DYNAMIC SIMULATION AND LIFE CYCLE ANALYSIS OF A 784 m^2 SOLAR THERMAL PLANT WITH EVACUATED FLAT PLATE COLLECTORS COUPLED TO A DISTRICT HEATING NETWORK

by

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One of the first solar plants in Switzerland to be integrated to a large urban district heating network has been monitored since its commissioning in 2021. Located in Geneva, this 784 m² solar field, equipped with innovative evacuated flat plate collectors, has confirmed the potential of vacuum solar collectors for industrial and district heating network applications. In 2022, the plant achieved a specific annual production of 684 kWh per m², corresponding to a 45% yearly average efficiency. A dynamic numerical model, developed under TRNSYS and validated against measurement data, allowed investigating the impact of several optimization strategies together with their economic viability. Additionally, a life cycle assessment and a life cycle cost analysis were conducted, confirming that incorporating solar heat into district heating network significantly reduces GHG emissions and non-renewable energy consumption at an energy production cost which is competitive with that of current district heating networks. These findings underscore the potential of solar thermal technology in decarbonating the thermal energy sector, notwithstanding its limited role in the current energy production arena.

Key words: *solar thermal district heating system, performances monitoring, high vacuum flat plat collector*

Introduction

District heating network and solar heat

The district heating network (DHN) sector in Switzerland has experienced a sustained growth in the last couple of years. With highly fluctuating fossil fuel costs, DHN often offers relatively cheap and stable prices over the long term, contributing to the high popularity of this technology for space heating (SH) and domestic hot water (DHW) production. In 2021, the DHN sector distributed 11% of the heat consumed in Switzerland, featuring a 69% renewable share in the distributed energy. This latter figure, when compared to the overall share of renewable heat for SH and DHW production in Switzerland (*i.e.* 35%) underscore the important role that DHN might have in efficiently lowering renewable heat cost and decarbonizing SH and DHW production.

Solar thermal technology is very promising as a source of heat for DHN applications [1]. In the case of large solar thermal plants, moreover, the economy of scale allows reducing

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the heat cost, making it more competitive, while attaining larger specific productivities, which in turns contributes further to the heat cost reduction. Solar heat is more and more popular in countries like Germany and Austria, where subsidy programs have been implemented to stimulate the development of large solar thermal fields for DHN and industrial applications [2]. The recent rebound observed in the solar thermal market is, in fact, mainly due to the development of large solar fields for DHN and process heat applications.

Since most of the DHN in Europe and Switzerland are still operated at medium to high temperature levels, it is important to develop innovative solar thermal technologies able to efficiently convert solar radiation into heat at medium to high temperatures. Evacuated flat plate collectors (EFPC) utilize a high vacuum as highly efficient thermal insulation, which significantly enhances efficiency and extends the operating temperature range up to 150 °C [3]. The EFPC technology holds immense promise, especially for operations exceeding 70-80 °C (*i.e.* DHN typical temperature levels). For instance, recent simulations conducted by Moss *et al.* [4] demonstrated that when operated at 85 °C, EFPC could potentially double the yearly specific productivity compared to classical flat plate collectors. However, the primary challenge associated with this technology is to assess its reliability in maintaining a suitable vacuum level inside the collector throughout its operational lifespan, often estimated in 20 years or more. The interest of this technology compared to conventional solar collector technologies is given in [5], where authors focused on the performance of one of the first commercial applications adopting the EFPC technology developed by the Swiss-based company TVP Solar SA.

