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Influence of different technologies on dynamic pricing in district heating systems: Comparative case studies

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ABSTRACT

District heating markets are often dominated by monopolies in both Denmark and Finland. The same companies, often owned by local municipalities, are usually operating both supplying plants and district heating networks, while the pricing mechanisms are rigid, often agreed upon for one year in advance. The mentioned ownership scheme may cause problems, when one tries to gain a third party access in order to deliver excess heat or heat from cheaper heating plants. In this paper, two case studies were carried out to simulate the district heating systems based on dynamic pricing. Case studies were carried out for Sønderborg, Denmark and Espoo, Finland. The results showed that dynamic pricing fosters feeding the waste heat into the grid, as dynamic pricing reduced the total primary energy consumption and CO_2 emissions in both case studies. In the best scenarios, the weighted average heat price decreased by 25.6% in Sønderborg and 6.6% in Espoo, respectively.

1. Introduction

During the last decade of the 20th century, the European Union (EU) decided to push for liberalization of energy markets of its Member States. The decision mostly referred to power and gas markets. A clear distinction was made between competitive parts, such as electricity generation and supply, and non-competitive parts, such as energy transmission and distribution. One important goal of the transition was to oblige the operators of transmission and distribution systems to grant equal access to the infrastructure to all the interested parties [1].

District heating (DH) sector was left outside of the immediate scope of the energy markets liberalization and different Member States approached it differently. Sweden is the country that went the furthest concerning the DH markets liberalization. Recent research showed that even though DH companies are supposed to be commercial in Sweden, the cost-based approach is still dominating over market pricing mechanism [2]. Furthermore, the authors concluded that still after 10 years from the initiation of the DH markets liberalization, Swedish integrated market for heat has not yet evolved [2]. On the other hand, DH systems in Denmark, both energy generation facilities and infrastructure, are still largely owned by local municipalities. Notable exceptions are the DH systems of Copenhagen and Aarhus which have some sort of dynamic pricing [3].

In Finland, DH systems are natural monopolies inside network, i.e., there is only one DH operator in a network, typically a municipal company, and customers cannot choose their DH supplier. However, customers often have no obligation to connect to the DH network in Finland; they can rather freely choose from different heating technologies. In Finland, DH pricing has typically been rigid and pricing for customers has been based on connection, capacity and energy fees. There has been some development in DH pricing in recent years and some DH companies offer a seasonal-pricing option, in which energy fees are lower in summer and higher in winter, alongside the classical rigid pricing structure. However, neither of these pricing methods represent DH production costs accurately [4]. Opening DH markets has been identified as one of the key aspects to tackle the challenges caused by new European regulations, which are affecting energy production and energy efficiency in Finland [5]. In March 2018, Fortum announced that they are going to progress with opening of DH networks in Finland by announcing publishing of daily waste heat prices on

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their web sites, starting from spring 2018 [6].

A review of different pricing methods for DH has been presented in Ref. [7]. The authors suggested that marginal pricing would have various benefits, including better representation of production costs and reflecting the heat markets as well as motivating the suppliers to reduce the costs of heat production. However, the authors stated that marginal costs could be hard to calculate. Sun et al. proposed two methods for marginal pricing, mainly setting the electricity price and entropy drop, but their methods could not reflect the changes in different heat production technologies [8]. Dynamic pricing possibility for the Espoo DH, Finland, was studied in Ref. [4]. The authors concluded that the open heat market could be beneficial for all parties and that significant economic and energy savings were possible [4]. Different authors carried out a research on the possibility of regional heat market in Sweden [9]. The authors focused on the region dominated by energy intensive industries with a large waste heat potential and results showed that the payback time of integrating DH systems ranged from two to eleven years, depending on the scenario [9].

Industrial and individual consumers could become so called prosumers in the future, if the access to the DH infrastructure were granted to them under the fair pricing mechanisms. In that way, significant amount of waste heat from industry could be fed back to the grid, while excess capacity that consumers sometimes have could be better utilized. Based on a case study in Malmö, Sweden, prosumers with continuous cooling demand could have a notable impact in DH network [10]. The case study also suggested that there has been a prominent amount of low temperature heat available, which could be utilized in DH network [10]. Kimming et al. concluded that the vertical integration of local fuel producers into DH systems resulted in lower costs and emissions in the energy system [11]. Moreover, it was found that both the conditions of the energy market, as well as the type of the heat production system impacts the system emissions from the life-cycle perspective [12]. Furthermore, it was found that the industrial excess heat fed into DH system can be beneficial even when it causes reduced local electricity generation [12]. Another study identified a significant untapped potential of industrial waste heat on the case of Sweden DH systems, confirming that the Third Party Access legislation would be beneficial if adopted [13]. Finally, it was shown that even the introduction of individual prosumers is possible, based on technologies such as solar collectors and heat pumps, although it demands management and control of the issues such as locally lower heat supply temperature, as well as the local changes in velocity and differential pressure [14].

Most of the papers presented here have not studied the potential of dynamic pricing in the DH systems in a systematic manner. No paper that dealt with the marginal pricing in district heating adopted the pure marginal based pricing used in power markets. As it was shown in the literature review that several papers suggested to carry out a simulation of marginal based pricing, this paper filled that research gap. Furthermore, one of the papers detected that it is needed to model the impact of solar thermal collectors, heat pumps and thermal energy storage (TES) on DH markets [5]. In order to fill all of the gaps in the literature presented here, this paper aimed for answering the following research question:

> “What is the potential effect of dynamic pricing based on marginal costs on DH systems?”

The approach used in this paper allowed more realistic evaluation of low marginal cost heat in different periods of the year, being especially relevant for evaluation of future DH systems, when more low marginal cost heat is expected to be used, such as industrial waste heat and solar thermal energy. In order to make the results robust, two case studies were carried out, one for the DH grid in Denmark and one for Finland.

The paper continues with the Methods section, in which the potential mechanism of dynamic pricing in the DH systems is presented, and case studies description. In the Results section, the total turnover of the dynamically priced DH systems, weighted average marginal costs of the heat generation and the CO_2 emissions in different scenarios are shown. The results of the paper are put in the perspective of other DH systems in the Discussion section, together with a discussion on the major uncertainties about the assumptions used in this paper. Finally, the key points are summarized in the Conclusion section.

2. Methods

District heating supply and demand was simulated in similar fashion as the current electricity day-ahead markets operate, such as El-spot market on Nordpool. Heat demand in the DH system was taken as fixed, using the real data obtained for the year 2015. Heat supply was simulated based on the marginal cost of heat generation in each hour. The point where the heat supply and demand curves intersect is the price of heat set for that hour, as it can be seen in Fig. 1.

The marginal heat generation price included variable operating and maintenance costs (O&M), fuel costs, different fees and taxes, as well as the feed-in premium, if eligible. The latter means that only the costs that depend on the amount of energy generated (running costs) are included in the price formation. Capital costs, such as annualized investment costs, are not included in the bidding price formation as those costs are considered as sunk costs, once they have occurred. If one had decided to invest in an energy plant and a certain capacity was installed, the capital costs would need to be paid for no matter on the amount of generated energy. Thus, in the short-term, the operator of the plant will accept any price that is higher than the running costs of the energy plant.

