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BECCS with combined heat and power: Assessing the energy penalty

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ABSTRACT

Bio-energy with carbon capture and storage (BECCS) is widely recognised as an important carbon dioxide removal technology. Nevertheless, BECCS has mostly failed to move beyond small-scale demonstration units. One main factor is the energy penalty incurred on power plants. In previous studies, this penalty has been determined to be 37.2 %–48.6 % for the amine capture technology. The aim of this study is to quantify the energy penalty for adding the hot potassium carbonate (HPC) capture technology to a biomass-fired combined heat and power (CHP) plant, connected to a district heating system. In this context, the energy driving the capture process is partly recovered as useful district heating. Therefore, a modified energy penalty is proposed, with the inclusion of recovered heat. This inclusion is especially meaningful if the heat has a substantial monetary value. The BECCS system is examined using thermodynamic analysis, coupled with modelling of the capture process in Aspen Plus™. Model validation is performed with data from a BECCS test facility. The results of this study show that the modified energy penalty is in the range of 2%–4%. These findings could potentially increase the attractiveness of BECCS as a climate abatement option in a district heating CHP setting.

1. Introduction

Apart from afforestation and reforestation, the most recognised of the carbon dioxide removal technologies (CDRTs) is bio-energy with carbon capture and storage (BECCS) (IPCC, 2014). This technology captures and permanently stores the CO_2 released from the energy conversion of biomass, such as the CO_2 emitted from power stations (Kemper, 2015). Although BECCS is an important technology for climate change mitigation (Gregory et al., 2018), its deployment has thus far failed to move beyond small-scale demonstration units (Gough et al., 2018). A limited number of ethanol plants are an exception (Global CCS Institute, 2019). This failure can be attributed to technological and financial (Clarke et al., 2014), social (Honegger and Reiner, 2017), political (Fridahl, 2017) and ecological challenges (Hoegh-Guldberg and Hijioka, 2018). If BECCS is to be realised at scale, the thresholds of these challenges must be lowered.

The most significant challenge to the implementation of BECCS at bio-energy plants is the considerable investment cost and operational cost of carbon capture and storage (CCS) (Budinis et al., 2018). The need to withdraw low-grade steam and electricity to operate BECCS at a power plant is particularly prohibitory, as it will incur an energy penalty and lower the overall efficiency of the power plant (Page et al., 2009). If the energy could be recovered and utilised, the cost of implementing BECCS could be lowered (Bui et al., 2017b).

Out of the plethora of potential carbon capture technologies, few are ready for implementation. In fact, the only technology that has been found to be ready for deployment at power stations is post-combustion absorption (Bui et al., 2018). Consequently, the only two full-scale CCS plants in operation at power stations both use this technique (Mumford et al., 2015). Post-combustion technologies have the major advantage of being suitable for retrofitting to existing point sources of CO_2 (Mumford et al., 2015). The concept of retrofitting bio-energy plants has an appealing aspect: namely, that the energy conversion part of BECCS is already in place. Hence, the time for deployment could be shorter and the investment cost lower than for a new, complete BECCS deployments.

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At present, research on BECCS within the energy sector is largely limited to power generation (Bhave et al., 2017; Cabral et al., 2019; Emenike et al., 2020), often in combination with the amine absorption technology (Budinis et al., 2018; Bui et al., 2017a; Pour et al., 2018; Sanchez and Callaway, 2016; Skorek-Osikowska et al., 2017), despite the tendency of amine absorbents to degrade in an oxidative environment (Borhani et al., 2015). As for how to perform energy integration between a carbon capture process and an energy conversion plant, studies on electrical power plants, such as those by Harkin et al. (2011); Kather (2016) and Bui et al. (2017a), have examined this topic.

If the ambition of deploying BECCS is broadened to combined heat and power plants (CHPs), absorbents other than amines could be an option. Levihn et al. (2019) suggest that the hot potassium carbonate (HPC) technology could be viable, since it would reduce the cost for capture and liquefaction by 17 %. The main reason for this reduction is that the substantial energy requirement for flue gas compression, which is inherent to HPC technology, can be partly recovered as useful heat. Furthermore, a crucial advantage of HPC in the post-combustion application is the high resistance to oxidative degradation (Borhani et al., 2015). Previously, BECCS in CHPs has been studied in an industrial context, with a focus on part load and amine technology (Kuramochi et al., 2010). Unlike the case of power plants, energy integration between a CHP and a post-combustion carbon capture process has been little studied. This is surprising, since there is apparent potential for keeping the energy penalty at a low level by recovering useful heat. Ideally, this could lower the threshold for investments in BECCS and thereby increase its attractiveness as a climate mitigation option.

This study expands the BECCS research field into CHPs in the energy sector. The aim is to quantify the energy penalty of applying the HPC technology to a CHP plant in a district heating system.

2. The potassium carbonate process

The potassium carbonate process was developed in the 1940s–1960s at the U.S. Bureau of Mines (USBM) (Milidovich and Zbacknick, 2013). Co-workers Benson and Field produced the original publications on the process, such as an article by Benson et al. (1954). Hence, the process is also known as the Benfield process. The initial aim of the USBM was to facilitate cost-efficient removal of CO_2 and sulphuric compounds from synthesis gas, to allow for the production of liquid fuels from coal gasification (Milidovich and Zbacknick, 2013). Since then, the technology has been adopted for a number of different gas mixes (Speight, 2019). Worldwide, more than 700 units have been licenced based on the UOP Benfield™ technology, while at least another 150 units have been established with technologies from other companies (Smith et al., 2016).

The potassium carbonate process relies on a pressure difference (pressure swing) between the absorption and desorption of CO_2 (Smith et al., 2016). In the common application of synthesis gas purification, the feed gas is already highly pressurised. This allows the potassium carbonate process to operate at a temperature considerably above the atmospheric boiling point, which increases the reaction kinetics and lowers the energy demand (Smith et al., 2016). Due to the elevated temperature, the method has also become known as the hot potassium carbonate (HPC) process. Apart from the test facility described in this paper, which removes CO_2 from flue gases generated by biomass combustion, the HPC process has previously been demonstrated at pilot scale with flue gases from coal combustion (Mumford et al., 2012; Smith et al., 2014).

A simplified flow diagram of the Benfield process is shown in Fig. 1. The feed gas enters the bottom of the absorber where it meets the absorbent, in a counter-current flow. CO_2 is absorbed into the potassium carbonate solution, as shown in reaction (1) (Smith et al., 2016). Subsequent chemical reactions (2–5) trap the CO_2 in the solution. The resulting summary reaction (6) is exothermal.

$$CO_2\ (g) \rightleftharpoons CO_2\ (aq) \quad (1)$$

$$CO_2\ (aq) + OH^-\ (aq) \rightleftharpoons HCO_3^-\ (aq) \quad (2)$$

$$CO_2\ (aq) + H_2O\ (l) \rightleftharpoons H_2CO_3\ (aq) \quad (3)$$

$$H_2CO_3\ (aq) + H_2O\ (l) \rightleftharpoons HCO_3^-\ (aq) + H_3O^+\ (aq) \quad (4)$$

$$HCO_3^-\ (aq) + H_2O\ (l) \rightleftharpoons CO_3^{2-}\ (aq) + H_3O^+\ (aq) \quad (5)$$

$$CO_2\ (g) + CO_3^{2-}\ (aq) + H_2O\ (l) \rightleftharpoons 2HCO_3^-\ (aq) \quad (6)$$

The rich (loaded) absorbent leaves the absorber at the bottom and is depressurised before it enters the top part of the stripper. In the stripper, reaction (6) is reversed in part due to the lower pressure, which causes the CO_2 to transfer to the gas phase. The CO_2 leaving the top of the stripper contains water vapour, which is partly recovered in the condenser and brought back to the stripper.

