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Biomass gasification opportunities in a district heating system

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Abstract

This paper evaluates the economic effects and the potential for reduced CO_2 emissions when biomass gasification applications are introduced in a Swedish district heating (DH) system. The gasification applications included in the study deliver heat to the DH network while producing renewable electricity or biofuels. Gasification applications included are: external superheater for steam from waste incineration (waste boost, WB), gas engine CHP (BIGGE), combined cycle CHP (BIGCC) and production of synthetic natural gas (SNG) for use as transportation fuel. Six scenarios are used, employing two time-perspectives - short-term and medium-term - and differing in economic input data, investment options and technical system. To evaluate the economic performance an optimisation model is used to identify the most profitable alternatives regarding investments and plant operation while meeting the DH demand. This study shows that introducing biomass gasification in the DH system will lead to economic benefits for the DH supplier as well as reduce global CO_2 emissions. Biomass gasification significantly increases the potential for production of high value products (electricity or SNG) in the DH system. However, which form of investment that is most profitable is shown to be highly dependent on the level of policy instruments for biofuels and renewable electricity. Biomass gasification applications can thus be highly interesting for DH suppliers in the future, and may be a vital measure to reach the 2020 targets for greenhouse gases and renewable energy, given continued technology development and long-term policy instruments.

Keywords: Biomass gasification; District heating; Optimisation; Global CO_2 emissions; Energy system; Biorefinery

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Nomenclature	
BIGCC	Biomass integrated gasification combined cycle
BIGGE	Biomass integrated gasification gas engine
CHP	Combined heat and power
DH	District heating
FGHR	Flue gas heat recovery
HOB	Heat-only boiler
LHV	Lower heating value
MILP	Mixed integer linear programming
MIND method	Method for analysis of industrial energy systems
NGCC	Natural gas combined cycle
TEP	Tradable CO_2 emission permits
TGC-El	Tradable green certificates for electricity
TGC-Fuel	Tradable green certificates for transportation fuels
TVAB	Tekniska Verken Linköping AB
SNG	Synthetic natural gas
WB	Waste boost

1. Introduction

With increasing concern for greenhouse gas emissions and anthropogenic climate change, interest in renewable energy resources is considerable. This is evidenced by for example the EU renewable energy directive, which imposes a target of a 20% share of energy from renewable sources, with a mandatory minimum share of 10% renewable energy in the transportation sector [1]. Biomass is expected to play a major role in reaching the target, in particular but not only, for member states with large forest resources, as is the case in Sweden for example. Since the supply of biomass is limited, efficient use is essential. Biomass gasification has been on the agenda as a means of efficient utilisation of biomass for more than 20 years. Initially, the focus was primarily on electricity generation since biomass gasification enables higher electrical efficiency than what is possible in combustion based processes. In recent years, the focus has shifted towards synthesis of liquid or gaseous biofuels[1], since while combustion limits the range of biomass applications to heat and electricity production, gasification also offers the possibility to upgrade biomass to high value biofuels or other chemicals. Today, biomass gasification is regarded as one of the key technologies for future biorefineries where biomass will be converted into fuels, power and value-added chemicals.

District heating (DH) offers opportunities to both decrease the use of fossil fuels for space heating and to achieve high total energy conversion efficiency. The best known example of the latter is combined heat and power (CHP) production, which is recognised by the European Parliament as a way to increase the energy

[1] In this paper the term biofuel is used to denote renewable transportation fuels.

efficiency of energy systems and to reduce global CO_2 emissions [2]. Biomass gasification with combined cycle CHP enables a higher power-to-heat ratio than conventional combustion with steam cycle technology, yielding more electricity produced for a given DH demand. For future full-scale biofuel production a significant amount of the energy content in the biomass can be recovered as low-grade heat, suitable for use in DH systems for example. Broad implementation of gasification based biofuel production in European DH systems is discussed by Berndes et al. [3], who conclude that if the 2020 target for biofuels would be met by gasification based fuels, the total heat sink of the EU DH systems would be large compared to the amount of heat delivered from the biofuel plants.

In an earlier study by some of the authors of this papers [4] it was found that the municipal DH system of Linköping, Sweden needs investments in new production capacity to be able to meet an increased heat demand with existing profitability margins. These results initiated this study, where possible new investments in biomass gasification for the DH supplier are evaluated.

The aim of this paper is to study how biomass gasification applications can offer interesting investment options for DH suppliers. Profitability for the DH supplier as well as consequences for global CO_2 emissions, are evaluated using Linköping as a case, with two different time perspectives – short-term (around 2010) and medium-term (around 2025). The analysis presented is made for Swedish conditions, but the results can be assumed to be similar for other regions with comparable conditions.

2. Biomass gasification

Gasification is thermo-chemical conversion of carbonaceous material into a combustible gas through partial oxidation. Depending on the type of gasifier, the gasification agent and subsequent cleaning and upgrading, the properties of the produced synthesis gas can be very different. For an overview, see e.g. [5–9]. Biomass gasification applications range from heat only, through electricity or CHP production in gas engines or combined cycles, to synthesis of biofuels, such as Fischer-Tropsch diesel (FTD) [10], dimethyl ether (DME) [11], methanol [12] or synthetic natural gas (SNG) [13]. Some gasification applications are commercially available today while others are still at the research or demonstration stage. A number of technical hurdles exist that need to be overcome for large-scale advanced gasification applications to be commercially available. Examples are tar formation, gas clean-up, high pressure feeding systems, availability and handling of mixed feed stocks. Process scale-up and high capital costs also constitute obstacles.

Biomass gasification applications for integration in DH systems have been investigated in several studies. Dornburg and Faaij [14] compare a number of biomass combustion and gasification technologies and conclude that the studied gasification technologies perform better than the combustion technologies, both economically and with respect to energy conversion performance. Fahlén and Ahlgren [15] study options for different levels of integration of biomass gasification with an existing NGCC[2] CHP plant, both for CHP production and for production of biofuels. They show that the profitability is highly dependent on the DH system's production mix, the price relation between biomass and fossil fuels and the cost of policy instruments, such as tradable green certificates for electricity and biofuels. Marbe et al. [16] compare biomass based CHP based on conventional steam turbine technology with biomass integrated gasification combined cycle (BIGCC) CHP. They conclude that BIGCC CHP has an economic advantage over conventional steam turbine CHP when the value of tradable green electricity certificates is high, but that BIGCC technology has limited operating flexibility as a result of a relatively high minimum load. Börjesson and Ahlgren [17] study the cost-effectiveness of biomass gasification applications in DH systems in the southwestern part of Sweden. Results from the study indicate that biomass gasification can be cost-competitive in DH systems, but that electricity prices and subsidy levels have large influence. Heat load size, annual operating hours and part load performance have been identified as key parameters for the economic performance of large-scale biomass gasification applications operating in DH systems [14–18].

