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Upgrading Technologies for Biogas Production Plants

Overview and life cycle cost analysis of available technologies

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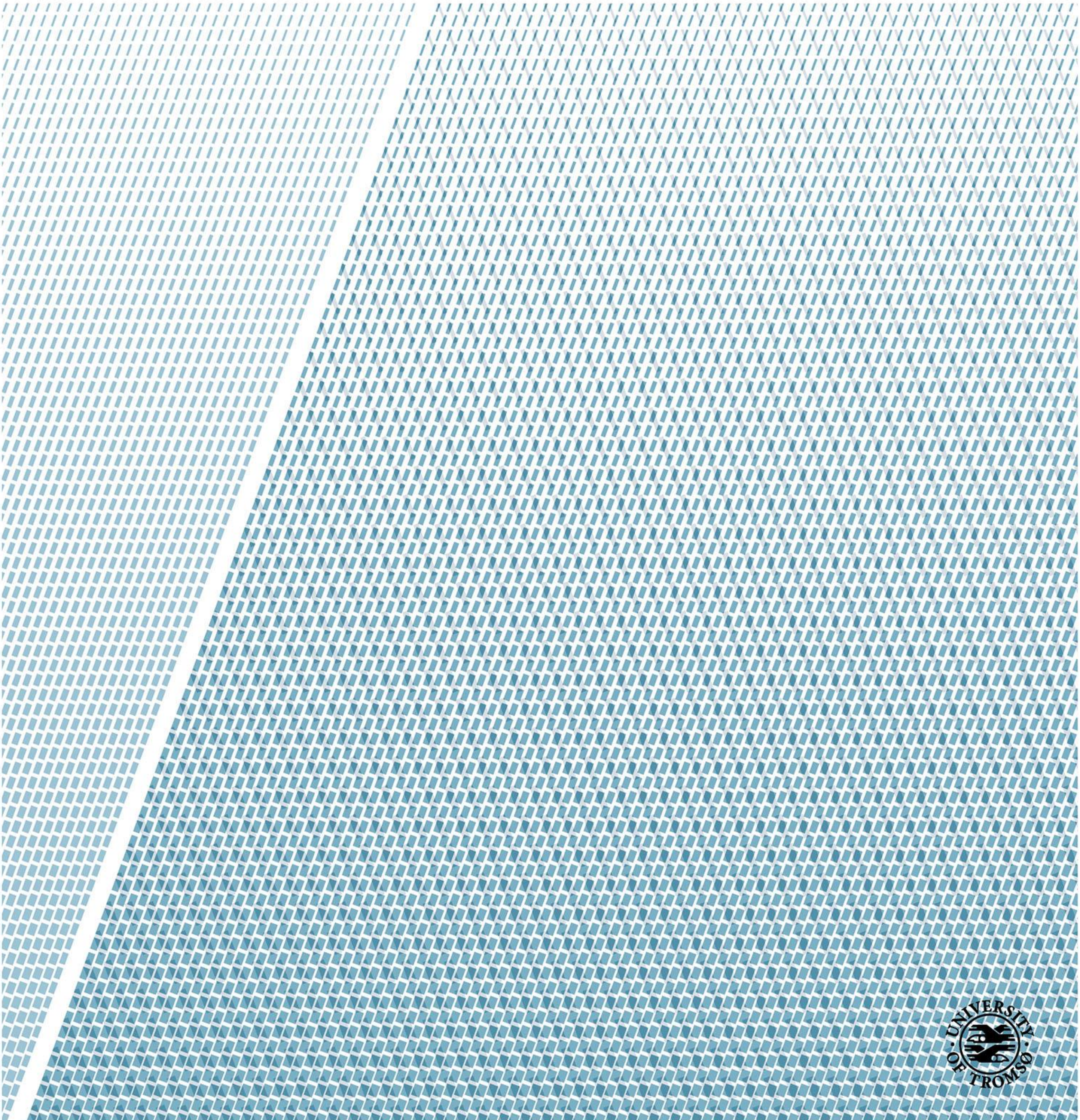

Abstract

An increased focus on waste management has emerged during the last decade. Renewable energy, efficient energy usage and cuts in greenhouse gas emissions are highly prioritized by the EU. The International Energy Agency (IEA) and the World Energy Council estimates that the global energy demand will grow within the next decades. The continuously increasing energy demand, contributes to development of new technologies for utilization of alternative energy resources. Energy resources with low environmental impact should be utilized to achieve a sustainable development.

Biogas production from organic waste has shown to be more environmentally friendly compared to other waste handling options such as composting, incineration and landfilling. Biogas production from organic waste is a treatment technology that generates renewable energy in forms of biogas, and recycles organic waste as a fertilizer and soil amendment. The results of several studies show that the best climate benefit is achieved when biogas is upgraded to biomethane and substituted with diesel.

Upgrading of biogas to biomethane is performed in the upgrading system, which is an optional process in a biogas production plant. Chemical scrubber, water scrubber, organic physical scrubber, membrane, pressure swing adsorption and cryogenic upgrading are different types of commercially used biogas upgrading technologies. The total life cycle cost for an upgrading plant is affected by different factors. This includes the investment cost and the operation and maintenance cost. There are three major consumables included in the operating cost; power, water and chemicals.

In this thesis, ten different small-scale upgrading plants based on five different upgrading technologies are investigated. A life cycle cost analysis (LCCA) is conducted for all the different upgrading technologies in order to find the most cost-effective system. Two different scenarios are analyzed; one where excess heat from the upgrading units is utilized, and one without heat recovery of the excess heat. By including heat recovery in the LCCA, it is possible to compare different upgrading technologies with respect to the whole biogas production plant.

The data used in the analysis are collected from various manufacturers for biogas upgrading plants. All the costs associated with the investment, operation and maintenance are identified and used in the LCCA. The collected data was given either as a fixed average number, or as a range with a minimum and maximum value. To account for the uncertainties in the data, an uncertainty analysis was conducted using a Monte Carlo simulation technique. For this aim, statistical approaches were used by developing different codes in Matlab to perform the uncertainty analysis. Furthermore, a sensitivity analysis is done in order to test the outcome of the LCCA by changing the electricity cost and discount rate in the initial analysis.

Results from this thesis is applicable for companies considering investing in a biogas upgrading plant. Information regarding the cost and consumables for different technologies are presented. Electricity price and access to water and chemicals, may affect the decision-making for selection of biogas upgrading technology. The LCCA shows that pressure swing absorption and water scrubber are the most cost-effective upgrading technologies for both with and without heat recovery. The least cost-effective technologies was found to be the cryogenic upgrading and amine scrubber.

Keywords: Biogas upgrading, Upgrading technologies, Biogas production, Life Cycle Cost Analysis, Biomethane

Preface and acknowledgements

This thesis is the last part of my master studies in Technology and Safety in the High North at UiT-The Arctic University of Norway, Department of Engineering and Safety. The research conducted in this thesis is a contributing part to the biogas project “BiogassNord”, which is a cooperation between SINTEF Nord and Remiks.

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Hanne W. Brendeløkken

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Abbreviations

AD	Anaerobic digestion
CBG	Compressed biogas
CHP	Combined heat and power plant
DMEA	Di-methyl ethanol amine
EU	European Union
GHG	Greenhouse gas concentration
LBG	Liquefied biogas
LCCA	Life Cycle Cost Analysis
MEA	Mono ethanol amine
MNOK	Million Norwegian kroner
MSW	Municipal Solid Waste
PSA	Pressure Swing Adsorption
TS	Total solids (dry matter content)
WtE	Waste-to-Energy

1 Introduction

1.1 Background and problem statement

In the last decade, there has been an increasing focus on waste management. Growing population and economic development have led to a continuous increase in waste generation, which has resulted in development of new technologies for waste management (Letcher & Vallero, 2011). In order to minimize the environmental impact from waste, the Waste Framework Directive (2008/98/EC) has established a waste management hierarchy. This hierarchy defines the priority order for waste management, and ensures a continuous effort to carry out waste management with best practice. New laws are frequently being established in order to improve the framework.

Another factor affecting waste management is the globally increasing energy demand. This has led to the concept of Waste-to-Energy (WtE), which is a process that produce energy from waste sources. WtE technologies can produce energy in various forms, from different types of waste (Re L, et al., 2013).

The International Energy Agency (IEA) estimates that the global energy demand is likely to increase with 37 % by 2040 (OECD/IEA, 2014). The World Energy Council further estimates, using two different scenarios, that the total primary energy supply globally will increase with 61 % and 27 % from 2010 to 2050, respectively (World Energy Council, 2013). The continuously increasing energy demand contributes to development of new technologies for improved utilization of alternative energy resources.

Around 19 % of the global energy consumption in 2008 came from renewable energy resources (Demirel, 2012). Generally, fossil fuels are known to be finite, while renewable energy is sustainable over a long term (Dincer & Rosen, 1998). To achieve a sustainable development, energy resources with low environmental impact should be utilized (Dincer & Rosen, 1998). If fossil fuels are replaced by renewable energy sources, it can contribute to climate change mitigation (IPCC, 2012). Renewable energy, efficient energy usage and cuts in greenhouse gas emissions are highly prioritized by the EU (European Commission, 2014).

Biogas production is a treatment technology that generates renewable energy, and recycles organic waste into a digested biomass, which can be used as fertilizer and soil amendment. Carbon footprints from food waste can be reduced by both the recovery of green energy, and the use of biofertilizers instead of chemical fertilizers (Masse, et al., 2012). Biogas is a renewable energy source, which is considered carbon-neutral since the organic waste has photosynthesized carbon dioxide (Masse, et al., 2012). Production of biogas from organic waste has shown to be more environmentally friendly compared to other waste handling options such as landfilling, incineration and composting (Lin, et al., 2012). Biogas production can therefore be considered a favorable treatment for organic waste.

Commercial biogas production has increased for at least two reasons. Firstly, biogas can be used as fuel or energy production. Secondly, it contributes to a lower greenhouse gas (GHG) concentration when it is collected in a closed process (Santos, et al., 2013). Methane is considered a strong greenhouse gas, and by capturing it in a biogas production plant it is not emitted to the atmosphere (Butz, 2014).

It is recommended that biogas is upgraded to a fuel, even though it can be used directly for power generation (López, et al., 2013). Analyses have shown that upgrading biogas to biomethane and substituting it with diesel, provides the best climate benefit (Arnøy, et al., 2013). There exist different technologies for biogas upgrading, such as chemical scrubber, water scrubber, organic physical scrubber, membrane, pressure swing adsorption and cryogenic upgrading.

The cost is a critical factor when considering if biogas should be upgraded. Studies are done regarding the cost of upgrading biogas into biomethane (Persson, et al., 2006; Persson, 2003; Forsberg, 2009), and some studies compare the cost for only a couple different technologies (Urban, et al., 2009; Bauer, et al., 2013; Patterson, et al., 2011). Conclusions from these studies show that the investment cost of an upgrading plant increases with an increased plant size, while the specific cost for upgrading per cubic meter biogas, increases with an increasing plant size. However, none of these studies include all the commercially used upgrading technologies. Another factor which is not considered is excess heat from the upgrading plant, even though it has an impact on the life cycle cost (LCC). If the upgrading unit is placed in context with the whole biogas production plant, the excess heat from the upgrading unit can be used in other parts of the production process. The pre-treatment and reactor are examples of components in the production process, which have a large energy consumption in form of heat. If excess heat from an upgrading unit is used in these components, the total energy cost for the whole system will be reduced. To this aim, one also needs to consider the cost of the upgrading technology when the principle of heat recovery is included in the total cost.

1.2 Research questions

The life cycle cost is an important factor when deciding between biogas upgrading technologies. By calculating the LCC, the most cost-effective system can be established. Based on this, the main research problem for this thesis is to analyze the LCC of different biogas upgrading plants, while assessing the uncertainties associated with the different cost elements. Such analysis is a key input for further decision-making processes regarding the selection of an upgrading unit for a biogas production plant.

In order to answer the main research problem for this project, some research questions are formulated:

1. How is biogas produced, and what are the key components in the process?
2. What types of technologies are available for biogas upgrading?
3. Which elements affect the life cycle cost for an upgrading unit?
4. What is the life cycle cost for a small-scale upgrading plant, based on different technologies both with and without heat recovery option?

1.3 Objective of the research study

The main objective of this thesis is to compare different biogas upgrading technologies for a small-scale plant, in order to find the most cost-effective system. Based on this, the specific objectives of this research are to:

- Describe how biogas is produced, and identify the main components in a biogas production process.
    - ➢ Provide a process description, including component functions.
    - ➢ Explain the microbiology for biogas production.
- Identify and discuss the existing upgrading technologies.
    - ➢ Provide an overview over the upgrading technologies, and explain their function.

- Analyze the life cycle cost of different upgrading technologies when the utilization of excess heat is both included and excluded.
    - List the elements that affect the life cycle cost.
    - Develop a life cycle cost model for each technology using their constituting elements.
    - Compare scenarios when excess heat is both included and excluded.
    - Conduct uncertainty analysis and sensitivity analysis.

1.4 Limitation and challenges

This thesis only considers the economic perspective of biogas upgrading; it does not include any environmental impact assessment. However, methane loss from different upgrading units are assigned a monetary value in order to distinguish different methane recovery rates.

In order to achieve the aim of this thesis, data regarding the investment cost and operational cost had to be obtained. This data are provided directly by manufactures of the respective biogas upgrading plants. Eight manufactures replied to the data request, and supplied the needed information. In total there are ten different upgrading units included in this analysis. All the commercial used upgrading technologies are examined, except for the organic physical scrubber. It was not possible to acquire the needed information for this upgrading technique, and it is therefore not included in this study. The collected data are valid at the time when conducting the presented research, and may be subjected to potential changes in future. Moreover, some of the manufactures did not provide any information regarding excess heat from their system, and it could therefore not be included for the corresponding upgrading units.

When life cycle cost is calculated, the availability is assumed to be 100% for all the units. A more extensive analysis could be conducted by using the information regarding the availability performance of different upgrading technologies. For the purpose of conducting an availability analysis, failure and repair time data for the given plants are needed.

Only the factors that have a direct effect on the different upgrading technologies are included in the life cycle cost. It is assumed that the cost of project management, salaries and property are the same for all options. This is done to simplify the analysis and remove the measures that are not influencing the specific upgrading technology.

All the upgrading units produce biomethane, except for the cryogenic unit. This technology cools down and liquefies carbon dioxide and biomethane. This means that the outcome from this plant is different from the other upgrading technologies. Liquefied biomethane might have other applications and sales prices than gaseous biomethane, but this has not been considered in this thesis.

1.5 Structure of the report

The first chapter of this thesis gives an introduction to the research problem and the objectives. It presents the limitations and challenges associated with the life cycle cost analysis. The next chapter presents the research methodology, and how the data collection and analysis are conducted. Thereafter, a literature review is presented on the biogas production process, treatment technologies for organic waste, and process description on commercially used biogas upgrading technologies. Results and discussion regarding the life cycle cost analysis, uncertainty analysis and sensitivity analysis are given in chapter 4. Recommendations for future work, and the final conclusion on the most cost-effective upgrading technology is in chapter 5.

There are five appendices attached. Appendix A gives information regarding the parameters in the data supplied by manufacturers. Appendix B is an overview of the calculated annual cost for all the included parameters when heat recovery is included. Appendix C is an overview when no heat recovery is used in the calculations. Appendix D shows the calculated discount rates for different years, which is used in the sensitivity analysis. Appendix E and Appendix F shows all the results from the sensitivity analysis when electricity cost and discount rate are changed.

