Dissertation

Economic and environmental assessment of CO_2-derived and biomass-based gases

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by

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Abstract

This thesis presents a comprehensive analysis of the economic feasibility and emission reduction potential of renewable methane production derived from biomass resources and carbon dioxide (CO_2). The motivation lies within the broader context of greenhouse gas emission reduction and investigates the integration of renewable gases, namely biomethane, bio-synthetic natural gas (bio-SNG) and e-methane, into the energy system. Through a combination of techno-economic assessment, greenhouse gas emission balances and regional energy system modelling, the thesis evaluates the role of these gases as strategic components in the transition toward a defossilised energy system.

The analysis demonstrates that small-scale synthetic methane production using CO_2 from biomass-based processes, while technically feasible, remains economically challenging under current market conditions. Even with optimistic assumptions regarding carbon pricing and technological learning, production costs exceed market prices of fossil-based natural gas.

The integration of hydrogen into biomethane and bio-SNG production is shown to enhance methane yields and improve carbon utilization. A hybrid energy supply model, combining wind, photovoltaic and grid electricity, is employed to reduce the electricity costs for hydrogen supply. The study further examines how e-methane can mitigate renewable energy curtailment in regional energy systems, focusing on Japan. Modelling results indicate that surplus electricity, particularly from offshore wind can be converted into e-methane under specific conditions, thereby enhancing regional gas self-sufficiency and reducing reliance on imported liquefied natural gas (LNG). However, the economic feasibility of this approach is highly sensitive to electricity prices, full-load hours and LNG market dynamics.

The findings underscore the importance of renewable gases as strategic enablers within a renewable energy system. Their systemic value lies in the capacity to provide energy balancing, integration of waste and residue streams and support hard-to-abate sectors. The successful deployment of renewable methane technologies will depend on continued technological innovation, robust carbon pricing mechanisms and policy frameworks that recognize and reward their co-benefits.

Kurzfassung

Diese Arbeit präsentiert umfassende ökonomische und ökologische Analysen der Produktion von erneuerbarem Methan aus Biomasse und Kohlenstoffdioxid (CO_2). Die Motivation liegt in der Reduktion von Treibhausgasemissionen durch die Integration der erneuerbaren Gase Biomethan, Bio-synthetisches Erdgas (Bio-SNG) und E-Methan in das Energiesystem. Durch die Kombination von techno-ökonomischer Bewertung, Treibhausgasbilanzierung und regionaler Energiesystemmodellierung wird der mögliche Beitrag dieser Gase zum Übergang in ein nachhaltiges Energiesystem bewertet.

Die Analyse zeigt, dass die kleinskalige Produktion von E-Methan unter Verwendung von CO_2 aus biogenen Prozessen zwar technisch umsetzbar ist, unter den derzeitigen Marktbedingungen jedoch wirtschaftlich herausfordernd bleibt. Selbst unter optimistischen Annahmen bezüglich CO_2-Bepreisung und technologischer Lernkurven liegen die Produktionskosten über den Marktpreisen von Erdgas.

Die Integration von Wasserstoff in die Biomethan- und Bio-SNG-Produktion erweist sich als vorteilhafter, da sie die Methanausbeute steigert und die Kohlenstoffnutzung verbessert. Ein hybrides Energieversorgungsmodell, das Wind-, Photovoltaik- und Netzstrom kombiniert, wird eingesetzt, um die Stromkosten für die Bereitstellung von Wasserstoff zu minimieren.

Darüber hinaus wird das Potenzial von E-Methanerzeugung durch Verwendung von Überschussstrom am Fallbeispiel regionaler japanischer Energiesysteme untersucht. Die Modellierungsergebnisse zeigen, dass überschüssiger Strom aus Offshore-Windenergie unter bestimmten Aspekten wirtschaftlich in E-Methan umgewandelt werden kann. Dadurch kann die regionale Gasautarkie gestärkt und die Abhängigkeit von importiertem Flüssigerdgas (LNG) verringert werden. Die wirtschaftliche Tragfähigkeit dieses Ansatzes hängt jedoch stark von den Strompreisen, den Volllaststunden und der Dynamik des LNG-Marktes ab.

Diese Arbeit unterstreicht die Bedeutung erneuerbarer Gase als strategische Bestandteile innerhalb eines erneuerbaren Energiesystems. Ihr systemischer Wert liegt in ihrer Fähigkeit, Energie zu speichern, Abfall- und Reststoffströme zu integrieren und schwer zu elektrifizierende Bereiche zu unterstützen. Der erfolgreiche Einsatz von erneuerbaren Gasen wird von fortlaufender technologischer Innovation und den politischen Rahmenbedingungen abhängen, die ihre vielfältigen Zusatznutzen anerkennen und fördern.

Contents

Abbreviations

AEL	Alkaline electrolyzer
AER	Absorption enhanced reforming
CAC	Cost of CO_2 avoided
CCS	Carbon capture and storage
CCU	Carbon capture and utilization
CH4	Methane
CHP	Combined heat and power
CO	Carbon monoxide
CO_2	Carbon dioxide
DFB	Dual fluidized bed
EIA	U.S. Energy Information Administration
EEA	European Environment Agency
EBA	European Biogas Association
EU	European Union
EU ETS	EU Emission Trading System
EUR	Euro
FLH	Full load hours
GHG	Greenhouse gas emissions
GHG eq.	Greenhouse gas equivalents
GoBiGas	Gothenburg Biomass Gasification
H_2	Hydrogen
H_2O	Water
kg	Kilogram
HHV	Higher heating value
km	Kilometers
kW	Kilowatt
kWh	Kilowatt hour
kWel	Kilowatt electric
LCA	Life cycle assessment
LCOE	Levelized cost of electricity
LHV	Lower heating value
LNG	Liquefied natural gas
LP	Linear programming

MJ	Megajoule
Mt	Megaton
Mtoe	Million Tonnes of oil equivalent
MW	Megawatt
N_2	Nitrogen
Nm^3	Normal cubic meter
O_2	Oxygen
PEM	Proton exchange membrane
PSH	Pumped storage hydropower
PtG	Power-to-gas
PV	Photovoltaic
RED	Renewable Energy Directive
SER	Sorption enhanced reforming
SMR	Steam methane reforming
SNG	Synthetic natural gas
SOEC	Solid oxide electrolyzer cell
SWOT	Strengths, weaknesses, opportunities and threats
TRL	Technology readiness level
URBS	Universal resource balancing system

1. Introduction

Reducing greenhouse gas emissions from fossil-fuel-dependent sectors is a central challenge in achieving climate goals. Renewable energy sources are expanding and technologies such as anaerobic digestion, biomass gasification and power-to-methane offer the potential to produce biomethane, bio-synthetic natural gas (bio-SNG) and e-methane as alternatives for natural gas, summarized as renewable methane. However, the economic viability of these alternatives remains a critical barrier, as high production costs and lack of policy support limit the large-scale deployment. This thesis investigates biomass-based and CO_2-derived gases from technical, economic and environmental perspectives.

1.1. Motivation

Gaseous energy carriers are playing an increasingly important role in modern energy systems. Historically, the global energy system transitioned from traditional biomass use to coal, oil and exploitation of natural gas, creating a shift to the “age of energy gases” (Hefner III, 2002). Natural gas is a versatile energy carrier, widely used in power generation, feedstock in the chemical industry and in manufacturing. The share of natural gas in global primary energy consumption increased to 22.1% in 2024, highlighting its continued relevance (Ritchie et al., 2020). However, the environmental impact of fossil fuels, including natural gas, has become a major concern. Combustion of fossil fuels such as natural gas is the major source of CO_2 emissions and causes global warming (Gielen and Bazilian, 2021). Even worse in terms of global warming potential can be the usage of liquefied natural gas (LNG) when emissions are caused by additional infrastructure for liquefaction and overseas ship transport (Carr et al., 2024). In this regard, a distinction needs to be made between associated gas, which is a by-product of oil production and non-associated natural gas production. Unfortunately, vast amounts of associated gas remain unused and are flared, due to lack of infrastructure or regulations. Flaring of associated gas reached 162 billion cubic meters (bcm) globally in 2024, which is equivalent to the yearly African gas consumption (World Bank Group, 2025). Although gas flaring remains an issue in oil production, non-associated gas production increases as well. While exact global numbers are not available, many major LNG export projects are supplied by non-associated gas fields (EIA, 2025, 2024). When referring to potentially worse climate impacts compared to pipeline-transported natural gas in this thesis, the focus is placed on non-associated gas production dedicated to LNG exports.

In response to climate change, the European Union has developed a long-term strategy for the reduction of greenhouse gas emissions by the replacement of fossil fuels (European Commission, 2024a). However, many EU countries are still dependent on imports to match the energy demand. The share of LNG in the total natural gas consumption increased from 21% in 2021 to 42% in 2023 (European Commission, 2024a).

At the same time, renewable energy sources are gaining importance in Europe and worldwide. Biomethane production increased to an essential part of the domestic energy production in Sweden, Denmark, Germany, Czech Republic etc. (Mathieu and Eyl-Mazzega, 2019; Schmid et al., 2019). The European Biomethane Map aims to locate all biomethane producing facilities in Europe. The number of biomethane plants on the map increased strongly from 1,023 in 2021 to 1,678 in 2025 (GIE and EBA, 2025).

Alongside the increasing production of biomethane, new challenges arise in the transformation of the energy system. Large-scale expansion of variable renewable electricity generation leads to a growing amount of surplus electricity, which can be utilized for renewable methane production. Electricity is required for the electrolysis process, which supplies the hydrogen required for the methane synthesis (methanation). A central part in the renewable methane production involves the utilization of CO_2, with a focus on CO_2 derived from biomass-based processes in this thesis.

The utilization of biogenic CO_2 for renewable methane production offers several key advantages:

- It provides a defossilisation opportunity for sectors that are difficult to electrify (Centi et al., 2020).
- More climate benefits than storing CO_2 when there is still a demand for hydrocarbon fuels and surplus electricity is utilized instead of curtailment (Millinger et al., 2021).
- Existing gas infrastructures, such as grids and storage facilities, can be reused, which simplifies the integration into the energy system (Speirs et al., 2018).
- Domestic production strengthens energy sovereignty and reduces import dependency of fossil fuels (Skorek-Osikowska et al., 2020).
- Moreover, CO_2 utilization aligns with the concept of a circular economy due to an integration with existing energy and infrastructure systems and may achieve higher levels of public acceptance (Oltra et al., 2021; Simons et al., 2021).

Despite the technical promise, biomass-based and CO_2-derived gases face considerable economic barriers, which are investigated in this thesis. Flexible operation, which supports the effective use of variable renewable energy, together with low-cost hydrogen, is essential for improving the economic viability of CO_2 utilization (Poluzzi et al., 2021). Since hydrogen is indispensable for the methane synthesis, reducing its cost is a key prerequisite for successful implementation. Technological learning and supportive policy frameworks could lower the capital costs of electrolyzers and methanation facilities to improve their economic competitiveness (van der Zwaan et al., 2022). Nevertheless, the effective management and minimization of electricity costs remain critical, as operating costs currently account for the largest share of production costs (Bampaou et al., 2022). This thesis combines techno-economic analysis with energy system modelling to assess the integration of renewable methane at the interface of bioenergy, variable renewable electricity and CO_2 utilization. The findings aim to provide insights for researchers and policy makers and to support the broader deployment of renewable gases within a defossilised energy system.

1.2. Core objectives and research questions

The core objective of this thesis is the analysis of costs and prospects of mitigating greenhouse gas emissions through the utilization of carbon dioxide for producing renewable methane. The investigation includes the requirement for a renewable hydrogen supply via electrolysis to enable the methanation process. The thesis contributes to the ongoing discussion on the integration of renewable methane into the energy system. The following research questions have been defined, to address the objectives of this thesis:

Research question 1: *What are the techno-economic prospects of decentralized small-scale e-methane production using CO_2 from biomass-based processes?*

The first research question is answered by identifying the cost drivers and investigation of different scenarios for learning rates and deployment. The methodology follows an input-oriented approach, incorporating the availability of renewable energy and biogenic CO_2 for producing renewable gases based on (Radosits et al., 2024b).

The CO_2 needed for methanation is captured at a separate location, for example from industrial facilities or district heating plants relying on biomass. This approach offers flexibility in the production locations but involves additional infrastructure for transporting CO_2 and/or hydrogen, increasing system complexity and cost.

A techno-economic assessment is conducted with emphasis on long-term learning rates separated into new and conventional components. The concept of small-scale e-methane production is based on regulatory developments in the European Union favouring biogenic CO_2 as a sustainable source for carbon capture and utilization (CCU). Most bioenergy facilities such as biomass district heating plants are in the range below 10 MW. This structural feature of the bioenergy sector inherently fosters decentralized, small-scale CO_2 utilization. Additionally, the availability of biogenic CO_2 in three important sectors in Europe is investigated and an analysis of strengths, weaknesses, opportunities and threats (SWOT) is conducted to consider also technical aspects.

Research question 2: *What are the benefits of integrating hydrogen into biomethane and bio-SNG production and how does this affect CO_2 avoidance costs?*

The second research question addresses the direct utilization of CO_2 at the point of origin in an output-oriented approach, where hydrogen is used to increase methane yields in biogas and biomass gasification processes. This is a more localized and process-integrated approach that avoids external CO_2 transport. Existing CO_2 streams in biogas plants or gasification units are converted, offering a more resource and energy efficient way of renewable methane production. However, the investigation of the first and second research question share a common topic: leveraging biomass as a sustainable carbon source according to the third renewable energy directive (RED III) and coupling it with renewable hydrogen to produce renewable methane.
This investigation under the second research question integrates the previously analysed cost reductions of electrolyzers into a techno-economic assessment of hydrogen-enhanced biomethane and bio-SNG production. The economic analysis, based on (Radosits et al., 2025), accounts for investment and operating costs, feedstock supply and transport costs, as well as the additional electricity costs for supplying hydrogen. The electricity costs for the hydrogen supply are minimized with a linear optimization of a hybrid energy system model combining onshore wind, photovoltaics (PV) and grid electricity. The results of the linear optimization are used as input parameter in the techno-economic analysis of the specific production costs. Another important aspect addressed under this research question is the evaluation of CO_2 avoidance costs, which provide a benchmark for the cost-effectiveness of the investigated technologies in terms of emission reduction.

Research question 3: *To what extent can e-methane production reduce renewable energy curtailment, considering regional infrastructure and LNG market conditions?*

The first two research questions examine the topic from the perspective of plant operators. Building on these findings, it is essential to evaluate conditions, under which CO_2 utilization, in the case of e-methane, can be integrated into an energy system from a system-level perspective. The regionally separated electricity system of Japan with limited transmission capacities and growing concerns about surplus electricity is the motivation for this investigation. The theoretical maximum amount of curtailment is assessed by using renewable energy targets and transmission-capacity extension plans from grid operators for 2030 and 2040. The core objective of this contribution, which is currently under review, is the analysis of the implementation of domestic e-methane production in two selected regions of the Japanese energy system by using the open access model universal resource balancing model (urbs), developed at TU Munich (Dorfner, 2019).

The selected regions are Kyushu and Hokkaido, located at the south and northern borders of the Japanese electricity system. The increasing shares of renewables in the energy systems of Kyushu and Hokkaido are expected to increase the curtailment in both regions, especially before suitable transmission grid reinforcements are in place. However, this development presents also an opportunity to utilize low-cost surplus electricity from the grid for e-methane production.

In the analysis, the two regions are modelled independently, without assuming mutual interactions between the regional energy systems. Storage technologies are integrated into the regional energy system models to absorb surplus electricity and balance the grid. The modelling framework is further adapted to promote self-sufficiency in regional gas consumption, where the LNG price serves as a benchmark to the economic feasibility of e-methane production.

In addition, a review paper on biomass-based gases (Radosits et al., 2024a) was conducted, which serves as a starting point for the literature analysis related to the research questions. Historical, economic and environmental aspects of biomethane and bio-synthetic natural gas production are examined. Cost and commodity prices are adjusted with data on average European inflation and expressed in EUR_{2023} in the thesis, unless stated otherwise. The literature analysis situates biomass-based gases within a broader context, recognizing challenges of resource availability and the fragmented policy framework in Europe. The discussion also considers issues of system boundaries in environmental assessment and economic challenges.

Overall, the core of the dissertation is based on the following four articles:

- F. Radosits, A. Ajanovic, M. Harasek: The relevance of biomass-based gases as energy carriers: A review. Wiley Interdisciplinary Reviews: Energy and Environment 13 (2024), e527. DOI: 10.1002/wene.527

- F. Radosits, A. Ajanovic, S. Pratschner: Costs and perspectives of synthetic methane and methanol production using carbon dioxide from biomass-based processes. Journal of Sustainable Development of Energy, Water and Environment Systems 12 (2024), 1120484. DOI: 10.13044/j.sdewes.d12.0484

- F. Radosits, A. Bartik, A. Ajanovic, S. Müller: Production costs and greenhouse gas mitigation potential of hydrogen-enhanced biomethane and bio-SNG production. Journal of CO_2 Utilization 97 (2025), 103105. DOI: 10.1016/j.jcou.2025.103105

- F. Radosits, B. C. McLellan, S. Zwickl-Bernhard, A. Ajanovic: Substitution Potential of Surplus Power-Based E-Methane Production for LNG: The case of Kyushu and Hokkaido in Japan. Under review

Figure 1 shows the connection of the literature review including the review paper and the three research questions. Research questions 1 and 2 are kept in a different color from research question 3, representing different spatial scales.

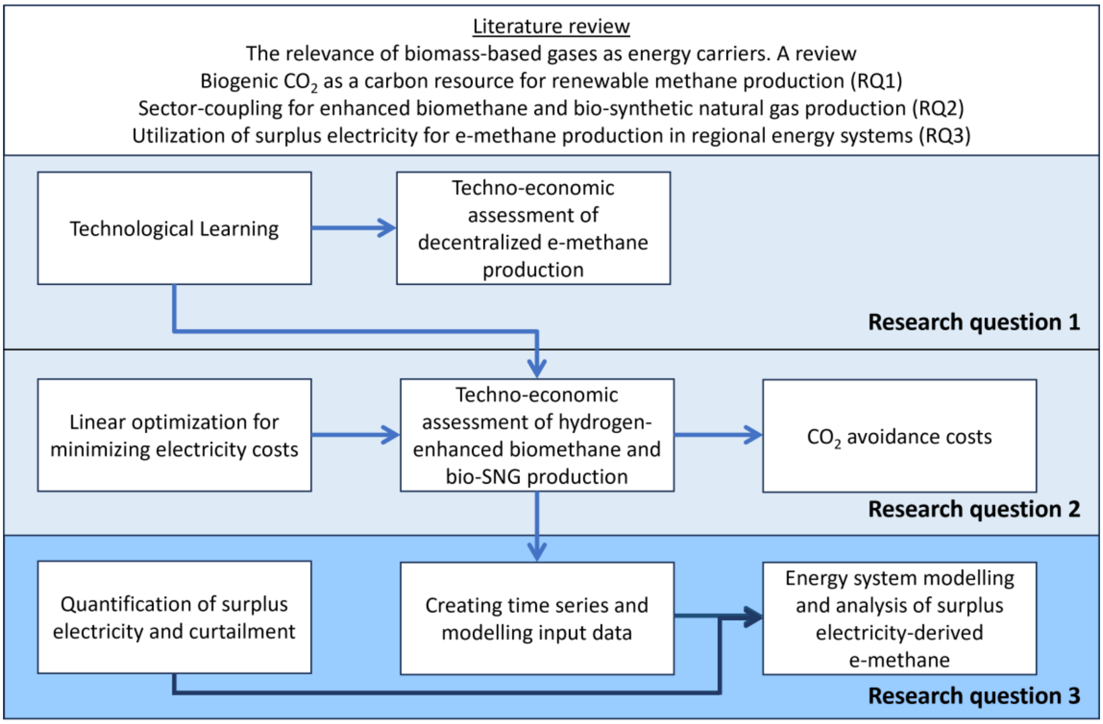


Figure 1. Overview of the thesis methods and their connection to the research questions.

1.3. Structure of the thesis

The thesis is structured into seven chapters. Chapter 1 introduces the motivation, objectives and research questions. Chapter 2 is derived from (Radosits et al., 2024a) and reviews the state of the art on biomass-based and CO_2-derived gases and outlines the progress beyond existing literature. Chapter 3, derived from (Radosits et al., 2024b) analyses the techno-economic feasibility of small-scale e-methane production using biomass-based CO_2. Chapter 4 is based on (Radosits et al., 2025) and examines the integration of hydrogen into biomethane and bio-SNG production and its impact on costs and CO_2 mitigation. Chapter 5 builds on a manuscript under review and applies energy system modelling for regional case studies in Japan to evaluate e-methane production from surplus electricity. The synthesis of results in chapter 6 places the individual research questions within the context of the thesis as a whole and chapter 7 presents conclusions and an outlook for future research.

2. State of the art and progress beyond

The urgent need for defossilisation has intensified research into sustainable alternatives to natural gas. Biomass-based and power-to-gas (PtG) systems provide complementary solutions for climate change mitigation (Brémond et al., 2021; D'Adamo et al., 2023; Lainez-Aguirre et al., 2017; Millinger et al., 2021; Wetzel et al., 2023; Yilmaz et al., 2022) . The conversion of biomass residues into biomethane and biomass-based synthetic natural gas offers the valorization of waste streams, whereas power-to-gas pathways enable the utilization of surplus renewable electricity for e-methane production. The combination of these approaches allows sector coupling for flexible energy supply. Both pathways are examined, highlighting their potential, limitations and the opportunities for integration to enhance renewable gas supply.

This chapter is based on the literature review of three peer-reviewed articles (Radosits et al., 2025, 2024a, 2024b) and the manuscript by Radosits et al. (under review).

A considerable part is dedicated to biomass-based gas production, which is investigated in the peer-reviewed review paper (Radosits et al., 2024a). Biomethane processes are well-established, but feedstock availability is limited in many regions, which restricts their scalability. Understanding the potential and limitations of biomass-based systems is essential for planning sustainable gas supply pathways. Power-to-methane technologies, although promising, depend on the temporal occurrence of excess electricity and face efficiency challenges (Blanco et al., 2021). The combination of these approaches allows sector coupling for flexible energy supply. Together, the state of the art highlights both the potential and the limitations of renewable gas pathways, underscoring the importance of examining how they can be embedded in future energy system developments. Building on this literature review, the progress beyond is presented at the end of this section.

2.1. Biomass-based gases

The production capacities of biomass-based gases played an almost neglectable role in the overall EU energy mix of the early 2000s. However, biogas production advanced to a noteworthy part of the European energy landscape. In Figure 2 the generation of bioelectricity and the production of biogas and biomethane in Europe are shown. Until 2015, Europe has seen a strong increase in the installation of biogas plants, which are now established as an alternative energy generation technology. The capacities stagnated then in Germany and Austria after running out of feed-in tariffs (Matschoss et al., 2020; Stürmer, 2017). Biogas can also be upgraded to produce biomethane as a direct substitute for natural gas (Miltner et al., 2017). Due to a shift in policies, biomethane increased constantly while biogas usage stagnated. Since 2022, biogas production increased again. Flexible biogas operation can potentially reduce overall system costs (Lauer and Thrän, 2018). However, usually additional market revenues, for example by providing secondary control reserves, or flexibility premiums are required for economic viability (Dotzauer, 2024). Instead of focusing on electricity, Mertins and Wawer (2022) emphasize that profitability increases with heat-demand oriented flexibility provision.

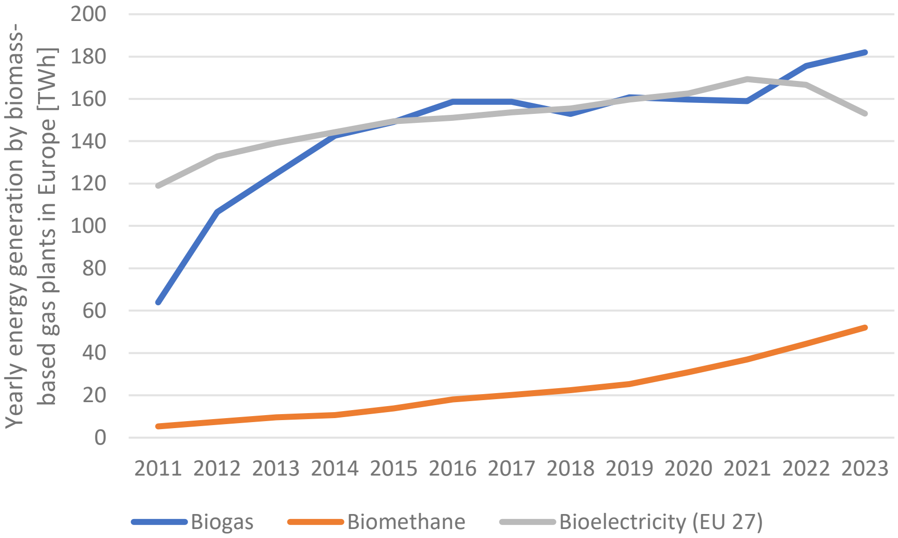


Figure 2. Yearly generation of bioelectricity, biogas and biomethane in Europe. Data sources: (Abdalla et al., 2022; EBA, 2023; Hrbek, 2022; IEA, 2023a; IEA, 2025a; Pio and Tarelho, 2021).

The conversion of agricultural waste feedstocks not has only a positive effect on replacing natural gas but also offers other benefits, such as the reduction of methane emissions from agriculture by thermal treatment of manure (Auer et al., 2017). This is in line with the recent EU legislative framework to decarbonize gas markets and reduce methane emissions (European Commission, 2021). In addition, sustainable biomass inputs can also include secondary cover crops, which are cultivated after the main harvest. Growing energy cover crops for biogas production and returning the digestate can improve the soil organic carbon content compared to other cover crops with significantly lower yield or bare soil (Levavasseur et al., 2023).

Although biogas production stagnated from 2016 to 2021, bioelectricity production increased in the same period. This is due to the establishment of biomass gasifiers for combined heat and power (CHP). Figure 3 shows the number of plants for biomass-based gas production installed in 2021. In the same year, only a few pilot plants, in total 5 projects, existed for synthesis gas or synthetic natural gas (bio-SNG) production in Europe and thereof only one was operational (Pio and Tarelho, 2021). The other facilities using biomass gasification were built for heat and/or electricity generation.

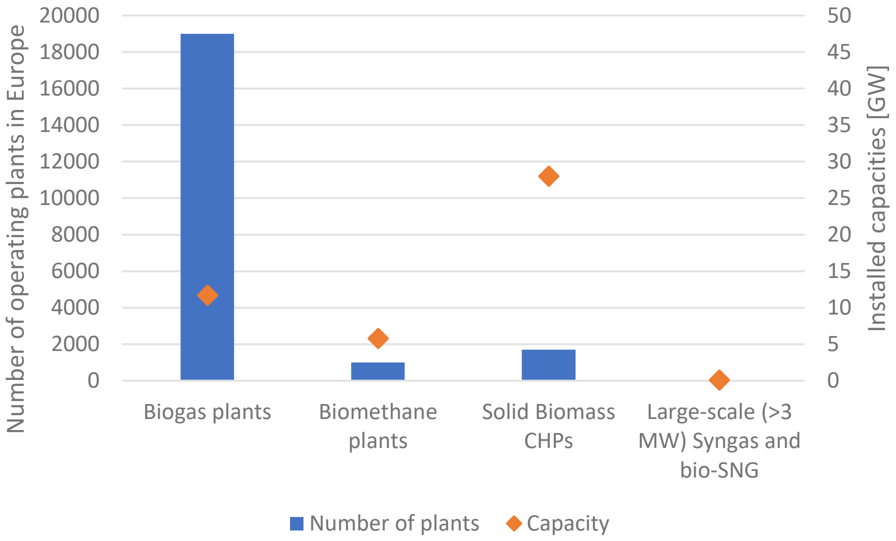


Figure 3. Number of green gas production plants for energy purposes in operation in Europe in 2021. Data sources: (Abdalla et al., 2022; EBA, 2023; Hrbek, 2022; IEA, 2023a; Pio and Tarelho, 2021).

An increasing importance of electricity generation from biofuels in various countries can be seen in Figure 4. The increase in the Czech Republic, Denmark and Germany is driven by electricity generation from biogas plants. In other countries, such as Finland and Sweden, solid biomass has played the major role. A decline in bioenergy production in these countries can be related to stricter EU regulations regarding the use of solid biomass (Brown and Jones, 2024).

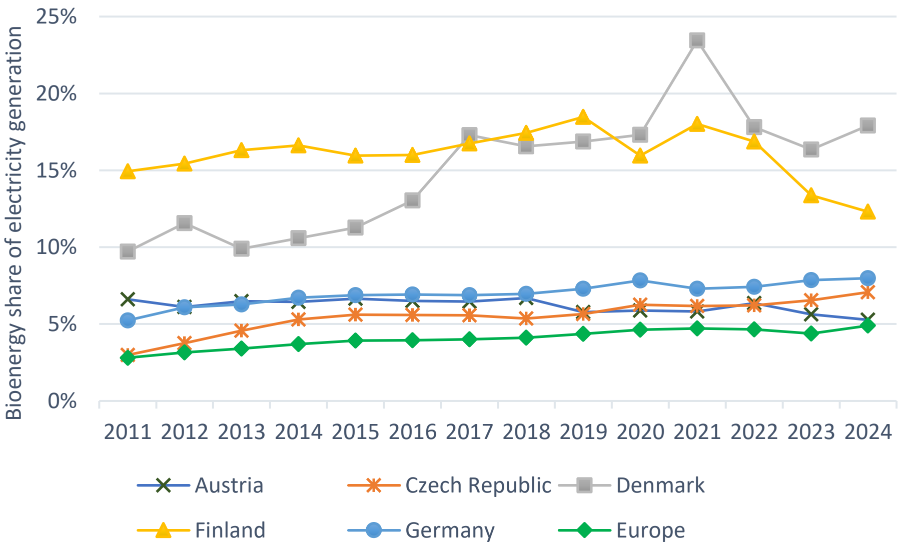


Figure 4. Bioenergy share of electricity generation in selected countries of the European Union compared to the EU average. Data source: (IEA, 2025a)

The use of biomass-based gases can also contribute to emission reduction in sectors other than electricity generation. One sector of particular interest is transport, where the emissions in Europe increased by approximately 22% from 1990 to 2019 (EEA, 2022). Green gases such as biomethane and hydrogen are discussed as possible alternative fuels to curb transport emissions (Ardolino and Arena, 2019). Although electrolysis is frequently mentioned as a sustainable production technology, it is also possible to use biomass as feedstock for hydrogen production.

Global hydrogen demand has grown by approximately 85% since 2000 and reached approximately 97 Mt of hydrogen, although still almost entirely based on fossil resources (IEA, 2019a, 2024). Sectors with the highest demand for hydrogen were ammonia production and oil refinery (Binder et al., 2018). The utilization of fossil fuels in hydrogen production results in significant emissions of CO_2 into the atmosphere. The demands for hydrogen and biomethane are expected to rise in the future (Baumann et al., 2021; IEA, 2021a). The increasing use of biomass-based green gases, which are produced sustainably, could decrease GHG emissions and contribute to the United Nations sustainable development goals 7 (affordable and clean energy) and 13 (climate action).

2.1.1. Historical development of biomass-based gas production technologies

Historical evidence exists that biogas was used to heat bath water in ancient Assyria and Persia (Auer et al., 2017; Lebuhn et al., 2014). It is also possible that fermented cattle manure was exploited as fuel in ancient China (Bond and Templeton, 2011; Chasnyk et al., 2015). It was already known that explosive gas was produced when cattle manure was stored in a tank for a certain period. As illustrated in Figure 5, scientific research into biogas started in 1776 when Alessandro Volta experimented with marsh gas. Around the year 1800, methane was discovered in swamp gas and the chemical formula CH_4 was confirmed by A. Avogadro in 1821 (Chasnyk et al., 2015). Early ideas about using hydrogen as an energy carrier began to appear in the second half of the 19th century (Ajanovic and Haas, 2021). Around the same period, early biogas experiments using sewage sludge laid the foundation for modern biogas production. The first biogas test plant was built in 1859 in Bombay, India (Lebuhn et al., 2014) and energy for street lighting in 1895 in England was provided by biogas. The first large-scale German biogas plant started operating in 1950, but the breakthrough was only achieved after the first oil crisis (Bond and Templeton, 2011).

Thermochemical conversion of wood has also been known for over a hundred years. Wood gas was in use as fuel for passenger cars as early as the 1920s in European countries such as Sweden (Kaijser, 2021), where vehicles were equipped with small gasifier units (Piętak et al., 2010). Many gasification reactors used for biomass conversion originated from coal gasification. The Lurgi gasifier was developed in the 1930s in Germany and was the only commercially feasible process for producing synthetic natural gas in pipeline quality in the 1960s and 1970s (Kopyscinski et al., 2010). From the 1950s onward, several companies began to develop their gasifiers. For example, Shell (Breault, 2010), Siemens and Linde also developed gasifiers in the 1970s.

The oil crisis in 1973 led to a rediscovery of biogas utilization and spread to several European countries, including Germany, Austria, Sweden, etc. (Kompost&Biogas Verband, 2016; Stürmer, 2017). Biogas plants can be part of integrated energy systems, a term which has been developed by the International Institute for Applied Systems Analysis (IIASA) in the 1980s (Häfele et al., 1981).

Since then, different regions of the world have also promoted biogas technologies, e.g., China and India (Mittal et al., 2018). In China, the first biogas plants were constructed at the end of the 19th century. In the 1970s, the Chinese government initiated a nationwide expansion of biogas plants to supply energy in rural areas. Unlike Europe, private households are significant contributors to the overall biogas production in Asia (Giwa et al., 2020). Households in Asia use very small digesters to convert animal manure and biowaste to produce less than 10 m^3 biogas daily.

A rediscovery of wood gasification with the new aim of producing bio-SNG was inaugurated in 1999 by a Swiss initiated collaboration between Gazobois SA, Ecole Polytechnique Fédérale de Lausanne and the Paul Scherrer Institute. In the early 2000s, a new method called absorption enhanced reforming (AER) was developed for producing a hydrogen-rich product gas. This process was then tested within an experimental campaign in Guessing, Austria (Koppatz et al., 2009). Later, in 2008, a $1MW_{SNG}$ process development unit based on the fast internally circulating fluidized bed, developed at TU Wien, was built to demonstrate the whole process chain from wood to bio-SNG (Kopyscinski et al., 2010). Other projects in Villach (Austria) and Senden (Germany) were set up to produce heat and power (Hofbauer et al., 2020). Biomass gasification for electricity and heat production was investigated intensely from 2000-2010 (Patuzzi et al., 2016). In the wake of this, the interest in using syngas for fuel production increased. In 2013 the Gothenburg Biomass Gasification (GoBiGas) project applying dual-fluidized bed (DFB) technology to produce biomethane went into operation in Sweden (Kopyscinski et al., 2010). However, on account of economic constraints, phase 2 did not go into operation. In 2016 the DFB process was further improved with sorption-enhanced reforming (SER) for hydrogen production (Schweitzer et al., 2016). In 2017 the semi-industrial platform GAYA was started in France, where bio-SNG could be produced via forest biomass conversion by 2019. One year later, in 2020, the world´s first production of renewable gas from non-recyclable waste was carried out (ENGIE, 2020). In 2022, a pilot plant for products applied in the energy and transport sectors or the chemical industry was successfully launched in Vienna, Austria (BEST, 2022).

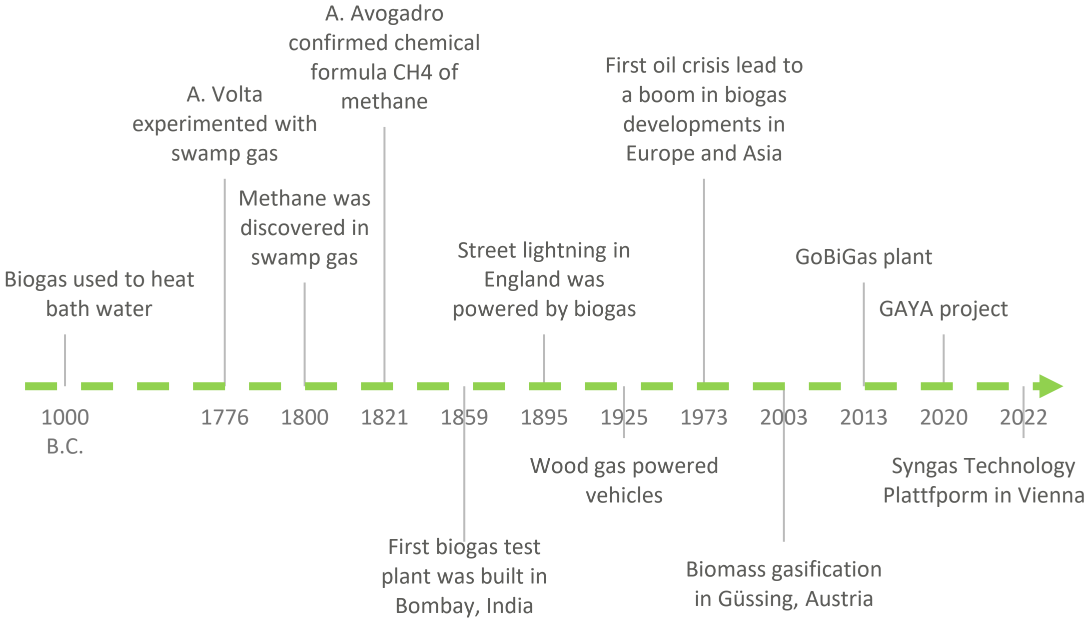


Figure 5. Milestones in the development of biomass-based gas production technologies. Source: (Radosits et al., 2024a).

2.1.2. Technical, economic and environmental aspects

Methane is the simplest hydrocarbon (a “C_1” molecule), composed of one carbon atom bonded to four hydrogen atoms in a tetrahedral geometry. It is a gas at standard temperature and pressure, colorless, odorless and relatively inert until combustion or other activation, e.g., reforming, oxidation. Its physical properties include a molecular weight of ∼16.04 g/mol, a boiling point about −161.5 °C, a melting point around −182.5 °C. Because of the strength of its C–H bonds and its small molecular size, methane has relatively low chemical complexity, which makes it comparatively easier to handle in terms of reactions, storage (e.g. liquefaction as LNG), transport (pipelines or compressed natural gas) and consistent energy content per unit mass or volume. Methane is widely used as an energy carrier because its combustion releases a high amount of thermal energy per unit mass. The heating values of methane are relatively high: the higher heating value (HHV) is about 55.5 MJ per kilogram of methane, while the lower heating value (LHV) is about 50 MJ/kg at standard temperature and pressure of 1 atmosphere pressure and 0° Celsius (273.15 K) (Candelaresi and Spazzafumo, 2021).