2.1. Applications included in this work

The choice of biomass gasification applications to include in this study was made from publicly available data for gasification applications delivering heat to DH systems, using wood chips as feed stock. The availability of detailed application data was found to be low, which limited the selection. The size of the applications as well as the state of commercialisation differs. Technical data for the applications is presented in Table 1, while investment costs can be found in section 5.1. The four applications considered are:

- *Waste boost (WB).* The process, developed by Babcock & Wilcox Vølund, Denmark, is used to boost steam data for steam from waste incineration, to increase electrical efficiency. Wood chips are gasified in a fixed bed updraft atmospheric gasifier (36 MW biomass input) whereafter the gas is fired for superheating of steam from waste incineration, thus enabling electricity production (see Fig. 1). In this study the tar is assumed to be recirculated to the waste boiler. Studies of other options for the tar are currently being undertaken [19]. The updraft gasifier is a proven technology, and the waste boost application can be considered near commercialisation. In the studied case the external superheater is assumed to replace an oil fired gas turbine and heat recovery steam generator (see section 3.1). Process description and input data has been obtained from [19, 20]. Note that in this study the waste boiler and steam turbine already exist, resulting in a considerably lower investment cost than would otherwise be the case.

- *Biomass integrated gasification gas engine CHP (BIGGE).* In this process a biomass gasifier is connected to a gas engine. Several gasification tech-

[2] Natural gas combined cycle.

nologies are possible. For the scale range desired in this study (8–50 MW biomass input) the process demonstrated in Güssing, Austria was deemed appropriate[3]. The Güssing process is based on gasification of wood chips in a dual-bed fluidised atmospheric gasifier, using steam as gasification agent, followed by cooling, cleaning and firing in a gas engine for CHP production. The process has been described in e.g. [21, 22]. The process has been successfully demonstrated and can be considered near commercialisation. Input data has been obtained from the literature [22, 23] and from Vienna University of Technology, Austria [24].

- *Biomass integrated gasification combined cycle CHP (BIGCC).* In this process the gas engine is replaced by a combined cycle. The process chosen for this study has been demonstrated in Värnamo, Sweden [25–27]. Wood chips are gasified in a pressurised (approximately 20 bar) circulating fluidised bed gasifier, using air as gasification medium. After hot gas cleaning the gas is fired in a gas turbine combined cycle CHP unit. The power-to-heat ratio is considerably higher in the combined cycle process than in the gas engine process. Commercialisation on the large scale considered in this study still lies rather far in the future.

- *Co-production of synthetic natural gas (SNG) and DH heat* in a biorefinery. A number of different biofuels can be synthesised from gasified biomass (see section 2). Since the studied city already has a well developed biogas system, SNG was chosen for this study[4]. A process designed within the Biokombi Rya project [28] is considered, where gasification in a pressurised, oxygen blown circulating fluidised bed gasifier is followed by a high temperature filter, catalytic tar reforming, water gas shift and methanisation (see Fig. 2). Electricity is co-produced, but in insufficient quantities to cover the process demand. The chain from biomass to SNG has not yet been demonstrated full scale and as for BIGCC, commercialisation is still rather distant.

As a reference technology *conventional biomass fuelled steam turbine CHP (bio-CHP)* is also included as an investment option.

The practical upper limit of biomass feed is here estimated to be approximately 300 MW, which is in line with estimates in e.g. [14, 16]. Thus, for the large-scale new investment options – BIGCC, SNG and bio-CHP – the maximum size considered is 300 MW biomass input. According to the local DH supplier ([20], see section 3), the required amount of biomass for applications of this size would be available in the region studied. The fuel for all new investments is assumed to be wood chips with a lower heating value of 2.6 MWh/tonne.

[3]It should be noted that the Güssing process could be scaled up above 50 MW, but for this study a medium-scale application was desired as a complement to the waste boost and the large-scale applications.

[4]Upgraded biogas and SNG both consist of methane and can be mixed in any proportions.

Table 1: Performance for the new applications considered in this study [19, 20, 22–24, 27, 28, 41, 42, 51]. All efficiencies concern LHV (lower heating value) of fuel at full plant load.

		Efficiency			
	Biomass input (MW)	Electricity	DH heat	SNG	Total
Bio-CHP small	20–160	0.30	0.81	–	1.1[a]
Bio-CHP large	160–300	0.34	0.74	–	1.1[a]
Waste boost	113[b]	0.18	0.69	–	0.87
BIGGE CHP	8–50	0.20	0.52	–	0.72
BIGCC CHP	20–300	0.43	0.47	–	0.90
SNG	150–300	-0.04	0.23	0.69	0.92

[a]With flue gas heat recovery

[b]36 MW biomass, 77 MW waste

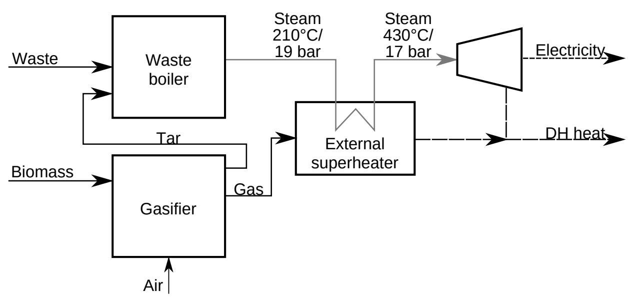

Figure 1: Schematic overview of the waste boost process.

As has been mentioned, part load operation performance has been identified as a key parameter for the profitability of large-scale biomass gasification plants [16, 18]. In this study the minimum acceptable part load, based on biomass input, is assumed to be 60% for all gasification applications and 50% for the bio-CHP. Efficiencies are for the purposes of this study assumed to be constant for part load operation.

3. Case study

The DH system considered is situated in the Linköping area. The city of Linköping, located about 200 km south west of Stockholm, has a population of about 140,000 inhabitants which makes it Sweden's fifth largest city. The municipally owned Tekniska Verken Linköping AB (TVAB) is the local DH supplier in the Linköping area. Besides residential heat, TVAB also delivers heat and process steam to a number of industries. The annual production (2007) of DH heat and steam is about 1,700 GWh and the maximum heat demand is approximately 500 MW. In Fig. 3 the annual load duration curve for the DH system is shown.

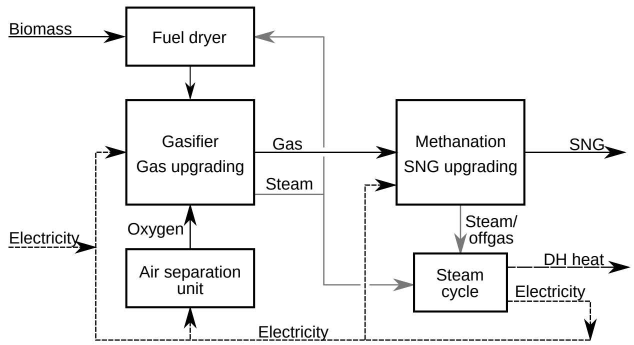

Figure 2: Schematic overview of the SNG process.

Besides the DH system, a district cooling network is also managed by TVAB. The annual district cooling demand is approximately 30 GWh with a maximum cooling load of 30 MW. 60% of the district cooling is supplied by heat driven absorption cooling, utilising heat from the DH system. The remainder is supplied by free cooling and compression cooling.

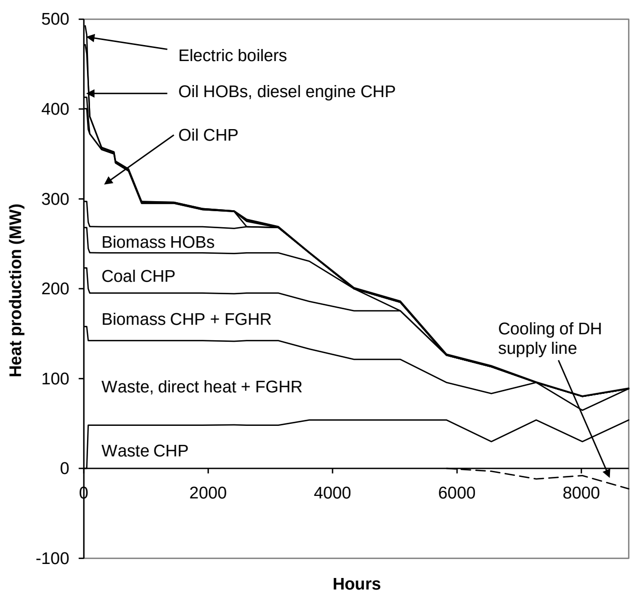

Figure 3: Annual load duration curve for the Linköping DH system (2007).

