Environmental, Economic and Policy Analysis of Energy Production from Biomass Residues in British Columbia

by

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Abstract

In this study, the availability of various biomass resources in British Columbia (BC) is estimated, including forestry resources, agricultural waste and municipal solid waste. Since the enormous potential for bioenergy production identified is insufficient to replace the entirety of fossil fuel consumption in BC, the exploitation of limited biomass resources must be optimized based on Greenhouse Gas (GHG) reduction and costs. Life Cycle Assessment is conducted to analyze the GHG reduction potential and other environmental impacts of various bioenergy options. Minimum selling prices and GHG reduction costs are calculated to indicate economic viability.

For lignocellulosic feedstocks, the biomass-fired heat-only boiler (HB) has the highest GHG savings; however, it may impose health risks in densely populated urban areas due to flue gas emissions and should be limited to large-scale implementations with effective emission control. HB is also the most cost-effective in GHG mitigation. In comparison, liquid biofuels and renewable natural gas slightly less effective in GHG mitigation and substantially more costly.

For animal manure, food waste, and crop residues, anaerobic digestion can be used to convert these biomass residues into biogas. The results show that the biogas-fired HB has higher GHG savings and lower GHG reduction costs than cogeneration or upgrading to RNG. Biogas-fired HB systems can be further integrated with other common agricultural practices in BC to generate additional environmental and economic benefits.

At present, full-scale implementation of refined biofuel technologies will lead to prohibitive extra costs; hence, HB systems should be prioritized in the short-term due to the inherent advantage in conversion efficiencies. In the long term, technological breakthroughs in improving efficiency and extracting high-value byproducts will be the key to the prospect of refined biofuels.

Lay Summary

British Columbia (BC), the western-most province of Canada, relies heavily on fossil fuel consumptions. The province also has vast forestry and agricultural sectors, generating a massive amount of biomass resources every year and showing great potential for the production and use of bioenergy. However, while the BC government has set up ambitious GHG reduction targets, the biomass resources in the province are still underutilized.

In a carbon-constrained world where GHG mitigation is an imperative task, it is crucial to maximize the GHG savings from the limited biomass resources. Economically, the cost-effectiveness of GHG mitigation must also be taken into account. Therefore, this thesis investigates the environmental and economic performances of various combinations of biomass feedstocks and conversion technologies. The results are critical to optimizing the exploitation of BC's biomass to contribute to mitigating GHG emissions and the development of policies in BC.

Preface

This dissertation is an original work completed by the author, H. Wang, under the supervision of Prof. X. Bi and Prof. R. Clift. Research proposal, data collection, model construction, analyses, and interpretation of the results were conducted by H. Wang independently, with suggestions from the two co-supervisors.

Estimates for biomass resources in Chapter 2, the results for a simplified version of the LCA and economic assessment in Chapter 3 and Chapter 4, and part of the policy implications in Chapter 6 have been submitted: (H. Wang, S. Zhang, X. Bi, and R. Clift, "Greenhouse gas emission reduction potential and cost of bioenergy in British Columbia, Canada," Manuscript under minor revision).

A version of Chapter 3 and part of the policy implications in Chapter 6 have been prepared for submission. (H. Wang, X. Bi, and R. Clift, "Utilization of forestry waste materials in BC: comparison of different options and recommendation on deployment strategies," Manuscript in Preparation).

Part of the results in Chapter 3 has also been presented. (H. Wang, X. Bi, and R. Clift, "How can forestry waste materials help British Columbia to meet its greenhouse gas emission target?" *Oral Presentation at 10th International Conference on Industrial Ecology*, Beijing, China, July 2019).

Parts of the work in this dissertation have been included in a chapter (R. Clift, X. Bi, H. Wang, and H. Yun, "Prioritising uses for waste biomass: A case study from British Columbia") accepted for publication in "Advances in Carbon Management Technologies", edited by Subhas Sikdar and Frank Princiotta, to be published by CRC Press in late 2019.

Table of Contents

List of Tables

List of Figures

List of Acronyms

Biomass

AAC = (Standing timbers within) Annual Allowable Cut

CM = Cattle Manure

CR = Crop Residues

FW = Food Waste (within municipal solid waste)

FWM = Forestry Waste Materials

LD = Liquid Digestate

MPB = Mountain Pine Beetle

PM = Poultry Manure

SD = Solid Digestate

WW = Wood Waste (within municipal solid waste)

Bioenergy technologies

AD = Anaerobic Digestion

DH = District Heating

EtOH = (Bio)Ethanol

CHP = Biomass-fired Cogeneration of Heat and Power

HB = Biomass-fired Heat-only Boiler

HTL = Hydrothermal Liquefaction

MeOH = (Bio)Methanol

PG = Biomass-fired Power Generation

RNG = Renewable Natural gas

Environmental and economic assessment

AP = Acidification Potential

EP = Eutrophication Potential

GHG = Greenhouse Gas

GWP = Global Warming Potential

HT = Human Toxicity

IRR = Internal Rate of Return

LCA = Life Cycle Assessment

LUC = Land-use Change

MSP = Minimum Selling Price

NPV = Net Present Value

RI = Respiratory Inorganics

Miscellaneous

BC = British Columbia

CAD = Canadian Dollar

DM = Dry Matter

FiT = Feed-in Tariff

FM = Fresh Matter

K = Potassium

Mt = Million tonne

MtDM = Million Tonne dry Matter

Mm^3 = Million cubic meter

N = Nitrogen

NG = Natural gas

P = Phosphorus

RLCF = Renewable and Low Carbon Fuel Requirements

RPP = Refined Petroleum Product

tDM = tonne Dry Matter

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To my beloved mother

Chapter 1 Introduction

1.1 BC's GHG mitigation target and opportunities for bioenergy

Canada is the second most carbon-intensive country among developed economies in the world [1]. British Columbia (BC), one of the most populated and developed Canadian provinces, relies heavily on the consumption of fossil fuels but also has abundant biomass resources. In 2016, BC consumed 1165 PJ of energy, 38% from refined petroleum products (RPPs) and 30% from natural gas [2]. Even though BC's electricity comes primarily from hydropower, fossil fuels, including natural gas and refined petroleum products (RPPs), still consist of 2/3 of BC's energy profile. 46% of natural gas is used in the residential and commercial sectors [3], primarily for heating [4]. 94% of RPPs is used in the transportation sector. Direct combustion of fossil fuels in BC generates 47.7 million tonnes (Mt) of GHG emissions, accounting for almost 80% of total provincial emissions [5]. Upstream processing of fossil fuels contributes a further 13.6 Mt of GHG emissions [6].

In efforts to combat climate change, both Canada and BC have declared ambitious GHG mitigation targets. In 2016, Canada ratified the Paris Agreement and committed to reducing GHG emissions by 30% below its 2005 level by 2030, from 738 million tonnes (Mt) CO_2-eq per year in 2005 to 516 Mt in 2030 [7]. In the same year, BC updated its Climate Leadership Plan, promising ambitiously to reduce its GHG emissions by 80% below the 2007 level by 2050 [8]. On the municipality level, Vancouver, BC's largest city, announced a long-term target of completely replacing fossil fuels with renewable energy by 2050 [9], including 60% from renewable electricity (mainly hydro), 15% from district heating and cooling fueled by renewable energy, 14% from biofuels for mobility, 10% from renewable natural gas (biomethane), and 1% from hydrogen.

These policy frameworks set out long-term action plans to reduce energy demand and build a low-carbon economy in BC. Having already secured more than 90% renewable power supply, BC still needs to develop other measures to displace its fossil fuel consumption, mainly for heating and mobility. Meanwhile, as BC stated in its Climate Leadership Plan to promote electric vehicles, its future electricity demand could substantially increase [8]. These give rise to opportunities for the production and use of various forms of bioenergy in BC. This dissertation explores the possible uses of biomass resources as part of the intended decarbonization of BC's energy system.

1.2 Opportunities for bioenergy production in BC

With abundant forestry resources, BC has enormous potential for a sustainable bioenergy industry (Figure 1.1). Over the past decade, about 60 million m^3 of timbers have been harvested annually under "sustainable harvesting" permits, from less than 1% of the total forest area suitable for harvesting [10], [11]. However, there is still a small fraction of timbers granted sustainable harvest permit but left unharvested due to many reasons. In addition, forestry waste materials are available, consisting mainly of trees killed by mountain pine beetles (MPB) and wood residues from logging and processing of timbers. These forestry waste materials are currently of little merchantable value and could be used to produce energy. In 2016, 140 PJ of forestry waste materials was used in BC, mainly by the pulp and paper industry for CHP [12], [13]. Surplus electricity is injected to the grid, accounting for 5% of BC's electricity supply. Meanwhile, about 40 PJ of wood fuel was exported [14], [15]. However, a significant fraction of forestry waste materials is still left unused and eventually destroyed by slash burning or forest fire, resulting in not only a waste of energy potential but also air emission problems.

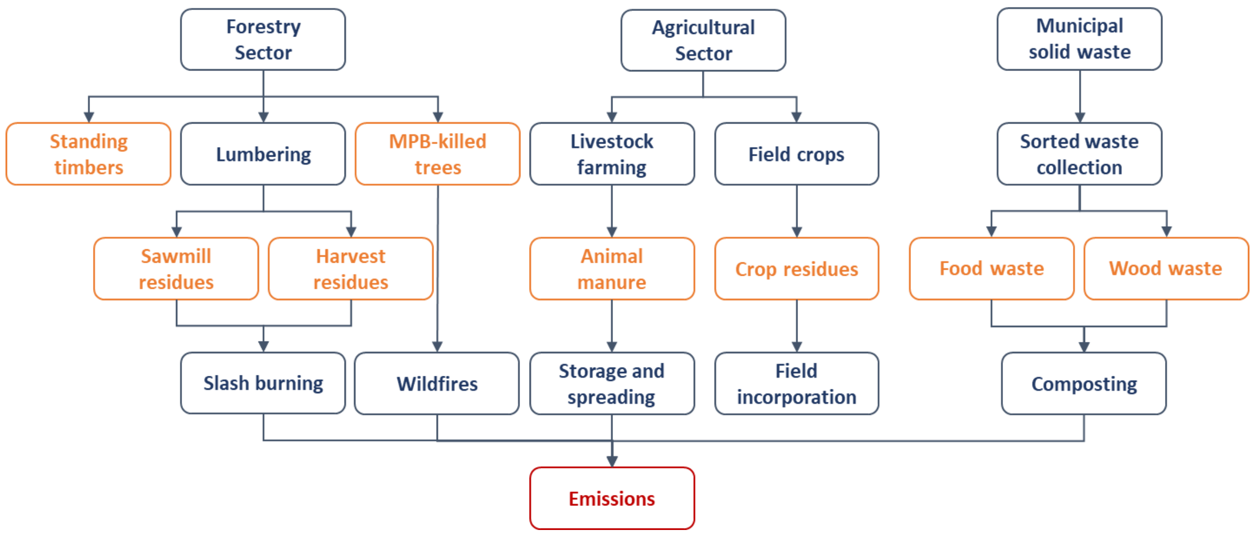


Figure 1.1 Available biomass resources and their current fate in BC

Additionally, waste streams generated in BC's other sectors, including animal manure, crop residues, and the organic fraction of municipal solid waste (OFMSW), are also potential bioenergy feedstocks. So far, the conventional waste management practices, including composting and land application, fail to harness the energy potential in these waste streams, calling for alternative utilization strategies.

Process waste streams, such as black liquor from the pulp and paper industry and sewage sludge from wastewater treatment, also possess significant heating values and thus should be utilized to recover energy. However, they contain toxins and other chemicals so that they require treatment before being used or disposed of. Therefore, these process waste streams should not be considered as general bioenergy feedstocks, and their management strategies are not considered in this study.

1.2.1 Bioenergy options for lignocellulosic feedstocks

Both woody and herbaceous biomass materials are characterized as lignocellulosic feedstocks. In BC, available lignocellulosic biomass feedstocks include forestry materials, wood waste in municipal solid waste, and crop residues generated by the agricultural sector. Lignocellulosic feedstocks can be thermally converted to liquid and gaseous biofuels by many technologies. Alternatively, biomass can be burned to produce heat, power, or both.

Hydrothermal liquefaction

Hydrothermal liquefaction (HTL) is an emerging bioenergy technology that can convert biomass to bio-oil, which can then be further upgraded to liquid biofuels for land, marine and aviation transportation. HTL uses wet feedstock and therefore avoids the energy consumption for drying [16]. As Pan-Canada action plans are being carried out to reduce aviation GHG emissions [17], HTL can potentially play a critical role in decarbonizing the aviation industry.

In the HTL process, biomass feedstocks are ground into fine particles and then mixed with water and buffer agent (Na_2CO_3) to form a slurry with 8-10 wt% dry mass contents [16]. The feed slurry is then fed into the HTL reactor and converted to bio-oil, typically at the temperature of 355℃ and pressure of 20.3 MPa [18]. After that, bio-oil is catalytically hydrogenated into a mixture of hydrocarbons with the addition of hydrogen usually generated from natural gas. In the last step, the hydrocarbon mixture is distilled to different biofuel fractions [19].

In addition to bio-oil, HTL also generates an aqueous phase, off-gases, and solids as by-products. The aqueous phase contains 30-40% of total the feedstock carbon and is therefore anaerobically digested to recover biogas. The off-gases include ~10% gaseous hydrocarbons [16], [18]. Recovery of biogas produced from the wastewater and hydrocarbons in the off-gases can fully meet the process demand for hydrogen and heat [18], [19]. As a result, the thermal energy required for the HTL process comes mostly from the feedstock. The solids mainly consist of wood ashes, biochar, and unreacted biomass. Since biochar contains carbon and nitrogen, it can be applied to the field as a soil improver, creating additional environmental benefits [19].

Ethanol, methanol, and renewable natural gas via gasification

Ethanol (EtOH) converted from lignocellulosic biomass is considered a 'second-generation' biofuel, which is commonly used as a gasoline substitute. Compared to gasoline and 'first-generation' ethanol produced from corn and sugarcane, ethanol produced from lignocellulosic biomass can have significantly lower life cycle GHG emissions [20]. For ethanol production from lignocellulosic biomass, there are two conversion pathways: thermochemical (gasification) and biochemical (fermentation). In comparison, the thermochemical pathway can process a broader range of feedstocks than the biochemical one [21]–[23] and is therefore considered in this study.

Gasification is a thermal process that partially oxidizes carbon-based materials, by reacting at high temperature (600-1000°C) and controlling the amount of oxidants such as air and steam [24]. In the thermochemical ethanol conversion process, biomass is gasified into syngas, a mixture of CO, H_2, CH_4, and CO_2. The syngas also contains tar among other impurities, which can condense on process equipment and cause blockages. Therefore, syngas must be cleaned up before it is synthesized into ethanol and higher alcohols, using cobalt molybdenum sulphide catalyst, for example [25]. The gasification process also generates biochar as a by-product, which is burnt in the combustor to recover energy. The entire conversion process can achieve autothermal operation, with heat and electricity provided within the process from the combustion of char and a slip-stream of syngas [25].

Syngas produced from gasification of biomass can also be synthesized to other biofuels, including methanol (MeOH) and methane (RNG), using different catalysts. Methanol is produced by hydrogenation of carbon oxides over catalysts such as copper oxide and aluminum oxide, whereas RNG is produced by the methanation reaction of hydrogen and carbon oxides over nickel-based catalysts [26]. Literature values for conversion efficiency, defined as the ratio between HHV of biofuel output and feedstock input, vary widely. Conversion efficiency of EtOH ranges from 40% to 49% [21], [25], [27]. For MeOH, the conversion efficiency ranges from 49% to 58% [26], [28], [29]. The efficiency of conversion for RNG ranges from 46% to 69% [26], [30]–[33].

Heat and Power

Instead of conversion to refined biofuels, lignocellulosic feedstocks can be combusted to provide district heating (DH) services and displace natural gas consumption, via the biomass-fired heat-only boiler (HB) and cogeneration of heat and power (CHP). In HB, thermal energy harnessed from biomass is dedicated to heating service, which is delivered to users for space and water heating. In CHP, thermal energy is partly converted to electricity through turbines or gas engines, and waste heat is recovered to provide low-grade heating. Alternatively, biomass can also be dedicated to power generation (PG) or co-fired in coal power plants [34]. For the CHP option, the total energy conversion efficiency, defined as the ratio between the overall heat and power output and HHV of biomass input, ranges from 81% to 90%, while the electricity efficiency ranges from 25% to 39% [30], [32], [34]–[36]. The wide range is caused by differences in system configuration, production capacity, and feedstock characteristics. In power-only mode, energy efficiency can reach 40% [34]. For the HB option, the energy efficiency ranges from 62-85% [36]–[39].

Conventionally, biomass feedstocks are directly combusted. In order to achieve cleaner combustion, gasification technology can be employed to turn biomass into syngas before the syngas is combusted [24]. Gasification can further be integrated with power generation; this is called biomass integrated gasification/combined cycle (BIG/CC) technology [40]. Many district heating and large-scale power generation projects employing gasification technology are now in operation globally [24], [30], [31], [37], [38], demonstrating reliable technological feasibility.

1.2.2 Anaerobic digestion of food waste and agricultural waste

Compared to lignocellulosic feedstocks, food and agricultural wastes typically have higher moisture contents yet lower energy densities. As a result, these waste streams are not suitable for thermal conversion technologies described in Section 1.2.1. Instead, anaerobic digestion (AD) technology can be used to convert these waste streams into biogas, a gaseous mixture typically consisting of 60% CH_4 and 40% CO_2 [41], [42]. Biogas can be then combusted to produce heat, power, or both, or upgraded to renewable natural gas.

AD employs microorganisms to decompose organic matter in the absence of oxygen. It includes four stages: hydrolysis, acidogenesis, acetogenesis, and methanogenesis. The use of AD allegedly dates back thousands of years [43]. Commercial and industrial use of biogas has been well documented since the late 19th and early 20th centuries [44]. Nowadays, as a promising technology that can simultaneously reduce waste volume and produce renewable energy, AD has received growing interest from government, academia, and industry. Conventionally, AD processes feedstocks with a solid content lower than 15% and is thus classified as liquid-AD (L-AD). This characteristic makes AD an ideal technology to process wet feedstocks. Alternatively, solid-state AD (SS-AD) as an emerging technology operates at a solid content of more than 15% [45]. SS-AD has received growing attention in recent years, as it has lower water and energy requirement and is thus suitable to handle dry feedstocks such as crop residues [46]. However, SS-AD systems still have many problems that can potentially reduce biogas yield, and are much less common than conventional L-AD systems[45], [46].

The nutrient elements in the feedstock, including nitrogen (N), phosphorus (P) and potassium (K), are retained in the organic residue of AD, which is called digestate [47], [48]. During AD, organic N is partly transformed into ammonium, which is more readily available to plants [49]. Meanwhile, P released from nucleic acids and phospholipids precipitates with Ca^{2+}, Mg^{2+}, and NH_4^+ ions [50]. Digestate is rich in nutrients and can be used as organic fertilizer and soil improver [50]. A common practice is to separate digestate into a liquid and a solid phase to facilitate the digestate application. Liquid digestate (LD) mainly consists of soluble nutrients such as inorganic N and K, whereas solid digestate (SD) contains insoluble matters including organic N, phosphate (PO_4^{3-}) precipitate and indigestible carbon residues [50]. LD can be used as irrigation water and fertilizer, and SD can be used as growing media and soil improver.

Table 1.1 Co-digestion of animal manure and other feedstocks

Study	Co-digestion	Mixing ratio	CH_4 yield Improvement
Zhang et al. [51]	CM+FW	33.3% CM	41.10%
Li et al. [52]	CM+FW	14.3% CM	80%
Callaghan et al.[53]	CM+ FVW	50.0% CM	95.60%
Cavinato et al.[54]	CM+FVW+EC	27.0% CM	52%
Macias-Corral et al.[55]	CM+FW	C/N = 20	72%
Lehtomaki et al.[56]	CM+CR+EC	70.0% CM	40.50%
Li et al.[57]	CM+CR	25.0% CM	14.60%
Yue et al.[58]	CM+CR	80.0% CM	25.90%
Yong et al.[59]	FW+CR	C/N = 31	39.50%
Shin et al.[60]	PM+FW	40.0% PM	22.20%
Wu et al.[61]	PM+CR	C/N = 20	>100%

* CM = cattle manure, CR = crop residues, EC = energy crop, FW = food waste, FVW = fruit vegetable waste, PM = pig manure

Co-digestion of different feedstocks can improve methane yield by adjusting the C/N ratio towards the optimal value [41]. Typically, animal manure has a low C/N ratio, while crop residues and food waste have a much higher carbon content. As shown in Table 1.1, many studies have confirmed that methane yield can be significantly improved by mixing feedstocks to achieve the desired C/N ratio.

1.3 Environmental and economic performance of bioenergy

1.3.1 Environmental impacts

There are many tools to evaluate environmental impacts of an economic system, such as life cycle assessment (LCA), material flow analysis (MFA), environmental impact assessment (EIA) and input-output analysis (IOA). Among them, LCA is one of the most widely-used tools that can comprehensively evaluate the environmental impacts of bioenergy systems. By definition, LCA is a technique that 'compiles and evaluates the inputs, outputs and the potential environmental impacts of a product system throughout its life cycle', from resource extraction through supply chain, manufacture, use, recycle and disposal [62]; i.e., LCA is concerned with systems delivering one or more products or services. Because of this perspective, LCA is often described as a "cradle-to-grave" assessment [63]. According to ISO standards, LCA includes four phases: goal and scope definition, life cycle inventory analysis, life cycle impact assessment, and interpretation [62], [64].

(1) *Goal and scope definition*. The goal of the LCA study should be clearly stated in the beginning and followed throughout the study. So is the scope of the study, including functional unit, system boundary, data sources, and assumptions.

(2) *Life cycle inventory (LCI)*. Data of input and output flows of materials and energy are collected and examined for validity and quality. Input flows should include all material and energy consumption within the system boundary, whereas output flows should include products, by-products, emissions, and waste. The set of processes whose selection or operation parameters are subject to decisions based on the LCA study is called the foreground system, whereas all other processes that interact with the foreground system are deemed the background system [65]. Data for the foreground system should be gathered from experiments, surveys or literature, and data for the background system can be based on existing LCI databases for simplicity.

(3) *Life cycle impact assessment (LCIA).* Based on the goal of the LCA study, impact categories to be investigated are specified. There are different impact categories, such as Global Warming Potential, Carcinogens, Non-carcinogens, Respiratory Inorganics, Acidification Potential, Eutrophication Potential, covering environmental aspects of climate change, human health impact, and local environmental impact. These impacts can be assessed by LCIA models, such as the IPCC model [66], IMPACT 2002+ model [67], and CML model [68], which quantify the impact of substances summarized in the LCI, in the unit of the benchmark substance. For example, Global Warming Potential is commonly quantified by the unit of CO_2-equivalent.

(4) *Interpretation.* LCI and LCIA results are interpreted in terms of identified issues, uncertainties, sensitivity analyses, limitations, recommendations, and conclusions. For example, a typical limitation of LCA is that it does not differentiate spatial and temporal factors. In this regard, a large amount of a toxic gas abruptly discharged to a city in one day would have the same environmental impact assessed by LCIA, as the same amount of the gas emitted globally over a year. Such limitations of LCA should be addressed in the interpretation phase to provide the more relevant and intelligible conclusion.

Since the primary goal of bioenergy is to reduce GHG emissions, many LCA studies have focused on bioenergy's impact on climate change. For thermal conversion of lignocellulosic biomass feedstocks, existing LCA studies on their process GHG emissions are reviewed here. As shown in Table 1.2, process GHG emissions of bioenergy are generally below 40 kgCO_2-eq/GJ and are affected by feedstock types and conversion technologies. Meanwhile, it is indicated that the inclusion of land-use change can substantially impact GHG emissions of bioenergy [69], [70]. In comparison, the GHG intensities of natural gas, RPPs, and electricity generated from coal are typically around 60, 90, and 250 kgCO_2-eq/GJ, respectively [6], [70], [71]. Therefore, it is evident that process GHG emissions of bioenergy are generally lower than those of fossil fuels.

Note that the GHG benefits of biomass and biofuels come from the fundamental difference between the source of carbon in fossil fuels and that in biomass. Combustion of fossil fuels releases the carbon locked in the ground over a long period in the non-renewable carbon cycle and increases the CO_2 concentration in the atmosphere. On the other hand, the carbon content in biomass has been captured from the atmosphere via photosynthesis. Therefore, CO_2 emissions from combustion of biomass form part of the renewable carbon cycle: the carbon is returned to the atmosphere, but this would occur through the decay and decomposition of the waste biomass regardless. Thus, biogenic emissions do not add to the stock of CO_2 in the atmosphere and are considered free of net greenhouse gas effect in the LCA [66].

Table 1.2 Review of LCA studies on GHG emissions of thermochemical conversion technologies of lignocellulosic biomass feedstocks

Conversion Pathway	Year	Location	Feedstock	Capacity	Bioenergy produced	Process GHG (kgCO2/GJ.)	Reference
HTL	2017	US	WR	N/A	Jet fuel	18-20	De Jong et al. [72]
	2018	BC	WR	948 tDM/d	Mixed	17-21	Nie and Bi [19]
	2014	US	WR	2000 tDM/d	Gasoline & Diesel	27	Tews et al. [18]
Gasification	2015	US	WC, WR, SG	2000 tDM/d	Ethanol	-15 - 50[a]	Daystar et al. [69]
	2010	US	WC, CR	2000 tDM/d	Ethanol	8-9[b]	Mu et al. [21]
	2014	Sweden	WR	N/A	Methanol	28	Brynolf et al. [73]
	2014	Sweden	WC	430MWth	Methanol	12	Holmgren et al. [29]
	2007	Switzerland	WC	50MWth	Methane	12	Felder and Dones [74]
	2011	Switzerland	WC	N/A	Methane	10	Steubing et al. [75]
Combustion	2011	BC	WP, WW	64000 t/yr	Heat	10-12	Pa et al. [37]
	2009	Norway	Firewood	Residential	Heat	21	Solli et al. [76]
	2007	Sweden	WR	N/A	Heat	6	Eriksson et al. [77]
	2013	Sweden	SRC	N/A	Heat	35	González-García et al. [39]
	2014	Denmark	CR	N/A	Heat	4	Parajuli et al. [36]
	2007	Norway	WR	120 MWth	CHP	5[c]	Guest et al. [35]
	2018	Finland	WC, WP	580 kWth	CHP	2-5	Havukainen et al. [78]
	2014	Denmark	CR	N/A	CHP	4	Parajuli et al. [36]
	2012	Sweden	SRC	N/A	Power	24	González-García et al. [79]
	2011	Spain	CR	350 MWe	Power	33	Sebastián et al. [71]
	2004	US	SRC, WR	96MWe	Power	22-82[a]	Heller et al. [70]

[a]LUC included; [b]Co-product credits of electricity production excluded; [c]Re-allocated based on energy output; WR = wood residues, WC = wood chips, WP = wood pellets, WW = wood waste, CR= crop residues, SG = switchgrass, SRC = short rotational coppice

LCA has also been used to evaluate non-climate change impacts of thermal conversion technologies for lignocellulosic biomass, such as human health, acidification, and eutrophication. Daystar et al. compared the environmental impacts of ethanol produced from various feedstocks with those of gasoline and found that ethanol produced from switchgrass has higher impacts in several categories than gasoline due to crop cultivation processes [69]. Brynolf et al. revealed that the use of methanol reduces the impacts of particulate matter (PM), acidification, and eutrophication by substituting the use of fuel oil as marine fuel [73]. Felder and Dones [74] compared bio-methane thermochemically converted from biomass with natural gas, and found that bio-methane has higher life cycle emissions of PM and NOx and uses more metal resources. Steubing et al. drew the same conclusion [80].

In terms of biomass combustion, research by US EPA has shown that residential wood combustion is a significant source of PM and organic compound emissions [81], [82]. In the context of BC, Pa et al. studied the environmental impacts of UBC's biomass-fired district heating system and raised concerns on local human health risks caused by air emissions [37]. This finding is confirmed by Felder and Dones [74]. To further investigate the health risks of the UBC project, Petrov et al. employed the dynamic intake fraction model and concluded that the plant location plays a critical role in minimizing human exposure to hazardous emissions and thereby health risks [83], [84]. On the other hand, Eriksson et al. compared HB and CHP projects using biomass with those using natural gas, and concluded that combustion of biomass leads to benefits in the weighted score of non-climate change impacts [77]. Thus, non-climate change impacts of bioenergy remain a controversial topic and require further investigation.

For anaerobic digestion (AD), many studies have shown that the GWP benefit is achieved collectively by renewable energy production, by-product credits, and reduction of direct emissions.

Weiske et al. modelled AD of cattle manure and co-digestion with other farm products. The average reduction of GHG emission of all scenarios was found to be 19%, with additional benefits including byproduct of organic fertilizer and reduction of odour and pathogens [85]. Whiting and Azapagic found that AD of agricultural waste can significantly reduce GHG emissions by substituting natural gas used in CHP [86]. Clemens et al. [87] discovered that CH_4 emission from the storage of digestate is significantly reduced compared to the undigested manure and that co-digestion with additives from waste biomass increases biogas yield.

Conflicting results on non-climate change impacts of AD are found in the literature. Mezzullo et al. discovered that AD of cattle manure leads to negative impacts on human health, acidification and eutrophication [88]. Börjesson and Berglund analyzed AD of different raw materials and found that benefits in acidification and eutrophication can be achieved by avoiding indirect environmental impacts from waste management [89]. In contrast, Evangelisti et al. showed that AD of food waste lowers GHG emissions but increases eutrophication and acidification due to digestate use [90]. These problems are caused by nutrient losses, suggesting better management strategies of digestate. De Vries et al. found that AD of dedicated energy crop conflicts in land use with food supply and causes greater environmental impacts, whereas co-digestion with residues and wastes has better overall environmental performance [91].

1.3.2 Economic performance

Most thermal conversion technologies producing refined biofuels from lignocellulosic feedstocks have not reached the commercialization stage yet. In order to evaluate the economic feasibility of these technologies, numerous studies have conducted techno-economic analyses to estimate their capital and operating costs based on process modelling. Dutta et al. used an N^{th}-Plant Economic

Model, which aims to ignore the additional costs associated with pilot plants and reflect a future cost from a mature industry, to estimate the cost of thermochemical ethanol conversion in the US [25]. Using the same model, Knorr et al. and Tews et al. both conducted cost estimations for biofuel production from the HTL technology in the US [18], [92]. Meanwhile, there are also several similar studies focusing on the cost estimation of bio-methanol [93]–[95] and bio-methane [30], [96] via the gasification pathway. The results of these economic analyses provide critical information for process optimization and decision making for the implementation of emerging technologies.

Based on estimated capital and production cost, many studies further calculated the minimum selling price (MSP) of refined biofuels produced by the HTL [16], [97], the thermochemical ethanol conversion [22], [23], [25], and the thermochemical methanol conversion technologies [98]. The MSP indicates the plant-gate price of biofuels that includes the costs and revenues of the bioenergy plant but excludes the costs and revenues of the retailer. The MSP of the biofuel can then be compared with the 'rack price' of the RPP to be substituted, to assess economic competitiveness and market penetration.

Meanwhile, as biomass-fired district heating options are more technically mature, many projects are already in operation, and their economic data are reported. Tallaksen and Kildegaard analyzed the cost of a biomass gasification heating project in the US and concluded that it is considerably more expensive than natural gas district heating [38]. Obernberger and Thek calculated nine case studies of biomass-fired CHP in Austria and strongly recommended higher feed-in tariffs and investment subsidies to promote biomass CHP projects [99]. Based on the economic data of HB and CHP projects in Sweden, Börjesson and Ahlgren developed a cost model for biomass-fired district heating systems [30]. Similarly, Wetterlund and Söderström modelled the cost of different biomass CHP configurations in Sweden [31]. Both studies used these cost models to study the impact of policy measures on biomass-fired district heating options.

The economic performance of anaerobic digestion has also been evaluated by many studies. Klavon et al. reported capital costs and cash flows of eight small-scale AD plants processing cattle manure in the US and found that annual net costs vary widely from $36 to $340 per cow, whereas annual revenues are only $55-160 per cow [100]. Nolan et al. modelled a small-scale AD plant that processed pig manure in Ireland and concluded that it is not economically competitive due to high treatment costs. Similarly, Gebrezgabher et al. developed an economic model for AD of pig manure in the Netherlands and found that it is not economically feasible unless government subsidies are provided [101]. In the context of Canada, Werner and Strehler investigated the economic feasibility of on-farm AD systems in BC and concluded that stronger government support is needed [102]. Ullah conducted a case study on AD of food waste in the Canadian province of Alberta and concluded that it could be economically feasible at larger scales with waste tipping fees and carbon credits [103]. From these studies, it is evident that AD projects in general still face economic challenges and require government support.

1.4 Research objective

BC's rich but under-utilized biomass resources are indispensable to the energy future of the province. Based on BC's energy profile, opportunities are identified for various bioenergy options. There exist numerous studies on the environmental impacts and economic viability of various bioenergy technologies. Based on the review in this dissertation, it is identified that most routes to converting biomass to energy have lower GHG intensities than their fossil fuel counterparts. However, reported studies have shown a wide variation in results on non-climate change impacts and economic viability. Most of these studies refer to activities outside BC, using a range of feedstocks from waste materials to dedicated energy crops. The variability arises from different contexts in which the biomass is taken to be used and differences in modelling the system within which the biomass is used. Therefore, to assess the environmental and economic performances of implementing bioenergy technologies using biomass resources available in BC, the specific context of the province must be considered, and a consistent modelling approach must be used.

Moreover, most reported studies focus on a single type of conversion, designed to decarbonize a specific sector. As the demand for renewable energy is increasing in every sector, policymakers must decide how to allocate limited biomass resources. From a societal perspective, the question "What is the most beneficial use of the biomass resources?" needs to be answered. Particularly following the realization that GHG mitigation is an imperative task [104], [105], all technically realistic bioenergy options must be considered and compared on the basis of GHG mitigation efficiency and cost-effectiveness.

Furthermore, most analyses reviewed in Section 1.3 have adopted output-based functional units, mostly per GJ bioenergy or per tkm transportation. While such function units emphasize the GHG mitigation capability per unit of bioenergy delivered, they nonetheless downplay the importance of energy conversion efficiencies. As the carbon content in biomass feedstocks is biogenic (see Section 1.3.1), process GHG emissions of bioenergy can be low (<20 $kgCO_2$-eq/GJ, see Table 1.2). Even if conversion efficiencies are to increase by 10%, the process GHG emissions will decrease by no more than 2 $kgCO_2$-eq/GJ, representing a nugatory numerical change. However, as more bioenergy products are produced from a given amount of biomass, the more fossil fuels can be displaced and hence the greater the potential benefits. Therefore, using output-based functional units could lead to misleading interpretations of the GHG accounting results, disadvantageous to bioenergy technologies with high energy conversion efficiencies. Instead, input-based functional units, such as per tonne biomass, can better capture the impact of conversion efficiencies. Especially as biomass resources are limited in quantities while the demand for alternative energy solutions continuously grows, it is critical to maximize potential benefits out of the scarce biomass resources. Therefore, comparison of GHG savings, impacts other than climate change, and economic profitability needs to be based on input-based functional units.

To our best knowledge, there has not been any study addressing the problems raised above. Therefore, the objectives of this study are as follows:

(1) Estimate the availability and energy production potential of BC's biomass resources, including forestry resources and waste streams;

(2) Investigate and compare the GWP benefits, health risks and local environmental impacts of implementing various bioenergy options in BC utilizing BC's biomass resources, based on the functional unit of per tonne biomass;

(3) Evaluate the economic viability of various bioenergy options in BC and compare their cost-effectiveness in GHG mitigation per tonne biomass processed;

(4) Facilitate the development of policies to optimize the use of BC's biomass in contributing to GHG mitigation.

1.5 Approaches

1.5.1 Life cycle assessment

Most biomass resources considered in this study are waste materials that arise from existing human activities intended for other economic purposes, including dead trees, wood, and herbaceous residues, and animal manure. The 'waste' nature of these materials means that the existing activities generating these wastes will be carried out regardless of how the wastes are used or managed. Therefore, they can be left out from the scope of the LCA, so the system boundary starts at the available but unused "waste" biomass. Bioenergy conversion from these waste materials should be simply considered as an alternative strategy for waste management allowing for recovery of energy and materials [65]. The basic LCA model for waste management systems is shown in Figure 1.2.

Therefore, the system boundary of the bioenergy production includes feedstock collection and transportation, bioenergy conversion, waste disposal, bioenergy distribution and consumption. Recovered bioenergy and materials displace existing energy commodities (mostly fossil fuels) and raw materials. The environmental impacts of fossil fuels and raw materials displaced are deemed avoided burdens, i.e. environmental credits or savings. Moreover, environmental impacts associated with existing waste management practices of these wastes are avoided by the alternative strategy of bioenergy production and thus should also be considered as avoided burdens.

LCA has been conducted in this work using the commercial LCA software, SimaPro 8.4.0, developed by PRé Consultants. The main advantage of SimaPro is that it has comprehensive built-in LCI databases and provides up-to-date LCIA models. LCI data for the background system is based primarily on entries in the Ecoinvent V3 database [106].

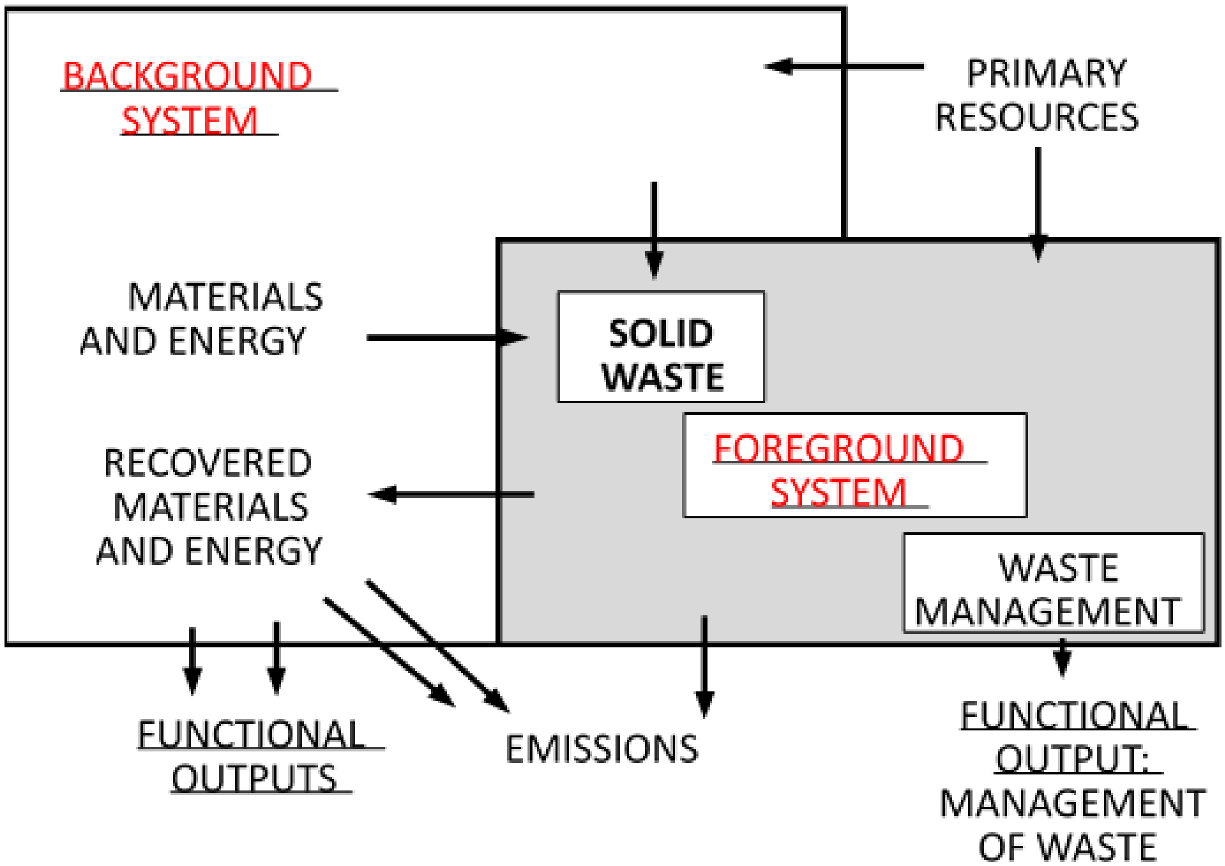


Figure 1.2 Life Cycle Assessment of waste management systems [65]

Since the primary goal of this study is to investigate how bioenergy can help BC to achieve its GHG mitigation targets, the impact of climate change is included in the LCA. Meanwhile, many studies have pointed out the health risks and other environmental concerns associated with the use of bioenergy. Therefore, this study also addresses the impacts on human health, acidification, and eutrophication from the life cycle of bioenergy. The LCIA models for these impact categories are introduced as follows. On the other hand, land-use change, which is a highly contentious issue particularly in the assessment of energy crops, is not covered in this study; this is also explained in the following.

1.5.1.1 Global warming potential

The environmental impact on climate change represented by Global Warming Potential (GWP), which is based on the IPCC Fifth Assessment Report on the time horizon of 100 years [66]. In this model, the climate forcing factors of CH_4 and N_2O are 28 and 265 kgCO_2-eq, respectively. Biogenic CO_2 is considered carbon-neutral, as explained above, and thereby assigned zero GWP.

1.5.1.2 Human health impact

In order to represent human health impacts, three impact categories are selected: Carcinogens, Non-carcinogens, and Respiratory Inorganics (RI), which are evaluated by the IMPACT 2002+ model [67]. Both Carcinogens and Non-carcinogens are caused by hazardous organic compounds and heavy metals and benchmarked by C_2H_3Cl. For simplicity, these two impact categories are combined in this study to form a single impact category called Human Toxicity (HT), based on a 1:1 weighting factor as suggested by the IMPACT 2002+ model [67]. Meanwhile, complementary to Human Toxicity, the impact category of Respiratory Inorganics measures the health risks caused by inorganic air emissions and is benchmarked by fine particulate matter ($PM_{2.5}$).

1.5.1.3 Ecosystem: acidification and eutrophication potential

Furthermore, two impact categories are selected to represent local environmental impacts: Acidification Potential (AP) and Eutrophication Potential (EP). Both AP and EP are analyzed by the CML-IA Baseline model V3.02, developed by the Institute of Environmental Sciences at Leiden University in the Netherlands [68]. In the CML model, AP is mainly attributed to gaseous emissions of oxides of nitrogen and sulphur, benchmarked by SO_2. EP is attributed to the discharge of nitrogen and phosphorus into the air, water and soil, benchmarked by PO_4^{3-}.

1.5.1.4 Exclusion of land-use change

Land-use change (LUC) is a common concern for bioenergy, especially if dedicated energy crops are planted and harvested for bioenergy production. A well-known example is palm oil, which has intensive LUC GHG emissions due to deforestation [107] and is thereby classified as unsustainable by the European Commission. Therefore, any bioenergy produced from dedicated energy crops should be subject to such an investigation to ensure its sustainability and GHG benefits.

On the other hand, waste biomass materials considered in this study arise from existing human activities [65] and thus should be free of LUC concerns associated with the activities that generate these materials. The only raw material investigated in this study is standing timbers within AAC. Even though the deforestation activity to harvest timbers could potentially involve LUC, such impact is neglected in this study. This assumption is mainly based on the argument that the land remains forested, so carbon sequestered in below-ground biomass, which is the dominant carbon stock, is not exposed by activities such as ploughing and tillage.

1.5.2 Economic assessment

1.5.2.1 Capital and production costs

In order to evaluate the economic viability of bioenergy production in BC, data for capital costs of bioenergy production are primarily taken from the existing literature. Since literature data vary in the location of projects and time of publication, they are converted to 2018 Canadian dollars, based on exchange rates at the time of publication [108] and an annual inflation rate of 2%.

After capital costs are determined, production costs can be then evaluated. Production costs include feedstock costs, other operating and maintenance (O&M) costs, loan interests, capital depreciation, and corporate tax. Note that the production cost defined in this study also includes investment cost. Feedstock costs are estimated based on supply chain parameters. Except for feedstock cost, other O&M costs include variable costs such as energy, chemicals, catalysts, and waste handling, and fixed costs such as labour, maintenance, and insurance, which are based on literature data. Production costs are also expressed in 2018 Canadian dollars.

Bioenergy projects are usually partly financed by loans. It is assumed that loan interests are compounded annually. The annual payment is calculated as follows:

$$\mathrm{L} = \frac{P \times r}{1 - (1 + \mathrm{r})^{-N}}$$

Where: L = annual loan payment, P = initial loan principal, r = the annual interest rate, and N = years of loan term.

Capital depreciation is determined by the Canada tax code Capital Cost Allowance (CCA) Class 43.2, which allows renewable energy projects to depreciate faster and thus write the capital cost off more quickly in earlier years [109]. In this schedule, depreciation is calculated by the declining balance method, which is to apply a constant depreciation rate to the residual value each year. Particularly, Class 43.2 allows renewable energy projects to depreciate at an accelerated rate of 50%. In the first year, however, the depreciation rate is halved to 25%. Capital depreciation is written off against revenues to calculate income taxes.

1.5.2.2 Minimum selling price

The minimum selling price (MSP) represents the selling price required to make bioenergy production viable. The MSP is calculated by making net present value (NPV) of the plant zero, based on a predetermined payback period and internal rate of return. Essentially, the MSP also accounts for the revenues needed to justify the capital investment, i.e., return on investment (ROI). Both future production costs and revenues are assumed to be subject to a fixed inflation rate, typically 2% in a developed economy like BC. The discount rate should then include both the real rate of return and inflation rate. The model is defined as follows:

$$NPV = -I + \sum_{t=0}^{n} \frac{(MSP * BC - CP + REV)_t}{(1+r)^t} = 0$$

Where I = initial investment, MSP = minimum selling price, BC = bioenergy capacity, CP = Production costs, REV = by-product and policy revenues, n = payback period, and r = discount rate.

1.5.2.3 Extra cost and GHG reduction cost

The extra cost is defined as the MSP of bioenergy minus the base price of the fossil fuel/electricity displaced. Negative extra costs mean that bioenergy is cheaper than its counterpart in BC's energy profile, indicating the competitiveness of bioenergy. On the other hand, positive extra costs represent the cost gap to be filled by investors, government, and consumers to support the deployment of bioenergy. Promotion of bioenergy with positive extra costs usually requires support from policy measures.

The GHG reduction cost is defined as the extra cost of bioenergy divided by the reduction in GHG emissions. The formula for the GHG reduction cost is shown as follows.

$$\text{GHG Reduction Cost} = \frac{MSP_{bioenergy} - Price_{base}}{GWP_{base} - GWP_{bioenergy}}$$

With the unit of $/tCO$_2$-eq, the GHG reduction cost thus serves as an indicator of cost-effectiveness in GHG mitigation, representing the extra cost needed to achieve each tonne of GHG mitigation. It can also be interpreted as the level of carbon price required to offset the extra cost of bioenergy and thereby promote its use. Bioenergy options with lower GHG reduction costs are more cost-effective and should be prioritized economically.

1.6 Structure of the thesis

Chapter 2 reviews the current status of the bioenergy industry in BC, including existing supporting policies, current production and use of bioenergy, and most importantly, the availability of biomass resources in the province.

Chapter 3 presents the data, models, and results for the environmental and economic assessment of selected bioenergy conversion technologies to utilize lignocellulosic biomass feedstocks in BC. Life cycle assessment is conducted to investigate the GHG reduction potential and non-climate change impacts of different bioenergy options. A discounted cash flow model is used to calculate minimum selling prices for bioenergy products, and GHG reduction costs are estimated to evaluate and compare the cost-effectiveness of different bioenergy feedstocks and technologies. Sensitivity analysis is conducted to investigate the impact of data uncertainties. Based on the results, the policy implications of different bioenergy utilization pathways are discussed.

Chapter 4 and Chapter 5 focus on the environmental and economic performance of bioenergy production from anaerobic digestion of waste streams in BC. Chapter 4 follows the structure of Chapter 3 and compares the GHG mitigation efficiency, non-climate change impacts, and cost-effectiveness of different standard biogas utilization options with the baseline scenario and each other. Policy recommendations are then given on how to promote the development of AD in BC. Chapter 5 further explores the feasibility of integrating farm-scale AD projects with common agricultural practices in BC to better utilize by-products from AD. Environmental and economic benefits of such integration schemes are then assessed. Additionally, material flow analysis is employed to evaluate the nutrient recyclability of the integrated systems.

Chapter 6 summarizes the environmental impact and economic viability of the production and use of bioenergy in BC and gives policy recommendations on the best strategy to exploit BC's biomass resources. Chapter 7 concludes the study, states the limitations of the study, and recommends future work.

Chapter 2 Current status of bioenergy development in BC

2.1 Review of BC's bioenergy policies

As the BC provincial and Canadian federal governments continue to set ambitious GHG reduction targets, new energy and environmental policies are being pursued to help facilitate market penetration and lower the cost penalty of bioenergy. This section provides a review of existing financial policy measures in BC that can directly impact the economics of bioenergy.

2.1.1 Carbon tax and energy tax

BC was the first jurisdiction in North America to introduce a revenue-neutral carbon tax. The tax rate was originally set at CAD \$10/tCO_2-eq in 2008 and gradually increased to \$35/t CO_2-eq in 2018. BC carbon tax is imposed on the consumption of fossil fuels, including refined petroleum products (RPPs) and natural gas, covering 70% of GHG emissions in the province [110]. However, it is not imposed on CH_4 and N_2O emissions, which are major concerns for agriculture and waste management. For Canada as a whole, the federal government has recently proposed a pan-Canada carbon pricing program, which is to start at \$10/tCO_2-eq in 2018 and reach \$50/tCO_2-eq in 2022 [111]. To match this federal policy, the BC government will increase its carbon tax by \$5/tCO_2-eq each year, until it reaches \$50/tCO_2-eq in 2021.

In addition, RPPs used in BC are subject to energy taxes, including provincial motor fuel tax and federal excise tax. Energy taxes amount to \$1.0/GJ, \$1.6/GJ, \$7.9/GJ and \$10.2/GJ for marine fuel, jet fuel, diesel and gasoline, respectively [110], [112]. Liquid biofuels are currently exempted from neither carbon tax nor energy taxes in BC, and tax exemption could provide a legislatively simple option to promote biofuels. On the other hand, energy tax for natural gas is only $0.6/GJ, because the BC government sees natural gas as a "clean energy" and preferable over other more GHG-intensive fossil fuels and plans to expand the natural gas sector in the province [8].

2.1.2 Renewable and Low Carbon Fuel Requirements

BC government has implemented Renewable and Low Carbon Fuel Requirements (RLCF), which currently requires a minimum renewable content (in volume) of 5% for gasoline and 4% for diesel [113]. To further promote the use of biofuels and enforce compliance with the requirements, the BC government allows suppliers to trade credits of low-carbon fuels, currently at a trading price of $170/t$CO_2$ [114]. Looking forward, the BC government aims to increase RLCF to 15% by 2030 [8]. RLCF positions biofuel produced from woody and herbaceous sources as essential replacements for fossil fuels, and has stimulated research and development to expand the range of feedstocks that can be converted to transport fuels and other possible products.

2.3.3 Renewable natural gas feed-in tariff

Promoting renewable natural gas (RNG) is also one of the major climate change action areas for the BC government [8]. So far, financial support to the production of RNG is mainly provided by a feed-in tariff (FiT) system. Fortis BC, the largest natural gas distributor in BC, offers premium RNG purchasing prices up to $30/GJ to participating suppliers and sells procured RNG to voluntarily enrolled consumers at a premium of $6.75/GJ [115]. So far, efforts to procure renewable natural gas have mainly focused on biogas production from anaerobic digestion and landfill gas capture. RNG production from the thermochemical conversion of forest biomass remains at the R&D and pilot stage but is gaining momentum in BC towards demonstration at BC pulp and paper mills.

2.3.4 Electricity and heat

BC is abundant in low-cost hydropower capacity and potential, which hampers the incentive for electricity generation from other renewable sources. BC's major electricity supplier, BC Hydro, is running the Standing Offer Program (SOP) that provides long-term contracts to independent renewable electricity suppliers. The current rate of the FiT is ₵11/kWh, which is slightly lower than the prices charged to residential and small business customers [116]. For renewable heating, the BC government has declared several action areas in its Climate Leadership Plan [8]. However, systemic financial support from policy measures is still lacking.

2.3.5 Financial support to waste management

Disposal of food waste and clean wood waste is charged with tipping fees in many regions in BC, where organic wastes are banned from landfilling. These regions include Metro Vancouver, Victoria, and Nanaimo, where 2.46, 0.38 and 0.16 million people reside, respectively, covering 60% of BC's total population [117]. In Metro Vancouver, the tipping fee for both food and wood waste is $95/t since 2019 [118], whereas in Victoria and Nanaimo the current rate is $110/t [119], [120]. However, for other types of biomass residues, including forestry waste materials, animal manure, and crop residues, there are at present no tipping fees or other forms of financial incentives available in BC.

2.2 Existing production and use of bioenergy in BC

The use and share of bioenergy in BC's economic sectors are summarized in Table 2.1 [12]. Note that the statistics also include other renewable energy sources such as solar and wind. However, since the use of non-biomass renewable energy for purposes other than electricity generation is negligible in BC, the statistics can be considered to represent bioenergy. More than 80% of bioenergy is consumed in the industrial sector, primarily in the pulp and paper industry where some of the wood residues are combusted for heat and power generation. The transportation sector consumed 13 PJ of biofuels in 2016, corresponding to nearly 4% of the sector's total energy use and showing rough compliance with BC's Renewable and Low Carbon Fuel Requirements. At present, there is only one biodiesel plant in BC, so most liquid biofuels consumed in the province are imported from the rest of Canada and the US [121]. The residential sector also consumed 13 PJ of bioenergy in 2016, primarily firewood for heating [122].

Table 2.1 Use and share of bioenergy in BC (2016)

Sector	Energy use (PJ)	Bioenergy use (PJ)	Bioenergy share
Industrial	537	114	21.2%
Transportation	334	13	3.9%
Residential	152	13	8.6%
Commercial	141	0	0%
Total	1165	140	12.0%

Table 2.1 does not capture the development of the AD industry in BC. At present, there are three AD projects processing food waste or cattle manure registered in BC, in addition to two landfill gas capturing projects. The total annual capacity of biogas production is 0.3 PJ [123], which is all

upgraded to renewable natural gas to substitute fossil natural gas in the grid. No evidence of electricity or heat generation from biogas in BC has been found.

2.3 Review of the bioenergy industry in the US and the EU

In the US, nearly all of the gasoline used for transportation contains 10% ethanol (E10); the low-carbon fuel requirement in 2017 was 10.7% [124]. While the ethanol used in the US mostly comes from its massive scale of corn production, the regulation explicitly lists the requirements for cellulosic and advanced biofuels, which amount to 4% in total. According to the statistics provided by US EIA, 5% of energy consumption in the transportation sector of the US came from bioenergy in recent years [125]. In the European Union (EU), the energy percentage of biofuel in the transportation fuels is 7.1% and reaches as much as 30% in Sweden [126]. Therefore, BC's use of biofuel in the transportation sector (4%) falls significantly behind the US and the EU.

BC also needs to catch up on the use of bioenergy in buildings. In the US, the share of bioenergy in the residential and commercial sectors is 7.3% and 3.5%, respectively, whereas the share of all renewable energy sources in these two sectors is 11.0% and 5.8%, respectively [125]. The EU has seen rapid growth in the past few decades: Coal and fuel oil as the dominant heating fuel has been gradually replaced, and the share of bioenergy has increased from less than 5% in 1990 to more than 20% in 2014 [127]. In Northern European countries such as Sweden, biomass has become the dominant energy source for heating [30], [128], [129]. Meanwhile, electricity generation from biomass has grown from almost 0 in 1990 to 18% in 2016 across the EU, particularly 50% in Demark and 30% in the UK [126].

In terms of the AD industry, the EU is the largest and the fastest-growing globally [130]. In the EU, the total biogas production in 2015 was 654 PJ, corresponding to 1.3 GJ per capita [131]. More than half of the EU's biogas capacity is located in Germany, which has an annual production of 329 PJ, equal to 3.97 GJ per capita. In the US, the total biogas capacity is about 1/4 of that in the EU, with an average capacity of 0.5 GJ per capita. In comparison, BC's average biogas capacity is only 0.06 GJ per capita, suggesting a huge potential for growth.

2.4 Estimation of available biomass resources in BC

2.4.1 Forestry resources

2.4.1.1 Standing timbers within AAC

In BC, most forests are managed in compliance with forest management certifications. By the end of 2016, there were 52 million hectares of forests in BC under management certified as "sustainable," which is the largest area in Canada and second only to Russia in the world [132]. To regulate timber harvesting and allow for reforestation, the BC government declares the Annual Allowable Cut (AAC) for each logging area and tree farm based on a plethora of criteria of sustainability. Historical volumes of AAC are shown in Figure 2.1.

Due to economic and other reasons, not all timbers within AAC are harvested. These trees left unharvested are referred to in this study as standing timbers within AAC. The volume of these standing timbers is calculated as the total AAC minus the actual harvested wood. The volume of standing timbers within AAC in 2017 was 6.6 million m^3, corresponding to 2.7 million tonne dry matter (MtDM) [10]. Since the standing timbers within AAC are deemed available for sustainable harvesting, they can be considered potential feedstock for bioenergy production.

