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Energy Engineering

School of Engineering

& Environmental Research Institute

University College Cork

**A technical, economic and environmental analysis of renewable gas
produced from power to gas systems**

Thi Quynh Truc Vo BSc, MSc

Thesis submitted for the degree of Doctor of Philosophy to the National University
of Ireland, Cork

Supervisors: Professor Jerry D. Murphy & Dr Jeremy Gault

Head of School: Professor Liam P. Marnane

2018

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Declaration

I would like to certify that this thesis, I am submitting, is my own and has not been submitted for another degree, either at University College Cork or elsewhere. All external references and sources are clearly acknowledged and identified within the contents. I have read and understood the regulations of University College Cork concerning plagiarism.

Signature

Date: August 2018

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Executive summary

Storing surplus or curtailed renewable electricity as a gaseous transport fuel is a suggested method of reducing greenhouse gas emissions, increasing the supply of indigenous energy, providing long-term energy storage, facilitating intermittent renewable electricity sources and providing an advanced source of renewable transport fuel. The technology involved is Power to Gas (P2G) which uses electricity to split water into hydrogen (H₂) and oxygen (O₂) through electrolysis (power to hydrogen). Subsequently power to methane involves combining the H₂ with carbon dioxide (CO₂) to produce methane (CH₄) via the Sabatier reaction ($4\text{H}_2 + \text{CO}_2 = \text{CH}_4 + 2\text{H}_2\text{O}$). Storage of renewable electricity as CH₄ allows for long term storage by utilising the existing natural gas grid infrastructure. The aim of this thesis is to evaluate the viability of renewable gas produced from P2G utilised as an upgrading system for a biogas plant by assessing the technical, economic, and environmental aspects of such a system. Various methods were applied in this thesis: a linear additive model was used for sustainability assessment; an Excel model and Superpro designer software were applied for technology and costs analysis; and GaBi software was used to assess environmental impact. The result of the sustainability assessments of large scale energy storage technologies (P2G, pumped hydroelectric storage (PHES), and compressed air energy storage (CAES)) indicated the benefits of P2G as a dynamic decentralised mechanism which facilitated long term storage in the natural gas grid and facilitated change in energy vector from electricity to gas and subsequent availability for renewable heat and transport. The potential resource of CO₂ from

biogas in Ireland was assessed at 430 Mm³ per annum if all potential feedstocks for anaerobic digestion are utilised; this required a resource of 7,654 GWh_e to be consumed to produce H₂ to react with the CO₂ in the biogas. The production costs of renewable gas from several feedstocks were calculated. These varied (depending on system inputs such as cost of electricity and feedstocks) between €1 and €2.5/m³ of renewable methane. The recast Renewable Energy Directive (RED) requires transport biofuels to effect a 70% GHG saving on a whole life cycle analysis when compared to the fossil fuel displaced. Our work shows that for power to gas to be sustainable as an upgrading method the maximum GHG emission of electricity used to produce the hydrogen should be less than 25.7 CO₂eq/MJ.

Thesis outputs

Chapters which have been published as papers in peer-reviewed journals:

Chapter 3: Vo, T.T., Xia, A., Rogan, F., Wall, D.M. and Murphy, J.D., 2017. Sustainability assessment of large-scale storage technologies for surplus electricity using group multi-criteria decision analysis. *Clean Technologies and Environmental Policy*, 19(3), pp.689-703.

Chapter 4: Vo, T.T., Xia, A., Wall, D.M. and Murphy, J.D., 2017. Use of surplus wind electricity in Ireland to produce compressed renewable gaseous transport fuel through biological power to gas systems. *Renewable Energy*, 105, pp.495-504

Chapter 5: Vo, T.T., Wall, D.M., Ring, D., Rajendran, K. and Murphy, J.D., 2018. Techno-economic analysis of biogas upgrading via amine scrubber, carbon capture and ex-situ methanation. *Applied Energy*, 212, pp.1191-1202.

Chapter 6: Vo, T.T., Rajendran, K. and Murphy, J.D., 2018. Can power to methane systems be sustainable and can they improve the carbon intensity of renewable methane when used to upgrade biogas produced from grass and slurry? *Applied Energy*, 228, pp. 1046-1056.

Conference papers:

Vo, T.Q.T, Murphy, J. D. *Store surplus electricity as renewable gaseous or liquid fuels.*

27th Irish Environmental Researches Colloquium, Athlone, Ireland, April 2017.

Vo, T.Q.T, Wall, D.M., Ring, D., Murphy, D.J. Techno-economic analysis of producing green gas via biogas plant with biological methanation as an upgrading unit.

International conference on Green Energy, Singapore, July 2017.

Contribution to the papers

I was the first author of four papers. I was responsible for planning all four articles, collecting relevant data, calculating the models, and analysing the results under supervision. I wrote the first drafts of the publications which were then completed in cooperation with the supervisor and co-authors

Units and acronyms

AD&P2G	P2G systems used as an upgrading element of a biogas plant
a:	Annual
AD:	Anaerobic Digestion
ATD:	Atmospheric deposition
CAES:	Compressed air energy storage
CAN:	Calcium Ammonium Nitrate
CAPEX:	Capital expenditure
CH ₄ :	Methane
CNG:	Compressed natural gas
CO ₂	Carbon dioxide
CRG:	Compressed renewable gas
CSTR:	Continuously stirred tank reactor
DEA:	Diethanolamine
DMEA:	Di-ethyl ethanol amine
DS:	Dry solids
E:	GHG (CO _{2eq}) saved
E ₁ :	CO ₂ in biogas used to combine with H ₂ to produce CH ₄
E ₂ :	CO _{2eq} emitted from P2G process (from life cycle assessment of P2G process)
E ₄ :	CO _{2eq} emitted from processing of substrate, transport and distribution of biogas from domestic and organic fraction of municipal solid waste (OFMSW)
E ₅ :	CO _{2eq} emitted from collection and processing of substrate, transport and distribution of biogas from agricultural slurries

E ₆ :	CO _{2eq} emitted from collection and processing of substrate, transport and distribution of biogas from slaughter waste
E ₇ :	CO _{2eq} emitted from cultivation and processing of substrate, transport and distribution of biogas from grass
E ₈ :	CO _{2eq} emitted from cultivation and processing of substrate, transport and distribution of biogas from seaweed
E ₉ :	CO _{2eq} emitted when diesel fuel used.
E _d :	CO _{2eq} saved when CH ₄ replaces fossil diesel fuel
EF:	Emission factor
EPA:	Environmental Protection Agency
ESS:	Energy storage system
EU:	European Union
FFC:	Fossil fuel comparator
GHG:	Greenhouse gas
GNI:	Gas Networks Ireland
GWP:	Global warming potential
H ₂	Hydrogen
HRT:	Hydraulic retention time
IEA:	International Energy Agency
IPPC:	Intergovernmental Panel on Climate Change
ISO:	International Organization for Standardization
LCA:	Life cycle analysis
LCAs:	Life cycle analyses
LCI:	Life cycle inventory
MAUT:	Multi-attribute utility theory
MCDAs:	Multi – criteria decision analysis

MDEA:	Methyldiethanolamine
MEA:	Mono-ethanol-amine
Mm ³ :	Million m ³
MSP:	Minimum selling price
Mt:	Million tonnes
N ₂ O:	Nitrous oxide
NGVs:	Natural gas vehicles
NPV:	Net present value
O&M	Operation and maintenance
O ₂ :	Oxygen
OFMSW:	Organic fraction of municipal solid waste
OPEX:	Operational expenditure
P2G:	Power to gas
PEM:	Proton exchange membrane electrolyser
PHES:	Pumped hydroelectric storage
PSA:	Pressure swing adsorption
PZ:	Piperazine
RED:	Renewable Energy Directive
S1:	Scenario 1
S2:	Scenario 2
S3:	Scenario 3
SCADA:	Supervisory control and data acquisition
SHW:	Slaughterhouse waste
SNG	Synthetic Natural Gas
SNSP:	System non-synchronous penetration

SOEC	Solid oxide electrolysis cell electrolyser
t:	Tonne
TEA:	Techno-economic analysis
Vol.	Volume
VS:	Volatile solids
WSM	Weighted sum method
wwt:	Wet weight tonne

Chapter 1 Introduction

1.1 Background

Greenhouse gas (GHG) emissions have been significantly increased from 2000 to 2010 in spite of the implementation of various climate change mitigation policies (Intergovernmental Panel on Climate Change 2015). In an attempt to tackle the increasing GHG emissions, the 21st meeting of the Conference of Parties in Paris (COP21) has agreed to keep global temperature increase well below 2°C as compared to pre-industrial levels (UNFCCC 2016).

Ireland contributed the third highest emissions of GHGs (CO₂eq) per capita in 2013 in the EU (Central Statistics Office 2016). In 2014, the Irish Environmental Protection Agency (EPA) stated that Ireland would not meet its EU 2020 targets for reducing GHG emissions. Even under the best case scenario (which assumes full implementation of government policies and measures), the emissions in 2020 are expected to be 5 to 12% below the 2005 levels thus, not meeting the 20% reduction target (Irish Environmental Protection Agency). The main contributors to GHG emissions in Ireland are agriculture, transport, and energy industries (Environment Protection Agency 2017). In 2015, agriculture contributed 33% of total GHGs, whilst transport and energy industries each accounted for approximately 19% of emissions (Environment Protection Agency 2017). Increasing renewable energy use in transport and energy is essential to mitigate GHG emissions. Thus far, Ireland has primarily focused on renewable electricity and as a result, electricity is far more decarbonised

and has far higher levels of renewable energy than that of the heat and transport sectors. As an island with limited interconnection, Ireland is expected to curtail approximately 7-14% of renewable electricity produced by 2020, due to periods when supply exceeds demand (Mc Garrigle, Deane, and Leahy 2013).

The EU 2020 target for renewable energy in Ireland is 16%; Irish national targets are 40% renewable electricity, and 12% renewable heat with an EU target of 10% renewable transport (Persson et al. 2014). Energy consumption in Ireland currently breaks down to 20% electricity, 40% heat, and 40% transport (Murphy and Thamsiriroj 2011). Furthermore, in 2014 Ireland imported 85% of its energy, of which 56% was oil, 31% natural gas, 10% coal, 2% was electricity, and 1% was biofuel (SEAI 2016). The reliance on imported fuel in Ireland is unsustainable and a shift to indigenous energy sources is therefore required. Additionally, any renewable fuels need to ensure sustainability which may be defined by the European Commission requirement of achieving 70% greenhouse gas saving compared to fossil fuel displaced by 2021 (EC 2017).

Power to gas (P2G) has been proposed as a means of reducing the renewables deficit, whereby surplus renewable electricity would be stored as a gas and hence contribute to Irelands EU 2020 targets for renewable transport fuel and heat. P2G involves electrolysis that ideally utilises surplus renewable electricity (that would be curtailed or constrained) to split water into hydrogen (H_2) and oxygen (O_2). Since storing and utilising H_2 would require expensive new infrastructure, currently it is more beneficial to convert the H_2 to methane (CH_4) that can be stored in the existing natural gas grid

infrastructure. The conversion of H_2 to CH_4 requires a methanation step that combines the H_2 from electrolysis with CO_2 in a Sabatier reaction ($4H_2 + CO_2 = CH_4 + 2H_2O$). The CO_2 can be sourced from the biogas generated from anaerobic digestion as biogas contains approximately 45% CO_2 . This renewable gas is chemically equivalent to natural gas and can be used for heating homes or fuelling compressed natural gas vehicles.

Biogas is produced through the anaerobic digestion of organic material; biogas contains 50-60% CH_4 and 40-50% CO_2 . Normally, biogas can be upgraded to biomethane by removing the CO_2 contained in the biogas and using as a natural gas substitute or to produce electricity by a combined heat and power system. If a biogas is upgraded by a methanation process, the final methane produced is practically doubled as the CO_2 in the biogas is converted to an equal amount of methane.

1.2 Ambition of Thesis

The aim of this thesis is to assess the techno-economic and environmental issues of power to gas systems when acting as an upgrading unit for a biogas plant. To achieve this, various methodologies were applied:

- multi-criteria decision analysis in a sustainability assessment;
- creating a model to assess the GHG savings;
- assessing the availability of CO_2 from biogas plants of different feedstocks in Ireland;
- calculating the potential H_2 that could be produced from curtailed wind;

- calculating the cost of the renewable methane from various feedstocks;
- using Superpro Designer and GaBi to assess the techno-economic and life cycle analysis specifications of a biogas plant with various upgrading methods.

The literature on in-depth systems analysis of P2G systems used as an upgrading element of a biogas plant (AD&P2G) is sparse in particular when considering techno-economic analyses and lifecycle assessments. Such techno-economic analysis and lifecycle assessments can allow an assessment of this technology in terms of the distance to commercialisation.

In essence, this research investigates whether the process is feasible by answering the following research questions:

- How sustainable is P2G when compared to other large-scale storage technologies? (Chapter 3)
- What is the combined production cost of renewable gas produced from AD&P2G fed by a range of feedstocks? (Chapters 4 & 5)
- What is the potential capacity of CO₂ from biogas sources and what are the GHG emission reductions if the P2G process is applied? (Chapters 4 & 6)
- What parameters would affect the production costs and environmental impacts of renewable methane? (Chapters 4, 5 & 6)

1.3 Brief overview of the chapters and structure of thesis work

The thesis is structured into seven chapters. Chapter one (Introduction) provides the background to the technology and the aims and objectives of the thesis with an

overview of the thesis. Chapter two (Literature Review) presents the state of the art including a literature review on biogas upgrading methods, renewable methane utilisation pathways, and power to gas systems. Chapter 3 then assesses the sustainability of large energy storage technologies. Chapter 4 evaluates the cost to produce renewable methane from an AD&P2G plant fed by various available feedstocks in Ireland. Chapter 5 focuses on the difference between traditional upgrading and biological methanation upgrading of a central biogas plant with grass and dairy slurry as feedstocks. Chapter 6 considers the greenhouse gas emissions as well as other environmental impacts of a biogas plant with grass silage and dairy slurry feedstocks with upgrading by a traditional upgrading process or a biological methanation process. The RED recast considers carbon capture and replacement (termed e_{ccr} in the RED recast) as a carbon credit. However, the CO_2 that is captured and utilised, will be emitted into the atmosphere when biomethane is combusted. Thus, Chapter 4 in this thesis examines the GHG emission saving when CO_2 from the biogas plant is considered as a carbon credit as per the RED recast. Meanwhile, in Chapter 6, no carbon credit is applied, which many scientists believe is more apt. Chapter 7 provides the conclusions for the whole thesis and recommends research plans in the future. The structure and the link between each chapter is presented in Figure 1-1.

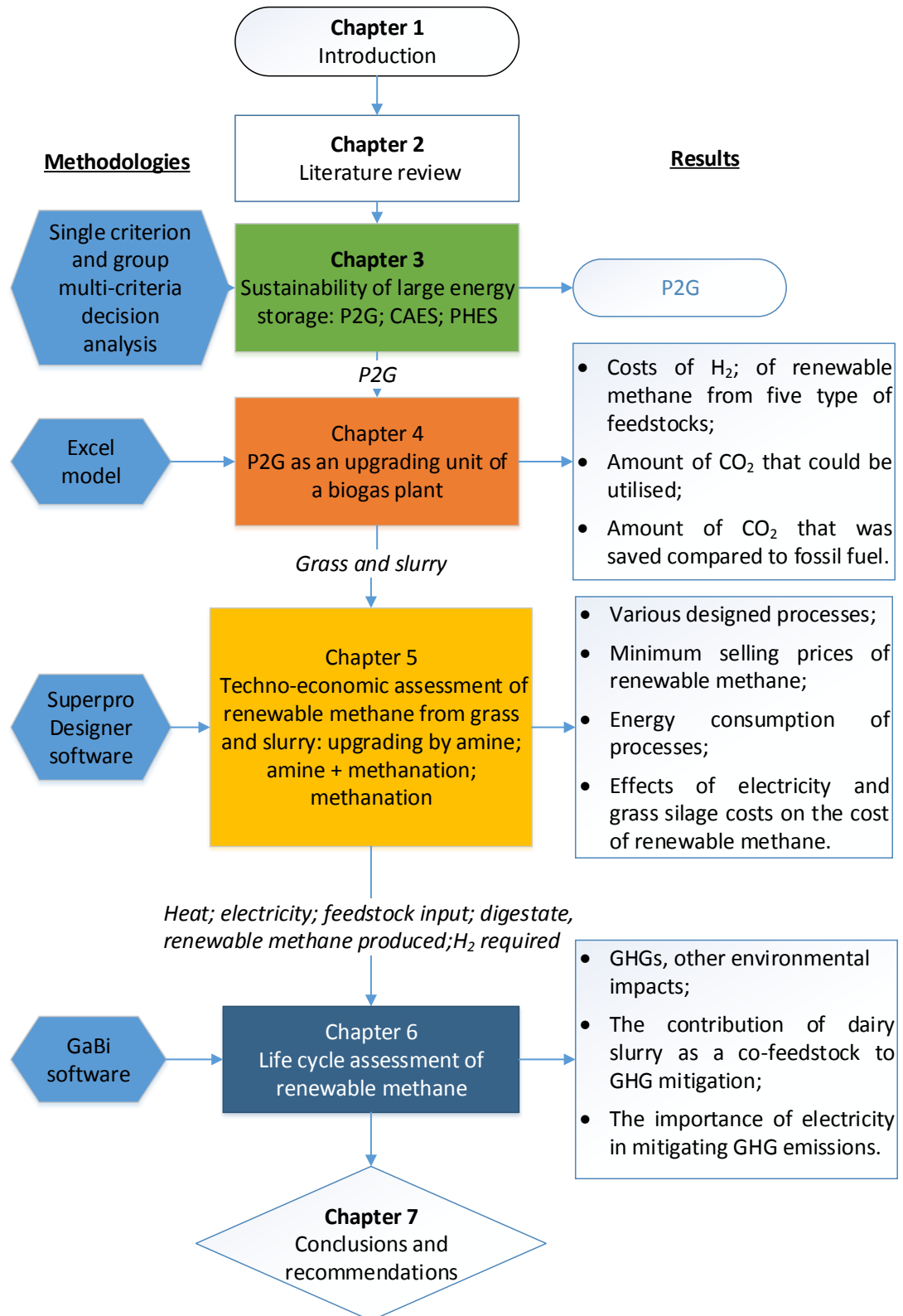


Figure 1-1. The structure of the thesis

Each chapter analysed one aspect of the AD&P2G system; the overall theme is the production of renewable gas from those processes. Chapters 3, 4, 5, and 6 are peer-reviewed journal papers and appear in the thesis as per published manuscripts with some minor modifications to ensure the logical and structural flow of the whole thesis. Each of those chapters contains its own abstract, introduction, methodology, results, and discussion and can be read independently or as a sequence provided in the thesis. Chapters 2 to 6 are summarised below.

Chapter 2: *Literature review*

This chapter aims to provide basic information on P2G. How does power to hydrogen work? How does methanation work? What are the differences between biological methanation and catalytic methanation? The chapter reviews potential sources of CO₂ and the scientific literature in the P2G area. Biogas utilisation pathways, type of upgrading methods, as well as the number of biogas plants in the world are detailed in this chapter.

Chapter 3: *Sustainability assessment of large scale storage technologies for surplus electricity using group multi-criteria decision analysis*

Chapter 3 assesses the sustainability of large scale energy storage technologies: power to gas (P2G) - methane, pumped hydroelectric storage (PHES) and compressed air energy storage (CAES) by using single criterion and group multi criteria analysis. The single criterion data was reviewed from literature and compared with each other. The normalisation processes were then applied for single criterion. The normalised data was used in a linear additive model to calculate preferable values (if a

technology has the highest preferable values, the technology is considered as the most sustainability). Other variables of the model were the weightings of the criteria, which were assessed by researchers by filling the assessment forms. The weight of a criterion reflects a relative important to the sustainable development objective.

Chapter 4: *Use of surplus wind electricity in Ireland to produce compressed renewable gaseous transport fuel through biological power to gas systems.*

As chapter 3 concluded that P2G is preferable in many situations among three large scale energy storage systems, chapter 4 follows on by evaluating the potential of renewable methane from a biogas plant upgraded by a P2G system in Ireland. This chapter gave an overview of how much CO₂ could be utilised, how much CO₂ was produced and how much CO₂ was saved compared to fossil fuel for seven types of feedstocks. Excel models were built to calculate the combined cost of renewable gas and biomethane produced from biological power to gas systems, the potential CO₂ capacity as well as CO₂eq emissions of renewable methane from various feedstocks including: grass; slurry; organic fraction of municipal solid waste; and seaweed.

Chapter 5: *Techno-economic analysis of biogas upgrading via amine scrubber, carbon capture, and ex-situ methanation.*

Chapter 5 further develops the thesis and builds upon chapter 4 by focusing on a techno-economic analysis for the feedstock combination of grass and dairy slurry. Based on a conceptual level of a process design, this chapter develops detailed process flow diagrams for a biogas plant upgraded by an ex-situ methanation; by an amine scrubber; and by combinations of these upgrading technologies. Superpro

Designer, a simulation software, was used which facilitates rigorous assessment of materials and energy requirements, capital expenditure (CAPEX) and the operational cost (OPEX). The output included for the minimum selling price of renewable methane.

Chapter 6: Can power to methane systems be sustainable and can they improve the carbon intensity of renewable methane when used to upgrade biogas produced from grass and slurry?

Chapter 6 advances upon the work carried out in Chapter 5 by conducting a life cycle assessment of those processes. GaBi software (Leinfelden-Echterdingen, Germany, version 8.2) was used to calculate the global warming potential, acidification potential, freshwater eutrophication potential, particulate matter\respiratory inorganics, and the ozone depletion potential of renewable methane produced from the process. This chapter also analysed the important roles of slurry in co-digestion with grass; of fugitive methane emission on GHG emissions; of carbon sequestration in the soil and the decarbonisation level of electricity used to produce hydrogen in the power to gas upgrading system.

Chapter 2 Literature review

2.1 Biogas

Biogas, a mixture of CH₄, CO₂, and some trace gases (H₂S, siloxanes, nitrogen, hydrogen and water vapour), is produced by the decomposition of organic material by microorganisms under an anaerobic condition. A biogas plant works by utilising municipal waste, sewage, agricultural waste, manure, plant material, waste water, or food waste to feed anaerobic digesters to produce biogas. The utilisation pathways of biogas are shown in Figure 2-1. A biogas plant with combined heat and power to produce electricity and heat is a common pathway in Germany (Poeschl, Ward, and Owende 2010). In order to be able to inject the gas into the gas grid, biogas needs to be upgraded to 97% biomethane (Persson, Jönsson, and Wellinger 2006). The traditional upgrading methods are water scrubbing, organic solvent scrubbing, amine scrubbing, pressure swing adsorption (PSA), and gas separation membranes (Bauer, Persson, et al. 2013). There are 480 biogas plants with upgrading units in Europe and 70 biogas plants outside Europe, most of the plants inject the gas into the gas grid (IEA Bioenergy Task 37 2016). Water scrubbing, PSA and amine scrubbing are widely applied in Europe (Bauer, Persson, et al. 2013). Each technology has its advantages and disadvantages. For example, amine scrubbing has a small amount of methane emissions (<0.1%) but consumes high quantities of heat. All those traditional upgrading technologies eliminate CO₂ from biogas. Catalytic or biological methanation is a new technology that utilises the CO₂ fraction to produce more

methane, thus this technology could be considered as an upgrading unit of a biogas plant.

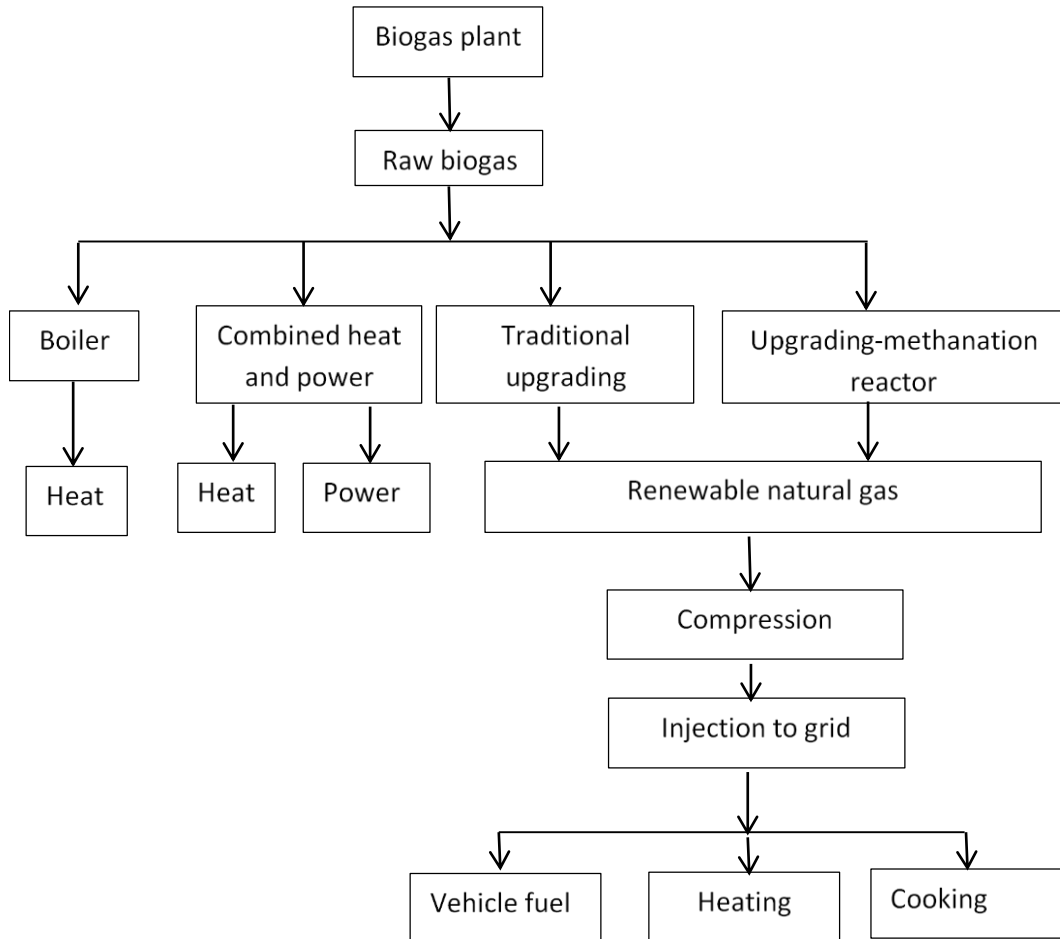


Figure 2-1. Pathways of biogas utilisations

2.2 Power to gas

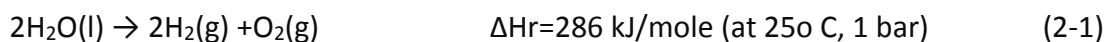
Electrical power is converted to gaseous fuel in the form of hydrogen or methane by a method termed power to gas (P2G). This technology links the power industry to the gas grid in two steps: the first step is converting electricity to hydrogen through electrolysis, and the second step is forming methane by combining carbon dioxide

with hydrogen in a Sabatier reaction (Schiebahn et al. 2015, Vandewalle, Bruninx, and D'haeseleer 2015).

It is possible to utilize the produced hydrogen directly. This has value in the chemical process industry. It may be used in the hydrogen economy (as a means of transport fuel in a fuel cell vehicle or injected into a distribution pipe network). A hydrogen distribution pipe network is very expensive due to the low molecular weight of hydrogen. Hydrogen may be pumped into the existing natural gas grid but the portion allowable is relatively small (2 to 12%) (Götz et al. 2016). Hydrogen addition to natural gas changes the combustion properties of the gas, in particular it reduces the Wobbe Index (an indicator of the interchangeability of the gas) (Grond, Paula, and Johan 2013). To avail of present energy infrastructure, it is advantageous to convert the hydrogen to methane. Therefore, in this thesis, only methane is considered as a final product.

2.2.1 Electrolysis

Water splitting in its simplest form uses an electrical current passing through two electrodes producing hydrogen and oxygen. The splitting of water is described as follow Eq. (2-1):



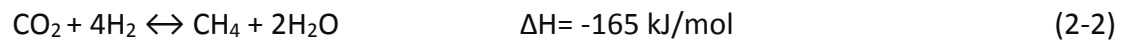
This process requires high purity water thus, a step to remove mineral and ions is always required before water can be used for electrolysis, typically achieved by reverse osmosis (Genovese et al. 2009). The production of hydrogen and oxygen takes place in an electrochemical cell, which consists of two porous electrodes (anode

and cathode), an electrolyte, and a membrane (i.e. gas barrier) which hinders the recombination of the two product gases. As seen in Eq. (2-1), water electrolysis is an endothermic reaction. Energy input is required to sustain the reaction. Hydrogen is formed via reduction at the cathode. Oxygen is formed via oxidation at the anode. The two electrodes are electrically connected via an external circuit and an ionic-conductive electrolyte. A typical electrolyser system is built up of numerous (tens to hundreds) single cells, electrically connected in series, forming a so-called cell stack. There are three techniques for water electrolysis: alkaline electrolyser, proton exchange membrane (PEM) electrolyser and solid oxide electrolysis cell (SOEC) electrolyser. The alkaline electrolyser is commercially available and commonly used because of its durability, maturity, and the fact that it has the lowest capital cost. However, alkaline electrolysis has the lowest efficiency (60-70%) (Benjaminsson, Benjaminsson, and Rudberg 2013); therefore it has the highest electrical energy cost. SOEC electrolyser has the highest electrical efficiency (90-95%) (Benjaminsson, Benjaminsson, and Rudberg 2013), however, the operation temperature of SOEC is high (700°C to 1000°C), which results in the total energy efficiency being in the range of 50%-90% (Grond, Paula, and Johan 2013). This technology has issues such as: corrosion, seals, thermal cycling, and chrome migration (Holladay et al. 2009). PEM electrolysis has a range of efficiencies similar to the alkaline electrolyser (60-70%) (Benjaminsson, Benjaminsson, and Rudberg 2013) but is more expensive. However, the efficiency of PEM technology is expected to improve in the future with 87-93%

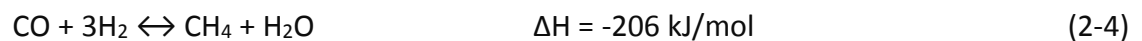
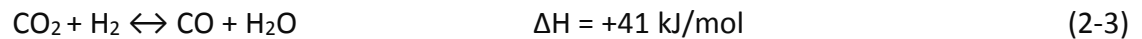
possible by 2020 (Grond, Paula, and Johan 2013). It is considered as a viable high efficiency technology in the short term future.

2.2.2 Methanation

Methanation is an exothermic reaction that converts carbon dioxide to methane Eq. (2.2). This process is named the Sabatier reaction, after its discovery by Paul Sabatier in the year 1902.



The reaction consists of two steps. The first step is endothermic Eq. (2-3) and the second step is exothermic Eq. (2-4):



There are two methods to produce methane: catalytic and biological. The principles of the two methods are based on Sabatier equation, however, they are fundamentally different (Table 2-1).

Table 2-1. The differences between chemical and biological methanation - adapted from (Newton 2014, Götz, Koch, and Graf)

Parameter	Catalytic	Biological
Max scale sold	~ 500MW	~ 500kW
Pressure	1-100 bar	1-10 bar
Temperature	250°C - 550 °C	20 °C -70°C
Heat produced in reaction	Useful	Not useful
Operating range	50-100% (needs H ₂ storage)	0-100% in < 5mins (less H ₂ storage)
During off periods	Temperature should keep at 200 °C	Need to prevent freezing
Reactor types	Fixed – bed; fluidized bed; three phase methanation and structured reactor	CSTR; membrane; trickle-bed; fixed bed
Tolerance of impurities	Low	High

2.2.2.1 Catalytic methanation

Catalytic methanation has been widely used in the coal gas methanation process and in large scale plants but not at small scale thus, this technology has been developed for a continuous electricity supply and not for variable intermittent renewable energy supply.

This is a mature technology and nickel is often chosen as the catalyst because of its high activity and low price. However, the feed-in gas requires a high purity. The efficiency of this process is 70% to 85%. As the equilibrium of Eq. (2-2) is impacted by pressure and temperature, low temperature and high pressure assist the

transformation of CO₂ to CH₄. The ratio of H₂/CO₂ also influences the formation of CH₄. An experimental process (Gao et al. 2012) found that in order to achieve a high CH₄ yield and avoid carbon deposition, the H₂/CO₂ ratio must be higher than 4. Thus, in order to optimise the methanation of the CO₂ process; the following conditions should be achieved:

- + Low temperature (200-400 °C);
- + High pressure;
- + Proper H₂ : CO₂ ratio ≥ 4 .

2.2.2.2 *Biological methanation:*

Renewable methane is produced by microorganisms that metabolise H₂ and CO₂ under anaerobic conditions. As mentioned in Table 2-1, this process differs from chemical methanation, as it occurs at lower temperatures, the mesophilic stage occurs at 20-40°C, and the thermophilic stage is at 45-60°C (Grond, Paula, and Johan 2013). Biological methanation can operate with flexible conditions and at a small scale. The dilution rate (the rate to replace the content in the reactor) for biological methanation ranges from 0.067/day to 1.2/day in a CSTR and 7.76/day in an Anaerobic Filters (Lecker et al. 2017). The final methane content in the gas produced from biological methanation process ranges from 75 to 98% (Benjaminsson, Benjaminsson, and Rudberg 2013).

'In-situ' and 'ex-situ' methanation are two methods for biological methanation. 'Ex-situ' is achieved by injecting H₂ into a separate reactor thus, the CO₂ can be from any

source. 'In-situ' methanation is normally carried out in the anaerobic digester of a biogas plant. The comparison of the two methods taking from Ahern et al. (Ahern et al. 2015) is presented in Table 2-2. Biogas mainly contains CH₄ (40-75%) and CO₂ (25-60%). When H₂ is introduced to the process, the methane content can be increased from 50% up to 75% in 'in-situ' method (Benjaminsson, Benjaminsson, and Rudberg 2013) and up to 98% in 'ex-situ' process (Burkhardt, Koschack, and Busch 2015).

Table 2-2. In-situ and ex-situ biogas upgrading - adapted from (Ahern et al. 2015))

Parameters	In-situ biogas upgrading	Ex-situ biogas upgrading
Introduction of H ₂	Directly into an anaerobic digester	Into separate bioreactor containing only hydrogenotrophic methanogens
Advantages	Simplest	Avoiding many biological and mechanical challenges in anaerobic digestion
Disadvantage	Rising pH inside the reactor	Additional CAPEX cost

2.2.3 Sources of CO₂

CO₂ maybe sourced from ambient air, fossil fuel driven power plants combined with carbon capture, anaerobic digestion, and fermentation processes (Reiter and Lindorfer 2015a). The energy required for capturing CO₂ is based on the concentration and purification of CO₂ in the exhaust sources. Among potential CO₂ sources fermentation, bioethanol, and ammonia production processes produce CO₂ at up to 100% purity, biogas contains CO₂ up to 40% by volume. Cement, steel, and iron production as well as coal combustion emit up to 20% CO₂ by volume. The CO₂

concentration in ambient air is especially low at 0.039% volume (Reiter and Lindorfer 2015a). The energy required to capture CO₂ is one of the factors in determining the efficiency of the methanation process. The methods which are used for separation of CO₂ from other gases are: absorption (chemical absorption and physical absorption); adsorption (absorber beds and regeneration method); and membranes (gas separation, gas absorption and ceramic based system) (Rubin et al. 2012).

Reiter and Lindorfer (Reiter and Lindorfer 2015a) carried out research on CO₂ sources for a power to gas application in Austria and concluded that the CO₂ from biogas and bioethanol plants is preferable in terms of low capital cost, low CO₂ penalties, and biogenic origin. O'Shea et al. (O'Shea et al. 2017) examined the sources of CO₂ for P2G in Ireland based on: annual quantity of CO₂ emitted; concentration of CO₂ in the gas; CO₂ source; distance to the electricity network; and distance to the gas network. The authors stated that the most suitable sources of CO₂ were found to be distilleries, and wastewater treatment plants with anaerobic digesters. Trost et al. (Trost et al. 2012) concluded that the CO₂ from a biogas plant is a sustainable biogenic source for P2G.

2.2.4 Development of P2G in the World

There are 46 lab, pilot, and demonstration P2G-methanation plants in the world, the development of those plants are mostly reported in Europe (Bailera et al. 2017). Germany has the biggest number of P2G-methanation projects, 17 out of the 46 plants in Europe. Denmark is the next biggest with seven plants. Of the 46 P2G plants, 19 apply methanation as an upgrading step in a biogas plant (Bailera et al. 2017).

The largest P2G demonstration plant commenced operation in June 2013 in Wertle, Germany by Audi AG called the Audi e-gas plant. The Audi e-gas plant produces about 1,000 metric tons of e-gas per year and this e-gas is then used as fuel for natural gas vehicles (NGVs), in this case Audi cars. The electricity used in this project is from offshore wind and the CO₂ is sourced from a nearby food waste digester (Bailera et al. 2017).

The first commercial P2G plant with biological methanation in the world is the BioPower2Gas plant located in Allendorf (Germany). This plant first injected renewable methane in the gas grid in March 2015. The P2G plant comprises of 2×150 kWe PEM electrolyzers and a 5 m³ biological methanation reactor (Bailera et al. 2017). The Power-to-Gas via Biological Catalysis (P2G-BioCat) project aims to build the largest commercial-scale plant for converting biogas into methane through biological methanation. The plant consists of a 1MWe alkaline electrolyser and biological methanation. The electricity for the electrolyser is from wind and the CO₂ is sourced from the Avedøre Wastewater Treatment Plant (Bailera et al. 2017).

2.2.5 P2G in previous research

P2G technologies have been widely analysed and studied in recent year. Schiebahn et al. (Schiebahn et al. 2015) conducted research in techno-economic analysis for catalytic P2G in Germany, with an electricity price of €0.06/kWh; the cost of renewable methane was assessed at 22.7 ct/kWh. Therefore, in this case feed-in of renewable methane into the gas grid is uneconomic. Gotz et al. (Götz et al. 2016) provided a comprehensive review of the technical and economic aspects of

renewable P2G. The research stated that biogas could be an important source of CO₂ as biological methanation does not require a high purity of CO₂.

Several life cycle analyses (LCAs) of methane production by P2G have been conducted, however, most of the studies focused on the LCA of catalytic methanation (Reiter and Lindorfer 2015b, Parra et al. 2017, Collet et al. 2017, Zhang et al. 2017). Reiter and Lindorfer (Reiter and Lindorfer 2015b) conducted an LCA of H₂ and CH₄ production. The processes included CO₂ separation, H₂ production, and catalytic methanation. By variation of electricity and CO₂ sources, the authors concluded that the global warming potential (GWP) break-even point of electricity utilised for H₂ production in power to gas - methane when compared to natural gas extraction is 113 g CO_{2eq} per kWh (32 g CO_{2eq} per MJ) without CO₂ separation and 73 g CO_{2eq} per kWh (20 g CO_{2eq} per MJ) with CO₂ separation. Collet et al. (Collet et al. 2017) analysed the techno-economic characteristics and did a life cycle assessment of methane produced from biogas with traditional upgrading and P2G. The authors focused on a sewage sludge biogas plant upgraded by a direct catalytic methanation; traditional upgrading methods and a catalytic methanation after upgrading by traditional technologies. The study concluded that the cost of methane produced by upgrading directly via catalytic methanation is the same as from upgrading via membranes if the electricity price is €38 MWh⁻¹. The GHG emissions of upgrading by P2G (direct methanation and methanation after traditional upgrading) are lower than upgrading by traditional technologies alone. The electricity sources have strong effects on GHG emissions. Parra et al. (Parra et al. 2017) also undertook techno-economic analyses

and LCA of P2G systems. The considered processes included a PEM electrolyser, CO₂ captured from air or biogas plant, and a catalytic methanation. The authors stated that P2G with CO₂ from biogas has a 2-9% lower environmental impact than the process that captured CO₂ from the atmosphere.

2.3 Conclusions

Biological methanation has proposed as an option for storage of electricity as gas at a smaller scale; catalytic methanation process is an option at larger scale. The CO₂ from the biogas plant is a potential source for producing P2G as this is a high concentration biogenic CO₂ source with a low cost of capture. Although the current cost of renewable methane from P2G is quite high, P2G is an important and promising technology for meeting the future requirement for renewable energy storage and for carbon capture and reuse. However, the technology is new in the market and there is much research required in terms of techno-economic and environmental assessments before the technology can be commercialised.

Chapter 3 Sustainability assessment of large scale storage technologies for surplus electricity using group multi - criteria decision analysis¹

Abstract

Power to gas (P2G) - methane, pumped hydroelectric storage (PHES) and compressed air energy storage (CAES) are three methods to store surplus electricity with high capacity and long discharge time. There is little previous research on P2G – methane in comparing with other storage technologies in general and in term of sustainability development. This chapter explored and compared the cost, efficiency, position flexibility, storage capacity/discharge time, energy carrier vector and environmental issues of those storage technologies in terms of single criterion and group multi criteria analysis. The single criterion data of each technology was reviewed from literature and compared with each other. The data from single criterion were normalised then used as inputs of the linear additive model. The weights of criteria were determined by sending out the weighting assessment form to 10 researchers. The comparison in terms of cost and efficiency showed that PHES is better than P2G and CAES. And P2G has many benefits such as: conversion of energy vector from electricity to gas which is available for renewable thermal and transport energy; longest storage time; and minimal impact on the environment. From sustainable development strategy perspective, the evaluation results of P2G, PHES and CAES are 4.03, 2.46 and 2.16, respectively; as such P2G was assessed as preferable.

¹ This chapter based on the published journal article: Vo, T.T., Xia, A., Rogan, F., Wall, D.M. and Murphy, J.D., 2017. Sustainability assessment of large-scale storage technologies for surplus electricity using group multi-criteria decision analysis. *Clean Technologies and Environmental Policy*, 19(3), pp.689-703.

