Comparative System Analysis of Parabolic Trough Power Plants with DSG and Oil using Integrated Thermal Energy Storage

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Abstract

In addition to the commercial parabolic trough power plants using synthetic oil, the direct steam generation (DSG) is one option for future trough plants. Besides its higher efficiency and lower environmental impact, the overall levelized electricity costs (LEC) will be decisive for the future application of DSG. This paper focuses on the thermodynamic and economic comparison of synthetic oil and DSG plants including the aspect of thermal energy storage – which gains more and more in importance by industry and investors.

Nomenclature

DETOP	German research project on DSG with thermal storage and optimized main steam parameters
DISS	Direct Solar Steam
DNI	Direct Normal Irradiance
DSG	Direct Steam Generation
FCR	Fixed Charge Rate
LEC	Levelized electricity cost
HTF	Heat transfer fluid, in this paper used synonymous with synthetic oil
O&M	Operation and maintenance
PCM	Phase change material
PTR	State-of-the-art receiver for parabolic troughs of SCHOTT
TES	Thermal energy storage

1. Introduction

At the moment most of the commercial parabolic trough power plants use synthetic oil as heat transfer medium. One alternative process is the direct steam generation (DSG), which was tested at the DISS test facility in Almería, Spain [1] and is currently built commercially for the first time with parabolic troughs in Thailand [2].

Several previous studies promoted the economic potential of DSG technology [3-5]. 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) by about 11% [6]. However, all of these studies only considered power plants without thermal energy storage (TES).

Therefore, a comparative system analysis including integrated TES was performed within the German research project DETOP by Flagsol GmbH and DLR together with Solar Millennium AG, Schott CSP GmbH and Senior Berghöfer GmbH. Two types of plants are analyzed and compared in detail: a power plant with synthetic oil (Fig. 1) and a DSG power plant (Fig. 2). The design of the synthetic oil plant is chosen very similar to the Spanish Andasol plants [7] 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. Components for such a plant are currently tested at the REAL-DISS test facility in Carboneras, Spain [8-9].

This paper describes and compares both plants' design, annual performance and investment. Based on these results, the LEC are calculated and the DSG plant's long-term potential is. Furthermore, consistency with former studies is discussed.

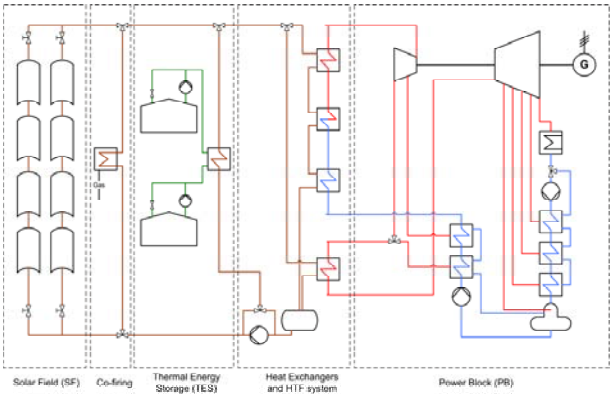

Fig. 1. Scheme of oil plant.

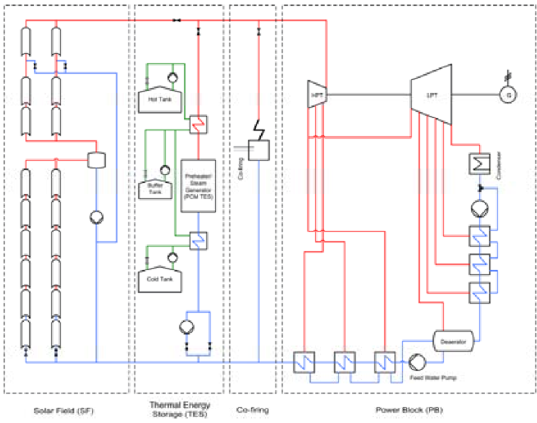

Fig. 2. Scheme of DSG plant

2. Boundary Conditions for Comparison

To compare different system configurations, it is most important that the same boundary conditions are applied to all analyzed systems. The predominant boundary conditions and components used are described in the following sections.

2.1 Design Parameters

Both assessed plants share three key design parameters:

- the same gross electric turbine capacity of 100 MW_{el},
- the same TES capacity of nine hours of full load equivalent and
- the same solar multiple of the collector field of about two.

The same electric gross capacity (instead of the same solar field size) was chosen to have comparable gross annual yields and power block constraints. However, due to the different power block efficiencies of the oil and DSG plants, the same gross power output means a smaller DSG solar field and a higher net electricity output. The same TES capacity also results in a smaller absolute amount of thermal energy stored in the DSG case.

