. During night time there will be a lower efficiency of power generation, either due to part load of the turbine or because of additional steam generation by fuel.

The solar share in design point operation is limited to the extra capacity of the steam turbine that is 20% of total. A base load plant with 8000 operating hours per year will operate for about 2000 hours (a quarter of the time) with 20% solar share and for 6000 hours (three quarters) on 100% fuel. This translates to an annual solar share of only 5%. This relatively small solar share will in any case be partially and in the worst case totally compensated by the lower efficiency during night time operation, as explained before.

If the system is build in a remote area because of higher solar irradiance, 95% of the input energy – fuel – will have to be transported there, and electricity will have to be brought back to the centres of demand, causing additional energy losses. There is a considerable risk that an ISCCS would consume more fuel per net delivered electric kWh than a standard fuel-fired combined cycle on a usual site". (DLR, 2007) pA-7

2.4.4 Solar Hybrid Gas Turbine



"Solar gas turbine systems use concentrated solar power to heat the pressurized air in a gas turbine before entering the combustion chamber. The solar heat can therefore be converted with the high thermal efficiency of a modern recuperated or combined gas turbine cycle". (Schwarzbözl et al., 2006) p1232

The turbine can so be run with solar power and/or fossil/renewable fuel.

Annual solar shares of 16 – 50% can be achieved with CRS. (European Commission, 2007) p26

The main advantages of the hybrid systems are the variable solar share and the 24h operation without storage (increased capacity factor).

Figure 2.13 Solar hybrid gas turbine plant (CRS) schematic
Source: Schwarzbözl et al., 2006 p1233

2.4.5 Stirling Engine

Stirling cycle engines are usually high-temperature externally heated engines that work with compressible fluids (for instance air, hydrogen, helium, nitrogen etc.). Because of the external combustion most heat sources can be used to power it. (Kongtragool et al., 2003) p133

"In the Stirling cycle, the working gas is alternately heated and cooled by constant-temperature and constant-volume processes. Stirling engines usually incorporate an efficiency-enhancing regenerator that captures heat during constant-volume cooling and replaces it when the gas is heated at constant volume". (SolarPACES, 1997) p4

There are various mechanical configurations that implement this thermodynamic cycle. In (Kongtragool et al., 2003) p134 three commonly used configurations are described. These configurations use cylinders/pistons, a regenerator, a cooler and a heater to establish a Stirling cycle.

Stirling engines can be used with parabolic dishes to directly convert solar energy into mechanical power/electricity. The Stirling engine is considered to be the cheapest way for solar electric generation in the range of 1 – 100 kW_{el}. (Kongtragool et al., 2003) p133

The efficiency of the engine lies between 30 and 40%.

2.5 Performance Data

The following Table 2.1 shows various performance data of the different technologies.

Table 2.1 Performance data of the CSP systems
Source: Based on DLR, 2007 p25 and p38

Concentration Method	**line concentrating system**		**point concentrating system**	
Solar field type	Parabolic Trough	Linear Fresnel	Central Receiver	Parabolic Dish
State of the art	commercial	pre-commercial	demonstrated	demonstrated
Cost of solar field [€/m²]	200 - 250	150 - 200	250 - 300	> 350
Typical unit size [MW]	5 - 200	1 - 200	10 - 100	0.01
Construction requirements	demanding	simple	demanding	moderate
Concentration	70 - 80	25 - 100	300 – 1000	1000 – 3000
Operating temp. [°C]	390 - 550	270 - 550	550 - 1000	800 - 900
Heat transfer fluid	synthetic oil, water/steam	synthetic oil, water/steam	air, molten salt, water/steam	air
Thermodynamic power cycle	Rankine	Rankine	Brayton, Rankine	Stirling, Brayton
Power unit	steam turbine	steam turbine	gas turbine, steam turbine	Stirling engine
Thermal cycle efficiency	30 – 40% ST	30 - 40% ST	30 – 40% ST 45 – 55% CC	30 – 40% Stirl. 20 – 30% GT
Peak solar efficiency	21% (d)	20% (p)	20% (d), 35% (p) for CC	29% (d)
Annual solar efficiency	10 – 15% (d) 17 – 18% (p)	9 - 11% (p)	8 – 10% (d) 15 – 25% (p) CC	16 – 18% (d) 18 - 23% (p) GT
Capacity factor (solar)	24% (d), 25 – 90% (p)	25 – 90% (p)	25 - 90% (p)	25% (p)
Experience	high	low	Moderate	moderate
Reliability	high	unknown	moderate	high
Thermal storage media	molten salt, concrete, PCM	molten salt, concrete, PCM	molten salt, ceramics, PCM	molten salt, ceramics, PCM
Integration to the environment	difficult	simple	moderate	moderate
Operation requirements	demanding	simple	demanding	simple
Land requirement [m²/MWh/y]	6 - 8	4 - 6	8 - 12	8 - 12

Explanation to Table 2.1: *(d) = demonstrated* *(p) = projected*
ST … Steam Turbine
GT … Gas Turbine
CC … Combined Cycle
PCM … Phase Change Media

Solar efficiency = net power generation / incident beam radiation
Capacity factor = solar operating hours per year / 8760 hours per year

In Table 2.1 it can be seen, that the line focusing systems have a lower solar concentration factor and so achieve a lower temperature (~550°C) than the point focusing systems (up to 1000°C).

Parabolic troughs, linear Fresnel systems and solar power towers (CRS) can run steam turbines of up to 200 MW (100 MW for solar tower) electric capacity with a thermal cycle efficiency of 30 - 40%, which is essentially the same as in fuel fired power plants.

Due to the very high operation temperatures of over 1000°C, CRS can produce hot air for gas turbines, which can be used in combined cycles with thermal cycle efficiency up to 55%. (DLR, 2005) p42

The so far highest demonstrated solar efficiency is reached with the Dish-Stirling systems, which are usually very small units with 10 kW_{el} engines and can be used for decentralised power supply and remote, stand-alone power systems.

The Fresnel systems have the lowest land use (m²/MWh/y) of all technologies and can easily be integrated into the environment. Today the experience with Fresnel systems is still low, because there are only a few demonstration projects running. So there are currently no data on the long-time reliability of such systems available.

"Each of these technologies can be operated with fossil fuel as well as solar energy. This hybrid operation has the potential to increase the value of CSP technology by increasing its power availability and decreasing its cost by making more effective use of the power block". (DLR, 2005) p42

2.6 Load Curve of a CSP Plant

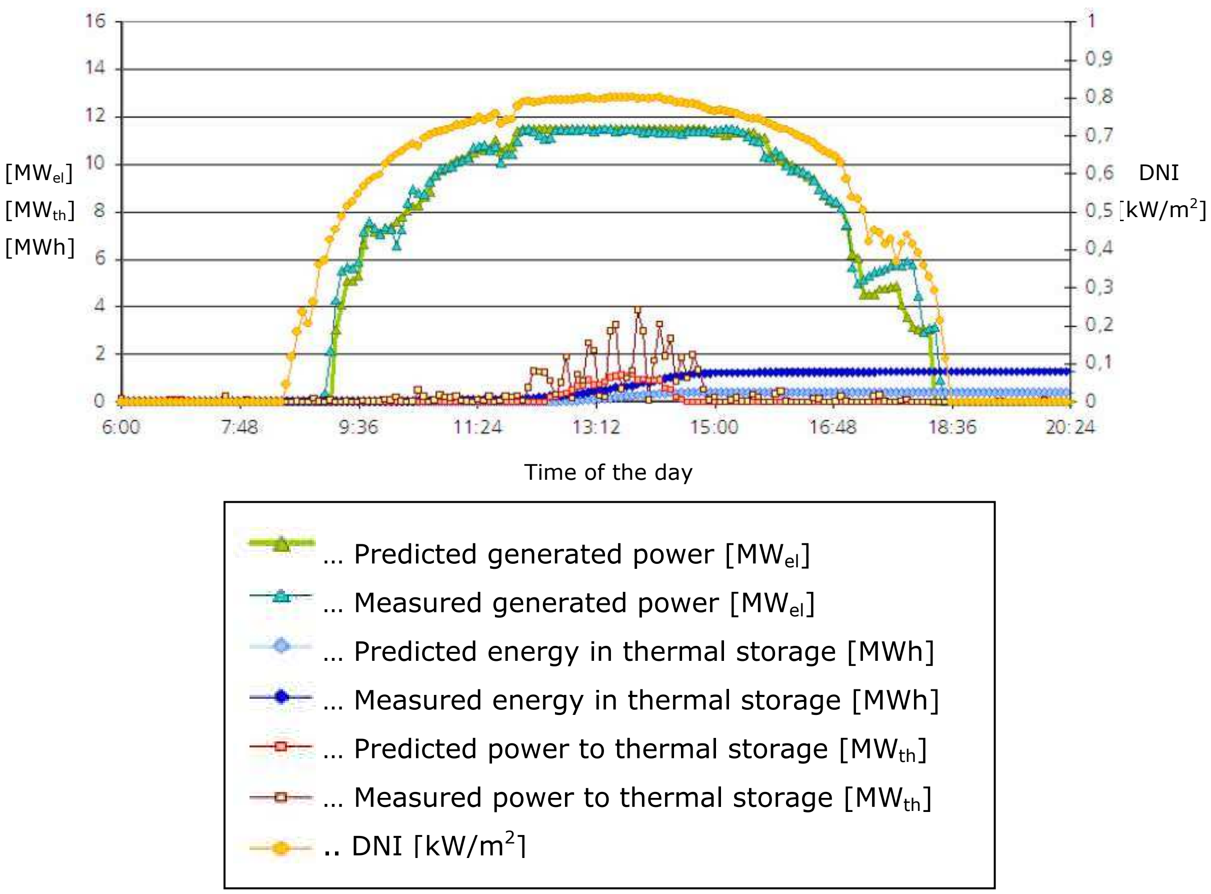


Figure 2.14 Operation curves of the 11 MW PS10 plant (CRS) of Feb. 10th, 2008
Source: Abengoa Solar, 2008

Figure 2.13 shows the operation curves of the commercial 11 MW PS10 (CRS) plant in Spain (see chapter 3 for detailed information on the plant) of Feb. 10th, 2008. The operation of the plant started at about 9:00, 45 minutes after the sunrise, and lasted until 18:36. In the time between 12:00 and 16:00 the plant reached its peak load of about 11.5 MW_{el}. In this period the thermal storage system of the plant is filled with the exceeding energy which is withdrawn again between 17:00 and 18:00 (leap of the turquoise curve).

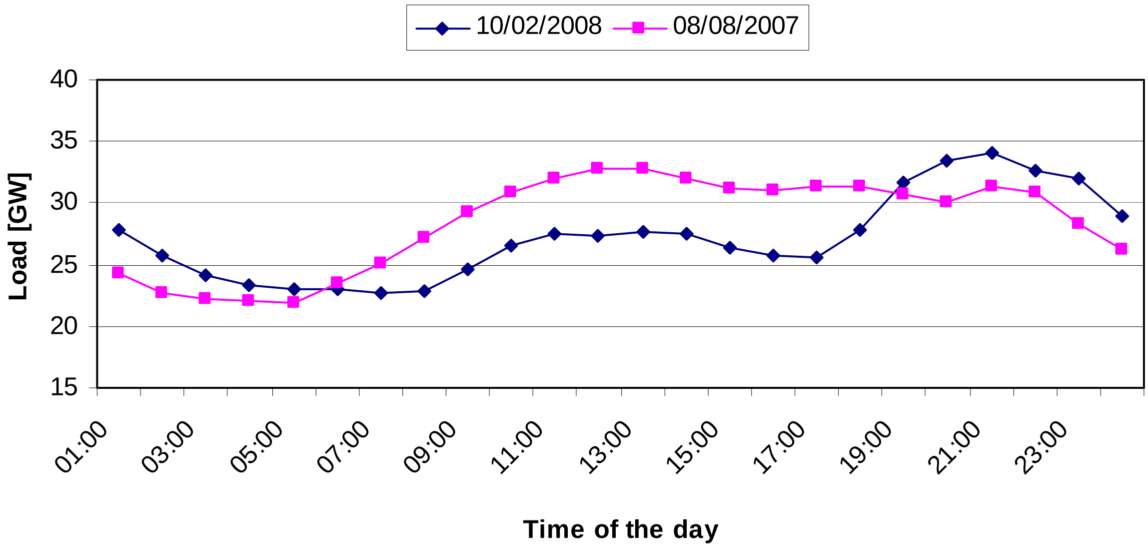


Figure 2.15 Hourly load curves of Spain of Aug. 8th, 2007 and Feb. 10th, 2008
Source: UCTE, 2008

Figure 2.14 displays the load curves of Spain of Aug. 8th, 2007 for a typical summer load and of Feb. 10th, 2008 for a typical winter load. The February load curve has two peaks; a small one between 10:00 and 16:00 and a big one between 18:00 and 1:00. If you compare the operation curve of the PS10 plant with the load curve of Spain, you can see that the curve of the generated power of the PS10 plant matches the first peak of the load curve very well. The load curve of Aug. 8th, 2007 has almost only two levels, a low one between 0:00 and 7:00 and a high one during the rest of the daytime. The highest peak in this load curve is at midday. This means that also the summer load matches the PS10 curve; both have about the same peaks. To supply the electricity demand in the early and late daytimes, bigger thermal storage systems and/or a fossil fuel backup burner needed to be used.

3 Cost Assessment

In the year 2005, the German Aerospace Centre (DLR) published the "ECOSTAR – European Concentrated Solar Thermal Road-Mapping"-document, in which the costs of several different CSP technologies were analysed.

This chapter is based on this document.

3.1 Methodology

For each of seven different reference CSP systems a detailed performance and cost model has been established by DLR, in order to analyse the impact of different innovations on the cost. Also a short description of the different CSP systems was added, including information on the status of the technology and current projects.

The cost model calculates the annual electricity production hour by hour and uses following common assumptions:

- Site: Seville, Spain 5.9° W, 37.2° N, 20 m above sea level, land costs 2,000,000 €/km²
- Meteorological data: hourly data of direct normal insulation and ambient temperature from measurements; DNI 2014 kWh/m²y; average temp. 19.5°C, min = 4.1°C, max = 41.4°C
- Load curve: Free-load operation or in hybrid operation 100% load between 9:00 and 23:00 every day, average availability of 96% to account for forced and scheduled outages resulting in a capacity factor of 55%
- Size of systems: 50 MW_{el}

The levelized electricity costs were calculated according to Figure 3.1.

$$LEC = \frac{crf * K_{invest} + K_{O\&M} + K_{fuel}}{E_{net}}$$

with

$$crf = \frac{k_d * (1 + k_d)^n}{(1+ k_d)^n - 1} + k_{insurance} = \mathbf{9.88\%}$$

k_d	real debt interest rate	= **8%**
n	depreciation period in years	= **30 years**
$k_{insurance}$	annual insurance rate	= **1%**

K_{invest}	total investment of the plant
$K_{O\&M}$	annual operation and maintenance costs
K_{fuel}	annual fuel costs
E_{net}	annual net electricity

Figure 3.1 Definition of the levelized electricity costs
Source: Based on Pitz-Paal et al., 2005 p13

3.2 Reference Systems

3.2.1 Parabolic Trough Technology using thermal Oil as Heat Transfer Fluid

Status of Technology

After the constructer of the SEGS systems, LUZ International Limited, went bankrupt in 1991, no new commercial parabolic trough solar thermal power plants were built in the United States for 16 years.

The first commercial CSP plant after the SEGS systems was the 64 MW Nevada Solar One plant in Boulder City, Nevada, which ran into action in June 2007. The system uses 760 parabolic concentrators and a supplementary gas heater to generate heat up to 390.5°C. No thermal storage system is included. (Acciona, 2008)

In 2006 began the assembly of the first commercial parabolic trough power plant in Europe, the 50 MW AndaSol-1. It is located near Guadix, Granada province (Spain) and started its test run on October 15th, 2008. (Solar Millennium, 2008a)

The concept of the AndaSol system is shown in Figure 2.11.

The AndaSol system uses synthetic oil as heat transfer fluid and a two-tank molten salt thermal storage which has a capacity for 7.5 hours. The two different media are coupled via a salt-oil heat exchanger. The solar field has a size of 510,120 m^2 on a total ground area of 200 ha. An auxiliary gas heater for hybridisation is included.

It is projected that the AndaSol will have 2000 annual full-load hours provided by the solar resource which can be increased to 3,589 full-load hours with the thermal storage system. The annual electricity production is planned to be 179 GWh. (European Commission, 2007) p14 - 16

Because of the possibility of decomposition of the synthetic oil, the maximum heat transfer fluid temperature is restricted to ~395°C. (Pitz-Paal et al., 2005) p36

Two similar plants (AndaSol-2 and -3) are planned/being built.

Cost and Performance of the Reference System

Based on the data of the SEGS and AndaSol systems a reference plant was designed with a 1.4 times larger solar field than needed to provide the 50 MW_{el} and with a thermal storage system. Due to the constrained load curve, the capacity of the thermal storage was set to three hours. The following Table 3.1 shows the design and cost data.

Table 3.1 Design and cost data of the parabolic trough reference system using thermal oil as HTF
Source: Based on Pitz-Paal et al., 2005 p37-38

Solar Field		
aperture area of the solar field	442,035	m²
total area of the plant	1.72	km²
length of one single collector	150	m
focal length	2.12	m
collector row spacing / aperture width	3	
average reflectivity	0.88	
optical peak efficiency	0.75	
HTF temperature at field entrance	291	°C
HTF temperature at field exit	391	°C
factor for solar field parasitics	0.0098	kW/m^2
design parasitics for pumping and tracking	4,332	kW
factor for power block parasitics	0.03	
heat loss factor piping	0.02	W/m²
Power Cycle		
design net electrical output	50,000	kW
design efficiency of the power block	0.375	
Storage		
storage capacity	3	h
thermal capacity of the storage	434,656	kWh
storage efficiency	0.95	
HTF temperature in storage discharging	371	°C
efficiency factor due to lower storage fluid temp.	0.975	
Investment (inc. engineering & construction)		
specific investment cost for solar field	206	€/m²
specific investment cost for power block	700	€/kW_{el}
surcharge for construction, engineering & contingencies	20	%
Operation and Maintenance		
annual O&M costs (43 persons + 1% of investment)	4,003,490	€/y
number of persons for plant operation	30	
number of persons for field maintenance	13	

The calculated economical results for the designed parabolic trough system are shown in Table 3.2. The total investment is about 176 Mio. € with the greatest share of the investment in the solar field (~51%) and the power block (~22%). The calculated LEC come to 0.172 €/kWh_{el}, 0.032 €/kWh_{el} being included for the O&M costs.

Table 3.2 Economical results for the parabolic trough reference system using thermal oil as HTF
Source: Based on Pitz-Paal et al., 2005 p38

Economical Results		
fixed charge rate	0.0988	
investment solar field	91,059,210	€
investment power block, BOP	39,082,710	€
investment storage	13,474,322	€
investment land	3,447,873	€
contingencies	29,412,823	€
sum total equipment costs	147,064,115	€
total investment including indirect costs	176,476,938	€
specific investment	3,530	€/kW_{el}
annual O&M costs	4,003,490	€
annual financing & insurance costs	17,440,763	€
levelized electricity costs (solar-only)	0.172	€/kWh_{el}
O&M cost / kWh	0.032	€/kWh

The results of the performance calculation can be seen in Figure 3.2.

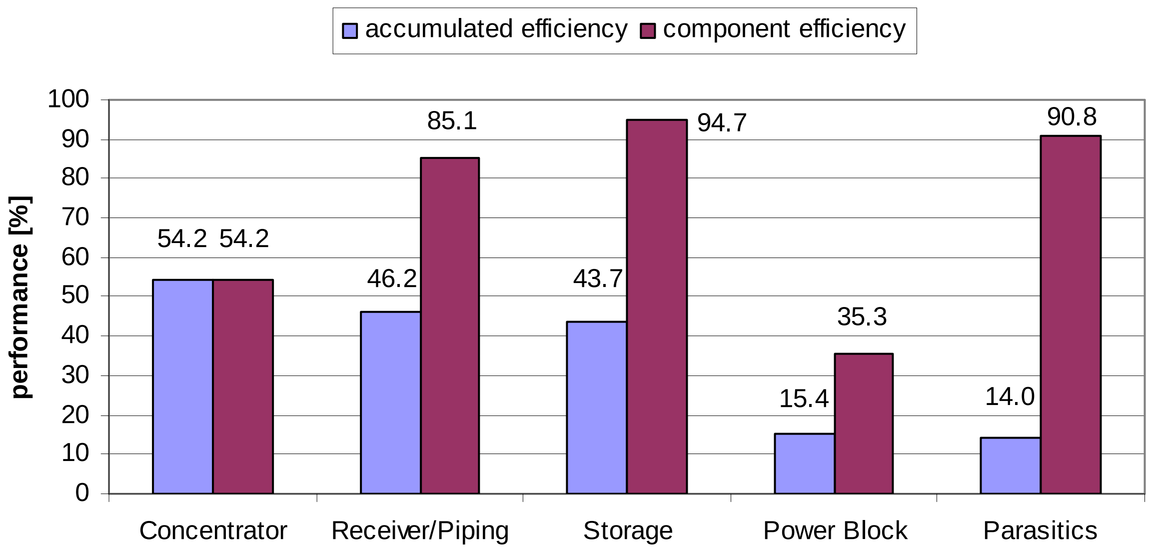


Figure 3.2 Results of the performance calculation for the parabolic trough reference system using thermal oil as HTF
Source: Based on Pitz-Paal et al., 2005 p39

In total the system has a solar-to-electric efficiency of 14% and a solar capacity factor of 29%. The low power block efficiency of 35.3% makes this system not very economical for hybrid operation with large fuel share.

Today the parabolic trough systems using thermal oil as HTF are the most common and also the most mature form of all CSP plants; over 460 MW (including AndaSol, which will operate soon) of electrical capacity are installed worldwide. But nevertheless the evaluated LEC of the reference system is still over 0.17 €/kWh$_{el}$. One major limitation for the system is the costly synthetic thermal oil with its low operation temperature.

3.2.2 Parabolic Trough Technology using Water/Steam as Heat Transfer Fluid

Status of Technology

The replacement of synthetic oil with water as heat transfer fluid has some big advantages:

- higher temperatures reachable
- solar heated water can be converted into superheated steam, which can be directly used in the steam turbine (400°C, ~100 bar) => Direct Steam Generation (DSG)
- lower investment and operating costs
- higher efficiency
- reduced environmental risk and fire hazards

A first test facility was built under the EU co-funded DISS project (DIrect Solar Steam) at the Plataforma Solar de Almeria (PSA), Spain. After the project start in 1996, various tests and studies on different steam operating modes, operating pressures etc. were made with a 300 kW$_{th}$ test loop.

The first pre-commercial DSG power plant design was made within the EU co-funded INDITEP project (INtegration of DIrect solar steam Technology for Electricity Production, 2002 – 2005). Figure 3.3 shows the scheme of the INDITEP project.

To limit the financial risk for investors the net nominal power was set to only 5 MW$_{el}$.

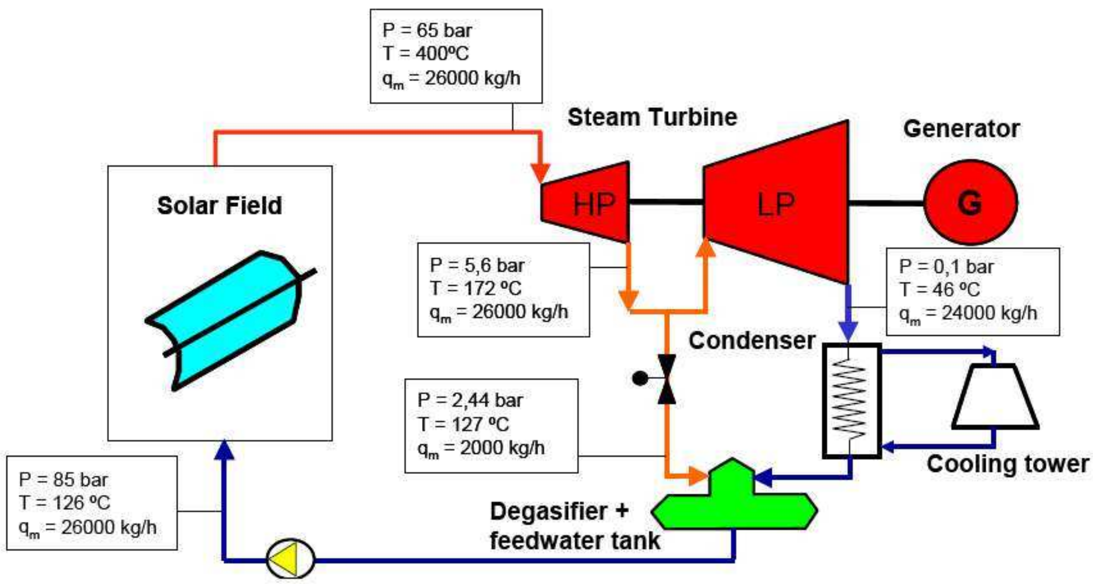


Figure 3.3 Simplified scheme of the parabolic trough reference system using water/steam as HTF (DSG, INDITEP project)
Source: Pitz-Paal et al., 2005 p43

Cost and Performance of the Reference System

The small size of the INDITEP plant led to low efficiency and high specific annual O&M cost. So the LEC were above 0.20 €/kWh.

A DSG reference system which consists of ten INDITEP systems working in parallel with a net nominal power of 47 MW_{el} was designed. No storage system was included, because there was no technical option for such a system at the moment of the MED-CSP study.

The following Table 3.3 shows the design and cost data of the DSG reference system.

Table 3.3 Design and cost data of the DSG parabolic trough reference system
Source: Based on Pitz-Paal et al., 2005 p44-45

Solar Field Design		
aperture area of the solar field	448,191	m²
total area of the plant	1.6	km²
length of one single collector	150	m
focal length (average)	2.12	m
collector row spacing / aperture width	3	
average reflectivity	0.88	
optical peak efficiency	0.75	
water temperature at field entrance	126	ºC
steam temperature at field exit	411	ºC
design parasitics for pumping and tracking	4,034	kW
heat loss factor piping	0.02	kW/m²
Power Block Design (10 equal power block units)		
design net electrical output	47,000	kW
design efficiency of the power block	26	%
overall plant availability	0.96	
Investment (inc. engineering & construction)		
specific investment cost for solar field	190	€/m²
specific investment cost for power block	435	€/kW_{el}
surcharge for construction, engineering & contingencies	20	%
Operation and Maintenance		
annual O&M costs (43 persons + 1% of investment)	3,515,128	€/y
number of persons for plant operation	30	
number of persons for field maintenance	13	

The calculated economical results for the designed DSG system in solar-only operation are shown in Table 3.4. The total investment is about 133 Mio. € with its greatest share in the solar field (~64%) and the power block (~17%). The calculated LEC come to 0.187 €/kWh_{el}, including 0.039 €/kWh_{el} for the O&M costs. Compared to the parabolic trough with oil as HTF reference system, the DSG system has lower investment costs but higher LEC.

A solar capacity factor of 21.7% is reached.

Table 3.4 Economical results for the DSG parabolic trough reference system
Source: Based on Pitz-Paal et al., 2005 p45

Economical Results		
fixed charge rate	0.0988	
investment solar field	85,156,338	€
investment power block, BOP	22,813,019	€
investment land	3,271,796	€
contingencies	22,248,242	€
sum total equipment costs	111,241,211	€
total investment including indirect costs	133,489,454	€
specific investment	2.84	€/kW_{el}
annual O&M costs	3,515,128	€
annual financing & insurance costs	13,192,420	€
levelized electricity costs (solar-only)	0.187	€/kWh_{el}
O&M cost / kWh	0.039	€/kWh

The results of the performance calculation can be seen in Figure 3.4.

