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Solar gas turbine systems: Design, cost and perspectives

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Abstract

The combination of high solar shares with high conversion efficiencies is one of the major advantages of solar gas turbine systems compared to other solar-fossil hybrid power plants. Pressurized air receivers are used in solar tower plants to heat the compressed air in the gas turbine to temperatures up to 1000 °C. Therefore solar shares in the design case of 40% up to 90% can be realized and annual solar shares up to 30% can be achieved in base load. Using modern gas turbine systems in recuperation or combined cycle mode leads to conversion efficiencies of the solar heat from around 40% up to more than 50%. This is an important step towards cost reduction of solar thermal power. Together with the advantages of hybrid power plants—variable solar share, fully dispatchable power, 24 h operation without storage—solar gas turbine systems are expected to have a high potential for market introduction in the mid term view.

In this paper the design and performance assessment of several prototype plants in the power levels of 1 MW, 5 MW and 15 MW are presented. Advanced software tools are used for design optimization and performance prediction of the solar tower gas turbine power plants. Detailed cost assumptions for the solarized gas turbine, the solar tower plant and further equipment as well as for operation and maintenance are presented. Intensive performance and economic analysis of the prototype plants for different locations and capacity factors are shown. The cost reduction potential through automation and remote operation is revealed.

Keywords: Solar thermal power; Solar-fossil hybrid power generation; Solar gas turbine; Solar tower plant; Pressurized air receiver; Solar incremental cost

1. Introduction

The reduction of fossil-fuel based power production by using solar power technology is one important step in the international commitment of CO_2 reduction. The direct way of producing electric power from solar energy, the photovoltaic technology (PV), is gradually extending its focus from purely decentralized small-scale systems towards large-area bulk power production. While current PV system prices are still around 5000 €/kW_p, a cost

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Nomenclature

Variables

E	energy
A	aperture area
η	efficiency
ρ	reflectivity
Δ	incremental value

Subscripts

cos	cosine effect
el	electric power
ref	fossil reference system

Acronyms

DNI	direct normal irradiation
LEC	levelized electricity cost
PSA	Plataforma Solar de Almerá
REFOS	receiver for fossil-hybrid gas turbine systems
TRR	total revenue requirement

reduction for very large-scale PV-systems (>10 MW) to 2000 €/kW$_p$ and below is predicted for the future (2010+). Generating costs of solar electricity of 5–10 €cent/kW h could then make this technology profitable (Kurokawa, 2003). In contrast, solar thermal power plants produce high-temperature heat that is converted to electricity by conventional power cycles. The nine commercial parabolic trough plants in the Californian dessert (SEGS) were built with system costs of 3000–4500 €/kW. They produce electricity from solar energy with an annual solar-to-electric efficiency of 10–14% and at a levelized cost of 16–19 €cent/kW h. Future large systems of 200 MW with 12 h storage are forecasted with system costs of 2500 €/kW and generating costs below 5 €cent/kW h (Price et al., 2002). Similar projections are made for other solar-only technologies. In any case, the key to cost reduction lies in mass production after successful market penetration.

One major option for the accelerated market introduction of solar thermal power technology are solar-fossil hybrid power plants. Their advantage, compared to solar-only systems, lies in low additional investment due to an adaptable solar share, reduced technical and economical risks due to fully dispatchable power, and higher system efficiency because of reduced part load operation and fewer start-up and shutdown-losses. And another important aspect can be put forward in favor of hybrid systems: until thermal or chemical storage technologies allow for guaranteed and predictable power delivery to the grid, a conventional power capacity has to be kept on stand-by to compensate the fluctuating power supply of renewable energies.[1] This is a kind of renewable-conventional hybrid power system but with completely separated system technology leading to economic drawbacks! Real hybrid plants share much of their system, hence leading to economic advantages. A solar-fossil hybrid technology with short-term perspectives is the integrated solar combined cycle system (ISCCS), where thermal power from parabolic troughs is integrated into the bottom cycle of a combined cycle power plant (Dersch et al., 2004). With this option, the generation cost of solar kW h is remarkably low (9 €cent/kW h without, 7.5 €cent/kW h with thermal storage for a 310 MW$_e$ ISCCS in California), but the achievable annual solar share is restricted (4% without, 9% with thermal storage).

In the following paragraphs, the potential of solar-fossil hybrid gas turbine systems will be described to be compared with the above mentioned technologies.

