Tampere University

ANNA PÄÄKKÖNEN

Feasibility of Flexible Biomass Utilization in Energy Systems

Tampere University Dissertations 166

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ACADEMIC DISSERTATION
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Tampere University, Faculty of Engineering and Natural Sciences
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To the memory of the great ladies in my family who with their example encouraged me to follow my own path.

PREFACE

Several years ago, as I took on the task of teaching associate at the Department of Chemistry and bioengineering at Tampere University of Technology, there was an idea that I should start to work on my thesis. After a long journey and many moments of disbelieve on my part, the day is finally here: I did it!

This work was carried out at Tampere University of Technology, the Department of Chemistry and Bioengineering (2013-2016) and the Laboratory of Chemistry and Bioengineering (2017-2018) and after unification of universities finalized at Tampere University Faculty of Engineering and Natural Sciences (2019).

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I would like to than my supervisors professor Jukka Konttinen and co-superviser Industrial professor Tero Joronen for the time and effort during my work. I would especially like to thank co-supervisor university lecturer Henrik Tolvanen for all the support and friendship during all the years spent at TUT and University of Tampere. I would also like to thank professor emeritus Risto Raiko for introducing me to the fascinating subject of energy economics. The support of my co-authors professor Jukka Rintala, Dr Lauri Kokko, Professor Pami Aalto, Postdoctoral Research Fellow Matti Kojo and the amazingly talented Kalle Aro is highly acknowledged.

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During my years at the university I have had the privilege to get to know and work with some amazing people. One very important environment was the working group of Energy and Eco efficiency thematic area. I would like to thank the whole working group, especially Fanni Mylläri, Mia Isotalo, Timo Korpela, Mirva Seppänen and Seppo Valkealahti. I would like to thank my co-workers Aino Leppänen and Tiina Keipi for all their support and friendship as well as the rest of the sewing club. During last couple of years that were critical to the finalizing of my thesis, Anna Pitkänen and Leena Köppä were a very important support group that helped me through some rough spots, I also appreciate the support of my mentor Paula Syrjänrinne at a critical time.

The support and love from my big family, both the one I was born into and the one I got along with my husband, has always been important. It gives enormous security when you know that there's always a bunch of people that have your back, even if they are not quite sure what you are working with. I'm especially grateful to my sister Aura with whom I had numerous discussions of the pros and cons of university life. I would also like to thank my friends Anne and "Kooma-ryhmä" for reminding me that there is life outside the university.

As is customary, I have saved the most important for last, the love of my life, my husband Tero. This has been quite a journey and I could not have done it without you.

Tampere October 2019

Anna Pääkkönen

ABSTRACT

Globally the fastest growing renewable energy production methods are weather dependent solar and wind power production. However, their locality and fluctuating nature may make the energy demand and production unbalanced and thus increases the need for system flexibility.

Biomass is available in one form or another almost everywhere on Earth. It has been recognized to have potential for providing flexibility into energy systems. Even though technological possibilities for biomass utilization are numerous, detailed costs of the flexibility means are often ignored. This thesis looks in detail into the feasibility of flexible biomass utilization methods through practical examples; biomass to chemicals, biomass to heat and power and biomass as a transport fuel.

The results of this study provides suggestions how to increase the feasibility of biomass utilization in energy system levels. The results showed that biomass can provide flexibility through demand response, flexible production, and useful power storage. These can be achieved with currently existing technologies that can be adopted in a short timescale through introducing subsidies.. It was also shown that the feasibility of biomass utilization method can be improved through side-product, optimized running mode, or technical improvements. The most efficient way to increase the feasibility was operational optimization. The key factors in the feasibility of biomass utilization methods are investment and fuel costs. However, as sustainable amount of biomass is limited other flexibility means will be needed.

Future studies should include accurate forecasting on cost and price development, since these are often based on assumptions. In addition, sustainability and carbon emissions of the whole biomass production chain should be studied.

TIIVISTELMÄ

Tuuli- ja aurinkoenergia ovat maailmanlaajuisesti nopeiten kasvavia uusiutuvan energian tuotantomuotoja. Nämä tuotantomuodot ovat sääriippuvaisia ja siten tuotanto voi olla vaihtelevaa, mikä voi aiheuttaa ongelmia energiajärjestelmälle ja kasvattaa järjestelmän jouston tarvetta.

Biomassa on monimuotoinen uusiutuva energialähde, jota on saatavilla jossain muodossa lähes kaikkialla maailmassa. Biomassalla on myös laajasti tunnistettu olevan potentiaalia energiajärjestelmien jouston kannalta ja mahdollisia teknologioita on olemassa runsaasti. Usein biomassan joustopotentiaalin yksityiskohtainen kustannustarkastelu kuitenkin unohdetaan. Tässä väitöstyössä tarkastellaan biomassan joustavan käytön kannattavuutta käytännön esimerkkien kautta. Tarkasteltavat esimerkit ovat kemikaalien valmistus biomassasta, joustava lämmön ja sähkön tuotanto biomassalla, sekä biomassapohjaiset liikennepolttoaineet.

Tämän tutkimuksen tuloksena on suosituksia siitä, kuinka biomassan käyttökohteiden kannattavuutta voidaan parantaa energiajärjestelmän eri tasoilla. Tulokset osoittivat, että biomassa voi tuoda joustavuutta energian kysynnän jouston, joustavan tuotannon ja sähkön varastoinnin kautta. Kaikki nämä mekanismit voidaan saavuttaa olemassa olevilla teknologioilla, mikä mahdollistaa biomassan joustopotentiaalin nopean käyttöönoton. Biomassan joustopotentiaalin kannattavuutta voidaan parantaa sivutuotteen, optimoidun ajotavan tai teknisten parannusten avulla. Näistä ajotapaoptimointi osoittautui parhaaksi tavaksi lisätä konseptin kannattavuutta. Tärkeimmät biomassan joustopotentiaalin kannattavuuteen vaikuttavat asiat ovat investointi- ja polttoainekustannukset. On kuitenkin selvää, ettei biomassa voi yksinään ratkaista energiajärjestelmien joustavuuteen liittyviä ongelmia, mikäli biomassan käyttö halutaan pitää kestävällä tasolla.

CONTENTS

LIST OF SYMBOLS AND ABBREVIATIONS

Latin symbols

d	yearly depreciation	€
h	hour	
i	investment interest	-
K	Yearly profit	€
ln	natural logarithm	-
P	Overnight investment cost	€
t	time	h, min

Abbreviations

AD	Anaerobic Digestion
CAPEX	Capital expenditure
CHP	Combined Heat and Power
DH	District heating
DK1	Nord pool Spot price area for Denmark
EAF	Electric Arc Furnace
EC	European Council
EJ	energy unit, 10^{18} Joules
EU	European Union
FI	Nord pool Spot price area for Finland
GHG	greenhouse gas
GW	energy unit, 10^{9} watts
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
LUCLUF	land use, land use-change and forestry emission sector
NG	Natural gas
NPV	Net present value

NREAP	National Renewable Energy Action Plan
OECD	Organization for Economic Co-operation and Development
OPEX	operational Expenditure
ROI	Return of Investment, also ROE
toe	energy unit, ton of oil equivalent
TRL	Technology Readiness Level
VRE	Variable Renewable Energy

ORIGINAL PUBLICATIONS

I. Pääkkönen, A. Tolvanen, H., Kokko, L. The economics of renewable CaC_2 and C_2H_2 production from biomass and CaO. Biomass and Bioenergy 120 (2019) 40-48

II. Pääkkönen, A. Tolvanen, H., Rintala, J. Techno-economic analysis of a power to biogas system operated based on fluctuating electricity price. Renewable Energy 117 (2018) 166-174

III. Pääkkönen, A., Joronen, T. Revisiting the feasibility of biomass-fueled CHP in future energy systems - Case study of the Åland Islands. Energy Conversion and management 188 (2019) 66-75

IV. Pääkkönen, A., Aro, K., Aalto, P., Konttinen, J., Kojo, M. The potential of biomethane in replacing fossil fuels in heavy transport – A case study on Finland. Sustainability 11 (2019), 4750

AUTHOR'S CONTRIBUTION

Publication I: Ms. Pääkkönen performed the calculations, wrote the first version of the manuscript and is the corresponding author of the paper. H. Tolvanen participated in the calculation model building and commented the manuscript. L. Kokko gave the original idea for the article and commented the manuscript.

Publication II: Ms. Pääkkönen performed the calculations, wrote the first version of the manuscript, and is the corresponding author. H. Tolvanen gave valuable insights in to the calculations and commented the manuscript. J. Rintala supervised the work and commented the manuscript.

Publication III: Ms. Pääkkönen built the CHP calculation model and performed all the calculations, was responsible for writing the manuscript, and is the corresponding author. T. Joronen was involved in research question phrasing and structure of the work, edited the manuscript and supervised the work.

Publication IV: Ms. Pääkkönen was responsible for the formal analysis and visualization of the results, and is the corresponding author. Ms. Pääkkönen and K. Aro wrote the first version of the manuscript together, Ms. Pääkkönen was responsible for writing the calculations and technical parts of the manuscript, whereas K. Aro wrote the policy related parts. Calculation methodology was developed by Ms. Pääkkönen together with K. Aro., K. Aro and P. Aalto were responsible for the conceptualization. P. Aalto participated in the writing, review and editing of the paper as well as supervised the work of K. Aro. J. Konttinen and M. Kojo commented the manuscript and J. Konttinen supervised the work of Ms. Pääkkönen.

1 INTRODUCTION

Currently global interest drives towards renewable energy production in order to decrease environmental emissions and dependence on fossil fuels. During last decade the amount of installed renewable power capacity has doubled from 1000 GW to over 2000 GW [1]. This is one of the signs of energy transition [2]. Most of the recent renewable production installations are wind and solar power capacity. However, biomass remains as the most important renewable energy source, with a 10% share of global energy supply [3], mainly used for heating and cooking. As the fastest growing renewable energy production methods are weather-dependent, the production typically fluctuates rapidly. As it possible to electrify the heating and transport sectors, the fluctuation problem concerns mostly the power system. The fluctuation of production reduces the stability of the electrical grid, and therefore the energy system needs flexibility or balancing [4]. Flexibility in energy systems can be defined as flexible generation, transmission, storage, flexible demand, and reducible demand [5].

Biomass has been recognized as a viable means to provide flexibility into energy systems with a lot of varying renewable energy (VRE) production [6-8]. In addition biomass is suitable for providing flexibility in most of the aforementioned flexibility means. Biomass can be used as a fuel for flexible generation with various technologies (e.g. gas engines or combined heat and power production). Moreover, biomass can be used as energy storage (e.g. power-to-biofuel and biomass-to-chemicals), as well as flexible reducible demand (power-to-biogas, biomass-to-chemicals and utilizing as a transport fuel). In this work, these means are handled as bio-to-x. In addition to the ability to provide flexibility services, biomass utilization method should be feasible.

In 2017, 57% of VRE capacity investments were on solar capacity [1]. This leads into a more distributed energy production system, and in many cases energy users become also energy producers. This increases competition in the energy production business and can lead to decreasing feasibility for current energy facilities that have

not reached their operating lifetimes. One option is to demolish these facilities, which on top of extra expenses, may cause a problem for the energy system flexibility and backup power capacity. The system flexibility can be increased by adding batteries or other energy storages to the system. However, currently efficient large scale power storages are still in the developing stage [9]. Another option is power transfer that also has problems due to lack of sufficient transmission connections between areas [10]. Until these storage and transfer related issues can be solved, the feasibility of existing energy production facilities can be improved by a novel earnings principle through operation logics or combining existing technologies and energy utilizing sectors to provide synergy gain. However, before adopting concepts that have not been tried before they should be thoroughly evaluated both energetically and economically to find out if they are worth considering. Energetic evaluation is needed to study that the concept does not use more energy than it can provide, and economical analysis reveals what the conditions are that can make the concept feasible.

Understanding the relations of biomass benefits and costs at a detailed level is essential for evaluating the sustainability of biomass at social and environmental level [11]. This includes assessment in plant, area, and society level as the interactions are complex and interconnected.

Energy system studies have recently been in the interest of many researchers. The studies cover a variety of energy systems from Combined Heat and Power (CHP) plant systems [12; 13], cities [14], islands [15; 16], countries [17; 18], to even continents [19], just to name a few. Most of these studies concentrate in future scenarios and not actual energy systems. However, as the energy transition is happening with an accelerating pace, it is also essential to understand the utilization possibilities and costs of currently available flexible and renewable energy resources, such as biomass.

1.1 Aims and scope

The aim of this thesis was to study the feasibility of biomass utilization methods (Bio-to-x) providing energy system flexibility and sustainability in different system levels (Fig. 1).

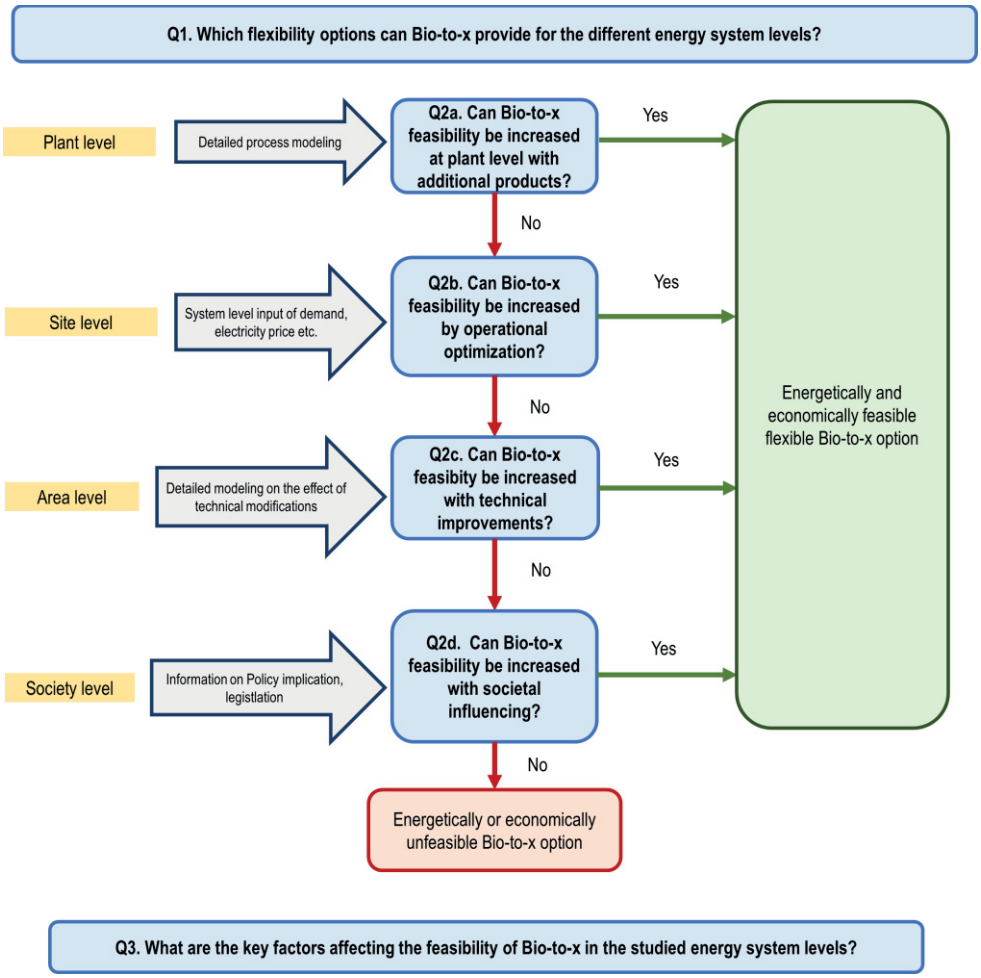

FIGURE 1. Feasibility of biomass utilization (Bio-to-x) in energy system with the research questions (blue boxes) and studied energy system levels (yellow boxes). The gray arrows include the main additional inputs in each system level.

This thesis contributes to the topic of the role of biomass in energy system balancing. The goal is to provide knowledge on effective and economical biomass resource utilization in energy system flexibility.

The study is based on two hypothesis:

1) Flexibility possibilities are dependent on geographical area; the availability of biomass, other resources, and socio-economic issues
2) Feasibility of flexible utilization method can improve as the study level broadens from plant level to society level

The main research questions including system level specific sub questions and focus of the Papers (I-IV) were:

1. Which flexibility options can Bio-to-x provide for the different energy system levels? **(Papers I-IV)**
2. How can the feasibility of Bio-to-x be increased in different energy system levels?
    a. at plant level with additional products? **(Papers I, and II)**
    b. with operational optimization? **(Papers II, and III)**
    c. with technical improvements? **(Paper III)**
    d. by societal influence? **(Paper IV)**
3. What are the key factors affecting the feasibility of Bio-to-x in the studied energy system levels? **(Papers I-IV)**

The Papers were organized according to expanding system level with each broader level including the previous level study. However, aspects of each level were at some level discussed in all of the Papers. The studied cases are examples of different end uses where biomass can be utilized. The studied end uses were biomass-to-chemicals (Paper I), renewable electricity storage by power- to-biogas (Paper II), biomass to heat and power (Paper III), and utilizing biomass as traffic fuel (Paper IV). Although CO_2 -emission reduction is not in the scope of this thesis, the matter is shortly discussed in papers II and IV.

1.2 Outline of the thesis

This thesis has been organized as follows. The introduction in Chapter 1 is followed by Chapter 2 that looks in more detail into the thesis subject background through biomass resources, biomass utilization options, energy systems and flexibility including a short introduction to some basic economic evaluation methods used in this thesis. Chapter 3 includes the materials and methods used in the studies. The results are presented in Chapter 4 where the research questions are answered and discussed; Q1 in Subchapter 4.1., Q2 and its sub questions in Subchapter 4.2., followed by Q3 in Subchapter 4.3. Conclusions are presented in Chapter 5, and the thesis ends in the future outlook in Chapter 6.

2 BACKGROUND

In 2017, total primary energy consumption in the World was 566 EJ (13511.2 Mtoe) with 2.2% increase from 2016 [20]. International organizations such as BP [21], and International Energy Agency (IEA) [3] believe that global energy consumption will continue to grow towards next decades, mainly due to increasing energy demand in developing countries. Historical trends of global energy use by source are presented in Fig. 2.

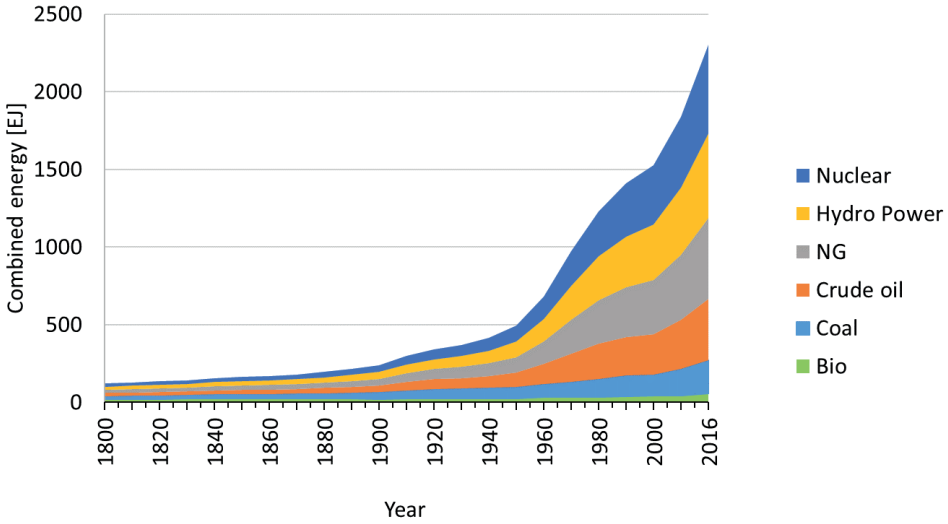

FIGURE 2. Historical global energy consumption. Historical data (1800-2000) from [22] and (2000-2016) from [3]

Even though the share of renewable energy sources is growing rapidly, the amount of fossil fuel utilization is also increasing, which lead to 1.6% increase in CO_2-emissions between 2016 and 2017 [20]. However, due to climate change and the global problems caused by it, the amount of CO_2-emissions should be decreased

dramatically in the near future. This can be achieved e.g. by improving the energy efficiency of energy systems or increasing the amount of renewable energy production.

Figure 3. presents the historical share of different energy sources in energy production. As can be seen in Fig. 3., historically biomass has been the most important fuel until coal and oil replaced it in the early days of industrialization. However, biomass is still the most important renewable energy source (Fig. 3).

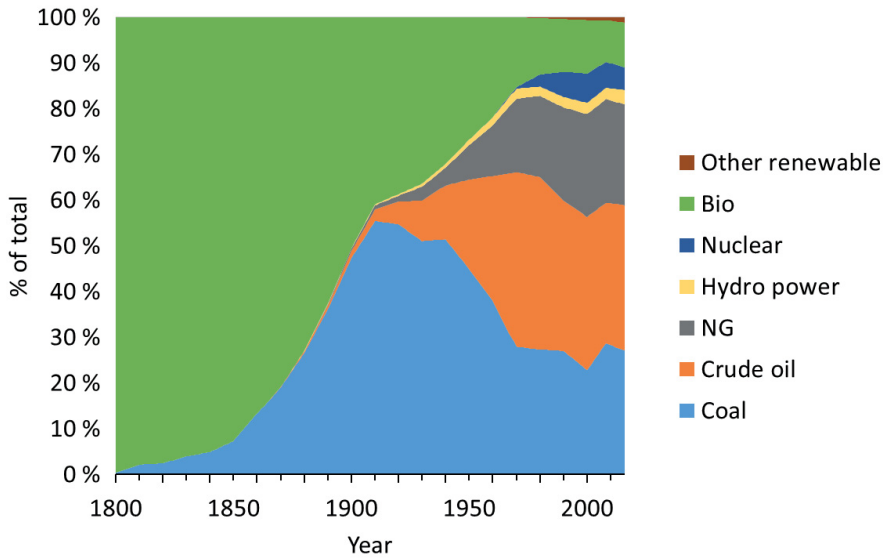

FIGURE 3. Share of energy sources in global energy production. Historical data (1800-2000) from [22] and (2000-2016) from [3]. Other renewables include wind and solar production.

In 2017, the fastest growing renewable energy production methods were wind and solar power production, over 50% of renewable capacity addition in 2017 was wind power and approximately one third was solar power [20]. As these production technologies are weather dependent and therefore the production fluctuates they may cause problems for the energy system balance. In addition to the electricity sector, the unbalance can also affect the heating and transport sectors. Currently the trend is towards electrifying also these sectors in order to decrease the fossil fuel utilization. This phenomena is further discussed in Subchapter 2.3.

The importance of biomass is still evident, as the total amount of utilized biomass has remained quite stable in terms of energy (Fig. 2). However, more than 50% of biomass use is inefficient traditional cooking and heating mostly in open fires [23].

Despite the fast growth of VRE production, biomass has kept its station as the most important renewable energy source, even if the traditional use of biomass is not considered [1; 23]. The role of biomass is believed to remain important also in the future. International organizations such as IEA, International Renewable Energy Agency (IRENA) [1; 6; 8; 11; 23], European Forest Institute [24] as well as many researchers [11; 25; 26] have suggested that up to 25% of global energy demand could be biomass. In a sense this would mean going back in history, as the share of biomass used to be equal to 25% in 1940's, as indicated in Fig. 3. However, the overall energy consumption has multiplied since then as Fig. 2 clearly shows. Therefore, 25% share of current total energy consumption would mean also multiplying the biomass utilization. Moreover, the biomass resources are limited and thus biomass should be utilized above all as a renewable resource supporting other renewable energy production. It has also been stated that reaching the climate goals might not be possible without the contribution of biomass [24; 26].

2.1 The role of biomass in energy production

IEA defines biomass as any organic matter that is available on a renewable basis [27]. Biomass, unlike fossil fuel sources is available in some form almost all around the World [28]. Biomass contains a great variety of feedstock from different origins including animal and plant derived feedstock, and organic waste from industrial and municipal sources. The energy density of biomass (MJ/m^3), is also dependent on the source. This makes the global amount of availability of biomass difficult to estimate, and most estimations vary from 50 to 300 EJ/a [29-33] although amounts as high as 1000 EJ/a have been reported [26]. Country level estimations are more readily available. In addition, the techno-economic amount of available biomass is dependent on social, political and economic aspects [26], which makes the estimations even more challenging.

Utilizing the full biomass potential requires major investments in the whole bioenergy production chain [29], therefore studying the different production paths and their feasibility is essential for determining the most efficient ones.

Even though the Earth is mainly covered by water, the net biomass carbon production happens mainly in forests (Fig. 4). This makes forestall biomass the most potential biomass source for large scale utilization.

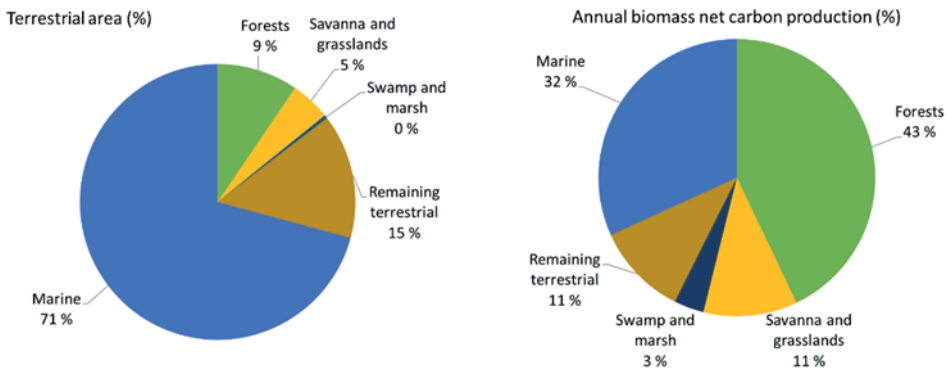

FIGURE 4. Terrestrial area and estimation of annual biomass net carbon production on Earth [34]

In addition to the availability of biomass, one of the advantages of biomass is that it easier to transport than other renewable energy forms such as wind and solar energy, and it is basically solar energy that has been stored as chemical energy in the

biomass compounds and be utilized on demand [35]. Technologies for biomass utilization are readily available, which increases its appealing to energy production [36]. Biomass causes less CO_2-emissions than fossil sources [36]. Currently biomass CO_2-emissions are calculated in the land-use sector (LULUCF) instead of the energy sector, which encourages biomass utilization in energy production in order to decrease the CO_2-emissions [37]. Furthermore, the locality of biomass makes countries less dependent on imported fuels and increases social equity between developed and developing countries [11; 28].

The downfalls of biomass include smaller energy density per cubic meter (MJ/m^3) than fossil fuels and the quality of even the same biomass species can vary depending on weather conditions and seasons [36]. This makes biomass a challenging energy source, as it has to be refined to a product that can be further used for producing electricity, heat or transport fuels. In addition to energy products, biomass can be converted to chemicals. It is essential for efficient biomass utilization that high-quality biomass is available throughout the lifetime of the biomass plant [36]. This is often dependent on the local policy and rivalry between other sectors interested in biomass such as food, feed and fiber industries [36]. In addition, increasing the energy use of biomass might have negative effects on land-use, biodiversity and greenhouse gas emission locally or globally [36]. The challenges of biomass utilization are discussed in more detail in Subchapter 2.1.2.

Currently, biomass is the most important renewable energy source in heating sector globally. In 2015, 70% of global renewable heating energy originated from biomass [23]. In power sector biomass is less important, in 2016 only 2% of the global power demand was covered by biomass [23].

Biomass has been recognized as an important renewable energy source in the European Union (EU) [38; 39], which is implemented in mandatory National Renewable Energy Action Plans (NREAP) of each member state. In 2016, 17% of gross final energy consumption in EU was from renewable sources and approximately half of this came from wood and other solid fuels [40]. The amount of bioenergy in EU is expected to increase in the next decade [7]. During the last decade the amount of wood used for energy production has continued growing from 2837 PJ (67.7 Mtoe) to 3940 PJ (94.1 Mtoe) [40]. The available biomass estimations, including both agro and woody biomass, in the EU area (11 countries) vary between 1745 PJ and 4953 PJ [41].

2.1.1 Biomass utilization and potential in Finland

In 2017, the total energy consumption in Finland was approximately 1.35 EJ (375 TWh), power consumption was 0.31 EJ (85.5 TWh), 36% of the total energy consumption was covered by renewable sources [42]. In 2017 27% of total energy consumption, and approximately 74% of renewable energy production was based wood fuels [42].

Main part of forest based biomass has for a long time been residual liquors and industrial wood waste. In 2017, 43% of the used wood fuels were forest industry waste liquors, mainly black liquor from pulp factories [43]. However, this makes flexible biomass energy production challenging since the main purpose of black liquor combustion is to recover the cooking chemicals. Power and heat are side products of this process.

Finland has agreed on the targets of the Kyoto protocol and EU 20-20-20 for diminishing the greenhouse gas emissions. The renewable energy target for Finland 2020 was 38% end use [38], which was achieved already in 2014 [40]. In 2017 the end use share of renewable fuels was approximately 40% [42].

Biomass, especially forest based biomass has been recognized as an important resource for the Finnish energy system and bio-economy in the future [44]. The national targets for renewable energy of Finland are strongly based on biomass, especially domestic forest based biomass [45].

2030 Targets at EU level give quite a lot of space for member countries to implement the greenhouse gas emission targets in the most cost efficient way, as long as the EU level target for reducing emissions by 32% compared with 1990 and share of renewables into 24% of energy end use is achieved [46]. Finland has set ambitious targets for emission reduction and renewable energy for 2030 and beyond. Targets for 2030 include 40% emission reduction from 1990 levels, increasing the share of renewables in energy production to 50%, increasing energy self-sufficiency to 50% and phasing out coal utilization completely [47]. This would mainly be replaced by wood based energy by increasing the usage from 0.35 EJ (97 TWh) in 2017 to 0.43-0.47 EJ(120-130 TWh) by 2030 [47]. This would be mainly forest industry side products. 2050 targets for greenhouse gas emissions reduction from the 1990 levels is 80-95% [47]. In practice this means increasing the share of biomass utilization in energy along with other renewable production methods.

Transport fuel targets for 2030 include 40% share of biofuels (gaseous and liquid) [47]. Achieving this seems more challenging, since in 2017 the share of renewable fuels in traffic was only 9% [42]. However, in 2017 the growth rate of renewable

transport fuel utilization in Finland was 101.9% [48], which was the fastest growth rate in the World.

In addition to emission reduction and fossil import dependence, self-sufficiency and security of supply are key elements in Finnish energy policy [47; 48]. Biomass, especially the forest based biomass, provides a viable opportunity for Finland to promote all of these goals. In addition, biomass utilization would bring a significant improvement to farm house profitability and employment in the country side [47].

2.1.2 Challenges in biomass utilization

Even though the potential of biomass in the energy sector is great, there are also some challenges related to the utilization of the full potential. Some of the greatest challenges are related to the global megatrends such as overpopulation and climate change. The population growth is concentrated in areas that are currently already suffering from energy poverty, such as Africa and some Asian countries [11]. Another challenge related to this is that in these areas the biomass is still used in efficient traditional manners for cooking and heating [1].

As discussed in Subchapter 2.1 the amount of available biomass is difficult to estimate. The main factors affecting the uncertainty of the estimations are land availability and agricultural production efficiency, water supply and efficiency of use, as well as population growth that has impact on the land use through increasing food/feed demand [35; 49]. Regional constraints include biomass production costs (compared with the fossil fuel price) and environmental issues (land use changes, biodiversity, and climate change) [35; 49]. EU has recognized several risks concerning biomass utilization in the energy sector [7] including increased air pollution, the inefficient use of resources, limited GHG savings, land use change, indirect land use change, impact on carbon stocks, impacts on biodiversity, water and soils, competition with other uses and distortion of a single market. Similar issues have been discussed in scientific literature as reviewed e.g. by [29; 49]. Moreover, biomass carbon neutrality or in larger context sustainability is disputable [24; 26], and arguments for [50] and against [51] can be found both in the scientific and common discussion. However, the complicated issue of biomass sustainability is not in the scope of this thesis.

As biomass comes in a variety of crops and sources, one of the challenges in biomass utilization is the complexity of supply chain. The necessary steps include feedstock production, feedstock logistics from the production site, conversion,

distribution, and end use [23]. After the feedstock has been collected and transported from the field, it has to be further chopped, dried or otherwise refined into a product before it can be further utilized for materials, transport fuel or power and heat production. Each step requires energy and this reduces the overall efficiency and economics of the production chain from field to end use.

Another challenge related to the variety of biomass is that the quality of biomass can vary even within the same species depending on the terrain and local weather conditions [28]. The main factors in the design of a biomass conversion technology are the heating value, ash content, moisture content and amount of components that can cause problems with the utilization method including Chlorine, Sulphur and ash forming metals [52]. In fact, the more chemically complex the biomass material is, the more difficult is the combustion or conversion of it [52; 53]. Moisture decreases the heating value of the biomass (MJ/kg and MJ/m^3). This increases the fuel consumption in terms of mass since more of the moist fuel is needed to produce certain amount of energy [54].

One obstacle to biomass utilization and conversion technology development has been the relatively low price of fossil fuels [7]. As the fossil fuels are gradually abandoned and fossil taxes introduced and increased in many sectors, the situation for biomass based utilization might improve.

2.2 Goals and feasibility of Bio-to-X options

Three main conversion routes for biomass have been recognized; thermochemical conversion, physicochemical conversion and biological conversion [35]. Possible end products include heat and power, as well as liquid or gaseous fuels. As discussed in Subchapter 2.1 the origins and conversion routes of biomass are numerous, and detailed introduction of the possible conversion routes is not in the scope of this thesis. This thesis includes studies on different biomass conversion and utilization methods, biomass to chemicals (Paper I), biomass to gaseous fuels (Paper II and IV), and biomass to heat and power (Paper III). In this theses, these are handled as bio-to-x options to keep the discussion more generally in biomass flexibility options.

As discussed in subchapter 2.1, biomass utilization has many advantages, and the utilization method should be chosen based on the desired goal. Motives for biomass utilization can be:

- CO_2-emission reduction
- fossil source dependence reduction
- increasing self-sufficiency and local welfare
- energy system demand and consumption balancing
- energy system overall efficiency improvement through storage and flexible generation

In addition to these goals, EU promotes energy security, sustainability, and affordability [55]. These can all be associated with bio-to-x options. The calculated CO_2-emission reduction depends on the bio-to-x sector and depending on biomass source, transport distance and production method it varies between -2 and 219% compared with fossil fuel utilization [55].

Basically, the biomass species (the amount of moisture and amount of lignin) determines the most economical conversion route [28]. Herbaceous plants are more suited for biochemical processes such as anaerobic digestion or fermentation, whereas less moisture and more lignin containing woody biomass is more suitable for thermal conversion processes such as pyrolysis or combustion [28]. Other thermal conversion processes are gasification and liquefaction [56]. As the energy

density of biomass is the key issue in transport costs, the local availability of biomass also determines the possible conversion technology.

The cost evaluation of biomass is a complex issue since each step of the production chain adds to the overall cost of biomass utilization. Harvest and transport costs are major cost factors for biomass utilization [28]. Agro and waste biomass costs for biogas production depend strongly on the origin of the biomass and location of the biogas plant. Some fractions such as sewage sludge may have a gate fee, which means income for the plant. Currently, biomass has no carbon tax in OECD countries as it is considered a carbon neutral fuel [57]. However, this might not be the case in the future.

Investment costs for biomass utilization methods depend on the chosen utilization route and maturity of the technology. As the matter of biomass cost is complex, detailed economic evaluation on biomass utilization should always be made case by case. Another important feature is investment costs of energy distribution grids. However, these are not affecting only on the feasibility of biomass but are rather an issue of the whole energy production system. Therefore the grid investment costs are discussed only briefly in this thesis.