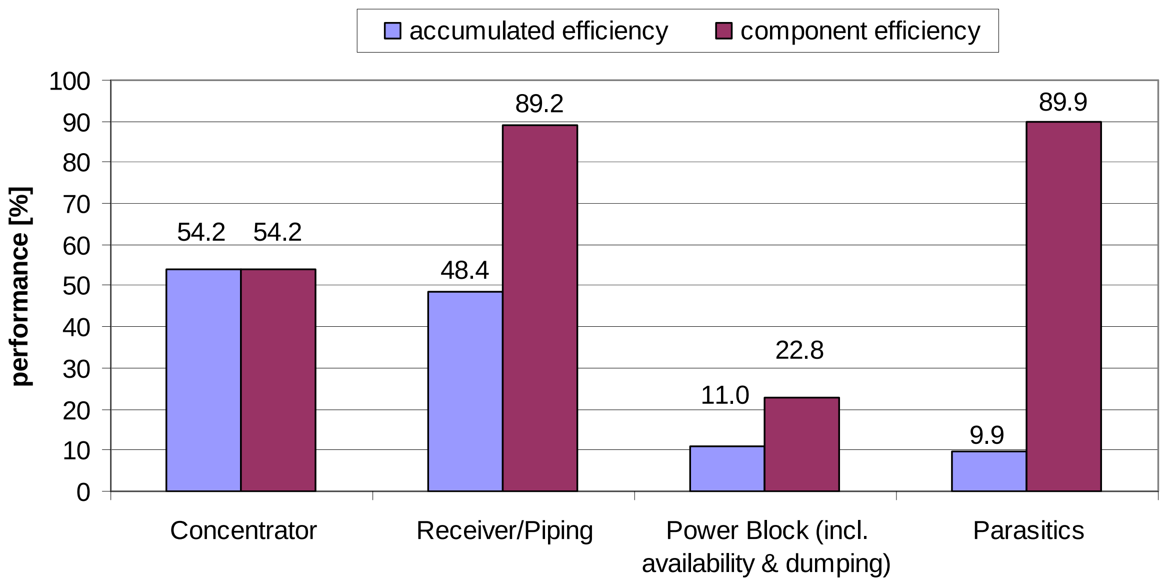


Figure 3.4 Results of the performance calculation for the DSG parabolic trough reference system
Source: Based on Pitz-Paal et al., 2005 p46

The system has a solar-to-electric efficiency of 9.9%, which is low "because of the low efficiency of the small reference block". (Pitz-Paal et al., 2005) p45

With the advantages of DSG systems summarized above and a proper thermal storage system, cheap water/steam could replace the costly synthetic thermal oil as HTF. Even with a lower power block efficiency and capacity and without a thermal storage system, the LEC of the DSG plant is not very far above (0.187 €/kWh_{el} compared to 0.172 €/kWh_{el}) the PT plant using thermal oil as HTF.

3.2.3 Linear Fresnel System using Water/Steam as Heat Transfer Fluid

Status of Technology

Today there are no commercial CSP plants using linear Fresnel collectors running; only some demonstration plants were built so far. The latest demonstration power plant with linear Fresnel reflectors is the FRESDEMO project which was built by MAN Ferrostaal in collaboration with the Solar Power Group in Almeria, Spain. It has one collector module of 100 m length which generates one MW_{th} (peak). The total reflector area is 1,433 m^2. The plant began a two year long trial operation on July 17^{th}, 2007. (BMU, 2006)

Cost and Performance of the Reference System

A DSG Fresnel system with 50 MW was designed "without storage based on performance figures evaluated by Fraunhofer ISE". (Pitz-Paal et al., 2005) p47

The input data for the DSG Fresnel system can be seen in Table 3.5.

Table 3.5 Design and cost data of the DSG linear Fresnel reference system
Source: Based on Pitz-Paal et al., 2005 p48

Solar Field		
aperture area of the solar field	376,200	m²
total area of the plant	0.5643	km²
length of one single collector	1,000	m
average reflectivity	0.88	
optical peak efficiency	0.64	
HTF temperature at field entrance	126	°C
HTF temperature at field exit	411	°C
factor for solar field parasitics	0.009	
heat loss factor piping	0.02	W/m²
design parasitics for pumping and tracking	3,386	kW
Power Block		
factor for power block parasitics	0.03	
design net electrical output	50,000	kW
design efficiency of the power block	0.385	
O&M Input		
labour costs per employee	48,000	€/y
number of persons (without field maintenance)	30	
number of persons for field maintenance	7.5	
O&M equipment costs percentage of investment	1	per a
Cost Input		
specific investment cost for solar field	120	€/m²
spec. investment cost for power block	700	$€/kW_{el}$
surcharge for construction, engineering & contingencies	20	%
overall plant availability	96	%

The calculated economical results for the designed DSG system with linear Fresnel concentrator are shown in Table 3.6. The total investment is about 102 Mio. € with the largest portion of the investment in the solar field (~44%, parabolic trough: ~64%) and the power block (~38%, parabolic trough: ~17%). The calculated LEC are 0.162 €/kWh$_{el}$, 0.036 €/kWh$_{el}$ being included for the O&M costs.

Table 3.6 Economical results for the DSG linear Fresnel reference system
Source: Based on Pitz-Paal et al., 2005 p49

Economical Results		
fixed charge rate	0.0988	
investment solar field	45,144,000	€
investment power block, BOP	38,420,410	€
investment land	1,128,600	€
contingencies	16,938,688	€
sum total equipment costs	84,693,440	€
total investment including indirect costs	101,632,128	€
specific investment	2,033	€/kW$_{el}$
annual O&M costs	2,921,659	€
annual financing & insurance costs	10,044,042	€
levelized electricity costs (solar-only)	0.162	€/kWh$_{el}$
O&M cost / kWh	0.036	€/kWh

The annual net efficiency is only 10.6% (Figure 3.5) compared to 14.1% of the DSG system with parabolic trough concentrators. Since no thermal storage system is included, a solar capacity factor of only 18.27% is reached.

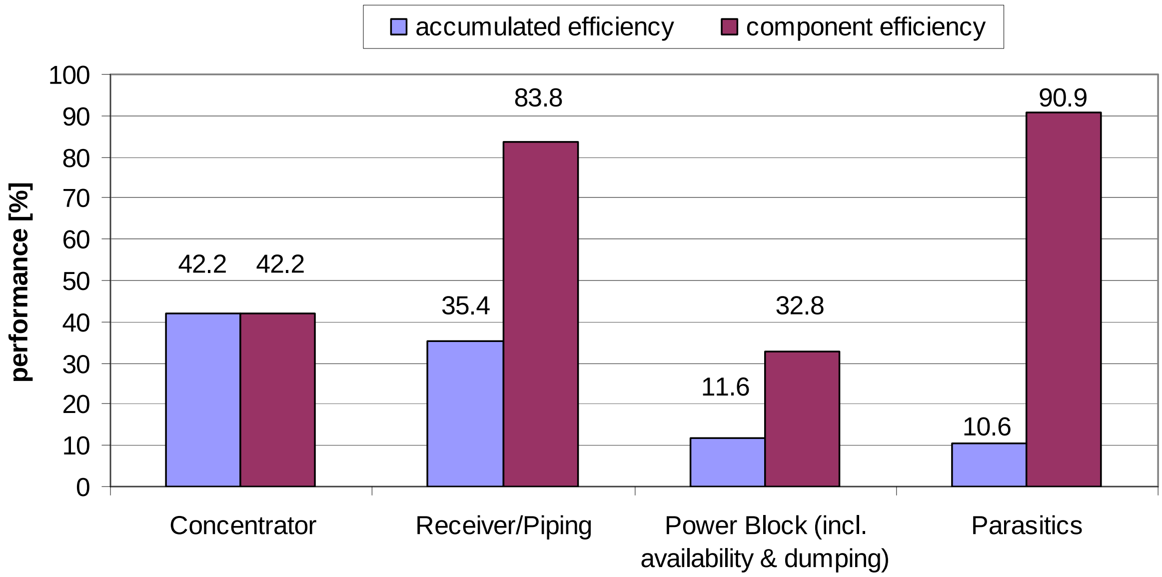


Figure 3.5 Results of the performance calculation for the DSG linear Fresnel reference system
Source: Based on Pitz-Paal et al., 2005 p47

One great advantage of this system is the low land use of one power plant; a 50 MW system needs only 0.56 km^2 (compared to 1.6 km^2 of the PT DSG plant). Another advantage is the low investment cost compared to other 50 MW systems.

If the linear Fresnel demonstration systems prove successful and a proper thermal storage system is developed and added, Fresnel systems will be able to replace parabolic trough systems as default CSP technology in the future.

3.2.4 Central Receiver System using molten Salt as Heat Transfer Fluid

Status of Technology

Molten nitrate salt is a mixture of 60% sodium nitrate and 40% potassium nitrate. "In a molten salt power, cold salt at 290°C is pumped from a tank at ground level to the receiver mounted atop a tower where it is heated by concentrated sunlight to 565°C. The salt flows back to ground level into another tank. To make electricity, hot salt is pumped from the hot tank through a steam generator to make superheated steam. The superheated steam powers a Rankine-cycle turbine". (Pitz-Paal et al., 2005) p50

Figure 3.6 shows a schematic of molten salt CRS.

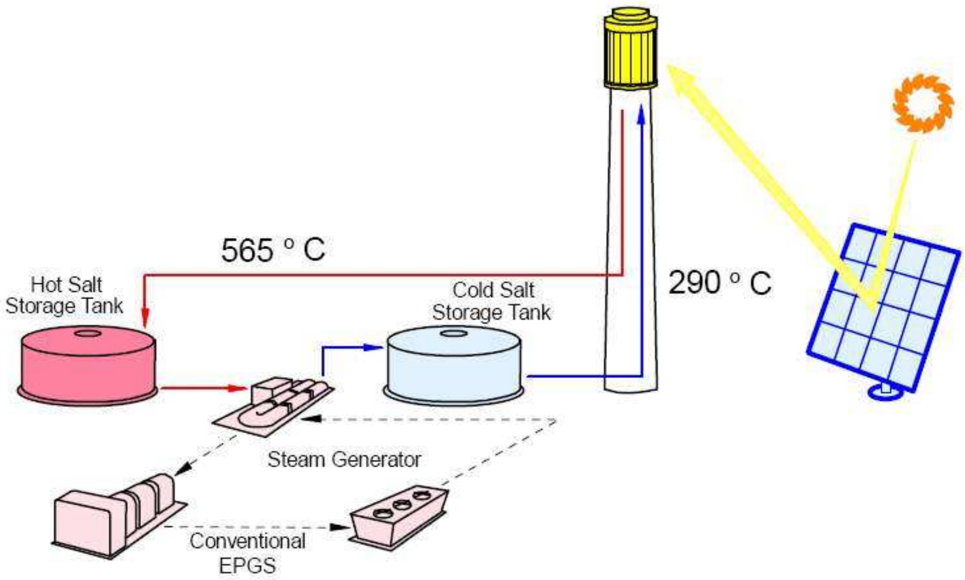


Figure 3.6 Process flow diagram of a molten salt CRS
Source: Pitz-Paal et al., 2005 p50

The 10 MW power tower project Solar Two near Barstow, California/USA, was the largest demonstration plant for the molten salt technology. It began to operate in 1996 and was shut down in 1999, after the plant successfully demonstrated the potential of the technology with peak-conversion efficiencies up to 13.5%.

The first commercial-scale molten salt demonstration plant will be the 17 MW Solar Tres project, located in Ecija/Spain. It will have approximately three times the size of Solar Two. The surface of the 2,480 heliostats will be about 285,200 m^2 on a total ground area of 142.31 ha. It is projected that the thermal storage system with a capacity of 15 h will increase the annual full-load hours of Solar Tres to 5,671 h (capacity factor ~65%). The annual electricity production is planed to be 96,400 MWh. (European Commission, 2007) p17 - 18

Table 3.7 Design and cost data of the central receiver reference system using molten salt as HTF
Source: Based on Pitz-Paal et al., 2005 p53-54

Heliostat Field	**17 MW Plant**	**50 MW Plant (3 Modules)**	
total reflective area of the solar field	152,720	458,160	m²
total area needed for the power plant	0.611	1.833	km²
area of one heliostat	121.34	121.34	m²
number of heliostats	1259	3776	
mean reflectivity	0.88	0.88	
optical peak efficiency	0.75	0.75	
design parasitics for pumping and tracking	2,482	7,445	kW
Storage			
storage capacity	3	3	h
thermal capacity of the storage	153,803	461,409	kWh
storage efficiency	0.95	0.95	
temperature at storage discharging	560	560	°C
efficiency factor due to lower fluid temperature	0.997	0.997	
Receiver			
design solar thermal input (to receiver)	73,993	221,979	kW
max. temperature at receiver exit	565	565	°C
Power Cycle			
design net electrical output	17,000	51,000	kW
design point cycle efficiency	38	38	%
O&M Input			
labour costs per employee	48,000	48,000	€/y
number of persons (without field maintenance)	30	30	
spec. number of persons for field maintenance	0.03	0.03	1/1000m²
number of persons for field maintenance	4.6	13.7	
water costs per MWh electricity produced	1.3	1.3	€/MWh
O&M equipment costs percentage of investment	1%	1%	per y
power block O&M fix	27	27	€/kW
power block O&M variable	2.5	2.5	€/MWh
Cost Input			
specific investment cost for solar field	150	142	€/m²
spec. investment cost for power block	750	694	€/kW_{el}
spec. investment cost for storage	14	13	€/kWh_{th}
total investment cost for tower	2,000,000	5,555,879	€
spec. investment cost for receiver	125	116	€/kW_{th}
annual O&M costs factor	1	1	
surcharge for construction, engineering & contingencies	0.2	0.2	
overall plant availability	0.96	0.96	

Cost and Performance of the Reference System

A 50 MW reference system was designed out of three Solar Tres modules with a three hour storage system and smaller solar field size. Original module technical data were provided by the Spanish company SENER. The economical inputs were estimated by DLR and CIEMAT from SolarPACES data. All input data can be seen in Table 3.7.

The calculated economical results for the designed molten salt CRS are shown in Table 3.8. The total investment is about 177 Mio. €, with only a share of 3% representing the storage. The calculated LEC are 0.155 €/kWh$_{el}$, whereby 0.037 €/kWh$_{el}$ are included for the O&M costs.

Table 3.8 Economical results for the central receiver reference system using molten salt as HTF
Source: Based on Pitz-Paal et al., 2005 p56

Economical Results	**17 MW Plant**	**50 MW Plant**	
fixed charge rate	0.0988	0.0988	
Investment solar field	22,908,000	65,050,759	€
Investment power block	14,993,903	41,652,152	€
Investment receiver	9,249,105	25,693,453	€
Investment tower	2,000,000	5,555,879	€
Investment storage	2,153,241	5,981,572	€
Investment land	1,221,760	3,665,280	€
indirect costs	10,505,202	29,519,819	€
sum total equipment costs	52,526,008	147,599,095	€
total investment including indirect costs	63,031,210	177,118,914	€
specific investment	3,708	3,473	€/kW$_{el}$
annual O&M costs	2,832,888	5,518,874	€
annual financing & insurance costs	6,229,213	17,504,208	€
levelized electricity costs	0.1825	0.1545	€/kWh$_{el}$

In Figure 3.7 the performance results are presented. The annual net efficiency is calculated to be 16% with a solar capacity factor of 34%.

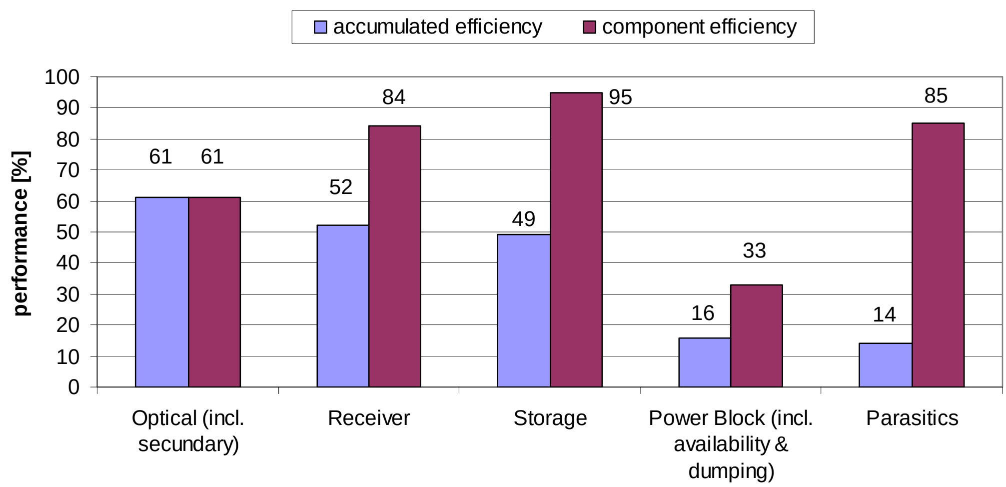


Figure 3.7 Results of the performance calculation for the central receiver reference system using molten salt as HTF
Source: Based on Pitz-Paal et al., 2005 p54

The CRS using molten salt as HTF is the most developed form of all CRS, proven by the 10 MW Solar Two demonstration plant in the United States. The CRS competes with the PT plants: Even the small 17 MW plant has comparable LEC to the 50 MW PT systems; the 51 MW CRS using molten salt as HTF offers the lowest LEC of all (non-hybridised) CSP systems. This is mainly attributed to the low costs of the thermal storage system, which benefits from the high outlet temperature of the receiver.

3.2.5 Central Receiver System using saturated Steam as Heat Transfer Fluid

Status of Technology

Today the PS10 project represents the state-of-the-art for the CRS with saturated steam technology. The 11 MW PS10 CRS located at Sanlúcar la Mayor, Southern Spain, was inaugurated on March 30th, 2007. It has 624 heliostats with 120 m^2 each on a total ground area of 55 ha. The plant has a cavity concept receiver on the top of the 100 m high tower, which "is designed to produce saturated steam at 40 bar - 250°C from thermal energy supplied by concentrated solar radiation flux". (European Commission, 2007) p12

Figure 3.8 shows the process flow diagram of the PS10 system.

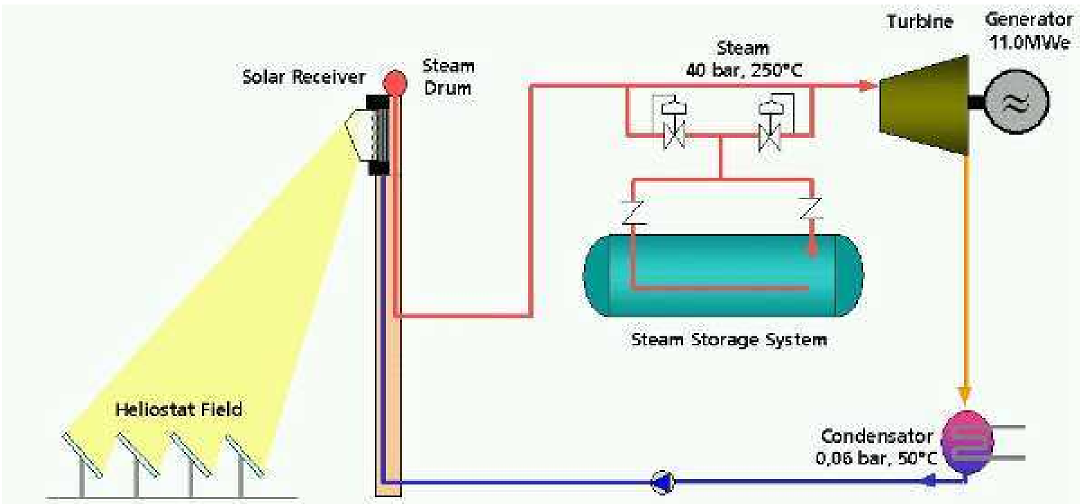


Figure 3.8 Process flow diagram of the PS10 CRS
Source: Pitz-Paal et al., 2005 p58

The plant includes also a steam storage system with a thermal capacity of 20 MWh (50 minutes at 50% load). The steam storage consists of four tanks which are loaded by a part of the produced steam at full-load operation. With 2,087 annual full-load operation hours, the plant is estimated to have an annual electricity production of 23 GWh. (European Commission, 2007) p12-13

The solar-to-electricity efficiency is approximately 17%. (Abengoa Solar, 2007) p14

Currently a similar plant, the PS20, is under construction. It has nearly twice the size of the PS10 system, with 1,255 heliostats and a 160 m high tower. (Abengoa Solar, 2007) p14

Figure 3.9 Aerial view of the PS10 (back) and PS20 (front) systems
Source: Abengoa Solar, 2007 p15

Cost and Performance of the Reference System

A reference system consisting of five modules based on the PS10 system has been designed with following characteristics:

- Storage capacity of 0.4 h => system can not provide 14 h full-load operation
- Solar field with 766 heliostats
- Original module technical data from SOLUCAR and ABENER

Table 3.9 shows the technical and economical input data for the reference CRS using saturated steam.

Table 3.9 Design and cost data of the central receiver reference system using saturated steam as HTF
Source: Based on Pitz-Paal et al., 2005 p61-62

Heliostat Field	**11 MW Plant**	**5 x 11 MW Plant**	
total reflective area of the solar field	93,006	465,032	m^2
total area needed for the power plant	0.372	1.86	km^2
area of one heliostat	121.34	121.34	m^2
number of heliostats	766	3832	
mean reflectivity	0.88	0.88	
optical peak efficiency	0.75	0.75	
factor for solar field parasitics	0.0016	0.0016	
design parasitics for pumping and tracking	149	744	kW
Receiver			
max. fluid temperature at receiver exit	260	260	°C
design solar thermal input (to receiver)	45,062	225,308	kW
design net electrical output	11,000	55,000	kW
Power Block			
factor for power block parasitics	0.03	0.03	
design efficiency of the power block	0.303	0.303	
mean plant availability	0.96	0.96	
Storage			
storage capacity	0.4	0.4	h
thermal capacity of the storage	14,718	73,590	kWh
storage efficiency	0.95	0.95	
temperature at storage discharging	260	260	°C
efficiency factor due to lower fluid temperature	0.8	0.8	
O&M Input			
labour costs per employee	48,000	48,000	€/y
number of persons (without field maintenance)	30	30	
spec. number of persons for field maintenance	0.03	0.03	$1/1000m^2$
number of persons for field maintenance	2.8	14	
water costs per MWh electricity produced	1.3	1.3	€/MWh
O&M Equipment costs percentage of investment	1%	1%	per y
power block O&M fix	20	20	€/kW
power block O&M variable	2.6	2.6	€/MWh
Cost Input			
specific investment cost for solar field	150	138	€/m^2
spec. investment cost for power block	636	568	€/kW_{el}
spec. investment cost for storage	100	89	€/kWh_{th}
total investment cost for tower	2,000,000	8,934,538	€
spec. investment cost for receiver	110	98	€/kWh_{th}
annual O&M costs factor	1	1	
surcharge for construction, engineering & contingencies	0.2	0.2	
overall plant availability	0.96	0.96	

The results of the economical calculation can be seen in Table 3.10. The LEC of the five-module plant are 0.168 €/kWh$_{el}$.

Table 3.10 Economical results for the central receiver reference system using saturated steam as HTF
Source: Based on Pitz-Paal et al., 2005 p63

Economical Results	**11 MW Plant**	**5 x 11 MW Plant**	
fixed charge rate	0.0988	0.0988	
investment solar field	13,950,972	64,361,472	€
investment power block	7,300,593	32,613,714	€
investment receiver	4,956,780	22,143,271	€
investment tower	2,000,000	8,934,538	€
investment storage	1,471,790	6,574,882	€
investment land	744,052	3,720,259	€
indirect costs	6,084,838	27,669,628	€
sum total equipment costs	30,424,188	138,348,138	€
total investment including indirect costs	36,509,025	166,017,765	€
specific investment	3,319	3,019	€/kW$_{el}$
annual O&M costs	2,175,105	4,977,789	€
annual financing & insurance costs	3,608,093	16,407,110	€
levelized electricity costs	0.2272	0.1681	€/kWh$_{el}$

Because of the small storage system, the plant has only a capacity factor of 26.4%.

Figure 3.10 shows the efficiency of the individual parts of the plant. The receiver has a very high efficiency of 88% because of its low-temperature and cavity design. The total solar-to-electricity efficiency of the system is 13.6%.

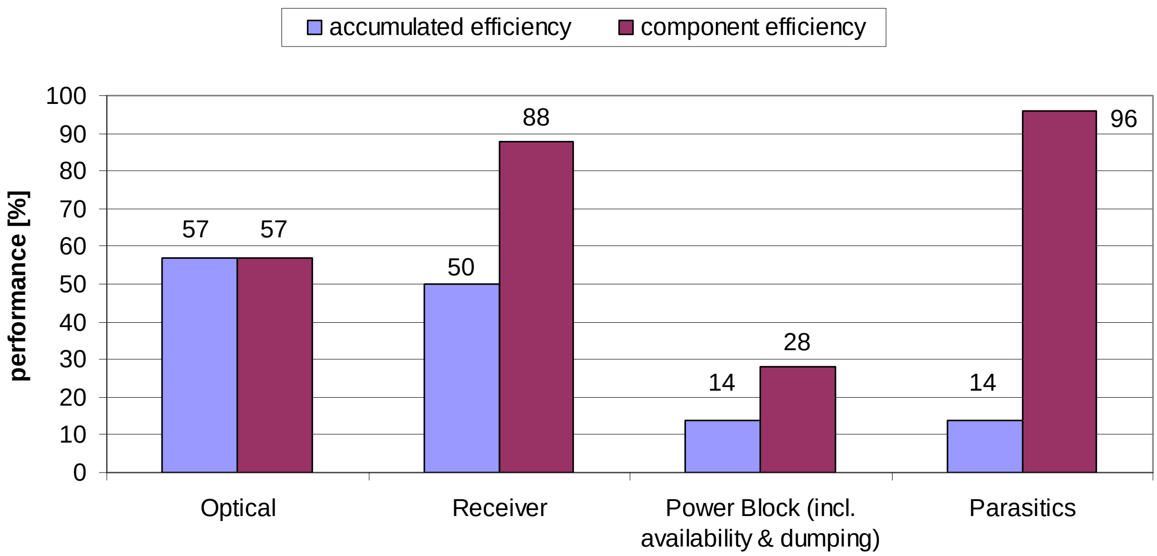


Figure 3.10 Results of the performance calculation for the central receiver reference system using saturated steam as HTF
Source: Based on Pitz-Paal et al., 2005 p63

The advantage of the CRS using saturated steam as HTF is its receiver, which offers low investment costs and a high efficiency. On the other hand, the LEC of the 11 MW plant is very high because of the small thermal storage system (no low-cost technology available, similar to the DSG systems) and the low efficiency of the power block (low inlet temperature) compared to the molten salt system. However, the PS10 system is still running in Spain and could prove the technology to be competitive to the molten salt technology.

3.2.6 Central Receiver System using atmospheric Air as Heat Transfer Fluid

Status of Technology

Figure 3.11 shows the process flow diagram of a CRS using atmospheric air as HTF (PHOEBUS scheme). Atmospheric air is heated in a porous absorber receiver to approximately 700°C and is then blown to the steam generator, which produces steam at 480 - 540°C and 35 - 140 bar. A ceramic thermocline thermal storage system, which can be charged/discharged with two axial blowers, is integrated as well.

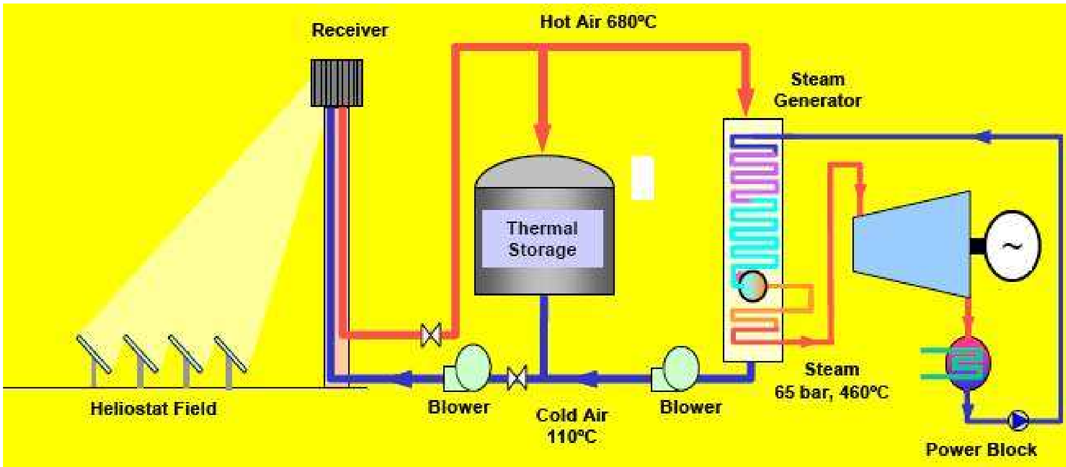


Figure 3.11 Process flow diagram of the Phoebus scheme PS10 system
Source: Pitz-Paal et al., 2005 p65

A first 2.5 MW_{th} system was assembled on top of the CESA-1 tower in Spain in 1991 and operated for several hundred hours in the years 1993 - 1994 and 1999.

