THESIS FOR THE DEGREE OF DOCTOR OF PHILOSOPHY

Integration Aspects of Biomass Gasification in Large Industrial or Regional Energy Systems – Consequences for Greenhouse Gas Emissions and Economic Performance

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Errata

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Kristina M. Holmgren 2015

Due to one calculation error, the following parts shall be changed:

Paper V, page 4, the column "Holmgren cost (CERA)" of Table 2: The values should be 2.1; 9.5; 1.9; 18.0 and 12.1 and not 2.9; 13.0; 2.6; 24.7 and 16.6.

Paper V, in the abstract the second last sentence, third clause should be: **"***gave differences in total plant investment of as much as 30 % for long or specific updating periods. For short updating periods the difference was small.*" The following text is thereby removed: ~~*gave differences in total plant investment of as much as 50 % for an updating period of 5 years.*~~

Paper V, page 4, the last sentence in paragraph 4.3 should be: *Results show that the refinery estimates are significantly higher, and that using the CERA index or the CEPCI index result in similar cost estimates for the updating period 2007-2012. If the cost estimates would have been updated over another period or longer time period, the difference between using the two indices could have been significant. For example, for the period 2002-2012 the difference is 30 %.* The following text in the last sentence is thereby removed: ~~*and that using the CERA index result in cost estimates almost 50 % higher than using the CEPCI index.*~~

Paper V, page 5, section 6 the fourth and fifth sentences, starting with "*Cost estimates* ... and ending with "*... difference will be small.*" are replaced by: *Cost estimates calculated by updating with the CEPCI and the CERA indexes differed only slightly for the updating period 2007-2012. However, for other or longer updating periods the difference can be significant, for 2002-2012 it was 30 %.*

As a result of the changes in Paper V the following changes in the thesis are needed:

Page 63, Table 10 is replaced by the table below. The values in the column "*Holmgren cost (CERA)*" and "*Ratio Holmgren/Refinery CERA*" have been corrected.

Equipment process	**Refinery size**	**Refinery cost**	**Holmgren size**	**Holmgren cost (CEPCI)**	**Holmgren cost (CERA)**	**Cost, refinery down-scaled**	**Ratio Holmgren/ Refinery**	
	$m^3 h^{-1}$	M€$_{2012}$	$m^3 h^{-1}$	M€$_{2012}$	M€$_{2012}$	M€$_{2012}$	CEPCI	CERA
Distillation	1450	340	23	16.0	-[a]	18.8	1.2	-
Naphtha hydrotreater	240	80	3.3	2.0	2.1	5.0	2.5	2.4
Naphtha reformer	220	290	2.9	8.9	9.5	22.0	2.5	2.3
C5/C6 Isomerisation	105	60	1.2	1.8	1.9	3.6	2.0	1.9
Wax hydrocracking	340	460	7.2	16.9	18.0	55.5	3.3	3.1
Distillate hydrotreater	270	190	10.9	11.4	12.1	27.4	2.4	2.3

Page 61, second paragraph, sentences 3-5 starting with *Cost estimates*... and ending with ... *in updated publications.* are replaced by**:** *Using the CEPCI or the CERA DCCI (downstream Capital Cost Index) indices for updating cost estimates of the same equipment to a common value basis resulted in similar values for the updating period 2007-2012. If the cost estimates would have been updated over another period or longer time period, the difference between using the two indices could have been significant. For example, for the period 2002-2012 the difference is 30 %.*

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ISBN 978-91-7597-240-4

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Doktorsavhandlingar vid Chalmers tekniska högskola
Ny serie nr 3921
ISSN 0346-718X

Publication 2015:3
Industrial Energy Systems and Technologies
Department of Energy and Environment
CHALMERS UNIVERSITY OF TECHNOLOGY, GÖTEBORG
ISSN 1404-7098

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Printed by Chalmers Reproservice
CHALMERS UNIVERSITY OF TECHNOLOGY
Göteborg, Sweden 2015

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ABSTRACT

Biomass gasification has been pointed out as a technology with significant potential to produce motor fuels with low greenhouse gas (GHG) emissions from a life cycle perspective. In addition, other chemicals can also be produced by this technology but so far biofuel and chemical production by this route is still under development and not commercially implemented.

This thesis identifies and evaluates important parameters for future large-scale solid biomass gasification systems and their integration with existing industry and infrastructure to reduce the GHG emissions and to improve the economic performance of these systems compared to stand-alone configurations.

Three development routes, each consisting of one gasification-based biofuel production system and a specific case study location with integration potential with a district heating system or nearby industry are analysed. The included biofuels are: SNG (synthetic natural gas), methanol and Fischer-Tropsch fuels. The considered integration options are; heat integration or integration of material streams, such as CO_2 for storage, and co-utilisation of process equipment. The feedstock used in the systems is forest residues and different raw material supply chains and pretreatments were analysed. Future energy market scenarios that correspond to a wide range of possible future energy and fuel prices under different climate policy scenarios are used in the evaluation.

For the investigated cases and energy market scenarios, heat integrating the gasification-based systems with industry show robust GHG emissions reductions and increases in profitability. On the other hand, the results of integration with district heating systems varies depending on the replaced heat production technology and energy market scenario. The results also show that connecting the biofuel production system to future infrastructure of CO_2 storage significantly improves the GHG emission reduction potential and can also contribute to important cost-reductions in scenarios with strong climate policies. The analysis of raw material supply chains showed that the GHG emissions are lower for the systems with onsite biomass drying. Systems using pellets transported by ship and dried by other excess heat could result in just slightly increased emissions.
Only some of the analysed SNG cases and one of the Fischer-Tropsch cases showed profitability for some of the investigated scenarios and economic assumptions.

Keywords: biomass gasification, system analysis, process integration, greenhouse gas emissions, CO_2 emissions, biofuel production, methanol, Fischer-Tropsch, synthetic natural gas, SNG

List of appended papers

This thesis is based on the work described in the following papers:

I. Evaluating the greenhouse gas impact from biomass gasification systems in industrial clusters - methodology and examples.
Holmgren KM, Berntsson T, Andersson E, Rydberg T. (2011).
World Renewable Energy Congress 2011, Linköping, Sweden, vol. 12(057): 3098-105. DOI: 10.3384/ecp110573098

II. System aspects of biomass gasification with methanol synthesis - Process concepts and energy analysis.
Holmgren KM, Berntsson T, Andersson E, Rydberg T. (2012).
Energy. 45(1): 817-828: DOI: 10.1016/j.energy.2012.07.009

III. Gasification-based methanol production from biomass in industrial clusters: Characterisation of energy balances and greenhouse gas emissions
Holmgren KM, Andersson E, Berntsson T, Rydberg T. (2014)
Energy 69(1): 622-637: DOI: 10.1016/j.energy.2014.03.058

IV. The influence of biomass supply chains and by-products on the greenhouse gas emissions from gasification-based SNG production systems
Holmgren KM, Berntsson TS, Andersson E, Rydberg T.
Accepted for publication in *Energy*

V. Perspectives on investment cost estimates for gasification-based biofuel production systems
Holmgren KM, Berntsson TS, Andersson E, Rydberg T. (2015)
Presented at the 18th Conference of Process Integration, Modelling and Optimisation for Energy Saving and Pollution Reduction, PRES 2015, Kuching, Malaysia 22-27 August 2015. Accepted for publication in *Chemical Engineering Transactions*

VI. Comparison of integration options for gasification-based biofuel production systems – economic and greenhouse gas emission implications.
Holmgren KM, Berntsson TS, Andersson E, Rydberg T.
Manuscript submitted to *Energy*

Co-authorship statement

Holmgren is the main author of Papers I-VI. Professor Thore Berntsson supervised the work in all papers and Eva Andersson, PhD and Tomas Rydberg, PhD co-supervised the work in all papers. Eva Andersson also contributed to the input data assessment of integration possibilities with the chemical cluster in Paper III.

Supervisors

Professor Thore Berntsson is professor at the Division of Industrial Energy Systems and Technologies (*until recently* Heat and Power Technology) at the Department of Energy and Environment at Chalmers University of Technology.

Eva Andersson has a PhD from the Division of Heat and Power Technology, Department of Energy and Environment at Chalmers University of Technology and works as a Project Leader at CIT Industriell Energi AB.

Tomas Rydberg has a PhD from the Department of Chemical Environmental Science at Chalmers University of Technology and is currently Manager for the group of Products and Environmental Management at IVL Swedish Environmental Research Institute Ltd.

Related work not included in this thesis

- Heat recovery aspects of importance for the product mix and GHG emission reductions in a bio-SNG system
  Holmgren KM, Berntsson TS, Andersson E, Rydberg T. (2014)
  Chemical Engineering Transactions 39 (Special Issue):373-378: DOI: 10.3303/CET1439063. This is an earlier version of Paper IV.
- Investment cost estimates for gasification-based biofuel production systems.
  Holmgren KM. (2015) IVL B-report no 2221. IVL Swedish Environmental Research Institute Ltd. Supplementary report to Paper V.
- Policies for promoting biofuels in Sweden.
  Holmgren KM. (2012) f3 synthesis report no 2012:2.

Table of Contents

1 Introduction

This chapter presents the main objectives of this work, and the scope of this thesis is defined. A short description of the appended papers and how they relate to each other are given along with an outline of the thesis.

1.1 Background and motivation

In biomass gasification, large complex molecules are thermally disintegrated to basic building blocks that can be used in a wide range of processes to produce biofuels, chemicals or materials. Biomass has the potential to replace fossil-based products in all of these categories. Biomass gasification has been suggested as a promising route for producing advanced biofuels on a large scale.

Two of the main objectives for developing the European Commission’s white paper towards a competitive and resource-efficient transport system were to reduce greenhouse gas (GHG) emissions to comply with the overall climate targets and to reduce the strong oil dependency in the transport sector (EC, 2011a). The white paper concludes that reducing GHG emissions by at least 60 % by 2050 (compared to the level in 1990) is needed in the transport sector (EC, 2011b). Synthetic biofuels, BtL (biomass-to-liquid), including gasification-based products, have a substantially higher potential to reduce GHG emissions than either conventional fossil fuels or first-generation biofuels (Edwards et al., 2007). Furthermore, gasification-based biofuels can be produced from raw materials that do not directly compete with food production.

The Swedish governmental investigation on a fossil fuel-independent transport sector in 2030 SOU (2013:84) showed a significant potential for producing biofuels in Sweden. According to an assessment by Börjesson et al. (2013), the potential energy from biomass feedstocks is approximately 50 TWh (in addition to the current utilisation), which could be used to produce ~25-30 TWh of biofuels, corresponding to one third of the current use of diesel and gasoline in the Swedish road transport sector. It is estimated that there is a potential for a significant increase in the available biomass by e.g. improved forestry until 2050. Further, Börjesson et al. (2013) state that biomass gasification and other bio-chemical processes based on lignocellulosic feedstocks configured as polygeneration systems are efficient and the most efficient configurations are estimated to reach fuel production costs similar to those of current (first generation) biofuel production systems.

In recent comparison of renewable solutions for different types of transports it was concluded that in the future, electric vehicles should be prioritised (Connolly et al., 2014).

However, electric vehicles are not appropriate for all types of transport, and there is still a need for energy-dense fuels for some parts of the transport sector. Connolly et al. (2014) identified biomass gasification, steam electrolysis and carbon capture as key technologies in the production of these future fuels.

The present study investigates the impact on the GHG emission reduction potential and the net annual profit (NAP) of different alternatives for utilising the excess heat and for storing the separated CO_2 from biomass gasification-based synthetic natural gas (SNG), methanol (MeOH) and Fischer-Tropsch (FT) fuel production under different future energy market scenarios. The analysis is based on three development routes for gasification-based biofuel production systems integrated at different industrial sites in the southwest of Sweden. The feedstock for the gasification systems considered is forest residues.

It is of significant importance to conduct system studies of these large-scale industrial systems considering both profitability aspects and impacts on GHG emissions to have a good knowledge base when planning for the actual implementation, design and construction of plants and when developing and designing policy instruments surrounding these systems. This motivation was the starting point of and the rationale for this work.

1.2 Objectives

The objective of this thesis is to identify and evaluate important parameters for future large-scale solid biomass gasification systems and their integration with existing industry and infrastructure to reduce the GHG emissions and to improve the economic performance of these systems compared to stand-alone configurations.

The aim is to find integration opportunities that both decrease the climate impact and increase the economic performance of the gasification systems. The aim is also to increase the general knowledge of how different parameters impact the economic performance and the GHG emission reduction potential in these systems to facilitate decisions made by both actors building and implementing the technology and policy makers. Biofuel-producing systems are emphasised, although some insights on olefin production via the MTO (methanol-to-olefins) process are also provided.

1.3 Scope

The work covered by this thesis is based on three case-study systems, hereafter referred to as ***development routes (DRs)***. The gasification-based (GB) production systems are limited to SNG, MeOH and FT-fuel production, with some additional cases, including an MTO process producing olefins in the MeOH DR. The DRs include gasification systems in three different locations with potential integration with existing industry in the southwest of Sweden. The analyses are designed to draw conclusions that are also valid for systems in other places than the specific case study locations. All of the systems are future commercial-scale systems. The feedstock considered for these systems is limited to forest-based biomass, and in most cases the feedstock is residues from local forest production, i.e., forest residues. Pelletised feedstock is considered in Paper IV.

The focus of this study is on the interactions between the gasification system and the surrounding system. Figure 1 is a general description of a biomass gasification system and the surrounding systems divided into four different system levels. Although the picture is general, it indicates the complexity of the overall system and the large number of parameters at each system level. System Level 1 includes only the gasifier and its utilities, which represents a system level dealing with specific technology choices for specific process steps. System Level 2 includes the entire gasification system: the biomass feed via gasification, gas cleaning, syngas conditioning, synthesis and final upgrading of the product (for a more detailed description of the process steps in a gasification system, see Chapter 3), representing the general process steps rather than specific technology choices. The gasification system also includes a system for heat recovery from the different process steps, comprising an HRSC (heat recovery steam cycle) for power, or heat and power, generation. In addition to the gasification system, System level 3 includes the surrounding energy system (with potential integration with DH (district heating) systems or the adjacent industry) and infrastructure for transporting feedstock, products and by-products. At the highest system level, Level 4, the energy market governed by fossil fuel prices in the international commodity market and by national and international policy instruments is considered. The work presented in this thesis mainly covers analyses at System levels 2-4.

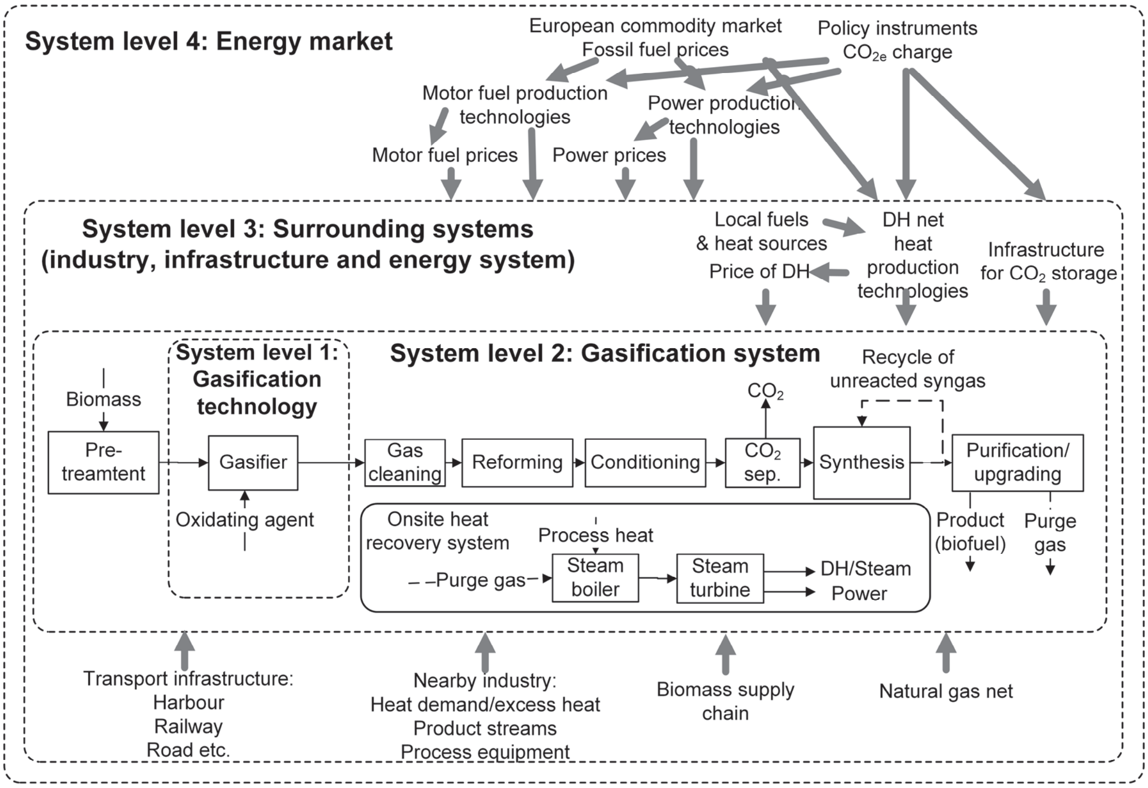

Figure 1 System levels in the analysis of the environmental and economic performance of biomass gasification systems. Grey, thick arrows indicate impact, whereas the thin black, arrows represent physical flows.

The evaluations of the GHG emission reduction potential and the economic performance have a wide, societal perspective. The GHG emission evaluations are made from a global perspective, i.e., considering not only emissions occurring at the gasification plant but also off-site emission changes due to product replacement. In the economic evaluation, the costs and incomes are not allocated between different actors (e.g., the owners of the biomass gasification system, the DH system, industry, etc.). How the costs, profits and associated risks are divided between the different actors is of significant importance for the realisation of large-scale biomass gasification systems but was not within the scope of the studies presented in this thesis.

1.4 Research approach and questions

To reach the aim and fulfil the objectives, an approach was applied where the biomass gasification systems are analysed at different system levels. The analysis can be divided into three parts, covering aspects at different system levels (numbered according to Figure 1) and answering different research questions:

I: Aspects of System Levels 1-2:
This part covers the identification of the process configuration (i.e., the technical choices made in the process steps) for the gasification systems. What are the conversion efficiencies, product mixes and energy balances of the SA gasification systems? Which factors are of significant importance for the GHG emission reduction potential in SA biomass gasification systems? What are the investment costs for the gasification systems?

II: Aspects of System Levels 2-3
This part includes the analysis of how integration impacts the GHG emission reduction potential in the systems. Different types of integration are covered, including

a) heat integration (exchange of hot water or steam, determined by energy targeting using pinch analysis, see Section 4.3.1)
b) material integration (e.g., utilising by-product streams from nearby industry)
c) equipment sharing

What impact on the GHG emission reduction potential does the available infrastructure, such as harbours, pipeline distribution net for transport of CO_2 to storage or natural gas, etc. have?

III: Aspects of System Levels 2-4
To analyse the economic performance of the development routes, the highest system level is also considered. Which factors are of significant importance for the economic performance of the SA gasification systems? What impact on the GHG emission reduction potential and the economic performance of GB biofuel production systems does integration with existing industry and infrastructure have under different future energy market conditions?

There are links between the different parts, but there are some issues that are specific to each of them. The third part is important because it explains how a single activity impacts both the economic performance and the GHG emission reduction potential. The simultaneous analysis of these parameters is important because synergies are desirable, such as measures that improve the profitability *and* the GHG emission reduction potential, which will be crucial for reaching the economic and environmental objectives.

1.5 Appended Papers

This thesis builds on six appended papers. A general overview of the papers and some of the most important knowledge transfers between the different papers are illustrated in Figure 2. Note that the method for evaluating GHG emissions developed in Paper I constitutes the basis for the evaluation in Papers III-IV and VI, and this method was further developed in the later papers.

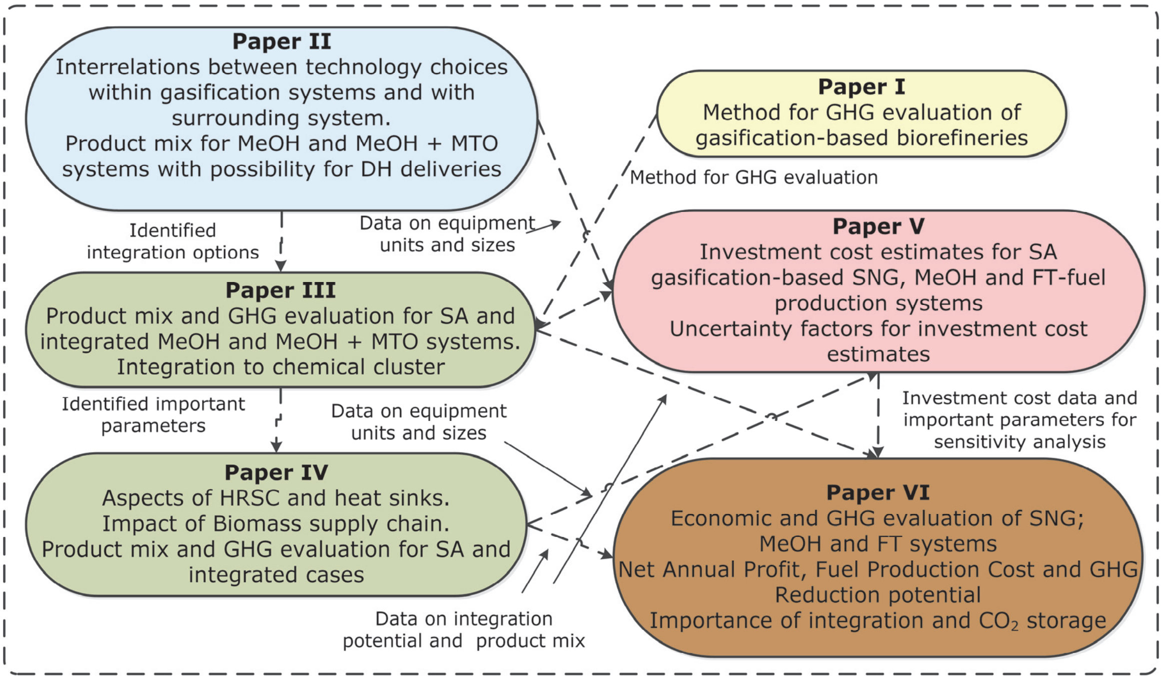

Figure 2 Overview of the papers included in this thesis, including content and interrelations

Paper I defines the method for evaluating the GHG emission reduction potential of biomass GB systems for the purpose of the overall project. The method is illustrated by analysing an SNG system, an MeOH with MTO synthesis system and an FT fuel production system based on the energy balances/product mixes of these systems given in the literature. The study includes a method for considering the timing of emissions for products with lifetimes significantly longer than 1 year, and the method is illustrated for the olefins produced in the methanol and MTO system. The methodology mainly covers System Levels 2-4.

Paper II summarises and discusses, in a structured manner, the interrelations between the different parts of the gasification system (i.e., the technical system) and the surrounding system (i.e., the raw material supply, product distribution, heat sinks, heat recovery possibilities, CO_2 storage, etc.). A reasonable technical setup for a commercial-scale GB MeOH production system is determined. The product mixes and energy balances of SA configurations and configurations with DH deliveries are determined. In addition, the impact on the product mix of having access to additional hydrogen and dry biomass is evaluated. The analysis in Paper II mainly covers System Levels 1-3.

In **Paper III**, the analysis of the MeOH system from Paper II is further developed by also analysing the GHG emission reduction potential. Integration between the MeOH system and the chemical cluster at the case study location is considered. The integration possibilities include low-temperature heat exchange for biomass drying and district heating, steam exchange and the utilisation of "stranded" hydrogen. This analysis focuses on System Levels 2-3, but the GHG evaluation also considers System Level 4.

Paper IV evaluates the product mix and GHG emission reduction potential for SA and an integrated SNG production system. The impact on the product mix of on- or off-site biomass drying is investigated. Biomass supply chains for dry biomass in the form of pellets are evaluated from the point of view of GHG emissions. This paper mainly focuses on System Levels 2-4.

In **Paper V**, the investment costs for GB SA systems producing SNG, MeOH or FT fuels are estimated. The investment costs are based on estimates for the components of the process equipment. The impact on the investment costs of using different updating indices is investigated. This paper also compares the investment cost estimates based on experience from industry and estimates in the scientific literature. The system levels mainly covered in this study are 1-2.

Paper VI builds on all of the other papers and estimates the NAP (net annual profit), FPC (fuel production cost) and GHG emission reduction potentials for all three biofuel production systems in SA and integrated settings under different future energy market and GHG policy scenarios. The paper focuses on the impact of integration on the economic and GHG emission performance. The configurations and investment costs from previous studies are used, so this study focuses on System Levels 2-4.

1.6 Thesis outline

Chapter 2 presents related system studies of integrated biomass gasification systems. Studies on GB production of olefins via the MTO-process are also presented in this chapter.

Chapter 3 gives a brief and general introduction to biomass gasification and to the production of the three biofuels considered in this thesis; SNG, MeOH and FT-fuels.

Chapter 4 describes the methodology, methods and tools used in the analyses of this project. It includes a motivation for the choices of methods. The general assumptions and some data for the GHG and economic evaluations are also presented.

Chapter 5 presents the development routes in detail, including technology choices in the gasification systems and the studied integration opportunities. In connection to the description of the technology choices, related studies of SA production for each of the biofuels are also presented. The studies from which data on the energy and mass balances, for the analysed gasification systems were retrieved, are also presented.

Chapter 6 starts with a section presenting the main results for each of the individual papers. In the following section the results from the different papers are compared and summarised.

Chapters 7-9 include a discussion of the results, conclusions and some suggestions for future work.

2

Related work

This chapter presents work related to the objective of this thesis. System studies of solid biomass GB fuel production integrated with existing industry, DH systems and/or infrastructure for CO_2 storage are described. The focus of the review is on studies evaluating the GHG emissions and the economic performance of systems producing one or several of the fuels included in this thesis (i.e., SNG, MeOH or FT fuels). Studies covering other fuels (e.g., H_2 (hydrogen), DME (dimethyl ether), MTG (methanol-to-gasoline), etc.) or other syngas applications are mentioned but are not fully covered. Studies of biomass gasification systems with syngas applications without synthesis and gas cleaning, such as integrated gasification combined cycle (IGCC), are not covered in this chapter. Further, the review covers neither studies of black liquor gasification (BLG) nor studies that combine BLG and solid biomass gasification, mainly because these studies are specific to the pulp and paper industry, and comparisons to the systems covered by this thesis are difficult to make without a deeper analysis, which is beyond the scope of this study.

Results from studies of solid biomass gasification systems integrated with the pulp and paper industry are presented, because some of the general conclusions from these studies are interesting as a background for the analysis in this study.

Literature on the system analysis of GB material production via MTO is presented. The MTO process is included because this process is a possible application for bio-MeOH, which is analysed in Papers II and III.

Literature on system studies of SA GB biofuel production systems of the three fuels included in this thesis is presented in Chapter 5 and in the appended papers. There is a specific focus on MeOH studies in Papers II and III (and VI) and on SNG systems in Papers IV (and VI), whereas FT fuel systems are mainly mentioned in Papers V and VI. Chapter 5 also gives specific details for integrated studies that relates to the technology choices and assumptions on integration for the DR presented there.

Studies covering the integration of GB biofuel production with DH systems are presented; however, studies covering the use of industrial excess heat in DH in general are not covered.

Some background literature for the choice of methodology for the GHG evaluation is given in Section 4.4.1.

A summary of the main motivations and additional contributions of the work in this thesis is given at the end of the chapter.

2.1 Integrating gasification-based biofuel production with existing industries

There are several incentives for co-locating biomass gasification with existing industry and/or DH systems, some of which are summarised by Wetterlund et al. (2013), including the potential benefits in terms of opportunities for efficient heat integration, feedstock and equipment integration; utilisation of existing fine-tuned supply chains; and access to existing experience and know-how. They also emphasise that integration can benefit existing industries when developing new value chains. In addition, there could also be opportunities for integrating material streams or other infrastructure.

Andersson et al. (2013b) made an assessment of studies on industrially integrated biomass gasifiers for motor fuel production. The results show that the reasons for the considerable differences between similar studies in terms of technical and economic performance are that the studies used different system boundaries and different technical and economic assumptions. They also found that many studies have analysed integration with the pulp and paper industry, but the integration opportunities with saw mills should be further studied.

2.1.1 Integration with pulp and paper industry

Most of the studies of GB biofuel production integrated with this sector have the perspective of pulp and/or paper mills, and integration is seen as one possible way of improving the profitability of the mills, as declared explicitly by, e.g., Wetterlund et al. (2011), Isaksson et al. (2012), and Ljungstedt et al. (2013). The studies analysing integration with the pulp and paper industry often apply a sizing restriction for the gasifier due to the specific conditions at the mill (e.g., for BLG, to replace the recovery boiler, and in the case of solid biomass gasification, to replace the bark boiler). Isaksson et al. (2015) evaluated the impact of the mentioned sizing criterion for integration with a chemical pulp and paper mill, and the results showed that not limiting the size of the gasifier, which is limited by the excess heat available for integration, but rather limiting by technical and practical limitations (~400 MW), resulted in a higher internal rate of return for all cases and all scenarios.

Isaksson (2015) provides an overview of studies that have analysed the integration of solid biomass gasification with pulp and/or paper mills. This section provides some conclusions that are general to these studies, and studies that specifically draw conclusions on the integration aspects are presented. These general conclusions include the following:

- The integration of biomass gasification can be profitable to the mill. This conclusion is stated by, e.g., Wetterlund et al. (2011), who evaluated the system aspects of two biomass gasification concepts: BIG-DME (biomass integrated gasification dimethyl ether production) and BIGCC (biomass integrated gasification combined cycle) integrated with a pulp and paper mill. The profitability strongly depended on the energy market conditions. In addition, Isaksson et al. (2015) showed that under some of the analysed future energy market scenarios for 2030, it will be profitable to integrate GB biofuel production to pulp and paper mills.

- Integrated cases are more efficient than SA cases. This conclusion is reached by Joelsson and Gustavsson (2012) in their analysis of BLG DME production and solid biomass GB FT fuel production and by Ljungstedt et al. (2013) in an analysis of GB FT production integrated with a Swedish pulp and paper mill, considering different future development pathways for the mill. In addition, Andersson et al. (2014), who analysed MeOH production integrated with a chemical pulp and paper mill, showed that the integrated cases had higher energy efficiencies than the SA cases.
- Whether the GHG emission reduction potential is lower for integrated systems than for SA systems depends on the reference power production technology. Ljungstedt et al. (2013) concluded that the GHG emission reduction potential would be lower if the reference power production technology has a carbon intensity of NGCC (natural gas combined cycle) or lower. Isaksson et al. (2012) showed that for systems (FT, MeOH and BIGCC) integrated with a thermo-mechanical pulp mill, the GHG emission reductions were higher than for the SA cases when the reference power production had a carbon intensity of NGCC or lower.
- CCS (carbon capture and storage) is of significant importance for the GHG emission reduction potential. This effect is shown by all the relevant studies.
- Most systems with integrated GB biofuel production (not including BLG) show lower GHG emission reduction potentials than the alternative use of the biomass in a coal power plant. Note that IGCC is the exception, as shown by, e.g., Isaksson et al. (2012). Joelsson and Gustavsson (2012) concluded that using the biomass for oil substitution in stationary applications would yield larger GHG reductions than integrated biofuel production.

Additional interesting conclusions from studies of the integration of biomass GB biofuel production with the pulp and paper industry include the following:

Consonni et al. (2009) analysed different GB biofuel production systems integrated with a kraft pulp mill and showed that systems with more advanced power production performed better both economically and from the point of view of GHG emissions.

