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Economic appraisal of small biofuel fired CHP plants

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Abstract

A study is presented in which an optimisation model is built to determine the economic viability of three small biofuel fired CHP plants. The model formulated to describe heat and electricity production with CHP plants is based on simulation data for three existing plants. The modeled system extends from the production facilities to the distrcit heating substations of the consumers, thus combining operational and design planning. We find that, compared to the long term average situation in the Nordic countries, higher electricity prices or lower investment costs are needed to make CHP plants attractive in small district heating networks. The results are relatively sensitive to the original economic parameters, and this uncertainity over future cashflows may further reduce investments in small CHP plants.

Keywords: CHP; Biomass; District heating; Optimisation

1. Introduction

Cogeneration of heat and electricity is generally considered to be an efficient way to produce these two products. This is also recognised by the EU, which has issued a directive to promote high efficiency cogeneration of heat and electricity [1]. In 1997, the European Commission also set a goal of doubling the share of electricity produced with cogeneration of heat and power (CHP) by the year 2010 [2]. Especially biomass based cogeneration has been seen as a good option for the future by the EU, and the use of biomass as an energy source in general is strongly promoted [3]. It has also been suggested that a CHP plant could serve as a regional anchor tenant, around which a recycling network could operate [4].

In Finland, district heating has a market share of approximately 48%. About 75% of this heat is produced with CHP plants [5]. This means that most densely populated areas are already connected to district heating and that the largest systems are supplied by CHP plants. Therefore, the growth in CHP production should be aimed at smaller networks, which currently often use heat only boilers. Small systems are also better suited for production with biomass, since the availability of the fuel is not as serious a problem for them as for larger plants. It has been estimated that from the perspecive of heat demand and fuel availability, a relatively large potential for biofuel fired small scale CHP plants exists in Finland [6].

This paper analyses the economic viability of small biofuel fired CHP plants through a nonlinear optimisation model. The data for the plants is obtained from simulations done for three existing facilities. The dimensionings of the CHP plants and the supplementary heat only boilers are results of the optimisation, as are the temperature levels of the district heating water. A simple mathematical description of the district heating network and the consumer substations is included in the model. Several economic parameters are varied to test how sensitive the results are.

Several models have been used previously to optimise district heating systems. One such model is MODEST [7–9]. MODEST is a mixed integer linear programming (MILP) model that has been used for several studies of dif-

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Nomenclature

A	area of heat exchanger
a	coefficient
ann	annuity factor
b	coefficient
C	price, cost (€/h, €/MWh or €/kW, depending on nature of cost)
c	coefficient
D	dimensioning coefficient
d	coefficient
dia	inner diameter (m)
f	frequency coefficient
L	limit for piecewise linearization of power production
l	length of district heating pipe (m)
$\dot{m}$	mass flow (kg/s)
n	coefficient for Nusselt number
Q	heat flow (kW)
q	share coefficient
P	electric power (kW)
p	pressure (Pa)
r	coefficient for piecewise linearization of power production
Re	Reynolds number
S	mass flow ratio
T	temperature (°C)
U	overall heat transfer coefficient for heat exchanger (W/m^2 K)
w	reduction term for electricity production (kW)
x	coefficient
y	coefficient

Greeks

α	convection heat transfer coefficient (W/m^2 K)
ε	relative roughness of pipe
η	efficiency
λ	thermal conductivity (W/m K)
μ	dynamic viscosity (kg/m s)
ξ	friction factor
ρ	density of water (kg/m^3)

Subscripts

bio	biofuel
c	cold water
cr	critical
design	design values used
dh	district heating
el	electricity
f	fuel
h	hot water
hyd	hydraulic
i	temperature bin
inv	dimensioning of plant, investment
inv0	dimensioning of original plant
loss	heat or pressure loss
o	operation cost
p	power production
r	radiator
ref	reference
s	secondary side in heat exchanger
spec	specific cost
tot	total cost
Tout	outside temperature

ferent natures. The objective function to be minimised is the discounted production and investment costs over a specified number of years. The model does not endogenously take into account the effect of part load operation on power to heat ratio or total efficiency. Distribution losses are assumed to be a constant share of the energy distributed, and operational considerations are mostly not taken into account. MODEST is mostly a planning tool for the production side, and the operational view is limited to demands and prices. The MILP model suggested in Ref. [10] is otherwise quite similar to MODEST, but it has the option of investing on the demand side and emphasises this heavily.

Bennysson et al. [11] concentrate more on the operational side of the issue. They present a nonlinear model in which the network and consumers as well as the temperature levels in the network are studied in detail. The effect of part load operation on power to heat ratio is taken into account, but no actual data is used to derive this relation. Only operational costs are considered, and no new investments are evaluated. Zhao et al. [12] also present a nonlinear model intended for short horizon operational planning. Also here, the network and the temperature of the hot district heating water are modeled in detail. However, the temperatures of the cold district heating water are assumed to be known. No investments are considered and the model concentrates mostly on the combined operation of a CHP plant and a heat storage.

The aim of this paper is to present an optimisation model that combines characteristics from the design and operational models and then use this model to evaluate how viable an investment in a small CHP plant is and how sensitive the results are to the economic parameters. Section 2 presents the description of the model and its components, Section 3 presents the results calculated with the model and Section 4 concludes.

