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SYSTEM STUDIES ON BIOFUEL PRODUCTION VIA INTEGRATED BIOMASS GASIFICATION

Report from an f3 project

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THE SWEDISH KNOWLEDGE CENTRE
FOR RENEWABLE TRANSPORTATION FUELS

PREFACE

This report is the result of a cooperation project within the Swedish Knowledge Centre for Renewable Transportation Fuels (f3). The f3 Centre is a nationwide centre, which through cooperation and a systems approach contributes to the development of sustainable fossil-free fuels for transportation. The centre is financed by the Swedish Energy Agency, the Region Västra Götaland and the f3 Partners, including universities, research institutes, and industry (see www.f3centre.se).

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EXECUTIVE SUMMARY

A large number of national and international techno-economic studies on industrially integrated gasifiers for production of biofuels have been published during the recent years. These studies comprise different types of gasifiers (fluidized bed, indirect and entrained flow) integrated in different industries for the production of various types of chemicals and transportation fuels (SNG, FT-products, methanol, DME etc.) The results are often used for techno-economic comparisons between different biorefinery concepts. One relatively common observation is that even if the applied technology and the produced biofuel are the same, the results of the techno-economic studies may differ significantly.

The main objective of this project has been to perform a comprehensive review of publications regarding industrially integrated biomass gasifiers for motor fuel production. The purposes have been to identify and highlight the main reasons why similar studies differ considerably and to prepare a basis for "fair" techno-economic comparisons. Another objective has been to identify possible lack of industrial integration studies that may be of interest to carry out in a second phase of the project.

Around 40 national and international reports and articles have been analysed and reviewed. The majority of the studies concern gasifiers installed in chemical pulp and paper mills where black liquor gasification is the dominating technology. District heating systems are also well represented. Only a few studies have been found with mechanical pulp and paper mills, steel industries and the oil refineries as case basis. Other industries have rarely, or not at all, been considered for industrial integration studies. Surprisingly, no studies regarding integration of biomass gasification neither in saw mills nor in wood pellet production industry have been found.

There are several reasons why the results of the reviewed techno-economic studies vary. Some examples are that different system boundaries have been set and that different technical and economic assumptions have been made, product yields and energy efficiencies may be calculated using different methods etc. For obvious reasons, the studies are not made in the same year, which means that different monetary exchange rates and indices have been applied. It is therefore very difficult, and sometimes even impossible, to compare the technical as well as the economic results from the different studies. When technical evaluations are to be carried out, there is no general method for how to set the system boundaries and no right or wrong way to calculate the system efficiencies as long as the boundaries and methods are transparent and clearly described. This also means that it becomes fruitless to compare efficiencies between different concepts unless the comparison is done on an exactly equal basis.

However, even on an equal basis, a comparison is not a straight forward process. For example, calculated efficiencies may be based on the marginal supply, which then become very dependent on how the industries exploit their resources before the integration. The resulting efficiencies are therefore very site-dependent. Increasing the system boundaries to include all in- and outgoing energy carriers from the main industry, as well as the integrated gasification plant (i.e. total plant mass and energy balance), would inflict the same site-dependency problem. The resulting system efficiency is therefore a measure of the potential improvement that a specific industry could achieve by integrating a biomass gasification concept.

When estimating the overall system efficiency of industrial biorefinery concepts that include multiple types of product flows and energy sources, the authors of this report encourage the use of electrical equivalents as a measure of the overall system efficiency. This should be done in order to take the energy quality of different energy carriers into concern.

In the published economic evaluations, it has been found that there is a large number of studies containing both integration and production cost estimates. However, the number of references for the cost data is rather limited. The majority of these have also been published by the same group of people and use the same or similar background information. The information in these references is based on quotes and estimates, which is good, however none of these are publically available and therefore difficult to value with respect to content and accuracy.

It has further been found that the variance in the operational costs is quite significant. Something that is particularly true for biomass costs, which have a high variance. This may be explained by natural variations in the quality of biomass used, but also to the different markets studied and the dates when the studies were performed. It may be seen from the specific investment costs that there is a significant spread in the data. It may also be seen that the differences in capital employed and process yields will result in quite large variations in the production cost of the synthetic fuels. On a general note, the studies performed are considering future plants and in some cases assumes technology development. It is therefore relevant to question the use of today's prices of utilities and feedstock's. It is believed that it would be more representative to perform some kind of scenario analysis using different parameters resulting in different cost assumptions to better exemplify possible futures.

Due to the surprising lack of reports and articles regarding integration of biomass gasifiers in sawmills, it would be of great interest to carry out such a study. Also larger scale wood pellet production plants could be of interest as a potential gasification based biorefinery.

SAMMANFATTNING

Ett stort antal nationella och internationella teknoekonomiska studier gällande industriellt integrerade biobränsleförgasare för produktion av syntesgasbaserade drivmedel har publicerats under de senaste åren. Studierna omfattar olika typer av förgasare, (fluidiserande bädd, indirekt och suspensionsförgasare) integrerade i olika industrier för produktion av olika typer av kemikalier och bränslen (SNG, FT-produkter, metanol, DME etc.) Resultaten används ofta för teknoekonomiska jämförelser mellan olika bioraffinaderikoncept. Det är dock vanligt att resultaten markant skiljer sig åt, även om teknik och biodrivmedel är desamma.

Huvudsyftet med detta projekt har varit att teknoekonomiskt granska publikationer gällande industriellt integrerade biobränsleförgasare för drivmedelsproduktion. Detta för att identifiera och lyfta fram de främsta anledningarna till att liknande studier skiljer sig åt och att presentera ett underlag för hur "rättvisa" teknoekonomiska jämförelser bör utföras. Ett annat syfte har varit att identifiera eventuell avsaknad av industriella integrationsstudier som kan vara av intresse.

Omkring 40 nationella och internationella rapporter och artiklar har analyserats och granskats. Majoriteten av studierna avser förgasare installerats i kemiska massa-och pappersbruk där svartlutsförgasning är den dominerande tekniken. Fjärrvärmesystem är också väl representerade. Endast ett fåtal studier har hittats gällande förgasning i mekaniska massa- och pappersbruk, stålindustri och oljeraffinaderi. Andra industrier har sällan, eller inte alls, varit föremål för industriella integrationsstudier. Exempel på sådana är överraskande nog sågverk och träpelletsproducenter.

Det finns ett antal anledningar till varför resultaten från de olika teknoekonomiska studier skiljer sig åt. Några vanliga orsaker är att studierna har olika systemgränser och att olika tekniska och ekonomiska antaganden har gjorts. Dessutom kan produktutbyten och energiomvandlingseffektivitet beräknas med olika metoder. Av uppenbara skäl är studierna inte utförda samma år, vilket innebär att olika monetära växelkurser och index har använts. Det är därför mycket svårt, och ibland omöjligt, att jämföra såväl de tekniska som ekonomiska resultaten från de olika studierna.

När tekniska utvärderingar skall genomföras finns det ingen generell metod för hur systemgränser ska dras och inget rätt eller fel sätt att beräkna systemets verkningsgrad så länge gränserna och metoderna är transparenta och tydligt beskrivna. Det innebär också att det blir meningslöst att jämföra exempelvis verkningsgrader mellan olika koncept om jämförelsen görs på inte görs på exakt lika villkor. Men även om villkoren är lika, är en jämförelse inte nödvändigtvis en enkel process. Exempelvis är det relativt vanligt att verkningsgrader och effektiviteter beräknas baserat på marginell bränsletillförsel. I dessa fall blir det viktigt att också ta hänsyn till hur industrin utnyttjade bränsleresurserna innan integrationen, vilket gör resultaten mycket platsberoende. Att utvidga systemgränserna och inkludera samtliga in-och utgående energi och materialströmmar orsakar samma platsberoendeproblem. Den resulterande effektiviteten i ett system är därför istället ett mått på den potentiella förbättring som kan uppnås genom integration av en biobränsleförgasare och syntesprocess.

Vid beräkning av total effektivitet för ett visst produktionssystem som innefattar flera olika typer av materialströmmar och energikällor, föreslås det att elekvivalenter används. Detta för att också ta hänsyn till kvaliteten på de olika energiformerna.

Ett relativt stort antal av de granskade studierna innehåller också ekonomiska utvärderingar. Dock är antalet referenser för kostnader och investeringar mycket begränsad. De flesta av dessa har också publicerats av samma forskargrupper med samma eller liknande bakgrundsinformation. Informationen är dock sällan offentligt tillgänglig och därför svåra att värdera med avseende osäkerheter.

Analyserna visar att driftkostnaderna för olika koncept varierar kraftigt, särskilt antaganden om biobränslekostnaderna. Detta kan dock delvis förklaras av att olika biobränslen med olika kvalitet används samt att studierna genomfördes olika år. Även de specifika investeringskostnaderna varierar betydligt. Många av de studier som analyserats räknar med all rätt med framtida teknik- och ekonomiprestanda för anläggningarna. Det är därför relevant att ifrågasätta varför dagens priser på exempelvis el och bränslen används i samma studier. Det borde vara mer representativt för att utföra någon form av scenarioanalys där framtida kostnader och priser antas.

På grund av den överraskande avsaknaden på rapporter och artiklar gällande integration av biobränsleförgasare i sågverk, det skulle vara av stort intresse för att genomföra en sådan studie. Också storskaliga produktionsanläggningar för träpellets skulle kunna vara föremål för vidare integrationsstudier.

CONTENTS

ABBREVIATIONS

ASU	Air separation unit
BIGCC	Biomass integrated combined cycle
BFB	Bubbling fluidized bed
CEPCI	Chemical Engineering Plant Cost Index
CFB	Circulating fluidized bed
CHP	Combined heat and power
DME	Dimethyl ether
DMFC	Direct methanol fuel cell
EF	Entrained flow
FB	Fluidized bed
FFV	Fuel-flexible vehicles
FT	Fischer-Tropsch
H2	Hydrogen
HHV	Higher heating value
HP	High pressure
LHV	Lower heating value
LP	Low pressure
MeOH	Methanol
MP	Medium pressure
MTBE	Methyl tertiary butyl ether
MTG	Methanol to gasoline
RME	Rapeseed methyl ester
SNG	Synthetic natural gas

1 INTRODUCTION

Several national and international techno-economic investigations have been carried out regarding industrially integrated gasifiers for the production of biofuels (for example CEC, 2007, Ekbom, *et al.*, 2003, Ekbom, *et al.*, 2005a, Larson, *et al.*, 2007). These studies comprise different types of gasifiers (fluidized bed, indirect and entrained flow) integrated in different industries for the production of various types of chemicals and transportation fuels (SNG, FT products, methanol, DME, etc.). The results are often used for techno-economic comparisons between different biorefinery concepts. However, even if the applied technology and the produced biofuel are the same, the results of the studies sometimes differ significantly. For example, recently published production costs for bio-SNG via indirect gasification vary in the range of 5-21 €cents (Rönsch, *et al.*, 2012), (Rasmussen, *et al.*, 2012), (Valleskog, *et al.*, 2008). Furthermore, Sues, 2011 reported efficiencies for methanol production via entrained flow biomass gasification in the range of 45-50%, while Andersson, *et al.*, 2013 reports an efficiency of 56% for the same technology and biofuel. The differences are often due to different system boundaries and different technical and economic assumptions.

One illustrative example is the installation of a biomass boiler to manage the heat and electricity balances of a biofuel production system. The total investment costs of the plant can be reduced if the boiler is under-dimensioned, but then at the expense of increased imports. Another example is if oxygen is purchased from an external source or produced internally via an air separation unit (ASU). The former option significantly reduces the investment cost as well as the power consumption. If external energy supplies (i.e., used to generate the purchased oxygen) are neglected this also has significant impact on overall energy efficiency of the plant (Ekbom, *et al.*, 2012).

Furthermore, product yields and energy efficiencies are often calculated using different methods. For obvious reasons, the studies are not made in the same year, which means that different monetary exchange rates and indices have been applied. It is therefore very difficult, sometimes impossible, to compare the technical as well as the economic results from the different studies.

In order to make meaningful techno-economic comparisons, it is necessary that the different technologies and biofuels are evaluated on the same basis in terms of plant capacity, energy content of the fuel, feedstock costs, method of calculating capital charges, system boundaries, and year in which the analysis is assumed, etc.

1.1 OBJECTIVES

The main objective of this project has been to carry out a comprehensive literature review of system studies regarding industrially integrated biomass gasifiers for motor fuel production. The primary purpose has been to identify and highlight the most important techno-economic differences between the different studies and to prepare a basis for "fair" comparisons. The resulting material and energy balances were therefore collected from the reviewed material, and recalculated to be able to compare the overall system efficiencies on an equal basis. Another purpose has been to identify industries where industrial integration studies are lacking, which may be of interest for future work.

1.2 METHODS AND DEMARCATIONS

Publications (scientific article, reports, etc.) relevant for the literature review were limited to studies that consider all of the following points:

- Biomass (wood, wood residue, black liquor, wood waste) used as feedstock
- Thermochemical conversion technology using entrained flow, fluidized bed or indirect gasifiers
- Motor (bio)fuel production (MeOH, DME, FT, SNG, H_2, MTG)
- Industrially integrated gasification plant

These points were used as the main keywords when performing the literature search. Google Scholar was used as a primary search database, and other unpublished material was provided by Chalmers University of Technology, Linköping University, Lund University and Luleå University of Technology.

Studies concerning plants where the excess heat is assumed to be sold as district heating and where no integration details were given were considered as non-integrated plants and therefore not included in this project. However, studies of biomass gasification integrated with district heating where the heat delivery was adjusted to fit/match the heat demand of the system were considered. Studies with integration of biomass gasifier with existing combined heat and power plant (CHP) were also included.