Andersson et al. (2014) performed a techno-economic analysis of GB MeOH production using a pressurised entrained flow (EF) gasifier in an SA configuration or integrated with a chemical pulp and paper mill. The economics were analysed both under current and future price scenarios. The integrated configurations showed higher energy efficiencies than the SA cases. The integrated cases could reduce the MeOH production costs by approximately 10 % compared to SA cases.

Tunå et al. (2012) analysed the integration of three different biofuel production pathways (DME, MeOH and FT fuels) with three different gasifiers (an atmospheric indirect fluidised bed, a pressurised oxygen-blown circulating fluidised bed (CFB) and an EF gasifier) with a pulp and paper mill and compared the integrated cases to SA cases. They concluded that integration is not beneficial in all cases. However, the assumptions of the reference energy production technologies were very specific for current Swedish conditions.

2.1.2 Integration with industries outside the pulp and paper sector

There are also studies analysing the integration of GB biofuel production with **other types of industries**, including the following:

Heyne et al. (2012) analysed the integration of a bio-SNG production plant with an existing biomass-fired CHP (combined heat and power) plant. The integration was deemed technically feasible, and the authors concluded that the use of existing energy production infrastructure for the efficient utilisation of excess heat from biofuel production shows interesting potential.

Brau et al. (2012) investigated the energy and CO_2 consequences of substituting a fossil fuel-based H_2 production unit with a GB bio-H_2 production unit in a large European refinery. Different degrees of heat integration between the GB H_2 production and different units at the refinery were analysed. The results showed that from an energy efficiency point of view, steam production is the best way to use the excess heat from the gasification process, whereas from an exergy point of view, it is better to produce power in an HRSC. All of the investigated cases showed significant GHG emission reduction potential. In related work, Brau and Morandin (2014) investigated different gasifiers in the bio-H_2 production process and their integration with an oil refinery. Both wet and dry biomass were considered for the gasification systems, assuming that the dry biomass could be dried by excess heat from the refinery. The GHG emission reductions depended on the reference power production technology, but the cases with dry biomass had better results, independent of the reference power production and the biomass gasification technology.

Johansson et al. (2012) analysed GB bio-H_2 production integrated with a hydroskimming refinery. Different gasification concepts and biomass drying technologies were analysed. The air drying had the best results in the GHG evaluation because flue gas drying required more electricity, and steam drying required more fuel. The global CO_2 emission reductions of the systems turned out to be sensitive to the assumptions of the alternative use of biomass.

Johansson et al. (2013) investigated FT-fuel production integrated with an oil refinery and found that in addition to the potential for using the existing equipment at the refinery for upgrading the FT syncrude, the potential also exists for heat integration between the oil refinery and the gasification process, which contributes to higher profitability and larger GHG emission reductions than SA FT fuel production. Johansson et al. (2014) compared FT production heat-integrated with a refinery with SA FT production. The results showed that the integrated cases generated larger GHG emission reductions than the SA cases. Upgrading the FT syncrude in existing or new processing units had a marginal effect on the global GHG emissions. The production of diesel can be maximised if new upgrading units are built, and the profit should be weighed against the additional investment costs.. The integrated cases showed the highest profitability in scenarios with low biomass prices, whereas the SA cases did not show profitability in any of the cases.

Lundgren et al. (2013) investigated the integration of bio-syngas production with off-gases from steelmaking to produce MeOH and showed that integrating the MeOH production in a steel plant can be economically viable and can lead to both energy efficiency improvements and environmental benefits for steel plants.

Petersen et al. (2015a) performed a techno-economic analysis of the integration of GB MeOH and FT fuel production at an average-sized sugar mill in South Africa. The raw material was sugarcane waste and bagasse. Conventional and advanced synthesis routes for MeOH and FT fuels were analysed. The results showed that the advanced cases were more efficient and profitable than the conventional cases. However, none of the investigated cases showed economic benefits strong enough to be viable for private investors. The best option based on the internal rate of return was the advanced MeOH case, whereas the FT route could better match (i.e., completely cover) the overall energy demands of the mill. In another study, Petersen et al. (2015b) compared three different concepts of biofuel production integrated with the sugar mill, including two different fermentation-based ethanol production routes and a GB FT fuel route. The results showed that heat integration was crucial for the FT production route, and this route also had the lowest environmental impact of the investigated cases.

A study by Wetterlund et al. (2013) built on the Swedish BeWhere model, which is used to determine the end products, sizes and locations of future production units for advanced biofuels in Sweden. The model is an optimisation model that is used to minimise the costs for the studied system, including the raw material supply, production costs, transport and delivery of biofuels, sales of by-products and policy instruments. Wetterlund et al. (2013) considered seven fuel production routes, including solid biomass gasification, BLG and integration opportunities with chemical pulp mills, mechanical pulp mills and paper mills, saw mills, mineral oil refineries and bio-CHPs in DH systems. Two scenarios for the production of advanced biofuels in Sweden, with capacities of 4 and 9 TWh y^{-1}, were analysed. The results showed that both scenarios could be accomplished using only national resources of forest-based biomass. Among the identified production units in the calculated solutions, BLG-DME and SNG production based on solid biomass gasification had the best results, due to the high biomass-to-fuel system efficiencies. The results also showed that a low biomass transport demand is important for the choice of localisation, identifying chemical pulp mills and saw mills as the most attractive host mills. The latest developments of the Swedish BeWhere model are presented in Pettersson et al. (2015). The results of their analysis of the future production of next-generation biofuels from forest biomass in Sweden showed that the cost of biomass and the biofuel plant capital cost dominate the biofuel cost, but the cost of biomass transportation and biofuel distribution can also have a significant impact. DME produced via BLG, and SNG produced via solid biomass gasification (mainly integrated with sawmills), dominated the future plants. Generally, plants with low specific investment costs (i.e., a high biofuel production) and/or plants with low specific biomass transportation costs occurred most frequently in the solutions.

A study by Morandin and Harvey (2015) compared three different routes of producing GB MeOH from forest biomass and included different options for localisation at existing industries to use the excess heat from the gasification process. The MeOH was assumed to be used in an MTO process integrated with the chemical cluster in Stenungsund. Three MeOH production routes were investigated: one with an indirect gasifier located at the Värö pulp mill (in the southwest of Sweden), producing SNG that could be transported to Stenungsund by the natural gas distribution net; one where the gasifier was located at the Iggesund pulp and paper mill (in eastern Sweden) and MeOH that would be shipped to Stenungsund was produced; and one where biomass was torrefied and transported to Stenungsund, where it was used in an EF gasifier to produce MeOH. The economic evaluation, which was performed in a parallel project (Joelsson et al., 2015) showed that the most capital-intensive option was to have the indirect gasifier at the Värö pulp mill, followed by the EF alternative using torrefied biomass, and finally the CFB gasifier at the Iggesund pulp and paper mill.

There have also been studies analysing the performance of GB synthetic fuel production where coal (or natural gas) is co-processed with biomass. The main advantage of this material integration is related to advantages of scale because the fossil fuel-based gasification systems can be built at much large scales. To achieve GHG emission reductions compared to the production of conventional fuel, these systems need to include CCS. Because coal gasification and natural gas reforming is outside the scope of this study, studies of co-processed biomass coal or natural gas are not completely covered here. However, a few extensive studies covering the energy efficiency and environmental and economic performance of the production of some of the fuels included in this study are mentioned:

Kreutz et al. (2008) analysed FT fuel production systems from coal and/or biomass, and Liu et al. (2011) analysed systems co-producing FT fuels and electricity from gasified coal and biomass with the possibility for CCS. They concluded that such systems could provide decarbonised power and fuels at lower costs than fossil fuels under a wide range of energy market conditions. Further, compared to the production of cellulosic ethanol, the fuel production costs would be lower and would require only half the amount of biomass. A study by Liu et al. (2013) provided a techno-economic analysis of the co-production of jet fuel and electricity from coal and biomass with CCS via enhanced oil recovery and concluded that reductions in the lifecycle GHG emissions of 10-20 % relative to using traditional fossil fuel systems could be achieved. Studies by Liu et al. (2015a) and Liu et al. (2015b) covered several process configurations for systems producing synthetic gasoline from coal, biomass, or coal and biomass via gasification, MeOH synthesis, and methanol-to-gasoline synthesis. Power co-production and CCS were also considered. They concluded that plants that co-process 35 % to 47 % sustainably provided biomass with coal achieve net-zero fuel cycle GHG emissions, but the logistics of biomass supply constrain these plants to modest scales (<10,000 bbl. d^{-1} gasoline). A biomass-only plant with CCS has highly negative net GHG emissions and a more severe scale constraint (approximately 4,000 bbl. d^{-1}) than plants that incorporate coal.

The studies of integrating biomass gasification with different types of mills in the pulp and paper industry show that in most cases, the integrated cases perform better with respect to the energy efficiency than the SA cases. The GHG emission reductions strongly depend on the energy market conditions. Additionally, the studies analysing integration with other industries show benefits of integration compared to the SA cases. CO_2 storage will be important for GHG emission reductions from the gasification systems. The profitability analysis results strongly depend on the assumptions of the energy market conditions, and it is difficult to compare between studies; however, several studies showed increased profitability for integrated cases, though there was a strong dependency on the energy market conditions and assumed levels of policy instruments.

2.2 Integration of gasification-based biofuel production in DH systems

Several studies have analysed the impact of integrating GB production of biofuels with DH systems. Difs et al. (2010), Fahlén and Ahlgren (2009) and Börjesson and Ahlgren (2010) had the perspective of the DH system (i.e., would biofuel and heat co-production be an economical option for heat production?), and all of these studies concluded that in a future with specific policy instruments promoting biofuels, bio-SNG production could be competitive with conventional bio-CHP and could reduce global CO_2 emissions. Wetterlund and Söderström (2010) evaluated policy instruments affecting the profitability of GB applications integrated to Swedish DH systems. They concluded that the investment in large-scale gasification systems entail a large risk for the DH suppliers and that long-term stability in policy instruments is needed.

Brandberg et al. (2000) studied the potential for a GB MeOH polygeneration plant in Trolhättan, Sweden. The analysed system had a once-through mode, from which significant amounts of off-gases were either used for power production or sold as a fuel. Different configurations for the power and DH deliveries were included. The results were compared to those from an earlier study (Ecotraffic, 1997), and their study concluded that a dedicated MeOH production plant would be the most feasible. However, the authors emphasised that an analysis for each specific location is needed due to the differences in economic parameters (prices, taxes, etc.). They also concluded that the use of the low-temperature heat from the biorefinery for DH and/or biomass drying is essential.

Ingman et al. (2006) analysed the energy efficiency and economic consequences of co-localisation of biomass gasification for CHP or biofuel production with a NGCC CHP plant in Gothenburg. They found no benefits of integrating bio-SNG production for use in the NGCC CHP. However, the introduction of SNG-production could be motivate if it would increase the number of delivery hours and if the SNG could be sold externally. Ingman et al. (2006) was part of the Biokombi Rya-Project, presented in Nyström et al. (2007) and Ahlgren et al. (2007) which investigated system effects of introducing biomass gasification in the Gothenburg DH system and the southwestern part of Sweden in a general and long term perspective. One of the highlighted conclusions from this project was that bio-SNG production for use in the transport sector was the most robust of the investigated alternatives.

Difs et al. (2010) studied the economic effects and potential CO_2 reductions of introducing biomass gasification applications in a Swedish DH system. Four different gasification applications were included: bio-SNG, BIGCC, BIGGE (biomass integrated gasification gas engine) and WB (waste boost, a case where a biomass gasifier produces gas, which is burnt to boost steam from waste incineration). An optimisation model was used to find optimal investments for the DH system, and the results showed that introducing biomass gasification in the DH system leads to economic benefits for the DH supplier as well as reduced global CO_2 emissions. Which investment should be made strongly depends on the level of policy instruments for electricity and biofuels. The high added value of the products from the gasification applications (electricity and SNG) made heat from these plants competitive even with heat from waste incineration, where the fuel has a negative purchase cost.

Egeskog et al. (2009) estimated the heat sink capacity of DH systems in the individual EU nations and assessed the possibilities for GB co-generation of biofuels for transportation and heat for DH systems, CBH, in the EU countries. They concluded that the European DH systems (in EU20) are significant heat sinks compared to the amount of excess heat produced in the estimated CBH until 2020 and that other factors will limit the deployment of CBH (e.g., biomass availability, policies etc.). They also state that there is competition for the heat sink, and further studies are needed. In a related study, Berndes et al. (2010) analysed the integration of GB biofuel production with DH systems in Europe and concluded that integration could increase competitiveness; and in many cases, this integration could increase the GHG emission reduction potential of the system. However, they also concluded that integration strongly depends on the competitiveness (which in turn strongly depends on local factors) compared to other heat production technologies.

Ekbom et al. (2009) analysed the production and supply system for bio-jet fuel via GB FT-fuel production for Arlanda airport (the largest airport) in Sweden. They considered the final upgrading of FT-waxes to take place at a refinery and also the possibility for the FT-plant to sell excess heat to a DH system. The economic analysis was performed from a current perspective, including current Swedish energy and CO_2 taxes. They concluded that for one of the chosen sites, the production cost for jet fuel would be lower than the current price of fossil jet fuels, indicating that this process would be profitable. Heat sales contributed to reducing the costs by ~20 %.

Tock et al. (2010) used a detailed thermo-economic model to consider different technological configurations for the production of biofuels, including FT-fuels, DME and MeOH. They used pinch technology to integrate the system and compute the optimal utility system. The results show that the most critical choice is the choice of gasification technology. They concluded that the best choice was the indirectly heated CFB gasifier followed by steam methane reforming. However, for SNG production, which unlike the production of liquid biofuels does not result in unconverted off-gases that can be used to heat the indirect gasifier, the oxygen-blown CFB gasifier was shown to be the best option.

Leduc et al. (2010) used a dynamic model to optimise the geographic position of a GB bio-MeOH plant by minimising the transport distances of the raw material and the final product. They considered the potential for selling excess heat to local DH systems, using the local heat demand and heat prices. It was assumed that 10 % of the input energy could be sold as heat to the local DH system (if the demand for heat was large enough). Leduc et al. (2010) found that the production cost could be reduced by 10 % if all of the heat could be sold to a DH system. In a similar study of MeOH production in Austria, Leduc et al. (2008) concluded that production costs could be reduced by 12 % by selling excess heat, so the possibility of selling heat strongly influences the location of the plant.

Steubing et al. (2011) performed a life cycle assessment (LCA) of a bio-SNG plant with CHP. The results showed that if the process heat was not used efficiently, the GHG emission reduction potential of the system declined substantially. In a later study, Steubing et al. (2014) assessed the optimal size and location of bioenergy plants with regards to environmental and economic performance by a spatially explicit value chain model of the production of SNG via wood gasification. The results showed that the most important driver of the environmental performance of these systems is the substitution of nonrenewable energy sources. The main drivers for the economic performance were the revenues from sales of the SNG plant products and the SNG production cost.

Huisman et al. (2011) analysed the FPCs for current and near-future GB biofuel production, including MeOH, DME and H_2 systems. They concluded that the MeOH production cost was not very sensitive to heat sales, due to the low amounts of delivered heat, but the H_2 system was very sensitive to heat sales.

Gassner and Maréchal (2012) investigated a GB bio-SNG system with the possibility of selling heat for DH or industrial use (with the same temperature level for both cases) and found that systems with the possibility of heat sales generally had lower production costs and higher biomass break-even costs than systems without heat sales.

In their study of the optimal localisation of biofuel production in Europe, Wetterlund et al. (2012) concluded that in general, replacing heat or power production results in greater GHG emission reductions than replacing transport fuels at current energy prices and production technologies.

Gustavsson and Truong (2011) analysed the potential to integrate power (BIGCC) or GB biofuel production (SNG; MeOH and DME) in a minimum-cost DH system under three different environmental taxation scenarios and two different crude oil prices when considering the current biomass price and a higher biomass price driven by policy measures. They concluded that GB biofuel production in the DH system is typically not cost-efficient, even for high oil prices. Furthermore, Truong and Gustavsson (2013) analysed the biomass-based production of DH, electricity, pellets and GB biofuels (SNG, MeOH or DME) and bio-ethanol. They determined the production costs and biomass use of products from SA production and from different DH production options, including heat-only production and various polygeneration options. The different DH systems were optimised considering the value of the co-generated products, other than DH, as equal to those produced in minimum-cost SA plants. They found that polygenerated DH is more cost- and fuel-efficient than that from heat-only production. Additionally, the co-production of electricity (BIGCC) is more efficient than the co-production of motor fuels, except for DME production in large DH systems. The integration of bio-pellet production increased the production of power or biofuels and reduced the production cost.

Hannula and Kurkela (2013) performed a techno-economic evaluation of four development routes for GB fuel production, including MeOH, DME, FT and MTG. They analysed five different process configurations for each fuel, with or without DH deliveries, with different gas cleaning technologies and gasifier pressures, and with or without storage of separated CO_2. The results show that, deliveries of DH could reduce the levelised cost of production by almost 10 % for the FT fuels, which was the case with the largest heat output of the investigated cases.

An earlier techno-economic study by McKeough and Kurkela (2008) evaluated GB systems producing SNG, MeOH, FT fuels and H_2. They noted the importance of considering the distribution costs and extra costs for vehicle conversions in the economic evaluation. Their evaluation showed that the FT fuels would be cheaper at the pump than either SNG or H_2.

Hannula (2015) compared the co-production of synthetic fuels (SNG, MeOH or MTG) and DH from biomass residues using three different production routes; (i) biomass gasification, (ii) from CO_2 and power via electrolysis of water and (iii) a combination of the two first routes. The results showed that the GB routes have better economic performance (lower levelised cost of production), and of these, SNG had the lowest cost.

Natarajan et al. (2014) analysed the optimal localisation of GB FT biodiesel in Finland. The study included an extensive sensitivity analysis of several parameters, including the feedstock supply, the industrial competition of raw materials, the transportation network, candidate sites, and the local energy demand. They concluded that the spatial distribution of the raw material supply and the energy demand (including the biofuel, heat and power demand) played a dominant role in determining the optimal localisation.

Djuric Ilic et al. (2014c) analysed the GHG benefits of introducing GB biofuel production to the DH system in Stockholm. Three production routes were included: GB DME fuel production, FT fuel production and ethanol production via the SSF process (simultaneous saccharification and fermentation) with down-stream biogas production. Several scenarios for the development of the transport sector (i.e., use of different fuels, biogas, biofuel, electricity) and the future energy market were analysed. They concluded that if the biomass resource is limited, then the alternative of using the biomass for biofuel production in the DH system will result in smaller GHG emission reductions than co-firing in coal power plants or in conventional bio-CHPs. They also stated that if CCS is available, introducing biofuel production in the DH system will be better than all of the alternative uses of the biomass (also co-combustion in coal power plants). Djuric Ilic et al. (2014c) stated that if DH producers invest in biofuel production instead of CHP, the GHG emissions of the studied systems will be between 35 % to 55 % lower in all of the considered scenarios except the scenario with high electrification of the transport sector and high carbon intensity in the reference power production.

Djuric Ilic et al. (2014a) evaluated the effects on profitability of four different biofuel production systems (including GB FT-diesel and DME production as well as two cases of ethanol with down-stream biogas production) of selling excess heat to DH systems. The ethanol production plant had the lowest FPC. The results showed that the heat and power by-production of the GB biofuel routes are significantly lower than for the ethanol production cases, so it would be easier to find sufficiently large DH systems. Djuric Ilic et al. (2014a) found only small economic benefits for introducing any of the GB concepts to the DH systems.

In the second part of the economic evaluation, Djuric Ilic et al. (2014b) analysed the cost of the DH prices in Stockholm as a result of the introduction of the biofuel concepts. They concluded that the profitability strongly depends on the type of biofuel production plants introduced and the energy market scenarios. The results show that large-scale biogas and ethanol production may significantly reduce the DH production costs in both of the energy market scenarios investigated. The investments in FT diesel and DME production are competitive with the investments in conventional CHP only if a high support for transport fuels from renewable energy sources is included. The main reason for the lower profitability of the GB concepts is the high investment cost.

System studies of forest-based biomass gasification by Wetterlund (2012) showed that large-scale gasification for biofuel or electricity production may be an economically interesting alternative for integration with DH systems or pulp and paper production in the future, but the economic performances of these systems are sensitive to a number of parameters, specifically the future energy market conditions, such as feedstock costs in relation to selling price of biofuels and power, revenues for heat sales and investment costs. Wetterlund also emphasised the need for economic policy support for GB systems to be economically attractive unless the oil and electricity prices are high enough to provide sufficient incentives for GB biofuel and electricity production.

Several of the studies mentioned above where GB biofuel production is integrated to DH systems showed that using excess heat from the gasification systems could contribute to important reductions in fuel production costs. Studies analysing the profitability of introducing gasification based production in DH systems come to different results, some conclude that there are no economic benefits while others claim it could be profitable. The results are of course reflecting the large variation in assumptions regarding the energy prices and policy instruments. Several studies also showed that integration of GB biofuel systems with DH systems could reduce the GHG emissions significantly.

2.3 System analysis of gasification-based material production via MTO

Gasification offers a wide variety of possibilities for the production of energy products (heat and power), fuels, chemicals and materials; see Chapter 3. Much focus has been on the potential to produce motor fuels, but other products could also be interesting. This thesis includes one pathway for producing materials: MTO, which uses MeOH to produce olefins, such as propylene and ethylene. The process was developed during the 1970 and 1980s, as described by Chen et al. (2005); however, only a few demonstration plants exist: Porsgrunn, Norway, since 1995, and Feluy, Belgium, since 2009 (the latter is seen as a semi-commercial scale unit (Senetar and Romers, 2011)). There are mainly three suppliers of the technology, UOP/Hydro, Lurgi and Exxon Mobil (Nouri and Tillman, 2005).

Ren and Patel (2009) found that the energy demand for olefin production via biomass GB MeOH production and the MTO process is significantly higher than the energy demand for conventional production routes via, e.g., naphtha- or ethane-based steam cracking. However, they found that the biomass GB route has the potential to reduce CO_2 emissions compared to the conventional routes. Ren et al. (2009) analysed the production costs of light olefins from a future perspective for different production routes based on oil, natural gas, coal or biomass. The production routes included not only conventional production but also gasification and fermentation-based routes. The biomass-based routes came out quite well in the comparison, especially for cases with a significant CO_2 cost. Favourable economics for olefin production via natural gas-based MeOH production followed by MTO, compared to naphtha steam cracking, was shown by Vora et al. (1997).

Johansson (2013b) studied the integration of a biomass GB MeOH production system, including a down-stream MTO synthesis with a steam cracker. The analysis did not include upgrading the blend of olefins resulting from the MTO process. The analysis showed that there is a potential benefit of integrating the MeOH production and the MTO process at a chemical plant with a steam cracker, although there would be a net loss in high pressure steam from the cracker. Additionally, Hannula et al. (2013) studied GB bio-MeOH production with a down-stream MTO process in two configurations integrated with a refinery site, including an existing ethylene production and also considering upgrading the olefins. The results showed that the olefin production costs could be reduced by ~12 % by avoiding additional investments in the olefin distillation capacity.

In the Swedish Skogskemi (forest chemicals) project, Joelsson et al. (2015) aimed at investigating promising and competitive options for the biomass-based production of chemicals and intermediates, including MeOH, olefins and butanol. They compared several different options for each of the three products, and the MeOH and olefin production routes included GB MeOH production and integrating the MTO unit with a chemical cluster, where the olefin blend could be upgraded in existing units. In a related project, Johansson and Pettersson (2014) analysed different production routes for olefins from forest biomass, including GB MeOH production followed by MTO and the dehydration of ethanol. They concluded that the ethanol-to-ethylene production pathway is probably the best alternative from a near-future perspective. Still, this pathway will be more expensive than other production pathways, and some type of premium, similar to what is given to the production of green transport fuels (tax exemptions and grants), is needed to encourage the implementation of these concepts. They also emphasise the need of more detailed studies of the MTO system and related costs. In an LCA analysis of the MTO route, Røyne et al. (2015) concluded that there is a potential to reduce GHG emissions compared to the conventional fossil fuel-based production.

Liptow (2014) assessed the environmental impact for three different routes of producing ethylene from biomass from a set of studies: Liptow and Tillman (2009) and Liptow and Tillman (2012) investigated the production of ethylene by the dehydration of ethanol produced from sugarcane fermentation compared to conventional production via naphtha steam cracking. Liptow et al. (2013) investigated ethanol produced via the fermentation of lignocellulosic biomass, and Liptow et al. (2015) made a comparison to production from GB MeOH via the MTO route. The comparison showed that GB ethylene production (via MTO) could perform better environmentally than fermentation-based ethylene.

2.4 Relation of earlier work to present thesis

Several aspects of integrating biomass gasification, including both BIGCC CHP and biofuel-producing systems, with existing DH systems have been analysed in the abovementioned literature. Many of these were performed from the perspective of the profitability of the DH system and not all compare with SA biofuel production.

The present thesis makes evaluations from the point of view of the gasification systems. The analyses of this thesis compare the impacts on the GHG emissions and the costs of utilising the excess heat from the GB biofuel production systems for different alternatives, e.g., for on-site power production, for DH or for heating industrial processes under different future energy scenarios. The analysed integration with industry comprises industries outside the pulp and paper industry and hence industry with a fossil-dominated feedstock. Furthermore, a detailed analysis is performed for on- and off-site biomass drying compared to importing dried (refined) biomass and the impacts of biomass drying on the GHG emission reduction potential of the system. This analysis was not found in previous studies but is of significant importance for localisation choices of future plants.

This thesis includes the analysis of the GHG emission reduction potential of GB MeOH production systems with down-stream MTO both in SA and in configurations integrated with a chemical cluster. A comparison is also made to the GHG reduction potential of systems producing only MeOH and of those producing SNG or FT. At the time of performing the studies including the MTO systems, no other studies comparing GB biofuel and olefin production were found. It should be pointed out that the more recently performed studies (2013 and onwards) presented in section 2.3 which include additional details on the MTO process and further comparison of this process to other production pathways for green olefins were not considered in the work of this thesis since the MTO systems were not analysed in the later part of the project (after 2012).

3 Biomass gasification

This chapter includes a general description of biomass gasification, its potential products and a short history and the current status of the technology.

3.1 Biomass gasification

Gasification is the conversion of any carbonaceous fuel to a gaseous product with a useable heating value (Higman and van der Burgt, 2008). Biomass is gasified by heating biomass and adding oxidising agents. The purpose is to convert the chemical energy from the biomass to chemical energy in the gaseous fraction. According to Higman's and van der Burgt's wide definition of gasification, pyrolysis, partial oxidation and hydrogenation are also included. The dominant technology, which is also the technology considered in this thesis, is partial oxidation, where the biomass is heated to temperatures above 700-800 °C, and the gasifying (oxidising agent) could be pure oxygen, air and/or steam. The composition of the gas from the gasifier of course depends on the composition of the feedstock, the gasifier technology, the oxidising agent, and the temperature and pressures. However, in the case of the forest biomass that is the focus of this thesis, and for technologies where the oxidating agent does not contain air (nitrogen), the main components in the gas leaving the gasifier are CO and H_2, as well as CO_2, water vapour, CH_4 and heavier hydrocarbons and other trace elements. The basic components, CO and H_2, can be used in fuel synthesis to create a desired fuel or chemical. Depending on the gasification technology and on the fuel synthesis, the syngas first needs to be cleaned to remove components that are poisonous or inhibit the synthesis reactions. Cleaning steps include tar removal, CO_2 and sulphur separation and the separation of other trace substances. Figure 3 shows the wide range of applications for syngas. Most of these possible applications are in use today but use syngas derived from fossil sources (coal or natural gas).

A 30-year review by Kirkels and Verbong (2011) of biomass gasification describes the long-term interest in this technology and verifies that it largely remains confined to research, development and niche demonstrations and that there has been no optimal design yet. Furthermore, they do not expect a breakthrough in the short term. Kirkels and Verbong (2011) also provide an overview of the accumulated operational capacity of biomass gasifiers for different applications. Historically, the most extensive applications are for heat or kilns and for CHP, followed by co-firing, resulting in only very low levels of fuel production.

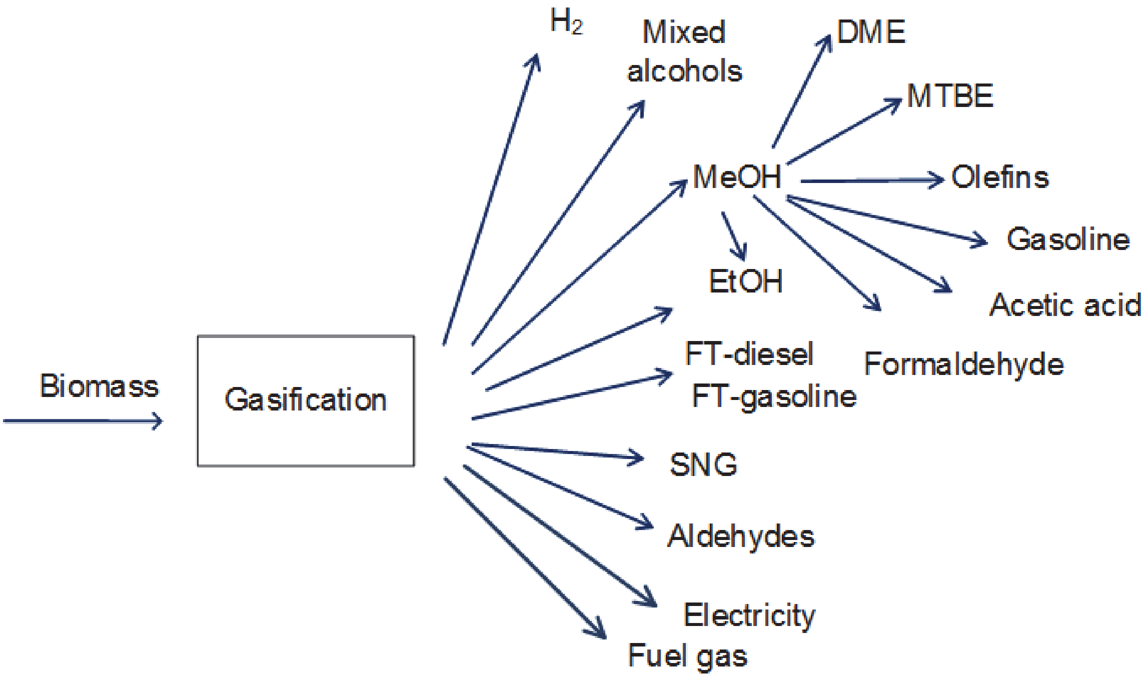

Figure 3 Syngas applications (modified from Higman and van der Burgt (2008))

Updated information on different biomass gasification projects world-wide can be found in the World Gasification Database (GTC, 2015). The latest development, identified by Kirkels and Verbong (2011), is the interest in second-generation biofuels produced by gasification. The technologies for producing the fuels (such as MeOH, FT, DME, H_2 etc.) have already been developed, demonstrated and commercialised to some extent based on fossil feedstock. The shift to biomass as the feedstock for the syngas production requires a completely different syngas cleaning process. This requirement is one of the major technical challenges for implementing biomass gasification. Another important challenge is that to be competitive with fossil alternatives, the raw material must be abundant and of low price. Heyne et al. (2013a) provides an overview of critical technology challenges for the large-scale deployment of the three main gasification concepts to be used for biosynfuel production for the production of biofuels or chemicals: direct fluidised bed gasification, EF gasification and indirect fluidised bed gasification. They also estimate the level of technology readiness (TRL-level) for these technologies. Hellsmark (2010) provides perspectives on the process of introducing large-scale biomass gasification in Europe.