3.1. Current energy system (short-term time perspective)

As can be seen in Fig. 3, the base production is waste incineration. The waste incineration plant consists of two parts. The first is a modern CHP plant with a steam turbine for electricity generation and flue gas heat recovery (FGHR). When the heat demand is high the steam turbine can be bypassed and the steam condensed to produce DH heat only. The second part is a hybrid CHP plant where steam from waste incineration is superheated with the flue gases from an oil-fired gas turbine. The superheated steam is expanded through a steam turbine. The oil-fired gas turbine is connected to the same generator as the steam turbine. It is therefore not possible to produce electricity in the hybrid CHP plant if the gas turbine is not operating. Here too a direct condenser can be used for heat only production. When the gas turbine was initially installed oil prices were low, which made operation profitable. Today, however, with high oil prices, the gas turbine is rarely operated. Since a certain amount of waste must be processed annually there is a minimum load that must be met for the operation of the waste incineration plants. During maintenance and when the heat demand is low, waste can be stored temporarily.

Besides the waste incineration plants there are both other CHP plants and a number of heat-only boilers (HOBs) in the system, giving the system a high degree of fuel flexibility. The DH supplier also has the option to cool the DH network supply line. Today this option is used during the summer to increase electricity production. Technical data for the existing utilities is shown in Table 2.

Table 2: Technical data for the existing utilities in the Linköping DH system. FGHR = flue gas heat recovery, ST = steam turbine, GT = gas turbine. All efficiencies are annual averages for LHV of fuel.

			Efficiency (at full load)			
Technical utility	Size (input)	FGHR/ Economiser	Electricity	DH heat	Total	Comments
Waste CHP	70 MW	14 MW	0.22/0[a]	0.85/1.1[a]	1.1	Steam from waste incineration to CHP ST, or to direct condenser for heat only production.
Waste hybrid CHP	77 MW waste, 76 MW oil	10 MW	0.31/0[b]	0.59/1.0[b]	0.9/1.0[b]	Fluegases from oil-fired GT superheats steam from waste incineration for expansion in CHP ST. If GT is not running, condensing of steam for heat only production, without passing ST, is also possible.
Coal CHP	63 MW	4 MW	0.19/0.27/0[c]	0.73/0/0.92[c]	0.92	Coal, oil and biomass boiler connected to common steam line.
Oil CHP	150 MW		0.20/0.28/0[c]	0.71/0/0.91[c]	0.91	The steam can be expanded in CHP ST or condensing ST, or
Biomass CHP	60 MW	15 MW	0.18/0.26/0[c]	0.91/0/1.1[c]	1.1	condensed for heat only.
Diesel engines	31 MW		0.39	0.41	0.8	CHP production in two oil-fuelled diesel engines.
Biomass HOBs	42 MW			0.85	0.85	
Oil HOBs	280 MW			0.85	0.85	
Electric boilers	25 MW			0.98	0.98	
Recoolers	45 MW					Cooling of DH supply line for increased electricity production during summer.

[a] Efficiencies for production of CHP/heat only, respectively
[b] Efficiencies when GT is used/not used, respectively
[c] Efficiencies for production of CHP/condensing power/heat only, respectively

3.2. Future energy system (medium-term time perspective)

By 2025 the energy system is likely to have changed. The coal CHP and the biomass CHP plants are planned to be taken out of operation since they will reach their maximum technical lifetime [20]. Furthermore, the DH demand is forecast to increase annually by 1%, while the heat demand for the heat driven absorption cooling is forecast to increase by about 3% annually, giving a new DH demand for 2025 of about 1,900 GWh [20]. The combination of plants taken out of operation and an increased heat demand will result in the need for investment in new heat production units for the DH supplier.

3.3. Scenario description

Six different biomass gasification scenarios are modelled to analyse the effect of variations in e.g. fuel prices and prices of tradable CO_2 emission permits on the profitability of biomass gasification applications in the DH system. Two time perspectives are used, short-term and medium-term, where scenario 1 has a short-term perspective representing the current energy system described in section 3.1, and scenarios 2–6 have a medium-term perspective representing the future energy system described in section 3.2. The scenarios differ both in economic input data and to some extent in investment options. The scenario for the short-term perspective includes biomass gasification applications that are commercial or near commercialisation today (waste boost and BIGGE). In the scenarios for the medium-term perspective biomass gasification applications that are still at the development stage (BIGCC and SNG) are also included, as is the possibility to invest in a new bio-CHP. All new applications are associated with an investment cost and the optimisation model chooses the economically most profitable alternative(s).

The scenarios used in this study are presented in Table 3. For each scenario, a reference scenario without gasification options is modelled. In the reference scenario for the short-term perspective (scenario 1), the present DH system with existing plants and heat demand is modelled. For the reference scenarios for the medium-term perspective (scenario 2–6) the DH system is modelled with plants taken out of operation (see section 3.2) and the option to invest in a modern bio-CHP plant, a reference plant that is a realistic future investment for the energy company [20].

Scenarios 1–2 and corresponding reference scenarios use present levels for the prices of fuels and policy instruments, while scenarios 3–6 with reference scenarios use various future levels (see section 5.2). Two levels of fossil fuel prices are used for the future scenarios – low in scenarios 3–4 and high in scenarios 5–6[5]. Four different energy policies are included in this study: tradable CO_2 emission permits (TEP), tradable green electricity certificates (TGC-El), energy taxation and tradable biofuel certificates (TGC-Fuel). As with the fossil fuel prices, two levels of TEP are used, corresponding to different CO_2 reduction ambitions –

[5]For the low level, the reference prices from IEA's World Energy Outlook 2007 [29] are used and for the high level, market prices for the first quarter of 2008 are used.

low in scenarios 3 and 5 and high in scenarios 4 and 6. Also, two levels of TGC-El are used in the scenarios, with high TEP levels assumed to lead to low certificate prices [30].

The prices and policy instruments used are further described in section 5.2 and shown in detail in Tables A.1 and A.2 in Appendix Appendix A.

Table 3: Modelled scenarios with assumed time perspectives and possible investment options for each scenario, together with levels for fuel and policy instrument prices.

			Prices of fuels and policy instruments			
Scenario	Time perspective[a]	Investment options[b]	Fossil fuel	TEP	TGC-El	TGC-Fuel
1	short-term	A	current	current	current	no[c]
2	medium-term	B	current	current	current	no[c]
3	medium-term	B	low	low	high	no
4	medium-term	B	low	high	low	no
5	medium-term	B	high	low	high	yes
6	medium-term	B	high	high	low	yes

[a] *Short-term:* existing plants, current heat demand. *Medium-term:* CHP plants out of operation, future heat demand
[b] *A:* WB and BIGGE. *B:* WB, BIGGE, Bio-CHP, BIGCC and SNG
[c] Current tax exemption, see section 5.2

4. Methodology

An optimisation model is used to analyse the economic performance of integrating biomass gasification applications in a DH system. Different scenarios, described in section 3.3, are used to examine the influence of various input data, such as fuel prices and costs for policy instruments. In addition to economic performance, effects on global CO_2 emissions are also evaluated.