2 Research methodology

2.1 Introduction

Research is conducted in a scientific manner in order to find the answer to questions. There are many different definitions for research, but the Oxford Learner's Dictionary (1952), defines research as "a careful study of a subject, especially in order to discover new facts or information about it".

There are different types of research approaches, depending on what type of research is being carried out. Qualitative and quantitative are two different approaches for conducting a research. According to Kothari (2004), the quantitative approach can be divided into inferential, experimental or simulation approaches. Depending on the research question and the method for solving it, the most appropriate approach is used. It is necessary to design the methodology for the problem, in order to carry out the research in a suitable way.

When conducting a research, different steps are done in the process. Figure 1 presents the steps in a research process, which are defined by Kumar (2008).

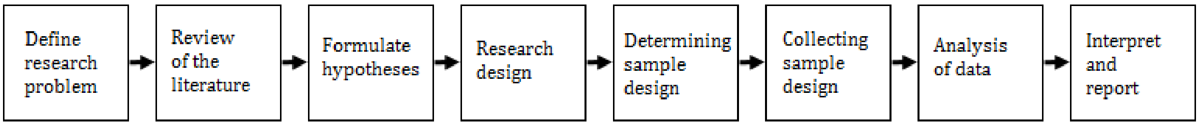

Figure 1: Research process adapted from Kumar (2008)

The first step is to define the research problem. This is one of the most important parts of the process. The research problem is the main focus in the research, and the aim is to answer the formulated research questions.

After the research problem is defined, a review of relevant literature is conducted. The literature review for this thesis is presented in chapter 3.

The next step is to formulate the hypothesis. A specific hypothesis for the problem is stated, and can be tested later. The research design is decided in order to have structured research.

2.2 Data collection

There are many methods for data collection, and the most appropriate method has to be established for each project. Different methods are used for this thesis. Information regarding the biogas production process was gathered through visits on three different biogas plants, in addition to a literature review. Hadeland og Ringerike Avfallsselskap (HRA), Mjøsanlegget and Interkommunalt vann, avløp og renovasjon (IVAR) were visited during the Spring of 2015, and Fall of 2016. A literature review was conducted in order to find information about the biogas production process, and different technologies for commercially used biogas upgrading units.

Data regarding initial and operation costs, performance, and consumables for different biogas upgrading technologies were gathered through a questionnaire that was sent to different manufactures. The collected data can therefore be classified as secondary data. Kothari (2004) defines secondary data as data that has been collected already, and analyzed by someone else. Another way to collect this data could be to contact different operating upgrading plants. However, the technology for biogas upgrading is constantly changing, and more effective upgrading plants are being built. The most precise information for today's technologies would therefore be collected from manufacturers. Another important factor is the capacity of the plants. When comparing different upgrading technologies, it is most accurate when the design flow rate is similar for all the plants. When manufacturers are contacted, it is possible to collect data for plants that corresponds with this design flow rate.

There has been some personal communication with people working in the biogas industry, suppliers of biogas upgrading units, and other researchers and experts.

2.3 Analysis of data

When all data are collected, the analysis can be carried out. In order to answer the research questions, an analyzing method needs to be established.

The method used for this thesis is a case study with quantitative data. In addition, some modelling is performed in order to analyze the uncertainty propagation through the model.

Two different cases are analyzed in this study:

1. Life cycle costs are calculated for the upgrading plants, when heat recovery are included in the calculations.
2. No heat recovery is included in the life cycle cost analysis for the upgrading plants.

Figure 2 shows the input and output for the two different scenarios. In addition to the energy, the investment cost, maintenance cost, and other essential consumables have been considered in the analysis.

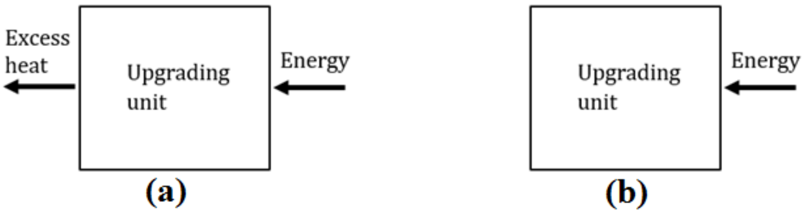

Figure 2: Scenario (a) with excess heat and (b) without excess heat

It is possible to use excess heat from the upgrading units in other parts of the biogas production process. For instance, the excess heat can be used for heating in the pre-treatment or the reactor in the biogas production plant. When comparing different biogas upgrading technologies in order to find the most cost-effective unit, one must consider the fact that heat recovery is an option.

A life cycle cost analysis (LCCA) was used to compare the different upgrading technologies. This method evaluates the economic perspective of all the systems during their entire life. The calculated LCC was compared for the upgrading units, and the most cost-effective technology was detected.

The collected data was given either as a fixed average number, or as a range with a minimum and maximum value. To account for the uncertainties in the data, an uncertainty analysis was conducted using a Monte Carlo simulation technique. For this aim, statistical approaches were applied by developing different codes in Matlab. In order to sample the possible outcomes from the input variables, random numbers were generated using an inverse transform method. Sampled values for each model input parameter were used to find the uncertainties associated with the model output.

The electricity cost and discount rate are parameters that can change on a daily basis. A sensitivity analysis was conducted for these two parameters, using the initial input data to evaluate the sensitivity of model output with respect to these variables. This analysis tests the outcome of the LCCA by changing some of the parameters in the initial analysis.

3 Literature review

Waste management is not a new concept, but it has developed a lot during the last decades. It exists various options for waste treatment, and the technologies are constantly improved. Biogas production, also referred to as anaerobic digestion, is a waste treatment technology used for organic waste. Anaerobic digestion is the breakdown of complex organic materials to simple substances, during which a high proportion of biogas is produced (Singleton & Sainsbury, 2006). Biogas can be burned for direct heating, or it can be used in a combined heat and power plant to generate power. Another option is to upgrade biogas into biomethane, and use it as fuel in the transportation sector.

3.1 Treatment technologies for organic waste

Combustion, composting and anaerobic digestion are different types of treatments for organic materials. Landfill is another type of waste handling which was used more in the past. Some countries still use landfill as the main handling option for organic waste, but regulations have minimized it. In 2009 a ban on the landfilling of biodegradable waste was introduced in Norway (Avfallsforskriften, 2004, § 9). This resulted in increased recycling of biodegradable waste, as well as reduced greenhouse gas emissions.

Selection of a waste treatment option, among other factors depends on the type of raw material. Table 1 presents different waste treatment options and their suitability in accordance with different raw materials.

Table 1: Best suited treatment technology (- = not suited; 0 = partially suited; + = well suited) (Deublein & Steinhauser, 2011)

	Feeding	Combustion	Composting	Biogas production
Liquid manure	-	-	0	+
Sewage sludge	-	0	0	0
Biowaste	-	-	0	+
Grass from lawns	0	-	+	+
Sewage from industry	+	-	0	+
Waste grease	-	-	-	+
Slaughterhouse waste	-	-	0	+
Wood	-	+	+	-
Excrement	-	-	+	+
Straw	0	0	+	0

As seen in Table 1, most of the presented raw materials are suitable for biogas production.

3.2 Biogas

Biogas is produced when organic materials are broken down anaerobically, i.e. without oxygen present. It occurs naturally in the cow's stomach, marshes or on landfills where there is organic material (Jarvie, 2011), (Badurek, 2011). Biogas mainly consists of methane and carbon dioxide, but there are also traces of other gases (Chaudhari, et al., 2012), which are presented in Table 2.

Table 2: Composition of biogas (Nizami, 2012)

Gas	**Percent**
Methane (CH_4)	55-80
Carbon dioxide (CO_2)	20-45
Nitrogen (N_2)	0-10
Hydrogen (H_2)	0-1
Hydrogen sulphide (H_2S)	0-3
Oxygen (O_2)	0-2

The temperature in the anaerobic digestion process is usually mesophilic or thermophilic, around 37°C or 55°C, respectively. In Europe, 87% of the biogas plants operate with mesophilic temperature (Nizami, 2012). Biogas is flammable if it consists of a methane content higher than 45% (Deublein & Steinhauser, 2011). When it is burned, carbon dioxide and water are formed.

3.2.1 Microbiology

Biogas production is a complex process, where many different microorganisms are involved. Organic materials are food for organisms, and a mix of different raw materials will result in a greater diversity of microorganisms (Schnürer & Jarvis, 2010). With more than 10^{16} bacteria/ml, there is an extensive diversity of different bacteria in an anaerobic digester (Chaudhari, et al., 2012).

Biogas is produced after four enzymatic and microbial processes are completed (Chaudhari, et al., 2012). Figure 3 shows these processes, which are called the hydrolysis, acidogenesis, acetogenesis and methanogenesis.

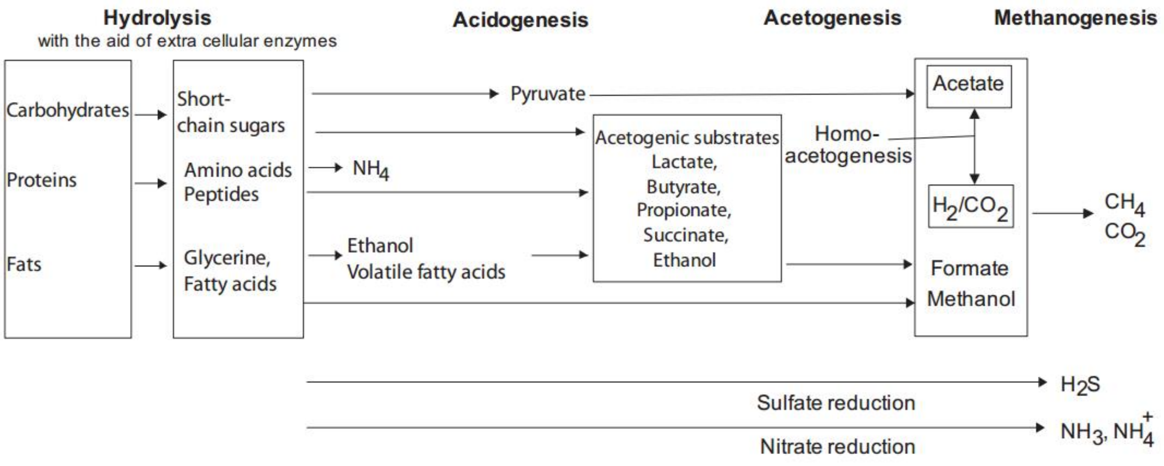

Figure 3: Biochemistry of biogas production (Deublein & Steinhauser, 2011)

3.2.1.1 Hydrolysis

The first step of the process is called hydrolysis. This part of the process consists of different reactions where protein, sugars and fat are separated into smaller organic compounds such as amino acids, short-chain sugars, fatty acids and glycerine. The microorganisms are not able to use protein, sugar and fat directly, and the organic molecules are therefore separated into smaller compounds by enzymes.

3.2.1.2 Acidogenesis

In the second stage, acid producing bacteria break down products from the hydrolysis into smaller compounds. Amino acid, sugars and fatty acids are broken down to various organic acids, alcohols, ammonia, hydrogen and carbon dioxide. The breakdown of the same compound might result in different products when different organisms break it down.

3.2.1.3 Acetogenesis

The intermediary products, which cannot be broken down directly to methane are converted into acetate, hydrogen and carbon dioxide. These products are then finally converted into methane during the methanogenesis.

3.2.1.4 Methanogenesis

The final step in the biogas production process, is called methanogenesis. The gas produced in this process mainly consists of methane and carbon dioxide, but there are some small amounts of other gases.

3.3 Biogas production process

The amount of biogas produced varies depending on many different factors such as raw materials, pre-treatment technology, temperature and time in reactor.

When producing biogas, there are mainly two different types of processes that are commercially used. This is either a “dry” or a “wet” process.

The dry process can be used when the raw materials have a high dry matter content, usually around 25 % - 35 % (Marthinsen, et al., 2009). To obtain a good environment for the microorganisms, the dry matter content should not be more than 35 % (Schnürer & Jarvis, 2010). The advantage of this type of process is that there is less fluid in the digested biomass. Storage and transportation of high amounts of fluids are therefore avoided when using this process. Another advantage is that microorganisms are less affected by interferences in the process, compared to a wet process. The dry process is not very widespread in Norway or Sweden, but there are a few facilities in Germany. In 2013, Scandinavia’s first dry digestion plant was built in Sweden (Västblekinge Miljö AB, 2016).

Today, the most commonly used biogas production process is the wet process. The dry matter content is usually between 2 % and 15 % in this process (Schnürer & Jarvis, 2010). Water is added to the raw materials during pre-treatment in order to achieve the right dry matter content.

3.3.1 Pre-treatment

Raw materials that are used in biogas production need to have some kind of pre-treatment, in order to sanitize it and avoid unwanted materials to enter the biogas process. Materials that are undesirable in the process might be plastic, metals, glass or other fractions. The selection of pre-treatment technology depends upon the type of raw material that is used in the process. Some materials require more pre-treatment than others, such as food waste compared to sewage sludge. Objects and other fractions are normally removed from the sewage sludge during the wastewater treatment process, and therefore this does not need any extra pre-treatment, except for sanitation. However, food waste can consist of bones, plastic, metals or other fractions and pre-treatment are therefore needed.

In order to make the contact area between the organic material and the microorganisms as large as possible, the material should be minced into small pieces. With smaller particle sizes, the contact area becomes greater, and the degradation time of the organic material increases.

According to Montgomery & Bochmann (2014), the pre-treatment process can provide several benefits:

- Speed up the anaerobic digestion process
- Could potentially increase the biogas yield
- Make it possible to use new or locally raw materials
- Prevent high electricity requirements for mixing

To be able to pump the substrate (slurry of pre-treated raw materials), the dry matter content should be less than 20 % (Seadi, et al., 2008). Therefore, water are often added to the mix to achieve a pump-able consistency.

The machines used in the pre-treatment process need to be able to withstand other waste fractions such as plastic, metal, textile, etc. However, by removing such fractions, some food waste may be lost as well.

There are a number of different types of pre-treatment technologies, and the best choice for technology depends upon which raw materials that are available, and the size of the plant.

3.3.2 Reactor

The reactor is the tank where biogas are produced by anaerobic decomposition of organic materials. Microorganisms ensure that methane is produced when the organic material is decomposed. A bacterial culture needs to be present for biogas to form, and this bacterial culture is naturally found in, for instance, cow manure. In the start-up of a biogas production process, it is necessary to add this culture.

The biogas reactor is a sealed tank with gas storage, which is made from concrete or other materials. The substrate is stirred around in the tank to ensure continuous movement, so the microorganisms get the best possible environment. In order to maintain the right temperature in the reactor, heat pipes in the walls or inside the reactor can be used. It is also necessary to isolate the reactor to avoid heat loss, especially in cold areas.

The temperature of the process is either mesophilic or thermophilic. If the thermophilic process is used, the microorganisms is 25 % - 50 % more active due to a higher temperature compared to the mesophilic process (Gerardi, 2003). The degradation time in a thermophilic process is shorter than in a mesophilic process. However, it is important to have good control of the process, since a higher temperature causes the microorganisms to change faster.

A rotary device or pump is used to mix the substrate in the reactor. This is to achieve an optimal temperature throughout the reactor in addition to a better contact between the organisms and the organic material. By stirring, it is avoided that the substrate drops to the bottom or floats in the top of the reactor. It is desirable to have a smooth rotation that is moving neither too slowly nor too fast, so that the microorganisms can collaborate in a best possible way.

