THESIS FOR THE DEGREE OF DOCTOR OF PHILOSOPHY

Combined heat and power plants in decarbonized energy systems

Techno-economics of carbon capture and flexibility services at the plant, city and regional levels

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Abstract

Our present energy system is the main driver of climate change. Variable renewable electricity generation and carbon dioxide removal (CDR) are key technologies in the transformation to a sustainable energy system, but their broad implementation implies challenges related to energy system flexibility and energy requirements of CDR technologies. The aim of this thesis is to investigate the potential and incentives for combined heat and power (CHP) plants in Sweden to contribute with CDR and flexibility services in the energy system. A techno-economic assessment scheme that considers variability in boundary conditions, such as electricity prices, and includes the CHP plant, city, and regional energy system levels is developed and applied. System optimization modeling and process-level case studies are performed to investigate how CHP plant flexibility measures are utilized and valued, and to estimate the cost and potential of CDR from Swedish CHP plants.

The results indicate a large potential for Swedish CHP plants to contribute to CDR, with at least 10 $MtCO_2$/year being available for capture and storage. The realizability of this potential is challenged by the cost of carbon capture which increases notably for CHP plants that are small and have few full load hours. CHP plants can cost-effectively contribute with flexibility provision in the studied electricity system, although the impact on the total system is limited, as the installed capacity of CHP plants is small relative to the magnitude of net load variability. From a plant perspective, the plant revenue can increase if the operation is scheduled to follow electricity price variability, but this requires a significant level of price volatility and access to large-scale thermal energy storage for maximum benefit. The fuel price has a strong impact on the competitiveness of biomass-fired CHP plants on a regional level, that compete with power-to-heat technologies in the district heating sector. In contrast, in cities, there are stronger incentives for CHP plants as heat producers regardless of how the surrounding energy system and market prices develop, due to a limited availability of other technology options and a limited grid connection capacity to drive power-to-heat.

Keywords: *Combined heat and power; Flexibility; District heating; Negative emissions; CCS; Techno-economic assessment, Energy system modeling.*

SAMMANFATTNING

En omfattande omställning av energisystemet har påbörjats för att motverka klimatförändringar. Storskalig utbyggnad av väderberoende elproduktionstekniker (vindkraft och solkraft) samt koldioxidinfångning spelar en allt större roll i systemet, men medför samtidigt utmaningar kopplade till flexibilitet i energisystemet och energitillförsel för koldioxidinfångning. Avhandlingen har som mål att undersöka potentialen och incitament för svenska kraftvärmeverk att bidra med koldioxidinfångning och flexibilitetstjänster i energisystemet.

Metodiken bygger på tekno-ekonomiska analyser där särskild hänsyn tas till variabilitet i randvillkor, som elpriser, och olika energisystemnivåer, som kraftvärmeverk, en stad, och en region. Systemoptimeringsmodeller och processmodelleringsstudier genomförs för att utvärdera hur kraftvärmeflexibilitet används och värderas i el- och värmesystemen, och för att uppskatta kostnader och potential för biogen koldioxidinfångning (BECCS) från svenska kraftvärmeanläggningar.

Resultaten indikerar att det finns en stor potential för BECCS från Sveriges nuvarande kraftvärmeverk, om minst 10 $MtCO_2$/år, som skulle räcka för att uppfylla det föreslagna målet för BECCS i Sverige om 3-10 $MtCO_2$/år till år 2045. Genomförbarheten utmanas av kostnaden för koldioxidinfångning, som ökar markant för anläggningar som är små och har få drifttimmar. Kraftvärmeverk kan bidra med flexibilitet i det studerade elsystemet på ett kostnadseffektivt sätt, men kraftvärmeverkens inverkan på det totala elsystemet är begränsad, då den installerade eleffekten för kraftvärmeverk är liten i förhållande till elsystemets storlek och förväntade nettolastvariationer. Från anläggningens perspektiv kan det dock ge ökade intäkter att matcha anläggningens drift mot elprisvariationer, men för detta krävs en hög nivå av volatilitet på elmarknaden och tillgång till storskaliga värmelager.

Bränslepriset har en stark påverkan på biomassaeldade kraftvärmeverks konkurrenskraft på regional nivå, där elvärme (t.ex. elpannor och värmepumpar, eng. *power-to-heat*) konkurrerar om marknadsandelar i fjärrvärmesektorn. Däremot finns det fortsatt starka incitament för kraftvärme i större svenska städer, oavsett hur bränslemarknader och energisystemet i stort utvecklas. Detta ges av en begränsad tillgång på konkurrerande tekniker för el- och värmeproduktion inom staden, och begränsad kapacitet för transmission av el från stamnätet till det lokala stadsnätet, som annars skulle gynna elvärmetekniker.

List of publications

The thesis is based on the following papers, which are referred to in the thesis by their Roman numerals:

I. Beiron, J.; Normann, F.; Johnsson, F. *A techno-economic assessment of CO_2 capture in biomass and waste-fired combined heat and power plants - A Swedish case study*. International Journal of Greenhouse Gas Control. **2022**, 118, 103684.

II. Beiron, J.; Montañés, R.M.; Normann, F.; Johnsson, F. *Combined heat and power operational modes for increased product flexibility in a waste incineration plant.* Energy. **2020**, 202, 117696.

III. Beiron, J.; Montañés, R.M.; Normann, F.; Johnsson, F. *Flexible operation of a combined cycle cogeneration plant – A techno-economic assessment.* Applied Energy. **2020**, 278, 115630.

IV. Beiron, J.; Göransson, L.; Normann, F.; Johnsson, F. *Flexibility provision by combined heat and power plants – An evaluation of benefits from a plant and system perspective.* Submitted for publication. **2022**.

V. Beiron, J.; Göransson, L.; Normann, F.; Johnsson, F. *A multiple system level modeling approach to coupled energy markets: Incentives for combined heat and power generation at the plant, city and regional energy system levels.* Energy. **2022**, 254, 124337.

Author contributions

Johanna Beiron is the principal author of all papers. Professor Fredrik Normann and Professor Filip Johnsson contributed with discussion and editing of all papers. Dr. Rubén M. Montañés contributed with discussion and editing of Papers II and III. Associate Professor Lisa Göransson contributed with discussion and editing of Papers IV and V.

Other publications not included in the thesis

- Beiron, J.; Karlsson, S.; Skoglund, H.; Svensson, E.; Normann, F. *The role of BECCS in providing negative emissions in Sweden under competing interests for forest-based biomass.* 2nd International Conference on Negative Emissions. **2022**.

- Sköldberg, H; Beiron, J; Fridahl, M; Gode, J; Grubbström, C; Gustavsson, M; Holm, J; Johnsson, F; Kjärstad, J; Lundberg, L; Löfblad, E; Möllersten, K; Nehler, T; Romson, Å; Sahlin, J; Solis, M; Steen, L; Svanberg Frisinger, MS; Unger, T; Wolf, J; Zetterberg, L. *Bio-CCS i fjärrvärmesektorn – Syntes*. Energiforsk AB. **2022**.

- Beiron, J.; Normann, F.; Johnsson, F. *A case study of the potential for CCS in Swedish combined heat and power plants*. In proceedings of: 15th International Conference on Greenhouse Gas Control Technologies, GHGT-15. **2021**.

- Beiron, J.; Montañés, R.M.; Normann, F.; Johnsson, F. *Dynamic modeling for assessment of steam cycle operation in waste-fired combined heat and power plants.* Energy Conversion and Management. **2019,** 198, 111926**.**

- Beiron, J.; Montañés, R.M.; Normann, F. *Operational flexibility of combined heat and power plant with steam extraction regulation.* In proceedings of: 11th International Conference on Applied Energy. **2019**.

- Beiron, J.; Normann, F.; Kristoferson, L.; Strömberg, L.; Garðarsdòttir, S.Ò.; Johnsson, F. *Enhancement of CO_2 absorption in water through pH control and carbonic anhydrase – A technical assessment.* Industrial & Engineering Chemistry Research. **2019**, 58, 14275-83.

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Six years ago, I would never have imagined myself where I am today, and I definitely had no plans whatsoever to end up doing research. But luckily, I did, and I would gladly do it again. This PhD journey has been the time of my life, so far...

★

Johanna Beiron

Göteborg, September 1st, 2022

“Always stay gracious, best revenge is your paper”

Beyoncé, Formation

“When it comes down to it, science is more art than science”

Magic, Mad Science Fair Project

“It’s not supposed to be easy”

Rubén Mocholí Montañés

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1 Introduction

With the urgent need to decarbonize global energy use and mitigate climate change, substantial action is required to transform the energy system. Two important actions are to (i) strongly reduce fossil carbon dioxide (CO_2) emissions, and to (ii) remove and permanently store CO_2 from the atmosphere (carbon dioxide removal, CDR, also known as negative emissions). CDR can contribute to mitigate emissions in hard-to-abate sectors and to reach net-negative emissions. Combined heat and power (CHP) plants have played an important role in the decarbonization of the Swedish heat and power supply, by substituting fossil energy carriers for biomass and waste fuels. This thesis discusses the role of CHP plants in future decarbonized energy systems.

With the transformation of the energy system, there are new or increased demands for carbon-neutral energy carriers and services, of which a few are listed in Table 1.1. Supplying these demands implies a challenge for the energy system, as well as an opportunity for technologies that can provide them. For provision of carbon-neutral electricity, variable renewable energy from wind and solar power is a low-cost option that is expanding at large scale to replace fossil energy in power plants and in adjacent energy sectors through electrification of, for example, transport, industrial processes and heating. However, strategies are needed to manage the inherent variability of wind and solar power to ensure a balance between electricity supply and demand at all times. In cities, the electrification occurs at a higher rate than the expansion of grid connection capacity, causing problems with congestion.

CHP plants, which cogenerate electricity and district heating in cities, could help resolving balancing challenges, by operating flexibly to provide dispatchable electricity generation when it is needed. Swedish CHP plants typically combust biomass (forest residues) or municipal solid waste. Thereby, they provide waste management and prevent pollution associated with landfilling. Having access to biomass infrastructures, they are also potential candidates for the establishment of biorefineries for biofuel production, and carbon dioxide removal through the application of carbon capture and storage (CCS) technology to biogenic CO_2 emissions (BECCS). Thus, there are several opportunities for CHP plants to contribute to the energy system decarbonization and climate change mitigation. This thesis focuses on carbon dioxide removal and flexibility services.

Table 1.1 An overview of challenges related to energy system decarbonization in a Swedish context, and opportunities for municipal CHP plants to contribute to meeting demands.

Energy system challenge	Swedish demand	CHP plant opportunity	Current capacity
Carbon dioxide removal	3-10 $MtCO_2$/yr by 2045 [1]	BECCS[a]	0 Mt/yr
Carbon-neutral electricity	170-290 TWh_{el}/yr by 2045-2050[b] [2–4]	Biomass-based power generation	5-12 TWh_{el} [5,6]
Electricity supply-demand balancing	Unknown	Dispatchable power generation	2.8 GW_{el} [6]
Power system stability	Depends on the type of service.	Ancillary services[c]	-
Carbon-neutral space heating	60-90 TWh_{heat}/yr by 2050[b] [7]	District heating generation	25 TWh_{heat} [8]
Congestion in transmission grid	Unknown	Local capacity in cities[d]	2.8 GW_{el} [6]
Waste management	36 Mt waste/yr in 2020[e] [9]	Waste-to-energy	6 Mt waste/yr [5]
Biofuels for transport	18-30 TWh_{fuel}/yr by 2030 [10,11]	Integrated biorefinery to produce biofuels	0 TWh_{fuel}

a. BECCS refers to CCS applied to biomass or waste-fired CHP plants (waste being of partly biogenic origin). The retrofit of an 800 $ktCO_2$/year BECCS-facility to a biomass CHP plant is currently being planned in Stockholm, Sweden.
b. The current Swedish electricity use is approximately 140 TWh/year. The current Swedish space heating demand is approximately 75 TWh.
c. Ancillary services in the form of frequency response are almost exclusively provided by hydropower in Sweden.
d. CHP plants currently contribute with around 30% of the electricity production in many Swedish cities [12].
e. Refers to treated waste in general (excl. mining waste), from the construction industry, households, service industries etc.

1.1. Research space

Flexibility as a concept is vague and have different meanings depending on context, but in the electricity sector it is generally understood as an ability to react to changes in demand or supply (net load) over time. For power plants, flexibility has been defined previously based on single-product (power) plants. Multi-product facilities, such as CHP plants, serve under a different set of operating conditions and possibilities to act flexibly, that are distinguished from those of single-product plants. A wider understanding of flexibility is needed that applies to and adequately characterizes CHP plants, which should be given its own definitions and concepts.

Table 1.2 gives an overview of flexibility measures that have been studied in the CHP context, including CHP plant-level measures, and competing types of flexibility provision in the electricity system (see, for instance, the review by Lund et al. [13]) and the district heating network. Apart from the most basic CHP plant flexibility measure – to vary production levels by adapting the fuel consumption rate (*operational flexibility*) – some flexibility measures enable the decoupling of heat and power generation (*product flexibility*), i.e., the power-to-heat ratio of the plant is varied, while others target a decoupling of fuel consumption and product supply (*load shifting*) by utilizing a storage capacity. These measures are further discussed in Chapter 4.

The published research on CHP plant flexibility mostly originates from China and Europe. The Chinese studies typically focus on large-scale (>300 MW) coal-fired CHP plants and how these can become more flexible on a plant-level so as to integrate more wind power in the electricity system and avoid curtailment. Coal-fired CHP plants have different technical properties than biomass and waste-fired plants that are generally smaller and have less complex configurations.

Table 1.2. Overview of flexibility measures considered in the literature, related to CHP plants, electricity systems and district heating systems.

Level of analysis	Flexibility measure	Example references	Function
CHP plant	Boiler load	[14–16]	Vary production level by fuel consumption rate, cycling. Operational flexibility.
	Extraction condenser	[17]	Increase power generation, reduce heat output. Typical design for coal-fired CHPs.
	Turbine bypass	[18,19]	Decrease power generation, increase heat production.
	Steam extraction regulation	[20,21]	Decrease power generation, heat is stored in feed-water heaters.
	Steam turbine renovation	[22]	Conversion to backpressure turbine.
	Low-pressure cylinder removal	[18]	Similar to SSS-clutch, decrease power generation, more heat produced.
	SSS-clutch	[23]	Temporary disconnect low-pressure turbine, reduced power generation, more heat.
	Internal heat storage	[24,25]	High-temperature heat storage, steam accumulator, molten salt storage.
	Thermal buffer	[26]	Metal plate heat storage, reduce thermal fatigue during cycling of GTCC plant.
	Plant-level electric boiler	[18,22,27]	Reduce electricity supply, increase heat supply.
	Plant-level TES	[18,22]	District heating water storage, load shifting.
Electricity system	Dispatchable power generation	[28–31]	Balancing net load through power plant dispatch.
	Electricity storage	[32,33]	Load shifting, e.g., batteries.
	Sector coupling, power-to-X	[19,34,35]	Absorption of "excess" electricity, managing negative net load.
	Transmission	[36,37]	Geographical smoothening of variability.
	Demand side response	[32,33,38,39]	Load shifting of electricity use in time.
District heating system	Thermal inertia in network	[40–42]	Heat storage in network piping.
	Demand side response	[43,44]	Load shifting of heat consumption in time.
	DH supply temperature	[45]	Vary turbine outlet pressure. Can be combined with network thermal inertia.
	System-level TES	[42,46,47]	Heat storage in e.g. tanks, load shifting.
Operating strategies	Load shifting with energy storage	Flexibility in time. Enables de-coupling of CHP heat and power supply. On a plant level, the minimum load level can be reduced when charging, and net output increased when discharging.	
	Heat-following	CHP plant dispatched to follow heat demand.	
	Electricity-following	CHP plant dispatched to follow electricity demand/net load.	

GTCC, Gas turbine combined cycle; TES, Thermal energy storage; SSS, Synchronous-self-shifting

Thus, the flexibility measures considered for large coal-fired CHP plants might not be applicable or equally profitable for smaller plants that combust waste or biomass, making it interesting to study the specific situation for small-to-medium CHP plants that have different cost structures. In fact, a literature search on Scopus[1] reveals that, to date, there are no published works on power generation flexibility applied to waste-fired CHP plants (except for the work in this thesis). Furthermore, the Chinese electricity market is regulated and might not be representative of optimal strategies to provide flexibility in deregulated markets, as in Sweden and Northern Europe.

Studies on CHP plants in Europe tend to focus on the system level and the competitiveness of CHP plants to provide flexible electricity (and heat) in contexts with large shares of variable electricity supply [48,49], and the coordination of CHP plants and other flexibility measures, for

[1] Search terms: "waste" AND "combined heat and power" AND "flexibility".

example, thermal energy storage and power-to-heat [50]. Some studies target biomass-fired CHP plants, but often do not analyze in detail the utilization of plant-level flexibility measures, as is done in several studies on fossil-fueled plants (for example, [18,20–22]). Design optimization of CHP plants for volatile electricity system contexts and fuel supplies is also found in the literature [51,52].

A distinction can be made between studies that focus on how CHP plants can *support* higher shares of variable electricity generation in the energy system (e.g., [18,22,53]), and studies that focus on how CHP plants are *affected by* increased shares of wind power (e.g., [54,55]), or how CHP plants can *benefit* from variability in terms of increased revenue (e.g., [56–58]). Clearly, various perspectives can be applied to study flexibility-related topics, and it is of interest to compare the different views, including technology-perspectives (e.g., plant design and operational strategies to increase revenue) and system-perspectives (e.g., cost-effective design of the electricity system and interaction between technologies).

In terms of carbon capture, previous studies have largely focused on the application of carbon capture technologies to large power plants (see, for example, the following reviews [59–61]) and industries (for instance, pulp and paper [62–65], iron and steel [66], cement [67,68], refineries [69–71], and overall assessments [72–76]). Small-to-medium size plants, such as CHP plants in Sweden, have received little attention, although recent publications have assessed the cost of absorption-based CCS for small-scale applications [77,78]. Levihn et al. [79] write that there is a "surprising absence of research on BECCS applied specifically to CHP plants", given the CDR potential that it constitutes. Hence, there is a need to expand the research field on CHP plants with CCS, in particular focusing on the specific conditions for district heat-supplying plants.

1.2. Aim of the work

The overall aim of this thesis is to contribute to the understanding of the role of CHP plants in future decarbonized energy systems. Such a broad aim can be analyzed on several levels, including the energy system at large with a socio-economic focus, and the technology level with a detailed focus on specific processes. The thesis aims to bring together these two perspectives (system and plant/technology) to approach a holistic understanding of challenges and opportunities. In doing so, the work involves the development of modeling and analysis frameworks that combine system and plant-level aspects. The specific aims of the thesis are to:

- Investigate the potential and incentives for CHP plants to contribute to climate and energy system services in the form of negative emissions and flexible supply of district heating and electricity.
- Identify flexibility measures and strategies for flexible operation that are available and relevant for CHP plants and evaluate their utilization.
- Compare the value and competitiveness of CHP plants and flexibility measures on different system levels (plant, city, region) and examine the sensitivity to energy system context.
- Develop a modeling framework to aid the analysis of the above points, i.e., combined process and system-level analyses.