After the successful demonstration of the operation principle, the Phoebus scheme became an option for the design of the PS10 system. So a detailed engineering was carried out on the atmospheric air system (even though water/steam was selected as HTF for the PS10 system).

The newest project for the Phoebus scheme is the solar tower in Juelich, Germany, which has been under construction since Aug. 31st, 2007. This CRS is projected to produce 1.5 MW_{el} (peak) and 1,000 MWh annually. (BMU, 2007)

Cost and Performance of the Reference System

The 50 MW reference plant for the CRS using atmospheric air is based on five 10 MW units of a modified version of the PS10 project (the thermal storage capacity and the number of heliostats have been increased). Most input data were provided by the company SOLUCAR and can be seen in Table 3.11.

Table 3.11 Design and cost data of the central receiver reference system using atmospheric air as HTF
Source: Based on Pitz-Paal et al., 2005 p68 - 69

Solar Field	**10 MW Plant**	**5 x 10 MW Plant**	
total reflective area of the solar field	104,580	522,900	m^2
total area needed for the power plant	0.418	2.092	km^2
area of one heliostat	121.34	121.34	m^2
number of heliostats	862	4309	
mean reflectivity	0.88	0.88	
factor for solar field parasitics	0.0065	0.0065	
design parasitics for pumping and tracking	680	3399	kW
Receiver			
max. air temperature at receiver exit	680	680	°C
design solar thermal input (to receiver)	50,669	253,345	kW
Power Block			
design net electrical output	10,000	50,000	kW
factor for power block parasitics	0.03	0.03	
design efficiency of the power block	0.34	0.34	
mean plant availability	0.96	0.96	
Storage			
storage capacity	3	3	h
thermal capacity of the storage	94,233	471,166	kWh
storage efficiency	0.95	0.95	
air temperature at storage discharging	650	650	°C
efficiency factor due to lower fluid temperature	0.985	0.985	
O&M Input			
labour costs per employee	48,000	48,000	€/y
number of persons (without field maintenance)	30	30	
spec. number of persons for field maintenance	0.03	0.03	$1/1000m^2$
number of persons for field maintenance	3.1	15.7	
water costs per MWh electricity produced	1.3	1.3	€/MWh
O&M equipment costs percentage of investment	1%	1%	per y
power block O&M fix	27	27	€/kW
power block O&M variable	2.5	2.5	€/MWh
overall plant availability	0.96	0.96	
Cost Input			
specific investment cost for solar field	150	138	€/m^2
spec. investment cost for power block	600	536	€/kW_{el}
spec. investment cost for storage	60	54	€/kWh_{th}
spec. investment cost for receiver	115	103	€/kW_{th}
total investment cost for tower	2,000,000	8,934,538	€
surcharge for construction, engineering & contingencies	0.2	0.2	

The economical results are presented in Table 3.12. It shows that the LEC can be reduced to 17.87 €/MWh with five modules on one site. "Compared to other systems the cost of the heat storage is also relatively high. This may result from the fact that the costs provided by industry include high additional risk surcharges since the requested sizes are not typical in other applications for the first of its-kind demonstration systems". (Pitz-Paal et al., 2005) p70

Table 3.12 Economical results for the central receiver reference system using atmospheric air as HTF
Source: Based on Pitz-Paal et al., 2005 p70

Economical Results	**10 MW Plant**	**5 x 10 MW Plant**	
fixed charge rate	0.0988	0.0988	
investment solar field	15,687,000	72,370,471	€
investment power block	6,587,922	29,430,020	€
investment receiver	5,826,936	26,030,491	€
investment tower	2,000,000	8,934,538	€
investment storage	5,653,996	25,257,920	€
investment land	836,640	4,183,200	€
indirect costs	7,673,182	34,825,793	€
sum total equipment costs	36,592,494	166,206,641	€
total investment including indirect costs	43,910,993	199,447,969	€
specific investment	4,391	3,989	€/kW_{el}
annual O&M costs	2,334,800	5,825,666	€
annual financing & insurance costs	4,339,611	19,710,931	€
levelized electricity costs	0.2342	0.1787	€/kWh_{el}

Figure 3.12 shows the various component efficiencies of the reference system. The total solar-to-electric efficiency is calculated to be about 14%.

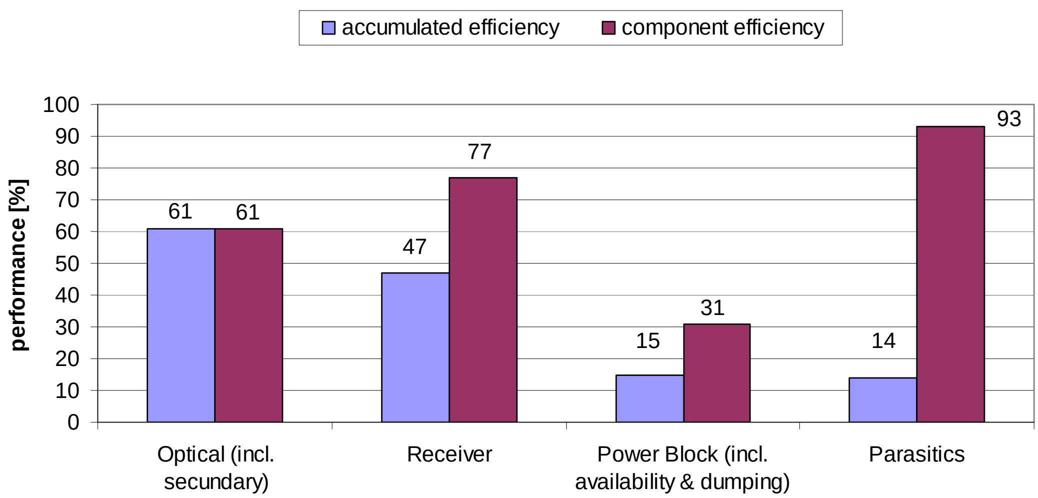


Figure 3.12 Results of the performance calculation for the central receiver reference system using saturated steam as HTF
Source: Based on Pitz-Paal et al., 2005 p71

Because of the 11% lower efficiency of the receiver and the higher investment cost of the storage, the LEC of the CRS using atmospheric air as HTF are slightly higher than the LEC of the saturated steam systems. The system has also a similarly low solar-to-electric efficiency like the saturated steam system. However, the technology is still at a low state of maturity with only one small demonstration plant. Therefore the cost and performance of the technology still have to be proved.

3.2.7 Central Receiver System with a solar-hybrid Gas Turbine

Status of Technology

Within the EU-funded project SOLGATE, a solar-hybrid test system was integrated into the solar tower test facility at the PSA in November 2002. "The solarized gas turbine was based on a helicopter engine, which was modified to enable external solar heating" and had a design power output of 250 kW_{el}. (European Commission, 2005) p2

Also various combined cycles systems were designed in the SOLGATE project. One of them, the PGT10, is taken as the reference system.

The PGT10 system consists of a solar field of 343 heliostats, a receiver with one low (600°C) and one high (800°C) temperature receiver element and a modified PGT10 gas turbine from GE Oil & Gas. It uses pressurized air as HTF. The heat flow diagram is shown in Figure 3.13.

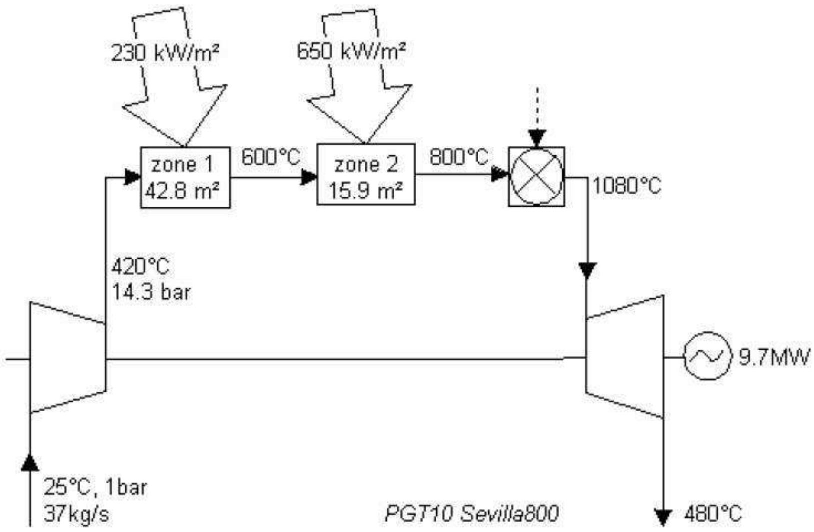


Figure 3.13 Heat flow diagram of a modified PGT10 gas turbine
Source: Pitz-Paal et al., 2005 p73

After the pressurized air has been heated up to 800°C by the two receiver elements, the air is fed into a combustion chamber, where natural gas is burned, so that the air reaches the inlet temperature of the gas turbine of 1080°C. Past the gas turbine, the still hot (480°C) air is used to produce steam for a Rankine cycle. With a solar fraction of 56.8% an electrical output of 15.8 MW_{el} is reached.

"Since the SOLGATE system is a hybrid power plant, it is not able to run in solar only mode, but it is able to deliver the design electrical output in pure fossil operation mode". (Pitz-Paal et al., 2005) p73

Cost and Performance of the Reference System

The reference system is based on four PGT10 systems. Design and cost data can be seen in Table 3.13.

Table 3.13 Design and cost data of the central receiver reference system using pressurized air as HTF in combination with a solar hybrid gas-turbine Source: Based on Pitz-Paal et al., 2005 p75 - 76

Solar Field	**14 MW Plant**	**4 x 14 MW Plant**	
total reflective area of the solar field	38,000	152,000	m^2
total area needed for the power plant	0.432	1.728	km^2
area of one heliostat	121.34	121.34	m^2
number of heliostats	313	1253	
mean reflectivity	0.88	0.88	
Receiver			
max. air temperature at receiver exit	800	800	°C
design solar thermal input	18,500	74,000	kW
Power Cycle			
design solar fraction	0.5631	0.5631	
design net electrical output	14,683	58,732	kW
design efficiency of the plant	0.447	0.447	
mean plant availability	0.96	0.96	
O&M Input			
labour costs per employee	48,000	48,000	€/y
number of persons (without field maintenance)	30	30	$1/1000m^2$
spec. number of persons for field maintenance	0.03	0.03	
number of persons for field maintenance	1.1	4.6	
water costs per MWh electricity produced	1	1	€/MWh
O&M equipment costs percentage of investment	1%	1%	per y
power block O&M fix	27	27	€/kW
power block O&M variable	2.5	2.5	€/MWh
Cost Input			
specific investment cost for solar field	150	140	€/m^2
spec. investment cost for power block	700	635	€/kW_{el}
spec. investment cost for storage	50	45	€/kWh_{th}
total investment cost for tower	2,000,000	7,260,153	€
spec. investment cost for receiver	150	136	€/kW_{th}
annual insurance cost	0.01	0.01	
surcharge for construction, engineering & contingencies	0.2	0.2	
fuel costs	15	15	€/MWh

In hybrid operation only 19% of the heat is provided by the solar system.

The economical results for the hybrid system can be seen in Table 3.14. With fuel costs of 15 €/MWh the LEC are 8.2 €/MWh. Different to all other systems, the power block of the hybrid plant has the largest share of 39% in the total investment.

Table 3.14 *Economical results for of the central receiver reference system using pressurized air as HTF in combination with a solar hybrid gas-turbine*
Source: Based on Pitz-Paal et al., 2005 p77

Economical Results	**14 MW Plant**	**4 x 14 MW Plant**	
fixed charge rate	0.0988	0.0988	
investment solar field	5,700,000	21,273,152	€
investment power block	10,278,100	37,310,291	€
investment receiver	2,775,000	10,073,463	€
investment tower	2,000,000	7,260,153	€
investment land	864,000	3,456,000	€
indirect costs	4,323,440	15,874,684	€
sum total equipment costs	21,617,199	79,373,419	€
total investment including indirect costs	25,940,639	95,248,103	€
specific investment	1,767	1,622	€/kWh_{el}
annual O&M costs	2,398,645	5,189,437	€
annual financing & insurance costs	2,563,647	9,413,126	€
annual fuel costs	2,156,205	8,624,820	€
levelized electricity costs	0.1004	0.0819	€/kWh_{el}
levelized solar electricity costs	0.1474	0.1385	€/kWh_{el}
levelized fossil electricity costs	0.0704	0.0688	€/kWh_{el}
fuel costs included in fossil LEC	0.0304	0.0304	€/kWh_{el}

"Hybrid operation would yield on the one hand side a constant and well defined capacity factor (55% in this case), on the other side it would result in relatively low LEC compared to solar only operation. However, the boundary conditions in some of today's political frameworks where solar electricity is supported by a feed-in tariff, hybrid operation is not applicable or very much restricted". (Pitz-Paal et al., 2005) p76

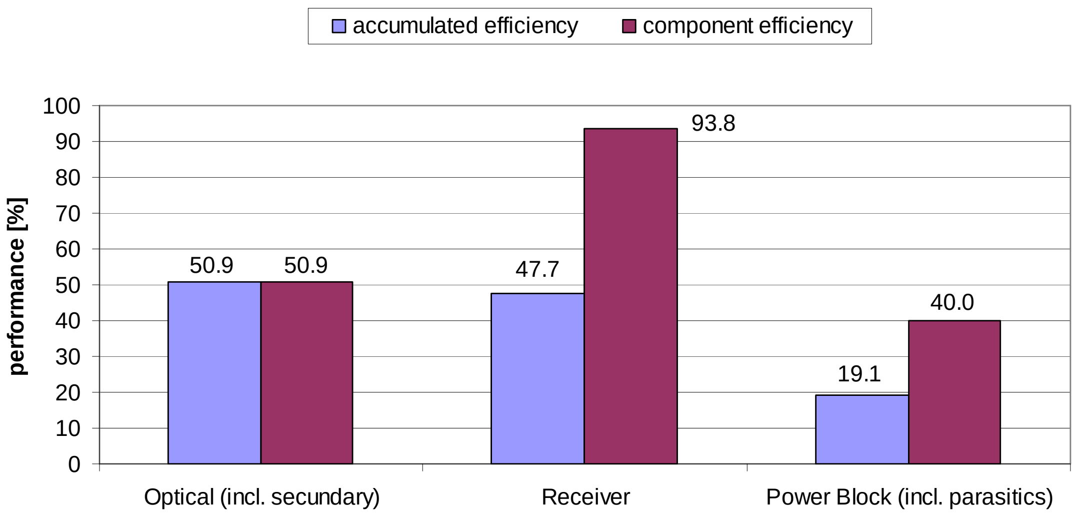


Figure 3.14 *Results of the performance calculation for the central receiver reference system using pressurized air as HTF in combination with a solar hybrid gas-turbine*
Source: Based on Pitz-Paal et al., 2005 p78

The annual performances of the components of the system are shown in Figure 3.14. The very high receiver efficiency of 93% leads to a total solar-to-electric efficiency of 19.1%.

Like the atmospheric air receiver technology, the pressurized air receiver technology is in an early state of development. The long term target of the technology is to generate high temperature heat to run combined cycle power plants with a very high efficiency. With the current state of the technology, only about 800°C are reached by the atmospheric air receiver, which leads to low solar contributions. If the outlet temperature could be increased to about 1000°C, the pressurized air could be directly used to run the gas turbine without the need of fossil fuel. But even now, with the low LEC of the system, the concept is an attractive option for a CSP system.

3.2.8 Dish-Engine Systems using Stirling or Brayton Cycles

Status of Technology

Over the last three decades, several dish-Stirling systems have been built and tested for thousand and more hours. Figure 3.15 shows some of these systems.

Figure 3.15 *Six different dish systems: McDonnell-Douglas (upper left), WGAssociates (upper middle), SAIC (upper right), Schlaich Bergermann und Partner (bottom left), HiTek`s 14 m^2 dish prototype (bottom middle) and the Australia National University 400 m^2 dish*
Source: Pitz-Paal et al., 2005 p80

The commercialisation of dish/Stirling systems has two problems: the dish cost and the absence of a Stirling engine industry, which produces engines appropriate for solarization (only SOLO, Germany, started small scale production so far).

A possible substitution for the Stirling engine is a small gas turbine (Brayton cycle, 30 – 100 kW) with a thermal-to-electric efficiency above 30%.

The two different modules are shown in Figure 3.16.

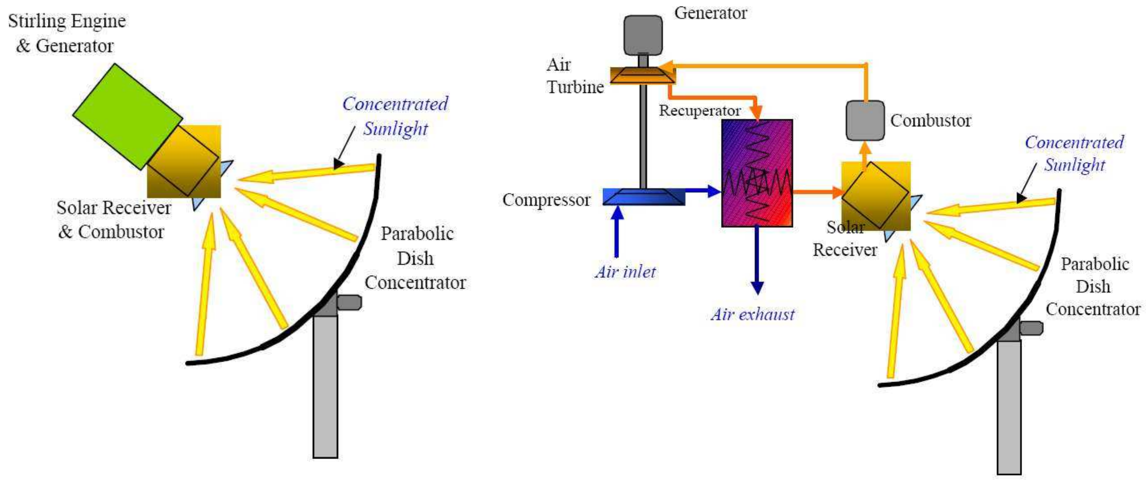


Figure 3.16 Left: Operational scheme of a dish/Stirling unit; Right: Operational scheme of a dish/Brayton unit
Source: Pitz-Paal et al., 2005 p81

A dish/Stirling module consists of a parabolic dish concentrator (typical 40 – 120 m^2), a solar receiver and a Stirling engine (10 – 25 kW). In a dish/Brayton module the Stirling engine is replaced by a recuperated gas turbine. Both modules are hybrid systems, meaning they can also operate without solar energy. A dish/Stirling or Brayton power plant can be built out of several modules.

Cost and Performance of the Reference System

The 50 MW reference plant was designed out of 2907 equal hybrid dish/Stirling systems at one site to get similar O&M costs like the other reference systems. The input data can be seen in Table 3.15 and Table 3.16.

Table 3.15 Design data for the dish/Stirling reference system
Source: Based on Pitz-Paal et al., 2005 p82

Solar Field		
total reflective area of the solar field	350,000	m^2
total area needed for the power plant	1.4	km^2
area of one dish	120.4	m^2
number of dishes	2907	
mean reflectivity	0.88	
Receiver		
max. hydrogen temperature at receiver exit	800	°C
design solar thermal input	233,125	kW
Power Cycle		
design solar fraction	1	
design net electrical output	50,000	kW
design efficiency of the plant	0.2145	
mean plant availability	0.9	

Table 3.16 Cost data for the dish/Stirling reference system
Source: Based on Pitz-Paal et al., 2005 p82 - 83

O&M Input		
labour costs per employee	48,000	€/y
number of persons (without field maintenance)	30	
spec. number of persons for field maintenance	0.06	1/1000m²
number of persons for field maintenance	21	
O&M equipment costs percentage of investment	1.5%	per y
power block O&M fix	40	€/kW
power block O&M variable	4.5	€/MWh
Cost Input		
specific investment cost for solar field	440	€/m^2
spec. investment cost for power block	3000	€/kW$_{el}$
spec. investment cost for receiver	120	€/kW$_{th}$
surcharge for construction, engineering & contingencies	0.2	
fuel costs	15	€/MWh

An annual capacity factor of 49.6% and 45% solar heat share were reached. The economical results are given in Table 3.17. With fuel costs of 15 €/MWh the hybrid LEC were calculated to be 28.11 €/MWh. The specific investment of 8,035 €/kW$_{el}$ is very high, but assuming that more than 2900 modules of one type form a plant, mass production of modules can lower the investment cost significantly.

Table 3.17 Economical results for the dish/Stirling reference system
Source: Based on Pitz-Paal et al., 2005 p84

Economical Results		
fixed charge rate	0.0988	
investment solar field	154,000,000	€
investment power block	150,000,000	€
investment receiver	27,975,000	€
investment land	2,800,000	€
indirect costs	66,955,000	€
sum total equipment costs	334,775,000	€
total investment including indirect costs	401,730,000	€
specific investment	8,035	€/kW$_{el}$
annual O&M costs	11,451,238	€
annual financing & insurance costs	39,701,945	€
annual fuel costs	9,893,639	€
levelized electricity costs	0.2811	€/kWh$_{el}$
levelized solar electricity costs	0.3835	€/kWh$_{el}$
levelized fossil electricity costs	0.1974	€/kWh$_{el}$
fuel costs included in fossil LEC	0.0456	€/kWh$_{el}$

In Figure 3.17 the component performance of the system, which has a total solar-to-electric efficiency of 16.7%, is presented.

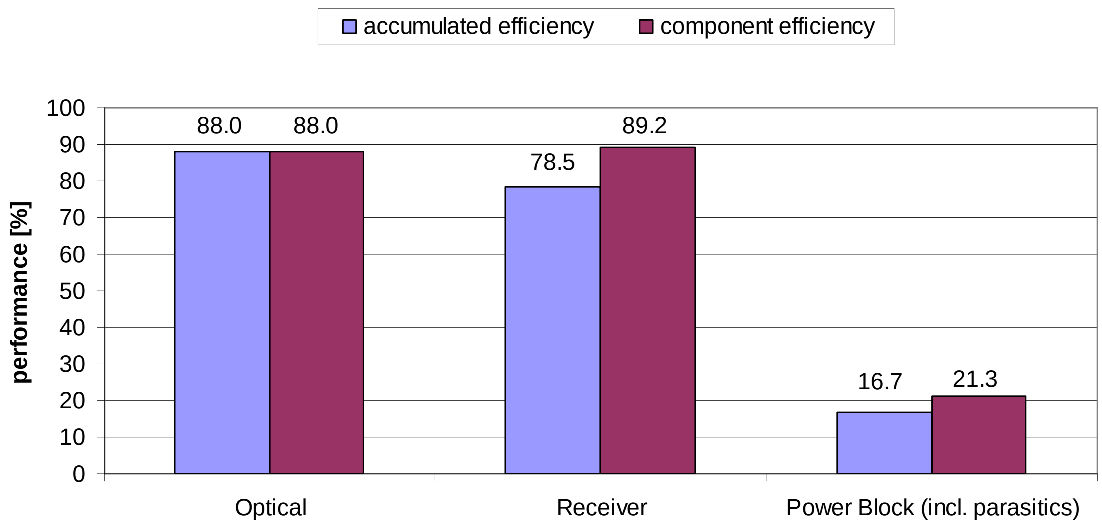


Figure 3.17 Results of the performance calculation for the dish/Stirling reference system
Source: Based on Pitz-Paal et al., 2005 p84

The dish/Stirling systems offer the highest solar-to-electric efficiency of all CSP systems, but they are still very expensive. Furthermore the Stirling engines' longevity and reliability are currently insufficient, leading to a low availability and high O&M costs.

3.3 Comparison of the Reference Systems

In Table 3.18 the different 50 MW (vary with technology from 47 to 58.73 MW) reference systems of the DLR cost study are summarized. The annual electricity production and full-load hours as well as the land requirement per annual electrical output (m^2/MWh/y) were calculated with data given by the reference models. Also four additional LEC were calculated with different financing parameters (real debt interest rate of 6.5 and 8.7%, depreciation period of 15 and 30 years, annual insurance 1%), to see how the LEC of the system vary with different financing situations.

If the data of the different CSP technologies are compared, it can be seen:

- That the Fresnel technology offers the lowest installation costs of about 2,000 €/kW as well as the lowest land requirement for the non-hybrid systems
- That the two DSG systems only offer annual full-load hours below 2,000 h/y because of the lack of a storage system
- That the average solar capacity factor of all non-hybrid systems is about 27%
- That the dish/Sterling system's investment/installation costs are about four times higher than those of the cheapest non-hybrid system (Fresnel)
- That all other non-hybrid systems offer installation cost of about 3,000 €/kW

In Figure 3.18 the LEC of the reference systems with a real debt interest rate of 6.5% and a depreciation period of 15 years are compared to the LEC of the parabolic trough system using oil as HTF. It can be seen, that the LEC of all non-hybrid systems are in a range of +/- 9% of the LEC of the PT (oil) system.

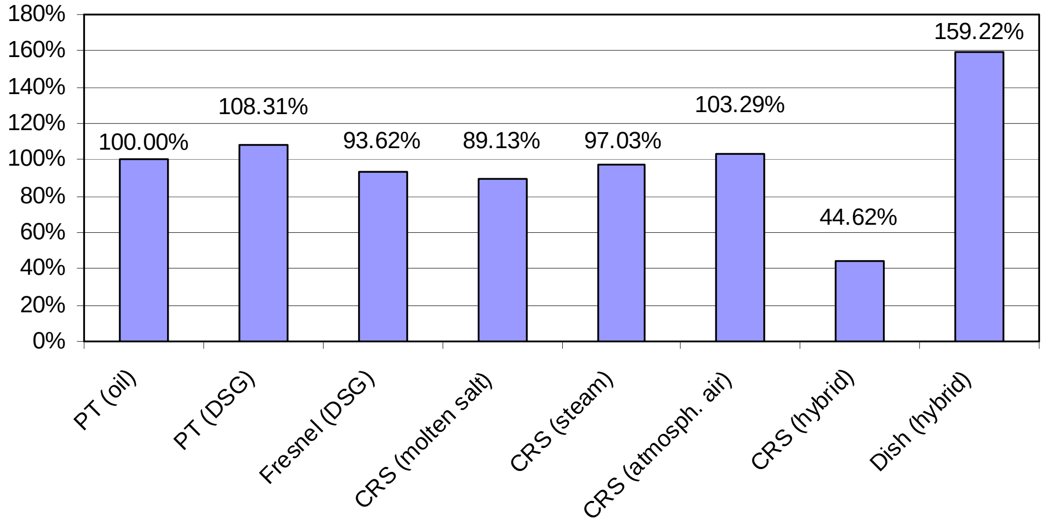


Figure 3.18 Comparison of the LEC of the 50 MW reference systems (PT (oil) = 100%, financing situation: 6.5% and 15 years)

However, all non-hybrid systems show similar LEC of 15 cents€/kWh +/- 1 cent€ for the financing situation of 6.5 % real debt interest rate and a depreciation period of 30 years. The lowest LEC of about 8 cents€/kWh can be reached with the hybrid CRS, the lowest LEC of the non-hybrid systems is 14 cents€/kWh (CRS using molten salt as HTF).

Because of the different state of maturity of the different technologies and the similar LEC, no technology of the non-hybrid systems can be preferred.

The hybrid CRS can't be easily compared to the non-hybrid systems, because at the current status of technology only a solar capacity factor of about 20% is reached. But with its low installation and levelized electricity costs, it is a very attractive solution, especially if the solar share can be increased by further development.

Because of the small unit size and the high costs of current Stirling systems, also the dish/Stirling system is hard to compare with other systems. Its market will be the decentralized electricity production.