Since the reversal of the absorption is endothermic, it is necessary to add thermal energy to the stripper. Heat is usually supplied through low-grade steam that condensates in the reboiler (Puxty and Maeder, 2016). The required amount of heat is called the heat duty (*qreb*) of the process, and is the sum of three terms (Oexmann and Kather, 2010):

$$qreb = qsens + qvap,H_2O + qabs,CO_2 \quad (7)$$

The first term (*qsens*) is the sensible heat for bringing the absorbent to the operating temperature of the stripper. For the HPC process, this term can be relatively low, as the process is often designed with similar temperatures in the absorber and the stripper (Smith et al., 2016). The second term ($qvap,H_2O$) is the heat required to evaporate the water that is mixed with the CO_2 leaving the column. This vaporisation of water is by far the most energy intense of the three terms (Kohl and Nielsen, 1997). The last term ($qabs,CO_2$) is the overall heat needed to break the chemical bonds created in the absorber and to enable the CO_2 to transfer to the gas phase – that is, to reverse the summary reaction (6). This third

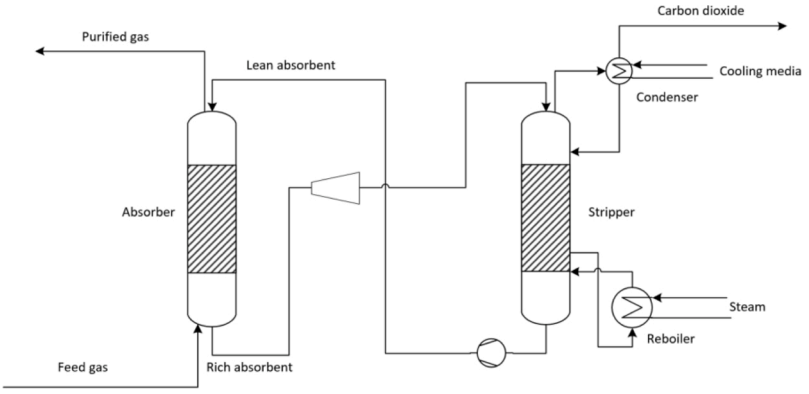

Fig. 1. A simplified illustration of the original Benfield process, adapted from Kohl and Nielsen (1997).

term is relatively small in the case of potassium carbonate, in comparison with other absorbents (Mumford et al., 2015).

3. Method

This paper is aimed at quantifying the energy penalty of adding carbon capture to a biomass-fired CHP plant connected to a district heating system. The applied methodology consisted of a thermodynamic analysis of the defined systems, coupled with modelling of the carbon capture processes in Aspen Plus. The results of the modelling were validated with experimental data from a test plant and from the literature. The method encompassed the following steps:

1) Defining the BECCS systems;
2) Defining the modified energy penalty and other performance indicators;
3) Collecting data on the CHP plant and the district heating system;
4) Modelling and simulating the full-scale carbon capture processes in Aspen Plus;
5) Validating the full-scale Aspen Plus capture models against test plant data and literature; and
6) Modelling the energy integration between the CHP and the CCS systems, including calculation of the energy penalty, other performance parameters and the cost-of-energy for the CO_2 capture.

The main analysis was performed on a defined base case with parameters from an existing CHP. Two different varieties of the carbon capture process were included in the base case: one basic concept and one more advanced concept. The reference case was the CHP plant without added carbon capture.

3.1. The BECCS systems

The two studied systems were limited to the CHP plant and the carbon capture equipment. The main components were the biomass-fired boiler, the flue gas cleaning equipment with condensation, the steam turbine, the carbon capture equipment including the compression of flue gases, and the CO_2 liquefaction plant (Fig. 2).

In Fig. 2, the parameters marked with (k) were kept constant, while the parameters marked with (δ) were varied between the BECCS system. Parameters marked with (δ) were varied within the analysis of each BECCS system. Unlike the fuel input, the district heating and electric power output varied. The variations in those outputs were mainly influenced by the variation of the steam and electric power need of the capture processes. For example, a high steam requirement resulted in a lower electric output, since less steam passed through the turbine. Similarly, a high need for electric power in the capture process yielded less electric output from the system. For the district heating output, the opposite was true. An increased need for steam and electric power gave a higher output of district heating, since more heat was recovered inside the capture process. The amount of captured CO_2 was constant due to unvarying fuel input and a fixed CO_2 capture rate (Eq. 16).

3.2. The energy penalty of carbon capture

Capturing CO_2 from the flue gases of an energy conversion plant requires energy input (Bui et al., 2017b). This results in a lowering of the net energy efficiency (η_{PPCC}) of the plant. For regular electric power generation plants with CCS, the net energy efficiency can be expressed as a percentage of the fuel lower heating value (LHV_f) (Cabral and Mac Dowell, 2017):

$$\eta_{PPCC} = 100 \cdot \frac{P_{PP} - P_{CC}}{m_f \times LHV_f} \tag{8}$$

where P_{PP} is the net electrical output from the power plant without carbon capture, P_{CC} is the electric output lost due to the capture process and m_f is the mass flow of the fuel. Note that the power used by the carbon capture process consists of two parts (Page et al., 2009). The first part is the electric power requirement of the capture process, which could be substantial for the HPC process, due to the reliance on elevated pressures for absorption. The second part is incurred by the steam that is withdrawn from the power plant turbine and utilised in the capture process, leading to a reduction of the electric power production.

There are two useful expressions for quantifying and comparing the energy cost of adding carbon capture at a power plant: the efficiency penalty and the energy penalty (Page et al., 2009). The efficiency penalty is an absolute expression:

$$Efficiency\ penalty = \eta_{PP} - \eta_{PPCC} \tag{9}$$

where η_{PP} is the net energy efficiency of the power plant without carbon capture. The energy penalty, on the other hand, is a relative expression:

$$Energy\ penalty = 100 \cdot \frac{P_{PP} - P_{PPCC}}{P_{PP}} \tag{10}$$

where P_{PPCC} is the electrical power output from the power plant after carbon capture has been attached.

While the Eqs. (9) and (10) are useful for studying plants producing

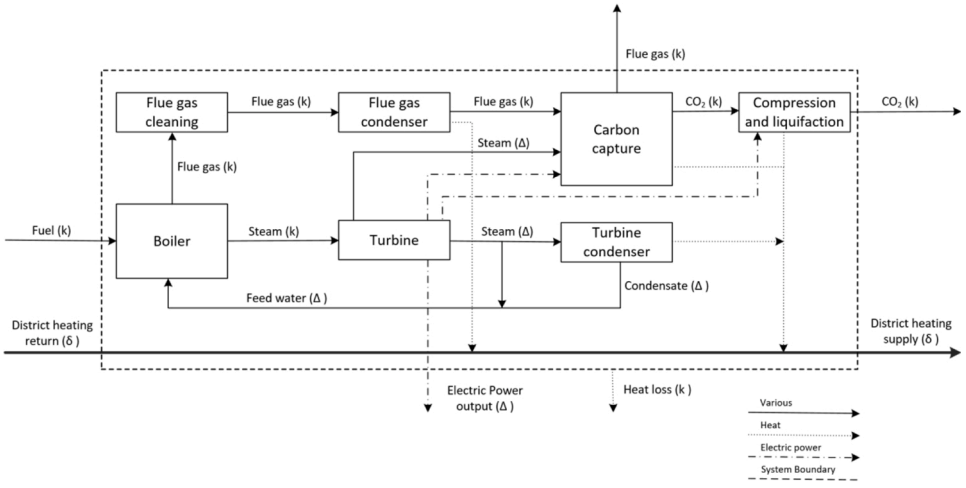

Fig. 2. The dashed box shows the limitation of the studied BECCS systems. The label (k) identifies streams with constant material and energy flows in the analysis, while (δ) identifies streams that were varied between the basic and advanced capture processes. District heating parameters, labelled with (δ), were varied within the analysis of each capture process.