3.2 The process

This thesis does not provide the full details of the biomass gasification process, but the interested reader is referred to, e.g., Knoef (2012), who provide many details on the basics of biomass gasification, including the different steps displayed in Figure 4. The general description of the GB biofuel/chemical production systems analysed in the present thesis is as follows: biomass is dried to a moisture content (MC) suitable for the gasification technology and comminuted to the required size, and then it is fed into the gasifier and is cleaned from unwanted compounds that are unwanted in the synthesis. The different syntheses applied have different requirements for the purity of the syngas and the H_2/CO ratio, which means that the gas is adjusted by, e.g., the water-gas-shift (WGS) reaction and

CO_2 separation to reach the required specification. Depending on the synthesis, there are also requirements for additional processing before the final product is ready for the market. In this thesis, three different syntheses are considered: methanation to produce synthetic natural gas (SNG), MeOH synthesis for MeOH production and Fischer-Tropsch synthesis to produce FT-fuels. Additional information on these three fuels is given in Section 3.3 and in Chapter 5, where the evaluated development routes are described in detail.

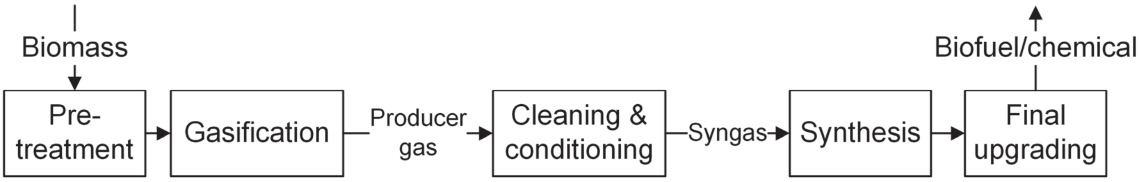

Figure 4 Schematic description of biomass gasification process and the major process steps.

3.3 Background and status of fuel pathways

This section provides a very brief description of the history and status of the production and use of the three GB biofuels considered in this project. Additional descriptions of the specific synthesis technologies are given in Chapter 5.

Bio-SNG

In the work of this thesis, SNG, synthetic natural gas refers to a gas of high purity produced by thermal gasification of biomass. SNG can also be produced from coal gasification. The gas consists mainly of methane and can be used in all applications utilising fossil natural gas.

Natural gas corresponds to approximately 21% of the world´s primary energy supply and within the EU it has a share of 24% (IEA, 2014). The distribution grid for natural gas is well developed in Europe, whereas the distribution net for natural gas in Sweden is limited to the southwestern part of the country, see Figure 5. The limited grid infrastructure also limits the natural gas to 2 % of the primary energy supply in Sweden. The natural gas supplied in the Swedish grid is imported from Denmark. The capacity in the Swedish natural gas distribution grid is approximately 22 TWh but the utilisation is about 10-12 TWh annually (EI, 2012). Natural gas and biogas can and are distributed in the same grid infrastructure and there are also local grids for biogas[1] in Sweden (Swedegas, 2015). In addition, gas can be compressed or liquefied (CNG or LNG) and transported by truck.

The annual production in a facility of the size investigated in the current work would be (if the annual running time would be 8,000 h) 2.8 TWh. The annual production of biogas in Sweden (from sources other than the Gobigas plant) is approximately 1.7 TWh (Energigas_Sverige, 2015).

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[1] Biogas can be produced by a number of different process and often has a significantly lower methane content than SNG or natural gas

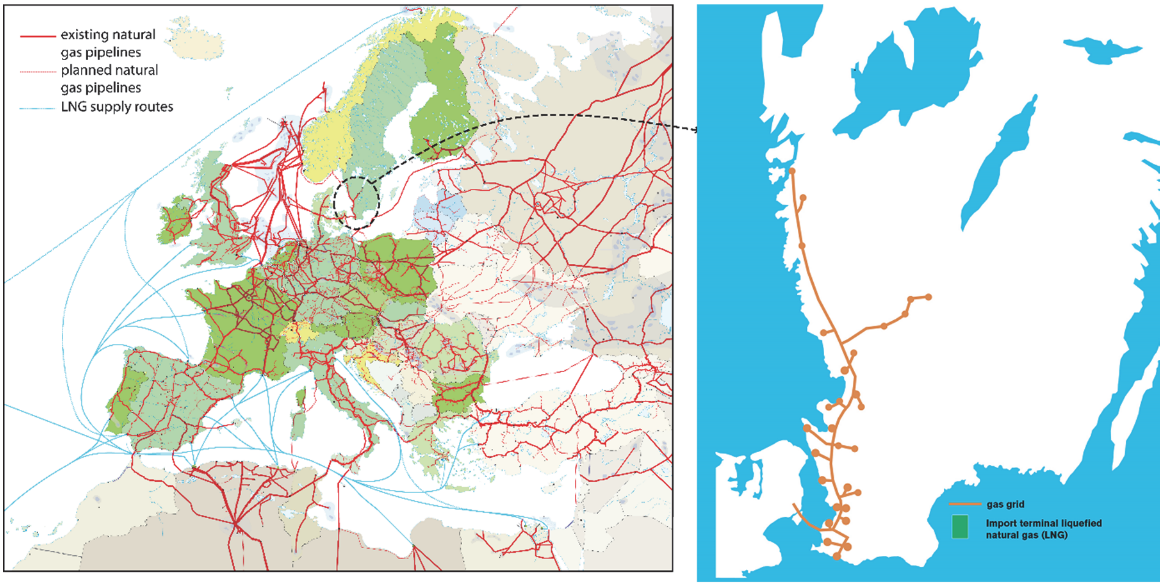

Figure 5 Natural gas grid infrastructure in Europe (right – modified from Heyne (2013)) and in Sweden (left)

The GoBiGas project in Gothenburg is a demonstration project for the production of GB SNG from lignocellulosic biomass. The first phase of the project has resulted in a plant with a production capacity of 20 MW_{SNG} with the first deliveries of SNG to the natural gas grid in December 2014 (Erdalen, 2014). Another demonstration plant for bio-SNG production in smaller scale is the 8 $MW_{biomass\ input}$ plant in Güssing, Austria. There are also plans for large commercial scale plants, however, none has so far reached commissioning state.

In 2013 approximately 1.5 TWh of “vehicle gas” was sold as vehicle fuel in Sweden. The vehicle gas consists of biogas or natural gas or a combination of the two. And there are currently over 150 public pump stations where vehicle gas can be bought. There are also several local bus-fleets that use vehicle gas. Since the importance of gas-based fuels and the distribution by grid infrastructure are more developed in Europe compared to Sweden, the potential for utilising SNG is significant in a European perspective. The Natural Gas Vehicle Knowledge Base provides statistics on the use and development of natural gas fuelled vehicles and pump stations, worldwide and regionally (NGV_Global, 2015).

Methanol

Methanol is one of the world’s most widely distributed chemical commodities. Methanol is a chemical that has been known and used by humanity since ancient times. During the 20th century, new production processes for MeOH were developed. The most common production route is via steam-reforming natural gas, and there are so-called mega MeOH plants located at sites with low-cost natural gas (“stranded” sites) producing several thousand tonnes per day. The global MeOH consumption was 45 Mt in 2011. In the past 10-15 years, the MeOH production in China has increased significantly, with coal gasification being an important production pathway, as described by Dolan (2013).

Bio-MeOH can be produced via several routes, including biochemical (fermentation) and gasification routes. According to Dolan (2013), biomass gasification is more attractive than other routes due to the higher carbon conversion rates and fuel yields. Currently, bio-MeOH is produced only in small quantities and is not used for fuel. The most common uses of MeOH include the production of formaldehyde, acetic acid and MTBE (methyl tertiary butyl ether, which is a fuel additive). However, the use of MeOH as a fuel has been increasing (by 25-40 % annually). MeOH can either be blended with gasoline (at different percentages: M15, M85 or even M100) or it can be converted to DME and be used as a diesel substitute or as part of the biodiesel production process. MeOH has a very high octane number, making it a good alternative to gasoline in conventional combustion engines requiring only minor engine modifications. Some material components in the vehicles and fuel handling systems also need to be replaced. MeOH has also been investigated as a fuel for shipping, and in early 2015, the first MeOH-powered ferry was launched at the route between Kiel (Germany) and Gothenburg (Sweden), according to the EBTP (2015c). The most important driving force for this development has been the stricter emission standards for sulphur introduced in the Sulphur Emission Control Areas (SECAs).

MeOH can also be produced from other sources of carbon, and even CO_2 from the atmosphere has been suggested. MeOH is also understood to be an efficient and easy-to-handle energy carrier compared to hydrogen, which is often suggested as the other energy carrier of the future; one example describing this idea is a comparison by Specht et al. (1998). The MeOH economy was described by Olah et al. (2009).

The MeOH plant analysed within this project would produce approximately 310 kt annually. If converted in the MTO process as suggested by Papers II and III the annual production would be approximately 105 kt olefins. According to the annual production of ethylene and propylene was 550 kt and 170 kt respectively at the chemical cluster chosen for integration with the MeOH plant in this study.

EBTP (2015b) mentions a few demonstration projects for GB production of bio-MeOH. The projects are in different stages of planning or commissioning. The Enerkem MSW gasification plant in Edmonton Canada was ready for commissioning in 2014, producing MeOH from municipal solid waste (MSW). The Woodspirit project in the Netherlands, in which imported pellets will be torrefied and used in an EF gasifier to produce MeOH; has been granted NER 300[2] support and is projected for start-up in 2017. In addition, the Swedish Värmlandsmetanol project plans for an MeOH plant with a 300 t day^{-1} capacity, using forest residues as feedstock. The project is awaiting decisions for long-term taxation strategies for biofuels.

Fischer-Tropsch fuels

FT synthesis was developed by the German scientists Fischer and Tropsch in the 1920s. The technology was first applied in areas where either the feedstock and/or the market was blocked or the feedstock was stranded from access to conventional fuels, such as Germany during the 2nd World War or South Africa in the 1970s. The feedstock for FT fuels has historically been either coal or natural gas. A few recent projects are based on stranded natural gas, such as the as the Shell Pearl and Oryx in Qatar, the Shell Bintulu in Malaysia or the Escravos in Nigeria (Goellner et al., 2013). These later projects have been important

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[2] NER 300 is the European Commission’s funding programme for innovative low carbon energy demonstration projects.

for the development and demonstration of new technology, especially with respect to synthesis.

The great advantages of FT fuels are that they are possible to use in current vehicles and distribution systems without any modification and hence the capacity and markets are not restricted to the development of new vehicles or infrastructures in the same way as in the case for bio-SNG and bio-MeOH. The upgrading of the final fuels can also utilise existing process equipment at oil refineries (as in the analysis of this thesis).

There is currently no commercial scale plant for production of FT fuels using biomass as feedstock. Several demonstration and large scale projects producing FT fuels from biomass feedstock have been put on hold, see (EBTP, 2015a).

4 Methodology, methods and tools

This chapter describes the overall methodology, the individual methods and the tools used in the thesis. The rationale behind the choices of method and evaluation criteria is also presented. In addition, this chapter includes the general assumptions used in the GHG and economic evaluations.

4.1 Methodological framework

The methodological framework developed and used throughout this project is illustrated by Figure 6. The starting point of the work was the case study approach, and the first step was to identify the development routes to be included. Each development route (DR) consists of a gasification system and a specific location with the potential for integration with existing industry or DH systems. The identification of DRs included deciding which products should be produced from the gasification system, determining the appropriate technology configuration and identifying localisations with potential integration opportunities. The criteria and strategy for identifying the appropriate DRs are further explained in Section 4.2. Note that within each ***DR***, different ***cases*** are evaluated to analyse and quantify the impact on the GHG emission reduction potential and the economic performance of the different configurations.

After identifying the DRs, the next step was to determine the mass and energy balances of the gasification systems and the integration opportunities, i.e., the energy demand at the appropriate levels for industry or DH systems. Detailed mass and energy balances for gasification systems are commonly determined using flow-sheeting models such as Aspen Plus. Stream data, mass balances and power demand from Aspen simulations of SA GB biofuel production systems were retrieved from other studies and were scaled (using simple scaling factors based on the biomass input) and sometimes adjusted to harmonise the assumptions for specific equipment pieces that were common for several of the DRs, e.g., the biomass drying or CO_2 separation. The technology configurations for the case studies are further explained in Chapter 5.

The next step in the analysis was to determine the product mix of the different cases for each DR. The available excess heat at different temperature levels can be determined using pinch analysis (see Section 4.3.1). Excess heat from the SA cases and excess heat not delivered externally from the integrated cases was used in an HRSC to generate power. A calculation routine was set up for generating stream data for the HRSC and to estimate its power production potential. A pinch analysis was performed to determine the maximum size of the HRSC for each case. In the integrated cases, the streams for heat integration with the nearby industry or DH system were also considered in the pinch analysis. The product mixes for the individual cases of each DR (both SA and integrated cases) were determined by combining the information from the pinch analysis and the mass and energy balances (see Section 4.3). The product mix was used for determining the GHG emission reduction potential of the system (see Section 4.4) and was also needed in the economic evaluation.

The profitability of the biofuel production systems was evaluated in terms of the NAP and the FPC. In addition to already determined parameters, the economic evaluation required investment cost estimates for the biofuel production systems and energy and fuel prices. A general description of the methodology for determining the FPC and the NAP is given in Section 4.5.1. The Energy Price and Carbon Balance Scenarios tool (the ENPAC tool) was used for identifying a set of consistent future energy market conditions (see Section 4.5.3).

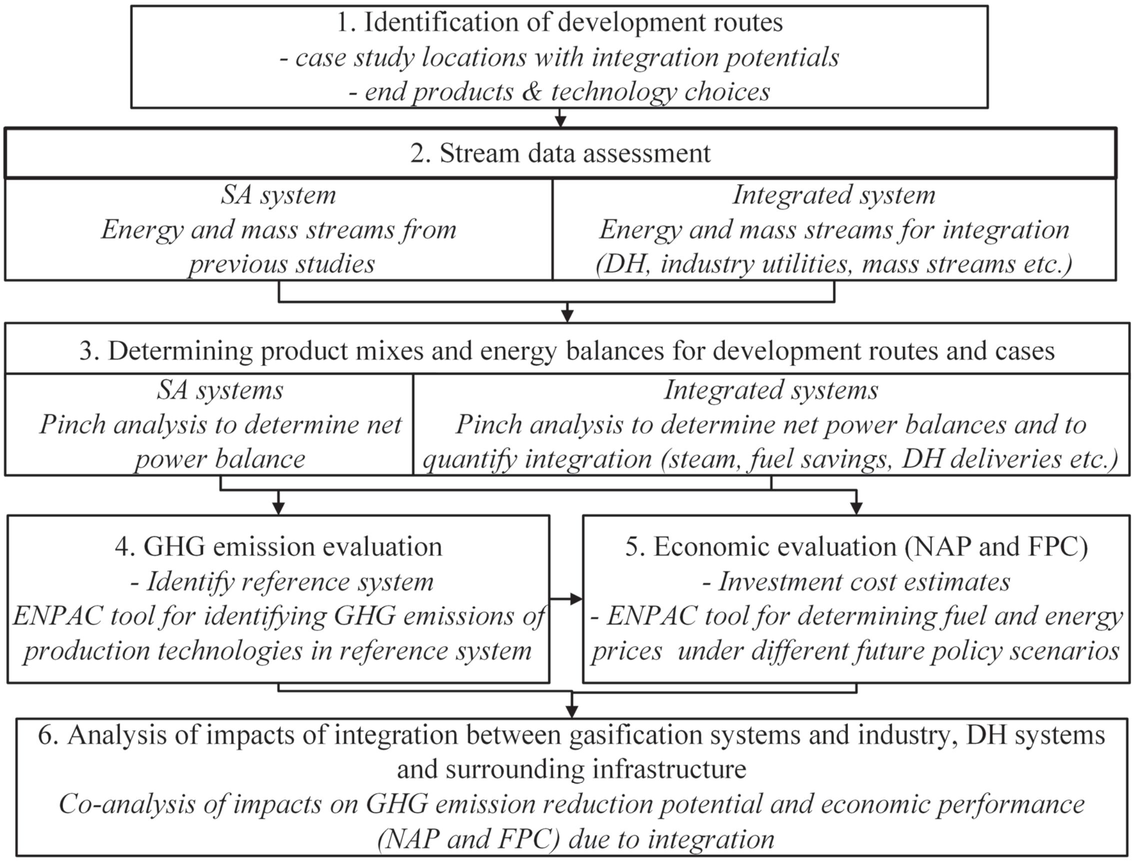

Figure 6 Methodological framework

By evaluating both the GHG emission reduction potential and the economic performance of the same set of cases, Step 6 in the methodological framework, a comparison of how these performance indicators are interlinked for specific integration options and energy market conditions can be performed. This information can be useful in the planning and implementation (investment) of future gasification systems and in the planning and implementation of policy instruments.

All steps in the methodological framework were not performed within each paper. In Paper I focus was on the GHG evaluation (Step 4). In Paper II the first three steps for the SA MeOH DR were performed whereas Paper III also includes integrated cases and Step 4. Paper IV includes Steps 1-4 for the SNG DR. Paper V includes the investment cost estimates for all three

DRs and finally in Paper VI all steps are included for all three DRs, however, utilising the performed work in previous papers.

4.2 Rationale for case study approach and identification process

As stated in the objectives, the aim of the analysis of the integration between large scale biomass gasification systems and existing industry or DH systems was to identify important parameters and conditions that reduce the GHG emissions and increase the economic profitability of the systems. The aim was to identify relationships and parameters in these systems for which general conclusions can be drawn. The chosen strategy for analysing the impact of the different integration possibilities and the surrounding systems were to compare SA and integrated cases.

Given the significant number of parameters that could be varied for a GB biofuel production system and the additional set of parameters that integration possibilities would add, the starting point of this study was a case-study approach that analyses a few relevant gasification systems at specific case study locations, i.e., a few relevant development routes were studied. In a relevant DR the technology choices, products and host sites are interlinked.

The area of focus for the case study locations is the southwest of Sweden. All of the included industrial partners have the main part or significant parts of their industrial activities within the region. This starting point was good for finding relevant DRs with relevant products and host sites. The engagement and interest by stakeholders facilitated the input data availability.

The DRs were identified based on workshops including industry representatives. Important prerequisites for the chosen development routes were that

- The studied gasification systems should be of commercial scale.
- The technology should be mature enough for implementation within 5-10 years.
- The combination of the GB production system and location for integration should be relevant for the existing industry (i.e., the industry should have an interest in the chosen product).

At an early stage in the process, the capacity of the studied gasification systems was determined to be 430 $MW_{th, LHV}$ (lower heating value (LHV) based on input biomass with a moisture content of 50 %). The background for this specific figure came from the general perception among stakeholders that this corresponds to a full scale unit. The 430 MW_{th} value also corresponds well to the sizes analysed in previous studies of GB biofuel production (e.g., studies by Hamelinck and Faaij (2001), Hamelinck et al. (2004), Tijmensen et al. (2002), van Vliet et al. (2009) and Swanson et al. (2010)). The analysis in this study is based on a fixed capacity of the gasification system. Possible limitations to the size (accept for the technical or practical) could be the availability of cheap feedstock, product market limitations or the opportunities for using the excess heat. The availability of feedstock was not analysed in detail, but it was assumed that it would be available from local sources or imports by sea would be possible to reasonable prices. The market for the chosen products was not considered to be a limitation in any of the cases since the produced SNG is a limited amount of what is distributed in the natural gas net, the produced amount of FT fuels corresponds to a small fraction of the fuels produced at the refinery (see Chapter 5) and the produced MeOH could either be used at the cluster or be shipped from the harbour to other users.

At the point of identifying the DRs, there were recently finished projects, such as one by Andersson (2007) and ongoing projects, such as one by Pettersson (2011), investigating different aspects of BLG and biofuel production integrated with the pulp and paper industry, so it was decided that the project presented in this thesis would focus on integration with industries from other sectors.

Three locations were chosen as case study locations, and the rationale for the chosen gasification system for each of these locations are described in the sections below. The three chosen locations are

- The harbour area in Gothenburg[3]
- The chemical cluster in Stenungsund
- The oil refinery in Lysekil

The bio-SNG development route in Gothenburg

It was decided that one of the DRs would be bio-SNG production, primarily for use in the transport sector and located close to the harbour area in Gothenburg with potential for integration with the DH system, injection of the SNG to the natural gas grid and importing biomass by ship. The exact choice of technology and data are further described in Section 5.1.

The research and interest in biomass gasification was already established in the region at the start of the current project. Nyström et al. (2007) had pointed out the production of bio-SNG for use in the transport sector as an interesting option for introducing biomass gasification in the Gothenburg area and this result, in combination with the great interest shown by the involved industries, was an important input for the decision of including this DR.

Some important characteristics for the SNG DR are

- The extensive DH system with annual deliveries of ~3.7 TWh and connections to the DH systems of several nearby communities (Mölndal, Kungälv etc.) (SOU, 2011:44). However, one drawback for additional heat production is that a significant part of the heat production is currently fulfilled by low-cost sources, such as industrial excess heat and heat from municipal waste incineration. The heat above the base load is to a large extent covered by natural gas-based production, e.g., NGCC CHP installations.

- The natural gas grid enables both the relatively cheap distribution of SNG and a redundancy for costumers during downtime. From a Swedish perspective, the natural gas grid is unique to the southwestern part of the country.

The MeOH development route in Stenungsund

The chemical cluster in Stenungsund was also identified as an interesting host site for biomass gasification. The DR based in Stenungsund includes MeOH production and integration possibilities between the chemical cluster and the gasification plant. In the first phase of the

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[3] This site is currently host site for the 20 MW bio-SNG demonstration plant GoBiGas.

project (Papers I-III), integration with the local DH system and the addition of an MTO process using the produced MeOH as feedstock were also considered.

MeOH can be used either as a biofuel for vehicles (in low blends without modifications or in high blends or pure with slight modifications) or as a platform chemical in the production of other chemicals or products. A chemical cluster produces and uses both platform chemicals and biofuels, which made the MeOH route particularly interesting from an implementation point of view. The choice of technology and data for the MeOH DR route are further described in Section 5.2.1.

The chemical cluster in Stenungsund is the biggest chemical cluster in Sweden, consisting of six different plants and five different companies. A detailed description of the processes and energy systems at the cluster is found in Hackl and Andersson (2010). Olefins (ethylene and propylene) are important feedstocks for processes at the cluster and are also produced from, e.g., naphtha or ethane in a steam cracker on-site. The main reason for including the MTO process was the scientific interest in comparing the GHG emission reduction potential for a route producing materials (i.e., products not primarily being burned) with the production of motor fuels (biofuels). Producing green olefins would also be one way of increasing the renewable feedstock and products from the cluster.

There are other possible routes for producing olefins from biomass (other than the MTO route), such as the dehydration of ethanol (as investigated for the Stenungsund cluster by Arvidsson and Lundin (2011)) or by steam cracking biomass-based FT naphtha. The MTO route was chosen because it is based on MeOH, which was considered a relevant route for the cluster. The MTO process mainly yields a mixture of ethylene and propylene, and the final products in the MTO cases were set to be low density polyethylene (LDPE) and polypropylene (PP). An LCA for the conventional production of LDPE at the specific cluster had been made by Liptow and Tillman (2009), which was a good basis for the reference system in the evaluation of this project.

In parallel to the project presented in this thesis, a total site analysis of the energy system at the chemical cluster was performed in two steps. Hackl and Andersson (2010) collected data on the overall utility consumption and identified potential steam savings by energy targeting. They also assessed the qualitative feasibility of some heat integration possibilities. Andersson et al. (2011) presented the practical issues of some of the integration options and conceptual designs. These studies, together with the Aspen simulations for the SA MeOH system made by Isaksson et al. (2012), have constituted important inputs for the analysis of the MeOH DR in this thesis.

The FT fuel development route in Lysekil

The third DR evaluated in this project includes biomass GB FT fuel production integrated with the oil refinery in Lysekil. The potential for integration includes both heat integration with the processes and the utilisation of process equipment for upgrading the FT syncrude. The oil refinery in Lysekil is a complex refinery with a capacity of processing 220,000 bbl. day^{-1}. For a more detailed description of the refinery, products, processes etc., the reader is referred to Johansson et al. (2014) and Andersson et al. (2013a).

At the time of deciding on the DRs of this project, there were several ongoing or planned parallel projects investigating different options for increasing the renewable feedstock and reducing GHG emissions in the refining sector, Johansson (2013a) and Brau (2013), as well as identifying potential strategies for improved energy efficiency (Andersson et al., 2013a), see Section 2.1.2.

EU regulations, (EC, 2009), require fuel suppliers to reduce the GHG emissions by 6 % per energy unit by 2020. A reasonable way to reduce GHG emissions and increase the renewable feedstock in the refinery is to feed liquid renewable feedstocks into existing or new processes. FT fuel production was therefore identified as an interesting option. Previous studies by e.g. Ekbom et al. (2005), Ekbom et al. (2009) and Johansson et al. (2014) suggested that the bio-syncrude should be upgraded to pump fuels at a conventional refinery.

Before the analysis in Paper VI the DR of co-locating and co-processing and/or heat-integrating the GB FT fuel production with a complex refinery was investigated by Johansson et al. (2014). Data from studies by Johansson et al. (2014) and Isaksson et al. (2012) were the basis for the FT DR analysed in Paper VI. The choice of technology and data for the FT DR are further described in Section 5.3.1.

4.3 Determining the product mix

The product mix is the amount (in MW) of products yielded from each analysed gasification system. The product mix includes biofuel/material (SNG; MeOH, olefin or FT-fuel), net power production, net usable heat (DH or steam delivered to industry processes) and in some cases also off-gases. The amount of biofuel produced was given by the mass and energy balances of the Aspen simulations taken from previous studies. The simulations also estimated the power demand of the processes and estimated the heating and cooling demands at different temperature levels. Process integration tools were used to analyse potentially efficient configurations for utilising the excess heat from the gasification system. For the analysis in Papers V and VI assumptions of e.g. power demand and heat demand for similar process equipment in the different gasification systems were harmonised.

4.3.1 Process integration

The definition of process integration used by the International Energy Agency (IEA) since 1993 (Gundersen, 2002) is

“Systematic and general methods for designing integrated production systems ranging from individual processes to total sites, with special emphasis on the efficient use of energy and reducing environmental effects.”

There are several applications of process integration. The applications used within this study include thermal heat integration within and between the processes of the GB system and between processes of the GB system and the adjacent industry or DH systems. Some of the papers (II and III) also consider the integration and exchange of material streams (e.g., H_2 and off-gases). The co-utilisation of process equipment is also covered for some processes.

Pinch technology is a well-established set of tools used worldwide for determining process integration opportunities, both within processes and between adjacent processes. The methods are based on the first and second laws of thermodynamics and were originally developed by Bodo Linnhoff and his research group during the 1970s, with the first pinch analysis user guide published in 1982 (Linnhoff et al., 1982). The concept has been further developed, and there are a number of later updates and extended books on the subject, e.g. Smith (2005) and Klemeš (2013).

The pinch analysis in this study covers energy targeting using grand composite curves (GCC) and background/foreground analysis (also known as split GCCs). The GCC is a graphical representation of all of the heat streams of a process, illustrating the opportunities for heat exchange as well as the minimum external heating and cooling demand of the process. A split GCC analysis is a graphical method for determining the integration potential between two processes. A basic description of the GCC and background/foreground analysis is given in Appendix I. For a more fundamental description of the background/foreground analysis, the reader is referred to Berntsson et al. (2013).

Stream data for the GB systems were retrieved from the modelling in previous studies. Necessary modifications were made in Microsoft Excel (scaling, adjusting etc.) and the ProPi MS Excel add-in (developed by CIT Chalmers Industriteknik) was used for plotting GCCs and split GCCs. A spreadsheet model was constructed and used for determining the streams for the HRSC.

4.4 GHG Evaluation

The objective of Paper I was to define and exemplify a methodology for evaluating the GHG impact of GB production systems. GHG evaluations are made in Papers III, IV and VI. This section describes the methodology, comments on the assumptions made and finally provides some of the data used in the evaluations.

4.4.1 Methodological choice and background

According to Cherubini et al. (2009), there is a broad agreement in the scientific community that LCA is one of the best methodologies for evaluating the environmental burdens associated with biofuel production. LCA is a standardised methodology for evaluating the environmental impact caused by a product or service during its entire life cycle (i.e., from its cradle to its grave). Details on the methodology can be found in (ISO, 2006a) and (ISO, 2006b). Even a standardised methodology allows different methods to be used, and depending on the goal and scope of a specific study, the results can differ significantly from another assessment of a similar system (Cherubini et al., 2011).

The GHG evaluation in this study has a life cycle approach including CO_2, CH_4 and N_2O emissions summarised using global warming potential factors for a 100-year period (GWP_{100}-factors) but is not a full LCA[4].

Cherubini et al. (2009) analysed the key issues influencing LCA outcomes for bioenergy systems and provided an overview of the GHG and energy balances of some relevant bioenergy chains compared with their fossil competitors. Cherubini et al. (2009) concluded that for biorefineries characterised by multiple high value products (such as electricity and transportation biofuels), the functional unit cannot be related to the unit output because the choice of one of the high-value products as the main product is an arbitrary decision. LCA

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[4] A full LCA considers more environmental impact categories than only the GHG emissions.

results for bioenergy systems based on biomass residues should be expressed on a per-unit output basis, if there is a need to be independent from the type of biomass feedstock, or a per-unit input basis, to be independent from the final products and conversion processes. Also Wetterlund et al. (2010) emphasised that results from the evaluation of CO_2 emissions from integrated biofuel production systems should be reported per-biomass unit or per-ha and per-year basis in order to reflect the scarcity of biomass and land for biomass production.

In this study, biorefineries with different conversion processes (although all based on biomass gasification) and different final products are compared, so they are evaluated on a per-unit input basis.

Wetterlund et al. (2010) analysed the impact of applying a system expansion when evaluating the well-to-wheel CO_2 emissions for different biofuel production systems and concluded that it is a useful method when evaluating complex systems, such as integrated biofuel production or biorefineries. In addition, Hoefnagels et al. (2010) analysed the impact of different assumptions and methodological choices on the life-cycle GHG performance of biofuels and concluded that system expansion is the preferred method to account for co-products. In the more recent study by Ahlgren et al. (2013) an extensive discussion on key methodological issues for LCA of biorefinery systems in relation to existing literature, standards and guidelines is given. Further, the study gives recommendations in several areas of the performance and comparison of LCA studies of biorefinery systems.

Based on the recommendations for the LCAs of biofuels and bioenergy systems given by, e.g., Cherubini et al. (2009) and Cherubini (2010), the GHG emission reduction potentials in this study are calculated as the difference between the life cycle emissions for the biomass-based system and the life cycle emissions of a reference system. As recommended by several studies, the system is expanded to include all of the products produced in the system; see Figure 7.

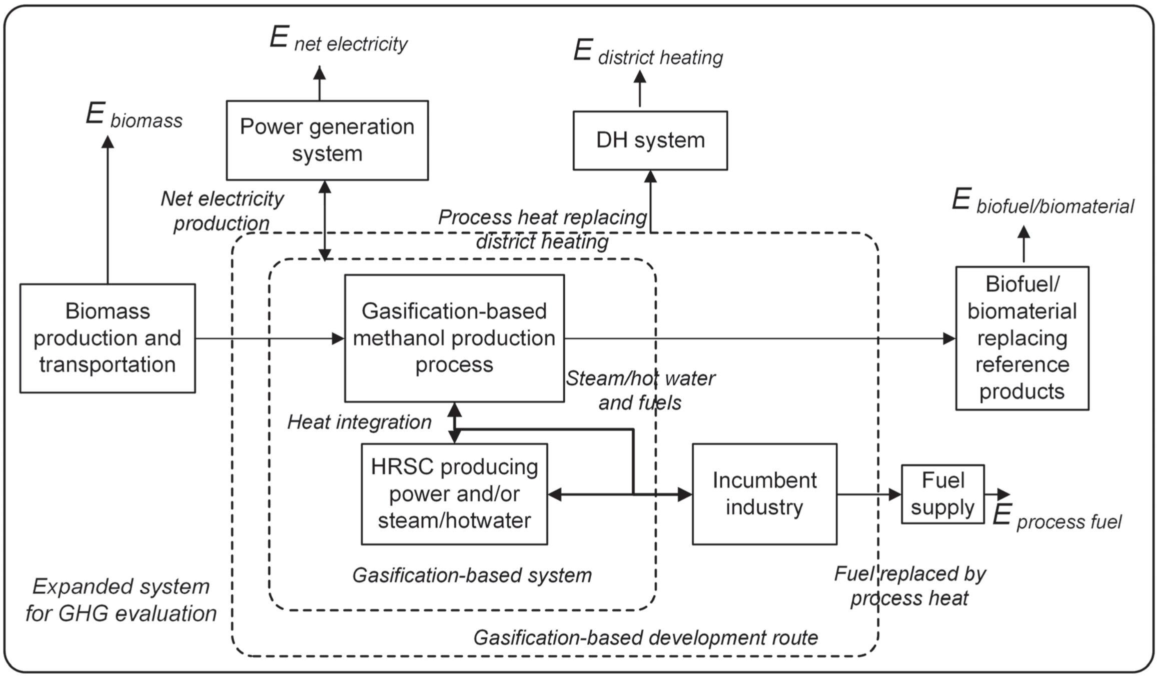

Figure 7 Schematic representation of the system analysed in the GHG evaluation.

