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Techno-economics of solar re-powering and *retro*-fitting an existing district heating network

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ABSTRACT

Most of the district heating systems today use higher operating temperatures than those in new-built systems, possibly limiting compatibility with solar energy. This study evaluates the cost-effectiveness in terms of unit heat cost of integrating solar heating into an existing district heating system compared to not using solar energy, under changing economic boundary conditions such as collector and fuel cost, in addition to discount rate. This is investigated for both a scenario where the solar heating and a boiler replacement is done concurrently, as well as a scenario where solar heating is added to an existing system without replacing the boiler. A theoretical district heating supply of 3 MW is modelled and simulated based on a real system and load profile. The heat supply is varied to include storage with or without solar heating. Results for a 3 % discount rate indicate that; Replacing a 3 MW boiler with a slightly smaller boiler of 2.5 MW and adding a storage is cost effective and yields a unit heat cost of 58.0 EUR/MWh (16.1 EUR/TJ) which is a reduction of about 6 %. Installing solar heating together with the boiler replacement yields a unit heat cost as low as 55.7 EUR/MWh (15.4 EUR/GJ) which is a reduction of about 8 %. When replacing the boiler, all system configurations have similar unit heat costs compared to a boiler-only system, so factors such as emission reductions due to solar heating are relevant when considering alternatives. Furthermore, adding solar flat plate collectors corresponding to a 13 % solar fraction without replacing the boiler can reduce the unit heat cost as low as 34.8 EUR/MWh (9.7 EUR/TJ), which is 32 % lower than without solar. Evacuated tube collectors can increase this solar fraction to 17 % with similar system size, although at a higher cost. At a discount rate of 5 % solar heating is cost-competitive when fuel cost is above 26 EUR/MWh (7.2 EUR/TJ) and at 7 % competitive when fuel cost is above 32 EUR/MWh (8.9 EUR/TJ). Increasing solar heating system size reduces the backup-boiler fuel use during summer maintenance and makes fuel type less relevant for the overall unit heat cost.

1. Introduction

The introduction is divided into four parts; background for the premise of the study, previous work in the field with identification of knowledge gap and statement of novelty, aim and scope with research questions and delimitations and overall method with an overview of how the study was conducted in phases.

1.1. Background

District heating (DH) is widely employed in Europe and builds on the premise of recycling, rather than wasting, low-grade heat whose temperature is too low to run industrial processes. In today's world of climate change and wide-spread adaptation of sustainability targets around the world [1], resource efficiency is essential to reduce fuel consumption so that it can be utilised for other needs and enable

Abbreviations: BO, Boiler-only; BC, Boiler central; C. pipe, Connection pipe; DFO, diesel fuel oil; DH, District heat(ing); DN, Nominal Diameter; EL, Electricity; ETC, Evacuated tube collector; FOH, heavy fuel oil; FPC, Flat plate collector; HDD, Heating degree days; HX, Heat Exchanger; IAM, Incidence angle modifier; IEA, International energy agency; KPI, Key performance indicators; LCC, Life cycle cost; LCOH, Levelised cost of heat; MTR, Minimum turndown ratio; O&M, Operation and maintenance; PLR, Part load ratio; PTC, Parabolic trough collector; SDH, Solar district heating; SF, Solar fraction; ST, Storage; VAT, Value added tax; WP, Wood-pellets; WPB, Wood-pellet boiler.

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reductions in carbon footprint. According to the Energy roadmap 2050 published by the European Commission, energy efficiency measures should lead to 41 % lower heat demand in 2050, compared to that in 2005/2006 [2]. As a follow up to this report, the international district energy association Euroheat & Power devised a second study to improve the analysis made in the original roadmap, as the efficiency measures imposed were deemed unfeasible. The follow-up study was called "Heat roadmap 2050" and included district heating as a measure for reaching the stated goals of decarbonisation, with the idea to provide efficiency measures that are realistically implementable. The concept involved using a wide palette of heat sources and situate the energy transition in an urban context, as future population centres drive the energy demand and thus, provide the boundary conditions for the energy supply. The report provided insight showing that district heating can obtain the desired goals of decarbonisation at a significantly lower cost than other alternatives and reduce the biomass use in heat supply, which makes it available for other purposes [3]. According to the international energy agency (IEA), biomass is an essential primary energy source to obtain net zero emissions by 2050 and demand for solid biofuels will increase by almost 70 % from 2020 to 2030 and more than double until 2050 [4]. This pressure on biomass supply may logically be expected to increase cost of heat from biomass significantly, which undermines the competitiveness of DH with other heat sources in countries that have high shares of biomass in DH supply. Yet, on the other hand, in the countries where fossil fuels make out the majority of DH supply, the biomass can have the opposite effect when emission quotas and other policy measures makes cost prohibitively high. In both scenarios, this should motivate increased efforts by district heating companies to include other heat sources in order to reduce the generation costs.

Europe has traditionally had a higher share of the heat demand supplied by DH compared to the world as a whole, with 13 % of the heat demand in 2017 [5] and 12 % in 2021 [6], although China's share was above the world average in 2019 [7]. The EU and China are responsible for the majority of DH supplies in the world, while the renewable share is still rather low, despite a few Scandinavian countries like Sweden, Denmark and Iceland, as well as France, Austria and the some Baltic countries having shares above 50 % [8]. In Europe, the average biomass share was about 34 % in 2022, although in Sweden, the share was 68 %. Despite this, fossil fuels made out about half of the primary energy in the 2022 DH supply in EU, which emphasises the need for re-distribution of renewable fuels such as biomass for decarbonisation of the DH sector. In the future, aside from biomass and waste heat, large heat pumps in combination with low grade heat from waste water is thought to play a significant role that provide sector coupling between electricity and heating sector [9]. However, for DH networks where waste heat may not be available, solar thermal is thought to play a role and offers an alternative to electricity-based heating [10].

Unfortunately, despite the development over the course of the industrial revolution and into the current information age, where heat from data-centres is available as a new energy source available at even lower temperatures, the distribution technology found in most DH systems today is of the 3rd generation and features high network operation temperatures [5], which makes integration of heat sources such as solar thermal more difficult. Although several studies [11,12] have highlighted the need to move on to lower operation temperatures in order to enable higher shares of low-grade heat which is a feature of the 4th generation of DH, this is only relevant when a DH network is built anew or being replaced, unless modifications are made to improve system performance and lower temperatures in existing networks [13]. However, also without such modifications, solar thermal may prove cost-effective, especially when used to reduce fuel consumption in the summer, when waste heat is scarce[10].

In countries like Sweden, many DH systems are using a biomass boiler or may be scheduled for one during an upcoming boiler replacement, where fuel saving may be equally relevant. According to a report on the future Swedish energy system published by the Swedish energy authority, biomass will become more valuable in the period towards 2050, which should lead to an increased interest in fuel saving measures [14]. Furthermore, main boilers commonly undergo maintenance periods during summer, during which the heat demand is supplied by a backup-boiler running on either a fossil fuel like oil, bio-oil made from biomass or on electricity. In either case, the use of a solar heating system may represent a cost-effective way to save resources, cut costs, cover heat losses and reduce emissions. The reduced carbon footprint may come from replacement of fossil fuels in marginal energy facilities, which emphasises the importance of using solar in biomass plants also at higher latitudes [15]. One report released by the Swedish energy agency in 2021 evaluated the potential for SDH in Sweden under different scenarios and found that solar heat could make out roughly 10 % of the entire DH supply of 50 TWh in 2035 and save around 11 TWh worth of biomass use if all conditions were in favour of solar thermal, i.e. low investment costs and high biomass costs. High biomass costs alone could lead the to a solar fraction (SF) of about 2 % while saving around 6 TWh of the biomass use, which is a significant share. In the report, solar heat is identified as most relevant for refined biomass fuels such as wood-pellets and points out that the installed solar heating capacity in the world is increasing rapidly[16]. This is supported by the upward trend in solar district heating (SDH) seen in Europe, with increases in total collector area the last years – a trend expected to continue [17].

Despite high temperatures being detrimental to the efficiency of solar collectors and particularly for flat-plate collectors (FPCs) that work better at lower temperatures [12], FPCs has so far been favoured for use in solar assisted district heating (SDH), due to volume effects leading to lower specific collector costs – despite the obvious temperature mismatch [11]. The share of FPCs has increased worldwide from 15 % to 34 % in the period 2011 – 2021, although the share decreased from 81 % to 72 % in the same period in Europe. On the other side, the share of newly installed evacuated tube collectors (ETC) remains high in the world and is increasing in Europe, which could indicate that collectors working efficiently in a higher temperature range and that are able to supply heat at temperatures closer to those found in many existing DH systems, are gaining an advantage over the FPC [17]. Nevertheless, reported employment of ETCs in large scale systems is scarce in existing scientific literature, and this could be due to higher costs for the collectors and pressure limitations. The estimated share of ETCs in DH systems was reportedly 2 % in 2019, the FPC collector being preferred due to lower costs, ease of installation and durability, among others [18]. However, with the introduction of ETCs specially designed for large scale applications, this is expected to change as volume effects drive the learning curve of these collectors downwards and reduces the costs [19], which may make the ETC an attractive alternative for capping fuel use and carbon emissions from existing DH systems.

In light of the background provided here, it is clear that the heat roadmap 2050 envisions an extended use of DH [20], which would entail more new DH networks with operating temperatures more suitable for solar thermal, although many of the systems that will be in operation in the future are the existing ones. Furthermore, despite the fact that these feature high temperatures, many of these are using biomass and may therefore reduce costs with solar heat, while saving precious renewable resource. Therefore, investigations on integration of solar heat into the existing DH networks using refined biomass fuel like wood-pellets and highlighting the boundary conditions under which it is cost-competitive is a necessary step to decarbonise the DH sector. Aside from input to manufacturers of solar collectors on potential obstacles to widespread adaptation, this enables policy development for optimal resource allocations as well as stakeholder decision-making, in the case of DH suppliers. This is the motivation for this study.

1.2. Previous work

There are many previous studies on SDH and some of these have been mentioned in a review article that outlines the general history of the field, along with the available system typologies found and different examples of technological solutions for various scales of heating systems [21]. For smaller DH systems and those where lower temperatures are used, solar heating can be made to work more efficiently due to higher collector efficiencies and shorter distances between heat source (collectors) and heat demand, but in these systems the heat density is often so low that the distribution losses become more significant and the investment cost too high relative to the demand. Among the advantages mentioned for central solar heating plants, where solar collectors are feeding a centrally located storage – usually in a larger DH system – is the lower specific cost of solar collectors and storage due to economy of scale. High DH operating temperatures is lifted as a major disadvantage due to lower collector performance and yield, while low unit heat cost of conventional heat sources are lifted as a major limitation [21].

For the case where SDH systems are built anew, the system design can often be adapted so that the system efficiency becomes high and the investment costs lower than for a comparative conventional DH system [22,23]. However, for the existing DH systems, the system design has already been implemented, so there may be limitations to the reduction in operating temperatures and/or the ability to integrate solar heating in the existing heat supply, which makes the techno-economically optimal solution less evident. In addition to this, every system have different boundary conditions in terms of solar irradiance and load profile, which may further complicate a feasibility study. Therefore, most systems will require a techno-economic analysis to arrive at whether or not solar heating can provide a cost-efficient heat supply, although it may be possible to draw some general conclusions for groups of systems with similar characteristics in terms of load pattern, boiler type and operational temperatures. The solar district heating scenario analysis for Sweden [16] which was described in the previous section goes a long way to suggest what fuel types solar heat should displace in order to be cost-effective and thus, studies that are investigating solar heat in biomass systems are of primary interest.

Unfortunately, despite the vast amount of studies in existing literature, those on the subject of SDH are poor when considering combined biomass and solar heating. Only two similar studies have been found, whereby the first was conducted in 2004, investigating a planned solar assisted DH system in northern Sweden [24]. It found that a decentralised solar heating system with collectors on the houses connected to the network and with local storage in each house would have a lower unit heat cost than a centralised system with collector and storage in the central heating plant. Nevertheless, it would not be sufficiently low to compete with the unit cost of direct electric heat for the prospected consumers, unless the electricity price increases by 35 %. Regardless, this study is not only outdated in terms of technical and economic boundary conditions, but also does not look at different collector technologies, array or storage sizes – something which is done in the current study. The second study (from 2021) [25] bears more similarity to the current study, in that in investigates both a similarly sized system in terms of boiler capacity, as well as installed collector areas. However, it separates in several respects, in that it firstly is based in Suonenjoki in Finland, some 600 km farther north from Gotland, the location of the current study. Secondly, it is based on the use of a wood-chip boiler and an unlimited storage volume (optimised to maximal solar fraction and not cost), as well as static (and high) boiler efficiencies and a high interest rate of 8 %. Combined this led to the result that solar heating was considered significantly more costly than running a wood-chip boiler by itself. Thirdly, the study did not consider boiler replacement, which is relevant for many DH companies in the near future. Lastly, a sensitivity study was not conducted and hence, no results were presented as to the cost-competitiveness of solar heat at other interest rates, fuel costs or collector cost. Thus, this represents a gap to be filled by the current study.

Other existing studies mostly focus on case studies with performance assessment [26–29] or on different forms of optimisation of already installed solar plants [30–32]. However, there are a limited number of studies that focus on techno-economic optimisation of integrating solar heating in an existing DH system [33,34], although such studies often include the use of either niche collector technologies and/or a combined heat and power (CHP) plant. Although there are a couple of studies highlighting economic conditions for Nordic conditions [35,36], these also include use of CHPs and/or other heat sources such as heat pumps in conjunction with the boiler and solar heat. Although the studies listed here don't provide a complete overview of the SDH field, the tendency is the same for the conducted studies, in that they either feature a different technical scope or are not comparable in concept. This makes the results less applicable for comparison of economy in systems with heat-only boilers, as is customary in many countries such as Sweden, where they are applied in smaller DH networks. Since DH systems in countries like Sweden, Denmark, Finland, Austria and France largely use bioenergy as fuel and this is expected to continue in the future both in Sweden [14] and in a range of other EU countries seeking to decarbonise the DH sector [37], studies reflecting the conditions for SDH with large shares of biomass are necessary in addition to studies supplying information on the techno-economics of solar heat in DH systems using heat-only boilers.