Furthermore, concerning the cogeneration (CHP) plants, electricity income from el-spot market was deducted from the total heat generation costs, while the total fuel costs were included in the marginal price. Using the latter approach, a complicated division between fuels used for power and heat generation was

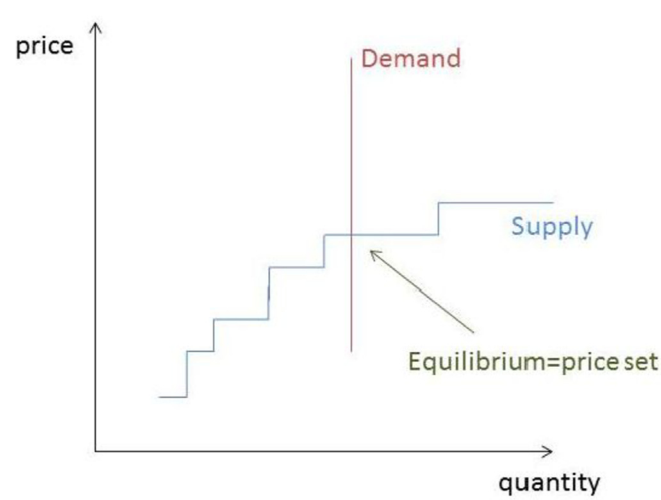

Fig. 1. A representation of the demand-supply curve in the simulated dynamic heat market (vertical demand curve represents the fixed heating demand that was assumed in each hour).

avoided. However, the latter approach can result in a bidding strategy that is not completely clear at first, i.e. high electricity prices will result in a high income for the CHP plant, which will consequently result in a lower marginal price set for bidding on the heat market. Hence, higher electricity prices, and higher corresponding income that will be deducted from the marginal heat offering price, the lower the marginal cost will be of the heat generation from CHP plant. The opposite also holds true, i.e. the lower the electricity price is achieved, the higher the heat marginal price will be offered to the market. Once again, investment costs in technologies were not taken into account when calculating marginal costs of heat production.

As the power market is much larger compared to the DH system potential markets, the influence of heat generation plants that consume or generate electricity on the day-ahead el-spot market was not modelled, i.e., it was assumed that there is no influence of them on the power market equilibrium price.

The indicators used for evaluation of the DH systems were CO_2 emissions and total yearly turnover. The latter two indicators were the output of the simulation of the dynamically priced DH systems, while the same indicators for the DH systems operated in the current way were obtained from the official websites of the DH companies.

In total, six different scenarios were developed for the case of Sønderborg and five different scenarios for the case of Espoo DH system. The simulations were carried out in Matlab. Moreover, a sensitivity analysis on the influence of electricity price changes was carried out and the results are discussed in the Discussion section.

2.1. Case study of sønderborg

The Sønderborg municipality covers the area of 496 km^2 and has a population of 75,000. Currently, the whole municipality has five distributed DH systems, although the connection of it proved to be feasible and economically viable [15]. The municipality aims for becoming CO_2 neutral by 2029, rapidly increasing its share of renewables in power, heat and gas sectors [16]. For the year 2013, the total CO_2 emissions were around 530 Mt [17], leaving significant challenges for the transition towards carbon neutrality. The total gross generation in DH systems in the municipality amounted to 488 GWh in 2013 [17]. The list of the heat generation plants that are operating in the DH system can be seen in Table 1.

As it can be seen from Table 1, gas CHP and gas boilers were dominating the heat generation mix. Recently, solar district heating (SDH) gained momentum and it is expected that its share will significantly rise in the future. The marginal cost of the heat production of different plants can be seen in Fig. 2.

Several issues concerning Fig. 2 need to be clarified. First, the price of electric boiler and heat pump heat generation is not constant as the electricity needed to drive them needs to be bought on the wholesale market where prices change on hourly basis. Thus, the Nordpool El-spot prices for the year 2015 were used [24]. Second, the cost of CHP plants is difficult to divide between the cost share of electricity generation and the cost share of heat generation. However, as the electricity sold on the day-ahead market was taken into account and deducted from the marginal costs of heat generation, this issue was not relevant anymore. Consequently, the prices were changing on hourly basis due to the different price obtained from the day-ahead el-spot market. In Fig. 2, presented total prices are the ones obtained by using the average electricity price as income for CHP plants, as well as the expenditure for electric boilers and heat pumps. Min ele price and Max ele price denote the marginal prices of different energy plants achieved for minimum and maximum electricity prices during the year, respectively. Third, it was taken into account that waste CHP plant receives a gate fee of 7.2 EUR/MWh of waste and further subsidy of 10 EUR/MWh of electricity sold.

The thermal energy storage (TES) sets its bids and offers in slightly different manner than the other heat generation plants. The marginal cost of the large TES is very low; however, the goal of its operation from the business-economic point of view is to buy the energy when the price is low and sell it when the price is high. In the case of Sønderborg, the considered technology was pit thermal energy storage (PTES).

The PTES was considered to be owned by third party in the scenarios, and thus the aim of the storage was not to minimize total production costs of the system, but rather to capitalize on price differences between different hours and maximize its profits. Storage bidding to the market could increase or decrease marginal prices of heat production, which would affect the costs or profits of storage. Storage made decision whether it should buy or sell heat depending on the marginal prices of each hour. Storage did not have a perfect foresight of the market. Table 2 presents the buy and sell offers of the storage in different time periods for the case of

Table 1
Heat generation capacity in the Sønderborg municipality [17] (Fuel efficiency values taken from Ref. [18] if not stated otherwise).

	Heat capacity [MW]	Power capacity [MW]	Fuel	Fuel efficiency
CHP Grasten	7.2	5.4	Gas	94% [19]
Boiler Grasten	14.5		Gas	96%
Boiler Grasten	12		Straw	80%
SDH Grasten	13		Solar collectors	–
CHP Broager	4	3.1	Gas	94% [19]
Boiler Broager	13.9		Gas	96%
SDH Broager	7		Solar collectors	–
CHP Nordborg	8.7	6.1	Gas	94% [19]
Boilers Nordborg	16		Gas	96%
CHP Augustenborg	4.9	3.8	Gas	94% [19]
Boiler Augustenborg	15.7		Gas	96%
Boiler Augustenborg	8		Electricity	99%
CHP Sønderborg	20	4.5	Waste	98% [20]
CHP Sønderborg	40	53	Gas	94% [19]
Boiler Sønderborg	100		Gas	96%
SDH Sønderborg	5.2		Solar collectors	–
Boiler Sønderborg	5.4		Bio-oil	95%
Geothermal + absorption heat pump	12.5		Geothermal and biomass driven heat pump	135%[a]
Total	308			

[a] Biomass-to-heat efficiency. Geothermal heat is extracted at 44 °C after which biomass driven absorption heat pump is used to raise the temperature to 82 °C.

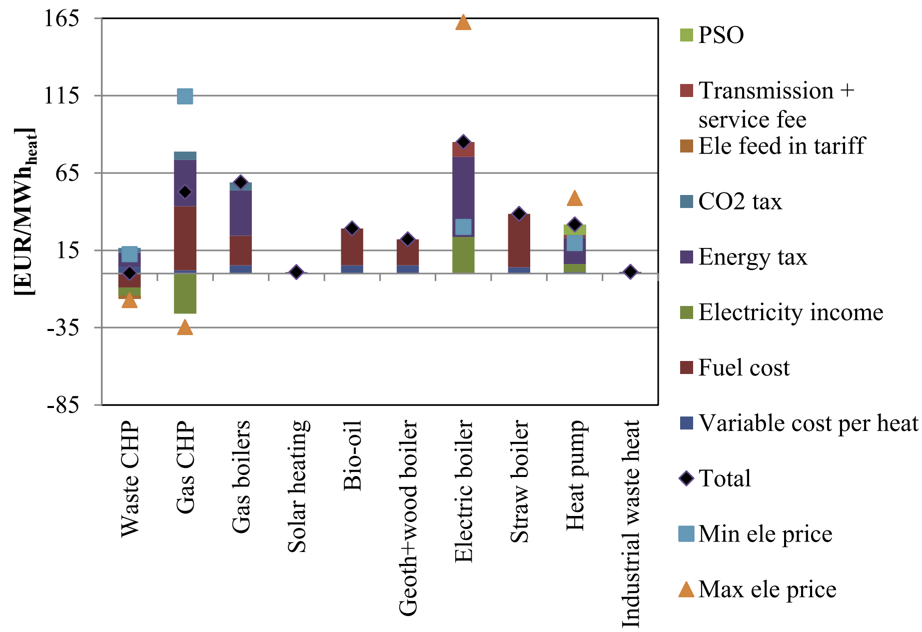

Fig. 2. Marginal costs of producing heating energy from different plants. Fuel costs taken from Ref. [21], biomass cost taken from Ref. [22] and taxes taken from Ref. [23].