Three biomass conversion technologies were chosen for this literature review with respect to their technology readiness level (TRL) and relevance to the energy system. These technologies make it possible to convert various feedstocks into gaseous energy carriers. Figure 6 shows the corresponding process pathways. Their production can be used as a sustainable way of transforming residues and biomass waste (municipal and industrial) into gaseous energy carriers for transportation and industrial applications (Ardolino and Arena, 2019). Another biomass processing technology worth mentioning is pyrolysis. Conventional slow and fast pyrolysis are mature technologies with a TRL of 7-9. Europe has a strong role in pyrolysis research. However, only few commercial plants could be established by 2023 (Volpi et al., 2024). The United States and Canada are ahead of Europe in total number of plants. Although a promising technology, pyrolysis faces techno-economic challenges and further innovation is needed to unlock the potential for a broader contribution to a sustainable energy system (Vuppaladadiyam et al., 2022).

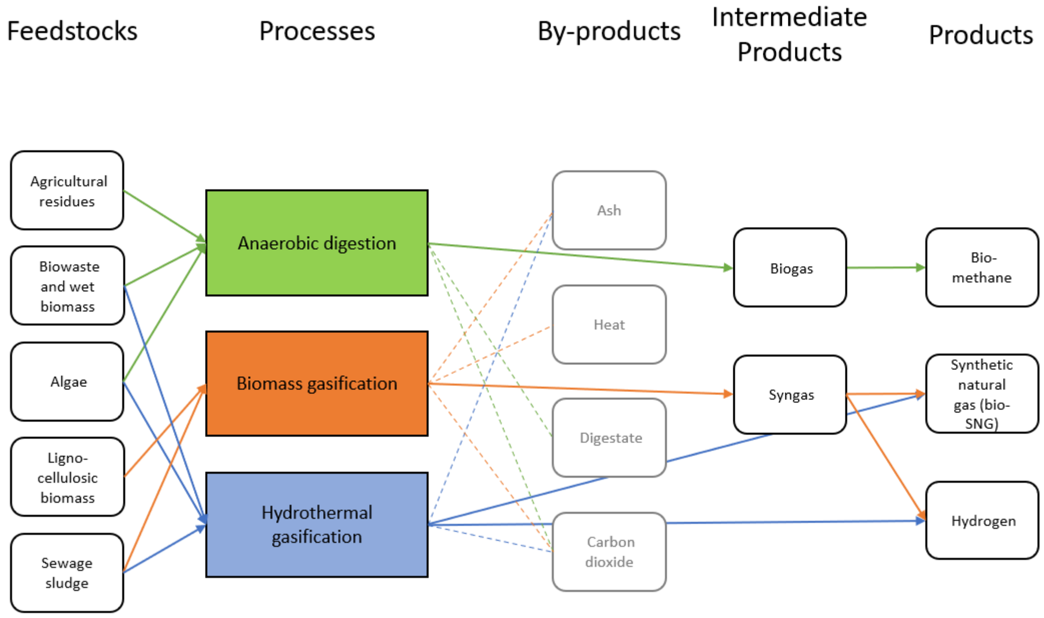


Figure 6. Production pathways for biomass-based green gases. Source: (Radosits et al., 2024a).

2.1.2.1. Biogas

Biogas is produced via anaerobic digestion and has an energy content of 19-26 MJ/ Nm^3 (6-6.5 kWh). Biogas comprises 50-70% methane, 30-50% CO2, water and traces of H_2S, O_2, H_2, etc. (Ardolino and Arena, 2019; Bond and Templeton, 2011).

The anaerobic digestion process is operated under anoxic conditions, atmospheric pressure and different temperature ranges: mesophilic (35-42°C) and thermophilic (45-60°C). Methane formation performed by methanogenic bacteria occurs in a pH range of 6.5-8.5. The biochemical degradation of macromolecules follows a step-wise pattern: hydrolysis, acidogenesis, acetogenesis and methanogenesis (Lübken et al., 2010). The water content in the biomass can be relatively high. There is a distinction made in the literature between dry digestion (15-35% total solids content) and wet digestion (total solids <10%) (Weiland, 2010).

Biogas reactors can be classified by the following characteristics (Chasnyk et al., 2015):

- Digester volume: small: 50-150 m^3, medium 500 – 1500 m^3, large: 1000-5000 m^3
- Organization of the process: batch or continuous stirred
- Single- or multistage biogas plant (acidogenesis and methanogenesis occur in separate reactors)

The most common reactor for anaerobic digestion in Germany is the continuous stirred tank reactor (vTI et al., 2009). Germany is a strong market for anaerobic digestion from a global perspective (Taboada et al., 2021). Plug flow reactors and covered lagoons are uncommon in Europe but widely used in Asian countries (Chasnyk et al., 2015).

Some biogas substrates are challenging to digest. Patinvoh et al. (2017) reviewed various pretreatment strategies to improve the economic feasibility of biogas production. Proper pretreatment is a precondition for a stable operation of the digestion reactor. The digester can be negatively influenced when waste contains high amounts of salt, oil and/or protein (Sridhar et al., 2021).

Besides agricultural products and residues, algae processing in biogas plants is also an option (Allen et al., 2013). The scientific interest in the use of algae in anaerobic digestion and biorefinery concepts (Markou et al., 2022; Naaz et al., 2023) has increased significantly over the last decade. Algae can be used as feedstock in all technologies described below (Bagnoud-Velásquez et al., 2015; Barroso Soares et al., 2020; Heaven et al., 2011). However, economic considerations are a major issue in using algae for gas production. (Barsanti and Gualtieri, 2018) show in their review that only a few biorefineries globally are established, but with a focus on high-value products. Therefore, Bose et al. (2022) investigated a biomethane and high-value product multi-generation concept. The environmental and economic performance improves compared to conventional biomethane plants.

The production costs of biogas depend very much on the feedstock and scale. It is difficult to state the costs for a specific feedstock. These depend on regional conditions and the particular project. For waste feedstocks, in the economic calculation, only a gate fee is usually considered, while other feedstocks such as energy crops can be very costly (IEA Bioenergy, 2023). Prices for maize silage increased significantly from approximately 45-55 EUR/ton in December 2019 to 60-80 EUR/ton in January 2023 (Fraunhofer IEE et al., 2023). According to Feiz et al. (2022), handling and personnel costs for waste collection are often underestimated. The running costs for the utilization of food waste at three different plants operating in Sweden are analysed in their work. The feedstock collection has a significant impact on the costs. The energy efficiency is not given and the results showed costs in EUR/ton of food waste. Assuming an efficiency of 50-60%, which is reasonable for food waste according to (Billig and Thraen, 2017) and an energy content of 6 kWh/kg biogas, the running costs amount to 5.4-24.7 EUR/MWh biogas. These consist of feedstock collection, pretreatment, O&M and personnel costs. The feedstock value itself is not considered within these running costs.

Feiz et al. (2022) also do not consider investment costs in the scope of their study. However, the investment costs are important for the overall evaluation of the economic feasibility. The investment costs for small-scale biogas plants <100 kW can reach up to 7000 EUR/kW whereas the investment costs for larger capacities > 1 MW drop usually below 3200 EUR/kW (Bartkowiak et al., 2022; Eftaxias et al., 2024). The effect of scale is shown in the work of Bhatt and Tao (2020). The authors simulate biogas plants with different feedstocks and tons of input per day and also incorporated the capital costs. The results vary between 4.5 ct./kWh and 16.3 ct./kWh. The extreme cases where a low amount of feedstock is used are hereby excluded. The amortization periods found in the literature vary widely from 14-30 years (Bhatt and Tao, 2020; Đurđević and Hulenić, 2020). However, an amortization period of 30 years is comparably long.

Biomass conversion concepts are often capable of producing by-products. This can be easily overlooked when only the production costs of the main product are mentioned. Gebrezgabher et al. (2010) used a linear programming model for maximizing electricity output and optimal digestate application. Constraints were the treatment capacity of the plant and the maximum applicable digestate. The result of the study is that the disposal of digestate is a key factor in the operation of a biogas plant and economic feasibility also depends on proper management of it. Nutrient management is conducted in the form of digestate spreading on agricultural land for fertilization (Gebrezgabher et al., 2010). Biogas digestate has the potential to replace mineral fertilizers (de Boer and van Ittersum, 2018) and reduce greenhouse gas emissions of the agricultural sector, which reached 10% of the EU's GHG emissions due to the substantial increase in nitrogen fertilizer consumption between 2010 and 2020.

In the life cycle analysis (LCA) of Schumacher et al. (2010), biogas digestate replaces 100% mineral phosphate and 60% nitrogen fertilizer in 6 out of 8 scenarios. Brienza et al. (2021) tested a novel NH_3 stripping and scrubbing technology for nitrogen recovery from digestates. With this new process, 57% of NH_3 in the digestate could be recycled in the form of ammonium sulfate ($(NH_4)2SO_4$), which has similar qualities to conventional nitrogen fertilizer. However, the utilization of digestate shows high uncertainty regarding the climate impact due to varieties in spreading and storage (Feiz et al., 2022). Nevertheless, improving nutrient recovery from digestates directly supports the ambitions of the EU Circular Economy Action Plan (2020), which aims to create sustainable growth while protecting biodiversity (European Commission, 2020). Besides nutrient recovery, biogas can be upgraded to biomethane and used as energy carrier in terms of a circular economy approach, for example in transport or agriculture.

2.1.2.2. Biomethane

Biomethane as a direct substitute for natural gas and can be injected into the natural gas grid, provided that it meets the required specifications. The production technology is also anaerobic digestion. However, gas cleaning to remove impurities such as H_2S, siloxanes, etc. and upgrading (CO_2 removal) are compulsory post-reactor steps to obtain biomethane in grid quality as the final product (Solarte-Toro et al., 2018). The gas cleaning and upgrading also requires additional energy and materials. The choice of the right technology can increase the energy efficiency of the process and reduce costs (Anca-Couce et al., 2021). (Lombardi & Francini (2020) investigate five different technologies for upgrading biogas. For large plant capacities, amine scrubbing was identified as the best solution. For small plants, high-pressure water scrubbing is preferred. However, Miltner et al. (2017) show that membrane permeation also has good prospects for applications on a large scale. The economic feasibility of membrane-based upgrading has been demonstrated and the number of biomethane plants using this technology is increasing in recent years (Gkotsis et al., 2023).

Revenues from biomethane plants are generated from selling biomethane, potential subsidies for injecting into the grid and sales of digestate as a by-product. Costs include energy costs for the feedstock, capital and other costs, e.g., electricity. The supply range for typical feedstocks with high moisture content is limited due to rising transport costs over longer distances (D'Adamo et al., 2021). The production costs are strongly affected by the processed feedstock. Organic waste shows lower production costs compared to energy crops such as maize. Straw can also be utilized, but the efficiency is lower than for other feedstock conversions and production costs were the highest. Skorek-Osikowska et al. (2020) examine three cases of biomethane production with different process characteristics. The lowest production costs for manure fermentation are between 59 – 81 EUR/MWh, as shown in Table 1. The break-even price of 81 EUR/MWh is reached when additional CO_2 capture is applied. Furthermore, there was a clear trend toward lower production costs at increasing plant scale. Billig & Thraen (2017) calculate the biomethane production costs of different agricultural feedstocks. Depending on the size of the plant (1.4-16 MW), the biomethane production costs were 72-116 EUR/MWh using organic waste, 105-133 EUR/MWh using energy crops and 123-157 EUR/MWh using wheat straw. D'Adamo et al. (2023) performe an economic analysis on the usage of organic municipal waste converted to biomethane for capacities ranging from 100 to 500 m^3/h in Italy. The production costs vary from 60-87 EUR/MWh. Cappiello et al. (2022) model a novel system of a biomethane production plant processing organic waste coupled with PV panels and lithium battery storage to supply electricity to the upgrading system. The payback period of the best configuration in terms of economic feasibility, using water scrubbing, was lower than ten years in the case of a biomethane selling price > 68 EUR/MWh. The costs for upgrading contribute to an extent of 5.9-17.6 EUR/MWh to the overall production costs of biomethane plant (Miltner et al., 2017; Solarte-Toro et al., 2018).

Table 1. Production cost of biomethane for different feedstocks and scales in EUR_{2023}.

Feedstock	Production costs [EUR/MWh]	Source
Manure	59 – 81	(Skorek-Osikowska et al., 2020)
Energy crops	123-157	(Billig and Thraen, 2017)
Biowaste	72-116	(Billig and Thraen, 2017)
Straw	105-134	(Billig and Thraen, 2017)
Biowaste	59-81	(D'Adamo et al., 2023)

The utilization of biowastes for biomethane production has the potential to contribute to the decarbonization of the energy system and progress towards a circular economy (D'Adamo et al., 2021). The LCA study of Ardolino & Arena (2019) about anaerobic digestion and thermochemical conversion of biowaste into biomethane shows a lower global warming potential for both technologies than for diesel as a reference. A 1 MW plant is chosen for both process pathways as the representative scenario. Compared to the diesel reference scenario, biomethane production has a 56% lower global warming potential. Some authors estimate higher emission savings of up to 95% when using biomethane as fuel in transport compared to fossil fuels (Cavaignac et al., 2021). Amato et al. (2023) also compare the usage of biomethane in transport with LNG from Qatar and diesel. Among fossil fuels, LNG shows an even worse environmental impact than fossil diesel in transport.

Compared to diesel, biomethane from manure or food waste can reduce GHG emissions by 45-70% or 50-75% respectively. Ferreira et al. (2019) assess the use of biomethane in Brazil in a LCA study, replacing liquefied petroleum gas in domestic use and diesel in heavy-duty vehicles and public transport buses. Biomethane from wastewater treatment shows an exceptional better environmental performance in all evaluated impact categories. The study by Feiz et al. (2022) also investigates the climate impact of biomethane production from food waste. All scenarios show a 62-80% lower climate impact than the fossil reference. However, methane emissions can be a heavy environmental burden because the greenhouse gas effect of methane is 28 times stronger than that of CO_2 over 100 years (European Commission, 2022a). Bakkaloglu et al. (2022) show that GHG emissions from biomethane plants are greater than previously estimated. In particular, the digestate needs to be handled carefully to prevent the offset of emission reduction by methane emissions.

Methane emissions also depend on the upgrading technology. Methane leakages can be either measured at single-point sources or for the whole plants. Sources are the pressure release valve, incomplete combustion, etc. Average numbers are difficult to obtain from the literature because biogas plants are often individually modified. It is also recommended not to consider the methane emissions in isolation, but to see them in the context of the whole process chain (Liebetrau et al., 2017). Membrane technology is the most environmentally friendly upgrading technology (Florio et al., 2019).

2.1.2.3. Synthesis gas

In addition to biogas pathways, the following three sections explore biomass gasification technologies that enable the conversion of biomass feedstocks into gaseous products. The current section and 2.1.2.4 discuss systems employing gaseous gasifying agents, whereas section 2.1.2.5 considers hydrothermal gasification using water.

Reactions of biomass with air, steam, O_2 or CO_2 lead to the transformation of solid carbon compounds such as cellulose into a mixture of gases. Synthesis gas (Syngas) contains the three main components carbon monoxide (CO), CO_2 and H_2 along with small amounts of methane, other hydrocarbons and trace substances (Mauerhofer et al., 2019). Typical syngas production varies from 1-3 Nm^3/kg biomass (Molino et al., 2016) depending on the feedstock and it usually has around 30% of the energy density of natural gas (Rauch et al., 2014).

The gasifier reactor designs vary according to the choice of the gasifying agent and the flow velocity. The overall nature of the reactions involved is endothermic (Binder et al., 2018). The gas composition is strongly influenced by the gasifying agent, temperature and elemental composition of the biomass (Mauerhofer et al., 2019). To partially exploit the energy content of the fuel for the gasification reactions, air, O_2 or a mixture of steam and O_2 in a stoichiometric ratio of $\lambda<1$ can be used, which causes complete oxidation of a portion of the biomass (Kaltschmitt et al., 2009). This type of gasification is referred to as autothermal and represented in the fixed bed gasifier, where a gas with low calorific values of 4-6 MJ/ kg is generated because of the 45-55% nitrogen present (Binder et al., 2018; Patuzzi et al., 2016). The investment costs of the fixed bed gasifier are low, but costly gas cleaning is necessary because of the nitrogen present in the resulting gas.

The fixed bed reactor has four separate zones where different reactions occur: drying, pyrolysis, oxidation and reduction (Molino et al., 2016). Two fixed bed gasifier types, downdraft and updraft, are operated globally and have their characteristic benefits and disadvantages, e.g., the updraft gasifier can utilize a broad range of feedstocks, but on the other hand, has high tar and water contents and requires, therefore, a more expensive gas cleaning procedure (Kaltschmitt et al., 2009).

The entrained flow reactor operates under much higher temperatures of 1300-1500°C and is fed with fine particles (0.1-1mm) or pretreated (torrefaction, pyrolysis) biomass. The benefits of this reactor type include low tar concentration, simple ash removal and the possibility of upscaling. The disadvantages, among others, are high plant and maintenance costs and that heat recovery is important. (Molino et al., 2016)

To address the nitrogen issue in syngas, the dual fluidized bed (DFB) reactor was developed and is the technology that has until now undergone most research in Austria (Anca-Couce et al., 2021). The DFB is a combination of two reactors. Using pure steam or CO_2 as gasifying agents is also possible, but an external heat supply to the gasification reactor is inevitable (Kaltschmitt et al., 2009) because of the endothermic reactions. In the combustion reactor, which is fluidized with air, full oxidation of char and extra biomass (when required) takes place and provides heat to the gasification reactor (Mauerhofer et al., 2021).

Syngas is the basis of various synthesis reactions to produce gaseous and liquid fuels and chemicals. However, syngas can also be directly utilized for heat and electricity generation in a combined heat and power plant (Rauch et al., 2014). Biomass gasification with CHP shows a relatively high overall efficiency compared to the direct combustion of woody biomass (Rivas et al., 2022) and higher than for biogas-CHP plants (Colantoni et al., 2021).

Relatively few papers exist on the production costs for syngas from biomass gasification, as it is usually not sold as a product. Syngas is generally burned for heat and power generation or upgraded to fuels. We were able to find a few papers on the investment cost and one article investigating the production costs of syngas integrated in a pulp and paper mill. The range of investment costs for fixed bed and fluidized bed gasifiers is 1965–5235 EUR/kW. The fixed operating expenses are between 3% and 10% (Copa et al., 2020; Lourinho et al., 2023).

In the study by Copa et al. (2020), 2940 EUR/kW are used as investment costs for a downdraft biomass gasifier plus gas cleaning and conditioning units, with costs for the power generator unit not included. The downdraft gasifier can be used for electricity generation and is less expensive than a dual-fluidized bed system.

(Arena et al., 2010) examine two distinct configurations for small-scale biomass gasification aimed at subsequent electricity generation, applying a discount rate of 5%. Revenue solely originates from the sale of electricity. Opting for a gas engine over an externally-fired gas turbine yielded higher internal rates of return, primarily due to reduced investment costs. Abdul Malek et al., (2020) evaluated electricity production through biomass gasification routes in Southeast Asian and EU countries in a review paper. Profitable operation, with payback times of 5-6 years, can be achieved under specific conditions, especially with low investment estimates. A key factor of profitability is the investment costs. The findings suggest that investment subsidies can contribute to reach economic feasibility. Guerrero et al., (2023) explore the co-production of syngas and biochar for use in steel manufacturing, aiming to enhance economic profitability. The plant with a biomass processing capacity of 10 kt/yr was evaluated to be the most promising and showed a payback time of approximately 7 years.

The investment costs of the GoBiGas DFB-gasifier in Sweden were approximately 5800 EUR/kW for 20 MW output capacity installed (Thunman et al., 2019). These assessed costs refer only to the gasifier and gas cleaning system. Ahmadvand & Sowlati (2023) investigate a 38 MW_{out} air-blown fluidized bed gasifier integrated at a pulp and paper mill in Canada with total syngas production costs of approximately 60 EUR/MWh.

When using the syngas directly for electricity generation, the process has the potential to curb emissions compared to NG-based electricity generation in g $CO_{2\ eq}$/kWh by > 85% compared to natural gas (Martinez-Hernandez et al., 2022). However, the emission reduction potentials depend on the type of biomass. Costa et al. (2022) investigated the utilization of forestry biomass together with olive pomace in a CHP gasification system for small-scale decentralized energy production. The capacities of the investigated system are 20 kW electric and 40 kW thermal. The CO_2 footprint of the electrical energy produced is approximately 140 g $CO_{2\ eq}$/ kWh, lower than most of the national electricity mixes in EU countries in 2022 (EEA, 2023). However, bioelectricity production exhibits higher emissions compared to wind and PV electricity production (Hengstler et al., 2021). Thermal energy produced has a lower CO_2 impact with approximately 29 g $CO_{2\ eq}$/ kWh (Costa et al., 2022). Activities in the supply chain are responsible for less than 3% of the impact. Although the olive pomace accounts for only 8% on a mass base, the total CO_2 emissions in the system are 17% higher than in the wood supply chain. The authors note that this type of energy production is intended for installation in areas where traditional energy plants face challenges in deployment due to infrastructure limitations.

2.1.2.4. Bio-Synthetic natural gas

Besides the major components of syngas H_2, CO and CO_2, unintended and equipment-damaging components are present in the gas mixture resulting from biomass gasification. These harmful components must first be removed before the methanation can be performed (equations 1 and 2). Catalytic methanation is usually performed under high pressures of up to 100 bar and temperatures between 200 and 550°C. Research at the GoBiGas plant has shown that biomass-to-biomethane efficiency of 70% can be reached (Thunman et al., 2019). Millinger et al. (2017) modelled the production of green gases from biomass and 57.9-72.6% are the simulation results.

Two main reactions are involved in the methanation process:

$$CO_2 + 4H_2 \leftrightarrow CH_4 + 2H_2O \tag{1}$$

$$CO + 3H_2 \leftrightarrow CH_4 + H_2O \tag{2}$$

Biological methanation occurs under anaerobic conditions, atmospheric pressure and much lower temperatures between 40 and 70 °C. In their review paper, Götz et al. (2016) compare catalytic and biological methanation. Smaller reactor sizes can be used for the same gas flow in the catalytic methanation. Andreides et al. (2022) investigate the coupling of a thermochemical process, which can be used to convert hardly biodegradable substances, with an anaerobic digestor for the methanation. This approach can be used to convert a variety of different biomass feedstocks. However, the costs of the combined process are not thoroughly assessed yet. When processing biomass feedstocks with initially high moisture content, hydrothermal gasification can be a suitable choice (Mian et al., 2015). Organic compounds can be directly converted to methane (CH_4) and CO_2 (Kruse, 2009).

The risks can increase with larger scales because the biomass availability can change from year to year (Roni et al., 2023). (Fuhrmann et al., 2022) investigate the operating costs of bio-SNG across various scenarios of industrial wood chip prices, spanning from approximately 26 EUR/t DM to 149 EUR/t DM. According to Singlitico et al. (2019), the production costs of bio-SNG under cost-optimal conditions are between 69 and 115 EUR/MWh. Veress et al. (2020) investigate bio-SNG production using low-grade feedstocks such as sewage sludge in a gasification plant with a 10 MW output capacity. The scale is relatively small compared to feasible industrial scales. However, the results are promising as the production costs are approximately 105 EUR/MWh in the base case and can be reduced by subsidies and negative purchase prices of sewage sludge to 19.2 EUR/MWh. The average natural gas prices for non-household consumers in the EU were approximately 30 EUR/MWh in 2020, 42 EUR/MWh in 2021 and 62 EUR/MWh in 2023 (Eurostat, 2023a).

Thunman et al. (2019) use cost data of the GoBiGas plant in Sweden to show the influence of upscaling on the production cost. 158 EUR/MWh for the 20 MW commercial plant, 85 EUR/MWh for the 100 MW plant and 71 EUR/MWh for a 200 MW bio-SNG plant are calculated. Table 2 shows the production costs of different scales and studies. Substantial reductions in investment costs are not expected from technological learning at least in the short term, because most components are already commercially available. The plant components accounted for less than 20% of the total investment cost. The largest expenditures result from construction and auxiliary equipment (Thunman et al., 2019). Other authors, such as Batidzirai et al. (2019), calculate slightly lower production costs of 62-89 EUR/MWh for a gasification plant with 100 MW biomass input and 46.8–61.9% efficiency. Interestingly, the production costs are relatively low, although costly short-rotation wood as feedstock was used. (Ahlström et al., 2022) investigate CO_2 utilization in biomass gasification processes. The aim of the analysis is to examine whether storage or utilization of CO_2 are more economically viable. The authors explain that there is a trade-off in CCS being more economical, however, allowing more fossil fuels remaining in the system compared to CCU.

Table 2. Production cost of bio-SNG for different feedstocks and scales in EUR_{2023}.

Feedstock	**Production costs [EUR/MWh]**	**Source**
Sewage sludge	105	(Veress et al., 2020)
Short rotation wood	80	(Batidzirai et al., 2019)
Forest residues	102	(Singlitico, et al., 2019)
Forest residues	71-158	(Thunman et al., 2019)

Residues in the form of lignocellulosic biomass have a greater potential to decrease GHG emissions when used as feedstock for green gas production than energy crops (Kargbo et al., 2021). However, less data is available for bio-SNG production because there are few demonstration plants in operation. Singlitico et al., (2019a) suppose that hybrid LCA (LCA + thermodynamic model) is necessary.

The global warming potential reduces by 78% in the long term when using bio-SNG in transport, according to Watanabe et al., (2022). The emissions for cultivation and conversion of forest residues correspond to 40 g $CO_{2\ eq}$/kWh plus additional 108 g $CO_{2\ eq}$/kWh (GWP 20) or 36 g CO_{2eq}/kWh (GWP 100) respectively, for fuel distribution and use. Kolb et al. (2021) find a large variety of negative values of -86.9 g CO_{2eq}/kWh (GWP 100) due to the replacement of fossil fuels in district heating up to 224 g CO_{2eq}/kWh (GWP 100). The average value is 44.5 g CO_{2eq}/kWh (GWP 100). It is also possible to achieve negative emissions by applying bioenergy carbon capture and storage (Olsson et al., 2020).

2.1.2.5. Hydrogen

The most applied process globally for hydrogen production is still steam methane reforming (SMR). The same process can be carried out with biogas instead of natural gas as feedstock. Hydrogen can also be directly produced through biomass gasification with steam and then separated from the syngas. According to Lepage et al. (2021), biomass gasification is the most studied technology for hydrogen production from biomass and also has the highest technical readiness level. A promising technology for H_2 production is sorption-enhanced reforming in DFB gasification. The usage of limestone as bed material makes in-situ CO_2 removal possible. In this way, a H_2-rich syngas with approximately 70 vol% H_2 can be reached (Schmid et al., 2021). Simultaneously a CO_2 stream with high CO_2 concentration >90% makes this process a suitable CCS technology (Schweitzer et al., 2016).

Kruse (2009), investigates the production of H_2 through hydrothermal gasification. Sub- or supercritical water is used as a solvent for this purpose, leading to fast degradation of the macromolecules of the feedstock. Temperature is the factor with the highest influence on H_2 yields. Okolie et al. (2020) examine the gasification reactions of model compounds. Increasing temperature combined with longer reaction times resulted in higher hydrogen yields. Increased reaction time at lower temperature levels did not influence hydrogen yields. However, a major disadvantage of HTG is the large amounts of heat required to bring the water up to 600°C. Therefore, heat recovery is essential to the feasibility of the overall process. Hydrothermal gasification is expected to reach industrial scale by 2025 (Jens et al., 2021).

The integration of hydrogen can lead to technical challenges when using the current infrastructure. Quintino et al. (2021) discussed limitations and prospects of biomethane and hydrogen integration in natural gas infrastructure. The main findings are:

- Transportation systems, predominantly constructed with steel, are susceptible to high concentrations of H_2.
- Hydrogen's lower energy density necessitates an increase in flow rate, limited by compressor stations. Turbines at these stations also face constraints on the amount of blended hydrogen.
- Natural gas is typically stored underground in salt caverns or aquifers. While aquifers pose no storage issues for biomethane, hydrogen cannot be stored in aquifers due to its reaction with bacteria, leading to the formation of hydrogen sulfide.

Hydrogen production costs depend on regional circumstances and raw material costs (Yukesh Kannah et al., 2021). In Europe and China, hydrogen production costs applying SMR were the highest due to fossil fuel costs (IEA, 2018). The hydrogen production costs for coal gasification are similar to those for SMR (Lepage et al., 2021).

Biomass-based hydrogen production has received less research attention compared to electrolysis and few publications were found on production costs. Biomass gasification is not cost-competitive against fossil fuel-based processes and has approximately 2-3 times higher production costs under natural gas prices of 2020. Hydrogen production costs analysed by Salkuyeh et al. (2018) are between 3.7 and 4.1 EUR/kg H_2 (112-123 EUR/MWh LHV H_2). All types of waste streams should be converted into value-added products to enhance sustainability and economic feasibility of biomass conversion. Özdenkçi et al. (2019) investigated the integration of supercritical water gasification (SCWG) process in a pulp and paper mill to convert black liquor into syngas. Production costs vary from 1.7 – 3.8 EUR/kg H_2. However, there was no price for black liquor available and the inaccuracy was reported to be 30-50%. The authors therefore suggest that the techno-economic assessment should be repeated. A novel process provides heat to the DFB gasification with solar energy. Production costs are calculated in the range of 2.9- 3.5 EUR/kg H_2 by Boujjat et al., (2021). As a reference, the production costs for hydrogen derived from water electrolysis can be used as the benchmark. They vary widely in the literature. The type of electrolyzer and the electricity costs are major factors influencing the overall costs (IEA, 2021a). Biomass-based hydrogen production can be competitive compared to electricity-based production under current market conditions and electrolyzer investment costs.

Emissions caused by biomass-based hydrogen production depend on the feedstock and production process. The reference method for fossil-based hydrogen is steam methane reforming (3) of natural gas and subsequent water-gas-shift reaction (4). Large quantities of CO_2, in the range of 9-11 kg CO_2/ kg H_2 occur in this process (Salkuyeh et al., 2018), (IEA, 2021a). When CCS is applied in the process chain, lower emissions can be achieved, but are still far from zero. Dawood et al. (2020) discuss what level of emissions permit calling H_2 green in their review. Green hydrogen is produced using electricity from renewable energy sources. Brown or grey hydrogen is generated from fossil-based processes without effective carbon capture, resulting in high emissions. Blue hydrogen lies between these two options, as it is also produced from fossil fuels, however, combined with CCS to reduce its climate impact (Ajanovic et al., 2022). Salkuyeh et al. (2018) calculate that H_2 from auto-thermal reforming or steam-methane reforming and CCS still results in 1.9 – 3.5 kg $CO_{2\,eq}$/kg H_2.

$$CH_4 + H_2O \leftrightarrow CO + 3H_2 \tag{3}$$

$$CO + H_2O \leftrightarrow CO_2 + H_2 \tag{4}$$

Utilizing renewable energy for water electrolysis or biomass gasification are considered currently the most sustainable ways of producing H_2. However, when CCS is applied to biomass gasification, it is possible to achieve net negative GHG emissions by carbon removal from the atmosphere (Salkuyeh et al., 2018). Full et al. (2023) show in their analysis a 2,67 times higher potential for CO_2 removal of biomass-based hydrogen and CCS compared to biomethane and CCS (4.4 kg CO_2 removal vs. 1.65 kg CO_2 removal for the same biomass input). However, the efficiency is lower at 40% compared to 44% and higher capital costs and additional infrastructure are needed for hydrogen production. Patrizio et al. (2021) examined different methods of converting biomass throughout the value chain. The optimal use of biomass varies depending on whether the goal is to mitigate emissions or remove CO_2. Biomass-based hydrogen production with CCS can be a noteworthy mitigation strategy in countries with a high CO_2 footprint of the electricity grid.

2.1.2.6. Comparison of production costs

Economic competitiveness of biomass-based gases is important for a successful deployment in the long term (Festel et al., 2014). Different strategies for cost reduction can be followed: economies of scale, intermodal transport, integration with existing industries and supply chain configurations (de Jong et al., 2017). However, certain trade-offs must be considered, e.g., the unit production cost of fuels decreases with larger plant size, but the increased feedstock demand results in longer transportation distances. Indicators from the discounted cash flow method are commonly used to evaluate the economic viability of biomass-based gases (Baena-Moreno et al., 2021; D'Adamo et al., 2021; Gebrezgabher et al., 2010; Perta et al., 2019).

The production costs of the biomass-based gases investigated are shown in Figure 7. The studies by Billig & Thraen (2017) and Thunman et al. (2019) showed economies of scale in their results. The production costs of biomethane and bio-SNG decreased significantly at larger production scales. The analysis of the literature also showed that low-cost feedstocks such as sewage sludge and biowaste are favorable from the economic perspective.

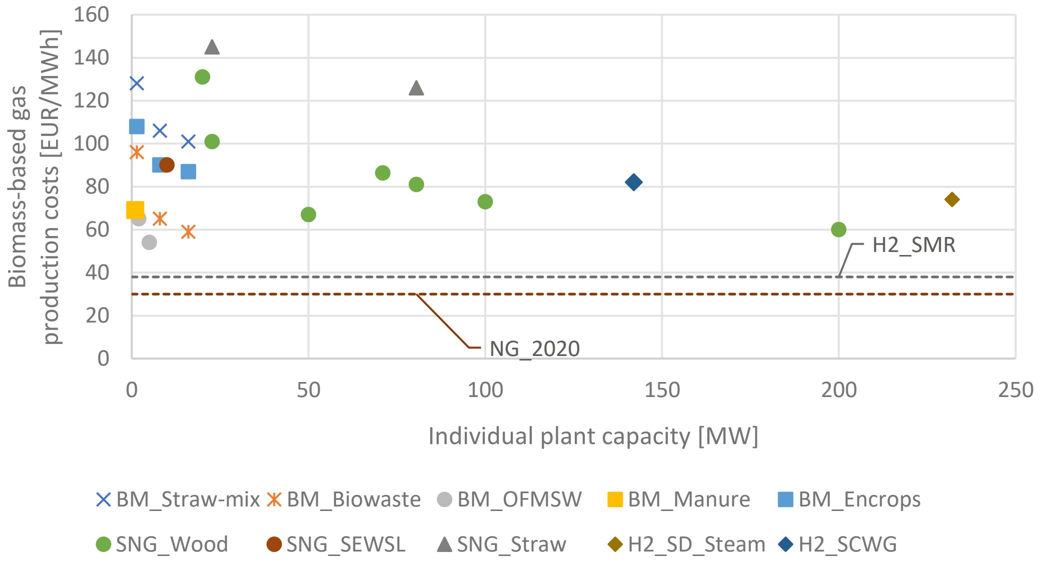


Figure 7. Production costs of biomass-based gases in EUR_{2020}. The dotted lines show the reference fossil fuel market prices for natural gas and H_2 derived from steam methane reforming (SMR) in 2020. BM= biomethane, H2= hydrogen, OFMSW= organic fraction of municipal solid waste, Encrops= energy crops, SCWG = supercritical water gasification, SD_steam = solar-driven steam gasification of biomass, SEWSL= sewage sludge, SNG= synthetic natural gas. Source: (Radosits et al., 2024a).

2.1.2.7. Comparison of greenhouse gas emissions

The environmental considerations regarding GHG emissions of biomass-based gases are discussed in this section. The emission reduction potential is a major reason to use biomass for energy. Cowie et al. (2021) explain the common misconceptions about the carbon neutrality of forest bioenergy systems and how they can be used to transition to a renewable energy system. CO_2 emissions from biomass usage are seen as carbon neutral because the CO_2 was formerly taken up by plants for their growth. However, the production of biomass-based gases is not actually carbon neutral because emissions are generated along the process chain, for example, by transportation of biomass, fertilizer usage, conversion processes, etc. Not only does the conversion technology influence the overall emissions, but feedstock-related emissions may contribute substantially. D'Adamo et al. (2021) analyse the environmental benefits of integrating biomethane production and waste management in a circular economy. Biomass cultivation, harvesting and transport substantially influence the environmental impact. The usage of local biomass is the most environmentally friendly and economically feasible way of producing biomass-based gases (Kargbo et al., 2021). Wood residues and biowastes have a lower environmental impact than the conversion of energy crops, primarily because the production of these crops involves agricultural activities such as fertilizer application, which currently relies heavily on fossil fuels (Rivas et al., 2022).

Figure 8 shows GHG emissions for biomass-based gases with data from the German life cycle database ProBas (2015) and from selected references in the literature. The embedded emissions in the production process and from combustion were considered and biogenic CO_2 released from combustion is seen as carbon neutral (Salkuyeh et al., 2018). Emissions for specific use cases, such as transport, heating, etc., were not included.

The lowest emissions can be achieved by biomass gasification using wood residues to produce bio-SNG or H_2. A significant influence on biomethane emissions stems from fertilizer usage for energy crops. The emissions for natural gas depend on indirect emissions by leakages.