3.1 Introduction

3.1.1 Energy storage

The intermittent nature of renewable electricity production requires potential storage systems to contend with any surplus electricity generated. Existing methods to store energy include pumped hydroelectric storage (PHES), compressed air energy storage (CAES), battery systems, superconducting magnetic energy systems, super capacitor energy systems and power to gas (P2G). Energy storage can be categorised into four groups (i) electrical energy storage, (ii) mechanical energy storage, (iii) chemical energy storage and (iv) thermal energy storage (Chen et al. 2009, Ma, Yang, and Lu 2014) or short - term storage (flywheels, super capacitor or batteries) and long term storage (pumping hydro, compressed air and hydrogen fuel cells) (Faias et al. 2008). The long-term energy storage technologies also store energy in a larger scale (Figure 3-1), therefore, this chapter focused on large scale energy storage technologies. Finding one storage method to meet all of the requirements for surplus renewable electricity storage (low cost, long lifetime, high efficiency and low environmental impact) is challenging. Based on the amount of energy that can be stored, PHES, CAES and P2G are categorised as large scale energy storage technologies (Persson et al. 2014).

PHES is a mature and commercially proven large-scale energy storage technology. The first pumped hydroelectric storage plant was constructed in 1909 in Switzerland and is still operational. More than 300 plants have been installed worldwide with a total installed capacity of over 95GWe (Deane, Ó Gallachóir, and McKeogh 2010).

PHES operates based on the gravitational difference between two water storage reservoirs. During off-peak demand periods, the low cost power is used to pump water from the lower reservoirs to the higher reservoirs. At peak demand periods, water is released from the higher reservoir to the lower reservoir through a turbine to generate electricity. Dependent on water management, PHES is categorized into three subtypes: open – system PHES; semi-open PHES and closed-loop PHES (Zach, Auer, and Lettner 2011).

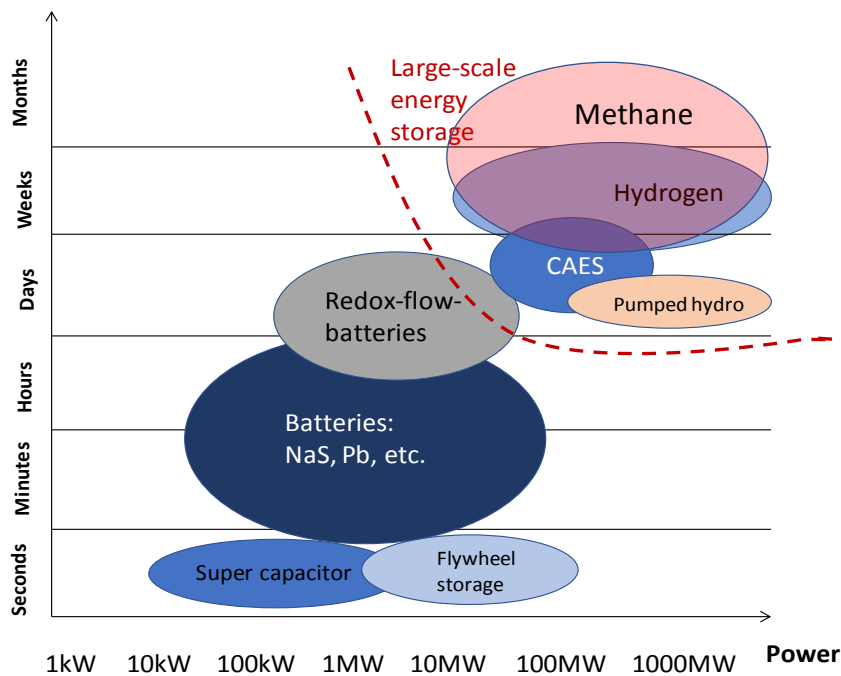


Figure 3-1. Large scale and small scale energy storage technologies (adapted from (Wolf 2015))

P2G is a method of transforming power into hydrogen or methane. This study only focuses on the P2G-methane technology. The P2G-methane process typically includes two phases: an electrolysis step where electricity is converted to hydrogen

and a methanation step where the hydrogen reacts with carbon dioxide to form methane (Schiebahn et al. 2015, Vandewalle, Bruninx, and D'haeseleer 2015).

Three techniques are available for water electrolysis, namely: the alkaline electrolyser; the proton exchange membrane (PEM) electrolyser; and the solid oxide electrolysis cell (SOEC) electrolyser. Currently, the alkaline electrolyser is commercially available, the PEM is at a pilot stage and the SOEC is currently at a research stage. The PEM electrolyser is considered a future technology for hydrogen production from intermittent energy sources (wind turbines) (Grond, Paula, and Johan 2013, Lehner et al. 2014) because of the ability to ramp from a cold start. The SOEC technology requires high temperatures when operating but has efficiencies of over 90% (Lehner et al. 2014). The heat for the SOEC process can be obtained from the catalytic methanation process (Benjaminsson, Benjaminsson, and Rudberg 2013) as the process operates at high temperature, is exothermic, and produces excess heat. Thus, the SOEC would be suitable in conjunction with a chemical/catalytic methanation process.

The methanation process can be chemical or biological. Chemical methanation is a mature technology with nickel often chosen as the catalyst due to its high activity and low price; the carrier metal is metal oxides (Götz et al. 2016). The biological process is an anaerobic process in which carbon dioxide and hydrogen are utilised by hydrogenotrophic methanogenic archaea to produce methane. This process takes place at lower temperatures; mesophilic at 20 - 40 °C and thermophilic at 45 - 60 °C (Grond, Paula, and Johan 2013). To date, there are no commercially built P2G plants

worldwide. However, demonstration plants have been built or are under construction such as the Audi e-gas plant in Wertle, Germany, the KIC-Project DemoSNG, and the BioCatProject in Denmark (Götz et al. 2016)

The principal of the CAES technology is that surplus energy is used to compress air which is stored in an underground cavern (for example salt, rock, and saline aquifers) or an above ground vessel or pipe. When energy is required, the compressed air is released, heated and expanded and passed through two turbines (high and low pressure) to generate electricity (Pickard, Hansing, and Shen 2009). The underground storage cavern for CAES depends on the geological availability. The above ground CAES is more flexible, and as such this type of plant can be sited anywhere. However, the storage scale of the vessel/pipe for CAES is small scale (100 kW) and only provides a short duration of energy supply (2-4 hours) (Arizona Research Institute for Solar Energy 2010).

There are four types of CAES system: diabatic; adiabatic; isotherm; and small – medium scale CAES (Akinyele and Rayudu 2014). Diabatic CAES (first generation) is a conventional CAES system where the heat from compression is not used for expansion, thus it is disadvantaged due to high energy loss (Kim et al. 2012). Natural gas is mixed with air for combustion to improve the power output of the turbine; hence diabatic CAES systems are not considered a ‘pure’ electricity storage method, but a hybrid system. Adiabatic CAES systems store the heat from compression and reuse it for the expansion process (Kim et al. 2012, Bullough et al. 2004). Isotherm CAES is a technology where the temperature of compressed air is kept ambient for

the storage and generation cycle (Akinyele and Rayudu 2014, Kim et al. 2012). Neither adiabatic or isotherm CAES systems require natural gas to mix with air for combustion (Kim et al. 2012). Small-medium scale CAES usually in the ranges from 1-10MW, this technology does not need to have underground storage dorm because it has artificial pressure reserves (Akinyele and Rayudu 2014). To date, there are only two CAES plants in the world (Hasan et al. 2013, Lund and Salgi 2009); the first built in 1978 in Huntorf, Germany with 290 MW capacity and a second in McIntosh, Alabama, USA, deployed in 1991 with 110 MW capacity. Both are diabatic CAES systems. As of yet, no advanced CAES (adiabatic and isotherm) plants have been built.

3.1.2 Multi-criteria decision analysis

Sustainable development is defined as a development that provides environmental protection, economic development and social equity (Drexhage and Murphy 2010). Assessing sustainability can be complex due to the number of associated criteria and indicators. Owing to its complexity, both quantitative and qualitative data can be used. Multi – criteria decision analysis (MCDA) is a tool that has been commonly used in the energy sector for sustainability assessment (Wimmler et al. 2015).

Various methods exist in conducting a MCDA such as: the weighted sum method (or linear additive model); weighted product method; analytic hierarchy process; MCDA combined fuzzy; elimination et choice translating reality (ELECTRE) method; and preference ranking organization method for enrichment evaluation (PROMETHEE) (Wang et al. 2009, Dorini, Kapelan, and Azapagic 2011).

3.1.3 Gaps and innovation of this study

Previous studies have reviewed and compared energy storage technologies such as the energy storage for sustainable power networks (Akinyele and Rayudu 2014), progress in electrical energy storage system (Chen et al. 2009), storage schemes for wind energy systems (Hasan et al. 2013), applications and challenges of energy storage (Kousksou et al. 2014), current development in electrical energy storage technologies and the application potential in power system operation (Luo et al. 2015), energy storage systems for renewable energy power sector integration and mitigation of intermittency (Yekini Suberu, Wazir Mustafa, and Bashir 2014) and energy storage system for wind power integration support (Zhao et al. 2015). For the studies that included P2G, typically hydrogen was considered as the end products. There is a scarce amount of literature related to the P2G - methane technology. One advantage of power to methane versus power to hydrogen is the availability of current infrastructure for methane distribution (natural gas grid) such a system is not available for hydrogen distribution.

Furthermore, the studies only compared single parameters of each energy storage technology. Thus, it is difficult for policy-makers to recommend a specific energy storage system. MCDA is a method of assessing different options in multi-criteria by considering objectives identified by the decision makers. Only two studies have used MCDA directly for energy storage assessment. Raza et al. (Raza, Janajreh, and Ghenai 2014) investigated the sustainability index as a selection criteria for three renewable energy storage technologies: lead acid; lithium polymer batteries; and fuel cells. Barin

et al. (Barin et al. 2011) applied an analytic hierarchy process and fuzzy multi-rules method for multiple criteria analysis of PHES, CAES, hydrogen storage, flywheels, super-capacitors and lithium-ion storage as well as NaS advanced batteries and Vanadium Redox Battery. The MCDA in this case did not include for P2G-methane. Furthermore, the criteria focused only on load management, technical maturity, environmental impacts (for example visual and biological impacts, greenhouse gas emissions), power quality and cost (Barin et al. 2011).

The two previous studies on MCDA for energy storage applied single decision maker MCDA methods (Raza, Janajreh, and Ghenai 2014, Barin et al. 2011). MCDA methods can be executed by a single decision maker or group decision maker method (Triantaphyllou 2013).

This study aims to fill the gaps which have been analysed above by:

- (i) Enhancing sustainability assessment of three storage technologies for surplus electricity: PHES; P2G-methane and CAES.
- (ii) Including investigated the criteria which have not been examined before such as: efficiency; cost; energy carrier vector; storage capacity and discharge time; position flexibility; and environmental impact.
- (iii) Conducting group MCDA method as the project relates to many fields and it needs to get the involvement of many decision makers.

3.2 Methodology

3.2.1 Multi-criteria decision analysis for sustainability assessment

The weighted sum method (WSM) or linear additive model, a common method of multi-attribute utility theory (MAUT), is used as a tool for MCDA. The WSM is commonly used in assessments of sustainable energy systems (Wang et al. 2009) and so will be used in this study for the sustainable assessment of electricity storage. The linear additive model is calculated as in equation Eq. (3-1):

$$S_i = \sum_{j=1}^n w_j p_{ij}, \quad i = 1, 2, \dots, m \quad (3-1)$$

where;

S_i : preference value (The best alternative was regarded as the option with the highest preference value)

n : number of criteria

w_j : weight for criterion c_j

p_{ij} : performance measure of alternative a_i for criterion c_j

3.2.1.1 Weight for criterion - Weighting method

The w_j values will be assessed by group decision makers; this is direct estimation of a criterion's relative importance to the sustainable development objective by assigning a value to each criterion. Depending on its perceived importance to the objective, a weight will be assigned according to the following five-point scale (Table 3-1):

Table 3-1. Weighting scale

1	2	3	4	5
Not at all important	Slightly important	Moderately important	Very important	Extremely important

In reality, the decision makers group does not involve too many people, thus the assessment form (Appendix A) for the weighting of criteria was sent out to ten researchers with relevant skill sets in the energy field in University College Cork. The assessments were made individually. Each researcher has a different background; therefore, each person was anticipated to have different individual preferences. The constraint of group decision makers was combining individual decisions into a collective preference. It is important to note that the assessment stressed the significance of each criterion to the sustainability development objective and was not particular to any specific storage technology.

Three ways were analysed in (Belton and Pictet 1997) to adapt individual results into a group preference, namely: sharing; aggregating; and comparing. The sharing method was deemed time-consuming due to the decision makers need to gather and discuss a preferred choice. The comparing method was conducted by using software. Thus, the aggregating method was applied in this chapter. Two aggregating methods were proposed (Huang et al. 2013, Salo 1995), whilst the method of Salo was for imprecise preference judgements, the Huang et al. (Huang et al. 2013) method could be applied to discrete data, applicable to this study.

However, the performance measures (p_{ij}) in this study were not based on the decision makers' evaluation, only the varying criteria weights between participants. Thus, for the criteria weights of the individuals to be interpreted into representative criterion weights for a group, Eq. (3-1) may be used. The Huang et al. (2013) methodology was applied for analysing the preferential differences and preferential priorities of the weights of criteria. The methodology is divided into two steps:

(i) Taking the standard deviation of criteria weights of each participant into consideration, w_{kj} are revised to $w_{kj}^{(1)}$ by Eq. (3-2):

$$w_{kj}^{(1)} = \begin{cases} w_{kj}^{1-\theta k} & \text{if } w_{kj} \geq \bar{w}_k \\ w_{kj}^{1/(1-\theta k)} & \text{if } w_{kj} < \bar{w}_k \end{cases} \quad (3-2)$$

where;

w_{kj} : the weight value of decision maker k on criterion c_j

\bar{w}_k : The mean of the weight values of decision maker k on all criteria

θk : the standard deviation of all criteria evaluated by decision maker k (the preference differences of criteria).

Huang et al. stated that the larger the standard deviation (θk), the better the capability to decisively distinguish decision maker preferences amongst the criteria.

(ii) Taking the skewness of criteria weights of each participant, normalised skewness values and priorities into consideration, the $w_{kj}^{(1)}$ are revised to $w_{kj}^{(2)}$ by using Eq. (3-3):

$$w_{kj}^{(2)} = \begin{cases} w_{kj}^{(1)} + (1 - w_{kj}^{(1)}) \delta_i \gamma_k^{NOR} [1 - \exp(-\bar{w}_k \cdot w_{kj})] & \text{if } w_{kj} \geq \bar{w}_k \\ w_{kj}^{(1)} (1 - \delta_i) \gamma_k^{NOR} [1 - \exp(-\bar{w}_k \cdot w_{kj})] & \text{if } w_{kj} < \bar{w}_k \end{cases} \quad (3-3)$$

where;

γ_k^{NOR} is normalised data of γ_k (skewness values of j criteria of decision maker k) and can be calculated using Eq. (3-4):

$$\gamma_k^{NOR} = \begin{cases} \frac{\gamma_k}{\sum_{k=1}^m \gamma_k} & \text{if } \gamma_k > 0 \\ \frac{\gamma'_k}{\sum_{k=1}^m \gamma'_k} & \text{if } \gamma_k < 0 \end{cases} \quad (3-4)$$

where;

$\gamma'_k = \gamma_k + \gamma^*$ and $\gamma^* = |\min_k(\gamma_k)|$ and δ_i is the preferential priority of criterion j for the group, calculated using Eq. (3-5):

$$\delta_i = \sum_{k=1}^m \sigma_i / \sum_{i=1}^n \sum_{k=1}^m \sigma_i \quad (3-5)$$

where;

$\sigma_{kj} = n/\rho_{kj}$, and σ_{kj} and ρ_k denote the priority coefficient and preferential ranking of criterion j for decision maker k , respectively (that is, the alternative with the highest utility simply has a priority coefficient of $n/1$, the alternative with the second highest utility has a priority coefficient of $n/2$, and so on).

Finally, if considering m decision makers have the same decisional power, the group alternative can be calculated using Eq. (3-6):

$$w_j^{(d)} = \sum_{k=1}^m w_j^2 / m \quad (3-6)$$

3.2.1.2 Performance measure

The p_{ij} values can be evaluated in three ways (Belton and Pictet 1997): (i) objective evaluation based on the real performance, which can be measured therefore the p_{ij} is independent of the decision maker; (ii) subjective evaluations by participants without reference to the statement of alternatives; and (iii) constructive assessments conducted through an explainable and justifiable framework in the case of no objective measurement of real alternative. The p_{ij} values in this study will be assessed based on objective evaluation. The performance matrix table, created based on the literature review of single criterion analysis, was assessed.

In order to compare different units of performance measures, a normalisation process was undertaken to get the performance data of each alternative under different criteria in the range of 0-1. The data in this chapter includes quantitative and qualitative data. For quantitative data, the normalisation was computed by linear scale transformation (max method) (Chakraborty and Yeh 2007). If the data are the benefit values, higher values are better, thus the normalised value of criterion n_{ij} can be calculated using Eq. (3-7):

$$n_{ij} = \frac{x_{ij}}{x_j^{max}} \quad (3-7)$$

For the cost values and carbon dioxide (CO₂) emissions data, lower values are better; with normalised values computed using Eq. (3-8):

$$n_{ij} = 1 - \frac{x_{ij}}{x_j^{max}} \quad (3-8)$$

where;

x_j^{max} is the maximum performance value among alternatives for criterion c_j , x_{ij} is the performance value of alternative i for criterion c_j .

For qualitative data, the normalisation process was approached the same as by Bernstein (Bernstein 2015) where a five point scale (Table 3-2) was applied:

The normalisation of scoring data was analysed as in Eq. (3-7) and Eq. (3-8).

Table 3-2. Quantifying the qualitative data

Criteria level	Criteria score
Best	100
Good	75
Medium	50
Poor	25
Worst	0

3.2.2 Criteria selection

Wang et al. (2009) reviewed criteria selection for sustainable development of energy supply systems and stated that the criteria are divided into four aspects: technical, economic, environment and social criteria. The criteria in this study were chosen using the recommendation of Wang et al., however, due to the characteristics of energy storage technologies differing from energy supply systems, some technical criteria such as position flexibility, storage capacity/discharge time and energy carrier vectors were assessed in this chapter. Moreover, this study assumed job creation and social benefits are similar in different storage technologies. Therefore, social criteria were not assessed as such.

3.2.2.1 *Costs*

Construction, operation and maintenance costs are the primary costs to be considered as these factors will decide if the storage plants are viable or not. Generally, the operation cost is spread over the life-span of the system and is proportional to the investment costs. For sustainable development, the cost of the storage plant should include environmental expenses, however, due to lack of data in literature, this chapter only considered the capital cost and the operation and maintenance (O&M) costs.

3.2.2.2 *Technical characteristics*

The efficiency factor is one of the most chosen criteria for multi-criteria analysis (Raza, Janajreh, and Ghenai 2014, Barin et al. 2011) as well as individual criterion comparisons (Akinyele and Rayudu 2014, Ibrahim, Ilinca, and Perron 2008, Zhao et al. 2015, Zafirakis 2010, Luo et al. 2015) for energy section. This criterion represents the quality of the system in terms of its ability to store energy.

Position flexibility is the ability to site a storage facility. Transferring energy long distances for storage is not recommended thus suitable plant location is essential.

The storage capacity/discharge time is another important indicator for a sustainable storage plant. If the plant has a long storage time and higher capacity, the seasonal variation of electricity can be considered.

Changing the energy carrier vector is the ability to store electricity in different forms of energy in the final storage product. For example, P2G technologies have the ability

to convert surplus electricity to hydrogen and methane which can then be used as a heat source or as a gaseous transport fuel. Such diversification can be an advantage when considering that electricity is ca. 20% of final energy consumption in Ireland, with the remainder of energy demand divided relatively equally by thermal and transport (Murphy and Thamsiroj 2011).

3.2.2.3 *Environmental issues*

Environmental impacts can include for general impacts due to the type of storage system being constructed and the CO₂ emissions footprint as a result of life cycle assessment (LCA). Each system must try to limit the environmental impacts for sustainable development.

3.3 Single criterion analysis and comparison

3.3.1 Costs

3.3.1.1 *PHES*

The cost of energy produced from a PHES system depends on the following factors:

- Capital cost:
 - hydraulic head for operation (the vertical distance between the upper and lower reservoir – typically of the order of 300 metres)
 - topography of both the reservoirs
 - plant utilization cost
 - size (smaller projects typically have higher costs (€-capital/kW) than larger projects)

- Cost of pumping energy
- Water availability

The capital cost of PHES systems can be split into two areas:

- power capacity (€-capital/kW) = capital costs/turbine power electricity generation
- energy storage (€-capital/kWh)= capital costs/amount of energy stored in one full charge

The power and storage capacities are both dependent on the head and the volume of the reservoirs (Connolly 2007). In terms of economic and environmental issues, it is better to design the facilities with the greatest hydraulic head possible rather than largest upper reservoir possible.

Table 3-3 presents the typical costs of PHES obtained from literature (Gonzalez et al. 2004, Zach, Auer, and Lettner 2011, Electric Power Research Institute 2011, Chen et al. 2009, Deane, Ó Gallachóir, and McKeogh 2010). Past studies analysed the capital costs of PHES plants which were built, under construction or planned to be built in Europe, the US, Asia and Africa. Typically, PHES plants have a long assets life (50 -100 years), high capital cost and low operation and maintenance costs. PHES is a mature technology, therefore no significant technology advance or cost decrease is expected in the future. The capital cost of PHES plants can be based on the topography of the reservoirs; therefore, a big variation in capital cost of PHES is evident. The most common ranges are 500 – 2000 €/kW (700 – 2800 \$/kW) and 8-60 €/kWh (11-84

\$/kWh), respectively. The operation and maintenance (O&M) costs of PHES plant is low, accounting for approximately 1-2 % of investment cost.

Table 3-3. Capital cost of PHES

Capital costs				References
€/kW	\$/kW	€/kWh	\$/kWh	
480-1600	672 - 2240	4-80	5.6 - 112	(Chen et al. 2009)
450-1500	630 - 2100	8-60	11 - 84	(Zach, Auer, and Lettner 2011)
450-2500	607 - 3375			(Deane, Ó Gallachóir, and McKeogh 2010)
375-1875 Majority 750 - 1500	525 – 2625 Majority 1050- 2100			(Electric Power Research Institute 2011)

3.3.1.2 P2G

P2G plants are only in demonstration stage. Thus, it is difficult to assess the cost of real P2G plants in the future. The capital cost of a P2G plant is assessed based on following factors:

- electrolyser investment cost
- methanation investment cost
- CO₂ purification investment cost
- piping
- compression

There is a variation in literature of the capital costs of P2G as well as production costs of methane. Electrolysis is the major contributor for capital cost of P2G, around 800-3000 €/kW_e (880- 3300 \$/kW_e) (Götz et al. 2016). The capital cost of a catalytic

methanation plant ranges from 130 to 400 €/kW (142 to 440 \$/kW) Synthetic Natural Gas (SNG), which is equivalent to 78 to 240 €/kW_e (86 – 264 \$/kWh_e) (at 75 % efficiency for electrolysis and 80 % for methanation). In total, the CAPEX for P2G are from 900-3240 €/kW_e (990- 3564\$/kW_e). The variation in investment costs is attributable to the technology used and scale of plant (Benjaminsson, Benjaminsson, and Rudberg 2013). In the future, cost are expected to be below €1,000/kW_e (1400 \$/kW_e) at a scale of 20-200 MW_e, at 68% efficiency for whole process, the cost equates to €1470/kW (1984 \$/kW) methane (€1,000/0.68 = €1470/kW methane) (Sterner 2009).

The operation and maintenance costs of a catalytic P2G plant is estimated at 3% of investment cost and is largely due to the replacement cost of the nickel catalyst and sulphur absorber in the reactor (fixed cost).

The production cost of methane is predominately based on electricity costs (particularly in hydrogen generation; electricity costs can be even higher than capital costs (Benjaminsson, Benjaminsson, and Rudberg 2013)), and the cost of CO₂ captured. The cost of methane from P2G in 2013 is in the range of 15-20 cent€/kWh (21 – 28 cent\$/kWh) (Benjaminsson, Benjaminsson, and Rudberg 2013), and the production cost of methane from biological P2G is lower than that of chemical P2G. According to Ahern et al. (2015), among three methods of CO₂ capture, the cost of CO₂ capture from ambient air is the most expensive, due to the low concentration of CO₂ in ambient air. The cost of CO₂ capture from an existing upgrading process converting biogas from anaerobic digestion to biomethane is less expensive. CO₂

captures from thermal plants at scale provide the least expensive source of the three. Ahern et al. (2015) recommended the cheapest method of CO₂ capture is biological P2G used as an upgrading system instead of conventional biogas upgrading.

3.3.1.3 CAES costs

The capital cost of CAES plants are based on the following parameters:

- availability of caverns
- price of natural gas
- compressor, cooler and generator investment

The capital costs of CAES systems are dependent on the geological location. The capital costs of conventional CAES plants are in the range of 450-1000 €/kW (630 – 1400 \$/kWh) and that of adiabatic CAES plants are in the range of 600-1200 €/kW (840 – 1680 \$/kW) (Zach, Auer, and Lettner 2011, Schwarzenegger 2008). The O&M costs is around 0.6 – 2 % of investment cost.

Above ground air storage vessels/pipes are good options for locations where underground caverns are not available. However, these systems are potentially five times more expensive than underground salt-based air storage caverns, and approximately 50 times more expensive than porous rock-based air storage systems (Schwarzenegger 2008).

3.3.1.4 Cost comparison

Currently, the cost of P2G is double the cost of PHES and CAES and the cost of PHES is slightly higher than that of CAES. However, there is no expectation for a reduction

in investment cost for developing PHES plants in the future, whereas the capital cost of P2G plant is expected to be €1470 /kW (1984 \$/kW) methane (Sterner 2009).

3.3.2 Efficiency

3.3.2.1 PHES

The PHES cycle efficiency is understood as the ratio of the energy used whilst generating to the energy consumed during the pumping process. The cycle efficiency (η_h) depends on both the pumping efficiency (η_p) and the generation efficiency (η_g) (Ter-Gazarian 2011) and is calculated by Eq.(3-9):

$$\eta_h = \eta_p \times \eta_g \quad (3-9)$$

PHES cycle efficiencies have been suggested to be in the range of 70-85% (Chen et al. 2009, Ter-Gazarian 2011, Rehman, Al-Hadhrami, and Alam 2015). PHES can be brought online within 90 seconds, and can be functioning at full power within 120 s. It can also be switched from pumping to generation or vice versa in 180-240 s, respectively. Detailed the efficiency of a PHES plant are shown in Table 3-4 (Cheng H. 1993).

Adjustable speed technology was developed in Japan in the early 1990's and was used in Europe in the late 1990's. This technology can improve the turbine efficiency and the operation flexibility as the turbine can be operated at its peak efficiency point under all head conditions, resulting in increased energy generated of the order of 3 % annually (Sætre 2013).

Table 3-4. Efficiency of a pumped hydroelectric storage plant - adapted from (Cheng H. 1993)

Pumped Storage (cycling)	Low %	High %
Generating component		
Water conductors	97.4	98.5
Pump Turbine	91.5	92
Generator motor	98.5	99
Transformer	99.5	99.7
Subtotal of generating component	87.35	89.44
Pumping component		
Water conductors	97.6	98.5
Pump turbine	91.6	92.5
Generator motor	98.7	99
Transformer	88.5	99.8
Subtotal of pumping component	87.8	90.2
Operational	98	99.5
Total	75.15	80.12

3.3.2.2 P2G

The overall P2G technology efficiency is based on the efficiency of three processes: electrolysis, methanation and CO₂ extraction. The efficiency data was collected from literature (Grond, Paula, and Johan 2013, Sterner 2009, Benjaminsson, Benjaminsson, and Rudberg 2013, Burkhardt, Koschack, and Busch 2015). The summary of P2G efficiency is presented in Table 3-5.

Table 3-5. Efficiency of P2G technology

Process	Efficiency (%)	
	Currently	Future
Electrolysis		
Alkaline	60-73 (Benjaminsson, Benjaminsson, and Rudberg 2013); 62-82 (Grond, Paula, and Johan 2013),	67-82 (Grond, Paula, and Johan 2013)
SOEC	90-95 (Benjaminsson, Benjaminsson, and Rudberg 2013), if energy required for heating included, efficiency: 50-90 (Grond, Paula, and Johan 2013)	
PEM	67-82 (Grond, Paula, and Johan 2013)	87-93 (Grond, Paula, and Johan 2013)
Overall	62-90	
Methanation		
Chemical	70-85 (Grond, Paula, and Johan 2013); 75-85 (Sterner 2009)	
Biological	75 - 98 (Benjaminsson, Benjaminsson, and Rudberg 2013, Burkhardt, Koschack, and Busch 2015)	
Overall efficiency		
CO ₂ from ambient air	41 (Grond, Paula, and Johan 2013)	
CO ₂ from concentrated source	57 (Grond, Paula, and Johan 2013)	
Undescribed CO ₂ source	46-75 (Benjaminsson, Benjaminsson, and Rudberg 2013); 52 (Benjaminsson, Benjaminsson, and Rudberg 2013)	65-68 (Sterner 2009)

Electrolysis:

The alkaline electrolyser has the lowest efficiency of all technologies, leading to the highest electrical energy cost. The SOEC electrolyser has the highest electrical

efficiency; yet the high operation temperatures (700 - 1000 °C) result in the total energy efficiency being 50 - 90 % (Grond, Paula, and Johan 2013) unless a free source of thermal energy may be obtained such as associated with a power plant which does not have a market for thermal energy. The efficiency of the PEM electrolyser is higher than that of alkaline electrolyser but lower than that of the SOEC. Efficiency of PEM technology is expected to improve in the future with an achievable efficiency of 87-93 % by 2020 (Grond, Paula, and Johan 2013) and is considered as an alternative technology for alkaline electrolyser. Currently, the average efficiency of electrolysis is stated as 75 % (Ahern et al. 2015, Sterner 2009).

Methanation:

The efficiency of methanation depends on the process type (chemical or biological) and the arrangement of input gases. Variations on the system include for: pure CO₂ injected to the system; hydrogen introduced into an anaerobic reactor (in-situ methanation): or hydrogen and biogas fed into a bioreactor containing hydrogenotrophic methanogenic archaea (ex-situ methanation). Biological methanation with reaction of hydrogen and biogas will maintain higher efficiency as compared to reaction of hydrogen with pure CO₂ as this requires extraction of CO₂ from ambient air or from the flue gas of a power plant, both of which are energy intensive. The methanation process works at high temperatures and has an efficiency of ca. 70 - 85 % (Benjaminsson, Benjaminsson, and Rudberg 2013). Biological methanation can operate with flexible conditions and at a smaller scale (Götz et al. 2016) with an efficiency range of ca. 75 - 98 % (Benjaminsson, Benjaminsson, and

Rudberg 2013, Burkhardt, Koschack, and Busch 2015). To date, biological P2G has been used at pilot scale with a capacity of 1 MW (<http://www.electrochaea.com/technology.html>). For chemical methanation, process temperatures are high (250– 550 °C). Efficiency can be increased by utilising the high output heat to meet the parasitic demands of a biogas plant. The average value used for the methanation process efficiency is 80 %.

Overall:

If the electrolysis efficiency is 75% and the efficiency of methanation is 80%, the overall efficiency of P2G-methane can be predicted at 60%. A study has previously shown that the efficiency of P2G-methane is 57% if the CO₂ is obtained from a concentrated source (Grond, Paula, and Johan 2013); this drops to 41% if the source of CO₂ is obtained from the atmosphere. A total efficiency of P2G-methane of 52% (combining 65% electrolysis efficiency and 80% methanation efficiency) in a previous work (Benjaminsson, Benjaminsson, and Rudberg 2013). The future efficiency of P2G systems is expected to be 65-68% (Sterner 2009). However, if PEM electrolysis efficiency is increased to 87 - 93 % as earlier indicated, the expected efficiency for P2G with biological methanation could potentially be in the range of 65-91%. Using biomethanation systems to upgrade biogas saves energy that would be used in biogas upgrading, provides a free source of CO₂, and as such is suggested by the authors as the most beneficial application of P2G-methane systems.

The transition of gas back to power in a combined cycle plant has an efficiency of 60%, lowering the efficiency of power-methane-power (PMP) systems to 34% for

concentrated CO₂ and 26% for atmosphere CO₂. The power to hydrogen to power process (PHP) has a higher efficiency than PMP process with the efficiency ranging from 33 to 37%. It is the viewpoint of the authors that power to gas systems should be used to create renewable thermal energy or transport fuel, thus negating this efficiency reduction in changing the vector back to electricity.

3.3.2.3 CAES

The efficiency of a CAES plant was analysed in a previous study (Elmegaard and Brix 2011) based on the gas turbine cycle efficiency and the efficiency of input to output. The diabatic CAES has low efficiency (40%) due to energy losses in the cooling process during compression to avoid overheating and reheating the air prior to burning it with the fuel. Adiabatic CAES has a higher efficiency (70 - 80 %) due to the added heat storage device.

3.3.2.4 Comparison of efficiency

The large variation in efficiencies makes a direct comparison between PHES, P2G, and CAES technologies challenging. Currently the average efficiency of PHES is higher than that of chemical P2G and CAES but lower than that of biological P2G. The challenge for the application of biological P2G is to develop a fully operational controllable system. As this technology is in a research and development stage, no field practice has been gained. In the future, while the efficiency of PHES is not expected to increase, P2G-methane efficiency may increase to 68% for chemical methanation or even 91% if PEM electrolysis is combined with biological methanation.

3.3.3 Position flexibility

The distributed (or decentralised) energy storage system (ESS) is described as numerous on-site storage systems, connected to the edge of the network and not restricted by location, whereas centralised ESS tends to be larger units, in smaller numbers, and connected to the transmission network. By definition, PHES is considered as a centralised ESS, and P2G plant is a decentralised ESS. The CAES plant would be deemed a centralised ESS if it had an underground cavern to store the compressed air and a decentralised unit if the air storage is by vessel or pipe. The capacity of above ground CAES storage is very small, 3-15 MW or 2- 4 h of discharge (Evans, Strezov, and Evans 2012). In this study CAES is assessed at large scale associated with subterranean geological caverns. If the locations of PHES plants and CAES cavern plants are far from the energy generation sites, the efficiency will be reduced due to transmission losses.

Both P2G and CAES systems can be deployed at smaller scale (100 kW) up to a large scale (tens of megawatts). This allows facilities to be sized optimally with regards to grid requirements and available resources.

3.3.4 Storage capacity

The availability of existing gas infrastructure offers high energy storage capacity for P2G technology. Gas storage capacity is up to 10 TWh and discharge times of 10,000 hours. The storage capacity of PHES and CAES are up to 100 GWh and 1 GWh, with discharge times of 1,000 and 100 hours, respectively (Persson et al. 2014).

3.3.5 Energy carrier vectors

The electricity generated and stored will be converted back to the electricity post-storage for both PHES (Rehman, Al-Hadhrami, and Alam 2015) and CAES (Elmegaard and Brix 2011) processes. However, with P2G, the electricity can be stored as a gas for heating, renewable transport fuel or potentially converted back to electricity. Thus, P2G offers diversity in terms of energy carrier vector compared to PHES and CAES. Furthermore, in contrast to PHES and CAES, where the charging and discharging are in the same location, renewable gas generated from P2G-methane can be easily transported over the long distances through a country's gas grid network with minimum losses of gas and no energy input. The end user simply has an account with the gas producer and withdraws the same amount of natural gas that is inserted by the renewable gas energy producer. The transmission grid is such that capacity is not a problem for gas grid injection and the scale of the gas grid is such that storage of the renewable gas is not a problem. This is not the case with electricity, which is why a storage mechanism is required.

3.3.6 Environmental issues

3.3.6.1 PHES

The construction of new PHES plants requires tunnels, dams and storage lakes to be built. Different types of PHES plant will have different infrastructure requirements, for example, artificial reservoirs and lake impoundment are needed for closed – loop plants. Dams are typically used in open or semi-open systems, while artificial reservoirs are used in semi - open systems. Environmental issues arising in PHES

development plants are unavoidable. In the US, proposed PHES projects have previously been blocked by environmental groups (Yang and Jackson 2011).

The environmental impacts of PHES projects are generally the same impacts of that arising from hydro power plants (Monica 2000), concerning biodiversity, fisheries, water resources and water quality. Hydrology and hydrogeology impacts are linked to the construction of reservoirs, dams, tunnels and caverns. Among the three modes of PHES, closed - loop PHES plants have fewer environmental impacts as they do not interfere with the natural flow of the river, or degrade existing aquatic habitats. Thus, such projects are more acceptable to resource agencies, environmental groups and the general public. In US, of the 36 proposed PHES projects, 29 were closed-loop/off stream design (Yang and Jackson 2011).

Denholm et al. (2004) used LCA to analyse the greenhouse gas emission from PHES and concluded that the CO₂ emissions equivalent from the PHES construction process and operation was 35.7 tons per MWh storage capacity and 0.5 g per MJ, respectively, with a project lifetime assumption of 60 years. For contrast the full life cycle analysis of petrol and diesel is typically assessed as 88g CO₂/MJ.

3.3.6.2 P2G

In contrast to PHES plants, P2G plants do not have extensive environmental impacts on ecology, land use or habitat in the construction period, due to the flexibility of site location. The water consumption of P2G is also low; for each MW_eh input, 200 L water is utilised (Sterner 2009). When methane is burned in a combined heat and power system, steam is released in a closed water circle, with little impact to the

environment. In the P2G-methane process, bound CO₂ will be emitted when methane is converted to final energy. However, in the idealised application of P2G in conjunction with biogas upgrading, the CO₂ would have been emitted anyway and thus no significant emissions contribution would result. Little research has been conducted on the LCA of P2G system construction. In this study, a CO_{2eq} emissions of 3.78kgCO_{2eq}/MWh for the construction process (Boer 2012) was used. If the CO₂ was taken from the flue gas of a coal power plant via amine scrubbing, the global warming potential (GWP) would be 23kg CO₂ eq/MJ higher than the GWP resulting from CO₂ taken from biogas upgrading (Reiter and Lindorfer 2015b). The electricity generation source for P2G processes is another important factor when GWP is considered. Reiter et al. (Reiter and Lindorfer 2015b) suggested that the electricity used to produce hydrogen gas has its own GWP below 190g CO₂/kWh (hydrogen), and that electricity used to produce methane has its own GWP below 113g CO₂/kWh (utilizing CO₂ from waste products) and 73g CO₂/kWh (utilizing CO₂ from the other sources). Thus, suitable electricity sources for P2G include: photovoltaics; hydropower; biogas CHP; and onshore/offshore wind farms (Jentsch, Trost, and Sterner 2011). It was also stated that if the electricity input to run P2G is from wind energy, the GWP is 6g CO₂ eq/MJ (if CO₂ is from waste product) and 29g CO₂ eq/MJ (if CO₂ is from fossil source). If the electricity input from electricity is equivalent to the mix of the EU-27 countries (the European network of transmission system operator for electricity), the GWP is 276g CO₂ eq/MJ (CO₂ as waste product) and 299g CO₂ eq/MJ (CO₂ from fossil source). It may be summarised that P2G-methane has a variable GHG emission depending on the source of electricity, depending on the source of CO₂ and of the alignment of the

system. Ideally the electricity is from renewable electricity that would be curtailed due to times of excessive production (Gonzalez et al. 2004) and the CO₂ would be from biogas and the alignment would use methanation to upgrade biogas.

3.3.6.3 CAES

Environmental impacts in the construction phase of CAES plants are primarily related to geological impacts in cavern formation. Furthermore, the sites of diabatic CAES plants are not flexible, thus construction activities affect the surrounding environment. For operational periods, due to its features, adiabatic CAES plants would not cause any environmental impacts. Conversely, diabatic CAES plants use fossil fuels for combustion resulting in pollutants such as CO₂, NO_x and SO_x being emitted, although only one third of the fuel is required compared to that of a conventional combustion turbine (Beckwith 1983, Wänn et al. 2012). The CO_{2eq} is taken as 80 g/MJ for the CAES operation and 19 tons/MWh for the construction process (Denholm and Kulcinski 2004).

The water used in the operational stage of diabatic CAES is required for cooling compressed air before storage, for cooling lubricating and for compensation. The water requirement will vary depending upon the cooling method chosen (Beckwith 1983).

3.3.6.4 Comparison of CO_{2eq} emissions

The development of PHES plants will have a more serious environmental impact than that the development of CAES and P2G plants. Construction of P2G plants will have

the least impact on the environment. The CO_{2eq} emission from construction and operation period of PHES, P2G and CAES are summarised in Table 3-6.

Table 3-6. CO_{2eq} emissions from PHES, P2G and CAES

	Construction period (g/MWh)	Operation period (g/MJ)	References
PHES	35,700,000	0.5	(Denholm and Kulcinski 2004)
P2G	3780	6	(Boer 2012)
Diabatic CAES	19,000,000	80	(Denholm and Kulcinski 2004)

The development of a PHES plant emits almost double the amount of CO_{2eq} than that of a CAES plant. P2G development plant has significantly reduced greenhouse gas emissions in terms of CO₂ eq/MWh installed capacity compared to both PHES and CAES in the construction phase. In operation, PHES has the smallest emissions footprint as a technology (Table 3-6). In contrast, natural gas is burned in diabatic CAES plants to heat the air up. If the CO₂ source is from biogas, the production of methane in P2G is low at 6g CO₂ eq/MJ (assuming the electricity input is from wind energy).

3.4 Multi-criteria decision analysis for sustainability assessment

3.4.1 Performance measures

The results of comparing single criteria are summarised in the performance matrix table (Table 3-7). To avoid anticipated future comparisons, only the current data for P2G, PHES and adiabatic CAES were used for the multi criteria decision analysis. Thus,

future P2G and adiabatic CAES systems are not considered in the MCDA. Moreover, the costs and efficiency data are in the range, thus maximum data were used to compare in this study. Using the data in Table 3-7 and following the normalised method presented in 3.2.1.2, the normalised data was calculated and is presented in (Table 3-8). Values are reported between 0 and 1; the closer the value is to 1 the better the outcome.