Table 2
Buy and sell offers of the PTES in different periods - Sønderborg case.

	Hours 1-3416	Hours 3417-6812	Hours 6813-8760
Buying bid	10 EUR/MWh	5 EUR/MWh	50 EUR/MWh
Selling offer	15 EUR/MWh	23 EUR/MWh	58 EUR/MWh

Sønderborg. Marginal prices may shift within certain limits when the storage is utilized. This can cause dropping certain production technologies from the markets, e.g. natural gas HOBs. The storage utilization was optimized based on assumed marginal costs of other technologies. The latter resulted in a different buying and selling bids during different seasons in order to take advantage of the price arbitrage.

To clarify Table 2, the buying offer represents the maximum price that can be achieved for which the storage will still buy certain amount of heating. Similarly, the selling offer represents the minimum price that needs to be achieved in order for storage to sell the energy to the DH grid.

In order to model the current and the future potential influence of the dynamic heat markets on the heat generation system, six different scenarios were developed. The first scenario represented the model of the heat generation portfolio in the Sønderborg municipality as it was in the year 2015. The second scenario incorporated the waste heat potential close to the Gråsten and Broager DH parts. The potential of excess heat being fed to the DH grid was pinpointed in the case study on industrial waste heat potential in Sweden [13], industrial waste heat potential in the municipality of Sønderborg [15] and the waste heat potential from data centers in Finland [25].

The third scenario took into account further possibility of expansion of the SDH in order to simulate the impact of the increased share of the low-marginal cost producer could have on the dynamic heat market. The latter technology was discussed in the DH perspective in several papers. Winterscheid et al. showed that solar thermal technology can be implemented in the existing network that does not undergo structural changes [26]. The potential of the same technology was also pinpointed for the case of Latvia [27], as well as in centralized and distributed integration of solar heat [28]. All three mentioned studies pointed to the significant potential of the SDH in the future. Furthermore, the fourth scenario added a large-scale heat pump to the system. The role of large-scale heat pumps in the future DH systems was discussed in many papers. Lund & Persson mapped the potential heat sources for heat pumps in future low temperature district heating in Denmark [29], while Münster et al. showed the role of heat pumps in combination with other technologies in the district heating [30]. Nevertheless, Dominković showed the potential role of large-scale centralized heat pumps in future district heating networks [31]. All three studies concluded that the potential of the heat pumps is much larger than they are currently being utilized.

The last two scenarios were constructed to assess the influence of large PTES, the technology choice for large thermal energy storage in several studies, for example in Ref. [31]. The efficiency of PTES of 95% was assumed [18]. In the Sønd PTES scenario, the impact of the PTES was assessed on the 2015 reference system, while in the Sønd ALL scenario the PTES technology was added to all the other technologies, i.e. increased SDH, heat pumps and industrial prosumers. Overview of the differences between scenarios can be seen in Table 3.

2.2. Case study of Espoo

Espoo is a city located in Southern Finland and it is Finland's second largest city with over 270,000 inhabitants. The Espoo DH network is operated by Fortum Ltd, and 70% of the inhabitants in Espoo were connected to the DH network in 2015 [32]. Fortum is one of the few non-municipal DH network operators in Finland. Nowadays, the Espoo DH network also covers the municipalities of Kirkkonummi and Kauniainen and the length of the network is over 1000 km is in total [32]. Table 4 presents heat production units and capacities in Espoo DH network in 2015. Current heat production capacity in the Espoo DH network is dominated by fossil fuel based heat production units, namely coal and natural gas CHPs. Opposite to the Sønderborg case, Fortum operates far larger CHP plants, which are mostly utilized for baseload heat production. In addition to plants presented in Table 4, Fortum has built a TES, namely hot

Table 3
Scenarios for Sonderborg DH network.

	Heat demand, electricity prices, fuel costs	Additional heat supply
Sønderborg reference (Sønd ref)	Based on the 2015 data	
Sønderborg industrial waste heat (Sønd WH)		33.89 GWh/year
Sønderborg solar district heating (Sønd WH SDH)		Sønd WH + Solar district heating capacity increased to 179 MW
Sønderborg central heat pump (Sønd WH SDH HP)		Sønd WH SDH + HP capacity of 25 MW_t
Sønderborg reference with pit thermal energy storage (Sønd PTES)		Sønd ref + PTES capacity of 750 MWh and 20 MW
Sønderborg all additional technologies (Sønd ALL)		Sønd WH SDH HP + PTES capacity of 750 MWh and 20 MW

Table 4
Heat generation capacity in Espoo DH network [32]. Fuel efficiency values taken from Ref. [4].

Plant	Heat capacity [MW]	Power capacity [MW]	Fuel	Fuel efficiency
CHP Suomenoja 1	162	75	Coal	90%
CHP Suomenoja 2	213	234	Natural gas	90%
CHP Suomenoja 6	80	49	Natural gas	90%
Boiler Suomenoja 3	70	–	Coal	85%
Boiler Suomenoja 7	35	–	Natural gas	85%
Boiler Kivenlahti	65	–	Heavy Fuel Oil (HFO)	85%
Boiler Tapiola	160	–	Natural gas	85%
Boiler Vermo	80	–	Natural gas	85%
Boiler Kaupunginkallio	80	–	Light Fuel Oil (LFO)	85%
Boiler Otaniemi	120	–	Natural gas	85%
Boiler Juvanmalmi	15	–	Natural gas	85%
Boiler Kalajärvi	5	–	LFO	85%
Boiler Vermo	45	–	Natural gas	85%
Boiler Masala	5	–	Natural gas	85%
Boiler Kirkkonummi	31	–	Natural gas	85%
External heat	12	–	–	
Heat pump Suomenoja	40	–	Electricity	COP 3.5
Boiler Vermo	35	–	Bio-oil	85%
Boiler Kivenlahti	40	–	Wood pellets	85%
Total	1418			

water storage tank, next to Suomenoja CHP plants with a capacity of 110 MW and an energy content of 500–800 MW h. The storage operates on a short-term basis, e.g., hourly or daily level. The storage started operation in the end of 2015, and thus it was not considered in our reference case, but as an additional scenario.

In the near future, Fortum is seeking new solutions to cut both production costs and emissions of DH production and they are aiming towards carbon-neutral DH production by 2030 in Espoo. In the last few years, Fortum has replaced fossil fuel based DH production in Suomenoja and Vermo with bioenergy, e.g. bio-oil and wood pellets. In order to increase profitability of DH, Fortum has been studying multiple novel solutions in Finland, such as demand side management of DH in an office building in Otaniemi, Espoo [33]. As a future source of industrial waste heat, Fortum is planning to utilize waste heat from data centers (DCs) [34]. Fortum has signed a letter of intent to utilize waste heat from Telia's 24 MW IT-load DC, which is expected to produce 200 GWh of heat annually [35]. There are also other plans to further utilize DC waste heat in Espoo DH network as Fortum has agreed to invest in heat pumps to utilize 10–15 GWh of waste heat from Ericsson's DC in Kirkkonummi [36].

