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What is the technological, environmental and economical potential of biogas as source of bio-hydrogen and bio-carbon dioxide within the transition to a renewable hydrogen energy system?

The case of the Netherlands within the wider European transition

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A Thesis presented for the degree of
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Abstract

A radical change of the energy system is required in light of the dramatic effects of human-induced climate change. In this perspective, a future renewable hydrogen energy system was proposed. Here, renewable hydrogen will be the energy carrier to cost-effectively transport cheap renewable electricity over time and space. Moreover, renewable hydrogen will allow for the balancing of the power sector, decarbonise hard-to-abate sectors and green processes, products and materials. In the proposed renewable hydrogen energy system, biogenic resources are ascribed relevant potential as source of bio-hydrogen and bio-carbon dioxide. In this light, the research brings forward the concept of third-generation upgrading as the highest valorisation potential of biogas. Here, biogas is ascribed a dual, time- and space-dependent potential as source of bio-hydrogen and bio-carbon dioxide, or syngas. The research highlights the technological potential of the autothermal reforming related process design, the environmental benefits associated with the concept of third-generation upgrading and indicates the positive economic results as compared to both competitive hydrogen production and alternative applications of biogas. Ultimately, the research proposes an alternative infrastructural design and regulatory framework to support the profitability of the concept of third-generation upgrading over time and space within the context of a future renewable hydrogen energy system. The research proposes to change the way biogas is seen.

Key words: Hydrogen, biogas, renewable energy, bio-hydrogen, bio-carbon dioxide

Dedication

For now, my gratitude for the time, assessment and feedback.

Declaration

Acknowledgements

Contents

Glossary

B

bio-carbon dioxide Term to address CO_2 from the upgrading of biogas.

bio-electricity Term to address electricity production from biogas.

bio-heat Term to address heat production from biogas.

bio-hydrogen Term used to describe hydrogen production from biogas.

biofuel Term to address a fuel produced from biogenic sources.

biogas Gaseous product from the digestion of biogenic sources which mainly consist of methane and carbon dioxide.

biogenic carbon dioxide Term to address CO_2 production from biogenic sources.

biogenic electricity Term to address electricity production from biogenic sources.

biogenic heat Term to address heat production from biogenic sources.

biogenic hydrogen Term to address hydrogen production from biogenic sources.

biomethane Term used interchangeably with green gas to indicate a product that is produced from biogenic sources and has similar characteristics as natural gas, or methane in this research.

E

e-hydrogen Term to address hydrogen production from renewable electricity.

F

fossil hydrogen Term to address hydrogen produced from fossil sources without any form of capture capture technology and includes both electrochemical- and thermochemical technologies.

G

green gas Term used interchangeably with biomethane to indicate a product that is produced from biogenic sources and has similar characteristics as natural gas, or methane in this research.

L

low-carbon hydrogen Overarching term to address hydrogen production from sustainable sources and fossil sources equipped with a form of carbon capture technology.

lower-carbon hydrogen Term to address hydrogen produced from fossil fuels including a form of carbon capture technology.

P

producer gas Gaseous mixture that is produced via gasification technology and exist of CO, CO_2, CH_4, H_2, other hydrocarbons, and more.

R

renewable hydrogen Term to address hydrogen production from renewable sources.

S

second-generation upgrading Describes the upgrading of biogas and utilisation of bio-carbon dioxide as opposed to direct usage of biogas or green gas without utilisation of the bio-carbon dioxide.

syngas Synthetic gas is a gas mixture containing hydrogen and carbon monoxide.

T

third-generation upgrading Describes the upgrading of biogas to bio-hydrogen and utilisation of bio-carbon dioxide.

Acronyms

A

AD Anaerobic digestion.

AE Alkaline electrolysis.

ATR Autothermal reforming.

B

BATR Biogas autothermal reforming.

bcm billion cubic meters.

BECCS Biogenic energy with carbon capture and storage.

BECCUS Biogenic energy with carbon capture, utilisation and storage.

BOX Dry biogas oxidation reforming.

BSR Biogas steam reforming.

C

CHs Hydrocarbons.

D

DR Dry reforming.

M

MC Methane cracking.

P

PEM Proton exchange membrane.

S

SCWG Supercritical water gasification.

SMR Steam methane reforming.

SOEC Solid oxide electrolysis cell.

Nomenclature

$C_6H_{12}O_6$ glucose

$CaCO_3$ calcium carbonate

CaO calcium oxide

CH_3COOH acetic acid

CO carbon monoxide

e^- electron

eV electronvolt

Fe iron

Fe_2O_3 iron oxide

Fe_3O_4 iron oxide

H^+ proton

H_2 hydrogen

H_2O water

H_2S hydrogen sulfide

N_2 nitrogen

NH_3 ammonia

Ni nickel

NO_x nitrogen oxides

O_2 oxygen

OH^- hydroxide ion

p^+ electron hole

SiO_2 silicon dioxide

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Chapter 1

Introduction

According to the Intergovernmental Panel on Climate Change (IPCC) "it is unequivocal that human influence has warmed the atmosphere, ocean and land." Moreover, the IPCC states that recent changes to the climate are unprecedented and that human-induced climate change is already affecting extremes in weather and climate. According to the researchers, temperatures are continuing to increase, changes in the climate system are becoming larger and many changes are irreversible. As a result, deep reductions in carbon dioxide (CO_2) and other relevant greenhouse gases (GHG)) have to be achieved, reaching at least net-zero CO_2 emissions by 2050, to limit human-induced global warming (IPCC, 2021). The United Nations (UN) Secretary-General António Guterres states that it is "a code red for humanity" and that "we must act decisively now, to keep 1.5 alive" (UN, 2021). Other renowned institutions like the International Energy Agency (IEA) and the European Central Bank (ECB) are bringing forward reports that indicate that the cost of inaction are immense, possess high risks and are higher than the transition to a low-carbon economy (Nelson, 2021)(I. E. A. IEA, 2021b).

Within the European Union (EU) a renewed policy framework to establish more stringent GHG emission reductions by 2030 is presented as part of the 'Fit for 55' package. According to the EU, achieving these reductions is crucial in order to make the European Green Deal a reality, which implies that the EU should be climate neutral by 2050. This will fundamentally transform the economy and society towards a fair, green and prosperous future (EU, 2021). This framework includes, among other things, tightening of the current EU Emission Trading System (EU ETS), broadening of the EU ETS, faster roll-out of low emissions transport, infrastructure and fuels, and tools to preserve and grow natural carbon sinks (EU, 2021).

According to van Wijk, 2017, this radical change will require a mentality shift towards embracing the need for radical transformations as incremental changes alone will not be sufficient.

Hydrogen will be an important factor in the future renewable energy system that needs to be net zero by 2050. According to senior professionals, the world is heading for hydrogen (DNV, 2021). Moreover, van Wijk and Chatzimarkakis, 2020 mention that hydrogen can play an important role in achieving a clean- and prosperous future as hydrogen will allow for cost-efficient bulk transport and storage of cheap renewable energy. Moreover renewable hydrogen can support the decarbonisation of the industry.

After an initial false start, hydrogen currently experiences unprecedented momentum (McKinsey, 2021). For example, the 'Fit for 55' package presents a unique opportunity for putting in place a framework for the development of a clean hydrogen economy (HydrogenEurope, 2021c).

Also, the international energy agency states that the time is ripe for hydrogen to fulfill its potential contribution to a sustainable energy system. Moreover, the IEA mentions that faster adoption is required to remain on track for a sustainable energy future by 2050 (Gül et al., 2021). In that way hydrogen can be used as feedstock, fuel, energy carrier and storage option to decarbonise the EU without emitting CO_2 or air pollution when used. The urgency to drastically reduce GHG emissions are opening up new opportunities in which hydrogen can act as support to reach carbon neutrality and even zero pollution as spelled out in the Paris Agreement (EC, 2020a).

The European Commission (EC) in its hydrogen strategy also name, next to circular usage of resources and large-scale electrification, renewable hydrogen as having a determining role in the integrated energy system. On top, the EC mention that fast deployment of hydrogen is key to achieve the climate ambitions. Also, the progressive uptake of hydrogen could support repurposing or re-using of the existing natural gas infrastructure in a way to avoid stranded assets in pipelines (EC, 2020a).

Future renewable hydrogen system

In accordance, van Wijk, 2021 paints a picture of a future hydrogen system that shows important similarities to the present natural gas system. Here, hydrogen fulfills the role as zero-carbon, globally-traded energy carrier and commodity. In this way, hydrogen facilitates the connection between the space and time dimensions in a renewable energy system. Moreover, the energetic usage will become in competition with local- or regional electricity production, regional produced hydrogen, and imported hydrogen. This trade-off becomes increasingly relevant due to location differences with respect to renewable energy resources, restricted area size and population density. In this perspective, hydrogen replaces natural gas and other fossil fuels, while contributing to a fast, cheap and reliable transition to a renewable energy system. Thereby, the future renewable energy system focuses on the reduction of greenhouse gas emissions, diversification of the energy supply, the integration of renewables, available economic growth, development of national technology, security of supply and strategic reserves, and the development of hydrogen for export and import (van Wijk, 2021).

The role of hydrogen as globally-traded energy carrier and commodity interconnects over time and space. More specifically, in the future renewable hydrogen system large-scale hydrogen production is connected with underground storage facilities and processing plants to facilitate the balancing of production fluctuations and to ensure adequate specifications. Moreover, intercontinental- and continental pipelines or shipping routes will facilitate the transportation of hydrogen from low-cost production locations to demand centers. This could specifically serve baseload demand and transport or as input for storage facilities. Through the hydrogen infrastructure, hydrogen can be transported in-land at reduced pressure levels to connect medium industrial customers, larger commercial sites and hydrogen fuelling stations (HRS). This in-land infrastructure also allows for coupling with local- and regional biogenic hydrogen production facilities. Additionally, local- and regional hydrogen production from renewable electricity could be connected, which primarily serves to alleviate electricity grid capacity constraints. Finally, at low pressures, residential customers could be served including houses, offices, schools and small shops. The lay-out of the envisioned hydrogen system can be seen in figure 1.1. Here, hydrogen fulfils two essential systemic functions as complementary energy carrier for transportation over time and space and as resource for the decarbonisation of hard-to-abate sectors (van Wijk, 2021).

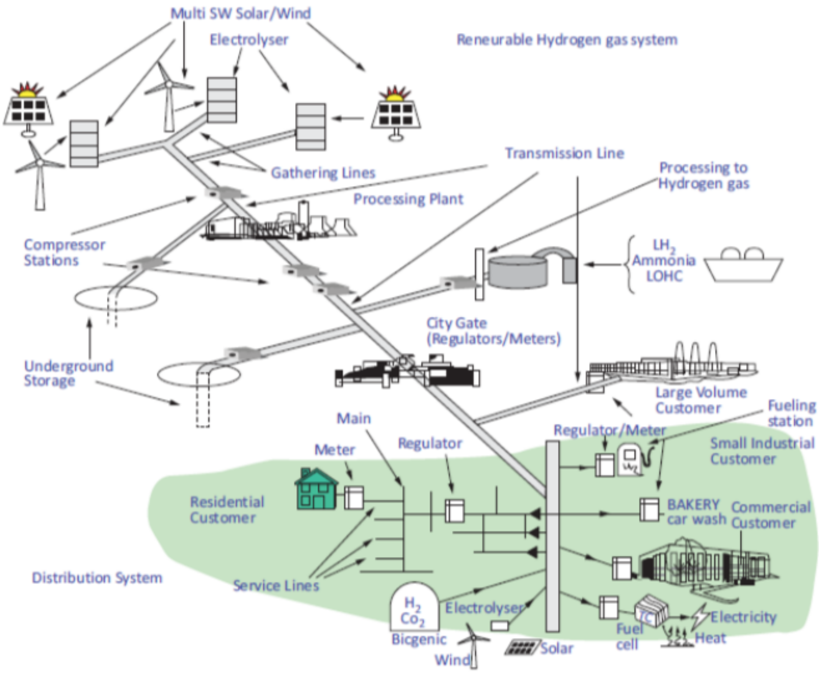


Figure 1.1: A schematic lay-out of a future renewable hydrogen system (van Wijk, 2021)

Despite the dominant role of hydrogen in a future sustainable energy system, the current production of hydrogen is primarily based on fossil resources resulting in a global carbon dioxide-equivalent emission of approximately 900 mega tonnes (Mt) for the production of around 90 Mt hydrogen in 2020 (Gül et al., 2021). According to HydrogenEurope, 2021a, clean hydrogen only represents 0.6% of the total production capacity in Europe at the moment. Even though considerable attention to low-carbon hydrogen production methods has resulted in a spark in production capacity, forecasts of 2030 levels are still significantly below the desirable levels. In this way, both capacity- and CO_2-eq reduction levels stay behind targets set in the 'IEA Roadmap for the Global Energy Sector' (Gül et al., 2021).

Also, van Wijk, 2021 indicate that hydrogen is currently absent or only at the beginning to be considered as energy carrier within energy laws, energy regulations and wider in the renewable energy system. As such, there is no public infrastructure, public market or public regulation. Therefore, the role of low-carbon hydrogen within the future energy system should become more ingrained within energy strategies and roadmaps. This includes an important role of demand- and market creation for lower-carbon hydrogen to support the clean energy transition. Here, van Wijk, 2021 identifies, next to renewable hydrogen and biogenic hydrogen, the opportunity for natural gas converted to hydrogen at the source without any CO_2 emissions, as potential transition route for the intermediate period towards the future renewable hydrogen gas system. This not only allows for a fast transition, but it also could support a cheap, reliable, secure and inclusive transition towards the renewable energy system (van Wijk, 2021). Government instruments are hereby an essential feature, but most measures are not yet into force. According to DNV, 2021, the most important enabler of the hydrogen economy is regulations, while a lack of infrastructure is the main reason for organisations not to invest or be involved in hydrogen.

Therefore, governmental instruments could not only support rapid adoption of low-carbon hydrogen within the current applications of hydrogen, but also stimulate wider adoption in potential new applications for hydrogen. In this way, low-carbon hydrogen is able to replace unabated fossil hydrogen as well as replace fossil fuels. Additionally, support for production- and manufacturing capacities could enhance low-carbon production capacity, stimulate continuous research and development (R&D) and ultimately lower the levelised cost of hydrogen (LCOH). Moreover, mobilisation of investments in the development of infrastructure could then ensure the connection between supply- and demand centers where adequate planning can prevent delays or the creation of future stranded assets (Gül et al., 2021). Thereby, both capacity- and CO_2-eq reduction levels could be stimulated.

Thus, the IPCC report indicates that it is required to act in order to counter human-induced climate change. Moreover, the 'Fit for 55' package clarifies that it is time to act now. However, this radical change will drastically alter the way the energy system is observed. In this energy system, renewable hydrogen will play a determining role as energy carrier over time and space as well as to provide an opportunity to decarbonise hard-to-abate sectors. This role will be key next to the circular usage of materials and large-scale electrification. Nonetheless, low-carbon hydrogen production capacity is limited which hinders the market development and ability to reach the CO_2 reduction goals. Therefore, low-carbon hydrogen requires a central role within policy strategies.

Low-carbon hydrogen production

For the production of low-carbon hydrogen, Gül et al., 2021 focus primarily on two production methods, namely via water electrolysis (WE) and fossil fuel reforming with carbon capture and storage (CCS). In the case of water electrolysis, Europe is dominant with around 40% of the electrolyser capacity. On the other hand, Canada and the United States (US) lead in the production of CCS technology with around 80% of the global capacity. However, both technological production routes face, besides capacity limitations, relevant shortcomings.

First of all, CCS technology is relatively new and only two commercial facilities to produce hydrogen from natural gas reforming with CCS exist globally. Therefore, several assumptions regarding the storage potential remain unproven. Moreover, not all carbon dioxide emissions can be captured during the process and therefore the process cannot be described as zero-carbon solution (Heiker et al., 2021). Schröder, 2021 state that despite a promised CO_2 capture of 80% the showcase project in Australia only captured around 30% of the CO_2 emissions. Moreover, Heiker et al., 2021 add to this that the CO_2-eq savings of CCS might even be lower than initially expected. This results from the additional usage of natural gas to power the CCS process. By inclusion of the methane emission rate present in the production of natural gas the CO_2 savings over the full life cycle result in only around [9-25]%. The methane emission rate is especially relevant since the curtailment of methane emissions during fossil fuel extraction is seen as one of the best near-term opportunities for limiting the negative effects of climate change (I. E. A. IEA, 2021a). Thus, next to a continued reliance on fossil fuels and a potential natural gas lock-in effect, the CCS technology is relatively immature and has questionable CO_2-eq savings.

In the case of water electrolysis technology, both the capacity and cost price are the dominant limiting factors (van Hulst, 2019). Especially the high cost of renewable hydrogen is seen as greatest risk in progressing the hydrogen economy (DNV, 2021). First of all, the price of electrolysers remain costly. However, the critical factor lies with the price of renewable electricity. While the price of electrolysers is expected to decrease, the price development of renewable electricity remains questionable. This results from the dependency on renewable electricity production capacity and demand. Additionally, the hydrogen cost is related to the nature of dedicated versus curtailed hydrogen production. Here, the annual operating hours are a strong influence on the production cost of renewable hydrogen. Moreover, the renewable electricity costs are strongly location dependent, where the lowest prices are expected in locations with good renewable sources and reliable operational conditions (Klessmann et al., 2021). While thermochemical hydrogen production methods are seen as economically viable, water electrolysis methods require governmental involvement and more research to become competitive. For example, thermochemical fossil hydrogen production routes are assigned a hydrogen production cost of [1.77-2.27] \$/kg H_2, while water electrolysis production routes are assigned a hydrogen production cost of [5.10-23.27] \$/kg H_2 (Nikolaidis and Poullikkas, 2017). Moreover, van Hulst, 2019 mentions fossil hydrogen production costs of around 1.50 €/kg H_2 and CCS costs of around [2.00-2.50] €/kg H_2, while water electrolysis results in a cost price of around [3.50-5.00] €/kg H_2.

However, low-carbon hydrogen can be produced from a range of renewable energy sources. Here, hydrogen can act as a unique energy hub to provide low- or zero-emission energy to all sectors. In this light, Albrecht et al., 2016 complement renewable hydrogen production via water electrolysis with alternative hydrogen generation technologies. These technologies are besides the low-carbon nature assessed on technological capabilities, maturity and economic performance to inform about the future potential. Albrecht et al., 2016 generate 11 possible hydrogen production pathways based on renewable energy from solar thermal energy, electricity, sunlight and biomass. Ultimately, based on hydrogen production costs, energy use and greenhouse gas emissions as major criteria relatively mature technologies are benchmarked against water electrolysis and traditional steam reforming of methane (SMR) for the year 2030. In the analysis steam reforming of biogas, biomass gasification and biomass pyrolysis are attributed most potential (Albrecht et al., 2016). In the case of biomass gasification and biomass pyrolysis it should be noted that this is constrained to woody biomass, due to the punishable efficiency losses in case of wet biomass (Holstein et al., 2018). This is in contrast to biogas from digestion which uses wet biomass as input. As a result, both could be seen as complementary and mutual exclusive renewable energy sources.

Also, van Wijk, 2021 indicates an important role for the production of hydrogen from biogenic waste. In the future renewable hydrogen system, biogenic waste can regionally and locally be converted into hydrogen and carbon dioxide. The hydrogen can be fed into the hydrogen infrastructure and used as energy vector or as feedstock, while carbon dioxide can be transported and used in for example the chemical industry as green feedstock or the horticulture to support plant growth. Moreover, the produced synthetic gas (syngas) could also be directly used as circular chemical feedstock. Hereby, the usage of biogenic hydrogen and biogenic carbon dioxide reduce the CO_2-eq related emissions as compared to the direct usage of biomass for electricity- and or heat generation, or indirect usage of biomass as biomethane for fuel applications. This supports a more efficient, economic and less polluting utilisation of biomass in a future zero-emission hydrogen system. On top of that, hydrogen is in this way valued as a more versatile molecule that can be used as source for heat- and electricity production, and also as chemical feedstock or within fuel cell applications. Here, the later two are associated with a higher value applications. Moreover, the additional conversion towards hydrogen and carbon dioxide reduces problems associated with methane leakage throughout the supply chain. Additionally, it could provide and add hydrogen volume into the system in light of a rapid transition. Finally, the use of biogenic waste for hydrogen production could support the avoidance of a natural gas infrastructure lock-in and in general reduce the necessity of a natural gas infrastructure to further support the adoption of a renewable hydrogen gas system (van Wijk, 2021).

While biomass gasification is attributed potential as relevant source for hydrogen production, van Soest et al., 2014 indicate the need for further technological developments before gasification can contribute substantially to green gas- and or biogenic hydrogen production. Therefore, van Soest et al., 2014 indicate that first the feasibility and relevancy of biomass gasification has to be determined. Moreover, van Soest et al., 2014 indicate that the competitive usage of the produced syngas could limit further upgrading towards biogenic hydrogen. Here, the relevant price points determine the ultimate end usage. Also, Lepage et al., 2021 indicate the lower technology readiness level (TRL) associated with biomass gasification as compared to reforming technologies. Moreover, Lepage et al., 2021 indicate the need for low-cost- and available biomass input as relevant character that could hinder the adoption of gasification for the production of biogenic hydrogen. This is strengthened by the social unrest regarding the utilisation of woody biomass for energetic purposes. Additionally, the biomass input material and process conditions have a strong effect on the output mixture. This subsequently hinders the process effectiveness and as a result the adoption of the gasification process. On top of that, Lepage et al., 2021 indicate the need for large-scale production due to the high cost associated with small-scale gasification. While small-scale gasification is assigned a hydrogen production cost of 10 \$/kg H_2, at larger scale this could lower to [1.21-3.5] \$/kg H_2. This is in contrast to small-scale biogas steam reforming (BSR) that is assigned hydrogen production cost of [1.21 - 2.57] \$/kg H_2 (Lepage et al., 2021). In line with the need to scale production sizes, Holladay et al., 2009 indicate the need for tremendous amount of resources that must be used to gather the large amounts of biomass to the central processing plant. This follows from the continuous production process need of the gasification reactors. As a result, high logistics cost is another factor that hinder the further development of gasification plants for biogenic hydrogen production. Lastly, despite the large-scale, biomass gasification sees lower higher heating value (HHV) efficiencies in comparison to reforming technologies (Holladay et al., 2009). Therefore, despite the assigned potential to biomass gasification technologies adoption for hydrogen production might be limited due to the technology maturity, cost price, product competition, biomass input problems, and process complexity and efficiency.

In contrast, several studies confirm the attractiveness of the biogas to hydrogen conversion route in terms of technological feasibility, economic performance and environmental score. For example, Braga et al., 2012 show that biogas steam reforming could be considered a technically and economically feasible alternative to fossil hydrogen production, which decreases the negative environmental effects but show similar levels of efficiency. It was shown that BSR requires an economic payback period of 8 years and scores an ecological efficiency of 94.95%. Another overlooked environmental benefit of biogas utilisation is attributed to the methane removal potential. Next to fossil fuel extraction, natural sources like waste disposal and agriculture are the main sources of methane emissions. In this perspective, biogas could be seen as potential methane removal source and thereby offers an interesting climate solution option (Jordan, 2021). On the techno-economic side, the study by Yao et al., 2017 indicated an after-tax H_2 break-even price of 0.152 €/kWh for BSR, which was significantly below the cost for alkaline electrolysis. Moreover, BSR showed the highest net present value (NPV) in comparison to both biomass steam gasification and water electrolysis. Additionally, two renowned European funded studies indicated the technological potential of innovative biogas to hydrogen production routes. In the BioRobur program an innovative autothermal reforming (ATR) technology was developed. Camacho et al., 2017 created a strengths and weaknesses analysis of the BioRobur technology to show the technological potential and suggested a bio-hydrogen delivery cost of [2.5-5] €/kg H_2. The BIONICO project in contrast developed a membrane-assisted catalytic autothermal reforming (MA-ATR) process. Marcoberardino, Foresti, et al., 2018 assessed the thermodynamic- and economic advantage of the MA-ATR process and showed an increase in efficiency of 20 percent point compared to traditional BSR and biogas autothermal reforming processes. Moreover, the MA-ATR process resulted in a lower LCOH of 4 €/kg H_2 at the same delivery pressure in comparison to 4.2 and 6.4 €/kg H_2 for BSR and BATR respectively (Marcoberardino, Vitali, et al., 2018). As a result, the biogas to hydrogen conversion route show high environmental scores, good economic performance and proves to be technological feasible.

Thus, while low-carbon hydrogen production is of pivotal importance the current production levels are limited. Even though most attention is devoted to CCS technology and water electrolysis, both routes face significant barriers. CCS technology is relatively unproven and CO_2 savings are questionable, while water electrolysis face high production costs. Nonetheless, also biomass as source of hydrogen fulfills an important role in a future renewable hydrogen system. In this perspective, gasification of woody biomass enjoys attention as potential renewable hydrogen source. However, biomass gasification also faces important barriers from a technological, social and economic perspective. On the other hand, biogas is relatively unknown as potential renewable hydrogen source. Nonetheless, several studies indicate the technological, environmental and economical potential of the bio-hydrogen production route.

Renewed perspective on biogas

Despite the technological, environmental and economical potential of biogas as source for the production of bio-hydrogen only limited attention has been devoted to this conversion route. This is primarily due to the focus on the direct energetic utilisation of biogas and indirect energetic utilisation via biomethane. Biomethane is obtained through upgrading of biogas, where via selective separation of CO_2 and methane (CH_4) a high purity biomethane stream is secured. In this perspective, Sheets and Shah, 2018 focused on the techno-economic feasibility of upgrading biogas for usage in grid injection, biogenic compressed natural gas (CNG) or thermochemical conversion to biogenic methanol. This was opposed to the direct usage of biogas in combined heat and power plants (CHP) which is the most common valorisation method but suffers from considerable heat losses. Sheets and Shah, 2018 showed that bio-CNG had the highest NPV, while biogenic methanol yielded a negative NPV. This was mainly contributed to the high selling price of bio-CNG and the high operational- and capital cost related to biogenic methanol production. Nevertheless, a techno-economic comparison of the subsequent upgrading to bio-hydrogen and bio-carbon dioxide is absent.

However, Pfau et al., 2017 ascribe more potential to biogas than the sole energetic utilisation of biogas or green gas. Pfau et al., 2017 indicate the opportunity for biogas to contribute, next to the renewable energy domain, to the bio-economy domain. In this way, biogas can efficiently be used as scarce resource to provide products for both domains. Biogas can thereby serve as a system service provider for the renewable energy domain and as main input for various bio-based products. However, diverging goals of both policy domains limit the optimal usage of biogas in innovative solutions or create innovative connections between both policy domains. As a result, Pfau et al., 2017 argue for a renewed perspective on biogas away from energy as single main product. Hereby, the competitive position of bio-based products over fossil-based products can be improved. Biomass resources should then be optimized based on the cascading principle, rather than inciting competition between the different biomass applications. In the bio-economy perspective bio-energy, specifically biogas for heat- and electricity generation, is ranked as low valuable utilisation of biomass. In the bio-economy, energy is seen as a by-product. To alter the perspective on biogas, Pfau et al., 2017 show the relevant constraints and opportunities of biogas in both policy domains, including a perspective on the logistic organisation of biogas production and potential synergetic value between both domains. Ultimately, Pfau et al., 2017 argue for the dual and time-dependent role of biogas in the two transitions.

In the same perspective, Villadsen et al., 2019 argue that the utilisation of biogas is limited to the energetic usage of biogas in the form of direct heat generation, power generation or green gas. Hereby, Villadsen et al., 2019 state that these processes disregard the potential of the bio-CO_2 that is co-produced, while this stream could be converted to hydrocarbon-based high energy-density fuels. This second-generation upgrading upgrading could support the replacement of fossil-based fuels in hard-to-abate sectors. In this perspective, bio-CO_2 is not seen as a waste product, but rather as a carbon source that enables the closure of carbon cycles through the conversion to carbon-based energy carriers. Therefore, biogas has been assigned an unused potential as a carbon capture, usage and storage (CCUS) technology. This not only helps to prevent CO_2 emissions, results in a valuable bio-CO_2 source, but also offers an option as flexible storage option which will become central in the interconnected energy infrastructure (Villadsen et al., 2019).

To conclude, due to the importance of hydrogen in the future renewable energy system, the potential of biogas as bio-hydrogen source, and the limited perspective on biogas utilisation the way biogas is seen has to change. Biogas should be seen as a bio-hydrogen and bio-CO_2 source. In this way, the bio-hydrogen could serve an important system service role in the renewable energy domain, while the bio-CO_2 could serve as main input for bio-based products. In this way, a shift from the perspective of bio-CO_2 as waste product could be altered into the perspective on the relevancy as carbon sink or even as valuable bio-product input. The third-generation upgrading upgrading could couple the role of bio-hydrogen with the role of bio-CO_2 for circular usage of materials and stimulate bio-based products over fossil counterparts. The production of bio-hydrogen can in the short term boost the EU focus on a faster roll-out of low emissions transport, infrastructure and fuels plus the repurposing or re-using of existing natural gas infrastructure in a way to avoid stranded assets. Over time the bio-hydrogen could become to be seen as energy by-product of bio-carbon. This ultimately could couple biogas with electrification, circular usage and renewable hydrogen. This radically shifts the perspective on the role of biogas.

Chapter 2

Research Proposal

The need to revise the current energy system is apparent in light of human-induced climate change. This change in perspective requires a mentality shift based on radical new ideas. In this light, incremental changes are insufficient to counter the negative, irreversible effects of human-induced climate change. This also requires new- and bold initiatives that are not boxed by political, professional or academic silos. As a result, this research aims to renew the focus on biogas as energy molecule towards a platform molecule that is possible of coupling the hydrogen-, circular- and electrified economy. Moreover, it places biogas central as important regional and or local bio-hydrogen and bio-carbon dioxide source within a future renewable hydrogen gas system, with additional benefits for a rapid, cheap, reliable, secure and inclusive transition. In this perspective, biogas should be attributed a time-dependent dual role based on the energetic hydrogen and molecular carbon constitutes. Here, biogas does not only offer a zero-pollution energetic fuel but also a potential life-cycle carbon-negative bio-product input material. Based on the cascading principle the upgrading of biogas to bio-hydrogen and bio-carbon dioxide could then be argued to represent a third-generation upgrading route. This renewed perspective on biogas could then fuel- and support coherent political priorities and strategies required to achieve a climate-neutral system by 2050. Not only does the biogas conversion route provide additional hydrogen production capacity, it also supports infrastructural-, transportation- and zero-pollution fuel initiatives. It boosts the repurposing of the existing gas infrastructure, redirects the market demand, and lowers the dependency on fossil- and polluting fuels in transportation, industry and the build environment. Moreover, through a renewed focus on bio-CO_2 the concept of third generation upgrading enables biogas to act as a natural carbon sink able to close the material cycle. To stimulate the revision on the role of biogas the goal of this research is to develop a system vision on the conversion of biogas to bio-hydrogen and bio-carbon dioxide from a technological-, environmental- and economical perspective. The system perspective aims to incorporate the time-dependent dual role of biogas over the short- to long-term with the ultimate goal of climate neutrality by 2050. Moreover, this perspective aligns with the vision on a renewable hydrogen energy system, where renewable hydrogen operates as a energy carrier connecting both the time- and place dimension. To do this, the research takes a dynamic perspective on the valorisation of bio-carbon dioxide and bio-hydrogen. The overall research question is:

What is the technological, environmental and economical potential of biogas as source of bio-hydrogen and bio-carbon dioxide within the transition to a renewable hydrogen energy system?

To move away from a descriptive towards a prescriptive analysis, this vision also takes into account the relevant boundary conditions that are related to the regulatory perspective and infrastructural development. In this way, the research aims to normatively describe the relevant boundary conditions required, within the overall European vision of climate neutrality by 2050, to reduce potential conflict in political priorities and shifting strategic objectives. The related research question is:

Which boundary conditions will make the upgrading of biogas to bio-hydrogen and bio-carbon dioxide profitable, over time, within the European context?

In order to formulate hypotheses the research context will be used to evaluate the relevant information. In this regard, the vision is evaluated along the lines of a renewed perspective on biogas that moves beyond the one-sided energetic use. Moreover, the vision sits within the wider perspective on a renewable hydrogen system. In this context, this research identifies biogas as a valuable bio-carbon and bio-hydrogen source. Moreover, this research observes biomethane usage devalued against bio-hydrogen usage due to the carbon emission factor. Therefore, this research identifies third-generation upgrading of biogas for bio-H_2 production and bio-CO_2 utilisation as the higher valorisation potential from a societal perspective, which also includes the potential direct utilisation as syngas. In this respect, the relevant and complementary valuation of the potential output streams justify the third-generation upgrading potential. Therefore, to achieve the climate-neutral perspective by 2050 a radical shift in the role of biogas is proposed. In this light, the relevant boundary conditions to support the renewed role of biogas are investigated and proposed.

Based on the research context, the following hypotheses are formulated:

- Biogas has untapped potential to operate as a platform molecule within the renewable hydrogen energy system for both energetic bio-hydrogen and molecular bio-carbon dioxide. The technological conversion is possible, the utilisation of carbon dioxide result in negative carbon emissions, the utilisation of hydrogen supports zero-pollution emissions, and the concept of third-generation upgrading shows positive economic results.
- The regulatory framework and infrastructural development will value the concept of third-generation upgrading through re-design, re-purposing and integration of the renewable energy infrastructure, and via production support, financial incentives and regulatory requirements related to a renewed vision on negative emissions, closing carbon cycles, and phasing out of fossil fuels.

To conclude, the research aims to normatively address the renewed vision on the utilisation of biogas as a platform molecule within the proposed future renewable hydrogen system. The dual role of the third-generation upgrading of biogas will be time- and place dependent and focus on the technological-, environmental- and economical potential. Moreover, the research addresses the relevant regulatory and infrastructural boundaries. Ultimately, the research aims to create a system vision for the role of biogas within the proposed future renewable hydrogen system with the end perspective of climate neutrality within the European Union by 2050.

Chapter 3

Methodology

The research proposal aims to describe a renewed vision on the role of biogas within the wider proposed renewable hydrogen system. Therefore, this research takes a system design perspective where it addresses the role of biogas from a dual, time- and place dependent viewpoint. Moreover, this research aims to place the role of biogas within the local- and regional context, which could open possibilities for further exploration of sector coupling and or regional integration options. As this research takes a prescriptive approach, in light of the end goal of climate neutrality by 2050, additional attention will be drawn to the non-technoeconomical perspectives to allow for the adequate incorporation of relevant boundary conditions, including regulatory- and infrastructural developments. This is ultimately assessed within the research context of the renewed vision on the potential of the concept of third-generation upgrading along the perspective on the technological, environmental and economical potential.

In order to do this, the methodology is build on a combination of academic papers, market research, expert interviews and data analysis. These sources of information are valued against the research context, as outlined in the research proposal and the introduction, and will be used to validate- or disregard the proposed hypotheses. Moreover, this subsequently serves to outline a potential roadmap towards the more detailed incorporation of the role of biogas within the wider renewable hydrogen system.

Academic papers have been reviewed in order to portray the current knowledge on the theoretical potential of the biogas to hydrogen conversion route. This includes technological-, environmental- and economical parameters. Moreover, these advances are weighted and assessed in the context of the proposed renewed role of biogas. Secondly, market reports serve to relate the theoretical potential to the market potential and helps to include additional factors to support the system boundary conditions. In this way, the research aims to the support the renewed perspective on the concept of third-generation upgrading beyond the theoretical foundation. Hereafter, the expert interviews guide the research towards the practical potential of the biogas to bio-hydrogen and bio-carbon dioxide. These interviews serve as an interpretation within the predefined research context and offer perspectives on the feasibility of the renewed role of biogas and are used to validate or disregard the proposed hypotheses. The interviews serve to define the solution space for the proposed alteration in the role of biogas within the relevant boundary conditions. In this way, the theoretical work is related to the practical usefulness. Finally, based on the proposed end state this offers the potential to draw a roadmap for the actualisation of the new role of biogas within the wider proposed renewable hydrogen system. This also serves as guiding principal for both the determination of the relevant boundary conditions and ultimately the potential over time and place of the concept of third-generation upgrading of biogas to bio-hydrogen and bio-carbon dioxide.

The research applies several different methodological methods. Firstly, a strengths- and weakness analysis indicates the relevance of the conversion of biogas to bio-hydrogen in comparison to alternative hydrogen production routes. Then, a strength- and weakness analysis is also applied to compare the upgrading of biogas to bio-hydrogen and bio-carbon dioxide or syngas in relation to alternative uses of biogas. Hereafter, a house-of-quality (HOQ) assessment is utilised to identify the most relevant conversion technologies to obtain bio-hydrogen and bio-carbon dioxide or syngas from biogas. Next, based on a process flow diagram (PFD) adequate production numbers are obtained for the third-generation upgrading route. Subsequently, the actual environmental value of the concept of third-generation upgrading is determined based on the carbon mass balance. Moreover, an economic assessment via the business case framework is performed to identify the economic feasibility of the concept of third-generation upgrading. The business case analysis and carbon mass balance analysis subsequently identify the relevant economic- and environmental parameters and numbers. A mapping exercise helps to further identify the potential infrastructural design, conditions and relevance. Additionally, based on a regulatory impact assessment the dominant policy conditions are characterised, proposed and assessed. These inputs are then combined and valued in the context of the renewed perspective on biogas. Here, the policy- and infrastructure insights serve to shed a first light on the relevant boundary conditions to support the the concept of third-generation upgrading. The expert interviews ultimately help to validate the research context as well as offer a solution space for adequate alteration of the boundary conditions to facilitate the renewed perspective on the role of biogas within the wider renewable hydrogen system. Ultimately, this serves to prescribe the required roadmap and relevant boundary conditions to support the third-generation upgrading perspective.

With respect to the expert interviews, over 60 respondents have been addressed out of which 40 plus responded. In the end, 33 interviews of [30-60] minutes each were conducted. These interviews were subsequently processed along the dominant takeaways and categorized along dimensions of the research. The raw notes were reviewed to nuance or strengthen the takeaways from the interviews and to correct for potential biases in the respondents answers as a result of the persons background. The interviews helped to interpret the initial hypotheses within the predefined research context and to create a solution space for the renewed perspective on biogas. A full list of respondents can be found in table 3.1.