Contribution

In fulfilling these aims, the thesis contributes with novel insights relating to carbon capture, with new results on the integration of, and potential for, BECCS in district heating systems. This might contribute to the deployment of carbon dioxide removal in Sweden. The work advances the field by applying carbon capture concepts to plant types and contexts that have received little attention in the literature previously, i.e., small-to-medium size CHP plants in district heating networks.

The thesis also contributes to the field of electricity system flexibility, by assessing the potential for and utilization of CHP plant flexibility measures, for example, waste-fired plants that have not been studied before. The assessment can give important guidance to both plant managers and system operators, regarding the feasibility of CHP plants to balance the electricity net load, and the economic incentives to do so. The work applies extensive modeling tools that combine process and system analyses, which can be considered novel (or unusual) in the field. This provides an expanded understanding of the challenges faced in terms of enabling flexibility services and CHP plant competitiveness on three levels of the energy system (plant, city, region).

Limitations

It should be noted that the thesis has a strong focus on the Swedish context and does not consider in detail the heat and electricity sectors in other countries. While policy measures and regulatory frameworks can have a strong impact on the competitiveness and development pathways of technologies, these are outside the scope of the thesis, which focuses on techno-economic factors. Close examination of fuel supply chains and fuel market development (for instance, biomass markets) are also excluded from the work.

Given the high representation of coal-fired plants in previous studies on CHP plant flexibility, as well as the focus on decarbonized energy systems, coal-fired plants are not examined in the thesis. While carbon capture services are evaluated for CHP plants, detailed modeling of the CO_2 capture process is outside the scope of this thesis.

1.3. Outline of the thesis

The thesis consists of a summarizing essay and five appended papers. The summarizing essay comprises seven thematic chapters that highlight the key outcomes of the papers and places the work in a context. Following the introductory chapter, Chapter 2 introduces concepts that are central to the methodology applied in the work and presents the scope of the five papers. The techno-economic assessment scheme applied is described and the system levels studied are explained. A short overview of the modeling framework developed within this work and the cases studied are also included.

Chapter 3 provides background information on the technical specifics of CHP plants and heat systems in Sweden and Europe. Results pertaining to the technical feasibility and performance of carbon capture retrofitted to CHP plants are also given. In Chapter 4, flexibility concepts are applied to CHP plants, and the types of flexibility measures that are relevant for the CHP plants considered are described. Chapter 5 presents findings of how the operation of CHP plants might be influenced by strategies for flexible operation and carbon capture. Results relating to the competitiveness of CHP installations in different system contexts and on different system levels are summarized in Chapter 6, together with an economic assessment of carbon capture. Finally, Chapter 7 concludes the thesis with a summary of the overall results and suggestions for future research directions.

2 Methodology

This chapter gives an overview of the methodology developed in the work, which relies on techno-economic modeling. Section 2.1 introduces the main aspects of importance in the techno-economic assessments. Section 2.2 describes the overall modeling framework applied to generate data for the analyses, while Section 2.3 presents the cases and scenarios studied in the appended papers.

2.1 Techno-economic assessments

Techno-economic analyses can be useful tools to support investment decision making processes and to compare technologies with different generation and cost structures or designs. In this thesis, techno-economic studies are applied to estimate the cost of CCS for CHP plants and to evaluate the incentives for CHP plants to provide flexible electricity generation. Traditionally, assessments focus on the levelized cost of energy (LCOE, €/MWh), which is calculated by considering all costs incurred over the lifetime of the technology for the construction and operation and the total amount of energy generated or carbon captured [80]. A similar measure is the levelized cost of carbon (LCOC, €/tCO_2), that can be applied to CO_2 reduction projects [81]. Important parameters in the calculations are the technology investment cost (CAPEX), operating and maintenance costs (OPEX), and the number of full load hours per year (capacity factor). These parameters are further described in Sections 2.1.1-3. Equation 2.1 provides a formula for calculating a simple LCOE metric, in which the annual costs are assumed constant over time. *E* denotes the total annual output of the energy carrier and is connected to the number of full load hours. The capital recovery factor (CRF) is calculated with Equation 2.2, where *i* denotes the discount rate, and *n* is the lifetime of the investment.

$$LCOE = \frac{CAPEX \cdot CRF + OPEX}{E} \tag{2.1}$$

$$CRF = \frac{i}{1-(1+i)^{-n}} \tag{2.2}$$

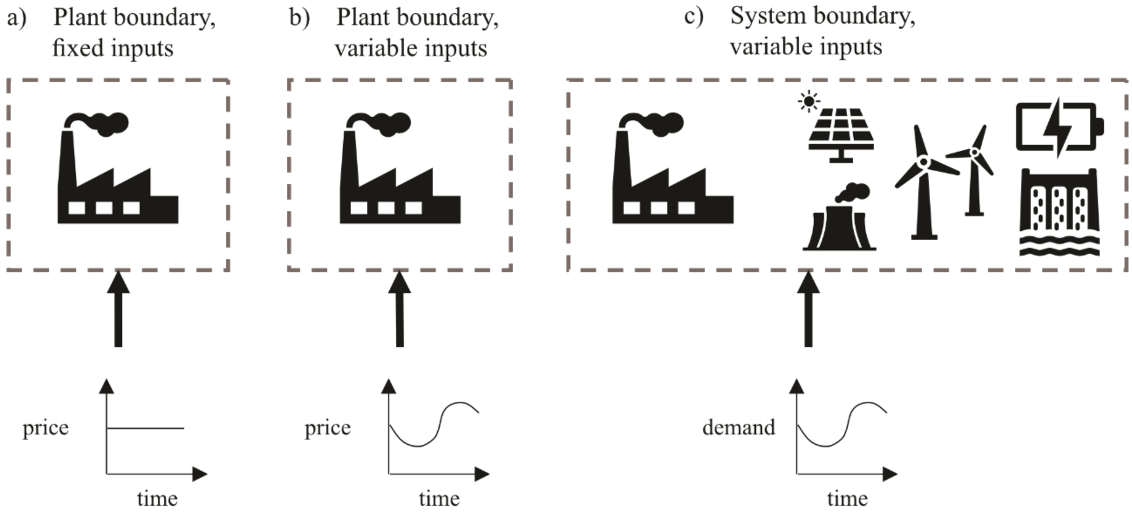

Figure 2.1. System boundaries that can be applied in techno-economic assessments. a-b) Plant-level boundaries with fixed (a) or variable (b) input data. c) System-level boundary with variable input data, that takes into account interaction between technologies.

The LCOC is in this work considered a suitable measure for the carbon capture application. However, in the case of a CHP plant owner that wants to evaluate the profitability of providing flexibility services, the LCOE is of limited use as it does not consider temporal variability in price signals. Therefore, the thesis expands on the LCOE method by including the temporal dimension in the estimation of full load hours and emphasizes the role of actual expected production profiles and the impact of intermittency. Section 2.1.4 motivates the choice of method.

Additionally, it can be argued that the relative competitiveness of a technology depends not only on the technology itself, but also on the interaction between technologies in a system. Thereby, a distinction is made between technology-based (plant-level) assessments that consider the technology on its own, and system-level techno-economic methods that include the interaction between technologies. Figure 2.1 illustrates the system boundaries and input characteristics of the approaches. Figure 2.1a represents the traditional LCOE plant boundary with fixed-value inputs for prices and full load hours, while Figure 2.1b shows an adapted version of the technology-based assessment in which a temporal dimension with variable input signals is added, and the full load hours of the plant are estimated as a part of the method. Figure 2.1c displays the system boundary option, where both the technology in focus and its competitors are represented, and input signals are varying. The system boundaries are further discussed in Sections 2.2-3.

2.1.1 Investment costs (CAPEX)

CHP plants have high technological maturity, as the designs been developed and refined over decades of operational experience. Thus, capital expenses can be estimated based on completed projects. In this work, CHP plant cost data are obtained from the Danish Energy Agency [82]. Since there are few installations globally of carbon capture plants, there is considerably less cost data available for CCS technologies. Rather, the CAPEX of a carbon capture plant design is typically estimated based on detailed process simulations that enable sizing of equipment. The costs of all process equipment are summed and multiplied by sizing parameters, contingency factors, and factors for other known costs, for example, administration, engineering, and commissioning.

In this work, the estimated CAPEX of the carbon capture plant (an MEA process, Section 3.4) is based on the work of Eliasson et al. [77], in which an equation for the CAPEX is presented as a function of the CO_2 flow captured (Eq. 2.3). The equation is derived based on the above described method for cost estimations, where a curve has been fitted to data points for capture plants of different sizes (m_{CO2}, kg/s). The equation represents cases with a flue gas CO_2 concentration of 13%, which resembles the conditions typically found in CHP plants, together with a design capture rate of 90% of the CO_2 in the flue gas at CHP plant full load. The CAPEX is annualized with a discount rate of 7.5% and an economic lifetime of 25 years (Eq. 2.2).

$$Absolute\ CAPEX_{CCS}\ (k€) = 15520 \cdot {m_{CO2}}^{0.6339} \tag{2.3}$$

2.1.2 Operating costs (OPEX)

Operating costs include fuel costs, variable and fixed maintenance costs, and start and part-load costs. Costs for emitting CO_2 might be applicable as well, although CHP plants that combust biomass or waste are currently exempt from the EU-ETS CO_2 trading scheme[2]. CHP plant maintenance costs are obtained from [82], while start costs are based on [83]. Part-load costs are accounted for as a lowering of the CHP plant efficiency. Fuel costs are based on historic price levels up until year 2021 (for example, wood chips cost around 20 €/MWh in Sweden [84]), but the sensitivity to increased biomass price is investigated, see Section 2.3.

The cost of operating a CHP plant with carbon capture is calculated according to Equation 2.4 and comprises the cost (C) of utilities needed to run the process [cooling water (V_{cw}), electricity ($P_{el,CCS}$), and make-up chemicals (V_{MEA})], and the costs for lost electricity production and district heating delivery from the CHP plant ($\Delta_{el,SC}$ and $\Delta_{DH,SC}$) caused by CO_2 capture. Assumed costs and utility demands can be found in **Paper I**, Table 4.

$$OPEX_{CCS} = C_{el}\left(-\Delta_{el,SC} + P_{el,CCS}\right) + C_{DH}\left(-\Delta_{DH,SC}\right) + C_{cw}V_{cw} + C_{MEA}V_{MEA} \tag{2.4}$$

2.1.3 Full load hours and plant operation

The number of full load hours expresses the utilization of a plant on an annual basis. The number of full load hours can be calculated from the capacity factor (CF, Eq. 2.5), which is the ratio of the energy produced within one year (E) and the maximum annual energy production if the plant operates at maximum load (E_{rated}) for 8760 hours. Multiplying CF with 8760 gives the number of full load hours the plant has been in operation during the year.

$$CF = \frac{E}{E_{rated} \cdot 8760} \tag{2.5}$$

Rather than making assumptions on how many full load hours a CHP plant operates, i.e., how much electricity and district heating that is produced, the thesis applies a set of modeling methods

[2] Sweden and Denmark are currently interpreting the EU-ETS as if waste combustion facilities should take part in the emission trading scheme. There is currently also a tax on waste incineration in Sweden. This is considered in Paper II as a sensitivity analysis on the impact of increased fuel cost, given that CO_2 emission costs and the waste incineration tax are directly proportional to fuel use.

to study in detail the operational patterns of CHP plants, as described in Section 2.2. In fact, for the assessment of flexibility services, it might not be the number of full load hours in themselves that are of main interest, but rather *when* the operating hours occur and to what extent they are impacted by variability and match price dynamics. Still, reaching a sufficient number of full load hours is important for technologies with high investment costs, like CHP plants and carbon capture technologies, otherwise the investment is challenging to motivate as the plant might not be able to recover capital expenditures.

2.1.4 Estimating the value of flexibility

To date, there is no established concept of a "levelized cost of flexibility", maybe because flexibility is a vague concept that is challenging to define in the first place. Admittedly, the *levelized cost of storage* has been developed [85], but it does not apply to the flexibility offered by dispatchable power generation. It is generally understood that there is a *system integration cost* (or system externalities) of installing variable renewable electricity generation, i.e., increased balancing costs, transmission grid reinforcement costs, and costs for backup capacity, and that these costs will decrease significantly with increasing levels of system flexibility [86]. However, it is challenging to find a clear definition of how to estimate system integration costs, and the numerical result can be impacted by the system set-up [87]. Measures that extend the LCOE have been suggested, such as the *levelized avoided cost of electricity* (LACE) [88] and the *value-adjusted levelized cost of electricity* (VALCOE) [89]. These extended measures are increasingly based on energy system modeling (in particular dispatch models with adequate temporal resolution), which were argued as being necessary tools to assess balancing costs [90].

Hence, this thesis applies techno-economic dispatch modeling to estimate the value of CHP plant flexibility measures by comparing the results of modeled scenarios. The comparisons are made between scenarios with flexibility measures available and reference scenarios without flexibility measures. The numerical result being compared can be a plant revenue, or the total cost of the system considered (for instance, the cost of a regional electricity system, see Section 2.2.1), depending on the choice of boundary (Fig. 2.1). An advantage of the method is that it also provides detailed insight into the operating patterns and utilization of a flexibility measure.

2.2 Modeling framework

The thesis is based on the development and application of an extensive modeling framework, comprising both process modeling and system modeling to generate data for the techno-economic assessments. This section provides a summary of the models developed and how they complement each other. Figure 2.2 illustrates the scope of models applied, with input data, resulting output and the soft-linking within the framework. Detailed descriptions of the modeling can be found in the appended papers and Appendix A.

2.2.1 Energy system models and production planning

As stated in Section 2.1.4, techno-economic dispatch modeling is the method chosen to assess CHP plant flexibility. Considering the system boundaries portrayed in Figure 2.1, the dispatch models are developed for three system levels of varying geographical scope: (i) a regional electricity price area, (ii) a city, or a district heating system, and (iii) a CHP plant site area. The

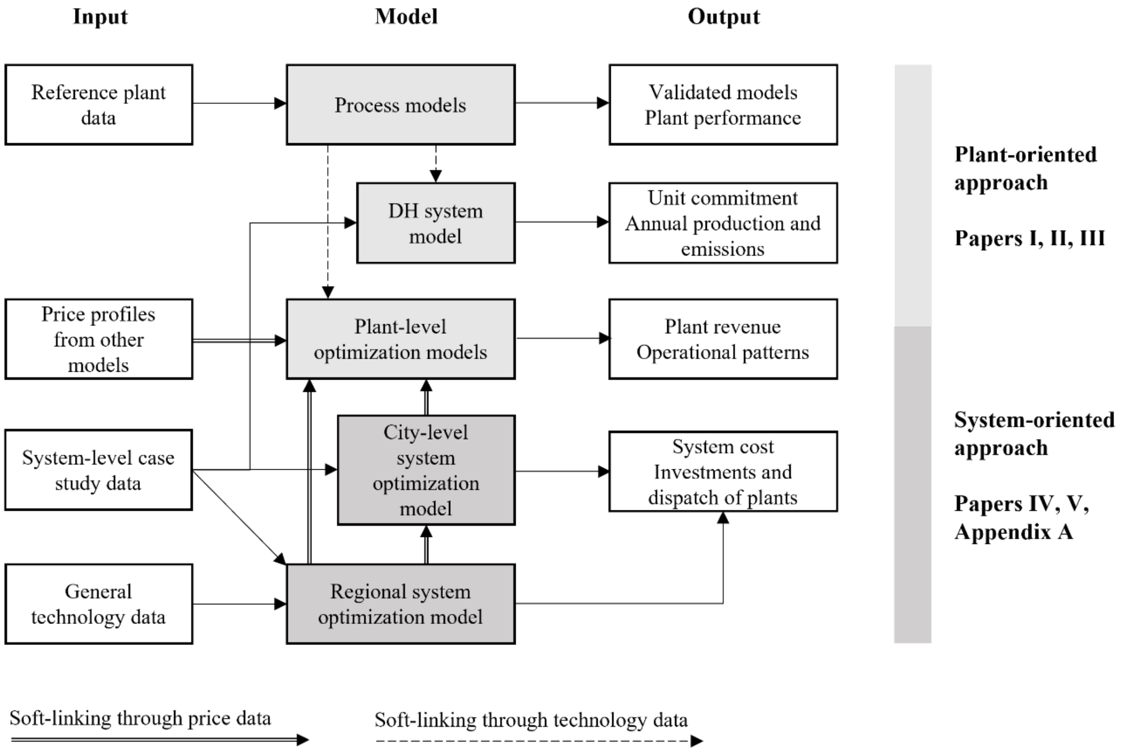

Figure 2.2 Modeling framework overview. DH, district heating.

levels are further described in Section 2.3. All models include both the electricity and district heating sectors and have temporal resolutions of 1-3 hours, spanning one year.

All system models (except for one, described below) are linear or mixed integer optimization models with the objective to either minimize the total system cost (regional and city levels) or maximize the plant revenue (CHP plant level). Here, the total system cost is defined as the total annual cost to supply electricity and district heating demands in the system, including investment and operating costs. The city and regional models are based on previous works [46,91] but have been extended with a detailed representation of CHP plant flexibility measures. The plant-level models have been developed within the thesis work.

Equation 2.6 shows a simplified version of the objective function in the regional system model[3], while Equation 2.7 gives the objective function in the CHP plant-level models[4]. The indexation is simplified for clarity. In the city model, a term is added to Equation 2.6 that takes into account the cost of importing electricity to the city from the regional grid (shown in Appendix A). Note that the plant-level optimization models do not include optimization of investments. Instead, the plant capacity is given as an input.

$$\min C^{tot} = \sum_i C_i^{inv} s_i + TT \sum_t (C_i^{run} e_{i,t} + C_{i,t}^{cycl}) \tag{2.6}$$

[3] Nomenclature: *C*, cost of investments (inv), operation (run) or cycling (cycl); *s*, capacity of investment in technology *i*; *TT*, length of timestep *t*; *e*, energy (electricity and/or district heating) produced.

[4] Nomenclature: *rev*, revenue; *C*, cost of electricity (el), district heating (heat), fuel and variable maintenance (run) or cycling (cycl); *p*, electricity generation; *q*, district heating generation; *y*, fuel use.

$$\max C^{rev} = TT \sum_t (C_t^{el} p_t + C_t^{heat} q_t - C^{run} y_t - C_t^{cycl}) \quad (2.7)$$

Additional constraints are included in the models that, for example, describe the operational space of technologies, and place demands on production levels through energy balances. The output from the regional and city dispatch models includes the optimal combination of technology investments (selected from a given portfolio of options with performance and cost data) to meet the demands, the optimal dispatch of these during the year, and the marginal costs of supplying electricity and district heating. From these results, conclusions can be drawn on the relative competitiveness of CHP plants compared to other technology options in the system, and how CHP plant flexibility measures are utilized (optimal operating strategies). The plant-level models require input data in the form of an electricity price profile and either a price or a demand profile for district heating (depending on whether heat supply is a requirement or optional) and give operating profiles as an output. The input price profiles can be based on historic data or marginal cost profiles from the regional or city optimization models (Section 2.2.3).

