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Techno-economic and sensitivity analysis of biomethane production via landfill biogas upgrading and Power-to-Gas technology

Mohammad Samim Ghafoori^a, Khaled Loubar^a, Mylène Marin-Gallego^b, Mohand Tazerout^a

^aIMT Atlantique, GEPEA UMR CNRS 6144, F-44307, Nantes, France

^bLaboratoire de Génie Chimique, Université de Toulouse, CNRS, INPT, UPS, Toulouse, France

*Corresponding author: khaled.loubar@imt-atlantique.fr - (ORCID: 0000-0003-1578-6475)

Abstract:

Power-to-gas is a technology, which produces synthetic methane through two-step processes: H₂ production via water electrolysis and methanation of CO₂. The technology valorizes CO₂ as a useful commodity from biogas plants. Biogas upgrading technologies have the capacity to capture CO₂ and supply it as a source of carbon to methanation processes hence to produce synthetic methane. In this study, we have carried out a techno-economic assessment of biomethane production and estimation of its production costs via the integration of landfill biogas to methanation process. The study assessed four different scenarios, scenario 1: water-scrubbing, scenario 2: membrane, scenario 3: direct methanation and scenario 4: methanation with membrane. Production costs in case of power-to-gas scenarios 3&4 are competitive with standard upgrading scenarios 1&2 for electricity price below 20 €/MWh. Presence of electrolyzer unit contributes to more than 75 % of the total biomethane production costs. Scenarios 1&2 are insensitive to change in electricity price as well as to operating time, but scenarios 3&4 are extremely sensitive to both electricity price variation and operating time. Increase in the plant size and vol% of CH₄ in raw biogas presented shorter payback period in case of scenarios 1&2 due to lower specific production costs.

Keywords: Techno-economic analysis, landfill biogas valorization, biomethane, power-to-gas technology, CO₂ utilization, biomethane production costs.

1. Introduction:

The greatest environmental problem for the present time is the combustion of fossil fuels such as coal, oil and natural gas. Due to the development and growth of world economic, the energy need of more and more countries is increasing enormously. Presently, the fossil fuels are responsible for the main energy resources approximately 80% of the global demand for use in our daily life, in economic or in industrial activities. Nearly 80% of the worldwide CO₂ emission derives from the combustion of such fuels [1]. Use of fossil fuels have many associated risks such as decreasing reserves, emissions of greenhouse gases (GHG) and also dependency on the importation [2]. Towards resolving these severe issues, international treaties like the Kyoto protocol and COP21 are emphasizing on development and utilization of renewable energy sources [3]. Thus, as an encouraging solution, renewable energy sources can serve as powerful alternatives to curb the use of fossil fuels [4]. Moreover, the EU members agreed to reach in the heating sector an annual increase of 1% of renewable energy and a target of 14% of renewable sources in the transportation sector by 2030. The projection is a long-term decarbonization up to 2050 [5].

In this perspective, the decomposition of biodegradable waste and substrates in anaerobic conditions is a well-established process for the biogas production and consequent biomethane generation. The leading countries in the production of biogas was Germany (46.7% of the total produced biogas of the EU) followed by United Kingdom and Italy as second and third major producers, with respectively 16.2% and 11.3% of the total biogas production in EU [5]. By end of 2017, there were 17783 biogas plants with a trend towards installations with bigger capacities [5]. In about 71% of plants, biogas is obtained from agricultural crops and residues, in about 16% from sewage sludge, in 8% from landfill and in the remaining 5% from other or unknown substrates [4].

The interest towards biogas upgrading to produce biomethane is rapidly growing in the EU, the substitution of fossil fuels by biomethane can increase the primary energy saving instead of converting biogas to green electricity only [6],[5]. Many purifications and upgrading technologies have been developed to obtain a rich-CH₄ product (biomethane) with higher purities (95-98%). These technologies are water scrubbing, chemical and physical absorption processes, membrane technology, pressure swing adsorption and cryogenic technology [4]. The upgrading costs of the established technologies depend on specific technology but more importantly on the plant characteristics. The amount of the energy needed to upgrade biogas to biomethane is a key consideration while selecting an upgrading method. Cost economics is not only the appropriate selecting criteria of biogas upgrading technology, but, in the meantime, it is related to the final utilization of biomethane and the percentage of CH₄ in the final mixture of the upgraded gas.

In case of some upgrading technologies such as: pressure swing adsorption, membrane technology and cryogenic distillation, capturing separated CO₂ is possible [5]. The captured CO₂ this way could be utilized in many ways and one of which is in the hydrogenation of CO₂ to produce synthetic methane via methanation in a process called power-to-gas (PtG) [7]. Thus, together with deployment of renewable technologies, the study of novel applications that can store such energy meanwhile utilizing CO₂ of biogas plants has gained excellent attention [8]. Installation of massive electricity production from renewable sources of energy such as photovoltaic panels and windfarms would lead to overproduction. Surplus renewable energy if not stored would be wasted since this renewably produced electricity would not be adjusted to the electricity demand. Several electricity storage technologies are available like pumped hydro storage (PHS), compressed air energy storage (CAES), batteries, flywheels, hydrogen storage and synthetic natural gas. These electricity storage technologies are characterized with different prices, run times and storage capacities [9]. Fundamental factor in an energy storage system is its potential of charge/discharge time and storage capacity. This is achieved only in case of chemical secondary energy carriers such as hydrogen and carbon-based fuels substitute natural gas, other storage technologies mentioned above are limited in storage capacity and discharge time [10].

Power-to-gas links power grid to gas grid, in this process surplus power of the grid is converted to synthetic biomethane also referred as SNG with the help of two-step process: production of H₂ with water electrolysis and conversion of H₂ to synthetic methane with CO or CO₂ via

methanation [11]. The drawbacks of renewable electricity production such as intermittency and substitution to high energy intensity fuels could overcome with power-to-gas technology [2],[10]. In addition to converting intermittent electrical power to chemical energy, PtG plays a vital role in valorizing CO₂ as a useful commodity [8]. Power-to-gas requires a carbon source either CO or CO₂. There are several sources of carbon exist like power plants and refineries, iron as well as cement industries. Carbon dioxide sources from such industries would require a CO₂ capture and storage and some upgrading technology to remove methanation poisoning gases such as sulphur. The removal of CO₂ from these gases reduces the energy efficiency and increases the costs considerably. In contrast, PtG does not need larger sources of CO₂, nevertheless, they require smaller sources of CO₂ [12]. Even small biogas plants could generate remarkable amount of CO₂ and helps to store several MWh of energy through power-to-gas technology. Meanwhile, valorization of CO₂ from relatively small biogas plants would require considerably larger electrolyzer to produce renewable hydrogen [13]. Furthermore, besides using pure CO₂ in methanation, a mixture of CO₂ and CH₄ could also be combined with H₂ to produce synthetic methane in this process. The gas, which is typically used to produce power with cogeneration plants, contains a mixture of CH₄ and CO₂ and free from impurities. Such mixture of biogas could be directly used in the methanation and chemically reacted with hydrogen to produce synthetic methane [14]. The essential advantages from using biogas in the chain of PtG processes is the low gas treatment cost and ability to use the heat produced from methanation and oxygen from electrolyzer.

In the present study, we focus on the cost estimations of two different approaches: firstly, upgrading of landfill biogas to biomethane by standard upgrading technologies and secondly, synthetic methane production with PtG technology by valorizing CO₂. The novelty present in this study is the integration of landfill biogas as a source of CO₂ in the process of PtG technology consequently, offsetting the specific cost of CO₂ supply to the PtG process. The present study assumed CO₂ is captured and supplied into PtG process at the outlet of an upgrading technology as a by-product present in the site and if necessary, it is compressed to the required level of pressure before injecting into methanation reactor. The associated costs of CO₂ compression are not accounted in the model. Subsequently, specific costs of CO₂ supply are taken as zero for the current study despite the fact that it is not easy to define in general, because they strongly depend on the concentration in the source stream. To our knowledge, this is the first time that landfill biogas and its CO₂ content valorization via methanation is performed to assess the costs of SNG production both in direct methanation and methanation integrated with a biogas upgrading technology. Alternatively, CH₄ is being transformed into H₂ and carbon black, where H₂ is used to decarbonize the natural gas grid [15]. This scenario is considered as valid and under intense research efforts. Yet this scenario has not been considered in the objective of this study since it focuses on the transformation of CH₄ nevertheless, in the scenarios we have considered, the CH₄ is being produced not transformed. The current study does not clearly distinguish between technologies while instead uses input parameters such as cost, efficiency and energy consumption of the parts to estimate the production costs of methane gas.

