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Performance Prediction of a CSP Plant Integrated with Cooling Production

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Abstract

The integration of a Concentrated Solar Power (CSP) plant with cooling energy production is investigated in the present paper. The power block is based on a steam Rankine cycle fully driven by two types of solar concentration devices: i) Parabolic Trough Collector (PTC) solar field and ii) Heliostat field with Central Receiver (HCR). Storage tanks allow the plant to operate also during nighttime hours. Cooling production is carried out by steam-driven double-effect absorption chillers feeding a district cooling network. The system was designed to operate in "island mode" to cover both the electrical and the cooling demand for a town of about 50,000 inhabitants. A typical location in the desert region of the Saudi Arabia Kingdom was selected as a case study. Commercial software and in-house computer codes were combined together to predict annual CSP plant performance. Results of annual plant operation on a one hour basis are presented and discussed. CSP plant showed a good capability of load-following operation, providing at the same time a relevant fossil fuel saving.

Keywords: Absorption chiller; Combined Cooling and Power; Concentrating Solar Power; Parabolic Trough; Solar Tower.

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1. Introduction

CSP plant technology is very scalable and it can be virtually employed to generate power in sunny sites from a few megawatts up to hundreds. Reliability and design flexibility make CSP plants especially ideal for remote locations, where they are meant to supplement or substitute other forms of power generation, such as gensets burning fossil fuels. This technology has recently gained particular significance and relevance, with an increasing number of international initiatives [1,2]. Beyond electricity generation for

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remote or weakly interconnected grids, CSP plants can provide a further opportunity. They can also supply process heat to generate cooling energy: low pressure steam can be extracted from the steam turbine to drive a set of absorption chillers generating chilled water for a district cooling system. This system can replace mechanical compression chillers leading to a significant peak power reduction on the grid and a general flattening of the electrical load profile [3].

The analysis presented in this paper demonstrates that a solar-driven Rankine cycle with a thermal storage can be flexibly operated to match both electric and cooling demand over a one-year period.

Nomenclature

ABS	absorption chiller	p_{cond}	condenser pressure (bar)
COMP	compression chiller	P_{chill}	electric chiller power consumption (MW)
COP	coefficient of performance	P_{dem}	power demand (MW)
CSP	concentrated solar power	P_{res}	residual power demand (MW)
DNI	direct normal irradiation (W/m^2)	PTC	parabolic trough collector
E_{coll}	collected heat (MWh)	Q_{abs}	absorption chiller cooling power (MW)
E_{dem}	heat demand (MWh)	Q_{coll}	collected thermal power (MW)
E_{rad}	incident solar energy (MWh)	Q_{cool}	cooling demand (MW)
HCR	heliostat field with central receiver	Q_{dem}	thermal power demand (MW)
HP	high pressure	Q_{rad}	incident solar radiation (MW)
HTF	heat transfer fluid	T	temperature (°C)
HX	heat exchanger	T_{amb}	ambient temperature (°C)
LP	low pressure	TES	thermal energy storage

Four CSP technologies are available, namely parabolic troughs, linear Fresnel reflectors, solar towers and dish/engine systems. Among these solutions, parabolic troughs and more recently towers have been installed in commercially operating plants, with the majority of PTCs [4].

Thermal energy storage (TES) can considerably improve the attractiveness of solar thermal power plants. It allows to mitigate the effects of fluctuations in solar intensity and to extend (or to shift) the operation of the plant. Thus, the plant can operate much more flexibly and the mismatch between power generated by the Sun and electricity demand profile can be reduced. The most common thermal energy storage for solar thermal power plants is a two-tank storage system where the HTF also serves as storage medium (direct storage) [5].

In spite of a large number of paper investigating plant performance of a single CSP technology, only a few works present a comparison between solar fields based on PTCs and solar tower. Solar collector efficiency is strongly related to site latitude and meteorological conditions (DNI, ambient temperature) [6]. Generally speaking, parabolic troughs can intercept a larger amount of incident radiation than heliostats in summer months, but their efficiency dramatically decays in winter [7,8].

