Swedish Environmental Research Institute

Enhanced Methane Production Through Carbon Dioxide Utilization at Biogas Plants

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Summary

The current energy crisis, driven by geopolitical instability, has led to increased natural gas prices and consequently attracted the attention towards biogas as an alternative energy carrier with the same properties. Sweden and the European Union are actively promoting the transition from natural gas to biogas through various incentives.

Biogas is a biobased fuel produced via anaerobic digestion of diverse organic substrates. The raw biogas contains a significant fraction of carbon dioxide (~40% vol), which must be separated to obtain biomethane with a methane content of at least 97% vol, suitable for vehicle fuel or other high-purity applications. Rather than releasing the separated carbon dioxide into the atmosphere, it can be utilized in a power-to-gas system, where renewable hydrogen—produced via electrolysis—is reacted with CO_2 to generate e-methane through a process called methanation. Integrating a methanation system into an existing biogas production facility could offer several advantages, including improved utilization of organic feedstocks and waste streams, as well as increased methane yield.

This study aimed to evaluate various methanation technologies currently available on the market, assessing their energy efficiency, renewable methane production potential, and economic feasibility for integration into existing Swedish biogas plants. The project was structured into four phases: (i) knowledge synthesis, (ii) case definition for further analysis, (iii) techno-economic assessment of the selected cases, and (iv) evaluation of the feasibility of implementing methanation technologies within the Swedish biogas sector.

The results highlight that the possibility of utilizing by-product and waste heat from the methanation system in the existing biogas plants is a critical factor for economic viability. The findings suggest that wastewater treatment plants present particularly advantageous sites for methanation implementation. This is due to the potential utilization of oxygen generated in the electrolyzer for aerated water treatment basins, thereby reducing the plant's electricity consumption. Additionally, excess heat from electrolyzers and catalytic methanation can be more effectively utilized in wastewater treatment facilities, which are often located near urban areas. In contrast, co-digestion plants do not benefit from oxygen utilization, and while some excess heat from electrolyzers can be used for hygienization and digester heating, a significant amount of heat remains unutilized.

The techno-economic assessment further indicates that the integration of a hydrogen storage and dynamic operation of the electrolyzer can improve economic performance by avoiding peak electricity prices. However, the optimal configuration of electrolyzer size and hydrogen storage depends on multiple factors, including electricity zone (bidding area), plant scale, choice of methanation and electrolyzer technology, and the extent of possible heat integration.

The estimated levelized production cost of renewable methane (CBG) for the evaluated cases ranged from 23.6–26.1 SEK/kg CH_4 for 20 GWh biogas plants and 16.0–18.8 SEK/kg CH_4 for 120 GWh biogas plants. The renewable methane produced via methanation is classified as e-methane, which falls under the category of "renewable fuels of non-biological origin (RFNBOs)". Under the revised Renewable Energy Directive (RED III), a minimum of 1% RFNBO is required within the transport sector, putting e-methane in direct competition with other electrofuels such as e-methanol and e-ammonia. Consequently, the production cost of e-methane should not only be assessed in relation to biomethane but also in comparison to alternative RFNBOs to evaluate its market competitiveness.

The study found that integration of methanation at biogas plants has the potential to increase production of renewable methane by approximately 62% without requiring additional biomass input. Based on assumptions regarding average Swedish biomethane and electricity prices, the minimum biogas plant capacity required for economically viable methanation implementation is estimated to be ca 40 GWh per year. If methanation were to be implemented at all existing and planned biogas plants with a capacity of 40 GWh or greater, the national annual renewable methane production could increase by approximately 2 200 GWh. This can be compared to the total amount of biogas that is produced in Sweden today, 2 300 GWh.

Furthermore, the increased renewable methane output, as a result of implementing methanation at biogas plants, would enhance the economic feasibility of LBG production by enabling economies of scale in liquefaction. Under the assumptions used in this study, an additional 500 GWh of annual LBG production could be achieved.

Sammanfattning

Den pågående energikrisen, pådriven av geopolitisk instabilitet, har lett till ökade naturgaspriser och därmed också ökat intresset för biogas som en alternativ energibärare med samma egenskaper. Sverige och EU främjar aktivt övergången från naturgas till biogas genom diverse initiativ.

Biogas är ett biobaserat bränsle som produceras via anaerob rötning av organiska restprodukter. Rågasen innehåller en betydande andel koldioxid (~40% vol), vilket behöver separeras för att få fram biometan med en metanhalt på minst 97% vol, som då lämpar sig för användning som fordonsbränsle och andra applikationer som kräver hög renhet. Istället för att släppa ut koldioxiden i atmosfären så kan det användas i så kallade Power-to-gas system, där förnybar vätgas – som produceras via elektrolys – reagerar med CO2 för att generera e-metan genom en process som kallas metanisering. Integrationen av ett metaniseringssystem på en befintlig biogasanläggning skulle erbjuda ett antal fördelar, bland annat ökad nyttjandegrad av organiska produkter och avfallsströmmar, samt ökad metanproduktion.

Den här studien hade målsättningen att utvärdera olika metaniseringstekniker som finns på marknaden, analysera deras energieffektivitet, produktionspotential av biometan och ekonomisk möjlighet till integration på svenska biogasanläggningar. Projektet delades upp i fyra faser; (i) kunskapssyntes, (ii) definition av case för vidare analys, (iii) teknoekonomisk analys av valda case, och (iv) utvärdering av genomförbarheten av implementeringen av metaniseringsteknologier på den svenska biogassektorn.

Resultaten visade specifikt att möjligheterna att använda biprodukter och restvärme från metaniseringssystemet på befintliga biogasanläggningar är kritiska faktorer för att uppnå ekonomisk genomförbarhet. Studien visade att avloppsreningsverk är särskilt väl lämpade för implementering av metanisering. Det beror på möjligheterna att använda sig av den syrgas som genereras i elektrolysören till luftning i vattenreningsbassängerna, och därmed minska anläggningarnas elkonsumtion. Utöver detta så kan även restvärme från elektrolysörer och den katalytiska metaniseringen användas mer effektivt på avloppsreningsverk, som oftast är belägna i närheten av städer. I motsats till detta så kan inte samrötningsanläggningar nyttiggöra syrgasen som produceras, och medan viss andel av restvärmen skulle kunna användas för exempelvis hygienisering och uppvärmning av rötkammare, så kvarstår en stor andel värme.

De teknoekonomiska beräkningarna visar vidare att etableringen av vätgaslager och dynamisk drift av elektrolysören kan förbättra de ekonomiska resultaten genom att undvika de högsta elpriserna. Men vilken konfiguration som är optimal när det gäller storlek på elektrolysör och vätgaslager beror på många faktorer, däribland elområde, storlek på anläggningen, val av teknologi för metanisering och elektrolysör, samt möjligheterna till användning av restvärme.

Genom att beräkna Levelized production cost, LPC, har en genomsnittskostnad per producerat kg metan tagits fram. Den uppskattade produktionskostnaden för CBG för de case som valdes ut i projektet är 23.6–26.1 SEK/kg CH_4 för biogasanläggningar på 20 GWh och 16.0–18.8 SEK/kg CH_4 för biogasanläggningar på 120 GWh. Den förnybara metanen som produceras via metanisering klassificeras som e-metan och faller därmed inom definitionen av ”renewable fuels of non-biological origin (RFNBOs)”. I det reviderade förnybarhetsdirektivet (RED III) krävs en inblandning av RFNBO på minst 1% inom transportsektorn, vilket leder till att e-metan konkurrerar med andra elektrobränslen som e-metanol och e-ammoniak. Därmed bör produktionskostnaden för e-metan inte bara jämföras med kostnaden för biometan utan för att kunna utvärdera dess konkurrenskraft så bör den också jämföras med andra alternativa RFNBOs.

Studien fann att integrationen av metanisering på biogasanläggningar har potential att öka produktionen av metan med cirka 62% från samma mängd substrat. Baserat på antaganden om svenska biogas- och elpriser behöver en biogasanläggning som implementerar metanisering vara minst 40 GWh stor för att det ska vara ekonomiska genomförbart. Om metanisering skulle etableras på alla existerande och planerade biogasanläggningar i Sverige med en kapacitet över 40 GWh så skulle den årliga nationella produktionen kunna öka med ca 2 200 GWh. Det kan jämföras med den totala produktionen av biogas idag som är 2 300 GWh.

Dessutom skulle den ökade biogasproduktionen, som ett resultat av implementering av metanisering, öka den ekonomiska genomförbarheten av LBG-produktion genom att möjliggöra stordriftsfördelar vid förvätskning. Under de antaganden som används i denna studie skulle ytterligare 500 GWh av årlig LBG-produktion kunna uppnås.

Abbreviations

3PM	Three Phase Methanation
AD	Anaerobic Digestion
AE	Alkaline Water Electrolyzer
BM	Biological Methanation
BoP	Balance of Plant
CAPEX	Capital Expenditure
CBG	Compressed Biogas
CEPCI	Chemical Plant Engineering Index
CSTR	Continuously Stirred Tank Reactors
EU ETS	European Union Emission Trading Scheme
IEA	International Energy Agency
LBG	Liquified biomethane
LCCA	Levelized Cost of Avoided Carbon Dioxide
LPC	Levelized Production Cost
MBR	Moving Bed Reactor
MSW	Municipal Solid Waste
OLR	Organic Loading Rate
OPEX	Operational Expenditure
ORP	Oxidation Reduction Potential
PEM	Proton-Exchange membrane
PtG	Power to Gas
SBCR	Slurry Bubble Column Reactor
SOEC	Solid Oxide Electrolyzer
TEA	Techno-economic Assessment
TRL	Technology Readiness Level
WWTP	Wastewater Treatment Plant
VFA	Volatile Fatty Acids

Clarification of terminology

The term *biogas* has for a long time generally been used to describe the renewable gas produced from anaerobic digestion of organic matter. Since then, other processes and paths, giving different qualities of the produced methane, have been developed. This has resulted in a need for more definitions than *biogas* to be able to distinguish and be more precise about the different methane-containing gases. To be as clear as we can, we have used the following definitions;

Biogas	Used as a broad definition of biogenic methane from anaerobic digestion (at times also including synthetic methane when mixed with biogenic methane), is commonly widely used
Raw biogas	A mixture between mainly methane and carbon dioxide, the gas that comes directly from the anaerobic digestion
Biomethane	Upgraded raw biogas, consists mainly of methane
E-methane	Produced from H_2 and CO_2, also known as synthetic methane, RFNBO (Renewable Fuels of non-biological origin)
Renewable Methane	Covers biogenic methane as well as synthetic methane
Upgraded biogas	Same as biomethane above
CBG	Compressed biogas
LBG	Liquified biogas

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1 Introduction

1.1 Background

The ongoing energy crisis related to the geopolitical situation in the world has driven up the price of natural gas and consequently attracted the attention towards biogas as an alternative energy carrier with the same properties. The biogas industry is currently experiencing an increase in demand to cover not only their primary market (light trucks and buses) but also heavy transport, industries, shipping and heating and electricity production. Sweden and the European Union are facilitating this transition from natural gas to biomethane by creating different incentives. In Sweden, investment support has been introduced using support measures for biogas produced from manure, support for biomethane that is liquefied, tax exemption as well as investment support through Klimatklivet. At the same time, the European Union has allowed biomethane from the gas network to be used in industry within the ETS directive and also proposed to raise the targets for biomethane production to an annual production of 35 billion cubic meters in 2030 within the EU (1). The energy crisis in 2022 also prompted the International Energy Agency (IEA) to issue a 10-point plan to reduce the EU's reliance on Russian natural gas. Among the proposed measures was an increase in biogas, biomethane, and low-carbon hydrogen production (2). This increased interest in biomethane has also led to an increased interest in liquefied biomethane (LBG). A liquefied form opens up for possible use in heavy duty transport and shipping and it also becomes more economically viable to transport longer distances leading to a larger potential market for biomethane producers (3).

Biogas is a biobased fuel which is produced by anaerobic digestion of diverse organic substrates such as municipal solid waste (MSW), industrial waste, municipal sewage sludge at wastewater treatment plants (WWTP) and agricultural residue and animal by-products such as manure. The raw biogas that comes out directly after the digester contains a high proportion of carbon dioxide (about 40% vol) which must be separated to obtain biomethane with vehicle gas quality (97% vol methane) or higher quality. The removed carbon dioxide, which is normally considered a waste stream and released into the atmosphere, has the potential to be utilized to produce more renewable methane and hence increase the efficiency of the process to meet the societal increase in demand. To achieve this, carbon dioxide needs to react together

with hydrogen in a process called methanation. If the hydrogen used in the reaction comes from the electrolysis of water using renewable energy (a technology called Power-to-Gas or PtG) the resulting methane is called e-methane and is a type of renewable methane which has the same properties as biomethane. The addition of the methanation step to existing biomethane production plants is a benefit in terms of effective use of by-products and increased production. Furthermore, the production of hydrogen as PtG can contribute to the storage of excess energy if intermittent renewable sources (e.g. wind, solar, etc.) are used.

The amount of biogas produced by anaerobic digestion in Sweden was 2.3 TWh in 2023. The same year the biogas consumption was 4.3 TWh, which meant that Sweden had to import part of this fuel, Denmark being responsible of 95% of this supply (4). A larger share of this use could be covered by domestically produced gas if methanation would be implemented.

1.2 Project description

This project has been carried out during September 2023 – March 2025 by IVL Swedish Environmental Research Institute together with Renewtec AB. It has been financed by Familjen Kamprad Stiftelsen.

The project aims to compare different methanation technologies available in the market and evaluate their energy efficiency, their potential to produce renewable methane, as well as their economic feasibility in case they are applied to existing biogas plants in Sweden. The result is intended to provide insight and guidance for existing biogas plant owners at wastewater treatment plants or co-digestion plants, in selecting the most suitable methanation technology for their specific substrate and operational requirements.

The project objectives have been to map and assess possible applicable concepts for methanation and hydrogen production at different types of biogas plants in Sweden. The project also aims to carry out a techno-economic and environmental evaluation of these concepts. If these technologies are implemented, it will lead to an increase in renewable methane production which can contribute to achieving an economies of scale required in order to establish a liquefaction plant. The project also aims to quantify the potential increase in renewable methane production that would be achieved if the above described concepts would be implemented at existing biogas plants in Sweden.

The project can be divided into four steps; the knowledge synthesis, the selection of methanation technologies and building cases, the technoeconomic assessment and the study of the potential when implementing methanation technologies in Swedish biogas plants, se Figure 1.

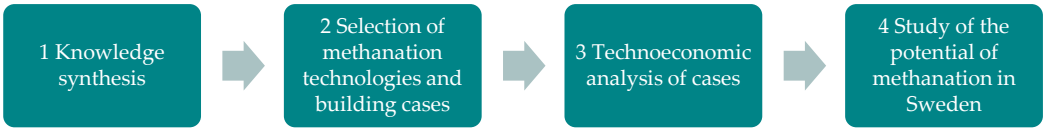

Figure 1. Overview of the steps of the project.

The different steps of the project are all described in the report. The methodology used is described in Chapter 2. For a summary of the knowledge synthesis, regarding methanation technologies and hydrogen production, see Chapter 4 & Chapter 5. The selection of technologies as well as the technoeconomic assessment of the cases can be found in Chapter 0. The final calculations of the increased potential for biogas production and liquefaction via methanation technologies are reviewed and described in Chapter 0.

2 Methodology

The following chapter gives a description of the knowledge synthesis, selection of cases for further evaluation, the techno-economic assessment, as well as how the study of the potential of methanation in Sweden was done.

2.1 Knowledge synthesis

The purpose of the knowledge synthesis is to map the different methanation technologies and to evaluate which of them has the potential to be integrated in Swedish biogas plants.

The knowledge synthesis of methanation technologies in this project is based on literature review and information from interviews with biogas plants operators as well as suppliers of methanation technologies. Information has also been gathered

through participation at conferences (5,6). Process descriptions, technical parameters as well as TRL-levels and mass- and energy balances have been mapped for different methanation concepts, which are presented in Chapter 5. The output of the knowledge synthesis is the input to building the cases whose potential is further evaluated through a techno-economic assessment.

2.2 Selection of methanation technologies and building cases

Based on the knowledge synthesis a selection of cases for further evaluation was made. The cases were selected in order to represent different methanation technologies as well as the application of methanation technologies at different types of biogas plants.

The cases were first divided into methanation at wastewater treatment plants (WWTP) and co-digestion plants. The two different biogas plant types give rise to different integration possibilities with the methanation system. The biogas plant types are further described in Chapter 3. The two main categories of methanation technologies are biological methanation and catalytic methanation, described in Chapter 5. Both types were evaluated for WWTP and co-digestion plants. There exist several different biological and catalytic methanation technologies. The selection of technology for the catalytic and biological methanation technology respectively, was made based on available data and TRL.

Apart from the type of biogas plant and methanation technology, an electrolyzer technology was also selected based on information presented in Chapter 4. Finally, each case was evaluated for a smaller and a larger scale biogas plant. This was done to capture the more favorable economics of larger scales due to economies of scale. A diagram showing the evaluated cases is presented in Figure 2.

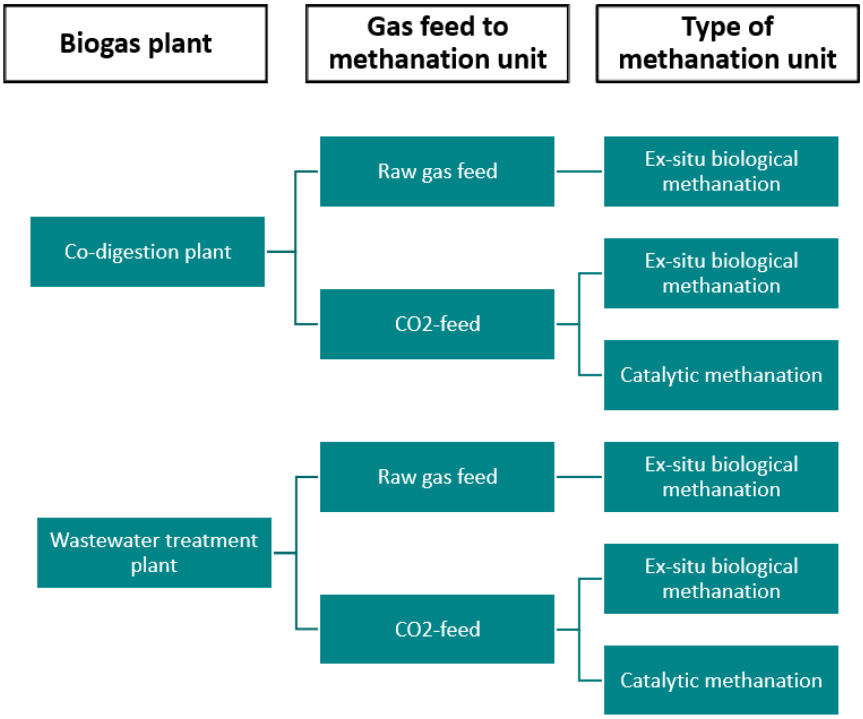

Figure 2. Diagram showing the 6 different cases that are being evaluated in the techno-economic assessment. Each case is evaluated for implementation at existing biogas plants with two different sizes (20 and 120 GWh).

2.3 Techno-economic assessment

Techno-economic assessment (TEA) is a method that can be used to analyze and estimate technical and economic performance of industrial processes. Key factors such as plant performance, capital and operating costs and emissions are considered in the assessment. The technical and economic feasibility of different methanation technologies can be compared using TEA. The input variables can be categorized into technical and economic variables.

2.3.1 Technical analysis

The technical analysis results in the mass and energy balance of the plant. The material and energy balance provides the efficiency, raw material, and energy usage as well as the equipment size of the plant. The plant capacity as well as the material and energy demand serve as input to the economic analysis.

2.3.2 Economic analysis

The economic analysis is based on costs and revenues of the system. There are several economic performance indicators that can be evaluated when doing a techno-economic assessment. Some of them are Levelized production cost (LPC) and Levelized cost of avoided CO_2 (LCCA).

The LPC and LCCA for the production of the different fuels is the average cost of produced fuel and avoided CO_2 over the economic lifetime of the investment respectively, and are calculated according to:

$$LPC = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + E_t - R_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{P_t}{(1+r)^t}} \qquad LCCA = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + E_t - R_t - F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{CA_t}{(1+r)^t}}$$

Where I_t is the investment in the year t, M_t is the operation and maintenance cost at year t, E_t is the energy and raw materials cost at year t, R_t is the revenue of co-products at year t, P_t is the produced product at year t, CA_t is the avoided CO_2 from a fuel switch at year t and F_t is the revenue from the product at year t, r is the discount rate (8%), and n is the economic lifetime of the system (20 years).

Based on the work of Sadhukhan et al. (7) it is assumed that 30% of the investment was made in year 1, while the remaining 70% was made in year 2 (start of operation. At year 2 it is assumed that the new plant operates at 75% of total capacity with 75% variable operating costs and 100% fixed operating costs. At year 3 the plant is running at full capacity).

The working capital and necessary refurbishment of the system is included in the yearly investment cost. The working capital is the capital tied up in sustaining plant operations (e.g. capital tied up in maintaining inventories of feeds, products, and spare parts), and is assumed to be 15% of the fixed capital investment (8).

2.3.3 Estimation of capital cost

The factorial method is a common method used to estimate the total project cost of a chemical process or plant. The method requires the costs of the major equipment items of the process, while other costs are estimated as factors of the major equipment cost. Therefore, the accuracy of the method is highly dependent on the accuracy of the cost data related to the major equipment items.

The costs accounted for by the factorial method in this work includes, among other things, instrumentation and control systems, electrical engineering, civil engineering, assembly, and commissioning. The factors are based on historical data of the cost of plants and can be found for different process types (fluids, fluids-solids, solids). The lang factors used in this work are presented in Appendix A – Lang factors. The total lang factor can be expressed as F and is used to estimate the cost of the entire project ($C_{project}$) based on the sum of the cost of equipment ($C_{equipment}$) according to:

$$C_{project} = F \times \sum C_{equipment}$$

The cost of the major equipment was estimated based on data from literature review, and scaled using the scaling factor (n) according to:

$$New\ cost\ of\ equipment = Cost\ from\ literature \times \left(\frac{New\ size}{Size\ in\ literature}\right)^{n}$$

and converted to current prices (year 2024) using the Chemical Plant Engineering Index (CEPCI), which is an index that reflects the cost changes in chemical engineering plant construction over time and is used according to:

$$Cost\ at\ year\ 2024 = Cost\ at\ reference\ year\ \times \frac{Index\ at\ year\ 2024}{Index\ at\ reference\ year}$$

The average CEPCI of 2024 that was used is 803.2 (7). The scaling factors used are presented in Appendix B – Methanation system scaling factors.

2.3.3.1 Cost estimate classes

The association for advancement of cost estimating international (AACE International) defines a cost estimation based on costs of similar processes with no further design information as a class 5 estimate (8). Class 5 estimates are used for initial feasibility studies and screening purposes. This type of estimate has an accuracy of about ±30–50 %. A class 4 estimate is an estimation based on limited cost data and design details and has an accuracy of about ±30%.

For the work presented in this report there is, to a certain extent, available detailed cost data. There are also some design details, however limited. The cost estimations in this work therefore falls in between a class 4 and class 5 estimate. The aim of the work is to evaluate different technologies and to compare alternatives to each other as well as to give insight into the contribution of different factors to the overall cost

for the different alternatives. A class 4 – 5 estimate is enough for this purpose. To account for the inaccuracy of the method, a sensitivity analysis is made by varying the estimated CAPEX between 70 and 130% of the initial value.

2.3.4 Sizing of process equipment

The process equipment and systems were based on the material presented in Table 1.

Table 1. Sources and methods used as base of estimation for technoeconomic assessment.

Process equipment/system	**Method**	**Reference**
Biological methanation system	Scaled based on data from the work done by Zauner et al. 2019	(11)
Catalytic methanation system	Scaled based on data from the work done by Zauner et al. 2019	(11)
Compressor	Sized based on methods presented in the work of Towler and Sinnot	(8)
Electrolyzer	Based on data from the work of Christensen A 2020 and Zauner et al., 2019	(11,12)
Hydrogen storage	Based on the work of Vinardell et al., 2024	(13)
Desulphurization	Scaled based on the work from Gantenbein et al., 2022	(14)
LBG system	Scaled based on information from personal communication and the methods from Towler and Sinnot.	(8)

The data found in the material was used as a reference for calculation and scaled to sizes matching the evaluated cases. All cost data was scaled to 2024 equivalent using

the CEPCI. Detailed techno-economic data can be found in Appendix B – Methanation system scaling factors and Appendix C – Techno-economic data and assumptions.

2.3.5 Optimization of hydrogen storage and electrolyzer size

In order to avoid peak electricity prices, the possibility of hydrogen storage for flexible operation was investigated. The calculations were based on hourly electricity price data from SE3 the year 2023 – 2024 (15). Electrolyzer and hydrogen storage size was varied to find the optimal solution that resulted in the lowest levelized cost of production for the cases investigated. An increased storage size meant that a longer period of high electricity prices could be avoided. However, a larger storage also requires a larger electrolyzer in order to meet the process demands and simultaneously fill the storage at favorable electricity prices. In contrast, a small storage requires a smaller electrolyzer, but results in a higher electricity price. The result of the storage size optimization for one of the cases is presented in Figure 3.

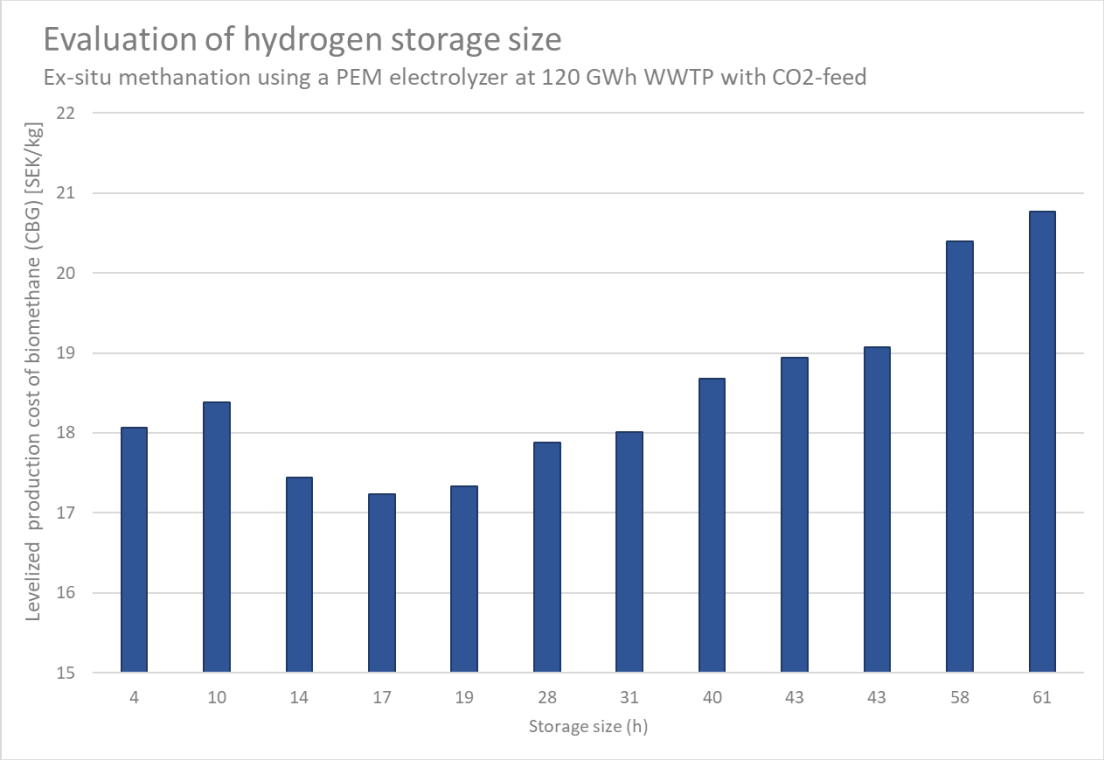

Figure 3. Levelized production cost of renewable methane (CBG) by ex-situ biological methanation at a 120 GWh WWTP with different hydrogen storage sizes.

As can be seen from the Figure 3, a storage size of 17h results in the lowest levelized cost of production. A 17h hydrogen storage requires an oversized electrolyzer of 120% compared to the size used for a configuration without hydrogen storage. The evaluation showed that a 120% capacity electrolyzer combined with a 17h hydrogen storage would operate 77% of the year. Similar results were obtained for all cases. Therefore, an electrolyzer of 120% capacity and a hydrogen storage with 17h storage capacity was chosen for all cases.

The hydrogen storage makes it possible to avoid running the electrolyzer at high electricity price. However, the rest of the methanation system will operate continuously. This means that all electricity consumption, excluding the electrolyzer, will follow the hourly electricity price.