Table 3.18 Technical and cost data of the reference systems

							Hybrid	**Hybrid**
type	**PT**	**PT**	**Fresnel**	**CRS**	**CRS**	**CRS**	**CRS**	**Dish-Stirling**
heat transfer fluid	oil	water/steam (DSG)	water/steam (DSG)	molten salt	water/steam	atmospheric air	pressurized air	-
storage	3h	-	-	3h	0.4h	3h	3h	-
electrical power [MW]	50.00	47.00	50.00	50.00	55.00	50.00	58.73	50.00
annual electricity production [GWh]	124.65	89.34	80.02	148.92	127.20	142.79	283.49	217.25
annual full-load hours [h]	2,493	1,901	1,600	2,978	2,313	2,856	4,827	4,345
capacity factor [%]	28.46	21.70	18.27	34.00	26.40	32.60	55.10	49.60
ground area [km^2]	1.72	1.60	0.56	1.83	1.86	2.09	1.73	1.40
total costs [€]	176,476,938	133,489,454	101,632,128	177,118,914	166,017,765	199,447,969	95,248,103	401,730,000
O&M costs [€]	4,003,490	3,515,128	2,921,659	5,518,874	4,977,789	5,825,666	5,189,437	11,451,238
fuel costs [€]	-	-	-	-	-	-	8,624,820	9,893,639
installation costs [€/kW]	3,530	2,840	2,033	3,542	3,019	3,989	1,622	8,035
land requirement [m^2/MWh/y]	13.80	17.91	7.05	12.31	14.62	14.65	6.10	6.44
LEC 6.5% & 15y [€/kWh]	0.1968	0.2132	0.1843	0.1754	0.1910	0.2033	0.0878	0.3134
LEC 6.5% & 30y [€/kWh]	0.1547	0.1687	0.1465	0.1400	0.1521	0.1617	0.0778	0.2583
LEC 8.7% & 15y [€/kWh]	0.2188	0.2364	0.2040	0.1939	0.2113	0.2250	0.0930	0.3421
LEC 8.7% & 30y [€/kWh]	0.1804	0.1959	0.1696	0.1617	0.1759	0.1871	0.0839	0.2920

PT … Parabolic Trough
CRS … Central Receiver System

3.4 Technical and Cost Data of current CSP Systems

Table 3.19 shows the cost and performance data of solar thermal plants which are currently operating (Nevada Solar One, PS10) or will start operation soon (AndaSol, Solar Tres). As for the reference systems, annual full-load hours, capacity factor, installation costs, land requirement and four LEC were calculated. The total costs data were found at (SolarPACES, 2008) for PS10 and Solar Tres, at (Solar Millennium, 2008b) for AndaSol and at (Acciona, 2008) for Nevada Solar One. Due to lack of information, the annual O&M costs were set to similar values as the respective reference systems in the DLR study.

Table 3.19 Technical and cost data of existing CSP plants

name	**Nevada Solar One**	**AndaSol**	**PS10**	**Solar Tres**
type	PT	PT	CRS	CRS
heat transfer fluid	oil	oil	water/steam	molten salt
storage	-	molten salt 7.5h	water/steam 0.4h	molten salt 15h
electrical power [MW]	64.00	49.90	11.02	17.00
annual electricity production [GWh]	130.00	179.00	23.00	96.40
annual full-load hours [h]	2,031	3,587	2,087	5,671
capacity factor [%]	23.19	40.95	23.83	64.73
ground area [km^2]	1.62	2.00	0.55	1.42
total costs [€]	204,615,385	300,000,000	35,000,000	196,000,000
O&M costs [€]	5,000,000	4,500,000	2,200,000	3,500,000
installation costs [€/kW]	3,197	6,012	3,176	11,529
land requirement [m^2/MWh/y]	12.46	11.17	23.91	14.76
LEC 6.5% & 15y [€/kWh]	0.2216	0.2201	0.2727	0.2729
LEC 6.5% & 30y [€/kWh]	0.1747	0.1702	0.2274	0.2123
LEC 8.7% & 15y [€/kWh]	0.2460	0.2462	0.2963	0.3044
LEC 8.7% & 30y [€/kWh]	0.2033	0.2007	0.2551	0.2493

The calculated LEC of the currently operating systems range between 17 and 30 cents€/kWh. Based on the current state of information, the Solar Tres plant will have the highest installation cost of about 11,500 €/kW and the highest capacity factor (64.7%) of all systems.

Compared to all other plants, the AndaSol system offers low land requirement due to its high capacity factor, but it has also very high installation costs of about 6,000 €/kW.

3.5 Sensitivity Analysis

To analyse the impact of a change to some LEC input data of a CSP system, a sensitivity analysis was made for four different plants/reference systems:

- 50 MW parabolic trough system using oil as HTF
- 50 MW linear Fresnel system (DSG)
- 17 MW CRS using molten salt as HTF
- 11 MW PS10 (CRS using water/steam as HTF)

The first three plants are reference systems of the ECOSTAR study, the fourth system analysed is the realised 11 MW PS10 plant. The calculated LEC with the real debt interest rate of 6.5%, an annual insurance rate of 1% and a depreciation period of 15 years was set as reference value for the LEC of the respective plant.

The following variables of the systems were modified from 50 to 150%:

- Total investment cost
- O&M cost
- Annual electrical production

Also the sensitivity of the LEC to the four different financial conditions (real debt interest rate of 6.5 and 8.7% with a depreciation period of 15 and 30 years, annual insurance 1%) is shown for each of the systems.

3.5.1 Sensitivity Analysis of a 50 MW PT System using Oil as HTF

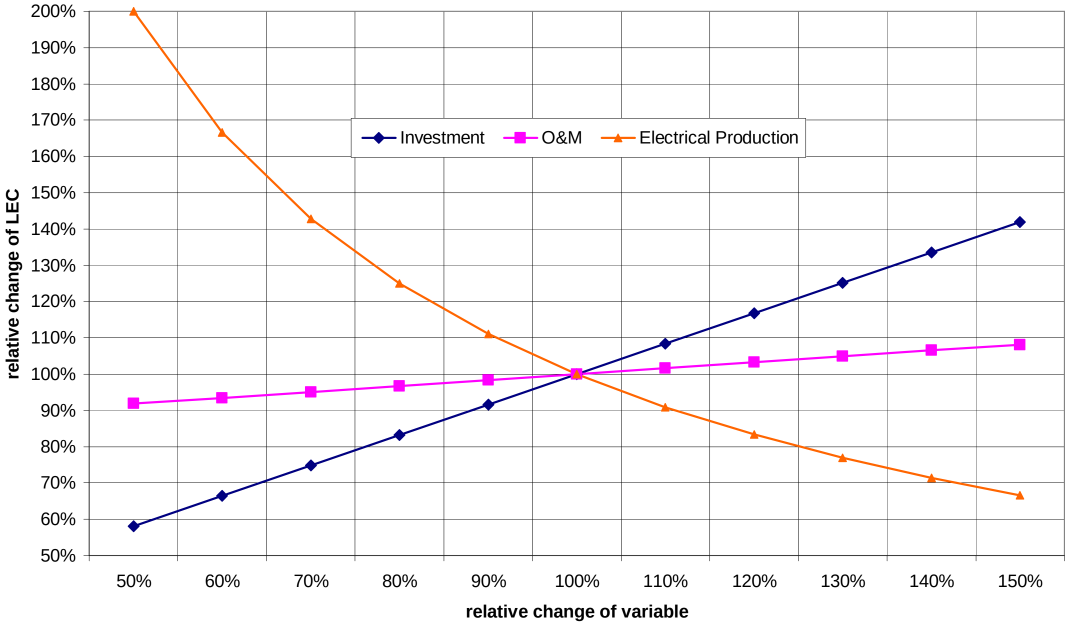


Figure 3.19 Sensitivity of investment cost, O&M cost and annual electrical production on the LEC of a 50 MW parabolic trough system using thermal oil as HTF

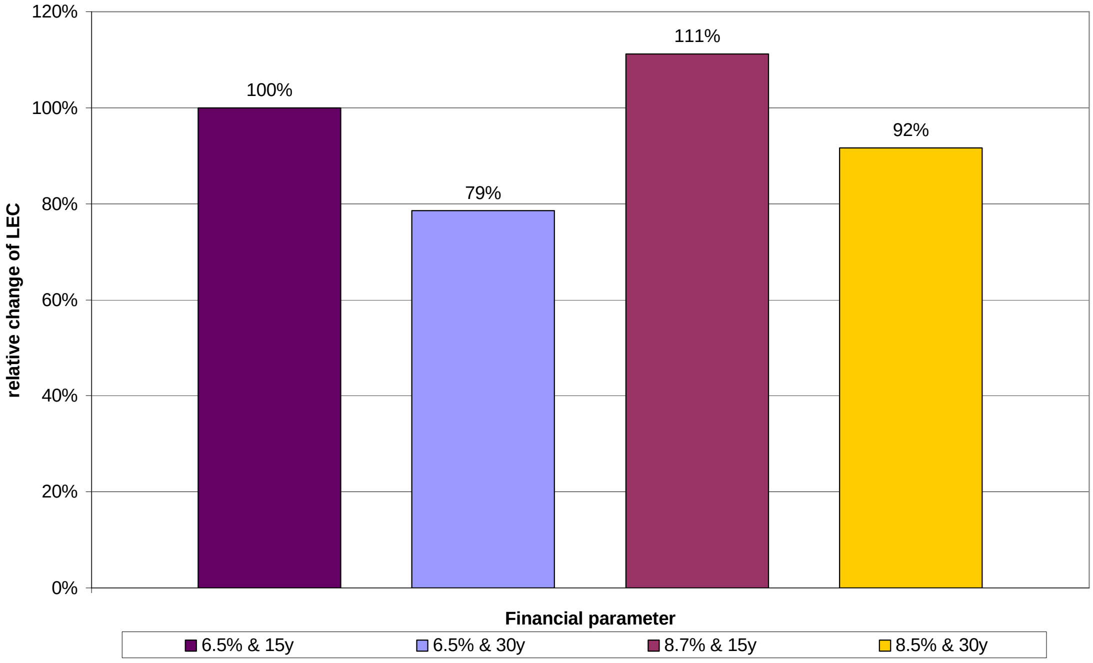


Figure 3.20 Dependency of the LEC of a 50 MW parabolic trough system using thermal oil as HTF on the fixed charge rate

3.5.2 Sensitivity Analysis of a 50 MW linear Fresnel System (DSG)

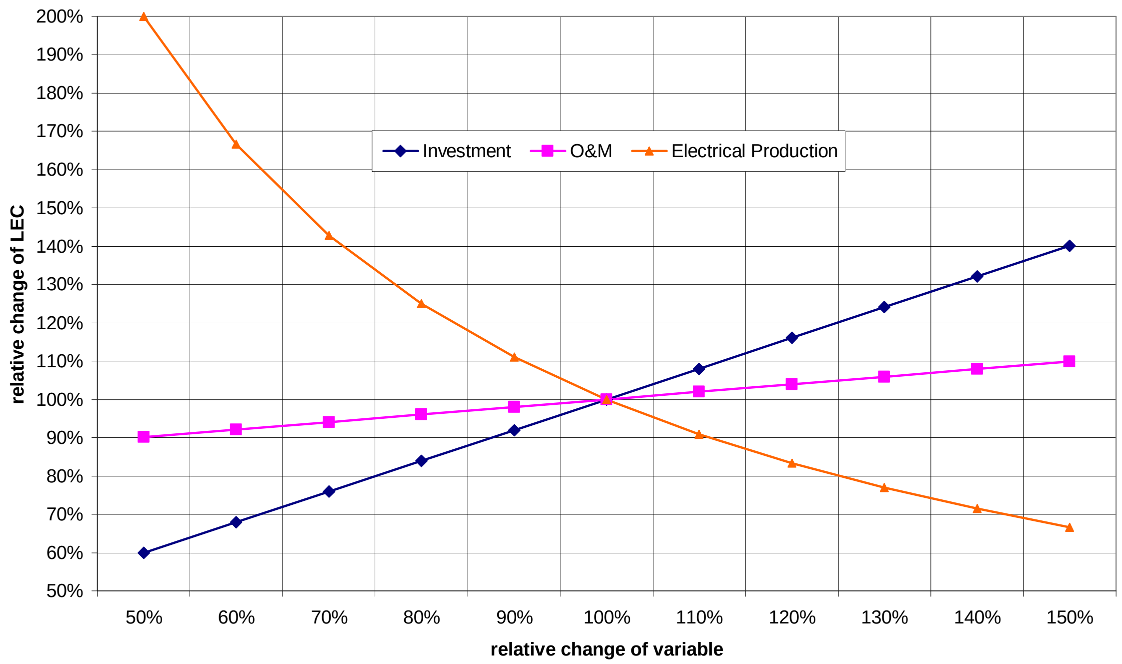


Figure 3.21 Sensitivity of investment cost, O&M cost and annual electrical production on the LEC of a 50 MW linear Fresnel system (DSG)

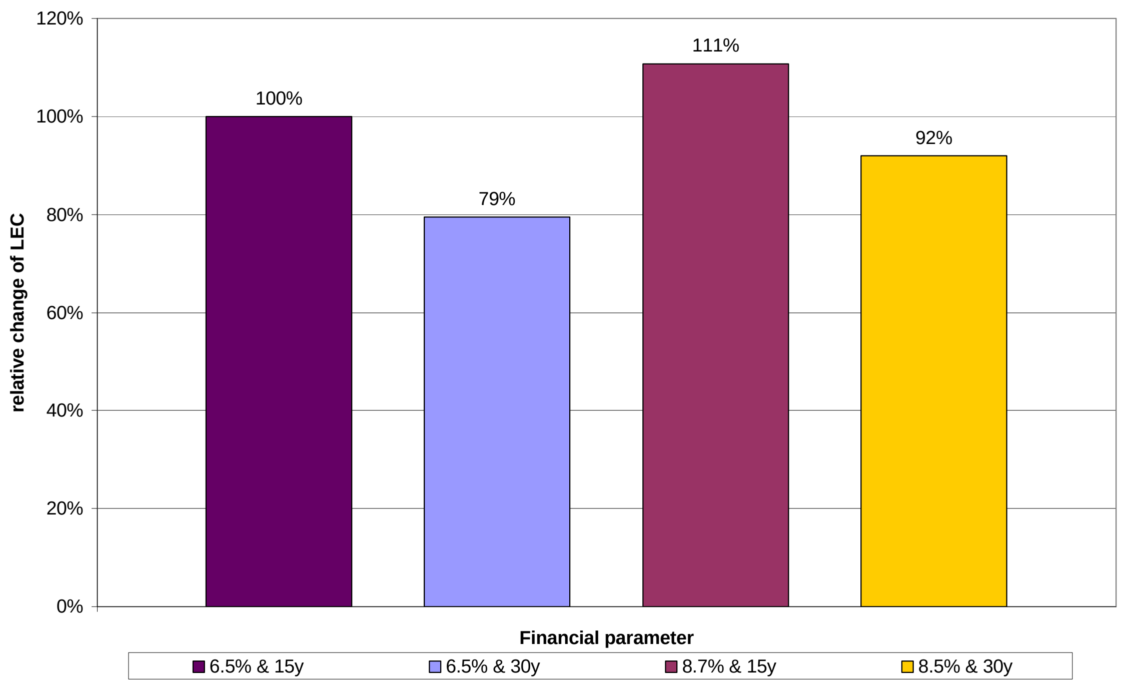


Figure 3.22 Dependency of the LEC of a 50 MW linear Fresnel system (DSG) on the fixed charge rate

3.5.3 Sensitivity Analysis of a 17 MW CRS using molten Salt as HTF

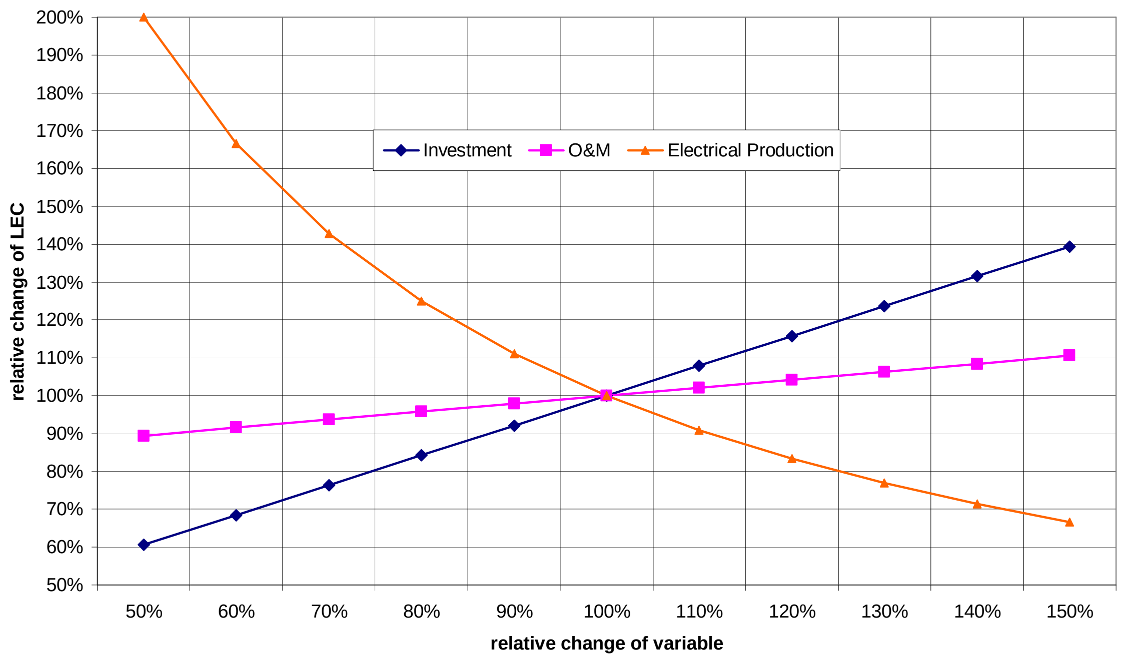


Figure 3.23 Sensitivity of investment cost, O&M cost and annual electrical production on the LEC of a 17 MW CRS using molten salt as HTF

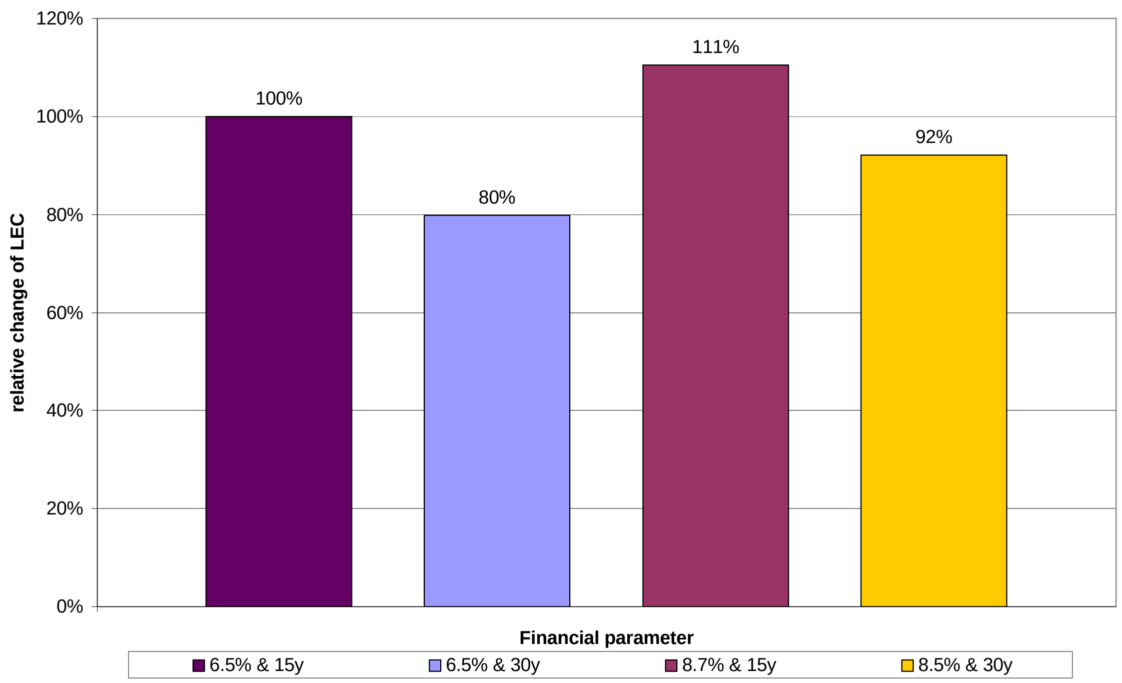


Figure 3.24 Dependency of the LEC of a 17 MW CRS using molten salt as HTF on the fixed charge rate

3.5.4 Sensitivity Analysis of the 11 MW PS10 Solar Power Plant

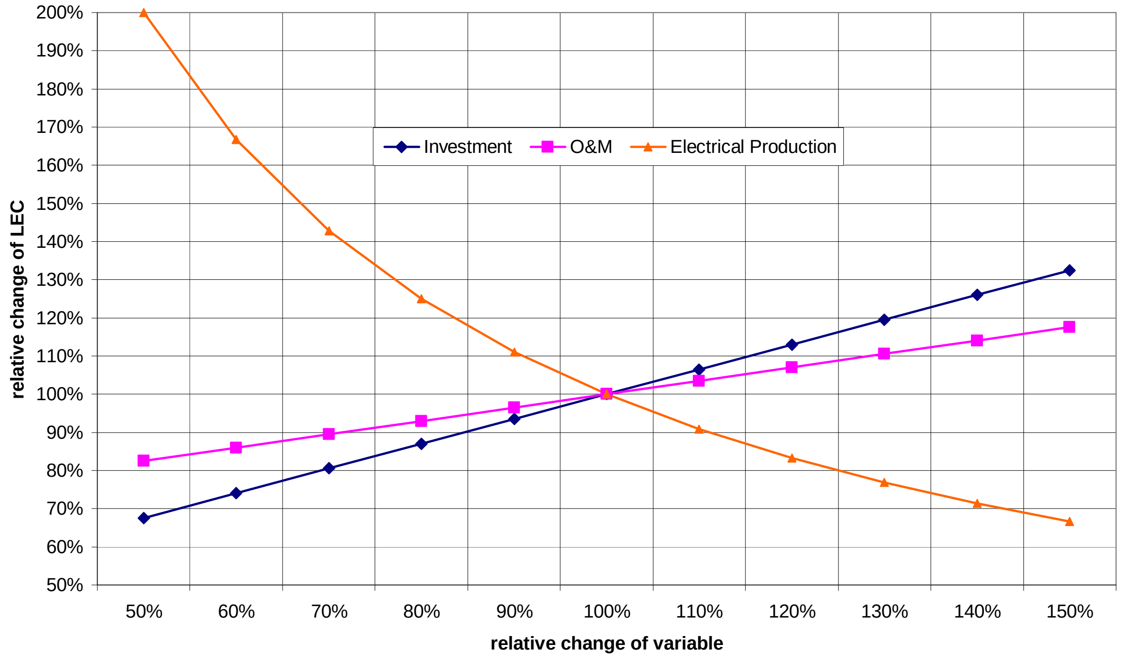


Figure 3.25 Sensitivity of investment cost, O&M cost and annual electrical production on the LEC of the 11 MW PS10 solar power plant

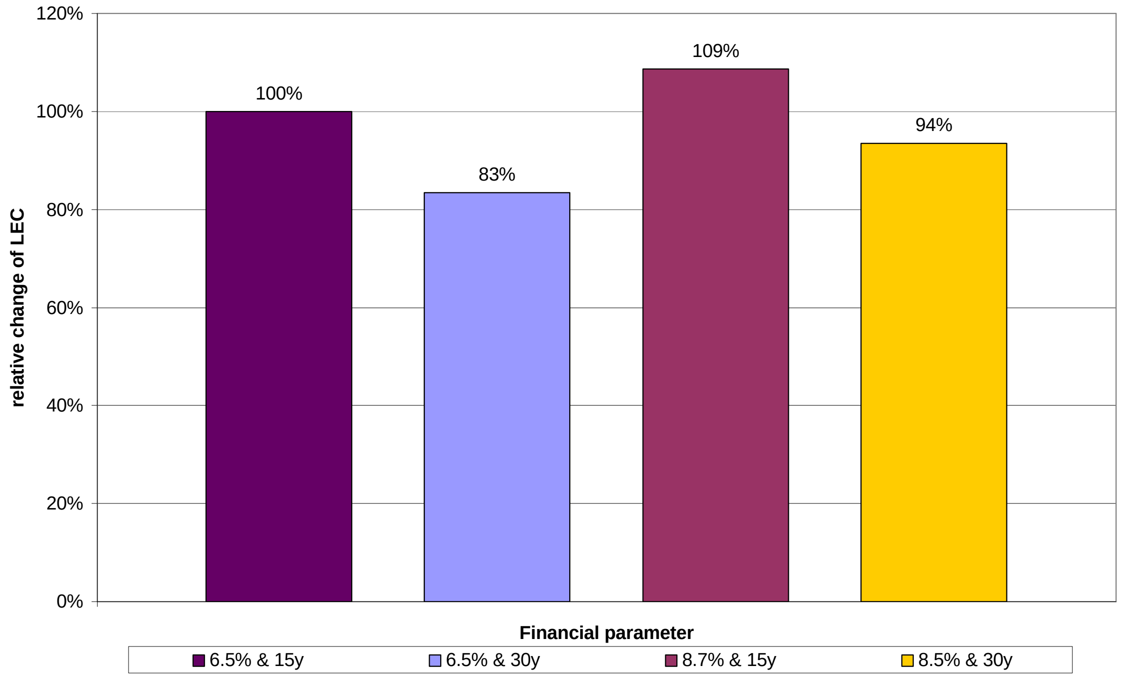


Figure 3.26 Dependency of the LEC of the 11 MW PS10 solar power plant on the fixed charge rate

3.5.5 Summary of the Sensitivity Analysis

All four different technologies show roughly the same dependencies of the LEC on the changed values. The electricity production (i.e. the achievable full-load hours) is an essential factor that strongly impacts the LEC. An increase of 50% of the electrical production leads to a decrease of 33% of the LEC in all systems. With a decreasing electrical production of 50%, the LEC rise to 200%. Also the investments have a strong impact on the LEC, a change of +/- 50% in the investment costs lead to a LEC modification in a range of +/- 32 to 42%. The O&M costs are of minor importance for the systems, LEC vary from +/- 8 to 18% if the O&M costs are changed by +/- 50%.

With a depreciation period of 30 years and a real dept interest rate of 6.5% a LEC reduction of up to 21% can be reached compared to the reference LEC with only 15 years.

Since the annual electricity production plays a great role for the LEC of a solar power plant, the site selection is very important, because it determines the DNI.

In Figure 3.27 the dependency of the LEC on the DNI is displayed.

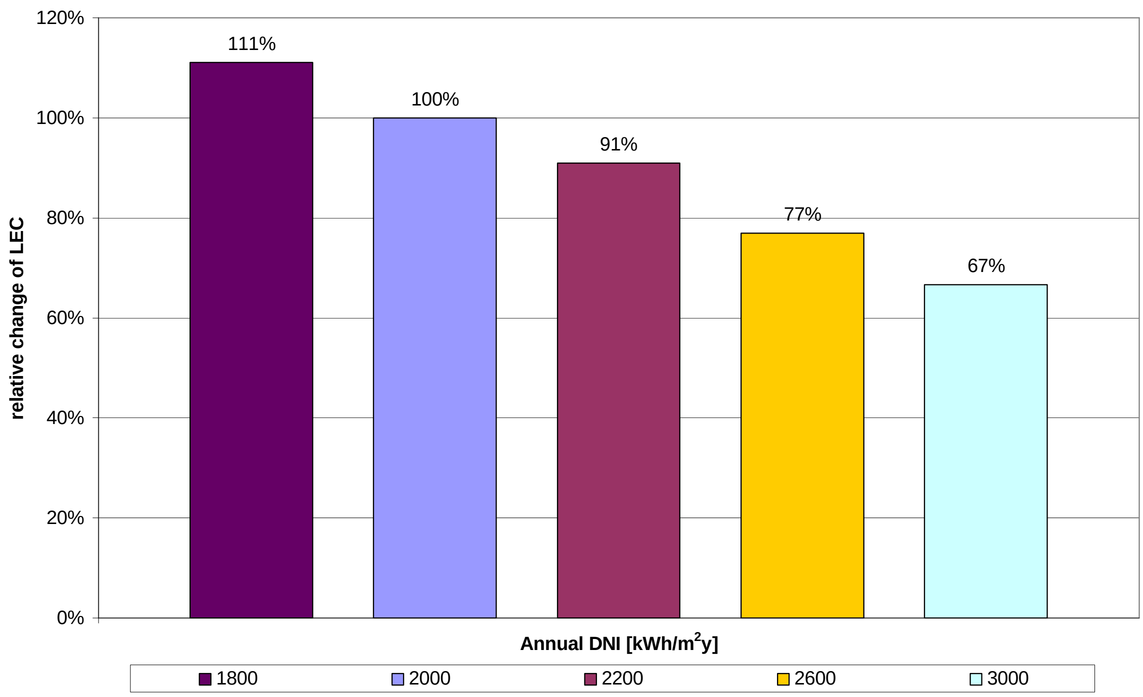


Figure 3.27 Dependency of the LEC on the solar resource

According to Figure 3.27 a cost reduction of 23% is reachable for a DNI of 2600 kWh/m^{2}y (good site in Northern Africa) compared to a DNI of 2000 kWh/m^{2}y (for example Southern Spain).