The GHG emission reductions for the GB DRs are calculated based on the following equation:

$$E_{reduction} = E_{biofuel/biomaterial} + E_{net\ electricity} + E_{DH} + E_{industrial\ integration} - E_{biomass} \quad \text{Eq. (1)}$$

where:

$E_{reduction}$	is the reduction in GHG emissions to the atmosphere (a positive number means reduced emissions compared to the reference system).
$E_{biofuel/biomaterial}$	is the reduction in GHG emissions due to the replacement of the reference fuel (e.g., MeOH replacing gasoline). Life cycle GHG emissions are considered for gasoline, and the transport and distribution emissions, as well as the combustion emissions of non-CO_2 greenhouse gases from the biofuels, are considered. Note that the combustion emissions of biogenic CO_2 are considered to be neutralised by uptake during the growth of the biomass.
$E_{net\ electricity}$	is the GHG emissions reduction caused by replacing reference power production (this factor is positive if there is a net power production from the GB system, whereas it is negative if there is a net power import).
E_{DH}	is the GHG emissions reduction caused by replacing DH production in the integrated DH system. Whether this factor is positive or negative depends on the production technologies that are replaced, and if they include CHP, this factor also depends on the reference power production. Note that in most cases the full capacity for DH deliveries cannot be utilised because the assumed number of running hours for the GB process is higher than the number of hours with a sufficient heat demand in the DH system.
$E_{industrial\ integration}$	is the GHG emissions reduction achieved by integrating the gasification process with the adjacent industry. Heat integration mainly results in fuel savings and hence corresponds to a reduction in the use of natural gas.
$E_{biomass}$	is the emissions caused by the production and distribution of biomass to the gasification plant. Note that in this study, where the biomass is forest residues, the reduction of soil carbon due to utilising the forest residues is taken into account (see Table 2).

An important distinction in the analysis of this project is that the reference system does not always consist of 100 % fossil-based systems. The evaluation is performed from a future perspective, so the reference is a future system. The assumptions regarding the reference system are based on the consistent energy market scenarios provided by the ENPAC tool (see Section 4.5.3) for power and DH production technologies, whereas for motor fuels, it was assumed that conventional diesel and petrol constitutes the reference, and for plastics, naphtha-based olefin production was used as the reference. The assumptions of the reference systems in the different papers are given in Section 4.4.2.

4.4.2 Assumptions for feedstock, products and the reference systems

The biomass feedstock - a limited resource
The biomass feedstock is in most of the analysed cases assumed to be chipped forest residues from local production. The GHG emissions for the raw material supply are based on works by Lindholm et al. (2011) and Berg (2010), also considering the soil carbon losses due to utilising the forest residues. In Paper IV, additional raw material supply chains are investigated. Because biomass is assumed to become a limited resource, it is important to compare it to alternative uses. In all of the papers, the GHG emission reduction potential of the GB systems is compared to the use of biomass for the direct replacement of coal (e.g., by co-firing in a coal power plant).

Biofuels
The biofuel replacements are similar in all of the papers except for the replacement of SNG. Two alternatives are used for the replacement of SNG: it is assumed either to replace petrol in passenger cars or to replace natural gas (in any application). In Papers IV and VI, where it is assumed that the gas will replace petrol in passenger cars, the power demand for additional compression of the gas needed for utilisation in the cars is considered. This need, however, was not considered in the GHG evaluation in Paper I. MeOH is assumed to replace conventional petrol in passenger cars, and for FT production, the gasoline fraction was assumed to replace gasoline, and the diesel fraction was assumed to replace conventional diesel.

Power production
The GHG evaluation considers the net power consumption or production. The reference power is determined by the build margin technology identified by the ENPAC tool for the different energy market scenarios. Four different reference power technologies are considered in the different papers (for the specific assumptions, see the individual papers): coal condensing power with and without CCS, NGCC and wind power.

Heat for DH systems
The assumptions for the replaced systems/production technologies in Papers I, III and IV are based on case study conditions, whereas the assumptions in Paper VI are more general and based on the standard systems described in the ENPAC tool. In addition, a sensitivity analysis with alternative production technologies is performed. The production technologies considered include bio-CHP and NGCC CHP or natural gas boiler. For the details of the assumed delivery hours and efficiencies, please refer to the individual papers. Paper VI includes two cases for the reference DH system: a European cost-ranked system, where additional heat replaces NGCC CHP-based production, and a Swedish cost-ranked system, where additional heat replaces bio-CHP-based production. The European cost-ranked system used in Paper VI resembles, to some extent, the case study situation (Gothenburg), where the current production above the base load is NGCC CHP.

The minimum temperature for DH deliveries was initially set quite high (> 100 °C in Paper II) but was then lowered in the later papers to better reflect the assumed development for DH systems to lower temperatures. In Papers IV and VI, the DH system is assumed to have a supply temperature of 90 °C and a return temperature of 45 °C.

Steam to industrial processes

The integration with the chemical cluster assumes that the delivered steam results in reduced fuel utilisation. In some cases, fuel gas is saved, but it is assumed that redistribution within the cluster results in a reduced demand for natural gas. The estimated fuel savings due to the delivered steam is based on Andersson et al. (2011). For the integration between the FT syncrude and the oil refinery, it is assumed that the high-temperature heat reduces the demand for natural gas. The estimate is based on Johansson et al. (2014), and the increased power demand due to less steam being available for powering pumps is also considered.

Olefins

The described method of considering the longer lifetime of products in Paper I based on Clift and Brandão (2008) is not used in any of the other papers. In Papers II and III, where MTO is included, the final use of the olefins is assumed to be in products with a short lifetime of ~1 year. The olefins produced in the MTO process are assumed to be used in the production of polyolefins and are assumed to replace naphtha-based polyolefins. The data for the energy consumption and GHG emissions for LDPE used in the evaluation are presented in Paper III. Based on Harding et al. (2007), it is assumed that the production of polypropylene results in similar GHG emissions as the production of polyethylene. The by-product stream of butene is assumed to replace fuel oil. For more details on the MTO system, see Section 5.2.1

4.4.3 Key data for the GHG evaluation

The emission factors used for the different fuels and energy production technologies are given in Table 2, and the GWP_{100}-factors used are given in Table 1.

Table 1. GWP_{100} factors used in the GHG evaluations of the different papers.

Paper	Reference	CO_2	CH_4	N_2O
I, III, IV	IPCC (2007)	1	25	298
VI	IPCC (2013)	1	34	298

Table 2 GHG emission factors used in the analysis of Paper VI. For additional details, see Paper VI.

	GHG emissions kg CO_{2e} MWh_{fuel}^{-1}			Reference[f]
Fuel	**Combustion only**	**Production & distribution**	**Total**	
Petrol	262.4	25.0	287.5	Gode et al. (2011)
Diesel	265.0	25.0	290.0	
Natural gas (combustion in boiler)	206.7	53.6	260.3	
Natural gas (used in passenger cars)[b]	205.1	61.5	266.6	
Coal Forest residues (wood chips)[c]	350.6 0.2	84 23.8	434.5 24.0	Gode et al. (2011) Lindholm et al. (2011), Berg (2010)
SNG, incl. compression from 30 bar to 270 bar for use in passenger cars	9.3 (coal power reference production technology) 1.4 (wind power reference production technology)			Paper IV
MeOH (green) use in passenger cars[d]	6.2			Lipman and Delucchi (2003), Axelsson et al. (2014)
FT diesel[e]			4.9	Axelsson et al. (2014)
FT gasoline[e]			5.9	
Coal-based power 2030 (2040) production	852.2 (804.9)			
Wind-based power production	0			
DH repl. bio-CHP in cost ranked Swedish system 2030 (2040) [saved biomass][a]	-189 (-177) (ref. power prod: coal condensing) [1.079 $MWh_{biomass}$ MWh_{heat}^{-1}] 18.3 (46.8) (ref. power prod: wind power) [1.079 $MWh_{biomass}$ MWh_{heat}^{-1}]			Axelsson et al. (2014)
DH repl. NGCC CHP in cost ranked EU system 2030 (2040)	-101 (-51) (ref. power prod: coal condensing) 505 (479) (ref. power prod: wind power)			Axelsson et al. (2014)

[a] For the cost-ranked Swedish system, the amount of biomass saved by replacing biomass-based production technologies is given. The GHG value is the total amount saved by reducing the use of fossil-based production. The amount of saved biomass is considered when calculating the GHG emission reduction per input biomass by reducing the amount of needed input biomass.

[b] The higher emissions from the production and distribution phase are mainly due to the power demand for compression that is required for vehicle use. The gas is compressed to 230 bar at pump stations for vehicle use. In this case, it was assumed that the reference power production technology was coal-based in 2030.

[c] The emission factor for forest residues is the same as in Paper IV and is based on the assumption of a transport distance of 200 km from forest to gate.

[d] The combustion emissions are based on the results by Lipman and Delucchi (2003), who say that methane emissions for a vehicle using 100 % MeOH would be approximately half of those for conventional petrol and that N_2O emissions would be approximately the same as for a petrol-fuelled vehicle. The emissions for distribution and production are based on Axelsson et al. (2014).

[e] The production and distribution emissions were based on Axelsson et al. (2014), and the combustion emissions were assumed to be the same as for conventional diesel/gasoline.

[f] Note that the emission data from the stated reference have all been updated to use the GWP_{100}-factors from the 5th assessment report. Axelsson et al. (2014) used Gode et al. (2011) as the source for many of the GHG emission estimates.

4.5 Economic evaluation

4.5.1 NAP and FPC

In Paper VI, the economic performance of the GB biofuel production systems is evaluated from a future perspective using two different energy market scenarios for two future time horizons, 2030 and 2040. The economic performance indicators evaluated are the net annual profit, NAP (M€ y^{-1}) and fuel production cost, FPC (€ $MWh_{biofuel}^{-1}$). The FPC is a commonly used metric in the scientific literature, which enables comparisons to other studies. The FPC considers the costs for producing the biofuel, including investment costs, operation and maintenance costs, and revenues for the selling of co-products. However, to indicate the profitability, the calculated FPC for a future scenario needs to be related to the selling price and distribution and sales costs for that specific fuel in that specific scenario. The NAP (M€ y^{-1}) is a measure of the profitability on an annual basis, which, in addition to the parameters of the FPC, also considers the selling price of the produced biofuel and the distribution and sales costs for the biofuel. The distribution and sales costs differ significantly between, e.g., FT diesel and bio-SNG used in vehicles, so simply comparing the FPC does not determine which of the fuels is the most profitable. The NAP provides the profitability for the system, so the size of the system is also relevant to consider. Paper VI also uses the ***specific NAP*** (€ $MWh_{biomass\ input}^{-1}$). The specific NAP is simply the NAP divided by the annual input of biomass. Equations for the NAP and FPC are given in Paper VI.

4.5.2 Investment cost estimates

The investment costs for the GB SA systems are estimated in Paper V, and data are presented in a supplementary report by Holmgren (2015). Paper VI uses the same investment cost estimates but also includes additional investment costs for the integrated cases.

The investment costs for the GB systems are estimated by dividing the plant into major process areas and sub-components. The capital cost of each component is estimated based on equipment cost estimates found in previous studies investigating similar systems. It is assumed that the investment cost is a function of the scale, according to Eq. (2):

$$C = C_0 \cdot \left(\frac{S}{S_0}\right)^f \qquad \text{Eq. (2)}$$

where C is the investment cost for a component of size S, C_0 is the cost estimate for the same component of size S_0 and f is a scaling factor. The scaling factor normally ranges from 0.6-0.8. The investment costs of all of the sub-components are then summarised to yield the overall investment cost for the biofuel plant. A detailed description of the investment cost estimate procedure is given in Papers V and VI.

The investment cost estimates are uncertain for GB systems that include equipment that is not commercial available. The cost estimates made in this study are so-called study estimates and have an estimated uncertainty range of ± 30 % according to Peters et al. (2003).

All of the costs were calculated with a 2012 money value, and the CEPCI (Chemical Plant Cost Index) was used to convert estimates with other money value bases. The analysis in Paper V shows that the use of other indices for updating cost estimates between years can have a significant impact on the estimate. In addition, Paper V shows that the investment costs for a specific location can deviate significantly from a general study estimate. Still, the comparison made in Paper V, including several studies for each of the analysed fuels with similar technical process equipment, show that most estimates fall within the ±30 % uncertainty range.

The investment cost estimates were annualised by applying a capital recovery factor (CRF) (also called annuity factor):

$$\mathrm{CRF} = \frac{(1+r)^{lt} \cdot r}{(1+r)^{lt}-1} \qquad (3)$$

where r is the interest rate, and lt is the lifetime of the investment. In Paper VI, the CRF was set to 0.1 in the base case (corresponding to an interest rate of 8 % and a lifetime of 20 years), and a sensitivity analysis indicated how much the NAP would change if the CRF was increased to 0.2. For strategic investments, such as an investment in a large-scale GB biofuel production plant, a CRF of 0.1-0.15 is considered reasonable.

4.5.3 Energy market scenarios

The GB systems evaluated in this study are future systems, assumed to be realisable within 5-10 years from now. The economic evaluation is therefore performed using future energy market scenarios. The ENPAC tool originally developed by Axelsson and Harvey (2010) including further updates by Axelsson and Pettersson (2014) generates consistent energy market scenarios for several future time horizons. The scenarios of the tool are set up to generate possible cornerstones of the future energy market, enabling the identification of robust investments. The input data to the tool are future prices for coal, oil and natural gas based on price projections made by the IEA and published in the World Energy Outlook (WEO) (IEA, 2013). Additionally, the projections for the required CO_{2e}-charges in the different scenarios are given in the WEO and used in the ENPAC tool. The tool contains relationships among the energy market parameters (e.g., energy prices, energy conversion technologies and associated GHG emissions). This study uses the New Policy scenario and the 450 ppmv scenario for 2030 and 2040 based on the ENPAC version from 2014 (Axelsson et al., 2014). Different policy instruments can be chosen in the tool, and the evaluation in this study used a general charge for GHG emissions. The ENPAC tool determines the build margin technology for power production in each of the scenarios by calculating which production technology has the lowest production cost. This production cost is then used as the price of power in the calculations.

This study assumed that the CO_{2e}-charge would apply to CO_2, CH_4 and N_2O emissions summarised by the GWP_{100} factors as defined by the IPCC (2013). The considered build margin technologies for power production are given in Table 3 and considered replaced DH production technologies are explained in section 4.4.2.

The projected price for biomass given by the ENPAC tool for the included 450 ppmv energy market scenario is considered to be unrealistically high, and the value used in this study is lower. The price of low-grade biomass is determined by the ENPAC by calculating the highest willingness to pay for the biomass by a number of potential marginal users. One important potential marginal user group is coal power plants that have a high willingness to pay for low grade biomass when CO_{2e}-charges are high. However, the long-term development and deployment of coal power plants with and without CCS is uncertain, and it might not be possible to distribute the biomass at low cost to the coal power plants in large quantities. Instead, biorefineries might become marginal users, and the price might be lower, which is the reason for choosing a lower price level for the low-grade biomass in the 450 ppmv scenario.

4.5.4 Key data in the economic evaluation

The operation and maintenance costs used in the calculations of the NAP and FPC are assumed to be 4 % of the total plant cost (based on Hannula and Kurkela (2013)), and the annual number of running hours for the gasification plant is 8,000. Table 3 and Table 4 show the data for the fuel and energy prices, with specified distribution and sales costs for fuels, for each of the energy market scenarios used in Paper VI.

Table 3 Fuel and energy prices from ENPAC used in Paper VI

	New Policy 2030	**New Policy 2040**	**450 ppmv 2030**	**450 ppmv 2040**
Fuel prices; input data to ENPAC				
Crude oil [€ MWh^{-1}][a] (USD $bbl.^{-1}$)	59 (121)	64 (133)	50 (104)	47 (98)
Natural gas [€ MWh^{-1}][b]	36	38	30	27
Coal [€ MWh^{-1}] (USD t^{-1})	11 (110)	11 (110)	9 (86)	7 (68)
CO_{2e}-charge [€ t^{-1}]	26	35	74	117
ENPAC output prices				
Electricity [€ MWh_e^{-1}][c]	70	74	77	77
Build margin power production technology[d]	Coal condensing	Coal condensing	Wind	Wind
Low grade wood fuel [€ MWh_{fuel}^{-1}][e]	19.5	23.3	28.3	38.1
DH, Swedish cost-ranked system replacing bio CHP [€ MWh^{-1}_{heat}]	3.4	6.7	12.7	26.9
DH, European cost-ranked system replacing NGCC CHP [€ MWh^{-1}_{heat}]	39.9	44.9	46.4	63.6
Natural gas, incl. CO_{2e}-charge [€ MWh^{-1}][f]	49	53	55	63
Petrol at pump, incl. CO_{2e}-charge	84	93	90	100
Diesel at pump, incl. CO_{2e}-charge	91	100	96	105

[a] Based on World Energy Outlook 2013 (IEA, 2013). The fossil fuel prices are from the EU-based commodity market prices (at Rotterdam harbour) without the CO_{2e}-charge.

[b] The natural gas price is the price for EU imports.

[c] The electricity price is based on the build margin power production technology and includes the CO_{2e}-charge.

[d] The technology with the lowest production costs according to ENPAC is the build margin technology. Nuclear was not considered among the potential build margin technologies.

[e] The price is given based on LHV for wet wood fuel including transport costs (4.9 € MWh^{-1}) for all cases. The transport cost corresponds to ~80 km by truck or 500 km by ship.

[f] Price on the European market, including transit and distribution costs and CO_{2e}-charge.

Table 4 Distribution and sales cots for biofuels and fossil alternatives used in the analysis of Paper VI.

Fuel	**Cost € MWh^{-1}**	**Reference**
Diesel (produced from mineral oil)	13.4	Axelsson et al. (2014)
Gasoline (produced from mineral oil)	15.4	
FT diesel	13.4	
FT gasoline	15.4	
MeOH (produced from natural gas)	20.3	
MeOH (biobased) (for vehicle use)	20.3	
Natural gas for use in cars	30.6	Axelsson et al. (2014), Kågeson and Jonsson (2012), SEA (2010)
Natural gas for use in industry	5.8	
SNG for industrial use	2.9	
SNG for use in cars	27.7	
Transport of FT syncrude to refinery[a]	7.4	Johansson et al. (2013)
CO_2 transport and storage cost (€ tonne^{-1})	23.3	Heyne and Harvey (2014)

[a] It is assumed that the transport distance is 300 km in the FT SA cases. In the cases where the FT plant is integrated to the oil refinery, no cost for transporting the FT syncrude to the refinery was considered.

5 Development routes – process descriptions and data

This chapter describes the three DRs, which each consist of a gasification system and a case study location with integration opportunities with adjacent industry or a DH system and a CO_2 storage infrastructure.

Commercialisation of large-scale GB biofuel production has not yet been realised, so the analysis in this thesis has a future perspective and applies different future energy market scenarios. An important guideline in the project has been to choose technologies that are possible to implement within the next 5-10 years. Sometimes this guideline disqualified systems or technologies that might have indicated higher energy efficiencies or performances.

5.1 The SNG development route

5.1.1 The SNG gasification system

Many previous studies have analysed the performances for GB bio-SNG production. An overview of the calculated and/or assumed efficiencies in previous studies is given by Gassner and Maréchal (2012). As noted by, e.g., Tock et al. (2010), the choice of gasification technology is one of the most critical choices in liquid biofuel production systems. In addition, the choice of gasification technology for SNG has been a recurring subject for analysis. Studies that have investigated which type of gasification technology is best suited for SNG production have reached different results. Mozaffarian and Zwart (2003) concluded in their comparison of different process configurations, including both atmospheric indirect gasification and pressurised oxygen-blown gasification, that considering the development potential, an indirect gasifier is the best choice both from cold-gas efficiency and economic points of view. Also van der Meijden et al. (2010) who compared different configurations for GB bio-SNG production, including atmospheric indirect, pressurised oxygen-blown CFB and pressurised oxygen-blown EF gasification; concluded that indirect gasification would perform best. According to van der Drift and Boerrigter (2006), there is a significant difference between SNG production and other GB biofuel production, in which a syngas free from methane is needed. For other syngas production, slagging EF gasification with pretreatment in the form of torrefaction or pyrolysis is preferred according to van der Drift and Boerrigter (2006), but for SNG, they concluded that either indirect or pressurised oxygen-blown gasification are the two obvious choices. Gassner and Marechal (2009), Jurascik et al. (2010) and Gassner and Maréchal

(2012) found that a pressurised CFB gasifier outperformed the indirect gasifier in the case of SNG production. Gassner and Maréchal (2012) concluded from their study with a systematic process integration analysis that the technology that seems to be the most efficient individually is not necessarily the best technology from an overall plant perspective. They noted that previous studies not applying a systematic process integration methodology might have overlooked this factor. Heyne et al. (2013b) performed an exergy-based comparison of indirect and direct gasification, considering the gasification and gas-cleaning steps of the bio-SNG production, and they came to the conclusion that none of the technologies could be identified as intrinsically superior to the others. Heyne et al. (2013b) concluded that the key aspect for biomass gasification is the efficient heat integration and cogeneration of power rather than the choice of gasification technology. In terms of real projects for bio-SNG production; the technology choices also differs; In the Gobigas project (20 MW_{SNG} demonstration plant in Gothenburg) an indirect atmospheric gasifier was chosen based on a pre-study conducted in 2006 (Gobigas, 2015); whereas in the full scale Bio2Gas project, a 200 MW_{SNG} system planned by E.ON, the choice of technology is instead slightly pressurised oxygen-blown CFB gasification (Möller et al., 2013b).

The SNG systems analysed in detail in Papers IV-VI all include an indirect gasifier, and they are all based on a work by Heyne (2013). A schematic process flow diagram is presented in Figure 8.

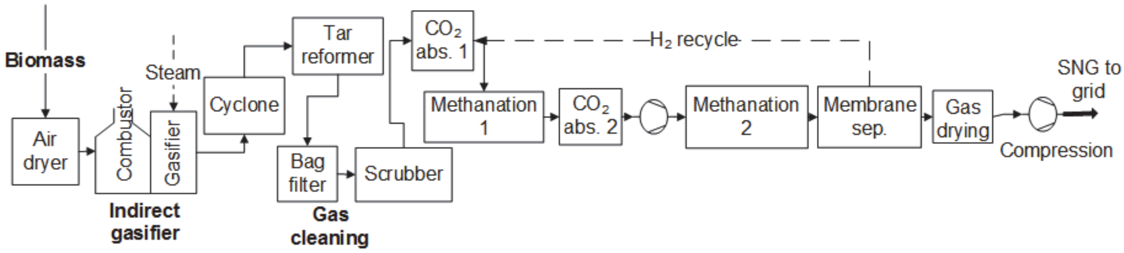

Figure 8. SNG production process flow diagram.

The gas cleaning technology used in the analysed SNG system includes a cyclone and a chemical looping reformer (CLR) that completely reforms tars to CO and H_2. According to Heyne (2013), the CLR is not yet a commercial technology, but preliminary experimental tests show promising results. After the CLR, a filter and a scrubber remove particles, ammonia and to some extent sulphur compounds as well. Before the methanation, which is performed in several steps, CO_2 is removed by an amine-based technology, which also removes sulphur compounds. The methanation technology in Paper IV is isothermal methanation, whereas in Papers V and VI, adiabatic methanation is used. Heyne et al. (2010) compared these two technologies and found no difference in terms of the performance of the overall system. The adiabatic technology is a commercially available technology that can be purchased from suppliers (e.g., Haldor Topsøe), whereas the isothermal technology is still under development and not commercially available. The maturity of the technology was the main reason for changing to this technology in the later papers. Because the changed methanation technology contributed to significantly change the shape of the GCC for the SNG system (compare the shapes of the two GCCs in Figure 9), the biomass drying technology was also changed from steam drying (which was applied in Paper IV) to air drying (in Papers V and VI) because the less conventional steam drying had shown specific advantages together with the isothermal methanation (Heyne and Harvey, 2009).

The CO_2 separation technology chosen in the SNG system is MEA (monoethanolamine). Heyne and Harvey (2014) compared several CO_2 separation technologies and concluded that amine-based absorption resulted in the highest cold gas efficiency

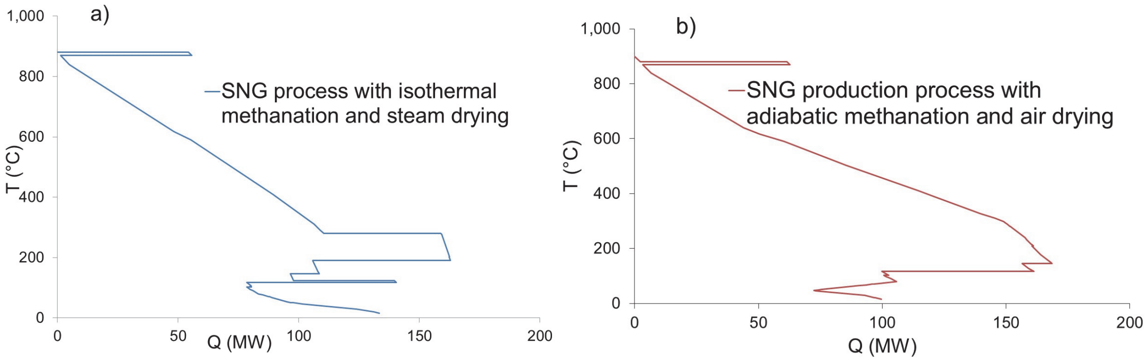

Figure 9. GCCs for bio-SNG systems with a) isothermal methanation and steam drying (based on Paper IV) and b) adiabatic methanation and air drying (based on Paper VI).

The SNG DR also assumes that the produced SNG is compressed and injected to the grid. The grid pressure in Papers IV-VI is 30 bar based on the pressure in the natural gas distribution network.

5.1.2 Integration with the DH system

Integration with the DH system in Gothenburg is considered by estimating the potential for heat deliveries from the gasification using pinch analysis and energy targeting (as described in Section 4.3.1). It was assumed that the heat delivered to the DH system would have a higher cost than the base-load production (which currently is constituted by industrial excess heat from the oil refineries and the municipal waste incineration) and that heat could be delivered only during the middle-load production hours (see each paper for the specific number of delivery hours). In Section 4.4.3, the assumed production technologies for the middle-load production are given along with the estimated supply and return temperatures of the DH system. The price of the DH was estimated by the ENPAC tool; see section 4.5.

5.2 The MeOH development route

5.2.1 The MeOH and MTO production system

The process of identifying an appropriate system for the MeOH production process is based on previously published literature. Paper II compares the system yields and technology choices from previous studies of GB bio-MeOH production systems. As noted for the SNG system, it was not possible to identify one gasification technology as the best for MeOH production, but the entire system needs to be considered. This section describes some of the studies that were available when deciding on the MeOH system. Chapter 2 presents studies analysing GB MeOH production systems integrated with other industries or DH systems.

An extensive study by Hamelinck and Faaij (2002) analysed the energy efficiency and FPCs for several configurations of SA biomass GB MeOH and H_2 systems, including different gasification technologies, MeOH syntheses, once-through and recycle configurations (for maximised fuel production). They concluded that systems optimised for fuel production performed somewhat better economically than once-through systems, which have more significant power production. The full data are presented in Hamelinck and Faaij (2001).

Sarkar et al. (2011) performed a techno-economic analysis of GB systems using forest residues as feedstocks for the production of MeOH, DME, FT fuel and ammonia comparing atmospheric and pressurised gasification systems. The systems with an atmospheric gasifier emerged as the least costly, due to lower investment costs.

Clausen et al. (2010) performed a techno-economic analysis of MeOH production systems where the syngas was produced from different sources including, biomass gasification, electrolysis of water, post combustion CO_2-capture and/or reforming of natural gas or biogas. All of the configurations were highly heat-integrated, and low-temperature excess heat was valorised by integration with a DH system. They concluded that systems combining biomass gasification with the electrolysis of water and CO_2 capture were the most competitive systems under the current energy market situation. For future conditions, systems combining electrolysis-and CO_2 capture may be competitive. Ng and Sadhukhan (2011) performed a process-integration and economic analysis of GB MeOH production including CHP. The feedstock to the analysed processes was bio-oil (pyrolysis oil). Configurations where the water-gas-shift process was replaced by H_2 addition to the syngas to achieve the desired H_2/CO ratio for MeOH synthesis were considered. The H_2 was produced by the electrolysis of water. They concluded that at current power prices, a configuration with an electrolyser is not economically feasible. They also concluded that the cost competitiveness of the systems increases by introducing recycle (for an increased MeOH yield). The studies by Clausen et al. (2010) and Ng and Sadhukhan (2011) inspired the analysis of using the excess H_2 stream in the cluster in Papers II and III.

Isaksson et al. (2012) studied the integration of several different GB production systems, including a MeOH production system with a mechanical pulp and paper mill. Isaksson identified a process configuration (see Figure 10) and modelled all of the process units (except the gasification and the biomass drying processes) in Aspen Plus. The mass and energy balances determined by Isaksson for the MeOH system were used in the analysis in this study. Compared with other systems studied in Paper II, Isaksson's system showed system yields that seemed reasonable. The analysed system uses a pressurised oxygen-blown CFB gasifier operating at 25 bar, originally described by Hamelinck et al. (2004).

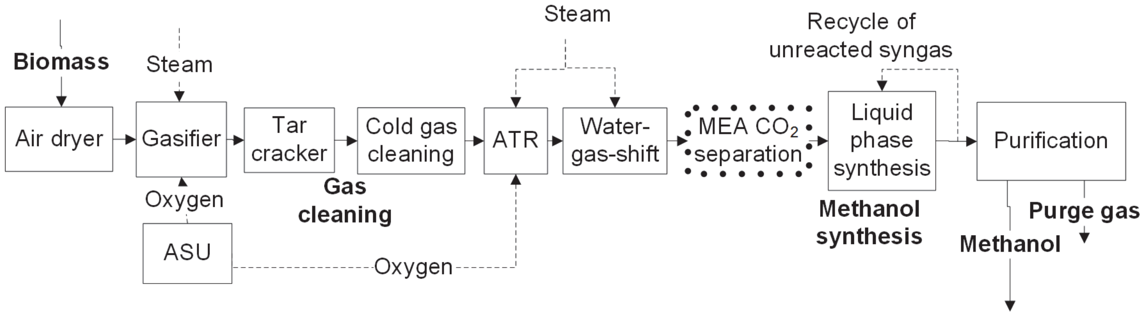

Figure 10 Process flow diagram for the MeOH production system. The CO_2 separation is optional because the LPMeOH synthesis is insensitive to CO_2.