2. The model

2.1. The general structure of the model

The operational optimisation of the model is based on dividing the year into 10 different bins, denoted by subscript i, based on the outside temperature. Division by outside temperatures allows taking into account the effects this temperature has on the operation of a district heating substation, where the temperature of the water in the radiotar circuit is used to control the room temperature, and it, thus, depends on the outside temperature. The design level of the optimisation takes the results from these bins into account and decides the dimensioning of the plants based on investment costs and operating costs which are weighed according to the frequencies of the outside temperature bins.

The model is built as a nonlinear model without integer variables. The general form for a problem like this is

$$\min f(x)$$
$$\text{subject to}$$
$$h(x) = 0,$$
$$g(x) \leqslant 0,$$
$$x \in X \subseteq \Re^n.$$

Here, x is a vector of continuous variables. If any of the functions is nonlinear, the problem also becomes a nonlinear programming problem.

2.2. The production facilities

Three small scale biomass CHP plants are chosen to represent the current situation. These three plants are mostly used as examples of current CHP *technology*, and therefore, their sizes and investment costs are varied considerably during this study. These particular plants are chosen based on the state of the art review done for small biomass fired CHP plants in the Nordic countries [6] and they all started their operation in 2002. These three plants together are considered to represent a general overview of current commercial technology in the Nordic countries. The plants are simulated using the software called PROSIM [13,14], a steady-state power plant simulation software, and the coefficients for the mathematical representation of the production are formulated based on the simulation results. More on the process simulations done with PROSIM, the regression analysis used to derive the coefficients for the following production equations and a more thorough description of the mathematical model for power production can be found in Ref. [15]. Some basic data for the original plants is presented in Table 1.

The fuel consumption, $Q_{\mathrm{f,i}}$, for a CHP plant is assumed to be a linear function of the heat production, $Q_{\mathrm{CHP},i}$, and temperature levels of the district heating water, $T_{\mathrm{h,i}}$ and $T_{\mathrm{c},i}$.

$$Q_{\mathrm{f},i} = a_{\mathrm{f}} \cdot Q_{\mathrm{CHP},i} + D \cdot b_{\mathrm{f}} \cdot T_{\mathrm{h},i} + D \cdot c_{\mathrm{f}} \cdot T_{\mathrm{c},i} + D \cdot d_{\mathrm{f}}. \tag{1}$$

The power production is modeled with Eqs. (2)–(6)

Table 1
Summary of the plants studied [15]

Power plant	Plant A	Plant B	Plant C
Power output (MW)	1.6	11.7	14.7
Heat output (MW)	8.3 + 2.7[a]	26 + 7[a]	30
Fuel input (MW)	11.5	42	48
Electrical efficiency	0.145	0.28	0.31
Total efficiency	1.04	1.06	0.93
Fuel	Sawdust, bark	Wood, peat	Wood chips, sawdust, bark, peat, REF
Technology	Biograte + steam engine	BFB	BFB
Power-to-heat ratio	0.19	0.45–0.49	0.49
Approximate investment cost, €/kW, el	3888[b]	1496	1429

[a] Produced with flue gas condensing. Not taken into account in the simulations but included in the efficiencies in the table, thus resulting in efficiencies above 1.
[b] Approximated from several sources describing similar projects of the manufacturer.

$$P_i = a_{\mathrm{p}} \cdot Q_{\mathrm{CHP},i} + D \cdot b_{\mathrm{p}} \cdot T_{\mathrm{h},i} + D \cdot c_{\mathrm{p}} \cdot T_{\mathrm{c},i} + D \cdot d_{\mathrm{p}} - w_{1,i} - w_{2,i}, \tag{2}$$

$$w_{1,i} \geqslant (L_1 \cdot Q_{\mathrm{inv}} - Q_i) \cdot r_1, \tag{3}$$

$$w_{2,i} \geqslant (L_2 \cdot Q_{\mathrm{inv}} - Q_i) \cdot r_2, \tag{4}$$

$$w_{n,i} \geqslant 0, \tag{5}$$

$$D = \frac{Q_{\mathrm{CHP,inv}}}{Q_{\mathrm{CHP,inv0}}}. \tag{6}$$

This formulation is used in order to describe also the reduction in power production during part load operation. Eq. (2) without the terms $w_{1,i}$ and $w_{2,i}$ would describe the power production of a CHP plant as a linear function of the heat production and district heating waters temperatures. However, part load operation effects this relationship between heat and power production, and small reduction terms for power production are added to describe this change. These terms get a value of zero as long as the fuel consumption remains above a set limit L. If the fuel consumption drops below limit L, the power production is reduced linearly according to Eqs. (3) and (4), making the power production a piecewise linear function.

The coefficients needed for Eqs. (1)–(4) are shown in Table 2. These coefficients are calculated as least square estimators for a multiple linear regression model from the simulation results presented in Ref. [15], and they, therefore, refer to the original plants. Variable D is used to scale the coefficients based on the optimized size of the power plant. It is also required that the power production always be non-negative.

