Integration of solar thermal systems in existing district heating systems

Citation for the original published paper (version of record):
Winterscheid, C., Dalenbäck, J., Holler, S. (2017). Integration of solar thermal systems in existing district heating systems. Energy, 137: 579-585. http://dx.doi.org/10.1016/j.energy.2017.04.159

Energy 137 (2017) 579–585

Contents lists available at ScienceDirect

Energy

journal homepage: www.elsevier.com/locate/energy

Integration of solar thermal systems in existing district heating systems

Carlo Winterscheid [a,*], Jan-Olof Dalenbäck [a], Stefan Holler [b]

[a] Chalmers University of Technology, Gothenburg, Sweden
[b] HAWK University of Applied Science and Arts, Göttingen, Germany

ARTICLE INFO

Article history:
Received 3 November 2016
Received in revised form
30 March 2017
Accepted 30 April 2017
Available online 3 May 2017

Keywords:
District heating
Solar district heating
Solar thermal systems

ABSTRACT

The integration of large solar heating systems in district heating (DH) networks with large combined heat and power (CHP) plants is rarely considered. This is often due to low costs for heat but also due to subsidies for the electricity by CHP plants. Possible changes in subsidies and requirements in the reduction of fossil fuel based CO_2 emissions raise an awareness of improving the operational flexibility of fossil fuelled CHP plants. This paper provides a rather simple but detailed methodology of including large solar heating systems in an existing district heating system, where heat is supplied by a large CHP plant. It uses hourly data of load and temperature patterns as well as radiation data and collector efficiency data to determine collector field size and storage size. The possibility of largely independent operation of sub-networks is analysed, which allows different system temperatures. It is demonstrated that a sub-network can operate without a back-up boiler and that both network parts benefit from the interaction.

1. Introduction

The integration of solar thermal systems in DH systems is a more and more common practice in some countries. 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. Previous studies have shown that a high solar fraction in solar district heating is feasible only by introducing a large scale seasonal storage into the system: 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 reason for this development can be explained due to the fact that 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 example cases of the DH system in Chemnitz and Salzburg, only a large change in the system structure in one district made a change feasible [4,5]. 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 analysed. Due to this, previous studies mainly focus on solar district heating systems with seasonal storage for new-built district heating systems. Yang et al. [6] have presented the impacts of integration of local distributed solar storage system with centralized short- and long-term storage systems on the overall performance of a solar district heating system. According to that study the degree of saving or reduction is dependent on the size combination of both centralized and distributed solar systems. The economic perspective however has not been covered. Lozano et al. [7] have presented the results of an economic analysis of solar heating plants in Spain, however, focusing on a large-scale system with seasonal storage, only. Other recent studies have presented results from TRNSYS simulations of centralized solar heating plants with seasonal storage solutions [8–10]. The "SOLAR-KWK" report [3] and the "SolnetBW" report [11] which were presented by researchers from the German Solites institute deal with the political and technical environment in Germany. The "SOLAR-KWK" report

* Corresponding author.
E-mail address: carlo.winterscheid@outlook.com (C. Winterscheid).

http://dx.doi.org/10.1016/j.energy.2017.04.159
0360-5442/

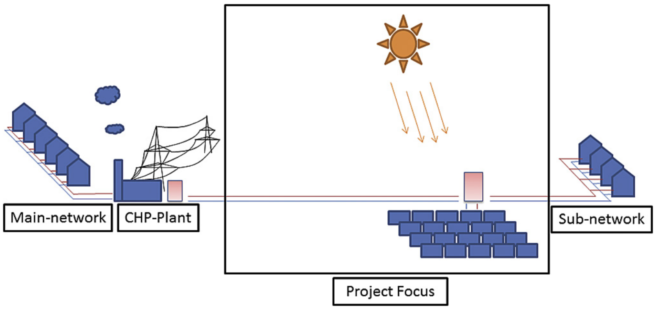

Fig. 1. Project focus: The solar thermal field and the thermal storage are located between main-network and sub-network.

deals with optimized operation of CHP facilities supported by solar heat with seasonal storages and the "SolnetBW" report deals with possible development in the federal state of Baden-Wüttemberg in Germany considering the national support schemes and the given local environment with existing DH networks and power plants. Results of both studies were used to set the boundary conditions for the analysis presented in this paper.