Payback time, Net Present Value (NPV), and Return of Investment (ROI) were chosen for the feasibility studies in this thesis as well as Papers I-IV since they are commonly used measures and moreover, they are also understandable for general public.

The simple payback time method can be calculated as (Eq. 1):

$$t = \frac{P}{K} \qquad (1)$$

where t is the payback time in years, P is the overnight investment cost of the plant [€], and K is the yearly net profit of the investment [€].

The downfall of this method is that it does not include the time value of money, which may lead to overestimating the profitability. The time value of money can be included by applying (Eq.2) that is a derivative from the present value of an annuity formula:

$$t(a) = \frac{-\ln\left(\frac{1}{i} - \frac{P}{K}\right) - \ln(i)}{(1+i)} \qquad (2)$$

where i is the interest of the investment presented as a decimal number [-].

The profitability of a plant or concept can also be evaluated through calculating the ROI [%] (Eq.3):

$$ROI\% = \frac{K-d}{P} * 100\% \qquad (3)$$

where d is the yearly depreciation [€]. ROI is also called Return On Equity (ROE) [58].

As mentioned in Subchapter 2.1, biomass has low energy density per cubic meter (MJ/m^3) compared with fossil fuels, which is a major factor in the transportation costs of biomass [54]. Moreover, the moisture content of the biomass increases the transportation costs since moisture decreases the heating value of the fuel [54].

In Finland, the tax treatment of fuels is different between heating and power sectors. In the heating sector there is an energy content and CO_2-emission related tax, whereas in the power sector the tax is mainly paid for the purchased electricity [48]. This means that the cost of biomass is higher for heating sector as the tax is paid by the biomass plant, whereas for electricity the CO_2-tax is paid by the electricity purchaser. This makes the biomass utilization sectors inequal.

2.3 Energy systems

Energy system is defined as: "a group of things that are used together to produce energy" [59]. However, this can mean very different things depending on the source. Dale et.al [60] used the term bioenergy system to describe the bioenergy supply chain from feedstock production to end use. Others have used energy system to describe a CHP plant system [12; 13], town energy system [14], or a system consisting of country area [17; 18]. In addition, the size of an energy system covers a large variety from a single building [61], islands [16; 62; 63] and villages [10] to the entire World [64]. Moreover, the sectors included in energy systems vary. While earlier many researchers concentrated in single sectors such as power, heat or transport there are more and more studies that include all energy using sectors in comprehensive manner [64-67]. Integration of all energy utilizing sectors, power, heat/cooling and transport enables more efficient flexibility possibilities through various storage options, such as heat, solid and gaseous fuels [65]. Combining all the sectors can bring significant savings in fuel economy and system level investment costs [65].

Energy systems can be complex, as illustrated in Fig. 5. In many countries, the energy system is dependent on imported fuels. Local power systems are often connected with neighboring countries and district heating networks may cover neighboring cities. In addition to the physical system, there is interaction between other actors such as policy makers, energy customers, and energy market places. Therefore handling and modeling the whole system is complicated and multidisciplinary. However, in order to model and understand the energy system as a whole, detailed information about the individual parts of the system need to be understood. This is one of the goals of this thesis.

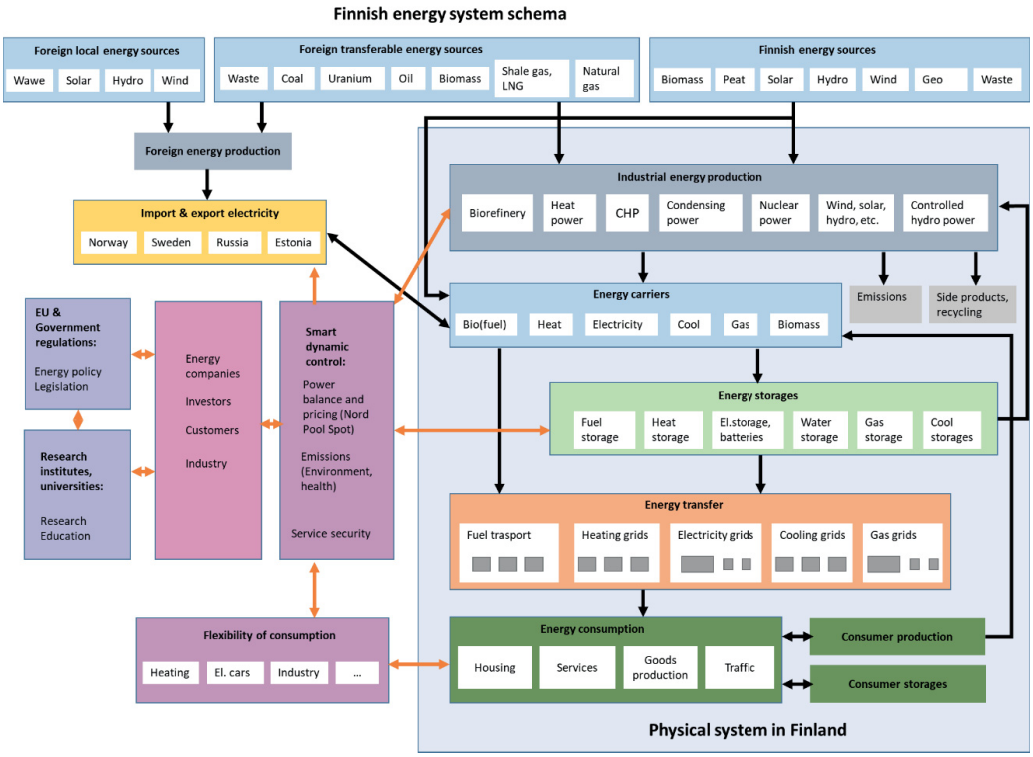

FIGURE 5. Scheme of the Finnish energy system, adapted from [68] © Timo Korpela, printed with permission.

2.3.1 Energy system flexibility

Energy production and demand in a physical energy system should at all times be in balance [69]. As the energy system changes and a growing amount of weather dependent renewable energy production is brought to the system, there might be times when the balance is disturbed, either by production gaps or by overproduction as illustrated in Fig. 6. This requires flexibility on both the demand and production side. IEA defines flexibility as the ability of the (power)system to response to sudden changes in production or demand side [70]. This should usually be met in the matters of minutes or hours.

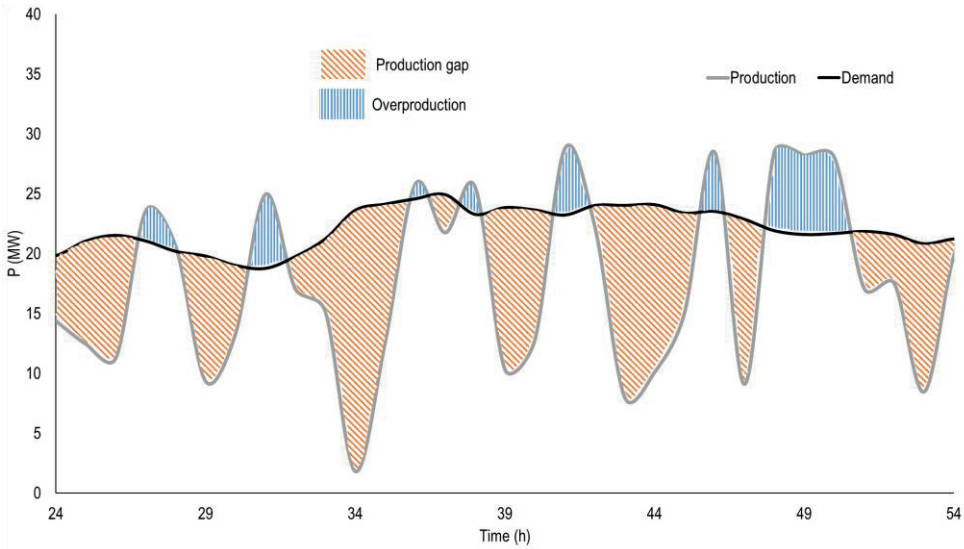

FIGURE 6. Example of an energy demand and varying production pattern

Traditionally, the system flexibility has been handled by using reserve power plants or energy storages [70]. This has been a successful approach in systems with relatively stable base-load production plants. However, as the wind and solar production are weather dependent the production unbalances often last only a few hours. Meanwhile, the production gaps may still require substantial back-up production in case the demand peaks occur on a windless time while there is also no solar radiation available. This leads to an uneconomic solution as reserve plants have to be built for peak demand and might be run only a few hours annually. In addition, existing plants that could be used for balancing are demolished due to the banning of fossil fuels or decreasing electricity or heat price, while fuel costs are not decreasing. Despite this, back-up power plants or energy storages will remain necessary in case of sudden break-up [70]. The most used renewable dispatchable and continuously available power production methods include hydro plants, geothermal energy and biomass [36].

Some of the demand gaps can be handled through energy storage. Energy storages also balance the production side as they can be loaded during peak production and unloaded during peak demand. Heat can be easily stored in hot water tanks or heat accumulators [71; 72], also buildings can be used for storing heat by increasing the temperature by 1-2 degrees [72]. However, electricity is difficult to store efficiently for long periods and is currently not economically feasible in large

scale [65]. Currently mainly pumped hydro storage is used for electricity storage [1; 9; 73; 74]. The downfall of pumped hydro storage is that suitable locations are limited.

As the trend towards completely renewable energy production systems continues due to climate issues and technology developments, it is evident that the energy systems become more complicated and novel balancing means are required. In addition, the electrification of traffic might cause more demand peaks and require smart demand control especially in the electricity sector.

The easiest way to consider the flexibility measures is at an individual site where the operator can choose the flexibility measure or combination of measures. However, the flexibility measures interact and local conditions such as biomass availability, energy demand pattern as well as socio-economic conditions determine the possible solutions for specific area. On the other hand, individual plants are built in a specific geographical area, but they can operate in system level (Fig. 7.). Understanding all the relevant operating levels (plant, area and system) is vital in designing the renewing energy sector since the most economical way to handle the flexibility depends on the viewpoint and it might not be the same at all levels.

As the energy demand and production should be in balance at all times, the issue of demand response time is also important, especially for electricity sector. For biomass technologies this is not an issue since quick response can be achieved with mature, existing technology for example with gas engines utilizing biomethane instead of natural gas. In the heating sector, response time of minutes or even hours is usually appropriate. This can be achieved with traditional technologies utilizing biomass, such as biomass boilers. In transport sector the response time is irrelevant. In addition, the time scale issue is more important for electricity sector as it is possible to electrify also the heating and transport sectors (excluding aviation). For biomass, the question is more related to the costs.

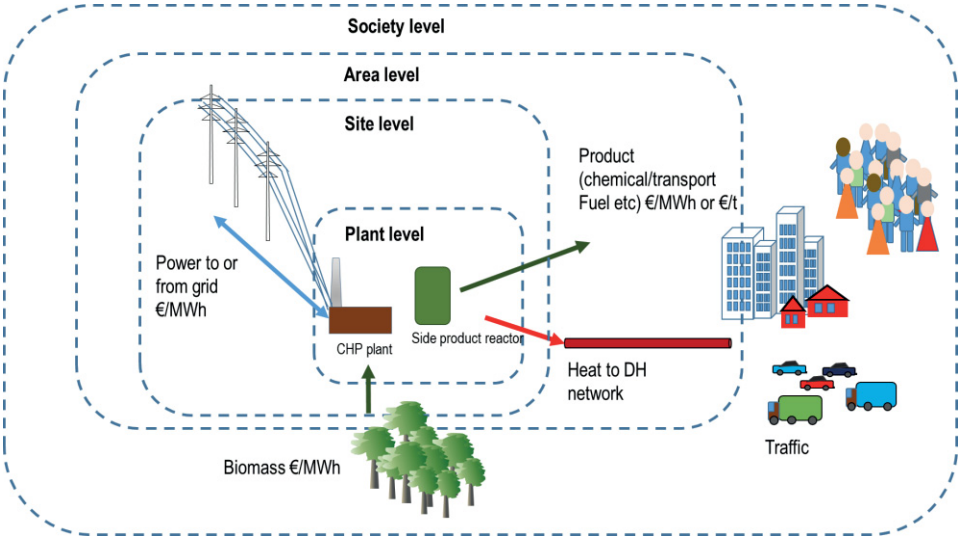

FIGURE 7. Energy system levels and boundaries studied in this thesis.

Several system level solutions for future energy systems have been introduced including the demand response, advanced batteries, electric vehicles (vehicle to grid), and power-to-x [75] solutions. Balancing power plants are needed also in the future, however the operation logic is different from what it is today [65].

Flexibility can also be handled at plant level through fuel flexibility, operational flexibility and solution flexibility. Fuel flexibility means that different variety (i.e. woody, agricultural, and waste) of biomass can be utilized either in the same facility or having separate plants for each biomass variety in the energy production system. Fuel flexibility can also mean that the quality of biomass mass can vary in a specific plant (e.g. moisture content, wood species, or share of agro fuel).

Operational flexibility means that a power (or heat) producing unit can be run in different modes depending on the needs of the energy network. Examples of operational flexibility include operating the plant in peak or basic load mode or the load following mode. Operational flexibility can also be used in the demand side by integrating a fuel refinement method into the plant and operating the refinement unit when power or heat demand in the system is lower than the VRE production.

Solution flexibility means that the biomass can be utilized for power, heat or refining in separate facilities or at a single plant site. In this work, refining includes biomass conversion to gaseous or liquid biofuels, chemicals production or any

process where the value of the raw biomass is increased, as well as using excess VRE production for refining the biomass (power-to-x).

2.3.2 Role of CHP in energy system flexibility

Combined heat and power (CHP) production has been recognized as an efficient technology in balancing the unevenness between energy consumption and production [76; 77]. One of the main advantages of CHP is that it is very efficient in comparison with producing an equal amount of power and heat separately and can save up to 20% of energy [78].

CHP production has been promoted in the European Communities since 1970's by European Council (EC) recommendations and resolutions [79; 80]. The EC has also encouraged the member states to invest in the usage of solid fuels since the 1980's [81; 82] because Europe was, and still is greatly dependent on imported fuels such as oil and natural gas. Solid fuels, such as coal, wood, turf and so on, can be used as fuels in CHP plants. CHP has also been identified as a suitable method for reducing greenhouse gas emissions [83]. However, as the recommendations and resolutions did not have enough effects on energy efficiency and CHP production, the Council gave first a directive on Cogeneration [84] and directive on energy end-use and energy services [85], which have been replaced by the energy efficiency directive [39] that still encourages EU countries to increase CHP production.

CHP is very important in bioenergy utilization, in 2016 approximately 30% of all biomass used for electricity and heat production globally (10.2 EJ) was used in CHP plants [86]. Benefits of biofueled CHP include reliability (not dependent on weather conditions), and high efficiency (typically 60-80%, even higher efficiencies are available) [87]. Biomass CHP technologies enable utilizing solid, liquid, and gaseous fuels [87] and some technologies allow utilizing fuel with varying quality such as municipal waste [88].

Existing CHP plants have often been built to mainly cover heat demand, which makes their utilization for power balancing challenging. However, the flexibility can be improved with heat accumulators or other heat utilization method [89]. CHP flexibility and profitability can also be improved by adding a side product production to the plant, such as gasification [90], drinking water [91], or biofuel [92].

Finland is globally the leading country in CHP production [48], in 2017 75% of district heating, and 32% of domestic power production was covered with CHP production [42]. CHP production has been struggling since the production cost of

power has been greater than the market price of electricity [48; 93]. As black liquor from the forest industry sector is very important in the Finnish CHP production and new pulp and bio-plants are currently being built and planned, it is likely that CHP will remain important for the Finnish energy system also in the coming years.

3 MATERIALS AND METHODS

Biomass has great potential to increase the flexibility of energy systems and recent scientific studies have agreed that the energy system should be handled as a whole [64-67]. This means that all the energy utilizing sectors, power, heat and transport should be included in energy system studies. However, as the dimensions of the system usually increase the level of detail decreases due to computational limits.

Biomass utilization concepts have to be feasible both energetically and financially. All the papers included in this study present a practical example of a biomass utilization method. In addition, the presented examples are based on available technology although the combination of technologies, a CHP plant combined with electric arc furnace (EAF) to produce biochemical (Paper I), and electrolyzer combined with a biogas plant to boost biomethane production (Paper II), are novel. The studied flexible biomass utilization methods include biomass refinement to chemicals or biofuels (Papers I, II and IV), power storage into biofuels (Paper II), flexible plant operation (Papers II and III), and the importance policy making (Paper IV). The papers included in this thesis are organized according to the size of the system level (Fig. 8), where also the inputs and main outputs of each paper are presented.

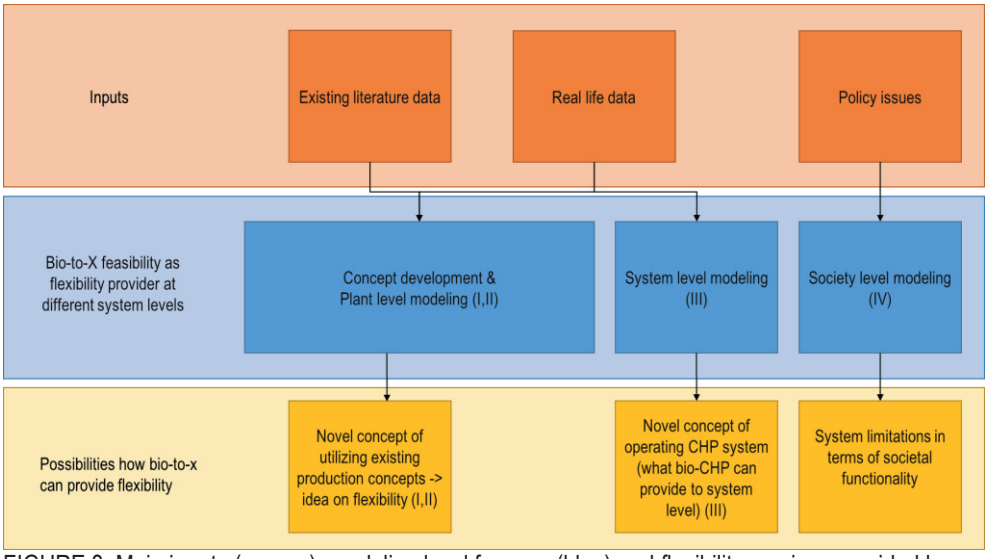

FIGURE 8. Main inputs (orange), modeling level focuses (blue) and flexibility services provided by biomass (yellow) in Papers I-IV. Broader study levels (system and society) also include the previous modeling levels.

The studied concepts were also chosen to represent different Technology Readiness Levels (TRL) [94], however, the organization of the papers does not follow these. The TRL's of the technologies are further discussed in subchapter 4.3. Paper I presents a novel concept idea for biomass to chemicals. In paper II, two existing technologies (electrolysis and anaerobic digestion(AD)) are combined in a novel way, while the concept of boosting AD biomethane production with H_2 addition is already used in the laboratory scale [95]. Paper III presents a mature technology (CHP) in a novel operation environment. Paper IV includes a mature technology (AD) and an early market development stage technology (wood gasification). These maturity stages were chosen to demonstrate the possibilities of biomass utilization currently and in the near future. As stated by Mathiesen et.al [65], it could be possible to run a 100% renewable energy system without biomass by the end of this century. However, before this can be achieved biomass will remain an important flexibility enabler with existing or currently emerging technologies [10; 65].

The economic feasibility of biomass utilization was studied in all the papers included in this thesis (Papers I-IV). The papers are organized according to studied system level (Fig. 7), and as the system level broadens the level of detail decreases in

order to keep the modeling simple. In all the papers spreadsheet simulation was used since it is a simple yet adjustable tool even for detailed plant level modeling. Paper I includes a detailed mass and energy balance at plant level as well as cost analysis of the produced CaC_2 and C_2H_2. In Paper II also economic operation optimization based on actual fluctuating electricity price was included in the site level study. In Paper III the modeling level was broadened to include local area power and heat network and the effect of technical improvements was studied at detailed level. In addition to area level, Paper IV handled the society level since policy making has a strong effect on viability of a biomass utilization method.

This chapter has been divided as follows. Subchapter 3.1 presents the basis of the detailed plant level modeling inputs used in the Papers. In subchapter 3.2, the feasibility study approaches used in this thesis and the accompanying papers is presented. Subchapter 3.3 concentrates in determining the key factors of Bio-to-x feasibility. In addition, as the evaluations of all the papers are based on an estimation of the main parameters a discussion about the result uncertainty is included in subchapter 3.4.

3.1 Detailed plant level modeling

First step in all the feasibility calculations is mass and energy balance. Often this requires knowledge on chemistry as well as information technical details of technologies. The required feedstock properties depend on the chosen conversion route, biochemical (AD) or thermochemical conversion route. In addition, detailed information on the process steps such as equipment efficiencies are required for complete mass and energy balances. After the mass and energy balance calculations, the feasibility requires detailed financial calculations. For this step, information on the feedstock price, installed equipment costs, product selling price and other financial background information. However, not all information is required in every study, since in many cases the detailed calculations or measurements of other researchers can be applied. This is practical especially for the larger system levels to keep the calculation time reasonable. Key technological parameters for detailed plant level feasibility modeling as well as the related Papers (I-IV) are collected in table 1, where some of the basic values are also presented. Values marked as varying or multiple can be found in more detail in the referred Papers that are attached as an appendix to the thesis. In addition, some of the parameters, such as the heat capacities of compounds can be fittings as for CaC_2 in Paper I.

The most important economic input parameters are presented in table 2.

Table 1. Collection of technical key parameters required for detailed plant level modeling

Parameter	Value	Unit	Paper
Feedstock chemical composition	50-% C, 7-% H	mass-%	I
Feedstock moisture content	40; 30	mass-%	I, II, III, IV
Feedstock biogas potential	0,5	m^3/m^3_{liquid}/day	II
Compound heating values	multiple	MJ/mol	I; II
Product gas composition	varying	vol-%	I; II; IV
Feedstoc heating value	20, 31;	MJ/kg	I; III; IV
Heat capacity of reaction compounds	multiple	kJ/mol	I
Reaction temperatures	varying	K	I; II
Chemical reactions and reaction products	varying	-	I; II; IV
Reaction Conversions	0.8, 1; 1	-	I; II; IV
Reaction entalphies	multiple	MJ/mol	I; II
Boiler or other reactor efficiency	0.9, 0.45*; 0.4, 0.7, 0.9**; 0.8***;	-	I; II; III;
Cold gas efficiency	0.7	-	IV
Minimum capacity	40	% of max	III
Pressure levels	1	bar	II
Pressure ratios	30	-	II
Process temperature levels	298, 773, 785, 1173, 2273, 2473****; 328[x];	K	I, II
Feestock temperature	293;	K	II
Starting time	6	h	III
End use efficiency	0.58, 0.40, 0.20[xx]	-	II
Power to heat ratio	0.2	-	III

*assumed bubbling fluidized bed boiler efficiency in Paper I and electric arc furnace efficiency [96]
**based on literature values of different electrolyzer technologies; alkaline, polymer electrode membrane (PEM), and solid oxide electrolyzer cell (SOEC) [97]
***typical steam boiler efficiency [88]
****assumed process temperature levels, H_2O feeding, Biochar feeding, CaO furnace, bubbling fluidized bed boiler, CO feeding to boiler, and electric arc furnace
[x]assumed anaerobic digester temperature
[xx]combined heat and power , small gas engine, gas fueled passenger vehicle

Table 2. The most important economic inputs of the plant level calculations

Parameter	Value	Unit	Paper
Equipment investment cost	1000, 3000, 3100*; 2431; 2640-5540, 8250**	€/kWe	II; III; IV
O&M costs	5	% of investment	III
Operational hours	5000; depends on production price; depends on production gaps;	h/a	I; II; III
Start-up costs	50	€/MW	III
Equipment lifetime	20; 30; 20	a	I; II; III
Investment interest	4; 4; 5; 4	%	I; II; III; IV
Feedstock price	20; 25;	€/MWh	I; III
Other chemical costs	0.2, 1; 1	€/kg, €/t, €/MWh	I; II
Electricity price	hourly varying ***	€/MWh	(I); II, III,
Product price	varying, based on literature or retailer price	€/MWh, €/t	I; II; III; IV

* based on literature values of different electrolyzer technologies; alkaline, polymer electrode membrane (PEM), and solid oxide electrolyzer cell (SOEC) [97]
**based on literature values of anaerobic digester [54] and wood gasifier [90]
***based on Nord Pool Spot hourly prices [98], see also Fig. 11

The required level of detail depends on the studied energy system level (Fig. 7). For the plant owner, the feasibility the study should be as detailed as possible to make the investment decision. At the society level it is usually enough to have a rough estimation of the costs of the biomass utilization method in order to make the decisions of policy measures, such as choosing to subsidize a certain sector of the energy system. In all the papers included in this thesis (Papers I-IV) the plant level calculations are based on available literature values. Basic assumptions in Papers I-IV are based on Finnish conditions and currently available technologies. Although the case examples included in this thesis are based on conditions and prices for Finland the results can be used to draw overall conclusions regarding research question 1.

3.2 Feasibility study approaches in this work

Despite the different operation environment/energy system levels discussed in this thesis, the angle of economic feasibility is the plant owner or operator level. This angle is chosen since the plant owner/operator makes the financial decisions based on the feasibility of the concept. If the planned concept is not economically feasible, the investment will most probably not be made. The related equations are presented in subchapter 2.2 and the basic input values in table 2 in subchapter 3.1.

Papers I and II included biomass utilization in novel concepts that are currently not commercially available. Therefore for these two papers the feasibility was based on the break-even price for the products. The break-even price was calculated by assuming that the production costs equal the revenues.

Production costs include capital expenditure (CAPEX) and operational expenditure (OPEX). The revenues can include the selling price of product and other revenues such as subsidies. In all the papers, the CAPEX has been treated as overnight costs including equipment, building, planning costs and fixed operational and management costs. Although the costs of the project are actually extracted during a long period of time (usually years), treating the overall capital costs of the project as overnight costs is a commonly used approach in engineering. The CAPEX was estimated based on actual costs (Papers I-IV) and costs of similar technologies when the studied concept contained process parts that are not currently utilized for biomass (EAF in Paper I).

In papers I and II the economic evaluation was based on the payback method with the time value of money (Eq. 2), while in paper III the simple payback time (Eq.1) and ROI% (Eq. 3) were applied. In Paper IV the investment costs and the price of saved CO_2-emission ton were calculated based on the annuity method.

The OPEX costs included in this thesis were electricity costs (Papers I and II), fuel/feed or additional material costs (Papers I, III, and IV) as well as start-up and spinning costs (Paper III). OPEX in Paper IV was based on literature values since focus was in the implementation barriers.

3.3 Determining the key factors of Bio-to-x feasibility

The determination of the key factors of Bio-to-x feasibility was based on the detailed plant level calculations described in Subchapter 3.1. First the product costs were determined for all the studied end products; CaC_2 and C_2H_2 (Paper I), biomethane (Paper II), heat and power (Paper III). In Paper IV the production costs were based on direct literature values since the focus of Paper IV was in the implementation of biomethane as heavy transport fuel. After determining the production costs the investment costs were calculated as €/t (Paper I) or €/MWh (Papers II-IV) to calculate the share of variable and fixed costs in the product cost. The relevant inputs and their values in each Paper are listed in Table 3.

Table 3. Average production and investment costs for determining the key parameters in feasibility of bio-to-x. n.a. refers to not applicable.

	Paper I	Paper II	Paper III	Paper IV
Investment cost [€/t, €/kWe]	858	2066	2431	5477
Electricity cost [€/MWh]	29,2	64,4	n.a.	n.a.
Feedstock energy [€/MWh]	20	n.a.	25	81
Other raw materials [€/kg]	0.20	0.0001	n.a.	n.a.
Average efficiency [-]	0.45	0.66	0.8	n.a.

Since there were several equipment investment costs in Papers II and IV as well as several equipment efficiencies in Paper II, for simplicity average values were used for the comparison in this thesis. The lifetime of all plants was assumed to be 20 years and interest 4%, all operational hours 5000 h. This figure was chosen since CHP plants (Papers I and III) in Finland are usually operated only during wintertime (September-April). The investment cost for all the concepts was determined using the annuity method described in Subchapter 2.2. In Paper I the basic value for electricity was used, in Paper II the average value of Nord pool Spot area price for Finland (2017) was used. In Paper II the feedstock cost was not included in the study since the focus was in the increased biomethane production form methanation of CO_2 originating from the AD reactor. For Paper IV the production costs were

assumed to be gasification feedstock costs since detailed cost analysis was not in the scope of the paper.

All of the Papers contributed to research question 2. How can the feasibility of Bio-to-x be improved in different system levels? The studied feasibility improvements (Fig. 1) included adding novel products to the plant (Papers I, and II), operational optimization (Papers II and III), technical improvements (Papers II, and III) and society level influencing through incentives and taxation (Papers I-IV, focus in Paper IV). For the purposes of this thesis, the results of the feasibility procedure presented in Fig. 1 for Paper II are presented since it includes all of the features. In addition, to make the results more utilizable, the analysis in Paper II was conducted for two different operation environments, Finland and Denmark. The operation environment difference was handled through different electricity price areas in Noord pool Spot prices (FI and DK1). However, the results will be discussed in relation to the other papers as well. The analysis was performed for four cases: Case 1 base case with constant operation throughout the year (8760 hours) and poor electrical efficiency (0.4); Case 2 operational optimization through an economic optimization method; Case 3 technical improvement by increasing the electrolyzer efficiency from 0.4 to 0.7; Case 4 calculating the amount of required subsidy for the plant to reach zero net income. The optimization method was based on determining a threshold price for electricity so that the production price of biomethane would be under 38 €/MWh and start producing when this threshold price would be reached. Biomethane price was chosen based on the selling price of natural gas in order to study the competitiveness biomethane without subsidies.

3.4 Result uncertainty

Energy systems are often complicated and in addition to different technologies it includes other aspects such as legal and societal issues. This requires a broad knowledge of different fields. As the studied system level broadens and the complexity increases it is usually beneficial to simplify the modeling with assumptions. This makes the broader system levels more uncertain than the detailed plant level studies. However, by making the basic simplification assumptions based on existing data the model becomes more accurate. In addition, future prices of investments and fuels is based on forecasts that might not prove to be right. This is also true when it comes to technological and energy market forecasting. Therefore some level of uncertainty has to be accepted and the results should be interpreted as indications of future development rather than exact numbers. This uncertainty was handled in the Papers by sensitivity analyses. This was to implicate how the feasibility of each studied concept is depending on different factors and how changes in the assumed parameter values change the feasibility.

Another limitation to energy system studies is that detailed data from existing plants is difficult to acquire since the details are often business secrets. This leads to simplifications as well. Despite the simplifications the studied concepts and systems included in this thesis are chosen based on realistic examples of existing technologies. Instead of relying on the actual results of the economics of the studied concepts the results should be treated as indicative of future possibilities. This includes technological potential of chosen concepts and the key factors in the studied cases. As many of the concepts presented in the papers included in this thesis (Papers I, II, and IV) are not commercial and will keep developing it is likely that the investment costs are overestimated and the efficiencies underestimated. This approach was chosen in order of not to underestimate the costs. However, the results give an indication of the most important parameters affecting the feasibility of the concepts. The results also indicate which of the technical aspects of each concept should be improved to make the technologies more energy efficient and economically feasible.

As discussed in Chapter 2, the variety of biomass feedstock and availability is depending on the area, and therefore covering all the aspects of biomass utilization is challenging. The case examples included in this thesis were chosen to represent

the biomass utilization options as widely as possible. As the flexible biomass utilization technologies are numerous it is not possible to include all of them in one study. Since the case examples represent the conditions in Finland, the results cannot be directly used in another environment. Energy demand patterns for example are dependent on consumer behavior and differ depending on the country as well as the geographical location. In developing countries with poor access to electricity and weather conditions that require cooling rather than heating the energy demand patterns can be rather different. This affects the feasibility of biomass utilization methods significantly and thus the feasibility should be estimated case-specifically.

Since some of the studied concepts (Papers I, and II) are novel ideas of biomass utilization and have not been adopted into practice, the validity of the operation of the concepts is difficult to assess. However, before adopting novel technologies, it is important to evaluate the energetic and economic feasibility of such concepts in order to decide if the idea is worth further developing or not.

4 RESULTS AND DISCUSSION

In this chapter the main results of the papers are presented and discussed in relation to each other. The full papers can be found in the appendix of the thesis. The chapter is divided into three subchapters according to the research questions. Subchapter 4.1 concentrates in research question 1: Which flexibility options can Bio-to-x provide for the different energy system levels? Subchapter 4.2 presents the answers to research question 2: How can feasibility of Bio-to-x be increased in different energy system level? Research question 3: What are the key factors affecting the feasibility of Bio-to-x in the studied energy system levels? is handled in subchapter 4.3.

4.1 Biomass flexibility options in energy systems

This Subchapter answers research question 1. Which flexibility options can Bio-to-x provide for the different energy system levels? The flexibility options of the different concepts are presented Fig. 9. In addition, the time scale of adopting each of the studied concept is briefly discussed.

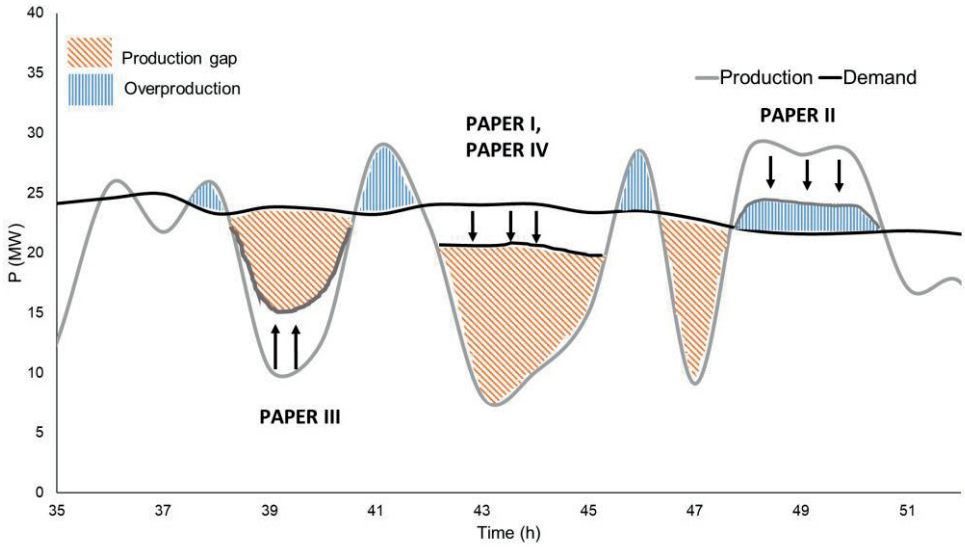

FIGURE 9. Main contribution of biomass to the energy system balancing from Papers I-IV. The magnitude of the effects depends on the amount of installed capacity and is presented only as indication of the provided flexibility advance.

In Paper I, the flexibility service provided by the plant is the demand response through operational flexibility. In practice this means that the Bio-to-x production can be adjusted to the heat and power demand. When the energy demand is smaller than the production, the amount of produced chemical can be maximized. When a production gap occurs, the chemical production can be shut off and thus a demand peak cut can be performed (Fig. 9.). The results of Paper I also showed that adding the by-product production in an existing CHP plant increased the overall resource

efficiency. The by-product production increased the overall plant fuel consumption only by 12% through plant site synergy as the side product flue gases could be utilized in the boiler replacing some of the required wood fuel. In addition, the renewable based C_2H_2 will help to decrease the utilization of fossil sources in society level when it is replacing fossil based acetylene. Even though the study showed that the concept could be energetically and economically feasible, the timescale for the adaption of the technology will happen only in the long run. Based on the results of Paper, the concept has reached technology readiness level (TRL) 2 [94], where the technology concept and application has been formulated. According to Mankins [94], there are 9 TRLs before a concept is "flight proven" and ready to be used in full scale.