only electric power, a modified definition of the net energy efficiency was required for this study. Since a CHP plant produces both electric power and heat, it was natural to incorporate heat into Eq. (8). This yielded an expression for the efficiency of a CHP plant with carbon capture, η_{CHPCC}:

$$\eta_{CHPCC} = \frac{P_{CHP} + Q_{CHP} - P_{CC} + Q_{rec}}{m_f \times LHV_f} \quad (11)$$

where P_{CHP} and Q_{CHP} are the net electrical and net heat output of the CHP plant without carbon capture, and Q_{rec} is the useful, recoverable heat from the capture process. Incorporating the heat into Eq. (11) is only meaningful if the heat has a monetary value and is of suitable quality – that is, has the required district heating supply temperature. Therefore, low-grade heat that would require heat pumps to meet the supply temperature was ignored when calculating recoverable heat. Furthermore, it was assumed that the lost electric power production can be supplied by other production units within the wider electric power system, and that the increased amount of heat produced can be utilised within the district heating system. In addition, only cases where the CHP operates at full load have been examined, i.e. part load operation has not been taken into consideration. From Eqs. (10) and (11), it follows that the energy penalty of a CHP plant with CCS can be expressed as:

$$CHP\ energy\ penalty = 100 \cdot \frac{P_{CHP} + Q_{CHP} - P_{CC} + Q_{rec}}{P_{CHP} + Q_{CHP}} \quad (12)$$

In an effort to provide a complete set of performance indicators, the following metrics were also included: the efficiency penalty of a CHP with CCS (Eq. 13); the net electrical efficiency for a CHP with CCS ($\eta_{el,net\ CHPCC}$) (Eq. 14); and the preservation of electric power output from the CHP after adding CCS (Eq. 15).

$$CHP\ efficiency\ penalty = \eta_{CHP} - \eta_{CHPCC} \quad (13)$$

$$\eta el, net\ CHPCC = \frac{P_{CHP} - P_{CC}}{m_f \times LHV_f} \quad (14)$$

$$HP\ power\ preservation = \frac{P_{CHPCC}}{P_{CHP}} \quad (15)$$

3.3. The CHP plant and the district heating system

The analysis of the energy penalty was made on an existing CHP. Such an approach was considered to make the results of the study less theoretical, and follows the line of thought of Page et al. (2009). A CHP plant situated in Stockholm was chosen. The plant, known as CHP 8, generates heat for the city's district heating network, as well as electric power. It should be noted that for CHP 8 there are few restrictions regarding the prioritisation between production of heat and production of electric power, except for process characteristics such as the alpha value and the turbine minimum load. There is, for example, no need to supply a specific amount of electricity at all times. Therefore, the operational mode can be gradually switched from heat and power production to heat only, at the cost of power production at a rate of 1:1 (Levihn, 2017). Moreover, a CHP plant typically operates as a base load unit if situated in a district heating system, which normally allows the produced heat to be fully utilised. The fuel used in CHP 8 is wood chips, which are produced from secondary biomass derived from forestry residues. The plant was deemed especially suitable since CHP 8 is being considered for full-scale BECCS (Gustafsson, 2018). As a further advantage, there is a test facility for carbon capture installed at the plant. This test facility was utilised for validation of the full-scale Aspen Plus models in this study.

The data on CHP 8 (Table 1) were mostly taken from the performance tests (Stockholm Exergi, 2016). The data are appropriate to use, since a performance test is a special period of operation during which all noteworthy performance parameters are documented with a higher degree of precision. Moreover, it is conducted by a third party, thus ensuring an impartial evaluation of the plant performance. However, flue gas composition data were taken as the measured yearly average (Stockholm Exergi, 2019). The measurement was performed continuously, by analysing the flue gases leaving the plant through the stack. This approach ensured a representative flue gas composition, since it took fuel variations into account.

Table 1
Data on CHP 8.

Parameter			Note
Fuel type[1]	Wood chips		
Fuel input (LHV) [1]	362.1	MW	
Fuel heating value (LHV) [1]	8.1	MJ/kg	As received, including moisture
Steam temperature[1]	558	°C	
Steam pressure[1]	13.6	MPa	
Flue gas flow, 3.4 % O_2, dry gas (dg) [1]	437,760	Nm^3/h	Reference: 0 °C, 101.32 kPa
Flue gas temperature, out from CHP 8[1]	39	°C	After flue gas condensation (FGC)
Turbine electrical power output, gross[1]	124.8	MW	From generator
Turbine condenser heat output[1]	207.9	MW	
Flue gas condenser heat output	79	MW	Calculated
District heating temperature, into turbine condenser[1]	59	°C	
District heating temperature, out of turbinecondenser[1]	81	°C	
Flue gas composition, wet gas (wg):			After FGC
Carbon dioxide[2]	17.8	vol%	
Oxygen[2]	2.1	vol%	
Water[2]	6.1	vol%	
Nitrogen and inert gases[2]	74.0	vol%	

References: [1] Stockholm Exergi (2016), [2]Stockholm Exergi (2019).

In this study, a generalised district heating system was chosen for the analysis, instead of a specific system. The motivation for this choice was to generate results that are more widely applicable. Therefore, Swedish average temperature levels were chosen for the base case (Table 2). To broaden the perspective even further, an analysis was performed of the impact of different district heating temperature levels (Table 2) on the energy penalty.

Concerning the district heating flow rates, it was supposed that the CHP plant was part of a site with additional production units (Fig. 3). More specifically, it was assumed that heat pumps or similar low-grade heat production units were available. The function of such units is partly to supply sufficient flow of district heating water at the right temperature level to the turbine condenser and partly to add flexibility into the system. In addition, it was assumed that a heat-only boiler (HOB) was available to increase the district heating temperature from turbine condenser output level to supply level. The functionality provided by these units is certainly needed to optimise the performance of a CHP plant, irrespective of the addition of CCS. For example, if there is no

Table 2
District heating temperature levels.

Parameter			Note
Base case			
District heating return[1]	47	°C	Swedish average
District heating supply[1]	86	°C	Swedish average
Low case			
District heating return[1]	43	°C	Danish average
District heating supply[1]	78	°C	Danish average
High case			
District heating return[2]	55	°C	Basel 2025
District heating supply[2]	100	°C	Basel 2025

References: [1] (Gadd and Werner, 2014), [2] (iwb, 2020).

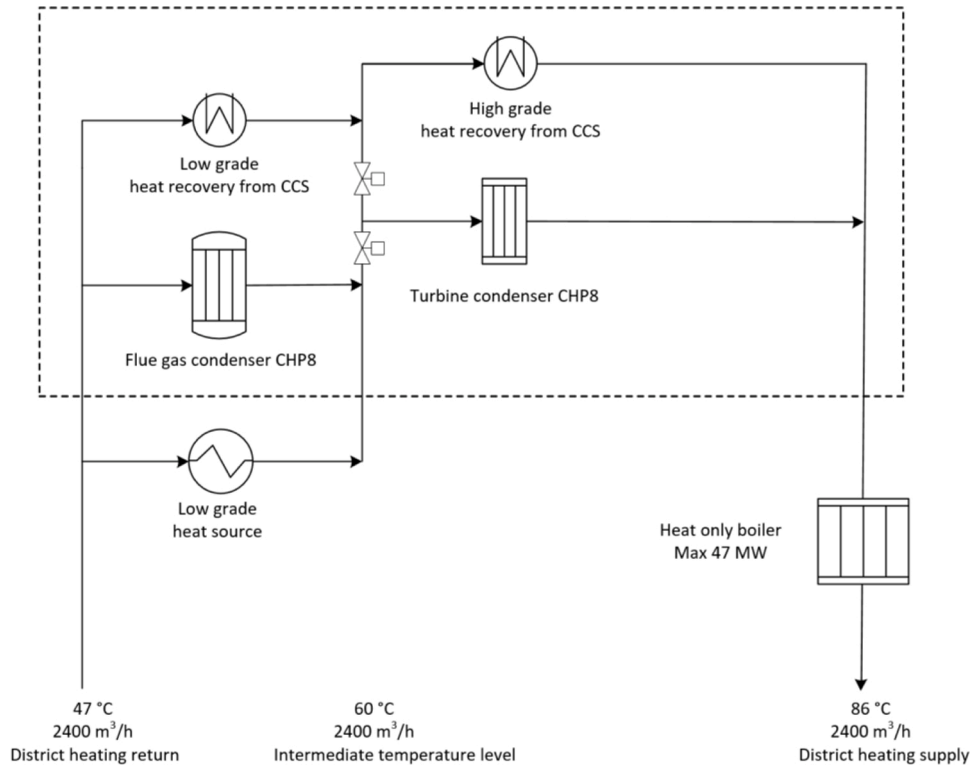

Fig. 3. The generalised district heating system, with the studied system in the dashed box. The numbers that are presented applies to the base case.