3.4.2 Weighted data

The weighted data from individual participants was compiled and normalised into a range 0-1. The data was then analysed using the Huang et al. method (weighting for criterion – weighting method section). The standard deviation between criteria was highest for researchers 2 and 3 and lowest for researchers 5 and 9. This meant that researchers 2 and 3 had a greater preference difference between criteria and could differentiate between them more decisively. In contrast, the preference difference among criteria for researcher 5 and 9 were small. Analysing the preferential priority data indicated that most the researchers' opinions listed the parameters in the following order: cost; environmental impacts; efficiency; CO_{2eq} emission; storage capacity; position flexibility; energy carrier (Table 3-9). Taking account of the standard deviation, preference priority of each criterion (Table 3-9) and skewness and applying the Huang et al. method, the criteria weights for energy storage are evaluated and presented in Table 3-10. The original data reported in Table 3-10 is the respective average for each criteria value in Table 3-9.

Table 3-7. Performance matrix table in contrasting P2G, PHEs and CAES

Criteria		P2G		PHES	CAES	
		Current	Future		Diabatic	Adiabatic
Costs	Capital costs	€ 900-3240/kWe \$1260-4536/kWe	€1000/kWe (\$1400/kWe)	€500-2000/kW _e (\$700- 2800/kWe)	€450-1000 /kW _e (\$630-1400/kWe)	€600-1200 /kW _e (\$840- 1680/kWe)
	Operation and management costs (%)	3	3	1-2	0.6-2	
Efficiency (%)		60	65-91	70-85	40	70-80
Energy carrier vectors		3 vectors (Hydrogen, methane, electricity)		1 vector (Electricity)	1 vector (Electricity)	
Storage capacity		Up to 10TWh		Up to 100GWh	Up to 1GWh	
Discharge time		10,000 hours		1,000 hours	100 hours	
Position flexibility		Flexible		Not flexible	Not flexible	N/A
CO _{2eq} emission from construction period (CO _{2eq} /MWh)		3.78 kg	N/A	35.7tonnes	19.4 tonnes	N/A
CO _{2eq} emission from production period (gCO _{2eq} /MWh)		6		0.5	80	
General environment impacts		Minor environmental impacts		Variety of serious environmental impacts ^a	Normal environmental impacts	

^aBiodiversity, fisheries, water resources, water quality, hydrology and hydrogeology impacts associated with the construction of reservoirs, dams, tunnels and caverns.

Table 3-8. Normalised data of performance matrix table in contrasting P2G, PHEs and CAES

Criteria		Current P2G	PHEs	Diabatic CAES
Costs	Capital costs	0.00-0.72	0.38-0.85	0.69 - 0.86
	Operation and management costs (%)	0.00	0.33-0.67	0.33 – 0.8
Efficiency (%)		0.71	1	0.44
Energy carrier vectors		1	0.33	0.33
Storage capacity		1	0.01	0.00
Discharge time		1	0.10	0.01
Position flexibility		1	0.5	0.5
CO _{2eq} emission from construction period (CO _{2eq} /MWh)		1	0.00	0.46
CO _{2eq} emission from production period (gCO _{2eq} /MWh)		0.93	0.99	0.00
General environment impacts		1	0.00	0.5

Note: The normalised value may be obtained as in the following example: Efficiency is benefit value, therefore efficiency for P2G is 60%, for the best case scenario is 85%, thus the normalised value is $60/85 = 0.71$.

For cost and CO_{2eq} emission value, the lower is the better. If the capital cost of P2G is €900/kWe, the maximum cost for P2G, PHEs and CAES is €3240/kWe, therefore the normalised value is $1 - 900/3240 = 0.72$.

Table 3-9. Normalised weighted for energy storage technologies

Criteria	Researcher										δ_i
	1	2	3	4	5	6	7	8	9	10	
Cost (capital, operation and management costs)	1	1	0.6	1	0.6	1	1	0.6	1	1	0.22
Efficiency	0.8	0.6	1	0.8	0.8	0.8	0.8	0.8	0.8	0.6	0.14
Energy carrier vectors (electricity or gas)	0.4	0.4	0.6	0.6	0.6	0.4	0.6	0.6	0.6	0.8	0.09
Storage capacity and discharge time	0.8	0.4	1	0.8	0.8	0.6	0.8	0.6	0.8	0.4	0.13
Position flexibility	0.6	0.2	1	0.6	0.6	0.6	0.8	0.4	0.6	0.6	0.11
CO _{2eq} emission	1	0.8	0.2	1	0.8	0.2	0.6	0.8	0.8	0.6	0.14
General environment impacts	0.8	1	1	0.6	1	0.2	0.4	1	1	0.4	0.18
Standard deviation (θ_k)	0.20	0.29	0.29	0.17	0.14	0.28	0.18	0.18	0.15	0.20	

δ_i : Preference priority of each criterion

Applying the Huang et al. method, the criteria weights can be seen to be more diverse (0.11 - 0.71) than those reported from the original data (0.60 - 0.88). The cost criterion is considered the most important factor in choosing any energy storage method, followed by efficiency for both the Huang et al. method and the original data. General environmental impacts and storage capacity/discharge time are ranked as joint third most important criteria in the Huang et al. method. The original data differs in that general environmental impact has a higher weight than that of storage capacity/discharge time. Energy carrier vectors (electricity or gas) were assessed as the least important criterion in choosing any energy storage. However, for some countries such as Ireland, where electricity demand is half of transport as well as thermal sector energy demand (Murphy and Thamsiroj 2011), the ability to transform the electricity storage to biofuel or gas is an enabling factor in deciding the energy storage method.

Table 3-10. Criteria weights in energy storage (P2G, PHES and CAES)

Criteria	Huang et al. method	Original data from this study*
Cost (capital, operation and management costs)	0.71	0.88
Efficiency	0.69	0.78
Energy carrier vectors (electricity or gas)	0.11	0.56
Storage capacity and discharge time	0.59	0.7
Position flexibility	0.27	0.6
CO _{2eq} emission	0.46	0.68
General environment impacts	0.59	0.74

* Average for each criteria value in Table 3-8.

Considering all researchers have equal importance in making a decision and taking the criteria weight results from the Huang et al. method (Table 3-10) and the normalised performance measures data in Table 3-8 and applying Eq. (3-1), the final preference values for P2G, PHES and CAES can be calculated at 4.03, 2.46 and 2.16, respectively.

The analysis of assessment results of each researcher by taking normalised weighted data in Table 3-2 and normalised data of performance matrix (Table 3-8) then applying Eq. (3-1) also indicates that the P2G system is preferred and PHES and CAES are ranked as second and third, respectively (**Error! Reference source not found.**). Thus, from a sustainable development perspective, P2G is shown to be superior to both PHES and CAES technologies.

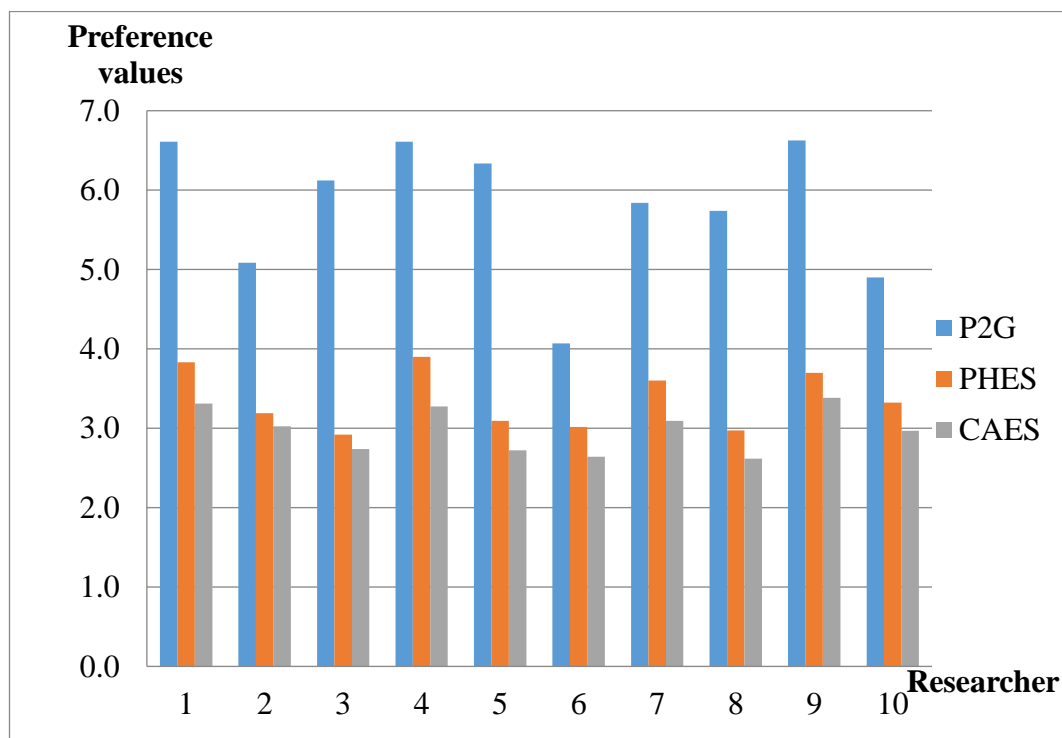


Figure 3-2. Selection of each researcher on sustainable energy storage

3.5 Sensitivity analysis

Given costs are ranked as the most important criteria and costs are variable, the sensitivity analysis in this study focused on the variation of the costs. It is assumed that the P2G technology is a new technology, therefore the capital cost is still high in the future, and meanwhile the PHES and CAES capital costs are low. Thus, the sensitivity analysis compared the highest capital cost of P2G with the lowest capital costs of PHES and CAES, other criteria were not changed. The results showed that the final preference values of P2G, PHES and CAES are 3.5; 2.5 and 2.2, respectively, which means the P2G technology was assessed as the most sustainable technology even with the cost of this technology still high.

3.6 Limitation and future works

As with any multi criteria decision analysis studies, the limitations exist in the assignment of weights to each criterion with respect to the objective. The weights are affected by a particular person's point of view. Furthermore, due to the shortage of future data for each storage technology, the current performance of each technology is used in this chapter. This may not reflect the future performance due to technology development in the interim period. Future work can update upon this approach to consider the problem in more detail using more sub-criteria.

3.7 Conclusions

If the criteria of electricity storage technologies are compared separately and only the investment cost or the efficiency is considered, PHES will be chosen. However, in

terms of sustainable development, which is identified through the MCDA model by assessing performances of seven criteria and evaluating the importance of those criteria to sustainable development objectives, P2G is assessed as the most sustainable. Thus, the results indicate clearly which future energy storage that the decisions and policy makers should consider for a sustainable development. Most of the previous studies only applied the single MCDA method. This chapter was conducted by integrating the individual weights into the group representative that always happen in reality

Chapter 4 Use of surplus wind electricity in Ireland to produce compressed renewable gaseous transport fuel through biological power to gas systems¹

Abstract

Power to gas (P2G) may be used to store curtailed electricity whilst converting the energy vector to gas. To be economically viable these systems require cheap electricity and a cheap concentrated source of CO₂. Biogas produced from anaerobic digestion typically comprises of 60% methane and 40% CO₂. The P2G system substitutes for the conventional upgrading system by using hydrogen (derived from surplus wind electricity) to react with CO₂ and increases the methane output. The potential CO₂ production from biogas in Ireland associated with typical wet substrates is assessed as more than 4 times greater than that required by the potential level of H₂ from curtailed electricity. Wind energy curtailment in 2020 in Ireland is assessed conservatively at 2175GW_eh/a. Thus, P2G is limited by levels of curtailment of electricity rather than biogas systems. It is shown that 1 GW_eh of electricity used to produce H₂ for upgrading biogas in a P2G system can affect a savings of 97 tonnes CO₂. The cost of hydrogen is assessed at €0.96/m³ renewable methane when the price of electricity is €c5/kW_eh. This leads to a cost of compressed renewable gas from grass of €1.8/m³. This drops to €1.1/m³ when electricity is purchased at €c0.2/kW_eh.

¹ Chapter based on the published article: Vo, T.T., Xia, A., Wall, D.M. and Murphy, J.D., 2017. Use of surplus wind electricity in Ireland to produce compressed renewable gaseous transport fuel through biological power to gas systems. *Renewable Energy*, 105, pp.495-504

4.1 Introduction

4.1.1 The need for storage of intermittent renewable electricity

Ireland's target is to achieve 40% renewable energy supply of electricity by 2020 (Sustainable Energy Authority of Ireland 2012), 12% renewable energy supply in heat and 10% renewable energy supply in transport (Persson et al. 2014). Within its renewable energy targets, Ireland has set a target of 500MW_e of ocean energy capacity by 2020 (Department of Jobs 2013). In 2012 wind energy and biomass provided 74% and 8% of the renewable electricity of the country, respectively (Persson et al. 2014).

McGarrigle et al. (Mc Garrigle, Deane, and Leahy 2013) stated that wind turbines are expected to produce 37% of the electrical energy needs of the island of Ireland in 2020, whereas the existing hydroelectric plants and other forms of renewable electricity generation will generate only 3% of the total electricity. The characteristics of marine renewable electricity are intermittent and fluctuating. In order to provide system security, sometimes wind energy needs to be dispatched down. A total of 196 GW_eh of energy from wind farms was estimated to be dispatched down in 2013; this is an increase of 86 GW_eh compared to that of 2012 (EirGrid and SONI 2014).

Currently, Ireland's solution for intermittent energy is grid interconnection with Great Britain. Connolly (Connolly 2007) highlighted that Denmark also has a similar approach for grid stability by selling wind power when excess power is available and buying power when it is needed. However, this approach is expensive as the electricity sales are cheaper than electricity purchase. If Ireland considers Great

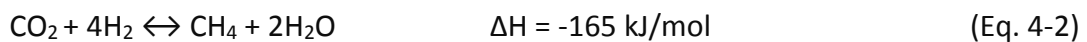
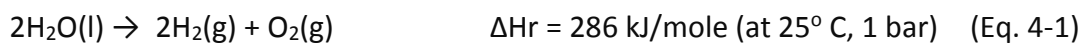
Britain as an energy storage source, this policy will involve the purchase of expensive electricity. If interconnection is also utilized to integrate wind power onto the grid, then Ireland's green power could be used to reduce the CO₂ emissions of Great Britain rather than Ireland (Connolly 2007). Therefore, new electrical storage systems are required for future energy security in Ireland.

4.1.2 Biological power to gas systems

Power to gas (P2G) is a method to convert electrical power to gaseous fuel in the form of hydrogen or methane. Large amounts of hydrogen addition to natural gas may change the combustion properties of natural gas, reduce the Wobbe Index of the gas, and not integrate sufficiently with the natural gas grid (Grond, Paula, and Johan 2013). Many countries have extensive infrastructure systems for methane distribution. Distribution and use of methane are far more readily available than hydrogen based on the current infrastructure.

At present, P2G technologies have high capital cost and relative low efficiency. However, one of its advantages is the diversification of the final products; gas produced may be used for heating, as a gaseous fuel for transport or be converted back to electricity when demand for electricity is high. Murphy and Thamsiroj (Murphy and Thamsiroj 2011) stated that the final energy demand in the transport and thermal sectors is each approximately 40% of total demand; the demand for electricity is of the order of 20% in Ireland. Therefore, the diversification of energy carrier vectors could meet the demand for green transport and thermal demand.

A study conducted by the International Energy Agency (IEA) Bioenergy Task 37 (Persson et al. 2014) concluded that P2G would be an optimal route to produce renewable transport fuel from surplus electricity. In order to produce methane, electricity is first converted to hydrogen through electrolysis as shown in Eq. (4-1). CO₂ is then combined with hydrogen to produce methane by the Sabatier reaction as shown in Eq. (4-2) (Buchholz et al. 2014). The efficiency of electrolysis process is based on the technologies. The efficiency of alkaline electrolyses and polymer electrolyte membrane electrolyzers vary from 55- 84% (Troncoso and Newborough 2011, Gahleitner 2013). Additionally, the efficiency of solid oxide electrolyzers is the range of 90-95% (Ahern et al. 2015). Therefore, this chapter assumed 75% is efficiency of electrolyser as in Ahern et al. (Ahern et al. 2015).



There are two methods to produce methane: chemical and biological methanation. The principles of the two methods are based on Eq. (4-2). Chemical methanation requires that the input CO₂ is free from impurities (such as siloxanes); however, biological methanation requires less stringent quality and may use the CO₂ in raw biogas derived from anaerobic digestion to produce methane (Götz et al. 2016). As such this acts as an upgrading process of biogas to biomethane.

The biological methanation process is an anaerobic process in which carbon dioxide and hydrogen are used by a group of microorganisms (hydrogenotrophic methanogenic archaea) to produce methane. This process happens at much lower

temperatures than for chemical methanation: the mesophilic and thermophilic processes are usually conducted under 20-40°C and 45-60 °C, respectively (Grond, Paula, and Johan 2013). "In-situ" and "ex-situ" biogas upgrading are two methods for biological methanation. When H₂ is introduced into the main anaerobic reactor this is known as the "in-situ" method (Díaz et al. 2015, Bensmann et al. 2014); the methane content can be increased from ca. 50% to 75% (Benjaminsson, Benjaminsson, and Rudberg 2013). When the biogas and the H₂ react in a separate reactor (filled with hydrogenotrophic methanogenic archae), a high methane content (up to 98%) can be achieved; this is known as an "ex-situ" process (Burkhardt, Koschack, and Busch 2015).

4.1.3 Biogas production and biogas upgrading methods

Biogas consisting of CH₄ (40-75%) and CO₂ (25-60%) can be produced from a broad range of feedstocks including organic fraction of municipal solid waste (OFMSW) (Browne, Allen, and Murphy 2014, Browne and Murphy 2013, 2014), agriculture slurries (Singh, Smyth, and Murphy 2010), grass (Smyth, Smyth, and Murphy 2011, Murphy and Power 2009, Smyth, Murphy, and O'Brien 2009) or seaweed (Allen et al. 2014). In order to be fed into the existing natural gas network or to be utilised as biofuel, biogas needs to be upgraded to remove contaminants and CO₂ (Pettersson 2009). Absorption (water scrubbing, organic solvent scrubbing, chemical) and adsorption (pressure swing adsorption) are two traditional methods for upgrading biogas. However, those processes have high costs and the sustainability may be affected by the discharge of small amounts of methane in the upgrading step (Luo and Angelidaki 2012). Biological methanation can potentially provide an alternative

method for the upgrading of biogas produced from a digester. The methane content after the “in-situ” methanation process is 75%, therefore gas upgrading (to remove CO₂) and gas cleaning (to remove impurities such as water and H₂S) is required. The methane content after the “ex-situ” process can reach 98%, consequently only gas cleaning is required. Thus, renewable gas (biomethane) from an “ex-situ” biological methanation process will be assessed in this chapter. A schematic of the process is shown in Figure 4-1.

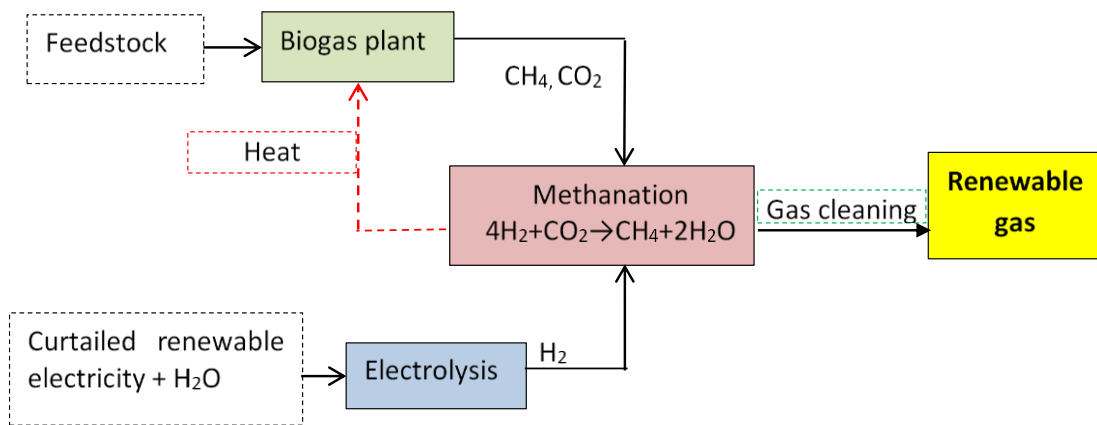


Figure 4-1. Design of biological P2G system as a biogas upgrading process

4.1.4 Potential gaseous fuel market in Ireland

Compressed natural gas (CNG) is a gaseous transport fuel stored under high pressure (ca. 250 bar). Approximately 18 million natural gas vehicles (NGVs) are used worldwide, with 1.9 million NGVs located in Europe. Owing to a lack of service stations to serve NGVs or policy to promote their use, there is no NGV industry in Ireland. However, Gas Networks Ireland (GNI), the owner and operator of the gas network in Ireland, are actively promoting the use of CNG fuel for transport. A target of 5% has been set for the commercial transport market (16,000 vans), 10% for buses

(1,130 buses) and 10% for trucks (2,720 trucks) in Ireland to operate on CNG by 2020 (Cottrell B. 2014, Twomey D. 2011). It is envisaged that this target will create a gas demand for NGVs of ca. 305 Mm³/year equating to 11.6 PJ of energy (DKM economic consultant 2011).

4.1.5 Rationale and objectives of the research

The aim of this chapter is to expand upon research assessing the combination of curtailed renewable electricity and CO₂ sourced from anaerobic digestion as a method of upgrading biogas using biological P2G systems and providing a source of renewable transport fuel. Previous studies have explored the reduction of greenhouse gas (GHG) emissions when biomethane (upgraded biogas) is used to replace fossil diesel fuel (Smyth et al. 2010, Korres et al. 2010, Ryan and Caulfield 2010, Krupnick 2010, Thamsiroj and Murphy 2011, Bacenetti et al. 2014). However, assessing the GHG reduction associated with biological P2G systems combined with biomethane production from a digester as a substitute for diesel transport fuel has not been assessed.

The cost of renewable gas originating for P2G systems has been reviewed (Götz et al. 2016) and examined (Benjaminsson, Benjaminsson, and Rudberg 2013). However, these studies considered the methanation process as a separate entity, and did not consider the upgrading of biogas in anaerobic digestion using a biological P2G process. Ahern et al. (Ahern et al. 2015) undertook an initial examination on financial sustainability of P2G such as the cost of hydrogen; the cost of carbon capture; revenue from sale of renewable gas as a transport fuel; and financial viability.

However, the costs of renewable gas from different digestion feedstocks have not been assessed. This chapter seeks to fill these gaps by:

- Examining the quantity of CO₂ associated with potential levels of biogas in Ireland;
- Determining the limiting factor for power to gas: curtailed electricity or CO₂ from biogas;
- Determining the potential gaseous transport fuel resource associated with biological power to gas systems in Ireland;
- Calculating the GHG savings associated with renewable gas;
- Calculating the combined cost of renewable gas and biomethane produced from biological power to gas systems for a range of feedstocks.

4.2 Methodology

4.2.1 Wind energy curtailment

Wind energy needs to be curtailed due to: (i) system stability requirements (synchronous inertia, dynamic and transient stability); (ii) operating reserve requirements, including negative reserve; (iii) voltage control requirements; (iv) morning load rise requirements and (v) system non-synchronous penetration (SNSP) limit (SNSP limit is constraint on non- synchronous penetration, in which SNSP is calculated as $SNSP = \frac{\text{wind generation} + \text{high voltage direct current imports}}{\text{system demand} + \text{high voltage direct current exports}}$) (Mc Garrigle, Deane, and Leahy 2013).

The total wind energy curtailment used in this study is based on the work of McGarrigle et. al (Mc Garrigle, Deane, and Leahy 2013) where it was suggested that

7-14% of electricity from wind could be curtailed in Ireland by 2020. This was based on SNSP limits of 70% and 60%, respectively. The total H₂ produced was modelled based on the energy curtailment as input to the electrolysis process (Mc Garrigle, Deane, and Leahy 2013).

4.2.2 Environmental benefits

The environmental benefits considered in this chapter are the GHG emissions (CO_{2eq}) saved when CO₂ from biogas is combined with H₂ to produce methane. The short term CO₂ in the biogas, which would have been released in the upgrading process will be reused to produce methane and thus displace fossil diesel.

4.2.2.1 CO_{2eq} saved from biogas upgrading process

The CO_{2eq} saved from the biogas upgrading process was calculated by Eq. (4-3):

$$E = E_1 - E_2 \quad (4-3)$$

Where:

E: GHG (CO_{2eq}) saved

E₁: CO₂ in biogas used to combine with H₂ to produce CH₄

E₂: CO_{2eq} emitted from P2G process (from life cycle assessment of P2G process).

The CO_{2eq} from electricity production from wind was included as a part of P2G process.

4.2.2.2 CO_{2eq} saved from replacement of fossil diesel fuel

The projected 2020 transport fuel demands for heavy vehicles in Ireland are dominated by diesel fuel (Irish academy of Engineering 2013). Therefore, this chapter

focused on analysing the replacement of diesel by renewable gas (the biomethane produced from the combination of the biogas plant and biological P2G process). Five digestion feedstocks for biomethane production were considered – grass, pig slurry, slaughter house waste (SHW), seaweed and OFMSW. Lifecycle assessment results from literature were collected in order to determine GHG emissions in replacing diesel with renewable gas. The "Well to Wheel" life cycle assessment includes emissions associated with fuel production, processing, transportation, distribution and consumption. The EU Renewable Energy Directive of 2009 (Official Journal of the European Union 2009) states that biofuel emissions are calculated as zero due to balancing the amount of carbon released with an equivalent amount sequestered, therefore such emissions were not considered. The total CO_{2eq} saved when the total CH₄ produced is used to replace diesel fuel was calculated by using Eq. (4-4):

$$E_d = E_9 - E_4 - E_5 - E_6 - E_7 - E_8 + E \quad (4 - 4)$$

Where:

E_d: CO_{2eq} saved when CH₄ replaces fossil diesel fuel;

E₄: CO_{2eq} emitted from processing of substrate, transport and distribution of biogas from domestic and organic fraction of municipal solid waste (OFMSW);

E₅: CO_{2eq} emitted from collection and processing of substrate, transport and distribution of biogas from agricultural slurries;

E₆: CO_{2eq} emitted from collection and processing of substrate, transport and distribution of biogas from slaughter waste;

E₇: CO_{2eq} emitted from cultivation and processing of substrate, transport and distribution of biogas from grass;

E₈: CO_{2eq} emitted from cultivation and processing of substrate, transport and distribution of biogas from seaweed;

E₉: CO_{2eq} emitted when diesel fuel used.

The CO_{2 emission} from well to wheel of diesel fuel was calculated through Eq. (4-5):

$$E_9 = \text{MJ fuel used} \times \text{gCO}_{2\text{eq}}/\text{MJ} \quad (4-5)$$

E: The CO_{2eq} saved from the biogas upgrading process (Eq. 4-3)

4.2.3 Economic benefits

The economic benefits were analysed in three areas:

- Total money saved through CO_{2eq} reduction when renewable gaseous fuel replaces diesel fossil fuel;
- Total money saved through reduction in wind energy curtailment;
- Comparison of the costs of biomethane produced from conventional upgrading and in a biological methanation system (renewable gas).

In order to compare the cost of biogas with conventional upgrading and upgrading via biological methanation, the methodology and data from the study of Browne et al. (Browne et al. 2011) was used in this chapter. The operational costs of the biogas plant do not change according to scale and are summarised in Table 4-1.

Table 4-1. Assumptions for calculating biomethane costs - adapted from (Browne et al. 2011)

	Grass	Pig Slurry	SHW	OFMSW
CH ₄ content in biogas	55%	65%	55%	60%
CO ₂ content in biogas	45%	35%	45%	40%
m ³ biomethane yield/tonne feedstock	59.4	14.4	41	66
Technology used	CSTR*	CSTR	CSTR	Batch process
Maintenance and overhead	€5/t	€5/t	€10/t	€25/t
Digestate disposal				€4/t
Electrical demand of biogas plant	10 kW _e h/t	10 kW _e h/t	10 kW _e h/t	6 kW _e h/t
Cost of feedstock	€17/t			
Storage pit	€30/t			
Gate fee			€20/t	€70/t
Compression and distribution cost	€0.149/m ³	€0.149/m ³	€0.135/m ³	€0.149/m ³
Interest rate	6%/a			
Life time	15 years			
Cost of electricity	€0.15/kWeh			
Gas grid connection	€300,000			
CNG service station	€500,000			

*. CSTR: Continuously stirred tank reactor

4.3 Results and discussion

4.3.1 The sources of CO₂ from biogas

Ahern and co-workers (Ahern et al. 2015) assessed potential feedstocks (agricultural slurries, SHW, grass and OFMSW) for renewable gas in Ireland as 7.4 Mtonnes/a.

These feedstocks can produce 430 Mm³ CO₂/a (58 m³ CO₂/tonne feedstock) as a by-product of anaerobic digestion as illustrated in Table 4-2. This represents a significant available resource of concentrated CO₂ in Ireland.

Table 4-2. Quantifying the CO₂ resource from anaerobic digestion of selected substrates in Ireland - adapted from (Ahern et al. 2015)

	Agricultural Slurries	Slaughter Waste	OFMSW	Grass	Total
Feedstock (Mt/a)	2.79	0.21	0.22	4.16	7.38
CH ₄ from Anaerobic Digestion (AD) (Mm ³ /a)	49.76	18.08	14.98	447.59	530.41
Practical resource from AD (PJ/a)	1.88	0.68	0.57	16.07	19.20
% CO ₂ in biogas	45	45	35	45	-
CO ₂ from AD (Mm ³ /a)	41	15	8	366	430

The gas volume in this chapter is expressed under standard temperature (0°C) and pressure (1 atm). For the purposes of this study, the following section will analyse in detail the potential CO₂ content in biogas from seaweed for the benefit of the reader.

Burton et al. suggested a total area of 700 ha for seaweed cultivation in Ireland by 2020 (Burton et al. 2009). It is assumed forty tonnes of seaweed (on a wet weight basis) may be produced per hectare per annum. *Laminaria* species in Cork was found to comprise of 10.34% volatile solids (VS) (Murphy et al. 2015). The methane yield from *Laminaria* species was assessed at 238 L CH₄/kg VS (Adams et al. 2011). Thus, the methane yield may be calculated as 24.6 m³ CH₄/tonne feedstock with the ratio of CH₄ to CO₂ in the biogas at 55%:45%. Using these figures, the potential biogas and analysis of the P2G system from the seaweed feedstock is summarised in Table 4-3.

It should be noted that the seaweed productivity used is a conservative value based on the current available technology; a much higher value may be achieved if advanced cultivation technologies are applied (Xia, Cheng, and Murphy 2015). For examples, a high productivity may be achieved by using multilayer textile substrates for seaweed cultivation (<http://www.atsea-project.eu/>).

Table 4-3. Potential biogas and P2G production from seaweed (*Laminaria* species) in Ireland

Component	Data	Quantity	Unit
Potential area		700	ha
Seaweed cultivated per year	40tonnes wet weight/ha	$700*40 = 28,000$	tonnes/a
Total VS	10.34% VS	$28,000*10.34\% = 2,895$	tonnes/a
CH ₄ yield from biogas	238 L CH ₄ /kg VS	$2,895 \text{ tonnes} * 238 \text{ m}^3/\text{tVS} = 689,058$	m ³ /a
Energy content of CH ₄	Energy value of CH ₄ : 37.8 MJ/m ³	$689,058 * 37.8 = 0.026$	PJ/a
CO ₂ from anaerobic digestion	45% CO ₂ from biogas	$689,058 * 45\% / 55\% = 563,774$	m ³ /a
CH ₄ produced from P2G	1 CO ₂ ≈ 1 CH ₄	563,774	m ³ /a
CH ₄ produced from biogas and P2G from seaweed		1,252,832	m ³ /a
H ₂ required*	H ₂ required at 4 times the volume of CO ₂ eq.(4-2)	$563,774 * 4 = 2,255,098$	m ³ /a
Electricity required to make H ₂ for P2G system	H ₂ energy value of: 12MJ/m ³ efficiency: 75%	$2,255,098 \text{ m}^3/\text{a} * 12 \text{ MJ}/\text{m}^3 / (0.75) * 28 / 10^6 = 10$	GWh/a

Overall, the potential capacity of CO₂ from biogas in Ireland in the year 2020 would be 430.6 Mm³/a predominantly originating from agricultural slurries, slaughter waste, OFMSW and grass (Table 4-2); with just 0.6 Mm³/a from seaweed (Table 4-3). If the total CO₂ capacity is used for upgrading in a biological P2G process, ca. 7,654 GWh/a of electricity could be used in P2G systems (shown in Table 4-4). However, McGarrigle et al. (Mc Garrigle, Deane, and Leahy 2013) concluded that the installed capacity of wind turbines in Ireland by 2020 will be between 5,911 MW and 6,890 MW. If the curtailment rate is 14% and the capacity factor is 30%, the total wind energy that will be curtailed in 2020 is in the range of 2,175 – 2,535 GWh/a. In order to simplify this calculation, this chapter only analyses the benefits based on 2,175 GWh/a of curtailed wind energy in 2020. If the curtailed electricity was used to produce H₂ through an electrolysis process, the H₂ amount would be sufficient to combine with 28.4% of CO₂ from biogas of potential indigenous feedstock. Thus, P2G is limited by levels of curtailment of electricity rather than biogas systems.

Table 4-4. Potential storage capacity by methanation of CO₂ from biogas.

Components	Quantity	Unit
CO ₂ from AD	430.6	Mm ³ /a
H ₂ requirement	403.6*4 = 1722	Mm ³ /a
Energy value of H ₂	1722Mm ³ /12MJ/m ³ = 20,664	TJ/a
Electricity required to produce H ₂	20,664TJ*0.2778/0.75 = 7,654	GWh/a

Note: - Energy value of H₂: 12MJ/m³, 1GWh = 3.6 TJ; 1TJ = 0.2778GWh
 - Efficiency from power to H₂: 75%
 - H₂ volume is 4 times that of CO₂ according to Eq. (4-2)

4.3.2 Environment benefits

4.3.2.1 Greenhouse gas savings when CO₂ from biogas is utilised

The combination of CO₂ from biogas with H₂ creates additional value from CO₂ by utilising that CO₂ to produce biomethane in a biological methanation process. If wind energy curtailment in 2020 in Ireland (2,175 GWh/a) is used to produce hydrogen for a biological methanation process, then 211,450 tonnes CO_{2eq} (outlined in Box 4-1) would be saved annually. This means that for 1GWh of surplus wind energy used to produce hydrogen for upgrading biogas, approximately 97 tonnes CO₂ can be fixed from biogas in a P2G system.

4.3.2.2 CO_{2eq} savings when fossil diesel fuel is replaced by CNG.

The total CO₂ from the feedstock needed to combine with H₂ produced from surplus wind energy is 122 Mm³/a. The data from Table 4-2 shows that one feedstock source alone will not meet the demand of CO₂ for biological P2G. Therefore, it is assumed that the CO₂ will be sourced from biogas from SHW, OFMSW, agricultural slurries (Table 4-2) and seaweed (Table 4-3). The remainder (57.4 Mm³/a) will be sourced from biogas from grass feedstock.

The efficiency of biomethane fuel at present is about 18-29% less than that of diesel fuel on a km/MJ basis (Korres et al. 2010, Adams and Home 2010). In this chapter, 20% lower efficiency of gaseous fuel than that of diesel fuel is used to calculate the total replaced diesel. It is expected that future vehicle efficiencies will improve.

Box 4-1. CO_{2eq} saved when CO₂ in biogas is utilized to produce CH₄

Assumptions:

- Efficiency from Power to H₂: 75%;

Calculations:

E₁- CO_{2eq} saved to produce CH₄ by biogas upgrading:

Sabatier equation: $4\text{H}_2 + \text{CO}_2 = \text{CH}_4 + 2\text{H}_2\text{O}$

2,175 GWh/a

Wind electricity curtailed in 2020:

7.83 PJ

H₂ produced from curtailed electricity:

$= (7.83 \text{ PJ}/12 \text{ MJ/m}^3) * 75\%$

$= 489 \text{ Mm}^3/\text{a}$

CO₂ required (H₂ : CO₂ ≈ 4:1):

$= 489 \text{ Mm}^3/4 = 122 \text{ Mm}^3/\text{a}$

$= (122 \text{ Mm}^3 * 1.96 \text{ kg/m}^3)/1000$

$= 239,120 \text{ tonnes/a}$

CH₄ produced from combination of CO₂ and H₂ 122 Mm³/a

process¹ (1 CO₂ ≈ 1 CH₄)

E₂ – Total CO_{2eq} emitted from P2G process = 122 Mm³* 37.8 MJ/m³ * 6 g

when producing CH₄:

CO₂/MJ = 27,670 tonnes CO_{2eq}/a

Total CO_{2eq} saved (**E**) through utilisation of CO₂ = 239,120 tonnes/a - 27,670

from anaerobic digestion in P2G and CH₄ used tonnes/a

as biofuel for transport²:

$= 211,450 \text{ tonnes CO}_2/\text{a}$

Notes:

- E was calculated as Eq. (4-3)

- Density of CO₂: 1.96 kg/m³; density of methane: 0.714 kg/m³

- Energy value of H₂: 12 MJ/m³; energy value of CH₄: 37.8 MJ/m³;

- CO_{2eq} emitted from producing CH₄ by catalyst P2G process: 6 gCO₂/MJ (Reiter and Lindorfer 2015b). The CO_{2eq} emitted from producing CH₄ by biological P2G is not available in literature. Thus, the GHG data of catalyst P2G is applied in this study.

The numbers may not sum exactly due to rounding.

¹ excluding CH₄ from biogas process.

² The CO₂ from the biogas plant will be released to the environment by conventional upgrading, therefore when it is utilised in combination with H₂, it is considered as CO₂ saved.

The calculation of GHG emissions ($\text{gCO}_{2\text{eq}}/\text{MJ}$) for conventional biogas production includes biomethane loss and biogas upgrading. However, the biological P2G process helps avoid biomethane slippage in upgrading systems as biogas upgrading is replaced by ex-situ biomethanation. Thus, the calculations of GHG emissions from biogas in this chapter do not include biomethane loss and GHG emissions from traditional biogas upgrading.

The Biograce GHG calculation tool (<http://www.biograce.net/home>) is used for demonstrating compliance with the sustainability criteria under Directives 98/70/EC and 2009/28/EC of the European Parliament and of the Council. In this tool, $\text{CO}_{2\text{eq}}$ from biogas upgrading including methane leakages by pressurized water scrubbing is 11.87 g/MJ . The $\text{CO}_{2\text{eq}}$ emitted from cultivation, processing, transport and distribution of biogas from OFMSW is 26.7 g/MJ and from wet manure is 26.1 g/MJ . Therefore, subtracting the upgrading emissions, calculation of GHG emissions from OFMSW and agricultural slurry derived biomethane were taken as 14.83 and $14.23 \text{ gCO}_{2\text{eq}}/\text{MJ}$, respectively, in this chapter.

The GHG emissions data of biogas from SHW is quite limited; only one study by Singh and Murphy (Singh and Murphy 2009) was found in the literature. However, the authors did not include emissions from transport and distribution as these processes will take place whether biomethane is produced or not. A figure of $31.42 \text{ kgCO}_{2\text{eq}}/\text{tonne}$ was reported, equating to $10 \text{ gCO}_{2\text{eq}}/\text{MJ}$ (using a biogas yield of $119.6 \text{ m}^3/\text{tonne}$ and energy content of biogas as 26 MJ/m^3), which would be emitted if slaughterhouse waste is utilized for biogas production. Korres et al. (Korres et al. 2010) suggested that the GHG emission savings of grass biomethane as compared to

diesel fuel (88.8 gCO_{2eq}/MJ) was 54.2% allowing for wind energy used in electricity production supplying parasitic demand, improved heating, improved vehicle efficiency and ignoring carbon sequestration in pasture land. This meant that the GHG emissions from grass biomethane was 40.7gCO_{2eq}/MJ. Removal of CO_{2eq} from biogas losses (10.82 gCO_{2eq}/MJ) and from biogas upgrading (12.64 gCO_{2eq}/MJ) (Korres et al. 2010), the total CO_{2eq} from grass biomethane used in this chapter was 17.24 gCO_{2eq}/MJ.

GHG emissions from seaweed biomethane was reported as 176 kgCO_{2eq}/tonnes dry seaweed [44], which equates to 35 gCO_{2eq}/MJ (at 133 m³ methane yield/tonne dry seaweed and energy content of methane at 37.8 MJ/m³); biomethane losses or biogas upgrading were not considered (Alvarado-Morales et al. 2013). Therefore, 35 gCO_{2eq}/MJ was used to calculate CO_{2eq} reduction from cultivation, processing, transport and distribution of biogas from seaweed. The GHG emission results of each feedstock type are shown in Table 4-5.

Table 4-5. Greenhouse gas emission from biogas of different feedstocks when biological P2G is used to upgrade biogas.

Feedstock	Greenhouse gas emissions (gCO _{2eq} /MJ)
Slaughterhouse waste	10
OFMSW	14.83
Agricultural slurries	14.23
Seaweed	35
Grass	17.24

Box 4-2 presents the results of the net GHG emissions saved when biomethane from digestion of feedstocks displaces fossil diesel fuel. The total methane produced from biological P2G is ca. 271 Mm³/a. Gas Networks Ireland have a target to fuel 10% of buses, 10% of trucks and 5% of commercial vans in 2020 (305 Mm³/a). Methane produced from biological P2G is sufficient to satisfy 89% of this target. If biomethane is used as a gaseous fuel to replace diesel fossil fuel, then 865,767 tonnes CO_{2eq} will be saved annually. This means the total CO_{2eq} reduction of biomethane compared with diesel fuel is 117%, which satisfies the requirement of the EU Renewable Energy Directive.

4.3.3 Economic benefits

4.3.3.1 Carbon tax

The sources of GHG emissions in Ireland are mainly from the non-emission trading sectors, in which agriculture accounts for 30.5%, energy industries emit 21.8% and transport 18.9% (Environment Protection Agency 2012). The Irish Environmental Protection Agency (EPA) stated that Ireland would not meet its EU 2020 targets for 20% GHG emission reduction (Irish Environmental Protection Agency). Ireland must rapidly decarbonise energy and transport to get further mitigation in GHG.