One early study from 2008 for small scale DH systems investigated the use of solar heating systems with FPCs to support existing DH systems in Finland and Sweden on fixed period heat supply contracts, i.e. a temporary "*retro*-fit", in order to save boiler fuel costs during summer. The results showed that the solar heating system could not be paid back in a system lifetime of 30 years when the boiler fuel was wood-pellets, unless the fuel costs increased by 5 – 10 % annually. However, if the boiler fuel was oil, then the solar heating system would be paid off in less than 20 years, even without cost increases [38]. Since the study was conducted, fuel costs have actually decreased slightly for pellets, while oil prices have increased 50 – 100 %, depending on oil type used. During the same time, the collector costs have decreased by 20–30 %, based on reference costs in this study (see *Ch. 3.4*). Furthermore, the study does not include the possibility of having different boiler types for covering main and summer loads, which is customary in many systems today (P. Nilsson, Personal communication)[39]. Also, how operating temperature affects the cost effectiveness (i.e. payback time) of solar was not covered. Studies investigating unit heat cost for common operating temperatures as well as updating the results of this initial study are therefore required and the current study aims to do just this.

A study made into a "hybrid" SDH plant in Taars, Denmark, investigated the optimal share of flat-plate and parabolic trough collectors (PTC) and found that combination of the two collector types may be an optimal solution in combination with a natural gas fuelled boiler, due to the high operating temperatures in the DH network and the higher efficiency of the PTC at elevated temperatures. However, the study only investigated the cost-performance of various ratios of FPC to PTC and did not compare these to the cost-performance of using only FPCs [30]. A master thesis based on this study went on to model and simulate the same SDH system, comparing the energetic performance of combinations of FPC and PTC to system variants using only FPC or PTC, finding that the hybrid solution was better from an energetic point of view. Unfortunately, no costs were presented for the collectors or other components, so unit heat costs were not included [40]. Another master thesis went on to extend the study on Taars SDH system to include the use of photovoltaic-thermal (PVT) collectors and base the study on the conditions in Hemse, Gotland, Sweden – the same plant used as base for this study. The results were presented using marginal operation and maintenance (O&M) costs and in part confirmed the results from the Taars plant in terms of appropriate collector ratios, although the differences to using only FPC were too small to be conclusive for the lowest assumed collector costs [41].

Based on the mentioned studies, it is unclear what the current unit heat cost for solar heat from FPCs could be when used for SDH, which is of interest for determination of competitiveness of FPCs as a heat source for existing DH systems. Furthermore, because investment costs are variable and thereby uncertain in nature, it is unclear under which circumstances the unit heat cost of solar is competitive with that of a conventional boiler system. Therefore, studies investigating these two aspects are needed. In addition, the extensive interest displayed in the previously mentioned studies on higher temperature solar technology motivates the need for more studies to be made on the competitiveness of unit heat cost for low vs higher temperature solar collectors.

The novelty of this study lies partly in the presentation of up-to-date information on DH systems using refined biomass in combination with solar heating for a 100 % renewable energy supply, in the light of expected price hikes on biomass due to increased demand for other purposes. This should be seen in the context of the gap identified in the third paragraph of this sub-section.

The previous study cited in the fourth paragraph of this subsection has been used as inspiration for the current study and the material presented in section 4.3.2 *Impact of discount rate on parity between heat costs*. This is a key novelty of this study, as it allows for interpreting the results of the analysis under different circumstances, both past and future and thus, provides the reader with a general result in terms of cost-effectiveness. Although the heat cost calculations are based on actual average specific collector costs for European systems, the study examines the required collector cost level for the solar assisted system to be competitive when the economic boundary conditions change. This makes the results applicable for a host of other DH systems with similar characteristics as the one studied, something that has not been found in other studies. Furthermore, this is done using both FPCs and ETCs in the solar heating system, which has not been found done in other studies. In addition. The approach used is deemed necessary in the techno-economic analysis made for each case where feasibility of solar thermal should be evaluated and hence provides the user with a methodological result that can be used in other case studies, which demonstrates innovation.

Furthermore, the study presents the most cost-effective FPC collector area to install in an existing DH system, in terms of unit heat cost, to make SDH competitive with a business-as-usual case that uses a boiler as the only heat source. The costs are calculated both for a "re-powering" scenario, where the boiler must be replaced and solar is installed simultaneously, as well as for a *retro*-fit scenario where the solar is added to an existing system and existing boiler is kept. This makes the results more general, at least for the Nordic/north European case.

Lastly, the study evaluates the influence of using various types of backup-boilers and thereby, boiler-fuels, on maintenance cost and ultimately on unit heat cost. This too, has no analogue in previous studies and ties in with the work outlined on feature use of solar heat in summer for district heating systems where waste heat is unavailable [10].

1.3. Aim and scope

The aim of this study is to find out the specific conditions for cost-efficient solar assisted DH in an existing DH system. The main research questions (RQ) of this paper are:

(I) How cost-competitive is installation of a solar heating system when adding ("*retro*-fitting") it to an existing DH system?
(II) In the event of boiler replacement ("re-powering"), how cost-competitive is installation of a solar heating system compared to a boiler-only system with and without storage?
(III) How does the use of a high-temperature collector compare to the results obtained in RQ I and II?
(IV) What is the effect of the economic boundary conditions on the results obtained for above research questions? I.e. how do the results change with change in discount rates and fuel costs?
(V) How does solar heating affect the backup-boiler fuel use during maintenance and consequently, the resulting unit heat cost?

This paper uses the terminology ***"retro-fit"*** to designate the process of suppl*ementing* a boiler-only system by installing a single system component, or a group of such, i.e. adding a storage and/or a solar heating system. The term ***"re-power"*** is used to designate the process of *replacing* the boiler and adding other system components simultaneously, i.e. replacing the existing heat supply by one with a storage and/or a solar heating system.

A theoretical study is made of a DH system and a simulation model is developed for the heat supply using the heat load profile from an existing DH system. The heat supply consists of three main configurations: one with only a boiler; one using a boiler with heat storage; and one that uses a boiler in combination with a solar heating system and heat storage. A parametric study with several sub-varieties is made, where a range of flat-plate solar collector areas are modelled together with a proportionally sized storage, as well as one sub-variety with evacuated-tube collectors and using an equal collector area to one of the flat-plate sub-varieties. The range of flat-plate collector areas is simulated to determine the most cost-efficient collector area, while the comparison with evacuated-tube collectors is made in order to determine the most techno-economic collector technology under the same technical boundary conditions. Furthermore, because the financial boundary conditions in this study may differ from those encountered in the future or in other DH systems, a sensitivity study is made to determine the influence of interest rate, boiler fuel costs and solar collector costs on the cost-competitiveness of the system configurations studied. Lastly, the impact on main boiler maintenance cost when changing the backup-boiler type and associated fuel, is investigated in order to determine the potential cost reductions due to solar heating.

1.3.1. Delimitations

This study is based on conditions similar to those in Sweden both in terms of climate, costs and characteristic heat demand. This includes most of northern Europe although there may be local variations in e.g. insolation for which the results are not valid. However, previous studies show harmony between result in Denmark and results for the particular location of the case study, which gives an indication of potential generality of results wrt. Location.

The DH system is a high-temperature system which imposes certain limitations on collector performance.

The study does not include optimisation of specific yield with regard to amount of storage volume to installed collector area, but instead adapts a common value for the specific storage volume per collector area, for reasons of simplicity.

The paper neither includes optimisation of collector flow rates or storage charge control, to reduce the complexity of the system.

Boiler modelling does not include flue gas condensation and therefore specific costs related to this are neither included.

The study does not include storage technologies other than sensible heat storage in water and alternative storage methods are considered out of scope for the article.

The article only considers diurnal storage and does not consider seasonal storage.

The article only includes procurement, installation and operation costs in the life cycle costs for the energy system and excludes disassembly costs related to waste disposal.

1.4. Overall method

Fig. 1 shows the work process sequence for this study, which started with a case study and went through modelling and simulations in TRNSYS 17 (v.17.02.0005) [42], before ending up with financial considerations and sensitivity study. The case study was used to investigate an existing DH system and its load profile, from which the boiler type and capacity was defined, as well as the solar collector technologies to investigate and the system variants. In the modelling phase, all system models were made according to the main system configurations of interest; Boiler-only (variant 1), boiler with storage (variant 2) and solar

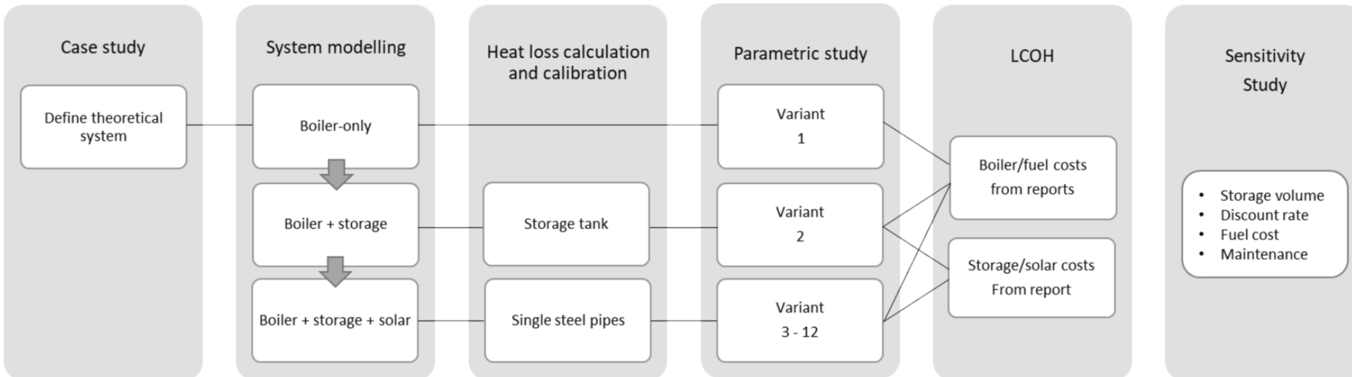

Fig. 1. Overall method – flowchart showing process from case study to financial considerations and sensitivity studies.

heating (variant 3 – 12). The latter system configuration had several variants due to variation in field size and storage tank volume.

These models were then calibrated to calculated U-values in storage tank and design heat loss of pipes according to the model variants to be simulated in a parametric study.

Based on simulation results, the energy balance was calculated based on simulation results to ensure the model worked properly and to derive some key performance indicators (KPI). Furthermore, the levelised cost of heat (LCOH) was calculated based on the estimated investment and operation and management (O&M) costs for a biomass-boiler from government reports, in addition to estimated investment and O&M costs for solar collectors and storage from an International Energy Agency (IEA) report and article, resulting in the LCOH for 12 variants that were compared. Subsequently, a sensitivity study was made by varying the storage volume for a selected variant in order to identify potential effects of increase in stored solar energy on LCOH, as well as varying the economic boundary conditions in terms of discount rate and fuel cost used in calculation of LCOH. For the various discount rates, the biomass fuel cost was changed to find the required collector cost for solar heating to be cost-competitive with the cheapest system without solar. Lastly, the boiler type used as backup-boiler during maintenance was changed to reveal the influence of solar heating on the O&M cost and resulting LCOH.

2. Case study

For this study, a hypothetical boiler central (BC) was modelled to supply a load profile for a real DH system in Hemse, on the island of Gotland in Sweden. This DH system has been subject to a feasibility study [43] (in Swedish) undertaken in 2018 by CIT Energy Management AB [44] for Gotland Energi AB (GEAB) through the EU project SDHp2m [45]. The readily available information about this system made it

Fig. 2. Boiler central – Satellite photo of the Hemse boiler plant (yellow square) and surrounding area. Available land for installation of solar collectors are located to the north. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

suitable for use as a case study in the current article.

2.1. Background information

The GEAB district heating system at Hemse has an annual heat demand of roughly 11.5 GWh (41.4 TJ) and is today supplied by a 7 MW wood-chip boiler and two 4 MW oil boilers, whereby one oil boiler acts as reserve and one is not in operation. Because the design heat load is 4 MW, the boiler is too big and challenging to operate, so that the DH system owner GEAB would like to replace the existing boiler with a new boiler of lower capacity, that is, to do a so-called "re-powering".

Furthermore, seeing that many DH systems may keep a functioning boiler beyond the economic lifetime and, in order to generalise the results, it is of interest to find out whether or not adding a solar heating system to a DH system without the boiler, so-called "retro fit", could be cost effective. Fig. 2 shows a satellite photo of the Hemse boiler central (yellow square), together with available land for a potential solar heating system 300 m north of this (red triangle). This land area is ∼ 10000 m^2, which is deemed sufficient for about 3000 m^2 of solar collectors [44]. However, the land area on the eastern side of the road from the marked area could also be used and the size of this is approximately the same. Any land area larger that this would require expanding towards the west.

2.2. Climate data and heat demand

Climate data for Hemse (57.2437° N, 18.3788° E) was downloaded from the Swedish meteorological and hydrological institute (SMHI) for the year 2015 (hereafter termed reference year) and the years 2013 – 2022, for means of comparison [46]. Fig. 3 shows the global horizontal irradiation (Gh), ambient temperatures (Ta) and calculated heating degree days (HDD) [47] for the reference year (2015) and the 10-year period 2013 – 2022, respectively. The annual irradiation in the reference year was 1184 kWh/m^2 and in the average (2013 – 2022) year was 1190 kWh/m^2 – a difference of less than 1 %. However, on a monthly basis, it varies 5 – 9 % in the summer season (March – August) and 5 – 28 % the winter season (September – February). Regarding temperature, it is clear that the reference year is warmer than an average year in the cold period Jan – Apr and Nov — Dec, i.e. winter and spring, while being colder in the warm period which makes out more or less the rest of the year (summer and autumn). This in turn leads to lower heat demand (HDD) in the cold period and higher demand in the warm period, than in the average year, which must be taken into account when evaluating the results. However, over the year, the heat demand is fairly similar, represented by 3130 HDD and 3108 HDD for 2015 and 2013 – 2022, respectively – a difference of less than 1 %.

2.3. Load profile in 2015

The load profile used during simulations in this study was supplied by GEAB for the Hemse DH system, Gotland, Sweden, for the year 2015. This profile was used as input to all the simulation models employed in this study and is shown in Fig. 4, together with simulated supply and return temperatures using the boiler-only (variant 1) model made in this study (see *Ch. 3.1 and 3.2*). The load varies from around 0.5 MW in the summer to slightly below 3.0 MW in winter, while the supply temperature varies between 65 °C and 84 °C degrees over the year, with the lowest values observed in summer. Occasional low values can be observed when load surges occur, although these are few and far between. On the other hand, return temperatures vary between 43 °C and 61 °C, with the highest values observed in summer. The total annual energy demand for 2015 is 11.7 GWh (42.1 TJ). Please note that the load profile for latter part of September is static, due to one week of missing values in the original load profile.