Boilers are described simply as units transforming fuel energy into heat with an efficiency of 0.9. As was done in previous studies [11,12], we also assume that the power needed for pumping turns into heat, since it is largely

Table 2
Coefficients for fuel consumption and power production

	Plant A	Plant B	Plant C
a_f	0.265285	0.501837	0.579103
b_f	−0.013420	−0.049631	−0.047802
c_f	0	0	−0.012534
d_f	0.770670	2.810384	2.449670
a_p	0.170036	0.407082	0.480720
b_p	−0.013255	−0.049126	−0.047368
c_p	0	0	−0.012324
d_p	1.493472	4.938716	4.868050
r_1	0.073020	0.070207	0.079772
r_2	0.057123	0.087737	0.095694
L_1	0.9	0.85	0.8
L_2	0.7	0.6	0.6

dissipated by the flow friction. Adding the pumping power $P_{\mathrm{pump},i}$, the heat production from a heat boiler $Q_{\mathrm{boiler},i}$ and the heat losses in the heat distribution network $Q_{\mathrm{loss},i}$, the energy balance for the district heat production for outside temperature bin i is

$$Q_{\mathrm{CHP},i} + P_{\mathrm{pump},i} + Q_{boiler,i} = c_{\mathrm{p}} \cdot \dot{m}_i \cdot [T_{\mathrm{h},i} - T_{\mathrm{c},i}] + Q_{\mathrm{loss},i}. \tag{7}$$

2.3. District heating network

In this study, an approximation of an existing network and its heat load is used. The maximum heat load of all the customers is approximately 4.5 MW. The total length of this tree shaped network is slightly over two kilometers. The pressure loss for a pipe with length l, and diameter dia is calculated from the Darcy–Weisbach equation (Eq. (8)) and the friction factor ξ, is estimated based on the Swamee–Jain equation (Eq. (9)). The density of water is ρ, ε is the relative roughness of the pipe and *Re* refers to the Reynolds number.

$$\Delta p = \xi \cdot \frac{8 \cdot l}{\pi^2 \cdot \rho \cdot dia^5} \cdot \dot{m}^2, \tag{8}$$

$$\xi = 0.25 \cdot \left[\lg\left(\frac{5.74}{Re^{0.9}} + \frac{\epsilon}{3.71} \right) \right]^{-2}. \tag{9}$$

Using these functions, the critical route between the plant and the critical customer is defined (i.e. the pressure drop along the route from the plant to each of the customers is calculated and the customer for whom this drop is the largest is the critical customer and the corresponding route is the critical route). A district heating network simulation software, Heat Nexus$^{\mathrm{Tm}}$, is used to verify that the critical customer remains the same during all relevant operating conditions.

Since the operational costs connected to the network are not usually significant compared to the heat production costs (see e.g. Ref. [12]) and the small size of the network used here makes its operation even less important economically, the following simplifications are made: (1) the efficiency of the pump is considered to always be 100%, (2) the density and dynamic viscosity (needed for calculating *Re*) of the water are assumed to be constants and (3) the friction factor is estimated for typical flow conditions on the critical route and used then as a constant. Doing this, we get the pressure loss from Eq. (8) for the critical route of our network, from the heating plant to the critical customer:

$$\Delta p_{\mathrm{loss,cr}} = \sum_{\mathrm{cr}} \xi_{\mathrm{cr}} \cdot \frac{8 \cdot l_{\mathrm{cr}}}{\pi^2 \cdot \rho \cdot \mathrm{dia}_{\mathrm{cr}}} \cdot \dot{m}_{\mathrm{cr}}^2 \Rightarrow 16.807 \cdot \dot{m}_{\mathrm{total}}^2 \frac{1}{\mathrm{kg} \cdot \mathrm{m}}. \tag{10}$$

The mass flow on the right-hand side of Eq. (10) refers to the total mass flow and the relation between that and the mass flow along the critical route is defined from the corresponding heat loads of the total system and the critical customer. The additional pressure loss reserved for the consumers substations is 60 kPa. The required power for pumping $P_{\mathrm{pump},i}$ can now be calculated by summing the total pressure loss together (right-hand side of Eq. (10) has to be multiplied by 2 to account for the return pipe) and multiplying this by the total volume flow.

Since the network is very small, the temperature drop of the district heating water from the plant to the substation is not calculated and the heat loss for a pipe $Q_{\mathrm{loss},i}$, is determined for steady-state conditions:

$$\frac{Q_{\mathrm{loss},i}}{l} = G \cdot \left(\frac{T_{\mathrm{h},i} + T_{\mathrm{c},i}}{2} - T_{\mathrm{ref}} \right), \tag{11}$$

where T_{ref} is the reference temperature of the soil, assumed to be +5 °C through the year and G is the total heat transfer coefficient for two buried pipes. Since G only depends on the dimensions and characteristics of the pipe, soil and insulation, it is constant for pipes of similar dimensions and type. For the calculation of G for different kinds of pipes, see e.g. [16] or documentation provided by pipe producers. The total heat losses are calculated from Eq. (12), where the sum includes all the pipes in the network. For this particular network, this sum of the products of G and pipe length l for all the pipes in the network is 934.4298 W/K.

$$Q_{\mathrm{loss},i} = \left(\frac{T_{\mathrm{h},i} + T_{\mathrm{c},i}}{2} - T_{\mathrm{ref}} \right) \cdot \sum_{\mathrm{pipe}} G_{\mathrm{pipe}} \cdot l_{\mathrm{pipe}}. \tag{12}$$

This heat loss, which depends on the district heating water's temperatures, is taken into account in the energy balance (see Eq. (7)).