2. Methodology

2.1 Overview of the system

In this paper, we focus on estimation of the production costs of biomethane from two different approaches: the first approach is to estimate the cost of biomethane from a standard biogas upgrading with no CO₂ valorization (Fig.1a). The second approach is to estimate the costs of synthetic methane or SNG via methanation processes Fig.1 (b&c). For the second approach, different configurations are analyzed: cost of synthetic methane from methanation process without upgrading i.e. direct methanation and cost of synthetic methane from methanation process with biogas upgrading using pure CO₂. The final cost of biomethane production would include all the costs associated in the process: CAPEX of the equipment, OPEX of the equipment, cost of power supply to the process, cost of injection to gas network, methanation and electrolysis to produce renewable hydrogen and finally electricity demand of the different equipment. The end product sometimes referred to “biomethane” with the signification to both biomethane from upgrading technologies and synthetic methane from methanation process.

Some case of the landfill sites is given in Table 1 [16] with the envision that this prospective of techno-economic analysis for biomethane production could be implemented. A waste landfill in the Ile de France region (Claye Souilly site, France) give off a biogas that contains about 40 vol% CO₂ and 50 vol% CH₄ [17]. In addition, landfill site of La Poitevineire give off a biogas that contains about 35 vol% CO₂ and 45 vol% CH₄ and up to 20 vol% N₂. For the current techno-economic study to estimate the biomethane production costs, a plant size (biogas flow rate) of 500 Nm³/h that contains about 35 vol% CO₂ and 45 vol% CH₄ is considered. Since the source of raw biogas and carbon dioxide is considered to be a landfill site, the cost of landfill biogas and CO₂ is taken as zero in the techno-economic assessment. As we are dealing with landfill biogas upgrading and given the fact that gas mixture contains 20 vol% N₂, an extra step of nitrogen removal with pressure swing adsorption is included for each scenario.

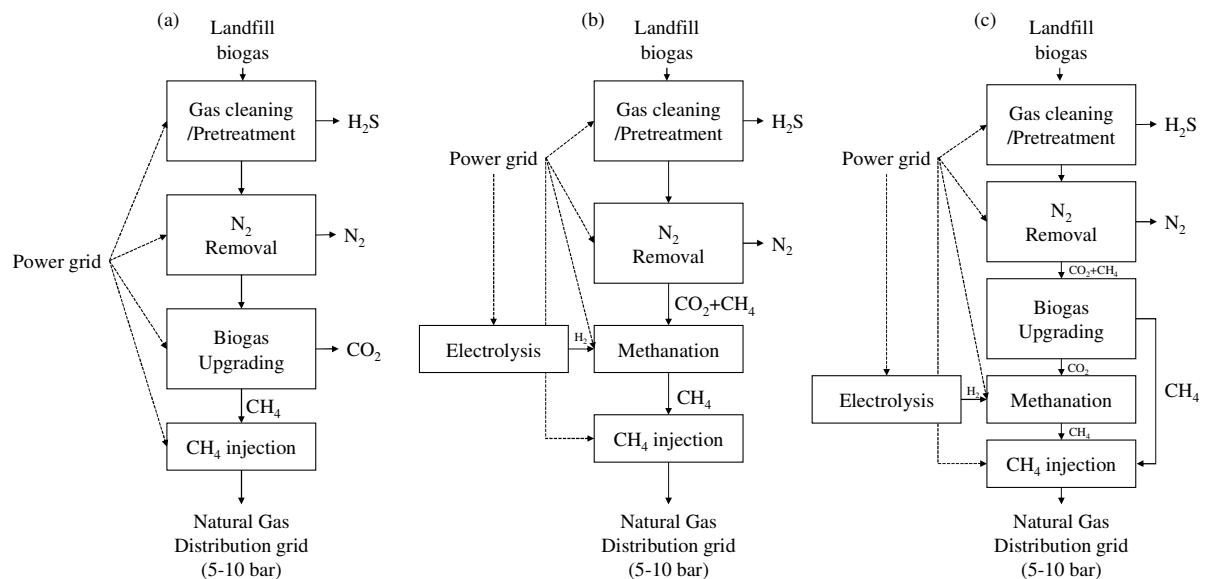


Figure 1. Modification of standard biogas upgrading by methanation process implementation (a) standard upgrading, (b) direct methanation and (c) methanation with upgrading.

This is a prospective of techno-economic analysis of biomethane production costs that does not yet exist. All the equipment is supposedly to be installed near the landfill site. This way we avoid the extra costs associated with the storage and transportation of landfill biogas.

Table 1. Examples of real cases of landfill sites [16].

Country	Place	Substrate	Utilization	Plant capacity (Nm ³ /h raw gas)	In operation since
France	Saint Maximin	Landfill	Gas Grid	160	2017
France	La Poitevinière	Landfill	CHP	220	2013
The Netherlands	Tilburg-De Spinder	landfill	Gas Grid	600	1989
Canada	Salmon Arm (BC)	Landfill	Gas grid	300	2013

Table 2 comprises the input data and general assumptions used in the current techno-economic study. Moreover, the electricity provided for the operation of different equipment as well as for the production of hydrogen with water electrolysis is supplied directly from power grid and the purchase price for such power is assumed at 71.7 €/MWh [18] for this study. In addition, biomethane sales prices are considered at 80, 75, 65 and 60 €/MWh corresponding to 100, 150, 200 and 250 m³/h (installation's maximum biomethane production capacity). These sales prices are taken from an introduction of feed-in-tariff for biomethane injected into natural gas grid networks as of December 2017 according to the type of feedstock and installations maximum capacity [19]. The 80 €/MWh corresponds to the case of biomethane from landfill biogas with the installation's capacity injecting 100 m³/h into natural gas distribution grid. The feed-in-tariffs differ based on the different installation's biomethane production capacity. The feed-in-tariff presented here is applied in France.

The analysis on economics for the estimation of biomethane production costs with different scenarios is done for one year of operation. The operating strategies could differ in whether or not electricity and gas are bought and sold according to hourly and daily varying price levels or via long-term contracts [20]. The basic operating strategy for the present work is studied where a long-term electricity purchase at a fixed price (71.7 €/MWh) is taken into account. This long-term contract guarantees the continuous operation of the plant and thereby does not necessitates a large storage facility neither for hydrogen nor for produced biomethane since the gas is continuously sold and electrolyzer to produce hydrogen is operated continuously.

Table 2. Input data and general assumptions for the present study.

Input data and general assumptions	value	unit
Plant life	15	years
Amortization period	15	years
Availability-stream factor	0.94 corresponding to 8200 h	hour [21]
Internal rate of return (IRR)	10	%
Biogas Production	500	Nm ³ /h
Methane content	45	volume %
CO ₂ content	35	volume %
Cost of landfill biogas	0	€
Electricity purchase price	71.7	€/MWh [22]
Pretreatment (Activated carbon cost)	41,700 €/year	1.85 g/Nm ³ raw biogas [5] 5.5 €/kg specific cost [5]
Biomethane sales price	80 (100 Nm ³ /h CH ₄)	€/MWh [23]

2.2 Biogas upgrading step

In the present study, the impurities contained in the biogas (particularly hydrogen sulfide H₂S) are removed with activated carbon adsorption. The cost of pretreatment with activated carbon is estimated annually at 41,700 €. This cost refers only to the cost of activated carbon used in the process. Biogas once pre-treated with activated carbon is thus considered as a mixture of CO₂ and CH₄+N₂ hence biogas upgrading focuses on the removal of CO₂ as well as N₂ from the landfill biogas. The presence of Nitrogen, which initiates from the entrance of air, is dominant in the composition of the landfill biogas. Removal of such gas requires an extra step of treatment to be integrated in the biogas upgrading process hence increases the overall final costs. Nowadays the technologies that can remove nitrogen from the landfill biogas are cryogenic, pressure swing adsorption and membrane. With the future proposed research and developments in the sector of membrane, it is possible to have the integrated H₂S removal with sophisticated membrane filters. This way the investment on activated carbon filters as a pre-treatment step would be avoided. Technical features and parameters of the 5 selected different biogas upgrading technologies to review are given in Table 3 ([2], [24], [25], [26]). It is evident from Table 3 that there is no optimal technology considering all parameters. Water scrubbing is the favorite technology for biogas upgrading. The technology has many advantages such as no demand on chemicals, higher methane recovery and no heat demand. The second preferred technology is chemical absorption. For this technology, the main drawback is the heat requirement at the regeneration step. Its dependency on the chemicals on the other hand could make the technology sometimes complex and expensive due to higher operational expenditures (OPEX). The drawback of heat requirement could though be overcome with the utilization of heat supplied by methanation. However, in the interest of this study we have not included the utilization of waste heat from the exothermic methanation reaction. Hence, instead of choosing chemical absorption, membrane technology was chosen due to its ease of operation and ability to capture CO₂. Similarly, the methane loss of membrane technology is not a concern anymore because the CO₂ containing some CH₄ will be later converted into CH₄ in the methanation step.