3.4 Biogas upgrading technologies

Removing carbon dioxide results in enriched biogas with higher methane content, which has a higher energy content per unit volume. Upgraded biogas is often referred to as biomethane.

Removal of carbon dioxide can be done by various techniques, such as adsorption, absorption, membrane or cryogenic upgrading. This may be achieved by applying different technologies, as illustrated in Figure 4 (Thrän, et al., 2014).

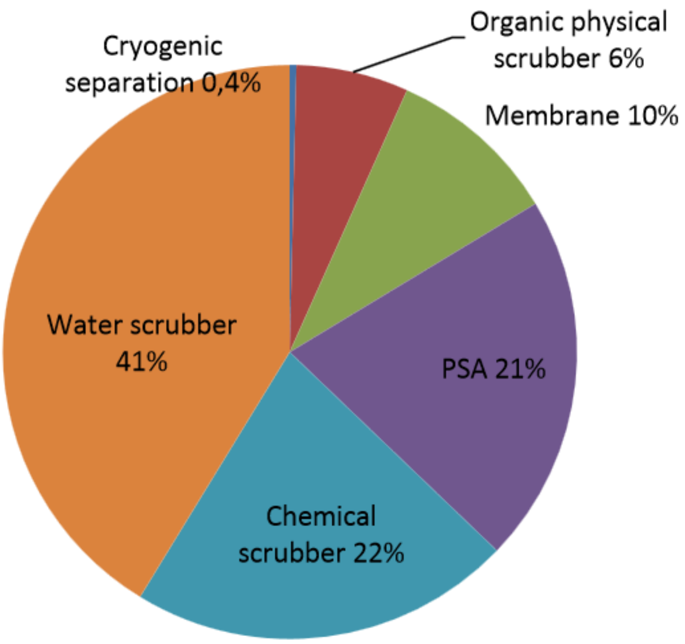

Figure 4: Technologies used for upgrading of biogas (Thrän et al., 2014)

As of today, there are no common European standard on the use of biomethane as vehicle fuel or in natural gas grid systems. The CEN project committee CEN/TC 408 is working on developing a standard for this purpose.

According to information published in 2015 by IEA Bioenergy Task 37, there are more than 330 upgrading plants existing in the member countries for Task 37. The locations of these plants are listed in Table 3. Germany and Sweden have the largest share, with over 200 plants.

Table 3: Upgrading plants in Task 37 member countries (IEA Bioenergy, 2016)

Country	Number of upgrading plants
Ireland	1
Brazil	4
Norway	4
South Korea	8
Denmark	7
Finland	9
France	9
Austria	12
Switzerland	19
The Netherlands	21
United Kingdom	27
Sweden	52
Germany	161
SUM	334

3.4.1 Absorption

Chemical scrubbing, organic physical scrubbing and water scrubbing are all types of absorption processes. Scrubbing is a process where liquid is sprayed over the gas in a column, and carbon dioxide gets absorbed by the liquid. Carbon dioxide are more solvable in liquid than methane, thus it is possible to separate them. There are different types of liquids that are used in this process, for instance water-, organic- or chemical solvent. Water scrubbing is the most common type of technology used for biogas upgrading (Thrän, et al., 2014).

3.4.1.1 Chemical scrubber

The chemical scrubber applies a chemical solution that both absorbs carbon dioxide and reacts chemically by binding CO_2 molecules. There are mainly two types of liquids that are used, di-methyl ethanol amine (DMEA) and mono ethanol amine (MEA) (Petersson & Wellinger, 2009).

There exist different variations of the process, depending on the manufacture (Bauer, et al., 2013). However, some components are relatively general. The process diagram of a chemical scrubber process is illustrated in Figure 5. Raw biogas is fed into the first column, where it meets the chemical solution that absorbs and reacts chemically with carbon dioxide. After the upgrading process, biogas has a higher proportion of methane, while the liquid leaves the column with an increased content of carbon dioxide. The chemical solution, which has absorbed a large amount of carbon dioxide, is regenerated in the next column. This is done by heating the chemical solution, and turning carbon dioxide into a gas. Gaseous carbon dioxide is removed from the top of the second column.

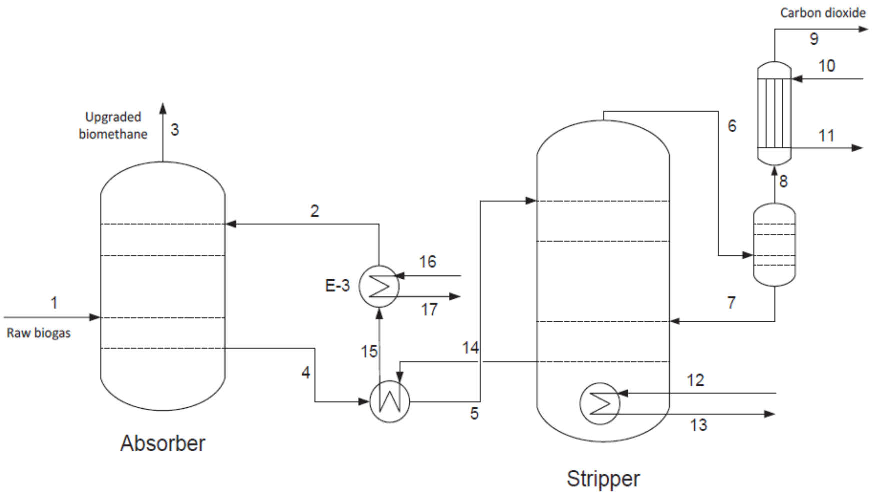

Figure 5: Chemical scrubber (Bauer, et al., 2013)

3.4.1.2 Water scrubber

Water scrubbers only use water as absorbing liquid. The principle of this process, is that carbon dioxide has a higher solubility than methane in water (Petersson & Wellinger, 2009). The solubility of carbon dioxide increases in water with decreasing temperature and increasing pressure (Persson, 2003).

There exists different constructions for this type of upgrading. Some types recycles the water, while others only add new water to the process. Figure 6 shows a process flow diagram of a water scrubber system, which regenerate water. In this process compressed raw biogas is injected in the bottom of the first column, and water is added from the top. Biomethane rises to the top of the column, while CO_2 and H_2S are absorbed by the water and leave the column from bottom. Since methane is also soluble in water, it is necessary to treat the waste water in a flash tank in order to minimize the methane loss. Next, the water enters a desorption column where carbon dioxide is separated from water by an added airflow. The water is then cooled down and regenerated for use in the absorption column.

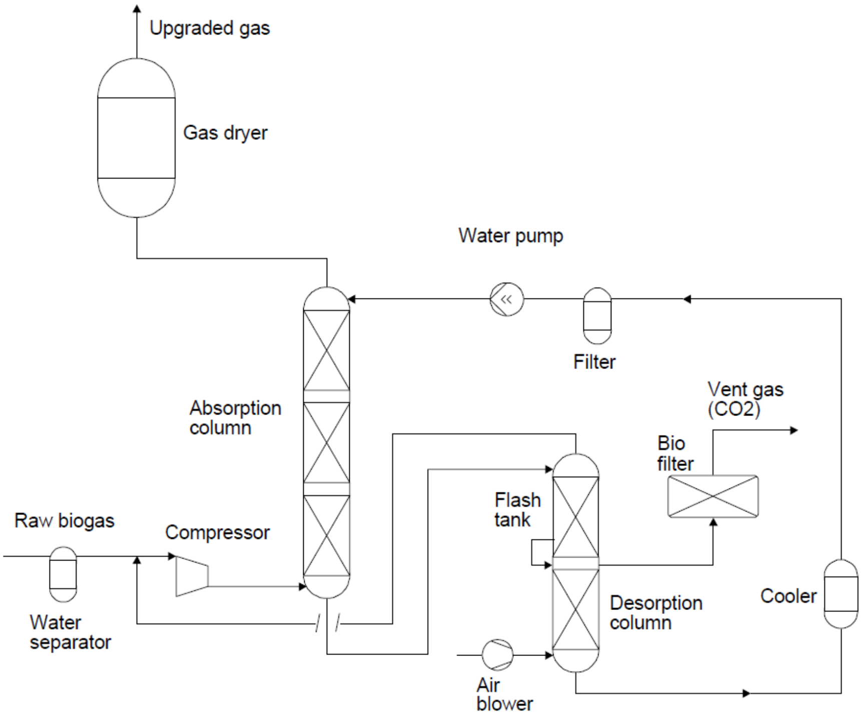

Figure 6: Water scrubber (Hagen, et al., 2001)

3.4.2 Membrane

When raw biogas is fed into the membrane upgrading unit, gas molecules are separated from each other. Methane is restrained, while carbon dioxide passes through the fiber wall in the membrane (Hagen, et al., 2001). Water and hydrogen sulfide are usually removed from the raw biogas, before being compressed and fed into the membrane (Bauer, et al., 2013). This process is shown in Figure 7.

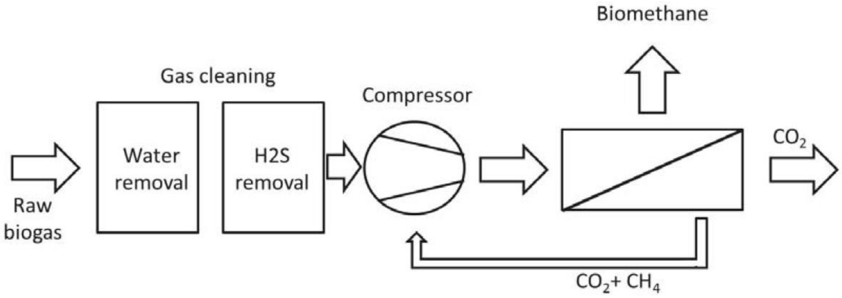

Figure 7: Membrane (Bauer, et al., 2013)

Upgraded biogas leaves the membrane at the high pressure side, while carbon dioxide leaves at the low pressure side (Hagen, et al., 2001). The partial pressure difference is the driving force for the separation of gases (Bauer, et al., 2013).

3.4.3 Pressure Swing Adsorption

Pressure swing adsorption (PSA) is an adsorption process where carbon dioxide is separated using physical properties (Bauer, et al., 2013). Biogas is upgraded using adsorbing material such as activated carbon or zeolites, which adsorb carbon dioxide (Petersson & Wellinger, 2009). Figure 8 illustrates a simplified pressure swing adsorption process. Hydrogen sulphide and water are removed before biogas enters the PSA columns. In this process, the pressure is increased and carbon dioxide is adsorbed in the material. The pressure is then reduced, which leads to a regeneration of the adsorbing material (Persson, 2003). Multiple absorbers operate in parallel cycles, with pressure build-up and regeneration. Biomethane leaves from the top of the columns, while carbon dioxide is pumped out during the regeneration.

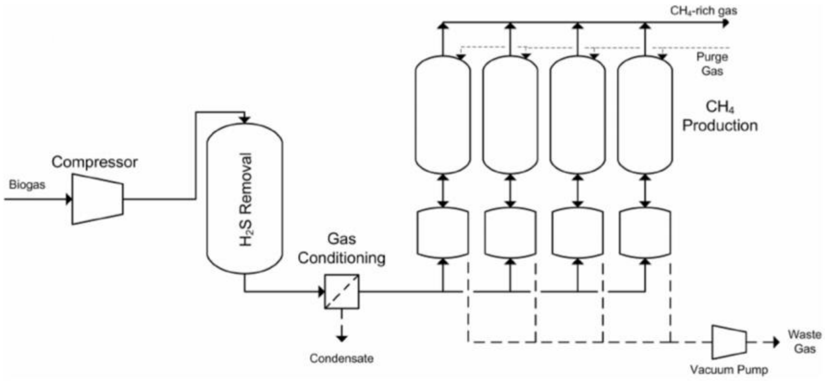

Figure 8: Pressure swing adsorption (de Hullu, et al., 2008)

3.4.4 Cryogenic upgrading

Cryogenic upgrading involves condensing various components of the biogas. The biogas is cooled down until some of its constituting components turn into liquid. This method can be used if the components in the gas have different condensing temperatures. For example, methane has a condensing temperature of -161.5°C in atmospheric pressure[1], while carbon dioxide has a condensing temperature of -78.4°C (Boles & Cengel, 2007). When the conditions are given as atmospheric pressure and room temperature, both methane and carbon dioxide are in gas phase. If biogas is cooled to -78.4°C, carbon dioxide begins to condense and can be removed in a liquid form. Figure 9 gives an illustration of the cryogenic upgrading process.

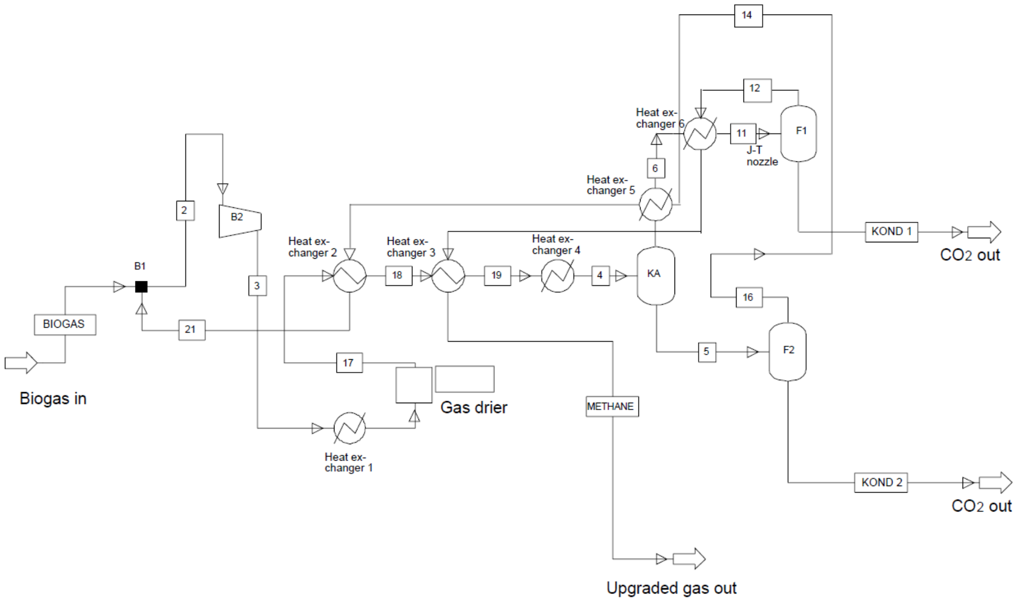

Figure 9: Cryogenic upgrading (Hagen, et al., 2001)

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[1] Atmospheric pressure is the air pressure on earth, with an average of 1,01325 bar.

4 Results and discussion

4.1 Biogas production and upgrading technologies

The main components in a biogas production system are identified through a detailed literature review. This includes the pre-treatment system, biogas reactor and biogas upgrading system, which are illustrated in Figure 10. Biogas upgrading is an optional process, while alternative options include utilization of raw biogas for direct heating, or in a combined heat and power plant. However, studies has shown that the best climate benefit is gained when biogas is upgraded and used as fuel in the transportation sector. For this purpose, biogas upgrading is the most suitable option.