2. Solar-hybrid gas turbine technology

Solar gas turbine systems use concentrated solar power to heat the pressurized air in a gas turbine before entering the combustion chamber (Figs. 1 and 2). The solar heat can therefore be converted with the high thermal efficiency of a modern recuperated or combined gas turbine cycle. The combustion chamber closes the temperature gap between the receiver outlet temperature (800–1000 °C at design point) and the turbine inlet temperature (950–1300 °C) and provides constant turbine inlet conditions despite fluctuating solar input. The solar power tower technology is used with concentration ratios up to 1000 suns to achieve the high receiver temperatures.

A pressurized volumetric air receiver with a secondary concentrator has been developed and suc-

[1] This is the case already today for photovoltaics and wind power at least in developed countries.

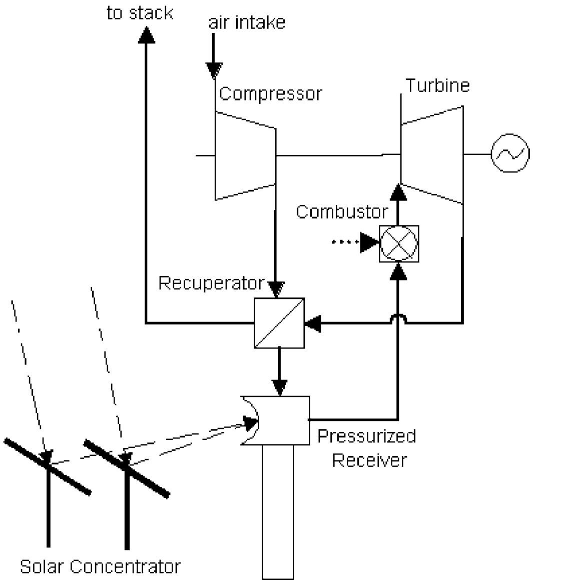

Fig. 1. Solarized gas turbine plant schematic: recuperated Brayton cycle.

cessfully tested, the so-called REFOS receiver technology in the scope of several German national and international R&D projects (Buck et al., 2000, 2002). In 2002, three receiver modules were coupled in series to a 240 kW_e gas turbine and successfully operated at receiver temperatures of up to 800 °C (Sugarmen et al., 2003). More detailed information about the receiver development and recent test results with receiver temperatures up to 960 °C can be found in Heller et al. (2005).

3. Layout, optimization and performance calculation

Modern computer based simulation models have been developed and adapted to analyze the performance of solar-hybrid gas turbines in commercial system size. The design of the optical part of the tower system (concentrator field arrangement and size, secondary acceptance angle, receiver aperture and orientation and tower height) can be cost-optimized using an adapted version of the HFLCAL code (Becker and Böhmer, 1989; Schwarzbözl et al., 2002, Fig. 3). The simulation environment TRNSYS with the model library STEC is used (Pitz-Paal and Jones, 1998; TRNSYS STEC, 2002, Fig. 4) for the annual performance calculation of the thermal power system. The link between the optical and the thermal models is realized with a 'field efficiency matrix', based on the fact that for a fixed layout of the solar part at a given location the heliostat field efficiency only depends on the solar angles (Eq. (1)). Both models were validated against measurement data from the solar experiments at the PSA 2002/2003.

$$\eta_{\text{Field}} = \rho_{\text{Mirror}} \times \eta_{\cos} \times \eta_{\text{Block\&Shadow}} \times \eta_{\text{Atmosph.Att.}} \times \eta_{\text{Intercept}} \times \eta_{\text{Secondary}} = f(\text{Azimuth}, \text{Elevation}). \tag{1}$$

Three industrial gas turbine systems are chosen for detailed technical and economical analysis as potential solar-hybrid prototype plants:

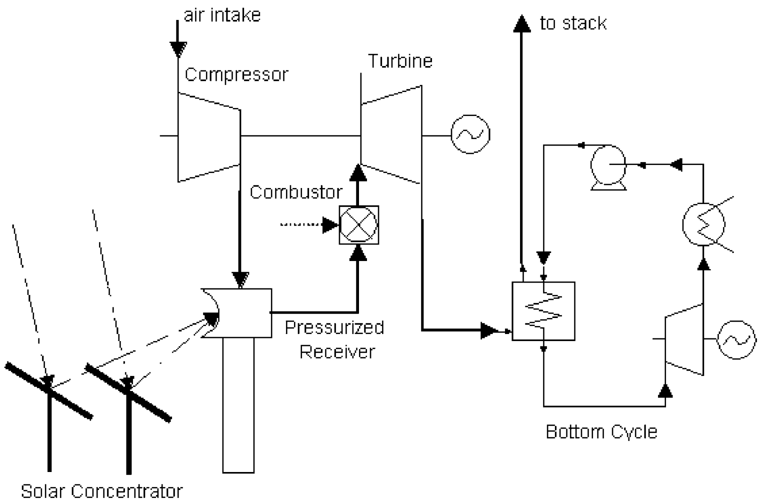

Fig. 2. Solarized gas turbine plant schematic: combined Brayton and Rankine cycle.