In Paper II, the flexibility is mainly balancing overproduction (Fig. 9.). Combining an electrolyzer to an existing anaerobic digester, and utilizing the produced H_2 to boost the biomethane production of the AD can improve resource efficiency, since the CH_4 production of the AD could be increased. In addition, the studied concept decreases the need for biogas upgrading, as with H_2 addition the final CO_2-concentration of the AD product gas would be 0-vol%. Moreover, this can be seen as a carbon sink since the process binds renewable based CO_2 into CH_4. With operational optimization the plant can be run as a power storage means (Power-to-x) instead of curtailment when the overproduction of electricity occurs (Fig. 9). In addition, the product biomethane, can be utilized to balance production gaps if the end use is chosen to be power or heat production. Thus the concept of power-to-biogas, introduced in Paper II can bring operational synergy to the overall energy system. By choosing the end use sector of the biomethane according to the whole energy system needs (power and heat production or transport fuel) the synergy can be even further increased. The power to biogas concept of Paper II could be adopted into practice in the near future, since the technical parts (biogas plant and electrolyzer) are already established technology. In addition, the biological methanation concept is in demonstration stage in Germany [99] and Denmark [100].

The main contribution of Paper III was providing flexibility for production gaps by utilizing biomass. This could be achieved by optimizing either heat production or power production. In addition to operational synergy, the approach in Paper III is to bring additional flexibility by upgrading the CHP plant operational flexibility with improvements to the plant. The studied improvements included decreasing the ramp up-rate, decreasing the minimum load of the plant and fastening the start-up time. The results showed that the flexibility can be increased with these improvements,

however, this would require further investments. Additional benefit from the approach used in Paper III is system optimization in a physical energy system which also improves the overall resource efficiency. Moreover, as the CHP technologies utilizing biomass are mature technology, the flexible operation of CHP plants could be adopted right away.

In Paper IV, the main contribution to increasing the flexibility would be through demand reduction. By utilizing biomethane in heavy traffic instead of electricity would bring demand peak reduction potential. By replacing fossil fuels with domestic biomethane would reduce the dependency on imported fossil fuels and decrease the amount of CO_2-emissions which would bring additional benefit for the ongoing energy transition as discussed in Chapter 1. As in the other Papers, the approach used in Paper IV would increase the overall resource efficiency when utilizing mainly waste materials and waste wood residual for the biomethane production. Moreover, it was shown that even though the technology to utilize biomethane for (heavy) transport exists, the time scale of adopting is mainly dependent on political will. This is mainly due to missing policy framework for the entire transport biomethane production chain. One challenge in the policy making is the complicatedness to find a unified renewable energy policy and therefore the slowness of the process. For instance, it took several decades to build a common energy policy in the EU [101].

One important issue in the flexibility issue is the local availability of biomass and the ability of different technologies to handle different biomass species. The ability to handle different biomass species for the studied technologies is presented in Table 4.

Table 4. The ability of the studied technologies to handle different biomass species.

Technology	Suitable biomass	Paper
Direct combustion (CHP)	any biomass with <50% moisture	I, III
gasification	woody biomass, agro biomass	IV
anaerobic digestion	agro biomass, sewage sludge, municipal bio-waste	II, IV
biochar production	woody biomass	I

The results from Papers I-IV clearly show that biomass can increase the overall system level flexibility by reducing demand (Papers I and IV), filling in production gaps (Paper III), and diminishing overproduction (Paper II) while

increasing the overall efficiency of resource utilization. Increasing the flexibility especially in the bioenergy conversion stage has been seen important by earlier research [65] and the potential has been shown in Papers I-IV. However, the flexibility measures should be feasible in order to be realizable and this is further discussed in the next Subchapter.

4.2 Increasing the feasibility of Bio-to-x in different system levels

This Subchapter concentrates on the second research hypothesis: Feasibility of the chosen flexible utilization method can improve as the study level broadens from plant level to the society level, and research question 2. How can the feasibility of Bio-to-x be increased in different energy system levels? This included detailed plant level studies (Papers I and II), operational optimization in the plant site (Paper II) and physical system level as well as improving the feasibility with technical improvements at the plant site (Paper III). In Paper IV increasing the feasibility was discussed at the society level with policy recommendations. This Subchapter also addresses the TRL levels and scalability of the studied concepts.

In Paper I it was evident that the CaC_2 and C_2H_2 production from renewable materials is currently not competitive with fossil based production. The production cost of CaC_2 was 1.5 times the current selling price. The production cost of C_2H_2 proved to be nearly twice the current selling price of fossil based C_2H_2. This means that the renewable production would become competitive only with the fossil banning, the major increasing of fossil carbon tax or a subsidy for the renewable production. The main result was that it would be possible to improve the feasibility of an existing plant in a changing energy system by introducing a side product to the plant.

The results of Paper II showed that the production cost of power-to-biomethane could become competitive with the current biomethane selling price (38 €/MWh) by optimizing the operation based on the price of electricity needed for the electrolyzer. However, the production costs did not include the CAPEX of the electrolyzer. Since the operation hours of the power-to-biogas plant were based on the determined electricity threshold price the operation hours were rather limited, which led to long payback times (8-58 a) depending on the chosen electrolyzer technology. This was evident even if the target production price of biomethane was increased by 50%. This means that the concept is not feasible unless the investment prices of electrolyzer decrease significantly or the selling price of biomethane increases, or unless there is a subsidy for the production. The investment price of electrolyzers may decrease as the technology matures and installations become more frequent. The price of biomethane might increase, especially if it would be utilized

for electricity peak demand balancing. The main result of Paper II was that in addition to introducing a side product production can bring operational synergy to an existing bio-to-x plant, the feasibility can be improved with operational optimization reducing the operational costs by 80% (see also subchapter 4.3.). However, optimizing the plants operation by minimizing the production costs, also reduces the production amounts which reduces the income of the plant and increases the payback time in worst case by decades.

It was shown in Paper III that the plant feasibility at area level is very much dependent on the chosen operation optimization logic. In Paper III, these were either the power load following or the heat load following mode. In current operation environment with heat selling being a monopoly, the plant is always feasible when run in the heat load following mode. If the goal is to maximize power production balancing, the plant is feasible only if there is an additional use for the heat or a compensation for the spinning hours. This means hours when the plant is kept warm and ready to produce in case of a power gap. As CHP technologies are mature, it not likely that the investment costs would decrease significantly in the future.

In addition to the operation logic, the possibility of increasing the feasibility of bio-to-heat and power with technical improvements was studied in Paper III. The studied technical improvements were minimizing the start-up time and minimum load of the plant and increasing the ramp-up rate of the plant. The results of Paper III showed that with current technologies the ramp-up rates are already good enough for hourly response, whereas the feasibility can be improved with minimizing the start-up time and minimum load of the plant. However, the improvements in the current operation environment should not increase the overall plant investment costs more than 6%. The main result of Paper III was that CHP plant has a role in energy system optimization through plant level operation optimization, and the feasibility of an existing bio-to-x plant can be increased with technological improvements.

In Paper IV the focus was at society level options for increasing the feasibility of bio-to-transport. It was shown that by choosing the sector carefully and concentrating incentives on constructing the fuel delivery infrastructure. Additionally, the policy cohesion and reorientation of subsidies are needed in order to speed up a transition in the transport sector. The main result of Paper IV was that bio-to-transport fuel can enhance the energy transition in sectors that are difficult to electrify such as the heavy transport sector.

The main results of the Papers I-IV are strongly in line with previous researchers finding that connecting the flexibility of all the energy system sectors (power, heating/cooling, and transport) is the most-cost effective way to balance the energy system [65]. However, in terms of feasibility the optimal choice of technologies can also be not to invest in excess balancing methods. For the overall system it might be necessary to accept energy shortage or constrained load control [102] at times or curtailment in peak production hours [65]. For existing plants adding a side product or improving the performance of the plant with technological improvements could be very beneficial especially when the plants CAPEX has been depreciated and there is still operational lifetime left.

Technology readiness level and scalability are important aspects of feasibility. The current TRL and scalability of the technologies is presented in Figure 10.

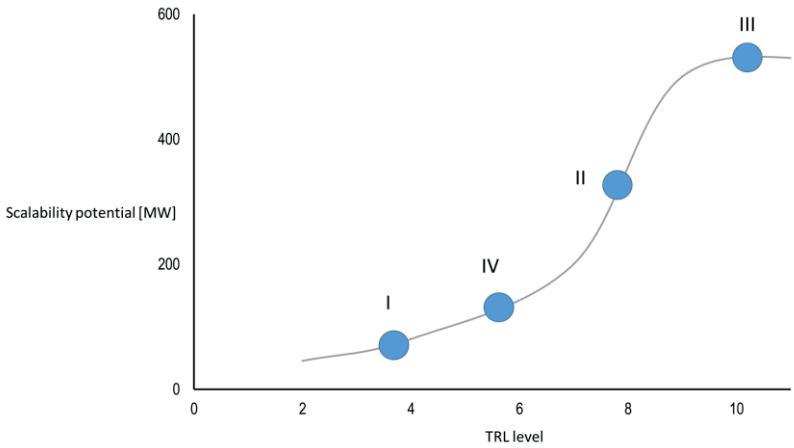

FIGURE 10. The scalability potential vs. TRL level of the studied concepts. The scalability potential is presented as indicative figure.

Paper I presented the material and energy balances of renewable CaC_2-production concept as well as economic analysis. The results clearly showed, that the concept is energetically and economically feasible. It can be placed in TRL 3 or 4 [94], as a characteristic proof of concept was achieved. However, as the concept has not been demonstrated even in laboratory scale, the scalability potential of the concept is uncertain and therefore the maximum scalability was chosen equal to the

EAF used in Paper I (50 MW). As the concept is based on availability of wood fuel and existing CHP plants, the potential building sites are limited.

In Paper II the main focus was in novel combination of known technologies, biogas plant and electrolyzer. These are both mature proven technologies, however, the biological methanation is only in demonstration phase [99; 100], the combined TRL level is close to level 8 [94]. Even though currently the maximum capacities of individual electrolyzers is in the magnitude of a few MWs [103], the system is highly scalable if multiple electrolyzer are feeding the same biogas plant.

The biomass fueled CHP plant presented in Paper III is mature technology (TRL 10) [94], and the scalability is mainly dependent on the availability of biomass, even 3000 MW biofueled plant has been estimated to be possible [56].

In Paper IV, two methods for producing the transport biomethane were studied, biogas plant and wood gasification. The gasification technology is currently in demonstration stage [90], and therefore the TRL level is considered in this thesis to be lower than for the technologies in Papers II and III. The scalability of the biogas plants is limited mainly by economically available feed material. However, the lacking policy for transport biomethane limits the scalability.

4.3 Key factors of Bio-to-x feasibility

This subchapter concentrates on the recognized key factors that affect the feasibility of Bio-to-x in different energy system levels. This was the third research question in this thesis.

Figure 11 presents the shares of production and investment costs in the final product cost of the studied concepts. These were biomass to chemicals (Paper I), biomass to transport fuel (Papers II and IV) and biomass to heat and power (Paper III). The production costs of each end product are divided into feedstock, other raw material and electricity costs. The electricity costs in Papers I and II included only the spot price of electricity. Grid fees were left out of the costs since they vary between countries and regions, and including these would make the results more difficult to apply for other cases. In Paper I this is a justified simplification since the electricity for the EAF can be electricity directly from the combined heat and power plant. In addition a sensitivity analysis for the electricity cost was performed, and the increasing electricity could also be from grid fee. In Paper II, a sensitivity analysis of the payback times to the increase in biomethane selling price can be seen as the compensation to the grid fee. All the costs are calculated as average production costs. This approach was chosen to indicate the effect of each economic parameter.

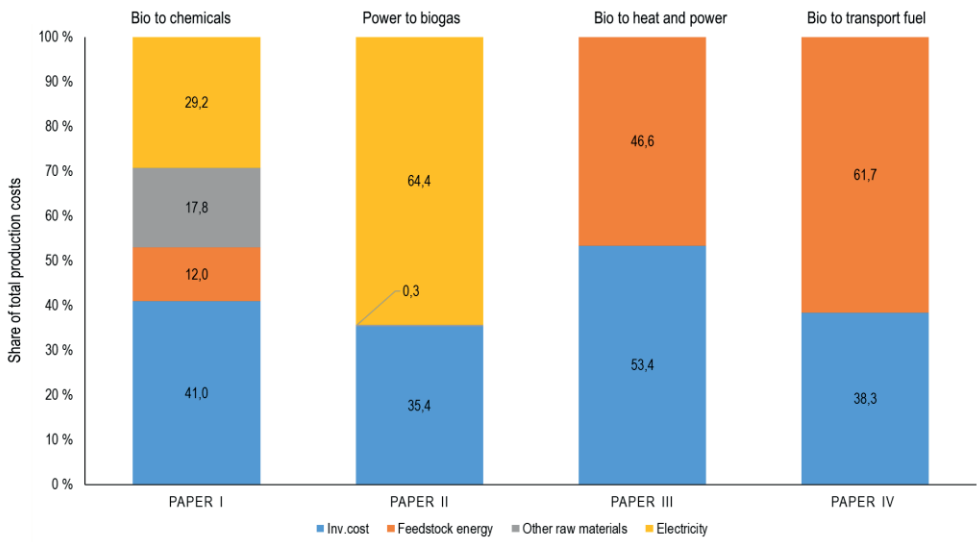

Figure 11. Share of Fixed costs vs. variable costs using average process values for papers I-IV.

As can be seen in Fig. 11, for most of the studied technologies, the production cost is mainly responsible for the overall costs of the product.

Paper I concentrated on the feasibility of a novel concept for producing renewable chemicals from biomass. In Paper I, the feedstock energy costs include the additional feedstock energy costs, other raw materials include CaO and water costs, and electricity costs include the electricity required for the EAF. As it was assumed that the CaC_2 production would be installed in an existing CHP plant, the investment costs were assumed to be only the additional costs for the chemical production. Therefore the main part of investment would come from the electric arc furnace.

The main aim of Paper II was to study a novel concept of combining hydrogen production by an electrolyzer into an existing anaerobic digester to boost the biomethane production. As the digester was assumed to be an existing one, the investment costs included only the additional electrolyzer investment costs. In Paper II three different electrolyzer technologies were studied and the investment costs represent the average value (2066 €/kW_e). The main production cost in Paper II was the electricity cost of the electrolyzer. In addition, the electricity cost was dependent on the electrolyzer efficiency which in Fig. 11 represents the average value of the studied electrolyzer technologies (0.66). In Paper II, the other raw materials included water for the electrolyzer (1 €/t). AD feedstock cost in Paper II was assumed to be 0, since the focus was in the possibility and costs of producing additional CH_4 by boosting the existing AD reactor with H_2.

The focus of Paper III was in the feasibility of a biomass fueled combined heat and power plant providing flexibility services in a changing energy system. In Paper III, the production costs of heat and power were assumed to be equal. Thus the production costs are dependent only on the feedstock price (25 €/MWh) and the overall efficiency of the boiler (0.8). As can be seen in Fig. 11, for CHP plant the share of the investment cost and the share of the production cost is almost equal. As CHP technologies in many cases are mature technologies, the investment cost is not likely to decrease in the future contrary to the early stage technologies studied in the other Papers.

The focus of Paper IV was in the implementation of biomethane fueled heavy transport sector. In Paper IV the production costs are based on literature values only

since detailed cost analysis was not in the focus of the paper. In addition the AD production cost depends on the feedstock and might also be negative (gate fee).

As a technology matures and the investments become more frequent, the investment costs are likely to decrease. However, as can be seen in Fig. 11, the effect of the production cost in all of the cases with a novel or emerging technology (Papers I, II, and IV), is more significant to overall product cost than the investment cost. In addition, with these technologies the overall efficiency is the main issue in the production cost. This was further discussed in the papers. However, the efficiencies of novel concepts are often expected to improve as the technology matures.

The feasibility can be improved with different operational or technical improvements as well as societal impact through subsidies and taxation. The effect of these affecting the overall feasibility in the different study levels was demonstrated by using Paper II as an example case. The analysis was conducted by applying the procedure in Fig. 1. Paper II was chosen for this since all the sub questions of research question 2 are included in Paper II. The analysis was performed for two specific cases where the plant would be situated either in Finland or in Denmark. These areas were chosen for the study in Paper II since they represent quite different power production environments which are indicated by different electricity price patterns (Fig. 13).

Results for the analysis are presented in Fig. 12, where Case 1 represents the reference case. In Case 1, the plant is operated throughout the year (8670 h). This also represents the approach used in Paper I where the CaC_2 production was supposed to be simultaneous with the CHP plant operation. In Case 2, the plant operation is economically optimized based on the biomethane production cost, which was the focus of Paper II. However, operational optimization was also performed in Paper III while the optimization logic was based on filling production and demand gaps rather than economic optimization. In Case 3, the plant operation was improved by increasing the efficiency of the electrolyzer. This approach was also studied in Papers I and III, either by efficiency improvement (EAF in Paper I) or other technical improvements (minimum load and start time in Paper III). In Case 4, a subsidy is introduced to improve the economics of the plant. This possibility was discussed in all of the Papers and further implication of policies was the focus of Paper IV.

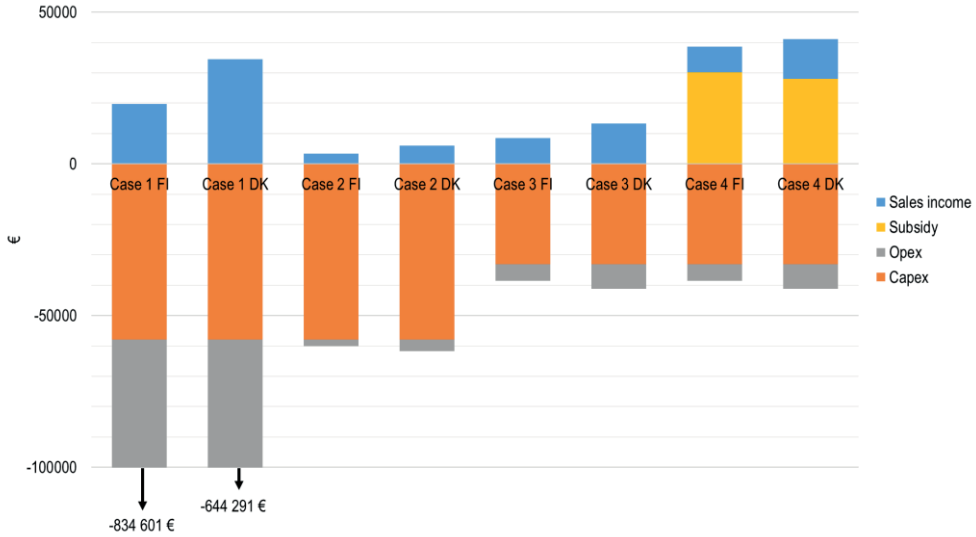

FIGURE 12. Effect of operational optimization (Case 2), technological improvement (Case 3) and societal impact through introducing a subsidy (Case 4). Case 1 represents the base case. FI and DK refer to different electricity price areas and thus different operational environments. The y-axis is cut to -10 000 € for presentation purposes.

As can be seen in Fig. 12 (Case 1) the operational environment plays a significant role in the feasibility of the studied concept. This is mainly through the lower average electricity price and at times even negative electricity price in price area DK (Fig. 13). This was also demonstrated in Papers I, and III where the fuel price was a significant factor in the overall production cost (Fig. 9). Furthermore, in Paper III, several different operation environments were studied with a varying amount of installed renewable power production. The results showed that increased varying wind production would decrease the overall feasibility of Bio-to-heat and power significantly. This strengthens the conclusion that operational environment has a significant role in the feasibility.

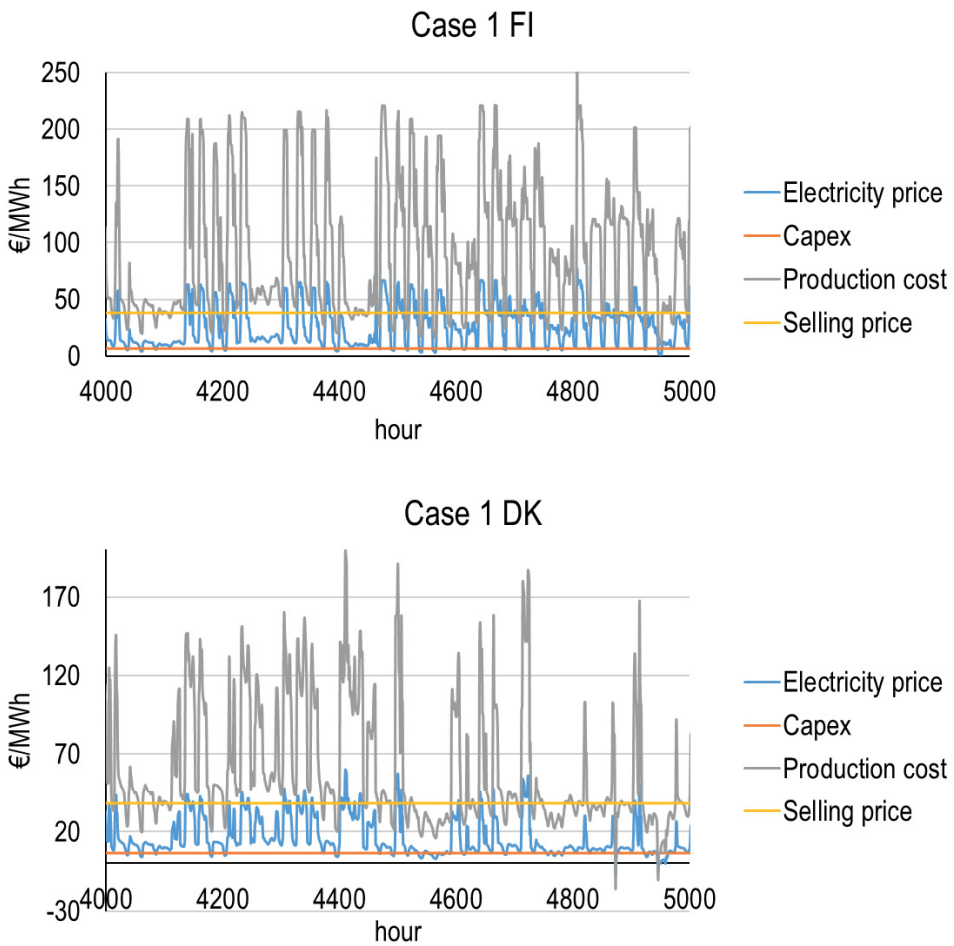

Figure 13. Breakdown of costs for Case 1 both FI and DK shown. Electricity costs from Nord Pool [98]. Only part of the year presented for figure clarity.

The results of Case 2 (Fig. 12) show that operational optimization is the most effective means to increase the feasibility of the studied concept. However, this will also reduce the operation hours and therefore reduce the profit. At the same time, it also decreases the production costs significantly. Moreover, as can be seen in Fig. 12 this does not necessarily mean that the plant will become profitable. In Paper III the optimization goal was different than in Paper I, instead of economic optimization, the goal was to optimize the system power or heat balance. This in turn resulted in decreasing feasibility as the investment cost of the plant would be amortized in a

longer period of time due to decreased operation hours compared with base load operation.

In Case 3 (Fig.v12) the profitability was improved by increasing the efficiency of the studied concept. This increased the profitability as the size of the required investment could be reduced. In addition, the production costs decreased since more of the energy would be left in the end product. The effect of technical improvements was also studied in Papers I and III. In Paper I, increasing the overall efficiency of the EAF from 0.45 to 0.6 lead to 14.5% decrease in the production costs of CaC_2 and C_2H_2. In Paper III the studied technical improvements were decreasing the start time and the minimum load of the CHP plant. The results showed that the plant overall feasibility could be improved with decreasing the start time from six to two hours and decreasing the minimum loads of the plant from 40% of maximum to as small as possible would increase the plant ROI% by 1 percentage unit.

However, as can be seen in Fig. 12, in addition to technical improvements some technologies might need a societal influence to become feasible. In Case 4 (Fig. 12) the power-to-biomethane concept subsidy was calculated based on break-even (income-costs=0). This means that for the FI case the subsidy would have to be approximately 30 000 €/a, which is almost equal to the Capex annuity (33 000 €). For the DK case, the required subsidy could be slightly less, approximately 27 000€/a. This is mainly due to the smaller production cost (lower average electricity price, see Fig. 13).

As the investment cost is in most cases decreasing with the maturity of the technology, the significance of the investment cost strengthens the conclusion that technology maturity is one of the key factors in feasibility. This means that the study timeline is one of the baseline choices when determining the optimal biomass utilization path in energy systems. This is in line with the EU RED II Directive as EU has recognized that funds should be allocated to decreasing the capital costs to enhance renewable energy infrastructure building [55].

5 SUMMARY AND CONCLUSIONS

Biomass has been recognized as an efficient means to bringing flexibility into energy systems. As biomass comes in many forms and the local availability varies depending on local conditions, the feasibility of the utilization is essential in terms of societal equality [11]. Currently there are still many developing countries that suffer from energy poverty and inefficient utilization of biomass resources [23]. Affordable and clean energy is one of the United Nations 17 goals for sustainable development [104], and biomass as a resource available almost all over the World is one solution to enhance the energy goal. However, in many studies and reports the possibilities are not studied intensively and in many cases the feasibility of utilizing biomass is ignored.

The aim of this thesis was to study what could be the role of biomass in the flexibility of energy systems both currently and in the future and how the chosen biomass utilizing method could become feasible. The study was conducted for four different system levels; plant, site, area, and society level. The original studies included in this thesis were chosen to represent biomass utilization sectors as comprehensively as possible including materials, heat and power, as well as transport. The studied biomass utilization methods included biomass to chemicals, power-to-biogas, biomass to heat and power, and biomass as transport fuel. The concepts were studied through practical examples using Finland as a case example. However, the results can be applied in other market environments as well.

The results showed that biomass has a role in providing flexibility services in energy systems. Biomass can provide flexibility by reducing demand with operational optimization or utilizing biomass in sectors that are difficult to electrify such as heavy traffic, and thus reduce potential power demand peaks. Biomass can be used efficiently for filling in demand gaps, and in power storage instead of curtailment. This result is an essential background information in finding the most optimal biomass utilization method for any energy system. In addition, this conclusion underlines the importance of operation environment in the feasibility assessments.

Each energy system is unique and should be handled as separate case study. This is further backed up by findings of Mathiesen et.al [65] that increasing the flexibility of especially the conversion stages is essential for the feasibility of bioenergy utilization. The studied concepts can deliver flexibility at different time scales; right away (Papers II and III) or in the long run (Papers I, II, and IV) whereas policy making enables the flexibility option in the long run (Paper IV).

Understanding the economics and societal importance of the whole bioenergy production chain is important in achieving sustainable development and competitiveness of biomass [11]. This has been shown also in the results of this thesis, as the feasibility of the studied concepts in current energy systems are depending on subsidies or tax exemptions. However, fighting the climate change is going to require major investments and biomass as a local resource might prove to be one of the most efficient ones. One of the greatest advantages of biomass is that it can be adapted right now since the technologies already exist. After all, sustainable development should also increase local know-how, social equity and bring environmental benefits [11]. However, it is clear that biomass cannot solve the flexibility of energy systems on its own if the usage is to remain sustainable.

The main findings of this thesis can be summarized as:

- Energy systems should be considered at four different levels to maximize flexibility and resource efficiency: plant, site, area, and society.
- Producing additional CaC_2 biochemical side product in a CHP plant offers means to increase both plant flexibility and profitability. (Paper I).
- At site and area level, balancing power overproduction through electrolyzer combined with AD instead of curtailment offers a possibility to increase biomethane production by 30-50%.(Paper II)
- Operational optimization at area level is the most efficient means to increase the feasibility of a bio-to-x concept. (Papers II and III)
- Utilizing domestic biomethane in heavy traffic instead of electrification could provide demand reduction and cover up to 66% of total energy consumption of current truck fleet in Finland. (Paper IV)
- Biomass can offer flexibility in all the studied sectors; power, heat and transport.

6 FUTURE OUTLOOK

As has been discussed in this thesis, energy system and the interactions between different sectors and operators in it are complicated. This requires deep knowledge in several different fields and multiple throughout studies. In addition, handling the energy system in the World as one entity is an impossible mission. Therefore studies in all the system levels handled in this thesis; plant, site, area, and system level, are needed also in the future. An interesting study could be a detailed study of the different interactions between different level operators and how these affect the overall picture.

Mostly energy system studies are based on assumptions of future demand and prices, which makes them only indicative. Therefore, more accurate energy system simulation on cost and product price development should be conducted. Combining detailed energy and financial calculations with futures research could bring a wider perspective to the possibilities of bioenergy in energy systems of the future. Other interesting research fields could be the impact of biomass to societal equity between developed and developing countries. Further studies combining policy research with energy system studies might bring novel policy suggestions and recommendations to increase the feasibility of biomass concepts. This was applied in Paper IV in a general level.

In this thesis, the sustainability and amount of available biomass was not studied intensively. This has been under discussion for example in the EU in relation to the new renewable energy directive (REDII). Therefore, a thorough life cycle analysis (LCA) of biomass concepts should be conducted in order to find out which of them are indeed carbon neutral (if any) and socially sustainable. As the biomass utilization possibilities and feasibility are dependent on the operation environment, also this should be conducted case by case. The analysis should also include detailed CO_2- and other greenhouse gas emission studies as this was out of the scope in this thesis.

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Appendix: ORIGINAL PAPERS

PUBLICATION
I

The economics of renewable CaC_2 and C_2H_2 production from biomass and CaO

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Research paper

The economics of renewable CaC_2 and C_2H_2 production from biomass and CaO

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ABSTRACT

This article presents the economics of a bio-based CaC_2/C_2H_2 production concept plant. The aim of the research was to study if renewable CaC_2/C_2H_2 production could be competitive in comparison with current technologies. The starting point was to integrate a wood char production unit into a combined heat and power (CHP) plant with a bubbling fluidized bed (BFB) boiler. The wood char was reacted with CaO in an electric arc furnace (EAF). The production costs of the CaC_2 were determined based on the wood char production costs as well as the EAF electric power consumption. The results showed that the C_2H_2 yield (18%) is similar to the current fossil-based production. However, the production costs proved to be even higher than the current selling prices of CaC_2 and C_2H_2. With the chosen basic feedstock (20 €/MWh) and electricity prices (45 €/MWh) the production costs of CaC_2 were calculated to be 725 €/t and for C_2H_2 1805 €/t. The cost effectiveness of the concept plant was determined using the payback time method including the time value of money. The break even selling prices were 747–920 €/t for the CaC_2 and 1940–3015 €/t for C_2H_2 depending on the desired payback time (4–30 years). The key factors in the production costs of CaC_2 and C_2H_2 are the price of electricity and the electrical efficiency of the EAF. The results also showed that recycling the Ca at the site could save up to 48% in fresh Ca material costs.

1. Introduction

Acetylene (C_2H_2) can be used as a building block for numerous chemicals and a variety of transformation paths is already known [1,2]. However, application of gaseous acetylene in everyday chemical production practice is difficult and requires special equipment and safety precautions [1]. Currently C_2H_2 is mostly produced from oil and natural gas [2,3] and there are numerous technologies in use [3,4], including partial pyrolysis, electric discharge processes, pyrolysis [3], as well as steam cracking of petroleum [2,3].

Calcium carbide (CaC_2) can be converted to C_2H_2 by reacting it with water. Other commercially important uses for CaC_2 include the preparation of cyan amide fertilizer and desulphurization of pig iron and steel [5]. The process of producing $CaC_2$from coal and $CaCO_3$ in an electric arc furnace (EAF) has been known a long time, and production in commercial quantities started in 1890's [6,7]. In fact, one of the first commercial CaC_2 plants in Shawinigan, Quebec, Canada, utilized hydroelectricity for the EAF [7]. The same technology is still used for CaC_2 production [8]. Disadvantages of CaC_2 production in EAF are, that due to low reaction rate and high temperature (close to 2200 °C), a long reaction time (1–2 h) is often required. This leads to high electricity consumption and therefore high production costs [2,9]. CaC_2 is a powdery substance easy to store, weigh, and handle [1], so the acetylene production could also happen elsewhere besides the CaC_2 plant site [3,10].

Attempts to reduce the production costs of CaC_2 and electricity consumption of the production process have been tried for decades. The studied technologies include the direct synthesis of acetylene from the pyrolysis of CH_4 [11–13], and a rotary kiln process [14]. The downfall of these technologies is, that they utilize fossil carbon source. As a recent IPCC report [15] states, there is a n urgent need to reduce the usage of fossil fuels to keep the global warming in less than 1.5 °C. The means of reducing fossil fuel utilization should also include finding methods of producing important chemicals from renewable sources.

A previous study [9] has shown that CaC_2 can also be produced from wood char. The proposed process [9] resulted in considerably reduced temperature, shortened reaction time, high calcium carbide yields, and increased thermal efficiency compared with the coal char

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process. This would suggest that using wood char in the traditional CaC_2 production by EAF has a great deal of potential, and it could possibly improve the existing overall process efficiency.

The aim of this work was to perform study if renewable CaC_2/C_2H_2 production from wood char could be competitive with traditional fossil fuel based production technologies. Along with the economic study, the purpose was to describe a novel concept of combining fluidized bed technology with the electric arc furnace as a biomass refining process chain. The main research questions were:

1. Is the C_2H_2 yield is even theoretically competitive with current methods utilizing fossil fuels (8–24%) [3]?
2. If yes, what would be the production costs of CaC_2 and C_2H_2?

Based on current knowledge, these have not been analyzed previously; only the thermodynamics of C_2H_2 production from coal has been reported before [16], and economic analysis of even fossil production seems to be lacking [2]. Also the possibility to improve the overall economics of a standalone CHP plant is discussed. In the Nordic countries, the main product of CHP plants is usually district heating, and therefore the annual operation hours are in the range of 5000 h.

The study was based on literature values of an operational hypothetical combined heat and power (CHP) plant, where the renewable CaC_2 production would be installed. The studied system consisted of a Bubbling Fluidized Bed (BFB) boiler where the wood char production is performed and an Electric Arc Furnace (EAF) where CaC_2 is produced from the wood char and calcium oxide (CaO). The calculations were performed for an example case where the CaC_2 and C_2H_2 production would be installed in a hypothetical operational CHP plant, that produces 100 MW of electricity and 200 MW of heat. The EAF power consumption was assumed to be 50 MW. Despite the possible beneficial properties of wood char [9] and the particle size of CaO and C [17], the process calculations were conducted with conventional process parameters. The CaC_2 can be further reacted to C_2H_2 by reacting it with water, and the economics of further refining of the CaC_2 to C_2H_2 was also studied, as well as the economics of recycling CaO in the system. In this study, the feedstock for the boiler fuel and the wood char production was assumed to be pine wood with the properties based on [18–20]. Use of the term wood char was chosen, since the carbon content of the char was assumed to be 83% [20]. However, also wood charcoal could be used for the CaC_2/C_2H_2 production.

2. Process description and modeling

The economic analysis of the CaC_2/C_2H_2 production concept was based on a hypothetical CHP plant with a power to heat ratio 0.5 retrofitted with the CaC_2/C_2H_2 - production (Fig. 1). All the calculations were performed in a spreadsheet, and the information used in the calculations were based on the available literature of existing plants or theoretical data. First the production process was evaluated based on mass- and energy balances, followed by economic assessment. A sensitivity analysis was also performed in order to determine the most critical process elements affecting the CaC_2/C_2H_2-production costs as well as the overall economics of the concept. Also the possibility to recycle CaO in the process was studied.