2.3.6 Investment and production support

The Swedish Energy Agency provides production support for the production of biogas and LBG (16). The support for production of biomethane is 26 EUR2025/MWh (30 öre/kWh) and 13 EUR2025/MWh (15 öre/kWh) for produced LBG. Furthermore, the electricity used for biogas production is exempt from tax (17).

In addition, the Swedish Environmental Protection Agency offers investment support for investments related to fossil free technology and the green transition of up to 65% of the investment (18). The full production support and an investment support of 45% is accounted for in the techno-economic assessments in this report.

2.4 Study of the potential of methanation in Sweden

From the results of the techno-economic calculations of the estimated increase in renewable methane production a number of estimations were carried out for the calculations of total potential increase in Sweden. The theoretical potential was calculated using open sources on the total domestic production today and by the project estimated increase in output. The project assessed the feasibility of methanation for different sizes of biogas plants. Data on existing biogas & biomethane production and planned facilities were compiled using open sources, including websites, Klimatklivet funding applications, news articles and personal contacts. This data was used to map the total current and planned renewable methane production. A size threshold was applied, and calculations were performed

to estimate the potential increase in renewable methane production through methanation. The same approach was used to evaluate the potential for increased liquefaction feasibility by identifying facilities exceeding 60 GWh/year in production capacity and assessing their theoretical output.

3 Biogas production

Biogas production in Europe is rapidly expanding, with over 21 billion cubic meters produced annually, supporting energy demand, and reducing reliance on natural gas imports. Biogas and other renewable gases have gained significant attention globally, particularly in Europe, due to carbon-neutral targets for 2030 and 2050, focusing on decarbonizing gas. In 2019, the European Investment Bank stopped funding fossil fuels, and the European Commission introduced the Green Deal, prioritizing a shift to biomethane and clean hydrogen in the gas grid (19).

Nearly 20 000 biogas plants and 1 500 biomethane plants (biogas plants with upgrading to biomethane quality) (20) are operational in Europe, playing a key role in decarbonizing energy systems by integrating renewable gases into existing infrastructure. By 2040, biomethane could meet 85% of reduced gaseous fuel demand. Unlike wind and solar power, which are intermittent, biogas is produced continuously, providing a reliable and stable energy source. One key advantage is that biomethane can be stored in large quantities within existing gas infrastructure, allowing it to meet demand fluctuations and provide energy security. Additionally, biogas production contributes to waste management by turning organic waste, agricultural residues, and sewage sludge into renewable energy, reducing methane emissions from landfills and improving nutrient recycling in agriculture (21). Biogas also contributes to job creation, rural development, and sustainable agriculture through the use of digestate as organic fertilizer (22).

Sweden was once, from the mid-90s, a leader in renewable biomethane production, but nowadays there are other countries more in the front. 2023 Sweden produced 2.3 TWh biogas, mainly from organic waste and sewage sludge. However, consumption nearly doubles production. Of the total biogas produced, 68% is upgraded to biomethane quality. The transportation sector, benefiting from tax incentives, is the primary user. Sweden has 296 biogas producing plants, including 132 treating sludge at WWTP, 32 co-digestion plants handling various organic materials, 74 farm plants processing manure and agricultural residuals, 8 biogas plants for industrial wastewater treatment and 50 landfills with collection of biogas. There are 70 biomethane upgrading units, and most of the market operates off-grid, as the European gas grid only extends to southwestern

Sweden. Biogas is commonly transported in compressed or liquid form to local filling stations. The biogas sector is growing, particularly with rising interest in liquid biogas (LBG) for heavy-duty vehicles, industrial applications, and the shipping industry (23).

3.1 The Anaerobic Digestion Process – How is the biogas produced?

Anaerobic digestion is a syntrophic biological process that produces biogas (mainly CH_4 and CO_2) by breaking down organic materials in the absence of oxygen. It is widely used to stabilize primary and secondary sludges from wastewater treatment plants, as well as method to treat food waste from households and restaurants, manure, agricultural residues, and more, contributing to a circular economy by converting these feedstocks into renewable energy and fertilizer (biogas and digestate). The process involves several groups of bacteria and archaea that must cooperate to complete the degradation pathway from complex organic materials, such as carbohydrates, proteins, and lipids, into methane and carbon dioxide. The anaerobic digestion process is divided into four main steps: hydrolysis, acidogenesis, acetogenesis, and methanogenesis (see Figure 4).

- During hydrolysis, particulate organic matter is converted into soluble compounds and further broken down into simple monomers like sugars, amino acids, and fatty acids by extracellular enzymes produced by various bacteria.
- In the acidogenesis stage, acidogenic bacteria convert these hydrolyzed products into volatile fatty acids (VFAs), CO_2, and hydrogen.
- Acetogenesis follows, where acetogenic bacteria further process the VFAs into acetate, CO_2, and hydrogen, preparing the substrates for the final stage.
- Methanogenesis is carried out by methanogenic archaea, which convert acetic acid, hydrogen, and CO_2 into methane and water, accounting for most of the methane production.

The microbiology of anaerobic digestion involves diverse groups of microorganisms that establish syntrophic relationships, particularly between methanogens and acidogens, to maintain efficient digestion processes. Challenges such as the production of toxic sulfide by sulfate-reducing bacteria can be managed by several techniques, including adding iron to precipitate sulfide (24).

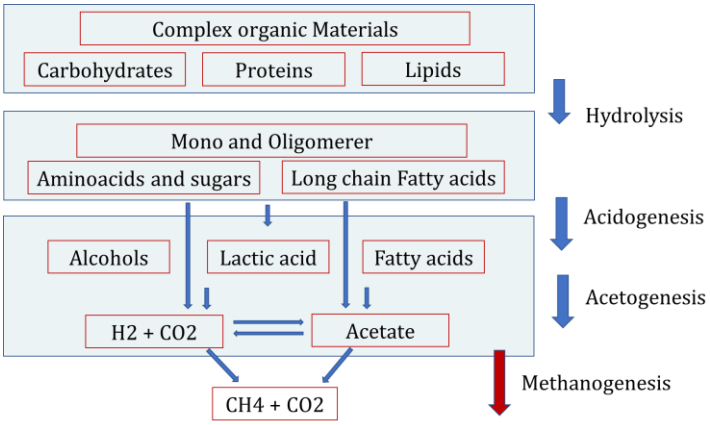

Figure 4 Anaerobic Digestion pathway

3.2 Biogas characteristics

Biogas varies widely, but in general, it is primarily composed of methane (~60% CH_4) and carbon dioxide (~40% CO_2), with small amounts of other gases such as hydrogen sulfide (H_2S), nitrogen (N_2), and oxygen (O_2). It can be used for energy production, as fuel for heating, electricity generation, and/or transportation, and as a building block in the chemical industry.

The energy value of biogas depends on the composition of the gas, which can vary depending on the substrate and the anaerobic digestion process. However, generally biogas produced at a wastewater treatment plant is similar to biogas produced at a co-digestion plant in terms of methane and carbon dioxide content. The type of impurities may however differ, where for example siloxanes can be a problematic impurity for wastewater treatments plants, originating from silica-compounds used by the households.

Generally, biogas has an energy content of around 14-29 MJ/Nm^3 (depending on the methane content), which is equivalent to approximately 4-8 kilowatt-hours (kWh) per normal cubic meter (25).

3.3 Biogas plants

3.3.1 Wastewater treatment plants

Over the past century, the exponential growth of urban populations worldwide has pushed the development of advanced wastewater treatment processes to protect water bodies. These processes are typically a combination of physical and biological steps. The first step includes the use of grids for the removal of large particles, followed by primary sedimentation, in which primary sludge settles at the bottom of these tanks. In the following step, biological treatment processes rely on bacteria to remove impurities in the wastewater, and with appropriate environmental controls, biological treatment can be applied in most cases.

Biological treatment primarily targets the removal of colloidal or dissolved biodegradable organic substances, nitrogen (N) and phosphorus (P) from wastewater. These nutrients cause eutrophication and detriment to water bodies, affecting aquatic life. These substances C, N and P are transformed into (a) gases that escape into the atmosphere and/or (b) biological cell tissue, which can be removed through settling or other solid separation processes. After the separation process, the treated water is released, and the remaining sludge needs to be stabilized. For several decades, anaerobic digesters (AD) were used solely for the purpose of stabilization of primary and secondary wastewater treatment sludge. However, the methane produced during this process has since been recognized for its potential value and is now often utilized for energy production. An example of a simple process-scheme for a WWTP is shown in

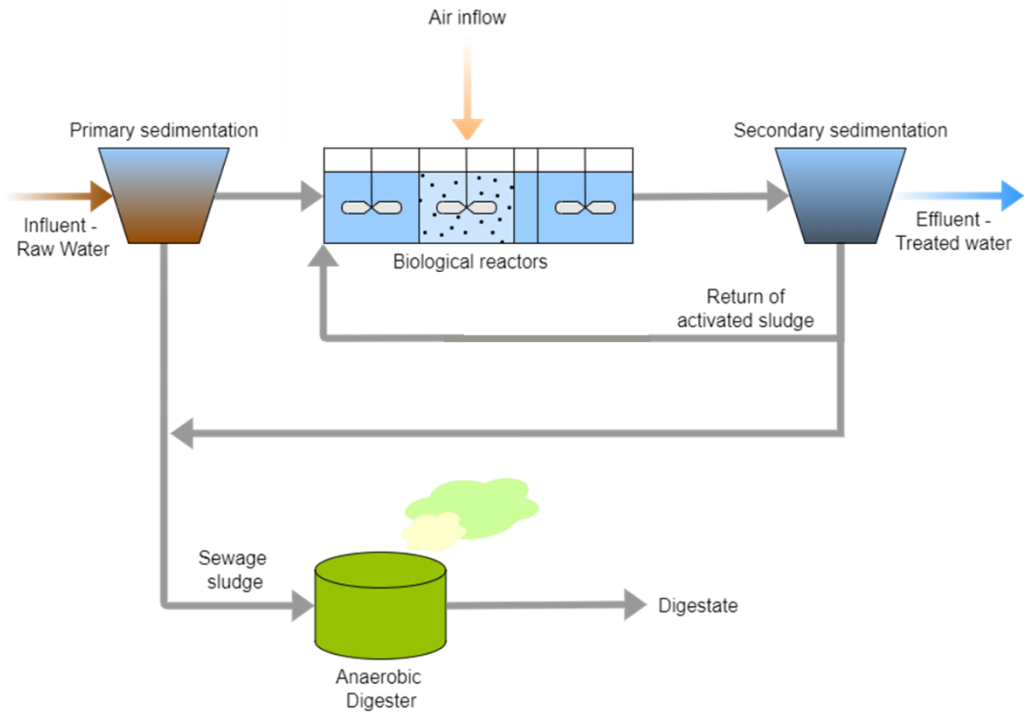

Figure 5.

AD is a long-established sludge treatment process. The thickened sludge, which typically contains between 4 and 12% total solids, is usually the main substrate and consists of macromolecules such as carbohydrates, proteins, and lipids. AD decomposes these organic macromolecules and reduces inorganic matter in the absence of oxygen, converting them primarily into methane and carbon dioxide. The biogas also contains other gases, including small amounts of carbon monoxide, hydrogen sulfide, hydrogen, and trace amounts of ammonia. Sometimes, siloxanes can also be present in biogas, and they can form silica deposits upon combustion, which in high quantities can cause damage to engines and other electrical equipment.

In 2023, a total of 132 wastewater treatment plants in Sweden contributed 32% of the country's biogas production. Sewage sludge, being the primary substrate for this production, accounted for 29% of the overall biogas output, highlighting the significant role that WWTPs play in Sweden's biogas market (23).

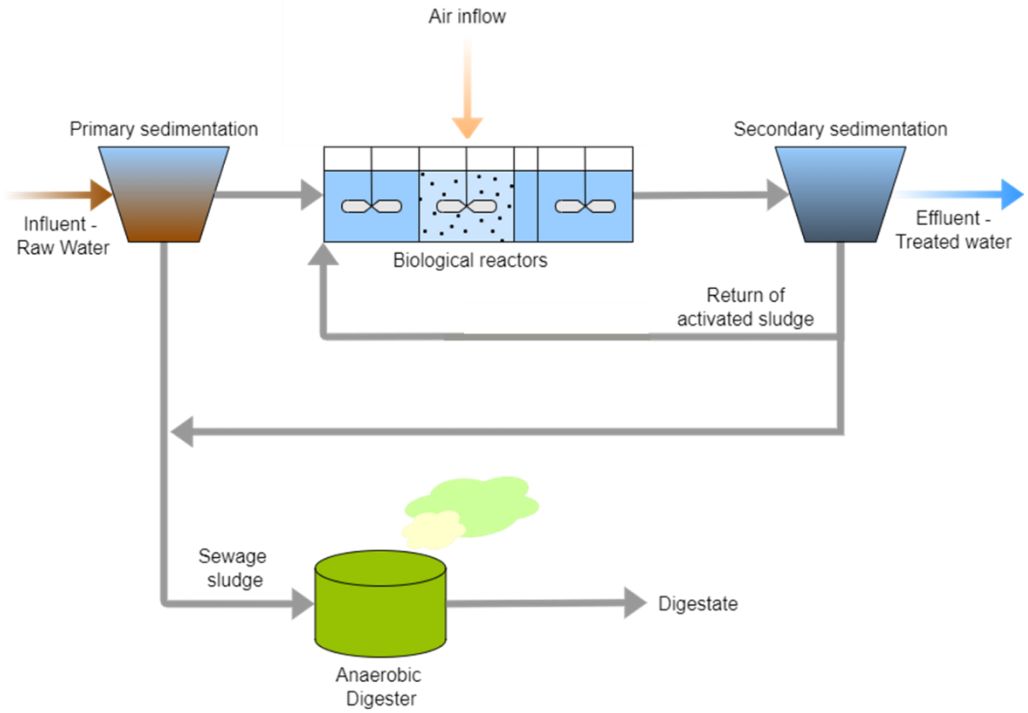

Figure 5. Example of wastewater treatment plant scheme.

3.3.2 Co-digestion plants

Co-digestion plants are advanced facilities designed to enhance biogas production by combining multiple organic waste streams, including municipal sludge,

agricultural residues, food waste, and industrial organic waste. This synergistic approach improves the efficiency of the anaerobic digestion process and increases biogas yield. The ”co" in co-digestion refers to the simultaneous digestion of various substrates, optimizing energy recovery and waste stabilization. The valorization of methane has shifted the focus towards energy production, making co-digestion—a process that combines multiple organic substrates to maximize biogas yield—a vital component in modern waste management. Furthermore, co-digestion increases biogas yield and improves waste stabilization compared to single-substrate digestion. Along with biogas, the co-digestion plant also produces biodigestate, a valuable fertilizing product being used on farmland.

Sweden currently has 32 co-digestion plants producing 51% of the total biogas production (2.3 TWh in 2023), and 74 farm plants producing 6% of the total biogas.

4 Electrolyzer technologies

Hydrogen electrolysis is an electrochemical process where water (H_2O) is split into hydrogen (H_2) and oxygen (O_2) using electrical energy. Hydrogen production through electrolysis is carried out in an electrolyzer, which consists of an anode, a cathode, and an electrolyte. Hydrogen is generated at the cathode and oxygen is generated at the anode when an electrical current is passed through the water (26).

An electrolyzer consists of a stack (or several stacks) where the electrochemical process where water is split into hydrogen and oxygen occurs. However, the electrolyzer unit also consists of a balance of plant (BoP) which includes the sub-systems and components required to operate the electrolyzer. Balance of plant includes functions to supply and recirculate water, manage heat, separate, and purify products and connect the stack to the power source (27).

The electrolyzer technology can be divided into three main categories: Alkaline water electrolyzer (AE), proton-exchange membrane electrolyzer (PEM), and solid oxide electrolyzer (SOEC). The different categories have different advantages and disadvantages and have reached different technology readiness levels (TRL). The main characteristics of the different electrolyzer technologies are summarized in

Table 2.

Table 2. Characteristics of the three primary electrolyzer technologies – AE, PEM, and SOEC (26,28–33).

	Alkaline	PEM	SOEC
Electrolyte	Alkaline (KOH)	Solid Polymer (Nafion)	Solid ceramic
Temperature, °C	70 – 90 °C	50 – 80 °C	700 – 850 °C
Pressure, bar	<30	<70	1
Electrical efficiency (LHV)	50% – 78%	50% – 83%	89%
Response time	Seconds	Milliseconds	Seconds
Scalability	High	Moderate	Moderate
Max stack unit size	10 MW	5 MW	2.68 MW
Lifetime, hr	75 000	50 000 – 80 000	25 000
Land footprint, m²/kWe	0.095	0.048	n.a.
Application	Large-scale	Small to medium-scale	Large-scale
Hydrogen purity	99.5% – 99.9998%	99.9% – 99.9999%	99.9%
Purity of water, µS/cm	< 1	< 0.1	n.a.
CAPEX, EUR/kWe (Expected 2030)	750 – 1400 (400 – 900)	800 – 1800 (600 – 1400)	800 – 2330 (500 – 1400)
Fixed OPEX (% of CAPEX)	2-4	2-5	5-7
Development status	Mature	Commercialized	Research & Development

Alkaline electrolyzer is a mature and reliable technology that has been used extensively in industry, mainly for large-scale hydrogen production (26). The electrolyzer has an efficiency between 50%-78% and operates at a temperature of 70-90°C and a pressure below 30 bar. The alkaline electrolyzer's scalability is high and is therefore suitable for large applications. The lifetime of an alkaline electrolyzer is about 75 000 hours and it produces high-purity hydrogen.

The PEM electrolyzer is operated in commercial scale but is not as mature as the alkaline electrolyzer. The electrolyzer operates at a temperature between 50-80°C and a pressure below 70 bar. The advantage of the PEM technology is its higher efficiency and smaller footprint. Furthermore, it has the fastest response time of the electrolyzer technologies and produces a high-purity hydrogen. The PEM electrolyzer is therefore suitable for flexible operation where hydrogen storage is used in order to avoid peak electricity prices. The downsides are the higher CAPEX and lower durability (shorter lifetime) compared to the alkaline electrolyzer. Additionally, the scalability of a PEM electrolyzer is not as high as for an alkaline

electrolyzer and it is generally more suitable for small to medium-scale applications (26).

The SOEC electrolyzer system is a novel technology that is still under development. The distinguishing features is its high efficiency and its ability to co-produce syngas if operated in reverse mode (26). The SOEC electrolyzer a high-temperature technology with an operating temperature between 700-850°C and an operating pressure of 1 bar. The resulting high temperature waste heat can be used for steam production and the technology is suitable to integrate into large-scale industrial applications. Compared to the other technologies, the SOEC has a high CAPEX, OPEX, and short lifetime (25 000 hours).

4.1 Quality of feedstock water

The water used as feedstock for hydrogen production must be of a certain quality to not damage the electrolyzer. What quality of water that is suitable for a certain electrolyzer is affected by type of electrolyzer, electrode material, system design and could even be different between different brands of electrolyzer (32). The impurities in the water can cause corrosion, increase need for cleaning, lower efficiency or even degrade the electrolyzer stack. The type of water used in an electrolyzer is commonly referred to as ultrapure water. The requirement for ultrapure water can be reached by ensuring that the water does not exceed a certain conductivity (32). As can be seen in

Table 2, the AE electrolyzer can handle more impurities than a PEM electrolyzer.

The main challenge to maintain water quality for an alkaline electrolyzer is to ensure that particles formed in the electrolyte solution is eliminated. In the PEM electrolyzer, the main challenge is the removal of ions (34). The steps from raw water (treated wastewater or surface water) to ultrapure water are ultrafiltration and UV treatment, followed by softening, demineralization, degassing and polishing through electrodeionization (EDI) or mixed-bed filter (35). The amount of raw water (treated wastewater or surface water) needed for 1 m^3 ultrapure water is about 1.5 m^3.

The CAPEX of the water treatment system is a relative minor part of the cost of the entire electrolyzer system and accounts for about 1% of the total electrolysis system CAPEX (32). The energy required for the treatment of wastewater for electrolysis is about 2.2 kWh/m^3 water. This can be compared to the energy required for electrolysis of water of ca 5600 kWh/m^3 water (35).

4.2 Electrolyzer stack and Balance of Plant

An electrolyzer plant can consist of one or several stacks. There is an upper limit of the capacity of an electrolyzer stack. There is ongoing research and development with the goal to increase the maximum stack size, however, the largest current stacks are about 10 MW. Therefore, if an electrolyzer plant is to be built that is larger than the upper limit of the stack size, several stacks are required. Consequently, the electrolyzer plants are usually built up of modules, which in turn result in that electrolyzer stacks does not experience a significant economy of scale. In contrast, the balance of plant is usually just one system and does therefore exhibit a decreased cost per installed capacity due to economy of scale.

5 Methanation technologies

Methanation is a process that converts carbon monoxide (CO) and carbon dioxide (CO_2)-rich streams into methane via hydrogenation. The methanation technologies can be broadly categorized into two primary types: catalytic methanation and biological methanation. Catalytic methanation involves a catalytic, highly exothermic reaction over a metal catalyst at elevated temperature and pressure known as the Sabatier reaction. In contrast, biological methanation is driven by methane-producing microorganisms (archaea) through methanogenesis at moderate

temperatures. Both catalytic and biological methanation encompass a range of methods and technologies, which are outlined in Figure 6.

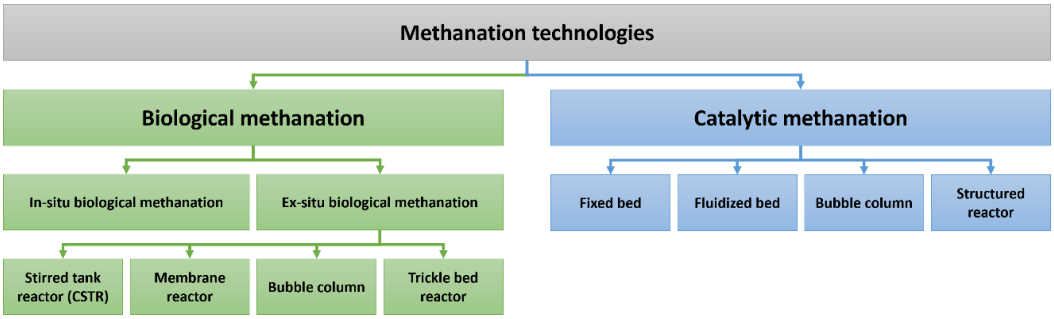

Figure 6. Outline of different methanation technologies.

The biological methanation technologies presented falls under the categories ex-situ or in-situ biological methanation. Ex-situ biological methanation is characterized by that the methanation occurs in a separate reactor, while in in-situ biological methanation hydrogen is injected into the anaerobic digester, eliminating the need for an additional process step. In the following sections, an examination of these technologies will be presented, discussing their respective advantages, disadvantages, and technology readiness levels (TRL).

5.1 Catalytic methanation

Catalytic methanation involves the conversion of hydrogen and CO/CO_2 to CH_4 at elevated pressure and temperature in the presence of a catalyst. The operating conditions are typically between 200 – 550°C and 1 – 100 bar (36–38). There are several metals such as nickel (Ni), ruthenium (Ru), rhodium (Rh), and cobalt (Co) that may be used as the catalyst for the methanation reaction, but the most common choice of catalyst is a nickel-based catalyst, since it has a relatively high activity, good CH_4 selectivity and low raw material price (38). Catalytic methanation consists of exothermic equilibrium reactions Click or tap here to enter text. as presented in Reaction I and II:

$$CO_2 + 4H_2 \leftrightarrow CH_4 + 2H_2O \qquad \Delta H = -165\ kJ/mol \qquad (I)$$

$$CO + 3H_2 \leftrightarrow CH_4 + H_2O \qquad \Delta H = -206\ kJ/mol \qquad (II)$$

The exothermicity of the reactions lead to challenges in heat management and potential catalyst deactivation (38). Specifically, at temperatures above 550°C,

catalyst deactivation can occur due to sintering (36,40). Additionally, the methanation reaction is constrained by thermodynamic equilibrium at around 300°C, needing cooling to achieve high conversion rates.

Furthermore, the catalyst is also sensitive to impurities in the feed gas stream and a proper separation of all impurities is required before inserting the biomethane CO_2 into the methanation reactor. The nickel-based catalyst is particularly sensitive to sulfur (H_2S or larger organic sulfur molecules) and deactivates by even a few tens or hundreds of ppbv (parts per billion volume) (41). In addition, a near-total removal of siloxanes is assumed to be necessary for catalytic methanation (42). Catalytic methanation usually includes an upgrading step, to extract unreacted gases – specifically hydrogen – to recover valuable reactants and meet the produced methane quality. This is done using either a second reactor or a membrane separation unit after intermediate condensation (42).

5.1.1 Operational strategies in Power-to-Gas applications

Catalytic methanation reactors used in power-to-gas applications can be operated using two main strategies. The first strategy involves operating the reactor at steady-state, which requires a high-capacity hydrogen storage system to ensure a constant supply of hydrogen to the reactor. The storage system is essential due to the intermittent nature of renewable electricity generated by solar or wind installations. However, maintaining a steady-state operation is costly because of the significant investment needed for hydrogen storage infrastructure.

The second strategy is dynamic operation, where the reactor adjusts to fluctuating hydrogen availability. This mode of operation has implications for the methanation catalyst and reactor design. In dynamic conditions, temperature variations can occur if the reactor's cooling systems are unable to adapt quickly enough. Such temperature fluctuations can reduce the lifespan of the catalyst, compromising long-term reactor performance. A solution to this would be methanation reactor concepts with dynamic temperature regulation (38). A combination of the two strategies could also be a solution.

5.1.2 Catalytic methanation technologies

There are several steady-state methanation reactor concepts that have been developed to meet the objective of controlling the temperature, namely fixed bed, fluidized bed, three-phase, and structured reactors (43). Depending on the catalytic

methanation concepts, different gases such as syngas, raw biogas, or a mixture of H_2 and CO_2 can be fed into the process.

5.1.2.1 Fixed bed methanation

Fixed bed methanation is a process in which the reactants are converted over a packed, solid catalyst. There are two different approaches to heat management: adiabatic fixed bed methanation, and isothermal fixed bed methanation.

The adiabatic fixed bed methanation process is the most commonly employed approach (44). In an adiabatic reactor, no external heat is added or removed, resulting in an increase in temperature as the reaction progresses. To achieve high conversion, multiple reactors in series with interstage cooling are therefore typically required as seen in

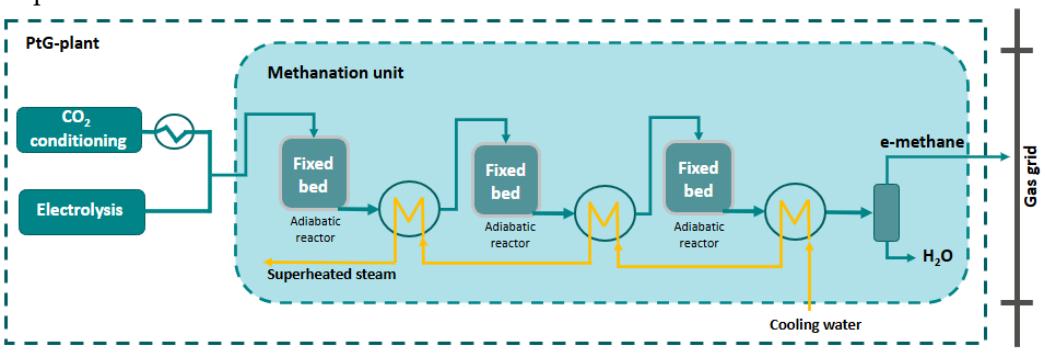

Figure 7.

An alternative to adiabatic fixed bed methanation is isothermal fixed bed methanation, where the reactor operates at a constant temperature, maintained by internal cooling (42) as seen in *Figure 8*. This approach eliminates the need for multiple reactors and reduces the complexity of the cooling system. However, the isothermal reactor design is more costly compared to the adiabatic option due to the additional requirements for internal cooling.

TRL lies between 7-9, depending on the type of fixed bed and feed in gas. See Table 3 for more details.

In the past adiabatic fixed bed methanation was applied to coal gasification plants in US (1984) and China (2013/2014) in scales larger than 1 GW_{SNG}. In Sweden the same technology was used in GoBiGas project using syngas from biomass gasifier (Schildhauer, 2016). Recently, in a reference plant in Gabersdorf by Hitachi Zosen a close to isothermal operating fixed bed plate reactor has been demonstrated where raw biogas was used as feed gas. This offers the opportunity of excluding the upgrading step in biogas plants (where CO_2 is separated from CH_4 in raw biogas).