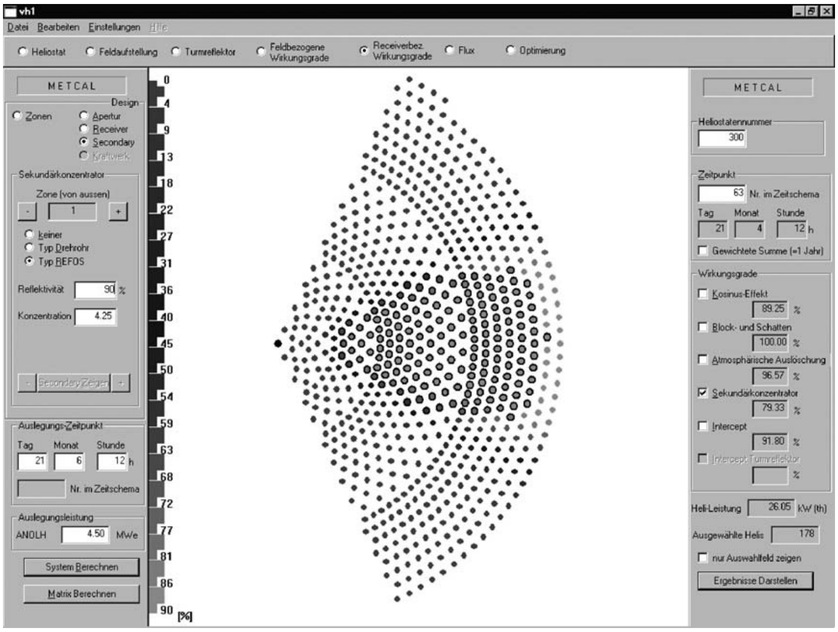

Fig. 3. Software for layout of solar gas turbine systems (screenshot of HFLCAL showing heliostat field arrangement with limited receiver acceptance angle).

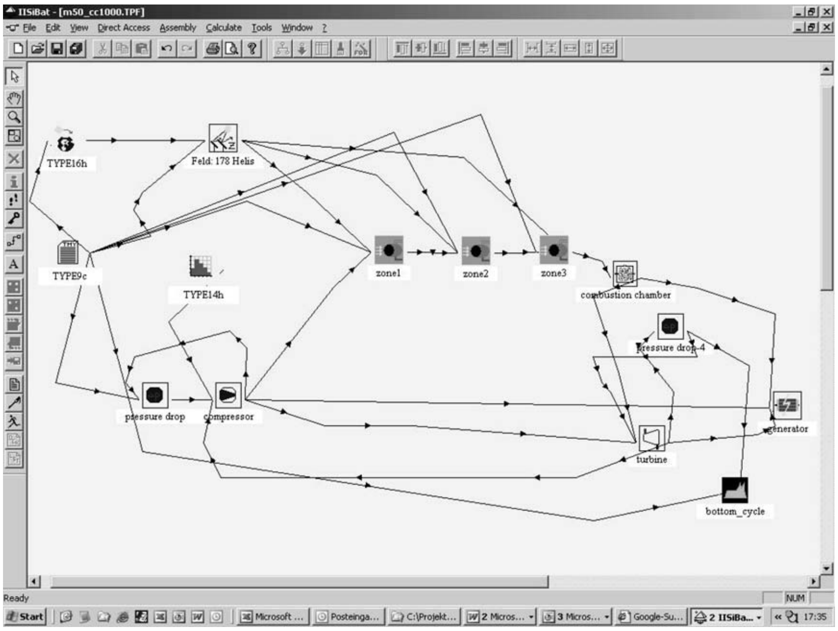

Fig. 4. Software for performance calculation of solar gas turbine systems (screenshot of TRNSYS STEC for solar-hybrid gas turbine with three serial receiver zones).

- Heron H1—intercooled recuperated two-shaft engine with reheat. ISO rating 1400 MW, thermal efficiency 42.9%.
- Solar Mercury 50—recuperated single shaft gas turbine. ISO rating 4200 MW, thermal efficiency 40.3%.

- PGT 10—simple gas turbine with bottom cycle. ISO rating 11 100 MW (gas turbine) respectively 16 100 MW (combined cycle), thermal efficiency 31.3% (gas turbine) respectively 44.6% (combined cycle).