2.1. Production process evaluation

The bio-based CaC_2 production concept plant was assumed to have two major functional components: BFB boiler and an EAF (Fig. 1). Since the interest in this study was on both the CaC_2 and C_2H_2 the process evaluation was divided into two parts accordingly (Fig. 1.). CaO recycling can be up to 60% to avoid possible contamination [2] such as iron oxides, SiO_2, Al_2O_3, MgO as well as nitrogen, sulfur and phosphorus compounds [5]. Feed, intermediate and end product characteristics used in this study, are gathered in Table 1 (CaC_2 production) and 2 (C_2H_2 production and CaO recovery). The process modeling calculations included mass and energy balances of the CaC_2 and C_2H_2 production as well as CaO recovery (Fig. 2.) (see Table 2).

2.1.1. CaC_2 production

The CaC_2 production process studied in this paper included two process stages (Fig. 1.), the wood char formation in BFB boiler, and reaction of the char with CaO in the EAF. The idea in the process was that additional lignocellulosic biomass fuel is inserted into the BFB boiler for wood char formation. The fuel feedstock for the boiler and the char production was assumed to be pine wood [18–20] (Table 1).

The additional fuel for the wood char production was planned to be transported through the furnace e.g. in a metal pipe equipped with a screw inside. The pipe can be mounted into a suitable spot based on the furnace geometry, the temperature level, and the flow field. As the screw rotates the fuel starts to dry and pyrolyse. The pyrolysis gases are discharged from the pipe into the furnace through holes in the pipe. The screw rotation speed can be adjusted to match suitable residence time for the fuel in terms of the required pyrolysis stage. However, detailed determination of the mounting spot and rotation speed were out of the scope of this study. The pyrolysis temperature inside the char formation screw was assumed to be 500 °C [24].

The starting point for the CaC_2 production mass and energy balances (Fig. 2) was the primary fuel amount for the BFB boiler, that was calculated based on the furnace efficiency (0.9) and the chosen output electricity and heat amounts (100 MW, and 200 MW, respectively). The lower heating value, q_{LHV} (kJ/kg) of untreated wood and char was calculated according to (Eq. (1)) [25]:

$$q_{LHV} = q_{HHV} - 212.2H - 0.8(O + N) \tag{1}$$

where q_{HHV} is the higher heating value of the wood [kJ/kg], and H, O and N represent the mass proportion of hydrogen, oxygen, and nitrogen in the wood [%]. The moist fuel lower heating value $q_{LHV,\ moist}$ [kJ/kg] was calculated according to (Eq. (2)) [25,26]:

$$q_{LHV,moist} = q_{LHV}{}^{*}\left(\frac{(100 - w)}{100}\right) - 24.4w \tag{2}$$

where w is the mass proportion water in the wood [−]. The amount of required wood char for the EAF was then calculated based on the chosen EAF power demand (50 MW) (Fig. 2.). The amount of additional fuel for the wood char formation was then calculated based on the amount of wood char for the EAF. The char was assumed to be inserted directly from the BFB into the EAF at the pyrolysis temperature, 500 °C, and the assumed CaO feeding temperature was 25 °C (Fig. 1.). The EAF electricity consumption was calculated as the sum of heating the input feeds to the required temperature, 2200 °C [27], and the reaction enthalpy required for the CaC_2 formation. Moreover, the energy losses of the process were taken into account with an overall furnace efficiency value (0.9).

The efficiency of the EAF was estimated based on steel production reports. In Ref. [28], the EAF efficiency seemed to grow close to 40% in the year 2000. An optimistic efficiency value of 45% was extrapolated based on this.

The CaC_2 formation from the bio char and calcium oxide (CaO) in the EAF was assumed to occur in 2200 °C [2,9] according to (Eq. (3)):

$$3C(s) + CaO(s) \rightarrow CaC_2(s) + CO(g) \tag{3}$$

The conversion of CaO to CaC_2 was assumed to be 0.8 [9]. The gaseous CO from (Eq. (3)) was assumed to recirculate back into the BFB boiler furnace at a temperature of 2000 °C. The sensible enthalpy and heat of combustion of CO was taken into account in the furnace energy balance as well as the heating of additional fuel for the wood char production.

2.1.2. C_2H_2 production

In this study the CaC_2 was assumed to be further processed at the

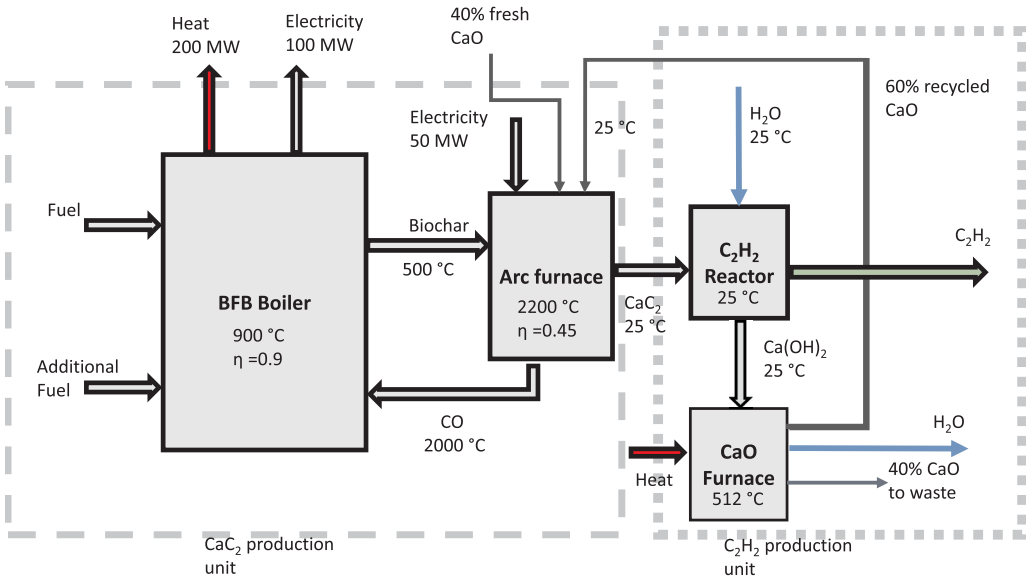

Fig. 1. Bio-based CaC_2 production concept, process temperature levels, process inputs and process outputs. The dashed line represents the CaC_2 production (see section 2.1.1) and the dotted line the C_2H_2 and CaO recovery production (see section 2.1.2.).

Table 1
Feedstock, intermediate and end product characteristics in CaC_2 production (Fig. 1) [9,18–23].

Process stage	Property	Value	Unit
BFB Boiler	HHV wood	20	MJ/kg
	m% of C in wood	50	%
	m% of H in wood	7	%
	moisture in wood	40	%
	calculated LHV of wood	10.1	MJ/kg
	c_p wood, dry	1500	J/kgK
	Reaction enthalpy of CO combustion	110.5	kJ/mol
Arc furnace	HHV char	31	MJ/kg
	m% of C in char	83	%
	m% of H in char	3	%
	calculated LHV of char	30.4	MJ/kg
	char left after treatment	20	%
	c_p char, dry	1900	J/kgK
	c_p CaO	1238.5	J/kgK
	conversion of CaO to CaC_2	0.8	–
	Reaction enthalpy of CaO to CaC_2 (Eq. (3))	464.8	kJ/mol (CaC_2) endothermal

plant site (Fig. 1) to produce acetylene (C_2H_2) by reacting it with water (Eq. (4)):

$$CaC_2(s) + 2H_2O(l) \rightarrow C_2H_2(g) + Ca(OH)_2(s) \quad (4)$$

The produced CaC_2 would be extracted from the EAF at a very high temperature (2200 °C) and cooled down to room temperature (25 °C) for safety reasons, since further reaction of CaC_2 with H_2O (Eq. (4)) is highly exothermic. In the mass and energy balance calculations (Fig. 2.) the conversion of CaC_2 to C_2H_2 was assumed to be 1, since the reaction (Eq. (4)) is rapid, and happens spontaneously. The reaction enthalpy (released energy) of the C_2H_2 formation reaction (Eq. (4)) was not taken into account in the calculations since utilizing the released heat is challenging, and would require further investments at the plant site. The energy need for further purification and pressurization of acetylene was also not covered in the current work, since further utilization of the C_2H_2 is not handled in this study. The CaC_2, which is a powdery substance could also easily be transported to another site for further processing [3,10].

2.1.3. CaO recovery

The downfall of the reaction of CaC_2 to C_2H_2 (Eq. (4)) is, that to prevent overheating it requires plenty of water, approximately 7–9 t/water per one tonne of CaC_2 [16]. This makes the formed $Ca(OH)_2$-slurry hard to utilize further unless it is dried to decrease the amount of moisture. The $Ca(OH)_2$- slurry from the reaction of CaC_2 to C_2H_2 (Eq. (4)) can be used as soil stabilizer in road construction sites [30,31]. However, the residue has high $Ca(OH)_2$ content [31], so the possibility to recycle $Ca(OH)_2$ in the process was also studied. $Ca(OH)_2$ can be converted back to CaO by heating it to 512 °C (Eq. (5)):

$$Ca(OH)_2 \rightarrow CaO + H_2O \quad (5)$$

In this study the amount of water was assumed to be 8 t/water per one tonne of CaC_2. The $Ca(OH)_2$- slurry was first assumed to be drained to 80 mass-% of moisture. The energy consumption of (Eq. (5)) was then calculated taking into account the heating of the drained $Ca(OH)_2$-slurry, latent heat of the water in the drained $Ca(OH)_2$- slurry, as well as the reaction enthalpy. The reaction was assumed to happen in constant ambient pressure (1 atm).

The cooling energy of (Eq. (4).) could be utilized at the plant site e.g. for $Ca(OH)_2$ - slurry drying in the Ca recycling process. However, the heat transfer is difficult, and it has been reported [5] that under 33% of the available heat can be reused. Based on this the available heat from CaC_2 cooling was determined using a fit for the specific heat capacity of CaC_2 [32], and assuming that 30% of the released heat can be further utilized at the site.

2.2. Financial calculations

Basically heat and power from the BFB could be used for the EAF and CaO recovery reactor. However, in order not to underestimate the production costs the financial analysis was calculated based on assumed grid electricity price (45 €/MWh). In the financial calculations, the profitability of adding the bio-based CaC_2/C_2H_2 production to the CHP

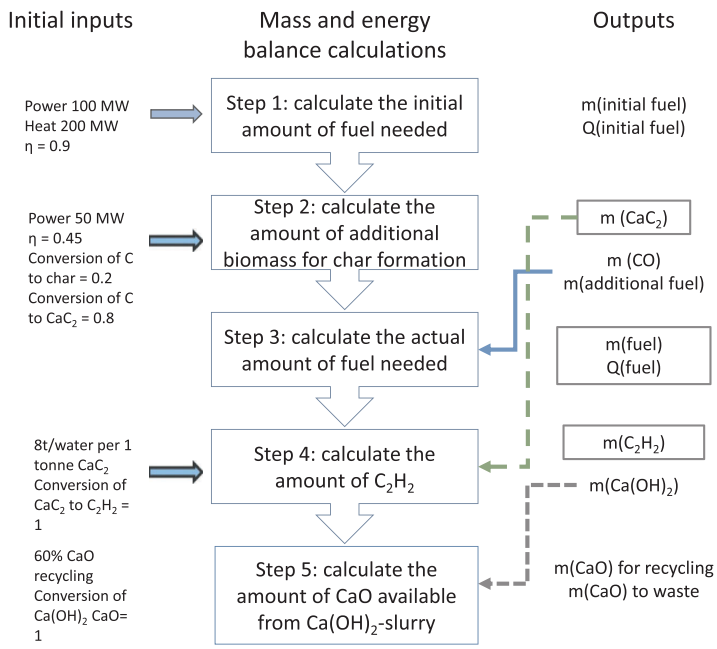

Fig. 2. Process mass- and energy balance calculation procedure. The main outputs of the evaluation are amount of the produced CaC_2 (m(CaC_2)), the amount and energy content of the fuel into the process (m(fuel), and Q(fuel)), and the amount of produced C_2H_2 (m(C_2H_2)).

Table 2
Feedstock, intermediate and end product characteristics in C_2H_2 production and CaO recovery (Fig. 1) [29].

Process stage	Property	Value	Unit
C_2H_2 Reactor	Conversion of CaC_2 to C_2H_2	1	–
	c_p $Ca(OH)_2$	1209.2	J/kgK
	Reaction enthalpy of $Ca(OH)_2$ recovery (Eq. (5).)	109.2	kJ/mol
	Enthalpy of liquid H_2O in 25 °C	104.8	kJ/kg
CaO Furnace	Enthalpy of liquid H_2O in 100 °C	419.1	kJ/kg
	Enthalpy of H_2O steam 100 °C	2675.6	kJ/kg
	Enthalpy of H_2O steam 512 °C	3514.4	kJ/kg
	Conversion of $Ca(OH)_2$ to CaO	1	–
	HHV of CaO	48.2	MJ/kg

plant was studied. The production costs of the CaC_2 and C_2H_2 were calculated based on (Eq. (6)):

$$Cost_p = \frac{P_{fuel} + P_{CaO} + P_{el} + (P_{water})}{m_p} \tag{6}$$

where p refers to the product, P_{fuel} is the price of the extra feedstock inserted into the BFB furnace for the bio-char production [€/h], P_{CaO} is the market price of CaO needed in the EAF (Eq. (3)) [€/h], P_{el} is the price of electricity consumed by the EAF [€/h], and m_p is the mass of the desired product. P_{water} is the price of water needed for C_2H_2-production (Eq. (4)) and taken into account only when calculating the production costs of C_2H_2.

For the production costs calculation the basic feedstock price was assumed as 20 €/MWh, the electricity price 45 €/MWh, CaO price as 0.2 €/kg [33], and the water price 1 €/t. Further purification and pressurization of the C_2H_2-gas were not taken into account in the financial calculations. Since the fuel used for the wood char production was considered the same as the fuel of the CHP plant, it was also assumed that the fuel handling and char production didn't need any extra personnel. Also the reaction of char and CaO in the EAF as well as the C_2H_2 formation can be automatized, and thus any extra personnel costs were ignored in this study.

The overall economics of the integrated plant was studied by determining break-even selling prices for the products (CaC_2 and C_2H_2) using different investment interests (1–15%) and payback times (4, 8, 15, and 30 years) for the investment. The break-even prices were determined from the yearly income of the plant, that can be solved from the number of paying periods (Eq. (7)) which is a derivative from the present value of an annuity formula:

$$n = \frac{-ln\left(\left(\frac{1}{i}\right) - \left(\frac{P}{K}\right)\right) - ln(i)}{(1+i)} \tag{7}$$

where *Ln* is the natural logarithm, i is the interest of the investment [−], *P* is the capital cost of the investment [€], and *K* is the income of the plant for one year [€]. The annual operating hours of the plant were assumed to be 5000 h. By setting the number of payment periods (*n*) equal to the desired payback time, the needed yearly income for the plant can be solved. After that the minimum selling price of CaC_2/C_2H_2 is calculated based on yearly mass production from the plant.

Since current technologies for C_2H_2 production are based on fossil fuels [2,3], reliable information on CaC_2 EAF and C_2H_2 reactor prices was not available, the capital costs for the EAF and the char producing screw were estimated. The estimation was based on recent steel mill EAF investment prices [34], and the Bridgewaters' method [35], where the plants investment costs are correlated according to the number of processing units. For a plant that produces under 60 000 metric tons of the desired product this can be calculated according to (Eq. (8)) [35]:

$$P = 380000 * N * \left(\frac{m_{plant}}{c}\right)^{0.3} \tag{8}$$

where *P* is the required investment cost in U.S. Dollars (2010), *N* is the number of processing units, m_{plant} is the annual maximum capacity of the plant in metric tonnes, and *c* is the mass of the desired product per mass fed into the reactor. The processing units mean significant process

steps, such as reactors and furnaces, pumps, heat exchangers are not counted as processing units [35]. The Bridgewaters' method can be used to roughly estimate the required investment costs (± 30% [35]), which was accepted to be appropriate for this study.

The investment costs was calculated in € by using the exchange rate of 1$ = 0.83 € [36]. Investment cost calculations did not include the BFB since it was supposed to be an operational unit. For CaC_2 production the number of processing units, N was assumed to be 2 (the EAF and the CaO handling unit), and for C_2H_2 production $N = 3$ (the EAF, the CaO handling unit and the C_2H_2 reactor). For both products m_{plant} and c were calculated from the product process evaluation results.

The economic benefit of recycling the Ca in the plant site by heating the residual $Ca(OH)_2$ from C_2H_2 production (Eq. (4)) was also studied by determining a production cost for CaO. The CaO production cost was determined assuming that the energy needed for the $Ca(OH)_2$- slurry drying after the excess water draining, with the assumption that the slurry still contained 80% of moisture, would be waste heat from the CaC_2 cooling (from 2200 °C to 25 °C).

The dependency of CaO production cost for the energy price was determined changing the price of energy from 0 to 100 €/MWh using 5 € intervals. The energy costs contained reaction enthalpy (Eq. (4)), 109,2 kJ/mol [29], and the energy required for the heating of dry Ca $(OH)_2$ from the assumed input temperature 25 °C to reaction temperature 512 °C. The investment cost for Ca recovery were ignored since the recovery can be performed in an ambient pressure reactor and the investment price is negligible in comparison with the EAF and C_2H_2 reactor prices.

2.2.1. Sensitivity studies

Since the economic analysis in this paper was based on literature information and estimation, the sensitivity of CaC_2 and C_2H_2 production costs to the feedstock price, electricity price, and EAF efficiency was studied.

The sensitivity of CaC_2 and C_2H_2 production costs to the feedstock price were studied by keeping the electricity price at constant value (45 €/MWh) while changing the feedstock price from 0 to 40 €/MWh with two euro's intervals. The sensitivity analysis of CaC_2 and C_2H_2 production costs to electricity price were conducted by keeping the feedstock price constant (20 €/MWh) while changing the electricity price from 0 to 100 €/MWh with five euro's intervals.

The affect of EAF efficiency to the break-even prices of CaC_2 and $C_2H_2$was performed by varying the EAF efficiency from 0.3 to 0.6 in 0.1 intervals while keeping the feedstock and electricity prices at the basic values (20 €/MWh and 45 €/MWh, respectively).

The accuracy of the Bridgewater's method for approximating the investment costs is ± 30% [35], and therefore a sensitivity analysis of the break-even prices of CaC_2 and C_2H_2 for investment costs was also performed. The analysis was performed by keeping the investment interest 4%, and using 15 years as the payback time, while varying the investment costs −30%, +30%, and +50% from the investment costs calculated based on the recent steel mill EAF investment prices [34], and (Eq. (8)).

3. Results and discussion

3.1. Production process evaluation

In the production process analysis the mass- and energy balances of the CaC_2/C_2H_2 production integrated in the BFB boiler, as well as the CaO recovery process were calculated (Fig. 3.).

3.1.1. CaC$_2$ production

Initially, to produce the 100 MW of electricity and 200 MW of heat in the BFB boiler, the primary fuel amount (moisture content 40%) was calculated to be 33.0 kg/s containing 333.3 MW of power. After this the amount of additional fuel, which was used to produce the wood char for the CaC_2 production (Eq. (3)), was calculated so that the EAF power input would be 50 MW. The process mass balance calculations showed (Fig. 3) that it requires approximately 12.0 kg/s of additional fuel to produce the char while maintaining the BFB boiler electricity and heat outputs at the initial level (100 MW and 200 MW, respectively).

The wood char exiting the BFB furnace was calculated to contain app. 36% (43.8 MW) of the initial chemical heating power of the additional fuel (121.2 MW). The char energy content was considered to be lost since it was not reacted with oxygen, but instead fed to the EAF. According to the calculations (Figs. 3), 1.1. MW of energy was required for the feedstock heating, and 38.3 MW for the furnace losses (efficiency 0.9). Since detailed modeling of the actual pyrolysis was not in the scope of the current work, the remaining 64.2 MW was assumed to be energy content of the wet volatile gases.

In addition the CO from EAF (Eq. (3)) containing 1.7 MW of heat was assumed to be combusted in the BFB (Fig. 3), releasing 2.95 MW heat. Taking also into account the heat losses of the furnace, the amount of the primary fuel for electricity and heat production could be reduced to 25.5 kg/s. This means that the overall fuel need for the plant (power, heat and char production) would be 37.5 kg/s. The wood char production would increase the overall fuel consumption only 4.5 kg/s (13.6%) compared with the CHP plant without additional char formation. This is also considerably less than the fuel consumption of separate CHP and CaC_2 plant with the same size, which would require 45 kg/s of the fuel. Integrating the CHP and renewable CaC_2/C_2H_2 production saves resources and is therefore beneficial.

The process calculations showed that with the chosen EAF maximum power (50 MW), and conversion of CaO to CaC_2 0.8 [9], a total of 1.7 kg/s of CaC_2 could be produced in the EAF consuming 1.9 kg/s of CaO (Fig. 3). After the EAF, the CaC_2 was cooled down (from 2200 °C to 25 °C) for safety reasons before further reacting with water to produce C2H2 (Figs. 1 and 3.) The available heat from CaC_2 cooling was calculated to be 80.7 MW (Fig. 3). Although utilizing the available heat from the cooling, according to [5] 30% (24 MW) of the total available heat could be utilized elsewhere in the process. With 5000 annual operational hours, the capacity of the CaC_2 unit was calculated to be 30 755 t/a.

3.1.2. C$_2$H$_2$ production

After the cooling the CaC_2 was assumed to be further processed at the plant site (Fig. 1) reacting it with water to produce C_2H_2. Based on literature [16], the amount of water needed for the CaC_2 conversion to C_2H_2 was chosen to be 8t/water per one tonne of CaC_2. This means that the 1.7 kg/s of CaC_2 in this study requires 15.8 kg/s of water (Fig. 3.). Since the reaction (Eq. (4).) is spontaneous, the conversion of CaC_2 to C_2H_2 was assumed to be 1, resulting in 0.7 kg/s of C_2H_2.

Considering that the original wood fuel contained 50 mass-% of C (dry matter), approximately 18% of the original fuel carbon could be converted to C_2H_2, which is in good accordance with traditional yield from fossil fuel methods (8–24%) [3]. With 5000 annual operational hours the capacity of the C_2H_2 unit was calculated to be 11 453 t/a.

3.1.3. CaO recovery

The possibility to recycle the Ca in the system (Fig. 1) was also studied. The mass- and energy balance calculations showed that recovery of all the Ca (conversion 1) in the process consumes 20.3 MW of energy (Fig. 3.). This could be the theoretically available energy (30%) from the cooling of the CaC_2 (24 MW).

The calculations also showed, that if all the $Ca(OH)_2$ could be recycled in the system, it would mean that the amount of bought CaO would be reduced by 1.5 kg/s, or in other words almost 80% annually. This would mean significant reduction in transport and waste costs since otherwise the $Ca(OH)_2$- slurry would have to be disposed of. However, in the literature [2] it is mentioned that only 60% of the Ca $(OH)_2$ can be recycled in the system due to possible contamination, this would mean that the actual annual CaO material savings would be 48%,

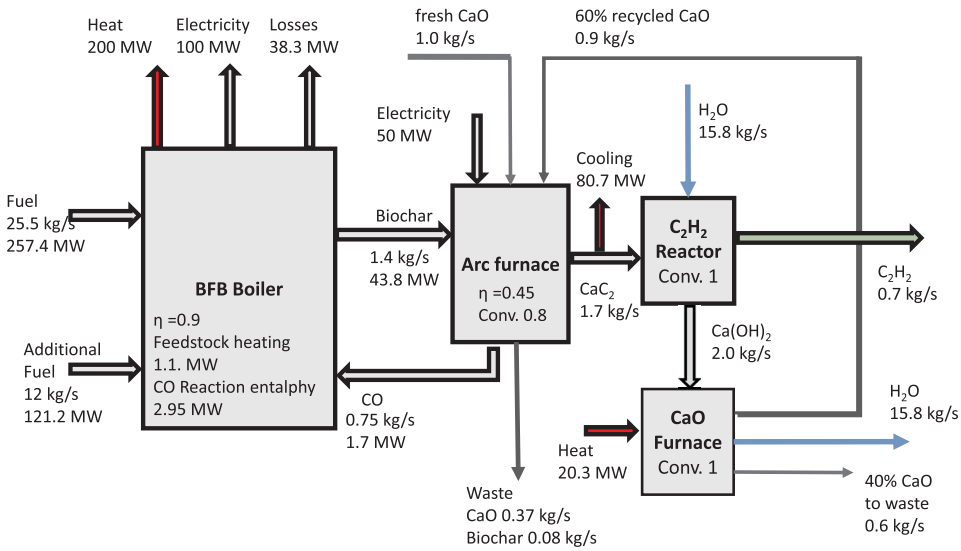

Fig. 3. The mass and energy flows (LHV) of the CaC_2/C_2H_2 production process including the CaO recovery. According to [2] only 60% of the $Ca(OH)_2$ can be recycled in the system due to possible contamination.

which is still a significant amount. The impurities include iron oxides, SiO_2, Al_2O_3, MgO as well as nitrogen, sulfur and phosphorus compounds [5], which cause energy consuming side reactions and dusting.

3.2. Financial calculations

In the financial calculations, the profitability of adding the bio-based CaC_2/C_2H_2 production to the CHP plant was studied. First the production costs of CaC_2, C_2H_2 and CaO were calculated (Eq. (6)) in €/t.

The CaC_2 production cost was calculated based on the price of the extra feedstock inserted into the BFB furnace, electricity consumed by the EAF, and the market price of CaO needed in the EAF. The chosen basic prices for the boiler feedstock, electricity and CaO were 20 €/MWh, 45 €/MWh, and 0.20 €/kg, respectively. Based on the production process evaluation, the excess fuel requirement for the wood char production was 4.5 kg/s, which equals fuel heating power 45.3 MW, the electricity consumption of the EAF was 50 MW, and the required calcium oxide amount was 1.9 kg/s (see Section 3.1.1). Based on these figures, the resulting CaC_2 production cost (Eq. (6)) was 725 €/t. This equals almost 1.5 times the current CaC_2 selling price, 500 €/t [33].

The production cost of C_2H_2 without the gas cleaning and pressurizing was calculated to be 1805 €/t (Eq. (6)) using the same nominal values for feedstock, electricity, and CaO as with CaC_2 basic production cost calculation. The current selling price of raw C_2H_2-gas was not possible to determine reliably, since only prices for welding gas were available. Therefore a price approximation was made based on the average price of acetylene in 2001 [10] 0.63–0.8 $/kg. Taking into account the consumer price index [37], and the exchange rate of 1$ = 0.83 € [36], the selling price approximation was determined to be 900–1100 €/t. This is 40–50% lower than the production cost of renewable C_2H_2 determined in this study (1805 €/t). These results indicate, that the production of renewable CaC_2/C_2H_2 would be beneficial if the price of electricity and basic lignocellulosic biomass for the wood char production would decrease. Other possibilities for improving the economics could include subsidies for renewable chemicals, the total ban of fossil fuel based substances or a very high fossil fuel tax.

The investment costs of the EAF and C_2H_2 reactor were calculated based on (Eq. (8)). For CaC_2 production the number of operational units N was assumed to be 2, and for C_2H_2 production N = 3. With 5000 annual operational hours, the capacity of the CaC_2 unit was calculated to be 30755 t/a and C_2H_2 11453 t/a. These were assumed to represent the annual maximum capacities (m_{plant}) for the plant. For the CaC_2 production unit the mass of the desired product per mass fed into the reactor (c) was calculated to be 0.52 (desired product CaC_2 1.7 kg/s, inputs CaO 1.9 kg/s and wood char 1.4 kg/s (Fig. 3)). With these assumptions the investment of the CaC_2 production unit was calculated to be 17 million €. This seems to be reasonable comparing to the OECD report on actual steel mill EAF investments [38] (average 712 €/t) and the fact that the CEPCI index seems to have decreased since 2010 [35]. For the C_2H_2 production, the total investment (including the CaC_2 production unit) was calculated to be 39.6 million €. However, the accuracy of the Bridgewater's method is ± 30% [35]so these investment costs are only rough estimations.

Based on the determined investment capital costs, an analysis of product break even selling prices (CaC_2 and C_2H_2) for different payback times (4, 8, 15, and 30 years) as well as investment interests (1–15%) was performed (Fig. 4). The analysis was performed using the basic feedstock and electricity prices, 20 €/MWh, and 45 €/MWh, respectively.

The results for the break even prices of CaC_2 and C_2H_2 (Fig. 4.) show that the investment would be beneficial if the selling price of CaC_2 would rise to approximately 1.5 times from it's current value (500 €/t). This could happen if the price of oil would rise significantly or if there would be a high demand for bio based CaC_2. Based on recent observations [39] the selling price of CaC_2 has been rising in the last decades, which could make the renewable production profitable in the near future. For C_2H_2 the current selling price (1100 €/t) would have to double (Fig. 4). However, the result is uncertain, since the price of C_2H_2 is based on literature [10]. The value of C_2H_2 is also dependent on which end product it is utilized for, the possibilities are numerous [2,40], including plastics, pharmaceuticals, fuel additives and chemicals. In addition, according to predictions [41] the demand for C_2H_2 is expected to increase in the near future, which could bring markets also for renewable C_2H_2. The results also show (Fig. 4), that the break even selling price of C_2H_2 is more sensitive to the interest than CaC_2. Also the break even price of CaC_2 is less dependent on the payback time than

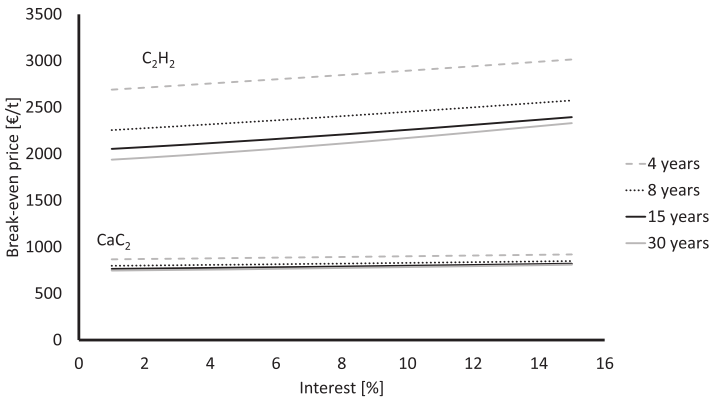

Fig. 4. Break even selling prices determined from the yearly income of the plant (Eq. (7)) of CaC_2 and C_2H_2 as a function of interest for different investment payback times: 4 years, 8 years, 15 years, and 30 years. The feedstock price and the electricity price were kept constant at basic values, 20€/MWh, and 45 €/MWh, respectively.

C_2H_2, the break even prices for CaC_2 differ only 1–9% between payback times 4 and 30 years, whereas the difference for C_2H_2 is 1–22%. This is because the CaC_2 price is more dependent on the electricity price than the investment capital cost, whereas the C_2H_2 price is more dependent on the investment price. It can also be seen (Fig. 4.), that increasing the payback time of C_2H_2 production investment from 15 years to 30 years does not decrease the break even price significantly, in fact during this time the break even selling prices differ only by 1–3%.

The cost of regenerated CaO (Eq. (5)) was also determined (Fig. 5) assuming that the available heat released from CaC_2 cooling (24 MW) could be utilized for the $Ca(OH)_2$ - slurry drying, and the heating energy needed for the reaction (Eq. (5)) would come from fuel combustion or electricity.

If the CaO market price is considered 0.2 €/kg [33], the results show that regenerating $Ca(OH)_2$ to CaO (Eq. (5)) saves the overall costs of the process even if the energy needed for the process costs more than 100 €/MWh (Fig. 5). This clearly means that recycling of Ca in the process is economical. Moreover, regenerating CaO saves material, since up to 60% of the EAF CaO load can be recycled per load [2]. Recycling the Ca at the plant site has also positive effects on the environment since there is less need for CaO transportation as well as less need for $Ca(OH)_2$-slurry disposal. The $Ca(OH)_2$ could also be sold as fertilizer or for cement production [2].

3.2.1. Sensitivity studies

Since the electricity feedstock and electricity prices are the main factors in the production costs of $CaC_2$and C_2H_2, a sensitivity analysis for of the production cost to both feedstock and electricity prices (Fig. 6) was performed. First the sensitivity to electricity price was studied by keeping the feedstock price at the basic level 20 €/MWh and varying the electricity price from 0 to 100 €/MWh with 5 euro's intervals. The same was done as the electricity price was kept constant at value 45 €/MWh as the feedstock nominal value was varied between 0 and 40 €/MWh using two euro's intervals.

The results of the production cost sensitivity analysis (Fig. 6) show that both the CaC_2 and C_2H_2 production costs are more dependent on the electricity price than the feedstock price. This is due to the high electricity consumption of the EAF. Based on this, it can be calculated that in order for the CaC_2 production cost to be less than the current selling price (500 €/t [33]). With the chosen feedstock basic value (20 €/MWh) the electricity price should be less than 42% of the basic electricity price chosen for this study (45 €/MWh), which is approximately 19 €/MWh. Currently this occasionally happens in areas, where the electricity price is determined based on market supply and demand. It is likely, that as the share of weather dependent electricity production (wind and solar) grows in near future, the electricity price will also fluctuate more. This would mean that the average electricity price in some areas could decrease, and therefore the production costs of CaC_2 would also decrease. For C_2H_2 the threshold price for electricity would be 12.7 €/MWh. However, while interpreting these numbers, the uncertainty of the acetylene selling price must be kept in mind, since it is highly dependent on the price of its current basic ingredients, petroleum or natural gas [2].

The production of CaC_2 as well as C_2H_2 with the basic feedstock and electricity price values (20 €/MWh and 45 €/MWh, respectively) could become economical if the selling price of the renewable product would

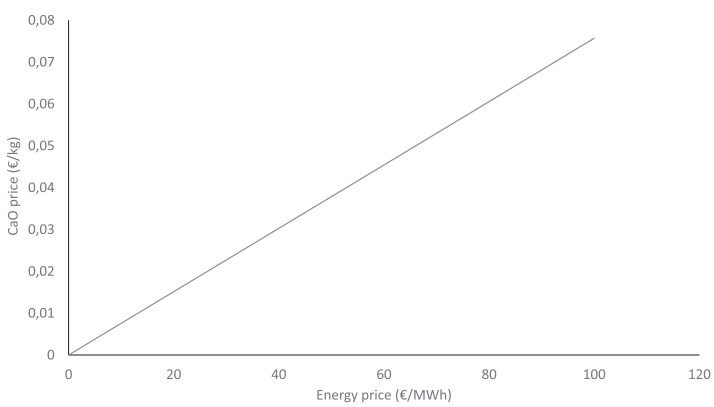

Fig. 5. The cost of regenerated CaO as a function of energy price, assuming that the $Ca(OH)_2$- slurry drying can be performed using heat released from CaC_2 cooling.