Water scrubbing and membrane scenario 1&2 given in Fig. 2 are thus the two different standard biogas upgrading technologies that have been assessed in the first approach of the present study to estimate the production costs of injected biomethane. In the second approach, the methanation process is integrated where these scenarios 3&4 focus on the valorization of CO₂ either in direct methanation a scenario without biogas upgrading or methanation with biogas upgrading (see Fig.2). It is important to note that an additional step of compression of the outputs of the upgrading process is needed before the methanation step.

Table 3. Technical features of different biogas upgrading technologies.

Characteristics	Unit	Water Scrubbing	Chemical Absorption (amines)	Pressure Swing Adsorption	Membrane Technology	Cryogenic
Electricity Demand	(kWh/Nm ³)	0.2-0.3	0.15	0.2-0.25	0.18-0.35	0.76
Heat Demand	(°C)	NO	120-160	NO	NO	NO
Operation Pressure	(Bar)	5-10	0.1	4-7	5-10	10-80
Methane Recovery	(%)	98	99-96	98	80-99.5	97-98
Methane Content in Upgraded gas	(%Mol)	>97	>99	>96	>95	>97
Water Demand		YES	YES	NO	NO	NO
Demand on Chemicals		NO	YES	NO	NO	NO
Ease of Operation		Complex	Intermediate	Intermediate	Easy	Intermediate
Removal of N ₂		NO	NO	Possible	Possible	Possible
Pre-purification		YES	YES	YES	Recommended	YES
H ₂ S co-removal		YES	contaminant	possible	possible	YES

Table 4 presents the input data, assumptions and expected biomethane production with water scrubbing scenario 1. With a stream factor at 0.94 which, is 8200 hours, 98% methane recovery and biogas flow rate at 500 Nm³/h, 45 vol% CH₄, scenario 1 is expected to produce 1,89,2160 Nm³/year of biomethane. This quantity of biomethane is equivalent to 19,868 MWh/year in terms of higher heating value (HHV) assuming each Nm³/h of CH₄ with 98% purity carrying 10.5 kWh of energy. Similarly, the total electricity consumption of water scrubbing is found to be 1095 MWh/year in full load operation. This total energy consumption of the technology is expected to upgrade 4,380,000 Nm³/year of raw biogas (500 Nm³/h, 8200 h) taking 0.25 kWh/Nm³ of raw biogas as specific energy consumption of the technology.

Table 4. Main assumptions, inputs and output related to water scrubbing scenario 1.

Description	Values	Reference
Main assumptions		
Methane Recovery	98 %	[9]
Electricity demand	0.2-0.3 (kWh/Nm ³ _{biogas})	[9]
Plant size	(200, 300, 400, 500 Nm ³ /h)	Present data
Inputs @ 500 Nm³/h		
Biogas from N ₂ Removal PSA	500 Nm ³ /h	Present data
	CH ₄ 45 vol%	
	CO ₂ 35 vol%	
Electricity consumption	1095 MWh/year	Present data
Output		
CH ₄ out water scrubbing (scenario 1)	216 (Nm ³ /h)	Present data
	1,892,160 (Nm ³ /year)	Present data
	19,868 (MWh/year)	Present data

Similarly, total annual CH₄ production with membrane (scenario 2) is presented in Table 5. The 90% of CH₄ recovery is chosen in this study to calculate the output of membrane technology. Like water scrubbing in scenario 1, the same approach is adopted for the membrane and the technology is supposed to work at 8200 h per year. Hence, 8200 h per year with 90% CH₄ recovery and with an input of 500 Nm³/h, 45 vol% CH₄, scenario 2 is expected to produce 18,625 MWh/year of biomethane. Similarly, the total electricity consumption of membrane (scenario 2) is estimated to be 1095 MWh/year. This total energy consumption of the technology is expected to upgrade 4,380,000 Nm³/year of raw biogas (500 Nm³/h, 8200 h) with 0.25 kWh/Nm³ of raw biogas as specific energy consumption. In addition, the quantity of CO₂ captured is estimated with 90% availability and is expected to be 157.5 Nm³/h. In methanation after upgrading (scenario 4), the proposed technology of biogas upgrading is membrane and captured quantity of CO₂ at the outlet of this technology is valorized in the hydrogenation of CO₂ via methanation. In addition to total electricity consumption of water scrubbing and membrane technology, the step of integrated nitrogen removal with pressure swing adsorption (PSA) has its own energy consumption. The yearly electricity demand of PSA with 0.25 (kWh/Nm³_{biogas}) [3] is found to be 1095 MWh/year.

Table 5. Main assumptions, inputs and outputs concerning membrane technology scenario 2.

Description	Values	Reference
Main assumptions		
Methane Recovery	80-99.5 %	[5], [9]
Electricity demand	0.18-0.35(kWh/Nm ³ _{biogas})	[5], [9]
Plant size	(200, 300, 400, 500 Nm ³ /h)	Present data
Inputs @ 500Nm³/h		
Biogas N ₂ removal PSA	500 Nm ³ /h	Present data
	CH ₄ 45 vol%	

CO ₂ 35 vol%		
Electricity consumption	1095 MWh/year	Present data
Outputs		
	202 (Nm ³ /h)	Present data
CH ₄ out Membrane (scenario 2)	1,773,900 (Nm ³ /year)	Present data
	18,625 (MWh/year)	Present data
CO ₂ out Membrane	157.5 (Nm ³ /h)	Present data

2.3 Power-to-gas

Power-to-gas links power grid to gas grid. In this process extra power of the grid is converted to gas with the help of two-step process: production of H₂ with water electrolysis and conversion of H₂ to synthetic methane with CO or CO₂ via methanation. The produced methane in this way is either easily injected to the natural gas grid or used as transportation fuel, bringing the same value as the natural gas grid.

2.3.1 Methanation step

The Sabatier reaction was discovered by the French chemists Paul Sabatier and Jean-Baptiste Senderens in 1897. Methanation is the process of synthetic CH₄ production from CO₂ and H₂[27]:



The process is exothermic with $\Delta H = -164.9$ kJ/mol. This reaction is a two-stage reaction including reverse water gas shift and methanation of CO.



In the first step (reaction 2), carbon dioxide and hydrogen are converted to carbon monoxide and water via reverse water-gas shift reaction and the reaction is endothermic $\Delta H = +41.5$ kJ/mol. In the subsequent reaction (reaction 3), with $\Delta H = -206.2$ kJ/mol, methane is formed from carbon monoxide and hydrogen. In this process, the source of CO₂ sometimes could be biogas, where the existing portion of CH₄ of biogas remains unreacted but CO₂ fraction of the biogas goes under chemical reaction with hydrogen to form synthetic methane.

In this study, H₂ produced from water electrolysis and CO₂ is supplied in two ways: as almost pure CO₂ which comes from a biogas upgrading step (membrane) or mixed with CH₄ in the direct methanation. Methanation can be done by chemical or biological catalysis [11]. In this study, a fixed bed catalytic methanation in the presence of chemical catalysts mainly composed of nickel has been considered. The choice of catalysts has a significant influence on the methanation reaction. The state-of-the-art catalyst is based on nickel because of high activity and the comparatively low price of nickel [9]. A stoichiometric ratio of CO₂/H₂ at 1:4 is considered. Ninety three percent of the CO₂ in the reaction is assumed to be converted into CH₄ [9]. In case of direct methanation, 100% of CH₄ in the gas mixture is assumed to exit the reactor unreacted.

Table 6. Main assumptions, inputs and outputs concerning direct methanation scenario 3.