In the present paper a fully solar driven CSP plant is considered: the aim is to show how a CSP steam plant with TES can operate in island mode, meeting the power demand throughout the year. The considered CSP plant is integrated with absorption units for cooling production. The power system was assumed to be isolated and conceived for a mid-size community (roughly around 50,000 inhabitants). Daily patterns of power and cooling demand were defined for a one-year period: Fig. 1 shows the power load and the chillers power consumption profiles for a typical summer and winter day. The peak power results to be 83 MW in summer, and only 42 MW in winter. A large variation in the power request can be noticed between day and night: about 50% in summer and 40% in winter. Furthermore, about 45% of the total electricity demand in summer is due to chiller consumptions, against only 15-20% in winter.

The integration of cooling production into the CSP plant allows to smooth the daily power load. In fact the use of absorption chillers makes the original grid load levels to be lowered down to the “residual electric demand”. The difference between the total and the “residual electric demand” quantifies the electric energy savings deriving from the usage of absorption chillers instead of compression chillers.

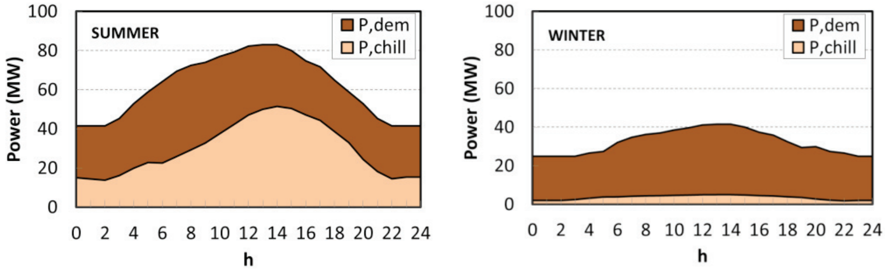

Fig. 1. Electric load and chiller power consumption (a) in the summer and (b) in the winter day.

2. CSP Plant

The power plant configuration assumed for the present analysis is shown in Fig. 2. It is based on a solar-driven Rankine cycle integrated with two-stage absorption chillers.

