Available online at www.sciencedirect.com

SciVerse ScienceDirect

Solar Energy 86 (2012) 520–530

SOLAR ENERGY

www.elsevier.com/locate/solener

Comparative system analysis of direct steam generation and synthetic oil parabolic trough power plants with integrated thermal storage

Jan Fabian Feldhoff [a,*], Kai Schmitz [b], Markus Eck [c], Lars Schnatbaum-Laumann [d], Doerte Laing [e], Francisco Ortiz-Vives [f], Jan Schulte-Fischedick [g]

[a] German Aerospace Center, DLR, Institute for Solar Research, Pfaffenwaldring 38-40, 70569 Stuttgart, Germany
[b] Flagsol GmbH, 50678 Cologne, Germany
[c] DLR, Institute for Solar Research, Stuttgart, Germany
[d] Solar Millennium AG, 91052 Cologne, Germany
[e] DLR, Institute of Technical Thermodynamics, Stuttgart, Germany
[f] Senior Berghöfer GmbH, 34121 Kassel, Germany
[g] Schott Solar CSP GmbH, 95666 Mitterteich, Germany

Received 29 August 2011; received in revised form 25 October 2011; accepted 28 October 2011
Available online 21 November 2011

Communicated by: Associate Editor Robert Pitz-Paal

Abstract

Parabolic trough power plants are currently the most commercially applied systems for CSP power generation. To improve their cost-effectiveness, one focus of industry and research is the development of processes with other heat transfer fluids than the currently used synthetic oil. One option is the utilization of water/steam in the solar field, the so-called direct steam generation (DSG).

Several previous studies promoted the economic potential of DSG technology (Eck et al., 2008b; Price et al., 2002; Zarza, 2002). Analyses' results showed that live steam parameters of up to 500 °C and 120 bars are most promising and could lead to a reduction of the levelized electricity cost (LEC) of about 11% (Feldhoff et al., 2010). However, all of these studies only considered plants without thermal energy storage (TES).

Therefore, a system analysis including integrated TES was performed by Flagsol GmbH and DLR together with Solar Millennium AG, Schott CSP GmbH and Senior Berghöfer GmbH, all Germany. Two types of plants are analyzed and compared in detail: a power plant with synthetic oil and a DSG power plant. The design of the synthetic oil plant is very similar to the Spanish Andasol plants (Solar Millennium, 2009) and includes a molten salt two-tank storage system. The DSG plant has main steam parameters of 500 °C and 112 bars and uses phase change material (PCM) for the latent and molten salt for the sensible part of the TES system. To enable comparability, both plants share the same gross electric turbine capacity of 100 MWel, the same TES capacity of 9 h of full load equivalent and the same solar multiple of the collector field of about two.

This paper describes and compares both plants' design, performance and investment. Based on these results, the LEC are calculated and the DSG plant's potential is evaluated. One key finding is that with currently proposed DSG storage costs, the LEC of a DSG plant could be higher than those of a synthetic oil plant. When considering a plant without TES on the other hand, the DSG system could reduce the LEC. This underlines the large influence of TES and the still needed effort in the development of a commercial storage system for DSG.
© 2011 Elsevier Ltd. All rights reserved.

Keywords: Direct steam generation; Parabolic trough power plant; System comparison; Thermal energy storage; Phase change material storage; Yield analysis

* Corresponding author. Tel.: +49 (0)711 6862 362; fax: +49 711 6862 747.
E-mail address: jan.feldhoff@dlr.de (J.F. Feldhoff).

0038-092X/$ - see front matter © 2011 Elsevier Ltd. All rights reserved.
doi:10.1016/j.solener.2011.10.026

Nomenclature

DETOP	German research project on DSG with thermal storage and optimized main steam parameters	HTF	heat transfer fluid, in this paper used synonymous with synthetic oil
DNI	direct normal irradiance	O&M	operation and maintenance
DSG	direct steam generation	PCM	phase change material (for storage)
FCR	fixed charge rate	PTR	state-of-the-art receiver of SCHOTT
LEC	levelized electricity cost	SCA	solar collector assembly

1. Introduction

A lot of research and development (R&D) projects of industry and research institutes are currently working on finding alternative heat transfer fluids for parabolic trough power plants. The overall plant concept, its operation and maintenance (O&M) effort, its costs and the final determination of the levelized electricity costs (LECs) are important decision criteria for this selection process. In the long run it is expected that plants with large thermal energy storage will have a significant advantage to deliver dispatchable energy compared to other renewable energy technologies.

Besides the state-of-the-art heat transfer fluid (HTF), synthetic oil, two promising concepts are mainly in discussion, molten salts and water. The German research project DETOP is aimed at the detailed analysis of water in the solar field and power block, better known as the direct steam generation (DSG) concept. To look in detail at the long term perspectives, the project especially focused on the integration of TES and the comparison to a state-of-the-art plant with synthetic oil.

In this paper, the methodology of the comparison, the design of systems, their yield and investment analyses, as well as the determination and comparison of the LEC are described.

2. Methodology

The main target of this study is to quantify the economic potential of a DSG power plant with integrated TES. Therefore, the following methodology for a detailed comparison is chosen.

First, two reference systems are chosen. One represents a state-of-the-art parabolic trough power plant with synthetic thermal oil in the solar field and a two-tank molten salt TES. This system is very similar to the configurations in the Andasol plants (Solar Millennium, 2009) and is referred to as oil plant within this paper. The second reference system is a plant applying DSG and using a TES system with molten salt and phase change material. This system will be referred to as reference DSG plant.

The design of both oil and DSG plants are chosen such that

(a) the same electrical gross output is delivered (100 MWel),
(b) the solar field has the same load at design irradiation conditions, and
(c) the same storage capacity in terms of charging hours is assumed (9 h).

Second, for both plants detailed annual electricity yield simulations are performed. Each system is calculated independently by both Flagsol's and DLR's performance tools.

In a third step, Flagsol determined the investment of the plants using the detailed engineering documents developed before. Cost assumptions for the DSG components receiver and flexible tube connections were provided by Schott and Senior Berghöfer.

With the yield results, investment information and O&M assumptions, the LEC were calculated and compared. A further sensitivity study is performed to gain an insight into important assumptions and the influence of possible future developments. A conclusion of the results and an outlook is given at the end of the paper.

3. Main boundary conditions for comparison

To compare different system configurations on the basis of their LEC, the same boundary conditions have to be applied to all analyzed systems. The major boundary conditions and components used are described in the following sections.