3. Method

Section 3.1 describes the overall modelling approach and differences between main variants simulated, including information about specific models which influence results. Section 3.2 outlines the parametric study and describes the system variants simulated. Section 3.3 treats the economic analysis and input to calculation methods, while section 3.4 describes the sensitivity analysis made on the economic input parameters. Lastly, section 3.5 lists the key performance indicators (KPI) used to evaluate the simulation results.

3.1. Modelling approach

Fig. 5 shows a simplified model of the district heating system simulated, the dashed squares indicate the three main variants simulated (see

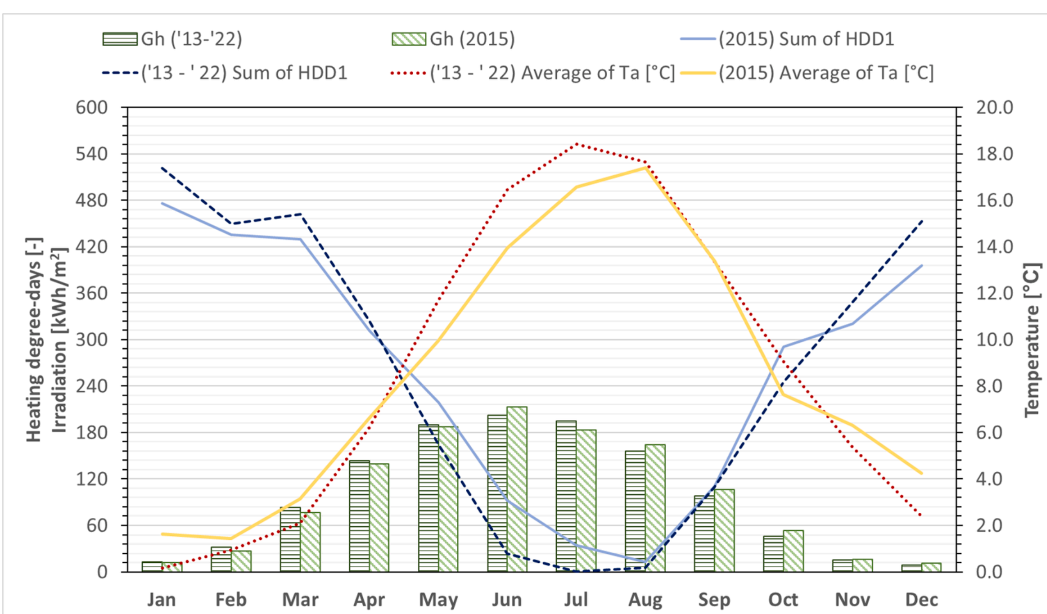

Fig. 3. Climate and heat demand – Monthly distribution of ambient temperature (Ta), heating degree-days (HDD) and global horizontal irradiation (Gh) for the reference year (2015) and an average year (2013 – 2022) for Hemse, Gotland, Sweden.

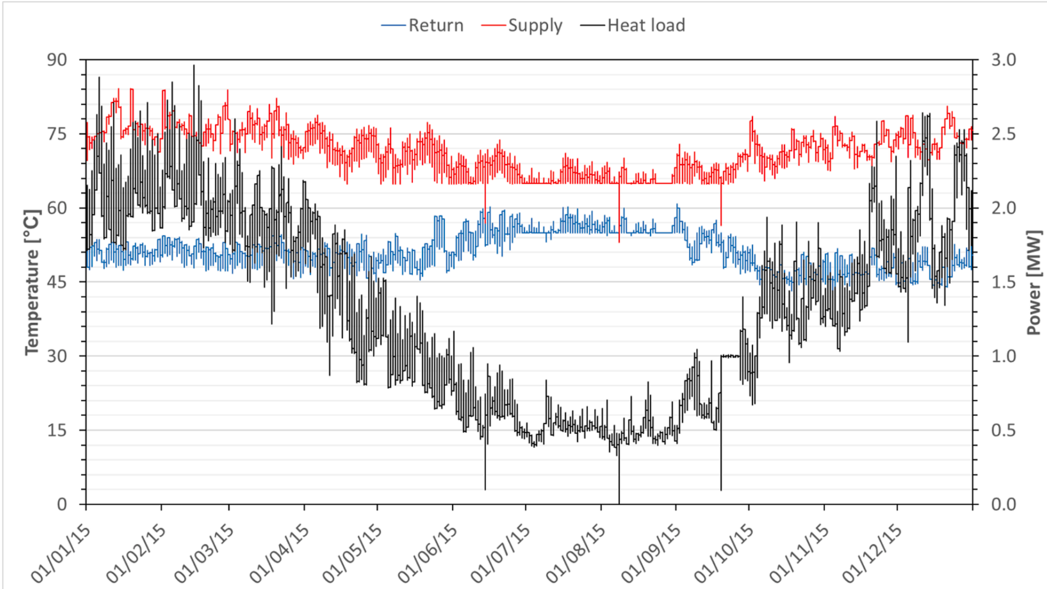

Fig. 4. Load profile – Overview over heat load for the year 2015 for the Hemse DH system in Gotland, Sweden.

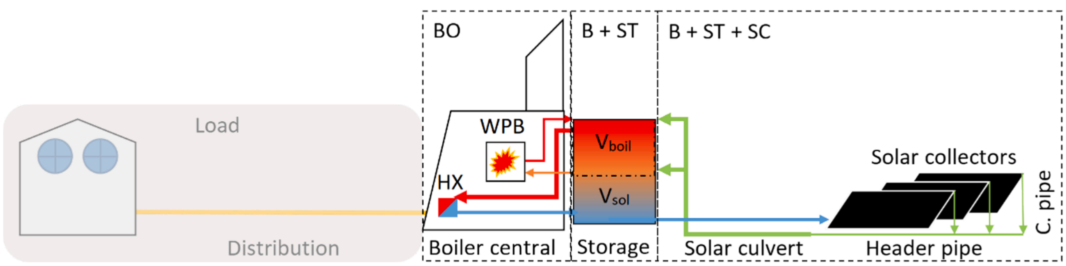

Fig. 5. Solar assisted model – Schematic showing the simulation model of the district heating system variations with solar collectors. Abbreviations: Boiler-only (BO), Boiler + storage (B + ST), B + ST + Solar collectors (B + ST + SC), Connection pipe (C. pipe), Wood-pellet boiler (WPB), Heat exchanger (HX).

Table 1
Heat supply – Overview of the heat supply configuration for the three main heat supply variants simulated in this study.

Parameters	Boiler-only	Boiler + storage	Boiler + storage + solar
Boiler	3.0 MW	2.5 MW	2.5 MW
Storage	NA	100 m^3 (V_{boil})	100 m^3 (V_{boil}) + 0.1 m^3/m^2 (V_{sol})
Collector Area	NA	NA	500 – 10000 m^2
Tilt/azimuth	NA	NA	40°/0°

Table 1) – additional sub-variants exist (see section 3.2) for the solar assisted system (B + ST + SC). The greyed-out load and distribution system to the left of the boiler central (BC) indicates the part that falls outside the system boundary in this study. For simplicity, the solar collectors are simulated as one large field instead of individually and pipes are lumped together, so that one pipe element corresponds to the entire length of all pipes of a certain type. For the solar culvert, one twin pipe is used between storage and solar collector field, while header and connection pipes (C. pipe) are modelled with one single pipe element each for supply and return, respectively.

The storage is divided into a boiler part (V_{boil}) that is charged by the wood-pellet boiler (WPB) and a solar part (V_{sol}) that is charged by the solar collector field. This is to give the solar heating system priority and ensure that the return flow to the collectors has the lowest temperature available, which is a condition for high collector efficiency as well as for the energy supplied by the field. The solar heating system has a simple stratification aid, in that it feeds to top/bottom of the V_{boil}, depending on the outlet temperature of the collector flow (see *section 3.1.3* for more information). The storage is discharged continuously through the heat exchanger (HX) and during winter months this entices a situation where the boiler is keeping V_{boil} warm and solar heat is used as preheating. In summer months, the solar keeps the entire storage warm and the boiler adds heat when necessary. For the system configuration using only a boiler and storage (B + ST), the system model is very similar to that shown here, although with the minor difference that the storage is charged fully by the boiler, i.e. V_{sol} is absent, so the boiler return flow is taken from the bottom of the tank.

For the boiler-only (BO) system, there is no storage and hence, the HX return (flow) is the same as the boiler return. More information on the model configuration is presented in the rest of this chapter and the data repository [48].

3.1.1. Heat supply configurations

Table 1 shows an overview of the three main heat supply variants in this study and how the balance of system components are configured in these. Note that pipes are excluded, as these will be presented in Ch. 3 in more detail. The DH load is supplied by a wood-pellet boiler (WPB) of 3.0 MW for the boiler-only variant and 2.5 MW in all variants where a buffer storage is included (the choice of boiler is discussed in Ch. 5). The larger capacity in the boiler-only variant is to cover the peak load in the load profile. A smaller capacity of boiler was possible with storage, as it reduced the peak power required from the boiler due to some power being delivered from storage. Iterative simulations using different boiler capacity for the given boiler buffer volume (V_{boil} – see Fig. 5) showed that 2.5 MW capacity was suitable to take full benefit of higher part load ratio (and hence efficiency) in the boiler, while still managing to supply the peak heat demand. According to previous studies [49], an average of 2.5 m^3 buffer storage is required per TJ of annual heat demand (see section 2.3) for stable and efficient boiler operation. On this basis and for simplicity, a round value of 100 m^3 static volume (V_{boil}) is dedicated to boiler buffer storage in all system configurations with storage. An additional storage volume (V_{sol}) of 0.1 m^3/m^2 is dedicated to the solar heating system, resulting in a total storage volume of 150 – 1100 m^3, for solar collector areas of 500 – 10000 m^2, respectively. For visualisation of the heat supply configurations, see section 3.1.

It should be noted that the boiler outlet temperature to top of storage is 95 °C year round, while the supply temperature from boiler central to load varies from 85 °C in winter (−10 °C and lower) to 65 °C in summer (16 °C and higher).

3.1.2. Main component models used in system models

Table 2 gives an overview of the main TRNSYS components used in this study, as well as some of their parameter settings. The solar collectors modelled were both designed for operation in DH systems, i.e. large scale solar heating, the efficiency parameters can be found in Table 3 and were taken from the Solar Keymark datasheets (these are found in the data repository together with the product brochure [48]).

Table 2
Main TRNSYS components and parameter settings [54]. Non-standard components are referenced individually. A description of TESS component is found in [55]. Abbreviations: Minimum turndown ratio (MTR).

Name	Component Type	Main Parameters	Descriptions.
Weather data	Type 15–6	Hemse, Gotland (57.2437° N, 18.3788° E).	Data from SMHI.
Heat load	Type 9	Power, return temperature.	Flow rate calculated based on power and supply/ return temperature.
Boiler	Type 700 (TESS)	2.5 MW/3.0 MW; MTR 0.1; Supply temperature 95 °C.	Wood-pellet boiler. Variable efficiency depending on load factor.
Storage	Type 340 [56]	100–1100 m^3; Avg. U-value: 0.15 W/m^2 K.	100 m^3 static + 0.1 m^3/m^2 collector area.
BC HX	Type 805 [57]	Input temperature/ flow (variable).	Calculates required flow from load side flow/ temperature and specified input temperature on supply side.
Sol HX	Type 5	UA value.	Variable UA-value according to size of collector field.
ETC	Type 538 (TESS)	3000 m2.	Fluid: 40 % propylene glycol/water. Tilt 40, azimuth 0.
FPC	Type 832v501 [58]	500–10000 m2.	Fluid: 40 % propylene glycol/water. Tilt 40, azimuth 0.
Pump(s)	Type 741 (TESS)	Variable flow rate.	Boiler circuit pump. Variable control signal.
Pump(s)	Type 114	Variable flow rate.	Storage charge pump.
Pump(s)	Type 3	Variable flow rate.	Solar circuit pump. Flow rate acc. Eq. 1a – c.
Twin-pipe(s)	Type 951 (TESS)	Varied parameters according to pipe size.	Solar culvert pipe.
Single-pipe(s)	Type 952 (TESS)	Varied parameters according to pipe size.	Solar header pipe.
Pipe(s)	Type 709 (TESS)	Varied parameters according to pipe size.	Connection pipes for solar collectors and internal supply pipes in BC.

Table 3
Efficiency parameters – Excerpt of values from the Solar Keymark certificates for the FPC and ETC modelled in this study. All parameters are related to collector gross area.

	η_0	a_1 [W/m^2 K]	a_2 [W/m^2 K]	a_5 [J/m^2 K]	Kd [-]	IAM (50°) [-]
FPC	0.782	2.27	0.018	5980	0.92	0.97
ETC	0.64	0.94	0.006	8206	0.95	0.98

The heat loss areas for the storage are modelled as having three sections of relative heights 0.1, 0.8 and 0.1 for the upper, middle and lower part of tank, respectively. However, heat losses through top and bottom have not been modelled separately, instead an overall U-value of 0.15 W/m^2 K was used to calculate the UA-value of the whole storage and this was divided among the relative sections of the storage for input to the tank model. The used U-value was the mean of the theoretically calculated U-values [48] for all modelled storage volumes by using thermodynamic formulae and heat transfer coefficients presented in a paper about heat losses in storages above ground [50] – taking into account top and bottom heat loss. This approach was chosen due to simplicity in modelling and the uncertainties in the cost drivers of the total storage cost, among others that related to insulation. The impact of this is discussed in Ch. 5.

Table 4 shows an overview of the UA-values and height for the storage volumes modelled in this study. Only the height is listed, as the diameter is calculated internally from the volume in TRNSYS. The height-to-diameter (h/D) ratio is equal to 1.381 for all volumes – the same as for off-the-shelf units of 2.5 m^3, which was used in a previously published study [22]. This value is notably lower than some storages installed in DH systems today, such as that of Ellös [51] with 200 m^3 and a h/D ratio of roughly 2, Hässleholm DH system with 15000 m^3 and an h/D ratio of 3 [52], and Ystad Energi with 6700 m^3 and an h/D ratio of 4.5 [53]. The optimal h/D ratio is 1, although the chosen ratio is subject to the available area for installation, which the mentioned examples portray.