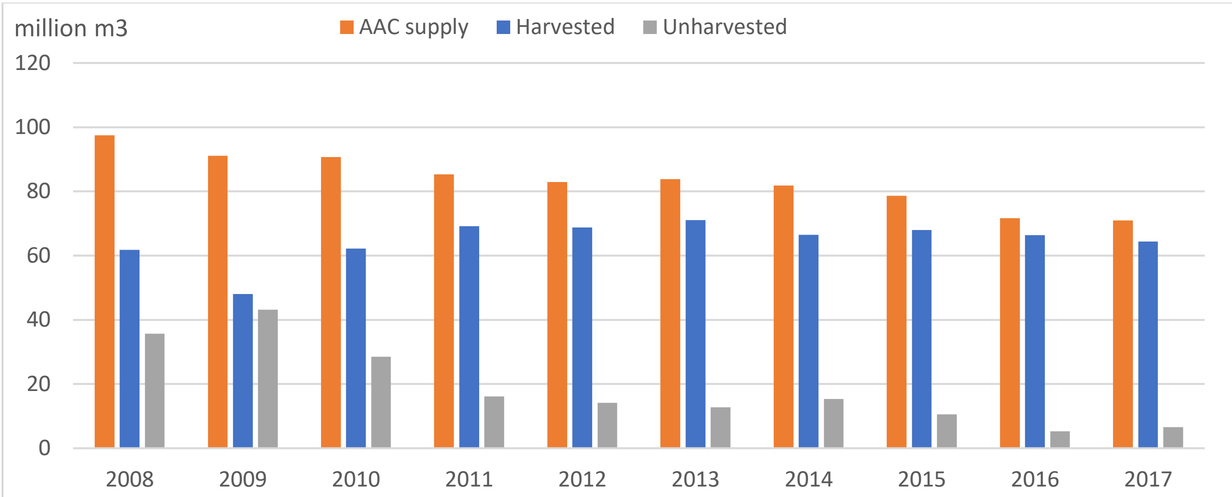


Figure 2.1 Annual allowable cut (AAC) and harvested timbers in BC [10]

2.4.1.2 Mountain pine beetle-killed trees

Mountain pine beetle (MPB)-killed trees refer to trees killed by MPB infestation. It is strongly suggested that the rapid expansion of the MPB infestation is associated with the continued warming in western North America during the last several decades [133]. In the early 2000s, the epidemic quickly developed into an outbreak (Figure 2.2). The cumulative volume of MPB-killed trees was initially predicted to be 1 billion m^3, of which 50% cannot be salvaged due to high cost and lack of possible use (other than as energy feedstock) and is thus categorized as 'non-recovered loss' [134]. In recent years, the volume of trees attacked and killed by MPB infestation has declined more rapidly than expected: by 2015, 730 million m^3 (Mm^3)of pine tree had been killed by MPB infestation, and the prediction of the cumulative volume by the end of the epidemic was reduced to 750 Mm^3 [135].

Even though wood starts to decay quickly post-mortality, recoverable volume remains high [136]. It has been found that at least 26 years are required for dead pine trees to lose 50% of the mass in Oregon [137]. As British Columbia has a similar oceanic but slightly cooler climate, decay of wood is expected to be even slower. Therefore, considering losses from both decaying and wildfire, it is assumed that 50% of non-recovered MPB-killed trees can be salvaged for bioenergy production over 20 years of harvesting from now. This leads to an annual feedstock availability of 9.4 Mm^3, or 3.8 MtDM.

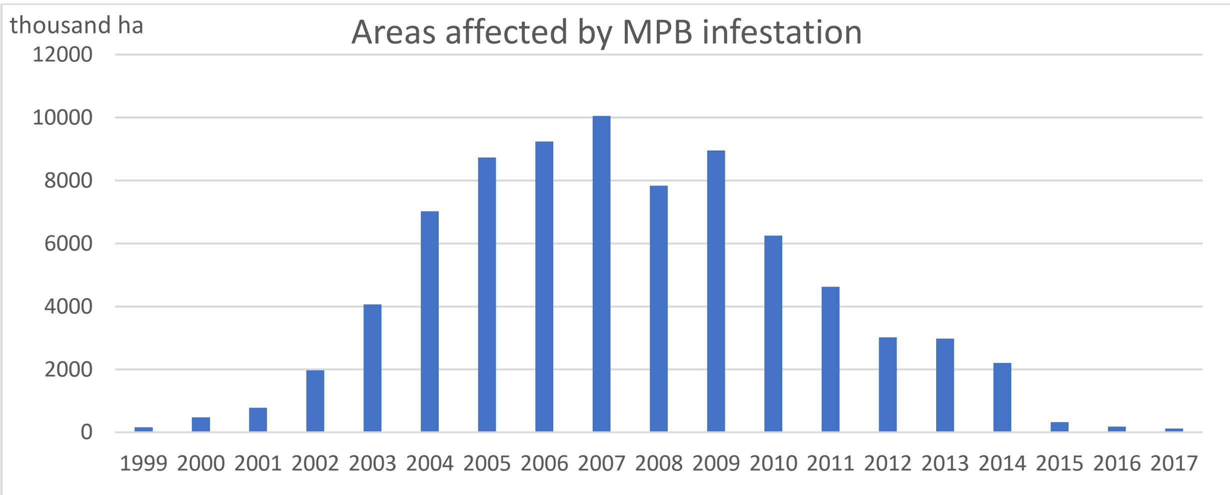


Figure 2.2 Areas affected by mountain pine beetle (MPB) infestation in BC [10]

During and after the MPB outbreak years, AAC was significantly raised to recover timbers affected by the MPB infestation. However, there's no regulation on how to salvage or dispose of the 'non-recovered loss.' These dead trees become dried and fall to the ground over time, thus representing a fire hazard if not removed [138].

2.4.1.3 Harvest residues

The term 'harvest residues' refers to woody debris removed from timbers and left on harvesting sites and roadside. Based on a case study in Campbell River, one of the main timber supply regions in BC, harvest residue/timber ratio is estimated to be 0.11 [139]. Based on the harvested volume of timbers in 2017, the total volume of harvest residues is estimated to be 7.1 Mm^3. At present, it is reported that 1.3 Mm^3 of harvest residues have found uses in pulp, chip, and pellet mills [13].

This means there are still 5.8 Mm^3 of harvest residues, or 2.4 MtDM, potentially available for bioenergy production annually.

2.4.1.4 Sawmill residues

The term ‘sawmill residues’ refers to residual chips, sawdust, shavings, and bark generated in sawmills, as the by-product of lumber production. In 2017, 16.6 Mm^3 of residual chips were produced in sawmills, but all were used in pulp mills, so there was no surplus left for bioenergy production [13]. Based on sawdust and shaving/timber ratio of 0.16 and total timber input to sawmill of 47.2 Mm^3 in 2017, the total volume of sawdust and shavings is estimated to be 7.7 Mm^3 [13]. Based on the sawdust and shaving/bark ratio of 1.2, the total volume of bark is estimated to be 6.4 Mm^3 [140]. In 2017, 4.7 million m^3 of sawdust and shaving and 5.4 million m^3 of bark were used in pulp and pellet mills [13][14]. Therefore, there are still 3.9 Mm^3 of sawmill residues left unused per annum, corresponding to an estimated mass of 1.6 MtDM.

According to BC’s regulation, unused harvest residues and sawmill residues must be disposed of by slash burning to reduce fire hazards. Slash burning is open-air, uncontrolled combustion that can release extensive, persistent air emissions, such as CH_4, NOx, and $PM_{2.5}$ [141]. These emissions can cause serious environmental and health concerns.

2.4.2 Agricultural waste and food waste

2.4.2.1 Animal manure

Livestock farming is critical to BC’s agricultural economy. Based on data provided by Statistics Canada [142] and BC Ministry of Agriculture [143], it is estimated that the entire industry generates 6.7 million tonnes (Mt) of animal manure (AM) each year (Table 2.2): 98% of animal manure generated in BC is either cattle manure (87%) or poultry manure (11%).

Table 2.2 Annual animal manure (AM) generation in BC

	Annual manure generation [142] (kg/head)	Livestock size [143] (10^3 head)	Total availability (,000 fresh tonne)
Cattle			**5883**
Dairy cows	22,706	7.51E+04	1705
Beef cows	13,444	1.92E+05	2580
Heifers	8,904	6.68E+04	595
Calves	4,321	1.90E+05	819
Bulls	15,364	1.20E+04	184
Poultry			**741**
Laying hen	42	3.01E+06	127
Breeder	42	9.17E+05	38
Pullets	21[a]	1.13E+06	24
Broilers	28[b]	1.56E+07	436
Turkeys	117[b]	8.62E+05	101
Other	28[c]	5.64E+05	16
Hog			**91**
Boars and sows	1,358	9.10E+03	12
Pigs (> 22 kg)	1,287	4.64E+04	60
Pigs (< 22 kg)	613	3.15E+04	19
Sheep and lambs	662	3.95E+04	**26**
Total			**6742**

[a]Assumed to be half of the manure generation from lay hens
[b]Multiple cycles a year
[c]Assumed to be the same as broilers

Conventionally, raw cattle manure is collected as liquid slurry from the livestock farm, stored in tanks for months over the winter, and applied to the field in the spring as organic fertilizers. Storage and spreading of manure lead to concerns of GHG emissions, including CH_4 and N_2O gases [144], [145]. Additionally, this practice also releases NH_3 and other forms of hazardous nitrogen and sulphur emissions, causing both environmental and health concerns [146].

2.4.2.2 Crop residues

Crop residues (CR) refer to debris materials left on agricultural fields after crops are harvested and grains are separated. In BC, more than 100,000 hectares of field crops are planted for food and fodder, including barley, canola, oat and wheat [143]. These crops provide a considerable amount of residual biomass every year as a potential source of bioenergy. The average yield of CR per hectare and total availability are summarized in Table 2.3, estimated from the area of crops planted in BC and the residue to grain ratio.

Table 2.3 Annual crop residues (CR) availability in BC

	Area [143] (,000 hectare)	Residue to Grain Ratio[147]	Grain yield[143] (t/ha)	Residue yield (tDM/ha)	Total availability (,000 tDM)
Barley	20.2	1.2	3.3	3.56	71.9
Canola	36.4	N/A	1.9	3 [148]	109
Oat	20.2	1.3	2.9	3.39	68.5
Spring wheat	39.6	1.3	3.4	3.98	158
Total CR	**116.4**			**3.50**	**407**

Conventionally, crop residues are incorporated into the field, which helps to increase soil organic matter, enhance nutrient cycling and retention, and reduce fertilizer costs [149]. According to the latest agricultural census data, crop residues are baled from only 12% of cropping areas in BC [150]. However, crop residues are essentially lignocellulosic materials and can be converted to bioenergy via various technologies. Therefore, crop residues can alternatively be removed from the field and used as bioenergy feedstocks. From a sustainability perspective, at least 750 kg/ha of (dry) residues must be retained on crop fields to prevent soil erosion [151], [152], and the rest can be safely collected.

2.4.2.3 Food waste and wood waste

Reduction of municipal solid waste is crucial to reduce landfilling and mitigate GHG emissions. Although *per capita* waste has been decreasing in recent years, the population of BC continues to grow so that the total generation of solid waste seems to be stabilizing [153]. As of 2014, 2.72 Mt of municipal solid waste was generated in BC, of which 0.94 Mt came from residential sources and 1.78 Mt from non-residential sources [153]. Food waste (FW) accounted for 39.7% of residential and 20.06% of non-residential waste [154] (Table 2.4).

Table 2.4 Annual generation of organic fraction of municipal solid waste in BC

	Residential	Non-residential	Total
Food Waste (Mt, fresh)	0.37	0.36	**0.73**
Wood Waste (Mt, fresh)	0.02	0.27	**0.29**

To facilitate recycling and divert waste from landfills, the BC government has been actively promoting organic waste sorting. By 2015, food waste and clean wood waste are banned from landfilling in areas where 64.3% of the provincial population lives [117]. At present, sorted food waste and wood waste in BC are mostly composted, due to the lack of alternative waste management methods such as AD. However, the composting process results in the loss of the energy potential in food and wood waste. Alternatively, food waste can be processed by anaerobic digestion to produce biogas, and wood waste is essentially lignocellulosic biomass and therefore a potential feedstock for energy production.

2.5 The scope for bioenergy development in BC

BC's energy profile heavily relies on oil and gas, but at the same time has abundant hydropower supply and potential. The province is also rich in biomass, notably in its extensive forests, along with various kinds of waste biomass materials. These features give rise to opportunities for bioenergy production from surplus forestry resources and waste streams in BC to displace natural gas for heating and refined petroleum products (RPPs) for mobility. Therefore, BC provides a representative case to explore the potential contribution of bioenergy to the mitigation of greenhouse gas (GHG) emissions. The following chapters in this dissertation will analyze the environmental and economic performance of bioenergy in detail and investigate the role of bioenergy in BC's endeavour in GHG mitigation.

Chapter 3 Bioenergy production from lignocellulosic biomass feedstocks in BC

This chapter analyzes the environmental and economic performances of bioenergy production from available lignocellulosic biomass resources in BC, including forestry waste materials (FWM), unharvested timbers within Annual Allowable Cut (AAC), wood waste in municipal solid waste (WW), and crop residues (CR). Bioenergy conversion technologies potentially suitable for BC's energy profile are investigated, including hydrothermal liquefaction (HTL), thermochemical methanol (MeOH), ethanol (EtOH), renewable natural gas (RNG), cogeneration of heat and power (CHP), heat-only boilers (HB) and power generation (PG).

3.1 LCA of bioenergy systems for utilizing lignocellulosic feedstocks

In this chapter, the system boundary of bioenergy production from lignocellulosic feedstocks includes feedstock supply chain, bioenergy conversion processes, waste disposal, bioenergy distribution, and consumption (Figure 3.1). Two functional units are used in this chapter, each having its distinct implications. The first functional unit is per GJ of bioenergy delivered to users. Note that for HB, CHP, and PG, this refers to 1 GJ of heat service, electricity, or both, delivered to users. For refined biofuel options including HTL, MeOH, EtOH, and RNG, the functional unit represents 1 GJ of biofuel product derived, delivered, and combusted. The second functional unit is per tonne dry matter (tDM) biomass feedstock. This one is significant because forestry waste materials and other biomass feedstocks are limited resources, compared to the enormous future demand for renewable energy. Therefore, the functional unit on a mass basis can identify the impact and potential benefit achievable with a given amount of feedstock. The following impact categories are investigated: global warming potential (GWP), human toxicity (HT), respiratory inorganics (RI), acidification potential (AP) and eutrophication potential (EP).

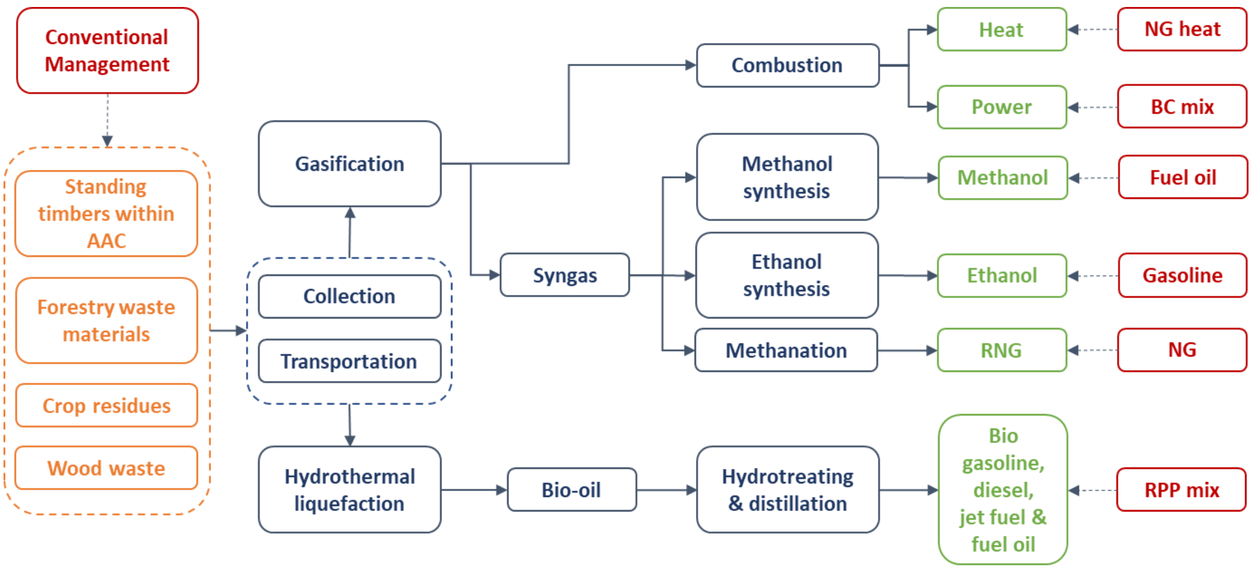


Figure 3.1 The system and boundary of thermal conversion of lignocellulosic biomass

3.1.1 Feedstock supply chain

The feedstock supply chain refers to the collection of biomass feedstocks and the subsequent transportation to the gate of the bioenergy plant. Converting biomass feedstocks to energy avoids any environmental impacts that would have been generated from the conventional way these materials are managed in BC. These avoided burdens are included in the credits of bioenergy production, along with the burdens of the baseline energy displaced by the bioenergy discussed in the following sections.

MPB-killed trees, roadside residues, and sawmill residues are considered altogether as forestry waste materials (Table 3.1). MPB-killed trees are assumed to be harvested in the northern logging regions in BC, chipped and loaded on-site, and then transported to bioenergy plants. Harvest residues are assumed to be chipped and loaded on-site and transported in the same way as MPB-killed trees, since these residues are by-products of the existing logging activities. Sawmill residues are assumed to be collected from sawmills, transported to and pelletized at pellet mills, and transported to bioenergy plants. The average environmental impacts of forestry waste materials are then calculated based on the ratio of the feedstock availability, as described in Chapter 2.

Note that 750 km of railway transportation for MPB-killed trees and roadside residues represents the distance between Prince George (the center of logging regions in northern BC) and Metro Vancouver (BC's most populated region). For sawmill residues, since sawmills and pellet plants in BC are scattered around Vancouver, the average transportation distance is assumed to be 180 km by HDV. While these assumptions represent a simplified case of the feedstock supply chain, the actual transportation distance may increase significantly over time as feedstocks are harvested from remoter sites due to the vast area of BC's forests. The impacts of the uncertainty in the transportation distance will be addressed in the sensitivity analyses further in this chapter.

Table 3.1 Parameters for supply chains of lignocellulosic biomass resources in BC

	Annual arising (MtDM)	MC	Collection	Processing	Transportation
MPB-killed trees	3.8	50%	Harvesting, 3.45 L diesel/tDM [155]	Chipping 1.30 L diesel/tDM [155]	Rail, 750 km [156] + HDV, 45 km
Harvest residues	2.4	50%	Loading, 0.82 L diesel/tDM [155]	Chipping 1.30 L diesel/tDM [155]	Rail, 750 km [156] + HDV, 45 km
Sawmill residues	1.6	50%	Loading, 0.82 L diesel/tDM [155]	Pelletizing 490 MJ power + 23.5 MJ diesel + 6.2 MJ propane/tDM [157]	HDV, 180 km (total distance)
Standing timbers	2.7	50%	Harvesting, 3.45 L diesel/tDM [155]	Chipping 1.30 L diesel/tDM [155]	Rail, 750 km [156] + HDV, 45 km
Crop residues	0.41	7%	Harvesting, 4.7 L diesel/tDM [6]	Chipping 1.30 L diesel/tDM [155]	HDV, 50 km
Wood waste	0.22	30%	HDV, 15 km	Chipping 1.30 L diesel/tDM [155]	HDV, 50 km

Standing timbers within AAC are also considered potential bioenergy feedstock. Their supply chain is assumed to be the same as that of MPB-killed trees. Crop residues and wood wastes are waste biomass streams generated by human activities, so their relevant life cycles start at the point where the waste is generated [65] as explained in chapter 2. Crop residues are collected on the field by harvesters, and wood wastes are collected by municipal solid waste collection services. These waste materials are then chipped and transported to bioenergy plants. Comparing to forestry resources, the transportation distance for crop residues and wood wastes is much shorter.

At bioenergy plants, it is assumed that woody feedstocks are air-dried to 30% MC to facilitate the thermal conversion. Environmental impacts from air-drying, intra-plant transportation, and storage are small and neglected here. Feedstocks are then assumed to be further dried by waste heat to 10% MC. The heat needed for drying is calculated as 0.89 MJ/kgDM, based on 2.8 MJ/kg water evaporated [26]. Higher heating value (HHV) of woody biomass is assumed to be 20 GJ/tDM, and that of crop residues is assumed to be 18GJ/tDM.

The environmental impacts of avoided burdens from conventional handling practices of these biomass feedstocks are described as follows. For harvest residues and sawmill residues, emission factors of slash burning are based on a literature review by Andreae and Merlet [141]. It is assumed that MPB-killed trees will be eventually destroyed by wildfire, generating the same uncontrolled emissions as slash burning. Wood waste in the municipal solid waste is assumed to be composted. Environmental impacts of wood waste composting are based on the work of Komilis and Ham [158]. Crop residues are assumed to be incorporated into the field as soil improvers. Diesel consumption for field incorporation of crop residues is assumed to be 4.11 L diesel/tFM, using the plowing process in the Ecoinvent Database as a proxy [106]. Standing timbers are assumed to be left unharvested, generating no environmental impacts.

3.1.2 Hydrothermal Liquefaction

Hydrothermal liquefaction (HTL) converts biomass into bio-oil, which is further upgraded to hydrocarbons and distilled into four liquid biofuel fractions. The overall energy conversion efficiency, defined as the ratio between HHV of final biofuel products and biomass input, is assumed to be 58% [19]. The final biofuel mixture consists of 21 wt% gasoline, 35 wt% diesel, 25 wt% jet fuel, and 19 wt% fuel oil [19]. These biofuels will substitute respective fossil fuels.

Table 3.2 Process parameters for hydrothermal liquefaction (HTL) of lignocellulosic biomass feedstocks

Parameters	Value	Unit	Reference
Input			
Electricity	284	kWh/tDM	Tews et al. [18]
Catalyst, upgrading	1.51E-1	kg/tDM	Nie and Bi [19]
Catalyst, H_2	1.56E-3	kg/tDM	Nie and Bi [19]
Na_2CO_3 buffer	122	kg/tDM	Zhu et al. [16]
Output			
Biofuels (HHV)	11.6	GJ/tDM	Nie and Bi [19]
Energy efficiency	58	%	Nie and Bi [19]
Waste			
Wood Ash	9.45	kg/tDM	Jungbluth [26]
Wastewater	1.40	m3/tDM	Tews et al. [18]
Other solid waste	56.2	kg/tDM	Tews et al. [18]
Biochar (Carbon credit)	51	%Solid waste	Wright et al. [159]
Biochar (Nitrogen credit)	4.5	%Solid waste	Wright et al. [159]

Table 3.2 presents the main process parameters of the HTL process. The main material inputs are Na_2CO_3 as the buffering agent and nickel molybdenum-based catalysts. Demand for the hydrogen and heat is assumed to be entirely met by biogas produced from wastewater from the process and hydrocarbons in the off-gases [18], [19]. Solid residues containing biochar are applied to the field as a soil improver and nitrogen fertilizer [19]. Environmental impacts from the HTL process are

allocated between the different factions of biofuels in proportion to their HHVs. Since emission data of the entire HTL process are missing, the emission inventory of the entry 'methane production, 96% by volume, from synthetic gas, wood CH' in the Ecoinvent database [106] is used as a proxy.

For product distribution, liquid biofuels are transported by HDV for 50 km. Emission factors of biodiesel consumption in heavy vehicles and bio-jet fuel consumption in airplanes are based on the GHGenius database [6], as shown in Table 3.3. As HTL is a relatively new technology, emission data for the combustion of HTL-derived gasoline and fuel oil are not available. Since these biofuels are hydrocarbons with low sulphur contents [160], [161], the emission factors are assumed to be the same as their fossil counterpart, except for changing the origin of carbon-based emissions from fossil to biogenic.

Table 3.3 Emission factors of the combustion of liquid biofuels and fossil fuels

kg/MJ	MeOH	EtOH	Biodiesel	Bio JF	Gasoline	Diesel	Jet fuel	Fuel oil
Fuel leakage	1.89E-05	9.56E-06	0	0	1.62E-05	0	0	0
NMOG	7.39E-05	7.39E-05	1.04E-05	1.08E-06	7.60E-05	1.29E-05	1.35E-06	2.94E-05
CH_4	3.84E-06	1.15E-05	3.87E-06	1.68E-06	7.11E-06	4.30E-06	1.68E-06	7.15E-07
CO	2.30E-03	2.30E-03	7.79E-06	7.00E-06	3.55E-03	1.20E-05	7.00E-06	1.91E-04
N_2O	3.45E-06	3.45E-06	2.99E-06	1.90E-06	7.97E-06	2.99E-06	1.90E-06	1.99E-06
NO_X	7.51E-05	7.51E-05	2.48E-05	2.50E-04	7.72E-05	2.61E-05	2.50E-04	1.79E-03
SO_X	2.72E-06	2.57E-06	2.36E-06	2.00E-08	1.73E-05	2.59E-06	1.20E-06	6.76E-07
PM	2.17E-06	2.17E-06	9.71E-07	2.50E-06	5.02E-06	1.28E-06	5.00E-06	3.58E-05
CO2, lube oil	7.82E-04	7.82E-04	7.39E-04	0	7.23E-04	7.39E-04	0	0
CO2, fossil	0	0	0	0	6.14E-02	6.85E-02	6.70E-02	7.02E-02

3.1.3 Ethanol, methanol, and renewable natural gas via gasification

In the gasification conversion pathway, biomass feedstocks are air-dried, further dried by waste heat, and then gasified and converted into syngas. With different catalysts, syngas is then synthesized into ethanol (EtOH), methanol (MeOH), or renewable natural gas (RNG). Based on BC's energy profile, methanol, ethanol, and renewable natural gas can displace fuel oil used in marine vessels, gasoline used in light vehicles, and natural gas in the grid, respectively.

Major process parameters for EtOH, MeOH, and RNG options are summarized in Table 3.4. It is assumed that heat demand for the conversion processes is provided by combustion of char and a slip-stream of syngas [25], so all three options are considered autothermal. Electricity is still needed from the grid to power equipment. The conversion efficiency of EtOH, MeOH, and RNG, defined as the ratio between HHV of biofuel output and feedstock input, is assumed to be 45%, 54%, and 58%, respectively, based on the median value in the literature [21], [25]–[33]. Note that these assumptions for conversion efficiencies represent averages for bioenergy production using these technologies. The impact of the uncertainties in the conversion efficiency, especially as a result of technological improvement, will be addressed in the sensitivity analyses further in the chapter.

Material consumptions of these biofuel technologies include gasification bed materials, gas cleaning agents, catalysts, and other chemicals [25], [26]. Wastes include wood ashes, other solid wastes, waste oil, and wastewater, and are estimated from the mass balances. Air emissions per tDM feedstock from these gasification-based biofuel technologies are assumed to be the same. Fugitive emissions of biofuels are assumed to be 0.05% [26]. H_2S emissions are based on an NREL report for bioethanol production [25]. Other main air emissions are based on RNG production from syngas in the Ecoinvent database [106].

Table 3.4 Process parameters for the production of methanol, ethanol and renewable natural gas from gasification of lignocellulosic feedstocks

Parameters	Ethanol [25]	Methanol [26]	RNG [26]	Unit
Input				
Aluminum oxide	1.17E-1	8.15E-2	1.16E-7	kg/tDM
Nickle	3.27E-2	6.79E-3	1.16E-7	kg/tDM
Molybdenum	1.77E-2	3.40E-03	0	kg/tDM
Sodium hydroxide (50%)	4.36E-1	2.01	3.29E-1	kg/tDM
Sulfuric acid	0	7.97	2.78	kg/tDM
Silica sand (Olivine)	2.97	30.5	48.9	kg/tDM
CuO	0	3.06E-2	0	kg/tDM
Zeolite	0	5.04E+00	0	kg/tDM
Dolomite	0	2.46E+01	0	kg/tDM
Other chemicals	4.19E-2	0	0	kg/tDM
Dimethyl ether	9.81E-3	0	0	kg/tDM
Amine	1.09E-3	0	0	kg/tDM
Cobalt	3.96E-3	0	0	kg/tDM
Charcoal	0	0	5.35	kg/tDM
Methyl ester	0	0	3.95	kg/tDM
ZnO	0	0	5.05E-1	kg/tDM
Calcium carbonate	0	0	5.76	kg/tDM
Electricity	0	94.1	190	kWh/tDM
Diesel	17.7	0	1.66E-1	MJ/tDM
Output				
Biofuel (HHV)	9	10.8	11.6	GJ/tDM
Energy efficiency	45	54	58	%
Waste				
Wood Ash [26]	9.45	9.45	9.45	kg/tDM
Wastewater	4.20E-2	1.81	2.91E-1	m3/tDM
Other solid waste	14.9	60.3	60.2	kg/tDM
Waste oil	9.81E-3	0	3.95	kg/tDM

In terms of product distribution, it is assumed that methanol and ethanol are transported by HDV for 50 km, and RNG distributed via natural gas pipelines for 50 km. Emission factors of methanol combustion in marine vessels and ethanol combustion in light vehicles are based on the GHGenius database [6] (Table 3.3). Emission factors of RNG combustion are assumed to be the same as fossil natural gas based on the Ecoinvent database [106].

3.1.4 Cogeneration of Heat and Power, Power Generation and Heat Boiler

Instead of conversion to refined biofuels, lignocellulosic feedstocks can also be combusted to generate heat and power. While the direct combustion of biomass is usually associated with intensive air emissions, gasification of biomass followed by combustion of the syngas has been assessed as a relatively clean combustion route [24]. Therefore, it is assumed that feedstocks are gasified before being combusted to achieve cleaner combustion. Electricity generated by CHP and PG is supplied to the BC electricity grid. The heat generated by CHP and HB is assumed to displace natural gas consumption, which is the most common heating method in BC.

Major process parameters for CHP, PG, and HB are shown in Table 3.5. For the CHP option, the electrical efficiency is assumed to be 30%, and the thermal efficiency is assumed to be 50% [30], [32], [34]–[36]. Emission factors of major air pollutants from CHP are taken from Guest et al. [35]. Selective catalytic reduction and electrostatic precipitation are deployed to reduce NOx emissions by 30% and PM emissions by 90%, respectively. The rest of the life cycle inventory is adjusted from the Ecoinvent database [106] on a per tDM feedstock basis.

Table 3.5 Process parameters for the utilization of lignocellulosic feedstocks via cogeneration of heat and power, power-only generation and heat boiler

Parameters	Value	Unit	Reference
Input			
Silica sand	9.50E-03	kg/tDM	Jungbluth et al. [26]
Sodium hydroxide	1.65E-04	kg/tDM	Jungbluth et al. [26]
Sulfuric acid	2.79E-03	kg/tDM	Jungbluth et al. [26]
Nickle	3.27E-05	kg/tDM	Jungbluth et al. [26]
Al_2O_3	3.27E-05	kg/tDM	Jungbluth et al. [26]
NOx retained, SCR (CHP&PG)	1.16E-03	kg/tDM	
NOx retained, SCR (HB)	7.47E-04	kg/tDM	
Output			
CHP power	30	%	[30], [32], [34]–[36]
CHP heat	50	%	[30], [32], [34]–[36]
Power-only Generation	38	%	[34]
Heat Boiler	73	%	[36]–[39]
Waste			
Wood Ash	9.45	kg/tDM	Jungbluth et al. [26]
Wastewater	2.84E-04	m^3/tDM	Jungbluth et al. [26]
Solid waste	9.57E-03	kg/tDM	Jungbluth et al. [26]
Emissions (CHP&PG)			
NO_X	4.98E-04	kg/tDM	Guest et al. [35]
SO_2	3.24E-06	kg/tDM	Guest et al. [35]
PM	1.01E-04	kg/tDM	Guest et al. [35]
CO	2.23E-03	kg/tDM	Guest et al. [35]
NMVOC	2.23E-04	kg/tDM	Guest et al. [35]
CH_4	1.68E-04	kg/tDM	Guest et al. [35]
N_2O	1.34E-04	kg/tDM	Guest et al. [35]
Emissions (HB)			
NO_X	3.20E-04	kg/tDM	Pa et al. [37]
PM	5.84E-05	kg/tDM	Pa et al. [37]
CO	2.13E-04	kg/tDM	Pa et al. [37]
NMVOC	6.28E-05	kg/tDM	Pa et al. [37]
CH_4	1.32E-04	kg/tDM	Pa et al. [37]

For the PG option, efficiency is assumed to be 38% [34], higher than the electrical efficiency of CHP. The rest of the life cycle inventory of PG is assumed to be the same as CHP. For the HB option, energy efficiency is assumed to be 73% [36]–[39]. It is assumed that HB shares the same material and energy input and waste disposal as CHP. Emissions of major air pollutants from HB are taken from Pa et al. [37]. The rest of the inventory is based on the Ecoinvent database [106]. The uncertainty in these conversion efficiencies will be discussed further in the chapter.

3.1.5 Environmental impacts of baseline energy in BC

The consumption of bioenergy replaces fossil fuels and electricity in the current BC energy consumption mix, which are set as the baseline. Environmental impacts of baseline energy commodities are mainly based on the Ecoinvent database [106]. Natural gas is based on data for production in Alberta without change. For natural gas heating, it is assumed to be provided by large-scale industrial furnaces with an energy efficiency of 90%. Data for other energy commodities are updated as follows, to represent the case of BC. For RPPs, it is assumed that crude oil is sourced from Alberta, transported via Trans Mountain Pipeline System (1150 km) to the Parkland Refinery in Metro Vancouver, and then refined there. In terms of fuel distribution, jet fuel is transported to Vancouver International Airport via pipeline (41 km) and other fuels to fueling stations via HDV (50 km). Emissions from the combustion of gasoline, diesel, jet fuel, and fuel oil are based on the GHGenius database [6], as shown in Table 3.3. BC electricity mix is assumed to consist of 88.6% hydro, 5.0% bioenergy, 1.2% wind, 2.4% natural gas, and 1.8% imported from the US and 0.8% imported from Alberta, based on data of the year 2016 from Statistics Canada [162]. There is still some electricity generation from refined petroleum products in BC, mostly in small off-grid communities. The use of coal has been eliminated in BC.

3.2 Description of the economic model

This section describes the parameters and data for the economic model used to estimate capital costs and production costs of bioenergy production from lignocellulosic feedstocks and hence the minimum selling prices (MSPs) of bioenergy products. Costs and minimum selling prices are expressed in 2018 Canadian dollars. Key assumptions and simplifications are based on the BC context, as shown in Table 3.6. Note that the loan financing, internal rate of return, and payback period are based on assumptions used in several studies [25], [97]. These assumptions will be addressed in the sensitivity analysis in Section 3.4.3.

Table 3.6 Parameters and assumptions of the discounted cash flow model for bioenergy production

Parameter	Value
Financing by equity/loan	40%/60%
Interest rate of loan	6.5% annually
Term of loan	10 years
Internal rate of return	10%
Annual inflation rate	2%
Depreciation	CCA Class 43.2 (50% accelerated depreciation)
Plant salvage value	0%
Construction period	3 years (8% Y1, 60% Y2, 32% Y3)
Payback period	20 years
Corporate tax	26%

3.2.1 Capital costs

Data for capital costs of bioenergy projects are retrieved from the literature, summarized in Table 3.7. Data published in different years and currencies are converted to 2018 Canadian dollars, based on exchange rates at the time when data were published [108] and an annual inflation rate of 2%.

Data of various production capacities are scaled to the feed rate of 2000 tDM/day based on the economy of scale:

$$\text{Capital cost}_A = \text{Capital cost}_B \left(\frac{Capacity_A}{Capacity_B}\right)^{0.6}$$

Table 3.7 Capital and operating costs of bioenergy technologies (scaled data)

	Year	Capacity (tonne/day)	Capital cost (million $)	O&M cost (million $)	Source
HTL	2014	2000	612	74	Zhu et al. [16]
	2014	2000	442	51	Tews et al. [18]
	2013	2000	434	40	Knorr et al. [92]
	2018	948	475	83	Nie et al. [97]
MeOH	2010	1728	638	77	Tock et al. [95]
	2017	1265	920	56	Carvalho et al. [98]
	2014	1460	709	52	Andersson et al. [94]
	2008	400	279	24	Kumabe et al. [93]
EtOH	2011	2000	586	35	Dutta et al. [25]
	2009	2000	492	9% of capital	Foust et al. [22]
	2011	2000	159	18	He and Zhang [163]
RNG	2010	1045	545	34	Wetterlund and Söderström [31]
	2006	432	384	9% of capital	Zwart et al. [96]
	2015	724	1025	Not specified	Thunman et al. [164]
	2013	1447	826	Not specified	Möller et al. [165]
CHP (&PG)	2010	1015	434	18	Wetterlund and Söderström [31]
	2007	1103	164	9	USEPA [166]
	2008	58	325	31	Obernberge [99]
	2010	2000	253	22	Börjesson and Ahlgren [30]
HB	2010	2000	245	19	Börjesson and Ahlgren [30]
	2011	27	147	7	Tallaksen and Kildegaard [38]

Average values of these data are then used to represent the capital costs of various bioenergy options in BC. Even though these values are adjusted by an inflation rate, they still do not account for the impact of technological improvement since the time the data were reported. For the same reason, the adjustment by exchange rates does not accurately reflect the regional differences in the costs of equipment and labour. The impact of the data uncertainty for capital costs will be examined in Section 3.4.3.

Parameters used to estimate feedstock costs are summarized in Table 3.8. Chips from unharvested timbers are commercial products, so their costs are directly based on the market price of $210/t [167]. Feedstock costs for forestry waste materials and crop residues include merchantable values of raw materials and costs of feedstock processing and transportation. The merchantable value of forestry waste materials is significantly lower than timbers, and the merchantable value of crop residues is based on its fertilizer value. The wood waste feedstock is considered free of charge, as otherwise it would be managed by services provided by the government and paid from tax revenue, and it is assumed that bioenergy plants processing wood waste receive 60% of the $95/t waste tipping fee as revenues.

Table 3.8 Parameters for estimating feedstock cost of forestry waste materials

Item	Cost	Reference
Raw value, forestry waste materials	$13.89/tDM	Sokhansanj [156]
Raw material, crop residues	$15.5/tDM	Estimated
Loading, waste materials	$5.29/tDM	Johnson [155]
Harvesting, MPB-killed trees	$19.8/tDM	Johnson [155]
Harvesting, crop residue	$31.7/tDM	Stephen [151]
Pelletizing, sawmill residues	$45.4/tDM	Sokhansanj [156]
Chipping, other materials	$7.09/tDM	Johnson [155]
HDV transportation	$0.125/tkm	Austin [168]
Rail transportation	$0.032/tkm	Austin [168]

In this chapter, other O&M costs are based on literature sources for simplicity, as summarized in Table 3.7. Capital depreciation is determined by the Canadian tax code of Capital Cost Allowance

(CCA) Class 43.2, which allows bioenergy projects to depreciate by 50% annually (see Section 1.5.2). In the first year, however, the depreciation rate is halved to 25% [109]. The annual loan payment is calculated based on the following formula:

$$\mathrm{L} = \frac{P \times r}{1 - (1 + \mathrm{r})^{-N}}$$

Where: L = annual loan payment, P = initial loan principal (60% of capital costs), r = the annual interest rate (6.5%), and N = years of loan term (10 years).

3.2.3 Minimum selling prices

Based on production costs of bioenergy systems, minimum selling prices (MSPs, in 2018 Canadian dollars) of bioenergy products calculated based on a discounted cash flow model. The payback period for bioenergy systems is assumed to be 20 years. Production costs are assumed to inflate at a constant annual rate of 2%. The total discount rate includes both the real rate of return (10%) and the inflation rate (2%). The model is defined as follows:

$$NPV = -I + \sum_{t=0}^{n} \frac{(MSP * BC - CF - CO - CD - CI - CT)_t}{(1+r)^t} = 0$$

Where I = initial investment, MSP = minimum selling price, BC = bioenergy capacity, CF = feedstock costs, CO = other O&M costs, CD = capital depreciation, CI = interest, CT = tax, n = 20 years, and r = discount rate (12% pa).

3.2.4 Energy prices in BC

MSPs of bioenergy products are compared with prices of baseline energy currently used in BC, as summarized in Table 3.9. For liquid biofuels and renewable natural gas, since they are sold to fueling stations and natural gas grid, respectively, their baseline prices refer to the bulk fossil fuel prices these energy distributors pay [169]–[171]. For electricity, since both the main producer and main distributor in BC is BC hydro, the average electricity purchasing price is unknown and difficult to determine. Therefore, the baseline electricity price is assumed to be the large business rate, the lowest electricity rate offered by BC Hydro [172]. Note that the large business rate is about ₵4/kWh lower than BC Hydro’s SOP purchasing price. For district heating, since this service is sold by the service provider directly to individual and corporate users, market energy prices should be used rather than bulk prices. In this study, biomass-fired district heating is compared with natural gas district heating. The baseline heating price is based on the annualized cost of UBC’s campus energy centre and natural gas business rate provided by Fortis BC [173]. Note the difference between the two baseline prices involving natural gas: renewable natural gas is supplied to the natural gas distributor, so the corresponding baseline price should be natural gas bulk price; biomass district heating is a service provided to consumers, hence the annualized cost of natural gas heating accounting for both equipment cost and retail energy price.

Table 3.9 Baseline prices of RPPs, natural gas, and electricity in BC

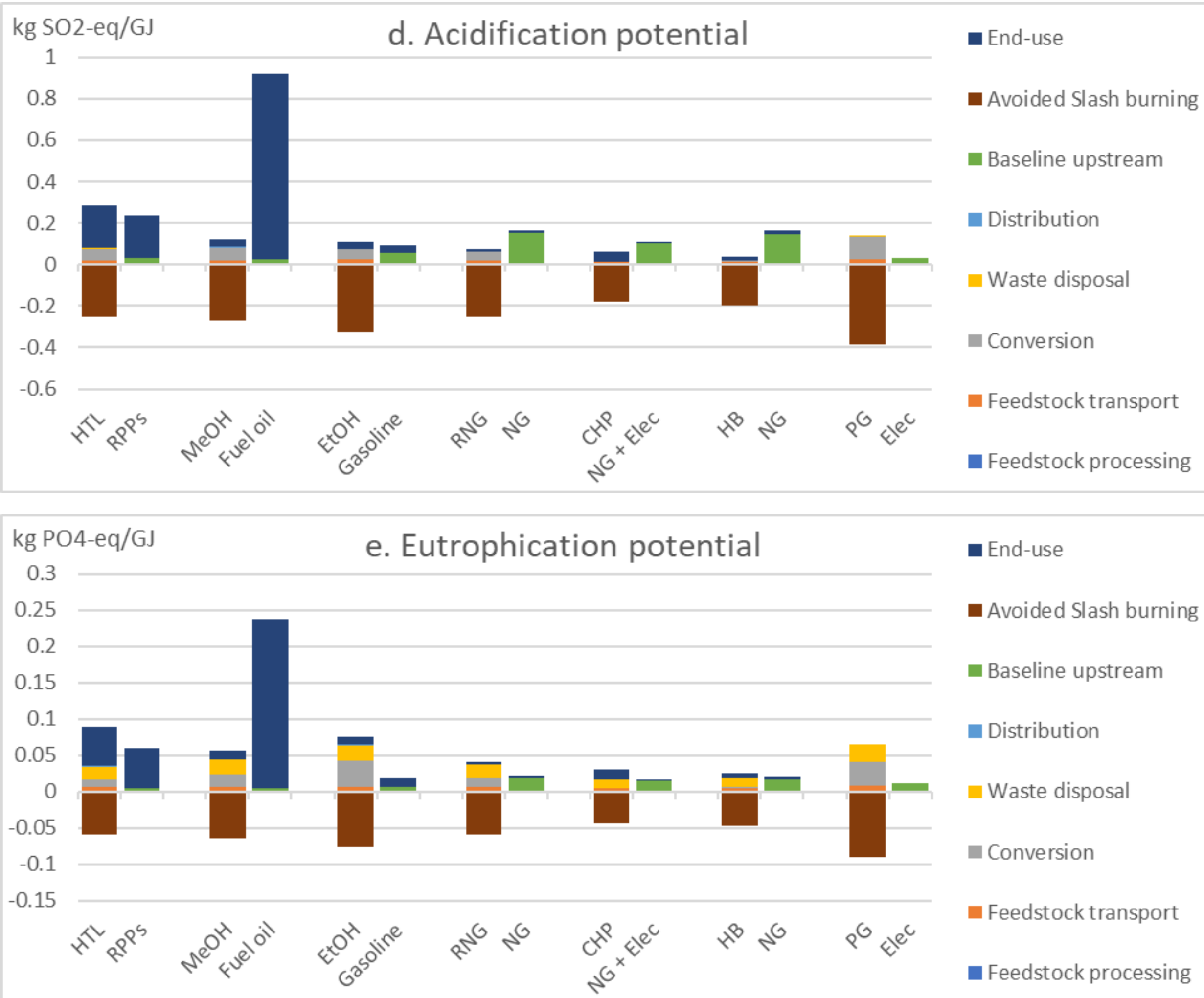
Energy	Cost ($/GJ)	Energy	Cost ($/GJ)
Gasoline [171]	21.4	Natural gas [169]	2.25
Diesel [171]	17.8	Electricity [172]	15.3
Jet fuel [170]	14.3	Natural gas heating	12.4
Fuel oil [171]	20.1		

3.3 Environmental impacts of bioenergy produced from forestry waste materials

3.3.1 Global warming potential

Estimates for the Global Warming Potential (GWP) per GJ bioenergy products are shown in Figure 3.2(a). Process GHG emissions of CHP and HB options are below 10 kg CO_2-eq/GJ, the lowest among all bioenergy options investigated. Process GHG emissions of refined biofuels are around 15 kg CO_2-eq/GJ, including MeOH, EtOH, HTL, RNG options. The PG option has the highest process GHG emissions, which are about 20 kg CO_2-eq/GJ. Stage-wise, feedstock supply chain is identified as the primary contributor to GHG emissions of bioenergy, accounting for at least 60% of total process emissions. This is because harvest sites of forestry resources are in remote areas in northern BC, far away from populated cities in the south. Besides feedstock, secondary GHG source varies for different bioenergy options. For CHP, HB and PG options, CH_4 and N_2O emissions from flue gases of biomass combustion account 10-20% of process GHG emissions, whereas GHG emissions from other production stages are negligible; however, these emissions are offset by the avoided emissions (shown in Figure 3.2(a)). Meanwhile, intensive energy and material consumption during conversion processes of HTL, MeOH, EtOH, and RNG options can contribute up to 20% of process GHG emissions. Tailpipe GHG emissions also contribute 10-20% to process GHG emissions of liquid biofuel options. Lastly, the energy distribution and waste disposal stages have limited GWP impact.

kg CO2-eq/GJ
a. Global Warming Potential
100
80
60
40
20
0
-20
-40
HTL
RPPs
MeOH
Fuel oil
EtOH
Gasoline
RNG
NG
CHP
NG + Elec
HB
NG
PG
Elec
End-use
Avoided Slash burning
Baseline upstream
Distribution
Waste disposal
Conversion
Feedstock transport
Feedstock processing
kgC2H3Cl-eq/GJ
b. Human Toxicity
10
5
0
-5
-10
-15
c. Respiratory Inorganics
kg PM2.5-eq/GJ
0.3
0.25
0.2
0.15
0.1
0.05
0
-0.6
-1.2



HTL = Hydrothermal Liquefaction, MeOH = Methanol, EtOH = Ethanol, RNG = Renewable Natural Gas, CHP = Cogeneration, HB = Heat-only Boiler, PG = Power Generation. RPP = Refined Petroleum Product, NG = Natural Gas

Figure 3.2 Environmental impacts per GJ bioenergy produced from forestry waste materials, in comparison with the baseline energy

Conversion of forestry waste materials to bioenergy can avoid GHG emissions generated by slash burning, dominantly CH_4 emissions. As shown in Figure 3.2(a), GWP credit from avoided slash burning can entirely offset process GHG emissions from biofuel production, resulting in net negative GHG intensities of all biofuel options. As a result, most bioenergy options are substantially lower in GHG intensities than their baseline energy counterparts. HTL, MeOH, and EtOH options can reduce GHG emissions by nearly 80 $kgCO_2$-eq/GJ by replacing refined petroleum products (RPPs), or at least 60 $kgCO_2$-eq/GJ without the avoided burdens from slash burning. The substitution of natural gas by HB and RNG can reduce GHG emissions by about 65 $kgCO_2$-eq/GJ with avoided slash burning accounted, or about 50 $kgCO_2$-eq/GJ without. On the other hand, BC's electricity mix dominated by hydropower has a critical effect on the net GWP of power generation from biomass: PG alone does not have any GHG benefits, but the CHP option can still mitigate GHG emissions by 30-40 $kgCO_2$-eq/GJ, owing to the displacement of natural gas by heat cogenerated.

3.3.2 Human toxicity and respiratory inorganics

Human toxicity (HT) is mostly due to hazardous organic emissions and heavy metals. In Figure 3.2(b), HT impact per GJ bioenergy and stage-wise contributions are illustrated. For all bioenergy options, the waste disposal stage is identified as the primary contributor to HT, due to the accumulation and disposition of heavy metals in wood ashes. Consumption of diesel during feedstock collection and transportation processes and combustion of biomass and refined biofuels also cause HT impact by emitting hazardous organic gases. All bioenergy options have substantially higher HT impact than baseline energy when avoided slash burning is not taken into account. However, because slash burning generates a significant amount of organic emissions such as benzene and polycyclic aromatic hydrocarbons (PAH) due to incomplete combustion, bioenergy production from forestry waste materials can avoid these emissions and lead to substantial environmental benefit in HT.

Respiratory inorganics (RI) results from inorganic air emissions. As shown in Figure 3.2(c), the primary source of bioenergy's RI impact is identified as PM and NOx emissions generated from the processing of forestry waste materials and the combustion of biofuels. Note that the results for CHP and HB options represent the case where PM and NOx control devices are already employed.

Feedstock transport is identified as the secondary contributor to RI for all bioenergy options. However, RI generated from these bioenergy life cycle stages is entirely outweighed by avoided burdens of slash burning: slash burning generates intensive PM emissions due to incomplete, open-air combustion (Note the difference in scale for avoided burdens in Figure 3.2(c)). Consequently, bioenergy production from forestry waste materials can generally achieve substantial environmental benefits and thereby reduce RI impacts below those for baseline energy. Methanol (MeOH) can achieve additional environmental benefits in RI by avoiding intensive acid gas emissions generated from the combustion of fuel oil as marine fuels.

Additionally, it is to be noted that emissions discharged to more populated areas impose a higher likelihood of human exposure and thus more severe health risks, which is why the public pays closer attention to health impacts of the end-use stage of bioenergy, i.e. combustion of solid biomass and derived biofuels. Even with NO_X reduction by SCR and PM reduction by electrostatic precipitation, the CHP and HB options still generate higher emissions and therefore additional health impacts than natural gas combustion from the end-use stage. As a result, while bioenergy production from forestry waste materials can avoid health hazards generated by wildfires and slash burning, biomass heating options can cause higher health risks in populated areas and may receive stronger public resistance. Such contradiction goes beyond the scope of LCA due to its spatial and temporal limitations. Therefore, the results derived from the LCA should not be interpreted as the actual impacts caused; instead, they should only be taken as indicators of potential hotspots for health risks. This calls for future study employing health impact models incorporating spatial, temporal, and population factors (see further discussion in Chapter 6).

3.3.3 Acidification and eutrophication potential

In the case of forestry waste materials, acidification potential (AP) is mainly caused by nitrogen-based emissions, including NH_3 and NOx. Therefore, as shown in Figure 3.2(d), the result for AP is close to that for RI, due to NH_3 and NOx emissions generated in the conversion and end-use stages of bioenergy and avoided from slash burning.

Eutrophication potential (EP) results from emissions of nitrogen and phosphorus. As shown in Figure 3.2(e), the result for EP is also similar to that for AP. The only difference is that EP also occurs during the conversion and waste disposal stages of bioenergy, due to emissions of phosphorus. Nonetheless, EP generated from these bioenergy life cycle stages is still outweighed by avoided burdens of slash burning.

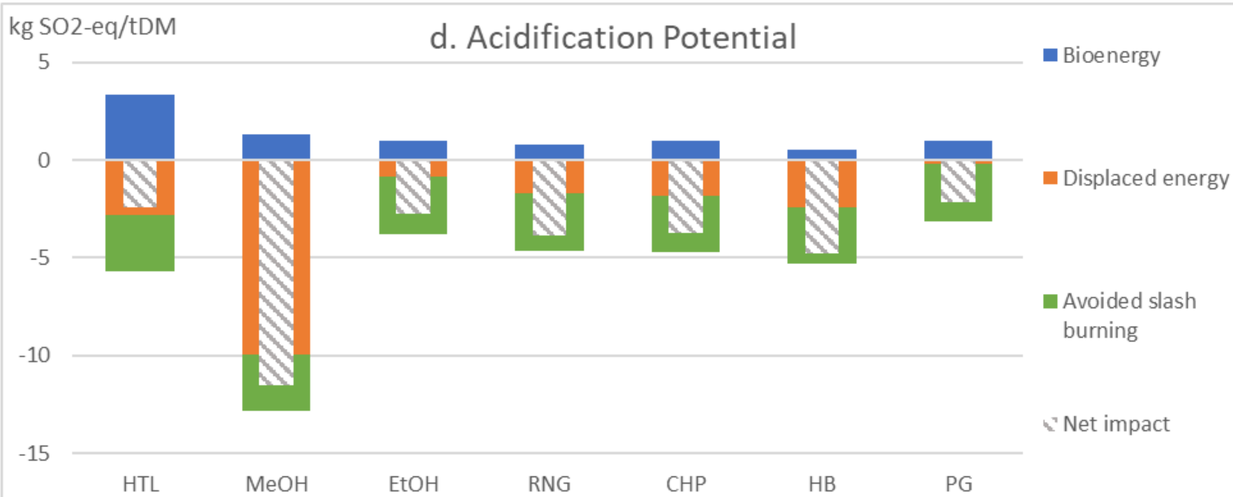
3.3.4 Environmental impacts per tonne dry matter

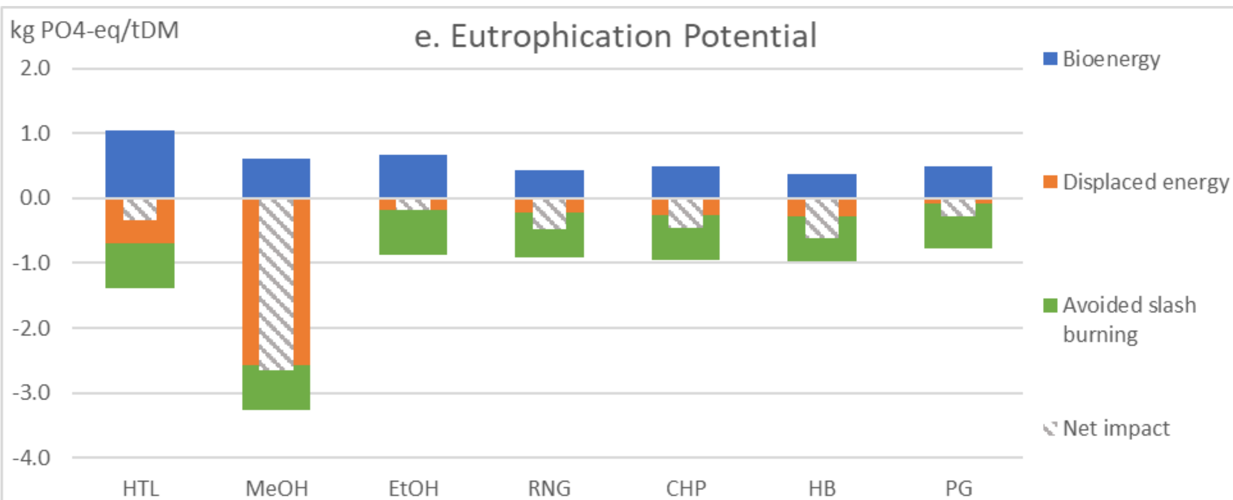
As forestry waste materials are limited in availability, the environmental impacts of bioenergy are evaluated based on the functional unit of per tDM feedstock. As shown in Figure 3.3(a), HB has the highest GWP benefit per tDM feedstock out of all bioenergy technologies investigated. This ranking substantially differs from that shown in Figure 3.2(a), where HB was shown to have significantly lower GWP benefits per GJ bioenergy than liquid biofuel options. This contrast clearly shows how the choice of the functional unit can critically impact the comparison of environmental impacts of bioenergy. Because HB has higher conversion efficiency, any given amount of biomass feedstock can displace more fossil fuels if used for HB, despite lower GWP benefits per GJ bioenergy compared with production of biofuels, which has a generally higher loss of energy due to more complex conversion processes (see Figure 3.1). For the same reason, even though CHP has lower GHG reduction potential per GJ bioenergy output, it demonstrates similar GWP benefits per tDM feedstock as EtOH and RNG options. Therefore, by using the input-based functional unit of per tDM feedstock, the impact of bioenergy conversion efficiencies can be reflected in the comparison of LCA results.

