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Integration of solar thermal systems into existing district heating systems

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Abstract

Modern district heating (DH) networks are usually operated with a changing flow temperature to cover the heat load of the supply area, depending on the outside temperature. Due to the minimum temperature requirements of individual customers, DH networks also need to operate during the summer months. During this time, the load on the system is relatively low. This requires combustion facilities to operate on low load levels as well. These systems have a potential of improving the energy efficiency by utilizing other energy sources such as waste heat from industrial processes or solar thermal systems. The overall aim of the presented work is to provide a new methodology for the integration of solar heat into existing DH systems.
The feasibility of including solar thermal systems in existing DH networks will be analyzed, based on the state of the art of solar DH. The main focus will be on large DH systems that are mainly supplied by fossil fuel powered combined heat and power (CHP) plants considering how such plants can be operated in the future. In this paper, characteristic technical and ecological key performance indicators of a transformed DH system will be displayed.
The work was carried out based on real data of an example DH network in Germany. It was analyzed how a sub-network of a system can be supplied during the summer season by a solar thermal system as far as possible independently from the main-network without using a back-up boiler system. The favored solution in this article is to use a thermal storage that can be recharged once a day by a central CHP plant.

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Keywords: District heating; Solar district heating; Solar thermal systems; Distributed renewable system; Solar field

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1. Introduction

The integration of solar thermal systems in DH systems is a more and more common practice in some countries; however, few studies have been performed on methodologies and benefits of integrating solar thermal systems in DH systems that are mainly supplied by large scale CHP plants with low heat generation costs.

The general idea behind including solar collector fields in DH networks is to lower or even completely supply the low heat demand of a DH network during the summer months. Since the 1980s Denmark and Sweden have built many solar heating plants [1]. In some of these cases a seasonal storage is used to provide a solar fraction even above 50 % of the total system demand. The high taxation of primary energy sources supported the ambitions in Denmark that lead to seasonal storages which are only feasible in a very large scale [2]. In comparison to the Danish and Swedish developments solar DH systems in Germany started to be built later, at the beginning of the 1990s.

The large DH systems in Germany are generally supplied by large CHP plants. These plants are often operating as base load power producers and can supply heat and electricity at a cost-efficient level during summer and winter due to funding through the CHP production law (KWKG) [3]. In addition to the availability of low-cost heat, high and very high system temperatures in the DH systems also prevented solar heat generating systems [4]. In the case of the DH system Chemnitz, only a large change in the system structure in one district made a change feasible. Possibilities of including solar collector systems in existing DH networks that are not about to change radically and are using large scale CHP plants as a main heat source were rarely analyzed. Despite of the higher specific generation costs a solar collector field can also bring several advantages to systems of the mentioned kind.

This paper presents aspects where a solar collector field can be beneficial for a DH system based on a large-scale CHP plant and how such a collector field can be included. The work was carried out by evaluating the load pattern of a part of an existing DH system in Germany.

In the given case, the system analyze was based on the following conditions:

- A fixed supply temperature in a connected sub-network that is not needed in the whole system
- A long connection pipeline between the main network plant and the connected sub-network
- A reduction of the primary energy factor (PEF)
- A reduction in CO_2 emissions

Considering the interests of the network owner, different methodologies of including a solar collector field were developed. In the given case, a solution without a local backup boiler is preferred; instead a daily reheat of a storage from the large CHP plant was suggested.