Current development in new constructed plants in Germany show also that Evacuated Tube Collector (ETC) systems are more and more considered [12] compared to the Flat Plate Collector (FPC) systems that are dominant in Denmark [13]. Both technologies are covered in this paper.

In addition to previous studies, as described above, this paper presents aspects where a solar thermal system can be beneficial for a DH system based on a large-scale CHP plant and how such a solar thermal system has to be dimensioned without the need of a seasonal storage. The work was carried out by evaluating the load pattern of a part of an existing DH system in Germany (see Fig. 1). In the given case the system analysis was based on the following conditions and objectives:

- A fixed minimum 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 thermal storage from the large CHP plant was suggested. To allow for an analysis of this rather specific case, the authors decided that the development of a Matlab code with the most significant relations can easier meet the required information of the DH network owner than a more complex TRNSYS simulation.

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 [14] for the specific location. Additional weather evaluation has been performed using outdoor temperature data from 1974 to 2014 from Germany's National Meteorological Service [15].

Fig. 2 below visualizes the methodology for the calculation algorithm used for the project. Input data of the simulation model comprehend climate data, DH system specification data, solar collector data and data of the thermal storage. Simulation scenarios where calculated for different values of the annual solar fraction, taking into account the dependence between collector and storage inlet and outlet temperatures. Output data of the scenario simulation cover the solar collector, the thermal storage and patterns of system operation. To evaluate the different scenarios the specific CO_2 savings are calculated as key performance indicator.

Fig. 3 shows the average heat load $\dot{Q}_{dem}$ of the given consumer, the sub-network of the years 2013–2015. The following Fig. 4 shows the solar radiation during a year on a surface tilted south with an angle of 35° for a location in southern Germany.

Based on the smoothened outdoor temperature line of the average outdoor temperature from 1974 to 2014 given by DWD [15] and a graph displaying the required supply temperature to the sub-network, the time span from hour 3241 at 15th of May to hour 6337 at 21st of September of a year was calculated when the supply temperature is at its allowed minimum (Fig. 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.

The efficiency of solar collectors η_c was calculated according to the European Standard EN 12975 [16] as follows:

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

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

η_0 Collector zero-loss efficiency (−)
a_1 First degree coefficients of the collector heat losses (W/Km^2)
a_2 Second degree coefficients of the collector heat losses (W/Km^2)
G Global radiation (W/m^2)
T_m Hourly medium collector temperature (°C)
T_a Hourly ambient temperature (°C)
T_{out} Hourly collector outlet temperature (°C)
T_{in} Hourly collector inlet temperature (°C)

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 ins given in 15 min steps the resolution was reduced to hourly steps in order 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 collector datasheets of a Arcon HT-HEATboost 35/10- flat plate collector (FPC) and a RitterXL XL 19/49P evacuated tube collector (ETC).

2.1. Area selection

Field sizes were calculated depending on five scenarios with different annual solar fraction *SF* 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 14% solar fraction, because this is the month with the lowest consumption throughout the year. The following calculation

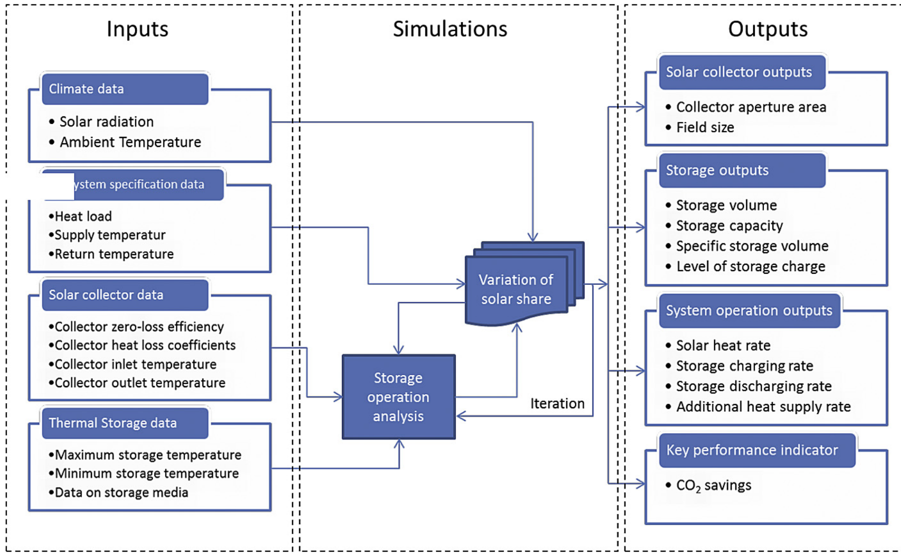

Fig. 2. Methodology for the integration of solar heat into existing DH systems.