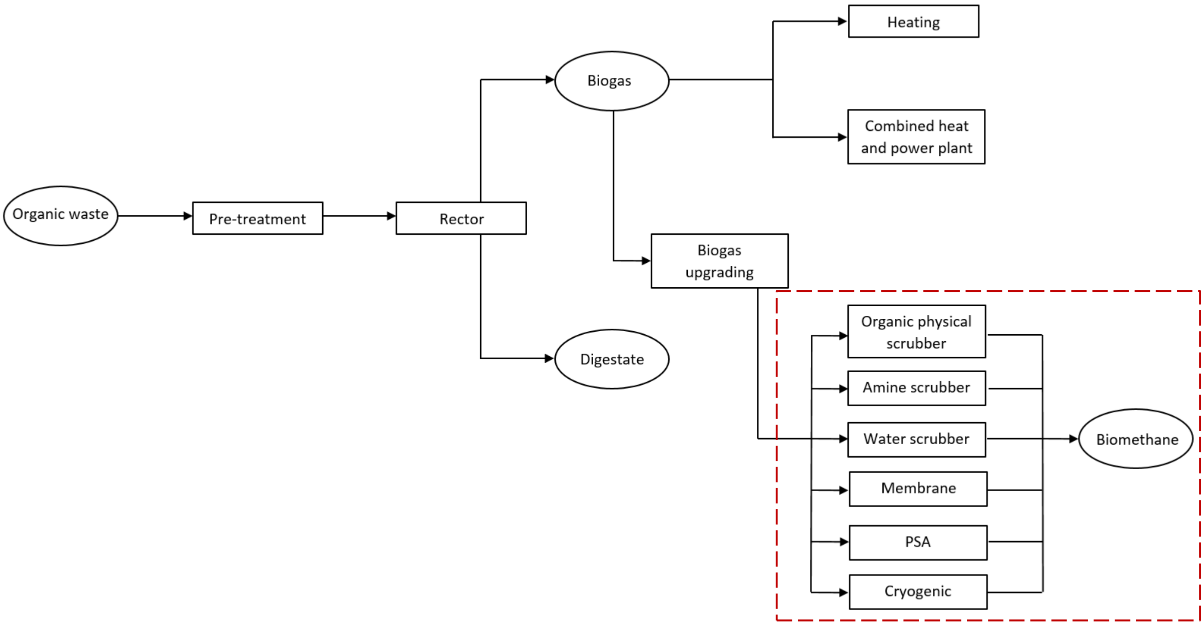

Figure 10: Biogas production process

The second objective of this thesis is also achieved through a literature review, where all the upgrading technologies are identified and described. Among the identified upgrading technologies, amine scrubber, amine scrubber, water scrubber, organic physical scrubber, membrane, pressure swing adsorption and cryogenic upgrading are utilized at a commercial scale. However, no data for organic scrubber was obtained, and is therefore not included in this study.

It was found that different upgrading technologies have different consumptions. For instance, only the amine scrubber has an amine consumption, while amine scrubber, water scrubber and cryogenic upgrading all have a water consumption. The technologies also differs in terms of energy consumption. Amine scrubbers have high energy consumption, due to the high heat requirement for the regeneration of the amine solution, when liquid is heated in order to vaporize carbon dioxide. With cryogenic upgrading, a considerable amount of energy is required for cooling when gases are liquefied. It is important to note that the cryogenic upgrading unit produces liquefied biogas and carbon dioxide.

Another difference between the upgrading technologies is the amount of excess heat generated by the units. The cryogenic plant produces a lot of excess heat, thus a large amount of energy can be recovered in form of heat. The high heat recovery from the cryogenic plant is due to the recovery of some electrical power, in addition to thermal power recovered from the biogas when carbon dioxide and methane are condensed.

4.2 Life cycle cost analysis

This section presents the results of the LCCA. Various upgrading techniques from different suppliers are analyzed in order to find the most cost-effective system. In total, ten upgrading units from eight different suppliers are included in this study. Upgrading technologies that has been compared are amine scrubber, membrane, water scrubber, PSA and cryogenic upgrading.

This thesis investigates two different scenarios for calculations on the life cycle cost of the upgrading units:

Scenario 1:	Heat is recovered from the upgrading unit, and used in other parts of the biogas production process.
Scenario 2:	No heat is recovered from the upgrading unit.

4.2.1 Input data

All the input data used in this study are given in Table 4, while a more detailed overview of the parameters for each upgrading unit is given in Appendix A. Input data are collected by direct contact with different suppliers for upgrading units, which are based in Sweden, Denmark, Netherland, Germany, France, United Kingdom and USA. The names of the suppliers are not given in this thesis, due to confidentiality. All the commercially used upgrading technologies are examined, except for the organic physical scrubber. The author did not succeed in acquiring the needed information for this specific upgrading technology, and it is therefore not included in this study.

Factors that are included in this analysis:

- Annual cost
    - Energy- Electricity
    - Energy- Heat
    - Water consumption
    - Active carbon
    - Amine
    - Maintenance/ Service
    - Methane loss
- Initial cost
    - Investment cost

Table 4: Initial input data

			Amine scrubber (1)	Amine scrubber (2)	Membrane (1)	Membrane (2)	Membrane (3)	Water scrubber (1)	Water scrubber (2)	PSA (1)	PSA (2)	Cryogenic (1)
Investment cost	***NOK***	***minimal***	8 836 100	-	-	-	-	-	5 650 000	-	11 219 915	-
		average	10 098 400	17 752 000	14 708 800	16 000 000	8 750 000	12 500 000	5 975 000	5 537 301	11 785 625	28 300 000
		maximal	11 360 700	-	-	-	-	-	6 300 000	-	12 351 335	-
Energy- Electricity	*kWh/Nm3*	*min*	0,10	0,25	0,20	0,20	0,30	-	0,21	0,22	-	0,60
		avg	0,11	0,28	0,24	0,21	0,33	0,24	0,30	0,23	0,24	0,65
		max	0,12	0,31	0,28	0,22	0,35	-	0,30	0,24	-	0,70
Energy- Heat	*kWh/Nm3*	*min*	0,600	-	-	-	-	-	-	-	-	-
		avg	0,625	0,59	-	-	-	-	-	-	-	-
		max	0,650	-	-	-	-	-	-	-	-	-
Energy- Heat recovery	*kWh/Nm3*	*min*	-0,1500	-	-0,1200	-	-	-0,0625	-	-	-	0,7800
		avg	-0,1563	-0,4900	-0,1450	-	-	-0,0688	-	-	-	0,8450
		max	-0,1625	-	-0,1700	-	-	-0,0750	-	-	-	0,9100
Water consumption	*m3/year*	*min*	-	-	-	-	-	-	-	-	-	-
		avg	90	180	-	-	-	730	600	-	-	300
		max	-	-	-	-	-	-	-	-	-	-
Active carbon	*kg/year*	*min*	-	-	950	-	-	-	-	-	-	-
		avg	-	1 030	1 375	-	-	-	-	-	697	1 100
		max	-	-	1 800	-	-	-	-	-	-	-
Amine	*kg/year*	*min*	-	-	-	-	-	-	-	-	-	-
		avg	1 200	120	-	-	-	-	-	-	-	-
		max	-	-	-	-	-	-	-	-	-	-
Maintenance/ Service	*NOK/year*	*min*	176 722	-	250 000	-	260 000	-	-	-	-	-
		avg	201 968	302 952	450 000	510 000	395 000	249 855	280 000	140 343	235 713	1 698 000
		max	227 214	-	650 000	-	530 000	-	-	-	-	-
Methane loss	*%*	*min*	-	-	-	-	-	-	-	-	1,00	-
		avg	0,10	0,10	0,50	0,30	0,50	1,00	1,00	3,00	1,25	0,30
		max	-	-	-	-	-	-	-	-	1,50	0,60

4.2.1.1 Assumptions and additional data

Besides the data provided by biogas upgrading manufacturers, some additional data was required. In addition, certain assumptions were necessary in order to conduct the LCCA. These assumptions and data are presented in Table 5.

Table 5: Input data and assumptions

Input data and assumptions		
Plant life	15	Years
Availability	100	%
Discount rate	6	%
Biogas production	3,000,000	m^3 raw biogas/year
Methane content	60	%
Tap water cost	11.64	NOK/m^3
Total electricity cost	0.711	NOK/kWh
Amine cost	233.31	NOK/kg
Activated carbon cost	60.86	NOK/kg
Biomethane sales price	4.5	NOK/Nm^3 upgraded biogas

Most of the upgrading units are pre-fabricated and delivered in a container. They are designed for different flow rates with a given minimum and maximum value. The flow rate for the considered upgrading plants are ranging from a minimum of 0 m^3/h to 260 m^3/h, while the maximum goes as high as 700 m^3/h. When comparing different upgrading units, the flow rate is set to 3,000,000 m^3 biogas annually. This corresponds to a flow rate of approximately 350 m^3/h. Initially, this was established through calculations based on produced biogas from 10,000 tons of food waste and 10,000 tons of sewage sludge, both with approximately 30 % total solids (TS). The result from this study is therefore only valid for small- scale biogas upgrading plants. The investment cost and consumables will increase for larger plants.

The price of tap water is set to 11.64 NOK/m^3, which was the price in Tromsø for water in 2015 (Tromsø kommune, 2016). Cost for amine and active carbon is found through personal communication with plant owners and suppliers.

When calculating the price for the energy, there are different factors that needs to be considered. In addition to the electricity price, the electrical grid rent is paid to the supplier who delivers the electricity. Table 6 shows the average electricity price for each year from 2011 to 2015 (Nord Pool, 2016).

Table 6: Electricity prices

Year	Price
2011	370.56 NOK/MWh
2012	233.32 NOK/MWh
2013	300.69 NOK/MWh
2014	242.77 NOK/MWh
2015	182.09 NOK/MWh
Sum	265.89 NOK/MWh

The electricity price varies over time, but an average of the spot price from the last 5 years is used as a basis for the electricity price in this project. Table 7 shows the calculation for the total energy price.

Table 7: Total electricity cost

Electricity cost	
Electrical grid cost	0.285 NOK/kWh
Electricity cost	0.266 NOK/kWh
Consumption tax	0.160 NOK/kWh
Total electricity cost	0.711 NOK/kWh

Some of the costs are given in other currencies from the suppliers, and are converted to NOK with the exchange rates given in Table 8. Since the exchange rate may change with time, it can cause a deviation from the calculated results. This has not been included in the model.

Table 8: Exchange rates

	Exchange rates	
1 DKK	1.2623	NOK
1 SEK	1.0144	NOK
1 EUR	9.4285	NOK

It is assumed that the investment costs are paid all at once, and the construction time has not been taken into account. The annual operational costs are assumed to remain constant each year throughout the lifetime of the upgrading plants. This is done due to lacking information regarding changing cost for maintenance and consumables over time.

For the calculations where heat recovery is included, it is assumed that all excess heat produced from the upgrading unit can be utilized in other parts of the biogas production process. Further costs for utilization of the excess heat, have not been considered. Cost of additional equipment such as pipelines and other components, might reduce the benefits of heat recovery.

4.2.2 Life cycle cost

In order to achieve the third objective of this project, a life cycle cost analysis is conducted. LCCA is used to evaluate the economic perspective of a system during its entire life. The scope of the life cycle cost analysis includes quantifying the life cycle cost, and using it for further technology evaluation or decision making.

ISO 15686-5:2008 defines LCC as the "*cost of an asset or its parts throughout its life cycle, while fulfilling the performance requirements*". LCCA can be used as a tool for long-term financial assessments throughout the lifespan of a system. Rather than saving money in a short-term perspective, the LCCA finds the best long-term economic option (Pica, 2014). The monetary investment, long-term expenses and income are analyzed in this cost-based process. The LCC can be compared for various designs or options in order to find the most cost-effective system (Davis, et al., 2005). If an economic comparison is established for different options, requirements and boundaries must be set.

Davis et al. (2005) suggests the following steps for conducting LCCA:

1. Establishing objectives for the analysis
2. Determining the criteria for evaluating alternatives
3. Identifying and developing design alternatives
4. Gathering cost information
5. Developing a life cycle cost for each alternative

Figure 11 shows a graphical overview of the elements that are included in the LCCA and the whole- life cost (WLC) (ISO, 2008). The LCC includes the cost for construction, operation, maintenance and end-of-life. These elements can be adjusted and other costs might be added for the specific case. With respect to future income, it is only considered by the WLC analysis, not the LCC analysis.

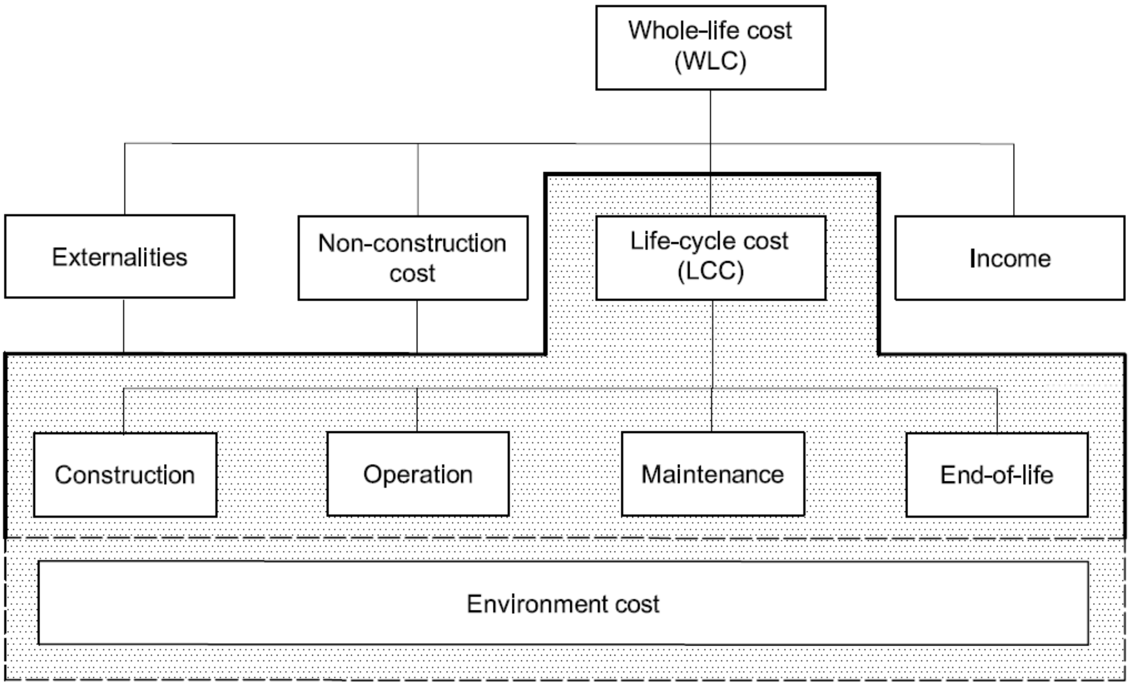

Figure 11: Graphical overview of LCCA and WLC elements (ISO, 2008)

All the monetary costs which occur in the future period of the project should be discounted, in order to be able to compare different cash flows from different time periods of the project (Pica, 2014). For this purpose, the present value of all cost elements is calculated.

To find the present value of a future cost, the following formula is used (Pica, 2014):

$$PV = A_n \cdot \frac{1}{(1+r)^n} \tag{1}$$

Where:

PV = Present value

A_n = Value of cost at time t

n = Time in years

r = Discount rate

For annual future costs that are recurring throughout the lifetime, the following formula is used (Pica, 2014):

$$PV = A_0 \cdot \frac{(1+r)^n - 1}{r \cdot (1+r)^n} \tag{2}$$

Where:

PV = Present value

A_0 = Value of recurring cost

n = Total time in years

r = Discount rate

To make the analysis result as comprehensive as possible, two scenarios have been analyzed. One with heat recovery, and one without heat recovery. It is possible to design biogas plants for the use of excess heat, and hence it is possible to include the reduction in cost due to heat recovery from biogas upgrading plants. Some of the upgrading technologies produce a large amount of excess heat, and in order to compare different upgrading technologies, the use of this excess heat should be included in the analysis. If the heat recovery is not taken into account when comparing different technologies, the result cannot be justified for a real case. When considering both scenarios with and without heat recovery, it is easier to consider the actual operating cost of the upgrading plant in context with the whole biogas plant.