Description	Values	Reference
Assumption		
CO ₂ conversion rate	93%	[9]
Temperature (°C) and pressure (bar)	300 °C & 1 bar	[9]
Methanation Reactor Capacity		

Maximum biogas input (35% CO ₂ , 45% CH ₄)	200, 300, 400, 500 Nm ³ /h	
Maximum hydrogen input (Nm ³ /h) (Estimated)	254, 378, 504, 630 Nm ³ /h	
Inputs @ 500 Nm³/h		
Biogas After N ₂ removal (CO ₂ +CH ₄)	500 Nm ³ /h CH ₄ 45 vol% CO ₂ 35 vol%	Present data
Hydrogen from electrolysis	630 (Nm ³ /h)	Present data
Output		
CH ₄ out Direct Methanation (scenario 3)	35,665 (MWh/year)	Present data

The yearly-expected amount of synthetic biomethane production by scenario 3 is given in Table 6. Landfill biogas once removed from H₂S and N₂ is fed directly into the methanation reactor and chemically combined with the help of nickel catalyst and is estimated to produce 35,665 (MWh/year) of synthetic biomethane under the full load (8200 h) and continuous operation. Hydrogen and CO₂ are fed together in a stoichiometric ratio into methanation reactor and rate of conversion of CO₂ is supposed to be 93% [9]

Table 7. Main assumptions, inputs and outputs related to methanation with upgrading scenario 4.

Description	Values	Reference
Assumption		
CO ₂ conversion rate	93 %	[9]
Temperature (°C) and pressure (bar)	300 °C & 1 bar	[9]
Methanation Reactor Capacity		
Maximum CO ₂ input (Estimated)	63, 94.5, 126, 157.5 Nm ³ /h	
Maximum hydrogen input (Nm ³ /h) (Estimated)	254, 378, 504, 630 Nm ³ /h	
Inputs @ 500 Nm³/h		
CO ₂ from Membrane output	157.5 (Nm ³ /h)	Present data
Hydrogen from electrolysis	630 (Nm ³ /h)	Present data
Outputs		
CH ₄ out Methanation After Upgrading	146.5 (Nm ³ /h) 13,473 (MWh/year)	Present data
CH ₄ out Membrane	18,625 (MWh/year)	Present data
Total CH ₄ out (scenario 4)	32,100 (MWh/year)	Present data

The scenario 4 is methanation with biogas upgrading using membrane technology. The CH₄ output of this scenario is the summation of CH₄ output from membrane and CH₄ output via methanation. Landfill biogas once purified from Hydrogen sulfide by activated carbon filters is fed into PSA where the nitrogen of the landfill gas is removed. The outlet of this technology, which is a mixture of CH₄ and CO₂ is fed into membrane to separate CH₄ from CO₂. Carbon dioxide is captured and fed into methanation process along with hydrogen, consequently synthetic methane is produced. Expected annual biomethane production is estimated and presented in Table 7. The produced methane this way is mixed with CH₄ produced via membrane and further fed into natural gas grid.

2.3.2 Electrolysis step

Electrolysis of water is the decomposition of water into hydrogen and oxygen under the effect of an electric power. Nowadays, integrating water electrolysis with intermittent renewable energy projects are gaining more attractions, because it holds mutual benefits, which is producing green and clean hydrogen and making use of intermittent wind or solar electrical power otherwise wasted due to demand-supply load variations. For instance, these technologies nevertheless are limited to some research and advancement [8].

The concept of electrolysis of water is given in the equation below:



The main water electrolysis technologies are alkaline water electrolysis, proton exchange membrane electrolysis (PEM) and solid oxide electrolysis (SOE). Alkaline water electrolysis is economically more favorable and a best candidate system to produce hydrogen on a large scale from renewable energies. Specifically, its benefit over other electrolyzer is that the electrolyte and electrode material are much cheaper and is abundantly available with higher energy efficiency and high gas purity [12]. Proton exchange membrane electrolyzer are commercially available only for low-scale production applications. Maximum hydrogen throughput is in the order of 30 Nm³/h with a power consumption of 174 kW [13]. Solid oxide electrolysis is also referred to as high temperature electrolysis and is the most newly developed technology of hydrogen production and the technology is still under development and research in the laboratory scale. Table 8 [28] lists and compares the three mentioned water electrolysis in terms of its technical data and capacity of hydrogen production and its availability.

PEM water electrolysis is much more expensive due to high capital cost of cell stock compared to alkaline liquid electrolyte water electrolysis [29]. Meanwhile alkaline water electrolysis has shown to be durable even on the intermittent operation [14]. Consequently, we chose alkaline water electrolysis in this study with the given assumptions in Table 8&9.

Table 8. Comparison of three-water electrolysis technologies [22].

	Alkaline Electrolysis	Membrane Electrolysis (PEM)	Solid Oxide Electrolysis (SOE)
Electrolyte	Liquid alkaline KOH	Solid acid polymer	Ceramic metal compound
Electrodes	Ni/Fe electrodes	Noble metals (platinum, Iridium)	Ni doped ceramic
Temperature	40-90 °C	25°C-100°C	700-1000 °C
Pressure	< 30 bars	< 200 bars	Atmosphere
Model size	Max. 720 Nm ³ H ₂ /h ~ 3.2 MW _{el}	Max. 30 Nm ³ H ₂ /h ~ 170 kW _e	~ 1 Nm ³ H ₂ /kWh range
Operating	Commercially available, MWs	Commercial, small scales	R&D and Demonstration

Though alkaline water electrolysis is compatible with intermittent operations, yet the continuous supply of power to the electrolysis and hydrogen production is essential for the operation of methanation process. The estimation of total energy consumption of alkaline water electrolysis is essential to find out the capacity of electrolysis, which can continuously produce needed hydrogen for the methanation process. Efficiency of alkaline electrolysis reported to be in the range (62-82) voltage efficiency (HHV) % [30]. Table 9 presents the main assumptions used the input data and outputs of the alkaline water electrolysis. The electrolysis efficiency considered here in this study is 70%.

Table 9. Main assumption, inputs and outputs at the electrolysis stage.

Description	Values	Reference
Specific energy consumption	45 kWh/kgH ₂	[31],[26]
HHV volume H ₂	0.0035 MWh/Nm ³ -H ₂	[32]
Electrolyzer efficiency	0.7 kWh HHV-H ₂ /kWh _e	Present data in line with [30] [32]
Electrolyzer Capacity	1.3 MW @ 252 Nm ³ /h H ₂ 1.9 MW @ 378 Nm ³ /h H ₂ 2.5 MW @ 504 Nm ³ /h H ₂ 3.2 MW @ 630 Nm ³ /h H ₂	
Inputs		

Total energy consumption	3.2 MW	Present data
Output		
Hydrogen from electrolysis	630 (Nm ³ /h)	Present data
	56.3 (kg/h)	Present data
CO ₂ out Membrane	157.5 (Nm ³ /h)	

2.4 Economic data

In Table 10, capital expenditure (CAPEX), operating expenditure (OPEX) for all the processes are presented. CAPEX corresponds to the fixed cost of the equipment and OPEX corresponds to the operation and maintenance costs of the equipment. The CAPEX and OPEX costs presented in the Table 9 are analogous for a raw biogas flow rate of 500 Nm³/h. In addition to OPEX, electricity consumption of the technologies is also estimated for each corresponding scenario see Tables 4, 5, 6, 7, 9). Electricity consumption, inputs and outputs given in the Tables 4, 5, 6, 7 and 9 correspond to the 500 Nm³/h of raw biogas flow rate. The specific costs given in Table 10 are addressed from the literature and subject to constant changes due to enhancements and developments brought to the technology each year.

Table 10. Main assumptions for the CAPEX and OPEX used in the present study.