For the CCS assessment, a spreadsheet district heating system unit commitment model is developed that determines the operational patterns and full load hours of CHP plants in the district heating system according to a pre-determined merit order. The spreadsheet model does not involve optimization algorithms, nor investment options, but provides an estimate of the yearly operating profile of a plant (with and without CCS) based on input in the form of plant performance data and a heat demand profile. These results are used in the calculation of the LCOC. However, a version of the city optimization model that includes CCS from CHP plants is presented in Appendix A and complements the assessment with a more detailed analysis of the optimal operating strategies of CHP plants with CCS.

2.2.2 Process models and performance assessments

Technology data for the system optimization models are available in the literature for standard power plants [82]. However, performance data for new operating modes, for example, operating a CHP plant with CCS, need to be estimated. Process models are developed for this purpose, including both steady-state models (i.e., fixed operating points) and dynamic models (transitions between operating points).

The software Ebsilon Professional is applied to derive steady-state models of CHP plant steam cycles. The software simulates the performance of the steam cycle (electricity and district heating generation, i.e., efficiencies) in nominal and off-design operating points, based on energy balances and user-specified conditions. The steam cycle configurations simulated are based on the reference plants described in Section 3.3 and the models are validated with measured data from the plants. Cases are also simulated for operating points involving carbon capture, boiler load level variations, and varied ratios of electricity and district heating outputs. These results are used as inputs in the dispatch models described in Section 2.2.1. To comply with the linear program formulations, surrogate models are derived based on the simulation results to linearize the steam cycle operational space, as described in **Papers II** and **III**.

A dynamic model of one of the reference plants (a combined cycle CHP plant, Section 3.3) is developed in the Dymola/Modelica environment, based on the Thermal Power component library from Modelon [92]. The dynamic model is based on a combination of algebraic and differential equations describing the physics of mass and heat transfer in the steam cycle components.

Dynamic modeling entails a higher level of complexity than steady-state modeling but enables the simulation of transient events, for instance, a change of boiler load level, and how this event propagates through the steam cycle to eventually cause a change in electricity output. The simulations are used to estimate parameters relating to flexible operation, e.g., ramp response times.

2.2.3 Soft-linking of models

The exchange of data between process and system models implies a soft-linking between the models and highlights the value of having a modeling framework that can generate different types of data. The range of models also lets the user choose between levels of analysis (plant/ city/region or technology/system, as well as static/dynamic and optimizing/non-optimizing) and enables the comparison of perspectives, so that a holistic understanding of the topic is approached. The techno-economic framework can output a wide range of results, including performance data, operating patterns, revenue estimations and relative competitiveness.

Figure 2.2 illustrates the scope of models applied, with input data, resulting output and the soft-linking within the framework. The soft-linking can be of two types, based on price data (system-oriented approach) or technology data (plant-oriented approach). Price data is used in the optimizing models as a driver for flexible operating strategies. Technology data is used in all models, but the system-oriented models get input in the form of general technology data based on literature values, while the plant-oriented models use specific process data from reference plants or from detailed process simulations.

Note that the soft-linking through price data assumes that the plant or city is a “price-taker” and not a “price-setter”. For the electricity market, this assumption is motivated, since individual CHP plants and cities comprise a relatively small part of a regional electricity system (at least in the case studies applied in this work). Thereby, it is not likely that a change in the operation of one CHP plant would impact the dispatch of the regional electricity system significantly.

While the modeling framework generates marginal cost data for electricity and district heating systems, it does not, in its present form, take into account interactions with fuel markets (e.g., biomass resources). Given the expected increase in competition for biomass and increased demand for electricity through electrification, the interaction between these energy markets, and the impact on modeling results, could be of interest to study and a potential future development of the framework.

2.3 Case studies

A range of case studies that apply the developed modeling framework are presented in the appended papers and Appendix A. This section gives an overview of the case studies and their main contributions to the thesis. Figure 2.3 shows the structural energy system levels that are considered, focusing on the Swedish energy system. While the CO_2 mitigation challenge is of global scale, Sweden has its own targets for CO_2 emissions reductions that biomass and waste-fired CHP plants can contribute to, which motivates a national system level. The Swedish electricity market is divided into regional price areas (SE1-4) to account for transmission grid bottlenecks in the electricity system. Within each electricity price area are cities in which CHP

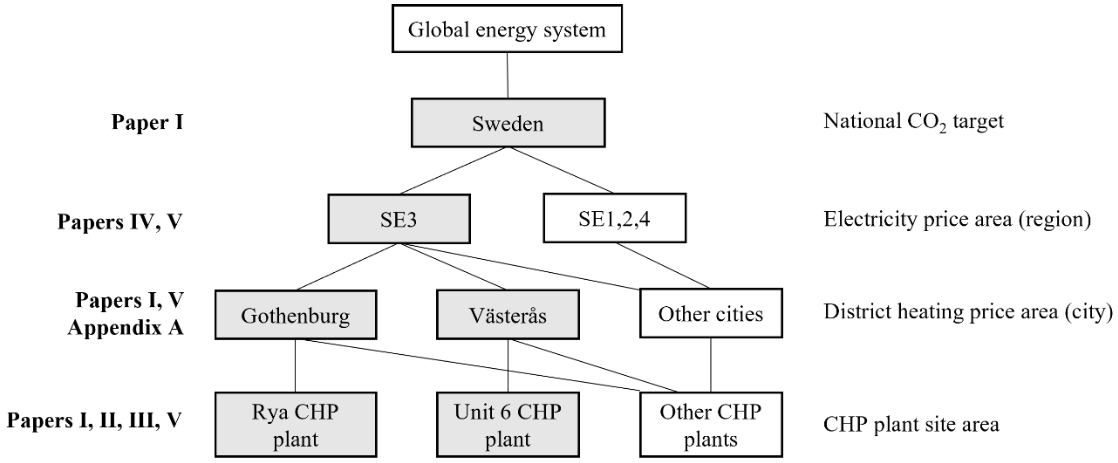

Figure 2.3. Overview of the case studies in the appended papers and Appendix A. SE1-4 are the Swedish regional price areas in the NordPool electricity market.

plants supply district heating. Heat is expensive to transport and therefore district heating networks are typically not interconnected unless they are located in close proximity, leading to city-level price areas for district heating. Finally, each CHP plant site can be considered its own energy system, with inputs and outputs of fuel, electricity, district heating, and CO_2 emissions.

2.3.1 Case study of CCS applied to CHP plants in Sweden (Paper I and Appendix A)

Paper I estimates the cost of carbon capture from the current portfolio of Swedish biomass and waste-fired CHP plants, and the amount of BECCS that can potentially be captured from these. The paper considers (i) process-level case studies for a range of differently configured CHP plants, listed in Table 1 in the paper, and applies a steady-state modeling approach to estimate the impact on steam cycle performance of carbon capture; and (ii) district heating system (city-level) case studies to assess the impact of BECCS on CHP plant operation and full load hours. The case study results are input to a calculation of the plant-specific LCOC that form a marginal abatement cost curve and indicate the total national potential for BECCS from Swedish CHP plants.

As mentioned in Section 2.2.1, **Paper I** applies a non-optimizing spreadsheet tool to estimate CHP plant operating patterns. In this thesis, dispatch results are also provided based on the optimization modeling approach described in Appendix A. Appendix A considers a case study of the district heating and electricity systems in the Swedish city Västerås. Key outcomes from the modeling described include (i) the impact on optimal CHP plant production patterns of BECCS, (ii) the optimal dispatch patterns for the carbon capture plant, and (iii) the impact on the city marginal costs of electricity and district heating.

2.3.2 Process-level case studies of CHP plant flexibility (Papers II and III)

Papers II and **III** assess the utilization and plant-level value of flexibility measures in two reference CHP plants. Process dispatch optimization models are applied to find the optimal operating patterns and plant revenues in response to a heat demand profile and an electricity price profile. The sensitivity of the results to electricity price profiles with varying levels of volatility is studied with a set of price profiles obtained from the work of Göransson et al. [93] (shown in the Supplementary Material of **Paper II**).

The CHP flexibility measures considered in the thesis are described in Chapter 4. **Papers II** and **III** focus on *product flexibility* (the ability to vary product ratios) and *thermal flexibility* (the ability to store heat). Steady-state process models are used to estimate the steam cycle performance in operating points with different product ratios. The optimized revenue of model runs with/without the flexibility measures are compared to estimate the value of each measure. In addition, **Paper III** also applies a dynamic model to estimate ramp response times, for an assessment of the value of *operational flexibility* in the form of increased ramp rate, considering an hourly electricity market context.

2.3.3 System-level case studies of CHP plant flexibility and competitiveness (Papers IV and V)

System-level case studies are found in **Papers IV** and **V**. Both papers consider the regional electricity price area SE3 in Southern Sweden, where a large share of the current Swedish CHP plants are located. Energy system optimization models are applied to study the cost-optimal system design and operation for year 2045, with a greenfield assumption (no existing capacity in place in the system) since most of the existing plants will have reached the end of technical life by that year. The exception is that existing hydropower capacity is assumed to be in place, and that hydropower from other electricity price areas (mainly SE1-2) can be imported to the region. A condition is that no carbon emissions are allowed in the system. In addition to a regional case study, **Paper V** also contains a city-level case study of Gothenburg, the second largest city in Sweden, located in the SE3 region.

The objective of **Paper IV** is to assess the competitiveness, utilization, and system-level value of CHP plant flexibility measures, as opposed to **Papers II** and **III** that focus on the process-level value. **Paper V** compares the competitiveness of CHP plants on the regional and city levels, considering that the levels are subject to different sets of technology options, and that the city might have a limited grid connection capacity.

Seeing that the set-up of the system studied might impact the results [87], several scenarios for the potential energy system development are studied. Since Sweden is a country with high availability of hydropower and a portfolio of nuclear plants that are approaching end-of-life, scenarios are included to assess the impact of continued use of nuclear power and the sensitivity to reduced hydropower availability. The biomass price and access to thermal energy storage (TES) are also varied. Finally, the availability of CHP plant flexibility measures is varied in **Paper IV** to enable the comparison of total system cost between the scenarios and reference runs without CHP flexibility measures (Section 2.1.4).

3 CHP plant technology

This chapter provides a background for the concepts discussed in the thesis, focusing on the technical aspects of CHP plants, as well as Swedish and European heating systems. The reference CHP plants studied in the thesis are described, and the possibility to integrate carbon capture processes is outlined, based on process modeling results from **Paper I**. Although there are both municipal and industrial CHP plants in Sweden, the thesis focuses on municipal plants that are operated primarily for district heating supply, in contrast to the industrial plants that primarily supply heat to industrial processes, for example, in the pulp and paper industry.

3.1 Combined heat and power in Sweden and Europe

3.1.1 Sweden

Since the emergence of district heating in Sweden in the 1950s, CHP plants have become an important part of the Swedish heat sector, supplying around 25 TWh of district heating annually [8], corresponding to 45-50% of total district heating deliveries [5]. The incentives for CHP plants have varied over time in response to energy policy and energy system development, as visualized in Figure 3.1. In the 1950s, there was a need for new electricity production capacity (and heat supply) as the hydropower capacity neared its maximum levels, and conditions were favorable for CHP plants. However, with the expansion of nuclear power in the 1960s, electricity prices decreased and favored direct electric heating rather than district heating, which lowered the profitability of CHP electricity production. With the oil-crisis in the 1970-80s, heat supply in residential buildings shifted from oil boilers to other technologies, including district heating, and district heating expanded in response to an increase in the building stock. Come the 2000s, policy measures granted green electricity certificates to CHP plants, increasing economic incentives [94].

As for the future, the uncertainty in electricity price development leads to challenging decision-making processes in projects that investigate the replacement of to-be-decommissioned CHP

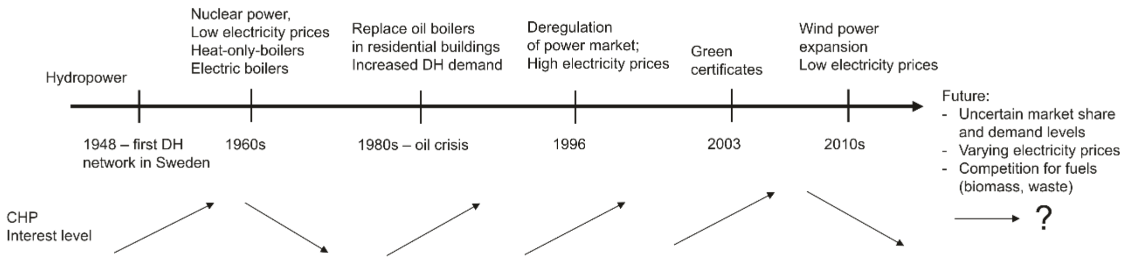

Figure 3.1. Timeline of major energy system developments in Sweden (1950-2020) that have influenced the incentives for CHP plants. DH, district heating.

plants with new CHP capacity. Instead, heat-only plants are considered, sometimes with the possibility to retrofit a steam turbine at a later point if profitable [95]. On the other hand, electrification, and thereby the electricity demand, is expected to increase, and electricity prices in 2021-2022 have increased sharply compared to previous levels, which favor cogeneration.

The fuel use in Swedish CHP plants has also shifted over time [96]. At the onset (1950s), most plants were coal or oil-fired. With the oil crisis, other fuels, such as peat and biomass, started to be used. Municipal solid waste was not incinerated in CHP plants until the 1980s, when the landfilling of several waste fractions (paper, packaging, furniture) was forbidden, making energy recovery from waste a necessity to meet regulatory standards.

As of year 2020, there are some 110 municipal CHP plants in regular operation in Sweden, of which the majority combust biomass (typically forest residues) or municipal solid waste fuels. Fossil fuels have nearly been phased out from the district heating sector, except for one natural gas-fired combined cycle plant (conversion to biogas under consideration) and reserve units that are seldom used. Figure 3.2 presents the distribution of Swedish municipal CHP plants with respect to installed capacity, fuel type and steam cycle power-to-heat ratio (α) (i.e., the ratio of electricity production capacity (P) and heat production capacity (Q), Eq. 3.1). Most plants are smaller than 200 MW thermal capacity but with varying power-to-heat ratios.

$$\alpha = \frac{P}{Q} \tag{3.1}$$

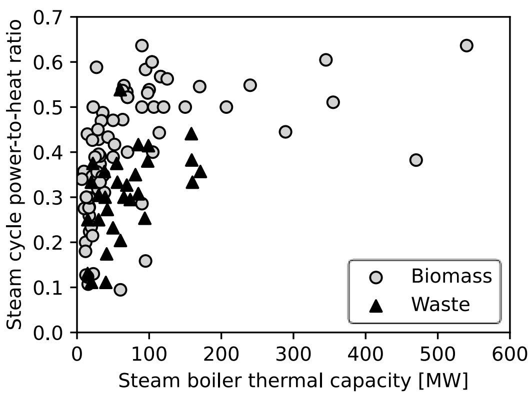

Figure 3.2. Characterization of the 110 Swedish CHP plants that combust waste or forest residues, with respect to boiler thermal capacity, steam cycle power-to-heat ratio and fuel type. Each marker represents one plant. Source: Paper I.

It is worth mentioning that district heating systems, although in widespread use in Swedish cities, stand in competition to other heat supply systems, for example electric heating using heat pumps in individual buildings [97]. With the implementation of building energy conservation measures, building heat demands are expected to decrease and might lead to reduced district heating demand levels [98], which on the other hand might be partly offset by an increased building stock.

3.1.2 Europe

As in the Swedish heat sector, other European countries' heat systems are based on a portfolio of technologies that reflects the country's energy system at large, heat demand patterns and resource availability. For instance, in Norway, the electricity system is to a large extent based on hydropower with low operating costs, and has traditionally made direct electric heating a competitive choice for space heating [99]. Iceland has good conditions for geothermal heating, including geothermal CHP plants that supply heat to a low cost [100]. Finland and Denmark have, like Sweden, a tradition of CHP plants for district heating, using a mix of fuels that include coal, natural gas, biomass and waste.

On a European level, CHP plants comprise around 9% of the total energy use for space heating, while natural gas covers the main share (42%), followed by direct electric heating (12%), oil boilers (12%) and biomass boilers (11%) [101]. Figure 3.3 shows the year 2015 fuel use in CHP plants (municipal and industrial) in a selection of EU countries [102]. Natural gas and solid fossil fuels dominate the CHP energy mix in most of the represented countries, whereas Sweden and Finland stand out with a large share of biomass fuels. In most of the countries represented, the share of municipal CHP plants is at least 40%, but in the UK and Spain it is close to 0%.

With the transition to a fossil-free energy system, natural gas-based heating is likely to need replacement. District heating has been suggested as a low-carbon alternative [103,104], although it would require large infrastructure changes. The EU energy efficiency directive promotes the use of district heating and cogeneration to improve energy efficiency [105,106]. EU countries must conduct a cost-benefit analysis of the potential of using cogeneration when planning to build or refurbish heat, electrical or industrial installations (if above 20 MW thermal input). Some studies that were presented prior to the currently high electricity prices indicate that power-to-heat units

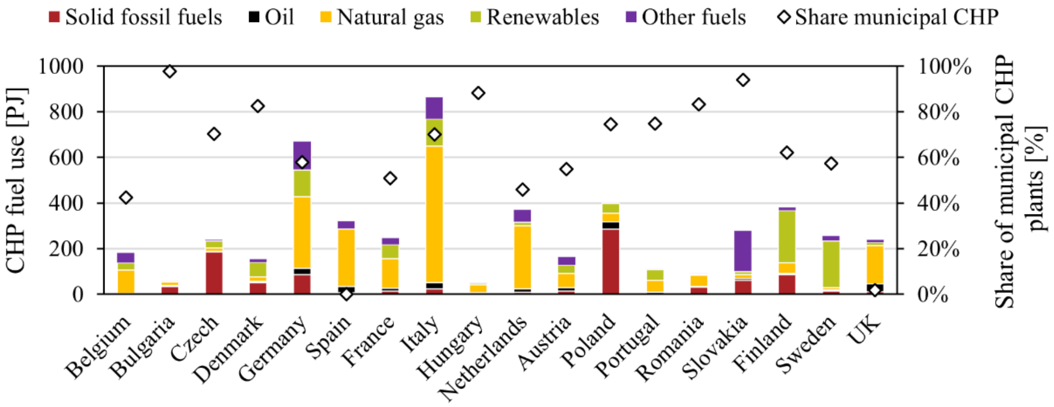

Figure 3.3. CHP plant fuel use in 2015 in EU countries (countries with <50 PJ fuel use are excluded). The fuel use is for both municipal and industrial CHP plants, but the secondary axis indicates the share of municipal plants. "Other fuels" include amongst others industrial wastes and coal gases. Based on Ref [102].

could be more favorable than CHP installations for German and Finnish district heating systems [107,108] and that CHP based heat production in Helsinki, Finland, might decrease by 70% by 2030 when phasing out fossil fuels [108]. In contrast, bioenergy in CHP plants was found to be a future competitive option in the German heat sector in another publication [109]. Policy measures are outside the scope of this thesis but are important factors to consider for CHP competitiveness, as well as differing national targets and energy strategies. Studies have found that support schemes for CHP plants might be necessary for plants to be competitive [110,111].