A general presentation of integrated biomass gasification is given in Chapter **Fel! Hittar inte referenskälla.**. The chapter also contains a description of the different gasification technologies and the different motor fuels, their characteristics and production processes. Chapter **Fel! Hittar inte referenskälla.** describes the main technical differences found during the literature review and summarizes the occurrence of different industries and gasifiers in relation to the type of motor fuel produced. Chapter **Fel! Hittar inte referenskälla.** discusses why it is difficult to compare the system efficiency between different studies. The same concept applies for investment and production costs, which are discussed in Chapter **Fel! Hittar inte referenskälla.**. Information was also collected during the review process to be able to compare the system efficiencies and the specific investment cost for the different industrially integrated biofuel production routes on an equalised basis. The methodology for calculating the system efficiencies and the specific investment cost on an equalised basis are given together with the results in Chapters **Fel! Hittar inte referenskälla.** and **Fel! Hittar inte referenskälla.**, respectively. Conclusions and recommendations for future work are found in Chapters **Fel! Hittar inte referenskälla.** and **Fel! Hittar inte referenskälla.**, respectively.

2 BACKGROUND

2.1 INTEGRATION OF BIOMASS GASIFIERS FOR MOTOR FUEL PRODUCTION IN EXISTING INDUSTRIES

Integrating biofuel production processes in existing industries may result in a number of technical, energy-related and economic benefits. There are a few different options for integrating the production process (Nohlgren, *et al.*, 2010):

- Feedstock integration, to utilize existing internal material streams that can be used for conversion processes (black liquor, glycerol and other industrial by-products)
- Energy integration, to utilize energy flows, for example for fuel drying, pre-heating, heating systems, etc.
- Equipment integration, to utilize existing or new up-scaled equipment such as air separation units, distillation columns, crackers, etc.

Integrating biofuel production processes in existing forest industries provides large feedstock handling and logistical advantages. Gasification of black liquor can be applied in chemical pulp mills, where it can also be possible to replace the bark boiler with a biomass gasifier for syngas production. Another alternative is a combination where both a solid-fuel gasifier and a black liquor gasifier are used to generate a larger volume of synthesis gas and thereby obtaining positive economy-of-scale effects in the downstream processes (gas conditioning and synthesis). Here, it should be emphasised that this combination means a very large increase in biomass demand for a mill, especially for integrated pulp and paper mills where the biomass intake will be more than doubled (Pettersson, *et al.*, 2010). This naturally puts additional requirements on biomass logistics. Biofuel production processes can also be co-located with other process industries with a steam or hot water demand, such as sawmills or biomass-based combined heat and power plants. In those plants, biomass handling and logistical benefits may also be obtained. Oil refineries and steel plants are also interesting from the point of view of integration. The former due to already existing downstream processes (distillation columns, cracking processes, etc.) and the latter due to the possibility to utilize energy-rich excess off-gases from steel making, which can be used for co-synthesis with biomass based syngas (Lundgren, *et al.*, 2012).

Sweden has a large number of industries and district heating networks where different processes for biofuel production could potentially be integrated. Figure 1 shows the geographical spread of a selection of industrial sites and district heating systems that may be of interest for integration of gasification-based biofuels in Sweden.

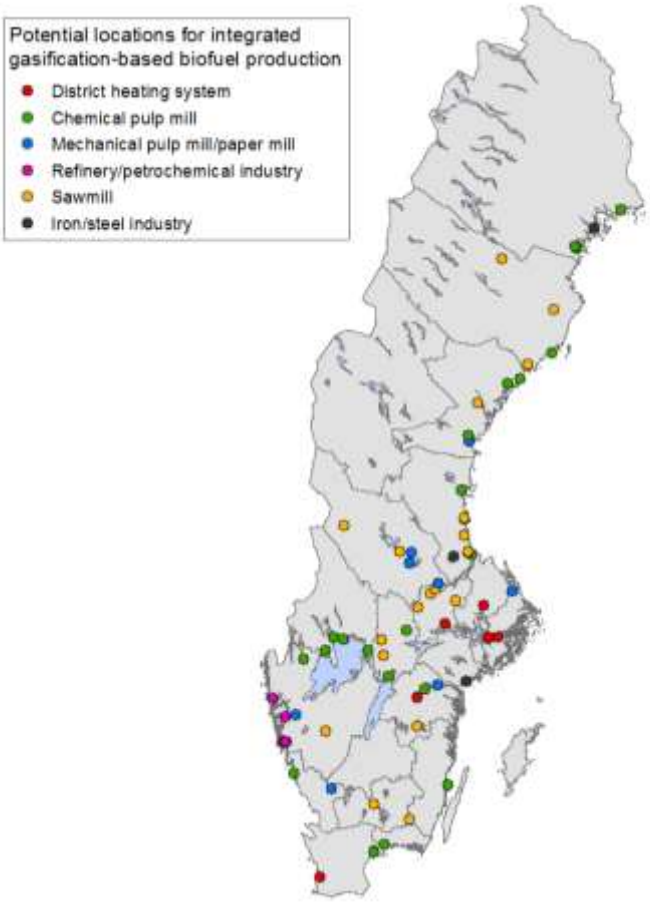

Figure 1. Locations of industrial sites of interest for integration of gasification-based biofuels in Sweden (Wetterlund, et al., 2013)

2.2 GASIFICATION TECHNOLOGIES

The following sections briefly describe the gasification technologies considered in this project.

2.2.1 Pressurized entrained flow gasification

In a pressurized entrained flow gasifier small fuel particles are fed into a heated reactor (often cylindrical) with a gasifying agent (usually pure oxygen) for partial combustion of the fuel. The ratio between the gasifying agent and the fuel (lambda ratio) is controlled to ensure a constant high temperature inside the reactor. The fuel may be a liquid, slurry or solid. In the first two cases, the fuel is atomized to small droplets by a burner nozzle. The latter case requires grinding of the fuel to a fine powder before it enters the reactor. The short residence time in the reactor requires droplets/particles smaller than 0.5 mm, in order to achieve high carbon conversion rates. Depending on the temperature in the reactor, entrained flow gasifiers operate either in a slagging mode (above the ash melting temperature) or in a non-slagging mode (below the ash melting temperature). The high temperatures (1000-1300°C) in the slagging operation mode generate a syngas nearly free from tars and other hydrocarbons. Fuel feeding system and burner designs are critical issues for use of solid biomass.

Black liquor gasification

Black liquor gasifiers using pressurized entrained flow technology generate relatively low reactor temperatures (1000-1100°C). Black liquor contains a large amount of spent cooking chemicals (alkali) from the pulping process. The alkali content has a catalytic effect that lowers the ash melting temperature and enhances the gasification reactions. This allows the gasification process to operate in a slagging mode and produce a tar-free syngas, despite the low reactor temperatures. One challenge with black liquor gasification is to obtain a refractory lining that is not corroded by the high alkali content. Furthermore, the high viscous black liquor is challenging for the atomization process to small droplets. Complete carbon conversion rates are required for black liquor gasification because the smelt (or slag), which is the basis for the green liquor, must be almost free from char particles before it is recycled back to the pulp mill.

2.2.2 Bubbling and circulating fluidized bed gasification

The fluidized beds are divided between bubbling and circulating fluidized beds, depending on the gas velocity. Bubbling fluidized beds (BFB) have a relatively low gas velocity, typically below 1 m/s, while the gas velocities are higher (3 to 10 m/s) in circulating fluidized beds (CFB). The gas stream flows upward through the fixed bed of solid particles creating a pressure drop across the bed from frictional forces. The bed starts to behave similar to a fluid, i.e., the bed is fluidized, when the forces from the gas velocity exceeds the bed weight, suspending the particles in the gas stream. Air, steam and steam/oxygen are examples of different fluidization agents. The high velocity in the CFB will suspend particles in the entire reactor, for which reason particles (bed materials and char) are transferred with the outgoing syngas. The particles are separated from the syngas by a cyclone and returned to the bed. In the BFB, the main part of the fuel conversion occurs in the denser lower part of the reactor and only to a small extent in the sparser upper freeboard. The inert bed material increases and distributes the heat exchange between the char and bed material, creating almost isothermal conditions in the reactor. Quartz sand is the most commonly used bed material. Other bed materials can also be used, preferably with catalytic properties.

Fluidized bed reactors are not very sensitive to variations in the fuel particle sizes, due to the intense mixing and the relatively long residence time in the reactor. The residence time for the particles in the reactors are however not long enough for slow gasification reactions to reach chemical equilibrium at these temperatures. This results in the presence of hydrocarbons (tars, methane) in the syngas. The gasification temperature is mainly limited by ash melting or sticking temperature, usually between 800 and 900°C. Both configurations operate well under pressurized conditions.

Perhaps the biggest potential problem for biomass gasification using fluidized beds regards gasification of biomass fuels with high ash and alkali content. Alkali has a tendency to form compounds with the bed material that (often significantly) lowers the melting and the sticking temperature. Alkali-rich ash facilitates the bed particles to melt and stick together, sometimes to such an extent that large lumps (agglomerates) are formed. Bed agglomeration can degrade the bed's fluidization ability to the point where the bed collapses (or is defluidized). Bed agglomeration can often be avoided by the right selection of operating temperature, fuel and bed material. Different alkali binding additives can also be added to reduce/remove the risk for bed agglomeration.

2.2.3 Indirect/Twin fluidized bed gasification

Indirect fluidized bed gasification technologies use a heated medium to supply the required energy for the endothermic gasification reactions. Systems can be designed with two reactors, one gasifier and one combustion chamber, connected via a bed material transfer system. Heated bed material supplies the required energy to the gasification process, transferred from combustion chamber. Unconverted char particles from the gasification process are in turn burned in the combustion chamber to heat the bed material. Gasification temperatures are normally in the range of 800 to 900°C at atmospheric pressure. The temperature is limited by the risk of bed agglomeration. The operating conditions generate a syngas with low carbon dioxide content, but with high methane and tar levels. Steam can be used as a gasifying agent, when nitrogen-free syngas is required.

A challenge for the indirect technology is primarily related to suitable design for large-scale capacities (i.e., operation under pressurized conditions). Bed materials and operating conditions that minimize the risk of bed agglomeration are also a challenge for the indirect technology. A cost- and energy-efficient combination for primary and secondary tar removal processes also needs to be solved.

2.3 SYNGAS COMPOSITIONS FOR THE GASIFICATION TECHNOLOGIES

The syngas composition varies depending on the gasification technology, as well as on the gasifying agent. Air, pure oxygen and steam are the main gasifying agents. Air is a cheap alternative, but the high nitrogen content dilutes the syngas quality. Pure oxygen will increase the syngas heating value, compared to air, but the production of pure oxygen is an energy- and cost-intensive process. Steam also increases the heating value of the syngas, due to the water-gas shift reaction that increases the hydrogen content of the gas. Table 1 shows the typical syngas composition for a number of selected gasification technologies and gasifying agents. Fuel type and other operating conditions also have an influence on the syngas composition.

Table 1. Syngas composition for various gasification technologies in mole%.

Gasification concept	Entrained flow		BFB	CFB		Indirect	
Gasifier	Chemrec	Carbona	Carbona	CUTEC	Uhde	Repotec	MILENA ECN
Gasifying agent	O_2	O_2 /Steam	O_2 /Steam	O_2 /Steam	O_2 /Steam	Steam	Steam
H_2	39%	37%	20%	32%	30%	38-45%	18%
CO	38%	36%	22%	22%	33%	22-25%	44%
H_2:CO	1.03	1.02	0.91	1.44	0.91	1.6-1.8	0.41
CO_2	19%	19%		34%	31%	20-23%	11%
H_2O	0.2%	7%		Dry volume	Dry volume		25%
CH_4	1.3%	0.06%	5%	8%	5.7%	9-12%	15%
N2	0.2%	0.1%		3%			4%
Hydrocarbons				~2%	<0.1%	~3-4%	~6%
Reference	Ekbom, *et al.*, 2003	NNFCC - The bioenergy consultants, 2009					

The entrained flow gasification technologies generate a syngas that requires low gas cleaning efforts due to the low concentration of short hydrocarbons (C_{2+}) and tars, as shown in Table 1. The other gasification technologies are more flexible in operation conditions, but the syngas composition is therefore varying more for these technologies compared to the entrained flow technology. Generally, the presence of tar and C_{2+} in the syngas requires primary as well as secondary measures to upgrade the gas to be suitable for fuel synthesis.

2.4 BIOFUEL CHARACTERISTICS AND PRODUCTION PROCESSES

In the following sections, a brief description of the main characteristics and production processes of the biofuels considered in this study are presented.

2.4.1 Methanol

Methanol can be used as a fuel in conventional combustion engines as well as in fuel cells (Rostrup, *et al.*, 2011). The fuel has a high octane number but a very low cetane number, making it a good alternative to replace fossil gasoline. Large-scale field demonstration using fossil-based methanol as a motor fuel has been carried out in USA and Europe in the early 1990s where M15 (15 vol.%), M85 and M100 were tested successfully (Ekbom, *et al.*, 2012). Due to reformulation of petrol and falling crude oil prices, the use of fossil-based methanol was not continued. Methanol is a liquid that can easily be reformed to produce hydrogen and methanol is considered by several car manufacturers to be an excellent hydrogen carrier for future fuel cell vehicles. Due to the simplicity of the methanol molecule and in particular its single carbon atom, methanol can also be used directly in a Direct Methanol Fuel Cell (DMFC) without requiring prior reformation. Methanol, when used directly in combustion engines, requires minor modifications to the fuel injection system. Also, some material components (plastic, rubber, aluminium, zinc and magnesium) have to be replaced due to the risk of corrosion.

Emissions of carbon monoxide, nitrogen oxides and hydrocarbons are lower during combustion of methanol compared to gasoline. Methanol contains low levels of sulphur and metals. The energy content (LHV) is however less than half the energy value of gasoline (15.8 MJ per litre or 19.8 MJ per kg). The high octane rating means that it can increase the compression in the engine and thus improve energy efficiency and partially compensate for the lower energy content. Methanol is toxic and fatal if swallowed and should be marked to the colour and odour (Ekbom, *et al.*, 2012).

Low level blending of methanol into present petrol is preferable as it opens up an immediate route to the entire fuel pool. Higher levels of methanol require changes in current fuel standard specifications. Properly formulated blends with alcohols in petrol have been and are today in safe use. Alcohols are not miscible with diesel fuel and would require emulsions, which is not preferable. It can be concluded that the "best" use of methanol on a short-term horizon is as a low blending component or for use in fuel-flexible vehicles. As no new methanol-compatible flexible-fuel vehicles (FFV) are available at the moment, the use of methanol for low blending is the most likely option for the near future (Lundgren, *et al.*, 2012).