2.4. District heating substations

The so-called "two-stage coupling" is used for the substations in this study. In this coupling, the district heating water coming to the substation is first divided into two flows, one being used for space heating and the other for domestic water heating. The flows are united again, after passing through their respective heat exchangers, in the heat exchanger that is used for preheating the domestic water. The cold domestic water temperature is assumed to be 10 °C, and the final hot domestic water has a temperature of 55 °C. Consumption of the hot domestic water flow is assumed to be constant, and the flow is calculated thus that the energy needed to heat that flow is 30% of the energy needed for space heating during the year.

The temperatures of the water in the radiator circuit are used to control the room temperature, and they are assumed to depend on the outside temperature as shown in Eqs. (13) and (14)

$$T_{\mathrm{r,h}} = 40 - T_{\mathrm{outside}}, \tag{13}$$

$$T_{\mathrm{r,c}} = 28 - \frac{2}{5} \cdot T_{\mathrm{outside}}. \tag{14}$$

The heat transferred in a heat exchanger at the substation is calculated from Eq. (15), where A is the area of the heat exchanger, U is the overall heat transfer coefficient for the heat exchanger and ΔT_{lm} is log mean temperature difference for a counterflow heat exchanger.

$$Q = A \cdot U \cdot \Delta T_{\mathrm{lm}}. \tag{15}$$

The overall heat transfer coefficient is calculated from Eq. (16).

$$\frac{1}{U} = \frac{1}{\alpha_{\mathrm{dh}}} + \frac{1}{\alpha_{\mathrm{s}}}. \tag{16}$$

To simplify the calculations, it is assumed that the conduction term normally included in determining U is insignificant, and it is, therefore, excluded from Eq. (16). It is furthermore assumed that the thermal conductivity, λ, is constant and identical on both sides of the heat exchanger in all the following calculations.

Convection heat transfer coefficients for the heat exchanger are calculated from Eqs. (17)–(19). Nu is Nusselt number, Re is Reynold's number, $\mathrm{dia_{hyd}}$ is the hydraulic diameter of the heat exchanger and Pr is Prandtl number.

$$\alpha = \frac{Nu \cdot \lambda}{\mathrm{dia_{hyd}}}, \tag{17}$$

$$Nu = C \cdot Re^n \cdot \mathrm{Pr}^m \tag{18}$$

$$\mathrm{Pr} = \frac{c_{\mathrm{p}} \cdot \mu}{\lambda}. \tag{19}$$

It is furthermore assumed that the dynamic viscosity μ and heat capacity c_{p}, needed to calculate Prandtl number, remain constants. These assumptions reduce the accuracy of the description of the substations but the model as a whole should still be accurate enough for the purposes for which it is created. The flow is also considered to be turbulent at all times. We now define the mass flow ratios S_{design} for district heating water flow and secondary side flow (i.e. domestic or radiator circuit) under design conditions (Eq. (20)) and S for the ratio between the variable district heating water flow and the same flow under design conditions (Eq. (21)).

$$\frac{\dot{m}_{\mathrm{dh,design}}}{\dot{m}_{\mathrm{s}}} = S_{\mathrm{design}}, \tag{20}$$

$$\frac{\dot{m}_{\mathrm{dh}}}{\dot{m}_{\mathrm{dh,design}}} = S. \tag{21}$$

With the above simplifications, the Reynolds number is a linear function of mass flow alone, and using the above defined mass flow ratios, we can estimate the overall heat transfer coefficient as a function of the mass flow ratios and the overall heat transfer coefficient in design conditions:

$$\frac{U}{U_{\mathrm{design}}} = \frac{1 + S^n_{\mathrm{design}}}{S^{-n} + S^n_{\mathrm{design}}}. \tag{22}$$

For the coefficient n in Eqs. (18) and (22), we use the value of 0.67 (based on [17]). Since the temperature levels of the district heating water are defined for the design conditions, the product of the heat exchanger area A, and the total heat transfer coefficient during design conditions, U_{design}, can now be calculated from Eq. (15).

A small Visual Basic program is created to calculate the required mass flow and the resulting temperatures of the cold district heating water for outside temperatures from −30 to 20 °C using different temperatures of the hot district heating water (from 70 to 115 °C) and the above defined equations for describing the heat transfer. The Visual Basic iteration increases the mass flow of the district heating water until it can fulfil the heat demand defined by Eq. (15) for each heat exchanger while taking into account how these exchangers are connected to each other. A minimum temperature difference of 5 °C is required between the flows in the inlet and outlet of all heat exchangers. The resulting temperatures for the cold district heating water as a function of hot district heating water and outside temperatures are shown in Fig. 1.

Based on the results of these iterations, a linear approximation, Eq. (23), is formulated and included as a constraint to the optimization formulation in order to estimate the temperature of the cold district heating water as a function of the hot water temperature for each outside temperature bin i:

$$T_{\mathrm{c},i} \geqslant x_i \cdot T_{\mathrm{h},i} + y_i. \tag{23}$$

The coefficients for Eq. (23) are determined using least square estimations for each bin i separately. $T_{\mathrm{c},i}$ is also required to be above 15 °C at all times and $T_{\mathrm{h,i}}$ has to be within the same range used in the Visual Basic iteration. R^2 for the regression estimates is over 0.93 for all the outside temperature bins. A minimum temperature difference of 5 °C between the temperatures in the primary and secondary circuits is required also in the optimization formulation. The mass flow cannot be more than approximately 15% above the original design flow. The required district heating water flow follows from the energy balance and is included in all relevant equations in the optimization formulation (e.g. Eqs. (7) and (10)).