The tar cleaning consists of a catalytic tar cracker based on a design by Spath et al. (2005) and a scrubber. The syngas is processed in an oxygen-blown autothermal reformer to reform methane, ethane, ethylene, etc. to CO and H_2. Prior to synthesis, a water-gas shift is needed to obtain the right H_2/CO ratio. Two types of MeOH synthesis exist, the traditional gas-phase synthesis and the more recently developed liquid-phase synthesis (LPMeOH). The latter has superior cooling properties, and it is also said to be insensitive to CO_2. In the system analysed within this study, the LPMeOH (liquid phase methanol) synthesis is applied, and in cases without CCS, no CO_2 separation unit was included. For cases including the possibility of CCS, an MEA CO_2 separation unit was added (based on the MEA system described by Heyne and Harvey (2014)). Unreacted gas from the synthesis is recycled back to the inlet of the reactor at a recycle rate of 2. Finally, a purification section includes, e.g., distillation to remove water from the MeOH.

In Papers II and III, there are cases of the MeOH DR that include an MTO process. There are several different MTO concepts from different technology suppliers. The technologies have different names, yields and compositions of olefins in the final product (Nouri and Kaggerud, 2006). The data for the MTO concept analysed in this study were based on the general data given by Joosten (1998) (see Paper III). A schematic process flowsheet of the MTO process is shown in Figure 11.

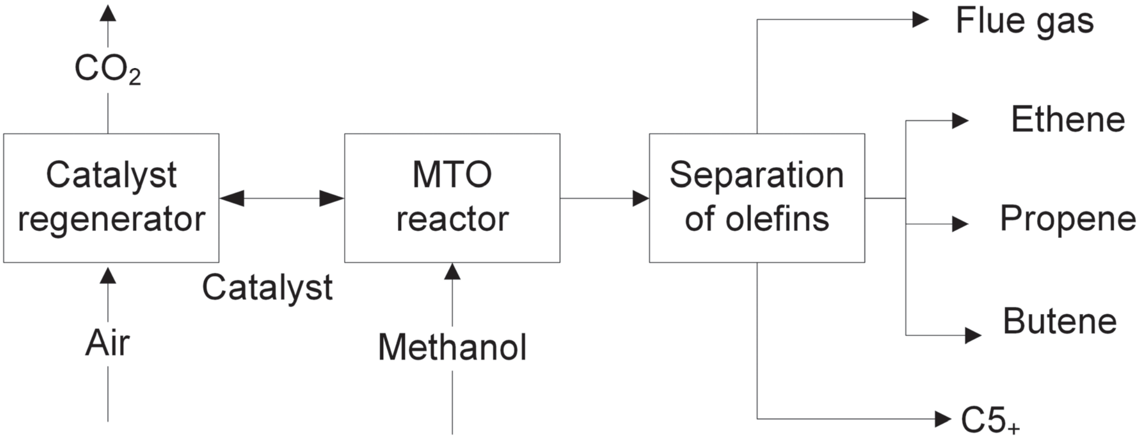

Figure 11 Schematic process flowsheet for the MTO process. Adjusted from Nouri and Kaggerud (2006).

5.2.2 Integration with the chemical cluster

In the first phase of the project covered by this thesis (Papers I-III), cases that included an MTO production unit were considered in the MeOH DR. In the second phase of the project (Papers IV-VI), the analysis was concentrated on the biofuel production routes, and the MTO case was omitted.

The analysis of integration opportunities to the chemical cluster are complex because the internal integration opportunities should be considered. The development of internal integration determines the future integration possibilities, see Papers II and III. Paper II investigated several different integration options between the cluster and the gasification system. The heat integration considered included integration with two of the cluster plants in terms of steam deliveries from the gasification systems to the utility system of the cluster plants, as identified by Andersson et al. (2011), and low-temperature heat deliveries supplied by a suggested hot-water circuit (Andersson et al., 2011) to the gasification plant for the use in biomass drying. Papers II and III also considered heat deliveries from the gasification plant to the DH system in Stenungsund.

In addition to the heat integration, the impact of boosting the MeOH production by adding H_2 produced from one of the cluster processes to the syngas was analysed. The H_2 stream is[5] used for only heating purposes at the cluster. When adding H_2 to the syngas, the need for water-gas shift is reduced, and for this analysis, Isaksson provided additional energy balances from Aspen simulations. When adding the MTO unit, it was assumed that the distillation unit was not needed for MeOH purification. The analysed cases that included MTO also assumed that the mixture of olefins produced could be upgraded in the existing equipment serving the olefin production from the steam cracker. However, no analysis on how this upgrading would impact the cracker or upgrading equipment was performed.

In Paper VI, one reasonable integration between the gasification plant and the cluster was chosen. The integration included low pressure (LP) steam delivery to the utility system at one of the cluster plants and hot water deliveries to the gasification plant for biomass drying.

5.3 The FT development route

5.3.1 The FT fuel production system

Just as for the other fuels, there is an extensive amount of literature dealing with biomass GB FT fuel production. A review of techno-economic analyses of thermochemical cellulosic biofuel pathways by Brown (2015) covers a significant part of the FT studies. There are also several studies mentioned in Chapter 2 of this thesis covering systems integrated with industry or DH systems.

According to Haarlemmer et al. (2012), who studied fuel production costs for GB bio-FT production, it is not possible to conclude from the available literature that a specific gasification technology is better than the others for the purpose of producing FT fuels via biomass gasification. Hamelinck et al. (2004) analysed the system components necessary for biomass-based FT diesel production and combined a set of promising conversion routes. Based on Aspen Plus simulations they determined energy and mass balances and also estimated FPCs for conventional and future systems.

The energy and mass balances of the FT syncrude system analysed in this study are based on Aspen simulations by Isaksson et al. (2012), which were used also by Johansson et al. (2014). Figure 12 shows the process flow diagram for the FT system, however not showing that there is a recycle of unreacted gas from the FT synthesis to the reformer. Off-gases are extracted to avoid the accumulation of inert compounds. The process flow diagram, shown in Figure 13, and the mass and energy balances for the syncrude upgrading, are based on a work by Johansson et al. (2014). Many of the process components in the FT system are similar to those used in the MeOH system (gasifier, gas cleaning section) because they are

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[5] This was the case at the time of conducting the analysis for Papers II and III.

based on the same study. In the FT system, a Rectisol unit is used for separating CO_2 prior to synthesis.

The FT synthesis for the system in this study is the low-temperature type and uses a slurry phase rector with Co-catalyst. The Co-catalyst is more expensive than the alternative Fe-catalyst, but according to Kumar et al. (2009), the Co-catalyst has a longer lifetime and higher selectivity, so it is the preferred choice. According to Goellner et al. (2013), the slurry-phase reactor and the Co-catalyst are used in several of the newer commercial FT fuel plants that uses fossil feedstock.

According to Johansson et al. (2014), there is an overcapacity in the equipment at the oil refinery, which could be used for co-processing biomass-based FT syncrude. The amount of diesel and gasoline produced from the syncrude from a gasification plant of 500 MW_{th} input corresponds to ~3 % of the oil refinery's total diesel and gasoline production. For a more detailed description of the upgrading section, please refer to Johansson et al. (2014). The present study assumes that existing installations at the refinery are used for upgrading the syncrude.

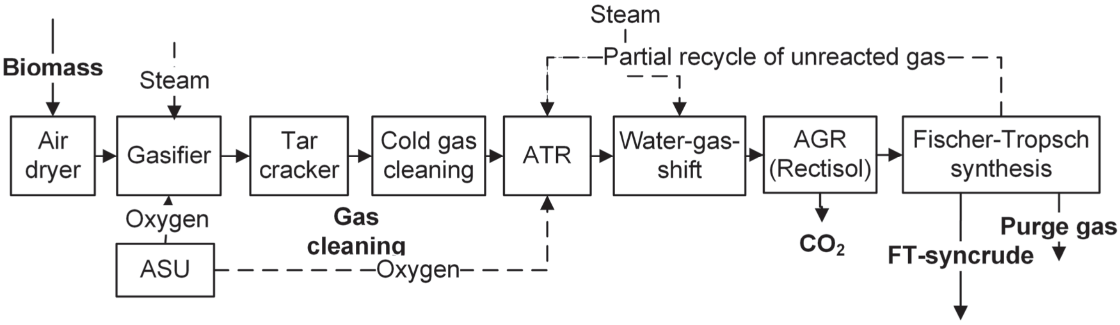

Figure 12 Process flow diagram for the FT syncrude production system.

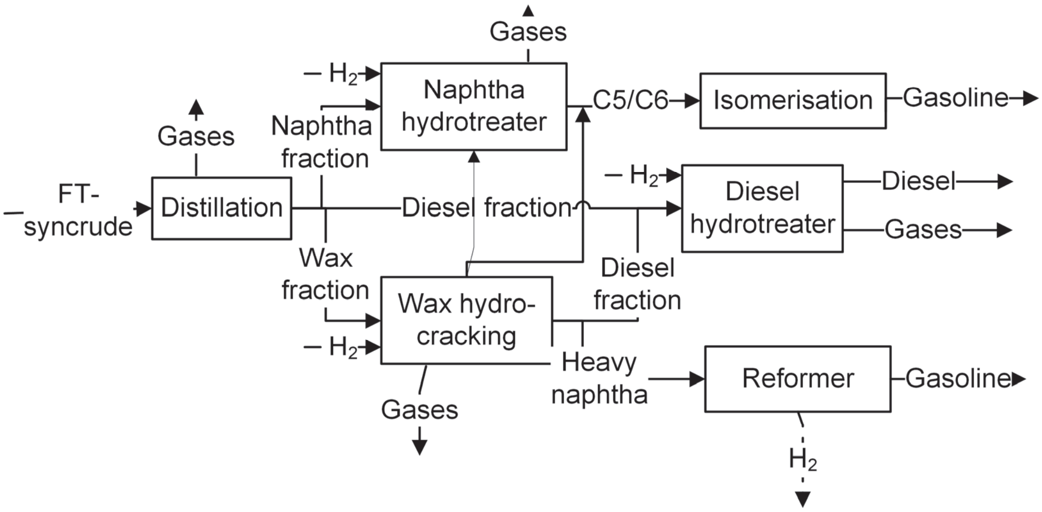

Figure 13 Process flow diagram for FT syncrude upgrading. Based on Johansson et al. (2014).

5.3.2 Integration with an oil refinery

Different options for heat integration between the GB FT syncrude production and an oil refinery were investigated by Johansson et al. (2014), and Johansson et al. (2013) also evaluated the economic implications. The evaluations of the integration opportunities by Johansson et al. (2014) are based on the heat demand at the refinery, which was described in an extensive pinch analysis performed at the refinery by Andersson et al. (2013a). Johansson et al. (2014) underline that in general, only a few of a refinery's subsections are heat-integrated with each other, due to process constraints such as different running times, safety and different sensitivities to capacity loss. Therefore, the refinery is not treated as one process but rather divided into subsections. Johansson et al. (2014) include several integration opportunities with several subsections of the refinery, but the heat integration between the refinery and the GB FT syncrude production analysed in Paper VI, and to some extent also in Paper V, of this thesis is the high-temperature heat delivery from the gasification process to the CDU/VDU area of the refinery. This is the heat integration analysed by Johansson et al. (2013).

According to Johansson et al. (2014), the hot utility demand in the refining process is mainly satisfied by furnaces using fuel gas from the refinery. Steam is also produced in process units and boilers. The integration of high-temperature heat between the gasification process and the CDU/VDU (crude distillation unit and vacuum distillation unit) area is assumed to be transferred via an organic molten salt system (because the temperatures are higher than the normal steam upper limit), and the heat is assumed to replace fuel use in furnaces at the refinery. However, the high-pressure steam produced by excess heat in the flue gases from the furnaces is used for generating mechanical work in pumps and compressors, so as a consequence of the replacement by heat from the gasification plant, the net electricity demand at the refinery is increased. The increased power demand is considered in the GHG and economic performance evaluations.

6

Results

This chapter starts with a section summarising the objectives and the most important results from each paper. The following section combines the results of the individual papers.

6.1 Main results of individual papers

6.1.1 Summary of objectives and main findings of Paper I

The objective of Paper I was to outline and exemplify the methodology for evaluating the GHG impact of biomass gasification systems integrated with industries, DH systems and/or infrastructure (e.g., pipeline networks for transporting CO_2 to storage).

Figure 14 shows some of the results for the evaluated cases of the three included production systems: an SNG system, an FT fuel system and an MeOH production system, the latter with a down-stream MTO process, in which olefins are ultimately converted to polyolefins (polyethylene, PE, and PP). All of the production systems had the potential for low-temperature heat deliveries to a DH system or industrial applications. In this paper, data for the production routes were taken directly from the literature (without performing any additional detailed analysis of the power production potential and potential for DH deliveries) because the methodology and exemplification were the main focus rather than the exact performance or conditions. The assumptions made for the GHG emissions evaluation that is presented in Figure 14 are explained in Table 6, and the product mix and input for the systems are given in Table 5.

Table 5 Product mix and inputs for analysed systems in Paper I.

Gasification plant	**Input [MW]**	**Output**				
	Biomass	Net power [MW]	FT-products [MW]	SNG [MW]	PE/PP kt y^{-1} (MeOH, MW)	Heat[b] [MW]
FT	371	9.8	167			50
SNG	371	-15.3		265		89
PE & PP[a]	371	37			32.1/15.7 (93)	134

[a] This system produces MeOH that is converted in an MTO process to olefins, which are ultimately converted to polyolefins.

[b] The amount of heat delivered to the DH system was limited to 300 GWh y^{-1} for all of the biorefineries, whereas the delivery to the industrial application was limited to 711 GWh y^{-1}.

Table 6 Main assumptions for the GHG evaluation of the cases in Paper I.

Case	**Assumptions**
FT, SNG and PE & PP base	The reference power production technology is coal condensing. SNG replaces petrol. FT products replace diesel in heavy-duty vehicles and petrol in passenger cars (85 % and 15 %, respectively). PE and PP replace fossil PE and PP produced from naphtha; the end-products are assumed to be short-lived (< 1 year). DH replaces heat produced in a biomass boiler. The biomass saved when not using the boiler replaces coal in, e.g., a coal power plant[a].
FT 2	DH deliveries replace heat from natural gas boilers in industry (industrial DH). The number of delivery hours is higher in the industrial application than in the base case.
SNG 3	SNG replaces natural gas in industry (combustion)
FT 4	The CO_2 separated in the process is assumed to be stored (CCS)
PE & PP 50	The lifetime of the end-products produced from the olefins is assumed to be 50 years, and the carbon storage in the products is taken into account according to the method suggested by Clift and Brandão (2008).
Alt. use of biomass	The biomass is assumed to replace coal by co-combustion in a coal power plant. All of the gasification-based cases should be compared to this case.

[a] Note that biomass savings were treated differently in subsequent papers.

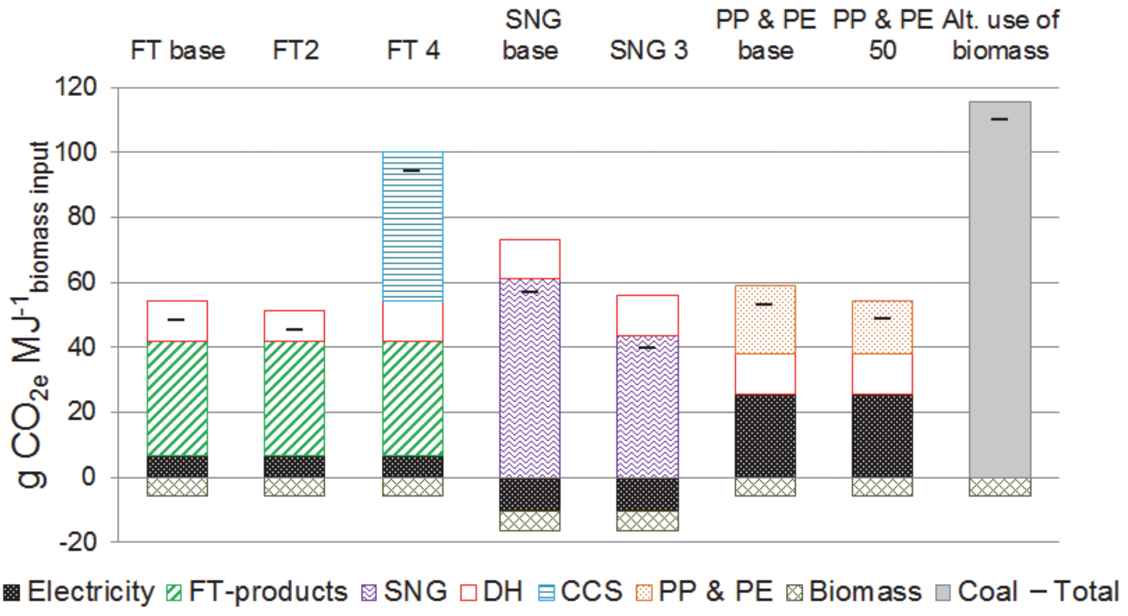

Figure 14 GHG emission reduction potential for different production systems (and different reference systems). The alternative use of biomass in the rightmost bar represents co-combustion in a coal power plant.

The results of Paper I showed that the emissions reductions due to replacing power production and due to replacing production of district heating constitute a significant part of the GHG emission reduction potential of most of the evaluated production systems. Because the GHG emissions intensity of the reference production technologies might change over time, it is important to perform calculations for different future energy scenarios. The results also showed that the storage of separated CO_2 is of significant importance for the overall GHG emission reduction potentials of the gasification systems. Using biomass to directly replace coal results in larger GHG emission reductions than all of the GB systems.

The main contributions of this paper were the following conclusions:

- In the case with CO_2 storage, the GHG emission reduction potential of the gasification system was almost as large as that of using biomass for replacing coal (compare FT4 to Alt. use of biomass in Figure 14).
- The SNG production system has the largest GHG emission reduction potential among the gasification systems (for cases where SNG is assumed to replace petrol). If SNG is assumed to replace natural gas in industrial applications (combustion), then both the olefin (MeOH-based) and FT fuel systems show larger potentials for reduction.
- With the applied methodology considering the timing of emissions, there is only a small difference in the GHG emission reductions potential between replacing long-lived or short-lived products. Replacing long-lived products has a somewhat lower potential for reduction.

6.1.2 Summary of objectives and main findings from Paper II (MeOH production)

The objective of Paper II was to identify a reasonable combination of technology choices for the individual process steps for an SA GB MeOH production system. In addition, the impacts of process-integrated drying compared to those of importing dried biomass and the impact of DH deliveries on the energy balance were investigated. Paper II also included a systematic analysis and summary of the most important interrelationships between the technical choices of the different steps in the gasification system and between the technical system and the different characteristics of the surrounding systems. The results of this analysis demonstrate the difficulty of identifying one specific technology for one specific process unit (e.g., the gasification technology) as being the best for a certain fuel production system. The entire system needs to be considered due to the many interactions that exist within it. The technology choices and process configurations are also affected by site-specific conditions for the surrounding systems and are also important to consider.

Paper II compared the product mix in terms of the MeOH, power and DH production for a large number of biomass GB MeOH production systems presented in the scientific literature. The technology choices for the gasifier, MeOH synthesis and some additional process steps were analysed and compared in detail for the included systems. This comparison identified a trade-off in the yields of MeOH, electricity and heat. Systems with H_2 (not originating from biomass) added to the syngas displayed not only the highest MeOH yields but also the largest net power deficits. The configuration of the SA MeOH production system chosen for the development routes analysed in the following papers were based on a system that had a reasonable performance and where the chosen process equipment was judged to be mature enough to implement the system within the next 5-10 years and for which stream data from Aspen simulations were available. The identified configuration for the MeOH system is displayed in Figure 10.

The analysis of the identified SA system for MeOH production in Paper II showed that

- The on-site energy balances for SA gasification systems strongly depend on whether biomass drying occurs on- or off-site. In the case of off-site biomass drying (i.e., assuming that the biomass would be dried elsewhere), the on-site cooling demand increased by 60 %. The increased cooling demand increased the potential for onsite power production (or DH production if integration with a DH system is possible).

- Compared to a case where the biomass would be dried off-site using additional biomass, on-site process-integrated biomass drying has the potential to increase the efficiency of the system.

- The SA MeOH production system also showed that if additional H_2 is available and can be added to the syngas to balance the required H_2/CO ratio (instead of using the water-gas-shift reaction), the MeOH yield could be improved by ~35 % compared to the base case; see Figure 15. The production of additional H_2 from the electrolysis of water would result in a significant power deficit for the system, so this configuration was considered unrealistic[6].

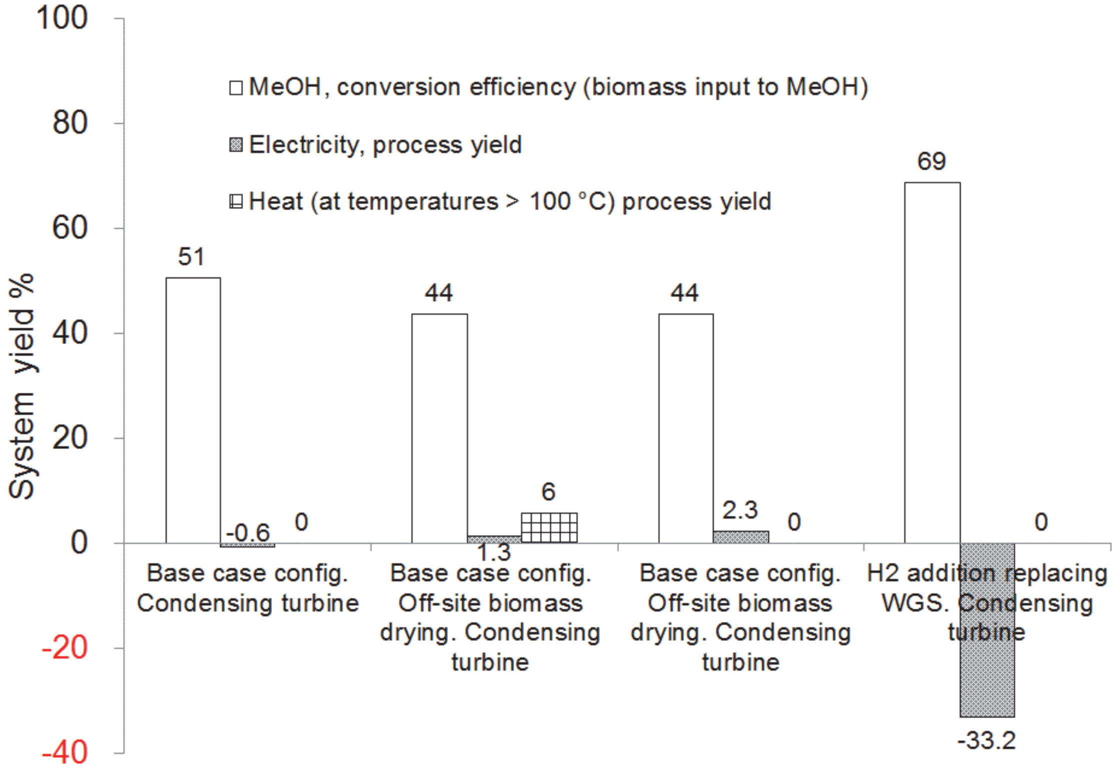

Figure 15 System yields of MeOH, electricity and heat for the different cases of the MeOH production system. The yield is the ratio of the product output to the biomass input (LHV of wet biomass, 50 % moisture content).

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[6] Power-to-gas concepts based on electrolysis of water and utilising power at times of low cost (e.g. due to high production from intermittent sources) have been given significant attention recently, however, such concepts were not analysed within this study.

The product mix (i.e., the system yields of different products) for a selection of the cases analysed in Paper II are shown in Figure 15. The system yield considers the net electricity production, and is based on the net biomass input. The cases where the biomass is dried off-site assumed that additional biomass is needed for the drying, so the biomass input to the system is higher than in the cases with onsite biomass drying. The higher input of biomass explains the lower specific system yield of MeOH for two of the cases in Figure 15.

The analysis in Paper II showed that adding MTO synthesis to the MeOH production system would have only a small impact on the overall energy balance of the system. However, the data for the energy demand of the MTO process were very limited (only the steam demand and power consumption were available), so this conclusion includes significant uncertainty. In the later studies of the MTO route performed within the Skogskemi project, Johansson and Pettersson (2014) presented additional details of the MTO process. They specify that the demand for high-pressure steam (which was the net demand used in Papers II and III) is mainly needed for driving compressors and air blowers. In their study, they replaced the high pressure steam demand with electricity and an increased demand for medium pressure steam. The impacts of these adjustments are outside the scope of this study.

6.1.3 Summary of objectives and main findings of Paper III (MeOH production)

The objectives of Paper III were to

- Determine the impact on the energy balance and the GHG emission reduction potential of a biomass GB MeOH production system when integrated with a chemical cluster compared to a configuration with integration limited to DH deliveries.

- Determine the GHG emission reduction potential of the GB production system for MeOH and MeOH with down-stream MTO synthesis compared to the production and use of conventional fuels (i.e., fossil-based petrol) or materials (naphtha-based olefins).

It should be noted that the SA cases in Paper III are integrated with a DH system (i.e., deliveries of DH are accounted for also in the so-called SA cases). The integrated cases are those that are heat-integrated with the chemical cluster. Cases with different amounts of exchanged heat or materials were evaluated.

The main results can be seen in Figure 16, which shows that

- For the investigated cases, the systems integrated with the cluster had higher GHG emission reduction potentials than the cases integrated with only the DH system. The GHG emission reduction potential was 25-35 % higher for cases with the current energy balances at the cluster or with some efficiency measures implemented at the cluster. However, for cases where significant energy efficiency measures at the cluster had been introduced, the increase was diminished to 0-2 %.

- With the conditions applied in the study, the GHG emission reduction potentials were of the same magnitude for systems using the produced MeOH to replace motor fuels (petrol) as for systems using MeOH to produce green olefins (via MTO) and replace naphtha-based olefins.

- The biomass-to-MeOH conversion efficiency was significantly increased (by approximately 10 %) in an integrated case where the excess (or “stranded”) H_2 available at the chemical cluster was added to the syngas before synthesis. The increase in efficiency is directly reflected in the GHG emission reduction potential of the system (compare Cases 3a and 3b in Figure 16). The estimated H_2 available at the cluster originated from chlorine production and was at the time used as fuel in steam boilers. (Note that the estimated amount of available H_2 was lower than the amount needed to completely erase the demand for water-gas-shift, which explains the lower increase than that shown in the results of Paper II).

- Despite the larger biomass demand, drying the biomass off-site has a small impact on the overall GHG emission reduction potential, at least for scenarios with coal condensing power as the reference production technology. The main reason for this small impact is that the on-site potential for power production increases (compare Cases SA 1 and SA 2 in Figure 16).

- Using excess heat from the gasification system for DH has the potential to either reduce or increase GHG emissions, depending on what heat production technologies it replaces. If the heat production technology being replaced is NGCC CHP (i.e., is of high electrical efficiency), and the marginal power production technology is coal condensing power (i.e., has a high GHG emissions intensity), then the GHG emissions will increase. Replacing the heat produced in bio-CHP slightly decreased the GHG emissions. If the excess heat from the gasification system replaces heat production in fossil boilers, then the GHG emissions reductions will be larger.

In scenarios A and B (Figure 16), the DH production technology being replaced is mainly bio-CHP with low electrical efficiency in Cases SA1, SA 2 and 2a. In SA3 and 3a and 3b, part of the heat replaces NGCC CHP; see Paper III for additional details.

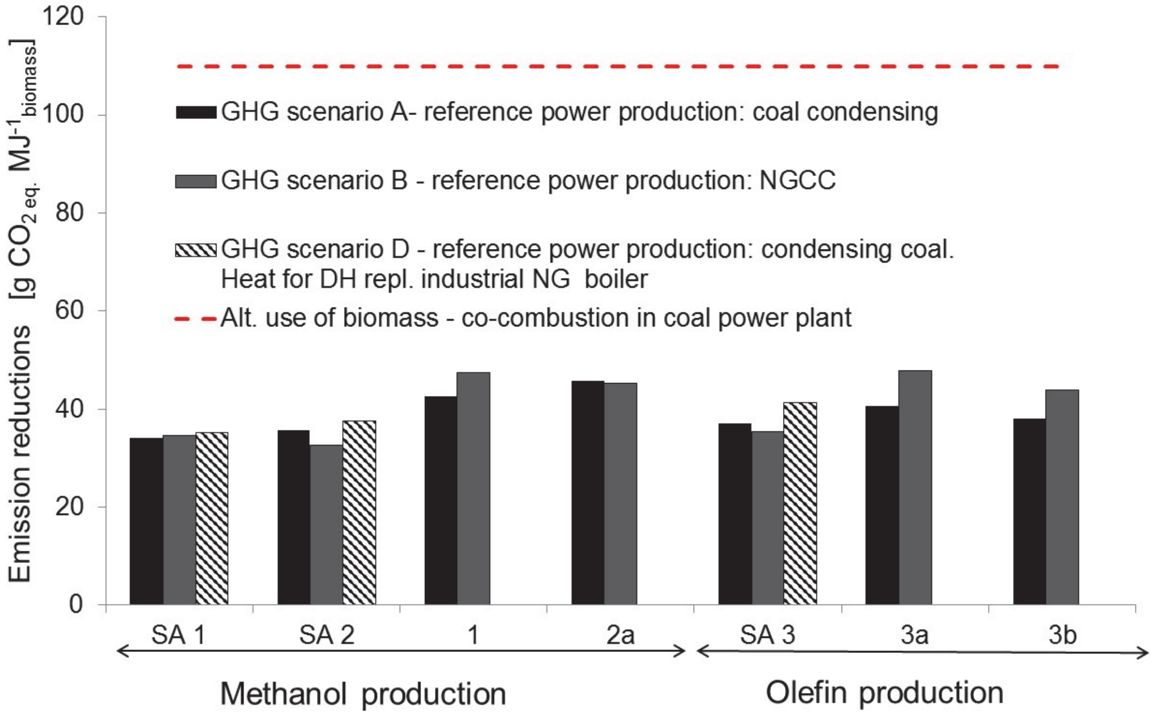

Figure 16 GHG emission reduction potential of the MeOH and olefin production routes. The reduction potential of utilising the biomass for replacing coal is indicated by the dashed line. The cases are described in Table 7.

Table 7 Case description for the MeOH and olefin production routes.

Case no	Description
SA 1	SA case with process-integrated drying. Delivery of heat to the DH system. MeOH is the end product.
SA 2	SA case with off-site biomass drying. Delivery of heat to the DH system. MeOH is the end product.
SA 3	SA case with process-integrated biomass drying and an MTO unit producing olefins. Heat delivery to the DH system.
1	GB MeOH production integrated with one of the cluster plants. The current energy balance at the cluster is assumed (i.e., no energy efficiency measures have been introduced). Low-temperature heat from the cluster is used for biomass drying. Excess heat from the gasification and MeOH production produces steam, which replaces fuel utilisation at the cluster plant and produces electricity.
2a	GB MeOH production integrated with one of the cluster plants. Energy efficiency measures have been implemented at the cluster, including a hot water system but no new steam lines. Low-temperature heat from the cluster is used for biomass drying. Excess heat from the gasification and MeOH production produces steam, which replaces fuel utilisation at the cluster and produces electricity and heat for DH.
3a	Current energy balance at the cluster. Biomass drying occurs at the cluster using low-temperature excess heat. An MTO unit converts the MeOH to olefins. Excess H_2 from the chlorine plant is used to increase the MeOH production and decrease the demand for WGS before MeOH synthesis. Excess heat from the gasification and MeOH/olefin production produces steam, which replaces fuel utilisation at the cluster plant and produces electricity and heat for DH.
3b	As in Case 3a but without the H_2 addition to the syngas.

6.1.4 Summary of objectives and main findings of Paper IV (SNG production)

The objectives of Paper IV were to describe and identify important parameters for the GHG emission reduction potential of a GB bio-SNG production system, focusing on the parameters in the surroundings, including the potential for by-product utilisation and the feedstock supply chain.