In Fig. 3, the marginal costs for different heat generation technologies in the Espoo DH network are presented. There are few issues in Espoo case, which need further clarification. First, similarly to the Sønderborg case, CHP production depends on el-spot prices, and thus revenues from electricity sales were deducted from CHP heat production costs. In Finland, CHP plants do not pay taxes for electricity production and they pay taxes only for 90% of the heat fed into DH network. In addition, CHP production has additional benefits as the carbon dioxide tax for fossil fuels utilized in CHP is only 50% compared to other consumption of the fuel in question, e.g. using coal in heat only production. Second, costs for heat pumps and DCs include el-spot price, electricity taxes and electricity transmission fees. Taxes and transmission fees for the Suomenoja heat pump and DC are summed up in tax column in Fig. 3. Finally, the price for the current external heat in Espoo DH network is confidential and thus, it was estimated at a very low price. As the exact costs were not available, the current waste heat was excluded from Fig. 3. Max and min electricity price scatters represent the maximum and minimum marginal costs for technologies, which are affected by electricity prices. El-spot system prices in Finland varied between 0.32 and 150 EUR/MWh in 2015 [24]. The total average marginal cost includes all the costs and income from electricity sales.

As previously mentioned, possibilities for marginal pricing of DH in Espoo DH network have been simulated in Ref. [4]. However, there are new plans for novel, large-scale heat supply, e.g. DC and a large-scale geothermal heat plant and thus, the effects of these plants on heat production require attention. These two projects together have been estimated to be able to supply approximately 20% of the DH demand in Espoo and both are expected to be producing heat by the end of 2019.

Five different scenarios were developed for the Espoo case. All of the scenarios were simulated with normalized hourly heat demand, hourly electricity prices and fuel costs in 2015. First, the reference scenario for 2015 was developed by utilizing heat production units presented in Table 5 to represent the current system. The second scenario considered the inclusion of TES to the

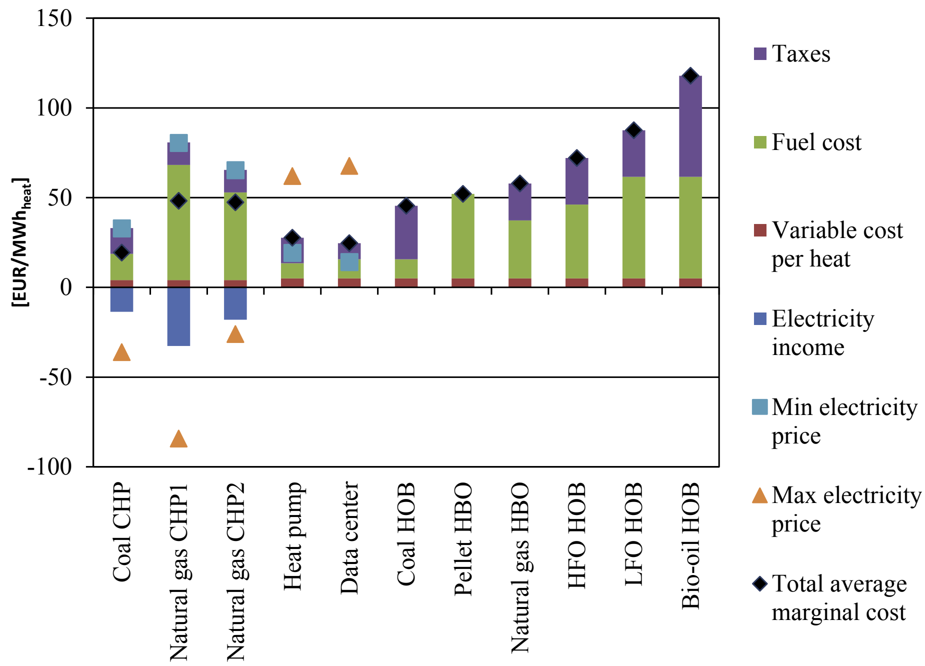

Fig. 3. Marginal costs for different technologies in Espoo DH. Electricity spot-prices taken from Ref. [24]. Taxes and fuel costs for coal, natural gas and biomass, as well as taxes and transmission costs for electricity, taken from Ref. [37]. Taxes and fuel costs for oil products taken from Ref. [38].

Table 5
Scenarios for Espoo DH network.

	Espoo reference REF	Espoo reference with storage REF + STOR	Espoo waste heat WH	Espoo geothermal with waste heat GEO + WH	Espoo geothermal with waste heat and storage GEO+WH+STOR
Heat demand, electricity prices, fuel costs	Based on 2015 data	Based on 2015 data	Based on 2015 data	Based on 2015 data	Based on 2015 data
Additional heat supply	–	TES 110 MW (800 MWh energy content)	200 GWh waste heat per year, monthly changing load	40 GW geothermal capacity, constant load + DC waste heat	40 GW geothermal capacity, constant load + DC waste heat + TES 110 MW (800 MWh energy content)

reference system. The third scenario considered industrial waste heat utilization, which in this case was waste heat from Telia's DC. The fourth scenario considered both Telia's DC waste heat and, in addition, St1's and Fortum's large-scale geothermal pilot in Espoo, which has been further discussed e.g. in Ref. [33]. The fifth scenario includes both waste heat and geothermal heat alongside TES.

Geothermal pilot is expected to produce approximately 10% of the DH demand in Espoo by drilling two holes up to 7 km and utilizing 120 °C source of heat. The geothermal plant is estimated to produce heat at a constant 40 MW load.

Possibilities and requirements, as well as different projects, for DC waste heat utilization in DH have been studied for example by Wahlroos et al. [34]. Waste heat production from DC is depending on cooling system in the DC. Typically, DCs produce more waste heat when air temperatures are higher, causing more waste heat to be available during summertime [25]. Waste heat can typically be captured at 35–40 °C in air-to-liquid heat recovery systems. In order to efficiently utilize DC waste heat in DH, waste heat temperature needs to be increased to sufficient temperatures for DH, i.e., supply side temperatures (75–115 °C) or return side temperatures (approximately 60 °C) in Finland. Heat pumps can be used to increase temperature of the heat, while coefficient of performance (COP) depends on the temperature difference of actual priming. DCs should be located close to DH networks in order to be connected to DH networks without significant investment costs [25].

Since Fortum has estimated that Telia's DC will produce 200 GWh annually, this amount was divided on a monthly basis based on average monthly DC electricity consumption in an actual DC. Hourly pattern of waste heat production was not available. Thus, it was estimated that the waste heat availability is continuous during each hour within a month. As a result, the hourly waste heat load varied between 20.85 and 26.75 MW in different months. It was assumed that the heat temperature has been elevated with a heat pump up to 85 °C. The COP value for the heat pump was assumed to be 2.8, which would make it technically possible for waste heat to be utilized in the supply side of DH system in Espoo. In Finland, DCs are considered as industrial electricity consumers and thus they have lower electricity taxation; however, the latter depends whether heat pump produces the cooling energy for the DC or not. The question of waste heat pricing has been further debated in discussion section.