4.1. Optimisation model

A model of the DH system is constructed using the energy system optimisation tool MIND (Method for analysis of INDustrial energy systems). MIND is a method for optimisation of dynamic energy systems, based on mixed integer linear programming (MILP) [31]. Areas where MIND has been used include analysis of forest industry [32, 33], steel industry [34], and interaction between industries and DH networks [35, 36].

On general form[6] the MIND model can be described as

$$\min Z = f(x, y) \tag{1}$$

subject to

[6] An extensive description of the equation formulation of the MIND method is given by Sandberg [37].

$$
\begin{aligned}
g(x,y) &= 0 \\
h(x,y) &\leq C \\
x \geq 0; y &\in \{0,1\}
\end{aligned}
\tag{2}
$$

where x represent real variables, y represent binary variables used for logical restrictions and to linearise non-linear functions, and $f(x,y)$ is the objective function to be minimised (generally the system cost). $g(x,y) = 0$ are equations describing the performance of the energy system, for example the relation between the flow of material through a process and the corresponding energy demand. $h(x,y) \leq C$ are inequalities describing for example capacity limits in the system. The dynamics of the energy system are represented by a flexible time division, to visualise variations in for example prices and heat demand. When the model is run a set of equations are created and solved using an optimisation tool, usually CPLEX [38].

In the MIND model of the Linköping DH system, existing DH production plants are included as well as possible investment options. The plants are described in the model by maximum capacity, efficiency, power-to-heat ratio, minimum acceptable load and maintenance period. One year, divided into 29 time steps, is modelled. For each of the winter months November through March three time steps are modelled: (1) days, (2) nights along with weekends and (3) peak day. For the remainder of the year each month is divided into two steps: (1) days and (2) nights along with weekends. The model is shown schematically in Fig. 4.

4.1.1. Evaluation of economic performance

The objective of the optimisation model is to minimise the annual system cost for the modelled system while meeting the demand for heat and steam, by choosing the best alternatives regarding investments and plant operation. Included in the system cost are costs for investments, fuel, electricity and maintenance, as well as revenues for sold electricity and biofuel (including tradable green certificates). Investment costs are discounted using the annuity method. In this study an interest rate of 6% and an economic plant life time of 20 years are used [20], giving a capital recovery factor of 0.087.

Results from the optimisation indicate which investments are profitable and how existing and new plants should operate.

The economic performance of the system in each of the six scenarios is compared to that of the corresponding reference scenario, i.e. the system cost of each scenario is subtracted from the system cost of the reference scenario.

4.2. Evaluation of effect on global fossil CO_2 emissions

The potential reduction of global fossil CO_2 emissions is evaluated by assuming that flows of energy and material entering or leaving the local energy system cause a change in the surrounding global system. Incineration of fuels in

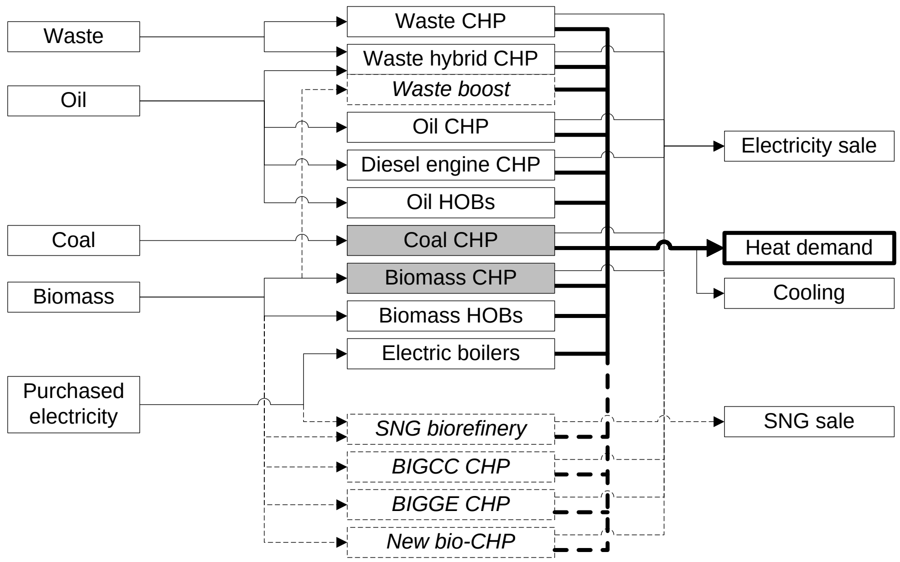

Figure 4: Overview of the MIND model of the Linköping DH system. Dashed lines and italicised text indicate investment options. Shaded boxes indicate existing plants planned to be taken out of operation (see section 3.2). The heat demand needs to be met, which is indicated by bold lines.

the DH production facilities cause local CO_2 emissions, while the products from the system, i.e. electricity and SNG, replace marginal electricity or alternative transportation fuels, causing a decrease in global CO_2 emissions.

The total CO_2 emissions are calculated as:

$$E_{global} = E_{local} - (F_{el}N_{el} + F_{SNG}N_{SNG}) \tag{3}$$

where E_{local} are the actual emissions from the operating plants in the local energy system, and F_{el} and F_{SNG} are the CO_2 emission factors from replaced electricity and transportation fuel, respectively, N_{el} is the electricity production and N_{SNG} is the production of SNG. The CO_2 emission factors used are shown in Table 4.

In this paper a tool for creating consistent energy market scenarios, developed by Axelsson et al. [39] was used to generate CO_2 emission factors for electricity. The marginal electricity production differs between the scenarios. In [39] consequences for global fossil CO_2 emissions from biomass use are discussed. In this study, however, biomass is assumed to be CO_2 neutral. The scenario tool is further described in section 5.2.

For transportation it is assumed that produced SNG will be used in gas hybrid passenger vehicles, with a fuel consumption of 39 kWh/100 km, and that these replace gasoline hybrid vehicles with a fuel consumption of 45 kWh/100 km, emitting 120 g CO_2/km [40].

As with the economic performance the CO_2 emissions from each scenario are evaluated in relation to the emissions from the corresponding reference scenario.

Table 4: Fossil CO_2 emission factors (kg CO_2/MWh) [39, 40, 52, 53].

	Scenario					
	1	2	3	4	5	6
Oil	295	295	295	295	295	295
Coal	340	340	340	340	340	340
Waste[a]	90	90	90	90	90	90
Biomass	0	0	0	0	0	0
Electricity	974[b]	723[c]	723[c]	136[d]	723[c]	374[e]
SNG	310	310	310	310	310	310

[a] CO_2 emissions from fossil fraction of waste
[b] Coal condensing power, electrical efficiency 0.35
[c] Coal condensing power, electrical efficiency 0.47
[d] Coal condensing power with carbon capture and storage, electrical efficiency 0.35
[e] NGCC, electric efficiency 0.58

5. Input data

5.1. New investments

The investment options considered in this study were described in section 2.1. Investment cost data for the new investment options is presented in Table 5. For the BIGCC all publicly available investment cost data was found to be several years old. The BIGCC investment cost was adjusted using the assumption that the cost increase for BIGCC since 2000 is equivalent to the cost increase of conventional biomass fuelled steam turbine CHP for the same period, an increase of almost 100% [41, 42].