For a full list of all components types and applied inputs, TRNSYS deck files (.DCK) are provided for all system variants in the data repository [48].

3.1.3. Solar heating model

For reasons of simplicity in modelling and to make the study more general, the solar collector installation area was assumed to be square shaped, instead of the triangular shaped as in Fig. 2.

The solar energy system model has the same configuration for all system variants, that is, it consists of the same component types, except for the solar collector model whose type is technology specific. However, the pipe lengths are different for the two collector technologies, due to the array size limitations for the employed large scale FPCs [59] and ETCs [60]. The size limitations are due to the pressure losses when fluid flows through the collector and these are significantly higher for ETCs than FPCs. Table 5 shows the array size limitations for the solar collectors modelled in this study, along with maximum number of collectors per array calculated from the collector size, as well as the maximum width of the largest possible array. Note that the calculations are purely arithmetic and does not take into account physical limitations, i.e. the requirement of integer number of collectors in a real system configuration. This is assumed sufficient for a theoretical study. Table 6 shows the actual dimensions of a theoretical 3000 m^2 solar heating system fit in a 10000 m2 square $(100\ m)^2$ land area. With 14 collectors per array both when using FPCs and ETCs, every collector row contains ($N_{arrays/row}$) roughly 3 ETC arrays or 1 FPC array in a 100 m wide area. This results in every ETC row having three header pipes each for supply and return flow, instead of one as in the case of an FPC row. The main consequence of this is that the total pipe length and hence, heat loss, is higher for a solar heating system based on ETC instead of

Table 4
Storage parameters – Height and UA-value for the modelled storage volumes in this study.

V [m^3]	100	150	200	250	300	350	400	600	850	1100
h [m]	6.24	7.14	7.86	8.47	9.00	9.47	9.90	11.34	12.73	13.88
UA [W/K]	18.1	23.7	28.7	33.3	37.6	41.7	45.6	59.7	75.3	89.5

Table 5
Solar limitations – solar array maximum size ($A_{max/array}$), collectors per array ($N_{col.\ max/array}$) and array width ($W_{max/array}$) using different collector technologies, taken from manufacturer product manuals for FPC and ETC.

	$W_{col.}$ [m]	$H_{col.}$ [m]	$A_{max/array}$ [m^2]	$A_{gr.\ col.}$ [m^2]	$N_{col.\ max/array}$	$W_{max/array}$ [m]
FPC	5.97	2.28	200	13.61	14.7	87.7
ETC	2.29	2.20	80	5.05	15.8	36.3

FPC. For more details on the solar heating system model, see data repository [48].

The control strategy of the solar collector loop is to vary the flow rate for a target collector outlet temperature, using Eqs. (1a)–(1c):

$$\dot{m}_{col} = \dot{Q}_{col}/(C_p \bullet T_m) \tag{1a}$$

$$\dot{Q}_{col} = A_{field} \bullet G_{tot} \bullet \eta_0 - a_1(T_m - T_a) - a_2(T_m - T_a)^2 \tag{1b}$$

$$T_m = T_{mset} - T_{min} \tag{1c}$$

Where $\dot{m}_{col}$ is the collector flow rate, $\dot{Q}_{col}$ the collected solar energy, T_m the collector mean temperature, C_p is the heat capacity of collector fluid (glycol), A_{field} the collector field size, G_{tot} the solar irradiance (plane of array), T_a is ambient temperature, $T_{m\ set}$ is target outlet temperature and $T_{m\ in}$ is the simulated collector inlet temperature. The collector related variables are presented in Table 3, where η_0 is the collector efficiency from datasheet (see, a_1 and a_2 is the first and second order coefficients of performance.

The target collector outlet temperature is 95 °C, although the pump control includes a minimum specific flow rate which is high enough to ensure lower starting temperatures and avoid intermittency in the form of excessive starts/stops due to feedback loop between controller and collector temperature. The pump of the solar collector loop starts whenever the collector mean collector temperature is equal to or above 30 °C and stops when it is at or below 25 °C, while the storage charge pump starts when the temperature difference between bottom of storage and heat exchanger inlet is more than 5 K. The storage charging loop is controlled by matched capacity flow, so that charge flow is equal to solar array flow, corrected for differences in specific heat capacity between fluids in respective loop. A simple stratification aid is enabled by sending charge flow to top of storage when temperature is 90 °C or more and to the top of the solar buffer volume (V_{sol} – see Fig. 5) when temperature is 85 °C or less.

3.1.4. Pipe model and calibration of heat losses

Pipes are primarily employed in the solar heating system and in the BC, where the solar culvert uses a pre-insulated steel twin-pipe (Type 951, TESS), header pipes use a pre-insulated steel single pipe (Type 952, TESS) and connection pipes between solar collectors and header pipes use a pre-insulated copper pipe (Type 709, TESS). The insulation class for pipes modelled in this study is series 1 for in twin-pipes and series 2 for single pipes utilised in solar culvert, while the solar connection pipes are of series 3. The pipe models employed have been described in two previous studies [22,23], together with the method used for calibrating pipe heat losses. The procedure used to calibrate is the same as that used in the previous two studies, that is, the pipe model is simulated iteratively for different pipe sizes and the insulation heat transfer coefficient (see Table 7) is changed until the simulated heat transfer corresponds to the manufacturer catalogue value, at operating conditions specified in the catalogue. The pipe sizing procedure has also been described in the referenced studies and relies on well-established fluid dynamics theory [61,62] and flow rates calculated from specific flow rate per unit collector area and field size. Further procedure is not outlined in detail here, but can be found in the referenced studies and in the data repository [48]. Nevertheless, the calibration performed in this study only extends to involve pipes that have not been calibrated previously, namely the larger twin-pipe sizes (DN100 – DN150) necessary for flows in large solar collector fields, as well as a limit range of required single-pipe sized required for header pipes. However, the results of the calibration are included for all pipe sizes used in this study and are shown in Table 8.

3.1.5. Boiler model

The boiler model main parameters are power and minimum turndown ratio (MTR), while the part load ratio (PLR) – the quotient of actual to maximum possible power output – is used as an input for calculation of boiler efficiency according to Eq. (2) [63]:

$$\eta_{boiler} = \eta_{boiler,\ 100\%} \bullet (1 - exp^{-K\bullet\beta}) \tag{2}$$

where η_{boiler} is the calculated boiler efficiency, $\eta_{boiler,100\%}$ is the boiler efficiency at full load (90 %), K (=0.140) is an empirical constant, and β is the boiler load factor in percent (PLR multiplied by 100). The boiler load factor is the quotient of Q_{boiler} and maximum boiler capacity Q_{max}.

The boiler efficiency is used as an input to the boiler model, which then calculates the annual boiler fuel use according to (Eq. (3)) for a time step of three minutes:

$$Q_{fuel,\ boiler} = \sum_{t=0}^{t=175200} Q_{boiler}(t)/\eta_{boiler}(t) \tag{3}$$

where $Q_{fuel,\ boiler}$ is the boiler fuel supply, Q_{boiler} is the boiler energy to

Table 7
Heat transfer coefficients and temperature input values to the pipe model used in TRNSYS simulations of specific heat loss for different pipe types. The pipe walls are assumed the same as operating temperatures (supply-return) specified in manufacturer catalogue.

Legend: Steel/Copper	Pipe	Casing	Ground	Insulation
Heat transfer coefficient [W/m K]	55.2/365.0	0.4/ 0.4	1.5/1.6	0.026/ 0.022
Temperature [°C]	85–55/ 85–45	–/-	5/10	50/50

Table 6
Pipe lengths – Calculated collector number ($N_{col.}$), minimum number of arrays ($N_{array\ min.}$), collectors per array ($N_{col./array}$), numbers of rows (N_{row}), number of arrays per row ($N_{arrays/row}$) and total length of rows ($L_{tot.\ row}$), header pipes ($L_{H.\ pipe}$) and connection pipes ($L_{C.\ pipe}$) for a field size A_{field} of 3000 m^2.

	A_{field}	$N_{col.}$	$N_{array\ min.}$	$N_{col./array}$	N_{row}	$N_{arrays/row}$	$L_{tot.\ row}$	$L_{H.\ pipe}$	$L_{C.\ pipe}$
FPC	3000 m^2	220	16	14	16	1	100	282	64
ETC	3000 m^2	594	43	14	14	3	85	738	172

Table 8
List of correction factors used to adjust the heat transfer coefficient (λ_{ins}) of pipe insulation for the range of twin and single pipe sized used in this study.

Pipe type	DN	50	65	80	100	125	150
Twin	Correction factor	d	e	f	q	r	s
		1.082	1.168	1.196	1.211	1.176	1.262
	Calibrated λ_{ins} [W/m^2 K]	0.028	0.030	0.031	0.031	0.031	0.033
Single	Correction factor	t	u	v	x	y	z
		1.980	1.974	1.964	1.959	1.949	1.928
	Calibrated λ_{ins} [W/m^2 K]	0.051	0.051	0.051	0.051	0.051	0.050

a fluid stream, and η_{boiler} is the calculated boiler efficiency at a given time-step and PLR.

The boiler is modelled with an MTR of approximately 1:10 (min. PLR of 0.1). In the system variants with storage, the boiler is operated by using a temperature sensor in the middle of the dedicated boiler volume (V_{boil}) with a fixed target temperature of 90 °C for this volume. This type of boiler control is implemented in reality, according to industry representatives at DH supplier Akershus Energi (Eivind Brokke, Personal communication)[64] and DH consulting company Andersson & Hultmark (Per-Erik Andersson Jessen, Personal communication)[65]. The target outlet temperature from boiler is 95 °C.

In order to model the boiler operation more realistically, the cycling behaviour was controlled so that once ignited, the boiler had a minimum run-time of 60 min. This is considered a rough estimate of the minimum cycling time for a cold pellet boiler, as the start-up time is usually around 30 min before stable operation is achieved, after which the boiler should run for another 30 min before shutting down to avoid excessive cycling – according to information from representative of boiler manufacturer Jernforsen (P. Nilsson, Personal communication)[39]. There is no limitation on the minimum off-time before re-ignition, as this was considered unnecessary due to the average number of daily ignitions being less than one, when evaluating the highest number of boiler ignitions for all variants. In the winter season, the boiler runs more or less constantly, while it in the summer season cycles between operation daytime and off-time during night. The operation cycle duration varies between variants, with decreasing on-time and increasing off-time with increasing solar field size. More information about this can be found in the variant output datasheets in data repository [48].

3.2. Parametric study

Table 9 shows an overview of the system variants simulated in this study and the components included in these. These variants are based on the heat supply configurations presented in section 2.4. The collector area is increased in increments of 500 m^2 up to 3000 m^2, which is assumed to be the largest readily available area in the Hemse DH system (see section 2.1). From 3000 m^2 up, the increments are larger, in order to investigate the potential benefit of extending the land area for installation. The storage volume is proportional to the collector area with a specific volume of 0.1 m^3/m^2 collector area, which is considered a large value and was chosen to maximise the stored solar energy. TRNSYS model images of simulation models for variant 1, 2, 8 and 12 can be found in Appendix A in the data repository [48].

Table 9
System variants – overview of the simulated system configurations and their included components. Abbreviations: boiler-only (BO), Boiler + storage (B + ST), B + ST + flat plate/evacuated tube collectors (B + ST + FPC/ETC).

Variant	Configuration	Collector area [m^2]	Storage volume [m^3]
1	BO	NA	NA
2	B + ST	NA	100
3	B + ST + FPC	500	150
4	B + ST + FPC	1000	200
5	B + ST + FPC	1500	250
6	B + ST + FPC	2000	300
7	B + ST + FPC	2500	350
8	B + ST + FPC	3000	400
9	B + ST + FPC	5000	600
10	B + ST + FPC	7500	850
11	B + ST + FPC	10,000	1100
12	B + ST + *ETC*	3000	400

Table 10
Storage volume – Overview of simulated system configuration for sub-variants 9.1 – 9.3 and the storage volume included in these.

Variant	Configuration	Collector area [m^2]	Storage volume [m^3]
9.1	B + ST + FPC	5000	600
9.2	B + ST + FPC	5000	1100
9.3	B + ST + FPC	5000	1600

3.3. Storage volume sensitivity analysis

A sensitivity analysis has been performed for variant 9 (see Table 9) using 5000 m^2 of FPCs with variation in specific storage volume between 0.1 m^3/m^2 – 0.3 m^3/m^2. This in order to see the effect of having a larger storage on the collector performance and LCOH. The sub-variants simulated in the analysis are presented in Table 10:

3.4. Economic analysis

The economic analysis is based on calculation of the levelised cost of heat (LCOH), as it was considered most appropriate cost parameter for studies undertaken from a heat supply perspective for an existing system and because the investment costs are well known. All cost figures used are for the year 2021 and figures from earlier references have been inflation adjusted to 2021 level according to data from Statistics Sweden [66], unless otherwise stated. This year was chosen as more representative than recent years, as energy costs increased in 2022 as a result of the war in Ukraine and costs for 2023 have been highly volatile due to instability in financial markets as a result of high inflation. All cost calculation results are given in EUR, using the official annual conversion rate of 10.145 SEK/EUR from the Swedish central bank [67] for conversion of all cost figures in SEK.

3.4.1. Levelised cost of heat

There are two forms of LCOH used in this study [30]:

1) Net LCOH (nLCOH) – when *retro*-fitting a DH system.

The nLCOH is the unit heat cost for the solar heat, which includes the investment cost for all components and O&M costs for the solar heating system. The nLCOH for a boiler-only system represents the unit heat cost of simply continuing to operate an existing boiler, while it for a boiler and storage system (variant 2) includes the investment cost of a storage and the running costs of an existing boiler. The nLCOH is calculated

Table 11
Boiler costs – investment and O&M costs for a biomass boiler used in this study.

Boiler type	Investment [EUR/kW]	Static O&M [EUR/kW]	Dynamic O&M [EUR/MWh]
Biomass	805.6	10.1	2.0

according to (Eq. (4)):

$$nLCOH = \frac{I_S + C_{storage} + \sum_{t=1}^{T} P_s \bullet (1+r)^{-t}}{\sum_{t=1}^{T} Q\_sol \bullet (1+r)^{-t}} \tag{4}$$

Where I_S and $C_{storage}$ is the investment cost for the solar heating system and storage respectively, while P_s is the annual operation and maintenance (O&M) cost of the solar heating system, Q_sol[1] is the solar energy delivered rom the collector loop to the boiler central in the year t, T is the system lifetime and r is the applied discount rate.