3.6 Cost Reduction Potential

To determine the cost reduction potential of the different CSP technologies, the impact of technological innovations on the LEC of the reference systems described above was calculated by DLR. These innovations include, for example, advanced storage systems (lower costs, longer storage times), more effective mirrors, increased maximum HTF temperature, etc.

A mix of such innovations was applied to each of the reference systems. Then the LEC were calculated and compared to those of the original reference systems. The result of this comparison is shown in Figure 3.28.

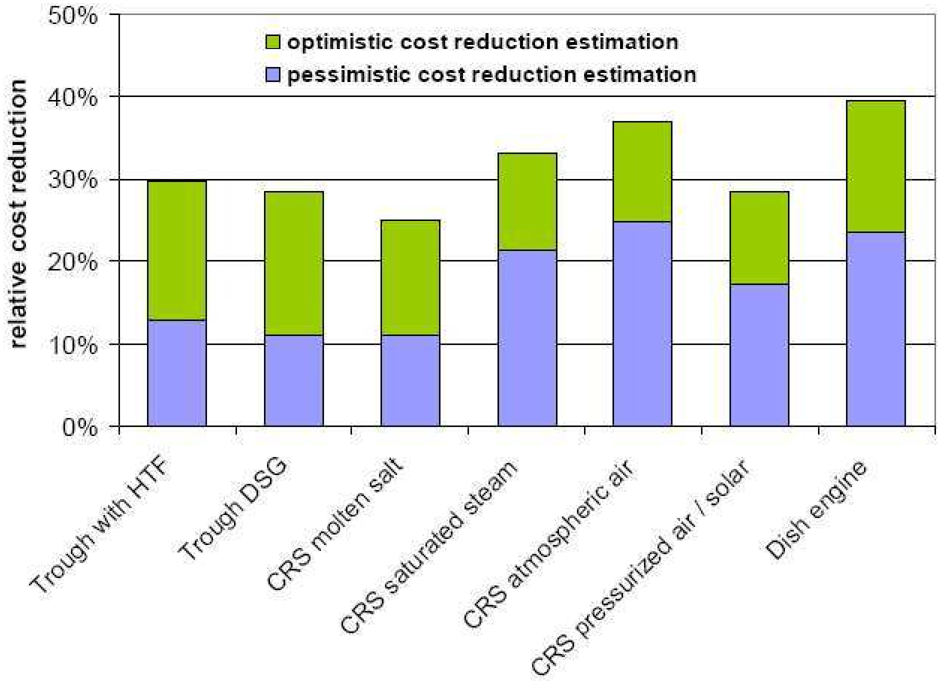


Figure 3.28 Cost reduction potential for the seven reference systems based on the LEC for the 50 MW reference systems and an applied innovation combination
Source: Pitz-Paal et al., 2005 p130

According to Figure 3.28 a cost reduction of 25 – 39% for an optimistic estimation seems to be feasible. In a pessimistic estimation 11 to 24% of cost reduction is stated. The technologies with the highest cost reduction potential are the CRS using saturated steam, respectively atmospheric air and the dish engines.

In these estimations no cost reducing effects of volume production and economies of scale (plant size >50 MW_{el}) were included.

In the CSP cost assessment of Sargent & Lundy (Sargent & Lundy, 2003), which was updated in 2005 (Sargent & Lundy, 2005), a LEC reduction for parabolic trough systems of about 40% in the period 2006 – 2020 is claimed, including cost reducing effects of plant upscaling (up to 400 MW_{el}, cost reduction of ~8%), volume production (2.8 GW_{el} of installed capacity by 2020, cost reduction ~10.5%) and technology improvements (~21.8%). For solar tower plants a LEC reduction of about 62% is claimed in the same period, with the largest cost reduction potential in upscaling the plants (up to 220 MW_{el}, cost reduction ~30%) followed by volume production (2.6 GW_{el} of installed capacity by 2020, cost reduction ~17%) and technological innovations (~15%).

With the cost reduction effects of plant upscaling and volume production based on the Sargent & Lundy study, the ECOSTAR study claims that "an overall cost reduction of 55 – 65% can be estimated in the next 15 years". (Pitz-Paal et al., 2005) p129

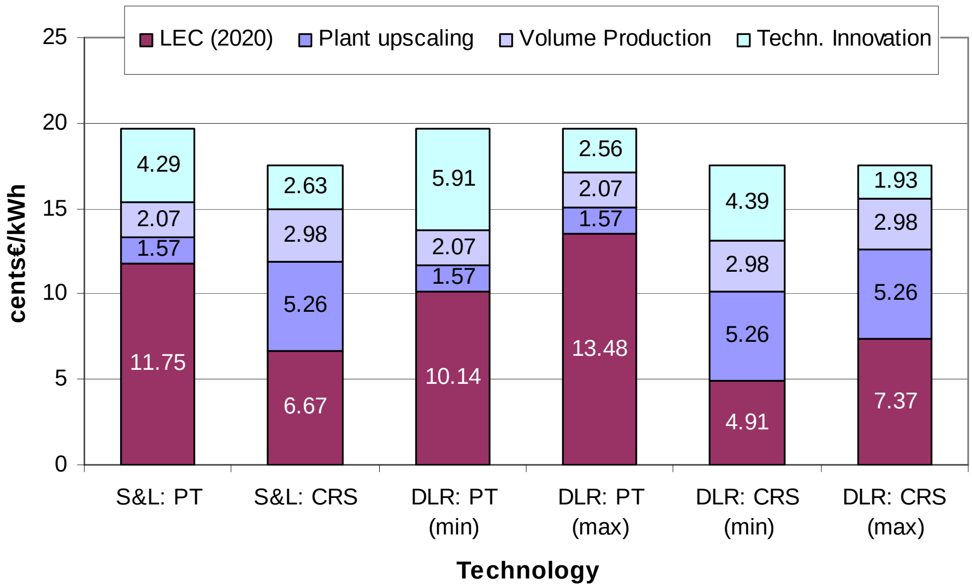


Figure 3.29 Calculated LEC in 2020 for two different CSP technologies using LEC reduction predictions S&L and DLR

The predicted LEC for 2020 are displayed in Figure 3.29. The calculations were made for the PT system which uses oil as HTF and for the CRS which uses molten salt as HTF (real debt interest rate 6.5%, annual insurance rate 1%, depreciation period 15 years). For each system three calculations were made: one with the predicted cost reductions of Sargent & Lundy (S&L) and two with the predictions of DLR (including LEC reduction of plant upscaling and volume production of S&L). It can be seen that CRS show great cost reduction potential, which could lead the LEC in 2020 to about 6 (+/- 1) cents€/kWh. PT systems show smaller cost saving potentials; LEC of PT plants could be lowered down to about 10 cents€/kWh by the year 2020. Technological innovations and plant upscaling are the main drivers of the cost decrease.

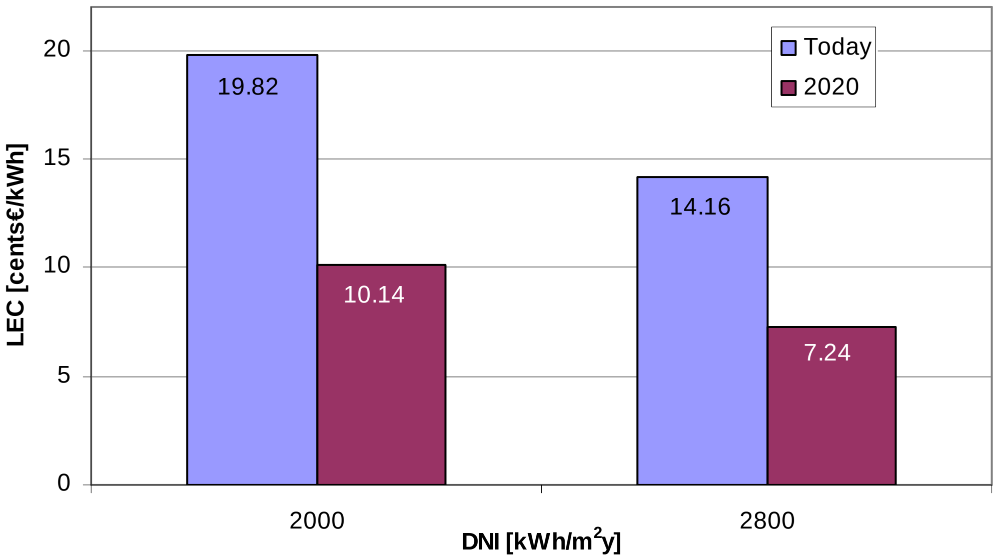


Figure 3.30 Predicted LEC today and in 2020 for two different solar resources/sites

Figure 3.30 shows the predicted LEC today and 2020 for the PT reference system (HTF: oil) for two different solar resources: one Southern Europe site (2000 kWh/m^2y) and one in a high insulation area (desert climate). In high insulation areas the LEC of PT systems could lower down to approximately 7 cents€/kWh by the year 2020.

4 Resources for Concentrating Solar Power

4.1 Calculation of the Potential

The following calculation of the potential for concentrating solar power systems is based on the MED-CSP study of the German Aerospace Centre (DLR).

To estimate the potential of CSP it is necessary to calculate the direct normal irradiance (DNI) on the ground. The DNI is dependent on the optical transparency of the atmosphere, in general of atmospheric components that absorb or reflect the sunlight, like clouds, which have the strongest impact on the DNI, aerosols, water vapour, ozone, gases and others.

The optical thickness of the clouds was derived from images of weather satellites (METEOSAT) with 5 x 5 km spatial and 0.5 h temporal resolution. Also the optical thickness of aerosols, water vapour, ozone etc. was derived from several orbiting satellite missions (like NOAA) and from reanalysis projects (like GACP) and transformed into maps/layers (with lower spatial and temporal resolution than the data of the clouds).

Another important variable for the DNI is the elevation above sea level as it defines the thickness of the atmosphere. The elevation was considered by a digital elevation model with a 1 x 1 km spatial resolution.

The combination of all layers yields to the optical transparency of the atmosphere.

With the optical transparency, the extraterrestrial solar radiation intensity and the varying angle of incidence, the DNI can be calculated for every site and for every hour of the year.

The analysis was performed in the year 2002 for the countries shown in Figure 4.1.

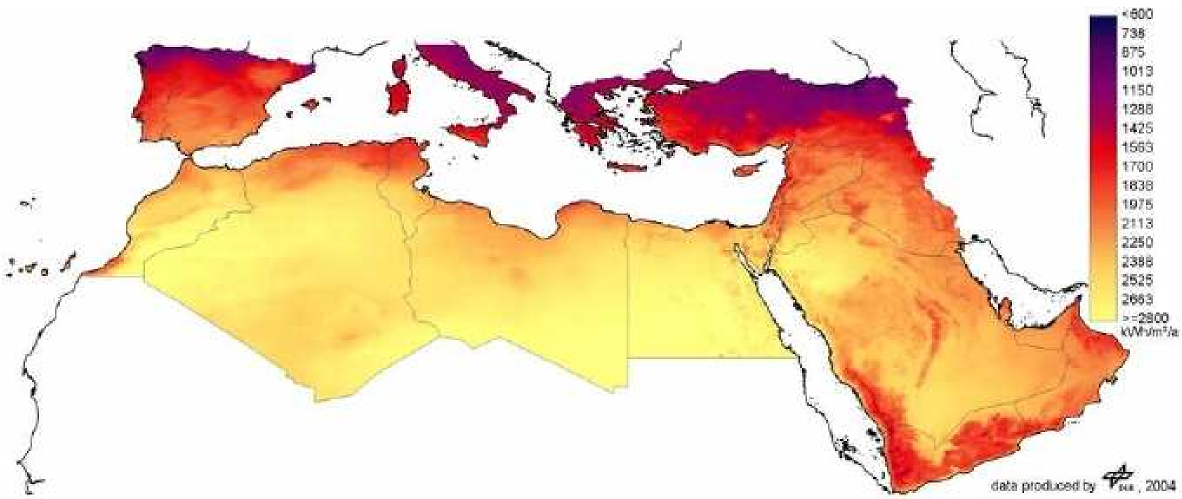


Figure 4.1 EU-MENA region with annual solar DNI of the analysed countries
Source: DLR, 2005 p59

The land resources which allow the placement of the concentrating solar collector fields were detected by excluding all land areas that are unsuitable for the erection of them due to ground structure, water bodies, slope, dunes etc. All compulsive and optional criteria for the exclusion of terrain for CSP plants are shown in the following Table 4.1. Within the MED-CSP study both, the compulsive and the optional criteria were applied for the site exclusion.

Table 4.1 Compulsive and optional area exclusion criteria for CSP plants
Source: Based on DLR, 2005 p61

Exclusion Criteria for CSP Plants	Compulsive	Optional
Slope of Terrain		
> 2,1 %	x	
Land Cover		
sea	x	
inland water	x	
forest		x
swamp	x	
agriculture		x
rice culture		x
Hydrology		
permanent inland water	x	
non-permanent inland water		x
regularly flooded area		x
Geomorphology		
shifting sand, dunes	x	
security zone for shifting sands 10 km		x
salt pans		x
glaciers		x
security zone for glaciers	x	
Land Use		
settlement		x
airport		x
oil or gas fields		x
mine, quarry		x
desalination plant		x
protect		x

The exclusion criteria were applied to the terrain of the EU-MENA region and lead to usable areas for CSP systems, which are shown in Figure 4.2.

With the exclusion criteria applied to each country and the knowledge of the DNI, the potentials of CSP for each country can be calculated.

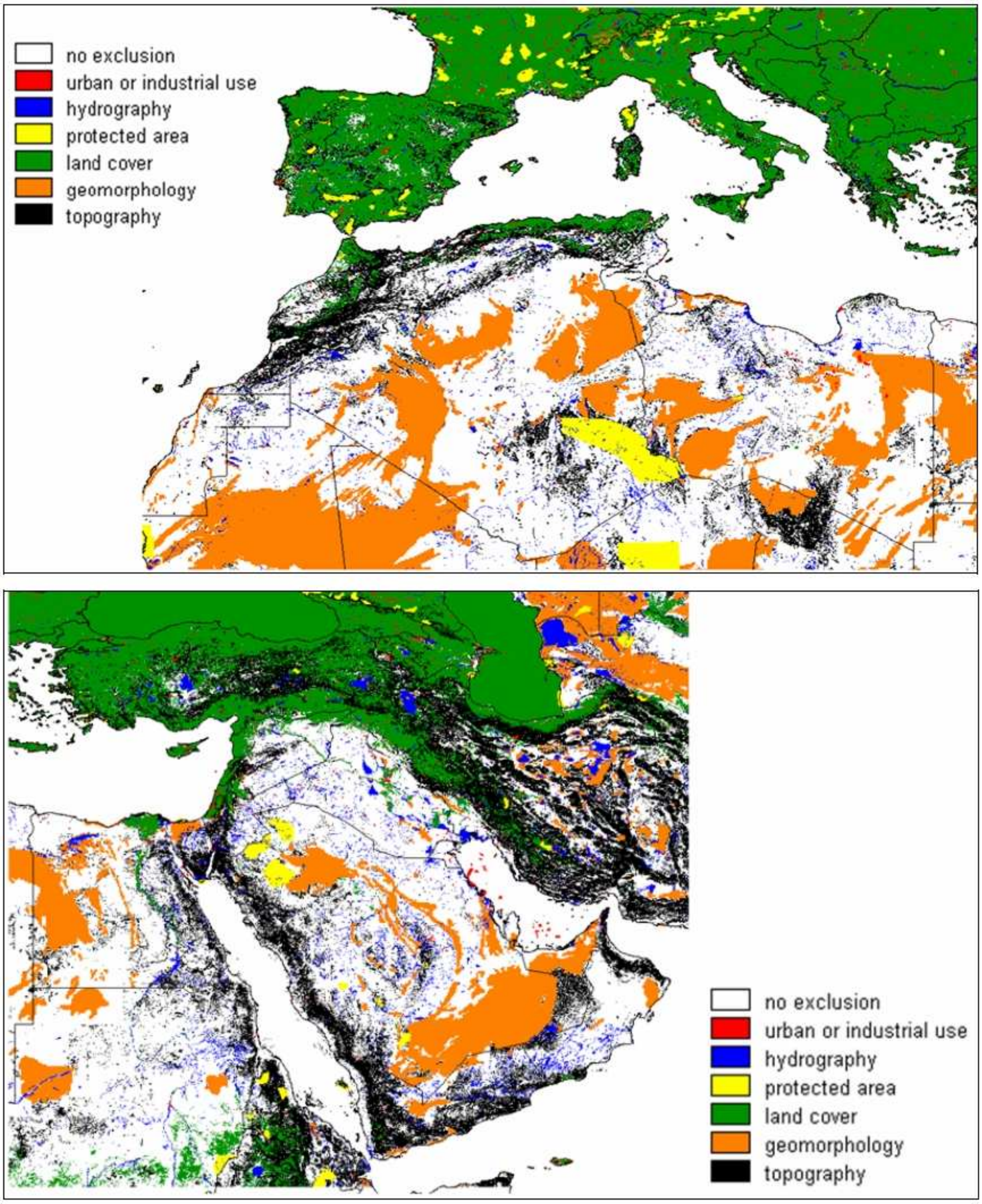


Figure 4.2 Exclusion areas for CSP systems in the EU-MENA region
Source: DLR, 2005 p60

Technical and economical potentials were defined as follows:

- Technical potential: places with DNI ≥ 1800 kWh/m^2y
- Economic potential: places with DNI ≥ 2000 kWh/m^2y

Solar electricity potentials were calculated from the annual DNI with

- an **average annual efficiency of 15%**
- a **land use factor of 30%** for CSP technology

=>which results in a **conversion factor of 0.045**.

4.2 Individual Country Data

The following sections show the CSP potential for the individual countries in the EU-MENA region in alphabetical order of the country name.

For each country a map showing the DNI in kWh/m^2y of all areas that are not excluded from the land resource assessment and a histogram viewing how much electricity (TWh/y) can be generated in each class of DNI $\geq$ 1800 kWh/m^2y is displayed.

The countries' electricity demand of 2005 (Source: IEA, 2007) and predictions for 2030 were also added for comparison purposes. For all European states the values of the PRIMES baseline scenario as of 2007 (NTUA, 2007) were used for the projections, except for Turkey, where the baseline as of 2003 (NTUA, 2003) was used. The electricity demand in the year 2030 for all other states was calculated with respect to the IEA World Energy Outlook to 2030 (IEA, 2007).

Furthermore an additional calculation of the electricity generation potential was done with a 50 MW PT system using thermal oil as HTF (annual efficiency of 14%, land use factor of about 26% - see the respective reference system in the cost assessment for detailed information) for each country. For this calculation, the area potentials for each class of DNI were determined with the histograms of DLR.

Also a preview on the amount of electricity which could be generated by CSP plants in the mid to long-term (2030) was added. CSP electricity generating data for the European countries in the year 2030 was taken from the computer simulation model ***Green-X*** (for further information see Resch et al., 2008). For all other states, about 30% of the country's electricity demand of the year 2030 was taken as the upper limit for electricity from CSP systems. Realisation constraints were defined in order to show how much of the area resource is needed to generate these 30% of the countries' electricity demand in 2030.

The countries' average DNI and full-load hours as well as the ratio realisable potential up to 2030/total potential are displayed too.

4.2.1 Solar Thermal Electricity Generating Potentials in Algeria

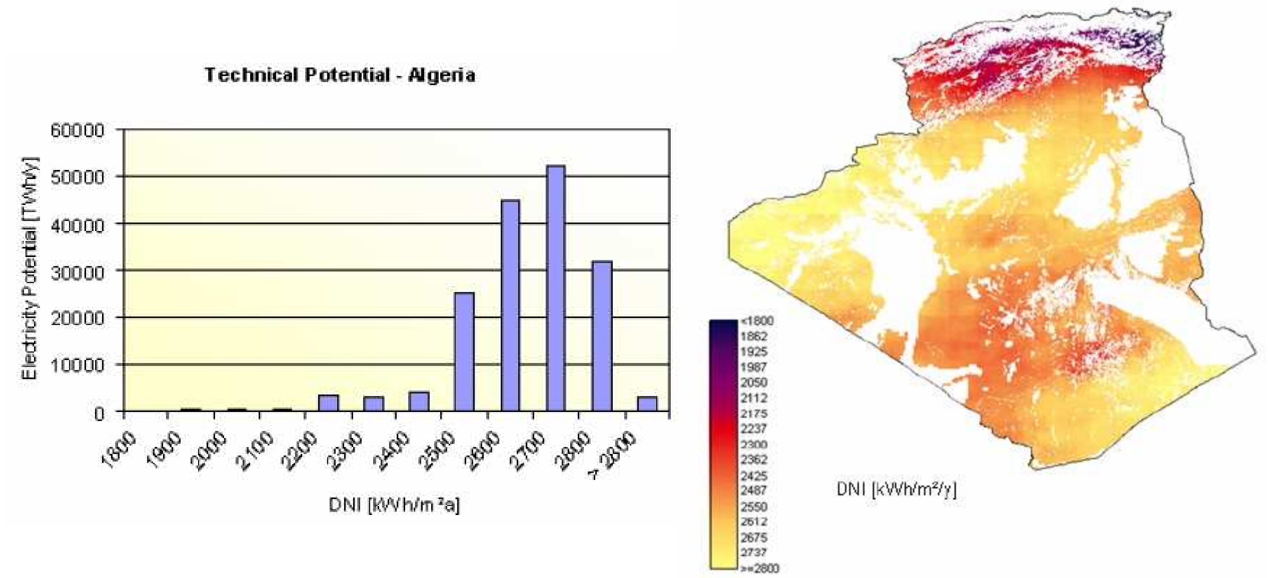


Figure 4.3 Algeria: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-4

Algeria is the biggest country in the EU-MENA region and also has the highest CSP electricity generation potential. Great parts of the country are covered by the Saharan desert with high solar insulation, which leads to high potentials in DNI's above 2400 kWh/m^{2}y. However, these potentials might be difficult to explore.

The following electricity generation potentials for Algeria were calculated by DLR:

- Technical potential: 169,440 TWh/y
- Economic potential: 168,971 TWh/y

Algeria's electricity consumption: - 2005: 29.52 TWh

- 2030: 67 TWh

For comparison: Even the world's electricity consumption of 16,695 TWh in 2005 is one scale smaller than the CSP potential in Algeria.

Table 4.2 shows the result of the calculation of the potential with a 50 MW PT using thermal oil as HTF. 0.8% of the country's highest insulation areas are enough to generate about 30% (~20 TWh) of Algeria's electricity demand of the year 2030. The unrestricted electricity generating potential was calculated to about 135,475 TWh/y.

Table 4.2 Algeria: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m²y]	Full-load hours [h]	Area potential [km²]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km²]	Realisable potential up to 2030 [TWh/y]
2900	3589	24,421	2,548.1	0.8	195	20.4
2800	3466	252,933	25,481.2	0	0	0
2700	3342	429,882	41,760.9	0	0	0
2600	3218	385,885	36,098.4	0	0	0
2500	3094	220,333	19,818.7	0	0	0
2400	2970	40,985	3,539.1	0	0	0
2300	2847	30,792	2,548.1	0	0	0
2200	2723	35,768	2,831.2	0	0	0
2100	2599	3,747	283.1	0	0	0
2000	2475	3,935	283.1	0	0	0
1900	2352	4,142	283.1	0	0	0
Total		**1,432,823**	**135,475.2**		**195**	**20.4**

Ø DNI [kWh/m²y]	2628	Ø Full-load hours [h]	3253
Ratio potential 2030 / total potential [%]			0.015

Algeria has agreed to develop solar energies to generate 5% of its electricity by 2010. To reach this target, elevated tariffs for renewable power production were published. These include hybrid CSP systems and ISCCS, which use Algeria's large natural gas deposit as fossil fuel source. However, so far only one 150 MW ISCCS is projected to be built near Hassi R'Mel with a 25 MW PT system.

4.2.2 Solar Thermal Electricity Generating Potentials in Bahrain

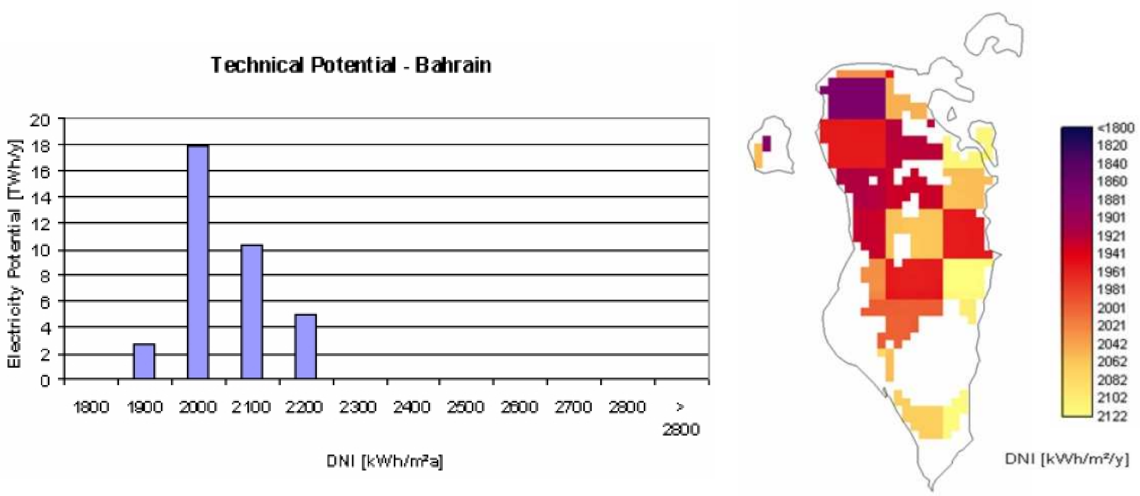


Figure 4.4 Bahrain: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-19

The islands of Bahrain, situated in the Persian Gulf, East of Saudi Arabia, offer a good CSP potential for the area given. The high desert coverage of the country contributes to this.

The following electricity generation potentials were calculated by DLR:

- Technical potential: 36 TWh/y
- Economic potential: 33 TWh/y

Bahrain's electricity consumption: - 2005: 8.26 TWh

- 2030: 20 TWh

Table 4.3 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF. The electricity generation potential of Bahrain comes to 28.8 GWh/y. To cover 30% of its electricity demand in the year 2030 with CSP systems, the total available area with a DNI of 2200 kWh/m^{2}y and 25% of the area with a DNI of 2100 kWh/m^{2}y is needed.

Table 4.3 Bahrain: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m^{2}y]	Full-load hours [h]	Area potential [km^2]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km^2]	Realisable potential up to 2030 [TWh/y]
2200	2723	51	4.0	100	51	4
2100	2599	109	8.3	25	27	2.1
2000	2475	201	14.4	0	0	0
1900	2352	30	2.1	0	0	0
Total		**391**	**28.8**		**78**	**6.1**

Ø DNI [kWh/m^{2}y]	2046	Ø Full-load hours [h]	2533
Ratio potential 2030 / total potential [%]		21.1	

4.2.3 Solar Thermal Electricity Generating Potentials in Cyprus

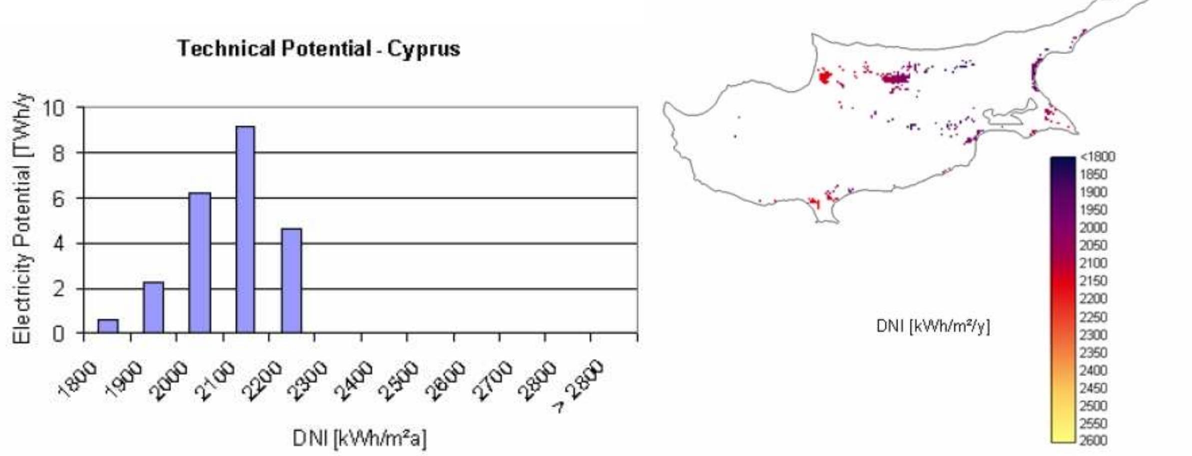


Figure 4.5 Cyprus: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-12

Because of the high land use, which is typical for all European countries (see Figure 4.2), only small solar thermal electricity generating potentials are reached in Cyprus. These potential areas are situated mostly in the Northern (Turkish) part of the island.