For all applications except the waste boost the plants are assumed to be scalable. The energy efficiencies are assumed to be the same as for the base size over the entire scale range. Investments costs are scaled using the general relationship:

$$\frac{C}{C_{base}} = \left[\frac{S}{S_{base}}\right]^R \tag{4}$$

where C and S represent the investment cost and plant capacity respectively for the new plant, C_{base} the known investment cost for a certain capacity S_{base}, and R is the scale-up factor. In this study a scale-up factor of 0.7, the average value for chemical process plants [43], is used for all scalable applications. Eq. 4 is linearised in discrete steps before implementation in the MILP optimisation model.

A maximum of one of each type of investment is allowed in the model.

Table 5: Investment costs for the new applications considered in this study [19, 20, 22–24, 27, 28, 41, 42, 51].

	Biomass input (MW)	Electricity/SNG output (MW)	Inv. cost (MEURO)	Specific inv. cost ($EUR/kW_{el/SNG}$)
Bio-CHP small	100	30	89	3,000
Bio-CHP large	235	80	183	2,300
Waste boost	113[a]	20	13	–[b]
BIGGE CHP	8.9	1.8	15	8,300
BIGCC CHP	116	50	117	1,900
SNG	242	173	230	1,300

[a] 36 MW biomass, 77 MW waste

[b] No specific cost is given, since the investment cost is for the gasifier and superheater only, as described in section 2.1

5.2. Prices and policy instruments

The prices and policy instruments used in this study are presented in Tables A.1 and A.2 in Appendix Appendix A. A short description of key assumptions is given below.

For scenarios 1–2 and corresponding reference scenarios, prices and policy instruments for 2008 are used. For scenarios 3–6 future energy market scenarios with interdependent parameters were created using the tool devised by Axelsson et al. [39] mentioned in section 4.2. The tool calculates marginal prices for electricity and biomass, as well as various end user fuel prices. Inputs to the tool are fossil fuel prices and costs associated with various policy instruments. The tool was initially developed to create scenarios for the energy intensive industry and has in this paper been adapted to be suitable for the DH sector. Input data to the tool has been updated from [39], to reflect recent developments in the energy market.

In scenarios 1–2 and corresponding reference scenarios electricity prices vary over the year and not over the day, reflecting the current electricity market situation in Sweden. For scenarios 3–6 it is assumed that Swedish electricity prices will converge towards European prices, with prices fluctuating over the day which is typical of a power dimensioned system (see e.g. [44]). Electricity prices generated by the scenario tool are assumed to constitute base load electricity prices and are used as off-peak prices (weekdays 6 pm–6 am and weekends). For the peak hour prices (weekdays 6 am–6 pm) the off-peak prices are multiplied by a factor of 1.7, which is an average of the relation between peak and off-peak electricity prices on the European market (2004-2005) [45].

SNG is assumed to have a price at the filling station equivalent to the price of petrol. Distribution of the SNG to the filling station is assumed to take place either using existing infrastructure for biogas distribution or as LNG (liquefied natural gas) at a cost of 21 EUR/MWh [46]. Today the main policy for promotion of renewable fuels in Sweden is tax exemption. Several policy instruments are possible for the future, among them tradable certificates similar to the certificates for green electricity (for an overview of biofuel support policies, see e.g.

[47, 48]). In this study TGC-Fuel are assumed to be in place in scenarios 5–6. It is assumed that the current tax exemption is removed in scenarios 3–6, and that biofuels will be subject to energy tax.

Energy taxation is often excluded from energy system studies because of their national limitations. Studies of DH systems, however, are of a local nature and taxes play a significant role as regards economic performance. In this study taxes are therefore included in all scenarios. Today energy taxation in Sweden consists of energy tax, CO_2 tax, sulphur tax and an NO_x charge. The tax levels vary depending on applications, with tax reductions for CHP production as well as for plants included in the CO_2 trading scheme. For scenarios 3–6 and corresponding reference scenarios the taxes are adjusted for changes expected to come into effect in 2010 [49].

6. Results

6.1. New investments

As has been described the optimisation model chooses the most profitable alternatives as regards new investments and plant operation[7]. In Table 6 the resulting new investments are presented. For each new investment the optimal build size (biomass input) as given by the optimisation model is shown. For scenarios 2–6 the alternative to new investments is operation of expensive plants such as oil HOBs as compensation for the loss in heat output when base load plants are taken out of operation, which makes large new investments profitable. Neither the maximum size of BIGCC nor SNG can alone substitute the removed heat output for the plants taken out of operation; only the bio-CHP plant has enough heat output.

For all reference scenarios (besides reference scenario 1 where no investments are possible), the optimisation model chooses to build a 220 MW bio-CHP.

Table 6: New investments in the modelled scenarios. Figures indicate biomass input to the new plants.

Scenario	Bio-CHP	WB	BIGGE	BIGCC	SNG
1		113 MW[a]			
2	118 MW	113 MW[a]			300 MW
3	77 MW	113 MW[a]		300 MW	
4	100 MW			268 MW	
5				300 MW	300 MW
6	170 MW				300 MW

[a] 36 MW biomass, 77 MW waste

[7] See Table 3 for possible investment options in each scenario.

6.2. Heat production

The production of heat in the scenarios is shown in Fig. 5. The heat production mix differs between the scenarios depending on the investments made. Interestingly, even though waste has a negative purchase cost the high added value of the gasification plant products (electricity and/or SNG) makes the heat from new gasification investments competitive even with the base load waste heat. However, since a certain minimum amount of waste has to be processed annually, the heat production from the waste plants remains relatively constant in the different scenarios. In the scenarios where the WB is built (scenarios 1–3) heat from the WB replaces direct or CHP heat produced in the hybrid CHP plant. The input of waste to the hybrid CHP, however, remains essentially unchanged.

As can be seen in Fig. 5 the heat production mix in reference scenarios 2–6, where 220 MW bioful CHP plants are built, is very similar.

In all of the scenarios, heat is removed in the recooler to achieve more electricity and/or SNG production. In scenarios 2–6 the cooling is substantial (up to 15% of total annual heat production).

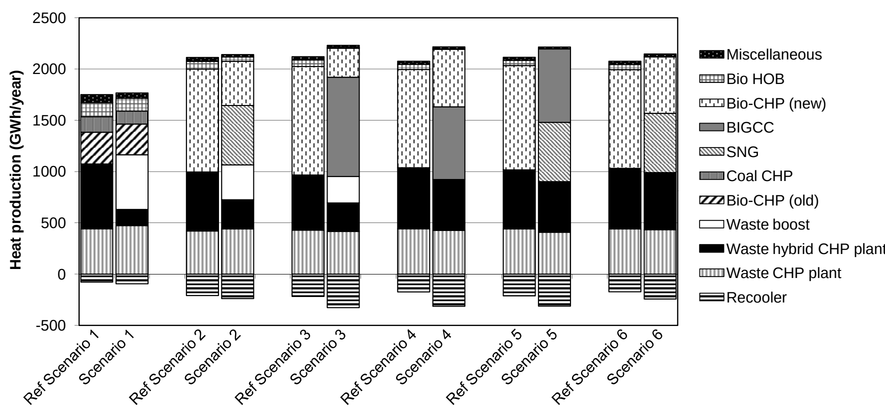

Figure 5: Annual heat production in the modelled scenarios. “Miscellaneous” includes oil CHP, diesel engine CHP, and oil and electricity HOBs. Note that for scenario 1, the current heat load is modelled while for scenarios 2–6 a future heat load is used (see section 3.1 and 3.2).