In the case of Espoo, the TES was considered to be owned by third party and storage operated according to the same method as in the case Sønderborg. The efficiency of the TES of 95% was also assumed in the Espoo case. Table 6 presents bidding values for storage during different seasons of the year in the case of Espoo.

3. Results

The results of the dynamic price based heat market simulation

Table 6
Storage bidding strategy in the case of Espoo.

	Hours 1-2999	Hours 3000-5999	Hours 6000 - 8760
Maximum buying bid limit	48 EUR/MWh	33 EUR/MWh	48 EUR/MWh
Minimum selling offer limit	55 EUR/MWh	40 EUR/MWh	55 EUR/MWh

Table 7
Economic results in different scenarios.

Scenario	Total yearly turnover [mil EUR/year]	Weighted average marginal price
Sønd ref	23.99	49.58
Sønd WH	23.16	47.86
Sønd WH SDH	21.71	44.86
Sønd WH SDH HP	18.25	37.71
Sønd PTES	23.25	48.03
Sønd ALL	18.45	37.82

consisted of economic indicators and an environmental indicator. Economic indicators were the achieved heat price during the every hour of the year and the total yearly turnover in different scenarios, while the environmental indicator was represented by CO_2 emissions.

3.1. Case study of sønderborg

Six scenarios were carried out in total for the Sønderborg case. Weighted average marginal heat price, as well as the total yearly turnover for different scenarios can be seen in Table 7.

It can be seen that the weighted average marginal heat price decreased when additional low marginal cost heat producers were introduced to the system. Furthermore, although PTES bidding strategy reduced prices in certain hours and increased in some of the other hours, on average, it reduced the marginal heat prices in Sønd PTES scenario compared to the Sønd ref scenario and increased the marginal heat prices in the Sønd ALL scenario compared to the Sønd WH SDH HP scenario.

Fig. 4 presents the yearly generation of different technologies in different scenarios. Availability of the industrial waste heat caused all the other plants to reduce their outputs except the solar-thermal plant that was still maximally utilized. The largest decrease in output came from gas boilers.

In Sønd WH SDH scenario, the increased output of solar DH caused lower outputs of all the other plants in the system. Moreover, it has decreased the output of industrial WH for 27%, compared to the Sønd WH scenario. The latter was caused due to the competition of the very low marginal cost technologies during the summer time, when there was a lack of demand for the available low-cost capacity. This points to the possible conflict in the future when large amount of waste heat could be fed to the grid during the time when there is no strong demand for DH.

In Sønd WH SDH HP scenario, the heat pump (COP = 4.5) was significantly utilized, i.e. it fulfilled 20% of the gross DH demand during the year. Compared to the Sønd WH SDH scenario, the geothermal energy coupled with absorption HP, solar DH and industrial WH had the same output, while the other plants had lower outputs. The most notable decrease in the heat generation occurred in gas and straw boilers, i.e. their output reduced for 78% and 43%, respectively.

Furthermore, in Sønd ALL scenario, the PTES allowed for increased effective utilization of solar DH, increasing its effective output for 19% compared to the Sønd WH SDH and Sønd WH SDH HP scenarios.

Comparing the Sønd ref and Sønd PTES scenarios, one can note

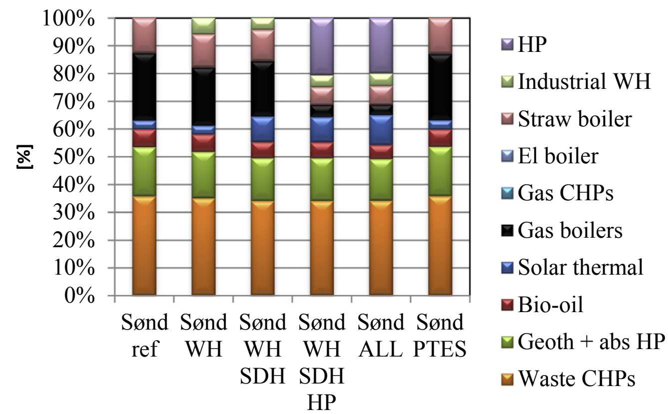

Fig. 4. Share of generation of different plants in scenarios. The total heat generation amounts to 484 GWh/year.

the influence of the large scale PTES on the current Sønderborg DH system. As the reference system did not have the excess capacity of certain low-cost generation technologies during certain periods of the year, the PTES caused only a minor change in operation of different plants. The main difference came from straw and gas boilers. The straw boiler increased its output for 2.3% while the gas boilers decreased their output for 1.6%.

Finally, Table 8 presents the CO_2 emissions from different heating generation plants. It can be observed that the scenarios that included waste heat from industry showed better performance in terms of CO_2 emissions. Even better performance was obtained when additional amount of SDH capacity and HP were introduced. It is interesting to note that the PTES increased the CO_2 emissions in both the scenarios, mainly due to the increased output of electric boilers. The reduction in CO_2 emissions between the Sønd WH SDH HP and Sønd ref scenarios was 36%.

Fig. 5 presents a price duration curve of the simulated heat market in the Sønderborg region. In Sønd ref, Sønd PTES, Sønd WH and Sønd WH SDH scenarios, approximately during half of the year the maximum price of 58.99 EUR was achieved, when gas boilers were on the margin. As the inclusion of HP significantly reduced the output of gas boilers, the maximum marginal price lasted for only 2065 and 1991 h in Sønd WH SDH HP and Sønd ALL scenarios, respectively. One can note from Fig. 5 that the addition of industrial prosumers with a low marginal price shifted the marginal price curve to the left, meaning that the overall prices of DH were reduced. Furthermore, in the third scenario when a significant increase in SDH occurred, on top of the addition of industrial prosumers, a marginal heat price curve further shifted to the left, as a consequence of further downward pressure on the marginal heat prices.

Comparing the Sønd ref and the Sønd PTES scenarios, one can note that the PTES reduced the amount of maximum marginal price and slightly increased the marginal prices during the period of relatively low marginal prices.

In the Sønd ALL scenario, during approximately 23% of the year achieved prices were less than 7 EUR/MWh.

Finally, the storage content in two scenarios that included PTES

Table 8
CO_2 emissions from different heating plants [kT-CO_2]. CO2 emission factors of different fuels taken from Ref. [21].

	Sønd ref	Sønd WH	Sønd WH SDH	Sønd WH SDH HP	Sønd ALL	Sønd PTES
Solar thermal	0	0	0	0	0	0
Bio-oil	0	0	0	0	0	0
Geoth + abs HP	0	0	0	0	0	0
Gas boilers	25	22	21	5	4	25
Gas CHPs	0	0	0	0	0	0
Waste CHPs	29	28	27	27	28	29
El boiler	49	49	49	27	35	61
Straw boiler	0	0	0	0	0	0
Industrial WH	0	0	0	0	0	0
HP	0	0	0	7	7	0
PTES	0	0	0	0	0	0
Total	103	99	97	66	73	115