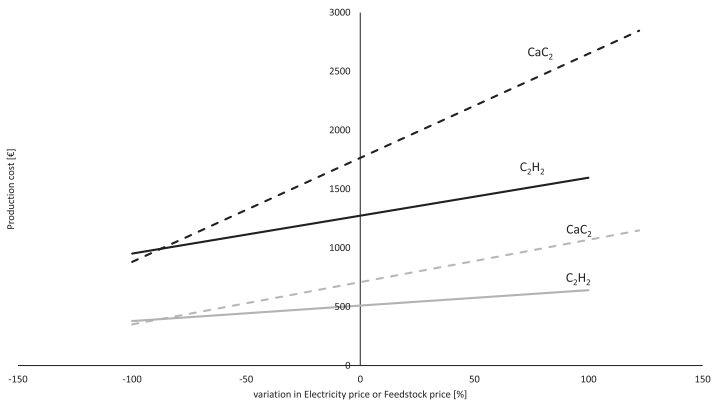

Fig. 6. The sensitivity of CaC_2 and C_2H_2 production costs to electricity price (black lines) and feedstock price (gray lines). Basic price for electricity was 45 €/MWh and for feedstock 20 €/MWh.

be higher than the current selling price (made from fossil sources). Based on the discussion above, it seems that production of only CaC_2 at the plant site and selling it to be further produced at another site is not beneficial even if only the production costs are considered, while ignoring the investment and transportation costs. Also C_2H_2 production would not be economical with current assumptions.

The results of production cost sensitivity to the feedstock price show (Fig. 6), that the CaC_2 production cost does not reach a value under the current market selling price (500 €/t [33]) if the electricity basic value is at the chosen basic level (45 €/MWh). A further analysis showed that even with the basic electricity price value 35 €/MWh, the production costs of CaC_2 are very close to the current selling price even if the feedstock price would be 0 €€/MWh. This strengthens the conclusion that the production costs of both the CaC_2 and the C_2H_2 are more sensitive to the electricity price. With the chosen basic value for the electricity price (45 €/MWh) also the cost of C_2H_2 would not decrease under the assumed current production price (900–1100 €/t) even if the biomass would be free (0 €/MWh).

A key factor in the EAF production cost is the overall efficiency of the furnace. The sensitivity of the break-even prices of CaC_2 and $C_2H_2$to EAF efficiency was performed by varying the EAF efficiency from 0.3 to 0.6 in 0.1 intervals while keeping the fuel and electricity price at the basic values (20 €/MWh and 45 €/MWh, respectively) (Table 3.). The results showed that the production costs would decrease significantly if the efficiency of the EAF would be better than the current approximation (0.45) (Table 3.) Further analysis of this showed that, if the EAF efficiency would be e.g. 0.6 the break-even electricity price would be 25 €/MWh in order to reach CaC_2 production cost lower than the current selling price (500 €/t [33]).

The results for the sensitivity analysis of the break even prices to investment costs show (Table 4), that the break even prices are not at all sensitive to the investment costs. The analysis was performed for investment interest 4% using 15 years as the payback time. The break even selling price for CaC_2 with 15 years payback time and 4% investment interest differs only 1% from the basic value if the investment cost increases or decreases 30%. For C_2H_2, the difference is app. 2%. This strengthens the conclusion that the system overall economics is highly dependent on the electricity price and the EAF efficiency.

Table 3
Sensitivity of CaC_2 and C_2H_2break even prices to EAF efficiency.

EAF efficiency	Production cost (€/t)	
	CaC_2	C_2H_2
0.3	889	2187
0.4	754	1856
0.45	709	1745
0.5	673	1657
0.6	619	1524

Table 4
The sensitivity of CaC_2 and C_2H_2 break even prices to investment costs. The analysis was performed using 15 years payback time and 4% investment interest.

investment cost	CaC_2 break-even price (€/t)	Difference to basic value (%)	C_2H_2 break-even price (€/t)	Difference to basic value (%)
basic	775	0	2115	0
+50%	800	+3.2	2271	+7.3
+30%	790	+1.9	2209	+4.4
−30%	760	−1.9	2022	−4.4

4. Conclusions

The purpose of this study was to examine the economics of a bio based CaC_2/C_2H_2 production integrated into an existing CHP facility consisting of a Fluidized Bed Boiler. The main research questions were whether the renewable C_2H_2 yield could be competitive with current production methods utilizing fossil fuels, and what would be the costs of CaC_2 and C_2H_2 production? The study also included discussion about the possibility to improve the overall economics of standalone CHP plant by integrating the CaC_2/C_2H_2 production into to the plant. The basic idea of the concept was to produce wood char in the BFB boiler utilizing the same fuel for the char production and the BFB boiler, and react the wood char further with CaO in an Electric Arc Furnace to produce CaC_2. Moreover, the economics of upgrading the CaC_2 to C_2H_2 and recycling the Ca at the plant site were studied. The calculations were conducted based on the process mass and energy balances, material prices, device efficiencies, and property values. The overall profitability was assessed based on the payback time method taking into account the time value of money. The investment costs for the new equipment were only roughly estimated since there was no reliable information available in the literature.

Results for the mass- and energy balance study proved that the C_2H_2 yield of the suggested renewable production system (18% of the original wood feedstock) for CaC_2/C_2H_2 is competitive with the currently mostly used fossil fuel based methods (yield 8–24%). C_2H_2 is a potential parent substance for numerous chemical compounds, and the suggested method would be a good production alternative in case fossil fuel

utilization is banned in the future. The suggested system also utilizes excising technology which would make it relatively fast to put into operation. The results also showed that the wood char production increased the overall fuel consumption approximately 12% at the studied site, which means that the fuel cost increase would be moderate.

The financial calculations in this study showed that the CaC_2 production cost with the chosen basic values for fuel (20 €/MWh) and electricity (45 €/MWh) costs would be 725 €/t, which is approximately 1.5 times the current selling price. The renewable production could become competitive with a subsidy for renewable chemicals. It is also possible that the price for fossil fuels will rise due to carbon taxes in the future. This would again make the suggested production system competitive. Moreover, as the calcium carbide is further processed with water, the resulting acetylene production cost was calculated to be 1805 €/t, which is nearly 2 times higher than the current selling price (1100 €/t). A sensitivity analysis of the CaC_2 and C_2H_2 production costs in relation to the electricity and fuel feedstock prices revealed that the product price is more sensitive to the electricity price. The overall economics of the concept is highly dependent on the electricity price as well as the overall efficiency of the EAF. Therefore future developments should be mainly put to increasing the EAF efficiency.

In the future, an experimental examination of using wood char in the production of CaC_2 and C_2H_2 would be a reasonable direction as a follow-up of this study. This would provide more in depth information for more accurate cost estimation, as the product yields, the required temperature levels, and process residence times could be determined. Experimental work would also provide detailed information about the most optimal mounting spot and rotation speed for the wood char production screw. Another interesting future study would be to analyze the most economical pathway to the C_2H_2 utilization.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.biombioe.2018.10.020.

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ABSTRACT

This article presents a feasibility analysis of a novel operating principle based on fluctuating electricity prices for an existing biogas plant. By investing in an electrolyzer, excess electricity from renewable production can be stored as CH_4 by biological methanation of H_2 with CO_2 originating from the biogas plant. The main components of the system are an electrolyzer that is connected to an electric grid and an anaerobic digester where the methanation takes place as well as a biogas upgrading unit. First the energy flow of the system was studied, and secondly the operation costs of the system as well as the electrolyzer investment payback time were evaluated.

The study showed that up to 40% of the electricity fed into the system can be stored as biomethane, and the system energy flow is most sensitive to the electrolyzer efficiency. The economics of the studied system depend mostly on the electrolyzer investment cost and desired target price for the CH_4. The system can be run economically with current electricity prices if the electrolyzer investment costs decrease 60–72% or the price of CH_4 increases 20–76% depending on the investment interest and price fluctuation scheme.

1. Introduction

There is a global interest to increase the renewable energy production in order e.g. to decrease environmental emissions and dependence on fossil fuels. Currently most of the renewable electricity production is hydro-power, while the amount of solar and wind power is increasing rapidly [1]. As these power production methods are dependent on weather conditions the power production typically fluctuates rapidly. This can reduce the grid stability and therefore means for balancing the power production is needed. Possible options for the power production balancing are flexibility of consumption [2,3], using electricity storages or additional production units [2,4]. However, due to current inefficiency of large scale storages and fossil fuel utilization of most back-up production units, other solutions are needed.

H_2 is considered a good option for power balancing or as an energy carrier [5–8], because it has high energy content per kg and the combustion product is clean water. H_2 can be produced using several technologies and sources, currently H_2 is usually made from natural gas or oil [9]. The most mature production method for renewable H_2 is water electrolysis utilizing renewable electricity [9]. H_2 can be used directly to balance renewable energy production, or utilized as transport fuel [7,10]. However, at the moment there is a lack of infrastructure to transport, store, and utilize H_2 as such [11], also storage of H_2 is expensive and the efficiency is low [2].

H_2 can be further converted into CH_4 [6,12,13], which is the main component of natural gas, so the infrastructure and technology for utilization are already available in many countries [14,15]. Methanation can be either catalytic or biological conversion of H_2 and CO_2 to CH_4. In order to produce renewable CH_4, also the CO_2 for methanation has to come from a renewable source. Biogas is produced in an anaerobic digester (AD) and the main components are CH_4 (50–70 vol-%) and CO_2 (30–50 vol-%). The feed material is usually waste material such as municipal bio-waste, sewage sludge, or agricultural residues, hence the CO_2 in the product gas is renewable. Before biogas can be utilized as transport fuel or injected to natural gas grid, biogas is upgraded and e.g. CO_2 is removed. The CO_2 can be removed from the product gas by

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chemical or physical absorption, membrane separation, adsorption on a solid surface, cryogenic separation or chemical conversion [16–18].

Recently there has been a lot of interest in biological methanation of H_2 [19–23], where micro-organisms use CO_2 and H_2 to form CH_4. It has been shown experimentally [19–21,23] and with simulation [22], that H_2 can be added to a waste digesting AD and it enhances the CH_4 production in the digester. The methanation can be done in a separate reactor [23–26] or in-situ in an AD [19,21]. All these studies showed that H_2 can be added to the digester with a ratio of 4:1 to the amount of CO_2 in the reactor with a conversion near to 100%.

The idea of using H_2 from electrolysis combined with biological methanation has been presented before [6,12], however, research concerning the energy efficiency and economics of the combined system is limited. Previous modeling work concentrates in the economic analysis of electrolysis [27,28] or biological methanation [13,22,24,29] separately. There are some reported commercial scale projects that use electrolysis combined with biological methanation; the P2G-Biocat-project in Hvidovre, Denmark [30] and the Biopower2gas project in Allendorf, Germany [31]. In both projects an electrolyzer is combined with a separate methanation reactor for H_2 and CO_2, not directly to AD.

The objective of this study was to assess the feasibility of an electrolyzer investment in an existing biogas plant treating municipal bio-waste. The facility was assumed to contain also a biogas upgrading unit. The investment was supposed to contain an electrolyzer producing H_2, that is fed directly or after intermediate storage to the existing AD, where it is converted to CH_4. The assessment of feasibility was based on analyzing the factors affecting the energy flow of the power to gas system (namely; the feedstock composition, AD liquid volume, electrolyzer efficiency, and end use efficiency) and operation costs of the system as well as the payback time of the electrolyzer investment based on current electricity prices. Two different electricity price areas were studied; a production area with a lot of installed renewable power production (DK2) and an industrial based power production scheme (FI). The system was designed to operate according to variable electricity price, which correlates with variable power production and consumption. The operation hours depend on a desired production price for the biogas and the operation is based on a price algorithm.

2. Materials and methods

2.1. Setup and operation of the power to biogas system

The studied power to biogas system consists of an electrolyzer, which is connected to an existing biogas plant with an anaerobic digester (AD) and gas upgrading and pressurization unit (Fig. 1). The upgrading unit can be e.g. water scrubber or other upgrading method to remove contaminats, such as H_2S from the biogas [16–18,32]. The system is connected to commercial electric and gas grids. Renewable electricity from power grid is used for water splitting to produce H_2. The H_2 is fed directly or after short storage to the AD. In the existing AD the added H_2 is converted stoichiometrically into CH_4 with CO_2originating from the feedstock originally used in the AD. The produced biogas is upgraded, fed into a commercial gas grid and utilized for heat and power production in CHP or gas engine, or as transport fuel.

The electrolyzer was supposed to be switched on when the hourly price of electricity is lower than a calculated threshold price. The electricity threshold price is dependent on a targeted production cost for the CH_4. If a H_2 storage is used, the CH_4 production can continue even after the electricity price reaches a value over the threshold price. During this time, the production cost of the CH_4 can be considered to be the same as the hour when the H_2 storage was filled. The system operation is described in detail in Fig. 2.

In this study alkaline and PEM electrolyzers were considered as they are commercially available and can be switched on and off rapidly [5,7], and thus the operation can be based on hourly power prices. Although the SOEC electrolyzers have the highest efficiencies (above 90%), they need to maintain a high temperature constantly, which requires extra energy and thus makes them less suitable for this study. The overall reaction in the electrolyzer was assumed to be [6,7]:

$$2H_2O \Rightarrow 2H_2 + O_2 \qquad \Delta H = 286 kJ/kg \tag{1}$$

The O_2 from the electrolysis might be used for combustion or industrial purposes, however, it was not included in this study. The storage of H_2 in ambient pressure is usually not reasonable due to the large volume required [11]. However, since the H_2 would be

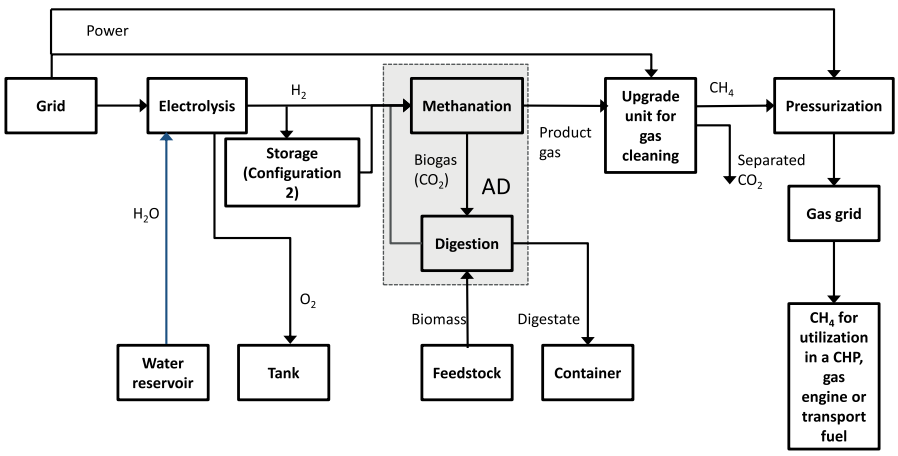

Fig. 1. Overall scheme of the studied power to biogas system. The system was studied using two different configurations; without H_2 storage (Configuration 1) and with a H_2 storage (Configuration 2).

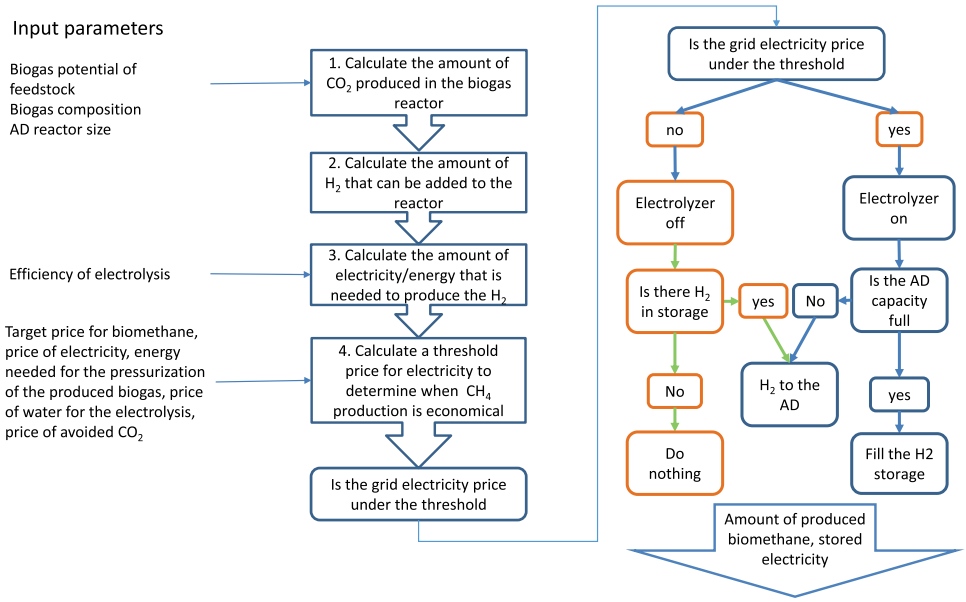

Fig. 2. Calculation algorithm for the economic analysis. The calculation is based on theoretical process values. First the rational electrolyzer maximum power is determined based on the biogas feedstock characteristics. Then the threshold price for electricity is determined based on Eq. (3). The operation hours are then decided based on the electricity threshold price.

added to the AD at ambient pressure, and the need for H_2 storage was only for short time, the H_2 storage tank was assumed to be a steel tank.

The existing AD, without the H_2 addition, was assumed to be continuously operating and the production rates of CO_2 and CH_4 were assumed to be constant (constant biogas production rate 500 m^3/d, share of CO_2 45 vol-%, share of CH_4 55 vol-%). It was assumed that H_2 is fed to the AD in stoichiometric amounts and the overall reaction used is the Sabatier reaction (Equation (2)).

$$CO_2 + 4H_2 \Rightarrow CH_4 + 2H_2O \quad (2)$$

The studied utilization methods for the biogas were combustion in a CHP facility or in a gas engine, and utilization as transport fuel. The CH_4 enrichment and removal of contaminants that is required for utilization as transport fuel or injection into a gas grid [16,17] for the CH_4 from H_2 addition was not taken into account since it was assumed that the amounts compared to the AD CH_4 production without H_2 addition were to be small. In addition to the biogas upgrading there should also be pressurizing unit before the gas can be fed to a commercial gas grid.

2.2. Energy flow analysis

In the energy flow analysis the effects the electrolyzer efficiency, feedstock characteristics (amount of CO_2 in the product gas), digester volume (liquid volume of the digester), and the CH_4 end use method on the energy flow were determined (Table 1.). The energy flow analysis was performed by varying one parameter at a time. The amount of energy from the power grid for the electrolysis was assumed to be 100%. The amount of energy left after each stage of the power to biogas system was calculated as a proportion to the energy from grid.

The maximum power of the electrolyzer and the amount of electrical energy needed for the H_2 production were calculated

Table 1
The studied parameters for the energy flow analysis of the power to biogas system.

Parameter	Unit	Studied values
Biogas potential of the feed	m^3/m^3_{liquid}/day	0.5
Share of CO_2 in the product gas	vol-%	45
Electrolyzer efficiency	–	0.4, 0.7, 0.9
Liquid volume of the digester	m^3	100, 500, 1000, 5000
End use efficiency	–	0.58, 0.40, 0.20

from the maximum amount of H_2 that can be fed into the AD and the electrolyzer efficiency. The amount of H_2 that can be fed into the AD is depended on the amount of CO_2, in proportion of 4:1 (H_2:CO_2) [19–23,33,34]. Biogas potential of the feedstock, share of CO_2 in the product gas and liquid volume of the digester affect the amount of CO_2 (m^3) and thus the amount of CH_4 that can be produced with the power to biogas system. In this study the feedstock characteristics (biogas potential of the feed, share of CO_2 in the product gas) were chosen to be constant (0.5 m^3/m^3_{liquid}/day, and 45%, respectively). A sensitivity analysis of the electrolyzer efficiency was performed using typical electrolyzer efficiencies, 40%, 70% and 90% [5,7,28].

The effect of AD volume (m^3_{liquid}) was studied with volumes of 100, 500, 1000, 5000 m^3_{liquid} for all the chosen electrolyzer efficiencies (0.4, 0.7, and 0.9). The CH_4 production directly from the feed material in the AD is not included in the results (Table 3.), since the scope of this study is in the added value of the electrolyzer in the power to biogas system. All the calculations are based on theoretical system parameter values.

The end use techniques and efficiencies were chosen to represent existing end use efficiencies; a large CHP plant with electrical efficiency $\eta_{el} = 0.58$ [35], a small scale gas engine with electrical efficiency $\eta_{el} = 0.40$ [36], and a gas fuelled passenger car with a fuel conversion efficiency $\eta_{cv} = 0.20$ [37]. All the energy balance

calculations are based on higher heating value.

2.3. Economic analysis

In the economic analysis, the electrolyzer investment cost that would make the investment economical with current electricity and biogas prices was defined, as well as the biogas price that would make the system economical with current electrolyzer investment cost. In addition, the economic benefit of the H_2 storage was determined. The economic analysis was conducted based on the energy flow calculations. The parameters used in addition to the energy flow analysis were: electricity price, feed water price, target price for the biogas and CO_2 emission allowance price (Table 2).

First, the amount of H_2 that could be added to the AD reactor and the amount of electricity needed to produce the H_2 was determined (section 2.2). After that, the variable costs of the produced biogas P_{bioCH_4} [€/MWh] were calculated for every hour using Equation (3).

$$P_{bioCH_4} = P_{el} \Big/ E_{inproducedCH_4} + P_{feedwater} + P_{pressurizing} - P_{avoidedCO_2} \tag{3}$$

where P_{el} is hourly price of electricity [€/MWh], $E_{inproducedCH_4}$ is the amount of grid energy left in the product CH_4 after the electrolysis and methanation steps [−], $P_{feedwater}$ is the price of water needed for the electrolysis [€/MWh of produced CH_4], $P_{pressurizing}$ is the price of energy needed for the pressurization of the biomethane [€/MWh of produced CH_4] and $P_{avoidedCO_2}$ is price of avoided CO_2-emissions [€/MWh of produced CH_4]. In this study the CH_4 production costs included the raw material and energy costs. A threshold price for electricity was solved from Eq. (3) by setting a target production price for the CH_4. The production of CH_4 was feasible when grid electricity price was lower than the threshold price, in which case the electrolyzer is turned on and thus the biomethane production starts. The amount of additional CH_4 production based on real electricity prices could be determined using an algorithm (Fig. 2.).

The economic analysis was performed both without (Configuration 1) and with the H_2 storage (Configuration 2). For Configuration 1 the rational electrolyzer maximum power was determined according to the maximum amount of H_2 that can be fed into the AD reactor. For Configuration 2, the produced H_2 was primarily fed directly into the AD reactor, and the storage was filled as well. In Configuration 2, the electrolyzer was optimized according to the desired size [m^3] of the H_2 storage. This could also be done vice versa; the storage size optimized according the desired size of the electrolyzer. When electricity price exceeds the electricity threshold price the electrolyzer is switched off, but H_2 can be still fed from storage to AD tank. The H_2 storage losses for configuration 2, were estimated to be 2 vol-% in 1 h based on [11] (transport losses 4%, 20–30 bar) and the H_2 storage size was chosen to be 85 m^3, which for the chosen AD size (1000 m^3) is equivalent storage for approximately 2 h AD H_2-capacity. Other components of the system (AD, biogas upgrading and pressurizing units) were considered existing ones, thus the fixed costs of these parts of the system were not covered in this study. Biomethane pressurizing was assumed polytrophic with a compression efficiency 0.8. The electrolyzer efficiency was kept constant at 0.7 and the lifetime of the electrolyzer was assumed 30 years [6]. All the input values for the economic evaluation are presented in Table 2.

Table 2
Input values for the economic evaluation.

	Parameter	Value	Unit
Electrolysis	Efficiency	0.7	–
	H_2 tank size	85	m^3
	Electrolyzer lifetime	30	a
AD	Reactor liquid volume	1000	m^3
	Biogas potential	0.5	m^3/m^3_{liquid}/day
	Share of CO_2	45	Vol-%
	Share of CH_4	55	Vol-%
H_2 storage	Storage losses	2	Vol-%
	CH_4 input pressure	100000	Pa
Pressurization	CH_4 temperature	328	K
	Compressor pressure ratio	30	–
	Compression efficiency	0.8	–
Price data	CO_2 emission allowance	10	€/t
	Water price	1	€/t

2.3.1. Electrolyzer investment payback time

The electrolyzer investment cost payback time was calculated (Eq. (4))

$$t(a) = \frac{-ln(1/i - P/K) - ln(i))}{(1+i)} \tag{4}$$

where ln is the natural logarithm, i is the interest of the investment [−], P is the investment price [€], and K is the income of the plant for one year [€]. The yearly income K was determined by calculating the yearly income from economical operating hours of the system, in other words from the hours when the biogas price was under the target price for the biogas (Fig. 2). Two electricity price curves (Fig. 3.), representing different production method distributions were used. The case FI represents an area with industrial based electricity production facilities including nuclear power and CHP, and case DK2 an area with a lot of fluctuating renewable power production (wind) [38]. The SPOT prices represent the price of energy which can at times be also negative, if the power production is greater than the demand [39]. In addition to the Spot prices used in this study, there might be other costs for electricity such as grid transfer prices, but since these depend on the price area they are not included in this study.

The investment payback times for different electrolyzer investment costs (100–1200 €/kW) were calculated with current biogas price of 38 €/MWh [40] and electrolyzer investment interest 4%. The effect of investment interest was studied by determining a boundary price for biomethane so that the investment payback time would not exceed the electrolyzer expected lifetime expectancy 30 years [6]. The boundary prices were determined using current electrolyzer investment cost, 1000 e/kW [6], and

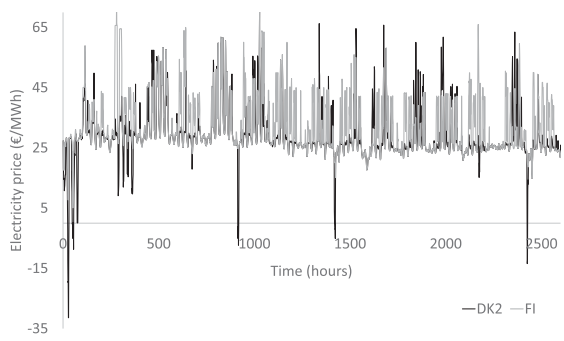

Fig. 3. Hourly Nordpool Spot electricity price fluctuation 2015, only beginning of the year is presented [38]. FI= Finland, DK2 = Denmark. The Spot price equals the price of energy.

investment interests 1–8% were studied.

The feasibility of adding an H_2 storage for the system was studied by comparing the payback times of the system without (Configuration 1) and with a H_2 storage (Configuration 2) (Fig. 1) for price case DK2 with more fluctuating electricity prices. The comparison was performed with current electrolyzer investment cost (1000 e/kW) and the H_2 storage size was chosen to be 85 m^3. The H_2 tank was assumed to be a steel tank in ambient pressure, and the investment costs (C_e) of the H_2 storage were estimated using the correlation [41].

$$C_e = a + bS^n \tag{5}$$

where a and b are cost constants (a = 5800, b = 1600 [41]), n is the exponential factor for specific equipment (n = 0.7 [41]), and S is the size of tank (85 m^3).

Electrolyzer maximum powers for both configurations according to the energy flow analysis were 190 kW (Configuration 1) and 592 kW (Configuration 2). The payback times were determined by using a target price of 51.55 e/MWh which was determined as the boundary price of biomethane for current electrolyzers (investment 1000 e/kW, lifetime 30 years) and investment interest 4% for price case DK2 (Table 4.). Other assumptions for the economic analysis of the power to biogas system were: electrolysis efficiency 0.7, AD reactor volume 1000 m^3, feedstock biogas potential 0.5 m^3/m^3_{liquid}/day, share of CO_2 in the product gas 45% and share of CH_4 55% (Table 2.). For the pressurization price calculations the chosen CH_4 input pressure was 1 MPa, CH_4 temperature 55 °C, pressure ratio 30 and compression efficiency 0.8. Chosen electrolyzer feed water price was 1 €/t and CO_2 allowance price 10 €/t (Table 2.). In addition a sensitivity analysis for the available electrolyzer technologies (AEL, PEM, and SOEC) on the investment payback time based on investment prices reported by Ref. [6] and the price change of biogas was performed. The analysis was performed by assuming a decrease of 25% and 50% on the investment costs, and increase of 25% or 50% on the biogas selling price. One parameter at a time was varied in the analysis. The investment interest was assumed to be 4%. The assumed efficiencies for the electrolyzers were 0.95 (SOEC), and 0.7 (PEM, and AEL) [5].

3. Results and discussion

3.1. Energy flow analysis

The energy flow analysis was performed in two phases, first the effect of AD feedstock (the amount of CO_2 in the product gas) and AD volume (m^3_{liquid}) was studied, secondly the effect of electrolyzer efficiency, and end use efficiency to the energy flow of the system was studied (Table 1). The energy flow analysis showed (Fig. 4) that since the AD feedstock affected to the amount of CO_2 in the reactor, it also had an effect on the amount of H_2 that can be fed to the reactor. The amount of H_2 in turn affects the rational maximum power of the electrolyzer [kW]. The dependency between the CO_2 amount in the reactor and the electrolyzer maximum power was linear (Fig. 4). The dependency of electrolyzer size was determined to be 20 kW/$m^3$of produced CO_2. However, the AD feedstock did not affect on the amount (%) of grid energy that can be stored as biogas, thus the feedstock characteristics were kept constant for the next phase of the energy flow analysis.

In addition to the feedstock characteristics, the AD volume (m^3_{liquid}) also defines the CO_2 amount in the reactor, and thus also the amount of H_2 that can be added to the AD. Eventually the AD volume determines the rational maximum power of the electrolyzer. The effect of AD volume (m^3_{liquid}) to the rational maximum of the electrolyzer proved to be linear (Fig. 5) for all the chosen electrolyzer efficiencies (0.4, 0.7, and 0.9). The results also show (Fig. 5.) that the correlation is dependent on the electrolyzer efficiency.

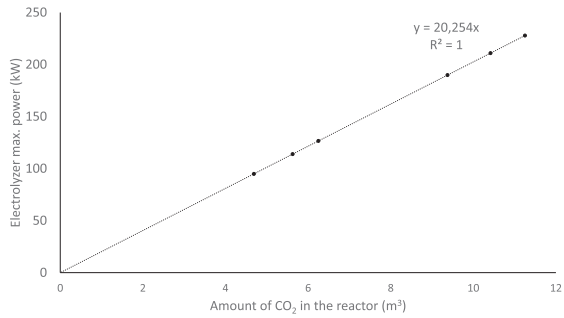

Fig. 4. The effect of AD feedstock to the electrolyzer maximum power for a typical AD reactor with the CO_2 potential of the feedstock 0.5 m^3/m^3_{liquid}/day, and share of CO_2 in the product gas 45%.

The dependency of electrolyzer maximum power on the AD volume (m^3_{liquid}) can also be formulated as 0.133 (kW/m^3_{liquid})/electrolyzer efficiency.

In the second phase the effect of the electrolyzer efficiency (0.4, 0.7, and 0.9), and the end use efficiency of biogas (0.58, 0.40, and 0.20) to the energy flow was studied (see section 2.2). As in the case of AD feedstock, also the AD volume did not have an effect on the amount (%) of grid energy that can be stored as biogas, therefore the size of the AD was kept constant (1000 m^3) for the next phase of the energy flow analysis. The results for the energy flow analysis are presented in Table 3. where the energy content of the product of each system part is presented relative to the energy from the power grid. The relevance of each part of the studied power-to-biogas system to the system energy flow is discussed in detail below.

Among the studied factors (the effect of AD feedstock, AD volume, electrolyzer efficiency and end use efficiency) the system energy flow is most sensitive to the electrolyzer efficiency and this is indeed the system part where the greatest amount of energy is lost depending on the electrolyzer efficiency (Table 3) With high efficiency (0.9) also most of the grid energy is left after the electrolyzer, 90% (Table 3). However, even with low electrolyzer efficiency (40%) the amount of electrical energy that can be stored as

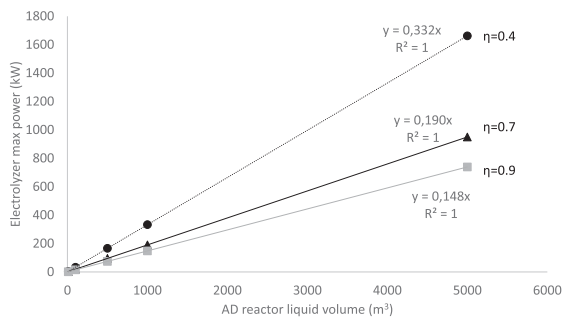

Fig. 5. Dependency of electrolyzer maximum power (kW) on the AD volume (m^3_{liquid}) for the chosen electrolyzer efficiencies 0.4, 0.7, and 0.9 with the assumptions of feedstock CO_2 potential 0.5 m^3/m^3_{liquid}/day and share of CO_2 in the product gas 45%.

Table 3
The effect of different system parts to the energy flow of the studied power-to-biogas with different electrolysis efficiencies and end use methods.

Electrolysis efficiency	Energy left in the end product (%)		Utilizable grid energy (%)		
	After electrolysis	After methanation	Large CHP ($\eta_{el} = 0.58$)	Gas engine ($\eta_{el} = 0.40$)	Gas fuelled vehicle
($\eta_{cv} = 0.20$)					
0.4	40	31	18	12.40	6
0.7	70	54	31.6	21.8	10.9
0.9	90	70	40.6	28	14

biomethane is over 30% (Table 3). The 90% grid energy left after the electrolyzer could be achieved using an SOEC electrolyzer with an efficiency between 90 and 95%. However, the SOEC needs high operation temperature, and since intermittent operation of the system is a crucial factor for economically feasible H_2 production, the temperature should be kept constant which requires additional energy. This will make the SOEC unsuitable for the suggested system unless there is supplementary energy available for the heating. Furthermore, according to literature [5,6] there are no SOEC electrolyzers currently commercially available, although the technology is appearing to market [42]. Current commercially operating electrolyzers, mostly alkaline and PEM electrolyzers, have efficiencies between 40 and 95% [5,7,28], which means that the studied system is energy economically competitive with current electricity storage systems with efficiencies between 50 and 85% [43]. The methanation step seems not be critical for the energy flow of the power to biogas system (Table 3), since it can be assumed, that the conversion of H_2 to CH_4 is close to 100% [19–23], if the hydrogen is fed into the reactor with sufficient flow speed. Some of the grid energy is lost during this step since part of the H_2 is converted to H_2O (Eq. (2)). The H_2 should not accumulate in the AD, since it inhibits the methane producing microbes [44] which means that the conversion should be close to 1.

3.1.1. End use of the biomethane

The energy flow of the studied system is sensitive to the final utilization method of the biomethane (Table 3). Depending on the utilization method, the product gas after the methanation might need some upgrading. However, after the H_2 adding to the AD there is no need for upgrading since the biologically upgraded biogas in this study contains 0 vol-% of CO_2.

The studied biomethane end use methods were: a large CHP plant ($\eta_{el} = 0.58$), a small scale gas engine ($\eta_{el} = 0.40$), and a gas fuelled passenger vehicle ($\eta_{cv} = 0.20$). The studied electrolyzer efficiencies were 0.4, 0.7, and 0.9. The energy flow analysis showed that even with the lowest electrolyzer efficiency (0.4), and end use efficiency (0.20) 6% of energy from the grid can be converted to biomethane (Table 3). This seems to be a small amount, but considering that at times the energy might be wasted, it is better to get at least some of it in utilizable form. If the electrolyzer efficiency is 0.9, and the end use efficiency 0.58 (large CHP) the amount of utilizable energy from the grid reaches up to 40%. As the amount of fluctuating renewable electricity production grows, the times when there is more energy produced than consumed will become more frequent. Moreover, if the utilizable energy replaces fossil fuel usage it also has a positive effect on the CO_2 emission balance.