6.3. Electricity and SNG production

Fig. 6 shows the production of electricity and SNG in the scenarios. Depending on the investments, the electricity and SNG production in the modelled scenarios differ, with the electricity production in the scenario with the highest electricity production (scenario 3) almost three times as high as in scenario 2, the scenario with the lowest electricity production (excluding reference scenarios). In all scenarios except scenarios 2 and 6, the electricity production is significantly higher than in the corresponding reference scenarios. In the scenarios where the SNG is built (scenarios 2, 5 and 6), the electricity production is lower than in the scenarios where only the BIGCC is built since the process for producing SNG consumes electricity. On the other hand, SNG is produced instead of electricity.

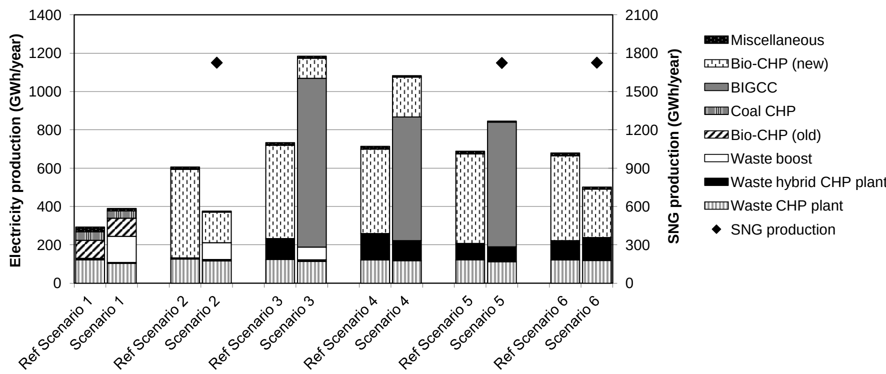

Figure 6: Annual production of electricity and SNG in the modelled scenarios. "Miscellaneous" includes oil CHP and diesel engine CHP.

6.4. *System costs and global CO_2 emissions*

In Fig. 7 the results from the evaluation of economic performance and of global CO_2 emissions are shown. As has been described in sections 4.1.1 and 4.2 system cost and CO_2 emissions for each scenario are evaluated in relation to the corresponding reference scenario. For all scenarios, the difference in system cost compared to the respective reference scenario is negative, implying that the scenarios where gasification applications are included are more cost-effective than the reference scenarios without gasification applications. Economically best performing are the scenarios where the SNG is built (scenarios 2, 5 and 6). The system cost is also negative in absolute figures for all scenarios, which indicates that the revenue from the electricity and/or SNG production is higher than the variable costs for producing DH heat.

As can be seen in Fig. 7 the difference in global CO_2 emissions between the respective scenario and reference scenario is negative for all scenarios, indicating larger reductions of global CO_2 emissions when gasification applications are included in the system compared to the reference scenarios without gasification options. The largest CO_2 reduction is achieved in scenario 5 where both SNG and BIGCC are built and the marginal electricity production is coal condensing power (see Table 4), giving a substantial CO_2 reduction for the additionally generated electricity compared to the reference scenario. The smallest CO_2 reduction is achieved in scenario 4, due to a low emitting marginal electricity production (coal condensing power with carbon capture and storage). Since biomass is considered CO_2 neutral, no CO_2 penalty is applied for the large additional quantities of biomass used in the gasification scenarios compared to the reference scenarios.

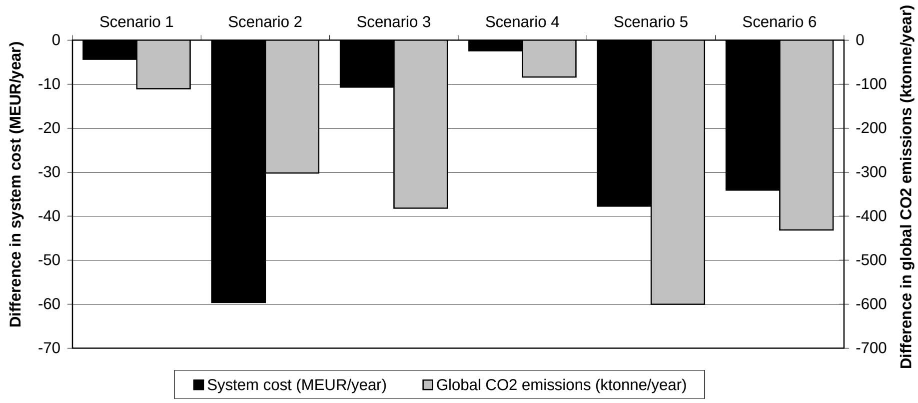

Figure 7: Relative system cost and global CO_2 emissions for the scenarios, compared to their respective reference scenarios.

6.5. Sensitivity analysis

The future energy market scenarios with interdependent parameters provide a form of sensitivity analysis on prices and policy instrument levels. To verify the robustness of the results from each scenario further sensitivity analysis was conducted on parameters identified as essential. Further analysis was made by:

- Increasing annual capital costs
- Decreasing annual capital cost for the BIGGE
- Increasing electric and overall efficiencies for the BIGGE
- Varying TGC-El levels
- Varying TGC-Fuel levels
- Leaving the old CHP plants in place, with current and future DH loads
- Removing the cooling option

The results of the sensitivity analysis are summarised in Table B.1 in Appendix Appendix B[8]. In the table, vertical arrows (up or down) indicate that a plant that was not built in the original optimisation run is built in the sensitivity analysis run, or vice versa for a plant that was built originally. Slanting arrows indicate change in build size or net revenue, respectively.

The sensitivity analysis shows that the waste boost is a very robust solution when the TGC-El level and oil prices are both relatively high, and that the

[8]More optimisation runs than are presented in Table B.1 were made but are omitted from the presentation for space reasons.

investment remains even with significantly increased annual capital cost. With higher electricity prices and lower TGC-El and oil prices the existing gas turbine becomes competitive. With small price variations, however, the waste boost replaces the gas turbine[9].

A thorough analysis was made of the BIGGE in scenario 1. The analysis shows that the investment cost needs to be greatly reduced for the BIGGE to be built. Analysis was also made with higher electrical and overall efficiencies. An efficiency increase in itself was not enough; a decrease in capital cost was also needed.

If the coal and biomass CHP plants are not taken out of operation, the biomass gasification applications are still profitable, while investments in a new bio-CHP are reduced or removed. Removing the cooling possibility did not affect the choice of types of new investments, but in general the optimum size was slightly smaller and the annual operating hours were reduced.

Since the type of optimal new investments differs between the scenarios, with conflicts on the one hand between BIGCC and SNG, and on the other hand between BIGCC and bio-CHP, additional analysis of the influence of electricity price on heat production cost was made. The net heat production cost was calculated for the BIGCC, SNG and bio-CHP plants, including revenues from electricity and biofuel as well as annual capital cost and annual fuel costs. The plant sizes considered were 300 MW biomass input for BIGCC and SNG respectively, and 220 MW for bio-CHP. For the BIGCC and bio-CHP an annual operating time of 4,500 h was used while for the SNG 7,500 h was used[10]. The results for two different biomass prices and three different SNG prices are shown in Fig. 8.