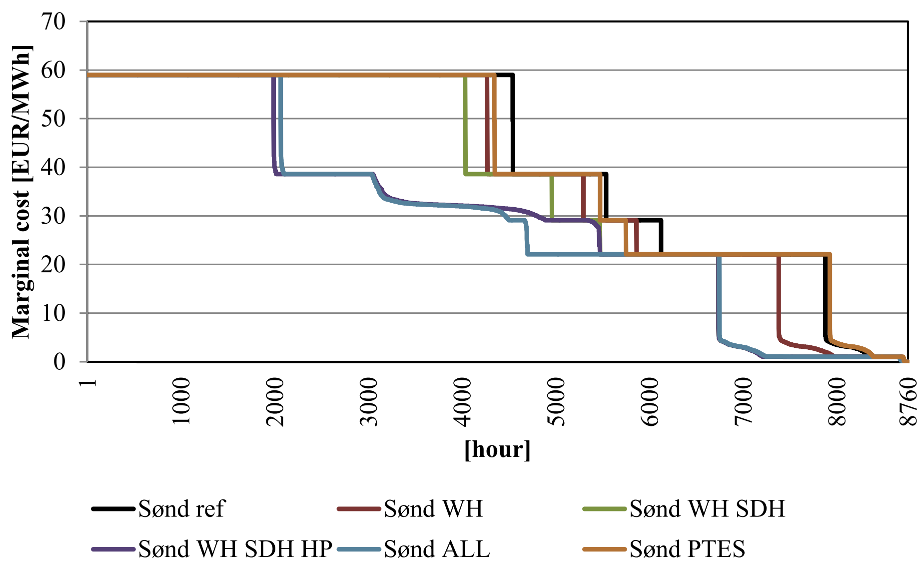

Fig. 5. Simulated marginal costs in different scenarios in a descending order for the Sønderborg case.

is presented in Fig. 6

The total yearly turnover of PTES was 124,669 and 259,879 EUR in Sønd PTES and Sønd ALL scenarios, respectively. Relatively large capacity of the PTES was most notably used for transferring the heat from the summer time to the autumn and winter time, approaching the role of a seasonal storage.

3.2. Case study of Espoo

Table 9 presents the weighted average marginal heat prices and the total turnover in different scenarios for Case Espoo. As both geothermal and DC waste heat had low marginal costs, the total turnover decreased in both Espoo WH and GEO+WH scenarios compared to the reference scenario. Addition of storage bidding to the market further decreased the average price and the total turnover.

Fig. 7 presents price duration curves of the simulated heat market in the Espoo DH system. Curves represent simulated marginal prices in descending order in different scenarios. The natural gas HOB was typically the marginal technology, which determined the marginal heat production price (i.e. for natural gas HOB 57.8 EUR/MWh). Natural gas HOBs represented 32% (2831 h) of the marginal prices in Espoo GEO+WH+STOR scenario, and natural gas HOBs were even further dominating in REF and WH scenarios with shares of 41% (3627 h) and 45% (3975 h), respectively. Otherwise, duration curves are descending in small steps because natural gas and coal CHP, as well as heat pumps, were affected by electricity prices, and thus their marginal prices fluctuated. The inclusion of both waste heat and geothermal heat shifted duration curves to the left, which implies that the overall marginal costs decreased. The operation of the storage affected marginal costs by shifting marginal costs from the most expensive hours to hours with lower costs when the marginal cost was high and vice versa when the marginal cost was low.

In the REF scenario, the marginal costs were over 45 EUR/MWh on 89% of the hours. Similar values for WH scenario and GEO+WH scenario were 80% and 66%, respectively. Fig. 7 shows that the amount of very low marginal cost hours increased significantly, especially in the GEO+WH scenario. In the reference scenario, the minimum marginal price was 14.7 EUR/MWh and marginal prices decreased below 30 EUR/MWh only during 295 h. In the GEO+WH scenario, minimum marginal prices were 6.2 EUR/MWh on few hours.

Fig. 8 presents annual share of heat production in different scenarios by different technologies. Heat production results show that production of all other heating plants decreased in Espoo WH scenario, while waste heat represented 7% of the total production. Furthermore, addition of geothermal heat, 15% of total production in GEO+WH and GEO+WH+STOR scenarios, further decreased operation of all other technologies. In addition, the inclusion of geothermal heat slightly affected waste heat production. It can be observed that the addition of waste heat and geothermal heat

Table 9
Economic results in different scenarios in Case Espoo.

	Espoo REF	Espoo REF+STOR	Espoo WH	Espoo GEO+WH	Espoo GEO+WH + STOR
Weighted average marginal heat price [EUR/MWh]	53.52	53.23	52.47	50.30	49.90
Total turnover [mil EUR/year]	127.18	126.65	124.70	119.52	118.75

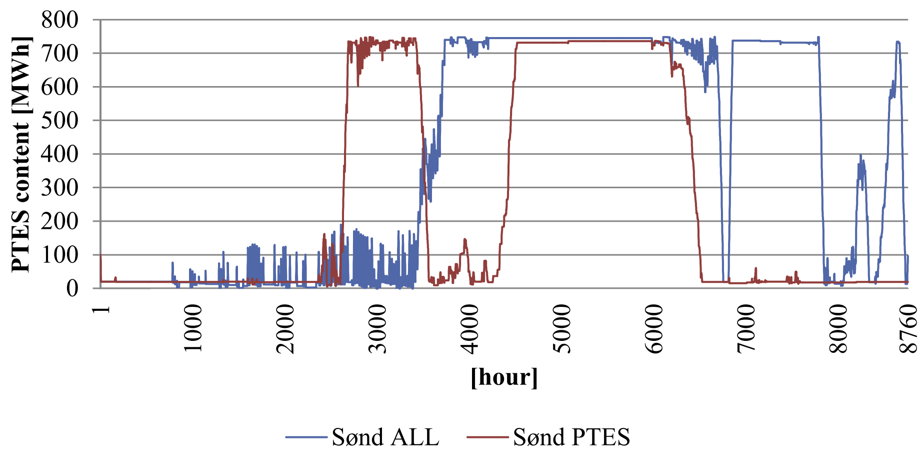

Fig. 6. PTES content over the year in Sønd ALL and Sønd PTES scenarios.

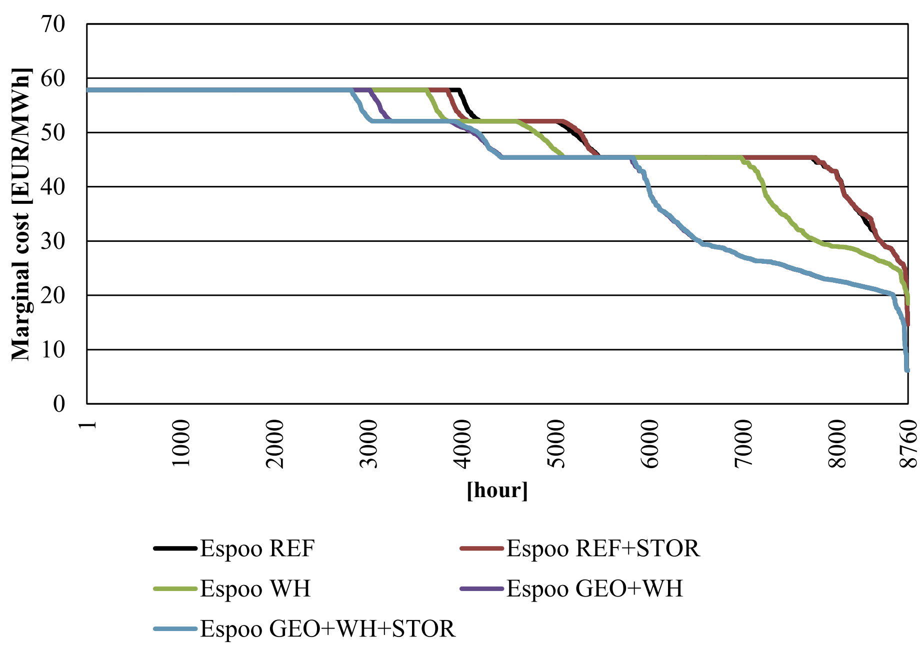

Fig. 7. Simulated marginal costs in different scenarios in a descending order in the case of Espoo.

replaced almost exclusively fossil fuel based heat production and pellet-based heat production. In the WH scenario, the heat pump production decreased by 4%, but in GEO+WH scenario the output of heat pump decreased by 21% compared to the REF scenario. Geothermal heat was utilized at the maximum capacity during all the hours. The introduction of storage decreased utilization of natural gas and pellet HOBs, but increased the use of natural gas CHP in both REF STOR and GEO+WH+STOR scenarios.