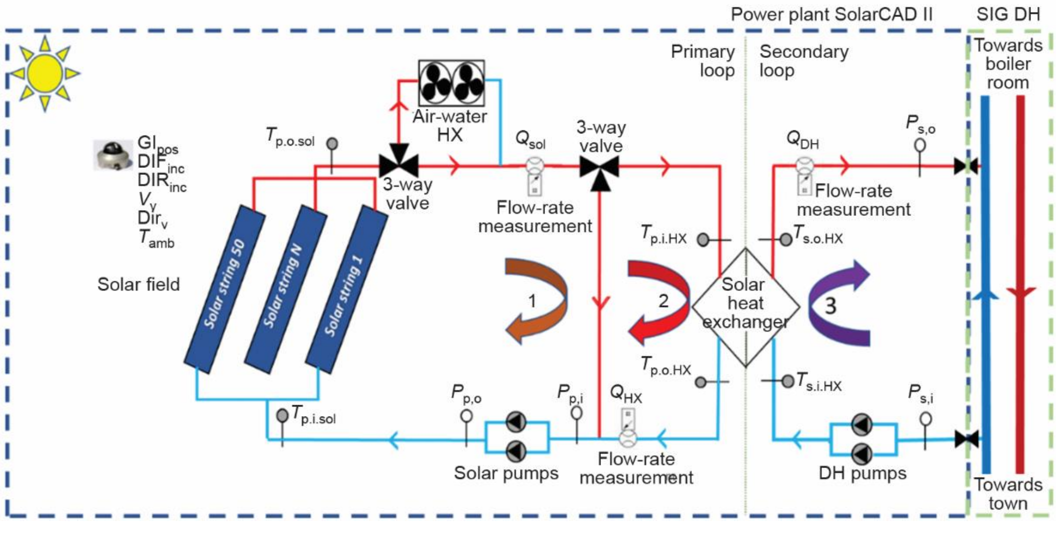

Figure 1. Hydraulic layout of the solar plant with the location of each sensor

The DHN and solar thermal field characteristics

The energy utility company of the Geneva canton (the *Services Industriels de Geneve* or SIG) operates one of the oldest and largest DHN in Switzerland, denominated *CADSIG*. This DHN was built in 1960 and currently uses a mix of heat produced by a municipal waste incinerator (MWI) and by gas combustion. In 2021, CADSIG distributed 359 GWh of heat along its 50 km long network. Operated at relatively high temperatures, this DHN features a forward temperature between 115 °C and 90 °C and a return temperatures between 70 °C and 80 °C.

In 2019, SIG embarked in the construction of *SolarCADII*, a decentralized large-scale solar plant, whose features are presented in tab. 1, integrated with the CADSIG DHN. The SolarCADII plant comprises two distinct sub-systems, fig. 1. The solar thermal plant and the heat transfer station. These components are linked *via* a plate heat exchanger (HX) and the collected solar heat is injected into the DHN according to the return-return feed-in mode (return to return injection), causing the DHN return flow temperature to raise.

Table 1. Main features of *SolarCADII*

Solar thermal field	
Solar thermal collector model	EFPC MT-POWER v4.3
Total number of collectors	400
Solar thermal field aperture area	784 m²
Nominal operating temperature	75-95 °C
Peak thermal power at 85 °C (T_a = 25 °C, G = 1000 W/m²)	537 kW
DHN and DHN connection	
Type of DHN connection	Decentralized, return/return
Inlet temperature at the solar substation	72 °C ±1.5 °C

Methodology

The solar plant and its injection point into the DHN have been equipped with several sensors that allow establishing the energy balance between the different sections of the plant and characterizing local weather conditions. See fig. 1 for their placement and [5] for their technical features. Since its start-up in January 2021, the solar plant performance is being monitored at a one-minute sampling rate through the periodical update of the various adopted key performance indicators (KPI), [6], presented in tab. 2. A numerical model of the plant, developed in TRNSYS® and operated at one minute time-step, has been used for fault detection and to evaluate and compare different potential optimization scenarios for the plant control and hydraulic layout. The TRNSYS® model can be thought of as being made by four main sections.

Section A, needed to process meteorological data from measurements acquired by the plant meteo-station (*i.e.* irradiance, air temperature and humidity, wind speed, and direction). This section also allow taking into consideration several sources of shadings on the solar field (*i.e.*, far field, near field, and reciprocal collector-shading) using TRNSYS® Type 30a (for reciprocal shading) and Type 67 (for far and near field shading).