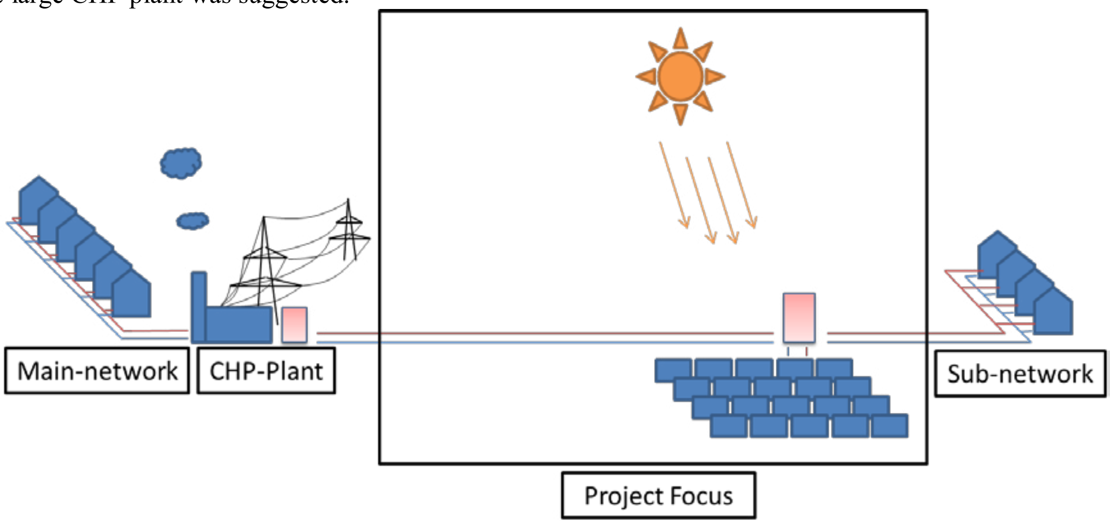

Figure 1. Project focus: The solar thermal field and the thermal storage are located between main-network and sub-network

Nomenclature

A	Aperture area (m²)
a_1	First degree coefficients of the collector heat losses (W/Km²)
a_2	Second degree coefficients of the collector heat losses (W/Km²)
c	Heat capacity of water (Wh/(kg*K))
$f_{sol,m}$	Monthly share of solar energy supply (-)
G	Global radiation (W/m²)
$\dot{Q}_{add}$	Additional heat supply rate (MW)
Q_{ch}	Storage state of charge (MWh)
$\dot{Q}_{dem}$	Heat load of the sub-network (MW)
$Q_{dem,tot}$	Annual energy demand of the sub-network(MWh)
$\dot{Q}_{sol,dir}$	Directly used solar heat rate (MW)
$Q_{sol,m}$	Monthly energy to be supplied by solar (MWh)
$\dot{Q}_{sol,stor}$	Stored solar heat rate (MW)
$Q_{sol,tot}$	Annual energy to be supplied by solar (MWh)
$\dot{Q}_{dis}$	Storage heat discharge rate (MW)
Q_{re}	Daily storage heat energy recharge (MWh)
Q_{sel}	Annual energy chosen to be supplied by solar (kWh)
$Q_{sol,m}$	Monthly energy to be supplied by solar (kWh)
$q_{sol,m}$	Specific net solar gain per month (kWh/m²)
$q_{sol,tot}$	Specific net solar gain per year (kWh/m²)
$\dot{Q}_{sol,dir}$	Directly used solar heat rate (MW)
$\dot{Q}_{sol,stor}$	Stored solar heat rate (MW)
Q_{st}	Storage energy capacity (MWh)
SF	Annual solar fraction
T_a	Hourly ambient temperature (°C)
T_{in}	Hourly collector inlet temperature (°C)
T_m	Hourly medium temperature (K)
T_{max}	Maximum storage temperature (°C)
T_{min}	Minimum storage temperature (°C)
T_{out}	Hourly collector outlet temperature (°C)
V	Storage volume (m³)
η_0	Collector zero-loss efficiency (-)
ϱ	Density of water (kg/m³)

2. Methodology

The calculations for this project have been performed in MATLAB and are based on four years of measurements of heat consumption, volume flow and flow temperatures. Values in 15 min time steps for the solar radiation of an average day of each month were imported from PVGIS [5] for the specific location. Additional weather evaluation has been performed using outdoor temperature data from 1974 to 2014 from Germany's National Meteorological Service (DWD) [6].

Figure 2 below visualizes the methodology in a flow-chart starting with the input over a decision in solar fraction, resulting in collector areas, storage sizes and finally an energy flow overview and a storage operation visualization.