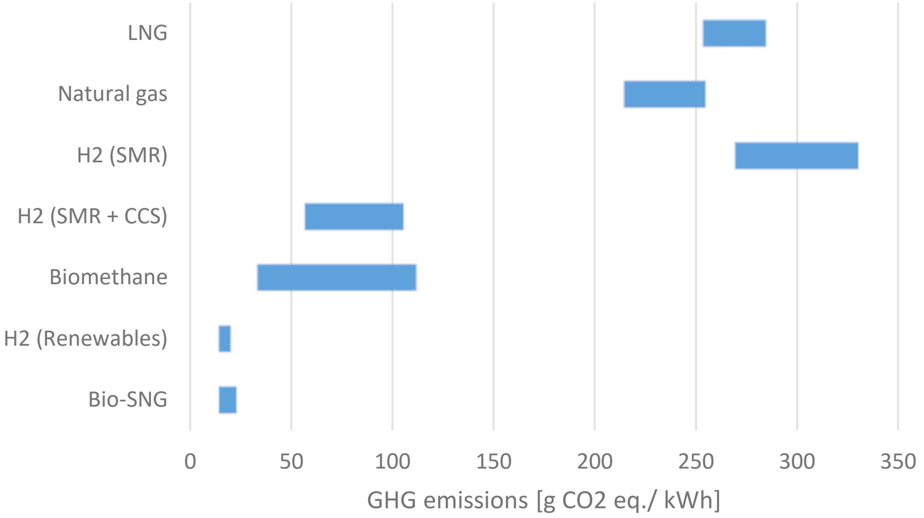


Figure 8. Greenhouse gas emissions of biomass-based gases production and combustion compared to the emissions resulting in use of natural gas. LNG refers to liquefied natural gas transported via ships. Data sources: (Al-Qahtani et al., 2021; Deutscher Bundestag, 2023; ProBas, 2015; Salkuyeh et al., 2018)

2.1.3. Emerging technologies

The research in new reactor designs aims to reach high efficiencies at low costs and to address the issue of utilizing feedstocks with varying conditions such as biomass in municipal solid waste. Francesco Zito et al. (2022) investigate different membrane designs and several permeation steps that not only save membrane area but also increase the purity of biomethane. Jung et al. (2022) examine a two-stage dynamic membrane reactor system with a comparable high energy recovery of 79%. Jafri et al. (2020) give an overview on the major emerging gasification reactor designs in recent years. Microwave-assisted gasification is highlighted among the mentioned technologies due to its ability to provide uniform heating and facilitate rapid thermal reactions (Arpia et al., 2022). Focusing on waste feedstocks, also the plasma technology seems promising, because almost any waste material can be processed (Akbarian et al., 2022). The conversion of waste to syngas was already demonstrated in a pilot plant of the National Renewable Energy Laboratory of the USA (Kramer and Haspel, 2022).

Dark fermentation and photofermentation (Keskin et al., 2011) are alternative biological processes for hydrogen production. However, high production costs compared to other technologies (Salkuyeh et al., 2018) and also lower yields (Lepage et al., 2021) are still the major challenges.

2.1.4. Biomass-based gas potentials

If using biomass as feedstock, it must be considered that it is a limited resource and there are conflicts with other sectors (Baumann et al., 2021; Muscat et al., 2020). The competing demand for agricultural land to produce food, feed and fuel will likely become stronger in the future (Poore and Nemecek, 2018). It is therefore essential to focus on residues and waste biomass to produce biomass-based gases.

The circular economy plays a vital role in the agricultural and bioenergy industries. (Muscat et al., 2020) state that it is essential to determine priorities for biomass usage.

Most countries in the EU process food waste and agricultural residues, except for Germany, which uses mainly energy crops (Schmid et al., 2019) and has the highest biogas production capacities (Taboada et al., 2021).

Although agricultural residues and wastes are already used in biogas production, considerable unused potential is available. In a bottom-up study, the IEA assessed the overall technical potential for biomethane production by anaerobic digestion and biomass gasification for 2018, considering only feedstocks with no food or agricultural land competition. It was estimated at around 730 Mtoe (30.54 EJ) and corresponds to 21.3% of worldwide gas demand. A huge gap exists between this potential and the actual production of 35 Mtoe in 2018 (IEA, 2020). The ambitious target of 35 billion cubic meter of biomethane in the RepowerEU plan for 2030 (European Commission, 2022b), which refers to 10.7 % of the natural gas imports and 8.9% of the usage in 2020, is also still a long way from the current production quantities of biomethane, which correspond to approximately 3.5 billion cubic meters (EBA, 2022).

A main driver for the developments in biomass-based gas production is the need for decentralized energy production (Akbarian et al., 2022). Logistical challenges arise from the low bulk density and dispersed availability of biomass. Rogala et al. (2023) discovered in a case study conducted in Poland that around 90% of the sources for biogas production are expected to have capacities of less than 100 Nm^3/h. While many components, such as gas cleaning, are commercially available for plants larger than 100 Nm^3/h in scale, downsizing the technologies would be necessary, which in turn poses economic challenges.

The economic potential depends on the CO_2 price and natural gas price. First low-cost feedstocks, e.g., manure and sewage sludge, will become cost-competitive. Therefore, the realistic potential will be lower than the full technical potential. In the case of EU-27 + UK, the overall potentials of feedstocks for advanced and waste-based biomass-based gas and biofuel production in 2030 and 2050 amount to 46-97 Mtoe and 71-176 Mtoe respectively (Imperial College London et al., 2021). Figure 9 shows the sustainable biomass potentials compared to natural gas consumption in 2020. Primary energy demand was approximately 1380 Mtoe, which was 5.6% less than in 2019 due to Covid-19. The final energy consumption in the EU in 2020 was 885 Mtoe (Eurostat, 2022).

Hydrogen derived from electrolysis can also be used to enhance the output of bio-SNG by 2.2 times when using steam gasification and 3.1 times in the case of oxygen gasification (Hannula, 2016). Using forest residues combined with hydrogen integration would make the production of additional 18-28 Mtoe/a bio-SNG in 2030 possible. When using all kinds of biomass, the potential becomes even higher.

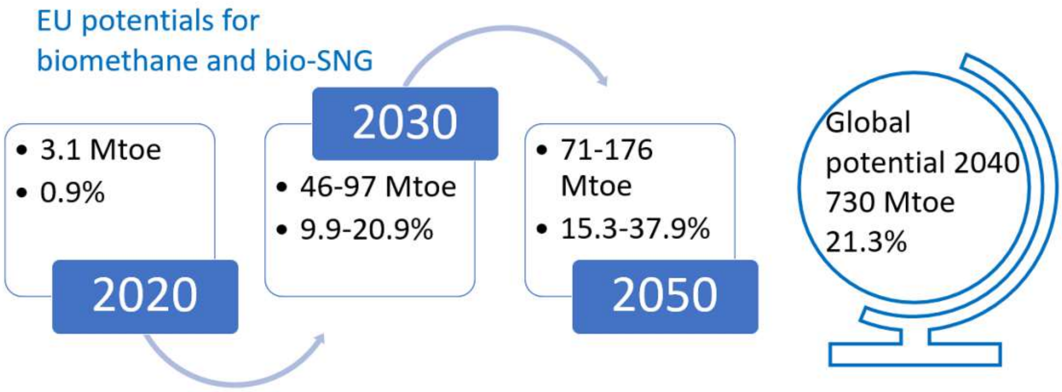


Figure 9. Potentials for biomethane and bio-SNG production in the EU-27 + UK and globally. The unit is Megaton oil equivalent. The percentages give the correspondent amount of natural gas consumption in 2020. Data sources: (IEA, 2020; Imperial College London et al., 2021).

2.1.5. Policy framework

Although substitutes for natural gas are renewable energy sources and contribute to a circular economy, there is still a lack of political support and public acceptance. Most of the EU member states have an existing infrastructure for natural gas and meet the important requirements for biomethane deployment. The minor changes in the existing gas network would generate relatively low costs for transporting and storing biomethane and compensate for the production costs (Speirs et al., 2018). However, a major issue is the lack of a reliable policy framework and support schemes (Kampman et al., 2017). The limited establishment of a common European biomethane register has hindered the growth of an international biomethane market (Gustafsson, 2024).

Taifouris & Martín (2023) claim that the valorization of wastes into green gases in terms of a circular economy is more important than ever in reducing the dependence on natural gas imports. More than a third of Spain's natural gas demand could be covered by green gases if the necessary investments are made, though without distinguishing between biomass-based and power-to-gas. D'Adamo et al. (2023) derived several policy implications from their profitability analysis of biomethane in Italy. The processing of organic municipal waste is economically feasible. However, incentives are necessary for small plants and information campaigns should be conducted. Khadivi & Sowlati (2022) investigated the value of an investment into biomass gasification at a pulp mill site with a multi-criteria analysis. The production of bio-SNG can increase economic viability and lower GHG emissions. Nevertheless, government incentives, changes in carbon accounting and stable market conditions are required to reduce the investment risk. Market-based assessments can offer a clearer insight into economic uncertainties as well. Zetterholm et al. (2020) explored forest-based biorefineries, revealing that the required policy support increased by 13-44% compared to a techno-economic model assuming stable biomass prices.

It is made clear in several publications that either subsidies or appropriate carbon pricing is important for the deployment of biomass-based gases. Table 3 gives an overview on selected papers discussing influential policy instruments.

Table 3. List of selected papers analysing policy instruments for the promotion of biomass-based gases.

Country	**Investigated policy instrument(s)**	**Major findings**	**Authors and year**
Belgium	Carbon prices	The development of the CO_2 price is the main driver for the fostering of biomethane plants. They will reach economic competitiveness to natural gas at an 85% emission reduction target in a cap-and-trade emission certificate market.	(Roach and Meeus, 2023)
Germany	Incentives	Carbon prices show a limited effect on the use of biomass-based gases in transport without incentives.	(Janke et al., 2022)
UK	Carbon prices	The conversion of organic waste into biomethane offers environmental benefits such as emission savings per treated ton of waste. However, the biomethane plants are not profitable without carbon taxes of 36.7 to 68.1 EUR/ ton CO_2.	(Gupta et al., 2022)
Canada	Government incentives and changes in carbon accounting	A mixture of different policy measures, such as environmental credits, higher incentives and lower loan rates should be pursued to increase the profitability of biomass gasification of waste streams from a specific investigated pulp and paper mill.	(Khadivi and Sowlati, 2022)
Germany	EU regulations and standards	GHG mitigation costs become a central aspect in comparing different biomass conversion processes as RED II came into force. Due to the credit given for manure treatment by the RED II methodology, this process route shows the highest GHG mitigation potential.	(Oehmichen et al., 2021)

Greece	Carbon prices and incentives	Different policy interventions such as landfill taxes, carbon prices, etc. are discussed. A tipping fee could make biomethane cost competitive with natural gas.	(Paris et al., 2021)
Austria	Carbon prices and subsidies	Investment subsidies or carbon taxes can lead to economic feasibility of bio-SNG production. Production costs of 69-115 EUR/MWh are calculated while incentives of 26-78 EUR/MWh are required to reach the break-even point.	(Veress et al., 2020)
Germany	Carbon prices	Economic competitiveness of biomass gasification increases with a carbon price on natural gas.	(Koch et al., 2020)
Ireland	Incentives	A novel method for large-scale bio-SNG production and subsequent injection into the gas grid is developed.	(Singlitico et al., 2019)
Germany	Incentives	EU countries' standards and quality requirements differ depending on the intended use for grid injection or transport fuel. Different national requirements have a negative effect on biomethane use in domestic transport (Schmid et al., 2019).	(Schmid et al., 2019)
Sweden	Carbon prices	A sector specific CO_2-cost is investigated to determine the profitable use of bio-SNG in the transport sector. The current Swedish CO_2-tax, the highest in Europe, is high enough to reach the economic feasibility of the investigated scenarios.	(Holmgren et al., 2018)

The most important policy instruments for the deployment of green gases at the EU level are the Renewable Energy Directive 2023/2413 and the European Emission Trading System (EU ETS). However, biogas production usually has a strong local connection and municipal policies have a major influence on local developments. Gustafsson (2024) describes the role of municipal organizations as actors in waste management and in creating local demand for biogas.

Biogas-promoting policies have been in place in Europe for 40 years. The first phase of promotion in Europe targeted electricity and heat production as the dominant uses of biogas (Mathieu and Eyl-Mazzega, 2019). Examples of policy implementation in the biogas and biomethane sector provide valuable insights for the deployment of biomass gasification for synthetic natural gas. Flexibility services will become more important in a renewable energy system. Schipfer et al., (2022) underscore the importance of policy instruments and certification schemes to support seasonal and long-term flexibility services provided by bioenergy. An example of flexibility-promoting policies can be found in Germany, where the aim is to incentivize flexible power production through output-related payments for a dedicated share of the capacity. Thrän et al. (2023) propose policy adjustments in Germany including extending remuneration periods and providing extra earnings for flexibility.

A second phase of policy support started in the early 2010s, when several countries started to shift from biogas-based electricity generation to premiums for biomethane production. Denmark incentivized the integration of biomethane into the grid, leading to its emergence as a significant exporter in the biomethane market (Gustafsson, 2024). Sweden, where most biomethane producers are not connected to the main grid, successfully increased local biomethane production and implemented a new support scheme for the upgrading of biomethane and liquefaction for transport applications. However, the phasing out of combustion engines will bring new challenges to the Swedish biomethane market (Klackenberg and Swedish Gas Association, 2023). The National Energy and Climate Plan of the Czech Republic proposes financial and institutional support for transforming existing biogas plants into biomethane producers (European Commission, 2024b). However, this transition could put additional pressure on the electricity grid amid ongoing electrification and decarbonization efforts, when electricity generation capacity is reduced. Approximately 7% of the country's electricity generation were derived from biofuels in 2024 and the government aims to phase out coal in power production. An advantage is the possibility to utilize heat in cases where currently only electricity is used.

2.2. Biogenic CO_2 as a carbon resource for renewable methane production

The European Union aims to ensure that carbon capture and utilization is achieved in a sustainable manner. The sources of CO_2 are therefore be restricted by the delegated acts supplementing the recast of the Renewable Energy Directive II (Hydrogen Europe, 2023). Carbon capture and utilization using CO_2 from fossil-based electricity production and industrial sources will not count as emission avoidance from 2036 and 2041. Only four sources of CO_2 will remain in the long term. Biomass-based CO_2 is one of these sustainable CO_2 sources.

In the past, in many publications such as from Lopes et al. (2021), the focus was on large industrial point sources from steel or cement manufacturing. The utilization of biomass-based CO_2 gains more attention in research based on the delimitation of sources for CO_2. However, a Scopus search for the term bioenergy carbon capture and utilization showed remarkably lower results than the umbrella term CCU. Further research on this topic is required.

Nevertheless, there exist also papers on the usage of biomass-based CO_2 for CCU. Koytsoumpa et al. (2021) analyse the potential of CO_2 from solid, liquid and gaseous biofuel consumption. Among the technological options, combined heat and power (CHP) plants emerge as key candidates for early BECCU deployment. Pilot and demonstration projects already show how post-combustion capture can be coupled with CHP, making it a practical and scalable route for implementation. Kuparinen et al. (2019) investigated the usage of CO_2 from pulp and paper mills. Cellulose from wood is used for paper production, but other carbon fractions, mainly lignin, are burned to generate heat and power, resulting in CO_2 release (Patel et al., 2023). Eggemann et al. (2020) conduct a life cycle assessment for e-methanol production using CO_2 from biogas plants. Schmid and Hahn (Schmid and Hahn, 2021) show a holistic picture of Germany's CO_2 supply and demand, including biomass-based CO_2 sources. Jafri et al. (2022) demonstrated that processes including CCU can enhance the amount of biogenic carbon that is converted to an energy carrier and contribute to large-scale greenhouse gas (GHG) emission reduction. Nonetheless, a disparity exists between the options that are socially optimal and those that are most economically viable.

2.3. Sector-coupling for enhanced biomethane and bio-synthetic natural gas production

Sector coupling refers to the integration of different energy sectors such as electricity, heating, transport and industry into a more interconnected and flexible system that maximizes the use of renewable resources. The concept goes beyond the simple utilization of surplus electricity, aiming at a systemic interconnection of energy carriers and infrastructures (Ramsebner et al., 2021).

The previously mentioned processes for biomass-based gas production cause CO_2 emissions during the conversion process. In many publications, the biogenic CO_2 is seen as carbon neutral, because it was taken up first by the plants during their growth. Despite this argumentation, the carbon utilization, meaning the actual conversion of biogenic carbon into the product is only between 30% and 40%, depending on the product.

Integration of hydrogen, as illustrated in Figure 10, can further enhance carbon utilization and boost the yields of biomethane and bio-SNG. The literature distinguishes between input- and output-oriented production of synthetic gases (Gorre et al., 2020). Input-oriented studies examine the available material and energy flows and aim to use these resources efficiently at low-cost. Output-oriented studies focus on product quantities or predefined targets. From a modelling perspective, the output-oriented approach can be understood as a hard constraint, since it sets a fixed production target.

Tartakovsky (2011) investigate the concept of enhanced biomethane production from wastewater with an integrated water electrolysis on a lab scale. Pääkkönen et al. (2018) are one of the first to examine different process schemes utilizing grid electricity to increase the methane output.

Van Dael (2018) analyse also a concept of enhancing the biomethane output from anaerobic digestion. Most of the produced hydrogen is piped to a gas converter, but a small share is directly introduced into the anaerobic digestion reactor. The CO_2 from the biogas upgrading is recycled and brought to the gas converter where it reacts with hydrogen to form methane. Michailos et al. (2020) explore the integration of an electrolyzer on an industrial scale into waste water treatment by anaerobic digestion. Jeanmonod et al. (2019) evaluate a sustainable biogas upgrading concept with solid-oxide electrolyzer based power-to-methane. The main challenges are dynamic production of biogas and renewable electricity from photovoltaics and wind power. Therefore, storage tanks are required. However, high costs are associated with gas storage. High efficiencies could be achieved, but the economics are not analysed.

The electricity needed for the electrolysis and the associated production costs of hydrogen are currently the major cost drivers and have the largest impact on the net present value (NPV) in the case of enhanced biomethane production. Under these circumstances this concept is not economically feasible (Van Dael et al., 2018). The production costs must be reduced so that the NPV becomes positive. Cost reductions for electrolyzers are expected due to learning effects (De Vita et al., 2018). Furthermore, Witte et al. (2018b) directly upgraded biogas with additional hydrogen in a catalytic methanation process to produce biomethane. Others examine biological methanation reactors (Sposob et al., 2021) or even directly injected hydrogen into the biogas plant with the result of increased methane concentrations (Bensmann et al., 2014; Voelklein et al., 2019). Pääkkönen et al. (2018) analyse the usage of excess electricity, which may originate from wind and solar energy, implying a fluctuating hydrogen supply. To achieve economic feasibility, either the investment costs of electrolyzers must decrease or the biomethane price must rise. Ghafoori et al. (2022) investigate biomethane production via landfill biogas upgrading and power-to-gas technology. The electrolyzer contributes approximately 75% of the total production costs. Studies such as (Calbry-Muzyka and Schildhauer, 2020) reported that H_2-enhanced biomethane production is the closest to economic feasibility among different power-to-gas process routes. Most papers, such as Katla et al. (2021), investigate using excess electricity, including a storage system.

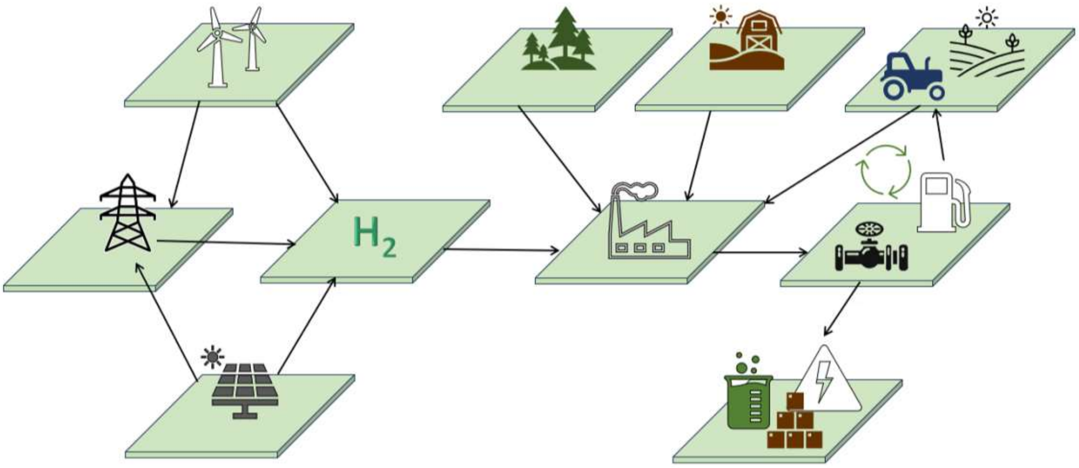


Figure 10. Integration of renewable energy and hydrogen into biomass-based gas production. Source: (Radosits et al., 2025).

Green hydrogen can also be used to enhance the synthetic natural gas output of gasification based-process schemes. Already in 2008, Gassner and Maréchal (2008) proposed the integration of H_2 in a gasification-based process to increase the carbon utilization of biomass. For the same purpose, Giglio et al. (2021) examine the integration of a high-temperature electrolyzer to increase the H_2 content in the product gas. Hannula (2016) analyses the potential for H_2-enhanced bio-SNG production and the required conditions to reach economic feasibility against the reference processes without hydrogen integration. The output of bio-SNG can be increased by 2.2 times when using steam gasification and 3.1 times in the case of oxygen gasification. The usage of forest residues combined with hydrogen integration would make the production of 18-28 Mtoe/a bio-SNG possible.

2.4. Utilization of surplus electricity for e-methane production in regional energy systems

Rising shares of variable renewable electricity sources require long-term storage and technologies such as power-to-methane to harness surplus electricity (Stančin et al., 2020). The current state of research on the use of surplus electricity for the production of e-methane is shaped by a range of technical, economic and system-level studies. The paper by Khalili et al. (2025) provides a comprehensive and systematic review of 1067 peer-reviewed studies that examine energy systems with at least 95% renewable energy (RE) integration, published between 1975 and 2023. E-methane is the most widely discussed electricity-based fuel after hydrogen and a central finding of the paper is that grid expansion remains essential but is not sufficient on its own. Batteries and power-to-X (PtX) technologies form the backbone of flexible, fully renewable energy systems (Satymov et al., 2025). Technically focused works, for example, Beyrami et al. (2022) analyse integrated systems for CO_2 capture and e-methane production using advanced thermodynamic cycles, yet place less emphasis on the utilization of fluctuating renewable electricity. In contrast, studies like Chauvy et al. (2021) investigate e-methane production integrated into industrial plants and highlight the economic benefits of using surplus electricity. Their findings show that production costs react most sensitive to electricity prices, emphasizing the cost advantage of producing e-fuels during periods of low-cost excess electricity.

Several studies concentrate on the operational flexibility and integration of power-to-gas technologies into renewable electricity generation. Gorre et al. (2020) use a Monte-Carlo analysis and cost-benefit analysis to analyse hydrogen storage and methanation capacities in dynamic operation. Outcomes of this study are that systems which rely on photovoltaics benefit from large hydrogen storages, whereas wind dominated systems can use large methanation units and small storages. Mucci et al. (2023) further emphasize the promise of flexible electrolyzers for variable electricity inputs but note that downstream processes such as methanation are not yet equally adaptable. However, Inkeri et al. (2021) show that dynamic methanation reactors are technically feasible and—if paired with hydrogen storage—can exceed 2000 full-load hours per year. Böhm et al. (2019) evaluated the demand for large-scale PtG projects and assume optimistic learning rates of 12-15%. Under these assumptions, proton exchange membrane (PEM) electrolyzers will gain advantages over alkaline electrolyzers (AEL). However, the costs in comparison to LNG prices remain a major challenge.

Other studies focus on the challenges associated with the transport and conversion losses of e-methane and hydrogen. Hank et al. (2020) evaluate the efficiency of PtX transport over long distances. Additional energy demand of 0.03-0.05 GJ/ GJ methane is required for liquefaction and transport. The regasification at the import terminal is not included. In another study, Patha et al. (2024) analyse the whole e-methane production chain with imports from Tunisia, Chile or the United Arab Emirates to Austria. The efficiency losses at import and export terminals are in the range of 2-4%. However, the costs can increase significantly, in the case of hydrogen for example from ~ 3 EUR/ kg to ~ 4 EUR/ kg (Heuser et al., 2019). Overall, e-methane as electricity storage shows low efficiency of 28-33.1% [19] and economic competitiveness with other electricity storage is low (Ajanovic and Haas, 2019; Raycheva et al., 2025). According to Baccioli et al. (2020), producing e-methane for storage purposes is unlikely to be economically viable in the short or long term.

Yan et al. (2024) investigate a PtX concept using an electrolyzer, a wind turbine and storages. Uncertainties in wind power generation are modelled using Monte Carlo simulation. The integration of e-methane production reduces CO_2 emissions, fossil energy use by ~ 39% and curtailment to nearly zero. Yilmaz et al. (2022) focus in their study on the EU using the PERSEUS model to optimize the investments in wind, solar, storage systems, electrolyzers and e-methane production, based on trajectories of the European Commission. Although the modelling is very detailed and the results show that integrating PtG into the system can lead to deep defossilisation. The issue of low round-trip efficiency remains.

The most relevant group of publications in the context of this paper includes modelling approaches that specifically address surplus electricity utilization for Power-to-X processes.

Kawakami et al. (2019) investigate the management of surplus electricity in Japan with a large scale-linear programming model in high temporal resolution. The authors note that different technologies such as batteries, electrolyzers and methanation are required for the management of surplus electricity, which arises under different CO_2 reduction targets. While the supply side is thoroughly modelled, these studies often neglect demand-side resolution. Similarly, Blanco et al. (2018) consider power-to-methane in a European context but do not resolve hourly timesteps. Their study is based on top-down CO_2 reduction targets. Bucksteeg et al. (2023) find that without properly crediting avoided CO_2 emissions, PtG units often operate when fossil generation sets electricity prices, potentially increasing system emissions.

In addition to system-level modelling and techno-economic assessments, several case studies provide valuable insights into the practical implementation and regional feasibility of PtG concepts, particularly for e-methane production. Koirala et al. (2021) investigate the interaction between electricity, hydrogen and gas markets and the effects on prices for the Dutch Infrastructure Outlook 2025, without assessing how much sectoral demand could be met by PtG based on surplus electricity. Al-Zakwani et al. (2019) evaluate Ontario's surplus baseload electricity for hydrogen production and allocation across four PtG pathways, including methanation. While hydrogen for mobility performs best in their analysis, e-methane shows long payback periods and poor economic performance. Lopez et al. (2024) conduct a case study on the energy system of the islands of Hawaii. The authors model a 100% renewable energy system by 2050. A limitation is that all islands are modelled as a single node. The self-supply from solar-based PtX is conducted with emphasis on the transport sector. Millinger et al. (2021) investigate the production of synthetic fuels using excess electricity in the context of a renewable electricity system in Germany. Although hydrogen and BEVs are seen as the most efficient technologies according to the authors, up to 70% higher climate benefits can be reached via synthetic fuel production, if hydrogen demand and surplus electricity are not already fully utilized elsewhere. The integration of CO_2 utilization with future electricity grids, accounting for dynamic electricity prices and competition for electricity remains a key research gap. These aspects are in the literature not sufficiently addressed in system-level analyses (Poluzzi et al., 2021). Cost-effective strategies are required to mitigate renewable energy curtailment while considering regional characteristics and the existing energy infrastructure on a system-level perspective.

2.5. Progress beyond the existing literature

Research on renewable methane production has expanded in recent years, yet several challenges remain unresolved. The literature lacks a systematic exploration of decentralized CO_2 utilization and the implications of policy design. Considering regulatory developments promoting the use of CO_2 from biomass-based resources, the analysis of techno-economic prospects of small-scale methane production (Radosits et al., 2024b) is a new contribution to the existing literature. Another less explored research field is the economic evaluation of hydrogen-enhanced bio-SNG production. Unlike many earlier studies focusing only on technical feasibility, this paper systematically compares hydrogen-enhanced biomethane and bio-SNG production against biomass-based reference cases, considering production costs, CO_2 avoidance costs and greenhouse gas emissions.

The new contribution in this field is based on the works of Bartik et al.(2024) and Pratschner et al. (2023). A linear optimization is used to minimize electricity costs and full-load hours for enhanced biomethane and bio-SNG production (Radosits et al., 2025).

Furthermore, the manuscript by Radosits et al. (under review) addresses the integration of e-methane production in electricity grids with high renewable shares, accounting for dynamic electricity prices and competition for electricity. Despite the diverse and growing number of publications, the self-sufficiency of gas consumption and the reduction of curtailment through domestic e-methane production have not been sufficiently investigated in regional energy contexts. By combining techno-economic analysis and system-level modelling in regionally differentiated case studies, this thesis responds to these gaps and contributes to a more comprehensive picture of the role of renewable methane in future low-emission energy systems.

3. Costs and perspectives of synthetic methane production using carbon dioxide from biomass-based processes

Bioenergy plays a crucial role in the energy system by offering flexibility services and contributing to energy security (Schipfer et al., 2022). The potential for biogenic CO_2 in the European Union is investigated because a target for biomethane production of 35 billion cubic meters was announced for the year 2030 (BIP Europe, 2022). In addition to biomethane production, the pulp and paper industry and biomass-based district heating are investigated as they belong to the most relevant sectors of biomass utilization (Malico et al., 2019). The capacity of most biomethane and district heating plants using biomass is less than 10 MW biomass input (Bioenergy4Business, 2016). An exception are large-scale pulp mills. Most pulp mills (72.2%) produce ≥ 100 kt product per year, corresponding to 270 kg CO_2/t pulp (CEPI, 2022).

3.1. Methodology

For answering the first research question, the following methodologies from (Radosits et al., 2024b) are applied in the analyses:

- Literature research was conducted to analyse the potential of CO_2 from biomass processes in the EU 27 with an outlook to 2030. The costs of CO_2 capture were derived from the literature.
- Hydrogen is required to produce e-methane. The costs for hydrogen are calculated with the levelized-cost method.
- The hydrogen costs are then used as input for the overall e-methane production costs.
- Finally, a SWOT analysis is conducted to compare e-methane and hydrogen process chains, considering the economic assessment results and technical aspects.

3.1.1. Techno-economic assessment

To conduct the techno-economic assessment, a process scheme is defined in Figure 11, which illustrates the schematic process chain for e-methane production via CO_2 utilization (Lopes et al., 2021). The system considers the biogenic CO_2 resulting from pulp and paper mills, district heating plants using biomass and biogas upgrading to biomethane. Methanation is conducted as separate processes after CO_2 capture and hydrogen production (Koytsoumpa et al., 2021).

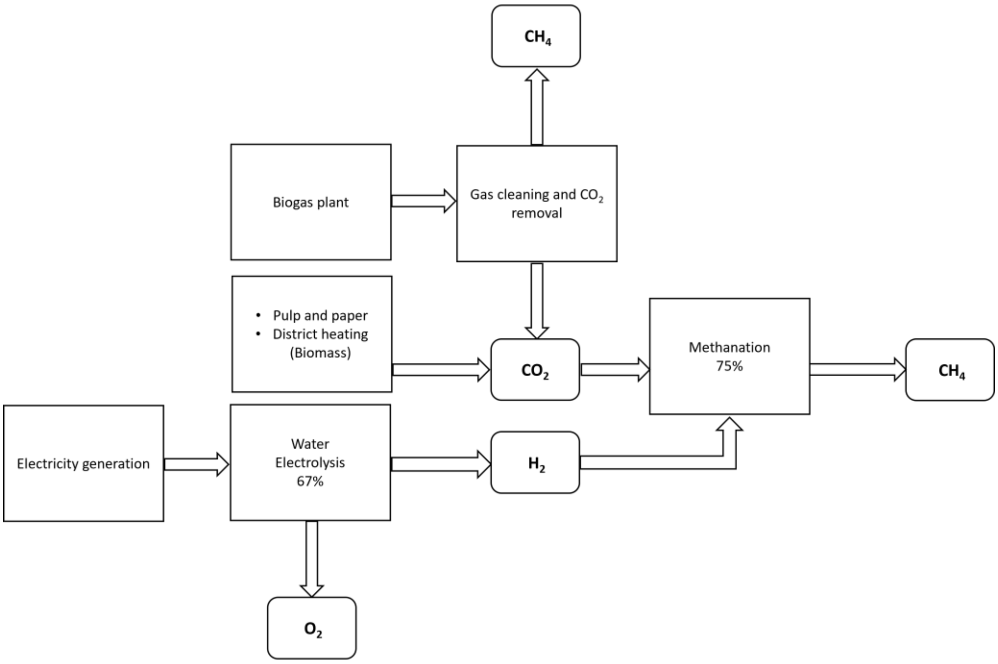


Figure 11. Process route of utilizing CO_2 for e-methane production. Data sources: (IRENA, 2020; Schmidt et al., 2018).

Alkaline and PEM electrolyzers are currently the most used technologies for hydrogen production via water splitting (IRENA, 2020). There are issues involved with the exclusive use of renewable energy, for example, the low number of full load hours and challenges in flexible fuel production. PEM electrolyzers were initially favored over alkaline electrolyzers for renewable electricity sources because they were thought to respond better to the intermittent behavior of the renewables (Shiva Kumar and Himabindu, 2019). However, in papers such as Bos et al. (2020) and Ince et al. (2023), alkaline electrolyzers are also coupled with wind turbines or a PV plant without the application of hydrogen storage.

In this work, both electrolyzers are compared and it is assumed that hydrogen storage can be avoided. Table 4 shows the technical parameters for the analysis. It is assumed that both electrolyzers have the same energy efficiency of 67%, as the literature gives a broad range. The efficiency is expected to increase to 74% in 2050 (IRENA, 2020). Electricity consumption for compression of e-methane is also considered in the case of gas grid injection. For the efficiency of methane synthesis, a value of 75% (Schmidt et al., 2018) and 90% CO_2 conversion was assumed. The maximum conversion efficiency achieved by the methanation in a single stage reactor with a 4:1 ration of hydrogen to carbon dioxide is approximately 82-85%. Adding a second and third reactor stage can increase conversion efficiencies >90% (Thompson, 2015). The overall process efficiency of e-methane production is assumed to be 49 % as consequence of the individual efficiencies.

Table 4. Technical parameters for hydrogen and e-methane production.

Technical parameters	**VALUE**	**UNIT**	**SOURCE**
Electrolyzer eff.	67	%	(IRENA, 2020)
Methanation eff.	75	%	(Schmidt et al., 2018)
CO_2 conversion rate	90	%	(Pratschner et al., 2021)
FLH (Grid)	8000	hours	(Pratschner et al., 2023)
FLH (Renewables)	1000-2600	hours	(DTU, 2023; European Commission, 2022)
CH_4 compression	0.22	kWh/ kg	(Steubing et al., 2011)
Water consumption	9-10	kg/ kg H_2	(Beswick et al., 2021)

The goal is to model the production costs of e-methane by 2050. The investment cost reductions depend on the scenarios of installed electrolyzer capacities. A sensitivity analysis is used to examine the influence of different parameters, such as the plant size on the overall production costs. The results in section 3.2 are shown in EUR_{2022}/ MWh.

3.1.1.1. Calculation of specific production costs

A standard method for calculating the specific costs per MWh is based on the annualization of investment costs over the project lifetime. This annuity method, initially applied for the calculation of electricity generation costs (NREL, 1995) is also commonly used for the evaluation of costs of gaseous energy carriers (Elhaus et al., 2024). It is conceptually different from the net present value (NPV). All future cash flows are discounted back to the present in the NPV method, resulting in a measure of the absolute value of a project in present terms. From the perspective of an investor, the NPV shows whether an investment is financially attractive and a positive value indicates that the return outperforms what could be earned from comparable alternative investments. The annuity method, by contrast, does not attempt to capture profitability directly. Instead, it converts the total discounted costs into a fixed annual amount, which is beneficial for comparing costs of different process routes in system-level analyses rather than tracking the return on individual projects (Gross et al., 2007).

The conversion of the project's investment costs is conducted through the capital recovery factor in equation (5), which incorporates the project lifetime and depreciation rate.

$$CRF = \frac{(1+r)^n r}{(1+r)^n - 1} \tag{5}$$

with:
CRF = capital recovery factor,
n = plant lifetime,
r = interest rate.

By including capital and operational cost components, a comprehensive measure of average unit production costs is assessed through the equations (6) and (7) based on the techno-economic assessment of Thunman et al. (2019).

$$c_{H_2} = \frac{CRF * I_0 + c_{O\&M} + c_{misc}}{FLH} + \frac{c_{ele}}{\eta} + c_{H_2O} \tag{6}$$

$$c_{fuel} = \frac{CRF * I_0 + c_{O\&M} + c_{misc}}{FLH} + \frac{c_{H_2}}{\eta} + \ c_{var} \tag{7}$$

with:
c_{H_2} = production costs of hydrogen [EUR/MWh],
c_{fuel} = production costs of e-methane [EUR/MWh],
I_0 = investment costs [EUR/MW],
FLH = full-load hours,
c_{H_2O} = costs for water [EUR/MWh H_2],
$c_{O\&M}$= fixed operating and maintenance costs [EUR/kW],
c_{misc} = miscellaneous costs such as insurance, taxes, etc. [EUR/kW],
c_{ele} = electricity costs,
η = energy efficiency of the process,
c_{var}=variable costs [EUR/MWh],
c_{CO_2} = variable costs including costs for CO_2 [EUR/MWh].

The parameters for the economic analysis are displayed in Table 5. The investment costs of the electrolyzers include all system components and the installation. These costs decrease in regards to the scale (IRENA, 2020). The investment costs used in this study for 2 MW_{el} alkaline and PEM electrolyzers are 1400 and 1800 EUR/kW_{el} and for 20 MW_{el} 900 and 1400 EUR/kW_{el} respectively (Detz and Weeda, 2022). Fees for the connection to the grid are added to these costs. The stacks need to be replaced after ten years, accounting for 50% and 60% of the system costs of an alkaline and PEM electrolyzer. Carbon capture costs as EUR/t CO_2 are included in the analysis as variable costs (Fuss et al., 2018). It is assumed that e-methane producers would cover carbon capture costs indirectly, for instance at a pulp and paper mill, by paying for the delivered CO_2. The investment costs of the methanation reactors represent the total costs, including plant installation (Bos et al., 2020). The system costs are adapted to 2022 price levels using the chemical engineering plant index. It is important to notice that the investment costs for electrolyzers are stated for the electricity input in kW_{el}, whereas for the methanation in product output kW_{out}.

The used system costs are conservative assumptions based on recent publications on fluidized bed methanation (Gorre et al., 2019; Schlautmann et al., 2021) which report higher values than estimations in other papers such as from (Götz et al., 2014).

Table 5. Parameters for the economic analysis of e-methane production.