The solarization adds a receiver cluster directly before each combustion chamber for solar preheating of the compressed air. The maximum receiver exit temperature is designed to be 800 °C. One case with a receiver design exit temperature of 1000 °C is analyzed. The receiver design temperature rules the maximum solar share. Two possible locations are chosen for the analysis: Seville (Spain) as a very good European site with interesting market perspectives and Daggett (California, USA) as a very high solar potential site (Table 1).

Table 2 summarizes the cost-optimized layout of the prototype plants for the chosen locations, Seville and Daggett.

Figs. 5–8 show the layout of the solarized gas turbine plants for Daggett. Each receiver zone consists of a group of parallel connected single receiver modules. Receivers are subdivided into low-temperature (up to 600 °C), medium-temperature (up to 800 °C) and high-temperature modules (up to 1000 °C). According to their temperature level, receiver zones are located in the low-, medium- and high-flux region of the focal spot (Schwarzbözl et al., 2002). The averaged design flux density for each receiver zone is indicated in the schematics of the plants.

The annual performance of the prototype plants was calculated by simulation of the system operation with the TRNSYS STEC software using a typical meteorological year on hourly basis for each location. The results for 24 h operation are summarized in the upper half of Table 5. The solar incremental electricity is defined as the annual amount of net electricity produced by the solar-hybrid plant compared to the pure fossil reference plant (i.e. same gas turbine system without solarization) using the same amount of fuel (Eq. (2)).

$$\begin{aligned}\Delta_{E_{\mathrm{el}}} &= E_{\mathrm{el,hybrid}} - \frac{E_{\mathrm{el,ref}}}{E_{\mathrm{fuel,ref}}} \cdot E_{\mathrm{fuel,hybrid}} \\ &= E_{\mathrm{el,hybrid}} - \eta_{\mathrm{ref}} \cdot E_{\mathrm{fuel,hybrid}} \qquad (2)\end{aligned}$$

Using this definition, all drawbacks of the solarization (e.g. additional pressure drop) are assigned to the solar part and we get a fair basis for comparing hybrid systems of different solar share with each other and with pure fossil plants. All other figures of merit are derived from the solar incremental electricity (Table 3). The incremental solar share varies according to the receiver inlet- and outlet-temperatures between 7.5% and 28% for 24 h operation (Table 5).

Figs. 9 and 10 show the change of the incremental solar share when reducing the capacity factor by limiting the operation to daytime only or sun hours only. A solar share of up to 70% is reached with the 1000 °C-Daggett case for 40% capacity factor

Table 1
Definition of plant locations and design points

	Seville (37.2°N)	Daggett (34.9°N)
Annual DNI	2015 kW h/m^2	2790 kW h/m^2
Design point definition	21.3 noon, 800 W/m^2	21.3 noon, 880 W/m^2
Design point conditions	25 °C, 1011 mbar, 60% r.h.	25 °C, 941 mbar, 20% r.h.

Table 2
Results of layout and cost-optimization of prototype plants

	Seville			Daggett			
Gas turbine system	Heron H1	Mercury 50	PGT10 CC	Heron H1	Mercury 50	PGT10 CC	PGT10 CC
Solar design temperature	800 °C	800 °C	800 °C	800 °C	800 °C	800 °C	1000 °C
Design point solar share	75%	38%	57%	75%	38%	58%	88%
Total receiver aperture	7.42 m^2	12.90 m^2	58.61 m^2	6.88 m^2	12.18 m^2	54.60 m^2	82.32 m^2
Tower height	41.2 m	50.6 m	103.7 m	39.6 m	50.6 m	100.2 m	130.2 m
Total reflective area	5460 m^2	8615 m^2	41 620 m^2	5732 m^2	8615 m^2	37 615 m^2	62 733 m^2
Total plant area[a]	0.06 km^2	0.09 km^2	0.43 km^2	0.04 km^2	0.07 km^2	0.37 km^2	0.47 km^2

[a] Total plant area stands for rectangular envelope of used land area.

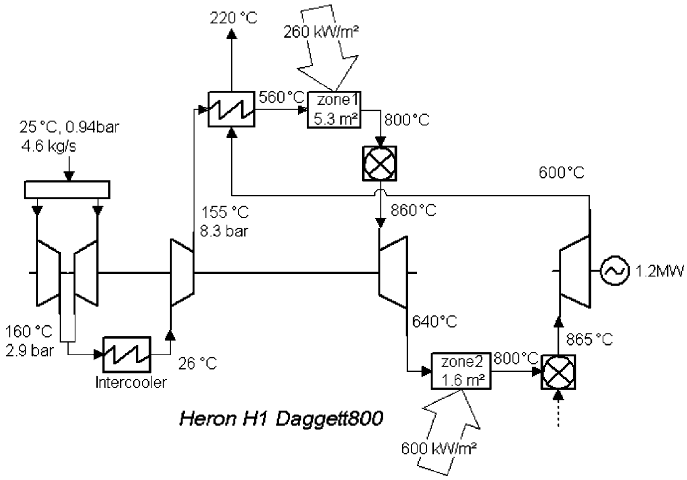

Fig. 5. Solarized gas turbine prototype plant: Heron unit (location Daggett).