The CHP plant seems to be the most beneficial of the studied end use methods; depending on the electrolyzer efficiency, 18–40% of the grid electrical energy can be returned to back the grid as electricity (Table 3). If the overall efficiency (electrical + thermal) of the CHP plant, typically 80–90%, is considered, the overall utilizable energy from the power grid is between 25 and 63% depending on the electrolyzer efficiency. Considering 1 MWh of energy from the grid would be stored as biogas, with the electrolyzer efficiency 0.7, it would mean that for large CHP plant 280 kWh of electricity could be produced. In average, one household in Europe consumes 2700 kWh per year [45] (excluding space and water heating), and the amount of utilizable electricity from the studied power to biogas system would equal more than one month electricity consumption for an average household. For countries with high electricity consumption, such as Norway (3700 kWh/household/year) [45] the electricity amount would cover nearly four weeks consumption whereas in countries where household consumption is much lower, for example Romania (1700 kWh/household/year) [45] the electricity would cover two months domestic electricity consumption for one household. However, with large scale CHP plants it must be kept in mind that the capacity of one commercial biogas plant can not provide enough gas to supply the plant. Thus, the biogas should be utilized to replace fossil CH_4 in an existing power plant rather than build a new plant for utilizing biogas.

Using the same logic, for the gas engine the amount of utilizable energy using the same electrolyzer efficiency (0.7) as in the large CHP example, the amount of electricity would be 190 kWh (from 1 MWh of grid energy). For an average European household (2700 kWh/year) [45] this would cover almost one month's electricity consumption. Moreover, small gas engines (kW scale) could be purchased for the biogas only.

If the biogas is used as a transport fuel, the overall efficiency (Table 3) seems low (6–14%). This is due to the low end use efficiency of gas fuelled passenger vehicles (0.20). On the other hand, considering the amount of energy left of the original energy from the grid after the methanation step (energy left in CH_4, 24.5–70%), and that the travel distance of a gas fuelled passenger vehicle is 0.27 km/MJ CH_4 [46], the amount of CH_4 from the process per one 1 MWh of electricity even if the system is operating with very low overall efficiency (η_{el}= 0.4) would move an average gas fuelled passenger vehicle almost 300 km. With current electrolyzer efficiencies (up to 90%), the distance can reach 670 km. Utilizing the biomethane directly as transport fuel would help to achieve the EU-20-20-20 goals for the transport sector. The transport sector is furthest from the EU 20-20-20 goals [47], currently the projected deployment is approximately 19 Mtoe while the goal for 2020 is 29.5 Mtoe [48]. Electricity from the large CHP and the gas engine could also be used for electric passenger vehicles. The electricity consumption of a small electric passenger vehicle is approximately 12 kWh/100 km [49] which would mean that with 280 kWh of electricity from large CHP one could drive for over 2300 km. However, the estimated distance per one charge is 130 km [49]. The utilization of the grid energy directly for electric vehicles was not included in this study, since using electric vehicles for power grid balancing might need smart metering and therefore further investments. However, the scope of this study was in exploiting existing infrastructure.

3.2. Economic analysis

In the economic analysis the biomethane production amount and economical feasibility was compared with two different system

configurations; one without an external H_2 storage (Configuration 1) and another where H_2 storage is added to the system (Configuration 2) to optimize the H_2 production at hours when the electricity price is under the determined threshold electricity price (Fig. 2.). The amounts of additional CH_4 from H_2 utilization were calculated for two real price cases FI and DK2 (Fig. 3.). The amount of additional CH_4 in addition to the AD normal CH_4 production (without the H_2 utilization) for the Case FI without and with the H_2 storage were 20.2% and 24.4%, respectively. For the more fluctuating price case DK2 the additional CH_4 amounts were 27.4% and 31.4%, respectively. The results show that by adding an electrolyzer to an existing AD plant can increase the amount of CH_4 production significantly. With the more fluctuating electricity prices (Case DK2) which has more renewable power, the addition can be up to one third of the normal production of the plant.

The results for the analysis of electrolyzer investment payback times for different electrolyzer investment costs (100–1200 €/kW) with current biogas price of 38 €/MWh [40] with the investment interest 4% could show that with more fluctuating electricity prices the system payback time is less (case DK2) than with a more traditional power production system (Case FI) (Fig. 6.). If more weather dependent renewable power production is added to the system the prices will fluctuate more and adding the electrolyzer to the existing AD plant will become more economical in the future. Assuming that the electrolyzer lifetime is 30 years [6] threshold investment prices for the electrolyzer with the current electricity and biogas prices would be 400 €/kW (DK2 prices) or even as low as 280 €/kW (FI prices) (Fig. 6).

The effect of electrolyzer investment interest was studied by determining a boundary price for biomethane so that the investment payback time would not exceed the electrolyzer expected lifetime expectancy of 30 years [6]. The boundary prices were determined using current electrolyzer investment cost, 1000 €/kW [6] and investment interests between 1 and 8% were studied (Table 4). This study was performed only for Configuration 1 (without the H_2 storage, see Fig. 2.).

Based on the electrolyzer investment interest analysis (Table 4), integrating an electrolyzer to an existing AD plant would be economical even with current electrolyzer investment price (1000 €/kW) and the lifetime expectancy of 30 years [6] if the price of biomethane would increase 20–76% from the current price natural gas (38 €/MWh [40]) depending on the investment interest. This would be possible e.g. if there would be a subsidy for CO_2 neutral biogas production. The price of biogas might also increase if the usage of natural gas would be prohibited. In the future these means are possible in order to reach the international climate agreements.

Table 4
The effect of electrolyzer investment interest to the price of biomethane using current electrolyzer investment cost (1000 €/kW) and lifetime of 30 years [6].

Interest	Target price for biomethane (€/MWh)	
	Case FI	Case DK2
1%	50.47	45.47
2%	52.75	47.54
3%	55.08	49.54
4%	57.47	51.55
5%	59.90	53.56
6%	62.36	55.59
7%	64.75	57.64
8%	67.07	66.27

The boundary prices for biomethane are significantly lower for the price case DK2 (Table 4), which is more fluctuating (Fig. 3.). These results strengthen the conclusion that adding an electrolyzer to an existing AD plant is more feasible when the electricity prices fluctuate more.

It can be seen (Fig. 7) that adding an H_2 storage to the power to biogas system, the payback time for the investment with H_2 storage (Configuration 2) is higher than without the storage (Configuration 1) for price case DK2. The comparison was performed with current electrolyzer investment cost (1000 €/kW), and the H_2 storage size 85 m^3. The electrolyzer maximum powers for both configurations according to the energy flow analysis were 190 kW (Configuration 1) and 592 kW (Configuration 2). The payback times were determined by using a target price of 51.55 €/MWh which was determined as the boundary price of biomethane for current electrolyzers (investment 1000 €/kW, lifetime 30 years [6]).

With the H_2 storage the electrolyzer maximum power is high compared to the benefit from the system. The critical part of the system is the AD capacity for H_2. The dependency of the system function from the electricity price combined with the H_2 capacity of the AD ends up in a situation where the H_2 storage and H_2 capacity of the AD are rarely filled at the same time and thus the electrolyzer maximum power is overestimated. This means that the investment price is high compared to the income from the H_2 storage. The H_2 storage would require more fluctuating electricity prices before it would be a feasible investment.

The results for the sensitivity analysis for the available electrolyzer technologies (AEL, PEM, and SOEC) on the investment payback time based on investment prices reported by Ref. [6] and the price change of biogas strengthen the conclusion concerning

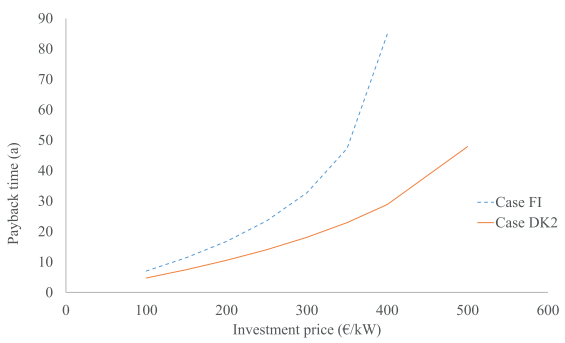

Fig. 6. Payback time for electrolyzer investment with biogas target price 38€/MWh [40] and electrolyzer investment interest 4%.

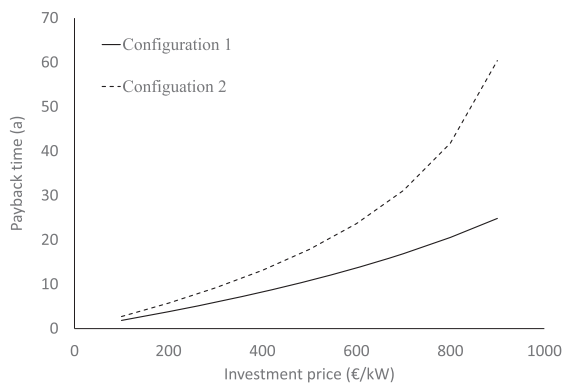

Fig. 7. The feasibility of adding an H_2 storage to the system for price case DK2 with current electrolyzer investment cost (1000 €/kW [6]), and the H_2 storage size 85 m^3.

Table 5
The sensitivity of payback times of different electrolyzer technologies to decrease in the investment cost and increase in the biogas selling price using investment interest 4%. Current investment costs were based on prices reported by Ref. [6] and biogas price [40]. Results could be determined only for Configuration 1.

	Investment cost	Payback times with different biogas prices		
		Current (38 €/MWh)	+25%	+50%
SOEC	Current (3100 €/kW)	–	–	–
	−25%	–	48	21
	−50%	36	21	12
PEM	Current (3000 €/kW)	–	–	–
	−25%	–	–	–
	−50%	–	–	40
AEL	Current (1000 €/kW)	–	–	47
	−25%	58	26	15
	−50%	18	11.5	7.6

the overall economics o the H_2 storage (Table 5). The analysis was performed by assuming a decrease of 25% and 50% on the investment costs, and increase of 25% or 50% on the biogas selling price, changing one parameter at a time. The investment interest was assumed to be 4%. The assumed efficiencies for the electrolyzers were 0.95 (SOEC), and 0.7 (PEM, and AEL) [5].

The investment price of the 85 m^3 H_2 steel tank was calculated to be appr. 42 000 €. Payback time figures for the Configuration 2 with the H_2 storage investment cost could not be determined, because it was not possible to find a situation where the H_2 storage investment would be profitable. This means that adding a H_2 storage to the system is not feasible even if the investment prices would decrease 50%. This happened also for the Configuration 1 with current investment costs (Table 5) even if the biogas selling price was increased 25% for all the studied electrolyzer technologies (SOEC, PEM and AEL). If the current lifetime of the electrolyzers (30 years [6]) is considered, the system is mostly economical when using the alkaline electrolyzer (AEL) technology (Table 5). The SOEC would become economical even with current biogas selling price, if the investment costs would decrease 50%. This is mainly due to the high efficiency compared to other technologies, even with higher investment costs. In the future, as the SOEC technology becomes more mature, the investment costs are likely to drop significantly. The PEM electrolyzers are not economical (Table 5) even if the investment cost would decrease 50% while the biogas price would increase 50%. This is mainly because of the high investment cost compared to the efficiency (0.7). For AEL (Table 5) the installation becomes economical if the investment price would decrease 25% while the biogas selling price would increase 25%. The results (Table 5) strengthen the conclusion that the electrolyzer efficiency is the key factor in the system overall economics.

However, there might also be other possibilities for existing biogasplants to utilize the studied integration of an electrolyzer in the existing system. In the case of excess electricity production the plant would utilize the H_2 production as discussed in this article, and in the case of not enough power production the plant would get extra earnings from compensation which are different depending on the country or power pricing area.

4. Conclusions

This study presented the techno-economic analysis of a power to biogas system that is operated according to fluctuating electricity price. The energy flow and operation costs as well as electrolyzer investment payback time were studied for a system consisting of an electrolyzer connected to a existing biogas plant. The electrolyzer uses electrical energy from grid for H_2 production from H_2O. The H_2 from the electrolysis was fed into the AD reactor for biological methanation. Three possible end utilization methods for the produced CH_4 were considered; power production in a CHP or in a gas engine, and utilization as transport fuel. The scope of the study was in exploiting existing infrastructure for biogas production, transfer and utilization.

The energy flow analysis showed, that with the studied power to biogas system 6–40% of electrical energy from the grid can be converted to utilizable energy depending on the end use method as well as electrolyzer efficiency. The lowest amount (6%) means that even if the electrolyzer efficiency and the end use efficiency are low (0.4, and 0.20, respectively) some grid energy can be converted to utilizable energy. However, with current electrolyzer technologies even the efficiency 0.9 can be achieved and up to 40% of grid energy can be converted back to utilizable energy (power to gas to power). The amount of grid energy that can be converted to biogas with the power to biogas system is most sensitive to electrolyzer efficiency since electrolyzer is the part of the system where most energy is lost (10–60%). The results also show that utilizing the biomethane as transport fuel seems to be the most energy efficient end use option for the biomethane.

The economical analysis of biomethane production costs showed that the power to biogas system can be used to produce CH_4 economically for the studied example cases. The example cases included two different real electricity prices from Denmark (DK2) and Finland (FI). The studied system can be run economically if the electrolyzer efficiency is high and the electrolyzer can be switched on and off quickly according to hourly changing electricity price. The economical analysis showed that inserting an electrolyzer to an existing biogas plant is more beneficial if the electricity prices are more fluctuating (Case DK2). With the electricity prices used in this study (2015 Nordpool Spot prices for FI and DK2) and electrolyzer investment costs (1000 €/kW) the system is economical if the biogas selling price is more than 50.5 €/MWh (Case FI), for the more fluctuating electricity prices (Case DK2) the boundary price is 45.5 €/MWh. This means that the CH_4 price would need to increase only 20% if the electricity prices fluctuate greatly (Case DK2). For the system to be economical with current electricity and biogas prices, the electrolyzer investment costs need to decrease 65–75%. In the future the SOEC might be the most interesting technology to consider, since the efficiency is very high (0.95), and the investment costs are likely to decrease as the installations become more frequent.

Acknowledgements

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Revisiting the feasibility of biomass-fueled CHP in future energy systems – Case study of the Åland Islands

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ABSTRACT

Biomass has been widely recognized as a sustainable fuel for balancing energy systems with high amounts of varying renewable energy production, mainly from wind or solar power. Combined heat and power (CHP) is an efficient technology for biomass utilization and energy system balancing. Currently, the increasing amount of renewable power production often reduces the price of electricity, which makes CHP plants uneconomical. However, this might not be the case in the future, when the subsidies for developing renewable energy sources are reduced or removed. This paper presents a feasibility analysis of the potential for operational flexibility in a bio-fueled CHP plant in a real-life environment using a spreadsheet model. Three different renewable power production schemes for the Åland Islands were analyzed: the present system, a balanced scenario and a high-wind scenario. The analysis was conducted for three different-sized CHP plants run in modes which followed either the heat or the power load. Moreover, in one case two more parameters affecting the magnitude and rate of the flexibility were thoroughly examined: the start-up time and the minimum plant load.

The results showed that biomass does have a place in future energy systems, and the spreadsheet tool can effectively be used for a CHP feasibility assessment in different operational environments; both for existing CHP plants and for planning new investments. The results indicate that the availability of inexpensive fuel and sufficient income from heat sales have to be secured as the operational environment of the CHP plant changes. The examination of the operational mode revealed that in the power-following mode, where the CHP plant can offer flexibility services, the plant's profitability depends on the rate of compensation for the excess heat or spinning hours.

1. Introduction

There is huge global interest in renewable energy production in order to decrease environmental emissions and the dependence on fossil fuels. Currently, hydropower is the most widespread method for the production of renewable electricity, although the amounts of solar and wind power are increasing rapidly. During 2016–2017, the global installed capacity of solar PV increased from 303 GW to 402 GW, while wind capacity increased from 487 GW to 539 GW [1]. As these power production methods are weather-dependent, their production typically fluctuates rapidly. This reduces the stability of the electricity grid, and therefore the energy system needs balancing [2]. Biomass is a viable solution for balancing weather-dependent power production [3–5]. However, although most of the above references recognize bio-energy as a means of balancing the systems, there is little detail about the specific technologies.

Combined heat and power (CHP) production can also balance an energy system [6,7]. CHP produces energy both efficiently and cleanly, and has 20% higher energy efficiency than separate power and heat production [8]. Its efficiency depends on the CHP technology, and a thorough description of the available technologies can be found in [9], for instance. Due to its better energy efficiency, CHP also reduces greenhouse gas emissions more efficiently than separate production [10]. Typically, CHP plants are fueled by natural gas or solid fuels, such as coal, wood and turf. Since the 1980's, the European Council (EC) has encouraged its member states to invest in the use of solid fuels [11,12] in order to reduce their dependence on imported fuels such as oil and natural gas. The EC is also promoting CHP as an efficient energy production method [13]. CHP has several alternative byproducts that can further balance the energy network. These include e.g. wood pellets

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[14], synthetic natural gas [15], bio-fuels [16], drinking water, sugar, biogas, and hydrogen [17].

Currently, the price of electricity is relatively low, so CHP might not appear to be profitable [18]. However, the subsidies that are given for wind power through a fixed production price distort the natural market-driven price of electricity, which remains extraordinarily low. Further increases in wind and solar power production will continue to decrease the price of electricity, which will affect the profitability of CHP plants even more. The price of wind power is dependent on the amount of wind, so the windier it is, the lower the price. As the amount of installed wind capacity increases, the drop in the price of electricity during windy periods is even greater [19]. The cost of producing CHP electricity is mainly dependent on the cost of the fuel. So, as the market price for electricity drops, the cost of producing CHP electricity is often higher than the market price. Thus, increasing the viability is important for both new CHP installation investment plans and existing CHP plants within their remaining operational lifetime.

Optimizing the operation of traditional power plants has been studied intensively in order to better understand the possibilities for responding to fluctuating renewable-energy power balancing. Recent examples include [20], who studied system-level power plant optimization. In addition, plant-level studies on the operational flexibility of coal-fired power plants [21] and the optimal maintenance scheduling of gas turbines [22] have recently been published. However, these studies did not include CHP plants. CHP-related optimization studies have been published by [23], who concentrated on Solid Oxide Fuel Cell technology for small scale CHP (kW) plants, and by [24], which studied the design of a CHP plant and its operation at two different energy system levels. Along with these optimization methods, CHP combined with solar-hybrid [25] and energy storage [26] have also been introduced. These optimizations involve a rather complicated modeling of the operational constraints and the utilization of dedicated optimization tools. However, not all of these optimization tools are available to plant owners, so simple tools for assessing the effects of different operational and economic parameters are needed. This paper presents a spreadsheet method for evaluating the feasibility of a bio-fueled CHP plant's operational flexibility through a real-life case study.

Even though the global availability of biomass is plentiful, the economic viability of any specific biomass is highly localized. In addition, other local conditions such as the patterns of demand for power and heat and the availability of other energy sources influence the optimal choice between different technologies and the costs of energy production. Therefore, the utilization of biomass should be optimized according to the local conditions, since a generic approach might lead to an economically sub-optimal solution.

Islands have great potential for demonstrating the use of 100% renewable-energy systems since they are often dependent on imported fuels and the energy system is usually smaller and less complicated than it is for mainland systems [27]. Recently several cases, including the Canary Islands [28–31], the Åland Islands [27] and Ometepe [32] have been carefully studied. Other examples have been reviewed by [33–35]. Scholz et al. [36] suggest using similarly limited test areas, or even villages on the mainland. Many of the island case studies only deal with electricity, and most are located in warm areas with solar radiation available throughout the year. Islands in the northern latitudes with district heating (DH) can provide useful information on the flexibility of CHP.

Åland is an autonomous province of Finland, located in the Baltic Sea between Finland and Sweden (Fig. 1). The province consists of a total of 6700 islands, although most of them are uninhabited [37]. The islands' total population is approximately 29,000, of whom one third live in the city of Mariehamn [37].

The Åland Islands have set themselves a target of converting their energy system to 100% renewable by 2025 [38]. The work has started with the FLEXe Demo project [39]. Currently, Åland is heavily dependent on imported electricity. There is an 80-MW AC power grid connection to Sweden, and a 100-MW DC connection to Finland. In 2017, approximately 75% of Åland's electricity was imported from Sweden [40]. These connections will still be available in the future and can be used for balancing the electricity network. Two electricity supply companies operate in Åland, Åland's Elandelslag and Mariehamn's Elnät Ab [40]. There are also DH networks in Mariehamn, Godby, and Jomala. In Mariehamn, the network mainly covers the city center, but it is currently being extended to the new Horelli district in the west [41]. About 90% of the DH comes from forest biomass based in Mariehamn [41].

Child et al. [27] have previously studied 100% renewable scenarios for Åland. Their study concentrated on electric transport systems and mostly wind and solar electricity production, leaving CHP production only a minor role. As Mariehamn has a large DH network, and the domestic forest biomass potential is 160,000–170,000 m^3 (including the residue and stumps) [42], the potential for CHP in balancing the electricity system should be carefully studied. Stimulating the local economy by further utilizing the domestic biomass feedstock increases the motivation for further biomass-based balancing of the electricity supply.

This study contributes to the options for a 100% renewable-energy system for the Åland Islands through a scientifically-based discussion of the issues. This real-world case study concentrates on the plant-level constraints affecting the feasibility and technical potential of biomass-fueled CHP installations. The results also give general guidelines on the design of CHP in flexibility services in other environments. The price indicators for a biomass CHP system's flexibility were defined, for example, when different solutions become economically feasible, and according to the constraints of profitable operation. The research questions were:

1. What are the most critical parameters affecting the economic viability of a CHP plant in a real-world environment?
2. What are the effects of the CHP plant's operational parameters (e.g. the plant's minimum load rate, the ramp rates/limits and the start-up time) on the overall economics of the plant?
3. What could be the role of biomass-fueled CHP plants in any future energy system with a lot of renewable power production?
4. How could the plant's overall economic viability be improved by changing the plant's operational parameters (minimum load, and start-up time) in a changing operating environment?

Because there are so many technological possibilities for side products, in this paper their possible integration is handled by a single parameter, power/heat-to-x. The case study is based on plant-level calculations that are explained in the following chapter. One of the greatest advantages of the current approach is the simplicity of the evaluation tool. By changing the parameter values, the tool can be applied easily and quickly for different operational environments or CHP technologies.

2. Materials and methods

The plant-level calculations presented in this paper are based on the theoretical plant values taken from the literature and actual hourly data on power consumption, heat and wind power production from Åland. Local companies (Krafnät Åland, Mariehamns Energi, and Allwinds,) provided the data for 2017. These are presented as duration curves in (Fig. 5.). The patterns of these data were assumed to represent an average year. Wind power production was calculated from 19 windmills situated in different locations on the Åland islands. The proportion of wind production in the future scenarios was scaled up from the 2017 data. First, the hourly total was divided with the current total installed capacity (20.7 MW) [43] and multiplied with the assumed amount of wind energy in the studied cases (Table 3). A similar approach was also applied in [7]. The quantities of solar PV production

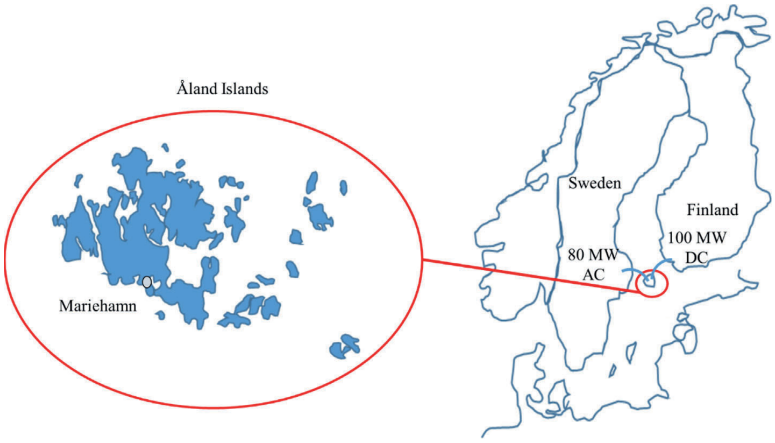

Fig. 1. Location of the Åland islands, and connections to the mainland power systems of Sweden and Finland.

were simulated based on actual hourly diffuse radiation data (W/m^2) [44] taken from the island of Utö (2017), which is the nearest measuring point, located 90 km southeast of Mariehamn. The solar PV and heat production were calculated from the radiation data by multiplying the hourly radiation by the area and the efficiency of the PV/heat panels.

2.1. Modeling procedure

The main inputs to the model were the hourly power demand at the area level, the heat demand, and the availability of other forms of power production (excluding CHP production). In addition to the operational parameters, the investment and operational costs are important inputs for the plant model (Table 1). In this model, all the inputs for any future scenarios for demand and production patterns can be altered in order to study the operation and costs of different CHP technologies, although this study used the data from 2017.

The main outputs of the calculations were the economic parameters of the plant (Table 1) as well as the production patterns for the studied cases. Even though the focus of this study is on modeling the economics of the CHP plant in the Åland Islands, the calculation model can be used in other environments by simply changing the inputs (demand curves, renewable power production curves, plant parameters, and cost parameters).

The part-load efficiency of a plant can be lower than its efficiency with an optimal plant load [9], which may increase the fuel costs of the plant. In addition, the operating mode usually has an effect on the costs, since constant ramping/start-up increases the maintenance costs (wear and tear) [9,45].

In this study, the fixed costs include the capital costs (CAPEX) of the plant, and the fixed operational and management (O&M) costs. The capital costs are defined as overnight installed costs. The variable costs were the fuel costs c_{fuel} of the plant, the start-up costs c_{st} and any possible spinning costs c_{sp}. The economic indicators used in this study were *the return of investment* (ROI), and *payback time*.

A facility is economically feasible when the income exceeds the

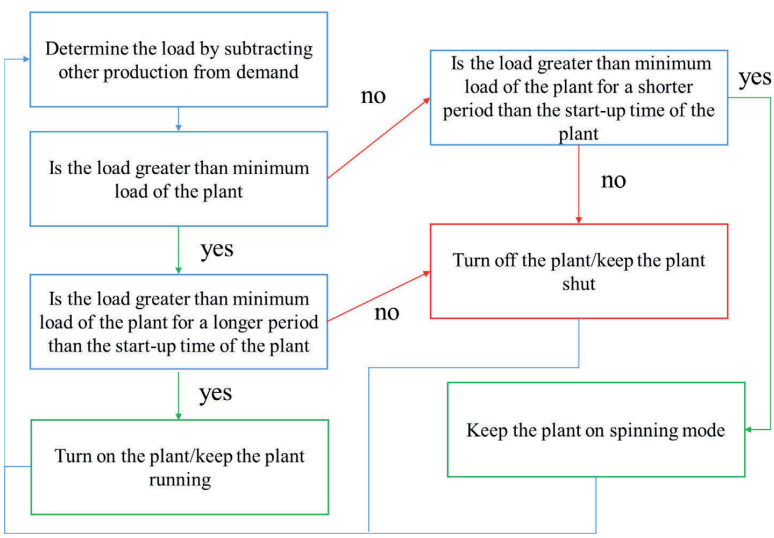

Fig. 2. Procedure for determining the operation hours of the plant. The cycle is repeated for each hour in one year (8760 h). The same procedure can be utilized for both running modes of the plant.

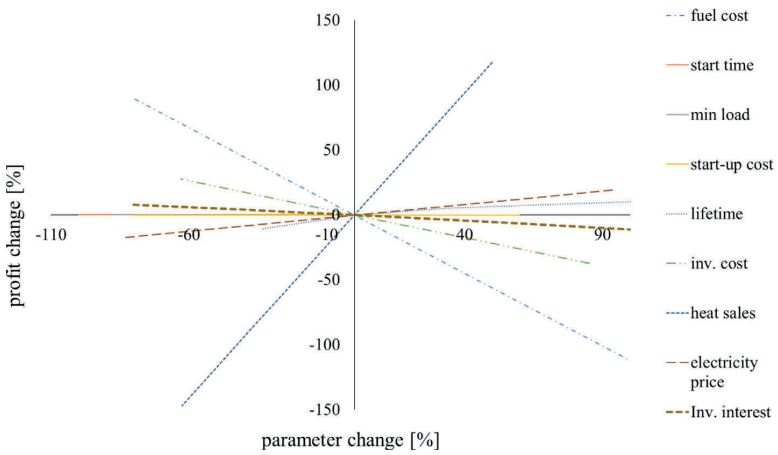

Fig. 3. CHP profitability sensitivity analysis for different operational and economical parameters. Start time, minimum load and start-up cost are overlapping with the zero line of profit change.

costs. This was studied on a yearly basis at a one-hour resolution. For a CHP plant, this is expressed as (Eq. (1)):

$$\sum_{h=1}^{N} P * p_{el} + \sum_{h=1}^{N} Q * p_q \geq c_{n/i} * CAPEX + O\&M + \frac{\sum_{h=1}^{N} (P + Q)}{n_{tot}} * c_{fuel} * n_{st} * c_{st} + t_{sp} * c_{sp} \quad (1)$$

The left side of (Eq. (1)) represents the yearly income and the right side the yearly costs. N is the number of hours per year (8760), h is the hour in question (1-8760), P is the hourly power production [MWh], p_{el} is the selling price of electricity [€/MWh], Q is the hourly heat production [MWh] and p_q is the selling price of the heat [€/MWh]. The hourly P and Q depend on the running mode (the power or heat load-following mode), as well as the maximum and minimum load of the plant. On the right side of the equation, the term $c_{n/i}$ is the annuity factor where n refers to the lifetime of the plant and i refers to the investment interest. The *CAPEX* and fixed operation and management costs (*O&M*) are presented as [€/kw$_{el}$], thus the actual costs depend on the plant's capacity.

The basic values for the variable cost parameters are listed in Table 2. The number of start-ups n_{st} can be determined from the algorithm for determining the operation hours of the plant (Fig. 2).

First, the production gap G [MW] is determined by subtracting the wind production W [MW] and solar production S [MW] from the hourly demand D [MW]:

$$G = D - W - S \quad (2)$$

Table 2
Basic operational and cost parameter values for the calculation

Parameter	Value	Unit	Reference
Max Q	9	MW	[41]
Power to heat ratio	0.2	–	[41]
Overall efficiency	0.8	–	[4,9,45,47–51]
Plant min load	40	% of max	[4,9,45,47–51]
Cold-start time	6	h	[4,9,45,47–51]
CHP Investment cost	2431	€/kW$_{el}$	[9,49,52]
Interest rate	5	%	
Fuel cost	25	€/MWh	
Fixed O&M costs	4	% of Investment	[9,49,52]
Start-up costs	50	€/MW	
Heat price for customer	80	€/MWh	[41]

The decision of the plant operation is then determined according to (Fig. 2). The amount of produced energy (power or heat) per hour depends on the P_{min} and P_{max} (Eq. (3)) and the production gap G (Eq. (4))

$$P_{min} * t \leq E \leq P_{max} * t \quad (3)$$

$$E \leq G * t \quad (4)$$

where t is the time (1 h). A similar procedure is performed for heat in the heat mode. To simplify the calculation, the plant was assumed to change the load without any time delay between the minimum and maximum loads. In addition, the power to heat ratio of the plant was assumed to be constant.

Table 1
CHP model inputs and outputs.

Calculation Inputs				Calculation Outputs	
CHP plant operational parameters		CHP plant costs			
Parameter	Unit	Cost	Unit	Parameter	Unit
Max Q	MW	CHP Inv. cost	€/kW$_{el}$	CHP power total	MWh/a
Min Q	% of max Q	Fixed O&M costs	% of investment	CHP heat total	MWh/a
Power to heat ratio	–	Plant lifetime	a	Heat-to-x	MWh/a
overall efficiency	–	interest	%	Number of start-ups	–
Start-up time	h	Fuel cost	€/MWh	Operational hours	h
		Start-up costs	€/MW	Variable costs	€/a
				Income from heat and power sales	€/a

Table 3
Studied cases.

Case	Description
1	Present system with present size CHP (9 MW_{th}/2.1 MW_{el}) run in heat mode
2	Present system with present size CHP (9 MW_{th}/2.1 MW_{el}) run in power mode
3	Balanced system with present size CHP (9 MW_{th}/2.1 MW_{el}) run in heat mode
4	Balanced system with present size CHP (9 MW_{th}/2.1 MW_{el}) run in power mode
5	High wind system with present size CHP (9 MW_{th}/2.1 MW_{el}) run in power mode
6	Balanced system with large CHP (30 MW_{th}/15 MW_{el}) run in heat mode
7	Balanced system with large CHP (30 MW_{th}/15 MW_{el}) run in power mode
8	Balanced system with optimized CHP (20 MW_{th}/10 MW_{el}) run in heat mode
9	Balanced system with optimized CHP (20 MW_{th}/10 MW_{el}) run in power mode
10	Effect of minimum load and start-up time on a balanced system with optimized CHP (20 MW_{th}/10 MW_{el}) run in power mode

The possible variation in the power to heat ratio was studied in a sensitivity analysis. The sensitivity analysis was performed by changing one parameter at a time. The basic values for the operational parameters (Table 2) are based on the current CHP plant in Mariehamn as well as the values given in the literature for typical biomass-fueled CHP plants. Additionally, the 2017 values for heat and power demand in the Åland Islands as well as the electricity price area SE3 prices [46] were used. Sensitivity to the electricity price was achieved by scaling the electricity price curves with the Excel goal seek function by changing the average yearly price. However, the pattern of the electricity price was assumed to be constant.

2.2. Modeled cases

The plant-level modeling was performed in a spreadsheet. Three different variable power production cases were studied; the present system with 20.7 MW of installed wind; a balanced system with 85 MW of wind power and 15 MW of solar power; and a high-wind system with 170 MW of wind and 15 MW of solar power. In the balanced system, the wind and solar power values are based on actual plans for the Åland Islands and the high-wind system is a modification of an earlier study [27].

In total, 10 different cases were calculated (Table 3).

A CHP plant normally runs in two modes, either in the *heat mode* (following heat demand) or in the *power mode* (following power demand). The existing CHP plant (9 MW_{th}/2.1 MW_{el}) was used as a reference case (Cases 1 and 2) and in the future scenarios in order to see how an increasing amount of variable power production will affect the plant's economics (Cases 3, 4, and 5). Case 1 was also used to validate the model. However, detailed information about the plant's operation is not available to the public.

Due to the operational logic of the heat mode (following heat demand) the production of heat and power does not change in line with changes in other forms of power production in the system, so the high-wind system was only studied in the power mode (Case 5).

In addition, a maximal heat production case (30 MW_{th} and 15 MW_{el}) was also studied. The size of the large plant was based on the maximum heat demand (35 MW Fig. 5.), and the existing 5 MW biomass-fueled heat only boiler that is currently installed in the Mariehamn DH system.

The size of the plant for cases 8 and 9 was based on plant economics. This was done by setting the yearly costs and income as equal (Eq. (1)) and solving Q_{max} and P_{max}. The power to heat ratio for this plant was chosen to be 0.5. This procedure will end up with a plant (20 MW_{th} 10 MW_{el}) that can compensate all the yearly costs with the income. The procedure also proved that unless there is a compensation for excess heat, a larger plant is uneconomical.

As the focus of this study was on the feasibility of flexible operation, the balanced system was studied intensively, which gives sufficient information on the role of the CHP plant in balancing the energy system (Cases 3, 4, 6, 7, 8, and 9). In the present and high-wind systems, the results for the current size CHP cases give a satisfactory indication of the changes in the plant economics.

For energy production facilities, the most important technical parameters of flexibility are *ramp-rate*, *start-up time*, and *minimum load* [47,48]. The ramp-rate describes the rate of change of the net power production ($\Delta P/t$), and is often presented as the % of full load (P_{max}). The start-up time is the period between start-up and the achievement of minimum load. The minimum load means the lowest possible net power under stable conditions [47]. The effect of ramp-rate, start-up time, and minimum load on the economic viability of the plant were studied in the power mode of an optimally sized CHP plant (Case 10, Table 3).