HOB, the district heating temperature from the turbine condenser would have to be increased to meet the supply temperature. In effect, this would reduce the possible electric power production from the turbine. Overall, the system in Fig. 3 is representative of the production optimisation of advanced urban multi-energy carrier systems (Levihn, 2017).

The adjoining production units were not part of the studied system when calculating the energy penalty. Instead, they were used for examining adverse effects that could render the results of the study invalid. Therefore, during the calculations, checks were performed to ensure that the low-grade heat source and the HOB were not utilised beyond the need for the reference case without CCS. To clarify further, it was a boundary condition of the base case that recovering heat from the CCS system should not require adding excessive amounts of heat at unreasonable temperature levels. Fig. 3 shows the district heating supply temperature that had to be met regardless of adding CCS to the system. Unlike the base case, the further analysis of the impact of district heating temperatures on the energy penalty allowed the HOB to be utilised beyond its usage in the reference case. This, in order to understand the effects of district heating temperatures on HOB utilisation.

Regarding the operational priority within the system, the performance of the BECCS plant was calculated first. Thereafter, the low-grade heat source and the HOB were adjusted to meet the required flows and temperature levels.

Table 2 summarises the various district heating temperatures. Apart from the base case, the impact on the energy penalty of a low- and a high-temperature district heating network was analysed. The low-temperature case was taken as the Danish average and the high-temperature case was taken from Basel, in Switzerland. The Basel district heating network represents a system that is moving towards lower temperatures – in this case, from the second to the third generation, as defined by Lund et al. (2018). The chosen temperatures for Basel are the expected values for 2025, after the development of the system (iwb, 2020).

3.4. Modelling and simulation of the carbon capture process

Aspen Plus was used to simulate a full-scale HPC carbon capture plant. The choice of Aspen Plus was partly motivated by its dominance in simulations of steady-state carbon capture systems in published scientific papers (Tumilar et al., 2016).

For this study, an equilibrium model adjusted with the Murphree Efficiency (ME) was used for the absorber. The rationale for using this simpler type of model was that the purpose of the simulations was not to design the internals of the absorber and the stripper, which would require a rate-based model (Isa et al., 2018), but rather to generate data for the overall mass and energy balance of the capture plant. For this purpose, an equilibrium model has been found to serve well (Fosbøl et al., 2017). Moreover, Wu et al. (2018) and Ooi (2008) have shown that an equilibrium model can generate valid results when compared with a rate-based model, if adjusted with the ME. The ME was acquired from the test plant trials, as explained in section 3.5.

In Aspen Plus, two different full-scale potassium carbonate system were modelled, one basic (Fig. 4a) and one more advanced (Fig. 4b). The aim of modelling two systems was to understand how efficiency enhancements of the capture system would affect the energy penalty and other performance indicators. The ambition was to quantify a performance difference between the process configurations, not necessarily to find the optimal configurations. The simulations were performed using the Aspen Plus in-built electrolyte non-random two-liquid (ENRTL) model, which is widely accepted among researchers (Isa et al., 2018).

The major difference between the basic and advanced systems was that the latter was equipped with lean vapour compression (Kohl and Nielsen, 1997). This is a common measure for reducing the heat duty by partly generating steam within the capture process itself, thus lowering the steam requirement for the reboiler. Steam generation is achieved by flashing the lean absorbent and compressing the vapour phase before injecting it back into the stripper.

For the basic capture system, the function of the absorber and stripper was similar to the simple system (Fig. 1). However, the

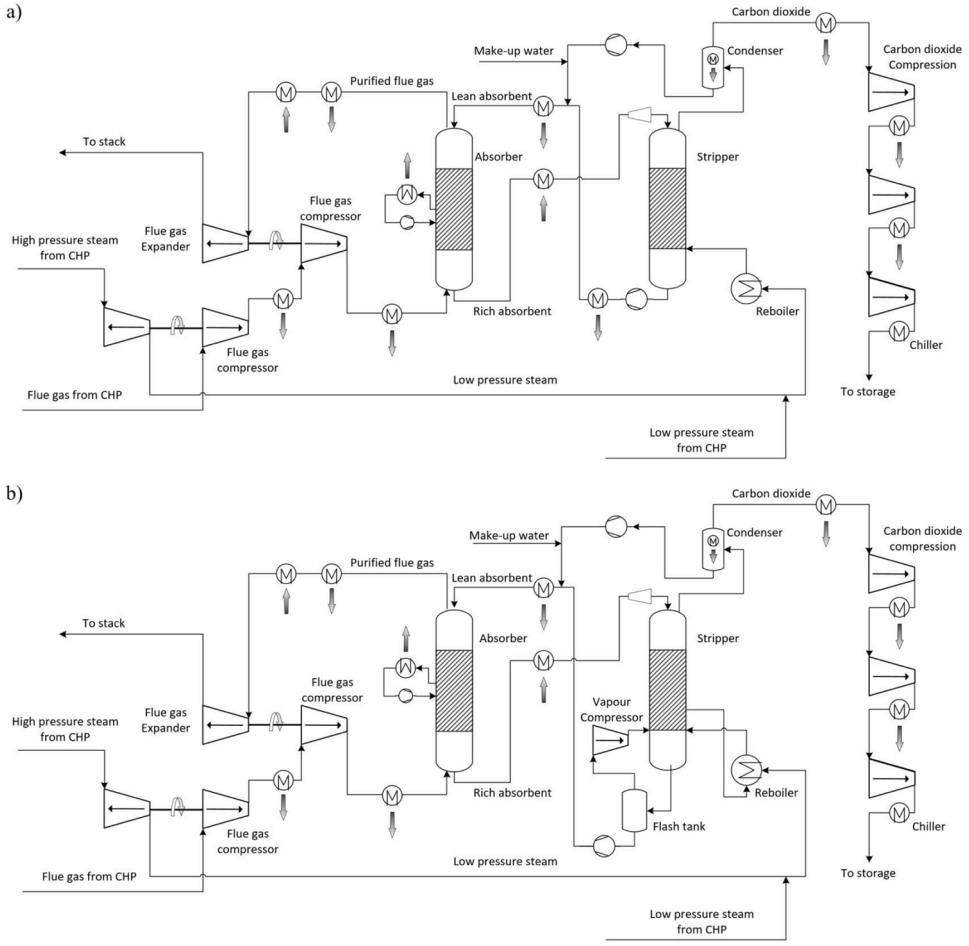

Fig. 4. The simulated a) basic and b) advanced carbon capture processes. The process streams from which heat can potentially be recovered at district heating temperature levels are marked with arrows pointing out of the heat exchanger symbol. Where heat input is required, the arrows point into the heat exchanger symbol.

condensate water from the flash tank was returned directly to the lean absorbent, instead of being returned to the stripper. Another modification was intercooling of the absorber, which was added to increase the loading capacity of the absorbent and to avoid excessive water vaporisation from the absorber top.