Name	Company	Position
René Slaghek	Sitech Services	Project Manager Chemelot Sustainability Team
Robin Bressers	Shell	Business Development Manager Europe BioLNG
Ellart de Wit	HyGear	Chief Technology Officer
Patrick Wolbers	DNV GL	Senior Consultant
Freek Leuveld	BioMCN	Process Engineer
Joey van Elswijk	Port of Amsterdam	Commercial Manager Renewable Fuels
Francoise van den Brink	NEN	Senior Standardization Consultant Energy
Bettina Kampman	CE Delft	Manager Energy
Jan Paul van Soest	De Gemeynt	Director
Bob Weehuizen	Proton Ventures	Business Development Manager
Har van Himbergen	Ministry of Economic Affairs	Policy Advisor
Johan Jonkman	Rendo	Asset Manager Gas
Marieke van der Werf	Groen Gas Nederland	Director Energy Transition
Bouke van der Velde	Groen Gas Nederland	Specialist Grid Connection
Anshuman Pandey	Bright Biomethane	Account Manager
Sander Lensink	PBL	Senior Researcher
Perry Wens	Greenpoint	Accountmanager Hydrogen
Bert van Halen	Gasunie	Business Developer Renewable Gases
Jabbe van Leeuwen	Ekinetix	Senior Consultant
Pier Stapersma	CIEP	Senior Researcher
Remco Detz	TNO	Scientist
Koen Smekens	TNO	Medior Consultant
Willem Frens	TNO	Senior Business Development Manager
Marc Londo	NVDE	Substantive Strategist
Bart Strengers	PBL	Senior Policy Researcher
Rugter Bianchi	Berenschot	Consultant Energy
Peter Perey	RUG	Researcher
Ruud Paap	New Energy Coalition	Theme Coordinator
Josja Roest	Hague Corporate Affairs	Senior Advisor
Anouk van Grinsven	CE Delft	Senior Researcher
Harmen Dekker	European Biogas Association	Director
Johan Voshaar	Cogas	Supply Chain Developer

Table 3.1: List of industry experts interviewed

Chapter 4

Hydrogen

Renewable hydrogen is ascribed to be the key pillar in a future renewable energy system next to the circular usage of materials and large-scale electrification. In the future renewable hydrogen system, hydrogen will not only act to decarbonise hard-to-abate sectors but will also be used as energy commodity over time and place. This will ultimately be based on the security, reliability, accessibility and affordability of the different hydrogen production processes over time and place.

However, only limited low-carbon hydrogen is produced- and or transported at the moment, which is attributed to several factors including feasibility, availability, and cost-effectiveness. Moreover, the adoption of hydrogen is interrelated with the current- and future applications and the current- and or proposed alternatives. Here, in a technology agnostic approach special attention lies on the interconnectedness with other energy carriers, biomethane, which finds end uses in similar applications. This is further complicated by the inherent relationship between hydrogen and biomethane. This is especially relevant due to the increased importance of climate-neutral carbon molecules in the proposed future renewable hydrogen system. In this respect, biogenic resources are ascribed potential for the local- and or regional production of biogenic hydrogen and biogenic carbon dioxide.

As a result, this chapter aims to address the relevancy of hydrogen within the future renewable energy system. Moreover, it compares the different hydrogen production methods from a technological-, environmental- and economical perspective in light of the proposed renewable hydrogen energy system. This is then input for the strength- and weakness analysis, which aims to ultimately paint a picture of the relevancy of the biogas to bio-hydrogen route within the proposed renewable hydrogen system.

4.1 Introduction

Gaseous- and liquid energy carriers will play an important role within the renewable energy system. This is next to energy reduction mechanisms, deployment of renewable energy production and large-scale electrification. The expectation is that between [40-60]% of the energy demand will require renewable molecules. This demand originates from those instances where electrons are insufficient or inefficient as decarbonisation option. Moreover, renewable molecules are needed as input within the process industry for the production of chemical products and materials. Finally, renewable molecules will be needed for large-scale transport, storage and balance of renewable electricity (Gigler et al., 2020).

The realisation that clean power alone is insufficient to overhaul the current energy system due to the complexity of decarbonising hard-to-abate sectors coupled with the global resolve to mitigate climate change has sparked a renewed momentum for hydrogen. For example, while power sector is proved to be decarbonised comparatively easily, the heat- and transport sector are expected to decarbonise at just one-third of this rate (Staffell et al., 2018). Here, hydrogen is seen as a critical and indispensable element of a decarbonised, sustainable energy system where it provides a secure, cost-effective and non-polluting energy vector. The reason is that hydrogen can play a dominant role in those sectors that are accountable for a significant part of the global CO_2 emissions and in turn limit the fossil fuel dependency. For example, hydrogen can counterbalance electricity as a zero-carbon, easily storable and transportable energy carrier with the versatility to operate across the transport-, heat-, industry- and power sector (Staffell et al., 2018). In the same line, Gielen et al., 2019 state that hydrogen or hydrogen-derived fuels are required to decarbonise a significant share of global emissions. Hydrogen can help tackle various critical energy challenges, can enable renewables to provide an even greater contribution and is versatile in terms of supply and use. Moreover, Gigler et al., 2020 ascribe to hydrogen a broad system role within the future renewable energy system. In this role, hydrogen is attributed both energetic- and non-energetic potential applications in the transportation-, industrial- and build environment sector. Moreover, hydrogen can be seen as flexible storage, transport and interchangeable, balancing medium for variable renewable electricity production both on a centralised- and decentralised scale. Here, hydrogen can operate as intermediate between the electricity- and gas sector, where important synergies are present between hydrogen and renewable energy (Gigler et al., 2020). R. Detz et al., 2019 mention that due to the various applications across different sectors and the infrastructural advantages of hydrogen, it enhances system integration, sector coupling, and the potential to safeguard the reliability and flexibility of the energy system. Conclusively, hydrogen will play a dominant role as CO_2-eq reducing fuel, raw material and system support mechanism within the renewable energy system, where hydrogen can help to improve air quality as zero-pollution fuel while also strengthen energy security, flexibility and integration (Gigler et al., 2020)(Gielen et al., 2019).

4.2 Potential

The energetic role as described by Gigler et al., 2020 follows from the potential of hydrogen to act as energy vector in the industrial-, build environment-, transportation- and power sector. For example, hydrogen can be used for heating in both the industrial- and build environment sector where it can act as replacement of the current fossil fuel usage. Moreover, hydrogen can be used in fuel cell technology or as hydrogen-based fuel to power transport for longer duration and or higher power requirement applications. This will be especially relevant in long-haul road transport, high power vehicles, maritime applications and aviation technologies, where battery technology proves to be insufficient. However, also in cases battery electric vehicles (BEV) are present, fuel-cell electric vehicles (FCEV) pose some options based on specific performance requirements. Moreover, hydrogen can also act as flexible and adjustable source for electricity production and on top of that help to reduce curtailment in the electricity grid. However, Gielen et al., 2019 indicate that the potential curtailment function of hydrogen requires a delicate balance between low cost curtailed renewable electricity and high utilisation or capacity of electrolysers. The non-energetic role relates to hydrogen as raw material in industrial processes. This could involve new processes, new products as well as the decarbonisation of current applications. Examples include direct reduced iron (DRI), the production of synthetic fuels and chemical products through a combination of renewable hydrogen and a carbon source, and the production of green ammonia (Gigler et al., 2020). The Hydrogen Council focuses on 35 current- and potential applications for hydrogen. These applications can be seen in figure 4.1 (HydrogenCouncil, 2020). However, this perspective inaccurately limits the hydrogen potential to possible end applications in predefined sectors. In this respect, van Wijk, 2021 argue that hydrogen is, next to the option to decarbonise hard-to-abate sector, predominantly an energy carrier that allow for the transport, distribution and storage of cheap renewable electricity over time and place. Moreover, this allows for a possible price competition to arise between imported hydrogen, locally- or regionally produced hydrogen and locally- or regionally produced variable renewable electricity. In the end, this supports a renewable hydrogen gas system which shows strong similarities with the current natural gas network, where hydrogen acts as an interconnected energy carrier (van Wijk, 2021).

4.2.1 Current potential

The current potential of hydrogen is around 120 million tonnes of hydrogen that is produced each year. This equals 14.4 exajoule (EJ) or about 4% of the global final energy- and non-energy demand (Gielen et al., 2019). Most hydrogen is produced and used on-site in the industrial sector for the production of ammonia or for usage in oil refining. Ammonia in turn is used as nitrogen fertiliser or for the production of other chemicals. The hydrogen in oil refining is added to heavier oil to crack the oil for transport fuel production or the hydrogen is used for desulfurisation and hydrogenation. Next to ammonia and oil refining, other applications include, for example the production of methanol and the usage of hydrogen in DRI (Gielen et al., 2019). Figure 4.2 shows the trend of global annual demand for hydrogen since 1980 up to 2018.

In Europe, the hydrogen potential is primarily primarily attributed to the chemical properties of hydrogen as feedstock rather than its energetic properties. Around 325 terawatt hour (TWh) of hydrogen is used as feedstock, while around 14 TWh is used as fuel for the transportation sector as can been seen in figure 4.3 (FCH, 2019).

However, the evolution of hydrogen demand varies across the countries within the European Union. In Europe, around 60% of the hydrogen demand is located in the North-western region attributable to the location of major industrial stakeholders. In North-Western Europe, which concentrates around 40% of the European chemical production, more than 6.3 Mt of hydrogen is used annually, representing roughly 5% of the global hydrogen demand IEA and CIEP, 2021. The historic and current demand for hydrogen per end application can be seen in figure 4.4. Here, pure hydrogen applications only tolerate small levels of contaminants and can be found in

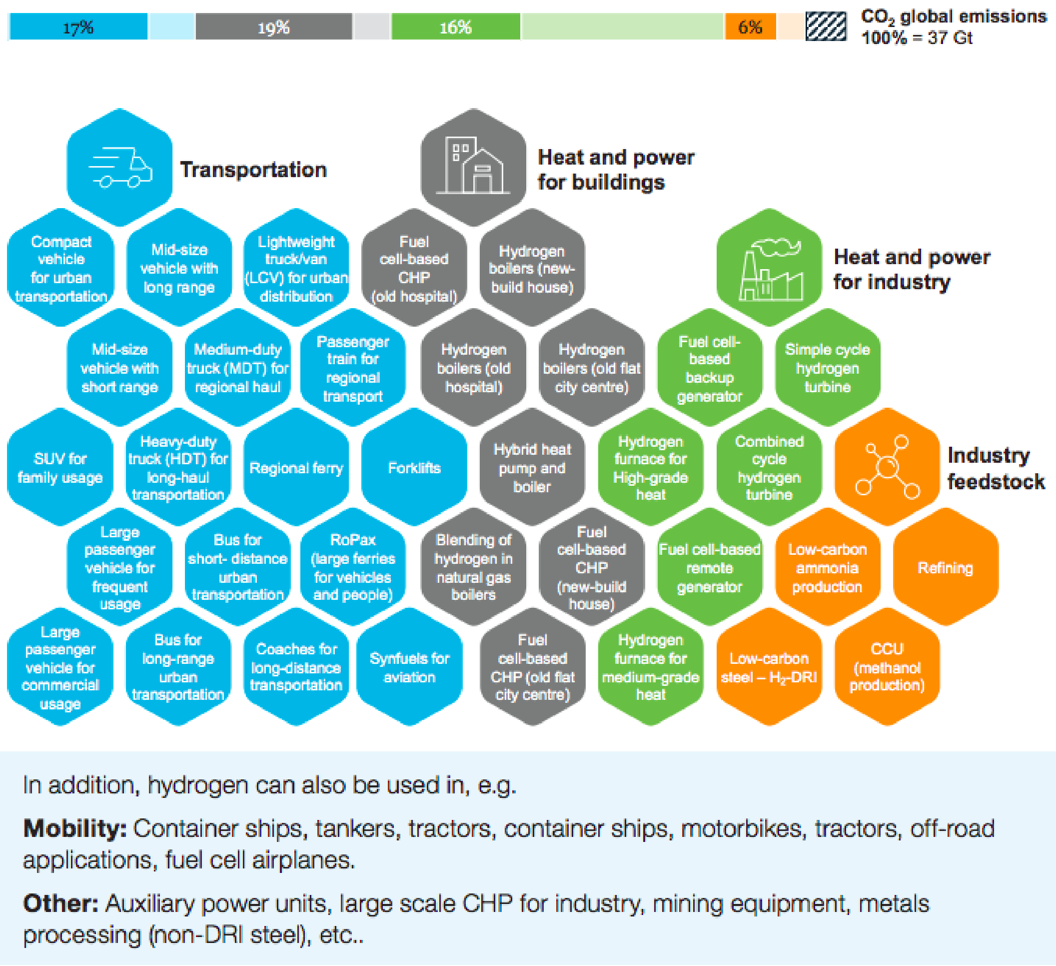


Figure 4.1: Hydrogen applications (HydrogenCouncil, 2020)

in ammonia production and oil refining, while mixed hydrogen allows for a gaseous mixture with carbon-containing gases for example in methanol production and DRI. From figure 4.4 it can be observed that the demand for pure hydrogen remained relatively stable, while the demand for mixed hydrogen fluctuated. Moreover, it can be seen that most hydrogen is demanded in the Netherlands and Germany. For Germany this is especially the case due to a large demand for mixed hydrogen for usage in the steel- and petrochemical industries (IEA and CIEP, 2021).

In the Netherlands specifically, the current hydrogen potential mainly lies in the industrial sector and amounts to around 100 petajoule (PJ) per year. Next uses in oil refining, ammonia production, methanol production and iron processing, hydrogen is used in the chemical industry, glass manufacturing, metallurgy, welding, cryogenic research and more (R. Detz et al., 2019).

Overall, it can be seen that hydrogen currently is almost exclusively used in the industrial sector with large demand from the ammonia- and oil refining industry and minor usage in the methanol industry. However, small differences exist with respect to the relative uses of hydrogen over locations and regions attributable to location specific demand centers.

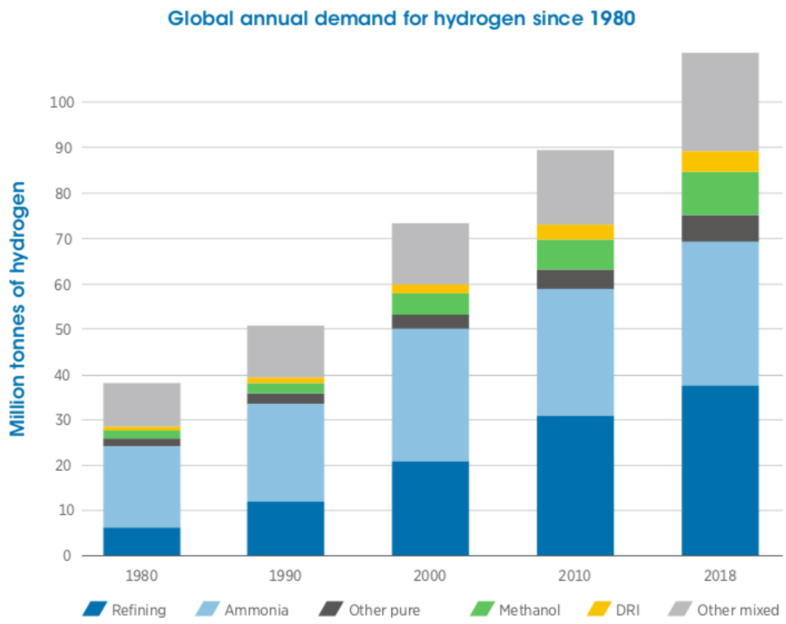


Figure 4.2: Hydrogen use trends from 1980 to 2018 (Gielen et al., 2019)

4.2.2 Future potential

The current potential of hydrogen has limited relevance for the energy transition. However, the future potential of hydrogen coincides with the importance of hydrogen for the energy transition. The future potential primarily stems from new applications and or from decarbonisation of the current applications (Gielen et al., 2019). Nonetheless, the future potential of hydrogen is presented with a wide range of outcomes, driven by different demand expectations across various sectoral applications. This is attributed to the differences in key determining factors and underlying assumptions deployed in the different studies (R. Detz et al., 2019). Therefore, R. Detz et al., 2019 state that detailed knowledge about each of the sectors is required to obtain a well-informed estimate about the future potential of hydrogen. Moreover, cross-sectoral relationships and available alternatives have to be addressed adequately.

However, hydrogen technology already exist in most segments and is ready for deployment (FCH, 2019). Based on two scenarios the expected deployment of hydrogen in the different end-use sectors over time can be seen in figure 4.5 (FCH, 2019). In figure 4.5 both the current hydrogen potential and the future potential over the different identified possible end-use cases is shown. Due to uncertainty with respect to future hydrogen potential different timescales for mass market acceptability are shown, which influence the potential over time. In the short-term, adoption in the transportation- and heating sector is expected. However, mass adoption, uses as feedstock and demand in the power sector is expected in the longer term (FCH, 2019).

With respect to the future global hydrogen potential, based on different scenarios, it is shown that the future hydrogen potential in the different scenarios will represent 7%, 24% and around 45% of the final energy need by 2050. The scenarios represent a supportive but piecemeal policy, a strong and comprehensive policy, and an all unlikely-to-electrify policy respectively. These policies aim to address a maximum

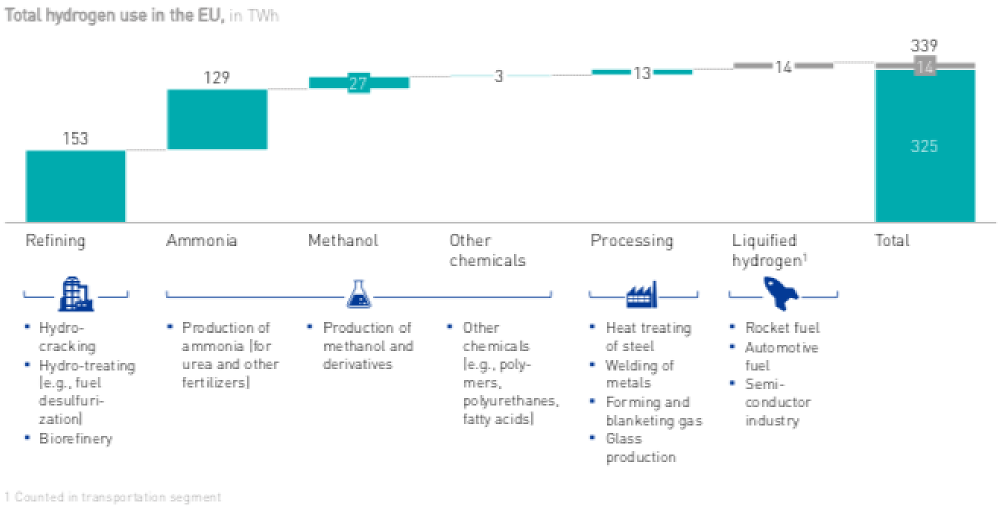


Figure 4.3: Total use of hydrogen in the EU today (FCH, 2019)

average global temperature increase of 1.5 °C. The results can be seen in figure 4.6 (Bhavnagri et al., 2020).
However, based on the IEA sustainable development scenario, the final prognosed global hydrogen demand over time and the share of hydrogen demand in the final energy demand in 2050 can be seen in figure 4.7 (Griffiths et al., 2021).

In the case the European Union, the future potential of hydrogen would fulfill 24% of the final energy need, or 2,251 TWh by 2050. This is based on the ambitious scenario, which follows the maximum 2 degrees celsius (°C) global average temperature increase from the Paris Agreement, and can be seen in figure 4.8 (FCH, 2019).

In the case of North-Western Europe in 2030 and based on both a baseline scenario, which describes how demand for hydrogen could evolve considering current policies in place, and a accelerated scenario, which focuses on enacting more ambitious energy- and climate-related policies and support mechanisms, the future hydrogen potential can be seen in figure 4.9 (IEA and CIEP, 2021). Figure 4.9 shows the projected hydrogen demand per sector and country for the respective scenarios. In the baseline scenario the demand of both pure- and mixed hydrogen could drop and a redistribution of hydrogen demand is suggested, where hydrogen could be adopted as energy carrier beyond the industry sector. The drop in hydrogen demand is mainly attributed to international competition and decreasing activity in the industry. However, this is partly offset by new demand in the transportation sector and new industrial uses. In the accelerated scenario, demand for pure hydrogen will growth by as much as 60%, to a total of almost 6,000 kilotonnes per year (kt/yr). While hydrogen uses in oil refining will decline more strongly in the accelerated scenario, due to more ambitious policies and targets, new demand in the heat-, transportation-, power- and advances fuels industry will offset the decline in demand. The same holds for the generation of hydrogen as by-product from petrochemical processes, which for mixed hydrogen is offset by demand in new industrial applications, for example in high-temperature processes (IEA and CIEP, 2021).

With respect to the future potential of hydrogen in the Netherlands, the results of a meta analysis can be seen in figure 4.10 (R. Detz et al., 2019). Here, it can be observed that a wide variety of outcomes is expected, but in basis an increase in the

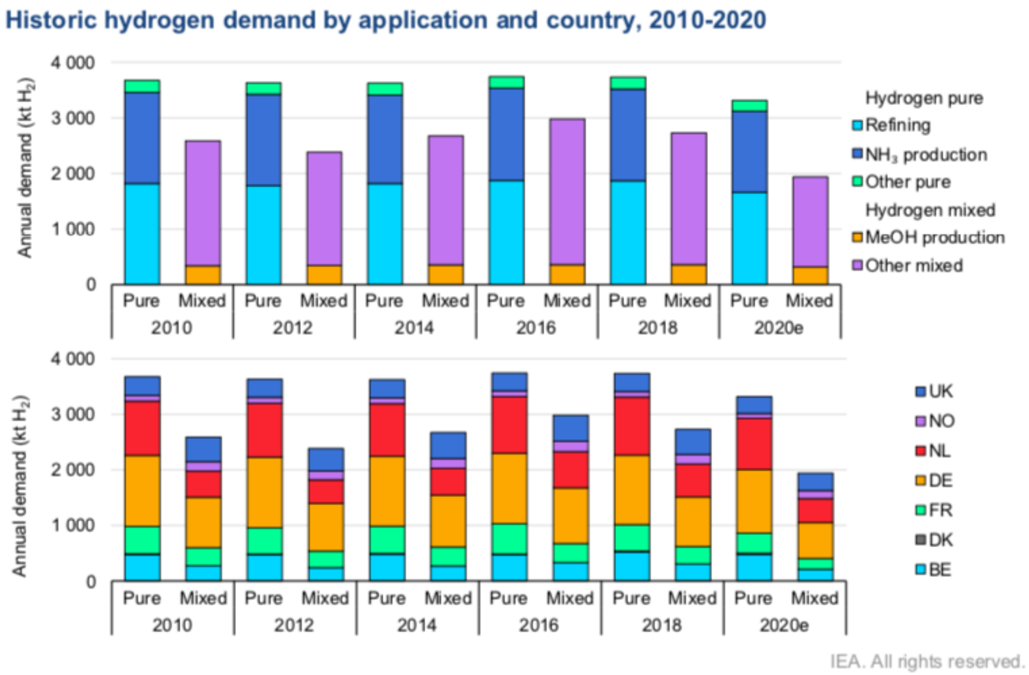


Figure 4.4: Historic hydrogen demand by application and country, 2010-2020 (IEA and CIEP, 2021)

demand of hydrogen is presumed. In the case of low hydrogen uptake levels, this is mainly related to assumed low penetration levels by 2050 and is despite the fact that the potential of hydrogen is widely recognized over the studies (R. Detz et al., 2019). With respect to the sectoral demand expectations for 2050, different numbers can be observed based on the prognosed average- and maximum hydrogen potential (R. Detz et al., 2019).

In the case of the build environment a maximum- of 200 PJ/yr and an average hydrogen potential of 34 PJ/yr is expected. In context, the current natural gas demand in the Netherlands is 414 PJ/yr. In the case of the build environment, energy usage is expected to decrease and alternative heating options are presumed. However, in locations where these options are insufficient the usage of hydrogen or alternative renewable gases are expected. In these cases the uptake of hydrogen is related to the relative costs and availability as compared to alternatives (R. Detz et al., 2019).

For the power sector, hydrogen is assumed to operate as an electricity generating source. Here, a maximum hydrogen potential of 306 PJ/yr for 30 TWh of electricity, taken into account [35-60]% efficiency losses, is presumed. The average hydrogen potential is expected to be 100 PJ/yr. In this case, the hydrogen is mainly used in dispatchable, hydrogen-fueled power plants, including fuel cells and CHP (R. Detz et al., 2019).

With respect to transportation sector, the primary use case is assumed to lie with heavy-duty vehicles due to the difficulty of electrification. This also holds for the maritime- and aviation industry. The relative uptake of hydrogen or hydrogen-based fuels in each industry relates to the respective performance and requirements as compared to available alternatives. An average- of 160 PJ/yr and a maximum hydrogen potential of 900 PJ/yr is expected. In the latter, synthetic fuels have a

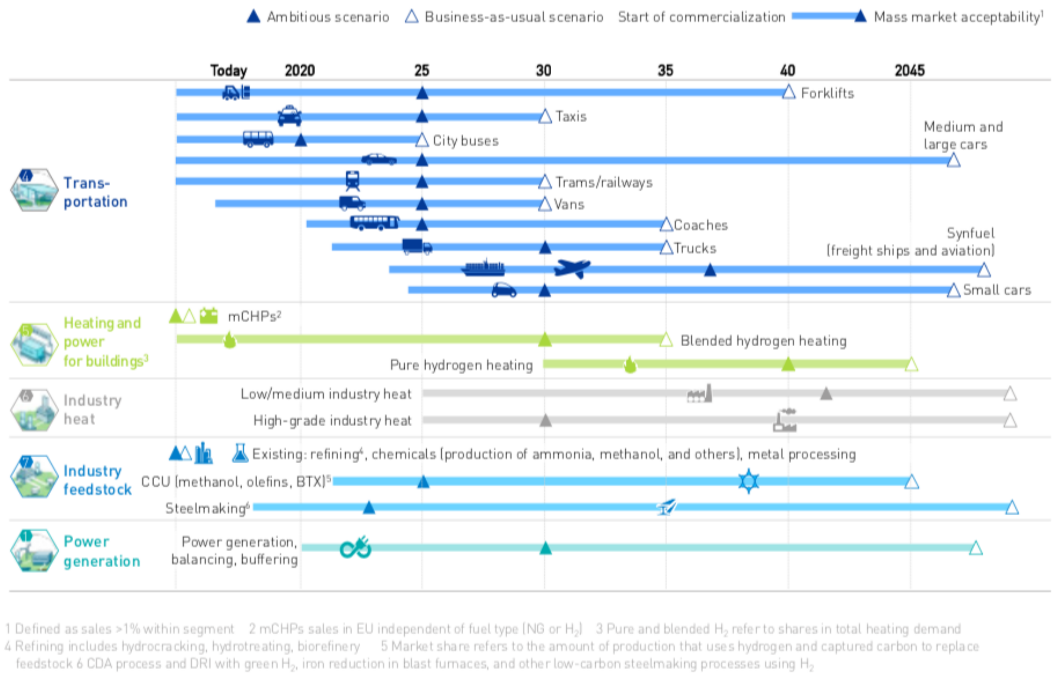


Figure 4.5: Deployment of hydrogen technology in the EU over time (FCH, 2019)

considerable impact on the expected potential of hydrogen (R. Detz et al., 2019).

In the industry, hydrogen is expected to replace natural gas as decarbonisation option for high temperature heat demand for temperatures over 250°C, and especially for high temperate demand with temperatures over 500°C. For the current heat demand this could provide a demand of approximately 100 PJ/yr. However, the highest potential is expected for hydrogen as feedstock. At the moment, around 110 PJ/yr of hydrogen via natural gas is produced. Moreover, the production of base chemical materials via hydrogen and CO_2 could unlock another hydrogen demand of 480 PJ/yr. Other use cases, like the use of hydrogen as reducing agent, might become limited due to lower dependency on fossil fuels. In the end, an average- of 254 PJ/yr and maximum hydrogen potential of 800 PJ/yr is expected (R. Detz et al., 2019).

Beyond the specific sectoral demand, the future hydrogen potential also includes the function of hydrogen within the wider system, which is used to the integration, reliability and flexibility of the future renewable energy system (R. Detz et al., 2019).

Ultimately, the results show a wide variety in the estimated future hydrogen potential, which mainly results from different scenarios and the respective assumptions in key variables. Moreover, there exist a difference in the presumed sectoral uptake of hydrogen, which is partly affected by geographical conditions as well as specific sectoral definitions. Therefore, a good understanding of each sector could help to obtain a more well-informed estimate about the future potential of hydrogen. Despite the differences, it can be observed that even in low hydrogen uptake scenarios an increase in demand is expected. This indicates a form of consensus regarding the central position assigned to hydrogen as renewable energy carrier in an increasingly sustainable future.

Thus, due to the increased realisation that renewable molecules will fulfill an important function in the future energy system and the enhanced focus on climate change

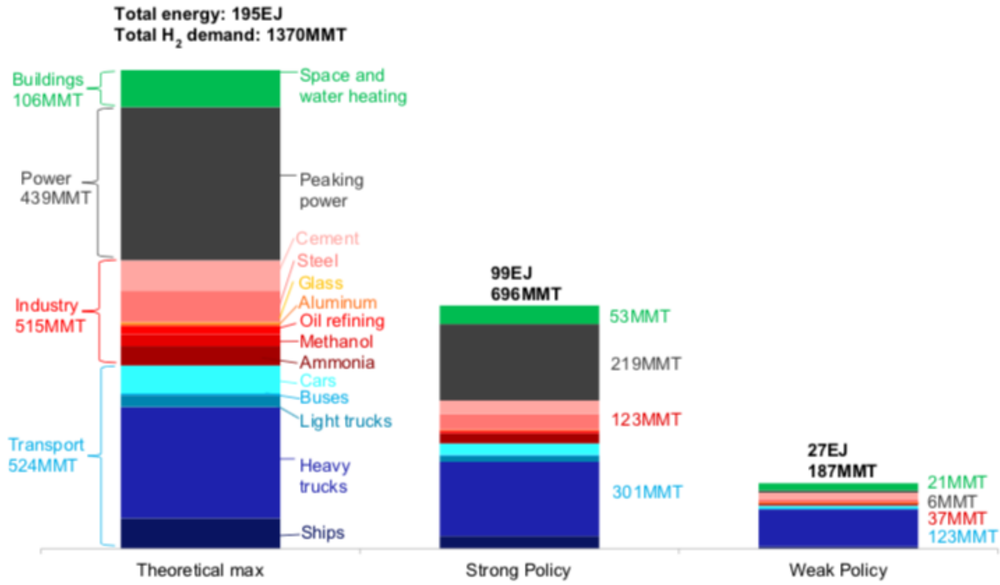


Figure 4.6: Future hydrogen potential per sector in 2050 (Bhavnagri et al., 2020)

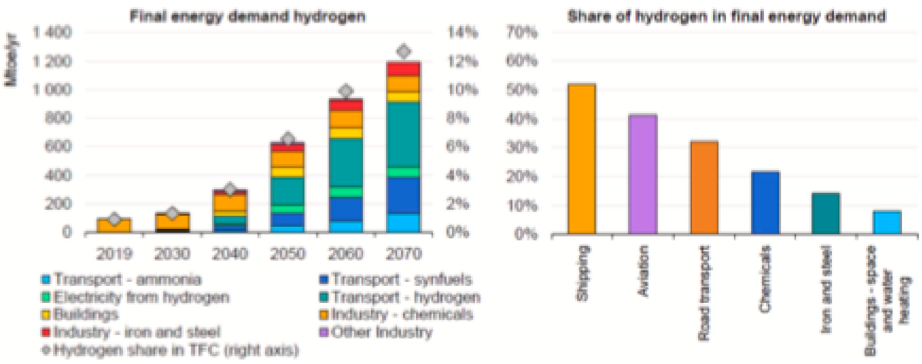


Figure 4.7: Future hydrogen potential per sector (Griffiths et al., 2021)

mitigation sparked a renewed momentum for hydrogen as important energy vector. As energetic source hydrogen is ascribed potential to decarbonise hard-to-abate sectors like the transport- and heat sector. Moreover, hydrogen is ascribed a non-energetic role in greening processes, products and materials. Additionally, renewable hydrogen can decarbonise the current hydrogen utilisation, which primarily finds demand in the industrial sector. Besides this, hydrogen is also ascribed a wider system role where hydrogen acts as flexible, storable and transportable balancing mechanism in the power sector. Therefore, hydrogen can become central in the renewable energy system as interconnected, secure, cost-effective and non-polluting medium coupled throughout the different sectors to lower fossil dependency and stimulate the adoption of renewable energy sources.

Here, the focus on the potential of hydrogen in semi-specified sectoral end applications limit the perspective on the potential wider renewable hydrogen system. In this respect, the renewable hydrogen system shows strong similarities with the current natural gas network, where hydrogen can act as a commodity over time and place. More specifically, hydrogen will act as a renewable energy carrier that allow for the transport, distribution and storage of cheap renewable electricity from spa-

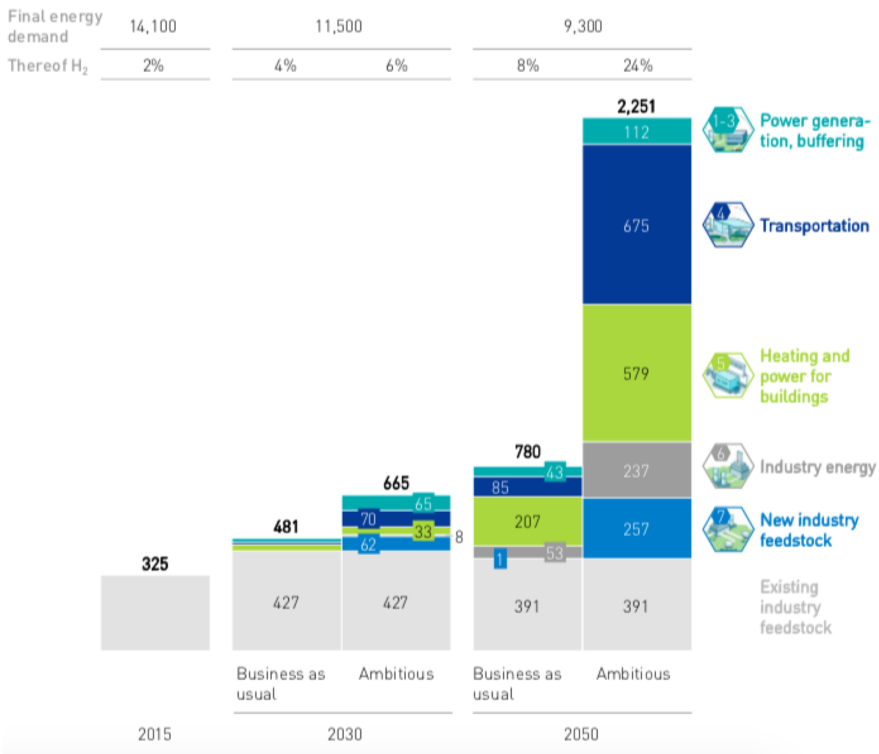


Figure 4.8: Future hydrogen potential in the EU (FCH, 2019)

tially distinct supply- and demand centers. Moreover, the commoditization of cheap renewable hydrogen allow for a price competition with local- or regional produced hydrogen and or local- or regional produced renewable electricity.

Even though the current use of hydrogen has limited direct relevance for the energy transition, the role of hydrogen within the total energetic- and non-energetic final use is significant and between [2-5]%. With the focus on decarbonisation, the greening of processes and products, and the deployment- and implementation of renewable energy production, the potential role of hydrogen will increase significantly. While predictions vary, it is estimated that hydrogen will at least make up [8-24]% of the final energy demand by 2050. In the 1.5°C scenario, the global demand for hydrogen is expected to growth at 7 percent per year (Tryggestad et al., 2021). Therefore, the potential of hydrogen is not only technical through the perspective of hydrogen as storage-, transportation-, balancing- and integration medium, or sustainable through the decarbonisation potential as non-polluting fuel or feedstock, but also economic via strong the market growth perspective over all sectors and throughout the world. In numbers, Alvera et al., 2020 estimates over USD 11 trillion of spending on hydrogen production, storage, transport and infrastructure for the development of low-carbon hydrogen to meet around 25% of the global energy demand. This will result in annual hydrogen sales amounting to USD 700 billion, excluding sales for end-use equipment (Alvera et al., 2020).