Health impacts, including HT and RI, are shown in Figure 3.3(b) & (c). With process emissions and avoided burdens included, the performance of bioenergy produced from forestry waste materials is dominated by the avoided burdens from slash burning. However, without such credit, most bioenergy options have higher health impacts than the baseline energy, except for the MeOH option, which has significantly lower environmental impacts in RI than its fossil fuel counterpart, i.e. fuel oil. For AP and EP, Figure 3.3(d) & (e) show that similar results to health impacts can be obtained.

In summary, with a limited supply of forestry waste materials, energy efficiency becomes a crucial factor for the overall benefit of bioenergy. Based on our analysis, HB has the best performance in terms of climate change, whereas MeOH has the best performance in health and other local environmental impacts investigated. PG has the worst performance as it has no GHG benefit while failing to show any advantage in other impact categories; however, this refers only to power generation in an area such as BC where the electricity supply has a very low carbon intensity.


a. Global Warming Potential
kgCO2-eq/tDM
400
200
0
-200
-400
-600
-800
-1,000
-1,200
HTL
MeOH
EtOH
RNG
CHP
HB
PG
Bioenergy
Displaced energy
Avoided slash burning
Net impact
b. Human Toxicity
kgC2H3Cl-eq/tDM
100
50
0
-50
-100
-150
-200
HTL
MeOH
EtOH
RNG
CHP
HB
PG
Bioenergy
Displaced energy
Avoided slash burning
Net impact
c. Respiratory Inorganics
kg PM2.5-eq/tDM
2
0
-2
-4
-6
-8
-10
-12
HTL
MeOH
EtOH
RNG
CHP
HB
PG
Bioenergy
Displaced energy
Avoided slash burning
Net impact





HTL = Hydrothermal Liquefaction, MeOH = Methanol, EtOH = Ethanol, RNG = Renewable Natural Gas, CHP = Cogeneration, HB = Heat-only Boiler, PG = Power Generation.

Figure 3.3 Environmental impacts of bioenergy per tDM of forestry waste materials

3.3.5 Sensitivity Analysis

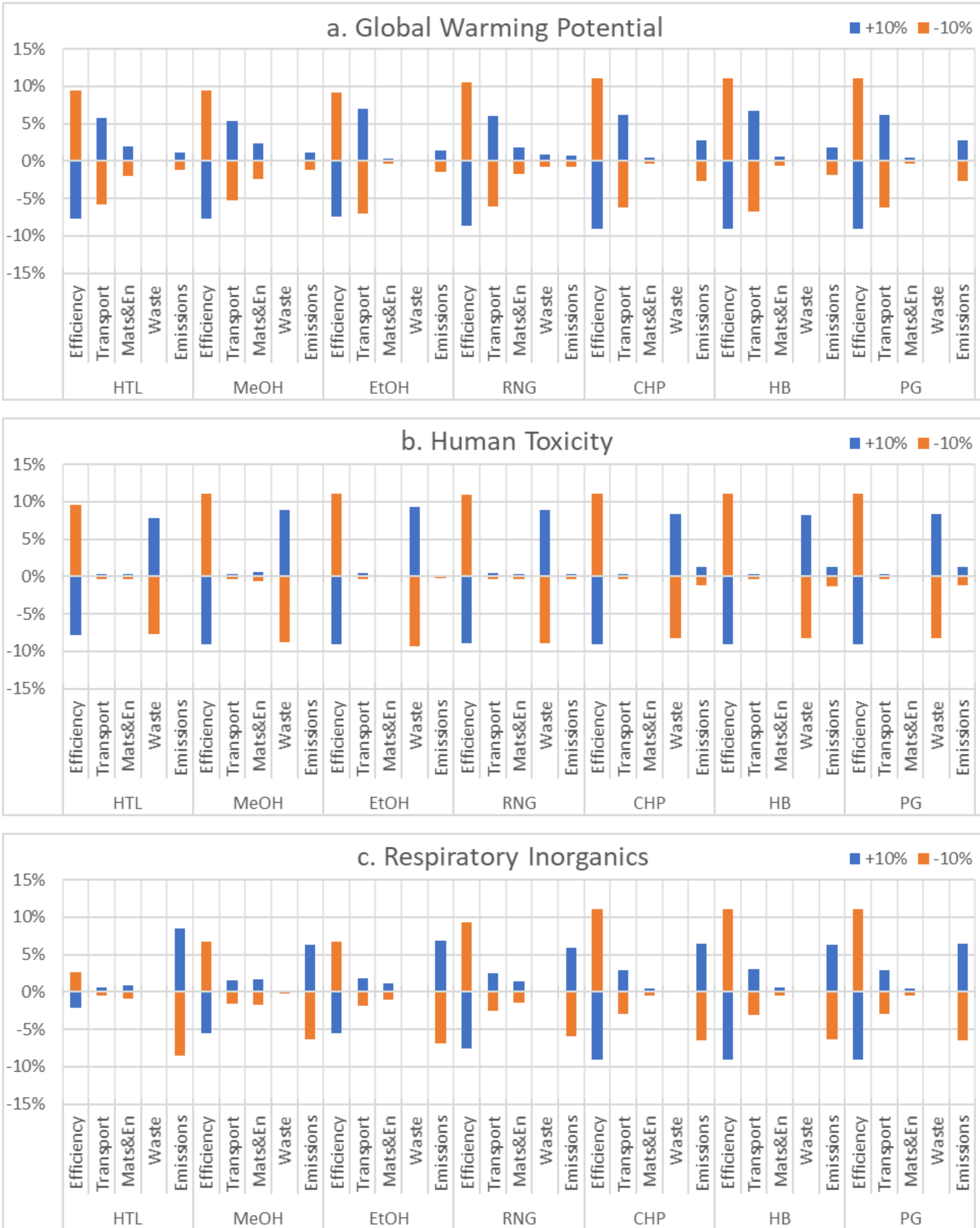
In order to investigate the impact of data uncertainty on environmental impacts of bioenergy produced from forestry waste materials, a sensitivity analysis has been conducted by adjusting the nominal values of key parameters by ±10% (Table 3.10). Note that the analysis explores the sensitivity of process environmental impacts per GJ bioenergy, with avoided burdens from baseline energy and slash burning excluded.

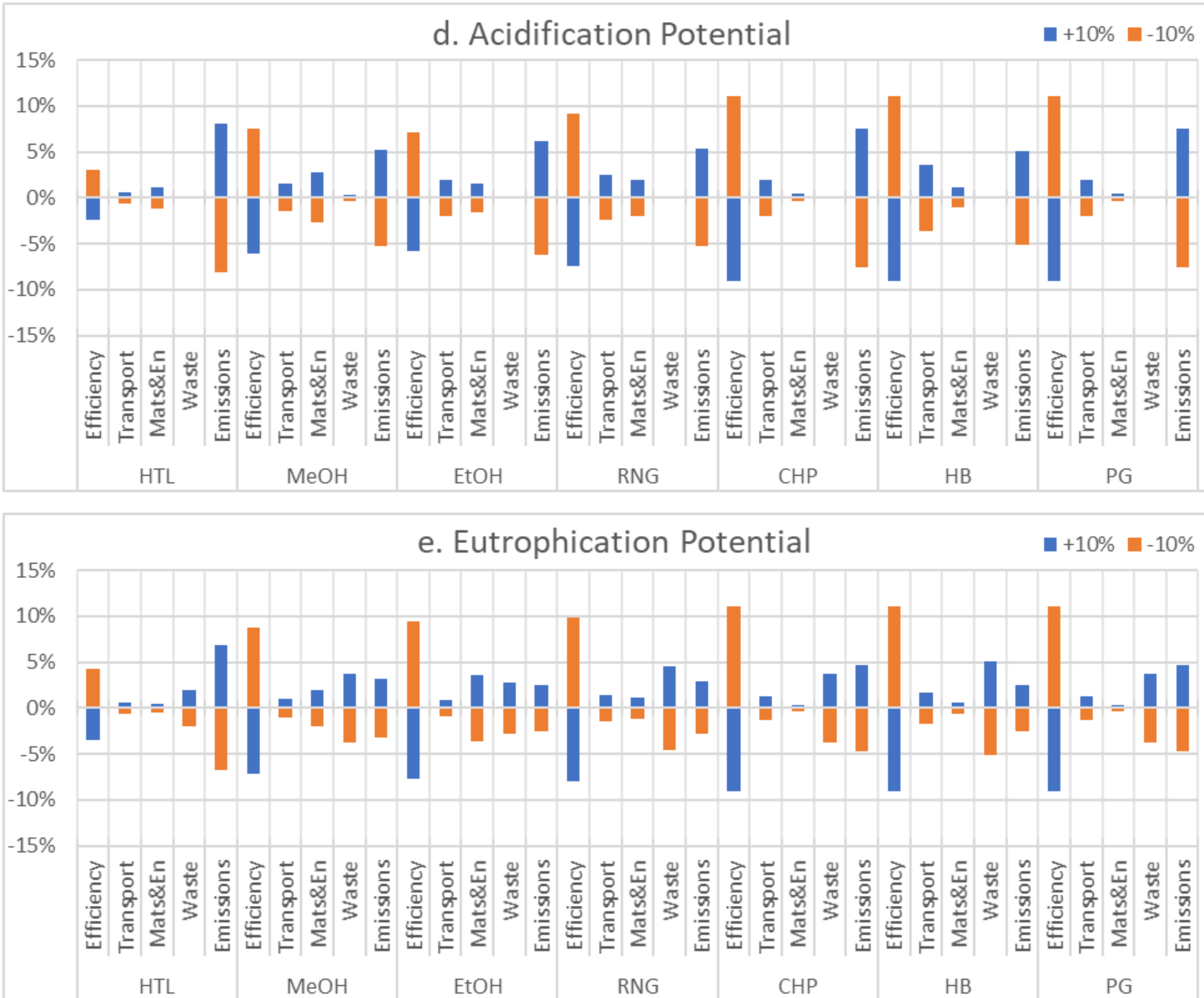
Table 3.10 Parameters used for sensitivity analysis of environmental impacts of bioenergy

Category	Parameter	Abbreviation	Variation
Energy output	Energy conversion efficiency	Efficiency	±10%
Transport	Transport distance of feedstock	Transport	±10%
Process parameters	Material and energy input	Mat&En	±10%
	Waste disposal	Waste	±10%
	Emissions from conversion and end-use	Emissions	±10%

As illustrated in Figure 3.4, the energy conversion efficiency is the most critical factor for all five environmental impact categories. This is because yield improvement can reduce all environmental impacts allocated to each GJ of bioenergy products. Furthermore, as yield improves, bioenergy output produced from each tonne of biomass increases, hence the more fossil fuels potentially displaced. Therefore, technological improvement is critical to improving the environmental performance of bioenergy.

For global warming potential (GWP), transport distance of forestry waste materials is identified as a hotspot, as ±10% change can result in a moderate change of ±5-8% on the results, indicating feedstock supply chain is critical to the GWP benefit of bioenergy. In comparison, other factors investigated show a much lower influence. For health impacts, waste disposal is identified as the hotspot for human toxicity (HT), and end-use emissions are identified as the hotspot for respiratory inorganics (RI). All other factors display low sensitivities (±0-3.0%). For acidification potential (AP) and eutrophication potential (EP), end-use emissions show moderate to high sensitivities, whereas other factors show low-moderate sensitivities.


a. Global Warming Potential
b. Human Toxicity
c. Respiratory Inorganics
+10%
-10%
15%
10%
5%
0%
-5%
-10%
-15%
Efficiency
Transport
Mats&En
Waste
Emissions
HTL
MeOH
EtOH
RNG
CHP
HB
PG



HTL = Hydrothermal Liquefaction, MeOH = Methanol, EtOH = Ethanol, RNG = Renewable Natural Gas, CHP = Cogeneration, HB = Heat-only Boiler, PG = Power Generation.
The bars indicate % change in response to a 10% change in model parameter

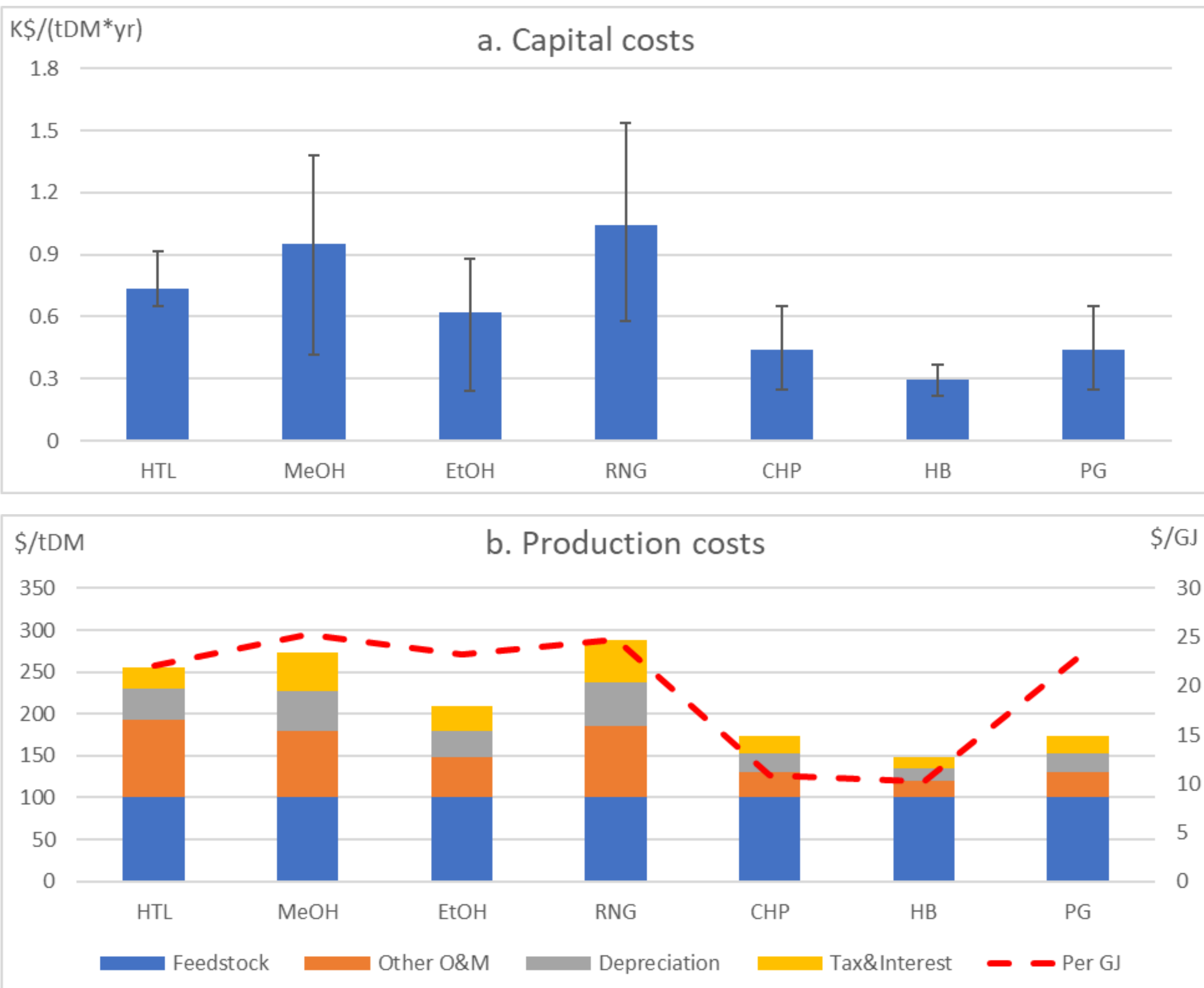
Figure 3.4 Sensitivity analysis on environmental impacts per GJ bioenergy

In summary, the energy conversion efficiency can strongly affect process environmental impacts in all categories, whereas uncertainties in transport distance of feedstock, waste disposal and end-use emissions can significantly affect at least one category. However, environmental impacts of bioenergy are dominated by the avoided burdens from the baseline energy and slash burning, whereas process emissions are insignificant. Therefore, based on the result of the sensitivity analysis, variations in the factors investigated are unlikely to change the conclusion on the environmental benefits of any bioenergy options.

3.4 Costs of bioenergy from forestry waste materials

3.4.2 Capital and production costs

Capital costs of different bioenergy options range from $300 to $1000 per tonne dry matter (tDM) of forestry waste materials processed annually, as shown in Figure 3.5(a). HB has the lowest capital costs per tDM, whereas refined biofuel options such as MeOH and RNG have much higher capital costs, even though there exists a high degree of uncertainty in the data.



HTL = Hydrothermal Liquefaction, MeOH = Methanol, EtOH = Ethanol, RNG = Renewable Natural Gas, CHP = Cogeneration, HB = Heat-only Boiler, PG = Power Generation.

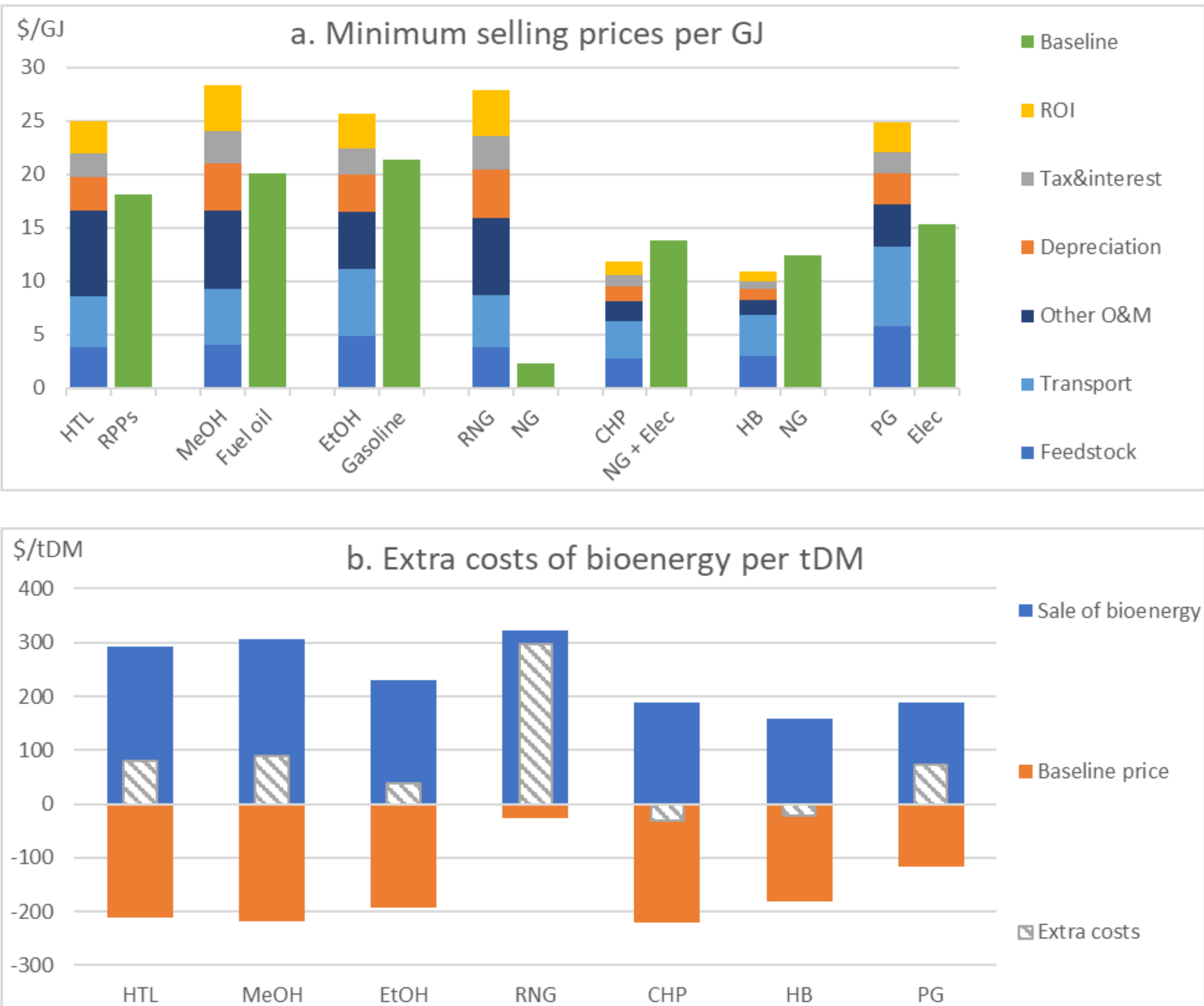
Figure 3.5 Capital and production costs of bioenergy production from forestry waste materials

As shown in Figure 3.5(b), production costs of different bioenergy options range from $150 to $290 per tDM feedstock processed, or $10-25/GJ bioenergy. HB has the lowest production cost per tDM feedstock, closely followed by CHP and PG options. HTL, MeOH, EtOH and RNG options show much higher production costs. This is because these refined biofuel options incur higher O&M costs due to more complex conversion processes, and higher depreciation, interest and tax, which are proportional to capital costs. For all bioenergy options, the feedstock cost, including raw material acquisition, processing and transportation, is identified as the largest expense. Even though forestry waste materials have low merchantable value, the delivered cost is greatly magnified by long-distance transportation. In terms of production costs per GJ bioenergy, HB and CHP are the lowest ($10-11/GJ), due to their advantage in energy conversion efficiency. Production costs of other bioenergy options are substantially higher, ranging from $22/GJ to $25/GJ.

Note that the feedstock costs for MPB-killed trees, harvest residues, and sawmill residues are estimated to be $106/tDM, $86/tDM, and $110/tDM, respectively; the average cost for forestry waste materials is $100/tDM. This result is slightly higher than the cost range of $70-90/t for forest residues in BC estimated in other studies [97], [174]. As stated in Section 3.1.1, the feedstock supply chain is subject to a high degree of uncertainty, which will be further investigated in the sensitivity analysis in Section 3.4.3.

3.4.2 Minimum selling prices and extra costs

Minimum selling prices (MSPs) of bioenergy per GJ are shown in Figure 3.6(a). MSPs of bioenergy products from HB and CHP, about $11-12/GJ, are the lowest by a significant margin. MSPs of all the other bioenergy options are above $25-28/GJ. When baseline energy prices are considered, HB and CHP are the most economically competitive bioenergy options, with MSPs slightly (<10%) lower than natural gas heating and BC electricity. This means HB and CHP can be profitable at current energy prices in BC. In contrast, MSPs of liquid biofuels are 30-50% higher than the prices of refined petroleum products (RPPs), equivalent to a cost gap of around \$0.30/L fuel. The RNG option has the most unfavourable economic performance, attributable to the low natural gas price of ~\$2/GJ in BC.



HTL = Hydrothermal Liquefaction, MeOH = Methanol, EtOH = Ethanol, RNG = Renewable Natural Gas, CHP = Cogeneration, HB = Heat-only Boiler, PG = Power Generation.

Figure 3.6 Minimum selling prices and extra costs of bioenergy from forestry waste materials

Extra costs per tDM forestry waste materials are defined as the difference between the MSP of bioenergy and the baseline energy price per GJ, multiplied by energy produced from 1 tDM feedstock. Extra costs indicate additional financial support needed to make bioenergy production from 1 tDM of feedstock profitable. As shown in Figure 3.6(b), HB and CHP have negative extra costs. The following are HTL, MeOH, EtOH and PG options, whose extra costs range from $50/tDM to $100/tDM. RNG option has enormous cost barriers (~$300/tDM) to overcome.

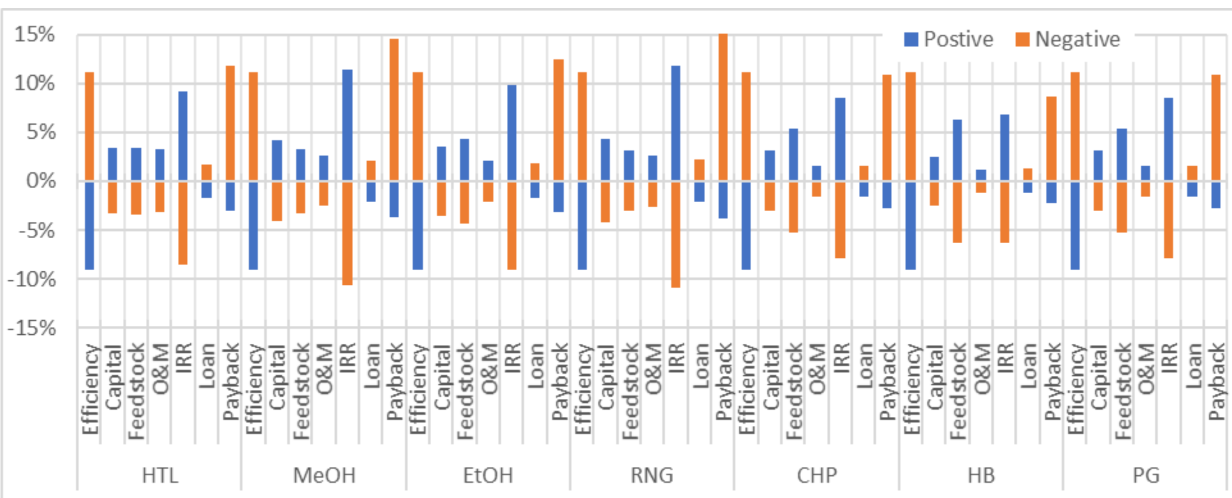
3.4.3 Sensitivity Analysis

Data uncertainties can also potentially affect MSPs for different bioenergy options. Therefore, a sensitivity analysis is conducted on key technical, economic and financial parameters, as summarized in Table 3.11.

Table 3.11 Parameters used for sensitivity analysis of MSPs of bioenergy

Category	Parameter	Abbreviation	Variation
Technical	Energy conversion efficiency	Efficiency	90: 100: 110%
Economic	Capital cost	CAPEX	90: 100: 110%
	Other O&M cost	OPEX	90: 100: 110%
	Feedstock cost	Feedstock	90: 100: 110%
Financial	Expected internal rate of return	IRR	5: 10: 15%
	Loan financing percentage	Loan	40: 60: 80%
	Expected payback period	Payback	10: 20: 30 year

As shown in Figure 3.7, variations in energy conversion efficiency can significantly affect MSPs of all bioenergy options, because higher efficiency increases yields and thereby lower costs per GJ bioenergy. This underlines the importance of technological improvement for the economic competitivity of bioenergy. Internal rate of return (IRR) and the payback period can also strongly impact MSPs of bioenergy: by increasing expected IRR from 10% to 15% or reducing the expected payback period from 20 to 10 years, 6-14% more profit will be needed to justify the return on investment. The feedstock cost shows moderate to high (±4-7%) influence. However, note that 10% of the feedstock cost of forestry waste materials roughly equals $10/tDM. As future demand for bioenergy increases and more easily accessible resources are depleted, both the merchantable value of forestry waste materials and the transportation distance needed to access resources in remoter areas may increase by far more than 10%, leading to a significant rise in the feedstock cost and thereby MSPs for bioenergy. In comparison, capital and other O&M costs demonstrate low to moderate sensitivities (±2-5%), whereas loan financing shows the lowest sensitivities (<±2%) on the MSPs for bioenergy.



HTL = Hydrothermal Liquefaction, MeOH = Methanol, EtOH = Ethanol, RNG = Renewable Natural Gas, CHP = Cogeneration, HB = Heat-only Boiler, PG = Power Generation.

Figure 3.7 Sensitivity analysis of MSP per GJ bioenergy. Blue bars indicate positive variation, and orange bars indicate negative variation, in % change

3.5 Bioenergy from other lignocellulosic feedstocks in BC

In this section, environmental impacts and economic performances of bioenergy options utilizing other lignocellulosic feedstocks are investigated, specifically unharvested timbers within Annual

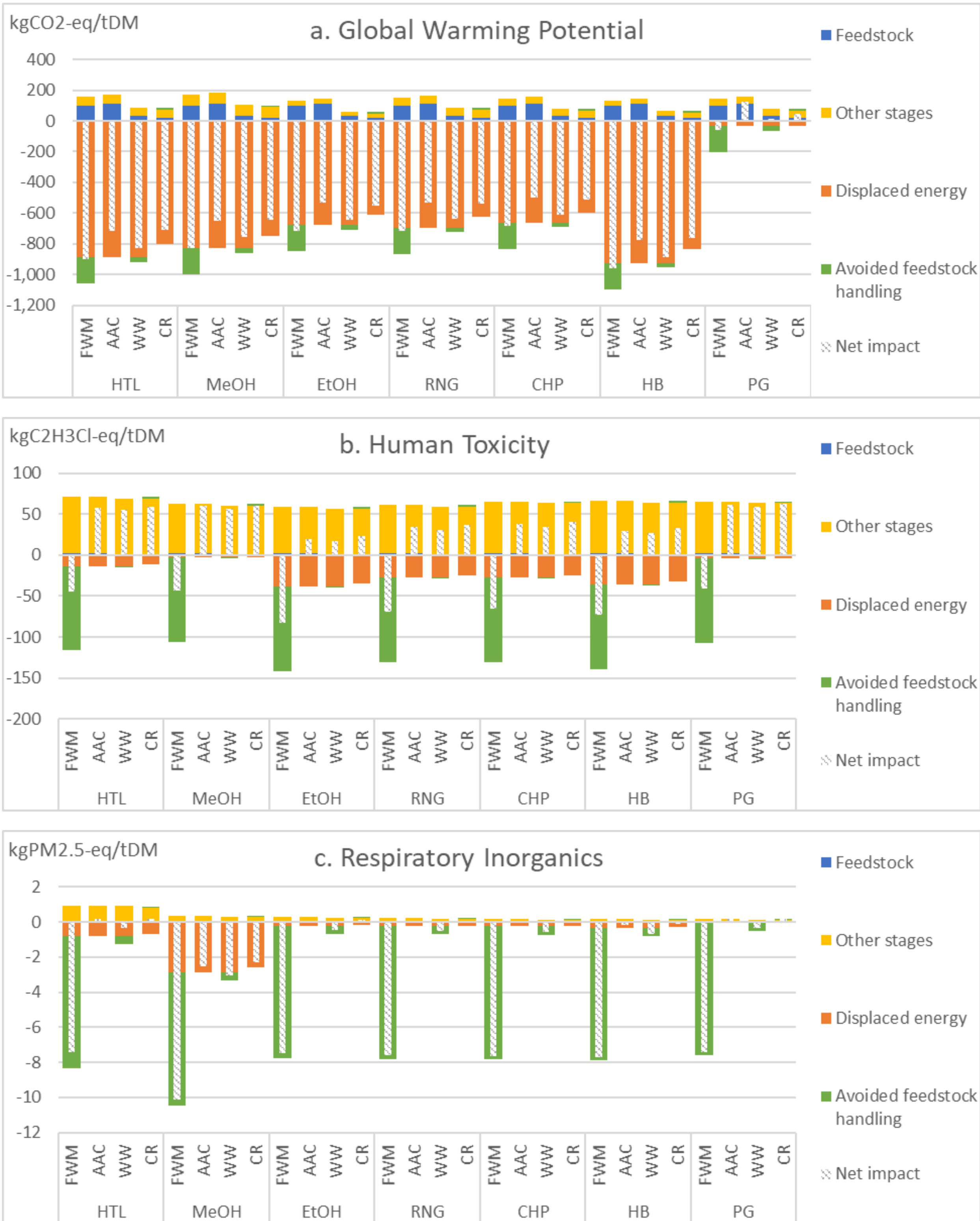
Allowable Cut (AAC), wood waste in municipal solid waste (WW), and crop residues (CR). The LCA model is as described in Section 3.1, and the functional unit is per tonne dry matter (tDM). The economic model is as described in Section 3.2.

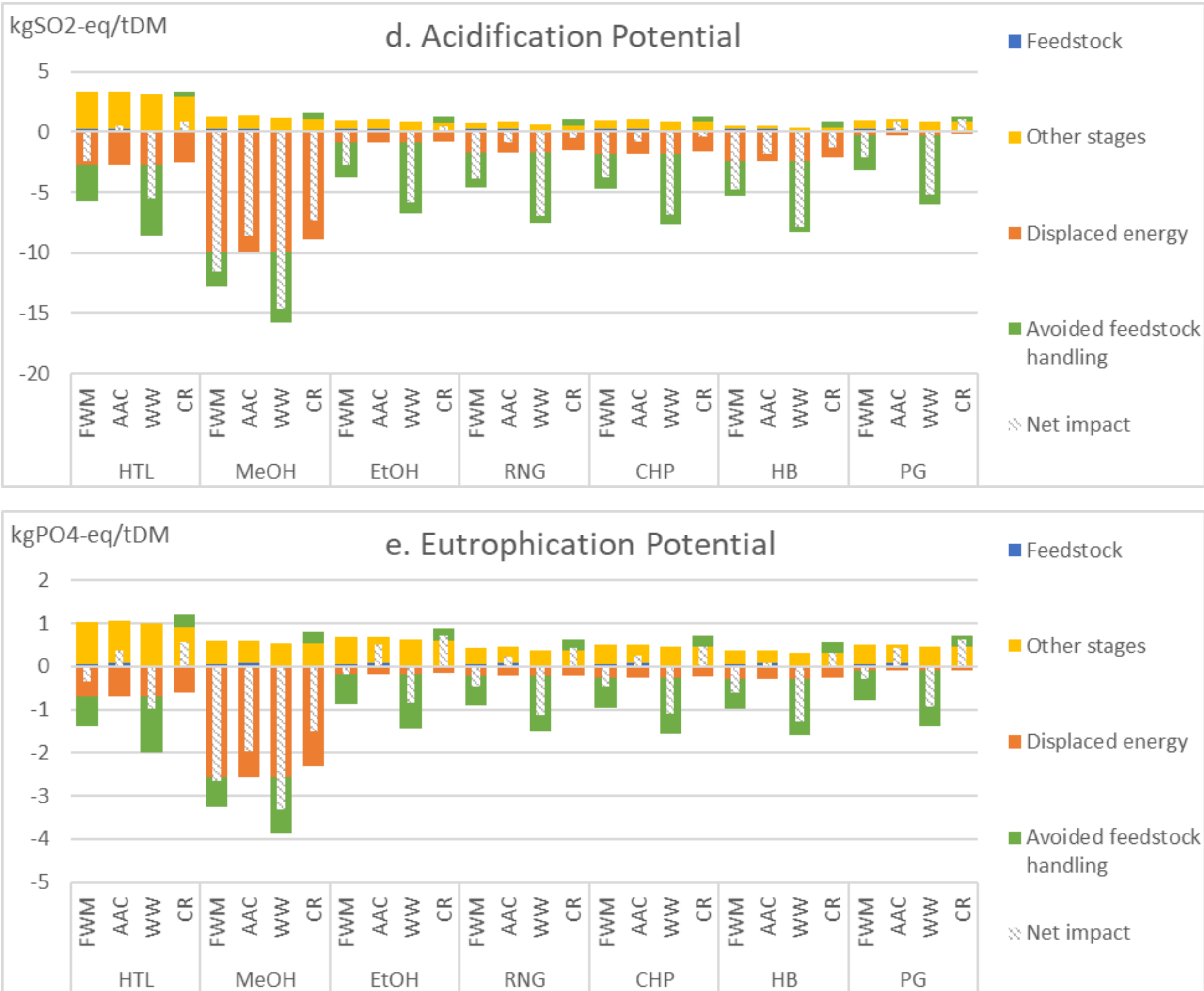
3.5.1 Environmental impacts

Since the same LCA model is used in this section and Section 3.3, all feedstocks differ little in the environmental impacts generated in the bioenergy conversion, distribution, and consumption stages. The main differences lie in the environmental impacts of feedstock supply chains and avoided burdens from conventional feedstock handling practices.

Global Warming Potential

Comparing different feedstocks, it is evident that the supply chain of waste streams, i.e. wood waste and crop residues, has lower global warming potential (GWP) impact than forestry resources, including unharvested timbers and forestry waste materials (Figure 3.8(a)). This is because forestry resources located in remote areas in BC require much longer transportation distance than waste streams. For avoided burdens from conventional feedstock handling, avoided slash burning of forestry waste materials can achieve the highest GHG benefit, whereas GWP impacts from the conventional handling practices of other lignocellulosic feedstocks are limited. In summary, bioenergy production from forestry waste materials leads to the highest GWP benefit per tDM feedstock, followed by wood waste. Bioenergy production from unharvested timbers and crop residues has much lower GWP benefits per tDM feedstock. For each lignocellulosic biomass feedstock, rankings of different bioenergy technologies in the performance of GWP are the same as in Section 3.3: HB generally has the highest GWP benefits per tDM, followed by HTL. PG has no GWP benefits in BC.


kgCO2-eq/tDM
a. Global Warming Potential
400
200
0
-200
-400
-600
-800
-1,000
-1,200
FWM AAC WW CR
HTL MeOH EtOH RNG CHP HB PG
Feedstock
Other stages
Displaced energy
Avoided feedstock handling
Net impact
kgC2H3Cl-eq/tDM
b. Human Toxicity
100
50
0
-50
-100
-150
-200
kgPM2.5-eq/tDM
c. Respiratory Inorganics
2
0
-2
-4
-6
-8
-10
-12



HTL = Hydrothermal Liquefaction, MeOH = Methanol, EtOH = Ethanol, RNG = Renewable Natural Gas, CHP = Cogeneration, HB = Heat-only Boiler, PG = Power Generation.

Figure 3.8 Environmental impacts per tDM of lignocellulosic biomass feedstocks

Other health and environmental impacts

As shown in Figure 3.8(b)-(e), health and environmental impacts, including human toxicity (HT), respiratory inorganics (RI), acidification potential (AP) and eutrophication potential (EP), are dominated by avoided burdens from feedstock handling, whereas impacts from variations in feedstock supply chains are negligible. As a result, avoiding the burdens from the slash burning of forestry waste materials leads to significant benefits in all impact categories. Conversion of wood waste to bioenergy also helps to reduce the impacts of RI, AP and EP by avoiding NH_3 emissions generated by the composting process. On the other hand, bioenergy production from other lignocellulosic feedstocks leads to additional HT and EP impacts in most cases. The exception is conversion to methanol (MeOH), in which case health and environmental benefits can be achieved by replacing fuel oil, such as marine fuels, and thereby reducing acid gas emissions.

3.5.2 Minimum selling prices and extra costs

As shown in Figure 3.9(a), the minimum selling prices (MSPs) of bioenergy products are strongly affected by feedstock costs. For each bioenergy conversion technology, utilization of wood waste always leads to the lowest MSP. This is because processing wood waste can receive waste tipping fees and generate extra revenues. As a result, MSPs of bioenergy produced from wood waste are lower than baseline energy prices in most cases, except for the renewable natural gas (RNG) option. For the rest of the biomass feedstocks investigated, bioenergy production from crop residues is much less costly than from forestry residues, mainly attributed to lower transportation costs. MSPs of bioenergy produced from crop residues are lower than the baseline prices for HB and CHP options, but slightly higher than the baseline prices for refined biofuel options. Bioenergy production from unharvested timbers is the most expensive due to the high merchantable value of the feedstock, showing prohibitive cost barriers relative to baseline energy prices.

Extra costs per tDM lignocellulosic feedstocks are shown in Figure 3.9(b). Note that for wood waste, revenues from tipping fees are excluded from the calculation of extra costs. HB and CHP options generally have negative extra costs and thus show economic competitiveness based on current natural gas and electricity prices in BC, except when unharvested timbers are used as the feedstock. Liquid biofuel options including HTL, MeOH and EtOH can only achieve negative extra costs ($-10/tDM to $-60/tDM) when wood waste is used. For the RNG option, prohibitive cost barriers relative to the baseline energy price of natural gas ($200/tDM to $400/tDM) are found for all feedstocks investigated.

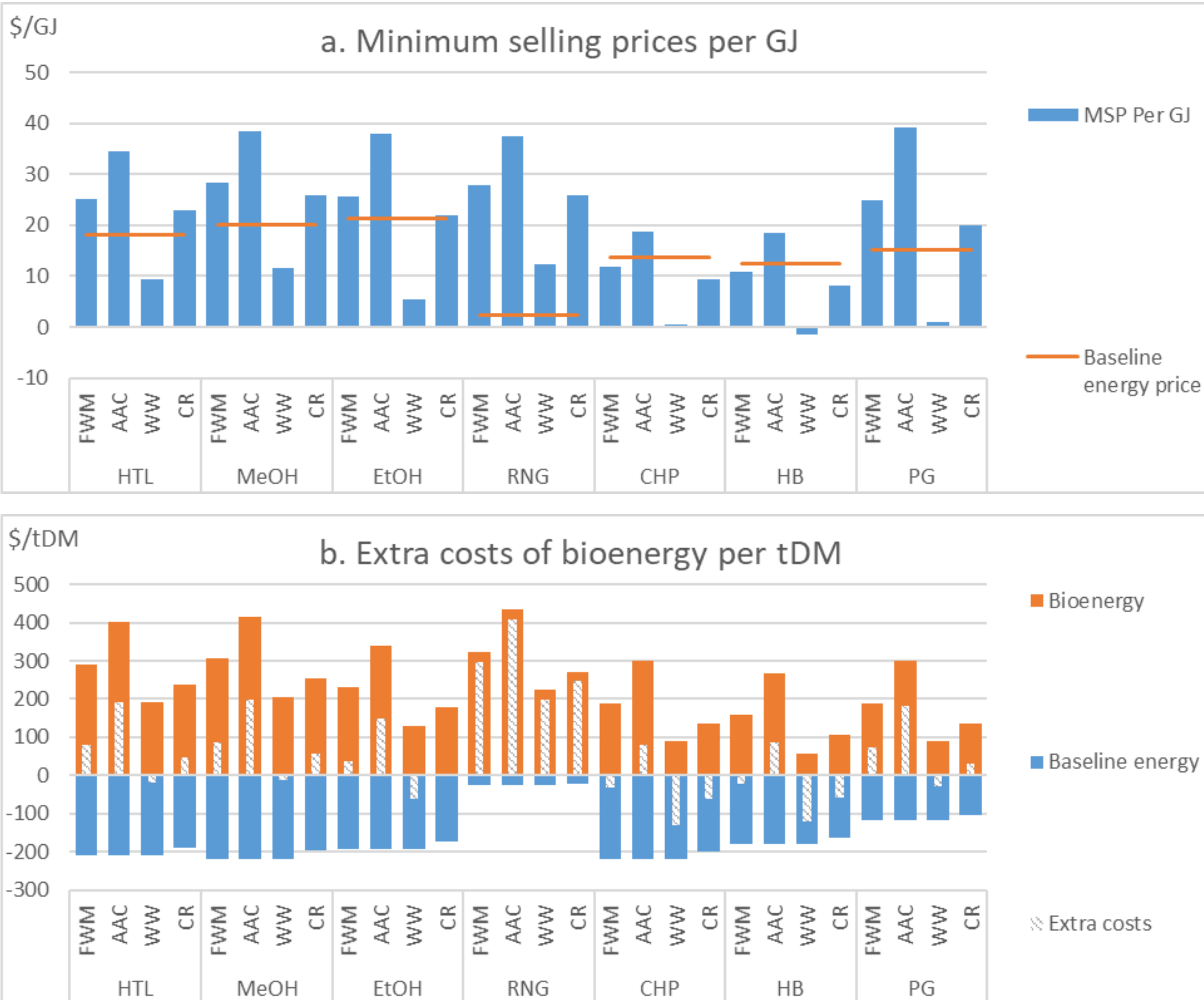


Figure 3.9 Minimum selling prices and extra costs of bioenergy produced from lignocellulosic biomass

3.5.3 GHG reduction costs

The GHG reduction cost is defined as the extra cost of bioenergy divided by the reduction in GHG emissions, which can be regarded as an indicator of cost-effectiveness in GHG mitigation (see Section 1.5.2). As shown in Figure 3.10, GHG reduction costs of bioenergy of various combinations of feedstocks and conversion technologies are calculated, with error bars indicating 20% of uncertainty in process GHG emissions and MSPs of bioenergy. To convert the same feedstock, biomass-fired heating options, specifically HB and CHP, generally show the lowest GHG reduction costs (<\$200/tCO_2). The next bracket consists of liquid biofuel options, including HTL, MeOH and EtOH, whose GHG reduction costs can reach as much as \$300/tCO_2. The RNG option has the highest GHG reduction costs, ranging from \$310/tCO_2 to \$770/tCO_2. Power-only generation is excluded, due to a lack of GHG savings in BC. This result clearly shows that HB and CHP are the most cost-effective way to utilize lignocellulosic feedstocks.

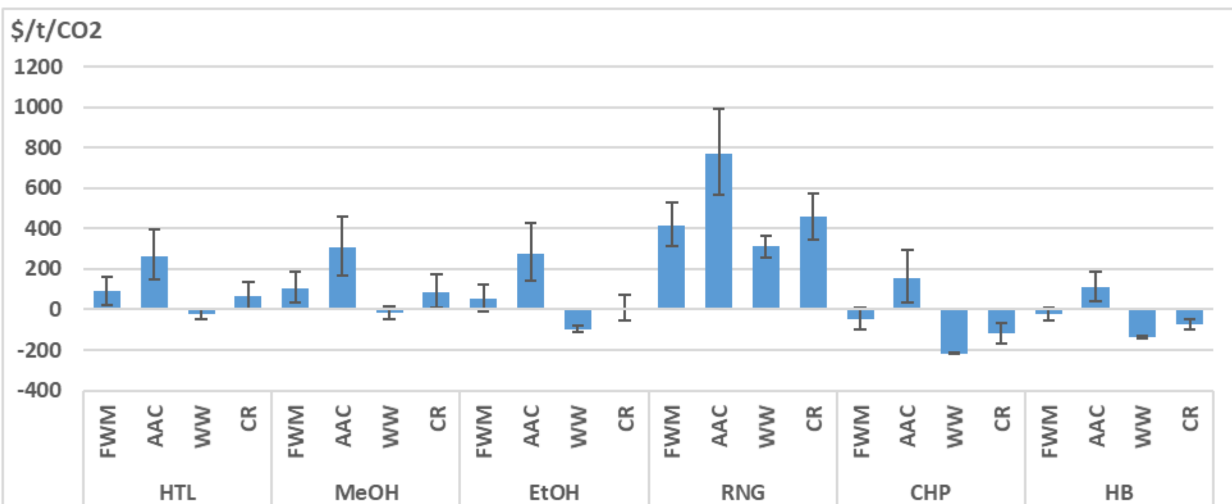


Figure 3.10 GHG reduction costs of bioenergy produced from lignocellulosic biomass resources in BC

GHG reduction costs of bioenergy are also strongly affected by the feedstock costs. For each conversion technology, utilization of wood waste always leads to the lowest GHG reduction costs. This is because the collection and transportation of wood waste are managed by the government and assumed to be free of charge. The following are crop residues and forestry waste materials. GHG reduction costs of bioenergy produced from unharvested timbers within AAC are significantly higher than waste biomass materials. GHG reduction costs of bioenergy produced from lignocellulosic biomass will be further discussed in Section 6.1.3.

3.5.4 Effectiveness of policy support

Figure 3.11 compares financial incentives from current policy measures with extra costs of bioenergy produced from lignocellulosic feedstocks in BC. For district heating options, specifically biomass-fired HB and CHP, standing timbers within AAC are the only feedstock that would lead to extra cost and therefore require financial support. However, there are no policy measures specifically designed to provide financial support to renewable heating options, except for the energy and carbon tax imposed on natural gas consumption. As summarized in Section 2.1.1, the taxation on natural gas is very low in BC, as the provincial government views natural gas as 'clean energy.' Consequently, such low natural gas taxation fails to provide sufficient incentive to promote biomass-fired heating options using premium forest resources.

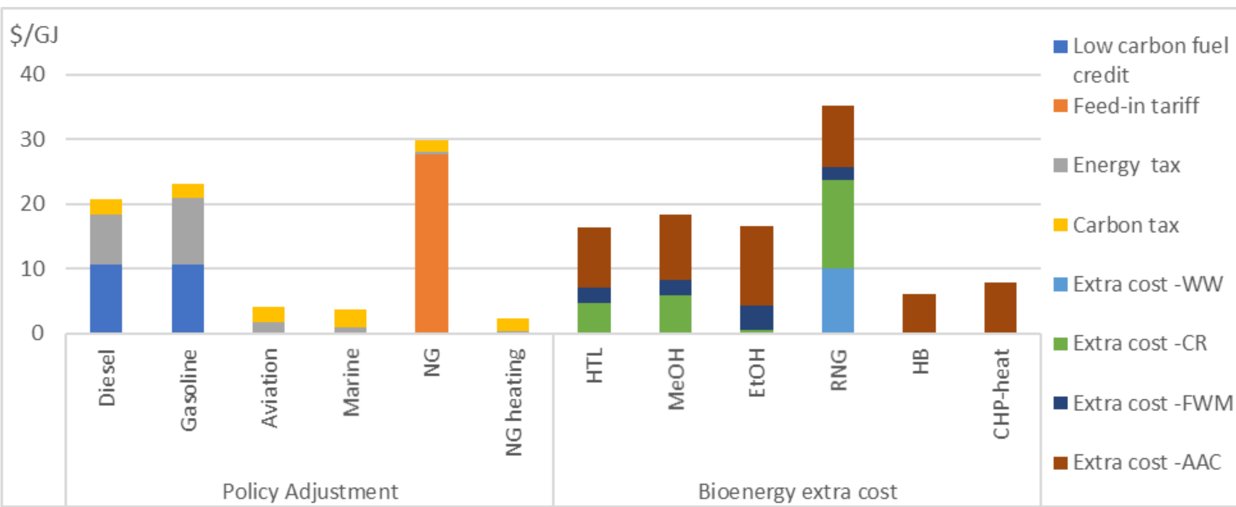


Figure 3.11 Policy incentives in BC vs extra costs of bioenergy

Production of liquid biofuels from crop residues, forestry waste materials and unharvested timbers are also associated with extra costs. For gasoline and diesel, BC's Low Carbon Fuel Standard provides a GHG reduction credit trading mechanism, with the current trading price of \$170/tCO_2 [114]. This incentive alone can sufficiently cover the extra costs of liquid biofuels produced from crop residues and forestry waste materials and used for land transportation. Meanwhile, provincial motor fuel tax and federal excise tax add up to $7.9/GJ for diesel and $10.2/GJ for gasoline. Even though liquid biofuels are currently not exempt from these taxes, tax exemption could potentially provide a legislatively simple mechanism to promote liquid biofuels produced from premium forest resources. For aviation or marine transportation, however, there is no policy measure to incentivize the use of liquid biofuels at present. Meanwhile, tax rates for aviation and marine fuels are very low, extending to tax exemption for international uses [110]. Therefore, additional supportive policy measures will be needed to close the cost gap of liquid biofuels used for aviation or marine transportation.

RNG produced from all lignocellulosic feedstocks, even the cheapest one, leads to extra cost, due to currently low natural gas prices. Currently, Fortis BC offers a renewable natural gas purchasing price of up to $30/GJ, in addition to carbon tax credits [123]. As shown in Figure 3.11, the combined financial support from policy measures is enough to make RNG produced from wood waste, crop residues, and forestry waste materials economically viable, but still fails to cover the extra costs of RNG production from premium forest resources.

3.6 Conclusion

Most bioenergy options investigated in this chapter can effectively reduce GHG emissions in BC, by converting available biomass into various bioenergy products and displace fossil fuels intensively consumed in the province. Liquid biofuel options, including hydrothermal liquefaction (HTL), thermochemical methanol (MeOH), and ethanol (EtOH), show the highest GHG savings per GJ bioenergy. Power generation (PG) does not have GHG benefits due to the existing low-carbon electricity mix in BC. Meanwhile, biomass-fired heat-only boiler (HB) systems have the highest GHG savings per tonne feedstock processed, attributed to its inherent advantage in energy conversion efficiency. As biomass is a scarce resource, HB is considered the most efficient way that maximizes GHG mitigation.

In terms of other health and environmental impacts, utilization of forestry waste materials shows substantial benefits by avoiding air emission from slashing burning. The MeOH option shows the highest health and environmental benefits by replacing fuel oil as a marine fuel. However, a shared health concern of different bioenergy technologies is the disposal of wood ashes, which are concentrated with heavy metals. Moreover, end-use emissions of NOx and PM from biomass-fired HB and CHP options impose additional health risks, compared with natural gas and the electricity mix in BC.

Economically, bioenergy production from standing timbers is much more costly than various waste biomass materials, specifically forestry waste materials, crop residues, and wood waste in MSW. To convert the same feedstock, biomass-fired HB and CHP have the lowest minimum selling prices, due to advantages in lower capital and operating costs and higher conversion efficiency. Compared with baseline energy prices, biomass-fired HB and CHP show the lowest extra costs and GHG reduction costs and are thus considered the most cost-effective in GHG mitigation. MSPs of biomass-fired HB and CHP using waste biomass materials are already lower than the baseline energy prices. However, biomass-fired HB and CHP using premium forestry resources still require additional financial support to become viable.

On the other hand, liquid biofuel options, including HTL, EtOH, and MeOH, are far less cost-effective than HB and CHP options. Production of renewable natural gas (RNG) from lignocellulosic biomass has the highest extra costs and GHG reduction costs by a substantial margin. Owing to strong financial support from the BC government, liquid biofuels and RNG produced from waste biomass materials are made economically viable. However, the prospect of refined biofuels produced from premium forestry resources is bound with the combined effort from further technology development and stronger policy commitment.

Chapter 4 Anaerobic digestion of agricultural and food waste in BC

Underdevelopment of the AD industry in BC calls for a comprehensive investigation of the environmental and economic performances of AD from various biomass residues in BC, including animal manure, food waste, and crop residues. This chapter sets out such an analysis to facilitate the development of policies and accelerate the exploitation of BC's biogas production potential.

4.1 LCA of AD systems for treating agricultural and food waste

In this chapter, the boundary of AD systems is drawn to include collection, processing and transportation of biomass residues, anaerobic digestion, biogas utilization, and digestate handling. This study focuses on three major environmental aspects of AD: GHG emissions, nutrient loss and health impacts. Therefore, the following impact categories are considered: global warming potential (GWP), acidification potential (AP), eutrophication potential (EP), human toxicity (HT) and respiratory inorganics (RI). The functional unit is defined as 'per tonne dry matter of organic material as feedstock to anaerobic digestion'.

4.1.1 Feedstock and scenarios

Four main types of biomass residues are considered for AD: cattle manure (CM), poultry manure (PM), food waste (FW), and crop residues (CR). The availability (in tonne dry matter, tDM) and characteristics assumed for these biomass residues are summarized in Table 4.1. Pig manure accounts for only 1% of animal manure generated in BC and is neglected here.

Table 4.1 Availability and characteristics of biomass residues in BC

AD Feedstock	DM (%)	Availability (,000 tDM)	Biogas yield (GJ/tDM)	N (kg/tDM)	P (kg/tDM)	K (kg/tDM)
Cattle manure [175]	13	765	6.2	49.0	7.9	28.9
Poultry manure [176]	36	1511	6.2	60	21	26
Food waste [177]	30	219	12.4	31.6	5.2	9.0
Crop residue [178]	80	407	7.1	8.0	1.5	12.0

For each feedstock, four scenarios are developed, representing different options to treat organic waste and utilize biogas (Table 4.2).

Table 4.2 Scenarios for AD of biomass residues in BC

Scenario	Description
Base	No anaerobic digestion
RNG	Biogas upgraded to RNG for grid injection
CHP	Biogas combustion for cogeneration
HB	Biogas combustion for heat-only boiler

In the Base scenario, no AD is implemented, and waste management is business-as-usual. In the RNG scenario, biogas is upgraded to renewable natural gas and injected into the BC natural gas grid. In the CHP scenario, biogas is combusted for cogeneration of heat and power (CHP). Heat is supplied to nearby users, and electricity is injected into the BC power grid. In the HB scenario, only heat is generated from biogas combustion.

4.1.2 Base scenarios

In this chapter, conventional waste management practices are set up as base scenarios against which the avoided burdens of biogas scenarios are assessed. This is because the environmental impacts of these waste streams comprise many components, including direct emissions, energy consumptions, and their own avoided burdens for displacing inorganic fertilizers. Setting up base scenarios helps to illustrate the contribution of each component clearly.

Manure storage and spreading

It is assumed that cattle and poultry manure are stored in covered tanks. Electricity consumption of cattle and poultry manure storage is assumed to be 0.375kWh/tonne fresh matter (tFM) [42]. Manure is then assumed to be transported to crop fields by tractors for 4 km (including return trip). Diesel consumption for spreading is assumed to be 9.9 MJ/tFM [179]. 5% of total nitrogen is lost as NH_3 volatilization at livestock barns before manure is collected and stored [180].

Nitrogen loss rates and utilization efficiencies are influenced by nutrient management practices and are thus highly uncertain. For example, the NH_3 volatilization rate from uncovered storage and direct spreading of manure can typically reach 50% [146], [181], but can be reduced to less than 10% by soil incorporation [180], [182]. Meanwhile, substantial nitrate (NO_3^-) leaching occurs when there is rainfall right after fertilization or positive soil nitrogen balance after harvest [183], so nitrate leaching rate in spring is found to be much smaller than fall [181]. In this study, conservative values for conventional practices are used, as shown in Table 4.3. It is assumed that 8% is lost as NH_3 volatilization during manure storage [146], and the rest is applied to the field. After manure spreading, 42% is lost as NH_3 volatilization [146], 20% is lost as NO_3^- leaching [181], [184], and a smaller amount is lost due to denitrification process [183], [185], in various other forms including N_2O, NO and N_2. Lastly, according to IPCC protocol, 1% of volatilized NH_3 and 0.75% of leached NO_3^- are converted to indirect N_2O emissions [186]. For phosphorus and potassium, the utilization rate of 80% is assumed [187]. Emission factor (EF) of phosphorus leaching is assumed to be 0.39% [188], and K loss is neglected. The emission factor for CH_4 is estimated using IPCC guidelines [185].