CAPEX			
Item	Specific Cost	Value (€)	References
Power Grid Connection		150,000	[32]
Water Scrubbing	10100 €/Nm ³	2,181,600	Present data in line with [33]
Membrane	3260 €/(m ³ /h)	1,630,000	Present data in line with [2]
N ₂ PSA	1-1.8 M€	1,200,000	Present data in line with [3]
Electrolysis	1000 €/kW	3,200,000	Present data in line with [2], [7],[32]
Methanation	1500 €/kW	2,331,800	Present data in line with [2], [7],[32]
Gas Grid Injection	130000 €	130,000	[32]
OPEX			
Water Scrubbing	1-2 % of CAPEX	43,630	Present data in line with [33]
Membrane	2-4 % CAPEX	48,900	Present data in line with [2]
N ₂ PSA	0.13 €/m ³	242,000	
Electrolysis	4.5 % of CAPEX	141,750	Present data in line with [2], [7],[32]
Methanation	5-10 % of CAPEX	116,000	Present data in line with [2], [7],[32]
Gas Grid Injection		100,000	[32]

3. Results and discussions

An overview of the four-biomethane production scenarios assessed in the current study is given in Fig. 2 as below:

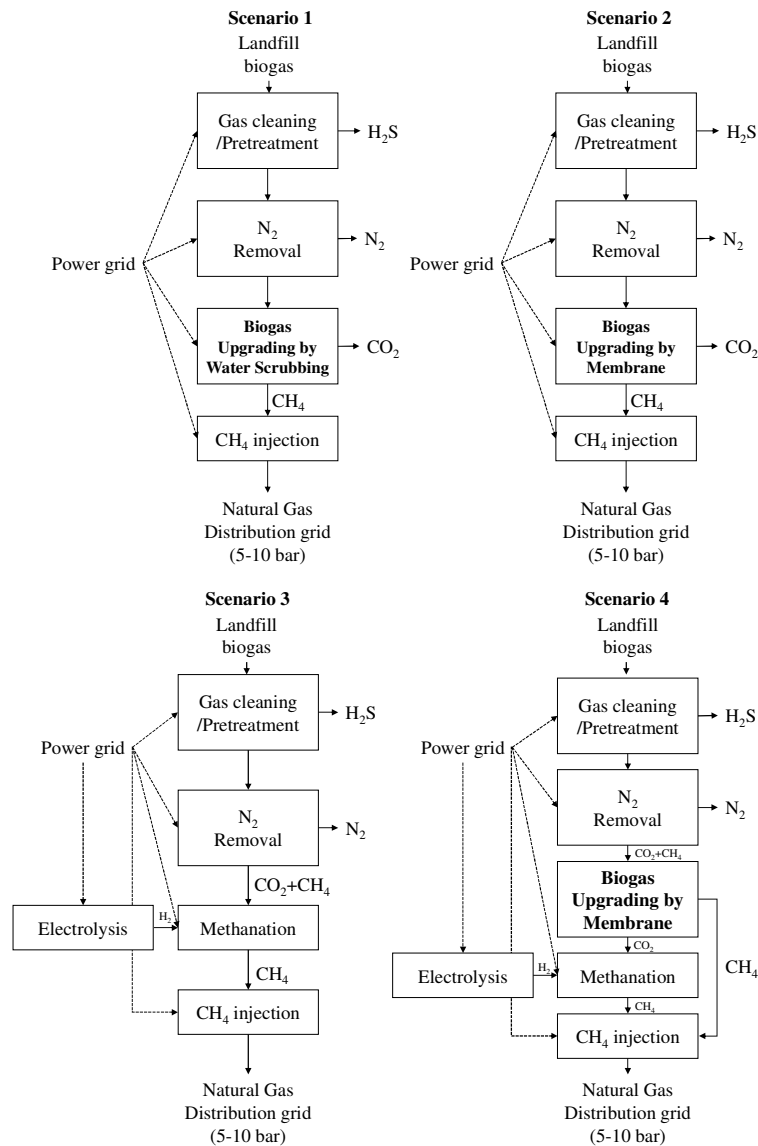


Figure 2. Overview of the four-biomethane production scenarios assessed.

3.1. Economic Results

Total annual production costs of biomethane production for the different proposed scenarios can be seen in Table 11. There is an important difference of total annual production costs with and without methanation: which is approximately 600 k€/year for standard upgrading with scenarios 1&2 and 3000 k€/year for upgrading with methanation scenarios 3&4. There is no contribution of landfill biogas production costs since the source of the gas is considered landfill site and is taken zero, this implies for all four scenarios presented in this study. In case of standard upgrading scenarios, total annualized costs are approximately distributed in a uniform way. The higher costs of the methanation scenarios are mainly due to the electrolysis step, its CAPEX, OPEX and more importantly electricity consumption of electrolysis to produce hydrogen. It represents more than 79% (scenario 3) and 74% (scenario 4) of the production costs with a large share due to electricity consumption (84% of the electrolysis costs). This huge contribution of electricity consumption is due to the high cost of electricity from the grid and operating the electrolysis in continuous mode. Biomethane production cost in case of scenario 2 is reaching approximately 34 €/MWh with electricity purchase price at 71.7 €/MWh. This cost is 87 €/MWh for direct methanation and 100 €/MWh for methanation after upgrading. Between scenarios 3 and 4, scenario 3 shows lower production cost due to directly using biogas and due to absence of upgrading steps.

Table 11. Biomethane annual production costs in function of different scenarios

Annual Costs of Items Included	<i>Scenario 1</i>	<i>Scenario 2</i>	<i>Scenario 3</i>	<i>Scenario 4</i>
	(€/year)	(€/year)	(€/year)	(€/year)
Activated Carbon Pre-treatment	41,700	41,700	41,700	41,700
Power Grid Connection	10,000	10,000	10,000	15,000
CAPEX Water Scrubbing	67,333	-	-	-
OPEX Water Scrubbing	20,200	-	-	-
CAPEX Membrane	-	108,667	-	108,667
OPEX Membrane	-	48,900	-	48,900
CAPEX N ₂ Removal PSA	80,000	80,000	80,000	120,000
OPEX N ₂ Removal PSA	56,000	56,000	56,000	56,000
CAPEX Electrolysis	-	-	210,000	210,000
OPEX Electrolysis	-	-	141,750	141,750
CAPEX Methanation	-	-	155,459	155,459
CAPEX Gas Grid injection	8,667	8,667	8,667	8,667
OPEX Gas Grid Injection	100,000	100,000	100,000	100,000
Electricity Consumption of Technologies				
Electricity Need of Water Scrubbing	78,512	-	-	-
Electricity Need of Membrane	-	78,512	-	78,512
Electricity Need of N ₂ PSA	78,512	78,512	78,512	78,512
Electricity Need of Electrolysis	-	-	1,978,490	1,978,490

3.2. Sensitivity analysis

In Fig.3 production cost of the water scrubbing and membrane technologies are presented for different upgrading plant sizes (100, 200, 300, 400 and 500 Nm³/h of raw biogas). The electricity price is fixed at 71.7 €/MWh. The fluctuations in the purchase price of electricity from the grid do not affect the final specific cost of biomethane production because the standard technologies are not energy intensive.

For a larger flow rate of biogas, some biogas upgrading technologies show a fixed CAPEX since the technology is designed for a large fluctuating range of biogas flow rate. Nevertheless, in case of some other technologies even the CAPEX increases with an increase in the biogas flow rate. Similarly, the OPEX and electricity consumption of the technology will increase and this way the overall production costs increase. For instance, the biomethane production cost is 51 €/MWh for a biogas flow rate at 300 Nm³/h in scenario 2, but the production cost decreases to 34 €/MWh for a biogas flow rate at 500 Nm³/h which shows approximately 50 % reduction in the production cost.

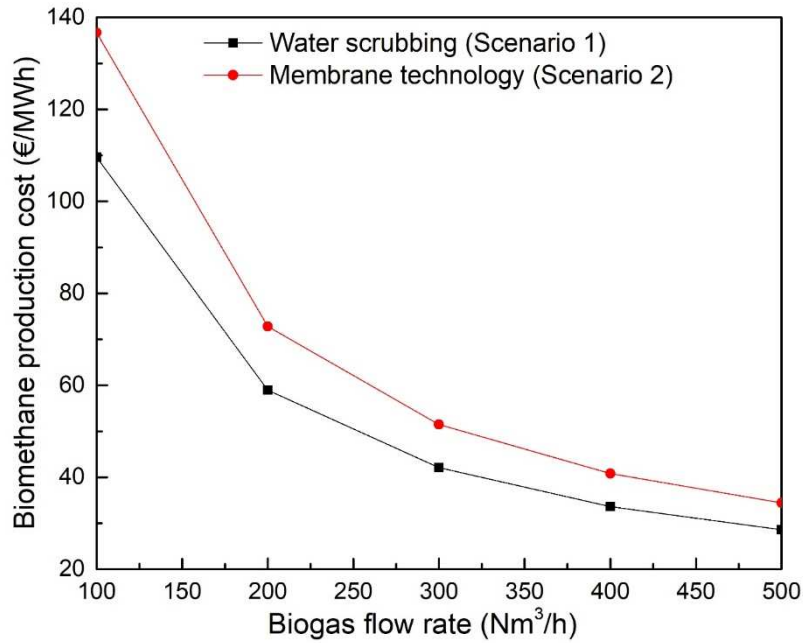


Figure 3. Variation of production costs depending on biogas flow rate.