Section B, making use of Type 832 to model the solar field as a single equivalent solar thermal collector, with parameters extracted form the Solar Keymark certificate (*i.e.* N. 011-7S1890F). Section B includes subsections for modeling the plant piping, pumps (*i.e.* with Type 31), 3-way valves (*i.e.* with Type 11f) and the solar side of the solar heat exchanger.

Section C, modeling the solar heat injection into the DHN as a sub-system made of a injection pump, the cold side of the solar heat exchanger and the DHN connecting pipings.

Section D, modeling the control and automation of the plant by processing all input signals (*i.e.* meteo-conditions and DHN states) to provide regulation and control signals for the active elements of the model (*i.e.* 3-way valves and pumps).

Table 2. Definition of the KPI used to quantify the plant performance and for numerical model validation

KPI name	KPI definition	Symbol
Yearly solar field production	Sum of the heat produced by the solar field over a year [MWh per year]	E_{sol}
Yearly solar plant production	Sum of the heat injected in the DHN over a year [MWh per year]	E_{DHN}
Solar field efficiency	Ratio of the yearly solar heat production over the yearly global irradiation in the plan of array [%]	η_{sol}
Solar plant efficiency	Ratio of the yearly heat injected in the DHN over the yearly global irradiation in the plan of array [%]	η_{tot}
Solar plant yearly specific productivity	Ratio of the yearly solar plant production over the solar field aperture area (784 m^2) [kWhm^{-2}]	$E_{\text{spec,DHN}}$
Solar field electrical coefficient of performance	Ratio of the solar field heat production and the solar field electricity consumption over one year [kWh$_{\text{th}}$/kWh$_{\text{el}}$]	COP$_{\text{sol}}$
Solar plant electrical coefficient of performance	Ratio of the solar plant heat production and the solar plant electricity consumption over one year [kWh$_{\text{th}}$/kWh$_{\text{el}}$]	COP$_{\text{tot}}$

The TRNSYS model of the plant was subsequentially validated by comparing acquired measurement data to the numerical simulation results on various time frames (*i.e.* 10 minutes, 1 hour, 1 day, and annually) and based on several indicators. In particular, the comparison was carried out first based on the root mean square error (RMSE), calculated by:

$$RMSE = \sqrt{\frac{1}{n}\sum_{i=1}^{n}(y_i - x_i)^2} \tag{1}$$

where y_i is the i^{th} simulated signal value, x_i – the i^{th} measured signal value, and n – the number of experimental samples. This indicator is a widely accepted metric to evaluate the quality of a predictive model [7]. The higher the RMSE value is, the lower is considered the quality of the predictive model. The RMSE metric is expressed in the unit of the evaluated model output, and its limiting factor is that it does not take into account the range of the evaluated variables (*i.e.* a large error for a small signal count as much as a large error for a large signal). As a consequence, to gain a better insight on the quality of the simulations, the coefficient of variation of the RMSE (*cvRMSE*) has been used as an additional validation metric. The *cvRMSE* is calculated using:

$$cvRMSE = \frac{\sqrt{\frac{1}{n}\sum_{i=1}^{n}(y_i - x_i)^2}}{\hat{x}} \tag{2}$$

where y_i is the i^{th} simulated signal value, x_i – the i^{th} measured signal value, n – the number of experimental samples, and $\hat{x}$ – the experimental average signal value. The *cvRMSE* is unitless and allows comparing signals with different absolute values, as it is computed by normalizing the RMSE by the signal average. The ASHRAE Guideline 14 [7] provides acceptance ranges for the *cvRMSE* in order for a predictive model to be considered sufficiently accurate. In particular, for a set of measurement data recorded over a period of 12 months at an hourly resolution, a predictive model is considered of good quality if the comparison between measured and simulated data yields a *cvRMSE* value equal or smaller than 30%.