Methanol can also be used for production of dimethyl ether (DME) (see Section **Fel! Hittar inte referenskälla.**) or biodiesel. Gasoline can be prepared via a so-called MTG process or in an integrated methanol / DME / petrol loop via exceeded process (Rostrup, *et al.*, 2011). Biomass-based methanol can also replace fossil-based methanol in the production of rapeseed methyl ester (RME) or methyl tertiary butyl ether (MTBE).

Production process

Currently, the majority of the syngas-based methanol is produced via steam reforming or partial oxidation of natural gas or naphtha. Production via coal or biomass gasification is possible but less applied. The syngas is fed into a reactor vessel in the presence of a catalyst producing methanol and water vapour. The crude methanol is fed to a distillation plant consisting of a unit that removes the volatiles and a unit that removes the water and higher alcohols. The unreacted syngas is recirculated back to the methanol converter (Spath, *et al.*, 2003).

2.4.2 DME

Dimethyl ether (DME) is a methanol derivative (CH_3OCH_3) and at normal atmospheric conditions, a colourless gas with physical properties similar to propane. DME is in liquid state at a pressure of about 5 bar and normal temperature. Bio-DME has a high cetane number (55-60) and a low octane number (35/13 RON / MON) and is therefore interesting as a substitute for fossil diesel. Bio-DME can be used in conventional diesel engines with compression ignition, but requires a new fuel injection system. Bio-DME cannot be blended with conventional diesel. Today there are four tank stations for bio-DME in Sweden (Piteå, Stockholm, Jönköping and Gothenburg).

Bio-DME contains no sulphur or metals and under normal circumstances is a harmless gas from a health and environmental perspective. DME is today commonly used as a propellant in spray cans. Bio-DME is not corrosive, but has a negative impact on rubber hoses and gaskets in engines. Combustion of DME results in significantly lower emissions of sulphur, nitrogen oxides and soot compared to conventional fossil diesel.

When bio-DME is used as a fuel in heavy-duty vehicles, the fuel is in liquid phase from the tank to the combustion chamber. The energy content in bio-DME (LHV) is 19.3 MJ per litre (28.8 MJ per kg). The fuel has poor lubricating properties and requires special additives to prevent engine wear.

Production Process

DME is currently mainly produced from coal or natural gas-based syngas. The synthesis gas is primarily converted to methanol over a catalyst, usually copper. DME is then produced by the dehydrogenation of the methanol in the presence of another catalyst (e.g. silica-alumina). DME can also be produced via direct synthesis, using bifunctional catalysts that allow both methanol synthesis and dehydration in the same process unit.

2.4.3 Synthetic Diesel (Fischer-Tropsch diesel)

FT fuels are synthetic hydrocarbon (gasoline, diesel, naphtha and kerosene). Typically, the diesel is the most interesting product fraction. Synthetic diesel or Fischer-Tropsch diesel (FTD) is a colourless, non-toxic liquid which is more or less free from sulphur and aromatics. The energy content of FTD is approximately 43-44 MJ per kg and has a slightly lower density than conventional diesel. FTD is easy to deploy as it can largely be mixed into regular diesel in accordance with the new diesel fuel standards. It can also be distributed in both pure and in mixed form in existing systems for diesel. FTD has a high cetane number (typically above 70) which enables very efficient combustion and very low exhaust emission levels in diesel engines.

Production Process

Production of biomass-based FT fuels mainly consists of three different steps after gasification (or the reforming). These steps are gas conditioning, catalytic FT synthesis and upgrading (e.g. hydrocracking and distillation). Depending on type and amount of FT product to be produced, synthesis at lower temperature (200-240°C) or at higher temperature (300-350°C) over either an iron or cobalt catalyst is applied. If the gasoline fraction is to be maximized, iron catalysts at high temperature in the fluidized bed reactor should be applied. If the diesel fraction is to be maximized, slurry reactors with cobalt catalyst are the best choice. FT reactors are pressurized to 10-40 bar (Spath, *et al.*, 2003).

FTD consists of a mixture of various hydrocarbons, principally carbon chains from 12 to 20 carbon atoms (C_{12}-C_{20}), such as olefins, paraffins, and products containing oxygen (alcohols, aldehydes, acids and ketones). The product distribution is mainly influenced by the temperature, gas composition (H_2/CO-ratio), pressure and the catalyst type.

2.4.4 Synthetic Natural Gas (SNG)

Bio-SNG can be distributed in gas grids and used in similar ways as natural gas and upgraded biogas. Infrastructure for gas transport in larger grids are mainly located in the western part of Sweden as well as in a number of small networks (a few kilometres in total length) in the remaining parts of the country (Ekbom, *et al.*, 2012). The requirement for supplying bio-SNG to the gas grid is that the gas quality meets Swedish standards for biogas (SS 15 54 38). If the gas is to be distributed over long distances, trucks with bottle packages of compressed gas can be used. It is also possible to cool the gas and transport it in liquid form (Liquid Natural Gas, LNG). This is common when transporting natural gas from distant sources, and then usually with sea transport.

Bio-SNG can be used both in spark ignition engines (gasoline engines) and in modified compression ignition engines (diesel engines). Diesel engines require glow plugs to initiate the ignition. Bio-SNG is a very good fuel from the environmental point of view with very low exhaust emissions. However, since methane is a very potent greenhouse gas it is important to ensure as complete combustion as possible.

Production Process

Product gas from biomass gasification can be refined into bio-SNG through gas cleaning and methanation followed by removal of carbon dioxide and water. The product gas may contain contaminants such as particles, tars, alkali, ammonia and hydrogen sulphide, which must be removed before the methanation. The purified gas passes the methanation process in which CO and H_2 are converted to CH_4 and CO_2. The gas is then conditioned to a quality suitable for transport fuel or for being supplied into the gas grid. Syngas-based methane production has been demonstrated in a number of plants on a large scale (over 1000 MW), but then based on coal gasification (Fredriksson Möller, *et al.*, 2013).

2.4.5 Hydrogen

The interest in hydrogen as a transportation fuel has increased considerably since the late 1990s in both USA and EU. Hydrogen is gaseous under normal temperature and pressure. If hydrogen is to be used as a motor fuel, it is compressed to 350 or 700 bar, leading to losses in the range of 5-10% of the energy content of the hydrogen (Vätgas Sverige, 2013).

Fuel cells can convert chemical energy into electricity and have the potential to achieve a higher efficiency than internal combustion engines. Hydrogen can theoretically be used in combustion engines as a temporary solution while waiting for fuel cells to be commercialized. The optimal fuel to a fuel cell is thus hydrogen, as other fuels must be converted (reformed) to hydrogen gas. The reforming reduces the energy efficiency and is associated with various technical problems.

Production Process

Today, hydrogen is produced mainly by steam reforming of natural gas (Steam Methane Reforming, SMR), but also from naphtha, coal and coke oven gas. Hydrogen can also be produced from ethanol, methanol and ammonia. Alternatively, hydrogen can be separated from synthesis gas with a membrane or PSA technology. Electrolysis of water can be used where the electricity is cheap. Reforming of methanol is practiced in Japan and to a lesser extent in Europe (Spath, *et al.*, 2003).

In Sweden, biomass gasification and steam reforming of natural gas or biogas are the most probable technologies for hydrogen production. In the future, hydrogen production via electrolysis based on electricity from wind power may be possible. Hydrogen production from blue-green algae or by artificial photosynthesis is still at the experimental stage and is not expected to have any major breakthrough before the year 2030 (Rydberg, *et al.*, 2011).

3 TECHNICAL FINDINGS

This chapter presents the literature review that has been conducted. As mentioned in the introduction, the selection of publications for the review was limited to studies that consider certain biomass feedstocks (wood, wood residues, black liquor, wood waste) using thermochemical conversion (entrained flow, fluidized bed or indirect gasifiers) to produce motor (bio)fuels, with industrial integration of the gasification plant. In this chapter the key technical properties identified in the reviewed publications are summarized and discussed, i.e., types of gasifiers, gasifier capacities, types of industries, and types of produced biofuels.

In total, 42 reports and articles regarding industrially integrated biomass gasifiers for motor fuel production have been reviewed and analysed. A list of all reviewed publications can be found in Table 2. Articles and reports that are connected and cover the same project are listed together in Table 2, making it 34 unique projects. The earliest reviewed report or article was published in the year 2000 (Brandberg, *et al.*, 2000) and the latest reviewed publications are submitted or accepted for publication during 2013 (for example Andersson, *et al.*, 2013, Lundgren, *et al.*, 2013). EF refers to (pressurized) entrained flow gasifiers; FB refers to fluidized bed gasification technology, either operating in a pressurized or an atmospheric environment, while indirect gasifiers (or twin bed) are denoted as Indirect.

Table 2. List of the reviewed publications.

Reference	Gasification technology	Product motor fuel(s)	Integration with:
Andersson, 2007	EF and FB	H_2	Chemical pulp & paper mill and CHP/district heating
Andersson, *et al.*, 2006a	EF	H_2	Chemical pulp & paper mill
Andersson, *et al.*, 2013	EF	MeOH	Chemical pulp & paper mill
Boding, *et al.*, 2003	FB	DME	District heating system
Börjesson, *et al.*, 2010	FB	SNG	District heating system
Brandberg, *et al.*, 2000	FB	MeOH	District heating system
Brau, *et al.*, 2012	Indirect	H_2	Oil refinery
Consonni, *et al.*, 2009, Larson, *et al.*, 2007	EF and FB	DME, FT crude	Chemical pulp & paper mill
Difs, *et al.*, 2010, Wetterlund, *et al.*, 2010c	FB	SNG	District heating system
Ekbom, *et al.*, 2003	EF	MeOH	Chemical pulp & paper mill
Ekbom, *et al.*, 2005a	EF	FTD and naphtha	Chemical pulp & paper mill
CEC, 2007, Ekbom, *et al.*, 2005b, Fahlén, *et al.*, 2009	FB	SNG	District heating system
Fornell, 2012	EF	DME	Chemical pulp & paper mill
Gustavsson, *et al.*, 2011, Truong, *et al.*, 2013	Not specified	DME	District heating system
Hansson, *et al.*, 2010, Tunå, *et al.*, 2012	FB	MeOH	Chemical pulp & paper mill
Heyne, *et al.*, 2013a	Indirect	SNG	CHP
Heyne, *et al.*, 2013b	Indirect	SNG	District heating system
Ince, *et al.*, 2011	Indirect	FT	Chemical pulp & paper mill
Isaksson, *et al.*, 2012	FB	MeOH, FT crude	Mechanical pulp & paper mill
Joelsson, *et al.*, 2008	EF	DME	Chemical pulp & paper mill
Joelsson, *et al.*, 2012	EF and FB	DME	Chemical pulp & paper mill
Johansson, *et al.*, 2012	EF and FB	H_2	Oil refinery
Johansson, *et al.*, 2013	FB	FTD, FTG	Oil refinery
Lundgren, *et al.*, 2013	FB	MeOH	Steel plant and CHP
McKeough, *et al.*, 2007, McKeough, *et al.*, 2008	FB	MeOH	Chemical pulp & paper mill
Naqvi, *et al.*, 2010	EF	DME	Chemical pulp & paper mill
Naqvi, *et al.*, 2012	FB	MeOH	Chemical pulp & paper mill
Pettersson, *et al.*, 2009, Pettersson, 2011	EF	DME	Chemical pulp & paper mill
Pettersson, *et al.*, 2010	EF	DME, MeOH, FT/Naphtha	Chemical pulp & paper mill
Pettersson, *et al.*, 2012	EF and FB	DME	Chemical pulp & paper mill
Rodin, *et al.*, 2010	FB	Burner gas and methane	Chemical pulp & paper mill
Saviharju, *et al.*, 2007	FB	FT Crude	Chemical pulp & paper mill
Wetterlund, *et al.*, 2010a	FB	DME	Chemical pulp & paper mill
Wetterlund, *et al.*, 2011	FB	DME	Chemical pulp & paper mill

It should be mentioned that the majority of the reviewed reports and articles originate from Sweden and are based on studies of Swedish industries. Most international studies that have been surveyed concern stand-alone biomass gasification for motor fuel production rather than integrated biomass

gasifiers. This may imply that there is a current lack of interest in industrially integrated biomass gasifiers in international industry.

Figure 2 shows the number of times a type of industry occurs in the reviewed material (i.e. in the 34 unique projects). Andersson, 2007 and Lundgren, *et al.*, 2013 include different types of industries, and each type of industry is accounted for once. The industries are also divided into specific or unspecific. The former relates to an existing industrial site, while the latter means a hypothetical non-existing industry.

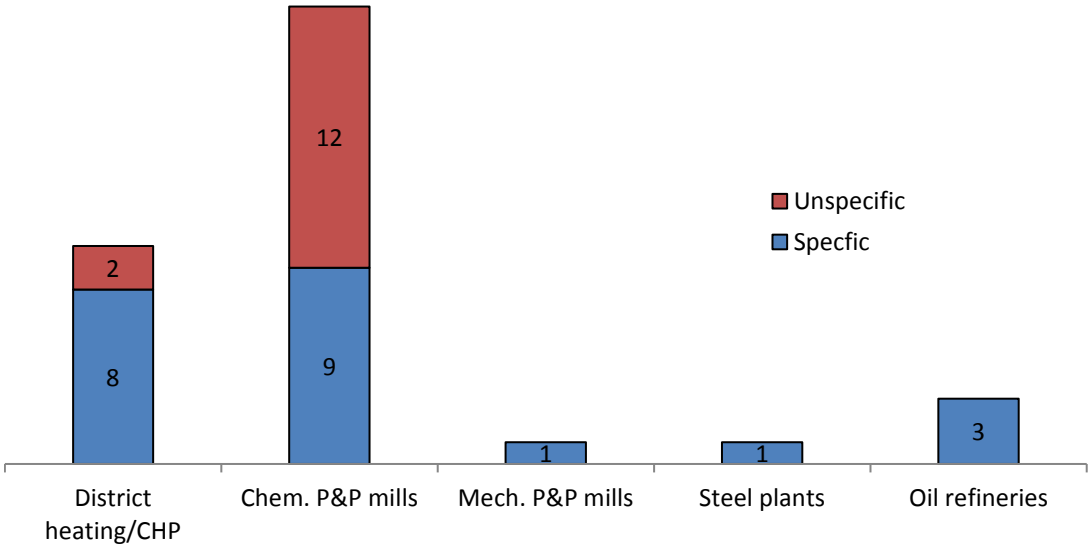

Figure 2. Type of industry for integration (number of studies where the industry type occurs).