3.1. Site

For the comparison irradiation and temperature data of Kramer Junction in California, USA was chosen. A very good year with 2851 W/m^2 of total direct normal irradiance (DNI) was taken for the yield simulations. The distribution leads to a sum of effective DNI, i.e. DNI corrected by the cosine of the incidence angle, of 2517 W/m^2. The sorted distribution of the effective DNI and its clustering in interval frequencies is shown in Fig. 1. One can see that during 523 h the effective DNI was between 850 and 900 W/m^2. The interval between 0 and 50 W/m^2 only includes values greater than 0, such that night times are not included. This irradiation distribution suggests designing the systems for quite high irradiation conditions.

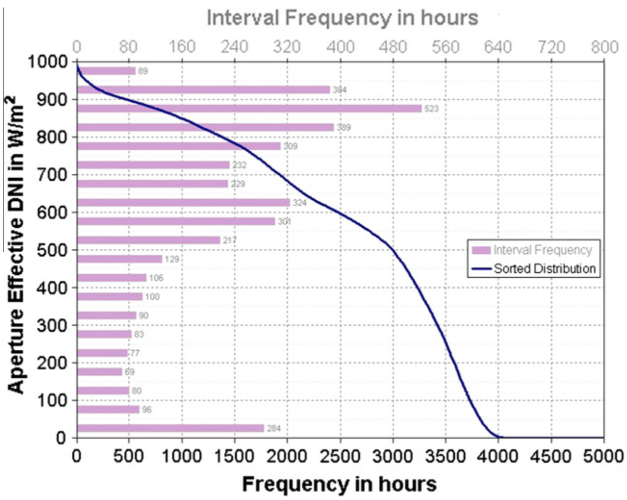

Fig. 1. Annual distribution of aperture effective DNI for the site at Kramer Junction, CA, USA.

3.2. Receiver

In the DSG collector field the pressure level must be chosen such that at the outlet the live steam pressure is available. Schott has developed special receivers for these DSG requirements (Eck et al., 2008b). Therefore, the receivers have been designed to stand a pressure of 150 bars including an allowance for pressure vibrations. Thus, the wall thickness had to be adjusted to the significantly higher pressure. An outer diameter of 80 mm is chosen in this study resulting in similar inner diameters of the PTR 80 DSG as the standard PTR 70 for oil-driven technology. In addition, the coating is developed to stand high temperatures of up to 550 °C.

Different receivers for the evaporator and super-heater part of the DSG collector field are used with steel grades optimized with respect to costs to the different operation conditions.

For the oil and DSG receivers the same coating is assumed, showing an emissivity of 0.1 at a temperature of 400 °C. The oil field runs with PTR-70 receivers, while the DSG field applies PTR-80 DSG receivers with an 80 mm absorber tube diameter. This reduces the pressure losses of the DSG field compared to PTR 70 DSG receivers and leads to a reduced design pressure level.

However, with the same coating assumed, the larger receiver shows a higher length-specific heat loss than the smaller one. The price will also be higher due to increased material and handling effort. However, because of the greater diameter of a PTR-80 receiver, the optical efficiency of the collector is slightly higher.

3.3. Collector

All systems use the same scaled Eurotrough (Skal-ET) collector. Its length is 150 m, its aperture width is 5.76 m and the optical efficiency to an absorber tube with 70 mm in diameter was assumed to be 78%. For a receiver with greater diameter the optical peak efficiency increases to about 78.6% and the incidence angle modifier also improves slightly. This is considered in the simulations.

3.4. Flexible joints

The same boundary conditions as for the receivers exist for the flexible tube connections. Senior Berghöfer has developed a solution with special expansion joints and seals.

In addition to in-house testing, these joints are currently in operation in the project REAL-DISS (Eck et al., 2008a, 2009) by DLR, Flagsol, Schott, Senior Berghöfer, Züblin (all Germany) and Endesa (Spain). At the corresponding test facility in Carboneras, Spain the new joints are tested and evaluated. For the simulations of this study adapted assumptions for the pressure loss and costs were made.

3.5. Financial model

The results of annual yield, operation and maintenance (O&M) costs and investment are merged to one major figure for comparison using the approach of levelized electricity cost (LEC). The LEC of the different systems are calculated according to

$$LEC = \frac{K_a}{W_{net}} = \frac{\mathrm{FCR} \cdot I_0 + k_{O\&M} \cdot A_{SF}}{W_{net}}, \tag{1}$$

with the total annual plant costs K_a, the yearly net electricity production W_{net}, the total net collector area A_{SF}, the area-specific O&M costs $k_{O\&M}$, the initial investment I_0 and the fixed charge rate FCR. The fixed charge rate is the sum of the administration and insurance costs f_{ins} relative to the initial investment and the annuity factor a for capital costs:

$$\mathrm{FCR} = f_{ins} + a; \quad a = \frac{(1+i)^n \cdot i}{(1+i)^n - 1}. \tag{2}$$

The fix values of Eqs. (1) and (2) are specified in Table 1. It is assumed that the power plant is completely debt financed to find a common basis for interest rates i. Although this not true in reality, the variety of financing models and conditions cannot be covered. Varying the fixed charge rate also showed a negligible influence on the comparison (compare Section 6.3).

Values for I_0, $k_{O\&M}$, A_{SF} and W_{net} are dependent on the analyzed system configuration.

Table 1
Parameters for financial model.

Symbol	Name	Value
i	Interest rate	8%/year
n	Depreciation period	20 years
a	Annuity factor	9.4%/year
f_{ins}	Insurance cost (fraction of I_0)	1%/year
FCR	Fixed charge rate	10.4%/year

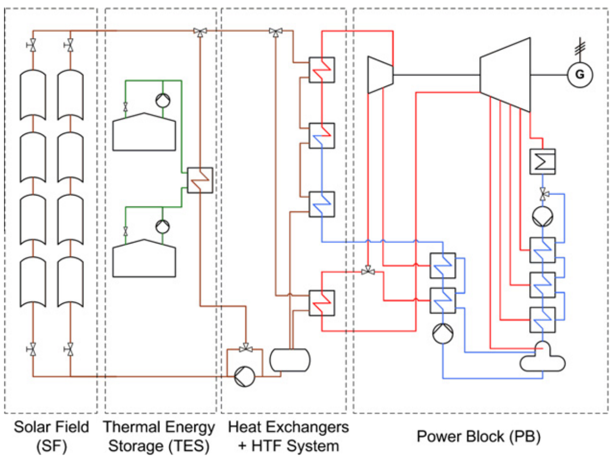

Fig. 2. Scheme of oil plant.