Since absorption is done at elevated pressure, it was necessary to include compression of the flue gases in the simulations. The pressure increase was simulated as two stages, which reduces the energy need due to the intercooling between the compressors. Moreover, this opened up the possibility of driving the compressors with energy carriers other than electricity, since the individual compressors were then of a suitable size to fit in-system available energy carriers. The first compressor was driven by a high-pressure steam turbine, with steam supplied from the CHP. The outlet, low-pressure (0.4 MPa) saturated steam, was used as part of the energy for the reboiler. The second compressor was driven by the flue gas expander, which recovers energy from the purified flue gases.

The compression and liquefaction of the captured CO_2 was designed similarly to a process modelled by Cabral and Mac Dowell (2017), with a three-step compression with intercooling. The CO_2 was pressurised to 1.6 MPa and cooled down below −26 °C, for storage and further transport. The pressure and temperature data are consistent with the preliminary requirements for Northern Lights, the geological storage site outside Norway, which is currently being developed (Equinor, 2020).

The simulations in Aspen Plus were performed with the requirement of achieving 90 % CO_2 removal. The target was set based on the findings of Harkin et al. (2011), which show that the heat duty increases drastically beyond a 90 % capture rate. The expression for the capture rate is shown in Eq. (16), which has been adapted from the work of Mumford et al. (2012).

$$Capture\ rate = 100 \cdot \frac{CO_2\ flow\ out\ from\ stripper}{CO_2\ flow\ in\ feed\ gas} \tag{16}$$

To give some initial stability to the Aspen Plus model and to avoid too wide of an approach, the absorbent strength was fixed to 30 wt% K_2CO_3. Kohl and Nielsen (1997) conclude that this is the recommended solution strength, if unwanted precipitation of salts is to be avoided. The strength of the potassium carbonate solution will influence the amount of CO_2 that can be captured at a given flow rate, as shown by Tosh (1959). This is an important aspect, since lowering the liquid-to-gas ratio (L/G) in the absorber generally lowers the required reboiler heat duty. This can be derived from Eq. (7), where q_{sens} will increase with a higher flowrate of absorbent.

To achieve a low L/G while simultaneously reaching a certain capture rate, a satisfactory loading of the absorbent with CO_2 must be accomplished. The loading is expressed as follows (Wu et al., 2018):

$$Loading = \frac{mole\ of\ CO_2\ absorbed}{mole\ of\ K_2CO_3\ in\ absorbent} = \frac{[HCO_3-]}{[K+]} \tag{17}$$

Apart from the data on solution strength, there is little conclusive data in the literature for designing post-combustion absorption with potassium carbonate. Studies by Bohloul et al. (2014) and Bohloul et al. (2017) are two exceptions. These studies indicate that, from an absorption capacity perspective, the optimal pressure in the absorber is around 0.6–0.8 MPa. Higher pressures provide little added effect in terms of capacity. Another limitation was to keep the lean solvent

loading above 18 %. Harkin et al. (2011) found that below this value the reboiler heat duty increases rapidly.

With these starting points, balancing of the capture process was done in the Aspen Plus model by varying design parameters, using the in-built sensitivity tool. The varied parameters were primarily the lean solvent inlet temperature, lean solvent loading, L/G, absorber pressure and number of stages in the absorber. The strategy for designing the absorber was to keep the L/G low, in order to decrease the reboiler heat duty and thus the steam consumption. This strategy was justified since the goal was to reach a fixed capture rate, with the column size being one of the variables. Others have employed a different approach, for example Harkin et al. (2011) and Artanto et al. (2012), where the absorber was fixed and the optimum heat duty was sought by allowing the capture rate, among other parameters, to vary.

It should be noted that the absorber pressure and temperature for post-combustion absorption will have to be substantially lower than those for traditional acid gas removal. In the latter application, the feed gas is inherently pressurised to 3–6 MPa (Borhani et al., 2015). Such a high pressure provides a sufficient driving force to dissolve CO_2 even at high temperatures close to the boiling point of the absorbent, at 100–140 °C. For post-combustion, the pressure must be lower to avoid spending an unreasonable amount of energy on compressing the flue gases. From this, it follows that the absorber temperature must be reduced in order to provide an adequate net driving force to dissolve CO_2.

3.5. Validation of the Aspen Plus models with data from the test plant and the literature

In this study, test plant trials were performed to obtain a valid ME for adjustment of the full-scale Aspen Plus equilibrium models, a procedure recommended by (Ooi, 2008). The test plant used in this case was commissioned in December 2019 by the utility company Stockholm Exergi. It is located at Värtaverket, in central Stockholm, and captures around 4 kg of CO_2 per hour from a flue gas slipstream originating from CHP 8. Its configuration is similar to the simple process in Fig. 1.

The validation of the full-scale Aspen Plus models consisted of the following steps:

1) Performing test plant trials with operating parameters reflecting the full-scale models in order to acquire performance data;
2) Developing an equilibrium model of the test plant in Aspen Plus;
3) Inserting data from the test plant trials into the Aspen Plus test plant model;
4) Fine tuning the Aspen Plus test plant model with a ME to align model capture rate with test plant capture rate;
5) Adjusting the Aspen Plus full-scale models with the ME acquired in point 4; and
6) Performing additional validation of the full-scale Aspen Plus models against the data from Bartoo (1984).

In the test plant trials, operating conditions such as L/G, temperatures and pressures was set close to those of the columns in the full-scale Aspen models. Table 3 shows the data used for the basic and advanced full-scale capture models, compared with the actual conditions of the test plant and with relevant, non-exhaustive, data found in literature.

One of the restrictions of the test plant was the height of the packing in the absorber, at 1.16 m. This limited the capture rate to around 10 %, while the aim for the full-scale simulation was to have 90 % capture rate. From this, it follows that a full-scale column could not be simulated by the test plant with just one point of operation. As a remedy, the test plant trials were expanded to include operation with several different CO_2 inlet concentrations and with different levels of lean absorbent loading. In effect, this approach made it possible to mimic the operating conditions of several sections throughout a full-scale absorber. The different levels of inlet CO_2 concentration was achieved by diluting the flue gas with air. This explains the wide range of oxygen, nitrogen and water vapour levels given for the test plant in Table 3.

Table 3
Test plant operating parameters and full-scale plant parameters in Aspen Plus, compared with a non-exhaustive list of relevant literature data.

Parameter	Test plant	Basic Aspen model	Advanced Aspen model	Literature	
Flue gas temperature	39	39	39		°C
Flue gas composition:					
Carbon dioxide[6]	7–18	17.8	17.8		vol% (wg)
Oxygen	2–9	2.1	2.1		vol% (wg)
Water	3–6	6.1	6.1		vol% (wg)
Nitrogen and inert gases	74–77	74.0	74.0		vol% (wg)
Absorbent concentration of K_2CO_3	25–30	30	30	30[1]	wt%
Lean absorbent loading	27–68	19	20	18-27[1]	mol %
Rich absorbent loading	29–71	80	81		mol %
Absorber top temperature	72	65	65	50–75[2]	°C
Absorber top pressure	0.7	0.7	0.7	0.6-0.8[3], 0.8[2], 1.05[4]	MPa
Absorber, number of stages	2	63	75		
Absorber liquid-to-gas ratio L/G	5	4	4		
Stripper top temperature	101	96	91		°C
Stripper top pressure	0.12	0.13	0.13	0.12[5], 0.25[1]	MPa

[1] (Harkin et al., 2011).
[2] (Smith et al., 2012).
[3] (Bohloul et al., 2017).
[4] (Bryngelsson and Westermark, 2009).
[5] (Kohl and Nielsen, 1997).
[6] The concentration of CO_2 in the flue gas was set to different levels, in order to simulate operating conditions in different parts of a full-scale absorber column.