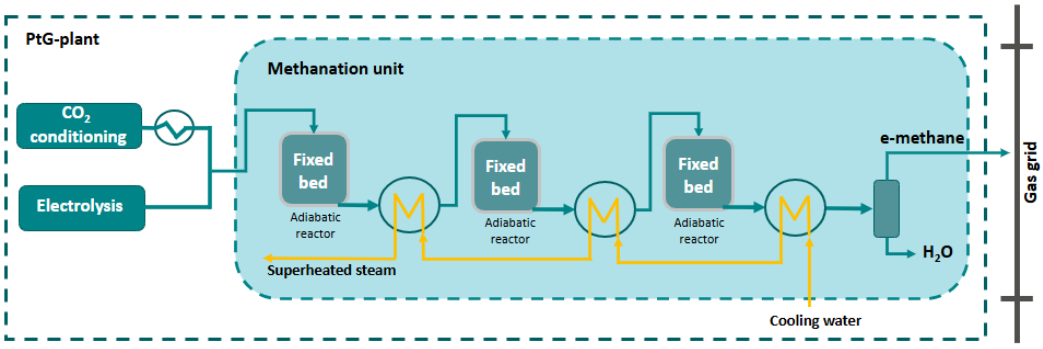

Figure 7. Multiple fixed bed reactors in series with interstage cooling.

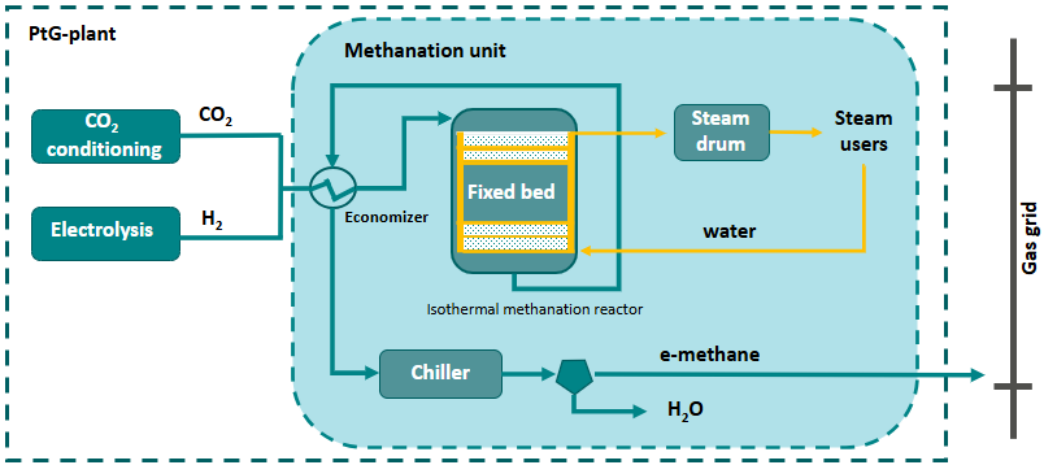

Figure 8. Methanation in isothermal fixed bed reactor. Scheme based on (28).

5.1.2.2 Fluidized bed methanation

The fluidized bed methanation is a technology suitable for small and medium scale operation (<10MW). The technology consists of catalyst particles being fluidized by the feed gas. The advantage related to fluidized bed methanation is a uniform mixing, which in turn results in almost isothermal conditions and easier temperature control. Furthermore, only a single reactor is needed with a rather simplified design. Similar to fixed bed reactors, the excess heat can be used where heating is required. The disadvantages of using fluidized bed technology are an incomplete CO_2 conversion due to bed bubbling and attrition of catalyst particles due to the harsh conditions inside the fluidized bed. The superficial gas velocity is limiting the reactor, since it cannot be too low or too high, to assure minimum fluidization conditions and to avoid catalyst elutriation (26) .

The Paul Sherrer Institute (PSI) in Switzerland, has developed a catalytic isothermal fluidized bed process for methanation of syngas, see Figure 9. In 2009 the methanation technology was successfully demonstrated in a scale of 1 MW in Güssing using syngas, and in 2019 the technology was demonstrated in a smaller scale using biogas as feed gas. TRL lies between 5-7, depending on the type of feed gas, lower for biogas and higher for syngas. PSI together with AlphaSYNT offers methanation units from 0.5MW_{SNG} up to 10 MW_{SNG}. In the figure below the process schematics of fluidized bed methanation by PSI and AlphaSYNT is shown.

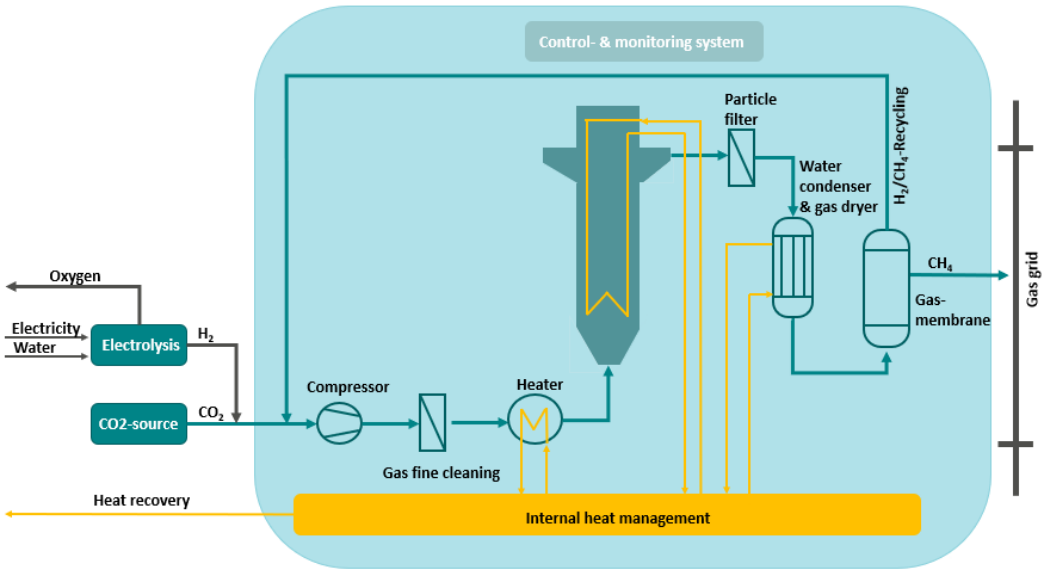

Figure 9. PSI and AlphaSYNT CoMeth Module – process schematics. CoMeth module consists of a catalytic fluidized bed methanation reactor, gas membrane for recovery of unreacted H_2 and CO_2, gas compressors and a thermal management system for heat extraction. The feed in gas is cleaned from sulfur before it enters the reactor. (Based on CO2 to Biomethane Refining Pla–t - CoMeth by AlphaSYNT)

5.1.2.3 Three phase methanation (3PM)

Three phase methanation is a technology under development that currently exists on pilot-scale. The technology consists of a solid catalyst suspended in liquids with stable temperature. The feed gas is thereafter passed through the suspension. The suitability of different ionic liquids and heat transfer oils for application as liquid phase in three phase methanation have been investigated, where dibenzyltoluene was identified as the most suitable liquid phase. In the past the 3PM research included both CO-methanation using slurry bubble column reactors (SBCRs) and fluidized bed reactors but has in more recent studies only focused on SBCRs (46). In Figure 10 the schematics of the 3PM methanation SBCR can be seen.

The advantage with the 3PM is the good heat dissipation which allows for good temperature control and thereby control of the reaction. It also allows for heat extraction for further purposes, which can increase the process efficiency (31), (47)). Furthermore, the high heat capacity of the liquid helps in handling process fluctuations. In addition, the 3PM reactor has showed to tolerate rapid load changes from 0 – 100% load within only a few minutes, which makes the technology promising for power to gas applications (31). The disadvantage, apart from the lower TRL of 5-6, is that the intermediary liquid phase limits mass transfer that reduces the effective reaction rate. Another disadvantage is unwanted reactions of the liquid phase with reactants and/or the catalyst (46).

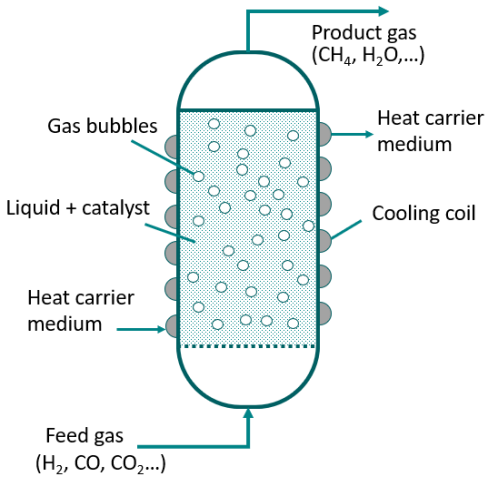

Figure 10. Schematic drawing of the 3PM slurry bubble column reactor based on figure in (15).

5.1.2.4 Structured reactor

Structured reactors have been developed to overcome the drawbacks of the adiabatic-fixed bed reactors, which is the high pressure drop and the temperature hot spots. The structured reactors such as monoliths (honeycomb and microchannel reactors) with their internal metallic structure have heat conduction through the reactor which result in enhancement of radial heat transport by two to three order of magnitude depending on the metallic material. One type of structured reactors is the micro structured reactor which is very compact with a high surface to volume ratio, with the advantage of having high heat transfer and a small pressure drop. The drawback of the structured reactor is the more complicated catalyst deposition on the metallic structure. Another drawback related to the design is the difficulty to replace deactivated catalyst, resulting in recoating the whole reactor once the catalyst has been deactivated (38). Honeycomb, milli-structured and microchannel reactors are types of structured reactors. The first two mentioned have been demonstrated in the Store&Go project. In the demonstration in Falkenhagen, Germany the methanation process used a honeycomb reactor followed by a fixed bed reactor for upgrading the gas to required quality, see Figure 11. In Troia, Italy the demonstration of milli-structured reactor was followed by a condensation unit and thereafter a membrane unit that recycled the H_2 and CO_2 back into the reactor. The methanation unit operated 824 h and the output of methane >95 vol % (49). Depending on type of structured reactor the TRL ranges from 5-7.

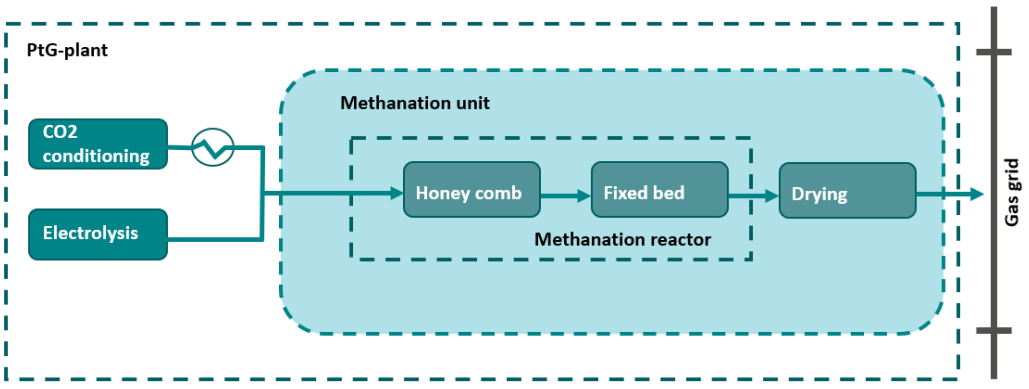

Figure 11. Block flow diagram of the demo site Falkenhagen, based on (49).

5.1.3 Summary catalytic methanation

In the following section the catalytic technologies are summarized. The reactor types and the TRL levels as well as advantages and challenges are presented. A common advantage for all the catalytic methanation technologies is due to the exothermal

reaction and high temperatures in the methanation process, which result in high quality waste heat that can be used to increase the overall efficiency of the process. A common challenge is management and temperature control inside the reactors which is a key parameter in almost all types of reactor configurations. Catalytic methanation technologies can be used for PtG applications and there are two operational strategies. Using a storage to enable steady state operations or operate dynamically using dynamic temperature regulation to handle temperature fluctuations. A common disadvantage is the sensitivity to impurities in the feed gas stream, resulting in the need of fine gas cleaning, to remove sulfur and other substances that could otherwise deactivate the catalysts. Some reference plants that implemented catalytic methanation are presented in Appendix D.

Table 3. Summary of catalytic methanation technologies.

Catalytic methanation				
	Fixed bed reactor	**Fluidized bed**	**3PM**	**Structured reactor**
Reactor type (catalyst)	Adiabatic fixed bed Cooled fixed bed	Fluidized bed reactor	Slurry bubble column reactor	Honeycomb, milli-structured, microchannel
TRL (feed gas)	7 (raw biogas), 9 (CO_2)	5 (raw biogas), 7-8 (syngas)	5-6 (syngas/CO_2)	5-6 (syngas/raw biogas), 7 (CO_2)
Advantages	+ Mature technology + Large scale operations + High space velocity -small reactors possible + High quality waste heat	+ Mature technology + Small to medium scale operations + Good temperature control due to mixing + Low risk of catalyst deactivation + Single reactor + High quality waste heat	+ Dynamic operations due to high heat capacity of liquid + Good heat dissipation/temperature control + High quality waste heat	+ Lower pressure drops (than adiabatic) + High heat conduction + Compact design + High quality waste heat
Challenges	- Need of reactors in series with intermediate condensation -High pressure drops -Temperature hot spots (adiabatic) - Catalyst sensitive to impurities, such as sulfur	- Incomplete CO_2 due to bubbling - Catalyst breakage due to harsh conditions - Catalyst sensitive to impurities, such as sulfur	- Intermediate liquid phase reduce effective reaction rate - Catalyst sensitive to impurities, such as sulfur	- Recoating whole catalyst when deactivation occurs - Complicated catalyst deposition - Need of second reactor or unit to recirculate H_2/CO_2 to reactor to reach accepted level of CH_4 - Catalyst sensitive to impurities, such as sulfur

5.2 Biological methanation

Biological methanation (BM) is the process in which microorganisms, called methanogenic archaea, more specifically *hydrogenotrophic methanogens*, reduce H_2 and CO_2 to CH_4 with H_2O as a by-product (Eq 1). These microorganisms, representing approximately 73% of all methanogen species, consume H_2 and efficiently drive this exergonic reaction at relatively low temperatures (35-70°C) without the need for external catalysts.

$$4H_2 + CO_2 \rightarrow CH_4 + 2H_2O \qquad \Delta G^0 = -165\frac{kj}{mol} \qquad Eq\ 1$$

Hydrogenotrophic methanogenic archaea used as catalysts in the reaction are part of the microbial community in biogas reactors. Biological methanation has a lower reaction rate compared to chemical catalytic processes due to the lower temperature. It also has a lower volumetric mass transfer coefficient (50) and exhibits a higher tolerance towards impurities in the input gas. Two technical pathways can be used for biological methanation i) direct injection of H_2 into an anaerobic digester and utilization of endogenous CO_2 – the **in-situ methanation**, and ii) parallel injection of H_2 and CO_2 in a stoichiometric ratio of 4:1 into another reactor – the so-called **ex-situ methanation** (51).

Both in-situ and ex-situ configurations can be operated at mesophilic (about 37 ^{0}C) or thermophilic temperature (about 55 ^{0}C), while ex-situ methanation can also operate at hyperthermophilic temperatures (about 60-80 ^{0}C). The temperature will define which type of microorganisms will produce the methane. In general, higher production rates can be achieved at higher temperatures while more diversity of microbes thrives at mesophilic conditions (52). Additionally, lower temperatures facilitate hydrogen solubility. The supplier's choice of temperature depends on the process design and the microorganisms they use.

5.2.1 Microorganisms involved in biological methanation

The primary hydrogenotrophic methanogens involved in the process are from the families *Methanobacteriaceae, Methanothermaceae, Methanococcaceae and Methanomicrobiaceae*. The *Methanothermobacter* genus is primarily responsible for the biological upgrading process in thermophilic anaerobic digesters and can be enhanced in

both in-situ and ex-situ BM. Microbes from the genus *Methanobacterium* are dominant in mesophilic conditions; research on other mesophilic archaea, such as *Methanobrevibacters*, is limited but potentially beneficial for BM applications due to increased hydrogen solubility at lower temperatures (53). Regardless of the temperature, these methanogens thrive under specific conditions that must be controlled to ensure the stability and efficiency of the process.

5.2.2 In-Situ Methanation

During in-situ methanation, external hydrogen (e.g., from an electrolyzer) is injected into the AD reactor, where the biogas is produced. The aim is to convert a share of the remaining CO_2 into more CH_4 and water, increasing the methane content. The final methane concentration in the biogas could be between 75% and up to 98% (54). In-situ integrates easily into existing AD systems, avoiding the need for additional reactors and nutrients. This reduces the investment and operational costs, making it an economically attractive option (51,55).

Since this technology introduces hydrogen directly into the AD reactor, it is important to understand the dynamics of the microbial community, because this will define the success of the process. Several microorganisms are involved and work in balance towards the stability of the process (52). As is mentioned in the section 3.1, the AD process converts organic residues (i.e., agricultural waste, sewage sludge, food waste, etc.), into biogas. AD comprises four main steps: hydrolysis, acidogenesis, acetogenesis, and methanogenesis. During the last step, simple substrates like H_2, CO_2, formate, acetate, and a variety of methyl-containing compounds (by-products from the fermentation step) are reduced to CH_4 with a residual CO_2 part (56). Two main types of methanogen archaea carry out methanogenesis: *Acetotrophic methanogens*, which convert **acetate to methane**, and *hydrogenotrophic methanogens*, which convert **hydrogen and carbon dioxide to methane and water** (see Figure 12). Methanogenesis reduces simple substrates, but it is a complex biochemical process that involves several microorganisms and the syntropy between them.

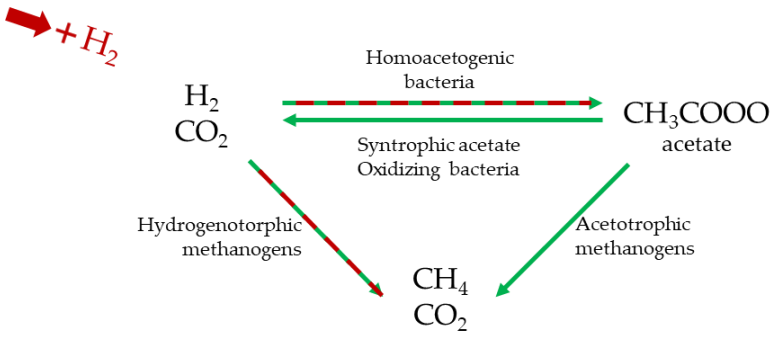

Figure 12. Methanogenesis step

Hydrogenotrophic methanogens are the microbes responsible for carrying out methanation, but in in-situ systems, the biological methanation reaction in mixed cultures can be carried out through two microbial pathways: (i) the direct pathway corresponding to the conversion of H_2 and CO_2 into CH_4 by *hydrogenotrophic methanogens* and (ii) an indirect pathway where H_2 and CO_2 are first converted into acetate by *homoacetogenic bacteria,* and then acetate is converted into CH_4 and CO_2 by acetotrophic methanogens (57), as shown in Figure 12.

However, directly injecting exogenous H_2 into the AD can lead to problems with the microbial community dynamics. Maintaining a balanced system with adequate hydrogen levels is important to allow acetogenic and hydrogenotrophic microbes to coexist and produce biogas. Increased H_2 affects VFA degradation bacteria since *acetotrophic methanogens* require low H_2 partial pressure (<10pa), or else the process becomes thermodynamically unfavorable. This inevitably promotes the accumulation of volatile fatty acids (VFAs) that lead to a decrease in pH and further failure of the system (58,59). For biogas plants with multiple AD in series, supplying hydrogen to the post-digester is likely more advantageous due to the favorable biochemical environment associated with a lower organic loading rate (OLR) (60). Additionally, adding hydrogen to the post-digester can serve as a safety measure, as it helps prevent process disturbances in the main digester, which is particularly important since the largest proportion of methane is produced here.

The balance of the process is theoretically achieved by maintaining H_2 content relatively low (61). To prevent hydrogen build-up, it's necessary to ensure high H_2 solubilization for easier uptake and utilization by microbes (62). However, the solubility rate of hydrogen is very low—0.7 mmol H_2/L·bar—compared to other gases like CO_2, which has a 24 times higher solubility rate at 55°C. The gradient between gaseous and dissolved hydrogen concentrations defines the driving force for hydrogen gas-liquid transfer, making it a bottleneck due to partial pressure. Factors such as system pressure,

temperature, mixing efficiency, and gas recirculation determine the final amounts of hydrogen dissolving into the solution (51). While increasing reactor pressure and improving mixing significantly enhance solubilization, the injection method is another critical factor.

Several methods are used to introduce hydrogen to the digester, including ceramic diffusers, microbubble diffusers, and hollow fiber membranes. Injection strategies also influence process stability and performance. For example, intermittent H_2 injection has demonstrated positive outcomes, increasing methane production to 0.19 mL CH_4/mL H_2, improving volumetric methane yield by 8.4%, and enhancing methane content by 5% by effectively controlling the partial pressure (60). Real-time H_2 monitoring in such setups ensures optimal stoichiometry, preventing microbial imbalances. Stepwise H_2 injection supports microbial adaptation, achieving methane content up to 97.9% with 99.2% H_2 consumption efficiency (54). High-pressure membrane systems further enhance gas-to-liquid transfer, achieving methane production rates of 1.7 Nm^3 CH_4/m^3 reactor/day with similar methane purity. Dynamic feedback systems, such as those using online H_2 and CH_4 sensors, maintain stoichiometric balance, achieving methane content above 96% with production rates of 0.9 Nm^3 CH_4/m^3 reactor/day (63).

These examples highlight the importance of combining effective injection methods with advanced monitoring to optimize hydrogen solubilization and process performance in in-situ methanation systems.

Key technical aspects:

Gas supplementation: It is crucial to achieving a stable and effective process. A ratio of 2:1 to 4:1 (H_2:CO_2) is found to be optimal for stable operation, while higher ratios can lead to VFA accumulation and system instability. For biogas plants with multiple ADs, hydrogen supply in the post-digester is likely beneficial due to the lower OLR (60). Furthermore, to enhance the gas-liquid mass transfer, gas recirculation, mechanical stirring, and proper gas diffusers with small pore sizes have been investigated to improve H_2 transfer and, consequently, CH_4 production (62,64).

Temperature Control: Both mesophilic (35-37°C) and thermophilic (50-55°C) conditions can be used. Thermophilic conditions generally enhance methane production rates but require robust microbial adaptation to temperature changes (61).

5.2.3 Ex-Situ Methanation

The ex-situ methanation process occurs in a separate reactor where H_2 and CO_2 are injected externally, allowing greater control over the process conditions and potentially higher methane yields. The CO_2 stream can be pure or combined with methane (raw biogas) taken directly after AD. Since it occurs in a separate reactor, ex-situ methanation provides a highly controlled environment for efficient biogas upgrading, achieving methane concentrations (>96%) for directly injecting into the grid or further liquefaction. It requires higher capital investment than in-situ processes, but its scalability and potential for integration with renewable energy sources make it a promising technology for future energy systems. Renewable sources are known to have interruptions because they depend on weather conditions, such as sunlight or wind availability, and turning the H_2 supply on/off has less effect on ex-situ than in-situ (Hydrogen storage would address the problem). Additionally, ex-situ systems can handle higher hydrogen loading rates since the process is more straightforward. It focuses only on methanation, avoiding the complexities of integrating with the earlier stages of anaerobic digestion, like hydrolysis and acidogenesis. This allows them to achieve higher gas (H_2 and CO_2) conversion rates into CH_4 than in-situ systems and could reduce the dimensions of the biogas upgrading reactor (65,66).

The microbiology of ex-situ methanation primarily involves hydrogenotrophic methanogens, like during in-situ methanation. Pure methanogenic strains and mixed cultures can be used as catalysts in this configuration. Depending on the process, these methanogens grow in a liquid phase or form biofilms on the packing materials within the reactors, creating a large surface area for gas interaction. The efficiency of methanation is highly dependent on the growth and activity of these biofilms, which are influenced by factors like temperature, pH, and nutrient availability (53).

Ex-situ biological methanation studies have found *Methanobacteriales*, M*ethanomicrobiales* and *Methanococcales* to be the dominant orders. As described in the section about in-situ methanation, the concentration of H_2 significantly influences the biochemical reactions. Adding external H_2 selects for hydrogenotrophic methanogens and homoacetogens like *Acetobacterium woodii* and *Moorella thermoacetica* while inhibiting syntrophic acetogens and acetate oxidizers (67), leading to the main problem in in-situ systems. Hydrogenotrophic methanogens play a critical role in methanation, and their abundance can be increased through strategies such as bioaugmentation or endogenous enrichment.

Mixed-adapted microbial communities are often chosen for practical applications when comparing pure and mixed cultures. While pure cultures can be useful, mixed cultures are more robust, do not need sterile environments, and can adapt to changing conditions, making them more suitable for industrial-scale applications. Mixed cultures also

eliminate the need to grow specific strains in large quantities, reducing the initial costs of full-scale digesters. Common hydrogenotrophic methanogens in mixed cultures include Methanobacterium, Methanoculleus, and Methanothermobacter, frequently found in various biogas upgrading configurations (65). Despite the theory behind the mixed culture preference, the supplier Electrochaea, employs a single-strain culture in their full-scale applications, achieving 97% methane content in the biomethane without reported complications (68).

An important addition to the ex-situ methanation is the optimal supply of nutrients for maximizing methanogen growth and activity. Nutrient media stabilizes pH fluctuations and includes synthetic and non-synthetic nutrients. Non-synthetic options such as digestate, cattle manure, and digested sludge are commonly sourced from biogas and wastewater treatment plants, promoting sustainability. However, these nutrients need pre-treatment to prevent unwanted microbial growth and endogenous CO_2 production. Methods include digestate pre-incubation, manure pasteurization, and nitrogen flushing. In some cases, nutrient recycling has also proven effective in boosting hydrogenotrophic methanogens and achieving high H_2 utilization. Continuous nutrient trickling through flushing or flooding has been found to enhance methanation performance by effectively wetting immobilized microbes (69). Proper management of nutrient supply and control of operational parameters, such as stirring intensity and adding reducing agents, can significantly enhance the stability and performance of the microbial community. Reducing agents are required to decrease the oxidation-reduction potential (ORP) and support the growth of oxygen-sensitive microorganisms. Methanogens are strictly anaerobe microbes, and the presence of oxygen can have a serious effect. To date, sodium sulfide (Na_2S) has been primarily used for this purpose (70).

This optimization ensures a more stable and efficient conversion process, ultimately improving the ex-situ methanation system's overall efficacy. As the process occurs in a separate reactor, ex-situ configurations offer better control over operational parameters, such as gas flow rates, pressures, and temperatures, leading to more stable and efficient methane production. For example, H_2 can be added proportionally to CO_2 without the need to account for the potential hydrogen effect on microbial activity (common in in-situ systems). This control allows ex-situ systems to achieve methane concentrations exceeding 98%, making the renewable methane suitable for grid injection without extensive purification. The modular design allows easy integration with existing biogas plants without requiring major infrastructure changes, making it scalable for industrial applications. However, the need for additional reactors, while advantageous for scalability, also increases initial capital costs compared to in-situ systems. Nutrient supply is another factor to manage, though it typically does not significantly impact operational costs. A key

challenge remains gas-liquid mass transfer, which affects overall methanation efficiency.

Key technical Aspects

Gas-Liquid Mass Transfer Rate: Enhancements in gas-liquid mass transfer are crucial for optimizing the methanation process. As in in-situ processes, improved transfer rates can significantly impact the methane evolution rate and methane content in the off-gas. Temperature, pH, biofilm formation, pressure and gas flow rates are also key parameters.

Reactor Design: Various reactor designs have been studied to improve conversion efficiency (69,71–73). The main reactor types are presented in the next section.

5.2.3.1 Ex-situ biological methanation reactor types

- **Continuous Stirred Tank Reactors (CSTRs):** This well-established reactor provides efficient gas/liquid mass transfer due to the high mixing speeds. These reactors introduce gases using agitators or spargers, including different types of diffusers. However, high energy consumption due to the need for constant agitation and scaling up can be challenging due to these energy requirements.

- **Membrane Reactors:** Hollow fiber membranes are introduced into the system to supply gases to the microbe-containing media. The membranes are made from porous material to separate the gas and liquid phases, and in this case, gases are introduced through the membrane. Due to the small pore membrane size, the gas is easily dissolved into the liquid phase and becomes available to the microbes. These types of reactors do not require mechanical mixing, reducing energy costs. However, membrane pores need regular maintenance to not clog due to biofilm formation.