Power-to-heat could be used as a flexibility measure in the electricity system [112], but it also puts additional strain on the electricity sector. It is estimated that the widespread use of CHP plants in Sweden has indirect electricity benefits corresponding to 7 GW of avoided power-to-heat electricity consumption [96], which equals around 25% of the current peak electricity consumption in Sweden.

3.2 Process description

A CHP plant is a thermal power plant that converts the chemical energy in a fuel into electricity and useful heat. Solid-fuel plants consist of three main parts: a boiler, a steam cycle, and a flue gas train. An alternative plant configuration is the combined cycle CHP plant that combusts gaseous (or liquid) fuels, in which the boiler is replaced by a gas turbine and a heat recovery steam generator. Solid-fuel plants (biomass and waste) are modeled in **Papers I** and **II**, while **Paper III** focuses on a combined cycle CHP plant. Figure 3.4 shows a principal diagram of a CHP plant steam cycle. A combined cycle is displayed in Section 3.3.

The boiler acts as a combustion chamber in which fuel energy is converted to heat. The heat is used to produce steam of high temperature and pressure that is sent to the steam cycle for power generation. Typical steam conditions in biomass and waste-fired CHP boilers are 540°C/140 bar and 400°C/40 bar, respectively, but other combinations of steam data are possible (see **Paper I**, Table 1). Although the boiler is a complex component consisting of different types of heat exchanger surfaces and combustion zones, the boiler is described with a fixed efficiency in this thesis. The focus is instead on the steam cycle.

In the steam cycle, a steam turbine converts the enthalpy of the high-temperature and high-pressure steam to kinetic energy that rotates the turbine, which in turn drives a generator that produces electricity. The steam that exits the turbine is condensed in a condenser before it is returned to the boiler to be regenerated. The turbine outlet steam is of low pressure, below 0.1 bar, for a condensing power plant, and between 0.4 - 1.2 bar for CHP plants. The exact pressure depends on the temperature of the condenser cooling medium. For a CHP plant the cooling medium is district heating water, which is heated to a temperature of around 75 - 110°C, depending on network operation and season. For a condensing power plant, the cooling medium is cold water or air, which can be around 5-35°C, that allows the steam to expand to a lower pressure (thereby enabling increased power generation) compared to a CHP steam turbine. To increase the electric efficiency in CHP plants, it is common to install two district heating condensers (backpressure and extraction condensers), so that the heating of the district heating water is performed in steps at two temperature levels.

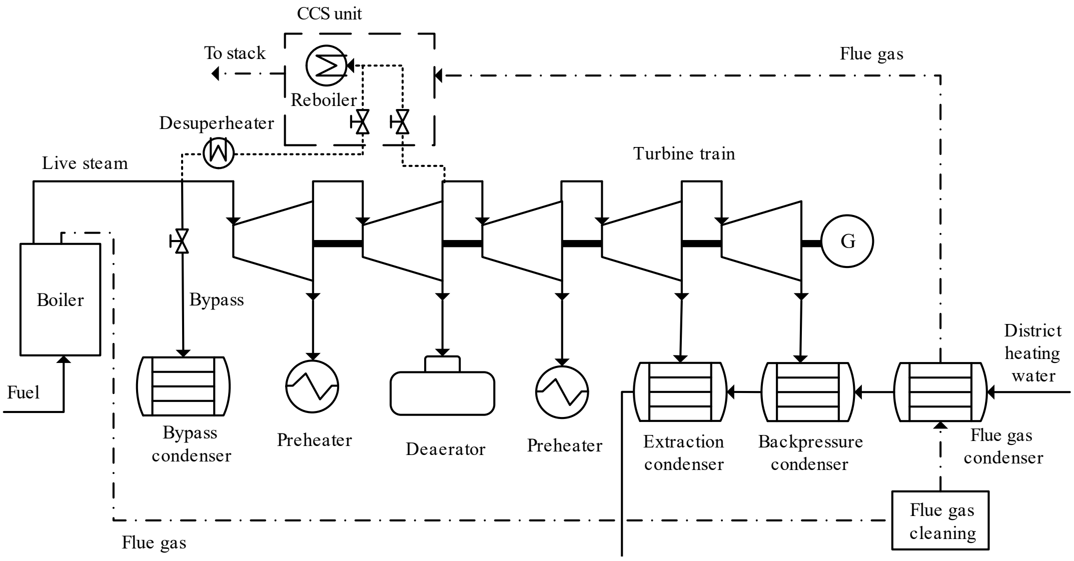

Figure 3.4. Process schematic of a CHP steam cycle. The feed water system is omitted for clarity. Dotted lines represent steam extraction alternatives that can be retrofitted to drive a carbon capture reboiler. Source: Adapted from Paper I.

The condensate that is recycled to the boiler (called the feed water) can be pre-heated in one or several steps to increase the electric efficiency of the process. For this purpose, steam can be extracted from the turbine to preheaters, in which the extracted steam condenses to heat the feed water. There is also a deaerator (feed water tank) to which steam is extracted. For operational safety, a bypass condenser is commonly installed in the steam cycle, allowing live steam to be directly condensed instead of entering the turbine.

During combustion, the fuel is converted to flue gases that are emitted to the atmosphere. The flue gases comprise a mixture of nitrogen (N_2), carbon dioxide (CO_2), water vapor (H_2O) and pollutant species such as carbon monoxide (CO), nitrogen oxides (NO_x), sulfur oxides (SO_x) and particles. The water vapor can be condensed in a flue gas condenser to generate low-grade heat for district heating. All Swedish CHP plants have some type of flue gas cleaning system to keep the emitted concentration of pollutant species at acceptable levels. Thereby, waste-fired boilers provide excellent waste management opportunities that to a large extent prevents pollutants from reaching the environment. However, CO_2 is released to the atmosphere, but might be removed from the flue gas by the installation of CO_2 capture technology. Apart from considering the process integration aspects of CO_2 capture from flue gases, the flue gas cleaning is outside the scope of this thesis and is not further discussed.

Finally, a control system is needed to enable safe and stable operation of the plant. Important variables to maintain at set point levels include: live steam temperature and pressure, fuel feed rate, and air intake (air/fuel ratio). By changing the set point value of a controlled variable, the plant can be brought into different operating points. For example, adjusting the fuel input will change the boiler load level and electricity and heat generation, and a re-routing of steam from the turbine to the bypass condenser can lower the electricity production in favor of increased heat output.

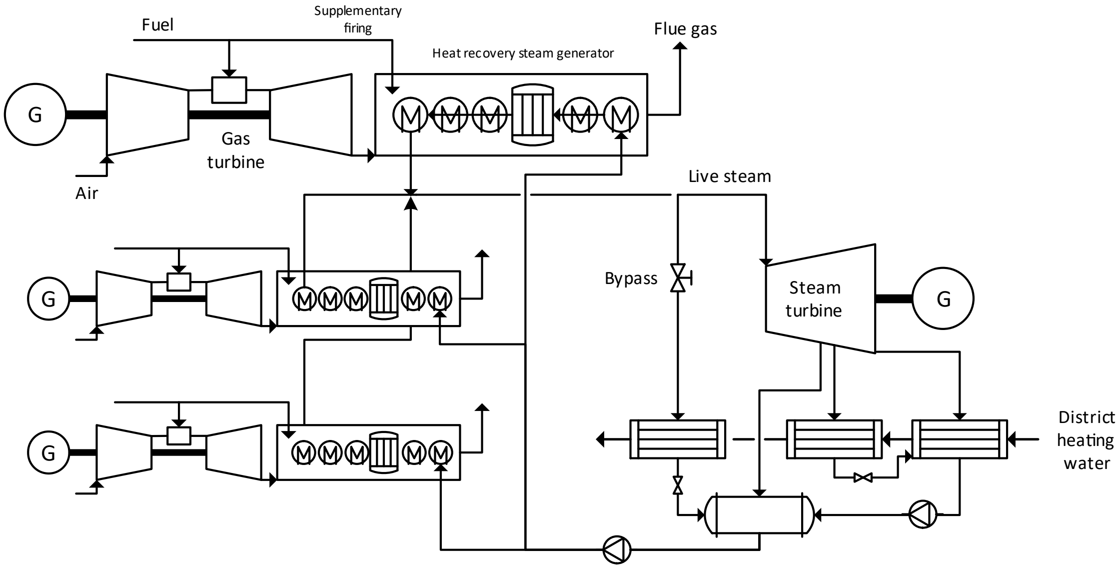

Figure 3.5. Process diagram depicting the combined cycle reference plant. Source: Adapted from Paper III.

3.3 Reference CHP plants

Two combined heat and power plants are used as references in **Papers II** and **III**: a waste-fired plant and a natural gas-fired combined cycle plant. Thus, the most flexible and inflexible types of CHP plants are represented in the work (further discussed in Chapter 4). A number of Swedish CHP plants (see **Paper I**, Table 1 for a list) are also used as cases in **Paper I**, although modeled with a lower level of detail.

The waste-fired plant is a 48 MW_{el} CHP plant, located in Västerås, Sweden, and operated by Mälarenergi AB as a baseload unit in the municipal district heating system. The total annual heat production in Västerås amounts to some 1.8 TWh, with a peak demand of around 630 MW. The waste-to-energy plant has a circulating fluidized bed boiler for steam regeneration with a load range of 70-100% of full load, and a nominal capacity of 167 MW fuel. The plant configuration, with emphasis on the steam cycle, is shown in Figure 3.4. The plant has extraction and backpressure condensers for district heating generation, and steam extractions for feed water preheating and deaeration.

The combined cycle plant is located in Gothenburg, Sweden, and is operated as an intermediate/peak load unit in the district heating network. The total annual supply of district heating in Gothenburg is around 4 TWh, with a peak demand of 1.2 GW. The combined cycle has a nominal capacity of 300 MW heat and 250 MW electricity, including three gas turbines with nominal power 43 MW (ISO conditions). The gas turbine load range is 30-100% of nominal capacity. The plant design is displayed in Figure 3.5. There are three parallel lines with one gas turbine, single-pressure heat recovery steam generator and supplementary firing burner each; and one steam turbine. District heating is extracted from the steam cycle condensers via one backpressure and one extraction condenser.

3.4 Integration of carbon capture

With the increasingly strong focus on reducing CO_2 emissions and achieving carbon dioxide removal, the possibility to retrofit Swedish CHP plants with CCS has received attention in the 2020s. The utility company Stockholm Exergi is planning to retrofit one of their biomass-fired CHP units with a carbon capture process to capture 800 ktCO_2 annually, with a potential second installation at a waste-fired plant [113]. The Swedish Energy Agency has announced that a reversed auctioning system for negative emissions will be put in place by 2023 to help finance CCS projects, and remain until 2045 [114]. Several district heating companies have shown an interest in CCS and conducted studies to investigate the technical and economic conditions for BECCS at their specific plants [115]. Norway is also a frontrunner with an upcoming 400 ktCO_2/year CCS installation by year 2026 at the waste CHP plant Klemetsrud [116], at which experimental pilot campaigns have been conducted for technology demonstration [117].

CO_2 can be sequestered by a range of technologies that differ in technological maturity [118]. Absorption of CO_2 from flue gases with an amine-based solution is a commercially available option [119] that can be retrofitted to power plants, and is the technology considered in this thesis. In the capture process, the flue gas enters an absorber column, in which a liquid solvent absorbs CO_2, while CO_2-lean flue gas is vented to a stack. The CO_2-rich solvent is passed to a stripper column, where heat is supplied, causing the desorption of CO_2 from the liquid. The solvent is recycled back to the absorber, and the pure CO_2 stream leaving the stripper is compressed and liquefied prior to transport to a permanent storage site.

CHP plants differ from condensing power plants and industries in that heat is the main product, and the capture process heat requirement might therefore interfere with the main business. Absorption-based CO_2 capture is energy-intensive due to the heat required to desorb CO_2 and regenerate the solvent. Heat would typically be provided by condensing steam at around 120°C. However, steam extraction from the CHP steam cycle to power CCS will impact the electricity and district heating generation. Magnanelli et al. [120] examined different options for amine-based carbon capture integration in a waste-fired CHP steam cycle, concluding that electricity production decreases with 6-30% depending on integration scenario, which can be lowered if only the fossil share of emissions is captured [121].

Paper I models the retrofit of a standard amine-based carbon capture process (30 wt% aqueous MEA) to a set of Swedish CHP steam cycles (listed in Table 1, **Paper I**). A 90% design capture rate is chosen, with a conservative reboiler heat duty of 3.6 MJ/kgCO_2 [72], although research efforts are being made to develop advanced solvents with a lower reboiler duty [122] and processes that efficiently achieve capture rates well above 90% [123,124]. Depending on the steam cycle design, steam is extracted either from the steam turbine or directly from the live steam to power the capture unit, see Figure 3.4. Additionally, there might be opportunities to recover low-grade heat from the capture process that could be used for district heating supply, possibly with the aid of heat pumps. Depending on the heat integration and capture process design, different percentages of heat recovery have been estimated. Based on Ignell and Johansson [125], the potential for heat recovery is estimated to around 64% of the amine-based capture plant heat demand, while the configuration studied by Eliasson & Fahrman [126] could potentially recover around 25% of the input heat.

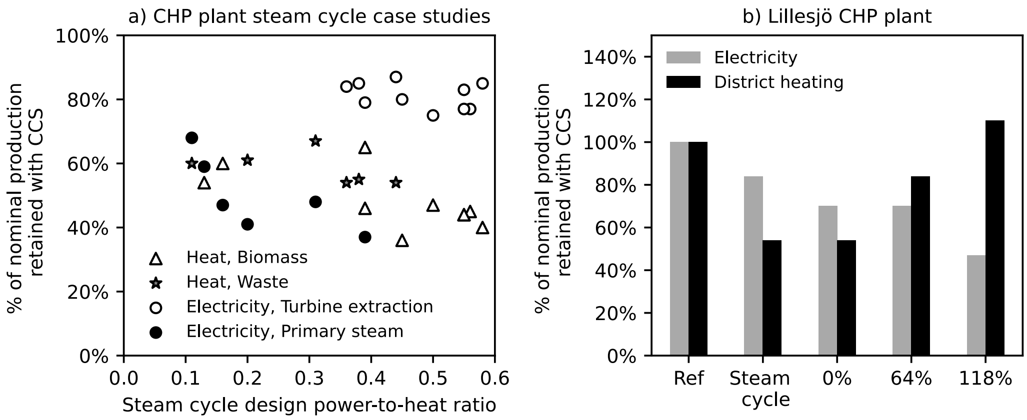

Figure 3.6. a) Performance of steam cycles retrofitted with a MEA process with 90% capture rate, as a function of power-to-heat ratio. b) Net CHP plant performance with carbon capture and conditioning, for the case of Lillesjö CHP plant. "Ref" represents the performance without CCS, "Steam cycle" is the steam cycle performance with CCS, and 0/64/118% represent the net plant performance with different levels of heat recovery. Source: Adapted from Paper I.

Figure 3.6 shows results from **Paper I** and the process modeling of CHP steam cycles with carbon capture. Figure 3.6a visualizes the range of performances simulated for steam cycles with different designs and power-to-heat ratios. Extracting steam from the turbine decreases electricity generation by 15-25%, while the reduction is up to 60% if using primary steam. Waste-fired steam cycles generally retain a higher percentage of heat production (54-67% retention) compared to biomass (36-65% retention). Figure 3.6b plots the net CHP plant performance for one of the studied plants (Lillesjö CHP plant), including the potential heat recovery from the capture unit and the electricity demand for CO_2 compression and liquefaction. Three levels of heat recovery are included: 0% = no heat recovery, 64% = heat recovery through heat exchangers, 118% = heat recovery through heat exchangers and heat pumps applied to low-grade heat below 60°C. If heat pumps are utilized, the CHP plant net electric capacity can decrease by up to 60%. The district heating generating capacity can either decrease or increase compared to the reference case depending on heat integration.

4 Flexibility potential of CHP plants

The traditional purpose of a CHP plant is to generate heat and electricity with high efficiency. One commonly discussed question is to what extent this can be done in a flexible way. “Flexibility” is a vague concept that can have various interpretations in different contexts. This chapter describes the definitions of flexibility that are derived and applied in the thesis and how they relate to the CHP process design and operation. Results from the appended papers are presented to illustrate the technical potential for flexibility in CHP plants. Table 1.2 (Section 1.1) gives an overview of CHP plant flexibility measures that have been considered in previous research. Several of the listed measures imply an investment cost (e.g., internal storage systems or turbine renovations) that might have low feasibility for Swedish plants of small-to-medium scale and lower complexity than previously studied plants, which also reduces the applicability of measures that require certain steam cycle configurations. Therefore, the thesis focuses on flexibility measures that might be readily available in most CHP plants to a low cost.

Cambridge Dictionary gives the following definition for flexibility: “the quality of being able to change or be changed easily according to the situation” [127]. For electricity systems, flexibility can generally be understood as the ability to change over time in response to net load variability. For condensing power plants that only produce electricity, flexibility has been studied in terms of *operational flexibility*, describing to what extent and at what rate the boiler can be operated to vary production level. For CHP plants (or polygeneration plants in general), there are additional opportunities to adjust output levels by varying product ratios. In this thesis, such flexibility is defined as *product flexibility*. There is also a temporal dimension of flexibility if storage possibilities are considered, often denoted as *load shifting* in the literature. District heating water is relatively low-cost to store in a thermal energy storage (TES). The TES can, depending on its location and integration, be considered either a plant or a system-level flexibility measure that can be utilized by CHP plants. In **Papers II** and **III**, TES is included as a parameter and denoted as *thermal flexibility*, while it is available as a dispatchable technology in the system models in **Papers IV** and **V**.