Validation was carried out for the period going from June 2021 to June 2022 and the model parameters reflected the settings implemented in the real solar plant (*e.g.* solar irradiance threshold, solar heat injection temperature, minimal and effective circulating flow rates, *etc.*). To minimize the impact of measurement uncertainties related to the Sun elevation and the highly non-linear effects occurring at the beginning and end of the day, furthermore, data corresponding to a solar altitude lower than 5° were filtered out and not taken into consideration during the validation process.

Following the model validation, a life cycle analysis (LCA) was carried out, according to the methodology detailed in [8]. The LCA study was conducted according to recent standards and recommendations, *i.e.* ISO14040 [9] and ISO14044 [10], by taking into account the environmental impact of all plant components and its operations. In particular, the plant environmental impact during operations was estimated based on the performance data derived for 2021 and by taking into account the maintenance planning and the foreseen replacement frequency for the components featuring a lifetime shorter than the one of the overall plant (*i.e.* often 5-10 years for the former, 25 year for the latter). The functional unit was chosen to be the [kWh] of heat injected into the DHN, while the adopted plant lifetime was 25 years. The performance of the plant, on the other hand, was assumed to be degrading trough the years at a given rate and proportional to the performance measured in 2021 (*i.e.* 537 MWh of injected energy with a total coefficient of performance, COP_{tot}, of 37.5).

The LCA analysis was then followed by a life cycle cost analysis (LCCA) aimed at evaluating the levelized cost of heat (LCOH) featured by the solar plant. In particular, in the framework of the LCCA, the following hypothesis were adopted:
– solar plant lifetime of 25 years,
– 3% discount rate and a 3% energy inflation rate,
– annual maintenance costs corresponding to 1% of the initial investment, and
– 0.4% performance annual degradation rate.

The total investment cost considered for the solar plant was amended by the additional components installed to address the stringent safety constraints related to the in-situ visits by the general public, foreseen in the framework of the sensibilization campains organized to increase the acceptance of renewable energy sources. Due to confidentiality issues, a detailed list of the actual costs considered in the LCCA cannot be given here, but the project budget can be derived from informations given at the 2019 Swissolar Solar Heat congress [11].

The LCOH can be computed according to:

$$LCOH = \frac{\sum_{t=1}^{n25} \frac{I_t + M_t + O_t}{(1+r)^t}}{\sum_{t=1}^{25} \frac{E_t}{(1+r)^t}} \tag{3}$$

where I_t, M_t, O_t, and E_t are the investment, the maintenance cost, the operating cost, and the produced heat at year t, respectively, and r is the discount rate.

Results and discussion

Plant performance

The annual performance of the SolarCADII is summarized in tab. 3 since its start-up in January 2021. Notably, solar irradiation values for 2021 and 2022 have been sensibly higher than those recorded for 2023. The solar field plant exhibit high efficiency, close to 45%, at an average operating temperature of about 80 °C to 85 °C. The measured efficiencies were very stable during the whole period, particularly during 2021 and 2022. This stable efficiency demonstrates that there has not been any noticeable performance degradation of the EFPC during the first two and half years of operation.

Table 3. Solar field and solar plant performances evolution since its start-up

KPI name	2021	2022	2023 (Nov.)
Specific global irradiation poa [kWhm^{-2} per year]	1512	1636	1485
E_{DHN} [MWh]	535	580	501
η_{sol} [%]	44.5	45.2	44
η_{tot} [%]	44.7	45.0	43.1
$E_{\mathrm{spec.DHN}}$ [kWhm^{-2} per year]	673	740	639
COP_{sol} [–]	50	50	48
COP_{tot} [–]	30	30	29

In comparison, efficiency values for classical flat plate collectors (FPC) are in the range of 30% for a mean solar collector temperature of 80 °C under Danish meteorological conditions [12]. Such pronounced difference in the yearly conversion efficiency illustrate the interest of the EFPC technology when compared to FPC, in particular for medium to high temperatures and for sites where the share of diffused irradiance is high. During the monitoring period, measured yearly specific productivities were also very high, featuring values varying from 670-740 kWh/m^2 per year. As a consequence, in order to obtain a certain solar fraction for a given DHN application, the EFPC technology requires 20% to 30% less surface than the FPC technology. This characteristic is important for sites where the available surface for a thermal solar field is limited.