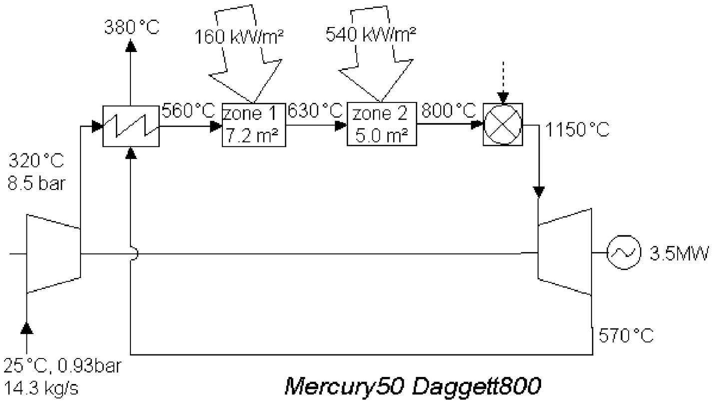

Fig. 6. Solarized gas turbine prototype plant: Mercury unit (location Daggett).

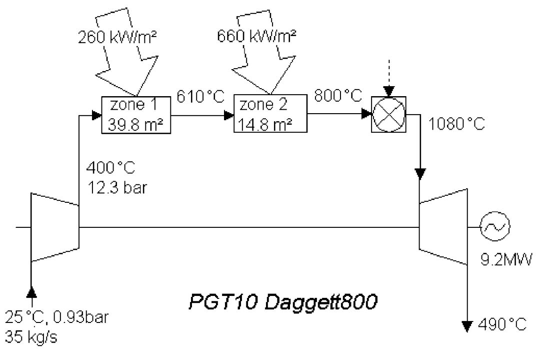

Fig. 7. Solarized gas turbine prototype plant: PGT10 unit, 800 °C (location Daggett).

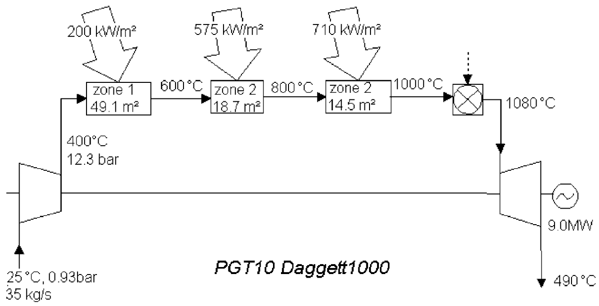

Fig. 8. Solarized gas turbine prototype plant: PGT10 unit, 1000 °C (location Daggett).

(about 3400 annual operation hours, a typical mid-load plant). For the incremental solar to electric efficiency values of 14–19% are reached with the prototype plants analyzed here.

4. Economic analysis

For economic analysis, an emerging market for solar tower plants is assumed with concentrator

Table 3
Definition of derived figures of merit

Incremental solar share	$\Delta_{\text{solarshare}} = \Delta_{E_{\text{el}}}/E_{\text{el,hybrid}}$
Incremental CO_2 avoidance	$\Delta_{CO_2} = (E_{\text{el,hybrid}}/\eta_{\text{ref}} - E_{\text{fuel,hybrid}}) \cdot f_{CO_2} = (\Delta_{E_{\text{el}}}/\eta_{\text{ref}}) \cdot f_{CO_2}$
Incremental solar to electric efficiency	$\Delta_{\eta_{\text{solel}}} = \Delta_{E_{\text{el}}}/A_{\text{Hel.field}} \cdot \int_{1a} DNI(t)\,\mathrm{d}t$
Solar incremental LEC	$(\text{levelized TRR} - (E_{\text{el,hybrid}} - \Delta_{E_{\text{el}}}) \cdot \text{LEC}_{\text{ref}})/\Delta_{E_{\text{el}}}$

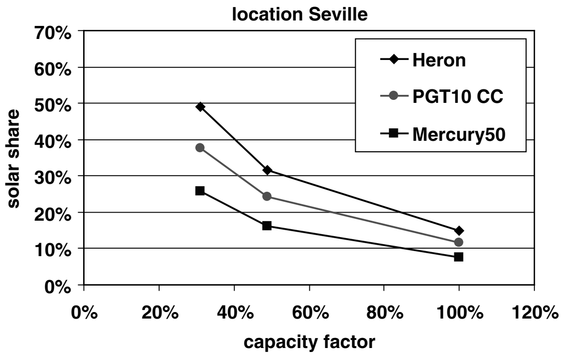

Fig. 9. Result of performance calculation: incremental solar share as a function of capacity factor for location Seville.