4. Reference system design

For a detailed comparison of the two types of parabolic trough power plants, it is reasonable to design a reference plant for each technology. The chosen designs and their comparison are explained in the following sections.

4.1. Oil power plant

The reference oil plant configuration is in principal similar to the Andasol power plants near Guadix, Spain. A scheme of the plant is shown in Fig. 2. It consists mainly of solar field, TES system, heat exchangers, HTF fluid system and power block. A co-firing or back-up heater is not shown.

In the solar field, the synthetic oil is heated from 295 °C to about 393 °C. The fossil co-firing can be used for electricity production in the Andasol plants, but is only a back-up system for keeping the oil above its minimum allowed temperature in the considered reference plant. The TES is a two-tank molten salt storage system with one hot and one cold tank. The heat exchangers transfer the heat from the oil to the water/steam cycle of the power block.

vvThe Andasol plants have been planned by Flagsol GmbH, providing a good data basis for the performance and investment of such a plant. However, there are a few differences to the Andasol plants. While Andasol has a solar field size of about 500,000 m^2 and 7.5 h TES, the reference plant has 922,000 m^2 and 9 h TES. This is due to the different irradiation conditions in Guadix and Kramer Junction as well as to the different gross capacity of the plants (50 MWel Andasol, 100 MWel reference plant).

4.2. DSG power plant

A schematic diagram of the direct steam generation (DSG) plant is shown in Fig. 3. It consists of the solar field, storage system, back-up heater, and power block. Heat exchangers to the turbine cycle are obviously not necessary for this concept.

Due to the positive experience reported by the European DISS project (Eck and Zarza, 2002), the DSG field is operated in recirculation mode. This means that the solar field is subdivided into an evaporation section and a

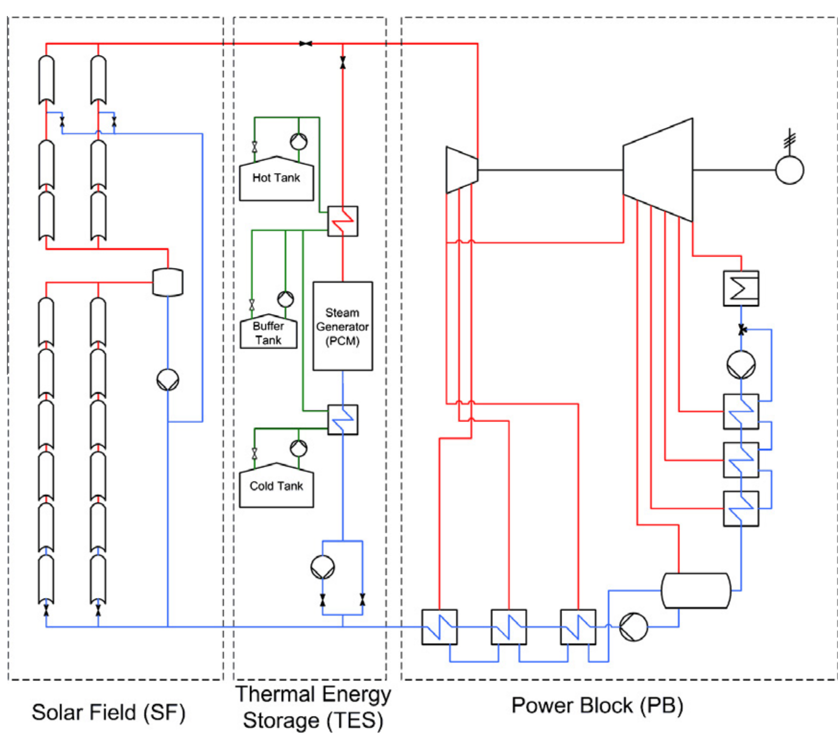

Fig. 3. Scheme of DSG plant.

super-heating section by a water-steam separator. Each evaporation loop consists of six collectors in series, while each super-heating loop has three collectors in series. This arrangement and the number of parallel loops of each section is chosen in order to guarantee a sufficiently low temperature difference within all absorber tube cross sections at a minimized pressure drop over the collector loop.

Within a former project, 500 °C as live steam temperature was identified as a promising option for DSG plants (Feldhoff et al., 2010). Therefore, this temperature is also used in this study. The live steam pressure was chosen to be 112 bars in order to match the boundary conditions of the TES system (Birnbaum et al., 2008). The design steam quality at the outlet of the evaporator section is about 80%. The power block is operated in modified sliding pressure mode to meet TES boundary conditions, i.e. it is operated in sliding pressure mode between 75 and 112 bars and in fixed pressure mode at 75 bars for smaller thermal loads.

The storage system of the DSG reference plant consists of two parts, a sensible part of three molten salt tanks and a latent part with phase change material (PCM). The latent PCM storage uses sodium nitrate ($NaNO_3$) as material, which shows a melting temperature at 306 °C (Bauer et al., 2009).

During TES charging, the super-heated steam from the solar field transfers its heat to the molten salt, which flows from the buffer tank to the hot tank. The steam is then condensed in the PCM storage system, in which the salt melts by the heat. The saturated water from the PCM system transfers its sensible heat to the molten salt flowing from the cold tank to the buffer tank. During discharge the process is run in the opposite direction.

In spite of the lower capacity for preheating the water, a higher salt volume is needed in the cold tank due to the much lower available temperature difference. Therefore, the buffer tank is needed. In the superheating section, the usable temperature difference is about twice that of the oil system, leading to high storage densities and therefore a lower storage volume. In consequence, the hot and cold heat exchangers will have different mass flows, balancing the deviation with the buffer tank.

In general the process can apply different types of sensible storage. However, since the cost basis was more reliable for such a sensible storage system, this configuration was chosen. A more detailed description of the process with concrete storage as sensible part is described in (Laing et al., 2011).

During discharge, the live steam pressure must be reduced to about 78 bars in order to be able to evaporate in the PCM storage aggregate. Therefore, the thermal power to the turbine must be reduced to about 70% of the nominal load.

4.3. Comparison of reference plant designs

The two reference plants have in common that the power block delivers the same gross electricity output of 100 MWel, the solar field thermal load (100%) is the same at the design irradiation conditions and that the storage capacity of 9 h is the same for the storage systems. However, due to the different efficiencies of the system, some differences exist. These differences are summarized in Table 2.