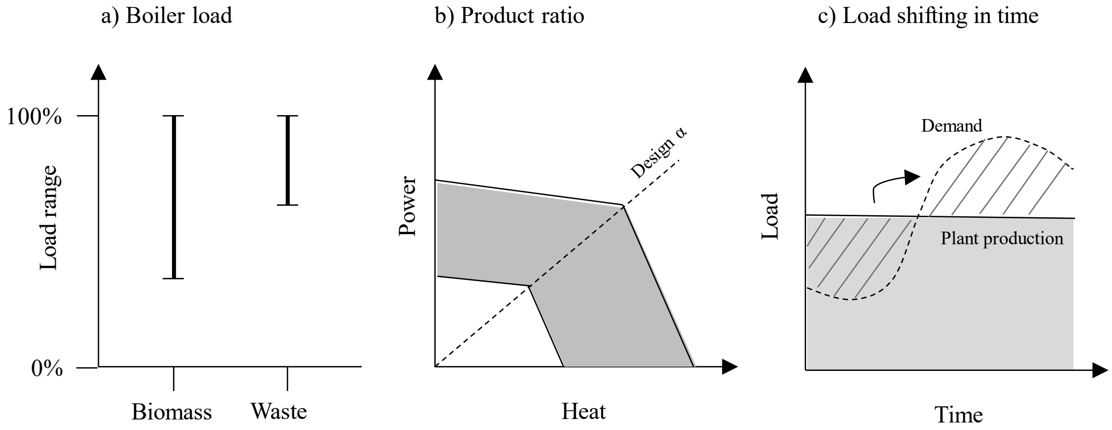

Figure 4.1. Dimensions of CHP plant flexibility. a) One-dimensional flexibility in the form of boiler load range. b) Two-dimensional flexibility obtained from the ability to vary product ratios (α) in addition to boiler load variation. c) Flexibility in time (load shifting) enabled by energy storage.

Figure 4.1 illustrates the three types of flexibility, highlighting that each type adds one additional degree of freedom to the plant feasible operating region. Operational flexibility can be seen as a one-dimensional flexibility, that enables an increase or decrease of the plant output depending on the rate of fuel consumption (load level, Fig. 4.1a). Biomass-fired boilers typically have a wider load span (40-100% of full load) than waste-fired boilers (70-100%). A flexible product ratio in the steam cycle adds a second dimension of flexibility, where the electricity and heat outputs can be varied through the steam cycle operation (Fig. 4.1b). Finally, Figure 4.1c illustrates the utilization of energy storage: production can be shifted in time to match fluctuating energy prices and demand levels, if adjustment of the production level itself is unwanted.

While flexibility services are needed on a range of timescales in the electricity system, from sub-second (system stability) to seasons, this work focuses on flexibility on hourly to seasonal timescales given that renewable energy generation is expected to vary in these intervals.

4.1 Operational flexibility: Boiler dynamics

Operational flexibility relates to the boiler operation and is often defined by three parameters:

- **Ramp rate**: the rate at which the boiler can transition between load levels, often expressed as MW/min.
- **Minimum load level:** the load range of the boiler that can be utilized, i.e., the magnitude of load changes that can be performed without turning off the unit.
- **Cycling properties**: parameters that describe the conditions for start and stop of the boiler, such as start-up time, and minimum down/up-time.

CHP plant boilers are (in Sweden) generally designed for stable operation, going towards circulating fluidized bed boilers with a large thermal inertia to enable stable combustion conditions for heterogeneous fuels. Thereby, fuel flexibility is prioritized rather than operational flexibility. Waste-fired boilers in particular have low operational flexibility, with a high minimum load level (around 70% of full load), long start-up times (at least 24 hours, preferably longer), and an operational role as baseload, designated to run on stable load for the main part of the year without

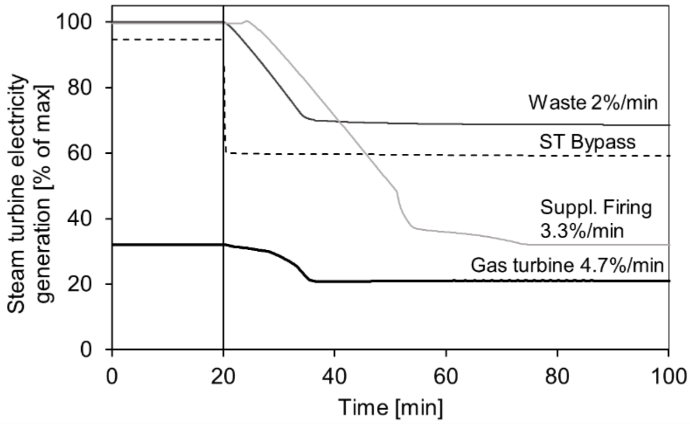

Figure 4.2. Steam turbine electricity generation responses when the thermal input to the steam cycle decreases from full to minimum load, for a waste-fired steam cycle, gas turbine and supplementary firing load changes. The dashed line represents the response from steam flow regulation through a turbine bypass in the waste-fired steam cycle. The ramp rates are indicated by the labels, in load-%/min of nominal capacity. The ramp is initiated at time = 20 minutes, indicated by the vertical line. Source: Paper III and Refs [129,130].

the need to design for rapid ramp rate capabilities. In general, dynamic operation of thermal plant boilers is to a large extent unwanted, since it causes thermal stress that is harmful to heat exchangers and boiler tubes, with decreased technical lifetime and increased maintenance costs as a potential result. Nevertheless, electricity price or net load volatility might incentivize flexible operation.

Efforts to improve the operational flexibility include the lowering of the minimum load level, faster cycling (e.g, start-up time and minimum down-time), and faster ramp rates. Dynamic simulation can be applied to study thermal power plant operation and control system designs that enable greater flexibility and faster response times for electricity generation, see for instance the review by Alobaid et al. [128]. In this work (**Paper III** and Refs [129,130]), dynamic simulations have been used to characterize the steam turbine electricity generation response times for linear load reduction ramps. Figure 4.2 plots the simulated steam turbine responses for load decreases induced by changes (from full to minimum load) in flue gas energy flow (corresponding to a boiler load decrease), supplementary firing load, gas turbines, or steam turbine bypass control, for the waste-fired and combined cycle reference plants.

The responses from the waste-fired and supplementary firing thermal input changes follow similar trends, with the electricity generation output following the linear ramp rate. Both of these responses are comparatively slow to completely settle at the new steady-state operating point, but 95% settling is reached within 17 minutes for the waste-fired case, and 34 minutes for the supplementary firing example, having a load reduction twice as large as in the waste-fired case. The combined cycle gas turbine load reduction induces a different trend, with a sustained steam turbine electricity generation close to the initial level before the electricity generation approaches the new operating point. This response pattern could be related to the increase in gas turbine exhaust temperature observed for gas turbine load changes (see Figure 7a in **Paper III**), causing the live steam enthalpy to decrease slower than for the supplementary firing load reduction, for which the flue gas temperature strictly decreases.

The steam turbine response times are in the range of 15-55 minutes for the thermal input reductions, depending on the magnitude of load reduction and ramp rate. In comparison, the response time for the steam turbine bypass option is within 3 minutes [129]. These results imply that flexible operation targeting the hourly electricity market is feasible for CHP plants, and that thermal input load changes might be a flexibility measure that can contribute to the management of net load variability. For markets with shorter timescales, such as ancillary services and frequency control, the steam turbine bypass could be a feasible option. Combined cycle gas turbines might, of course, also contribute with rapid load changes, but have not been studied in this work.

4.2 Product flexibility: Operational modes

Product flexibility relates to the ability to change production levels (i.e., vary steady-state operating points) by adjustment of product ratios, with or without concurrent variation of the boiler load level. The measures can be combined for increased effect, but this is not necessary. For a CHP plant, the steam cycle power-to-heat ratio can be varied by, for example, using the bypass condenser (Figure 3.4) to regulate the steam flow to the turbine, or by switching to condensing operation if the plant is designed with this possibility. Additional products might also be considered for a greater span of operational points and product ratios, for instance ancillary services [131,132] and carbon capture. It could also be possible to integrate biofuel production through thermochemical conversion of biomass or waste, as discussed in [133,134].

Product flexibility enables a load range expansion, as is visualized in Figure 4.3 for the reference plant steam cycles. The solid lines indicate operation between minimum and full load in three operational modes (product ratios). The diagonal lines represent conventional cogeneration of heat and electricity with a fixed power-to-heat ratio (denoted CHP). The feasible operating regions, marked by the dotted lines, are significantly enlarged with product flexibility compared to conventional operation. Operation in condensing modes could potentially increase the electricity generation at full load with 27% and 39% for the waste-fired and combined cycle plants, respectively. The corresponding numbers for increased heat production potential are 44% and

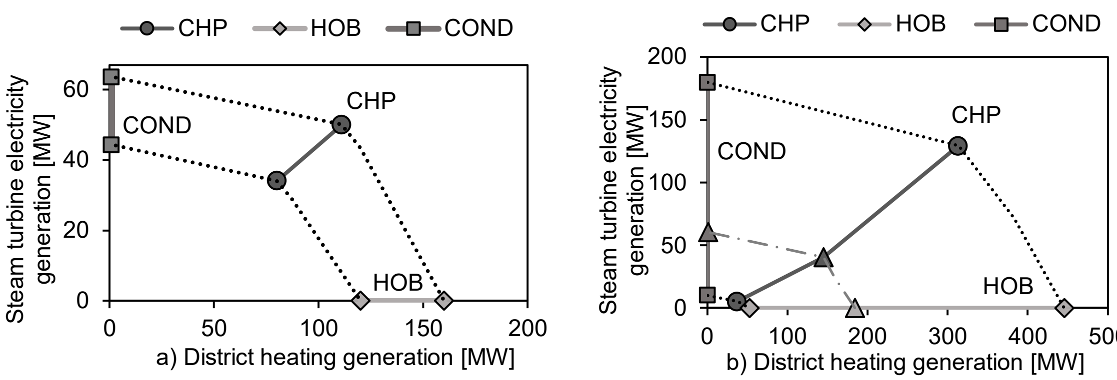

Figure 4.3. Steam cycle load range expansion from product flexibility, for the a) waste-fired, and b) combined cycle reference plants. CHP, combined heat and power generation; HOB, heat-only generation; COND, electricity-only generation. Dotted lines mark the feasible operating regions. Triangles mark combined cycle performance at nominal gas turbine load without supplementary firing. Note the different scales on the axes. Source: Adapted from Paper II and Paper III.

42%. The variable product mix may also decrease outputs down to 0 MW without cycling of the boiler or gas turbine, and is an alternative to lowering the minimum load (production) level.

The combined cycle obtains its comparatively large load range expansion from the possibility to use supplementary firing: without supplementary firing the upper bound of the load range would be the vertices given by the triangles in Figure 4.3b, marking full load gas turbine operation without supplementary firing. In addition, owing to the three parallel lines of gas turbines and heat recovery steam generators (Figure 3.5), the combined cycle has a lower minimum load level than the waste-fired plant (approximately 13% of plant full load compared to 70% load in the waste-fired boiler), that places the lower rims of the enclosed area closer to the origin. Thus, the combined cycle reference plant has, by design, a greater number of feasible operating points and a stronger potential for flexible operation than the waste-fired plant.

4.3 Flexible carbon capture

The retrofit of an absorption-based carbon capture process to a power plant has been found to not significantly affect the load-following capabilities of coal-fired [135] or combined cycle [136] plants. Reducing the steam extraction to the carbon capture process was also identified as a feasible option to provide primary frequency control [137]. That is, the operational flexibility of a CHP plant should not be limited by a carbon capture retrofit. In terms of product flexibility, integrating a carbon capture process with the CHP plant steam cycle gives additional operating points that increase the potential for product flexibility. By varying the amount of carbon captured, the level of electricity and heat generated can be varied.

In addition to load-following (flexible) operation of the CHP plant boiler, four strategies have been suggested for flexible operation of the carbon capture process itself:

1. *Venting*, i.e., bypassing the flue gas directly to the stack without CO_2 capture. Bypassing implies reduced CO_2 capture and thereby a reduced penalty on electricity and heat generation. However, CO_2 is emitted to the atmosphere and the electricity or heat price must be significantly higher than the price of emitting CO_2 (or, in the case of BECCS, the cost or lost revenue of not capturing CO_2) for this strategy to be profitable. Furthermore, a complete bypass (shut-down of capture unit) is associated with operational costs of returning to steady-state when the capture is resumed, which might offset the profitability of flexible operation [138]. There is no upper limit on the duration of such operation, but it is, of course, counter-productive to emit CO_2. The venting strategy is considered in the modeling included in Appendix A.
2. *Solvent storage tanks* that shift the solvent regeneration in time, i.e., a decoupling of CO_2 absorption from the (energy consuming) solvent regeneration and CO_2 compression. This strategy requires a sufficiently large solvent storage capacity, and the timescale of flexibility in such systems would typically be a few hours at most. It has been concluded that the increased revenue from selling more electricity does not outweigh the storage capital costs, but this depends on the assumed pay-back period [138], and could potentially increase the plant revenue [139]. An advantage of storage tanks is that CO_2 is not emitted.
3. *Variable capture level*, i.e., adjusting the energy provided to the capture plant reboiler and thereby lowering the capture rate. Similar to the venting option, a lowered capture rate

implies emission of CO_2, but might avoid the cost associated with cycling of the capture process.

4. *Variable solvent regeneration*, involving the accumulation of CO_2 in the solvent with subsequent regeneration at a later point in time. This strategy has been identified as the most profitable of the listed options [138,140]. However, the cited studies consider a timeframe of 24 hours, and it is unclear on which timescales the strategy can be utilized.

In addition to these four strategies, seasonal operation of the capture unit has been studied [141], which could be applicable to CHP plants [120] that supply district heating on a seasonal basis, and thereby have seasonally available excess heat to drive the capture unit without interfering with the main business of the plant. Seasonal CO_2 capture would lead to a lower overall capture efficiency and utilization of the capture plant, which could increase the total annual cost of CO_2 capture [77], but the value of the otherwise potentially lost district heating production might also impact the specific capture cost and could incentivize seasonal operation.

A consequence of flexible carbon capture is that it causes transience in the downstream CO_2 transport system, that might require handling and/or imply increased costs in the CO_2 transport and storage chain. This might constrain the power plant carbon capture operation [142]. The CO_2 compressor might also have operating limitations that might challenge flexible carbon capture strategies [143]. The development of advanced solvents with lower solvent regeneration heat duty might also imply decreased incentives for flexibility as the electricity penalty of carbon capture is lowered, i.e., the potential for increased electricity price revenue from flexible carbon capture decreases since the difference in electricity generation with/without capture is lowered.

While many previous studies consider flexible carbon capture applied to fossil-fired power plants, the incentives for flexible CCS might differ for CHP plants that capture biogenic CO_2. A distinction might therefore be made between flexible CCS and flexible BECCS, as they have different purposes. In the literature, CCS applied to fossil-fueled power plants is discussed in terms of flexible operation for electricity system balancing, while BECCS might support the energy system more by being dispatched as baseload generation as a means to increase CDR, with lower interest in flexible operation [144].

5 CHP plant operation

Chapters 3 and 4 have outlined the technical features of CHP plants. This chapter examines the operating patterns of CHP plants based on results from the appended papers. Conventional operation, as governed by the demand for district heating, is compared to operating strategies that could be applied to provide flexibility or carbon capture.

5.1 Conventional operation

The operation of CHP plants in Sweden is strongly connected to the district heating demand profile, that varies both seasonally and diurnally based on air temperature fluctuations and social factors. That is, district heating is conventionally regarded as the main CHP plant product and electricity generation is considered a bonus that gives additional revenue [95]. While heat supply is the main priority, some district heating systems take into account electricity price forecasts in their production planning. Thereby, the local district heating demand and the electricity market are the main factors that impact CHP plant operation.

With the seasonal heat demand variability, the district heating production portfolio of larger cities typically comprise baseload, intermediate load, and peak load units (not necessarily CHP plants). Baseload plants operate more or less year-round to supply space heating and hot tap water, while intermediate and peak load units are operated when the heat demand is high (winter). It follows that the utilization of CHP plants differs depending on plant type and role in the district heating system, and is on average around 4,000 full load hours per year. Waste-fired plants are normally operated as baseload and have a higher number of full load hours, since waste is inappropriate to store and must be managed continuously.

5.2 Utilization of CHP plant flexibility measures

The results in **Papers II – IV** demonstrate that the expansion of variable renewable electricity generation can impact the way CHP plants are operated, in terms of production planning and interaction with other production units. The electricity net load (or electricity price) has a strong influence on CHP plant operating patterns and incentivizes flexible operation. On a system level

(**Paper IV**), flexible CHP plant operation occurs when it contributes to reducing the net load variability (i.e., lowering the amplitude of variations) and to a lowering of the total system cost (cost of supplying electricity and district heating). In contrast, on the plant level (**Papers II** and **III**), flexibility is an operational strategy that is applied to increase the plant revenue, by scheduling electricity production and plant operation to periods when electricity prices are high. Thus, the motivation for flexible operation differs between the plant and system levels, although similar operational trends are observed.

A number of CHP plant operating patterns involving flexibility are identified as cost-optimal in the system studied and are visualized in Figure 5.1, showing results that pertain to a scenario for year 2045 with large-scale installations of wind and solar power. In Figure 5.1, the net load (panel a) can be seen to co-vary with operational patterns in the district heating sector (panel b) and the operation of CHP plants (panels c and d). When the net load is negative, biomass CHP plants reduce the boiler load (sometimes to zero, i.e., cycling) and might switch to heat-only operation, thereby lowering the cost of fuel consumption and avoiding electricity generation that the system would need to store or curtail to maintain balance between supply and demand. During periods when the net load is high, the load level and electricity generation is instead maximized, to some extent regardless of the district heating demand level, and plants might operate in electricity-only (condensing) mode, as seen in panel d for the waste-fired plant.

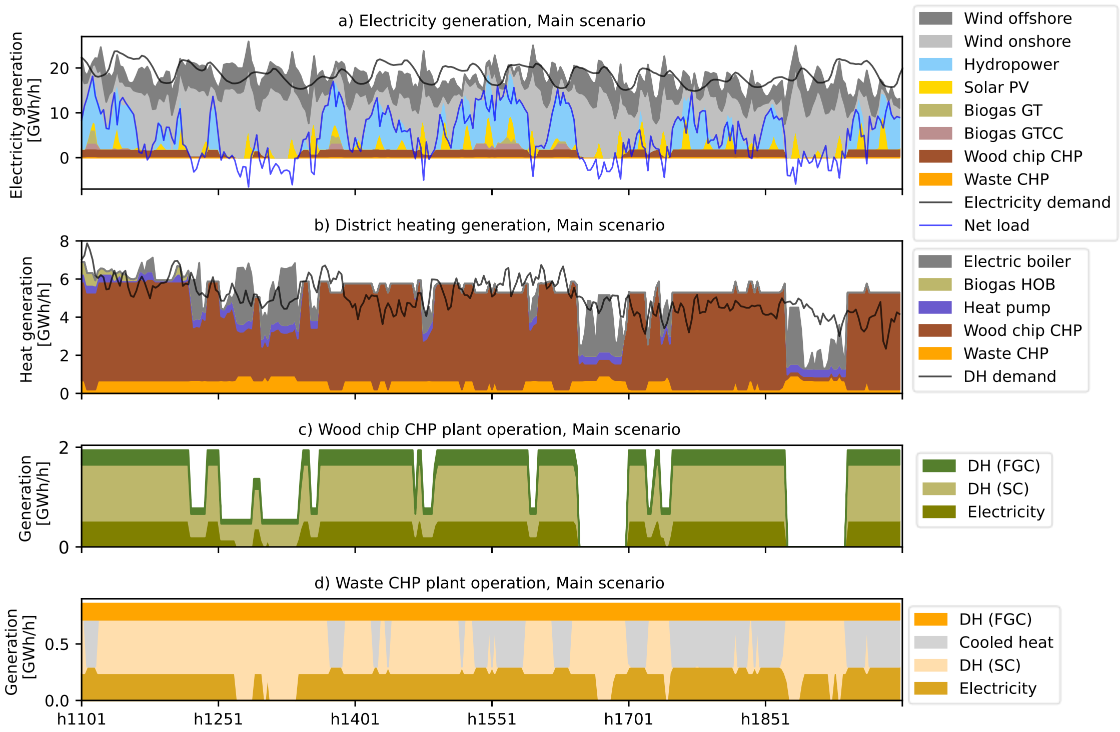

Figure 5.1. Optimal dispatch of the: a) electricity sector, b) district heating sector, c) biomass (wood chip) CHP plant, and d) waste-fired CHP plant, during five weeks in springtime. DH, district heating; FGC, flue gas condenser; SC, steam cycle turbine condenser. Source: Based on Paper IV.