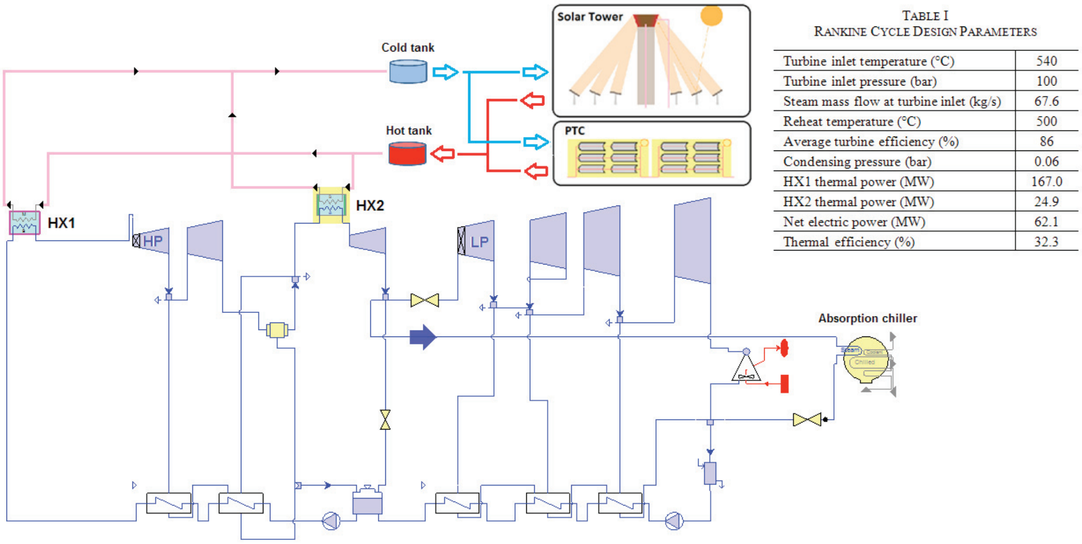

TABLE I
RANKINE CYCLE DESIGN PARAMETERS

Turbine inlet temperature (°C)	540
Turbine inlet pressure (bar)	100
Steam mass flow at turbine inlet (kg/s)	67.6
Reheat temperature (°C)	500
Average turbine efficiency (%)	86
Condensing pressure (bar)	0.06
HX1 thermal power (MW)	167.0
HX2 thermal power (MW)	24.9
Net electric power (MW)	62.1
Thermal efficiency (%)	32.3

Fig. 2. Schematic of the investigated CSP plant: screenshot of Thermoflex®.

The power block is a single reheat, regenerative Rankine cycle with 6 heaters: the feed water is preheated in three LP feed-water heaters, a de-aerator and two HP feed-water heaters. Primary thermal design parameters are from [9]. Molten salt was chosen to transfer heat to the water loop in the Rankine cycle so to increase the cycle efficiency by about 2-3% as compared to the oil case [10]. The cycle design parameters are summarized in the Table I embedded in Fig. 2. No auxiliary boiler was included in the plant. A steam extraction upstream of the LP turbine is driving absorption chillers. Condensate flow exiting the chillers at 3.15 bar and 99°C is returned to the condenser hot well. Four Li-Br two-stage absorption chiller units, for a total cooling capacity of 82.8 MW, have been supposed to be installed. Each units has a nominal capacity of 20.7 MW and COP_{ABS} 1.31.

Two different configurations have been considered for the solar field: i) Parabolic Trough Collectors (PTC) and ii) Heliostat field with Central Receiver (HCR). The goal is to investigate which solar configuration is the most appropriate to meet a variable heat demand, according to the instantaneous electric load on the grid. It has to be reminded that the CSP plant is designed to operate in "island mode": hence TES and solar field must cover hour by hour the heat demand required by the Rankine cycle.

For each solar configuration a two-tank molten salt direct storage system is considered. HTF coming from solar field fills the hot tank; then it is withdrawn to transfer heat to the steam generator. A cold tank finally collects molten salt exiting heat exchangers and acts as a buffer.

3. Simulation method and assumptions

The location selected for the present analysis was assumed to have climatic conditions and latitude corresponding to those of Riyadh (KSA). Meteonorm database from the Trnsys® weather library provided the meteorological data for daily and annual simulations. The power block was modeled by Thermoflex® whereas Trnsys® with the model libraries STEC and TESS was used to model solar field and absorption chillers operation all over the year. Full details on solar devices modeling are given by reference [7,11]. Firstly, an iterative procedure within Thermoflex® provided hour-by-hour HTF flow rates ensuring that the Rankine cycle power output equals the "residual electric demand", under real climate conditions. In this way the power block was simulated to match both power and cooling requests all the time, coherently with the island operation mode. Then, Trnsys® took those HTF flow rates as a mandatory request to be fulfilled by the solar field (PTC or HCR) coupled with the TES system.

Concerning the power block, it has to be pointed out that the steam turbine is called to operate most of the time in off-design conditions. The steam flow rate at turbine outlet may differ significantly from design condition since LP turbine flow is always adjusted to match both electrical and cooling requests. Therefore the turbine Thermoflex® model included both admission control valves and exhaust losses to carefully simulate the turbine off-design behavior. Absorption chillers were modeled according with performance maps taken from manufacturer's catalogs. More details on the part-load operation of the chiller are given in [7].