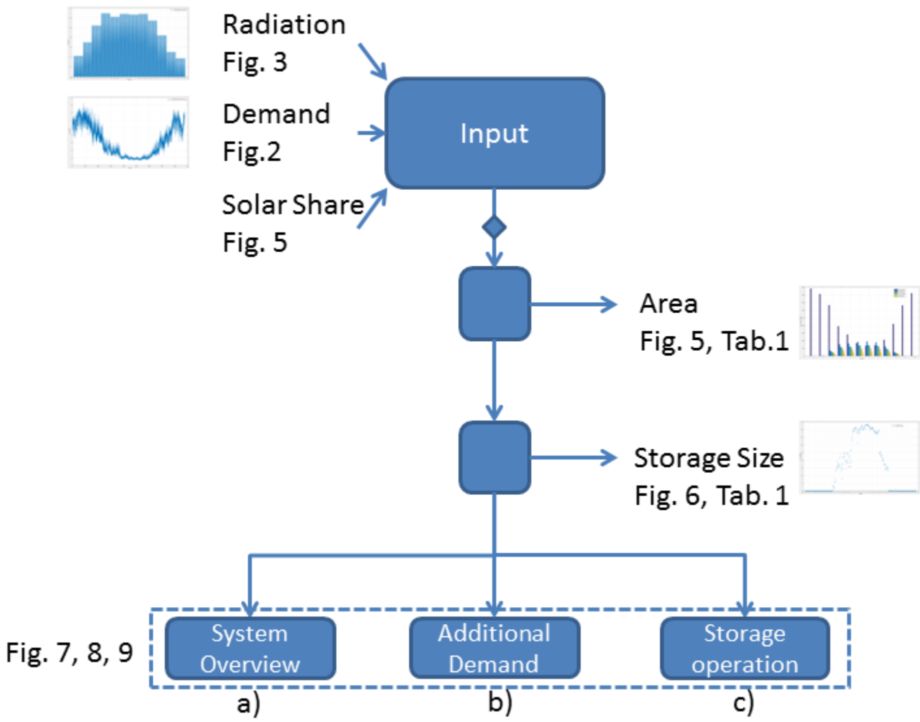

Figure 2. Methodology for the integration of solar heat into existing DH systems

Figure 3 shows the average heat load $Q_{dem,av}$ of the given consumer, the sub-network of the years 2013-2015. The following figure 4 shows the solar radiation during a year on a surface tilted south with an angle of 35°.

Based on the smoothened outdoor temperature line of the average outdoor temperature from 1974 to 2014 given by DWD [6] and a graph displaying the required supply temperature to the sub-network, the time span from hour 3241 to hour 6337 of a year was calculated when the supply temperature is at its allowed minimum (Figure 5). In this time span the DH main-network could further decrease the supply temperature, if it could operate independently of the sub-network. The focus of this project was how the sub-network can be supplied by a solar heating system during this period.