Table 4.3 Emission factors from biomass residues, digestate and synthetic fertilizers

	CM	PM	FW	CR	LD	SD	Syn N	Unit
CH4	15.4	1.6	6.1	0	0	11.9	0	kg/tDM
NH_3, pre-app	8%	8%	50%	0%	8%	30%	0%	kg N/Total N
NH_3, post-app	42%	42%	3.3%	3.3%	42%	3.3%	6%	kg N/Applied N
N_2O, direct	2%	2%	1%	1%	1%	1%	1%	kg N/Applied N
N_2	9%	9%	9%	9%	9%	9%	9%	kg N/Applied N
NO_3^- leaching	20%	20%	3%	3%	15%	20.8%	10%	kgN/ Applied N
NO	21%	21%	21%	21%	21%	21%	21%	kgN/N_2O-N
N_2O, indirect	1%	1%	1%	1%	1%	1%	1%	kg N/NH_3-N
N_2O, indirect	0.75%	0.75%	0.75%	0.75%	1%	1%	0.75%	kg N/NO_3-N
N uptake	29%	29%	42%	84%	34%	59%	74%	kg N/Applied N

* CM = cattle manure, PM = poultry manure, FW = food waste, CR = crop residues, LD = liquid digestate, SD = solid digestate, Syn N = synthetic nitrogen fertilizer

Food waste composting

Food waste is assumed to be collected by HDV over a radius of 15 km [90]and then the loaded HDV travels 50 km to a composting site. Diesel consumption for food waste composting is assumed to be 5.64 L diesel/tFM[189], with other consumptions negligible. CH_4 and NH_3 emissions from food waste composting are found to be substantial [189], [190]. As shown in Table 4.3, CH_4 emissions are assumed to be 1.83 kg/tFM, and NH_3 emissions are assumed to be 50% of total N. Finished compost is then transported over 10 km to consumers. Nitrogen loss rates from field application of compost are found to be small [184].

Crop residue incorporation

Conventionally, crop residues are incorporated into the field to increase soil fertility. Diesel consumption of field incorporation is estimated to be 4.1 L diesel/tFM [106]. Nutrient loss rates from incorporated crop residues are assumed to be the same as compost (Table 4.3).

4.1.3 Anaerobic digestion

The system and boundary of anaerobic digestion of organic wastes are shown in Figure 4.1.

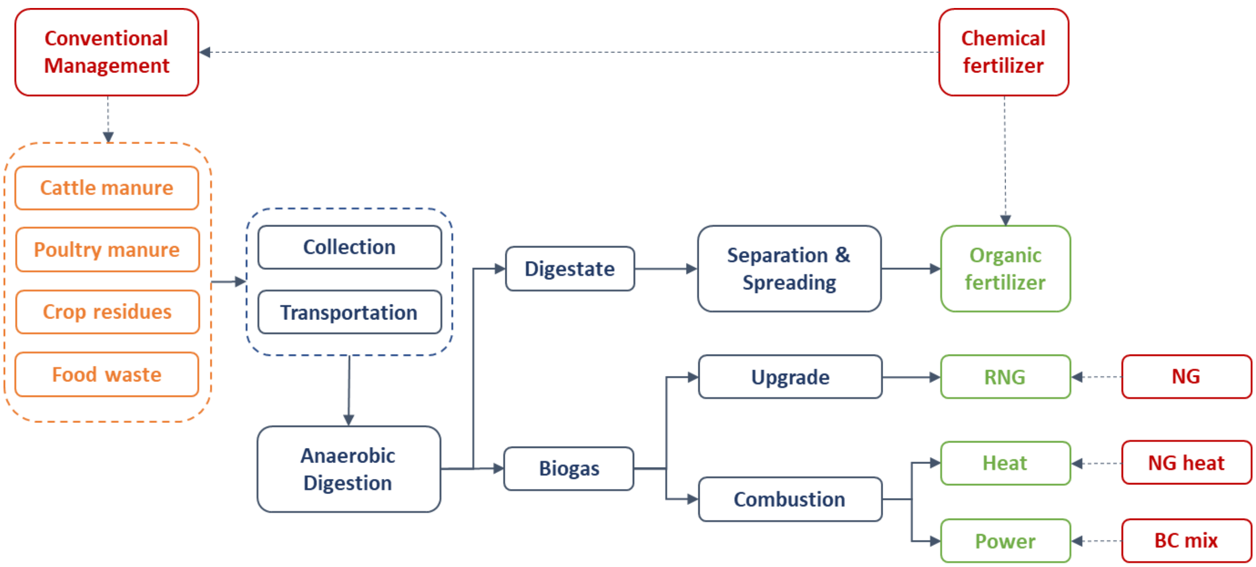


Figure 4.1 The system and boundary of anaerobic digestion of organic wastes

Feedstock supply

Assumptions for the collection and transportation of cattle manure, poultry manure, food waste and crop residues are summarized in Table 4.4. AD systems of animal manure are assumed to be installed on livestock farms, so feedstock transportation is neglected. For other feedstocks, it is assumed that average transportation distance to AD systems is 50 km (including return journey). As these waste materials are generated by human activities, their transportation distances are typically much shorter than those for forestry resources. The impact of these assumptions will be discussed in the sensitivity analyses further in this study.

Table 4.4 Collection and transportation of biomass residues

	Collection	Transportation to AD plant
Cattle manure	Tractor, 2 km	Neglected
Poultry manure	Tractor, 2 km	Neglected
Crop residues	1.6 L diesel/tDM [6]	HDV, 50 km
Food waste	MSW collection, 15 km	HDV, 50 km

NH_3 emissions during the manure collection process are assumed to be 5% of the total nitrogen content [180]. Nitrogen losses occurring during the collection and transportation of food waste and crop residues are neglected.

Pretreatment and anaerobic digestion

Anaerobic digestion is assumed to be carried out in a continuous stirred-tank reactor [47], [90], which operates at mesophilic temperature (35-38 ℃). Conventional liquid-AD technology is employed, which receives feedstock at dry matter (DM) content of 12% [90], [179]. Regardless of feedstock type, the biogas composition is taken as 60% CH_4, 37.9% CO_2, 0.1% H_2S, with the remaining 2% comprising H_2O, N_2 and other negligible trace impurities [42].

Before AD, feedstocks need to be pretreated and sterilized. Pretreatment such as shredding and mixing can improve the homogeneity of feedstock slurry and facilitate digestion [191]. After that, feedstocks are sterilized in a heated and pressurized environment to eliminate pathogens [192]. Total electricity consumption for pretreatment and digestion is assumed to be 33MJ/tFM feedstock. Additional electricity consumption of 33MJ/tFM is needed to shred lignocellulosic feedstocks such as crop residues [47], [90]. The heat required to maintain digestor temperature is assumed to be 110 MJ/tFM [47], [90], which is supplied by natural gas/biogas combustion at 90% boiler efficiency. Air emissions from AD are limited if the system is enclosed and maintained correctly. CH_4 and H_2S emissions are assumed to be 1% of the total biogas generated [89]. Biogas yields of cattle manure, poultry manure, food waste and crop residues are assumed to be 6.2, 6.2, 12.4 and 7.1 GJ/tDM, respectively [47] (Table 4.1).

Biogas cleaning and utilization

Biogas can be upgraded to renewable natural gas (RNG) for grid injection, by removing CO_2, H_2S and other impurities. It is assumed that a biological H_2S removal system is employed to reduce equipment corrosion and pollution [193], [194]. Meanwhile, CO_2 is assumed to be removed by a water scrubber system. In RNG scenarios, electricity consumption for the biogas upgrading process is estimated to be 0.9 MJ/m3 biogas [195]. Material consumption is neglected.

Biogas can also be directly combusted to generate electricity, heat, or both. H_2S removal is still needed. However, CO_2 removal can be spared to save energy consumption and cost. Thermal energy harnessed via direct combustion can be utilized either in a CHP unit for cogeneration, or in a heat-only boiler (HB) to provide heating service. CHP efficiency, defined as the ratio between energy delivered and biogas HHV, is assumed to be 30% for electricity and 50% for heat. HB efficiency is assumed to be 90% for heat. In both CHP and HB scenarios, electricity consumption for biogas cleaning and utilization is assumed to be 0.0185 MJ/m3 biogas [194], and material consumption is neglected.

During the biogas upgrading process, there is an additional 1% of CH_4 loss, on top of 1% fugitive emission from biogas production [89]. For biogas combustion, emission factors of CO, NOx and

NMVOC are 0.115, 0.148 and 0.105 kg/GJ HHV biogas, respectively [196]. Other emissions are considered the same as natural gas combustion, taken from the Ecoinvent database [106]. Differences between the distribution and consumption of RNG and natural gas are neglected.

Digestate Separation, transportation and spreading

Total digestate weight is derived from the mass balance of feedstock input and biogas output. Digestate is mechanically separated by a screw press separator into a liquid and a solid phase, which is assumed to have an electricity consumption of 10MJ/tFM digestate [47]. Partition of nutrients between liquid digestate (LD) and solid digestate (SD) is based on digestate characteristics reported from 13 biogas plants in Italy [197]. LD is rich in soluble N and K, which can substitute synthetic fertilizers in both hydroponic and field application without yield losses [50], [198]. SD can also be used as organic fertilizer, as it is rich in N, P and organic matter [50]. However, SD still contains active microorganisms and will continue to generate CH_4 and odour if improperly handled. Therefore, it is assumed that SD is dried and composted before any application. During this process, 30% of total nitrogen is lost as NH_3 volatilization, and the rest is transformed into organic and nitrate form and stabilized [199], [200]. Emissions of CH_4 and N_2O from the SD composting process are assumed to be the same as from manure composting [201] (Table 4.3). Energy consumptions for loading, transport and spreading of liquid and solid digestate are shown in Table 4.5.

Table 4.5 Characteristics and energy consumption for liquid and solid digestate

	DM [50], [197] (%)	N [50] (%)	Loading (MJ/tFM)	Transport (tractor, km)	Spreading (MJ/tFM)
Liquid Digestate	4.5-5.5	4.0-5.1	3.9	4	17
Solid Digestate	21-22	4.6-6.5	7.8	4	14

The use of digestate as fertilizers can reduce the use of synthetic fertilizers. As AD retains the nutrient elements in the feedstock, nutrient loss during AD is neglected. The use of digestate generates gaseous nitrogen emissions, as well as leaching of nitrate and phosphorus into groundwater. Because AD breaks down organic nitrogen into inorganic forms [50], digestate is higher in nutrient absorbability than untreated organic waste but has a greater tendency for NH_3 volatilization [146], [182]. Many studies compared the NH_3 volatilization rate between untreated manure and digestate, and conflicting results have been reported [181], [182]: NH_3 volatilization from digestate is not necessarily less than from untreated manure, and is highly dependent on proper management practices such as covered storage and soil incorporation. In this study, NH_3 volatilization from LD is taken as the same as from manure. However, LD does slightly reduce N_2O emissions [186] and nitrate (NO_3^-) leaching [184], and ultimately improves nutrient utilization efficiency [181]. Emission factors of composted SD are assumed to be the same as composted food waste and field-incorporated crop residues (Table 4.3).

Note that the emission factors of the use of organic fertilizers are dependent on soil types, climate conditions and management practices and therefore subject to a high degree of uncertainty. As a result, it is difficult to judge whether the use of digestate has lower emission factors than the use of undigested waste unless site-specific data are available. The impact of this uncertainty will be discussed in the sensitivity analysis further in this chapter.

4.1.4 Environmental impact of natural gas, BC electricity mix, and fertilizers

Renewable natural gas produced in the RNG scenario will replace natural gas. Heating service produced by HB will also replace natural gas (at 90% boiler efficiency). CHP scenarios will displace the BC electricity mix and natural gas used for heating. Biomass used directly for district heating will also replace natural gas. Burdens avoided by replacing natural gas and BC electricity mix are based on the Ecoinvent database [106], as shown in Table 4.6. NPK fertilizers replaced by the use of organic waste and digestate are represented by urea, mono-ammonium phosphate and potassium chloride, respectively, whose environmental impacts and nutrient loss rates are based on the Ecoinvent database [106], [202].

Table 4.6 Environmental impacts and prices of natural gas, BC electricity mix, and synthetic fertilizers

	Natural gas in the grid (GJ)	BC electricity (GJ)	Natural gas for heating (GJ)	N fertilizer uptake (kg)	P_2O_5 fertilizer uptake (kg)	K_2O fertilizer uptake (kg)
GWP (kg CO_2-eq)	6.18E+01	1.69E+01	6.93E+01	9.21E+00	2.09E+00	5.52E-01
AP (kg SO_2- eq)	1.34E-01	1.03E-01	1.58E-01	1.76E-01	2.63E-02	2.92E-03
EP (kg PO_4- eq)	1.48E-02	4.24E-02	2.00E-02	9.55E-02	3.40E-02	1.00E-03
HT (kg C_2H_5Cl- eq)	2.23E+00	1.75E+00	2.59E+00	3.54E-01	1.65E-01	3.53E-02
RI (kg $PM_{2.5}$-eq)	1.71E-02	1.62E-02	2.11E-02	1.69E-02	4.63E-03	5.39E-04
Price (Can$)	2.25	15.3	7.45	1.11	1.13	0.76

4.2 Description of the economic model

This section describes the economic model for estimating capital costs and production costs of farm-scale AD systems, as well as the minimum selling prices (MSPs) of biogas products. All assumptions and simplifications of the economic model are specific to the current BC context, as shown in Table 4.7.

The model is essentially the same as that described in Section 1.5.2 and Section 3.2; however, AD systems are assumed to be subject to a lower corporate tax rate and require faster payback, since farm-scale AD plants are typically small businesses. These assumptions will be examined in the sensitivity analysis in Section 4.4.4, along with uncertainties in the capital and total production costs described in the following section. The annual processing capacity of farm-scale AD systems is assumed to be 1400 tDM, which corresponds to animal manure generated in a large dairy farm with 400 cows and 200 heifers.

Table 4.7 Major parameters and assumptions of the discounted cash flow model for Anaerobic digestion

Parameter	Value
Financing by equity/loan	40%/60%
The interest rate of loan	6.5% annually
Term of loan	10 years
Internal rate of return	10%
Annual inflation rate	2%
Depreciation	CCA Class 43.2 (50% accelerated depreciation)
Plant salvage value	0%
Construction period	3 years (8% Y1, 60% Y2, 32% Y3)
Payback period	10 years
Corporate tax	12% (Small business rate)

4.2.1 Capital costs

Capital costs of farm-scale AD systems mostly depend on the amount and type of AD feedstock and the capacity and utilization option of the biogas produced. The basic equipment costs (BEC) of AD systems include costs for pretreatment, digestion, gas cleaning, digestate separation, storage and biogas utilization systems. Other associated capital cost items include civil work, engineering, and contingency. The model for capital cost estimation is shown in Table 4.8. All costs are converted to 2018 Canadian dollars (Can$), based on exchange rates at the time when data were published and an annual inflation rate of 2%.

Pretreatment, anaerobic digestion and digestate separation

Costs of pretreatment, anaerobic digestion and digestate separation equipment are proportional to the volume of feedstock input. Capital costs per tDM feed are calculated, based on average values from seven farm-scale AD case studies presented by the Cornell Dairy Environmental Systems Program [203]. Capital costs of these case studies are scaled to the capacity of AD systems assumed in this study based on the usual 0.6-power rule:

$$\text{Capital cost}_A = \text{Capital cost}_B \left(\frac{Capacity_A}{Capacity_B}\right)^{0.6}$$

Table 4.8 The model for estimating capital costs of farm-scale AD systems

	Capital cost item	Parameters	Reference
1	Pretreatment + AD	\$287/tDM feed/year	Gooch [203]
2	Gas cleaning	\$97.8/1000m^3 biogas/year	Bailon [194]
3	Digestate separation	\$28.3/tDM feed/year	Gooch [203]
4	Storage		
4.1	Feedstock storage	\$66.0/m^3 FW	Nolan [204]
4.2	Biogas storage	\$93.4/m^3 gas	Nolan [204]
4.3	Liquid digestate storage	\$66.0/m^3 LD	Nolan [204]
4.4	Solid digestate compost site	\$11.4/tFM SD/year	Nolan [204]
5	Biogas utilization		
5.1	Biogas upgrade	\$471/1000m^3 biogas/year	Rotunno [195]
5.2	CHP unit	\$1365/kWe	IEA [205]
5.3	Heat boiler	\$32500	Enahoro [206]
	Basic equipment cost (BEC)	1+2+3+4+5	
6	Civil work	13% of BEC	Karellas [207]
	Total installed cost (TIC)	BEC+6	
7	Engineering	7.5% of TIC	Karellas [207]
8	Contingency	5% of TIC	Karellas [207]
9	Grid connection		
9.1	Natural gas grid	\$250000/system	Werner [102]
9.2	Electricity grid	\$300000/system	Werner [102]
9.3	Heat distribution	\$3.36/GJ	Persson [208]
	Total capital cost (TCC)	TIC+7+8+9	

Storage

Storage tanks are required for feedstock, biogas and digestate. In terms of feedstock, storage costs of animal manure and crop residues are neglected, because livestock farms are normally equipped with storage facilities for these materials. The size of the food waste storage facility required for food waste is designed based on the storage requirement of seven days, as municipal waste is collected weekly. Storage of biogas is assumed for one day's production capacity, as gas storage is expensive. Liquid digestate is stored in tanks for two months, and solid digestate is treated and stored at the compost site before being used.

Gas cleaning and biogas utilization

All biogas options require a gas cleaning system for H_2S removal. The capital cost is based on the biological desulfurization technology developed by the Danish company Biogasclean®, at a capacity of 200 m^3/h biogas [194].

Capital costs of biogas upgrade systems for RNG scenarios are based on a small-scale biogas water scrubbing system [195]. In CHP scenarios, the capital costs of gas-fired CHP units are based on IEA's predicted costs of small-scale CHP units (0.07-6 MW_e) in the year of 2020 [205]. In HB scenarios, the cost of the boiler is also based on farm-scale capacity [206].

Civil work, engineering and contingency

The aggregated cost of equipment used in the AD system is defined as the basic equipment cost (BEC). Civil work includes the construction of buildings and infrastructure to support and shelter AD equipment and is estimated to be 13% of BEC [207]. BEC and cost of civil work in combination make up total installed cost (TIC). Engineering and contingency are then assumed to be 7.5% and 5% of TIC, respectively. The total capital cost (TCC) is determined as the sum of TIC, engineering cost and contingency.

4.2.2 Total production costs and revenues

Total production costs of AD systems include feedstock, consumables, utilities, labour, maintenance, depreciation, and loan interest. Meanwhile, revenues from digestate application and food waste tipping fees help to offset part of the operating costs. Total production cost is defined as operation costs minus revenues (other than biogas products). All costs and revenues are expressed in 2018 Canadian dollars.

Feedstock costs

As shown in Table 4.9, feedstock costs consist of the raw value of the material, the collection cost, and the avoided cost of conventional waste management practices. The raw values of animal manure and crop residues are estimated based on the fertilizer values of NPK contents. The collection cost of animal manure is neglected since it is part of routine farm operations. The collection cost of crop residues is assumed to be $32/t based on a case study in Alberta [151]. The avoided cost is assumed to be the fuel cost of conventional waste management practices. Note that equipment and labour costs of avoided waste management practices are not accounted for, assuming the handling of digestate in AD systems would require the same equipment and labour. Food waste is considered free of charge, as the service of waste management is provided by private companies on behalf of governments and paid for from tax revenues. On the contrary, receiving and processing food waste can generate extra revenues from waste tipping fees.

Table 4.9 Feedstock costs of farm-scale AD systems

Feedstock	Raw value	Collection	Avoided cost	Total	Unit
Cattle manure	48.4	0	-5.6	42.8	$/tDM
Poultry manure	81.9	0	-2.0	79.9	$/tDM
Food waste	0	0	0	0	$/tDM
Crop residues	15.5	31.7	-6.1	41.1	$/tDM

Consumables and utilities

In AD systems, consumables refer to chemicals used for feedstock pretreatment, gas removal and odour control. For simplicity, It is assumed that production costs for consumables are 2.5% of capital costs [207]. Utilities used in AD systems consist of electricity, natural gas and diesel. Electricity is consumed in pretreatment, gas cleaning and digestate separation processes. Natural gas is combusted to provide heat for sterilization and digestion processes. Diesel is used in machinery to load, transport and spread digestate. Costs of utilities are calculated based on total consumption accounted in the LCA model and their respective business rates in BC.

Labour and maintenance

It is assumed that farm-scale AD systems require one full-time engineer and one part-time worker, with a salary of $52000/year and $13520/year ($13/hr and 20hr/week), respectively. Particularly in an area with a number of AD systems, an engineer may be shared between several units; the consequences of this assumption are explored in section 4.4.4. Labour-associated costs include benefits and overhead, which are assumed to be 30% and 10% of the total salary, respectively. Annual maintenance costs are assumed to be 3% of capital costs [25], [207].

Depreciation and interest

The AD system is assumed to depreciate following the Class 43.2 of Capital Cost Allowance in Canadian tax code [109], described in Section 3.2. The capital depreciation rate is 25% in the first year and 50% for the rest. 60% of capital costs are financed by loans, compounded annually at an interest rate of 6.5%. Term of the loan payment is ten years, and the annual payment is calculated using the method set out in Section 3.2

Revenues from the sale of biogas and digestate

Revenues from biogas are calculated based on market energy prices, without any influence from policies. The values of RNG and electricity exported to the grid are based on natural gas rack price and electricity commercial rate, respectively. For direct biogas heating, the revenue is assumed to be the avoided heating cost based on the natural gas commercial rate. Revenues from digestate are based on the nutrient uptake rate of digestate and the market value of synthetic fertilizers. Market prices for energy and synthetic fertilizers are shown in Table 4.6.

Revenues from policy support

AD systems can receive extra revenues from policy measures in BC, including feed-in tariffs (FiTs), carbon tax credit, and waste tipping fees. RNG scenarios can receive FiT of up to $30/GJ, and CHP scenarios can receive FiT of $32/GJ. Meanwhile, carbon tax credits of $35/$CO_2$, or $1.74/GJ natural gas, can be generated by avoiding natural gas consumption. For tipping fees, it is assumed that AD facilities can receive 60% of the $95/t food waste tipping fee. There is no tipping fee for other feedstocks.

4.2.3 Minimum selling prices

Based on the production costs and revenues from digestate and policy support, minimum selling prices (MSPs, in 2018 Canadian dollars) of biogas products are estimated using the discounted cash flow model described in Section 3.2. The payback period for the AD system is assumed to be ten years. Both production costs and revenues are assumed to increase at a constant inflation rate of 2%, and that the discount rate includes both real rate of return (10%) and inflation rate (2%). The model is defined as follows:

$$NPV = -I + \sum_{t=0}^{n} \frac{(MSP * BG + RD + RP - CP)_t}{(1+r)^t} = 0$$

Where I = initial investment, MSP = minimum selling price, BG = biogas capacity, RD = revenues from digestate, RP = revenues from policy measures, CP = production costs, n = 10 years, and r = discount rate (12% pa).

4.3 Environmental impacts of AD systems

4.3.1 Global warming potential

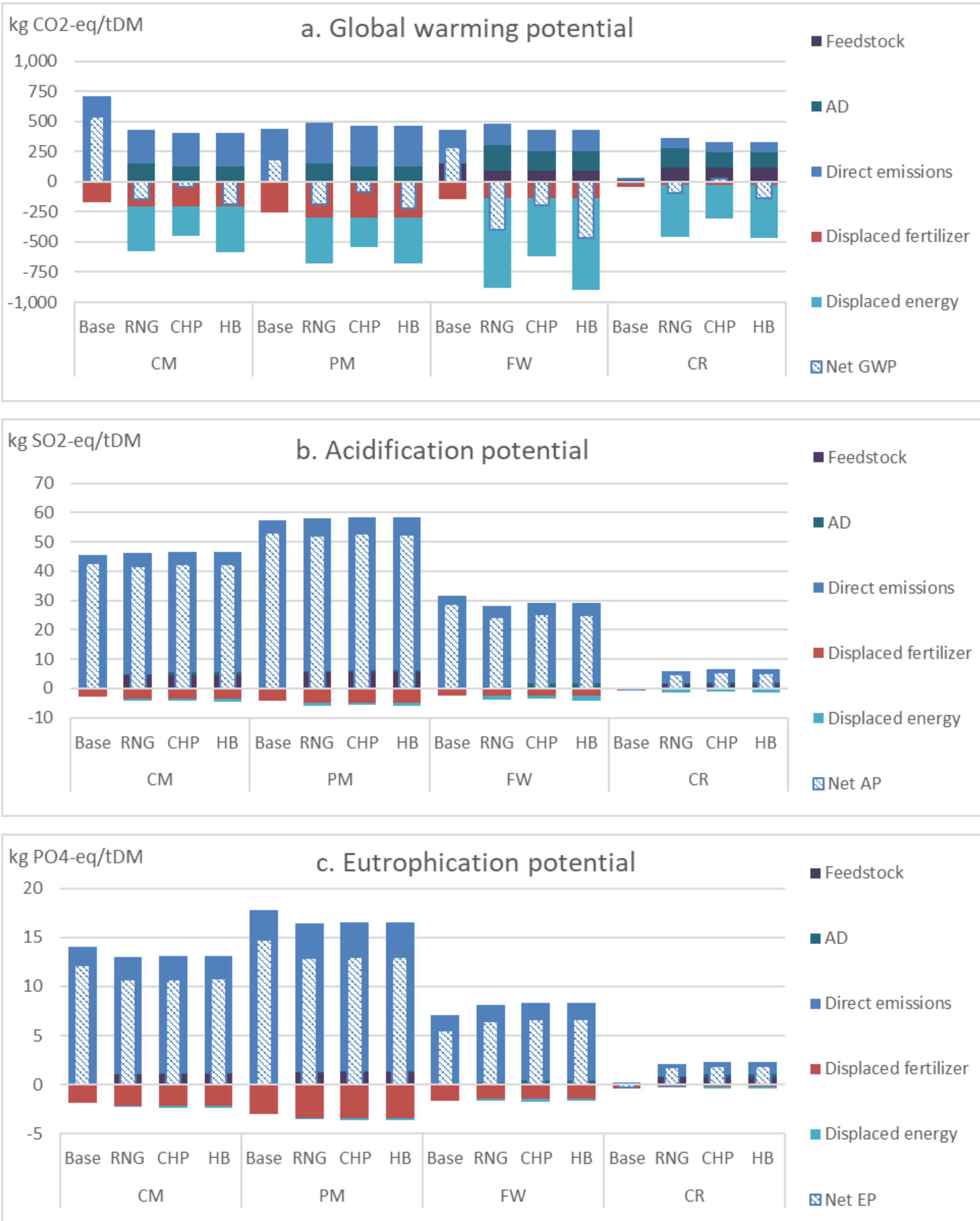
For each tonne dry matter (tDM) processed, AD of cattle manure, poultry manure, and food waste can reduce GWP from the base scenario by 589-728, 271-411, and 479-757 kg CO_2-eq, respectively (Figure 4.2(a)). These GWP benefits arise primarily from three sources: displacement of energy, displacement of synthetic fertilizers and reduction in field emissions. AD of cattle manure shows the highest reduction in field GHG emissions, and AD of food waste has the highest avoided burdens for displacing energy. On the other hand, the GWP benefits of AD of crop residues are limited to displacement of energy, as the feedstock has low nutrient values. RNG and HB for AD of crop residues reduce GWP from the base scenario by 84 and 124 kg CO_2-eq/tDM, respectively, whereas the CHP scenario actually increases GWP by 35.3 kg CO_2-eq/tDM.

In terms of biogas utilization options, HB and RNG can reduce GHG emissions more than CHP when using the same AD feedstock. This is because 90% of BC's electricity is supplied primarily by hydropower and is therefore less GHG intensive than natural gas. Due to the extra CO_2 removal process for biogas upgrade, the RNG option has higher CH_4 emissions and thus displaces slightly less natural gas than the HB option.

Due to the rich nutrient content of animal manure and food waste, avoided burdens for fertilizers displaced by the use of digestate are crucial to the overall GWP benefits of AD systems. Meanwhile, AD can also effectively reduce CH_4 emissions from base scenarios of animal manure and food waste, provided fugitive emissions are properly managed. Via displacement of synthetic fertilizers and reduction in field emissions, GWP benefits for AD of animal manure and food waste can be significantly strengthened.

4.3.2 Acidification and eutrophication potential

Acidification potential (AP) is mainly attributed to emissions of nitrogen and sulphur oxides, while eutrophication potential (EP) is due to nitrogen and phosphorus compounds discharged to water bodies. Therefore, nutrient loss from the use of organic fertilizers plays a vital role in these environmental impacts, whereas the use of fossil fuels and synthetic fertilizers has much less influence. As shown in Figure 4.2(b)&(c), AD of all feedstock types shows net increases in AP and EP, primarily due to various forms of nitrogen emissions from biogas production and digestate application processes. Management of poultry manure has the highest impact in AP and EP, due to its high nitrogen content.



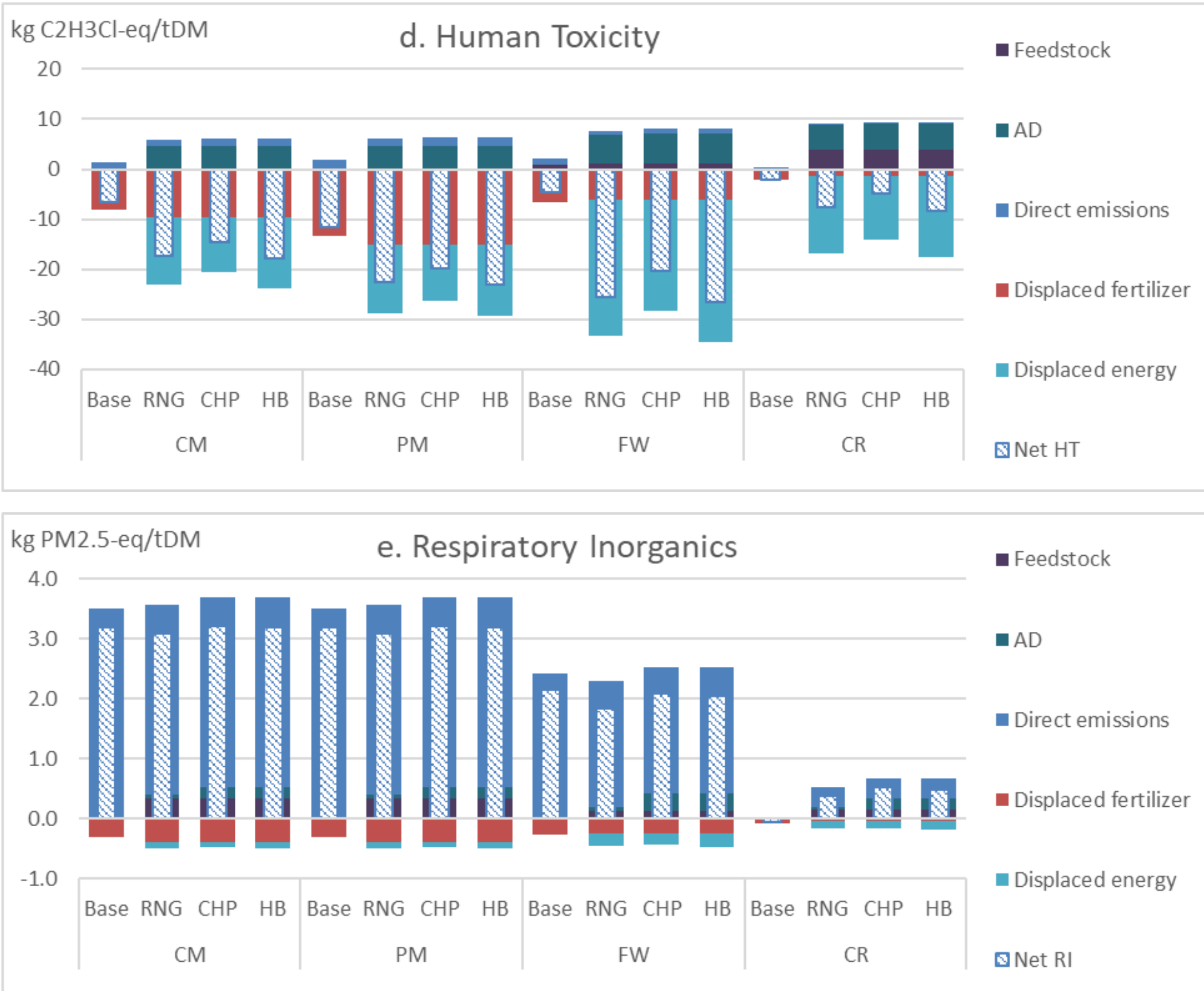


Figure 4.2 Environmental impacts of AD per tDM feedstocks processed

Compared with the base scenario, AD of cattle and poultry manure shows a 12% reduction in EP. A similar degree of reduction can be seen for AD of food waste in AP, as AD can slightly reduce nutrient loss from the application of these organic wastes. On the other hand, AD of crop residues significantly increases both AP and EP from the base scenario, as digestate use has much higher nutrient loss rates than field incorporation of crop residues.

4.3.3 Human Toxicity and respiratory Inorganics

Human Toxicity (HT) is primarily caused by emissions of hazardous organic compounds. As upstream processes of fossil fuel production are associated with massive emissions, all biogas scenarios can significantly reduce HT impact by displacing natural gas (Figure 4.2(d)). This benefit far exceeds the impact associated with feedstock procurement and AD production processes. Due to higher biogas yield, AD of food waste shows much higher HT benefit than AD of animal manure and crop residues.

Respiratory Inorganics (RI) measures the health impact of respirable inorganic emissions such as $PM_{2.5}$, NH_3, SOx and NOx. As shown in Figure 4.2(e), the hotspot for organic waste management is identified as NH_3 volatilization, whereas the contribution from the displacement of energy is much smaller. Therefore, the result for RI is similar to acidification: AD can slightly reduce RI for cattle manure, poultry manure and food waste, but can significantly increase that for crop residues. Similar to Section 3.3.2, LCA results of HT and RI should only be interpreted as a proxy for health risks, due to the inherent limitation of the methodology.

4.3.4 Sensitivity analysis on LCA results

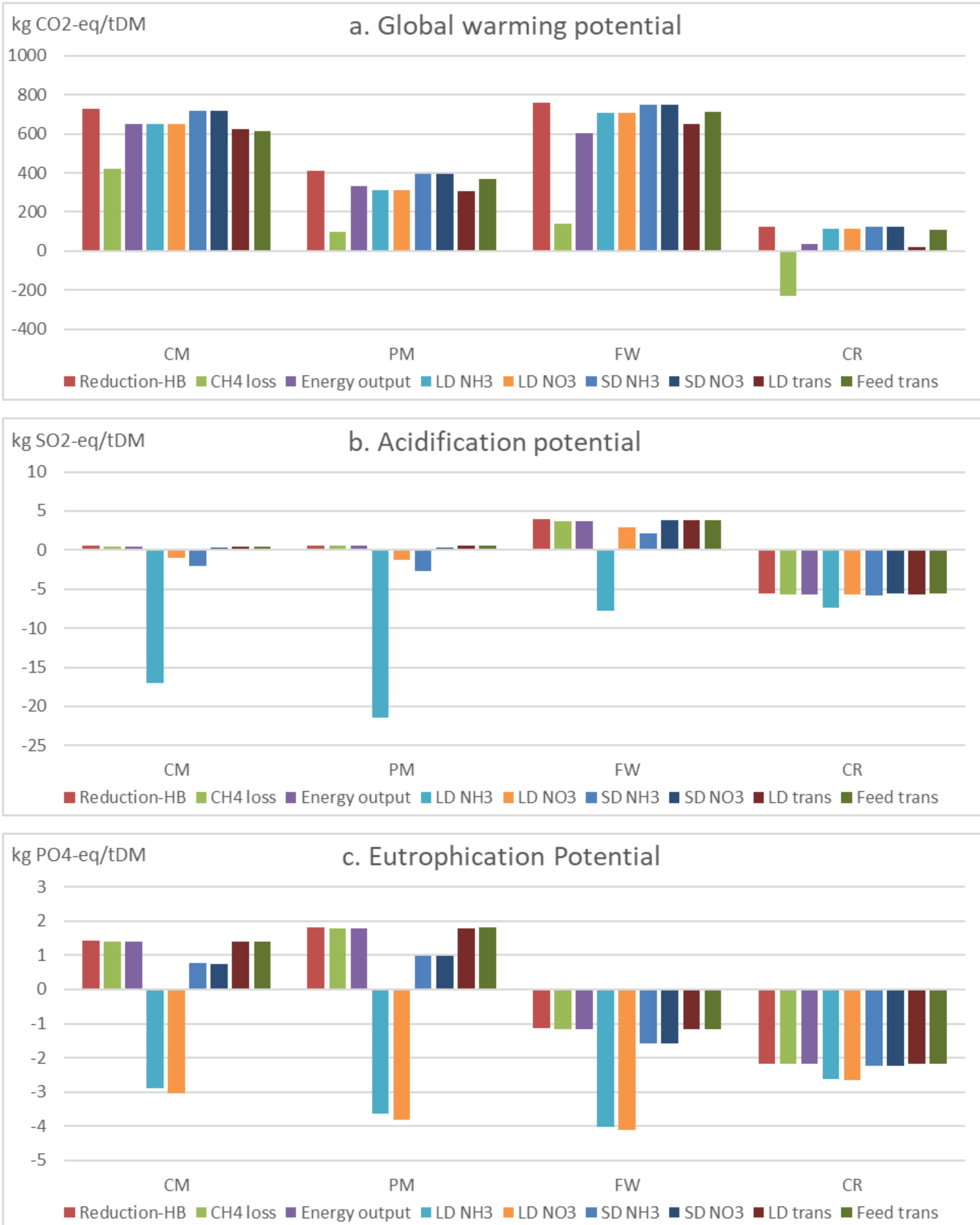
To evaluate the impact of data uncertainties on LCA results of AD systems, we conducted a sensitivity analysis on key factors including energy output, nutrient loss and transport, by altering these factors in ways that lower the performance of AD systems (Table 4.10). HB scenarios are selected as an example. In general, we find that uncertainties in all these factors can significantly influence the environmental performance of AD systems in at least one impact category.

Table 4.10 Parameters for sensitivity analysis on LCA results of AD scenarios

Category	Parameter	Abbreviation	Variation
Reference	Environmental benefits from HB scenarios	HB-reduction	N/A
Energy output	CH_4 fugitive emissions	CH_4 loss	+10%
	Energy output from biogas	Energy output	-20%
Nutrient loss	NH_3 emission factor of liquid digestate	LD NH3	+20%
	NO_3^- emission factor of liquid digestate	LD NO3	+20%
	NH_3 emission factor of solid digestate	SD NH3	+20%
	NO_3^- emission factor of solid digestate	SD NO3	+20%
Transport (incl. empty return)	Transport distance of liquid digestate	LD trans	+100km
	Transport distance of feedstock	Feed trans	+100km

CH_4 emissions and energy output

CH_4 fugitive emissions are a common concern for the AD system. In our calculation, the emission factor (EF) is assumed to be 1% for CHP and HB options, and 2% for RNG. However, it is reported to vary between 0.2% and 13% [209]. Because CH_4 is strong in climate-forcing, uncertainty in fugitive emissions introduces large uncertainty into the global warming potential (GWP) benefit of biogas systems. As shown in Figure 4.3(a), 10% increase in CH_4 emissions elevates GWP by 300-600 kg CO_2-eq/tDM. This leads to 40%, 75%, 80% and 290% reduction in GWP benefits for AD of cattle manure, poultry manure, food waste and crop residues, respectively.


kg CO2-eq/tDM
a. Global warming potential
1000
800
600
400
200
0
-200
-400
CM
PM
FW
CR
Reduction-HB
CH4 loss
Energy output
LD NH3
LD NO3
SD NH3
SD NO3
LD trans
Feed trans
kg SO2-eq/tDM
b. Acidification potential
10
5
0
-5
-10
-15
-20
-25
CM
PM
FW
CR
Reduction-HB
CH4 loss
Energy output
LD NH3
LD NO3
SD NH3
SD NO3
LD trans
Feed trans
kg PO4-eq/tDM
c. Eutrophication Potential
3
2
1
0
-1
-2
-3
-4
-5
CM
PM
FW
CR
Reduction-HB
CH4 loss
Energy output
LD NH3
LD NO3
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SD NO3
LD trans
Feed trans

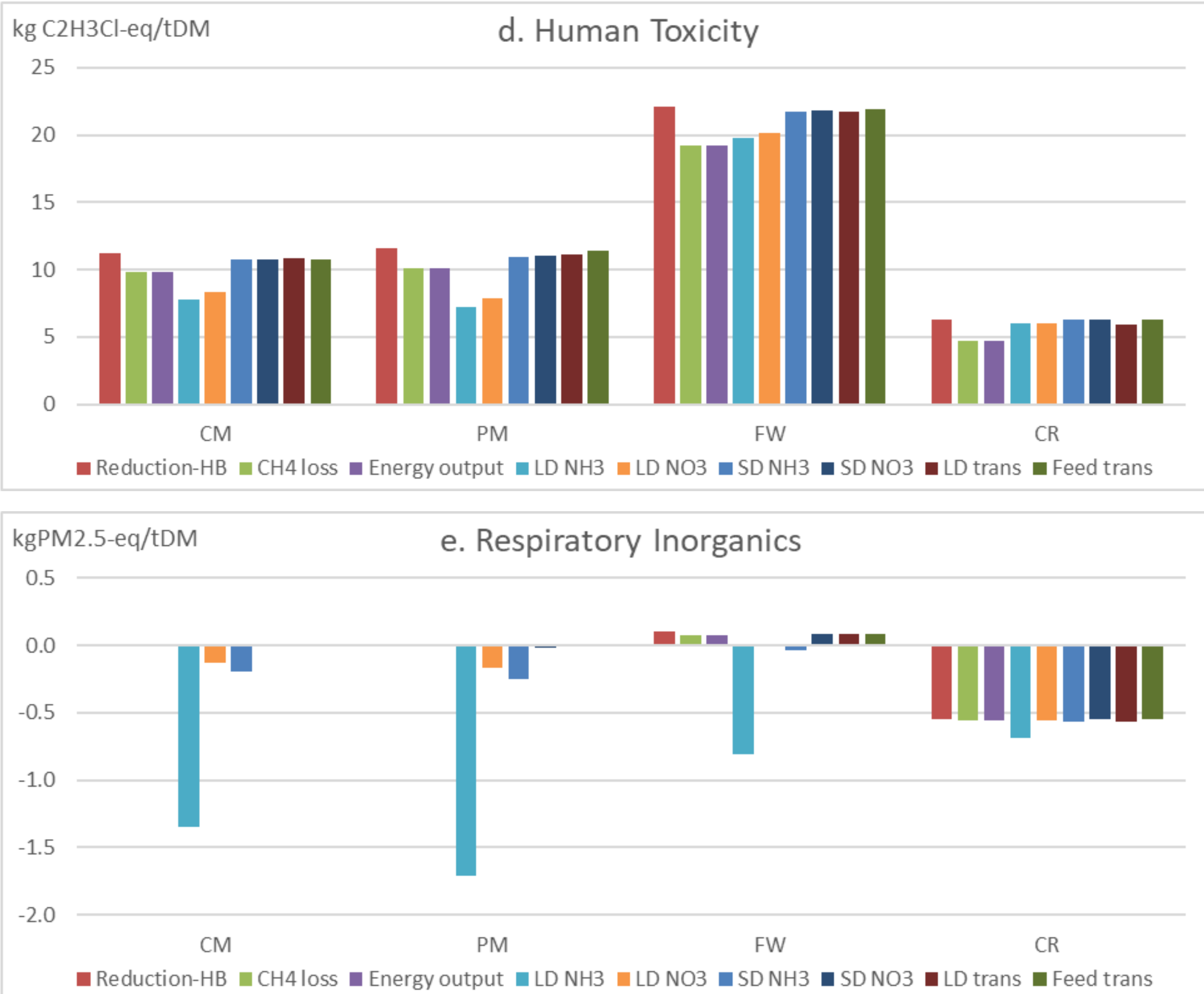


Figure 4.3 Sensitivity analysis on LCA results of AD scenarios

We further calculated the threshold CH_4 fugitive emission factors, at which each biogas scenario would have the same GWP as the corresponding base scenario. As shown in Table 4.11, AD scenarios for cattle manure have the highest CH_4 emission threshold of 21-25%, far exceeding the normal range of reported EFs. AD scenarios for poultry manure, food waste and crop residues show much lower CH_4 emission thresholds, indicating that CH_4 fugitive emissions in these scenarios need to be more closely monitored and controlled to ensure GWP benefits.

Table 4.11 Threshold CH_4 fugitive emission factors to neutralize GWP benefits

Scenarios	Cattle manure	Poultry manure	Food waste	Crop residues
RNG	24%	14%	13%	4%
CHP	21%	10%	9%	0%
HB	25%	14%	13%	4%

Biogas energy output is affected by fluctuations in biogas yield, CH_4 loss and energy efficiency. It is found that uncertainty in biogas energy output can affect the environmental benefit of AD systems on GWP and human toxicity (HT). For AD of animal manure and food waste, due to improvement in nutrient management and reduction of CH_4 emissions, the GWP benefits are less dependent on energy output. It is to be noted that the energy output of HB and CHP options also depends on the heat demand available to the AD systems. As farms in BC are mostly located in rural areas where the population is sparse, it can reasonably be inferred that there might not be enough residences closeby, whereas it is uneconomical to over-extend the district heating network. Under circumstances where the heat utilization rate is 80% or lower, GWP and HT benefits of HB and CHP scenarios can be significantly reduced.

Loss of nutrient

Nitrogen loss rates of digestate use are also subject to a high degree of uncertainty, as controversial claims are reported. The impact of uncertainty in nutrient loss is found to be higher on nutrient-rich feedstocks, including animal manure and food waste. Because most nitrogen in the feedstock reports to the liquid digestate (LD), nitrogen emission factors from LD are much more significant than those from solid digestate (SD).

As shown in Figure 4.3, increased NH_3 volatilization rate of LD can dramatically deteriorate the performance of AD of animal manure and food waste on acidification potential (AP), eutrophication potential (EP), respiratory inorganics (RI), and human toxicity (HT). On the other hand, NO_3^- leaching from LD shows a critical impact on EP, and slightly less impact on AP, HT and RI. These findings indicate the importance of proper nutrient management practices, such as storing liquid digestate in covered tanks, using field incorporation methods for digestate spreading, and avoiding fertilization before forecasted heavy rainfall.

Transportation

High moisture contents of animal manure, food waste and liquid digestate raise concerns about the environmental impact of extended transportation. As shown in Figure 4.3(a), the results of the sensitivity analysis confirm that the impact of extended transportation mainly lies in GWP. By increasing the transportation distance of liquid digestate by 100 km (including empty return), GWP of biogas scenarios will elevate by 100 kg CO_2-eq/tDM. This corresponds to a 14% reduction in GWP benefits for AD of cattle manure and food waste, a 25% reduction for AD of poultry manure, and 84% reduction for AD of crop residues. Extending transportation of feedstocks for 100 km also leads to substantial reduction (40-110 kg CO_2-eq/tDM) in GWP benefits for AD of animal manure and food waste, 6-16% below the reference level. Therefore, transportation for feedstock procurement or digestate discharge should not exceed the local range to ensure the environmental benefit of AD. It thereby indicates that a joint AD system is an environmentally feasible way to process animal manure from several smaller farms and food waste from scattered residences in the same region. On the other hand, extended transportation of LD and feedstocks should be avoided.

4.4 Costs of AD systems and MSPs of biogas

4.4.1 Capital and production costs

As shown in Figure 4.4(a), the capital costs of farm-scale AD systems are estimated at $680-1260 per tonne dry matter (tDM) processed annually. For RNG and CHP scenarios, costs of biogas utilization systems (biogas upgrade or CHP unit) and grid connection contribute 8-20% and 14-22% of total capital costs, respectively, making RNG and CHP scenarios 39-53% more expensive than HB scenarios. Comparing different feedstocks, AD of food waste has slightly higher capital costs than animal manure and crop residues per tDM feedstock processed, due to higher biogas yield and thereby higher equipment capacity. Nonetheless, when it comes to capital costs per kW_{th} biogas production capacity, AD of food waste requires the lowest capital costs and is thus the most cost-effective to build.

Production costs consist of feedstock costs, other operating costs, depreciation, and loan interest (Section 4.2). As shown in Figure 4.4(b), production costs of AD scenarios range from $250 to $340 per tDM feedstock processed, corresponding to $19-55/GJ biogas. The largest component is depreciation with a payback period of ten years, accounting for 23-41% of total production costs. Due to lower capital costs, HB scenarios are much lower in depreciation than RNG and CHP scenarios. Labour costs are also identified as a major source of expenditure. In terms of costs per GJ biogas, HB is the cheapest biogas utilization option, whereas RNG and CHP are $6-8/GJ more expensive, mostly due to differences in capital depreciation. Comparing different feedstocks with the same biogas utilization option, costs per GJ for AD of food waste ($19-26/GJ) are about half the costs for AD of animal manure and crop residues ($37-55/GJ), mainly attributed to free feedstocks and higher biogas yields.

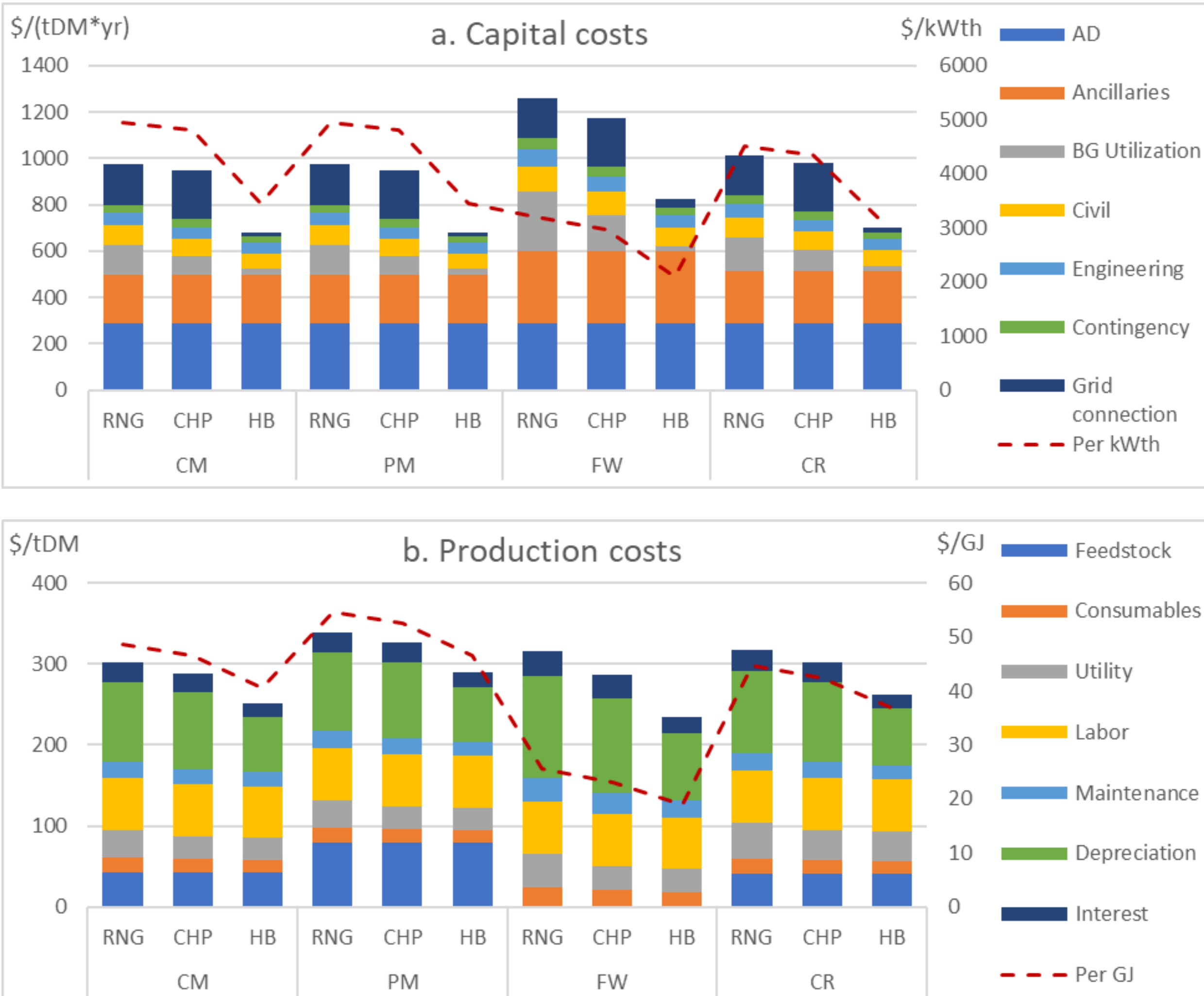
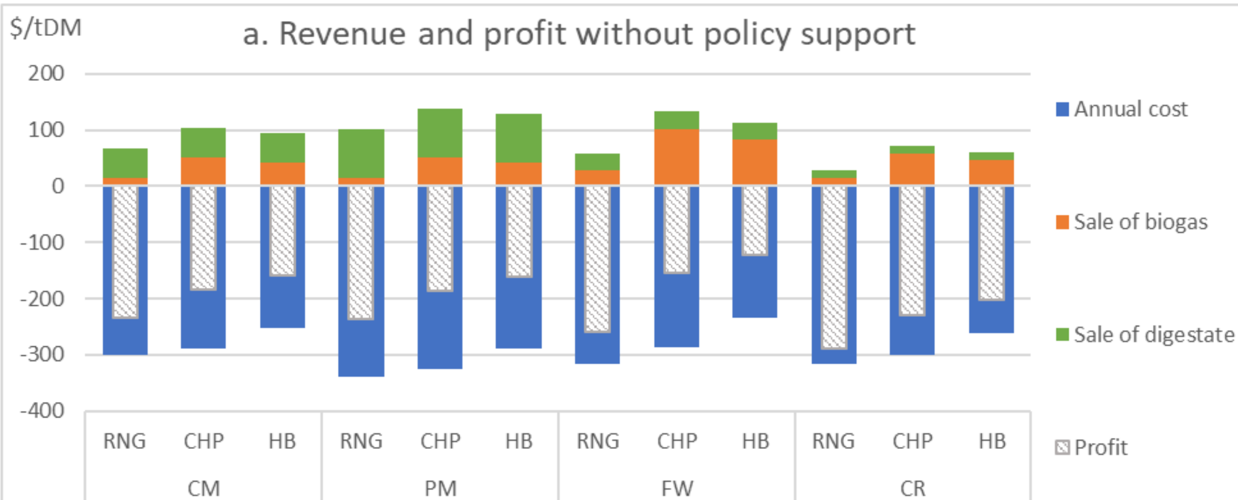


Figure 4.4 Capital and production costs of AD systems

4.4.2 Revenues and profits without and with policy support

As shown in Figure 4.5(a), revenues of AD systems are estimated based on the baseline prices of energy and fertilizer, excluding financial support from policy measures. Because electricity has a higher baseline price than natural gas, CHP can generate more revenues than RNG and HB from the sale of energy. Comparing different feedstocks, AD of food waste has the highest revenue from the sale of energy, whereas AD of poultry manure has the highest revenue from the sale of digestate. For AD of cattle manure and food waste, the sale of digestate is also identified as a significant source of revenue. However, revenues from the sale of biogas and digestate are not enough to cover production costs in all biogas scenarios: for each tDM feedstock processed, net loss ranges from $120 to $290. The RNG option generally has higher net losses than CHP and HB, due to both lower revenues and higher production costs. The HB option has the lowest net losses.



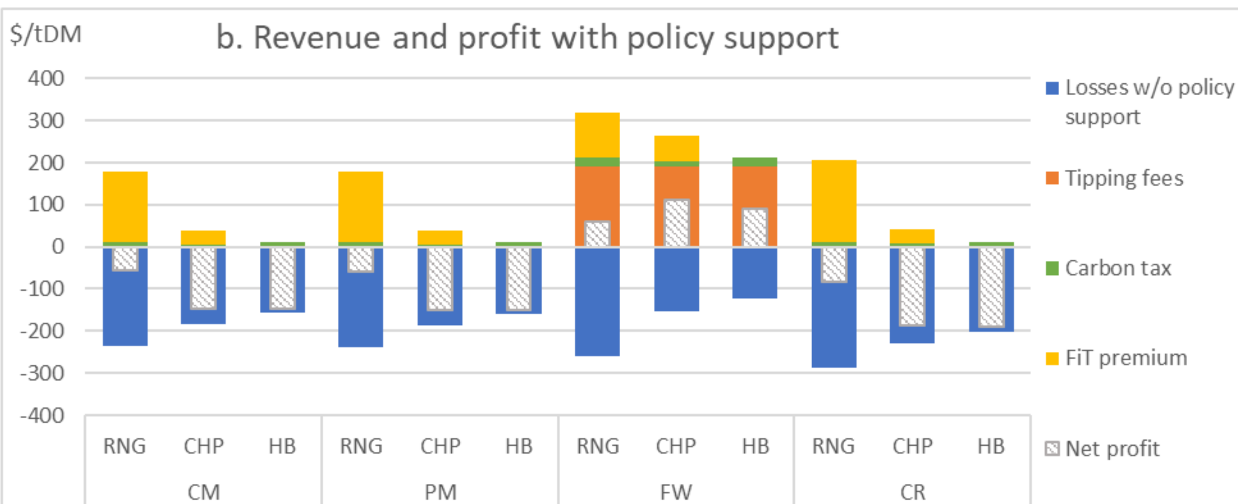


Figure 4.5 Revenues from biogas, digestate and policy support

Extra revenues from existing policy measures in BC significantly vary amongst AD scenarios. As shown in Figure 4.5(b), current food waste tipping fees of $95/tFM can effectively make all biogas utilization options for AD of food waste profitable. The current RNG FiT program also provides substantial financial incentives, up to $200/tDM feedstock to biogas RNG scenarios. However, it is still insufficient to make the RNG option for AD economically viable for any feedstock (excluding food waste). By comparison, financial incentives from BC Hydro's SOP and the generic carbon tax are nugatory. As a result, additional financial support is needed to promote the utilization of animal manure and crop residues via biogas-fired HB/CHP systems.