2) System LCOH (sLCOH) – When re-powering a DH system.

The sLCOH is the unit heat cost for all heat, including investment cost for the wood-pellet boiler and the solar heating system (where applicable), as well of O&M costs for both the boiler system and the solar heating system (where applicable). It is calculated according to Eq. (5):

$$sLCOH = \frac{I_S + C_{storage} + I_b + \sum_{t=1}^{T} (P_s + P_b) \bullet (1+r)^{-t}}{\sum_{t=1}^{T} (Q\_sol + Q\_BE) \bullet (1+r)^{-t}} \tag{5}$$

Where I_b, P_b and Q_BE is the investment cost for, O&M cost for and delivered energy from, the boiler system, respectively. The remaining variables has been explained for Eq. (4).

These equations rely on some simplifications, such as assuming depreciation and corporate tax rate of zero for a DH system in the residential sector, no residual value at end of economic life as well as static annual costs for O&M and static annual heat generation for the system lifetime. The economic lifetime is assumed to be 30 years for both boiler and solar heating system.

3.4.2. Solar heating system and storage costs

The assumed reference cost of flat plate collectors is 240 EUR/m^2 ready installed, excluding VAT and subsidies [68]. This cost has not been inflation adjusted, due to the large cost span for large scale solar collectors (the inflation adjusted cost is within the span) and that a sensitivity analysis is performed to reveal the required collector cost for cost competitive solar assisted DH systems, rendering "correctness" of the initially assumed cost less important.

For evacuated tube collectors, the assumed reference cost is 395 EUR/m^2, ready installed (J. Jensen – Personal communication) [69]. Actual costs may vary and decrease somewhat with increasing collector area, so this should be considered worst case.

For both collector types, the assumed solar maintenance cost is 0.269 EUR/MWh (converted with an exchange rate of 7.437 DKK/EUR) and assuming an electricity consumption of 1.5 kWh electricity/100 kWh solar heat fed from the solar loop to the storage loop [30], using the electricity cost in Table 12.

The storage investment cost ($C_{storage}$) is calculated according to (Eq. (6)) [30]:

$$C_{storage} = (11680 \times V_{storage}^{-0.5545} + 130) \tag{6}$$

Where $V_{storage}$ is the storage volume in m^3.

[1] For non-solar systems (variant 1 and 2), Q_sol is replaced by Q_BE, which represents the delivered boiler energy and is dependent on boiler system efficiency rather than solar heating system efficiency.

3.4.3. Boiler system costs

The cost calculations for the boiler system were based on investment and O&M costs from a 2020 report from the Swedish Energy Agency (Energimyndigheten) [14]. These are presented in Table 11:

The 2021 fuel costs (see Table 12) used as input to calculations were taken from various sources; For wood-pellets (main/backup boiler), from statistics published by the Swedish Energy Agency [70], while costs for fuels used for backup-boiler, such as bio-oil, diesel fuel oil (DFO) and heavy fuel oil (FOH) were sourced from the weekly oil bulletins of the European Commission [71]. The cost of electricity used was composed of the 2021 mean spot price (66.0 EUR/MWh) published by the Swedish consumer Energy Markets Bureau (Energimarknadsinspektionen) [72] and the utility cost (18.8 EUR/MWh) for a 1 MW connection (backup boiler/electrical cartridge) with an annual consumption of 1 MWh [73]. The wood-pellet costs are used as reference fuel cost in the economic analysis presented in section 4.

3.4.4. Operating costs during boiler maintenance

The operating costs of the DH supply during the maintenance of the main boiler is investigated by calculating the fuel cost for two different types of backup-boilers for the month of July, based on the load profile presented in Fig. 4. This period was assumed realistic due to the low heat demand during summer holidays, after advise by industry representative at DH supplier Akershus Energi (Eivind Brokke, Personal communication)[64].

In order to calculate the fuel use for different backup-boilers, heat demand for the simulation model was summed up for the month of July. This heat demand was then divided by an assumed static efficiency of 85 % for an oil boiler and 95 % for an electric boiler/cartridge. Assuming static efficiency was done for simplicity and considered appropriate as oil boilers have high overall efficiencies both due to faster start-up and high turndown ratios. according to information from representative of boiler manufacturer Jernforsen (P. Nilsson, Personal communication) [39] – while electric boilers usually have very short start-up time and no flue losses, leaving only heat losses from the stack to the environment and resulting in high and stable overall efficiency.

The operating costs of the DH supply using the backup-boiler fuels presented in Table 12 were compared to the cost of supplying the same energy by wood-pellets in the main boiler, i.e. without having a backup-boiler. This in order to reveal the effect of the backup-boiler fuel cost on the LCOH and determine the most cost-effective solar collector area for various backup-boiler types. The results are presented as a comparison of sLCOH for all variants, meaning for a re-powering scenario, although assuming that the backup boiler is already present in the system and does not need replacement.

3.5. Cost sensitivity analysis

Due to uncertainty in assumed values for discount rates, as well as fuel and collector costs, two types of sensitivity analysis were conducted:

- Sensitivity of LCOH – Eq. (4) and Eq. (5).

Done by simply exchanging the discount rate in the calculation of the listed equations for all variants.

- Sensitivity in fuel and collector cost to reach parity between solar and non-solar DH.

Table 12
Fuel costs – Costs for various fuels, used both in main boiler (wood-pellets) and backup boilers. Abbreviations: diesel fuel oil (DFO), fuel oil – heavy (FOH), electricity (EL).

FUEL	Wood-pellets	Bio-oil	DFO	FOH	EL
[EUR/MWh]	31.4	62.9	165.3	88.2	84.8

Done by selecting a fuel cost in the range 20 – 50 EUR/MWh in steps of 5 EUR/MWh and iteratively changing the collector cost until the LCOH value of one or more solar assisted DH system variants was equal to the cheapest variant without solar heating. Singular values for parity fuel cost have also been obtained by iteratively changing the fuel cost at reference collector cost (see *section 3.4.2*) until LCOH value of a 3000 m^2 FPC/ETC solar heating system matches that of the cheapest non-solar variant.

The first sensitivity analysis intends to investigate how the competitiveness of the different system variants change in terms of unit heat cost when the financial costs become higher. The second analysis intends to investigate how low the collector cost must be for a certain fuel cost level, in order for the solar heating cost to be competitive with the cheapest system heating cost without solar. This can be used as a design guideline for the DH system investigated, if the economic boundary conditions such as collector and fuel cost should change. Furthermore, threshold fuel cost values for a particular solar heating system size and reference collector cost are obtained to show how cost-competitive solar heating is under assumed economic boundary conditions for this study.

3.6. Key performance indicators (KPI)

The key performance indicators used to evaluate system performance are shown in Table 13. The energy quantities (Q) have units of Wh or J with prefixes k, M and G. Specific yield has unit of kWh/m^2. The LCOH unit is EUR/MWh or EUR/GJ.

4. Results

The results are divided into an analysis of the techno-economic performance of the simulated system variants, followed by a sensitivity analysis on the influence of discount rate on the LCOH for these. Furthermore, the collector cost at parity LCOH with an unassisted SDH system is presented, before the influence of backup boiler fuel cost during maintenance periods is revealed.

4.1. Techno-economic analysis

The analysis is split into three parts (refer to Section 3.2 for overview of variants): one part comparing the boiler-only system (variant 1) with a solar assisted system using FPCs with various collector areas (variant 3 – 11)*,* one part presenting the system with boiler and buffer storage (variant 2) and one part presenting the solar assisted system using ETCs (variant 12).

Table 13
KPI – overview over key performance indicators used in this study.

Symbol	Description
$Q_{\_FB}$	Fuel supplied to boiler.
$Q_{\_BE}$	Energy supplied from boiler.
$Q_{\_LB}$	Losses from boiler (stack).
$Q_{\_BC\_loss}$	Internal heat loss in boiler central (pipes and storage).
$Q_{\_col}$	Solar energy delivered from collectors.
$Q_{\_sol}$	Solar energy delivered to storage charge loop.
$Q_{\_sol\_loss}$	Solar energy lost in solar loop.
$Q_{\_load}$	Heat demand of load (DH network).
SF	Solar fraction: Ratio of solar energy loaded into store to total energy supplied.
Y_s	Specific yield: Supplied solar energy per unit collector area.
LCC	Life cycle cost.
sLCOH	System LCOH – including boiler investment cost.
nLCOH	Net LCOH – excluding boiler investment cost (solar LCOH).

4.1.1. Boiler with/without storage versus solar assisted system with flat plate collectors

Fig. 6 shows the simulated boiler fuel use, transferred boiler energy and solar energy, along with calculated values for sLCOH (repowering case) and nLCOH (retrofit case) for non-solar variants and solar variants 3 – 11. The break-even LCOH – that is – the lowest value found for any *non-solar* variant, is the value for variant 2. Note that this graph is valid for the baseline scenario using a discount rate of 3 %. Beware the non-linear x-axis when reading the results. The use of a slightly smaller boiler in combination with a buffer storage (variant 2) by itself leads to a reduction of about 5 % in boiler fuel use compared to a boiler without storage (variant 1), despite a very small increase in boiler supplied energy. This leads to a reduction in sLCOH of about 6 % to 58.0 EUR/MWh (16.1 EUR/TJ) in variant 2, while nLCOH is reduced 4 %, going to 49.5 EUR/MWh (13.7 EUR/TJ). Thus, it is a cost-efficient measure is to invest in a storage, no matter if made together with solar or not and, regardless of installed at the same time as a boiler replacement or as a supplement to an existing boiler-only system. This seems logical, considering that the reason for adding storage is to ensure more stable operation and avoid excessive cycling that leads to suboptimal performance [49].

In the re-powering scenario, all variants 2–11 give similar results when comparing to a boiler-only system (variant 1) with a wide optimum obtained around 5000 m^2 installed collector area where the sLCOH is 55.7 EUR/MWh (15.4 EUR/GJ). This sLCOH is about 8 % lower than that of variant 1, which is considered significantly more cost efficient. However, seeing that the sLCOH is more or less the same for all except variant 1, other factors may become decisive when choosing system configuration, such as emissions reductions from i.e. boiler operation or transport of fuel when installing a solar heating system, although this is considered outside the scope of this article.

In the case of *retro*-fit, a solar heating system appears a good way to reduce energy costs. The lowest nLCOH is 34.8 EUR/MWh (9.7 EUR/TJ), which is about 32 % lower than the value for variant 1 and is obtained for variant 8 with a SF of 13 %. In fact, with the exception of variant 3, the nLCOH values for all solar assisted variants are significantly lower than that for variant 1. Thus, having a solar heating system with 1000 m^2 or more of collector area appears cost effective compared to a boiler-only system with (variant 2) or without storage (variant 1). The differences between variants 7 and 8 are so small (below 2 %) that it is difficult to conclude on which one is better, although it seems clear that installing systems larger than 3000 m^2 yield diminishing returns. This indicates that a cost-efficiency limit for installed FPC area is met around 3000 m^2, which is clear when considering how the specific yield (Ys) is reduced for collector areas above this (Fig. 7 – Beware the non-linear x-axis when reading the results).

Fig. 7 shows how the specific yield, solar fraction and heat cost varies with installed solar collector area. It provides some of the same information as Fig. 6, but provides an improved view of the correlation between LCOH and solar heating system performance. For an installed collector area up to 3000 m^2, the FPC specific yield is fairly similar (506 – 516 kWh/m^2; 1.82 – 1.86 GJ/m^2), but starts declining rapidly and losing 31 % over the interval 3000–10000 m^2. The solar fraction, on the other hand, co-varies with the specific yield in that it increases linearly for the interval 500 – 3000 m^2 although it appears to be flattening out in the interval 5000 – 10000 m^2 indicating diminishing returns. The high specific yield in solar heating systems with collector area up to 3000 m is reflected in decreasing values for sLCOH and particularly visible for the nLCOH. In contrast, the reduced specific yield over 5000 m^2 collector area is reflected by an increase in sLCOH and nLCOH and indicates why there is such a clear optimum around 3000–5000 m^2. This is likely related to the energy balance and decrease in utilisable solar heat when harvested solar energy is larger than the demand, specifically in summer.

Fig. 6. Energy use and heat cost 1 – overview of energy use and resulting LCOH for variant 1 and 3 – 11 simulated in this study. Beware the non-linear x-axis in the figure.

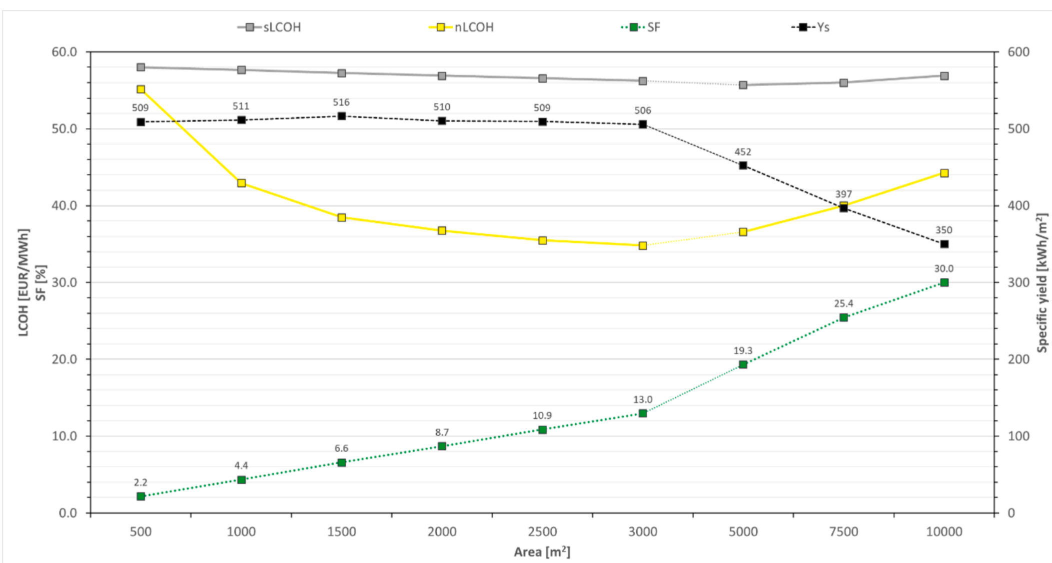

Fig. 7. Solar system performance and heat cost – overview of sLCOH and nLCOH for solar district heating system variants 3 – 11, representing collector areas of 500 – 10000 m^2, respectively. Abbreviations: solar fraction (SF), specific yield (Ys). Beware the non-linear x-axis in the figure.