As shown in tab. 3, the measured values for the COP of the solar field, COP_{sol}, and for the COP of the solar plant, COP_{tot}, are stable through the monitoring period, but they are much lower than what is derived from literature, *i.e.* COP values greater than 100, [13]. Such low COP values are explained on one hand by the high flow regime chosen for the solar field (*i.e.*, ~30 Lph per m^2) and, on the other hand, by unforeseen pressure drops in the solar hydraulic circuit.

Figure 2 shows the monthly profile of the solar heat injected in the DHN, of the solar plant efficiency and of COP values. Notably, thanks to the EFPC technology, the solar plant is injecting useful solar heat into the DHN even in winter months, when the solar resource is scarce and ambient temperatures are low. Naturally, in winter times, the conversion efficiency of the solar plant decreases strongly, but this decrease in efficiency is much less important than with classical FPC. As shown in [4], the performances of EFPC are much less impacted by outdoor conditions than FPC. The EFPC continue to maintain reasonable conver-

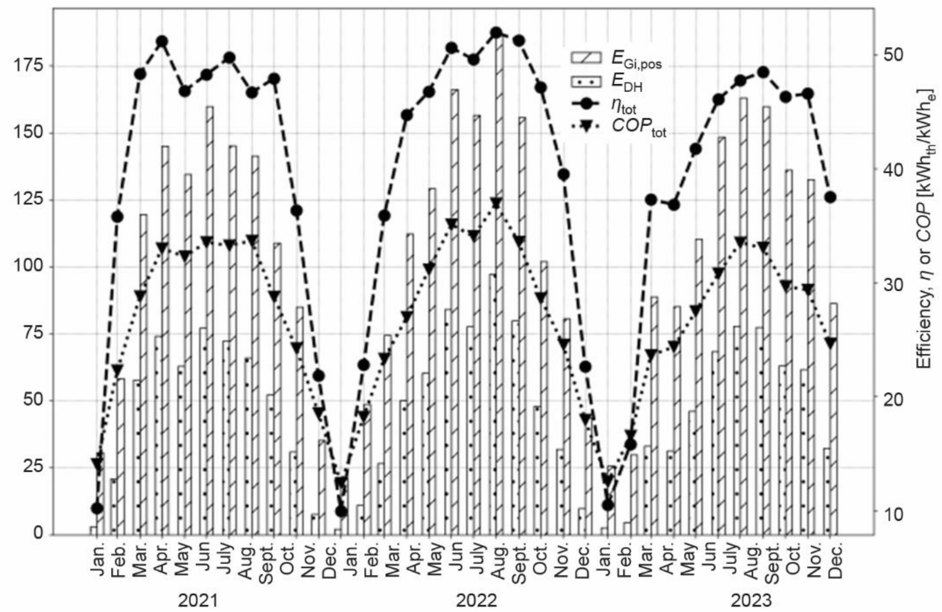

Figure 2. Solar plant monthly performances since January 2021

sion efficiencies even at irradiance values below 500 W/m^2, whereas the conversion efficiency of FPC drops sharply in the same conditions. The COP values also exhibit high seasonality. When irradiation is low, as in winter time, the COP decreases strongly, indicating a higher electricity consumption per [kWh] of injected solar heat.

The TRNSYS model validation

The numerical model of SolarCADII has been validated against experimental measurements on two timescales. A first level of validation has been performed on a period of one day of operations to verify the ability of the numerical model to reproduce the dynamic behaviour of the solar plant on a one-minute time-step. A second level of validation, aimed at testing the ability of the model to predict the heat production, has been performed, on the other hand, over a period of one year with one-hour time-steps.