- **Bubble Column Reactors:** These reactors utilize rising gas bubbles to mix the reactants and enhance mass transfer. The smaller gas bubbles increase the volumetric interfacial area, improving mass transfer. It is a relatively simple construction with low capital cost, but agitators and optimized recirculation can be introduced to enhance the process further. Controlling bubble size and distribution can be difficult; these reactors may require additional equipment to manage the gas flow.

- **Plug Flow Reactors:** Plug-flow reactors are well-known and widely used in several other processes. It consists of tubular reactors where gas flows through the tube, with length, diameter, and flow rate defining the residence time. One study by (74) evaluated a novel biofilm plug-flow specifically for methanation. It was designed to reduce energy consumption. Using a biofilm of microbes, the reactor achieved over 98% methane conversion with minimal mixing and energy input, reaching high methane production rates. While promising for biogas upgrading and renewable energy conversion, the study was conducted on a small scale, and its performance at larger scales remains to be tested.

- **Trickle Bed Reactors:** Gas-filled cylindrical columns packed with biocarrier material, typically constructed vertically. Methanogenic microorganisms are suspended in the liquid, which is trickled over the packing bed, allowing them to form a biofilm on its surface. This process provides essential nutrients to the microorganisms and supports gas-phase biological conversion around the packing bed. This configuration offers a large gas-biofilm contact area (depending on the packing material), enhancing mass transfer without extra energy for mixing, making them efficient for scaling up hydrogen and CO_2 conversion, provided the biofilm stays hydrated and nutrient-supplied. The methanation process is exothermic; however, additional temperature control (heating or cooling) is often necessary to maintain the desired operating temperature, depending on the specific process conditions (75). Full-scale applications typically require cooling, while scientific studies on smaller-scale reactors have reported significant heat losses due to large surface areas and poor insulation, requiring additional heating.

- **Fixed-bed reactors:** Microorganisms are immobilized on solid particles, allowing independent control of biomass and hydraulic retention times. They are similar to trickle-bed reactors, but they rely on passive diffusion. Since there is no constant liquid flow over the bed, the system relies on the natural diffusion of gases and liquids to the immobilized microorganisms.

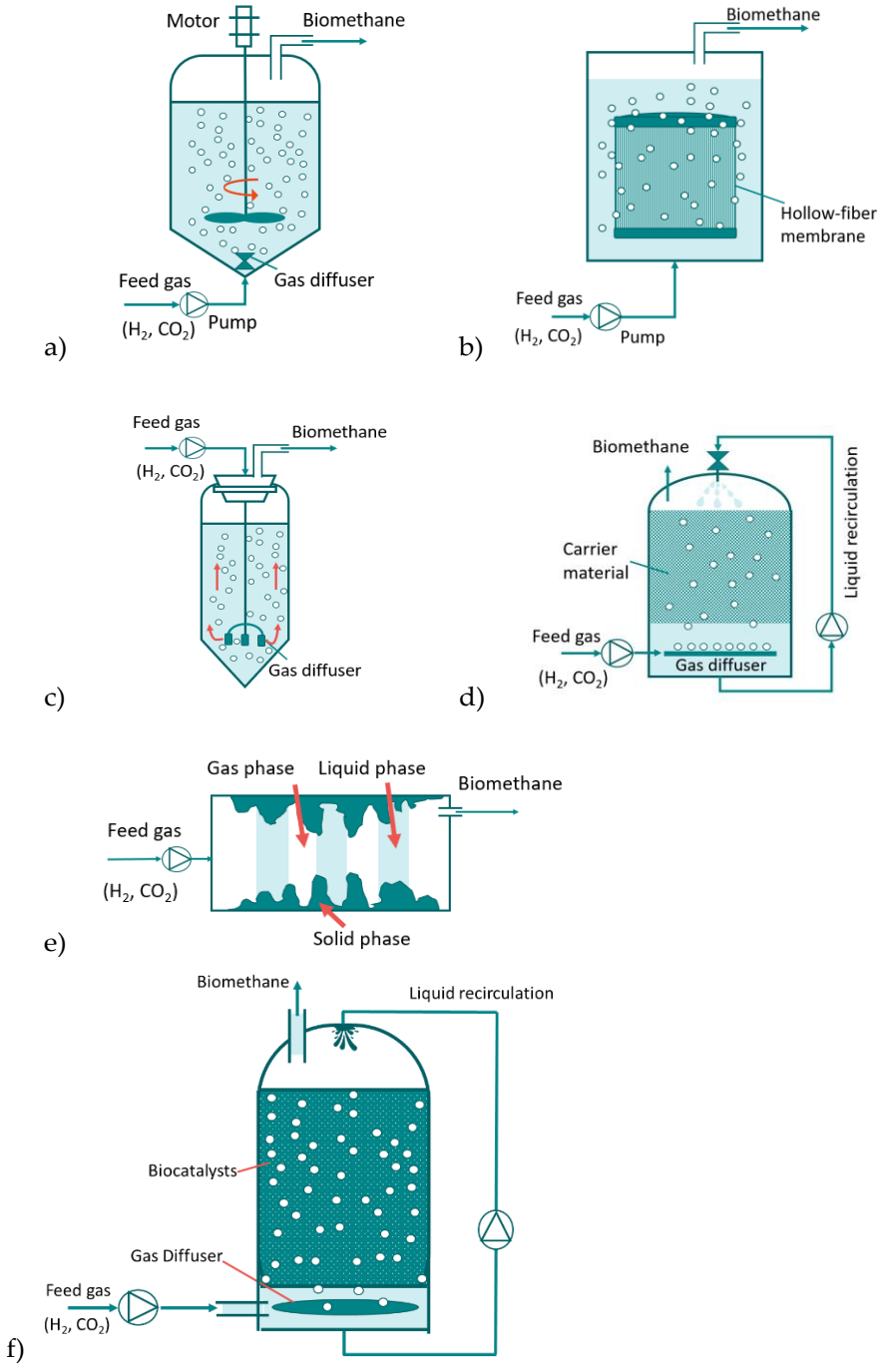

Figure 13. Different types of reactors a) CSTR, b) MBR, c) Up-flow and bubble column reactor, d) trickle bed reactor, e) plug-flow reactor, f) fixed bed reactor. Adapted from Thapa et al. (2023).

5.2.4 Summary Biological Methanation

Biological methanation (BM) involves methanogenic archaea microbes. This process operates at relatively low temperatures (35-80°C) without external catalysts, offering an efficient means to upgrade biogas by increasing methane content. The two main technical approaches are in-situ methanation, where H_2 is injected directly into the anaerobic digester, and ex-situ methanation, where H_2 and CO_2 are introduced into a separate reactor. While both approaches can operate at mesophilic (37°C) or thermophilic (55°C) temperatures, ex-situ configurations provide better control over the process and can accept higher hydrogen loading rates (10 to 13 times higher than in-situ processes on a lab-scale), resulting in higher conversion efficiencies (~10% more H_2 and CO_2 are converted to CH_4 on a lab scale) and easier scalability.

Biological methanation presents promising solutions for biogas upgrading and renewable energy storage by converting electricity into storable biogas. Ex-situ systems, while offering greater control, efficiency, and higher methane production rates, require higher capital investment due to the need for additional reactors. In-situ systems, on the other hand, integrate well with existing biogas processes, improving the calorific value of biogas by directly adding H_2. However, they require careful management of hydrogen partial pressures to avoid microbial inhibition. A key challenge in both systems is the solubilization of H_2 in the medium, which limits bacterial uptake and utilization. A few full-scale ex-situ methanation plants are currently operational, with the first full-scale in-situ methanation plant installed at Grøngas biogas plant in Hjørring, Denmark in the summer of 2024 and a second one in Linköping, Sweden, with plans to start-up in the next upcoming years. Some reference plants are presented in Appendix E. A summary of the different biological methanation technologies is presented in Table 4.

Table 4. Summary of biological methanation technologies.

	Ex-situ methanation	In-situ methanation
Reactor type (TRL)	• Continuous Stirred Tank Reactors (9) • Bubble column reactor (7) • Membrane Reactors • Plug flow reactor (4) • Trickle Bed Reactors (9) • Fixed Bed Reactors (9)	n/a
TRL	Depends on reactor type (see reactor type)	9
Advantages	+ Good control of process due to reaction occurring in separate reactor + High methane yields and purity (98% methane) + Scalability due to being modular + High gas conversion efficiency + Several different reactor's design available/being developed	+ Easy integration with existing systems + Cost-efficient since no extra reactor is necessary
Challenges	- Higher capital investment compared to in-situ - Gas-Liquid mass transfer due to the low solubility of H_2 - Increased plant maintenance since more equipment is required - Energy Demand: Some reactors (ex. CSTR) have a high energy consumption due to the need for agitation	- Microbial Balance: Injection of H_2 in the AD reactor can disrupt the microbial balance - Hydrogen Solubilization: The low solubility of H_2 in water limits the methane production - Process Control: Maintaining the optimal H_2 partial pressure is important, but a challenge in in-situ methanation - Lower Methane Yields compared to ex-situ methanation

5.3 Methanation technology providers

There are several technology providers of catalytic and biological methanation technologies. Some of the technology providers are presented in Table 5.

Table 5. Catalytic and biological methanation technology providers, reactor type, and where the headquarter of the provider is located.

Technology type	Company	Reactor type	Headquarters
Catalytic methanation	Kanadevia INOVA	Fixed bed plate-type reactor, shell and tube type	Zurich, Switzerland
	Haldor Topsøe	Adiabatic fixed-bed reactors	Lyngby, Denmark
	MAN Energy Solutions	Isothermal reactor	Augsburg, Germany
	AlphaSYNT	Fluidized bed reactor	Switzerland
Ex-situ Biological methanation	Kanadevia INOVA	CSTR	Zurich, Switzerland
	Q Power	Solid-state reactor	Finland
	GICON	Trickle-bed reactor	Dresden, Germany
	Electrochaea	CSTR	Munich, Germany
	Biogasclean	Trickle-bed reactor	Odense, Denmark
	Micropyros	CSTR	Straubing, Germany

An overview of each technology providers methanation solution is presented in the following section.

5.3.1 Catalytic methanation technology providers

5.3.1.1 Kanadevia INOVA

Kanadevia INOVA (76) (former Hitachi Zosen INOVA) has been part of Kanadevia Corporation since 2010. Both companies offer methanation solutions. Kanadevia Inova offers a proprietary fixed bed plate-type reactor that comes in a compact and modular plant design, which can be operated stand alone or as a cluster. The technology enables both dynamic and continuous operation.

- **Technology:** Fixed bed plate-type reactor
- **Capacity:** Pythia2000/4000/6000 with 2 000-6 000 Nm^3/h feed gas throughput and above.
- **Product Gas Flow:** 400-1 200 Nm^3/h at 100% load, with pressure up to 7 bar(g).
- **Feed Gas:** CO_2 and H_2, raw biogas, sewer gas, syngas
- **Operation:** Full dynamic and continuous modes; wide operating range and fast load changes, modular and simple design (stand-alone or cluster)
- **Methane Output:** > 96 % (gas purification as add-on)
- **Steam Production:** Simple reactor heat control by natural draft water-steam cooling, providing high-pressure steam as by-product
- **Electricity consumption**: Methanation technology has minimum electrical consumption due to minimum moving parts and gravity flows. Power consumption caused by the auxiliary units only.
- **Features:**
    - Wide operating range and fast load changes
    - Compact and simple design (by optimizing all key media streams transiting between sub-systems and components)
    - High conversion rate and reaction selectivity
    - Good temperature control and production of high-pressure steam
    - Plant design for outdoor installation. No additional housing for the methanation system is necessary due to the skid structures.

5.3.1.2 Haldor Topsøe

Haldor Topsøe (77) offers a methanation technology with thousands of hours of demonstrations. The reactor technology consists of adiabatic fixed-bed reactors in series, with the number of reactors and configuration customized for each application.

- **Technology:** Adiabatic fixed-bed reactors (TREMP™ methanation with MCR catalyst)

- **Feed Gas:** Syngas
- **Operating Temperature:** 250ºC to over 700ºC
- **Methane Output:** 94-98% CH_4 (compatible with pipeline specifications)
- **Additional Features:** Superheated steam production

5.3.1.3 MAN Energy Solutions

MAN Energy Solutions (78) offers an isothermal reactor (MAN DWE Methanation reactor) that operates at 20 bar(g), producing both high- and low-pressure steam. The technology includes a first-generation molten salt reactor and a second-generation boiling water reactor, achieving 99% CO_2 conversion.

- **Technology:** Isothermal reactor (MAN DWE Methanation reactor)
- **Capacity:**
  - Plant capacities: 1 MWel to 200 MWel
  - H_2 input: 18/900/1 800/3 600 kg/h
  - CO_2 input: 100/5 000/10 000/20 000 kg/h
  - E-methane output: 36/1 800/3 600/8 200 kg/h
- **Feed Gas:** CO_2, H_2, and raw biogas
- **Methane Output:**
  - Standard: >95% CH_4, <2% CO_2, <3% H_2
  - Liquefaction-ready: >98% CH_4, <50 ppm CO_2, <3% H_2
- **Reactor Type:** Molten salt (first-gen) and boiling water (second-gen) reactors
- **Conversion:** 99% CO_2 to methane.

5.3.1.4 AlphaSYNT

AlphaSYNT (79) offers a production plant with their CoMeth methanation module, featuring a catalytic fluidized bed reactor and integrated heat management for efficiency.

- **Technology:** CoMeth methanation module
- **Reactor Type:** Catalytic fluidized bed reactor
- **Capacity:** 50 to 1 000 Nm^3/h renewable methane production (4 250 to 85 000 MWh annual renewable methane output)
- **Feed Gas:** Raw biogas, CO_2, and H_2
- **Methane Output:** ~97 vol-% CH_4
- **Additional Features:**
  - Gas membrane for H_2 and CO_2 recovery

- Integrated heat management system

5.3.2 Biological methanation technology providers

5.3.2.1 Kanadevia INOVA

Kanadevia INOVA (80) (former Hitachi Zosen INOVA) has been part of Kanadevia Corporation since 2010. Both companies offer methanation solutions. Kanadevia Inova offers the proprietary biological BiON® methanation process, a continuously stirred tank reactor (CSTR) that is scalable and available in different sizes.

- **Technology:** BiON® methanation, stirred tank reactor with mixed culture of archaea, operating up to 10 bar and at 65°C
- **Capacity:** BiON®400 module for up to 400 Nm^3 H_2/ h in different configurations (Basic, Economic, Pro versions) and as stand-alone module or in clusters for higher gas throughput.
- **Feed Gas:** CO_2 and H_2, raw biogas, sewer gas, pyrolysis gas, syngas
- **Methane Purity:** > 96 % (gas purification as add-on)
- **Features:**
  - Very dynamic plant operation with rapid on/off cycles possible
  - High tolerance to trace gases
  - Scalable and available in different sizes
  - Designed as a container solution for outdoor installation that can be tailored into customer needs in terms of length and width. The solution provides good accessibility for maintenance and high safety.

5.3.2.2 Q Power

Q Power (81) offers methanation solutions based on its solid-state reactor, designed for modular small- to large-scale applications.

- **Technology:** Solid-state reactor, operating at 50-70°C
- **Feed Gas:** CO_2 and H_2
- **Methane Purity:** 97%
- **Features:**
  - Modular design, supporting capacities from 50 kW to over 150 MW
  - No need for mixing, pressurizing or constant fluid pumping

5.3.2.3 GICON

GICON (82) is developing a trickle-bed technology with a current TRL of 7.

- **Technology:** Trickle-bed reactor with mixed culture of archaea, operating at thermophilic conditions (55-65°C)
- **Feed Gas:** Raw biogas, CO_2, and H_2
- **Energy Efficiency:**
  - Self-energy demand: 0.06-0.27 kWhel/Nm^3 CH_4
  - Heat release: 3.137 kWh/Nm^3 CH_4
- **Methane Purity:** >95%
- **Features:**
  - Low energy requirement (no mixing, no recirculation)
  - Mixed culture
  - Flexible operation

5.3.2.4 Electrochaea

Electrochaea (83) offers design for a stirred methanation reactor that can be scaled to 10 and 25 MW system in a single bioreactor design, and several 100 MW with replicable 25 MW units. An overview of the methanation system is presented below:

- **Technology:** Stirred methanation reactor with patented monoculture of archaea, operating at 1-10 bar and 60-65°C
- **Feed Gas:** Raw biogas, landfill gas, CO_2 and H_2
- **Methane Purity:** 97-100%
- **Features:**
  - Scalability: From 1 MW field trials to systems scaled to 25 MW, which in turn is replicable to several 100 MW.
  - Quick return to methane production, making it ideal for intermittent duty cycles and load followings.
  - Tolerant to oxygen, H_2S, CO, Sulfate, Ammonia, and particulates.
  - Special nutrient package is applied for the archaea

5.3.2.5 Biogasclean

Biogasclean (84) offers a trickling reactor system that produces methane with high purity.

- **Technology:** Bio trickling reactor with insulated tanks (stainless steel or reinforced fiberglass, filled with random packed material) with mixed culture of archaea, operating at thermophilic conditions (60-65°C) without additional pressure.
- **Feed Gas:** Raw biogas, CO_2 and H_2
- **Production Capacity:** References up to 381 Nm^3/h CH_4 (using 7.5 MW alkaline electrolyzers). Theoretically, there is no limit as the system can be scaled up to the desired gas volume.
- **Methane Purity:** 97-98%
- **Features:**
    - Tolerant to sulfur and other impurities
    - Biological full-scale reactor needs cooling to keep temperature at desired level

5.3.2.6 Micropyros

Micropyros (85) offers a turnkey biomethanation plant including a stirred tank reactor. Micropyros installed a R&D plant designed for continuous operation in 2023.

- **Technology:** Stirred tank reactor-based biological methanation, operating at 6-10 bar and up to 100°C.
- **Feed gas:** Raw biogas
- **Capacity:** 1 Nm^3/h CH_4
- **Methane Purity:** >96%

A summary of the technologies is presented in Appendix H – Technology providers.

5.4 Summary of methanation technologies

Catalytic Methanation

This process occurs at high temperatures (200–550°C) and pressures (1–100 bar) using metal catalysts, primarily nickel-based. The main challenges include managing heat and catalyst deactivation due to impurities. Various reactor designs are employed:

- Fixed Bed Reactors: Adiabatic (requiring multiple reactors) and isothermal (more complex and costly).

- Fluidized Bed Reactors: Provide good temperature control but may struggle with incomplete CO_2 conversion.
- Three-Phase Methanation (3PM): Combines solid catalysts with liquids, improving heat management but limiting mass transfer.
- Structured Reactors: Include honeycomb and microchannel designs, offering high heat transfer efficiency but facing challenges in catalyst deposition and replacement.

Biological Methanation

This microbial process utilizes methanogenic archaea to convert hydrogen (H_2) and CO_2 into methane and water at moderate temperatures (35-80°C) and pressures (1-10 bar). BM can occur in two ways:

- In-situ Methanation: Hydrogen is injected into anaerobic digesters, enhancing methane production while requiring careful management of hydrogen levels.
- Ex-situ Methanation: Conducted in separate reactors for greater control over reaction conditions, potentially yielding higher methane purity but requiring a larger capital investment.

A summary and comparison of the catalytic and biological methanation solutions are presented in Table 6.

Table 6. Summary of catalytic and biological methanation technologies.

	Catalytic methanation	Biological methanation
R&D needs	• Fixed bed: Improved heat dissipation • Fluidized bed: Improved catalyst • 3PM reactor: Improved temperature stability of heat transfer fluid	• Improvement of H_2 transfer into liquid phase • Deepened proof of concept
Process parameters	+ High-quality waste heat (high temperature) + High space velocity/smaller reactor possible – More extreme operating conditions (temperature and pressure).	+ Low-temperature process. Electrolyzer waste heat can be used to heat the process. – Mass transport limitation of H_2 in liquid phase resulting in large reactor volumes and high energy for mixing for CSTR:s.
Complexity	– Complex cooling system – Need for several reactors (fixed bed methanation) – Catalyst sensitivity to impurities in feed gas stream, need to be cleaned upstream. – Catalyst breakage (fluidized bed reactor) – Low reaction rate (3PM)	+ Only one reactor required. Less complex. + Not sensitive to impurities in feed gas. No extensive gas cleaning required.
Efficiency	+ Efficiency can be increased by utilization of waste heat. + Higher efficiency	– Low-temperature waste heat. Heat pump might be needed to utilize waste heat.

Flexibility	+ Fluctuating throughputs are tolerated. + Longer downtimes possible – Catalyst sensitive to impurities and fluctuation in composition of input gas	+ Fluctuating gas composition is not a problem. + High tolerance to impurities (e.g. H_2S) – Microorganisms cannot handle long downtimes

5.5 Use of resources produced out of methanation technologies

By implementing methanation technology, oxygen from the electrolyzer and heat from both the electrolyzer and methanation will be produced. The possibility of using these resources will impact the plant's overall process efficiency and economy. Below is a general overview of how WWTP and co-digestion plants could utilize oxygen and excess heat. However, how these resources might best integrate at the site will depend on the local circumstances.

5.5.1 Integration at Wastewater Treatment Plants

- Oxygen:

Oxygen, which is an excess product from electrolysis (see chapter 4), can be used at WWTPs for organic matter oxidation and nitrogen removal (nitrification), both key parts of the wastewater treatment process that need oxygen. Nitrification is where nitrogen in the form of ammonium (NH_4^+) is oxidized into nitrite (NO_2^-) and then into nitrate (NO_3^-). This conversion requires 3.56 grams of oxygen per gram of NH_4^+. Oxygen is usually supplied through air diffusers located at the bottom of the reactors with help from compressors. Organic matter oxidation is an important step in plants with no nitrogen removal. Regardless of the process, these steps are generally the biggest energy consumers at WWTPs, typically demanding around 40% of the total energy consumption.

Air contains 21% oxygen (O_2) and 78% nitrogen gas (N_2). Recent studies have shown that increasing the oxygen concentration in the air supplied for nitrification leads to improvement in the oxygen transfer efficiency (86). This is because there is a linear relationship between the oxygen concentration in the supplied air and the oxygen transfer. This means that using excess oxygen produced at electrolyzers could reduce the energy demand for blowers/compressors by allowing more effective oxygen transfer and uptake in nitrification and/or organic removal processes.

This excess oxygen—aligned with the hydrogen production—could not fully meet the WWTPs' total oxygen demand. However, it could contribute to lowering the speed needed for the blowers when the electrolyzer is in operation, thereby lowering the electricity consumption. An estimation of saving energy by applying this integration possibility is shown in Figure 14 in Chapter 6.3. The blowers supplying air to water treatment basins are regulated by the dissolved oxygen concentration measured by sensors in the water. Therefore, storage of excess oxygen is not considered necessary, and the oxygen produced in the electrolyzers can be used intermittently when available.

- Excess heat:

Besides oxygen, excess heat will also be produced in the electrolyzer. This excess heat will have a temperature of about 80 °C and at an amount of 535 kWh per MWh renewable methane being produced in the later methanation step (Table 8 in Chapter 6). Less than half of this excess heat is estimated to cover the entire need for heating the anaerobic digesters (see Table 8 in Chapter 6); the rest could, for example, be delivered as district heating or steam by raising the temperature with the help of a heat pump. How this low-temperature excess heat from the electrolyzers is used in the best way will depend on the local circumstances at the specific site. As, at least larger, WWTPs generally are closely situated in urban areas, the integration and possibility of exploiting excess heat are considered rather promising.

In addition to low-temperature excess heat from electrolyzers, high-temperature excess heat will be produced during catalytical methanation (if this methanation technology is chosen). This excess heat will hold a temperature of about 350 °C with an estimated amount of about 200 kWh per produced MWh methane from methanation (see Table 9 in Chapter 6). This heat could be used, for example, to produce steam for regenerating the carbon dioxide absorber (amine) if the amine scrubber is used for biogas upgrading. Over half of this high-temperature heat is estimated to meet the scrubber's total heat demand, leaving about 90 kWh per MWh produced methane for other uses (see Table 9 in Chapter 6).

5.5.2 Integration at co-digestion plants

- Oxygen

There is no direct use of oxygen from the electrolyzer at a co-digestion plant, which will likely be released into the atmosphere. The addition of small amounts of air/oxygen into the headspace of anaerobic digesters is a common method for reducing H_2S in raw biogas at, for example, farm-scale biogas plants. This method is only used in plants that use the gas to generate heat and/or electricity, as the resulting biogas will contain oxygen, which is undesirable in upgraded biomethane. If air/oxygen for H_2S reduction is applied, only a small share of excess oxygen from the electrolyzer would be needed. Therefore, the possibility of integration synergies with excess oxygen at co-digestion plants is considered negligible in general.

- Excess heat

Excess heat from the electrolyzer will have a temperature of about 80 °C, amounting to 535 kWh per MWh renewable methane produced in the later methanation step (see Table 8 in Chapter 6). Less than half of this excess heat is estimated to cover the need for hygienization and heat to the anaerobic digesters (see Table 8 in Chapter 6); the rest could, for example, be delivered as district heating or steam by raising the temperature with the help of a heat pump. As many co-digestion plants are situated at more rural locations, getting valuable use of the excess heat is considered more challenging than for WWTP´s. Whether this low-temperature excess heat from the electrolysers can be used in any way will depend on the local circumstances at the specific site.

In addition to low-temperature excess heat from electrolyzers, high-temperature excess heat will be produced during catalytical methanation (if this methanation technology is chosen). This excess heat will hold a temperature of about 350 °C with an estimated amount of about 200 kWh per produced MWh methane from methanation (see Table 9 in Chapter 6). This heat could be used, for example, to produce steam for regenerating the carbon dioxide absorber (amin) if the amine scrubber is used for biogas upgrading. Over half of this high-temperature heat is estimated to meet the scrubber's total heat demand, leaving about 90 kWh per MWh produced methane for other uses (see Table 9 in Chapter 6).

Other possible uses for excess heat can be to process and productize the digestate in various ways, such as drying and pelletizing the dry fraction of the digestate or to evaporate the nitrogen in the liquid fraction into a concentrated fertilizer

product. This is of particular interest for biogas plants that are located so that there are long distances to possible spreading areas of the biofertilizer.

6 Techno-economic assessment

Following chapter contains the techno-economic assessment of 6 cases where methanation technologies are implemented at biogas plants. The first section presents the evaluated cases, followed by a section describing the assumptions made for the evaluation of the cases. The final section presents the results, including the CAPEX, OPEX, levelized production cost (LPC) and levelized cost of avoided CO_2 (LCCA). The LPC is equal to the minimum selling price of the product at the plant gate that makes the net present value (NPV) of the project equal to zero with 8% discounted cash flow rate over the plant lifetime of 20 years.

In addition, the result section includes a subchapter investigating the effect of size and electricity price on the levelized cost of production, as well as a calculation showing the effect on the energy balance if excess heat cannot be used in the upgrading equipment. Finally, the application of methanation in combination with a liquefaction plant is evaluated for two of the cases. Additional data, assumptions and results of the techno-economic assessment are presented in Appendix A – D.

6.1 Definition of cases

The techno-economic assessment was made to evaluate and compare the implementation of different methanation technologies in co-digestion plants and wastewater treatment plants (WWTP). The different cases are presented in

Table 7.

Table 7. Cases evaluated in the techno-economic assessment.

Case number	Key	Existing plant	Methanation technology	Feed to methanation plant
1	CD_BM_CO2	Co-digestion plant	Ex-situ biological methanation	CO_2-feed
2	CD_BM_BG	Co-digestion plant	Ex-situ biological methanation	Raw biogas feed
3	CD_CM_CO2	Co-digestion plant	Catalytic methanation	CO_2-feed
4	WWTP_BM_CO2	WWTP	Ex-situ biological methanation	CO_2-feed
5	WWTP_BM_BG	WWTP	Ex-situ biological methanation	Raw biogas feed
6	WWTP_CM_CO2	WWTP	Catalytic methanation	CO_2-feed

All cases were evaluated in detail for implementation on existing plants with the sizes 20 GWh and 120 GWh. This means that the energy output from the biogas producer before implementation of a methanation technology was 20 and 120 GWh. Furthermore, evaluation of the different technologies was done for the entire range of 20 – 120 GWh.

6.1.1 Electrolyzer technology

In all cases, proton exchange membrane (PEM) electrolyzer was considered. The PEM-electrolyzer has a higher efficiency than the conventional alkaline electrolyzer,

a smaller footprint and is ideal for flexible operation due to its fast response time. The operating pressure was assumed to be 50 bar and the operating temperature 80°C. The components considered for the electrolyzer plant was:

- Electrolyzer stack
- Power electronics
- Gas conditioning, including drying and cooling components as well as H_2 purification
- Balance of plant, including thermal and fluid management as system controlling

In addition to the mentioned components, a hydrogen storage was included to facilitate flexible operation of the electrolyzer in order to avoid peak electricity prices.