In Fig.4, the production costs of scenarios 1&2 are presented for a range of 45 to 60 vol% of CH₄ in the raw biogas for a biogas flow rate at 500 Nm³/h. The energy content of the biogas that in fact comes from CH₄ is captured at the outlet of upgrading technology. This way the higher share of CH₄ in the biogas could eventually increase the energy content and production capacity of technology and lowers the production costs. A range of 45 to 60% of CH₄ in the raw biogas, which in most cases is the CH₄ percentage in landfills, is chosen for the sensitivity analysis. From Fig. 4, production cost in case of scenario 1, for a 45 vol% CH₄ share, is 29 €/MWh and for a 60 vol% CH₄ share it is 21 €/MWh.

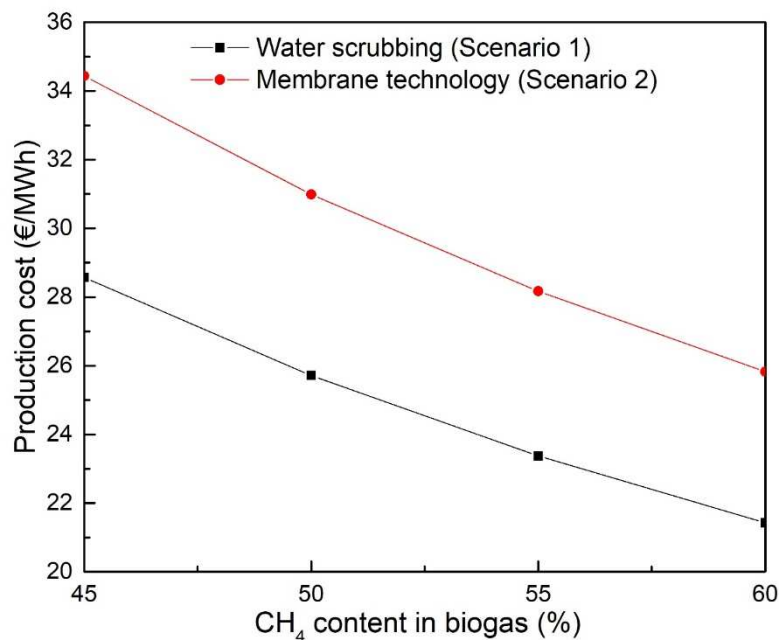


Figure 4. Effect of methane content in raw biogas on production cost of scenario 1&2.

In Fig.5, overall production costs of the different scenarios are presented for electricity prices ranging from 50 to 130 €/MWh in continuous operation. Biogas flow rate at 500 Nm³/h and 45 vol% CH₄ is

chosen. Power-to-gas scenarios are extremely sensitive to the electricity price, which is mainly because of the electrolysis step and electricity consumption of this step. Due to high proportion of fluctuating generation capacities, electricity prices are becoming more volatile. Moreover, extremely low and extremely high prices are arising in the electricity exchange. These extreme prices are found to prices equal to or less than 0 €/MWh and more than 100 €/MWh [34]. The expected relation between these extreme price ranges, which are expected to rise sharply from 2026 onwards, bring opportunities for new participants and technologies on the market, such as storage systems [35]. As the electricity price goes from 60 to 120 €/MWh the production costs increase from 78 to 131 €/MWh in direct methanation and from 92 to 150 €/MWh in methanation after upgrading. This increase represents 64 and 60% in the production cost in case of direct methanation (Scenario 3) and methanation with upgrading (Scenario 4) respectively.

Moreover, cost of production from standard upgrading technologies (scenario 1 and 2) are almost insensitive to electricity price, as they are mainly driven by the fixed costs. Other relevant OPEX corresponds to the injection step and OPEX of the equipment that is not related with the electricity price. Similarly, as the electricity price goes from 60 to 120 €/MWh, the production costs increase from 34 to 40 €/MWh which is only 15% increase (scenario 2) compared to 64% in case of PtG scenario 4.

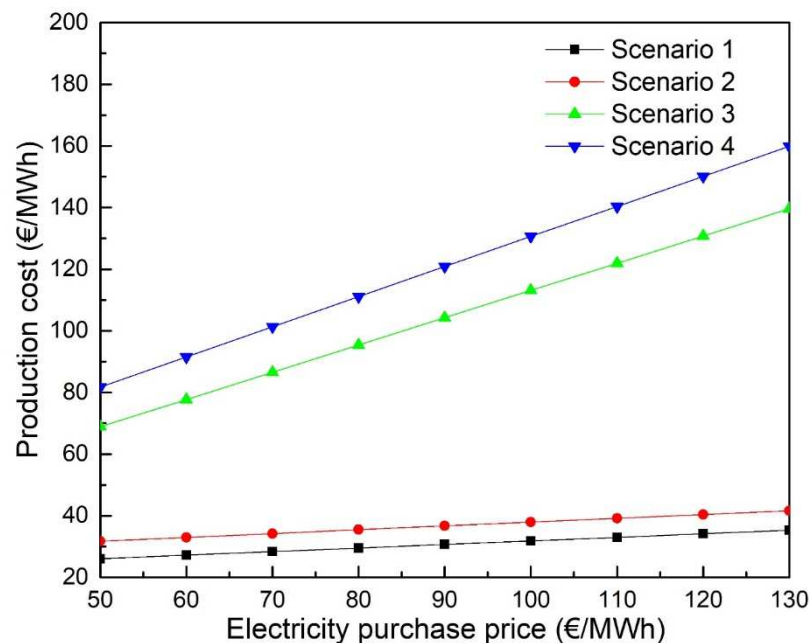


Figure 5. Variation of biomethane production costs depending on electricity purchase price.

In contrast, PtG scenarios, 3 and 4 are exceedingly sensitive to electricity purchase price. Specific cost of CH₄ production with PtG scenarios would be in between 35 €/MWh – 45 €/MWh for electricity purchase price at 10 €/MWh for scenarios 3 and 4 respectively. It is seen from Fig. 6 that the production cost of CH₄ in case of scenario 3 (direct methanation) is nearly close to scenario 2 (membrane). If a competitiveness has to be achieved between PtG and standard biogas upgrading scenarios, the most important factor in this case would be the electricity purchase price and the later has to be extremely low for PtG scenarios.

As previously described, PtG is a relevant way to store overproduced electricity. This way, surplus power can be converted into chemical energy within a two-step process: electrolysis of water to produce hydrogen and hydrogenation of CO₂ via methanation to synthesize CH₄. Alkaline electrolysis is adoptable in intermittent operation and hence this operation worth analyzing in the process of PtG. The use of fluctuating power sources are satisfying and compatible with the intermittent operation of water electrolysis and is currently in use in PtG pilot plants [2].

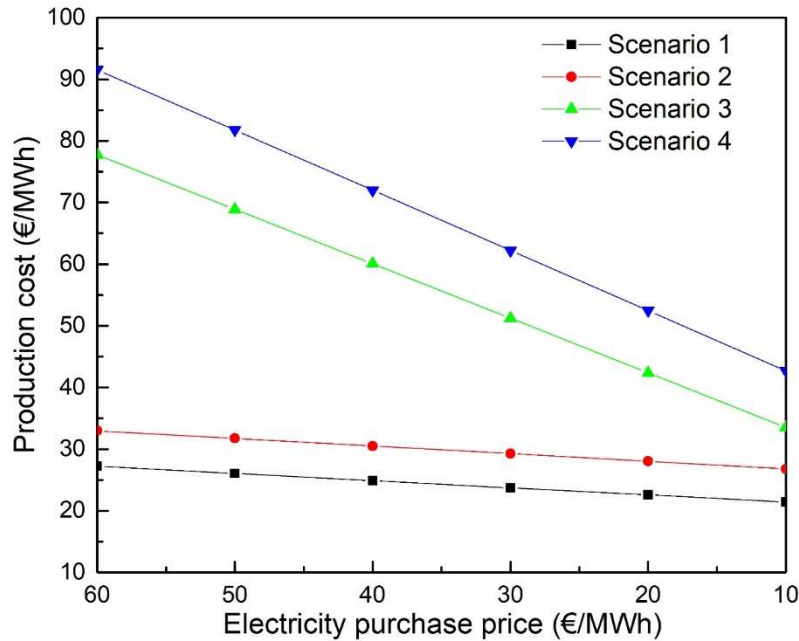


Figure 6. Influence of electricity prices on the competitiveness of the four scenarios.