An optimization procedure interacting with Trnsys® model and based on GenOpt tool [12] was used to size the two considered solutions for the solar fields. On the base of annual Trnsys® simulations, the optimization algorithm determines the minimum aperture area of the solar field assuring the required HTF flow rate from TES. Charging and discharging cycles of TES were ruled by the HTF flow rate required for each hour of the year and the hot storage tank was assumed to be never empty. The same storage capacity was selected for both solar configurations: based on the author's experience, a 48,000 m^3 volume tank was considered adequate to compensate for daily fluctuations in the heat demand and solar energy availability. The resulting aperture area is 1,834,400 m^2 for PTC and 1,022,040 m^2 for HCR case respectively.

4. Results and discussion

Simulation of the whole CSP plant have been carried out over a one-year period to evaluate the annual performance for both the solar field configurations. However, first the focus is on two representative summer and winter days in order to enlighten the plant behavior during the extreme conditions occurring over a year.

Fig. 3 shows the cooling load profiles for the two selected days. It can be observed that in summer absorption chillers are not able to cover the whole cooling demand. The limit of 82 MW provided by absorption chillers depends on the installed chiller capacity. Auxiliary compression chillers are thus used to fill the gap with respect to the overall cooling load. COP_{COMP} of compression units was assumed to vary with ambient temperature in the range between 2.5 (at T = 42°C) and 5 (at T = 24°C). During the winter day (Fig. 3b), the request of cooling is reduced by a factor of about 5. Consequently only a small fraction of the steam flow rate entering the HP turbine is extracted to drive the absorption chillers; all the remaining steam is sent to the LP turbine section for power production. The cooling load demand is completely covered by absorption chillers, meaning that in the winter day there is no need for compression chillers at all.

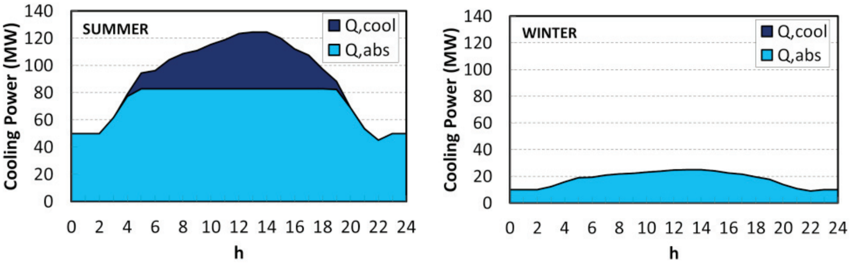

Fig. 3. Cooling load curve (a) in the summer day and (b) in the winter day.

The day electric power resulting from the usage of absorption chillers instead of compression chillers is presented in Fig. 4a; the original grid load levels (dashed lines) are lowered down to the "residual electric demand", P_{res}. The peak power in the summer day decreases by about 33 MW, from 85 MW down to 52 MW. A much smaller drop off (from 41 MW to 36 MW) occurs in the winter day. The CSP plant is flexibly operated to produce both P_{res} and Q_{abs} for air conditioning. It means that the steam flow rate entering the HP turbine is determined hour by hour so to make the steam turbine fulfill P_{res} anytime. Of course power output depends not only on steam flow rate but also on ambient temperatures. Fig. 4b shows the pressure level variation taking place in the condenser during the two selected days. This is the result of the air temperature variation but also of the steam flow rate discharged by the turbine, according to absorption chillers request.