2.5. The weather data, the price of electricity and the objective function

The outside temperatures are organised in 10 bins of equal temperature range (bins 1 and 10 are exceptions from this), and the frequency of these bins is used to weight the

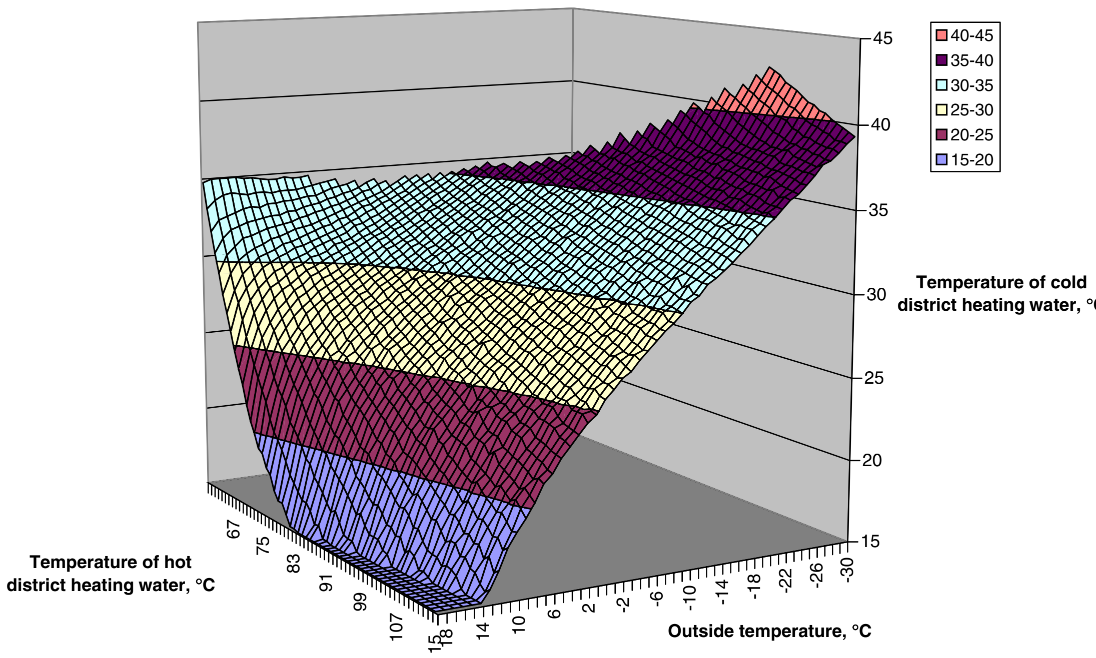

Fig. 1. The temperatures of the cold district heating water.

costs associated with a particular bin in the objective function (Table 3). The frequencies for the bins are calculated based on the weather data given in [18].

Fig. 2 shows the heat load duration curve for the whole system calculated based on the outside temperature distribution given in Table 3 and the assumptions on hot domestic water consumption given in Section 2.4. This estimation we use here seems to correspond reasonably well to results derived from actual measurements of the annual distribution of heat load (see e.g. [19,20]). However, some of the peaks are naturally lost when average values are used.

The price of electricity has a lot of seasonal and yearly variation. Because of its large share, the status of the hydro power is the most important element in determining the price of electricity in the Nordic electricity market area. The level of the reservoirs, the expected rainfall and the production capacity structure of the market area largely define what price the hydro power producer requires for the electricity produced. The outside temperature has an effect on the demand and, therefore, on the price (Ref. [21] reports for Finland a correlation of 0.8 between the district heating load and electricity price), but it is not the most important factor in determining the price. For our study, the use of seasonal averages over several years should give a relatively good approximation for the temperature related electricity price variation.

Table 3
The weather data

Bin number, i	Upper limit for bin	Lower limit for bin	Temperature used	Frequency for bin
1	−26	n.a.	−28	0.003080
2	−21	−25	−23	0.010951
3	−16	−20	−18	0.030972
4	−11	−15	−13	0.049110
5	−6	−10	−8	0.095311
6	−1	−5	−3	0.130903
7	4	0	2	0.190794
8	9	5	7	0.139117
9	14	10	12	0.167180
10	n.a.	15	18	0.182580

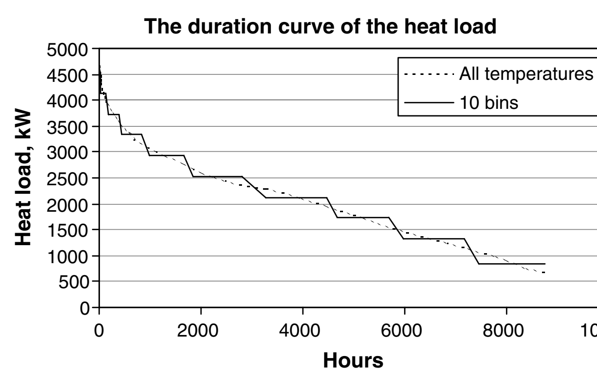

Fig. 2. The duration curve for the heat load.