Figure 3 shows that the model is able to correctly reproduce the dynamic behaviour of the solar plant. The simulated temperature of the heat transfer fluid (HTF) at different locations of the plant follows very closely measurement data. During the night time, conversely, the numeric model temperature profile deviates significantly from the measured temperatures. This phenomenon is explained by the fact that temperature sensors are exposed to cooled HTF, since they are located in spots with less efficient insulation. As a consequence, the value of the HTF temperature inside the collectors is much higher than the measured one. On the other hand, the simulated flowrate, which depends from the model implantation of the control strategy and from the measurement sampling rate, features non negligible differences, especially during the preheating phase and when the flowrate changes abruptly at the end of daily operations. Table 4 provides the RMSE and the *cvRMSE* values for the comparison between modelled and measures temperatures at the inlet and outlet of the solar field, and at the inlet and outlet of the HX on the DHN side. Notably, the *cvRMSE* for temperatures are all smaller than the ASHRAE 30% limit, while that for the solar collected energy injected into the DHN features a value which is slightly less than 40%. As such, the numerical model can be considered reasonably accurate and it can be adopted to optimize the solar plant control and regulation strategy.

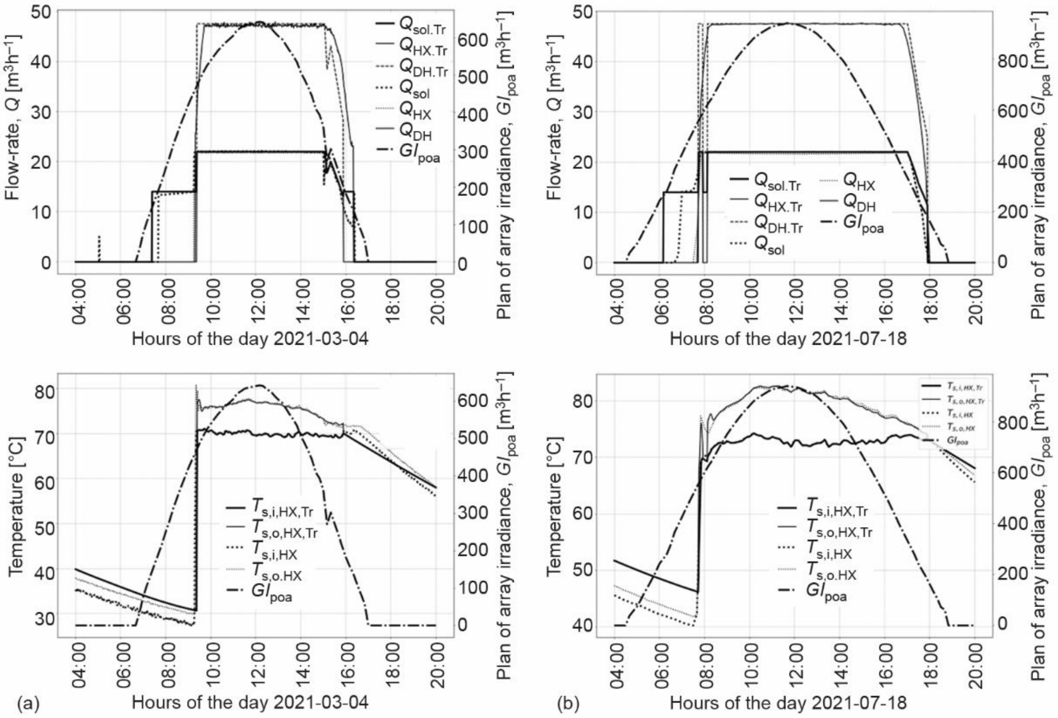

Figure 3. Dynamic comparison between experimental measurements and the TRNSYS model for two days; (a) March 4, 2021 and (b) July 18, 2021, with a one-minute sampling rate

Table 4. The RMSE and *cvRMSE* comparing measured data with predicted data for different solar plant temperatures at an hourly time step from June 2021 to June 2022

Variable name	*RMSE* [°C]	*cvRMSE* [%]
Tp_i_sol	11.6 °C	20.7%
Tp_o_sol	13.0 °C	20.6%
Ts_i_DH	13.1 °C	23.7%
Ts_o_DH	13.6 °C	23.2%
E_DH	52.7 kWh	39.2%