4.3 Production

While hydrogen is the simplest and most abundant element in the universe, it is mostly non-existent in free from. Therefore, hydrogen has to be produced from other

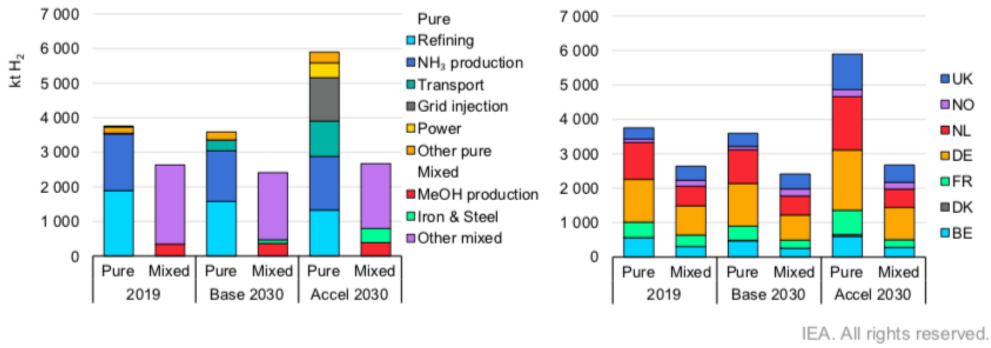


Figure 4.9: Future North-western EU hydrogen demand by sector and country in two scenarios (IEA and CIEP, 2021)

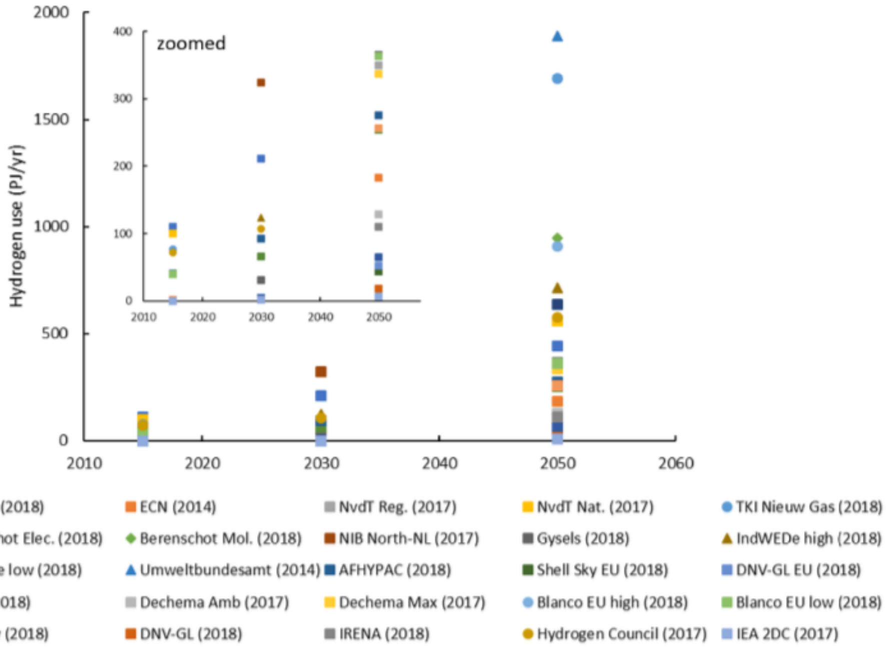


Figure 4.10: Meta analysis of current and future hydrogen potential in the Netherlands (R. Detz et al., 2019)

molecules (Alvera et al., 2020). The hydrogen value chain today can be characterised by demand for pure hydrogen and demand for mixed hydrogen. Around 60% of the hydrogen is produced in dedicated hydrogen facilities, where hydrogen is the primary product and mainly serves the demand for pure hydrogen. One-third of the hydrogen supply is produced as by-product from facilities and processes. Less than 0.7% of hydrogen today is supplied by low-carbon hydrogen production methods. A simplified overview of the hydrogen value chain can be seen in figure 4.11 (IEA, 2019). Figure 4.11 shows that around 75% of the dedicated hydrogen production stems from natural gas uses, while almost all the rest originates from coal. The latter is primarily used in China. This results in a consumption of around 205 billion m^3 (bcm) natural gas and 107 Mt of coal, representing 6% and 2% of global consumption respectively. As a result of the strong reliance on fossil fuel, the production of hydrogen is estimated to be responsible for 830 Mt CO_2-eq emissions per year. This number arises from the significant CO_2 emissions related to the different fossil sources, namely 10 tCO_2/tH_2

for natural gas, 12 tCO_2/tH_2 for oil products and 19 tCO_2/tH_2 for coal. Only a limited amount of this CO_2 is captured to be used in the production of urea fertiliser (IEA, 2019).

The hydrogen production market can generally by divided into captive-, merchant- and by-product production. Here, captive hydrogen is produced on-site to be used directly at the same location. The merchant production originates from gas producers that are most often located in industrial clusters and supply hydrogen, mainly to refineries. The by-product production, results from industrial processes, like chlorine production, and is mostly used for on-site heat generation or sometimes trades the hydrogen. An overview of the EU hydrogen production market can be seen in figure 4.12 (Wouters et al., 2020). As a result of the demand- and supply characteristics, Moraga et al., 2019 state that only around 10% of the hydrogen is sold today on open, competitive markets. In general, the demand for pure hydrogen supplied through captive production facilities is the most straightforward way to replace fossil-based hydrogen with low- or zero-carbon alternatives (IEA, 2019).

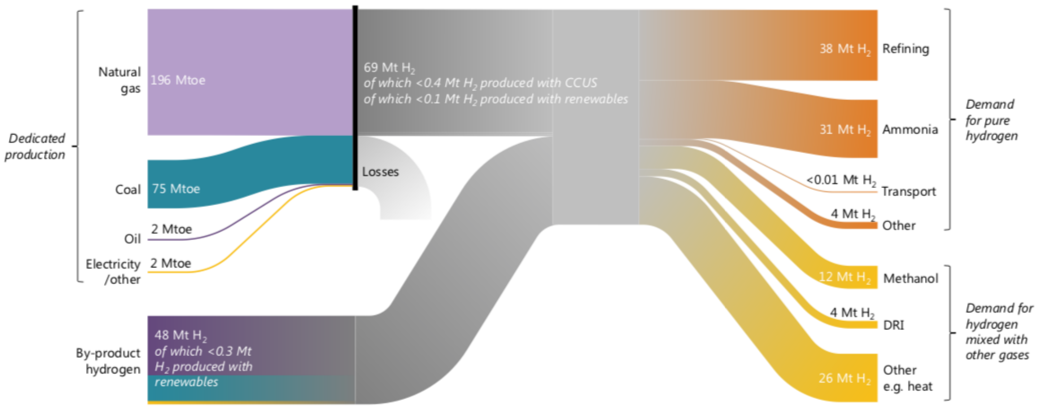


Figure 4.11: Today's hydrogen value chains (IEA, 2019)

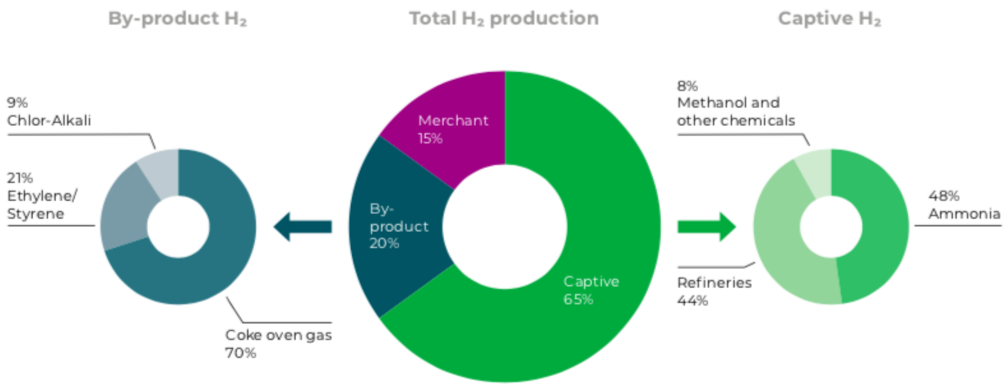


Figure 4.12: Share of captive, merchant and by-product hydrogen in the EU in 2018 (Mt) (Wouters et al., 2020)

To reduce the dependency on fossil fuels and minimise harmful emissions, hydrogen is seen as an ideal sustainable energy carrier with near-zero or zero end-use emissions (Dincer and Acar, 2015). However, as shown the current production of hydrogen results in significant CO_2-eq emissions, similar to the annual emissions of Indonesia and the United Kingdom combined (IEA, 2019). Therefore, alternative production methods that focus on abundant resources with environmentally benign methods should be established in order to remove the adverse effects on the environment, human health and the climate from fossil fuel usage in the production of hydrogen (Dincer and Acar, 2015). Next to environmental claims, increasing economical- and political claims favor the usage of environmental benign methods over the continued use of fossil fuels. For example, the limited nature and non-homogeneous distribution in combination with less accessibility of fossil fuels could hinder the supply of fossil fuels. This loss of accessibility not only directly influence the price of fossil fuels it also sparks an increase reliance on fossil fuel exporting countries, creating political uncertainties. Moreover, stringent and tightening regulations increase the price for the usage of fossil fuels through raising the price point on CO_2-eq emissions (Dincer and Acar, 2015). Thus, climate change and fossil fuel depletion are the primary reasons leading to the increased interest in the development of renewable hydrogen technology (Nikolaidis and Poullikkas, 2017). With enough investments and policy support, low-carbon hydrogen could abate up to 37% of energy-related GHG emissions (Alvera et al., 2020).

The most discussed low-carbon hydrogen technologies are water electrolysis and thermochemical fossil fuel conversion routes supplemented with CCUS technology. Water electrolysis makes use of renewable electricity to split water into it constituents hydrogen and oxygen. CCUS technology relies on the capture of the process related CO_2 emissions, which is subsequently stored or utilised to reduce the overall CO_2-eq related emissions (Klessmann et al., 2021). However, while electrolysis faces issues with the cost of hydrogen production and the availability of renewable electricity capacity, CCUS development is hindered by factors like geographical availability, public acceptance and deployment related issues (Moraga et al., 2019). Several other potential dedicated hydrogen production routes exist, which can be more broadly defined along the conversion process and relevant production method as is highlighted in figure 4.13. These production methods are in common terminology distinguished via colour coding. However, as the environmental impact of each production route vary significantly by source, region and or type of CCUS technology the colour coding does not hold any specific relevance and will not be used throughout this research (IEA, 2019). Rather bio-hydrogen is reserved for the conversion of biogas or green gas to hydrogen, while renewable hydrogen will be used to classify renewable energy based hydrogen production, e-hydrogen from hydrogen produced from renewable electricity and lower-carbon hydrogen is applied to carbon from fossil sources equipped with carbon capture technology.

4.3.1 Technology

First of all, the conversion of the primary- or secondary energy source to hydrogen should be feasible. This relates primarily to the TRL of the different technologies, assessed along the definition as brought forward by the European Commission (EC, 2017). Moreover, related technological parameters like hydrogen output or capacity and the process efficiency can further be used to assess the different technological options as potential relevant hydrogen production route. In case of the efficiency over the whole value chain, this can, in the situation of absence of constraints to renewable energy supply and adequate CO_2 valuation, largely be equalised to economics (IEA,

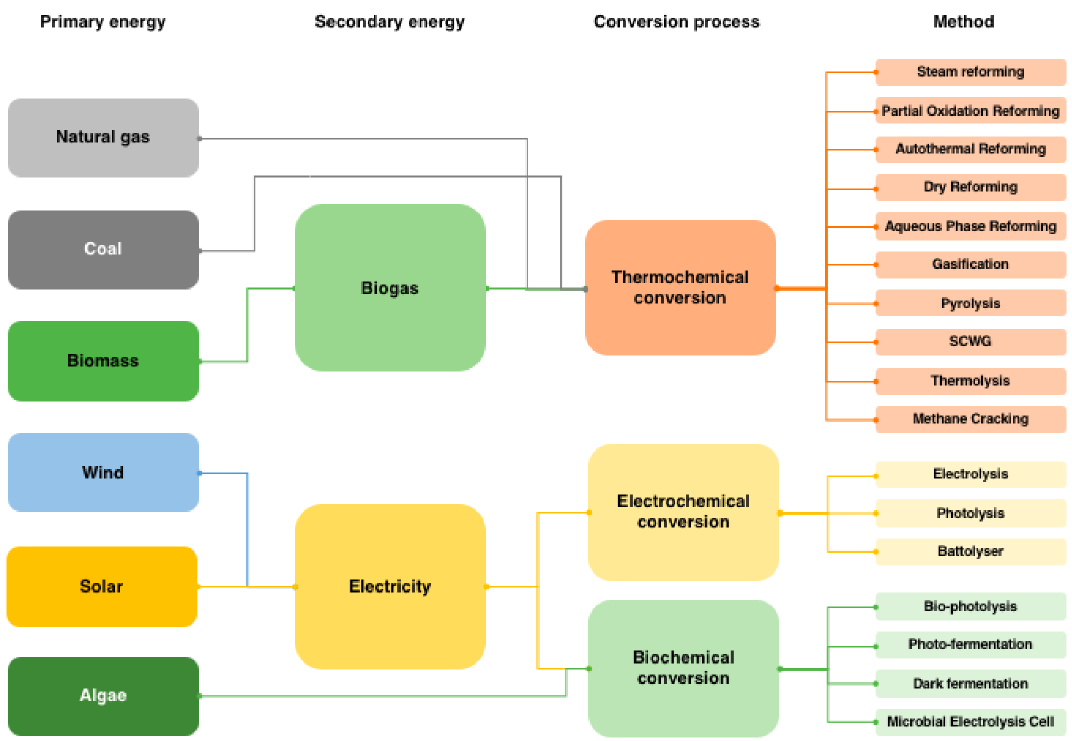


Figure 4.13: Overview hydrogen production methods

2019).

The possible dedicated hydrogen production routes will be discussed along the conversion processes methods.

Thermochemical conversion

Thermochemical conversion is the use of heat to promote the chemical transformation of hydrocarbons into chemical products and energy (BEL, 2011).

Steam reforming

Steam reforming (SR) is the catalytic conversion of hydrocarbons and steam into hydrogen and carbon oxides. The process involves reforming or syngas generation, the water-gas shift reaction (WGSR) and gas purification. Hydrocarbons could range up to heavy naphtha but mainly methane is used for the production of hydrogen in a process called steam methane reforming. In case the methane stream contains contaminants, primarily sulfur compounds, the reforming step is preceded by a desulphurisation step that serves to prevent catalyst poisoning. In the endothermic reforming step, the process occurs at a high temperature, high pressure and high steam-to-carbon ratio to create a syngas, according to the following reaction mechanism (Nikolaidis and Poullikkas, 2017):

$$CH_4 + H_2O\ (+heat) \rightarrow CO + 3H_2 \tag{4.1}$$

The reforming process yields a reformate with high H_2/CO ratio of around 3:1, which directly shows the benefit for hydrogen production. However, since the reformate still contains a significant amount of carbon monoxide the process mostly contains two endothermic WGSR where the CO reacts with steam to produce additional hydrogen. Typically, a high temperature and low temperature reactor are used in tandem, where the high temperature WGSR favors fast kinetics and the low temperature WGSR favors the thermodynamic equilibrium and thereby the amount of carbon monoxide that can be shifted (Holladay et al., 2009). The WGSR can be stated according to following reaction mechanism:

$$CO + H_2O \rightarrow CO_2 + H_2 \tag{4.2}$$

Through a purification step, mostly in the form of pressure swing adsorption (PSA) of hydrogen, a high purity hydrogen stream can be obtained. Ultimately, the SMR yields a high purity hydrogen stream and a CO_2 output stream and can be summarized as follows (Nikolaidis and Poullikkas, 2017):

$$CH_4 + 2H_2O \rightarrow CO_2 + 4H_2 \tag{4.3}$$

The SMR process is the most widely used method for large-scale hydrogen production and has a conversion efficiency of [74-85]% based on higher heating values (Nikolaidis and Poullikkas, 2017) (Holladay et al., 2009). A simplified flow diagram of the SMR process can be seen in figure 4.14 (Nikolaidis and Poullikkas, 2017).

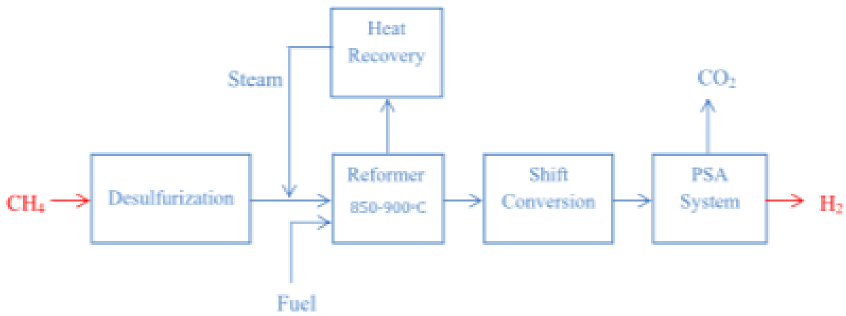


Figure 4.14: Flow diagram of the steam methane reforming process (Nikolaidis and Poullikkas, 2017)

Partial oxidation reforming

Partial oxidation reforming is the conversion of steam (H_2O), oxygen (O_2) and hydrocarbons (CHs) to hydrogen and carbon oxides. POX can be both the catalytic- and non-catalytic processing of feedstock, from methane up to heavy oils. After the removal of sulfur contaminants, pure oxygen is, primarily, used to partially oxidise the hydrocarbon feedstock in an exothermic reaction. The resulting syngas is processed in similar fashion as the SR process. The catalytic reforming reaction and the complete POX of methane process can be described according to the following reaction mechanism:

$$C_nH_m + \frac{1}{2}nO_2 \rightarrow nCO + \frac{1}{2}mH_2 \ (+heat) \tag{4.4}$$

$$CH_4 + \frac{1}{2}O_2 + H_2O \rightarrow CO_2 + 3H_2 \tag{4.5}$$

POX is mostly used to produce hydrogen from heavier feedstock like heavy oil residues and coal. As the reformate has a lower H_2/CO ratio between [1:1-2:1], the feed is mostly favored for hydrocarbon synthesis reactors such as Fischer-Tropsch (FT) synthesis reactions (Holladay et al., 2009). Moreover, the conversion of methane to hydrogen via POX shows thermal efficiencies of [60-75]% based on HHV, which is lower than can be achieved through the SMR process (Holladay et al., 2009). A simplified flow diagram of the POX process for the conversion of coal to hydrogen can be seen in figure 4.15. This process is referred to as coal gasification and is an important source of hydrogen in coal dense production regions, like China (Nikolaidis and Poullikkas, 2017).

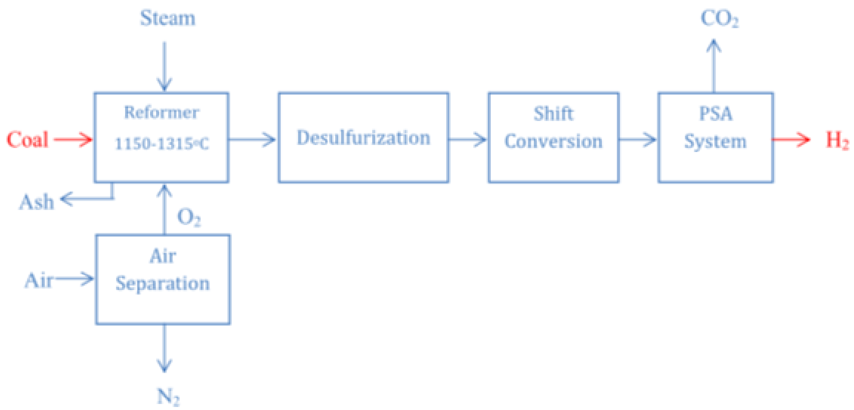


Figure 4.15: Flow diagram of partial oxidation (or coal gasification) process (Nikolaidis and Poullikkas, 2017)

Autothermal reforming

Autothermal reforming utilises the exothermic POX to provide the heat required for the endothermic SMR in order to enhance the hydrogen production and lower the associated costs. Through injection of steam and oxygen in the reformer both the reforming and oxidation reactions occur simultaneously (Nikolaidis and Poullikkas, 2017). More specifically, the ATR reactor consists of a thermal zone where the POX produces the heat required to drive the downstream SMR reaction in the catalytic zone. In this way, the ATR is a thermally neutral process and does not require an external heat source for the reactor (Holladay et al., 2009). The ATR process can be summarized as follows:

$$CH_4 + \frac{1}{2}H_2O + \frac{1}{4}O_2 \rightarrow CO + 2\frac{1}{2}H_2 \tag{4.6}$$

After the combined reforming and oxidation reaction the resulting syngas is processed in the same way as the SR process. The process operates at a lower steam-to-carbon ratio and achieves a thermal efficiency of [60-75]% based on HHV. Just like SMR and POX, the ATR is a proven technology with existing infrastructure in place. A simplified flow diagram of the ATR process can be seen in figure 4.16 (Nikolaidis and Poullikkas, 2017).

Dry reforming

Dry reforming (DR), also called CO_2 reforming, is the production of syngas through the reaction of carbon dioxide with a hydrocarbon, mostly methane. The reaction

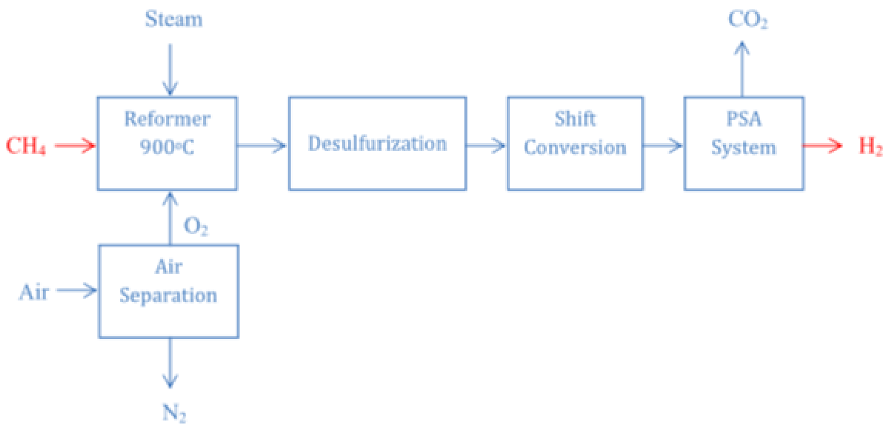


Figure 4.16: Flow diagram of the ATR process (Nikolaidis and Poullikkas, 2017)

can be stated as follows:

$$CH_4 + CO_2 \rightarrow 2CO + 2H_2 \tag{4.7}$$

The extremely high endothermic nature of the reaction coupled with rapid carbon formation, which leads to catalyst deactivation, hinder the development of the dry reforming process. Moreover, the process is characterised by long reaction times and pure CO_2 requirements which further limit the practical usefulness. A simplified process flow diagram can be seen in figure 4.17 (Kennedy et al., 2019).

Nonetheless, the dry reforming process finds renewed attention with respect to the reforming of biogas as it could utilise the CO_2 stream present. Moreover, by using the CO_2, the energy consumption associated with steam production of traditional SMR is avoided. Nonetheless, among other things, the lower H_2/CO ratio and coke formation remain areas of research before DR could be applied (Ugarte et al., 2017).

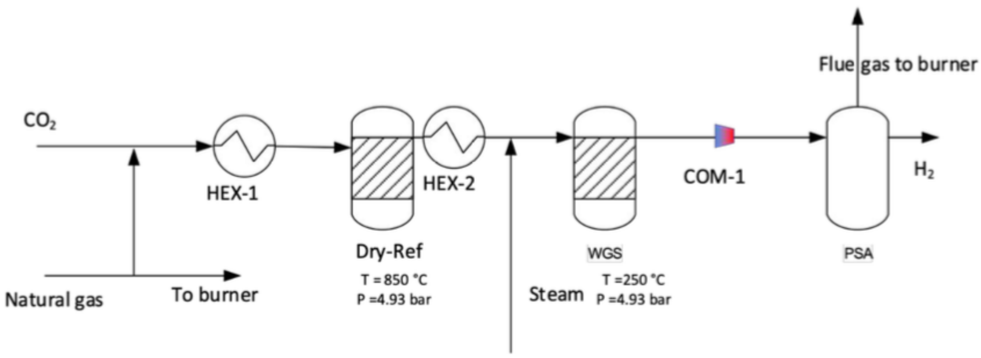


Figure 4.17: Flow diagram of the DR process (Kennedy et al., 2019)

Plasma reforming

Plasma reforming is similar to the above discussed reforming methods but differs in the sense that the energy and free radicals are provided by a plasma that is typically generated with electricity or heat. The plasma reforming technologies have primarily been developed to facilitate the POX, ATR and SR processes and as such this research does not consider plasma reforming in vacuum (Holladay et al., 2009).

Aqueous phase reforming

Aqueous phase reforming (APR) is the process to produce hydrogen from oxygenated hydrocarbons or carbohydrates. While the reactions are rather complex, in its simplest form the APR reactions can be summarized to follow the SR reaction and the WGSR. As APR occurs at low temperatures and elevated pressures the hydrogen yield is favored in the WGSR. Moreover, since the reforming and WGSR occur in a single step, the need for multiple reactors is eliminated. However, the technology is still under development and suffers from the thermodynamic favorable methanation and FT reactions (Holladay et al., 2009).

Gasification

Gasification, specifically biomass gasification is the conversion of biomass into syngas in a gasification medium such as air, oxygen and or steam at high temperature and elevated pressure. It is therefore based upon partial oxidation of the materials (Holladay et al., 2009). Moreover, gasification can be seen as an intermediate between pyrolysis and combustion and can be considered an endothermic process (Holstein et al., 2018). The conversion of biomass into syngas when it reacts with air or steam results in a mixture of gases including CO, CO_2, CH_4, H_2 and other hydrocarbons. Moreover, in the process tar and char are produced. The addition of steam and or oxygen results in a steam reforming reaction that produces the syngas with a H_2/CO ratio of around 2:1 (Holladay et al., 2009). Methane and other hydrocarbons subsequently can be reformed after which the WGSR can result in enhanced hydrogen production. Next, a purified hydrogen stream can be obtained through application of a purification step, like PSA. The process is estimated to reach up to 52% overall thermal-to-hydrogen efficiency (Nikolaidis and Poullikkas, 2017). Holladay et al., 2009 indicate that biomass gasification can typically achieve efficiencies of [35-50]% based on lower heating value (LHV), while Holstein et al., 2018 mention an efficiency of around 65% based on HHV. A simplified flow diagram of the biomass gasification process can be seen in figure 4.18. For the biomass gasification process the hydrogen yield is strongly influenced by parameters like biomass type, particle size, temperature, steam-to-biomass ratio and the type of catalyst (Nikolaidis and Poullikkas, 2017). More generally, the gasification products and relative amounts are a function of the gasification medium, temperature, pressure, heating and feedstock characteristics (DNV, 2021).

The biomass gasification can be divided along four principles that are based on the applied reactor technology. This includes fixed bed reactors, fluidised bed bubble bed reactors, circular fluidised bed reactors and entrained flow reactors. At the moment, entrained flow reactors are most widely used, however the entrained flow reactors find only limited practical application for biomass gasification. The reason is attributed to the relatively low caloric content of biomass, the high energetic biomass preparation step and additional pretreatment steps required. Nonetheless, the almost tar free syngas that results from the entrained flow reactors makes it one of the more promising technologies (Holstein et al., 2018). Momentarily several demonstrations are available in operational environment which show different product purity depending on the plant (Kennedy et al., 2019).

Pyrolysis

Pyrolysis, specifically biomass pyrolysis, yields liquid oils, solid charcoal and gaseous compounds through heating biomass at high temperature and elevated pressures

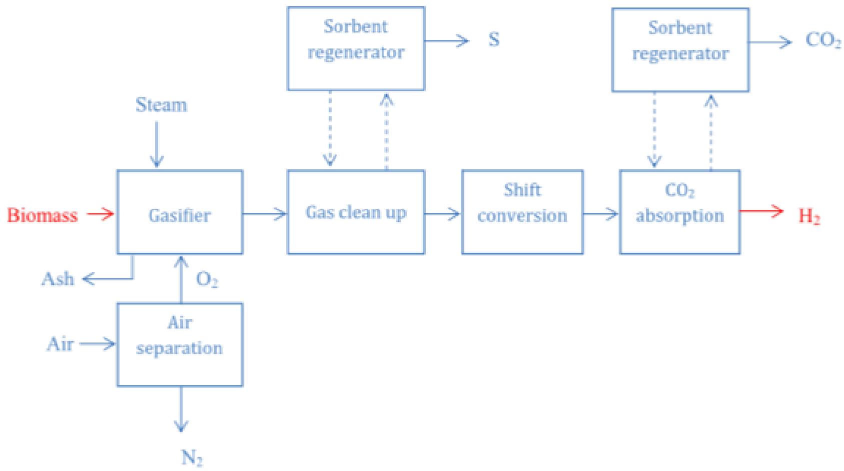


Figure 4.18: Flow diagram of the gasification process of biomass (Nikolaidis and Poullikkas, 2017)

under the absence of oxygen. Biomass pyrolysis can yield methane and other hydrocarbons, which can be reformed as is the case with biomass gasification. Like the biomass gasification process, the hydrogen yield of biomass pyrolysis is dependent of the type of feedstock, catalyst used, temperature, but also the residence time. A simplified flow diagram of the biomass pyrolysis process can be seen in figure 4.19 (Nikolaidis and Poullikkas, 2017).

In case of hydrocarbon pyrolysis, the hydrocarbon is decomposed without the presence of water and oxygen in its constituents hydrogen and carbon. Since there is no water or air present, the process does not form any carbon oxides and this eliminates the need for secondary reactors (Wouters et al., 2020). However, in case air or water is present, for example if the materials have not been dried or biomass is used, significant volumes of CO_2 and CO will be produced (Holladay et al., 2009).

Plasma arc decomposition is another high-temperature pyrolysis related process. The plasma arc decomposition makes use of plasma, which is defined as an ionised state of matter that contains electrons in an excited state and atomic species, to dissociate methane into hydrogen and carbon as a result of thermal plasma activity. The decomposition reaction can be summarised as follows:

$$CH_4 \rightarrow C + 2H_2 \tag{4.8}$$

Here, the carbon remains in the solid phase at the bottom while the hydrogen is collected in the gas phase. This has the potential to produce 100% pure hydrogen with zero CO_2 emissions (Dincer and Acar, 2015). Even though plasma arc decomposition shows relevant potential, it is not considered to have a relevant market potential in the foreseeable future Holstein et al., 2018.

Methane cracking

Methane pyrolysis or methane cracking (MC) is a special form of hydrocarbon pyrolysis and an alternative option to produce hydrogen at a large-scale. In this process, next to hydrogen, a high-purity solid carbon stream is created. As a result, this high-temperature breakdown of methane captures all the carbon present in solid carbon rather than emit it as CO_2, which reduces the need for CCS (Daliah,

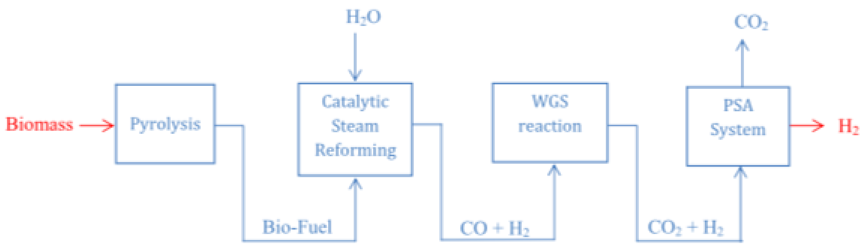


Figure 4.19: Flow diagram of the pyrolysis process of biomass (Nikolaidis and Poullikkas, 2017)

2021). The process is characterised by a theoretical energy requirement of around 66.7 kWh/kg H_2 (Dagle et al., 2017), which translates in an emission factor of 2.5 $kgCO_2/kgH_2$ (Al-Qahtani et al., 2021). However, depending on the energy input to heat the process no- or indirect CO_2 emissions take place in the process (van Wijk, 2021). While, the process requires high temperatures, methane cracking has only half the energy requirement for the same amount of hydrogen as SMR (Daliah, 2021). Moreover, the solid carbon directly carriers a commodity value as carbon black for deployment within the industry, for example as filler in rubber for the production of tires. Nonetheless, the carbon black market is limited in size and therefore, wide-scale deployment of methane cracking and the potential increase in the availability of carbon black could result in strong devaluation of the carbon black material (Daliah, 2021).

Methane cracking can be characterised as either thermal-, plasma- or catalytic pyrolysis. In case of plasma pyrolysis, a plasma torch is used to pyrolyse the methane at temperatures of [1,000-2,000] °C. This results in a methane conversion of [50-90]%, with higher conversion rates achieved at higher temperatures, without the use of catalysts. This is in line with the conversion potential observed by Muradov, 2017, which showed an conversion efficiency of 85% based on a H_2/CH_4 ratio of 1.7. However, the use of catalyst might improve the conversion rate at lower temperatures. In case of thermal pyrolysis, methane dissociation is achieved at temperatures between [1,000-1,500] °C and sees different reactor designs. Catalytic pyrolysis in contrast uses a nickel- or iron-based catalyst to breakdown methane at temperatures below 1,000 °C (Daliah, 2021).

However, the methane cracking process is currently at an early stage of development (Wouters et al., 2020). Also, Daliah, 2021 observes that methane pyrolysis is at an early-stage with a fragmented focus on the different technologies. While, plasma pyrolysis is most developed, the performance is uncertain and most research occurs at laboratory scale. Also, in case of thermal pyrolysis no commercial scale deployment is expected before 2030. With respect to catalytic pyrolysis, no clear commercialisation targets are present (Daliah, 2021). At this stage, the development, of all variants, is faced with technical challenges like the high process temperature required for high conversion rates, the hydrogen gas purity, the separation of solid carbon from the gas phase in order to avoid catalyst poisoning in case a catalyst is present, and finally reactor system blocking (Daliah, 2021).

Nonetheless, some commercial opportunities are starting to arise, for example Monolith established the first pilot plasma pyrolysis factory in the US and BASF expects its pilot plant based on thermal pyrolysis to be operational by 2025. In the case Monolith, the demonstration facility primarily focused on the production of carbon black and limited information is available about the project. In the case of BASF, both TNO and BASF do not expect to reach commercial scale before 2030 (Daliah, 2021). However, in this respect regulatory support could boost the efforts and speed up the commercialisation.

Supercritical water gasification

The above described, traditional gasification technologies are limited to dry biomass streams due to the high energy requirements needed to evaporate residual water. The high energy requirements makes traditional gasification technologies inefficient and punishable expensive for wet biomass streams (Holstein et al., 2018).

However, the gasification of biomass in a high temperature, high pressure water-rich environment show the potential to convert wet biomass into a hydrogen or methane rich output gas. At temperatures and pressures above 275°C and 220 bar respectively, the water medium operates under supercritical conditions. Due to the high pressure, water has an oxidising effect, where the oxygen creates chemical bonds with carbon in the biomass (Holstein et al., 2018). During supercritical water gasification (SCWG), the reaction process mainly includes the SMR, WGSR and the reverse methanation reaction (Cao et al., 2020). The latter can be written as:

$$CO + 3H_2 \rightarrow CH_4 + H_2O \tag{4.9}$$

$$CO + 4H_2 \rightarrow CH_4 + 2H_2O \tag{4.10}$$

For the process, depending on the process temperature and biomass feedstock, a syngas output containing [10-35]% hydrogen is achieved within a matter of seconds and at high pressure. Hereafter, the syngas can be converted through the WGSR and purification step to a high purity hydrogen stream in similar fashion as conventional gasification technologies (Holstein et al., 2018).

Although SCWG shows a high potential in field-scale applications, the selectivity- and efficiency of hydrogen still requires improvements in order to ensure cost-effective industrial applications. This potential is attributed to high hydrogen conversion levels without coke- and tar formation or secondary pollution while processing high moisture content biomass streams. Nonetheless, the difficulties arises due to the problems associated with catalyst recycling, strict operating conditions, technological developments and energetic costs. Thus, while some breakthroughs and innovations have been made, the process still requires scientific advances to make it economically competitive and environmentally benign for large-scale industrial production (Cao et al., 2020).

Thermolysis

Thermolysis is the thermochemical process of water splitting at which water is heated until decomposed in hydrogen and oxygen. In general, this requires a temperature of >2500°C in order for the Gibbs function to become zero and thus allow for the separation of the equilibrium mixture. To overcome the heat requirement, which cannot be achieved by sustainable heat sources, several cycles have been proposed in order to lower the temperature and also enhance the overall efficiency of the process. This involves a series of chemical reactions at different temperatures (Nikolaidis and Poullikkas, 2017). Overall efficiencies of close to 50% are believed to be achievable, however the processes are not yet competitive in terms of cost and efficiency as compared to other hydrogen production technologies (Holladay et al., 2009). Moreover, the process still requires significant high temperatures for which concentrated solar heat might be the only feasible solution. A simplified flow diagram of the process can be seen in figure 4.20 (Nikolaidis and Poullikkas, 2017).

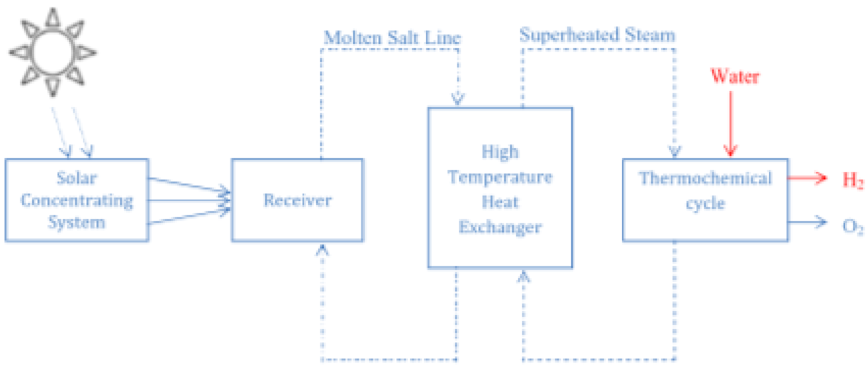


Figure 4.20: Flow diagram of the thermolysis solar-based process (Nikolaidis and Poullikkas, 2017)

Electrochemical conversion

Electrochemical conversion is the use of electrochemical methods of energy conversion utilised in fuel- and photoelectrochemical cells (Badwal et al., 2014).

Electrolysis

Electrolysis is the endothermic process of water splitting by electricity. In basis, an electrolyser consists of a cathode and an anode immersed in an electrolyte. Through the application of an electrical current the water splits into its constituents hydrogen and oxygen. The hydrogen is produced at the cathode while oxygen evolves on the anode side. The conversion can reach up to 73% efficiency, based on HHV (Nikolaidis and Poullikkas, 2017). Holladay et al., 2009 reported system efficiencies of [56-73]% or [70.1-53.4] kWh/kg H_2. In simplest form, the reaction can be summarized as follows:

$$2H_2O \rightarrow 2H_2 + O_2 \tag{4.11}$$

Several electrolysis technologies exists, where the main ones are alkaline electrolysis (AE), proton exchange membrane (PEM) and solid oxide electrolysis cell (SOEC). In case of PEM, water is split into protons (H^+) at the anode which in turn travel via the electrolyte through the membrane to the cathode side in order to form H_2. In alkaline and SOEC, water is split into H_2 at the cathode and hydroxide ions (OH^-) travel via the electrolyte through the membrane to the anode side to form O_2 (Nikolaidis and Poullikkas, 2017). The SOEC replace part of the electrical energy, required to split water, with thermal energy where the higher temperature increases the electrolyser efficiency by lowering the overpotential at both the anode and cathode (Holladay et al., 2009). The respective half reactions could be summarized as follows for PEM:

$$Anode : 2H_2O \rightarrow O_2 + 4H^+ + 4e^- \tag{4.12}$$
$$Cathode : 4H^+ + 4e^- \rightarrow 2H_2 \tag{4.13}$$

While for alkaline and SOEC this could be summarized as:

$$Anode: 4OH^- \rightarrow O_2 + 2H_2O + 4e^- \quad (4.14)$$

$$Cathode: 2H_2O + 2e^- \rightarrow 2OH^- + H_2 \quad (4.15)$$

A simplified process diagram can be seen in figure 4.21 (Nikolaidis and Poullikkas, 2017). The output gases in most cases need an additional separation step, mostly in the form of gas/liquid separation due to the crossover of water and gases. Moreover, in case of hydrogen utilisation an additional purification step might be needed to meet the quality requirements (Kennedy et al., 2019).