As Figure 2 illustrates, chemical pulp and paper industry was found to be the most frequently occurring type of industry where integration of gasifiers has been studied. District heating system and CHP were also well represented, although these systems were only considered depending on the integration level. Integration in mechanical pulp and paper mills, steel plants and oil refineries only occurred in very few studies and, surprisingly, no studies that consider integration with forest-based industries like sawmills or pellet industries were found. The latter is quite remarkable since they, as previously mentioned in Chapter 2.1, may serve as heat sinks during large parts of the year at the same time as they provide large biomass handling and logistical benefits.

One explanation for the high representation of the chemical pulp and paper industry in the reviewed material is probably the attractive process integration options in pulp and paper mills (see Section **Fel! Hittar inte referenskälla.**), where the presence of black liquor is the main reason. Other plausible causes are increasing energy prices and stronger competition for raw materials, forcing the pulp and paper industry to search for alternatives to add extra revenues to their existing production[1] (Klugman, *et al.*, 2007). It should also be mentioned that many of the reviewed studies

[1] It would seem like this should cause other large biomass importing industries (e.g. sawmills and pellet industries) to also search for new alternatives to increase their revenues. These industries perhaps have selected other measures or alternatives to face the increasing competition of raw material and increasing energy prices, than the gasification route.

conclude that integrating a biomass gasifier for motor fuel production in a pulp and paper mill would indeed constitute an attractive investment opportunity (for example Ekbom, *et al.*, 2003, Ekbom, *et al.*, 2005a, Larson, *et al.*, 2007, Pettersson, *et al.*, 2012).

Table 3-**Fel! Hittar inte referenskälla.** present a breakdown between the different case studies presented in all publications dependent on gasification technology, industry of integration and produced motor fuel. The number of cases using a specific gasification technology in Table 3 and**Fel! Hittar inte referenskälla.** exceed the total number of cases in Table 4. This is due to that some of the studies consider parallel operation of different gasification technologies. Each publication usually contains more than one case and for this reason the number of cases in Table 3-**Fel! Hittar inte referenskälla.** exceeds the number of publications.

Table 3. Gasifier types integrated in the different industries. Number of case studies reviewed.

Gasification technology /Industry of integration	Chemical pulp and paper mill	Mechanical pulp and paper mill	Steel plant	District heating or CHP	Oil refinery
Entrained flow (EF)	58	-	-	-	7
Fluidized bed (FB)	43	4	3	19	9
Indirect gasifiers	7	-	-	10	8

Fluidized bed gasifiers integrated in either a pulp and paper mill or a district heating system are, as seen in Table 3, well represented in the reviewed material. Cases with integration of FB gasifiers in steel and oil industries have also been found. Entrained flow gasifiers integrated in pulp and paper mills are also well represented, mainly due to a large number of black liquor gasification publications.

The reviewed material involves integrated gasifiers of a wide capacity range. Figure 3 shows the thermal capacity range and average thermal capacity for different gasification technologies found in the reviewed material.

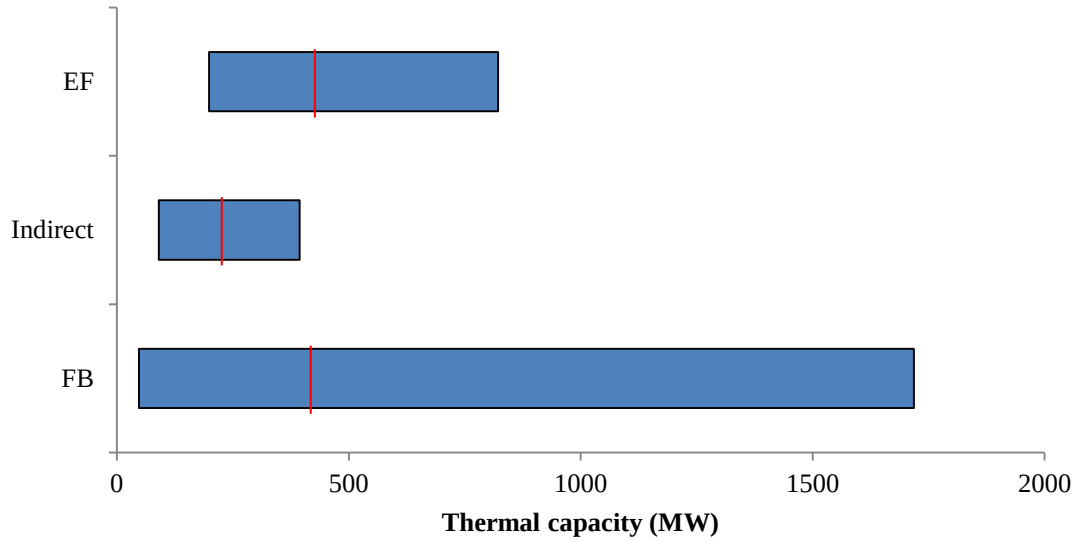

Figure 3. Thermal capacity range for the different gasification technologies. The average gasification capacity is marked by a red line.

EF gasifiers usually have higher gasification capacities than FB and indirect technologies. However, as seen in Figure 2, FB gasifiers constitute the largest capacities in the reviewed material. Isaksson, *et al.*, 2012 studied integration of CFB gasifiers in a mechanical pulp and paper mill that covered a wide thermal capacity range, 170-635 MW_{th}. The absolutely largest thermal capacities were found in Pettersson, *et al.*, 2012where CFB gasifiers up to 1750 MW were considered. The overall lowest gasification capacity was also found for the FB technology, in Rodin, *et al.*, 2010, where integration of a 48 MW FB gasifier in a pulp and paper mill was studied. Integration of FB gasifiers has on average been studied for gasification capacities around 400 MW_{th}.

The compiled average thermal capacity is slightly larger for EF gasifiers (410 MW_{th}) than for FB gasifiers, mainly due to several studies with black liquor EF gasifiers with capacities just below 500 MW_{th} (for example Ekbom, *et al.*, 2003, Ekbom, *et al.*, 2005a, Pettersson, *et al.*, 2012). The largest considered EF gasification capacity (822 MW_{th}) was found in Andersson, *et al.*, 2013.

Brau, *et al.*, 2012 studied integration of the largest indirect gasifier (395[(2)] MW_{th}) in an oil refinery. The indirect gasifiers have the lowest average gasification capacity in the considered studies (195 MW_{th}).

Andersson, *et al.*, 2013 and Pettersson, *et al.*, 2012 are two examples of studies where really large gasification capacities were found to be required in certain scenarios. It should be noted that these figures refer to the total installed capacity and not the capacity of an individual gasification unit. The technical feasibility of gasification capacities has generally not been discussed in the reviewed publications.

Fluidized bed gasifiers are less sensitive to variations in particle sizes than the entrained flow technology and are today well established for heat and power applications. This may be one reason why primarily fluidized bed gasifiers have been found in the publications related to integration with district heating systems/CHP. The entrained flow technology requires a pressurized environment, pure oxygen as gasifying agent and small biomass particle sizes or a liquid/slurry fuel to maintain a stable operation. Solid biomass fuels used in EF therefore require extensive pre-treatment and advanced fuel feeding systems. The higher complexity of EF gasification systems requires larger capacities (>200-250 MW_{th}) to reach positive economies of scale effects. Most of the district heating system studies concern gasifiers with a capacity of 250 MW_{th} or less. This can also explain why EF gasifiers have not been found in the literature related to district heating systems/CHP. Correspondingly, cases integrated in the pulp and paper industry with gasifier capacities lower than 250 MW_{th} almost exclusively consider (only) replacing the bark boiler with a fluidized bed gasifier.

A reasonable number of cases with gasifier integrated in the oil refineries industry have been found, but as seen in Figure 2, these originate from only three publications. Oil refineries, mechanical pulp and paper mills and steel plants have also been found in too few studies to be able to conclude any trends or preferences regarding gasification technologies and capacities.

Methanol or DME are the two most common fuel products (Table 4 and

[2] The thermal capacity has here been converted from higher heating value (HHV) to lower heating value (LHV).

Table 5), in particular in combination with fluidized bed technology and entrained flow gasification. Using entrained flow technology for SNG or methane production is less suitable, due to the low methane content in the raw syngas (<1.5 mole%). Fluidized bed and indirect gasifiers can produce a syngas with methane content in the range of 5-10 mole% and 10-15 mole%, respectively (see Table 1). Hence, a large part of the final fuel product already exists in the raw syngas. Fischer-Tropsch products are also quite well represented in the reviewed material, especially when the motor fuel production route is integrated in the pulp and paper industry.

A biomass gasification process for SNG production generates excess heat in the order of up to 25% of the thermal biomass input and for FT plants the excess heat is even higher (up to 33% of the thermal biomass input). These motor fuel production routes are therefore favourable for integration with district heating systems, although part of the recovered heat will be used internally for drying and preheating processes. In oil refineries there are clear advantages to producing FT crude and H_2. The former is due to existing downstream processes (distillation columns, cracking processes, etc.) while the latter is a required product for hydrocracking and sulphur removal processes. The integration approach for a biomass gasification plant in pulp and paper mills is almost exclusively to replace a boiler (or two). A variety of products can therefore be produced from the gasification plant, if the heat demand of the mill is maintained.

Table 4. Number of cases found regarding biofuel production in the different industries and with the different technologies.

Industry of integration	Produced motor fuel				
	SNG/CH_4	MeOH	DME	FT	H_2
Chemical pulp and paper mill	1	23	46	16	2
Mechanical pulp and paper mill	-	2	-	2	-
Steel plant	-	3	-	-	-
District heating/CHP	20	6	5	-	-
Oil refinery	-	-	-	2	15

Table 5. Number of cases found regarding biofuel production using the different gasification technologies.

Gasification technology	Produced motor fuel				
	SNG/CH_4	MeOH	DME	FT	H_2
Entrained flow	-	17	30	8	9
Fluidized bed	11	14	33	11	8
Indirect	10	2	2	3	8

3.1 SUMMARY

Based on the number of published studies, chemical pulp and paper mills and district heating systems/CHP are the main industrial sites of interest for integrating gasification plants for biofuel

production. Methanol and DME are the two most common fuel products, in particular in combination with fluidized bed and entrained flow gasification technologies.

Oil refineries, mechanical pulp and paper mill and steel plants are present in the reviewed material, but the number of publications is very small. The sawmill industry and the wood pellet production industry are examples of industries that are surprisingly not found in the reviewed material, but that should be of great interest for integration of biomass gasifiers.

4 ENERGY EFFICIENCY CALCULATIONS

As previously mentioned, integration of biomass gasification plants in different industries offers better possibilities to make use of by-products like heat, steam and electricity compared to stand-alone units. It can, however, be difficult to compare the results of these studies systematically, since they often have different system boundaries, production capacities etc., and since for example efficiencies are often calculated using different methodologies and standards. This makes comparisons of system efficiencies between different integrated biorefinery concepts and studies difficult (or unfair), even for studies that are very similar to each other (i.e., same industry of integration, gasification technology, motor fuel, etc.).

This chapter discusses the problems regarding systematic comparisons of system efficiency measures for different industrial integrated biomass gasification plants, as well as why the system efficiency measures often differ to such an extent. Furthermore, the system efficiency is recalculated based on compiled mass and energy balances from the reviewed material, to make a comparison on an equalised basis.

4.1 SYSTEM EFFICIENCY ISSUES

This section covers aspects that can have a significant impact on the system efficiency of a specific biofuel production system.

Four main methods for calculating the system efficiency are frequently used: (i) using mixed sources of energy carriers by the first law of thermodynamic; (ii) describing the mass and energy flow in terms of exergy; (iii) by the use of electricity equivalents; or (iv) by converting the mass and energy flow to its biomass equivalents (except the main product). In addition, different defined system boundaries are used together with the different calculation methods. The choice of system boundaries and calculating methods affects the calculated system efficiency, as will be illustrated in the next section.

While issues related to choice of methodology and system boundaries apply also to stand-alone biofuel production, one problem specifically related to industrially integrated biofuel production concepts, is how changes to the original operation of the industry are accounted for. As an example, prior to the potential integration, the industry produces power, but not enough to cover the industry's entire power demand. After the integration the power production is reduced. The reduced power production can be accounted for by two different approaches:

1. Reduced outgoing power, accounted for on the numerator side.
2. Increased power demand, accounted for on the denominator side.

Efficiency calculation uses fractions (outgoing energy products divided by incoming energy products) and the possibility to use different approaches will cause discrepancies.

Further, the feedstock type (wood residue, black liquor, stem wood, etc.) and quality (particle size, moisture, ash content, etc.) considered in a study have both direct and indirect impacts on the resulting system efficiency. Directly by, having different pre-treatment requirements, technology-wise as well as energy-wise, and indirectly, by having an impact on the gasification feedstock conversion efficiency and the gas cleaning requirements.

Another cause of differences in system efficiencies is variations in feedstock conversion efficiencies, as the feedstock-to-biofuel conversion efficiency can often vary ± 10%. Figure 4 shows the variation in the feedstock conversion efficiencies for different motor fuels compiled from the reviewed material. This efficiency is defined as the ratio between the energy content in the produced motor fuel and the thermal energy input of biomass to the gasifier, both based on their lower heating value (LHV).