Solar plant optimization

Using the validated numerical model with the meteorogical data recorded in 2022, different strategies of optimization have been investigated to maximize the solar heat injection and minimize the plant electrical consumption (*i.e.* increasing the COP_{tot}). The optimization study investigated the following parameters:

– The HTF flowrate in the solar field, in the range from 15-33 m^3 per hour (*i.e.* current HTF flow rate is about 22 m^3 per hour).
– Solar irradiance threshold, corresponding to the minimum impinging plan of array irradiance at which HTF circulation starts in the morning. Usually set in the range from 50-300 W/m^2 (*i.e.* the current plant irradiance threshold value is 200 W/m^2);

Figure 4 shows the variation of solar heat production and plant COP as a function of the flowrate in the solar loop. It confirms that the plant COP increases from 33 to 42 as the flowrate decreases from 33 to 15 m^3 per hour, corresponding to a decrease of roughly 20% in electricity consumption per [kWh] of solar heat injected in the DHN. This important reduction of electricity is explained by an important reduction of the pressure drop in the solar hydraulic circuit. On the other hand, the flow rate reduction impacts negatively the solar heat production, affected by a reduction from 549.3-537.5 MWh per year, which corresponds roughly to a 2% reduction. This small reduction of the collected solar heat points to the weak sensitivity of EFPC to production temperatures for values less than 100 °C. At the current costs of electricity (about 0.30 CHF/kWh) and heat (about 0.15 CHF/kWh) in Switzerland, there is a small financial optimum at about 23 m^3 per hour, value which is close to the current flowrate in the solar field.

Figure 5 shows the impact of the variation of the irradiance threshold on the COP and the solar heat production. A current practice to define the solar irradiation threshold is to calculate with the Solar Keymark parameters the minimum solar irradiance needed to reach the minimum operating temperature (about 85 °C for the SolarCADII) without producing any heat (*i.e.* at 0% efficiency). When this threshold is reached for a given duration (5 minutes for the SolarCADII), the solar plant is started. With the TVP EFPC, such threshold is in the range of 100 W/m^2 (for a 10 °C ambient temperature). As shown in fig. 5, the solar heat production is relatively stable for a threshold between 50 W/m^2 and 150 W/m^2. Above 150 W/m^2, the solar heat production starts to decrease slightly because a portion of the solar resource at low irradiance is not exploited. The impact on the COP of minimum solar irradiance is more important with a constant increase from 50 W/m^2 to 300 W/m^2, corresponding to a decrease in electricity consumption of 27% per [kWh] of solar heat produced. At current selling price for heat and electricity, an almost flat financial optimum is found around 200 W/m^2, as lower threshold irradiance values see an increase in the plant electrical consumption without having any impact on the overall heat production. It demonstrates that the current practice to determine the minimum value for the solar irradiation threshold is not strictly valid for EFPC. The very low irradiance threshold value that can be computed, in fact, would imply that the HTF

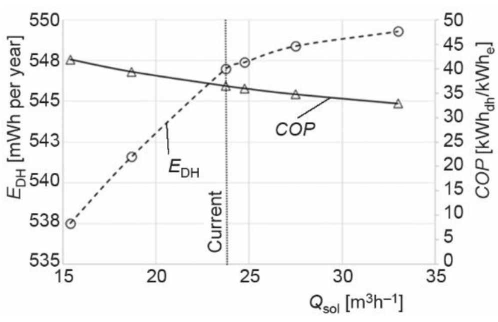

Figure 4. Impact of the flowrate in the solar field on the solar heat production and COP