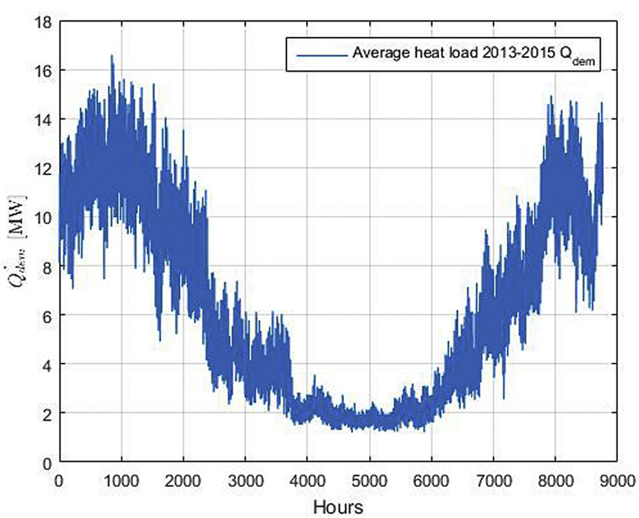

Fig. 3. Example of annual the heat load curve in a sub-network.

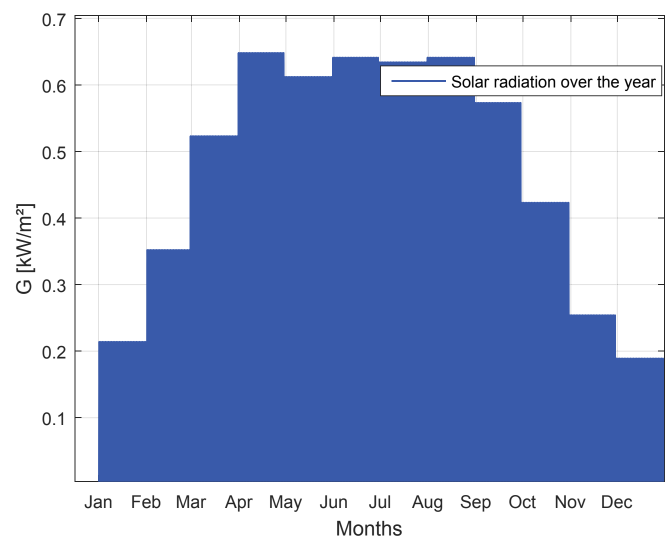

Fig. 4. Example of maximum solar radiation on an average day on a south oriented 35° tilted surface in southern Germany.

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 $f_{sol,m}$:

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

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

$$Q_{sol,\ tot} = SF^* Q_{dem,tot} \tag{7}$$

$$Q_{sol,m} = Q_{sol,\ tot}{}^* f_{sol,m} \tag{8}$$

Calculation of required collector aperture area:

$$A = \frac{Q_{sol,m}}{q_{sol,m}} \tag{9}$$

$f_{sol,m}$ Monthly share of solar energy supply (−)
$Q_{dem,tot}$ Annual energy demand of the sub-network (MWh)
$Q_{sol,m}$ Monthly energy to be supplied by solar (MWh)
$Q_{sol,\ tot}$ Annual energy to be supplied by solar (MWh)
$q_{sol,m}$ Specific net solar gain per month (kWh/m^2)
$q_{sol,tot}$ Specific net solar gain per year (kWh/m^2)
A Aperture area (m^2)
SF Annual solar fraction