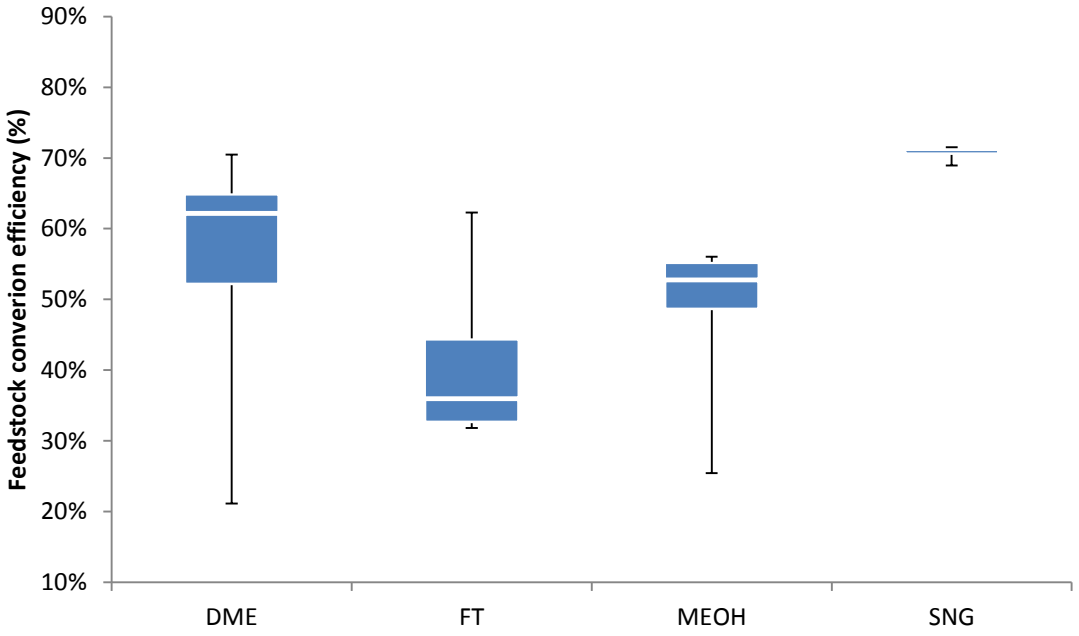

Figure 4. Occurrences of feedstock conversion efficiencies found in the reviewed material3. The blue box represent the upper and lower quartile, the median value is represented by the white line.

As the figure shows, SNG production generally reaches the highest feedstock conversion efficiencies, typically in the range of 64-72%. DME production shows an average efficiency in the range of 56-65% of the supplied biomass, values that are slightly higher than for methanol production (50-60%). Due to the low conversion rate per pass over the fuel catalyst, recycling of the unreacted syngas is required to reach the abovementioned conversion efficiencies for DME and methanol. Some of the cases are configured without syngas recycling (i.e., once-through concepts) as the unreacted syngas is instead used for heat and power production. DME and methanol can therefore have feedstock conversion efficiencies below 30%. FT fuels and hydrogen (not included in Figure 4) generally show lower feedstock conversion efficiencies. FT synthesis often results in two or more products and if only the conversion to synthetic diesel is taken into account, the net efficiency typically ranges from 32 to 44%. Regarding hydrogen, a black liquor to hydrogen efficiency of 54% was reported in (Andersson, *et al.*, 2006a, Andersson, *et al.*, 2007), although Brau, *et al.*, 2012 report conversion efficiencies up to 61%[(4)] for hydrogen production via biomass gasification.

[3] Too few individual cases for hydrogen were found to make a cumulative graph.

[4] Calculated from: 0.1 ton of H_2 production per ton of dry biomass. LHV for dry biomass was assumed to be 19.6 MJ/kg.

4.2 SYSTEM EFFICIENCY CALCULATION ON AN EQUALISED BASIS

In order to address the issues discussed above and to be able to make relevant and fairer comparisons, material and energy balances for all of the cases in the reviewed material were compiled, to re-evaluate the system efficiencies on an equalised basis. The balances were collected on an incremental basis compared to the operation of the industry prior to the integration, i.e., required marginal supply of biomass and other energy carriers needed to produce a motor fuel. The system efficiencies for all cases were calculated based on the marginal energy supply using both mixed sources of energy carriers in MW_{out}/MW_{in} (Eq 1) and electrical equivalents (Eq 2), by the first law of thermodynamics. All energy carriers (motor fuel, biomass, etc) were converted to their electricity equivalents according to the efficiency (η) of the best-available technologies known to the authors according to

Table **6**. Only using mixed sources of energy carriers in efficiency calculations contributes to a tendency to overestimate the "quality" of certain energy carriers, especially when the level of exergy in the different flows (biomass, bark, hot water, steam, power and motor fuel products) is so diverse (Tunå, *et al.*, 2012).

$$\eta_{MW} = \frac{Q_{Motor\ fuel} + Q_{Power} + Q_{Other}}{Q_{Biomass} + Q_{Power} + Q_{Other}} \qquad \text{Eq 1}$$

$$\eta_{EL} = \frac{\eta_{Motor\ fuel} \cdot Q_{Motor\ fuel} + Q_{Power} + \eta_{Other} \cdot Q_{Other}}{\eta_{biomasss} \cdot Q_{Biomass} + Q_{Power} + \eta_{Other} \cdot Q_{Other}} \qquad \text{Eq 2}$$

Table 6. Electricity generation efficiencies used for calculation of electricity equivalents.

Fuel	η	Comment	Reference
Biomass	46.2%	BIGCC	Stahl, 2001
Bark	46.2%	BIGCC	Stahl, 2001
District heating	10.0%	Opcon power box	Tunå, *et al.*, 2012
MeOH	55.9%	Gas turbine combined cycle	Tunå, *et al.*, 2012
DME	55.9%	Gas turbine combined cycle	Tunå, *et al.*, 2012
FT diesel	55.9%	Gas turbine combined cycle	Tunå, *et al.*, 2012
SNG	57.6%	Natural gas combined cycle	Chiesa, *et al.*, 2005
H_2	58.3%	H_2 combined cycle	Chiesa, *et al.*, 2005
LP steam 4.5 bar(a) 150°C	16.6%	Steam levels from KAM, calculated using 30°C condensing temperature, 25°C reference point, 72% $\eta_{isentropic}$ 90% $\eta_{mechanical}$	Andersson, *et al.*, 2006b
MP Steam 11 bar(a) 200°C	19.6%		
IP Steam 26 bar(a) 275°C	22.6%		
HP steam 81 bar(a) 490°C	27.2%		

Regarding district heating the demand varies with the season and is also dependent on geographical location. Although, only studies of biomass gasification integrated in district heating plants where the heat delivery is adjusted to fit/match the heat demand of the heating system have been considered. An annual district heating demand during 5000 h was therefore assumed, used for both methods of calculating the system efficiency. For the other energy carriers an annual operation time of 8000 h were applied.

Table 7 summarises 11 of the 143 cases where the system efficiency was recalculated using the equalised incremental balances compiled from the reviewed material. These cases were selected to highlight important differences, problems or lack of differences between the calculation methods. The resulting system efficiencies on an equalised basis for the selected cases are presented in Figure 5, where the calculation method using mixed source of energy carriers is denoted by MW and with electrical equivalents is denoted by El.

Table 7. Cases used for comparing the system efficiency in Figure 5.

Name	Industry	Integration approach	Motor fuel production capacity	Feedstock	Comment	Reference
MeOH-1	Pulp and paper mill	Replacing the recovery boiler	273 MW	Black liquor	Unspecific plant	Ekbom, *et al.*, 2003
MeOH-2	Pulp and paper mill	Replacing the bark boiler	187 MW	Wood residue	Specific plant	Andersson, *et al.*, 2013
MeOH-3	District heating system	Polygeneration plant in DH system	65 MW	Wood residues	Specific plant	Brandberg, *et al.*, 2000
MeOH-4	Pulp and paper mill	Replacing the recovery boiler	272 MW	Black liquor	Unspecific plant	Pettersson, *et al.*, 2010
DME-1	Pulp and paper mill	Replacing the recovery boiler	275 MW	Black liquor	Unspecific plant	Ekbom, *et al.*, 2003
DME-2	Pulp and paper mill	Replacing the bark boiler	172 MW	Bark	Specific plant	Wetterlund, *et al.*, 2010a
DME-3	District heating system	Integration with CHP for combusting of off-gases in GT/off-gas boiler.	158 MW	Wood chips	Specific plant	CEC, 2007
DME-4	Pulp and paper mill	Replacing the recovery boiler and bark boiler	74 MW	Black liquor and wood residue	Unspecific plant	Consonni, *et al.*, 2009, Larson, *et al.*, 2007
FT-1	Pulp and paper mill	Replacing the recovery boiler and bark boiler	Crude FT 112 MW	Black liquor and wood residue	Unspecific plant	Consonni, *et al.*, 2009, Larson, *et al.*, 2007
FT-2	Pulp and paper mill	Replacing the recovery boiler	FTD 272 MW	Black liquor	Unspecific plant	Pettersson, *et al.*, 2010
FT-3	Oil refinery	Integration a biomass-to-FT syncrude process with a refinery.	H_2 12 MW FTD 162 MW FTG 59 MW	Wood fuel	Specific plant	Pettersson, *et al.*, 2010
FT-4	Pulp and paper mill	Replacing the bark boiler	FT crude 162 MW	Wood residue	Unspecific plant	McKeough, *et al.*, 2007
SNG-1	District heating network	Polygeneration plant in DH system	173 MW	Wood chips	Specific plant	Truong, *et al.*, 2013
SNG-2	CHP	Stand-alone (integrate with advanced steam cycle)	63 MW	Wood fuel	Unspecific plant	Heyne, *et al.*, 2013a
SNG-3	District heating network	Polygeneration plant in DH system	286 MW	Wood chips	Specific plant	Wetterlund, *et al.*, 2010c

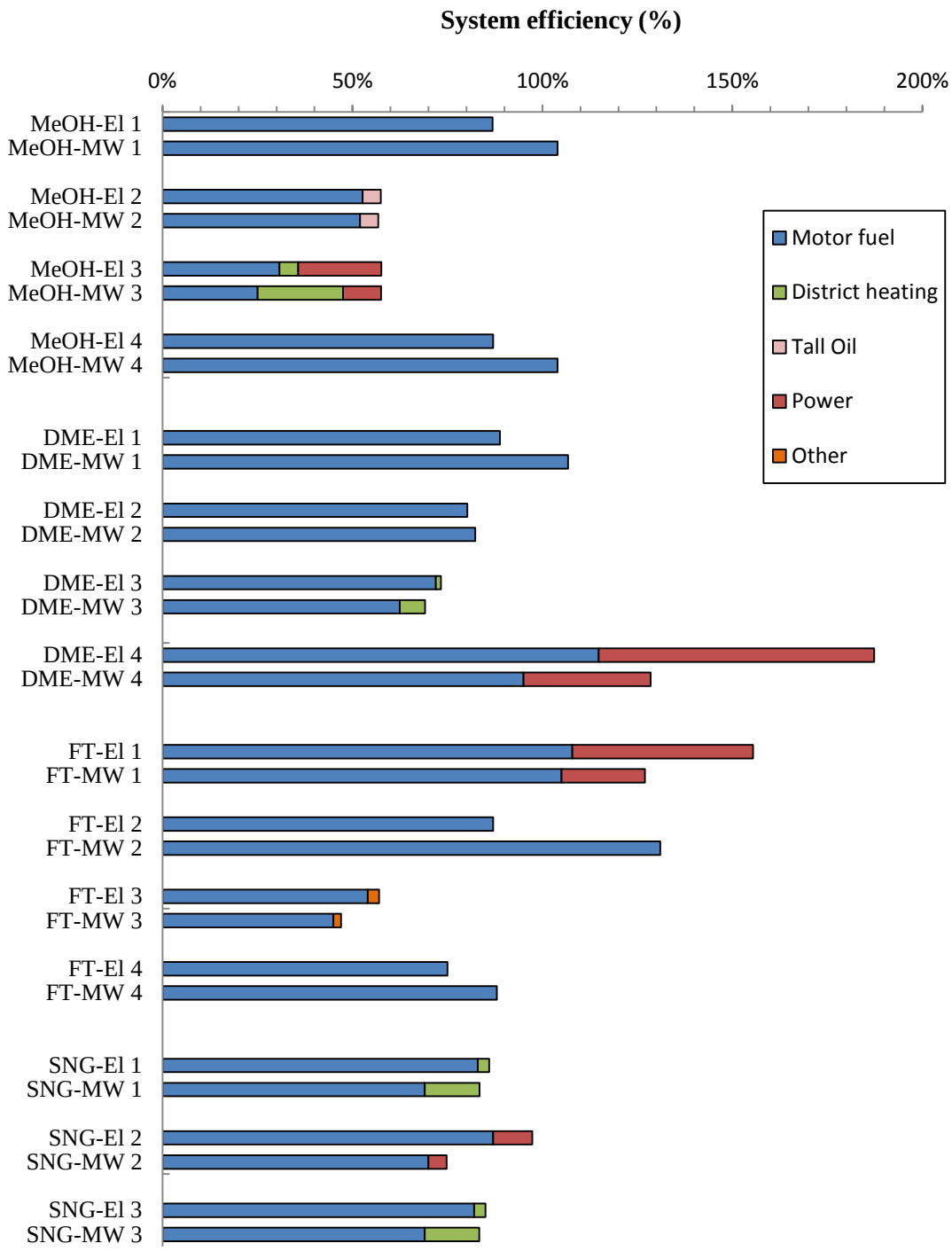

Figure 5. System efficiency for methanol, DME, SNG and FT cases calculated in the conventional MWout/MWin and with electrical equivalents.

As seen in Figure 5 efficiencies over 100% are calculated for some cases. This is due to the fact that incremental energy and material balances have been used. This may lead to the marginal supply of energy commodities being lower than the outgoing products as internally available feedstock or energy streams may be used.

A lower received system efficiency with the electrical equivalent calculation method indicate the use of high level exergy resources, like power (η_{power}=1 in Eq 2). The largest difference between the two calculation methods (mixed source of energy carriers and electricity equivalents, respectively) is obtained for cases where the integration of the gasification plant imposes a "big" impact on the power demand and/or the power production (either negative or positive) compared to the original operation of that specific industry. DME-4 and FT-1 are two cases where the net power balance is significantly improved compared to original operation of the plant, hence the endorsement by the electrical equivalent calculation method. The reverse effect is seen for FT-2, where the production of motor fuel demands a significant power import increase to the plant.