Economic parameters	VALUE	UNIT	SOURCE
Investment costs			
Alkaline electrolyzer	900-1400	EUR/kW$_{el}$	(Detz and Weeda, 2022)
PEM electrolyzer	1400-1800	EUR/kW$_{el}$	(Detz and Weeda, 2022)
Methanation	2200-4300	EUR/kW$_{out}$	(Gorre et al., 2019; Schlautmann et al., 2021)
Fixed Operating & Maintenance			
Electrolysis	28-56	EUR/kW$_{out}$	(De Vita et al., 2018)
Methanation	3.5	% of IC	(De Vita et al., 2018)
Grid connection fees	70	EUR/kW$_{el}$	(ElWOG 2010, n.d.)
Variable costs			
Water costs	3.1	EUR/litre	(Water news europe, 2021)
CO_2 capture Biomethane	20-40	EUR/t CO_2	(Fuss et al., 2018)
CO_2 capture Pulp&paper/ District heating	60-90	EUR/t CO_2	(Onarheim et al., 2017)
Electricity costs (Grid)	90	EUR/MWh	(Eurostat, 2023b)
Electricity costs (Wind)	45	EUR/MWh	(De Vita et al., 2018; Kost et al., 2021)
Electricity costs (PV)	74	EUR/MWh	(De Vita et al., 2018; Kost et al., 2021)
Other parameters			
Interest rate	6	%	(Kourkoumpas et al., 2016)
Lifetime time	20	years	(Babarit et al., 2019)

3.1.1.2. Cost reductions through technological learning

The concept of technological learning provides a fundamental framework for understanding the cost developments of energy technologies. At its core, technological learning describes the systematic reduction in production costs and improvement in performance that occurs as a technology accumulates experience through production and deployment (Haas et al., 2023). These learning processes are commonly quantified using learning curves, which empirically link cumulative production to cost reductions, highlighting the potential for large-scale adoption of innovative energy solutions over time (Grübler et al., 1999; Neij, 2008).

Technological learning can lead to lower costs per kW installed. The learning rate gives the percentual cost reduction per doubling of unit output. The range of learning rates in literature varies tremendously. Bioenergy systems illustrate the principles of technological learning, but they also reveal the limitations of these processes. Technological development in this sector has shown that iterative improvements in conversion efficiency, feedstock logistics and system integration can reduce costs and environmental impacts (Junginger et al., 2006). Modular technologies such as photovoltaic modules, where standardization and mass production enabled rapid and predictable learning. However, existing bioenergy plants are typically customized to local feedstock availability and process specifications. This lack of modular design slowed the gains of technological learning and limits the potential for cost reductions (Neij, 2008). Unlike bioenergy, electrolyzers benefit from higher degrees of standardization, facilitating more predictable and rapid learning effects.

Schoots et al. (2008) analyse the historical learning rates of electrolyzer equipment and define a value of 18 ± 13%. Detz and Weeda (2022) use a low rate of 12 % and a high learning rate of 20% for their analysis. Reksten et al. (2022) estimate high learning rates of 25-30% for alkaline and PEM electrolyzers. The main argument for these high rates is that the scaling up has not been considered in previous publications. However, the highest learning rate for a technology in history has been seen for PV panels with 22% (Haas et al., 2023). The applied learning rates are derived from (Böhm et al., 2019), who assessed different learning rates of the main electrolyzer components. The difference in this work is that a learning rate of 18% is only used for the electrolyzer stacks. Other parts such as power electronics are assumed to be the conventional share and account for 50% and 40% of alkaline and PEM electrolyzer investment costs respectively. Technological learning is not applied for the conventional components (Haas et al., 2023). Stacks also need to be produced more often than the other components because the current stack lifetime is approximately ten years (IRENA, 2020).

For the methanation section, a learning rate of 10% can be found in the literature (Babarit et al., 2019). The equipment typically accounts for approximately 20% of the system cost and technological learning is rather derived from the plant engineering and project-specific costs (Thunman et al., 2019).

The total investment costs in equation (8) consist of conventional and new components. The cost reductions are calculated with the equations (9) and (10). The learning rates are only applied to the share of new components.

$$IC_{total} = IC_{new} + IC_{conv} \tag{8}$$

$$IC_{new}(t_1) = IC_{new}(t_0) * \left(\frac{Y_{t_1}}{Y_{t_0}}\right)^{-b} \tag{9}$$

$$LR = 1 - 2^{-b} \tag{10}$$

with:

IC_{new} = investment costs of new components,

IC_{conv} = investment costs of conventional components,

$IC_{new}(t)$= investment costs of a unit at time t,

$Y(t)$= installed capacity at time t,

LR = learning rate,

b= parameter for the extent of learning measured.

To determine the actual cost reduction, future installed capacities need to be estimated and incorporated into learning curve calculations. Table 6 shows the installed capacities for electrolyzers and methanation based on IEA and IRENA scenarios. At the end of 2022, approximately 690 MW electrolyzer capacities were installed globally. This number shall increase to 2200 MW at the end of 2023 (IEA, 2023b). For the 1.5°C climate target an increase to 550 GW in 2030 is proposed by the IEA. However, there can be some restrictions for this tremendous growth. For example, the current iridium mining makes only 3-5 GW of PEM electrolyzers installations per year possible (IRENA, 2020).

Therefore, two different scenarios are investigated for capacity installations of hydrogen. One is the business as usual (BAU) scenario with historic growth rates of 2015-2022 (IEA, 2021b), extrapolated for 2030 and 2050. The growth scenario is based on the Global Hydrogen Review 2023, where 175 GW in 2030 are feasible to reach and 3670 GW is the target for 2050. Currently, 2/3 of the total installed electrolyzers are alkaline, PEM accounting for approximately 1/3 and high-temperature solid oxide cell electrolyzers (SOEC) for less than 1%. This ratio is supposed to change in the investigated scenarios to 40:40:20 for alkaline, PEM and SOE until 2050 (Lloyd and Wang, 2024).

Table 6. Installed hydrogen and methane synthesis capacities in 2022, 2030 and 2050. The growth is based on literature data from the IEA and the business as usual (BAU) scenario was extrapolated based on historic capacity additions from 2015 to 2022.

Year	**2022**	**2030**	**2050**	**Source**
H_2_Growth	0.69 GW	175 GW	3670 GW	(IEA, 2023b)
H_2_BAU	0.69 GW	22 GW	445 GW	(IEA, 2021b)
Methanation	30 GW	65 GW	450 GW	(van der Zwaan et al., 2022)

3.1.1.3. Sensitivity analysis

From the literature analysis, the individual variables are expected to show different effects on the overall production costs of e-methane. Therefore, the following sensitivity analyses is conducted and the variables are modified in a range of ± 50%:

- Reductions in electrolyzer and methane synthesis reactor investment costs depend on the learning rates. The base cases for learning rates are 18% for electrolyzers and 10% for methanation.
- Hydrogen production costs are examined in relation to the full-load hours and the electricity price.
- Investigation of different variables on e-methane production costs: The initial value of operating hours was changed to 5000 hours, the capture costs to 60 EUR/t CO_2 and a scale of 5MW was chosen for the sensitivity analysis to depict a broad range of the variables. Other input data was not modified and used as stated in Tables 1 and 2.

The effect of carbon taxes on current market prices of fossil natural gas is also investigated as part of the sensitivity analysis. Emission factors of 297 g CO_2/ kg natural gas (Lechtenböhmer et al., 2005) cover the direct and indirect emissions resulting from sourcing, handling and the consumption of natural gas. The externalities of fossil fuel use were not reflected adequately in previous times. Therefore, the European Union adopted an emission trading system to set a price on carbon emissions of businesses. Carbon prices are very effective measures to restrict the use of fossil fuels and support alternatives (Holmgren et al., 2018).

3.1.2. Analysis of strengths, weaknesses, opportunities and threats

The method was designed in the 1960s at the Stanford Research Institute and related corporate planning circles to help managers of large companies improve long-term planning. Its early purpose was very practical: to give executives and managers a structured, participatory tool for identifying internal and external issues and aligning organizational strategies. According to Puyt et al. (2023), SWOT was conceived in the 1960s as a participatory planning tool with a much broader purpose than its common contemporary use. The framework aimed to facilitate dialogue and creativity, bringing managers together across organizational units to stimulate discussion, problem-finding and problem-solving, rather than simply enforcing top-down planning.

In academic contexts, SWOT analysis is often used as a structured framework to examine and evaluate complex systems, organizations, or phenomena in a systematic and holistic way (Pagot and Andrighetto, 2024). The SWOT analysis can describe the status quo and strategies for the future can be derived. This analysis aims to compare the technical aspects found in literature and results from the economic assessment for e-methane and hydrogen, which can also be directly applied as fuel (Wulf and Zapp, 2021).

3.2. Results

The results in this section begin with the quantified potentials of biomass-derived carbon dioxide in the European Union (EU 27). The following subsections emphasize cost reductions through technological learning and sensitivity analyses, followed by the results of the SWOT analysis.

3.2.1. Biomass-derived carbon dioxide potentials in the European Union

According to the Biomethane Industrial Partnership (BIP Europe, 2022), the goal is to reach 35 billion cubic meters (bcm) of sustainable biomethane production capacity in 2030 in the EU. Biomethane is produced through anaerobic digestion which is an effective strategy to recover bioenergy from different types of biowastes (Duarte et al., 2021). To obtain biomethane, impurities and CO_2 must be removed (Ardolino and Arena, 2019). At the mentioned target capacity, approximately 41-69 Mt CO_2/a will be generated. The direct emissions of the European pulp and paper industry were 28 Mt CO_2 in 2021 (CEPI, 2022). A yearly decline of approximately 1.1% could be observed since 1991, resulting in approximately 25 Mt direct CO_2 emissions in 2030. However, based on wood consumption, which showed a slightly increasing tendency since 2000, 152 million cubic meters of consumption were reached in 2021. The lignin content of softwood lies in the range of 27-32% (Tarasov et al., 2018) and 18-25% in hardwood (Ahmad et al., 2020). When the carbon from the lignin is emitted, the rate of on-site emission reduction cannot continue this way. It is assumed that the process flows in the pulp and paper mills remain as they are for the scope of this publication.

The biggest amount of biogenic CO_2 is coming from district heating. Figure 12 shows the relation of CO_2 potential derived from the three sectors. It is assumed that the quantities of 99 Mtoe (EurObserv'ER, 2020) of solid biofuels used for heating and/ or electricity generation will not decrease in the near future. Assuming 5 kWh/kg dry wood and an average carbon content of 42-47% (Kaltschmitt et al., 2009) this corresponds to a total amount of 230 Mt/ a biomass, meaning approximately 354-396 Mt CO_2/a. These numbers correspond to technical potentials of 208-243 billion cubic meter e-methane, assuming a minimum of 90% carbon capture rate (Mikulčić et al., 2019) and 90% CO_2 conversion rate in the fuel production process.

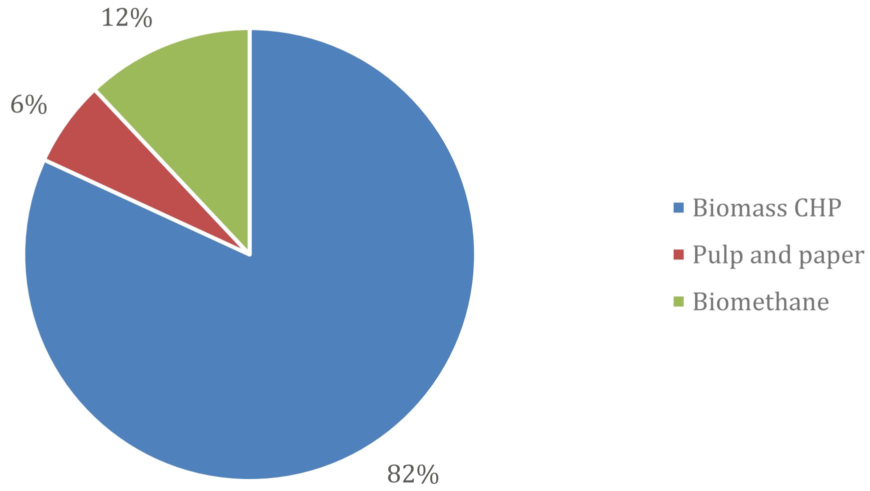


Figure 12. Estimated CO_2 potentials from biomethane production, pulp and paper and solid biofuel use for heating and electricity generation in 2030. Data source: (Radosits et al., 2024b)

3.2.2. Investment cost developments

Table 7 and Figure 13 display the results of the investment and overall system costs for the expansion scenarios. It compares the results between the base year 2022 and results for 2050 under both a *Growth* and a *Business-as-usual* (BAU) scenario. The investment costs in 2050 for the electrolyzers depend on the scenario and decrease substantially over this period for alkaline electrolyzers (AEL) by 31-36% and for PEM electrolyzers by 41-46%. However, the difference between the growth and the BAU scenario is smaller than expected. Although the installed capacity is almost eight times higher, the investment costs differ only by 7-9%. This is mainly due to the conventional part becoming the dominant share of costs. However, the capacities of electrolyzers in the BAU scenario are insufficient for the expected capacities of e-methane in 2050. A substantial increase in capacity additions is needed to reach the defossilisation targets. The cost reductions for the total system in the growth scenario are 32-38% for e-methane. The values of the growth scenario are the input used for the calculation of the overall e-methane production costs in the following sections.

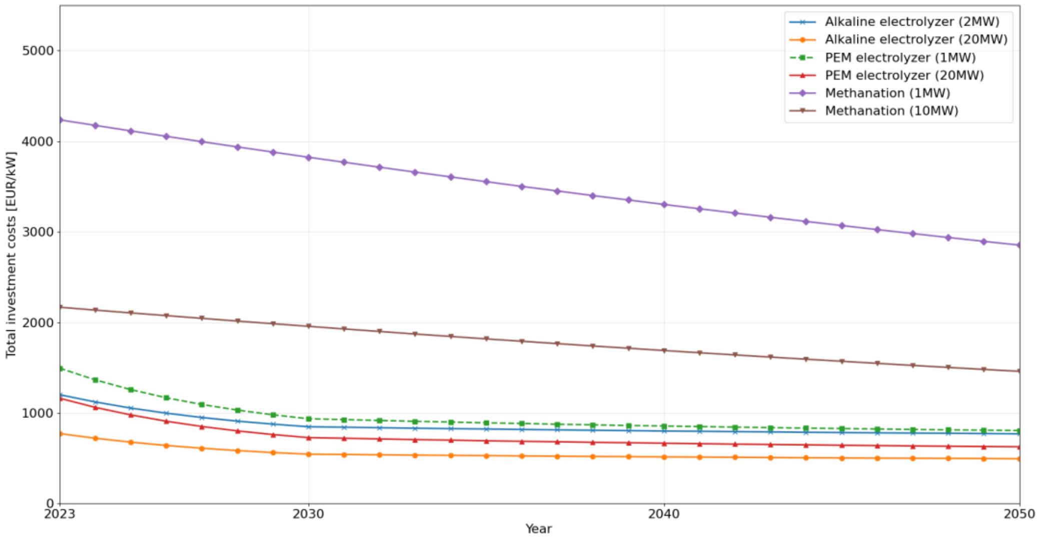


Figure 13. Total system cost and investment cost reductions for e-methane and electrolyzers up to 2050.

Table 7. Electrolyzer investment and total system costs in 2050 compared to 2022. The learning rates for electrolyzers are 18% and for methanation 10%.

Year	**2022**	**2050**	**Unit**
H_2 Growth			
Alkaline (2-20 MW)	900-1400	495-770	EUR/kW
PEM (2-20 MW)	1400-1800	620-810	EUR/kW
H_2 BAU			
Alkaline (2-20 MW)	900-1400	535-830	EUR/kW
PEM (2-20 MW)	1400-1800	680-880	EUR/kW
E-methane (1 MW)	5700-6100	3910-3950	EUR/kW
E-methane (10 MW)	3100-3600	2105-2230	EUR/kW

3.2.3. Hydrogen production costs

The production costs for hydrogen significantly depend on the full-load hours among other variables. Figure 14 illustrates the relationship between hydrogen production costs and the number of yearly full-load hours in the *Growth* scenario for a 20 MW_{el} electrolyzer. The relationship shown is strongly non-linear and inverse as higher utilization spreads capital expenditure across a larger number of operating hours.

In the case of 1000 FLH, which is typical for PV in Central Europe, the costs are 102%-150% higher compared to 8000 FLH. At typical values of 2600-2900 FLH for onshore wind, the production costs increase by 26-44%. However, this evaluation did not consider the trade-off of faster degradation of the electrolyzer stacks with more FLH.

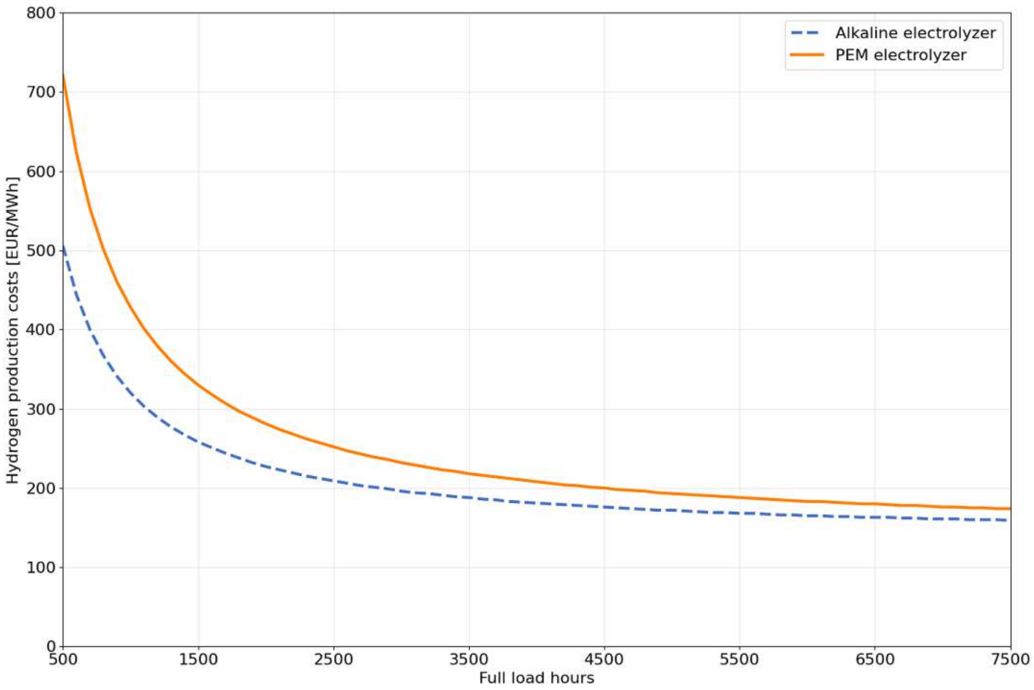


Figure 14. Hydrogen production costs in relation to the full load hours at 90 EUR/MWh electricity price.

The electricity price was modified in Figure 15 to visualize the impact of this essential parameter on the hydrogen production costs, while keeping full load hours fixed at 8000. The visualization shows the proportional (linear) rise of hydrogen costs as the electricity price increases. The figure underlines that hydrogen production requires access to low-cost renewable electricity to compete with fossil fuels in economic terms.

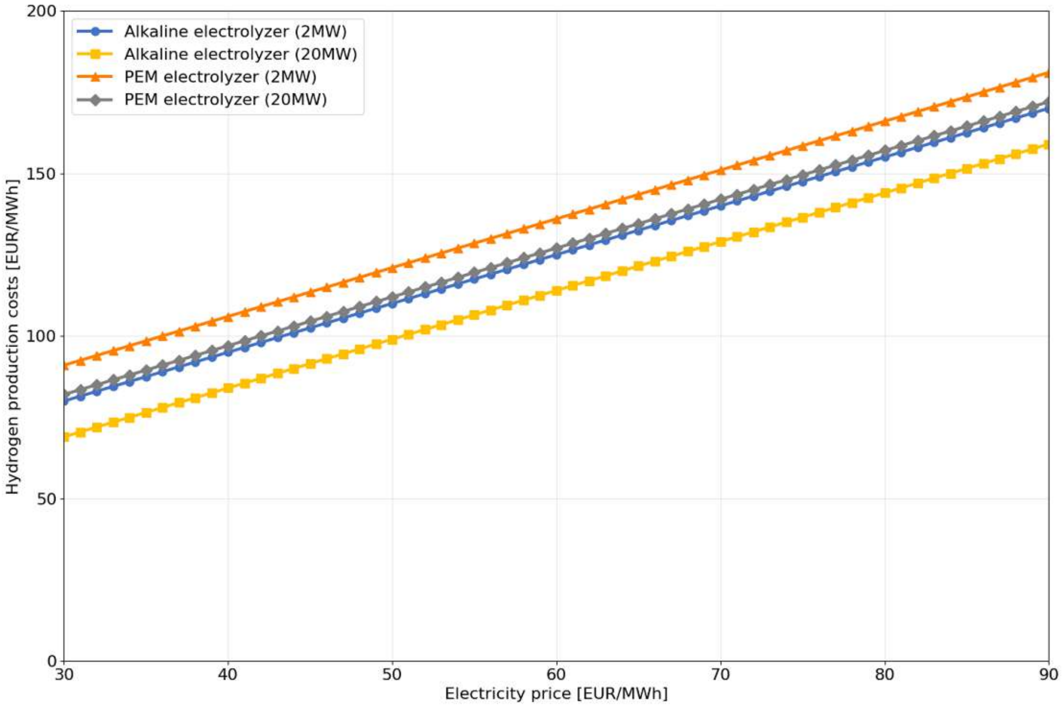


Figure 15. Hydrogen production costs in relation to the electricity price at 8000 FLH.

Having less influence on production costs, though still relevant are investment cost reductions for electrolyzers under different technological learning rates. Figure 16 compares two distinct learning rates, 50% higher and lower than the anticipated learning rates used in the techno-economic assessment. Both technologies see a decline in costs. However, the extent of cost reduction is substantially different. PEM electrolyzers, which are still at a comparatively early stage of commercialization, benefit more strongly from high learning rates than the more mature alkaline technology.

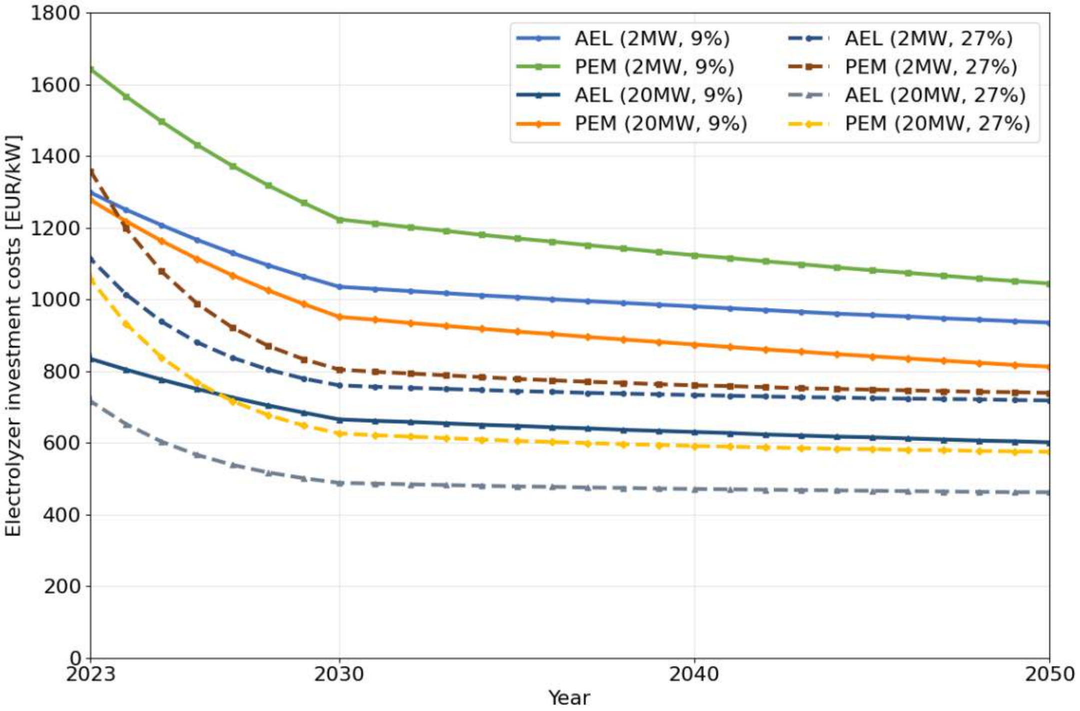


Figure 16. Investment cost reductions of alkaline (AEL) and proton exchange (PEM) electrolyzers up to 2050 for 9% (low) or 27% (high) learning rates.

A similar analysis is presented in Figure 17 for methanation plants, showing investment cost reductions under low and high investment rates of 5% and 15%. The figure complements the preceding one by showing that, whereas electrolyzer costs may fall rapidly, cost reductions in the downstream methanation process are expected to decline at a slower pace.

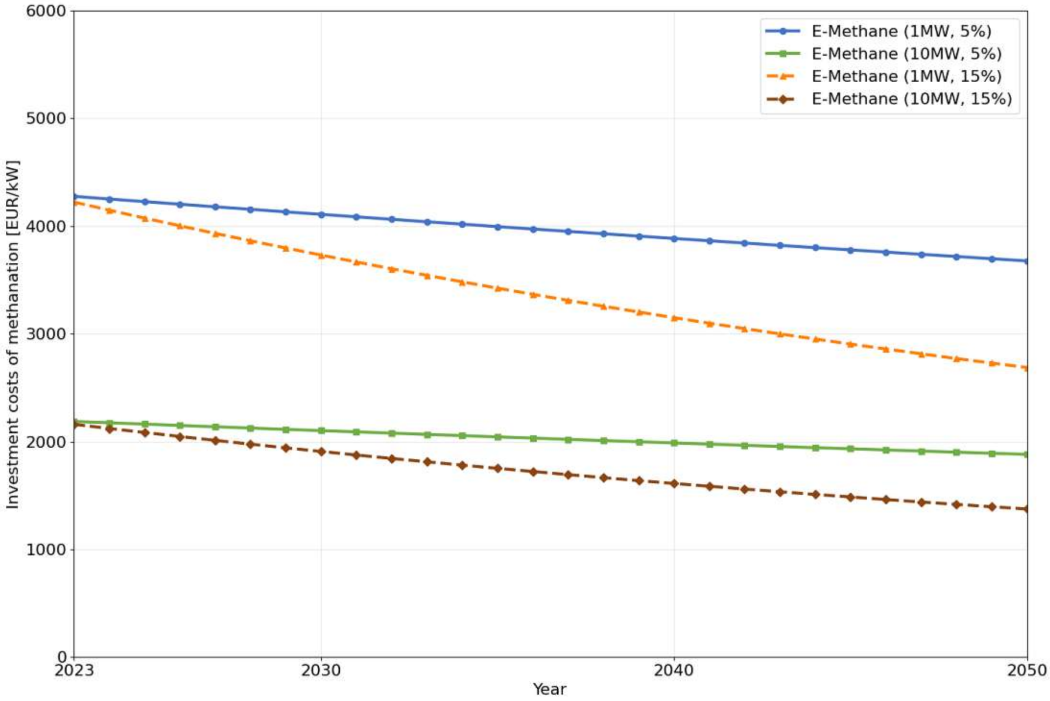


Figure 17. Investment cost reductions of methanation (CH4) up to 2050 for 5% (low) or 15% (high) learning rates.

3.2.4. Production costs of e-methane

The effect of the scale on the production costs can be seen in Figure 18 and is lower than expected in this work although the total system costs for e-methane are significantly lower with 3135 EUR/kW for a 10 MW plant compared to 5590 EUR/kW for a 1 MW plant.

The total production costs will be reduced by 5-10% in 2023 from a 1 MW plant to the 10 MW scale. In 2050 the difference between the sizes accounts for 5-7%. The reason is that other variables affect the production costs more than the scale, which will be shown in the sensitivity analysis results.

The current production costs decrease by 17-22% in 2050. The production costs in 2050 are still too high to be cost competitive under these assumptions. Production costs can be reduced with accounting for revenues for off-heat and oxygen. Oxygen sales can be a valuable revenue stream. However, it is questionable if all the oxygen from electrolyzers can be sold on the market.

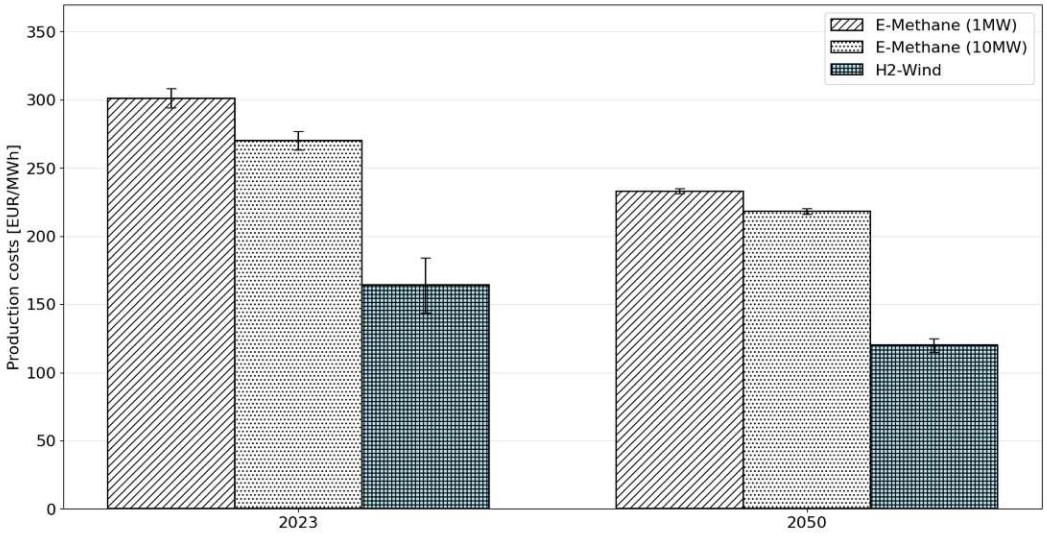


Figure 18. Production costs of e-methane and hydrogen powered by wind energy in 2023 compared to 2050. The error bars indicate effects from variations in learning rates (9-27%).

Currently, a grid-connected electrolyzer leads to the lowest production costs. However, wind-based hydrogen production will already show better economic performance in 2030, assuming that the grid electricity price is 90 EUR/MWh, as mentioned in the methodology. The wind-based hydrogen production costs are currently 6 EUR/kg H_2 and will fall to 4 EUR/kg H_2 in the growth scenario.

The costs for wind-based e-methane are, on the contrary, 15-37% (2030) and 10-35% (2050) higher than for the grid-connected electrolyzer.

Production costs for PV-based production were also calculated, however, not shown here, because they are the highest still at the scale of 10 MW with 470-510 EUR/MWh for e-methane in 2050. PV plants as the only electricity source in the process chain are unfavorable in Central Europe mainly due to the low FLH, thereby increasing the capital costs significantly.

An alkaline electrolyzer can also be coupled with a PV plant as in the work of Ince et al. (2023). However, the efficiency of the electrolyzer was less than 60%, which is not favorable from an economic point of view.

3.2.5. Sensitivity analysis of e-methane production costs

The sensitivity analysis regarding production costs of e-methane in the *Growth* scenario in 2050 is visualized in Figure 19. The results showed that electrolyzer efficiency, electricity prices and the full-load hours have the most impact. The effect of full-load hours becomes even more decisive for values less than 3000 FLH, as previously shown for hydrogen. The CO_2 capture costs and the production scale displayed the lowest impact on the costs.

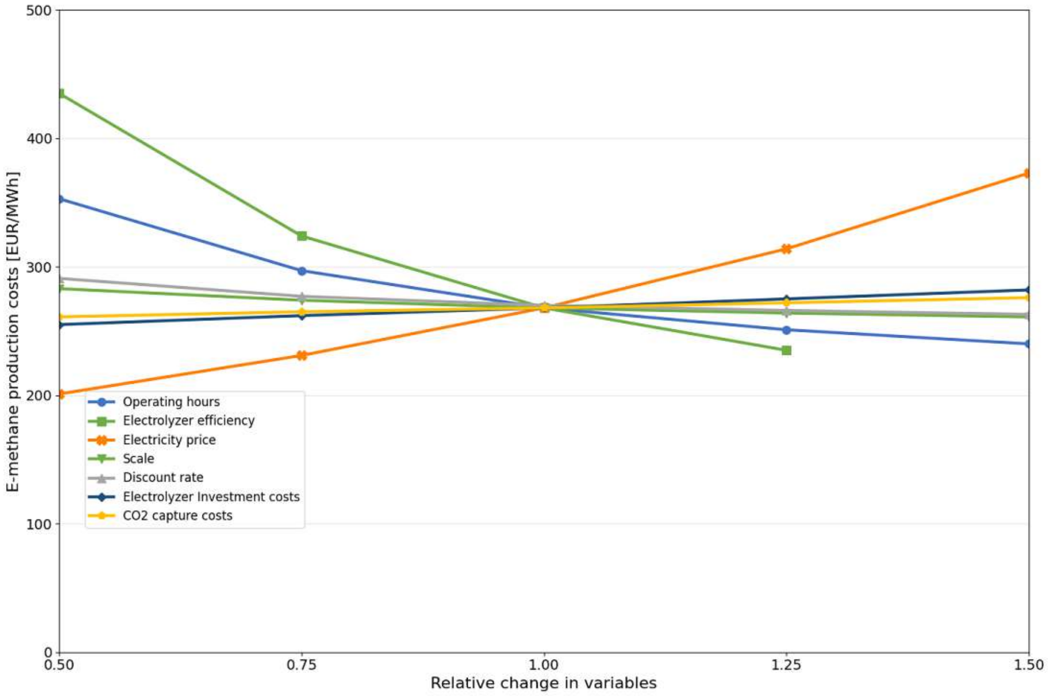


Figure 19. Sensitivity analysis of e-methane production costs in 2050 using an alkaline electrolyzer in the growth scenario.

The investigation of the carbon taxes supports the previous findings. A natural gas price of 83 EUR/MWh is used for this analysis (Eurostat, 2023c). Figure 20 shows that even a high carbon price of 500 EUR/t CO_2 is not sufficient to ensure economic competitiveness under the taken assumptions. The production costs of e-methane are above the elevated natural gas market prices regarding a carbon tax.

A 50% lower grid electricity price of 45 EUR/MWh leads to a 34% decrease in e-methane production costs, intersecting the natural gas market prices including a tax of 320 EUR/t CO_2. However, other costs for the market distribution, such as gas network charges still need to be added to the production costs of e-methane. Other authors, such as van der Zwaan et al. (2022), calculated 270 EUR/t CO_2 for different scales than in this work, making e-methane competitive with natural gas. Hydrogen will become competitive with natural gas rather than e-methane. Approximately 180 EUR/t CO_2 will be required to promote hydrogen production from wind in 2050.

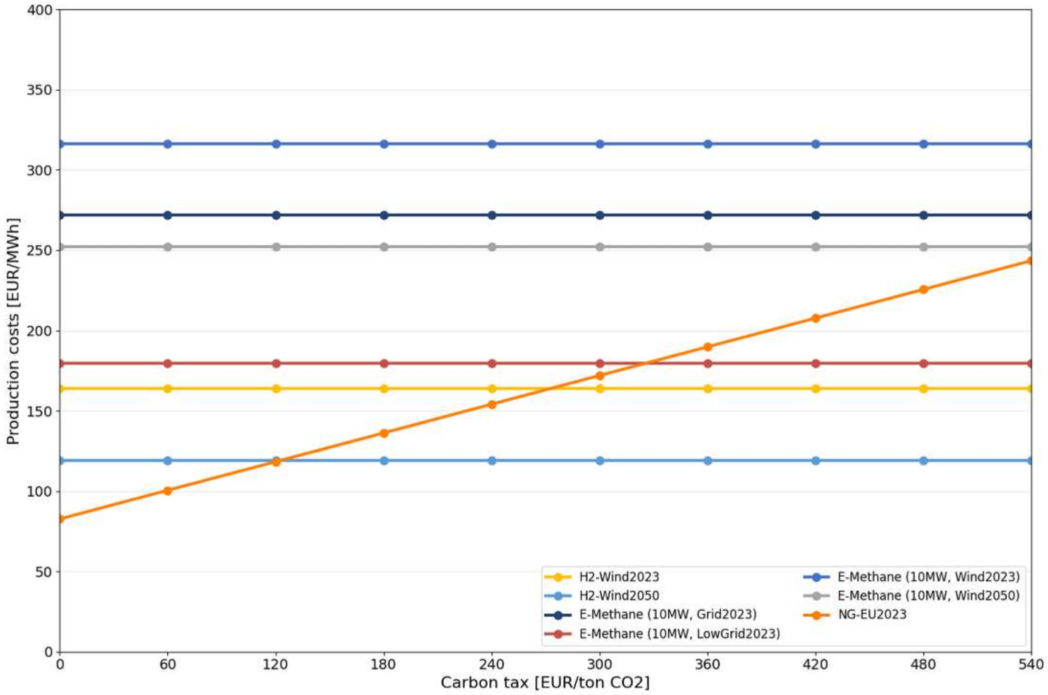


Figure 20. Production costs of e-methane compared to natural gas prices including carbon taxes.

3.2.6. Results of the SWOT analysis

Table 8 displays the results of the SWOT analysis. The production of hydrogen can be increased extraordinarily because of the possibility of using renewable electricity. The overall process efficiency of H_2 use is higher than e-methane because of the synthesis reactions as additional steps in the process chain. Therefore, the production costs are also less for H_2. However, the energy density is much lower and compression or liquefaction is necessary. High investments are also required for the H_2 infrastructure. E-methane producers on the other hand can profit from existing terminals and storage capacities.

The usage of biomass-based CO_2 as an input stream is an option to produce renewable platform chemicals or e-methane in this case. This creates the possibility to contribute to the defossilisation of the energy sector and chemical industry within the following decades.