The AE has typical current densities of [200-400] milliampere per square centimeter (mA/cm^{-2}) and achieve [50-60]% efficiencies based on LHV, [73-86]% based on the HHV of hydrogen and [62-82]% voltage efficiency (Holstein et al., 2018). As the PEM electrolyser has low ionic resistance, high current densities of >1600 mA/cm^{-2} can be achieved while maintaining efficiencies of [55-70]% based on LHV and voltage efficiencies of [67-82]% (Dincer and Acar, 2015). The SOEC operates at high electrical efficiencies of [85-90]% or [81-86]% voltage efficiency and current densities of [300-1000] $mA/cm{-}1$. However the inclusion of the thermal source reduces the achievable efficiency up to 60% (Dincer and Acar, 2015).

AE is at the moment a mature and well-developed technology, PEM electrolysers is a mature technology at small scale. In the case of PEM, field experience at > 25 MW are not yet available. SOEC electrolysers on the other hand still requires further research in order to solve issues to the technology before it can be commercialised. These issues are mostly related to specific material requirements for the high-temperature SOEC process (Kennedy et al., 2019).

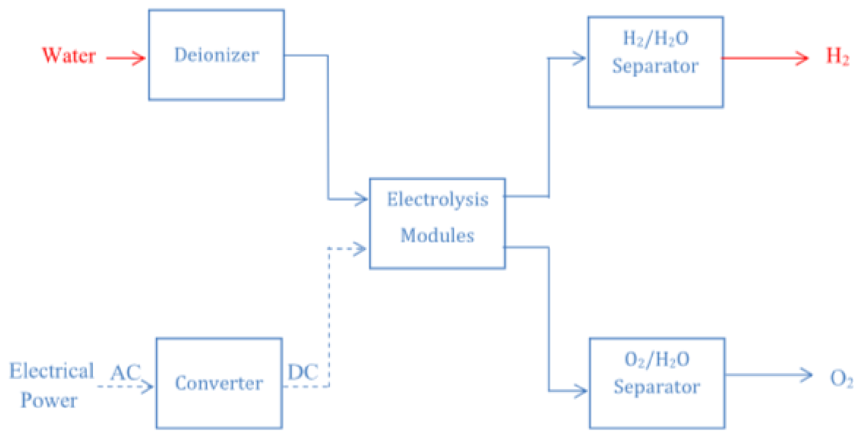


Figure 4.21: Flow diagram of the electrolysis process (Nikolaidis and Poullikkas, 2017)

<u>Photolysis</u>

Photolysis is the process in which water is decomposed in hydrogen and oxygen with the help of photo-catalyst adsorbed solar light. In this case the electricity of electrolysis is provided by a semiconducting material. In this process a photon is adsorbed at the semiconducting surface of the anode where it creates an electron-hole pair. While the electron (e^-) travels through the external circuit, the remaining hole (p^+) split water into O_2 and protons, which subsequently travel to the cathode side where it recombines with the electron to form H_2 at the cathode. This process can be summarized as follows:

$$Anode : 2p^+ + H_2O \rightarrow \frac{1}{2}O_2 + 2H^+ \tag{4.16}$$

$$Cathode : 2e^- + 2H^+ \rightarrow H_2 \tag{4.17}$$

More specifically, the following steps for the process can be identified, firstly an electron-hole pair is generated with the help of a photon of sufficiently high energy. Secondly, the electrons flow from the anode to the cathode generating an electric current. Thirdly, water is decomposed in hydrogen ions and gaseous oxygen. Fourthly, the hydrogen ions are reduced at the cathode to form gaseous hydrogen. Finally, the product gases need to be separated, processed and stored (Dincer and Acar, 2015). A simplified flow diagram of the process can be seen in figure 4.22 (Nikolaidis and Poullikkas, 2017). The separation of the electron-hole pair without any external bias potential dramatically reduces the overall efficiency as compared to the required free energy of 1.23 eV to split water, which could be as low as 0.06%. Nontheless, lab-scale efficiencies of over 15% have been achieved (Nikolaidis and Poullikkas, 2017). This also makes that the production method via photolysis is not expected to mature before the long-term (Holladay et al., 2009).

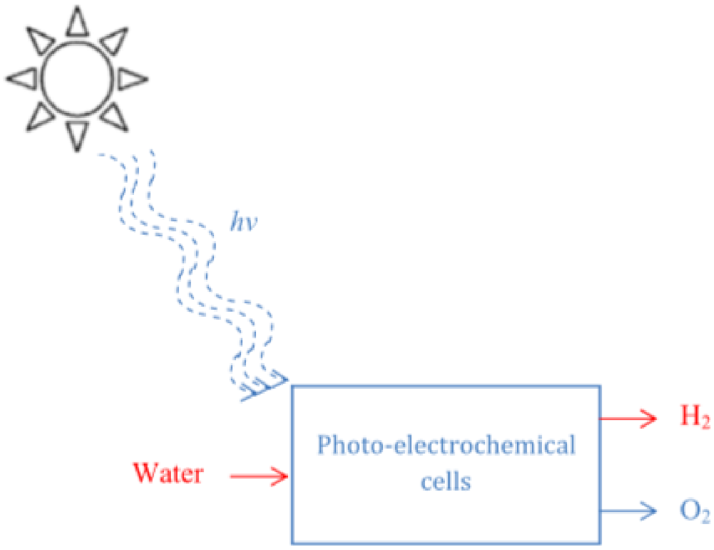


Figure 4.22: Flow diagram of the photolysis process (Nikolaidis and Poullikkas, 2017)

Battolyser

The battolyser technology is based on the Ni-Fe battery technology, where the traditional losses through the production of hydrogen and oxygen are used as a positive attribute. In this way, the battolyser integrates both a Ni-Fe battery and alkaline electrolyser. The production of hydrogen increase the battery capacity utilisation and the battery regeneration due to overcharging. Moreover, it has the potential to increase electrolyser efficiency above current standards. Thereby, the battolyser uses the overcapacity of the battery to produce hydrogen, potentially continuously (Kennedy et al., 2019). However, the battolyser technology is a new development that is for now only tested on a lab scale (Kennedy et al., 2019).

Biochemical conversion

Biochemical conversion is the conversion of biomass that makes use of the enzymes of bacteria and other microorganisms (Sam and Barik, 2019).

Bio-photolysis

Bio-photolysis is a biological process that adapts the principle of photosynthesis for the generation of hydrogen. While in green plants only CO_2 reduction takes place, algae contain hydrogen-producing enzymes that produce hydrogen under certain conditions either via direct- or indirect bio-photolysis. In direct bio-photolysis, green algae split water into hydrogen ions and oxygen via photosynthesis. The hydrogen ions are subsequently converted to hydrogen gas with the use of the hydrogenase enzyme. Nevertheless, the sensitivity to oxygen and the 'light-saturation effect' hinder the hydrogen production (Nikolaidis and Poullikkas, 2017). While the theoretical maximum efficiency for direct photosynthetic hydrogen production is about 1%, claims are made that production efficiency could be increased to [10-13]% through the engineering of organisms. However, light-hydrogen efficiencies of 0.5% have been reported and only limited continuous operations are expected (Holladay et al., 2009). Overall, the conversion can be generalised as follows:

$$2H_2O + light\,energy \rightarrow 2H_2 + O_2 \tag{4.18}$$

A simplified flow diagram of the direct bio-photolysis process can be seen in figure 4.23 (Nikolaidis and Poullikkas, 2017).

In indirect bio-photolysis, blue-green algae form hydrogen from water. The hydrogen is produced with the help of both hydrogenase and nitrogenase enzymes where first glucose is produced and subsequently converted into hydrogen and carbon dioxide both under the influence of light energy. In this case, the required electrons originate from the fermentation of glucose and the hydrogenase enzyme subsequently converts H^+ into H_2. The process is still in conceptual stage and show low H_2 production potential (Nikolaidis and Poullikkas, 2017).

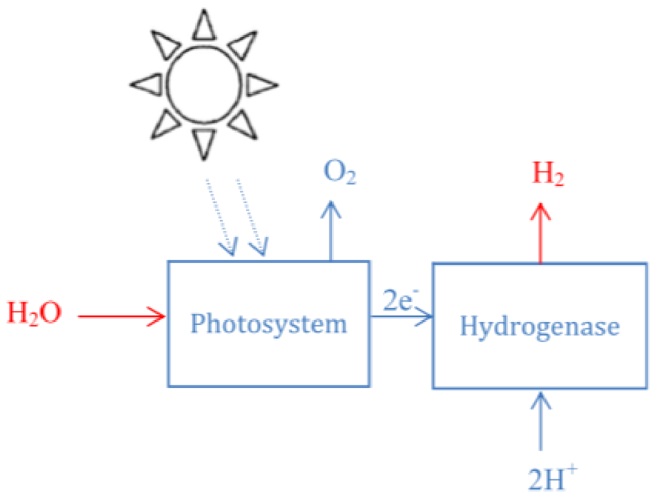


Figure 4.23: Flow diagram of the direct-photolysis process (Nikolaidis and Poullikkas, 2017)

Fermentation

Fermentation is a biochemical process that performs microbial transformations of organic feedstock into alcohols, acetone and hydrogen as well as CO_2. Fermentation could operate with- or without the presence of oxygen. The most renowned production methods for hydrogen via fermentation are dark fermentation and photo-fermentation. Dark fermentation uses anaerobic bacteria under anoxic (without oxygen) and dark conditions to convert carbohydrates rich substrates, for example acetate or butyrate, to hydrogen and carbon dioxide as extra output products. This process is relatively simple and does not rely on the availability of a light source (Nikolaidis and Poullikkas, 2017). Fermentation processes are producing [2.4-3.2] moles of hydrogen per mol glucose. However, while the reaction mechanism points to 4 mol of hydrogen per mol glucose, the uses of molecular engineering might enhance the production theoretical maximum to 12 moles hydrogen per mol glucose (Holladay et al., 2009). An example of the conversion of glucose under dark fermentation of acetic acid is:

$$C_6H_{12}O_6 + 2H_2O \rightarrow 2CH_3COOH + 4H_2 + 2CO_2 \tag{4.19}$$

Photo-fermentation converts with the use of photosynthetic bacteria and the presence of nitrogenase organic acids into hydrogen and carbon dioxide. The process requires a deficient nitrogen environment and solar energy. Using acetic acid as reactant, the conversion to hydrogen could be presented as follows:

$$CH_3COOH + 2H_2O + light\,energy \rightarrow 4H_2 + 2CO_2 \tag{4.20}$$

In general, hydrogen production is enhanced under illuminated conditions. However, low solar energy conversion efficiency, elaborate anaerobic photo-bioreactors and limited availability of organic acids hinder the conversion method (Nikolaidis and Poullikkas, 2017). Holladay et al., 2009 indicate an efficiency of around 1.9%, while the theoretical limit for this technology could lie at 68%. Nonetheless, reduced light energy demands and higher production yields could be obtained by hybrid systems comprising of both non-photosynthetic- and photosynthetic bacteria. This combination is referred to as sequential or multi-stage fermentation where carbohydrates can be digested by non-photosynthetic bacteria producing hydrogen, while the resulting organic acids could be sources for photosynthetic bacteria to enhance the hydrogen production. In simple form it combines both reaction mechanisms. A simplified flow diagram of sequential fermentation can be seen in figure 4.24. The process in practice yields up to 7.1 mol H_2/mol glucose and is mainly affected by the temperature and pH value (Nikolaidis and Poullikkas, 2017). However, as with bio-photolysis the fermentation process is currently characterised by a long-time to market and relatively low hydrogen production potential (Holstein et al., 2018).

Microbial electrolysis cells

Microbial aided electrolysis cells (MEC) use electrohydrogenesis to directly convert biodegradable material into hydrogen. In this way, MEC uses an electric current to produce hydrogen from organic material. The MEC operates in an anaerobic state where an external voltage is applied since the acetate substrate decomposition is not spontaneous under standard conditions. The MEC system had similar components as used in PEM fuel cells, but limiting surface areas and high ohmic resistance for the elextrogens hindered the conversion. Therefore, design alterations raised the efficiency of the MEC, based on the LHV of hydrogen divided by the organic material

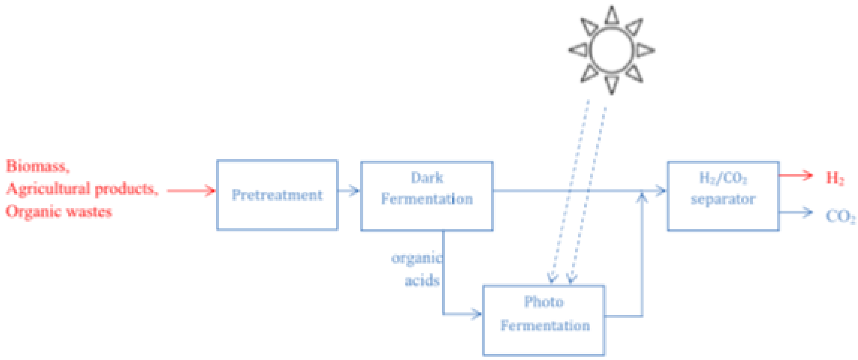


Figure 4.24: Flow diagram of the sequential fermentation process (Nikolaidis and Poullikkas, 2017)

plus the electrical energy provided, from 23% to 76% at a hydrogen production rate of 3.12 $m^3H_2/(m^3reactor/day)$ (Holladay et al., 2009). An overview of the MEC cell can be seen in figure 4.25 (Kadier et al., 2016). While MEC resembles water electrolysis, the difference lies primarily in the reaction occurring at the anode, where the biomass feedstock is oxidised instead of the production of oxygen gas from water. Moreover, in MEC systems, the production of H^+ is performed using microorganisms as catalyst. However, the inability to directly use biomass and the slow conversion rate limit the competitiveness of the process, despite the lower electrical consumption required. Moreover, the production of MEC is limited due to the negative impact of the production of less complex molecules from biomass on the economics and total energy balance of the MEC process (Lepage et al., 2021).

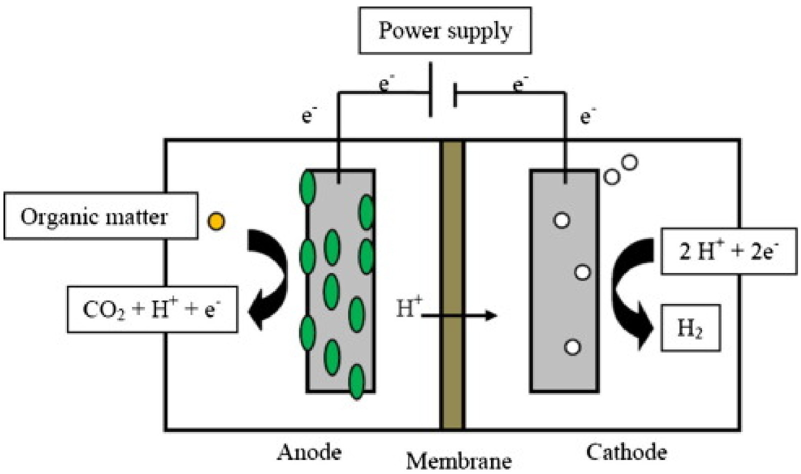


Figure 4.25: Schematic of typical MEC cell and operation (Kadier et al., 2016)

Comparison

Thus, for hydrogen to fulfill its role within a future renewable energy system the conversion process of the primary- or secondary energy source should be feasible. The different production methods can be assessed on the basis of the TRL level and additional related parameters like production output and efficiency. Here, the production levels and efficiency values stated are based on the available data in the respective papers. In table 4.1, an overview of the different production methods are given. It can be seen that except for the traditional production routes of hydrogen only limited alternative production methods are expected to commercialize in the foreseeable future. Especially, in the case of biochemical production routes the lack of production yield and the low TRL make these route unsuitable as relevant production method at the moment. Except for AE and PEM electrolysis, alternative water-splitting technologies also do not provide a relevant perspective upon technological readiness. However, gasification technologies and innovative reforming technologies might show some relevancy for the production of hydrogen, including gasification, SCWG, DR and MC. APR due to focus on oxygenated hydrocarbons, lower levels of efficiency and the low TRL shows less potential.

Technology	TRL	Production (ktH_2/yr)	Efficiency (% HHV)	Explanation
Thermochemical				
SMR	9	329	79.5	Mature technology
POX	9	746	82.7	Mature technology
ATR	9	329	79.9	Mature technology
DR	4-6	176	70	Research
APR	4-5	unk.	35-55	Under development
Gasification	6-7	0.3	65	Demonstration
Pyrolysis	5-8	unk.	35-50	Early-stage development
Methane cracking	2-8	unk.	50-90	Technology dependent
SCWG	4	unk.	unk.	Scientific advances required
Thermolysis	< 5	2.1	17.4-20.8	Long term maturity
Electrochemical				
Electrolysis	5-9	0.13-13.9	73-86	Technology dependent
Photolysis	< 5	unk.	>15	Long term maturity
Battolyser	3	0.204	85-90 (electricity)	New development
Biochemical				
Bio-photolysis	< 5	0	10	Conceptual stage
Photofermentation	4	0	0.1	Long term maturity
Dark fermentation	5	0	60-80	Long term maturity
MEC	2-4	unk.	78	Long term maturity

Table 4.1: Hydrogen production technology comparison (Kennedy et al., 2019) (Nikolaidis and Poullikkas, 2017) (Holladay et al., 2009) (Lepage et al., 2021)

4.3.2 Sustainability

The current supply of hydrogen is mostly met by the reforming of fossil fuels, primarily natural gas and coal. This results in significant annual CO_2-eq emissions, equivalent to around 2.2% of global energy-related emissions in 2018 (Alvera et al., 2020). Therefore, demand for lower- or zero-carbon hydrogen production solutions should be established to counter the negative effects of human-induced climate change. Around 60% of the current hydrogen demand is produced in dedicated hydrogen facilities. It was stated that especially the demand for pure hydrogen supplied from these facilities is the most straightforward way to replace fossil hydrogen with lower- or zero carbon alternatives (IEA, 2019). Therefore, next to technological feasibility the relevant production routes require environmentally benign methods for hydrogen production to fulfill the role of hydrogen as renewable energy carrier in the future sustainable energy system. Besides clear environmental benefits, the relevant CO_2-eq emissions also constitute an import economic value with increasing relevance under the taxonomy and through the increase in CO_2-eq prices. This might become especially true in a sustainable energy system, where the carbon content becomes a form of currency. Therefore, the different production routes are, based on the feedstock, assessed on the life-cycle CO_2-eq emissions. Moreover, related parameters like heat-, energy-, water- or land requirements could assist further assessment. However, it should be noted that in the context of a fully-renewable energy system, no indirect CO_2 emission should be present, which limit the added value of the LCA results.

Fossil hydrogen production

The dependency on fossil fuels means that hydrogen production momentarily generates significant CO_2-eq emissions. Respective CO_2-eq emission factors for the generation of hydrogen, independent of the production method, from the different fossil fuel inputs are (IEA, 2019):

- Natural gas: 10 tCO_2/tH_2;
- Oil products: 12 tCO_2/tH_2;
- Coal: 19 tCO_2/tH_2.

Depending on the production technology and feedstock, Wouters et al., 2020 state the emissions of fossil hydrogen to range from [104-237] $gCO_2/MJ\,H_2$ or [12.5-28.4] tCO_2/tH_2 over the life cycle. Holladay et al., 2009 mention that despite operating at a lower temperature, SMR is characterised by higher emissions as compared to ATR and POX. In case of SMR, Nikolaidis and Poullikkas, 2017 mention an energy requirement of 63.3 kJ/mol H_2 which is primarily provided by natural gas. This would amount to [30-35]% of the total natural required and results in a total of [0.3-0.4] m^3CO_2/m^3H_2 (Nikolaidis and Poullikkas, 2017).

CCUS hydrogen production

CCUS technology can be applied to most thermochemical production technologies. SMR plants can be refrofitted, ranging from small- to large-scale, with CO_2 capture technology (Wouters et al., 2020). The integration of CCUS technology could reduce the carbon emission up to 90% if applied to both the process- and energy emission stream (IEA, 2019). For the SMR process, several options exist to capture and store the relevant CO_2 steams. In case the CO_2 is separated from the high-pressure syngas stream, emissions of up to 60% can be saved, while CO_2 capture at the flue gas can boost the overall emission reduction to 90% or more. The integration of CCUS technology can be seen in figure 4.26.

The ATR process allows for even higher rates of CO_2 recovery as the required heat for the process is produced in the reformer itself thereby limiting the need for CO_2 removal to only inside the reactor. Moreover, the higher CO_2 concentration eases the CO_2 capture (IEA, 2019). Other alternative ways to lower the CO_2-eq impact are, directly by increasing the efficiency of the process, or indirectly by using hydrogen instead of natural gas as fuel for the furnace and or by using oxygen from electrolysis in case of ATR plants (Wouters et al., 2020).

Despite the capture technology, the upstream emissions from the natural gas production are still present which increases the life cycle related GHG emissions for this production route. Moreover, since not all emissions are captured momentarily this would require offsetting of the carbon emissions in order for the process to be considered carbon-neutral (Alvera et al., 2020). Additionally, potential availability issues related to CO_2 storage options might limit the sustainability of the CCUS technology. This potential shortage is both a result of public acceptance and possibly of storage capacity and infrastructure, where CO_2 storage need is not only limited to hydrogen production facilities. Moreover, issues arise with respect to the potential lock-in effect with respect to the fossil-fuel based gas system. As a result, natural gas sourced hydrogen could be reported not to be an effective solution for 2050 (Moraga et al., 2019).

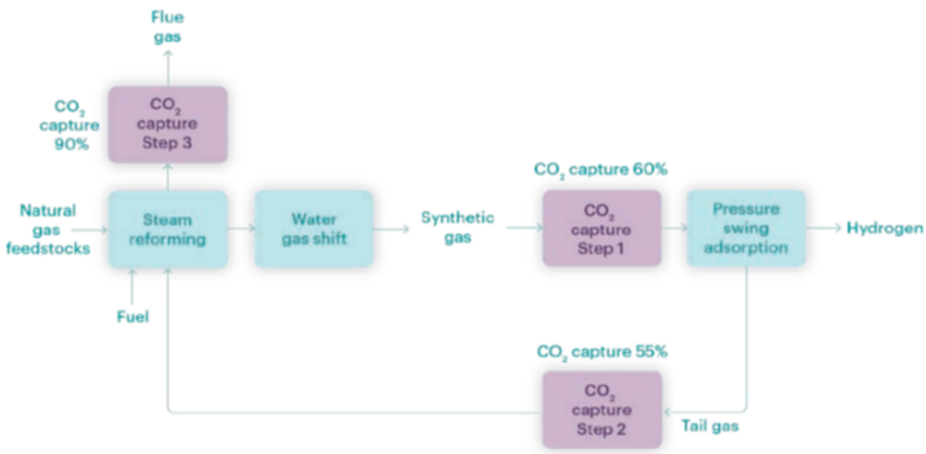


Figure 4.26: Production process of hydrogen from methane with CCUS (IEA, 2019)

Biogenic hydrogen production

Biomass-based reforming technologies can directly lower the life-cycle related emissions by substitution of natural gas for bio-based feedstock in the production of hydrogen. This results from the fact that the short-cycled biogenic carbon dioxide, in comparison to long-cycled fossil carbon dioxide, in basis is not assigned a CO_2-eq emission factor. This results from the fact that the feedstocks used to create hydrogen absorb carbon dioxide from the air as they grow. An additional benefit from biogenic sources is the perspective on the role of biogenic sources with respect to contribution to the circular carbon economy by closing the carbon loop. Moreover, in case the carbon dioxide emitted in the process is captured and subsequently stored or used it has the potential to remove the carbon from the system resulting in negative CO_2 emissions (Alvera et al., 2020).

Thus, biomass is in general considered to be carbon neutral, as the emissions from processing and combustion are offset during plant growth. As a result, a zero global warming potential (GWP) score is assigned to biogenic CO_2 emissions. Nonetheless, it might be more accurate to account for the impact on climate change of the entire system, including geologically stored biogenic CO_2. Thus, in the case of green gas, the utilisation of digestate might negatively affect the climate impact, for example in case the digestate is incinerated or if field application does not lead to a long-term carbon sink. Nonetheless, Antonini et al., 2020 state that in case substantial carbon in the digestate remains in the soil, biomass-based hydrogen production reaches net-negative life-cycle emissions. This is further enhanced by the use of CCUS. The environmental benefit as compared to fossil-based hydrogen production is further strengthened by the observation that both green gas and methane result in similar process efficiencies and as result electricity balance (Antonini et al., 2020).

Electrolysis hydrogen production

Electrolysis requires electricity and water as input products for the production of hydrogen. Per kilogram (kg) of hydrogen, around 9 litres of water is needed and 8 kg of oxygen is produced as by-product. The need for freshwater might become an issue in water-stressed areas. However, the use of reverse osmosis for desalination which requires around [3-4] kilowatt hours per m^3 of water could solve this at minimal additional cost in relation to the hydrogen production cost via water electrolysis (IEA, 2019). Typical system energy uses, including periphals, are in the order of [3.7-6.6] kWh/Nm^3H_2, partly depending on the specific electrolysis technology, out of which [3.2-5.9] kWh/Nm^3H_2 comes from the electrolyser stack. Holladay et al., 2009 mention system efficiencies of [56-73]% or requiring [53.4-70.1] kWh/kg H_2. However, more recently AE technology sees efficiencies based on HHV of [73-86]%, lowering the required electricity input (Holstein et al., 2018).

This is especially important as the production of hydrogen via electrolysis is strongly dependent on the electricity input. In case of grid electricity generated hydrogen, the emission factor is higher than fossil fuel-based hydrogen production due to the efficiency losses for the generation of electricity via gas or coal. On average, the emission factor is around 26 $kgCO_2/kgH_2$. Nonetheless, the production e-hydrogen via dedicated renewable electricity is assumed to emit no carbon due to the renewable nature of the electricity source (IEA, 2019).

Comparison

Thus, for hydrogen to operate as a renewable energy vector in a future energy system, the different production routes are, based on their input material, assessed on the life-cycle CO_2-eq emissions. The CO_2-eq impact of different hydrogen technologies vary significantly. The production of fossil hydrogen via coal results in considerable higher emissions compared to natural gas, while the production of hydrogen via electrolysis is strongly dependent on the electricity input. Moreover, system boundaries and technologies affect the CO_2 intensity of CCUS. For biomass, additional energy requirements could negatively impact the CO_2 emissions. Figure 4.27 indicate the general CO_2 intensity of hydrogen production for different feedstocks and production methods (IEA, 2019) (IEA, 2019).

Additionally, an overview of the different production methods can be seen in table 4.2. In table 4.2 the LCA results of the discussed studies and the results from the original- and harmonised GWP are listed (Valente et al., 2017). Even though, the harmonised GWP results aim to counter the bias which is related to most LCA results, following differences in LCA scores due to differences in assumptions and system boundaries, these might still require careful interpretation. However, based on the results it can generally be seen that current fossil production methods significantly increase the carbon intensity of hydrogen production. Moreover, it can be observed that all other production methods stimulate strong reductions in carbon emissions. Due to the renewable nature of the electricity feedstock, electrolysis shows potential as zero-carbon hydrogen production method. CCUS technology for biogenic hydrogen production offers the potential for biomass to operate as negative CO_2 source or carbon sink. On the other hand, while CCUS technology shows great potential in lowering the CO_2 emissions of the fossil hydrogen production process, issues with capacity, public acceptance, continued reliance on fossil-fuel and downstream CO_2 emissions limit the sustainable nature of this process.

Nonetheless, in light of a future fully-renewable energy system, the continued reliance on LCA scores might be inadequate. This results from the fact that no indirect CO_2 emissions should be present.

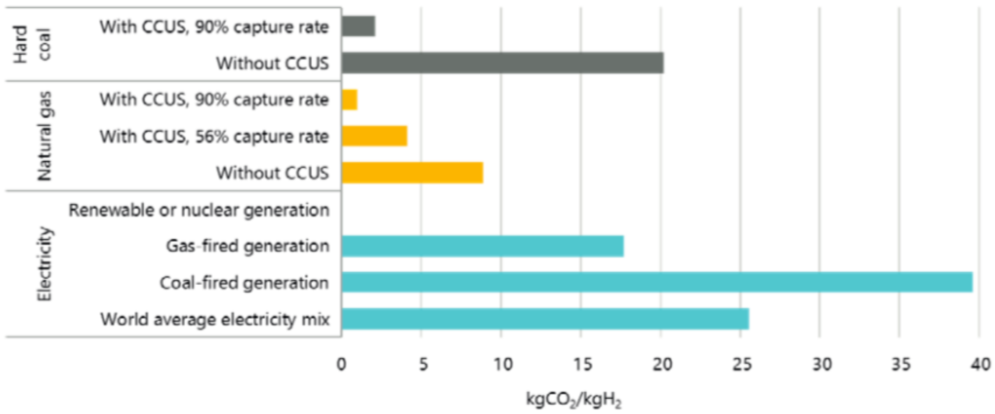


Figure 4.27: CO_2 intensity of hydrogen production (IEA, 2019)

Technology	**LCA** ($kgCO_2/kgH_2$)	**Original GWP** ($kgCO_2/kgH_2$)	**Harmonised GWP** ($kgCO_2/kgH_2$)
Fossil			
SMR	8.9-15	12.95	12.95
POX	18.96	unk.	unk.
ATR	11.0	unk.	unk.
DR	5.46	unk.	unk.
MC	2.5	unk.	unk.
CCUS			
Low-end	4.6-5.8	unk.	unk.
High-end	2.5-3.5	unk.	unk.
Biogenic	-15	-14.63	-24.14
Biogenic			
Reforming	4	4.8-5.84	5.79-7.34
Gasification	5	0.34-8.64	-0.13-8
SCWG	unk.	unk.	unk.
Electrolysis			
Fossil	26	unk.	unk.
AE	0	0.03-2.18	0.16-2.18
PEM	0	0.6-3.0	0.74-3.22
SOEC	0	unk.	unk.

Table 4.2: Hydrogen production sustainability comparison (Kennedy et al., 2019) (Dincer and Acar, 2015) (IEA, 2019) (Wouters et al., 2020) (Holladay et al., 2009) (Antonini et al., 2020) (Valente et al., 2017)

4.3.3 Economics

The strong and continued reliance on fossil fuels for dedicated hydrogen production results from the higher cost associated with producing low-carbon hydrogen at the moment. Besides governmental interference, economies of scale and continued research and development opens areas for cost reductions and performance improvement for renewable hydrogen, which is relevant to become cost competitive with traditional fossil hydrogen production methods. However, the relative costs of producing hydrogen has some ambiguity due to the difference across for example sources, processes, end uses and regions which limits the potential for an adequate overall relative comparison. In general however, the production costs are highly dependent on the specific feedstock price and capacity utilisation and or availability (IEA, 2019).

Therefore, besides technological feasibility and environmental performance the different hydrogen production routes require good economics in order to support widespread adoption. Moreover, this ensures hydrogen uptake as cost-effective energy carrier and lowers the financial burden of the renewable energy transition. As a result, the different hydrogen production methods will be, based on their input material and production process, assessed on the economic performance based on the levelised cost of hydrogen. The LCOH incorporates the dominant production parameters like fuel costs, efficiency, investment costs, other operational costs and capacity over its lifetime in order to determine the final production price. Therefore, it allows for equal comparison of the different production methods (Holstein et al., 2018). Other, LCOH related parameters like annualised capital expenditures (CAPEX) or operational expenditures (OPEX) per product unit might support further assessment.

Fossil hydrogen production

The production cost of hydrogen via natural gas is influenced by technical- and economic factors, for which the gas price and capital expenditures are most important. In general, fuel cost is the largest cost component of the hydrogen production cost accounting for [45-75]% of the total cost (IEA, 2019). Alvera et al., 2020 estimate a production cost price of around [0.7-2.3] USD/kg H_2 depending on the fuel price for SMR-based production. Moraga et al., 2019 state a break-even price for hydrogen of 40 EUR/MWh. As capital costs are dominated by hydrogen-related units like the reformer and WGSR reactor, plant capacity is an important factor for the production cost price. Wouters et al., 2020 estimate that the production costs can decrease by [20-30]% for an increase in production capacity from 100 to 500 tonnes H_2/day, or from 60 MW to 300 MW. According to Nikolaidis and Poullikkas, 2017, the costs categories as percentage of the total H_2 production costs for SMR are around 60% of feedstock, 30% of CAPEX and 10 of % operations and maintenance (O&M) costs. At a design capacity of around 400 tH_2/day, at 90% capacity, and at a natural gas price of 10 USD/MBtu the cost of SMR-based hydrogen is around [2.08-2.27] USD/kg H_2 (Nikolaidis and Poullikkas, 2017).

In coal-dominant regions, the use of coal for the production of hydrogen is currently most economic at a price of around 1 USD/kgH_2 in comparison to around 1.80 USD/kgH_2 for SMR. Here, CAPEX account for around 50% of the cost of hydrogen production, while fuel accounts for an additional [15-20]% (IEA, 2019). Nikolaidis and Poullikkas, 2017 showed in case of coal gasification via POX that distribution of costs are approximately 26% of feedstock, 55% of CAPEX and 19% of O&M. At an output of around 300 tH_2/day the hydrogen cost were determined to be 1.34 USD/kg H_2 (Nikolaidis and Poullikkas, 2017).

For ATR, the investment costs are around [15-25]% and 50% lower with respect to SMR and POX technology respectively (Nikolaidis and Poullikkas, 2017).

CCUS hydrogen production

The addition of CCUS technology adds on average around 50% for CAPEX, 10% for fuel and 100% for OPEX, with exact amounts depending on the design of the system (IEA, 2019). This stems for example from the equipment, infrastructure, and storage requirements (Wouters et al., 2020). The separation- and capture of CO_2 at the high-pressure stream, which results in up to 60% CO_2 savings, costs typically around 53 USD/tCO_2 for merchant plants. Capturing CO_2 at the more diluted furnace flue gas, which could boost overall emissions reduction up to 90%, costs typically around 80 USD/tCO_2 or [90-115] USD/tCO_2 for merchant or integrated plants respectively (IEA, 2019). Overall, this adds around [0.50-1.00] USD/kgH_2 to the hydrogen production costs. A cost comparison for the production of hydrogen over different regions and with- and without CCUS technology can be seen in figure 4.28 (IEA, 2019). Depending on the technology and infrastructural requirements, Wouters et al., 2020 estimate the current cost of CCUS-based hydrogen production at [37-41] EUR/MWh, which is based on a natural gas price assumption of 15 EUR/MWh. Alvera et al., 2020 state that production cost of SMR with CCUS is around [1.3-2.9] USD/kg H_2 with variation mostly dictated by the fuel price.

For coal gasification with CCUS, the production cost are estimated between [2.5-3.3] USD/kg H_2 (Alvera et al., 2020). Holladay et al., 2009 showed an increase in production cost from 1.34 USD/kg H_2 to 1.63 USD/kg H_2 in case of CCUS integrated technology for coal gasification.

For ATR this is expected to be around 1.48 USD/kg H_2 (Nikolaidis and Poullikkas, 2017).

However, while the price of CCUS hydrogen production is currently lower than renewable hydrogen production methods, the production cost of this route has less potential to fall in the future. This is explained by the fact that the CAPEX of the CCUS unit has less of an impact on the production cost than the efficiency losses and additional operational expenditures associated with CCUS technology. (Alvera et al., 2020).

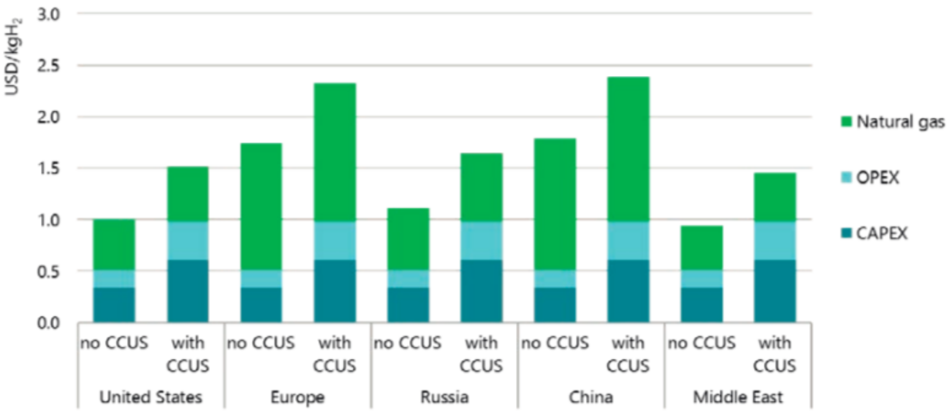


Figure 4.28: Hydrogen production costs using methane in different regions in 2018 (IEA, 2019)

Biogenic hydrogen production

The production of hydrogen from biogas and or green gas is characterised by strong economies of scale. While for large-scale production investment costs of around 29,000 EUR/(kg H_2/hour) are observed, this increases 25 fold to 725,000 EUR/(kg

H_2/hour) for small-scale production (Holstein et al., 2018). Next to biogas, compressed air, electricity and water inputs are required for the process which dominate the feedstock cost and OPEX (Holstein et al., 2018). Braga et al., 2012 evaluated the attractiveness of a biogas steam reforming process based on the investment, operations and maintenance costs and the expected annual revenues. Here it was shown that a higher operational period, decreases the hydrogen production costs. Moreover, based on the hydrogen production cost curve, it was observed that the payback period is around 8 years, at a hydrogen production costs of around 0.27 USD/kWh H_2. Based on a sensitivity analysis with respect to the principle variables for the hydrogen production costs, a hydrogen production cost of [0.2-0.43] USD/kWh H_2, or [5.8-12.3] EUR/kg H_2 was shown with the lower end amounting to a higher operational period.