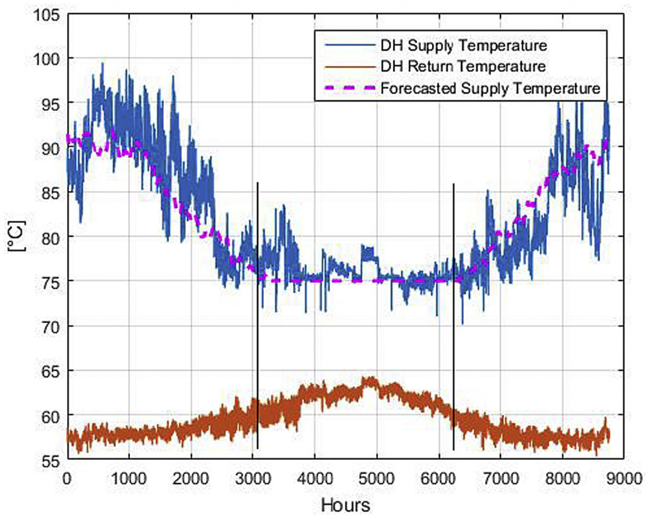

Fig. 5. Average supply and return temperature and expected supply temperature of the sub-network.

Fig. 6 shows an overview of the monthly solar energy gain $Q_{sol,m}$ compared to the monthly energy demand of the sub-network $Q_{dem,m}$ for different values of solar fraction *SF*. At an annual solar fraction of 14% the solar heat energy fully covers the heat demand in the month of lowest demand (July) – a similar approach to meet the summer load with alternative heat sources is also suggested in Ref. [17]. 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 scenarios with the collector area, the relative storage dimension and the achieved CO_2 savings for the given example system.

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. Fig. 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 14%).

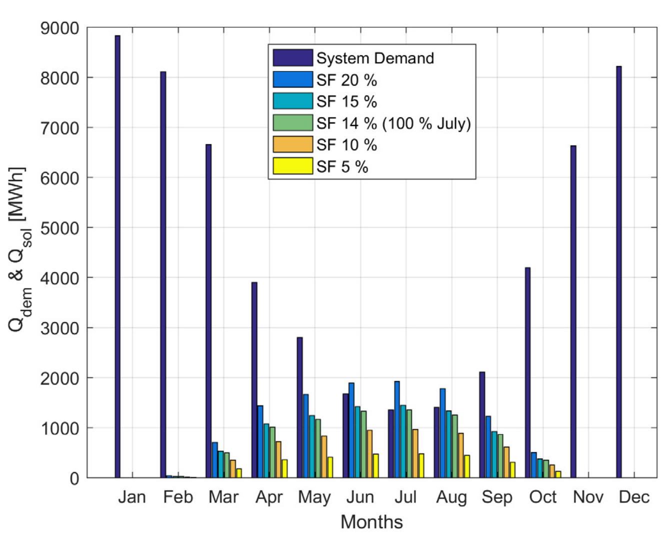

Fig. 6. Monthly net solar gain compared to demand for scenarios with different solar fraction.

The conversion from storage energy capacity Q_{st} [MWh] to storage water volume V [m^3] was performed according to the following equation:

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

V Storage volume (m^3)
Q_{st} Storage energy capacity (MWh)
ϱ Density of water (kg/m^3)
c Heat capacity of water (Wh/(kg K))
T_{max} Maximum storage temperature (°C)
T_{min} Minimum storage temperature (°C)
T_{min} is the maximum return temperature measured, 63 °C and T_{max} is the maximum allowed temperature in the storage 95 °C.

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 which corresponds to an average supply temperature during summer in the main-network. This means that during summer time three 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.

2.4. Storage temperature levels

DH supply and return temperatures influence the collector inlet and outlet temperatures when connecting the system to the thermal storage whereas inlet and outlet temperature determine the collector efficiency significantly. As the thermal storage needs to be charged during summer with higher temperatures to achieve a higher storage capacity an iteration step is needed. Therefore, an iteration step was included when calculating storage parameters.

To utilize the thermal storage to its maximum the storage temperature was set to a maximum of 95 °C. For the days that the storage is charged to its maximum the collector outlet temperature needs to be at least 95 °C. With the adjusted temperatures and thereby changed efficiencies the area and storage calculation has to be repeated.

2.5. CO_2 emissions

A CO_2-emission factor of 172 g/kWh$_{heat}$ was predefined for this study. This value is valid for typical modern fossil-fuelled CHP units. Other CO_2 emission factors for German DH systems can be found in Ref. [18].