Fig. 8 shows an energy balance for variant 8 and 9 with installed FPC collector areas of 3000 m^2 and 5000 m^2, respectively. Monthly energy balances can be found in the data repository [48]. These variants were chosen as they are representable for a trend reversal in cost-efficiency as collector area increases, as shown in Figs. 6 and 7. Although variant 9 has a total heat demand (load and all losses) which is about 2 % lower than that of variant 8, the boiler fuel use is 8 % lower and collected solar energy is 49 % higher. Lower fuel use with almost equal demand, implies a lower unit heating cost, although the increase in collected solar energy in variant 9 is not proportional to the increase in installed collector area (67 %), which implies a less cost efficient solar heating system. This might explain why the nLCOH increases when installing 5000 m^2 FPCs instead of 3000 m^2, while the sLCOH decreases. In order to confirm this, the life cycle costs (LCC) can be evaluated from Fig. 9.

Fig. 9 shows the LCC for variant 8 and 9, with installed FPC collector areas of 3000 m^2 and 5000 m^2, respectively – using a discount rate of 3 %. Note that all values are in 10^3 EUR, for the sake of precision. The boiler investment cost is the same in both cases, while boiler O&M costs are about 8 % lower in variant 9 than in variant 8, which seems logical considering that this much less fuel was used in variant 9, making the cost and fuel use proportional. However, when looking at the combined costs of investment for storage, investment for solar and solar O&M cost, these are approximately 56 % higher in variant 9 than in variant 8, despite that the increase in solar energy transferred to storage was only about 49 % higher, as stated for Fig. 8. Hence, the cost increase is about 5 % (1.56/1.49 = 1.05) on per unit basis, which corresponds well to the higher nLCOH for variant 9 when compared to variant 8, shown in Fig. 6. Combining all costs (i.e. the re-powering case), the total LCC differs less than 2 % between variant 8 and 9, the latter having the lowest value.

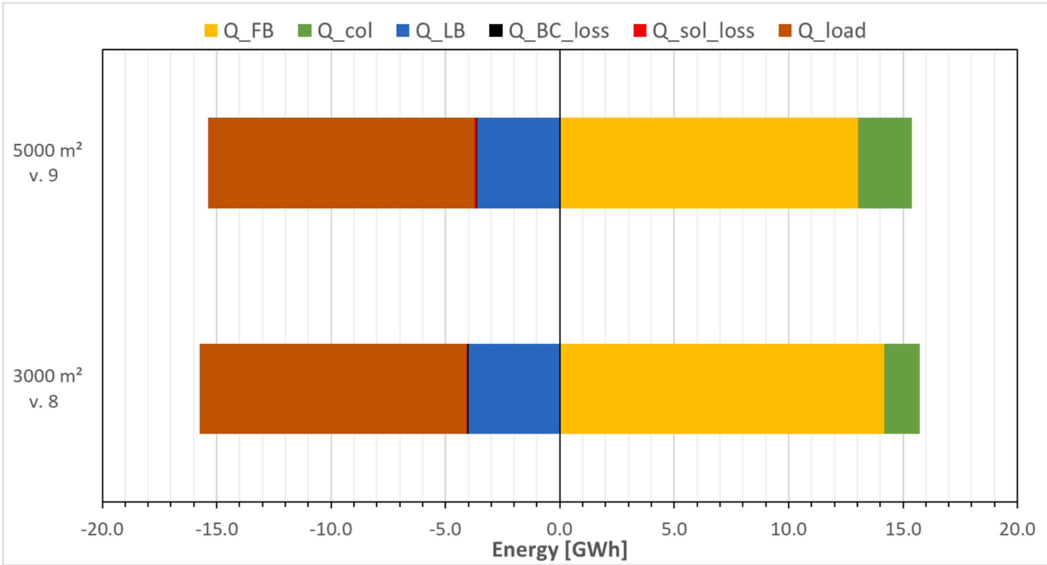

Fig. 8. Energy balance for variant 8 and 9, with 3000 m^2 and 5000 m^2 of installed flat plate collector area, respectively.

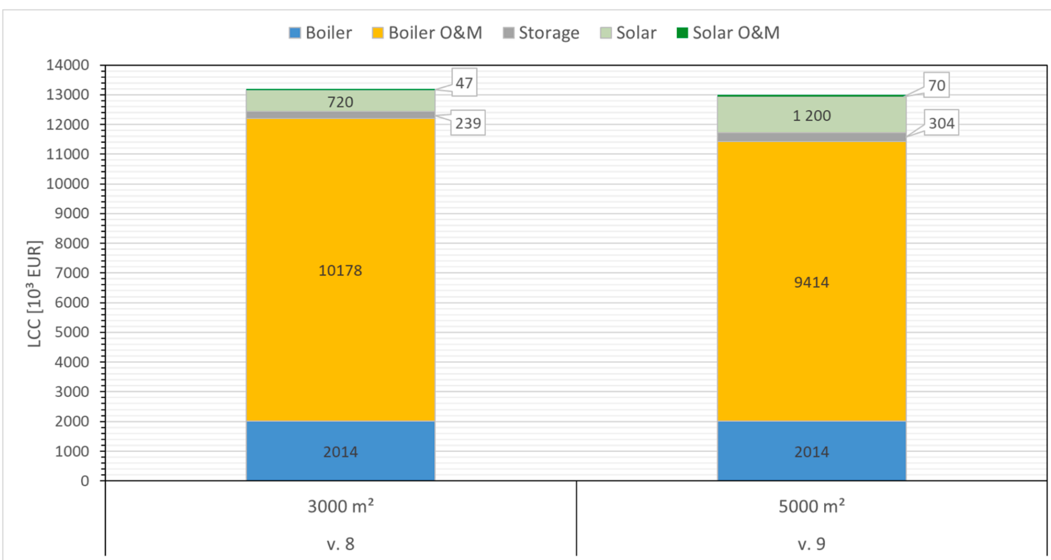

Fig. 9. Life cycle costs (LCC) in thousands of euros for system variant 8 and 9, with 3000 m^2 and 5000 m^2 of installed flat plate collector area, respectively.

Summing up, the results are:

- Installing a slightly smaller boiler with storage is cost-effective compared to a larger boiler-only when re-powering.
- All system alternatives to the boiler-only system gives similar heat cost when re-powering, hence other factors such as potential emissions reductions are relevant for the choice of installing solar or not.
- Solar heating is cost-effective for all except the smallest system sizes when *retro*-fitting; at most a 32 % reduction in unit heat cost is enabled by a 13 % solar fraction.

4.1.2. Solar assisted system with evacuated tube collectors

Table 14 shows an overview of unit heat costs for, as well as energy delivered to and from, a boiler with storage system (variant 2) and two solar assisted systems – one with 3000 m^2 FPC (variant 8) installed and another with 3000 m^2 ETC (variant 12) installed. More or less all values, both for costs and energy, are significantly lower for solar assisted variants than for variant 2. Although the sLCOH (re-powering) for both variant 8 and 12 is only 3 % lower than for variant 2, the nLCOH is 30 % and 21 % lower, respectively. Thus, when *retro*-fitting a solar heating system, the FPCs are more cost-effective than ETCs. For variant 12, the specific yield (662 kWh/m^2; 2.38 GJ/m^2) and solar fraction (17 %)

Table 14
Overview major KPIs for variant 12 with 3000 m^2 of ETCs, compared to those of variant 8 with 3000 m^2 of FPCs and variant 2 with boiler and storage (see Table 9).

Variant	sLCOH [EUR/MWh]	nLCOH [EUR/MWh]	Q_FB [GWh]	Q_BE [GWh]	Q_sol [GWh]	SF [%]	Ys [kWh/m^2]
2	58.0	49.5	16.3	11.8	–	–	–
8	56.2	34.8	14.2	10.2	1.5	13	506
12	56.1	39.3	13.4	9.7	2.0	17	662

achieved is significantly higher than for a corresponding FPC field, which had specific yield of 506 kWh/m^2 (1.82 GJ/m^2) and a SF of 13 %. This, along with reduction in boiler fuel use of 18 % when compared to variant 2 and 6 % when compared to variant 8, supports a better match between DH operating temperatures and ETC supply temperatures. Nevertheless, the difference in sLCOH for variant 12 is negligible (less than 1 %) when compared to variant 8 – due to the higher collector cost, meaning ETCs and FPCs appear equally cost-effective for re-powering. Therefore, other aspects such as fuel and/or emission savings could be considered by stakeholders in order to reach an investment decision, although this is considered outside the scope of this article.

4.2. Storage volume sensitivity study

Table 15 shows an overview of the unit heat costs (sLCOH/nLCOH), boiler fuel use ($Q_{\_BE}$) and delivered energy ($Q_{\_BE}$), delivered solar heat ($Q_{\_sol}$), solar fraction (SF) and specific yield (Y_s)for three sub-variants 9.1 – 9.3 with 5000 m^2 collector area and variation of storage volume from 0.1 m^3/m^2 – 0.3 m^3/m^2 as presented in Table 10. Despite an 8 % increase in specific yield to 486 kWh/m^2 (1.75 GJ/m^2) for variant 9.3 when storage volume has been tripled, corresponding to an increase in SF from 19 to 21 %, the sLCOH and nLCOH increases. However, the sLCOH values are too similar between sub-variants in this sensitivity study and other variants to conclude on the significance of installing a larger tank when repowering, although the nLCOH values increase markedly with increasing storage volume. Retro-fitting with triple specific storage volume and 1600 m^3 in total (variant 9.3) gives a unit heat cost approximately equal to that of variant 10, but with a significantly lower SF. Thus, when *retro*-fitting, installing a larger tank does not seem to make economic sense compared to increasing solar heating system size. The reason for this is due to significantly higher monthly SF due to higher production, particularly in spring, early summer and autumn, which can be seen by visiting the monthly energy balances (Figure B.5 – B. 8) presented in Appendix B of the data repository [48]. Nevertheless, performing a sensitivity study is essential when dimensioning a solar heating system for DH and should be performed every time.

4.3. Cost sensitivity study

The sensitivity study is divided into two parts: one treating the impact of discount rate on LCOH for the simulated variants and one treating the impact of discount rate on the required collector cost to reach parity LCOH with a non-solar assisted district heating system for a range of fuel costs.

4.3.1. Impact of discount rate on heat cost

Fig. 10 shows the variation in LCOH with change in discount rate (DR) for all variants simulated in this study; selected values have been labelled, for example to show graph bottoms and peaks. The most important thing to note is that the major trends outlined in *Ch. 4.1* for a DR of 3 % are maintained when the DR increases, although there are some exceptions. The main points to note are as follows:

- Variant 2 has significantly lower sLCOH (6 %) and nLCOH (3–4 %) than variant 1, for all DR. This implies that installing a storage is cost-effective both when re-powering and when *retro*-fitting.
- For a DR of 3 %, the results have been explained in *Ch. 4.1*.
- When *retro*-fitting, increasing DR leads to reduced cost-competitiveness of solar, with a narrowing range of collector areas being cost-effective, as the nLCOH exceeds that of non-solar variants.
- For a DR of 5 %, a collector area of 1500 m^2 (variant 5) − 7500 m^2 (variant 10) appears cost-effective with an nLCOH ranging 4–17 % lower compared to running a boiler-only system (variant 1).
- For a DR of 7 %, all solar variants appears to have a higher nLCOH than the non-solar variants, although the values for variant 7–8, with 2500 – 3000 m^2 collector area, respectively, are very similar to those of variant 1. Therefore, solar heating appears cost-competitive with a boiler-only system (variant 1), although a boiler with storage (variant 2) system appears more cost-effective than solar heating at high DRs.
- When re-powering, the sLCOH increases the most for large collector areas, i.e. 7500 m^2 – 10000 m^2. For a DR of 5 %, the sLCOH is similar for all except variant 11 and is significantly (6 – 7 %) lower than for variant 1, which indicates that re-powering with solar heating is cost-effective as long as the collector area is not larger than 7500 m^2.
- For a DR of 7 %, the sLCOH is similar for variants 3 – 9 and 12, being significantly lower (3–6 %) than variant 1, while the value for variant 11 is actually higher (albeit insignificantly so). Thus, re-powering is cost effective as long as the collector area is not larger than 5000 m^2.
- Installing a 3000 m^2 solar heating system with ETCs (variant 12) yields a significantly (13 %) higher nLCOH than an FPC system of the same size (variant 8), at all DR, so it is generally less cost-effective when *retro*-fitting. The difference between the same variants in sLCOH is too small (about 1 %) to conclude on the best option.

4.3.2. Impact of discount rate on parity between heat costs

Fig. 11 displays the relation between fuel and collector costs at parity sLCOH (re-powering) for fuel costs in the range 20.0 – 50.0 EUR/MWh (5.6 – 13.9 EUR/GJ) and three discount rates; 3 % (top solid line – brown), 5 % (middle dashed line – orange) and 7 % (bottom dashed lines – yellow). Parity sLCOH is obtained when the unit heat cost is the same for a solar assisted system (here: variant 8 – 3000 m^2 FPC) and non-solar system (here: variant 2 – slightly smaller boiler with storage). The graph for 5 % DR has been chosen to show how to read the figure; The reference collector (FPC) cost this study of 240 EUR/m^2 (see *section 3.4.2*) has been marked with an arrow from the y-axis and to the fuel/collector cost trend line (orange) − and from the trend line to a corresponding fuel cost of 26.0 EUR/MWh (7.2 EUR/GJ). Thus, the figure shows that assuming a (reference) collector cost of 240 EUR/m^2 at a discount rate of 5 %, solar heating is cost-effective when the fuel cost is higher than 26.0 EUR/MWh. If at this fuel cost, the collector cost is higher than the reference cost, solar heating is *not* cost-effective and, if it is lower, solar *is* cost-effective. Nonetheless, seeing that the reference fuel cost for this study is 31.4 EUR/MWh (see *section 3.4.3*), parity has already been reached at 5 % DR and hence, when re-powering, installing solar heating is more cost efficient than a non-solar system. Fig. 11 may be used to deduce the required fuel cost to achieve parity between variant 2 and 8, for arbitrary choices of DR and collector cost, by following the outlined method that was used for a DR of 5 %. Similar graphs can be found for the *retro*-fit (nLCOH) alternative with FPC and for both re-powering/*retro*-fit alternatives using ETC in Appendix B in data repository [48].