4.3.2.1 LCCA with heat recovery

The annual cost is calculated for the different elements and added together in order to find the total annual cost. Furthermore, the present value for the total annual cost is calculated for all upgrading plants, as presented in Table 9. The present value is then added to the investment cost, which sums up to the total life cycle costs for all the respective upgrading units.

Table 9: Calculated costs with heat recovery

		Amine scrubber (1)	Amine scrubber (2)	Membrane (1)	Membrane (2)	Membrane (3)	Water scrubber (1)	Water scrubber (2)	PSA (1)	PSA (2)	Cryogenic (1)
Investment cost	**NOK**	**10 098 400**	**17 752 000**	**14 708 800**	**16 000 000**	**8 750 000**	**12 500 000**	**5 975 000**	**5 537 301**	**11 785 625**	**28 300 000**
Annual costs	**NOK/year**	**1 725 564**	**1 214 375**	**776 823**	**982 230**	**1 128 725**	**704 629**	**997 219**	**873 933**	**891 311**	**1 376 807**
Energy- Electricity	NOK/year	234 630	597 240	511 920	447 930	693 225	511 920	629 235	490 590	511 920	1 386 450
Energy- Heat	NOK/year	1 333 125	1 258 470	-	-	-	-	-	-	-	-
Heat recovery	NOK/year	-333 281	-1 045 170	-309 285	-	-	-146 644	-	-	-	-1 802 385
Water consumption	NOK/year	1 048	2 095	-	-	-	8 497	6 984	-	-	3 492
Active carbon	NOK/year	-	62 690	83 688	-	-	-	-	-	42 428	66 950
Amine	NOK/year	279 974	27 997	-	-	-	-	-	-	-	-
Maintenance/ Service	NOK/year	201 968	302 952	450 000	510 000	395 000	249 855	280 000	140 343	235 713	1 698 000
Methane loss	NOK/year	8 100	8 100	40 500	24 300	40 500	81 000	81 000	243 000	101 250	24 300
Present value of annual cost		16 759 105	11 794 308	7 544 698	9 539 662	10 962 458	6 843 529	9 685 239	8 487 857	8 656 632	13 371 896
TOTAL LIFE CYCLE COST		**26 857 505**	**29 546 308**	**22 253 498**	**25 539 662**	**19 712 458**	**19 343 529**	**15 660 239**	**14 025 159**	**20 442 257**	**41 671 896**

Figure 12 shows a graphical presentation of the LCC, when heat recovery is included. The investment cost and the present value for the annual cost are illustrated using two different colors.

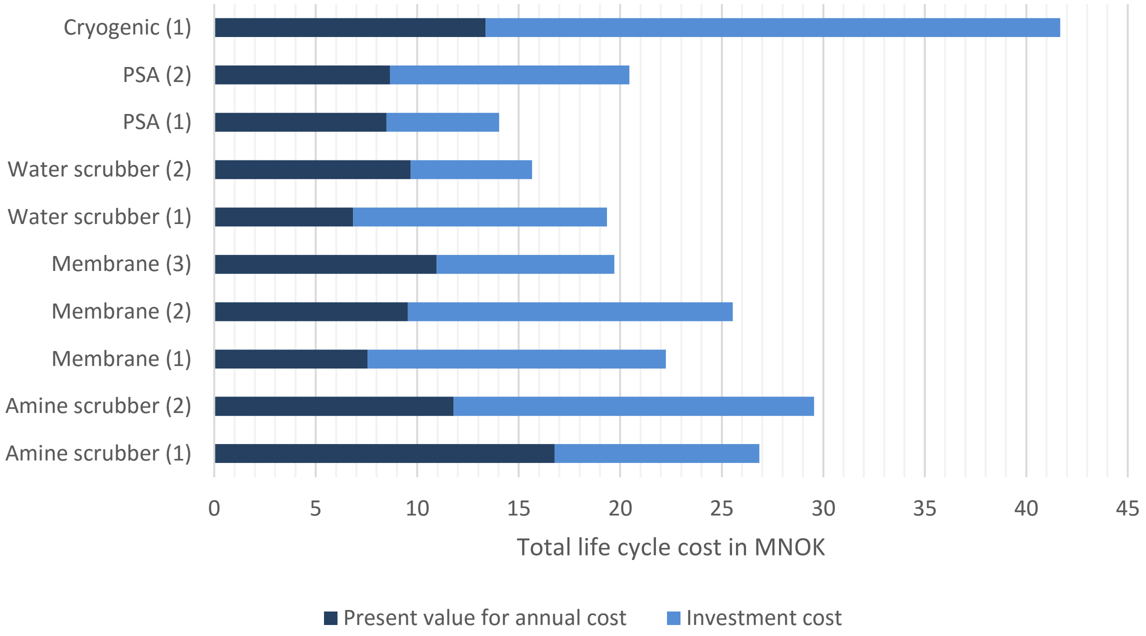

Figure 12: Present cost with heat recovery

The cryogenic upgrading unit is estimated to have the highest LCC. With an annual cost of 1.4 MNOK and an investment cost of 28.3 MNOK, this system has a LCC over 41.7 MNOK. However, due to the extremely high heat recovery rate, this unit does not have the highest annual cost. The unit with the highest annual cost is the amine scrubber (1). The reason why the cryogenic upgrading unit has a higher LCC than amine scrubber (1), is the investment cot.

As seen in Figure 12, water scrubber (1) has the lowest annual cost. This is due to the heat recovery, as well as the relatively low maintenance cost. However, the investment cost for this unit is higher than water scrubber (2), and the LCC are therefore also higher than water scrubber (2).

In order to assign the different technologies a more generalized value for the LCC, an average cost is calculated based on results from each upgrading unit. This average life cycle cost is presented in Table 10.

Table 10: Average life cycle cost with heat recovery

		Amine scrubber	Membrane	Water scrubber	PSA	Cryogenic
Investment cost	[MNOK]	13.92	13.15	9.24	8.66	28.30
Present cost	[MNOK]	14.28	9.35	8.26	8.57	13.37
Life cycle cost	[MNOK]	28.20	22.50	17.50	17.23	41.67

The PSA technology has the lowest life cycle cost. The water scrubber technology has a slightly higher life cycle cost, with 0.3 MNOK more than the PSA technology.

4.3.2.2 LCCA without heat recovery

The annual cost for the upgrading units with excess heat is greater when heat recovery is not considered. The calculated annual cost and life cycle cost for the scenario without heat recovery is presented in Table 11. A graphical presentation of the LCC for the scenario without heat recovery are illustrated in Figure 13.

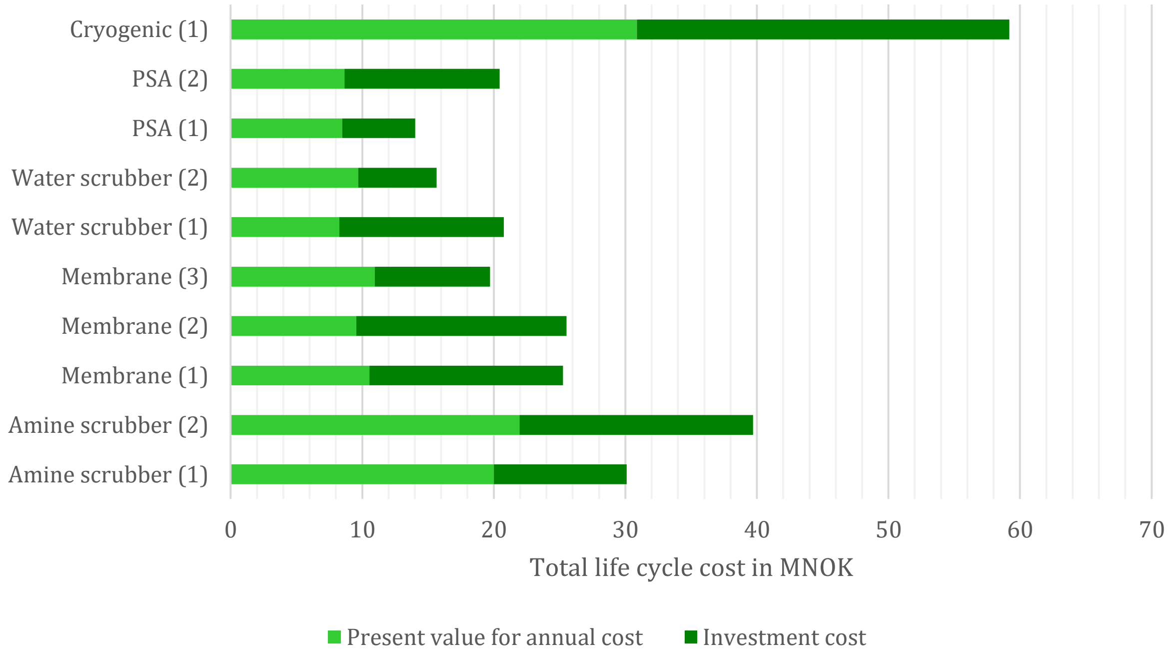

Figure 13: Life cycle cost without heat recovery

Table 11: Calculated costs without heat recovery

		Amine scrubber (1)	Amine scrubber (2)	Membrane (1)	Membrane (2)	Membrane (3)	Water scrubber (1)	Water scrubber (2)	PSA (1)	PSA (2)	Cryogenic (1)
Investment cost	**NOK**	**10 098 400**	**17 752 000**	**14 708 800**	**16 000 000**	**8 750 000**	**12 500 000**	**5 975 000**	**5 537 301**	**11 785 625**	**28 300 000**
Annual costs	**NOK/year**	**2 058 845**	**2 259 545**	**1 086 108**	**982 230**	**1 128 725**	**851 272**	**997 219**	**873 933**	**891 311**	**3 179 192**
Energy- Electricity	NOK/year	234 630	597 240	511 920	447 930	693 225	511 920	629 235	490 590	511 920	1 386 450
Energy- Heat	NOK/year	1 333 125	1 258 470	-	-	-	-	-	-	-	-
Heat recovery	NOK/year	-	-	-	-	-	-	-	-	-	-
Water consumption	NOK/year	1 048	2 095	-	-	-	8 497	6 984	-	-	3 492
Active carbon	NOK/year	-	62 690	83 688	-	-	-	-	-	42 428	66 950
Amine	NOK/year	279 974	27 997	-	-	-	-	-	-	-	-
Maintenance/ Service	NOK/year	201 968	302 952	450 000	510 000	395 000	249 855	280 000	140 343	235 713	1 698 000
Methane loss	NOK/year	8 100	8 100	40 500	24 300	40 500	81 000	81 000	243 000	101 250	24 300
Present value of annual cost		19 996 015	21 945 259	10 548 551	9 539 662	10 962 458	8 267 770	9 685 239	8 487 857	8 656 632	30 877 108
TOTAL LIFE CYCLE COST		**30 094 415**	**39 697 259**	**25 257 351**	**25 539 662**	**19 712 458**	**20 767 770**	**15 660 239**	**14 025 159**	**20 442 257**	**59 177 108**

By excluding the option for heat recovery, the results of the LCCA changed for some of the upgrading units. The units that produce excess heat, are the ones affected by the elimination of heat recovery. Amine scrubber (1) and (2), membrane (1), water scrubber (1) and the cryogenic upgrading received a higher LCC for this scenario.

The greatest change in LCC is found for the units with the highest heat recovery. The annual cost for the cryogenic upgrading unit increased with 1.8 MNOK, resulting in an increase of 17.5 MNOK for the LCC. Amine scrubber (2) had an increased annual cost of 1.0 MNOK, which equals a total increase of 10.2 MNOK for the entire life cycle cost of this unit. Besides the units without excess heat, the lowest change in LCC was found for water scrubber (1).

The average life cycle cost for the upgrading technologies is calculated and presented in Table 12. By excluding heat recovery, PSA and water scrubber appear as the most cost-effective upgrading technologies.

Table 12: Average life cycle cost without heat recovery

		Amine scrubber	**Membrane**	**Water scrubber**	**PSA**	**Cryogenic**
Investment cost	[MNOK]	13.93	13.15	9.24	8.66	28.30
Present cost	[MNOK]	20.97	10.35	8.98	8.57	30.88
Life cycle cost	[MNOK]	34.90	23.50	18.21	17.23	59.18

4.3.2.3 Comparing scenarios

By comparing the results from analyzing two different scenarios, it is clear that heat recovery has a rather big impact on the LCC for some of the upgrading technologies. Figure 14 shows a graphical representation of the two different scenarios.

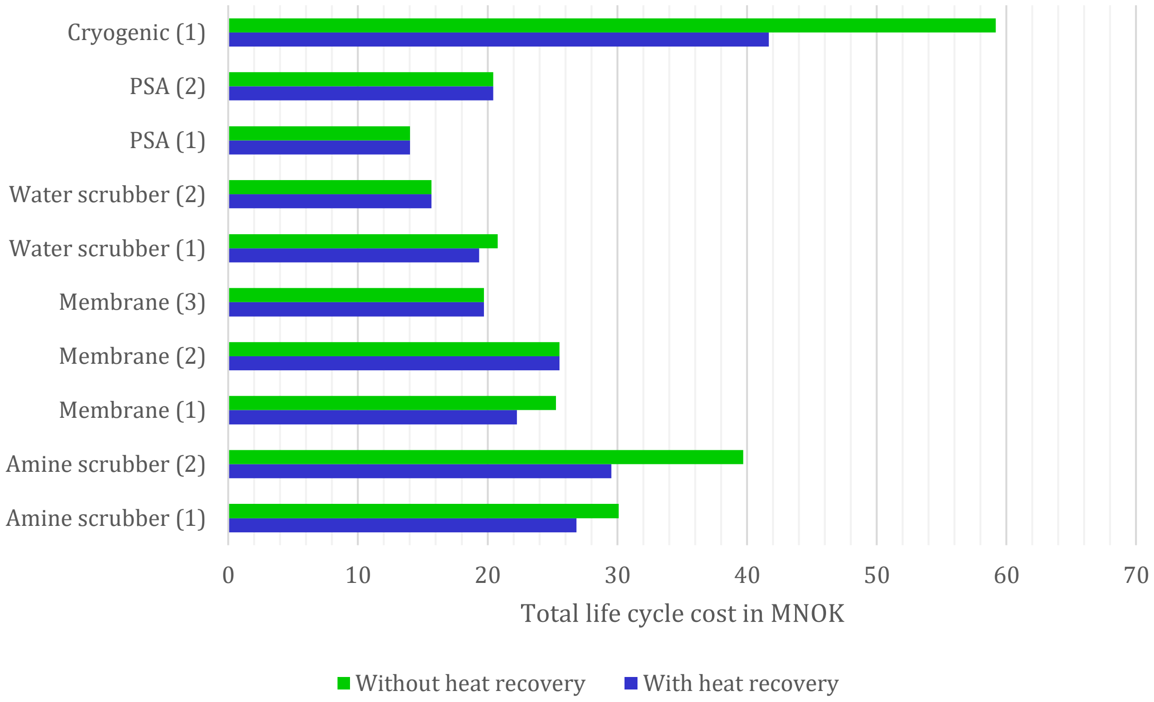

Figure 14: Comparing scenarios with and without heat recovery

For the cryogenic upgrading and amine scrubber (2), the change in LCC was significant. The difference in LCC when heat recovery is included and excluded is 17.5 MNOK for the cryogenic upgrading, and 10.2 MNOK for amine scrubber (2).