2.2 Site

For the comparison irradiation and temperature data of Kramer Junction in California, USA is used. A very good year with 2851 W/m² of total direct normal irradiance (DNI) was taken for the yield simulations. The sum of effective DNI, i.e. DNI corrected by the cosine of the incidence angle, is 2517 W/m² for that year (see Figure 1 for sorted distribution). During 523 hours the effective DNI is between 850 and 900 W/m², which suggests designing the systems for quite high irradiation conditions.

2.3 Main Components

Receiver

The synthetic oil plant applies standard PTR-70 receivers, while for the DSG plant PTR-80-DSG receivers are used. To get comparability, both plants use the same coating, i.e. absorber surface specific heat losses. This coating is developed to stand high temperatures of up to 550°C to be used for DSG plants and shows an emissivity of 0.1 at a temperature of 400°C.

The DSG receivers have also 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 as of the standard PTR-70 for oil-driven technology. 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.

With the same coating assumed, the larger PTR-80 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.

Collector

All solar fields 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 %, based on the net aperture area of 817.5 m². For a receiver with greater diameter the optical peak efficiency increases to about 78.6 % and the incidence angle modifier also improves slightly.

Flexible joints

The same DSG boundary conditions as for the receivers exist for the flexible tube connections, i.e. high pressures and temperatures. Senior Berghöfer has developed a solution with special expansion joints and seals, called Rotationflex-EJ©. In addition to in-house testing, these joints are currently tested and evaluated in the project REAL-DISS [8, 10] by DLR, Flagsol, Schott, Senior Berghöfer, Züblin (all Germany) and Endesa (Spain) at the corresponding test facility in Carboneras, Spain.

2.4 LEC 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

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

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 relative to the initial investment and the annuity factor a for capital costs:

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

The fix values of equations (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 with sensitivity analysis below).

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

Tab.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

2. Reference System Design

A coherent design of the plants is a prerequisite for system comparison. Therefore, the design aspects are described and compared in the following sections. A more detailed description can be found in [11]. General factors like availability, average cleanliness of the mirrors, transmission losses and overhaul periods are chosen the same for both systems.

2.1 Power Block

The power blocks of both systems have a nominal capacity of 100 MW_{el} gross and use a dry cooling system. The oil system applies a power block with 383°C and 103 bars main steam parameters. As the DSG system is not limited to the same temperature, it applies parameters of 500°C and 112 bars. The power block is operated in modified sliding pressure mode to meet the boundary conditions of the TES [12], 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. Due to different main steam parameters, the gross efficiencies of the power block differ significantly. The power block of the DSG system is about 6% more efficient. 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 MW_{el} for the oil and 92.4 MW_{el} for the DSG plant. This underlines the significantly higher net efficiency of a DSG system. The power blocks are assumed to be operated only between 20 % and 100 % thermal load. Exceeding energy is either led to TES or dumped.

2.2 Solar Field

The solar field of the oil plant consists of 922,140 m² of net aperture area, which corresponds to 282 loops with 4 collectors each. The synthetic oil is heated from 295°C to about 393°C. Due to the higher power block efficiency, the DSG solar field can be chosen more than 5% smaller, with a total aperture area of 879,000 m². The DSG solar field is operated in recirculation mode [13], with six collectors in series in the evaporation section and three collectors in series in the superheating section. The feed water from the power block has a temperature of about 295°C and is superheated to about 500°C at the outlet. Both solar fields are designed for the same solar multiple close to 2.

2.3 Thermal Energy Storage

The thermal energy storage (TES) systems of both plants are designed for a nominal thermal charging capacity of 9 hours. As the nominal thermal power depends on the gross electric capacity and the gross efficiency, the absolute TES capacity is slightly smaller for the DSG system. The oil plant uses a two-tank molten salt storage system, e.g. as applied in the Andasol plants.

The DSG reference system consists of a combination of sensible and latent heat storage (see Fig. 2). The latent phase change material (PCM) storage uses sodium nitrate ($NaNO_3$) as material, which has a melting temperature of 306°C [14]. This storage is used for evaporation and condensation, respectively. To reach an appropriate temperature difference between saturation temperature and PCM, during charging a main steam pressure of about 110 bars and during discharging a pressure of about 78 bars is to be applied on the water/steam side. Therefore, during discharge, the thermal power to the turbine is reduced to about 70 % of the nominal load.