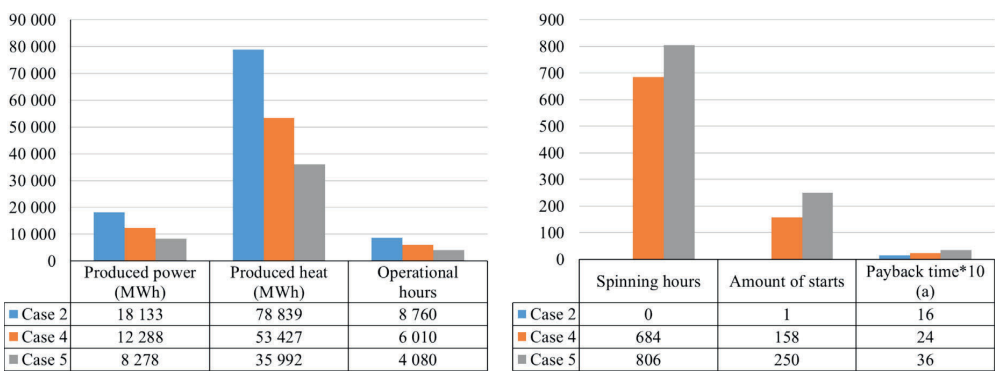

Fig. 4. Current plant with different amounts of variable power production (Cases 2, 4, and 5). Only the power mode results are shown, as in the heat mode other power production does not affect the economics of the CHP plant.

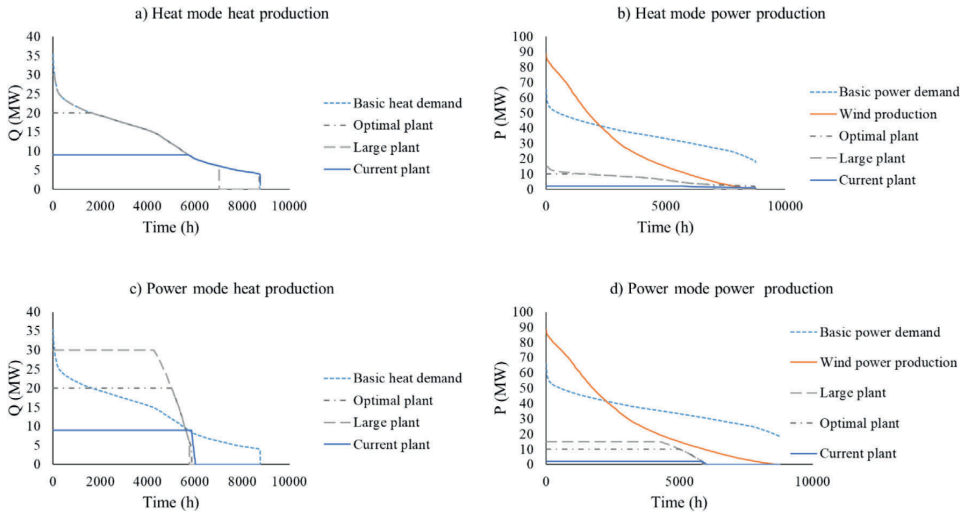

Fig. 5. The simulated duration curves of production in a balanced system. Fig. 5a) and b) present Cases 3, 6, and 8. Fig. 5c) and d) present cases 4, 7, and 9. The power to heat ratio for the current plant is 0.23, while for the larger optimally sized plant it is 0.5.

3. Results and discussion

Fig. 3 shows the effect of the input parameters (Table 1) on the economics of the CHP plant, and the results for the CHP plant economic analysis for cases 1–10 are presented in Figs. 4–9, as well as in Table 4.

3.1. Sensitivity analysis

The sensitivity analysis was performed in order to see that the model works as expected since model validation details about the current plant are not public information. The results of the sensitivity analysis (Fig. 3) show that the factors that most affect the CHP plant's profitability are the fuel costs and the selling price for the heat. Other important parameters (Fig. 3.) are the investment cost, investment interest, and the electricity selling price. This shows that the model works as planned. Other parameters, such as the start-up time, minimum load of the plant, start-up cost and the lifetime of the plant play a less important role in the plant's overall profitability.

3.2. Economic analysis

The results for the economic indicators for cases 1 to 9 are presented in Table 4, and the effect of increasing other power production methods (wind and solar) on the performance and economics of the plant are shown in Fig. 4. In fact, only the power mode results are shown in Fig. 4 since in the heat mode, any other power production has no effect on the

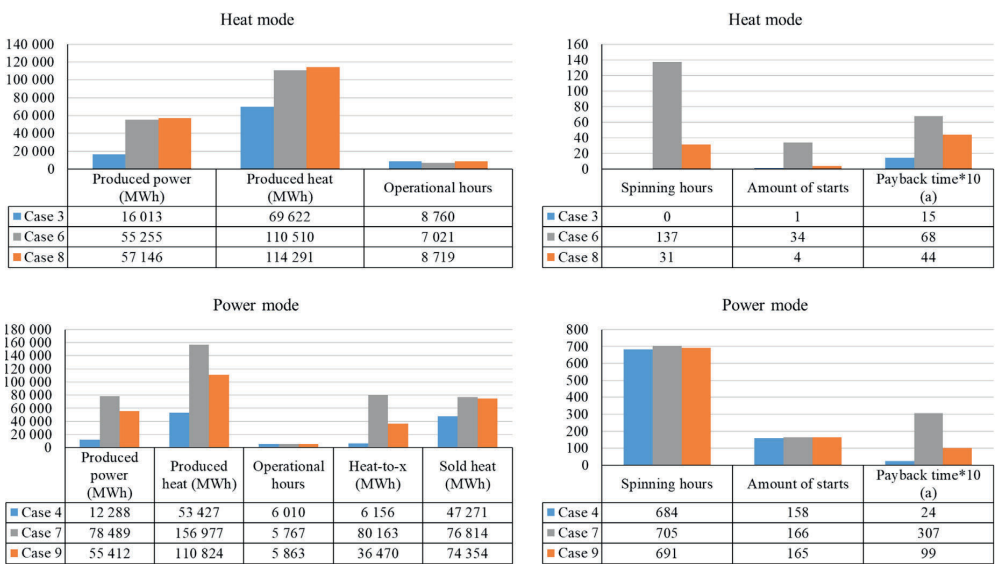

Fig. 6. The balanced system results for different plants (Cases 3, 4, 6, 7, 8, and 9). Payback time is multiplied by 10 in order to fit to the scale for presentation purposes.

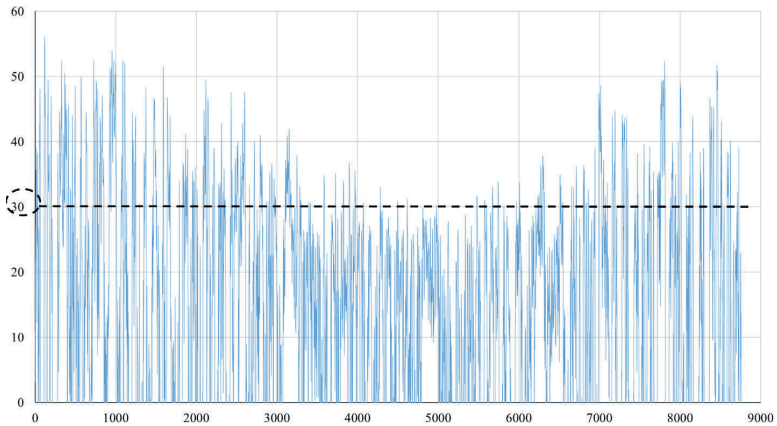

Fig. 7. Power gap in the balanced system after the wind and solar production has been taken into account (curtailment not shown).

profitability or production rate.

The results presented in Table 4 show that in heat mode the economics of a CHP plant are not dependent on the amount of variable power production in the system, as the heat demand determines the production rate. The estimate of ROI for the current plant in the present energy system is high (64.1%). The real figure is lower since the shutdown and maintenance costs, and possible other heat production methods are ignored in this study and the plant is assumed to be running all year (8760 h). In power mode, the plant will be less economical with the present energy system (Table 4 and Fig. 4), leaving the overall economics 5.7 percentage points lower. This is as expected, since the plant's profitability is highly dependent on the selling price of the heat, and the amount of heat, which can be sold, is lower in the power mode. However, the plant will still be highly economical.

4. Reference plant performance

The economic situation is clearly changing as the amount of power production from other methods (solar and wind) is increasing (Table 4, and Fig. 4). For the large CHP plant in power mode (Case 7) the ROI turns negative (Table 4) because the plant produces a lot of excess heat (Fig. 5), which increases the fuel costs of the plant. At the same time, the heat cannot be sold as district heat (Fig. 5). In this case, the ROI of the plant will become negative if there is no compensation for the excess heat. In addition, the investment cost of the large plant vs. the operational hours affects the ROI of the plant.

Increasing the amount of variable power production diminishes the overall economics of the plant. This is mainly due to the reduction in operation hours (Fig. 4), and therefore decreased heat and power production. As the profitability of the plant is highly dependent on the selling price of heat (Fig. 3), this leads to poorer profitability for the plant (Table 4). The number of start-ups and the amount of spinning hours (Fig. 4.) also affect the economics of the plant by increasing the variable costs. However, the current-size CHP plant (9 MW_{th}/2.1 MW_{el}) remains profitable even in the high wind scenario (Table 4 and Fig. 3).

4.1. Analysis of the plant size

Increasing the size of the plant decreases its overall profitability (Table 4). This is mainly due to the reduction in operational hours and the excess production of heat (Figs. 5 and 6), especially in power mode operation. For a larger plant, the minimum load is greater than it is for a smaller plant since it is dependent on P_{max}. Heat and power production for all cases are dependent on each other due to the chosen constant power to heat ratios.

As can be seen from the power production duration curves (Fig. 5), there is excess wind power production with the increased amount of installed wind capacity (85 MW). In heat mode (Fig. 5a), the heat

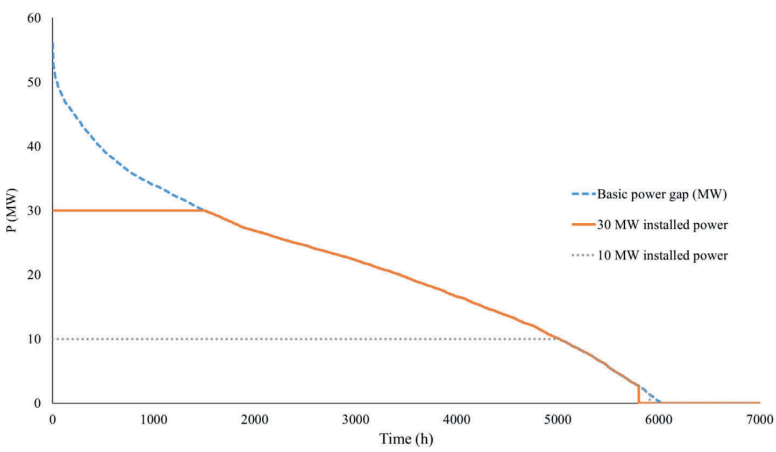

Fig. 8. Duration curves for plant optimizing options.

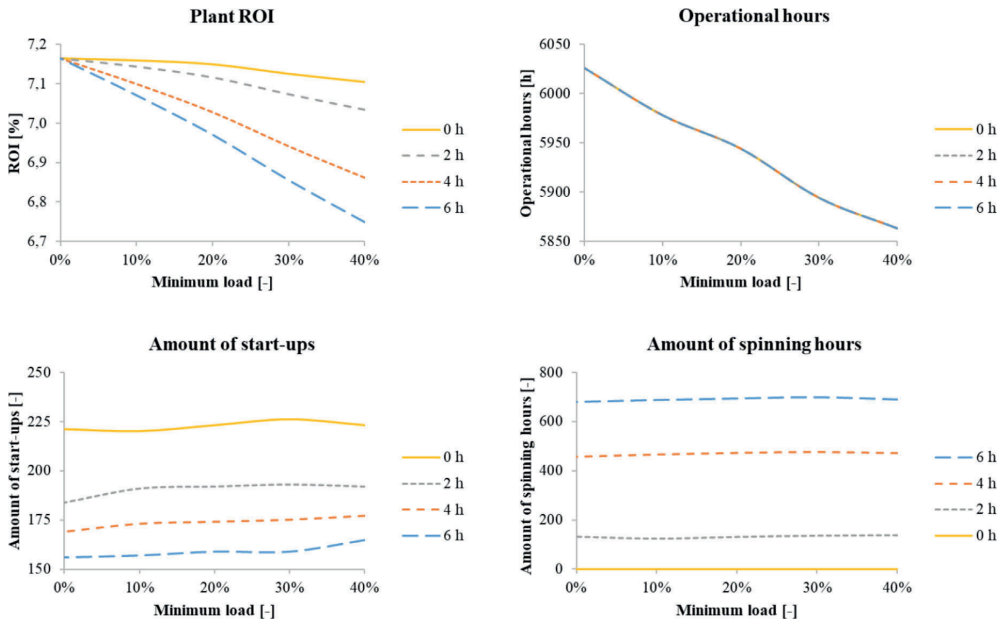

Fig. 9. Effect of start-up time and minimum load on the profitability of the plant (Case 10).

demand can be met more precisely by increasing the plant size. However, increasing P_{max} from 10 MW to 15 MW only changes the amount of power production in heat mode by 4 GWh (Fig. 6). This is due to the shape of the heat-demand curve that determines the operational hours. The plant does not produce heat when the demand is below the minimum load of the plant (40% of P_{max}), which for the large plant (30 MW_{th}/15 MW_e) is 6 MW. The heat demand is thus below this plant's minimum load for over 1700 h (Fig. 6), mainly during the summertime. Since most power storage technologies are currently inefficient and expensive [53], one option instead of curtailment is utilizing the excess power as heat, especially in cases 3 and 4 (with the current CHP plant). However, this might require seasonal heat storage. Utilizing the excess power for heat would affect the optimal size of the CHP, and this should be studied more thoroughly, as well as the timeliness of the excess power with heat demand.

Producing excess heat (heat-to-x) means increased fuel costs, which decreases the overall economics of the plant even though more heat can be sold (Fig. 6). However, as this is combined with higher investment costs, the profitability of the plant will decrease dramatically (Table 4, Fig. 6). This indicates that if the plant is to remain profitable while providing flexible power services, there should be some sort of compensation for the plant's operation. This could be either heat-to-x compensation or compensation for the flexibility service. Heat-to-x compensation could be in the form of heat storage for the district heating system, where heat would be stored during peak production and utilized during peak demand. Currently there is a heat storage capacity of 350 MWh in Mariehamn (Mariehamns Energi, Personal communication), which might be sufficient for such storage. However, the timeliness of the peak production and peak demand might cause a problem with the storage of heat, since peak demand usually occurs during wintertime while peak production is dependent on the gap between variable power production and power demand. These gaps can also occur during summertime when heat demand is usually low. Therefore, improving the overall economics of the CHP plant with heat storage might require seasonal storage.

Utilizing the heat for other purposes, such as drying fuel, could in general be beneficial, although the potential for heat-utilization industries in the Åland Islands is limited. Another way to improve the overall economics of the CHP plant could lie with dynamic operation logic if the plant was equipped with a low-pressure turbine and/or a turbine bypass. The power or heat production could then be adjusted according to demand. However, this could mean higher investment costs for the plant as well as increased equipment costs due to the higher stress levels caused by continuous ramping. Therefore, this possibility should be studied in more detail before reaching any conclusion about the operation logic. In addition, the timeliness of the peak

Table 4
Economic results from the studied cases.

Case	ROI (%)	Payback time (a)
Case 1 (9 MW_{th}/2 MW_{el}, Present System, Heat mode)	64.1	1.5
Case 2 (9 MW_{th}/2 MW_{el}, Present System, Power mode)	58.4	1.6
Case 3 (9 MW_{th}/2 MW_{el}, Balanced scenario, Heat mode)	64.1	1.5
Case 4 (9 MW_{th}/2 MW_{el}, Balanced scenario, Power mode)	38.5	2.4
Case 5 (9 MW_{th}/2 MW_{el}, High wind scenario, Power mode)	24.7	3.6
Case 6 (30 MW_{th}/15 MW_{el}, Balanced Scenario, Heat mode)	11.4	6.8
Case 7 (30 MW_{th}/15 MW_{el}, Balanced scenario, Power mode)	−0.1	30.7
Case 8 (Optimized 20 MW_{th}/10 MW_{el} Balanced scenario, Heat mode)	19.6	4.4
Case 9 (Optimized 20 MW_{th}/10 MW_{el} Balanced scenario, Power mode)	6.7	9.9

heat demand and production should be studied in more detail to determine the benefit of heat storage for the CHP plant, although this is beyond the scope of the current study.

Since the economics are clearly dependent on the heat sales and heat-to-x compensation, it might be tempting to choose a plant with minimum or no heat production at all (a condensing power plant) in order to maximize the flexibility of power production. This would indeed increase the flexibility of the plant in terms of power production. However, it would also mean poorer overall efficiency and increased power production costs (€/MWh). This might mean a need for flexibility compensation or higher electricity selling prices at peak demand hours. A better solution would be to increase the plant's heat-production flexibility by adding a side process (heat-to-x) to the plant. Heat-to-x would secure the plant economics and keep the overall efficiency of the heat and power production processes higher than they would be for separate production. This would also maximize the efficiency of the utilization of biomass. Further study of the operating logic and economics of a condensing bio-fueled plant is needed in the future, as well as a more thorough analysis for finding the most interesting heat-to-x process for the Åland Islands.

It must also be noted that the optimized plant size (Figs. 5 and 6) is based on minimizing the required heat-to-x compensation in order for the plant to remain profitable. If the plant size were to be optimized based on minimizing the power demand gap after wind and solar power production (Fig. 7), the optimal maximum power production rate would be around 30 MW.

Even though the maximum power gap is 56 MW (Fig. 7), gaps above 30 MW occur relatively infrequently. There are only approximately 1500 h when the gap is greater than 30 MW, which is equal to 2.5 months. Gaps greater than 35 MW only occur for less than 900 h per year. As the investment cost of the plant is dependent on the installed power capacity (Table 1), increasing the power capacity of the plant for only a few operating hours is uneconomical, especially since the existing cable connections to Åland can also be utilized for peak hours in the future. Optimizing the plant's installed power capacity according to the power gaps (30 MW_{el}) rather than for the plant's overall economics (10 MW_{el}) would decrease the power gap by 91% (Fig. 8).

However, increasing the plant's installed power capacity would more than triple the investment costs of the plant, from 24.3 M€ (10 MW installed power capacity) to 74 M€ (30 MW installed power capacity). This would affect the overall profitability of the plant, as can be seen for both the 15 MW and 10 MW installed power capacities (Table 4). As the installed power capacity increases, the installed heat capacity also increases, even if the power to heat ratio were to equal 1 (heat capacity 30 MW), which is a rather high power to heat ratio and might increase the investment cost even further. Increasing the installed heat capacity will weaken the plant's overall economics due to the increasing amount of excess heat (or heat-to-x) (Table 4, Fig. 5). Optimizing the CHP plant's capacity according to the power gaps would benefit the power system by maintaining a balance between production and demand, but it would require some further compensation for the CHP to remain profitable.

4.2. The effects of technical features

The effect of the most important technical features on the economy of the plant, ramp-up rate, start-up time and minimum load, were studied for the optimally-sized CHP plant in power mode (Table 3). Based on the literature [9,47–50], steam turbines can achieve their maximum load in less than one hour. Based on the average ramp-up rate of 3.4% P_{max}/minute a plant can reach 3.4%*60 min/h = 200% of P_{max}/h. Thus, the ramp rate is not an issue in this study since the calculation is made on an hourly basis.

The effect of start-up time and minimum load on the profitability of the plant was studied by changing the minimum load from 40% to a theoretical 0% in 10% steps, and the start-up time from 6 h to 0 h with 2-hour steps (Fig. 9.).

Fig. 9 shows that as the minimum load and start-up time decrease the profitability of the plant increases. However, this increase is only slight; approximately one percentage unit (Fig. 9). Decreasing the minimum load has a greater effect on the profitability of the plant with start-up times longer than 2 h. It can also be seen that the operational hours of the plant are not dependent on the start-up time as the points overlap. Instead, decreasing the start-up time to even less than 2 h will significantly increase the number of start-ups (Fig. 9), which in turn increases the operational costs of the plant. This diminishes the profitability in relation to the achieved benefit. The cost of improving the minimum load and the start-up time was determined using the Goalseek function in Excel by assuming that the ROI of the plant would remain constant (6.75%). This analysis showed that the plant investment cost should not increase by more than 6%-units. Further analysis of the operational hours of the plant (Fig. 9) revealed that the increase in the profitability (ROI %) is in line with the increase in operational hours. It is also evident that the minimum load has a greater effect on the plant's profitability. When the plant can produce heat and power with a smaller minimum load (less than 40% of P_{max}), the operational hours increase and therefore the amount of the products (heat and power) available for sale increases. At the same time, the spinning costs decrease, since less fuel is required to keep the plant in the spinning mode and ready for production. However, for spinning hours and start-ups, the effect of the start time is more significant (Fig. 9). A shorter start-up time increases the number of start-ups which increases the start-up costs, while decreasing the amount of spinning hours and decreasing the spinning costs. These results reinforce the conclusion that operation hours and the amount of sold heat are the most important factors in the plant's overall profitability.

5. Conclusions

By means of a practical case study from the Åland Islands, this study contributes to the scientific discussion of the feasibility of using biomass in a Combined Heat and Power (CHP) plant in future energy systems offering flexibility services. Two CHP running modes, heat-load following and power-load following, were studied. CHP is an efficient energy production method, especially where the heat is needed for district heating or for processing purposes.

The main contribution of this study is a tool for estimating the effects of different technical and economic parameters on the overall economics of a CHP plant. Although the focus of this study was on the Åland Islands, the feasibility assessment tool can easily be utilized for other cases.

The results showed that bio-fueled CHP plants could be used for balancing the power gaps and could be run profitably in future energy systems. However, this requires that the fuel costs remain close to their current level (25 €/MWh) or by compensating for the production of excess heat with subsidies or by further utilizing the heat-to-x. In addition, sufficient compensation of the electricity price can improve the overall economics of the plant. Selecting which CHP technology to use should be done on a case-by-case basis since the availability and cost of fuels for a plant vary according to local conditions. Furthermore, when interpreting the results of this study for other areas, it should also be noted that the economics of the plant are strongly affected by the patterns of demand, which is another reason why the profitability of any plant should be determined separately for each case.

The most important technical parameter for increasing a plant's flexibility while also improving its economic feasibility is the minimum load. Improving the minimum load of the CHP plant and decreasing the required start-up time in power mode can improve the ROI of the plant by one percentage unit. This means that improving the operational parameters ought not to increase the investment costs of the plant by more than 6%-units given the current selling price of the heat and the fuel costs (80 €/MWh, and 25 €/MWh, respectively).

In the future, the effects of seasonal heat storage, low-pressure turbine and turbine bypass options on a CHP plant's overall economics should be studied. In addition, different heat-to-x technologies might improve the overall economics and options for Åland, and should be studied further.

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Declaration of interests

None.

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PUBLICATION IV

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The Potential of Biomethane in Replacing Fossil Fuels in Heavy Transport—A Case Study on Finland

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Abstract: Electrification is a frequently discussed solution for reducing transport related carbon dioxide emissions. However, transport sectors such as aviation and heavy-duty vehicles remain dependent on on-board fuels. Here, biomethane is still a little exploited solution, and the case of heavy-duty vehicles is particularly underappreciated despite the recent technical advances and potentially notable emission reductions. This paper discusses the potential of biomethane in heavy-duty road transport in the case of Finland, where the utilization rate is low compared to the technical potential. To this end, the potential of biomethane production through both anaerobic digestion and gasification was calculated in three scenarios for the heavy-duty transport fleet, based on the literature values of biomethane potential and truck class fuel consumption. The authors find that approximately half of the heavy-duty transport in Finland could be biomethane fueled by 2030. The estimated production costs for biomethane (81–190 €/MWh) would be competitive with the current consumer diesel price (152 €/MWh). Utilizing the total biomethane potential in heavy-duty transport would furthermore decrease the respective carbon dioxide emissions by 50%. To accelerate the transition in the heavy-duty transport sector, a more comprehensive political framework is needed, taking into account both production and consumption.

Keywords: renewable transport fuels; biomethane; carbon emission reduction; heavy-duty transport; transition; Finland; anaerobic digestion; wood gasification

1. Introduction

The transport sector is responsible for 14% of global CO_2 emissions [1]. This share is set to increase further with economic growth in the developing countries [2]. In 2015, approximately half of total oil end use worldwide (49.7%) was for transport [3]. At the same time, reducing the utilization of fossil fuels in all sectors is essential to reduce the emissions of CO_2 and other greenhouse gases (GHGs) in order to combat global warming. Several European countries are considering bans on fossil fuelled passenger vehicles. Norway aims to achieve such a ban by 2025 alongside severe emission reductions for all vehicle classes by 2030 [4]. Similar plans also exist in France, Ireland, Sweden, Germany, and the UK, while in Finland the issue was discussed in connection with the 2019 parliamentary elections.

The electrification of transport is a frequently discussed solution for reducing GHG emissions in this sector. For passenger and medium-duty vehicles, electrification will be the most efficient emission reduction technology, assuming a high share of renewable low carbon power in the electric energy system. However, aviation, shipping, and a significant part of heavy-duty transport will remain dependent on on-board, high energy density transportable fuels for a considerable time to come [5,6]. In this article, we focus on the provision of low-carbon fuels for heavy-duty transport. While this is a

global policy challenge, it is typically a more acute need for countries with low population density or with long distances between major concentrations of raw materials and sites of production and consumption. One study suggests that, in particular, countries where heavy truck-trailer combinations are widespread require solutions since such combinations are difficult to electrify even with high battery capacity [7]. Electric road systems, for their part, require very high investments and are unlikely to be able to serve all traffic needs [7].

In short, because it is unlikely that one solution for delivering low-carbon heavy transport will be applicable across all countries [6,7], several options need to be explored, including gaseous fuel solutions. Particularly in the European context, the considerable, yet largely unexploited technical potential of biomethane, or upgraded biogas, is one such option with several raw material streams available [8,9].

1.1. Background

Biomethane is currently emerging as one viable solution for the heavy-duty transport sector [10–12], with comprehensive reviews of its benefits and constraints [13,14], and of the required heavy-duty vehicle fleet [15]. The European biomethane market comprises 90% of the global supply [16] and has grown seven-fold since 2000 [17]. Production can be doubled by 2030 [8,17,18]. The global potential is also promising. Using energy plants for the production of biogas has a better energy output per unit area than using the same plant-based raw material for producing liquid biofuels—which is so far remains the preferred solution in several countries around the world owing to its relative compatibility with vehicles using oil-based fuels. While in this respect it is possible to view biogas as a renewable fuel with a great deal of potential, its competitiveness can further be enhanced by also using the associated CO_2 for commercial applications in numerous sectors [19].

For the use of biogas in transport, biomethane can be either pressurized (200 bar) or liquefied. Unlike hydrogen (H_2), which is constrained by costs, availability of vehicles and deficiencies in the transport and storage infrastructure [20], biomethane can be used in existing systems where natural gas methane (CH_4) is utilized. Suitable gas fuelled heavy traffic vehicles are commercially available, including so-called dual fuel (diesel/NG diesel for ignition and as a fuel) and spark ignition engines (only NG) [10,11]. The scenario of the Natural and Bio Gas Vehicle Association Europe (NGVA) expects the number of methane fuelled trucks to increase from 9000 to 480,000 by 2030, reaching a 25% market share, while liquefied natural gas (LNG) vehicles would take up a 10% share of the market [21]. The main constraint in promoting gas fuelled heavy trucks is the approximately 30–40% higher purchase price compared with fossil fuelled trucks [10], depending on the equipment [22–24].

A life cycle assessment has found that biomethane solutions, when used to power Euro6 buses, generally have a lower environmental impact than their main competitors—including liquid biodiesels—in terms of global warming, stratospheric ozone depletion, photochemical oxidant formation, acidification potential, and eutrophication potential [14]. Kalinichenko et al. [19] find crop-based biogas to provide a greater amount of vehicle fuel energy than the biodiesel or ethanol options. According to Hijazi et al. [25] and Baldino et al. [8], the raw material used for producing biomethane is crucial to the environmental sustainability of the fuel. Differences exist, for example, between crop-based and animal manure-based raw material, while the storing, management and production technologies also have a role. Livestock manure offers the greatest technical potential of biomethane in the EU compared with other raw materials, constituting 43% in the transport use case [8,25].

The use of biomethane for transport has to compete with its use for power and heat, where biogas is more cost-efficient than in the transport sector when considering conceivable financial incentive structures [8]—while biogas can also be used to produce chemicals. However, the current incentives typically prioritize low carbon power production, not the heat or transport sectors. The existing transport sector incentives focus mostly on electric vehicles, which in Ireland, for example, enjoy sixteen-fold incentives compared to a natural gas vehicle operating on biomethane [26]. Moreover, since the transport case requires more complex infrastructure than the heating case, for example,

filling stations, higher incentives would be natural [26]. Great energy efficiency and environmental benefits exist in the transport use case [9], including minimization of particle emissions and reduction of emissions in agriculture [26].

In the EU context, biomethane-based transport is at its most advanced in the case of Sweden, with half of biogas production used for transport [19]. Börjesson et al. [11] focus on the system level (per vehicle km), bypassing the question of the actual number of vehicles. Ammenberg et al. [27] address the demand side actors and policies as well as the supply and distribution side through expert interviews in Stockholm County in Sweden. Biogas was found to have potential for buses and taxis, while utilization for heavy fuel transport was only mentioned as a future possibility. In addition, Lönnqvist et al. [28] explored the potential for biogas produced in anaerobic digestion (AD) in Stockholm County based on a survey of key actors. Jensen et al. [29] examined three biogas production scenarios in Denmark with a focus on commercial light and heavy-duty vehicle utilization, using three different technology assumptions for AD biogas production and assuming a 100% share for biomethane fuelled heavy-duty vehicles. Uusitalo et al. [30] found biogas a potent transport fuel in Finland in view of its cost-effectiveness (calculated from the point of view of the gas grid owner), as well as GHG and particle emission reductions, but they did not directly examine the heavy-duty transport sector.

1.2. Scope of the Paper

This article breaks new ground by examining biomethane solutions in the context of heavy-duty transport, which so far has been little studied. Finland is presented as a typical case within a larger group of countries [31], wherein the heavy-duty transport sector is relatively large [32], showing a growing trend [33] (Countries meeting these criteria include, for example, France, Poland, Portugal and Spain) and in particular, where truck-trailer combinations are widespread [7]. Crucially, no studies have been published that include a vehicle class analysis of this case. The transport sector accounts for 20% of Finland's GHG emissions [34], while the country's exports consist predominantly of transport intensive commodities, including forest, chemical and metal industry products as well as machinery and vehicles. The presence of the forestry industry in Finland enables the production of liquid or gaseous biofuels from the industry's side-products. Consequently, liquid biofuels are a key part of the national energy and climate strategy, where biogas is also mentioned [35]. Yet the large-scale production of liquid biofuels is associated with much-discussed problems. Production from forest-based biomass may become limited by the availability of suitable raw material, and may have negative implications for the carbon sink, while the large-scale use of crop-based raw materials risks competing with food production [8,20].

NG vehicles so far represent a niche sector in Finland, numbering only 3600 in 2017 [36]. However, Finland's techno-economic potential for biogas is large, estimated at 10 TWh [37], making it larger for the transport use case than Sweden, the current leader, and twelfth largest in the EU [8]. Finland's 2016 Energy Strategy foresees the gasification of woody biomass for producing transport fuel as part of the 40% target for renewable fuels by 2030 [35]. The key constraints for the low utilization rate of the biogas potential include limitations in the distribution network and economic feasibility [38]. Moreover, Huttunen et al. [39] identify inadequate policy cohesion resulting from conflicting political targets and policy instruments. Winquist et al. [40] find some improvement in the recognition of biogas and the related benefits in recent policy documents, also outside of the energy sector. However, actual objectives and measures to promote biogas usage remain very generic. At the same time, significant additional potential exists for increasing biogas production from forest residues and agricultural by-products that could further improve Finland's raw material base. In the case of Sweden, Börjesson found that the realization of similar potential requires improved political guidance and regulation for this production not to conflict with environmental goals [41]. Moreover, for both Sweden and Norway, a need has been identified to co-ordinate the regulatory system and to provide subsidies to enable the most environmentally advantageous use of biogas [42,43].

This paper seeks to contribute to this debate by first assessing how high a share of Finland's heavy-duty transport could be biomethane fuelled. Drawing upon a pilot study on the potential of AD biogas for heavy traffic in Finland [44], this study uses an illustrative vehicle fleet model and calculates three different scenarios for a biomethane fuelled heavy-duty transport fleet. The biomethane potential was estimated based on the values in the existing literature of available raw material from AD processes as well as from woody biomass gasification. In addition, an estimate of CO_2-emission reduction/ton is provided. In light of the results, this paper also discusses the respective constraints for biomethane production, delivery infrastructure and policies. Our primary research questions are:

(1) How large a share of heavy-duty road transport could the techno-economic potential of biomethane cover?
(2) What would be the cost of biomethane utilization for the heavy-duty truck fleet?
(3) How much transport related CO_2 (and other) emissions could be avoided?

The biomethane potential suitable for the heavy-duty transport sector was found to be 7.4 TWh annually, which is substantial in the context of Finland. Depending on the priority order of vehicle classes, domestic biomethane could fuel as many as 66% of the vehicles in the current heavy vehicle fleet. Utilizing the entire potential of biomethane in the heavy-duty transport sector was found to halve the sector's GHG emissions as well as its NO_x-emissions, regardless of the scenario chosen. Economic analyses conducted to ascertain the theoretic magnitude of the financial investments required conclude that biomethane production (81–190 €/MWh) would be competitive with the current consumer price for diesel (152 €/MWh). However, limited fuelling and delivery infrastructure, in addition to the small number of gas operated vehicles currently in use, imply that additional investments will also be required over and above biomethane production alone. Biogas has remained a niche technology in Finland, as both production and usage levels have remained low. The biogas production chain is characterized by a high level of uncertainty stemming from political incoherence between targets and means, as well as a low level of local co-operation. A more comprehensive and cross-sectoral framework is required to address obstacles to production and demand simultaneously, and to trigger a transition in heavy-duty road transportation in Finland. The results provide insights beyond Finland to other EU Member States by adjusting the vehicle classes, availability of biomethane and features of biogas policy-making according to the respective characteristics of each case.

2. Methods, Materials and Assumptions

A case study on biomethane solutions in the heavy-duty transport sector in Finland is reported here. Single case studies are particularly useful in little explored areas such as those discussed herein. They can generate observations to be subsequently explored in other typical cases [31]—in this context, heavy transport intensive countries with a relatively high biomethane potential, of which there are many in the EU. As suggested above, Finland is a somewhat difficult case in this group owing to the dominant role of the forest industry and, hence, a vested interest in liquid biofuels [45], while the widespread use of truck-trailer combinations curtails the prospects for electrification and necessitates considering several options, including biomethane. In other words, if biomethane solutions are found to be readily applicable in Finland, it is reasonable to expect the same for other cases in this group of countries. However, prospective comparisons must recognize the regional and local variation in the raw material, the distance to production sites and the effectiveness of transport [14,19,46,47]. Yet the authors expect the procedures used to be replicable and the results to be applicable to other countries in this group after adjustment for vehicle class, raw material base, and transport conditions.