To see the required fuel cost for parity sLCOH (re-powering)/nLCOH (*retro*-fitting) at reference collector cost level, please see Table 16. The

Table 15
Results for sensitivity study sub-variants 9.1 – 9.3 for a 5000 m^2 collector area and storage volume of 0.1 m^3/m^2 – 0.3 m^3/m^2 as presented in Table 9. Abbreviations: St. vol. = Storage volume. KPIs explained in section 3.6.

Variant	St. vol. [m^3]	sLCOH [EUR/MWh]	nLCOH [EUR/MWh]	Q_FB [GWh]	Q_BE [GWh]	Q_sol [GWh]	SF [%]	Y_s [kWh/m^2]
9.1	600	55.7	36.5	13.0	9.4	2.3	19	452
9.2	1100	56.0	38.0	12.9	9.3	2.4	20	474
9.3	1600	56.1	39.7	12.7	9.2	2.4	21	486

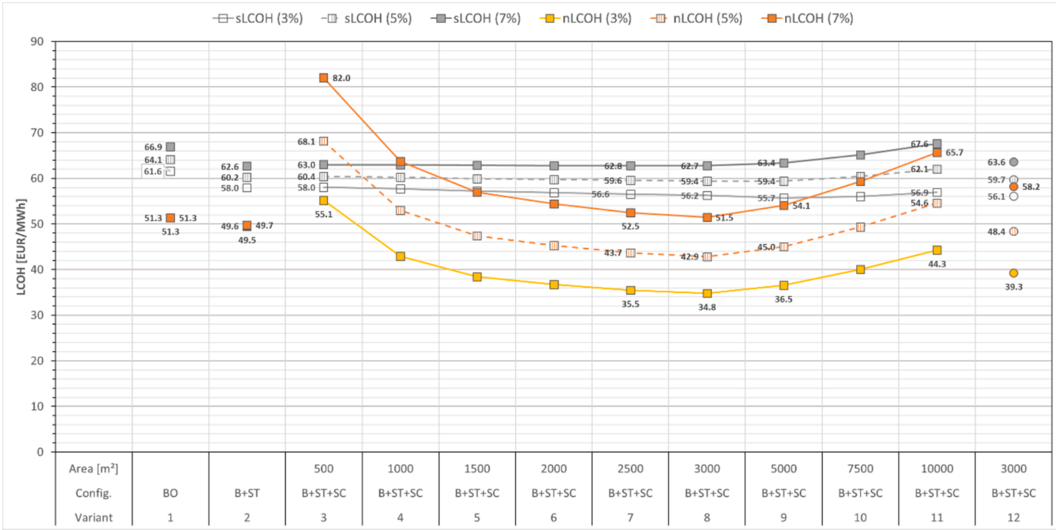

Fig. 10. Cost variation – Change in LCOH for the simulated variants with discount rates of 3%, 5% and 7%.

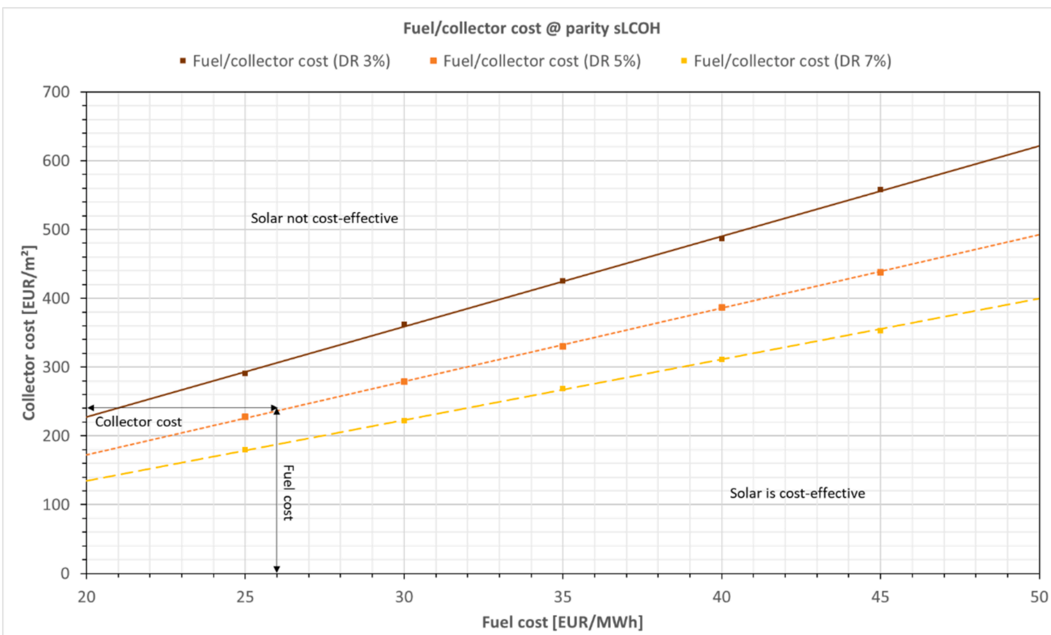

Fig. 11. Collector cost at parity – Overview of corresponding fuel and collector costs when sLCOH is equal for a boiler with storage system (variant 2) and solar assisted system with 3000 m^2 of FPCs (variant 8) for a discount rate of 3 % (top lines), 5 % (middle lines) and 7 % (bottom lines).

Table 16
Fuel cost at parity sLCOH/nLCOH for variant 8/12 at three different discount rates (DR) and the reference collector cost levels assumed in this study.

		DR 3 %		**DR 5 %**		**DR 7 %**	
	Fuel cost @ parity	[EUR/MWh]	[EUR/GJ]	[EUR/MWh]	[EUR/GJ]	[EUR/MWh]	[EUR/GJ]
FPC	sLCOH	21.0	5.8	26.0	7.2	31.9	8.9
	nLCOH	20.9	5.8	26.6	7.4	32.7	9.1
ETC	sLCOH	23.3	6.5	29.1	8.1	35.3	9.8
	nLCOH	24.1	6.7	30.6	8.5	37.6	10.4

table shows the required fuel costs for variant 8 (3000 m^2 FPC) and 12 (3000 m^2 ETC) to achieve the same sLCOH/nLCOH as variant 2. From the table, it is apparent that, as long as the collector costs are stable at reference cost levels and using a discount rate of 3 %, then solar is more cost effective if fuel costs are above 21.0 EUR/MWh when installing FPC and 23.3 EUR/MWh when installing ETC. Hence, at reference fuel costs, solar is more cost-effective. Furthermore, for a 5 % discount rate, solar is already more cost-effective as was stated previously, given that the fuel

Table 17
Overview of FPC solar variants with lowest sLCOH at parity for different fuel costs and discount rates (DR). Bold face cells indicate fuel costs where the sLCOH of the solar variants is not cost-competitive.

Fuel cost [EUR/MWh]	**20**	**25**	**30**	**35**	**40**	**45**	**50**
DR 3 %	***3–8***	5–9	8–9	9/10	9–11	10/11	10/11
DR 5 %	***3–6***	***3–8***	5–9	7–9	9/10	9–11	9–11
DR 7 %	***3/4***	***3–7***	***3–8***	4–9	6–9	8–10	9/10

costs must be higher than 26.0 EUR/MWh or 29.1 EUR/MWh when re-powering with FPC or ETC, respectively. Lastly, for a 7 % discount rate, fuel costs would have to rise from reference level to 31.9 EUR/MWh or 35.3 EUR/MWh, respectively, for FPC or ETC to be cost competitive with variant 2 when re-powering. Thus, a high discount rate makes solar heating less cost competitive due to increased marginal cost of solar heat, which is reflected by reduced cost competitiveness for smaller system sizes (see nLCOH in Fig. 10 and Table 17). One consequence of this is that the collector cost must be lower for solar heat to compete at a high discount rate, while collector cost can be higher when solar heat is competing at high fuel costs.

Table 17 shows the solar variants with lowest value of sLCOH (re-powering) for different wood-pellet fuel costs. The cells with bold and indented text indicate fuel costs where listed solar variants are not cost competitive, as the fuel cost shown in header is lower than the break-even fuel cost shown in Table 16. However, the values are included for sake of clarity. According to Table 17, the most cost-effective system size is increasing with increasing fuel cost and at high DR, the most cost-effective system is smaller than for a low DR. This seems logical, seeing that the solar heat cost (nLCOH) is independent of the fuel cost, which favours larger solar heating systems with higher specific yields and solar heating system efficiency. As the discount (interest) rate increases, the solar heating cost increases as well and along with it the economic limit for smallest cost competitive field size as well, so that only variants with sufficiently low solar heat cost (nLCOH) are cost-efficient.

4.4. Unit heat cost according to backup boiler fuel

Fig. 12 shows the calculated sLCOH for all simulated variants in this study when the July heat demand is covered by either an oil boiler using three different fuels or an electric boiler, normalised to the sLCOH when running with wood-pellets (WP) alone. On the left axis are the normalised values, while the right hand axis shows the sLCOH of running the WP boiler. The main results can be summarised as follows:

- As the installed solar collector area increases, the difference in sLCOH between boiler types evens out.
- When installed collector area is 7500–10000 m^2, the sLCOH for all boiler types and fuels are similar.

The employed fuel has little impact on unit heat cost when the July solar fraction is high, which appears logical considering that the need for backup fuel very low when most of the demand is covered by solar. Hence, even if the cost of the fuel is high, the impact is small when the demand for that fuel is very low. This emphasises the benefit of re-powering with solar heating when the backup-boiler in place is running on fossil-fuels.

5. Discussion

The discussion section directs focus to specific aspects that may be considered to influence the results and treats potential impacts on the results of these. The presented content is considered the most relevant, although additional content can be found in Appendix C in the data repository.

5.1. Modelling

The section treats influence of modelling approach on simulation results.

5.1.1. Simulation model simplifications

The simulation model has been made with two major simplifications:

1) One collector model representing the entire collector area.
2) One pipe element to represent a group of pipes.

The collector model is modelled as one large collector and does not distinguish between separate collectors and therefore doesn't take into account row distances and the reduced insolation due to inter-row shading. This naturally affects the results and could mean that the harvested energy is slightly higher than would be if shading effects were taken into account. Similarly, the solar pipes are modelled using one pipe element for each pipe type, lumping the entire pipe length of a certain pipe type in one long pipe. For the solar culvert, this is appropriate, as is connects the header pipes with the connection pipes and thereby the collectors. However, the header and connection pipes are lumped into two single pipe elements in series with the solar collector model at the end, which means that the heat losses in the pipes could be higher than they would in reality. These simplifications therefore have the following impact:

- The collector supply temperature at storage is lower than in reality.
- The solar loop takes longer to heat up and it takes longer until the charge loop starts charging.
- Average temperature in the pipes are lower than in reality.
- Heat losses from the pipes may be slightly underestimated in model (but are very small in the overall energy balance).

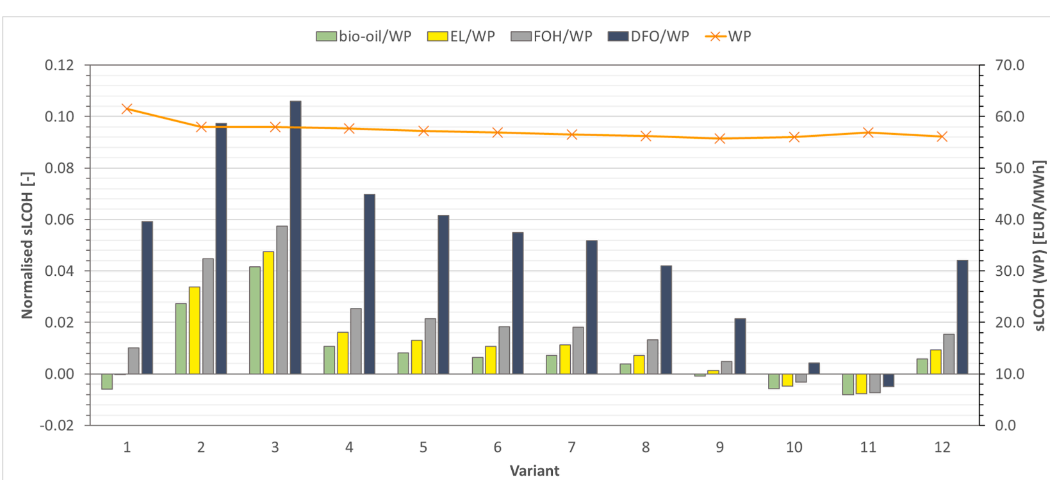

Fig. 12. Alternative fuels – Overview of the unit heat cost when re-powering and employing various backup boiler fuels during maintenance of the main boiler during the month of July. Abbreviations: Electricity (EL), fuel oil – heavy (FOH), diesel fuel oil (DFO). Other abbreviations listed in introduction.

However, seeing that the same modelling approach is used for all variants simulated, this is assumed to not influence results significantly.

Other minor simplifications made were:

i. No minimum run-time for boiler-only system.
ii. Theoretical U-values for storage.

Having no minimum run-time for the boiler encourages on–off behaviour which is not realistic. However, due to the small thermal inertia in the system (no storage) such a behaviour is assumed an appropriate modelling approach due to the short time period where this behaviour may be observed and hence, limited impact on results. In reality, a backup-boiler would be activated in periods of low demand, but this was omitted for simplicity (see *section 5.1.2*). Furthermore, using theoretical U-values is probably underestimating the heat losses for the storage, although the impact on results should be very limited. The losses from the entire boiler central make out less than 1 %, so even a doubling of the storage losses would not lead to significant changes in the results.

5.1.2. Validity and influence of weather data

As was shown in Fig. 3, the difference in annual irradiance is rather low between the reference year (2015) and an average year (2013 – 2022). Six months of the reference year show lower irradiance than an average year, while the remaining six months show higher irradiance and on an annual basis the difference is about 1 %. Therefore, the performance of the solar heating system is assumed not to deviate significantly for weather data based on either years (see *section 2.2*). However, it is worth noting that Gotland is among the locations in Sweden where the solar irradiation is highest throughout the year and that this has implications for the results. Locations that have less solar radiation and/or higher heat demands would yield different results in a similar study to this one, as the solar heating would be less cost competitive. Therefore, further studies on this are needed.