The exergy level of district heating is low-valued in the calculation with electrical equivalents (i.e., hot water). The district heating contribution to the total system efficiency will for this reason decrease when using electrical equivalents, as seen in Figure 5, but the total system efficiency will generally not differ much between the calculation methods (MeOH-3, SNG-1, SNG-3). This is because the incremental balances have been used and the higher valued products (electricity, motor fuel, etc.) often compensate for the low-valued district heating, in comparison to the energy/exergy in the incremental inputs.

Based on the recalculation of the system efficiency for all 143 cases, studies that use unspecific plants (i.e., hypothetical plants) generally received higher system efficiencies compared to studies that used specific plants. One reason for this could be that black liquor gasification systems generally receive the highest system efficiencies for most types of biofuels and in the reviewed material these studies have often been conducted using hypothetical plants. Another reason could be that hypothetical plants do not necessarily constitute sufficiently realistic models of the industry sites, which could cause overestimations in potential improvements.

4.3 SUMMARY

There are several available methods to calculate energy system efficiencies. Nevertheless, no right and wrong answer really exists in how to define the system boundaries and which method to use to calculate the system efficiency. System efficiency comparisons between different industrially integrated biomass gasification concepts are for this reason ineffective and can be highly misleading, unless the comparison is done on an equalised basis.

Even on an equalised basis, comparing the system efficiency for different industrially integrated gasification plants is far from a straightforward process. The calculated efficiency based on the marginal supply becomes very dependent on how the industries exploit their resources before the integration. The resulting efficiencies are therefore very site-dependent. Increasing the boundaries to include all in- and outgoing energy carriers from the main industry, as well as the integrated gasification plant (i.e., total plant mass and energy balance), would produce the same site-dependency problem. The same problem will also occur if the integration of the gasification plant is compared to a future state of the art version of the industry without the gasification plant. The resulting system efficiency can therefore often be viewed as a measure of the potential improvement that a specific industry could achieve by integrating a biomass gasification concept. A method for a more accurate equal comparison between studies is to present the system material and energy balances in table form. By doing this it gives the reader an opportunity to make the calculations that suit their needs.

5 ECONOMY

This section presents published production costs for the different motor fuels. The costs are shown as a function of plant production capacity to illustrate possible economy-of-scale effects. This is followed by a background data check of the references included in the reviewed papers (see Table 8). The investment assumptions and the strength in the underlying material in these papers are scrutinized and discussed. Additionally, the investments and the operational costs are recalculated to an equalised basis.

With the exception of black liquor cases, many studies state that the feedstock cost as well as economy-of-scale effects have large influence on the resulting production cost. Figure 6 to Figure 9 present published production costs for different motor fuels (MeOH, DME, SNG and FT) as a function of production capacity. The results are presented independently of industry type, value year, and other economic and technical assumptions. Studies with production costs presented in currencies other than Euros were converted according to the exchange rate (Riksbanken, 2013) of the value year given in the specific study. The specific biomass purchase cost for each case is given in € per MWh (LHV) beside the markers.

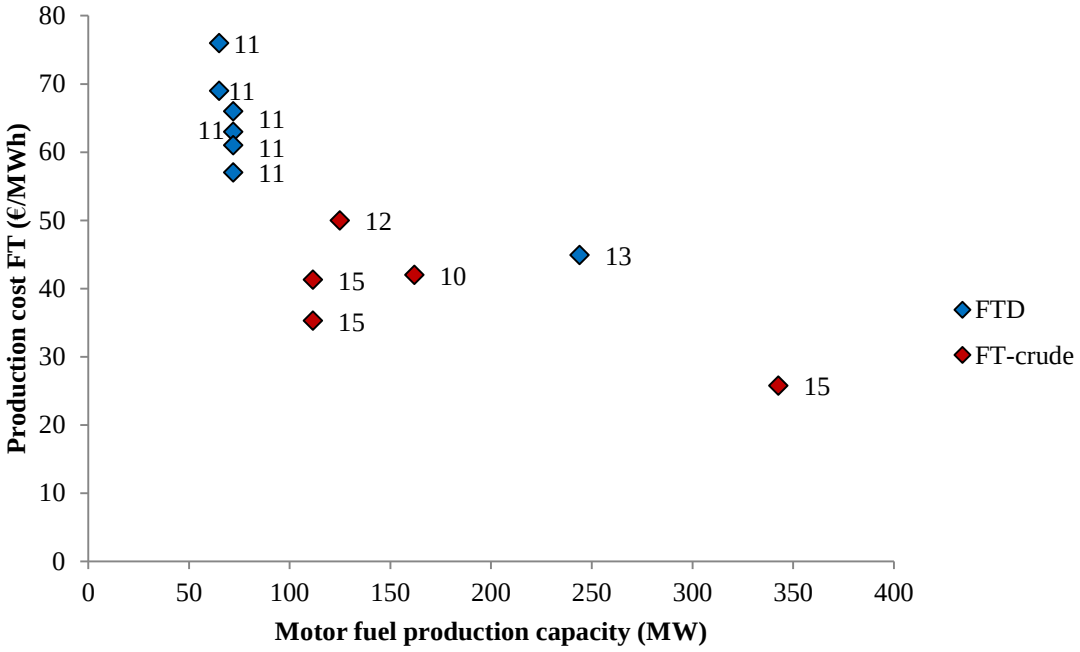

Figure 6. Production cost of FTD and FT crude as a function of production capacity. The biomass purchase cost is given in €/MWh beside the markers.

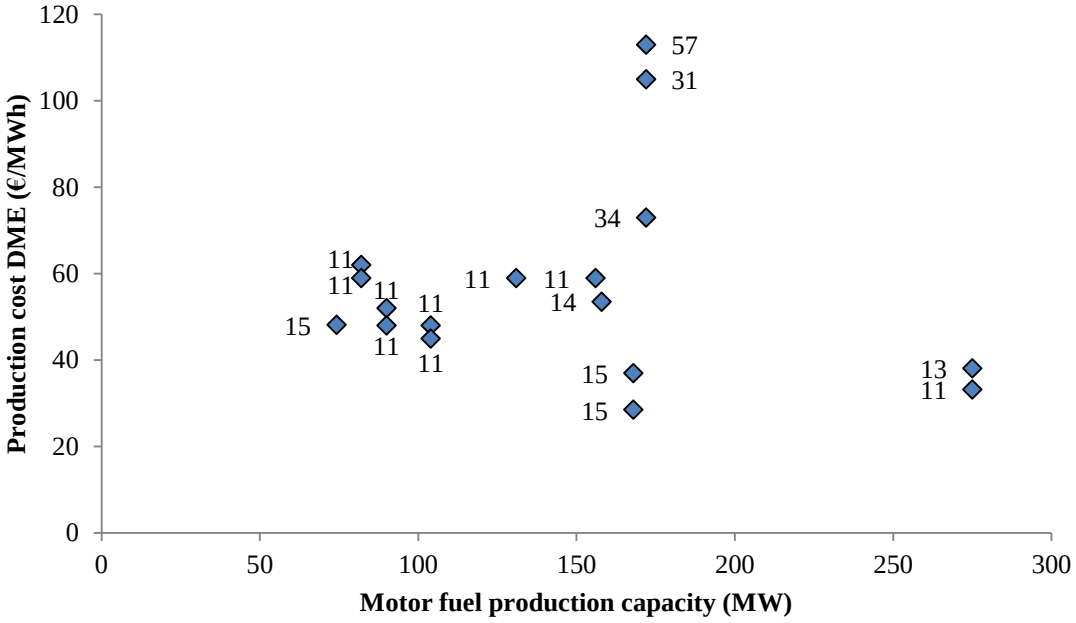

Figure 7. Production cost of DME as a function of the production capacity. The biomass purchase cost is given in €/MWh beside the markers.

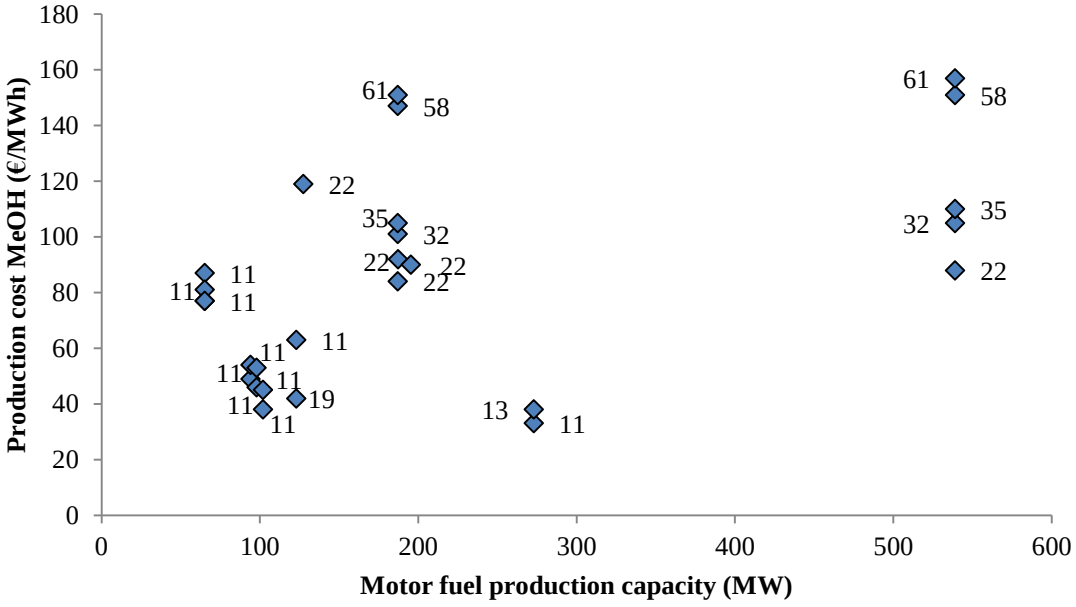

Figure 8. Production cost of methanol as a function of the production capacity. The biomass purchase cost is given in €/ MWh beside the markers.

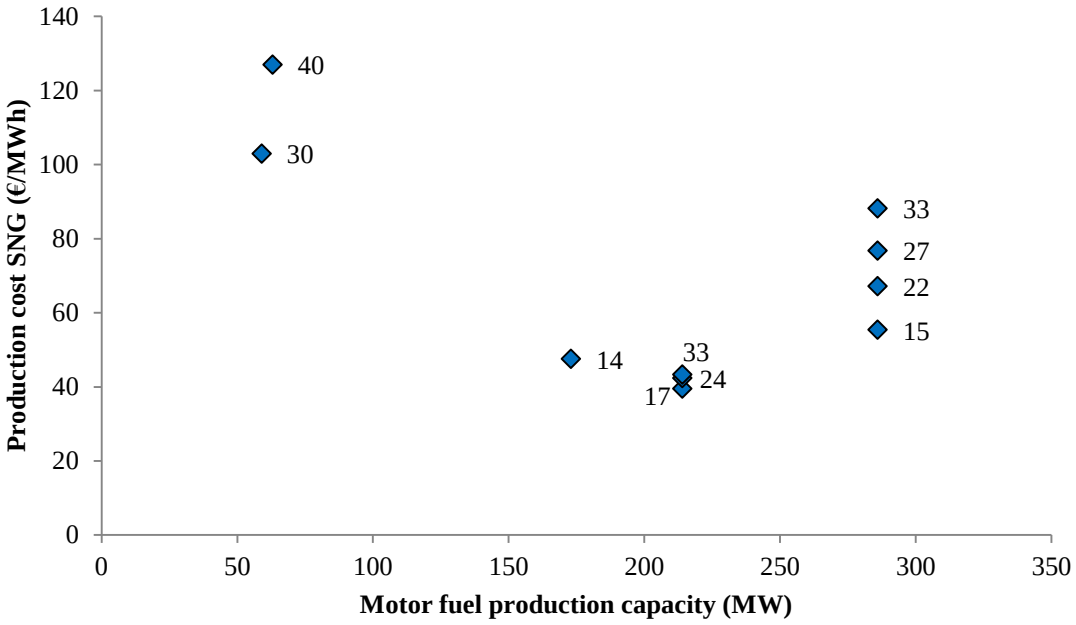

Figure 9. Production cost of SNG as a function of the production capacity. The biomass purchase cost is given in €/MWh beside the markers.

For feedstock costs around 22 € per MWh for methanol production, and also for biomass cost of 11 € per MWh for DME and methanol, a clear economy-of-scale trend can be seen. The opposite trend is also present, however, for example, methanol production with a biomass cost of 58 or 61 € per MWh shows an increased production cost with increasing production capacity.

Some studies apply different energy market scenarios to the same technical configuration, for example SNG production capacity around 300 MW, also for FTD production around 75 MW. For the FTD cases the biomass cost (11 € per MWh) is unchanged and other economic parameters are changed, indicating that other parameters also have large influence on the production cost.

Some of the energy market scenarios are designed for future price levels for 2020 and forward. These scenarios should reflect a future energy market when the technology of biomass gasification plants should be fully commercialised. The production costs in Figure 6-Figure 9, are therefore valid for a time span ranging over more than 20-30 years.

5.1 ECONOMIC CONSIDERATIONS

In order to address the economics on an equalised basis the following sections evaluate the reviewed studies containing economic results in further detail to investigate different specifications, conditions and assumptions used in the calculations of the investment and production costs. Based on this the specific investment costs are recalculated on an equalised basis along with the recalculated operational costs and other investment assumptions.

Only studies containing investment cost data will be discussed. These studies have been listed in Table 8 together with industrial and economic specifications that are relevant when comparing investment and production costs.

Table 8. Publications and data used for the economic evaluations.