4.4.3 Minimum Selling Prices of biogas

Based on production costs and revenues from digestate and policy support, minimum selling prices (MSPs) per GJ bioenergy produced from AD are then determined. As shown in Figure 4.6, without policy support, MSPs for renewable natural gas, electricity and heating service generated from AD are $28-51/GJ, $72-146/GJ, and $22-45/GJ, respectively.

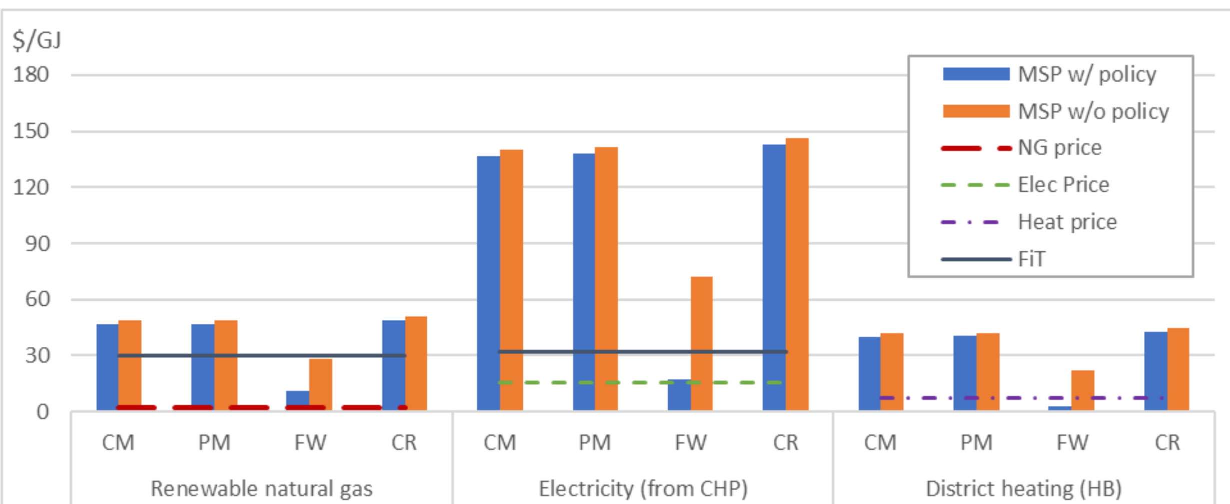


Figure 4.6 Comparison of MSPs of biogas products and baseline energy prices.

With financial support from policy measures, the MSPs for the heating service from AD of food waste can be reduced below the baseline energy prices, while the MSPs for renewable natural gas and electricity can be reduced below their feed-in tariffs. On the other hand, the MSPs for the bioenergy products from AD of animal manure and crop residues are considerably higher. Even with current policy support, MSPs for renewable natural gas, electricity and heating service generated from AD of animal manure and crop residues are still about $50/GJ, $140/GJ, and $40/GJ, respectively, substantially above baseline energy prices and feed-in tariffs.

4.4.4 Sensitivity analysis on MSPs

To investigate the potential impact of data uncertainties on MSPs for biogas, we conducted a sensitivity analysis on critical technical, economic and financial parameters, as summarized in Table 4.12. In general, we find that MSPs for biogas produced from cattle manure (CM) and crop residues (CR) are more sensitive to data uncertainties than those from food waste (FW). CHP scenarios are more sensitive than RNG and HB scenarios.

Table 4.12 Parameters for sensitivity analysis on MSPs of biogas

Category	Parameter	Abbreviation	Variation
Technical	Biogas yield	BG yield	110: 100: 90%
	CH4 emission from biogas upgrade	CH_4 loss	0.5: 2: 10%
	CHP electricity efficiency	Elec eff	35: 30: 25%
	HB boiler efficiency	Heat eff	95: 90: 85%
Economic	Total capital cost	CAPEX	80: 100: 120%
	Production cost	OPEX	80: 100: 120%
	Fertilizer value of digestate	Digestate	120: 100: 80%
	Feedstock price	Feedstock	±$20/tDM
Financial	Internal rate of return	IRR	5: 10: 15%
	Loan financing percentage	Loan	40: 60: 80%
	Payback period	Payback	15: 10: 7 year

As shown in Figure 4.7, uncertainties in biogas yield, CH_4 fugitive emissions and conversion efficiency significantly influence the MSPs for biogas products from cattle manure, poultry manure, and crop residues. This is because higher yield leads to higher production capacity and thus lower cost per GJ energy. It further signifies that improvement in biogas yield and conversion efficiency is the key to improving the economics of AD of animal manure and crop residues. However, these parameters demonstrate a much smaller impact on the MSPs for biogas products from food waste. This is because the largest source of revenues for AD of food waste is waste tipping fees, which significantly downplays the importance of biogas sales.

A high degree of uncertainty in capital and production cost is reported by many studies. As shown in Figure 4.7, 20% of uncertainty in the capital and production cost can substantially impact the MSPs of biogas products. For example, it is assumed in this study that each farm-scale AD project employs a full-time engineer, accounting for more than 20% of the production cost. If more AD projects are installed, it may be possible for these projects to be managed by the same engineer, thus reducing the cost and consequently MSPs of biogas products. Another important aspect of uncertainty exists in the prices of AD feedstocks. Even though biomass residues are currently of low merchantable values, their future prices could be driven up by increased demand for bioenergy feedstocks. The result shows that price fluctuation of ±$20/tDM in biomass residues can change the MSPs of renewable natural gas, electricity and heating service from biogas by $1.6-3.3/GJ, $5.4-10.9/GJ and $1.8-3.6/GJ, respectively. In comparison, variations in the sale of digestate have much less impact.

Financing parameters are also investigated, including the IRR, loan percentage and payback period. As shown in Figure 4.7, IRR and payback period can significantly impact MSPs for all biogas products, whereas loan financing has little impact. From the investment perspective, this implies that more extended renewable energy contract between biogas producers and the government can effectively reduce the price of biogas products.

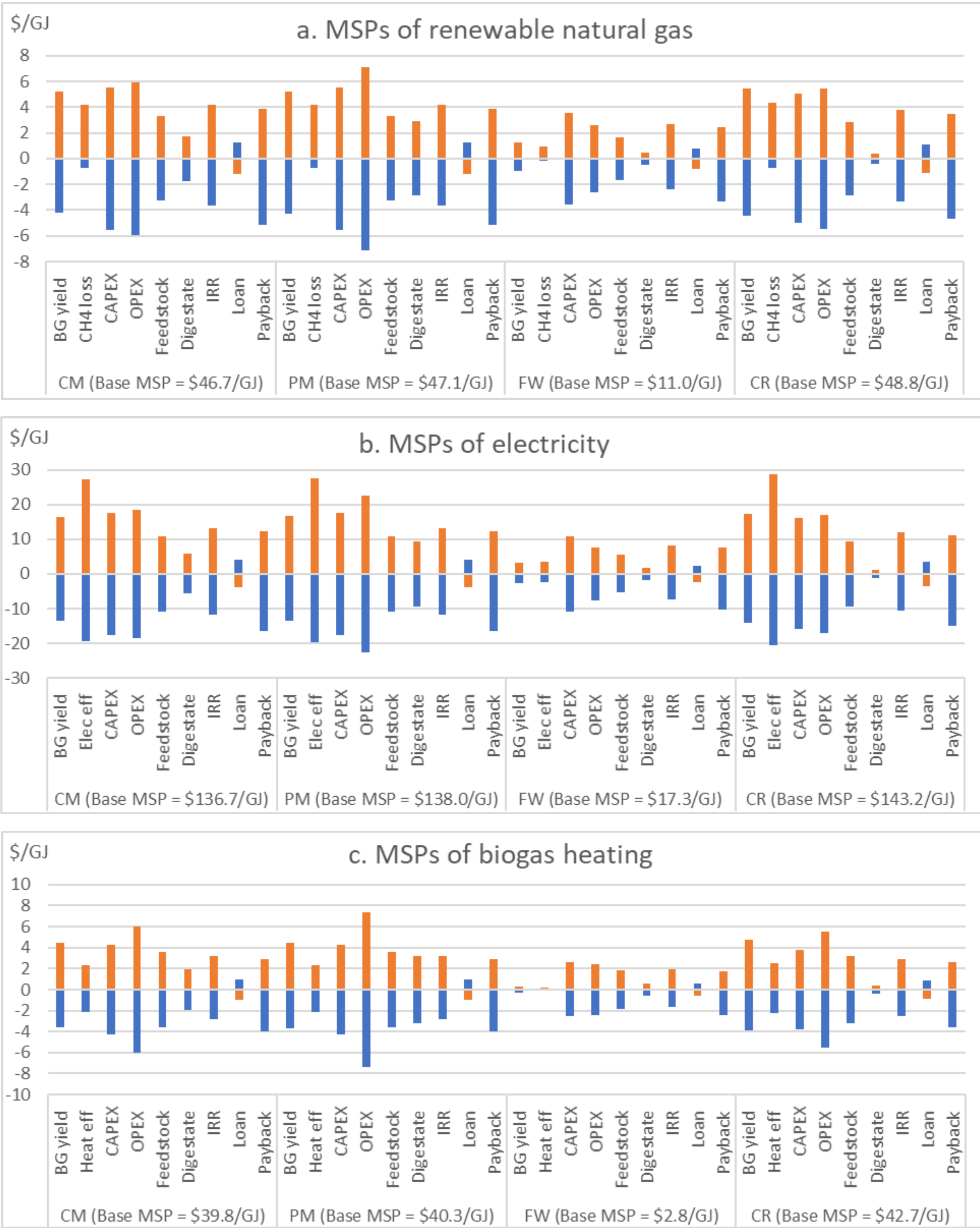


Figure 4.7 Sensitivity analysis on MSPs of biogas

Overall, variation in any single factor does not change the conclusions on the economic viability of biogas products from various feedstocks. Barring unforeseeably large and unfavourable variations in several factors, AD of food waste will remain economically competitive based on current energy prices and policy support. On the other hand, AD of other biomass residues is unlikely to be profitable under current circumstances.

4.5 Development of effective policies in BC

4.5.1 GHG reduction costs of biogas

GHG reduction costs of farm-scale AD systems are calculated, shown in Figure 4.8. Due to a high degree of uncertainty in both GWP benefits (Section 4.3.4) and MSPs (Section 4.4.4), GHG reduction costs of biogas are also associated with high uncertainties, as indicated by the error bars. AD of cattle manure and food waste have similar GHG reduction costs ($210-460/tCO_2$-eq), followed by AD of poultry manure with GHG reduction costs of $470-860/tCO_2$-eq. AD of crop residues has the highest GHG reduction costs (>$1900/tCO_2$-eq) due to low GWP benefits and is thus excluded from Figure 4.8. Therefore, AD of cattle manure and food waste is more cost-effective than that of poultry manure and crop residues. Comparing different biogas utilization options, HB generally has the lowest GHG reduction costs and is thereby the most cost-effective way to utilize biogas produced from these feedstocks. On the other hand, despite being heavily subsidized by feed-in-tariffs (FiT), RNG is the least cost-effective biogas utilization option, exerting enormous economic impacts on the government, producers and consumers.

GHG reduction costs of biogas products will be further discussed in Section 6.1.3 and compared with those of bioenergy products analyzed in Chapter 3. The overview of the cost-effectiveness of different bioenergy options provides useful information for the prioritization of the bioenergy development in BC.

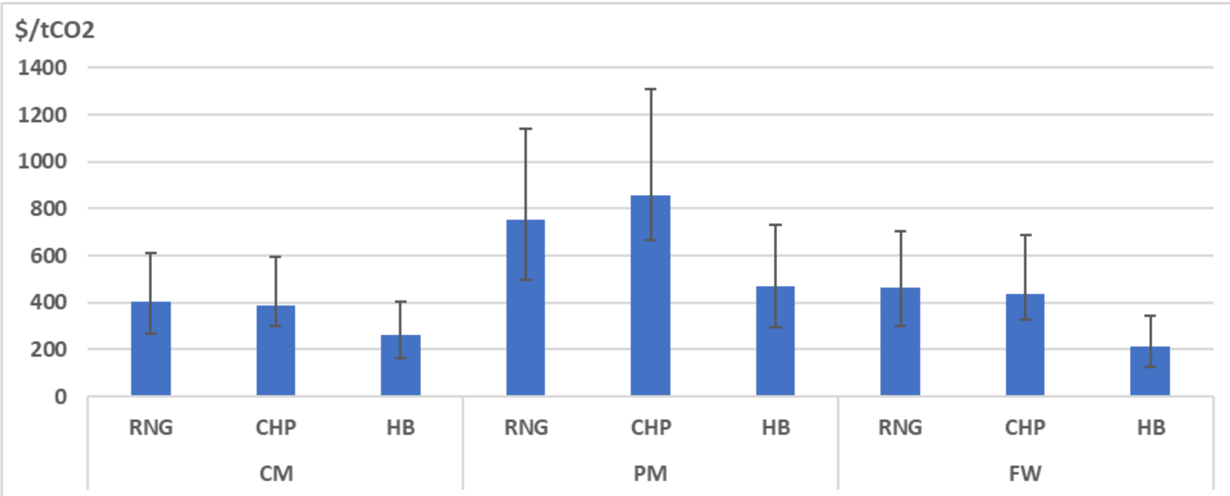


Figure 4.8 GHG reduction costs of biogas produced from animal manure and food waste

4.5.2 Biogas supporting policies in Europe

Globally, biogas production is proliferating in Europe. A policy review is conducted on four EU countries leading in biogas development, including Germany, France, UK and Sweden; these countries were selected for comparison because they illustrate a range of background economies, energy systems and policy approaches. As shown in Table 4.13, investment support, the feed-in tariff (FiT), and carbon tax are widely adopted to incentivize the development of the AD industry. All these countries provide capital grants to relieve the financing pressure for AD plant owners. Germany, France, and the UK, the three largest economies in the EU, offer premium purchasing prices to biogas products. While Germany has passed the early stage of extensive support and is now focusing on renewable electricity generation, the UK and France are providing FiTs to all biogas utilization options. On the other hand, Sweden is taking a different approach to incentivize biogas production by imposing heavy carbon and energy tax on fossil fuel consumption.

Table 4.13 Review of biogas supporting policies in Germany, France, the UK and Sweden

Carbon Tax	Germany	\$21/tCO2 in the EU Emissions Trading System (EU ETS)
	France	EU ETS plus additional \$45/tCO2
	UK	EU ETS plus additional \$29/tCO2
	Sweden	EU ETS or \$176/tCO2
	BC	\$35/tCO2
Biogas RNG	Germany	FiT incentive cancelled after EEG 2014
	France	FiT up to \$50/GJ for small-scale waste AD projects [210]
	UK	FiT up to \$26/GJ from Renewable Heat Incentive (RHI)
	Sweden	A requirement of renewable NG blend + incentive for clean NG vehicle
	BC	FiT up to \$30/GJ from FortisBC RNG Program
Biogas electricity	Germany	FiT up to \$94/GJ for small-scale manure AD projects [211]
	France	FiT up to \$69/GJ for small-scale manure AD projects [211]
	UK	FiT up to \$21/GJ for electricity generation + extra \$24/GJ for export
	Sweden	Electricity Certificate System
	BC	FiT of \$32/GJ BC from Hydro Standing Offer Program
Biogas Heating	Germany	Requirement of renewable energy in heat supply
	France	Extra FiT of \$17/GJ for biogas CHP plants with >70% efficiency
	UK	FiT up to \$22/GJ from Renewable Heat Incentive (RHI)
	Sweden	None
	BC	None
Investment support	Germany	Market Incentive Program, up to €50000 per unit for heating projects [212]
	France	Subsidies from French Energy and Environmental Agency (ADEME), covering on average 35% of investment to biogas projects [213]
	UK	Financing support from Green Investment Bank and WRAP
	Sweden	Local Investment Programme (LIP) + National Climate Investment Programme (KLIMP), 87 million Euro in total
	BC	None
Support for small-scale and waste AD	Germany	Favourable FiT to smaller-scale, manure and biowaste AD projects [211]
	France	Favourable FiT to smaller-scale, manure and biowaste AD projects [210]
	UK	On Farm Anaerobic Digestion Loan Fund & Rural Community Energy Fund; Favourable FiT to smaller-scale AD projects
	Sweden	Rural development program, supporting farm-scale biogas production
	BC	None

*In Canadian Dollars, using the annual exchange rates of 2017 from Bank of Canada

Meanwhile, a policy feature shared by these countries is the additional incentives for AD systems that are small-scale, on-farm or using waste materials. This can be explained by both environmental and economic reasons: (1) AD brings other environmental benefits via waste reduction and improved nutrient management, as confirmed by this study and other peer-reviewed studies [89], [90]; (2) small business owners are more financially vulnerable, and small-scale biogas plants are less economically favourable due to economy of scale. In comparison, BC is clearly falling behind these EU countries in the magnitude of policy support.

4.5.3 Development of effective policies in BC

Figure 4.9 presents the combination of capital investment grant and energy price adjustments needed to make bioenergy from AD of organic waste break even with baseline energy prices. By reducing the initial investment needed for AD projects, capital grants can lower depreciation and loan interests, as well as margins required to justify the return on investment. At a reasonable range of 25-50% capital grant, the MSPs for RNG produced from AD of cattle manure, poultry manure, and crop residues are reduced below the current RNG FiT. In order to support biogas-fired HB systems, modest increases in carbon and energy tax in combination with FiT for renewable heating (such as $17-22/GJ in France and the UK) will be needed. Potential waste tipping fees for cattle and poultry manure, equal to or higher than the current level for food waste, can also help to facilitate the exploitation of these biomass residues.

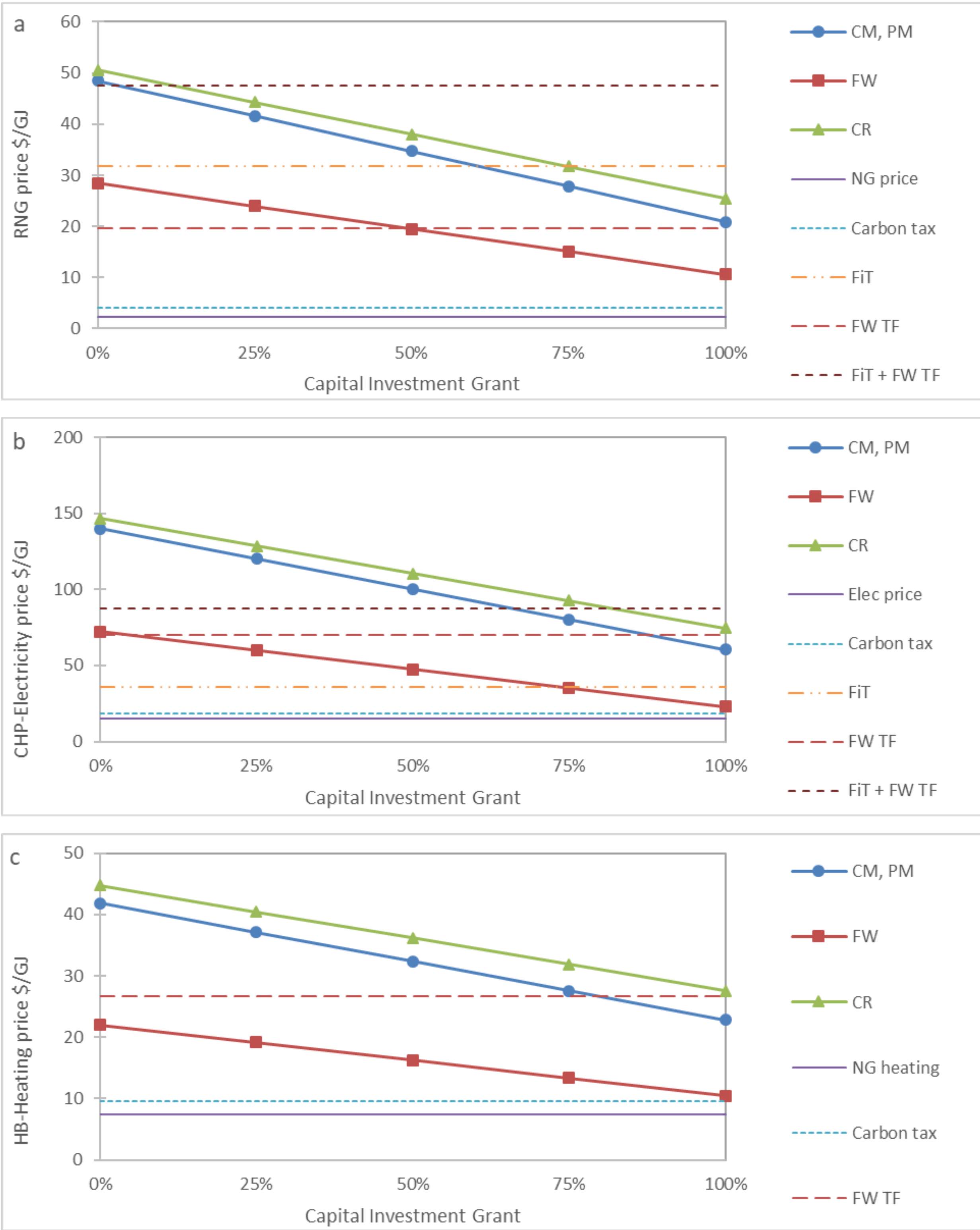


Figure 4.9 Policy support required to make biogas economically viable in BC

4.6 Conclusion

Anaerobic digestion (AD) of cattle manure, food waste, and poultry manure can effectively reduce greenhouse gas (GHG) emissions by 589-728, 479-757, and 271-411 kg CO_2-eq/tonne dry matter (tDM), respectively. GWP benefits arise primarily from three sources: substituting fossil natural gas, displacing synthetic fertilizers and reducing direct emissions from conventional waste management practices. AD of crop residues lacks GWP benefits. A significant benefit can also be achieved in the impact category of human toxicity (HT). However, the environmental impacts of AD in acidification potential (AP), eutrophication potential (EP) and respiratory inorganics (RI) are dictated by the nutrient loss from digestate use and thereby highly uncertain. This highlights the critical role digestate plays in the overall environmental benefit of AD, and the importance of proper nutrient management practices to minimize the nutrient loss from digestate use.

Three utilization options for biogas are investigated: upgrade to renewable natural gas (RNG), biogas-fired cogeneration of heat and power (CHP), and biogas-fired heat-only boilers (HB). Because 90% of BC's electricity is supplied by hydropower, environmental benefits from CHP are smaller than RNG and HB. HB can theoretically achieve the highest GHG mitigation per tonne feedstock used when the thermal energy can be fully utilized. In order to ensure the GWP benefits of AD, extended transportation of feedstock and digest should be avoided.

Economically, HB has the lowest capital and production costs, mainly because it requires considerably lower investment in both the heat boiler and distribution network. Due to currently low energy prices, all AD scenarios require financial support from policy measures to be economically viable. HB has the lowest extra cost and GHG reduction cost and is therefore the most cost-effective biogas utilization option.

Due to extra revenues from waste tipping fees, AD of food waste is already economically competitive. However, BC still lacks effective policy incentives for AD of cattle and poultry manure and biogas-fired HB systems. In order to close the cost gaps, the combination of a feed-in tariff (FiT) for renewable heating, waste tipping fees for animal manure, and capital grants for farm-scale AD projects are recommended. This recommendation can be supported by the policy review on several European countries leading in the development of the biogas industry.

The policy implication of the environmental impacts and economic viability of biogas products obtained in this chapter will be further discussed in Chapter 6, where a strategy for the prioritization of bioenergy development in BC is developed based on the results obtained in this chapter and in Chapter 3.

Chapter 5 AD systems integrated with agricultural practices

This chapter highlights anaerobic digestion (AD) of cattle manure, which is the largest stream of animal waste in BC. As shown in Chapter 4, AD of cattle manure can lead to comprehensive environmental benefits, including mitigation of GHG emissions, alleviation of human health impact and improvement in nutrient management. Upgrade to renewable natural gas (RNG) can effectively reduce GHG emissions by displacing fossil natural gas consumption and is thus heavily promoted by the BC government. However, the major drawback of the RNG option is its high production cost. In comparison, biogas-fired heat-only boiler (HB) systems are much more cost-effective in GHG mitigation. However, this utilization option suffers from two major problems: Lack of heat demand in thinly populated rural areas, and lack of financial support from current policy measures in BC.

BC's agricultural sector consumes 10.6 PJ of natural gas annually [3]. This gives rise to many opportunities to integrate on-farm biogas-fired heating systems with agricultural activities in BC. A potential use of low-grade heat is the production of greenhouse vegetables, which is one of the most important agricultural activities in BC [143]. Due to BC's high latitude and cool climate, greenhouse production in BC consumes a large amount of natural gas to maintain the temperatures necessary for plant growth. Furthermore, greenhouse production also requires CO_2 enrichment to enhance the photosynthesis of plants, which is usually provided by the flue gas from natural gas combustion [179], [214]. Especially from May to October when heating demand is low while CO_2 demand is high, additional natural gas is combusted solely to produce CO_2 enrichment [179], [215]. This represents a potential synergy between the greenhouse industry and the on-farm AD system, as the CO_2 content in biogas can provide additional CO_2 enrichment for greenhouse plants.

Mushrooms are another of the most common agri-food products in British Columbia. Mushrooms are generally cultivated at moderate temperature, representing another demand for heat from biogas combustion. During the growing process, mushrooms consume O_2 and generate CO_2 through biological respiration. As a result, ventilation is required to remove CO_2 and maintain suitable O_2 and humidity levels. The average CO_2 concentration in the ventilation air can reach 800 ppm, which is high enough for CO_2 enrichment of plants in greenhouses [42], [216].

There are many other potential synergies between farm-scale AD systems and production of greenhouse vegetables and mushrooms. In greenhouse production, rock wool is often used as the growing medium [217], [218]. Recent research has shown that substitution of commercial growing media with solid digestate need not reduce yields [216], [217]. Furthermore, it has been found that mushroom substrate made from solid digestate and wheat straw leads to higher yield for some types of mushroom [219], [220]. These synergies represent opportunities for the utilization of solid digestate to reduce raw material consumption and create extra economic value.

Field grain and oilseed crops are other common agricultural products in BC, including wheat, oats, barley and canola. In 2016, about 200,000 ha of field crops were planted and harvested in BC [221]. Field crops are a critical sink for nutrients from organic wastes and thus indispensable to the agricultural nutrient cycle. Crop residues (CR) have many applications such as animal feed, bedding, and mushroom substrate, in addition to bioenergy feedstocks. Loss of nutrient and organic matter in the soil caused by the removal of crop residues can be replenished by surplus digestate from AD and spent mushroom compost (SMC) from mushroom production.

Based on the synergies identified, integration of the dairy-based on-farm AD system with common agricultural practices in BC is examined here, including greenhouse vegetable and mushroom production, and field crops. Meanwhile, there are many other types of organic waste in BC, such as food waste, crop residues and poultry manure, which can be co-digested with cattle manure to enhance biogas production. Especially for small livestock farms, co-digestion is an effective way to scale up biogas production capacity and increase economic efficiency. Therefore, this section examines the environmental impact and economic viability of such integrated AD systems for cattle manure, with or without co-digestion of other organic waste in BC.

5.1 Modeling of agricultural practices

5.1.1 Dairy farm

The dairy farm is modelled as a hypothetical, but representative, large dairy farm with 400 cows and 200 heifers (Table A.1). Feed requirement and manure generation of cows and heifers are based on US data [175]. Total manure generation from such a hypothetical farm is estimated to be 1430 tonne dry matter (tDM), with the moisture content (MC) of 87% and NPK contents of 68.0t, 11.7t and 31.4t, respectively [175]. Volatilization of ammonia from cattle barn is assumed to be 6% of manure N content, and animal bedding materials are assumed to be crop residues, at a consumption rate of 548 kg DM/animal/year [180]. Seasonal heating demands are shown in Table 5.1.

5.1.2 Greenhouse

Greenhouse operation is modelled as bell pepper production, which accounts for nearly half of the greenhouse area in BC [215]. The annual yield of greenhouse peppers is assumed to be 28 kg/m^2 based on the BC average [143]. Plant debris is assumed to be 15% of the main product yield [218]. Seasonal heating and CO_2 demands are shown in Table 5.1. Nutrient uptake for N, P and K is 1.8, 0.35, and 3.4 kg/t product, respectively [202]. The annual consumption of greenhouse growing media is 1.25 kg/m^2, assumed to be entirely rock wool [179]. Other material consumptions are neglected.

5.1.3 Mushroom

Annual mushroom yield is assumed to be 221 kg/m^2 bed, based on the BC average [222]. For each kg of fresh matter (FM) of mushroom substrate consumed, 0.25 kg of mushroom can be produced [223]. The CO_2 generation rate is assumed to be 0.2 kg CO_2/kg FM substrate [42]. Seasonal heating demands are shown in Table 5.1. Substrate recipe is based on button mushroom (Table A.2), which is the main mushroom strain grown in BC.

Table 5.1 Seasonal heat and CO_2 data for integration components

	Unit	Spring	Summer	Fall	Winter	Annual
Dairy, Heat demand	GJ/farm	136.8	4.8	116.4	222	1440
Digester, Heat demand	MJ/t FM	9.6	6.7	9.1	11.3	110
Greenhouse, Heat demand	GJ/ha land	1430.1	579.9	1100.2	1739.8	14550
Mushroom, Heat demand	GJ/ha land	781.5	30.8	661.5	1261.5	8206
Greenhouse, CO2 demand	t/ha land	103.9	138.5	103.9	13.5	1079
Mushroom, CO2 supply	t/ha land	534.8	534.8	534.8	534.8	6418

5.1.4 Field crops and residue collection

The acreage of crop fields adjacent and available to the hypothetical dairy farm is estimated based on BC's crop field/cow ratio of 0.68 ha/head and crop residue collection ratio of 12% [150], [221]. As described in Chapter 2, average crop residue yield in BC is 3500 kg/ha, but 750 kg/ha of crop residues need to be retained on crop fields to prevent soil erosion [151], [152]. Therefore, for an integrated AD system built on a dairy farm with 400 cows, on average 657 tDM of crop residues can potentially be collected and utilized. Energy consumption of residue collection is assumed to be 1.6 L diesel/tDM, according to the GHGenius database [6]. It is assumed that crop residues collected locally will displace the same material that would otherwise be transported from other regions by HDV for 200 km.

5.1.5 Co-digestion feedstocks

Common digestible organic wastes are considered for co-digestion, including poultry manure, food waste and crop residues. Their biogas yield, moisture content and nutrient contents are described in Chapter 4 and shown in Table 4.1. Transportation distance for cattle manure is neglected, as the AD system is installed on the dairy farm. Other feedstocks are assumed to be transported for 50 km to the AD system by HDV (including empty return trip).

5.2 LCA system description

In this chapter, the system boundary of the LCA includes feedstock supply, anaerobic digestion, biogas utilization, digestate handling, and use of by-products. Note that all these feedstocks are waste materials, so the production processes of the primary products, i.e. agricultural commodities such as milk and crops, are not included in the system boundary [65]. The functional unit is defined as “disposal of 1400 tDM of organic waste”, which corresponds to animal manure generated in the representative farm with 400 cows and 200 heifers. Impact categories investigated in this chapter include global warming potential (GWP), acidification potential (AP), eutrophication potential (EP), human toxicity (HT) and respiratory inorganics (RI).

Four types of potential feedstock for the farm-scale AD systems are considered. In the case of cattle manure (CM), manure from dairy farms is the only AD feedstock. In co-digestion cases, cattle manure and a different type of organic waste, including poultry manure (CM-PM), food waste (CM-FW), and crop residues (CM-CR), are mixed in a ratio of 3:1 based on dry matter. This mixing ratio represents the proposed limit of 25% for off-farm and non-agricultural feedstocks allowed for on-farm AD systems in BC [224]. For each feedstock, four biogas utilization scenarios are developed: a base scenario (Base), a biogas upgrading scenario (RNG), a cogeneration scenario (CHP), and an integrated scenario (INTEG).

5.2.1 Base, RNG and CHP scenarios

In the base scenarios, no AD is implemented. Manure collection, storage, and spreading in livestock farms are the same as described in Chapter 4. Food waste is composted, and crop residues are incorporated into the field. All other agricultural activities are conducted according to business-as-usual. The RNG and CHP scenarios are the same as described in Chapter 4: an on-farm AD system is implemented to process cattle manure and spent bedding materials generated on the dairy farm, and biogas is then either upgraded to renewable natural gas or combusted for cogeneration. Except for digestate fertilization, no other connections are established between agricultural activities and the on-farm AD system.

5.2.2 Integrated scenarios

The system and boundary of the integrated scenarios are shown in Figure 5.1. The system configurations of each of the integrated scenarios are shown in Table 5.2. In the integrated scenarios, cleaning and utilization of biogas are assumed to be the same as in the HB scenarios in Chapter 4. Biogas combustion provides heating to the dairy farm, the greenhouse, and mushroom production. In greenhouse production, additional CO_2 enrichment is supplied from flue gas from biogas combustion and ventilation air from mushroom production. Liquid digestate is used to fertilize greenhouse vegetables, and solid digestate is dried and then used to displace the consumption of rock wool as growing media completely. In mushroom production, solid digestate is used to replace urea and some of the straw consumption in the conventional mushroom substrate recipe, based on nitrogen requirement (Table A.1). The rest of the greenhouse and mushroom production processes in the integrated scenarios remain the same as the conventional practices and are thus neglected. Field crops provide fodder for animals and absorb nutrients and organic matter in surplus digestate. Crop residues can be collected and used as animal bedding, mushroom substrate, and co-digestion feedstocks.

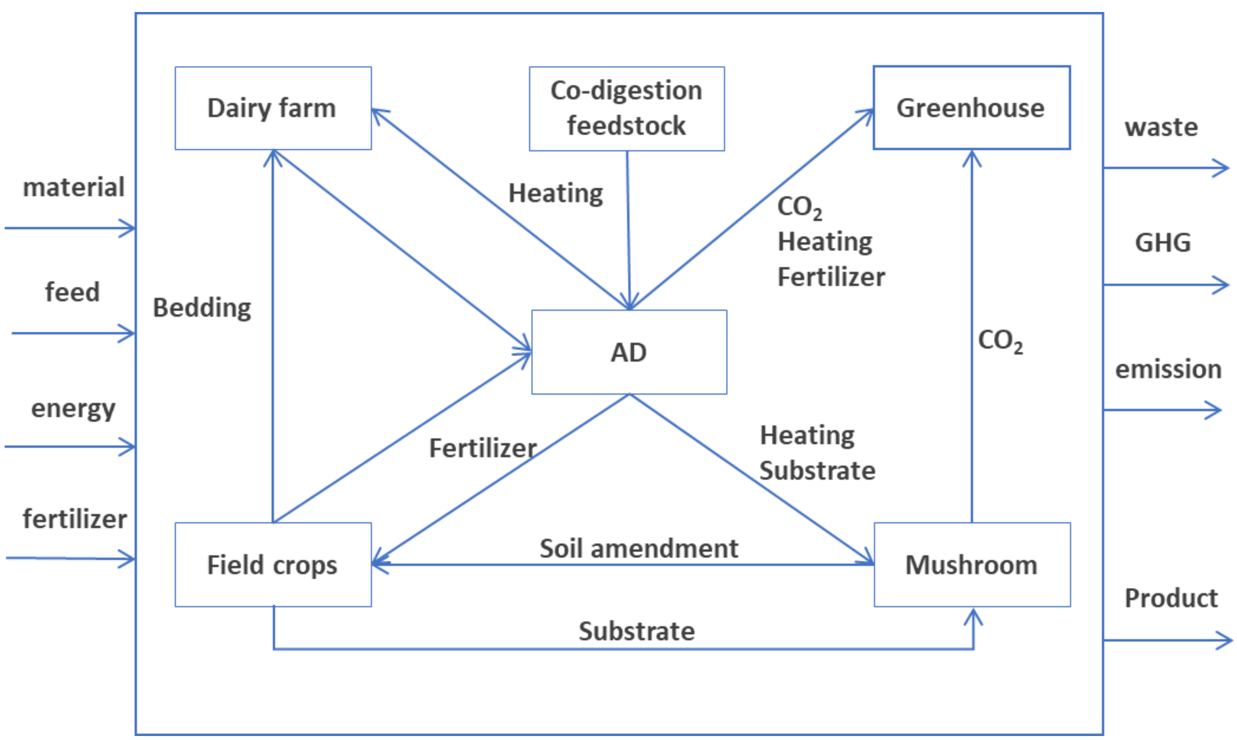


Figure 5.1 System description and boundary for the integrated scenarios

Based on the functional unit (1400 tDM feedstock), the total heat and CO_2 supply from the biogas combustion are calculated. Then, the scales of the greenhouse and mushroom production are determined by the following two criteria: (1) Total heat demand in the summer is matched with the biogas capacity, and (2) CO_2 demand of the greenhouse in the summer is matched with CO_2 supply from biogas and mushroom ventilation air. Eliminating natural gas consumption for heating and greenhouse CO_2 enrichment in the summer avoids waste of thermal energy from biogas combustion, but means that natural gas is used during other seasons when heating demand is higher. However, no extra CO_2 enrichment is needed during other seasons when plants grow slower.

The areas of the greenhouse and mushroom production were calculated as follows:

$$\mathrm{NC} = \mathrm{AG} * CG$$

$$\mathrm{CG} = \sum_{i=1}^{3} (\mathrm{c}_{\mathrm{G,i}} - h_{\mathrm{G,i}} * I)$$

$$\mathrm{AG} = \frac{\mathrm{HBG} * \frac{c_{M,2}}{h_{M,2}} - CBG}{h_{G,2} * \frac{c_{M,2}}{h_{M,2}} - c_{G,2}}$$

$$AM = \frac{HBG - h_{G,2} * AG}{h_{M,2}}$$

Where NC = natural gas displaced by CO_2 integration, AG = area of the greenhouse, AM = area of the mushroom production, CG = additional CO_2 enrichment of greenhouse per ha, c = CO_2 supply per ha (CO_2 demand of greenhouse is indicated by negative value), h = heat demand per ha, G = greenhouse, M = mushroom, i = season (1 = spring, 2 = summer, etc.), I = CO2 intensity of natural gas, HBG = heat supply from biogas and CBG = CO_2 supply from biogas.

Table 5.2 System configuration and performance of the integrated scenarios

	Unit	CM	CM-PM	CM-FW	CM-CR
Feedstocks and biogas capacity					
Cattle manure processed	tDM/year	1400	1050	1050	1050
Co-digestion feedstock		None	Poultry Manure	Food Waste	Crop Residues
	tDM/year		350	350	350
Heat supply, biogas	GJ/month	840	796	962	820
CO_2 supply, biogas	t/month	76	92	115	95
CO_2 supply, mushroom	t/month	96	72	86	74
System configurations and raw materials displaced					
Dairy	Head	400	300	300	300
Straw as animal bedding	tDM/year	328	246	246	246
Greenhouse	Ha	1.24	1.57	1.94	1.62
Rockwool displaced by SD	tDM/year	15.6	14.8	18.3	15.3
Mushroom	Ha	0.54	0.68	0.86	0.71
SD as Mushroom substrate	tFM/year	1892	1796	2261	1863
Urea displaced	tN/year	8.6	8.2	10.3	8.5
Straw displaced	tDM/year	398	377	475	392
Field crop	Ha	239.4	179.5	179.5	179.5
Crop residues collected	tDM/year	649	486	486	486
Heat balance					
Natural gas as heating	GJ/year	15503	14434	17601	14894
Heat demand, spring	GJ/month	2478	2324	2828	2397
Heat demand, summer	GJ/month	840	796	962	820
Heat demand, fall	GJ/month	1975	1851	2247	1909
Heat demand, winter	GJ/month	3233	3024	3678	3119
CO_2 balance					
Natural gas as CO_2 enrichment	t/year	0	0	0	0
CO_2 demand, spring	t/month	129	122	152	127
CO_2 demand, summer	t/month	172	163	202	169
CO_2 demand, fall	t/month	129	122	152	127
CO_2 demand, winter	t/month	17	16	20	16
Fertilizers displaced					
N fertilizer displaced	t/year	35.7	41.1	32.8	27.8
P fertilizer displaced	t/year	5.9	9.7	5.3	4.6
K fertilizer displaced	t/year	23.7	25.4	19.8	20.9

5.3 Economics

The economic model used in this chapter is the same as in Chapter 4. All values are expressed in Canadian dollars of 2018. The principle of change-oriented accounting is applied to calculate the economic impact of on-farm AD systems, by estimating the incremental capital cost and cash flow relative to the "business as usual" base scenarios in which no AD system is implemented and all agricultural activities are operated conventionally. For the RNG and CHP scenarios, capital and production costs of on-farm AD systems and revenues generated from biogas and digestate utilization and policy measures are included.

Table 5.3 Revenues from by-products and avoided transportation

Item	Cost	Unit	Source
Natural gas (excl. carbon tax) displaced	6.6	$/GJ	[225]
Nitrogen (N) fertilizer	1.11	$/kgN	[226]
Phosphorous (P) fertilizer	2.61	$/kgP	[226]
Potassium (K) fertilizer	0.92	$/kgK	[226]
Growing media displaced by SD	6.29	$/m2/year	[227]
Mushroom substrate displaced by SD	79.3	$/t product	Appendix A.2
Avoided HDV Transportation	0.134	$/tkm	[168]

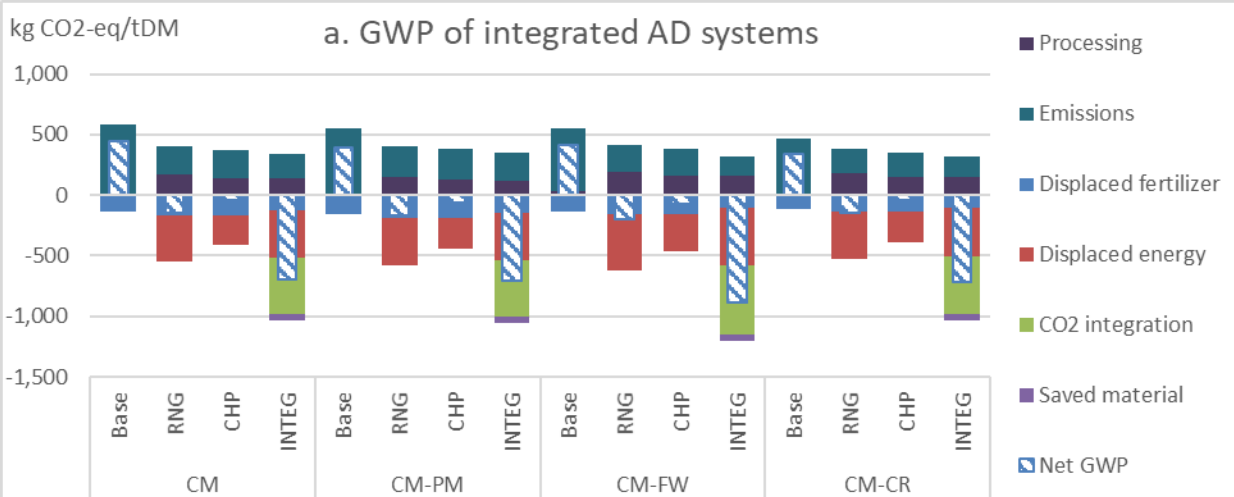
For integrated scenarios, capital and production costs are assumed to be the same as the HB scenarios in Chapter 4, neglecting piping and any other costs to integrate different components. In addition to revenues from biogas-fired heating service, integrated scenarios generate extra revenues via byproduct utilization to displace natural gas for CO_2 enrichment, synthetic fertilizers, and raw materials (Table 5.3). Revenues from displaced CO_2 enrichment are calculated based on the small business rate of natural gas [225]. Revenues from displaced synthetic fertilizers are based on their market prices [226]. Revenues from the substitution of raw materials, including greenhouse growing media and mushroom substrate, are estimated based on the market value of these materials, plus avoided transportation costs for 50 km by HDV. Crop residues collected locally are assumed to avoid the cost of transportation over 200 km by HDV, as they otherwise must be imported from other regions of the province.

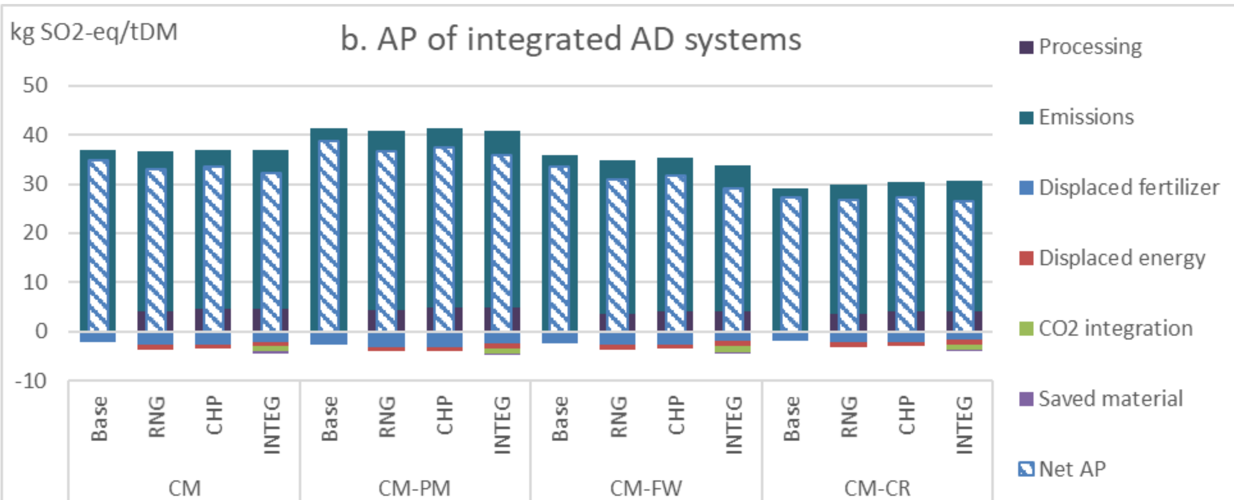
5.4 Environmental impact results

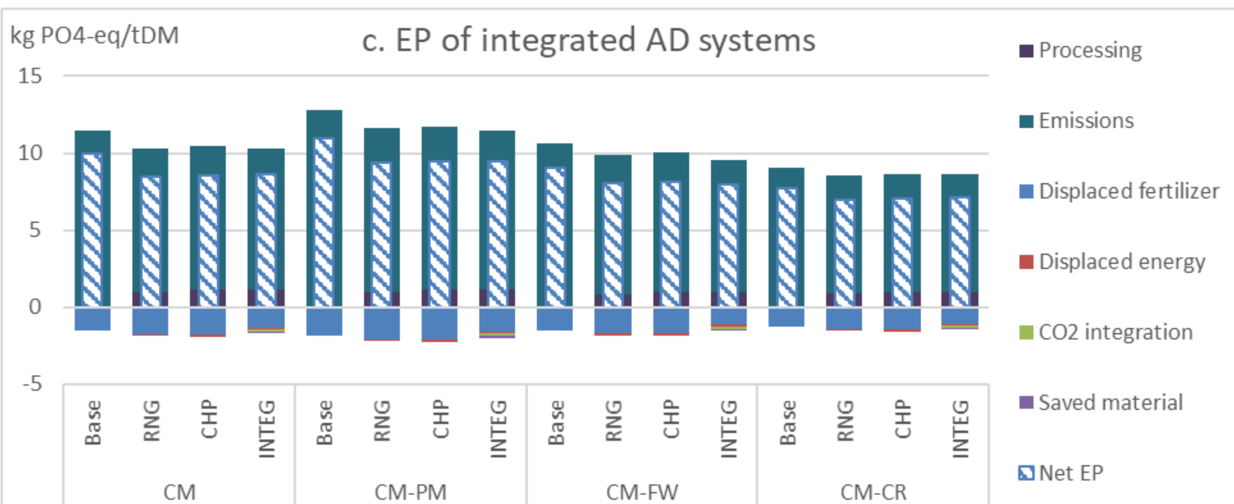
5.4.1 Global warming potential

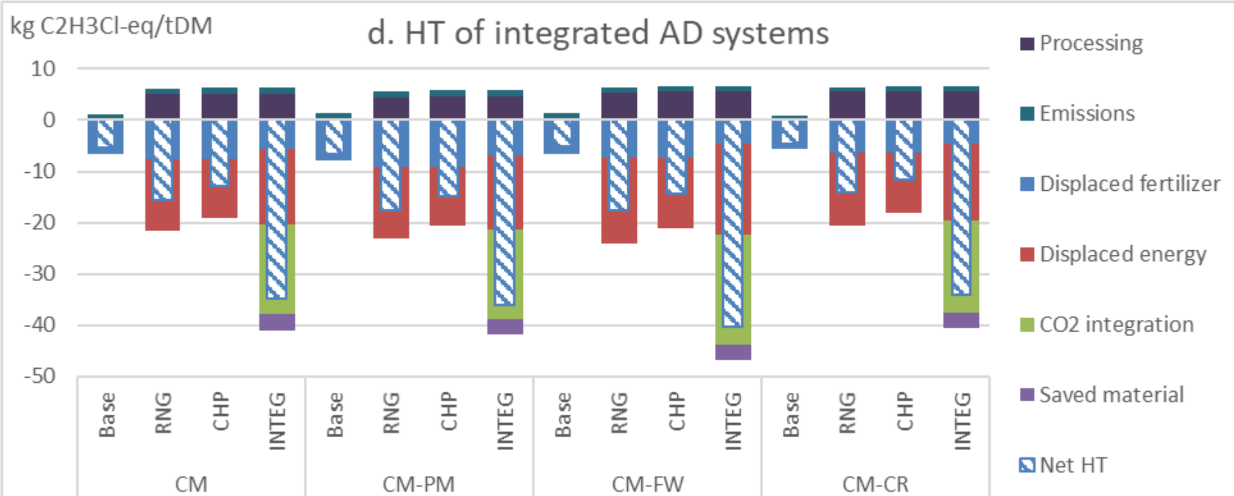
As shown in Figure 5.2(a), all AD scenarios can reduce global warming potential (GWP) below the base scenarios, as in the results for AD systems without co-digestion or integration in Section 4.3. For integrated scenarios, CO_2 integration can effectively displace natural gas consumption that provides CO_2 enrichment to the greenhouse; this even surpasses avoided burdens for natural gas consumption displaced by biogas-fired heating. As a result, integrated scenarios can achieve twice as much GWP benefits as the RNG and CHP scenarios. In comparison, the GWP benefits from displaced synthetic fertilizers and avoided raw materials are much less significant in the integrated scenarios.

Co-digestion with food waste is also seen to be an effective strategy to increase the GWP benefits of integrated AD systems: food waste increases the yield of biogas and thereby increases the potential GWP benefits of integrated AD systems via CO_2 integration in addition to the provision of biogas heating. On the other hand, as crop residues and poultry manure have relatively low biogas yield, co-digestion with these feedstocks shows no improvement in GWP benefit. Overall, integrated AD systems with co-digestion of food waste give 20% greater GWP benefits than other feedstock types.


kg CO2-eq/tDM
a. GWP of integrated AD systems
1,000
500
0
-500
-1,000
-1,500
Base
RNG
CHP
INTEG
CM
CM-PM
CM-FW
CM-CR
Processing
Emissions
Displaced fertilizer
Displaced energy
CO2 integration
Saved material
Net GWP


kg SO2-eq/tDM
b. AP of integrated AD systems
50
40
30
20
10
0
-10
Base
RNG
CHP
INTEG
CM
CM-PM
CM-FW
CM-CR
Processing
Emissions
Displaced fertilizer
Displaced energy
CO2 integration
Saved material
Net AP


kg PO4-eq/tDM
c. EP of integrated AD systems
15
10
5
0
-5
Base
RNG
CHP
INTEG
CM
CM-PM
CM-FW
CM-CR
Processing
Emissions
Displaced fertilizer
Displaced energy
CO2 integration
Saved material
Net EP



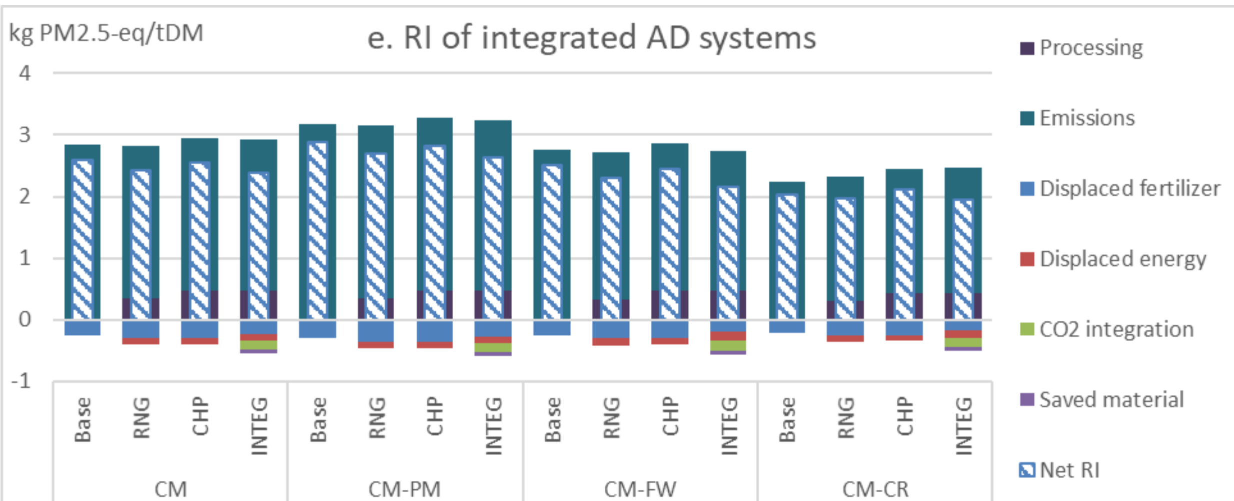


Figure 5.2 LCA results for base and biogas scenarios of different feedstock

5.4.2 Acidification and eutrophication potential

As explained in Section 4.3, acidification potential (AP) and eutrophication potential (EP) are mostly attributed to emissions from processing and spreading nutrient-rich waste materials such as manure and digestate. Consequently, AD can slightly reduce AP and EP below the base scenarios, due to improved nutrient management. As shown in Figure 5.2(b)&(c), integrated scenarios can achieve additional benefit in AP and EP via CO_2 integration, which avoids emissions generated in the upstream production and supply of natural gas. However, the magnitude of improvement from other biogas utilization options is nugatory (<10%).

5.4.3 Human toxicity and respiratory inorganics

Human Toxicity (HT) is caused by emissions of hazardous organic compounds from upstream processes and the consumption of natural gas and fertilizers. Therefore, integrated scenarios can substantially reduce HT impact of RNG and CHP scenarios, by displacing natural gas consumption via CO_2 integration (Figure 5.2(d)). The substitution of raw materials by solid digestate leads to additional benefits in HT impact. Co-digestion with food waste has higher HT benefit than other feedstock types due to higher biogas yield and CO_2 integration capacity.

Respiratory Inorganics (RI) refers to one of the impacts of inorganic emissions. As explained in Section 4.3, the primary source of RI from organic waste management is NH_3 emissions. Emissions from the consumption of fossil fuels also contribute to RI. As shown in Figure 5.2(e), both CO_2 integration and substitution of raw materials in integrated scenarios lead to additional benefits in RI. As a result, integrated scenarios have slightly lower RI than the RNG and CHP scenarios.