The GHG emissions for different possible biomass supply chains were evaluated, and the impact on the GHG emissions reduction of gasification using raw materials with different origins was evaluated.

The results showed that

- The overall GHG emissions from the bio-SNG production system are higher when using imported pellets than when using wood chips that are dried onsite. Therefore, using excess heat from the bio-SNG plant for process-integrated on-site biomass drying is efficient from a GHG emissions perspective (see Figure 18). This result, of course, depends on the assumption that biomass is available at a reasonable distance when transporting it in a wet condition to the plant.

- Pellet chains for which the shipping distance are moderate (e.g., from Latvia to Gothenburg, Sweden) and for which biomass drying is achieved using excess heat only slightly increased the overall GHG emissions from the bio-SNG system compared to the case where wood chips that are dried onsite were used. Therefore, if these raw material supply chains could be realised, the raw material supply area for the bio-SNG plant can be substantially increased without significantly increasing the GHG impact (compare the four leftmost bars in Figure 18). The results also show that if the off-site biomass is dried by utilising fossil fuels, the impact on the GHG emission reductions for the entire production system is significantly increased (compare Figures 5 and 6 in Paper IV).

- As long as the reference power production technology is carbon-intensive, e.g., coal condensing, and the production technology replaced in the DH system is CHP-based with high electrical efficiency, it is not beneficial from a GHG emissions perspective to replace the heat production with excess heat from the bio-SNG system. However, as the reference power production technology becomes less carbon-intensive, this replacement will become more attractive from a GHG emission reduction perspective (compare the S2a cases in Figure 18).

- Under the conditions of this study, the storage of separated CO_2 can double the GHG emission reduction potential of the bio-SNG production system (Figure 17)

The case descriptions referred to in Figure 17 and Figure 18 are found in Table 9, and Table 8 describes the biomass supply chains (BM chains).

Table 8 Descriptions of the raw material supply chains and associated GHG emissions for production and transport to the biorefinery gate.

Supply chain	**Description**	**GHG emissions kg CO_{2e} MWh^{-1}**
A	Direct delivery of wet woodchips to the gasification plant. On-site drying. The transport distance from harvesting area to the gasifier was 200 km.	23.7
B	Pellets imported from Canada (Vancouver). Direct transport of raw material from the harvesting site to the pellet plant (70 km). The biomass was dried using excess heat. The pellets were transported by train to the harbour (750 km) and by a Handysize[a] bulk carrier to Gothenburg (17,000 km). The marginal electricity production for the electricity used in the pellet production was NGCC.	65.6
C	Pellets from Canada. Same as case B, but the biomass was dried using natural gas.	99.9
D	Pellets from Canada. Same as Case B, but the biomass was dried using wet biomass. In the GHG calculations, the biomass used for drying was considered limiting, and the emission factor for coal replacement was used.	141.9
E	Same as B, but the transatlantic shipment occurred using a Handymax[b] bulk carrier.	56.3
F	Same as C, but the transatlantic shipment occurred using a Handymax bulk carrier.	90.7
G	Pellet production in Latvia. Biomass was dried using excess heat. Direct transport of raw material from harvesting site to pellet plant (70 km). The pellets were transported 100 km by truck to the harbour. The marginal power production (for the electricity use in pellet production) was coal power. The sea transport (1,100 km) occurred using a coastal bulk carrier[c].	47.8
H	Same as G, but the marginal electricity in Latvia was assumed to be NGCC.	36.8

[a] Handysize has a capacity of 15-35 kDWT; [b] Handymax has a capacity of 35-60 kDWT; [c] A costal bulk carrier has a capacity of 5-15 kDWT

Table 9 Case descriptions of SNG production systems (from Paper IV).

Case	**Biomass drying**	**Operating mode of HRSC and use of backpressure heat**	**Turbine inlet data for HRSC**	**Storage of separated CO_2**
S1	Process integrated steam drying to 20 % MC	Condensing	450 °C, 60 bar	No
S1,st		Condensing	450 °C, 60 bar	Storage of process CO_2
S2a S2b		Backpressure 0.95 bar, heat delivery during: a = 5,500 h y^{-1} and b = 8,000 h^{-1}	450 °C, 60 bar 450 °C, 60 bar	No No
S3		Backpressure 2.5 bar, heat used for. CO_2 separation from flue gases	450 °C, 60 bar	Storage of process and flue gas CO_2
S4		Condensing	600 °C, 115 bar	No
O1	Pellets imported, 10 % MC	Condensing	450 °C, 60 bar	No
O2a O2b		Backpressure 0.95 bar, heat delivery during a = 5,500 h y^{-1} and b = 8,000 h y^{-1}	450 °C, 60 bar 450 °C, 60 bar	No No

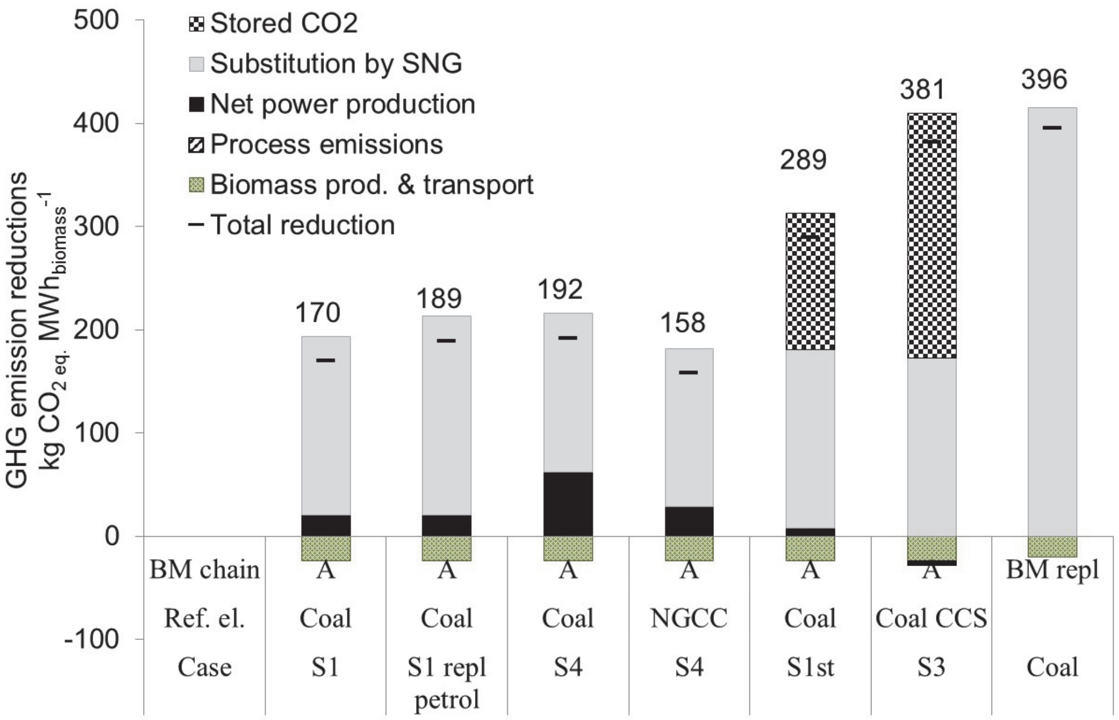

Figure 17 GHG emission reduction potential for the GB SNG production system.

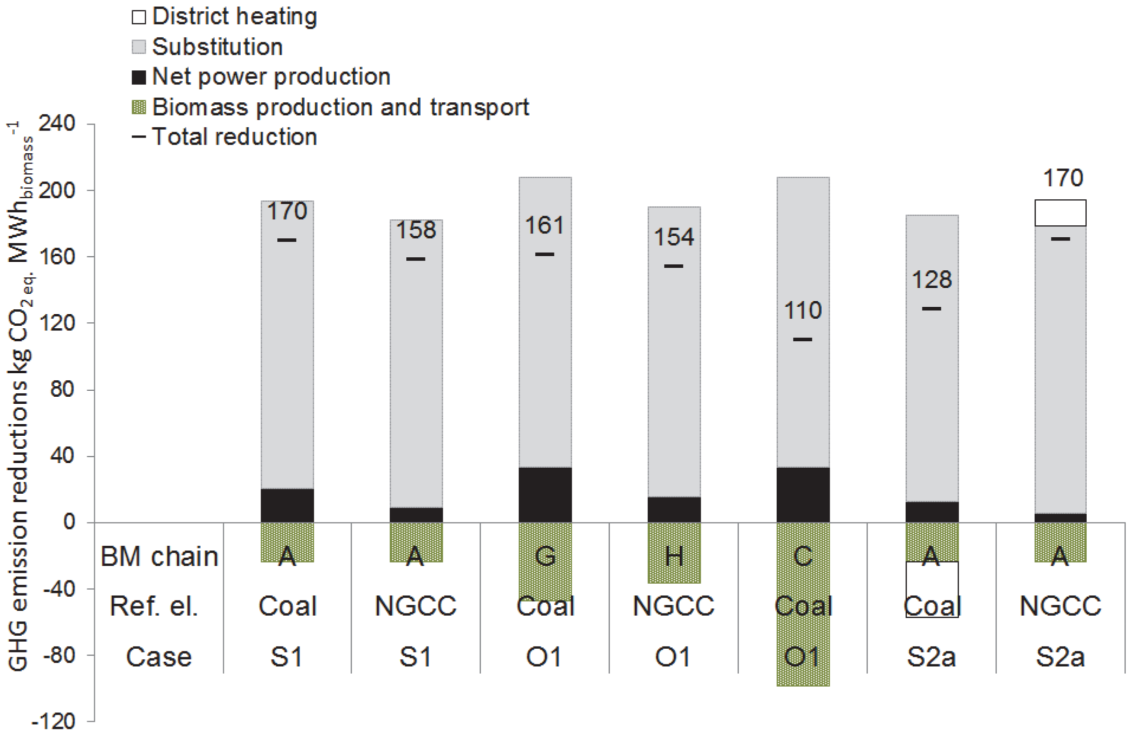

Figure 18. GHG emission reduction potential of some bio-SNG production systems.

6.1.5 Summary of objectives and main findings of Paper V

In Paper V, the investment costs of the GB systems (SNG, MeOH and FT) were determined. The aim of the study was to identify some important sources of uncertainty for the investment cost estimates for GB biofuel production systems. Specifically, the impact of the index used for updating the cost estimates to a common value basis (currency and year) was analysed. In addition, literature-based cost estimates and estimates made by industry experts for a specific set of equipment was were compared. Paper V compared the investment cost estimates of SNG, MeOH and FT fuel production systems determined in the study and from the literature on a common basis with respect to the size of the gasifier (biomass input) and money value (year and currency).

The results are displayed in Figure 19, Figure 20 and Figure 21 (the points marked by “Holmgren et al. 2015” were the values determined within Paper V). The analysis of the impact of using different cost-escalating indices showed that the most commonly used indices have developed differently over time. Cost estimates for the same installations calculated by the CEPCI and the CERA DCCI (downstream Capital Cost Index) indices differed by 50 % for the updating period 2007-2012. For longer updating periods, the difference can be even greater, whereas for updates of only one or two years, the difference is small. However, the cost estimates used in the literature are sometimes older than five years because estimates are often “reused” in updated publications. Still, in the comparison of several cost-estimates for similar gasification systems in literature, most of the estimates fall within the ± 30 % uncertainty range of a study estimate.

Paper V suggests that one of the reasons for the outlier, Haarlemmer et al. (2012), in the investment cost assessment for FT production (Figure 21), could be the use of the CERA index in that study. However, there are also differences in the biomass pretreatment that might explain part of the difference. The Norrtorp study (Möller et al., 2013a) in Figure 19 represents non-optimised and site-specific estimates.

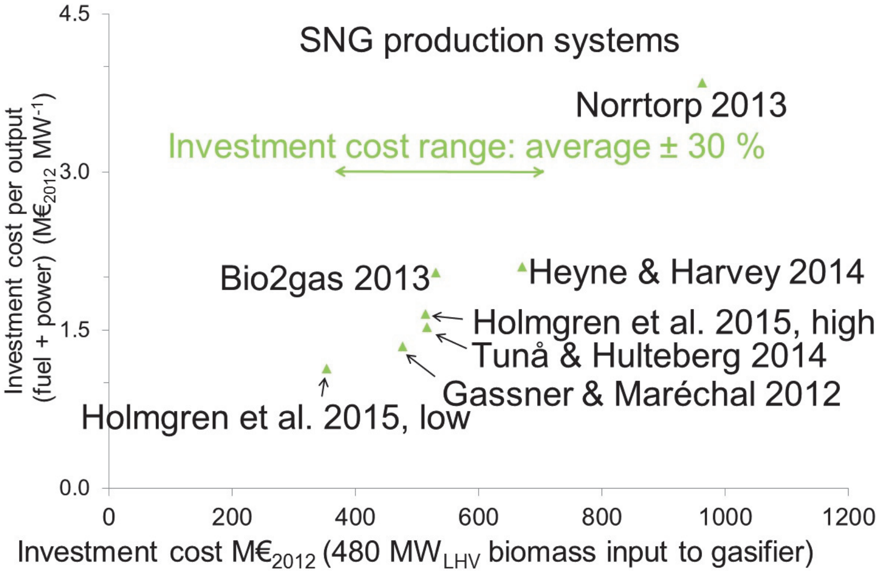

Figure 19 Total plant investment cost estimates for SNG production systems from different studies. All of the estimates have been updated to M€$_{2012}$ (using the CEPCI index) and to a capacity of a 480 MW$_{LHV}$ biomass input to the gasifier.

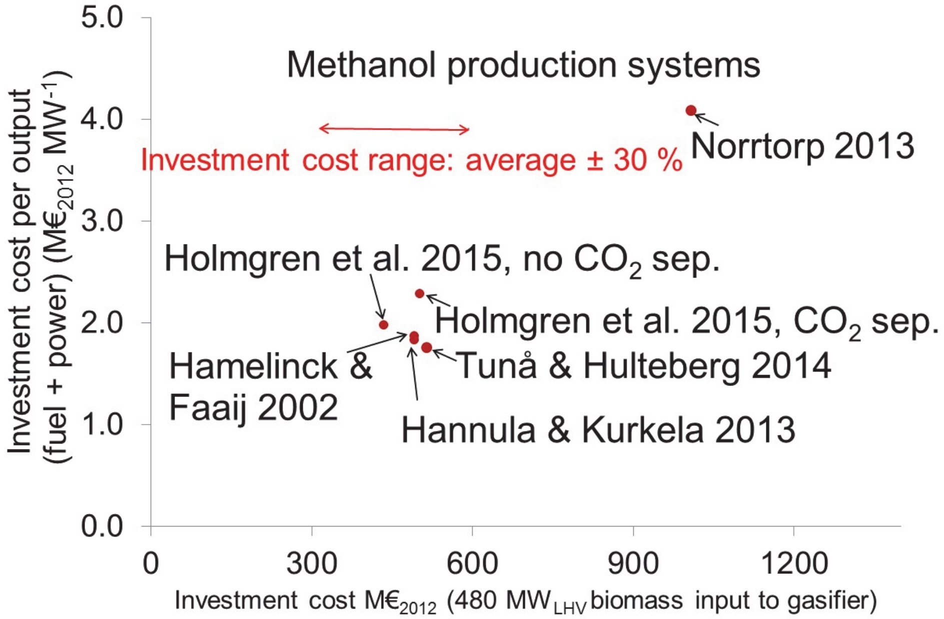

Figure 20 Total plant investment cost estimates for MeOH systems from different studies. All of the estimates have been updated to M€$_{2012}$ (using the CEPCI index) and to a capacity of 480 MW$_{LHV}$ biomass input to the gasifier.

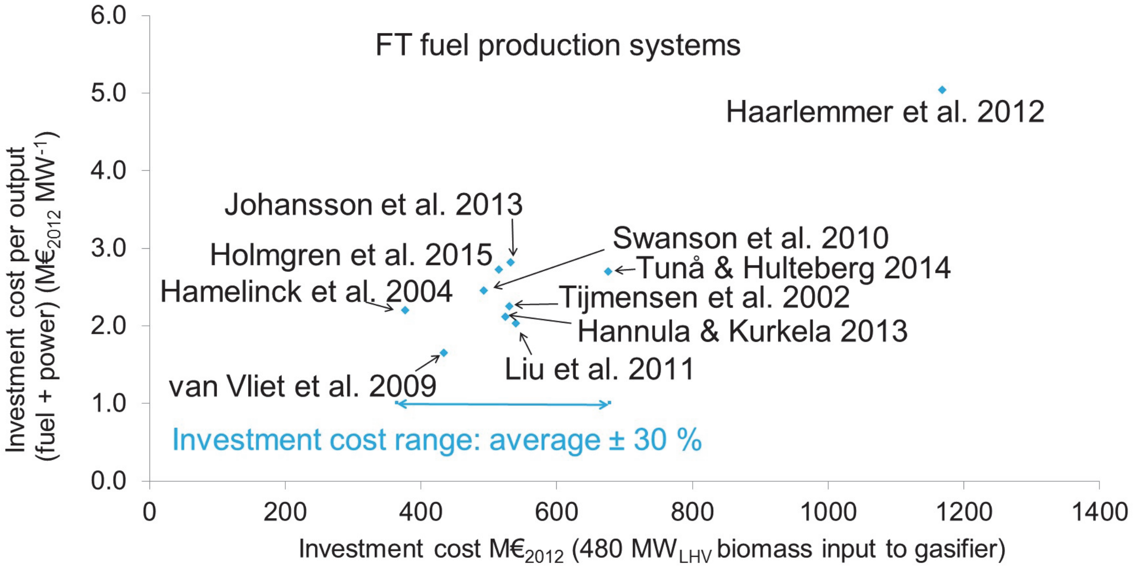

Figure 21 Total plant investment cost estimates for FT fuel production systems from different studies. All of the estimates were updated to a capacity of a 480 MW$_{LHV}$ biomass input to the gasifier and the M€$_{2012}$ money value using the CEPCI index.

A comparison between cost estimates based on literature values for FT syncrude upgrading equipment and estimates made by experienced refinery staff at a specific industrial site showed that the estimates could differ by more than ± 30 %; see Table 10. Note that the size of the refinery equipment was significantly larger than the size needed for the GB system analysed in Paper V (indicated by Holmgren cases in Table 10), which means that factored scaling might be inappropriate. One possible explanation for the significant difference is that the local conditions can deviate significantly from the general conditions considered in the literature estimates.

The ratios between the refinery staff cost estimates and the cost estimates based on the literature are displayed in the two rightmost columns of Table 10. They show significant differences, and a change in the investment cost of a corresponding magnitude will significantly affect the profitability of the system (see Section 6.3).

Table 10. Equipment capacities and investment costs for FT syncrude upgrading equipment. (Columns marked with Refinery are based on industry experts, whereas columns marked with Holmgren are based on the assessment made in Paper V).

Equipment process	**Refinery size**	**Refinery cost**	**Holmgren size**	**Holmgren cost (CEPCI)**	**Holmgren cost (CERA)**	**Cost, refinery down-scaled**	**Ratio Holmgren/ Refinery**	
	$m^3 h^{-1}$	M€$_{2012}$	$m^3 h^{-1}$	M€$_{2012}$	M€$_{2012}$	M€$_{2012}$	CEPCI	CERA
Distillation	1450	340	23	16.0	-[a]	18.8	1.2	-
Naphtha hydrotreater	240	80	3.3	2.0	2.9	5.0	2.5	1.7
Naphtha reformer	220	290	2.9	8.9	13.0	22.0	2.5	1.7
C5/C6 Isomerisation	105	60	1.2	1.8	2.6	3.6	2.0	1.4
Wax hydrocracking	340	460	7.2	16.9	24.7	55.5	3.3	2.2
Distillate hydrotreater	270	190	10.9	11.4	16.6	27.4	2.4	1.7

[a] The cost estimate for the distillation was not calculated with the CERA index because the original cost estimate was older than the CERA index timeline.

The main contributions of this paper are the following findings:

- There could be a significant difference in the estimated investment cost depending on which cost-escalating index is used. Which index is used in different studies is mentioned but seldom given any further attention.
- Despite several differences, the estimated investment costs for SNG, FT and MeOH systems with similar technical setups and gasifier sizes fall within the ± 30 % uncertainty range for the study estimates.
- There could be larger differences (larger than ±30 %) between the cost estimates from literature-based study estimates and the estimates made for site-specific conditions by industry sources.

The data for determining the investment cost estimates are presented in the supplementary report to Paper V, Holmgren (2015).

6.1.6 Summary of objectives and main findings of Paper VI (all three DRs)

The aim of Paper VI was to analyse and quantify the impact on the economic performance and the GHG emission reduction potential of the different integration options for the three identified DRs. The considered integration options are heat delivery to DH systems, heat integration (steam deliveries) with industries (chemical clusters and oil refineries) and integration with infrastructure for transporting CO_2 to storage. The analysed cases for each of the DRs are described in Table 11.

Table 11. Descriptions of the different cases analysed for each DR.

DR	Case	Description[a]
SNG	SNG SA	Stand-alone case. Excess heat produces power in a condensing steam cycle.
	SNG DH	Same as SNG SA but the steam cycle (HRSC) operates in backpressure mode producing heat delivered to a DH system. The power production is maximised, i.e., the backpressure is at the lowest possible level, determined by the supply temperature to the DH system. 28.5 MW heat is delivered to the DH system.
	SNG DH CCS	As SNG DH but the CO_2 separated before methanation is compressed and sent for storage.
MeOH	MeOH SA	Stand-alone case. Excess heat is used in a condensing HRSC and additional heat from combusting the off gases from the MeOH production is used for superheating the steam. No CO_2 separation.
	MeOH SA CCS	Same as MeOH SA but CO_2 is separated by MEA (same as in SNG cases) and sent for storage.
	MeOH INT	Heat integrated case with one of the cluster plants. 40 MW low pressure steam is delivered to the cluster plant and replaces natural gas use in boilers. Low temperature heat from a hot water circuit at the cluster is used for drying the biomass used in the gasification plant.
	MeOH INT CCS	Same as MeOH INT but the separated CO_2 is sent to storage.
FT	FT SA	Stand-alone production of FT syncrude. The syncrude is sent (by truck) to a refinery for upgrading in existing equipment. Excess from the syncrude production is used in a condensing HRSC for power production. Additional heat from combusting off gases are also used in the steam cycle.
	FT SA CCS	As FT SA but CO_2 separated from the syncrude production is compressed and sent for storage.
	FT INT	Heat integration between the refinery and the FT syncrude production. 65 MW high temperature heat from the gasification is transferred via a molten salt system to the refinery and replaces natural gas combustion in boilers.
	FT INT CCS	Same as FT INT but the separated CO_2 is compressed and sent for storage.

[a] For all cases except where specifically noted the biomass is dryer by an air dryer using low-temperature heat from the biofuel production.

The evaluated indicators for the economic performance were the NAP and the FPC. The study included four future energy market conditions based on the New Policy and 450 ppmv scenarios for the years 2030 and 2040 provided by the ENPAC tool. The system yields for the analysed DR cases are presented in Figure 24.

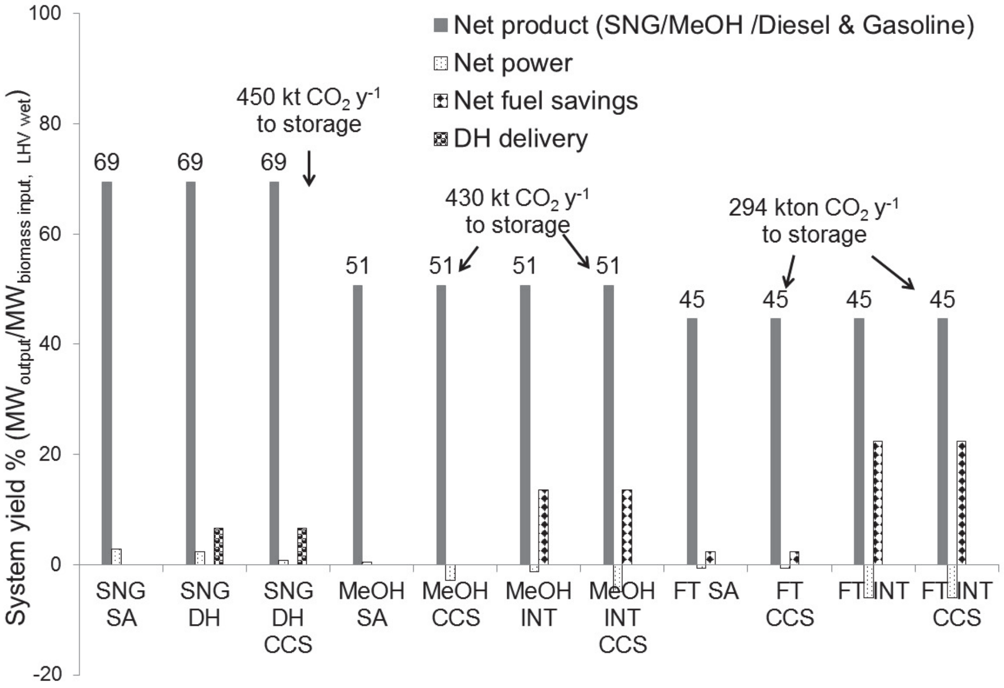

Figure 22 Product mix for the different DR cases. Note that net fuel savings occur in cases with industry integration.

The main results showed that

- The raw material costs, investment costs and revenues from selling produced biofuels constitute the largest share of the NAPs of the investigated biofuel production systems. Integration with an adjacent industry by delivering heat to replace the combustion of primary fuels also constitutes an important share of the NAPs for the investigated MeOH and FT fuel DRs; see Figure 25.

- The effects on the NAP and the GHG emission reduction potential from integrating a GB biofuel production system with a DH system strongly depends on the specific production technologies replaced in the DH system and on the reference power production. For the included DH production technologies and prices (see Table 14 and Table 3 respectively), the impact on the NAP of the integration with the DH system was limited, whereas the GHG emissions either increased or decreased, depending on the reference power production.

- Heat markets are local markets, and the prices can be significantly different from the two analysed cases. Therefore, the local conditions should be analysed for any real case.

- Heat integration with an adjacent industry was robust in terms of increased NAPs for both energy market scenarios. The considered integrations (MeOH production with a chemical cluster and FT syncrude with a refinery) contributed to a 7-13 % reduction of the FPC (see Table 12).

- The analysis of the NAP showed that (for an CRF of 0.1)
    - All of the SNG cases (where the SNG is assumed to be paid for as petrol) had positive NAPs, with the exceptions of cases without CCS in the 450 ppmv scenario. All of the SNG cases where the SNG is assumed to be paid for as natural gas had negative NAPs.
    - All of the MeOH cases had negative NAPs.
    - All of the FT fuel cases had negative NAPs, with the exception of the FT INT case in the New Policy scenario (with CRF 0.2, this case is also negative).

For a CRF of 0.2 all cases for all DRs have negative NAPs.

- For the MeOH production system, heat integration increased the GHG emission reduction potential by 17-18 % in the New Policy scenario, whereas for the integrated FT production systems, the increase was limited to 6-9 %. In the 450 ppmv scenario, the emission reduction potential increased by 30 % for the integrated MeOH production system and by almost 50 % for the integrated FT production systems; see Figure 24.

- The contribution of CO_2 storage to reduced FPCs strongly depends on the CO_{2e}-charge, but for the systems and conditions investigated in this study, the contribution could be as much as 20 % if additional equipment for separation is not needed (Figure 27).

- All of the cases show lower GHG emission reduction potentials than the alternative of directly using the biomass for replacing coal.

The following conclusions can also be drawn from the simultaneous analysis of the GHG emission reduction potential and profitability:

- Of the SA cases (when assumed to be paid for as petrol), the SNG case shows the largest GHG emission reduction potential and the largest NAP.
- The SNG case with both DH deliveries and CCS has the highest NAP and the highest GHG emissions reductions of all of the investigated cases.

The analysis showed that the uncertainty in the investment cost estimates could significantly affect the NAP; see Figure 23. The two scenarios in Figure 23 show a trend of lower profitability in future scenarios with higher prices of low-grade biomass. The increase of the prices of the low-grade biomass is due to higher willingness to pay when CO_{2e}-charges are higher. The results in Figure 23 are based on a CRF-factor of 0.1.

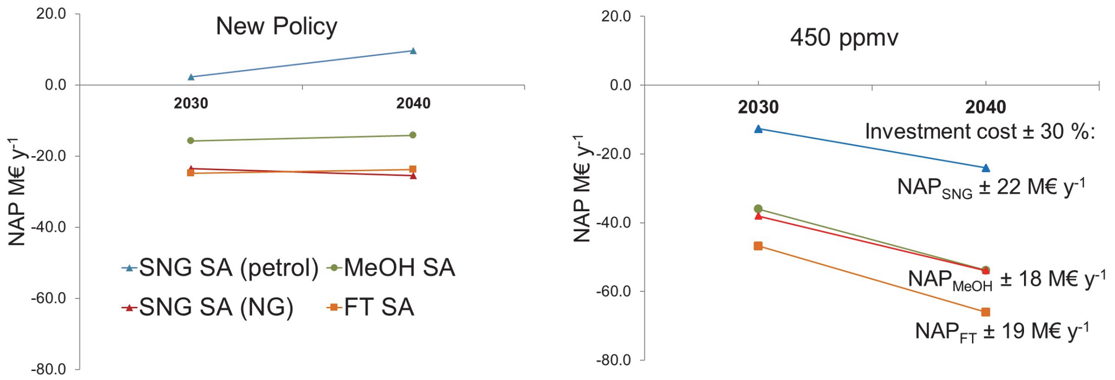

Figure 23 NAPs for SA cases in the New Policy (left) and 450 ppmv (right) scenarios. The changes in the NAPs due to increased or decreased investment costs (± 30 %) are displayed to the right. The CRF factor is 0.1 for all cases.

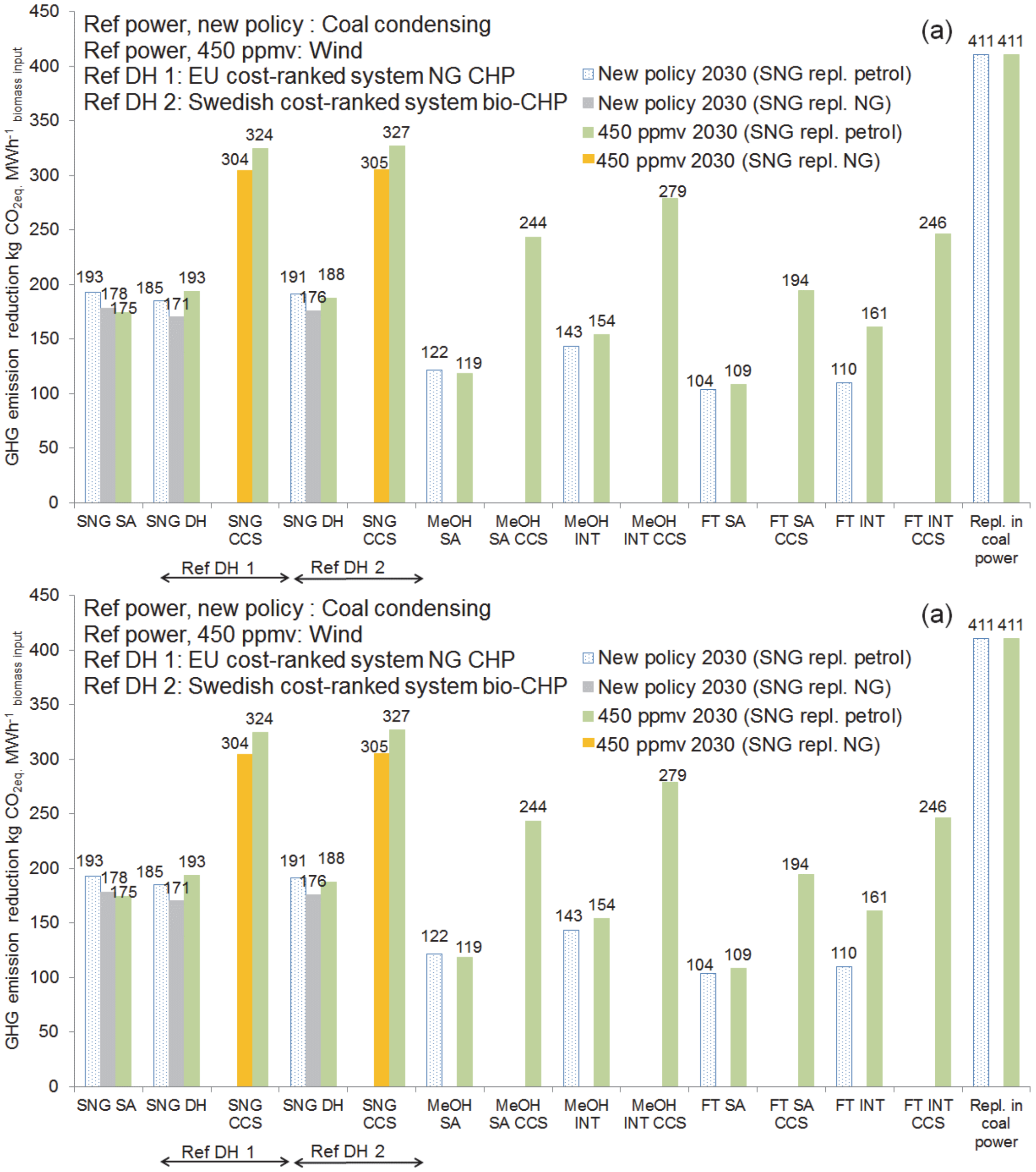

Figure 24 GHG emission reduction potential for GB production systems in 2030 (a) and 2040 (b).