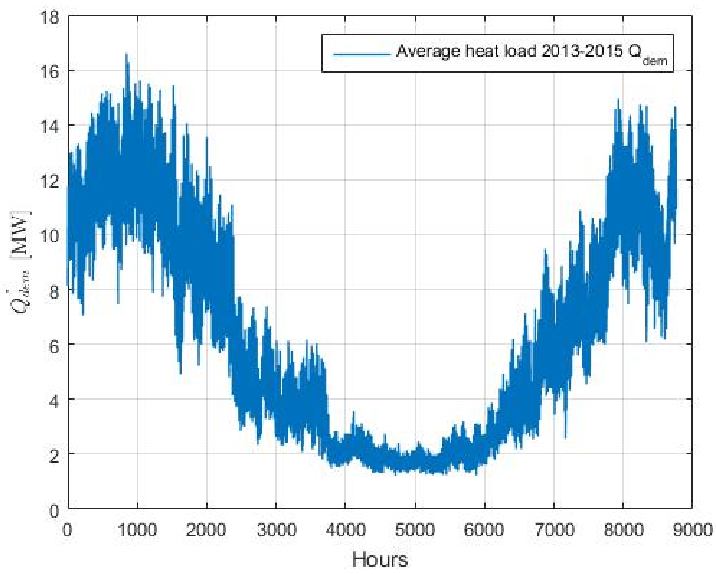

Figure 3. Example of annual the heat load curve in a sub-network

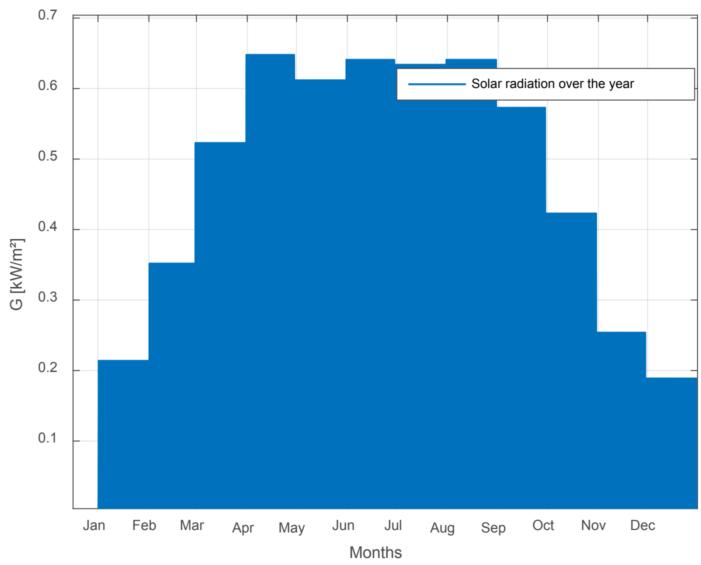

Figure 4. Example of maximum solar radiation on an average day on a south oriented 35° tilted surface in southern Germany

The efficiency of solar collectors η_c was calculated according to the European Standard EN 12975 [7] as follows:

$$\eta_c(t) = \eta_0 - a_1 \frac{(T_m(t)-T_a(t))}{G(t)} - a_2 \frac{(T_m(t)-T_a(t))^2}{G(t)};\ t=\{1,2,3,\ldots,8760\} \qquad (1)$$

$$T_m(t) = \frac{(T_{out}(t)+T_{in}(t))}{2} \qquad (2)$$

Accordingly, the hourly specific net solar gain $\dot{q}_{sol}(t)$ is:

$$\dot{q}_{sol}(t) = \eta_c(t) * G(t) \tag{3}$$

As the average global irradiance is given in 15 minute steps but the resolution was reduced to hourly steps. This allows, to use the actual DH return temperature as collector inlet temperature T_{in} and the DH supply temperature as the collector outlet temperature T_{out} if it was above 80 °C, otherwise T_{out} was set to 80°C. The ambient temperature T_a was taken from PVGIS as well. The collector dependent values η_0, a_1 and a_2 were taken from Solar Keymark Datasheets [8] of an representative flat plate collector (FPC) and a representative evacuated tube collector (ETC).

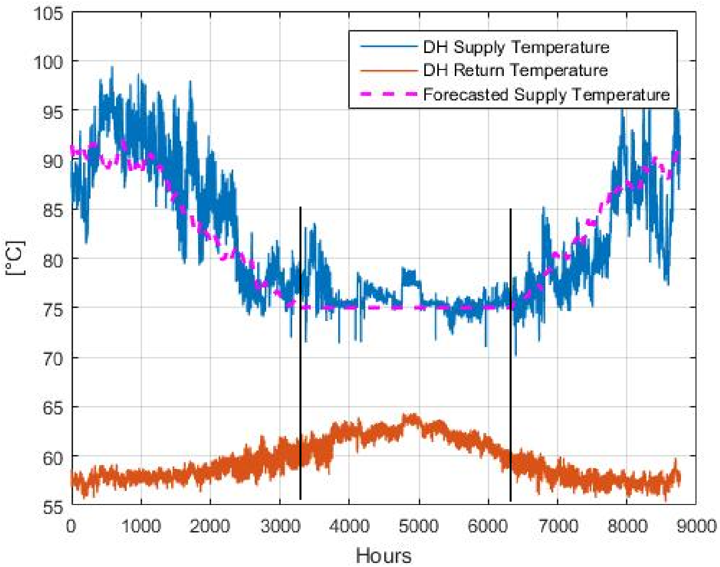

Figure 5. Average supply and return temperature and expected supply temperature of the sub-network