Box 4-2. CO₂ saved when fossil diesel fuel is replaced by biomethane and renewable methane

	CH ₄ from combination of CO ₂ and H ₂ (Box 4-1):	122 Mm ³ /a
	CH ₄ from anaerobic digestion (assume 55%CH ₄ : 45%CO ₂):	= (122 Mm ³ /a * 55%)/45% = 149 Mm ³ /a
		271 Mm ³ /a
	Total CH ₄ produced:	= (271 Mm ³ /a * 37.8 MJ/m ³)/10 ⁹ =10.24 PJ/a
	Energy content of biogas from OFMSW	0.57 PJ/a
E ₄	CO _{2eq} emitted from cultivation, processing, transport and distribution of biogas from OFMSW:	= 0.57 PJ/a * 14.83 gCO _{2eq} /MJ = 8,453 t/a
	Energy content of biogas from agricultural slurries	1.88 PJ/a
E ₅	CO _{2eq} emitted from cultivation, processing, transport and distribution of biogas from agricultural slurries:	= 1.88 PJ/a * 14.23 gCO _{2eq} /MJ = 26,752 t/a
	Energy content of biogas from slaughter waste	0.68 PJ/a
E ₆	CO _{2eq} emitted from production of biogas from slaughterhouse waste:	= 0.68 PJ/a * 10 gCO _{2eq} /MJ = 6,800 t/a
	Energy content of biogas from grass	2 PJ/a
E ₇	CO _{2eq} emitted from cultivation, processing, transport and distribution of biogas of from grass	= 2 PJ/a * 17.24 gCO _{2eq} /MJ = 34,480 t/a
	Energy content of biogas from seaweed	0.026 PJ/a
E ₈	CO _{2eq} emitted from cultivation, processing, transport and distribution of biogas of from biogas of seaweed:	=0.026 PJ/a * 35 gCO _{2eq} /MJ = 910 t/a
	Total diesel will be replaced:	= 10.3 PJ/a * 80% = 8.24 PJ/a
		260 ML/a
E ₉	CO ₂ emitted from diesel fuel (from well to wheel gCO ₂ /MJ):	= 8.24 PJ/a * 88.8 gCO _{2eq} /MJ =731,712 tonnes/a
E _d	CO ₂ saved when biomethane and renewable methane replace diesel fuel:	865,765 tonnes/a
Notes: - E _d = E ₉ - E ₄ - E ₅ - E ₆ - E ₇ - E ₈ + E Eq. (4- 4)		
- E _d = 731,712 - 8,453 - 26,572 - 6,800 - 34,480 - 910 + 211,450 (E from Box 4-1)		
- Energy value of Automotive Diesel Fuel: 36.8MJ/L; energy value of CH ₄ : 37.8 MJ/m ³ ;		
- The GHG emission of diesel fuel is 88.8 gCO _{2eq} /MJ (Murphy et al. 2011).		

According to Murphy et al. (Murphy et al.), energy demand of transport in 2020 will be 188 PJ/a. If CH₄ from biological P2G in this study is used as a renewable transport fuel (10.3 PJ/a), it would meet 5.5% of energy demand in the transport sector. A carbon tax of €20 per tonne of CO₂ emitted for transport fuels was stated in the Irish Governmental Budget of 2012 (Environment Protection Agency 2012). If the renewable methane produced from wind energy curtailment and CO₂ from anaerobic digestion replaces fossil diesel fuel around €17 million euros would be saved per year in carbon fines.

4.3.3.2 *Money saved through utilization of wind curtailment*

As mentioned in section 4.3.2.2, of the order of 2175GWh/a of wind energy will be curtailed in Ireland by 2020. Wind energy developers would not be paid for this. However, if this is used for P2G a monetary value for wind energy of 5c€/kWh could be achieved (Ahern et al. 2015), generating around €109 million annually.

4.3.3.3 *The costs of renewable gas*

The costs of renewable gas include the cost of hydrogen, the cost of methane from the biogas plant and the cost of biomethane from methanation. It is assumed that the gas is compressed to ca. 250 bar for use as a transport fuel and this cost is included for in the compression and distribution costs in Table 4-1.

- **Biomethane cost:** The costs of renewable gas include for capital expenditure (CAPEX) and operational expenditure (OPEX). This process is a combination of the biogas plant and the biological methanation system, and as such the CAPEX and OPEX for the two processes must be assessed.

According to Götz et al. (Götz et al. 2016), the size of biological methanation should not be greater than 5MW. If the capacity is higher than 5 MW, catalytic methanation is suggested as being more economical. Therefore, a 5MW biological methanation plant is used to calculate the capacity of biogas plant in this study. If an assumption is made of a 5MW system with a capacity factor of 50%, this will produce 21,900 MWh/a, which equals with 2,190,000m³ methane per year (at 1 m³CH₄ ≈ 0.01MWh). For an ex-situ process, with biomethane at 98% methane content, this is equivalent to 2,234,694 m³ biomethane. It may be assumed that half of the biomethane is derived from the original biogas, therefore approximately 1,117,347 m³CH₄/a is from biogas. Taking the methane yield of each feedstock in Table 4-2 and 24.6 m³CH₄/t for seaweed (section 4.3.1), we can find that the quantity required for each feedstock type for a 5 MW biological methanation is different: 19,000 tonnes/a of grass; 77,000 tonnes/a of slurry; 27,000 tonnes/a of SHW; 19,000 tonnes/a of OFMSW and 46,000 tonnes/a of seaweed.

Browne et al. (Browne et al. 2011) assessed the costs of biogas facilities for food waste, SHW and combined grass and slurry at a scale of 50,000 tonnes/a. These costs will be used as a basis for the following analysis but will be adjusted for scale.

- **Biogas plant CAPEX:** Biogas plant capital costs are effected by economies of scale; the relationship of maize silage feedstock and investment cost of biogas plant (Browne et al. 2011) is shown in Eq. (4- 6):

$$y = 558.89 * x^{-0.159} \quad (4- 6)$$

In which, y is investment cost (€/t feedstock) and x is tonnes of feedstock per annum.

Based on this equation, different quantities of feedstocks will have different investment costs. Applying the feedstock quantities calculated previously for grass, slurry, SHW, OFMSW and seaweed (19000 t/a, 77000 t/a, 27000 t/a, 19000 t/a and 46000 t/a, respectively), Table 4-6 determines the investment costs as would apply for these quantities of maize silage feedstock. Table 4-6 also illustrates the percentage cost difference as compared to a 50000 t/a maize silage plant.

Table 4-6. Percentage difference in investment cost of different scale of maize silage biogas plant

Tonne of maize silage	Investment cost (€/t/a feedstock)	% cost difference comparing to 50 000 tonnes
19000	116	16
27000	110	10
46000	101	1
77000	93	-7
50000	100	0

The capital cost of grass, OFMSW, SHW and slurry biogas plants have been reported in previous literature as 140 €/t/a, 280 €/t/a, 140€/t/a and 110 €/t/a (shown in Table 4-7). It is assumed that the calculated percentage cost difference (reported in Table 4-6) can similarly be applied for grass, slurry, SWH and OFMSW biogas plants to adjust for a 5MW scale biological methanation system. This is outlined in Table 4-7.

The capital cost of a seaweed biogas plant at 50,000 tonnes scale is not available in the literature, therefore it will be calculated in this chapter. To the authors knowledge, there is no commercial biogas plant with a feedstock of 100% seaweed. The Solrød biogas plant in Denmark uses seaweed as one part of feedstock, however

this only accounts for approximately 3% (Kommune 2014). Due to the characteristics of cast seaweed with high salt content, low C/N ratio, heavy metals and high sulphur content (Murrphy et al. 2015), seaweed biogas plants may need to have pre-treatment processes and H₂S removal prior to digestion. The capital cost of a seaweed biogas plant in this study is assumed to be 20% higher than a maize silage biogas plant. At 46,000 tonnes per year, maize silage has an investment cost of €101/t/a, thus the capital cost of seaweed plant is taken as €134/t/a. Seasonal variation greatly affects seaweed biomethane potential. Herrmann et al. (Herrmann et al. 2015) suggested that seaweed should be harvested in summer and stored via ensiling process for maximising biogas production. In this study, the investment cost of storage pit for seaweed is assumed the same as for grass (€30/t/a) (Browne et al. 2011). The capital costs of different feedstocks at 5MW biological methanation plant are presented in Table 4-7. For example the investment cost of a seaweed digester is €7.54M (Table B2 Appendix B).

Table 4-7. Capital costs of biogas plants with different feedstocks at 5MW biological methanation plant

Feedstocks	% cost difference comparing to 50,000 tonnes biogas plant	Capital cost of different biogas plants at 50,000 tonnes scale (€/t/a)	Capital cost at 5MW scale (€/t/a)
Grass	16	140	162
OFMSW	16	280	325
SHW	10	140	154
Seaweed	1		164
Slurry	-7	110	102

- Biomethanation capital cost:** The challenge when microorganisms are used as a biocatalyst is the poor solubility characteristic of H₂. Continuously stirred tank reactors, trickle-bed reactors and membrane reactors have been applied to improve this issue. Among the three technologies the trickle-bed reactor was shown to have a high methane conversion of 98%. The investment cost for a 5MW ex-situ biomethanation plant is suggested as €3,000,000 (Graf, Krajete, and Schmack 2014).
- Biomethane OPEX:** The waste heat from a biological methanation facility for a 5 MW plant according to Götz et al. (Götz et al. 2016) was 420 kW, thus the thermal demand of a biogas facility in this case could be satisfied by the waste heat from biological methanation (Figure 4-1). The operational data is not greatly effected by scaling, therefore data from Browne et al. (Table 4-2) is used (Browne et al. 2011). Seaweed was not included in the study by Browne et al. (Browne et al. 2011), thus this study will illustrate the biomethanation cost with seaweed feedstock.

Due to the characteristics of certain seaweeds, especially beach cast mixes, the anaerobic digestion process may suffer due to high levels of ammonia, volatile fatty acids and/or hydrogen sulphide (Montingelli, Tedesco, and Olabi 2015). It is suggested that the maintenance cost of a seaweed biogas facility will be higher than that of a grass biogas facility; a value of €15/t is assumed. The technology used to convert seaweed to biogas is modelled as a CSTR with an electrical demand of biogas plant is 10 kW_eh/t (Murphy, McKeogh, and Kiely 2004). The digestate produced from digestion of cast seaweeds (as opposed to cultivated seaweeds) may have high heavy metal content, in particular cadmium (Nkemka and Murto 2010) as well as salt (Allen et al. 2014), and so may not be readily applicable as fertiliser. The biodegradability index of seaweed is suggested at ca. 54% (Allen et al. 2014), thus the seaweed digestate in this study is taken as 43,516 tonnes. The cost of seaweed in Ireland is taken at €40/t wet weight or €267/t dry weight (Burton et al. 2009) if it is harvested mechanically (total solids content 15%). However, other studies suggest seaweed costs in the future associated with large scale cultivation at ca. €50/t dry weight (Dave et al. 2013). This is the assumed cost in this study for seaweed. The lifetime of biogas plant as well as the interest rate are the same for all feedstocks (Table 4-3). The operation cost of the biomethanation facility is assumed at 3% of the investment cost. Biomethane production costs for each type of feedstock are based on the assumptions in Table B1 in the Appendix B. The costs of biomethane are shown in Table 4-8.

Table 4-8. Cost of renewable gas production (excluding hydrogen production costs)

	Grass	Slurry	SHW	OFMSW	Seaweed
Biomethane yield from biogas plants (m ³ /a)	1,128,600	1,108,800	1,107,000	1,254,000	1,131,600
Biomethane yield from combination of CO ₂ from biogas and H ₂ from wind energy (m ³ /a)	923,400	597,046	905,727	836,000	925,855
Total biomethane yield (from biogas and from methanation) (m ³ /a)	2,052,000	1,705,846	2,012,727	2,090,000	2,057,455
Annual cost of renewable gas production (€)	1,478,167	2,152,228	918,478	660,987	2,790,565
Cost of renewable gas production (€)	0.7	1.3	0.5	0.3	1.4

- **Hydrogen production costs:** The cost of H₂ production is mostly based on the cost of electricity which is even higher than the capital costs. According to Benjaminsson et al. (Benjaminsson, Benjaminsson, and Rudberg 2013) the production cost of hydrogen by electrolysis (including maintenance costs, electricity grid cost, electricity cost and capital cost) from three manufacturers (Proton-Onsite, NEL and ErreDue) are in the range €0.09 – 0.1/kWh. Of these costs, €0.047 - 0.055/kWh and €0.02 – 0.028/kWh are from electricity and capital costs, respectively. Gonzalez et al. (González, McKeogh, and Gallachóir 2004) examined the cost of hydrogen from surplus wind energy in Ireland and concluded that hydrogen cost (excluding capital cost) would be $3.53 * C_e$ €/GJ, where C_e is the surplus electricity value in c€/kWh. The

study of Ahern et al. (Ahern et al. 2015) recommended the bidding price of electricity for P2G is 0.05 €/kWh therefore C_e in this study is assumed as 5 c€/kWh. Thus, the production cost of H_2/m^3 of methane in 2020 in Ireland is assessed as €0.96/ m^3 renewable methane as shown in Box 4-3.

Box 4-3. Hydrogen production cost

Cost of hydrogen (excluding capital cost) per GJ = $3.53 * C_e$ (González, McKeogh, and Gallachóir 2004) $= 3.53 * 5 = 17.65 \text{ €/GJ}$

Cost of hydrogen (excluding capital cost) per kWh = $17.65\text{€/GJ} / 278\text{kWh} = 0.06\text{€}$

In which C_e is surplus electricity value in c€/kWh = 5 c€/kWh (1GJ = 278 kWh)

The annualised capital cost of hydrogen plant of NEL manufacture: 0.02 €/kWh (Benjaminsson, Benjaminsson, and Rudberg 2013)

Hydrogen production cost (including capital cost): $= 0.02 + 0.06 = 0.08 \text{ €/kWh}$

Sabatier equation: $4H_2 + CO_2 = CH_4 + 2H_2O$

To produce one cubic meter of methane, requires four cubic meters of H_2

1 $m^3 H_2$ contains 3 kWh

Cost of H_2/m^3 biomethane = $0.08 \times 4m^3H_2/m^3CH_4 \times 3 \text{ kWh}/m^3H_2 = 0.96 \text{ €/m}^3$

The production costs of biomethane from biological P2G with H_2 production, compression and distribution included are in Table 4-9. Compression and distribution are included for the purposes of assessing compressed renewable gas (CRG) as a transport fuel. The costs are variable according to different types of feedstocks. Due to the gate fee supports for SHW and OFMSW, the cost of biomethane from these two feedstocks are lowest. Meanwhile, the lower methane yield of slurry and the high capital and operational cost of seaweed biogas plants make the biomethane

costs of these two feedstocks quite high. Comparing with conventional upgrading, the costs are much higher (Table 4-9). The cost of H₂ production accounts for a high portion in producing renewable gas, in which the cost of electricity used for H₂ production, plays an important role. It must be borne in mind in comparing the two systems that the quantity of renewable gas generated is significantly increased when the P2G system is incorporated and that this electricity would otherwise be curtailed.

4.3.4 Sensitive analysis for renewable gas costs

There are a lot of assumptions in the calculation of compressed renewable gas costs. This study will not focus on the sensitivity of the biogas production but instead focus on the biological methanation. The H₂ production cost is the most expensive element of the total renewable gas cost, therefore, the variability of electricity price used to produce H₂ will be analysed.

On March 1st 2013, the Single Electricity Market committee decided that *“The cessation of compensation for curtailment on January 1 2018”* (SEM committee 2013). This means that in 2020, the price of electricity associated with wind energy curtailment in Ireland could be free in theory. However, there may be a market for this surplus electricity and the manufacturer is likely to pay for curtailed wind energy used for electrolysis. The results show that if the surplus electricity price is 0.2c€/kWh, the biomethane costs from grass feedstock of conventional upgrading and biological methanation are the same (Table 4-10). To this must be added the benefit of carbon savings which was assessed as potentially € 17 million per year (section 4.3.3.1)

Table 4-9. Production of compressed renewable gas from biological methanation systems (excluding VAT)

Total production cost in €/m ³ biomethane	Grass	Slurry	SHW	OFMSW	Seaweed
Renewable gas production	0.7	1.3	0.5	0.3	1.4
H ₂ production	0.96	0.96	0.96	0.96	0.96
Compression and distribution	0.149	0.149	0.149	0.135	0.149
Cost of CRG production	1.8	2.4	1.6	1.4	2.5
Cost of CRG production from conventional upgrading	1.02-1.21 ¹		0.54 ²	0.3 ²	

¹(Smyth, Smyth, and Murphy 2010): ²(Browne et al. 2011)

Table 4-10. Impacts of surplus electricity prices on CRG production costs.

Cost of CRG production (€/m ³ biomethane)	Grass	Slurry	SHW	OFMSW	Seaweed
5 c €/kWh (Base case)	1.8	2.4	1.6	1.4	2.5
At 0.2 c €/kWh	1.1	1.6	0.9	0.7	1.8
At 4 c €/kWh	1.7	2.3	1.5	1.3	2.4
At 6 c €/kWh	2.0	2.6	1.8	1.6	2.7

4.4 Conclusions

The potential CO₂ production from biogas in Ireland associated with typical wet substrates (grass, slurry, slaughter house waste, the organic fraction of municipal solid waste and seaweed) is 431 Mm³/a. If this CO₂ were used in a biological power

to gas system, this would require 1722 Mm³/a of H₂. This would in turn require 7653 GW_eh/a of electricity. Wind energy curtailment in 2020 in Ireland is assessed conservatively at 2175 GW_eh/a. H₂ produced from curtailed electricity would be sufficient to combine with 28.4% of CO₂ from potential biogas sources. Thus, P2G is limited by electricity rather than biogas systems. It is shown that 1 GW_eh of electricity used to produce H₂ for upgrading biogas in a P2G system can affect a savings of 97 tonnes CO₂. In total, compressed renewable gaseous transport fuel offers GHG savings of 117% compared to diesel fuel, which satisfies the requirement of the EU Renewable Energy Directive.

Chapter 5 Techno-economic analysis of biogas upgrading via amine scrubber, carbon capture and ex-situ methanation¹

Abstract

Biogas upgraded to biomethane can provide a renewable gaseous transport fuel and is one of the proposed solutions in meeting the renewable energy supply in transport targets set under the EU Renewable Energy Directive. The upgrading process for biogas involves the removal of CO₂. Amine scrubbing is one traditional method of upgrading that is applied due to its low methane slippage and its capability to provide a high purity renewable methane product. However, new technologies such as power to gas (P2G) can also upgrade biogas through biological methanation by combining the CO₂ in biogas with H₂ to produce renewable methane. The H₂ for P2G can be produced through electrolysis of renewable electricity. Through simulation software – SuperPro Designer, the economics of different pathways for upgrading biogas from a grass silage and slurry fed digester are analysed and compared in this chapter. Three scenarios are investigated: biogas upgrading through amine scrubbing (scenario 1); biogas upgrading through amine scrubbing with CO₂ directed to ex-situ biological methanation (scenario 2) and biogas upgrading through ex-situ biological methanation only (scenario 3). The results show that at a net present value of zero, the minimum selling price (MSP) per m³ of renewable methane for scenario 1, 2 and 3 is €0.76; €1.50 and €1.43, respectively (with an electricity price to produce H₂ of

¹ Vo, T.T., Wall, D.M., Ring, D., Rajendran, K. and Murphy, J.D., 2018. Techno-economic analysis of biogas upgrading via amine scrubber, carbon capture and ex-situ methanation. *Applied Energy*, 212, pp.1191-1202.

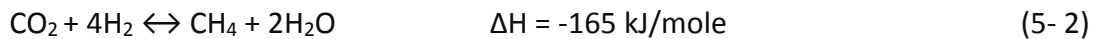
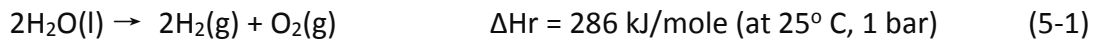
€0.10/kWh and a grass silage production cost of €27/t). The electricity price has a significant effect on the cost of renewable methane in both scenarios 2 and 3. The MSP reduces to €1.09 and €1.00 per m³ of renewable methane, respectively for scenarios 2 and 3, if the electricity price is reduced to €0.05/kWh. Since the renewable methane MSP from scenario 2 is higher than scenario 3, it is suggested that direct biogas injection to the methanation reactor is financially more attractive than capturing CO₂ from biogas and feeding it to the methanation step. The MSP of renewable methane from both scenarios 2 and 3 are significantly higher than that of scenario 1. However, when considering climate change mitigation, balancing of the electricity network and storage of surplus electricity, utilising P2G can offset some of these costs. If considering methanation as the upgrading unit of a biogas plant, its fixed capital cost is approximately the same as that of the amine scrubber. The cost of H₂ is a significant factor in determining the cost of renewable methane.

5.1 Introduction

A simplified breakdown of energy consumption in Ireland is ca. 20% electricity, 40% heat and 40% transport (Murphy and Thamsiroj 2011). The EU 2020 targets for renewable energy is 16% with a national breakdown in each of those sectors set at 40%, 12% and 10%, respectively (Persson et al. 2014). The production of renewable electricity has primarily been the focus in Ireland and as a result, its production has accelerated beyond renewable heat and transport. Anaerobic digestion of available biomass to generate renewable methane is one pathway that has been identified for potentially contributing to both the transport and heat sectors. For instance, grass is the most important agricultural crop in Ireland; over 90% of agricultural land is covered by grass (Smyth, Murphy, and O'Brien 2009). Excess grass, surplus to livestock requirements, may provide a potential feedstock for renewable methane production in Ireland (McEniry et al. 2013). Grass is deemed a promising feedstock due to its high yield, low production energy input and potentially high methane yields (Nizami, Korres, and Murphy 2009). Previous studies have indicated that in order to have sufficient nutrients for long term digestion, grass silage should be co-digested with slurry (Wall, O'Kiely, and Murphy 2013). Dairy slurry is also an abundant resource in Ireland with an annual production of ca. 7 Mt (Wall, O'Kiely, and Murphy 2013).

Ireland, an island state with limited electrical interconnectivity, is also expected to spill between 7-14% of its renewable electricity production by 2020, as supply will periodically exceed demand (Ahern et al. 2015). Thus, a method of storing surplus electricity is crucial. One potential method of storage is to change the energy vector from electricity to gas. This can be done through electrolysis, utilising the surplus electricity to split water

into hydrogen (H₂) and oxygen (O₂) (Eq. 5-1). Currently, three electrolysis technologies are used for producing H₂. The alkaline electrolyser is at commercial stage, the polymer electrolyte membrane is at pilot stage and the solid oxide electrolysis cell (SOEC) is in a research and development stage (Vo et al.). A further methanation step, combining the H₂ with carbon dioxide (CO₂), is required to produce methane (CH₄) in a Sabatier reaction. These combined processes are known as Power to Gas (P2G). The equation for production of CH₄ from CO₂ and H₂ is expressed in Eq. (5-2).



The methanation step can be carried out through chemical or biological means (Vo, Xia, Wall, et al. 2017). Chemical methods use a catalyst for methanation. This is a mature technology and nickel has often been chosen as the catalyst due to its high activity and low price. The efficiency of catalytic methanation is between 70% to 85% (Benjaminsson, Benjaminsson, and Rudberg 2013). In contrast, biological methanation uses hydrogenotrophic methanogenic archaea to consume H₂ and CO₂ as energy sources and produce CH₄ (Vo, Xia, Wall, et al. 2017). The CO₂ source can be extracted from industry through carbon capture; or from biogas plants as biogas typically contains ca. 45% CO₂. The latter is of particular interest as methanation of CO₂ and H₂ may potentially provide a form of biogas upgrading for biogas plants, offsetting costly traditional upgrading methods such as amine scrubbers. The operation of biological methanation can be in-situ or ex-situ. The in-situ method feeds H₂ directly into an anaerobic digester, while the ex-situ method uses an

external reactor for the methanation step, reacting the biogas (including for CO₂) and H₂. In terms of output, in-situ biological methanation can achieve a final CH₄ content of up to 75%, whereas ex-situ can reach up to 98%, a quality similar to that of natural gas (Vo, Xia, Wall, et al. 2017). The CH₄ produced from P2G systems is equivalent to biomethane and can again be used as fuel in the heat and transport sectors. P2G technologies have generated much interest of late and have previously been reported as a more sustainable energy storage method as compared to other large scale storage technologies such as pumped hydroelectric storage and compressed air energy storage (Vo, Xia, Rogan, et al. 2017). However, P2G systems will not always have a supply of surplus electricity at a cheap price to produce H₂, thus, sometimes it may be necessary to combine traditional biogas upgrading with methanation. In this case, when electricity prices are cheap (when supply exceeds demand), the electricity can be used to produce H₂ for methanation and when electricity demand is high the biogas can be upgraded by traditional upgrading.

Biogas from a biogas plant can be upgraded by water scrubbing, organic solvent scrubbing, amine scrubbing, pressure swing adsorption or by a membrane (Bauer, Persson, et al. 2013). To the authors' knowledge, there is little research on techno-economic analyses of upgrading of biogas by methanation processes. Previous studies have compared the costs of CH₄ production from traditional biogas upgrading with CO₂ capture for methanation (Johanesson, Collet et al. 2017, Parra et al. 2017), however these studies only considered catalytic methanation. Vo *et al.* (Vo, Xia, Wall, et al. 2017) calculated the costs of renewable methane from different types of feedstocks with upgrading of biogas provided by biological methanation. However,

the study did not consider the capture and utilisation of CO₂ from the biogas plant. Amine scrubber technology was chosen as the upgrading methodology in this study because of its low methane loss (<0.1%) (Bauer, Persson, et al. 2013), in addition to this, the CO₂ from the amine scrubber could be captured and reused.

This is the first research to undertake a techno-economic analysis of biogas upgrading comparing amine scrubbing with or without carbon capture and ex-situ biological methanation. No previous works have compared carbon capture from amine scrubbing integrated with biological methanation. Superpro Designer (Intelligen Inc., Scotch Plain, NJ, V10) was used to develop the process models. SuperPro Designer is a software tool for engineers and scientists used in process development, process engineering and manufacturing. It has been applied previously in bioprocess studies such as bioethanol production (Kwiatkowski et al. 2006, Kumar and Murthy 2011), biodiesel production (Marchetti, Miguel, and Errazu 2008) and the optimisation of biogas plant configurations (Balussou et al. 2014).

The aim of this study is to investigate the economic viability (in terms of € per m³ renewable methane produced) of three pathways for upgrading biogas to renewable methane generated from a typical biogas plant digesting grass silage and slurry. The three scenarios are as follows:

Scenario 1: Biogas production + amine scrubbing: The plant produces biogas (CH₄ and CO₂) from grass silage and dairy slurry, which was then upgraded by amine scrubbing to remove CO₂. This scenario did not consider CO₂ capture; CO₂ is emitted upon methane upgrading.

Scenario 2: Biogas production + amine scrubbing + ex-situ biological methanation:

The plant produces biogas (CH_4 and CO_2) from grass silage and dairy slurry, which was then upgraded by amine scrubbing to remove CO_2 . The CO_2 removed was captured and sent to ex-situ biological methanation in which H_2 and CO_2 was reacted to form CH_4 . This scenario takes advantage of the fluctuation of wind energy (when wind electricity is not available, only the biogas plant and amine upgrading unit are applied and when wind electricity is accessible, three units work together); and for methanation process that requires higher purification of CO_2 .

Scenario 3: Biogas production + ex-situ biological methanation: Unlike other scenarios, the biogas from grass silage and dairy slurry was directly transferred to the ex-situ biological methanation system, where CO_2 in the biogas was reacted with H_2 to form CH_4 .

The objectives of this study are as follows:

- Simulate and develop the three biogas upgrading scenario processes: amine scrubber; amine scrubber and ex-situ biological methanation; and ex-situ biological methanation;
- Calculate costs of renewable methane from grass silage and dairy slurry biogas plants with the three different upgrading technology scenarios;
- Analyse and compare the energy consumption of the biogas plant, amine scrubber and methanation elements;
- Estimate the effects of electricity cost and grass silage cost on the cost of renewable methane.

5.2 Methodology

5.2.1 Process development and description

The simulation was separated into two parts: i) biogas production, which includes feedstock processing, digester operation and digestate handling and ii) gas upgrading or utilization using amine scrubber and/or methanation reactor. The electrolysis step (producing H₂) was excluded from the analysis, however the cost of electricity, which affects the cost of H₂, was analysed to assess the effect of scale in the costs associated with converting H₂ to CH₄. The renewable methane produced is assumed to be compressed and injected to the distribution gas grid at 7 bar. As indicated, all three scenarios included for the same biogas plant but had a different upgrading method (Figure 5-1). The screenshot of different scenarios is available from the Appendix C. The assumptions of the process are reported in Table 5-1.

The biogas section was simulated as in Figure 5-2. For the purposes of the study, the grass silage feedstock was stored in a silo pit (P-8/SL- 101), with sufficient storage capacity for a year's supply. Dairy slurry was considered to be stored in sealed, water – tight and reinforced concrete container (P-3/V- 101) for two days. The silage is shredded (P-2/SR -101) and mixed with dairy slurry before being loaded to the digester, while the pump (P-9/PM-101) functions as both a pump and a mixer. The characteristics of the grass silage and dairy slurry (Table 5-2) are adopted from Wall et al. and Lukehurst et al. (Wall, O'Kiely, and Murphy 2013, Lukehurst, Frost, and Al Seadi 2010). The ratio of grass silage and dairy slurry fed to the biogas section was calculated on a volatile solids (VS) basis; 80%VS from grass silage and 20%VS from

dairy slurry. Grass silage benefits from co-digestion with dairy slurry in maintaining an optimal C:N ratio and as a source of micro-nutrients (Wall, O’Kiely, and Murphy 2013). Both grass silage and dairy slurry contain nutrients, nitrogen, phosphorous and potassium (Lukehurst, Frost, and Al Seadi 2010) which are important factors in order to utilise the digestate as a fertiliser.

Table 5-1. Assumptions made for the three scenarios

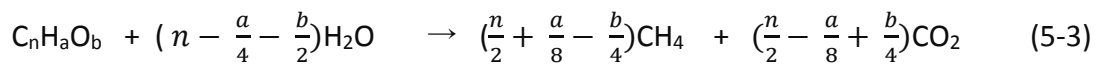
Items	Assumptions
Process	Continuous (7,920h per year)
Grass silage (wwt/h)	3.2
Dairy slurry (wwt/h)	3.5
HRT at CSTR1 (days)	40
HRT at CSTR2 (days)	30
Project life time	20 years
Construction period	1 year
Calculation year	2016
Start-up period	6 months
NPV for three scenarios	0 (At MSP, NPV is 0)
Interest rate	8%
Income tax	12.5%
Start-up capital	No requirement from the Government ¹
Mono-ethanol-amine	€1,500/t
Grass silage feedstock	€27/wwt ²
Electricity cost for running process	€0.15/kWeh ³
Electricity cost for producing H ₂	€0.10/kWeh

¹(Joint committee on communications and energy and natural resources 2011); ²(McEniry et al. 2011);

³(Browne et al. 2011).

5.2.1.1 Biogas section

The grass silage/slurry mixed feedstock, now with a dry solids (DS) content of 18%, is pumped to two CSTRs (in series). The two CSTRs were assumed to be operating at a mesophilic temperature range of 38°C. The HRT was set at 40 days in the first CSTR (P-6/AD-101) and 30 days in the second CSTR (P-7/AD-102). It is assumed that 80% destruction of VS takes place in the first CSTR, with 20% of remaining VS removed in the second CSTR. In total, 84% of VS is destroyed in the process. The concentrations of CH₄ and CO₂ generated are based on the Buswell equation shown in Eq.(5-3) (Buswell and Hatfield 1936):



Grass silage does not contain sulphur, while dairy slurry has 0.4 kg total sulphur per t fresh weight (Table 5-2). Under anaerobic conditions, sulphate is converted into hydrogen sulphide (H₂S) by sulphate – reducing bacteria. Sulphur in feedstocks containing protein when digested may also form H₂S (Wellinger, Murphy, and Baxter 2013). H₂S causes corrosion to equipment and pipes when injected to the grid; it can also be toxic and inhibit anaerobic processes (Krayzelova et al. 2015). For injection to the gas grid or to use as gaseous fuel, the concentration of H₂S must be below 5mg/m³ (Graf and Klaas 2009, Subramanian et al. 2013); an important step of biogas upgrading is eliminating H₂S. There are many methods to remove H₂S from biogas such as biological desulphurisation, iron chloride, impregnated activated carbon, iron hydroxide or oxide, and sodium hydroxide scrubbing (Sun et al. 2015).

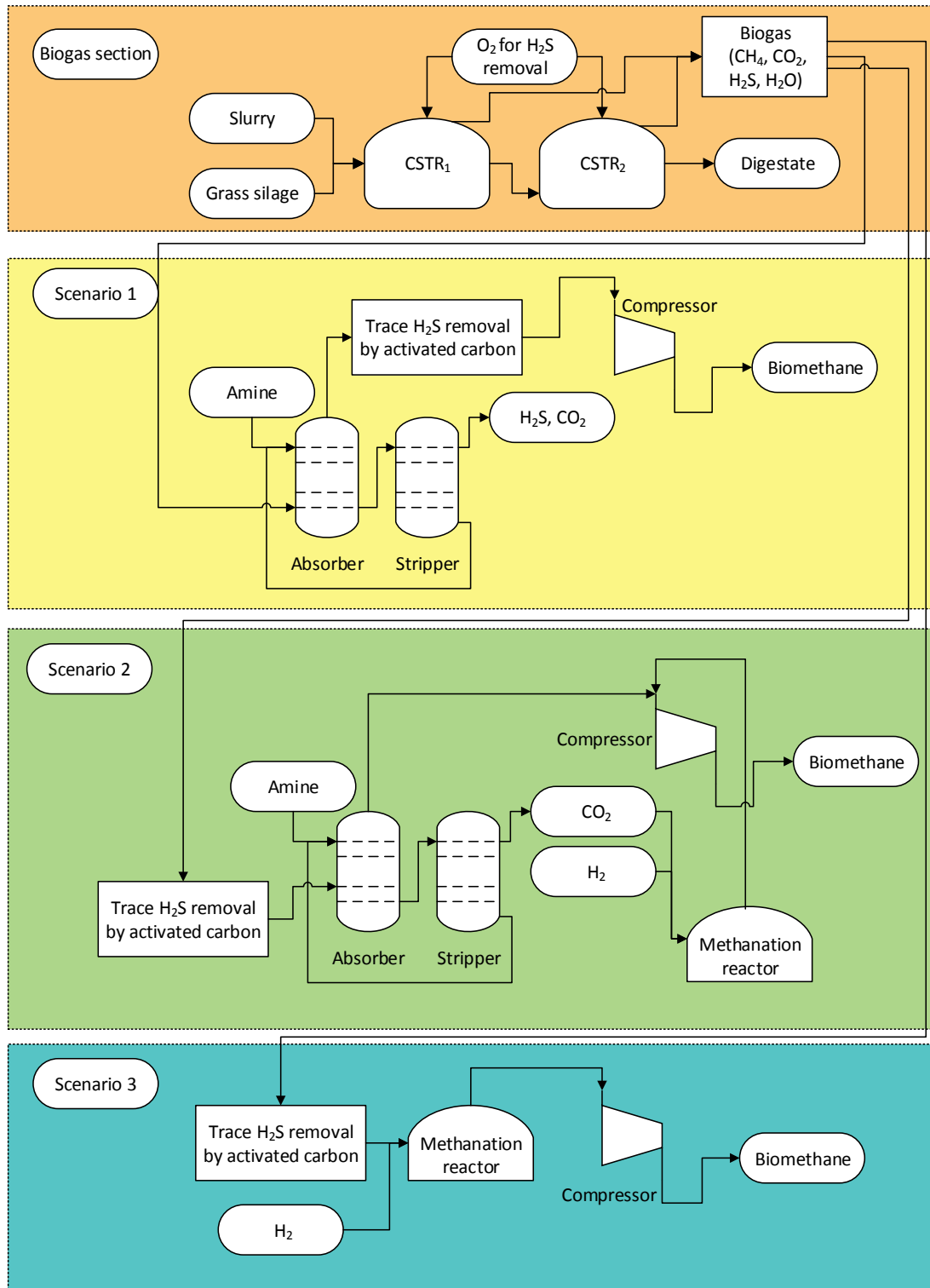


Figure 5-1. Process flow diagram of three biogas-upgrading methods.

Scenario 1 corresponds to upgrading the biogas via amine scrubbing, while Scenario 2 corresponds to biogas upgrading via amine scrubbing and methanation reactor and Scenario 3 refers to biogas upgrading via methanation reactor.

H₂S can also be removed by combining the removal of CO₂ by pressurised water scrubbing and amine scrubbing (Vienna university of technology 2012). Thus, for scenario 1, H₂S was removed with CO₂ by the amine scrubber (see section 5.2.1.2) as the CO₂ in this scenario is not otherwise utilised. Scenarios 2 and 3 need a separate component in order to eliminate H₂S in the methanation step. Among those methods, biological desulphurisation was chosen due to its simplicity, efficiency and low cost. In such a method, small amounts of air or O₂ (0.3 – 3%) (S-106) are added into the headspace of the CSTRs; under micro-aerobic environments, sulphide-oxidizing bacteria oxidize sulphide to elemental sulphur (Krayzelova et al. 2015). If air is added to the headspace, nitrogen will also be added to the biogas as a consequence, thus pure O₂, a by-product from the electrolysis process was assumed to be utilised for biological desulphurisation. Research has shown little potential for explosion; two of ten studies found a slightly lower specific methanogenic activity in micro-aerobic reactors compared to anaerobic reactors (Krayzelova et al. 2015). The removal efficiency of H₂S for biological desulfurization process and amine scrubbing is 88% (Krayzelova et al. 2015) and 98% (Huertas, Giraldo, and Izquierdo 2011) respectively, thus another step should be added to reduce H₂S to 5ppm. A desulphurization process via activated carbon (Siloxa company) was chosen to reduce H₂S levels below 1ppm with a technology cost of €0.01/m³ biogas (Kvist 2011).

Table 5-2. Characteristics of substrates (%) and nutrient concentrations kg/t fresh weight - adapted from (Wall, O’Kiely, and Murphy 2013) and (Lukehurst, Frost, and Al Seadi 2010)

Substrate	Chemical formula	DS (%)	VS (%)	Fixed solids or ash (%)	Water (%)	Total N	P	K	S
Grass silage	$C_{30}H_{50}O_{23}$	30	28	2	70	4	0.5	-	-
Dairy Slurry	$C_{22}H_{34}O_{19}$	8.8	6.7	2.1	91.2	3	0.5	2.9	0.4

The CH_4 product was assumed to contain some water vapour; two methods are appropriate to remove water from the gas: (i) gas dehumidification and (ii) ground tube dewatering (Kim and Lee 2015). To reduce the energy consumption, ground tube dewatering was applied in this work.

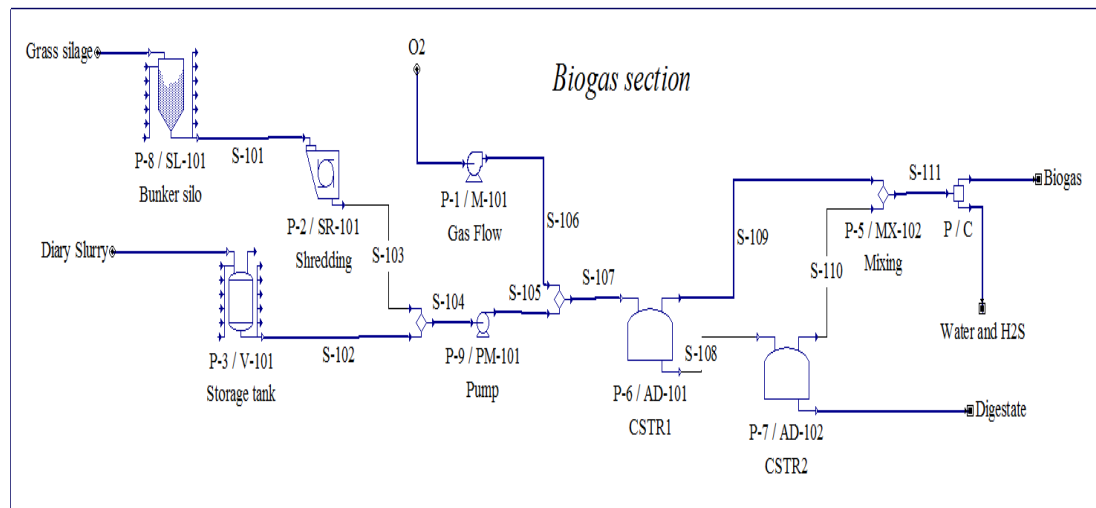


Figure 5-2: Biogas section simulation

5.2.1.2 Upgrading by amine scrubber and biological methanation

An amine scrubbing process is composed of the following elements: an absorber column; a heat exchanger; a stripper; a condenser and a re-boiler. The role of the re-

boiler is to heat up the incoming amine liquid solvent and vaporise the CO₂ to obtain a lean stream of solvent. In this case (Figure 5-3), a blower (P-20/M-102) at the bottom introduces biogas into the absorber (P-4/C-101) and amine solution (S-112) is fed at the top of the absorber. The biogas flows up the column and the solution flows counter-currently down the column (Huertas, Giraldo, and Izquierdo 2011). Plates or packing can provide additional surface area increasing the contact time between the gas and the solution. At the bottom of the absorption column, the solution is saturated by CO₂ and H₂S, the saturated solution is called rich amine (S-113) (the stoichiometric loading ratio is of 0.5 mole CO₂ per mole amine) (Li et al. 2016, Abu-Zahra et al. 2007). CH₄ (S-120) is discharged at the top of absorber and compressed to inject into the gas grid. The stripper (P-10/C-102) acts as a regeneration column whereby the rich amine solution (S-114) is heated by steam (S-118) from the re-boiler (P-15/HX-103). At a temperature of ca. 120°C, CO₂ is liberated into a concentrated stream and exits at the top of the stripper (S-115) (Yeh, Pennline, and Resnik 2001). However, not all of the CO₂ becomes free of the amine solution (called lean amine). The lowest energy requirement of 176 kJ/mole CO₂ (4 GJ/t CO₂) can be achieved at lean solvent loading between 0.25 and 0.30 mole CO₂/ mole mono-ethanol-amine (MEA) (Pellegrini, Moioli, and Gamba 2011, Li et al. 2016, Abu-Zahra et al. 2007). The CO₂ in the stripper is vaporised with water, thus this gaseous phase needs to be condensed (P-19/CSP-104) to separate water that is recycled back (S-117) to the stripper. The high temperature lean amine solution (the solution from the stripper) goes through a heat exchanger (P -17/HX-104) with the lower temperature rich amine solution. Lean amine is cooled down (P-18/HX-105) once

more before going back to the absorption column, while rich amine is fed into the stripper (Huertas, Giraldo, and Izquierdo 2011). The requirements of upgraded renewable methane (CH_4) for gas grid injection and as a potential vehicle fuel is typically >96% volume CH_4 (less than 4% volume CO_2) (Persson, Jönsson, and Wellinger 2006). Amine scrubbers can provide low methane slippage (0.1%) and a high purity renewable methane end product (Bauer, Persson, et al. 2013). CO_2 is emitted to atmosphere if CO_2 is not utilised in a further step; if CO_2 is used for methanation, it is injected into methanation reactor.