CO_2 emissions for different scenarios in the Espoo case are presented in Table 10. Additional waste heat in WH scenario decreased CO_2 emissions 4.6% compared to the REF scenario. In GEO+WH scenario, emissions were reduced by 17.6% compared to the REF scenario. Emissions for current system were calculated by reported fuel consumption in 2015. Emission factors of different fuels in the Espoo case are presented in Appendix A. It must be noted that storage actually increased emissions in the simulations. This results from the fact that including storage in the model increased utilization of natural gas CHP plants, but decreased operation of wood pellet HOB, which was considered CO_2 neutral. Furthermore, due to the storage losses, the total DH production increased by over 3000 MWh in both storage scenarios.

Fig. 9 presents thermal energy content in TES in scenarios with storage in Espoo. Bidding structure was the same in both scenarios. In the GEO+WH+STOR scenario, the storage was able to utilize

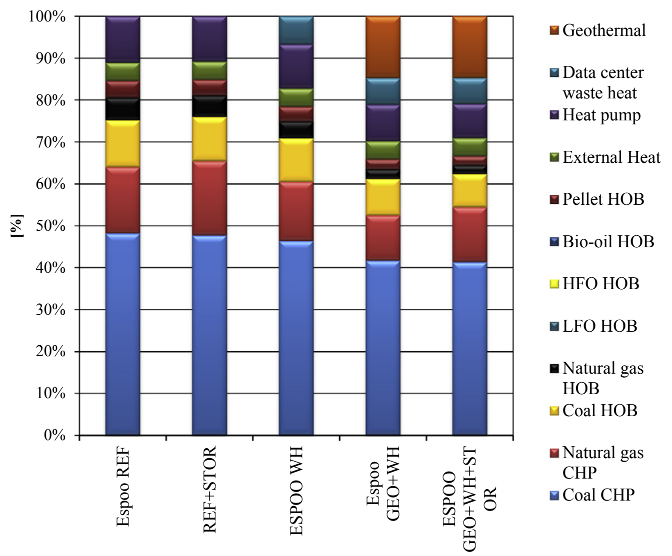

Fig. 8. Share of heat production of different technologies in scenarios. The total heat generation amounts to 2376 GWh/year.

cheaper hours during the wintertime to charge the storage more than in REF+STOR. However, the selling prices were not high enough during summertime and thus, the storage could not sell the heat to the market with current pricing structure in GEO+WH+STOR. The total yearly turnover of TES in case Espoo was 501,276 and 556,076 EUR in Espoo REF+STORand Espoo GEO+WH+STOR scenarios, respectively.

4. Discussion

One can note from the results that the maximum marginal prices of heat in the Sønderborg DH system in the first four scenarios occurred during approximately half of the time, at 58.99 EUR/MWh. In the Sønd ALL and Sønd WH SDH HP scenarios, the same maximum price level occurred only during approximately one third of the year. The highest prices occurred during the winter period. During the autumn and summer periods, the prices were oscillating around the mid-level between the summer and winter prices. Finally, low demand during the summer caused very low prices, especially in Sønd ALL and Sønd WH SDH HP scenarios, in which during the 1998 h marginal heat prices were lower than 5 EUR/MWh.

In the case of Espoo, the highest marginal prices occurred in wintertime when peak hourly load was over 800 MW and marginal prices were 57.8 EUR/MWh of heat. In Espoo, several HOB boilers and fuels, i.e. HFO, LFO and bio-oil, were not utilized in any of the scenarios, instigating that there is excessive HOB production capacity. The latter behavior could have been emphasized also due to the exclusion of the network constraints. Being the marginal heat technology for most of the hours, natural gas HOBs had the largest proportional decrease in both WH and GEO+WH scenarios, in which natural gas HOBs produced 58% less than in the reference scenario. Inclusion of both waste heat and geothermal heat resulted in decreased turnover of 2.0% in WH and 6.0% in GEO+WH scenario.

One can conclude from both Sønderborg and Espoo cases that the behavior of different plants causes similar effects on the dynamic prices of DH grids. During the winter periods when demand was high, prices are relatively stable at a high level. Autumn and spring were transitional periods during which prices gradually dropped (spring) or rose (autumn), following the changes in the demand for DH. Both case studies show that the inclusion of low marginal cost producers cause a shift of the marginal price curve to the left, putting a downward pressure to the prices. This behavior is especially visible in the Sønderborg case, which had larger capacities of low marginal cost producers in alternative scenarios. One should further note that the low cost of heat during the summer period causes operation of waste CHP plants to be unviable, potentially making problems for the handling of waste.

Fig. 10 presents the effects of sensitivity analysis on electricity prices in Sønd WH SDH HP and Espoo GEO+WH scenarios. Electricity prices affected the two DH systems differently due to the different heat production portfolio. The case of Espoo was more sensitive to changes in electricity prices than the case of Sønderborg, with high capacity of CHP electricity production and moderate heat-pump based production. A significant decrease of 50% in electricity prices increased marginal prices by 4%. If electricity prices were to decrease in the case of Espoo, it would increase marginal prices, as CHP production would become less profitable. Simultaneously, CO_2 emissions from heat production would decrease, as the coal-based CHP would generate less energy.

The case of Sønderborg shows slightly lower sensitivity to electricity price changes. For changes in electricity price of ±50%, the changes in weighted average marginal prices were ±2%, as heat pump, electric boiler and CHP units were rarely on the margin. By tracking CO_2 emissions in the case of Sønderborg, which was a dependent variable, one can note that significantly lower electricity prices can lead up to 6% of reduction in CO_2 emissions. The reason is that lower electricity prices result in lower generation from CHP plants driven by gas, as well as increased competitiveness of heat generation units driven by electricity, such as electric boiler and

Table 10
CO_2 emissions from different producers in Case Espoo.

	Espoo REF [kT-CO_2]	Espoo REF+STOR [kT-CO_2]	Espoo WH [kT-CO_2]	Espoo GEO+WH [kT-CO_2]	Espoo GEO+WH+STOR [kT-CO_2]	Current system – calculated based on the fuel consumption [32]
Coal CHP	631.2	626.4	609.6	548.0	544.5	704.0
Natural gas CHP	157.6	178.2	141.6	109.6	134.4	58.5
Coal HOB	106.9	100.2	98.9	83.4	75.3	0
Natural gas HOB	29.5	28.5	22.2	12.4	11.9	28.3
LFO HOB	0	0	0	0	0	0.7
HFO HOB	0	0	0	0	0	24.9
Bio-oil HOB	0	0	0	0	0	0
Wood pellet HOB	0	0	0	0	0	0
External heat	0	0	0	0	0	0
Heat pump	13.2	12.9	12.6	10.4	9.7	16.5
DC waste heat	–	–	9.9	9.4	9.2	–
Geothermal	–	–	0	0	0	–
Total	938	946	895	773	785	833

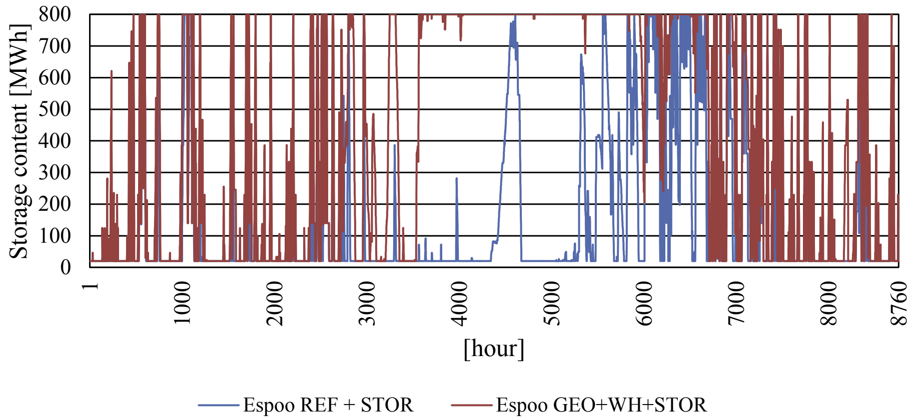

Fig. 9. Hourly TES content in scenarios Espoo REF+STOR and Espoo GEO+WH+STOR.