In the case of biomass gasification, Holstein et al., 2018 state that the immaturity of the biomass gasification technology in combination with a lack of commercial industrial application limit an adequate determination of the cost price for hydrogen production. Therefore, Holstein et al., 2018 rely on models and where possible practical data to come to an estimation of the production costs. In general the production cost are estimated to consist of around [20-40]% of biomass fuel costs. Moreover, the current capital costs are estimated in the range of [1700-3000] EUR/$kW_{th,input}$ with possible reduction of [10-15]% in the next [10-15] years, which are partly attributed to learning effects. An estimation of the operation and maintenance costs, show costs of around 285 EUR/kW_{output}. Nikolaidis and Poullikkas, 2017 estimated the production cost for a typical biomass gasification route with an expected output of around 140 tH_2/day and at a biomass price of [46-80] USD/dry-ton to be [1.77-2.05] USD/kg H_2. However, due to alternative use cases of woody biomass, the demand for climate-neutral carbon, and the direct usage in the form of syngas might increase the hydrogen production cost and or hinder the conversion to hydrogen. For example, it is estimated the the LCOH increase with around 0.22 EUR/kg H_2 for an increase of 1 EUR/GJ in biomass input price (Holstein et al., 2018).

For biomass pyrolysis, Nikolaidis and Poullikkas, 2017 indicates a hydrogen cost of around [8.86-15.52] USD/GJ H_2 or [1.25-2.20] USD/kg H_2 depending on the facility size and biomass type.

In the case of SCWG, Lepage et al., 2021 indicate for a H_2 yield of [1-40] $gH_2/kg\,feedstock$ a cost of [1.51-3.89] USD/kg.

Electrolysis hydrogen production

For electrolysis the main factor influencing the production cost is the price of the electricity input. Other factors that influence the product cost are the CAPEX, conversion efficiency and annual operating hours. However, the latter two indirectly influence the electricity cost and CAPEX cost as percentage of the production cost respectively (IEA, 2019). Moreover, the scale of the project has an influence, where small-scale projects show higher costs (Wouters et al., 2020).

The CAPEX differ per electrolysis technology and are in the range of [500-1800] USD/kWe for commercially available electrolysers (IEA, 2019). However, the CAPEX costs might be as low as 200 USD/KWe in the case of AE technology in China, with a further expected decrease to 135 USD/kWe by 2030 and 98 USD/kWe by 2050 (Bhavnagri et al., 2020). Here, the electrolyser stack represents around [50-60]% of the CAPEX costs where the use of a multi-stack system is expected to reduce the electrolyser CAPEX with [10-40]% (IEA, 2019). In this regard, it should also be noted that the larger-scale installations are simply a function of increasing the number of electrolysis cells, while other apparatus could in those instances have economies of scale potential through increases in capacity (Holstein et al., 2018).

The annual operating hours affect the CAPEX cost in the levelised cost of hydrogen. An increase in annual operating hours lower the CAPEX cost and also decrease the relative impact of the CAPEX, as compared to the electricity costs. This could result in a trade-off between low electricity costs and low operating hours or increased electricity prices at higher operating hours. This is especially the case for curtailed and grid-connected hydrogen production (IEA, 2019). Therefore, as long as the CAPEX make up a significant part of the LCOH, the capacity factor remains key and as such does the optimisation of renewable electricity sources (Wouters et al., 2020). However, as a result of this apparent trade-off large-scale renewable hydrogen production is envisioned to be dedicated instead of grid connected (van Wijk, 2021)

With respect to electricity prices, variation by location and uncertainty regarding external factors like the power generation mix and power demand in end-use sectors make the evolution of electricity price hard to determine. In case of dedicated production this relates to the levelised cost of energy (LCOE) while for non-dedicated production this relates to the electricity price (Wouters et al., 2020). Therefore, in case of large-scale renewable hydrogen production the electricity cost are mainly dependent on the location, where locations with good renewable resources are able to produce low cost e-hydrogen (van Wijk, 2021). On the contrary, in the vision of non-dedicated hydrogen production the electricity price development will depend on the penetration levels of renewable electricity as well as the competitive demand for electricity, which expected due to increased levels of electrification. Moreover, this is further complicated by opposing goals within the value chain. In this respect, investors in renewable electricity aim at high electricity prices in order to recoup the investment, while this hinder the cost perspective of non-dedicated hydrogen producers. The higher electricity price could partly be due to the inclusion of negative externalities in the grid electricity price from a climate policy perspective and subsequently lead to tension between the renewable electricity- and e-hydrogen deployment. However, the apparent trade-off is expected to become minimal at higher levels of renewable electricity generation (Moraga et al., 2019). Nonetheless, the vision on non-dedicated hydrogen production does not overlap with the wider perspective on the future renewable hydrogen system neither does int adequately address an optimisation from a system perspective.

Looking at the e-hydrogen production cost, Wouters et al., 2020 estimate the current price for e-hydrogen to be in the order of [70-130] EUR/MWh, or [2-3] times the production cost of lower-carbon hydrogen. However, trends in increasing plant- and stack size plus increased efficiency of the hydrogen production could lower the cost price in the foreseeable future. For 2050, Wouters et al., 2020 estimate the cost for e- hydrogen to be in the range of [17-84] EUR/MWh. Moraga et al., 2019 state a break-even price of 85 EUR/MWh for e-hydrogen, which is based on the electricity price of that moment. As a result of the high hardware costs and small industry, Alvera et al., 2020 state that the hydrogen production from renewable electricity is high at an estimated cost of [2.5-4.6] USD/kg H_2 or [19-34] USD/MBtu. Nikolaidis and Poullikkas, 2017 shows depending on the electricity source, production capacity and capacity factor a hydrogen cost range of [5.10-6.46] USD/kg H_2. However, the expected drop in cost of both electrolysers and renewable electricity could result in a cost price of around [1.1-2.7] USD/kg H_2 or [8-20] USD/MBtu by 2030 and [0.7-1.6] USD/kg H_2 or [5-12] USD/MBtu by 2050 (Nikolaidis and Poullikkas, 2017).

However, these estimate lack an adequate representation of the presumed costs, specifically the incorporated electricity price. As a result, this limits the predictive value due to the importance of the electricity price on the e-hydrogen production cost.

Comparison

Thus, the economic performance is important to support wide-scale adoption and lower the transition costs towards a renewable hydrogen system. Therefore, relevant parameters that influence the production price of hydrogen are assessed. Since fuel costs are in general the largest component of the hydrogen production costs, future hydrogen costs are assumed to be largely influenced by the development in input prices and related parameters. However, also CAPEX and related parameters might remain to play an important role. Figure 4.29 shows indicative prices for hydrogen production costs for different technologies by 2030 (IEA, 2019). Here, it can be observed that low-carbon hydrogen in most cases is more costly than unabated fossil hydrogen production cost. In case of the fossil hydrogen the costs are assumed to be around [1-3] USD/kgH_2, while for e-hydrogen this is assumed to be around [2.5-6] USD/kgH_2. These numbers neglects wider system costs and focuses purely on the production cost. Moreover, due to the strong influence on input prices, the relevant production cost prices vary strongly over geographical location (IEA, 2019). In general, it is expected that a carbon price will be required for lower- or zero-carbon hydrogen to be cost-competitive with traditional, fossil hydrogen. This is especially true in regions with low fossil fuel prices and is expected for all sectors and end applications, with a potential exception for transport (Alvera et al., 2020).

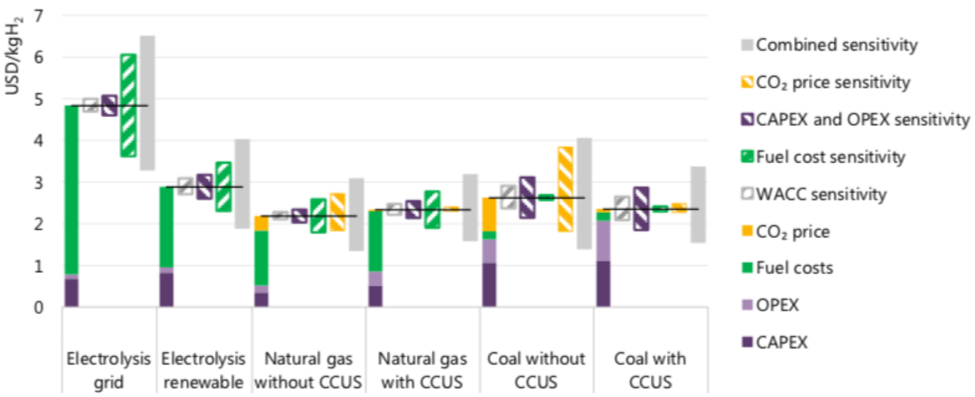


Figure 4.29: Hydrogen production costs for different technologies by 2030 (IEA, 2019)

A summary of the economic performance of the production routes can be seen in table 4.3. Here, it can also be observed that biogenic- and e-hydrogen production generally have a higher price point than fossil hydrogen production. It is assumed that renewable production methods require at least a 2 times higher premium as compared to traditional methods. Moreover, the high relative contribution of input costs can be observed most strongly in methane-based or electricity-based production methods. As a result, close monitoring of variation in input prices could give rise to a different perspective in relative price competitiveness in production methods. However, in case of biomass gasification the feedstock costs are assumed to be relatively less relevant to the production costs. Nonetheless, it was shown that a price increase in the cost of biomass could result in a considerable spike in the hydrogen production cost. Especially, with a renewed focus on biogenic carbon sources, public scrutiny of woody biomass and alternative use cases this might play a dominant role for the biomass gasification route.

However, besides the production cost, other factors will remain to be important in the choice for low-carbon hydrogen production. This includes, but are not limited to, geographical resource availability, public acceptance, scale of investments, system flexibility, system security and more broadly system cost (IEA, 2019) (Wouters et al., 2020) (Alvera et al., 2020) (Dincer and Acar, 2015). Nonetheless, it could be concluded that a carbon price or other incentives will be required for low-carbon hydrogen to be cost-competitive with traditional fossil hydrogen.

Technology	**LCOH (€/kg H_2)**	**Feedstock (% LCOH)**	**CAPEX (% LCOH)**
Fossil			
SMR	0.6-2.6	60	30
POX	0.9-2.83	25	55
ATR	unk.	unk.	unk.
DR	unk.	unk.	unk.
MC	unk.	unk.	unk.
CCUS			
Methane	1.3-2.9	50	35
Coal	1.4-2.8	20	55
Biogenic			
Reforming	1.83-7.8	unk.	unk.
Gasification	1.5-3.73	35	30
SCWG	1.3-3.4	unk.	unk.
Electrolysis			
Non-dedicated	2.9-5.6	80	15
Dedicated	2.3-10.00	65	30

Table 4.3: Hydrogen production economics comparison (Alvera et al., 2020) (Nikolaidis and Poullikkas, 2017 (IEA, 2019) (Wouters et al., 2020) (Holstein et al., 2018) (Braga et al., 2012) (Lepage et al., 2021)

4.3.4 Analysis

Thus, for hydrogen to fulfill its promise as renewable, cost-effective and versatile energy carrier the production method needs to be feasible, sustainable and cost-competitive. Therefore, the different production methods were assessed based on technological-, environmental- and economical performance parameters. This helps to understand how hydrogen can be produced and how this impacts the potential of hydrogen as a non-polluting- and low-carbon energy vector in the future renewable energy system.

Firstly, it was indicated that only limited renewable- or lower-carbon hydrogen production methods show short-to-medium term potential as viable production route. Nonetheless, the electrolysis routes of AE and PEM, and the biogenic routes of reforming, gasification and SCWG positively indicate medium- or even short term potential. Secondly, the considerable negative climate impact of the fossil hydrogen production routes was shown through an assessment of the related production emissions, which restated the need to find alternative low-carbon hydrogen production methods. Here, it was also shown that the use of e-hydrogen could yield near-zero or zero-carbon hydrogen production. Moreover, the integration of CCUS technology with biogenic resources was shown the potential to yield negative carbon emissions and as such act as a carbon sink. However, fossil CCUS technology deployment was shown to face some important barriers. Lastly, the comparison of the hydrogen production cost indicated the need for external influences in order to stimulate the adoption of low-carbon hydrogen production. Nonetheless, as the production methods rely strongly on input costs, close monitoring over time and place might show cost-competitive low-carbon hydrogen production within the short-to-medium term. A recap of the relevant technological-, environmental- and economical parameters can be found in table 4.4.

However, table 4.4 is utilised to provide an overview of the results listed in the respective studies. Nonetheless, this results should be interpreted carefully as the result are impacted considerably by the respective study methodology, time frame and location. Moreover, these results are stand-alone and require careful analysis within the renewed research context and interpretation within the current context. This for example includes the ability to compare the LCOH results in light of to the provided input costs of the feedstock or scale of production.

Technology	**TRL**	**GWP** ($kgCO_2 - eq/kgH_2$)	**LCOH (EUR/kgH_2)**
Fossil			
SMR	9	8.9-15	0.6-2.6
POX	9	18.96	0.9-1.2
ATR	9	11.0	unk.
DR	4-6	5.46	unk.
MC	2-8	2.5	unk.
CCUS			
Methane	8	2.3-5.8	1.3-2.9
Coal	8	2.3-5.8	1.4-2.8
Biogenic	unk.	(24.14)-(14.63)	unk.
Biogenic			
Reforming	8	4.8-7.34	1.83-7.8
Gasification	6-7	(0.13)-8.64	1.5-3.73
SCWG	4	unk.	1.3-3.4
Electrolysis			
Non-dedicated	9	26	2.9-5.6
Dedicated	5-9	0-3.22	2.3-10.0

Table 4.4: Overview of the hydrogen production methods

4.4 Analysis

Within the research context, hydrogen has been ascribed an important role as renewable energy vector in the future sustainable energy system. In this role, hydrogen can do almost all the same as natural gas does in the current economy as well as displace the non-power sector uses for coal and oil (Alvera et al., 2020). Moreover, within the proposed future renewable hydrogen system, hydrogen will allow for the cost-effective transport- and storage of renewable electricity over time and place. On top of that, hydrogen is ascribed to offer strategic benefits with respect to energy security, opening synergies with existing industries, the creation of viable transition pathway, sector coupling and the integration of renewables. In this way, hydrogen can fulfill a broad system role as interconnected, secure, cost-effective and non-polluting medium to lower fossil dependency and stimulate the adoption of renewable energy sources.

In this perspective, it was indicated that the current potential of hydrogen is primarily related to traditional use cases in the industrial sector. However, the future potential acknowledges the ascribed relevance of hydrogen as key energy vector within the renewable energy system. In this respect, hydrogen can replace fossil fuel utilisation over sectors and applications, which spans the build environment-, power-, industry-, and transport sector. In the latter, this could be supported by hydrogen-derived fuels, which couple hydrogen with, primarily, carbon-containing molecules. Moreover, hydrogen offers the potential to green processes, products and materials to further decrease the reliance on fossil fuels. Most importantly, renewable hydrogen offers the potential to transport- and storage cheap renewable electricity over time and place. This could further spark the competition between regional- and or local renewable electricity- and renewable hydrogen production.

Thus, hydrogen offers the potential to overhaul the current fossil energy system as renewable, non-polluting, versatile and cheap energy vector. However, in order to fulfil the future role of hydrogen, production methods should become feasible, sustainable and cost-competitive. In this respect, a multitude of primary- or secondary energy sources can be harnessed via different conversion processes and methods to produce hydrogen. Here, traditional fossil hydrogen production methods show the highest technological- and economical potential but suffers from low environmental performance. In contrast, CCUS technology has been ascribed potential to cost-effectively improve the environmental performance despite the continued reliance on fossil resources. On the other hand, several renewable hydrogen production methods show good technological- and environmental potential, but suffer at the moment from low economical performance. These include, e-hydrogen- and biogenic hydrogen production. Other, innovative, primarily biological, hydrogen production methods have been ascribed low technological performance.

However, within the research context the traditional assessment based on the described technological-, environmental- and economical parameters might prove to be insufficient. This relates to the complete overhaul of the energy system and as result the need for more radical changes. This is in contrast to the more gradual approach, which flourishes with the more traditional assessment metrics. As a result, a strength- and weakness analysis is proposed to analyse the relevant hydrogen production methods within the future renewable hydrogen energy system.

Strengths and weaknesses analysis

The strengths and weaknesses analysis is used to identify the relevant hydrogen production methods within the perspective of the future renewable hydrogen system. This relates both to technological- and non-technological parameters. In this respect, renewable hydrogen is seen as the key energy carrier within the future energy system in similar terms as natural gas in the current energy system. Moreover, hydrogen is, among other, assigned relevance for the replacement of oil-related products in non-power sector applications. In this respect, renewable hydrogen is presumed to overhaul other energy vectors as sole renewable molecule in the energy system. Here, large production scale, low production costs and no-carbon emissions are important to assess the different hydrogen production methods in order to support an affordable-, accessible-, secure-, reliable- and fair transition.

More general, with respect to the current dominant fossil hydrogen production methods, SMR shows the highest H_2/CO ratio and is the most widely deployed technology. On the contrary, POX is characterised by a low H_2/CO ratio and more complex handling, but does not require a catalyst. Moreover, POX is primarily used in case of coal resources. In this respect, POX is seen as the more preferential method for FT hydrocarbon synthesis reactions. On the other hand, ATR in general has a lower H_2/CO ratio as compared to SMR, but higher than POX. Nonetheless, ATR is able to operate along a broad range of H_2/CO output ratios in case of alterations in the process inputs and conditions (Wouters et al., 2020). However, ATR does require an air- or oxygen input as opposed to SMR, but due to thermal neutrality does not require an external heat source, which simplifies the system. Moreover the ATR process has a lower start-up time and has more flexible operations. On top of that, ATR is characterised by almost unlimited scalability. Lastly, in case of carbon capture technology, ATR shows higher CO_2 capture rates at lower costs (Wouters et al., 2020).

Secondly, looking at e-hydrogen production, AE is discussed to be the most developed and cost-efficient at the moment. Nonetheless, AE is stated to be electrically less efficient as compared to PEM and SOEC technology. However, the latter faces challenges with corrosion, thermal cycling and chrome migration, which are mostly absent in PEM electrolysers. On top of that, AE show lower start-up- and reaction time as compared to PEM, which become more relevant in case of system balancing. Moreover, this could impact hydrogen production due to variable renewable electricity generation input and as result of alternations in case of curtailed hydrogen production. However, the relative strengths might become obsolete in locations of good renewable electricity resources and or good process control. Nevertheless, PEM is at the moment primarily dominant in commercial applications within smaller-scale local hydrogen production facilities, while SOEC technology in contrast lacks commercial scale. Despite the limitations, SOEC shows promise to operate in reverse mode as fuel cell or as co-electrolysis to create syngas from steam and carbon dioxide (Holstein et al., 2018).

Thirdly, in case of biogenic hydrogen production the production through biogas via anaerobic digestion (AD) is technically most mature. In this case, biogas is converted to bio-hydrogen and bio-CO_2, primarily, after upgrading to green gas. However, the lack of available and feasible feedstock material might pose a problem for large-scale deployment. On the other hand, biomass gasification has the potential to convert a wider-range of feedstock. Nonetheless, gasification technology lacks commercial deployment beyond demonstration plants at the moment. Moreover, gasification technology suffers from the formation of tars and is susceptible to alterations in process conditions (IEA, 2019). Steam gasification is discussed to be suitable for large-scale industrial production with high gasification rates, however it remains to suffer from problems with separation and purification of the gas products. Moreover, steam gasification still require a reduction in energetic- and material costs, for example related to tar content and catalyst deactivation. On the contrary, fast pyrolysis benefits from an oxygen free environment and relatively high hydrogen concentrations. Nonetheless, the scaling of the fast pyrolysis process is hindered by high equipment requirement, high energy consumption, low hydrogen yield and catalyst deactivation. Lastly, SCWG shows potential for high feedstock conversion and hydrogen concentration without tar- and coke formation or secondary pollution. However in case of SCWG, the strict operating conditions, the high energetic costs and the difficulty to recycle the catalyst limit technological development at the moment (Cao et al., 2020.

Lastly, with respect to the biochemical production of hydrogen, these routes are favoured due to the mild reaction conditions and positive ecological performance. Nonetheless, biochemical production routes show low hydrogen conversion, production rates and yields. In the case of biophotolysis, the reliance on an abundant supply of water and the lack of carbon- or polluting output products stimulate the production route. Nonetheless, biophotolysis suffers from the separation of the output products, low conversion efficiencies and large surface area requirements. For photofermentation, the availability of supply of waste streams and the nearly complete substrate conversion is a plus, while low production rates and conversion efficiencies hinder development. Dark fermentation, in contrast could allow for higher production rates. Moreover, dark fermentation is relatively simple and can use a variety of waste streams. However, dark fermentation is characterised by large amounts of byproducts and reactor-to-reactor variations (Dincer and Acar, 2015). Also, at the moment dark fermentation still shows low hydrogen rates and yields (Nikolaidis and Poullikkas, 2017).

An analysis of the relevant strengths and weaknesses of the different production methods in light of the renewable hydrogen gas system can be seen in table 4.5.

From table 4.5 it could be stated that, in light of the renewable hydrogen energy system, e-hydrogen production shows great potential. In this respect, AE technology can cost-effectively be deployed in locations with good- and abundant resources. On the contrary, PEM might prove to be more useful in regional- and or local applications, or in case of more fluctuations in renewable electricity input. The actual deployment of SOEC- and battolyser technology could prove to become useful in more niche- and or local scale applications.

Moreover, traditional reforming technologies deployed with carbon capture technology and or biogenic resources seem to prove a reliable production method. This is especially relevant in the transition phase, where e-hydrogen deployment might be hindered by the lack of adequate renewable electricity capacity. In this respect, ATR technology could provide relevant benefits as compared to the traditional SMR- and POX production process, including higher CO_2 capture rate potential and more flexible-, scalable- and adjustable production processes. Also, the development of methane cracking shows a relevant lower-carbon alternative that can be applied at large-scale without the need for carbon storage. Therefore, MC offers the potential for lower-carbon hydrogen production at locations without carbon storage potential and or expensive infrastructural requirements.

On top of that, biogenic hydrogen production shows relevancy for the incorporation of hydrogen production on both a local- and regional scale. Here, it is presumed that biogenic conversion methods are stimulated by economies of scale. In case of traditional gasification technologies, this is supported by the higher energy density and availability of the feedstocks. On the other hand, reforming technologies show potential for more local production, where it benefits from experience in fossil hydrogen production. This is further stimulated by the potential to act as a direct substitute of natural gas, thereby easing the transition. Moreover, the biogenic hydrogen production methods show potential for local- and or regional integration options, where the utilisation of biogenic carbon dioxide shows relevant potential, both as feedstock or as carbon sink. The former is presumed to become increasingly relevant in the future renewable hydrogen system.

On the contrary, despite the benefits of biological conversion methods, these methods are not presumed to significantly support the renewable hydrogen gas system. This primarily relates to the lower hydrogen production rate and yield, which limits the production scale. Nonetheless, location-specific utilisation might become relevant in the long-term. Moreover, this could become more interesting as result of molecular engineering that stimulate production yields above the theoretical maximum.

Thus, within the proposed renewable hydrogen system e-hydrogen shows great potential to operate as the main renewable hydrogen production method. This is supported by cheap electricity input and good production operations at a large-scale. This could be flanked by innovative- and niche e-hydrogen production methods. Nevertheless, especially, during the transition phase, e-hydrogen utilisation might be limited due to insufficient renewable electricity production capacity and or competitive electrification demand. In this light, lower-carbon hydrogen production capacity and methane cracking facilities could stimulate the production capacity of hydrogen at a large-scale. Moreover, the conversion of natural gas at the source to hydrogen could support the proposed hydrogen infrastructure. Nonetheless, both remain to rely on fossil resources, which could continue to facilitate a natural gas lock-in. Moreover, lower-carbon hydrogen still requires the storage of fossil CO_2, while complete capture of CO_2 is questionable. On the other hand, biogenic resources could be used as a direct substitute, especially in more local- and or regional applications. Also, gasification technologies could build upon a proven technology design to ease the transition. Nonetheless, the deployment in the short-term is limited due to the lack of commercial applications and the presence of technological barriers. In contrast, bio-hydrogen production capacity could, already in the short-term, support the transition towards the proposed future renewable hydrogen system. This is especially relevant in local- and or regional applications in light of the relatively lower technical availability of feedstock. As a result, bio-hydrogen can, in the short-term, fulfil the demand for, local- and or regional, renewable-, affordable- and reliable hydrogen.

To conclude, renewable hydrogen is seen as a key pillar in a renewable energy system. Here, hydrogen can overhaul the current natural gas system, displace the non-power sector used for coal and oil, green products and processes, and allow for the cost-effective transport of renewable electricity over time and place. In this perspective, hydrogen is the energy vector that integrates- and couples the energy system. Here, biogas could play an important role as source of bio-hydrogen and bio-carbon dioxide. In this way, biogas shows potential to drive a rapid-, affordable- and secure transition to a renewable hydrogen gas system. In this perspective, bio-hydrogen can add relevant volumes of renewable hydrogen, lower CO_2 related emissions, limit CH_4 leakage, prevent a natural gas lock-in and ultimately valorise the use of biogas over different applications. This relates to the potential to fulfil, already in the short-term, the, local- and or regional demand for renewable hydrogen. Moreover, this allows for the decoupling of the valuable energetic bio-hydrogen and molecular bio-carbon dioxide. This is expected to become increasingly important over time due the demand for climate-neutral carbon molecules. In this way, biogas provides a potential carbon-negative method that converts problematic waste streams into valuable renewable molecules.

Technology	Strengths	Weaknesses
Fossil		
SMR	High H_2/CO ratio, low cost per kg hydrogen	Inflexible operations, strong economies of scale
POX	No catalyst requirement	Low H_2/CO ratio, O_2 requirement, adapted for longer hydrocarbons
ATR	Flexible-, scalable- and adjustable process, higher CO_2 capture potential	Potential lower H_2/CO ratio, O_2 requirement
DR	Synergies with biogas, CO-rich output	Catalyst deactivation, low H_2/CO ratio, CO_2 requirement
APR	Aqueous phase feedstock solution, low temperature, process intensification	Oxygenated hydrocarbon specific, competitive- and complex reactions
MC	Large-scale, no direct CO_2 emissions, carbon black output, easy process	High temperature, lower hydrogen yield and purity, difficult separation
Biogenic		
Reforming	Similar to fossil-based technology, carbon-neutral feedstock	Feedstock availability, quality and affordability, pretreatment requirement
Gasification	Existing technology design, producer gas formation, lower hydrogen cost potential	Tar formation, catalyst deactivation, process susceptibility, high pollution potential, strong economies of scale
Pyrolysis	Existing technology design, simple conversion, high hydrogen concentration	Tar formation, process susceptibility, catalyst deactivation, lower H_2 yield, dry biomass requirement
SCWG	Feedstock flexibility, high feedstock conversion, high hydrogen concentration, no tar- or coke formation	High energy requirement, strict, operating conditions, catalyst recycling
Biological		
Biophotolysis	CO_2 consumption, only O_2 byproduct, low theoretical efficiency	Large reactor volume, O_2 sensitivity, requires sunlight, process discontinuity
Photo-fermentation	Waste recycling, feedstock flexibility, high conversion	Requires sunlight, large reactor volume, O_2 sensitivity, bacteria control
Dark-fermentation	Simple operations, no sunlight need, no O_2 limitation, high growth rate	Pretreatment need, by-product generation, production variation
MEC	No purification need, low electrical consumption	Expensive catalyst, slow production rate, complex
Electricity		
AE	Uses abundant materials, well-developed technology	Less flexible operations
PEM	Flexible operations	Challenging long-term stability, platinum group metal catalyst
SOEC	Reversible operation, high current efficiency and production capacity	Unproven technology, material degradation, special material requirements
Thermolysis	Couple with concentrated solar heat possible	High heat requirement, low overall efficiency, toxicity and corrosive problems
Photolysis	Intensification of e-hydrogen production	Material effectiveness, low conversion efficiency, external bias required
Battolyser	Power sector coupling, abundant materials	Only lab tested, competition with battery usage

Table 4.5: Strengths and weaknesses of hydrogen production methods (Nikolaidis and Poullikkas, 2017) (Lepage et al., 2021) Holstein et al., 2018) (Dincer and Acar, 2015) (Holladay et al., 2009) (Kennedy et al., 2019)

Chapter 5

Biogas

Biogas has been ascribed an important role for the local- and or regional production of bio-hydrogen within the future renewable hydrogen system. In this perspective, through the concept of third-generation upgrading, biogas is seen as a relevant source of bio-hydrogen and bio-carbon dioxide. Moreover, this perspective includes the potential of the direct utilisation of the produced syngas. In this respect, biogas can be considered an indispensable source of biogenic carbon that simultaneously could allow for negative carbon emissions. On top of that, biogas is able to couple waste management with renewable energy production, thereby offering a potential solution to an increasingly relevant societal- and environmental problem.

Nonetheless, the perspective on biogas as relevant source of renewable energy has been prone to several different influences. Here, biogas has first been attributed potential as source of renewable electricity. Later, this perspective changed towards the increased utilisation of biogas for heat- or combined heat- and power generation. At the moment, the perspective shifted towards the use of biogas as source of biomethane. The biomethane subsequently found increased attention for the use within the industrial-, transport-, and more recently, the build environment sector. Moreover, the upgrading towards biomethane has sparked attention for the utilisation of the bio-carbon dioxide stream, which originates from the upgrading of biogas to biomethane. Here, the concept of second-generation upgrading values the bio-carbon dioxide streams as relevant source of bio-carbon, which, for example, could be used to produce hydrogen-derived fuels.

Nevertheless, within the research context biogas has been ascribed higher valorisation potential through the concept of third-generation upgrading. Therefore, this chapter aims to describe the relevant potential of biogas as well as discuss the related technological-, environmental- and economical factors. Ultimately, to assess the potential of biogas within the concept of third-generation upgrading the chapter provides attention to the relative strengths and weaknesses with respect to the alternative uses of biogas. This is related to the perspective as portrayed on renewable hydrogen. Ultimately, this should highlight the potential of the concept of third-generation upgrading as highest valorisation potential over time and place.

5.1 Introduction

The production of biogas is an established sustainable process for the simultaneous generation of renewable energy and treatment of organic waste (Angelidaki et al., 2018). I. Khan, 2020 state that the waste-to-energy production offers two benefits. Firstly, it allows for the management of the generated waste and secondly it generates energy from the waste. Sharma et al., 2020 adds to this that escalating waste generation, environmental pollution and increase in energy demand are the foremost global concerns. In this perspective, biogas can play a major role in the development of a renewable energy market where its usage was expected to double between 2012-2022. The use of biogas therefore provides a source of renewable energy which can be used as substitute for fossil fuel and thereby reduces the emission of CO_2 in case of combustion. Moreover, the production of biogas reduces the methane emissions to the environment related to natural digestion of the residual waste streams (I. U. Khan et al., 2017). In this respect, Sharma et al., 2020 reports that AD is significantly more sustainable as compared to waste incineration considering economic0, social- and environmental factors. Here, in general AD is preferred over other waste-to-energy routes, like thermal methods of pyrolysis and gasification or biochemical routes like fermentation or composting. Therefore, national energy policies should consider biogas as an important renewable source towards a sustainable energy future (I. Khan, 2020).

Biogas is produced by microorganisms through the anaerobic digestion of organic matter. More formally, anaerobic digestion is defined as a biochemical process that converts a variety of organic matter under oxygen depleted conditions using naturally occurring microorganisms to a gaseous mixture containing mainly methane and carbon dioxide I. Khan, 2020. The organic matter include, among other, manure, waste and residues from the agricultural- and industrial sectors. Moreover, the organic matter includes municipal organic waste and sewage sludge (Scarlat et al., 2018). The biogas mixture primarily consists of methane and carbon dioxide in a range of [50-70]% and [30-50]% respectively. Other trace species, like nitrogen (N_2) , hydrogen sulphide (H_2S) , ammonia (NH_3) , carbon monoxide, oxygen and hydrogen are also present. Moreover, biogas is typically saturated with water, dust particles, siloxanes, aromatic and halogenated compounds (I. U. Khan et al., 2017). The exact biogas specifications are mainly a function of the organic matter substrate and pH of the reactor. Also the process conditions, bacteria used and effluents could impact the exact compound mixture (Angelidaki et al., 2018). In general, all other gases apart from the methane are unwanted and therefore seen as biogas pollutants. One reason includes the fact that the higher the carbon dioxide- and nitrogen content the lower the lower calorific value of the biogas. While the lower calorific value of methane is 50.4 MJ/kg CH_4 or 36 MJ/$m^3 CH_4$, this reduces to [20-25] MJ/$m^3 biogas$ based on a methane content of [60-65]% (Angelidaki et al., 2018). However, a renewed focus on biogenic CO_2 disregards the perspective on CO_2 as unwanted side product. Rather the CO_2 stream has the potential to serve as relevant input for the creation of hydrocarbon-based high-energy density fuels and materials, in what is termed second-generation upgrading Villadsen et al., 2019. In contrast to CO_2, the H_2S and NH_3 present are toxic and corrosive and therefore require to be separated, independent of the downstream application. In case of H_2S, this mainly involves scrubbing to ensure no catalyst poisoning downstream in the process. Also, the siloxanes present, even in minor concentrations, require separation as these could generate sticky residues, which deposit during combination in engines and valves, causing malfunction (Angelidaki et al., 2018).

The exact composition of the biogas is more specifically a function of the feedstock, the potential co-substrates and the digester conditions. In general, the relevant waste stream affects the methane-, carbon dioxide- and biogas contaminants specifications. A summary of the specific biogas compositions for the relevant waste streams, and compared to natural gas, can seen in table 5.1 (Calbry-Muzyka et al., 2021). Note that in table 5.1 other traces like sulfides, siloxanes, and alkanes are not included as most exist in low- or undetectable levels in agricultural biogas. Here, it can be seen that agricultural- and waste biogas are relatively similar. However, both are characterised by a broad range of potential compositions which shows the need to account for considerable site-to-site differences in CH_4 content. Nonetheless, an observation with respect to manure digestions shows only limited difference in methane content between sites with significant variation in manure origin and co-substrate content. On the other hand, the range for landfill biogas is even wider than for agricultural- and waste biogas, where older landfills produce gas with the lowest CH_4 fractions. Nevertheless, while landfills generally have lower levels of methane, its utilisation still proves environmental benign as otherwise the anaerobic bacteria, naturally present in waste and in soil harm, the environment through the emissions of both methane and carbon dioxide. However, the potential high levels of siloxanes in landfill biogas makes siloxane cleaning required, while this can be avoided for agricultural gas and sometimes for waste biogas (Calbry-Muzyka et al., 2021).

Thus, biogas is a sustainable energy source that both treats organic waste as well as generate energy. In this way, biogas can substitute fossil fuel and reduce methane emissions to the environment. As a result, AD is seen as the most economic-, social- and environmental waste processing method. The residual waste stream is processed in an anaerobic digester and the resulting biogas consists of mainly methane and carbon dioxide. However, also minor traces of biogas contaminants including nitrogen, oxygen and hydrogen sulfide are present. After treatment, the biogas can be utilised either directly or as source of biomethane. Moreover, the biogas can be used as bio-carbon dioxide source for example through second-generation upgrading where the bio-CO_2 can be used to produce hydrocarbon-based high-energy density fuels. As a result, biogas can be seen as a versatile-, environmental- and potentially economic renewable energy source.

Content (%v)	**Agricultural biogas**	**Waste biogas**	**Landfill biogas**	**Natural gas**
CH_4	49-69	44-67	40-70	89-91
CO_2	29-44	30-44	25-40	1-6
N_2	0.6-13	0.1-6	0-17	-
O_2	0.2-3	0.1-3	0-3	0-1
H_2S (ppm_v)	7-6570	2-3174	0-5143	3-10
NH_3 (ppm_v)	0-70	unk.	unk.	0-5
Low caloric value (MJ/m^3)	20-25	20-25	20-25	36

Table 5.1: Biogas specifications (compared to natural gas) (I. Khan, 2020) (Calbry-Muzyka et al., 2021)

5.2 Potential

The potential of biogas is derived from the both the economic availability of the required feedstock material as well as the economic utilisation of biogas in the proposed end use sectors. Moreover, the economic potential is influenced by the respective production methods of biogas. More broadly, the economic potential for biomethane is affected by the development of innovative technologies that do not rely on the utilisation of biogas. Lastly, the potential is considered to be heavily dependent on the respective regulatory perspective. This includes strict requirements, targets and or stimulation measures. This also entails the identification of economical- and or social valorisation potential of the respective value chain.

5.2.1 Current potential

The global biogas production sparked between 2000 and 2014 from 0.28 EJ to 1.28 EJ which accounted for an installed capacity for electricity production of around 2.5 GW to 14.2 GW respectively. The biogas production capacity was primarily concentrated in Europe and the United States, as can been seen in figure 5.1. The global biogas production volume was around 59 bcm biogas or 35 bcm biomethane equivalent. In Europe, the biogas production showed an increase from 167 PJ to 654 PJ, or 0.17 EJ to 0.65 EJ from 2005 to 2015. This equaled an increase from 2.5 bcm biomethane equivalent in 2000 to 18 bcm biomethane equivalent in 2015 and represented half of the global biogas production (Scarlat et al., 2018).