5.4.4 Sensitivity analysis

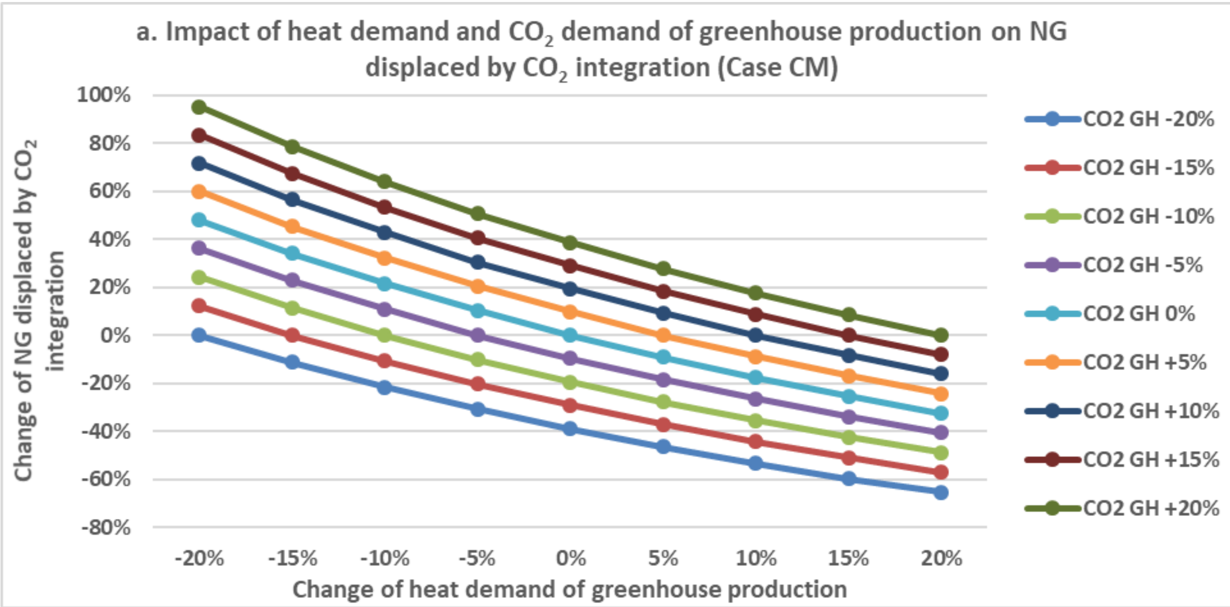
Influences of AD parameters on the environmental and economic performance of conventional biogas utilization options such as RNG, CHP and HB have already been discussed in Chapter 4. Those findings would also apply to integrated AD systems. In the following section, sensitivity analysis is conducted only on factors specific to integrated scenarios.

Heat and CO2 demand for greenhouse production

Heat and CO_2 demands for greenhouse production are subject to a high degree of uncertainty, such as cultivation method, climate and plant species. Variations in heat and CO_2 demand result in changes in the configuration of integrated AD systems and affect the amount of natural gas displaced by CO_2 integration, as described in Section 5.2.2.

As shown in the last section, natural gas displacement via CO_2 integration is the dominant contributor to the additional environmental benefit of the integrated scenarios, especially in the impact categories of global warming potential and human toxicity. Therefore, the heat and CO_2 demand of greenhouses is a source of significant uncertainty in the estimates for the additional environmental benefit of the integrated scenarios. Meanwhile, CO_2 integration is also a major source of additional revenues for the integrated scenarios. Therefore, a sensitivity analysis is conducted to investigate how changes in greenhouse heat and CO_2 demand data affect the amount of natural gas displaced by CO_2 integration, using the case of cattle manure (CM) as an example.

As shown in Figure 5.3(a), ±20% change in heat and CO2 demand for greenhouse production has a significant impact (-65% to +95%) on the amount of natural gas displaced by CO_2 integration. As heat demand for greenhouse production increases while the heat supply from biogas remains the same, the greenhouse area in the integrated system decreases. The increased heat demand also reduces the requirement of additional CO_2 enrichment per hectare greenhouse area. Both these effects reduce the potential avoided burden for displacing natural gas. On the other hand, as CO_2 demand increases, even though the greenhouse area decreases slightly, additional CO_2 enrichment per hectare significantly increases, which leads to more natural gas displacement overall. Increases in heat demand and increases in CO_2 demand act in opposite directions and cancel each other. This result clearly shows that natural gas credit of CO_2 integration has a positive correlation with CO_2 to heat demand ratio of greenhouse production.



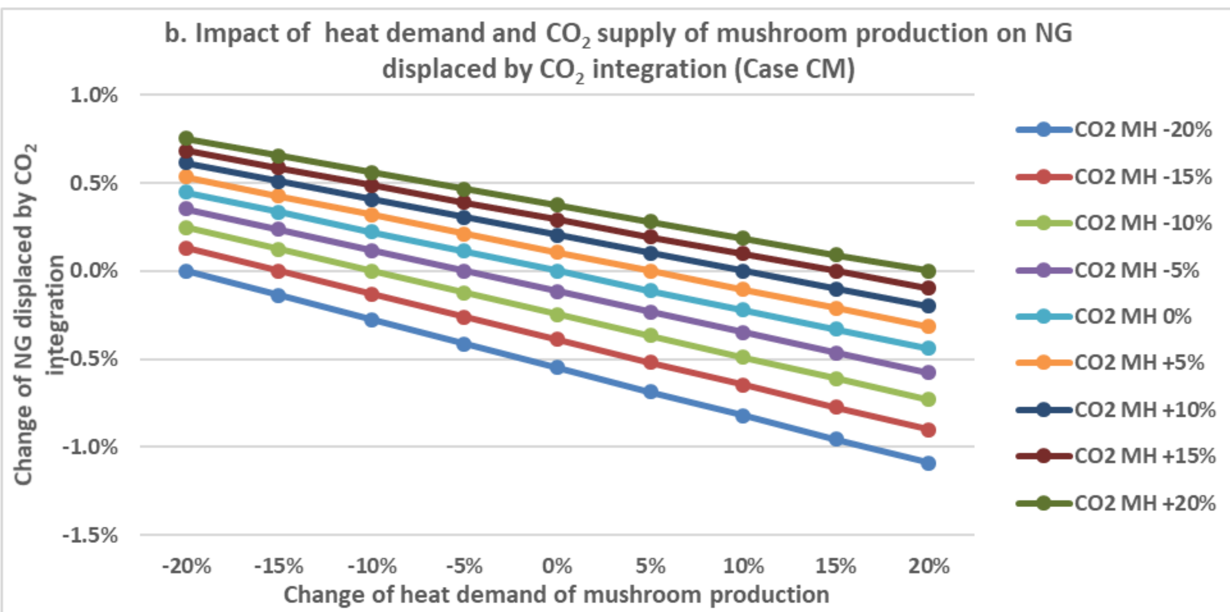


Figure 5.3 Impact of heat and CO_2 demand for greenhouse and mushroom production on NG displaced by CO_2 integration

Heat demand and CO_2 supply for mushroom production

Sensitivity analysis has also been conducted on heat demand and CO_2 supply for mushroom production. As shown in Figure 5.3(b), a decrease in heat demand or an increase in CO_2 supply from mushroom production can increase the amount of natural gas displaced by CO2 integration. However, the degree of change is negligible (±1%). Therefore, variation in the parameters for mushroom production has a much smaller impact than for greenhouse production on the additional benefits of the integrated scenarios.

Field crops and residue collection

Local field crops are an integral part of the nutrient cycle of the AD system. Crop residues collected from local field crops can reduce materials purchased and transported from outside the integrated AD system. However, due to variations in crop species, farm practices, climate, and soil conditions, assumptions on the availability and transportation of crop residues are highly uncertain.

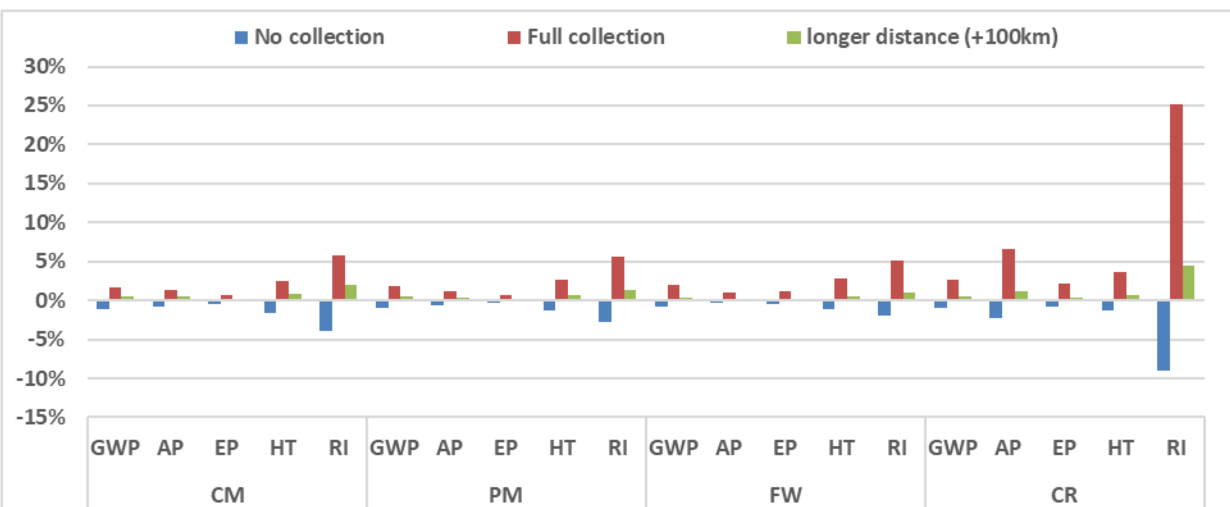


Figure 5.4 Impact of local crop residue collection and avoided transportation on the environmental benefits of integrated scenarios

In the sensitivity analysis, three crop residue collection scenarios are considered. In the first case, it is assumed that there are no crop residues collectable from local fields. In the second case, it is assumed that the supply of crop residues locally is sufficient to meet the material demands of the integrated AD system. These two cases present the two extremities of the avoided burdens for crop residue transportation. As shown in Figure 5.4, variations in the availability of local crop residues show low impact (<5%) on the environmental benefits of the integrated AD system for most scenarios. The only exception is the integrated AD system with co-digestion of crop residues, which has lower overall environmental benefits and thereby shows higher sensitivity to the avoided burdens of crop residue transportation. Overall, impacts from availability and transportation of crop residues on the environmental benefits of integrated scenarios are expected to be small, unless the supply chain changes dramatically.

5.5 Cost, revenue and financial support from policy measures

5.5.1 Capital and operation costs

As shown in Figure 5.5(a), the capital costs of on-farm AD systems range from 1.0 to 1.7 million dollars, or \$610-990 per tonne dry matter (tDM) processed annually. Since the integrated AD systems have the same system configuration as biogas-fired HB systems, their capital costs are considerably lower than RNG and CHP scenarios, the latter requiring costly components including grid connection and biogas upgrade or CHP unit. As co-digestion with food waste can significantly increase biogas yield, it requires the lowest capital cost per kW_{th} biogas capacity.

Production costs of biogas scenarios range from 0.38 to 0.48 million dollars, or \$220-290 per tDM organic matter processed (Figure 5.5(b)). Overall, there is little difference in production cost across the different integrated scenarios. Due to lower capital costs, integrated scenarios are also lower in production costs than RNG and CHP scenarios. By increasing biogas yield, co-digestion with food waste reduces production cost per kW_{th} biogas capacity ($29-37/GJ). Co-digestion with poultry manure or crop residues has similar production costs per kW_{th} as mono-digestion of cattle manure ($35-43/GJ).

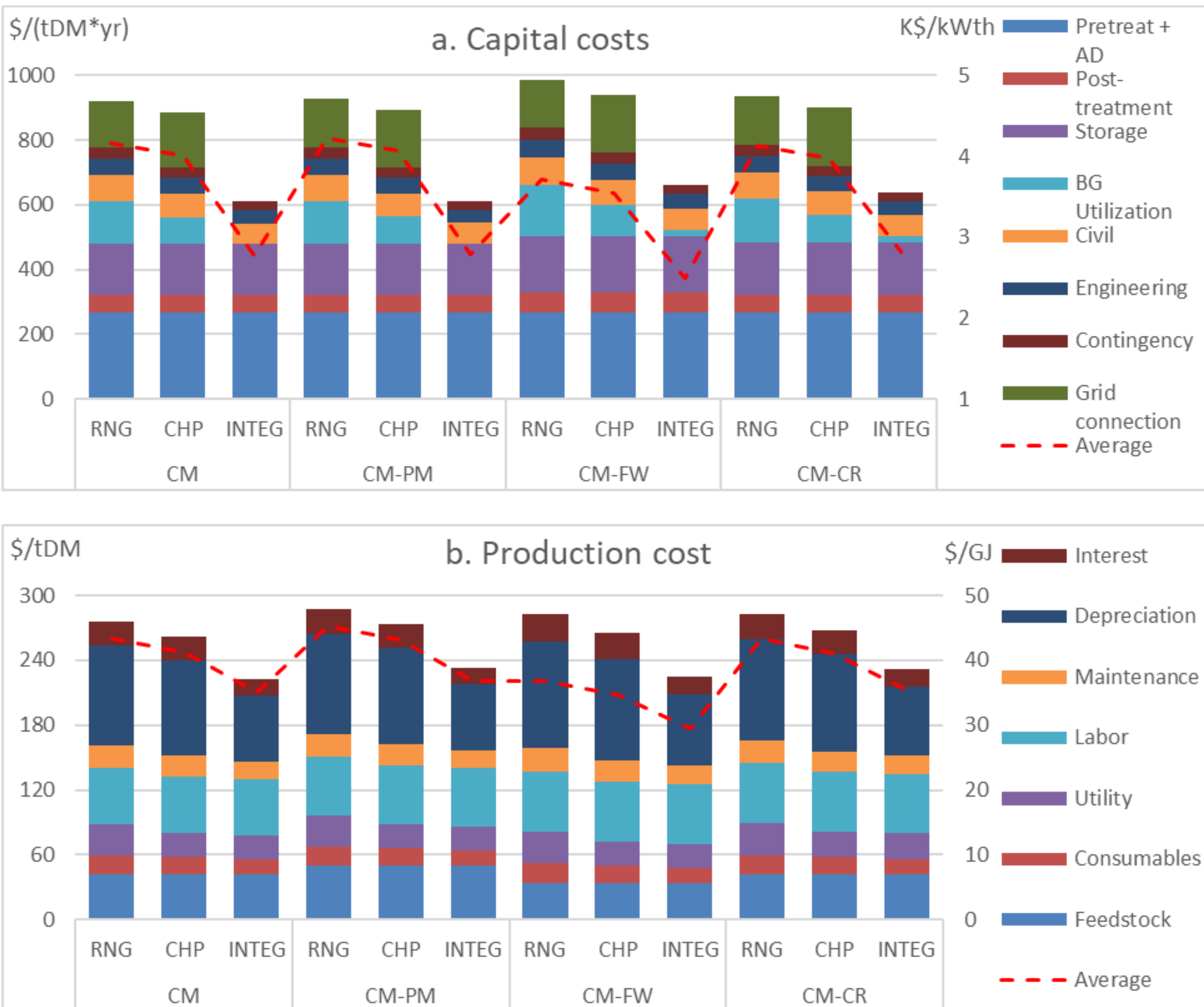


Figure 5.5 Capital and production costs of integrated AD systems

5.5.2 Revenues from biogas products and value-added by-products

As shown in Figure 5.6(a), integrated scenarios generate much higher revenues than RNG and CHP scenarios. For RNG and CHP scenarios, revenues from the sale of biogas and digestate are not enough to cover production costs. In integrated scenarios, however, extra revenues generated from each integration scheme, including displaced natural gas by CO_2 integration and displaced raw materials by SD in greenhouse and mushroom production, can surpass the revenues from the main product of biogas-fired heating. With both extra revenues from value-added byproducts and lower production costs, integrated AD systems can break even in annual cash flows or achieve net profits, not including any financial support from policy measures, such as feed-in tariffs or tipping fees. This finding highlights the importance of pursuing extra revenues from value-added by-products for on-farm AD systems, due to the current low natural gas price in BC.

5.5.3 Impact of policy measures on cash flows of on-farm AD systems

So far, we have excluded policy measures to evaluate the economic viability of on-farm AD systems. In the following section, the impact of policy measures on the profitability of on-farm AD systems is analyzed, including feed-in tariff (FiT), carbon tax, and waste tipping fees.

As shown in Figure 5.6(b), integrated scenarios can receive much more carbon tax credits than RNG and CHP scenarios, by displacing substantially more natural gas via biogas heating and CO_2 integration. Extra revenue of $40,000-50,000 per farm, or $3.8/GJ, can be generated from carbon tax credits, significantly improving the profitability of integrated AD systems. Even though specific financial support to biogas heating is lacking, whereas renewable natural gas is heavily subsidized by FiT, integrated scenarios still outperform RNG and CHP scenarios. This result confirms that integration with agricultural practices is an effective way to improve the profitability of on-farm AD systems and reduce financial dependence on policy incentives. Furthermore, extra revenues from food waste tipping fees give co-digestion with food waste a clear economic advantage over other AD feedstocks.

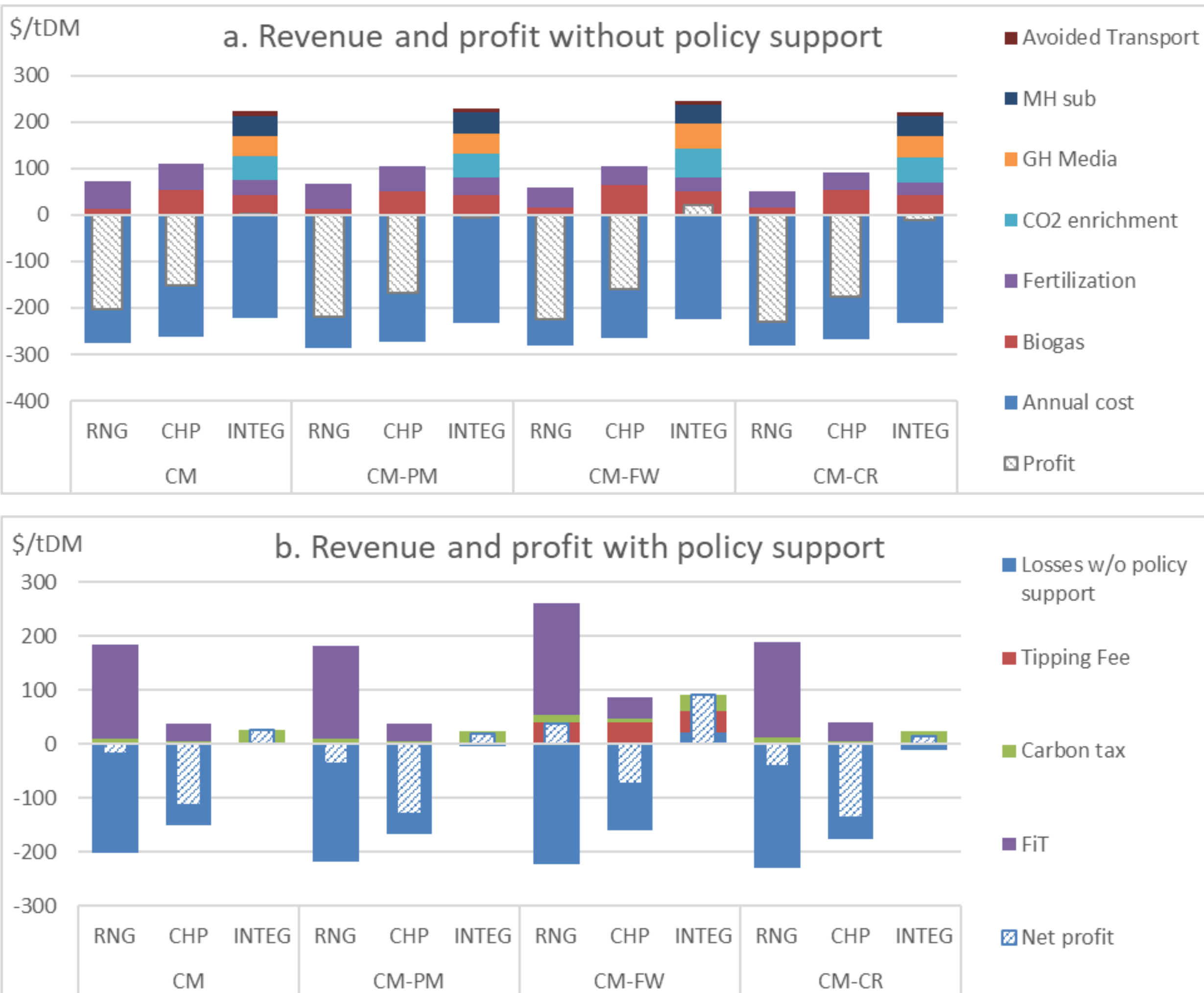


Figure 5.6 Revenues and profits without and with policy support for on-farm AD systems

5.5.4 Sensitivity analysis

Sensitivity analysis has been conducted on economic factors related to the integrated scenarios, including commodity prices, saved materials, saved transportation and carbon tax. The ranges of variation considered are shown in Table 5.4.

Table 5.4 Range of variation of economic factors

Factor	Variation	Factor	Variation
NG price	±20%	GH Media	±20%
Fertilizer price	±20%	MH Sub	±20%
Material transport	±20%	Carbon tax	±$15/tCO2-eq
CO2 integration	±20%	Feedstock price	±$20/tDM

As shown in Figure 5.7, different feedstocks all show similar sensitivity to each economic factor. Variation in natural gas and feedstock price can significantly impact the profitability of the integrated scenarios. Since natural gas price is currently at its 20-year low, the economic prospect of the integrated scenarios is expected to improve, should natural gas price start to recover. Meanwhile, high sensitivity to variation in feedstock prices implies the importance of waste tipping fees for the profitability of on-farm AD systems. On the other hand, an increase in feedstock prices, which may be caused by prolonged transportation distance or shortage of feedstock, can significantly reduce the profitability of integrated AD systems.

The result also shows that carbon tax has a moderate impact: As carbon tax increases to $50/t CO2 from the current level of $35/tCO2, additional revenue of $10/tDM can be expected for integrated scenarios. Uncertainties in fertilizer prices, avoided natural gas via CO_2 integration, and avoided raw material consumption and transportation show moderate to low impact on the profitability of integrated scenario, as none of these factors has a strong influence on revenues. Therefore, uncertainties in these factors are unlikely to affect the economic prospect of integrated AD systems with co-digestion of food waste. On the other hand, the profitability of integrated AD systems with other feedstocks is much more uncertain.

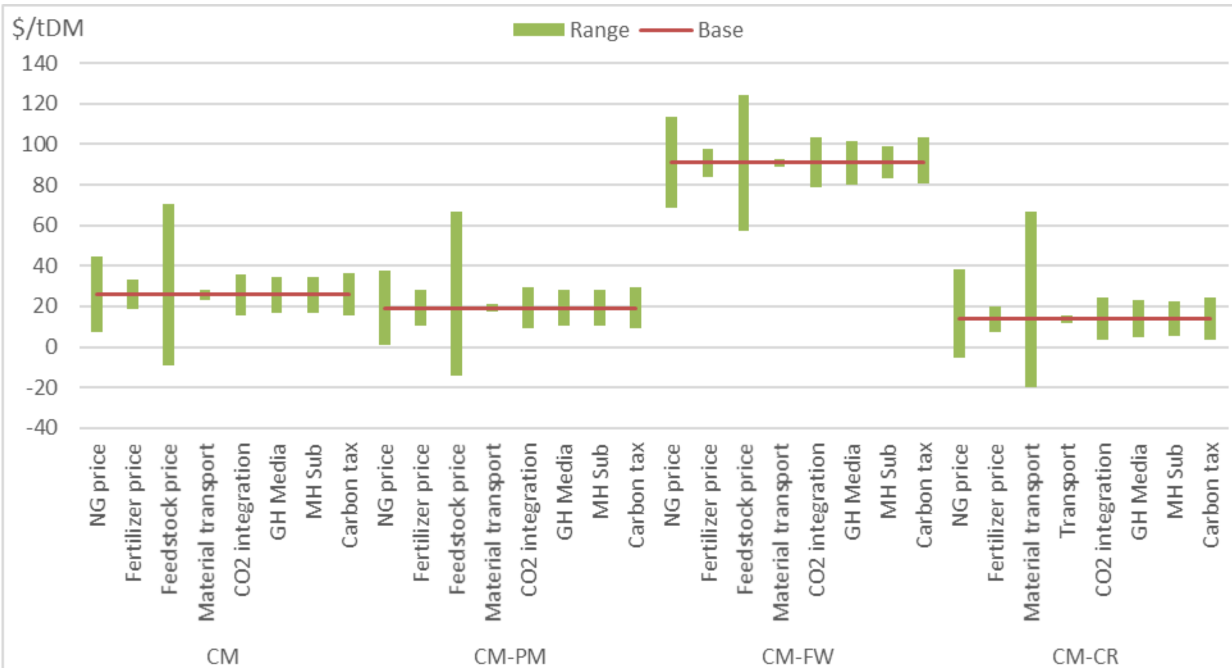


Figure 5.7 Sensitivity analysis of economic factors on the net profit of integrated AD systems

5.6 Regional nutrient flows

A high ratio of livestock to crop production can lead to imbalances between the nutrient flows that are generated by livestock husbandry and can be absorbed by field crops. For example, Cederberg has shown how the local concentration of beef and dairy farming in southwest Sweden leads to pollution by nitrogen run-off [228]. Figure 5.8 identifies the regions in BC with intensive cattle husbandry, with statistics shown in Table A.3. Agriculture in the Lower Mainland includes 20% of cattle, 90% of poultry, and 80% of swine production in the province but only has 4% of the agricultural land to provide a nutrient sink [221]. Furthermore, 60% of BC’s population lives in the Lower Mainland [229], generating food waste that calls for composting and land application as well. These statistics underline why nutrient management is a problem in areas like the Lower Mainland of BC.

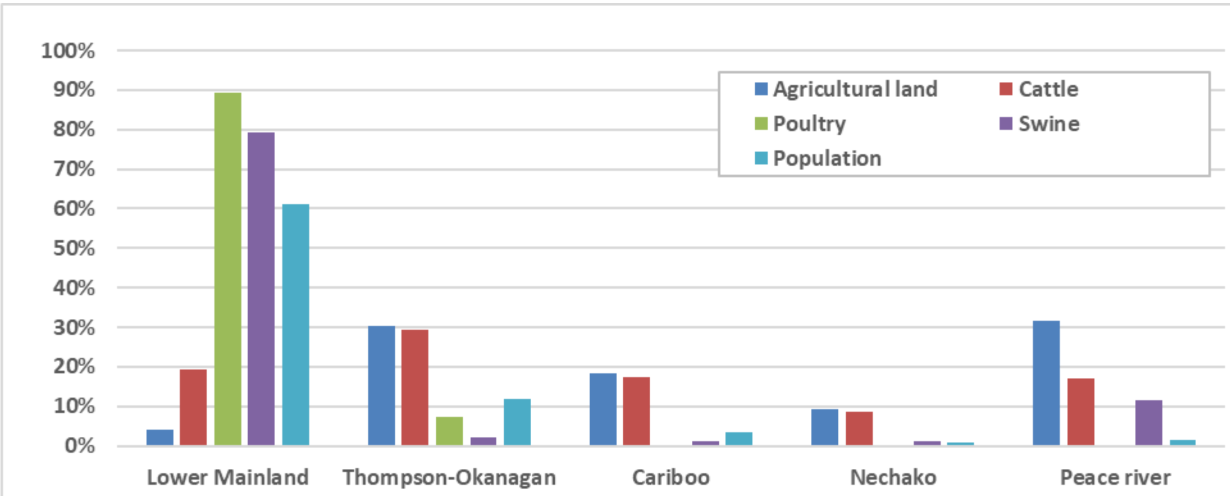


Figure 5.8 Regional distribution of agricultural lands, livestock, and population in BC [221], [229]

Based on nitrogen and phosphorus contents and loss rates of animal manure and food waste, nutrient flows in organic wastes can be estimated on a regional basis. Based on the acreage of different crops in each region [221], [230] and the recommended fertilization rates of different crops [231], regional nutrient demand for organic N fertilization can be obtained. Note that it is assumed that the use of organic N should not exceed 50% of the total fertilization. Many studies have shown that the ratios of manure N to total N fertilization in Canadian provinces are generally less than 30% [232], [233], so the assumed organic N fertilization rate of 50% represents a conservative value, favourable to the management of manure and food waste.

As shown in Figure 5.9, it is evident that agriculture in the Lower Mainland generates a serious nitrogen surplus, due to the intensive livestock farming and the shortage of agricultural land. The resulting pressure to dispose of animal manure could lead to improper manure management and therefore higher nutrient losses, which can lead to environmental impacts including serious nutrification of water bodies already observed in other areas with intensive livestock production [234]. On the other hand, there is abundant agricultural land (mostly pasture) with much higher land/animal ratio in other regions of BC [221], where there is a high demand for fertilization. Therefore, surplus animal manure in the Lower Mainland could be exported to adjacent regions [235]. However, while the removal of manure may be desirable to alleviate local environmental impacts, transportation significantly increases the general environmental impacts and costs.

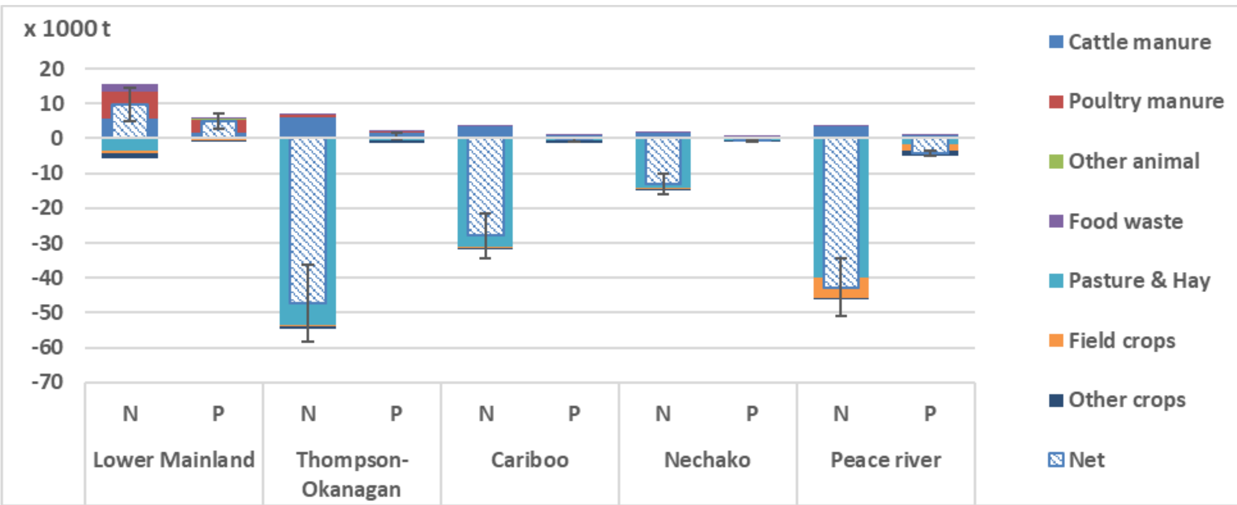


Figure 5.9 Regional nitrogen and phosphorus balances in BC

It is to be noted that this issue of the regional nutrient surplus is not captured by the LCA, due to the spatial limitations of the LCA methodology, similar to the issue with the interpretation of the health impacts generated from the end-use stage (Section 3.3.2.) The results in Section 4.3.2 and Section 5.4.2, that AD and integration do not have substantial benefits in reducing the acidification and eutrophication potential, represent the average case for manure management and digestate use, where there is no land restriction on the spreading of these organic fertilizers. However, the regional nutrient surplus in the Lower Mainland, shown in Figure 5.9, could induce farmers to improperly dispose of animal manure to avoid the costs of inter-regional transportation. According to Statistics Canada, 62% of the farms in BC had no formal Environmental Farm Plan in 2017 [236]. While the extent of improper manure management is still unknown, it will inevitably increase the nutrient loss.

A number of studies have shown that full substitution of inorganic fertilizers with liquid digestate can maintain crop productivity [216], [237]. Thus, the use of digestate could lead to more fertilization by nitrogen sourced from local organic wastes, reducing the use of nitrogen fertilizers imported into the region and hence reducing the nitrogen surplus in the Lower Mainland. As shown in Table 5.5, implementation of AD can potentially increase the efficiency of use of nitrogen in organic waste from 19% to 37%, completely displacing inorganic fertilizers in the region. Consequently, the nutrient surplus would be reduced from 34% to 18%. Furthermore, integration of AD with the greenhouse and mushroom industry in the Lower Mainland at the current production scale can increase the efficiency of nitrogen use by a further 2%. These measures would reduce the need for inter-regional transportation of animal manure, as well as reducing the pressures that could provoke poor nutrient management practices.

Table 5.5 Effect of AD on nutrient balances in Lower Mainland

	Base, no AD		AD, land application of digestate		Integrated AD system	
	,000 tonne	%	,000 tonne	%	,000 tonne	%
Total N supply	29.6	100%	29.6	100%	29.6	100%
Available N	15.6	52%	16.3	55%	16.3	55%
N loss	14.1	48%	13.3	45%	13.3	45%
Crop N demand	11.0	N/A	11.0	N/A	11.0	N/A
Manure N applied	5.5	19%	11.0	37%	11.0	37%
GH+MH	0.0	0%	0.0	0%	0.6	2%
Surplus	10.1	34%	5.3	18%	4.7	16%

5.7 Conclusions

Integration of dairy-based on-farm AD systems with common agricultural practices in BC, including greenhouse, mushroom and field crops, is an effective way to promote biogas heating by increasing its environmental benefit. By turning CO_2 content in biogas and mushroom ventilation air into useful CO_2 enrichment for greenhouse production, a significant amount of natural gas consumption can be displaced. Other byproduct integration schemes, such as the substitution of greenhouse growing media and mushroom substrate with solid digestate, can also reduce the consumption of raw materials, but their environmental benefits are more limited. Primarily due to avoided natural gas consumption from CO_2 integration, integrated AD systems can further reduce the environmental impacts of global warming potential and human toxicity beyond the reductions available from conventional biogas utilization options such as RNG and CHP. Integrated AD systems also show a slight improvement in respiratory inorganics, but no significant improvement in acidification and eutrophication. Co-digestion of cattle manure with food waste can magnify benefits of integration schemes and further improve the overall environmental performance of integrated AD systems, due to higher biogas yield.

Economically, by-product integration can significantly improve the profitability of on-farm AD systems. A significant source of extra revenues is avoided natural gas consumption via CO_2 integration. Meanwhile, the substitution of greenhouse growing media and mushroom substrate with solid digestate also leads to significant extra revenues, far exceeding the value if solid digestate is simply used as fertilizers. Crop residue collection from local crop fields also slightly reduces transportation costs of imported crop residues from other regions, which depends on the existing supply chain of each region. These extra revenues combined can effectively offset the economic disadvantage of biogas due to low natural gas prices and result in positive net profits of on-farm AD systems even without financial support from policy measures. Other co-digestion scenarios show similar economic performance, whereas co-digestion with food waste can significantly increase the extra revenue from integration.

Moreover, integrated scenarios can benefit more from carbon tax than other biogas utilization options due to additional natural gas avoided by CO_2 integration. Allowing for the impact of policy measures, integrated scenarios are much less dependent on financial support but still more profitable than RNG and CHP scenarios. Food waste tipping fees bring a substantial amount of revenue to on-farm AD systems, but financial incentives for handling agricultural wastes are still missing. As a result, food waste is the most favoured co-digestion feedstock to increase the profitability of integrated AD systems.

AD can significantly assist regional nutrient management in the Lower Mainland, with its exceptionally high density of livestock. By converting nitrogen in the organic form sourced from animal manure and food waste to chemical forms, AD can increase the efficiency of use of nitrogen in organic fertilizers applied to the agricultural lands. Moreover, integration of AD with agricultural practices can lead to even more efficient utilization of digestate and further improve nutrient management in the region. This finding has global significance, applicable to many other areas with dense livestock husbandry where serious problems of nitrogen run-off have been reported.

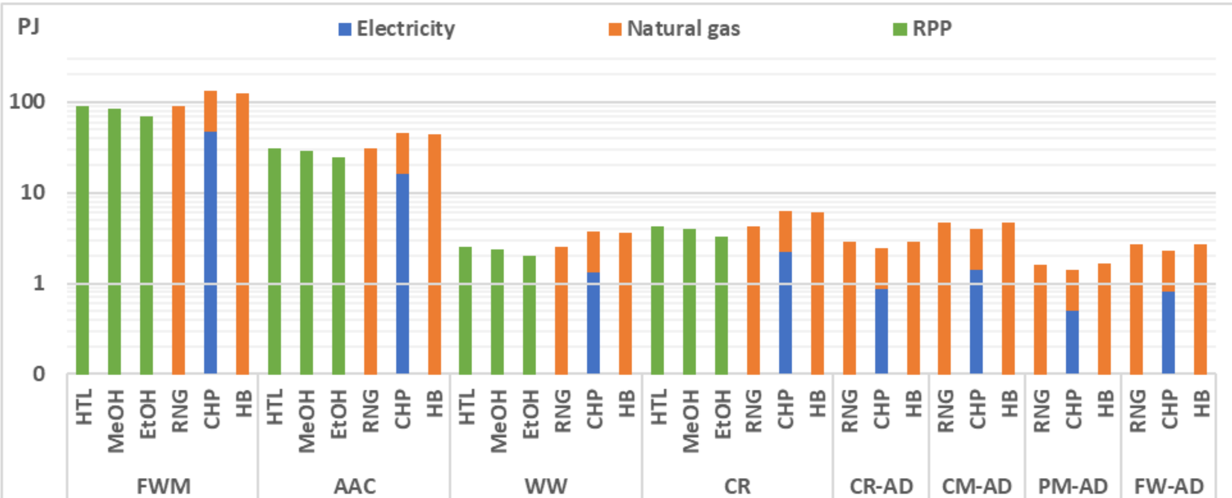
Chapter 6 Policy implications

6.1 Overview of bioenergy production in BC

6.1.1 Total bioenergy production potential

Based on the estimates for BC's biomass resources summarized in Chapter 2 and energy conversion efficiencies described in Chapters 3 and 4, the total potential for bioenergy production in BC can be estimated. Figure 6.1 shows the total demand (in higher heating value) of electricity, natural gas, and refined petroleum products (RPPs) that can be displaced by various combinations of feedstocks and bioenergy technologies. Biomass-fired and biogas-fired heating, specifically heat-only boilers (HB) and the heat output of cogeneration of heat and power (CHP), are assumed to displace natural gas that is consumed for heating at a furnace efficiency of 90%. Liquid biofuels and electricity produced from CHP are assumed to displace the RPPs, as energy carriers rather than primary energy, and BC electricity mix respectively. Note that power-only generation is not included in Figure 6.1, due to low conversion efficiency and lack of GHG benefits in BC (see Chapter 3), nor will it be discussed in the rest of this chapter for the same reason.

As shown in Figure 6.1, the potential for bioenergy production in BC mostly comes from forestry waste materials, including harvest residues, sawmill residues, and MPB-infested trees. (Note that the ordinate of Figure 6.1 is expressed on a logarithmic scale.) The next largest are standing timbers in AAC, about one-third the size of forestry waste materials. In comparison with forestry resources, the total potential for bioenergy produced from other waste streams, specifically wood waste and food waste in MSW, crop residues, and animal manure, is much smaller.



Conversion: HTL = Biofuels from Hydrothermal Liquefaction, MeOH = Methanol, EtOH = Ethanol, RNG = Renewable Natural Gas, CHP = Cogeneration, HB = Heat-only Boiler, AD = Anaerobic Digestion.

Feedstock: FWM = Forestry Waste Materials, AAC = Standing timbers within AAC, WW = Wood Waste in MSW, CR = Crop Residues, CM = Cattle Manure, PM = Poultry Manure, FW = Food Waste in MSW.

Figure 6.1 Total energy demand potentially displaceable by bioenergy produced in BC

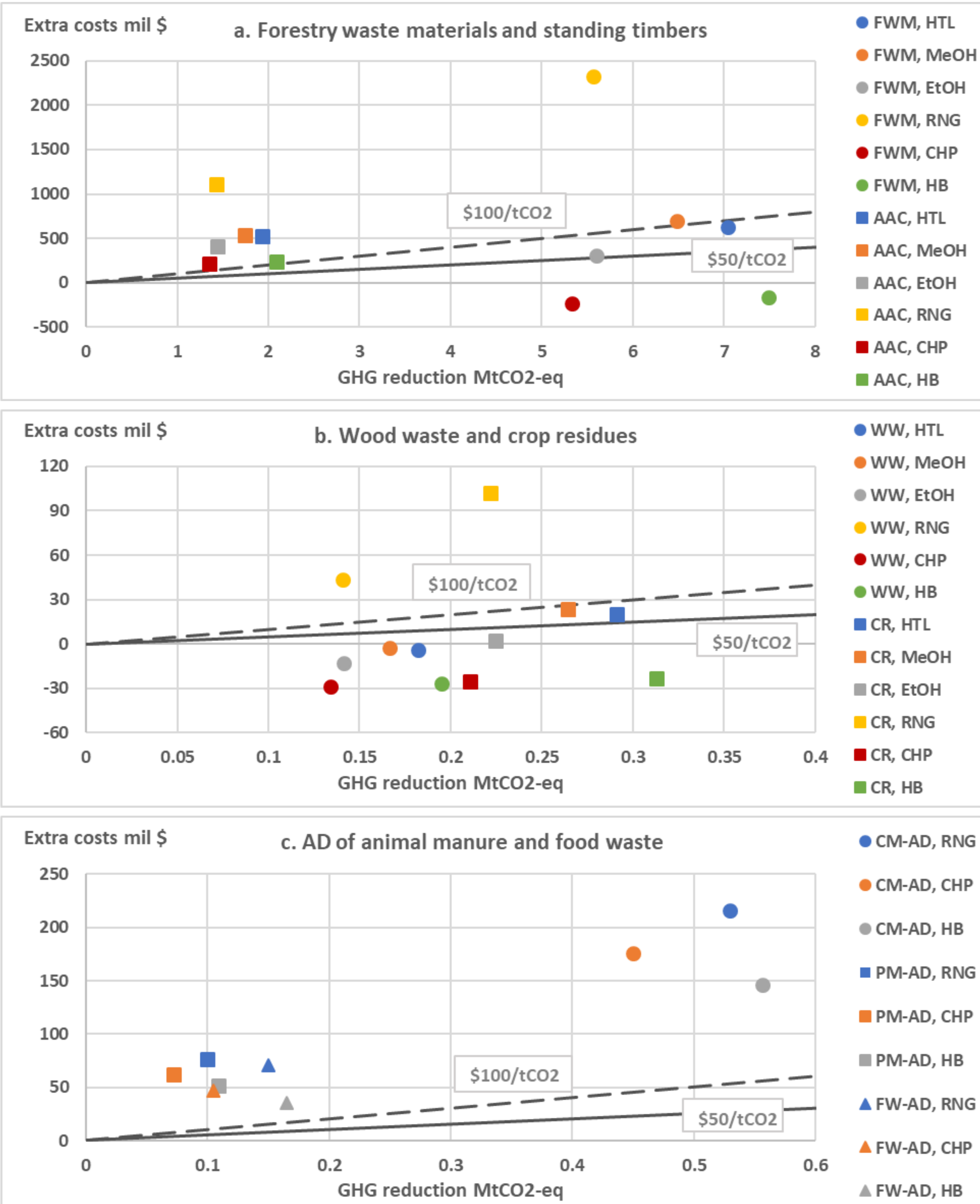
The potential for bioenergy production is affected by the overall efficiency of the technology selected. For all lignocellulosic biomass feedstocks, CHP and HB have higher overall energy conversion efficiencies than technologies that produce refined biofuels, and can therefore produce more usable energy. For anaerobic digestion (AD) of organic wastes, the primary constraint for energy conversion is the digestion process to produce biogas; for utilization of biogas, HB and RNG can achieve higher energy yields than CHP. For crop residues, thermal conversion can achieve much higher energy yields than AD.

Total energy produced from lignocellulosic biomass could replace up to 180 PJ of natural gas via the HB option, amounting to 52% of current natural gas demand in BC (346PJ). Alternatively, via the HTL option, 129 PJ of liquid biofuels could potentially be produced, equal to 29% of current RPP demand in BC (447 PJ). For AD of organic wastes, up to 9.0 PJ of natural gas could be displaced via HB or RNG options, equal to 2.6% of BC's total natural gas consumption. It is thus confirmed that BC's biomass resources are insufficient to replace the entirety of fossil fuel consumption. Therefore, it is crucial to optimize the exploitation of the limited biomass supply based on GHG reduction and cost.

6.1.2 Total potential GHG reduction

Figure 6.2 shows the estimates for the potential GHG reduction and total extra cost (without policy support) for the various combinations of feedstocks and technologies, obtained by multiplying the estimates for BC's biomass resources with GHG mitigation potential and extra costs per tonne feedstock derived in Chapter 3 and 4. The abscissa shows the potential GHG reduction if each feedstock is fully utilized by a specific technology. The ordinate shows the total associated total extra cost, in Canadian dollars, for the full exploitation of each feedstock by a specific technology. The gradient of the line from the origin to the point representing each bioenergy option shows the cost per tonne CO_2-eq GHG reduction, an indicator of the cost-effectiveness by that option. The economic aspect will be discussed in detail in Section 6.1.3. Thermal conversion of crop residues shows much higher GHG savings but lower extra costs than AD; therefore, the latter is excluded from Figure 6.2 and not discussed further in this chapter.

As shown in the abscissa of Figure 6.2, full utilization of BC's biomass resources investigated in this study could reduce GHG emissions by 7.7-10.9 million tonnes CO_2-eq ($MtCO_2$), depending on bioenergy technologies selected. Based on BC's GHG emissions of 63.9 Mt in 2005 [7], this would lead to 12.0-17.1% reduction in GHG emissions based on the 2005 level. Potential GHG reductions are mainly dependent on feedstock sizes.



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Feedstock: FWM = Forestry Waste Materials, AAC = Standing timbers within AAC, WW = Wood Waste in MSW, CR = Crop Residues, CM = Cattle Manure, PM = Poultry Manure, FW = Food Waste in MSW.

Figure 6.2 Total GHG reduction and extra costs of bioenergy options in BC

As the bioenergy feedstock with potentially the largest flow, forestry waste materials could contribute 8.4%-11.7% of GHG reduction based on the 2005 level. Standing timbers within AAC come next, potentially contributing 2.1%-3.3% of GHG reduction. In comparison, the potential GHG reduction from each individual waste stream is much smaller, but in total these streams could contribute reductions amounting to 2.2%.

For each lignocellulosic feedstock, HB leads to the highest potential GHG reduction, followed by technologies to produce liquid biofuels and renewable natural gas (RNG). As shown in Chapter 3, the main advantage of HB is its higher energy conversion efficiency and hence greater ability to displace fossil fuels than technologies that produce refined biofuels. For biogas produced from AD, the HB option also shows the greatest potential for GHG reduction, though closely followed by the RNG option. This is because the process of upgrading biogas to remove its CO_2 content leads to additional CH_4 fugitive emissions and parasitic energy use. To utilize both solid biomass and biogas, CHP appears to give the least GHG reduction, due to BC's low-carbon electricity mix.

6.1.3 Total extra costs and GHG reduction costs

Total extra costs to fully exploit each biomass feedstock are shown as the ordinate of Figure 6.2. For each lignocellulosic feedstock, biomass-fired CHP and HB have the lowest extra costs, followed by liquid biofuel options. The RNG option has the highest total extra cost by a large margin. For biogas produced from AD of animal manure and food waste, HB also has the lowest extra costs, whereas RNG has the highest. The aggregated annual extra cost from full utilization of the bioenergy potential is estimated at 0.2–3.9 billion dollars, displaying an enormous cost gap between the least and the most expensive bioenergy options. While biomass-fired CHP and HB for forestry waste materials, wood waste, and crop residues have negative extra costs, most other options involve positive extra costs and therefore require policy intervention to provide financial support. Production of refined biofuels from forestry resources may involve much higher extra costs than other waste streams because forestry resources are more expensive with much higher annual arisings.

As explained in section 6.1.1 above and explored further in section 6.2 below, we argue that the economic performance of bioenergy should be evaluated based on its cost-effectiveness in GHG mitigation; hence, the economic indicator should be extra costs per tonne CO_2 mitigated, i.e. GHG reduction costs, rather than per tonne feedstock or GJ energy product. In Figure 6.2, GHG reduction costs are shown as the gradient of the line from the origin to the data point representing each option. Using the foreseeable pan-Canadian carbon tax of \$50/tCO_2 as the reference [111], we categorize bioenergy options by their GHG reduction costs: negative, low (\$0-50/tCO_2-eq), moderate (\$50-100/tCO_2-eq), and high (>\$100/tCO_2-eq).

Biomass-fired CHP and HB for forestry waste materials, wood waste, and crop residues show negative GHG reduction costs: full utilization of these waste lignocellulosic feedstocks would lead to total annual economic savings of 220-300 million dollars based on current energy prices in BC. Therefore, these options should already be pursed on both environmental and economic grounds. On the other hand, conversion of these materials to liquid biofuels shows low to moderate GHG reduction costs and would lead to extra costs totalling 290-710 million dollars per year. The RNG option for these materials shows high GHG reduction costs (>\$300/tCO_2) and would lead to total extra costs of 2.5 billion dollars per year. Even though the current RNG feed-in-tariffs (FiT) program in BC provides sufficient incentive to cover the extra costs of RNG produced from these waste lignocellulosic feedstocks, enforcing this strategy will place enormous economic demands on the government, producers and consumers.

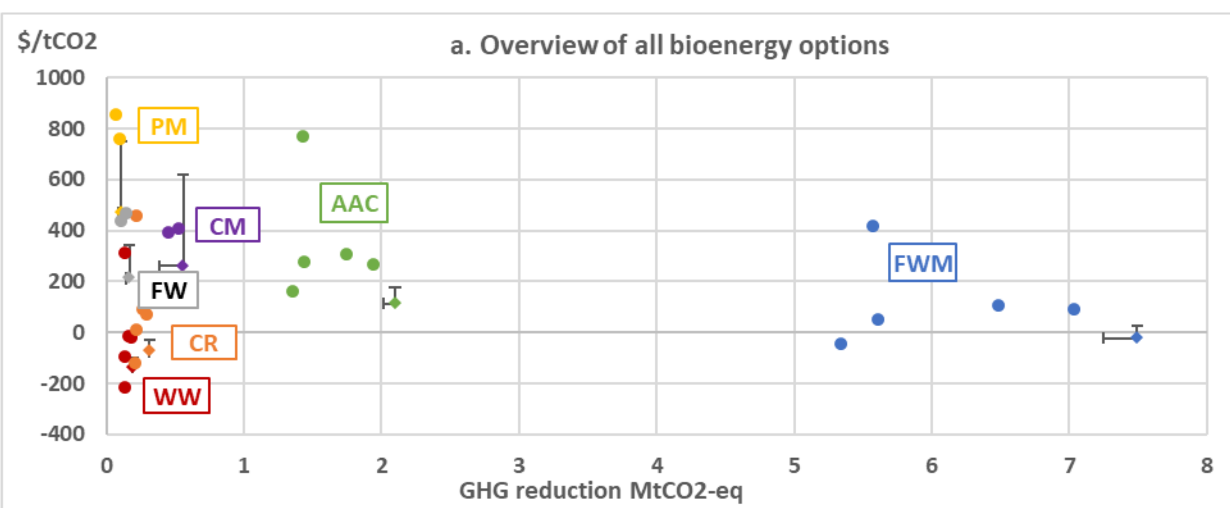
The least cost-effective lignocellulosic feedstock is unharvested timbers within AAC, which has high GHG reduction costs (\$113-768/tCO_2) for all the technology options investigated, but the feedstock is considered further in view of the large annual arisings. Use for biomass-fired HB and CHP (\$113-157/tCO_2) is the least costly and thereby the most realistic option, leading to total extra costs of 213-238 million dollars per year. Nonetheless, this use is still expensive, due to the high merchantable value of the material and costs of harvesting and transporting, and should only be considered after waste streams and forestry waste materials are fully utilized.

AD of organic wastes also shows high GHG reduction costs: AD of cattle manure and food waste show similar GHG reduction costs (\$212-463/tCO_2), whereas AD of poultry manure demonstrates even higher GHG reduction costs (\$469-855/tCO_2). HB generally has the lowest GHG reduction costs amongst different biogas utilization options and is thereby the most cost-effective. Full utilization of animal manure and food waste via AD will lead to total extra costs of 232-360 million dollars per year.

6.2 Prioritization of bioenergy options

Due to the imperative to mitigate GHG emissions, it is critical to maximize potential GHG reduction from the limited supply of biomass. Economically, it is also crucial to maximize cost-effectiveness. Therefore, the prioritization of bioenergy options to utilize each feedstock can be regarded as a multi-objective Pareto optimization problem [238], with the two criteria of maximizing potential mitigation and minimizing mitigation cost. Note that for each feedstock, different bioenergy options are mutually exclusive, so only one option can be picked. In Figure 6.3, the potential GHG reduction from the exploitation of each biomass feedstock is plotted on the abscissa, and the GHG reduction cost is plotted on the ordinate. Pareto optimization means selecting options that are the lowest and furthest to the right. Figure 6.3 (a) shows an overview of the potential GHG reductions and costs of all bioenergy options, with the diamond dot indicating the HB option for each feedstock. It is evident that the full utilization of forestry waste materials via biomass-fired HB systems ensures the maximum potential mitigation, and that the exploitation of wood waste and crop residues leads to the minimum mitigation costs.

As shown in Figure 6.3(b)&(c), for utilization of forestry waste materials, crop residues, and wood waste, biomass-fired HB and CHP options define the Pareto-optimal frontier: HB has the highest GWP benefits, and CHP has the lowest GHG reduction costs. Liquid biofuel options form a "second-best" group; within this group, HTL generally is higher in GWP benefits but less cost-effective. RNG is always the farthest away from Pareto-optimal. This finding agrees with the conclusions from other studies that HB and CHP are more cost-effective than conversion to biofuels provided that heat can be used efficiently [239], [240]. Meanwhile, to utilize standing timbers, biomass-fired HB always has the highest GWP benefits and the lowest GHG reduction costs, and therefore is the sole optimal option. For the same reason, biogas-fired HB is the optimal option to utilize biogas produced from AD, shown in Figure 6.3(d).



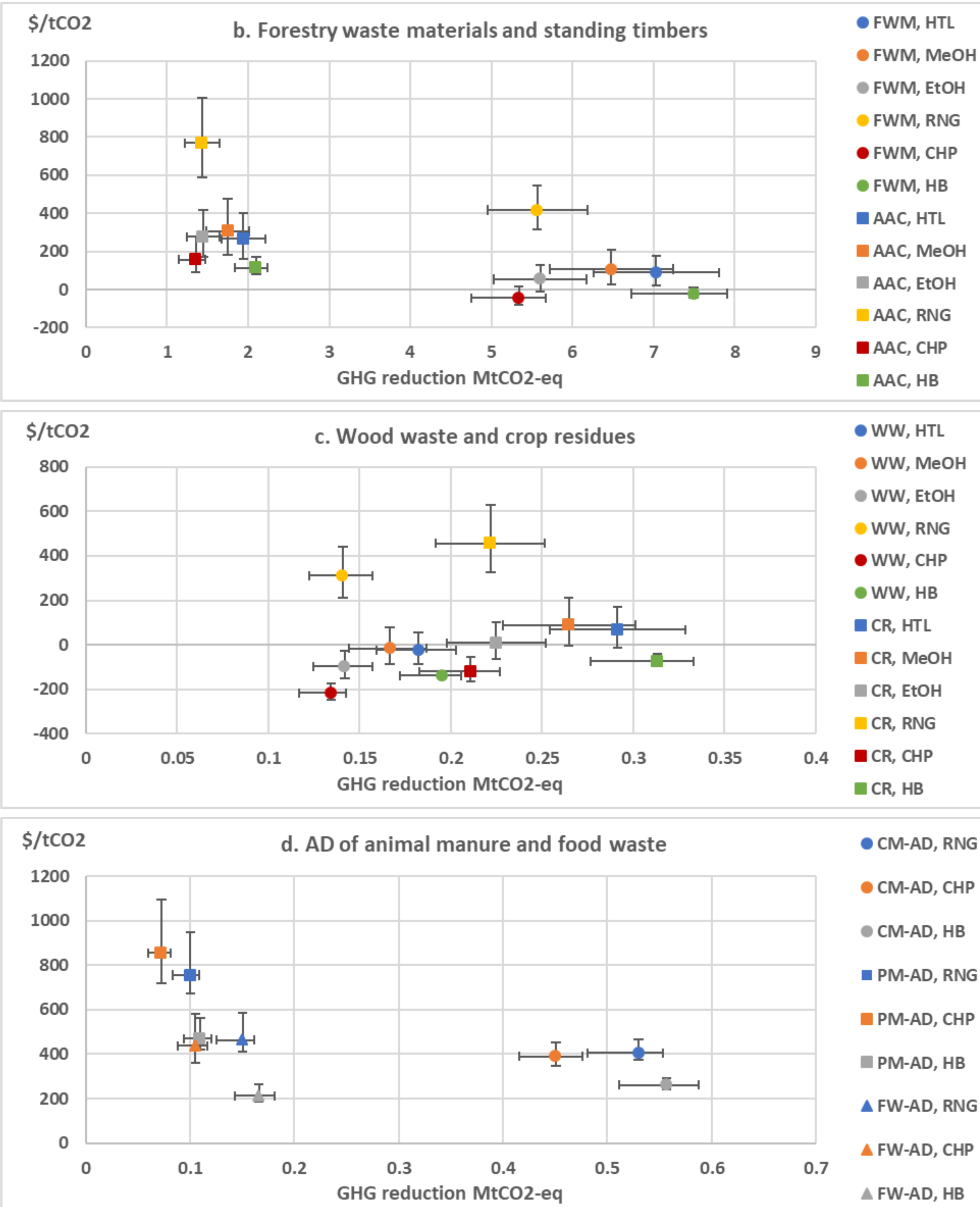


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Figure 6.3 Prioritization of bioenergy options based on GHG reduction and costs

However, in addition to the criteria of potential GHG reduction and cost-effectiveness, the prioritization of bioenergy options depends on several other factors, particularly energy demand and health impact. The significance of these factors is discussed in the following sections.