2.1. Area selection:

Field sizes were calculated depending on different annual solar fractions of 5 %, 10 %, 15 % and 20 % of the total annual heat consumption. Additionally, one approach aims to supply the heat consumption of July completely, which corresponds to 13.2 % solar fraction, because this is the month with the lowest consumption throughout the year. The following calculation steps are used to receive the actual collector aperture area A:
Calculation of specific net solar gains for each month $q_{sol,m}$:

$$q_{sol,m} = \sum \dot{q}_{sol}(t) \cdot \Delta t_i;\ i: hours\ of\ each\ month \tag{4}$$

Calculation of specific net solar gains for a year $q_{sol,tot}$:

$$q_{sol,tot} = \sum \dot{q}_{sol}(t) \cdot \Delta t_j;\ j: hours\ of\ the\ year \tag{5}$$

Calculation of the monthly share of solar energy supply $f_{sol,m}$:

$$f_{sol,m} = \frac{q_{sol,m}}{q_{sol,tot}} \quad ; m = \{Jan, Feb, Mar, \dots, Dec\} \tag{6}$$

Calculation of annual and monthly solar energy ($Q_{sol,tot}$, $Q_{sol,m}$) supplied:

$$Q_{sol,tot} = SF * Q_{dem,tot} \quad (7)$$

$$Q_{sol,m} = Q_{sol,tot} * f_{sol,m} \quad (8)$$

Calculation of required collector aperture area:

$$A = \frac{Q_{sol,m}}{q_{sol,m}} \quad (9)$$

Figure 6 shows an overview of the different solar fractions compared to the monthly energy demand. At an annual solar fraction of 13.2 % the solar heat energy fully covers the heat demand in the month of lowest demand (July). A higher annual solar fraction provides a surplus of solar heat during the summer that cannot be used.

Table 1 shows an overview of the calculated variations with the collector area, the relative storage dimension and the achieved CO_2 savings.