The presence of thermal energy storage (TES) capacity in the district heating sector is a key enabler of cost-effective utilization of CHP plants for net load balancing. Firstly, the TES allows CHP plants to operate in cogeneration mode at a higher load level than is motivated by the heat demand (Figure 5.1b) when market conditions are favorable, without "wasting" the heat produced. Secondly, when it is favorable to reduce the CHP load (low net load) or operate in electricity-only mode (high net load), the stored heat in the TES compensates for the decrease in heat production. In this way, the TES acts as a peak heat supply unit that decreases the need for additional peak capacity (e.g., heat-only boilers) in the district heating system. A seasonal TES capacity of 1-2% of the annual district heating demand is found to be optimal for the systems studied in this thesis (similar to findings in Ref [145]), together with a smaller capacity of tank TES.

As can be seen in Figure 5.1b, the low net load events usually coincide with heat production from power-to-heat units (electric boilers and heat pumps) that take advantage of low-cost electricity. This implies a change in the district heating system merit order during periods when power-to-heat units have a lower cost of heat production than CHP plants, which further explains the reduction in CHP plant load level during these occasions.

The results in **Papers II** and **III** provide complementary insights into the operating strategies of the waste-fired and gas turbine combined cycle reference plants. Depending on plant design and fuel cost, the CHP plants utilize the flexibility measures differently. Waste-fired plants with a low fuel cost can afford to operate in condensing mode and has little interest in the strategy involving reduced boiler load and heat-only operation. In contrast, the combined cycle plant is more inclined towards heat-only operation to reduce fuel consumption while still meeting heat supply targets, especially when the electricity price is low. The availability of TES impacts the utilization of flexibility measures. Without access to a TES, the combined cycle plant utilizes a wider span of operational points, i.e., greater use of operational and product flexibility. More details can be found in the respective papers.

The results indicate that operational flexibility (varying boiler load) is a flexibility measure that is motivated for two main reasons: (i) to vary the electricity production in response to net load fluctuations or electricity price volatility, and (ii) to reduce the boiler load, and thereby save fuel expenses, e.g., at times when other heat production units (e.g., power-to-heat units) can produce heat to a lower cost than the CHP plant. Product flexibility (varying product ratios) can be used in combination with operational flexibility to enhance the effect, for instance, to operate in heat-only mode when the boiler load is reduced, to further decrease electricity production without cycling the plant.

5.3 Operating CHP plants with carbon capture

The modeling presented in Appendix A provides results on the cost-optimal operation of CHP plants retrofitted with a carbon capture process (MEA) in a city energy system context. CO_2 capture targets are set for two CHP plants in the city based on a reference scenario without CCS, so that 90% of the (reference) annual plant CO_2 emissions must be captured. For the waste-fired baseload plant, the operation is to a large extent unaffected by the retrofit of the carbon capture unit. The plant operates close to maximum capacity in the reference scenario, leaving little room for other operational patterns when CCS is integrated. Figure 5.2a shows a duration curve of the CO_2 capture from the waste-fired plant, indicating that the process operates at full capacity (55

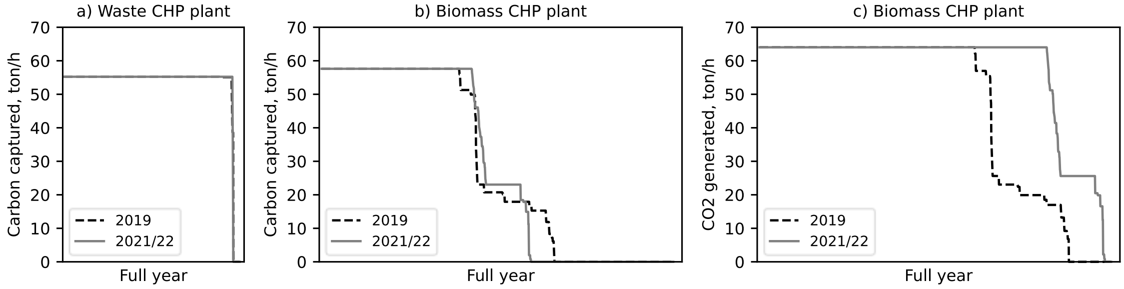

Figure 5.2. Carbon capture plant load duration curves for the capture processes when applied to a) a waste-fired CHP plant, and b) a biomass CHP plant. Panel c) shows the duration curve of CO_2 generated by the biomass CHP plant. The data are arranged from highest to lowest load, i.e., not in chronological order. Based on the modeling in Appendix A, where the 2019 and 2021/22 scenarios are explained.

tCO_2/h) for most of the year. However, as plotted in Figure 5.3c, the capture unit is shut down when the electricity cost is high, or when the heat demand peaks, to maximize the district heating and electricity production from the CHP plant.

The second CHP plant retrofitted with carbon capture is biomass-fired and operates as intermediate load in the district heating system. Thereby, the plant CO_2 capture target is set at around 50% of maximum utilization, leaving room for flexibility in the dispatch of the carbon capture unit through increased CHP plant utilization (increased fuel consumption). Figure 5.2 illustrates that the carbon captured (panel b, based on the set target) is significantly lower than the CO_2 generated by the plant when operated cost-optimally (panel c). Figure 5.3 further indicates that volatility in the city marginal cost of electricity causes flexible operation of the capture process. A high electricity cost causes the capture unit to shut down, to maximize electricity generation from the CHP plant and avoid electricity use in the CO_2 compressors.

The CO_2 emission market set-up might impact the incentives to operate CCS flexibly. With a market price on CO_2 emissions (fossil and/or biogenic), it could be relevant to consider flexible

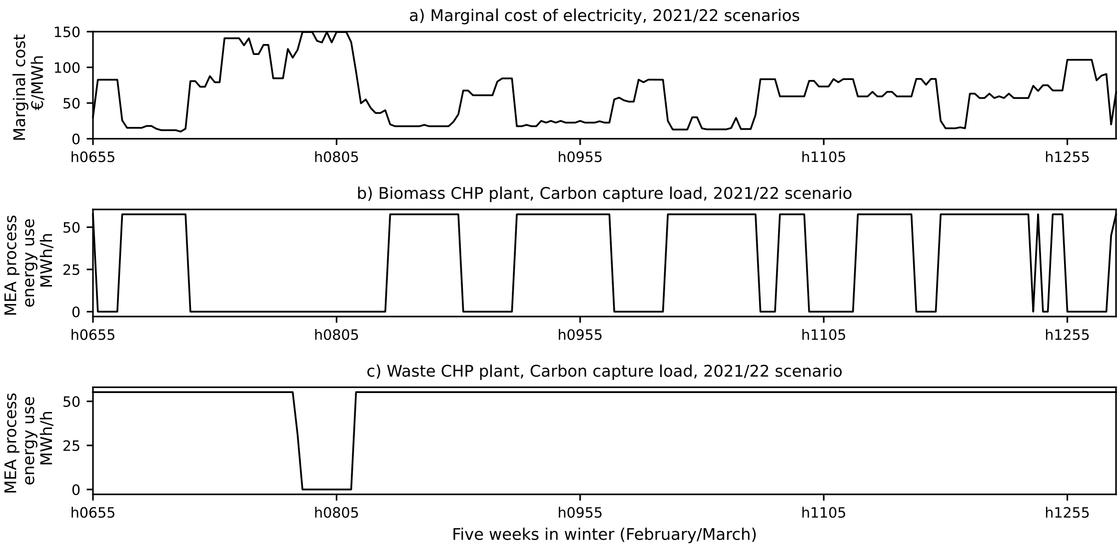

Figure 5.3. a) Marginal cost of electricity in the modeled 2021/22 scenario. b-c) MEA process energy consumption when retrofitted to the b) biomass CHP plant, and c) waste-fired CHP plant. The figure shows five weeks in winter (February/March). Based on the modeling in Appendix A.

operation of the carbon capture unit to match temporal price variations. In contrast, a reversed auctioning system, as is underway in Sweden, might inhibit flexible operation strategies and rather benefit the maximization of carbon capture. Additionally, to keep the specific cost of carbon capture [€/tCO_2] low, it is beneficial to capture as much CO_2 as possible to make the capture plant investment worthwhile. Thereby, the design of carbon capture targets might be adapted to suit either flexible carbon capture (target set lower than maximum capture rate) or cost-effective maximization of carbon capture.

Paper I takes a non-optimizing approach to CCS in the district heating system, assuming that the CO_2 capture rate is fixed at 90% of generated emissions and that CHP plant full load hours are determined by a pre-defined district heating system merit order (i.e., no target on CO_2 capture, the CO_2 capture rate is directly given by the CHP plant operation). The results show that depending on the level of heat recovery from the capture unit, i.e., if the net CHP plant heat delivery increases or decreases with CCS, operating a baseload CHP plant with carbon capture can impact the utilization of other units in the local district heating system. As illustrated in Figure 6 in **Paper I**, extensive heat recovery from the carbon capture plant leads to reduced operation of intermediate load CHP plants, which implies a lower carbon capture potential from these plants if retrofitted with CCS. Similarly, without heat recovery from the capture plant, the utilization of CHP plants increases to cover the loss of heat production, leading to a higher potential for CO_2 capture. This trend indicates a conflict between different targets: high energy efficiency (heat recovery) vs high CO_2 capture (favored by low energy efficiency that causes increased fuel use).

5.4 Discussion on the provision of new CHP plant services

Although there might be opportunities for CHP plants to contribute with flexibility services in the electricity sector and to provide negative emissions, the main priority of a CHP plant is conventionally to supply heat. Thereby, the realizability of additional CHP plant services is, to some extent, limited by the demand for district heating, which varies over time. During the summer, the heat demand is low (Figure 5.4a), and the availability of CO_2 to capture from CHP plants is limited to baseload plants. Similarly, the provision of dispatchable electricity generation from biomass CHP plants is difficult to motivate during the summer when there is no/low economic compensation for the heat produced, Figure 5.4b. The exception is seen in the scenario without hydropower in the regional energy system, i.e., low system flexibility, in which it becomes cost-effective for CHP plants to act as peak capacity with electricity-only generation, Figure 5.4c.

Thus, if the value of, or demand for, other services is greater than the demand for heat, there might be situations when CHP plant operation is motivated regardless of the heat demand level. However, such operation would greatly reduce the energy efficiency of cogeneration plants, as the utilization of low-grade heat for district heating is a main reason that CHP plants are considered to have a high resource efficiency. The fact that, for instance, high economic compensation for carbon dioxide removal might incentivize CHP plants to operate solely for carbon capture and not for heat supply is something to be mindful of. Setting appropriate boundary conditions (e.g., CO_2 capture targets) for optimization models is important to obtain results that are representative of real systems.

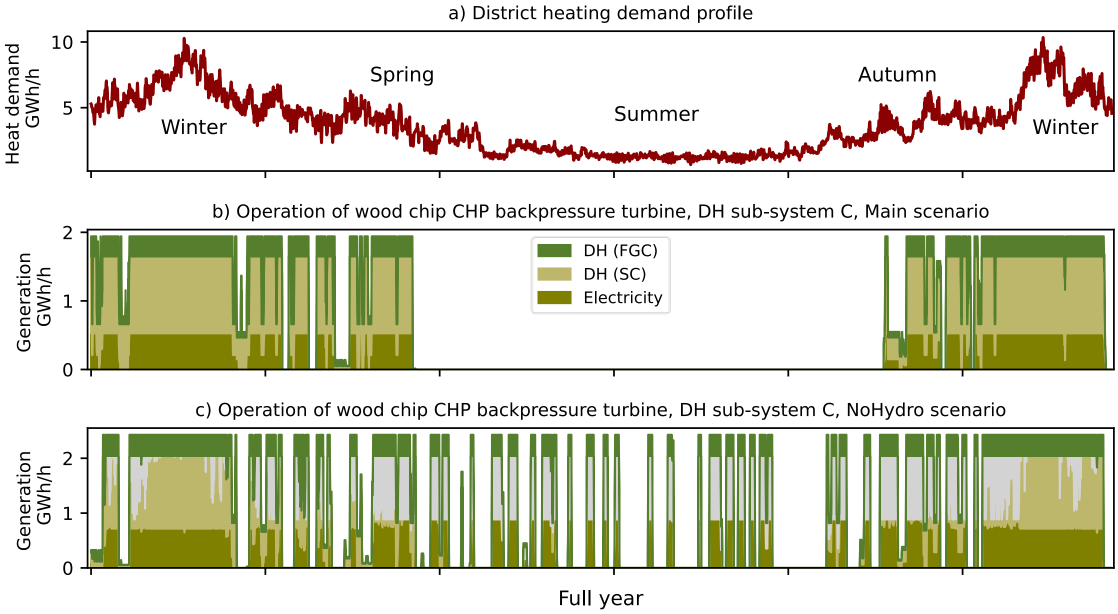

Figure 5.4. a) District heating demand profile for one year. b-c) Optimal dispatch of biomass (wood chip) CHP plants in the (b) main scenario (current biomass price level and access to hydropower), (c) scenario without hydropower. The grey color in panel c represents cooled heat (condensing operation). DH, district heating; FGC, flue gas condenser; SC, steam cycle. Source: Based on the modeling in Paper IV.

During periods with high heat demand, the availability of additional CHP plant services can be high, but it could also be that the priority to supply heat, in itself, limits the opportunity to supply other services. That is, services that imply a reduced district heating output, e.g., electricity-only operation or carbon capture without heat recovery, might have low realizability because they interfere with the plant's main business. In sum, co- or polygeneration offers a high energy and resource efficiency, as well as resilience to market price fluctuations if it is possible to shift product output ratios over time, but a diverse product portfolio and interactions with several markets increase operational complexity and competition between different objectives.

6 CHP plant competitiveness

This chapter discusses the economic conditions for CHP plants in decarbonized energy systems, for providing flexibility services and carbon dioxide removal. The chapter is based on results from all the appended papers.

6.1 Economic viability of CHP plants in different system contexts

The construction of solid-fuel thermal power plants is associated with substantial investment costs. Operating costs (fuel, start and part load costs, variable maintenance, and CO_2 costs, if applicable) must therefore be sufficiently low to enable many full load hours to generate revenue and recover capital costs. Gas turbines and combined cycles are less capital-intensive plant types and can be economically viable with a lower number of full load hours and higher operating costs than solid-fuel plants.

Papers IV and **V** highlight the importance of fuel cost for CHP plant competitiveness and analyze the sensitivity of investments to biomass fuel prices on the regional and city levels. Figure 6.1 plots the cost-optimal installed capacity of CHP plants and power-to-heat units in the region and city as a function of wood chip price (which directly impacts the biogas price, see Section 2.3 in **Paper V**). On the regional level, increased biomass cost has a strong impact on wood chip CHP plant investments, which approach zero at 50 €/MWh of wood chips. In the city, there are fewer technology options available for investments and limited access to low-cost electricity due to a limited grid connection capacity. In that context, wood chip CHP plants remain competitive up to wood chip prices of 70 €/MWh.

Figure 6.2 plots results from the energy system scenarios analyzed in **Papers IV** and **V** for the regional and city levels, in which technology availability is varied (nuclear, hydropower, TES). On the city level, CHP investments are more or less robust, corresponding to around 70% of the peak heat demand in the city regardless of the external energy system development. On the regional level, the competitiveness of biomass CHP plants varies between scenarios. Again, increasing the wood chip price (HighBio, wood chips 40 €/MWh) has the strongest impact and

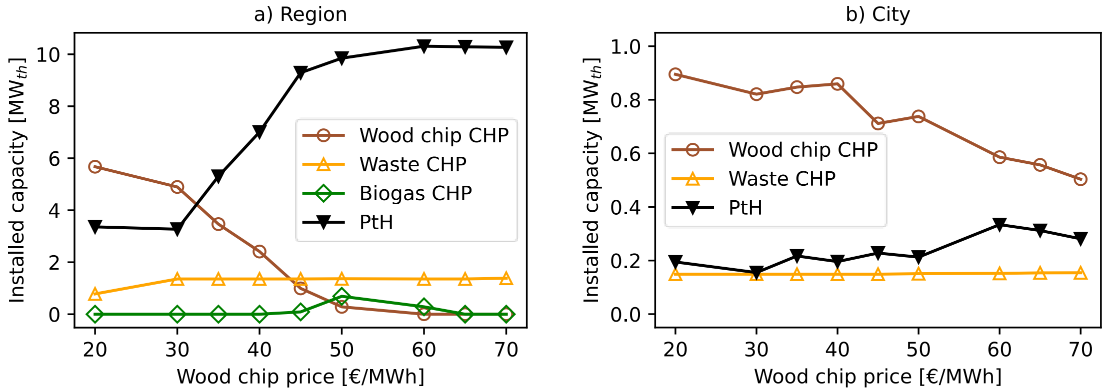

Figure 6.1. Optimal investments in CHP capacity and power-to-heat technologies as a function of wood chip price, in a) the SE3 region and, b) the City of Gothenburg. Source: a) Paper IV, b) based on Paper V with complementary model runs. Please note the different scales on the y-axes.