The observations in this paper concern the production and potential of biomethane, its use in the heavy-duty traffic fleet in three different scenarios and the respective policy needs. All calculations represent theoretical process values. In addition, the authors calculated the amount of biomethane potential for gasification. The analysis of the constraints and required policies for the implementation of biogas solutions in Finland draws upon the literature available.

2.1. Assumptions on the Production of Biomethane

AD processes can utilize residual biomaterial such as municipal bio-waste, sewage sludge or agricultural residues, resulting mainly in CH_4 (50–70 vol-%) and CO_2 (30–50 vol-%). Prior to utilization as a transport fuel, CO_2 and other impurities must be removed by means of chemical or physical absorption, membrane separation, adsorption on a solid surface, cryogenic separation or chemical conversion [48–50]. In biomass gasification, the main product is H_2 (40–50 vol-% of the dry product gas) that can be utilized directly as a transport fuel or further reacted catalytically or biologically with CO or CO_2 to form CH_4. Other gasification products include CO (typically 21 vol-%), CO_2 (15 vol-%) and CH_4 (10 vol-%) [47,51]. Commercial projects for transport fuel production via biomass gasification include GoBiGas in Sweden and GAYA in France [52] (Figure 1). Due to limitations of space, we do not consider power-to-gas technologies here, which can also be used to produce biomethane.

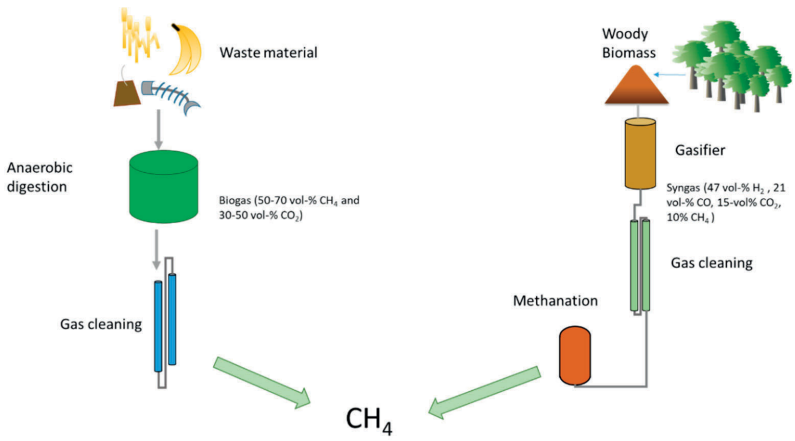

Figure 1. Simplified production paths for biomethane.

In 2017 there were 71 biogas production sites in Finland. Total production including collection from landfill sites was approximately 700 GWh [53], of which only 30 GWh was used as transport fuel. As of 2018, a mere 708 gas fuelled vehicles ran on natural gas (NG) only, and 2925 on both NG and petrol. Most of these vehicles were passenger vehicles. Only 18 NG and 75 dual fuel trucks were registered. In 2017, there were altogether 3,099,566 cars, vans and trucks in Finland [36]. The potential for the expansion of the fleet of gas fuelled vehicles is considerable.

In this paper it is assumed that all the biomethane available to be used solely for heavy-duty transport, originating from both AD of waste material and gasification of woody biomass. Furthermore, based on [37], the techno-economic biomethane potential from AD in Finland is estimated to be 10 TWh. The amount of available woody biomass for transport fuels is expected to be 4 Mm^3 by 2030 according to the Finnish Government's estimate as calculated by the Ministry of Employment and the Economy for the country's 2016 Energy Strategy [35]. In addition, it is assumed that the wood contains 30% of moisture, higher heating value (HHV) is 20 MJ/kg and average mass 238 kg/m^3 [54]. The amount of syngas from woody biomass can be calculated based on cold gas efficiency η_G [47]:

$$\eta_G = \frac{\dot{M}_g LHV_g}{\dot{M}_b LHV_b} \tag{1}$$

where M_g is the mass flow of product gas, LHV_g is the lower heating value of the product gas, M_b is the mass flow of wood, and LHV_b the lower heating value of wood. In this study, η_G = 0.7 based on [47,55]. The amount of available biomethane from wood gasification for its part is based on typical wood syngas composition (dry basis) (Table 1).

Table 1. Typical wood gasification product gas composition [47,51] and lower heating values (LHV) of the gas components.

Compound	Vol-%	LHV (kJ/mol)
H_2	47	241.8
CO_2	21	-
CO	15	283
CH_4	10	802.3
C_xH_y	4	
N_2	3	-
sum	100	

The LHV of the syngas was calculated as a weighted average based on the gas composition and LHV of each of the gas components (Table 1). For gases, the volume fraction equals the molar fraction.

Syngas typically contains contaminants such as tars, solid particles and acids, which must be removed before further processing. Cleaning methods usually include cyclones, wet scrubbers and catalytic steps [56,57]. H_2 and CO as well as CO_2 from the syngas can be further reacted to CH_4. The overall reactions can be simplified as Equations (2) and (3):

$$3H_2 + CO \text{ –> } CH_4 + H_2O \tag{2}$$

$$4H_2 + CO_2 \text{ –> } CH_4 + 2H_2O \tag{3}$$

Both reactions are exothermic (e.g., demand heat). The conversion of CO and CO_2 (Equations (2) and (3)) was assumed equal to 1 [58]. Methanation of CO and CO_2 include several reactions [52,59], however the overall reactions were found to be sufficient for the purposes of this study.

Since the amount of H_2 in the syngas (Table 1) does not suffice for reacting all the CO and CO_2 from the syngas, we preferred the methanation of CO (Equation (2)). Any excess H_2 left from (Equation (2)) would then be utilized in CO_2 methanation (Equation (3)). Several methods for methanation exist, including fixed and fluidized bed reactors, structured reactors, as well as slurry reactors [52]. A more detailed description of the CO and CO_2 methanation technologies can be found in [52,59]. The LHV of methane is 802.3 MJ/kmol. For the sake of simplicity, the energy losses from gas purification and pressurization were ignored.

2.2. *Assumptions Regarding Heavy-Duty Traffic: Vehicle Model and Scenarios*

The travelling distance estimates for the three existing commercial manufacturers of gas fuelled heavy-duty vehicles vary between 1000 and 1600 km [22–24]. The total energy consumption of trucks in Finland (2017) was 14.1 TWh [60], which exceeds the biomethane potential available (10 TWh). In order to examine the most effective scenario for biomethane in heavy-duty transport, the heavy transport trucks were divided into three vehicle classes, namely:

Light duty (LD) including delivery vans, refuse collection vehicles and other single unit trucks <18 t
Medium duty (MD) including semi-trailer combination vehicles >18 t < 60 t
Heavy duty (HD) including all articulated vehicles >60 t

In 2017, the combined mileage of all the heavy-duty vehicles in Finland was 3,369,642,891 km [60] and was expected to increase 6% from the 2012 levels by 2030 [61]. The number of vehicles and the mileage of each vehicle class are presented in Table 2. [62]

Table 2. Number of vehicles and average mileage of the vehicle classes [62].

Truck Class	Number of Vehicles	Mileage per Vehicle (km/a)
LD	65,616	19,476
MD	5652	80,060
HD	18,123	73,358

The potential number of biomethane fuelled trucks was examined in three scenarios with different classes of target vehicles. The number of vehicles in each scenario was calculated on the basis of maximum quantities of biomethane theoretically available.

The target vehicle class in scenario I was LD trucks. First, the number of LD trucks that could be run with biomethane was calculated based on mileage (Table 2) and fuel consumption (Table 3). If the available volume of biomethane were to exceed the needs of the maximum number of LD trucks (Table 2), the next target class would be MD trucks. Were some biomethane potential still to remain, it would be used for as many HD trucks as possible.

Table 3. Average truck diesel consumption (kWh/100 km) [60,63].

	Highway		Freeway	
Truck Class	Empty Load	Full Load	Empty load	Full Load
LD	173	207	207	283
MD	246	374	306	498
HD	335	553	424	770

The target truck class in scenario II was HD, then MD and as many LD trucks as possible and in scenario III, the share of biomethane fuelled vehicles was divided equally between all classes (%).

The vehicle fuel consumption and theoretical amount of biomethane fuelled heavy transport vehicles was based on the relevant literature. Average fuel consumption (Table 3) of the chosen vehicle classes was based on diesel truck measurements by [63] and statistical data by [60].

The average energy (kWh/100 km) consumption per vehicle class was calculated as:

$$D_e * (b_f * c_{fr,e} + b_h * c_{h,e}) + D_f *(b_{fr} * c_{fr,f} + b_h * c_{h,f}) \quad (4)$$

where D is the mileage fraction (empty or full load), b is the road fraction (highway or freeway), and c is the fuel consumption [l/100 km]. The subscript e indicates empty load, f full load, fr the freeway, h highway, and d diesel. Empty running average 28% of total mileage was based on [64]. For the sake of simplicity, it was assumed that for the rest of the mileage the trucks run on full load.

The trucks were assumed to be driving 80% highway, 20% freeway [65]. The average consumption for biomethane trucks was assumed to be 18% higher than for diesel fuelled trucks [11]. However, gas truck manufacturers claim that the fuel economy of gas fuelled trucks equals that of diesel equivalents [23] or exceeds it [24]. However, preferring to err on the side of caution, we assumed a lower efficiency for biomethane trucks.

2.3. Assumptions Concerning Economic and Emission Saving Analysis

Our estimate for the overall costs of transforming the heavy transport fleet to biogas is tentative. A detailed calculation regarding the production and distribution costs as well as CO_2 savings of biomethane in the whole transport fleet in the Swedish context can be found in [11], while these results can be expected to be largely applicable to the Finnish case.

According to the International Renewable Energy Agency (IRENA) [12], the main constraint regarding biomethane as a transport fuel is currently the production cost, which mainly depends on the feedstock used. Here, this study proceeded from the expected biogas potential (10 TWh) of Finland

and for AD production facilities followed the IRENA estimate [66] of the investment costs to vary between 2640–5540 €/kW. For wood gasification plants, the chosen values refer to the experiences of the GoBiGas plant in Gothenburg, Sweden [47], with 8250 €/kW of gas production capacity. Since this is a pilot plant, the cost will most likely decrease once the technology matures. Yet again to err on the side of caution, this more conservative reference value was chosen. Plant investment costs refer to overnight building costs. Gas filling stations are assumed to be located by the plant site and are included in the overnight costs of the plants. For both types of biomethane plants (AD and gasification), the yearly operational hours were assumed to be 8000 h. The yearly share of investment costs was calculated based on the annuity method with the assumption of 4% investment interest and plant lifetime of 20 years. Based on [11], the assumed production costs for AD biomethane is approximately 57 €/MWh and for gasification biomethane 72–114 €/MWh, depending on the gasification technology chosen (direct or indirect gasification). The equivalent diesel fuel price was calculated from consumer diesel price (1.4 €/L) [67], energy content of diesel (11.5 MWh/t), and diesel density (0.08 kg/L). Since the calculations are based on assumptions in the literature, a sensitivity analysis for investment and production costs was performed by changing one parameter at a time by ±30% in order to calculate whether investment or operational and fuel costs affect the overall costs of biomethane more.

The amount of CO_2-equivalent and NO_x emissions for diesel trucks (Table 4) were based on emission calculations data by VTT, the Technical Research Centre of Finland Ltd. [60], using standard EN 16258. The amount of CO_2-equivalent emissions for each vehicle class was determined by substituting energy consumption in Equation (4) with emissions. As a rough estimate, the CO_2 emission of biomethane vehicles can be expected to be approximately 80% less than that of diesel trucks, depending on the calculation method used (ISO vs. RED) [11]. The NO_x emissions of biomethane fuelled vehicles are reported to be 86% lower [10] than those of diesel fuelled vehicles, while the fine dust emissions and noise levels are also lower for gas fuelled vehicles [12]. The total CO_2 and NO_x emissions for scenarios I-III were determined on the basis of the number of biomethane and diesel fuelled trucks in each scenario.

Table 4. Average NO_x and CO_2-equivalent emissions for the truck classes running with diesel [g/km] [60].

	NO_x [g/km]				CO_2-eqv. [g/km]			
	Highway		Freeway		Highway		Freeway	
Truck Class	Empty Load	Full Load	Empty Load	Full Load	Empty Load	Full Load	Empty Load	Full Load
LD	2.2	2.8	3.4	4.5	402	507	531	815
MD	4.3	5.3	6.9	9.7	630	962	965	1662
HD	4.7	6.5	8.3	14.0	834	1319	1298	2376

2.4. Limitations of the Methodology

Limitations of the methodology stem mainly from the vehicle class categorization. As each of the three vehicle classes examined includes a fairly wide range of vehicles, a more detailed analysis could be provided by sub-dividing the vehicle classes into more specific analytical units. Moreover, the assumptions regarding average mileages, loading levels (full/empty) and relative shares of highway and freeway do not fully reflect the differences in the use of different types of heavy vehicles. Light delivery trucks, for example, often operate within a certain area and could have more predictable routes in their operations than the other types of vehicles considered here. Therefore, it can be expected that the share of freeway use is higher in the case of such vehicles than the average value would suggest.

Another limitation is utilizing the average values for fuel consumption and emissions. These are heavily dependent on the driver's behavior, such as time of idling and might in reality differ greatly from the average value. However, as heavy-duty transportation systems consist of a diverse range of actors and vehicles with different operating logics, it is feasible to expect the chosen approach to

usefully indicate the benefits from transitioning the heavy-duty vehicle fleet into running on renewable resource based gaseous fuels such as biomethane. Finally, it should be kept in mind that the amounts of biomethane available through both AD and wood gasification are purely theoretical—the actual available amounts are dependent on many contingencies such as the interest of farmers in collecting agricultural side streams (for the related, possible policy incentives, see below).

3. Results and Discussion

In this section, the availability of biomethane and potential number of trucks in the three scenarios examined are discussed in relation to current biomethane policies. In addition, recommendations for policy measures to enhance biogas utilization in the heavy truck fleet are presented.

3.1. Amount of Biomethane Available

According to [37] the energy consumption of a biogas plant itself is 24% of the energy content. Consequently, the biomethane from AD available for use as transport fuel (10 MW minus the plant energy need) is 7.4 TWh. The amount of biomethane available from wood gasification was based on an estimate of 4 Mm^3 of wood [35] with a moisture content of 30%. The mass of 4 Mm^3 of wood was calculated to be 952,000 t, with a total LHV of 3509 GWh. The LHV of product gas from gasification was calculated Equation (1) to be 2456 GWh. The calculated amount of total biomethane available (CH_4 directly from gasification and from CO plus CO_2 methanation reaction Equations (2) and (3) resulted in 2147 GWh of energy. Therefore, the total amount of biomethane available for heavy duty transport would be 9.5 TWh.

3.2. Vehicle Class Scenarios

Calculations of the vehicle class scenarios were based on the current number of trucks and average mileages (Table 2) as well as the average energy consumption calculated for each vehicle class. The energy consumption of biomethane fuelled trucks per vehicle class Equation (4) with the assumed 18% lower efficiency [11] would result in 257 kWh/100 km (LD trucks), 454 kWh/100 km (MD trucks) and 675 kWh/100 km (HD trucks). The numbers of trucks in each class and the respective average energy consumption for the examined scenarios are presented in Figure 2 and compared to the current heavy-duty transport vehicle fleet.

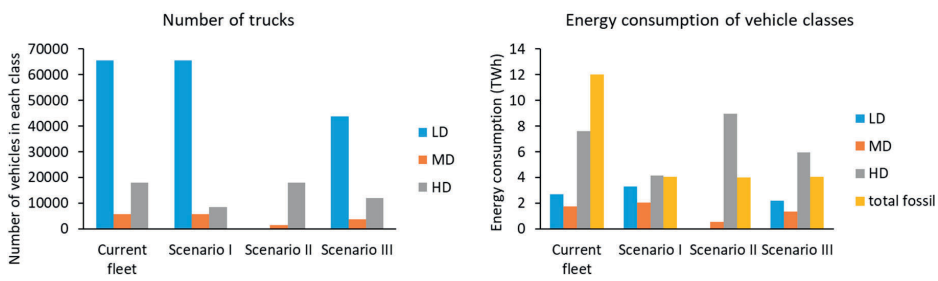

Figure 2. Number of trucks and energy consumption of vehicle classes for the scenarios. Note: for scenarios I-III the number of trucks and energy consumption in vehicle classes represent biomethane fuelled trucks with 18% higher energy consumption.

In scenario I, the available biomethane (9.5 TWh) would suffice for all the LD trucks (65,616) and MD trucks (5652) currently in traffic (Table 2), as well as 46% of HD trucks (8400).

In scenario II, the available biomethane (9.5 TWh) would suffice for all the HD trucks currently in traffic (18,123; Table 2) and for 26% of the MD trucks (1450). With HD trucks preferred in this scenario, no biomethane would be available for LD trucks.

In scenario III, the biomethane would suffice for a 66% share of trucks currently in traffic (Table 2) divided between the three classes (LD 43,744, MD 3768, and HD 12,082). Assuming that up to 35% of heavy transport in Finland could be electrified [7], in principle the entire volume of the country's heavy traffic could either run on biomethane or be electrified.

3.3. Economic and CO_2 Savings Analysis

The overall costs of transforming the heavy-duty transport fleet to run on biomethane are difficult to estimate since, for example, the price of gas fuelled trucks depends on the accessories. The lack of gas fuelled vehicles and fuelling infrastructure also hampers cost estimation. Gas fuelled trucks may be up to 30%–40% more expensive than diesel fuelled trucks [10]. The availability of used gas trucks is currently limited, while renewing the whole truck fleet in Finland within a short timeframe is unrealistic. However, by investing in the fuelling station network and promoting investments in gas fuelled vehicles, a large share of the fleet could be gas fuelled in 10 to 20 years. Börjesson et al. [11] and Angelbratt [10] estimate slightly lower operating costs for liquefied gas fuelled vehicles than for diesel fuelled vehicles, but 15%–20% higher costs for compressed NG (or BG) fuelled vehicles, however, this depends heavily on the production costs of biomethane [11]—for AD biomethane, these are case and feedstock specific, while plants can charge gate fees [37]. With these limitations, we propose a rough estimate of the plant capacities, production costs needed, and the investments required.

Traffic fuel biomethane use in Finland was 30 GWh [53] in 2017. Total biogas production (including collection from landfill sites) was approximately 700 GWh, and the number of production sites 71 [53]. This means that only approximately 8% of the techno-economic potential (10 TWh) of biogas was utilized. There are currently no wood gasification plants in Finland. To produce the 9.5 TWh of biomethane for transport fuel with the assumed 8000 h yearly operational hours (see Section 2) would require investing in 1250 MW capacity for AD plants and 265.5 MW for wood gasification plants. The overall investment would amount to 5.5–9.1 billion €. This amount can be compared to the overall import of oil products, which in 2017 which was worth 8.4 billion € [68]. The share of the investment annuity for AD biogas would be 24.3–50.9 €/MWh, and for gasification biomethane 75.9 €/MWh. Together with the assumed production costs [11], the total production cost for AD biomethane would be 81–108 €/MWh, and for gasification biomethane 148–190 €/MWh. The consumer price for diesel in 2018 was 152 €/MWh, which makes biomethane a competitive product given the assumptions. Since the gasification plants investment costs are based on a pilot plant [47], it is likely that the cost of gasification for biomethane will decrease as the technology matures.

The sensitivity analysis showed (Figure 3) the costs of biomethane to be more sensitive to the investment costs than the production costs. In addition, the investment costs will likely decrease rather than increase with more frequent installations. However, one must bear in mind the dependence of production costs on feedstock costs [37]. Finally, the examination of the slope of sensitivities indicates how changes, for example in the chemical engineering index, or interest costs may also affect costs, yet these effects cannot be estimated in detail within the scope of this study.

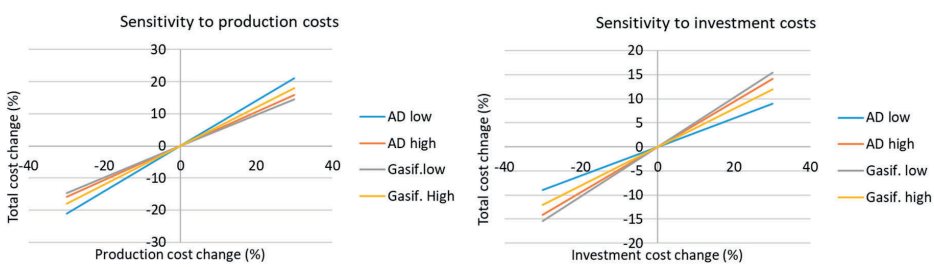

Figure 3. Biomethane overall cost sensitivity to production and investment cost.

The total CO_2-equivalent emissions and NO_x emissions for the scenarios examined (Figure 4) were calculated on the basis of average emissions for each vehicle class (Table 4), with the limitations discussed in Section 2.3. For scaling purposes, the CO_2 emissions (Figure 4 are presented as 100 t/a.

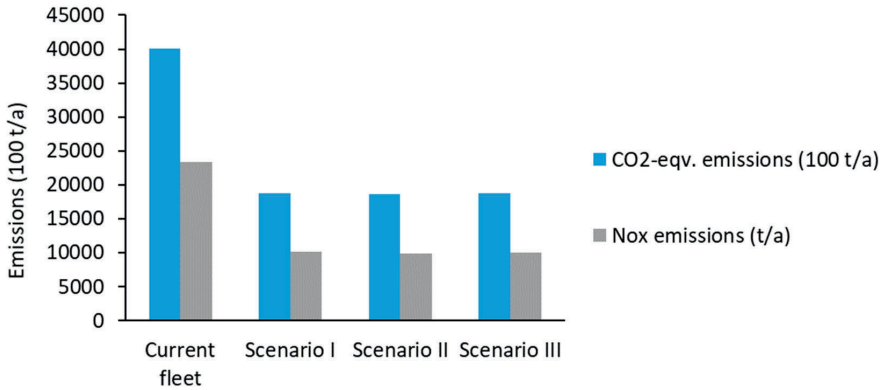

Figure 4. CO_2-equivalent and NOx emissions for the scenarios examined and current truck fleet. Note: the CO_2-equivalent emissions are presented on a scale of 100 t/a for scaling purposes.

Running as many trucks as possible with the 9.5 TWh of biomethane reduces CO_2 emissions by more than 50% (Figure 4) from 400,000 tons/a to 190,000 tons/a. The preferred vehicle class does not significantly affect emission reduction. Considering only the investment costs (5.5–9.1 billion €) of plants with the assumed 4% interest with a 20-year plant lifetime (annuity 0.0736), the cost of CO_2-emission reduction would be 190–315 €/ton of CO_2. While this may seem to be a high cost compared to the current prices of emission allowances, it is balanced by savings in the avoided importation of fossil fuels. A detailed analysis of the economic effects should be a subject of future research.

Similar results are observed in relation to NO_x emissions (Figure 4). This means that the amount of emissions per vehicle class is compensated by the number of vehicles in the different scenarios. In other words, emission reduction benefits are greater in areas with many frequently driven vehicles. Given that HD vehicles are mainly used for long distance haulage between cities, utilizing biomethane in intra-city delivery traffic is preferable due to improvements in local air quality through diminished NO_x emissions.

3.4. Policy Instruments

Despite recognition in the national energy strategy (see Section 1), the high technical potential and tangible emission savings enabled by biogas solutions (see Sections 2 and 3), no substantial progress in the transport use of gas has been made in recent decades in Finland [53]. The trends in the production of biogas, vehicle gas and the size of the gas operated vehicle fleet are relatively modest [36,53]. The sector faces a deadlock, as present and potential producers lack confidence in the market. Potential consumers in the transport sector for their part remain unsure of the availability of biogas. Resolution of the deadlock requires taking into account the whole production chain including both the supply and demand ends and the deployment of suitable policy instruments.

Biogas as a policy sector is difficult to organize effectively. The biogas production chain includes multiple use cases competing with each other (see Section 1). The established principles of technology neutrality and preference for market-based solutions make Finnish policy planning tricky in the biogas sector, as all use cases should be treated equally [35]. This is evident in the recent policy documents which, while recognizing the possibilities of domestic biogas production, remain very generic in terms of objectives and measures proposed [40]. Moreover, biogas faces a range of competitors and regulations in the transport use case in particular. Overall, the transport sector is difficult to govern [39],

while in the passenger vehicle segment, biogas faces fierce competition from the growing number of electric vehicles (often supported by incentives directed at electricity production), and from drop-in biofuels compatible with contemporary petrol and diesel engines.

3.4.1. Feasibility of Biogas Production

Subsidies are crucial for the development of the biogas sector [69]. Biogas typically features an immature solution when compared with existing solutions with their own incumbent actors, established infrastructures and dominant rules [9]. In general, the competition from the fossil fuel sector faced by emerging renewable solutions is not fair [5], with numerous effects of historically accumulated direct and indirect subsidies.

The current policy instruments supporting the biogas sector in Finland focus heavily on the production end. The main instrument is investment grants for production facilities [70]. A separate scheme subsidizes biogas plants located on farms with a requirement to utilize the energy produced on agricultural activities on site [71]. Should the farm prioritize selling biogas to the transport sector, a separate company has to be formed in order to be eligible for an investment grant [40]. This, in turn, leads to some limitations in terms of investments covered and a lower level of financial support. Additionally, biogas and biomethane are currently supported through tax exemptions. Whereas investment grants are crucial for laying a solid economic foundation for the production of biogas, the growth of the whole biogas ecosystem can be greatly accelerated by subsidizing biomethane directly, or by adjusting taxation costs for competing fossil fuels in the transport sector [43]. However, taxation policies should avoid generating long-term unpredictability for the biogas sector [27]. In Finland, where investment grants and tax exemption for biogas currently exist, this would suggest focusing upon stabilizing biogas related policies and goals as producers and consumers alike value long-term predictability more than short-term subsidies [69]. As long as a comprehensive strategic niche management approach linking the energy, transport, agricultural, forestry, industrial and other sectors is largely lacking [72]—something that biomethane solutions usually require in the transport sector [9]—many potential producers deem this market too uncertain.

To meet the biomethane potential identified in this study, currently unused feedstock potential needs to be enabled for biogas production. The bulk of the resource potential is located near farms, which often lack sufficient funding, the required know-how, and bargaining power to engage in economically feasible biogas production [73]. According to Lyng et al. [74], sizeable incentives are usually needed to make agricultural biomasses available for biogas production. Equally important would be consolidating the role of digestate as a byproduct to create strong value chains and maximize GHG emission reductions [74]. This integration option could be highly beneficial, especially for farms, but is simultaneously the most unlikely because of the increased costs [74]. To enable large-scale biogas production, feeding resources such as manure and other agricultural residues could also be supported [38]. Moreover, as farms are not linked to traditional chains of energy production, agricultural policies need coupling with energy policies. On regional and local levels, new business models are needed between energy producers and farms enabling better utilization of both biogas and digestate [75,76]. Careful planning of the whole supply chain has proven to be a key aspect for successful biogas systems in Danish conditions [73] but lags behind in Finland due to poor cross-sectoral co-operation between relevant actors [39]. However, encouraging examples such as that of the Biohauki company [77], suggest that local biomethane production from waste materials can indeed be feasible in Finland with proper planning and willing actors. Ultimately, the production scales needed for heavy-duty transport would most likely favour production in larger centralized co-digestion units. At the same time, gaining acceptance is easier for small plants as seen in some cases in Denmark, Italy and Germany [9].

3.4.2. Fuelling Infrastructure and Vehicles

The delivery system is the most vital part of the biogas chain by virtue of linking production with end use. Of the 41 gas filling stations in Finland, only four provide liquefied gas for heavy-duty vehicles [78]. This infrastructural limitation hampers most seriously the market entry of biogas fuelled vehicles [38]. This is particularly evident in the concentration of the heaviest part of the truck fleet using LNG-infrastructure on the coastal regions of Western and southern Finland, where both fuelling stations and LNG terminals are located [38]. The Eastern and Northern parts of Finland lack similar infrastructure. These limitations stem, at least partially, from the geography of the main commercial ports and the location of the natural gas grid in southern Finland. Uusitalo et al. [38] deem the limited natural gas grid a major hindrance to vehicle gas development. Meanwhile in Sweden, biogas ecosystems have evolved especially in the Mälardalen area, located outside of the gas grid [43]. While access to the natural gas grid could decrease the costs of compression and help in overcoming transport distances, alternative infrastructural solutions exist. Gasum, the state-controlled gas company operating the natural gas grid plans to significantly expand the LNG-fuelling infrastructure suitable for heavy-duty vehicles [79].

To expand the market, or the gas operated truck fleet, additional subsidies for heavy-duty vehicles running on biomethane should be considered. While biomethane is currently exempt from fuel tax, the vehicle tax for trucks does not differentiate between fuels [80]. Differentiating between fuels, followed by a lowering of the vehicle tax for gas-operated trucks in contrast to diesel fuelled trucks, could greatly improve the feasibility of vehicles and create demand for vehicle gas. The size of the vehicle fleet could also be expanded by offering grants for gas operated vehicles or low-emission vehicles in general [81]. Public authorities can help to create stable demand for vehicle gas and demonstrate the potential of gas-fuelled vehicles, for example by deploying them in public sector tasks such as waste collection. In fact, public authorities can support the overall development of local biogas systems as they have leverage over both the supply and demand sides [28].

Here, the importance of strategic niche management [9] is again evident, since merely offering investment grants for the production of biogas may channel that production towards the non-transport uses of biogas (heat and power production; see Section 1 above) in the absence of public policies generating sufficient initial demand for vehicle gas [69]. From this perspective, subsidizing energy carriers, delivery systems and/or the acquisition of vehicles would seem to be an obvious choice. However, subsidizing end-use only can have the unintended consequence of promoting the usage of natural gas in place of biogas owing to the current price advantage of the former. The question regarding natural gas in relation to biomethane is decidedly ambiguous. As noted above, biomethane and natural gas can be transported and fuelled using the same infrastructure and are mutually substitutable fuels.

Increased use of natural gas in heavy-duty vehicles could actually serve the needs of the biomethane sector as it could accelerate the development of gas infrastructure [82], strengthen the availability of vehicle gas in general and decrease the fuelling costs of gas-fuelled vehicles. A higher number of gas-operated vehicles would in turn provide stable demand for vehicle gas, thereby incentivizing biogas producers to upgrade their product into vehicle gas. However, it is uncertain if consumers would eventually switch to biomethane even with higher production volumes. In heavy-duty transportation, the fuel volumes are significantly larger than in passenger transportation; hence the price at the fuel pump is significant. This means that biomethane needs to become competitive with natural gas. Subsidies granted to encourage the usage of renewable and domestic energy resources may otherwise end up promoting imported fossil fuels instead.

3.4.3. Policy Cohesion—Towards the National Biogas Plan

An incoherent and unstable policy framework is a frequently overlooked constraint on the development of biogas systems [27]. That know-how, institutional capacity, and supply-side coordination have recently been identified as the main constraints for bioenergy in general on the European level [9] speaks for the need for policy cohesion. Although biogas amply supports the

contemporary Finnish strategies for bio-economy and circular economy and the national targets for a higher share of renewable energy and energy independence, these targets and the respective policy instruments are neither well defined nor aligned [39,40]. Uncertainty as to how political institutions treat biogas and gas operated vehicles hampers the development of forest-based biogas, in particular due to the high capital costs and intensive energy consumption inherent in the gasification process [83]. Such uncertainty quite possibly deters potential investors and negates innovations in the sector [39].

Finland has yet to introduce a systematic national plan for biogas utilization, in contrast to the situation in neighbouring Sweden [84] and Norway [85]. While the Norwegian plan may not be as detailed as its Swedish counterpart, the mere existence of a formal plan encourages actors in the biogas sector. At best, the preparation process of such a plan enables systematic account to be taken of the various actors' concerns about the biogas value chain. This is what Finland is currently lacking—actors from different sectors hold highly diverse views on the subject and their roles, and biogas related issues remain to be addressed from multiple narrow perspectives [39]. A report by a think tank close to the government identifies four different paths for the use of biogas, one of them transport-centred [75]. However, this report so far lacks political recognition and follow-up. A process leading to the adoption of a national biogas strategy could kick start a much needed robust, comprehensive and cross-sectoral policy framework for the Finnish biogas sector.

It is suggested here that such a process could proceed from an effort to improve the profitability of agricultural production in Finland, taken that currently 36% of the turnover is subsidized [86]. First, national regulation should better consolidate the use of digestate, a byproduct from AD biogas production, as a fertilizer to enhance the portfolio of business models of farms. The exploitation of digestate requires careful control of the whole process from production to use in the field, and the drafting of respective national standards on the basis of existing international guidelines [87]. Biogas producers frequently struggle to find commercial uses for digestate, and farmers instead rely on mineral fertilizers. This in turn leaves biogas producers with an excess resource, which has negative implications for the sector's emissions and the national security of supplies. Second, supporting consolidation in the agricultural sector by means of incentivizing co-operatives between farms and energy producers would additionally improve the business model of biogas production and digestate exploitation as a fertilizer. The average Finnish livestock farm so far produces too little manure to make the initial investment cost-effective [88]. In short, at the production end, a national plan should propose biogas-specific investment support schemes directed at farms and co-operatives of farms to create economies of scale. Third, attaining the goal of improved policy cohesion would require simultaneous and coordinated measures regarding the feeding of biogas into the distribution network, for example direct subsidies, while at the consumption end vehicle acquisition could also be directly subsidized (see Sections 3.4.1 and 3.4.2 above).

Overall, proceeding from the views of different actors along the production chain of biogas and bringing them under the same framework would highlight cross-sectoral problems and render them more easily solvable. Simultaneously the formulation of a biogas strategy should be based on an analysis of the current system structure on local and regional levels [27]. A biogas strategy must be ambitious to attract the actors of the value chain, but realistic in terms of its analysis of the structures of the society in question. In Finland, where regional differences in available feedstock, transport distances, existing infrastructure and vehicle fuel demand can be deemed substantial, understanding the local level realities will be a crucial starting point in building the national biogas strategy.

4. Conclusions

This paper examined the potential of transforming the heavy-duty transport sector in Finland into a biomethane fuelled fleet. Biomethane can help to reduce GHG emissions in the transport sector since it can be produced from waste materials such as sludge, agricultural waste or forest industry wastes without significant effects on the carbon sink. Moreover, it is compatible with natural gas

fuelled infrastructures and technologies, which enables direct substitution of a large share of fossil fuels in transport.

The results suggest a great technical potential in this respect; in the second scenario, where the target truck class was HD, then MD and as many LD trucks as possible, the whole heavy-duty truck fleet and 26% of the medium duty fleet could run on biomethane. Alternatively, in the third scenario, where the share of biomethane fuelled vehicles was divided equally between all classes (%), 66% of all truck classes could use biomethane. Combined with the potential of electrification within the heavy-duty sector [7], the use of biomethane would make it possible to run the entire truck traffic without the use of fossil fuels. By maximizing the biomethane fuelled heavy transport fleet, the CO_2 emissions could be reduced 50% compared with the current diesel fuelled fleet. A rough estimation including only the investment costs of biomethane production suggested that the respective reduction of CO_2 emissions in the Finnish case would cost 190–315 €/ton of CO_2 saved.

The constraints for the transition concentrate on policy cohesion. This includes insufficient financial incentives and uncertain business models for investors in AD biogas production, which currently hinder the economic feasibility of biogas production. Further interlinked problems include limited fuelling infrastructure and a lack of demand in the transport sector. In the absence of a stable and coherent policy framework accounting for the entire production chain, distribution and use of biogas as a transport fuel, the biomethane sector struggles to meet its potential.

The transition to biomethane in heavy-duty transport requires substantial investments, political leadership, and the respective deployment of coherent, strategic niche management policies. Regional realities and local actors should also be taken better into account as part of a national biogas strategy, which should carefully align direct and indirect policy instruments into a coherent framework.

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