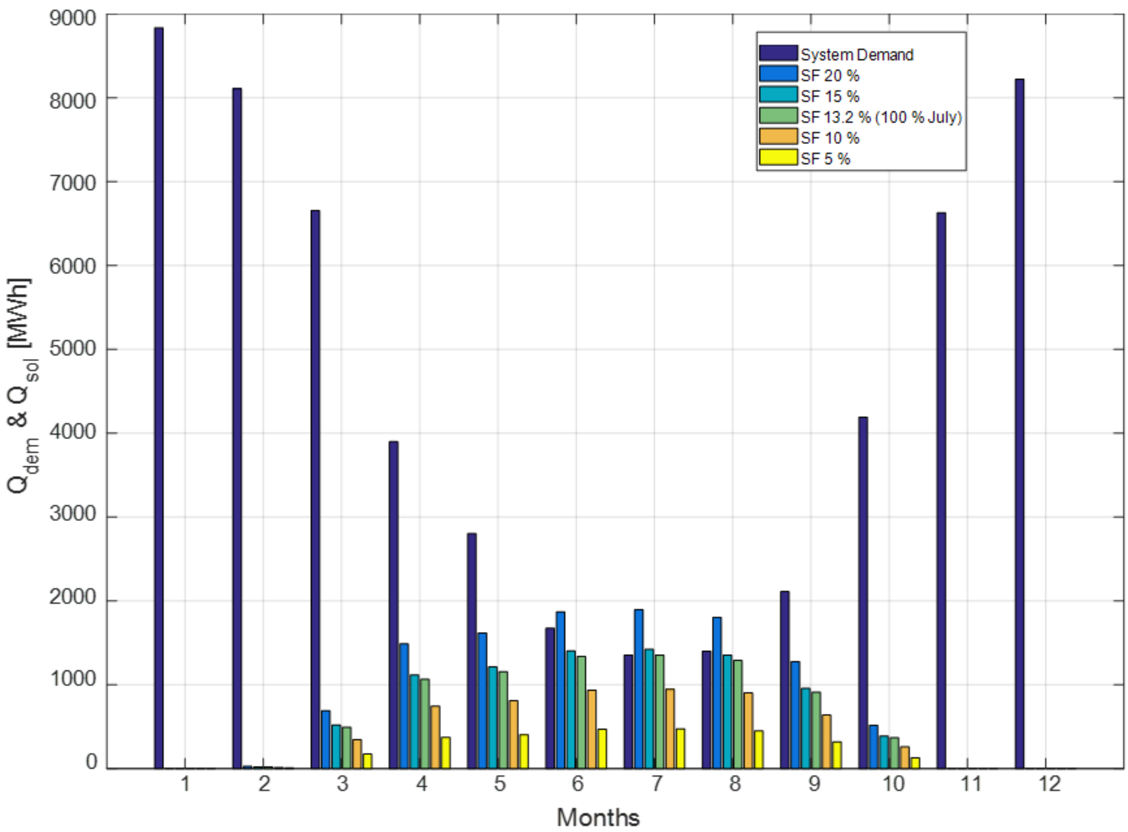

Figure 6. Net solar gain compared to demand for different solar fraction variations

Table 1. Calculation results for different annual solar fraction

Solar fraction	Collector area (m²)	Specific storage volume (l/m²)	Storage volume (m³)	CO_2 savings (t/a)
5 %	6467	7.3	47	480
10 %	12934	30.3	392	961
13.20 %	18481	39.5	730	1369
15 %	19401	40.5	785	1424
20 %	25854	46.2	1194	1725

2.2. Storage Dimensioning:

For this project, it was required to store only the surplus solar heat that can be received within a single day and dimension the storage size accordingly. Figure 7 shows the solar surplus of each day that can be received when having an average load and a solar collector field size corresponding to the July demand (annual solar fraction of 13.2 %).

The conversion from MWh storage capacity to m³ water in storage capacity was performed according to the following formula:

$$V = \frac{Q_{st}}{\varrho * c * (T_{max} - T_{min})} \tag{10}$$

Practically, T_{min} is the maximum return temperature measured, 63 °C and T_{max} is the maximum allowed temperature in the storage 95 °C.

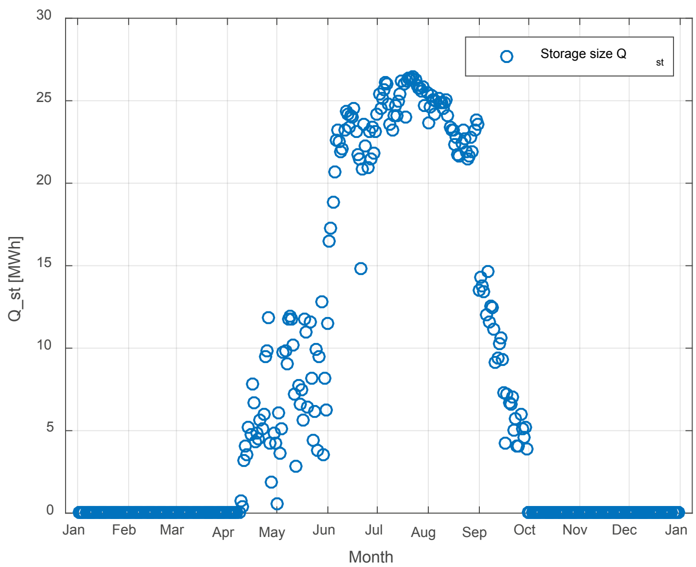

Figure 7. Needed storage capacity to store the solar surplus energy

2.3. Storage operation:

To enable the sub-network to operate as independently as possible without having a backup boiler it is considered that the storage is reheated once per day. In this scenario, the recharge from the main-network is set to be done every evening at 21.00 h with a supply temperature of 80 °C. This means that during summer time 3 different temperature zones will develop in the storage; one with the DH return temperature, one with 80 °C from the CHP plant and one with a maximum of 95 °C from the collector field.