Seasonal averages for electricity price are calculated based on the data from the Nordic Power Exchange, Nordpool, from the beginning of 1996 to the beginning of April in 2003. We define each season to consist of 3 months, winter starting with December. Using these definitions and this period, the average prices for the seasons are: 27.18 €/MWh during winter, 19.21 €/MWh during spring, 16.92 €/MWh during summer and 21.67 €/MWh during autumn.

The weather data from [18] is used to connect an electricity price to an outside temperature. Eq. (24) is used to calculate the electricity price for each outside temperature by weighting the average seasonal cost, C_{season}, with the share of observations of the given outside temperature experienced during a particular season, $q_{Tout,season}$ and then summing over all the seasons.

$$C_{Tout,el} = \sum_{season} q_{Tout,season} \cdot C_{season}. \qquad (24)$$

The electricity prices for the bins, which combine a range of outside temperatures, are calculated according to Eq. (25). Eq. (25) also takes into account the different frequencies of different outside temperatures *within* the bin i by calculating the electricity price for the bin as a weighted average over the individual outside temperatures in the bin:

$$C_{el,i} = \frac{\sum_{Tout} q_{Tout} \cdot C_{Tout,el}}{\sum_{Tout} q_{Tout}}. \qquad (25)$$

In Eq. (25). T_{out} includes all the outside temperatures of bin i. Fig. 3 shows the relationship between the outside temperature and the calculated average electricity prices.

The objective function being minimised in our problem formulation is

$$C_{tot} = \frac{C_{inv} + \sum_i f_i \cdot C_{o,i}}{\sum_i f_i \cdot Q_{i,demand}}. \qquad (26)$$

Investment costs, C_{inv}, and operational costs, $C_{o,i}$, are determined according to Eqs. (27) and (28), respectively, and the frequency of a bin i, f_i, is read from Table 3.

$$C_{inv} = \frac{\text{Ann} \cdot \sum_{plant} Q_{plant,inv} \cdot C_{plant,inv,spec}}{8760}. \qquad (27)$$

Using this formulation, we get the total costs in units of €/MWh. A discount rate of 5% and operation time of 20 years are used for calculating the annuity factor Ann. The specific investment cost, $C_{plant,inv,spec}$ used is 133 €/kW$_{heat}$ for an oil boiler and 200 €/kW$_{heat}$ for a biofuel boiler [22,23].

$$C_{o,i} = \frac{C_{oil} \cdot Q_{oil,i}}{\eta_{oil}} + C_{bio} \cdot \left(\frac{Q_{bio,i}}{\eta_{bio}} + Q_{f,i}\right) - C_{el,i} \cdot (P_i - P_{pump,i}). \qquad (28)$$

In the cost equation for operational cost, Eq. (28), P_i is the power production, $Q_{oil,i}$ and $Q_{bio,i}$ are the heat productions using heat boilers and $Q_{f,i}$ is the fuel consumption for the CHP plant. The prices for fuels, including taxes, are 10 €/MWh for biofuel ($C_{bio,i}$) and 20 €/MWh for oil ($C_{oil,i}$) [24].

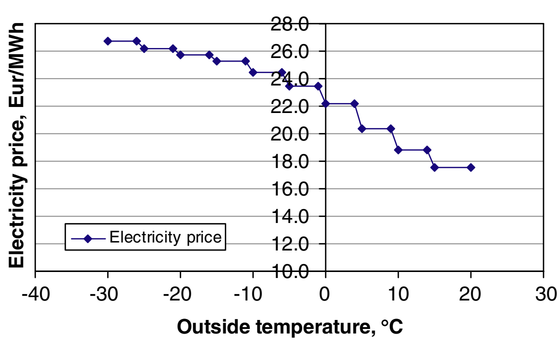

Fig. 3. The relation between outside temperature and the price of electricity.

3. Results

In the first case studied, an old oil boiler is assumed to be still available. A biofuel fired boiler is not among the options in this first case. Therefore, the options are either to produce heat using the old oil boiler or to invest in a CHP plant. The second case assumes that no old boiler or other heat production facility is available. In this case, it is also possible to invest in a biofuel fired boiler. Each CHP plant is studied as an investment option separately, with no possibility to invest in the other two CHP plants. Optimization software GAMS/conopt [25,26] is used to formulate and solve the problem.

3.1. Results for the case with an old oil fired boiler available

The results of the optimisation of the first case are presented in Table 4. The specific investment costs shown in Table 1 were used for CHP plants and the electricity prices were calculated as shown in the previous section. An old oil boiler was assumed to be available without additional investment. Different starting levels were tried for the variables to make it more likely that the global optimum is found instead of a local one.

The oil fired boiler has a variable heat production cost of 22 €/MWh, but it still covers almost 50% of the peak load, no matter which of the three CHP plants is considered. Plant B is able to produce the heat with the lowest average total cost. Plant A suffers from the high specific investment cost and has, therefore, circa 20% higher average production costs than the other two plants. The size of the real existing plants has an impact on their investment costs and some performance related characteristics (e.g. power to heat ratio), which also shows in our results. As was the case with earlier studies (see e.g. [12]), also here, it turns out that the costs from heat losses and pumping are low compared to the costs resulting from energy production and the investment in production facilities.