Similarly to the full-scale models, Aspen Plus equilibrium models were built to simulate the test plant trials. One Aspen model was built for every test plant trial since parameters, such as lean loading and CO_2 inlet concentration, were varied in the test program.

The MEs for the different trials were then calculated with the Aspen Plus models. The procedure was to insert the data obtained from the test plant, i.e. absorbent solution strength, temperatures, pressures, L/G, flue gas composition and lean absorbent loading. Thereafter, the ME was adjusted in the Aspen Plus model until the rich absorbent loading in the model matched that of the specific test plant trial. This procedure aligned the capture rate between the model and the specific test plant trial.

In Table 4 both the lean and rich absorbent loadings are shown for seven selected test plant trials with different lean absorbent loading. The loadings are compared with the calculated loadings from the test plant Aspen Plus models. As can be seen, they match quite well. Therefore, it was concluded that the Aspen Plus models were able to accurately simulate the test plant performance. The presented trials were selected because they matched the lean and rich loading of the absorbent at certain stages throughout a full-scale column in the Aspen Plus basic model. There was also a similarity between the CO_2 inlet concentration to the test plant and that of the matching stage in the full-scale absorber. An important consideration in this context is that a specific ME is only valid close to the pressure and temperature for which it has been

Table 4
Data on lean and rich absorbent loading for the test plant trials and resulting Murphree efficiencies.

Trial point	Lean loading test plant (mol%)	Lean loading test plant Aspen model (mol%)	Rich loading test plant (mol%)	Rich loading test plant Aspen model (mol%)	Matching stage in full-scale Aspen basic model[1] (mol%)	Murphree efficiency
1	26.9	26,6	28,9	28,5	22	0.050
2	32.8	32.9	35.7	35.7	28	0.059
3	37.4	37.5	40.0	40.0	33	0.051
4	40.1	39.6	42.9	42.4	35	0.076
5	45.0	45.0	46.0	46.1	38	0.023
6	57.2	56.3	60.1	59.2	46	0.040
7	67.8	67.0	70.5	69.7	52	0.041
Average						0.049

[1] Matching primarily refers to lean and rich loading, but also CO_2 concentration in the flue gas. The total number of stages in the absorber is 63.

calculated, as these parameters affect the mass transfer rate. Therefore, pressure and temperatures were set at similar levels for the test plant and the full-scale Aspen Plus models, as can be seen in Table 3.

The values for the MEs obtained from the Aspen Plus calculations are shown in Table 4. The variation was higher than expected, between 0.023–0.076. More importantly, the variation does not display any discernible trend. Typically, a continuous variation of the ME along the height of the column should be expected, as shown by Al-Ramdhan (2001). After scrutiny of the sampling procedure, it was concluded that the variations were likely to be a result of inaccuracies in the titration method, rather than from real variations in the process. With this in mind, an ME of 0.04 was chosen to be used for both the basic and the advanced full-scale Aspen Plus simulations. This value is lower than all the measured MEs, except one. Consequently, it was considered to a conservative approach.

As an additional measure, the chosen ME was compared with the literature. Wu et al. (2018) found the ME to be as low as 0.01; however, the conditions for those tests were less beneficial, compared to those of the test plant trials in this study, having atmospheric pressure and ambient temperatures in the absorber. Working with more advantageous parameters, Ooi (2008) found that the ME was between 0.05 and 0.25. Those findings were based on existing industrial acid gas removal absorbers, operating at 7 MPa and 110 °C. In yet another study, Al-Ramdhan (2001) fond the ME to be between 0.04 and 0.08, with a test rig operating at 3.6 MPa and around 108 °C. The results of Al-Ramdhan (2001); Ooi (2008) and Wu et al. (2018) indicate that the determined ME in this study is in line with what has been found in other experimental settings.

Despite the plausible robustness of the above validation, an analysis was performed to see how a change of the ME influences the heat duty of the simulated processes. The resultant heat duties were then compared with the work of Bartoo (1984). This comparison was done in an effort to determine whether the heat duty complied reasonably well with industrial processes, such as natural gas sweetening. To explain further, it was assumed that the heat duties for the basic and advanced carbon capture processes were comparable with those of industrial processes. This is not necessarily true, as the conditions in the strippers differ. Nevertheless, it was reasoned that only the first term, q_{sens}, in Eq. (7) was expected to differ. As this term is small compared with $q_{vap,H2O}$ in the same equation, the assumption was deemed to be justified, as long as the

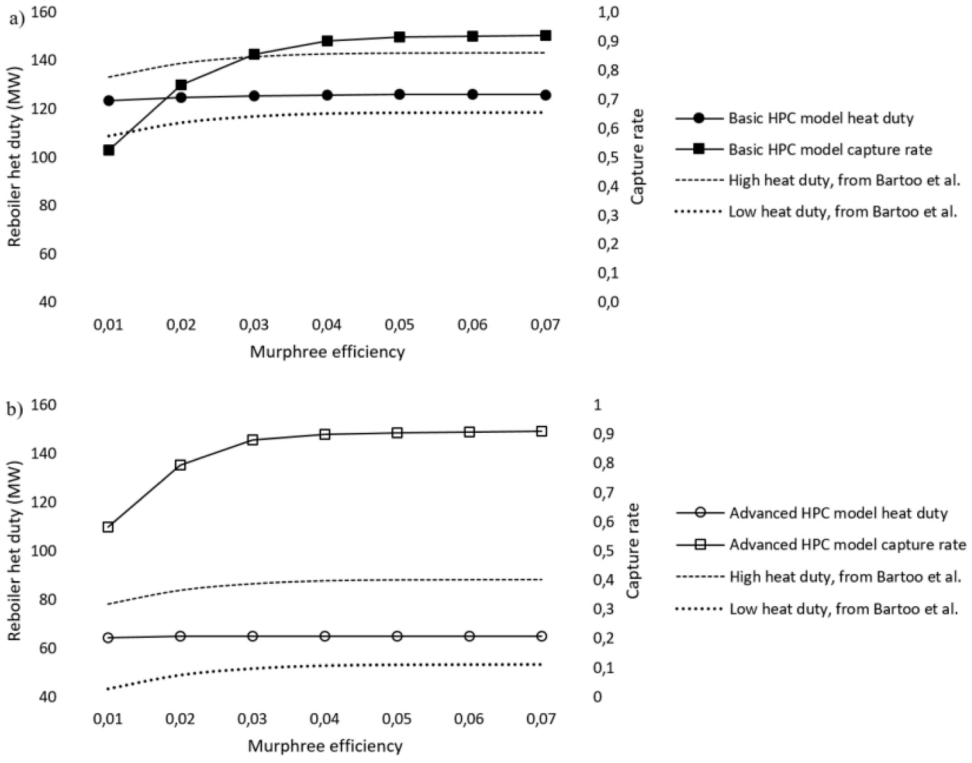

Fig. 5. The reboiler heat duty and CO_2 capture rate as a function of the absorber ME for the Aspen Plus simulations of (a) the basic HPC process and (b) the advanced HPC process. The dotted lines show the expected upper and lower limits of the heat duty for industrial carbon capture processes. These limits have been adjusted with the change in $qabs,CO_2$ due to the change in capture rate.

respective heat duties were well within the range of the data from Bartoo (1984).

In Fig. 5, a comparison is made between expected heat duties, as indicated by Bartoo (1984), and calculated heat duties for the Aspen Plus full-scale models, for a range of MEs. Fig. 5 shows that the heat duties are well within the ranges of Bartoo (1984), for both the basic capture process and the more advanced process. Moreover, the heat duty is only mildly affected by the ME. This implies that from an energy requirement point of view the value of the ME is not critical within this range. Therefore, setting the ME to 0.04 in this study was judged reasonable. In contrast to the heat duty, the capture rate is strongly influenced by the ME at lower values. This was to be expected, since additional absorber stages would be needed to compensate for the lower ME, in order for the same capture rate to be achieved. Such an adaption of the number of absorber stages would cause the heat duty to become constant over the range of the ME in Fig. 5.