The following electricity generation potentials were calculated by DLR:

- Technical potential: 23 TWh/y
- Economic potential: 20 TWh/y

The electricity consumption of Cyprus: - 2005: 4.21 TWh

- 2030: 8 TWh

Table 4.4 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF. 19% of Cyprus electricity demand in the year 2030 can be generated on a total area of 19 km^2.

Table 4.4 Cyprus: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m^{2}y]	Full-load hours [h]	Area potential [km^2]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km^2]	Realisable potential up to 2030 [TWh/y]
2200	2723	47	3.7	20	9	0.8
2100	2599	98	7.4	10	10	0.7
2000	2475	69	5.0	0	0	0
1900	2352	26	1.8	0	0	0
1800	2228	8	0.5	0	0	0
Total		**248**	**18.4**		**19**	**1.5**

Ø DNI [kWh/m^{2}y]	2061	Ø Full-load hours [h]	2551
Ratio potential 2030 / total potential [%]			8.1

4.2.4 Solar Thermal Electricity Generating Potentials in Egypt

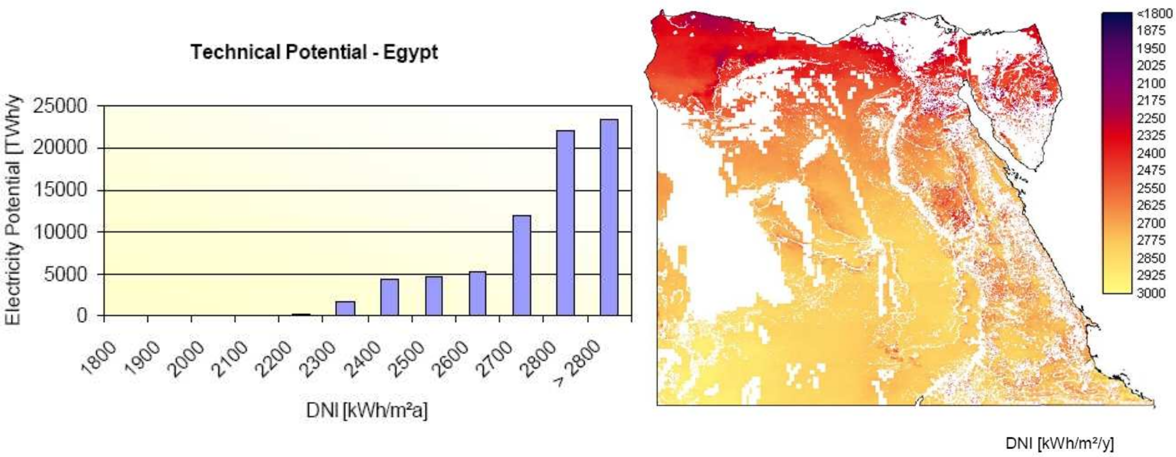


Figure 4.6 Egypt: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-6

Just like Algeria, which has a similar desert cover and climate, Egypt offers huge potentials for CSP systems. Figure 4.2 shows that only small parts of the country are used by its population, and also the geomorphology criteria exclude only some areas in the West of the country, because of desert sand dunes etc.

The following electricity generation potentials were calculated by DLR:

- Technical potential: 73,656 TWh/y
- Economic potential: 73,655 TWh/y

Egypt's electricity consumption: - 2005: 90.73 TWh

- 2030: 207 TWh

The electricity generation potential for CSP systems in Egypt is also higher than the electricity consumption of the world in 2005.

Table 4.5 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF. A land use restriction of 0.3% for the highest insulation area result in an electricity generation potential of 56 TWh/y, which is about 27% of Egypt's electricity demand in the year 2030. Egypt has the highest average DNI and full-load hours of all analysed countries.

Table 4.5 Egypt: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m²y]	Full-load hours [h]	Area potential [km²]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km²]	Realisable potential up to 2030 [TWh/y]
2900	3589	179,024	18,679.5	0.3	537	56
2800	3466	175,304	17,660.6	0	0	0
2700	3342	97,891	9,509.6	0	0	0
2600	3218	47,197	4,415.2	0	0	0
2500	3094	41,534	3,735.9	0	0	0
2400	2970	39,331	3,396.3	0	0	0
2300	2847	16,416	1,358.5	0	0	0
2200	2723	1,716	135.9	0	0	0
Total		**598,413**	**58,891.4**		**537**	**56**

Ø DNI [kWh/m²y]	2735	Ø Full-load hours [h]	3385
Ratio potential 2030 / total potential [%]			0.1

Currently Egypt relies on wind as new RES-E with about 230 MW of installed electrical capacity. But also a 140 MW ISCCS with a solar capacity of 20 MW is planned to be operational in mid 2010 at Kuraymat, 90 km South of Cairo.

4.2.5 Solar Thermal Electricity Generating Potentials in Greece

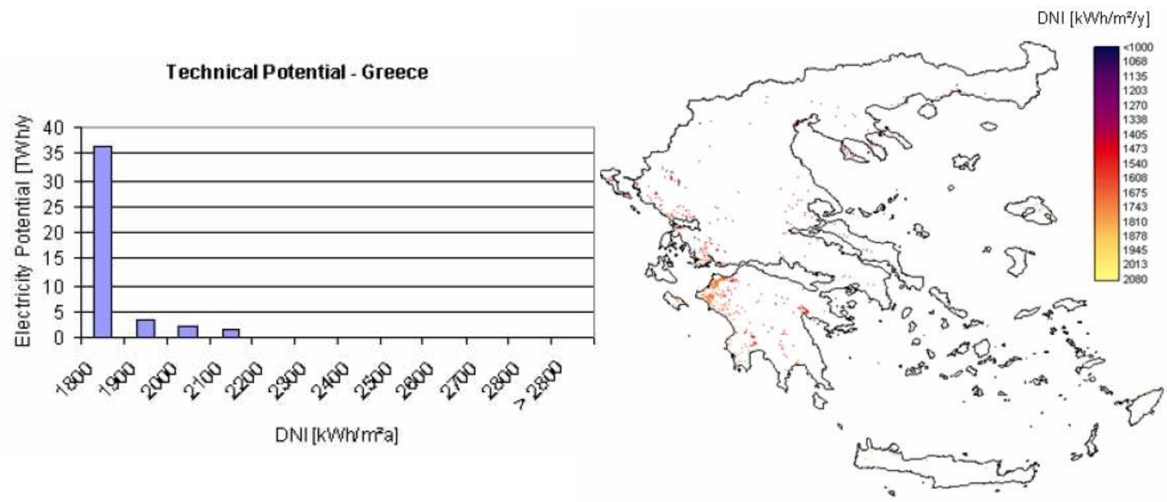


Figure 4.7 *Greece: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)*
Source: DLR, 2005 pA-11

The CSP potential in Greece is rather low for a Mediterranean country of this size, with the biggest share in sites with a DNI of 1800 kWh/m^{2}y. The map in Figure 4.7 shows that the area potential for CSP systems is mainly situated in the West of the country.

The following electricity generation potentials were calculated by DLR:

- Technical potential: 44 TWh/y
- Economic potential: 4 TWh/y

The electricity consumption of Greece: - 2005: 58.2 TWh
- 2030: 90 TWh

Greece is one of the few analysed countries, where the electricity generation potential for CSP systems is lower than the demand.

Table 4.6 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF for Greece. Great parts of the available area resources have to be used to provide about 13% (11.3 TWh) of Greece’s electricity demand in the year 2030.

Table 4.6 Greece: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m^{2}y]	Full-load hours [h]	Area potential [km^2]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km^2]	Realisable potential up to 2030 [TWh/y]
2100	2599	16	1.2	100	16	1.2
2000	2475	24	1.8	75	18	1.3
1900	2352	43	2.9	50	21	1.5
1800	2228	453	29.3	25	113	7.3
Total		**536**	**35.2**		**168**	**11.3**

Ø DNI [kWh/m^{2}y]	1826	Ø Full-load hours [h]	2260
Ratio potential 2030 / total potential [%]			32.1

A Greek feed-in tariff for CSP systems was published in the year 2006 which grants solar energy systems - besides PV systems - with an installed capacity up to five MW_{el} a tariff of 0.25 €/kWh on the main land and of 0.27 €/kWh on non-interconnected islands and of 0.23 / 0.25 €/kWh for systems with capacities above five MW_{el}.

4.2.6 Solar Thermal Electricity Generating Potentials in Iraq

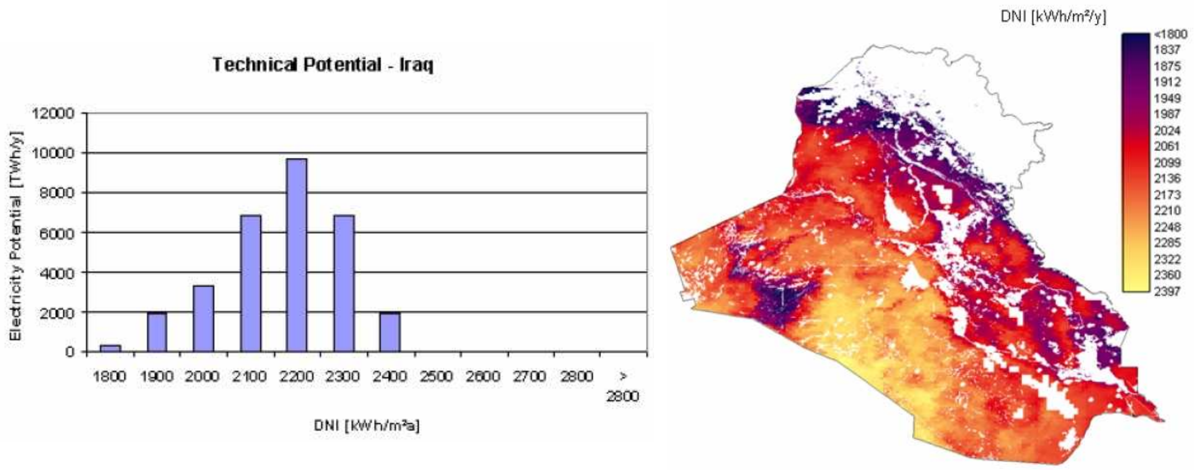


Figure 4.8 Iraq: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-18

Due to its high desert coverage in the Eastern and Southern parts of the country, Iraq has a high area potential for CSP systems. With DNI's of as high as 2400 kWh/m^{2}y, this leads to high electricity generation potentials.

The following electricity generation potentials were calculated by DLR:

- Technical potential: 30,806 TWh/y
- Economic potential: 28,647 TWh/y

The electricity consumption of Iraq: - 2005: 33.26 TWh

- 2030: 79 TWh

Just like Algeria and Egypt, Iraq has an electricity generation potential for CSP systems higher than the world's electricity demand in 2005.

Table 4.7 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF. 1.5% of the highest available insulation area of Iraq is enough to generate about 29% of the country's electricity demand in the year 2030.

Table 4.7 Iraq: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m²y]	Full-load hours [h]	Area potential [km²]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km²]	Realisable potential up to 2030 [TWh/y]
2400	2970	17,553	1,515.7	1.5	263	22.7
2300	2847	66,221	5,480.0	0	0	0
2200	2723	97,586	7,724.5	0	0	0
2100	2599	72,528	5,480.0	0	0	0
2000	2475	36,457	2,623.4	0	0	0
1900	2352	22,173	1,515.7	0	0	0
1800	2228	4,501	291.5	0	0	0
Total		**317,019**	**24,630.8**		**263**	**22.7**

Ø DNI [kWh/m²y]	2159	Ø Full-load hours [h]	2673
Ratio potential 2030 / total potential [%]			32.1

4.2.7 Solar Thermal Electricity Generating Potentials in Israel

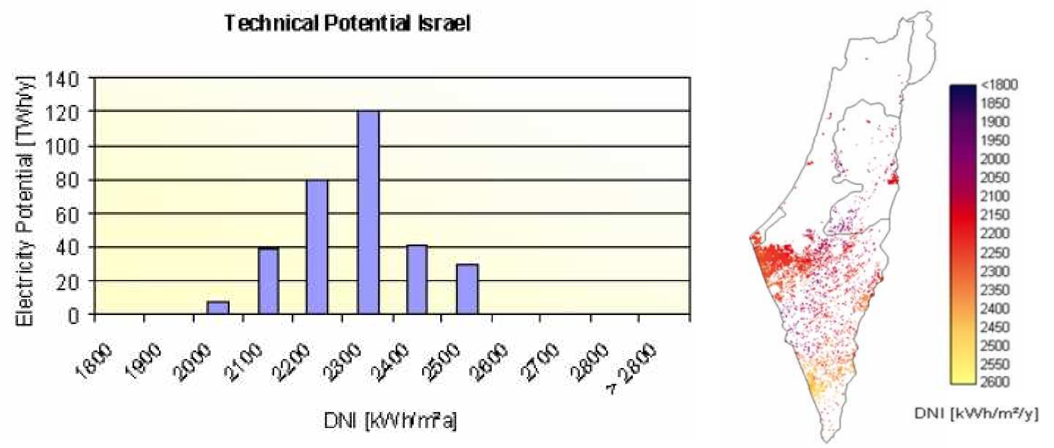


Figure 4.9 Israel: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-14

Most of Israel's CSP potential is situated in the high insulation areas of the Negev desert in the South of the country. DNI's of up to 2500 kWh/m^{2}y are reached in Israel (including Gaza strip and the West Bank).

The following electricity generation potentials were calculated by DLR:

- Technical potential: 318 TWh/y
- Economic potential: 312 TWh/y

The electricity demand of Israel:
- 2005: 46.8 TWh
- 2030: 111 TWh

Table 4.8 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF for Israel. To generate 33.9 TWh/y (31% of electricity demand 2030) an area of 352 km^2, which is about 13% of the highest insulation area available, is necessary.

Table 4.8 Israel: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m^{2}y]	Full-load hours [h]	Area potential [km^2]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km^2]	Realisable potential up to 2030 [TWh/y]
2500	3094	259	23.3	75	194	17.5
2400	2970	381	32.9	50	191	16.5
2300	2847	1,165	96.4	0	0	0
2200	2723	812	64.3	0	0	0
2100	2599	415	31.3	0	0	0
2000	2475	84	6.0	0	0	0
Total		**3,116**	**254.3**		**385**	**33.9**

Ø DNI [kWh/m^{2}y]	2268	Ø Full-load hours [h]	2807
Ratio potential 2030 / total potential [%]			13.3

In the year 2006, the Israel Public Utilities Authority published a feed-in tariff for solar driven independent power producers with a maximum fossil fuel backup of 30%. Currently Israel is planning to build two CSP systems with a capacity of 80 to 125 MW in Ashalim in the Negev desert.

4.2.8 Solar Thermal Electricity Generating Potentials in Italy

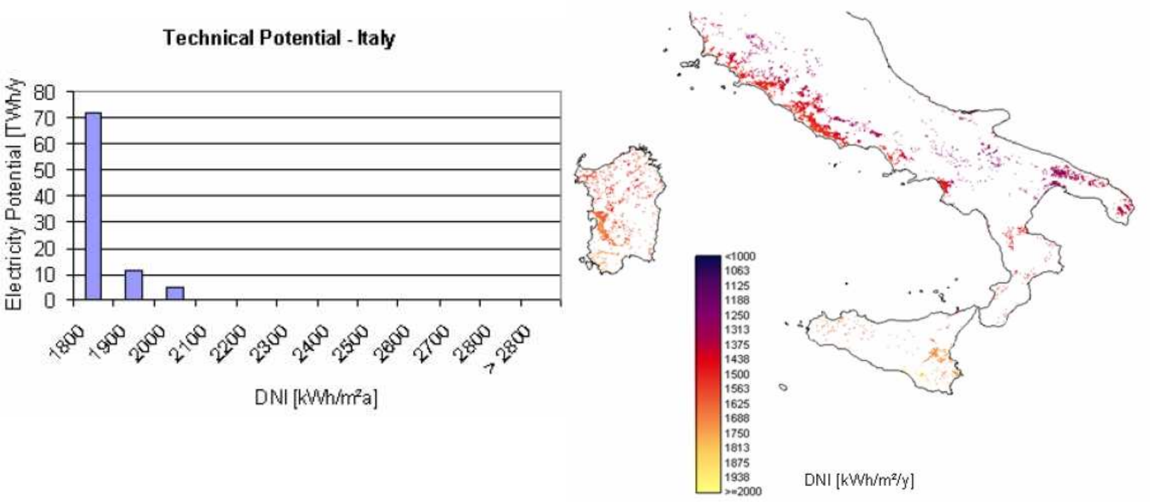


Figure 4.10 Italy: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-10

Only small areas with a DNI above 1800 kWh/m^{2}y are available for CSP plants in Italy. Most of the area potential is situated on the West coast of the mainland and on Sardinia.

The following electricity generation potentials were calculated by DLR:

- Technical potential: 88 TWh/y
- Economic potential: 5 TWh/y

Italy's electricity consumption: - 2005: 332.23 TWh
- 2030: 540 TWh

Table 4.9 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF. According to ***Green-X***, Italy could cover about 10% of its electricity demand in the year 2030 with CSP systems.

Table 4.9 Italy: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m^{2}y]	Full-load hours [h]	Area potential [km^2]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km^2]	Realisable potential up to 2030 [TWh/y]
2000	2475	61	4.4	100	61	4.4
1900	2352	129	8.8	75	96	6.6
1800	2228	883	57.2	50	441	28.6
Total		**1073**	**70.4**		**598**	**39.6**

Ø DNI [kWh/m^{2}y]	1823	Ø Full-load hours [h]	2257
Ratio potential 2030 / total potential [%]			56.3

4.2.9 Solar Thermal Electricity Generating Potentials in Jordan

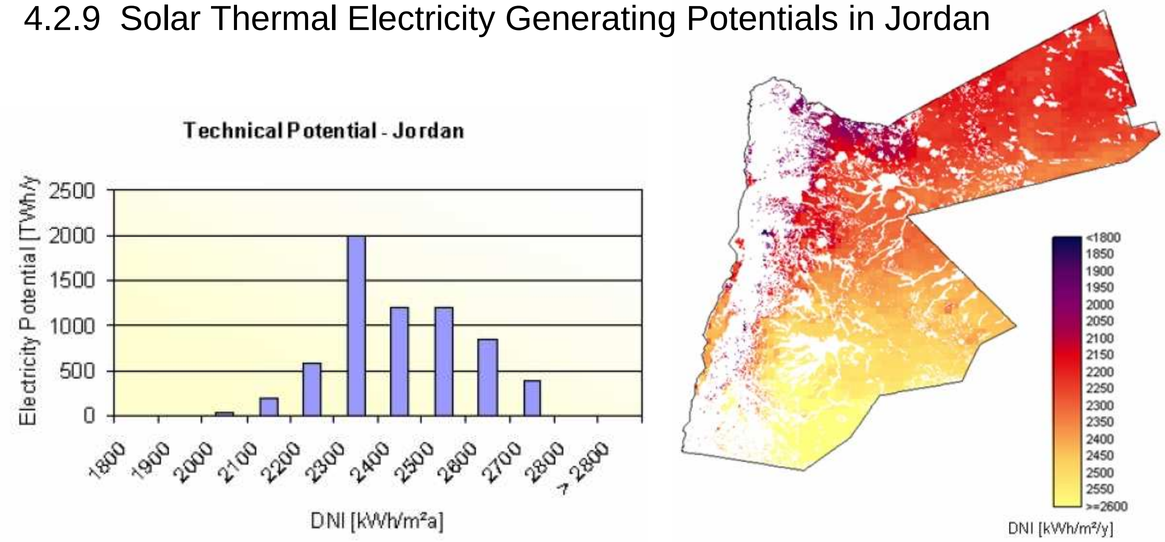


Figure 4.11 Jordan: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-15

Great parts of Jordan are uninhabited and unused, especially the Eastern and South-Eastern parts of the country. The low land use and the high insulation of up to 2700 kWh/m^{2}y result in high electricity generation potentials for CSP systems.

The following electricity generation potential was calculated by DLR:

- Technical potential: 6,434 TWh/y
- Economic potential: 6,429 TWh/y

The electricity consumption of Jordan:
- 2005: 9.07 TWh
- 2030: 22 TWh

Table 4.10 Jordan: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m^{2}y]	Full-load hours [h]	Area potential [km^2]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km^2]	Realisable potential up to 2030 [TWh/y]
2700	3342	3,314	321.9	2	66	6.4
2600	3218	7,170	670.7	0	0	0
2500	3094	10,588	952.4	0	0	0
2400	2970	11,029	952.4	0	0	0
2300	2847	19,290	1,596.3	0	0	0
2200	2723	5,931	469.5	0	0	0
2100	2599	1,953	147.6	0	0	0
2000	2475	466	33.5	0	0	0
Total		**59,741**	**5,144.3**		**66**	**6.4**

Ø DNI [kWh/m^{2}y]	2393	Ø Full-load hours [h]	2962
Ratio potential 2030 / total potential [%]			0.13

Table 4.10 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF of Jordan. 2% of Jordan's available land resource with an insulation of 2700 kWh/m^{2}y could produce about 29% of the country's demanded electricity in the year 2030.

4.2.10 Solar Thermal Electricity Generating Potentials in Kuwait

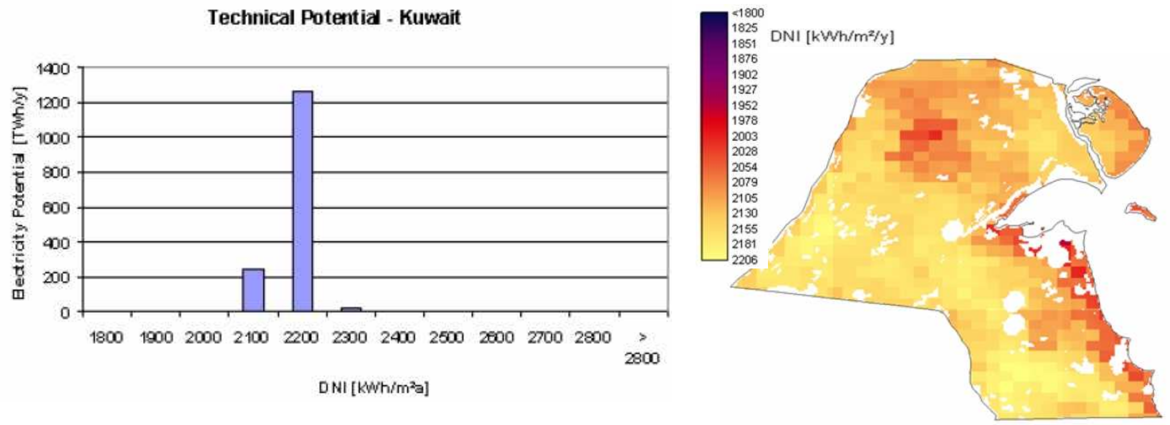


Figure 4.12 Kuwait: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-22

Most parts of Kuwait are covered by the flat Arabian Desert, where a DNI of 2200 kWh/m^{2}y dominates. These desert areas of Kuwait offer great electricity generation potentials for CSP systems.

The following electricity generation potential was calculated by DLR:

- Technical potential: 1,525 TWh/y
- Economic potential: 1,525 TWh/y

The electricity consumption of Kuwait: - 2005: 38.91 TWh
- 2030: 93 TWh

Table 4.11 Kuwait: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m^{2}y]	Full-load hours [h]	Area potential [km^2]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km^2]	Realisable potential up to 2030 [TWh/y]
2300	2847	214	17.7	100	214	17.7
2200	2723	12,725	1,007.3	1	127	10.1
2100	2599	2,573	194.4	0	0	0
Total		**15,511**	**1,219.3**		**341**	**27.8**

Ø DNI [kWh/m^{2}y]	2185	Ø Full-load hours [h]	2704
Ratio potential 2030 / total potential [%]			2.3

Table 4.11 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF for Kuwait. With 2.3% of its total CSP potential, Kuwait could produce 30% of its electricity demand in the year 2030.

4.2.11 Solar Thermal Electricity Generating Potentials in Lebanon

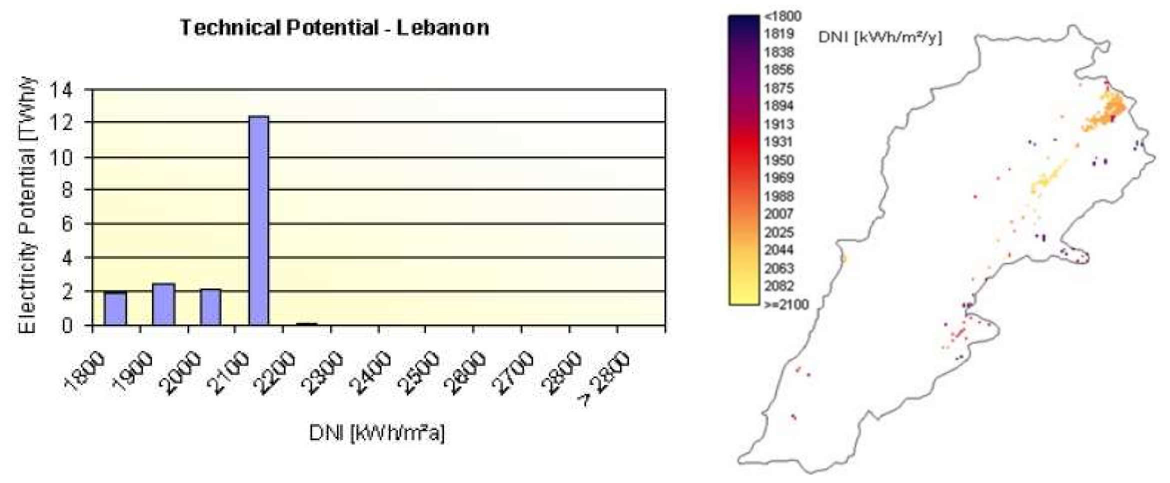


Figure 4.13 Lebanon: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-16

In Lebanon the most electricity generating potentials for CSP systems are found in the North-Eastern parts of the country and with a DNI of 2100 kWh/m^{2}y.

The following electricity generation potentials were calculated by DLR:

- Technical potential: 19 TWh/y
- Economic potential: 14 TWh/y

The electricity consumption of Lebanon: - 2005: 8.99 TWh
- 2030: 21 TWh

Table 4.12 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF for Lebanon. Great parts of the available area (80 km^2) are needed to generate about 29% of Lebanon's electricity demand in the year 2030.