6.2.1 Assessment of uncertainty

The results of the sensitivity analyses in the previous chapters have shown that the uncertainties in data and assumptions can have significant impacts on the predictions of GHG savings and GHG reduction costs of bioenergy options. Therefore, it is critical to investigate how robust our conclusions are against these uncertainties. These parameters and assumptions are categorized into two groups: (1) factors that influence the utilization of a specific feedstock, and (2) factors that are specific to some bioenergy technology. The impact of factors in each group on the prioritization rankings of different bioenergy options should be analyzed and interpreted separately. Note that the objective of this section is not to assess the range of total GHG reductions and aggregated costs; instead, it is to determine whether the prioritized rankings of different bioenergy options may change due to the uncertainties in parameters and assumptions.

(1) Uncertainties in feedstock parameters, such as the transportation distance (particularly for forestry resources), conventional waste management practices (particularly for animal manure and food waste), and the relative feedstock supply cost, can influence the prioritization of different feedstock types, but do not affect the relative rankings of different bioenergy options competing for the same feedstock. Note that most factors for AD of organic waste belong to this group, including the biogas yield and nutrient contents of different feedstocks, and the process GHG emissions and costs for the AD systems, except for those specific to different biogas utilization options. The impact of factors in this group is shown by the uncertainty bars in Figure 6.3(a), using

the biomass-fired and biogas-fired HB options as an example. These uncertainty bars represent the case where the uncertainty lowers the performance of bioenergy: the feedstock transportation distance is increased by 100 km, the raw feedstock value is increased by $20/tDM, and the GHG emissions of the conventional management practices are decreased by 20%.

As shown in Figure 6.3(a), these uncertainties can slightly impact the performance of bioenergy production from forestry waste materials and standing timbers within AAC; however, the impact is not sufficient to alter the relative ranking of these materials. For animal manure and food waste, these changes substantially increase the GHG reduction costs of biogas products, reiterating the finding in Chapter 4 that extended transportation of these materials should be avoided. The impact on wood waste and crop residues is nugatory. Overall, these uncertainties do not change the ranking of the cost-effectiveness of different biomass feedstocks.

(2) In contrast, uncertainties in technology-specific factors, such as the conversion efficiency, capital cost, operating cost, and process GHG emissions, can influence the rankings of different bioenergy options for a given feedstock. The impact of these factors is shown as the uncertainty bars in Figure 6.3(b)-(d), by assuming an uncertainty of ±10% for the conversion efficiencies and ±20% for other process parameters (excluding feedstocks). Note that a positive range of +5% is assumed for the conversion efficiencies of HB and CHP options since these direct combustion options are already efficient and unlikely to be further improved. For the same reason, a positive range of +1% is assumed for upgrading biogas to RNG, since the default assumption for the methane loss during the upgrading process is already as low as 2%.

As shown in Figure 6.3(b)&(c), the lower limits for the potential GHG reductions for biomass-fired HB systems overlap with the upper limits for HTL and MeOH options. As explained in

Section 3.3.5, the conversion efficiency is the main factor affecting the GHG performance of bioenergy; this indicates that HTL and MeOH options can potentially catch up with biomass-fired HB systems in GHG savings if the conversion efficiencies of the former can be significantly improved. However, in terms of GHG reduction costs, it is unlikely that the refined biofuel options can surpass the biomass-fired HB systems in cost-effectiveness within the range of the uncertainty investigated. Overall, the result that biomass-fired HB systems have superior performance in GHG savings and cost-effectiveness remains robust, at least in the short-term when any substantial improvement in the performance of refined biofuel options is unlikely.

As shown in Figure 6.3(d), the lower limits for biogas-fired HB options overlap with the range for RNG options, which reflects that upgrading to RNG is a more flexible option when heat produced from direct biogas combustion cannot be fully utilized, especially in thinly-populated rural areas where a large heat demand may be lacking. On the other hand, the advantage of biogas-fired HB options in cost-effectiveness is robust.

6.2.2 Biomass-fired HB and CHP

In 2016, BC’s natural gas consumption in the residential and commercial sectors was 71 PJ and 73 PJ, respectively, primarily to provide space and water heating [12]. Given that 59% of BC’s population lives in large urban population centers where district heating systems are deemed feasible [229], the theoretical demand for district heating is estimated to be 85 PJ. In order to meet this demand, roughly half the available lignocellulosic feedstocks in BC will be needed. It represents an enormous opportunity for biomass-fired HB and CHP. Biomass-fired HB has much higher GWP benefits than CHP, whilst CHP shows only a minimal advantage in cost-effectiveness. Therefore, we argue that biomass-fired HB should be prioritized in BC.

However, as shown in Section 3.3, HB and CHP options impose additional health risks in the end-use stage compared to natural gas and BC electricity mix, resulting from PM and NOx emissions. This finding agrees with the results of several studies on the biomass-DH system at the University of British Columbia [37], [83]. To suppress health impacts from PM and NOx emissions, more effective gas cleaning devices are essential. Therefore, biomass-fired heating systems are more suitable for large-scale projects such as populated residential and commercial areas and universities, where the implementation of air emission control devices is feasible, rather than for less populated areas and discrete homes.

Additionally, while the LCA provides an indicative result on the health impact of HB and CHP options, it is to be noted that the methodology is limited by its inability to differentiate spatial and temporal factors. Therefore, further evaluation of health impact requires models that can dynamically integrate site-specific population and climate factors, such as the Intake Fraction model [241], which goes beyond the scope of this thesis. Thus, assessment of the health impacts of biomass-fired HB and CHP systems must be carried out for each project, as was the case for the analysis of the UBC gasification district heating plant [83], [84]. Even though a district heating project using waste wood was abandoned in 2007 due to public concern about health risks [242], more and more projects are being planned in BC, and some have already started operation [243].

On the other hand, some other renewable energy technologies, such as geothermal and solar energy systems, are free of air emissions and local health impacts during the end-use stage. These renewable heating technologies potentially provide flexible alternatives to less populated areas and individual buildings. Over the past decade, the costs of these alternative technologies, especially for solar energy, have been dropping rapidly [244]. USEIA predicted that onshore wind, solar and geothermal energy would be cheaper than energy generated from biomass by 2022 [245].

Therefore, the implementation of biomass-fired district heating systems may also be economically challenged by other emerging renewable heating technologies.

6.2.3 Liquid biofuels: HTL, MeOH and EtOH

Due to lower potential GHG reduction and higher costs, liquid biofuel options are less attractive than biomass-fired HB and CHP and therefore should not be prioritized. However, as stated in the Climate Leadership Plan, BC intends to increase its Low Carbon Fuel Standard from 4-5% at present to 15% by 2030 [8]. Based on the current annual RPP demand of 443 PJ [12], short-term demand for liquid biofuels is expected to increase by about 45 PJ, which will require 80-90 PJ of primary biomass to produce and therefore take up roughly one-third of the available lignocellulosic feedstocks in BC. Liquid biofuels may also be used for aviation or marine transportation, but policy measures incentivizing such use, particularly as international "bunker" fuels, are lacking.

As shown in Section 3.6, the current trading price of GHG reduction credits in the Low Carbon Fuel Standard can sufficiently cover the extra costs of liquid biofuels produced from waste lignocellulosic biomass. Therefore, a more stringent mandate will provide opportunities for HTL and EtOH that produce biofuels for land transportation. However, extra costs will eventually be transferred to users. Given the current BC gasoline retail price of $1.5/L as a reference, an extra 10% blend of liquid biofuels produced from lignocellulosic waste materials will increase the retail fuel price by 2%.

In terms of health impact, conversion and waste disposal stages are identified as hotspots. Therefore, to reduce health concerns, liquid biofuel plants and waste disposal sites should be located outside populated areas. However, as combustion of liquid biofuels has the same or even lower health risks than combustion of fossil fuels, the promotion of liquid biofuels is more likely to gain public acceptance despite the health risks associated with the conversion processes.

In summary, the full-scale implementation of liquid biofuel options should not be considered until the heating demand in BC is saturated with biomass-fired heating, low-carbon electricity, and other renewable energy options. Taking a long-term perspective, technology development, especially by improving conversion efficiency, will be the key to establishing the environmental and economic viability of liquid biofuels.

6.2.4 Renewable natural gas from lignocellulosic feedstocks

The RNG option shows no advantage in GHG savings compared to other bioenergy options (except for PG) but imposes the highest extra costs per tDM feedstock. Based on the current natural gas price, the RNG option would always require substantial financial support, even if the cheapest biomass feedstock is used. Currently, Fortis BC has implemented a renewable natural gas feed-in tariff of $30/GJ, in the hope of achieving a 15% renewable natural gas supply by 2030 [115]. Based on current natural gas consumption, the short-term demand for RNG is estimated to be 52 PJ.

As shown in Figure 3.11, the combined financial support from policy measures is enough to make RNG derived from lignocellulosic waste materials economically viable. However, under the business model of Fortis BC's RNG program, the extra costs are partly transferred in the form of commodity premium ($6.75/GJ) to enrolled individual and corporate customers. Therefore, the production of RNG from lignocellulosic feedstocks should be the last option to pursue, especially when biomass supply is limited. At the current stage, research should focus on improving conversion efficiency and economics. Its future success will be highly dependent on technological improvement and rising natural gas prices.

6.2.5 Anaerobic digestion

AD of animal manure and food waste is also associated with high GHG reduction costs. Nonetheless, we argue that AD should be pursued even so, for two main reasons:

(1) In addition to GHG mitigation, AD also brings other environmental benefits, including waste reduction, improved nutrient management, and mitigation of adverse health impacts [89], [90], as shown in section 5.6;

(2) Total extra costs of the implementation of AD are small, due to the limited size of feedstocks. Due to the extra revenues from the existing waste tipping fees, AD of food waste has already become profitable (see Section 4.4). To minimize extra costs, HB should be prioritized over RNG, if heat can be efficiently used. However, due to the low population density in rural areas, efficient heat use may be difficult to achieve in many areas; in such cases, RNG appears to be a more flexible option. As demonstrated in Chapter 5, the integration of AD with local agricultural practices should be pursued, especially in suitable areas such as the Lower Mainland, to improve GHG benefits, nutrient management, and increase economic savings.

6.3 Bioenergy prioritization scenarios

In order to demonstrate the contribution of bioenergy to GHG mitigation and the associated extra costs, five bioenergy prioritization scenarios have been developed. The production of each form of bioenergy, the substitution of each fossil fuel, total GHG reductions, and total extra costs of each scenario are summarized in Table 6.1. The elements of each scenario are as follows.

Table 6.1 Bioenergy prioritization scenarios

Scenario	(a)	(b)	(c)	(d)	(e)
Bioenergy production					
Heating (as NG, PJ)	189	85	60	60 (by CHP)	0
Biofuels (via HTL, PJ)	0	68	45	45	77
RNG (PJ)	0	9	50	30	61
Fossil fuel displaced					
Natural gas	49.1%	27.2%	31.8%	26.3%	17.6%
RPPs	0%	15.2%	10.1%	10.1%	17.2%
Total GHG reduction and extra costs					
Reduction ($MtCO_2$)	10.9	10.5	9.8	8.7	9.4
Reduction (%)	17.1%	16.5%	15.3%	13.6%	14.7%
Extra costs (million $)	251	983	1909	1317	2494

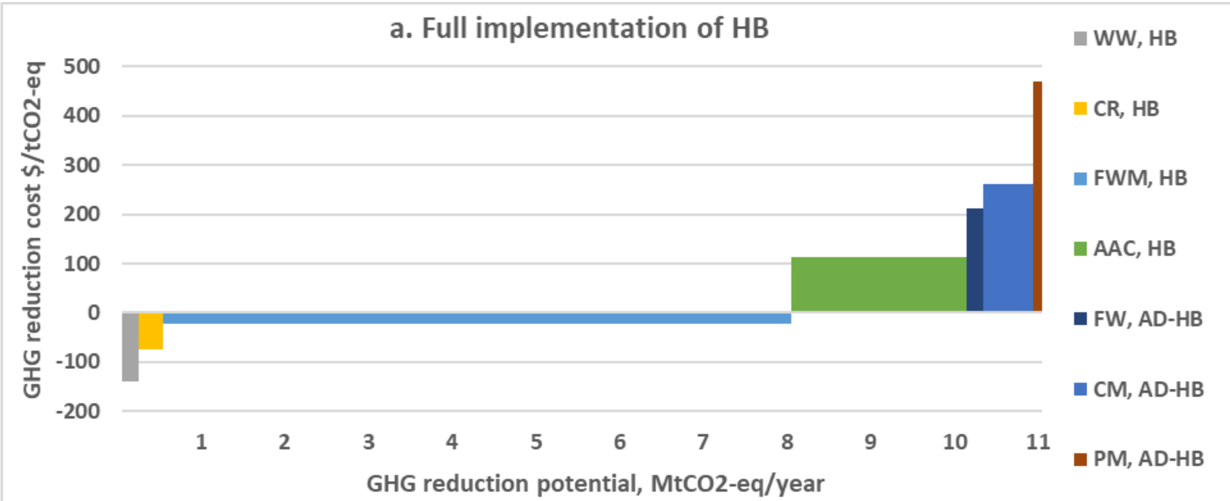
Scenario (a) represents the ideal case where all biomass resources are utilized by biomass-fired or biogas-fired HB systems. However, due to the limitations discussed in Section 6.2.2 and Section 6.2.5, full implementation of HB systems may be unrealistic. In Scenario (b), biomass-fired HB is only implemented in areas suitable for large-scale systems with high-efficiency emission control devices, replacing natural gas demand of 85 PJ. In this scenario, the remaining lignocellulosic feedstocks are devoted to the production of liquid biofuels via HTL and biogas produced from AD of organic wastes is upgraded to RNG.

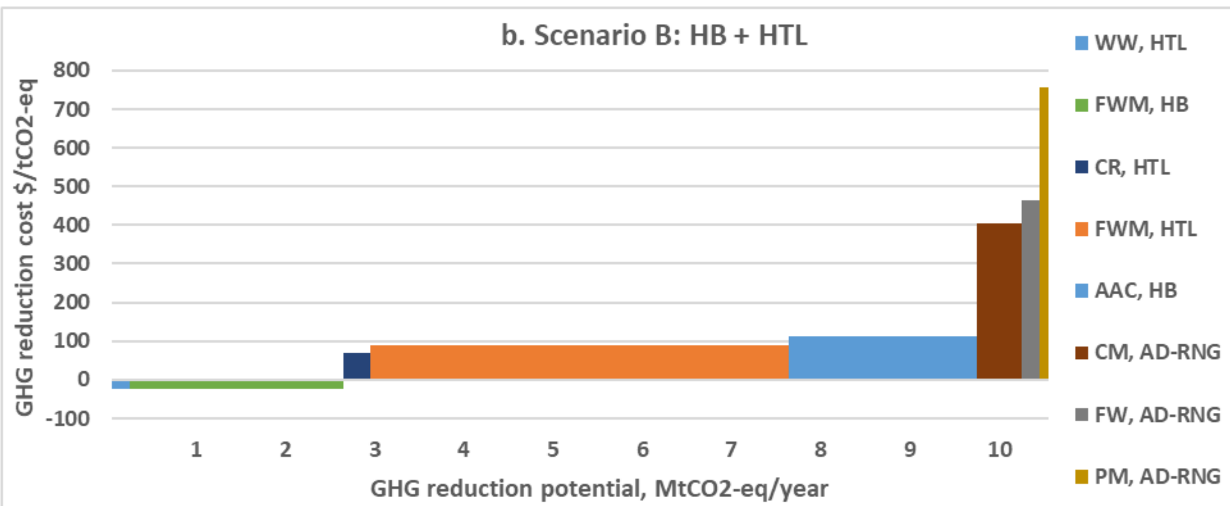
Scenarios (c) and (d) account for more ‘balanced’ allocation of biomass resources, assuming the implementation of biomass-fired HB systems will face more constraints. In Scenario (c), biomass-fired HB is prioritized to displace 60 PJ of natural gas, representing 70% of the natural gas consumption in the buildings in BC’s metropolitan areas. The next step is to produce 45 PJ of liquid biofuels via HTL to displace 10% of current RPP consumption. The remaining lignocellulosic feedstocks are devoted to the production of RNG, in addition to AD of organic wastes. This allocation assumes that all biomass resources are used within BC to contribute to the GHG mitigation target of the province. In Scenario (d), the prioritization of bioenergy demand is the same as in Scenario (c), but biomass-fired CHP is implemented rather than HB.

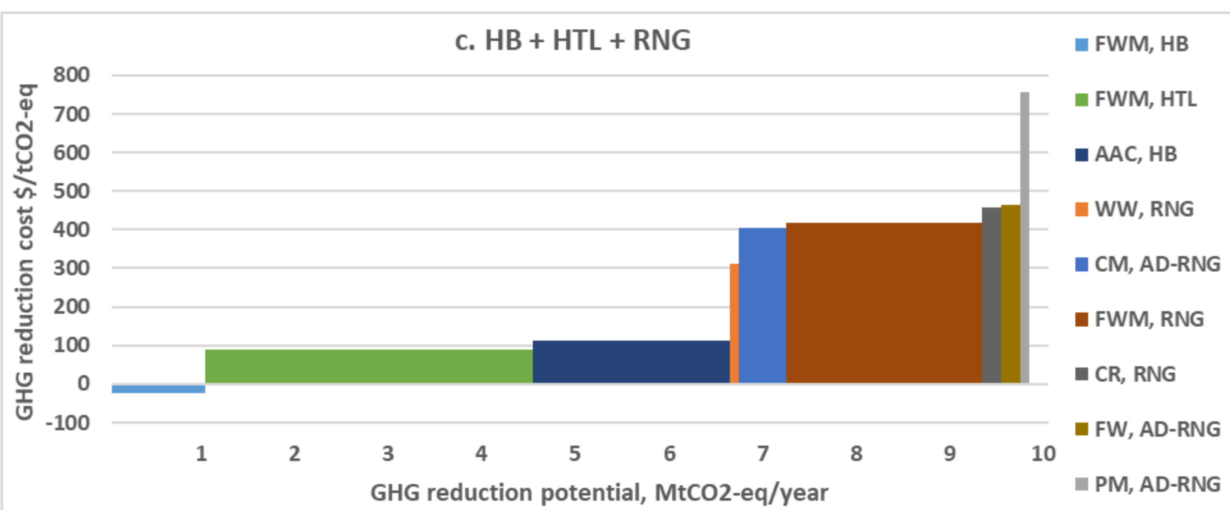
Scenario (e) represents the other extreme for future use of biomass resources, where biomass-fired HB is not implemented at all; instead, biomass resources are only converted to refined liquid biofuels and RNG.

GHG reductions and marginal reduction costs of the combinations of feedstock and technology in each scenario are shown in Figure 6.4. In Scenario (a), 8.0 $MtCO_2$ of GHG emissions can be mitigated annually without inducing any extra costs, via the use of waste biomass as fuels for heating, shown in Figure 6.4(a). The implementation of HB systems also keeps the extra costs low for other biomass feedstocks: full utilization of standing timbers and AD of organic wastes can achieve GHG reductions of 2.1 $MtCO_2$ at an extra cost of 238 million dollars and GHG reductions of 0.8 million tonnes at an extra cost of 232 million dollars, respectively. Scenario (a) has the highest potential reduction at the lowest extra costs amongst all scenarios.

In Scenario (b), 100% of standing timbers and 33% of forestry waste materials are used as fuels for heating. The remaining lignocellulosic feedstocks are used to produce liquid fuels via HTL, significantly increasing extra costs. As shown in Figure 6.4(b), only 2.6 $MtCO_2$ of GHG emissions are free of extra costs in Scenario (b), as compared to 8.0 $MtCO_2$ in Scenario (a). The next 7.1 $MtCO_2$ of GHG emissions are associated with GHG reduction costs of ~\$100/tCO_2 and therefore dependent on moderate financial support. Upgrading biogas to RNG also has considerably higher total extra costs than biogas-fired HB systems to utilize animal manure and food waste. Scenario (b) is 4% lower in GHG reductions but 0.7 billion dollars per annum more expensive than Scenario (a); however, Scenario (b) represents a more realistic and flexible way of exploiting biomass resources in BC.







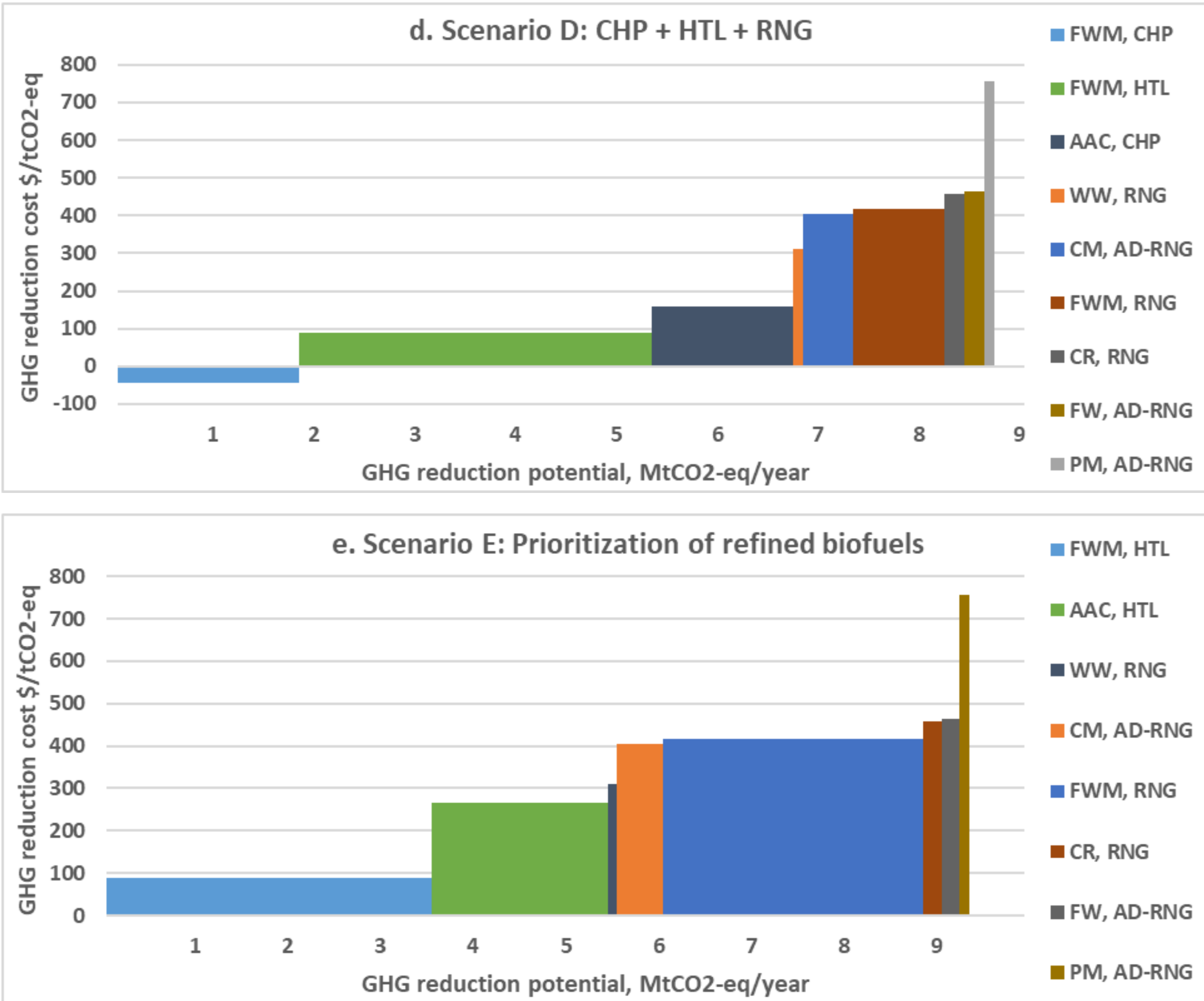


Figure 6.4 Marginal abatement cost curve of bioenergy options in BC

In Scenario (c), biomass-fired HB systems are prioritized to displace 60 PJ of natural gas demand, which consumes 100% of available standing timbers and 13% of forestry waste materials. 49% of forestry waste materials are used to produce liquid biofuels via HTL, and the remaining biomass resources are converted to RNG. In Scenario (d), more feedstocks will be devoted to biomass-fired CHP systems, and consequently less to RNG, than in Scenario (c). As shown in Figure 6.4(c)&(d), the implementation of CHP in Scenario (d) leads to lower GHG benefits but also lower extra costs than Scenario (c). However, both Scenario (c) and (d) are substantially inferior to Scenarios (a) and (b), primarily due to the high extra costs of RNG produced from lignocellulosic feedstocks.

In Scenario (e), there is no biomass-fired HB. Instead, all biomass resources are converted to refined biofuels: standing timbers within AAC and 50% of forestry waste materials are used for HTL, and the rest is used for RNG. As shown in Figure 6.4(e), Scenario (e) is the highest in extra costs but second-lowest in GHG reductions amongst all scenarios.

The total GHG reduction and extra costs of each scenario are shown in Figure 6.5. It clearly shows that the prioritization of HB systems is critical to reducing GHG emissions in BC while maintaining an acceptable extra cost. While not all biomass resources can be utilized in HB systems, HB should still be prioritized for the greatest deployment possible. On the other hand, it is evident that the conversion of biomass resources to refined biofuels, especially RNG, is economically undesirable in BC at present. Current environmental and economic limitations on production of refined biofuels lead to the option of exporting biomass resources, which will be discussed in Section 6.4.

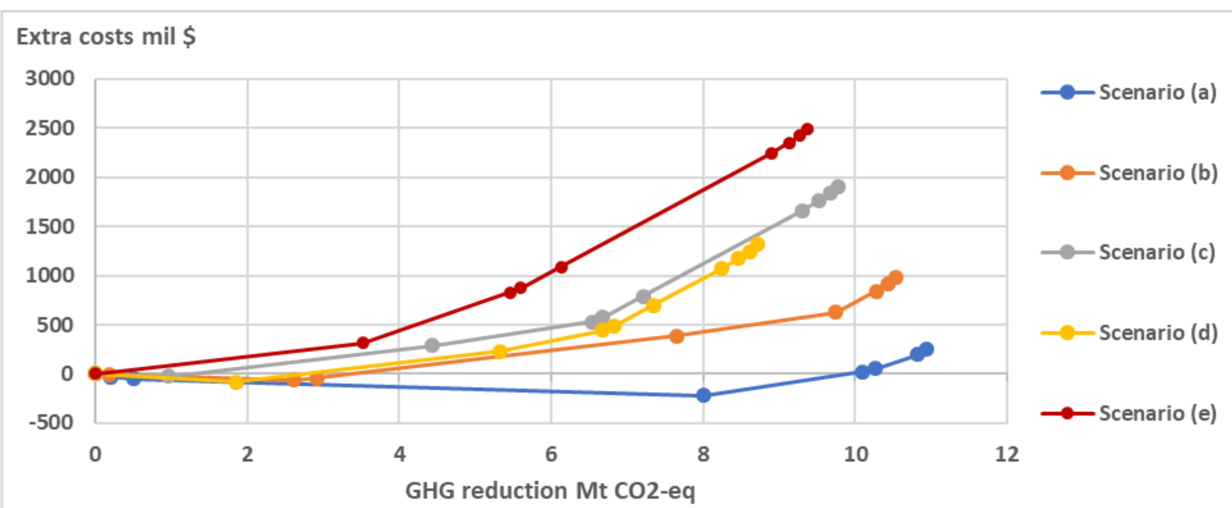


Figure 6.5 Total GHG reduction and extra costs of bioenergy prioritization scenarios

6.4 Discussion and implications

6.4.1 Choice of functional units

The results in Section 3.3 confirmed that using the input-based functional unit of per tDM feedstock leads to a different ranking of bioenergy options than using the output-based functional unit of per GJ bioenergy. The distinction between these two kinds of functional units can be interpreted as follows:

The output-based functional units, such as per GJ bioenergy, emphasize the function of the bioenergy products. Results reported in output-based functional units illustrate the GHG intensity of bioenergy, which can then be easily compared to those of fossil fuels and other forms of energy that serve the same function. Bioenergy producers and consumers are also required to use output-based functional units to report the carbon intensities of biofuel products and thus fuel blends to comply with government low carbon fuel regulations [114].

However, output-based reporting focuses on the performance of a single bioenergy system/product without concern for regional or global availability of biomass resources; this reflects an implicit assumption that there is no constraint on biomass availability so that the feedstock supply to the bioenergy system of interest is secure. This basis is relevant for the study of a single bioenergy system. However, biomass availability will eventually become a critical constraint as the system of concern expands to a regional level and beyond, and includes potential uses for bioenergy in multiple applications and economic sectors. In such a case, expressing the results in terms of output-based functional units, which downplays the significance of energy conversion efficiency, may lead to misleading ranking of options and hence perverse conclusions for resource allocation.

For BC specifically, while the first 5-10% of RPP and natural gas consumption may be replaced by products from available biomass feedstocks in the province (see Section 6.3), the supply will eventually run out as more stringent low-carbon fuel regulations are enforced in the future [246]. Therefore, from the perspective of the BC government, the utilization of limited biomass resources must be strategized: while it is impossible for the government to dictate the allocation of resources in a market economy, the development of policy measures can and should lean towards the utilization pathways that can maximize the potential for GHG mitigation, minimize the GHG reduction cost, or ideally achieve both, for each tonne of biomass resources. Thus, the BC government, as well as policymakers in other areas rich in biomass supplies, should incorporate the results of LCA and economic analysis based on input-based functional units into the decision making for future bioenergy strategies.

6.4.2 Global implications

The potential for the exploitation of biomass resources depends on the energy profile of each specific jurisdiction. In BC, fossil fuels are intensively consumed for heating and mobility, which is also the case for most other developed economies in the North Temperate Zone, including the US, most European countries, China, Japan and other Canadian provinces. To these economies, our finding that biomass-fired HB is more efficient and cost-effective in GHG mitigation than refined biofuels is generally applicable, because it arises from HB's inherent advantages of lower capital investment and higher conversion efficiency. This conclusion is supported by the specific example of the Nordic countries, specifically Denmark, Finland and Sweden. These countries have many similar characteristics to BC, including comparable population, a high proportion of renewable electricity supply, and a traditionally high proportion of fossil fuels for heating [126],

[247]. The market share of biomass-fired district heating systems in these countries has already grown and surpassed the use of fossil fuels [126], [127], validating this bioenergy development model for BC.

On the other hand, annual heating demand in lower latitudes and tropical countries is generally low so that non-heating bioenergy options are more applicable. For example, the Central American country, Costa Rica, is similar to BC in terms of abundant forestry resources and hydropower capacity. Since half of the country's energy supply comes from renewable sources and the other half is predominantly refined petroleum products [247], conversion to liquid or gaseous biofuels could be a suitable utilization option for biomass resources there.

Note that the reason why power generation (PG) from biomass is not suitable for BC is that the province has abundant hydropower, with scope to further expand hydro-generation. As shown in Figure 6.6, if electricity generated from biomass is to displace fossil-based heat and electricity, GWP benefits can substantially increase by more than 1000 kgCO_2-eq/tDM feedstock. Since BC still imports fossil-based electricity from the US and BC's adjacent province of Alberta to cover seasonal variations in supply and demand, biomass generation will appear much more attractive to BC if this marginal burden of fossil-based electricity is displaced. More importantly, even though this sensitivity analysis does not consider the transportation of biomass or transmission of electricity, the result implies that biomass power generation can be a viable and competitive option, for economies such as the US, parts of Europe, China, and Alberta, where coal is still the main source of primary energy.

Currently, substantial quantities of wood pellets and chips are already exported from BC, mainly for use in power generation in Europe [14], [15]. For BC wood pellets shipped from Vancouver to the UK via the Panama Canal, the life cycle GHG emissions only offset about 15% of the avoided burdens for replacing power generation from coal [248]. Based on the estimates in Figure 6.6, exportation of BC wood pellets to the UK for power generation would still outperform liquid biofuel options used in BC in GWP benefits, even allowing for inter-continental shipping. Meanwhile, the GHG reduction cost over the life cycle of BC wood pellets exported to the UK for power generation is in the range of $90 to $130 per tonne of CO_2-eq [248], which is in the same range as liquid biofuels produced from forestry waste materials. Therefore, notwithstanding the processing and long transport distances, exporting BC wood pellets to the UK for power generation is proved to be environmentally attractive and economically viable.

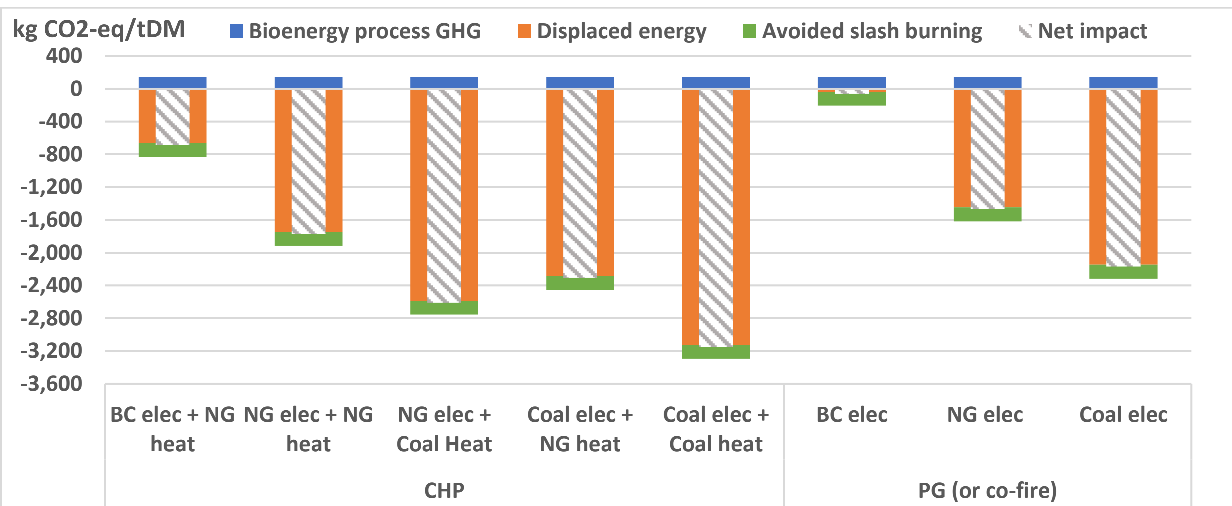


Figure 6.6 Impact of coal-based heating and electricity on the GWP benefits of power generation and cogeneration from forestry waste materials in BC

However, under international protocols for GHG accounting, GHG emissions associated with energy consumption are borne by the user [249], [250], which indicates that the GHG benefits of bioenergy are credited to the user rather than the producer. Therefore, while exporting biofuels or low-carbon electricity from BC can reduce global GHG emissions by displacing fossil fuels or fossil-derived electricity in other jurisdictions, it does not contribute to progress towards BC's own

GHG mitigation target. Such perversity of GHG accounting may force BC to adopt globally sub-optimal bioenergy prioritization scenarios, shown in Section 6.3, to maximize provincial GHG mitigation but not necessarily lead to the greatest global benefits.

Economic prospects for bioenergy in each region are also affected by regional fossil fuel prices and taxes. Fossil fuel prices depend in part on taxes and other fiscal policies, which vary between jurisdictions and lead to differences in the GHG reduction costs of different bioenergy options. In Europe, fossil fuel prices are much higher than in BC and Canada, mainly due to higher government taxes [110], [112], [251]. Higher taxes help to close the cost gap between biofuels and fossil fuels, to foster a supportive environment for bioenergy development (and to encourage international trade in commodity biofuels such as wood pellets).

6.4.3 Implications of the cost and supply of forestry biomass

As shown in Sections 3.3 and 3.4, the biomass supply chain, particularly long-distance transportation from remote harvest sites to populated areas in southern BC, is the largest contributor to the process GHG emissions and production costs of bioenergy produced from forestry biomass. While such a simplified model of the biomass supply chain, including collection and transportation processes, aims to represent a general case, the actual supply chain can differ substantially depending on the harvest site of biomass, the location of the bioenergy facility, and the targeted location of bioenergy consumption. Such a high degree of uncertainty not only has significant impacts on the performance of bioenergy (Sections 3.3.5 and 3.4.3), but also has implications for how the results of this study should be interpreted. The latter will be discussed in this section.

In terms of feedstock collection, sawmill residues are generally readily available for loading. However, the harvest of MPB-killed trees and the collection of harvest residues can be severely constrained by economic feasibility, as these materials can be far away from existing roads and thus difficult to access. While research on biomass availability in BC is still ongoing, published results for various logging areas in BC have shown that 50-70% of residual biomass is recovered to the roadside [252]–[254]. As shown in Figure 6.7, the collection cost for residual biomass in Prince George typically ranges from $50-170/tDM, with a median collection cost of $80-90/tDM [254]. Similar curves can be observed in other logging regions investigated [252], [253]. Therefore, the supply shows price elasticity: as prices rise, higher collection costs can be covered and more residual biomass can be collected from the roadside, resulting in higher GHG mitigation from bioenergy. On the other hand, the estimated ultimate GHG mitigation (see Section 6.1.2) cannot be achieved if only easily-accessible forestry waste materials are utilized; the collection of less accessible forestry biomass will require higher market price to ensure its profitability, which should arise from higher demand for bioenergy in the future. Nonetheless, variations in the cost and supply of forestry biomass will not change the relative ranking of bioenergy use pathways (see Section 6.2.1).

Furthermore, there are also many possibilities to reduce GHG emissions and costs from the transportation of biomass feedstocks and bioenergy products. For example, bioenergy HB and CHP systems in populated areas can always resort to nearby timber harvest sites and sawmills for feedstock supply if available, which can significantly reduce the transportation distance. For biofuels, as they have much higher energy density (GJ/tonne) than forestry waste materials, savings in transportation costs may be achieved by locating the conversion facility closer to the harvest site and then transporting bio-crude oil, rather than transporting the feedstock for long distances and then producing biofuels near the populated areas where the market is. This is already common practice in bioethanol production from sugar. A case study on the production of HTL fuels in BC has shown that converting forestry waste materials to bio-oil before transportation can significantly lower transportation emissions [19]. Therefore, there exists a high degree of uncertainty in the supply chains of various combinations of feedstocks and technologies, potentially causing a significant impact on the environmental and economic performances of bioenergy. This indicates the necessity for case-based future work on the supply chain of biomass feedstocks and bioenergy products.

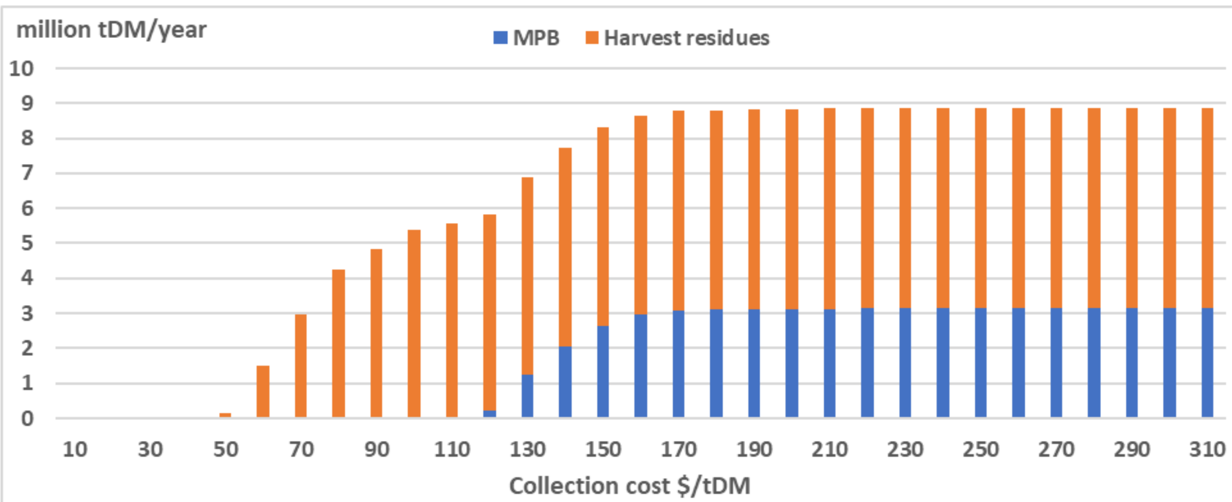


Figure 6.7 Cost-supply curve of MPB-killed trees and harvest residues in the Prince George TSA:10-year base case [254]

Chapter 7 Conclusions and future work

7.1 Conclusions

British Columbia (BC)'s vast forestry and agricultural sectors generate abundant biomass resources every year. In this study, unused biomass resources available in BC have been estimated. Compared to BC's enormous fossil fuel consumption to be displaced, biomass is a scarce resource for the use of energy. In order to exploit the optimized use of BC's biomass to contribute to GHG mitigation and facilitate the development of relevant policies, this study has investigated the GHG mitigation efficiency and cost-effectiveness of various bioenergy options. Non-climate change impacts associated with the production and consumption of bioenergy, including health impact, acidification, and eutrophication, have also been examined. In the context of limited biomass supply, all evaluations and comparisons must be made using the input-based functional unit of 'per tonne feedstock', instead of the output-based functional unit commonly seen in the literature.

The key findings on the utilization of lignocellulosic biomass resources are listed below:

(1) With the functional unit of "per tonne biomass," biomass-fired heat-only boiler (HB) systems give the highest GHG reduction, mainly due to the inherent advantage of higher energy conversion efficiency. Cogeneration of heat and power (CHP), conversion to liquid biofuels, and conversion to renewable natural gas (RNG) are slightly lower in GHG reduction than the HB option. Biomass-fired power generation (PG) has no GWP benefits in BC because of the low carbon-intensity of the electricity supply. This ranking significantly differs from that derived from the output-based functional unit of 'per GJ bioenergy'.

(2) Economically, biomass-fired CHP and HB options using waste materials are the most cost-effective, potentially profitable without market intervention. Liquid biofuels generally have positive extra costs and are thus much less cost-effective than CHP and HB. Production of RNG from lignocellulosic biomass resources is the least cost-effective option, due to currently low natural gas prices. Bioenergy production from wood waste is the most profitable due to waste tipping fees. For other feedstocks, utilization of forestry waste materials and crop residues is much more cost-effective than standing timbers.

(3) The health impact is a crucial concern for the production and consumption of bioenergy. Bioenergy production from forest waste materials can avoid the substantial health impact arising from slash burning and wildfires. Biomass-fired CHP and HB options generate higher local health impact than natural gas combustion. Therefore, these two options should only be implemented in large-scale projects equipped with high-efficiency emission control devices. For advanced biofuels, the local health impacts are expected to be equal to or lower than their fossil counterparts.

The key findings on the anaerobic digestion of agricultural and food wastes are as follows:

(1) Anaerobic digestion (AD) of cattle manure, poultry manure, and food waste can effectively reduce GHG emissions, by displacing the consumption of natural gas and fertilizers and reducing direct emissions from conventional waste management practices. AD of crop residues shows significantly lower GHG benefits. AD generally leads to significant benefits in health impact, but its benefits in acidification and eutrophication are highly dependent on proper nutrient management practices. To utilize biogas, heat-only boilers (HB) and upgrading to renewable natural gas (RNG) show similar GHG benefits, both significantly higher than CHP.

(2) AD of waste streams in BC generally has positive extra costs and thus requires financial support from policy measures. However, the additional revenues of food waste tipping fees are sufficient to make AD of food waste profitable in BC. AD of other feedstocks is still in need of financial support, in addition to current policy measures. In comparison, HB has the lowest extra cost and GHG reduction cost and is therefore the most cost-effective biogas utilization option.

(3) Integration of AD with greenhouse production and mushroom cultivation provides demand for the heat from biogas-fired HB systems in scarcely-populated rural areas. Integration with greenhouse production can effectively displace natural gas consumption for CO_2 enrichment and generate further GHG benefits and profits. The substitution of greenhouse growing media and mushroom substrate with solid digestate can significantly increase the profitability of the whole system and slightly reduce GHG emissions and health impacts. Field crops serve as a crucial nutrient sink for digestate application, but crop residue collection shows a limited effect on the performance of the integrated AD system.

Based on the environmental and economic performance of bioenergy options, biomass-fired HB should be prioritized to utilize the limited lignocellulosic feedstocks in BC. For the same reason, waste lignocellulosic materials generated in the forestry and agricultural sectors should be prioritized for bioenergy production, over unharvested timbers with much higher feedstock costs. AD of animal manure and food waste should also be actively pursued due to small feedstock sizes and comprehensive environmental benefits, despite the relatively high GHG reduction costs.

Conversion of lignocellulosic feedstocks to liquid biofuels is slightly less effective in GHG reduction but much less cost-effective than the use of biomass for heating, due to higher costs and lower energy conversion efficiencies. Conversion of lignocellulosic feedstocks to RNG is the least cost-effective option. In the short term, full-scale implementation of refined biofuel production in BC should not be considered, unless the heating demand in BC is fully met by biomass-fired heating and other renewable energy options. In the long term, improvement of conversion efficiency and reduction in costs resulting from technological advancement and value-added byproduct development will be the key to establishing the environmental and economic viability of refined biofuels, in the world where GHG mitigation is imperative.

7.2 Limitations and future work

This study is based on data retrieved from the literature and assumptions made in the BC context. Even though sensitivity analyses conducted in this work have ensured that the conclusions are robust within a specific range of data uncertainty, there are still many limitations inherent in the methodologies used in this study.

(1) The model of the feedstock supply chain is simplified in this study, with a number of assumptions. A more realistic model is needed in the future, which accounts for crucial factors such as locations of feedstock sources, seasonality, yield disturbance, and temporary storage. Furthermore, the estimates of biomass availability are based on current data. Therefore, such estimates need to be updated regularly based on the future development of the forestry and agricultural sectors.

(2) This study aims to illustrate the prioritization strategy of the potential development of a bioenergy industry in BC, by working on case studies of available biomass resources and suitable bioenergy technologies using average data in the literature. Consequently, the results may not reflect the environmental and economic performance of state-of-the-art bioenergy technologies. In

order to assess the environmental impacts and economic viability of individual projects accurately, site-specific data on the selection of feedstocks, technologies, and equipment will be needed.

(3) The parameters for AD and agricultural operations are associated with high degrees of uncertainty. While Chapter 5 provides a high-level analysis of the environmental and economic viability of the AD system integrated with agricultural practices, the actual performance can only be validated by implementing such systems in BC. Many assumptions and parameters remain to be tested, such as the nutrient availability and emission factors, the practicality of CO_2 integration, the impact of flue gases on the air quality in greenhouses and associated crop health, and the impact of all these factors on crop yields.

(4) This study focuses on existing biomass materials that are left unused but ignores the plantation of dedicated energy crops due to the controversial topic of land-use change. Given the contradiction between the limited biomass supply and the enormous fossil fuel demand to be replaced, energy crops may be critical to the future low-carbon economy, if the plantation process can be sustainably managed. Therefore, the potential contribution from plantation of energy crops in BC, with a focus on land-use change, is worthy of examination.

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Appendices

Appendix B Supplementary materials for modelling agricultural activities in BC

A.1 Dairy farm

The cow/heifer ratio in the hypothetical dairy farm varies on the size and management of different farms, typically around 150% as reported in Wisconsin [255] and the Netherland [180] and 210% across Canada [256]. The cow/heifer ratio is assumed to be 200% in this study. The ratio of lactating/dry cows are then estimated based on the length of lactating period and dry period in a typical lactation cycle of 14 months.

Table A.1 shows the daily generation of manure in fresh matter and dry matter, and the contents of nitrogen (N), phosphorus (P), and potassium (K) in it [175]. Based on these values, the total annual manure generation of this farm is 1429.9 tDM, with an average moisture content of 13%.

Table B.1 Manure generation in the dairy farm [175]

	Head	Fresh matter kg/d/head	Dry matter kg/d/head	N (kg/d/head)	P (kg/d/head)	K(kg/d/head)
Lactating cow	340	66.3	8.52	0.44	0.074	0.20
Dry cow	60	38.6	4.54	0.23	0.051	0.096
Heifer	200	24.5	3.74	0.12	0.020	0.060

A.2 Mushroom substrate recipe

A typical conventional substrate recipe for button mushroom consists of straw, manure, urea, and gypsum [223]. Before composting, the starting mixture should contain 1.6% of nitrogen in dry weight [257]. During the composting process, about 30% of solid matter is lost [223], [258], but nitrogen loss can be neglected[258]. The finished compost ready for mushroom cultivation has an MC of about 70% [219], [223].

Table B.2 Conventional and new recipes for mushroom substrates

Input	FM (kg)	DM (kg)	N, g/kgDM	Total N(t)	P, g/kgDM	Total P(t)	K, g/kgDM	Total K(t)
Conventional recipe								
Total	1465	1109	16	17.8	3.2	3.6	13.9	15.4
Straw	1000	900	5	4.5	0.6	0.5	13.0	11.7
Manure	400	144	60	8.6	21.0	3.0	26.0	3.7
urea	10	10	467	4.7	0	0	0	0
Gypsum	55	55	0	0	0	0	0	0
New recipe								
Total	2239	1109	16	17.6	3.6	4.0	14.2	15.7
Straw	733	660	5	3.3	0.6	0.4	13.0	8.6
SD	1136	250	25	5.7	2.3	0.6	13.6	3.4
Manure	400	144	60	8.6	21.0	3.0	26.0	3.7
Gypsum	55	55	0	0	0	0	0	0

In the new substrate recipe, it is assumed that solid digestate displaces urea and part of straw components in the conventional recipe, ensuring 1.6% of nitrogen content in the starting mixture before composting. The rest of the composting process and the yield of mushrooms from the new recipe are assumed to remain unchanged. Based on these two recipes, each tDM of solid digestate (SD) can displace 0.96 tDM of crop residues, 18.7 kg of nitrogen fertilizer (urea), and 0.094 tkm of transportation by HDV, assuming these displaced raw materials would have been transported by HDV for 50 km. Based on the straw retail price of $200/t, Urea retail price of $1100/tN [226], and HDV transportation costs of $0.134/tkm [168], substitution of SD can save production costs by $0.079/kg mushroom product.