In the biological methanation upgrading section, the CO_2 source can come from the CO_2 stream produced as a result of biogas upgrading with amine (scenario 2), or by utilising the biogas itself directly (CH_4 and CO_2) produced from the biogas section (scenario 3). H_2 and CO_2 are assumed to be consumed biologically by hydrogenotrophic methanogenic archaea to produce CH_4 and water (Figure 5-3). The biological methanation reactor operates at 60°C , ambient pressure (Götz et al. 2016) and the ideal ratio of CO_2 and H_2 is 1:4 (Bensmann et al. 2014). The parasitic energy demand for stirring was suggested between 0.1 -1 kWh per m^3 methane produced (Graf, Krajete, and Schmack 2014), this study assumes this parasitic energy is 1 kWh per m^3 renewable methane produced.

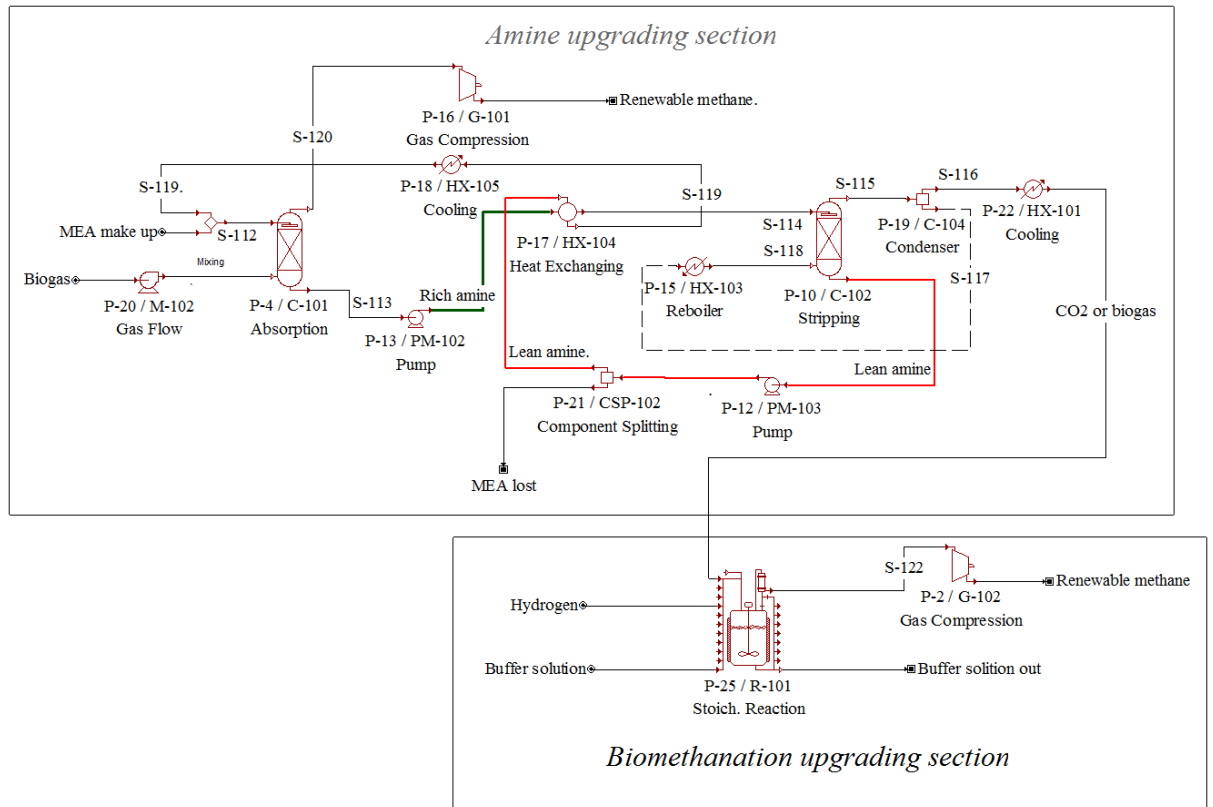
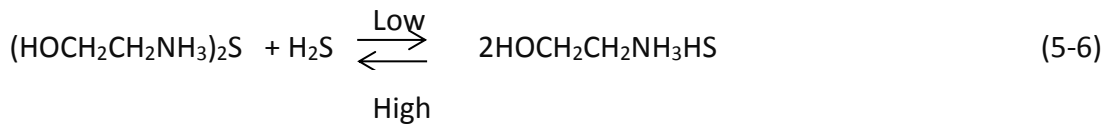
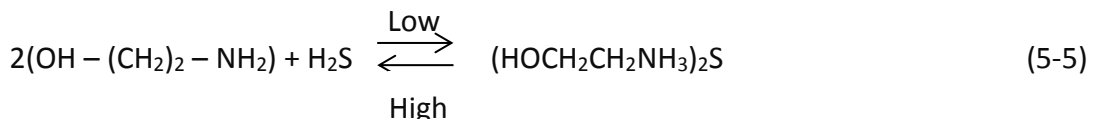
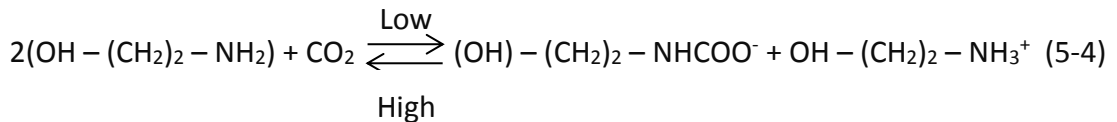


Figure 5-3. Upgrading section simulation

a. Solvent selection

There are many amine chemicals that dissolve into water as a solvent for biogas scrubbing such as mono-ethanol-amine (MEA), di-ethyl ethanol amine (DMEA), diethanolamine (DEA) or a mixture of methyldiethanolamine (MDEA) and piperazine (PZ)(Bauer, Persson, et al. 2013). MEA ($\text{HOC}_2\text{H}_4\text{NH}_2$) was chosen for this study as previous literature has indicated it has a rapid reaction rate, low cost, ease of reclaiming, reasonable thermal stability, low molecular weight, high absorbing capacity on a mass basis, and relatively low solubility of hydrocarbons (CH_4) in the solution (Ma'mun et al. 2005). MEA concentrations normally range from 12 to 30%wt (Kohl and Nielsen 1997). Park et al. (Park et al. 2017) found that at the same gas – liquid ratio and re-boiler temperature, CO_2 removal efficiency is higher at 30%wt

MEA solution than 20%. The disadvantage of using high amine concentrations is corrosion; however with the help of some corrosion inhibitors, 30%wt MEA solvent can be used (Rao and Rubin 2002). Thus, 30%wt MEA solution is assumed in this simulation. The overall reaction of MEA with CO₂ is presented in Eq. (5-4) and H₂S in Eq. (5-5) and (5-6).



The reaction between MEA and CO₂ is an exothermic reaction; for each mole of CO₂ absorbed in MEA solution, 72kJ of thermal energy is released (Yeh, Pennline, and Resnik 2001). The maximum CO₂ loading of amine solutions is 0.4 mole CO₂/mole amine.

b. Absorber and stripper designs

The absorber and stripper are packed with packing material to increase the contact time between solution and CO₂ and H₂S. The choice of packing material for the absorber and stripper is important as risk of flooding increases if surface area is excessive. Plastic palls or *Raschig* rings are usually used as packing material in absorbers but stainless steel must be applied in the stripper due to the high temperature. In addition to this, Sinnott (Sinnott 1999) recommended that the

diameter of packing size is linked to the column diameter. Plastic and metal pall rings are applied for the absorber and stripper in this study, respectively (Table 5-3) (Sinnott 1999) . The absorber operates at a temperature of 40°C and pressure of 1bar, whilst the stripper operates at temperature 120°C to 150°C (Yeh, Pennline, and Resnik 2001) and pressure 1.5bar to 3bar (Bauer, Persson, et al. 2013). The stripper operates at 120°C and 1.5 bar in this study.

Table 5-3. Design data for packing (Sinnott 1999)

Name	Size(mm)	Surface area (m ² /m ³)	Packing factor (m ⁻¹)
Plastic pall ring	38	128	130
Metal pall ring	16	341	230

The pressure drop of packing absorbers and strippers ranges from 15 to 50 mm of water per meter of packing height; if the liquid has foaming characteristics, the pressure drop will be halved (Sinnott 1999). The MEA solution is likely to foam in the absorber and stripper (Thitakamol, Veawab, and Aroonwilas 2009) and the loss of MEA is very small (Bauer, Hulteberg, et al. 2013); a pressure drop of 15mm water per meter of packing height (147 Pa/m) is therefore chosen in this study. The variables used in the absorber and the stripper are summarised in Table 5-4.

Table 5-4. Variables input for absorber and stripper in Superpro Designer

Variables	Unit	Value	
		Absorber	Stripper
Diffusivity of CO ₂ in gas phase	m ² /s	0.016	0.016
Diffusivity of CO ₂ in liquid phase at 40°C	m ² /s	0.0087 (Emyra Ezzaty et al. 2016)	0.0087 (Emyra Ezzaty et al. 2016)
MEA 30%wt solution surface tension	N/m	0.054 (Vázquez et al. 1997)	
MEA 30%wt solution phase viscosity	cP	1.67 (Amundsen 2008)	2.7 (Amundsen 2008)
Gaseous phase viscosity	cP	0.012 (Abdel-Hadi 2009)	0.68
Pressure drop per unit length	Pa per metre of packing height	147	147

5.2.2 Economic analysis

5.2.2.1 Capital expenditure

In this study the capital costs include for direct fixed capital (the cost paid for building a plant: equipment, installation, building, engineering, construction, etc.) and working capital (the cost needed to start the plant up and operate it to the point when income is earned). The working capital is calculated to cover 30 days of expenses for labour, raw materials, utilities (i.e., heating/cooling agents and power) and miscellaneous costs. The purchase prices of equipment to be installed are important factors in calculating the fixed capital.

The Lang factor is the ratio of the direct fixed capital cost to equipment purchase price (Sinnott 1999), thus Lang factor will be used in this study to calculate the fixed

capital of biogas plant as in the studies by Tao et al. (Tao et al. 2014) and Amigun et al. (Amigun and Von Blottnitz 2009). According to Tao et al. (Tao et al. 2014) the Lang factor of cellulosic fuels was 1.8 whilst Amigun et al. concluded that the Lang factor for a centralised biogas plant in Africa was 1.78 (Amigun and Von Blottnitz 2009). Thus, a value of 1.79 was chosen as the Lang factor for the biogas section in this study. For biogas upgrading via an amine scrubber, the Lang factor is 5 as indicated in literature (Gawel 2012). The methanation reactors were given a Lang factor of 1.25 for ex-situ methanation and 1.27 if CO₂ is captured from biogas plant and injected into methanation reactor, as per Graf et al. (Graf, Krajete, and Schmack 2014)

The costs of equipment are based on: (i) built-in costs of the Superpro Designer model (dairy slurry storage tank, feedstock shredder, pump, stripper, absorber, heat exchanger, condenser and compressor); and (ii) data from literature (anaerobic digesters, gas compressors, activated carbon bed, reboiler, methanation reactor and pump – Table 5-5). The costs of SCADA and switch boards, tractor, pipes and biogas flare for the biogas section are calculated at 20% of the purchase equipment costs of the biogas section and all unlisted equipment (pipe, connection and amine storage tank) for the amine scrubber section is assumed at 5% of the amine equipment costs. The equipment costs of biological methanation section are taken from literature (Graf, Krajete, and Schmack 2014) and include for the compressor and any unlisted equipment. If the cost of equipment is based on a different year than the year that the plant is built, inflation or deflation is taken into account using Eq. (5-7) (Brown and Brown 2013):

$$C_{p,c} = C_{p,p} \left(\frac{I_c}{I_p} \right) \quad (5-7)$$

Where:

$C_{p,c}$ is the inflation-adjusted cost of equipment in current year

$C_{p,p}$ is the known cost of equipment in a previous year

I_c is the cost index for current year

I_p is the cost index for the previous year in which equipment cost is known

This research calculates the cost of product for the year 2016. The year when equipment purchased costs are used to calculate in this process is 2010 (Table 5-5).

The chemical engineering cost indexes (CECI) of the year 2010 and 2016 are 550.8 and 535, respectively.

Furthermore, if the scale of the facility is not the same as the current scale, the cost is adjusted using Eq. (5-8) (Brown and Brown 2013).

$$\text{New cost} = \text{original cost} \left(\frac{\text{new size}}{\text{original size}} \right)^n \quad (5-8)$$

Where:

n is the economy of scale sizing exponent (less than unity) and is dependent on the type of equipment or plant.

The base costs, original sizes and 'n' of process component data are presented in Table 5-5. For the components which 'n' is not known, the traditional index of 0.6 will be used (Sinnott 1999).

Table 5-5. Base equipment costs and its scaling factors from literature

Component	Base cost (€)	Scale factor (n)	Base size	Sizing parameter	Base year
Biogas plant section					
Dairy slurry storage tank	From Superpro Designer				
Feedstock shredder					
All pumps					
Silage storage pit	€503,000*				
CSTR 1 ¹	566,000	0.6	4,210	Volume (m ³)	2010
CSTR 2 ¹	180,000	0.6	1,885	Volume (m ³)	2010
Amine upgrading section					
Boiler (100kPa) ²	2,648	0.5	1	Mass flow rate steam (kg/h)	2010
Condenser; absorber; stripper; heat exchanger; cooler	From Superpro designer				
Methanation section					
Ex-situ methanation plant ³	2,464,000			5MW	
Captured CO ₂ from biogas plant and inject into methanation plant ³	2,314,700			5MW	

* €900,000 for capital cost of silage storage pit (Browne et al. 2011) (if the Lang factor is 1.79, the equipment cost is €900,000/1.79 = €503,000)

¹: (Fischer 2010); ²: (Brown and Brown 2013); ³: (Graf, Krajete, and Schmack 2014)

5.2.2.2 Operating costs

Fixed and variable operating costs are the two main categories of operating costs.

The fixed operating cost includes the costs of maintenance, labour and taxation.

These are estimated by using factors that are normally based on direct fixed capital cost (Table 5-6). The personnel, laboratory and insurance costs are analysed and based on literature (Brown and Brown 2013).

Table 5-6. Operation cost assumptions

Fixed operating costs	Cost estimation		
	Biogas plant	Methanation upgrading	Amine scrubber upgrading
Maintenance	3% equipment purchase cost (Gutierrez, Xia, and Murphy 2016)	3% equipment purchase cost (Graf, Krajete, and Schmack 2014)	4% direct fix capital (Abu-Zahra et al. 2007)
Personnel*	2 operators	2 operators	2 operators
	1 manager		
Laboratory	15% of operating labour		
Insurance	0.7% direct fix capital		

* Annual salary for manager: €70, 000; annual salary for operator: €40, 000

The variable operating costs consist of raw materials and utilities costs, which are calculated, based on the simulation processes in the SuperPro Designer model. The steam, cooling and chilling water costs taken from the SuperPro Designer model are €12/t, €0.05/t and €0.4/t, respectively. It is assumed that the electricity for the electrolyser to produce H₂ is produced from nearby wind farms with electricity price of €0.10/kWh, the corresponding price of H₂ is €0.147/kWh (Vo, Xia, Wall, et al. 2017). This is equivalent to €5.78/kg H₂ ((14.7c€/kWh * 3.54kWh/m³)/0.09kg/m³) – excluding costs of compression and storage tank. The price of grass silage feedstock is taken at €27/t and the dairy slurry is assumed free of charge, as the farmer will

receive the return digestate. Since the CO₂ is taken from the biogas plant, the price of CO₂ is assumed zero. The initial amount of amine that is used for biogas upgrading is a one-off expense and not an operating cost, as this is a cost paid at the beginning of the plant operation (not annually). Therefore, the amine costs are calculated in start-up and validation expenses, the amine lost in the process is replenished every cycle.

5.2.2.3 Revenues

There are two products, renewable methane and digestate, which can be sold from the processes. Digestate is a fully fermented nutrient-rich material that can be utilised as an organic fertiliser, which is assumed free for farmers as they provide slurry. In order to be able to compare different pathways, the value of renewable methane from all scenarios is defined as the minimum selling prices for an 8% internal rate of return (the lowest product price that is capable of yielding a net present value of zero).

5.3 Results and discussion

5.3.1 Mass analysis

If every hour 3.5 wwt dairy slurry and 3.2 wwt grass silage are fed into the CSTR, this equates to 27,720 wwt of dairy slurry and 25,344 wwt of grass silage per year. The energy and material balance of each process are shown in Appendix D. As stated in section 5.2.1.1, dairy slurry and grass silage contain fixed solids (ash) (not consumed by the microorganisms in producing CH₄), nutrients and VS (which are used mostly as energy for microorganisms to produce CH₄). Total annual renewable methane

production from scenario 1, 2 and 3 are: 3.44 Mm³; 6.63 Mm³ and 6.64 Mm³, respectively. It is noted that the renewable methane is not only pure methane, it contains trace H₂S and small amounts of CO₂ that could not totally be eliminated. The mass flows in and out of the three scenarios are summarised in Figure 5-4. If 3.28Mm³ pure methane is generated per year and the total VS added per year is 8,953t , then one tonne of VS can be calculated to produce 366m³ pure methane; this is consistent with yields suggested in previously literature (Wall et al. 2014).

The digestate composition was made up of fixed solids, nitrogen, phosphorus, potassium, water and some VS from slurry and grass, which was not consumed by the microorganisms. In total, 44,539 t digestate are discharged per year. Among the three scenarios, only CO₂ out from scenario 1 is emitted directly to the atmosphere because it is not re-used in a further step (as in scenario 2 and 3). The higher CO₂ content in renewable methane suggests that that energy content in renewable methane from scenario 2 (95.5%vol. of CH₄) is lower than that of scenario 3 (97% vol. of CH₄). The quantities of methane produced are almost double in scenario 2 and 3 as compared to that of scenario 1 (as biomethane converts each volume of CO₂ to an equivalent volume of CH₄). Due to the small amount of CO₂ in renewable methane, which results from biogas upgrading, the total quantity of CO₂ from the amine scrubber is less than the total CO₂ volume in the biogas which is fed directly to the ex-situ biological methanation reactor. H₂ is assumed to be fed into the methanation reactor at the recommended ratio of 4 H₂: 1 CO₂.

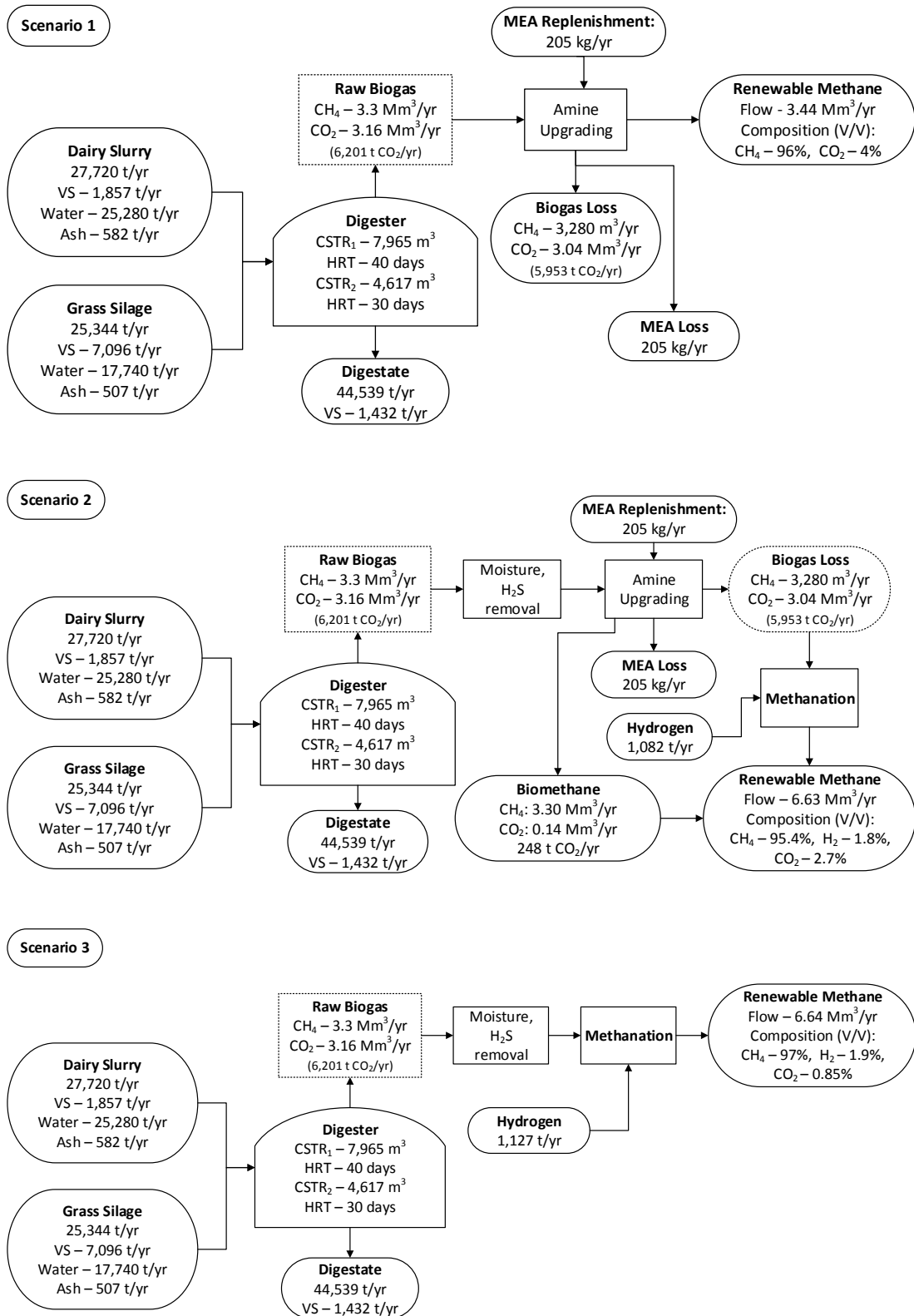


Figure 5-4. Mass balance of three scenarios

The amount of H₂ fed into the methanation reactor in scenario 2 is again less than that of scenario 3. In order to ensure less than 2%vol. of H₂ in the final gas as required for gaseous fuel (Ball, Basile, and Veziroğlu 2015), 99% of H₂ which is fed into methanation reactor needs to be converted to CH₄. A quantity of 3,472 kg mono-ethanol-amine, which is fed at the start of the process, is recycled. However, annually 205 kg mono-ethanol-amine is lost due to evaporation, thus this amount needs to be replenished to the process to compensate for this loss.

5.3.2 Energy analysis

The different types of energy, which are used in the three scenarios, are: electricity; steam; cooling and chilling water. Scenario 2 contains three sections (biogas, upgrading by amine and methanation) of the process; the energy consumption (electricity and steam (heat)) in this scenario are analysed (Figure 5-5) to understand the energy consumption in each section. Upgrading biogas by an amine scrubber only requires a very small amount of electricity (0.023kWh/m³ renewable methane) but has the highest energy requirement for heating. This is because a large amount of heat is required to regenerate CO₂ from rich amine solution. The biogas section has a lower consumption of standard power than that of methanation due to electricity requirement for mixing H₂ into solution. The total energy consumed in the biogas section is lower than from the amine scrubber section.

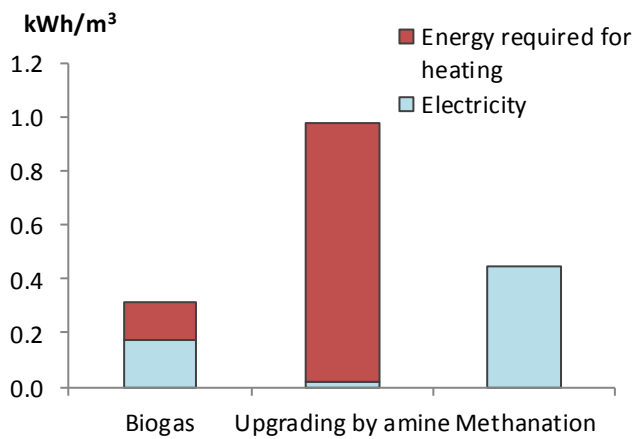


Figure 5-5. Energy consumptions per m³ of renewable methane of different sections in Scenario 2

By dividing each energy subdivision for a whole year by the total renewable methane produced, the energy consumed per m³ of renewable methane can be calculated as shown in Figure 5-6. The electricity requirement is higher for scenarios 2 and 3 than for scenario 1. However, the amount of steam used in scenario 3 is lowest as there is no amine scrubber. Although the amine scrubber for both scenarios 1 and 2 consumes steam, it should be noted that the renewable methane production from scenario 2 is almost double that of scenario 1. Thus, for each m³ of renewable methane, the steam used for scenario 2 is practically half that of scenario 1. Total energy consumption is highest in scenario 1 and lowest in scenario 3. If one m³ of renewable methane contains 10kWh, the energy consumption for scenario 1, 2 and 3 account for 25.7%; 18.7% and 9% respectively of final produced energy.

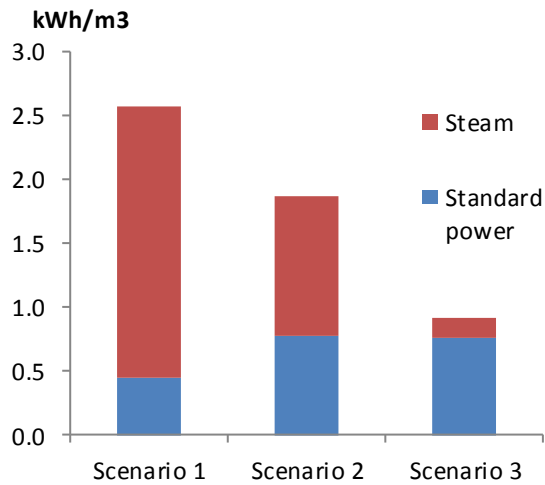


Figure 5-6. Energy consumptions per m³ renewable methane of different scenarios

5.3.3 Economic analysis

5.3.3.1 Direct fixed capital cost

The biogas section accounts for the highest direct fixed capital investment cost (€3.91M), followed by the cost of upgrading by methanation (€2.9 -3.1M) and subsequently the cost of upgrading by amine (€1.57 M). The major equipment costs and their sizes for scenario 2 and 3 can be found in the Appendix D. Table 5-7 gives an example of equipment purchase costs for scenario 1. The name of sections can be seen in Figure 5-2 and Figure 5-3. In this study, hydrogen was purchased separately; the analysis did not include the cost of the electrolysis plant.

Table 5-7. Component purchase costs of scenario 1

Name	Description	Cost (€)
1. Biogas section		
SL-101	Grass silage storage pit For storing 30,000 t grass silage/year	503,000
V-101	Slurry Receiver Tank Vessel Volume = 170 m ³ (2days storage)	70,000
SR-101	Shredder Rated through put = 3,200kg/h	56,000
PM-101	Centrifugal Pump Pump Power = 0.51 kW (pump and mixer)	7,000
AD-101	Anaerobic Digester Vessel Volume = 7965 m ³	805,000
AD-102	Anaerobic Digester Vessel Volume = 4616 m ³	308,000
Total 1		1,749,000
2. Amine scrubber section		
M-102	Blower	3,000
C-101	Absorber Flow rate of biogas 813m ³ /h; column diameter 1m; column height 15m.	35,000
C-102	Stripper Flow rate 403 m ³ /h; column diameter 1m; column height 15m.	35,000
PM-102	Centrifugal Pump Pump Power = 0.69 kW	12,000
HX-104	Heat Exchanger Heat Exchange Area = 15.63 m ²	10,000
HX-105	Heat Exchanger Heat Exchange Area = 9.69 m ²	8,000
PM-103	Centrifugal Pump Pump Power = 0.64 kW	12,000
HX-103	Reboiler	84,000
C-104	Condenser	22,000
G-101	Centrifugal Compressor Compressor Power = 30.13 kW	47,000
Total 2		268,000
Unlisted Equipment		451,000
Total 1+2 + unlisted equipment		2,468,000

5.3.3.2 Economic comparison of overall process.

For an NPV equivalent of zero, an electricity price to produce H₂ of €0.10/kWh and a grass silage production cost of €27/t, the minimum selling price of one m³ renewable methane (CH₄) excluding tax for scenario 1, 2 and 3 are €0.76; €1.50 and €1.43, respectively. A detailed economic breakdown of the three scenarios is presented in Table 5-8. Total capital investment cost is highest in scenario 2, because this scenario includes the biogas plant, biogas upgrading and biomethanation. The capital investment of scenario 3 is slightly higher than that of scenario 1 despite a more unique upgrading method. As mentioned in section 5.2.1.1, the removal of H₂S below 1-ppm costs €0.01/m³ biogas, which means it costs €0.01/m³ renewable methane in scenario 2 and 3 as the final volume of renewable methane in those scenarios is similar to the volume of biogas. The costs are €0.02/m³ renewable methane in scenario 1 as the volume of renewable methane after eliminating CO₂ is only half of biogas volume.

Table 5-8. Overall economics of three scenarios

	Scenario 1	Scenario 2	Scenario 3
Total capital investment (M€)	5.486	8.81	7.8
Operating cost (M€/yr)	1.97	8.98	8.6
Renewable methane revenue (M€/yr)	2.5	9.9	9.28
Produced renewable methane (Mm ³ /year)	3.44	6.636	6.642
Minimum selling price (€/m ³)	0.76	1.50	1.43
Net unit production cost (€/m ³)	0.57	1.35	1.3

The costs of raw materials account for the largest percentage of the operating costs in scenario 2 and 3 and is slightly lower than utilities cost in scenario 1 (Figure 5-7). It may be noted that the facility-dependent costs consist of maintenance and miscellaneous costs. The cost of grass silage accounts for 35% in scenario 1 and approximately 8% in scenarios 2 and 3. The cost of CH₄ may be reduced if feedstocks are available free of charge such as for food waste (which may even accrue a gate fee) or slaughterhouse waste (Vo, Xia, Wall, et al. 2017). H₂ cost in scenario 2 is 70% and 76% in scenario 3.

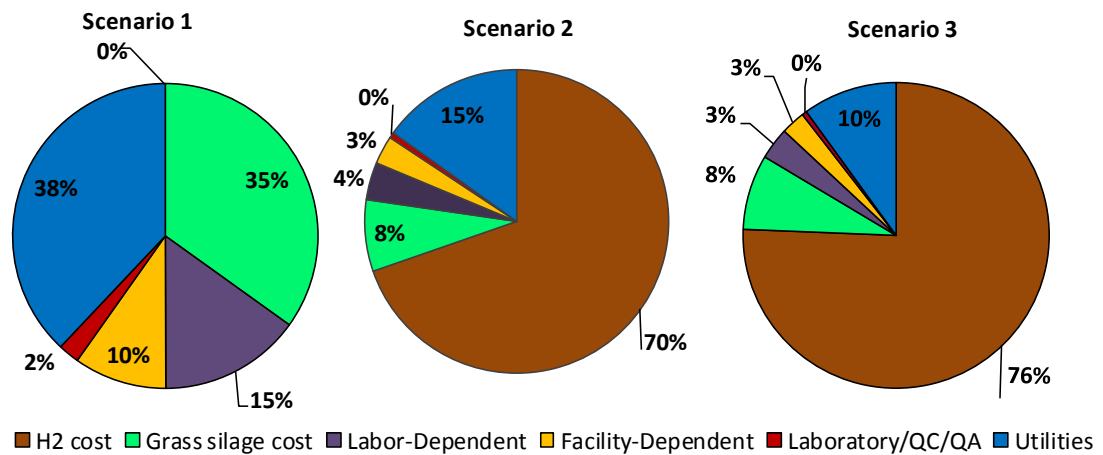


Figure 5-7. Operation costs in percentage of three scenarios

5.3.4 Comparison of data with literature

When comparing the CAPEX per m³ methane per year to previous studies analysing different feedstocks, the CAPEX of the plants in the three scenarios fit within the range of previous research (Figure 5-8).

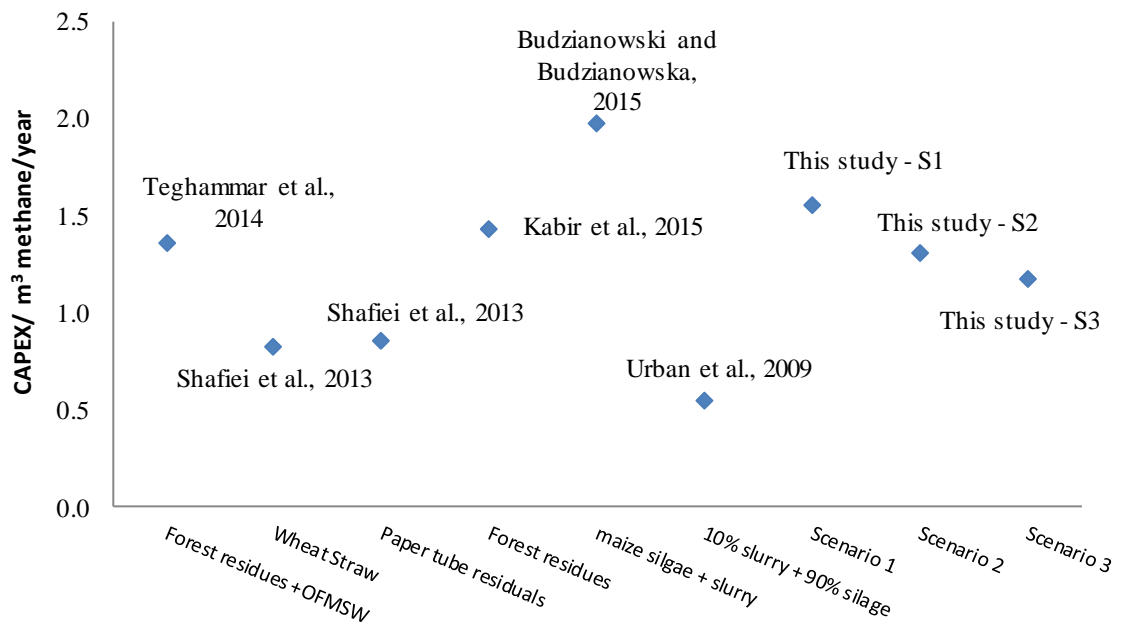


Figure 5-8. CAPEX/ m³ methane/ year in this study and previous research

Note: Teghammar et al. (Teghammar et al. 2014), Shafiei et al. (Shafiei et al. 2013), Urban et al. (Urban, Girod, and Lohmann 2008), Kabir et al. (Kabir et al. 2015), Budzianowski and Budzianowska (Budzianowski and Budzianowska 2015)

The CAPEX of amine scrubbing was compared to other biogas upgrading methods (Figure 5-9). The CAPEX of the amine scrubber from this study (€1,936/Nm³/h) was close to values reported in the literature. Although water scrubber upgrading is the most popular method, it is not ideally suited to carbon capture and reuse as it does not produce a free stream of CO₂. In addition to this, the losses of methane are relatively high for water scrubbing in comparison to amine scrubbing (Pettersson 2009).

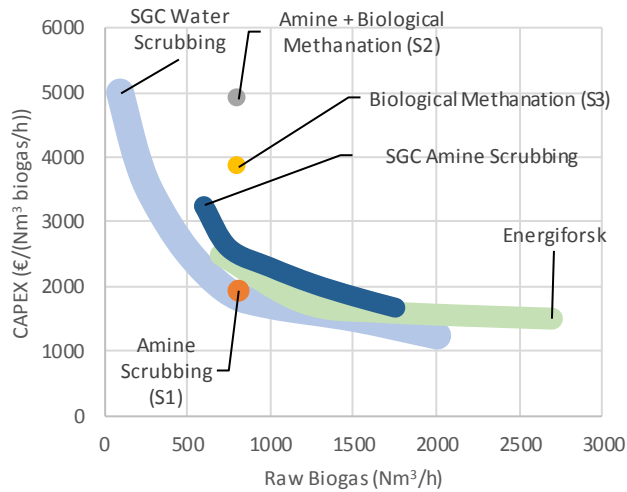


Figure 5-9. Comparison of CAPEX of different upgrading methods (Paturska, Repele, and Bazbauers 2015, Hoyer 2016)

S1: Scenario 1 Amine scrubbing

S2: Amine scrubbing and biological methanation

S3: Biological methanation

The energy demand of amine upgrading in this study was compared with the data in the literature. Similar power consumption was reported in this study as with literature (Bauer, Persson, et al. 2013), while the heat demand to release CO₂ from amine solution in this research was approximately three times higher than that reported in literature (Figure 5-10). The rationale behind the higher heat requirement was based on the CO₂ content in the biogas. To release 1 ton of CO₂, 4GJ of heat was required (Li et al. 2016, Abu-Zahra et al. 2007, Pellegrini, Moioli, and Gamba 2011); the total CO₂ produced in scenario 1 was 5,953 tons. The total heat required to release all the CO₂ was 23,812 GJ. When the heat required was recalculated based on the methane-produced, this generated a figure of 1.9 kWh/Nm³ methane. This study reported a heat requirement of 1.85 kWh/m³ methane from calculations in SuperPro.

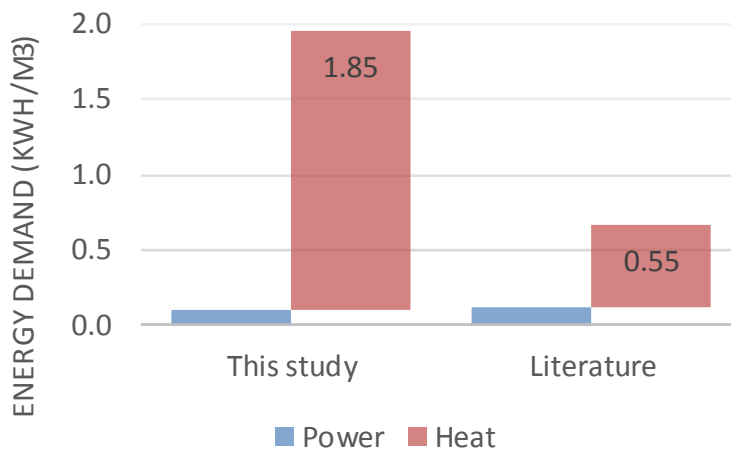


Figure 5-10. Comparison of energy demand of amine upgrading with literature data (Bauer, Persson, et al. 2013)

5.3.5 Sensitivity analysis

As indicated, raw material costs contribute to a high percentage of the operating costs for the three scenarios. However, the production price of grass silage and the cost of H₂ are variable. The cost of H₂ production varies in that the cost of electricity fluctuates with temporal supply and demand issues. For example, at times of excess production electrolysis is seen to have a stability function in the electricity grid and the cost of the electricity may be minimal, reducing the price of H₂. A number of factors influence the cost of grass silage, including: the number of harvests; fertiliser application; fuel usage; supply and demand. Thus, a sensitivity analysis will take into account the variation in grass silage cost per tonne at prices of €13.5, €27, €40.5 and electricity cost per kWh at €0.05; €0.10 and €0.15.

If grass silage costs increase by 50%, it is calculated that the cost of renewable methane will increase by €0.10 per m³ in scenario 1. The renewable methane cost only increases by €0.05 per m³ for scenarios 2 and 3. This due to the fact that

approximately half of the renewable methane is produced by combining H₂ and CO₂, thus, the grass silage cost does not have as much of an impact (Table 5-10).

Table 5-9. Effect of grass silage price on renewable methane production

Grass silage price per t	Renewable methane price at electricity cost €0.10/kWh		
	Scenario 1	Scenario 2	Scenario 3
€13.5	€0.66	€1.45	€1.38
€27	€0.76	€1.50	€1.43
€40.5	€0.86	€1.55	€1.48

Hydrogen cost will not affect the renewable methane cost in scenario 1 as this process does not include for biomethanation. If the electricity price changes by €0.05 per kWh (by 50%), the renewable methane cost will change by approximately €0.41 for scenario 2 and €0.43 for scenario 3 (Table 5-10). Therefore, the electricity price used to calculate H₂ costs has a very significant effect on the price of renewable methane.

Table 5-10. Effect of electricity price (to produce hydrogen) on renewable methane production

Electricity price change per kWh	Renewable methane price at grass silage €27 per t		
	Scenario 1	Scenario 2	Scenario 3
€0.05	€0.76	€1.09	€1.00
€0.10	€0.76	€1.50	€1.43
€0.15	€0.76	€1.91	€1.85

Besides grass silage cost and electricity price, the authors were aware that the quantity of renewable methane could be increased if higher quantities of grass silage feedstock were fed to the digester. Currently the ratio modelled was 80% VS from grass silage and 20% VS from dairy slurry. Therefore, the effect of increasing the

percentage VS from grass silage was also analysed. A maximum grass silage scenario was investigated with 45,000wwt of grass silage and a minimum dairy slurry concentration of 5,238 t wwt (for nutrient addition) assumed to be fed to the digester annually. The cost per m³ renewable methane calculated for scenarios 1, 2 and 3 at €27/t grass silage and €0.10/kWh electricity (to produce H₂) was €0.74; €1.45 and €1.40, respectively. This equates to a €0.02; 0.05 and 0.03 drop in price for scenario 1, 2 and 3, respectively.