3.6. Energy integration of the carbon capture process with the CHP

Fig. 2 shows the integration between the CHP and the CCS process, whereas Fig. 3 gives an overview of how the CHP and the CCS fit within the wider production of district heating. As can be seen in Fig. 2, the required amounts of steam, heat and electricity for the capture process were generated by the CHP. In addition, steam, heat and electricity generated by the CCS process itself was utilised within the capture process to enhance the efficiency. The low-pressure (LP) steam for the reboiler was mainly supplied by withdrawing high-pressure (HP) steam before the CHP turbine. To reach the correct temperature and pressure, the HP steam was passed through a steam turbine driving the first flue gas compressor. Neveux et al. (2017) have found this solution to be efficient for reducing the need for electric power. Any remaining steam demand in the basic capture process was de-superheated, incurring electric generation efficiency losses. De-superheating was necessary because the turbine lacks the capability to extract enough steam for the basic capture process at the correct pressure. Conversely, for the advanced capture process, the turbine bleed-off capacity was found to be sufficient for supplying additional LP steam.

The heat integration calculation was performed in Microsoft Excel®. The minimum approach temperature was set to 5 °C for liquid-liquid heat exchangers and condensers, 10 °C for gas-liquid heat exchangers and 15 °C for gas-gas heat exchangers. These values are in the range suggested by Turton et al. (2018). Radiation and convection heat losses amounting to 0.5 % of the input energy were used for both the CHP and the CCS system. This assumption was based on the performance test for the CHP (Stockholm Exergi, 2016). No efficiency loss in the electrical system was considered. The energy integration model allowed the CHP energy penalty (Eq. 12) to be calculated, along with the other performance parameters defined in Section 3.2. Based on these parameters, a calculation was made of the monetary cost-of-energy for the CO_2 capture. In these calculations, the base monetary value of both electricity and heat was set to 40 € per MWh. While the value of heat was kept constant, the value of electricity was increased stepwise to a maximum of 160 € per MWh. These numbers are in alignment with those used by Bui (2020). Naturally, depending on the contextual setup of different electric power and district heating systems, the monetary base value levels for heat and electricity can be different from those assumed here. It should be noted that the value of generated electric power differs from wholesale power market prices, which include additional fees for taxes and distribution. Likewise, the value of generated heat is relative to the substituted heat production, rather than the wholesale price.

4. Result

4.1. Energy penalty and other performance indicators

The performed thermodynamic analysis showed that the CHP energy penalty (Eq. 12) was in the range of 2%–4% (Table 5). For comparison, the common electricity-based energy penalty (Eq. 10) was calculated for the CHP, and was found to be in the range of 51 %–71 % (Table 5). The reason for the difference in energy penalty between Eqs. (10) and (12) is that a major part of the utilised electric power and steam can be recovered as useful heat into the district heating system. A particularly notable finding was that the energy penalty for the more advanced carbon capture process was almost half of that for the basic process. This difference shows that there is a substantial potential in optimising the process design configurations in order to reduce the energy penalty

Apart from the energy penalty, further performance indicators were quantified (Table 4). The advanced capture process was found to be the better performing process on all accounts. It was particularly notable that the electric efficiency differed substantially between the two capture processes, and was 70 % higher for the advanced process. Nevertheless, the electrical efficiency was still halved compared with the reference system. Another noteworthy point was that adding CCS did not increase the dependency on HOBs for meeting the required supply district heating temperature, compared with the reference.

4.2. The influence of district heating temperatures

An analysis was performed on how the district heating return and supply temperatures affected the energy penalty of adding carbon capture to the CHP plant. In Table 6, it can be seen that all parameters are positively impacted by a low-temperature network, when compared with the base case in Table 5. The opposite is also true: a high-temperature system negatively impacts all parameters. In addition, it was found that the need for HOBs to raise the district heating supply temperature disappears in the low-temperature case. In contrast, for the high-temperature case, there is a dramatic increase of the need for HOBs.

4.3. The monetary cost-of-energy for carbon capture

In Fig. 6 it is shown how the monetary cost-of-energy for the capture processes relates to the difference in monetary value of electric power and heat. As expected, a low difference in value between electricity and heat is highly beneficial for the cost-of-energy of carbon capture. For equal monetary values of electricity and heat, at 40 €/MWh, the monetary cost-of energy for the carbon capture is around 2 €/ton of CO_2 for

Table 5
Data on CHP 8 without and with CCS.

Parameter	CHP 8 alone (reference)	With basic CCS	With advanced CCS	
Fuel input (LHV)	362	362	362	MW
Turbine electrical power output, gross	125	59	88	MW
Turbine electrical power output, net	110	31	53	MW
Turbine condenser heat output	208	115	153	MW
Flue gas condenser heat output	79	79	79	MW
CCS heat recovery	–	160	105	MW
Total heat output	287	354	337	MW
Energy efficiency (Eq. 11)	87.7	84.5	86.0	%
Electric efficiency, net (Eq. 14)	30.3	8.7	14.7	%
Energy penalty, CHP (Eq. 12)	–	3.6	1.9	%
Energy penalty, power plant (Eq. 10), for comparison	–	71.4	51.3	%
Efficiency penalty, CHP (Eq. 13)	–	3.1	1.7	%
Efficiency penalty, power plant (Eq. 9), for comparison	–	21.6	15.5	%
Power preservation, CHP (Eq. 15)	–	28.6	48.7	%
Reliance on HOBs to meet district heating supply temperature	47	47	47	MW

Table 6
Analysis of the impact of district heating temperatures.

Parameter	Basic CCS with low-temperature system	Basic CCS with high-temperature system	Advanced CCS with low-temperature system	Advanced CCS with high-temperature system	
District heating temperature (return/ supply)	43/78	55/100	43/78	55/100	°C
Fuel input (LHV)	362	362	362	362	MW
Turbine electrical power output, gross[1]	60	57	90	83	MW
Turbine electrical power output, net	33	30	56	48	MW
Turbine condenser heat output[2]	115.	115	153	153	MW
Flue gas condenser heat output	85	65	85	65	MW
CCS heat recovery	161	157	105	102	MW
Total heat output	361	337	343	320	MW
Energy efficiency (Eq.11)	85.4	83.5	86.6	83.7	%
Electric efficiency (Eq 14)	9.0	8.2	15.4	13.3	%
Energy penalty, CHP (Eq. 12)	2.6	4.7	1.2	4.6	%
Efficiency penalty, CHP (Eq. 13)	2.3	4.2	1.1	4.0	%
Power preservation, CHP (Eq. 15)	29.7	27.2	50.7	43.9	%
Reliance on HOBs to meet district heating supply temperature	None	222	None	162	MW

[1] The turbine electric power output was only adjusted with the impact of the district heating return temperature. The influence of district heating flow rate was neglected within the studied flow interval.
[2] The approximation was made that the turbine condenser heat output is independent of the district heating return temperature within the studied temperature interval.

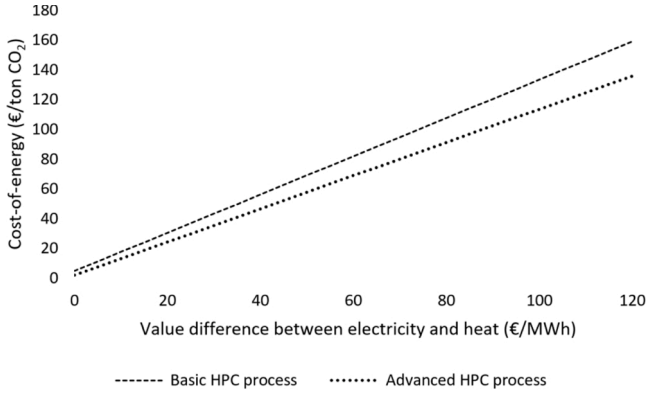

Fig. 6. The monetary cost-of-energy for the basic and the advanced capture process in relation to the monetary value difference between electric power and heat.

the advanced capture process and around 5 €/ton of CO_2 for the basic process. This difference grows as the value gap between electricity and heat increases.