Table 2
Comparison of main reference plant parameters.

	Oil	DSG	DSG to oil
Net aperture (m^2)	922,140	879,090	−5.3%
Gross efficiency (%)	38.3	40.6	+6%
Gross power (MWel)	100	100	Equal
Net power incl. nom. TES charge (MWel)	85.9	92.4	+7.6%
Cooling type	Dry	Dry	Equal
TES capacity (h)	9	9	Equal
Live steam parameters	383 °C/103 bar	500 °C/112 bar	–
TES temperatures in cold/hot tank (°C)	292/386	290/495	–
Receiver type	PTR-70	PTR-80-DSG	–

Because of the different main steam parameters, the power block efficiency of the DSG plant is about 6% higher than the oil plant's power block. Therefore, the nominal heat input is smaller, too, and the solar field area can be reduced. Due to design restrictions and slightly different solar field efficiencies, the solar field size of the DSG system is designed 5.3% smaller than the oil collector field. The net power output at 100% solar field load, i.e. 100% power block load and nominal charge power to the storage system, is 85.9 MWel for the oil and 92.4 MWel for the DSG plant. This shows the about 7.6% higher gross to net efficiency of the DSG system.

As the water consumption of wet cooling poses challenges to water resources in arid areas, the plants considered here already use dry cooling systems. Their efficiency decreases, but water consumption can be significantly reduced.

Both plants can use fossil back-up burners to keep the solar field above the anti-freeze temperature, but not to directly generate electricity. Influence of co-firing is negligible for this study. The power blocks can only be operated between 20% and 100% load. Exceeding energy is either led to TES or dumped. All other important factors like availability, average cleanliness, transmission losses and overhaul periods are the same for both of the systems.

The storage system shows the same nominal charge time capacity, but differs significantly in technology. While the two-tank storage of the oil plant is state-of-the-art, the DSG storage system with PCM and three-tank molten salt storage is more complex. However, compared to other DSG storage options, it is already technically feasible and shows the lowest technical risks at the moment (see Section 6.1).

5. Reference system assessment

The task of the system assessment is the comparison of the systems regarding the electricity yield, the investment and, eventually, the LEC.

Table 3
Annual yield results of reference plants.

	Unit	Mean results DSG	Mean results oil	Flagsol model (%)	DLR model (%)
DNI available	GWh/y	2’489.2	2’629.1	−5.3	−5.3
SF thermal energy	GWh/y	1’037.4	1’115.1	−7.1	−6.9
Gross electricity	GWh/y	405.7	410.7	−1.5	−0.9
Net electricity	GWh/y	371.5	362.1	+2.5	+2.7
Net electricity –offline	GWh/y	367.8	358.1	+2.5	+2.9
Online auxiliaries	GWh/y	29.1	43.1	−33.5	−31.4
Gross full load hours	h	4’057	4’107	−1.5	−0.9
SF mean efficiency	–	41.7%	42.4%	−1.8	−1.6
PB mean gross efficiency	–	39.1%	36.8%	+6.0	+6.4
Net plant efficiency	–	14.9%	13.8%	+8.3	+8.4

5.1. Yield analysis

The main results of the yield analysis are shown in Table 3. As the simulations for each system were performed with two independent models by DLR and Flagsol, only the mean yield is given in the table. Nevertheless, to compare the results between the systems, it is more convenient to take the results of the same model. This avoids comparing possible structural model deviations and leads to a more consistent evaluation. Therefore, in the last columns of Table 3 the comparison of a DSG system to an oil system is displayed for both models.

The available DNI of the systems differ by 5.3% because of the different solar field size. The thermal energy of the solar field is around 1100 GWh/year with about 7% less output from the DSG field. The gross output of the DSG plant is about 406 GWh/year, being 0.9–1.5% less than the oil gross output. Because of the higher gross to net efficiency, at the end of the year the DSG plant generates about 372 GWh/year of net electricity. This is 2.5–2.7% more than the net oil plant’s electricity generation. The online auxiliary demand of the DSG plant is more than 30% lower than the oil plant’s demand due to the significantly lower mass flow and pumping power needed in the solar field.

Looking at the net global electricity generation, i.e. the net electricity reduced by the offline auxiliary demand, the DSG plant increases the output by 2.5–2.9%. The net plant efficiency (without offline parasitic consumption), is expected to be 14.9% for the DSG plant and 13.8% for the oil plant. That is an increase by almost one percentage point or 8.3%.

Drawing a conclusion on the yield results, with a smaller solar field and the same turbine gross power the DSG plant suggests more than 2.5% more net electricity output and an efficiency gain of more than 8.3%.

5.2. Investment analysis

The investments for both of the systems were determined by Flagsol based on basic engineering work. The data for the oil plant is based on Flagsol’s experience with the Andasol plants. Prices for the DSG plant have the same basis when comparable or rely on new and not yet negotiated offers from suppliers. The investments for the PCM storage are estimations by DLR. Table 4 summarizes the results and Fig. 4 shows the relative procurement costs.

The total project investment of the reference DSG plant is about 10% higher than the one of the oil plant. This increase in investment is predominantly driven by two factors, the storage system and the solar field costs.

Although the DSG solar field is 5.3% smaller, its total investment is about 7.5% higher. The reasons for this can be found in the high design pressure, forcing the receivers, valves and piping to be thicker and more costly. Especially the receivers are about 40% more expensive than the oil receivers due to the larger diameter (PTR-80 instead of PTR-70) and greater wall thickness. Header piping costs increase by about 50%, while insulation costs, due to the decrease in piping diameter, are reduced by about 45%.

Table 4
Investments relative to total oil project investment.

Category	HTF (%)	DSG (%)	Diff. (%)
Construction	3	3	−3.8
Solar field	36	39	+7.5
Fluid system (incl. fluid)	7	3	−54.2
TES	14	24	+70.2
Power block and BOP	15	15	−0.7
Procurement/erection	74	83	+11.5
Other costs	26	27	+3.8
Total project investment	100	110	+10.1

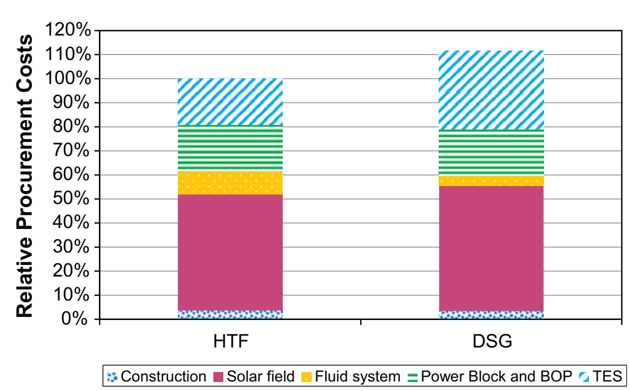

Fig. 4. Procurement cost structure and comparison.