Table 8. SWOT analysis. Source: (Radosits et al., 2024b)

	H_2	e-Methane
STRENGTHS	Higher efficiencies than e-methane and e-methanol Emission reduction compared to conventional fuels Lowest production costs of the three investigated fuels	Easier to store than H_2 with lower storage costs Applicability in different industries Sector coupling with biomass-based gas production possible
WEAKNESSES	Development of drive and fueling system (maritime transport and aviation) necessary Low energy density Highly diffusive gas High material requirements for storage	Offset of emission reduction in case of methane leakages Low overall process efficiency Currently high production costs
OPPORTUNITIES	Scalable with renewable electricity Repurposing of natural gas pipelines Flexible use in different applications Adaptation of industrial burners and stoves	Gas storage capacities for long-term storage CO_2 utilization Usage of current infrastructure Industry is heavily based on methane as feedstock
THREATS	Investments in new infrastructure Lack of regulation Energy input for compression	Lock-in effects of natural gas infrastructure Energy input for compression and preheating

4. Production costs and greenhouse gas mitigation potential of hydrogen-enhanced biomethane and bio-SNG production

To reduce the costs of CO_2 utilization for renewable methane production, sector coupling of biomass-based gas production and the electricity sector is investigated. A central challenge lies in the temporal availability of renewable electricity and the inherent variability (Schindler et al., 2022). To understand the true potential and limitations of sector coupling, modelling frameworks need to cover temporal resolution, reflecting daily, seasonal and interannual variations in renewable electricity generation. A hybrid energy model using mainly PV and wind can reach a high number of full load hours. The advantages of such sector coupling include the possibility of electricity feed-in when the production of renewable electricity exceeds the demand of the electrolyzer or consume electricity when the renewable generation is too low (Pratschner et al., 2023). At the same time, however, grid connection requirements and grid fees must be considered, as they can significantly affect the economic feasibility of these systems. From a methodological standpoint, it is therefore important to capture both the operational flexibility benefits and the cost implications of grid access when evaluating hydrogen-enhanced biomethane and bio-SNG pathways, as these determine the system value of sector coupling.

The choice of modelling approach also has important implications for the interpretation of results. Linear optimization models, for instance, are well-suited for identifying cost-minimizing operation strategies across a full year of operation while maintaining computational efficiency. They allow researchers to simulate multiple scenarios of renewable electricity availability, hydrogen demand and gas production, providing insight into the trade-offs between capital expenditure, operational flexibility and overall system costs. However, these models require careful parameterization to ensure that physical constraints such as conversion efficiencies are accurately represented. Sensitivity analyses further enhance methodological robustness by testing the influence of uncertain parameters, such as future electricity prices, feedstock availability and technology learning rates (Luenberger and Ye, 2008).

Another methodological consideration concerns the integration of environmental assessment into techno-economic analysis. While cost optimization is critical for evaluating economic feasibility, a holistic assessment should also consider the evaluation of greenhouse gas emissions. Life cycle thinking is particularly relevant, as it allows the quantification of emissions not only from the conversion process but also from upstream activities, such as feedstock collection, transport and infrastructure construction. Methodologically, this integration requires linking optimization outputs with life cycle inventory databases, ensuring that results capture the broader sustainability implications of renewable methane production (Ardolino and Arena, 2019; Skorek-Osikowska et al., 2020).

From a research perspective, the motivation for this contribution derived from (Radosits et al., 2025) also stems from policy and investment relevance. Renewable methane technologies are expected to play a key role in achieving national and regional defossilisation targets, yet uncertainties in technology performance, market development and regulatory frameworks hinder strategic decision-making. By combining cost optimization with scenario analysis, researchers can generate insights that are directly applicable to policymakers and investors. For example, identifying the conditions under which hybrid renewable energy systems can supply electrolysis units cost-effectively informs decision makers about grid expansion, renewable capacity allocation and support schemes for emerging technologies. Moreover, exploring trade-offs between different energy pathways allows stakeholders to prioritize investments that maximize greenhouse gas emission reduction potential while minimizing economic risks (Blanco et al., 2018; D'Adamo et al., 2023; Gustafsson, 2024; Taifouris and Martín, 2023).

4.1. Methodology

Initially, the production costs of biomethane and bio-SNG production are assessed, considering feedstock costs, transportation, processing technologies and operating costs. For biomethane production, different agricultural and biowaste feedstocks are considered. Bio-SNG production is focused on low-grade woody biomass and residues from the timber industry.

The upper part of Figure 21 shows the reference cases of biomethane and bio-SNG production with CO_2 removal as an integral part of the process chains. Typically, there is not enough H_2 present in the synthesis gas. The output can be increased with external hydrogen. The advantage of the process routes investigated is that energy for CO_2 separation can be avoided by simultaneously increasing the product output. The separation of CO_2 requires, with the currently available technologies, at least 1 MWh per ton of CO_2 captured (Kuparinen et al., 2019; Michailos et al., 2020). However, therefore, the methanation section must be increased accordingly.

In this work, the catalytic methanation is chosen for CO_2 utilization in both process chains. The catalytic methanation is anyway part of synthesizing bio-SNG. It is assumed that an additional methanation section will be added for the enhanced output of biomethane. The technical feasibility of the direct biogas methanation is demonstrated by Witte et al. (2018b). An economic analysis is conducted in the second part of the overall study Witte et al. (2018a). However, the new contribution of this contribution (Radosits et al., 2025) is the detailed investigation of the electricity supply for omitting a hydrogen tank.

An alkaline electrolyzer is selected for hydrogen production due to the lowest investment and operating costs of available electrolyzers (Detz and Weeda, 2022). Another benefit worth noting is that no rare metals are required compared to the proton exchange membrane type. According to a report by IRENA (IRENA, 2020) on cost reductions of green hydrogen, the availability of critical raw materials can hamper the deployment of electrolysis. The current platinum and iridium production supports only an estimated 3 – 7.5 GW manufacturing capacity globally per year in 2030 whereas 270 GW would be needed to fulfill a trajectory well below 2°C as outlined in the Transforming Energy Scenario. There are no restrictions mentioned for alkaline electrolyzers and these can be scaled up to the requirements of biomass-based gas production.

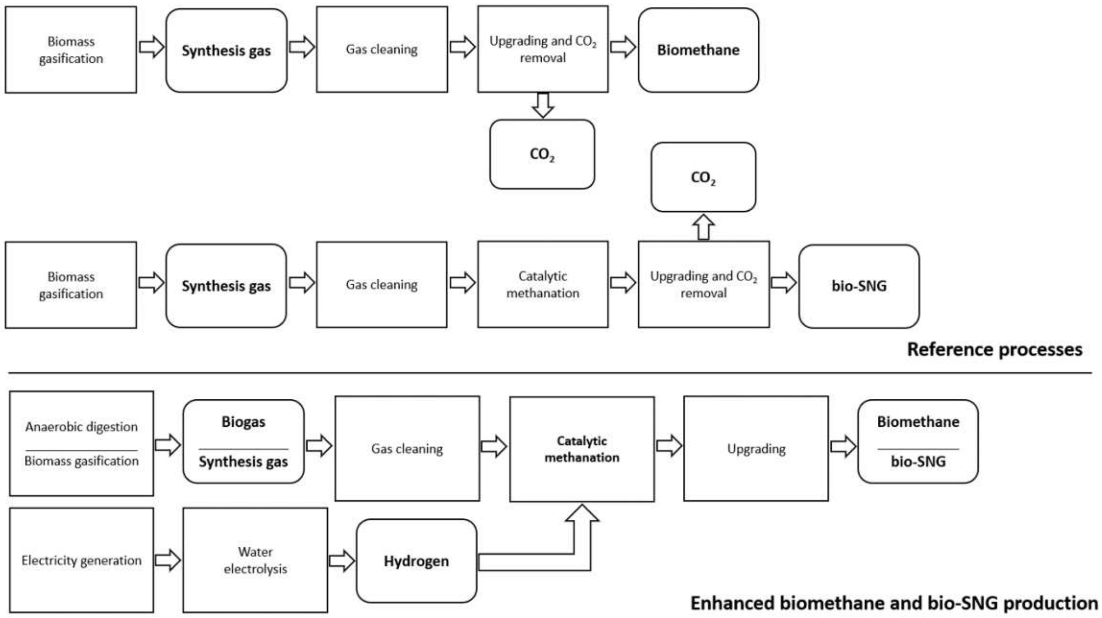


Figure 21. Reference processes and H_2 enhanced production of biomethane and bio-SNG through hydrogen integration.

For both technologies, two different plant sizes are selected, referring to the product output capacity of the reference cases. For biomethane production, 2 and 5 MW production capacities are selected, corresponding to 350 and 875 Nm^3 biogas per hour, according to Billig and Thraen (2017). The lower end for economic feasibility is 100 Nm^3 (Fajrina et al., 2023). The scalability of biomethane production is limited to approximately 16 MW. The limiting factor is mainly the feedstock supply as the costs increase significantly with larger transport distances.

For bio-SNG production, typically, larger scales are constructed due to the technical characteristics of the reactor and catalytic methanation system. SNG production capacities of up to 200 MW could be realized (Thunman et al., 2019). Based on the GoBiGas design, a 20 MW-sized bio-SNG plant is assumed. An additional 50 MW plant size was investigated, using the same ratio for increasing the plant scale as for the biomethane reference cases. Both technologies have their advantages as different feedstocks can be processed and are therefore seen rather complementary than competitive to each other. The lignocellulosic structure in wood is difficult to decompose for microorganisms. However, it is a preferable feedstock for biomass gasification due to low ash content (Mauerhofer et al., 2019). On the other hand, wet feedstocks such as biowaste and silage are preferred for biomethane production (Weiland, 2010). Wet feedstocks would require a lot of energy for drying in order to be used in biomass gasification.

4.1.1. Economic analysis

The underlying economic study for biomethane production is based on the investment costs and conversion efficiencies for biomethane plants derived from Billig and Thraen (Billig and Thraen, 2017). The biomass conversion efficiencies and investment costs depend on the type of feedstock. Also, the investment costs for plants dealing with organic waste, such as biowaste and manure, are almost twice as high as for energy crops. Easily degradable material shows better conversion efficiencies than lignocellulosic material such as wheat straw. The feedstock costs are taken from Statistik Austria (2023) and Brown et al. (2020). The major literature regarding biomass gasification and the equipment costs of a 20 MW bio-SNG plant are derived from the GoBiGas project (Thunman et al., 2019), which was the first bio-SNG plant of its kind with this capacity and the investment costs, therefore, are relatively high. The total investment costs are achieved by multiplying the equipment costs by the lang factor of 4.87 (Hammerschmid et al., 2023). The investment costs for the 50 MW plant are derived from Hofbauer et al. (Hofbauer et al., 2020). The specific costs for biomethane and bio-SNG production are then calculated using the equations outlined in section 3.1.1.1.

A discount rate of 6% and a plant lifetime of 20 years is used for the biomethane and bio-SNG plants to calculate the capital recovery factor. For the processes with H_2-enhanced output, a discount rate of 8%, according to the literature, is applied (Pratschner et al., 2023). The replacement of stacks every ten years, according to IRENA (2020), was considered an additional investment cost at the time of replacement. The lifetime in the CRF was adjusted to ten years for this part of the investment costs. Other components are assumed to last for at least 20 years. A maximum of 7500 full load hours and an efficiency of 67% was assumed for the electrolyzer (IRENA, 2020).

The costs for hydrogen are included in the variable costs for enhanced production. The relative amount of hydrogen per unit of biogas or syngas is essential for the overall results. In the case of biomass gasification, it is derived from the paper by Hannula (2016), where 0.98 kW H_2/kW synthesis gas are considered for steam gasification. For biomethane plants, the amount is calculated for the assumption that 40% CO_2 is present in the biogas, meaning 0.81 kW H_2/ kW biogas. Other variable costs, such as consumables for gas cleaning, etc. were already investigated in detail in the work of Bartik (2024) for biomass gasification and Skorek-Osikowska et al. (2020). In this work, factors of 0.6% and 1.25%, shown in the next section, in relation to the investment costs are applied for the operating costs.

Most by-products are not considered in this work, except for excess heat from biomass gasification. Heat supplied to district heating is included in the economic analysis. According to (Tretter et al., 2024), 33 EUR per MWh are assumed as revenues for heat sold to district heating. Due to the lower temperature of biological methanation, explained in section 2.1.2.1, there is practically no excess heat usable for other applications. Digestate from anaerobic digestate can be utilized as fertilizer and contribute to economic profitability (Gebrezgabher et al., 2010). However, it is difficult to define a market value due to differences in nutrient composition. If oxygen from the electrolysis can be sold, it also contributes an additional revenue stream (Pratschner et al., 2023).

4.1.1.1. Investment and fixed operating costs

The economic parameters such as the investment cost for modelling production costs, are summarized in Table 9. On the one hand, there are cost savings from the avoidance of the CO_2 separation, as mentioned before. However, additional investments in the methanation section are required to enhance the output. The investment costs are adjusted for the year 2023 by using the chemical engineering plant cost index, which has been used since the 1960s to adjust plant construction cost over time periods (Vatavuk, 2002).

Table 9. Investment costs of key technologies for renewable methane production.

Investment costs	**Value**	**Unit**	**Source**
SNG plant	6450-8500	EUR/kW_{out}	(Thunman et al., 2019)
Biomethane plant	1930-5430	EUR/kW_{out}	(Billig and Thraen, 2017)
Alkaline electrolyzer	900-1400	EUR/kW_{el}	(Detz and Weeda, 2022)
Methanation	2200-4300	EUR/kW_{out}	(Gorre et al., 2019; Schlautmann et al., 2021; Thunman et al., 2019)

Table 10 shows the operating and maintenance costs, including the labor costs and other relevant input variables such as the discount rate, which has important implications in the economic assessment. The sum of labor hours was based on normal operation without major disturbances (Hammerschmid et al., 2023). The efficiency of the catalytic methanation process was assumed to be 83% according to (Bartik, 2024).

Table 10. Operating, maintenance and miscellaneous costs.

Fixed costs (O&M and miscellaneous)	Value	Unit	Source
Electrolyzer	29	EUR/kW	(De Vita et al., 2018)
Methanation	3.5	% of IC	(De Vita et al., 2018)
Maintenance	3 (Biomethane)	% of IC	(Skorek-Osikowska et al., 2020)
	1.5 (SNG)	% of IC	(Thunman et al., 2019)
Insurance	2	% of IC	(Skorek-Osikowska et al., 2020)
Property tax	1	% of IC	(Skorek-Osikowska et al., 2020)
Labor (Sum of working hours)			
2 MW Biomethane	4160	h/year	(Skorek-Osikowska et al., 2020)
5 MW Biomethane	6240	h/year	Assumption
20 MW SNG	10400	h/year	Assumption
50 MW SNG	14560	h/ year	Assumption
Labor costs	39.4	EUR/h	(Statista, 2023)

Table 11 shows the variable costs. The costs for energy maize are calculated from the prices of corn with a factor between 2,1 and 2,2 to find the approximate price of maize silage. The underlying calculation can be found in an article of the agricultural chamber of Upper Austria (Hunger, 2023). For simplicity, an assumption for the costs of consumables is used in the calculation. Based on the literature research, the costs of consumables are approximately twice as high for bio-SNG production because of the gas cleaning and costs for the catalyst, bed material, etc. More details on the costs of consumables can be found in Bartik (2024).

Table 11. Variable costs.

Variable costs	**Value**	**Unit**	**Source**
Biomethane			
Biowaste	-17	EUR/ ton FM	(Brown et al., 2020)
Energy maize	90	EUR/ ton DM	(Statistik Austria, 2023)
Manure	30	EUR/ ton DM	(Brown et al., 2020)
Consumables	0.6	% of IC	(Billig and Thraen, 2017)
Bio-SNG			
Wood chips	55	EUR/ton DM	(Statistik Austria, 2023)
Consumables	1.25	% of IC	(Bartik, 2024; Thunman et al., 2019)

4.1.1.2. Electricity costs

This work is output-oriented by focusing on a defined amount of gas being produced because the amount of full load hours is a crucial factor in the economic viability of biomass-based gas and hydrogen production, as shown in the preceeding publication (Radosits et al., 2024b). A pre-determined amount of renewable electricity is required to increase the output of biomethane and bio-SNG. A hybrid energy supply model using wind, PV and grid electricity derived from the work of Pratschner et al. (2023) is investigated to supply the needed electricity to the electrolyzer. It is assumed that the renewable capacities are built only to supply electricity to the electrolyzer. The idea is adapted for this work and extended to a linear optimization model.

A hybrid electricity supply combines the benefits of low-emission electricity by renewables and a high number of full load hours achieved by the grid access, thereby avoiding investments in storage. The location of the case study is Austria. However, the methodology can be applied to any region using the respective weather data. The yearly electricity costs in the hybrid model will change in relation to the full load hours of renewable electricity technologies. Historic data from 1980-2019 was analysed to calculate the average capacity factors of wind and PV over this period (Staffell et al., 2023). While research is put into load flexible methanation concepts, a highly fluctuating hydrogen supply remains challenging. Thus, this study mitigates these issues by utilizing a hybrid system with a continuous electricity supply. Two scenarios are used in the hybrid model with variable grid prices from the Energy Exchange Austria: 2020 represents low and 2023 represents high grid prices.

The additional grid connection fees are considered in the investment costs. Due to the current economic situation in recent years, an interest rate of 6% was used to invest in renewables and grid infrastructure. Table 12 shows the investment costs for windmills and solar panels, including the installation costs. The network usage charges depend on the connected power. According to the size of biomethane and bio-SNG production, it is determined that the electrolyzer for enhancing bio-SNG production would be in network level 4 and for enhancing biomethane production in network level 5. The costs for lower network levels are generally higher than for upper levels. The variable network usage charges are the average values for Lower Austria and Burgenland, the regions in Austria with the most windmills currently.

Table 12. Installation costs for windmills and PV plants and electricity network usage charges.

Total installation costs	**VALUE**	**UNIT**	**SOURCE**
Wind	1300	EUR/kW	(Danish Energy Agency, 2024)
PV	600	EUR/kW	(Danish Energy Agency, 2024)
Biomethane			
Grid installation	108	EUR/kW	(Wiener Netze, 2024)
Grid usage fees	16.8	EUR/MWh	(SNE-V, 2018)
Bio-SNG			
Grid installation	63	EUR/kW	(Wiener Netze, 2024)
Grid usage fees	10.2	EUR/MWh	(SNE-V, 2018)

A linear optimization is used to assess required installation capacities of the renewable wind and solar power systems at minimal installation costs for minimized electricity costs.

Linear optimization, commonly also referred to as linear programming (LP), is a central methodology in operations research and applied mathematics. It provides a systematic way to optimize a linear objective such as maximizing profit or minimizing cost, which is subject to a set of linear constraints that capture the physical, economic, or technological limits of the system under consideration. The development of LP represents one of the most important intellectual achievements of the twentieth century in applied mathematics regarding the practical impact (Dantzig, 1991; Luenberger and Ye, 2008).

Historically, the origins of linear programming are closely associated with resource allocation problems in industry and defense. Leonid Kantorovich introduced the conceptual framework in the late 1930s, but it was George B. Dantzig who, in 1947, formulated the general mathematical structure and devised the Simplex method, which became the first broadly applicable algorithm for solving large LP problems. As (Dantzig, 1991) explains, the Simplex method exploits the geometry of feasible solutions, moving systematically along the edges of the polyhedron defined by the constraints until an optimal vertex is reached. This algorithm not only enabled the practical solution of real-world problems but also established LP as a core field of study. John von Neumann's theory of duality further enriched the field, providing a deep link between the primal and dual formulations and laying the groundwork for sensitivity analysis (Balinski and Tucker, 1969).

Mathematically, a linear program can be expressed in canonical form as (Dantzig, 1991):

$$\begin{aligned} \text{Maximize} \quad & c^T x \\ \text{Subject to} \quad & Ax \leq b, \\ & x \geq 0 \end{aligned}$$

where c represents the coefficients of the objective, A is the matrix of constraints, b is the vector of resource bounds and x is the vector of decision variables.

The feasible region $\{x \in \mathbb{R}^n : Ax \leq b, x \geq 0\}$ is a convex polyhedron. A key theoretical result emphasized in both Dantzig's classic text and in modern treatments states that if an optimal solution exists, it will be attained at an extreme point (vertex) of this polyhedron. This geometric property is the cornerstone of both the theory and algorithms of LP.

The algorithms developed to solve LPs exploit precisely this structure. The Simplex method, introduced by Dantzig, is one of the most renowned algorithms in applied mathematics. Although its worst-case complexity is exponential, in practice it has proven remarkably efficient, solving problems with thousands or even millions of variables and constraints (Dantzig, 1991). Later developments introduced interior-point methods, which, as Luenberger and Ye (2008) detail, move through the interior of the feasible region rather than along its boundary. These methods are polynomial-time and have become increasingly important for very large-scale applications. Today, commercial solvers combine the strengths of both approaches, often beginning with interior-point iterations and then adopting simplex methods for accuracy starting from a suboptimal solution (Ge et al., 2024).

The applications of LP are extraordinarily broad. In production planning, LP models determine the optimal output mix subject to labor, material and capacity constraints. In transportation and logistics, LP minimizes the costs of distributing goods across networks while meeting supply and demand. In energy systems, LP underpins models for unit commitment and dispatch, ensuring reliability at minimum cost. Financial analysts employ LP in portfolio optimization when objectives and constraints can be linearly expressed. Even in agriculture, classic diet models optimize nutritional intake at minimum expense. As Dantzig (1991) and Luenberger and Ye (2008) emphasize, the power of LP lies not only in the efficiency of its solution methods but in the simplicity and universality of its modelling framework.

The linear optimization in equation (11) is designed to feed the surplus electricity into the grid and variable grid prices would also be used to calculate the feed-in revenues. The result of the linear optimization shows the yearly costs for electricity. A constraint was added that there would be only feed-in when the grid electricity price in the historical data was positive. Initially, the amount of electricity taken from the grid was set to 10% of the total demand, as shown in the constraints below, in order to prevent the model from simply buying cheap electricity in times of low prices and sell it later at high prices.

$$\underset{P_W, P_S, E_{grid}, E_{in} > 0}{minimize} \sum_{i\epsilon\,\{W,S\}} (IC_i * CRF + O\&M_i) * P_i + \sum_{t=1}^{n} (E_{grid} * c_{grid} - E_{feed-in} * c_{in}) \tag{11}$$

$$P_W, P_S, E_{grid}, E_{in} \geq 0 \tag{11.1}$$

$$\sum\nolimits_{t=1}^{n} E_{grid} \leq 0.1 * \sum\nolimits_{t=1}^{n} D \tag{11.2}$$

$$E_{feed-in}(t) + D(t) = CF_W(t) * P_W + CF_S(t) * P_S + E_{grid}(t) \tag{11.3}$$

$$E_{feed-in}(t) \geq 0 \tag{11.4}$$

$$\sum\nolimits_{t=1}^{n} E_{feed-in} \geq \sum\nolimits_{t=1}^{n} E_{grid} \tag{11.5}$$

with:

P = total installed power [MW],

E_{grid} = electricity from the grid [MWh],

$E_{feed-in}$ = feed-in of surplus electricity [MWh],

c_{grid} = grid electricity price at hour (t),

c_{in} = feed-in price at hour (t),

$CF\ (t)$ = capacity factor at hour (t),

$D\ (t)$ = hourly demand of the electrolyzer.

4.1.1.3. Feedstock transport costs

Increasing the size of a biomass conversion plant presents a trade-off between lower capital expenditure and higher feedstock transport costs. On the positive side, scaling up the plant size can lead to economies of scale and reduce the overall capital costs per product unit. However, the downside involves higher feedstock transport costs, as larger plants may necessitate the transportation of biomass over longer distances. The analysis of the transport costs is related to the availability of sustainable biomass. This section is not centered on transportation but on the availability of sustainable biomass. An increased demand for biomass and the competition between different sectors could lead to higher prices. However, this has not been investigated in this work.

The costs per km for wood transport are derived from a model by Kain (2011) assuming that the transport is conducted with heavy-duty trucks. Kilometer-related costs c_{km} of 1.54 EUR/km are used in equation (12) for the calculation of specific transport cost per ton of dry biomass [EUR/t DM]. As transport is charged per ton of wet biomass, moisture content y is included to convert the costs to a dry-matter basis, which is further used in the economic assessment.

It is assumed that the feedstock supply radius for the 20 MW plant is within 56 km and for the 50 MW plant within 128 km, based on the work by Mola-Yudego et al. (2014).

$$c_T = c_{km} * \frac{s}{(1-y)*m} \tag{12}$$

with:

m = loading mass,

y = moisture content,

s = transport distance,

c_{km} = kilometer-related costs derived from the model of the Austrian Chamber of Economics (Kain, 2011).

Finding the right balance between plant size, capital cost optimization and feedstock transport logistics is crucial for achieving cost-effectiveness and sustainability in biomass conversion projects. In particular, biomethane plants face limitations in transport distances. Feedstocks such as manure with a very high water content are supposed to be transported within 10 km from the source to the biomethane plant for economic reasons (Scarlat et al., 2018). The range of transport costs is between 4.4-5.5 EUR/ ton of fresh matter based on the publication by Billig and Thraen (2017). It is assumed that the transport costs would increase by approximately 25% from 2MW to 5MW based on the work by Skovsgaard and Jacobsen (2017).

4.1.1.4. Cost reductions by technological learning

Technological learning imposes uncertainties for biomass-based technologies. Bioenergy systems are very complex and involve different feedstocks and conversion technologies. In biomethane production, the investment costs depend on the feedstock used (Billig and Thraen, 2017). Different reactor designs and gasification agents can be used for biomass gasification. It is, therefore, not possible to determine one universal learning rate. The learning rates in literature are relatively low for biomethane production, between 4 and 5% (Lambert and Oluleye, 2019). Higher learning rates of 7-11% are estimated for bio-SNG production based on developments of fluidized bed gasification (Uyterlinde et al., 2007). Cost reductions for electrolyzers are more probable due to the implementation of modular systems. For catalytic methanation, a learning rate of 10% can be found in the literature (Babarit et al., 2019). The cost reductions for electrolyzers are based on the previous study presented in chapter 3, based on the own contribution (Radosits et al., 2024).

4.1.2. Concepts of life cycle assessment in CO_2 utilization

Life cycle assessment (LCA) is the standard method for environmental impact evaluation of goods or products (Escobar and Laibach, 2021). The methodology departs from the traditional, stage-specific analyses by adopting a comprehensive “cradle-to-grave” perspective that encompasses raw material extraction, production, distribution, use and end-of-life management. Through this systemic lens, LCA prevents the displacement of environmental burdens from one stage of the life cycle to another and offers a holistic foundation for sustainability-oriented decision-making. Its principal objective is to generate scientifically robust insights that support industry, policymakers and researchers in designing and selecting systems with reduced environmental impacts.

Although applicable in diverse contexts, the LCA framework is consistently structured around four iterative phases, as defined by ISO 14040/44 standards. The following description of the four phases is based on the text book by (Hauschild et al., 2018):

1. Goal and Scope Definition

The first stage requires a precise articulation of the intended application of the study, the primary audience and the manner in which the results are to be disseminated. Within this phase, two elements are particularly critical. The functional unit establishes the quantified reference function of the system under analysis and thereby ensures comparability between alternatives. The system boundary defines which processes are to be included, ranging from a full cradle-to-grave assessment to more restricted perspectives, such as cradle-to-gate or gate-to-gate analyses. Assumptions, limitations and allocation rules are also defined at this stage, providing the methodological foundation for subsequent analysis.

2. Life Cycle Inventory

The inventory phase entails the systematic collection and compilation of quantitative data on all relevant inputs and outputs associated with the system. Inputs include energy carriers, raw materials and auxiliary substances, while outputs consist of products, by-products, emissions and waste streams. Data quality expressed in terms of representativeness, completeness and transparency is important for the credibility of the assessment. Processes with several by-products and issues of multi-functionality must be addressed either by allocation procedures (e.g., based on mass, energy, or economic value) or by system expansion, where alternative product systems are incorporated into the analysis.

3. Impact assessment

In this phase, inventory results are translated into potential environmental impacts. The impact assessment consists of classification, in which inventory flows are assigned to relevant impact categories and characterization, where flows are quantified using scientifically derived equivalence factors. For instance, greenhouse gas emissions are aggregated into carbon dioxide equivalents to assess climate change potential. Optional steps include normalization, where impacts are related to reference values such as regional or per capita totals, or weighting, where impacts are aggregated based on normative priorities. Impact categories typically addressed include climate change, ozone depletion, acidification, eutrophication, human toxicity, ecotoxicity, resource depletion and water scarcity.

4. Interpretation

The interpretive phase synthesizes the results, evaluates their consistency with the defined goal and scope and identifies methodological or data-related limitations. Sensitivity and uncertainty analyses are indispensable components, as they provide insight into the robustness of conclusions under varying assumptions. The interpretation phase ultimately conveys the findings into conclusions and recommendations that are transparent, scientifically defensible and directly relevant to the addressed audience.

Compared with conventional LCAs, CCU systems introduce unique methodological challenges. A central aspect is the definition of system boundaries and the handling of multifunctionality. The captured CO_2 often originates from industrial point sources or biogenic streams, raising questions of whether it should be considered a waste, a burden-free input, or a by-product that carries upstream emissions. This choice strongly influences the calculated carbon footprint of the resulting renewable methane (Müller et al., 2020).

Another methodological issue relates to temporal system dynamics. Since CO_2 emissions are not permanently avoided but rather delayed until the renewable gas is combusted, LCAs of CCU products must carefully define the time horizon of assessment and account for the temporal profile of emissions (Cruz et al., 2021).

From an LCA perspective, the environmental benefits of substituting fossil gas with CCU-based renewable methane depend on several conditions: the source of the captured CO_2, the carbon intensity of the electricity used for hydrogen production and the efficiency of the methanation process. Kolb et al. (2021) highlight that the integration of renewable hydrogen with CO_2 utilization for synthetic methane production offers significant potential for defossilisation, but only when the electricity supply is predominantly renewable and when system-level interactions, such as grid balancing, are taken into account.

Recent research stresses the importance of integrating LCA with complementary modelling approaches in order to adequately capture the complexities of CCU-based renewable gas systems. Singlitico et al. (2019a) show that conventional LCAs often fail to represent spatial variability, such as feedstock availability and infrastructure siting. The use of geographic information systems (GIS) has been proposed to include regional factors such as transport distances and plant locations, which are decisive for the environmental profile of biogas and SNG production systems. In addition, process modelling and thermodynamic simulations are increasingly combined with LCA to fill data gaps for pre-commercial technologies. Kolb et al. (2021) argue that such hybrid LCAs are particularly relevant for CCU pathways, where empirical data on long-term performance is still limited. By linking process models with LCA inventories, more realistic mass and energy balances can be derived, reducing uncertainty.

4.1.3. Greenhouse gas mitigation potential and avoidance costs

The GHG mitigation potential is derived from the comparison of the global warming potential, which is a standardized impact category in LCA. The aim is to quantify the number of CO_2 equivalents that can be reduced by replacing natural gas and LNG with the production of biomethane, bio-SNG and the H_2 enhanced output scenarios. Other impact categories are not considered in this work.

The ProBas database, connected to GEMIS and acknowledged by the European Commission, was used to investigate the influence of different variables such as feedstock-related emissions, embedded emissions, energy input and others (European Commission, 2023a). Embedded emissions result, for example, from the material input for facility construction.

Hammerschmid et al. (2023) investigated the embedded emissions for a bio-SNG plant and used the order of magnitude to apply the data on material usage from the GoBiGas plant to bigger scales. Data for the assessment of embedded emissions of the 20 MW plant is available in Appendix A.

It is important to note that the selected processes from ProBas refer to Germany as the location. The electricity mix differs from country to country, influencing the results. The data from the ProBas database relating to electricity use was adapted to the values of the Austrian electricity mix and the average EU electricity mix (IEA, 2019b). The CO_2 factor of the electricity influences the results of the biomass-based references. It is assumed that 0.06-0.075 kWh electricity / kWh biomethane (Billig and Thraen, 2017) is used in the plant operation and upgrading section and 0.05 kWh/kWh bio-SNG (Larsson et al., 2018). Figure 22 shows the system boundaries of the GHG mitigation potential analysis. In this work, no specific use case is investigated.

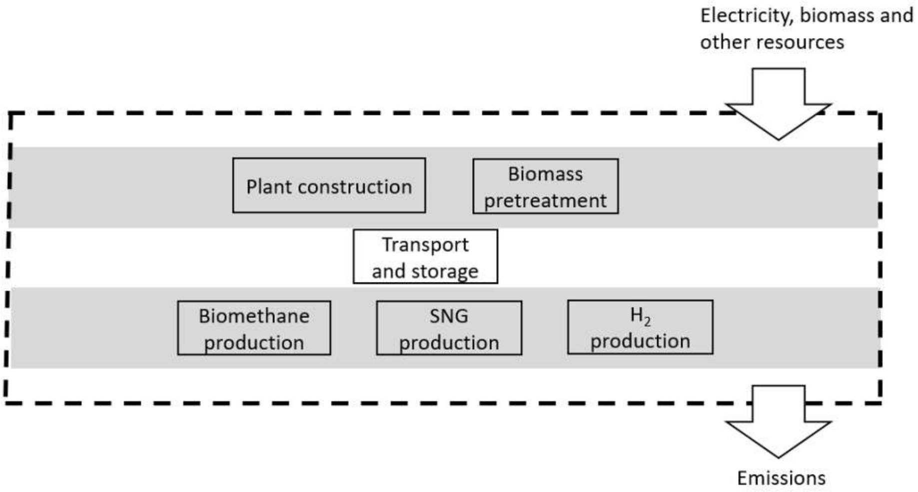


Figure 22. System boundaries of the GHG emission assessment.

Biomethane and bio-SNG are promising for CO_2 mitigation compared to conventional natural gas and LNG. Both biomethane and bio-SNG have the advantage of being renewable and reducing emissions to a large extent when sustainable feedstocks are utilized. The GHG emissions in the process chain are investigated according to the guidelines of the European Commission for emissions accounting of alternative fuels (European Commission, 2023a). All relevant emissions along the process chain, including consumption, are accounted for in equation (13).

$$e = e_i + e_P + e_{td} + e_u \tag{13}$$

with:

e = sum of greenhouse gas emissions in the process chain,

e_i = emissions associated with feedstock production,

e_P = embedded emissions from the plant construction and materials,

e_{td} = emissions from transport and distribution,

e_u = emissions from usage.

The GHG mitigation potential is then calculated by using equation (14). Specific criteria are defined by the European Commission for renewable fuel production (European Commission, 2023b).

The CO_2 factors of 53 g CO_2/ kWh and 9.3 g CO_2/ kWh are selected for PV modules and wind turbines, respectively, according to a study by the German Environmental Agency (Hengstler et al., 2021). The CO_2 intensity of the electricity of the EU mix was 265 g CO_2/ kWh in the year 2023 (EEA, 2023).

The material used, construction and maintenance of an electrolyzer are relevant, however, they contribute to a lower extent to the overall emissions than the electricity source. Burkhardt et al. (2016) conduct an LCA study for an alkaline electrolyzer. In total, 11.1 g CO_2/ kWh result from the global warming potential for the material usage and construction of an alkaline electrolyzer.

According to RED III, the benchmark for GHG emission reduction is at least 70 %. It is applied to compare with the fossil counterpart natural gas, for which the CO_2 factors vary widely in the literature depending on the supply region. The emissions of natural gas usage consist of 201 g CO_2/ kWh direct emissions and conservatively estimated indirect emissions are around 34 g CO_2/ kWh related to sourcing and transport, assuming Norwegian pipeline gas. Emissions of LNG depend strongly on the country of origin. The USA became one of the major exporters, being responsible for approximately 20% of global LNG shipments. The study by Howarth (Howarth, 2024) critically examines the greenhouse gas (GHG) footprint of U.S. LNG exports, emphasizing the significant impact of methane emissions throughout the supply chain. The analysis reveals that methane leakage from shale gas extraction, processing and transport accounts for a major share of total emissions, making LNG potentially more damaging to the climate than coal, particularly over short time horizons.

The EU imports LNG from several key suppliers, including the United States (46%), Qatar (12.1%), Russia (11.7%), Algeria (9.5%), Nigeria (5.6%) and Norway (4.8%) as of 2023. The non-associated gas production has approximately doubled for the major supplier USA from 2013-2023 (EIA, 2024).

The well-to-tank carbon intensity of LNG imports differs widely, with the United States exhibiting the highest emissions at 27.4 g $CO_{2\,eq.}$/MJ followed by Algeria 19.02 g $CO_{2\,eq.}$/MJ and Russia 18.75 g $CO_{2\,eq.}$/MJ. These variations arise from differences in gas extraction methods, infrastructure efficiency and regulatory oversight. Notably, methane leakage and flaring in countries like the U.S., Algeria and Russia contribute significantly to their high well-to-tank emissions. The average carbon intensity for the LNG imported to the EU was approximately 93 g $CO_{2\,eq.}$ /MJ, which is approximately 42% higher than the assumed natural gas carbon intensity (Carr et al., 2024).

$$e_\delta = \frac{(e_F - e)}{e_F} \tag{14}$$

with:

e_δ = emission reduction,

e_F = total emissions from fossil reference fuel.

By utilizing biomass feedstocks together with hydrogen-enhanced production, carbon dioxide can be effectively utilized that would otherwise be released into the atmosphere. Another option is to capture CO_2 and store it underground.

One of the most widely applied indicators in the evaluation of carbon capture and storage systems is the cost of CO_2 avoided (often abbreviated CAC). This metric links the incremental cost of electricity or other energy products from a CCS-equipped facility with the corresponding reduction in net carbon dioxide emissions compared to a reference plant without CCS (Roussanaly, 2019). The purpose of the CAC is therefore twofold: to provide a normalized measure of the economic efficiency of a CCS project in terms of abatement cost per unit of CO_2 and to enable meaningful comparison of CCS systems against other mitigation measures and technologies across industries and energy sectors. As international frameworks such as the Paris Agreement call for deep reductions in greenhouse gas emissions, policymakers and industry require a robust basis for comparing the cost-effectiveness of alternative mitigation pathways. Whereas simple project costs or levelized cost of electricity (LCOE) reveal the financial burden of deploying CCS, they do not directly express the environmental benefit of emission reductions. By contrast, CAC integrates both economic and environmental dimensions into a single figure, usually expressed in EUR/tCO_2 avoided (Roussanaly et al., 2021).

The underlying rationale for CO_2 avoidance costs is applied to carbon capture and utilization for renewable methane production in this thesis. Roussanaly et al. (2019) emphasize that the CAC is often misunderstood as being equivalent to the cost of CO_2 capture. In fact, capture cost refers only to the expenses per ton of CO_2 physically removed from the flue gas, independent of the actual net change in emissions at the system level. The CAC, by contrast, accounts for the avoided emissions relative to a defined baseline system and thus provides a more comprehensive indication of mitigation performance. This distinction is essential, as the same capture technology applied to two different industrial processes may result in similar capture costs but very different avoidance costs, depending on process efficiency, fuel mix, or system boundaries (Haaf et al., 2020).