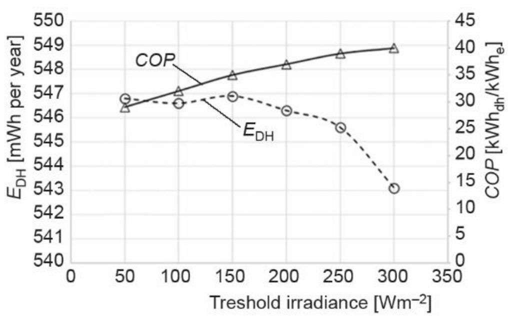

Figure 5. Impact of the threshold irradiance value on the solar heat production and the COP_{tot}

circulations is started for several days featuring very low probability to provide enough irradiation to reach the production temperatures. With classical FPC, irradiation thresholds are, instead, often above 300 W/m^2, which is an irradiance value that is usually reached during days with higher probabilities to have enough irradiation to reach the production temperature limit.

Solar plant environmental and financial analysis

A complete LCA, together with a financial analysis, have been realized on the SolarCADII. The detailed results of this study have been presented in [8]. In particular, a GHG content varying between 15 g/kWh and 18 g/kWh has been calculated for the solar heat injected in the DHN. This value is of the same order of magnitude as the one found in a Swiss LCA database in the case of a solar field for the domestic hot water production in a multi family building, *i.e.* a value of 15 g/kWh, [14]. The GHG value computed for the SolarCADII is lower than the average GHG content of the typical Swiss DHN, which is about 67 g/kWh, demonstrating that the EFPC is a very efficient technology for the decarbonization of the heat sector.

The financial analysis has been carried out using the actual costs of the solar plant built in Geneva. As one of the first installations of this size manufactured by TVP Solar, the investment costs were rather high. The TVP Solar has since further increased its expertise in large solar thermal projects for DHN applications, as the one for which TVP Solar collectors have been selected in 2023, featuring a 48000 m^2 of aperture area and located in Groningen, Netherlands.

For SolarCADII, the total investment was roughly around 1.25 MCHF, which corresponds to an LCOH of 174 CHF/MWh without subsidy and to 146 CHF/MWh with 20% subsidy. This figure is in line with what has been reported in literature for a Swiss case study for applications in the industrial sector [15]. With such LCOH values, the solar heat produced by this plant is comparable to the cost of heat sold on Swiss DHN. A recent study, aimed at comparing the cost of heat delivered at customer substations for seven different Swiss DHN, has resulted, in fact, in a cost range going from 115 to 200 CHF/MWh. Given the recent general increase in energy prices in Switzerland, partly due also to the increasing share of the renewable heat in the DHN supply, the recent cost reduction of TVP solar collectors following the company production ramp-up and a higher subsidy rate could contribute to decrease further the solar heat cost obtained with the EFPC technology.

Conclusions and perspectives

This study provides an update on the performances of a large EFPC solar thermal field connected to a DHN located in Geneva, Switzerland. The 784 m^2 solar thermal plant commissioned in January 2021, has been fully equipped with a monitoring system to assess its performances. After close to three years of operation, no degradation of the solar plant was observed and reported EFPC performances are very promising for industrial and DHN applications with medium to high temperature (80-100 °C).

A dynamic numerical model of the SolarCADII has been developed under TRNSYS and validated against the collected measurement data. The validated model has been used to evaluate the impact of some optimization strategies, like the optimization of the HTF flowrate circulating in the solar field and that of the solar irradiance threshold, used to start circulation in the morning and to stop the pumps at the end of the day or during unfavorable meteo conditions. The implemented optimization strategies have illustrated that EFPC technologies, analogously to evacuated tube collectors, are much less sensitive to operating conditions than regular FPC thanks to their high vacuum insulation. As a consequence, the solar conversion efficiency is less dependent on the operating temperatures and on the fraction of diffused solar irradiance.

An LCA and an LCCA have been also realized on the solar plant. The former confirms that EFPC technology is very attractive for the decarbonization of the heat sector, in particular for industrial and DHN applications. The latter shows that the LCOH for this application is competitive on the heat market. The LCOH could be further lowered by decreasing the cost of the collector and more generous subsidies, that could support the development of the solar sector in Switzerland, similar to the recent trend in Germany and Austria [2].

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