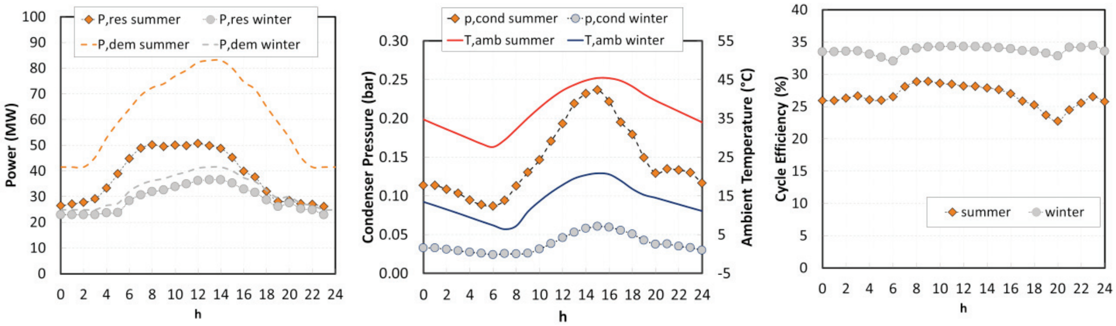

Fig. 4. (a) CSP plant electricity production; (b) condenser pressure; (c) cycle efficiency.

CSP plant performance in terms of steam Rankine cycle efficiency is reported in Fig. 4c. The efficiency being evaluated as the ratio of the net power output to the solar heat input through HX1 and HX2. Note that a relevant difference takes place between winter and summer. In the winter day, efficiencies are in the range between 32% and 34.5%, not far from the design value (32.3%). But in summer, hot temperatures joined to steam extraction for cooling needs cause a relevant performance penalty.

Summer and winter results for the solar block configuration based on parabolic troughs are shown in Fig. 5. Plots report intercepted solar radiation (Q_{rad}), effective collected heat (Q_{coll}) and instantaneous heat demand required by the power plant (Q_{dem}). The hot storage tank level is also reported. One can see that there is a significant difference in PTC performance between summer and winter: in the central hours of a sunny day the collected heat is strongly exceeding the heat input required by the power plant, thus allowing the hot storage tank to charge. In central hours of the summer day, i.e. from 10^h to 16^h, TES is completely full: this requires defocusing of some parabolic troughs [13]. In winter thermal dumping occurs only for about one hour. In both days the storage permits a 24-hour operation.

Fig. 6 shows the same results for the second solar block configuration, based on the solar tower with heliostat field. In this case, a lower aperture area and consequently a lower solar intercepted radiation Q_{rad} are needed to cover the heat demand: the peak value is about 900 MW against 1650 MW of PTC case. In the central hours of summer days, when sun is close to zenith, a typical decrease of collected power takes place due to high heliostats to tower reflection angle. Conversely to PTC case, thermal dumping takes place in winter for about 4 hours; this is the effect of the low thermal power demand joint to a good solar field efficiency.

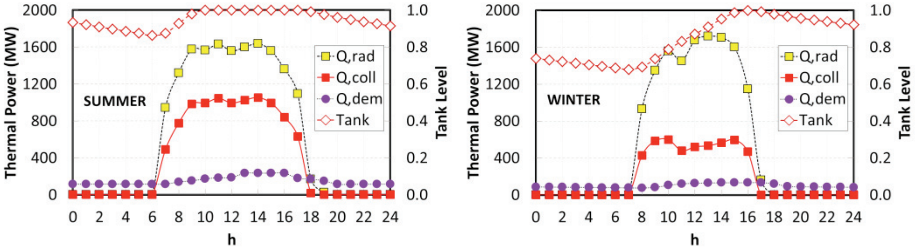

Fig. 5. Solar Block day simulation results (PTC configuration) (a) in the summer day and (b) in the winter day.

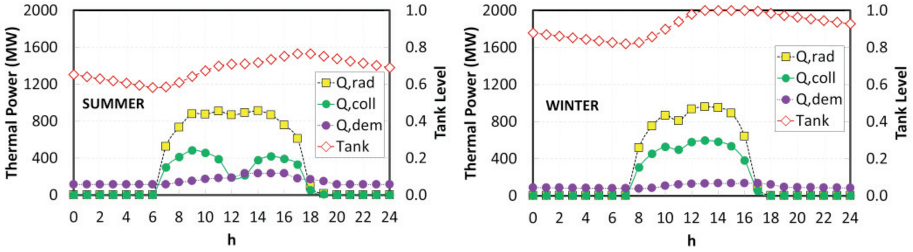

Fig. 6. Solar Block day simulation results (HCR configuration) (a) in the summer day and (b) in the winter day.