The calculation of CO_2 avoidance costs using equation (15) focuses on hydrogen-enhanced biomethane and bio-SNG production as well as biomethane/bio-SNG with carbon capture and storage. The formula shows the difference in costs from the alternative option to the natural gas price divided by the emission savings (Roussanaly, 2019).

The calculation of the GHG emissions per kWh serves as input for the CO_2 avoidance costs (Caesary et al., 2025). The method of total avoidance costs is used in this study, providing a long-term economic perspective, making it crucial for investment decisions in new technologies such as hydrogen production, carbon capture and utilization, or large-scale renewable energy projects. The marginal abatement cost approach, which gained prominence in the early 2000s, focuses on short-term emission reductions by identifying the most cost-effective measures at a given time. In policy discussions, results from using the marginal approach are typically compared to the EU ETS carbon price to evaluate immediate actions. However, this approach is insufficient for long-term decarbonization, as it does not account for infrastructure investments, systemic changes, or technological shifts required to reach net-zero emissions. Instead, the method of calculating total CO_2 avoidance costs is applied in this thesis, which provides a more comprehensive perspective by considering all project related costs (Hallegatte, 2023).

$$c_{CO_2,avoidance} = \frac{c_{fuel} - c_F}{e_{fuel} - e_F} \tag{15}$$

with:

c_{fuel} = costs of the alternative energy carrier,

c_F = costs of the fossil energy carrier,

e_{fuel} = GHG emissions of the alternative energy carrier,

e_F = GHG emissions of the fossil energy carrier.

The evaluation of CO_2 avoidance costs is not only a financial measure but also a strategic tool to prioritize investments in low-carbon technologies with the highest mitigation potential. In this regard, literature values are compared with own findings, considering two different scenarios for natural gas prices of 40 and 50 EUR/MWh and two for CO_2 capture costs in the range of 80-120 EUR/ ton for bio-SNG and 60-100 EUR/ ton for biomethane depending on the capture rate.

The CO2 avoidance costs are calculated for comparing the process pathways investigated in this study with natural gas and LNG. The reason for using LNG as a reference lies in its increasing role in Europe's energy supply, particularly as LNG imports have risen to replace natural gas traditionally transported via pipelines. Since LNG often has a higher carbon footprint due to energy-intensive liquefaction, transport and regasification processes, it serves as a useful emissions benchmark when evaluating alternative decarbonization measures.

4.2. Results

This section presents the key findings of the economic viability of biomethane, bio-SNG production, enhanced outputs and results from the GHG mitigation potential. First, the results of the economic evaluation and the contribution of different variables to the overall production costs are presented. These present valuable insights into the implications of sector coupling with biomass-based gas production. Afterward, the results of the environmental analysis illustrate the potential contribution of the process routes investigated to CO_2 mitigation in the energy sector.

4.2.1. Biomethane and bio-SNG production costs

This section shows the production costs for biomethane and bio-SNG without the integration of hydrogen. These reference cases serve as benchmarks for production costs of renewable methane and consist of 20 MW and 50 MW bio-SNG plants and 2 MW and 5 MW biomethane. Low-grade wood, which cannot be used for timber production, is the investigated feedstock for bio-SNG production. Figure 23 shows the production costs of the reference process routes for bio-SNG and biomethane production in 2023. The two selected scales for bio-SNG production, 20 MW and 50 MW, are compared. The costs of the bio-SNG output decreased significantly from 161 EUR/MWh for a 20 MW plant to 127 EUR/MWh for a 50 MW plant due to the economies of scale. On the opposite, the share of transport costs increases from 9 EUR/MWh (5%) at a 20 MW plant to 20 EUR/MWh (16%) at a 50 MW plant due to the extended distance. The capital costs contribute approximately 58-60% to the bio-SNG production costs. The CEPCI index, the basis for the inflation adaptation, increased from 2018 to 2022 by approximately 35%, a stronger increase than the average European inflation rate over the respective period (Maxwell, 2024). Therefore, the share of capital costs has increased even more in recent years.

Shifting to biomethane production, the utilization of biowaste, energy maize and manure as feedstocks is compared. In the results, also economies of scale are observed, changing from 2 MW to 5 MW, reducing costs by 5-19%. Another result is that the costs depend on the feedstock utilized. This is no surprise as it is already investigated by the study by Billig and Thraen (Billig and Thraen, 2017), from which the investment costs are taken. However, interesting to note is, that the operating costs of 48-52 EUR/MWh predominate in the production costs of utilizing energy maize. In contrast, the capital costs exceed the operating costs in utilizing biowaste and manure. In reality, a mixture of different biomass materials is often used in anaerobic digestion. Therefore, the results of the following sections show the average production costs of biomethane. The horizontal lines indicate average household and non-household natural gas prices in 2023. These values include transmission and distribution costs, taxes and supplier margins, whereas the production costs shown for bio-SNG and biomethane represent plant-gate costs. The comparison is indicative and should not be interpreted as direct evidence of market competitiveness, emphasizing the importance of regulatory and policy frameworks.

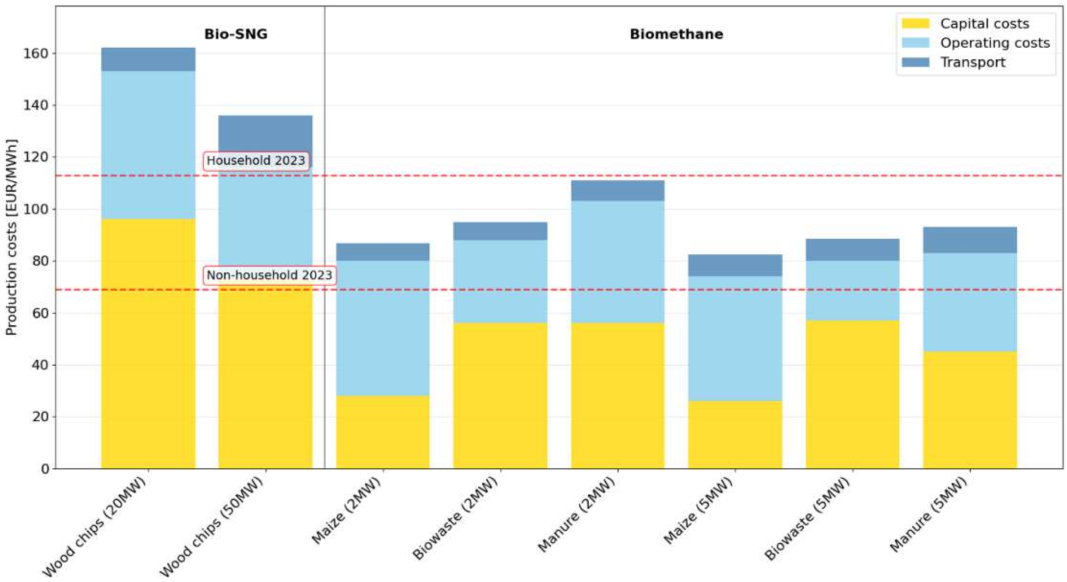


Figure 23. Production costs of bio-SNG and biomethane in the reference cases compared to average European household consumer and non-household consumer prices for natural gas, including taxes (Eurostat, 2024).

4.2.2. Electricity costs for the enhanced biomethane and bio-SNG production

The electricity costs for the enhanced biomethane and bio-SNG production are obtained with the linear optimization. The main differences lie in the network charges and investment costs of the renewables in relation to the scale. The electricity demand for biomass conversion by anaerobic digestion or biomass gasification is not considered in the linear optimization; only the electrolyzer demand is investigated.

In Figure 24, the seasonal and daily variations of electricity generation by the renewable sources, feed-in into the grid and the grid consumption are shown for the enhanced production at the 2 MW biomethane and 20 MW bio-SNG plant reference capacities, which relate to the energy output from the biomass.

The yearly electricity demands of the electrolyzers are approximately 17990 MWh and 219 000 MWh, respectively with 7500 full load hours assumed distributed over the whole year with an average demand of 2.053 MWh and 25.079 MWh per hour. The optimization solution is to install mainly wind and a minor share of PV panels from a cost perspective under the assumptions made in all scenarios. Most of the grid consumption occurs in the summer because wind availability is naturally lower during this time in Austria.

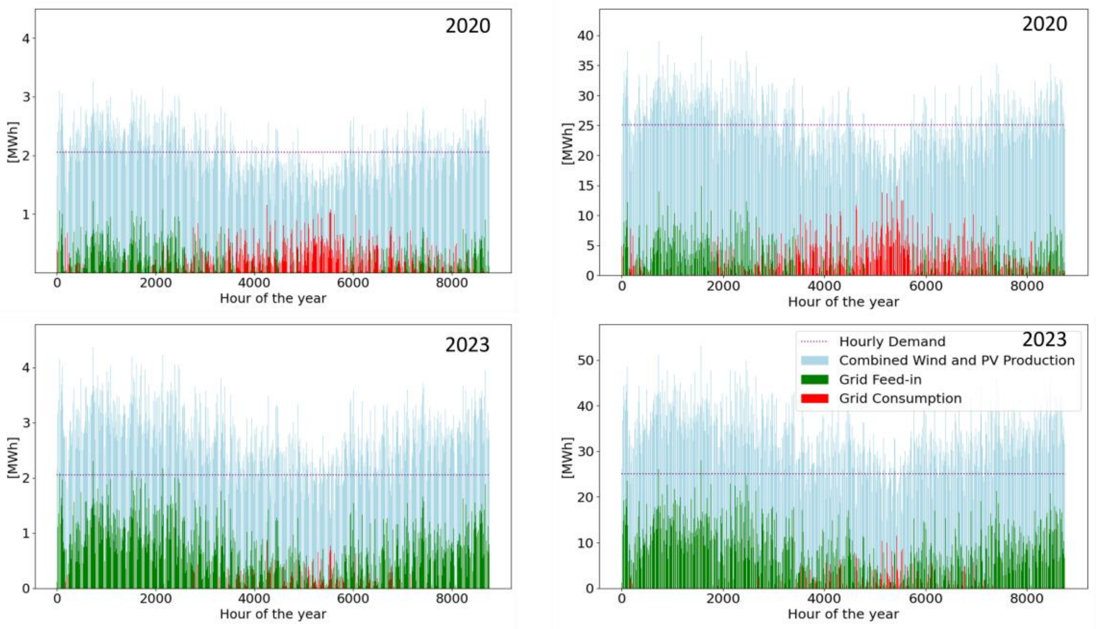


Figure 24. Results of the linear optimization show electricity generation by renewables, grid consumption and feed-in. The left side shows the results for enhanced biomethane production and the right side shows the results for enhanced bio-SNG.

The model reacts very sensitively to the grid electricity prices. Compared to the work of Pratschner et al. (2023), grid electricity prices for two years are compared. Table 13 illustrates the results of the optimization more clearly. A major difference is that the grid consumption and feed-in are equal in the year with low electricity prices (2020). The feed-in is much higher in 2023 and more capacities of renewables are installed because the costs are lowered in the model by 30% in this sense. Greater variability in electricity prices encourages producers to feed in more electricity when spot market prices are high, whereas low or negative prices provide a signal to increase electricity consumption from the grid. Therefore, grid consumption has been constrained to not rely on the electricity grid and prioritize the use of additional renewable capacities.

The high energy prices of recent years are an exception in the last 25 years and lead to higher revenues in the case of feed-in. Given these exceptional circumstances, the results of the first scenario (reference year 2020) with higher yearly electricity costs are applied for further calculations of the production costs. The specific electricity costs per MWh input are approximately 61 EUR/MWh for enhanced bio-SNG production and 67 EUR/MWh for enhanced biomethane. Revenues for feed-in are accounted for in these costs. The range of electricity costs for economic operation is 50 – 70 EUR/MWh, according to Witte et al. (2018a).

Table 13. Results of the linear optimization showing the yearly electricity generation, grid consumption, feed-in and yearly costs.

	Enhanced biomethane production		**Enhanced bio-SNG production**	
Year	**2020**	**2023**	**2020**	**2023**
Wind cap [MW]	7.36	9.67	89.90	117.03
PV cap. [MW]	0.91	1.39	11.2	16.94
Electricity consumption from the grid [MWh]	1493	292	18333	4011
Feed-in into the electricity grid [MWh]	1493	6203	18333	73183
Electricity costs [Million EUR]	1.20	0.85	13.27	9.22

The regulation by the European Commission for sustainable hydrogen production specifies that additional renewable energy capacities must be installed, which is fulfilled as the surplus electricity equals or exceeds the grid consumption, leading to a net addition of renewable capacities. However, when consuming grid electricity, the share of renewables must be at least 90% in the previous calendar year to count as green hydrogen. According to the Renewable Expansion Act (BMK, 2021), this will happen in a few years in Austria. Other countries such as Sweden and Denmark (EEA, 2024) already have a very high share of renewables in the energy system. Therefore, the hybrid system can also be applied to other countries in the EU.

4.2.3. Costs of hydrogen-enhanced biomethane and bio-SNG production

This section discusses the effect of hydrogen integration on the enhanced production of biomethane and bio-SNG. Figure 25 illustrates the results for production costs for 2023 and 2050. The results for the reference cases are displayed against the process routes with enhanced production. The capacities given are the base capacities in relation to the biomass input. All costs are stated without taxes and revenues for by-products such as digestate are not considered.

The displayed error bars represent the cost deviation created by a 7% and 11% learning rate, with the average value in between. The yearly electricity costs of 13.27 million EUR (bio-SNG) or 1.20 million EUR (biomethane), according to reference year 2020 are derived from the linear optimization of the hybrid energy model. These values are used in the cost calculations, as these are more realistic based on historical wholesale electricity prices. The integration of hydrogen significantly increases the production costs in all cases. While cost savings result from avoiding CO_2 separation, these savings are insufficient to offset the increased capital costs and energy costs associated with hydrogen production.

In the enhanced bio-SNG production, the costs increase from 138 to 149 EUR/MWh (20 MW) and from 106 to 136 EUR/MWh (50 MW). The lowest costs of the enhanced production routes are seen for the 50 MW bio-SNG plant. The rise in production costs for biomethane is more pronounced than that for bio-SNG, from the reference case (anaerobic digestion and upgrading without additional H_2) to the enhanced production. Costs increase by 45% (103 to 150 EUR/MWh) and 51% (90 to 136 EUR/MWh) for facilities with capacities of 2MW and 5MW, respectively. The main reason is that no methanation section exists in the reference case and the installation significantly contributes to the overall investment costs.

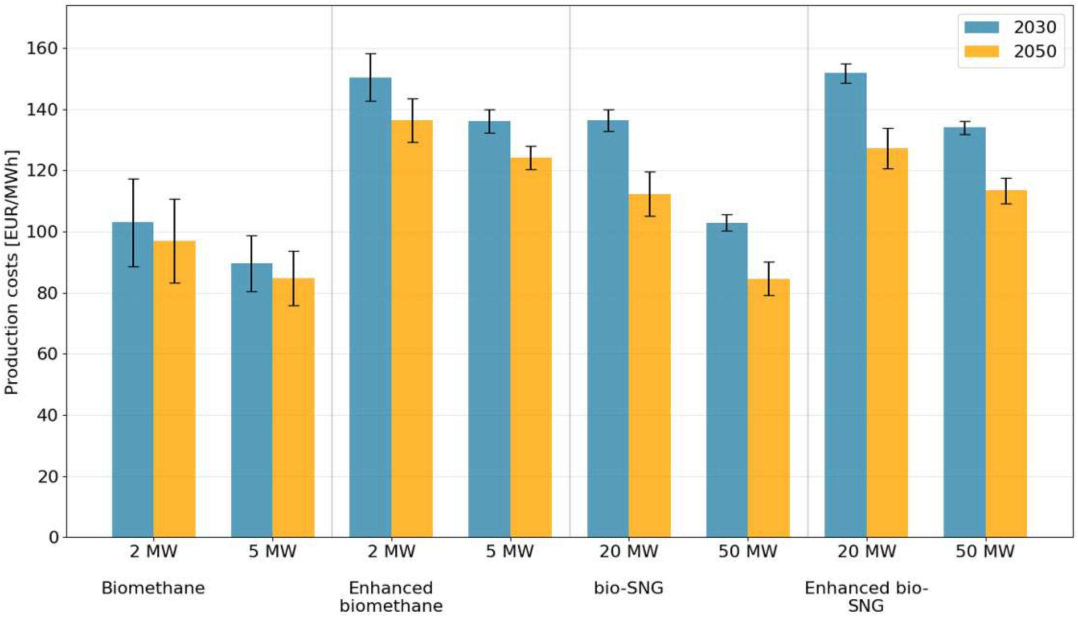


Figure 25. Costs of reference cases and enhanced biomethane and bio-SNG production.

4.2.4. Greenhouse gas emission reduction potential

Enhanced biomethane production, derived from organic waste and bio-SNG, produced from wood, both present viable pathways toward CO_2 mitigation when also using renewable electricity. The results show a substantial reduction in greenhouse gas emissions depending on the scenario compared to conventional natural gas and LNG

Figure 26 presents the GHG emissions in CO_2 equivalents per kWh of produced gas and utilized biomass material. The specific emissions are not capacity-related. The feedstock-related emissions have the highest impact on the results of the biomass-based reference cases (without additional H_2). Fertilizer application negatively influences the results in the case of energy maize utilization. Therefore, exploiting energy crops causes more emissions than waste or forest biomass conversion and does not comply with the emission reduction goal of 70% for renewable fuels, according to the Renewable Energy Directive (RED III) 2023/2413 (European Parliament, 2023).

The results for enhanced biomethane production clearly show the influence of the electricity mix and the feedstock. Emissions increase compared to natural gas when using the EU electricity mix. Interestingly, the specific emissions for energy maize utilization decrease from 105 to 86 g $CO_{2\ eq.}$/kWh in the hybrid scenario because the hydrogen-related emissions are less than those related to the biomethane production from maize. However, the 70% reduction goal, which is approximately 70 g $CO_{2\ eq.}$/kWh for the assumptions in this paper, still cannot be reached. Utilizing the EU electricity mix of 2023 would lead to even higher emissions than the use of imported LNG. A different situation occurs for enhanced biomethane production, where biowaste and manure are used as feedstocks. The specific emissions for the product increase slightly due to the hydrogen input from approximately 33-35 g $CO_{2\ eq.}$/ kWh to 46-48 g $CO_{2\ eq.}$/ kWh. However, the emissions for waste and residue utilization remain below the 70% reduction threshold of 70 g $CO_{2\ eq.}$/kWh. Studies such as Liebetrau et al. (2017), also propose to give CO_2 credits for manure utilization because the methane leakages can be prevented compared to many on-site storages at farms. Negative emissions can be calculated using this method of emission accounting without the application of carbon capture and storage. This was not taken into consideration in this assessment.

The results for the enhanced bio-SNG production are on the same level as those of biowaste and manure utilization, also for the enhanced production. The CO_2 factor of the electricity source has again the strongest influence on the results. The embedded emissions for the bio-SNG plant account for only a minor share of the emissions compared to the energy input.

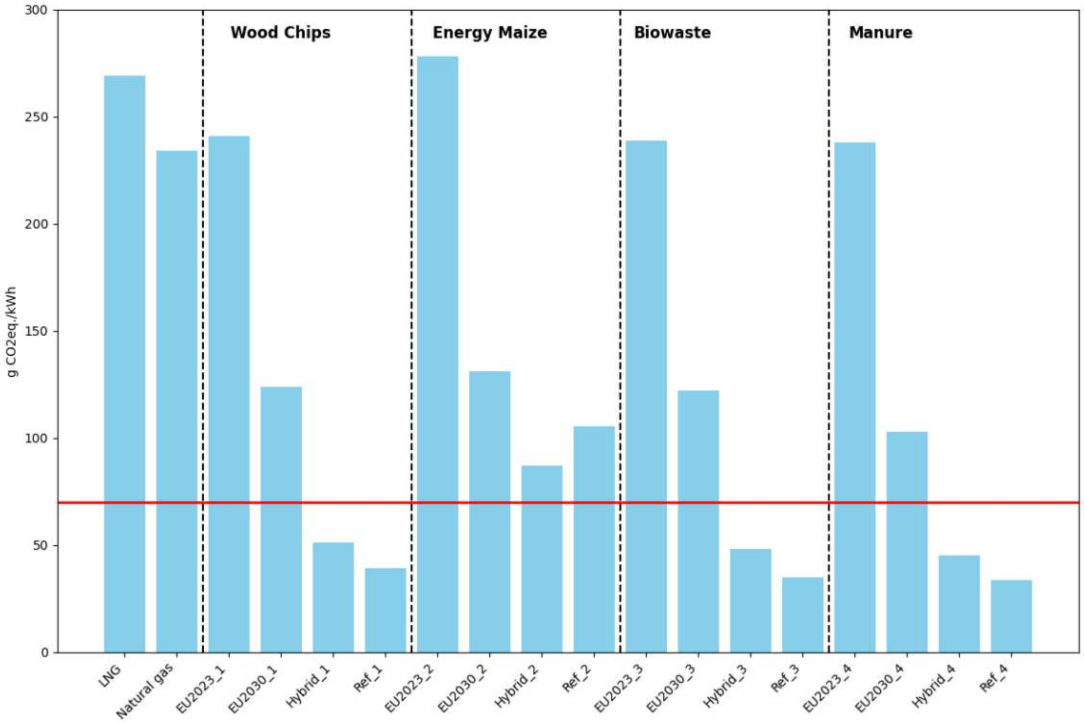


Figure 26. Greenhouse gas emissions of the process routes analysed. Ref = biomass-based production, Hybrid = H_2-enhanced biomethane or bio-SNG production using electricity from the hybrid energy supply, EU2023/ 2030 = enhanced production using the electricity from the grid with the average CO_2 intensity of the EU in 2023/ 2030.

4.2.5. CO_2 avoidance costs

The results are shown for reference cases (without hydrogen integration), hydrogen-enhanced production using the hybrid energy model and the hypothetical case of using the EU grid electricity mix 2030 to supply H_2 in Table 14. The lowest CO_2 avoidance costs are achieved for implementing carbon capture and storage due to negative emissions. On the contrary, using the average European electricity mix anticipated for 2030 will lead to the highest avoidance costs. The hydrogen integration in biomethane and bio-SNG production, ranging from 526–667 EUR/t $CO_{2eq.}$ to 341–431 EUR/t $CO_{2eq.}$ is in between the two mentioned extremes. The avoidance costs can be influenced by a variety of factors, such as emission, factors external energy sources, the policy framework, etc.

Table 14. Results of total CO_2 avoidance cost calculation.

Process route	**Natural gas**	**LNG**	**Unit**
SNG_Reference	341-553	279-365	EUR/t $CO_{2eq.}$
SNG_EU2030	1099-1330	574-695	EUR/t $CO_{2eq.}$
SNG_Hybrid	529-667	342-431	EUR/t $CO_{2eq.}$
SNG + CCS	186-246	156-237	EUR/t $CO_{2eq.}$
Biomethane_Reference	198-316	131-210	EUR/t $CO_{2eq.}$
Biomethane_EU2030	915-1108	483-585	EUR/t $CO_{2eq.}$
Biomethane_Hybrid	526-595	341-386	EUR/t $CO_{2eq.}$
Biomethane + CCS	138-305	107-228	EUR/t $CO_{2eq.}$

5. Substitution potential of surplus power-based e-methane production for LNG: The case of Kyushu and Hokkaido in Japan

The scope of this study is to investigate the potential for green gases within future electrification scenarios. The core objective is to assess the potential installation and utilization of e-methane production capacities, thereby contributing to the literature on regional energy self-sufficiency and the role of e-methane in the defossilisation of isolated energy systems such as Kyushu and Hokkaido.

The energy transition in Japan has already started but faces challenges such as integrating renewable energy technologies into a partly isolated and constrained electricity grid. The country has limited land area for power plants, a high population density and many mountainous regions that constrain typical renewable installation, leading to innovative solutions like offshore wind farms (IEA, 2021c). Nevertheless, the installations of solar power plants gained a strong momentum in Japan, leading to the need for the integration of short-term (hourly, daily) and seasonal fluctuations into the energy system (JEPIC, 2024). Curtailment is already a common challenge in western Japan. In three out of eight geographic regions, curtailment rates for wind and solar energy ranging from 3.1% to 6.7% were reported for 2023 (Zissler, 2024). Curtailment often occurs because the electricity generated by the renewable sources can be highly variable and surpass the grid's immediate consumption needs or the infrastructure's ability to transmit and distribute the power efficiently. In addition, Japanese energy policy has changed and reduced the reliance on nuclear power after the Fukushima disaster in 2011, following many years of pro-nuclear policies (McLellan et al., 2013). Nevertheless, nuclear power will remain an integral part of the future energy system. However, certain types of thermal power plants such as nuclear plants and coal power plants cannot respond fast enough to the variability of wind and solar energy generation (Agora Energiewende, 2017). Currently, renewable power plants need to be switched off to maintain the stability of the electricity grid.

5.1. Methodology

The methodology section first provides a brief scenario description related to the methodology overview in Figure 27. Afterwards, the case study is introduced and input datasets are presented. The main part of the methodology is the quantification of curtailment and modelling using the energy system model *urbs* (Dorfner, 2019).

5.1.1. Methodology overview

Two scenarios (*Moderate* and *Fast*) are defined for creating the time series of electricity demand and generation. The two scenarios differ in the adoption rates of installed capacities of solar and offshore wind energy, which are critical for producing e-methane from surplus electricity in Japan and the demand for electricity and gas by different sectors. The *Moderate* scenario assumes a steady but gradual increase in solar and offshore wind capacity, aligning with current policies and market trends. It reflects a more conservative outlook, with incremental growth in renewable infrastructure, realistic technological advancements and policy support. The *Fast* scenario represents the optimistic pathway, where the upper limits of projected renewable expansion are reached. It envisions a more ambitious deployment of solar and offshore wind, driven by strong policy incentives. This contribution is derived from a manuscript by Radosits et al. (under review). The time series are used to quantify curtailment separately of the energy system modelling in *urbs*. Gas demand, which varies across scenarios, is another key input parameter for the model. The degree of self-sufficiency is defined as the ratio of annual domestic e-methane production from the modelling output data to the annual gas demand input data. Electricity used for e-methane production is considered as curtailment reduction.

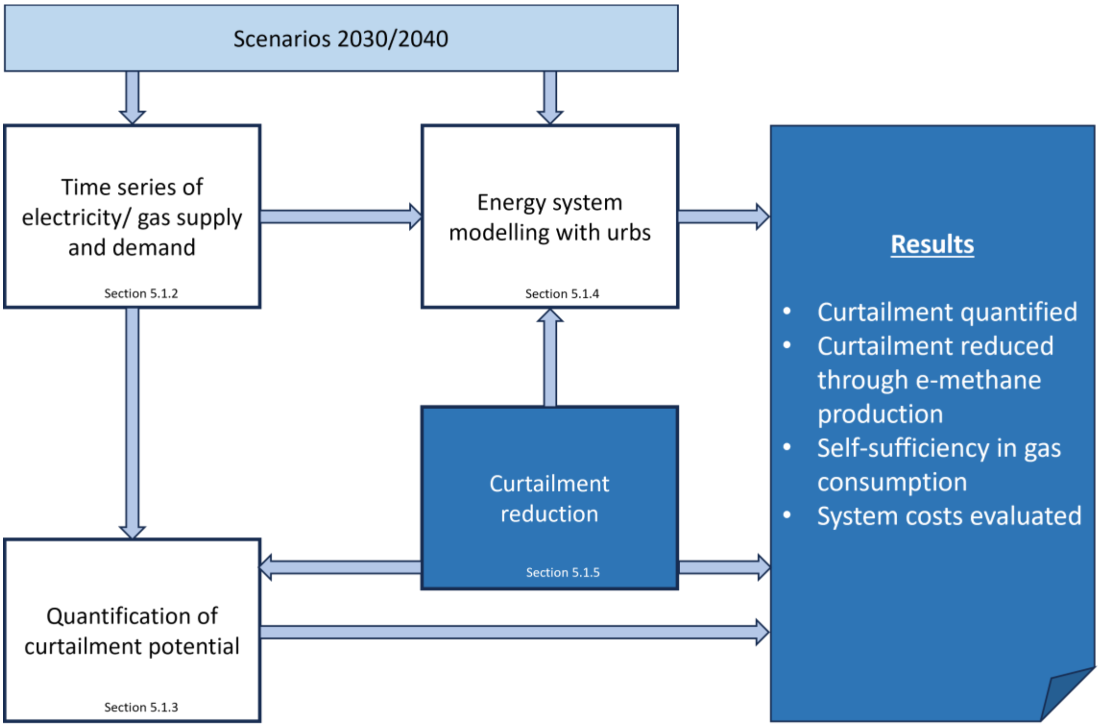


Figure 27. Assessment of theoretical curtailment and energy system modelling are combined for the evaluation of curtailment reduction through e-methane production.

5.1.2. Case study in Japan and input data

The following subsections provide an overview of the Japanese electricity and gas systems, highlighting how they are shaped by geographical factors (REI, 2023) and input data for creating the time series used in the quantification of curtailment and energy system modelling.

5.1.2.1. Japanese electricity system

Japan is divided into 10 different regions for electricity transmission. The country is also divided into 50 Hz and 60 Hz frequencies (JEPIC, 2024), which increases the complexity of increasing the renewable shares in the county's energy system. The rising share of curtailment and the challenges associated with decarbonization are the reasons for choosing Kyushu and Hokkaido as case studies in this work. These two regions are highlighted in Figure 28 and located at the periphery of Japan's power system, with limited transmission capacities restricting electricity exchange. Their distinct climatic conditions favour different renewable technologies, solar in Kyushu and offshore wind in Hokkaido, making them preferable case studies for analysing surplus electricity utilization. By comparing two distinct climatic conditions, this study aims to enhance the applicability of the results to other regions exhibiting similar characteristics and challenges.

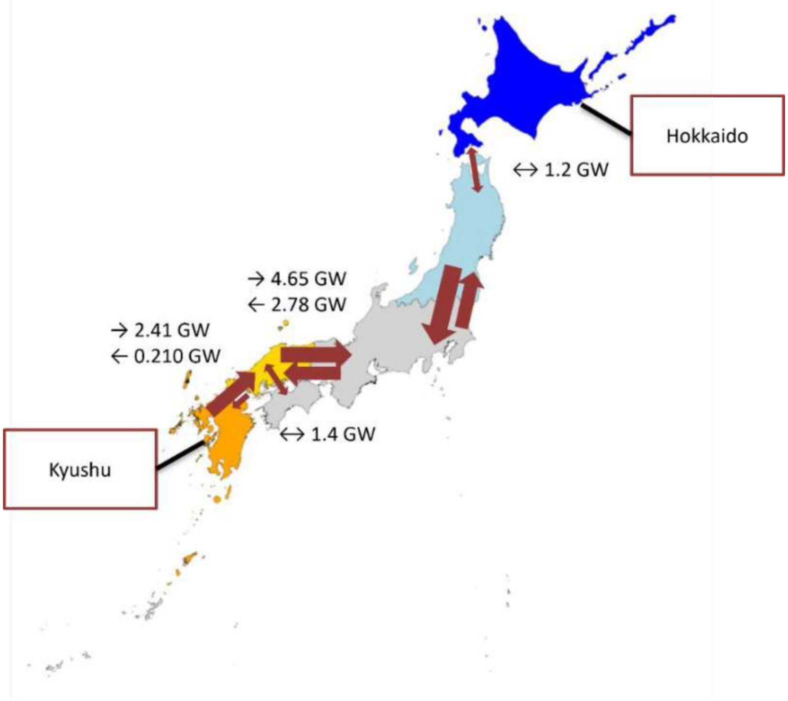


Figure 28. Investigated regions Kyushu-Chūgoku and Hokkaido-Tohoku for surplus electricity utilization in Japan. Import and export is considered to the grey area without detailed modelling of transmission. Created by editing basic map data (country and regional borders) from the Geospatial Information Authority of Japan. Data sources: (Geospatial Information Authority of Japan, 2016; JEPIC, 2024).

In the southern regions, such as Kyushu and Shikoku, solar radiation levels are among the highest in the country (IRENA, 2021). Kyushu has a diverse energy mix, with a strong presence of solar power, which has expanded rapidly and now constitutes a significant share of regional electricity generation. In addition to renewables, Kyushu relies on thermal power plants, including coal, LNG and oil, along with nuclear energy from the Sendai and Genkai reactors, which provide stable baseload power (Zissler, 2024). Hydropower also contributes to the mix, though to a lesser extent. Hokkaido's energy portfolio is shaped by a combination of fossil fuels, hydropower and a growing share of wind energy, particularly offshore, given the area's strong wind conditions (Mitsubishi UFJ Financial Group Inc., 2023). LNG is playing an increasingly important role as a flexible power generation technology in Hokkaido. While coal remains a significant energy source, old plants are scheduled for decommissioning starting in 2027. The electricity strategy until 2050 focuses on achieving carbon neutrality by leveraging its abundant renewable resources, particularly wind power (Johnston, 2024) and to transfer electricity to demand centers like Tokyo (Batten et al., 2024). One of the main challenges for the region is also the limited transmission capacity, which restricts the ability to distribute surplus wind power efficiently, highlighting the importance of infrastructure upgrades (Batten et al., 2024). The largest regional investments in transmission capacity across Japan are considered to expand the transmission capacity of Hokkaido to Tohoku from 1200 MW to 7200 MW (Mitsubishi UFJ Financial Group Inc., 2023).

5.1.2.2. Japanese gas sector

Japan's city gas network is a fragmented system developed around individual urban areas, primarily due to the country's mountainous terrain and the independent establishment of LNG terminals in each region (EIA, 2023). The total pipeline network comprises 86% low-pressure grids for local distribution and only 0.9% designated as high-pressure pipelines ("Japan Natural Gas Security Policy – Analysis," 2022).

Japan has a projected need according to the 6th Strategic Energy Plan of 25 Mt/yr e-methane (35 billion cubic meter per year) for the city gas supply (METI, 2021), including the future gas demand for high-temperature heat processes in industry, commercial and residential sectors. Japan is called a first mover by the IEA (2023c) regarding the drop-in of e-methane. The government has ambitious plans to replace fossil LNG by e-methane and decrease its costs. The goal is to reach 1% e-methane in 2030 and 90% of city gas supply by e-methane in 2050 (IEA, 2021c). The domestic production of e-methane is not mentioned as a primary target as the focus is rather on imports. However, there is an interest in carbon capture and utilization technologies and alternative fuels (METI, 2021).

Table 15 shows the gas demand without gas used for electricity generation. Industry is the largest gas consumer in all regions except for Hokkaido. Kyushu, Tohoku and Chūgoku have energy-intensive industries, such as steel, petrochemicals and ceramics, which rely heavily on natural gas for process heat and feedstock. Historically, industries in Hokkaido have relied more on coal, oil and electricity (Otsuka, 2017).

Table 15. Regional gas demand in PJ per year (2022) in the industrial, residential and commercial sectors in four analysed regions of Japan. Source: (METI, 2024)

	Kyushu and Okinawa	**Hokkaido**	**Tohoku**	**Chūgoku and Shikoku**
Industry	29.9 PJ	8.3 PJ	31.5 PJ	43.7 PJ
Residential	15.1 PJ	13.6 PJ	8.2 PJ	10.4 PJ
Commercial	7.4 PJ	10.1 PJ	3.9 PJ	4.7 PJ

The future gas demand is primarily influenced by reductions resulting from a shift toward electrification in most sectors. This trend reflects Japan's broader decarbonization strategy, which promotes electricity-based alternatives for heating, transport and industrial processes. The shift takes time and strategic roles for gas may persist in peak power generation and hard-to-electrify industries.

The exact hourly gas demand could not be derived from statistical data. It is therefore separated into seasonal gas demand by accounting for regional conditions. Based on assumptions according to seasonal consumption current seasonal patterns excluding electricity generation (EIA, 2011), factors for the seasonal gas demand were derived, which is shown in Table 16. In Hokkaido, the cold winters drive high heating demand in the residential and commercial sectors, while Kyushu's milder winters and warmer summers result in a smaller heating load (Kong et al., 2015).

Table 16. Estimated share of the annual gas consumption per season in Hokkaido based on historical data of sectoral consumption patterns.

Season	**Kyushu**	**Hokkaido**
Winter, December 1 – February 28 (or 29)	35%	45%
Spring, March 1 – May 31	25%	20%
Summer, June 1 – August 31	20%	15%
Autumn, September 1 – November 30	20%	20%

5.1.2.3. Electricity demand evaluation

In this study, a bottom-up approach is applied by using different electrification targets. Electricity demand is modelled across four key sectors: industry, residential, commercial and transport. The growing electricity demand is determined by applying electrification targets shown in Table 17. The electrification scenarios for the residential and commercial sector are derived from the carbon neutral vision of the Kyushu Electric Power Company (Kyuden Group, 2021). The aim is to reach a 100 % electrification in the residential and commercial sector by 2050.

Industry: Electrification in the industrial sector is a key part of the 6th strategic energy plan to maintain clean and affordable energy for the Japanese industry, which accounts for approximately 20% of the nation's GDP. In the *Moderate* scenario, electrification is achieved by covering both low- and medium-temperature processes. To achieve this, industrial companies can invest, for example, in electric furnaces, heat pumps and other electric heating solutions. However, high-temperature processes still primarily rely on natural gas, e-methane and hydrogen (METI, 2021). In the fast scenario, Japan's industrial sector rapidly adopts electrification across all temperature ranges and reduces the need for fossil fuels faster.

Table 17. Sectoral electricity consumption in the final energy demand based on the neutral vision of the Kyushu Electric Power Company (Kyuden Group, 2021).

Share of Electricity	2022	Moderate 2030	Fast 2030	Moderate 2040	Fast 2040
Households	54%	65%	70%	75%	80%
Commercial	58%	60%	65%	70%	75%
Industry	36%	40%	45%	55%	60%
Transport	2%	26%	31%	46%	64%

Transport: The electricity demand for road transport in Japan is modelled with equation (16) based on simplified assumptions for changes in the vehicle stock (IEA, 2021c) and general charging patterns derived from literature, focusing on commuter and vehicle behaviours (Iwafune et al., 2019; Masuta et al., 2014).

$$D^{trans}(d,h) = \sum D^{trans}(d) * f_{charge}(d,h) \qquad (16)$$

with:

$D^{trans}(d,h)$ = hourly electricity demand of transport,
$\sum D^{trans}$ = daily transport energy demand,
$f_{charge}\ (d,h)$ = hourly factor based on assumptions of charging patterns.