The preheating and superheating sections of the TES system use a three-tank molten salt assembly. The concept equals the two-tank concept of the oil system, but using a buffer tank at the medium temperature level (corresponding to the melting temperature of the PCM storage).

Tab.2. Comparison of reference system designs.

	Unit	DSG Plant	HTF Plant
Net aperture in m²	922,140	879,090	-5.3 %
Gross efficiency in %	38.3	40.6	+6 %
Gross power in MW_{el}	100	100	equal
Net power (incl. nom. TES charge) in MW_{el}	85.9	92.4	+7.6 %
Cooling	dry	dry	equal
TES capacity in hours	9	9	equal
Live steam parameters	383°C/ 103 bar	500°C/ 112 bar	-
TES temperatures in cold/hot tank in °C	292/386	290/495	-

3. Reference System Assessment

The system assessment is divided into three parts, the annual yield analysis, the investment estimation and the determination of the levelized electricity costs (LEC).

3.1 Annual Yield

The annual yield analysis was performed with two independent tools by Flagsol and DLR for both plants. The results are listed in Tab. 3. The annual yield results are shown as average value from both tools. In addition, the comparison is made based on simulations with one tool, e.g. the deviation between DSG and oil is not given for the average, but for the Flagsol model results. This allows a better comparability by avoiding considering general approach deviations between the models.

Tab.3. Comparison of reference system annual yield results.

	Annual Yield			Comparison DSG to Oil	
	Unit	**DSG Plant**	**HTF Plant**	**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 output	**GWh/y**	**405.7**	**410.7**	**-1.5%**	**-0.9%**
Net electricity output	GWh/y	371.5	362.1	+2.5%	+2.7%
Net electricity global	**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%

Due to the different solar field size, the available DNI of the systems differ by 5.3 %. Therefore, also the thermal energy of the solar field is about 7 % less from the DSG field. The gross output of the DSG plant is about 406 GWh/year, being 0.9 to 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 to 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 % to 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%.

Summing up, the DSG plant shows more than 2.5 % more net electricity output and an efficiency gain of more than 8.3 % compared to the oil system with a larger solar field and the same turbine gross capacity.

3.2 Investment

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 system are estimations by DLR.

Figures 3 and 4 show the investment structures of the plants. The solar field share is the largest for both plants and is between 45% and 48%. Power block and BOP have a share of about 18% to 20%. The big difference in investment lies in the costs for the thermal energy storage system. While TES is only about 20% for the oil plant, the more complex DSG storage system takes a share of almost 30% of direct investment costs. This can only slightly be compensated by a smaller share of fluid system costs.

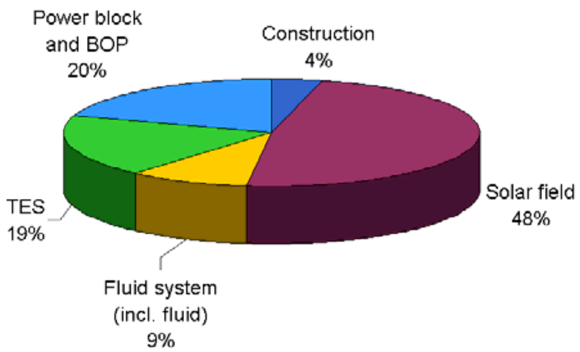

Fig. 3. Investment structure of oil plant.

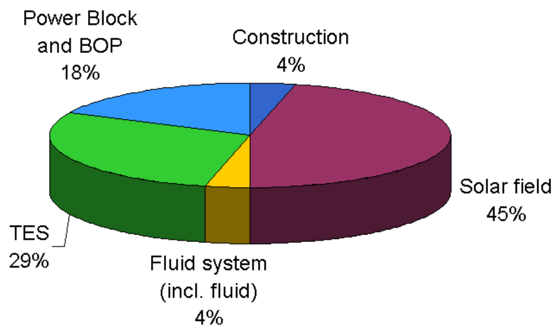

Fig. 4. Investment structure of DSG plant

Table 4 lists the shares of the total project costs in more detail. With the cost assumptions made, 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 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 and design temperature, resulting in greater wall thicknesses and partly higher grade materials for the components. 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 %. The design pressure effect would decrease, if smaller solar fields – and in consequence smaller electric capacities – were applied.

Looking at the absolute costs related to the solar field, i.e. the two categories solar field and fluid system together, the DSG system shows a slight cost reduction of about 2.5 %. Referring this to an area-specific value, the DSG solar field is about 2 % more expensive per square meter than the oil field.