3. Results

The first thing to realize throughout the calculation was that the needed storage size to store a solar surplus was below 50 l/m² collector area. A relatively small dimensioned storage is also recommended by [2]. [2] also points out that a solar storage is normally not used for the largest part of the year. That the storage in this calculation is also only needed during the summer season can be seen in Figure 7.

Figure 8a shows the supply and demand curves for the summer season if a recharge every evening is done for a solar collector area of 18,481 m² which corresponds to 13.2 % solar fraction. Figure 8 b) shows the additional demand of the system, meaning the heat power that is needed at some hours to cover the demand of the sub-network if the storage is empty and not enough direct solar energy is available. Equation 8 below shows the relation between the different heat power terms:

$$\dot{Q}_{dem} = \dot{Q}_{sol,dir} + \dot{Q}_{dis} + \dot{Q}_{add} \qquad (11)$$

Figure 8c and 9c display the storage charge and the energy the storage is charged with during the reheating process. In Figure 9a it can also be seen that when the storage is recharged, $\dot{Q}_{dem}$ of the sub-network at that moment is covered by the main-network, too.

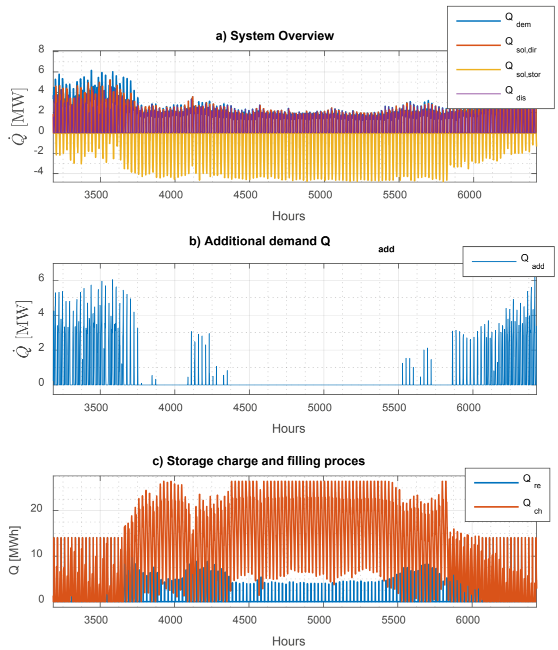

Figure 8. Supply and demand curves (a), additional heat power demand (b) and storage charging (c) during the summer season with 13.2 % solar fraction

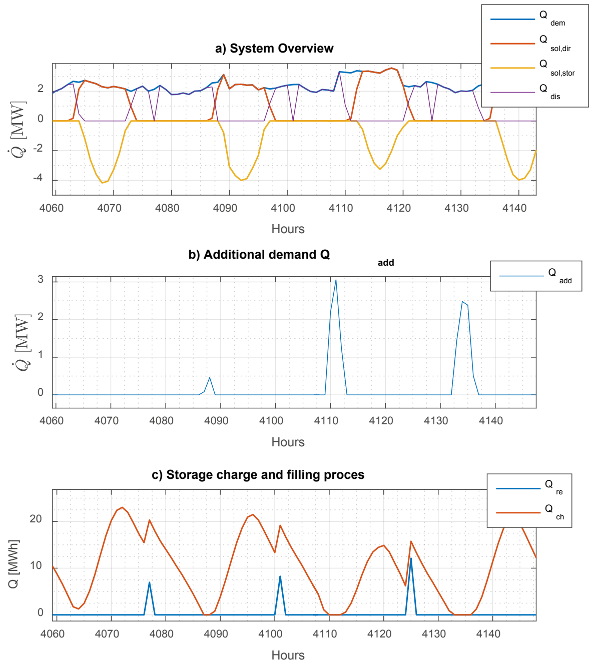

Figure 9. Zoomed in 4 days of supply and demand for the scenario with 13.2 % annual solar fraction