5.4 Conclusions

The process simulation performed using SuperPro Designer has shown that among three scenarios, the production cost of renewable methane from a grass and slurry fed biogas plant using traditional upgrading (amine scrubber in this study) was the cheapest (€0.76/m³ renewable methane). If surplus renewable electricity needs to be stored as methane, the direct methanation of biogas is more economically advantageous than capturing the CO₂ from upgrading and subsequently providing methanation of the captured CO₂. From an environmental/sustainability/decarbonisation perspective, the renewable methane generated from biological methanation (Scenario 3) is more sustainable than amine scrubbing (Scenario 1) as no CO₂ is released to the atmosphere. The key drivers for feasible processes include technical advancements such as a single-unit upgrading systems with carbon capture, increases in the efficiency of biomethanation, reduced costs for feedstock, reduced costs for electricity in the production of hydrogen. Power to gas systems are relatively new technologies that still need maturity to allow reduction in investment costs.

Chapter 6 Can power to methane systems be sustainable and can they improve the carbon intensity of renewable methane when used to upgrade biogas produced from grass and slurry?¹

Abstract

The recast renewable energy directive (RED recast) considers power to gas (P2G) an advanced transport biofuel if a 70% greenhouse gas savings as opposed to the fossil fuel displaced is achieved. Power to methane systems can store electricity as gas and the system can be optimised in sourcing CO₂ from biogas to upgrade biogas to biomethane. The crucial question in this work is whether P2G systems can be sustainable and if they can improve the sustainability of biomethane systems using traditional upgrading systems. This work evaluates a comparative lifecycle assessment of grass and slurry (50:50 wet weight equivalent to 80:20 volatile solid weight) biomethane using P2G and/or amine scrubbing as an upgrading choice. The sustainability of P2G upgrading systems is heavily dependent on the carbon intensity of the source of electricity. Using a 41% decarbonised electricity mix the sustainability was reduced using P2G and would not be deemed sustainable under criterion set by the RED recast. Maintaining a maximum of 2% fugitive CH₄ emissions, using 74% slurry (wet weight) in a grass slurry feedstock, allowing for 0.6 t carbon sequestration per hectare per annum in grasslands and using an electricity mix with 85% renewable electricity the whole system including P2G upgrading could satisfy the GHG savings of 70%. However, the tradition system employing amine scrubbing had higher levels of sustainability.

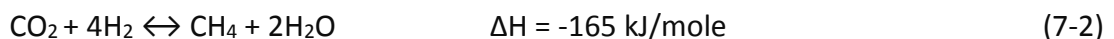
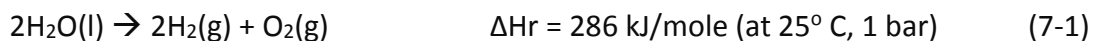
¹ Vo, T.T., Rajendran, K. and Murphy, J.D., 2018. Can power to gas systems be sustainable and can they improve the sustainability of biomethane systems when used to upgrade biogas? *Applied Energy*, 228, pp.1046-1056.

6.1 Introduction

The transition from fossil fuels to renewable decarbonised energy needs evidence of sustainability and of a significant reduction in environmental impacts. The recast Renewable Energy Directive (RED recast) states that advanced biofuels should make up at least 3.6% of transportation fuels by 2030. These advanced biofuel systems must meet a threshold of 70% greenhouse gas (GHG) savings as compared to the fossil fuel displaced (EC 2017). It is unlikely that biomethane produced from mono-digestion of crops such as maize will meet this criterion: however, maize is not considered as a source of advanced biofuel. Perennial ryegrasses are included in the list of advanced biofuels, but mono-digestion of grass is unlikely to meet the strict sustainability criteria of 70% GHG savings set for transport biofuels. However, it is likely that when grass is co-digested with slurry at certain ratios sustainability may be achieved. This is due to the methane emission credit obtained by avoiding the open storage of raw manure. When slurry is stored in an open tank fugitive methane emissions occur; methane has a global warming potential (GWP) of 21 times that of CO₂ in a 100 year time frame. In anaerobic digestion systems the slurry is not open to the atmosphere and these emissions are thus avoided. When biogas is combusted it releases CO₂ (21 times less GWP than CH₄) whilst displacing the emissions from a fossil fuel. The credit for digesting manure is given as 14.6% of the methane content of the slurry stored using methodology developed by the European Commission Joint Research Centre (JRC) (Giuntoli et al. 2014, Agostini et al. 2015). Mono-digestion of slurry is carbon negative, however, slurries have low volumetric energy content,

produce a low specific methane yield and as such are uneconomic (Wall, O’Kiely, and Murphy 2013).

A recent paper by the authors described a techno-economic analysis (TEA) of co-digesting grass silage with manure and injection of the produced renewable methane to the gas grid (Vo et al. 2018). Three upgrading scenarios were assessed: 1. amine scrubbing, 2. amine scrubbing + ex-situ biological methanation, and 3. ex-situ biological methanation. The amine scrubbing upgraded the biogas to biomethane (renewable methane) in scenario 1 by removing the CO₂. Scenarios 2 & 3 offer CO₂ capture. In Scenario 2 the CO₂ from the amine scrubber is sent to an ex-situ biological methanation unit to produce renewable methane. In Scenario 3 an amine scrubber is not used, and the biogas is sent to an ex-situ biological methanation unit to upgrade biogas. First, the electrolyser splits water into hydrogen and oxygen Eq. (7-1); the hydrogen then reacts with carbon dioxide to produce renewable methane Eq.(7- 2) (Vo, Xia, Rogan, et al. 2017).



The results of the TEA analysis (Vo et al. 2018) concluded that Scenario 1 amine scrubbing was the cheapest method to upgrade biogas followed by Scenario 3 (ex-situ methanation). Using both amine scrubbing and ex-situ methanation as described in Scenario 2 was the most expensive method investigated. The sustainability analysis of such systems has not previously been assessed in the scientific literature to the authors’ knowledge. This innovation in this chapter is the assessment of whether P2G

scenarios can improve the sustainability of a biomethane system and whether a P2G system can meet the sustainability criteria for advanced biofuels when used as an upgrading system of a biogas system digesting slurry and grass; furthermore the work examines at what ratio of grass silage to slurry, greenhouse gas emission savings of biomethane exceeds 70% GHG saving as compared to the fossil fuel displaced.

A *cradle-to-gate* LCA was carried out including for grass cultivation, ratios of grass and slurry in the digester, methane slippage at biogas plants, and hydrogen production from electrolysis. The three primary scenarios evaluated are as follows:

Scenario 1 (S1): Grass cultivated and transported to the biogas facility within a 10-km radius, while slurry transported within 3 km. Biogas produced from the plant was upgraded by an amine scrubber. The CO₂ from the biogas was emitted to the atmosphere after upgrading.

Scenario 2 (S2): Similar to S1 with an addition of the CO₂ sent to ex-situ biological methanation where it is reacted with hydrogen from an electrolyser to produce more renewable methane.

Scenario 3 (S3): Similar to S1 with the change that amine scrubber is not used and the entire upgrading process was undertaken by ex-situ biological methanation where hydrogen from an electrolyser combines with CO₂ to produce more renewable methane.

The objectives of the chapter are to assess: the parameters (including ratios of grass to slurry in feedstock, methane slippage, and sequestration of carbon in grasslands) that will allow slurry grass biomethane systems be considered sustainable; the

parameters with the greatest impact on the sustainability of P2G systems, in particular the share of renewables in the electricity grid mix; and the optimum combination of parameters that allow sustainability of biomethane and P2G systems.

6.2 Methodology

The LCAs were conducted by applying GaBi software (Thinkstep AG). This is a world's leading life cycle assessment software that used to assess the impacts of a process or a product on the environment. GaBi databases contain 12, 000 life cycle inventory profiles. Based on the life cycle of a product, the user defines the inputs and outputs of material and energy of each process. From those profiles, GaBi provides the CO_{2eq} and other emissions from producing of this product.

6.2.1 System boundaries and functional unit

A *cradle-to-gate* LCA boundary was used to measure the environmental impacts in this study. The system boundaries included: the cultivation of grass including fertilizers and machinery associated with cultivation; transportation of grass silage, dairy slurry and digestate (organic fertilizer) to and from the biogas facility; biogas production by anaerobic digestion (AD); upgrading by amine scrubbing; electrolyser for hydrogen production; and ex-situ biological methanation (Figure 6-1). The grass silage used in this study is assessed at 25,344 t/a cultivated in a land area of 634 ha (40 t wet weight/ha/a). The least distance needed to cultivate this volume of grass silage corresponds to a radius of 3.17 km. In the base case, 10 km was considered for transporting grass to the biogas plant and digestate back to the fields.

Previous work by the authors (Vo et al. 2018) assessed injection of the renewable methane to the gas grid at 8 bar. This chapter examines transportation fuel with compression to 250 bar. The functional unit used in this study was one MJ of compressed renewable gas. The data from this work was compared with fossil fuel comparators (FFC) from the RED recast. Based on the guidelines of the Directive 2009/28/EC, the emissions from the manufacturing of equipment and machinery within the biogas facility were not considered (Official Journal of the European Union 2009).

6.2.1 Life cycle inventory

The data for diesel supply, deionised water, and fertilizers were gathered from the proprietary software package GaBi (Thinkstep AG).

6.2.1.1 Biogas plant, amine scrubber and ex-situ biological methanation

The data for the feedstocks, biogas plant, amine upgrading and ex-situ biological methanation were based on Vo et al. (Vo et al. 2018). For the base case scenarios, grass silage and slurry were used at a ratio of volatile solids (VS) of 80:20. The processing capacity of the biogas plant was assessed with a total feedstock supply of 53,064 t/a consisting of 27,720 t/a dairy slurry and 25,344 t/a grass silage. It was assessed that approximately a 50:50 wet weight ratio is equivalent to an 80:20 VS ratio (VS of grass silage and dairy slurry are 28% and 6.7% of wet weight (Vo et al. 2018)). The digestate (organic fertilizer) production is equivalent to 44,539 t/a. About 84% of the VS loaded to the system were converted to biogas in the digesters, which had a retention time of 40 days.

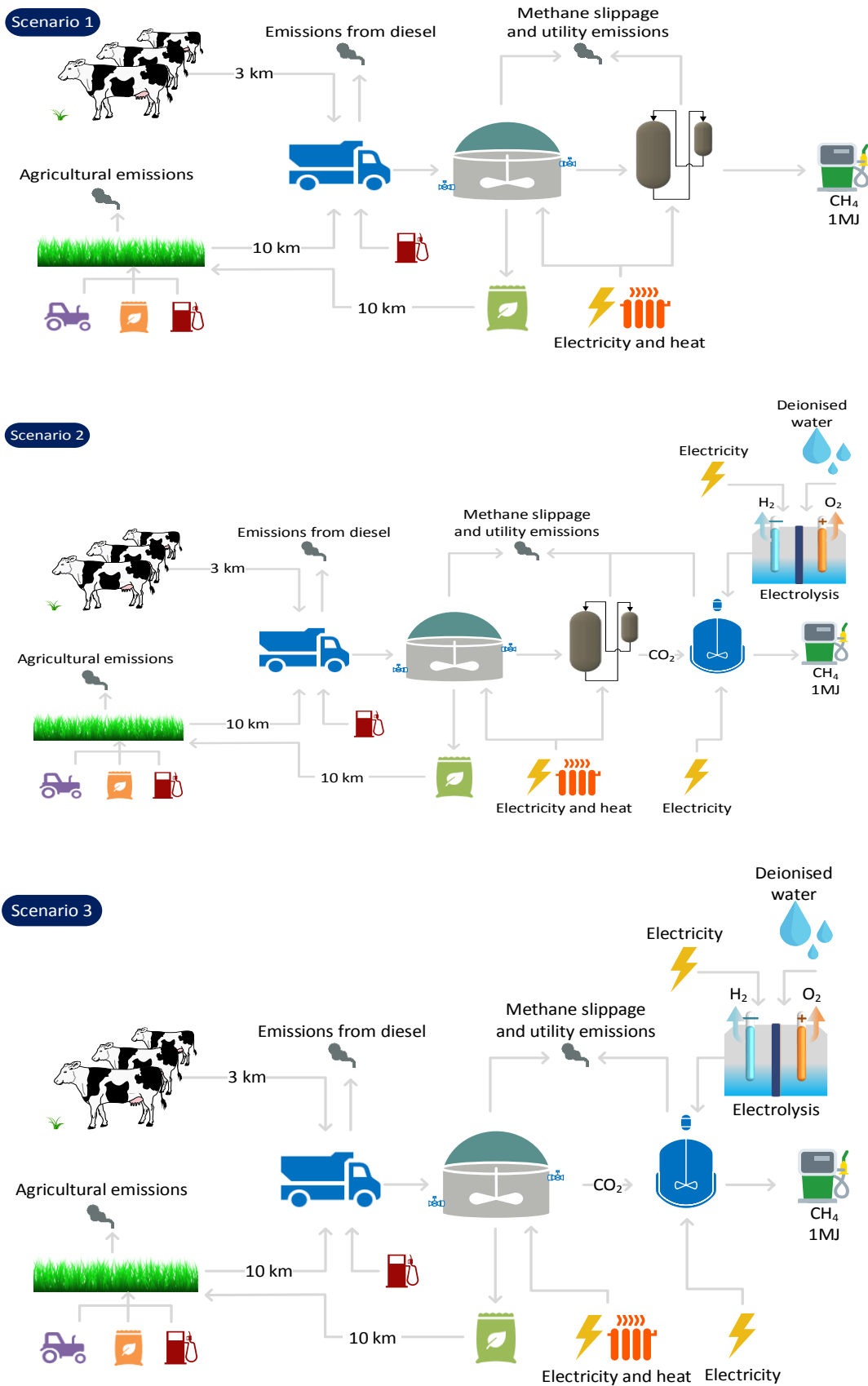


Figure 6-1. System boundaries of three scenarios

The biogas plant produced 3.3 million m³ renewable methane/a and 3.2 million m³ CO₂/a; broadly equivalent to 122.5m³ biogas/t at 51% methane content or 62.2 m³ CH₄/t. The base case scenarios assumed a 2% fugitive methane emission of the total methane produced from the biogas system. The sources of fugitive emissions includes: leakages from the digesters; short-term substrate storage; upgrading of biogas; digestate storage and the pressure release valve (Liebetrau et al. 2017). To compress the purified methane to 250 bar and use it as a transportation fuel, 0.35kW_eh electricity is needed per m³ of renewable methane produced.

The input data including for electricity, heat, amine scrubbing and biological methanation were adapted from Vo et al. (Vo et al. 2018). To upgrade the biogas via amine scrubber, 0.55 kWh heat per m³ raw biogas (Bauer, Persson, et al. 2013) was used. The consumption of heat in the process was based on natural gas (Ireland steam) taken from GaBi (Thinkstep AG). The input data for utilities used in three scenarios are summarised in Table 6-1. It should be noted that the energy produced from Scenario 1 is just from the biogas produced in the AD plant, whilst the energy produced from Scenario 2 and 3 are from the AD plant and the methanation upgrading where CO₂ in the biogas is converted to CH₄. As such the energy produced from Scenario 2 and 3 is roughly double that of Scenario 1.

Table 6-1. Parasitic energy demand for the three scenarios

	Scenario 1		Scenario 2		Scenario 3	
Energy produced - MJ (LHV):	116,500,442		225,561,198		229,561,534	
	Heat (kWh)	Electricity (kWeh)	Heat (kWh)	Electricity (kWeh)	Heat (kWh)	Electricity (kWeh)
Biogas production	957,169	1,149,008	957,169	1,149,008	957,169	1,149,008
Amine upgrading	3,556,268	141,930	3,556,268	141,930	-	-
Ex-situ biological methanation	-	-	0	2,985,840	0	3,088,800
Compression		1,132,643		2,192,956		2,231,848

6.2.1.2 Grass silage cultivation

Using water for agriculture, especially for biofuel production creates pressure on water usage due to irrigation and land use change (Agostini et al. 2015). The United Nations reported that 70% of potable water is used for irrigation purposes in agriculture (The United Nations 2014). However, those problems have not been an issue in Ireland as 90% of agricultural land are grass and Ireland has the lowest water stress index in the world (McKiernan; 2013) due to the plentiful availability of rainfall throughout the year.

Smyth *et al.* (Smyth, Murphy, and O'Brien 2009) carried out a comprehensive study on energy requirements of grass silage production in Ireland. From a single hectare of land, about 12 t dry solids (DS) of baled grass silage can be produced in a year at a

dry solids content of 30% (Wall, O’Kiely, and Murphy 2013). This corresponds to 40 t/ha/a wet weight from 634 ha. The crop production process encompassed cultivation and harvesting. The agricultural inputs for the grass cultivation include fertilisers, lime, and herbicides. Diesel is used in agricultural machinery for different activities including ploughing, sowing, harrowing, rolling and application of fertilisers. The emission data associated with agricultural machinery usage were included in the LCA.

The digestate from the biogas plant was assumed to be applied to the pasture land as organic fertiliser replacing synthetic fossil fuel-based fertiliser. Smyth et al. (Smyth, Murphy, and O’Brien 2009) calculated the amount of nitrogen needed for grass cultivation as 259.37 kg N/ha/a. The maximum permissible nitrogen load on farmland from an organic fertiliser is 170kg N/ha/year (Lukehurst, Frost, and Al Seadi 2010). Thus, synthetic fertilizer of 89.37 kg N/ha/a is still required. On a wet weight basis, grass silage and dairy slurry contain 4 and 3 kg N/t respectively (Vo et al. 2018). During anaerobic digestion, 6% of nitrogen is used for growth of microbes (Giuntoli et al. 2015). This corresponds to 3.89 kg N per ton of digestate (Appendix F). Therefore, 43.65 t digestate was applied in one ha of grass; for 27,674 t/a digestate the area corresponds to 634 ha. The extra 16,865 t/a digestate was assumed to be spread on adjoining agricultural land. For the impact assessment, the GHG emissions from digestate storage, transportation, and field application were included in the assessment.

The benefits of digestate as a biofertiliser include avoiding the production of synthetic fertiliser and associated emissions. The commonly used synthetic fertilisers

in Ireland are Calcium Ammonium Nitrate (CAN), Potassium Chloride and Triple Superphosphate (Teagasc). The GHG emissions to produce 1kg of CAN, Potassium Chloride and Triple Superphosphate are 979g, 210g and 232g CO₂ eq., respectively (Thinkstep AG). Using digestate avoids the GHG emissions from producing synthetic fertilisers. According to ISO 14044, whenever possible the system expansion should be applied for the process which produces more than one product. Thus, the system expansion was applied in this research. Table 6-2 shows the total amount of nutrients needed, nutrients from digestate and the amount of nutrients that were substituted by the synthetic fertilisers in the grass field.

Spreading of lime on the field leads to CO₂ emissions; an emission factor of 0.12 was used (De Klein et al. 2006). GaBi lacks the data for herbicide application, harrowing, rolling and energy needed to produce grass seed. Hence, the data from Smyth *et al.* (Smyth, Murphy, and O'Brien 2009) was used.

Nitrous oxide (N₂O) is a GHG that has a GWP 298 times higher than that of CO₂ (EPA). In Ireland, applying fertilizer and emissions from animal wastes corresponds to 90% of N₂O emissions (Teagasc). N₂O is formed in the soil by nitrification and denitrification processes.

Phosphate (PO₄-P) is deemed to be discharged to the surface water at 1% of total P content in inorganic and organic fertilisers (van der Werf, Kanyarushoki, and Corson 2009). Indirect and direct N₂O emissions from synthetic and organic fertiliser were also calculated following the IPCC's guideline (Tier 1 method) (De Klein et al. 2006).

The direct emission factor (EF) of N₂O-N by applying synthetic fertilisers as well as organic fertiliser is one percent of total N.

Table 6-2. Inputs for grass silage production, nutrients from digestate and synthetic fertiliser

	Total nutrients required (kg/ha/a) (Smyth, Murphy, and O'Brien 2009)	Nutrients from digestate (kg/ha/a)	Nutrients substituted by synthetic fertiliser (kg/ha/a)
Nitrogen	259.37	170	89.37
Phosphorous	38.75	26	12.75
Potassium	308.75	66	242.75
Herbicide	0.72		
Seed	3.125		
Lime	1500		

The indirect N₂O emissions were calculated from the atmospheric deposition (ATD) of N volatilised from the managed soil, N₂O (ATD)-N, Eq. (6-3) and from N leaching/runoff from managed soils in regions where leaching/runoff occurs Eq. (6-4) (De Klein et al. 2006):

$$N_2O \text{ (ATD)} \text{ (kg } N_2O/a) = (FSN*0.1 + FON*0.2) * 0.01*44/28 \quad (6-3)$$

Where:

FSN = annual amount of synthetic fertiliser N applied to the soil in kg N/a

FON = annual amount of organic N added to the soil in kg N/a

$$N_2O \text{ (kg } N_2O/a) = (FSN + FON) * 0.3 * 0.0075*44/28 \quad (6-4)$$

FSN = annual amount of synthetic fertiliser N applied to the soil in regions where leaching/runoff occurs, kg N/a.

FON = annual amount of animal manure, compost, sewage sludge and other organic N added to the soil in regions where leaching/runoff occurs, kg N/a.

Using manure as a feedstock in AD reduces the GHG emission, as methane is processed and captured in a controlled environment. Using the dairy slurry provides a methane credit of 14.6% of the biomethane potential (Liebetrau et al. 2017). The biomethane potential of the dairy slurry is 239 L CH₄/kg VS (Wall, O'Kiely, and Murphy 2013).

6.2.1.3 *Electrolyser*

Proton exchange membrane (PEM) was selected as an electrolyser in this study as it was deemed most suitable to handle the fluctuations of the wind electricity (Vo, Xia, Rogan, et al. 2017). To consume the CO₂ produced from S2 (5,953 t/a) and S3 (6,201 t/a) (Vo et al. 2018), 1,082 t/a (S2) and 1,127 t/a (S3) H₂ is needed. The electrolyser plant (termed the distributed electrolyser plant (U.S . Department of Energy)) can be built beside a biogas plant thus negating the need for storage.

The total energy consumed to produce 1 m³ H₂ varies between 3.75 and 7.5 kWh (Götz et al. 2016, Marshall et al. 2007, Barbir 2005). In the future, the average energy consumption to produce 1m³ H₂ could reduce to 4.3 kWh (James et al. 2013). Therefore, this study used a conservative approach of 4.4kWh electricity to produce 1m³ H₂. This equates to 49 kWh electricity to produce 1kg H₂ (ca. 75% conversion

efficiency) (Appendix F). Hydrogen is produced closer to the biogas facility and hence the compression of 1 bar was used.

Deionised water is necessary for smooth operation of the electrolyser (Carmo et al. 2013). The deionised water used in this study was assumed to be produced via reverse osmosis. GaBi professional database (Thinkstep AG) provided the life cycle inventory (LCI) data for the production of deionised water. According to Eq. (6-1), 9.09 kg water is needed to produce 1 kg H₂. However, in reality, the water consumption is 25% higher (Barbir 2005); therefore, 11.36 kg water was used to produce 1kg H₂.

6.2.1.4 *Electricity mix*

This work assessed the LCA for the plants that will be built after 2020. Therefore, in the base case, an electricity mix from 2020 from EirGrid (Irish electricity utility) was used for all the electrical needs (SONI 2017). This projected electricity mix could be divided into steady evolution and low carbon living. The difference between these two electricity mixes are a 1.4% higher renewable share in low carbon living. This study used a conservative approach of steady evolution. This includes 41% renewables spread as follows: 36.3% wind electricity, 2.2% biomass/landfill gas, 2% hydropower, and 0.7% PV. The remaining electrical demand (59%) is met by fossil fuels, including natural gas (37.8%), hard coal (7.9%), peat (2.85%), distilled oil and heavy fuel oil (9.19%) and waste (0.74%). The GHG emissions from this 2020 electricity mix are 117g CO₂ eq. /MJ.

6.2.2 Life cycle impact assessment

The GaBi software (Leinfelden-Echterdingen, Germany, version 8.2) (Thinkstep AG) was used to perform the LCA of the three scenarios. The assessments were based on midpoint life cycle impact assessment method as recommended by the European Union Joint Research Centre (JRC) on LCA in the European context; these conform to ISO 14040 and 14044 requirements (EU-JRC 2010, International Organization for Standardization 1997).

The environmental impacts assessed in this study include global warming potential (GWP), acidification potential, freshwater eutrophication potential, particulate matter emission (PM_{2.5}) and ozone depletion potential.

6.2.2.1 Global warming potential (GWP)

Greenhouse gases (GHG) such as CO₂, CH₄ and N₂O trap heat in the atmosphere at different capacities due to radiative forcing. GWP refers to the equivalent amount of GHG released to the atmosphere from a process, expressed in terms of kg CO_{2eq}. The IPCC developed this metric to compare global warming impacts of different GHGs. The different GHGs were converted to CO_{2eq}, as CO₂ corresponds to the most abundant GHG with uniformity in reporting. The GWP reporting period used in this study is 100 years (GWP 100).

6.2.2.2 Acidification potential

Acidifying substances such as sulphur oxides, nitrous oxides and ammonia increase the hydrogen ion concentration in the atmosphere which leads to acid rain.

Acidification potential measures the amount of acids emitted as mole H⁺ eq. This is a relative unit for different acids measured.

6.2.2.3 Freshwater eutrophication potential

The excess nutrient release from a process leads to augmentation of the aquatic ecosystem. This results in environmental issues such as eutrophication. Eutrophication potential measures amount of excess nutrient released as kg P_{eq}.

6.2.2.4 Particulate matter \ Respiratory Inorganics

This category measures the fine particulate matter (PM_{2.5} eq.), a critical environmental impact category that affects human health. An intake fraction concept was used to calculate this impact category (Agostini et al. 2015).

6.2.2.5 Ozone depletion potential (ODP):

ODP expresses the potential degradation of gases on the ozone layer compared with trichlorofluoromethane (CFC-11), which is set at an ODP of 1.

6.2.3 Sensitivity analysis

The effects of four crucial factors were assessed. Three of these related to the biogas system: CO₂ sequestration in the soil; ratio of slurry and grass silage in the feedstock; the fugitive emissions in the biogas facility. The fourth relates to the power to gas system and is seen as the critical parameter in such systems; the carbonisation level of the electricity.

6.2.3.1 *CO₂ sequestration in soil*

The base case did not include for carbon sequestration by photosynthesis in the LCA; the rationale for this is expanded upon in section 6.3.1. Within the grass silage production, carbon is captured by the grass and the soil; grasslands are identified as a CO₂ sink source (Scurlock and Hall 1998). Kiely et al. (Kiely et al. 2017) showed that the Irish grassland soil has a large potential for carbon sequestration. Tillage practice releases CO₂ back to the atmosphere from the soil (Rastogi, Singh, and Pathak 2002, Davidson and Ackerman 1993, Pinheiro et al. 2015). However, grasses are perennial and tillage is not necessary. Grasslands may be reseeded every 4 to 8 years in theory (and less often in practice); direct sowing is recommended for grasslands (Smyth, Murphy, and O'Brien 2009). Earlier studies (Korres et al. 2010, Jones and Donnelly 2004) reviewed carbon sequestration rates of temperate grasslands across the EU. The results from their study showed that CO₂ sequestration varied between 0.6 and 8.7 t C ha⁻¹ a⁻¹. In the sensitivity analysis the CO₂ sequestration from the soil was considered conservatively at 0.6 t C/ha/a. This equates to 2.2 t CO₂ /ha/a.

6.2.3.2 *Feedstock*

In the base case, grass and slurry were used on an 80:20 VS basis. Using slurry as a feedstock reduces the GHG emissions due to the mitigation of methane emitted from open storage systems (Agostini et al. 2015). For the sensitivity analysis, 60:40 VS ratio of grass silage and slurry was evaluated for S1, S2 and S3. The mass and energy balance data was obtained based on the modified process using SuperPro designer (Intelligen Inc., Scotch Plain, NJ, V10)(Vo et al. 2018). The amount of grass silage for

the variations was maintained at 25,344 wet weight t/a (7,603 tDS/a at 30% DS and 7096 t VS/a at 28% VS). The amount of slurry varied depending on the VS ratio used. If grass silage accounted for 60% of the VS in the feedstock and dairy slurry 40% of the VS in the mix, then the wet weight of dairy slurry (6.7% VS) per year would be 70,607 t. This yields a ratio of 26:74 grass silage to slurry ratio on a wet weight basis. The utilities consumption and energy production data were presented in Appendix F.

6.2.3.3 Fugitive methane emissions

The fugitive emissions in a biogas plant can vary between 1% and 7% of the produced biomethane (Liebetrau et al. 2017). The base cases assumed 2% methane fugitive emissions, while the sensitivity analysis evaluated 6% methane fugitive emissions.

6.2.3.4 Carbonisation level of the electricity

The primary or theoretical purpose of converting power to gas is to store the excess renewable electricity and convert to a renewable decarbonised gaseous energy vector. To ensure sustainability, the share of renewables in the electricity grid should be significant. Generating hydrogen from brown electricity produces brown hydrogen and as such is not deemed renewable. The majority of renewable electricity such as wind and solar are intermittent sources. This is also the reason why higher penetration of intermittent renewable electricity in the grid is not easy. Earlier studies investigated the possibilities of higher penetration of renewables in the grid. The results concluded that flexibility of the grid and external storage were the two factors that can help achieve higher penetration of renewables in the grid (Hohmeyer and Bohm 2015) (Denholm and Hand 2011). International Energy Agency (IEA)

forecasts that the global renewable electricity share by 2050 will be between 57% and 71%; this needs a strong policy support (Guandalini et al. 2017). Denmark for example plans for 100% renewable electricity by 2050 (The Danish Government 2013).

The base case used a 2020 electricity mix from the EirGrid. Even though the level of renewable was 41% which is relatively admirable and a significant improvement over the last 20 years, the mix is still 59% fossil or brown. However, in future scenarios there is an absolute necessity to decarbonise electricity through increasing the share of renewable sources. The EirGrid projection for 2040 was evaluated. This 2040 projection could be divided into four categories including steady evolution, low carbon living, slow change, and consumer action. Low carbon living was assessed in the sensitivity analysis. The share of electricity from different sources are as follows: fossil natural gas sources (24.5%), with the remaining 75.5% renewable and consisting of: wind (50.4%), PV (18%), biomass and landfill gas (including biogas CHP) (4.1%), hydro (1.2%), ocean energy (1.3%) and energy from waste (0.5%). The electricity from biomass and landfill gas were split equally for landfill gas and biogas CHP. The emissions for different electricity sources were retrieved from GaBi (Thinkstep AG), excluding ocean energy. As GaBi lacks the data for wave and tidal energy, the data from Uihlein (Uihlein 2016) was used. The GWP, ozone depletion and freshwater eutrophication per kWh of wave energy are: 43.7 gCO₂eq., 1.8g CFC-11 eq. and 0.16 mg P eq. respectively. The carbon intensity for the electricity 2040 mix is 38.5 gCO₂eq/MJ electricity produced; this is 33% of the carbon intensity of the 2020 modelled mix. A theoretical 100% renewable electricity mix (with 75% from

wind electricity and 25% from other renewable sources) was also assessed in this sensitivity analysis.

6.3 Results and discussion

6.3.1 Carbon balance

A carbon balance analyses was undertaken to understand the flow of carbon from grass cultivation to the production of methane and associated emissions when released back to the atmosphere. Wall et al. (Wall, O’Kiely, and Murphy 2013) previously calculated the chemical formula of grass silage and dairy slurry based on VS content as $C_{30}H_{50}O_{23}$ and $C_{22}H_{34}O_{19}$ respectively. Based on volatile solids content, carbon accounts for 46.27% and 43.85% of grass silage and slurry respectively. The dairy slurry has a lower volatile solids content (6.7%) than grass silage (28%) (Wall, O’Kiely, and Murphy 2013). The photosynthesis process results in sequestration of 130 kg carbon for every ton wet weight of grass silage produced, it equates to 475 kgCO₂/t wet weight. In 1 ha of grassland, ca. 40 wwt (wet weight tonne) grass silage is produced, which holds 5,182 kg C (19 t CO₂) in the above ground grass which is cut for silage. Further carbon is sequestered in the soil below the grass (Saggar, Hedley, and Mackay 1997, Smyth, Murphy, and O’Brien 2009). Likewise, a wet weight ton of dairy slurry has 29 kg carbon (107 kg CO₂). Figure 6-2 shows the carbon balance for different scenarios used in this study on a 1t wet weight slurry and 1t wet weight grass basis. Scenario 1, which does not capture carbon dioxide in the upgrading process releases 43% carbon in the form of methane, 39.5% as CO₂, and the digestate holds 18.5% of the carbon. Using power-to-gas systems, S2 and S3 capture CO₂ and

release 79.5% of the carbon in methane with the remaining carbon held in digestate. The amount of carbon released from CO₂ in S1 and S2 decreased from 39.5% to less than 0.07% respectively. S2 and S3 have a higher percentage of carbon that can be used for energy compared with S1, due to CO₂ capture. In this work in the base case study, the CO₂ sequestered by photosynthesis and the CO₂ emission due to methane combustion were not considered in the LCA calculations as the absorption and emission would be in theory neutralized by each other. Therefore, the emissions from combustion of renewable methane are set to zero.

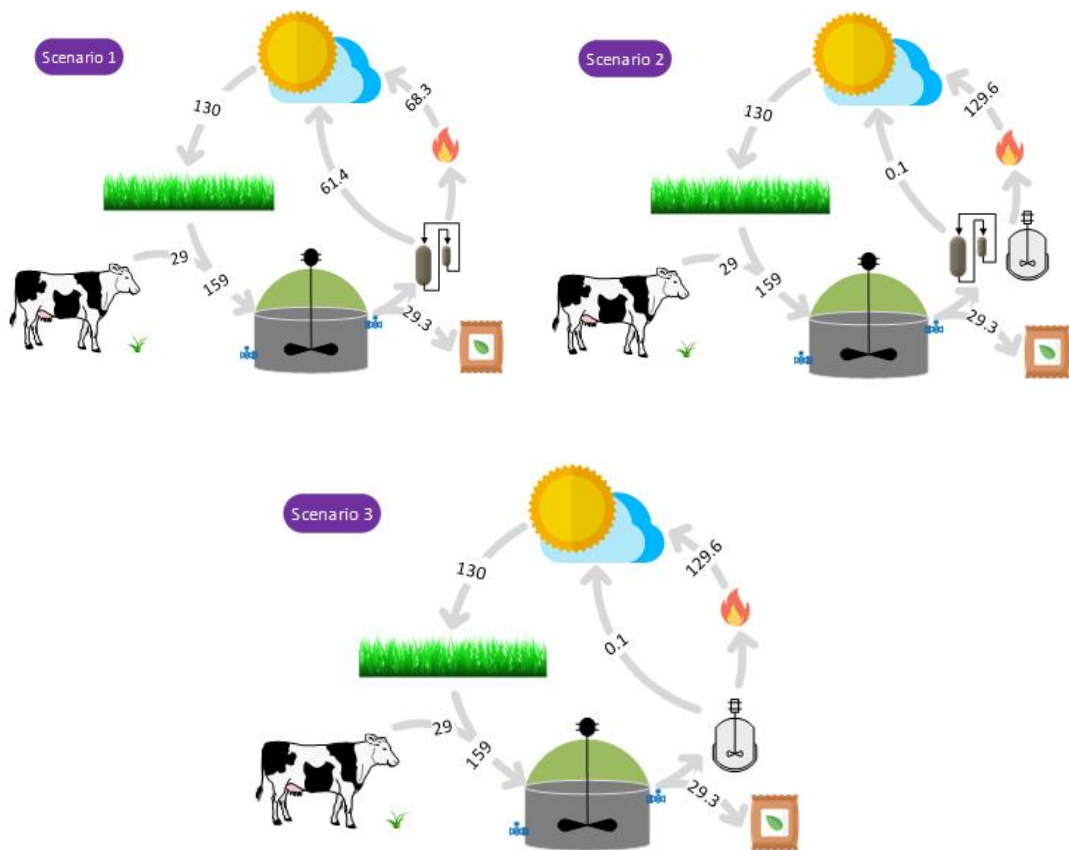


Figure 6-2. Carbon balance in three scenarios based on 1 tonne of slurry and 1 tonne of grass on a wet weight basis.

6.3.2 Life cycle impact assessment

6.3.2.1 Process contributions

Figure 6-3 & Figure 6-4 show the process contributions as a percentage of different impact categories. There are different processes in the whole chain including silage production, transportation, biogas production, upgrading by amine, electrolysis and biological methanation. Of the different processes, electrolysis is a dominant contributor for all categories except eutrophication impact. The electrolysis process alone contributes to 80% of GHG emissions; 86% of acidification; 70% of ozone depletion and 85% of particulate matter (S2 and S3). This high-impact is due to the significant consumption of electricity (0.235 kW_eh/MJ biomethane or 0.357 kW_eh/MJ hydrogen) as it converts electricity to hydrogen. In essence the carbon intensity of the hydrogen is increased beyond that of the electricity by the reciprocal of the efficiency in converting electricity to hydrogen expressed as a decimal. The Irish 2020 grid mix contains 41% renewables and 59% fossils. This high amount of fossil electricity leads to higher environmental impacts.

Grass silage cultivation contributes the most to freshwater eutrophication and GWP in S1 (45%). Eutrophication is due to the nutrient value of the fertiliser and its potential leakage of phosphorous, while the GHG emissions are from fertiliser production, fieldwork activities and emissions from applying fertilisers.

For all scenarios, the share of GWP contributions were split between the biogas production, compression, upgrading by amine and biological methanation (Figure 6-3). It should be noted that the amount of methane produced in S2 and S3 is

significantly increased by power-to-gas upgrading, which reduced the emissions per functional unit. Using the slurry as a co-digestion substrate mitigates GWP at the rate of 29% in S1, 4% in S2 and S3. When the digestate was applied at other fields, the credit for avoiding synthetic fertiliser production for S1 is 6%, and 0.8% for S2 and S3. For the digestate applied at the grass fields, the credit was automatically calculated in GaBi for grass cultivation process. For S1, the fugitive methane emissions correspond to 29% of the GWP, which is significant. This highlights the importance in reducing fugitive emissions to reduce the GWP. The use of diesel in the transportation contributes 41% in S1, 4% in S2 and S3 to PM2.5 and 31% in S1, 2.5% in S2 and S3 to acidification.

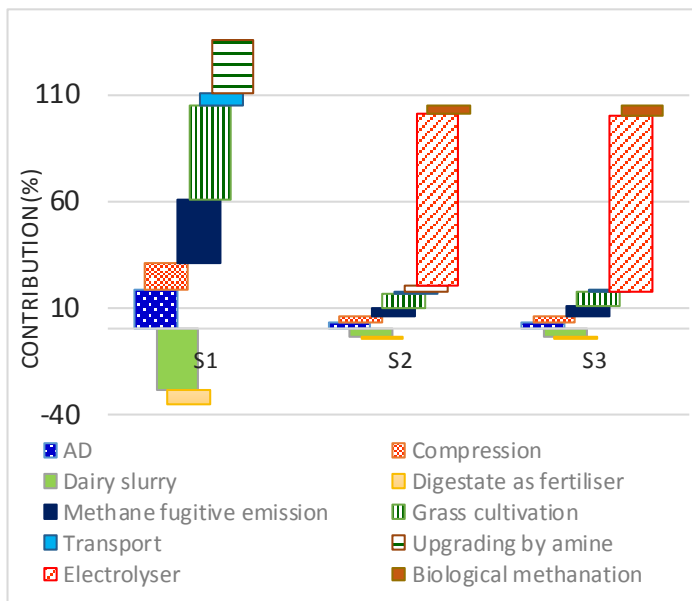


Figure 6-3. Percentage contributions of S1, S2 and S3 to global warming potential.