This pressure effect would decrease, if smaller solar fields, with smaller gross capacities, were used. This effect is not equally relevant for an oil field.

Looking at the absolute solar field-related costs, i.e. the two categories solar field and fluid system together, the DSG system shows a slight cost reduction of about 2.5%. Transformed to specific values, this would result in an area-specific increase of about 2% by the DSG system.

The second cost driver of the DSG plant is the thermal energy storage system (compare Fig. 4). The total storage investment increases sharply by over 70% with the assumed costs. Due to the higher temperatures of the hot molten salt tank with about 495 °C, the hot tank's material is significantly more expensive and the specific costs of the molten-salt tank increase. Additionally, the heat exchangers and pumps must be doubled compared to the two-tank solution of the oil plant.

The cost of PCM storage is not yet reliably available. So far, only smaller scale prototypes have been built, not reflecting the costs of a large system. To get a first estimation, DLR scaled up the small scale costs and reduced them by assumptions for expected design and production savings. From the assumed range, costs of the DSG storage system could have a total project's investment share of 21–27% – compared to a TES share of about 14% for the oil plant. However, there is still cost reduction potential for a commercial PCM storage design.

The costs for power block and construction do not differ much. Therefore, without storage the DSG investment would be smaller than the oil investment, while with storage it looks vice versa.

5.3. LEC reference comparison

Based on the annual yield simulations, the investment data, and the prediction of the O&M costs, the LEC can be calculated. The results are shown in Table 5. The LEC of the DSG plant with storage are about 5.9–6.3% higher than the comparable oil reference plant.

This result looks contrary to the expectations and to results gained from a former study without storage (Feldhoff et al., 2010). In the latter a reduction of more than 7% was determined, while in this study with storage an increase of 6% is estimated. The main reason for this contradictory result is the high storage cost of the DSG plant, due to the immatureness of the PCM system.

The comparison here is limited to the reference systems. However, it is important for evaluation to get an insight into its sensitivity and the results for other DSG options. This is performed in the following sections.

Table 5
Main results of reference plant comparison.

	DSG to oil
Total investment	+10.2%
Net electricity generation	+2.4%...+2.9%
LEC	+5.9%...6.3%

6. DSG variants and sensitivity

The task of the system assessment is the identification of the system which shows with a high probability the lowest LEC. Although a quantitative statement on probability levels cannot be given here, some further options are discussed in the following and the influence of certain assumptions is depicted.

6.1. Variants of DSG system

The DSG reference system represents a DSG plant, how it could be build at the moment. Other variations on the system configuration are also possible. These variants include: solar field configuration, solar field layout, solar field operation mode, receiver type, solar field size, storage size and storage system. Starting with the reference system, these aspects are described in more detail.

6.1.1. Configuration

The solar field configuration can be improved by changing the ratio of evaporation to super-heating collector area. If the ratio increases, the efficiency of the solar field also increases. However, it cannot be raised arbitrarily due to control and heat balancing reasons. Increasing the ratio of the reference field from 1.5 to about 1.7 for a new field, leads to a higher efficiency with negligible control and distribution changes. The field efficiency and with it the net electricity output could be improved by 0.3% with this option.

6.1.2. Layout

The recirculation mode of the DSG solar field requires a central field separator and connection piping from and to it. By designing a different subfield layout with shorter connection piping, the pressure losses could be reduced significantly compared to the reference layout. This would reduce the design pressures and also the investment. The LEC reduction potential of this variant was not assessed in detail.

6.1.3. Concept

The recirculation mode with its central separator suffers from an additional piping pressure loss. This limits the maximum practicable solar field size for a DSG system. Pressure losses could be reduced using the once-through mode, which pre-heats, evaporates and super-heats the steam in one loop without any separation device. It is described in more detail in (Eck and Zarza, 2002). However, problems with this mode are under assessment, but have not been solved yet. First estimations suggest that a once-through mode field could increase the electricity output by about 4% compared to a recirculation field. The specific investment could also be over 3% lower. Assuming about 25% increased O&M costs for higher uncertainties in control and higher component replacement rates, the LEC still could be more than 4% below those of a recirculation plant.

6.1.4. Receiver

The DSG reference plant applies Schott PTR-80 DSG receivers. Using a PTR-70 DSG receiver would, on the one hand, lead to lower heat losses. On the other hand, the optical efficiency is reduced, pressure losses are increased and pump consumption is higher. At the design point, the reduced heat losses and the decreased optical efficiency almost totally compensate each other. The annual net electricity output only differs by 0.2% and is lower for the PTR-70 variant. This is due to higher pressure losses of about 10 bars at the design point. It must be stressed that this pressure increase is not compatible with design pressure levels. Neglecting this fact could reduce the LEC by 1%, mainly due to the lower price for a PTR-70 than for a PTR-80. It was not further investigated, which consequences the needed design pressure increase would have for the investment, since critical components are not available for such pressures. It is doubted that the PTR-70 design would be cheaper for a plant of such a size. Nevertheless, for small solar fields the pressure level could remain under the current limit and the PTR-70 option could lead to very small cost advantages.