3. Results

The first thing to realize throughout the calculation was that the necessary specific storage volume to store a surplus of solar energy was below 50 l/m^2 collector area. A relatively small dimensioned storage is also recommended by Ref. [2]. [2] also point out that a solar storage is normally not used for the largest part of the year. This statement is also visually confirmed in Fig. 7.

Fig. 8a) shows the supply and demand ($\dot{Q}_{sol,dir}$, $\dot{Q}_{sol,stor}$, $\dot{Q}_{dem}$, $\dot{Q}_{dis}$) curves for the summer season if a recharge (Q_{re}) every evening

Table 1
Calculation results for scenarios with different annual solar fraction.

Solar fraction	Collector area [m^2]	Specific storage volume [l/m])	Storage volume [m^3]	CO_2 savings [t/a]
5%	6507	7.3	50	480
10%	13029	30.3	403	961
14%	18319	39.5	728	1348
15%	19536	40.5	802	1424
20%	26044	46.2	1220	1725

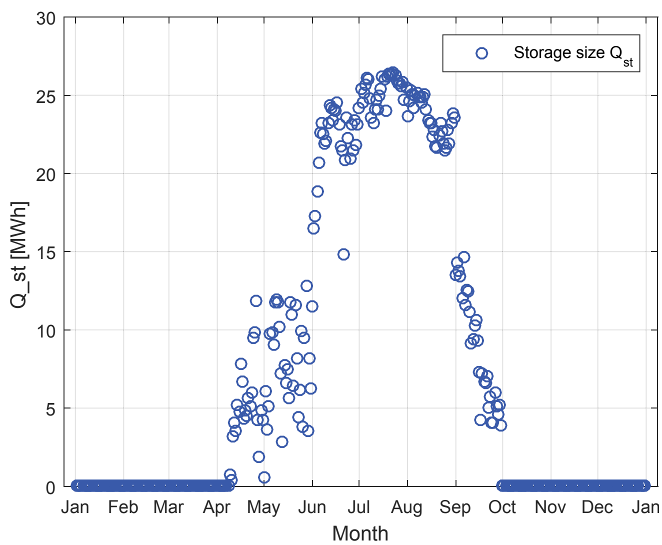

Fig. 7. Needed storage capacity to store the solar surplus energy.

is done for the scenario of 14% solar fraction (compare Table 1). Fig. 8b) shows the additional heat demand of the system $\dot{Q}_{add}$, 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 (11) below gives the relation between the different heat power terms:

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

$\dot{Q}_{dem}$ Heat load of the sub-network (MW)
$\dot{Q}_{sol,dir}$ Directly used solar heat rate (MW)
$\dot{Q}_{add}$ Additional heat supply rate (MW)
$\dot{Q}_{sol,stor}$ Stored solar heat rate (MW)
$\dot{Q}_{dis}$ Storage heat discharge rate (MW)
Q_{ch} Storage state of charge (MWh)
Q_{re} Daily storage reheat (MWh)

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

While Fig. 8 represents the complete summer season of a system with 14% solar fraction, Fig. 9 shows the supply and demand curves ($\dot{Q}_{sol,dir}$, $\dot{Q}_{sol,stor}$, $\dot{Q}_{dis}$, $\dot{Q}_{dis}$) for the same system but this time only for 4 days. In Fig. 9c, the detail of Fig. 8c, it becomes visible that a regular reheating (Q_{re}), e.g. during the night, enables a projectable operation of main- and sub-network. When analysing the state of charge line (Q_{ch}), red line in Fig. 8c), one can see that a daily recharge is not even needed every day, because the thermal storage is not even close to be emptied within the 24 h-interval of reheating and discharge.

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 small as possible to reduce the system costs as well as to reduce the losses during the summer due to storage limitations.

Fig. 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 reheating of the storage to 80 °C is given.

An increase from 14% 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 fully discharged for the largest part of the summer season. Furthermore, the difference in the collector area between 14% and 20% solar fraction is 7725 m^2 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* [19], 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.

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.

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

Thirdly, 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_{heat} for the given example DH system was used. The SDH-Online tool however uses different reference emission factors [19].