In 2015, Europe was the world leader in biogas electricity production, which accounted for 10.4 GW of the total global installed biogas capacity for electricity production of 15 GW, or between [70-75]% of global electricity production from biogas. As part of the total biogenic electricity production, bio-electricity constituted a share of about 20%. In case of biogenic heat production, bio-heat production is becoming more important and by 2015 reached around 4% of biogenic heat production worldwide. In the European Union, about 50% of the total biogas consumption was utilised for heat generation by 2015 (Scarlat et al., 2018). In 2017, bio-electricity made up around 35% of the biogenic electricity production in the European Union. This accounted for approximately 5,515 kilo tonne of oil equivalent (ktoe). In contrast, bio-heat accounted for around 0.05% of the biogenic heat production and constituted around 3,909 ktoe (Banja et al., 2019). Next to bio-electricity and bio-heat production, biogas upgrading to biomethane has emerged as an attractive alternative for the direct usage of biogas. Here, the use of biomethane as biofuel in the transport sector is increasing, with the largest market being in Europe. By 2015, the EU accounted for around 0.16 bcm of biomethane fuel in the transport sector, or 1% of the total biomethane production potential (Scarlat et al., 2018). The biomethane production plants produced in Europe around 1.2 bcm biomethane, while the total capacity equaled approximately 1.23 bcm biomethane. In Europe, this accounted for around 6% of the total biogas production. Nevertheless, the biomethane production was primarily centered in Germany, UK, Sweden and the Netherlands. While, Germany constituted the highest percentage of biomethane as part of the total methane usage, the Netherlands was the only notable country injecting biomethane in the grid at around 1.11 million m^3 in 2015 (Scarlat et al., 2018).

In 2015, around 17,400 biogas plants were operational in Europe of different types and sizes. As can be seen in figure 5.2 this growth is mainly attributable to AD plants, while the contribution of sewage gas- and, especially, landfill recovery gas (LFG) plants have been constant. This is in contrast to the US, where the energy potential in 2016 was around 7.3 bcm from AD plants, 8.0 bcm from landfill recovery gas plants and 3.2 bcm from sewage gas plants. However, the US is assigned a potential of 13,000 biogas plants, while it currently covers around 2,100 biogas plants. This potential is primarily attributed to AD plants, which constitutes 65% of the growth potential. In contrast, the potential growth from landfill recovery gas plants accounts for 5%, and sewage gas plants for around 30% (Scarlat et al., 2018).

Moreover, in 2015 Europe was the world leading biomethane producer with 414 biomethane production plants out of the worldwide capacity of 459 biomethane production plants (Scarlat et al., 2018).

Additionally, in Europe the biogas production is very different across countries both in terms of volume as well as sources of biogas. With respect to the production of biogas, the volumes and sources of biogas for the different European countries can be seen in figure 5.3. Here, it is shown that Germany alone accounts for around 50% of the primary biogas energy production in the Europe (Scarlat et al., 2018).

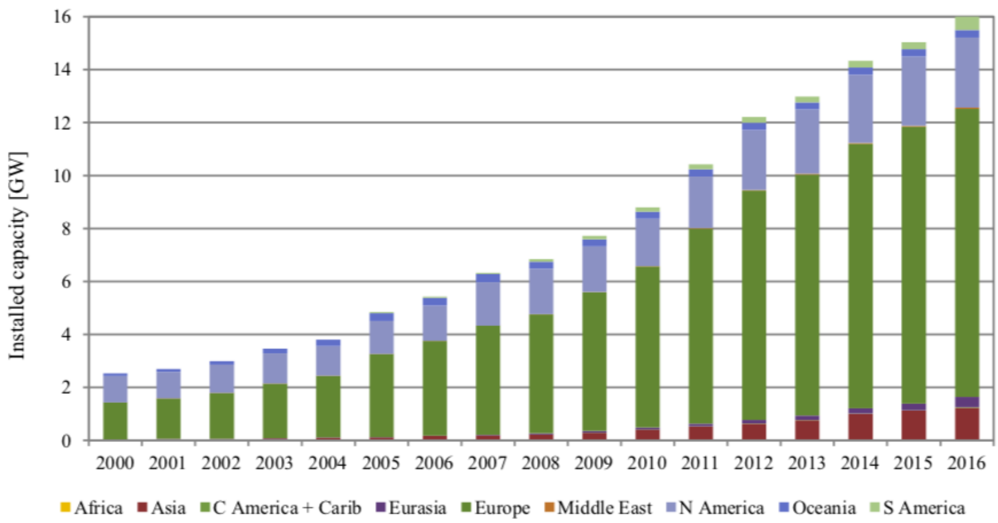


Figure 5.1: Development of global installed electricity biogas plant capacity (Scarlat et al., 2018)

5.2.2 Future potential

The technical production potential of biogas in Europe, is estimated by the German Biomass Research Centre to range between [151-246] bcm biomethane equivalent. By 2030, the production is presumed to arise from both AD and gasification. Here, [48-143] bcm is estimated from the use of energy crops and another 26 bcm from wet biomass. Especially the latter could show the relevancy of AD production. Nonetheless, The true production potential of biogas was in the same study estimated between [48-50] bcm in Europe. This includes raw biogas, upgraded biogas and syngas. In this case, the upgraded biogas, either for grid injection or transport, was estimated to reach up to 20 bcm by 2030 (Scarlat et al., 2018).

Another estimate from the European Biomass Association showed a biogas potential of about 78 bcm biomethane equivalent, from which 46 bcm could be used by 2020. In this estimation, agriculture accounted for around 59 bcm from which 20.5 came from manure specifically. In this case, it was estimated that around 35% or 253 PJ could be used by 2020 (Scarlat et al., 2018).

However, lower estimates of [20-22] bcm for 2020 were estimated by the National Renewable Energy Action Plans (Scarlat et al., 2018).

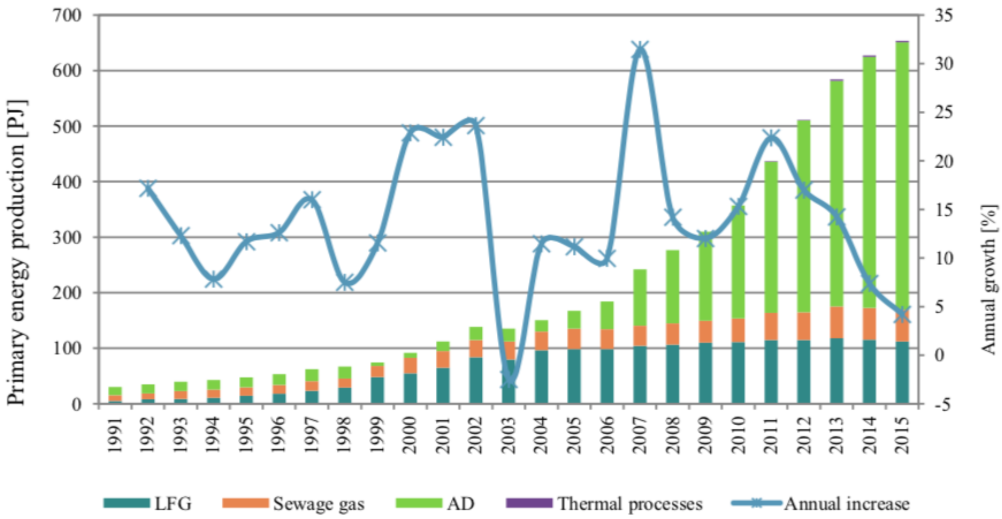


Figure 5.2: Development of primary energy biogas production in the EU (Scarlat et al., 2018)

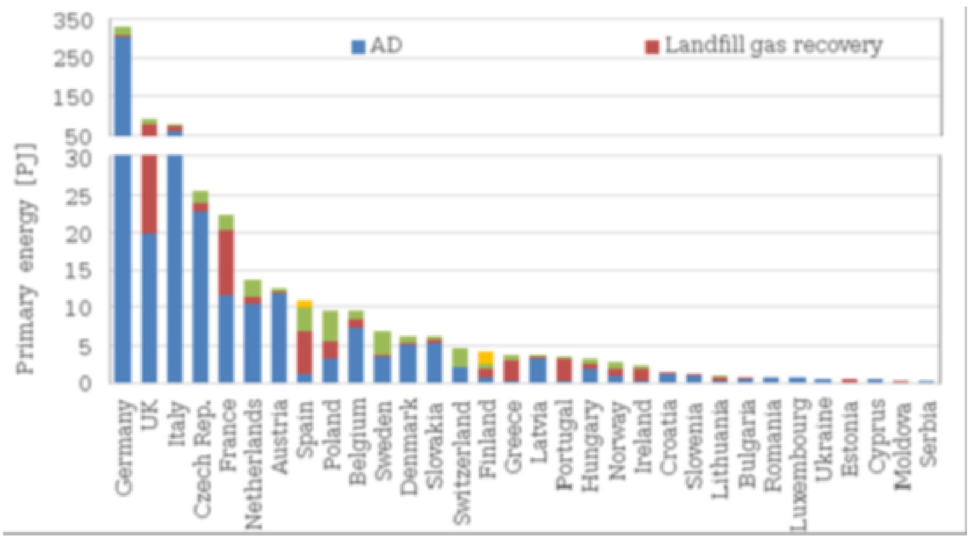


Figure 5.3: Primary energy production from biogas in European Countries (2015) (Scarlat et al., 2018)

In the Netherlands, the ambition is to increase the biomethane production level to 2 bcm by 2030. However, it is expected that this ambition is only realisable in case of both strong supportive policy measurements and the upscaling of the production capacity. In case of the latter, this especially includes the commercial development of innovative gasification techniques that process local biomass streams (van der Veen et al., 2020). In this scenario, 0.18 bcm is produced in the current digester systems, 0.17 bcm is produced in planned digester systems, 0.33 bcm is produced from biogas transformed digester systems, and 0.39 bcm is produced from new digester systems for the conversion of the residual manure and other wet biomass streams. As a result, around 0.92 bcm is assigned to new gasification systems. This scenario excludes both the usage of algae and energy crops, due to the limit economic potential. Also, in the case of farming and horticulture only residual streams are included as crops are assumed to provide a higher value as source for food and because indirect land use change would be undesirable. However, in case of the utilisation of plastics and or biomass imports higher production levels can be obtained (van der Veen et al., 2020).

More specifically, an economic green gas production potential of [0.36-2.0] bcm is predicted based on the different scenarios. In basis, the level of policy support has the highest effect on the production level, which increase a factor [2-3] in comparison to the base situation without strong policy support. On the other hand, the development of new- and or large-scale technologies increasing the production capacity with a factor [1.2-2] as opposed to the situation with limited upscaling. This can be explained by the high contribution of unrealised production facilities in the 2 bcm scenario, which indicates the need for strong policy support. Here, the policy support mechanisms include, among other, production subsidies, higher market prices for green gas and lower biomass prices. This subsequently should allow for higher levels of economic potential for biomethane production, for example through enhancing the incentive for upgrading installations in comparison to the direct usage of biogas. However, it should be noted that the technical potential is at least a factor 3 times larger than the economic potential. It is estimated that the technical potential is 5.1 bcm in the Netherlands, assuming the biomass streams will be digested and around 9 bcm in case SCWG is included, while the available biomass remains constants. The lower economic potential is related to competitive usage of biomass in for example biofuel production, or animal feed production, soil improvement or as chemical feedstock (van der Veen et al., 2020).

Similarly, Corbey and van Asselt, 2020 estimates the potential for biogas production at around 1.3 bcm biogas or 0.9 bcm green gas. This is based on the current availability of 9.5 Mt dry matter bio-feedstock from agricultural residual streams, or 40 Mt wet manure, to arrive at a potential of 0.9 bcm biogas through digestion. The additional availability of biogenic feedstock from regional residual waste streams like green waste adds an additional 0.17 bcm biogas. Lastly, another 0.2 bcm biogas potential arises from industry residual waste streams and agricultural cultivation. However, it should be noted that the biogas production from manure could increase twofold in case SCWG is used instead of AD. Moreover, higher levels of economic availability could arise from efficiency increases, adequate processing technologies, higher- and or optimal utilisation of residual streams, quality improvement and better logistics (Corbey and van Asselt, 2020).

Moreover, van Soest and Warmenhoven, 2018 indicate a biogas potential through digestion of 0.97 bcm biomethane equivalent in 2030 and 1.1 bcm biomethane equivalent by 2050. According to van Soest et al., 2014 the production potential of biogas from digestion in 2030 is around 3.7 bcm or 2.2 bcm green gas equivalent, as can be seen in figure 5.4. Here, the strong growth in biogas potential is attributable to the increased utilisation of alternative biomass streams as well as the enhanced utilisation of current biomass streams. However, it should be noted that this relates to the technical potential. For example, the considerable potential attributable to the usage of seaweed is contested by van der Veen et al., 2020. In this perspective, it is argued that biogenic carbon should be cascaded as much as possible and carbon feedstock should be used as energetic source after all cascading options are exhausted. This could limit the economic potential of biomethane production for biogas both through a reduction of demand for biogas as well as competitive uses of biomass feedstock. Additionally, van Soest et al., 2014 indicate that the usage of green gas will require support, either in the form of a carbon price, stimulation packages and or regulations like quotas and requirements as the fossil fuels production costs are lower. The subsequent maximum potential per application and per type for biogas from digestion is shown in figure 5.5 (van Soest et al., 2014).

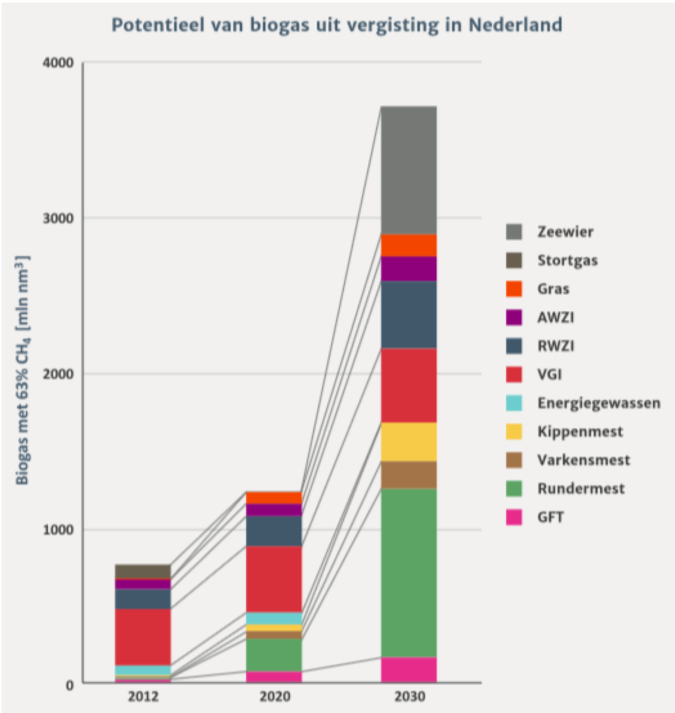


Figure 5.4: Biogas potential from digestion in the Netherlands (van Soest et al., 2014)

More elaborately, the freely available biomass for energy usage, or the theoretical potential minus current usage in non-energy applications as percentage of technical availability, in the Netherlands in 2017 is shown in figure 5.6. In this respect, figure 5.6 gives an indication of the current utilisation of biomass streams over the different use cases. For example, it shows that only 14% of manure can be economically utilised for soil improvement, or biogas- or green gas production. From the data in 5.6 and based on the expected biomass demand, economic valuation and supportive demand in the respective application, the economic potential for 2030 can be established (van der Veen et al., 2020). Here, the use of biomass for energetic applications is assumed to be of lower added value as compared to uses in the chemical-, food- and health sector. Nonetheless, the use of biomass in energetic applications show higher volumes, while the application in the health sector shows the lowest volumes. Moreover, it is expected that the use of biomass as source of biofuel and soil improvements both

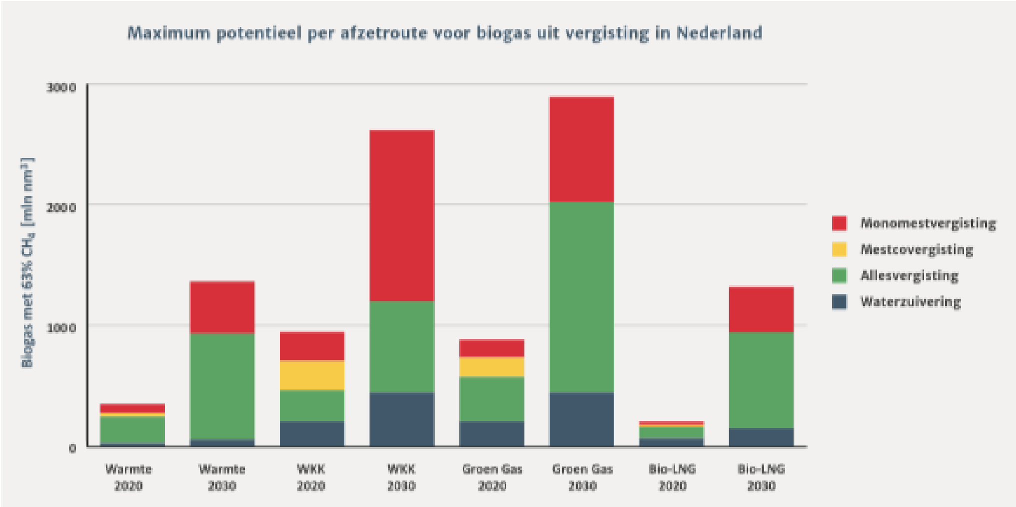


Figure 5.5: Maximum potential per application for biogas in the Netherlands from digestion, per type (van Soest et al., 2014)

show a small increase in demand with average high economic value, while the use in biochemistry will increase strongly at high economic value. The use of biomass for electricity- and heat generation is expected to remain the same, representing low economic value. Figure 5.7 shows the expected economically available biomass for green gas production by 2030 for the different scenarios and uptake of SCWG (van der Veen et al., 2020). Additionally, figure 5.8 shows the green gas production from local biomass in the different scenarios.

		Huidige inzet (alle toepassingen)					
Biomassa-stromen	Huidig aandeel vrij beschikbaar [1]	*Veevoer*	*Bio-brand-stoffen*	*Grond-verbete-raar*	*Elektri-citeit en warmte*	*Biogas en groengas*	*Anders*
VGI	40%						
RWZI-slib	88%						
Natte gewasresten	17%						
Stro	0%						
Mest	14%						
GFT en ONF	61%						
Rest- en afvalhout	53%						
Papierresiduen	93%						
Productiebossen	18%						
Hout van fruit- en boomteelt	29% [2]						
Hout uit landschap	50%						
Natuur- en bermgras	20% [2]						

Figure 5.6: Percentage freely available biomass for energy usage and current utilisation in the Netherlands (2017) (van der Veen et al., 2020)

To achieve the high scenario economic potential for green gas production, a summary of realised- and planned installations with assigned production levels can be seen in figure 5.9. However, it should be noted that installations at sewage treatment plants and the food industry are missing. In figure 5.9 it can be observed that around 80% of the production capacity is related to green gas production. From the total

Reststroom biomassa	Scenario's A en B (sterk ondersteunend beleid)		Scenario's C en D (matig ondersteunend beleid)	
	Op basis van vergisting	*Op basis van superkritische vergassing*	*Op basis van vergisting*	*Op basis van superkritische vergassing*
GFT en ONF uit restafval (huishoudens)	55	110	34	68
Afvalhout huishoudens	76	89	48	56
RWZI-slib	52	104	17	35
Natuurgras	36	73	24	48
Houtige biomassa natuur	28	33	17	20
Dunne mest	879	1.757	293	586
Vaste mest	97	194	32	65
Gras (landbouw)	250	500	167	333
Akkerbouw	56	112	12	25
Tuinbouw	14	28	8,4	16,9
Glastuinbouw	4,5	9,1	2,7	5,3
VGI	119	239	74	147
Totaal	**1.667**	**3.247**	**729**	**1.404**

Figure 5.7: Percentage economically available biomass per stream and scenario in the Netherlands (2030) (van der Veen et al., 2020)

Type biomassastroom	Scenario A - Sterk ondersteunend beleid en beperkte schaalvergroting	Scenario B - Sterk ondersteunend beleid en sterke schaalvergroting	Scenario C - Matig ondersteunend beleid en beperkte schaalvergroting	Scenario D - Matig ondersteunend beleid en sterke schaalvergroting
Mest	982	1.210	285	338
Overige natte biomassa	410	478	79	286
Hout	110	110	-	69
VGI	119	119	0	0
RWZI-slib	52	52	0	0
Totaal	**1.673**	**1.969**	**364**	**693**

Figure 5.8: Green gas production from local biomass sources in the Netherlands in million m^3 (2030) (van der Veen et al., 2020)

capacity only around 30% comes from realised production facilities, indicating the need for support and development to scale up the production capacity. In case of green gas, the current realised production is only around 0.18 bcm and thus requires a scaling factor of at least 10 times to achieve the goal of 2 bcm by 2030.

Moreover, despite a technical potential of around 1.3 bcm in case of manure, as result of the large livestock in the Netherlands, it can be seen that only 0.11 bcm of green gas is currently produced from manure. Here, the economic potential mainly suffers from the low energy density of manure and as result the punishable expensive transportation of manure. However, for the scenarios in 2030 the contribution of manure is significantly higher in the economic potential scenario where it contributes around 53%, as can been seen in figure 5.7. This is in contrast to the contribution of 23% in the technical potential scenario (van der Veen et al., 2020). This can partly be explained by the need for scaling of the production capacity, as the upgrading of biogas to green gas requires a significant volume in order to be profitable. Moreover, also for the extraction and processing of the by-products like CO_2 and digestate, and the refining of minerals and feedstock a certain scale is required (Bianchi, 2018). Moreover, Bianchi, 2018 argues that adequate selection of a centralised location could ease the extraction of residual streams at relatively low costs. Ultimately, the centralisation and professionalisation offer costs reductions and optimalisation options due to the scale of production, system efficiencies, innovation, valorisation of residual flows and unburdening throughout the value chain. Especially the latter could support the increased utilisation of current untapped small-scale manure processing (Bianchi, 2018).

Additionally, it can be observed in figure 5.9 that manure accounts for approximately 35% of the total production capacity, while other wet biomass streams account for around 8%. However, in case of a reduction in the livestock of 20% the green gas production, in the high scenario, is expected to reduce by 12% from 1.97 bcm to 1.73 bcm. This is due to the strong contribution of manure in the economical potential scenario, which almost reaches 60% (van der Veen et al., 2020. The livestock reduction potential overlaps with the proposed plan by the Dutch coalition to reduce the number of livestock by one-third to battle the nitrogen crisis (Levitt, 2021).

Moreover, different installations sizes for the production capacity are assumed based on the amount of green gas production per hour. In case of manure digestion these are 50, 500, 1,500 and 3,000 m^3 and are based on small-, medium- and large size for the different scenarios (van der Veen et al., 2020). An overview of the current digestion installations, the total amount and installed capacity can be seen in table 5.2 (RVO, 2021).

Lastly, looking at the other scenarios the availability of SCWG and woody biomass as sources of green gas become more relevant in case of strong scaling and innovation, which increases the green gas production potential significantly.

	Mest (miljoen m^3)	Overige natte biomassa (miljoen m^3)	Hout (miljoen m^3)	Super-kritische vergassing (miljoen m^3)	Totaal (miljoen m^3)
Groengas					
Gerealiseerde installaties	111	69	0	0	**180**
Geplande installaties - vergisting	161	9	0	0	**171**
Geplande installaties - nieuwe technieken	24	0	300	593	**917**
Biogas*					
Gerealiseerde installaties	216	54	0	0	**270**
Geplande installaties - vergisting	62	2	0	0	**64**
Geplande installaties - nieuwe technieken	0	0	0	0	**0**
Totaal (groengas en biogas)					
Gerealiseerde installaties	327	124	0	0	**450**
Geplande installaties - vergisting	223	11	0	0	**235**
Geplande installaties - nieuwe technieken	24	0	300	593	**917**
Alle installaties	**574**	**135**	**300**	**593**	**1.602**

Figure 5.9: Production capacity of realised and planned green gas- and biogas installations (van der Veen et al., 2020)

Thus, it can be observed that several predictions arise for the technical- and economical potential of biogas production. Here, different resources and different production technologies are considered. Moreover, regulatory support and technological innovation are assumed to have a considerable influence on the respective predictions.

Type	Digestor count	Installed capacity (MWth)	Installed capacity (MWel)
Manure Digestion	116	47929	45613
Other Digestion	27	3818	5805
Wastewater Treatment	82	1089	4434
Food and Beverages	7	1467	1071
Landfill	41	0.25	16.60

Table 5.2: Digesters in the Netherlands in 2021 (RVO, 2021)

On top of that, the competitive use cases for biomass resources and biogas utilisation are relevant to derive a more adequate picture of the future potential. Nevertheless, it can be seen that biogas production capacity has significantly increased over the last decade and is presumed to continue to expand. This is further supported by a renewed vision on the valorisation of biogas, where the shift from bio-electricity to bio-heat and ultimately biomethane can be observed. Nonetheless, these predictions do not account for the proposed utilisation of biogas for the production of bio-hydrogen and bio-carbon dioxide or syngas.

5.3 Production

The production of biogas entails the conversion of biogenic feedstock, primarily residual waste stream, through digestion into biogas. In this respect, technological parameters can be used to further identify the economical potential of biogas production. Moreover, in-depth understanding of the environmental benefits of the biogas production routes can assist in understanding the societal benefits of biogas. This ultimately shed light on the economic parameters most dominant in the production of biogas as well as the utilisation in end application sectors.

5.3.1 Technology

For waste-to-energy conversion technologies, several types of waste, both solid and liquid, can be used and different technologies can be identified. The type of waste include household waste, agricultural waste, discards from slaughterhouses, and effluents from the sugar-, dairy-, brewery-, and pulp and paper industry. The conversion technologies can broadly be classified as either biological or thermochemical. In this perspective, thermochemical methods involve the decomposition of organic matter at elevated temperatures and include pyrolysis, gasification and incineration. Biological methods in contrast provide an alternative where waste is converted to various forms of energy, including bio-ethanol, bio-hydrogen and biogas. In case of the biological routes, pretreatment options exist to enhance the respective yields. These pretreatment routes include physical methods, physico-chemical methods, chemical methods and biological methods and depend primarily on the type of waste material or feedstock. These biological methods consist of ethanol fermentation, aerobic composting, dark- and photofermentation, and anaerobic digestion (Sharma et al., 2020).

Anaerobic digestion or also called biomethanation is the process to produce biogas in absence of oxygen through the decomposition of the substrate. The feedstock for this process include municipal solid waste (MSW), agricultural discard, manure, and fruit- and vegetable waste. AD comprises of three steps called hydrolysis, acidogenisis and methanogenesis. Firstly, in the hydrolysis step, the substrate is transformed into simpler units like amino acids and monosaccharides under the influence of bacteria. Secondly, the acidogenisis transforms the broken material to organic acids and other simple products like hydrogen and carbon dioxide. Lastly, in the methanogenesis, methanogens transform organic acids into methane gas (Sharma et al., 2020). In this process, the hydrolysis step is characterised as the rate-limiting step due to its dependence on the type of feedstock. In this respect, pretreatment options can enhance the digestibility of the substrates and thereby reducing the digestion time as well as improve the biogas yield. Next to the biogas produced, a digestate by-product is the output of the process, where the digestate is rich in nutrients and can be utilised as fertilizer.

For the AD process, parameters including the pH, temperature, ammonia-level, reactor-type, co-substrates, microbes and more all affect the productivity and as such provides a range for optimization of the respective outputs (Sharma et al., 2020). In general, a small pH window of [6.8-7.2] is preferred as well as thermophilic conditions of [50-60] °C to stimulate biogas yields, both of which are associated with an optimal ammonia level. Next to the ammonia level, the C/N ratio, which is a reflection of the nutrients level of the substrate, is a key parameter to control during the AD process as it can cause a release of ammonia, nitrogen and or volatile fatty acids in the digester, which in turn inhibit the AD process. Moreover, a process operating in a two-stage continuous process, with various methanogens, as opposed to a batch process or an one-stage continuous process showed better performance associated with effluent quality, methane yield, depletion of volatile solids and process stability. Here, the utilisation of a co-substrate could provide a good alternative to stimulate the efficacy of the degradation of substrates and energy output, for example through balancing the C/N ratio (Sharma et al., 2020). Moreover, in general the addition of a co-substrate increase the biogas yield and energy output, improves the economy of the biogas plants, boost the digestate fertiliser value and mitigates GHG emissions (Scarlat et al., 2018). Additionally, in case of visually contaminated waste streams like organic waste, digestion has to occur in non-clean regional digestion systems and require post-composting to remove any present litter for the digestate to be utilised. However, strongly contaminated waste streams would better be processed through a different waste processing method, like gasification (Corbey and van Asselt, 2020).

Overall, several studies covering different feedstocks and digester types showed methane yields per volatile solid (VS) of [60.9-474.4] $mL\ CH_4/g\ VS$ or [141.8 - 827] $mL\ biogas/g\ VS$ (Sharma et al., 2020). Ultimately, the process for anaerobic digestion can be summarized as seen in figure 5.10 (Sharma et al., 2020).

The digestion conversion methods towards biogas can be distinguished as mono-manure digestion, co-digestion and everything digestion. Here, mono-manure digesters are mostly associated with small-scale, agricultural biogas production facilities at a size of around [0-50] m^3 *biomethane/hour* (van der Veen et al., 2020). Approximately only 2% of the usable manure is currently processed via mono-manure digestion (van Soest and Warmenhoven, 2018). On the other hand, everything digesters are mostly related to large-scale processes of over 2000 m^3 *biomethane/hour* at industrial hubs or harbours that convert both mono-substrates as well as co-substrates. However, the size and feedstock used for the classification of the digestion conversion methods does not affect the process technology as described above (van der Veen et al., 2020). Besides these classifications, new conversion technologies

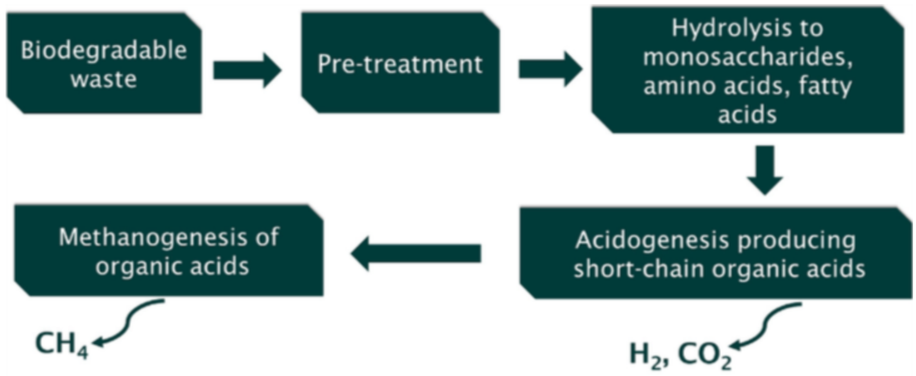


Figure 5.10: Summary of steps involved in the anaerobic digestion process (Sharma et al., 2020)

arise, for example autogenerative high pressure digestion (AHPD). In the case of AHPD, a high biomethane volume concentration of over 90% is obtained, where the high pressure is utilized to concentrate the CO_2 in the liquid phase to produce biomethane. Potential addition of hydrogen and or CO_2 could further enhance the biomethane concentration to 99%. However, the process is ascribed most potential for usage in waste water treatment plants or for the conversion of alternative waste streams like pig manure (van der Veen et al., 2020).

Developments in biogas anaerobic digestion in developed countries has primarily focused on achieving a larger scale. Moreover, even though AD is a well-established technology several improvements are expected that can boost cost reductions due to improved biological processes that can enhance the biological efficiency and biogas yield. Also, improved pretreatment technologies offer the possibility to use more feedstock types and or increase the biodegradability of the feedstock. Additionally, the use of new enzymes and bacterial strains with greater tolerance to process- and feedstock changes can further enhance the biogas production. Lastly, process improvements could support a reduction in the need for gas cleaning and contaminants removal (Scarlat et al., 2018).

In the Netherlands, a similar focus on upscaling and professionalisation of the biogas production can be observed. Currently however, unlocking available biomass streams is a bottleneck due to the lack of adequate biomass logistical concepts for collection and distribution. This limits the production of biogas to small-scale and local options. Moreover, the high moisture content of the biomass make transport relatively expensive and thereby limiting larger-scale production processes. Centralisation on top of that requires complex and long-term distribution contract of manure, limiting the adoption. Another limitation is associated with the need for rapid collection of manure which requires significant investments. This is strengthened by the fact that biogas production is not the main business of agricultural professionals and as such lack focus. Lastly, the lack of economic incentives hinder process upscaling (Bianchi, 2018). Nonetheless, new technologies, professional exploitation and potential CO_2 utilisation supports centralisation and professionalisation. Moreover, this can result in simpler processes, efficient conversion and cost reductions (Bianchi, 2018). van der Veen et al., 2020 add to this that upscaling is supported by economies of scale, accessible locations and avoidance of resistance from local residents. In this scenario, feedstock is transported from decentral, high biomass-dense locations to a centralised production facility designed for optimal system yield, efficiencies and costs (Bianchi, 2018). However, it should be ensured that manure can be transported and converted as soon as possible as the biogas yield of fresh manure is around 40% higher than for less fresh manure, decreasing yield per day (Corbey and van Asselt, 2020). Lastly, centralisation could offer additional benefits associated with local heat production and distribution as well as manure processing and extraction (Bianchi, 2018).

5.3.2 Sustainability

Biogas production via anaerobic digestion can be seen as a technological production route for simultaneous waste reduction and energy production. This is especially relevant since waste management is one of the greatest global challenges (I. Khan, 2020). van Soest et al., 2014 adds to this the potential for biogas to contribute to the solution for the increasing manure processing problem in the Netherlands. The production of biogas as biochemical waste-to-energy approach was seen to be the most economic, social and environmental. Moreover, it provides a reasonable- and environmental-friendly alternative to meet the sustainable development goals (Sharma et al., 2020). Here, the use of biogas replaces the use of fossil fuel and thereby contributes to GHG- and other pollutants emissions reductions. Since biogas production originates from short-cycled carbon in plants, the CO_2 emissions are considered carbon-neutral and high GHG emission reductions can be realised (Scarlat et al., 2018). According to Villadsen et al., 2019 it could be even considered a carbon-capture technology since the carbon caught in the reactor would otherwise been released to the air. As a result, biogas could be utilised to green agricultural production or more broadly to strengthen energy supply and security (Scarlat et al., 2018) (Villadsen et al., 2019). For example, biogas could substitute for low caloric natural gas in the Netherlands after local production of natural gas decreases (Bianchi, 2018). On top of that, biogas also helps to develop rural areas and encourage the creation of new supply chains for biomass feedstock. Biogas production offers next to the reduction of waste and generation of renewable energy the potential to decrease the water-, soil-, and air pollution (Scarlat et al., 2018). More specifically, biogas production for example, can reduce leachate into groundwater and the emissions of methane and carbon dioxide in the air, due to natural degradation of manure during storage (Sharma et al., 2020). Additionally, AD mitigates odours associated with the storage- and decomposition of manure and removes pathogens harmful to human- and animal health. Lastly, an other added benefit related to biogas production is the use of the digestate as natural fertiliser, having the same nutrient content as manure, to reduce the use of chemical fertilizers. This also reduces nutrient runoff and avoids methane emissions related to production of chemical fertilizers (Scarlat et al., 2018). This also ensures conservation of soil quality with respect organic matter content and adheres to the circularity perspective (Corbey and van Asselt, 2020).

However, the major environmental concerns related to AD consist of the release of highly corrosive hydrogen sulfide as well as greenhouse gases like SO_x and N_2O from organic residues in the digestate. Nonetheless, actual emissions numbers are varying widely (Sharma et al., 2020). The major environmental concerns also relate to the emission of methane and ammonia, especially in central digestion plants, in which case separation of manure and urine could lower the impact (Corbey and van Asselt, 2020). Also, I. U. Khan et al., 2017 indicate the ongoing issues associated with methane losses plus the environmental impact and energy consumption related commercial biogas production. Additionally, the end application emissions levels of biogas are similar to fossil counterparts. For example, the emission levels of bio-CNG and fossil CNG are similar at around 114 g/km (I. U. Khan et al., 2017). Nonetheless, the CO_2 emissions related to bio-CNG are considered carbon neutral. Moreover, biogas production used to be associated with the usage of dedicated energy crops for production. However, due to sustainability considerations associated with energy crops, for example with respect to land use changes and availability, the usage of energy crops for biogas production is expected to be limited. In this way, the production of biogas has no side effects like land use changes and or food security. Moreover, new legislation ensures that biogenic energy is produced without harmful effects like deforestation, degradation of habitats or loss of diversity. Moreover, legislation focuses on the reduction of unintended impacts on other competitive uses, where biomass feedstock should be cascaded in, preferably, long-lasting and or recyclable materials (Scarlat et al., 2018) (Corbey and van Asselt, 2020). In case of biogas, it should be noted that the residual waste stream otherwise requires processing and thus the energetic and molecular usage of biogas directly adds societal benefits (van Soest et al., 2014). Lastly, in case of low-quality feedstock digestion, especially in the case of co-digestion, the quality of the digestate might be negatively effected. In this case, quality requirements and post-composting helps to eliminate this concern (Corbey and van Asselt, 2020).

5.3.3 Economics

The utilisation of biogas has been altered over the past decade. Biogas traditionally found usage as source of electricity production. In this respect, 1 m^3 of biogas obtained via AD produces, at 35% efficiency, 2.04 kWh of electricity, or 21 MJ of energy (Sharma et al., 2020). However, the combined- or confined use of biogas for heat production emerged as opportunity to enhance the income and thereby profitability of biogas plants. This resulted in a shift from electricity only plants to heat only and or combined heat and power (CHP) plants. Here, the heat generated is used to meet local heat demand on for example farms or is used to generated heat and or steam in households or the industry (I. U. Khan et al., 2017).

More recently, upgrading of biogas towards biomethane has benefited from new uses and various support schemes, programmes and targets. Moreover, this trend was sparked by advancement in biogas upgrading technology, the poor economics of electricity biogas plants and new opportunities for biomethane in the transport sector. For example, an increase in CNG vehicles and fuelling stations supported the growth of biomethane production (Scarlat et al., 2018). Also, the increasing share of variable renewable energy source enhance the benefit of biogas upgrading technology. This is due to the fact that for heat- and or power production the process needs to run continuously as raw biogas cannot be cost-efficiently stored for more than a few hours. Therefore, biomethane storage in the gas grid supports adoption of variable renewable energy production through provision of flexibility which in turn add value to biomethane for use in periods of highest value. On top of that, while raw biogas mostly replace solar-, heat- and biomass power, the use of stored biomethane replaces fossil based transport fuels and or the fossil electricity marginal supply and thereby reduces overall environmental impacts (Angelidaki et al., 2018).