Amine scrubber (1), membrane (1) and water scrubber (1) also produces some excess heat, which can be recovered. The difference in LCC with and without heat recovery for these upgrading units was 3.2 MNOK, 3.0 MNOK and 1.4 MNOK, respectively. The LCC remained the same for all upgrading units without heat recovery. This included PSA (1) and (2), water scrubber (2), membrane (2) and (3).

When comparing the two scenarios, it is evident that the heat recovery does not have any impact on the rating of the most cost-effective plants. However, the overall rating for all components change somewhat. The rating of the upgrading units from most cost-effective to least cost-effective for both scenarios are given in Table 13.

Table 13: Rating of upgrading units from most to least cost-effective

	Rating with heat recovery	**Rating without heat recovery**
Amine scrubber (1)	8	8
Amine scrubber (2)	9	9
Membrane (1)	6	6
Membrane (2)	7	7
Membrane (3)	4	3
Water scrubber (1)	3	5
Water scrubber (2)	2	2
PSA (1)	1	1
PSA (2)	5	4
Cryogenic (1)	10	10

In terms of relative rating, only three plants are affected by the inclusion of heat recovery. The ranking changes for the plants that are rated as number 3, 4 and 5. This means that the two most cost-effective units, and the five least cost-effective units are not affected whether heat recovery is included or not. However, if the choice is between water scrubber (1), membrane (3) and PSA (2), the heat recovery has an effect on the life cycle cost, and should therefore be consider in the selection of upgrading unit.

4.3.3 Uncertainty analysis

By using a statistical approach, uncertainties in the data have been identified. Typically, there are many uncertainties related to the costs and savings in an investment. This might lead to uncertainties and challenge the validity of the LCCA. A way to identify the distribution of possible costs, is to use statistical techniques to model the uncertainty. To account for uncertainties in the data, a triangular distribution has been used for simulation in Matlab.

The period of analysis, in addition to the uncertainties and risks related to the LCC should be defined in the scope. It is necessary to make assumptions about future behavior, and there will always be an uncertainty and risk related to this. The quality of the data, cost assumptions and calculation methods play a part in the level of uncertainty.

The initial costs that influence the life cycle cost, can cause a widely spread result. This spread gives information about the uncertainty in the data. When this uncertainty is known, it is possible to assess the quality of the data.

By identifying the standard deviation, spread in the data can be quantified (Bell, 1999). Bell (1999) states that the estimated standard deviation can be expressed mathematically as:

$$s = \sqrt{\frac{\sum_{i=1}^{n}(x_i - \bar{x})^2}{(n-1)}} \tag{3}$$

The result from measurement i is x_i, and the $\bar{x}$ is the arithmetic mean from all n results.

When there are limited data available, triangular distribution can be used to represent the probability distribution in a simplistic manner. It is a continuous probability distribution shaped like a triangle. The parameters are defined with the lower limit *"a"*, the upper limit *"b"* and a peak in the data. Triangular distribution is commonly used for project management planning (Schmee & Oppenlander, 2010).

For a triangular distribution, the probability density function and the cumulative distribution function are given by (Forbes, et al., 2010):

Probability Density Function

$$f(x|a,b,c) = \begin{cases} \dfrac{2(x-a)}{(b-a)(c-a)} & ; \quad a \leq x \leq b \\ \dfrac{2(b-x)}{(b-a)(b-c)} & ; \quad c \leq x \leq b \end{cases} \tag{4}$$

Cumulative Distribution Function

$$F(x|a,b,c) = \begin{cases} \dfrac{(x-a)^2}{(b-a)(c-a)} & ; \quad a \leq x \leq c \\ 1 - \dfrac{(b-x)^2}{(b-a)(b-c)} & ; \quad c \leq x \leq b \end{cases} \tag{5}$$

a	Lower limit
b	Upper limit
c	Shape parameter

The shape parameter is the most likely value to occur. Figure 15 illustrates a probability density function, and a cumulative distribution function for a triangular distribution.

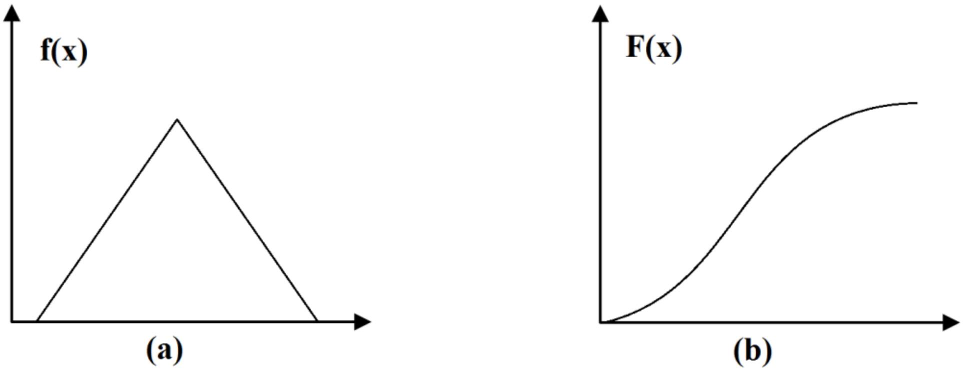

Figure 15: (a) PDF and (b) CDF for a triangular distribution

When evaluating the uncertainties associated with the input parameters, a Monte Carlo simulation can be used. This method makes it possible to analyze the propagation of uncertainty involved in input variables through the model. Random numbers are generated in order to sample possible outcomes from the distribution of each input data. By repeating this method a large number of times, it is possible to represent the output uncertainties from the distribution of the model output.

In this project case, the input variables have a triangular distribution. The simulation of random numbers is done using triangular distribution, and the inverse transform method from the continuous distribution are used.

Let U be a uniform (0,1) random variable for any continuous distribution function F, then the random variable X is defined by (Ross, 2010):

$$X = F^{-1}(U) \tag{6}$$

The inverse cumulative distribution function for a triangular distribution is then defined as:

$$X = F^{-1}(U) = \begin{cases} a + \sqrt{(b-a)(c-a)U} & ; \quad 0 < U < \dfrac{c-a}{b-a} \\ b - \sqrt{(b-a)(b-c)(1-U)} & ; \quad \dfrac{c-a}{b-a} \leq U < 1 \end{cases} \tag{7}$$

4.3.3.1 With heat recovery

In order to determine the reliability for the calculations of LCC when heat recovery is included, an uncertainty analysis is used. This can identify the distribution of cost and the uncertainties in the results calculated in section 4.3.2.1. The calculated annual cost for the minimal and maximal values for all parameters when heat recovery is included, are given in Appendix B. Figure 16 illustrates uncertainties in the data. The distribution of life cycle cost is presented on the x-axis.

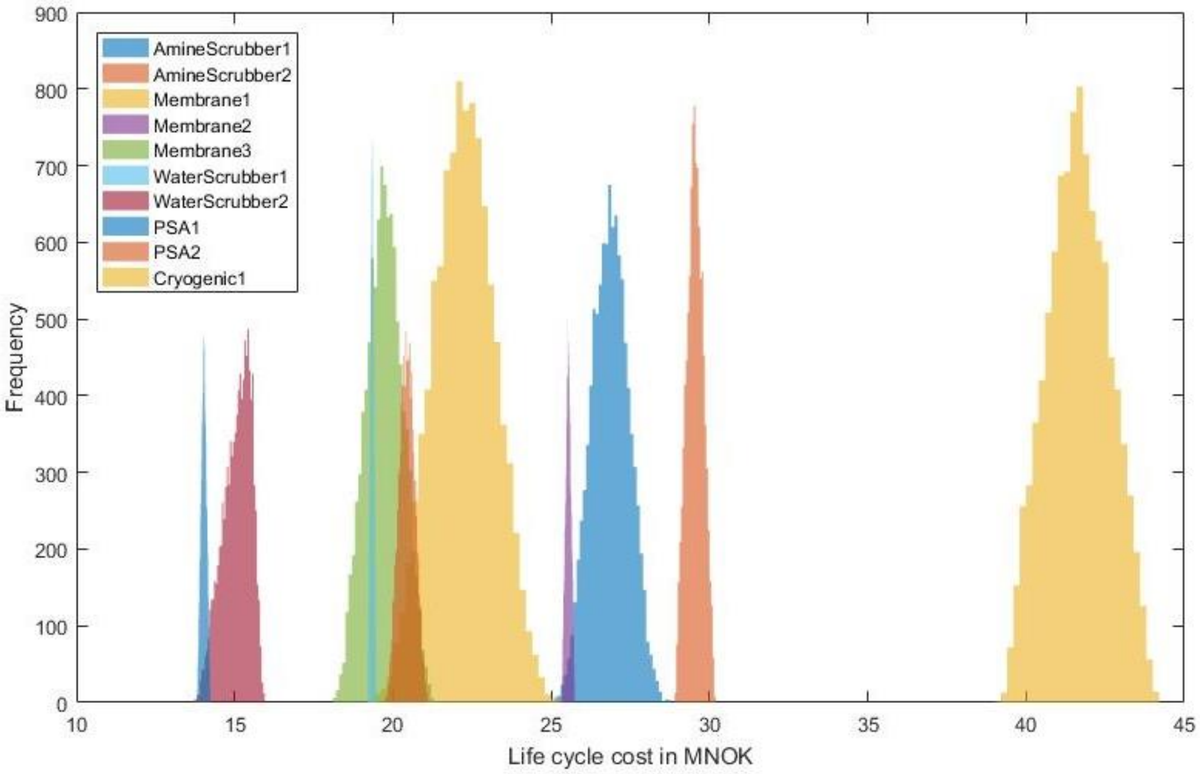

Figure 16: Distribution of life cycle cost with heat recovery

It is evident that different upgrading units have different distributions in LCC. It was possible to rate the upgrading units from most cost-effective to least cost-effective in the LCC calculations, but the result from the uncertainty analysis shows that some of the LCC distributions overlap. This overlap indicates that there is a possibility that the rating of cost-effectiveness might change. However, it is still clear that PSA (1) and water scrubber (2) are the two most cost-effective upgrading units, and that the cryogenic upgrading is the least cost-effective unit. The LCC of membrane (3) and water scrubber (1) overlaps, and as a result of this uncertainty, their relative rating might change.

The mean and standard deviation for each upgrading unit are calculated and the results are presented in Table 14. In addition, the minimal and maximal simulated life cycle cost are given in the table.

Table 14: Standard deviation with heat recovery

Upgrading unit	**Standard deviation**	**Mean**	**Minimal value**	**Maximal value**
	[MNOK]	[MNOK]	[MNOK]	[MNOK]
Amine scrubber (1)	0.59	26.86	25.08	28.95
Amine scrubber (2)	0.26	29.54	28.93	30.17
Membrane (1)	0.97	22.25	19.20	25.20
Membrane (2)	0.08	25.54	25.34	25.74
Membrane (3)	0.57	19.72	18.11	21.37
Water scrubber (1)	0.05	19.34	19.22	19.47
Water scrubber (2)	0.44	15.07	13.66	15.95
PSA (1)	0.08	14.03	13.82	14.23
PSA (2)	0.24	20.44	19.74	21.11
Cryogenic (1)	0.99	41.66	39.20	44.17

Standard deviation is used to quantify the amount of variation in the simulated data. A low standard deviation indicates that the simulated data set is close to the mean, while a high standard deviation tends to be more spread out over a wide range.

According to the analysis results, membrane (1) and cryogenic (1) received the highest standard deviation of 0.97 MNOK and 0.99 MNOK, respectively. The smallest standard deviation was found to be 0.05 MNOK for water scrubber (1). Both Membrane (2) and PSA (1) had a small standard deviation of 0.8 MNOK. The source for the large uncertainty in the LCC for the cryogenic upgrading, is associated with the variation in heat recovery rate. Water scrubber (1) has all values as fixed, except for the heat recovery, which ranges from 0.13 MNOK to 0.16 MNOK annually.

Membrane (1) had the largest difference in minimal and maximal LCC. This unit has a simulated LCC ranging from 19.2 to 25.2 MNOK. The difference in the data corresponds to 6 MNOK. The second largest difference in the minimal and maximal LCC was found to be the cryogenic upgrading unit, with a minimal LCC of 39.20 MNOK and a maximal LCC of 44.17 MNOK. The unit with the smallest difference in the minimal and maximal value was water scrubber (1), with a difference of only 0.25 MNOK.

4.3.3.2 Without heat recovery

The distribution of life cycle costs without heat recovery is given in Figure 17. It is evident that the simulated costs are affected when the option for heat recovery is neglected. Appendix C shows the values which is used in the simulation, when no heat recovery is included.

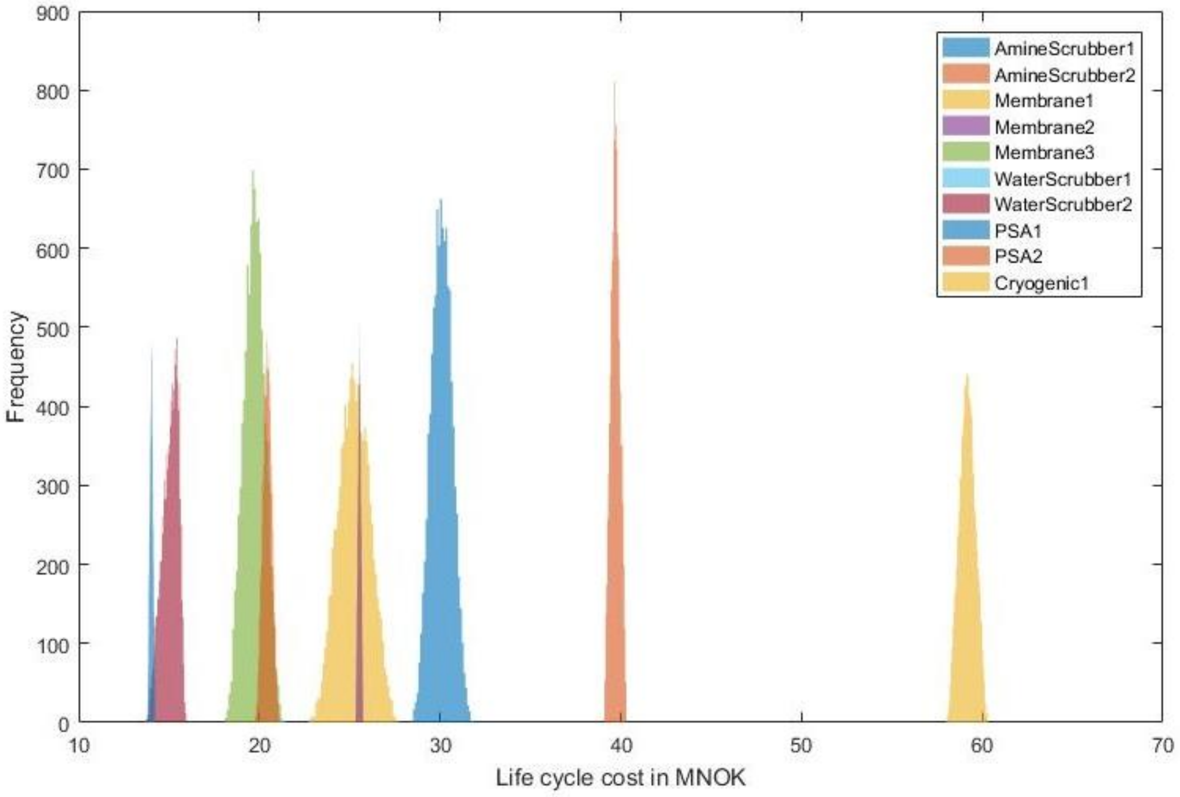

Figure 17: Distribution of life cycle cost without heat recovery

In this scenario, the tendency to overlap is not as prevalent. When heat recovery was included, there was an overlap between the membrane (1), PSA (2) and membrane (3). Without heat recovery, the LCC distribution for membrane (1) is reduced, and it is not overlapping with these units anymore. Generally, all the upgrading units received a lower uncertainty when heat recovery is excluded. The exception is the units without excess heat.