6.1.5. TES system

The main cost driver of the reference DSG plant is the storage system. Due to the characteristics of the DSG concept, PCM storage seems the only reasonable way for evaporation/condensation storage, i.e. charging and discharging with two-phase flow media. The main configuration changes are therefore limited to the sensible part or to the different usage of the PCM storage system. In Fig. 5 three different storage options (a–c) are depicted and described in the following:

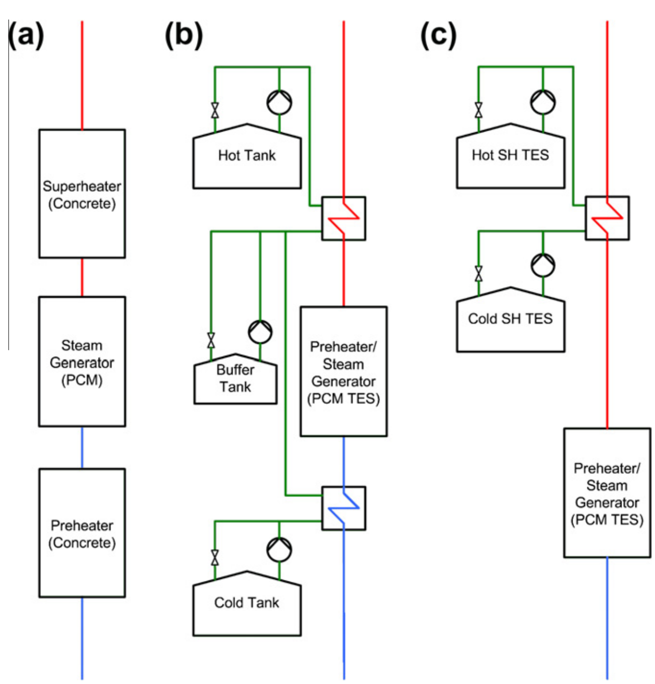

Fig. 5. Selected DSG storage options.

(a) One option is the usage of concrete storage for the sensible parts (Fig. 5a). The advantage of such a system is that no additional active components like pumps are needed. A disadvantage is that the achievable outlet temperature during discharge depends on the remaining 'fill level' or the energy still useable in the storage, respectively. Characteristics of this storage option are currently investigated by DLR and Züblin at a test facility in Carboneras, Spain (Laing et al., 2011). Simulations for this option have not been performed within this study.

(b) The reference storage configuration in Fig. 5b uses a three-tank sensible system with a buffer tank as described in the reference plant section. The advantage is the good controllability of the process and especially the achievable constant outlet temperature during discharge. However, many active elements are needed and three tanks increase the specific investment.

(c) This option (Fig. 5c) is the currently favored design for a high temperature system. PCM storage is not only used for condensation/evaporation, but also for subcooling/preheating. The de-/superheating of the steam is performed by a two-tank molten salt system. This system has not been demonstrated so far, but its operation is not supposed to cause any problems in a modular PCM storage design. Compared to the oil system's storage, the specific investment of this two-tank variant differs due to two main effects. First, it is reduced due to the higher temperature difference. Second, it is increased by the use of more expensive material for the hot storage tank and heat exchangers. Compared to the three-tank option, option c offers high reduction potential as the specific investment for the PCM system also decreases, while the absolute size of the system is expected to be the same.

Concluding the storage system design, option c looks most promising at the current development status. Assuming, as a first estimation, equal specific costs for superheating two-tank storage as for two-tank oil system storage (considering the two opposite effects temperature difference and material) and the same PCM storage costs would result in a reduction of about 1.3% in total LEC of the reference system. Detailed offers for such a system would be necessary to verify or adapt this influence.

6.1.6. TES size

For the DSG system, the storage size for the reference systems was adapted to the needs of the oil plant and the solar field size was chosen to match the same thermal load as the oil field. Due to the differing costs of the subsystems, the economical optimum DSG system size will differ from an optimum oil size. This effect can be shown by either varying the solar field or the storage size. Keeping the same solar field size and varying the storage size using the same specific costs, yields the results shown in Fig. 6. Due to the

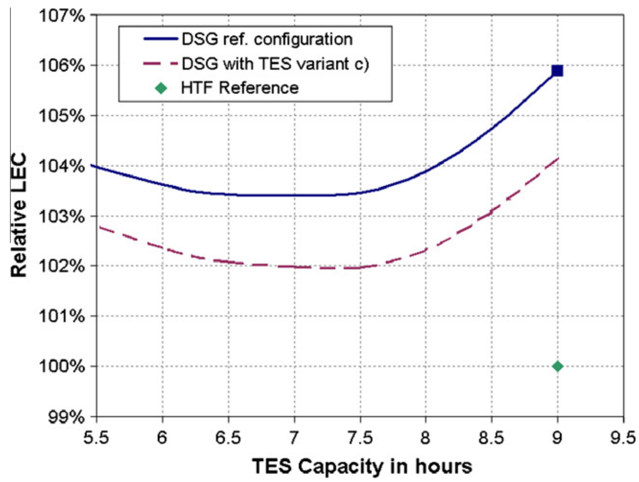

Fig. 6. Influence of DSG storage size variation on LEC.

high storage costs, a smaller size seems more favorable and could reduce the LEC by more than 2%. It is important to note, though, that the assumption of constant specific costs proofed not correct, neither for DSG storage nor for oil system storage. Therefore, only the trend of storage size reduction seems reliable.

6.1.7. Main steam temperature

It is also important to note that the live steam temperature for a DSG system should be optimized under the condition of temperature-variable storage costs. In a former study the influence of the main steam temperature was only analyzed for a system without storage. Including storage data could lead to lower or even higher temperatures that would be beneficial for such DSG plants. At the moment, this influence is not quantifiable.

6.2. System without storage

As mentioned in Section 5.3, for a system without storage a significant cost reduction by the DSG plant was expected. To check the general assumptions of this study, a system comparison without storage was also performed.

The main boundary conditions are kept constant, i.e. the gross capacity of the turbine, dry cooling, gross efficiencies and solar field thermal load at design point are the same as for the reference plants. The net solar field sizes are chosen to 575,520 m^2 for the oil plant and 529,740 m^2 for the DSG plant. The net electricity generation at design point is then 91.9 MWel and 94.1 MWel, respectively.

Main results are shown in Table 6. The yield analysis is again performed with the two independent tools by DLR and Flagsol. The gross electricity production is again smaller for the DSG system, with an average of 227.5 GWh/year. This is, depending on the tool, 0.5–1.6% less than the oil plant's output. The net electricity production to the grid is for both systems slightly above 200 GWh/year, with the DSG system performing 0.7–3.1% better than the oil system. The mean net plant efficiency of the DSG plant would be 13.9%, while the oil plant would only show a net plant efficiency of 12.6%.

Table 6
Main results of reference plant comparison.

	DSG to oil
Total investment	−5.8%
Net electricity generation	+0.7%...+3.1%
LEC	−5.5%...−7.7%

The total investment of the plant is again based on a basic engineering and results in an about 5.8% cheaper DSG system. Especially the total DSG solar field costs 1.3% less than the oil field. Based on the solar field aperture this is an increase of about 7% – while for the reference plant, with almost twice the area, an area-specific increase of 13% was determined. This shows the sensitivity of the DSG solar field cost to solar field size and ratio of evaporation to super-heating area. Costs for fluid system and fluid can also be reduced by almost 50%.