Weekday charging shows peaks during the evening and early morning, while weekends have flatter distributions due to less structured usage. EV charging patterns assume widespread home, workplace and public infrastructure (METI, 2023), without considering flexibility measures such as vehicle-to-grid interaction in this work.

Table 18. Electricity consumption in the final energy demand of transport. Two scenarios were created for different electrification rates in the road transport. "Clean diesel vehicles" are defined according to emission standards from 2009 and following years (IEA, 2021c).

Sector	2018	Moderate 2030	Fast 2030	Moderate 2040	Fast 2040
Hybrid EV	32.6%	35%	30%	15%	10%
BEV	0.5%	15%	20%	40%	50%
PHEV	0.6%	15%	15%	15%	10%
FCV	0.01%	2%	3%	5%	10%
Clean Diesel	4%	5%	5%	10%	10%
Sum	37.7%	72%	73%	85%	90%
Diesel (other) and gasoline	62.3%	28%	27%	15%	10%

The additional electricity demand is added to the demand of 2023 and then multiplied by a factor in equation (17) to adjust for demographic changes. The forecast (IPSS, 2018) assumes a significant decline in the Japanese population by 2040.

$$D_{n,j}(t) = \gamma_s(t) * \frac{P(t)}{P_0} * D_{n,j}^{base} \tag{17}$$

With:

$D_{n,j}(t)$ = electricity demand,

$\gamma_s(t)$ = factor for electrification,

$P(t)$ = population in year t,

P_0 = population in the base year 2023,

$D_{n,j}^{base}$ = energy demand of 2023.

<u>Data centers:</u> Peak data center demand is projected to rise from 0.56 GW in 2025 to 5.1–5.4 GW in 2030, with greater uncertainty by 2040 (5.7–15 GW) (Japan Energy Hub, 2025; Onodera et al., 2025). Hokkaido is among three key regions for data center deployment, while no installations of large data centers are currently planned for Kyushu (Onodera et al., 2025). For Hokkaido, two

best-guess scenarios assume 20% and 30% of national demand, adding electricity demand of 1.02–1.08 GW by 2030 and 1.5–2.25 GW by 2040.

5.1.2.4. Renewable electricity generation

The focus in this section is on solar- and wind-based electricity production. The capacity factors for PV and wind power were derived from the Renewables.ninja project based on the works of Pfenninger and Staffell (2016) and (Staffell and Pfenninger, 2016) for the year 2019 for Kyushu. This year is considered as representative for electricity generation calculation (JMA, 2019). In contrast, Hokkaido experienced significantly higher solar irradiation in 2019, being 10–20% above the long-term average across the entire region. Therefore, for Hokkaido, the PVGIS database of the European Commission is used to obtain typical meteorological year data for PV and wind energy (European Commission, 2022). The average global horizontal radiation of two important sites with PV projects (coordinates) is used to calculate the hourly capacity factors for PV with the formula:

$$CF_{PV} = \frac{GHI * \eta_s * f_{tilt}}{1000} \tag{18}$$

with:

CF_{PV} = capacity factor for solar panels,
GHI = global horizontal irradiation in [W/m^2/h],
η_s = system efficiency 0.8,
f_{tilt} = average tilt correction factor 1.1.

Wind speed data at 10 meters above ground level is also obtained from the PVGIS database (European Commission, 2022). Four selected locations with major onshore and offshore wind projects in Hokkaido are used to calculate the capacity factors. The values with an average of 5.26 m/s need to be adapted to the wind speed at rotor height. First, the power law (Ryu et al., 2022) is applied using a shear exponent α of 0.1 for offshore wind and a hub height of 100 meters, according to the following formula, to extrapolate wind speed to rotor height:

$$v_{h2} = v_{h1} * \left(\frac{h_2}{h_1}\right)^{\alpha} \tag{19}$$

with:

v_{h2} = wind speed at hub height,
v_{h1} = wind speed at 10 m above the ground level,
h_2 = hub height,
h_1 = 10 m above the ground level.

In the next step, the extrapolated wind speed data is used to derive the capacity factors by using data on energy yield at the respective wind speed from the global wind atlas (DTU, 2023).
The regional electricity generation portfolios, illustrated in Figure 29, are developed according to scenario assumptions to ensure demand coverage while adhering to regional energy strategies.

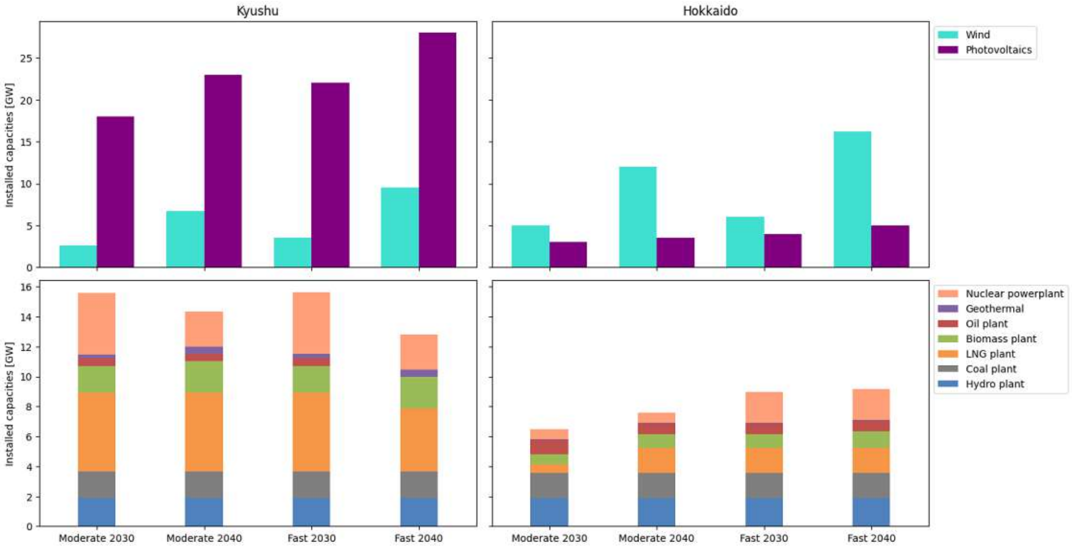


Figure 29. Installed capacities in Moderate and Fast scenarios for 2030/2040 in GW peak.

5.1.3. Quantification of curtailment potential

Curtailment potentials are quantified independently prior to the energy system modelling. A distinction between surplus electricity and curtailed electricity is made in this paper. Surplus electricity $P_n^{surplus}(t)$ in this context refers to the amount of generated electricity $P_n^{generation}(t)$ that exceeds the local demand (load) $P_n^{load}(t)$ at a given time step. This excess energy can be transmitted to other regions, stored for later use, or utilized directly for applications such as the production of synthetic fuels. The curtailed electricity is a consequence of restrictions in the grid. For economic reasons, it is assumed using equations (20) and (21) that the curtailed fraction of the surplus will be predominantly the source of e-methane production.

$$P_n^{surplus}(t) = P_n^{generation}(t) - P_n^{load}(t) \tag{20}$$

$$E_{curtailed}(t) = CF_W(t) * P_W + CF_S(t) * P_S - D(t) - E_{feed-in}(t) - E_{stored}(t) \tag{21}$$

with:

$P_n^{surplus}(t)$ = surplus power,

$P_n^{generation}(t)$ = power generation capacity,

P_n^{load} = hourly load

$E_{curtailed}$ = curtailed energy,

CF_W = hourly capacity factor of wind power,

P_W = installed power of wind plants,

CF_S = hourly capacity factor of solar power,

P_S = installed power of PV plants,

D = hourly electricity demand,

$E_{feed-in}$ = electricity fed into the grid in hour t,

E_{stored} = stored electricity in hour t.

5.1.4. Energy system modelling

Linear programming constitutes a foundational methodology in the field of energy system modelling. A considerable number of widely used models are based on this approach, as it facilitates the optimization of complex energy systems containing a large variety of technological options and long-term development trajectories. While nonlinearities exist in real-world systems, the linear formulation provides computational tractability and transparency, which are essential when handling extensive datasets and long-term scenarios. This methodological choice has proven particularly valuable for the analysis of transition pathways towards GHG mitigation in energy systems in the mid- to long-term horizons, such as 2040 or 2050. Within this tradition, several model families have emerged, each with distinctive characteristics in terms of technological detail, geographical coverage and sectoral scope.

The TIMES family, which evolved from the earlier MARKAL framework (Fishbone and Abilock, 1981) under the Energy Technology Systems Analysis Program of the International Energy Agency, represents one of the most established approaches. It relies on linear and mixed-integer optimization to determine cost-optimal system configurations across electricity, heating and transport sectors. TIMES is characterized by its high level of technological resolution and its capacity to represent long-term horizons extending in some applications up to the end of the century. This makes it particularly relevant for strategic policy analysis and for international comparisons of technology pathways and associated costs (Loulou and Labriet, 2008).

MESSAGE of the International Institute for Applied Systems Analysis (IIASA) is another prominent linear programming model. Similar in scope to TIMES, it distinguishes itself through its close integration with macroeconomic representations, such as the MACRO model. This integration enables the simultaneous consideration of energy system dynamics, economic development and greenhouse gas emissions. MESSAGE has been extensively applied to global and regional scenarios, with particular relevance for the exploration of climate policy strategies and the assessment of pathways consistent with international mitigation targets. Its defining feature is thus the embedding of energy system optimisation within a broader framework of climate-economy interactions (Schrattenholzer, 1981).

OSeMOSYS, an open-source energy system model, has emerged more recently as a streamlined alternative to TIMES and MESSAGE. It adopts a comparable linear optimization framework but with a significantly reduced level of complexity in terms of data requirements and structure. This design makes OSeMOSYS particularly suitable in contexts where comprehensive datasets are unavailable, while still enabling systematic analysis of long-term planning options. It has therefore been widely adopted in developing and emerging economies to support national energy planning. The main distinguishing feature of OSeMOSYS lies in its accessibility and transparency, which lower the entry barriers to advanced modelling while maintaining methodological robustness (Howells et al., 2011).

Beyond these large-scale, long-term models, a new generation of open-source frameworks has been developed, focusing on electricity systems and regional or sectoral detail. PyPSA (Python for Power System Analysis) exemplifies this trend. Initially designed for power system applications, PyPSA has been extended to cover multiple sectors, including heat, hydrogen and transport. Its linear optimization structure enables large-scale applications, such as PyPSA-Eur, which model continental energy systems with high spatial resolution. The development has been driven by an active research community, making it particularly well suited for studies of grid expansion, renewable integration and storage deployment (Brown et al., 2025).

Balmorel, initially developed for the Nordic electricity and heating sectors, is another example of a linear programming model with an explicit market orientation. It captures the interaction between physical system operation and liberalized market structures and is therefore frequently employed in market modelling, capacity expansion studies and analyses of renewable integration in competitive settings. The distinguishing characteristic of Balmorel lies in its integration of system optimisation with economic market mechanisms (Wiese et al., 2018).

A suitable model for answering the research question in this thesis is URBS, also Python-based, which follows a similar principle of linear optimization but emphasizes flexibility and modularity. It allows for the representation of multi-sector energy flows and is frequently employed in case studies at regional scales. Its design facilitates the rapid adaptation of objective functions and constraints, which renders it a useful tool for addressing specific research questions concerning the integration of renewable resources or the deployment of storage technologies.

The existing modelling framework of urbs (Dorfner, 2019) is adapted to meet the needs of this work. Its open-source framework and modular design allows for flexible representation of temporal, spatial and technological dynamics, making it a valuable tool for evaluating renewable energy integration, storage technologies and decarbonization pathways. Van Ouwerkerk et al. (2022) compared this tool with other energy system models. The authors highlight urbs as a highly adaptable energy system model, offering flexibility in both temporal and spatial resolution, making it well-suited for analysing energy distribution and storage dynamics.

The modelling is based on two different energy system frameworks, each covering two regions: Kyushu- Chūgoku and Hokkaido-Tohoku. The models for the two energy system frameworks are run independently. It is assumed that the energy system in Kyushu is not directly affected by the system in Hokkaido. Between them, there are large consumption centres, for example Tokyo, of which the electricity generation is not modelled in detail. Purchase and selling of electricity, however, is allowed with the market outside system borders.

The basic model version is extended by adding storage systems (batteries, hydrogen), fuelcells and the e-methane production chain (electrolyzers, methanation plant). Constraints on storage capacity and the requirements to meet the hourly electricity and gas demands push the system toward self-sufficiency, where methanation becomes a strategic option to cover local gas needs and integrate surplus renewable electricity. The methodology is not unrestricted transferable to well-interconnected power systems such as continental Europe or regions with strong grid flexibility.

The objective function (22) of urbs minimizes the total system cost over the optimization horizon by considering all relevant cost components. The model calculates annual capital costs based on investment decisions and depreciation periods as well as short-term operational strategies to determine the most economical configuration of generation, storage and transmission technologies within one year.

$$\underset{x}{minimize}\ \zeta_{inv} + \zeta_{fix} + \zeta_{var} + \zeta_{fuel} + \zeta_{sell} + \zeta_{purchase} \tag{22}$$

$$x_{1,2\dots n} \geq 0$$

$$P_n^{generation}(t) \leq P_n^{installed} \tag{22.1}$$

$$P_n^{load}(t) \leq P_n^{supply}(t) \tag{22.2}$$

with:

ζ_{inv} = investment costs,

ζ_{fix} = fixed operating and maintenance costs,

ζ_{var} = variable costs,

ζ_{fuel} = fuel costs,

ζ_{sell} = revenues from selling electricity,

$\zeta_{purchase}$ = costs from purchase of electricity,

$P_n^{generation}$(t) = generation capacity in time t,

$P_n^{installed}$ = installed capacity,

$P_n^{demand}(t)$ = electricity load,

$P_n^{supply}(t)$ = electricity generation power in time (t).

The installed capacities of renewable energy generation technologies and pumped storage hydropower (PSH) are predetermined. Capacities of electrolyzers, methanation units, fuel cells and additional storage units, including batteries and hydrogen storage tanks, are subject to the optimization. Due to the existing gas infrastructure, additional costs for storage of e-methane are not considered. Transmission capacities are defined based on existing transmission expansion plans with currently installed capacities, however, can be expanded in the model run according to the proposed investments into the transmission infrastructure (OCCTO, 2024).
The storage balancing constraint (23) for hydrogen production describes the in- and outflow from a hydrogen storage tank.

$$S_{n,H_2}(t+1) = S_{n,H_2}(t) + E^{H_2,\,add}(t) - E^{H_2,\,use}(t) \tag{23}$$

with:

$S_{n,H_2}(t+1)$ = altered storage level,

$S_{n,H_2}(t)$ = initial storage level,

$E^{H_2,\,add}$ = produced hydrogen, which is added to the storage,

$E^{H_2,\,use}$ = hydrogen retrieved for fuel cells or e-methane production.

The installation of batteries and hydrogen storage tanks is initially set to zero by default in the input file and is subject to optimization. Batteries and hydrogen tanks are considered short-term storage solutions (Gabrielli et al., 2024). Their maximum installed capacity is limited to twice the maximum hourly peak electricity demand in equation (24), which corresponds to short-term storage consistent with typical utility-scale batteries (Cole and Karmakar, 2023).

$$S_n^{max} \leq 2 * D_n^{peak} \tag{24}$$

with:

S_n^{max} = maximum installed storage capacity of batteries and hydrogen tanks,

D_n^{peak} = maximum peak demand in a year.

Input data such as the investment costs, load factors, etc. are available in Appendix B.

5.1.5. Assessment of curtailment reduction through e-methane production

This contribution focuses on the economic potential of integrating e-methane production into the energy systems of Kyushu and Hokkaido, thereby contributing to curtailment reduction. E-methane production, coupled with hydrogen storage, provides a sink for surplus electricity and aims to enhance regional self-sufficiency. Equation (25) describes the efficiency of the process chain from surplus electricity to the chemical energy carrier. The amount of electricity allocated to e-methane production results is derived from the modelling output. Due to high production costs, only low-cost electricity, occurring when renewable generation exceeds the demand, is assumed to facilitate e-methane production. Curtailment reduction is here defined as the ratio of electricity used for e-methane production to the previously identified curtailment.

$$E_n^{fuel}(t) = \eta_{process} * P_n^{curt}(t) \tag{25}$$

with:

$E_n^{fuel}(t)$ = chemical energy contained in e-methane,

η_{conv} = process efficiency,

$P_n^{curt}(t)$= power capacity of curtailed energy.

The economic feasibility of e-methane is influenced by a combination of investment, operational, technical constraints and market-related factors. Specific costs can be determined by using the capital recovery factor and the equation for the production cost evaluation, as described in section

3.1.1.1. Low full-load hours increase the costs, while low electricity costs reduce the production costs of e-methane (Radosits et al., 2024b).

An important economic parameter which influences the amount of installed e-methane capacities is the LNG price. Marginal LNG prices were derived from the study by Zwickl-Bernhard and Neumann (Zwickl-Bernhard and Neumann, 2024) from two distinct scenarios: a net-zero scenario and a new momentum scenario, which anticipates an increase in LNG consumption by 2040. The price in 2030 as used for this study is 35 EUR/MWh for both scenarios. By 2040, there is a difference between 36 and 47 EUR/MWh. The LNG price is then varied stepwise to determine the effect on the installation of e-methane production capacities. The system costs increase by raising the LNG prices is derived from the model output and presented in the results section.

5.2. Results

Initially, the quantification of curtailment is presented in the results section as an intermediate outcome. This provides the baseline for the modelling results, where the installed e-methane production capacities and the full load hours are emphasized, contributing to curtailment reduction. Furthermore, regional self-sufficiency and system costs related to the increase in LNG prices are presented as key indicators of the integration of e-methane production in the energy systems of Kyushu and Hokkaido.

5.2.1. Curtailment potential

Figure 30 illustrates that curtailment will increase in both regions in 2030 and 2040, compared to 2023 levels. In 2030, 6-7.9 TWh electricity remain unused for Kyushu, which cannot be transmitted or handled by the available capacity of the pumped storage hydropower. In Hokkaido, the amount of surplus electricity, which cannot be transmitted or stored reaches 2.8-4.4 TWh under the given assumptions. The chart also shows the influence of data centers as additional electricity consumers on the possible curtailment compared to conventional electricity consumption in the base scenario from households, industry, etc.

The transmission capacities increase significantly from 2030 to 2040 and also will the electricity demand due to electrification of different sectors. This is reflected in the results and shows a decrease in curtailed energy in Kyushu to 1.85-5.1 TWh, whereas in Hokkaido the range varies greatly from approximately 0.1-6.2 TWh. In contrast to Kyushu, there is an increase in the Fast scenarios from 2030 to 2040. This maximum available curtailed electricity depends strongly on the installed offshore wind capacities. In this analysis of the theoretical surplus electricity potential, it is neglected that other regions such as Chūgoku also aim to expand their renewable capacities, which might lead to less exports from Kyushu in times of strong renewable production.

A limitation of this approach is the low granularity, which does not consider specific local grid conditions.

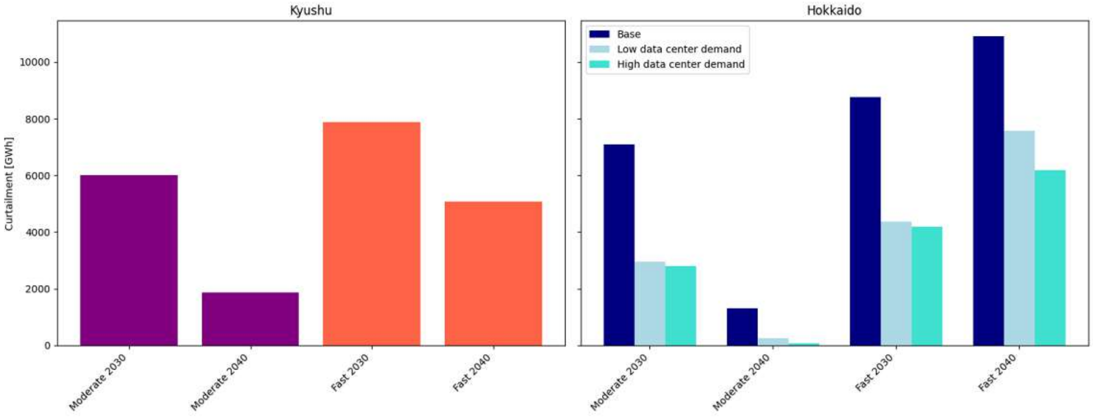
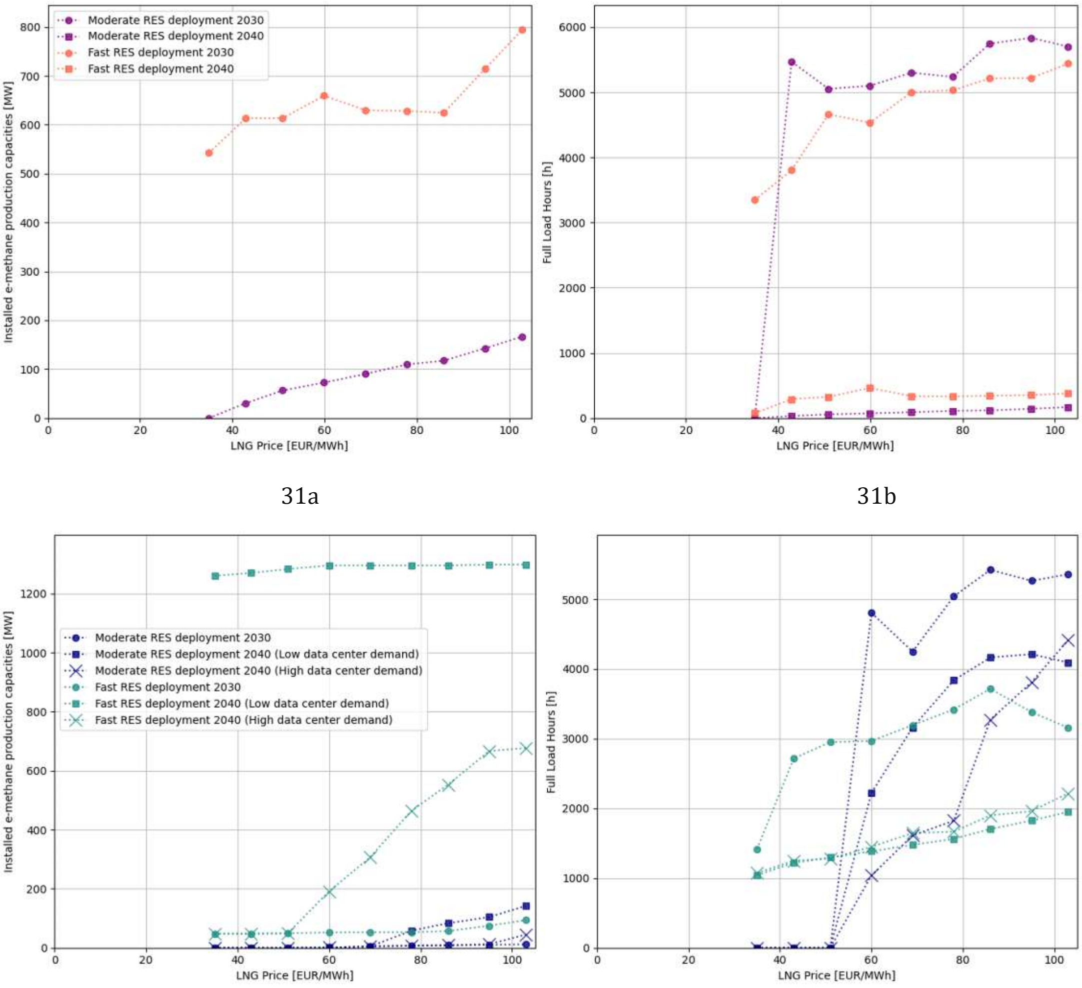


Figure 30. Theoretic curtailment potential based on the modelling of electricity demand and supply for Hokkaido and Kyushu in 2030/2040.

5.2.2. E-methane capacities

The results of this section show the utilization of surplus electricity by the installation of e-methane production capacities from the urbs model. At the base LNG price there are no capacities for e-methane production installed in Kyushu and Hokkaido in the *Moderate* 2030 scenarios. A similarity in both regions is that battery storage is not installed in the *Moderate* scenario, instead there is hydrogen storage installed. As the renewable energy capacities increase in the *Fast* 2030 scenarios, also battery storage is employed for balancing the grid. Increasing the LNG price leads also to more e-methane production as expected, illustrated in Figure 31. In the *Fast* 2030 scenario, 542 MW and 48 MW are installed in Kyushu and Hokkaido respectively. The installed e-methane production capacities remained unchanged in Kyushu by 2040. A limitation of the modelling in this work is that the previously installed capacities are sunk costs and the yearly capital costs are no longer accounted for in 2040. The full load hours of methanation are reduced significantly for Kyushu in 2040. In contrary, in Hokkaido there is an increase to 48-1260 MW. In case of high data center demand and moderate renewable deployment, additional capacities are only installed at LNG prices > 59 EUR/MWh. The increase in methanation capacities compensates for lower full-load hours.



31a 31b

31c 31d

Figure 31. Modelling results for the installation of e-methane production capacities and full-load hours in relation to the LNG price. Figures 31a/ 31b show the results for Kyushu and Figures 31c/ 31d for Hokkaido.

5.2.3. Curtailment reduction through e-methane production

The reduced e-methane production in Kyushu is also reflected in a smaller decrease in curtailment in 2040, illustrated in Figure 32. Similar to previous results, the curtailment reduction increases in Hokkaido in 2040, although it hast to be noted that curtailment in the *Moderate* scenario is already relatively low.

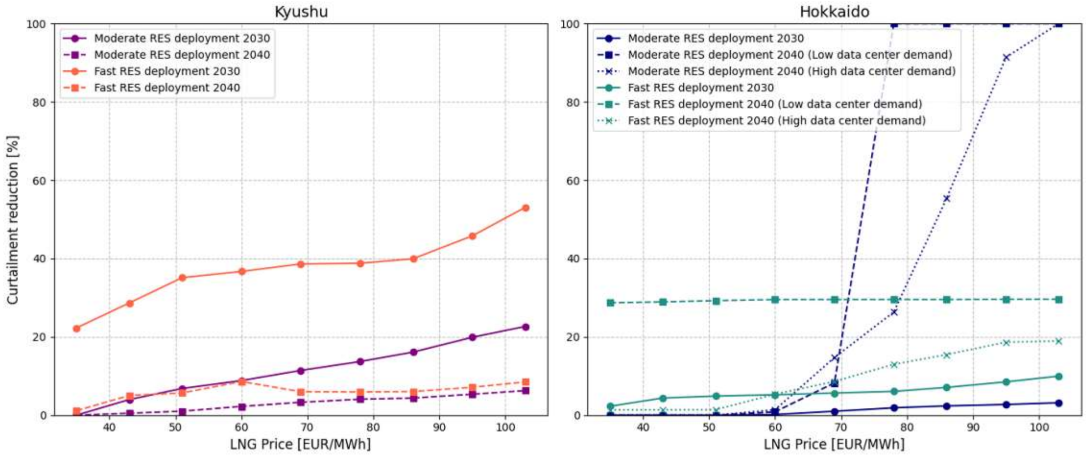


Figure 32. Curtailment reduction by e-methane production.

5.2.4. Self-sufficiency and system costs

The self-sufficiency in gas consumption increases in Hokkaido in 2040 compared to 2030. The installed e-methane capacities in Hokkaido remain in use and additional capacities are added. In the scenario with high electricity consumption by data centers, the surplus is lower and the self-sufficiency is approximately 1% at the base LNG prices and increases to approximately 14%. In the *Fast* 2040 scenario with low electricity demand by data centers, the self-sufficiency is 26% even under the base LNG price. The opposite situation as illustrated in Figure 33, occurs for Kyushu. The highest self-sufficiency of 30.7% is reached in the *Fast* 2030 scenario and is significantly lower in the scenarios of 2040 as the utilization of the already installed capacities is reduced.

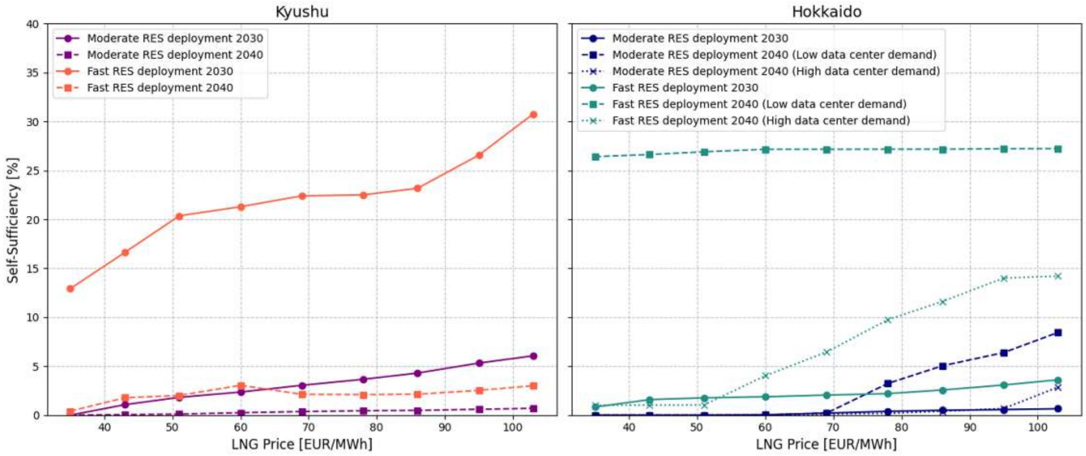


Figure 33. Self-sufficiency in gas demand through e-methane production in 2030/ 2040 depends on LNG prices.

Additionally, Figure 34 illustrates the relative increase in total system costs within 2030 and 2040 in relation to a rise in LNG prices. The increase is higher in Kyushu, as there is a stronger reliance on LNG for electricity generation. Differences in the self-sufficiency do not influence the system costs, which is expected when the e-methane production from surplus electricity becomes economically competitive with the respective LNG prices. The system costs are in absolute values higher in 2040 than in 2030 and the upfront investment costs for the renewables are neglected. Therefore, the system costs can be lower in the *Moderate* scenarios in Hokkaido compared to the *Fast* scenarios. The increase is not linear, because of the complexity of different measures that can be adopted.

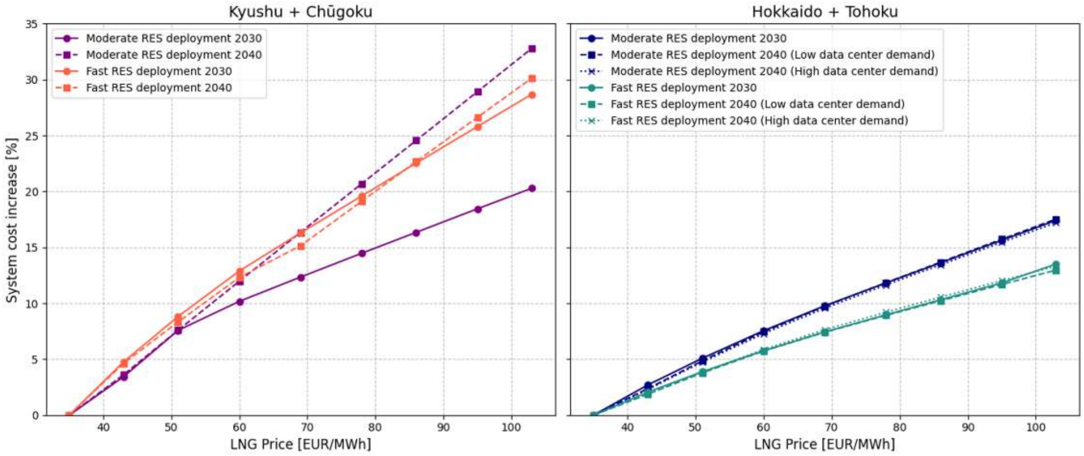


Figure 34. Relative increases in total system costs within 2030/ 2040 caused by a rise in LNG prices.

6. Synthesis of results

The key findings based on the three published articles (Radosits et al., 2025, 2024a, 2024b) and the manuscript by Radosits et al. (under review), corresponding to each research question, are presented in this chapter. For clarity, the research questions are restated and subsequently addressed with the insights obtained throughout this thesis. The presentation of findings follows a gradual expansion in geographic scale: it begins with small-scale systems relying on renewable self-generation, proceeds to sector coupling between the electricity system and biomass-based gas production from the perspective of plant operators and ultimately extends to regional energy system modelling.

Research question 1: *What are the techno-economic prospects of decentralized small-scale e-methane production using CO_2 from biomass-based processes?*

Biomass processes such as biomethane production, district heating plants and the pulp and paper industry represent a significant and sustainable source of CO_2 that could serve as a basis for renewable fuels. This is becoming increasingly relevant as European regulations restrict the use of fossil-based CO_2 sources and emphasize sustainable alternatives.

In the EU, 420-490 Mt biomass-derived CO_2 will be generated from biomethane production, biomass-based district heating and the pulp and paper industry in 2030. This corresponds to technical potentials of 208-243 billion cubic meters of e-methane using alkaline or proton exchange membrane electrolyzers and catalytic methanation.

In comparison with hydrogen, the study highlights a clear efficiency and cost advantage for hydrogen production. However, hydrogen production faces major challenges in storage, transport and infrastructure development. In contrast, e-methane benefits from compatibility with existing natural gas infrastructure and storage facilities, allowing its integration into current energy systems with fewer adjustments. This creates a trade-off: hydrogen performs better in terms of efficiency and cost, but e-methane offers clear advantages in infrastructure utilization and system integration. At the same time, a heavy reliance on e-methane could reinforce a lock-in effect, perpetuating the role of natural gas infrastructure in the energy system.

The distributed biomass-based CO_2 sources offer in theory a valuable opportunity for localized CO_2 utilization, reducing the need for CO_2 transport infrastructure and enabling regional value creation. Small-scale concepts are also well aligned with biomethane expansion targets of the EU, as these facilities are typically embedded in rural areas with access to local renewable electricity. From an economic perspective, the findings show that production costs for e-methane are expected to remain high by 2050 compared to natural gas, despite reductions from technological learning and economies of scale. Furthermore, capacity additions of electrolyzers remain well below anticipated projections and manufacturing capacities of approximately 20 GW in China are heavily underutilized as the manufacturing demand was only 2 GW in 2024 (IEA, 2025b). Given the current pace of project development and deployment, it is unlikely that the 2023 estimate of 175 GW (IEA, 2023b) of electrolyzer capacity by 2030 can be achieved.

The key factors for achieving cost competitiveness are low electricity prices and a high number of full-load hours. E-methane production based exclusively on photovoltaic power is economically unfavourable in the central European context due to low annual operating hours, while onshore wind power offers better prospects. Nevertheless, small scale e-methane projects with their own electricity supply, remain uncompetitive in central Europe, even under high carbon prices of several hundred euros per ton CO_2.

Research question 2: *What are the benefits of integrating hydrogen into biomethane and bio-SNG production and how does this affect CO_2 avoidance costs?*

Biomethane shows the lowest production costs per MWh, however, bio-SNG production shows clear advantages for CO_2 utilization in the long- term when learning effects and economies of scale are considered in the investigated scales. Coupling biomass-based gas production with the electricity market through hydrogen integration leads to higher full load hours. Furthermore, economies of scale can be utilized when increasing the plant sizes of bio-SNG and biomethane facilities.

The sector coupling with the electricity market can partly offset investment costs for grid access and network charges through low or even negative electricity spot market prices. The surplus electricity fed into the grid generates additional revenues that enhance overall economic viability. Hydrogen-enhanced production increased the costs of biomethane from 91-105 EUR/MWh to 137-149 EUR/MWh and the costs of bio-SNG from 105-138 EUR/MWh to 136-151 EUR/MWh, which is up to 143% higher than the average natural gas price of 2023 in the EU.

A direct comparison of production costs is of limited relevance, as different feedstocks are typically used and the technologies involved can be complementary in enhancing the overall production of renewable gases.

Although the costs increase by hydrogen integration, the results of this work are promising in comparison to the existing literature. Witte et al. (2018a) reported costs of 102-107 EUR/MWh for enhanced biomethane production. However, lower electricity prices of only 50 EUR/MWh and full load hours of 8322 are assumed, compared to 7500 FLH in this study, resulting in lower capital costs. Additionally, it must be mentioned that investment costs increased by 35% from 2017 to 2023 according to the chemical engineering plant index, which is higher than the average inflation in the EU during this period.

Furthermore, the results are lower than some power-to-gas concepts where CO_2 is first captured and then used for synthetic methane production. Chauvy et al. (2021) calculated production costs for synthetic SNG to be at least 198 EUR/MWh, adjusted for average inflation with data from (Statista, 2024). This is approximately 11 % higher than the highest cost of this study. Gerloff (2023) calculated synthetic methane production costs of 150-156 EUR/MWh using biomass-derived CO_2, 4000 full load hours and low-cost electricity at 50 EUR/MWh.

Comparing values of the years 2020 and 2023 in the linear optimization show that the grid electricity prices significantly influence the results of installed renewable energy capacity. When wholesale prices were comparatively low (2020), grid consumption and feed-in balance each other, resulting in higher overall electricity costs within the model. In contrast, the high-price environment of 2023 leads to greater renewable capacity installation and a significant increase in feed-in volumes, which reduces the modelled yearly electricity costs by around 30 percent. This outcome underscores the strong interplay of network costs, spot-market prices and installed renewable capacities influencing the economics of sector coupling. However, there is a trend across Europe toward lower feed-in tariffs for solar PV (Hartvig, 2025), which makes grid export less financially attractive and thus more challenging as a means of cost recovery for system owners. This must be considered in future modelling works.

A beneficial side effect occurs when looking at the predominant wind power installation. Electricity surplus feed-in from the hybrid energy model occurs mainly during the winter months when the demand is usually the highest in Austria. The surplus electricity will be fed into the grid primarily when a demand exists. However, a significant expansion of renewable energy is required to produce relevant amounts of biomethane and bio-SNG for the energy market. Additional 10 TWh (1bcm) require approximately the same amount of wind capacity as installed in Austria in 2023.

The second part of the research question addresses the greenhouse gas mitigation potentials of enhanced biomethane and bio-SNG production. Emissions along the process chains are accounted to derive the mitigation potential compared to natural gas usage.