Considering temperatures, months November – March are warmer in the reference year than an average year, so the boiler performance in a boiler-only scenario for an average year could be slightly lower than presented, which theoretically could increase the LCOH values of this variant. Despite this, an evaluation of eq. (2) for boiler efficiency (see Table 18) using the lowest observed boiler power output in this period, which is 1.1 MW (December – see Fig. 4), gives less than 1 %-point difference from the assumed maximum boiler efficiency of 90 %. On the other hand, when considering that the reference year has a higher heat demand compared to the average year during months May – July and considering that the boiler power is 0.3 – 0.4 MW at the lowest during this period, then the boiler efficiency would be very low. Hence, if an average year has even lower heat demand, then the boiler efficiency could be expected to be even lower and therefore the results in this study may under-estimate the boiler fuel use. However, this would mostly impact the boiler-only variant, because a boiler with storage system would have higher load factors and a solar assisted system would replace boiler heat with solar heat, during the period mentioned. In light of this, the results for an average year would probably show larger differences in LCOH between variant 1 (boiler-only) and the other variants, to the benefit of solar heating. Therefore, it is likely that solar heating is more cost-efficient than portrayed if considered for a longer period, although more studies are needed to conclude on this.

5.2. Cost calculations

The section treats influence of financial inputs on simulation results.

5.2.1. Costs for backup-boiler

In this study the investment costs for the backup-boiler have not been included, and this could impact the sLCOH for the various system configurations simulated. However, these were omitted partly due to difficulty in getting hold of such costs and partly because the choice of backup-boiler in DH systems is subject to the load considerations and fuel availability during the DH system design. Furthermore, it may not be considered necessary to replace the existing backup-boiler, so that the only impact of its use is the resulting fuel cost, as is presented in *section 4.4*. In fact, back-up boilers are often in service for very many years as the running time is very low. The presented results for sLCOH are therefore valid under the assumption that the backup-boiler is not replaced during re-powering and that when comparing unit heat costs, all varieties use the same type of backup-boiler, so that difference between the system configurations in terms of sLCOH are the same.

Running the main biomass boiler with wood-pellets (WP) during the one month (July) maintenance instead of using a smaller 1 MW backup boiler is usually an unrealistic mode of operation, as the boiler is required to be shut off for maintenance and a smaller backup boiler could have been used in its place. Essentially, this alternative depicts a scenario where summer maintenance is skipped and, therefore, the comparison of unit heat costs for WP and other fuels may appear illogical. However, despite a significantly lower boiler efficiency (and average part load ratio), the unit heat costs when using the WP main boiler are lower than when using backup boilers and other fuels, despite these having higher efficiencies. If a backup boiler using WP were to be included, this would have yet lower unit heat costs than the main boiler, due to running on higher part load ratio (and efficiency). This shows how difficult it is to compete with biomass as an energy source, at current prices and the need for higher valuation to drive investments in renewables. However, this wouldn't change the results significantly, as the unit heat costs of backup-boilers were the ones compared and their relative competitiveness is the same regardless.

The cost for electricity in this study was based on the annual average, which may overestimate the unit heat costs when using an electric backup boiler. In a real system, the electricity could be bought at spot price and in summer this can be very low. If the monthly average *spot* electricity price was zero instead of the annual average (66.0 EUR/MWh), the total electricity cost would be reduced by 78 % from 84.8 EUR/MWh to just 18.8 EUR/MWh (the utility cost for 1 MW electric boiler). This in turn would make the electric boiler only slightly more cost-effective than an oil boiler using bio-oil, although the difference is 3 % at most for non-solar variants and for solar variants the difference is less than 2 %. The small effect of electricity price is due to the relatively small share of annual energy demand supplied by the backup-boiler. Thus, the results presented are valid even when the electricity costs are low or even zero.

Table 19
Quoted costs for a pellets boiler from a boiler manufacturer [39].

Size [kW]	1000	2000	3000	4000
Investment [EUR/kW]	789	542	427	357

Table 18
Evaluation of eq. 2 for boiler load factor 0 – 40% and the corresponding boiler efficiency.

Q_{boiler} [MW]	0	0.15	0.3	0.45	0.6	0.75	0.9	1.05	1.2
β [%]	0	5	10	15	20	25	30	35	40
η_{boiler}	0.0	45.3	67.8	79.0	84.5	87.3	88.7	89.3	89.7

5.2.2. Influence on results from boiler cost

For the boiler it is assumed that the investment costs increase proportionally to the purchased boiler capacity in a linear fashion. This was due to the use of these costs in other studies [14] and uncertainty in the costs for boilers in reality. According to the information from industry representative at a boiler manufacturer [39], the investment costs don't necessarily increase linearly, rather having a sinking specific cost [EUR/kW] with increasing size, due to economy of scale (Table 19). For a 3000 kW boiler, the assumed cost in this study is roughly 806 EUR/kW (see Table 11), while the quoted cost estimate from the boiler manufacturer is about 427 EUR/kW, a reduction of about 47 %. Costs for a 2500 kW boiler wasn't quoted, but linear interpolation puts this at 485 EUR/kW, a reduction of about 40 %. This doesn't impact the nLCOH, as the *retro*-fitting excludes the boiler investment costs, but naturally affects the sLCOH where these costs are included. Unfortunately, the quoted costs only included the boiler itself and not all of the related costs in terms of additional components (control systems, etc.) and installation, which means that the exact cost reduction due to economy of scale is probably lower than calculated here and varies from case to case. Although the quoted costs aren't correct, they are included to inform the reader about the potential cost benefits of building larger systems.

Nevertheless, due to the relatively small share of the boiler investment cost relative to the total LCC of the heat supply (see Fig. 9), the sLCOH for a boiler-only system (variant 1) would be reduced by about 8 %, going from 61.6 EUR/MWh (17.1 EUR/GJ) to 56.8 EUR/MWh (15.8 EUR/GJ), if calculated with the quoted cost instead of the assumed cost in this study. For the best performing solar heating system (variant 8) the sLCOH would be reduced by about 6 %, from 55.7 EUR/MWh (15.5 EUR/GJ) to 52.3 EUR/MWh (14.5 EUR/GJ). Although this would lead to slightly lower values for sLCOH overall and slightly higher cost competitiveness of the boiler-only system, the difference is so small that the results remain valid. Thus, the presented results are valid also with a lower assumed boiler investment cost, except for the difference between sLCOH and nLCOH being slightly lower.

5.3. Relevance of results

As was mentioned in section 1.2, the results presented in the most relevant previous study with similarities to the current study was conducted in Suonenjoki in Finland and, it showed that solar heating was unable to compete with conventional heating using a wood-chip boiler [25]. The current study presents results showing that solar heating is considered cost efficient for lower interest levels and this is not at all covered in the previous study. The results of the current study therefore oppose the previous study in that it demonstrates that solar heat can be cost-competitive with conventional heat-only DH supply. However, the results in the current study are similar to those in the previous study, in that they show solar heating to be un-competitive for high interest rates. The results thus partly confirm the previous results. Another difference in the current study is the presentation of a method to decide the economic boundary conditions under which solar heating is cost-efficient, as well as demonstrating cost-competitiveness of solar heating with or without boiler replacement. A third difference is the use of an oil based peak boiler during the whole year in the previous study, which the current study doesn't. This, in addition to having larger difference in the ratio of minimum to peak load, should affect the results. Aside from these differences, the previous study maintains focus on emission reductions and economy related to this. As such, the current study provides complementary information to the previous study.

Disregarding the previous study just discussed and, in relation to other studies, the current study both updates and elaborates the 2008 study conducted for Finland and Sweden [38] on the cost-competitiveness of using a wood-pellet boiler. It complements the previous study in that it provides an updated economic viability of solar heating and provides insight into the required fuel and collector costs for cost-efficient employment of solar thermal. However, it also contrast the former study by demonstrating that solar heating can be cost-effective compared to using wood-pellets.

This study provides results showing that FPCs are still more cost-efficient than using high-temperature collectors such as ETCs, which had been stated previously in 2008 [11]. This is an important result, as it showcases the importance of investment cost for the economic viability of solar heating. The results provide complementary information to the existing literature and provides incentives for collector cost reduction efforts. Furthermore, the detrimental economic impact of high interest rates on solar heating cost-competitiveness further emphasises the need for policy measures such as subsidies to make solar heating cost-competitive to alternatives such as direct (combustion) or indirect (heat-pump) heating. In light of the need for biomass to replace marginal energy production by fossil fuels [15] or the massive strain on the electric grid by electrification for decarbonisation [74], direct heat sources such as solar heating provide a key technology in the green transition. Furthermore, recently, biomass costs have increased by almost a factor 2 since the year 2021 [70] and, these costs may remain high while the electricity costs increase due to increased demand [14]. Thus, this study provides essential information on cost-competitiveness of solar heating versus alternative complimentary heat sources for DH.

6. Conclusions

A hypothetical district heating supply has been modelled in TRNSYS using a load profile for one year from a real system. Three heat supply configurations have been simulated; boiler-only, boiler with storage and boiler with storage and solar collectors. The solar configuration consisted of 10 variants, whereof nine with solar heating using 500 – 10000 m^2 of solar flat plate collectors, as well as one with 3000 m^2 of evacuated tube collectors. The results have been analysed and an energy balance has been made, together with calculated unit heat costs for the different system configurations. The economic boundary conditions have been changed to investigate the sensitivity of the results and the effect of solar heating on fuel costs during boiler maintenance have been studied. Results give the following conclusions (divided according to RQ – see *section 1.3)*:

RQ I: How cost-competitive is installation of a solar heating system when adding it to an existing DH system?

- Adding solar heating to an existing DH system (*retro*-fit) is cost-effective compared to a boiler-only system for any collector area of 1000 m^2 or more.
- The lowest unit heat cost is obtained with 3000 m^2 of flat plate collectors which supplies 13 % of the annual energy demand and results in a unit heat cost 32 % lower than that of a boiler-only system.

RQ II: In the event of boiler replacement (re-powering), how cost-competitive is installation of a solar heating system compared to a boiler-only system with and without storage?

- Installing a slightly smaller boiler in combination with a buffer storage during boiler replacement (re-powering) is more cost-effective than a having a larger boiler without storage as in conventional DH.

- In the event of a boiler replacement (re-powering), installing a solar heating system is cost-efficient for any collector area. A conventional boiler-only system has a unit heat cost more than 10 % above that of the cheapest solar assisted system.
- The difference in unit heat cost is too small to be conclusive for all system alternatives to the boiler-only system, making other factors such as emissions reductions decisive to the choice of installing solar, although that is outside the scope of this article.

RQ III: How does the use of a high-temperature collector compare to the results obtained in RQ I and II?

- A solar heating system with ETC yields significantly higher unit heat cost (nLCOH) when *retro*-fitting, but is cost-competitive with an equally sized field with FPCs when re-powering.

RQ IV: What is the effect of the economic boundary conditions on the results obtained for above research questions? I.e. how do the results change with change in discount rates and fuel costs?

- When *retro*-fitting (RQ I); Increasing DR leads to reduced cost-competitiveness of solar, with a narrowing range of collector areas being cost-effective, as the nLCOH exceeds that of non-solar variants. For a DR of 5 %, a collector area of 1500 m^2 – 7500 m^2 appears cost-effective. For a DR of 7 %, no solar variant appears to be cost competitive with non-solar variants, although the values for 2500 – 3000 m^2 collector area are very similar to that of a boiler-only system.

When re-powering (RQ II); For a DR of 5 %, solar heating is cost-effective as long as the collector area is not larger than 7500 m^2. For a DR of 7 %, re-powering is cost effective as long as the collector area is not larger than 5000 m^2.

- High discount/interest rates requires low collector costs for solar heating to be cost-competitive, while high fuel cost allows for higher collector costs when competing with non-solar heating. Retro-fitting generally allows for higher collector costs than re-powering.

RQ V: How does solar heating affect the backup-boiler fuel use during maintenance and consequently, the resulting unit heat cost?

- As the installed solar collector area increases, the difference in sLCOH (re-powering) between backup-boiler types (and fuels) evens out. When installed collector area is 7500–10000 m^2, the sLCOH for all boiler types and fuels are similar. This means that solar decreases fuel demand to the degree that fuel type becomes insignificant.

Based on the conclusions, the key insights are:

- Heat supply units in DH systems should be coupled with storages to enable higher operation efficiency.
- DH system owners/operators should investigate the potential for solar heating in existing systems.
- Adding solar thermal should be considered where boiler replacement is due, as it can give similar unit heat costs with lower fuel consumption.
- Using high temperature collectors for DH is so far not cost efficient unless the collector/fuel costs change.
- Installing a solar heating system reduces backup-boiler fuel use and is cost-efficient regardless of boiler fuel type when the system size becomes sufficiently large.

7. Future work

This study has focussed on the most cost-effective system configurations under the assumptions that the boiler must be replaced or can be supplemented by additional balance of system components. The sizing conditions of storage volume and solar heating system design has not been optimised for the particular system and therefore a future study should include more detailed calculations to find the configurations that lead to the lowest unit heat costs for a specific case. Future studies could also include combinations of ETC and FPC within the same collector field, in order to compare this to previous studies of combinations of FPC with PTC, to find the most promising collector technologies for different operating conditions. Aims of future studies should include determination of some general design parameters with validity for a broader range of district heating systems and relate this to a limited set of input variables, so that the results are valid many of the existing systems that require either re-powering or could benefit from *retro*-fitting.

Aside from this, future studies should focus on what can be done on the demand side to reduce return temperatures to the boiler central, in order to enable the solar thermal system to operate more efficiently. Such measures could be cooling the return actively or increasing the thermal length of heat exchangers in consumer substations and the cost-efficiency of implementing such measures should be investigated.

Lastly, considering the increasing biomass and solar collector costs in recent years and how this may negatively impact cost-competitiveness of solar district heating for 100 % renewable energy supply, future studies should look into policy requirements to support low-emission energy supply like solar thermal. Particularly considering the high adaptation of solar photovoltaics and heat pumps in combination with strained electric grids in many countries, SDH provides a relief to grid capacity shortage and therefore is worthy of support.

CRediT authorship contribution statement

Martin Andersen: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Funding acquisition, Formal analysis, Data curation, Conceptualization. **Chris Bales:** Writing – review & editing, Supervision, Methodology, Conceptualization. **Jan-Olof Dalenbäck:** Writing – review & editing, Supervision, Methodology, Formal analysis, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Data availability

The data referred to in this study can be found in a data repository made available through Mendeley Data [48]. A data index has been made with an overview of available files and their content, for ease of access.

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