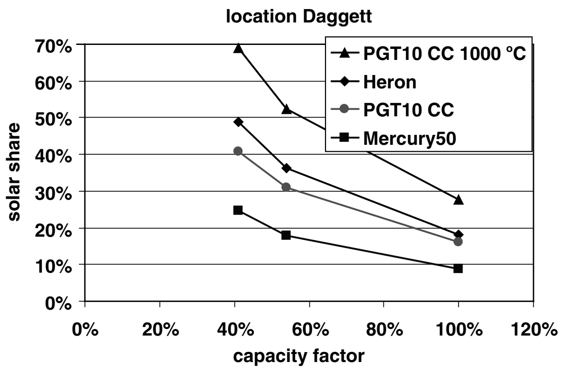

Fig. 10. Result of performance calculation: incremental solar share as a function of capacity factor for location Daggett.

costs of 132 €/m^2 (for 120 m^2 glass-metal heliostat). The receiver costs are 16 k€/m^2, 33 k€/m^2 and 37.5 k€/m^2 for the low-, medium- and high-temperature receiver. The investment costs for the conventional part (power block, fuel system, cooling system, generator, grid connection) are 1520 €/kW for the Heron system, 560 €/kW for the Mercury system and 510 €/kW for the PGT10 combined cycle system.

For detailed cost calculations two types of plant projects are notable with regard to investment and operational cost assumptions:

- 1st plant (stand-alone)
  - ‘first-of-its-kind’ plant with completely new plant engineering,
  - covering all expenses for engineering and development of gas turbine solarization (i.e. adaptation of combustion chamber and control),
  - fully operated by the staff on site (3 shifts for 24 h operation).
- 2nd generation plant (remote in virtual park)
  - gas turbine solarization costs shared amongst 10 similar plants,
  - operated remotely in a ‘virtual park’ of 4 similar plants,
  - high degree of automation,
  - reduced expenses for instrumentation, control- and auxiliary equipment,
  - reduced general engineering and construction costs,
  - reduced personnel expenses due to shared staff for operation and maintenance.

For calculation of levelized electricity costs (LEC) financial parameters are assumed according to Table 4 and Fig. 11.

The results of the LEC calculations can be found in Table 5. The total LEC for a 1st plant range from about 6.3 €cent/kW h to 19.9 €cent/kW h depending on power level and solar share. The solar incremental LEC are calculated according to Table 3. They range from 12.7 €cent/kW h to 89.7 €cent/kW h for the 1st plant. The lower part of Table 5 shows the cost reduction that can be achieved by 2nd generation plants with remote operation and

Table 4
Additional parameters for performance and LEC calculation

Fuel heat rate	kJ/kg	42100
Specific CO_2 emissions (f_{CO_2})	kg/MW h$_{\text{fuel}}$	200
Losses due to outages	%	2.5
Parasitic losses: Heron & Mercury	%	1
PGT10 CC	%	2.5
Debt-equity ratio	—	75:25
Debt interest rate	%	4.2
Equity interest rate	%	14
Debt payback time	a	12
Plant operation time	a	20
General inflation rate	%	2.5
Fuel cost	€/MW h	13.43

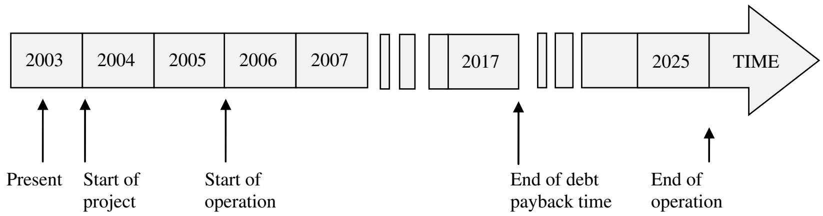

Fig. 11. Time schedule assumptions for prototype plant projects.