Study	Industry	Plant type	Interest rate (%)	Depreciation (year)	Operating time (h/y)
Andersson, *et al.*, 2013	Pulp and paper	Specific	10	20	8000
Boding, *et al.*, 2003	District heating	Specific	8	15	8000
Brandberg, *et al.*, 2000	District heating	Specific	8	15	8000
Börjesson, *et al.*, 2010	District heating	Specific	-	-	8000
Difs, *et al.*, 2010	District heating	Specific	6	20	8040
Ekbom, *et al.*, 2003	Pulp and paper	Unspecific	15	25	8330
Ekbom, *et al.*, 2005a	Pulp and paper	Unspecific	15	25	8330
Ekbom, *et al.*, 2005b	District heating	Specific	5	20	8000
Hansson, *et al.*, 2010	Pulp and paper	Unspecific	7	10	8330
Joelsson, *et al.*, 2008	Pulp and paper	Unspecific	6	25	-
Johansson, *et al.*, 2013	Oil refinery	Specific	8	25	8400
Larson, *et al.*, 2007	Pulp and paper	Unspecific	15	25	8330
Lundgren, *et al.*, 2013	Steel plant and CHP	Specific	10	20	8000
McKeough, *et al.*, 2007	Pulp and paper	Unspecific	10	20	8000
Pettersson, *et al.*, 2009	Pulp and paper	Specific	10.1	25	8330
Pettersson, *et al.*, 2012	Pulp and paper	Unspecific	9	15	7838
Truong, *et al.*, 2013	District heating	Specific	6	25	7200
Wetterlund, *et al.*, 2010a	Pulp and paper	Specific	-	-	8592
Wetterlund, *et al.*, 2010c	District heating	Specific	6	20	7296-8040
Wetterlund, *et al.*, 2011	Pulp and paper	Specific	6	15	8000

Most of the reviewed studies have not compiled their own economic data when generating the investment costs, but have instead used information and figures from a number of previously published reports. The investment costs have usually then been updated using the Chemical Engineering Plant Cost Index (CEPCI) and different forms of factor methods. However, it is not recommended to use CEPCI over a time period exceeding five years, due to uncertainties in value appreciation and surrounding world factors. The majority of the reviewed studies lie within this timeframe. Since no other method for cost update is available, CEPCI will also be used for those studies that are older than five years. This will cause a higher uncertainty in the results but will still give an indication on current prices. The reports that contain original economic data that have been used as economic references in the case with integration of biofuel production and traditional processes are as follows: Algehed, 2002, Boding, *et al.*, 2003, Brandberg, *et al.*, 2000, CEC, 2007, Ekbom, *et al.*, 2003, Ekbom, *et al.*, 2005a, Larson, *et al.*, 2007.

5.2 ECONOMIC RE-CALCULATION METHOD

To assess the cost of production given in a number of the examined papers, both the investment costs and operating costs have been investigated. The investment costs in the various papers have been analysed with respect to origin and the investments have been streamlined to be valid the same year (2012). The origin of the investment costs has been traced back to the original source as far as possible and the original source will be commented in detail. In the analysis of the investment cost, the methods used for estimating the investment cost, what is included in the investment cost and the depreciation parameters have been assessed.

The streamlining of the investment cost has been performed by first determining the year the investment in each paper refers to; if no year is given in the paper, the date of submission (journal articles) or publication (reports, etc.) has been used as a guideline. The investment cost has then been converted to USD (unless the number has been given in USD originally) using the yearly average of the given year. Thereafter the investment cost has been updated using the chemical engineering plant cost index (CEPCI) for the given year and to 2012 (Ulrich, 2004):

$$Investment_{2012} = Investment_{year\ x} * \frac{CEPCI_{2012}}{CEPCI_{year\ x}}$$

The investment costs have then been used for assessing the investment per MW of fuel to give an indication of the spread between the assessments and for the technologies. The operating costs used in the literature have also been investigated with respect to variations. The operating costs have been updated in a similar fashion to the investment cost, but using the producer price index for chemical and allied products instead of CEPCI (Brown, 2007). The process is exemplified in Figure 10.

Figure 10. The conversion path followed for investment and operational costs.

Based on data from the papers, a mean value has been calculated for the cost of biomass and electricity, the depreciation and the interest rate. These values were used to calculate new production costs on an equal basis for the different motor fuels in the different scenarios using the same assumptions with regards to yields, operation hours, etc. done in each paper. There was an initial ambition to break up the investment costs and get a resulting bare-module cost and the same

assumptions on contingency and auxiliary components in all cases. This would have resulted in more equal assumptions on the investment costs for the investigated papers. However, since few papers give details on the component costs, this method was not applicable in this case and it was hence decided to use the investment cost determined in the paper for performing the assessments.

5.3 RESULTS

5.3.1 Background data check

Investments costs reported in Börjesson, *et al.*, 2010, Difs, *et al.*, 2010, Truong, *et al.*, 2013, Wetterlund, *et al.*, 2010a and Wetterlund, *et al.*, 2010b are completely or partly based on CEC, 2007. Truong, *et al.*, 2013 use CEC, 2007 when estimating the investment costs for the DME and methane cases. For the methanol case, data from Boding, *et al.*, 2003 is used. Investments costs reported in Pettersson, *et al.*, 2009 and Pettersson, *et al.*, 2012 are partly based on Ekbom, *et al.*, 2005a. In addition to Ekbom, *et al.*, 2005a, Pettersson, *et al.*, 2012 use factoring methods Hamelinck, *et al.*, 2004 and Larson, *et al.*, 2005 while Pettersson, *et al.*, 2009 use data from Olsson, 2009, which in turn is based on Algehed, 2002 for the evaporation units and Carlsson, 1996 for the heat exchangers. The investment costs in Algehed, 2002 are based on estimates by Kvaerner Pulping AB. Carlsson, 1996 was published in 1996 and this data is therefore deemed to be outdated.

Johansson, *et al.*, 2013 takes most cost data from Kreutz, *et al.*, 2008, which is in turn based on Bechtel Corp., 1992. This source however is from 1992 and is deemed to be outdated. Data that is not included in Kreutz, *et al.*, 2008 is obtained by using factors from Hamelinck, *et al.*, 2004 and Trippe, *et al.*, 2011. Investment costs reported in Lundgren, *et al.*, 2013 are "turn-key" and have been estimated by CAPEX. They are assessed based on conducted studies, quotes and in-house information. Joelsson, *et al.*, 2008 uses data from Ekbom, *et al.*, 2003 and Berglin, *et al.*, 2003 but it is not described in what extent data from either reference is used. The estimated investment cost for the gasification system in Berglin, *et al.*, 2003 is scaled from Griffis, 2002, while the gas cleaning plant, shift reactor and methanol plant are estimated from in-house data. The Griffis, 2002 report has not been readily available to the project group and therefore is left without analysis and assessment in this report. Hansson, *et al.*, 2010 uses investment costs from Huisman, *et al.*, 2010. The foundation of the Huisman, *et al.*, 2010 data is unknown, which creates some uncertainty as to how the data is derived and what is included. This does not mean that it is inaccurate, only that the source cannot be verified. Andersson, *et al.*, 2013 takes most of the investment data from Ekbom, *et al.*, 2003, but also from Wetterlund, *et al.*, 2011 (which have been previously discussed) and Clausen, *et al.*, 2010, which is mostly based on Kreutz, *et al.*, 2008 and Hamelinck, *et al.*, 2002. Hamelinck, *et al.*, 2002 have developed factor methods based on quotes for biomass gasification developments; there are some discrepancies in the paper with respect to e.g. dryer costs when comparing to e.g. Brammer, *et al.*, 1999.

5.3.2 The Biokombi Rya project – CEC, 2007, Ekbom, et al., 2005b

The Biokombi Rya project was performed by Chalmers EnergiCentrum and is a case study of Rya Kraftvärmeverk. Its intention is to increase the understanding of biomass gasification in Sweden. TPS Termiska Processer AB and Nykomb Synergetics AB are responsible for assessing the investment costs. The costs consider a "turn-key" plant and they are rough estimations made to be

used for comparison between the different cases that are discussed. No sensitivity analysis has been made and the accuracy of the estimates cannot be verified. Cost data relevant to 1st quarter of 2006 were used throughout the report. The plant is assumed to operate 8000 h/y and to have a depreciation of 20 years and use a 5% discount rate.

5.3.3 The BLGMF (Black Liquor Gasification to Motor Fuels) – Ekbom, et al., 2003

The Ekbom, *et al.*, 2003 report presents incremental investment and production costs in comparison to a reference KAM2 mill. The plant is considered to be "turn-key" and most costs were assessed using factoring methods and previous estimates. Quotations were used for the methanol and DME process units and the boiler. A sensitivity analysis has been made on the production costs by either varying the biomass cost, the incremental investment cost, the availability or the electricity cost by ±30%. Cost data relevant to 3rd quarter of 2003 were used throughout the report. The plant is assumed to operate 8330 h/y, to have a depreciation of 25 years and use a weighted average cost of capital of 10% (8% external capital and 15% on equity).

5.3.4 BLGMF II – Ekbom, et al., 2005a

The BLGMF II report is an updated version of the BLGMF report. In addition to the original methanol and DME studies, a FTD study has been added. In comparison to the methanol and DME cases, the FTD units have been estimated by factoring methods and not by quotes, thus the results cannot be said to have the same accuracy as the methanol and DME cases. It is believed that the investment cost estimates for the methanol and DME cases have an accuracy of ±30% and accuracy of the FTD investment cost estimate is believed to be at least ±40%. The incremental investment cost for the FTD unit is made in comparison to Sasol's Oryx 1 plant. The methanol and DME studies have been slightly modified and the original economics have been updated using CEPCI. Cost data relevant to 4th quarter of 2005 were used throughout the report. The plant is assumed to operate 8330 h/y, to have a depreciation of 25 years and use a weighted average cost of capital of 10% (8% external capital and 15% on equity).

5.3.5 BioMeeT – Brandberg, et al., 2000

The purpose of the BioMeeT (Planning of Biomass based Methanol energy combine – Trollhättan region) study was to investigate the possibility of constructing a plant for the production of motor fuels, fuel gas, electricity and heat by gasification of mainly lignocellulosic feedstock. The plant is considered to be "turn-key" and investment cost estimates are partly based on quotes and partly on in-house information and factoring methods. A sensitivity analysis has been made on the production costs by either varying the biomass cost, the investment cost, the availability or the electricity price by ±30%. Cost data relevant to 3rd quarter of 1999 were used throughout the report. The plant is assumed to operate 8000 h/y, to have a depreciation of 15 years and to use an 8% interest rate.

5.3.6 BioMeeT II – Boding, et al., 2003

The BioMeeT II report is an updated version of the BioMeeT report. Changes that influence the investment cost have been made to the gasification island, the CO_2 removal island and the methanol synthesis island, and a shift unit has been added to the sulphur removal island. Also,

start-up costs have been added into the total investment costs. The data has been updated to 1st quarter of 2003 using normal inflation; however, the rate of inflation has not been reported.

5.3.7 A Cost-Benefit Assessment of Gasification-Based Biorefining in the Kraft Pulp and Paper Industry – Larson, et al., 2007

The project was co-funded by the American Forest and Paper Association and the Biomass Program of the U.S. Department of Energy. Its purpose was to assess if any economic benefit could be made by replacing the recovery boiler in pulp and paper mills with black liquor and biomass gasification. Several integrated biorefinery process designs were developed. Investment cost estimates for "turn-key" plants were made by Nexant and the accuracy is believed to be ±30%. Cost data relevant to 2005 were used throughout the report. The plant is assumed to operate 8,330 h/y, to have a depreciation of 25 years and use a 15% return on equity and 8% on external depth, which gives a weighted average investment cost of 11.5%. The paper is the only one differing between total plant investment (overnight investment) and total plant cost (including interest during construction).

5.3.8 Energy Efficient Evaporation in Future Kraft Pulp Mills – Algehed, 2002

The total investment cost for a "turn-key" plant was estimated by Kvaerner Pulping AB. Based on those estimates a linear investment model for evaporation units, depending on evaporator size and number of effects, was developed.

5.4 EVALUATION OF USED FIGURES

To analyse the investment cost, the specific investment costs were determined per MW of product output in all of the papers listed above. The results contain total investment and not incremental investments. Figure 11 shows the specific investment cost in €$_{2012}$ of gasification-based DME production plants.

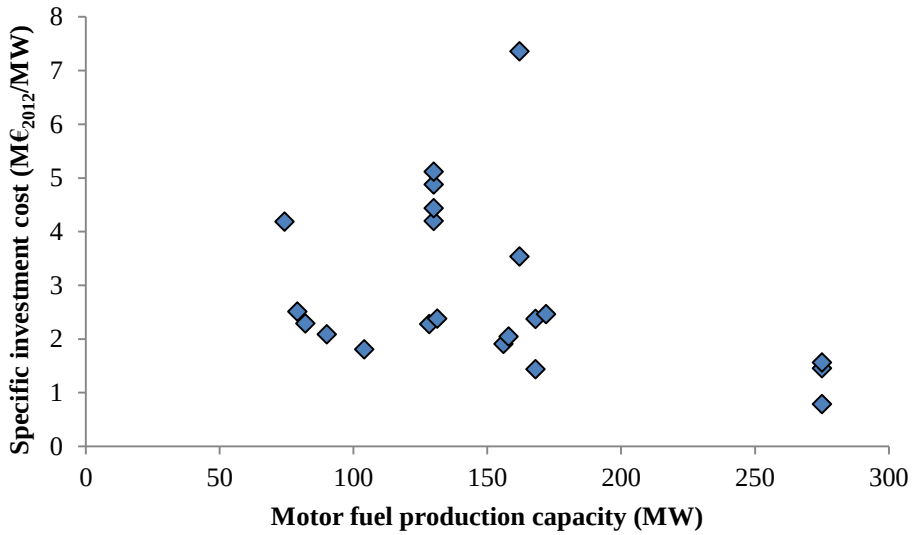

Figure 11. The specific investment costs of the DME production plants.

As may be seen in the figure, there is quite a significant spread in the specific investment costs at the lower end of the production capacity with an absolute difference of more than 6 M€$_{2012}$/MW. There is also a significant scattering in the data, making any trends difficult to see and any regressions without significance. There does however appear to be an economy-of-scale effect since the larger capacities show lower specific investment costs but the trend is unclear from the presented data. In Figure 12 the same exercise has been performed for the production of FT products.