The “Coal PP” bar in Figure 24 represents the GHG emission reduction potential by co-combusting biomass in a coal power plant and thereby directly replacing coal. Note that the GHG emission savings of co-combusting coal and biomass is the same as when considering CCS at the coal power plant in the 450 ppmv scenario because CO_2 both from the combusted coal and from the biomass will be captured and stored.

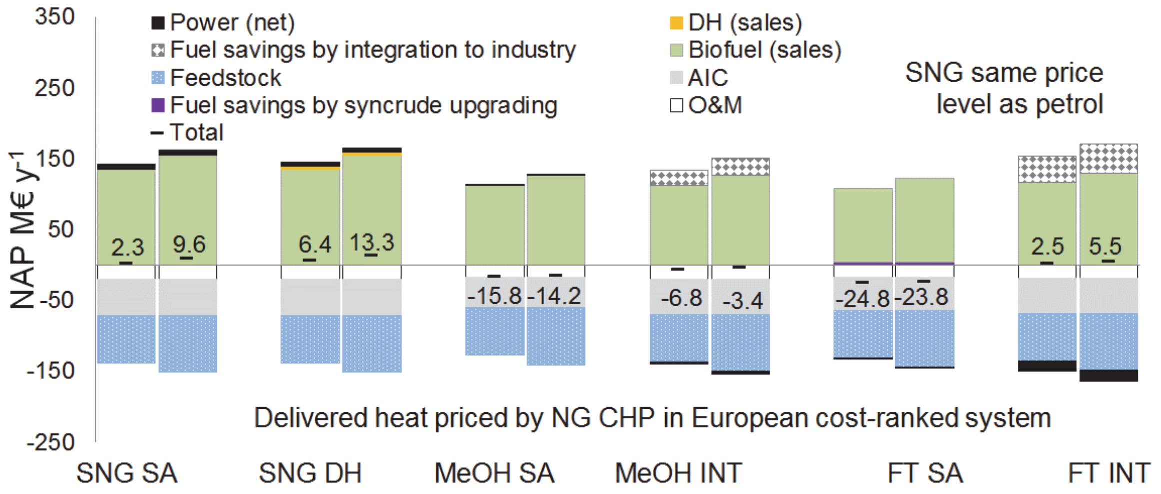

Figure 25 NAP for SA and integrated cases for evaluated for the New Policy scenario. The left bar in each pair is for 2030, and the right bar in each pair is for 2040.

Table 12 shows the following FPC ranges:

- For SNG:
  - For cases without CO_2 storage: 54-61 € MWh^{-1} in the New Policy scenario and 66-82 € MWh^{-1} in the 450 ppmv scenario.
  - For cases with CO_2 storage: 58-64 € MWh^{-1} in the 450 ppmv scenario.
- For MeOH:
  - For cases without CO_2 storage: 68-80 € MWh^{-1} in the New Policy scenario and 84-109 € MWh^{-1} in the 450 ppmv scenario.
  - For cases with CO_2 storage: 83-97 € MWh^{-1} in the 450 ppmv scenario.
- For FT:
  - For cases without CO_2 storage: 74-92 € MWh^{-1} in the New Policy scenario and 91-125 € MWh^{-1} in the 450 ppmv scenario.
  - For cases with CO_2 storage: 82-109 € MWh^{-1} in the 450 ppmv scenario.

Table 13 summarises the impact on the specific NAPs[7] and GHG emission reduction potentials of the analysed integrations. The integration of the SNG production system with the DH system has negative effects on both the GHG emission reduction potential and for the specific NAP in the case of the Swedish cost-ranked systems with bio-CHP in the New Policy Scenario. For the same scenario and the case where the DH system is an EU cost-ranked system with NGCC CHP, the specific NAP is slightly increased but the GHG

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[7] The specific NAP is the NAP divided by the annual amount of input biomass, which for all of the cases is 430 MW * 8000 h.

emissions are increased more. In the 450 ppmv scenario, integration with both DH systems results in reduced GHG emissions; however, the improvement in the specific NAP is relatively small.

The heat integration possibilities with nearby industry considered in the MeOH and FT fuel DRs have different characteristics. More heat (in MW), at a higher temperature, is delivered to the refinery from the FT syncrude production than from the MeOH production to the cluster. This difference means that the reduction in power production is more significant for the FT DR. The analysis shows that the FT integration has a larger positive impact on the (specific) NAP for all of the investigated energy market conditions. The integrated MeOH system shows a larger increase of the GHG emission reduction potential in the New Policy scenario, whereas the integrated FT system has the largest increase in the 450 ppmv scenario. In the New Policy scenario, the reference power production is GHG-intensive (coal condensing power), whereas it is wind power in the 450 ppmv scenario. Therefore, in the latter case, the loss in power production does not result in a decrease of the GHG emission reduction potential.

Table 12 Fuel production costs M€$_{2012}$ MWh^{-1}.

	FT SA	FT SA CCS	FT Int	FT Int CCS	MeOH SA[a]	MeOH SA CCS	MeOH Int	MeOH Int CCS	SNG SA	SNG DH[c]	SNG CCS
New Policy 2030	84		74		73		68		55	54	
New Policy 2040	92		81		80		74		61	59	
450 ppmv 2030	103	94	91	82	90	88	84	83	68	66	58
450 ppmv 2040	125	107	109	92	109	97	102	90	82	79	64

Gate prices for comparative fuels

	New Policy 2030	New Policy 2040	450 ppmv 2030	450 ppmv 2040
Petrol (incl. CO_{2e}-charge)	69	77	75	84
Diesel (incl. CO_{2e}-charge)	78	87	83	92
Natural gas (incl. CO_{2e}-charge)	49	53	55	63
MeOH (incl. CO_{2e}-charge)[b]	74	80	80	88

[a] Excluding CO_2 separation.

[b] Produced from natural gas.

[c] DH is assumed to replace NGCC CHP in the European cost-ranked system.

Table 13 Impacts on the specific NAP[7] and GHG emission reduction potential of integration with a DH system, nearby industry and CO_2 transport infrastructure for the development routes analysed in Paper VI.

Case	**Specific ΔNAP[7] [€ MWh^{-1}][a]**				**ΔGHG kg $CO_{2eq.}$ MWh^{-1} (%)**			
	New Policy		450 ppmv		New Policy		450 ppmv	
	2030	2040	2030	2040	2030	2040	2030	2040
SNG								
Integration (SNG DH – SNG SA)								
DH priced by bio-CHP in a Swedish cost-ranked system	-0	-0	0	1	-1	-1	13 (7)	14 (8)
DH priced by NGCC-CHP in an EU cost-ranked system	1	1	1	2	-7	-5	19 (11)	15 (9)
CO_2 storage (SNG DH CCS – SNG DH)			5	11			131 (~70 %)	
MeOH								
Integration (MeOH INT-MeOH SA)	3	3	3	4	21	22	35 (30 %)	
CO_2 storage (MeOH CCS-MeOH SA)			1	6			125 (105 %)	
FT								
Integration (FT INT-FT SA)	8	9	9	10	7	9	52 (48 %)	
CO_2 storage (FT SA CCS – FT SA)			4	8			85 (79 %)	

[a] A positive specific ΔNAP means that the profitability increases, and a positive ΔGHG means that the GHG emission reduction potential increases. The change referred to by the Δ is indicated for each case by subtraction given in the case column.

6.2 Important factors for the climate impact and economic performance of gasification-based production systems

6.2.1 The impact of integration

Heat integration with industry

Paper III concluded that GB MeOH production integrated with industry had a larger GHG emission reduction potential than SA configurations. In Paper VI, this conclusion also holds for the FT fuel production system. The analysis in Paper VI showed that the heat integration with adjacent industry (in the MeOH and FT DR) increased the GHG emission reduction potentials for both investigated energy market scenarios and time frames. The integration with industry also showed robust positive impact on the economic performance for all investigated cases and scenarios. The increase of the GHG emission reduction potential is larger in scenarios where the reference power production has lower GHG emission intensity. The impact of the integration on the NAP is similar in magnitude for all the analysed energy market scenarios.

Integration with DH systems

The impacts on the GHG emission reduction potential of integrating the gasification systems with a DH system is discussed in Section 6.2.3, where the importance of the reference production technologies, i.e., the production units being replaced, is presented. The quantifications of the impacts of integrating the SNG production with different DH systems show that GHG emissions can be reduced by 7-11 % in the 450 ppmv scenario (with wind power as reference power technology) with either NG CHP or bio-CHP being replaced (Table 13). For the New Policy scenario, where coal power is the reference production technology, the GHG emissions slightly increased as a result of the integration. The cases of integration of GB biofuel production to DH systems analysed in this study show only minor impact on the NAPs and the FPCs.

CO_2 storage possibility

Papers I, IV and VI include DR cases that consider CCS, and all of these cases show significantly higher GHG emission reduction potentials than cases without CO_2 storage possibilities. The FT case in Paper I, and the SNG case where both emissions from the process and from the flue gases are separated and sent for storage in Paper IV, showed emission reduction potentials of similar magnitudes to the alternative of utilising the biomass to replace coal (see Figure 14 and Figure 17). In Paper VI, the impact of storing separated CO_2 was evaluated for all three DRs, and the results show that the possibility of storing separated CO_2 increases the GHG emission reduction potential by 70-100 %. The impact on the NAP and FPC of CO_2 storage can be significant for systems with strong climate policies.

It should be noted that the analysis of how much of the separated CO_2 actually can be stored is limited in this study, so there is uncertainty in terms of the difference between the different DRs. The CO_2 separation technology used in the FT DR was not the same as in the SNG and MeOH DRs and it is somewhat uncertain whether the difference in separated CO_2 solely depends on the different amounts of CO_2 separated from the processes or if some of the difference also depends on the technology.

6.2.2 The impact of raw material supply on GHG emissions

The base-case raw material supply chains considered in Papers I, III, IV and VI are all based on locally produced wood chips from forest residues (based on the emission estimates from Lindholm et al. (2010)) and have modest impact on the overall GHG emissions. However, other sources of raw materials being used could have a more significant impact.

The MeOH production systems analysed in Paper III included both the use of locally produced wood chips dried at the gasification plant and biomass that was assumed to be dried elsewhere. However, the GHG emission analysis of the on- or off-site biomass drying in Paper III was simplified. It was assumed that biomass was the fuel used for drying the wood chips off-site, and some reduction in the transportation emissions was achieved because the dried biomass could be transported more efficiently than wet biomass. The results showed that the off-site drying increased the demand for biomass but provided more on-site excess heat that could be used for improving the power balance of the system. Whether the overall GHG emission reduction potential was reduced or increased by off-site drying depended on the reference power production.

Figure 26 shows the split GCCs for the GB MeOH production with and without on-site biomass drying and an HRSC (from Paper III) and split GCCs for SNG production systems with and without biomass drying and an HRSC (from Paper IV). The onsite biomass drying in the MeOH case is accomplished by an air dryer, whereas in the SNG case, a steam dryer is used. Note that in both cases (MeOH and SNG), the energy demand for the off-site biomass drying is not displayed. The results show that the amount of on-site excess heat available for power production in the HRSC is significantly larger in the case with off-site biomass drying.

Paper IV more thoroughly analysed the raw material supply chain, including drying. The dried biomass was assumed to come to the gasification plant in the form of pellets. Other and more refined assumptions regarding the transportation distances were made, involving longer transport distances (before reaching the gasification plant) for the biomass in the pellet supply chains than for the wet wood chip chain. The results showed that even if the raw material supply chain had significantly higher GHG emissions (+50 %), the impact on the GHG emission reduction potential for the SNG-production system could be small (~2 %) because the raw material supply constitutes a small part of the total GHG emissions, and the improved onsite power balance partly compensates for the increased emissions.

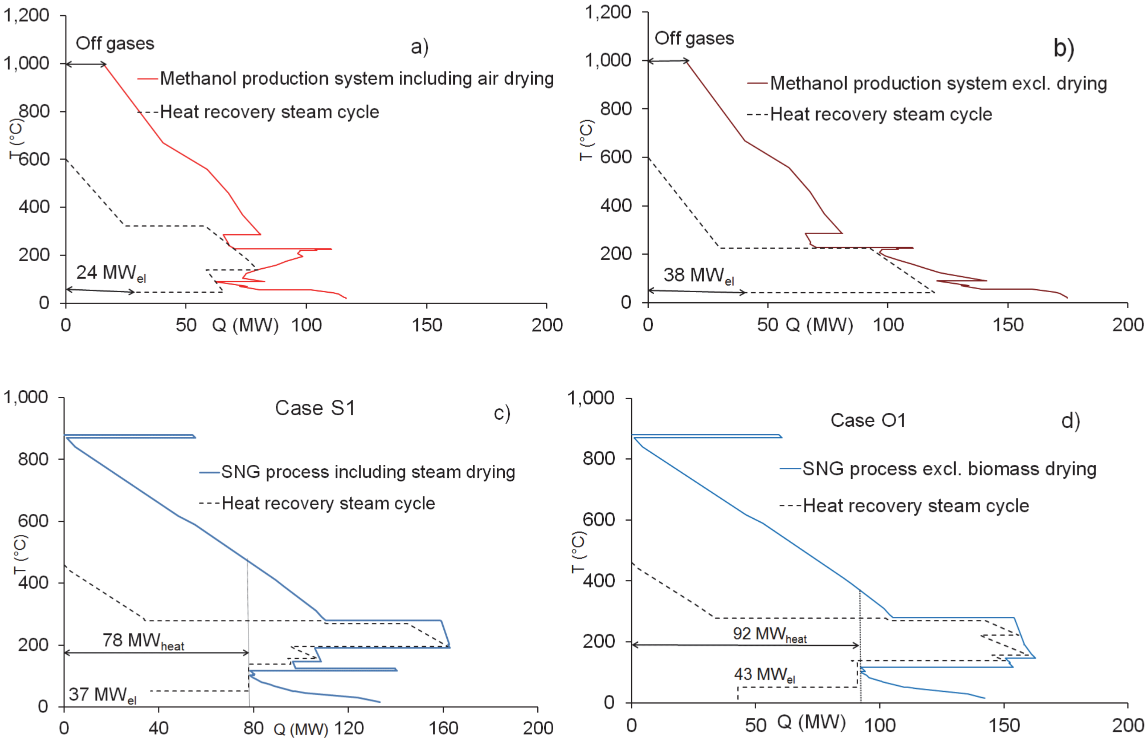

Figure 26 Split GCCs for GB MeOH production with process-integrated air drying (a) and without on-site biomass drying (b) and HRSC (from Paper II) and split GCCs for SNG production with process-integrated steam drying (c) and without on-site biomass drying (d) and HRSC (from Paper IV).

The analysis in **Paper IV** also shows that if the raw material supply chain includes long-distance transportation, the impact on the overall GHG emission reduction potential of the systems could be significant. For the setup in **Paper IV**, the results show that using on-site process integrated biomass drying is efficient in terms of the GHG reduction potential. The price of the feedstock is the dominating part of the FPC (Figure 27) and an important part of the NAP (Figure 25).

6.2.3 The importance of the reference system to the GHG emission reduction

Reference power production

The reference system, i.e., the production technologies and raw materials used for the production of the replaced products, is of significant importance for the GHG performance. In particular, the reference power production has turned out to significantly affect the outcome of different options for utilising the excess heat from the gasification plant. In all of the papers where GHG emissions were analysed (with the exception of Paper I), different alternatives for the reference power production were included as a sensitivity analysis for this parameter. In future scenarios with stricter climate policies, the carbon intensity of the build margin power production is projected to decrease. The different reference power technologies have some effect on the SA cases, especially the SNG cases, which have larger positive net power productions. The impact of the reference power production technology is more important for the integrated cases, since the integration with industry leads to lower power production.

DH production systems

In Paper I, the evaluation of the GHG emission reduction potential of the analysed systems shows that the delivery of DH could constitute an important part of the total GHG emissions. The impacts shown in later papers are smaller, mainly because other DH production technologies were assumed to be replaced.

The results from Paper III show that the integration of the MeOH production system with a DH system has the potential to either increase or decrease the overall GHG emissions of the system, depending on what heat production technologies it replaces. If the replaced heat production technology is a co-generation technology, the reference power production technology will also significantly affect the GHG emissions. Similar results were found in Paper IV and Paper VI. The evaluation in Paper IV of the impact on the overall GHG emissions of replacing heat production from NGCC CHP for different reference power production technologies can be seen in Figure 18 (compare the S2a cases). The impacts on the system overall GHG emissions of delivering heat to a nearby DH system for different GB production systems are summarised in Table 14. The general conclusion is that the impact on the GHG emission reduction potential of integrating the GB system with a DH system could be either positive or negative, depending on the replaced heat production technology. The properties of the local DH system, in terms of production technologies and the heat demand, should therefore be investigated for each specific localisation. This result is also in line with the results of the economic evaluation.

Table 14 Summary of the impact on the GHG emission reduction potential by the integration of GB production with DH systems with different DH production technologies.

Replaced heat production technology/DH system	Reference power production technology	Effect on GHG emissions	Paper number
NGCC CHP (high electrical efficiency)	Coal condensing power	Increase	Paper III, IV
	NGCC	Decrease	Paper III, IV
Bio-CHP (low electrical efficiency)	Coal condensing	Small decrease	Paper III
Bio CHP (high electrical efficiency)	Coal condensing	Increase	Paper IV
Natural gas boiler	-	Decrease	Paper III
NGCC CHP, in European cost-ranked system	Coal condensing	Increase	Paper VI
	Wind power	Decrease	
Bio-CHP in Swedish cost-ranked system	Coal condensing	Increase	Paper VI
	Wind power	Decrease	

From the results of Paper VI and Paper III, it can be concluded that as the reference power production technology will become less carbon-intensive (i.e., moving from coal condensing to NGCC or wind power), the replacement of heat from NGCC CHP by industrial excess heat will be more attractive from a GHG emissions point of view.

SNG replacement (petrol or natural gas)

Figure 17 shows the difference between assuming that the SNG replaces natural gas (in the S1 case) or petrol (in the S1 repl. petrol case) based on the analysis in Paper IV. The GHG emission reduction potential is ~12 % higher when SNG replaces petrol than when it replaces natural gas. Paper VI includes the same two options for fossil replacement by utilising SNG. However, the difference is even smaller, only 10 %, due to higher GHG emissions for natural gas when applying the updated GWP_{100}-factors, which more strongly affect methane emissions (which are more abundant in the natural gas case); see Figure 24.

MeOH replacing petrol or olefins

The results from Paper III show that under the conditions of the study, the GHG emission reduction potential is of the same magnitude for systems using the produced MeOH to replace motor fuels (petrol) as for systems using the MeOH to produce green olefins (via MTO) and thereby to replace naphtha-based olefins; see Figure 16. The main reason for this result is that in both cases oil-based products are replaced.

Paper I analysed the impact on the GHG emission reduction potential of replacing short-lived or long-lived products by a methodology that takes the timing of emissions into account. The conclusion from that comparison was that it is somewhat better to replace short-lived products because emissions that occur later have somewhat lower climatic impacts; see Figure 14. The model used in this study for considering the timing of emissions is just one of several models, see Section 7.4 for other alternatives.

6.2.4 The relative importance of factors influencing the economic performance

The analysis of the FPC in the SA GB biofuel production systems presented in Figure 27 shows that the cost of feedstock and the annual investment costs (AIC) and operation an maintenance (O&M) costs are the dominating factors. Figure 25 shows that the incomes from the system are dominated by the sales of the biofuel. The figures show that the impact of DH and net power sales/purchases are small for all of the cases.

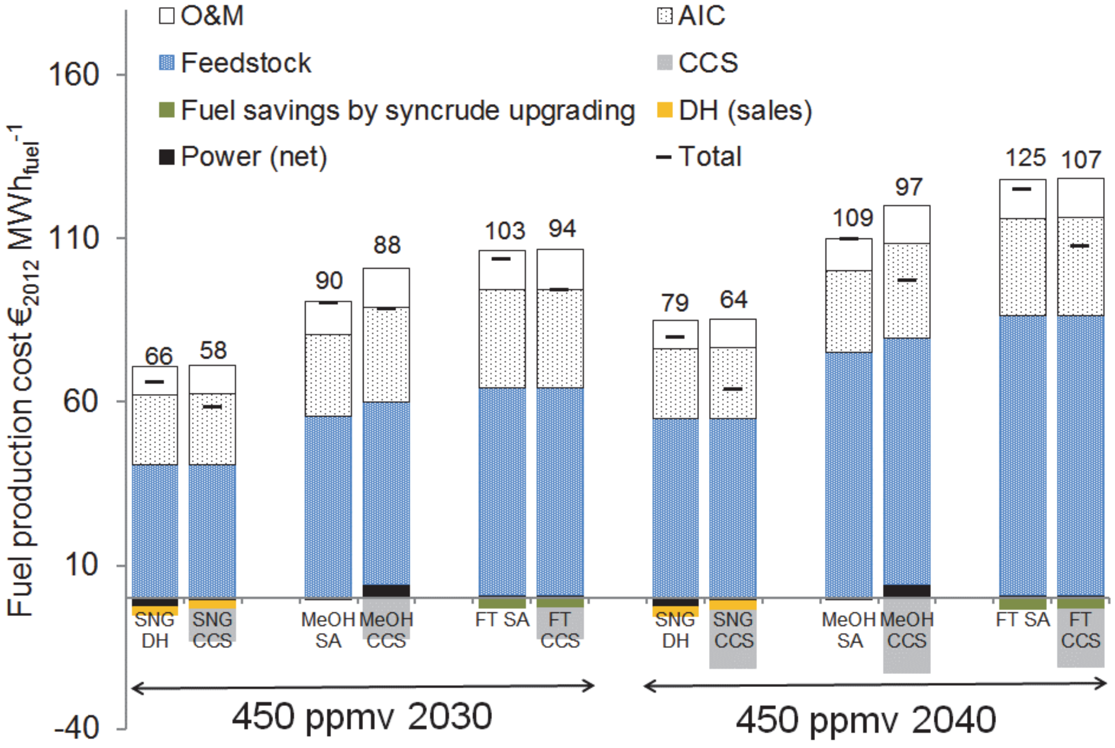

Figure 27 FPCs for some of the analysed systems in the 450 ppmv scenario: the SNG case integrated with the DH system, and the SA cases for the MeOH and FT systems and systems with storage of separated CO_2. Based on the analysis in Paper VI.

6.2.5 The alternative use of biomass

The alternative use of biomass considered, throughout all of the papers with GHG emissions evaluation, is the replacement of coal by co-combustion in a coal power plant. The GHG emission reduction potentials of the gasification systems were significantly lower than the alternative of utilising the biomass for replacing coal in all of the cases in Papers I, III, IV and VI, except for some of the cases with the storage of separated CO_2 (see Figure 14, Figure 16, Figure 17 and Figure 24).

7 Discussion

7.1 Use of biomass and product replacement

To determine whether it is better to produce biofuels or materials from the gasification systems, a broader system perspective than in the present study is needed to include other alternatives for replacing these products. In the case of fuel utilisation, there are other ways to produce biofuels, and for both the transport sector and the heat and power sector, there are also alternative production technologies that do not require biomass. Means of producing materials other than the evaluated MTO route also need to be evaluated and compared.

For the systems and with the assumptions used in the analyses of this thesis, only small differences in the GHG emission reductions were found between systems using biomass for GB biofuel production compared to systems producing materials via the MTO process. A common argument for different uses of biomass is that it is better to first use the biomass for materials, to reuse it and finally to use it as a fuel because this process allows more fossil resources to be replaced. However, this assumption is not always true. The reuse of the olefin products, as well as the end use, could be exactly the same for the fossil case and the biomass-based case. The recycling and reuse can be equally introduced both in a fossil-based and a bio-based production chain. Therefore, reusing and recycling products are good ways of reducing the carbon footprint but do not favour fossil or green origins unless there are chemical or physical differences between the products.

The results in Paper IV showed that in a future where the reference power generation will be less carbon-intensive (less than coal condensing), GB production systems will achieve larger GHG emission reductions by replacing oil-based motor fuels than replacing power. However, the study did not consider the development in the transport sector of other fuels. Petrol was also considered to be the reference fuel in the future systems. A development is likely to occur also in this sector that could result in less carbon-intensive motor fuels and power trains using other sources (i.e., electric vehicles or fuel cells). On the other hand, it is also possible to produce liquid fuels from natural gas and coal that directly replace petrol and diesel and have significantly higher GHG emission profiles than the conventional-oil-based fuels. If motor fuel production systems with significantly higher GHG emission profiles existed in the future, then the systems analysed in this study would further reduce the GHG emissions.

7.2 Uncertainties

System analysis like that of the present study depends on many assumptions and data sources. Each of these assumptions and datasets has its own uncertainties, and some are more important to the overall result than others. Some of the most significant uncertainties are noted below.

- Biomass GB biofuel production systems of the scale analysed in this study do not exist today. Therefore, there is uncertainty in the description of the processes. Further, the simulations of the systems performed by other researchers and used as input data to this study have involved many assumptions and simplifications relative to the real systems. Different models were also used for the different DRs, which might introduce additional uncertainty.

- The gasification systems are analysed based on energy targeting, and the result of an energy targeting analysis is an ideal system with maximum heat integration. Therefore, it might not be possible to achieve the performance described for the systems because there are aspects not taken into consideration, such as safety, practical concerns, or other technical aspects. However, the compared systems are treated in the same way, which means that some of this uncertainty would cancel out in the comparison to a similar system.

- The prices of fuels and energy from the energy market scenarios are important and significant sources of uncertainty. However, the strategy of using different scenarios and time horizons is a structured way of reducing the uncertainty. Still, the projections of fuel prices made by the IEA, upon which the ENPAC tool scenarios rest, are very uncertain. Just during a short period of time, quite radical and unexpected changes in the energy markets have occurred. Two things to mention are the prices of oil and natural gas. The oil price reached all-time high levels in 2008 (over 140 \$ bbl.$^{-1}$), after some fluctuations it has remained at high levels until late 2014, when it again decreased and has since then remained below \$ 60 bbl.$^{-1}$. The oil price significantly affects many of the other energy prices. The natural gas price does not have a worldwide market in the same way that the oil price does, but the introduction of significant volumes of shale gas in the energy supply of North America has significantly reduced the price on the US market.

- The price of biomass is uncertain. As discussed in Section 4.5.3, the price for low-grade biomass retrieved from the ENPAC tool for some of the scenarios was considered to be too high and was adjusted. The biomass price significantly affects the results. Better models to project or relate the price of low-grade biomass in a carbon-constrained future are needed.

- Investment cost estimates are uncertain, especially for systems that do not yet exist and that have not been fully demonstrated. If and when commercial-scale installations are realised, the investment costs can be estimated with increased certainty. To address this uncertainty, a sensitivity analysis was included both for an increase in the investment costs and the CRF-factor

- With respect to the impact of the possibility of storing separated CO_2, it should be noted that none of the appended papers considered potential leakage from the storage sites or the transportation from the gasification plant to the storage sites. Other practical, social or technical difficulties were not considered either.

The main purpose of the study was to analyse the impact of integrating biomass gasification with existing industries and infrastructures rather than to determine exact costs and emissions reductions.

7.3 Aspects of integration and implementation

In this study the size of the gasification system is the same in all DRs and cases. In the SA cases, the excess heat from the biofuel production system is used for power production and, in the integrated cases some of the excess heat is used for DH or process heating in other industries thereby reducing the internal power production. To size the gasification systems based on the heat demand in the integrated industry could have been a strategy to compare the impact of integration. However, changing the size of the gasification system changes some of the important parameters for the systems profitability, such as the specific investment cost. Results from previous studies, e.g. Isaksson et al. (2015) indicate that a large system will be more profitable.

There are several important aspects of integration between large complex industrial systems (such as the GB biofuel production systems, the chemical cluster, the oil refinery, etc.) that have not been analysed in this study and that need to be analysed in additional detail before pursuing these integrations. Heat integration will make the complex systems depend on each other. If the running times do not match, then some type of reserve capacity might be needed. The costs for such systems have not been considered in this study. Risk assessment, which might identify the need for additional process units or reserve units, is necessary to perform.

Further, the business models for the integrations also need to be determined. The present study includes the investment costs for integration, so the profit is allocated to the system. However, how the investment and the profit should be shared between different actors was not analysed.

7.4 Comments on some methodological alternatives

The climate impact is one of the main reasons for society's engagement in biomass gasification and is therefore a natural choice for evaluation. Only profitable systems will find investors and therefore have the potential of being realised, so the profitability is also a key aspect. For many systems, profitability and efficiency go hand in hand, but obviously efficiency and environmental performance do not. Gerber et al. (2011) showed that a reduced environmental impact is not directly equivalent to an increased process efficiency for a GB polygeneration system. Therefore, the energy efficiency was not explicitly evaluated in any of the appended papers.

The climate impact is evaluated in terms of GHG emissions, summarised by GPW_{100} factors. All three main GHGs are included, mainly because one of the studied systems consider more-or-less pure methane (SNG), and recent research has shown that the impact of methane emissions is larger than previously considered. There are, however, other measures of the climate impact that are more directly related to the impacts or time perspectives than emissions, such as, e.g., radiative forcing (or relative radiative forcing commitment) as used for biomass-based systems by Kirkinen et al. (2008), global average surface temperature as described by Zetterberg and Chen (2015) or greenhouse gas payback times as suggested by Elshout et al. (2015). However, the GWP-summarised emissions constitute a well-established measure that can easily be related to. However, it is important to develop easily understandable measures that also consider the timing of emissions, especially for biomass-based systems that as in the present study, rely on the assumption that the biomass is CO_2-neutral, expressed by the assumption that emissions during combustion are compensated for by uptake during growth. However, if the amount of biomass being burnt is increased without a simultaneous increase of biomass growth, there is a risk that we at least temporarily increase the CO_2 emissions to the atmosphere compared to a reference case where fossil sources were used but less biomass was burnt.

LCA results from transportation biofuel production could (and perhaps should) be expressed on a per-km basis to account for the engine mechanical efficiency, the type of fuel and the emissions of combustion. The reason for avoiding the per-km basis in the present study, is that the main objective was not to analyse the GHG reduction potential of different transportation biofuels but rather to analyse different biomass GB production systems. The products in the analysed DRs, SNG, MeOH and FT fuels can all be used not only as transportation fuels but also for other purposes, and it was important to be able to compare to other uses for the biomass.