The LEC of the DSG system are then about 5.5–7.7% lower than the LEC of the oil system. This emphasizes again the influence of the storage system on the DSG system's cost effectiveness. It also supports the main results of (Feldhoff et al., 2010), although the potential in the study presented here seems slightly lower than assumed. Of course, these results vary with different cost assumptions, but would more or less support the general trend.

6.3. Sensitivity of comparison and variants

Fig. 7 shows a sensitivity study for some selected aspects, starting from the reference system comparison including storage with about 5.9% higher LEC of the DSG system (simulation with DLR tool). LEC parity would be reached, if the total procurement costs of the plant were about 6% lower. Assuming other financial conditions, i.e. a different fixed charge rate (FCR), has negligible influence on this comparison. The total uncertainty of the results originating from price and simulation

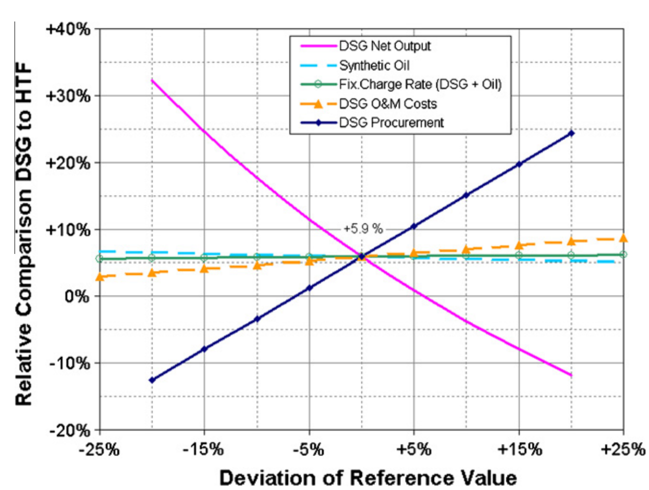

Fig. 7. Sensitivity analysis for selected influence factors.

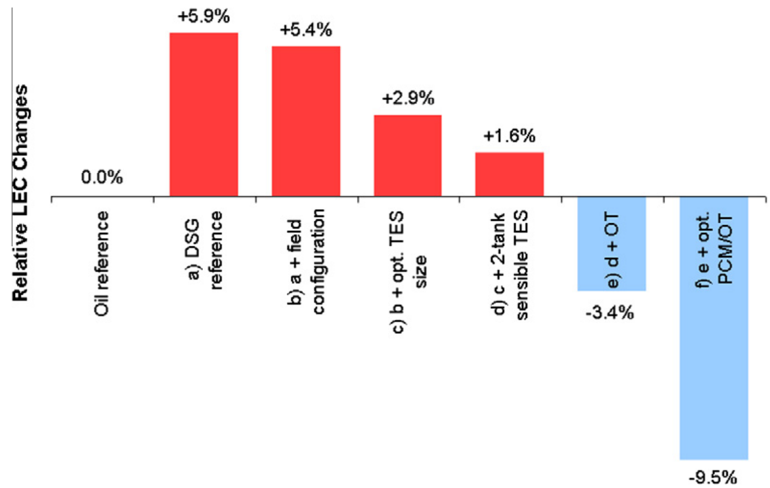

Fig. 8. LEC changes by different DSG options compared to oil reference (TES = storage, OT = once-through mode, PCM = PCM storage).

assumptions could lead to either 8% lower LEC or 17% higher LEC of the DSG plant.

Start-up procedures and times of the two systems are not investigated in detail for this study. They could – but not necessarily do – lead to changes in the comparison. Start-up optimization is a crucial topic under investigation, though not quantifiable at the moment.

The increase in LEC with integrated TES is a drawback for the DSG market development. However, sensitivity analyses show that the result of the reference system is not necessarily true in general and that the distance to the oil system's LEC is lower, when simple design changes are applied (Sections 6.1 and 6.2).

Fig. 8 shows the main measures to decrease the LEC of the DSG system. As the results are based on further yield analyses, the values shown represent annual yield calculations by DLR only. By simple design changes the difference in LEC can be reduced to a level which would be only 1.6% more than the oil reference.

Starting from the reference system (+5.9%), the solar field configuration can be adapted such that a better ratio of evaporator to superheater sections is applied (+5.4%). Variations of the TES system's capacity showed that – as a consequence of the high TES costs – a smaller capacity is of advantage for the DSG system. This optimum would be in the range of 7–8 h rather than at 9 h of equivalent storage capacity (+2.9%). A further reduction of TES cost might be possible, if the PCM system is used for preheating as well as evaporation, and if a simple two-tank system is applied for the superheating section only (+1.6%). This should be assessed in more detail than it was possible within this study. By the storage design changes, a significant LEC reduction is already possible.

Looking at future developments on the solar field part, two options should be assessed. One is to further optimize the recirculation mode and analyze, if design changes are possible to reduce costs further. The other option is the assessment of the once-through concept for DSG. First estimations show that a reduction of LEC compared to the oil plants would be feasible (variant e). However, this must be analyzed further in detail, and especially the process challenges must be solved for this operation mode.

To give a development goal for the PCM storage in the long run, an LEC reduction by more than 9% compared to the oil system could be achieved for the DSG system with storage, if the investment for the PCM storage system reaches about 50 €/kWh.

7. Conclusions and outlook

This paper presents the system comparison of two reference parabolic trough plants with integrated thermal energy storage (TES), one using the state-of-the-art synthetic oil and one using direct steam generation (DSG). Both systems have a 100 MWel gross turbine and a 9 h storage capacity. While the efficiency of the DSG plant is about 8% better, its project investment is about 10% higher. This causes about 6% higher levelized electricity costs (LECs) of the DSG system. The main reasons for the significantly higher investment are the specific solar field costs and the storage costs. If both issues are optimized by simple, already feasible means, the LEC increase is decreased to about 2%.

DSG solar fields with recirculation mode are limited in size due to the high design pressure and resulting limits of critical components and header piping. Reducing the field size, e.g. to meet a size comparable to an Andasol plant, is therefore advantageous. The trend that smaller DSG plants are probably more cost effective than larger plants is in contradiction to the trend of current oil plant projects looking at capacities of 250–1000 MWel. However, whether e.g. two 50 MWel DSG plants would operate with lower LEC than one 100 MWel oil plant was not investigated in this study.