Biogenic CO_2 is considered carbon neutral because plants previously absorbed it. However, two aspects need to be considered: forest wood takes a long time to grow and CO_2-derived fuels can contribute to replacing fossil fuels. From an environmental perspective, it makes sense to utilize CO_2 therefore in either way to avoid or offset hard-to-abate CO_2 emissions to advance towards a sustainable energy future.

The results showed that hydrogen integration can potentially contribute to greenhouse gas mitigation in the EU. The hybrid energy model has a significantly lower CO_2 factor than the average grid electricity mix of the EU because the renewables produce most electricity and a minor share comes from the grid.

The cost of CO_2 mitigation plays a critical role in determining the economic feasibility of different defossilisation pathways. Understanding the financial burden associated with carbon capture and storage or alternative CO_2 reduction strategies helps policymakers and industry leaders navigate the transition to a net-zero economy. The costs of CO_2 avoidance vary widely across industries and mitigation strategies. Adjusting for cost inflation, the updated CO_2 avoidance costs for waste-to-energy plants are 195-292 EUR/t $CO_{2eq.}$ (Roussanaly et al., 2020) and 105 EUR/ t $CO_{2eq.}$ at cement plants (Roussanaly, 2019).

A study by Qiao et al. (Qiao et al., 2023) explores the techno-economic aspects of integrated carbon capture and utilization versus conventional CCU processes that produce syngas (CO + H_2). The costs of CO_2 avoided of the integrated carbon capture and utilization are 293 EUR/ t $CO_{2eq.}$ whereas for the conventional process approximately 1138 EUR/ t $CO_{2eq.}$. Similarly, the results of (Radosits et al., 2025) show that integrated CO_2 utilization leads to lower costs compared to the previously investigated small-scale e-methane production (Radosits et al., 2024b).

When comparing different CO_2 mitigation options, it is important to also mention carbon sequestration. Helferty (2023) proposes agro-sequestration, where biomass crops are dried, salted and buried in biolandfills to prevent decomposition, aiming for permanent carbon storage with costs of approximately 56 EUR/t CO_{2eq} . Although it sounds like a promising low-cost solution, the large scale-implementation may face challenges related to land availability and supply chain constraints. Frank et al. (2024) focus on incremental, proven approaches including biochar application, agroforestry and improved soil management, resulting in sequestration costs of 74–148 EUR/t CO_{2eq}

The social cost of carbon represents the broader economic and environmental damage caused by each additional ton of CO_2 emissions. According to Caesary et al. (2025), social cost of carbon projections are subject to significant uncertainty, as they depend on variables like economic growth, climate responsiveness and discount rates. Their study forecasts that, in the absence of additional CCS deployment, the social costs of carbon could increase from 665 EUR/t CO_{2eq} in 2040 to 961 EUR/t CO_{2eq} by 2100, whereas in the CCS expansion scenario, these decrease to 425 EUR/t CO_{2eq} in 2040. The results under research question 2 for the enhanced biomethane and bio-SNG production are below these social costs of carbon.

Research question 3: *To what extent can e-methane production reduce renewable energy curtailment, considering regional infrastructure and LNG market conditions?*

This contribution reveals two key outcomes. Firstly, it demonstrates that electricity curtailment will become an increasing issue. The reduction of curtailment and reaching self-sufficiency as a goal requires flexibility measures such as storages or conversion to energy carriers in an island-like context or with limited interconnections. Secondly, the analysis on self-sufficiency with domestically produced e-methane presents an often-overlooked researched topic. The quantification of the theoretical curtailment and e-methane production capacities is important for making statements regarding the local energy policy, affected by regional characteristics.

The curtailment is affected by the increased electricity transmission capacity and shift from fossil fuels to electrification. The main renewable energy source in Kyushu is solar PV and the region has a historically greater dependence on natural gas. In contrast, Hokkaido is characterized by the highest potential for offshore wind in Japan and introduced LNG later for balancing the electricity grid.

The impact of e-methane production on curtailment is region- and time-dependent. Curtailment reduction is initially approximately 22% in Kyushu for the scenario with fast renewable adoption in 2030. While overall curtailment tends lower in 2040, installed e-methane capacities are not effectively used for utilizing the remaining surplus electricity. A low curtailment reduction is observed in the 2030 results for Hokkaido whereas the curtailment reduction improves in the 2040 results to a maximum of 28%. Self-sufficiency rates of 0-26% can be reached depending on the scenario. Under conditions of rapid renewable energy adoption and high LNG prices, self-sufficiency through e-methane increases in Hokkaido, while in Kyushu, batteries and hydrogen are preferred.

The findings from the regional case studies are mainly applicable to island-like systems or regions with limited grid interconnections, such as Japan, South Korea, the UK, etc. The imposed limitations on storage capacity and the requirement to meet electricity and gas demands strongly influence the model results. These constraints push the system toward self-sufficiency, where methanation becomes a strategic option to cover local gas needs and integrate surplus renewable energy. Methanation helps to promote self-sufficiency and reduce greenhouse gas emissions from imports of fossil LNG or efficiency losses from transport of renewable e-methane.

7. Conclusions and outlook

The integration of green gases into the energy system is investigated from different perspectives in this thesis. The impact of biomethane, bio-SNG and e-methane to a climate neutral energy system will be determined by the policy framework and technological advancements. While sharing the common characteristic of being renewable alternatives to fossil natural gas, their role is less about direct substitution and more about a strategic and system-stabilizing value for the energy transition. Biomass-based gas production and hydrogen integration offer the possibility to contribute to a circular economy, store energy for several months, regional value creation and might contribute to establishing a hydrogen economy.

It is neither realistic nor desirable in terms of the environment to assume that renewable gases will fully replace fossil natural gas. Feedstock limitations, economic challenges and competing demands make such an approach unattainable. Instead, renewable gases should be recognized as strategic enablers rather than mass substitutes for natural gas. They can provide seasonal balancing, act as renewable carbon carriers for hard-to-abate sectors and integrate waste and residue streams into energy and material cycles. By reframing their role away from volume substitution toward systemic value, their deployment can be optimized within broader pathways for greenhouse gas emission reduction.

Anaerobic digestion and thermochemical gasification rely on different feedstocks and scales, which avoids direct competition for resources. Instead, both pathways can valorise different types of residues: wet organic wastes for biomethane and lignocellulosic feedstocks for bio-SNG. Both processes therefore increase resource efficiency by using waste and residue streams. Importantly, this avoids conflicts over biomass use and reduces pressure on agricultural land. Biomethane production provides multiple co-benefits beyond energy provision. Digestates from biomethane production can be reintegrated into agricultural systems, improving soil fertility, reducing reliance on synthetic fertilizers and mitigating methane emissions from agriculture. Policies that recognize these systemic values can strengthen the role of biomethane in supporting sustainable agriculture and circular economy practices.

The main scope referring to the research questions is the utilization of CO_2 for renewable gas production. Regulatory developments in the EU target CO_2 from biomass-based processes as sustainable option. In contrast to the broader trend toward decentralized energy systems, small-scale CO_2 utilization faces considerable challenges, even under favorable assumptions of learning curves and cost reductions. A particularly promising concept is the integration of renewable hydrogen into bio-SNG production. Hydrogen can be used to convert CO_2 already present in syngas streams into additional methane, thereby boosting yields and carbon utilization. From a climate perspective, this process also achieves higher greenhouse gas mitigation per unit of biomass, since more of the biogenic carbon is retained in the bio-SNG. This increases the overall efficiency of biomass use in the energy transition, a critical factor given the limited availability of sustainable biomass. This approach avoids the energy-intensive separation of CO_2 and creates a direct synergy between the power sector and the gas sector. The investigated hybrid energy system creates more favorable conditions than in the stand-alone e-methane concepts by increasing full load hours, using low-cost electricity supply and the opportunity to feed electricity into the electricity grid.

To test the strategic role of renewable methane in sectors where a gas demand will remain, this thesis examines the cost-effectiveness of domestic e-methane production in two distinct Japanese regions as a means of reducing renewable-energy curtailment. The integration and economic feasibility of domestic e-methane production mainly depends on the yearly full load hours and the LNG prices. The results indicate that the implementation of e-methane production appears particularly challenging in regions where PV is the main renewable energy source due to the strong temporal variability and relatively low full load hours. While research often focuses on reducing solar curtailment, the results suggest that greater attention should be given to avoiding wind curtailment when considering e-methane production pathways. Since this analysis shows from a systems perspective that regions such as Hokkaido have the potential to produce e-methane by avoiding curtailment, appropriate policy measures can promote pilot projects in this field.

To unlock the potential of renewable gases, three enabling conditions are essential. First, technological learning and technological developments must drive down costs of electrolyzers, methanation and gasification. Second, targeted policies should reward the co-benefits of renewable gases, such as waste treatment, circular agriculture and CO_2 recycling. Third, robust carbon pricing is needed to internalize the externalities of fossil gas and make renewable alternatives competitive. Although natural gas is cheaper, new investments in gas power plants or LNG infrastructure creates lock-in effects that contradict defossilisation goals and may lead to stranded assets. Strong policy signals are therefore essential to direct capital flows away from LNG imports toward sustainable options.

A comprehensive defossilisation strategy across all sectors requires a balance between cost-effective CO_2 reduction and efficient carbon storage, which can be achieved through a combination of electrification, energy efficiency, sustainable fuel production and negative emission technologies.

Building on the findings of this thesis, several areas have been identified where further research is needed to enhance the efficiency and sustainability of biomass and CO_2 utilization technologies.

Determining the optimal location for biomass gasification facilities remains critical to maximize system efficiency and cost-effectiveness. Proximity to feedstock supply chains and integration with local energy infrastructure, particularly district heating networks, could enhance the utilization of excess heat. Spatially resolved optimization models that consider both biomass logistics and local heat demand patterns can identify the most beneficial locations for coupling bio-SNG production with district heating.

Another trade-off concerns the upgrading of biogas to biomethane and the use of forest biomass for SNG production versus the provision of flexibility in combined heat and power plants from a system level perspective. Future research should reflect the objective of reaching greenhouse gas emission reduction targets through policy design, while representing operational and investment decisions of plant operators seeking profitability.

Also important from the policy perspective is the question of decentralized CO_2 utilization, not necessarily limited to synthetic fuel production, compared to the deployment of new infrastructure, for example CO_2 pipelines. Such analyses would help identify cost-optimal solutions, which align with national pathways for emission reduction.

Declaration on the application of generative and supportive AI in the writing process

Grammarly and ChatGPT were used during the preparation of this thesis for improving the readability and language of the document. After using these tools, the edited text was reviewed carefully. The author takes full responsibility for the content of the published thesis.

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Appendix to Chapter 4

A.1. Sensitivity analysis of enhanced biomethane and bio-SNG production

The sensitivity analyses reveal significant insights into the factors influencing production costs. Figure shows the sensitivity of the production costs of the 50 MW bio-SNG plant for 2023 with hydrogen-enhanced production. A great impact comes from the investment costs of the bio-SNG plant, signifying their essential role in shaping the economic viability of the process. An investment cost reduction of 50% would lead to 22% lower costs per MWh. Two aspects must be considered: the investment costs are conservatively estimated using data from the relatively expensive GoBiGas plant and equipment and engineering costs have increased drastically in recent years. In the work of Hofbauer et al., (2020), it was calculated that investment subsidies positively influence production costs.

Among the variables investigated, full load hours emerge as the most influential, showing the importance of a stable operation. An increase from the estimated 7500 to 8250 full load hours will reduce the production costs by 3.5%. Hydrogen costs are nearly as important as the investment costs. Lowering investment costs of electrolyzer technologies such as solid oxide electrolyzers, which can reach very high efficiencies of > 80%, could lead to significant cost reductions for hydrogen integration (IRENA, 2020).

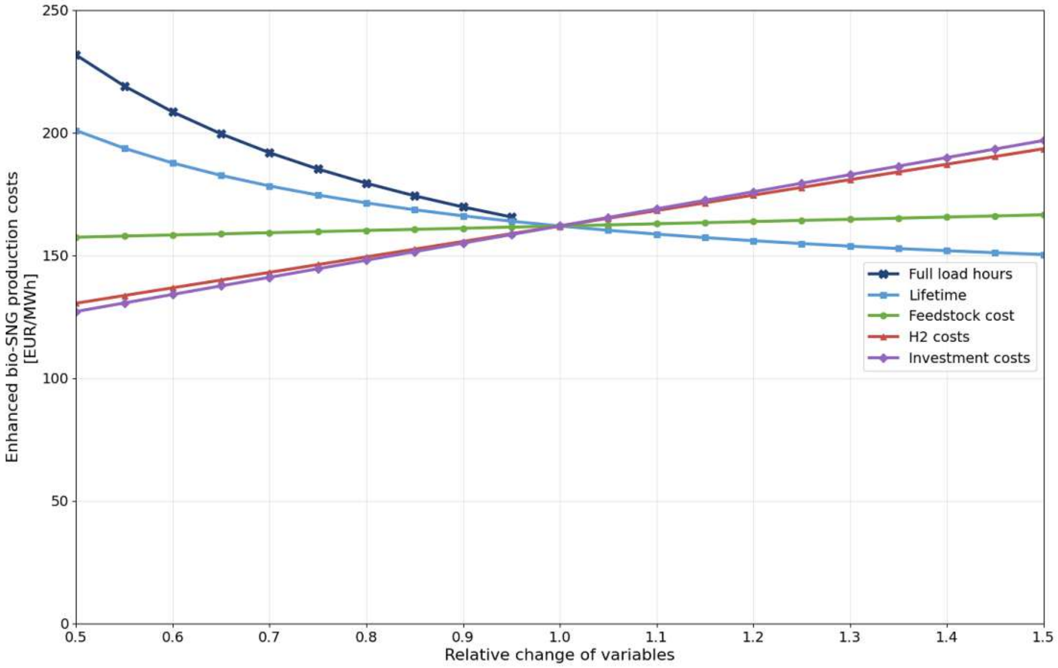

Figure A.1. Sensitivity analysis of enhanced bio-SNG production.

The results for the enhanced biomethane production at 5MW using biowaste as feedstock showed similar results in Figure. Full load hours play an essential role, emphasizing the significance of operational efficiency. Similarly, the impact of hydrogen costs indicates their crucial role in shaping the economic feasibility of CO_2 utilization in enhanced biomethane production. The sensitivity analysis is an important tool. However, it also has some limitations because parameters are changed independently and market impacts substantially influence the profitability of biomass-based gas production (Zetterholm et al., 2020). The costs for biowaste and wood chips show less influence in this work for enhanced production because they lose relative importance due to the hydrogen energy input. However, in Veress et al. (2020), it is argued that revenues for waste conversion to bio-SNG can lower production costs.

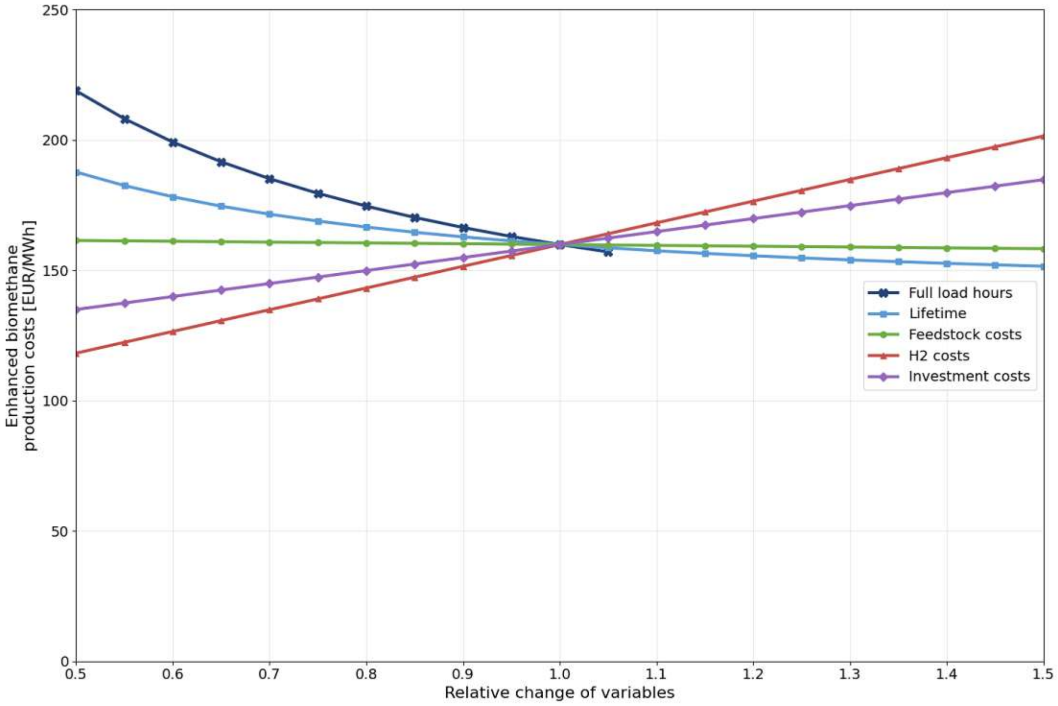

Figure A.2. Sensitivity analysis of enhanced biomethane production.

A.2. CO_2-factors used in the environmental assessment

Table A.1 shows the quantities of materials used for the construction of the 20 MW GoBIGas plant, the variable inputs and the corresponding CO_2-factors.

Table A.1. CO2 factors for the assessment of the embedded emissions of an SNG plant.

Input parameter	Value	CO_2-factor	Source
Steel	2,468 t	1.76 kg/ kg	(Larsson et al., 2018), ProBas
Concrete	9,495 m^3	0.93 kg/ kg	(Larsson et al., 2018), ProBas
Cables	170 km	0.98 kg/ kg	(Larsson et al., 2018; Zhang et al., 2022)
Bed material	1.9 kg/ MWh	0.008 kg/ kg	(Hofbauer et al., 2020), ProBas
RME	3.5 kg/ MWh	0.011 kg/ kg	(Hofbauer et al., 2020; Umweltbundesamt, 2023)
Wood chips	0.31 t/ MWh	0.014 kg/ kWh	(Hofbauer et al., 2020), ProBas
Electricity AT-mix (2023)	0.05 kWh/ kWh	0.202 kg/ kWh	ProBas

Appendix to Chapter 5

B.1. Electricity demand in Japan (2015-2022)

The industrial, residential and commercial and public services sectors dominate in the electricity demand of Japan, as illustrated in Figure B.1. Agriculture and fishing together account for less than one percent of the overall electricity demand in Japan and are therefore neglected in the analysis. The transport sector currently accounts for a small share of electricity demand, similar to the global situation (IEA, 2021d), however, it is expected to grow significantly with the electrification of vehicles (IEA, 2021c).

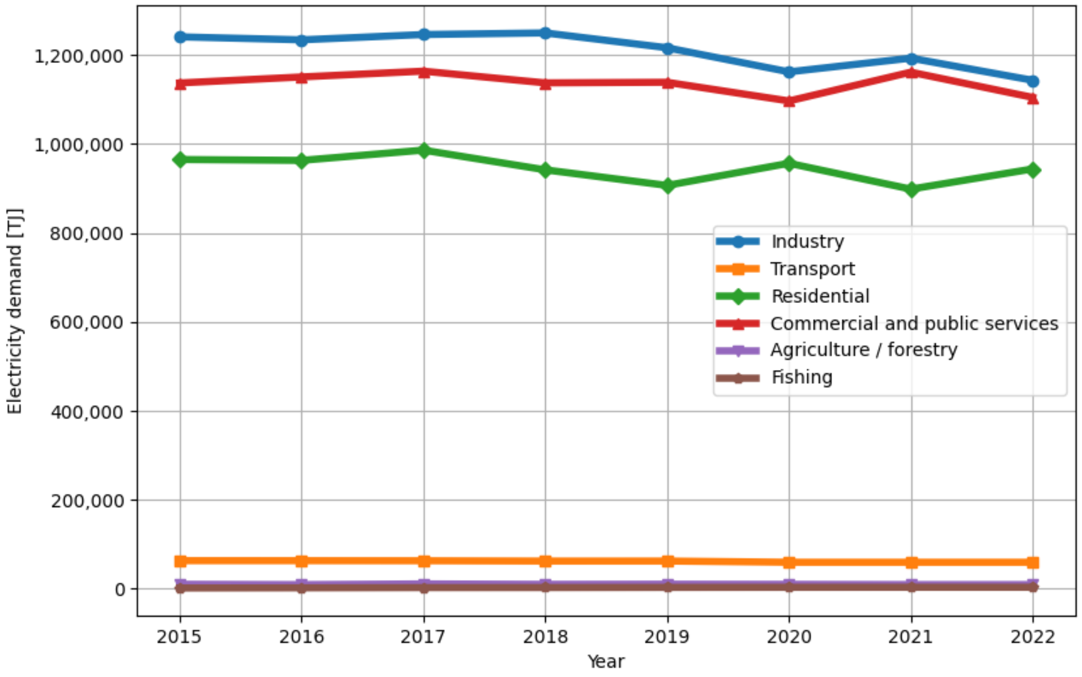

Figure B.1. Electricity demand in Terajoules of the main sectors of Japan. Industrial, residential and commercial sectors accounted for the largest demand from 2015 to 2022. Data source: (IEA, 2024b).

B.2. Electricity generation capacities used for the energy system modelling

Table B.1 shows the exact installed capacities, which are illustrated in Figure 29 and used in the quantification of curtailment and energy system modelling.

Table B.1. Installed capacities in Moderate and Fast scenarios for 2030/2040 in GW peak. Most important are the capacities of renewable energy technologies for the analysis of the curtailment.

	Kyushu				**Hokkaido**			
	Moderate 2030	Moderate 2040	Fast 2030	Fast 2040	Moderate 2030	Moderate 2040	Fast 2030	Fast 2040
Hydro plant	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Wind	2.6	6.7	3.5	9.5	5.0	12.0	6.0	16.2
Photovoltaics	18.0	23.0	22.0	28.0	3.0	3.5	4.0	5.0
Coal plant	1.8	1.8	1.8	1.8	1.7	1.7	1.7	1.7
LNG plant	5.3	5.3	5.3	4.2	0.6	1.7	1.7	1.7
Biomass plant	1.8	2.1	1.8	2.1	0.7	0.9	0.9	1.1
Oil plant	0.5	0.5	0.5	0.0	1.0	0.7	0.7	0.7
Geothermal	0.3	0.5	0.3	0.5	0.1	0.1	0.1	0.1
Nuclear	4.1	2.4	4.1	2.4	0.7	0.7	2.1	2.1

B.3. Modelling of hydropower generation

Japan has in total approximately 50 GW of hydropower plants and PSH, the latter being an important long-term storage with notable storage capacities. Storage power is derived from (REI, 2024) and from data of regional power companies (HEPCO Group, 2023; Kyuden Group, 2020). Data on storage power in terms of energy content is not always available. Therefore, it was estimated based on the volume and height of the reservoir, using equation (26).

$$E_{useful} = \eta * \rho * g * V * h \tag{26}$$

with:

E_{useful} = stored potential energy,
ρ = density of water (approx. 1000 kg/m^3),
g = gravitational acceleration (approx. 9.81 m/s^2),
V = volume of water [m^3],
h = reservoir height [m].

Seasonal generation patterns are derived from climate data and historical production trends derived from literature. Key influences, including snowmelt in Hokkaido and monsoons in Kyushu, are incorporated to reflect regional hydrological cycles (Nagatomi, 2014). Capacity factors for hydropower were estimated with regional characteristics and used to model the electricity production with river power plants (Wang et al., 2020). A random sampling in the ranges show in Table is conducted as the hourly values can change rapidly due to changing weather patterns.

Table B.2. Estimation of seasonal load factors of hydro power plants in four different regions.

Region	**Winter (Dec-Feb)**	**Spring (Mar-May)**	**Summer (Jun-Aug)**	**Autumn (Sep-Nov)**
Kyushu	25% - 40%	30% - 50%	35% - 60%	30% - 45%
Hokkaido	30% - 50%	40% - 70%	25% - 40%	30% - 50%
Chūgoku	30% - 50%	35% - 55%	40% - 60%	35% - 50%
Tohoku	25% - 45%	40% - 65%	30% - 50%	30% - 45%

B.4. Charging patterns of electric vehicles

Charging patterns are relevant to estimate future hourly electricity demand for the energy system modelling. The charging patterns applied for the demand time series creation are explained in this section. These are estimates based on literature. On weekdays, EV charging behavior in Japan is strongly shaped by commuting patterns, as illustrated in Figure B.2. Most private and corporate vehicles are used during the morning and evening rush hours, which results in limited daytime charging and a pronounced charging peak in the late evening when cars return home (Masuta et al., 2014). Commuter vehicles are often parked at workplaces during the day, allowing for potential workplace charging, but the majority of energy demand still occurs overnight (Iwafune et al., 2019).

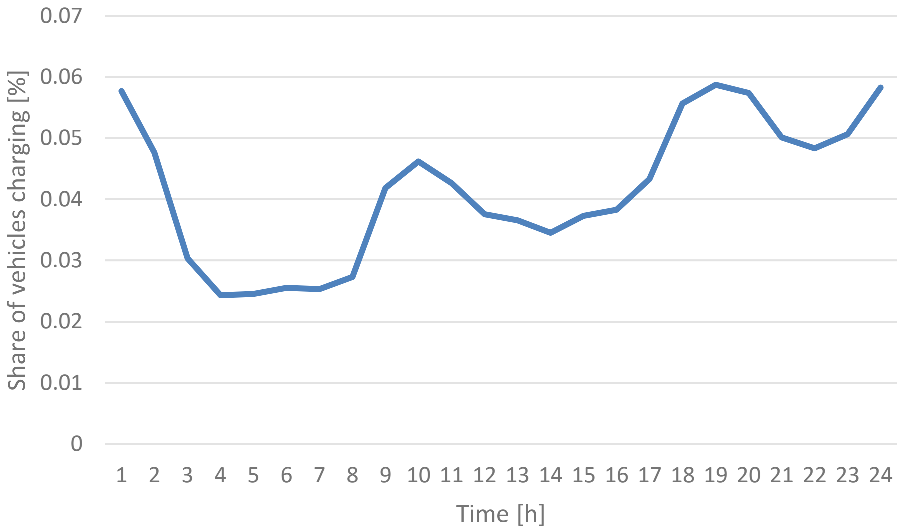

Figure B.2. Estimated weekdays charging behavior in Japan. Data sources: (Iwafune et al., 2019; Masuta et al., 2014).

In contrast, weekend charging, shown in Figure B.3 behavior is more irregular and evenly distributed throughout the day. Many vehicles might be used for leisure or local travels rather than scheduled commuting, which leads to a wider variation of driving times throughout the day. This leads to smaller fluctuations from 6 a.m. to 10 p.m. (Iwafune et al., 2019; Masuta et al., 2014).

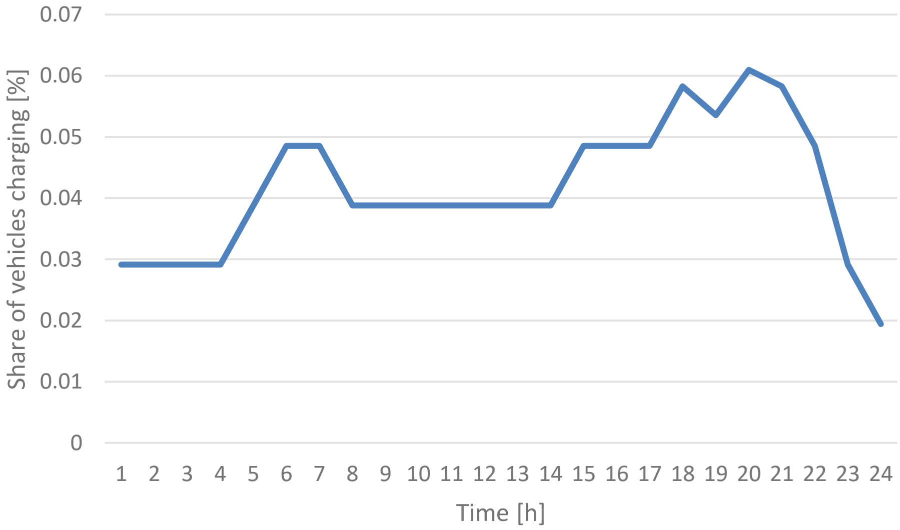

Figure B.3. Estimated weekend charging behaviors in Japan. Data sources: (Iwafune et al., 2019; Masuta et al., 2014).

B.5. Modelling of the surplus electricity

Modelling of demand and supply serves as basis for the evaluation of curtailment. The figures B.4 and B.5 show the strong daily fluctuations of the demand. Historic values showed that also from 2017 to 2022 the demand could change 30-50% within the day (Japanese Electricity Market Data Hub, 2024) LNG is therefore on the one hand used to match the peak demands and on the other hand there are generation peaks of solar power which will remain unused if no additional measures are taken. In Kyushu, surplus is mainly a result of electricity generation by photovoltaics. The peak demands are covered by gas-fired power plants and pumped storage hydropower. Other storage technologies were not considered for this part of the study. The main source of curtailment in Hokkaido is energy generated by offshore wind turbines.

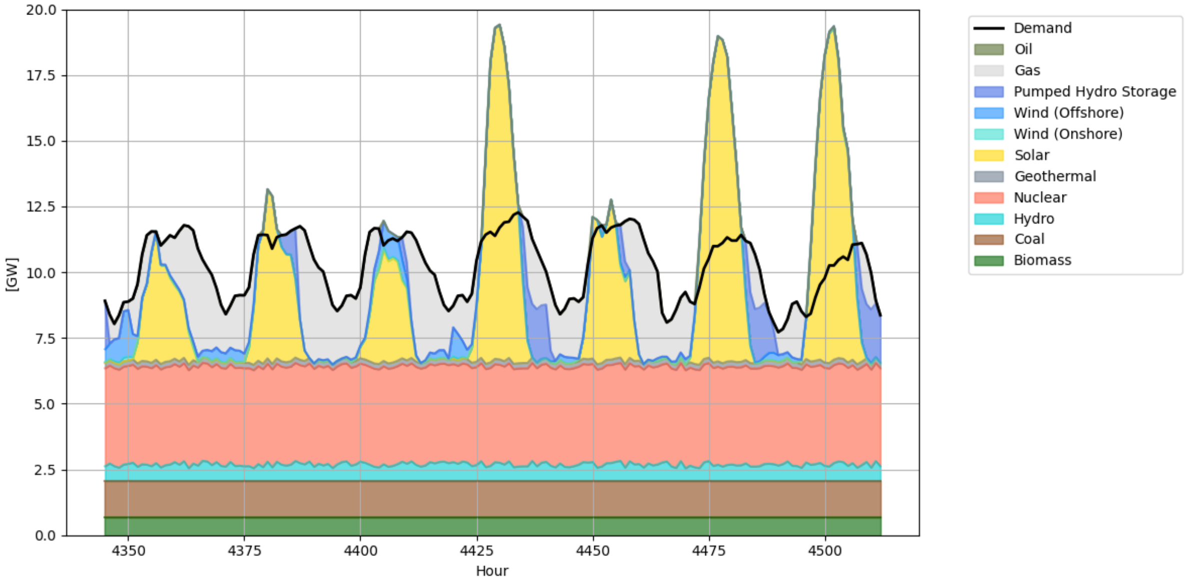

Figure B.4. Modelled electricity demand and supply for the first week of July in Kyushu with the energy generation portfolio of the Moderate 2030 scenario (Japanese Electricity Market Data Hub, 2024; Kyuden Group, 2020).

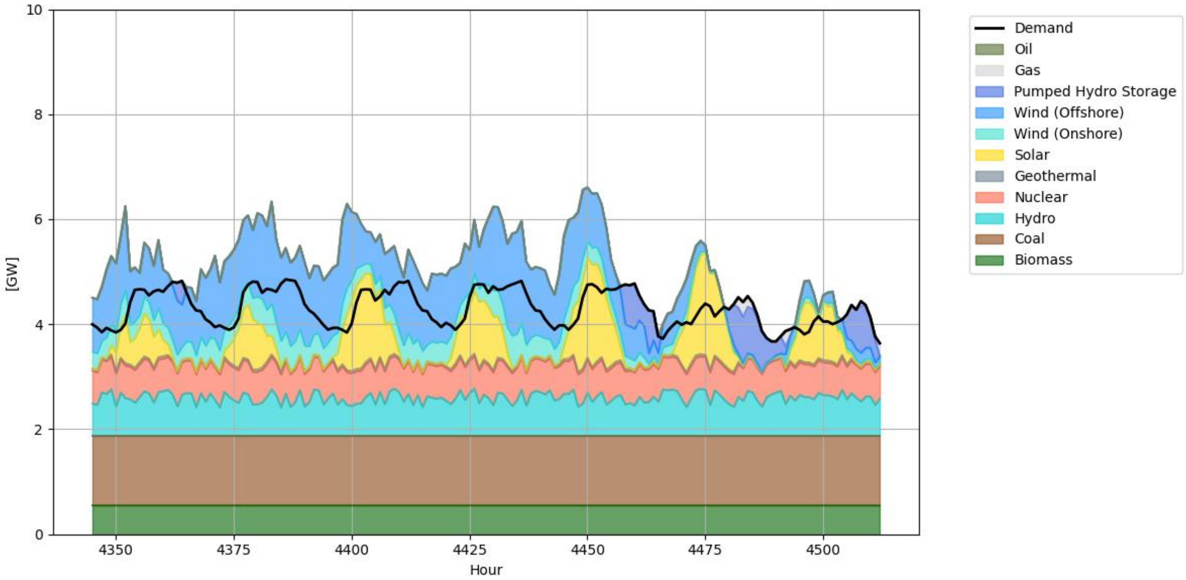

Figure B.5. Modelled electricity demand and supply for the first week of July in Hokkaido with the energy generation portfolio of the Moderate 2030 scenario (HEPCO Group, 2023; Japanese Electricity Market Data Hub, 2024; Mitsubishi UFJ Financial Group Inc., 2023).

B.6. Gas demand

The gas demand decreases due to the ambitions in electrification. The changes from winter to summer are higher in Hokkaido compared to Kyushu, where a prominent industrial gas demand exists. Table B.3 shows the hourly gas demand in MW per season based on the assumptions on the consumption patterns.

Table B.3. Hourly gas demand in MW related to seasonal demand patterns.

	Moderate 2030	**Moderate 2040**	**Fast 2030**	**Fast 2040**
Hokkaido				
Winter	1540	1131	1346	937
Spring	885	650	777	542
Summer	499	370	445	315
Autumn	758	559	669	470
Kyushu				
Winter	1737	1284	1547	1094
Spring	1481	1098	1327	943
Summer	1363	1012	1224	873
Autumn	1368	1015	1229	876

B.7. Input data for the energy system modelling

The overall cost of an energy system is influenced by a combination of investment, operational, technical constraints and market-related factors. Table B.4 gives an overview on two core parameters:

- Commodity prices affect operational expenses; higher fuel prices lead to increased running costs and can shift the preference toward renewables or efficiency measures.
- Minimum load requirements reduce operational flexibility by forcing certain generators to stay online, potentially resulting in inefficient operation and higher costs.

Modern nuclear reactors are technically designed to operate between about 50% and 100% of the installed power. However, it affects the lifetime of certain components and the fuel performance, which increases the costs significantly given a load factor of 60% is applied instead of 100% (OECD and Nuclear Energy Agency, 2011). Göke et al. (2025) describe that the operation of nuclear power plants is not economically feasible in a load-flexbile operation, although it is technically possible. In this contribution, it is assumed that nuclear power plants run at 90% base load, with 10% as flexibility reserve.

A partial phase out of coal power plants is planned until 2030, the remaining are assumed to operate in the typical configurations with minimum loads of 40-50% (Mayer et al., 2013).

Table B.4. Commodity prices and minimum load factors for operating the electricity generation technologies.

Process	**Commodity price [EUR/MWh]**	**Minimum load**	**Sources**
	2030		
Hydro plant	-	0.2	(Willingshofer, 2025)
Coal plant	15	0.5	(IEA, 2023d; Mayer et al., 2013)
LNG plant	35	0.3	(Willingshofer, 2025; Zwickl-Bernhard and Neumann, 2024)
Biomass plant	20	0.1	(USDA, 2023; Willingshofer, 2025)
Oil plant	60	0.4	(IEA, 2023e; Mayer et al., 2013)
Geothermal	-	0.3	(Willingshofer, 2025)
Nuclear	0.1	0.9	(OECD and Nuclear Energy Agency, 2011; Willingshofer, 2025)
Electrolyzer	-	0.1	(Qi et al., 2021)
H_2-Fuelcell	126	0.4	(E4tech Sàrl, 2023; Radosits et al., 2024b)
Methanation	-	0.4	(Lasser, 2021)

Furthermore, investment costs also determine the economic feasibility of new technologies. Lower capital costs make technologies more attractive, reducing total system expenditure.

Estimated reductions in investment costs over time are derived from the Danish Technology Catalogues (Danish Energy Agency, 2024; The Danish Energy Agency, 2025) and the 2023 Annual Technology Baseline of the National Renewable Energy Laboratory of the U.S. Department of Energy (Cole and Karmakar, 2023; NREL, 2023). Investment costs are only considered for technologies that utilize surplus electricity. Capacities for electricity generation are assumed to be already available in the respective target year. However, fixed operating costs are included for all technologies in Table B.5. Fixed operating costs add annual financial burdens regardless of usage. High fixed costs discourage the deployment of technologies unless these are operated at high loads related to the installed power.

Table B.5. Relevant cost data used for system cost modelling.

Process	**Investment costs [EUR/kW]**		**Fix operating costs [EUR/kW]**		**Sources**
	2030	2040	2030	2040	
Hydro plant	-	-	20	20	(Danish Energy Agency, 2024)
Wind onshore	-	-	30	26	(Danish Energy Agency, 2024)
Wind offshore			70	65	(NREL, 2023)
Photovoltaics	-	-	12	10	(Danish Energy Agency, 2024)
Coal plant	-	-	22	21	(NREL, 2023)
LNG plant	-	-	20	19	(NREL, 2023)
Biomass plant	-	-	200	200	(NREL, 2023)
Oil plant	-	-	7	7	(NREL, 2023)
Geothermal	-	-	1	1	(NREL, 2023)
Nuclear	-	-	40	40	(NREL, 2023)
Electrolyzer	759	600	34	29	(IRENA, 2020; The Danish Energy Agency, 2025)
H_2-Fuelcell	1,500	1,200	60	30	(Danish Energy Agency, 2024)
Methanation	1,300	1,100	35	20	(The Danish Energy Agency, 2025)