Table 15 presents the standard deviation, mean, as well as the minimum and maximum values for the simulated life cycle cost for the different upgrading units. Since the data for water scrubber (1) is not acquired as a range when heat recovery is removed, no distribution is assigned to it.

Table 15: Standard deviation without heat recovery

Upgrading unit	Standard deviation	Mean	Minimal value	Maximal value
	[MNOK]	[MNOK]	[MNOK]	[MNOK]
Amine scrubber (1)	0.58	30.09	28.37	31.82
Amine scrubber (2)	0.25	39.70	39.08	40.31
Membrane (1)	0.86	25.25	22.74	27.71
Membrane (2)	0.08	25.54	25.34	25.74
Membrane (3)	0.57	19.72	18.11	21.37
Water scrubber (1)	0	20.77	-	-
Water scrubber (2)	0.44	15.07	13.66	15.95
PSA (1)	0.08	14.03	13.82	14.23
PSA (2)	0.24	20.44	19.74	21.11
Cryogenic (1)	0.44	59.17	58.04	60.33

Membrane (1) received a standard deviation of 0.86 MNOK, and thus also the highest uncertainty among the different technologies. Membrane (1) have many factors with relatively large variations in the input data, resulting in a high uncertainty. The upgrading unit with the second largest uncertainty was found to be amine scrubber (1), with 0.58 MNOK. For this scenario, there is a large gap between the highest and second highest standard deviation. Both PSA (1) and membrane (2) have low standard deviations of 0.08 MNOK.

4.3.4 Sensitivity analysis

Saltelli, et al., (2008) define sensitivity analysis as "*The study of how uncertainty in the output of a model (numerical or otherwise) can be apportioned to different sources of uncertainty in the model input*". Conducting a sensitivity analysis, makes it possible to identify which input data that has the greatest impact on the LCC. It tests the outcome of the LCCA by changing some of the input parameters in the initial analysis.

Two parameters are considered in the sensitivity analysis. This is the electricity cost and the discount rate. The sensitivity analysis is conducted using the initial average data.

4.3.4.1 Changing electricity price

The electricity cost can vary extensively throughout the year, and is therefore a critical factor. The highest and lowest annually average electricity price since year 2000, was found to be 459.78 NOK/MWh and 100.70 NOK/MWh, respectively. The total electricity cost is therefore set to a minimum value of 0.500 NOK/kWh and a maximum value of 1.000 NOK/kWh.

The total LCC for the different upgrading units with changing electricity price is illustrated in Figure 18 and Figure 19, corresponding to the upgrading units with and without heat recovery, respectively.

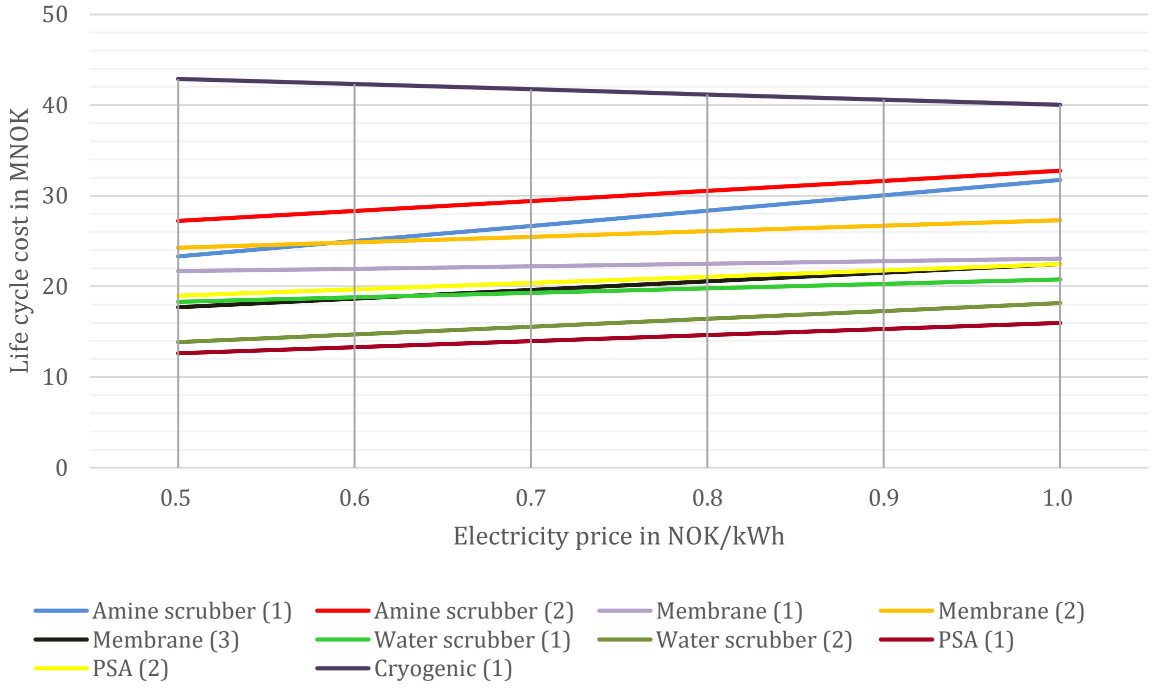

Figure 18: Sensitivity analysis for electricity cost with heat recovery

As shown in Figure 18, increasing electricity price results in an increasing LCC for all upgrading units, except for the cryogenic upgrading unit. An increasing electricity price results in a decreasing LCC for the cryogenic upgrading unit, since the heat recovery is larger than the energy input. However, the other units show a steady increasing trend for LCC, with growing electricity price. The changing electricity price has the greatest impact on the LCC for amine scrubber (1). With a changing electricity price from 0.5 NOK/kWh to 1.0 NOK/kWh, the LCC for amine scrubber (1) increased from 23.30 to 31.73 MNOK. The lowest impact on the LCC from changing electricity prices is for the cryogenic upgrading unit. Membrane (1) also shows a low impact, with a slight increase of 1.38 MNOK.

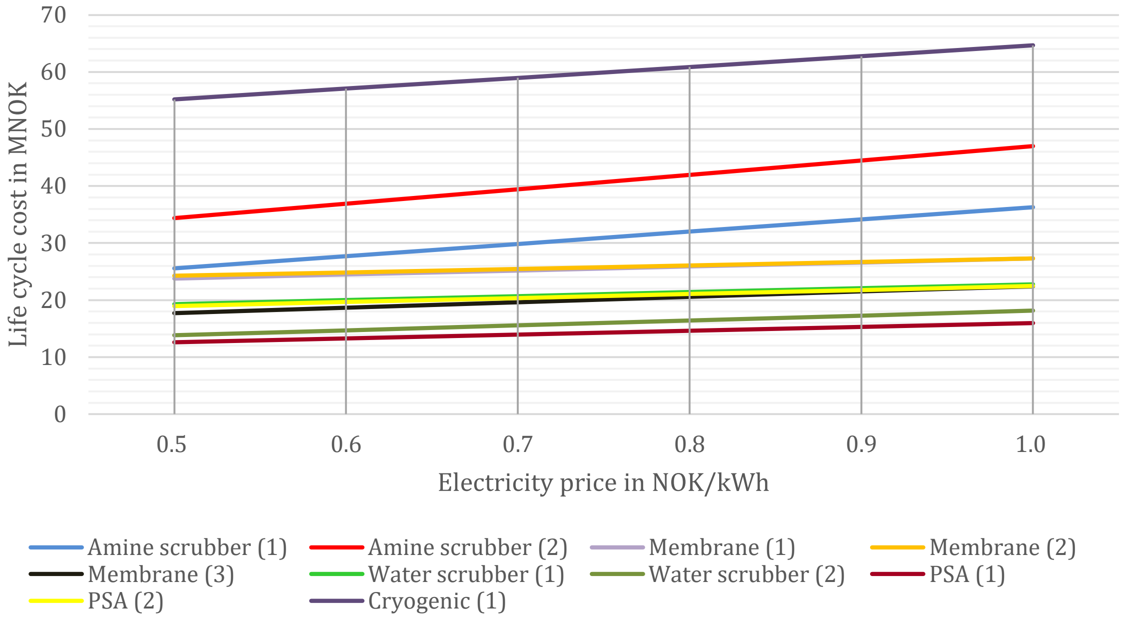

Figure 19: Sensitivity analysis for electricity cost without heat recovery

The sensitivity analysis for changing electricity price was also conducted for the case without heat recovery (see Figure 19). In this case, the highest impact from the changing electricity price is on amine scrubber (1) and amine scrubber (2). From 0.5 NOK/kWh to 1.0 NOK/kWh the LCC changed with a rate of 1.42 and 1.37, resulting in an increase of 10.71 MNOK and 12.67 MNOK for amine scrubber (1) and (2), respectively.

4.3.4.2 Changing discount rate

The discount rate affects all the parameters from the annual cost. The present value of the annual cost is calculated by multiplying the total annual cost with the discount factor as given by Equation 2. Appendix D shows the discount rates used for calculations, while Appendix F shows the results from sensitivity analysis. Changes in the discount rate cause a proportional change in the present value for the annual cost. An increase in the discount rate, results in a decrease in LCC. The LCC for all upgrading plants decreases, when the discount rate is increased.

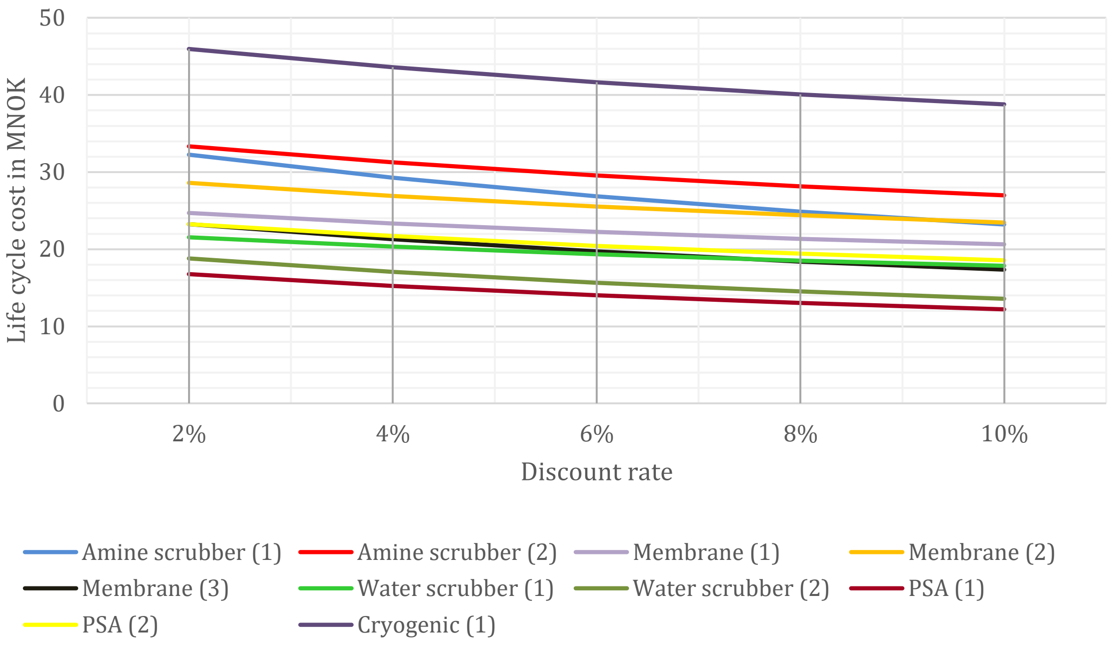

Figure 20: Sensitivity analysis for discount rate with heat recovery

The largest change in LCC are seen on the upgrading units that have the highest annual cost. When heat recovery is included, the highest annual cost is for amine scrubber (1). It is clear that the amine scrubber (1) also ends up with the largest change in LCC, when the discount rate is changed.

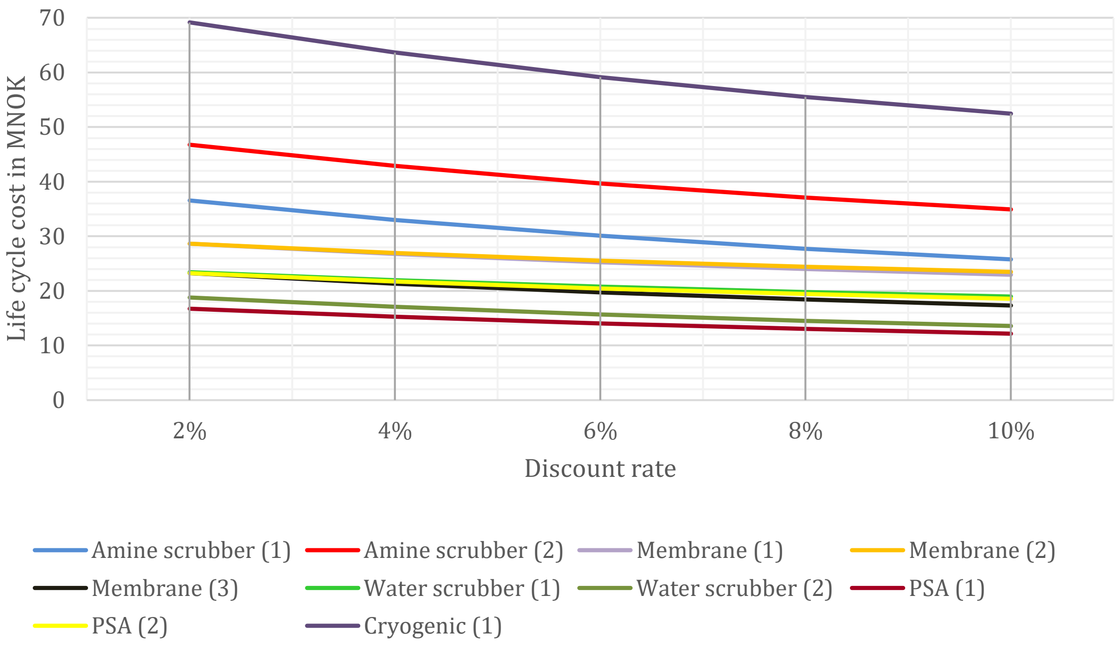

Figure 21: Sensitivity analysis for discount rate without heat recovery

For the case when heat recovery is not included, the cryogenic upgrading unit has the largest annual cost. This is also reflected on the result from the sensitivity analysis, where the cryogenic upgrading is the unit that is most affected by changes in the discount rate. Both amine scrubbers have high annual costs, and are therefore highly affected by the changing discount rate. When the discount rate is changed from 2 % to 10 %, the LCC for amine scrubber (1) and (2) decreases with 10.79 MNOK and 11.85 MNOK, respectively. The cryogenic upgrading unit has a decrease in LCC of 16.67 MNOK for the same change in discount rate.