The second and main cost driver of the reference DSG plant is the storage system. A storage system with a three-tank molten salt sensible part and a PCM part was chosen for the main comparison. Especially the PCM storage system is not yet commercially available.

Therefore, the uncertainty in cost assumptions is quite high. Nevertheless, it is obvious that still a lot of research and cost reduction effort is needed to make the DSG storage system competitive. Apart from research, reducing the TES costs is possible by optimizing storage capacity (e.g. to 7–8 h, which is lower than that of an optimum oil plant) and changing the system approach (using PCM storage for evaporation and preheating, and a two-tank molten salt system for the superheating part).

Applying all measures would, nevertheless, still result in a slightly higher LEC. In order to be able to evaluate this outlook in more detail, the approach of a simple cost assumption should be replaced by a probabilistic approach similar as suggested in (Ho et al., 2011). This will be included in future studies.

In addition, two main research topics are identified that could make DSG plants with TES competitive:

- Development of once-through concept.
- Development/market introduction of PCM storage.

First assumptions show that with the once-through concept the LEC could be more than 3% lower than the oil system's LEC. However, this concept is complex to control, results in higher thermal stresses in the receivers at certain parts of the loops and no long term experience is available. More research is needed in this field and DLR will start a project dedicated to this topic.

Further research for high temperature PCM storage is a pre-requisite for DSG success. Also suitable manufacturers for PCM storage modules should be identified and included in the process to enable a fast, effective commercial introduction. With ambitious targets for PCM costs, a DSG plant could reach about 9% LEC reduction compared to an oil plant. DLR will also continue its work on this topic.

Further, but not yet quantifiable, potential is seen in the parameter optimization of the whole system. Former studies focused on temperature optimization for systems without TES. These results could change, if TES system costs are included.

As a DSG plant without storage shows already about 5–8% lower LEC than an oil plant, these plant types are already competitive. These plants could also afford to apply a small DSG storage system. This also makes the coupling to conventional plants as a solar 'fuel saver' an attractive market for DSG application. However, in the long run, solar thermal power plants should develop in the direction of constant electricity production with a thermal storage as prerequisite. Introducing storage with larger capacities to DSG currently makes this system less attractive.

Therefore, other options should also be investigated in detail. Looking at parabolic troughs, using molten salt as heat transfer medium offers the advantage of direct storage. This system looks promising, with expected LEC reductions similar to those expected in first DSG papers, but poses various problems to the system design (Kearney et al., 2003, 2004). For a reliable long term system evaluation, a detailed comparison of molten salt, oil and DSG must be performed including thermal energy storage and a reliable cost basis.

Acknowledgements

The authors would like to thank the German Ministry for the Environment, Nature Conservation and Nuclear Safety for the financial support given to the DETOP Project (Contract Nos. 0325164A-E).

References

Bauer, T., Laing, D., Kröner, U., Tamme, R., 2009. Sodium nitrate for high temperature latent heat storage. In: Proceedings of the 11th International Conference on Thermal Energy Storage (EffStock), Stockholm, Sweden.

Birnbaum, J., Eck, M., Fichtner, M., Hirsch, T., Lehmann, D., Zimmermann, G., 2008. A direct steam generation solar power plant with integrated thermal storage. In: Proceedings of the 14th Bienial SolarPACES Symposium, Las Vegas, USA.

Eck, M., Zarza, E., 2002. Assessment of operation modes for direct solar steam generation in parabolic troughs. In: Proceedings of the 11th CSP SolarPACES Symposium, Zurich, Switzerland.

Eck, M., Bahl, C., Bartling, K.-H., Biezma, A., Eickhoff, M., Ezquierro, E., Fontela, P., Hennecke, K., Laing, D., Möllenhoff, M., Nölke, M., Riffelmann, K.-J., 2008a. Direct steam generation in parabolic troughs at 500°C – a German–Spanish project targeted on component development and system design. In: Proceedings of the 14th Biennial CSP SolarPACES Symposium, Las Vegas, USA.

Eck, M., Benz, N., Feldhoff, J.F., Gilon, Y., Hacker, Z., Müller, T., Riffelmann, K.-J., Silmy, K., Tislaric, D., 2008b. The potential of direct steam generation in parabolic troughs – Results of the German Project DIVA. In: Proceedings of the 14th Biennial CSP SolarPACES Symposium, Las Vegas, USA.

Eck, M., Eickhoff, M., Fontela, P., Laing, D., Meyer-Grünefeldt, M., Möllenhoff, M., Nölke, M., Ortiz-Vives, F., Riffelmann, K.-J., Sanchez-Biezma, A., Bahl, C., 2009. Test and demonstration of the direct steam generation (DSG) at 500 °C. In: Proceedings of the 15th CSP SolarPACES Symposium, Berlin, Germany.

Feldhoff, J.F., Benitez, D., Eck, M., Riffelmann, K.-J., 2010. Economic potential of solar thermal power plants with direct steam generation compared with HTF plants. Journal of Solar Energy Engineering 132, 041001–041009.

Ho, C.K., Khalsa, S.S., Kolb, G.J., 2011. Methods for probabilistic modeling of concentrating solar power plants. Solar Energy 85, 669–675.

Kearney, D., Herrmann, U., Nava, P., Kelly, B., Mahoney, R., Pacheco, J., Cable, R., Potrovitza, N., Blake, D., Price, H., 2003. Assessment of a molten salt heat transfer fluid in a parabolic trough solar field. Journal of Solar Energy Engineering 125, 170–176.

Kearney, D., Kelly, B., Herrmann, U., Cable, R., Pacheco, J., Mahoney, R., Price, H., Blake, D., Nava, P., Potrovitza, N., 2004. Engineering aspects of a molten salt heat transfer fluid in a trough solar field. Energy 29, 861–870.

Laing, D., Bahl, C., Bauer, T., Lehmann, D., Steinmann, W.-D., 2011. Thermal energy storage for direct steam generation. Solar Energy 85, 627–633.

Price, H., Lupfert, E., Kearney, D., Zarza, E., Cohen, G., Gee, R., Mahoney, R., 2002. Advances in parabolic trough solar power technology. Journal of Solar Energy Engineering 124, 109–125.

Solar Millennium, 2009. The parabolic trough power plants Andasol 1 to 3 – The largest solar power plants in the world – Technology premiere in Europe. Solar Millennium Report, Erlangen, vol. 26.

Zarza, E., 2002. DISS Phase II Final Report. CIEMAT-PSA Report, EU Contract No. JOR3-CT98-0277, Almeria, Spain.