Similarly, since biomethane can be used as flexible- and storable energy carrier it is utilised to support the balancing of the energy grid via injection in the grid. The grid injection of biomethane gained more importance due to the depletion- and low quality of natural gas resources. Moreover, biomethane found new opportunities as transportation fuel, showing promising signs to act as a renewable fuel in the transport sector both in the form of bio-CNG and bio-liquefied natural gas (LNG) (Scarlat et al., 2018). Here, bio-CNG reduces CO_2 emissions by around 80% as opposed to the usage of fossil fuels and has 20% less global warming related emissions as compared to CNG, while having the same properties and performance. In this respect, the conversion of biogas to bio-CNG, is despite the high cost associated with pressurization, justified due to the higher heating value and higher product value (I. U. Khan et al., 2017).

Lately, the potential of biogas for the production of hydrogen is shown. In this perspective, the biogas or biomethane can be used as alternative for natural gas, thereby reducing the CO_2 emissions associated with the process. Other advantages include that biogas is a domestic and local energy source, that biogas is a cheap feedstock and that biogas production is considered an environmentally friendly process (I. Khan, 2020).

Additionally, Villadsen et al., 2019 add to this the renewed perspective on the utilisation of biogas as neutral carbon source through second-generation upgrading. Here, the CO_2 from upgrading can be utilised to produce high energy-density hydrocarbon fuels, with options for energy storage and the potential to close the carbon cycle. This limits the need for energy-expensive carbon capture technology and enables a better overall energy efficiency for the creation of hydrocarbon-containing molecules. In this perspective, biogas could the connection between the power-, transport- and gas sector as can be seen in figure 5.11 (Villadsen et al., 2019).

Conclusively, biogas is generally utilised in six different applications, namely electricity- and power generation in CHP, the production of heat and steam, injection into the natural gas grid, as vehicular fuel, for the production of hydrogen and for the utilisation of biogenic carbon dioxide (I. U. Khan et al., 2017). On top of that, the remaining digestate in case of AD biogas could provide an additional source of income (van Soest et al., 2014).

However, van Soest and Warmenhoven, 2018 highlight the importance of renewable, scarce and climate-friendly molecules that in the long-term perspective primarily should be utilised as feedstock. Here, these molecules should only be used for energetic ends if no other option exist. This perspective follows the transition from the initial use of biogas for electricity production, to biogas for the production of green gas to ultimately the shift towards the usage of biogas in bio-refineries. This perspective arises from the expected continued demand for renewable molecules despite large-scale deployments of renewable electricity production. In this respect, the renewable molecules benefit from relatively low cost of transportation, storage and distribution. Moreover, these renewable molecules offer the required flexibility and more importantly can be used as building block for further synthesis. An overview of the supply chain of renewable gases can be seen in figure 5.12. However, especially in case of renewable carbon-containing molecules, van Soest and Warmenhoven, 2018 argue that these should be reserved for usage in the chemical industry due to the lack of available alternatives for the production of materials and products. More precisely, van Soest and Warmenhoven, 2018 estimate the demand for feedstock to be around 10 bcm by 2050. In contrast, the total energy demand is expected to decrease to as low as 17.5 bcm in the Netherlands by 2050. Therefore, only in case of surplus, these carbon-containing renewable molecules should be used in heavy- and or long-distance mobility, in storage and buffering application and or for the provision of peak supply (van Soest and Warmenhoven, 2018).

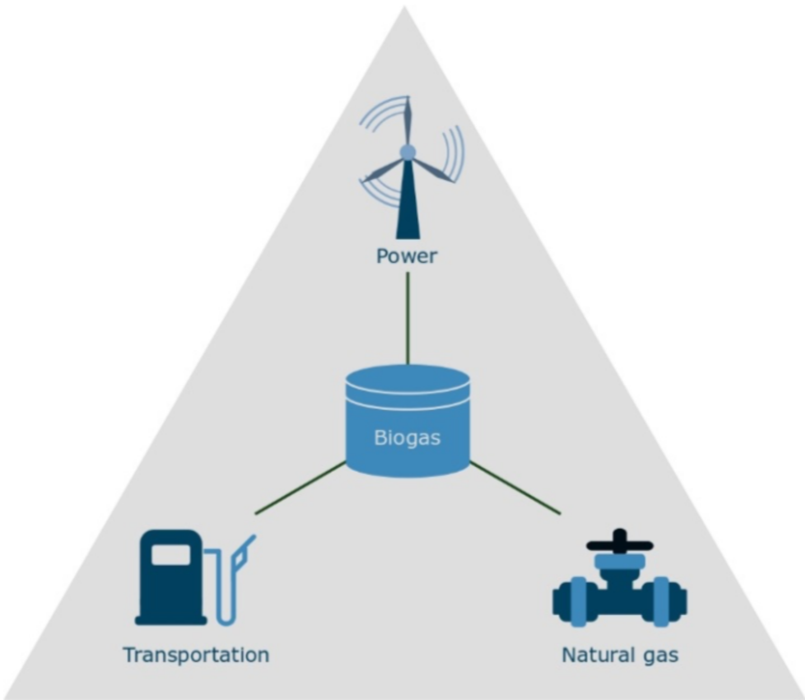


Figure 5.11: Platform role of second-generation biogas upgrading (Villadsen et al., 2019)

With respect to the production costs of biogas, these are strongly related to the different production options and applications. In case of co-digestion, the feedstock costs account for over 50% of the cost price, while these are 0% in case of mono-manure digestion since these are assumed to be cost free. However, in case of mono-manure digestion the investment costs make up around [60-65]% of the total production costs, which reduces to [25-30]% in case of co-digestion (van Soest et al., 2014). According to van Soest and Warmenhoven, 2018, the production costs of the different production methods show potential for significant costs reductions and as such might limit the need for additional subsidies. The expectations can be seen in figure 5.13.

More precise cost calculations for the production are derived from the calculation of the required subsidies for biogas production and usage in the Netherlands for 2022. Here, a distinction is made between large-scale digestion, large scale- and small scale mono-manure digestion, and sewage digestion. These production routes either generate biogas for green gas, for usage in CHP or for the production of heat. In case on large-scale digestion, installations that require residuals from the food industry are considered where the price of the feedstock is in competition with the animal feed market. As a result, large-digestion is characterised by a biomass input price of around 28 €/ton in comparison to manure digestion where the manure is assumed to have zero costs per ton, as the used manure is primarily produced on the farm site.

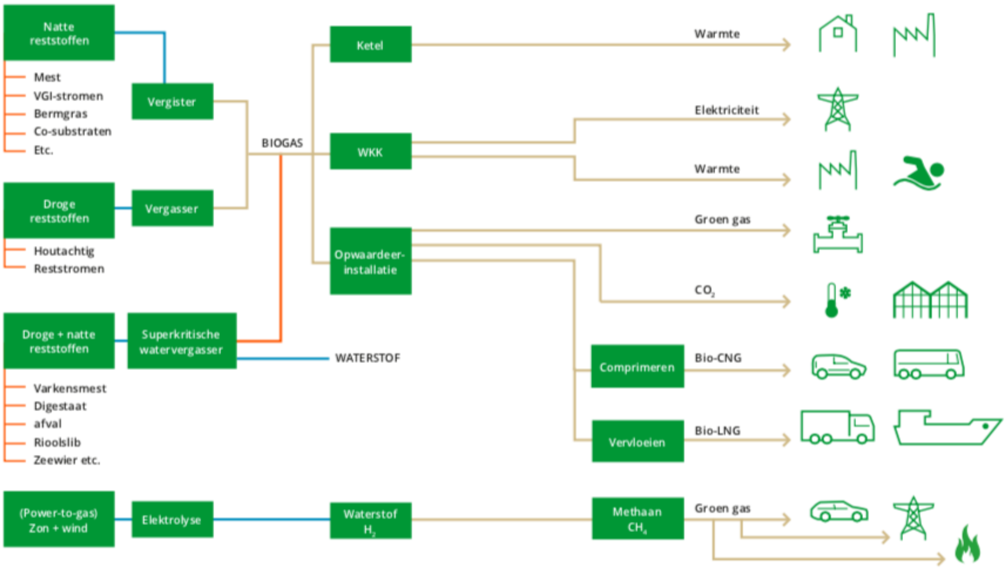


Figure 5.12: Renewable gases supply chain (van Soest and Warmenhoven, 2018)

In case of manure digestion a yield of 25 m^3 biogas or 0.53 GJ per ton of manure is assumed (Wolbers et al., 2021). For large-scale digestion, reference installations are from the industrial food industry, where the installations is integrated in the system and the input are residuals from the process. These processes have a reference capacity of around 950 $m^3/hour$ of raw biogas or 591 $m^3/hour$ green gas. The installation processes around 47 kt substrate per year based on an average biogas yield of 160 m^3 biogas/tonnes substrate. The total investment costs are estimated to be €4.9 million, with fixed O&M costs of €0.4 million per year. In case of small-scale mono-manure digestion for green gas, the reference system has a maximum size of 400 kW and a production of 47 $m^3/hour$ of raw biogas or 30 $m^3/hour$ of green gas. The total investment costs are estimated to be €0.9 million, with fixed O&M costs of €92,000 per year. In the case of large-scale mono-manure digestion the reference systems are larger than 400 kW and produce around 381 $m^3/hour$ of raw biogas or 248 $m^3/hour$ of green gas, at a reference size of 2200 kW. This overlaps with a manure input of around 120 kt per year, consisting of a mix of pig- and cattle manure combined with slurry and a solid fraction. The large-scale installations are primarily in the range of [400-3000] kW as larger scale digestion, which was assumed due to scaling and centralisation of the manure processing, seems to be limited. This was primarily due to uncertainty in the manure market. As a result, the realisation of digestion projects with a size larger than 3 MW are limited. The reference system is estimated to have a total investment cost of €5.4 million with fixed O&M costs of €0.64 million per year. In case of sewage digestion, the primary digestion process as part of the water purification- and sludge reduction system does not require additional subsidies as the business case is already positive. However, alternative technologies that enhance the biogas production from secondary sludge does require additional subsidies. In this case, the reference production capacity is around 130 $m^3/hour$ of green gas. Since the cost of sludge processing is reduced, the O&M costs show negative costs. Ultimately, a summary of the relevant technological-economical parameters for the production of green gas through the different production methods can be seen in table 5.3 (Wolbers et al., 2021).

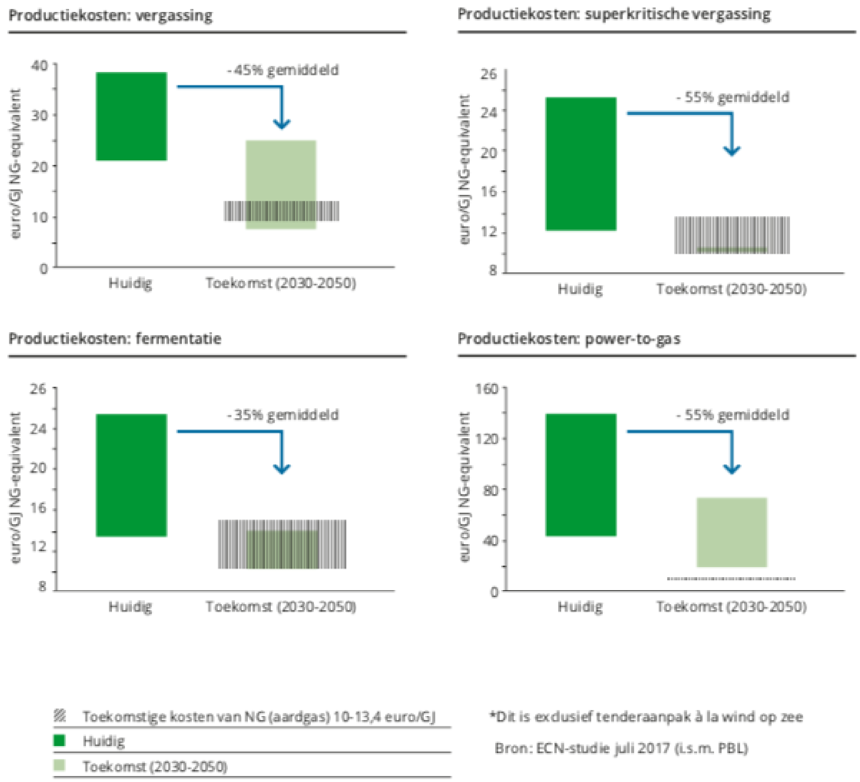


Figure 5.13: Cost price perspective of different conversion technologies (van Soest and Warmenhoven, 2018)

Parameter	Unit	Large-scale	Small-scale mono-manure	Large-scale mono-manure	Secundary sludge
Reference size	MW input	5.5	0.27	2.2	1.9
Load hours	hours/year	8000	8000	8000	8000
Internal heat demand	% biogas	5	18	16	N/A
Investment costs digester	€/kW input	880	3300	2080	incl. upgrading
Investment cost upgrading	€/kW output	404	incl. digester	370	9106
Fixed O&M cost digester	€/kW input	111	340	291	-676
Energy-content substrate	GJ biogas/t	3.4	0.53	0.53	N/A
Feedstock costs	€/t	28.2	0	0	N/A
Value SDE++ subsidy (2021)	€/kWh	0.0664	0.0930	0.0741	0.0848
Duration subsidy	year	12	12	12	12

Table 5.3: Technological-economical parameters for digestion systems in the Netherlands (2021) (Wolbers et al., 2021)

It can be seen that most biogas production methods and applications still require financial support. Therefore, the strong growth of biogas production in Europe was primarily driven by favourable support schemes in the different member states. These include, for example feed-in-tariffs (FIT) and feed-in premiums (FIP) for bio-electricity, subsidies for bi-oheat and blending quotas for biofuel. Other support schemes included grants and tenders (Banja et al., 2019). For biomass in general and biogas in specific several financial- and regulatory measures are applied throughout Europe. Financial measures include subsidies, tax reliefs, energy schemes, eco-funds, investment grants, incentive programs, guaranteed purchases prices, zero-rated eco-loans, energy taxes, pollution taxes, and more support and promotion (Banja et al., 2019). van Soest et al., 2014 additionally mention the usage of green certificates trades, which is increasingly important especially in the mobility sector. Regulatory measures included quotas, mandatory blending, sustainability targets, and more. Overall, in the period between 2005 and 2015 26.7% of the financial measures were directly dedicated to biogas, while another 4.4% and 2.7% were dedicated to CHP and co-generation respectively. With respect to regulatory measures, 12.8% was attributed to biogas, while 68.8% was assigned to biofuels, mainly for usage in the transport sector. With respect to the usage of biogas for electricity production specifically, manure received the highest average support level throughout the EU with a FIT and FIP of 222 €/MWh and 231 €/MWh respectively. In the Netherlands a FIP of 75.7 €/MWh is observed to support biogas in the electricity sector as compared to 187.5 €/MWh and 109 €/MWh in the case of France and Germany respectively (Banja et al., 2019).

5.4 Analysis

Within the research context biogas has been ascribed higher valorisation potential through the concept of third-generation upgrading. In this respect, biogas does not operate solely as renewable energy source, but also as renewable carbon source. Moreover, it allows for biogas to operate as carbon sink in order to close the carbon cycle and result in negative carbon emissions. This is in contrast to the current perspective on the utilisation of biogas. Here, biogas is, primarily, seen as a source of renewable energy either as biogas in the heat- and or power sector or as biomethane in the industrial-, transport- and or build environment sector.

It was seen that, all over the world, the attention for biogas as sustainable-, cost-effective- and social- waste-to-energy conversion method is sparking. In this light, biogas has been ascribed direct benefits in relation to renewable energy production, carbon neutrality and the deployment of circular digestate, without having a negative effect on land-use changes and biodiversity. This resulted in a strong growth and high growth expectations with respect to biogas production capacity.

An additional driver for the growth potential of biogas capacity are the identified potential cost reductions, efficiency gains and increases in biogas yield. This relates to the deployment of new technologies, economies of scale, simpler processes and the unlock of new- and unused biomass streams. Identified trends here are the increased commercialisation and professionalisation of the biogas production sector, which enhances the reliability and security of production. Moreover, continued policy support through regulatory- and financial measures are expected to further increase the economic viability of biogas production to support further growth.

On top of that, the growth potential of biogas production capacity was strengthened by the identified higher value applications for biogas. This ensures that the technical potential and the economic potential of biogas production capacity are increasingly aligned. Here, the usage of biogas was initially limited to electricity production, but the perspective on biogas utilisation shifted towards heat- or combined heat- and power production. More recently, the perspective shifted towards the use of biogas for biomethane production. The biomethane subsequently found higher value applications in the industrial-, transport- and or build environment sector.

Nonetheless, this perspective ignores the potential of biogas as source of bio-hydrogen and bio-carbon dioxide. In this perspective, biogas could be seen as a platform molecule which consist of an energetic bio-hydrogen- and molecular bio-carbon dioxide component. In this way, the concept of third-generation upgrading aligns with the renewed vision on a future renewable hydrogen system. Moreover, it aligns with the perspective on the ultimate utilisation of biomass as source of feedstock rather than energy. This was sparked by the realisation that there is a lack of alternative options for renewable carbon in a fossil fuel-free energy system.

Moreover, within the perspective of the future renewable hydrogen system, biogas could be seen to both stimulate a rapid- and affordable transition as well as fulfill an important role as local- and or regional bio-hydrogen and bio-carbon dioxide production method. In this way, biogas could find a high value application as zero-pollution bio-hydrogen source. Moreover, this allows over time for the increased valuation of bio-carbon as source for climate-neutral carbon. This subsequently, supports the devaluation of, direct, biomethane utilisation with respect to bio-hydrogen. In turn, this could spark a new transition in the perspective on biogas valorisation. Moreover, cost reduction potential for the production of biogas could further stimulate the adoption of bio-hydrogen and bio-carbon dioxide production.

Specifically, in the Netherlands the current production potential of biogas is around 0.18 bcm biomethane equivalent. Here, the production of biogas from manure is stated to be around 0.11 bcm, despite a technical potential of 1.3 bcm. With respect to the total economical biogas production capacity, this is presumed to be maximally increased to around [0.97-1.07] bcm biomethane equivalent by 2030 or [1.1-2.2] bcm by 2050, while the technical potential is stated to be around 5.1 bcm biomethane equivalent. However, the reduction of livestock in the Netherlands would limit the available manure and as such affect both the technical- and economical potential. Here, a reduction of [20-33]% could be expected, which could subsequently lower the technical potential of manure digestion to [0.87-1.04] bcm biomethane equivalent.

In this respect, in case of the renewable hydrogen energy system, the total technical potential of biogas-, the technical potential of manure biogas- and the economic potential of biogas could fulfill up to approximately 45%, 9% and 16% of the current natural gas demand in the build environment. The same levels approximately represent the natural gas demand in the power sector. However, in case of road transport this would lower to around 40%, 8%, 14% respectively. With respect to the energy demand in the aviation- and maritime industry this relates to around 25%, 5% and 10% respectively based on a presumed energy equivalent calculation. Overall, based on the current total natural gas demand in the Netherlands, the manure theoretical potential could support approximately 2%. On the other hand, the potential could constitute to a, theoretical, bio-hydrogen potential of around 20 bcm in case of the total technical potential for biogas or around 5 bcm in case of manure digestion only. These estimations are based on reforming via the SMR- or ATR production route, but do not account for potential energy efficiency losses and or utilisation of extra biomethane. This could lower the technical potential by an estimated [50-70]%. In the same line, the economic potential of bio-hydrogen production from biogas could be estimated to be between [4-9] bcm bio-hydrogen. However, the current economic potential calculation does not account for the higher valorisation potential of the concept of third-generation upgrading. To put in perspective, the technical potential of manure digestion could fulfill almost one-third of the total current demand for hydrogen, or two-third in the case of natural gas-produced hydrogen, in the industrial sector in the Netherlands.

Next to the proposed potential of biogas production capacity in the Netherlands, biogas is shown to offer significant environmental benefits, including the reduction of methane emissions, reduction of problematic waste streams and the by-production of bio-fertilisers. Moreover, in case of biomethane production it could theoretically support the capture of around [0.30-0.40] bcm CO_2 per bcm biogas. This subsequently translates into around [0.15-0.20] bcm CO_2 per bcm biomethane. On top of that, in the case of the concept of third-generation upgrading, based on the chemical composition of the reforming reactions, an additional theoretical [0.8-1] bcm CO_2 per bcm biomethane could be captured and utilised. Therefore, theoretically, around [300-400]% more CO_2 could be captured in case of the concept of third-generation as opposed to the concept of second-generation upgrading. This is especially relevant as in the case of biomethane combustion the captured short-cycled carbon is ultimately released in the form of CO_2. As result, in case of the total technical potential of manure digestion in the Netherlands, this allows for a, theoretical, total carbon capture potential of around 1 bcm CO_2, or around 1% of the current fossil CO_2 emissions in the Netherlands at around 2 Mt CO_2. However, this ignores the energy requirements for the system. Nonetheless, these could be fulfilled by renewable electricity and biomethane, including additional capture technology, to lower the process related emissions. This also strengthens the case for scaling over the value chain and further support system integration.

Moreover, the economic potential could be stated to suffer from the requirement of governmental subsidies for the production of biomethane from biogas. In this respect, the subsidies account for around [0.06-0.1] €/kWh to support the production of biogas for usage as biomethane. Therefore, to support the unprofitable peak, approximate €[0.8-1.1] billion per year is required to support the total, technical, biomethane potential from manure digestion. This account for around 0.3% of the current total budget of the Netherlands, or [33-50]% of the subsidy budget for renewable energy. However, the estimate focuses on the current production cost perspective and does not include a proposed expected drop in production costs of on average around 35%. This could arise from the deployment of new digestion technology, the enhancement of production yield or efficiency, and or improved value chain design, among others. Also, the estimate does not account for other potential regulatory- and or price mechanisms present. Moreover, this does not account for the potential higher valorisation potential, minus additional production costs, from the production of bio-hydrogen and the additional sales potential of bio-carbon dioxide.

Therefore, it can be observed that the concept of third-generation upgrading provides, within the proposed renewable hydrogen system, a higher valorisation potential option. This includes support of the relevant demand for, especially local- and or regional, bio-hydrogen. Moreover it was shown that the concept of third-generation upgrading is able to open a sizeable and indispensable stream of bio-carbon dioxide. However, to adequately assess the concept of third-generation upgrading, within the perspective on the renewable hydrogen system, special attention needs to be devoted to the alternative uses of biogas.

Strengths and weaknesses analysis

The respective use case of biogas have been subject to several different perspective over time. Moreover, the perspective on biogas differs not only over time, but also over location as the end applications for biogas differ over European countries. This is further complicated by contrasting and overlapping policy domains. In the case of the renewable energy domain, biogas should primarily be used as energetic feedstock, while in the bio-economy domain biogas finds applications as molecular feedstock. Therefore, to portray the potential of the concept of third-generation upgrading within the wider perspective on the future renewable hydrogen system, the respective strengths and weaknesses of the different end applications for biogas can be seen in table 5.4.

In table 5.4 it can be seen that the concept of third-generation upgrading is supported by the useful- and complete utilisation of biogenic carbon. In this way, the concept of third-generation upgrading could support the ultimate use of biogas as negative carbon source. Moreover, this is supported by the potential to optimise the exact interpretation of the concept of third-generation upgrading over time and location. This is supported by the presumed increase in the value of bio-carbon over time, while the sales value of bio-hydrogen could reduce over time. On top of that, the exact location and integration potential stimulate the optimalisation of the process and could spark direct biogas and or bio-hydrogen and bio-carbon dioxide in demand centers. Additionally, the concept of third-generation upgrading supports the required transition towards the proposed renewable hydrogen system and as a result could initiate the devaluation of biomethane. However, the proposed production cost increase associated with the additional reforming step is needed to be recovered.

To conclude, the notion of third-generation upgrading shows important potential within the perspective on the future renewable hydrogen system. In this respect, bio-carbon can contribute significantly to the expected demand for renewable feedstock. Moreover, bio-hydrogen can constitute relevant production capacity of renewable hydrogen. Here, the exact interpretation of the concept of third-generation upgrading could be optimised over time and place depending on the demand centers and relative value perspective. On top of that, the third-generation upgrading could allow for a rapid- and cheap transition towards the renewable hydrogen system. Moreover, the concept of third-generation upgrading could add necessary capacity of negative carbon emissions. In this respect, it could support the development of the required infrastructure and regulatory design. This also includes the support for zero-pollution applications. In this respect, the utilisation of biogas, and specifically biomethane, will be devalued against its constituents bio-hydrogen and bio-carbon.

End application	Strengths	Weaknesses
Electricity production	Additional renewable electricity capacity, direct local utilisation, continuous production potential	Full bio-carbon waste, low efficiency, low value application, could compete with other renewable electricity sources, continuous production requirement
Heat production	Additional renewable energy capacity, direct local utilisation, combined heat- and power production potential, baseload fulfillment	Full bio-carbon waste, low value application, continuous production requirement, system efficiency losses
Gas grid injection	Direct carbon reduction potential, cost-effective solution, focus on specific harder-to-abate (residential) buildings, green gas certificate allocation, regional optimalisation	Natural gas lock-in, bio-carbon waste, require alterations infrastructure, require alterations in regulations, reduce adoption alternatives
Transport sector	Direct carbon reduction potential, hard-to-abate industry, cost-competition with synthetic fuels	Infrastructure lock-in, emission pollution, bio-carbon waste, reduce adoption alternatives, questionable scale for maritime- and aviation applications
Hydrogen production	Zero-pollution fuel, valuable bio-carbon source, output optimalisation potential, regional- and sectoral coupling options, infrastructure overhaul, emission reduction goals, no- or lower methane leakage, fast transition, system optimalisation	Higher production cost, higher investment costs, additional input material requirements, market sales value bio-hydrogen time-dependent

Table 5.4: Strengths and weaknesses of biogas utilisation

Chapter 6

Technology

The conversion of biogas to bio-hydrogen and bio-carbon dioxide is mentioned to provide great potential within the future renewable hydrogen system. Here, bio-hydrogen could add relevant production capacity of renewable hydrogen, especially for local- and or regional demand. This adds increased relevance in the short-term to support the transition towards the proposed renewable hydrogen system. Moreover, the perspective on the utilisation of bio-carbon dioxide support the higher valorisation potential of biogas. In this case, climate-neutral carbon should ultimately be reserved for applications as feedstock. In this perspective, the conversion of biogas and the intermediate utilisation of the produced syngas could also provide significant advantages. These advantages could be supported through optimalisation over time and place. This specifically relates to the inherent value of bio-carbon within the future fossil-free energy system. Within this perspective, the ultimate conversion of biogas to bio-hydrogen and bio-carbon needs to be feasible. Moreover, the technical parameters could provide relevant insights with respect to the potential use cases for the local- and or regional conversion of biogas.

As a result, this chapter aims to identify the relevant technological production routes and parameters that characterise the conversion of biogas to bio-hydrogen and bio-carbon dioxide, with additional attention to the produced syngas. To do so, this chapter identifies the technological value chain for the complete conversion of biogas and assess the different technological options based on relevant characteristics within the context of the renewable hydrogen system. Ultimately, this chapters aims to discuss the most relevant technological production route for the conversion of biogas to bio-hydrogen and bio-carbon dioxide. This supports the concept of third-generation upgrading within the wider proposed renewable hydrogen system.

6.1 Introduction

The conversion of biogas to bio-hydrogen and bio-carbon dioxide requires several steps. As raw biogas contains, besides its main constituents methane and carbon dioxide, several contaminants, the raw biogas is cleaned before further processing. Hereafter, the raw biogas is traditionally upgraded towards green gas by the separation of carbon dioxide. The subsequent methane-rich stream is converted through the steam methane reforming process. Here, two WGSR are used to enhance the hydrogen yield by converting the carbon monoxide in the syngas to hydrogen under the presence of steam. Finally, the resulting gas mixture consisting of hydrogen and carbon dioxide is separated to obtain a high-purity hydrogen stream and a carbon dioxide stream. However, the purified biogas stream has the potential to also be directly converted without the need for an additional upgrading step. Moreover, the purified biogas stream could also in-situ be converted to a high-purity hydrogen stream without the need for a later purification step (Nalbant and Colpan, 2020). As a result, high-purity hydrogen could be produced through either the direct delivery of biomethane through the grid or in the form of CNG or LNG, or through the upgrading or direct usage of delivered or on-site produced biogas (Matton et al., 2016). A high-level overview of the conversion route of biogas to high-purity hydrogen can be seen in figure 6.1 (Nalbant and Colpan, 2020).

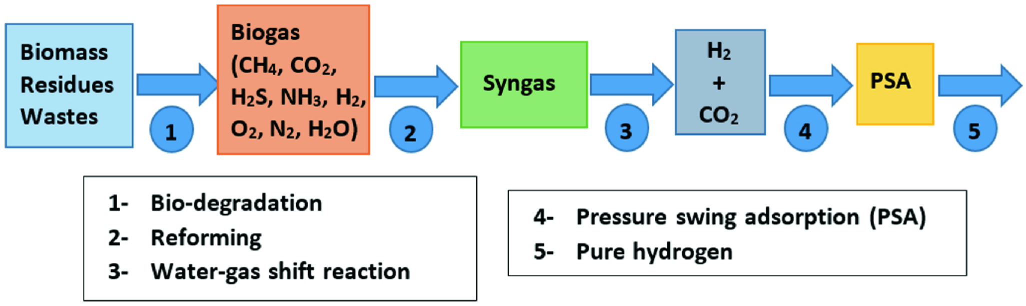


Figure 6.1: High-level overview of biogas to hydrogen conversion (Nalbant and Colpan, 2020)

6.2 Conversion

At current, the conversion of biogas directly to hydrogen, while technically possible, is not instantly ready to be deployed (Matton et al., 2016). As a result, the production of hydrogen through methane steam reformation remains the primary production process, where the upgraded biogas is used to green the process by replacing fossil methane as chemically identical compound (Primmer and Tredd, 2021). Therefore, the process firstly involves the separation of contaminants in the input raw biogas flow, like hydrogen disulfide and ammonia, as these could, for example, lead to catalyst poisoning (Chattanathan et al., 2014). In case of H_2S removal, activated carbon is mostly utilised while for H_2O removal condensation and adsorption on, for example, silica gel is mostly used (I. U. Khan et al., 2017). Hereafter, the biogas is upgraded to natural gas-quality biomethane by separation of the carbon dioxide. Several upgrading techniques exist, however the dominant process in the market operates by means of membrane separation (Wouters et al., 2020). Subsequently, the green gas is firstly converted to a synthetic gas mixture consisting of hydrogen and carbon monoxide by means of steam methane reforming and then the carbon monoxide is further processed with the help of steam to a combination of hydrogen and carbon dioxide through a high-temperature and low-temperature water gas shift reaction in order to increase the hydrogen content of the outlet mixture. The conversion of natural gas via SMR is the currently the most used technology covering over 50% of the global production processes (Marcoberardino, Foresti, et al., 2018). Finally, the hydrogen and carbon dioxide are purified by means of pressure swing adsorption. While alternative separation methods exist, PSA remains the dominant method due to the high hydrogen purity requirement, the low operation costs and the long service life associated with PSA (Du et al., 2021).

6.2.1 Contaminants removal

It was shown that impurities likes H_2S have a detrimental effect on the conversion efficiencies of the biogas to hydrogen conversion route. Chattanathan et al., 2014 for example showed that the effect of H_2S on commercial methane reforming, at even small amounts of H_2S of 0.5% mol, resulted in a drop to around 20 percent points in the conversion of both CO_2 and CH_4. This was in comparison to conversion levels of around 70% and 90% for CH_4 and CO_2 respectively. This showed the effect of catalyst poisoning, where with the introduction of H_2S the sulfur deposition reaction was more favored (Chattanathan et al., 2014). However, besides H_2S other contaminants include other sulphur compounds, halogenated compounds, siloxanes, water, ammonia and volatile organic compounds (VOCs). The presence of the biogas impurities all have associated negative effects on the further conversion of biogas and therefore require removal. For example, ammonia is corrosive when dissolved in water and can cause the formation of nitrogen oxides (NO_x) , while siloxanes can cause the formation of silicon dioxide (SiO_2) and result in deposition in cylinders and valves (I. U. Khan et al., 2017).

In basis, both the moisture and H_2S have to be removed from the biogas. An overview of the pretreatment and removal methods can be seen in figure 6.2 (I. U. Khan et al., 2017). For moisture, this is related to the potential damages to the equipment by corrosion. This can be conducted through condensation or adsorption. In the case of H_2S, besides a sharp reduction in conversion efficiencies, the presence of H_2S can also cause corrosion. Several pretreatment methods exists, which are in general most effective at high sulphur concentrations. With respect to the other contaminants, siloxanes can be removed with the help of activated carbon, while water scrubbing technology can be used to remove water soluble halogenated compounds, sulphur compounds and ammonia (I. U. Khan et al., 2017).

H_2S pretreatment methods	H_2O removal methods
Air/O_2 dosing to biogas reactor	Condensation
Iron sponge	Demister
Iron oxide	Cyclone
Iron chloride dosing to digester slurry	Moisture trap
Air stripping and recovery	Adsorption dryer
Biological removal on a filter bed	Silica
Membranes	Aluminium
Adsorption on activated carbon	Physical absorption with glycol
Physical and chemical absorption	Absorption with hygroscopic salts
Zinc oxide sorbents	

Figure 6.2: H_2S and H_2O pretreatment and removal methods (I. U. Khan et al., 2017)

An overview of the advantages and disadvantages of the relevant contaminants removal technologies for H_2S and other contaminants can be found in table 6.1. It is noted that H_2S is poisonous and corrosive in nature, which limit economical regeneration. Therefore, R&D should focus on the production of sulfur recovery at lower cost, while minimizing the impact on equipment and the environment. In this perspective, the combination of two- or more technologies for the removal of H_2S and other contaminants show promising signs (Awe et al., 2017). In general, H_2S and other contaminants removal is either carried out through physical-, chemical- or biological processes and can be internal or external. Moreover, the technologies are mostly divided into two levels with decreasing levels of H_2S to fulfill specifications and requirements (Domingues et al., 2021). Moreover, the removal of contaminants per cleaning technology can be seen in figure 6.3 (Zabava et al., 2019).

In case of H_2O removal, as biogas could contain water concentrations between [3-10]%, to protect downstream equipment against corrosion and lower the need for post-treatment, the main technologies include condensation-, adsorption-, and absorption drying. In case of condensation drying, the advantages are the simple process, which allows for any biogas flow and pretreatment application, and the additional removal potential of hydrocarbons and oil particles. On the contrary, condensation drying is characterised by a high energy consumption and high investment- and maintenance costs. Adsorption drying in contrast, benefits from regeneration of the adsorbent, high removal rates and low operating cost, while suffering from prior removal requirements of particles and oil, high investment costs, and has limits to biogas volume flows. Absorption drying benefits from high removal rates and regeneration of materials, and also removes hydrocarbon particles. Nonetheless, the high investment costs, economic viability only for high biogas flow rates and high pressure- and temperature requirements for regeneration of materials limit the deployment (Domingues et al., 2021).

Biogas Cleaning Process	H_2S	O_2	N_2	VOCs	NH_3	Siloxanes	H_2O
Adsorption	**	/	-	**	*	**	**
Water Scrubbing	**	--	--	**	**	**	--
Biofiltration	**	--	--	**	/	/	--
Refrigeration	/	-	-	/	**	*	**

Legend: ** High removal (intended) * High removal (pre-removal by other cleaning technology preferred) / Partial removal - Does not remove -- Contaminant added R Must be pretreated

Figure 6.3: Contaminants removed by different biogas contaminants removal technologies (Zabava et al., 2019)

6.2.2 Biogas upgrading

After the contaminants removal stage, upgrading technology is utilised to increase the biomethane content of the biogas input stream by separation of the bio-carbon

Technology	Advantages	Disadvantages
Physical absorption	Potential for CO_2 removal	Not regenerative, difficult solvent, complex operation, strong economies of scale
Chemical absorption	Low CH_4 losses	consumption of chemicals, complex operation, not regenerative
Iron chloride dosing	Elemental sulphur is formed, low investment costs, simple operation, compact technique	Low efficiency, expensive iron salt, change in pH and temperature not beneficial for digestion, high pressure problem
Adsorption using oxides	Similar to iron chloride dosing	Sensitive to water, exothermic regeneration, reduction surface reactions, toxic disposal
Adsorption on activated carbon	High efficiency, high purification rate, compact technique, high loading capacity	CH_4 losses, prior treatment required, strong temperature effect in process
Biological desulphurisation	Elemental sulphur is formed, simple operations, no chemicals required, low maintenance	Possible O_2 sensitivity, potential explosive mixture, low purification level
Biological filtration	High removal possible, no extra chemicals, no internal O_2 injection, enables ammonia removal	Need to renew nutrients, not suitable for treatment of CH_4, suitable for small biogas flows
Biological gas scrubber	Anaerobic process not effected, high purification, suitable for high biogas flows	Requires chemicals, high maintenance, fresh water need
Membrane separation	Removal of H_2S at >98% possible, CO_2 is also removed	Expensive operation and maintenance, highly complex

Table 6.1: Advantages and disadvantages of alternatives and technical features of H_2S and other contaminants removal (Awe et al., 2017) (Domingues et al., 2021)

dioxide. In this way, the green gas has the same characteristics as natural gas, like the caloric value. The separation of methane and carbon dioxide can be based on the different chemical- and physical behaviours of methane and carbon dioxide and could occur through one of four currently prevailing technologies. These technologies are membrane technology, pressure swing adsorption, cryogenic technology and scrubbing technology (Welink et al., 2007) (Wouters et al., 2020). A high level overview of the different biogas upgrading technologies can be seen in figure 6.4 (I. U. Khan et al., 2017).