For high SNG prices (85 EUR), high electricity prices are needed to make electricity production more profitable than SNG production. The SNG and BIGCC plants that use more biomass to produce the same amount of heat are more sensitive to a higher biomass price than the bio-CHP. When the biomass price increases the bio-CHP is competitive with the BIGCC up to a higher electricity price. For SNG the situation is the opposite; when the biomass price increases heat from the SNG plant becomes less competitive with heat from the electricity producing plants. The figures verify the results from the sensitivity analysis where it was shown that the choice between bio-CHP and BIGCC was not very robust. In the diagrams it is evident that the biomass prices used in this study give a break-point between bio-CHP and BIGCC around the electricity price levels used. In general it is clear that the SNG price needs to be high for the heat from the SNG plant to be competitive with the heat from the electricity producing plants. This is especially evident when biomass prices increase.

[9] Not shown in Table B.1

[10] Plant sizes and annual operating time were chosen after analysis of the optimisation results.

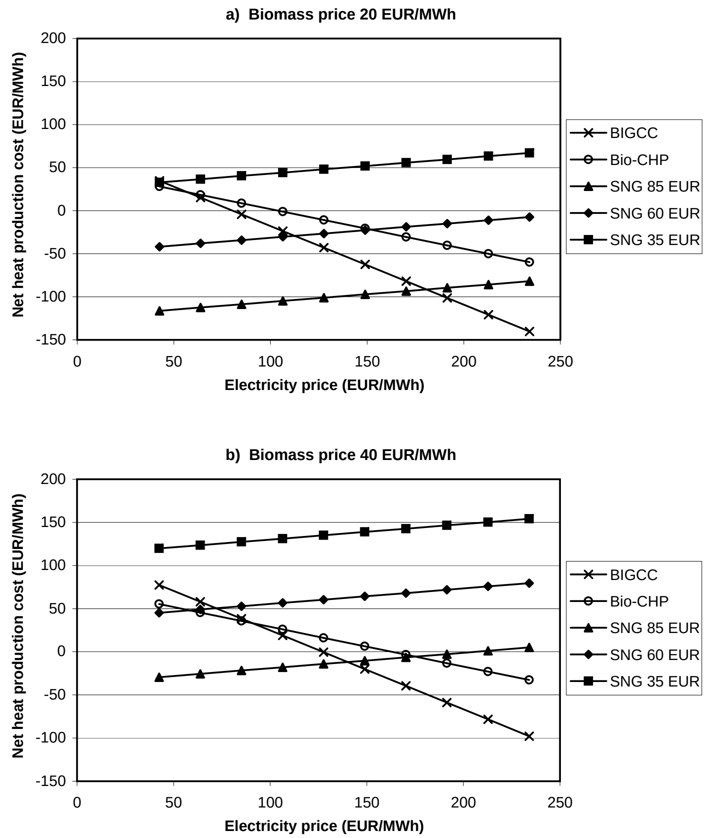

Figure 8: Net heat production cost for different technologies as a function of electricity price, for a biomass price of a) 20 EUR/MWh and b) 40 EUR/MWh. Electricity and SNG prices include tradable green certificates.

6.6. Verification and validation

The optimisation tool MIND has been continuously verified during its development. For this study, the functioning of the MIND models representing the DH system has been verified continuously throughout the construction of the model and the final model output has been checked thoroughly for errors.

The final model of the current energy system has been validated against real operation data from the DH supplier TVAB. For each month the modelled heat demand has been validated to ensure that the modelled monthly heat demand is equivalent to the actual monthly heat demand. The modelled plant operations have been comprehensively checked against real operation data, showing that the modelled operation is consistent with real operation data. Both input data and model output have been discussed with representatives of TVAB to ensure realistic results.

7. Discussion

In this paper the effects on the DH system in Linköping when introducing the possibility to invest in different biomass gasification applications have been studied using an optimisation model. The studied DH system is in its current design characterised by a high degree of flexibility and a rather large waste incineration base load production that covers more than 50% of the annual heat demand. Despite the negative purchase cost of waste the heat from new gasification plants to a certain extent outcompetes the waste incineration heat. However, since a minimum amount of waste must be processed annually this effect was not very pronounced.

For the scenario with a short-term time perspective (scenario 1) the waste boost was shown to be a very robust solution, leading to increased electricity production, increased revenues for the DH supplier and a potential for decreased global CO_2 emissions. For the scenarios with a medium-term time perspective (scenarios 2–6), the results show that production of SNG only becomes profitable when policy instruments promoting biofuels (tax exemption in scenario 2 and TGC-Fuel in scenarios 5–6) are included. Since the price levels in scenario 2 are in fact based on today's levels, the conclusion can be drawn that the SNG plant would be profitable already today. The levels of TGC-Fuel assumed was enough to prove SNG production as a robust solution, insensitive to increases in annual capital cost.

Annual operating hours and part load performance have been described as important parameters for the profitability of large-scale gasification applications. In this study the minimum part load was fixed at 60% for all gasification applications. The operating hours were not fixed but determined by the optimisation model. In no scenario has the operating time of a new plant been lower than 4,000 hours, and in most cases significantly over this. For the SNG plant the operating time was never below 7,600 hours.

For all the scenarios where biomass gasification applications are built, the amount of biomass used to fulfil the heat demand is higher than in the respective reference scenario without gasification applications. This phenomenon can especially be identified for the scenarios where SNG is built. For this study, biomass is considered a renewable energy source with no net emissions of CO_2 but since the amount of biomass is limited, an alternative use of biomass should be considered. Alternative use of biomass is not included in this study but will be considered in future work.

The largest uncertainty as regards the results is that the applications are still under development, with commercialisation for in particular BIGCC and SNG in the fairly remote future, which makes both investment costs and expected efficiencies uncertain. Another limitation is that the maximum size of BIGCC and SNG plants was assumed to be 300 MW biomass feed. Only one plant of each type was allowed. In most of the scenarios where those plants were built the optimisation model chose to include the largest size possible. For neither the BIGCC nor the SNG was the heat delivery enough to satisfy the DH demand, which led to additional investments in new production capacity, in most cases in the form of a bio-CHP. The results indicate that larger sizes of the BIGCC and the SNG could be even more profitable.

8. Conclusions

The results from this study show that biomass gasification applications are interesting investment options for the local DH supplier, Tekniska Verken in Linköping. Not only are the scenarios where gasification applications are included more cost-effective than the reference scenario without gasification applications, but the potential reduction of global CO_2 emissions is also greater for the gasification scenarios. The major conclusions of this paper are:

- The large-scale gasification applications, BIGCC and SNG, have both been shown to be economically profitable and advantageous from a CO_2 emission perspective. Which is most profitable was shown to be highly dependent on the level of policy instruments for electricity and biofuels. Since the investments are very capital intensive with a high financial risk for the DH supplier, long-term policy instruments are of utmost importance.

- The potential for production of high value products (electricity and SNG) is significantly higher for a given heat demand when biomass gasification is included.

- The global CO_2 emission reduction potential for the system studied is larger when gasification applications are included.

- For the system studied, the removal of old production capacity and an increase in heat load were not prerequisites for investments in gasification applications to be profitable.

- The high added value of the products from the gasification applications (electricity and SNG) makes heat from these plants competitive even with heat from waste incineration, where the fuel has a negative purchase cost.