5. Discussion

BECCS is widely recognised as one of the key methods to facilitate carbon dioxide removal, which is a necessity if global temperature is to be kept within relatively safe levels (IPCC, 2018). However, many deterring factors hinder development. Of these, the costs for investment and operation are especially impeding, as there are no apparent economic returns (Gustafsson, 2018). Therefore, it is of interest to lower the costs for operating BECCS facilities and thereby lower the threshold for investments. This study investigated whether the energy penalty of integrating CCS with a biomass-fired CHP plant could contribute to such cost reductions. The energy penalty, which normally only includes the reduction of electricity output, was modified to include the useful heat (Eq. 12). This was motivated by the fact that a CHP plant has two valuable products: heat and electric power. The study was performed using thermodynamic analysis coupled with process modelling in Aspen Plus.

The results showed that the CHP energy penalty was in the range of 2%–4% (Table 5). This is generally lower than the findings of other studies examining the addition of the amine carbon capture to electric power stations, utilizing pulverized coal (PC) as a fuel. In those studies, which largely focused on non-standard advanced steam cycles, the theoretical energy penalty was found to be 15 %–28 % (Page et al., 2009). The explanation for the lower energy penalty in this study is that a large proportion of the steam and electricity utilised in the capture process could be recovered into the district heating system as useful heat. For the sake of transparency, the conventional energy penalty based on electric power (Eq. 10) was also calculated. By that definition, the energy penalty was found to be in the range of 51 %–71 % (Table 5). As a comparison, Page et al. (2009) calculated the energy penalty to be 37.2 %–48.6 % for real-world, sub-critical PC power plants with the amine capture technology. The high energy penalty when considering only electric power (Eq. 10) in this study probably explains why the HPC process has been little studied for post-combustion capture at power plants.

From a monetary cost-of-energy perspective, it is reasonable to believe that BECCS could be deployed at a lower cost in a CHP and district heating setting than in corresponding power plants settings. From this follows that the need for monetary incentives to reach a sufficient return on investment could be lower. Naturally, the validity of these statements is highly dependent on the difference in the monetary value of heat and electricity in the specific system. Essentially, a low value difference between electricity and heat will also yield a low monetary cost-of-energy for the capture process. This finding is in general agreement with the findings of Bui (2020). In this study it was found that the cost-of energy is 2–5 €/ton of CO_2, if the value of both electricity and heat is 40 €/MWh, with the advanced capture process being the more advantageous. This is due to its lower energy penalty and higher electric efficiency. In conclusion, optimization of the capture process is likely to be worthwhile if cost-of-energy reductions are sought.

The CCS process modelled in the full-scale Aspen Plus models could have been more advanced. This can be deduced from Fig. 5, where it can be seen that the reboiler heat duty might be further decreased to the lower levels found by Bartoo (1984). In a real-world plant, further improvements such as multistage lean compression (Milidovich and

Zbacknick, 2013), split flow arrangements of the absorber and the stripper, and multiple strippers could be evaluated (Moullec and Neveux, 2016), to name a few examples. Drawing on the results of this study, such measures would probably not affect the overall energy penalty dramatically, but rather increase the electrical efficiency of the system.

A notable result of this study was that the implementation of the HPC capture process at a CHP does not increase the dependency on auxiliary HOBs at average Swedish district heating temperature levels. This effect stems from the possibility of recovering heat at elevated temperatures from the HPC process. Still, these results should be interpreted with caution, as it was also shown that the requirement of HOBs is strongly dependent on the district heating temperature levels. Consequently, the demand for HOBs will vary in a real district heating network in which the temperatures are fluctuating. The same is true for the energy penalty, which will also change with temperature levels. A dynamic study on how district heating temperature levels influence the energy penalty would therefore be valuable. Whether a reduced need of HOBs could motivate moving towards low-temperature district networks will have to be evaluated in relation to the individual district heating system. However, it can be concluded that low-temperature networks are well worth exploring when considering the implementation of CCS, as there are other benefits, such as improvement of the electrical efficiency of the BECCS system.

Iterative calculations, in which the results from the heat integration were allowed to influence the design of the capture system, were not performed in this study. The findings of Harkin et al. (2011) suggest that such an optimisation could decrease the overall energy need. For example, an increase of the stripper pressure could lead to a higher preservation of electric power production from the CHP, since the carbon dioxide compression work would be reduced. Another option that was not investigated is to integrate mechanical heat pumps into the BECCS system. Such a strategy would recover more heat at the further expense of electric power.

This study solely encompassed the HPC technology. For future studies, amine technology is an obvious choice for exploration, due to its high technological readiness level (Bui et al., 2018). A CHP-CCS system in a fossil-fuel setting is another avenue that could be worth investigating, to see whether it would yield similar results. Even if a fossil-fuel CHP would not generate negative emissions (Kemper, 2015), it could be part of a climate mitigation strategy. It would also be of interest to see what results a similar study on industrial CHPs would generate, as such CHPs operate under different conditions and have different requirements on energy delivery.

6. Conclusion

In this study, the energy penalty for establishing carbon capture at CHP plants in district heating systems was found to be 2%–4%, if the useful heat is recovered. This result is notably lower than the energy penalty for power plants. In a setting where the monetary value of heat and electric power are at similar level the cost-of-energy for carbon dioxide capture can be in the range of 2–5 €/ ton of carbon dioxide. From this, it follows that the operational cost of BECCS might be lower in a CHP-district heating setting than in other applications, since the total energy output from the CHP is largely preserved. This reduced cost could potentially increase the attractiveness of BECCS in this context, especially if the difference in the monetary value of the produced electricity and heat is low. As a result, the economic burden of implementation could be reduced, thus increasing the economic efficiency of BECCS as a climate change abatement option. Consequently, the need for added business value, policy instruments or other incentives to promote investments in the CCS part of BECCS may be smaller. Therefore, CHP plants could be of interest as a starting point for BECCS to finally take off as a climate mitigation tool. District heating systems with low temperatures and a small difference between the monetary value of heat and electric power are especially well equipped for development. Furthermore, when electrical output is of importance, optimisation of the capture process should be a priority.

Data availability

The data, which this study is based on, will be made available on reasonable request.

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CRediT authorship contribution statement

Kåre Gustafsson: Conceptualization, Methodology, Data curation, Validation, Software, Writing - original draft. **Ramiar Sadegh-Vaziri:** Methodology, Software, Writing - review & editing. **Stefan Grönkvist:** Supervision, Writing - review & editing. **Fabian Levihn:** Supervision, Writing - review & editing. **Cecilia Sundberg:** Supervision, Writing - review & editing.

Declaration of Competing Interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests:

This research has been made possible through collaboration between industry and academia. Funding and affiliations are disclosed in the manuscript. Kåre Gustafsson is an industrial doctorate candidate at KTH – Royal Institute of Technology, externally employed at Stockholm Exergi. Fabian Levihn is employed at Stockholm Exergi and KTH - Royal Institute of Technology. Furthermore, Stockholm Exergi has funded the supervision performed by Cecilia Sundberg and Stefan Grönkvist. Ramiar Sadegh-Vaziri have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Appendix A. Supplementary data

Supplementary material related to this article can be found, in the online version, at doi:https://doi.org/10.1016/j.ijggc.2020.103248.

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