Fig. 4 shows the optimal temperature levels of the district heating water as a function of the outside temperature. These temperatures correspond to the lowest temperatures

Table 4
Results for the CHP plants for the case with an old boiler and a new CHP-plant

Plant	A	B	C
Total production costs (€/MWh)	17.358	14.348	14.400
Total fixed costs (€/MWh)	6.644	6.921	6.778
Total variable costs (€/MWh)	10.714	7.427	7.622
Invested heat production for CHP (kW)	2169	2570	2277
Invested power output (kW)	361	977	1002
Plant peak production time (h)	6958	6297	6757
Share of energy produced	89.3%	95.8%	91.0%
Share of peak load	47.8%	56.7%	50.2%

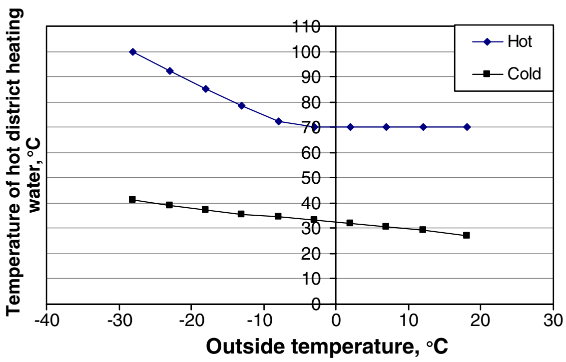

Fig. 4. The optimal temperature levels of the district heating water.

allowed. The same result is achieved with all further cases. This result is somewhat expected and similar results have been reported before (see e.g. [12]).

If specific investment costs are changed and a similar cost is used for all plants, plant A is clearly the cheapest option. This is because the specific investment cost is defined for the maximum electricity output and does not take into account how much heat is produced in addition to this. If the specific investment cost is lowered to 3000 €/kW$_{el}$, plant A is affected by the minimum load restriction (i.e. non-negative electricity production at all times). If the specific investment cost is 4000 €/kW$_{el}$ or more, no investment is made on plant C. The same applies to plant B when the specific investment cost reaches 4500 €/kW$_{e}$. Plant A would be built, even if the specific investment cost was as high as 5000 €/kW$_{el}$. Fig. 5 shows how the average production costs of plants B and C change when the specific investment cost is varied. The original specific investment cost is used as the reference value. Plant A is not included, since its original specific investment cost already reflects its small size.

If the original investment costs are used, but the price of electricity is changed, plant A remains the most expensive option. However, plant C is able to produce electricity slightly more than plant B, and therefore, a uniform price increase of 2 €/MWh$_{el}$ over all temperature bins is enough to make plant C the cheapest option. If the same average price increase is distributed differently, and instead of a uniform absolute price increase, a uniform *relative* increase is used (i.e. a percentage increase), all plants perform better. This is because, in absolute numbers, the increases are higher during winter, when the heat demand and, therefore, the load of the plant, is also the highest. The plants with a high power to heat ratio benefit the most. Fig. 6 shows the relation between the changes in average electricity price and average heat production costs. A uniform price increase is used for the figure and the original weighted average price of electricity over the year is 20.95 €/MWh$_{el}$. No price reductions were considered, since in the long run, such changes cannot be considered very likely.

If an equal specific investment cost is used together with the increased electricity price, plant A is again the cheapest option. However, the larger is the increase in electricity price, the narrower is the gap between the production costs of the plants.

3.2. Results for the case with investments in boilers required

The results for the first case do not yet tell how much of the benefit of not relying only on the oil fired boiler can be attributed to the cheaper biofuel and how much to the additional possibility to produce electricity. This is studied next by introducing the option to invest in a biofuel fired heat boiler. In addition to this, it is also assumed that the old oil fired boiler has to be removed, but a new oil fired boiler is among the investment options. Table 5 has the results for a case where the original investment costs for CHP plants and electricity prices, as calculated in Section 2.5, are used.

The results in Table 5 differ from those in Table 4 significantly. With plants B and C, the CHP plants cover less of the peak load and no investment is made at all with plant A. Plant C is now the most economic option instead of plant B. The biofuel fired boiler is the largest unit no matter which CHP plant is considered with it. The oil fired boiler is used to cover the demand during peak load hours.

A sensitivity analysis is performed for the price of electricity. Fig. 7 shows the share of the peak load delivered by

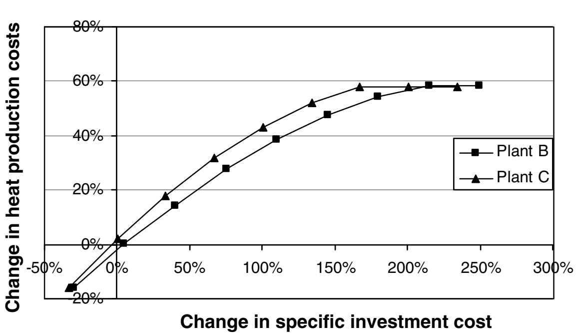

Fig. 5. The relation between specific investment cost and average heat production cost.