5. Conclusion

Previous work focused in many cases on large systems with seasonal storage solutions and large solar shares or refurbishments of smaller DH sub-networks. In contrast to the so far published work, this article presents an analysis of integrating solar energy in a sub-network that doesn't undergo structural changes and is so far

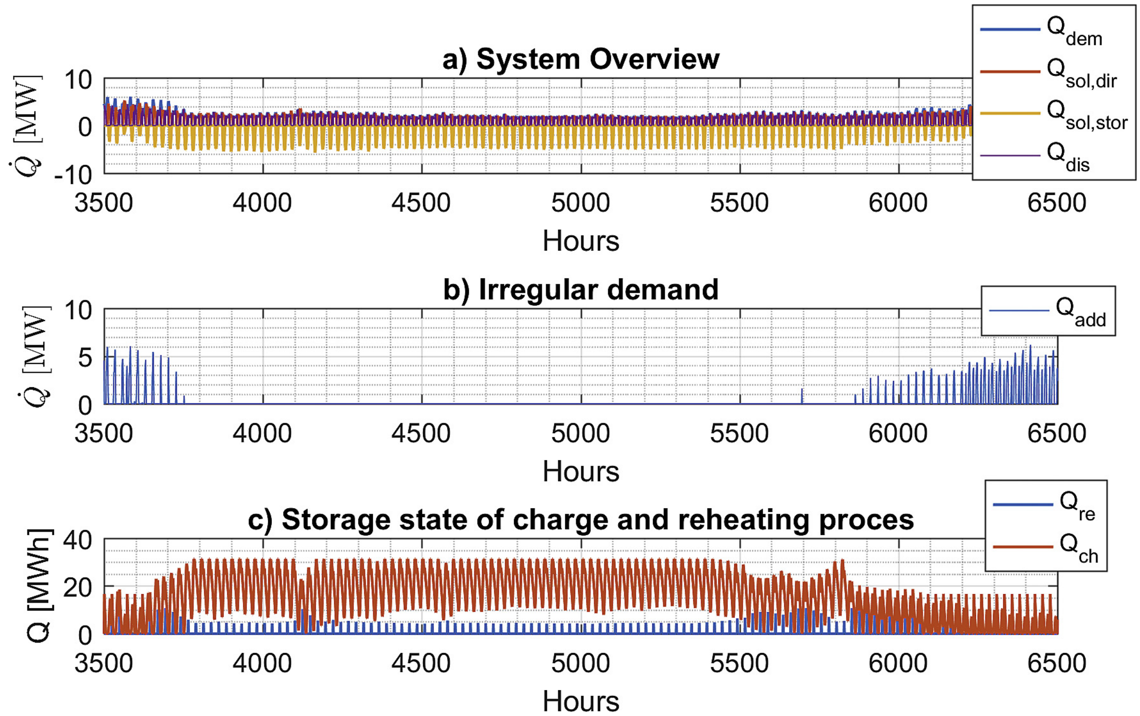

Fig. 8. Supply and demand curves (a), additional heat power demand (b) and storage state of charge (c) during the summer season with 14% solar fraction.