6.1.2 Methanation technologies

Two methanation technologies were implemented: ex-situ biological methanation, and catalytic methanation. The ex-situ biological methanation was further broken down into two configurations: 1) raw biogas feed into the methanation reactor and 2) CO_2-feed into the methanation reactor. The catalytic methanation technology was only evaluated for a CO_2-feed into the reactor. In-situ biological methanation was not selected partly due to lack of data, and partly due to it being a less mature technology. Catalytic methanation with raw biogas as feed was not selected due to lack of available data.

Biological methanation

The ex-situ biological methanation system selected for this study is a continuous stirred tank reactor (CSTR). The motivation of the choice of technology is partly due to that the biological methanation in a stirred reactor currently is one of the technologies with highest TRL (9), see Table 4. The second reason for the choice of technology is the data availability of ex-situ biological methanation in a stirred tank reactor, which is made available due to the STORE&GO project where Electrochaea participated with their methanation technology (87,88). Based on the work from the STORE&GO project and Electrochaea's technology, the system evaluated in this report consists of a stirred tank reactor with a working pressure of 10 bar and operational temperature between 60 – 65°C. The resulting methane has a purity of 97 – 98.5 vol-%. The methanation system evaluated includes:

- Methanation reactor with a reactor heat management

- Electrical installation
- Gas conditions after the methanation reactor, including drying and cooling as well as methane purification
- Balance of plant, including thermal and fluid management, storage tanks, and system controlling
- Compressor for the CO_2/biogas-feed to meet the operating conditions of the methanation unit

The two configurations of the biological methanation, CO_2 and raw biogas feed, were identical in process layout. However, the subcase with a raw biogas feed required larger equipment due to the larger gas flow. The compressor and the gas conditioning were the units mainly affected by the increased gas flow.

Catalytic methanation

The catalytic methanation system selected for this study is a honeycomb reactor. The motivation of the choice of technology is partly due to that the catalytic methanation in a honeycomb reactor has a relatively high TRL (7), see Table 6. The second reason for the choice of technology is the data availability of a honeycomb reactor for catalytic methanation, which is made available due to the STORE&GO project (87). Based on the work from the STORE&GO project the catalytic methanation reactor evaluated in this project is an isothermal honeycomb reactor with a working pressure of 14 bar and an operational temperature of 350°C. The purity of the methane is 99 vol-%. The methanation system evaluated includes:

- Methanation reactor with a reactor heat management and catalyst
- Electric installation
- Gas conditioning after the methanation reactor, including drying and cooling as well as methane purification
- Balance of plant, including thermal and fluid management, storage tank and system control
- Desulphurization unit before the reactor
- Compressor for the CO_2-feed

6.2 Assumptions

The following are assumptions made regarding the evaluated cases. Economic and technical data used in the evaluation is presented in Appendix A – C.

6.2.1 Existing biogas plant and upgrading unit

- The biogas has a composition of 40 vol-% CO_2 and 60 vol-% CH_4
- The upgraded biogas has a composition of 97 vol-% methane.
- It is assumed that there is an existing upgrading unit before the implementation of the methanation technologies.
- The upgrading unit is assumed to be an amine scrubber.
- The amine scrubber is assumed to be heated by steam from a biomass boiler
- The existing AD is assumed to be heated by district heating (WWTP) or biomass boiler (CD)

6.2.2 Implementation of methanation technologies

- There is a 100% conversion of hydrogen in the methanation reactor.
- The oxygen from electrolysis is used in the aeration step of the WWTP. In the co-digestion plant the oxygen is not utilized.
- During catalytic methanation high temperature steam is produced from the cooling of the methanation reactor. This steam is used in existing amine scrubber. The excess heat is used for district heat generation in the WWTP. In the co-digestion plants the excess heat is removed by cooling.
- In the case where raw biogas is used as feed to the reactor, it is assumed that the operating costs of the existing amine scrubber, which would be needed to upgrade the biogas, are avoided. These avoided costs are included as a profit in the evaluation.

6.2.3 Electrolyzer and hydrogen storage

- The electrolyzer is over-sized to meet the hydrogen demand and at the same time fill the hydrogen storage at low electricity price.
- The electrolyzer waste heat is used to heat the AD.
- No compressor is needed from hydrogen storage to methanation unit due to the high operating pressure and storage pressure of the electrolyzer and hydrogen storage.
- The hydrogen storage is optimized based on hourly electricity price data from 2023 – 2024.

6.3 Results

6.3.1 Material and energy balance

The material and energy balances of the different cases were calculated based on the assumptions presented in Chapter 6.2 and Appendix A – C. Results that applies for all cases are presented in Table 8.

Table 8. Efficiencies, conversion, waste heat and oxygen production for all cases. Values presented per MWh CH_4 indicate how much that is produced per MWh CH_4 obtained from methanation.

Item	Unit	Value	Comments
Efficiency, conversion, and reduced energy demand			
Increased biogas production		61.90%	As a result of implementing methanation
Power-to-Gas efficiency		56%	Energy conversion from electricity to product.
Hydrogen conversion		100%	H_2 to CH_4
Waste heat			
Total produced low temperature waste heat	MWh/MWh CH_4	0.54	Waste heat at 80°C from electrolyzer
Available low temperature waste heat	MWh/MWh CH_4	0.33	After integration with AD
Co-products			
Oxygen production	kg/MWh CH_4	287	Not utilized in co-digestion plants

The increased biogas production by implementing methanation is about 61.9% based on the assumptions. However, depending on the composition of the raw biogas the possible increased yield varies. The methanation efficiency is about 82-83% and is defined as the ratio between the energy input to the reactor compared to the energy in the product. The power-to-gas efficiency is about 56% and is defined as the ratio between the energy in the product compared to the energy input to the system in form of electricity to the electrolyzer.

Furthermore, it is assumed that some of the waste heat from the electrolyzer is utilized to heat the anaerobic digestion. The excess low temperature waste heat after integration with the AD is about 0.33 MWh per produced MWh methane.

The oxygen produced as a co-product from electrolysis of water is assumed to not be used in co-digestion plants, while in WWTP the oxygen is utilized in the aeration step. Due to the high pressure of the produced oxygen (50 bar) no blower is needed to utilize it in the aeration step.

In addition to the low temperature waste heat produced in the electrolyzer, high temperature waste heat is produced from catalytic methanation. The amount of produced high temperature waste heat is presented in Table 9.

Table 9. High temperature waste heat available from catalytic methanation. The values are presented per renewable methane produced from the methanation unit.

Item	Unit	Value	Comment
Total produced high temperature waste heat	MWh/MWh CH_4	0.20	Waste heat at 350°C from catalytic methanation reactor
Available high temperature waste heat	MWh/MWh CH_4	0.09	After integration with amine scrubber
District heating	MWh/MWh CH_4	0.83[a,b]	Catalytic methanation at WWTP

a) Only in wastewater treatment plants.

b) Assumed district heating heat exchange efficiency of 90%.

Table 9 shows that the total produced high temperature waste heat from the catalytic reactor is 0.2 MWh per produced MWh methane from methanation. This heat can be

used to produce steam at the plant. In the assessment, it is assumed that some of the produced steam can be used for an existing amine scrubber, reducing the operational costs of the existing upgrading step. The remaining waste heat, after integration with the scrubber, is about 0.09 MWh per produced MWh renewable methaneTable 9. In a WWTP, it is assumed that the excess high temperature waste heat can be recovered as district heating. The energy efficiency of the heat exchange is assumed to be 90%, resulting in district heating production of 0.083 MWh per produced MWh of CH_4.

In addition to the recovery of waste heat as district heating, a WWTP has the possibility of recovering the oxygen to reduce their electricity demand in the aeration step. The specific electricity demand of the methanation systems implemented at co-digestion plants and WWTP are presented in Figure 14.

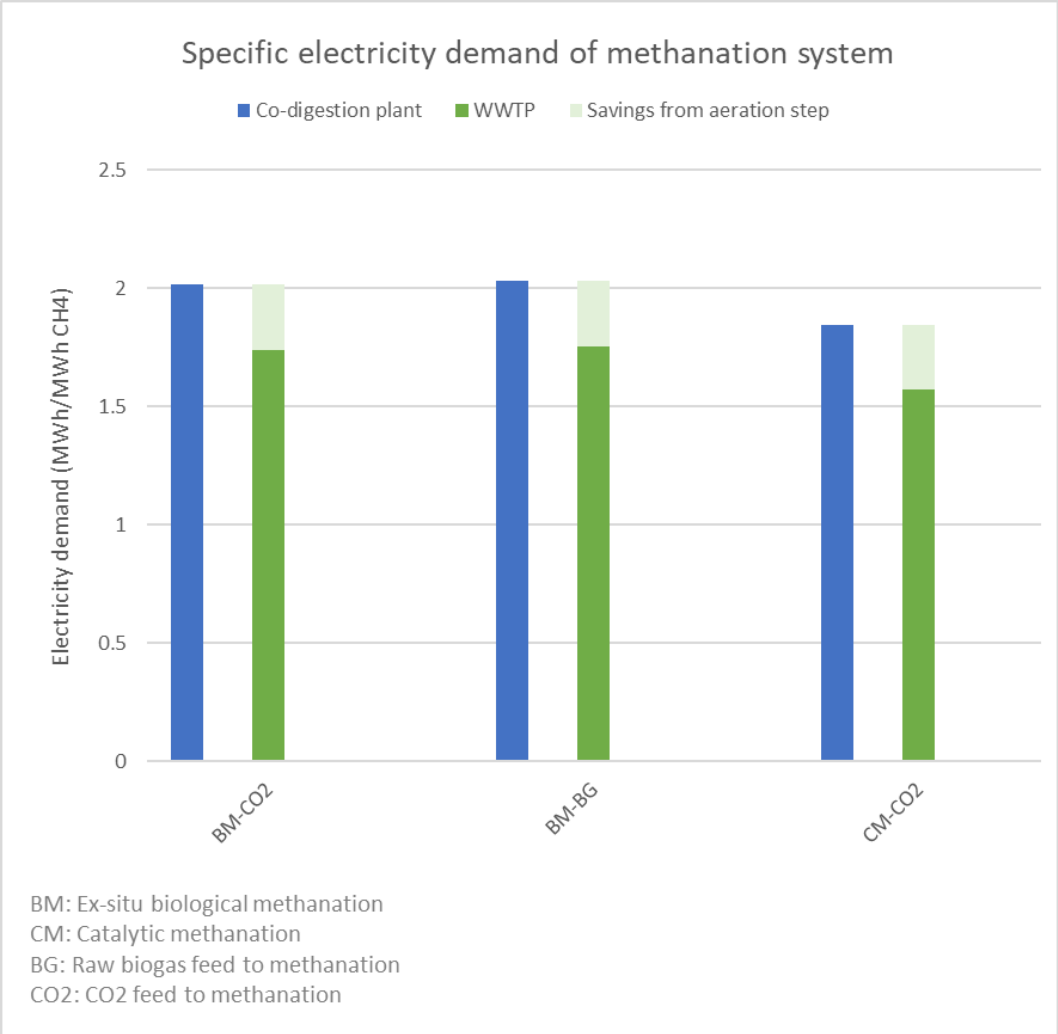

Figure 14. Specific electricity demand of methanation systems, at co-digestion plant compared to electricity demand at wastewater treatment plant after electricity savings due to oxygen use in the aeration step of the WWTP.

The reduced electricity demand in the aeration step at the WWTP can reach up to 37.8% reduction. This results in a total reduced electricity demand of 13.7%, 13.6%, and 15% for biological methanation with CO_2 feed, raw biogas feed, and catalytic methanation respectively, if implemented in a WWTP. The overall energy efficiency of the different cases, including energy recovery and reduced electricity demand due to aeration, is presented in Figure 15.

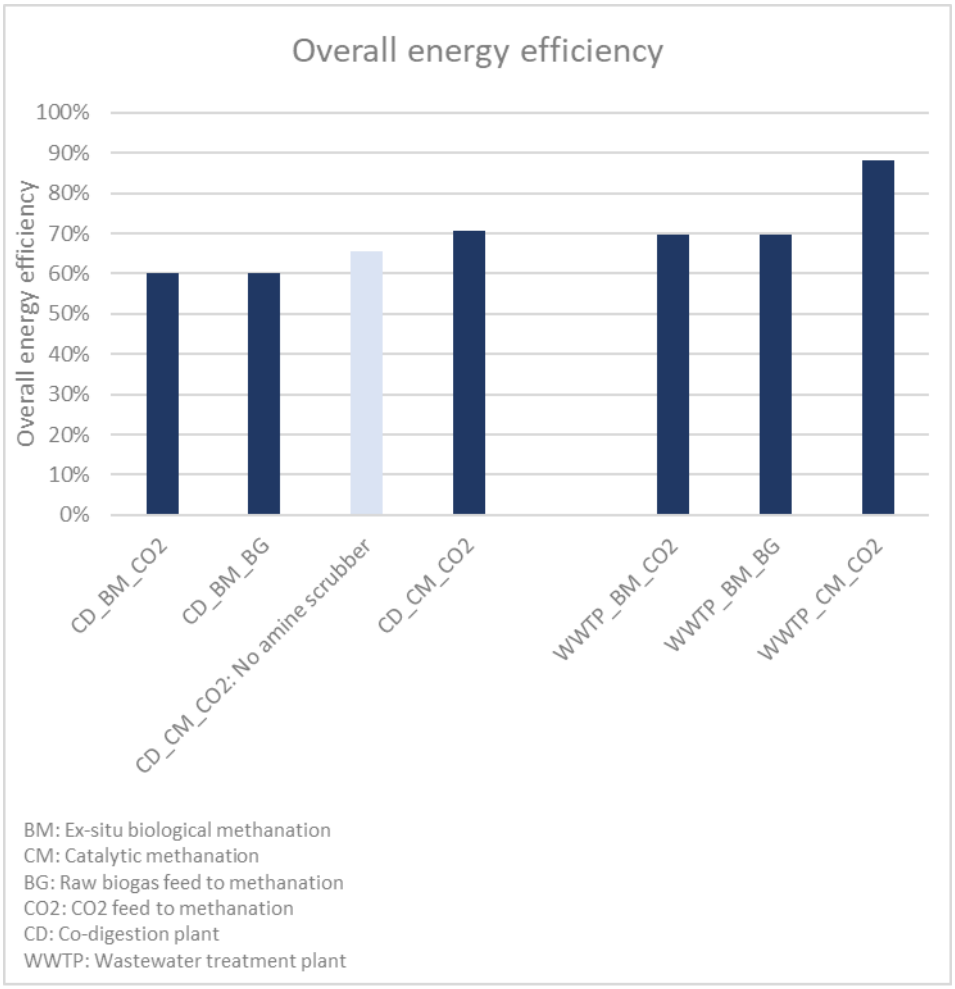

Figure 15. The dark blue bars show the overall energy efficiency for all evaluated cases, including all electricity inputs, waste heat recovery and reduced electricity demand due to utilization of oxygen in aeration. The light blue bar shows the alternative case where a co-digestion plant uses another upgrading technology than an amine scrubber and therefore do not have the possibility of integrating the waste heat from the catalytic reactor with the amine scrubber.

The energy efficiency is higher in WWTP since the oxygen is used to reduce electricity demand in the aeration step. Furthermore, the selected catalytic methanation technology is more energy efficient than the selected biological methanation technology since the catalytic honeycomb reactor does not require mixing like the stirred biological methanation reactor. In addition, the high temperature waste heat produced from catalytic methanation can be utilized to reduced energy demand in assumed existing amine scrubber. In WWTP the excess high temperature waste heat from the catalytic methanation can further be used to produce district heating. The light blue bar in Figure 15 shows the energy efficiency for a catalytic methanation system at a co-digestion plant without utilization of the

waste heat from the reactor, showing a decrease in overall energy efficiency with about 5%.

6.3.2 Investment cost and operational costs

The sizes of the electrolyzer and methanation systems required for all cases, at biogas plants of 20 GWh and 120 GWh, are presented in Table 10.

Table 10. Electrolyzer and methanation system size for a 20 GWh and 120 GWh biogas plant.

Equipment	Unit	Biogas plant size: 20 GWh	Biogas plant size 120 GWh
Electrolyzer	MW_{el}	3.3	19.9
Methanation system	MW_{CH4}	1.5	9.2

Figure 16 shows the total project investment costs associated with the different cases implemented at a 20 GWh biogas plant.

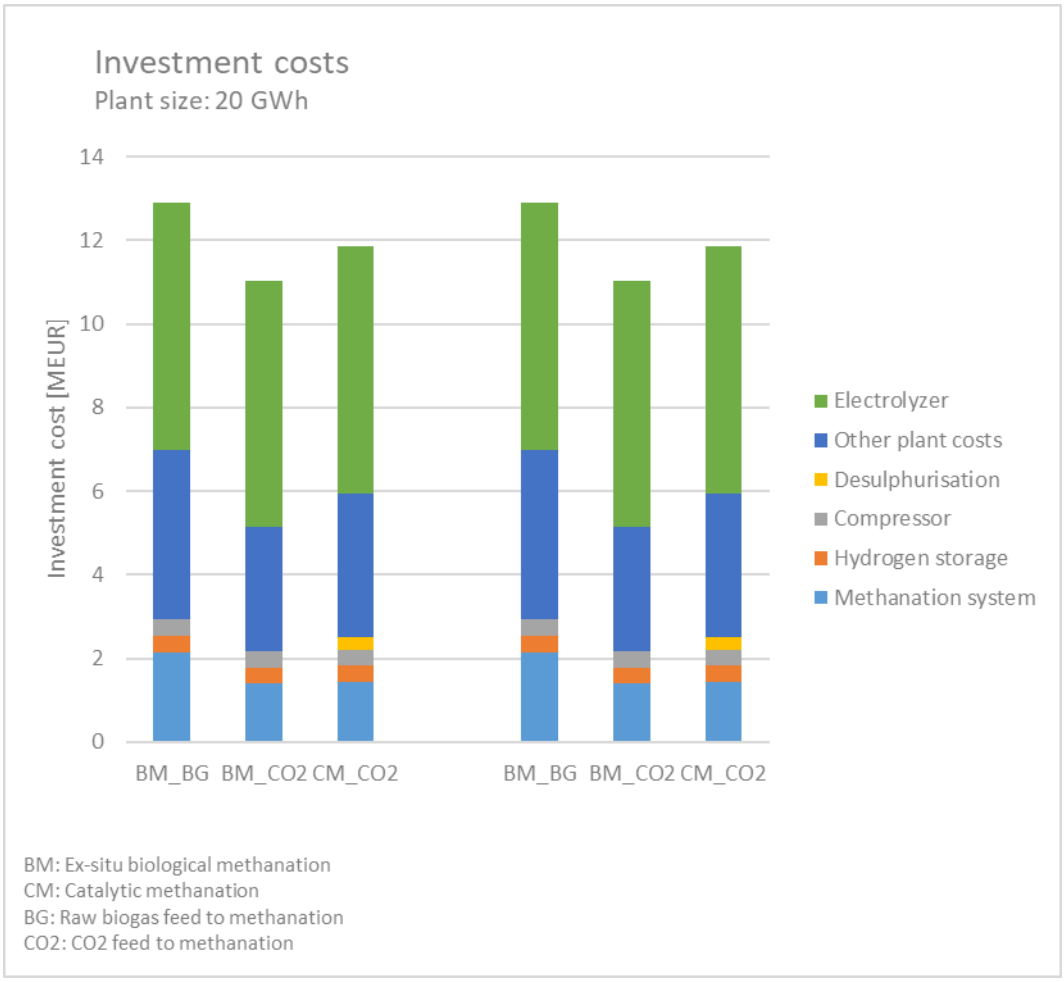

Figure 16. Investment costs associated with implementation of methanation at 20 GWh biogas plants.

The investment of the electrolyzer is the largest single contributor to the investment in all cases (46% - 53%), followed by plant costs associated with the engineering, assembly, piping, electrical and instrumentation (in the graph aggregated to other plant costs) which contribute about 27% - 31% of the total cost. Third largest contributor to the investment is the methanation system (12% - 17%).

The methanation system with highest cost is the biological methanation with raw biogas as feed. This is mainly due to the larger system required to handle the higher gas flow. The higher gas flow through the system is a result of the already existing methane in the biogas is passed through the reactor together with the CO_2 that is converted to methane. In the cases where catalytic methanation is implemented, a desulphurization step is required before the methanation in order to avoid catalyst

poisoning from H_2S. The corresponding results are presented in Figure 17 for the implementation of different methanation technologies at a 120 GWh biogas plant.

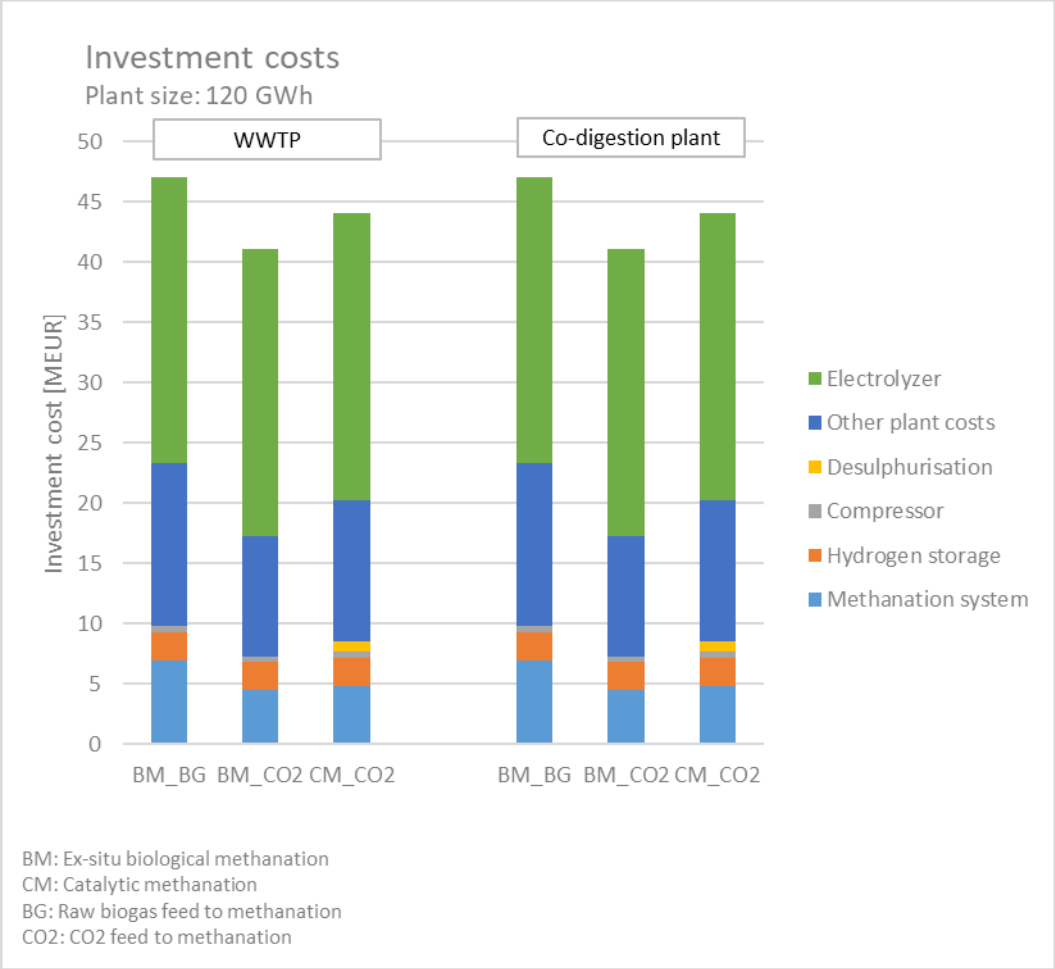

Figure 17. Investment costs associated with implementation of methanation at 120 GWh biogas plants.

The three largest contributors to the investment cost are, as in the 120 GWh cases, the electrolyzer (51% - 58%), other plant costs (24% - 29%), and the methanation system (11% - 15%). However, in the 120 GWh case the electrolyzer constitutes a larger share of the total investment. This is because the methanation systems' cost scale different than the electrolyzer system. The operational costs for the 20 GWh and 120 GWh cases are presented in Figure 18 and Figure 19.

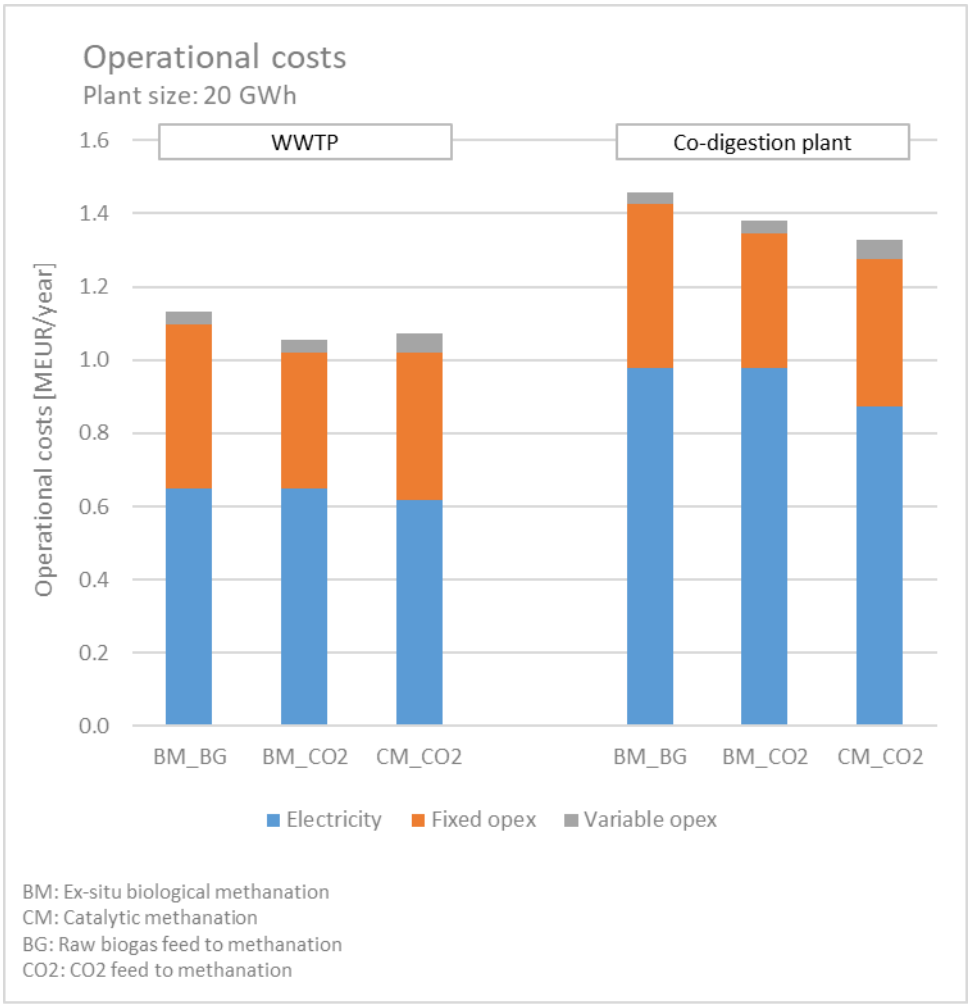

Figure 18. Operational costs associated with electrolysis and methanation at a 20 GWh biogas plants.

Figure 19. Operational costs associated with electrolysis and methanation at a 120 GWh biogas plants.

In all cases, the electricity demand is the largest share of the operational costs, followed by the fixed operating costs (operation and maintenance). The variable operating costs, excluding electricity, includes water purification for the electrolyzer and catalyst replacement for the catalytic methanation.

6.3.3 Levelized production cost

The levelized production cost of renewable methane, for all evaluated cases, at biogas plants of 20 GWh and 120 GWh are presented in Figure 20.