While Figure 8 presents the complete summer season of a system with 13.2 % solar fraction, Figure 9 shows the supply and demand for the same system but this time only for 4 days. In Figure 9c, the excerpt of Figure 8c, it becomes visible that when the storage is empty, additional demand is needed from the main-network, visible in Figure 9b, at hours 4088, 4111 and 4135.

The optimal system choice is therefore an offset between a system that needs as little additional energy during the summer season as possible, with the aim to let the main-network operate as independent as possible and a system that has a collector area as little as possible to reduce the system costs as well as to reduce the losses during the summer due to storage limitations.

Figure 8 shows that a system of the given specification can supply the sub-network's demand during the summer season to a large extent independently of the main-network if an overnight charging of the storage to 80 °C is given. An increase from 13.2 % solar fraction to 20 % solar fraction will reduce the need for additional energy supply from the main network during the summer season but will also increase the losses of solar energy as the storage is not emptied for the largest part of the summer season. Furthermore, the difference in the collector area between 13.2 % and 20 % solar fraction is 7373 m² and will also have a large economic impact.

Additionally, a decrease in CO_2 emissions, as visible in Table 1, is possible by up to 1725 t CO_2 per year in the case of 20 %.

4. Discussion

The comparison of the presented results against results of a freeware calculation tool (SDH Online-Calculator [9]) with similar input data shows a generally good validity of the method. However, due to different methodological approaches the results cannot be compared to each other directly.

Firstly, the irradiation on the collector field was about 16% higher in this project. This is due to a different location that was chosen but most of all due to the different meteorological data source of both calculations.

Secondly, in case of higher collector outlet temperatures during summer, when the storage capacity is fully needed, the collector efficiency will decrease. This will reduce the net solar gains.

Thirdly, it has to be mentioned that losses in the piping system and the storage of about 5 to 10 % have to be added.

Fourthly, results in the CO_2 savings differ in this project compared to the SDH-Online tool as the CO_2-emission factor of 172 g/kWh for the given example DH system was used.

5. Conclusion

The integration of solar heat into existing DH systems brings benefits to a fossil CHP plant based system such as CO_2 reduction, primary energy factor improvement and operational flexibility. The possibility to supply a sub-network for certain periods of the year mainly by solar heat, allows an increasing efficiency of the CHP plant in the main network.

Furthermore, it brings economic benefits due to the German CHP funding regulations. A solar thermal system enables the whole DH network to react better on future changes in the German electricity price market when it may be economically beneficial to decrease the energy production of the plant from an electricity production point of view.

The study shows that the accuracy of dimensioning a solar district heating system highly depends on the quality of the input data used. Calculations on the basis of annual data provide a rough idea on the necessary collector area and storage volume for a given heat demand. However, an exact dimensioning can only be done by using hourly-data of solar radiation and heat load for a whole year period.

The methodology for the integration of solar heat into DH systems that is presented in this paper leads to more detailed results and avoids over-dimensioning of solar fields and storage volume.

The example calculation shows that a solar thermal DH sub-network with an annual solar fraction of 13.2 % can be realized without auxiliary gas or biomass boiler, if a storage with recharging option is given. During the summer months the solar heat gains cover the total heat demand of the network whereas in other times of the year the main-network provides the additional heat. A short-term storage with a specific volume below 40 l/m² is sufficient.

6. Outlook

The results of the presented calculations will be improved in the next phase of the project by optimizing the storage recharging time and level as well as by adding the piping system as a usable storage. In the example of a DN300 pipe without extractions an additional specific volume of 78 m³/km can be taken into account to store water at 80 °C for a short time once a day.

Furthermore, an economic analysis will be undertaken in order to provide investment cost of the system as well as levelized costs of solar heat energy.

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