In the present study, policy instruments are included as a sector-wide and sector-neutral CO_{2e}-charge. Ideally, such an instrument would promote the use of biomass wherever it saves the most emissions at the lowest cost. Still, there might be reasons in a non-ideal world for implementing instruments that are specific to a sector or technology. However, the purpose of this study was not to indicate specific policies but rather to investigate the importance of the integration of GB production systems with existing industry and infrastructure.

8 Conclusions

The impact of integration with existing industry or DH systems

For the conditions of this study, heat-integrating gasification-based biofuel production to nearby industries improves the economic performance and the GHG emission reduction potential under a wide range of future energy market conditions. The heat integration means that excess heat from the gasification system is used in fossil fuel fired boilers and furnaces instead of using it for power production. As the reference power production becomes less carbon intensive, i.e. due to stronger climate policies, the benefits of the integration are improved. For the investigated cases and energy market scenarios, the heat integration of the biofuel production systems with industry showed stronger and more robust GHG emissions reductions and increases in profitability than the integration into DH systems.

Integrating the GB biofuel production system with a DH system (i.e., utilising low-grade excess heat from the gasification system) could also be a way of improving the economic performance and the GHG emission reduction potential. However, the benefits strongly depend on local conditions, both on the number of delivery hours and on the production technologies in the DH system. In DH systems, where heat is produced in CHPs (e.g., bio-CHP or NGCC CHP), the electrical efficiency will be important for both price and the GHG emission reduction potential; for the latter, the reference power production technology is also of significant importance. The GHG emission reduction potential could be reduced if the replaced production technologies have high electrical efficiencies (e.g., NGCC) and the reference power technology is of high GHG intensity. In a future where the GHG emissions intensity of the build margin power production is reduced, it will be more beneficial from the standpoint of the GHG emission reduction potential to replace CHP-produced heat by industrial excess heat.

For the DH systems and energy market scenarios analysed in the present study, the integration of the biofuel production system with the DH system showed small positive or negative impacts on the NAP and FPC. Because the heat price is determined on local markets, the option of delivering heat should be analysed for every specific case. The price relation between heat for DH and power, together with the number of possible delivery hours will determine whether it is profitable or not to deliver heat and produce less power.

Material integrations can also contribute to improvements in performance. The specific case in the MeOH DR where “excess” hydrogen was available showed that the biomass-to-biofuel conversion could be increased significantly (the exact value depends on the amount of H_2 available). The GHG emission reduction potential was also shown to be increased as a consequence of the H_2 addition.

The impact of accessibility to a CO_2 storage infrastructure

The impact on the GHG emissions reduction of storing CO_2 separated from the biofuel production system is significant, in some cases the GHG reductions are of the same order of magnitude as using the biomass to directly replace coal. The impact of the CCS on the FPC depends on the CO_{2e}-charge, and can be significant if the charge is high, and additional equipment for separation is not needed.

The positive effect on both the profitability and the GHG emission reduction potentials imply that in a future where CCS is a viable technology and the infrastructure is in place, it will be important to also connect large-scale biomass gasification facilities to these technologies.

Raw material supply

The raw material costs constitute a significant part of the fuel production costs and of the cost side of the NAP, which makes the raw material and the raw material supply chain factors of significant importance for the economic performance of the biofuel production system. The analysis of different raw material supply chain showed that using forest residues from a nearby area (i.e., with limited transportation distances) will minimise the contribution to the total GHG emissions. The analysis also showed that it is possible to significantly increase the biomass supply area without major impact on the overall GHG emissions by using pellets, if the pellet production is energy efficient, uses low-carbon heat sources and transports.

General profitability

Of all the analysed systems in this study only a few showed profitability for some of the investigated cases and scenarios. Positive NAPs were found only in a few SNG cases of the New Policy scenario and with a low CRF factor and for one of the integrated FT cases. The SNG system with CCS in the 450 ppmv scenario also showed positive NAP. All the other systems had negative net annual profits in all analysed scenarios. This indicates that the economic conditions (energy prices, policy instruments etc.) need to be different from the ones analysed in this study in order to make these systems profitable.

Biomass drying

Process-integrated biomass drying utilising low-temperature excess heat from the gasification process seems to be an efficient way of utilising the excess heat from the point of view of reducing the GHG emissions. However, the results show that importing dry biomass (pellets) will not necessarily increase the GHG emissions from the system significantly if the biomass is dried elsewhere utilising other industrial excess heat and if the transportation distances are not too great with GHG-intense transport modes. Eventually, because the profitability depends so strongly on the raw material costs, the price of the feedstock will determine whether local wet or imported dry biomass will be used.

Current and future effects of substitution

For the systems and conditions investigated in this study, the GHG emission reduction potentials of replacing motor fuels (oil-based) or plastics (naphtha-based) by biomass gasification-based products are of similar magnitude because in both cases, oil-based products are being replaced.

The carbon intensity of the reference system changes over time, so depending on the time frame of an evaluated system, the results can differ. Specifically, the carbon intensity of power generation is predicted to decline (from a European perspective, with climate policy being an important part of the future development), and with that development GHG emission reductions will be higher for systems having higher biofuel yields and replacement of fossil fuel-based steam production in industries than for systems with high co-generation of power.

9

Future work

A better understanding and projections of future prices of low-grade biomass under different energy market scenarios is needed. The price of the raw material is crucial for the implementation of the studied systems. Currently, there is no sector-wide CO_{2e}-charge like the one included in the analysis in this project. However, the impacts of different policies on future prices and applications (including GHG implications) would increase knowledge for future important policy development and biomass utilisation strategies. Further analysis is needed of where the biomass best is used and how it is used sustainably.

Further analysis of the raw material supply chain is of significant importance. The direct and indirect effects on carbon stocks should be considered. In the analysis in this study, the data for the soil carbon impact in the raw material supply chain were based on Swedish conditions for forest residues. For biomass from other regions (outside of Sweden) the conditions in terms of climate, rotations periods, forestry practices, etc. might be significantly different, so it is important to better understand the difference between different raw material supply chains. The soil carbon impact should be considered in system studies of the entire biofuel production process, as in the present study.

Some studies of bioenergy systems, including environmental impact categories in addition to the GHG emissions, show an increased impact in at least some other categories compared to the conventional motor fuel or chemical production systems. Therefore, it might be interesting to include additional environmental impact categories in future analyses. There might be other impact categories with lower impacts. A broader set of impact categories would yield a better understanding of benefits and drawbacks.

Further analysis of synergies and especially potential cost reductions of integrating GB production at the chemical cluster (or similar sites) should be investigated. The analysis of using the H_2 by-product stream from the chemical cluster for increasing the MeOH yield could also be supplemented with an economic analysis, perhaps comparing to the current use of the H_2 (steam production) or other potential utilisation. The addition of H_2 to the GB systems impacts the capacities for the technical equipment and the amount of separated CO_2, which means that not only the economic performance but also the climate impact analysis could change (Paper III, which included the H_2 addition, did not include CCS). The future existence of the H_2 by-product stream was also uncertain, so future studies might be specifically interesting if it still remains. H_2 could also be produced by power-to-gas concepts, which could be an interesting comparison and would also be possible for the other DRs.

In the case of the chemical cluster, an initial feasibility study of internal integration opportunities had already been performed and was considered. Considering similar aspects for the integration with the refinery could also yield insights into the integration potential on a more practical level.

It would also be interesting for future studies to relate the identified benefits of integration to potential risks and alternative investments at the industries. Quantifying the costs of the integrations that are not directly connected to the technical equipment would yield better knowledge of which integrations show greater potentials for realisation.

Nomenclature

CH_4	Methane
Co	Cobalt
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_{2e}	Carbon dioxide equivalent
Fe	Iron
H_2	Hydrogen
N_2O	Nitrous oxide

Abbreviations

AIC	Annualised investment cost
ASU	Air separation unit
ATR	Autothermal reformer
BIGCC	Biomass integrated gasification combined cycle
BLG	Black liquor gasification
CCS	Carbon capture and storage
CDU	Crude distillation unit
CFB	Circulating fluidised bed
CHP	Combined heat and power
CLR	Chemical looping reforming
CNG	Compressed natural gas
CRF	Capital recovery factor
DME	Dimethyl ether
DH	District heating
DWT	Deadweight tonnage
EF	Entrained flow
FT	Fischer-Tropsch
FPC	Fuel production cost
GB	Gasification-based
GCC	Grand composite curve

GHG	Greenhouse gas
HRSC	Heat recovery steam cycle
IGCC	Integrated gasification combined cycle
LDPE	Low density polyethylene
LHV	Lower heating value
LNG	Liquefied natural gas
LPMeOH	Liquid phase methanol
MC	Moisture content
MEA	Monoethanolamine
MeOH	Methanol
MTBE	Methyl tertiary butyl ether
MTG	Methanol-to-gasoline
MTO	Methanol-to-olefin
NAP	Net annual profit
NGCC	Natural gas combined cycle
O&M	Operation and maintenance
PP	Polypropylene
PE	Polyethylene
SA	Stand-alone
SNG	Synthetic natural gas
VDU	Vacuum distillation unit
WGS	Water gas shift

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Acknowledgements

This thesis has one author, but there are many people involved who have made it possible to do the hard work that was needed. First of all I would like to thank my supervisor Thore, who believed in my capability of pursuing this work and arranged a suitable project together with engaged financers. Thanks for all the interesting discussions of various subjects, both related to and not related to the work of this thesis. Thank you also for the significant support during the final part of the work, which coincided with vacation times!

Special thanks also go to my two co-supervisors Eva and Tomas who have supported me throughout the project. Eva, you have an eye for detail that has been very helpful and I really appreciate that you regularly asked me if things were OK; and if I had all I needed to do the work. I am also very grateful that you were prepared to go all the way to Borneo to present our work at the conference! Tomas, you have been my main connection to IVL and helped me a lot with the administrative part of the project. Thank you also Tomas and Eva for all the discussions of results and methods during the many supervision meetings.

This project has been financed by; the Foundation of Research and Development of Göteborg Energi, E.ON. Gasification Development Ltd, Preem, Perstorp Oxo; the Swedish Energy Agency; the Swedish Environmental Protection Agency and the Research Foundation Formas. The project steering group has met twice a year and these meetings have been crucial for the project, always giving me new energy and enthusiasm to continue the analysis and include new perspectives. These meeting made me realise that there were people out there, with a true interest in the work I was doing! I would like to thank all the industrial representatives that have been part of the group throughout the years: Lars Holmquist, Anders Ådahl, Ingemar Gunnarsson and Erika Antonsson representing Göteborg Energi, Owe Jönsson and Björn Möller representing E.ON, Lars Lind and Oleg Pajalic representing Perstorp and Bertil Karlsson and Stefan Nyström representing Preem. Also John Munthe and Jenny Arnell from IVL have contributed by joining some of these meetings. Jenny has also been very supportive in the administrative part of the project and as a colleague.

I would also like to thank all my colleagues (current and former) at IEST/VoM for all the interesting discussions and good times at seminars, conferences, lunches, fika and other activities that I have shared with you during my time as a PhD student.

I want to specifically thank Stefan, Daniella and Johan who shared data and results and answered all my detailed questions about their work which I used as a starting point. Roman and Maria have also shared results and the discussions with you have given many answers to questions I had. I also enjoyed the detailed and fruitful discussions on system studies and methodological issues with Karin and on various subjects with Matteo. I hope that we might work together again in the future!

Valeria, thank you for being such a great room mate and friend. Our sharing of all the good and bad things in life (and research?) during the five years was at times what saved me from giving up. I wish you the best of luck for the future. Let us stay in touch!

Viktor, I do not know if I won the race or lost it? But thanks for helping me and sharing all the planning of the final deadlines and for booking the printing of the thesis and the room for the public defence. Let me know if there is anything in your final phase that I can help you with!

I would like to thank all my colleagues at IVL for the support, the interest you have shown and for the good work we performed together during the part-time that I have spent at IVL alongside with the PhD-project. I would like to thank Lars Zetterberg, who encouraged me and who contributed to the application that finally resulted in this project. I am also grateful for the support from Anna Jarnehammar, Jenny Gode and Markus Wråke with the sometimes tricky economics of the project. Sus should also be mentioned for being patient with all the special circumstances that needed extra administration. I would also like to thank Mathias Gustavsson who saved me by taking on the PeatImpact challenge at the start of this project, and for being my EndNote expert! To the rest of the co-workers at group 8020 - I look forward to work more with you now!

I am also grateful for the support I have from family and friends, who make my life joyful when not researching!

I would like to thank my mother who has been very supportive during this time; you always did the best that you could. I truly appreciate your support.

Last, but not least, I am so grateful for the love and support from my husband and children. Magnus, without you it would not have been possible. I love you so much! Thank you for taking care of all the practical things when I was busy with my research and for the final proofreading! Anton, you have also been there throughout the entire project and you always made it so easy to forget about the difficult things and refill with new energy. Victoria, I am so happy for your victory and arrival in the midst of the project. I love you both more than everything. Nu kommer mamma inte att behöva åka till jobbet lika ofta!

The show goes on……

Appendix 1: GCCs and split GCCs

A common representation of the thermal integration potential of processes in pinch technology is the Grand composite curve (GCC). The GCC is a graphical representation of all heat streams of a process, illustrating the opportunities for heat exchange as well as the minimum external heating and cooling demand of the process. Figure A1 is an illustrative example of a GCC displaying some of the information that can be withdrawn from the analysis. In the GCC diagram the net heat flow is plotted against shifted interval temperatures. The interval temperatures are shifted to include the temperature difference (driving forces) necessary for heat exchange between streams.

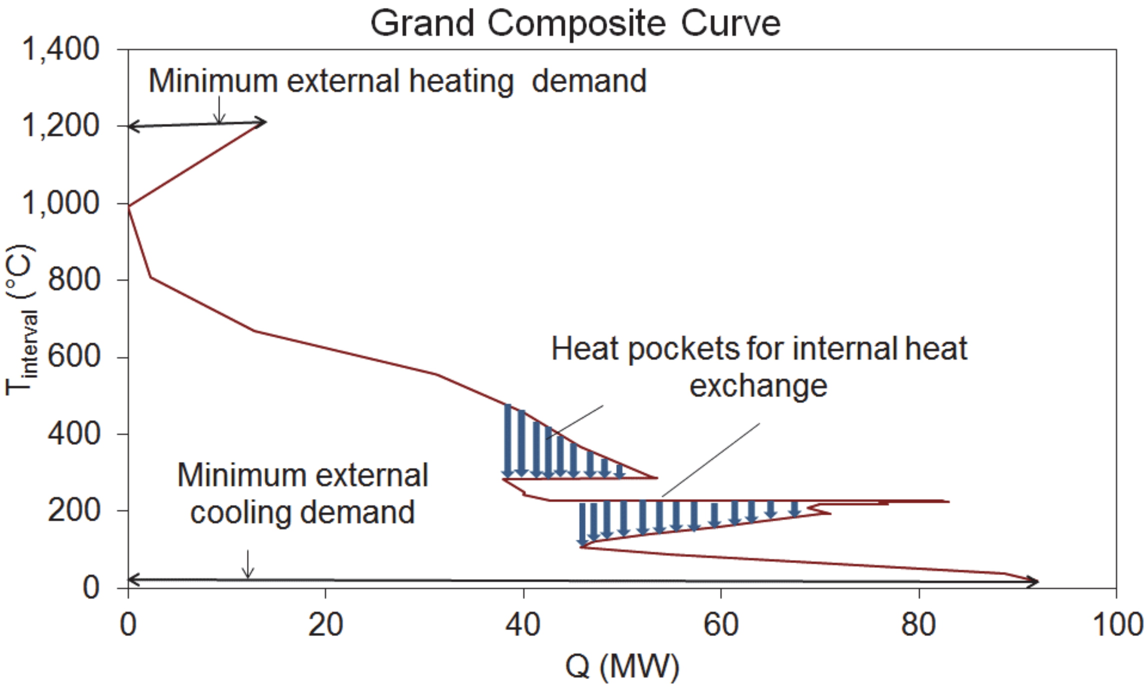

Figure A1. Example GCC with minimum external heating and cooling demand and internal heat integration potential.

Another tool in pinch technology is the background/foreground analysis, also referred to as split GCCs. In a background/foreground analysis, two GCCs are represented in the same diagram to determine the potential for heat integration between the processes or process parts. A split GCC is achieved by mirroring one of the GCCs followed by shifting the two curves along the x-axis until they touch (pinch). The mirrored GCC is referred to as the foreground curve/process and the other curve is referred to as the background. Figure A2 is an example of a background/foreground analysis of a steam power cycle utilising excess heat from the background process.

The background process is represented by the red curve (in Figure A2) and the foreground process, the HRSC, is represented by the blue curve. Heat is transferred from the background process to the foreground process (striped area) and from the foreground process to the background process (dotted area); there is also internal heat exchange (crossed area). For a more fundamental description of the background/foreground analysis, the reader is referred to Berntsson et al. (2013).

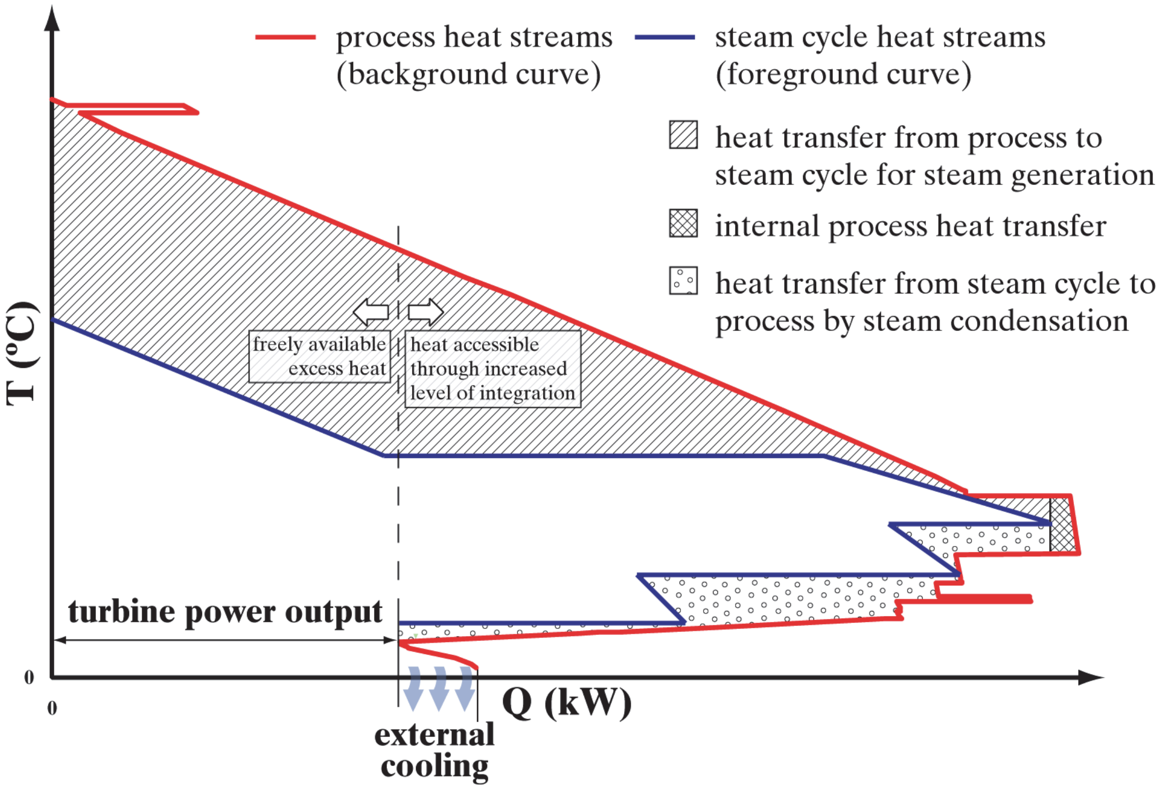

Figure A2 Split GCC representation with a steam power cycle as foreground process. Reprint from Heyne (2013).

Appendix 2: Equipment cost data

The equipment cost data presented here was assessed during the work of Paper V and also used for Paper VI. Additional details of this data can be found in the supplementary report to Paper V (Holmgren, 2015).

Equipment Unit	Base equipment cost current study[a] M€$_{2012}$	Base cost, original unit	Base scale	Scale unit	Scale factor	Scale in present study	BOP (balance of plant) (%)	Indirect cost (%)	Reference
Biomass pretreatment and drying									
Biomass receive and unload	10.0	3.51 M\$$_{2007}$	198.1	wet biomass input, t h^{-1}	0.62	196.7	15.5	32	Black (2013)
Biomass storage, prep. and feed to gasifier of 30 bar	5.9	2.94 M\$$_{1999}$	64.6	biomass feed, wet t h^{-1}	0.77	115.7	Eq. 5[h]	32	Liu et al. (2011)
Biomass storage, prep., feeding to atmospheric gasifier	3.3	2.028 M\$$_{1999}$	64.6	biomass feed, wet t h^{-1}	0.77	100.6	Eq. 5[h]	32	Liu et al. (2011)
Biomass air dryer	11.3[b]	0.72 MSEK$_{2003}$	1.08 *10^6	m^3 h^{-1}	Eq. 6[h]	5.02*10^6	200	110	Heyne and Harvey (2014)
Gasification island, pressurized CFB gasifier									
GTI gasifier, gas cooling and gas cleaning excl. scrubber	150	173 M\$$_{2007}$	483	MW$_{LHV}$ as-received biomass	0.5	485	Included	Included	Liu et al. (2011)
GTI gasifier, gas cooling and gas cleaning incl. scrubber	180	208 M\$$_{2007}$	483	MW$_{LHV}$ as-received biomass	0.5	485	Included	Included	Liu et al. (2011)
Scrubber	5.4	0.42 M€$_{2010}$	200	m^3 h^{-1}	0.6	12,101	15	32	Trippe et al. (2011)

Equipment Unit	Base equipment cost current study[a] M€$_{2012}$	Base cost, original unit	Base scale	Scale unit	Scale factor	Scale in present study	BOP (balance of plant) (%)	Indirect cost (%)	Reference
ASU (including O_2 and N_2 compression)	70.0[b]	82.7 M\$$_{2007}$	2,202	pure O_2 t day^{-1}	0.5	1,024 (For FT and MeOH cases)	15.5	27	Liu et al. (2011)
Gasification island, indirect gasifier									
Indirect gasifier + combustor	260[c]	8 M€$_{2003}$	8	MW$_{th,LHV}$ (at MC in to gasifier)	0.72	476	200	110	Heyne and Harvey, (2014)
Indirect gasifier, slightly pressurized	130.2[c]	9.7 M\$$_{2007}$	500	t day^{-1}	0.6	2,720	Inst. factor 2.31 + land cost	0.6	Dutta et al. (2011)
Indirect gasifier+ combustor	104.4[c]	6.7 M€$_{2007}$	20	MW$_{th}$ input	0.72	476	200	110	Tock et al. (2010)
Tar reformer	19.0	93.7 M\$$_{2007}$	31,000	syngas flow at exit kmol h^{-1}	0.9	6,182 (SNG)	Included	Included	Liu et al. (2011)
Fabric filter	2.0	68.8 k\$$_{2002}$	15.6	m^3 s^{-1}	-	74 (SNG)	240	140	Heyne and Harvey (2014)
Water scrubber	8.4	3 M\$$_{2002}$	12.1	m^3 s^{-1}	0.7	43.0 (SNG)	23	50	Hamelinck et al. (2004)
Guard bed (Zink bed and guard bed)	4.0	2,690 k\$$_{2007}$	2020	MW$_{HHV,SNG}$	0.67	331 (SNG)	Based on estimates by Arvidsson et al. (2014)		Arvidsson et al., (2014)
Water gas shift	2.4[b]	3.36 M\$$_{2007}$	815	MW$_{LHV}$ (dried biomass)	0.67	485 (FT, MeOH)	15	32	Liu et al. (2011)
CO_2 removal									
MEA (in SNG and MeOH cases) (without CO_2 storage)	60.0[b]	5.19 M€$_{2010}$	.5 kg $CO_{2,\ sep.}$ s^{-1} 46.7 vol.- % CO_2; 3.9 Nm^3 $_{raw\ gas}$ s^{-1}			16.8 kg $CO_{2,sep.}$ s^{-1} 46.7 vol.- % CO_2; 18.6 Nm^3 $_{raw\ gas}$ s^{-1}	Based on Heyne and Harvey (2014)		Heyne and Harvey (2014)

Equipment Unit	Base equipment cost current study[a] M€$_{2012}$	Base cost, original unit	Base scale	Scale unit	Scale factor	Scale in present study	BOP (balance of plant) (%)	Indirect cost (%)	Reference
Gas drying (SNG case)	1.3[b]	20 k$\$_{2000}$	1,180	$m^3 h^{-1}$	0.7	34,200	Based on Heyne and Harvey (2014)		Heyne and Harvey (2014)
H_2 membrane (in SNG case)	4.8[b]	500 $\$_{2006}$	420	Cost per unit of mounted skid	1	2010	Based on Heyne and Harvey (2014)		Heyne and Harvey (2014)
Rectisol (in FT case)	19.9	28.8 M$\$_{2007}$	200,000	Syngas feed $Nm^3 h^{-1}$	0.63	139,200 (FT) (MeOH)	Eq. 5[h]	32	Liu et al. (2011)
Rectisol compressor (in FT case)	4.7	6.31 M$\$_{2007}$	10	Compressor power MW_{el}	0.67	8.1 (FT)	Included	32	Liu et al. (2011)
Heat exchangers in Rectisol	8.5	52 M$\$_{2007}$	355	Boiler duty MW_{th}	1	67.3 (FT)	Eq. 5[h]	27	Liu et al. (2011)
CO_2 compression for storage									
CO_2 compression for storage	3.0-4.0 (depending on case)	6.31 M$\$_{2007}$	10	Compressor power MW_{el}	0.67	Different for the different cases	Included	32	Liu et al. (2011)
Syntheses									
Methanation									
Adiabatic methanation reactor	26.4[e]	4381 k€$_{2012}$	175	$MW_{HHV,SNG}$	See note e	331	Based on the estimates by Arvidsson et al. (2014)		Arvidsson et al. (2014)
Catalyst (initial fill)	See the estimate for the reactor[e]	845 k€$_{2012}$	175	$MW_{HHV,SNG}$	See note e	331	Based on the estimate by Arvidsson et al. (2014)		Arvidsson et al. (2014)
FT-synthesis									
FT slurry reactor	28.6	246.31 M$\$_{2011}$	2,420	Amount of produced gasoline and diesel MW	0.75	192	15.50	Included	Goellner et al. (2013)

Equipment Unit	Base equipment cost current study[a] M€$_{2012}$	Base cost, original unit	Base scale	Scale unit	Scale factor	Scale in present study	BOP (balance of plant) (%)	Indirect cost (%)	Reference
Initial fill of FT catalyst	0.5	7.89 $\mathrm{M\$_{2011}}$	2,420	Amount of produced gasoline and diesel, MW	1	192	15.50	Included	Goellner et al. (2013)
FT slurry reactor and heat exchangers	20.6	13.6 $\mathrm{M\$_{2007}}$	71,360	FT input vol. flow rate, $m^3 h^{-1}$	0.75	283,200	Eq. 5[h]	32	Liu et al. (2011)
Syngas compressor	1.6	6.31 $\mathrm{M\$_{2007}}$	10	Compressor power MW_{el}	0.67	70	Included	32	Liu et al. (2011)
LPMeOH synthesis									
MeOH Synthesis LPMeOH	2.3	3.5 $\mathrm{M\$_{2001}}$	87.5	t MeOH h^{-1}	0.72	39.1	Installation factor 2.1		Hamelinck and Faaij (2002)
Recycle compressor	5.4	12.9 M€$_{2002}$	13.2	MW_{el}	0.85	4.3	Installation factor 2.1		Hamelinck et al. (2004)
Syngas compressor (before MeOH synthesis)	11.1	12.9 M€$_{2002}$	13.2	MW_{el}	0.85	10.1	Installation factor 1.86		Hamelinck et al. (2004)
MeOH synthesis LPMeOH	48.9[f]	81.87 $\mathrm{M\$_{2002}}$	10.81	kmol s^{-1} (syngas feed)	0.7	3.96	15	Included	Larson and Tingjin (2003)
MeOH product separation and purification	2.5	1.72 $\mathrm{M\$_{2002}}$	4.66	kg s^{-1} MeOH produced	0.291	10.85	15	Included	Larson and Tingjin (2003)
Final upgrading									
SNG									
Flash tank	0.3[b]	13 k€$_{2010}$	8.85	m^3	0.67	42.14	Same factors as used by Heyne and Harvey (2014)		Heyne and Harvey (2014)
TSA-drying	1.2[b]	74 $\mathrm{k\$_{2004}}$	21	kg adsorbed H_2O h^{-1}	0.67	39.15	Same factors as used by Arvidsson et al. (2014)		Arvidsson et al. (2014)
Drying adsorbent	0.4[b]	47 $\mathrm{k\$_{2004}}$	21	kg adsorbed H_2O h^{-1}	0.67	39.15	Same factors as used by Arvidsson et al. (2014)		Arvidsson et al. (2014)

Equipment Unit	Base equipment cost current study[a] M€$_{2012}$	Base cost, original unit	Base scale	Scale unit	Scale factor	Scale in present study	BOP (balance of plant) (%)	Indirect cost (%)	Reference
Final compression	0.8	6.31 M\$$_{2007}$	10	MW$_{el}$	0.67	0.65	Included	32	Liu et al. (2011)
FT upgrading									
HC[g] recovery plant (distillation)	24.1[b]	74.15 M\$$_{1993}$	3,190	MW diesel and gasoline	0.65	192	Included	Included	Johansson et al. (2014)
Wax hydrocracker	15.1	9.3 M\$$_{2007}$	4.1	t h^{-1}	0.55	6.44	Eq. 5[h]	32	Liu et al. (2011)
Diesel (distillate) hydrotreater	10.1	2.49 M\$$_{2007}$	1.30	t h^{-1}	0.6	9.17	Eq. 5[h]	32	Liu et al. (2011)
Naphtha hydrotreater	1.8	0.75 M\$$_{2007}$	0.93	t h^{-1}	0.65	2.41	Eq. 5[h]	32	Liu et al. (2011)
Naphtha reformer	8.0	5.18 M\$$_{2007}$	1.54	t h^{-1}	0.6	2.15	Eq. 5[h]	32	Liu et al. (2011)
C5/C6 isomerization	1.6	0.96 M\$$_{2007}$	0.54	t h^{-1}	0.62	0.86	Eq. 5[h]	32	Liu et al. (2011)
MeOH upgrading									
MeOH refining	9.9	15.1 M\$$_{2001}$	87.5	t MeOH h^{-1}	0.7	39.05	Installation factor 2.1		Hamelinck and Faaij (2002)
Heat recovery and integration									
Boiler/steam generator/ ductwork/ stack	Depending on case	52 M\$$_{2007}$	355	Boiler duty MW$_{th}$	1	Depending on case	Eq.5[h]	27	Liu et al. (2011)
Steam cycle (steam turbine, condenser, piping, auxiliaries)	Depending on case	66.7 M\$$_{2007}$	275	Gross power prod. MW$_{el}$	1	Depending on case	15.5	Included	Liu et al. (2011)

[a] When not specifically note, this is the base cost without BOP and indirect costs.

[b] This cost includes BOP and indirect costs.

[c] This corresponds to the Total plant cost, including BOP and indirect costs and working capital. Three gasifier trains were used.

[e] This estimate includes both BOP and indirect costs and the initial cost of catalyst

[f] This estimate is assumed to include the syngas compression and recycle compression.

[g] HC is hydro carbon.

[h] Eq. 6 and Eq. 5 refers to the Equation number in Holmgren (2015).