Table 4.12 Lebanon: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m²y]	Full-load hours [h]	Area potential [km²]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km²]	Realisable potential up to 2030 [TWh/y]
2200	2723	1	0.1	100	1	0.1
2100	2599	131	9.9	60	79	6
2000	2475	24	1.7	0	0	0
1900	2352	28	1.9	0	0	0
1800	2228	24	1.5	0	0	0
Total		**208**	**15.2**		**80**	**6.1**

Ø DNI [kWh/m²y]	2028	Ø Full-load hours [h]	2510
Ratio potential 2030 / total potential [%]			39.7

4.2.12 Solar Thermal Electricity Generating Potentials in Libya

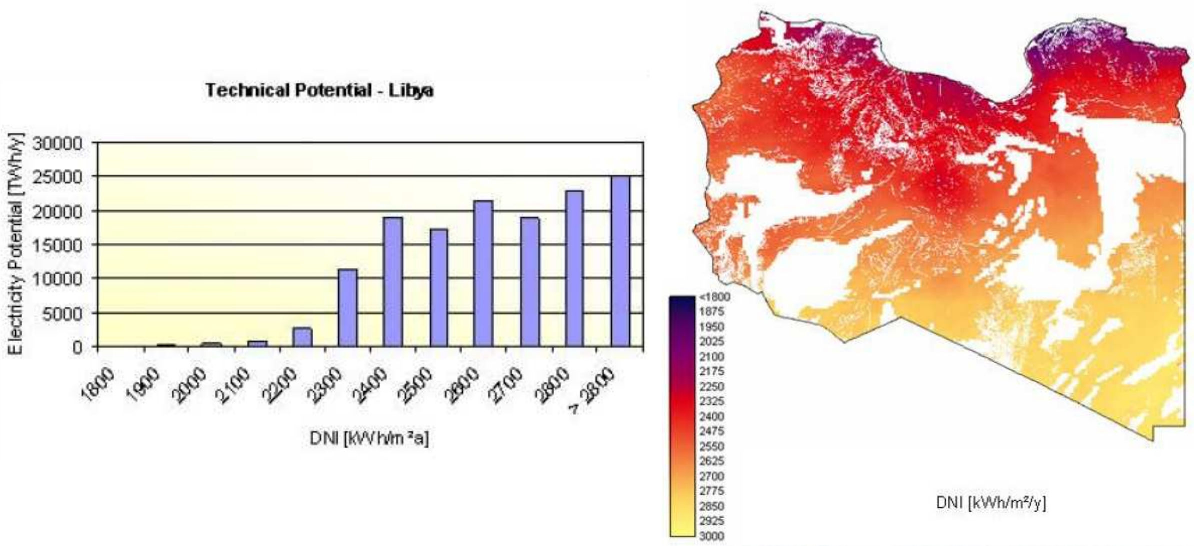


Figure 4.14 Libya: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-5

Libya offers the second largest electricity generation potential for CSP systems in the EU-MENA region. Like in Algeria, which has the largest CSP potential, large parts of the county are covered by desert, where high solar insulation predominates. Especially the Southern parts of Libya, where DNI's above 2800 kWh/m^{2}y are common, offer great CSP potential.

The following electricity generation potentials were calculated by DLR:

- Technical potential: 139,600 TWh/y
- Economic potential: 139,470 TWh/y

The electricity consumption of Libya:
- 2005: 19.53 TWh
- 2030: 45 TWh

Table 4.13 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF. Libya can cover 31% of its electricity demand in the year 2030 with only 0.7% of its highest insulation areas available.

Table 4.13 Libya: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m²y]	Full-load hours [h]	Area potential [km²]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km²]	Realisable potential up to 2030 [TWh/y]
2900	3589	191,660	19,998.0	0.07	134	14
2800	3466	180,040	18,137.7	0	0	0
2700	3342	153,196	14,882.2	0	0	0
2600	3218	178,974	16,742.5	0	0	0
2500	3094	155,111	13,952.1	0	0	0
2400	2970	172,346	14,882.2	0	0	0
2300	2847	112,399	9,301.4	0	0	0
2200	2723	29,377	2,325.3	0	0	0
2100	2599	9,848	744.1	0	0	0
2000	2475	6,463	465.1	0	0	0
1900	2352	2,721	186.0	0	0	0
Total		**1,192,136**	**111,616.7**		**134**	**14**

Ø DNI [kWh/m²y]	2602	Ø Full-load hours [h]	3221
Ratio potential 2030 / total potential [%]			0.013

4.2.13 Solar Thermal Electricity Generating Potentials in Malta

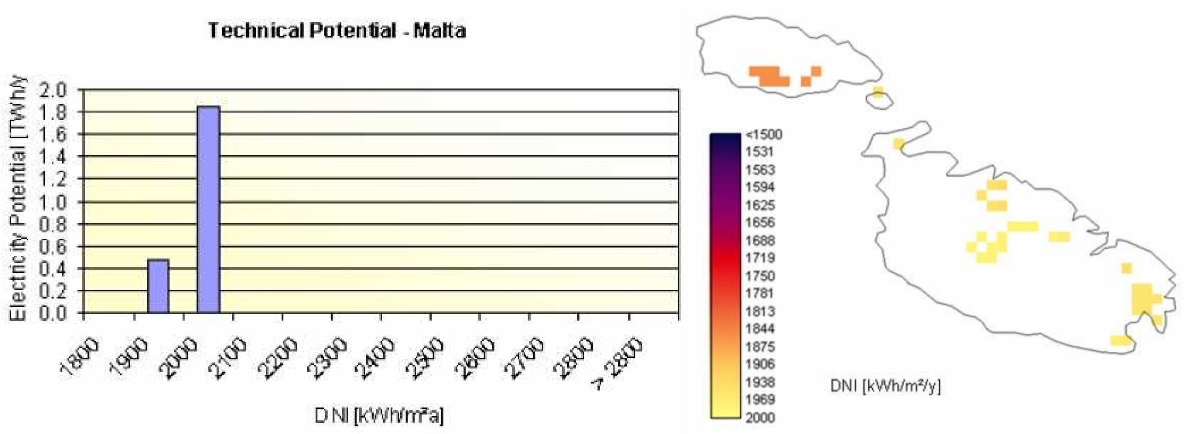


Figure 4.15 Malta: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-7

Malta has, due to its small country size, only small area potentials for CSP systems. These are distributed over all three inhabited islands of Malta. DNI's of up to 2000 kWh/m²y are reached on the main island.

The following electricity generation potentials were calculated by DLR:

- Technical potential: 2.3 TWh/y
- Economic potential: 1.9 TWh/y

The electricity consumption of Malta: - 2005: 1.98 TWh

- 2030: 3 TWh

Even though the technical electricity generation potential of Malta seems to be small, it is enough to cover the demand of electricity in the year 2005.

Table 4.14 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF. With 4.5 km^2 of its available area, Malta can produce about 11% of its electricity demand in the 2030.

Table 4.14 Malta: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m^{2}y]	Full-load hours [h]	Area potential [km^2]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km^2]	Realisable potential up to 2030 [TWh/y]
2000	2475	20	1.5	20	4	0.29
1900	2352	5	0.4	10	0.5	0.04
Total		**25**	**1.9**		**4.5**	**0.33**

Ø DNI [kWh/m^{2}y]	1979	Ø Full-load hours [h]	2449
Ratio potential 2030 / total potential [%]			18

4.2.14 Solar Thermal Electricity Generating Potentials in Morocco

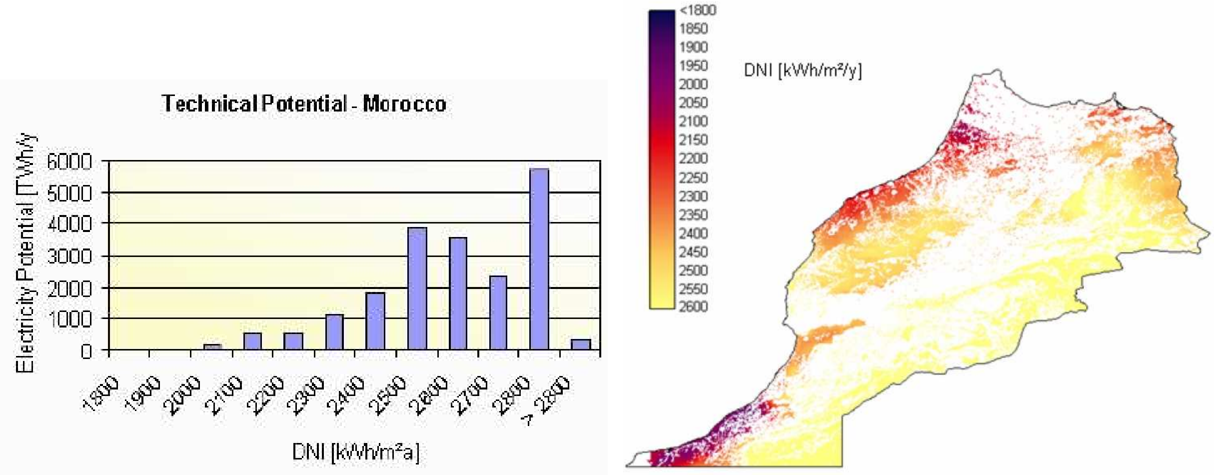


Figure 4.16 Morocco: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-2

Morocco, which is partly covered by the Sahara desert, offers high electricity generating potentials for CSP systems. DNI's above 2800 kWh/m^{2}y are reached in the Southern and

South-Eastern parts of the country. Great parts of Morocco are mountainous and are excluded from the area potential.

The following electricity generation potentials were calculated by DLR:

- Technical potential: 20,151 TWh/y
- Economic potential: 20,146 TWh/y

Morocco's electricity consumption: - 2005: 19.4 TWh

- 2030: 44 TWh

Table 4.15 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF for Morocco.

Table 4.15 Morocco: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m²y]	Full-load hours [h]	Area potential [km²]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km²]	Realisable potential up to 2030 [TWh/y]
2900	3589	2,774	289.4	4.5	125	13
2800	3466	45,010	4,534.4	0	0	0
2700	3342	18,869	1,833.1	0	0	0
2600	3218	30,940	2,894.3	0	0	0
2500	3094	34,322	3,087.3	0	0	0
2400	2970	16,759	1,447.2	0	0	0
2300	2847	10,493	868.3	0	0	0
2200	2723	6,094	482.4	0	0	0
2100	2599	6,384	482.4	0	0	0
2000	2475	2,681	193.0	0	0	0
Total		**174,326**	**16,111.7**		**125**	**13**

Ø DNI [kWh/m²y]	2569	Ø Full-load hours [h]	3179
Ratio potential 2030 / total potential [%]			0.08

Today one CSP system is constructed in Morocco: the 470 MW Ain Beni Mathar ISCSS with a solar capacity of 20 MW. The construction of the plant is made by the Spanish company Abengoa and began on March 28th, 2008. The solar filed size will be about 183,000 m^2.

4.2.15 Solar Thermal Electricity Generating Potentials in Oman

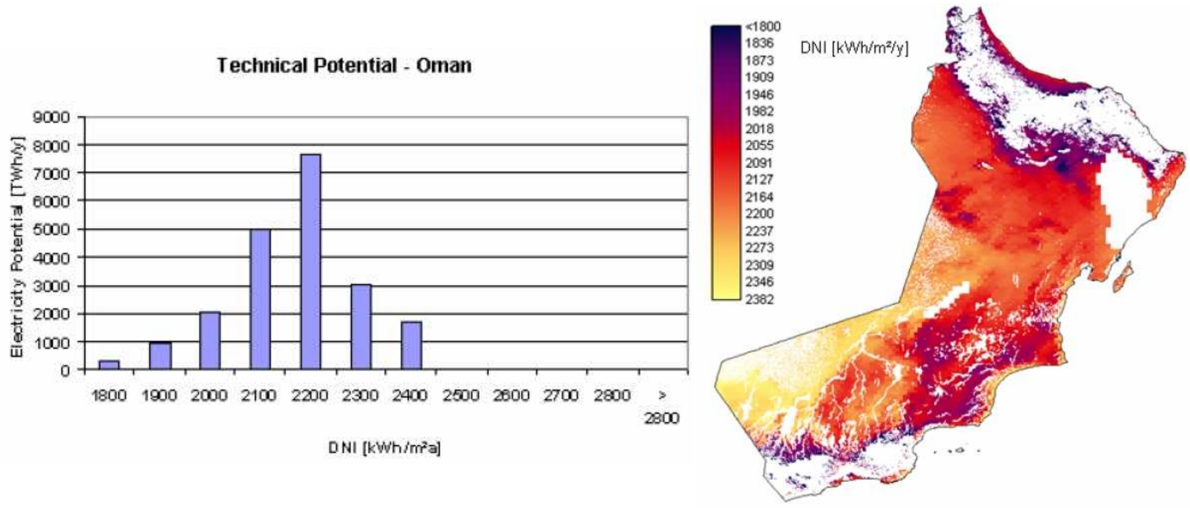


Figure 4.17 Oman: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-23

Oman offers a higher technical electricity generating potential for CSP systems as Morocco, even though Morocco has an area which is 1.5 larger than that of Oman. This is because great parts of Oman are covered by a plain desert, and are not excluded from the area potential like the mountainous parts of Morocco. Regions with a DNI of 2200 kWh/m^{2}y have the greatest share of the electricity generation potential.

The following electricity generation potentials were calculated by DLR:

- Technical potential: 20,611 TWh/y
- Economic potential: 19,404 TWh/y

The electricity consumption of Oman: - 2005: 9.42 TWh

- 2030: 22 TWh

Table 4.16 Oman: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m^{2}y]	Full-load hours [h]	Area potential [km^2]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km^2]	Realisable potential up to 2030 [TWh/y]
2400	2970	17,741	1,532.0	0.4	71	6.1
2300	2847	28,562	2,363.6	0	0	0
2200	2723	76,862	6,084.0	0	0	0
2100	2599	52,137	3,939.3	0	0	0
2000	2475	21,897	1,575.7	0	0	0
1900	2352	11,205	766.0	0	0	0
1800	2228	3,379	218.9	0	0	0
Total		**211,783**	**16,479.5**		**71**	**6.1**

Ø DNI [kWh/m^{2}y]	2163	Ø Full-load hours [h]	2677
Ratio potential 2030 / total potential [%]			0.04

Table 4.16 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF. Oman can produce 28% of its electricity demand in the year 2030 with only 0.4% of its available area resource at a DNI of 2400 kWh/m^{2}y.

4.2.16 Solar Thermal Electricity Generating Potentials in Portugal

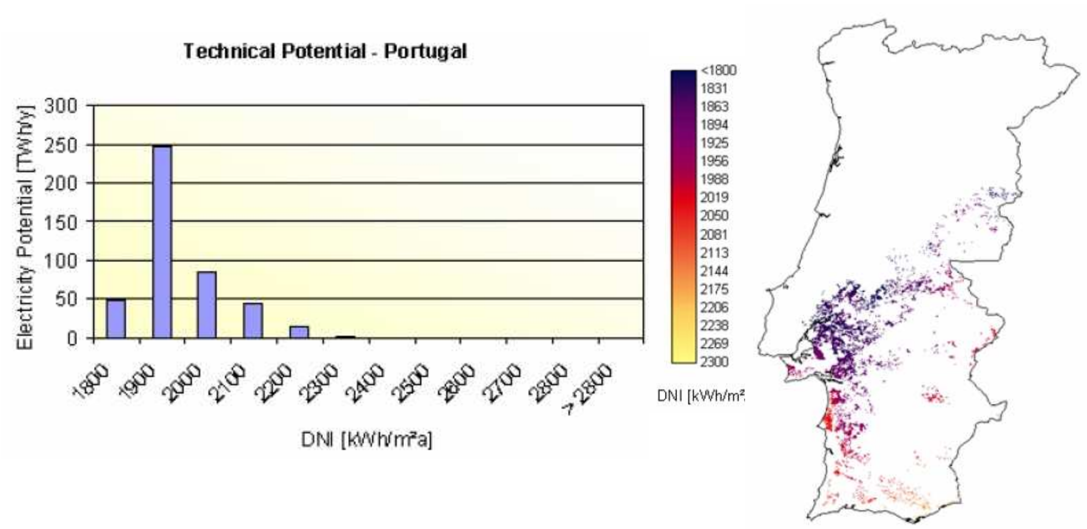


Figure 4.18 Portugal: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-8

Portugal offers the second highest electricity generation potential for CSP systems in Europe. The greatest parts of the area potential are situated in the Southern and South-Western regions of the country and have a DNI of 1900 kWh/m^{2}y.

The following electricity generation potentials were calculated by DLR:

- Technical potential: 436 TWh/y
- Economic potential: 142 TWh/y

Portugal's electricity consumption: - 2005: 49.19 TWh
- 2030: 94 TWh

Table 4.17 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF. Portugal could produce more than 22% of its electricity demand in the year 2030 with about 273 km^2.

A Portuguese feed-in tariff for electricity generating solar systems was published in 2007, which grants 0.27 €/kWh for CSP plants of up to 10 MW and 0.16 – 0.20 €/kWh for CSP plants beyond 10 MW. However, currently there are no CSP plants planned in Portugal.

Table 4.17 Portugal: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m²y]	Full-load hours [h]	Area potential [km²]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km²]	Realisable potential up to 2030 [TWh/y]
2300	2847	19	1.6	100	19	1.6
2200	2723	149	11.8	66	99	7.8
2100	2599	470	35.5	33	155	11.7
2000	2475	932	67.0	0	0	0
1900	2352	2,827	193.2	0	0	0
1800	2228	609	39.4	0	0	0
Total		**5,005**	**348.6**		**273**	**21.5**

Ø DNI [kWh/m²y]	1936	Ø Full-load hours [h]	2396
Ratio potential 2030 / total potential [%]			6.1

4.2.17 Solar Thermal Electricity Generating Potentials in Qatar

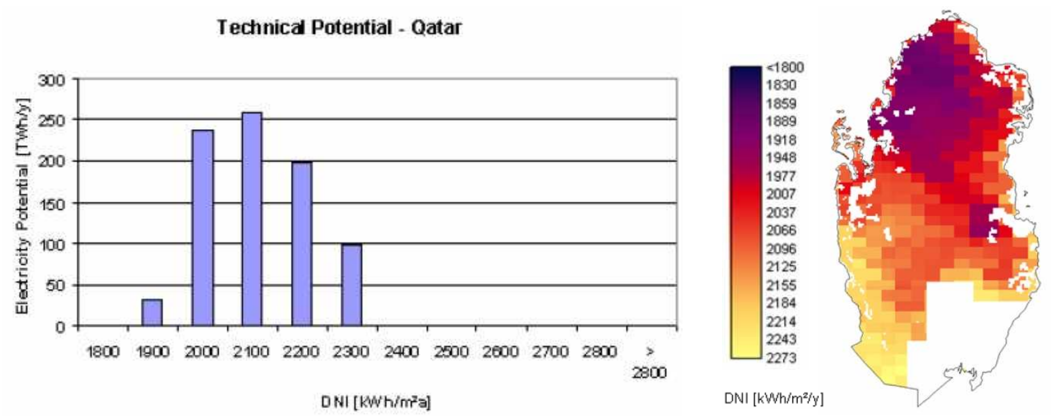


Figure 4.19 Qatar: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-20

The plain sand covering the peninsula of Qatar offers CSP-potential areas with DNI's between 1900 and 2300 kWh/m²y. Only some Southern parts of the country are excluded from the area potential due to geomorphology (sand dunes etc.). Areas with a DNI of 2100 kWh/m²y have the greatest shares of the electricity generating potential.

The following electricity generation potentials were calculated by DLR:

- Technical potential: 823 TWh/y
- Economic potential: 792 TWh/y

The electricity consumption of Qatar:
- 2005: 13.38 TWh
- 2030: 32 TWh

Table 4.18 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF for Qatar. Qatar could generate 30% of its electricity demand in the year 2030 with 1.4% of the country's total CSP potential.

Table 4.18 Qatar: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m²y]	Full-load hours [h]	Area potential [km²]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km²]	Realisable potential up to 2030 [TWh/y]
2300	2847	952	78.8	12	114	9.5
2200	2723	1,991	157.6	0	0	0
2100	2599	2,731	206.3	0	0	0
2000	2475	2,628	189.1	0	0	0
1900	2352	384	26.3	0	0	0
Total		**8,685**	**658.0**		**114**	**9.5**

Ø DNI [kWh/m²y]	2106	Ø Full-load hours [h]	2606
Ratio potential 2030 / total potential [%]			1.4

4.2.18 Solar Thermal Electricity Generating Potentials in Saudi Arabia

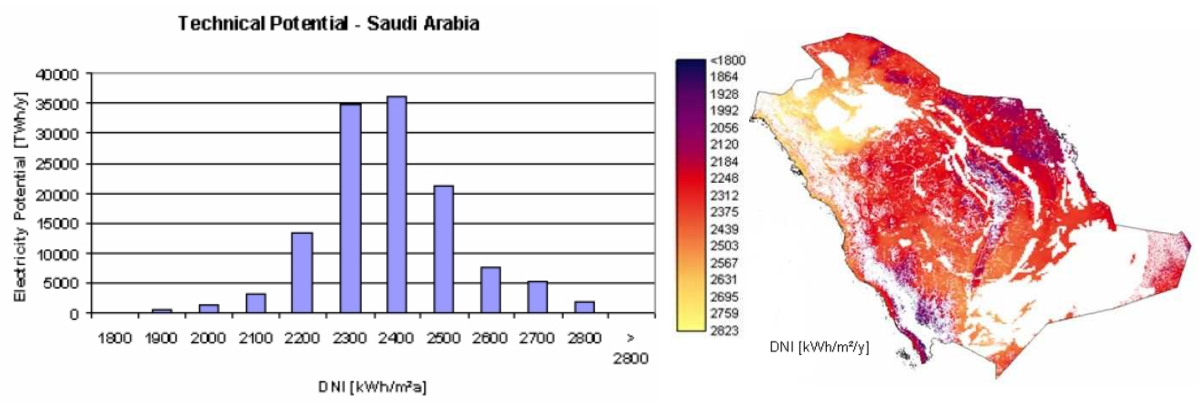


Figure 4.20 Saudi Arabia: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-24

After Algeria and Libya, Saudi Arabia offers the third largest electricity generating potential for CSP systems in the EU-MENA region. The DNI of the area potential ranges from 1900 to 2800 kWh/m^{2}y, with the greatest shares in regions with an insulation of 2300 and 2400 kWh/m^{2}y. Only some parts of the country are excluded from the area potential due to geomorphology and land protections.

The following electricity generation potentials were calculated by DLR:

- Technical potential: 125,260 TWh/y
- Economic potential: 124,560 TWh/y

Saudi Arabia's electricity consumption: - 2005: 157.52 TWh

- 2030: 375 TWh

Table 4.19 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF for Saudi Arabia. If 10% of the usable land with the highest DNI is used for CSP systems, Saudi Arabia can generate about 32% of its projected electricity demand in the year 2030 with solar thermal power.

Table 4.19 Saudi Arabia: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m²y]	Full-load hours [h]	Area potential [km²]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km²]	Realisable potential up to 2030 [TWh/y]
2800	3466	12,026	1,211.5	10	1,203	121.2
2700	3342	41,570	4,038.4	0	0	0
2600	3218	64,754	6,057.5	0	0	0
2500	3094	190,808	17,163.0	0	0	0
2400	2970	339,059	29,278.1	0	0	0
2300	2847	339,160	28,066.6	0	0	0
2200	2723	133,923	10,600.7	0	0	0
2100	2599	33,405	2,524.0	0	0	0
2000	2475	14,030	1,009.6	0	0	0
1900	2352	2,954	201.9	0	0	0
Total		**1,171,689**	**100,151.2**		**1,203**	**121.2**

Ø DNI [kWh/m²y]	2376	Ø Full-load hours [h]	2940
Ratio potential 2030 / total potential [%]			0.12

4.2.19 Solar Thermal Electricity Generating Potentials in Spain

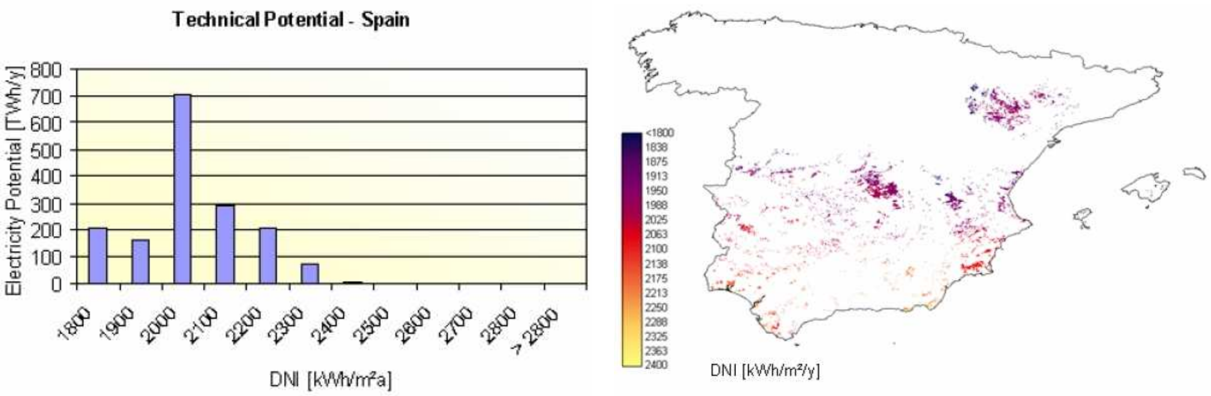


Figure 4.21 Spain: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-9

Spain offers the highest CSP potential of all analysed European countries. Area potentials are existing in central and Southern parts of the country at DNI's between 1800 and

2400 kWh/m^{2}y. The highest electricity generating potential is reached in areas with a DNI of 2000 kWh/m^{2}y.

The following electricity generation potentials were calculated by DLR:

- Technical potential: 1,646 TWh/y
- Economic potential: 1,278 TWh/y

The electricity consumption of Spain: - 2005: 266.77 TWh

- 2030: 417 TWh

Table 4.20 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF. According to the computer model ***Green-X***, Spain will be able to produce more than 30% of its electricity demand in the year 2030 with CSP plants, which would require a large area of about 1,620 km^2.

Table 4.20 Spain: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m^{2}y]	Full-load hours [h]	Area potential [km^2]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km^2]	Realisable potential up to 2030 [TWh/y]
2400	2970	49	4.2	100	49	4.2
2300	2847	715	59.1	75	536	44.4
2200	2723	2,082	164.8	50	1,041	82.4
2100	2599	3,075	232.4	0	0	0
2000	2475	7,779	559.8	0	0	0
1900	2352	1,854	126.7	0	0	0
1800	2228	2,609	169.0	0	0	0
Total		**18,164**	**1,316.1**		**1,625**	**131.0**

Ø DNI [kWh/m^{2}y]	2014	Ø Full-load hours [h]	2492
Ratio potential 2030 / total potential [%]			10

Spain was the first European country which introduced a feed-in tariff for solar thermal power in the year 2002. However, the first premiums were too low to cover the costs of CSP systems. Therefore, the tariffs were increased in 2004 and again in 2007 to about 0.27 €/kWh for CSP plants with a capacity of up to 50 MW for 25 years. Spain's CSP target is to reach 500 MW in the year 2010.

Spain is currently the hottest spot in the world for CSP projects. Some of them have already been described in the cost analysis.

4.2.20 Solar Thermal Electricity Generating Potentials in Syria

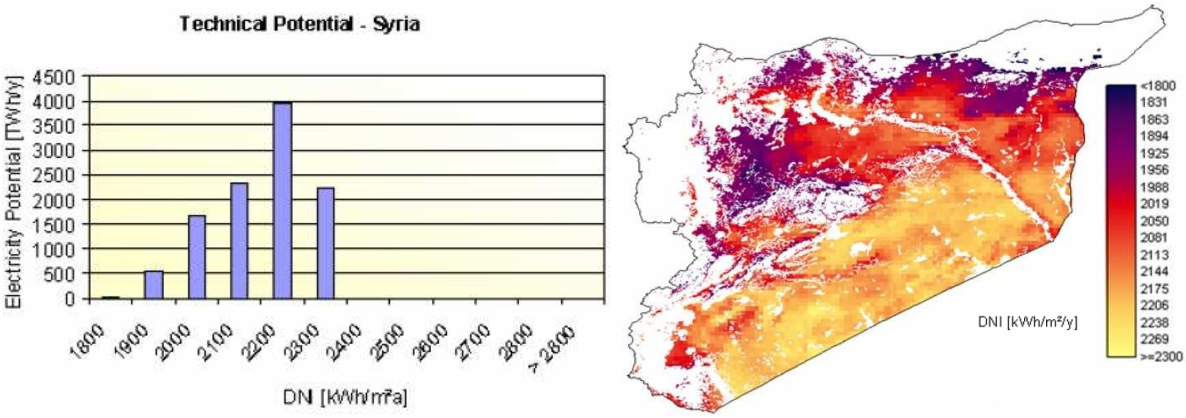


Figure 4.22 Syria: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-17

Syria offers high area potential for CSP systems, especially in the Southern and Eastern parts of the country, where DNI's of up to 2300 kWh/m^{2}y occur.