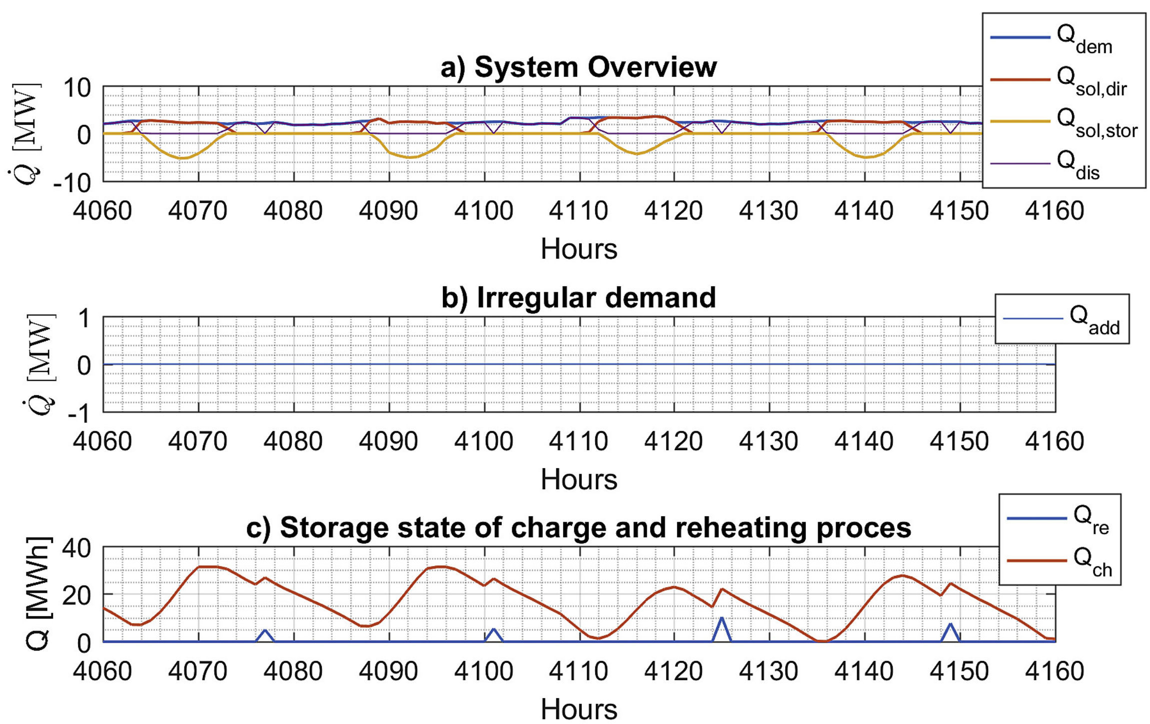

Fig. 9. Zoomed in 4 days of supply and demand for the scenario with 14% annual solar fraction.

supplied by a large CHP facility from the main DH network. The article describes the developed methodology and shows the main physical phenomena that were used in a MATLAB code to analyse possible solutions.

Results of this paper show that the integration of solar heat into existing DH systems brings benefits to DH systems where heat is supplied mainly by fossil CHP plants. The benefits can be quantified in terms of CO_2 emission reduction and a larger 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 for the time that the temperatures can be lowered.

Furthermore, a solar thermal system enables the whole DH network to react better on future price fluctuations in the German electricity market when it may be economically beneficial to decrease the energy production of the plant from an electricity production point of view.

The example calculation shows that a solar thermal DH sub-network with a thermal storage and an annual solar fraction of 14% can be realized without auxiliary gas or biomass boiler, if the main-network can adapt to a lack of heat power in the sub-network. The option of a regular recharge of the storage makes the operation of the centralized CHP plant more predictable. During the summer months the solar heat gains cover the total heat demand of the sub-network for long periods, whereas in other times of the year the main-network provides the additional heat. The performed calculations also show that a short-term storage with a specific volume below 40 l/m^2 is sufficient under the used load pattern.

The results of this work show that including solar heat in a DH sub-network is feasible from the technical perspective and improves evidently the ecological performance of the system.

6. Outlook

When a feasibility study was carried out for the project the system costs showed to be very instable and heavily depending on the actual collector price per m^2. Due to developing collector market prices, which make up the main investment costs, a feasibility study rather needs to be performed using up to date offers from suppliers that often offer a turn-key system. In general, it can be said that Arcon Sunmark expects heat generating costs of 25–45 €/MWh for their large SDH plants [20].

The results of the presented calculations can be improved by optimizing the storage recharging time and level as well as by adding the piping system as a temporary storage. In the example case a DN300 pipe without extractions gives an additional specific volume of 78 m^3/km to be taken into account for storing water at 80 °C for a short time once a day. However, in that case the heat losses of the pipeline have to be considered, as well. Future work will analyse the economic performance of such a system and will apply the methodology on an operating DH system. This includes especially indirect benefits of solar thermal integration that might occur in a district heating sub-network and costs that relate to large CHP facilities.

References

[1] Fisch M, Guigas M, Dalenbäck J-O. A review of large-scale solar heating systems in Europe. Sol Energy 1998;63:355–66. http://dx.doi.org/10.1016/S0038-092X(98)00103-0.

[2] Meißner R, Abrecht DS, Beherrschen D, Stagnation D. Sinn und Unsinn von Solarspeichern. FEE Heizungsjournal - Spec 2012:1–6. Heizungsjournal-special FEE, http://ritter-xl-solar.com/feedback/footer/info-material/download/ [Accessed 25 October 2016].