Global performance from annual simulations over a one-year period have been computed. Fig. 7 reports on monthly basis the amount of the available solar energy (E_{rad}), the collected energy (E_{coll}) and the power block thermal energy demand (E_{dem}).

The monthly performance of the two solar concentration technologies results very different. Parabolic troughs exhibit a relevant excess (even up to 130%) in the collected heat from March to October that requires the defocusing of many troughs. This excess is due to the need to cover E_{dem} in winter months when PTC solar-to-thermal efficiency is quite low; so, a very large aperture area was required in PTC field to meet the heat demand. The alternative strategy based on huge capacity tanks for seasonal thermal storage would be too expensive.

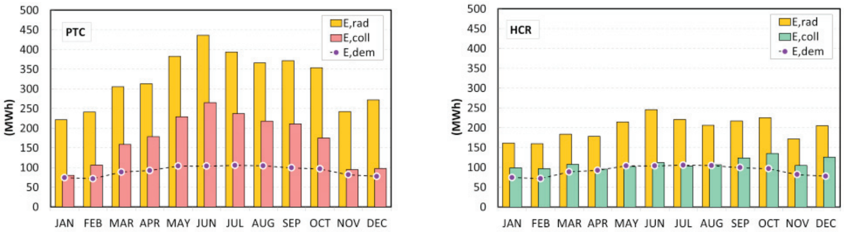

Fig. 7. Monthly results (a) for PTC configuration and (b) for HCR configuration.

Conversely, HRC configuration in summer months is capturing almost exactly the thermal energy (E_{dem}) requested by the steam cycle, and only a low thermal dumping occurs in autumn and winter months. This is strictly related to solar tower field efficiency that is lower in summer and higher in winter.

In order to globally evaluate the performance of the two investigated configurations, the annual energy balance reported in Table II has been evaluated. The CSP plant based on HCR requires a lower amount of solar energy to drive the power cycle; excess heat is minimized, but a surplus of 15.5% still remains. PTC, on the opposite, are characterized by a 46.1% annual overproduction because collector field has been oversized to cover the heat demand in winter.

TABLE II
PTC VS. HCR CONFIGURATIONS: ONE-YEAR PERIOD PERFORMANCE

	PTC	HCR
Intercepted solar energy (GWh)	3898.6	2388.4
Collected heat (GWh)	2051.4	1308.2
Heat demand (GWh)	1090.7	
Energy surplus (%)	46.1%	15.5%
Average efficiency (%)	52.6%	54.8%

5. Conclusions

In this work a CSP plant including a steam Rankine cycle, integrated with double-effect steam driven absorption chillers, was modeled in detail. Simulations of this plant were carried out under real operating conditions for a location with climatic conditions and latitude corresponding to Riyadh (KSA). Both the solutions matched the same load and cooling demand and both systems were designed to operate in “island mode” according with a load-following logic. The use of absorption chillers fed by low grade steam allowed to significantly reduce the actual electric power requested to the CSP system. As regards to the solar field, PTC technology requires a larger aperture area to guarantee the complete coverage of the Rankine cycle heat input. As a consequence, a huge thermal dumping takes place in summer months. HCR appears to perform better: a lower aperture area is needed and the collected heat slightly exceeds the power plant demand only in winter months. It can be concluded that solar tower is the best solution for a CSP plant in terms of capability of load-following operation.

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Biography

Giuseppe Franchini is Associate Professor of Turbomachinery and Energy Systems at the Department of Engineering and Applied Sciences, University of Bergamo. He is author of about 60 papers of international relevance in the field of Renewable Energy, Gas Turbines and Energy Conversion Systems.