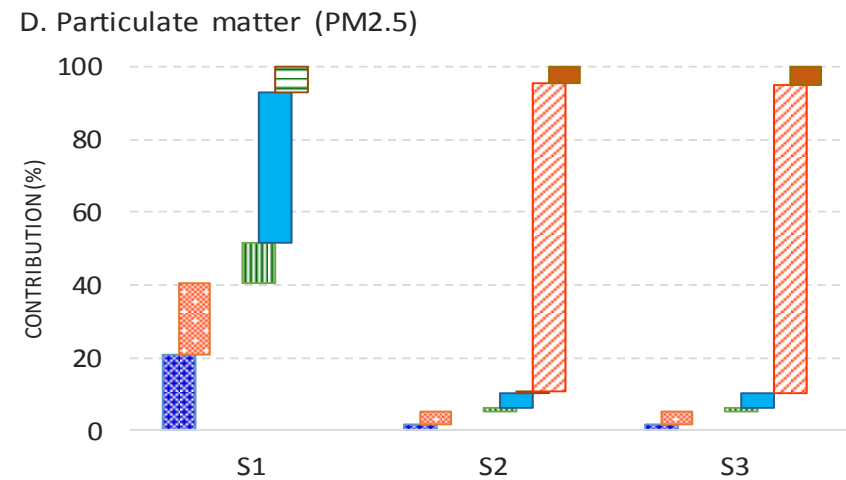
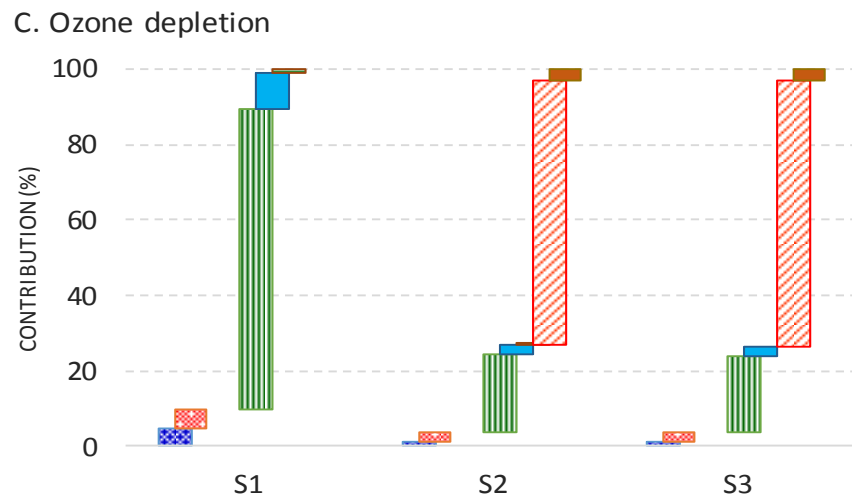
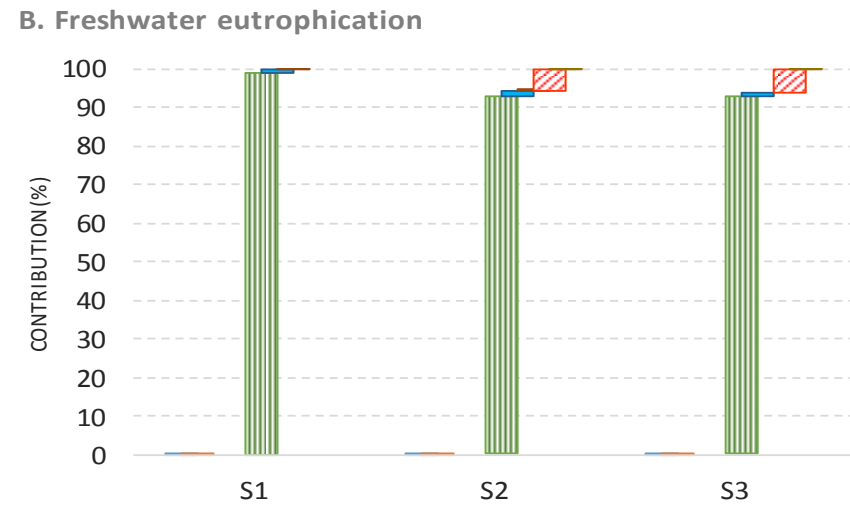
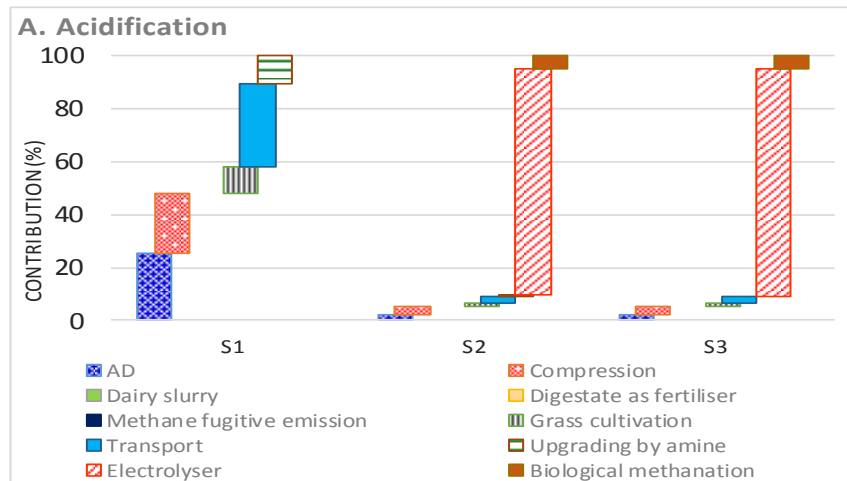


Figure 6-4. Percentage contributions of different processes to impact categories

6.3.2.2 *Global warming potential*

The GWP in S1 was the lowest at 34 g CO_{2eq} per MJ. Scenario 3 reduced the GWP by 3.2% as compared to Scenario 2, which used both amine scrubbing and biological methanation in upgrading. However, the GWP of S2 (124 g CO_{2eq} per MJ) and S3 (120 g CO_{2eq} per MJ) were approximately 3.5 times higher than S1. The use of 2020 Irish grid mix (with 41% green electricity) for the hydrogen production in the electrolysis led to this high GWP. It may be said that P2G does not improve the sustainability of biomethane systems when used to upgrade biogas if the source of electricity is 59% brown.

6.3.2.3 *Other environmental impact categories*

The accumulated exceedance method was used to calculate the acidification potential, which is expressed as mole H⁺_{eq} (Agostini et al. 2015). The major contribution to acidification potential is sulphur dioxide (43% - 68%) and nitrogen oxides (31%-46%) (Figure 6-5). The emission of nitrogen oxides was 10% higher than sulphur dioxide in S1, but N₂O was 25% lower than sulphur dioxide in S2 and S3. Nitrogen oxides in S1 are due to transportation; a major share of sulphur dioxide in S1 is emitted from biogas production and compression. Overall, biogas production, compression, and transport of grass in S1 have contributions of the same order to acidification potential. The acidification of S2 and S3 are six times higher than that of S1. The use of grid electricity in the electrolyser resulted in higher emissions of sulphur dioxide, which affected the acidification potential for S2 and S3.

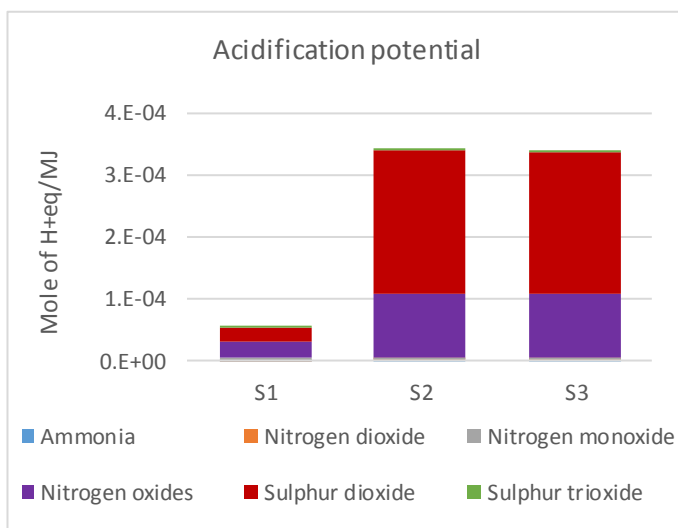


Figure 6-5. The contribution of different substances to acidification potential

In all scenarios, the grass silage production is the main contributor to freshwater eutrophication potential. Among the five impact categories, only freshwater eutrophication potential in S1 is higher than that of S2 and S3 (Table 6-3). This impact is due to the phosphate emission from phosphate fertiliser to the fresh water in grass cultivation. The reason for higher potential in S1 is the almost doubling of renewable methane output in S2 and S3.

The larger consumption of deionised water and electricity used in the electrolyser had a high impact on the ozone depletion potential (Table 6-3). Moreover, the production of calcium ammonium nitrate fertiliser also contributes to this category. PM_{2.5eq} effects the local atmosphere due to the contribution of potassium chloride fertiliser. The transportation of grass from the field to the biogas plant also contributes to this impact category.

Scenario 1 has two times higher potential in freshwater eutrophication than S2 and S3. Acidification potential and particulate matter (PM2.5eq) are higher in S2 and S3 than S1 (Table 6-3). The renewable methane production is almost doubled in S2 and S3, which reduced the environmental impacts because of grass production. In contrast, the use of the electrolyser in S2 and S3 resulted in higher other categories compared with S1.

Table 6-3. Impacts of different scenario to impact categories per MJ

Impact categories	Unit	S1	S2	S3
GWP	gCO ₂ eq	34	124	120
Acidification	Mole of H ⁺ eq.	5.31E-05	3.41E-04	3.38E-04
Eutrophication freshwater	kg P eq.	8.09E-07	4.46E-07	4.39E-07
Ozone depletion	kg CFC-11 eq.	1.42E-14	2.81E-14	2.80E-14
Particulate matter	kg PM2.5 eq.	2.91E-06	1.63E-05	1.62E-05

6.3.3 Sensitivity analyses

6.3.3.1 Carbon sequestration in soil.

Each ha of grassland produces 40 wwt grass silage. To produce 1MJ of renewable methane the area under grass cultivation needed for S1, S2, S3 was 0.0544 m²; 0.0281 m² and 0.0276 m². Using an alternative metric, the gross energy production per hectare is 183, 356 and 362 GJ/ha/a for S1, S2 and S3 respectively. The sensitivity analysis considered sequestering 2.2 t CO₂ ha⁻¹ a⁻¹ into the soil. Sequestering the CO₂ reduced the GWP of S1, S2 and S3 to 22, 118 and 114 g CO₂eq./MJ respectively. When

compared with the base case, carbon sequestration in the soil lowers the GWP of S1 by 35%, S2 and S3 by 5%.

6.3.3.2 *Co-digestion of grass silage and slurry at different ratios*

In the base case, the ratio of grass silage and slurry was 80:20 on a VS basis. The ratio of the slurry was increased to 40% on a VS basis in the sensitivity analysis to check its effect on GWP. The result shows that the GWP of 60% VS grass silage and 40% VS slurry ratios was 19 gCO_{2eq}/MJ (S1). The base case reported a GWP of 34 gCO_{2eq}/MJ; thus, increasing the slurry from 20% to 40% VS in the mix decreased the GWP by 43.4% (S1-IS). Increasing the slurry also increases the amount of nitrogen in the digestate. Replacing the fossil fertilizer with biofertilizer increases the GHG emission savings. The methane credit increased from 29% to 102% due to the higher portion of slurry used and the methane slippage from open slurry holding tanks displaced. However, the GWP savings did not increase proportionally to slurry added. Slurry suffers from high water content (91.2%) leading to higher electricity and heat parasitic demand lowering the potential reduction in GWP. The GHG credit for replacing fossil fertilisers increased from 6% to 24%. This shows that slurry contributes significantly in reducing GHG emissions in a biogas plant.

However, this increased slurry did not have a significant effect on the GWP reduction in S2 and S3; the GWP in S2 and S3 were 118 and 117 gCO_{2eq}/MJ, respectively. When comparing with the base cases, the GHG reduction varied from 2.5% to 5%. Electricity used to produce H₂ accounted for 80% of the GHG emissions in S2 and S3 and as such the emissions credit from slurry has a lesser effect on the overall system including

P2G. Therefore, increasing slurry content of the feedstock is not an effective method to reduce GHG emission in S2 and S3.

6.3.3.3 *Methane fugitive emissions*

Increasing the fugitive methane emissions from 2% to 6% in the sensitivity analysis increased the GWP for all the scenarios. The GWP for S1, S2 and S3 at 6% fugitive emissions were 57, 138 and 137 gCO₂eq/MJ. When compared with the base case, increasing the fugitive emissions increased the GWP by 40% in S1, 10% in S2 and S3 respectively. Minimizing the methane emissions plays an important role in reducing the GHG emissions of the biogas plant. IEA Bioenergy (Liebetrau et al. 2017) recommended measures to reduce methane slippage including gas tight digestate tanks, or complete degradation, frequent leakage control surveys, avoidance of open handling and storage of digestate under anaerobic conditions, and gas management.

6.3.3.4 *Electricity*

The base case scenarios used the Ireland electricity mix projected for 2020, which contains 41% renewable electricity. In the sensitivity analysis, the proposed 2040 grid mix containing 75.5% renewable electricity was evaluated. The GHG results of S1, S2, and S3 when consuming 75.5% renewable electricity were 28, 49 and 45.5 gCO₂eq/MJ. Replacing the 41% renewable electricity mix with the 75.5% renewable electricity reduced the GWP 1.2-fold in S1 and 2.5 times in S2 and S3. Thus, as expected greening of the electricity, will green the hydrogen used in the power to gas process significantly improving the renewable methane in S2 and S3. Increasing the level of renewables in the electricity grid did not increase the GHG savings for S1 at

the same rate as it did in S2 and S3. This is due to the reason that for S1, the electricity is used as a utility satisfying parasitic demand, while for the other scenarios it is the precursor for hydrogen production, which is the source of almost half the renewable methane.

6.3.3.5 Greenhouse gas savings

The recast Renewable Energy Directive (RED recast) proposed to use 94 gCO₂eq/MJ as a fossil fuel comparator (FFC) for transportation (EC 2017). The data from the base case and all sensitivities were compared to the RED recast (Table 6-4).

Among the various sensitivities assessed, only S1 meets the sustainability criteria under the following conditions: 1. Carbon sequestration of 0.6t C/ha/a in the soil; 2. Increasing the slurry from 20% to 40% on a VS basis; 3. Electricity grid mix from 2040 with 75.5% renewables; 4. Under the combination of these conditions (Optimum). The optimum conditions in S2 and S3 could save only 60% and 63% GHG emissions. These conditions did not satisfy the RED recast of 70% GHG savings

The questions posed in this chapter are *“Can power to methane systems be sustainable and can they improve the carbon intensity of renewable methane when used to upgrade biogas produced from grass and slurry?”* An answer at this stage is no and no even with electricity at 75.5% renewable. It is necessary to find out under what conditions power to gas systems can be deemed sustainable when used to upgrade biogas.

Table 6-4. Greenhouse gas savings of sensitivity analysis in comparison with fossil fuel comparator from the EU.

Scenario	Name	GWP (CO ₂ eq)	GHG Savings with RED recast (%)
S1	Base case	34	64
	CO ₂ sequestration in the soil	22	77
	60 GS: 40 Slurry (VS basis)	19	80
	6% fugitive emissions	57	39
	2040 -75.5%renewable electricity	28	70
	Optimum	S1-Optimum	3.9
S2	Base case	124	-32
	CO ₂ sequestration in the soil	118	-26
	60 GS: 40 Slurry (VS basis)	118	-26
	6% fugitive emissions	138	-47
	2040 -75.5%renewable electricity	49	48
	Optimum	S2-Optimum	38
S3	Base case	120	-28
	CO ₂ sequestration in the soil	114	-21
	60 GS: 40 Slurry (VS basis)	117	-25
	6% fugitive emissions	137	-46
	2040 -75.5%renewable electricity	45.5	52
	Optimum	S3-Optimum	35

Note: The negative value indicates those scenarios had higher GWP than the FFC. The green colour represents those scenarios that meet the GHG emission savings in comparison with RED, while the red colour represents the scenarios that did not meet the recast RED criteria. Optimum case includes 2% fugitive methane emissions, 60:40 slurry grass, CO₂ sequestration and 75.5% green electricity

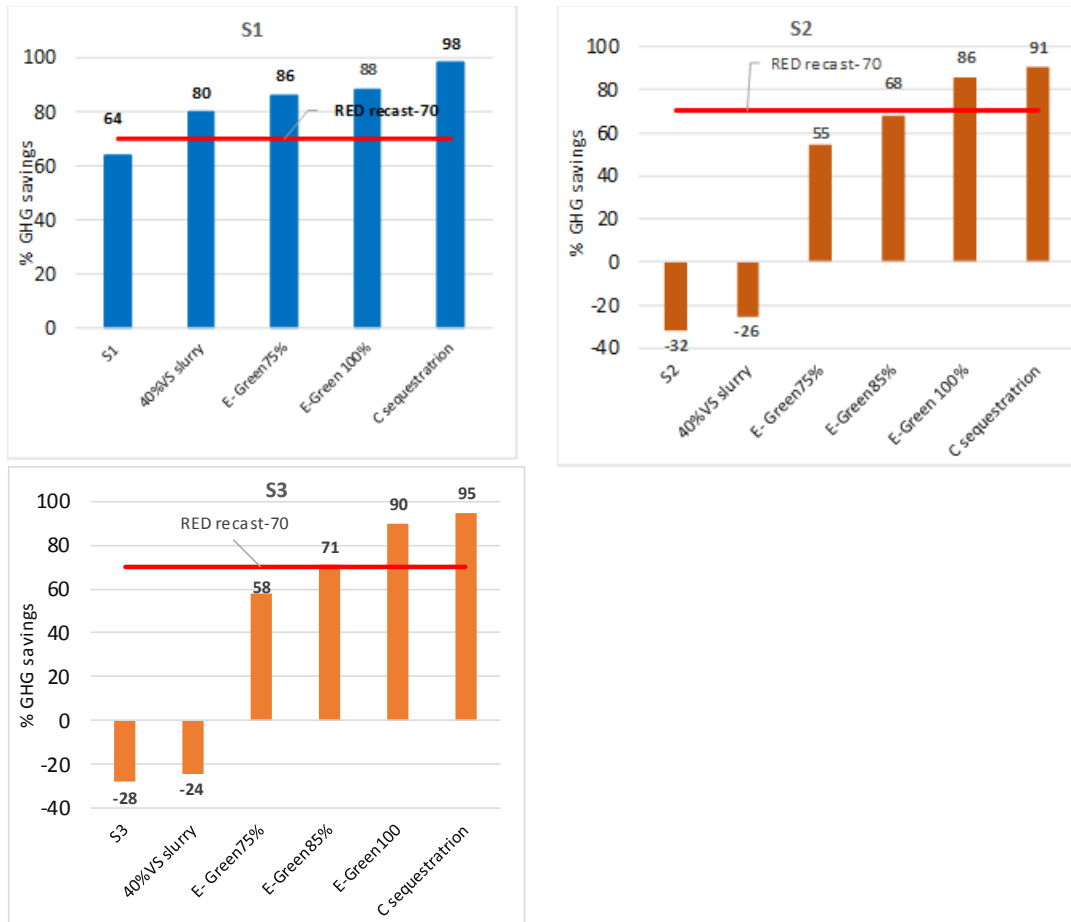


Figure 6-6. Cumulative (left to right) percentage GHG savings (e.g C sequestration for S1 included electricity 100% green and 60:40 grass slurry)

To examine this the share of renewables in the electricity grid was increased from 75.5% to 85% to 100%, which obviously had a positive effect on the GHG savings (Figure 6-6). S2 and S3 both surpassed the 70% GHG savings criteria. With greening electricity S2 and S3 can both surpass the 70% GHG savings criteria. When the electricity for the processes are 100% renewable, the GHG saving for S3 increased from -24% (40% VS slurry, 40% renewable electricity) to 90%. This shows that the

share of renewables in the grid is crucial for P2G as an upgrading choice for renewable methane production to meet the RED recast sustainability criteria.

6.3.4 Data comparison with literature

Figure 6-7 shows the data comparison from this study to the earlier studies reported in the literature. To meet the RED recast of 70% GHG savings, the GWP of renewable methane should be less than or equal to 28 gCO₂eq/MJ.

The GWP of the grass silage and slurry production (S1) is higher than the seaweed, ley crop and cereal crop; but is comparable with maize. If only grass is used as a feedstock, it produces more GHG than when co-digested with slurry; the GWP drops from 49.7 (only grass) to 34 (S1 50:50 grass silage slurry on a wet weight basis) and to 19 gCO₂eq/MJ (S1-IS allowing for carbon sequestration in grass lands). This shows the importance of slurry in decreasing the GWP of renewable methane. The fugitive emissions from the biogas plants have a considerable impact on the GWP. When comparing the literature that used open digestate storage (Biowaste-O, Maize-O) (EC 2017) and 6% fugitive emissions (this study) with the GWP of closed digestate storage (Biowaste-C, Maize-C) (EC 2017) and 2% methane slippage (this study), the latter had lower GHG emissions. This means that reducing the methane slippage is another key factor in reducing the GHG emissions.

The GWP of catalytic P2G (when not used as an upgrading unit) in the literature was 113 gCO₂/MJ (Parra et al. 2017). When the biological methanation is considered as an upgrading unit, the GWP was 133 gCO₂/MJ (this study). When more renewable electricity was used in S2 and S3, the GWP of those two-scenarios decreased

significantly to 45 and 49 gCO₂eq/MJ as in S2-Green75.5% and S3-Green75.5% and to 30.5 and 27 gCO₂eq/MJ as in S2-Green85% and S3-Green85%. This further drops to 1.8; 8.87; 5.08 gCO₂eq/MJ For S1; S2 and S3, respectively if electricity is 100% green and carbon sequestration into soil was considered. Similar results were reported in the literature for P2G unit, which consumed wind electricity resulting in a GWP between 6 and 29 gCO₂/MJ (Parra et al. 2017).

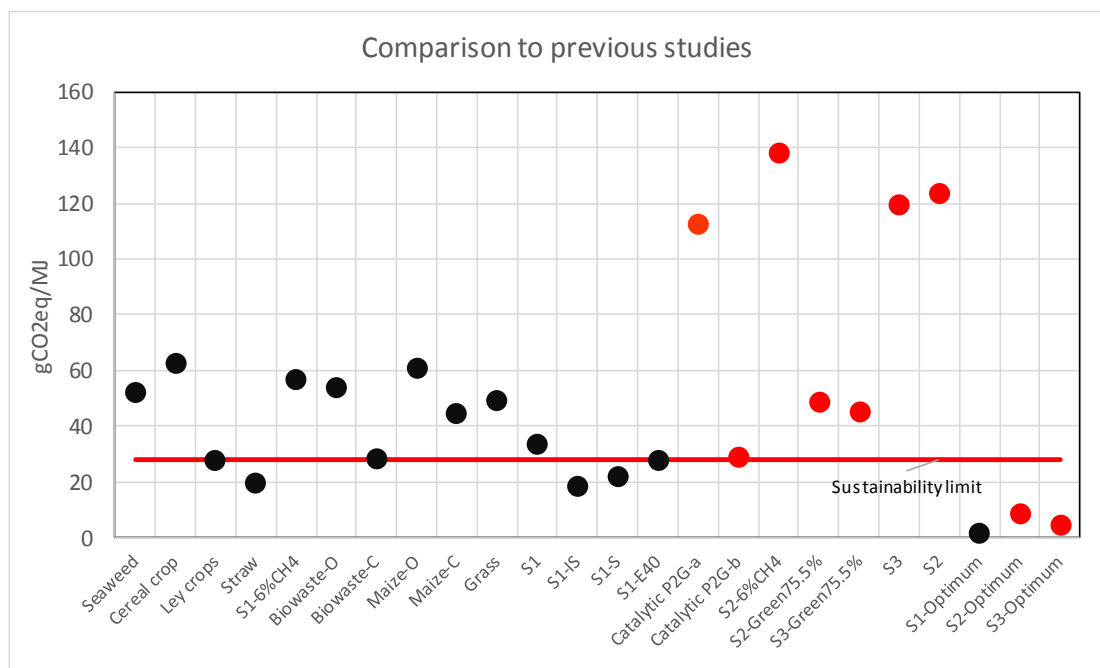


Figure 6-7. Comparison of output to previous studies on sustainability of biomethane systems

Note: O- open digestate storage; C- Close digestate storage;

Seaweed (Czyrnek-Delêtre et al. 2017); cereal crop (Buratti, Barbanera, and Fantozzi 2013); biowaste – O & C, maize whole plant – O&C (EC 2017); ley crops, straw (Uusitalo 2014); grass (Korres et al. 2010); catalytic P2G-a&b(Parra et al. 2017), of which P2G –b consumed wind electricity; all S scenarios – this study. The red dots are for the processes involved P2G, the black dots are for biogas plants with traditional upgrading units.

6.4 Conclusions

The question posed in this paper is *“Can power to methane systems be sustainable and can they improve the carbon intensity of renewable methane when used to upgrade biogas produced from grass and slurry?”* The biogas system considered a grass silage slurry system. According to the recast renewable energy directive, biofuels need to have a 70% GHG savings as compared to the fossil fuel displaced on a whole life cycle analysis to be considered as an advanced transport biofuel. This chapter undertook a life cycle assessment of biomethane with and without carbon utilisation in a P2G system.

The optimised biogas system in terms of sustainability included for larger percentages of slurry than grass silage to avail of the carbon credit in displacing open storage of slurry, minimisation of methane slippage, and allowing for carbon sequestration in the soil. This system readily met the 70% GHG savings criteria.

The P2G system was heavily influenced by the source of electricity. The carbon intensity of the hydrogen is increased beyond that of the electricity by the reciprocal of the efficiency in converting electricity to hydrogen expressed as a decimal. As the electrolysis efficiency was assumed at 75%, the hydrogen had a 33% higher carbon intensity than that of the electricity. To meet the RED recast sustainability criteria, the carbon intensity of the electricity needed to be less than 15%. Thus, the answer to the question posed is that power to gas systems can be sustainable but are unlikely to improve the sustainability of biomethane systems when they are used to upgrade biogas, if the electricity supply has an element of fossil fuel.

Chapter 7 Conclusions and recommendations

7.1 Overview

The thesis had an ambition to assess the sustainable, feasible development of the combination of the P2G process with a biogas facility by considering three overarching parameters: technical, economic and environmental. In order to evaluate these parameters, the thesis needs to answer these research questions:

- How sustainable is P2G when compared to other large-scale storage technologies? (Chapter 3)
- What is the combined production cost of renewable gas produced from AD&P2G from a range of feedstocks? (Chapters 4 & 5)
- What is the potential capacity of CO₂ from biogas sources and what are the GHG emissions reductions if the P2G process is applied? (Chapters 4 & 6)
- What parameters would affect the production costs and environmental impacts of renewable methane? (Chapters 4, 5 & 6)

7.2 Conclusions

The following sections summarise the conclusions of this thesis corresponding to these research questions.

7.2.1 Sustainable of P2G and other large-scale storage technologies (Chapter 3)

The development of any renewable energy requires balance between economic development, environmental protection, and social equity. Due to the involvement of many criteria and indicators, the sustainability assessment is complex. The sustainability of P2G, CAES and PHES were evaluated by exploring and comparing seven criteria. The results of a single criterion highlighted that the investment cost and the efficiency of PHES are better than that of CAES and P2G. Nevertheless, when taken into account of the ability to change the energy vector; the storage capacity and the duration of storage; the flexibility of the geographical situation and CO₂eq emission, P2G was assessed as the most sustainable.

7.2.2 Combined production cost of renewable gas (Chapters 4 & 5)

Chapter 4 and chapter 5 both calculated the production costs of renewable methane, but each had a different approach. Chapter 4 used secondary data as inputs for an Excel spreadsheet to calculate the production costs of renewable methane from a range of feedstocks such as: grass, slurry, SHW, OFMSW, and seaweed. Chapter 5 focused on the production cost of grass silage and slurry at an 80:20 VS mix via a simulation software – Superpro Designer. Moreover, the configuration of the process in chapter 4 was generic in nature; the chapter did not focus on any specific configuration. However, chapter 5 focused on specific processes in detail: biogas + upgrading by amine; biogas+ upgrading by amine and methanation; and biogas + upgrading by methanation. In conclusion, the production costs of renewable gas from AD&P2G processes are higher than that of renewable gas from the biogas plant with

standard upgrading processes (an amine scrubber in this instance). The cost of renewable methane varied from €1 to €2.5 per m³ renewable methane depending on what type of feedstocks. It was assumed that the electricity to produce hydrogen was obtained on the wholesale market with a bid price of €0.05/kWh. Among those feedstocks, renewable methane from grass and slurry (at an 80:20 VS mix) had the lowest production costs, in the range €1 to €1.09/m³ renewable methane. Renewable methane from OFMSW had a production cost of €1.4/m³ renewable methane; this benefited from a gate fee and avoidance of costs in feedstock production. The renewable methane produced from seaweed feedstocks accounted for the highest production cost: €2.5/ m³ renewable methane. The seaweed cultivation and costs were based on conservative values utilising current available technologies. The production cost could be lower if advanced cultivation and biogas production technologies are available in the future. The production cost of renewable methane from slurry feedstock in mono-digestion was also high, €2.4/ m³ renewable methane. However, if slurry is utilised as feedstock for biogas, it is beneficial in GHG emission reduction due to the avoidance of CH₄ emission storing raw slurry in open slurry tanks. The minimum selling price of renewable methane from grass and slurry in a biogas plant upgraded by amine was also assessed in chapter 5 as €0.76 per m³ renewable methane.

7.2.3 Potential capacity of CO₂ from biogas sources and GHG emissions reductions in P2G process (Chapters 4 & 6)

Chapter 4 contains information on potential capacity of CO₂ from biogas sources. Previous literature did not include a resource of seaweed and as such Chapter 4 is the first to undertake an assessment of the potential capacity of CO₂ from biogas plant fed by seaweed. Other feedstocks such as grass, slurry, SHW, and OFMSW were adapted from previous studies. The potential capacity of CO₂ from biogas in Ireland would be 430.6 Mm³ per year if all potential feedstocks were used for an AD plant. This would allow storage of 7,654 GWhe of electricity per year. This chapter also evaluated that 97 tonnes CO₂ were utilised for 1 GWh of electricity used to produce hydrogen for upgrading biogas in a P2G system.

Similar to the calculation of the production costs, this thesis also applied two methods to evaluate GHG emissions. In chapter 4, the data from previous studies were used to calculate the GHG emission via an Excel model of all feedstocks: grass, slurry, SHW, OFMSW and seaweed. However, the limitation of this method is each reference had a different way to calculate GHG emissions with different boundaries, thus, the reference data were inhomogeneous.

In the light of this, chapter 6 applied a professional life cycle analysis software – GaBi- to evaluate the GHG emissions of renewable methane from a co-digestion feedstock: grass silage and slurry. The GWP of renewable methane from biogas with an amine upgrading unit was much lower than that from biological methanation upgrading. In a conservative base case the carbon intensity was 34 gCO₂eq (amine upgrading)

compared to 120 g CO₂eq (biological methanation upgrading) per MJ with 41% of the electricity sourced from renewables.

7.2.4 Effects of parameters on the production costs and environmental impacts of renewable methane (Chapters 4, 5 & 6)

7.2.4.1 Renewable methane production costs:

The cost of electricity to produce hydrogen had a significant effect on the production cost of renewable methane. This was highlighted in chapter 5. Changing the price of electricity by €0.05/kW_{eh} to produce H₂ resulted in a change of renewable methane production cost of €0.41/mn³ CH₄. Meanwhile, the feedstock cost did not have as big an influence on the cost of renewable methane in the AD&P2G combined system; however, the feedstock cost had a bigger effect on the cost of biomethane from a biogas with traditional upgrading only. Varying the price of grass silage by €13.5 per tonne, the renewable methane from AD&P2G fluctuated by €0.05/mn³ CH₄ and from AD plant varied by €0.1/mn³ CH₄. This is due to the fact that approximately half of the produced methane in the AD&P2G system is from electricity.

7.2.4.2 Environmental impacts of renewable methane:

The GHG emission of renewable methane from AD&P2G was strongly affected by the GHG emission of electricity. The GWP of renewable methane dropped 2.5 fold when the renewable sources in producing electricity increasing from 41% to 75.5%. The GHG emission of biomethane from a biogas plant with amine upgrading was influenced by the ratio of slurry in co-digestion with grass, fugitive methane emission, carbon sequestration into grassland soil and the decarbonisation level of the

electricity mix. The percentage of GHG savings of renewable methane compared to fossil fuel increasing from 64% to 80% when slurry in the mix with grass increased from 50 to 74% (wet weight).

7.3 Recommendations and future works

The two parameters which have the most significant impacts on renewable methane from AD&P2G in term of cost and sustainability are the decarbonisation level of the electricity grid and the price of electricity. If an amine scrubber is used then the most important variables are feedstock ratio of grass and slurry, methane fugitive emission at the biogas facility, feedstock price and the carbonisation level of the electricity. Based on the research in this thesis, the author proposed:

1. In order to produce renewable methane from AD&P2G at a comparable production cost with the cost of producing biomethane from a biogas plant with present upgrading technologies (such as amine scrubbing), the electricity to produce H₂ should be at least less than €0.05/kW_eh.
2. The decarbonisation level of electricity used to produce H₂ has a significant impact on the GWP of the produced renewable methane. In order to meet the sustainability criteria of the RED a minimum level of 70% GHG savings, the electricity used in the AD&P2G should be at least 85% decarbonised.
3. Increasing proportions of slurry in the mix of grass silage and slurry reduces the GHG emission but also lowers the biomethane produced. A higher grass silage percentage in the mix results in higher levels of biomethane produced but also higher GHG emissions. This research recommends a ratio of 60:40

grass and slurry (on a VS basis). At these levels the renewable methane can satisfy the requirement of the RED, 70% GHG savings compared to the fossil fuel comparator and still produce a significant quantity of renewable gas per t of feedstock.

4. The fugitive methane emission at the biogas facility plays an important role in reducing GHG emissions of the overall system. Thus, for any biogas plant, it is essential to limit the emission of fugitive methane by using closed slurry and digestate storage and applying frequent leakage control surveys and gas management.
5. Carbon sequestration in grassland is a factor that helps renewable methane meet the sustainability requirement. A conservative value of 0.6t carbon sequestration in the soil was used however, that calculation and process needs to be accepted by the IPCC.

The future works in assessing P2G as an upgrading unit of a biogas facility needs to be absolutely sure of the decarbonisation of the electricity used. The carbonisation level of the electricity may be divided by the efficiency of hydrogen production expressed as a decimal to assess the carbon foot print of the hydrogen. For example, if electricity is sourced at 70% green and converted to hydrogen at 75% efficiency than the hydrogen will be 60% green. Prior to decarbonisation of the national electricity grid an arrangement to purchase green electricity (such as a direct connection to an adjacent wind or PV farm) to produce H₂ may be seen as a way to ensure the sustainability of P2G. Nevertheless, the intermittency of renewable

electricity will reduce the working capacity of the electrolyser plant leading to under utilisation of working capital and higher production costs of H₂. A full techno-economic assessment when electricity from wind is used to produce H₂ could be conducted.

Each feedstock has its own GWP emissions. It is plausible that such an AD&P2G system fed by another feedstock might require higher or lower percentage of electricity from renewable sources. Therefore, the LCAs of various feedstocks for AD&P2G plant need to be carried out to find out which type of feedstock will make the system sustainable.

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Appendix A– Chapter 3: The assessment form

Weighting

1. Please weight these criteria based on their importance in deciding **sustainability development** of energy storage (base on the following scale).

1	2	3	4	5
Not at all important	Slightly important	Moderately important	Very important	Extremely important

No.	Criteria	Weighting
1	Cost (capital, operation and management costs)	
2	Efficiency	
3	Energy carrier vectors (electricity or gas)	
4	Storage capacity and discharge time	
5	Position flexibility	
6	CO _{2eq} emission	
7	General environment impacts	

Note:

Energy carrier vectors: The ability to store electricity into many types of energy carrier vectors such as: electricity, gas, transport fuel.

CO_{2eq} emission: Greenhouse gas emission calculated for the whole cycle of energy products.

Position flexibility: The ability to site the storage plant

Appendix B– Chapter 4: Biomethane production costs for each type of feedstock

Table B1: Summary of assumptions used for biogas plant and biomethanation reactor

	Unit	Grass	Pig Slurry	SHW	OFMSW	Seaweed
CH ₄ :CO ₂ ratio in biogas		55%: 45%	65%: 35%	55%: 45%	60%:40%	55%:45%
m ³ biomethane yield/ton feedstock		59.4	14.4	41	66	24.6
Capital cost	€/t/a	162	102	154	325	164
Ton feedstock/year		19000	77000	27000	19000	46000
Storage pit	€/t/a	30				30
Technology used		CSTR	CSTR	CSTR	Batch process	CSTR
Maintenance and overhead	€/t	5	5	10	25	15
Digestate disposal	€/t				4	
Electrical demand of biogas plant	kWeh/t	10	10	10	6	10
Electricity price	€/kWeh	0.15	0.15	0.15	0.15	0.15
Cost of feedstock	€/t	17				50
Gate fee	€/t			20	70	
Cost of capital	%	6%				
Life time	(years)	15				
Electricity demand for biomethanation	kWh/m ³	1				1
Gas grid connection	€	€300,000				
CNG service station	€	€500,000				

Table B2. Capital investment (€) of renewable gas

	Grass	Pig Slurry	SHW	OFMSW	Seaweed
Biogas plant	3078000	7854000	4158000	6175000	7544000
storage	570000				1380000
Methanation reactor	3000000	3000000	3000000	3000000	3000000
Gas grid connection	30000	300000	300000	300000	300000
CNG service station	500000	500000	500000	500000	500000
Total capital cost	7178000	11654000	7958000	9975000	12724000

Table B3. Annual cost (€) of biogas production

	Grass	Pig Slurry	SHW	OFMSW	Seaweed
Maintenance and overhead	95000	385000	270000	475000	690000
Electric demand of biogas plant	28500	115500	40500	17100	69000
Operation and maintenance cost of methanation	90000	90000	90000	90000	90000
Plant operation					
Substrate cost	323000	0	0	0	280000
Digestate disposal	0	0	0	76000	
Cost of capital	739067	1199928	819378	1027054	1310098
Depreciation fund	202600	361800	238600	305833	351467
Total annual cost	1478167	2152228	1458478	1990987	2790565
Income from gate fee	0	0	540000	1330000	0
Annual cost of renewable gas production	1478167	2152228	918478	660987	2790565