Here in this study, economic results for flexible operating strategy varying between 2000 to 8200 h (continuous operation time) with 0.94 stream factor have been assessed for (scenario 3 and scenario 4) which are direct methanation and methanation with upgrading with membrane. Biogas upgrading technologies are insensitive to the operation time. Impact of operating time from 2000 to 8200 h on the production cost of biomethane has been presented in Fig.7.

The SNG production costs strongly differ on the electricity purchase price and the operating time of the electrolysis and methanation units. In the calculations for flexible operation, the operating hours of electrolysis are supposed to be regularly distributed over the entire year. This could be correlated either with the higher willingness to pay for electricity price or the low electricity price periods. In the case where no electricity is available, the operation of electrolysis is maintained in hot standby mode where in this case no gas is expected to be produced. Integration of a small hydrogen storage system could separate the electrolyzer from methanation that is eventually to compensate for the different rates of load changes of both sub-systems. The number of full-load hours (FLH) of electrolyzer could be regulated to the fact that it corresponds to the low electricity price times.

The inputs for this assessment are 500 Nm³/h biogas flow rate with an electricity price equal to 71.7 €/MWh. It can be seen from Fig.7 that, costs of direct methanation are very strongly connected with the operation time, with costs between 180 €/MWh for 2000 h of operating time, and 90 €/MWh for continuous operation. This illustrates that intermittency in the operation of PtG processes potentially increases the overall cost of biomethane production costs. In fact, the volume of energy produced is drastically reduced with the increase of the intermittency. On the other hand, fixed costs (all the CAPEX, OPEX and rental of the injection unit) are unchanged. Therefore, the direct methanation leads to a dramatic increase of the production costs with an intermittent functioning and hence this technology is not suitable for non-continuous operation mode. In contrast, production costs increase to a much lesser amount in case of methanation with upgrading due to share of membrane technology. Constant supply of hydrogen is necessary to operate methanation in continuous mode. In some of the cases, installation of hydrogen storage facility as an intermediate step could help to store hydrogen and feed in a continuous manner into methanation reactor. Nevertheless, it is worth to mention that the costs associated with the integration of intermediate hydrogen storage would be accounted in the PtG plant.

Overall, the installation of intermediate hydrogen storage facility would result in the reduction of SNG production costs. A detailed study illustrating the percentage reduction of gas production costs (GPC)

due to integration of intermediate interim hydrogen storage system is not included in the scope of current study. However the studies carried out with [34],[36], show a reduction of 5 to 8% GPC by integrating hydrogen storage. In the calculation to account for the reduction of GPC due to hydrogen storage system and seeking cost benefits of optimizing hydrogen storage, the associated CAPEX, OPEX of hydrogen storage are unavoidable. A bigger hydrogen storage capacity separates two sub-systems and guarantees that SNG is supplied constantly over 8200 h in a year. This manner, the produced and stored hydrogen is fully processed with methanation unit. With an optimized size of the hydrogen storage and the methanation is used, the fluctuated load of the electrolyzer can be flattened and longer continuous operation of the methanation is possible. A suitable size of hydrogen storage depends on the profile of the electrical input of electrolyzer as well as the methanation capacity. Well-balanced hydrogen storage and methanation capacities increase the annual full-load and decrease SNG production costs.

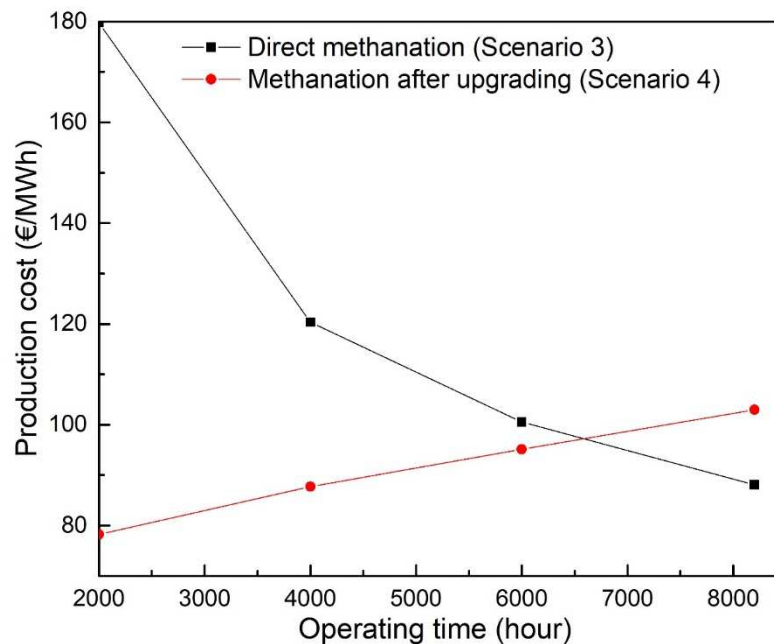


Figure 7. Effect of operating time on the production costs of Power-to-Gas scenarios (3&4).

3.3. Financial analysis

Techno-economic studies carried out in this work show that, the PtG scenarios 3&4 have presented negative cumulative discounted cash flow for the selected input parameters. Total annual sales of revenue expected from these scenarios are lower than the total annual expenses or total costs of biomethane production. On the other hand, it was interested to financially analyze the selected standard upgrading technologies, scenario 1&2 and show the discounted payback period to draw a conclusion on what period the initial investment could be recovered. Hence, the graphs illustrating the discounted payback period versus time in years are drawn for water scrubbing. The discounted payback period against cumulative discounted cash flow for different biogas flow rates at 45 vol% CH₄ can be seen in Fig.8 for water scrubbing scenario 1. Similarly, the effect of different vol% of CH₄ in the biogas has also illustrated with the help of Fig.9. A discounted rate of 10% to calculate the net present value of future cash flows is considered in the present financial analysis. When biogas flow rate is 500 Nm³/h it is expected that the payback period of the scenario 1 will be 6 years and within this period, the initial investment is expected to be recovered. This scenario will start cumulating positive cash flow after the 6th year. With the assumption of continuous operation and electricity purchase price equal to 71.7 €/MWh, this scenario is expected to cumulate 2000 k€ in 10 years when

each MWh of produced biomethane worth 60 €, which is the feed-in-tariff for biomethane injection into natural gas grid networks.

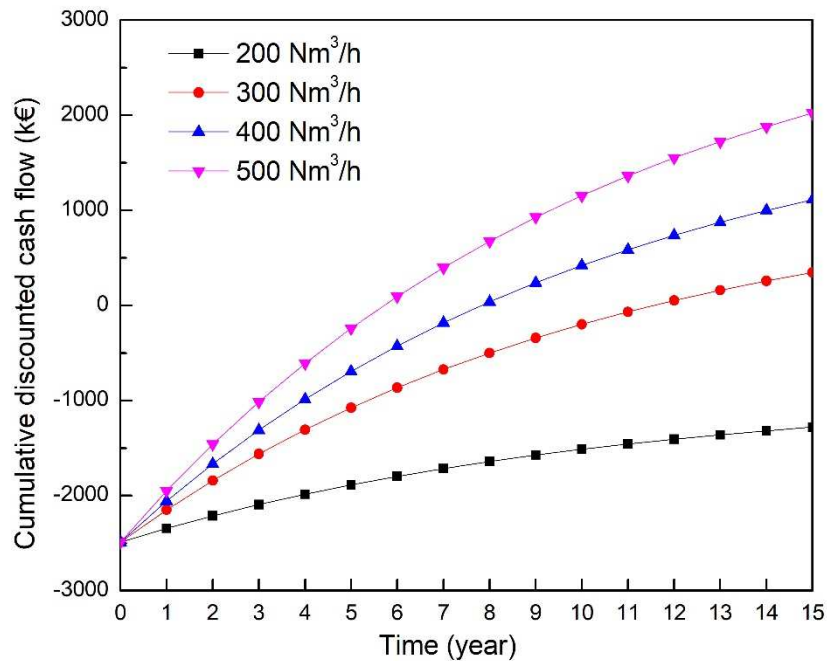


Figure 8. Discounted payback period and discounted cumulative cash flow depending on biogas flow rates at 45 vol% CH₄ (Scenario 1)

For the same scenario illustrated in Fig.8, a biogas flow rate of 200 Nm³/h will never recover the initial investment that is due to higher initial investment, higher total yearly expenses, and lower sales of revenue. The net cash flow expected in this case is negative which is due to higher total expenses than total sales of revenue.