[3] Berberich M, Deschaintre L, Mangold D, Schmidt T, Willwerth L. SOLAR-KWK Entwicklung multifunktionaler Systeme zur solar unterstützten Kraft-Wärme-Kopplung – solare Fernwärme und saisonale Wärmespeicher für die Energiewende. 2015. http://www.solites.de/Infothek/Literatur.aspx [Accessed 25 October 2016].

[4] Urbaneck T, Oppelt T, Platzer B, Frey H, Uhlig U, Göschel T, et al. Solar district heating in east Germany – transformation in a cogeneration dominated city. Energy Procedia 2015;70:587–94. http://dx.doi.org/10.1016/j.egypro.2015.02.164.

[5] Mahler B, Strasser H. Stadt Werk Lehen: solar heating in a concerto district. In: Proc EuroSun 2010 Conf, 3; 2010. p. 1–7. http://dx.doi.org/10.18086/eurosun.2010.05.05.

[6] Yang L, Entchev E, Rosato A, Sibilio S. Smart thermal grid with integration of distributed and centralized solar energy systems. Energy 2017;122:471–81. http://dx.doi.org/10.1016/j.energy.2017.01.114.

[7] Lozano MA, Anastasia A, Palacin F. Simulation study and economic analysis of large-scale solar heating plants in Spain. In: Proc EuroSun 2010 Conf; 2010. p. 1–8. http://dx.doi.org/10.18086/eurosun.2010.05.04.

[8] Couturier S, Verdier I, Guichard M. Dynamic simulation of central solar heating plant with seasonal storage (CSHPSS) with TRNSys software. In: Proc ISES Sol World Congr, 2011; 2011. p. 1–7. http://dx.doi.org/10.18086/swc.2011.21.02.

[9] Sibbitt B, Mcclenahan D, Djebbar R, Thornton J, Wong B, Carriere J, et al. Measured and simulated performance of a high solar fraction district heating system with seasonal storage. In: Proc 30th Ises Sol World Congr, 2011; 2011. p. 3037–48. http://dx.doi.org/10.18086/swc.2011.21.06. Swc 2011.

[10] Jensen MV, From N, Sørensen PA. Large scale solar thermal plants with long term heat storages. Examples from Marstal, Brædstrup and Dronninglund, DK. In: SDH Conf. 2015 B. Pap; 2015.

[11] Solites. Solnet BW - Solare Wärmenetze für Baden-Württemberg. 2015.

[12] Ritter XL Solar. Stadtwerke Senftenberg - Ein wegweisendes Projekt für deutsche Fernwärmenetze n.d. http://ritter-xl-solar.com/anwendungen/waermenetze/senftenberg/ [Accessed 6 March 2017].

[13] Dalenbäck J-O. SDH plant database. 2017. http://solar-district-heating.eu/ServicesTools/Plantdatabase.aspx [Accessed 12 March 2017].

[14] European Commission. PV GIS. 2012. http://re.jrc.ec.europa.eu/pvgis/apps4/pvest.php# [Accessed 10 May 2016].

[15] Deutscher Wetterdienst. Klimadaten Deutschland. 2016. http://www.dwd.de/DE/leistungen/klimadatendeutschland/klimadatendeutschland.html [Accessed 10 May 2016].

[16] Kovacs P. A guide to the standard EN 12975. 2012. http://www.estif.org/fileadmin/estif/content/projects/QAiST/QAiST_results/QAiST D2.3 Guide to EN 12975.pdf [Accessed 25 October 2016].

[17] Holter C. Solar district heating taking the full summer load in cities. In: Proc EuroSun 2010 Conf; 2010. p. 1–5. http://dx.doi.org/10.18086/eurosun.2010.05.03.

[18] AGFW. Liste der CO2-Bescheinigungen nach FW 309-6. 2016. https://www.agfw.de/erzeugung/energetische-bewertung/ [Accessed 26 October 2016].

[19] Schmidt T, Deschaintre L. SDH online-rechner. 2013. http://www.sdh-online.solites.de/?lang=en-US [Accessed 25 October 2016].

[20] Arcon Sunmark. We harvest the sun. 2016. arena.gov.au/files/2016/02/Arcon-Sunmark-Gosser-Brewery.pdf [Accessed 25 October 2016].