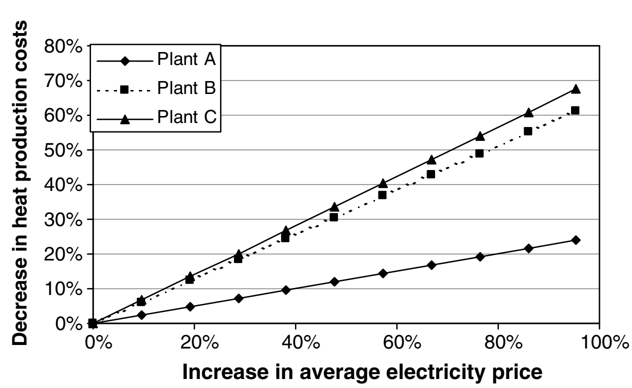

Fig. 6. Relation between changes in average electricity price and average heat production costs.

Table 5
Results for the case where investments in boilers are required

Plant	Plant A	Plant B	Plant C
Total costs of heat production (€/MWh)	15.425	14.911	14.840
Total fixed costs of heat production (€/MWh)	3.963	6.770	6.952
Total variable costs of heat production (€/MWh)	11.462	8.141	7.888
Heat production capacity of the CHP-plant (kW)	0	1607	1472
Heat production capacity of the oil-fired boiler (kW)	1217	1217	1217
Heat production capacity of the boiler using biofuel (kW)	3377	1770	1905
Invested power output (kW)	0	611	648
CHP-plants peak production time (h)	0	7734	7929
Share of heat produced with the CHP plant	0%	73.6%	69.1%
CHP-plants share of the peak load	0%	35.5%	32.5%

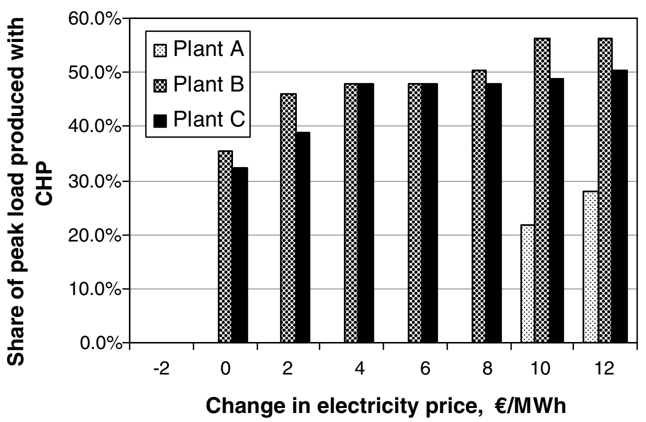

Fig. 7. The effect of electricity price on dimensioning of the plants.

the CHP plant when the electricity price is varied. The dimensioning of the oil fired boiler remains unchanged (about 27% of the peak load), and the remaining share is delivered by the biofuel fired boiler.

According to Fig. 7, plant A would require a uniform electricity price increase of 10 €/MWh before an investment in it would be economical. Plants B and C do get built with the original electricity prices, but a reduction of 2 €/MWh in electricity price is enough to remove them from the optimal solution and to rely on heat boilers alone. Table 6 shows the limits for investment costs and electricity prices after which the CHP plants are not built, and the heat is produced using only oil and biomass fired biolers.

Table 6
Requirements for the electricity prices or investment costs to make an investment viable

Plant	Plant A	Plant B	Plant C
Maximum specific investment cost (€/kW$_e$)	2517	1725	1664
Allowed/required change in electricity price (€/MWh)	9.16	−1.75	−1.85
Allowed/required change in electricity price. Percentage change	43.6%	−7.5%	−7.2%

"Percentage change" in Table 6 refers to a case where all the electricity prices for the bins are raised with an equal percentage instead of an equal absolute amount. The results indicate that significant changes are needed to make plant A profitable. Furthermore, if the interest rate were raised to 8%, the result with each of three CHP plants would include only the two heat-only boilers.

The results here indicate that much higher electricity prices or lower investment costs would be needed to make plants in the size range of plant A economical. Plants B and C are originally much bigger and have much lower specific investment costs. However, as Table 6 indicates, there is little room for changes in the undesirable direction, and the specific investment cost would move to this direction if these plants were to be dimensioned considerably smaller. The small margin and the fact that the cash flows from the sale of electricity include a high level of uncertainty make the situation look less promising also for these plants.

4. Discussion and conclusions

In this paper, we have studied the profitability of an investment in a small biofuel fired CHP plant. An optimisation model describing production, distribution and consumption of district heat was constructed. This model combines characteristics from operational and design models that have previously been mostly used separately. The energy production from the CHP plants is based on simulations done for three different plants, thus giving a wider perspective on the behaviour of such plants.

The results indicate that the economically feasible scale for biofuel fired CHP plants remains relatively large. When a biofuel fired boiler is among the options for heat production, no investment is made in the smallest of the three CHP plants. Specific investment costs for the two larger plants could be only slightly higher until no investment in them would be made either. This means that if these plants were scaled down, their specific investment cost should not rise considerably. A rise of 3% units in the discount rate causes again the same effect. When it is taken into account that, in the real world, future electricity prices are not deterministic and, therefore, a higher rate of return would be required, the competitiveness of the biofuel fired boiler increases even more. This competitive edge of the heat only boiler has been noted before [9,27]. Emission trading and the resulting rise in the price of electricity or increased subsidies could, however, tip the scales in favor of the CHP plant in the long term. More research is needed to estimate the effects of short and long term uncertainities on investment decisions.

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