5 Conclusions and recommendations for future work

5.1 Conclusions

This study compare ten biogas upgrading plants based on five different upgrading technologies. The technologies that are analyzed is amine scrubber, membrane, water scrubber, PSA and cryogenic upgrading. This includes all the commercially used technologies, except the organic physical scrubber. No similar work has been carried out previously, comparing all the above-mentioned technologies from a life cycle point of view. Investment cost and annual operation and maintenance cost was obtained for all the plants, and analyzed in order to find the most cost-effective upgrading technology.

Through data collection it was established that the investment cost for the upgrading units was ranging widely. PSA (1) and water scrubber (2) have the lowest investment cost, while the cryogenic upgrading unit appear as the most expensive unit. Five of the upgrading plants could recover heat, which includes the amine scrubbers, cryogenic, membrane (1) and water scrubber (1). Three of the presented technologies have a water consumption, which are the amine scrubbers, water scrubbers and cryogenic upgrading. The highest methane loss was found to be for the PSA, while the amine scrubbers had the lowest loss.

According to the life cycle cost analysis, PSA (1) and water scrubber (2) are the most cost-effective upgrading units, both when heat recovery is included and excluded. However, none of these units utilize excess heat, thus the results were equal in both scenarios. The least cost-effective units turned out to be the cryogenic upgrading and amine scrubbers. When considering an average life cycle cost for the five different upgrading technologies, PSA and water scrubber appear as the most cost-effective technologies. The analysis shows that heat recovery does not have any large impact on the relative rating of the upgrading units. The most cost-effective upgrading units was found to be the same for both calculations.

The uncertainty and sensitivity analysis confirmed that the PSA (1) and water scrubber (2) are the most cost-effective units. However, the analysis indicates that it is not clearly one technology that is more cost-effective than the others. It depends a lot on the investment cost, which varies for the similar technologies.

5.2 Recommendations for future work

The amine scrubber, water scrubber, organic physical scrubber, membrane and PSA produces upgraded biogas with about the same quality. However, the cryogenic upgrading plant produces liquefied upgraded biogas. If the goal is to produce liquefied biogas (LBG), analysis should be done in order to find whether biogas upgrading followed by liquefaction or cryogenic upgrading is most cost-effective.

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Appendix A

Table 16: Information additional to given data

	Amine scrubber (1)	**Amine scrubber (2)**	**Membrane (1)**	**Membrane (2)**	**Membrane (3)**	**Water scrubber (1)**	**Water scrubber (2)**	**PSA (1)**	**PSA (2)**	**Cryogenic (1)**
Investment cost	Given	Given	Given	Given	Given	Given	Given	Given	Given	Given
Energy-Electricity	Given	Given	Given	Given	Given	Given	Given	Given	Given	Given
Energy-Heat	Given	Given	Not required	Not required	Not required	Not required	Not required	Not required	Not required	Not required
Energy-Heat recovery	Given	Given	Given	No information	No information	Given	No heat recovery	No information	No heat recovery	Given
Water consumption	Given	Given	Not required	Not required	Not required	Given	Given	Not required	Not required	Given
Active carbon	Included in maintenance cost	Given	Given	Included in maintenance cost	Included in maintenance cost	Included in maintenance cost	Included in maintenance cost	Included in maintenance cost	Given	Given
Amine	Given	Given	Not required	Not required	Not required	Not required	Not required	Not required	Not required	Not required
Maintenance/ service	Given	Given	Assumed	Given	Given	Given	Given	Given	Given	Given
Methane loss	Given	Given	Given	Given	Given	Given	Given	Given	Given	Given

Appendix B

Calculated annual costs, with heat recovery

With heat recovery

			Amine scrubber (1)	Amine scrubber (2)	Membrane (1)	Membrane (2)	Membrane (3)	Water scrubber (1)	Water scrubber (2)	PSA (1)	PSA (2)	Cryogenic (1)
Investment cost	**NOK**	***min***	8 836 100	-	-	-	-	-	5 650 000	-	11 219 915	-
		avg	10 098 400	17 752 000	14 708 800	16 000 000	8 750 000	12 500 000	5 975 000	5 537 301	11 785 625	28 300 000
		max	11 360 700	-	-	-	-	-	6 300 000	-	12 351 335	-
Energy- Electricity	*NOK/year*	*min*	213 300	533 250	63 990	426 600	639 900	351 945	445 797	469 260	-	-661 230
		avg	234 630	597 240	202 635	447 930	693 225	365 276	629 235	490 590	511 920	-415 935
		max	255 960	661 230	341 280	469 260	746 550	378 608	629 235	511 920	-	-170 640
Energy- Heat	*NOK/year*	*min*	933 188	-	-	-	-	-	-	-	-	-
		avg	999 844	213 300	-	-	-	-	-	-	-	-
		max	1 066 500	-	-	-	-	-	-	-	-	-
Water consumption	*NOK/year*	*min*	-	-	-	-	-	-	-	-	-	-
		avg	1 048	2 095	-	-	-	8 497	6 984	-	-	3 492
		max	-	-	-	-	-	-	-	-	-	-
Active carbon	*NOK/year*	*min*	-	-	57 821	-	-	-	-	-	-	-
		avg	-	62 690	83 688	-	-	-	-	-	42 428	66 950
		max	-	-	109 555	-	-	-	-	-	-	-
Amine	*NOK/year*	*min*	-	-	-	-	-	-	-	-	-	-
		avg	279 974	27 997	-	-	-	-	-	-	-	-
		max	-	-	-	-	-	-	-	-	-	-
Maintenance/ Service	*NOK/year*	*min*	176 722	-	250 000	-	260 000	-	-	-	-	-
		avg	201 968	302 952	450 000	510 000	395 000	249 855	280 000	140 343	235 713	1 698 000
		max	227 214	-	650 000	-	530 000	-	-	-	-	-
Methane loss	*NOK/year*	*min*	-	-	-	-	-	-	-	-	81 000	-
		avg	8 100	8 100	40 500	24 300	40 500	81 000	81 000	243 000	101 250	24 300
		max	-	-	-	-	-	-	-	-	121 500	48 600

Appendix C

Calculated annual costs, without heat recovery

No heat recovery

			Amine scrubber (1)	Amine scrubber (2)	Membrane (1)	Membrane (2)	Membrane (3)	Water scrubber (1)	Water scrubber (2)	PSA (1)	PSA (2)	Cryogenic (1)
Investment cost	**NOK**	***min***	8 836 100	-	-	-	-	-	5 650 000	-	11 219 915	-
		avg	10 098 400	17 752 000	14 708 800	16 000 000	8 750 000	12 500 000	5 975 000	5 537 301	11 785 625	28 300 000
		max	11 360 700	-	-	-	-	-	6 300 000	-	12 351 335	-
Energy- Electricity	*NOK/year*	*min*	213 300	533 250	426 600	426 600	639 900	-	445 797	469 260	-	1 279 800
		avg	234 630	597 240	511 920	447 930	693 225	511 920	629 235	490 590	511 920	1 386 450
		max	255 960	661 230	597 240	469 260	746 550	-	629 235	511 920	-	1 493 100
Energy- Heat	*NOK/year*	*min*	1 279 800	-	-	-	-	-	-	-	-	-
		avg	1 333 125	1 258 470	-	-	-	-	-	-	-	-
		max	1 386 450	-	-	-	-	-	-	-	-	-
Water consumption	*NOK/year*	*min*	-	-	-	-	-	-	-	-	-	-
		avg	1 048	2 095	-	-	-	8 497	6 984	-	-	3 492
		max	-	-	-	-	-	-	-	-	-	-
Active carbon	*NOK/year*	*min*	-	-	57 821	-	-	-	-	-	-	-
		avg	-	62 690	83 688	-	-	-	-	-	42 428	66 950
		max	-	-	109 555	-	-	-	-	-	-	-
Amine	*NOK/year*	*min*	-	-	-	-	-	-	-	-	-	-
		avg	279 974	27 997	-	-	-	-	-	-	-	-
		max	-	-	-	-	-	-	-	-	-	-
Maintenance/ Service	*NOK/year*	*min*	176 722	-	250 000	-	260 000	-	-	-	-	-
		avg	201 968	302 952	450 000	510 000	395 000	249 855	280 000	140 343	235 713	1 698 000
		max	227 214	-	650 000	-	530 000	-	-	-	-	-
Methane loss	*NOK/year*	*min*	-	-	-	-	-	-	-	-	81 000	-
		avg	8 100	8 100	40 500	24 300	40 500	81 000	81 000	243 000	101 250	24 300
		max	-	-	-	-	-	-	-	-	121 500	48 600

Appendix D

Calculated discount rate

Year	**Discount rate**									
	1 %	**2 %**	**3 %**	**4 %**	**5 %**	**6 %**	**7 %**	**8 %**	**9 %**	**10 %**
1	0,99010	0,98039	0,97087	0,96154	0,95238	0,94340	0,93458	0,92593	0,91743	0,90909
2	0,98030	0,96117	0,94260	0,92456	0,90703	0,89000	0,87344	0,85734	0,84168	0,82645
3	0,97059	0,94232	0,91514	0,88900	0,86384	0,83962	0,81630	0,79383	0,77218	0,75131
4	0,96098	0,92385	0,88849	0,85480	0,82270	0,79209	0,76290	0,73503	0,70843	0,68301
5	0,95147	0,90573	0,86261	0,82193	0,78353	0,74726	0,71299	0,68058	0,64993	0,62092
6	0,94205	0,88797	0,83748	0,79031	0,74622	0,70496	0,66634	0,63017	0,59627	0,56447
7	0,93272	0,87056	0,81309	0,75992	0,71068	0,66506	0,62275	0,58349	0,54703	0,51316
8	0,92348	0,85349	0,78941	0,73069	0,67684	0,62741	0,58201	0,54027	0,50187	0,46651
9	0,91434	0,83676	0,76642	0,70259	0,64461	0,59190	0,54393	0,50025	0,46043	0,42410
10	0,90529	0,82035	0,74409	0,67556	0,61391	0,55839	0,50835	0,46319	0,42241	0,38554
11	0,89632	0,80426	0,72242	0,64958	0,58468	0,52679	0,47509	0,42888	0,38753	0,35049
12	0,88745	0,78849	0,70138	0,62460	0,55684	0,49697	0,44401	0,39711	0,35553	0,31863
13	0,87866	0,77303	0,68095	0,60057	0,53032	0,46884	0,41496	0,36770	0,32618	0,28966
14	0,86996	0,75788	0,66112	0,57748	0,50507	0,44230	0,38782	0,34046	0,29925	0,26333
15	0,86135	0,74301	0,64186	0,55526	0,48102	0,41727	0,36245	0,31524	0,27454	0,23939
16	0,85282	0,72845	0,62317	0,53391	0,45811	0,39365	0,33873	0,29189	0,25187	0,21763
17	0,84438	0,71416	0,60502	0,51337	0,43630	0,37136	0,31657	0,27027	0,23107	0,19784
18	0,83602	0,70016	0,58739	0,49363	0,41552	0,35034	0,29586	0,25025	0,21199	0,17986
19	0,82774	0,68643	0,57029	0,47464	0,39573	0,33051	0,27651	0,23171	0,19449	0,16351
20	0,81954	0,67297	0,55368	0,45639	0,37689	0,31180	0,25842	0,21455	0,17843	0,14864

Appendix E

Sensitivity analysis for electricity cost, with heat recovery

Electricity price [NOK/kWh]	**0.5**	**0.6**	**0.7**	**0.8**	**0.9**	**1.0**
	[MNOK]	[MNOK]	[MNOK]	[MNOK]	[MNOK]	[MNOK]
Amine scrubber (1)	23.30	24.99	26.67	28.36	30.04	31.73
Amine scrubber (2)	27.21	28.32	29.42	30.53	31.64	32.75
Membrane (1)	21.67	21.95	22.22	22.50	22.78	23.05
Membrane (2)	24.25	24.86	25.47	26.08	26.70	27.31
Membrane (3)	17.71	18.66	19.61	20.56	21.50	22.45
Water scrubber (1)	18.29	18.79	19.29	19.79	20.29	20.79
Water scrubber (2)	13.85	14.71	15.57	16.43	17.28	18.14
PSA (1)	12.61	13.28	13.95	14.62	15.29	15.96
PSA (2)	18.97	19.67	20.37	21.06	21.76	22.46
Cryogenic (1)	42.87	42.30	41.73	41.17	40.60	40.03

Sensitivity analysis for electricity cost, without heat recovery

Electricity price [NOK/kWh]	**0.5**	**0.6**	**0.7**	**0.8**	**0.9**	**1.0**
	[MNOK]	[MNOK]	[MNOK]	[MNOK]	[MNOK]	[MNOK]
Amine scrubber (1)	25.58	27.72	29.86	32.00	34.14	36.28
Amine scrubber (2)	34.35	36.88	39.42	41.95	44.49	47.02
Membrane (1)	23.78	24.48	25.18	25.88	26.58	27.28
Membrane (2)	24.25	24.86	25.47	26.08	26.70	27.31
Membrane (3)	17.71	18.66	19.61	20.56	21.50	22.45
Water scrubber (1)	19.29	19.99	20.69	21.39	22.09	22.79
Water scrubber (2)	13.85	14.71	15.57	16.43	17.28	18.14
PSA (1)	12.61	13.28	13.95	14.62	15.29	15.96
PSA (2)	18.97	19.67	20.37	21.06	21.76	22.46
Cryogenic (1)	55.18	57.07	58.97	60.86	62.76	64.65

Appendix F

Sensitivity analysis for discount rate, with heat recovery

Discount rate in %	**2%**	**4%**	**6%**	**8%**	**10%**
	[MNOK]	[MNOK]	[MNOK]	[MNOK]	[MNOK]
Amine scrubber (1)	32.27	29.28	26.86	24.87	23.22
Amine scrubber (2)	33.36	31.25	29.55	28.15	26.99
Membrane (1)	24.69	23.35	22.25	21.36	20.62
Membrane (2)	28.62	26.92	25.54	24.41	23.47
Membrane (3)	23.25	21.30	19.71	18.41	17.34
Water scrubber (1)	21.55	20.33	19.34	18.53	17.86
Water scrubber (2)	18.79	17.06	15.66	14.51	13.56
PSA (1)	16.77	15.25	14.03	13.02	12.18
PSA (2)	23.24	21.70	20.44	19.41	18.57
Cryogenic (1)	45.99	43.61	41.67	40.08	38.77

Sensitivity analysis for discount rate, without heat recovery

Discount rate in %	**2%**	**4%**	**6%**	**8%**	**10%**
	[MNOK]	[MNOK]	[MNOK]	[MNOK]	[MNOK]
Amine scrubber (1)	36.55	32.99	30.09	27.72	25.76
Amine scrubber (2)	46.79	42.87	39.70	37.09	34.94
Membrane (1)	28.66	26.78	25.26	24.01	22.97
Membrane (2)	28.62	26.92	25.54	24.41	23.47
Membrane (3)	23.25	21.30	19.71	18.41	17.34
Water scrubber (1)	23.44	21.96	20.77	19.79	18.97
Water scrubber (2)	18.79	17.06	15.66	14.51	13.56
PSA (1)	16.77	15.25	14.03	13.02	12.18
PSA (2)	23.24	21.70	20.44	19.41	18.57
Cryogenic (1)	69.15	63.65	59.18	55.51	52.48