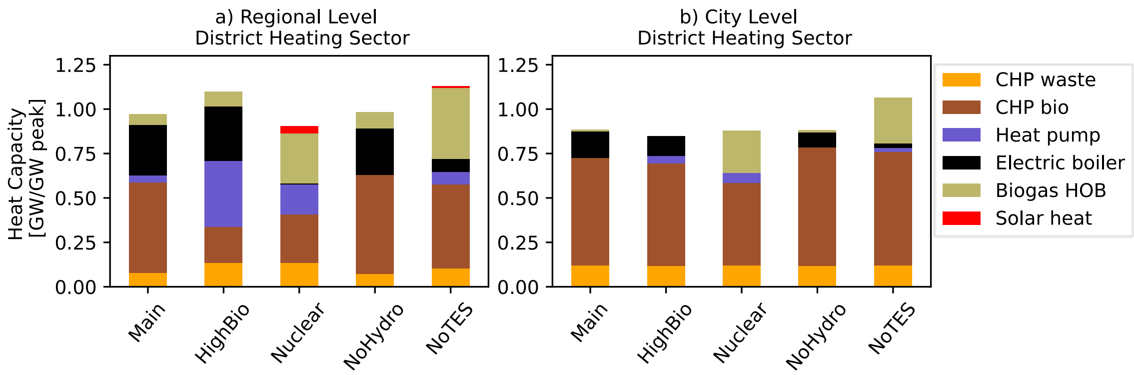

Figure 6.2. Optimal normalized investments in heat generation capacity in a) the SE3 region and, b) the city of Gothenburg. Cases: Main: current biomass price. HighBio: biomass price doubled. Nuclear: current capacity of nuclear power is forced into the regional system. NoHydro: no hydropower available. NoTES: to thermal energy storage available. Source: Based on Paper IV and V, with complementary model runs.

significantly reduces the cost-optimal investments in biomass CHP plants. Forcing investments in nuclear power in the modeled region leads to high availability of stable low-cost electricity generation, which reduces investments in wind and solar power compared to the Main scenario (see Figure 3 in **Paper V**), with less CHP and power-to-heat capacity. Removing access to hydropower has little effect on CHP investments but impacts the plant dispatch (Figure 5.4). Not being able to invest in TES mainly impacts power-to-heat installations, that benefit from the possibility to store low-cost electricity as heat. This leads to larger investments in biogas heat-only boilers, since TES tends to replace peak heat production (Section 5.2). However, the bulk part of the heat demand still needs to be produced, which incentivizes CHP plants.

It is notable in Figures 6.1 and 6.2 that waste-fired CHP plants with a low fuel cost are competitive in all scenarios, and in many cases reach the maximum capacity (i.e., consume all the waste available). It is also clear that investments in biogas combined cycle CHP plants are not competitive in any of the scenarios presented in Figure 6.2, and only reach a low investment level for wood chip prices in the range 45-65 €/MWh in Figure 6.1a. Thus, a high level of CHP plant operational flexibility, as is feasible in combined cycles, is not cost-competitive in the systems studied: the cost of biogas is too high in comparison to the other available technologies that have lower fuel costs. For flexibility provision in the electricity sector, it is preferable to invest in condensing biogas turbines and combined cycles without district heating generation and with a higher electric efficiency.

Based on the system modeling results presented in **Papers IV** and **V**, it is seen that market shares in the district heating sector are a necessity for CHP plants to remain competitive in future energy systems. A similar conclusion is drawn in Ref [146]. **Paper IV** also indicates that the potential for CHP plants to provide flexibility services in the studied regional electricity system is small, given that the cost-optimal CHP plant investments in the region constitute a small share (2-4%) of the total electric capacity. Annually, the modeled CHP plant electricity generation corresponds to around 4-8% of the total regional electricity production. The potential for CHP plant flexibility provision receives its upper limitation from the heat demand, which corresponds to 24% of the annual regional electricity demand. The optimal CHP investments do not exceed the instantaneous demand for district heating in any scenario (Figure 6.2).

6.2 The value of CHP plant flexibility

The value of CHP plant flexibility can be analyzed on a system level and a plant level. In the energy system optimization models used in **Papers IV** and **V**, the objective is to minimize the total system cost, i.e., the cost of meeting electricity and district heating demands in the system. The cost minimization approach implies that the resulting marginal cost of electricity will be as low as possible (assuming a perfect market), and the model finds the least-cost solution to manage variability. In contrast, on the plant level, the objective of the optimization models in **Papers II** and **III** is to maximize the plant revenue. The plant revenue benefits from high electricity prices and thereby contrasts the system-level objective to minimize costs.

6.2.1 System-level value

Overall, **Paper IV** presents findings that indicate that CHP plant flexibility has a small impact on the total cost of energy supply in the studied regional electricity and district heating sector. The total system cost increases with less than 1% when restricting the use of CHP plant flexibility measures (no operational or product flexibility allowed), and around 0.5% when removing TES. Operational flexibility (cycling, part load operation) has a stronger impact on the system cost than restricting product flexibility measures. The interpretation of this result is that there are other technologies in the regional system that can provide flexibility services to a cost that is approximately equal to the cost for CHP plants to provide flexibility.

Restricting the use of flexibility measures can impact the competitiveness of CHP plants in the energy system. In Figure 1 in **Paper IV**, it is shown that in the scenario without access to hydropower, i.e., with low electricity system flexibility in general, biomass CHP plants lose competitiveness when flexibility measures are restricted, and even more so if the wood chip price increases in addition to restricted flexibility. For low wood chip prices and access to hydropower, CHP plant flexibility has a limited impact on cost-optimal investment levels, and low-cost heat supply from CHP plants is high enough for the plants to be economically viable in the system even if flexible operation is not enabled.

From a stakeholder perspective, if the system cost reduction accrued from CHP plant flexibility measures is given as a benefit to CHP plant owners, a 1% system cost reduction would for the studied cases correspond to an annual "bonus" of around 54 k€/MW installed electric capacity. In a situation with 4,000 – 8,760 full-load hours per year, the hourly operating benefit would be in the range of 6-14 €/MWh electricity, whereby operational flexibility confers a major part of the benefit. Product flexibility would correspond to an hourly operating benefit of less than 1.5 €/MWh. In comparison, the wood chip fuel price is 20–40 €/MWh in the scenarios.

6.2.2 Plant-level value

Papers II and **III** estimate the value of flexibility measures for the reference plants studied. Here, the value is expressed as an increase in annual plant revenue, under the requirement to deliver a given amount of district heating. Figure 6.3 visualizes the impact on plant revenue in k€/MW installed electric capacity of product and thermal flexibility (access to TES), for the waste-fired and combined cycle reference plants. Overall, the total increase in annual revenue grows as electricity price volatility increases (which is largest in the 2050 scenario, see **Paper II**, Section 2.3), where up to 90 k€/MW_{el} could be gained from operation with product and thermal flexibility. In the reference years of 2016 and 2018 with low electricity price volatility, the revenue increase is around 10 k€/MW_{el} for the combined cycle and up to 60 k€/MW_{el} for the waste-fired plant. Translated to an operating benefit, as in Section 6.2.1, 90 k€/MW_{el} would correspond to 10-22 €/MWh assuming 4,000 – 8,760 full load hours. Thus, product and thermal flexibility potentially have a higher value for the plant (to increase revenue) than for the energy system (to reduce costs).

For the waste-fired plant, the value of product and thermal flexibilities are additive, i.e., they do not compete and can be combined. For the combined cycle, Figure 6.3b indicates that as thermal flexibility increases (larger TES capacity), the revenue increase from product flexibility diminishes. The difference between the plant types is explained by the difference in fuel cost. The waste-fired plant utilizes the flexibility measures to provide additional services (e.g., condensing operation, Figure 5.1d) by increasing the fuel consumption, and the thermal energy storage is beneficial in terms of matching the production to price fluctuations. The combined cycle uses product flexibility to lower the heat production cost (heat-only operation with reduced load level), i.e., heat-load following operation rather than load shifting.

Operational flexibility has not been restricted in any of the cases in Figure 6.3, since not being able to vary the load to match the hourly heat demand profile would disagree with the model set-up. It follows that the value of operational flexibility is more suitable to assess with a system model that includes the possibility to choose which unit to operate. However, results from the dynamic process simulations in **Paper III** indicate that for the combined cycle there is a low value (impact on plant revenue) of operating with increased ramp rate, for electricity sold on the hourly market. The revenue increase from increasing the ramp rate (i.e., responding to day-ahead electricity price changes faster) is less than 5 k€/MW_{el} in most scenarios. Reducing the minimum load level might be a more profitable measure to increase operational flexibility [147].

While the main priority of a CHP plant is to supply district heating, Figure 5 in **Paper IV** shows that 60-75% of the optimized CHP plant revenue in the system modeled comes from electricity generation. In comparison, electricity generation constitutes only 25-40% of the annual CHP plant energy output. One interpretation of this result is that it is not the amount of electricity produced that is the most important performance indicator, but rather the ability to produce electricity at the right time, i.e., when electricity prices are high. Flexibility measures can play an important role in adapting electricity output to price fluctuations. Of course, in market contexts where there is low electricity price volatility, the potential value of flexible operation strategies will be lower, as is shown in the scenarios plotted in Figure 6.3. On a similar note, Sorknæs et al. [148] found that a Danish CHP plant could benefit economically from participating in electricity balancing tasks, although it is uncertain if the benefit is large enough to keep CHP plants in operation.

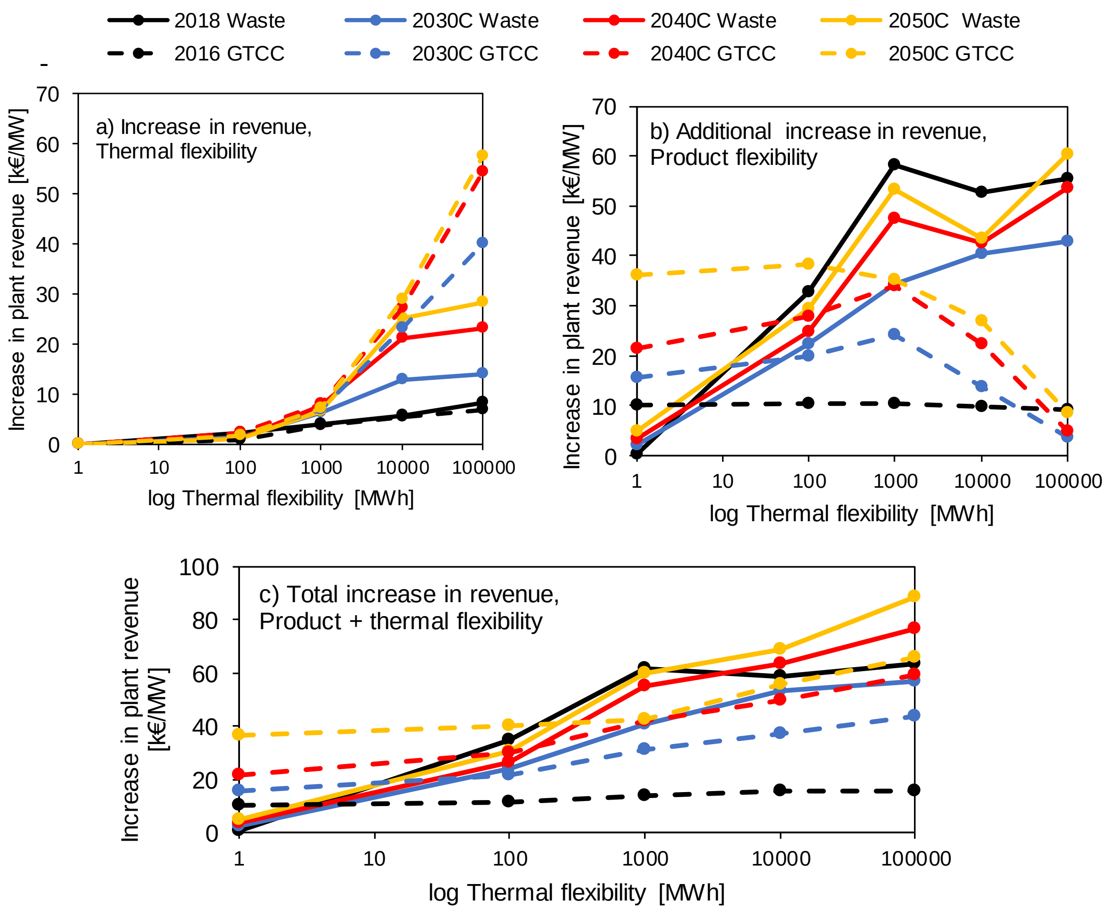

Figure 6.3. a) The annual plant revenue increase per installed electric capacity as a function of thermal flexibility (TES storage capacity), for different electricity price scenarios. b) The *additional* increase in plant revenue when product flexibility is added to thermal flexibility. c) The total increase in revenue from product and thermal flexibility is given by the sum of a) and b). Solid lines represent the waste-fired plant, and dashed lines the combined cycle (GTCC). Note the logarithmic scale on the x-axes. Source: Paper II and Paper III.

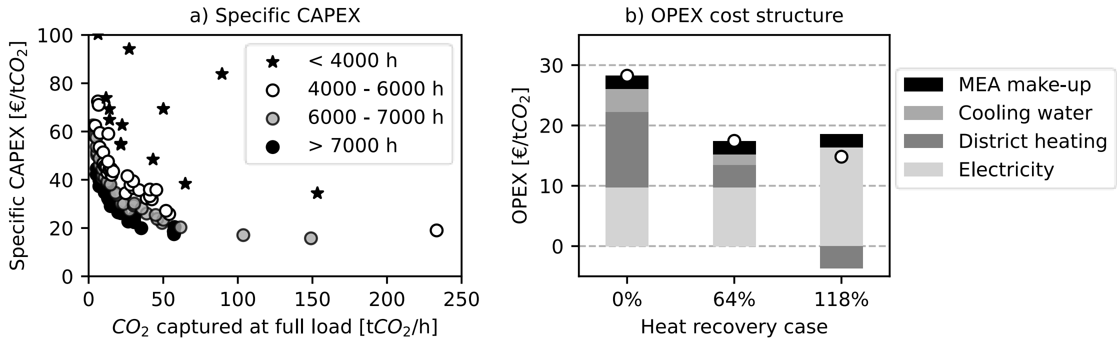

Figure 6.4. a) Specific capital cost (CAPEX) of the CO_2 capture and conditioning plant for CHP plants as a function of plant size (CO_2 flow treated) and full load hours. Each point represents one CHP plant. Note that the y-axis is cut at 100 €/tCO_2. b) The cost of operating a CHP plant with carbon capture (OPEX) under three heat recovery scenarios (Section 3.4). The white dots indicate the net OPEX. Source: Adapted from Paper I.

6.3 Economy of carbon capture from CHP plants

6.3.1 Estimated cost of carbon capture

Paper I provides cost estimations for carbon capture applied to Swedish CHP plants, including capital and operational expenditures for the capture, compression and liquefaction plant. Costs are also estimated for land-based transport (truck) from the CHP plant to a harbor, awaiting further ship transport to a permanent storage site (Norwegian Kollsnes in the Northern Sea is, at the moment, the most likely storage site for Sweden). The ship transport and storage costs are not assessed in this work, but are estimated to 30-55 €/tCO_2 by the Northern Lights project [149].

Figure 6.4a shows the dependency of the capture plant specific capital cost (CAPEX) on CHP plant size (CO_2 in flue gas flow available for capture) and full load hours (utilization). The costs plotted represent the portfolio of Swedish CHP plants (year 2020) with the corresponding modeled full load hours. The specific CAPEX strongly increases with decreasing plant size, for CO_2 flow rates below 50 t/h. For higher flow rates the impact of plant size is less pronounced. The cost also increases with fewer full load hours. For CHP plants that are relatively small and with low utilization, the capital cost is a large cost component that might prevent the economic viability of CCS.

Operational expenditures (OPEX) are in the range of 15-30 €/tCO_2 (Figure 6.4b), with the lower cost representing cases in which heat is recovered from the capture plant for district heating. The OPEX is not expected to vary with plant size. Truck transport costs are generally proportional to the driving distance between the CHP plant and harbor, although the cost increases with low utilization. With these estimates, the total specific cost of CO_2 capture and truck transport is in the range of 45-125 €/tCO_2 for most Swedish CHP plants, depending on plant size and utilization.

6.3.2 Carbon capture potential

A market for carbon dioxide removal is yet to be defined, making it challenging to put a value on BECCS as a product. Governments that set targets to achieve negative emissions might need to create financial support schemes, regulatory frameworks, and accounting schemes to incentivize technology deployment, as is currently underway in Sweden with a reversed auctioning system.

Another possibility is that a voluntary market emerges, in which companies or other actors buy negative emission credits to offset their current or historic CO_2 emissions.

Regardless, the plants that can provide carbon dioxide removal to the lowest cost will have a market advantage. In Sweden, BECCS can be provided mainly by CHP plants and pulp and paper mills, and these plants compete for market shares. The total potential for negative emissions in Sweden from these two plant categories amounts to at least 25 $MtCO_2$ per year based on **Paper I** and Johnsson et al. [73], where the existing portfolio of CHP plants could potentially contribute with at least 10 $MtCO_2$ to a maximum cost of 100 €/tCO_2 (capture and truck transport), depending on heat recovery options. Figure 6.5 plots a marginal cost curve for carbon capture, liquefaction and compression, and truck transport, for the existing portfolio of Swedish CHP plants, distinguishing between biomass and waste-fired plants. Based on [73], the corresponding cost for carbon capture from pulp mills (>500 $ktCO_2$/year emitted) are of a comparable order of magnitude, ranging from 45 to 60 €/ton for the larger emission sources, and up to 110 €/ton for smaller stacks. However, pulp mills are generally larger emitters of CO_2 than CHP plants and might provide larger amounts of BECCS to a lower cost.

Waste-fired plants have a different business case than biomass-fired plants due to the mix of biogenic and fossil emissions, and both fractions need financial coverage [150]. Nevertheless, some Swedish district heating companies have expressed their ambition to retrofit CCS to waste-fired CHP plants to reduce their climate impact, and have conducted feasibility studies [151–154]. In the future, there might, however, be competing interests for the use of waste, to recycle waste materials by recovering the carbon atoms in line with circular economy principles and the waste hierarchy [155,156].

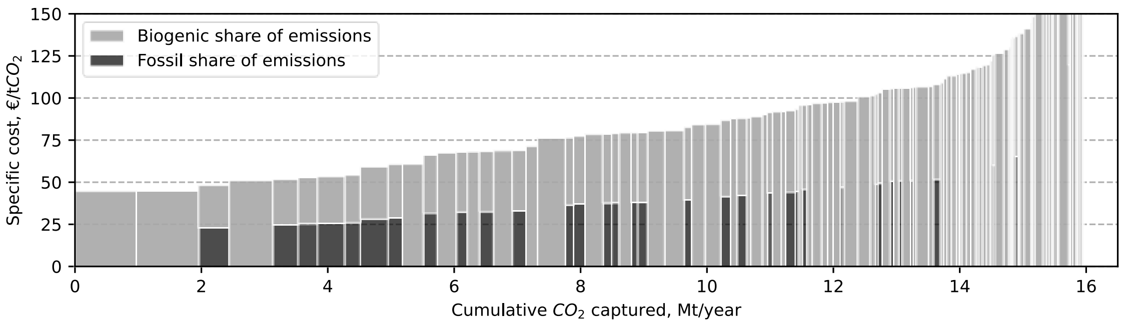

Figure 6.5. Marginal cost of carbon capture from Swedish CHP plants, including cost of capture, liquefaction and compression, and truck transport to an intermediate storage hub. Each bar represents one CHP plant, distinguishing between biogenic (gray) and fossil (black) emissions. Source: Adapted from Paper I.