The second and main cost driver of the DSG plant is the thermal energy storage system. The total storage investment increases significantly 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. However, there is still cost reduction potential for a commercial PCM storage design.

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

Tab.4. Comparison of reference systems' investment structure.

	HTF Plant	**DSG Plant**	**Difference DSG to Oil**
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%**

3.3 LEC

The LEC of the systems are used for an overall comparison. Based on the determined annual yield and investments, the LEC can be calculated using a prediction of the operation and maintenance (O&M) costs. The results are shown in Table 5. The LEC of the DSG plant with storage are then about 5.9 to 6.3 % higher than the comparable oil reference plant.

The main reason for this increase in LEC is the high storage cost of the DSG plant due to the immatureness of the PCM system. Although the PCM storage system will most likely stay more expensive than a simple two-tank solution, the cost difference to the oil system could be reduced, if research and industry will effectively work together on the open issues – or could be even higher, if this is not done. To evaluate the outlook for PCM development in terms of LEC, a probabilistic approach for an investment range (rather than a single cost value) would be suited better and will be added to the comparison in the future.

Tab.5. Comparison of the LEC for the reference systems with TES.

	Difference DSG to Oil
Total investment	+10.2%
Net electricity generation	+2.4 … +2.9%
LEC	+5.9% … 6.3%

3.3 Comparison to Former Studies

The increase in LEC by the introduction of DSG looks contrary to the expectations and to results gained from a former study without storage [6]. In the latter a reduction of more than 7 % was determined, while in this study with storage an increase of 6 % is estimated. To check the comparability, another system assessment was performed without storage, but apart from that with the same boundary conditions as for the reference systems described above.

The yield analysis is again performed with the two independent tools by DLR and Flagsol. The gross electricity production is smaller for the DSG system, with an average of 227.5 GWh/year. This is, depending on the tool, 0.5 % to 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 % to 3.1 % better than the oil system.

The total investment of the plant is 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 (without fluid system). This shows the sensitivity of the DSG solar field cost to solar field size. Costs for fluid system and fluid can be reduced by almost 50 %.

The LEC of the DSG system are then about 5.5 to 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 [6], while obviously the results vary with different cost assumptions for different components. The general trend, that DSG can reduce LEC for systems without storage, is supported.

4. Sensitivity and Outlook

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.

Figure 5 shows the main measures to decrease the LEC of the DSG system. As the results are based on further yield analyses, the figures shown represent annual yield calculations by DLR only. By simple design changes (red bars) 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 to 8 hours rather than at 9 hours 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.

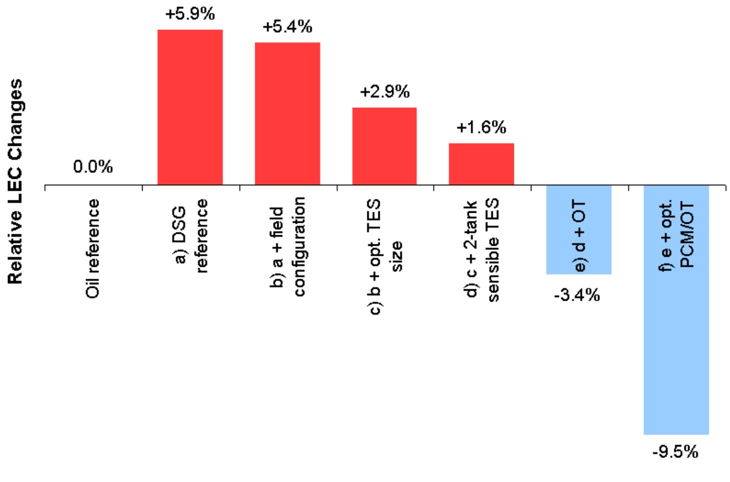

Fig. 5. LEC changes by different DSG options compared to oil reference (TES = storage, OT = once-through, PCM = PCM storage).

Looking at future developments on the solar field part, two options should be assessed. One is to further optimize the recirculation mode and analyse, if design changes are possible to reduce costs further. The other option is the assessment of the once-through concept [13] for DSG. First estimations show that a reduction of LEC compared to the oil plants would be feasible (variant e). However, this must be analysed 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.

4. Conclusions and Consequences

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 MW_{el} gross turbine and a 9 hours 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 (LEC) 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 to 1000 MW_{el}. However, whether e.g. two 50 MW_{el} DSG plants would operate with lower LEC than one 100 MW_{el} 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 hours, 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 [15]. 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 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 to 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 changes 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 [16-17]. 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.

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