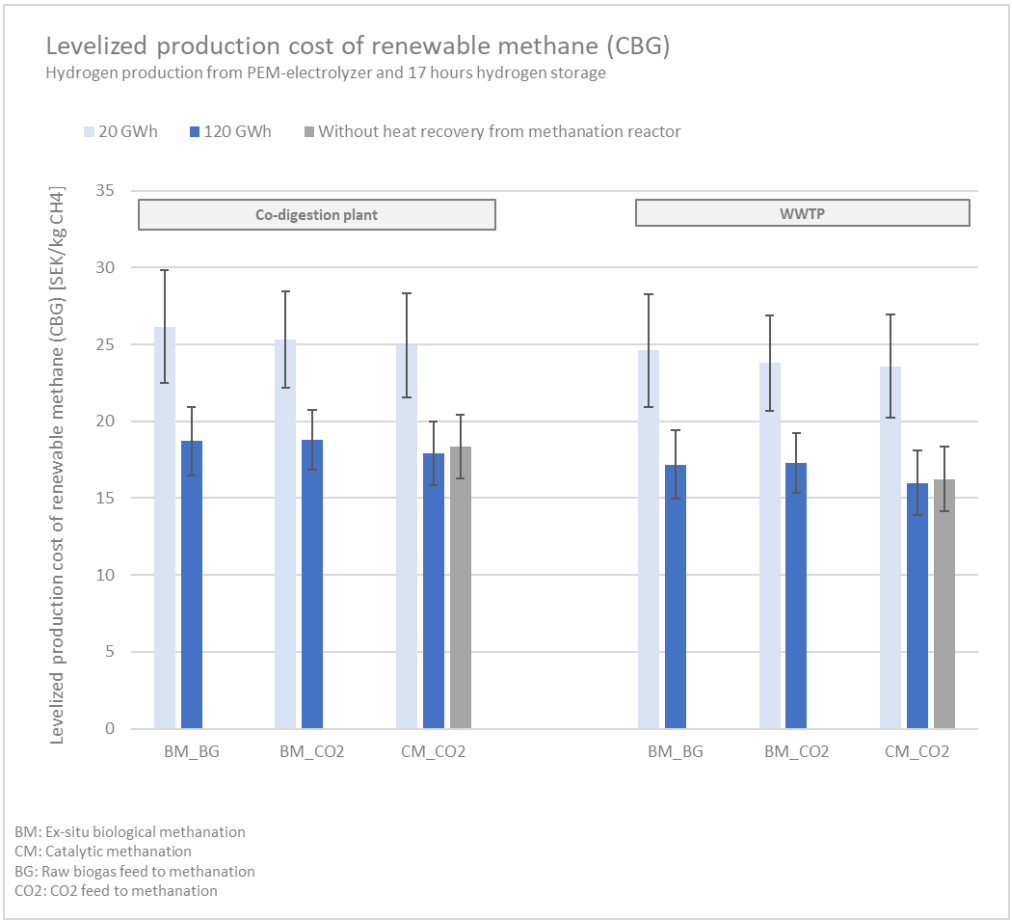

Figure 20. Levelized production cost of renewable methane for all cases, implemented at existing biogas plants of 20 GWh and 120 GWh. Gray bars show the result from catalytic methanation without utilization of waste heat from the methanation reactor for heating of an amine scrubber at 120 GWh.

The error bar shows the result of the sensitivity analysis made to account for the 30% uncertainty of the method used to estimate the total cost of the project. The result shows that the cost per produced methane decreases as the size of the system increases. This is due to the effect of economies of scale.

The diagram also shows that the implementation of catalytic methanation results in the lowest levelized cost. Some of the contributing factors to the lower cost of the catalytic process is that it does not require mixing and that the higher temperature waste heat from the catalytic reactor can be recovered and used to reduce the operational cost of the assumed existing amine scrubber.

Moreover, the excess waste heat can be used to produce district heating where it is available. In this study the assumption was made that the WWTP have access to

district heating network and can therefore utilize more of excess waste heat than the co-digestion plants, which is also reflected in the results.

In addition, the use of oxygen in the aeration step in the water cleaning basins of the WWTP reduces the electricity demand further and contributes to the lower levelized cost of implementing methanation at WWTP.

Finally, it can be seen that the use of raw biogas as a feed result in a higher levelized cost, which is mainly related to the need for a larger system due to the larger gas flow. This, in turn, results in a higher investment cost. The advantage is that the upgrading unit, which in the calculations is assumed to be an amine scrubber, does not need to operate at full capacity, which lowers the operational cost of the upgrading unit. However, the higher cost of the larger system outweighs the profit of not running the assumed amine scrubber.

6.3.4 Cost of avoided CO_2

Figure 21 shows how much the investment per avoided CO_2 for the evaluated methanation technologies implemented at biogas plants of 20 and 120 GWh.

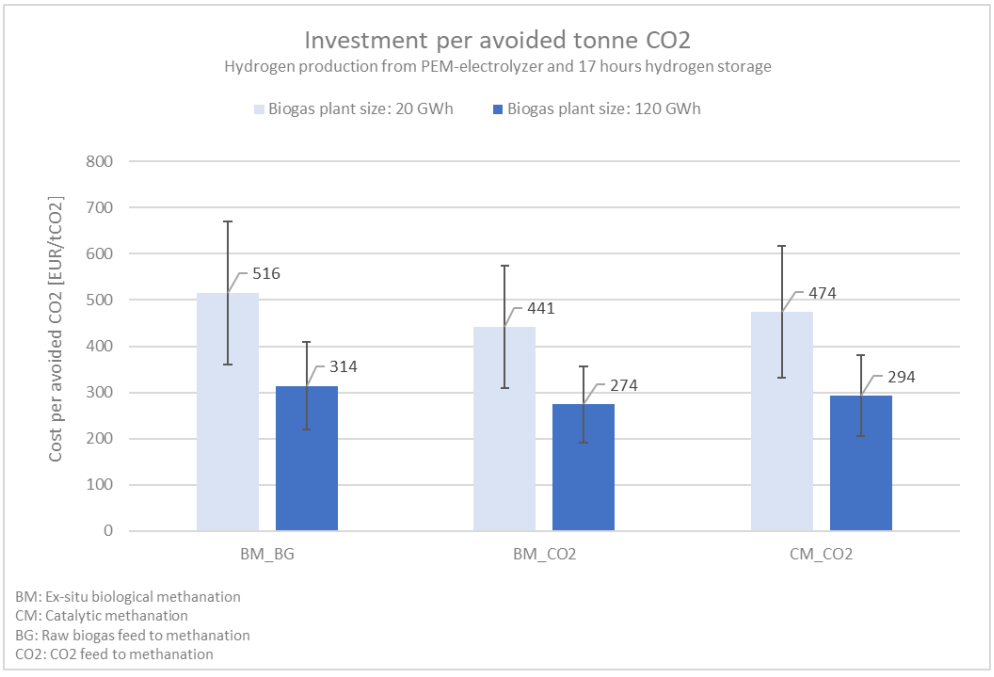

Figure 21. Investment cost per avoided CO_2 for the evaluated methanation systems implemented at existing biogas plants of size 20 and 120 GWh.

The values indicate only the investment cost per avoided tonne CO_2. To evaluate the cost per tonne avoided CO_2 of the project over its lifetime, including operating costs and revenue(s), the levelized cost of avoided CO_2 (LCCA) is calculated for each case. The LCCA at different prices of renewable methane, for all different evaluated methanation technologies, implemented at a co-digestion plant of 20 and 120 GWh, are shown in Figure 22.

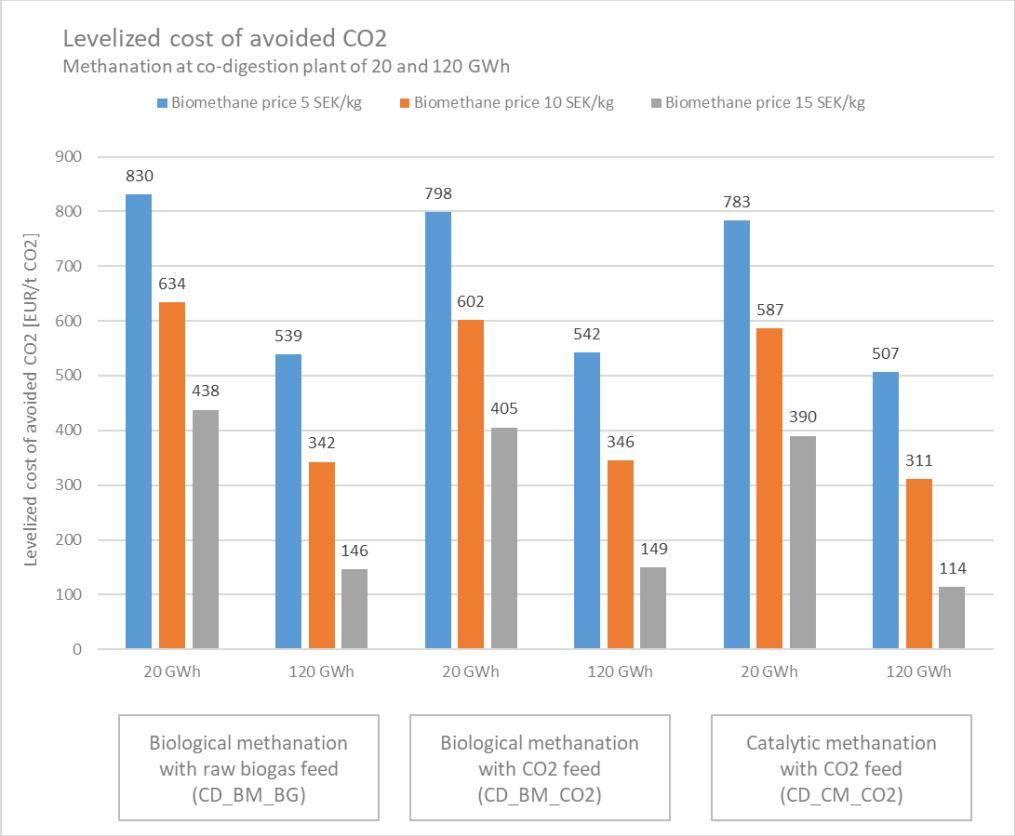

Figure 22. Levelized cost of avoided CO_2 as function of biogas price at a co-digestion plant of 20 and 120 GWh.

The LCCA of the methanation technologies at a WWTP, evaluated for different renewable biogas prices, are presented in Figure 23.

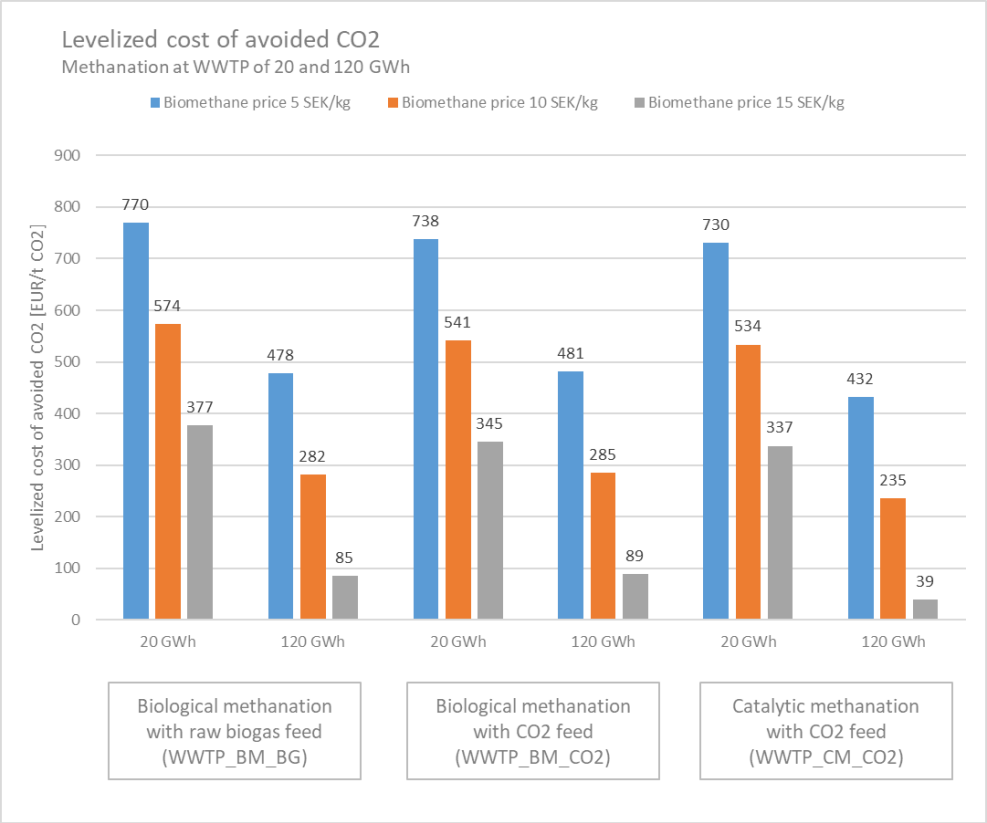

Figure 23. Levelized cost of avoided CO_2 as function of biogas price at a WWTP of 20 and 120 GWh.

All cases presented in Figure 22 and Figure 23 have in common that the larger size results in a lower cost per avoided CO_2. This is explained by economies of scales, i.e., larger scale processes tend to cost less per produced unit (or avoided CO_2).

Furthermore, the LCCA results show that the same technology in general has a lower cost applied to a WWTP than a co-digestion plant as a result of the possibility of utilizing produced oxygen in the aeration step in the water cleaning basins. Furthermore, the WWTP cases give more opportunities of heat recovery as the WWTPs are assumed to be in the vicinity of the district heating infrastructure. This especially favors catalytic methanation since it gives more possibilities of utilizing the high-quality waste heat from the catalytic reactor.

For reference, the cost of avoided CO_2 can be compared to the EU ETS price and the cost of CCS. EU carbon price had, during 2024, an average price of 60 EUR/tCO_2 and is forecast to reach 80 EUR/tCO_2 2025 and 146 EUR/tCO_2 2030 (89). The cost per captured tonne CO_2 in gas processing and biofuel industries is on average 95 EUR/tCO_2. If the cost of transport and storage is included, the price per captured

tonne CO_2 is 114 – 123 EUR/tCO_2 (90). Assuming an average cost per captured CO_2 of 118 EUR/tCO2, the biogas selling price required to make the implementation economically feasible at co-digestion plants and WWTP of sizes 20, 70 and 120 GWh are presented in Table 11.

Table 11. Biogas price (CBG) at which implementation of methanation at biogas plants of sizes 20, 70, and 120 GWh is economically feasible compared to installation of CCS with an assumed CCS cost of 118 EUR/tonne captured CO_2.

	Existing biogas plant size		
Biogas plant	20 GWh	70 GWh	120 GWh
WWTP	21-22 SEK/kg	15-16 SEK/kg	13-15 SEK/kg
Co-digestion plant	22-24 SEK/kg	17-18 SEK/kg	15-16 SEK/kg

Detailed graphs showing the cost per tonne avoided CO_2 for different renewable methane prices for each methanation technology at 20, 70 and 120 GWh, can be found in Appendix G – Cost of avoided CO_2.

6.3.5 Effect of electricity price on levelized cost of production

As seen in Chapter 6.3.2 the cost of electricity is a major contributor to the operational cost and the total production cost. In order to capture the results dependence on electricity price a sensitivity analysis investigating the electricity price effect on the levelized cost of production for all cases was done. The sensitivity analysis on a WWTP with ex-situ biological methanation with CO_2 feed is presented in Figure 24. All cases can be found in Appendix F – Sensitivity analysis: Effect of electricity price on levelized cost of production.

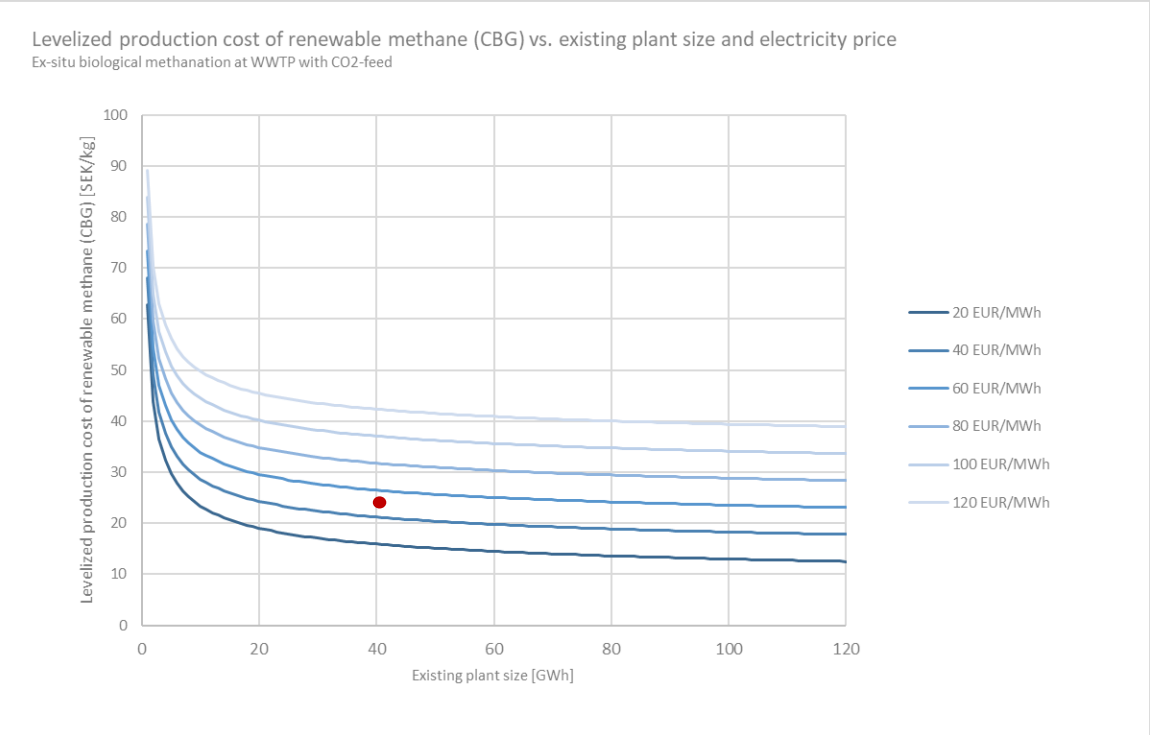

Figure 24. Effect of biogas plant size and electricity price on levelized production cost of CBG at WWTP with ex-situ biological methanation with CO_2- feed. The production cost does not include possible revenue from carbon credits. The red dot indicates the size for which methanation is economically feasible, assuming an average electricity price of 50 EUR/MWh and a biogas (CBG) selling price of 23 SEK/kg.

For the presented case, with the assumed average electricity price in SE3 of 50 EUR/MWh (Appendix C), and a CBG selling price of 23 SEK/kg (91), the minimum size of existing biogas plant (excluding methanation) where which implementation of methanation would be economically feasible, is about 40 GWh. Based on evaluation of all cases the determined reasonable minimum size of a WWTP for implementation of methanation is about 40 GWh, while for a co-digestion plant the size is about 60 GWh.

6.3.6 Liquefaction of biogas

In addition to the results presented in Chapter 696.3.1 - 6.3.5 two of the cases were evaluated with the addition of a liquefaction plant to produce LBG. The cases evaluated were ex-situ biological methanation with CO_2 feed at a co-digestion plant and a WWTP. The evaluation was done for plant sizes between 5 GWh and 160 GWh.

Included in the evaluation is electrolyzer and methanation system, liquefaction unit as well as all operating costs associated with the system. Data and assumptions are presented in Appendix C – Techno-economic data and assumptions.

In addition to the methanation and liquefaction plant, the costs of distribution of the LBG are included. The data is presented in Appendix C – Techno-economic data and assumptions. The result is presented in Figure 25. Profit from LBG production at co-digestion plant with ex-situ biological methanation. Break-even at 50 GWh.Figure 25 and Figure 26.

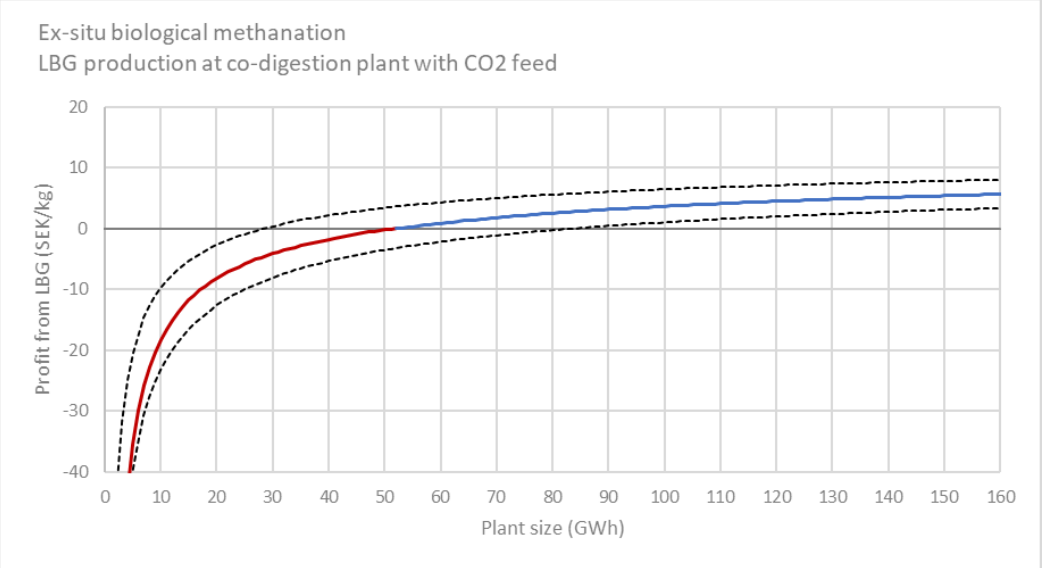

Figure 25. Profit from LBG production at co-digestion plant with ex-situ biological methanation. Break-even at 50 GWh. The dashed lines indicate the result for a CAPEX of 70% and 130%.

The result shows the profit, calculated as the difference between the cost of production and selling price of LBG, at a co-digestion plant as a function of biogas plant size. The sensitivity analysis done account for the 30% uncertainty of the method used to estimate the total cost of the project. The result shows that the investigated configuration of biological methanation and liquefaction breaks even if applied to a plant with size of 50 GWh, (30 – 80 GWh), and earns a profit beyond that size. The same evaluation was done for a WWTP. The result is presented in Figure 26.

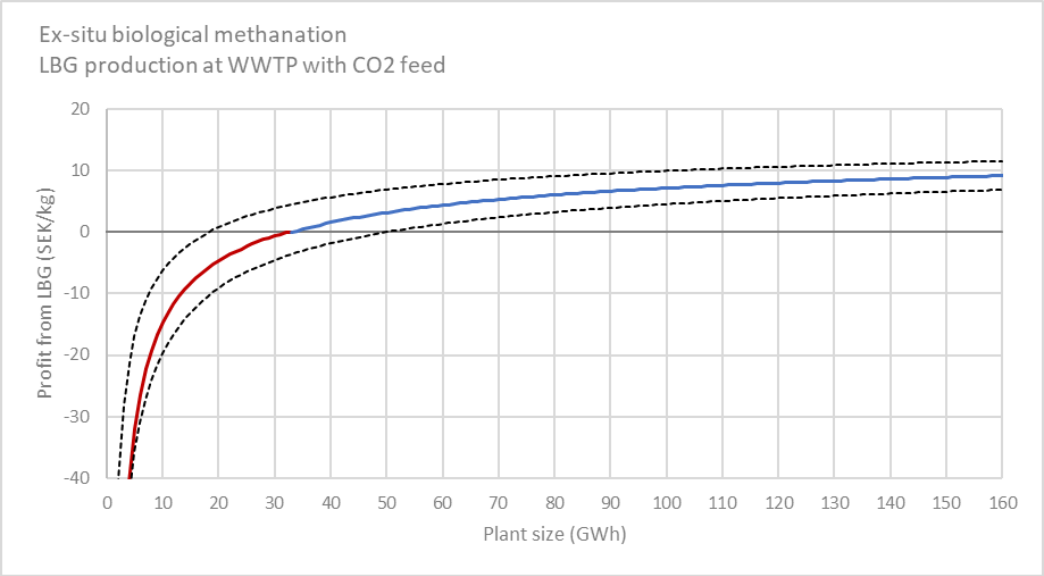

Figure 26. Profit from LBG production at WWTP with ex-situ biological methanation. Break-even at 30 GWh. The dashed lines indicate the result for a CAPEX of 70% and 130%.

According to the result presented in Figure 26 the investigated configuration of biological methanation and liquefaction breaks even if applied to a plant with size of 32 GWh, (19 – 51 GWh), and earns a profit beyond that size.

The result shows that the implementation of ex-situ biological methanation and liquefaction at a biogas plant (WWTP or co-digestion) could be economically feasible at sizes above 50 GWh, and that liquefaction at co-digestion plants in general require larger scale than at a WWTP to be economically feasible. This is a result of the higher potential for heat integration and use of oxygen at the WWTP compared to the co-digestion plants.

It is important to consider that the biogas must have a high methane content (>99%) for liquefaction. Depending on the technology for liquefaction a modified amine scrubber or membrane configuration might be necessary in order to achieve the required purity before liquefaction (92,93). Certain technology providers include the polishing step as part of the liquefaction, while others separate the two steps (94,95). There are also catalytic methanation units that have the possibility to produce liquefaction ready methane (see Chapter 5.3.1). In this work an extra polish step before liquefaction has not been considered.

7 Potential of increase of renewable methane production through methanation

In order to understand how the implementation of methanation technologies could impact the volume of renewable methane produced in Sweden today a number of estimations were made on potential impact. The methanation technologies could increase the total volume of produced biogas in Sweden, depending on for example which size of the biogas plant it is found suitable. The increase of production volume at biogas plants could also mean that economies of scale for a liquefaction plant is achieved at more sites, leading to a possible additional volume of LBG.

7.1 Increased production of renewable methane in Sweden

According to the latest statistics on biomethane production in Sweden in 2023 (23) the total amount of biomethane that was produced in Sweden was 1 542 GWh. This is excluding the amount of biogas that is produced and not upgraded into biomethane quality. The biogas plants that today do not have an upgrading unit have been considered being of smaller size and not likely to install methanation technology.

The theoretical increased production of renewable methane with the use of methanation technologies has been calculated as if all biogas plants with biogas upgrading implemented the new technology. Previous calculations in this project (seeTable 8.

Table 8, Chapter 0 and specifically Chapter 6.3.1) show that the increase in biomethane production at a biogas plant when implementing methanation technology, with given assumptions, would be 61,9%. The total amount of produced renewable methane would then theoretically be increased from about 1 500 GWh to about 2 500 GWh if all of the biogas plants with upgrading facilities would also apply methanation technologies (96).

According to the techno-economical calculations (see Chapter 0), methanation technologies require a certain size of plant to be more viable for the plant owner. For the estimation of increased national biogas production potential, we have assumed

two ranges of sizes as the minimum level for the biogas plant in order for them to be expected to consider implementing methanation technologies, due to economic feasibility. These ranges were defined as 40 and 60 GWh per year (for more information on the characteristics of these sizes see Chapter 6.3.5). What could be considered a suitable level for economic feasibility depends on several factors that will vary for different types of plants; such as size, ownership, business model, development of electricity and biomethane price etc. The plant sizes of at least 40 and 60 GWh per year have been chosen to give an indication of possible increase in production potential for implementation of the methanation technologies.

The calculation of increased biogas production for biogas plants of a size of at least 40 and 60 GWh/year respectively was carried out using a review of current and planned biogas production plants in Sweden. Biogas plants that are in use today and that have a production capacity of at least 40 GWh biomethane per year amount to a volume of about 1 300 GWh per year, with implementation of methanation technology at these sites that would increase to about 2 100 GWh/year (see

Table 12). The corresponding amount for plants with at least 60 GWh per year is about 1 000 GWh/year, or about 1 700 GWh/year using methanation technologies (see

Table 12). This implies that if methanation technology would be implemented in all existing Swedish biogas plants with an existing production volume of at least 40 GWh per year, an additional 800 GWh of renewable methane per year could be produced.

Except existing biogas plants, there are a considerable amount of new biogas production facilities that are under construction or planned during the coming years. This total planned biogas production capacity is estimated to be around 2 300 GWh per year for biogas plants of a production size of at least 40 GWh/year, according to our own compilation through continuous external monitoring (newsletters, official documents such as approved Klimatklivet applications and environmental permits) (see

Table 12). Including both existing and planned biogas production plants, with a production size of at least 40 GWh/year, implementation of methanation technologies could increase the national yearly biogas production with about 2 200 GWh, without the need to exploit more biomasses.

Table 12. Swedish production potential of renewable methane for existing and planned biogas plants with a minimum plant size of 40 and 60 GWh/year respectively, with and without the use of methanation.

	Swedish biomethane production capacity and with minimum plant size (GWh/year)			
	Without methanation		**With methanation**	
	≥ 40GWh/yr	**≥ 60 GWh/yr**	**≥ 40GWh/yr**	**≥ 60 GWh/yr**
Existing biogas plants	1 330	1 050	2 150	1 700
Planned biogas plants	2 260	2 200	3 670	3 560
Sum existing and planned biogas plants	3 590	3 250	5 810	5 260

7.2 Increased possibilities for liquefaction -LBG production

The commercial interest in liquified biomethane is growing due to a growing market and the possibility of transporting it longer distances whilst maintaining economy (3). Most of the biogas plants being planned today therefor include a liquefaction plant. The economies of scale for these technologies are considerable and for that reason they require a certain size in order to be economically viable. The introduction of a methanation plant increases the volume of produced renewable methane and could thereby lead to a possibility for more biogas plants to invest in liquefaction.