A.3 Regional distribution of agricultural operations in BC

Table B.3 Regional distribution of agricultural operations in BC [221]

	BC	Lower Mainland	Thompson -Okanagan	Cariboo	Nechako	Peace river
Pasture (ha)	1.6E+06	2.5E+04	6.0E+05	3.4E+05	1.5E+05	4.3E+05
Hay crops (ha)	3.5E+05	2.4E+04	5.3E+04	6.1E+04	4.6E+04	1.3E+05
Field crops (ha)	2.0E+05	1.9E+04	1.0E+04	5.4E+03	8.9E+03	1.4E+05
Other crops (ha)	3.5E+04	2.1E+04	1.1E+04	1.4E+02	3.3E+01	4.0E+01
Greenhouse, vegetable (m^2)	3.1E+06	2.9E+06	7.5E+04	6.1E+03	1.2E+03	8.4E+02
Greenhouse, other (m^2)	2.3E+06	2.0E+06	8.9E+04	1.7E+04	6.5E+03	7.2E+03
Mushroom (m^2)	2.1E+05	2.1E+05	4.5E+01	0.0E+00	0.0E+00	0.0E+00
Chicken (head)	2.2E+07	2.0E+07	1.6E+06	2.2E+04	1.1E+04	3.8E+04
Cow (head)	2.9E+05	6.1E+04	7.9E+04	5.0E+04	2.5E+04	5.1E+04

Appendix C Numerical results for Chapter 3

B.1 LCA results

Table C.1 Environmental impacts of upstream processes of baseline energy in BC

Upstream	Global warming	Acidification	Eutrophication	Human toxicity	Respiratory inorganics
Kerosene	6.75E-03	2.75E-05	4.68E-06	2.86E-04	4.66E-06
Diesel	7.17E-03	2.95E-05	4.97E-06	3.01E-04	5.04E-06
Heavy fuel oil	6.16E-03	2.39E-05	4.59E-06	2.70E-04	4.39E-06
Gasoline	1.08E-02	5.50E-05	6.86E-06	4.27E-03	7.88E-06
BC Electricity	1.69E-02	1.03E-04	4.24E-05	1.75E-03	1.62E-05
NG, DH	6.52E-03	1.46E-04	1.67E-05	2.44E-03	1.87E-05
NG, Small	6.91E-03	1.53E-04	1.88E-05	2.55E-03	1.98E-05

Table C.2 Environmental impacts of the consumption of baseline energy in BC

Consumption	Global warming	Acidification	Eutrophication	Human toxicity	Respiratory inorganics
Kerosene	6.76E-02	1.25E-04	3.30E-05	0.00E+00	3.68E-05
Diesel	7.02E-02	1.31E-05	4.20E-06	0.00E+00	4.60E-06
Heavy fuel oil	7.08E-02	8.94E-04	2.33E-04	0.00E+00	2.63E-04
Gasoline	6.45E-02	3.86E-05	1.22E-05	0.00E+00	1.48E-05
BC Electricity	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
NG, DH	5.68E-02	1.76E-05	3.01E-06	4.35E-05	3.51E-06
NG, Small	5.96E-02	9.71E-06	2.49E-06	4.15E-05	2.45E-06

Table C.3 Environmental impacts of the collection of lignocellulosic feedstocks in BC

Collection	Global warming	Acidification	Eutrophication	Human toxicity	Respiratory inorganics
HR	6.35E+00	3.49E-03	7.53E-04	2.47E-02	7.91E-04
SR	7.05E+00	1.67E-02	6.34E-03	2.56E-01	2.79E-03
MPB	1.42E+01	7.83E-03	1.69E-03	5.53E-02	1.77E-03
FWM	1.03E+01	8.31E-03	2.35E-03	8.71E-02	1.68E-03
AAC	1.42E+01	7.83E-03	1.69E-03	5.53E-02	1.77E-03
WW	2.28E+01	1.25E-02	2.70E-03	8.85E-02	2.84E-03
CR	1.41E+01	7.75E-03	1.67E-03	5.48E-02	1.75E-03

HR = harvest residues, SR = sawmill residues, MPB = Trees killed by mountain pine beetles, FWM = Forestry waste materials (HR+SR+MPB), AAC = Standing timbers within annual allowance cut, WW = wood waste, and CR = crop residues

Table C.4 Environmental impacts of the transportation of lignocellulosic feedstocks in BC

Transportation	Global warming	Acidification	Eutrophication	Human toxicity	Respiratory inorganics
HR	9.92E+01	2.22E-01	7.11E-02	2.52E+00	5.46E-02
SR	5.66E+01	9.03E-02	2.57E-02	2.14E+00	3.72E-02
MPB	9.92E+01	2.22E-01	7.11E-02	2.52E+00	5.46E-02
FWM	9.92E+01	2.22E-01	7.11E-02	2.52E+00	5.46E-02
AAC	1.12E+01	1.79E-02	5.11E-03	4.25E-01	7.39E-03
WW	8.46E+00	1.35E-02	3.84E-03	3.20E-01	5.56E-03
CR	9.05E+01	1.95E-01	6.18E-02	2.44E+00	5.10E-02

Table C.5 Environmental impacts of management of waste lignocellulosic feedstocks

Transportation	Global warming	Acidification	Eutrophication	Human toxicity	Respiratory inorganics
FWM	1.71E-01	2.93E-03	6.91E-04	1.03E-01	7.57E-03
WW	-1.17E-02	-4.59E-04	-2.69E-04	-2.04E-03	-5.20E-05
CR	2.50E-02	5.85E-03	1.29E-03	7.34E-04	4.73E-04

Table C.6 Global warming potential per GJ of bioenergy produced from forestry waste materials

Per MJ	HTL	MeOH	EtOH	RNG	CHP	HB	PG
Collection	8.85E-04	9.56E-04	1.15E-03	9.89E-04	6.45E-04	7.07E-04	1.36E-03
Transport	7.76E-03	8.38E-03	1.01E-02	8.67E-03	5.65E-03	6.20E-03	1.19E-02
Mat In	1.09E-03	3.30E-03	3.66E-04	1.51E-03	3.91E-04	2.01E-04	8.23E-04
Energy In	1.48E-03	4.91E-04	1.49E-04	1.03E-03	0.00E+00	3.38E-04	0.00E+00
Emission	3.12E-05	3.37E-05	4.05E-05	3.12E-04	2.49E-03	1.71E-03	5.24E-03
Waste disposal	1.55E-04	1.83E-04	3.34E-05	1.19E-03	2.42E-05	1.16E-05	5.10E-05
Distribution	5.12E-04	6.34E-04	5.66E-04	3.66E-05	0.00E+00	0.00E+00	0.00E+00
Consumption	1.45E-03	1.79E-03	1.99E-03	7.06E-04	0.00E+00	0.00E+00	0.00E+00
Total	**1.34E-02**	**1.58E-02**	**1.43E-02**	**1.44E-02**	**9.20E-03**	**9.16E-03**	**1.94E-02**
Fossil	7.61E-02	7.69E-02	7.52E-02	6.65E-02	4.13E-02	6.33E-02	4.69E-03
Reduced	**6.27E-02**	**6.11E-02**	**6.09E-02**	**5.20E-02**	**3.21E-02**	**5.41E-02**	**-1.47E-02**

Table C.7 Global warming potential per tonne of forestry waste materials processed

Per t	HTL	MeOH	EtOH	RNG	CHP	HB	PG
Bioenergy	1.56E+02	1.70E+02	1.29E+02	1.51E+02	1.47E+02	1.34E+02	1.47E+02
Displaced energy	-8.87E+02	-8.31E+02	-6.77E+02	-6.94E+02	-6.61E+02	-9.24E+02	-3.56E+01
Avoided slash burning	-1.71E+02	-1.71E+02	-1.71E+02	-1.71E+02	-1.71E+02	-1.71E+02	-1.71E+02
Net impact	**-9.02E+02**	**-8.31E+02**	**-7.19E+02**	**-7.14E+02**	**-6.84E+02**	**-9.61E+02**	**-5.90E+01**

Table C.8 Human toxicity per GJ of bioenergy produced from forestry waste materials

Per MJ	HTL	MeOH	EtOH	RNG	CHP	HB	PG
Collection	7.47E-06	8.07E-06	9.68E-06	8.35E-06	5.45E-06	5.97E-06	1.15E-05
Transport	2.10E-04	2.26E-04	2.72E-04	2.34E-04	1.53E-04	1.67E-04	3.22E-04
Mat In	6.42E-05	3.21E-04	3.52E-05	9.36E-05	3.60E-05	2.07E-05	7.58E-05
Energy In	1.53E-04	9.82E-06	5.79E-07	9.31E-05	0.00E+00	3.50E-05	0.00E+00
Emission	7.95E-05	8.75E-05	1.05E-04	9.04E-05	5.09E-04	5.73E-04	1.07E-03
Waste disposal	4.74E-03	5.12E-03	6.05E-03	5.24E-03	3.40E-03	3.72E-03	7.16E-03
Distribution	8.60E-04	3.13E-05	2.87E-05	5.99E-06	0.00E+00	0.00E+00	0.00E+00
Consumption	0.00E+00	8.01E-08	6.57E-09	1.13E-04	0.00E+00	0.00E+00	0.00E+00
Total	**6.11E-03**	**5.80E-03**	**6.50E-03**	**5.88E-03**	**4.10E-03**	**4.53E-03**	**8.64E-03**
Fossil	1.13E-03	2.70E-04	4.27E-03	2.60E-03	1.73E-03	2.48E-03	4.85E-04
Reduced	**-4.98E-03**	**-5.53E-03**	**-2.22E-03**	**-3.28E-03**	**-2.37E-03**	**-2.05E-03**	**-8.15E-03**

Table C.9 Human toxicity per tonne of forestry waste materials processed

Per t	HTL	MeOH	EtOH	RNG	CHP	HB	PG
Bioenergy	7.13E+01	6.26E+01	5.85E+01	6.13E+01	6.57E+01	6.61E+01	6.57E+01
Displaced energy	-1.32E+01	-2.92E+00	-3.85E+01	-2.71E+01	-2.77E+01	-3.62E+01	-3.69E+00
Avoided slash burning	-1.03E+02	-1.03E+02	-1.03E+02	-1.03E+02	-1.03E+02	-1.03E+02	-1.03E+02
Net impact	**-4.52E+01**	**-4.36E+01**	**-8.33E+01**	**-6.91E+01**	**-6.54E+01**	**-7.34E+01**	**-4.13E+01**

Table C.10 Respiratory inorganics per GJ of bioenergy produced from forestry waste materials

Per MJ	HTL	MeOH	EtOH	RNG	CHP	HB	PG
Collection	1.44E-07	1.56E-07	1.87E-07	1.61E-07	1.05E-07	1.15E-07	2.21E-07
Transport	4.38E-06	4.73E-06	5.67E-06	4.89E-06	3.19E-06	3.50E-06	6.72E-06
Mat In	5.34E-06	4.95E-06	3.38E-06	1.80E-06	5.32E-07	3.26E-07	1.12E-06
Energy In	1.42E-06	2.56E-07	1.85E-08	8.86E-07	0.00E+00	3.24E-07	0.00E+00
Emission	7.40E-06	8.01E-06	9.60E-06	8.28E-06	7.12E-06	7.33E-06	1.50E-05
Waste disposal	2.48E-07	7.10E-07	4.49E-08	2.30E-07	1.51E-08	1.54E-08	3.19E-08
Distribution	5.15E-07	4.92E-07	4.43E-07	4.87E-08	0.00E+00	0.00E+00	0.00E+00
Consumption	6.07E-05	1.17E-05	1.17E-05	3.20E-06	0.00E+00	0.00E+00	0.00E+00
Total	**8.02E-05**	**3.10E-05**	**3.11E-05**	**1.95E-05**	**1.10E-05**	**1.16E-05**	**2.31E-05**
Fossil	6.69E-05	2.68E-04	2.27E-05	2.23E-05	1.56E-05	2.22E-05	4.49E-06
Reduced	**-1.33E-05**	**2.37E-04**	**-8.36E-06**	**2.77E-06**	**4.63E-06**	**1.06E-05**	**-1.86E-05**

Table C.11 Respiratory inorganics per tonne of forestry waste materials processed

Per t	HTL	MeOH	EtOH	RNG	CHP	HB	PG
Bioenergy	9.35E-01	3.35E-01	2.80E-01	2.04E-01	1.75E-01	1.69E-01	1.75E-01
Displaced energy	-7.80E-01	-2.89E+00	-2.04E-01	-2.32E-01	-2.49E-01	-3.25E-01	-3.41E-02
Avoided slash burning	-7.57E+00	-7.57E+00	-7.57E+00	-7.57E+00	-7.57E+00	-7.57E+00	-7.57E+00
Net impact	**-7.42E+00**	**-1.01E+01**	**-7.50E+00**	**-7.60E+00**	**-7.65E+00**	**-7.73E+00**	**-7.43E+00**

Table C.12 Acidification potential per GJ of bioenergy produced from forestry waste materials

Per MJ	HTL	MeOH	EtOH	RNG	CHP	HB	PG
Collection	7.12E-07	7.69E-07	9.23E-07	7.96E-07	5.19E-07	5.69E-07	1.09E-06
Transport	1.67E-05	1.81E-05	2.17E-05	1.87E-05	1.22E-05	1.34E-05	2.57E-05
Mat In	2.52E-05	3.23E-05	1.75E-05	9.87E-06	2.52E-06	1.90E-06	5.30E-06
Energy In	9.07E-06	1.09E-06	8.19E-08	5.46E-06	0.00E+00	2.07E-06	0.00E+00
Emission	2.42E-05	2.62E-05	3.14E-05	2.71E-05	4.79E-05	1.87E-05	1.01E-04
Waste disposal	1.11E-06	3.94E-06	1.75E-07	8.54E-07	5.81E-08	5.80E-08	1.22E-07
Distribution	2.44E-06	2.30E-06	2.24E-06	1.83E-07	0.00E+00	0.00E+00	0.00E+00
Consumption	2.05E-04	3.76E-05	3.76E-05	1.32E-05	0.00E+00	0.00E+00	0.00E+00
Total	**2.85E-04**	**1.22E-04**	**1.12E-04**	**7.61E-05**	**6.32E-05**	**3.66E-05**	**1.33E-04**
Fossil	2.39E-04	9.18E-04	9.36E-05	1.63E-04	1.13E-04	1.63E-04	2.87E-05
Reduced	**-4.60E-05**	**7.96E-04**	**-1.80E-05**	**8.64E-05**	**4.97E-05**	**1.27E-04**	**-1.04E-04**

Table C.13 Acidification potential per tonne of forestry waste materials processed

Per t	HTL	MeOH	EtOH	RNG	CHP	HB	PG
Bioenergy	3.32E+00	1.32E+00	1.00E+00	7.95E-01	1.01E+00	5.35E-01	1.01E+00
Displaced energy	-2.78E+00	-9.91E+00	-8.43E-01	-1.70E+00	-1.81E+00	-2.39E+00	-2.18E-01
Avoided slash burning	-2.93E+00	-2.93E+00	-2.93E+00	-2.93E+00	-2.93E+00	-2.93E+00	-2.93E+00
Net impact	**-2.39E+00**	**-1.15E+01**	**-2.76E+00**	**-3.83E+00**	**-3.72E+00**	**-4.78E+00**	**-2.13E+00**

Table C.14 Eutrophication potential per GJ of bioenergy produced from forestry waste materials

Per MJ	HTL	MeOH	EtOH	RNG	CHP	HB	PG
Collection	2.02E-07	2.18E-07	2.61E-07	2.25E-07	1.47E-07	1.61E-07	3.10E-07
Transport	5.30E-06	5.72E-06	6.86E-06	5.92E-06	3.86E-06	4.23E-06	8.13E-06
Mat In	5.74E-07	1.04E-05	2.73E-05	2.77E-06	9.47E-07	5.62E-07	1.99E-06
Energy In	3.72E-06	4.05E-07	1.76E-08	1.83E-06	0.00E+00	8.49E-07	0.00E+00
Emission	6.29E-06	6.80E-06	8.16E-06	7.03E-06	1.44E-05	6.39E-06	3.04E-05
Waste disposal	1.80E-05	2.06E-05	2.08E-05	1.88E-05	1.17E-05	1.28E-05	2.46E-05
Distribution	9.49E-07	7.99E-07	8.10E-07	7.86E-08	0.00E+00	0.00E+00	0.00E+00
Consumption	5.43E-05	1.07E-05	1.07E-05	4.77E-06	0.00E+00	0.00E+00	0.00E+00
Total	**8.93E-05**	**5.56E-05**	**7.50E-05**	**4.14E-05**	**3.11E-05**	**2.50E-05**	**6.54E-05**
Fossil	5.96E-05	2.38E-04	1.90E-05	2.13E-05	1.68E-05	1.98E-05	1.18E-05
Reduced	**-2.98E-05**	**1.82E-04**	**-5.59E-05**	**-2.01E-05**	**-1.43E-05**	**-5.24E-06**	**-5.37E-05**

Table C.15 Eutrophication potential per tonne of forestry waste materials processed

Per t	HTL	MeOH	EtOH	RNG	CHP	HB	PG
Bioenergy	1.04E+00	6.01E-01	6.75E-01	4.32E-01	4.97E-01	3.65E-01	4.97E-01
Displaced energy	-6.95E-01	-2.57E+00	-1.71E-01	-2.22E-01	-2.68E-01	-2.88E-01	-8.96E-02
Avoided slash burning	-6.91E-01	-6.91E-01	-6.91E-01	-6.91E-01	-6.91E-01	-6.91E-01	-6.91E-01
Net impact	**-3.44E-01**	**-2.66E+00**	**-1.87E-01**	**-4.81E-01**	**-4.62E-01**	**-6.14E-01**	**-2.83E-01**

B.2 Economic results

Table C.16 Costs of forestry waste materials

	Costs $/tDM	Annual rising	%
Harvest residues	86	2.4	31%
Sawmill residues	110	1.6	21%
MPB-killed trees	106	3.8	49%
Forestry waste materials	100	7.8	100%

Table C.17 Minimum selling prices of bioenergy produced from forestry waste materials

Per GJ	HTL	MeOH	EtOH	RNG	CHP	HB	PG
Feedstock	3.75	4.06	4.87	3.78	2.74	3.00	5.76
Transport	4.85	5.23	6.28	4.87	3.53	3.87	7.44
Other O&M	7.99	7.28	5.39	7.31	1.89	1.33	3.97
Depreciation	3.16	4.42	3.44	4.49	1.38	1.01	2.90
Tax	2.20	3.07	2.39	3.13	0.96	0.70	2.02
ROI	3.04	4.25	3.31	4.32	1.32	0.97	2.79
Total	24.99	28.31	25.67	27.90	11.82	10.88	24.88

Table C.18 An example of the discount cash flow model for bioenergy produced from HTL of forestry waste materials

Year	-2	-1	0	1	2	3	4	5	6	7	8	9	10
Finance by Equity	16	118	63										
Working Capital			25										
Loan payment				41	41	41	41	41	41	41	41	41	41
Interest payment	2	13	19	19	18	16	15	13	11	9	7	5	3
Loan principle	24	200	295	273	250	225	198	170	140	109	75	38	0
Biogas sale				**198**	202	206	210	215	219	223	228	232	237
Op Ex				68	70	71	72	74	75	77	78	80	82
By-product				63	65	66	67	69	70	71	73	74	76
Net Op				132	134	137	140	142	145	148	151	154	157
CCA schedule				0.25	0.38	0.19	0.09	0.05	0.02	0.01	0.01	0.00	0.00
Depreciation				123	184	92	46	23	12	6	3	1	1
Net revenue				-75	-134	-39	10	36	51	60	67	72	76
Loss forward				0	-75	-209	-248	-238	-202	-151	-91	-25	0
Taxable income				-75	-209	-248	-238	-202	-151	-91	-25	47	76
Income tax				0	0	0	0	0	0	0	0	12	20
Cash flow					26	27	28	30	31	32	34	35	25
IRR	1.26	1.12	1.00	0.89	0.79	0.71	0.63	0.56	0.50	0.45	0.40	0.35	0.32
PV 275				23	21	20	19	17	16	15	14	9	6
TCI + interest	22	147	107										
NPV			**0.00**										

In million dollars. Loan, interest, and depreciation are estimated based on capital costs. Sales and costs inflate 2% annually

Net Revenue = Biogas Sale – Net Op – Interest – Depreciation. Income tax = Max (0, (Net revenue + Loss forward)) * Tax rate.

Cash flow = Total Sale – Net Op – Loan payment – Income tax.

Continued

11	12	13	14	15	16	17	18	19	20
242	246	251	256	261	267	272	278	283	289
83	85	87	88	90	92	94	96	97	99
77	79	80	82	84	85	87	89	91	92
160	164	167	170	174	177	181	184	188	192
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0	0	0	0	0	0	0	0	0	0
81	83	84	86	88	90	91	93	95	97
0	0	0	0	0	0	0	0	0	0
81	83	84	86	88	90	91	93	95	97
21	21	22	22	23	23	24	24	25	25
60	61	62	64	65	66	68	69	70	72
0.28	0.25	0.22	0.20	0.18	0.16	0.14	0.13	0.11	0.10
17	15	14	13	12	11	10	9	8	7

Appendix D Numerical results for Chapter 4

C.1 LCA results

Table D.1 Global warming potential of AD per tDM feedstocks processed

GWP	kg CO_2-eq/tDM	Feedstock handling	Direct emissions	Anaerobic digestion	Digestate utilization	Displaced fertilizer	Displaced energy	**Net GWP**	**Reduction**
CM	Base	8.0E+00	7.0E+02	0.0E+00	0.0E+00	-1.7E+02	0.0E+00	**5.4E+02**	**N/A**
	RNG	9.4E-01	2.8E+02	1.3E+02	1.5E+01	-2.1E+02	-3.8E+02	**-1.5E+02**	**6.9E+02**
	CHP	9.4E-01	2.8E+02	1.1E+02	1.5E+01	-2.1E+02	-2.4E+02	**-4.5E+01**	**5.9E+02**
	INTEG	9.4E-01	2.8E+02	1.1E+02	1.5E+01	-2.1E+02	-3.8E+02	**-1.8E+02**	**7.3E+02**
PM	Base	2.9E+00	4.4E+02	0.0E+00	0.0E+00	-2.5E+02	0.0E+00	**1.9E+02**	**N/A**
	RNG	3.4E-01	3.4E+02	1.3E+02	1.5E+01	-3.0E+02	-3.8E+02	**-1.9E+02**	**3.8E+02**
	CHP	3.4E-01	3.4E+02	1.1E+02	1.5E+01	-3.0E+02	-2.4E+02	**-8.3E+01**	**2.7E+02**
	INTEG	3.4E-01	3.4E+02	1.1E+02	1.5E+01	-3.0E+02	-3.8E+02	**-2.2E+02**	**4.1E+02**
FW	Base	1.5E+02	2.9E+02	0.0E+00	0.0E+00	-1.5E+02	0.0E+00	**2.9E+02**	**N/A**
	RNG	8.8E+01	1.8E+02	2.0E+02	1.5E+01	-1.3E+02	-7.5E+02	**-4.0E+02**	**6.9E+02**
	CHP	8.8E+01	1.8E+02	1.5E+02	1.5E+01	-1.3E+02	-4.9E+02	**-1.9E+02**	**4.8E+02**
	INTEG	8.8E+01	1.8E+02	1.5E+02	1.5E+01	-1.3E+02	-7.7E+02	**-4.7E+02**	**7.6E+02**
CR	Base	1.5E+01	2.1E+01	0.0E+00	0.0E+00	-4.8E+01	0.0E+00	**-1.2E+01**	**N/A**
	RNG	1.1E+02	8.4E+01	1.5E+02	1.5E+01	-2.6E+01	-4.3E+02	**-9.5E+01**	**8.4E+01**
	CHP	1.1E+02	8.4E+01	1.2E+02	1.5E+01	-2.6E+01	-2.8E+02	**2.4E+01**	**-3.5E+01**
	INTEG	1.1E+02	8.4E+01	1.2E+02	1.5E+01	-2.6E+01	-4.4E+02	**-1.4E+02**	**1.2E+02**

Table D.2 Acidification potential of AD per tDM feedstocks processed

AP	kg SO_2-eq/tDM	Feedstock handling	Direct emissions	Anaerobic digestion	Digestate utilization	Displaced fertilizer	Displaced energy	**Net AP**	**Reduction**
CM	Base	5.4E-03	4.6E+01	0.0E+00	0.0E+00	-2.9E+00	0.0E+00	**4.3E+01**	**N/A**
	RNG	4.6E+00	4.1E+01	2.6E-01	1.6E-02	-3.6E+00	-8.1E-01	**4.2E+01**	**9.2E-01**
	CHP	4.6E+00	4.1E+01	7.2E-01	1.6E-02	-3.6E+00	-6.8E-01	**4.2E+01**	**3.2E-01**
	INTEG	4.6E+00	4.1E+01	7.2E-01	1.6E-02	-3.6E+00	-8.7E-01	**4.2E+01**	**5.2E-01**
PM	Base	1.9E-03	5.7E+01	0.0E+00	0.0E+00	-4.1E+00	0.0E+00	**5.3E+01**	**N/A**
	RNG	5.5E+00	5.2E+01	2.6E-01	1.6E-02	-5.0E+00	-8.1E-01	**5.2E+01**	**1.0E+00**
	CHP	5.5E+00	5.2E+01	7.2E-01	1.6E-02	-5.0E+00	-6.8E-01	**5.3E+01**	**4.2E-01**
	INTEG	5.5E+00	5.2E+01	7.2E-01	1.6E-02	-5.0E+00	-8.7E-01	**5.2E+01**	**6.1E-01**
FW	Base	1.1E-01	3.1E+01	0.0E+00	0.0E+00	-2.6E+00	0.0E+00	**2.9E+01**	**N/A**
	RNG	4.3E-01	2.7E+01	3.4E-01	1.6E-02	-2.3E+00	-1.6E+00	**2.4E+01**	**4.7E+00**
	CHP	4.3E-01	2.7E+01	1.3E+00	1.6E-02	-2.3E+00	-1.4E+00	**2.5E+01**	**3.5E+00**
	INTEG	4.3E-01	2.7E+01	1.3E+00	1.6E-02	-2.3E+00	-1.7E+00	**2.5E+01**	**3.9E+00**
CR	Base	8.2E-03	3.3E-01	0.0E+00	0.0E+00	-8.0E-01	0.0E+00	**-4.6E-01**	**N/A**
	RNG	1.3E+00	4.3E+00	3.0E-01	1.6E-02	-3.9E-01	-9.3E-01	**4.7E+00**	**-5.1E+00**
	CHP	1.3E+00	4.3E+00	8.3E-01	1.6E-02	-3.9E-01	-7.7E-01	**5.4E+00**	**-5.8E+00**
	INTEG	1.3E+00	4.3E+00	8.3E-01	1.6E-02	-3.9E-01	-1.0E+00	**5.1E+00**	**-5.6E+00**

Table D.3 Eutrophication potential of AD per tDM feedstocks processed

EP	kg PO_4-eq/tDM	Feedstock handling	Direct emissions	Anaerobic digestion	Digestate utilization	Displaced fertilizer	Displaced energy	**Net EP**	**Reduction**
CM	Base	1.4E-03	1.4E+01	0.0E+00	0.0E+00	-1.8E+00	0.0E+00	**1.2E+01**	**N/A**
	RNG	1.0E+00	1.2E+01	6.9E-02	5.0E-03	-2.2E+00	-9.0E-02	**1.1E+01**	**1.5E+00**
	CHP	1.0E+00	1.2E+01	1.9E-01	5.0E-03	-2.2E+00	-1.4E-01	**1.1E+01**	**1.4E+00**
	INTEG	1.0E+00	1.2E+01	1.9E-01	5.0E-03	-2.2E+00	-1.1E-01	**1.1E+01**	**1.4E+00**
PM	Base	4.9E-04	1.8E+01	0.0E+00	0.0E+00	-3.0E+00	0.0E+00	**1.5E+01**	**N/A**
	RNG	1.2E+00	1.5E+01	6.9E-02	5.0E-03	-3.5E+00	-9.0E-02	**1.3E+01**	**1.9E+00**
	CHP	1.2E+00	1.5E+01	1.9E-01	5.0E-03	-3.5E+00	-1.4E-01	**1.3E+01**	**1.8E+00**
	INTEG	1.2E+00	1.5E+01	1.9E-01	5.0E-03	-3.5E+00	-1.1E-01	**1.3E+01**	**1.8E+00**
FW	Base	3.3E-02	7.1E+00	0.0E+00	0.0E+00	-1.6E+00	0.0E+00	**5.5E+00**	**N/A**
	RNG	9.5E-02	7.9E+00	1.0E-01	4.9E-03	-1.5E+00	-1.8E-01	**6.5E+00**	**-9.4E-01**
	CHP	9.5E-02	7.9E+00	3.5E-01	4.9E-03	-1.5E+00	-2.8E-01	**6.6E+00**	**-1.1E+00**
	INTEG	9.5E-02	7.9E+00	3.5E-01	4.9E-03	-1.5E+00	-2.2E-01	**6.7E+00**	**-1.1E+00**
CR	Base	1.8E-03	1.7E-01	0.0E+00	0.0E+00	-4.5E-01	0.0E+00	**-2.8E-01**	**N/A**
	RNG	7.8E-01	1.2E+00	8.6E-02	5.0E-03	-2.3E-01	-1.0E-01	**1.8E+00**	**-2.1E+00**
	CHP	7.8E-01	1.2E+00	2.2E-01	5.0E-03	-2.3E-01	-1.6E-01	**1.9E+00**	**-2.2E+00**
	INTEG	7.8E-01	1.2E+00	2.2E-01	5.0E-03	-2.3E-01	-1.3E-01	**1.9E+00**	**-2.2E+00**

Table D.4 Human Toxicity of AD per tDM feedstocks processed

HT	kg C_2H_3Cl-eq/tDM	Feedstock handling	Direct emissions	Anaerobic digestion	Digestate utilization	Displaced fertilizer	Displaced energy	**Net HT**	**Reduction**
CM	Base	4.9E-02	1.4E+00	0.0E+00	0.0E+00	-8.1E+00	0.0E+00	**-6.6E+00**	**N/A**
	RNG	1.5E-01	1.3E+00	4.2E+00	1.9E-01	-9.5E+00	-1.4E+01	**-1.7E+01**	**1.1E+01**
	CHP	1.5E-01	1.3E+00	4.3E+00	1.9E-01	-9.5E+00	-1.1E+01	**-1.5E+01**	**8.1E+00**
	INTEG	1.5E-01	1.3E+00	4.3E+00	1.9E-01	-9.5E+00	-1.4E+01	**-1.8E+01**	**1.1E+01**
PM	Base	1.8E-02	1.8E+00	0.0E+00	0.0E+00	-1.3E+01	0.0E+00	**-1.1E+01**	**N/A**
	RNG	1.8E-01	1.7E+00	4.2E+00	1.9E-01	-1.5E+01	-1.4E+01	**-2.2E+01**	**1.1E+01**
	CHP	1.8E-01	1.7E+00	4.3E+00	1.9E-01	-1.5E+01	-1.1E+01	**-2.0E+01**	**8.4E+00**
	INTEG	1.8E-01	1.7E+00	4.3E+00	1.9E-01	-1.5E+01	-1.4E+01	**-2.3E+01**	**1.2E+01**
FW	Base	9.5E-01	1.1E+00	0.0E+00	0.0E+00	-6.6E+00	0.0E+00	**-4.5E+00**	**N/A**
	RNG	1.1E+00	8.7E-01	5.5E+00	1.9E-01	-6.0E+00	-2.7E+01	**-2.5E+01**	**2.1E+01**
	CHP	1.1E+00	8.7E-01	5.8E+00	1.9E-01	-6.0E+00	-2.2E+01	**-2.0E+01**	**1.6E+01**
	INTEG	1.1E+00	8.7E-01	5.8E+00	1.9E-01	-6.0E+00	-2.9E+01	**-2.7E+01**	**2.2E+01**
CR	Base	5.8E-02	1.0E-02	0.0E+00	0.0E+00	-2.1E+00	0.0E+00	**-2.0E+00**	**N/A**
	RNG	3.9E+00	1.4E-01	4.9E+00	1.9E-01	-1.3E+00	-1.6E+01	**-7.7E+00**	**5.7E+00**
	CHP	3.9E+00	1.4E-01	5.0E+00	1.9E-01	-1.3E+00	-1.3E+01	**-4.8E+00**	**2.7E+00**
	INTEG	3.9E+00	1.4E-01	5.0E+00	1.9E-01	-1.3E+00	-1.6E+01	**-8.4E+00**	**6.3E+00**

Table D.5 Respiratory inorganics of AD per tDM feedstocks processed

RI	kg $PM_{2.5}$-eq/tDM	Feedstock handling	Direct emissions	Anaerobic digestion	Digestate utilization	Displaced fertilizer	Displaced energy	**Net RI**	**Reduction**
CM	Base	1.1E-03	3.5E+00	0.0E+00	0.0E+00	-3.1E-01	0.0E+00	**3.2E+00**	**N/A**
	RNG	3.5E-01	3.2E+00	4.6E-02	3.0E-03	-3.8E-01	-1.0E-01	**3.1E+00**	**1.1E-01**
	CHP	3.5E-01	3.2E+00	1.6E-01	3.0E-03	-3.8E-01	-9.5E-02	**3.2E+00**	**-1.3E-02**
	INTEG	3.5E-01	3.2E+00	1.6E-01	3.0E-03	-3.8E-01	-1.2E-01	**3.2E+00**	**9.5E-03**
PM	Base	1.1E-03	3.5E+00	0.0E+00	0.0E+00	-3.1E-01	0.0E+00	**3.2E+00**	**N/A**
	RNG	3.5E-01	3.2E+00	4.6E-02	3.0E-03	-3.8E-01	-1.0E-01	**3.1E+00**	**1.1E-01**
	CHP	3.5E-01	3.2E+00	1.6E-01	3.0E-03	-3.8E-01	-9.5E-02	**3.2E+00**	**-1.3E-02**
	INTEG	3.5E-01	3.2E+00	1.6E-01	3.0E-03	-3.8E-01	-1.2E-01	**3.2E+00**	**9.5E-03**
FW	Base	2.5E-02	2.4E+00	0.0E+00	0.0E+00	-2.7E-01	0.0E+00	**2.2E+00**	**N/A**
	RNG	1.3E-01	2.1E+00	6.5E-02	3.0E-03	-2.5E-01	-2.1E-01	**1.8E+00**	**3.1E-01**
	CHP	1.3E-01	2.1E+00	3.0E-01	3.0E-03	-2.5E-01	-1.9E-01	**2.1E+00**	**5.5E-02**
	INTEG	1.3E-01	2.1E+00	3.0E-01	3.0E-03	-2.5E-01	-2.3E-01	**2.1E+00**	**9.9E-02**
CR	Base	1.8E-03	2.9E-02	0.0E+00	0.0E+00	-8.2E-02	0.0E+00	**-5.2E-02**	**N/A**
	RNG	1.5E-01	3.3E-01	5.3E-02	3.0E-03	-4.3E-02	-1.2E-01	**3.7E-01**	**-4.2E-01**
	CHP	1.5E-01	3.3E-01	1.9E-01	3.0E-03	-4.3E-02	-1.1E-01	**5.2E-01**	**-5.7E-01**
	INTEG	1.5E-01	3.3E-01	1.9E-01	3.0E-03	-4.3E-02	-1.3E-01	**4.9E-01**	**-5.4E-01**

C.2 Economic results

Table D.6 Capital costs of AD systems

Per farm	CM			PM			FW			CR		
Scenario	RNG	CHP	INTEG	RNG	CHP	INTEG	RNG	CHP	INTEG	RNG	CHP	INTEG
Total Capital Cost (k$)	**1392**	**1353**	**971**	**1392**	**1353**	**971**	**1804**	**1676**	**1176**	**1450**	**1398**	**1000**
1.Total Installed Cost	**1015**	**936**	**844**	**1015**	**936**	**844**	**1381**	**1223**	**1002**	**1067**	**976**	**866**
Anaerobic digester	411	411	411	411	411	411	411	411	411	411	411	411
Biogas Cleaning	38	38	38	38	38	38	76	76	76	44	44	44
Digestate separation	40	40	40	40	40	40	40	40	40	40	40	40
Biogas Storage	225	225	225	225	225	225	327	327	327	239	239	239
Biogas Utilization	184	114	32	184	114	32	368	228	32	210	130	32
Civil	117	108	97	117	108	97	159	141	115	123	112	100
2.Engineering	**76**	**70**	**63**	**76**	**70**	**63**	**104**	**92**	**75**	**80**	**73**	**65**
3.Contingency	**51**	**47**	**42**	**51**	**47**	**42**	**69**	**61**	**50**	**53**	**49**	**43**
4.Grid connection	**250**	**300**	**22**	**250**	**300**	**22**	**250**	**300**	**49**	**250**	**300**	**26**

Table D.7 Production costs and revenues of AD systems

Per farm	CM			PM			FW			CR		
Scenario	RNG	CHP	INTEG	RNG	CHP	INTEG	RNG	CHP	INTEG	RNG	CHP	INTEG
Production cost (k$/yr)	**431**	**413**	**360**	**484**	**466**	**413**	**452**	**410**	**335**	**453**	**431**	**375**
Feedstock	61	61	61	114	114	114	0	0	0	59	59	59
Consumables	25	23	21	25	23	21	35	31	25	27	24	22
Utility	48	40	40	48	40	40	60	42	42	63	53	53
Labor	92	92	92	92	92	92	92	92	92	92	92	92
Maintenance	30	28	25	30	28	25	41	37	30	32	29	26
Depreciation	139	135	97	139	135	97	180	167	117	145	140	100
Interest	35	34	24	35	34	24	45	42	29	36	35	25
Revenue (k$/yr)	**351**	**202**	**150**	**401**	**251**	**199**	**536**	**567**	**463**	**334**	**163**	**103**
Energy from biogas	20	73	59	20	73	59	39	146	118	22	84	67
Digestate as fertilizers	76	76	76	125	125	125	44	44	44	18	18	18
Tipping fees	0	0	0	0	0	0	272	272	272	0	0	0
Carbon tax	15	8	15	15	8	15	30	17	31	17	10	17
FiT	241	45	0	241	45	0	152	89	0	276	51	0
Net Rev (k$/yr)	**-79**	**-211**	**-210**	**-83**	**-215**	**-214**	**84**	**157**	**128**	**-119**	**-268**	**-272**

Table D.8 An example of the discount cash flow model for biogas products (AD of cattle manure, upgrading to RNG)

Year	-2	-1	0	1	2	3	4	5	6	7	8	9	10
Finance by Equity	45	334	178										
Working Capital			70										
Loan payment				116	116	116	116	116	116	116	116	116	116
Interest payment	4	37	54	54	50	46	41	37	31	26	20	14	7
Loan principle	67	568	835	773	707	637	562	483	398	308	211	109	0
Biogas sale				**430**	438	447	456	465	475	484	494	504	514
Op Ex				262	268	273	278	284	290	295	301	307	313
By-product				-77	-79	-80	-82	-83	-85	-87	-88	-90	-92
Net Op				185	189	193	197	201	205	209	213	217	221
CCA schedule				0.25	0.38	0.19	0.09	0.05	0.02	0.01	0.01	0.00	0.00
Depreciation				348	522	261	130	65	33	16	8	4	2
Net revenue				-158	-323	-52	88	163	206	233	253	269	283
Loss forward				0	-158	-480	-533	-445	-282	-76	0	0	0
Taxable income				-158	-480	-533	-445	-282	-76	157	253	269	283
Income tax				0	0	0	0	0	0	19	30	32	34
Cash flow				128	133	138	143	149	154	140	134	138	142
IRR	1.26	1.12	1.00	0.89	0.79	0.71	0.63	0.56	0.50	0.45	0.40	0.35	0.32
PV 780				114	106	98	90	84	77	63	54	49	45
TCI + interest	62	416	302										
NPV			**0.01**										

In thousand dollars. Loan, interest, and depreciation are estimated based on capital costs. Sales and costs inflate 2% annually

Net Revenue = Biogas Sale – Net Op – Interest – Depreciation. Income tax = Max (0, (Net revenue + Loss forward)) * Tax rate.

Cash flow = Total Sale – Net Op – Loan payment – Income tax.

Appendix E Numerical results for Chapter 5

D.1 LCA results

Table E.1 Global warming potential per tDM feedstock of integrated AD systems

GWP	kg CO_2-eq/tDM	Processing	Emissions	Replaced fertilizer	Replaced energy	CO2 integration	Saved material	**Net GWP**	**Reduction**
CM	Base	9.3E+00	5.8E+02	-1.5E+02	0.0E+00	0.0E+00	0.0E+00	**4.4E+02**	**N/A**
	RNG	1.7E+02	2.3E+02	-1.6E+02	-3.9E+02	0.0E+00	0.0E+00	**-1.5E+02**	**5.9E+02**
	CHP	1.4E+02	2.3E+02	-1.6E+02	-2.5E+02	0.0E+00	0.0E+00	**-4.3E+01**	**4.8E+02**
	INTEG	1.4E+02	1.9E+02	-1.2E+02	-3.9E+02	-4.7E+02	-5.3E+01	**-7.1E+02**	**1.1E+03**
CM-PM	Base	7.9E+00	5.5E+02	-1.7E+02	0.0E+00	0.0E+00	0.0E+00	**3.9E+02**	**N/A**
	RNG	1.5E+02	2.6E+02	-1.9E+02	-3.8E+02	0.0E+00	0.0E+00	**-1.7E+02**	**5.6E+02**
	CHP	1.2E+02	2.6E+02	-1.9E+02	-2.5E+02	0.0E+00	0.0E+00	**-6.2E+01**	**4.5E+02**
	INTEG	1.2E+02	2.1E+02	-1.4E+02	-3.9E+02	-4.6E+02	-5.0E+01	**-7.2E+02**	**1.1E+03**
CM-FW	Base	3.9E+01	5.2E+02	-1.5E+02	0.0E+00	0.0E+00	0.0E+00	**4.1E+02**	**N/A**
	RNG	2.0E+02	2.2E+02	-1.6E+02	-4.6E+02	0.0E+00	0.0E+00	**-2.0E+02**	**6.1E+02**
	CHP	1.6E+02	2.2E+02	-1.6E+02	-3.0E+02	0.0E+00	0.0E+00	**-7.4E+01**	**4.8E+02**
	INTEG	1.6E+02	1.4E+02	-9.7E+01	-4.7E+02	-5.7E+02	-5.0E+01	**-8.9E+02**	**1.3E+03**
CM-CR	Base	1.0E+01	4.6E+02	-1.3E+02	0.0E+00	0.0E+00	0.0E+00	**3.4E+02**	**N/A**
	RNG	1.8E+02	2.0E+02	-1.3E+02	-3.9E+02	0.0E+00	0.0E+00	**-1.5E+02**	**4.9E+02**
	CHP	1.5E+02	2.0E+02	-1.3E+02	-2.6E+02	0.0E+00	0.0E+00	**-3.9E+01**	**3.8E+02**
	INTEG	1.5E+02	1.6E+02	-9.6E+01	-4.0E+02	-4.8E+02	-5.0E+01	**-7.2E+02**	**1.1E+03**

Table E.2 Acidification potential per tDM feedstock of integrated AD systems

AP	kg SO_2-eq/tDM	Processing	Emissions	Replaced fertilizer	Replaced energy	CO2 integration	Saved material	**Net AP**	**Reduction**
CM	Base	5.9E-03	3.7E+01	-2.5E+00	0.0E+00	0.0E+00	0.0E+00	**3.5E+01**	**N/A**
	RNG	4.2E+00	3.2E+01	-2.8E+00	-8.4E-01	0.0E+00	0.0E+00	**3.3E+01**	**1.7E+00**
	CHP	4.7E+00	3.2E+01	-2.8E+00	-6.9E-01	0.0E+00	0.0E+00	**3.4E+01**	**1.1E+00**
	INTEG	4.7E+00	3.1E+01	-2.1E+00	-9.0E-01	-1.1E+00	-3.8E-01	**3.2E+01**	**2.9E+00**
CM-PM	Base	5.1E-03	4.1E+01	-2.8E+00	0.0E+00	0.0E+00	0.0E+00	**3.9E+01**	**N/A**
	RNG	4.3E+00	3.7E+01	-3.3E+00	-8.3E-01	0.0E+00	0.0E+00	**3.7E+01**	**1.8E+00**
	CHP	4.8E+00	3.7E+01	-3.3E+00	-6.9E-01	0.0E+00	0.0E+00	**3.7E+01**	**1.2E+00**
	INTEG	4.8E+00	3.5E+01	-2.4E+00	-8.9E-01	-1.1E+00	-3.8E-01	**3.5E+01**	**3.3E+00**
CM-FW	Base	2.8E-02	3.6E+01	-2.5E+00	0.0E+00	0.0E+00	0.0E+00	**3.3E+01**	**N/A**
	RNG	3.5E+00	3.1E+01	-2.7E+00	-1.0E+00	0.0E+00	0.0E+00	**3.1E+01**	**2.4E+00**
	CHP	4.0E+00	3.1E+01	-2.7E+00	-8.3E-01	0.0E+00	0.0E+00	**3.2E+01**	**1.6E+00**
	INTEG	4.0E+00	2.9E+01	-1.7E+00	-1.1E+00	-1.3E+00	-3.7E-01	**2.8E+01**	**5.0E+00**
CM-CR	Base	6.4E-03	2.9E+01	-2.1E+00	0.0E+00	0.0E+00	0.0E+00	**2.7E+01**	**N/A**
	RNG	3.5E+00	2.6E+01	-2.3E+00	-8.6E-01	0.0E+00	0.0E+00	**2.7E+01**	**3.9E-01**
	CHP	4.0E+00	2.6E+01	-2.3E+00	-7.1E-01	0.0E+00	0.0E+00	**2.7E+01**	**-2.3E-01**
	INTEG	4.0E+00	2.6E+01	-1.7E+00	-9.2E-01	-1.1E+00	-3.8E-01	**2.6E+01**	**1.2E+00**

Table E.3 Eutrophication potential per tDM feedstock of integrated AD systems

EP	kg PO_4-eq/tDM	Processing	Emissions	Replaced fertilizer	Replaced energy	CO2 integration	Saved material	**Net EP**	**Reduction**
CM	Base	1.4E-03	1.1E+01	-1.6E+00	0.0E+00	0.0E+00	0.0E+00	**9.9E+00**	**N/A**
	RNG	9.8E-01	9.3E+00	-1.8E+00	-9.3E-02	0.0E+00	0.0E+00	**8.5E+00**	**1.4E+00**
	CHP	1.1E+00	9.3E+00	-1.8E+00	-1.4E-01	0.0E+00	0.0E+00	**8.5E+00**	**1.3E+00**
	INTEG	1.1E+00	9.0E+00	-1.3E+00	-1.1E-01	-1.4E-01	-1.3E-01	**8.5E+00**	**1.4E+00**
CM-PM	Base	1.2E-03	1.3E+01	-1.9E+00	0.0E+00	0.0E+00	0.0E+00	**1.1E+01**	**N/A**
	RNG	1.0E+00	1.1E+01	-2.1E+00	-9.2E-02	0.0E+00	0.0E+00	**9.4E+00**	**1.6E+00**
	CHP	1.1E+00	1.1E+01	-2.1E+00	-1.4E-01	0.0E+00	0.0E+00	**9.4E+00**	**1.5E+00**
	INTEG	1.1E+00	1.0E+01	-1.5E+00	-1.1E-01	-1.3E-01	-1.3E-01	**9.4E+00**	**1.5E+00**
CM-FW	Base	8.1E-03	1.1E+01	-1.6E+00	0.0E+00	0.0E+00	0.0E+00	**9.0E+00**	**N/A**
	RNG	8.2E-01	9.0E+00	-1.7E+00	-1.1E-01	0.0E+00	0.0E+00	**8.0E+00**	**9.8E-01**
	CHP	9.7E-01	9.0E+00	-1.7E+00	-1.7E-01	0.0E+00	0.0E+00	**8.1E+00**	**8.9E-01**
	INTEG	9.7E-01	8.4E+00	-1.0E+00	-1.4E-01	-1.7E-01	-1.2E-01	**7.9E+00**	**1.2E+00**
CM-CR	Base	1.5E-03	9.0E+00	-1.3E+00	0.0E+00	0.0E+00	0.0E+00	**7.7E+00**	**N/A**
	RNG	8.9E-01	7.6E+00	-1.4E+00	-9.5E-02	0.0E+00	0.0E+00	**7.0E+00**	**7.3E-01**
	CHP	1.0E+00	7.6E+00	-1.4E+00	-1.5E-01	0.0E+00	0.0E+00	**7.1E+00**	**6.5E-01**
	INTEG	1.0E+00	7.4E+00	-1.0E+00	-1.2E-01	-1.4E-01	-1.3E-01	**7.1E+00**	**6.4E-01**

Table E.4 Human Toxicity per tDM feedstock of integrated AD systems

HT	kg C_2H_3Cl-eq/tDM	Processing	Emissions	Replaced fertilizer	Replaced energy	CO2 integration	Saved material	**Net HT**	**Reduction**
CM	Base	5.0E-02	1.2E+00	-6.9E+00	0.0E+00	0.0E+00	0.0E+00	**-5.7E+00**	**N/A**
	RNG	5.0E+00	1.0E+00	-7.6E+00	-1.4E+01	0.0E+00	0.0E+00	**-1.6E+01**	**9.8E+00**
	CHP	5.2E+00	1.0E+00	-7.6E+00	-1.1E+01	0.0E+00	0.0E+00	**-1.3E+01**	**7.2E+00**
	INTEG	5.2E+00	1.0E+00	-5.4E+00	-1.5E+01	-1.7E+01	-3.0E+00	**-3.4E+01**	**2.9E+01**
CM-PM	Base	4.3E-02	1.3E+00	-8.3E+00	0.0E+00	0.0E+00	0.0E+00	**-6.9E+00**	**N/A**
	RNG	4.4E+00	1.2E+00	-9.2E+00	-1.4E+01	0.0E+00	0.0E+00	**-1.8E+01**	**1.1E+01**
	CHP	4.6E+00	1.2E+00	-9.2E+00	-1.1E+01	0.0E+00	0.0E+00	**-1.5E+01**	**7.9E+00**
	INTEG	4.6E+00	1.1E+00	-6.5E+00	-1.5E+01	-1.7E+01	-2.9E+00	**-3.6E+01**	**2.9E+01**
CM-FW	Base	2.4E-01	1.2E+00	-6.9E+00	0.0E+00	0.0E+00	0.0E+00	**-5.5E+00**	**N/A**
	RNG	5.4E+00	9.9E-01	-7.3E+00	-1.7E+01	0.0E+00	0.0E+00	**-1.8E+01**	**1.2E+01**
	CHP	5.6E+00	9.9E-01	-7.3E+00	-1.4E+01	0.0E+00	0.0E+00	**-1.4E+01**	**9.0E+00**
	INTEG	5.6E+00	9.2E-01	-4.4E+00	-1.8E+01	-2.1E+01	-2.9E+00	**-4.0E+01**	**3.4E+01**
CM-CR	Base	5.2E-02	9.3E-01	-5.9E+00	0.0E+00	0.0E+00	0.0E+00	**-4.9E+00**	**N/A**
	RNG	5.5E+00	8.4E-01	-6.3E+00	-1.4E+01	0.0E+00	0.0E+00	**-1.4E+01**	**9.3E+00**
	CHP	5.7E+00	8.4E-01	-6.3E+00	-1.2E+01	0.0E+00	0.0E+00	**-1.2E+01**	**6.6E+00**
	INTEG	5.7E+00	8.3E-01	-4.4E+00	-1.5E+01	-1.8E+01	-2.9E+00	**-3.4E+01**	**2.9E+01**

Table E.5 Respiratory Inorganics per tDM feedstock of integrated AD systems

RI	kg $PM_{2.5}$-eq/tDM	Processing	Emissions	Replaced fertilizer	Replaced energy	CO2 integration	Saved material	**Net RI**	**Reduction**
CM	Base	1.3E-03	2.9E+00	-2.7E-01	0.0E+00	0.0E+00	0.0E+00	**2.6E+00**	**N/A**
	RNG	3.5E-01	2.5E+00	-3.0E-01	-1.1E-01	0.0E+00	0.0E+00	**2.4E+00**	**1.6E-01**
	CHP	4.7E-01	2.5E+00	-3.0E-01	-9.7E-02	0.0E+00	0.0E+00	**2.6E+00**	**3.4E-02**
	INTEG	4.7E-01	2.4E+00	-2.2E-01	-1.2E-01	-1.4E-01	-6.1E-02	**2.3E+00**	**2.5E-01**
CM-PM	Base	1.1E-03	3.2E+00	-3.1E-01	0.0E+00	0.0E+00	0.0E+00	**2.9E+00**	**N/A**
	RNG	3.6E-01	2.8E+00	-3.6E-01	-1.1E-01	0.0E+00	0.0E+00	**2.7E+00**	**1.8E-01**
	CHP	4.8E-01	2.8E+00	-3.6E-01	-9.7E-02	0.0E+00	0.0E+00	**2.8E+00**	**4.6E-02**
	INTEG	4.8E-01	2.7E+00	-2.6E-01	-1.2E-01	-1.4E-01	-5.9E-02	**2.6E+00**	**2.7E-01**
CM-FW	Base	6.4E-03	2.8E+00	-2.7E-01	0.0E+00	0.0E+00	0.0E+00	**2.5E+00**	**N/A**
	RNG	3.2E-01	2.4E+00	-2.9E-01	-1.3E-01	0.0E+00	0.0E+00	**2.3E+00**	**1.9E-01**
	CHP	4.6E-01	2.4E+00	-2.9E-01	-1.2E-01	0.0E+00	0.0E+00	**2.5E+00**	**3.8E-02**
	INTEG	4.6E-01	2.2E+00	-1.8E-01	-1.4E-01	-1.8E-01	-6.0E-02	**2.1E+00**	**3.8E-01**
CM-CR	Base	1.4E-03	2.3E+00	-2.3E-01	0.0E+00	0.0E+00	0.0E+00	**2.0E+00**	**N/A**
	RNG	3.1E-01	2.0E+00	-2.5E-01	-1.1E-01	0.0E+00	0.0E+00	**2.0E+00**	**5.1E-02**
	CHP	4.3E-01	2.0E+00	-2.5E-01	-1.0E-01	0.0E+00	0.0E+00	**2.1E+00**	**-8.3E-02**
	INTEG	4.3E-01	2.0E+00	-1.8E-01	-1.2E-01	-1.5E-01	-5.9E-02	**1.9E+00**	**1.0E-01**

D.2 Economic results

Table E.6 Capital costs of integrated AD systems

Per farm	CM			CM-PM			CM-FW			CM-CR		
Scenario	RNG	CHP	INTEG	RNG	CHP	INTEG	RNG	CHP	INTEG	RNG	CHP	INTEG
Total Capital Cost (k$)	**1620**	**1557**	**1074**	**1555**	**1499**	**1026**	**1656**	**1578**	**1109**	**1568**	**1508**	**1071**
1.Total Installed Cost	**1217**	**1118**	**955**	**1160**	**1066**	**912**	**1250**	**1136**	**986**	**1171**	**1074**	**952**
Anaerobic digester	471	471	471	449	449	449	449	449	449	449	449	449
Biogas Cleaning	48	48	48	46	46	46	55	55	55	47	47	47
Digestate separation	46	46	46	44	44	44	44	44	44	44	44	44
Biogas Storage	279	279	279	268	268	268	291	291	291	269	269	269
Biogas Utilization	232	144	0	220	136	0	266	165	32	227	141	32
Civil	140	129	110	133	123	105	144	131	113	135	124	109
2.Engineering	**91**	**84**	**72**	**87**	**80**	**68**	**94**	**85**	**74**	**88**	**81**	**71**
3.Contingency	**61**	**56**	**48**	**58**	**53**	**46**	**62**	**57**	**49**	**59**	**54**	**48**
4.Grid connection	**250**	**300**	**0**	**250**	**300**	**0**	**250**	**300**	**0**	**250**	**300**	**0**

Table E.7 Production costs and revenues of integrated AD systems

Per farm	CM			CM-PM			CM-FW			CM-CR		
Scenario	RNG	CHP	INTEG	RNG	CHP	INTEG	RNG	CHP	INTEG	RNG	CHP	INTEG
Production cost (k$/yr)	**485**	**461**	**392**	**481**	**458**	**391**	**473**	**444**	**377**	**473**	**449**	**388**
Feedstock	75	75	75	85	85	85	56	56	56	71	71	71
Consumables	30	28	24	29	27	23	31	28	25	29	27	24
Utility	50	39	39	47	36	36	50	37	37	51	40	40
Labor	92	92	92	92	92	92	92	92	92	92	92	92
Maintenance	37	34	29	35	32	27	37	34	30	35	32	29
Depreciation	162	156	107	155	150	102	165	158	111	157	151	107
Interest	40	39	27	39	37	26	41	39	28	39	38	27
Revenue (k$/yr)	**452**	**263**	**437**	**420**	**241**	**423**	**536**	**320**	**529**	**403**	**219**	**411**
Energy from biogas	25	92	74	23	87	70	28	106	85	24	90	73
Digestate as fertilizers	104	104	57	90	90	66	70	70	51	63	63	46
CO_2 Integration	0	0	88	0	0	84	0	0	104	0	0	87
Saved GH media	0	0	78	0	0	74	0	0	92	0	0	77
Saved MH substrate	0	0	77	0	0	74	0	0	66	0	0	73
Saved transportation	0	0	19	0	0	15	0	0	15	0	0	15
Tipping fees	0	0	0	0	0	0	68	68	68	0	0	0
Carbon tax	19	11	42	18	10	40	22	12	49	19	10	41
FiT	305	56	0	289	53	0	349	65	0	297	55	0
Net Rev (k$/yr)	**-33**	**-198**	**45**	**-61**	**-217**	**32**	**64**	**-124**	**152**	**-70**	**-231**	**23**

Appendix F Numerical results for Chapter 6

Table F.1 Total production potential, GHG reduction, extra costs and GHG reduction costs of bioenergy produced from lignocellulosic biomass in BC

		Total energy potential (PJ)	Total GHG reduction ($MtCO_2$)	Total extra cost (Million$)	GHG reduction cost ($\$/tCO_2$)
FWM	HTL	90 (RPPs)	7.03	629	89
	MeOH	84 (RPPs)	6.48	688	106
	EtOH	70 (RPPs)	5.60	301	54
	RNG	90 (NG)	5.57	2321	417
	CHP	87 (NG) + 47 (E)	5.34	-241	-45
	HB	127 (NG)	7.49	-169	-23
	PG	59 (E)	0.46	569	1238
AAC	HTL	31 (RPPs)	1.94	514	265
	MeOH	29 (RPPs)	1.75	534	305
	EtOH	24 (RPPs)	1.45	400	277
	RNG	31 (NG)	1.43	1100	768
	CHP	30 (NG) + 16 (E)	1.35	213	157
	HB	44 (NG)	2.10	238	113
	PG	21 (E)	-0.34	493	-1470
WW	HTL	2.6 (RPPs)	0.18	-4.3	-24
	MeOH	2.4 (RPPs)	0.17	-2.7	-16
	EtOH	2.0 (RPPs)	0.14	-13.6	-97
	RNG	2.6 (NG)	0.14	43.4	311
	CHP	2.4 (NG) + 1.3 (E)	0.13	-28.9	-217
	HB	3.6 (NG)	0.20	-26.8	-138
	PG	1.7 (E)	0.00	-6.0	1382
CR	HTL	4.3 (RPPs)	0.29	19.9	68
	MeOH	4.0 (RPPs)	0.26	23.3	88
	EtOH	3.3 (RPPs)	0.22	1.9	9
	RNG	4.3 (NG)	0.22	101.3	457
	CHP	4.1 (NG) + 2.2 (E)	0.21	-25.4	-121
	HB	6.0 (NG)	0.31	-23.3	-74
	PG	2.8 (E)	-0.02	12.9	-647

Table F.2 Total production potential, GHG reduction, and extra costs of biogas in BC

		Total Energy potential (PJ)	Total GHG reduction ($MtCO_2$)	Total extra cost (Million$)	GHG reduction cost ($/t$CO_2$-eq)
CM	RNG	4.6 (NG)	0.53	215	405
	CHP	2.6 (NG) + 1.4 (E)	0.45	176	390
	HB	4.7 (NG)	0.56	145	261
PM	RNG	1.6 (NG)	0.10	76	755
	CHP	0.9 (NG) + 0.5 (E)	0.07	62	855
	HB	1.6 (NG)	0.11	51	469
FW	RNG	2.7 (NG)	0.15	70	463
	CHP	1.5 (NG) + 0.8 (E)	0.10	46	438
	HB	2.7 (NG)	0.17	35	212
CR	RNG	2.8 (NG)	0.03	137	4021
	CHP	1.6 (NG) + 0.9 (E)	-0.01	113	N/A
	HB	2.8 (NG)	0.05	96	1903

Table F.3 Allocation biomass in Scenario (a)

	%		Total Energy potential (PJ)	Total reduction ($MtCO_2$)	Total extra cost (Million$)	$/t$CO_2$
WW	100%	HB	3.6 (NG)	0.20	-27	-138
CR	100%	HB	6.0 (NG)	0.31	-23	-74
FWM	100%	HB	128 (NG)	7.49	-169	-23
AAC	100%	HB	44 (NG)	2.10	238	113
FW	100%	AD- HB	2.7 (NG)	0.17	35	212
CM	100%	AD- HB	4.7 (NG)	0.56	145	261
PM	100%	AD- HB	1.6 (NG)	0.11	51	469
Total			189 (NG)	10.9	251	

Table F.4 Allocation biomass in Scenario (b)

	%		Total Energy potential (PJ)	Total reduction ($MtCO_2$)	Total extra cost (Million$)	$/t$CO_2$
WW	100%	HTL	2.6 (RPPs)	0.18	-4	-24
FWM	33%	HB	42 (NG)	2.44	-56	-23
CR	100%	HTL	4.3 (RPPs)	0.29	20	68
FWM	67%	HTL	61 (RPP)	4.74	427	90
AAC	100%	HB	44 (NG)	2.10	238	113
CM	100%	AD- RNG	4.7 (NG)	0.53	215	405
FW	100%	AD- RNG	2.7 (NG)	0.15	70	463
PM	100%	AD- RNG	1.6 (NG)	0.10	76	755
Total			94 (NG) + 68 (RPPs)	10.5	983	

Table F.5 Allocation biomass in Scenario (c)

	%		Total Energy potential (PJ)	Total reduction ($MtCO_2$)	Total extra cost (Million$)	$/t$CO_2$
FWM	13%	HB	15 (NG)	0.96	-22	-23
FWM	49%	HTL	45 (RPP)	3.48	313	90
AAC	100%	HB	44 (NG)	2.10	238	113
WW	100%	RNG	2.6 (RPPs)	0.14	43	311
CM	100%	AD- RNG	4.7 (NG)	0.53	215	405
FWM	38%	RNG	34 (NG)	2.10	876	417
CR	100%	RNG	4.3 (RPPs)	0.22	101	457
FW	100%	AD- RNG	2.7 (NG)	0.15	70	463
PM	100%	AD- RNG	1.6 (NG)	0.10	76	755
Total			110 (NG) + 45(RPPs)	9.8	1909	

Table F.6 Allocation biomass in Scenario (d)

	%		Total Energy potential (PJ)	Total reduction ($MtCO_2$)	Total extra cost (Million$)	$/t$CO_2$
FWM	35%	CHP	30 (NG) + 16(E)	1.85	-83	-45
FWM	49%	HTL	45 (RPP)	3.48	313	90
AAC	100%	CHP	30 (NG) + 16 (E)	1.35	213	157
WW	100%	RNG	2.6 (RPPs)	0.14	43	311
CM	100%	AD- RNG	4.7 (NG)	0.53	215	405
FWM	16%	RNG	14 (NG)	0.89	371	417
CR	100%	RNG	4.3 (RPPs)	0.22	101	457
FW	100%	AD- RNG	2.7 (NG)	0.15	70	463
PM	100%	AD- RNG	1.6 (NG)	0.10	76	755
Total			90 (NG) + 45(RPPs)	8.7	1317	

Table F.7 Allocation biomass in Scenario (e)

	%		Total Energy potential (PJ)	Total reduction ($MtCO_2$)	Total extra cost (Million$)	$/t$CO_2$
FWM	50%	HTL	45 (RPP)	3.52	317	90
AAC	100%	HTL	31 (RPPs)	1.94	514	265
WW	100%	RNG	2.6 (RPPs)	0.14	43	311
CM	100%	AD- RNG	4.7 (NG)	0.53	215	405
FWM	50%	RNG	45 (NG)	2.78	1159	417
CR	100%	RNG	4.3 (RPPs)	0.22	101	457
FW	100%	AD- RNG	2.7 (NG)	0.15	70	463
PM	100%	AD- RNG	1.6 (NG)	0.10	76	755
Total			61 (NG) + 77(RPPs)	9.4	2494	