Similarly, discounted payback period calculations have also been carried out for scenarios 1&2 with a biogas flow rate at 500 Nm³/h. Scenario 2 with higher total annual expenses would have a discounted payback period at 8 years compare to scenario 1 at 6 years. The longer discounted payback period of the scenario 2 in other hand is due to smaller net cash flow collected compared to scenario 1. The effect of different vol% of CH₄ in the raw biogas is illustrated with the help of Fig. 9&10 on discounted payback period. The scenario selected for this performance is scenario 1. A range of 45 to 60 vol% of CH₄ in raw biogas at 200 Nm³/h in Fig. 9 and at 500 Nm³/h in Fig.10 is selected for the discounted payback period. Discounted payback period in case of 60 vol% CH₄ would be shorter comparing to the discounted payback period in case of 55 and 45 vol% CH₄ which is due to higher sales of revenue and higher net cash flow. Biogas flow rate at 200 Nm³/h will not recover the initial investment at 45 vol% CH₄. Nevertheless, at the same flow rate but this time with much higher vol% CH₄, at 60 vol% CH₄, discounted payback is expected to be 12 years.

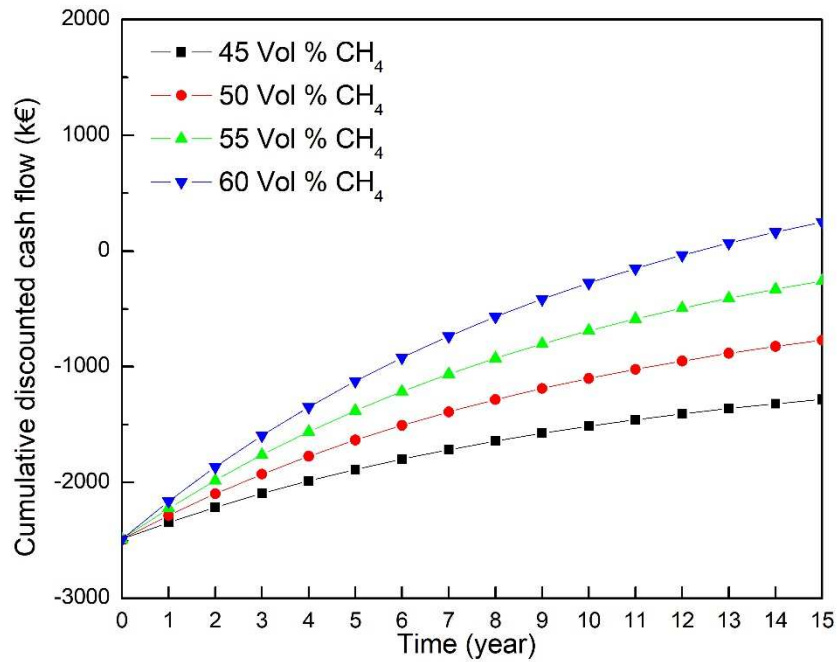


Figure 9. Discounted payback period and discounted cumulative discounted cash flow: Scenario 1 with different vol% of CH₄ in biogas at 200 Nm³/h

Even with 60 vol% CH₄ the discounted payback period is expected to be 12 years with 200 Nm³/h, which is quite a long time to recover the initial investment done on such a project where the aim is to produce biomethane from landfill biogas. One of the major contributions on the total annual production costs of biomethane in case of treating landfill gas is the removal of nitrogen. Increasing the biogas flow rate would lower the specific costs of biomethane production. The more favorable case to lower the biomethane production cost and shorten the payback period would be the higher biogas flow rate with higher vol% of CH₄ in the biogas. Effect of different vol% of CH₄ in raw biogas on the discounted payback period at 500 Nm³/h can be seen from the Fig.10. The five year of discounted payback period at 45 vol% CH₄ is reduced to 3 years when we have 60 vol% CH₄ at the raw landfill biogas.

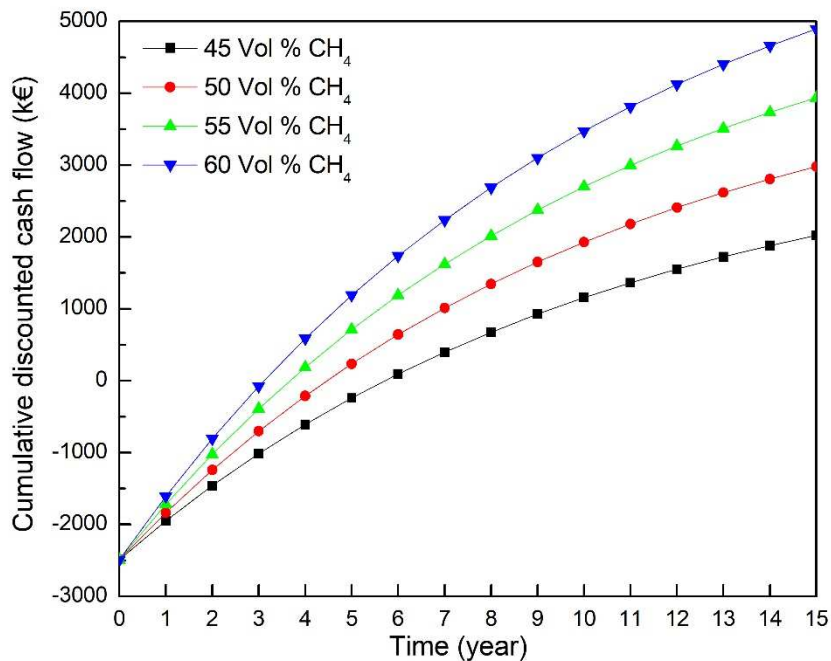


Figure 10. Discounted payback period and discounted cumulative cash flow: Scenario 1 with

4. Conclusions

A techno-economic assessment and estimation of biomethane production costs via biogas upgrading and PtG technologies have been performed. This work is a first attempt to assess the economics of biomethane production from landfill biogas by PtG technologies. To assess biomethane production costs, four different scenarios have been analyzed: two standard biogas-upgrading technologies (water scrubbing and membrane) and two PtG technologies (direct methanation and methanation with upgrading by membrane). Sensitivity analysis have been carried out, both on economic and financial assessments. From the economic point of view, PtG technologies are competitive with upgrading ones for an average electricity price below 20 €/MWh for direct methanation and below 10 €/MWh for methanation with biogas upgrading with membrane. PtG scenarios are extremely sensitive to the electricity price, which is due to the presence of electrolysis step and electricity consumption of this step. In contrast, biogas-upgrading technologies are insensitive to change in electricity prices because they are mainly driven with fixed costs and not energy intensive. As the electricity price goes from 60 to 120 €/MWh, the production costs of biomethane increase from 78 to 131 €/MWh in direct methanation and from 92 to 150 €/MWh in methanation with upgrading. This represents an increase up to 64 and 60% in the production costs in case of scenario 3 and scenario 4. It appears that direct methanation cannot be used in intermittent operation, as the produced energy is highly reduced because of the biogas lost when methanation is not operating. Similarly, cost of biomethane production with PtG technologies are lower in continuous operation than in intermittent operating mode. Nevertheless, biogas-upgrading technologies remain insensitive to the intermittent operating mode. Both higher biogas flow rate and higher share of CH₄ in the biogas could result to obtain a shorter discounted payback period and quicker recovery of initial investment done on the equipment. The financial analysis carried out show that, a 500 Nm³/h with 45 vol% CH₄ scenario 1, the initial investment is recovered within 6 years. With 200 Nm³/h at 45 vol% CH₄, the cumulated discounted cash flow even at the end of 12 years is negative which is due to higher expenses involved. The production costs of synthetic methane in PtG process depend in particularly on the electricity price and the full load hours of the plant sub-systems specially electrolysis to produce hydrogen. With the further development of capital expenditure, operational expenditure, electricity prices, gas costs and efficiencies, an economic production of synthetic methane for the year 2030, especially 2050, is feasible. Some strategies such as direct coupling of the PtG plant with a renewable energy source and the seasonal use of surplus energy from renewables are considered as future opportunities for PtG application soon for the near future 2030-2050. The future availability of appropriate incentives or governmental support schemes for these strategies have a positive effect on the economic efficiency of PtG plant and a potential reduction of production costs.

5. Acknowledgments

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