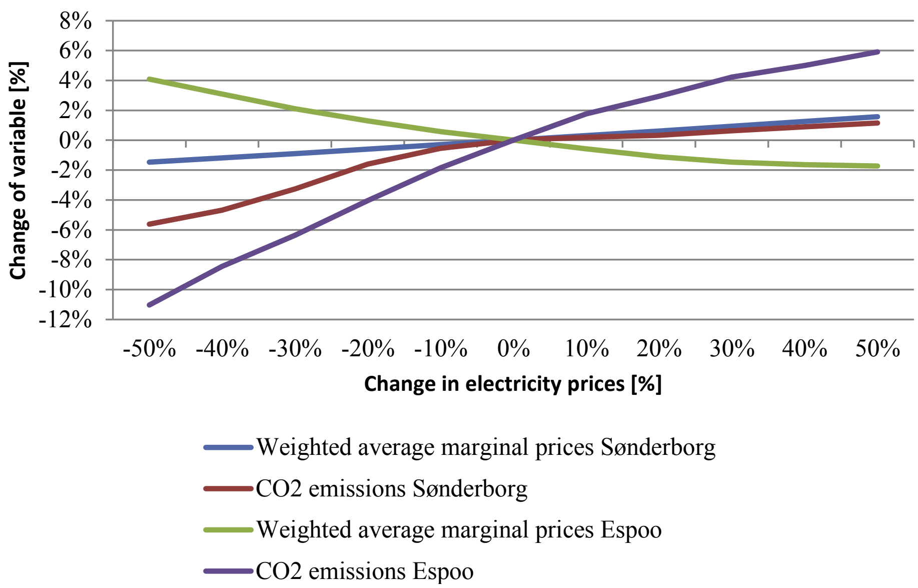

Fig. 10. The impact of electricity prices on the total heat turnover and marginal prices in Sønderborg and Espoo cases.

heat pump.

Due to the nature of marginal cost based pricing, investment costs were left out of the analysis. However, investment costs and technical constraints of different technologies may require attention. Some of the technologies are highly capital-intensive, e.g., large-scale geothermal, heat pumps and storages. If lots of capital-intensive technologies would be installed, adding some premium on top of the marginal cost bid would probably be needed.

Waste heat should be priced according to the equilibrium price set on the day-ahead market while the providers of the waste heat should bid according to their marginal cost. However, temperature levels of waste heat should be taken into account. Industrial waste heat from factories and industrial processes may have high enough temperatures to be directly supplied to supply side of DH network, but waste heat from DCs might be even lower than 35–40 °C, and thus could not be efficiently utilized if the temperature is not increased with heat pumps beforehand [39]. Therefore, temperature levels of available waste heat should be considered in further research.

There is a significant uncertainty originating from the storage bidding strategy. Storage was set to bid on an hourly level, without the knowledge on prices of future hours. With a short-term storage, it can be assumed as a reasonable approach. Short-term storage typically capitalizes lower prices during the night and sells the heat during the day. In the case of Sønderborg, the large volume of the PTES (160,000 m^3) made it closer to the behavior of a seasonal storage than a short-term storage. Operation of such storage should be separately optimized in order to achieve the maximum business-economic gains. However, relatively small amount of generators could make it relatively easy for the heat storage operator to significantly interfere with the marginal prices by offering different capacities during certain periods and the vice versa. In the case of Espoo, TES was mainly used as a short-term storage. However, the bidding strategy was not optimal as there were long periods when storage was not utilized, especially in the case with increased amount of low marginal cost heat production.

The latter point also leads to an issue in DH systems with a lack of suppliers. For the DH systems, the chosen cases are considered to be relatively competitive as DH systems often have only one base and one peak plant operated by the same company (municipality). In that case, the marginal pricing system would face issues, in the same time reducing the incentive for the suppliers to reduce the generation costs. One approach could be to make some benchmarking generation prices based on similar conditions and DH generators in different competitive systems. Consequently, upon establishing the benchmark prices, a system of bonus and malus in prices could be introduced in the smaller systems. Integration of smaller DH systems in the marginal based dynamic pricing is a research topic that should be addressed in the future research.

Lower utilization of CHP may increase the electricity price, especially when there is high capacity of CHP production. Consequently, increased utilization of heat pumps increases electricity demand. The effects of decreased CHP production and increased demand of electricity on the electricity prices were not accounted in this study. Moreover, different external factors can influence DH demand and consequently the equilibrium price achieved, such as energy efficiency of building stock and weather conditions. The latter factors were outside of the scope of this study. Heat demand in this study was set from the historical time series, meaning that all the external factors were included implicitly via the set demand curve. However, in future research, it would be interesting the show the impact of heat demand dynamic on the potential development of the DH supply, both in the short term and in the long term, where the influence of heat demand on investments would be seen. Furthermore, the future research should address the possibility of using the similar approach to this study on district cooling markets, as the district cooling has a significant potential, especially in the currently developing regions located in the hot and humid climates [40].

Finally, as it was shown in this paper that the potential effect of dynamic pricing based on marginal costs on DH systems is significant, this research presents a valuable contribution to the development of the future DH systems, the ones that will be dominated by lower supply and return temperatures. The latter will further foster the integration of waste heat from different sources that generate low quality (low temperature) heat, whose potential impact on the DH market needs to be taken into account.

5. Conclusions

To conclude, results indicate that utilizing waste heat decreased both total heat production costs and CO_2 emissions. The addition of low marginal cost heat production decreased marginal prices close to zero during the summertime in both scenarios. To avoid providing too large prices for third party heat supply, dynamic heat markets are a viable solution if a very large amount of waste heat would be connected to the grid. Further research on dynamic pricing should address several limitations of this study that were discussed in the Discussion section.

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Nomenclature

HFO	Heavy fuel oil
HOB	Heat only boiler
CHP	Combined heat and power
COP	Coefficient of performance
CO_2	Carbon dioxide
DC	Data center
DH	District heating
LFO	Light fuel oil
PTES	Pit thermal energy storage
SDH	Solar district heating
TES	Thermal energy storage

Appendix A

Table A.1
Emission factors of different fuels in the case of Espoo

	CO_2 Emission factor kg_{CO2}/MWh_{fuel}
Coal	341
HFO	284
LFO	267
Natural gas	198
Electricity	175
Biomass	0

Table A.2
Emission factors of different fuels in the case of Sønderborg [41].

	CO_2 Emission factor kg_{CO2}/MWh_{fuel}
Waste	133
Natural gas	205
Electricity	304
Biomass	0

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