Input from commercial stakeholders in the biogas sector (both producers and liquefaction technology providers) has referred to 60 GWh yearly biogas production as a minimum level for introduction of liquefaction technology (97,98). Calculations within the project show that LBG production reaches a break-even level at about 50 GWh per year for a co-digestion plant (see Figure 22). However, considering the economic gain by taking advantage of produced oxygen from electrolyzers in the aerated parts of the water cleaning lines at a WWTP, the calculations show a break-

even level as low as 30 GWh per year for a WWTP (see Figure 23). Wärtsilä's liquefaction equipment, which is an established liquefaction technology, is available with capacities corresponding to approximately 65 and 130 GWh/year respectively (97).

From these input data we assume that the implementation of liquefaction is economically viable from a yearly biomethane production level of at least 60 GWh per year (though for WWTP´s it could be much lower) and choose to base the calculations on this level. When methanation technologies have been implemented, this would lead to liquefaction becoming more viable for more biogas plants, since these plants will increase their yearly methane production. If we look at the present and planned production facilities in Sweden the total production volume in biogas plants larger than 60 GWh amount to a total production of about 3 200 GWh of biogas per year, not including the possibility of methanation. If all biogas plants between 40 and 60 GWh/year would implement methanation technology this would push more biogas plants over the 60 GWh limit for implementation of liquefaction. That would amount to an additional potential of LBG production of about 500 GWh per year.

8 Discussion

The project aimed to understand the possibility to integrate methanation technology at existing biogas plants and to evaluate under which circumstances this could be implemented. The results show that an implementation of methanation technologies enables a considerable increase in biogas production without the need to exploit more biomasses. In view of possible future increased competition on biomass resources an optimized use of these substrates will be an important factor to consider when building the fossil-free societies of the future. The increased production of renewable methane would help to achieve the European goals as well as decrease the domestic dependency on imported biomethane, in line with current discussions on energy security and resilience. The project evaluates the implementation of different methanation solutions on existing biogas plants and does not evaluate the feasibility of establishing a new biogas plant with methanation included.

8.1 Methanation technologies and hydrogen production

There is a large interest in both hydrogen production and methanation technologies and the technology development in both areas is moving forward quickly. The review of the status of technology and reference plants is therefore ongoing and needs to be updated continuously in order to keep track of the current status. There are several technology providers both regarding biological and catalytical methanation processes that have reached a high TRL and that can be considered ready to install at existing biogas plants. However, with a broader implementation of the techniques at biogas plants more knowledge through experiences, improvements and innovations in the area are expected.

A possible advantage with in-situ biological methanation is that there might be a lower threshold to implement it as there is a more limited need for investment in new process units, leading to lower investment costs. The concept of introducing hydrogen in the post-digester, so-called in-situ methanation as planned to do at Tekniska verken in Linköping, seems to be a very interesting solution to easier overcome possible process disturbances connected with the implementation of in-situ biological methanation in the main reactor. In-situ methanation probably also will be more beneficial at plants that want to increase their biogas production without the ambition to use all the carbon dioxide for methanation. For full, or near

to full, conversion of carbon dioxide into methane ex-situ biological methanation or catalytical methanation seems to be a more promising choice.

The hydrogen needed for methanation can be produced through electrolysis of water in an electrolyzer. There are different electrolyzer technologies with the two most mature technologies being PEM and alkaline electrolyzers. The alkaline electrolyzer is more suited to large scale operation and has a lower investment cost compared to the PEM electrolyzer. However, the PEM electrolyzer has a higher electrical efficiency and is more suited to dynamic operation than the alkaline electrolyzer.

The advantage with dynamic or flexible operation of an electrolyzer is that peak electricity prices can be avoided by only running the electrolyzer when the electricity price is sufficiently low to make operation economically feasible. However, flexible operation of the electrolyzer would also require flexible operation of the entire methanation system. To be able to run the methanation system continuously, while at the same time avoiding peak electricity prices, a hydrogen storage that works as a buffer could be used. The downside is that flexible operation with hydrogen storage would require a higher investment, both in the extra hydrogen storage, but also in the electrolyzer. This is due to the fact that the electrolyzer would need to be oversized to be able to meet the methanation systems demand and at the same time produce excess hydrogen during the time when the electricity price is low.

There are advantages and disadvantages with all electrolyzer configurations and the choice between alkaline and PEM electrolyzer and if hydrogen storage should be used or not is therefore something that needs to be evaluated on a case-to-case basis.

8.2 Pre-requisites to achieve economic feasibility

A number of factors impact the economic feasibility of implementing methanation at biogas plants. It is highly dependent on electrolyzer and electricity prices, where the future development for both are very unclear. Up until recently it has been suggested that capital costs for electrolyzers will decrease in coming years. However current discussions infer that this might not be the case and that the cost of these technology will continue to be high. Furthermore, the possibility of

utilizing waste heat from the catalytical methanation reactor and electrolyzer, as well as the oxygen from the electrolysis, has a significant impact on the economic feasibility. WWTP could be particularly interesting for methanation technologies since there is a possible use for oxygen and probable use of excess heat. Identifying a possible use of excess heat can be simplified if the plant is located nearby a district heating system or a stakeholder or process with a heating demand. For plants located in remote areas this could therefore be a challenge.

Six different cases have been used in the project to show the difference in cost- and energy efficiency. These are catalytical and ex-situ biological methanation with either raw biogas or a concentrated CO_2-feed, at either co-digestion or wastewater treatment plant. The calculations show lower cost and higher energy efficiency in all calculated cases for catalytic methanation; however, all the cases are within the uncertainty level of the calculations. For the cases with ex-situ biological methanation also a technique with a stirred reactor (CSTR) has been chosen, for which the energy consumption for stirring is relatively high. This was done based on our availability of data. Doing the same calculations with data for example for a trickled bed or fixed bed reactor type could have given values more similar to what was achieved for the catalytic methanation. It has to however be remembered that what was made in the project concerning techno economical aspects needs to be seen as an early pre-study evaluation and should not at this stage solely be used for the selection of the most promising methanation technique. Possibly the future will show that what is most beneficial will vary for each specific plant.

The energy efficiency and, as a result, the economic performance of the catalytic methanation is partly due to the heat integration possibilities related to the technology. Catalytic methanation occurs at higher temperatures than biological methanation. This results in higher quality waste heat which in turn enables higher degrees of heat integration. In current work, the assumption was made that the existing biogas plant had an amine scrubber that could utilize some of the high temperature waste heat. The excess waste heat was thereafter used to produce district heating. However, if there is no offset for the waste heat it instead requires cooling, which would result in an extra cost instead of an extra revenue. The catalytic methanation's economic viability is therefore partly dependent on the possibility of heat integration. Furthermore, the low temperature waste heat from the biological methanation could also be integrated with the district heating system with the use of a heat pump.

8.3 Possible replacement of upgrading unit

It would be attractive from an economic point of view to be able to replace today's upgrading units with methanation technology instead, since investment and operating costs would then only be incurred for one of these plant parts. Such a replacement has however not been seen for the few full-scale methanation plants that have been established up until now and will most likely be considered first after more time of proof of concept of the technique. The major challenge with being able to replace the upgrading unit with methanation is considered to be that it is dependent on available cheap green hydrogen. This would be produced from intermittent solar and wind-based electricity and hydrogen storage, that then would be necessary, is expensive. However, calculations in the project based on electricity prices for 1 year (SE3 during 2023-2024) show that even a rather small hydrogen storage corresponding to 17 hours of storage volume could be sufficient to achieve continuous operation of a methanation step at the same time as giving optimal cost efficiency in comparison with no or bigger hydrogen storage. Even though the hydrogen storage, under current assumptions, resulted in the optimal production cost, it still requires a larger investment in both hydrogen storage and an oversized electrolyzer. A higher investment could in turn mean a higher risk.

The technical review also shows that by applying biological or catalytical methanation technologies high enough methane concentration can be reached to achieve the right quality of the methane. The project therefore indicates that ex-situ methanation techniques could possibly replace the need for having an upgrading unit. It does not seem likely though that by applying in-situ biological methanation, methane quality could be stably achieved without having a complementary upgrading plant due to biochemical pre-requisites in the anaerobic digestion process. The calculations made in the project will be needed to be deepened to look further into the possibilities of replacing the up-grading unit, with for example analysis of dependence on electricity price and variation in electricity availability as the estimation only is based on electricity price for electricity area 3 in Sweden (SE3) during one specific year.

In addition, if the methane should be liquefied, the methane purity must be >99. Most methanation technologies does not produce methane with purity that meets the demand required for liquefaction. Depending on the chosen liquefaction technology, an extra cost might be incurred on top of the liquefaction plant to polish the methane before liquefaction. There are technology providers that offer liquefaction solutions that also includes the polish step. However, these solutions are aimed at small scale production of LBG.

8.4 Carbon dioxide as a commodity

In the up-coming market for trading of so called green-CO_2, Danish biogas stakeholder have already identified methanation as a competitor in accessing carbon dioxide for long-term storage in CCS (99). There are also other potential buyers of carbon dioxide, for example methanol-producers. How the market for carbon dioxide will develop, and how well methanation will compete with other potential uses of carbon dioxide, is still unclear.

8.5 Policy instruments

In order to achieve economic feasibility, the introduction of policy instruments and financial support could be considered to support the development. A support scheme, the methanation support, could be an alternative similar to the current support scheme for biogas from manure or for liquefaction. At what level this support should be in order to have an impact on the market needs to be evaluated further. Other support measures that steer the development towards a higher level of resource utilization could also be explored, since this will be a necessity if the existing biomass is to meet the increasing demand of renewable resources.

The revised Renewable Energy Directive (RED III) imposes an obligation of ensuring that share of energy from renewable sources (RES) in the gross final consumption 2030 in EU is 42.5% (100). Additionally, targets were set for different sectors such as transport. In the transport sector the revised RED III gives the option to either reduce GHG emission intensity by 14.5% until 2030 or have a 29% share of renewables in the final energy consumption by 2030. An additional sub-target for 2030 of 5.5% of advanced biofuels and renewable fuels of non-biological origins (RFNBOs) were set for the transport sector. A sub-sub-target of 1% RFNBO (e.g. e-methane) for the transport sector until 2030 was also set. In order to aid in the compliance with the targets a multiplier for RFNBOs was established for calculations of energy content towards the target. The requirement of at least 1% of RFNBO in the transport sector entails that e-methane will compete with other electrofuels such as e-methanol and e-ammonia. The production price of e-methane should therefore not only be compared to biomethane, but also to the production cost of other RFNBOs.

8.6 Environmental assessment

From an environmental perspective integration of methanation process contributes to resource efficiency by utilizing the biogenic carbon dioxide and increasing the produced methane with about 62%. In addition to increased resource efficiency the additionally produced e-methane can replace the use of natural gas and other fossil fuels reducing GHG emissions. The process can thereby be seen as a measure to reduce climate impact. The project has calculated the levelized cost of avoided carbon dioxide. Calculations show that the cost lies between 114 EUR/t CO_2 and 830 EUR/t CO_2 depending on the renewable methane price for co-digestion plants and between 39 EUR/t CO_2 and 770 EUR/t CO_2 for wastewater treatment plants. The lowest costs are achieved with catalytic methanation with CO_2 feed and the highest for biological methanation with biogas feed. The size of the plant impacts the cost, with lower production costs at larger plants. The nature of the investigated methanation technologies is such that they are not expected to have a large effect on other environmental parameters, so other potential impacts have not been investigated further. A broader environmental assessment such as a life cycle assessment (LCA) should be done which could include a deeper investigation on climate impact from electricity supply, material and upstream processes. Also, other social and environmental impacts could be included in the LCA. This since the electrolysis technologies also consists of several rare earth elements (Ce, Ga, La, Sc, Yt), several critical metals (Ta, V, Sr, Ba, Al) and strategic metals (PGM, Co, Ni, B, Mg, several others) for which extraction of metals relates to both social and environmental impacts (101). In addition to this, the production of hydrogen through electrolysis is very dependent on availability of considerable amounts of water. Therefore, the selection of water supply, with adaptation to local conditions, is of uttermost importance for a sustainable implementation and water management.

8.7 Safety aspects of hydrogen

Hydrogen is a highly explosive gas and knowledge and safety measures for its handling are essential for methanation technology to be safely implemented at biogas plants. Energigas Sverige is currently working together with stakeholders within the industry to develop instructions on safe production of hydrogen gas through electrolysis and they are expected to be published in about a years' time (102). Risk assessments and risk analysis, where distance issues play a major role, are essential. Documents and works like this are considered important to create security for biogas plants that want to implement methanation technologies at their facilities.

The current evaluation on safety aspects of hydrogen might show that more investments are necessary in order for the basic safety requirements to be fulfilled. This would increase the investment costs for methanation technologies. This would need to be investigated further when these guidelines are in place.

9 Conclusion

The following conclusion have been drawn from the project:

- The project indicates that it may be particularly advantageous to install methanation technology on digestion plants at wastewater treatment plants. This is because the oxygen produced in the electrolyzers can be used in the aerated water treatment basins and can significantly reduce the treatment plant's electricity consumption. Excess heat from electrolyzers and potentially catalytic methanation can more easily find a use at wastewater treatment plants since they often are located in close proximity to urban areas. In co-digestion plants, there is no use of excess oxygen, and even if excess heat from, for example, electrolyzers can be used for hygienization and heating of digesters, a large amount of heat remains, and due to that these plants commonly have a more remote location, it may be more challenging to find a suitable use.

- The project indicates that ex-situ methanation techniques possibly could replace the need for having an upgrading unit in the future. It does however not seem likely that the right methane quality could be stably achieved by applying in-situ biological methanation without having a complementary upgrading plant, due to biochemical pre-requisites in the anaerobic digestion process.

- The techno economic evaluation indicates that hydrogen storage to avoid peak electricity prices could be economically feasible. However, the economic feasibility is dependent on several parameters such as electricity zones (so called bidding areas), plant size, methanation technology, electrolyzer technology, and heat integration possibilities. It is therefore important to evaluate the techno economic feasibility from case to case.

- The methane produced through methanation is e-methane. The requirement from the revised RED III of at least 1% of RFNBO in the transport sector entails that e-methane will compete with other electrofuels such as e-methanol and e-ammonia. The production price of e-methane should therefore not only be compared to biomethane, but also to the production cost of other RFNBOs.

- The techno economic assessment indicates that the CBG-price, at which implementation of methanation is economically feasible compared to conventional CCS, is between 13 – 16 SEK/kgCH_4 at 120 GWh biogas plants, 15

– 18 SEK/kg at 70 GWh biogas plants, and 21 – 24 SEK/kg at 20 GWh biogas plants.

- The investment cost per reduced tonne CO_2 ranges from 441 – 516 EUR/tCO_2 for methanation systems suited for 20 GWh biogas plants. For methanation at biogas plants with the size of 120 GWh the cost per reduced tonne CO_2 is between 274 – 314 EUR/tCO_2.

- The levelized production cost of CBG for the evaluated technologies ranges from 23.6 – 26.1 SEK/kgCH_4 at biogas plants of 20 GWh and 16.0 – 18.8 SEK/kgCH_4 at biogas plants of 120 GWh.

- By implementing methanation at a biogas plant the methane production is calculated to increase with about 62 %, without the need to exploit more biomass.

- There are technology providers, both regarding biological and catalytical methanation, with equipment ready for installation at biogas plants. Nevertheless, it must be considered this still is an early emerging market for these technologies. There is a big interest but until now only a limited number of full-scale installations of the technique have been established.

- There is a minimum size of biogas plant, where implementation of methanation could be economically feasible, and with made assumptions in the project that is about a yearly production of 40 GWh.

- The different techno economical cases analyzed all show a better performance regarding cost- and energy- efficiency for catalytical methanation compared to ex-situ biological methanation. However, all cases are within the margin of error for the calculations.

- Including both existing and in the near future planned biogas production plants, with a production size of at least 40 GWh/year, implementation of methanation technologies could increase the national yearly biogas production with about 2 200 GWh. This can be compared to the total amount of biogas that is produced in Sweden today, 2 300 GWh.

- By the implementation of methanation technique at Swedish biogas plants more plants would achieve economy of scale to make implementation of liquefaction equipment economically viable. Then liquefied biogas will be more transportable and be available for broader use, for example as marine fuel, fuel

for heavy trucks and different industrial applications. Calculations made in the project estimate an additional potential of LBG production of about 500 GWh per year by this economy of scale effect, based on present and in the near future planned biogas production facilities in Sweden.

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11 Appendices

11.1 Appendix A – Lang factors

Table A1. Lang factors presented as % of CAPEX used to calculated investment cost of the project (11).

Item	**Lang factor**
Engineering	15%
Material and civil engineering	20%
Assembly of main components	15%
Process control technology	40%
Electrical engineering	20%
Other costs	27%
Total	137%
CAPEX	100%
Lang factor	237%

11.2 Appendix B – Methanation system scaling factors

Table B1. Cost shares and scaling factor for methanation systems (11).

Item	Biological methanation		Catalytic methanation	
Specific cost (EUR2024/kW$_{CH4}$)	601/928[a]		639	
	Cost shares	Scaling factor	Cost shares	Scaling factor
Reactor	13%	0.51	20%	0.68
Reactor	77%	0.50	54%	0.56
Heat management	23%	0.56	16%	0.59
Catalyst[b]	n/a	n/a	30%	1
Electric installation	24%	0.75	18%	0.75
Gas conditioning	21%	0.60	21%	0.60
Balance of Plant	42%	0.67	42%	0.67

a) If raw gas is used as the feed instead of CO_2 the system cost increases due to the increased gas flow.

b) The catalyst is included in the investment cost instead of the operating cost.

Table B2. Cost shares and scaling factor for electrolyzer systems (11,12).

Item	PEM electrolyzer	
Specific cost (EUR2024/kW)	1 600	
	Cost shares	Scaling factor
Stack	42%	0.89
Power electronics	21%	0.75
Gas conditioning	22%	0.60
Balance of Plant	15%	0.73

11.3 Appendix C – Techno-economic data and assumptions

Table C1. Techno-economic data and assumptions used in techno-economic assessment.

Item	Data/assumption	Unit	Comment	Source
Methanation system				
Fixed operating cost	10%	of system CAPEX	Operating and maintenance	(11)
Electricity demand of agitator and compressor	10%	of electrolyzer electricity consumption	Only biological methanation system.	(a)
Electrolyzer				
Electrolyzer lifetime	60 000	h/year		Table 2
Stack degradation	1% per year	per year		Table 2
Electrolyzer efficiency	67%			Table 2
Fixed OPEX	2% of electrolyzer CAPEX	of electrolyzer CAPEX		(11)
Stack replacement	50% of electrolyzer CAPEX	of electrolyzer CAPEX		(12)
Waste heat recovery efficiency	90%			(82)
Specific water cost	0.077 EUR/kgH_2	EUR/kgH_2		(12)
Hydrogen storage				

Specific CAPEX	416	EUR/kgH_2		(13)
Specific energy consumption	0.9	kWh/kgH_2		(13)
Desulphurization				
Reference CAPEX	463 000	EUR	For a capacity of 327 m^3 CO_2/h	(14)
Scaling factor	0.6			(8)
OPEX	5.8%	of unit CAPEX		(14)
Compressor				
Size parameter (S)	Driver power	kW	$Cost = a + bS^n$	(8)
a	260 000		Cost constant	
b	2 700		Cost constant	
n	0.75		Scaling factor	
Liquefaction				
Specific CAPEX	Personal communication			(a)
Scaling factor	0.38			(b)
Fixed OPEX	3%	of liquefaction plant CAPEX		(104)
Specific electricity consumption	Personal communication	kWh/kg LBG		(a)

a) Personal communication

b) Calculated

Table C2. Economic parameters used for techno-economic assessment (8).

Parameter	Value	Comment
Discount rate	8%	
Yearly price increase	2%	
Working capital	15% of total project cost	Returned at end of plant lifetime
Depreciation rate	5% per year	Straight line method
Plant lifetime	20 years	
Plant availability	92%	

Table C3. Price data used in techno-economic assessment.

Item	Value	Comment
Electricity spot price	50 EUR/MWh	Average in SE3 from 2023 – 2024 (15).
District heating	23.50 EUR/MWh	From personal communication
Biomass	31.9 EUR/MWh	(105)

Table C4. Assumptions regarding existing co-digestion plant and wastewater treatment plant used for techno-economic assessment.

Item	Value	Reference
Energy demand – Anaerobic digester	13% of produced biogas energy content	(106)

Biomass boiler energy efficiency	80%	(107)
Amine scrubber energy demand	3 MJ/kg removed CO_2	(108)
WWTP energy demand	0.5 kWh/m^3 treated water	(109)
Amount of energy demand for aeration	50%	(110)
Oxygen demand	0.06 Nm^3/pe/day	Personal communication

Table C5. Data used for estimation of cost of LBG distribution.

Item	Unit	Value	Source
Reference size: Filling station	GWh LBG	30	(111)
Reference investment: Filling station	EUR	2 400 000	(111)
O&M: Filling station	EUR/GWh LBG	4 363	(111)
Electricity consumption	kWh/GWh LBG	100	(111)
Transport distance (incl. return):	km/trip	200	(111)
Average speed	km/h	60	(111)
Distribution cost (truck + driver)	EUR/h	131	(111)
Truck capacity	tonnes	30	(111)
LBG selling price	SEK/kg	28.99	(112)

11.4 Appendix D – Catalytic methanation reference plants

Table 13. Catalytic methanation reference plants. For more reference plants and planned methanation plants, see EBA report – Mapping e-methane plants and technologies.

Provider	Location	Year	Feed gas	Gas source	Reactor (pressure, temperature)	TRL	E-methane production	Product gas quality (CH_4 content)	Electrolyzer	Ref
Karlsruhe Institute of Technology (KIT)	Karlsruhe, Germany	2019 -	Syngas/ CO_2	Biomass gasification	Slurry bubble column, 3PM (20 bar, 330°C)	5-6	100 kW	-	-	(113)
Karlsruhe Institute of Technology (KIT)	Köping, Sweden	2018	Syngas/ CO_2	Biomass gasification	Honeycomb fixed bed (-,-)	5-6	100 kW	Further CO_2 separation required	-	(114,115)
Uniper and partners of Store&Go project	Falkenhagen, Germany	2019	CO_2	Bioethanol plant	Honeycomb and fixed bed polishing in series	7	576 kW	> 99 vol.-%	Alkaline, 1 MW	(116)
Paul Scherrer Institut (PSI)	Güssing, Austria	2009	Syngas	Biomass gasification	Bubbling fluidized bed	7	1000 kW	-	-	(117)

Paul Scherrer Institut (PSI)	Zürich, Austria	2019	Raw biogas	WWTP/Biowaste digestion	Bubbling fluidized bed (6 bar, 280-360°C)	5	1.4-2.3 Nm^3/h	87 vol% CH_4, but 97 % after upgrading	-	(118)
Kanadevia Inova (Etogas)	Werlte, Germany	2013	CO_2	Co-digestion	EPC delivery of entire plant	9	325 Nm^3/h	92 %	Alkaline, 6.3 MW	(119,120)
Kanadevia Inova / Kanadevia Corporation	Nagaoka, Japan	2019	CO_2	From bottles	Shell and tube type	7	≤10 Nm^3/h		PEM 200kW	(120)
Kanadevia Inova	Gabersdorf, Austria	2022	Raw biogas	Co-digestion	Fixed bed plate-type (9 bar, -)	7 (pre-industrial scale)	≤ 10 Nm^3/h	>90%	Installed PEM 1 MW, 200kW is used for methanation	(120,121)
Kanadevia Inova / Kanadevia Corporation	Yokohama, Japan	2022	CO_2	From bottles	Shell and tube type	7	≤ 12.5 Nm^3/h	97-99.8%	Installed PEM 2 MW, 250kW is used for methanation	(120)
Kanadevia Inova / Kanadevia Corporation	Odawara, Japan	2022	CO_2	CO_2 provided by Carbon Capture from Waste-to-	Shell and tube type	9	≤ 125 Nm^3/h	[-]	[-]	(120)

Haldor Topsoe	Foulum, Denmark	2013	Biogas	Co-digestion	Two cooled fixed bed in series with intermediate condensation (20 bar, 280-680°C)	5	4 Nm^3/h	94.6 %, but 97.9% CH_4, <2% H_2 after upgrading	-	(75)
Aarhus University	Heden, Denmark	2017	Biogas		Fixed bed with intermediate cooling (8 bar, 270-550°C)	5-6	10 Nm^3/h,0.25 MW	94-96 vol-% CH_4	Alkaline, 16Nm3/h	(122)
Ineratec GmbH	Sabadell, Spain	2018	Biogas	WWTP	Two microstructured heat exchange reactors in series with intermediate condensation	5	15.4 kW	72.7 % after first reactor, 93%, <5% H_2 after second reactor (upgrading)	Alkaline 37 kWh_e	(123)

11.5 Appendix E – Biological methanation reference plants

Table E1. Biological methanation reference plants. For more reference plants and planned methanation plants, see EBA report – Mapping e-methane plants and technologies (124).

Provider	Location	Year	Feed gas	Gas source	Reactor/Culture	TRL	E-methane production	Product gas quality (CH_4 content)	Electrolyzer	Ref
PFI	Pirmasens-Winzeln Energy Park	2015 (active)	Biogas	Biogas plant	-	-	-	-	-	(124)
Kanadevia INOVA (Microbenergy)	Allendorf, Germany	2013	Raw biogas, CO_2	Biogas plant	BiON® anaerobic technology -stirred reactor	7 (industrial pilot scale)	15 m^3/h	> 96 vol.-%	PEM 0.3 MWe	(120,125)
Kanadevia INOVA (Microbenergy)	Dietikon, Switzerland	2022	Raw biogas	WWTP	BiON® anaerobic technology -stirred reactor	9	100 Nm^3/h	>96 vol%, <2 vol% H_2, <5 vol% CO_2, <5 mg/Nm^3 H2S	PEM 2.5 MWe	(120,126)
Kanadevia INOVA (Microbenergy)	Goldenstedt, Germany	2023	Syngas (CO_2, H_2)	Pyrolysis process	BiON® anaerobic technology -stirred reactor	6	2 Nm^3/h	>96 vol%,	No using pyrolysis process	(120)

Electrochaea GmbH (BioCat)	Avedøre, Denmark	2016	Biogas	WWTP	Stirred reactor / Pure	7	50 Nm^3/h	> 97 vol.-%	1 MWe	(125,127)
Electrochaea GmbH (Store&Go-project)	Solothurn, Switzerland	2019	CO_2	WWTP	Stirred bubble column / Pure	7 (industrial pilot scale)	326 kW	> 96 vol.-%	PEM, 0.7 MWe	(116,127)
Electrochaea GmbH	Roslev, Denmark		CO_2/Biogas	Biogas	Stirred bubble column / Pure	9	500 Nm^3/h	100 %	12 MWe	(127)
Electrochaea GmbH (ongoing project - Design package together with Baker Hughes)	TBD		CO_2	TBD	Stirred bubble column / Pure	9	3 750 Nm^3/h	100%	3x25 MWe	(127)
Micropyros (BioFarm)	Straubing, Germany	2023	Biogas	WWTP	Stirred reactor / Mixed	6-7 (R&D facility)	1 Nm^3/h	>96 %	AEMWE, 20 kW	(128,129)
Micropyros (SynBioS)	Bologna, Italy	2025	Biogas	WWTP	Stirred reactor / Mixed	7 (industrial pilot scale)	50 Nm^3/h	>96 %	PEM, 1 MWe	(129)

GICON	Cottbus, Germany	2017-today	CO_2	Bottle	Trickle bed reactor Mixed	5-6 (large scale research facility)	2,6 kW	>95% CH_4	no	(130)
GICON (Cométha)	Paris, France	2017-today	Syngas	Gasification	Trickle bed reactor Mixed	5-6	1 kW	>95% CH_4	no	(130)
GICON (WeMetBio2)	Nordhack-stedt, Germany	2024-2026	Biogas	Biogas plant	Trickle bed reactor	7-8	220 kW	>95% CH_4	no	(130,131)
Q Power Oy	Harjavalta, Finland	2025	CO_2		Solid State Reactor / Mixed	9			20 MWe (some of the H2 to methanation)	(132)
Biogasclean A/S	Denmark	2021-2022	Biogas	Co-digestion	Trickle bed co-current / Mixed	6-7 (pilot)	20 Nm^3/day	>95% CH_4	Pilot scale alkaline electrolyzer	(133)
Biogasclean A/S	Denmark	2023-2024	Biogas	WWTP	Trickle bed co-current / Mixed	6-7 (pilot)	20 Nm^3/day	>95% CH_4	Hydrogen batteries	(133)
Biogasclean A/S	Glansager, Denmark	2022-now	Biogas	Co-digestion	Trickle bed co-current / Mixed	9	381 Nm^3/h (34 GWh/y)	>95% CH_4	Alkaline, 7.5 MWe	(133)
Biogasclean A/S	Spain	2025	Biogas	Co-digestion	Trickle bed co-current / Mixed	9	20 Nm^3/day	>95% CH_4	Hydrogen batteries	(133)

Enosis	Èpinal, France	2018	CO_2	AD	-	-	-	-	Alkaline, 0.05 MWe	(124)
Enosis	Toulouse, France	2022	CO_2, CO	Gasification	-	-	-	-	-	(124)
Enosis	Lesquilles Saint-Germain France	2024 (under constr uction)	CO_2	AD	-	-	-	-	-	(124)

11.6 Appendix F – Sensitivity analysis: Effect of electricity price on levelized cost of production

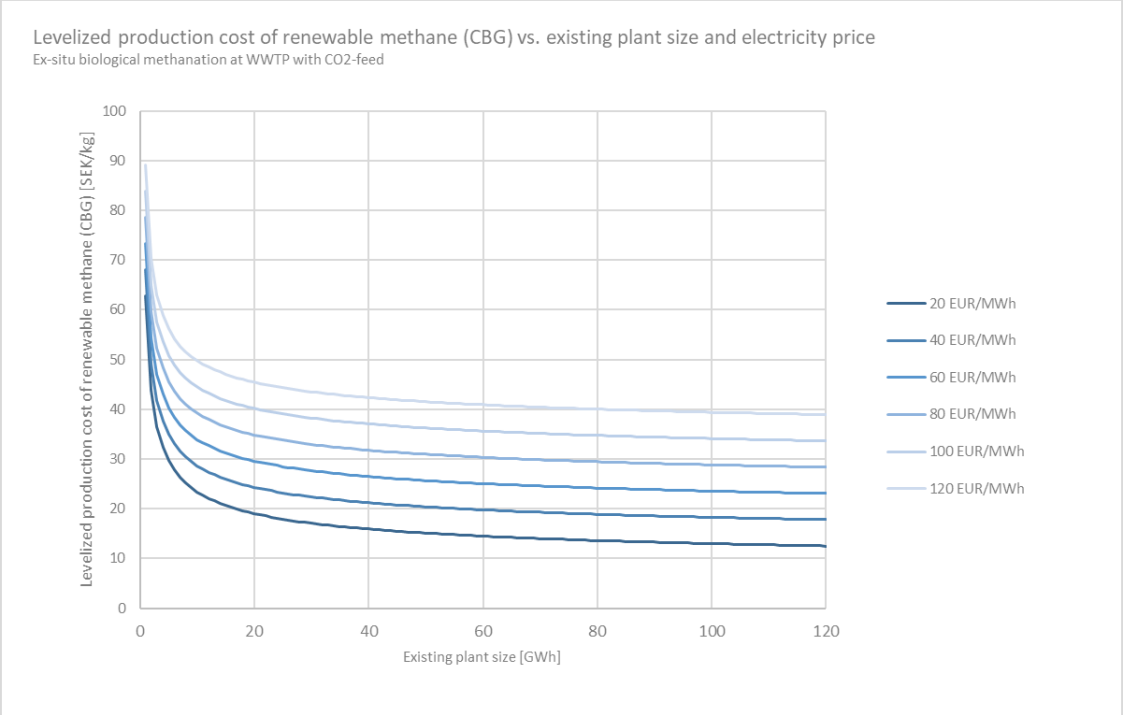

Figure 27. Effect of biogas plant size and electricity price on levelized production cost of renewable methane (CBG) at WWTP with ex-situ biological methanation with CO_2- feed. The production cost does not include possible revenue from carbon credits.