- For the short-term future the waste boost technology was shown to be profitable, leading to increased electricity production and reduced global CO_2 emissions. At current prices the pay-off time of the investment would be less than three years. For the more distant future it is a more uncertain solution, since high electricity prices render the existing solution with an oil-fired gas turbine more cost-effective.

- The BIGGE included in this study was shown not to be profitable due to high investment cost and low efficiency.

While the economic results as well as the potential for reduction in global CO_2 emissions are of course only valid for the studied case a general conclusion that, given continued technology development, biomass gasification applications will be highly interesting for DH suppliers in the future can be drawn. Commercialisation of the large-scale gasification applications included in this study still lies, however, rather far in the future. The results presented in this paper show that there are considerable incentives for continued and accelerated development.

To reach the energy targets for 2020 set by the European Council [50] biomass gasification applications can be a step on the way. For the next generation of biofuels, such as SNG, the large amount of heat generated must be utilised in a resourceful way which makes a biorefinery with a DH system or another heat sink a necessity. But to attain this, long-term policy instruments promoting biofuels are necessary, as this paper has shown. The EU also promotes increased CHP production as a means to reach higher energy efficiencies [2]. BIGCC CHP, with substantially higher electrical efficiency than conventional bio-CHP, could therefore be an option in realising the targets for primary energy savings, security of supply and increased use of renewable energy sources. As for SNG, long-term policies are required.

9. Further work

One of the main conclusions of this paper was that long-term policy instruments for promotion of biofuels are essential for investments in large-scale gasification plants for production of biofuels to be realised. Thorough analysis to determine suitable instruments and necessary levels is therefore required. In this paper only one form of biorefinery for production of biofuels was considered. In future work other product mixes, including more flexible mixes, will be considered. Also, means to increase the DH heat load, in particular the summer load, will be studied.

The CO_2 analysis made in this paper was rather simplified. In a coming paper a more detailed analysis of the potential to decrease global CO_2 emissions using biomass gasification will be made, taking for example the limitations on biomass supply into consideration.

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Appendix A. Prices and policy instruments

Table A.1: Fuel and electricity prices used in the scenarios.

	Scenario					
	1	2	3	4	5	6
Fuel prices (EUR/MWh)[a]						
Light fuel oil	41	41	38	38	52	52
Heavy fuel oil	31	31	31	31	42	42
Coal	12	12	6	6	12	12
Wood chips	17	17	18	26	24	33
Wood byproduct	14	14	15	22	21	28
Waste wood	9	9	9	13	12	17
Waste	-16	-16	-16	-16	-16	-16
Electricity price (EUR/MWh)[b]						
Off-peak hours	48[c]	48[c]	58	68	70	82
Peak hours	48[c]	48[c]	99	116	119	139
SNG price (EUR/MWh)						
Gate price[d]	77	77	33	39	47	53
SNG distribution cost	21	21	21	21	21	21

[a]Fuel prices excluding CO_2 charge
[b]Electricity prices including CO_2 charge
[c]Annual average
[d]TGC-Fuel not included

Table A.2: Policy instrument levels used in the scenarios.

		Scenario					
		1	2	3	4	5	6
TEP[a]	EUR/tonne	21	21	27	48	27	48
TGC-El[b]	EUR/MWh	23	23	16	5	16	5
TGC-El quota	%	16.3	16.3	11.2	11.2	11.2	11.2
TGC-Fuel[c]	EUR/MWh	0	0	0	0	29	35
Taxation on fuels[d] (heat only/CHP heat)							
Light fuel oil	EUR/MWh	37/4.6	37/4.6	35/2.1	35/2.1	35/2.1	35/2.1
Heavy fuel oil	EUR/MWh	35/5.3	35/5.3	33/3.1	33/3.1	33/3.1	33/3.1
Coal	EUR/MWh	38/5.4	38/5.4	35/2.6	35/2.6	35/2.6	35/2.6
Waste	EUR/MWh	14/2.1	14/2.1	13/0.99	13/0.99	13/0.99	13/0.99
Taxation on electricity							
Industrial use	EUR/MWh	0.53	0.53	0.53	0.53	0.53	0.53
Other use	EUR/MWh	29	29	29	29	29	29
Taxation on transportation fuel							
SNG	EUR/MWh	0	0	33	33	33	33

[a]Tradable CO_2 emission permits
[b]Tradable green certificates for electricity
[c]Tradable green certificates for biofuels
[d]Includes energy tax, CO_2 tax and sulphur tax

Appendix B. Sensitivity analysis results

Table B.1: Results from the sensitivity analysis. Arrows indicate change in build size and net revenue for the DH supplier, where net revenue is the profit for the DH supplier.

Scenario	Parameter variation	Bio-CHP	WB	BIGGE	BIGCC	SNG	Net revenue
1	*Base case*		*113 MW*				
	Waste boost inv. cost +200%		→				↘
	BIGGE inv. cost -75%		→	↑			↗
	BIGGE η_{el} +50%, η_{tot} +10%, inv.cost -50%		→	↑			↗
	No cooling possibility		→				↘
2	*Base case*	*118 MW*	*113 MW*			*300 MW*	
	Waste boost inv. cost +100%	→	→			→	↘
	Bio-CHP inv. cost + 50%	↓	→		↑	→	↘
	SNG inv. cost +200%	→	→			→	↘
	SNG price -50%	↓	→		↑	↓	↘
	Old CHP still in place, current DH load	↓	→			→	↗
	Old CHP still in place, future DH load	↘	→			→	↗
	No cooling possibility	↘	→			→	↘
3	*Base case*	*77 MW*	*113 MW*		*300 MW*		
	Waste boost inv. cost +50%	↗	↓		→		↘
	Bio-CHP inv. cost +50%	↓	→		→		↘
	BIGCC inv. cost +50%	↗	→		↓		↘
	BIGCC inv. cost +50%, TGC-El +50%	↗	↓		→		↘
	Old CHP still in place, pres./fut. DH load	↓	→		→		↗
	No cooling possibility	↘	↓		→		↘
4	*Base case*	*100 MW*			*268 MW*		
	Bio-CHP inv. cost +50%	↓	↑		↗		↘
	BIGCC inv. cost +25%	↗	↑		↓		↘
	BIGCC inv. cost +50%, TGC-El +400%	→			↗		↗
	Old CHP still in place, current DH load	↓	↑		↘		↗
	Old CHP still in place, future DH load	↓	↑		↗		↗
	No cooling possibility	↘			↘		↘
5	*Base case*				*300 MW*	*300 MW*	
	BIGCC inv. cost +50%	↑	↑		↓	→	↘
	SNG inv. cost +100%				→	→	↘
	TGC-Fuel -75%	↑	↑		→	↓	↘
	TGC-Fuel -50%, TGC-El +100%	↑			→	↓	↘
	Old CHP still in place, current DH load				↘	→	↗
	Old CHP still in place, future DH load				→	→	↗
	No cooling possibility				↘	→	↘
6	*Base case*	*170 MW*				*300 MW*	
	Bio-CHP inv. cost +50%	↓			↑	→	↘
	SNG inv. cost +100%	→				→	↘
	TGC-Fuel -75%	↘	↑		↑	↓	↘
	TGC-El +100%	↓			↑	→	↗
	Old CHP still in place, current DH load	↘				→	↗
	Old CHP still in place, future DH load	↓			↑	→	↗
	No cooling possibility	↘	↑			→	↘