Appendix C– Chapter 5: Process simulations

Biogas plant with amine upgrading

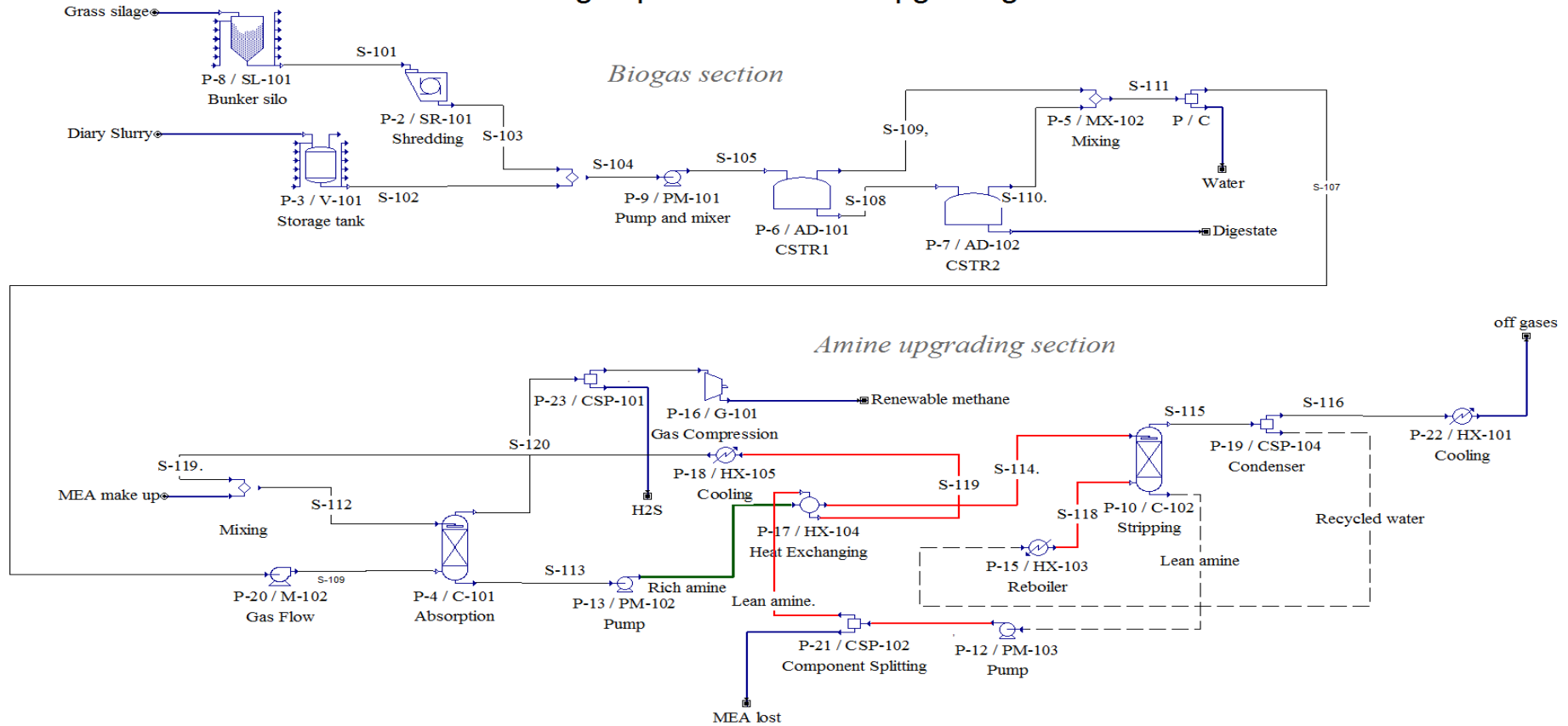


Figure C1. Biogas plant with an amine upgrading – scenario 1

Biogas plant with amine and methanation upgrading

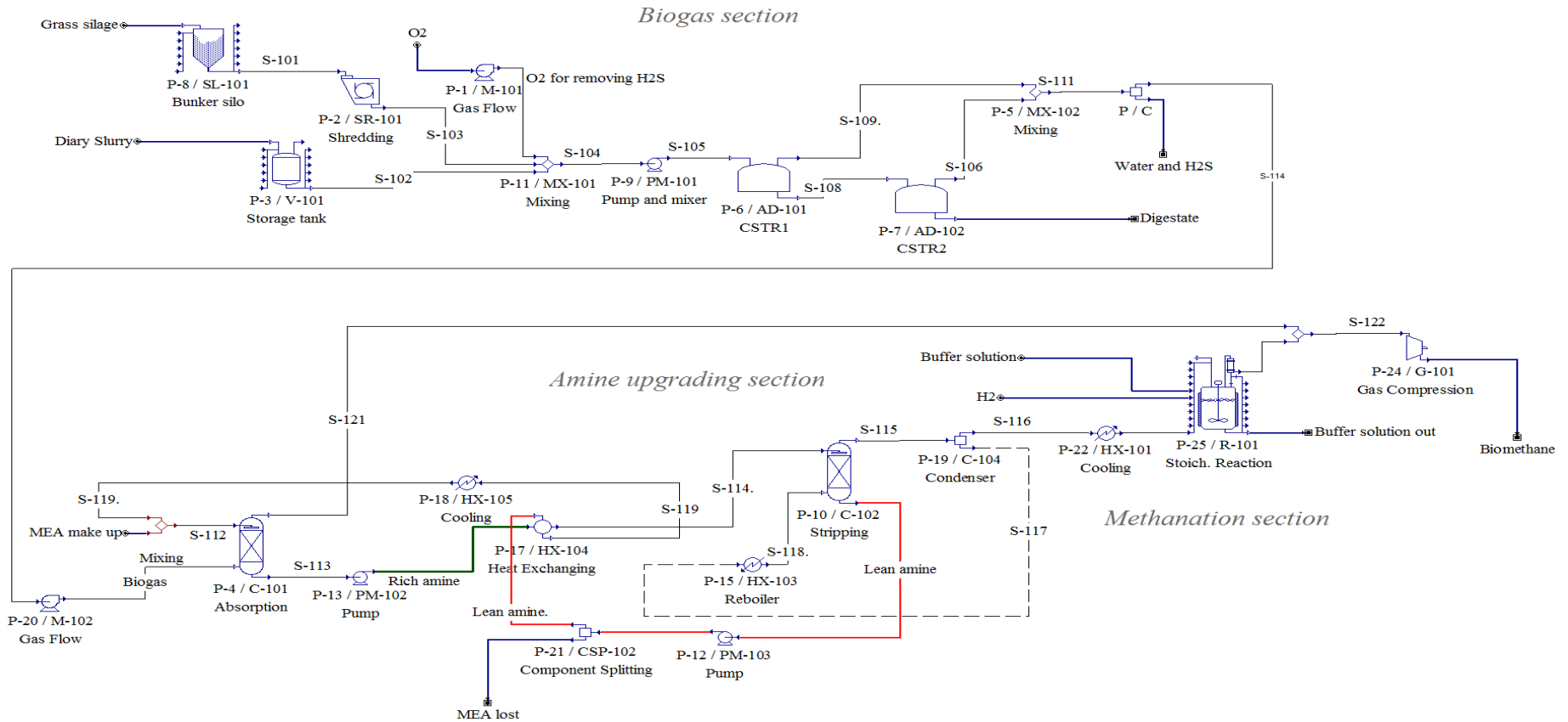


Figure C2. Biogas plant with an amine and methanation upgrading – scenario 2

Biogas section with methanation upgrading

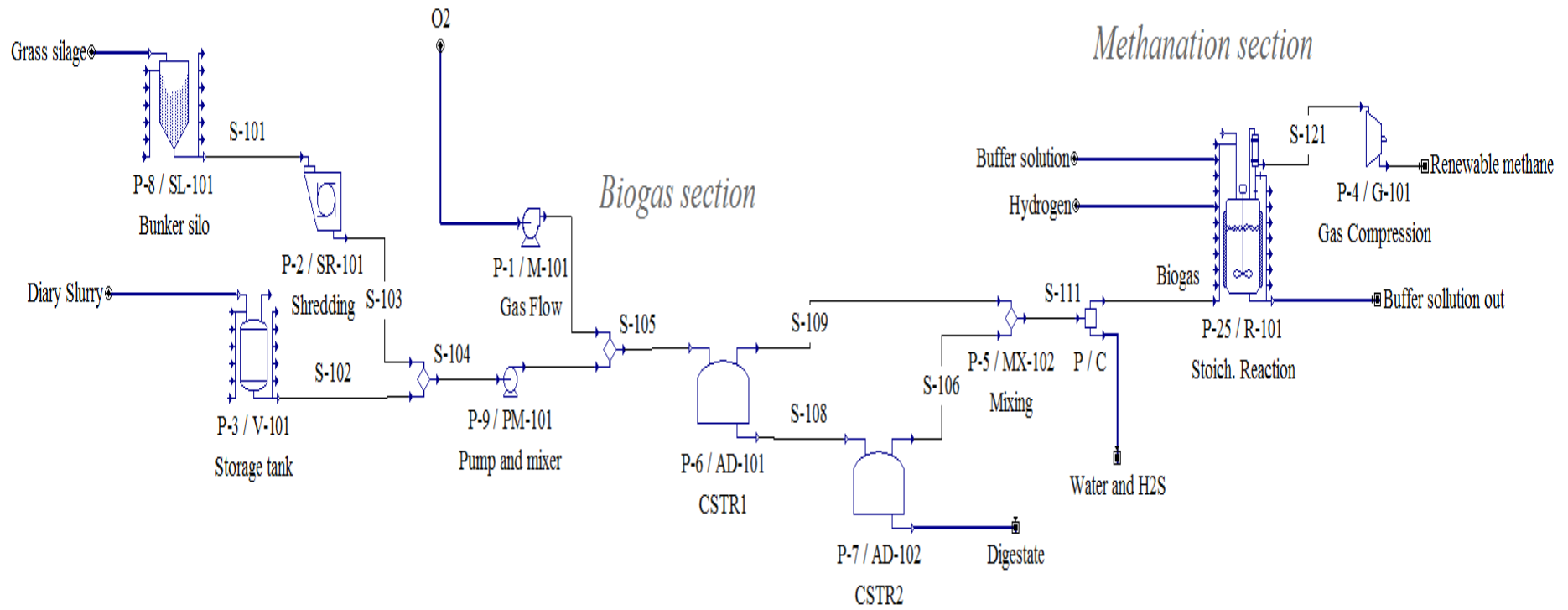


Figure C3. Biogas plant with biological methanation reactor – scenario 3

Appendix D- Chapter 5: Material and energy balance

Materials & Streams Report for Scenario 1

Stream Name	Diary Slurry	S-102	Grass silage	S-101
Source	INPUT	P-3	INPUT	P-8
Destination	P-3	P-11	P-8	P-2
Stream Properties				
Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (°C)	10.00	10.00	10.00	10.00
Pressure (bar)	1.01	1.01	1.01	1.01
Density (kg/m ³)	1,018.03	1,008.90	1,019.66	1,010.01
Total Enthalpy (kW-h)	37.20	37.20	26.31	26.31
Specific Enthalpy (kcal/kg)	9.14	9.14	7.07	7.07
Heat Capacity (kcal/kg-°C)	0.91	0.91	0.71	0.71
Component Flowrates (kg/h)				
Ash	61.60	61.60	62.40	62.40
Phosphorus	1.75	1.75	0.00	0.00
Potassium	10.15	10.15	0.16	0.16
Sulfur	1.40	1.40	0.00	0.00
Total N	10.50	10.50	12.80	12.80
VS grass	0.00	0.00	896.00	896.00
VS slurry	234.50	234.50	0.00	0.00
Water	3,180.10	3,180.10	2,228.64	2,228.64
TOTAL (kg/h)	3,500.00	3,500.00	3,200.00	3,200.00
TOTAL (m ³ /h)	3.44	3.47	3.14	3.17
Stream Name	S-103	S-104	S-105	S-109,
Source	P-2	P-11	P-9	P-6
Destination	P-11	P-9	P-6	P-5
Stream Properties				
Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (°C)	10.00	10.00	10.01	38.00
Pressure (bar)	1.01	1.01	2.01	2.01
Density (kg/m ³)	1,010.01	1,009.43	1,009.42	2.32
Total Enthalpy (kW-h)	26.31	63.51	63.59	60.29
Specific Enthalpy (kcal/kg)	7.07	8.16	8.17	50.38
Heat Capacity (kcal/kg-°C)	0.71	0.82	0.82	0.30
Component Flowrates (kg/h)				
Ash	62.40	124.00	124.00	0.00
Carb. Dioxide	0.00	0.00	0.00	745.67
H ₂ S	0.00	0.00	0.00	1.40

Methane	0.00	0.00	0.00	281.60
Phosphorus	0.00	1.75	1.75	0.00
Potassium	0.16	10.31	10.31	0.00
Sulfur	0.00	1.40	1.40	0.00
Total N	12.80	23.30	23.30	0.00
VS grass	896.00	896.00	896.00	0.00
VS slurry	0.00	234.50	234.50	0.00
Water	2,228.64	5,408.74	5,408.74	1.06
TOTAL (kg/h)	3,200.00	6,700.00	6,700.00	1,029.72
TOTAL (m3/h)	3.17	6.64	6.64	443.27

Stream Name	S-108	S-110.	Digestate	S-111
Source	P-6	P-7	P-7	P-5
Destination	P-7	P-5	OUTPUT	P

Stream Properties

Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (°C)	38.00	38.00	38.00	38.01
Pressure (bar)	2.01	2.01	2.01	2.01
Density (kg/m3)	1,000.81	2.34	1,000.91	2.32
Total Enthalpy (kW-h)	234.89	3.03	234.55	63.33
Specific Enthalpy (kcal/kg)	35.64	50.31	35.91	50.38
Heat Capacity (kcal/kg-°C)	0.94	0.30	0.95	0.30

Component Flowrates (kg/h)

Ash	124.00	0.00	124.00	0.00
Carb. Dioxide	0.00	37.28	0.00	782.95
H2S	0.00	0.00	0.00	1.40
Methane	0.00	14.08	0.00	295.68
Phosphorus	1.75	0.00	1.75	0.00
Potassium	10.31	0.00	10.31	0.00
Total N	23.30	0.00	23.30	0.00
VS grass	179.20	0.00	143.36	0.00
VS slurry	46.90	0.00	37.52	0.00
Water	5,285.64	0.53	5,279.01	1.59
TOTAL (kg/h)	5,671.10	51.89	5,619.25	1,081.61
TOTAL (m3/h)	5.67	22.16	5.61	465.45

Stream Name	S-107	Water	S-109	S-112
Source	P	P	P-20	.
Destination	P-20	OUTPUT	P-4	P-4

Stream Properties

Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (°C)	38.01	38.01	40.00	40.00

Pressure (bar)	2.01	2.01	3.01	1.01
Density (kg/m3)	2.32	989.96	3.45	31.72
Total Enthalpy (kW-h)	63.26	0.07	64.00	572.17
Specific Enthalpy (kcal/kg)	50.40	37.94	50.99	34.29
Heat Capacity (kcal/kg-°C)	0.30	1.00	0.30	0.79
Component Flowrates (kg/h)				
Carb. Dioxide	782.95	0.00	782.95	751.63
H2S	1.40	0.00	1.40	0.00
Methane	295.68	0.00	295.68	0.00
Monoethanolamin	0.00	0.00	0.00	3,474.70
Water	0.00	1.59	0.00	10,131.00
TOTAL (kg/h)	1,080.03	1.59	1,080.03	14,357.34
TOTAL (m3/h)	465.45	0.00	312.97	452.61

Stream Name	S-120	S-113	Rich amine	Lean amine.
Source	P-4	P-4	P-13	P-21
Destination	P-23	P-13	P-17	P-17

Stream Properties

Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (°C)	40.00	40.00	40.02	133.50
Pressure (bar)	3.01	1.01	3.01	5.01
Density (kg/m3)	1.97	16.94	48.89	110.93
Total Enthalpy (kW-h)	9.49	626.69	627.01	1,799.92
Specific Enthalpy (kcal/kg)	24.98	35.68	35.70	107.87
Heat Capacity (kcal/kg-°C)	0.51	0.76	0.76	0.79

Component Flowrates (kg/h)

Carb. Dioxide	31.32	1,503.26	1,503.26	751.63
H2S	0.03	1.37	1.37	0.00
Methane	295.38	0.30	0.30	0.00
Monoethanolamin	0.00	3,474.70	3,474.70	3,474.68
Water	0.00	10,131.00	10,131.00	10,131.00
TOTAL (kg/h)	326.73	15,110.63	15,110.63	14,357.31
TOTAL (m3/h)	165.45	891.94	309.08	129.43

Stream Name	S-114.	S-119	S-118	S-115
Source	P-17	P-17	P-15	P-10
Destination	P-10	P-18	P-10	P-19

Stream Properties

Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (°C)	83.02	89.93	120.00	101.00
Pressure (bar)	3.01	5.01	1.01	1.01
Density (kg/m3)	43.19	122.87	0.56	0.59

Total Enthalpy (kW-h)	1,199.36	1,227.57	64,365.33	63,627.16
Specific Enthalpy (kcal/kg)	68.29	73.57	692.27	677.94
Heat Capacity (kcal/kg-°C)	0.76	0.79	0.46	0.45
Component Flowrates (kg/h)				
Carb. Dioxide	1,503.26	751.63	0.00	751.63
H2S	1.37	0.00	0.00	1.37
Methane	0.30	0.00	0.00	0.30
Monoethanolamin	3,474.70	3,474.68	0.00	0.00
Water	10,131.00	10,131.00	80,000.00	80,000.00
TOTAL (kg/h)	15,110.63	14,357.31	80,000.00	80,753.30
TOTAL (m3/h)	349.85	116.85	143,261.11	136,863.78

Stream Name	Lean amine	S-116	Recycled water	,
Source	P-10	P-19	P-19	P-12
Destination	P-12	P-22	P-15	P-21

Stream Properties

Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (°C)	133.50	101.00	101.00	143.98
Pressure (bar)	3.01	1.01	1.01	5.01
Density (kg/m3)	42.70	1.43	0.59	108.40
Total Enthalpy (kW-h)	1,937.53	66.39	63,560.77	1,937.87
Specific Enthalpy (kcal/kg)	116.11	75.83	683.61	116.13
Heat Capacity (kcal/kg-°C)	0.78	0.22	0.45	0.79

Component Flowrates (kg/h)

Carb. Dioxide	751.63	751.63	0.00	751.63
H2S	0.00	1.37	0.00	0.00
Methane	0.00	0.30	0.00	0.00
Monoethanolamin	3,474.70	0.00	0.00	3,474.70
Water	10,131.00	0.00	80,000.00	10,131.00
TOTAL (kg/h)	14,357.33	753.30	80,000.00	14,357.33
TOTAL (m3/h)	336.22	526.14	136,337.64	132.45

Stream Name	MEA lost	S-119.	MEA make up	off gases
Source	P-21	P-18	INPUT	P-22
Destination	OUTPUT	.	.	OUTPUT

Stream Properties

Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (°C)	133.50	40.00	50.00	25.00
Pressure (bar)	5.01	5.01	1.01	1.01

Density (kg/m3)	953.74	140.14	985.59	1.80
Total Enthalpy (kW-h)	0.00	572.17	0.00	51.83
Specific Enthalpy (kcal/kg)	39.31	34.29	14.72	59.20
Heat Capacity (kcal/kg-°C)	0.29	0.79	0.29	0.20
Component Flowrates (kg/h)				
Carb. Dioxide	0.00	751.63	0.00	751.63
H2S	0.00	0.00	0.00	1.37
Methane	0.00	0.00	0.00	0.30
Monoethanolamin	0.02	3,474.68	0.03	0.00
Water	0.00	10,131.00	0.00	0.00
TOTAL (kg/h)	0.02	14,357.31	0.03	753.30
TOTAL (m3/h)	0.00	102.45	0.00	418.29

Stream Name	.	H2S	Renewable methane
Source	P-23	P-23	P-16
Destination	P-16	OUTPUT	OUTPUT
Stream Properties			
Activity (U/ml)	0.00	0.00	0.00
Temperature (°C)	40.00	40.00	40.00
Pressure (bar)	3.01	3.01	10.01
Density (kg/m3)	1.97	989.24	6.57
Total Enthalpy (kW-h)	9.49	0.00	9.49
Specific Enthalpy (kcal/kg)	24.98	21.11	24.98
Heat Capacity (kcal/kg-°C)	0.51	0.53	0.51
Component Flowrates (kg/h)			
Carb. Dioxide	31.32	0.00	31.32
H2S	0.00	0.03	0.00
Methane	295.38	0.00	295.38
TOTAL (kg/h)	326.70	0.03	326.70
TOTAL (m3/h)	165.45	0.00	49.74

**Materials & Streams Report
for Scenario 2**

Stream Name	Diary Slurry	S-102	Grass silage	S-101
Source	INPUT	P-3	INPUT	P-8
Destination	P-3	P-11	P-8	P-2
Stream Properties				
Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (°C)	10.00	10.00	10.00	10.00
Pressure (bar)	1.01	1.01	1.01	1.01
Density (kg/m3)	1,008.90	1,008.90	1,010.01	1,010.01
Total Enthalpy (kW-h)	37.20	37.20	26.31	26.31
Specific Enthalpy (kcal/kg)	9.14	9.14	7.07	7.07
Heat Capacity (kcal/kg-°C)	0.91	0.91	0.71	0.71
Component Flowrates (kg/h)				
Ash	61.60	61.60	62.40	62.40
Phosphorus	1.75	1.75	0.00	0.00
Potassium	10.15	10.15	0.16	0.16
Sulfur	1.40	1.40	0.00	0.00
Total N	10.50	10.50	12.80	12.80
VS grass	0.00	0.00	896.00	896.00
VS slurry	234.50	234.50	0.00	0.00
Water	3,180.10	3,180.10	2,228.64	2,228.64
TOTAL (kg/h)	3,500.00	3,500.00	3,200.00	3,200.00
TOTAL (m3/h)	3.47	3.47	3.17	3.17
Stream Name	S-103	O2	O2 for removing H2S	S-104
Source	P-2	INPUT	P-1	P-11
Destination	P-11	P-1	P-11	P-9
Stream Properties				
Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (°C)	10.00	25.00	26.35	10.02
Pressure (bar)	1.01	1.01	1.03	1.01
Density (kg/m3)	1,010.01	1.31	1.33	229.22
Total Enthalpy (kW-h)	26.31	0.20	0.21	63.72
Specific Enthalpy (kcal/kg)	7.07	5.47	5.76	8.14
Heat Capacity (kcal/kg-°C)	0.71	0.22	0.22	0.81
Component Flowrates (kg/h)				
Ash	62.40	0.00	0.00	124.00
Oxygen	0.00	31.30	31.30	31.30

Phosphorus	0.00	0.00	0.00	1.75
Potassium	0.16	0.00	0.00	10.31
Sulfur	0.00	0.00	0.00	1.40
Total N	12.80	0.00	0.00	23.30
VS grass	896.00	0.00	0.00	896.00
VS slurry	0.00	0.00	0.00	234.50
Water	2,228.64	0.00	0.00	5,408.74
TOTAL (kg/h)	3,200.00	31.30	31.30	6,731.30
TOTAL (m3/h)	3.17	23.93	23.57	29.37

Stream Name	S-105	S-109.	S-108	S-106
Source	P-9	P-6	P-6	P-7
Destination	P-6	P-5	P-7	P-5

Stream Properties

Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (°C)	10.03	38.00	38.00	38.00
Pressure (bar)	2.01	2.01	2.01	2.01
Density (kg/m3)	372.37	2.32	316.78	2.34
Total Enthalpy (kW-h)	63.80	60.26	235.24	3.03
Specific Enthalpy (kcal/kg)	8.15	50.42	35.49	50.31
Heat Capacity (kcal/kg-°C)	0.81	0.30	0.93	0.30

Component Flowrates (kg/h)

Ash	124.00	0.00	124.00	0.00
Carb. Dioxide	0.00	745.67	0.00	37.28
H2S	0.00	0.17	0.00	0.00
Methane	0.00	281.60	0.00	14.08
Oxygen	31.30	0.00	30.72	0.00
Phosphorus	1.75	0.00	1.75	0.00
Potassium	10.31	0.00	10.31	0.00
Sulfur	1.40	0.00	1.16	0.00
Total N	23.30	0.00	23.30	0.00
VS grass	896.00	0.00	179.20	0.00
VS slurry	234.50	0.00	46.90	0.00
Water	5,408.74	1.06	5,286.29	0.53
TOTAL (kg/h)	6,731.30	1,028.49	5,703.63	51.89
TOTAL (m3/h)	18.08	443.27	18.00	22.16

Stream Name	Digestate	S-111	S-114	Water and H2S
Source	P-7	P-5	P	P
Destination	OUTPUT	P	P-20	OUTPUT

Stream Properties

Activity (U/ml)	0.00	0.00	0.00	0.00
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Temperature (°C)	38.00	38.01	38.01	38.01
Pressure (bar)	2.01	2.01	2.01	2.01
Density (kg/m3)	314.82	2.32	2.32	989.96
Total Enthalpy (kW-h)	234.90	63.30	63.23	0.07
Specific Enthalpy (kcal/kg)	35.76	50.41	50.44	36.24
Heat Capacity (kcal/kg-°C)	0.94	0.30	0.30	0.95
Component Flowrates (kg/h)				
Ash	124.00	0.00	0.00	0.00
Carb. Dioxide	0.00	782.95	782.95	0.00
H2S	0.00	0.17	0.00	0.17
Methane	0.00	295.68	295.68	0.00
Oxygen	30.72	0.00	0.00	0.00
Phosphorus	1.75	0.00	0.00	0.00
Potassium	10.31	0.00	0.00	0.00
Sulfur	1.16	0.00	0.00	0.00
Total N	23.30	0.00	0.00	0.00
VS grass	143.36	0.00	0.00	0.00
VS slurry	37.52	0.00	0.00	0.00
Water	5,279.66	1.59	0.00	1.59
TOTAL (kg/h)	5,651.78	1,080.38	1,078.63	1.75
TOTAL (m3/h)	17.95	465.45	465.45	0.00

Stream Name	Biogas	S-112	S-121	S-113
Source	P-20	P-14	P-4	P-4
Destination	P-4	P-4	P-16	P-13
Stream Properties				
Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (°C)	40.00	40.00	40.00	40.00
Pressure (bar)	3.01	1.01	3.01	1.01
Density (kg/m3)	3.45	31.72	1.97	16.94
Total Enthalpy (kW-h)	63.97	572.19	9.49	626.67
Specific Enthalpy (kcal/kg)	51.03	34.29	24.98	35.69
Heat Capacity (kcal/kg-°C)	0.30	0.79	0.51	0.76
Component Flowrates (kg/h)				
Carb. Dioxide	782.95	751.63	31.32	1,503.26
H2S	0.00	0.00	0.00	0.00
Methane	295.68	0.00	295.38	0.30
Monoethanolamin	0.00	3,472.49	0.00	3,472.49
Water	0.00	10,132.00	0.00	10,132.00
TOTAL (kg/h)	1,078.63	14,356.12	326.70	15,108.05
TOTAL (m3/h)	312.97	452.61	165.45	891.93

Stream Name	Rich amine	Lean amine.	S-114.	S-119
Source	P-13	P-21	P-17	P-17
Destination	P-17	P-17	P-10	P-18
Stream Properties				
Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (°C)	40.02	133.50	83.02	89.93
Pressure (bar)	3.01	5.01	3.01	5.01
Density (kg/m3)	48.88	110.92	43.18	122.86
Total Enthalpy (kW-h)	627.00	1,799.97	1,199.33	1,227.64
Specific Enthalpy (kcal/kg)	35.71	107.88	68.30	73.58
Heat Capacity (kcal/kg-°C)	0.76	0.79	0.76	0.79
Component Flowrates (kg/h)				
Carb. Dioxide	1,503.26	751.63	1,503.26	751.63
Methane	0.30	0.00	0.30	0.00
Monoethanolamin	3,472.49	3,472.48	3,472.49	3,472.47
Water	10,132.00	10,132.00	10,132.00	10,132.00
TOTAL (kg/h)	15,108.05	14,356.11	15,108.05	14,356.10
TOTAL (m3/h)	309.08	129.43	349.85	116.85

Stream Name	S-118.	S-115	Lean amine	S-116
Source	P-15	P-10	P-10	P-19
Destination	P-10	P-19	P-12	P-22
Stream Properties				
Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (°C)	120.00	101.00	133.50	101.00
Pressure (bar)	1.01	1.01	3.01	1.01
Density (kg/m3)	0.56	0.59	42.65	1.43
Total Enthalpy (kW-h)	64,365.33	63,626.59	1,938.07	65.81
Specific Enthalpy (kcal/kg)	692.27	677.95	116.16	75.31
Heat Capacity (kcal/kg-°C)	0.46	0.45	0.78	0.22
Component Flowrates (kg/h)				
Carb. Dioxide	0.00	751.63	751.63	751.63
Methane	0.00	0.30	0.00	0.30
Monoethanolamin	0.00	0.00	3,472.49	0.00
Water	80,000.00	80,000.00	10,132.00	0.00
TOTAL (kg/h)	80,000.00	80,751.93	14,356.12	751.93
TOTAL (m3/h)	143,261.11	136,862.55	336.62	524.91

Stream Name	S-117	S-120	MEA lost	S-119.
Source	P-19	P-12	P-21	P-18
Destination	P-15	P-21	OUTPUT	P-14
Stream Properties				
Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (°C)	101.00	144.02	133.50	40.00
Pressure (bar)	1.01	5.01	5.01	5.01
Density (kg/m3)	0.59	108.38	955.16	140.13
Total Enthalpy (kW-h)	63,560.77	1,938.41	0.00	572.19
Specific Enthalpy (kcal/kg)	683.61	116.18	39.30	34.29
Heat Capacity (kcal/kg-°C)	0.45	0.79	0.29	0.79
Component Flowrates (kg/h)				
Carb. Dioxide	0.00	751.63	0.00	751.63
Methane	0.00	0.00	0.00	0.00
Monoethanolamin	0.00	3,472.49	0.02	3,472.47
Water	80,000.00	10,132.00	0.00	10,132.00
TOTAL (kg/h)	80,000.00	14,356.12	0.02	14,356.10
TOTAL (m3/h)	136,337.64	132.46	0.00	102.45
Stream Name	MEA make up	S-45	Buffer solution	H2
Source	INPUT	P-22	INPUT	INPUT
Destination	P-14	P-25	P-25	P-25
Stream Properties				
Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (°C)	50.00	25.00	25.00	25.00
Pressure (bar)	1.01	1.01	1.01	1.01
Density (kg/m3)	985.59	1.80	994.70	0.08
Total Enthalpy (kW-h)	0.00	51.81	116.01	13.58
Specific Enthalpy (kcal/kg)	14.72	59.29	24.96	85.48
Heat Capacity (kcal/kg-°C)	0.29	0.20	1.00	3.42
Component Flowrates (kg/h)				
Carb. Dioxide	0.00	751.63	0.00	0.00
Hydrogen	0.00	0.00	0.00	136.66
Methane	0.00	0.30	0.00	0.00
Monoethanolamin	0.03	0.00	0.00	0.00
Water	0.00	0.00	4,000.00	0.00
TOTAL (kg/h)	0.03	751.93	4,000.00	136.66
TOTAL (m3/h)	0.00	418.28	4.02	1,658.49

Stream Name	S-126	Buffer solution out	S-122	Biomethane
Source	P-25	P-25	P-16	P-24
Destination	P-16	OUTPUT	P-24	OUTPUT
Stream Properties				
Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (°C)	60.00	60.00	49.67	40.00
Pressure (bar)	1.01	1.01	1.01	8.01
Density (kg/m3)	0.58	981.95	0.62	5.09
Total Enthalpy (kW-h)	11.38	320.51	20.87	17.25
Specific Enthalpy (kcal/kg)	34.48	59.89	29.40	24.30
Heat Capacity (kcal/kg-°C)	0.56	1.00	0.53	0.52
Component Flowrates (kg/h)				
Carb. Dioxide	13.23	0.00	44.55	44.55
H2S	0.00	0.00	0.00	0.00
Hydrogen	1.37	0.00	1.37	1.37
Methane	269.46	0.00	564.85	564.85
Water	0.00	4,604.51	0.00	0.00
TOTAL (kg/h)	284.06	4,604.51	610.77	610.77
TOTAL (m3/h)	485.92	4.69	977.42	119.89

**Materials & Streams Report
for Scenario 3**

Stream Name	Diary Slurry	S-102	Grass silage	S-101
Source	INPUT	P-3	INPUT	P-8
Destination	P-3	P-11	P-8	P-2
Stream Properties				
Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (K)	283.15	283.15	283.15	283.15
Pressure (Pa)	101,325.00	101,325.00	101,325.00	101,325.00
Density (kg/m3)	1,008.90	1,008.90	1,010.01	1,010.01
Total Enthalpy (kW-h)	37.20	37.20	26.31	26.31
Specific Enthalpy (J/kg)	38,260.73	38,260.73	29,598.99	29,598.99
Heat Capacity (J/kg-K)	3,826.07	3,826.07	2,959.90	2,959.90
Component Flowrates (kg/h)				
Ash	61.60	61.60	62.40	62.40
Phosphorus	1.75	1.75	0.00	0.00

Potassium	10.15	10.15	0.16	0.16
Sulphur	1.40	1.40	0.00	0.00
Total N	10.50	10.50	12.80	12.80
VS grass	0.00	0.00	896.00	896.00
VS slurry	234.50	234.50	0.00	0.00
Water	3,180.10	3,180.10	2,228.64	2,228.64
TOTAL (kg/h)	3,500.00	3,500.00	3,200.00	3,200.00
TOTAL (m3/h)	3.47	3.47	3.17	3.17

Stream Name	S-103	S-104	S-114	O2
Source	P-2	P-11	P-9	INPUT
Destination	P-11	P-9	P-10	P-1

Stream Properties

Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (K)	283.15	283.15	283.16	298.15
Pressure (Pa)	101,325.00	101,325.00	201,325.00	101,325.00
Density (kg/m3)	1,010.01	1,009.43	1,009.42	1.31
Total Enthalpy (kW-h)	26.31	63.51	63.59	0.02
Specific Enthalpy (J/kg)	29,598.99	34,123.78	34,166.24	22,880.41
Heat Capacity (J/kg-K)	2,959.90	3,412.38	3,412.38	918.12

Component Flowrates (kg/h)

Ash	62.40	124.00	124.00	0.00
Oxygen	0.00	0.00	0.00	3.13
Phosphorus	0.00	1.75	1.75	0.00
Potassium	0.16	10.31	10.31	0.00
Sulphur	0.00	1.40	1.40	0.00
Total N	12.80	23.30	23.30	0.00
VS grass	896.00	896.00	896.00	0.00
VS slurry	0.00	234.50	234.50	0.00
Water	2,228.64	5,408.74	5,408.74	0.00
TOTAL (kg/h)	3,200.00	6,700.00	6,700.00	3.13
TOTAL (m3/h)	3.17	6.64	6.64	2.39

Stream Name	S-110	S-105	S-109	S-108
Source	P-1	P-10	P-6	P-6
Destination	P-10	P-6	P-5	P-7

Stream Properties

Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (K)	299.50	283.16	311.15	311.15
Pressure (Pa)	103,325.00	103,325.00	103,325.00	103,325.00
Density (kg/m3)	1.33	756.03	1.19	740.50
Total Enthalpy (kW-h)	0.02	63.61	60.26	234.97
Specific Enthalpy (J/kg)	24,118.15	34,161.54	210,937.09	149,045.07
Heat Capacity (J/kg-K)	918.44	3,411.21	1,245.75	3,922.24

Component Flowrates (kg/h)

Ash	0.00	124.00	0.00	124.00
Carb. Dioxide	0.00	0.00	745.67	0.00
H2S	0.00	0.00	0.17	0.00
Methane	0.00	0.00	281.60	0.00
Oxygen	3.13	3.13	0.00	2.55
Phosphorus	0.00	1.75	0.00	1.75
Potassium	0.00	10.31	0.00	10.31
Sulfur	0.00	1.40	0.00	1.16
Total N	0.00	23.30	0.00	23.30
VS grass	0.00	896.00	0.00	179.20
VS slurry	0.00	234.50	0.00	46.90
Water	0.00	5,408.74	1.06	5,286.29
TOTAL (kg/h)	3.13	6,703.13	1,028.49	5,675.46
TOTAL (m3/h)	2.36	8.87	863.70	7.66

Stream Name	S-106	Digestate	S-111	Biogas
Source	P-7	P-7	P-5	P
Destination	P-5	OUTPUT	P	P-25

Stream Properties

Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (K)	311.15	311.15	311.16	311.16
Pressure (Pa)	103,325.00	103,325.00	103,325.00	103,325.00
Density (kg/m3)	1.20	738.79	1.19	1.19
Total Enthalpy (kW-h)	3.03	234.63	63.30	63.23
Specific Enthalpy (J/kg)	210,479.41	150,200.82	210,915.10	211,024.05
Heat Capacity (J/kg-K)	1,272.43	3,952.66	1,247.05	1,242.59

Component Flowrates (kg/h)

Ash	0.00	124.00	0.00	0.00
Carb. Dioxide	37.28	0.00	782.95	782.95
H2S	0.00	0.00	0.17	0.00
Methane	14.08	0.00	295.68	295.68
Oxygen	0.00	2.55	0.00	0.00
Phosphorus	0.00	1.75	0.00	0.00
Potassium	0.00	10.31	0.00	0.00
Sulphur	0.00	1.16	0.00	0.00
Total N	0.00	23.30	0.00	0.00
VS grass	0.00	143.36	0.00	0.00
VS slurry	0.00	37.52	0.00	0.00
Water	0.53	5,279.66	1.59	0.00
TOTAL (kg/h)	51.89	5,623.61	1,080.38	1,078.63
TOTAL (m3/h)	43.19	7.61	906.92	906.91

Stream Name	Water and H2S	Buffer solution	Hydrogen	S-121
Source	P	INPUT	INPUT	P-25
Destination	OUTPUT	P-25	P-25	P-4
Stream Properties				
Activity (U/ml)	0.00	0.00	0.00	0.00
Temperature (K)	311.16	298.15	298.15	333.15
Pressure (Pa)	103,325.00	101,325.00	101,325.00	101,325.00
Density (kg/m3)	989.96	994.70	0.08	0.59
Total Enthalpy (kW-h)	0.07	116.01	14.14	22.85
Specific Enthalpy (J/kg)	151,579.83	104,412.99	357,639.99	139,142.79
Heat Capacity (J/kg-K)	3,987.89	4,176.52	14,325.42	2,334.11
Component Flowrates (kg/h)				
Carb. Dioxide	0.00	0.00	0.00	13.78
H2S	0.17	0.00	0.00	0.00
Hydrogen	0.00	0.00	142.36	1.42
Methane	0.00	0.00	0.00	576.07
Water	1.59	4,000.00	0.00	0.00
TOTAL (kg/h)	1.75	4,000.00	142.36	591.27
TOTAL (m3/h)	0.00	4.02	1,727.61	1,009.48

Appendix E– Chapter 5. Economic analysis of three scenarios (2016 prices)

Economic analysis of scenario 1 – E1

Table E1-1: Component purchase costs of scenario 1

Name	Description	Cost (€)
1. Biogas section		
SL-101	Grass silage storage pit	503,000
	For storing 30,000 tonnes grass silage/year	
V-101	Slurry Receiver Tank	70,000
	Vessel Volume = 170 m ³	
SR-101	Shredder	56,000
	Rated through put = 3,200kg/h	
PM-101	Centrifugal Pump	7,000
	Pump Power = 0.51 kW (pump and mixer)	
AD-101	Anaerobic Digester	805,000
	Vessel Volume = 7965 m ³	
AD-102	Anaerobic Digester	308,000
	Vessel Volume = 4616 m ³	
Total 1		1,749,000
2. Amine scrubber section		
M-102	Blower	3,000
C-101	Absorber	35,000
	Flow rate of biogas 746m ³ /h; column diameter 1m; column height 15m.	
C-102	Stripper	35,000
	Flow rate 403 m ³ /h; column diameter 1m; column height 15m	
PM-102	Centrifugal Pump	12,000
	Pump Power = 0.69 kW	

HX-104	Heat Exchanger	10,000
	Heat Exchange Area = 7.52 m ²	
HX-105	Heat Exchanger	8,000
	Heat Exchange Area = 5.04 m ²	
PM-103	Centrifugal Pump	12,000
	Pump Power = 0.64 kW	
HX-103	Reboiler	84,000
C-104	Condenser	22,000
G-101	Centrifugal Compressor	47,000
	Compressor Power = 30.13 kW	
Total 2		268,000
Unlisted Equipment		451,000
Total 1+2 + unlisted equipment		2,468,000

Table E1-2. Investment cost

1. Direct fixed capital cost	Unit (€)
Biogas plant	3,913,000
Upgrading by amine	1,409,000
2. Working capital	157,000
3. Cost of monoethanolamine	8,000
Total investment	5,486,000

Table E1-3. Utilities costs

Utility	Unit Cost (€)	Annual amount	Annual cost (€)	%
Standard Power	0.15	1,507,581(kW-h)	226,137	30.35
Steam	12	12,519(T)	150,232	20.16
Cooling Water	0.05	104,140(T)	5,207	0.7
Chilled Water	0.4	909,053(T)	363,621	48.8
			745,198	100.00

Table E1-4. Annual operating cost

Cost Item	€	%
Raw Materials	685,000	34.76
Labor-Dependent	295,000	15
Facility-Dependent	200,000	10.16
Laboratory/QC/QA	44,000	2.25
Utilities	745,000	37.82
TOTAL	2,087,000	100.00

Economic analysis of scenario 2 – E2**Table E2-1.** Component purchase costs of scenario 2

Name	Description	Cost (€)
1. Biogas section		
SL-101	Grass silage storage pit	503,000
	For storing 30,000 tonnes grass silage/year	
V-101	Slurry Receiver Tank	70,000
	Vessel Volume = 170 m ³	
SR-101	Shredder	56,000
	Rated through put = 3,200kg/h	
PM-101	Centrifugal Pump	7,000
	Pump Power = 0.51 kW (pump and mixer)	
AD-101	Anaerobic Digester	805,000
	Vessel Volume = 7965 m ³	
AD-102	Anaerobic Digester	308,000
	Vessel Volume = 4616 m ³	
M-101	Blower	3,000

Total 1		1,752,000
2. Amine scrubber section		
M-102	Blower	3,000
C-101	Absorber	35,000
	Flow rate of biogas 746m ³ /h; column diameter 1m; column height 115m.	
C-102	Stripper	35,000
	Flow rate 403 m ³ /h; column diameter 1m; column height 15m	
PM-102	Centrifugal Pump	12,000
	Pump Power = 0.69 kW	
HX-104	Heat Exchanger	10,000
	Heat Exchange Area = 7.52 m ²	
HX-105	Heat Exchanger	8,000
	Heat Exchange Area = 5.04 m ²	
PM-103	Centrifugal Pump	12,000
	Pump Power = 0.64 kW	
HX-103	Boiler	84,000
C-104	Condenser	22,000
Total 2		221,000
3. Methanation section		
R-101	Reactor + compressor	2,315,000
	This is cited from a reference in which the equipment costs are presented for a whole section. Thus compressor and unlisted equipment do not separate in this section.	
Total 3		2,315,000
Unlisted equipment		449,000
Total 1+2 +3 unlisted equipment		4,736,000

Table E2-2. Investment cost

1. Direct fixed capital cost	Unit (€)
Biogas section	3,919,000
Upgrading by amine section	1,161,000
Methanation section	2,940,000
2. Working capital	787,000
3. Cost of monoethanolamine	8,000
Total investment	8,814,000

Table E2-3. Utilities cost

Utility	Unit cost (€)	Annual amount	Annual cost (€)	%
Standard power	0.15	5,097,198 (kW-h)	764,580	56.47
Steam	12	12,521 (T)	150,251	11.1
Cooling water	0.05	1,516,122 (T)	75,806	5.6
Chilled water	0.4	908,379(T)	363,352	26.84
TOTAL			1,353,989	100.00

Table E2-4. Annual operating cost

Cost Item	€	%
Raw Materials	6,941,000	77.25
Labor-Dependent	359,000	3.99
Facility-Dependent	278,000	3.09
Laboratory/QC/QA	54,000	0.6
Utilities	1,354,000	15.07
TOTAL	8,985,000	100.00

Economic analysis of scenario 3- E3

Table E3-1. Component purchase costs of scenario 3

Name	Description	Cost (€)
1. Biogas section		
SL-101	Grass silage storage pit	503,000
	For storing 30,000 tonnes grass silage/year	
V-101	Slurry Receiver Tank	70,000
	Vessel Volume = 170 m ³	
SR-101	Shredder	56,000
	Rated through put = 3,200kg/h	
PM-101	Centrifugal Pump	7,000
	Pump Power = 0.51 kW (pump and mixer)	
AD-101	Anaerobic Digester	805,000
	Vessel Volume = 7965 m ³	
AD-102	Anaerobic Digester	308,000
	Vessel Volume = 4616 m ³	
Total 1		1,749,000
2. Methanation section		
R-101	Reactor + compressor	2,464,000
	This is cited from a reference in which the equipment costs are presented for a whole section. Thus compressor and unlisted equipment do not separate in this section.	
Total 2		2,464,000
Unlisted equipment		438,000
Total 1+2 + unlisted equipment		4,653,000

Table E3-2. Investment cost

1. Direct fixed capital cost	Unit (€)
Biogas section	3,919,000
Methanation section	3,129,000
2. Working capital	759,000
Total investment	7,807,000

Table E3-3. Utilities cost

Utility	Unit Cost (€)	Annual amount	Annual cost (€)	%
Std Power	0.15	5,081,928 (kW-h)	762,289	88.6
Steam	12	1,635 (T)	19,615	2.28
Cooling Water	0.05	1,568,799 (T)	78,440	9.12
TOTAL			860,345	100.00

Table E3-4. Annual operating cost

Cost Item	€	%
Raw Materials	7,201,000	83.58
Labor-Dependent	291,000	3.37
Facility-Dependent	220,000	2.56
Laboratory/QC/QA	44,000	0.51
Utilities	869,000	9.99
TOTAL	8,616,000	100.00

Appendix F- Chapter 6: Calculation data and Superpro designer simulation results

Kg N in digestate (section 6.2.2.2)

50:50 grass: slurry

4 kg N/t grass and 3 kg N/t slurry equates to 3.5 kg N/t feedstock

94% N remaining = 3.29 kg N/t

84% reduction in volume of digestate

Thus $3.29/0.84 = 3.89$ kg N/t digestate

H₂ conversion efficiency (section 6.2.2.3)

1 kg H₂ equivalent to 11.2 m³ H₂ equivalent to 134 MJ or 37 kWh.

49kWh to produce 37 kWh equates to 75% conversion efficiency.

Simulation results from Superpro Designer for S1, S2 and S3 with 60 : 40 VS grass and slurry (section 6.2.4.2).

Table F1. Inputs and outputs for three scenarios

	S1	S2	S3
Grass silage (tonnes)	25,344	25,344	25,344
Slurry (tonnes)	70,607	70,607	70,607
Hydrogen (tonnes)	-	1436	1496
Renewable methane (m ³)	4,174,132	8,196,291	8,341,716
Digestate (tonnes)	84,660	84,660	84,660

Table F2. Parasitic energy demands

	Scenario 1		Scenario 2		Scenario 3	
Energy produced - MJ (LHV):	150,268,753		295,066,477		300,301,780	
	Heat (kWh)	Electricity (kWh)	Heat (kWh)	Electricity (kWh)	Heat (kWh)	Electricity (kWh)
Biogas production	1,842,305	1,558,781	1,842,305	1,558,781	1,842,305	1,558,781
Amine upgrading	8,767,488	185,872	8,767,488	185,872	-	-
Ex-situ biological methanation	-	-	0	3,966,336	0	4,126,320
Compression		1,460,946		2,868,702		2,919,601