Table 5
Summary of results of performance calculation and cost analysis for 24 h operation

Name		sev_H1	dag_H1	sev_M50	dag_M50	sev_PGT10	dag_PGT10	dag_PGT10_1000
Power system		Heron-HI	Heron-HI	Mercury 50	Mercury 50	PGT10	PGT10	PGT10
ISO rating	[MW]	1.4	1.4	4.2	4.2	16.1	16.1	16.1
Location		Sevilla	Daggett	Sevilla	Daggett	Sevilla	Daggett	Daggett
Annual DNI	[kW h/m^2]	2015	2791	2015	2791	2015	2791	2791
Capacity factor	[%]	100%	100%	100%	100%	100%	100%	100%
Annual field efficiency	[%]	52.7%	56.1%	55.8%	60.4%	54.1%	57.9%	55.8%
Annual receiver efficiency	[%]	79.0%	77.2%	78.9%	79.9%	73.3%	75.4%	75.3%
Annual power cycle efficiency	[%]	40.4%	38.4%	35.9%	35.9%	44.9%	43.4%	43.9%
Net electric energy	[MW h]	11259	10610	32842	32769	130999	125612	119678
Solar incremental electricity	[MW h]	1689	1918	2459	2871	15251	20298	33237
Incremental solar share	[%]	15.0%	18.1%	7.5%	8.8%	11.6%	16.2%	27.8%
Incremental CO_2 avoidance	[t/a]	826	972	1359	1576	6837	9438	15454
Incremental solar to electric Efficiency	[%]	15.4%	14.5%	14.2%	14.6%	18.3%	19.3%	19.0%
1st plant (stand alone)								
Total investment costs	[k€]	8632	8456	8974	8678	25406	24578	31155
There of solar equipment		22%	21%	27%	26%	33%	32%	40%
Spec. investment costs	[€/kW$_e$]	6640	7046	2362	2480	1728	1731	2225
Fixed O&M costs	[k€/a]	1032	1028	1337	1331	2090	2072	2419
Thereof personal expenses		69%	70%	58%	59%	53%	54%	54%
Levelized electricity costs								
(LEC)	[€/kW h]	0.1913	0.1993	0.1004	0.0988	0.0631	0.0633	0.0694
Reference plant LB3	[€/kW h]	0.0667	0.0698	0.0563	0.0563	0.0458	0.0474	0.0474
CO_2-avoidance cost	[€/kg]	1.6976	1.4129	1.0655	0.8843	0.3318	0.2125	0.1708
Solar incremental LEG	[€/kW h]	0.8969	0.7857	0.6452	0.5417	0.1945	0.1462	0.1268
2nd generation plant (remote in virtual park)								
Total investment costs	[k€]	5763	5595	6583	6302	21206	20421	26023
Thereof solar equipment		31%	30%	36%	34%	39%	37%	47%
Spec. investment costs	[€/kW$_e$]	4433	4663	1732	1801	1443	1438	1859
Fixed O&M costs	[k€/a]	451	447	731	725	1653	1637	1952
Thereof personnel expenses		47%	48%	33%	34%	49%	49%	51%
Levelized electricity costs								
(LEC)	[€/kW h]	0.1161	0.1196	0.0752	0.0736	0.0568	0.0568	0.0616
Reference plant LEC	[€/kW h]	0.0667	0.0698	0.0563	0.0563	0.0458	0.0474	0.0474
CO_2-avoidance cost	[€/kg]	0.6732	0.5434	0.4561	0.3602	0.2111	0.1257	0.1099
Solar incremental LED	[€/kW h]	0.3960	0.3452	0.3084	0.2540	0.1404	0.1058	0.0985

automation. The reduction potential of the solar LEC is especially high (>50%) for small power levels. For the largest plant a cost digression of >20% is possible, leading to solar LEC below 10 €cent/

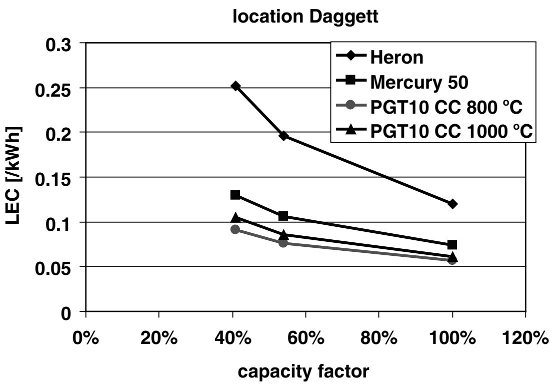

Fig. 12. Results of cost analysis. Total LEC as a function of capacity factor for 2nd generation plant in Daggett.

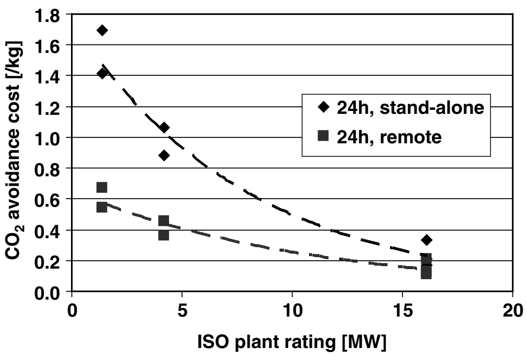

Fig. 13. Results of cost analysis. CO_2-avoidance cost for 2nd generation plant in Daggett as a function of power level.

kW h. The investment cost is then reduced to 1860 €/kW (−16%) and the fixed O&M costs are reduced to 1950 k€/a (−20%).