7 Summary and outlook

7.1 Summary and conclusions

The main contribution of the thesis is found in the application of flexibility and carbon capture concepts to the specific context of combined heat and power (CHP) plants in Sweden, and the assessment of the potential, utilization, cost/value and competitiveness of carbon capture and flexibility measures in a decarbonized energy system. The thesis applies a method based on techno-economic assessments that takes into account variability in model inputs and the spatial boundaries of three levels of analyses. The results indicate that the choices of boundary conditions and inputs have a strong impact on the outcome of the assessments. For instance, the perceived CHP plant competitiveness differs between the regional and city levels studied, and variable electricity price input data is found to be a market opportunity at the CHP plant level. Hence, the methodological approach is relevant for the case of CHP plants and might be applicable also to other technologies that have a strong dependency on markets with high volatility, and/or produce multiple outputs.

The combination of system levels in the method provides insights on both the technology and system levels, as summarized in Table 7.1 for the three CHP plant types covered in the thesis (waste, biomass and combined cycle CHP plants). The cost structure, fuel markets and typical operating patterns differ between the plant types and impact their potential and competitiveness for carbon capture and flexibility services.

In terms of flexibility, the functionality-based categorization of flexibility measures is found to be a useful approach to identify process and system components that might be prioritized when designing for cost-effective flexibility provision. The thesis distinguishes between operational flexibility (boiler operation), product flexibility (steam cycle operation) and thermal flexibility (heat storage, load shifting in time). The flexibility measures are used differently depending on CHP plant cost structure, especially fuel cost. Product flexibility is used to (i) increase plant production for low-cost fuels (waste), and (ii) to decrease fuel consumption for high-cost fuels (e.g., biogas).

In the regional electricity system studied, the potential to provide flexibility services is limited, as the installed CHP capacity is small relative to the electricity demand and net load variability. Thereby, the system value of CHP flexibility measures is low, as there are competing technology options that can provide the same service to a comparable cost. On the plant level, flexibility can give increased revenue by scheduling production to follow electricity price variations (if volatility is high), although realizing this potential might require substantial heat system flexibility through thermal energy storage. In this sense, the overall district heating system (with heat storage) has a large potential to provide flexibility services in the electricity system.

The potential for carbon dioxide removal is large for the current portfolio of Swedish CHP plants. At least 10 $MtCO_2$/year could be captured cost-effectively, which is sufficient to meet the proposed target for negative emissions of 3-10 $MtCO_2$ by 2045. The market potential is, thus, promising, although the realization is challenged, primarily by financial aspects. The cost of capturing CO_2 is strongly dependent on plant size and full load hours, which makes the cost high for small CHP plants that operate as intermediate load. The estimated specific cost of CO_2 capture and truck transport is in the range of 45-125 €/tCO_2 for most Swedish CHP plants, to which the cost of ship transport and storage should be added. The impact of carbon capture on district heating delivery is considered marginal, as it might be possible to recover low-grade heat from the capture process.

The overall competitiveness of CHP plants is strongly impacted by the development of fuel prices and fuel availability, especially biomass. However, there are conditions under which biomass-fired CHP plants are competitive under increased fuel price levels, for instance in cities with limited grid connection capacity where other technology options for heat and electricity supply are scarce.

In sum, the main conclusions drawn are:

- The potential for carbon dioxide removal is large for Swedish CHP plants (at least 10 $MtCO_2$/year), but financial support or market development is needed for technology deployment to cover the cost of CCS.
- Flexibility provision on hourly to seasonal timescales is a weak to moderately strong business case for CHP plants. High volatility in electricity price or net load is required to incentivize flexible operation.
- Heat storage capacity is an important and cost-effective enabler of electricity system flexibility services, both for CHP plants and the district heating sector in general.
- The system level chosen for assessment can impact the perceived potential and competitiveness of a technology. Multi-level approaches are beneficial in elucidating diverging expectations, e.g., between the plant and system levels.

Table 7.1. Summary of technology and system-level results that relate to the potential and competitiveness of combined heat and power (CHP) plants to provide carbon capture and flexibility services.

Plant type	Cost structure	Fuel market	Typical operation	Carbon capture	Flexibility
Waste CHP	High investment cost, low fuel cost	Relatively stable availability, but potentially competing uses for waste might emerge (recycling).	Baseload. Potentially competes with industrial waste heat.	Relatively low cost feasible due to many full load hours. Might be necessary to capture the fossil share of emissions in the future.	Not designed for operational flexibility. Competitive without flexibility due to a low fuel cost. Revenue can increase from product flexibility (increased output).
Biomass CHP	High investment cost, moderate fuel cost	Limited availability of biomass and potentially competing uses. Fuel cost has a strong impact on competitiveness.	Baseload or intermediate load. Potentially competes with PtH.	Relatively low cost feasible. BECCS might be a market opportunity.	Moderately flexible. Flexibility can increase competitiveness if overall electricity system flexibility is low.
Combined cycle CHP (natural gas or biogas)	Lower investment cost, high fuel cost	Limited availability of biogas, high cost. Biogas infrastructure and production facilities need development.	Intermediate or peak load. Potentially competes with HOB or TES in DH sector.	Not studied, but low CO_2 concentration and few full load hours might increase cost.	Relatively high flexibility, but not competitive in a CHP-scheme due to high fuel cost. Product flexibility can decrease heat production cost (decreased fuel use).
System-level	DH market share is needed for CHP plants to be competitive, unless main product shifts (e.g., BECCS).	Electrification is expected to increase in general. Slow grid capacity expansion to cities is a market opportunity for CHP capacity. (Local electricity production)	DH system operation is expected to become increasingly influenced by the electricity system.	Large CDR-potential from current Swedish CHP plant portfolio (>10 $MtCO_2$/year). Infrastructure, financial and regulatory frameworks needed.	Low potential for hourly-seasonal flexibility provision in the studied region, total CHP plant capacity is small relative to electricity demand and expected net load variability.

PtH, power-to-heat; HOB, heat-only boiler; TES, thermal energy storage; DH, district heating; CDR, carbon dioxide removal.

7.2 Recommendations for further research directions

Based on the key outcomes of the thesis, new research directions can be pursued. A selection of recommendations is listed in this section.

Since the biomass price is identified as a governing factor for (biomass) CHP plant competitiveness, it is of interest to further study the development of the biomass market. Concerns for biodiversity and the long-term sustainability of biomass have been raised and might limit the availability of biomass. Increased demand for biomass in other sectors might impact district heating producers, as well as the business cases for carbon dioxide removal from CHP plants, and for polygeneration of biofuels. As these different pathways might compete, it is relevant to compare which product combination (electricity, carbon dioxide removal, biofuels) that would be most cost-effective for the plant and for the overall energy system, considering the competition from other technologies and production processes. The system optimization modeling applied might thereby be extended with a representation of the biomass sector, although this would imply that the computational complexity of the model increases. Process modeling is needed to provide designs and performance data for polygeneration plants.

Energy efficiency directives might imply that industrial waste heat should be used for district heating, if cost-effective. In that case, the baseload market share for CHP plants might be reduced and enforce new operational practices and merit orders. A study has shown that there is potential to increase the use of industrial waste heat in district heating networks [157]. Future industrial establishments might increase the share of waste heat in some places, for instance low-grade heat from data centers [158] or hydrogen production combined with district heating generation. The risk of fewer operational hours would limit the economic viability of capital-intensive CHP baseload plants, and could be assessed by modeling the co-existence of CHP plants and high shares of industrial waste heat recovery in district heating systems.

Furthermore, the thesis focuses on decarbonized energy systems, primarily around year 2045-2050, and assesses the future competitiveness of CHP plants. However, the transition from the present to 2050 is not covered in the work. CHP plants that exist in the energy system today might have a different business case than future installations, since not all competing technologies and infrastructures needed are in place today (e.g., large-scale batteries or biogas production systems). Modeling studies might therefore target the transition of the energy system, and focus on the impact of policy measures on the district heating sector and incentives for CHP plants over time.

Heat storage is found to be a beneficial installation in the district heating system. Research efforts could focus on studying the practical feasibility of constructing large-scale storages in urban areas, and how the spatial location of the storage impacts the possibility to use it as a flexibility measure. The optimal design of storages can also be considered, for example if several tank storages that are distributed across the district heating network are preferrable compared to one large, centralized storage volume, and the cost-effectiveness of each option.

Appendix A – Implementation of CCS in city energy system model

This appendix describes a cost-minimizing energy system optimization model to study the impacts of retrofitting BECCS to CHP plants in a city-level energy system context, including the district heating and electricity sectors. The city energy system model is presented in **Paper V**. In this appendix, equations for the implementation of carbon capture processes at CHP plants are added.

The objective of the model is to minimize the costs of investments and operation in the city, Eq. A1, while meeting demands for electricity and district heating, Eqs. A2-3. In addition, the model must also comply with targets on annual CO_2 capture from CHP plants, Eq. A4, and is subject to a maximum electricity import capacity, Eq A5. The nomenclature is given at the end of the appendix and in Table A.1.

$$MIN: C^{tot} = \sum_{i\in I\setminus I_{store}} \left(C_i^{inv} s_i + TT \cdot \sum_{t\in T}\left(C_i^{run} p_{i,t} + C_i^{run} q_{i,t} + C_{i,t}^{cycl}\right)\right) + \sum_{i\in I_{store}} C_i^{inv} s_i + \sum_{t\in T}\left(C_t^{el} w_t + C^{cool} q_{cool,t}\right) + C_{CC}^{inv} s_{CC} \quad \text{(A1)}$$

$$D_t^P + z_{bat,t}^{ch} + \sum_{i\in I_{PtH}} p_{i,t} + \omega \sum_{i\in I_{CHP}} m_{CO2,t,i} \le \sum_{i\in I_{El}} p_{i,t} + w_t + z_{bat,t}^{dch}, \forall t \in T \quad \text{(A2)}$$

$$D_t^{DH} + \sum_{i\in I_{TES}} z_{i,t}^{ch} \le \sum_{i\in I_{Heat}} q_{i,t} + \sum_{i\in I_{TES}} z_{i,t}^{dch} + q_{recov,t}, \forall t \in T \quad \text{(A3)}$$

$$\sum_{t\in T} m_{CO2,t,i} \le 0.9 E_i \quad , \forall i \in I_{CHP} \quad \text{(A4)}$$

$$w_t \le W \quad , \forall t \in T \quad \text{(A5)}$$

The MEA process is considered as a possible retrofit to CHP plants. The process is driven by heat through the condensation of steam extracted from the CHP steam cycle and is modeled as described in Equations A6 – A11. The steam extraction causes a reduction in CHP steam turbine electricity generation (Eq. A6) that also incurs a penalty on district heating delivery (Eq. A7). The electricity reduction is calculated assuming that 10% of the nominal electricity generation is lost. However, it is assumed that a share of the heat extracted to drive the capture process can be recovered as low-grade heat of sufficient temperature to be used for district heating [125], as stated in Eq. A8. The share of low-grade heat that cannot be recovered for district heating directly through heat exchanging must either be cooled from the process (Eq. A9) or recovered for district heating generation with a heat pump (Eq. A10, coefficient of performance (COP) = 3). A cooling cost of 5 €/MWh [159] is included in Eq. A1. The mass flow of carbon captured is limited by the fuel load, the design capture rate of the CCS unit (assumed to be 90% of CO_2 emissions at full load) and the carbon content of the fuel, σ_C, Eq. A11. The actual capture rate during operation can vary between 0 – 90% of flue gas emissions. The parameters in Equations A6-A11 are given in Table A.1.

$$p_{i,MEA,t} = p_{i,t} - \phi_{i,MEA} m_{CO2,i,t} \quad , \forall t \in T, i \in I_{CHP} \quad \text{(A6)}$$

$$q_{i,MEA,t} = q_{i,t} - m_{CO2,i,t}\left(\lambda_{MEA} - \phi_{i,MEA}\right) \quad , \forall t \in T, i \in I_{CHP} \quad \text{(A7)}$$

$$q_{recov,t} \le \lambda \cdot \gamma \sum_{i\in I_{CHP}} m_{CO2,t,i} \quad , \forall t \in T \quad \text{(A8)}$$

$$q_{cool,t} = \lambda \sum_{i \in I_{CHP}} m_{CO2,t,i} - q_{recov,t} - q_{HP,CCS,t} \frac{COP_{HP}-1}{COP_{HP}} \quad ,\forall t \in T \tag{A9}$$

$$q_{HP,CCS,t} \leq \sum_{i \in I_{CHP}} m_{CO2,t,i}\, \lambda(1-\gamma) \frac{COP_{HP}}{COP_{HP}-1} \quad ,\forall t \in T \tag{A10}$$

$$m_{CO2,i,t} \leq 0.9 \cdot q_{fuel,i,t} \cdot \sigma_{C,i} \quad ,\forall t \in T, i \in I_{CHP} \tag{A11}$$

In addition to the energy demand for carbon capture, the electricity consumption associated with CO_2 compression and liquefaction (ω) is included in Eq. A2. Costs for CO_2 transport and storage are neglected. CO_2 capture and conditioning plant investment costs are included in the form of a linear term in Eq. A1.

Table A.1. Parameters describing the carbon capture processes.

Parameter	MEA	Unit	Reference
Steam turbine electricity reduction, φ	0.31-0.37	$MJ_{el}/kgCO_2$	
Electricity for compression and liquefaction, ω	0.1	MWh_{el}/t_{CO2}	[125]
CCS energy demand, λ	3.6 (heat)	$MJ/kgCO_2$	[72]
Heat recovery factor, γ	0.64	[-]	[125]
	Biomass	**Waste**	**Unit**
CO_2 emissions, σ_C	0.405	0.33	tCO_2/MWh_{fuel}

Case study and scenarios

The model is applied to a case study of the city Västerås in Southern Sweden (NordPool electricity price area SE3). A brownfield approach is chosen, in which current capacities of district heating production units are included in the system, but it is possible to replace existing capacity with new investments. It is unlikely that Swedish district heating companies will invest in fossil-based capacity (the exception being waste fuels of partly fossil origin), therefore, fossil-fueled technologies are excluded from the investment options (listed in **Paper V**). Table A.2 gives the current plant portfolio of the district heating system in Västerås, which is largely CHP-dominated. Hourly demand profiles for district heating and electricity are adapted from data from the city of Gothenburg, Sweden, year 2012, and scaled to fit the annual demand data in Table A.2. The shape of the demand profiles can be seen in **Paper V**.

Table A.2. District heating system plant portfolios of Västerås and annual electricity and district heating demand. Based on [160]**. The CHP heat generation capacity excludes flue gas condenser heat.**

Plant type	Capacity	Unit
Waste CHP	48 / 98	MW_{el} / MW_{heat}
Recycled wood CHP	53 / 92	MW_{el} / MW_{heat}
Wood chip CHP	56 / 118	MW_{el} / MW_{heat}
Heat pump	27[a]	MW_{heat}
Tank thermal energy storage	2,100	MWh_{heat}
Annual electricity demand (current)	1,248	GWh_{el}
Annual district heating demand (current)	1,695	GWh_{heat}

[a] COP = 3.5

The model is run for four scenarios, summarized in Table A.3. Firstly, two electricity import price profiles are compared, based on historical price data in the SE3 area for year 2019 and the period July 2021 – June 2022. The electricity price profiles are displayed in Figure A.1. Year 2019 had a relatively flat electricity price profile with an average value of 38 €/MWh, while the 2021/2022 profile is significantly more volatile and with higher price levels (on average 95 €/MWh). Ambitious scenarios are considered, in which the MEA process is installed at both the waste-fired and the recycle wood CHP plants. For the plants that are retrofitted with CCS, the CHP plant annual CO_2 capture targets are derived from reference runs without carbon capture, and set to 90% of plant CO_2 emissions in the reference run (i.e., corresponding to regular operation with a 90% carbon capture rate). The fuel costs in all scenarios are: waste: 1 €/MWh, recycled wood: 10 €/MWh, wood chips: 20 €/MWh.

Table A.3. Scenarios studied. CO_2 capture targets are based on the 2019-Ref scenario.

Scenario	Electricity price profile	CHP plants with BECCS	Carbon capture target [ktCO_2/year]
2019-Ref	2019	None	0
2019-MEA	2019	Waste CHP + Recycled wood CHP	518 + 282 (waste CHP + wood CHP)
2021/22-Ref	2021/22	None	0
2021/22-MEA	2021/22	Waste CHP + Recycled wood CHP	518 + 282 (waste CHP + wood CHP)

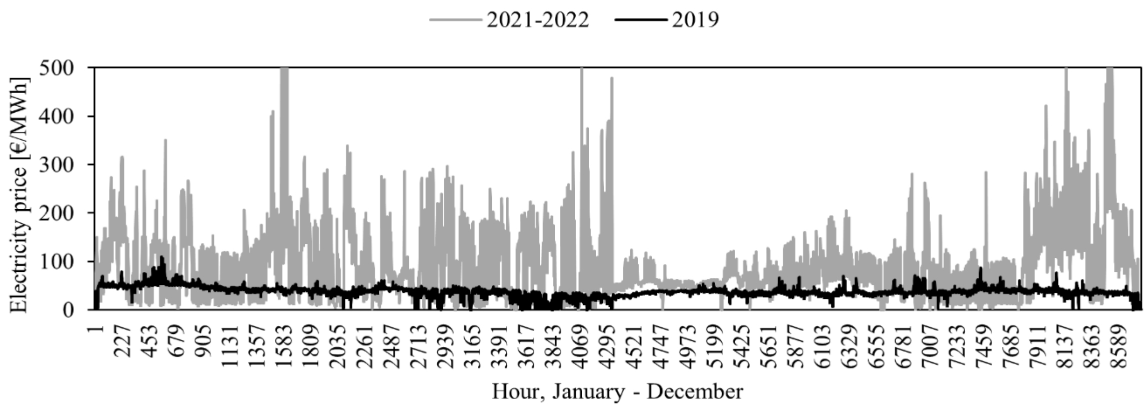

Figure A.1. Import electricity price profiles, based on price data for the SE3 area, for year 2019 and the period July 2021 – June 2022.

Nomenclature		*Subscripts and superscripts*	
C	Cost	*bat*	Battery
D	Demand	*CC*	Carbon capture
E	Annual CO_2 emissions	*ch*	Charge
i	Technology in the set of technologies, I	*comp*	Compression
m	Mass flow of CO_2 captured	*cool*	Cooling
p	Electricity	*cycl*	Cycling
q	Thermal energy (heat, fuel, cooling)	*dch*	Discharge
s	Capacity of investment	*el*	Electricity
t	Timestep in the set of timesteps, T	*inv*	Investment
TT	Length of timestep	*recov*	Recovered heat
w	Imported electricity	*run*	Running
W	Limit on electricity import	*store*	Storage
z	Stored energy		

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