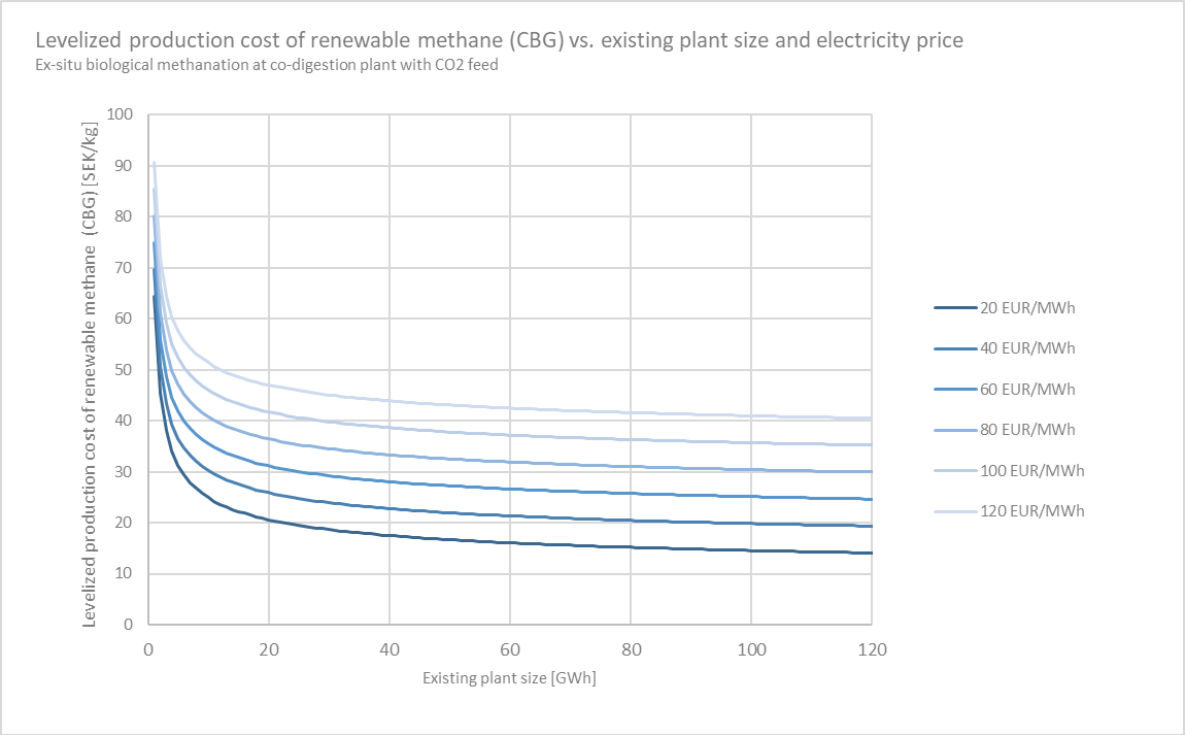

Figure 28. Effect of biogas plant size and electricity price on levelized production cost of renewable methane (CBG) at co-digestion plant with ex-situ biological methanation with CO_2- feed. The production cost does not include possible revenue from carbon credits.

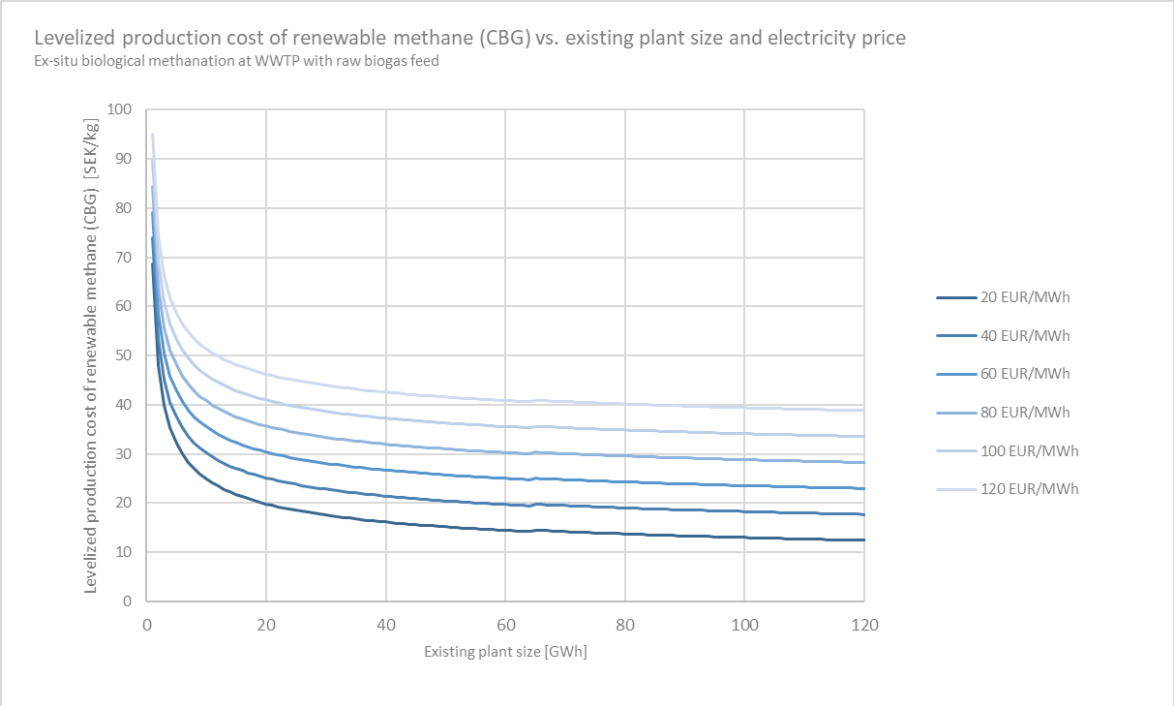

Figure 29. Effect of biogas plant size and electricity price on levelized production cost of renewable methane (CBG) at WWTP with ex-situ biological methanation with raw biogas feed. The production cost does not include possible revenue from carbon credits.

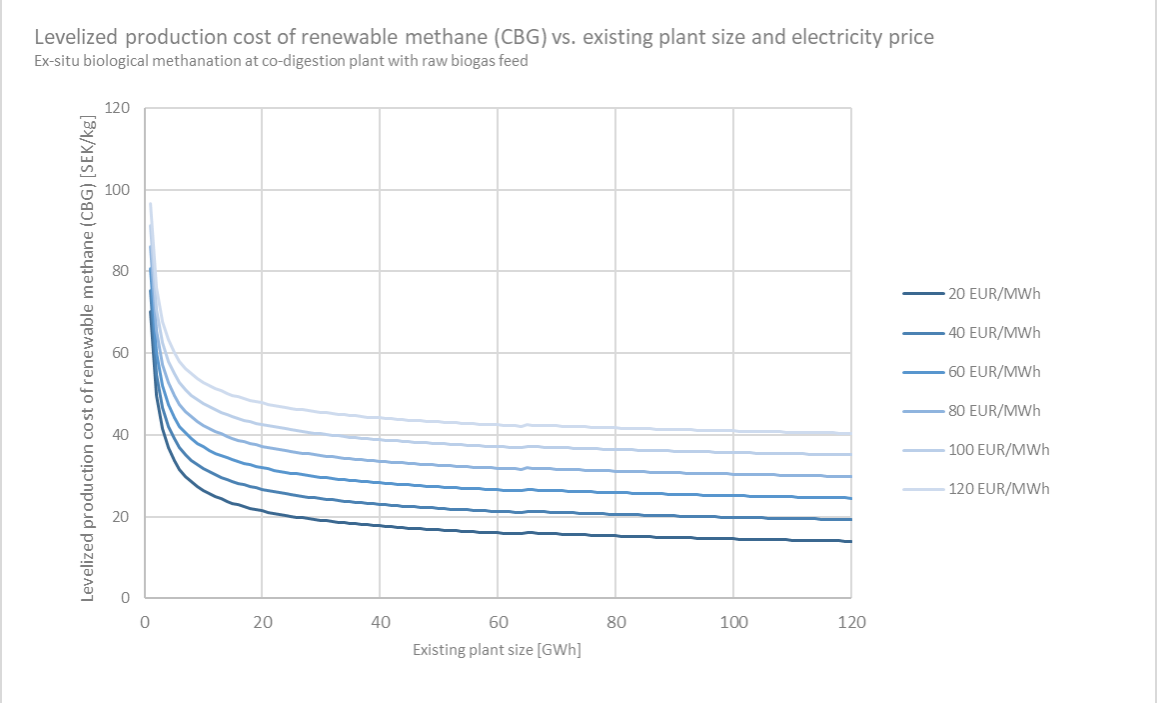

Figure 30. Effect of biogas plant size and electricity price on levelized production cost of renewable methane (CBG) at co-digestion plant with ex-situ biological methanation with raw biogas feed. The production cost does not include possible revenue from carbon credits.

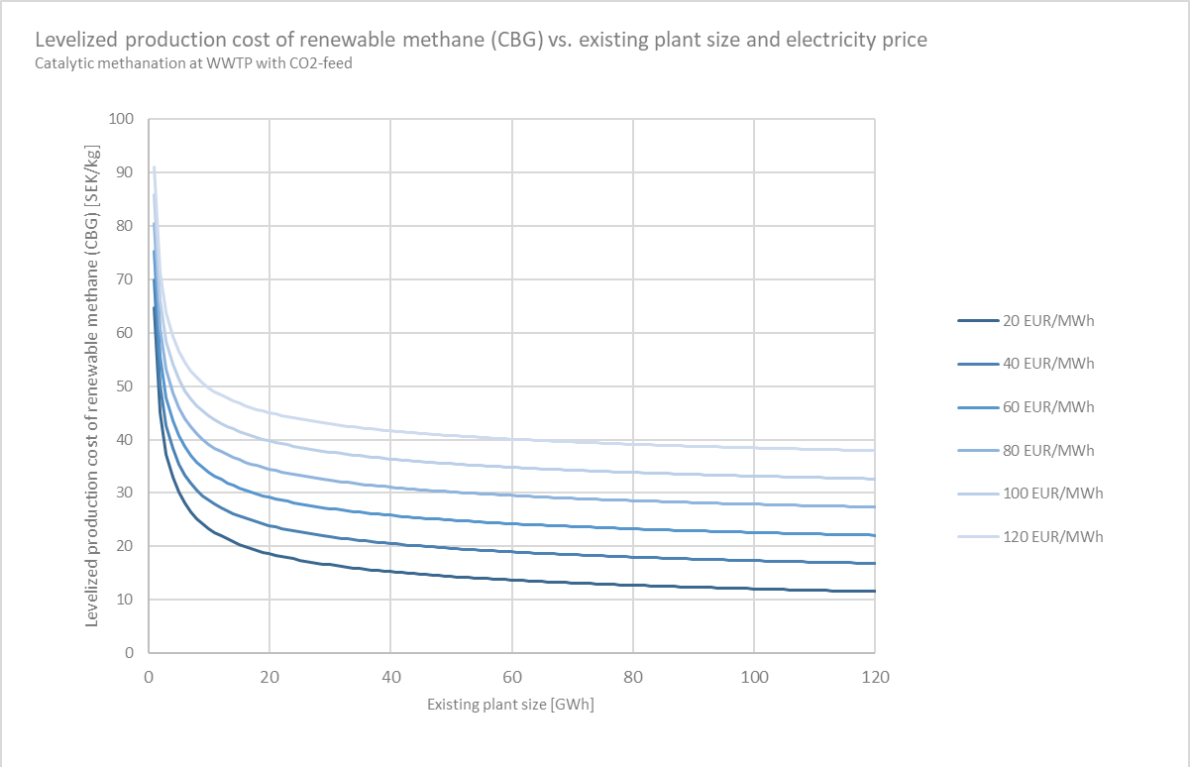

Figure 31. Effect of biogas plant size and electricity price on levelized production cost of renewable methane (CBG) at WWTP with catalytic methanation with CO2-feed. The production cost does not include possible revenue from carbon credits.

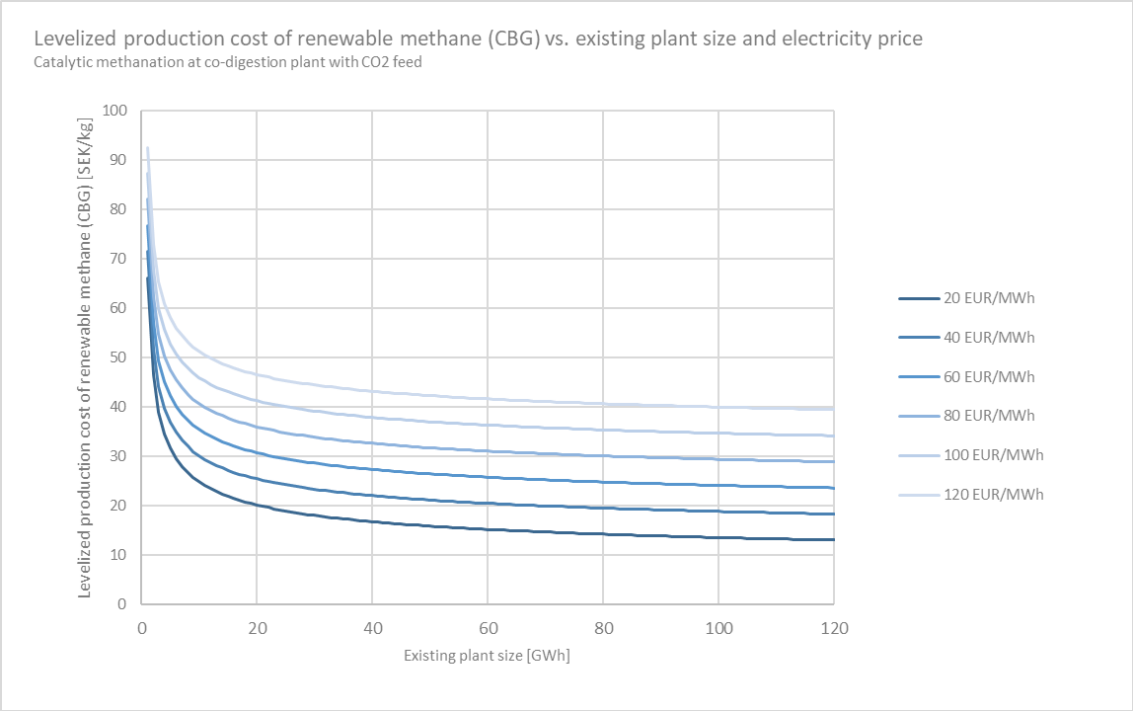

Figure 32. Effect of biogas plant size and electricity price on levelized production cost of renewable methane at co-digestion plant with catalytic methanation with CO2-feed. The production cost does not include possible revenue from carbon credits.

11.7 Appendix G – Cost of avoided CO_2

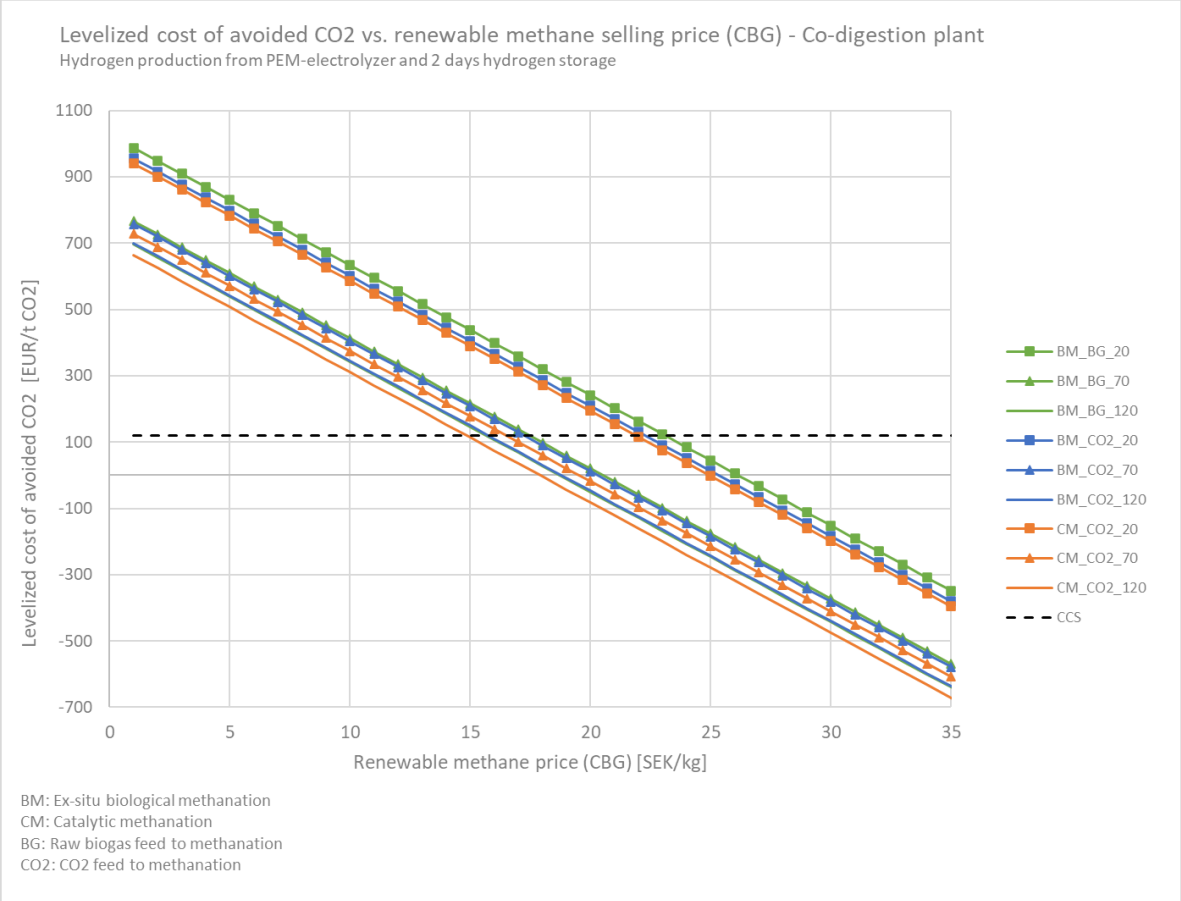

Figure 33. Cost of avoided CO2 vs. renewable methane selling price (CBG) presented for each methanation technology: biological methanation with raw biogas feed (green lines), biological methanation with CO2 feed (blue lines), and catalytic methanation with CO2 feed (orange lines). Each technology is evaluated for implementation at a co-digestion plant of 20 GWh (squares), 70 GWh (triangles), and 120 GWh (no marker), and compared to the average cost of CCS (black, dashes line).

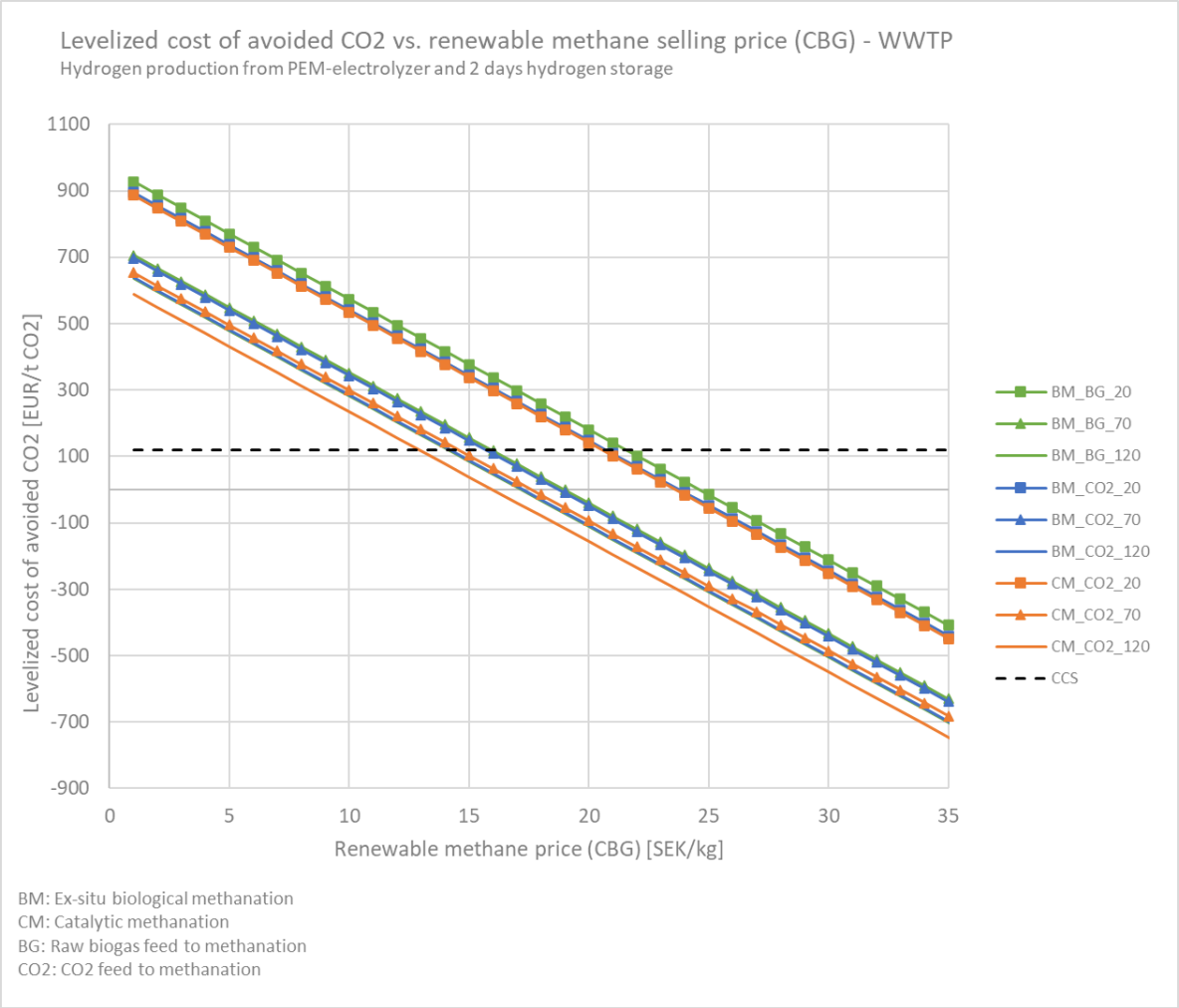

Figure 34. Cost of avoided CO2 vs. renewable methane selling price (CBG) presented for each methanation technology: biological methanation with raw biogas feed (green lines), biological methanation with CO2 feed (blue lines), and catalytic methanation with CO2 feed (orange lines). Each technology is evaluated for implementation at a WWTP of 20 GWh (squares), 70 GWh (triangles), and 120 GWh (no marker), and compared to the average cost of CCS (black, dashes line).

11.8 Appendix H – Technology providers

Table 14. Summary of technologies from technology providers presented in Section 5.3.

Technology provider	Methanation technology	Reactor type	Feed gas	Opearting conditions	Methane output	Comments
Kanadevia INOVA / Kanadevia Corporation	Catalytic	Fixed bed plate-type / shell and tube type	Raw biogas, sewer gas, syngas, CO_2 and H_2	7-9 bar 200-250 °C	>96 CH_4 (gas purification as add-on)	• Wide operating range and fast load changes • Compact and simple design • High conversion rate and reaction selectivity • Good temperature control and production of high-pressure steam
Haldor Topsøe	Catalytic	Adiabatic fixed-bed	Syngas	250-700°C	94-98% CH_4	• Superheated steam production.
MAN Energy Solutions	Catalytic	Isothermal	Raw biogas, CO_2 and H_2	20 bar	Standard: >95% CH_4, <2% CO_2, <3% H_2 Liquefaction-ready: >98% CH_4, <50 ppm CO_2, <3% H_2	• Produces both high- and low-pressure steam.
AlphaSYNT	Catalytic	Fluidized bed	Raw biogas, CO_2 and H_2		~97% CH_4	

Kanadevia INOVA / Kanadevia Corporation	Biological	Stirred tank reactor	Raw biogas, sewer gas, pyrolysis gas, CO_2 and H_2	6-10 bar 65°C	>96 CH_4 (gas purification as add-on)	• Very dynamic plant operation • High tolerance to trace gases in feed gas • Process & plant design scalable • High methane concentration
Q Power	Biological	Solid-state	CO_2 and H_2	50-70°C	97% CH_4	• Modular design • No need for mixing, pressurizing or constant fluid pumping
GICON	Biological	Trickle-bed	Raw biogas, CO_2 and H_2	55-65°C	>95% CH_4	
Electrochaea	Biological	Stirred	Raw biogas, landfill gas, CO_2 and H_2	1-10 bar 60-65°C	97-100% CH_4	• Modular system • Allows for flexible operation • Tolerant to oxygen, H_2S, CO, Sulfate, Ammonia, and particulates
Biogasclean	Biological	Trickle-bed	Raw biogas, CO_2 and H_2	< 200 mbar < 80°C	97-98% CH_4	• Tolerant to sulfur and other impurities
Micropyros	Biological	Stirred tank	Raw biogas	6-10 bar up to 90°C	>96% CH_4	

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This report has been reviewed and approved in accordance with IVL's audit and approval management system.