Fig. 12 left shows the variation of total LEC for the 2nd generation plants as a function of capacity factor. With the largest plant (PGT10 CC 1000 °C), electricity at an annual solar share of 70% can be produced at total cost of 10.5 €cent/kW h (compare to Fig. 10). This can be an interesting option for green power markets. Relating the solar LEC to the annual amount of CO_2 that can be avoided when operating the hybrid plant instead of the pure fossil reference plant, the CO_2-avoidance costs can be calculated for each individual plant (Fig. 13). For the higher power level a value well below 200 €/ton CO_2 can be reached.

5. Further development and market introduction

At the current status of the development of solar-hybrid gas turbine systems with pressurized volumetric receivers the main issues for further R&D are:

- verification of O&M assumptions for the receiver and the power conversion subsystem;
- further increase of the solar share to reduce greenhouse gas emissions;
- further cost reduction of solar components (i.e. heliostats, receiver modules).

Test operation of the 240 kW_e solar-hybrid system at the PSA was continued until summer 2004 within the HST project, funded by the German Ministry of Environment (BMU). As part of this project one receiver was tested at air outlet temperatures up to 1030 °C. This results in a further increase of the solar share of solar-hybrid power plants. Another future option is the inclusion of high-temperature heat storage systems, also leading to an increased solar share.

Although the cost predictions indicate potential competitive applications in the green power market, the introduction of this new technology is hampered by several factors:

- Power production costs are still higher than with conventional fossil fuel options.
- Up to now, only a few possibilities exist for the funding of hybrid systems with fossil contributions above 30% (solar shares <70%).
- Exploiting the full potential of high efficiencies of combined cycle plants (>50%) requires power levels above 50 MW_e; this means a very high investment cost which is not realistic for the introduction of a new technology.

From the latter it is clear that market introduction is mainly possible at lower power levels, with the option of future scale-up. At power levels below 10 MW_e, gas turbine systems are mainly used for decentralized power generation with cogeneration of heat or cooling power. First cost assessments for such cogeneration units indicated a potential for solar-hybrid gas turbine units (Sugarmen et al., 2003). Therefore, the planned steps towards market introduction of this new technology are as follows:

1. Gain further experience in long term behavior of the key components.
2. Design and installation of a first prototype plant based on a small gas turbine or microturbine, with cogeneration.

3. Market introduction of the technology at power levels up to several MW_e, as cogeneration units.
4. Upscaling to power plants with combined cycle for high efficiency.

A first demonstration system is currently under construction in Empoli, Italy. Two small solar tower plants, each with receiver, microturbine, absorption chillers and water heat exchanger, will deliver 160 kW_e, hot water and cooling for a hospital. Other small-scale applications are planned.

6. Conclusions

The cost-optimized design and performance prediction for solar-hybrid gas turbine plants in the power levels 1.4 MW_e, 4.2 MW_e and 16.1 MW_e for two different locations were shown. An annual average solar to net electric efficiency of up to 19% was calculated, amongst the highest conversion efficiencies for solar electric technologies. The cost analysis showed total plant investment costs from 7000 €/kW down to below 1800 €/kW, depending on power level and solar share. Solar LEC between about 13 €cent/kW h up to 90 €cent/kW h were calculated. Using the cost reduction potential that lies in combined design, construction and operation of multiple distributed plants leads to solar LEC of below 10 €cent/kW h for an electric power level of 16.1 MW. So, the solar-hybrid gas turbine power technology shows interestingly low cost for solar produced bulk electricity at a moderate power level. The values predicted for ISCC plants can be reached, but with a smaller system (16 MW instead of 310 MW) and with a significantly higher solar share (28% instead of 9%, see chapter 1). The advantage compared to large-scale PV plants and other pure solar systems lies in full dispatchability.

CO_2-avoidance cost down to 20 €/ton were calculated for this technology. This is an interesting figure especially when compared to published costs for CO_2 avoidance through fuel substitution in the conventional utility-scale power sector ranging from 70 to 700 US$/ton (e.g. Narula et al., 2002).

The high technical and economical potential of this technology is outlined. While larger units (>10–15 MW) especially combined cycle systems show very low cost for solar produced bulk electricity (which will further decrease with increasing power level), small-scale units (<5–10 MW) should be applied in distributed markets using cogeneration to start market introduction.

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