The following electricity generation potentials were calculated by DLR:

- Technical potential: 10,777 TWh/y
- Economic potential: 10,210 TWh/y

Syria's electricity consumption: - 2005: 26.66 TWh
- 2030: 63 TWh

Table 4.21 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF. Syria is able to produce 17.8 TWh/y or 28% of its electricity demand in the year 2030 with only 1% of its area potential with 2300 kWh/m^{2}y.

Table 4.21 Syria: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m^{2}y]	Full-load hours [h]	Area potential [km^2]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km^2]	Realisable potential up to 2030 [TWh/y]
2300	2847	21,522	1,781.0	1	215	17.8
2200	2723	39,614	3,135.6	0	0	0
2100	2599	24,900	1,881.4	0	0	0
2000	2475	18,824	1,354.6	0	0	0
1900	2352	6,422	439.0	0	0	0
1800	2228	387	25.1	0	0	0
Total		**111,670**	**8,616.7**		**215**	**17.8**

Ø DNI [kWh/m^{2}y]	2145	Ø Full-load hours [h]	2654
Ratio potential 2030 / total potential [%]			0.2

4.2.21 Solar Thermal Electricity Generating Potentials in Tunisia

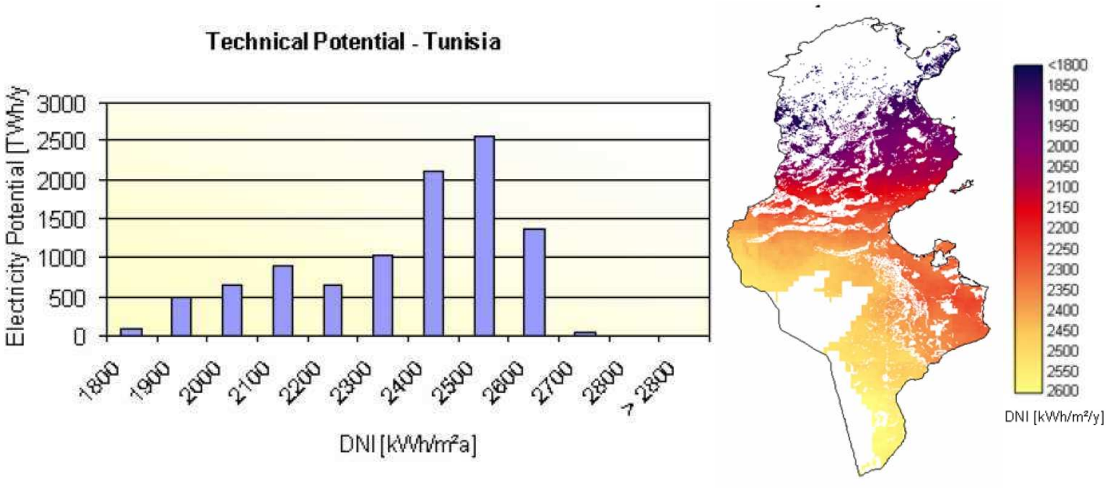


Figure 4.23 Tunisia: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-3

Due to high solar insulations of up to 2700 kWh/m^{2}y, Tunisia also offers high area potential for CSP systems. Large parts of Northern Tunisia are excluded from the area potential for CSP systems because of land use and geomorphology (mountainous). Some Southern parts are excluded (geomorphology) as well.

The following electricity generation potentials were calculated by DLR:

- Technical potential: 9,815 TWh/y
- Economic potential: 9,244 TWh/y

The electricity consumption of Tunisia: - 2005: 11.97 TWh
- 2030: 27 TWh

Table 4.22 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF for Tunisia. It can be seen that 0.1% of Tunisia's CSP potential could cover 30% of its electricity demand in the year 2030.

Table 4.22 Tunisia: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m^{2}y]	Full-load hours [h]	Area potential [km^2]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km^2]	Realisable potential up to 2030 [TWh/y]
2700	3342	434	42.2	19	83	8
2600	3218	11,726	1,097.0	0	0	0
2500	3094	22,515	2,025.2	0	0	0
2400	2970	19,544	1,687.6	0	0	0
2300	2847	10,197	843.8	0	0	0
2200	2723	6,396	506.3	0	0	0
2100	2599	8,934	675.1	0	0	0
2000	2475	7,036	506.3	0	0	0
1900	2352	5,555	379.7	0	0	0
1800	2228	1,303	84.4	0	0	0
Total		**93,640**	**7,847.5**		**83**	**8**

Ø DNI [kWh/m^{2}y]	2329	Ø Full-load hours [h]	2883
Ratio potential 2030 / total potential [%]			0.1

4.2.22 Solar Thermal Electricity Generating Potentials in Turkey

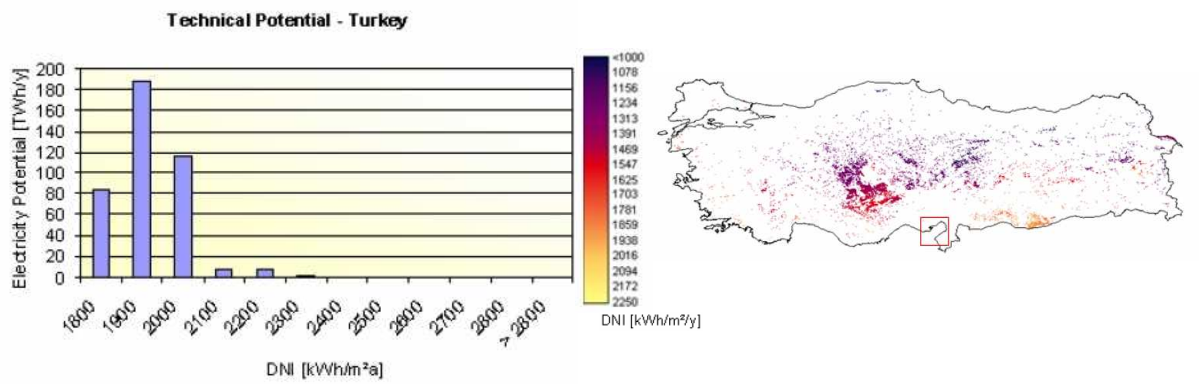


Figure 4.24 Turkey: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-13

Central Turkey offers some areas with DNI's of up to 1900 kWh/m^{2}y for CSP plants. In some spots in Southern Turkey, especially at the border to Syria, DNI's with a maximum of 2300 kWh/m^{2}y are reached. However, the greatest share of the electricity generation potential in Turkey is achieved in regions with a DNI of 1900 kWh/m^{2}y.

The following electricity generation potentials were calculated by DLR:

- Technical potential: 405 TWh/y
- Economic potential: 131 TWh/y

Turkey's electricity consumption: - 2005: 136.75 TWh

- 2030: 283 TWh

Table 4.23 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF. In the ***Green-X*** scenario Turkey is able to provide approximately 22% of its electricity demand in the year 2030 with CSP power. With the land use restrictions chosen for this calculation, an area of nearly 860 km^2 would be needed for the installation of the CSP systems.

Table 4.23 Turkey: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m^{2}y]	Full-load hours [h]	Area potential [km^2]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km^2]	Realisable potential up to 2030 [TWh/y]
2300	2847	14	1.2	100	14	1.2
2200	2723	73	5.8	80	59	4.7
2100	2599	77	5.8	60	46	3.5
2000	2475	1,293	93.0	40	517	37.2
1900	2352	2,211	151.2	10	221	15.1
1800	2228	1,032	66.9	0	0	0
Total		**4,700**	**323.8**		**857**	**61.6**

Ø DNI [kWh/m^{2}y]	1915	Ø Full-load hours [h]	2370
Ratio potential 2030 / total potential [%]			19

4.2.23 Solar Thermal Electricity Generating Potentials in the United Arabian Emirates

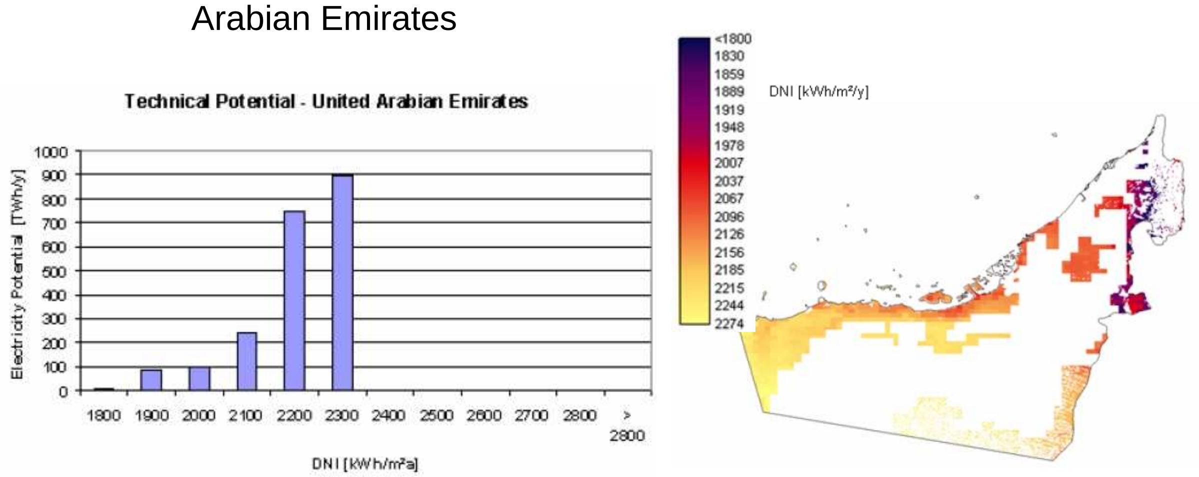


Figure 4.25 United Arabian Emirates: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-21

Most parts of the United Arabian Emirates (UAE) are excluded from the CSP area potential due to geomorphology (desert/dunes). Nevertheless good potentials are reached with DNI's of 2200 and 2300 kWh/m^{2}y in Western and coastal parts of the country.

The following electricity generation potentials were calculated by DLR:

- Technical potential: 2,078 TWh/y
- Economic potential: 1,988 TWh/y

The electricity consumption of UAE: - 2005: 56.26 TWh

- 2030: 134 TWh

Table 4.24 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF. 6% of the useable land resource with a DNI of 2300 kWh/m^{2}y is sufficient to provide 32% of the projected UAE electricity demand in the year 2030 with CSP systems.

Table 4.24 United Arabian Emirates: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m^{2}y]	Full-load hours [h]	Area potential [km^2]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km^2]	Realisable potential up to 2030 [TWh/y]
2300	2847	8,721	721.7	6	523	43.3
2200	2723	7,598	601.4	0	0	0
2100	2599	2,587	195.5	0	0	0
2000	2475	1,045	75.2	0	0	0
1900	2352	916	62.6	0	0	0
1800	2228	77	5.0	0	0	0
Total		**20,945**	**1,661.5**		**523**	**43.3**

Ø DNI [kWh/m^{2}y]	2205	Ø Full-load hours [h]	2729
Ratio potential 2030 / total potential [%]			2.6

4.2.24 Solar Thermal Electricity Generating Potentials in Yemen

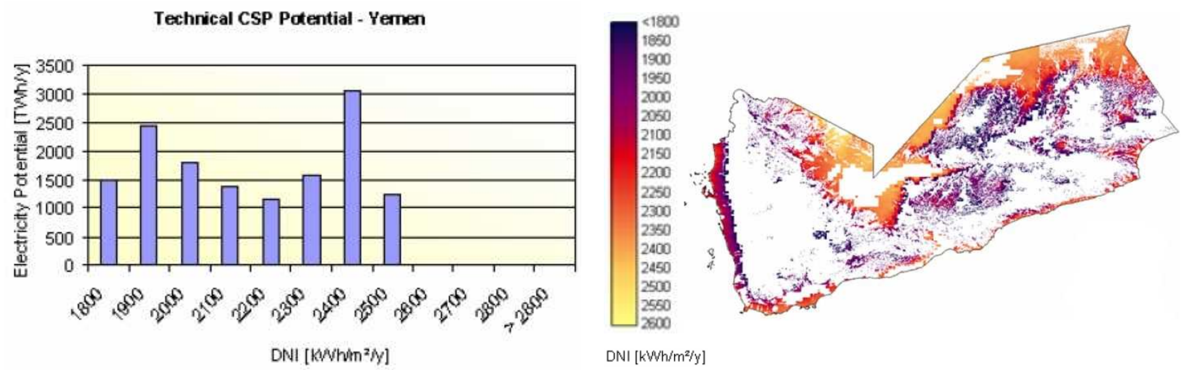


Figure 4.26 Yemen: Electricity generating potential for CSP systems distributed to different classes of DNI (left) and annual DNI in non-excluded areas (right)
Source: DLR, 2005 pA-25

Even with its large mountainous areas, Yemen offers a good electricity generating potential. The DNI's of the usable land for CSP systems vary from 1800 to 2500 kWh/m^{2}y. The greatest potential is reached in the desert areas with a DNI of

2400 kWh/m²y which are situated in the North of the country, next of the border to Saudi Arabia.

The following electricity generation potentials were calculated by DLR:

- Technical potential: 5,143 TWh/y
- Economic potential: 5,100 TWh/y

Yemen's electricity consumption: - 2005: 3.67 TWh

- 2030: 9 TWh

Table 4.25 shows the result of the potential calculation with a 50 MW PT using thermal oil as HTF for Yemen. 0.7% of Yemen's total CSP potential would be enough to generate about 30% of its electricity demand in the year 2030.

Table 4.25 Yemen: Total/realisable in the mid to long-term (2030) area and electricity generation potential for a 50 MW PT system using thermal oil as HTF distributed to different annual DNI's/full-load hours

DNI [kWh/m²y]	Full-load hours [h]	Area potential [km²]	Electricity generation potential [TWh/y]	Realisation constraint (2030) [%]	Area potential (2030) [km²]	Realisable potential up to 2030 [TWh/y]
2500	3094	3,918	352.5	8	30	2.7
2400	2970	10,340	892.9	0	0	0
2300	2847	5,584	462.1	0	0	0
2200	2723	4,205	332.9	0	0	0
2100	2599	5,287	399.5	0	0	0
2000	2475	7,347	528.7	0	0	0
1900	2352	10,426	712.8	0	0	0
1800	2228	6,652	430.8	0	0	0
Total		**53,759**	**4,112.1**		**30**	**2.7**

Ø DNI [kWh/m²y]	2126	Ø Full-load hours [h]	2631
Ratio potential 2030 / total potential [%]			0.7

4.3 Summary of the CSP-Potential in the Mediterranean Area

The Table 4.26 shows a summary of the technical and economic potential for solar thermal electricity generation, including electricity demands for 2005 and projections for 2030 as well as realisable CSP potentials in the mid to long-term (2030).

Table 4.26 Summary of the solar thermal electricity generating potentials, realisable potentials in the mid to long-term (2030) and electricity demands of the EU-MENA countries

[TWh/y]	**CSP Potentials**		**Realisable up to 2030**	**Electr. Demand**	
Country	**Technical (DLR)**	**With PT (oil)**		**2005**	**2030**
Algeria	169,440	135,475	20.4	29.52	67
Bahrain	36	28.8	6.1	8.26	20
Cyprus	23	18.4	1.5	4.21	8
Egypt	73,656	58,891	56.0	90.73	207
Greece	44	35.2	11.3	58.20	90
Iraq	30,806	24,631	22.7	33.26	79
Israel	318	254.3	31.7	46.80	111
Italy	88	70.4	39.6	332.23	393
Jordan	6,434	5,144	6.4	9.07	22
Kuwait	1,525	1,219	27.7	38.91	93
Lebanon	19	15.2	6.0	8.99	21
Libya	139,600	111,617	14.0	19.53	45
Malta	2.3	1.8	0.3	1.98	3
Morocco	20,151	16,112	13.0	19.40	44
Oman	20,611	16,480	6.1	9.42	22
Portugal	436	348.6	21.1	49.19	94
Qatar	823	658	9.5	13.38	32
Saudi Arabia	125,260	100,151	121.2	157.52	375
Spain	1,646	1,316	131.0	266.77	417
Syria	10,777	8,617	17.8	26.66	63
Tunisia	9,815	7,848	8.0	11.97	27
Turkey	405	323.8	61.6	136.75	283
UAE	2,078	1,662	43.3	56.26	134
Yemen	5,143	4,112	2.7	3.67	9
Total	**619,136**	**490,916**	**676.7**	**1,433**	**2,659**

In the summary it can be seen that countries from North Africa/Middle East have the biggest potentials (Algeria, Libya, Saudi Arabia etc.) for CSP electricity generation. The most important reasons for this are the high desert cover in these countries, which leads to low cloud cover and high DNI, and the low land cover (exclusion criterion). But these desert potentials might be very difficult to explore, since there is no infrastructure (streets, electricity etc.) available. Nevertheless, all countries (except Malta, Lebanon, Italy and Greece) could produce more electricity with CSP systems than they need by 2030.

In TREC, 2008 p17 is stated: "The largest accessible but least tapped form of energy on earth is solar radiation on deserts. (…) The hot deserts cover around 36 million km^2 of the 149 million km^2 of the earth land surface. The solar energy arriving per 1 year on 1 km^2 desert is on average 2.2 Terawatt hours (TWh), yielding 80 mio. Terawatt hours/year. This is a factor 750 more than the fossil energy consumption of 2005 (…). We know how to convert 15% of solar radiation into the useful energy form of electricity (MED-CSP, 2005). This means, that 1% of the area of the global deserts would be sufficient to produce the entire annual primary energy consumption of humankind as electric power".

The technical and the economic potential of the Mediterranean Region are a factor 36 more than the approximate current world consumption of 17,000 TWh/y. The following Figure 4.27 shows the accumulated areas needed to generate the approximate current world, EU-25 and MENA consumption with CSP plants.

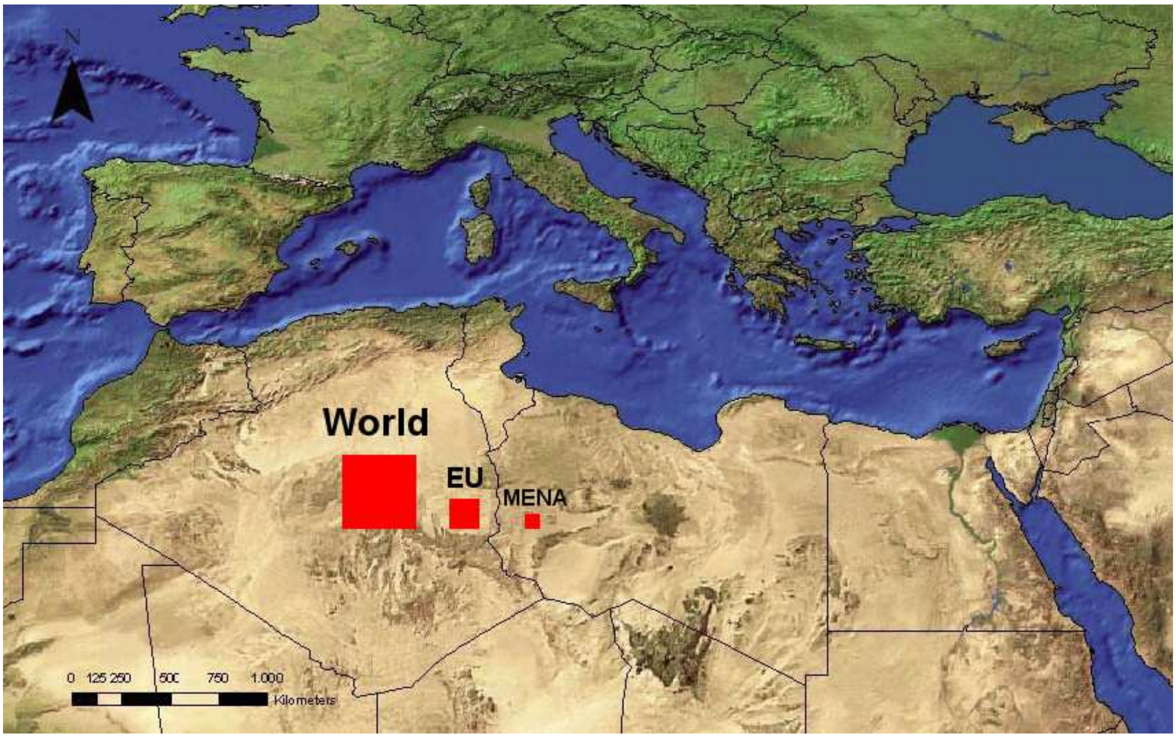


Figure 4.27 Area needed to produce sufficient electricity with CSP systems for the World's, the EU and MENA consumption (indicated as red areas)
Source: DESERTEC, 2008

With such high potentials, CSP could become a main renewable energy technology in the future electricity mix in high insulation areas around the world.

5 Conclusion

Climate change and the dependency on fossil fuels are problems which can be solved by using renewable energy sources, especially in the electricity generation. CSP is one renewable energy technology which offers an opportunity to produce sustainable electricity (and heat) for sunny regions of the world.

The objectives of this thesis were to summarize the current state of the CSP technology for electricity generation and to analyse its costs and potentials in EU-MENA region. To reach these objectives, an in-depth desk research based on available literature and information on realised/planned projects was conducted, accompanied by an analysis of derived data.

There are four different common CSP technologies today: Parabolic trough, central receiver, Fresnel and dish systems. They all rely mainly on the same process: Direct sunlight is concentrated with glass parabolic or flat mirrors/reflectors that continuously track the position of the sun and focus the sunbeam onto/into a receiver. Inside the receiver a HTF is flowing through, which takes the heat towards the thermal power unit. The power unit can consist of conventional Brayton-/Rankine-/Stirling- or combined cycles. A thermal storage system and/or fossil fuel backup can be used to increase the capacity factor of the power plant. Thermal cycle efficiencies of 30 – 40% and capacity factors of about 25% are reached today; capacity factors of up to 90% are projected.

Today CSP plants with a total capacity of about 400 MW are installed worldwide; most of them are PT systems in California, USA. LEC for different technologies with several HTF and financing parameters were calculated (plant size 50 MW):

- PT systems: 15 to 24 cents€/kWh
- Fresnel systems: 14 to 20 cents€/kWh
- CRS: 14 to 23 cents€/kWh (solar-only); 8 to 10 Cents€/kWh (hybrid, 20% solar share)
- Dish/Stirling systems (hybrid): 26 to 34 cents€/kWh

All non-hybrid systems show similar LEC ranges. The lowest LEC of about 8 cents€/kWh can be reached with the hybrid CRS, the lowest LEC of the non-hybrid systems is 14 cents€/kWh (CRS using molten salt as HTF). Because of the different states of maturity of the different technologies and the similar LEC, no technology of the non-hybrid systems can be preferred. The hybrid CRS can’t be easily compared to the non-hybrid systems, because at the current status of technology only a solar capacity factor of about 20% is reached. But with its low installation and levelized electricity costs, it is a very attractive solution, especially if the solar share can be increased by further development. Because of the small unit size and the high costs of current Stirling systems, also the dish/Stirling system is hard to compare with the other systems. Its market will be the decentralized electricity production.

Cost reduction potentials by plant upscaling, mass production and technological innovations are in the range of 50 - 60% until the year 2020. This would lead to LEC of PT systems of approximately 7 cents€/kWh in high insulation areas in the year 2020.

The highest CSP potentials are reached in North African countries (20,000 – 100,000 TWh/y, see Figure 5.1), but also in most of the other analysed countries the CSP electricity generation potentials exceed the demand in the year 2030. In total about

600,000 TWh/y are reached in the 24 analysed countries, which is far more than the current world electricity demand of approximate 17,000 TWh/y.

Future Prospects

With its high electricity and cost reduction potentials, CSP could become a main renewable energy technology in the future electricity mix in high insulation areas around the world. The ability to produce power on demand (with thermal energy storages) also contributes to this.

But today the LEC of CSP systems are still too high for an economical production. Until electricity from CSP systems becomes cheaper, it will be necessary to offer adequate financial support as done in Spain with favourable feed-in tariffs to cover the costs of new plants. Reduced financial support should also be provided to hybrid CSP systems since they offer attractive costs and low CO_2 emissions.

As the CSP systems described in this paper are all at different states of maturity but show similar LEC, there will be a need to test the various CSP technologies in order to choose a technology for research and development prioritization.

It might also be a problem that the highest CSP potentials are situated in North African and Middle Eastern countries, which mostly rely on their cheap domestic fossil fuels to generate electricity and have so far less need to invest in the costly CSP systems. So there will be a need to start a process of rethinking in the energy supply of these countries and also for European states – e.g. to offer at least technical support to them. If North African and/or Middle Eastern countries choose to tap their CSP potential, European states could also profit from it by importing clean CSP electricity to the European market.

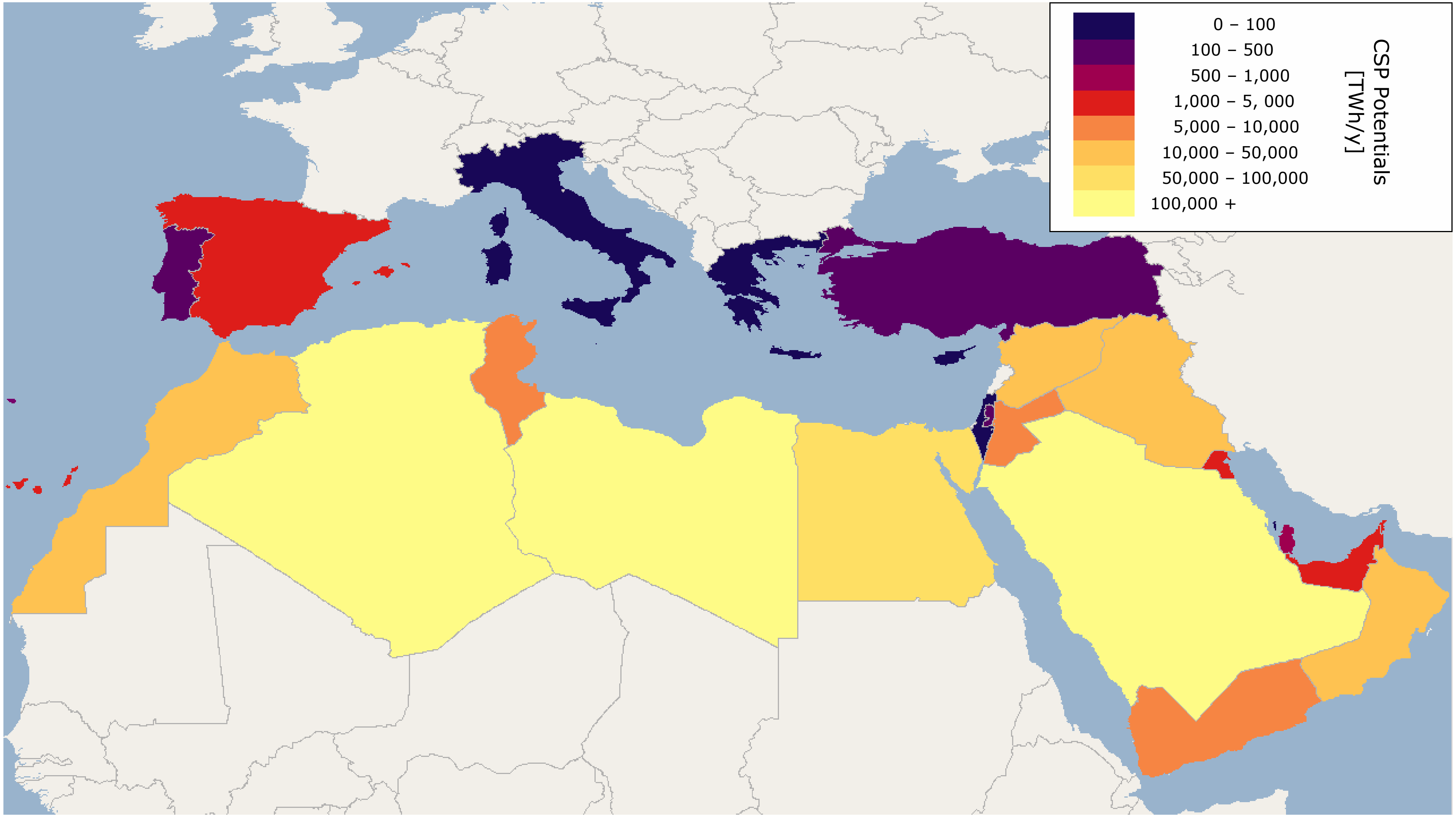


Figure 5.1 Map of the CSP electricity generating potentials in the EU-MENA region

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