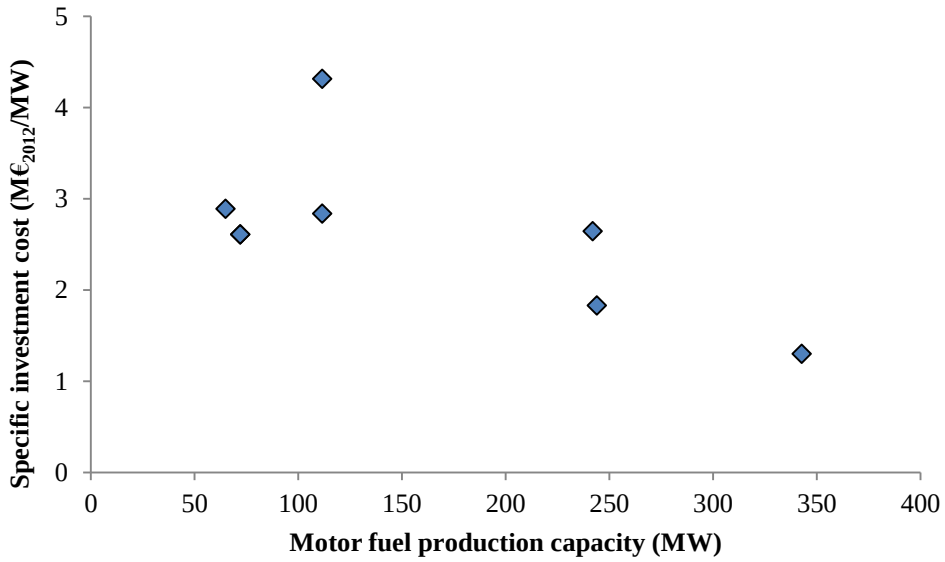

Figure 12. The specific investment costs for FT products.

As may be viewed in the figure, there is more of a trend in this type of equipment with a clearly noticeable economy-of-scale. A regression using an exponential expression gives an expression with $x^{-0.36}$ for the given data set and 43% of the decrease may be explained with increasing scale. This accentuates the dependency of the specific investment cost with increasing scale, a trend which is also clearly seen for methanol in Figure 13.

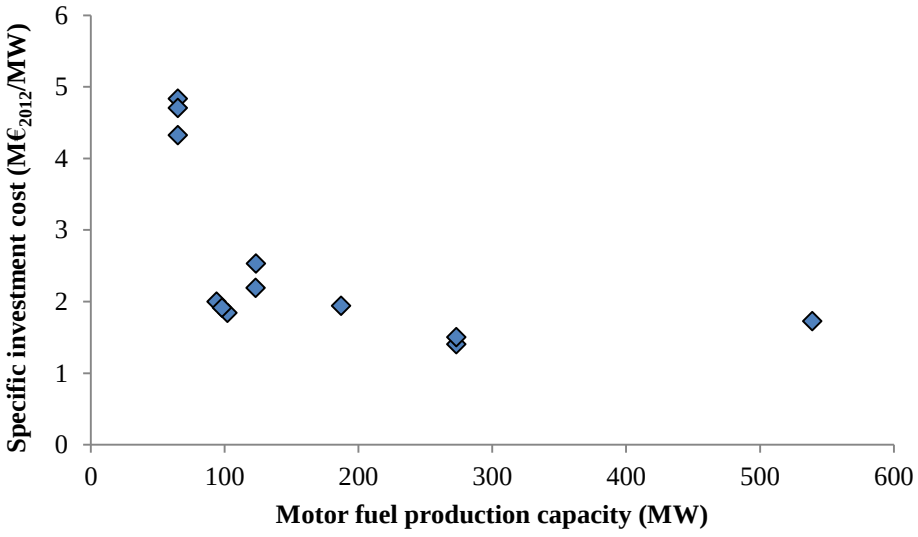

Figure 13. The specific investment costs for MeOH.

Again the graph shows a significant economy-of-scale and a regression using an exponential expression with an even steeper decrease with increasing capacity compared to the DME case; the exponential factor is -0.50 and 58% of the decrease may be explained by the increase in scale. The economy-of-scale trend is continued in the case of SNG production, Figure 14.

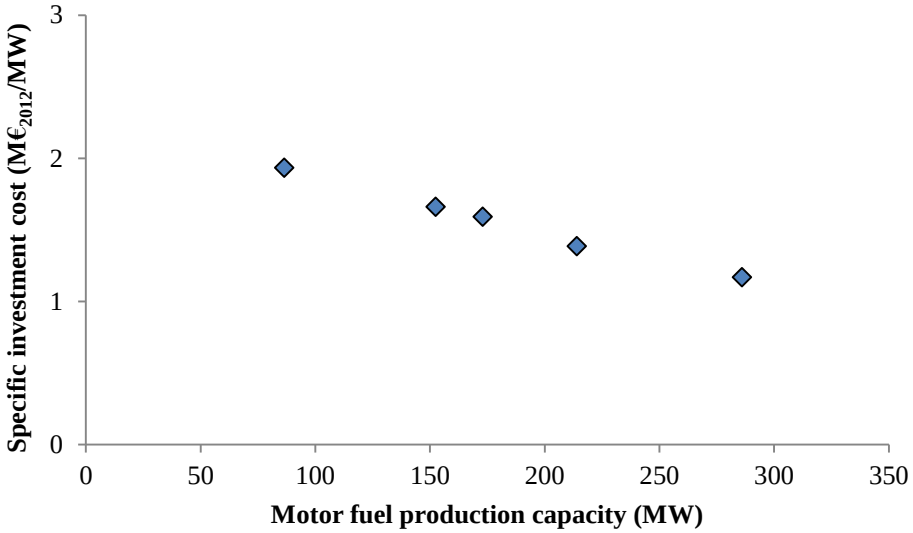

Figure 14. The specific investment costs for SNG.

Even though the SNG case does not contain as many data points as the previous cases, it is still possible to see a prominent economy-of-scale trend. The exponential factor is -0.42 and as much as 94% of the decrease may be explained by the increase in scale. For the mixed alcohol cases, not enough data is available for analysis. There appears to be a large spread in all of the data, except for perhaps the SNG cases. This is also true for the data used for production of FT products. This may be explained primarily by the complexity of the technology (choice of reactors, downstream equipment, etc.), but also to some extent by the choice of data source for the investment cost. Some of the cited investment costs date to the early 1990s and it is unlikely that an index update will accurately describe the cost evolution during such a long time period. The DME and MeOH is more standardized technology and with fewer design options compared to FT, which should lead to more coherent specific investment costs but this is not visualised by the analysed data. The specific investment costs correspond well to the previously presented specific production costs with the exception of a few data points, showing the dangers of comparing figures from reports performed at different dates.

In addition to the investment costs, the operation costs are of significant interest in determining the production costs of a specific fuel. The investment cost represents somewhere between 10-50% of the cost per tonne of fuel produced, which is why it is of importance to review the chosen parameters, mainly for biomass and electricity costs which represent a majority of the operation costs. The data has been averaged for each paper and thereafter the average, max, min and standard deviation has been determined, Table 9. All figures have been recalculated to €$_{2012}$ using the index-methods as described in Figure 10.

Table 9. Investment and operating parameters, converted to €$_{2012}$.

	Average	Maximum	Minimum	Standard deviation
Biomass (€$_{2012}$/MWh)	25.9	58.3	10.2	15.8
Electricity (€$_{2012}$/MWh)	66.9	108.1	29.1	24
Depreciation (year)	20.3	25	10	4.6
Interest rate	9%	15%	5%	3%

As can be viewed in the table, the average value of the biomass cost is 26 €$_{2012}$/MWh with the maximum value more than twice that and a minimum value of 10 €$_{2012}$/MWh. This is quite a large span, which is also reflected in the standard deviation being more than half of the average value. The same is true in the case of electricity where there is a rather large variation in the chosen values but not as large as in the case of biomass. Since the feedstock and electric cost/credit are the major costs in the production of synthetic fuels from biomass, a large part in explaining the difference in results between various studies is differences in feedstock cost assumptions. However, this difference in feedstock cost is not enough to explain the differences in the resulting cost of production. Indeed when performing calculations for the references given in the introduction, using the average values as input (as per Table 9), the variations in production costs are substantial, Table 10.

Table 10. Variations in production costs (€$_{2012}$/MWh)

	Average	Maximum	Minimum	Standard deviation
DME	108.1	245.9	51.8	58.2
FT	77.5	99.7	50.7	51.8
MeOH	108.8	199.8	52.8	49.1
SNG	68.7	87.8	51.4	12.8

This may primarily be explained by the difference in investment cost between the various studies for the same biofuel type. Secondly, there is a rather large difference in yield between the different studies which translates to a difference in specific production cost.

The area where there is the least spread is in the investment parameters governing the annuity. There appears to be consensus that 20-25 years is a reasonable timeframe to consider for this kind of investment despite some outliers. The same is true in the case of the interest rate which is chosen to be about 10% in most cases. There are some groups using a weighted average investment cost in which the interest rate on equity is set rather high, but in this case a lower external interest rate yields an overall rate in the same vicinity as the other studies.

5.5 SUMMARY

The number of studies containing both integration and production cost estimates is quite large, but they use a rather limited number of references for the cost data. Most of these (Boding, *et al.*, 2003, Brandberg, *et al.*, 2000, CEC, 2007, Ekbom, *et al.*, 2003, Ekbom, *et al.*, 2005a) have been performed by the same group of people and use the same or similar background information. The

information in these references is based on quotes and estimates, which is good, however none of these are publicly available and therefore difficult to evaluate with respect to content and accuracy. A significant number of studies use figures from CEC, 2007 and Ekbom, *et al.*, 2005b even though it is stated in the reports that the economic figures are rough and for comparing different internal options. However, since this report is one of the few publications that presents relatively detailed steam and energy balance data it is useful in system studies of how to integrate biomass gasification in industry or district heating, which can be a reason why it has been so extensively used in integration studies.

Based on the investigation it is also possible to say that the variance in the operational costs is quite significant, which is particularly true in the case of the biomass cost, which has quite high variance. This may be explained by natural variations in the quality of biomass used, but also by the different markets studied and the dates when the studies were performed. It may be seen from the specific investment costs that there is a significant spread in the data and in particular for the production of DME. It may also be seen from using the averaged production costs that the differences in capital employed and process yields will result in quite large variations in the production of the synthetic fuels. On a general note, the studies performed refer to future plants and in some cases assume technology development. It is therefore relevant to question the use of today's prices of utilities and feedstocks. It is believed that it would be more representative to perform some kind of scenario analysis using different parameters resulting in different cost assumptions to better exemplify possible futures.

6 CONCLUSIONS

This study has reviewed around 40 national and international reports and articles regarding industrially integrated biomass gasifiers for motor fuel production. The main objectives have been to identify and highlight the most important techno-economic differences between the different studies as well as identify possible lack of industrial integration studies.

The majority of the reviewed studies concerned gasifiers installed in pulp and paper mills, in which black liquor gasification was the dominant technology. District heating systems and CHP plants were also well represented. A few studies have been performed in the steel industry, but only with one gasification technology producing one type of motor fuel. Other industries have rarely, if ever, been considered for industrial integration studies. Suggestions for complementary integration studies are discussed in Chapter **Fel! Hittar inte referenskälla.**.

The system efficiencies presented in the reviewed studies were compared on an equal basis based on the incremental mass and energy balance compiled from the material. This was done because different system boundaries, methods and standards were used in the reviewed material for assessing the system efficiency. Even on an equalised basis it is difficult to compare the system efficiency between different integrated concepts. The resulting system efficiency for industrial integrated biomass gasifiers will depend greatly on how efficient the industry operates prior to the integration. The system efficiency is therefore found to be very diverse between the different biofuel concepts. However, black liquor gasification concepts will generally receive the highest system efficiency for most types of biofuels. A method for a more accurate equal comparison between studies is to present the system material and energy balances in table form. By doing this it gives the reader an opportunity to make the calculations that suit their needs.

The number of studies containing integration as well as production cost estimates is quite large, but they use a rather limited number of references for the cost data. Many have based their investment values on the following studies: Algehed, 2002, Boding, *et al.*, 2003, Brandberg, *et al.*, 2000, CEC, 2007, Ekbom, *et al.*, 2003, Ekbom, *et al.*, 2005a, Larson, *et al.*, 2007. The cost information in these studies is based on quotes and estimates, but these studies are publicly unavailable and therefore difficult to value with respect to content and accuracy.

The investment cost represents in the range of 10-50% of the total cost per tonne of fuel produced. This is explained by the quite significant variance in the operational costs. The biomass feedstock, which is often one of the largest operational costs, was found to vary in the range of 10-58 €$_{2012}$/MWh. The costs/credits for electricity were also found to vary rather greatly between the studies (29-108 €$_{2012}$/MWh). The substantial variation of the biofuel production costs are mostly explained by these large variations in operational costs. In addition, the rather large differences in yield/efficiency between the studies also cause divergences for the biofuel production cost.

A trend was identified for the production cost influenced both by the plant size (i.e., economy-of-scale) and the cost for purchasing biomass for DME, FT products and methanol. This is independent of industry of integration, value year, and other techno-economic assumptions. By recalculating the studies to be valid for the same year (2012), a regression with increasing plant capacity (i.e., economy-of-scale effect) was still spotted for FT products and methanol, but not for DME. This shows the dangers of comparing figures from studies performed at different dates.

7 RECOMMENDATIONS FOR FUTURE WORK

The potential techno-economic improvements gained from integration of biomass gasification plants in existing industries are strongly connected to the operation of that specific industry. The performance for a biofuel production route integrated in an industry is therefore not known before it has been thoroughly techno-economically assessed. “New” industries therefore require evaluation with basically all gasification technologies and motor fuel products. From the review process it was found that oil refineries, mechanical pulp and paper mills and steel plants are rarely considered for integrated gasification studies. Furthermore, publications with sawmills and other forest-based industries, like the wood pellet industry, were not found once in the review process as a potential site for integration of a biomass gasifier. All the above mentioned industries can be expected to have good potential for integration of a biofuel production route and should therefore be targets of future studies.

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