Membrane technology as gas separation method is common within industrial processes and is based on the difference in permeability of the membrane for the different gases (Welink et al., 2007). The permeability is based on the applied driving force, for example difference in concentration, pressure, temperature or electric charge, and could be explained by the solution-diffusion model. In this model, the permeates dissolve in the membrane material and subsequently diffuse through the membrane as a result of concentration differences. At a later stage, the permeates are separated through a pressure-driven convective flow through small pores. In the case of biogas upgrading, the CO_2 permeates through the membrane and the CH_4 retains on the inlet side (I. U. Khan et al., 2017). Membrane separation benefits from the simplicity

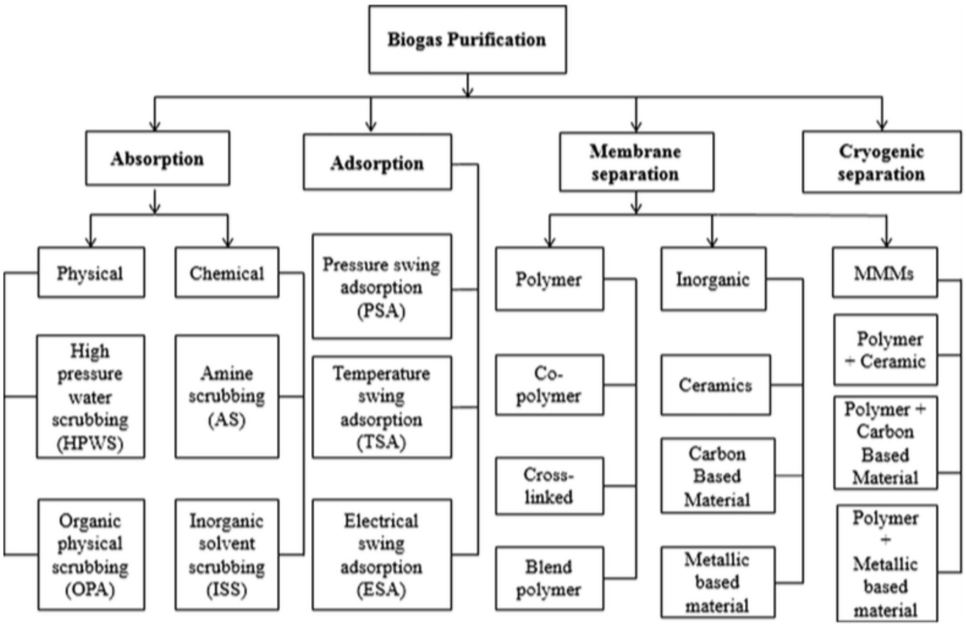


Figure 6.4: Current technologies for biogas upgrading (I. U. Khan et al., 2017)

of operations, low costs, low energy usage, and environmental friendliness. This is attributable to the physical barrier rather than the usage of a liquid or elevated pressure. However, membrane separation requires pretreatment and has a relatively higher methane loss as compared to chemical scrubbing (Wouters et al., 2020). While different types of membranes could be utilised, in general the utilisation of a multi-stage membrane process is more economic, has a lower energy demand and facilitates simple operations. Moreover, the multi-stage membrane process has in comparison to the a one-stage process lower operating costs, while achieving high CH_4 purity (I. U. Khan et al., 2017).

PSA on the other hand utilises the difference in adsorbency between methane and carbon dioxide with a liquid and or under elevated pressure. In this case, the raw biogas is send through an adsorber at higher pressures in which the carbon dioxide is adsorbed, as a result of physical- or Van Der Waals forces, while the methane passes. However, in case of saturation of the adsorbent, traces of carbon dioxide might pass. Therefore, the adsorber is switched off and, in case of vacuum pressure swing adsorption (VPSA), vacuum pressurized which results in the release of the adsorbed carbon dioxide. In case of VPSA, a high-purity methane stream at high-utilisation level can be obtained (Welink et al., 2007). According to Wouters et al., 2020, the pressurised swing adsorption method results in the most methane losses between the different upgrading technologies, however it has the lowest energy demand. I. U. Khan et al., 2017 adds to this that a high methane concentration can be achieved, but the process requires extensive control and has high investment- and operation costs. Moreover, since H_2S is considered toxic to the process, a pretreatment step is required. Commercial technologies exist at low- and high capacity ranging from 10- to 10,000 m^3/h of biogas (I. U. Khan et al., 2017).

Cryogenic technology in contrast uses the difference in melting point between methane and carbon dioxide. Through a strong reduction in temperature, the gaseous carbon dioxide is converted into solid carbon dioxide through sublimation.

This results in a high-purity methane stream. Moreover, the solid carbon dioxide, or dry-ice, is utilised within the industry and contains a commodity value (Welink et al., 2007). The downside of the process is the need to use different process equipment, like turbines, heat exchangers, distillations columns and compressors which increase the capital- and operational cost and have high energy requirements. Moreover, cryogenic technology also requires a pretreatment step. On the other hand, the process could be well-suited for the production of bio-LNG (I. U. Khan et al., 2017).

Lastly, scrubbing technologies, or also called absorption technologies, are based on the ability of gaseous components to transition into the liquid phase. This is related to the solubility of the components in a liquid and is governed by Henry's law. Additional chemicals can be added to the washing liquid to enhance the adsorption of the respective molecule, through conversion of the absorbed components, and thereby increase the separation. In case of carbon dioxide, water can be utilised, while methanol could support the separation of methane (Welink et al., 2007). In case of biogas upgrading, the raw biogas meet a counter-flow liquid in a column filled with packaging material to enhance the contact area. As the CO_2 is more soluble, a high-concentration CH_4 stream leaves the column, while the liquid is increased in concentration of CO_2 (I. U. Khan et al., 2017). Based on the liquid used, the process is either called chemical scrubbing, physical scrubbing or water scrubbing in case of the use of chemical solvents, organic physical material or water respectively. An example of chemical scrubbing is amine scrubbing. Chemical scrubbing has the advantage of faster upgrading and limited methane loss, however it requires high amounts of energy for steam production and requires pretreatment and chemical inputs. Physical scrubbing in contrast is simpler, has lower operational costs and maintenance, but requires large amounts of water, energy and an external heat source (Wouters et al., 2020). Moreover, the efficiency of physical scrubbing is higher in comparison to water scrubbing in terms of CO_2 separation, but is also characterised by higher costs and energy due to the solvent used (I. U. Khan et al., 2017). In the case of high-pressure water scrubbing the process is seen as eco-friendly, highly efficient and has no chemical requirements. Moreover, the process is characterised by ahigh methane recovery. Nonetheless, the process might still require a pretreatment and post-treatment process, has high investment- and operational costs, and has a high energy consumption (I. U. Khan et al., 2017).

An overview of some of the strengths and weaknesses of the relevant upgrading technologies can be seen in table 6.2.

Nevertheless, Within the European Union membrane separation is the most common upgrading technology and has been increasingly adopted over the last decade due to the associated benefits. In 2019, membrane separation was operational at around 34% of the biomethane plants, while water- and chemical scrubbing lost preference and have a combined share of approximately 46%. The specific changes in the respective utilisation of upgrading technique can be seen in figure 6.5 (Wouters et al., 2020).

6.2.3 Biomethane reforming

The traditional production of fossil hydrogen has primarily relied on the different thermochemical production methods. In this respect, the direct replacement of natural gas with biomethane offers potential for rapid uptake of bio-hydrogen production.

Technology	Advantages	Disadvantages
Pressure swing adsorption	CH_4 concentration >95%, other impurities removal, easy startup, adsorbent regeneration, small-scale application	CH_4 losses, pretreatment of H_2O and H_2S required, extensive process control
Water scrubbing	Adjustable and tolerable process, CH_4 concentration >97%, other impurities removal, continuous- and automatic operation, no chemicals required	high CH_4 losses, pretreatment and post-treatment required, less efficient, slow process
Physical scrubbing	CH_4 concentration >97%, removal of organic components, low CH_4 loss	Strong economies of scale, difficult solvent, intensive regeneration, H_2S pretreatment advised, require external heat source
Chemical scrubbing	CH_4 concentration >99%, low pressure, complete H_2S removal possible, fast process	H_2S pretreatment advised, chemicals input, potential contaminants buildup
Membrane separation	CH_4 concentration >96%, compact system, simple system, low maintenance, purity adjustable, no solvent or high pressure need, fast installation and startup, low throughput capacity possible	H_2S and H_2O removal advised, high CH_4 losses, multiple steps required
Cryogenic technology	CH_4 concentration >98%, high-purity solid CO_2 production, suitable for bio-LNG, no chemicals required	complex equipment, multiple process equipment requirement, pre-treatment requirement

Table 6.2: Advantages and disadvantages of the different biogas upgrading technologies (I. U. Khan et al., 2017) (Domingues et al., 2021)

Steam methane reforming is one of the most important industrial processes for hydrogen production dating back to 1991 and still dominates industrial hydrogen production (Rosen, 1991) (Carapellucci and Giordano, 2020). As a result, this process is well established, relies on mature technology and also offers a developed infrastructure from production to utilisation. The SMR process relies on the conversion of biomethane with steam under high temperature and high pressure. Moreover, the reforming process uses a bed of catalysts to produce syngas. The syngas is then converted through a series of high-temperature- and low-temperature water gas shift reaction to convert the carbon monoxide and steam present in the syngas to hydrogen and carbon dioxide, in order to enhance the hydrogen production. Finally, the output gas is purified by the separation of carbon dioxide, methanation and cooling (Rosen, 1991). A process flow diagram of a real plants SMR hydrogen production process can be seen in figure 6.6 (Boyano et al., 2012).

Thus, firstly the biomethane feed in the reforming step is mixed with superheated steam. The biomethane and superheated stream then reacts in the endothermic reforming reaction, in a furnace-type configuration, at a temperature in the range of [700 - 900] °C and a pressure of [14 - 31] bar over a nickel-based, ring-shaped catalyst,

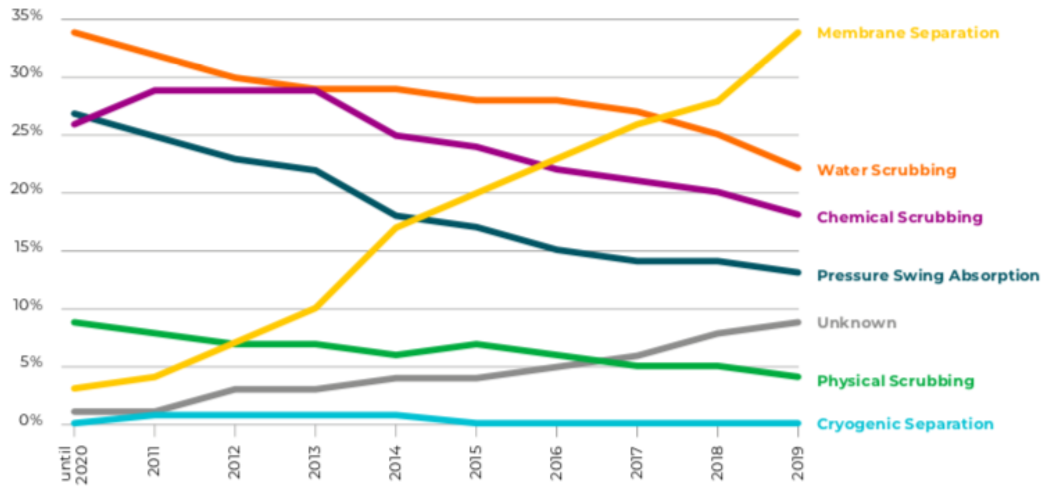


Figure 6.5: Cumulative change in upgrading technology technique based on the number of plants in Europe (Wouters et al., 2020)

according to the following formula (Boyano et al., 2012).

$$CH_4 + H_2O \rightarrow CO + 3H_2 \quad (+206kJ/mol) \tag{6.1}$$

The relatively low pressure follows from the Le Chatelier principle where SMR is promoted by low pressures as the number of molecules increase in the products. Moreover, the reaction is operated with an excess of steam to limit catalyst deactivation and balance the pressure drop as a result of CH_4 decomposition via the Boudouard reaction, which result in the formation of solid carbon and hydrogen from carbon dioxide (Carapellucci and Giordano, 2020). The resulting raw synthesis gas exits the reformer at around 370 °C and high pressure of up to 3.5 MPa. In order to produce the required steam and process heat for the reforming reaction and additional stream of methane fuel is combusted, which produces additional CO_2 emissions (Rosen, 1991).

In the second step, a high-temperature WGSR is applied as the hydrogen-rich syngas mixture still contains a significant volume content of CO, mostly over 5%. In the high-temperature WGSR subsequently, around 94% of the CO present in the raw syngas is converted in the exothermic WGSR at a temperature in the range of [310 - 450] °C over an iron-oxide-, or nickel-based catalyst, according to the following formula (Boyano et al., 2012):

$$CO + H_2O \rightarrow CO_2 + H_2 \quad (-41kJ/mol) \tag{6.2}$$

The stream exist the high-temperature WGSR at a temperature of around 220 °C and is utilised to preheat, among others, the incoming boiler feed (Rosen, 1991).

In the third step, around 83% of the remaining CO, in the raw syngas is converted in the low-temperature WGSR, resulting in a decrease of CO content in the range of [0.05-3]% (Rosen, 1991). This is a result of the high equilibrium CO-selectivity in the low-temperature WGSR in contrast to the favorable rapid reaction kinetics in the high-temperature WGSR. The low-temperature WGSR operates in the range of [180 - 250] °C over a copper-based catalyst (Boyano et al., 2012) (Carapellucci and

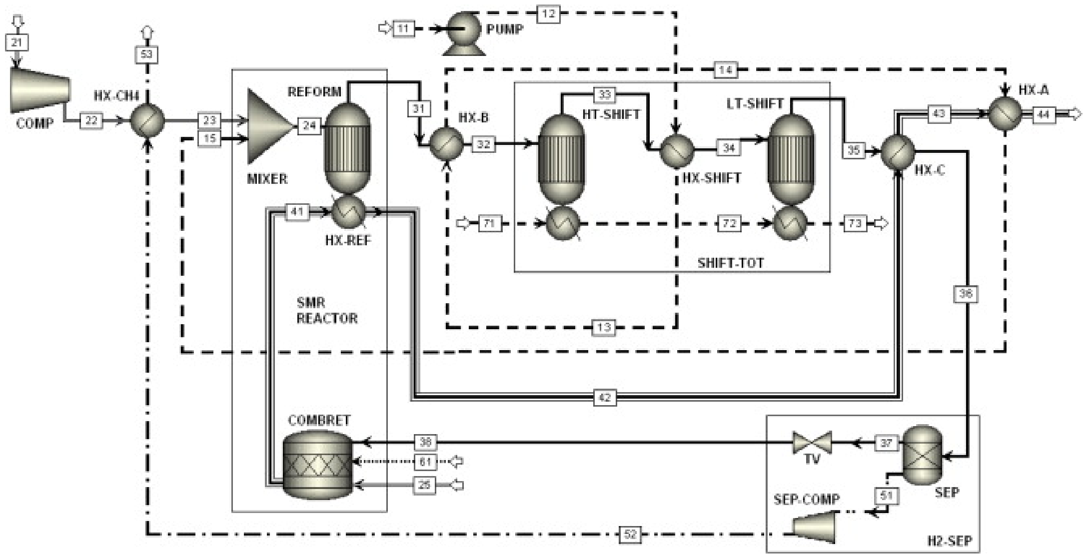


Figure 6.6: Schematic of a real plant SMR hydrogen production process (Boyano et al., 2012)

Giordano, 2020), according to the same reaction mechanism:

$$CO + H_2O \rightarrow CO_2 + H_2 \quad (-41kJ/mol) \tag{6.3}$$

The gas exists the low-temperature WGSR subsequently at a temperature of around 150 °C, which can be used to preheat the incoming feedwater (Rosen, 1991).

Additional steps, include the removal of the primary diluent CO_2 from the gas, the cooling of the hot product gas and potentially the methanation of the residual CO. Ultimately, the SMR reaction can be summarized as follows (Rosen, 1991):

$$CH_4 + 2H_2O \rightarrow CO_2 + 4H_2 \tag{6.4}$$

Here, it can be seen that on an atomic basis half of the hydrogen is derived from the methane and half from the fueled steam.

The overall process efficiency is stated to be around [70-85]% based on lower heating value. Here, the main energy efficiency losses are attributable to losses in the reforming-, CO_2-removal- and cooling step respectively (Rosen, 1991). However, limited potential for improved SMR efficiencies are presumed to be available (Rosen, 1991).

However, besides steam other oxidants, or a mixture of oxidants, are able to reform the biomethane into syngas and ultimately hydrogen. These include carbon dioxide and oxygen. The interest in the usage of CO_2 as oxidant has sparked due to the potential to valorise CO_2, reduce the carbon footprint, and because of the low H_2/CO ratio in the syngas. The latter could be especially useful for certain applications, for example in FT synthesis reactions (Carapellucci and Giordano, 2020). However, the sole reforming of methane with carbon dioxide as oxidant, or dry reforming, is mainly excluded from studies and applications due to carbon formation and as a result catalyst deactivation and pipeline blockages (Galvagno et al., 2013). Other reasons include the very high energy requirement which leads to high operating temperatures. This results from the low chemical stability of the oxidant (Carapellucci and Giordano, 2020). Also, partial oxidation attracted attention as a way to reduce the energy duty for CH_4 reforming. In this respect, POX is an exothermic reaction that can start up easily and does not require a catalyst. However, the relatively low H_2/CO ratio and high-operating temperature in the non-catalytic process limit the adoption for hydrogen production. This is further suppressed by the need for an air separation unit, which increases the capital cost and could offset the lower operating costs as compared to SMR (Carapellucci and Giordano, 2020).

The reforming reactions, characterised by their reaction mechanism and oxidants usage, are (Araki et al., 2010):

Dry reforming (DR)

$$CH_4 + CO_2 \rightarrow 2CO + 2H_2 \quad (247.2kJ/mol) \tag{6.5}$$

Partial oxidation (POX)

$$CH_4 + \frac{1}{2}O_2 \rightarrow CO + 2H_2 \quad (-35.6kJ/mol) \tag{6.6}$$

Autothermal reforming (ATR)

$$CH_4 + H_2O + \frac{1}{2}O_2 \rightarrow CO_2 + 3H_2 \quad (-77.2kJ/mol) \tag{6.7}$$

Here, autothermal reforming can be observed as combination between SMR and POX. In this respect, ATR is ascribed several relevant benefits, like low energy requirement, high space velocity, controllable H_2/CO ratio, high efficiency, high hydrogen yield, easy startup and rapid response potential. Moreover, the lower operating temperature as compared to POX lowers the formation of catalyst hot spots and is favorable for downstream processes. As a result, ATR offers reduced operating costs as compared to POX. Additionally, as compared to POX, the ATR process enhance H_2 production similar to SMR, with a H_2/CO ratio between [2-3.5] depending on the temperature, pressure and inflow ratio. The potential variation in the H_2/CO ratio can further benefit different applications. Moreover, the easy startup and rapid response potential can further add valuable flexibility to the process. On the contrary, the ATR reaction requires the additional inflow of an oxygen stream which increases the operating costs as compared to SMR. Moreover, the ATR reactor design is more complicated as compared to the SMR reactor and operates at a higher temperature and pressure (Carapellucci and Giordano, 2020).

The ATR process can be described following the same process steps as the SMR process. However, in case of the reforming step, the POX and SMR reaction are combined in one reactor which includes a burner section, a combustion chamber and a catalytic reactor. In the burner section the CH_4 and steam are mixed with sub-stoichiometric O_2 thereby enabling the production of heat through the POX reaction. Then, in the combustion chamber, further conversion takes place in homogeneous gas-phase reactions, whereby the thermal power is produced through properly adjusting the O_2/CH_4 ratio. Here, through recirculation the hot gases continue to react. Nonetheless, this reaction occurs far from equilibrium conditions. The reaction in the combustion zone takes place at around [550-600] °C and can be described as (Carapellucci and Giordano, 2020):

$$CH_4 + \frac{1}{2}O_2 \rightarrow CO + H_2O \quad (-519kJ/mol) \tag{6.8}$$

Lastly, in the catalytic reactor the residual methane reacts with steam to produce hydrogen in the endothermic SMR reaction. The reaction takes place at around [950-1100] °C and 100 bar over a nickel-based catalyst, in order to achieve a gas mixture as close to equilibrium conditions as possible. Here, the reactions can be described as (Carapellucci and Giordano, 2020):

$$CH_4 + H_2O \rightleftharpoons CO + 3H_2 \quad (+206kJ/mole) \tag{6.9}$$
$$CO + H_2O \rightleftharpoons CO_2 + H_2 \quad (-41kJ/mol) \tag{6.10}$$

After the ATR reaction, a two-step WGSR and hydrogen purification are used to increase the hydrogen production and purity levels. Ultimately, due to the usage of heat generated in the POX reaction to fuel the SMR reaction, the ATR process is characterised by a higher thermal efficiency level of around [60-75]%. Overall, the ATR is characterised by a process efficiency based on the LHV of around [60-75]% (Carapellucci and Giordano, 2020).

An overview of some of the strengths and weaknesses of the relevant methane reforming technologies can be seen in table 6.3. Next to relative difference, Alves et al., 2013 mention that in basis all reforming technologies require additional focus on reduction of the costs and the energy required. Here, the development and use of catalyst with high activity and stability could further enhance the reduction of high-temperature requirements, increase of reaction speed, lower the catalyst deactivation, and limit coke formation, which are described as the main problems usually encountered. Related, Alves et al., 2013 mention the inherent downstream problem associated with the purification of hydrogen from the syngas stream. Here, the separation of hydrogen and carbon monoxide is characterised by the WGSR and purification step and is considered to be a significant cost component of the total production costs.

Technology	**Advantages**	**Disadvantages**
Steam methane reforming	Most developed, no O_2 requirement, H_2/CO ratio of 3	Catalyst regeneration requirement, strong economies of scale, external heat source required
Dry methane reforming	Utilisation of CO_2, CO-rich syngas, suitable for small-medium scale plants	Catalyst deactivation due to carbon formation, low chemical stability CO_2
Partial oxidation reforming	No catalyst requirement, low desulfurisation requirement, exothermic reaction	H_2/CO ratio around 1, O_2 requirement, adopted for longer hydrocarbons molecules
Autothermal methane reforming	Adjustable H_2/CO ratio, H_2/CO >2 possible, suitable for smaller-scale, flexible process	O_2 requirement, lower level of commercialisation, complex reactor design, multiple catalyst required, catalyst stability

Table 6.3: Advantages and disadvantages of the different methane reforming technologies (Lepage et al., 2021) (Dincer and Acar, 2015) (Kennedy et al., 2019) (Nahar et al., 2017)

6.2.4 Hydrogen purification

For the upgrading of the hydrogen-rich outlet stream an additional purification step is needed to adhere to the high hydrogen purity requirements. Here, the composition of the outlet stream is impacted by the different hydrogen production methods and feedstocks used. For example, the hydrogen volume content before purification is around [70-75]% in the case of methane reforming, [25-35]% for coal gasification and [25-35]% in the case of biomass gasification (Du et al., 2021). However, the purity requirements are generally standardised over the different applications despite difference across the various applications. In general, the purity levels are higher than can be obtained in an optimized WGSR step function. This is case since even a low amount of impurities could negatively impact the end applications. For example, low levels of impurities might irreversibly damage the fuel cell performance and running life (Du et al., 2021).

The hydrogen purification methods can overall be classified as either physical- or chemical methods. Here, physical methods include adsorption methods like, PSA, temperature swing adsorption (TSA) and VPSA. Moreover, it includes low-temperature separation methods like, cryogenic distillation and adsorption as well as membrane separation methods, including organic membrane- and inorganic membrane separation. Chemical methods on the other hand, include metal hydride separation and catalysis methods. An overview of the respective separation methods can be seen in figure 6.7 (Du et al., 2021).

Currently, the dominant technology is pressure swing adsorption, which is an industrially mature technology that benefits from low operational costs and long service life, of around 30 years, and is mainly used in centralised, large-scale H_2 production plants. However, the PSA technology might not be suitable for smaller-scale, lower-purity required applications, due to decreased recovery rate, lower yield, and reduced cost-efficiency. This relates to lower specific impurity removal requirement, large floor area necessity, inflexibility and low adaptability. In basis, this relates to both CAPEX and OPEX due to the specific energy demand for PSA.

Cryogenic distillation is also applicable for large-scale production processes, but suffers from lower H_2 purity levels of [85-99]%, which do not meet specific application requirements. In contrast, low-temperature adsorption-, metal hydride- and metal membrane separation might become more useful in small-scale, on-site hydrogen production based on the types and amounts of impurities. In this case, low-temperature adsorption can remove multiple impurities, however suffers from high energy consumption and complex processes. Metal hydride separation on the other hand, is reasonable effective in separating gas sources with high content of inert components. However, metal hydride separation faces issues associated with the reduction in the purification efficiency due to reaction of purified materials with impure gas. Moreover, new technologies, like carbon molecular sieve membranes, and electrochemical H_2 pump membranes, are developing but the industrial implementation is unknown (Du et al., 2021).

The PSA separation method is based on the periodical pressure change, and relates to the difference in adsorbent capacity for the different gases, to achieve gas separation and purification. The separation effect is primarily dependent on the type of adsorbent and technical process utilised. Since hydrogen differs significantly in terms of static capacity from other majority gas molecules like carbon dioxide, carbon monoxide,

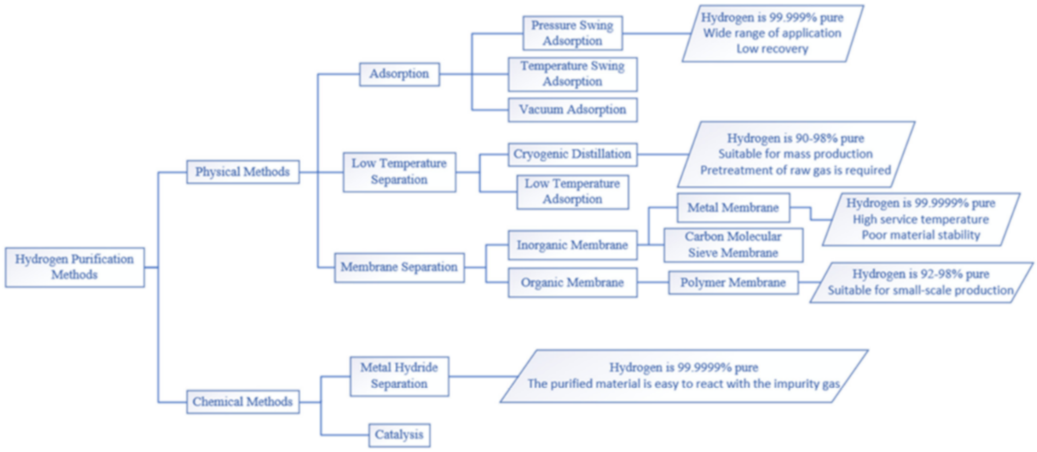


Figure 6.7: Classification of hydrogen purification technologies (Du et al., 2021)

methane and water PSA is very suitable as separation- and purification method. The traditional adsorbents include silica gel, activated carbon, activated alumina and zeolite molecular sieves. However, modifications and innovations are applied with specific focus on different impurities, like CO_2 removal or the removal of a multitude of impurities. Moreover, these improvements and optimisations are used to enhance the hydrogen purification efficiency, which could include variation in the number of beds and steps for the PSA purification. Another innovation focuses on VPSA in order to enhance the hydrogen purity and recovery rate. The VPSA results indicate an increases in recovery rate of 10%, as well as a significant increase in the hydrogen yield, at reasonable cost-efficiencies.

In general the hydrogen purity for PSA technology is at least higher than 99.95% with a hydrogen recovery rate of [75-90]% (Du et al., 2021). The multi-column PSA flow diagram of Air Liquide for the purification of hydrogen can be viewed in figure 6.8. These multiple columns operate simultaneously with adsorption, depressurization, desorption and pressurisation steps following in time. This ultimately results in a semi-continuous process that yields a high purity hydrogen stream and a purge stream following the desorption step of CO_2, other impurities and some hydrogen losses. Air Liquide reports purity levels of up to 99.9999% and a hydrogen recovery rate of [60-90]%. Ultimately, the hydrogen purity level is a trade-off with the hydrogen yield and controlled by the type of adsorbent and the gas volume (AirLiquide, 2021).

Membrane separation methods are establishing as emerging gas separation technology due to the flexible- and simple operation in combination with a compact structure, low energy consumption and environmental friendliness. In case of membrane separation, a perm-selective membrane act as a separation medium where components selectively permeate through the membrane under the influence of a driving force, for example pressure-, concentration- or potential difference to achieve separation and purification. In this case, the performance of the membrane material is most critical and the most used materials include metal- and polymer membranes, with novel materials surfacing like nanomaterial, carbon molecular sieve and metal-organic frameworks (Du et al., 2021).

In case of metal membranes, the hydrogen is catalysed into protons and electrons on the metal membrane structure. Subsequently, the protons pass through and

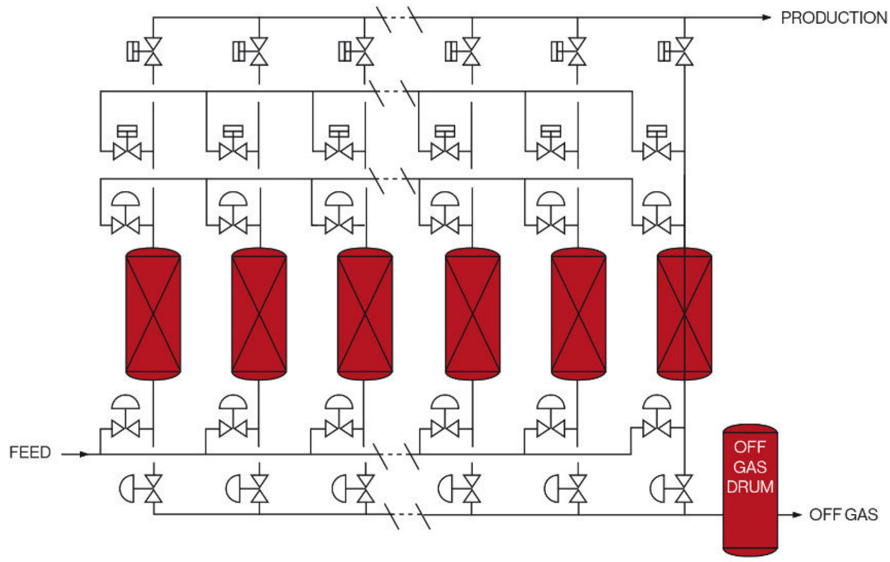


Figure 6.8: PSA process flow diagram (AirLiquide, 2021)

bind with the electrons to form hydrogen again at the other side of the metal membrane. In theory, metallic membranes enjoy an infinite selectivity for hydrogen as it blocks all other gas molecules. Palladium membranes are mostly used due to the excellent hydrogen permeability and high resistance against hydrogen fluidity and auto-catalytic hydrogenolysis reactions. However, palladium membranes suffer from high manufacturing costs and is prone to hydrogen embrittlement, especially at low temperatures. As a result, metallic membranes are a less mature technology, which still faces issues with the trade-off between mechanical strength and hydrogen flux, sensitivity to CO and H_2S, and high operating temperatures. Potential innovations include the creation of palladium alloy membranes to solve the hydrogen embrittlement problem, enlarge the lattice and increase the hydrogen permeation rate. Also, alternative metals like the vanadium group metals have been studied due to higher permeation ability and mechanical strength (Du et al., 2021).

In case of polymer membranes, the working principle is based on the different permeation rates of gases through the polymer material. In this case, the polymer material requires high selectivity, permeability, thermal stability and mechanical performance. Nevertheless, in basis a trade-off exists between permeability and selectivity. Especially, this trade-off limits the usage of membrane separation. As a result, innovation focuses on mixed matrix membranes or polymer blending to improve the overall performance. This is especially relevant due to the high purity requirements of hydrogen applications. Other issues include sensitivity to swelling, vulnerability to poisoning, limited mechanical strength and limited hydrogen flux. On the other hand, the polymeric membrane separation shows lower operating temperatures and capital costs as compared to PSA (Du et al., 2021).

Metal hydride separation method relies on the reversible absorption and desorption of hydrogen within the metal storage to purify hydrogen. The hydrogen molecules decompose into atoms catalysed by H_2 storage alloys through lowering temperature and increasing pressure. The metal hydrides are then generated via diffusion, phase transition and other reactions and processes, while impurity gases are trapped among metal particles. An increase in temperature and decrease in pressure then discharges the impurity gases while H_2 comes out from the crystal lattice. Metal hydride separation methods can be classified along the type of metal alloy and type of alloy or atomic ratio. The efficiency of hydrogen purification is in the end determined by the performance of the hydrogen storage alloys. This relates to chemical stability, tolerance of hydrogen and reduction of the influence of impurity gases (Du et al., 2021).

Cryogenic distillation utilises the difference in relative volatility of the different components in the feed gas to separate- and purify hydrogen. This is related to the relatively high volatility, and as such low condensation point, of hydrogen, which can be used for H_2-hydrocarbon separation. The cryogenic distillation can assure a high hydrogen recovery rate, but suffers performance in case of treating different feed gases and therefore require for example the removal of CO_2 and H_2O before the separation in order to avoid equipment blockage at low temperature. Moreover, the separation method is characterised by high costs and high energy consumption. Lastly, as some impurities remain in the gas phase as saturated steam it proves difficult to obtain high purity hydrogen (Du et al., 2021).

An overview of the respective advantages and disadvantages of the different separation methods can be seen in table 6.4.

Technology	**Advantages**	**Disadvantages**
PSA	H_2 purity >99.99%, mature technology, service life around 30 years, economy of scale, static capacity H_2	H_2 recovery [70-85]%, suitability for smaller-scale, process adaptability and flexibility
Cryogenic Distillation	Suitable for high flow rates, removal all impurities, H_2-hydrocarbon separation	Hydrogen purity [90-98]%, pretreatment required, feed gas inflexibility
Palladium Membrane	H_2 purity > 90%, H_2 recovery up to 98%, small-scale, simple process, hydrogen permeability, high-purity inlet possible	Membrane cost, low mechanical stability, sensitive to sulphur contamination, hydrogen embrittlement, limited input flexibility
Polymeric Membrane	Membrane cost, small-scale, simple process	H_2 purity [92-98]%, trade-off permeability and selectivity, membrane swelling and poisoning, mechanical strength, recompression need
Metal hydride	Acceptable H_2 purity of > 99.5%, H_2 recovery > 90%, separation of inert compounds	Chemical stability, impurity intolerance

Table 6.4: Advantages and disadvantages of hydrogen purification technologies (Succi et al., 2017)

6.3 Alternatives

To avoid the effect of a different gas composition on the performance of the SMR process, the conventional process is to separate the CO_2 present in the biogas stream before feeding it as biomethane to the reformer. An example of this is shown by Ohkubo et al., 2010 who studies the hydrogen supply capacity of a plant that processes the manure of 1,000 diary cows to indicate the feasibility of a biogas-to-hydrogen plant. In this case, the biogas was first purified through the use of a membrane separator before fed to the SMR. Ultimately, this resulted in a methane conversion rate of around 90%, a 78 volume % hydrogen output gas, a hydrogen purity stream after PSA of 99.9% or higher, with a hydrogen recovery rate of 73%, and a hydrogen production of 280 Nm^3/day, based on 200 Nm^3/day biogas or 108 Nm^3/day of biomethane (Ohkubo et al., 2010).

However, the reforming process does not necessarily require the CO_2 to be separated from the methane stream. This could especially be relevant in cases where the reforming process is co-located with the biogas plant and as a result where the upgrading step can be eliminated. Therefore, it is expected that this route will reduce the total hydrogen production cost as compared to the conventional route. This process is called biogas reforming. Like the methane reforming process, the biogas reforming process can be characterised by the oxidant or combination of oxidants present, which mostly involves steam, oxygen or both. However, in basis, the reforming of biogas could be characterised as dry reforming, due to the CO_2 naturally present in the biogas (Albrecht et al., 2016).

Biogas dry reforming

The dry reforming of biogas could be used to achieve a more useful syngas (Chattanathan et al., 2014). The endothermic dry reforming reaction occurred at [750-850] °C and at atmospheric pressure using a nickel-based reforming catalyst. The results showed CH_4- and CO_2 conversion levels of 67% and 87% respectively, yielding a syngas composition of around 33 volume % H_2 and 39 volume % CO (Chattanathan et al., 2014). It can be seen that generally lower conversion levels and H_2/CO ratio levels are achieved in the case of dry reforming. However, the sole reforming with CO_2 as oxidant yields negative performance, mainly as a result of carbon decomposition. Moreover, the lower H_2/CO ratio would it make less suitable for dedicated hydrogen production (Kennedy et al., 2019). Galvagno et al., 2013 showed that the reactions involved in the formation of solid carbon, where the rates are dependent on the process conditions, the feedstock composition and in particular a decrease in H/C ratio. The respective reaction can be summarised as:

$$Boudouard\ reaction: \quad 2CO \rightarrow C + CO_2 \tag{6.11}$$

$$Methane\ cracking: \quad CH_4 \rightarrow C + 2H_2 \tag{6.12}$$

$$CO\ reduction: \quad CO + H_2 \rightarrow C + H_2O \tag{6.13}$$

Biogas steam reforming

Several studies have investigated the potential of biogas steam reforming as alternative to biogas dry reforming, which combines DR with SMR. In this regard, Hajjaji et al., 2016 reasoned that the addition of steam functions as prevention mechanism for the deactivation of the catalyst as well as the avoidance of the need to add steam to the WGSR. With respect to the viability of BSR, Albrecht et al., 2016 showed a hydrogen yield potential of around 64% with a biogas composition of 50% CO_2 in comparison to 74% for natural gas after the WGSR, which indicates the potential of the BSR process. However, the presence of CO_2 in the feed results in unfavorable equilibrium conditions in the WGSR, a lower efficiency due to heat- and compression losses associated with additional CO_2, and possible lower hydrogen recovery rate in the purification step, due to the lower hydrogen content in the PSA feed (Albrecht et al., 2016). The respective identified key performance indicators of the BSR process as compared to SMR and electrolysis can be seen in figure 6.9 (Albrecht et al., 2016).

In figure 6.9 the BSR is assumed to be of smaller scale, due to the advantages and primary use cases associated with local production in the case of BSR. This is in contrast to SMR, which benefits from centralised production. As a result, BSR at the moment suffers from a lack of experience with respect to small, compact and reliable steam reformers for localised production, as SMR generally operates at a large-, centralised scale. Moreover, the availability of biogas and or biomethane feedstock in comparison to natural gas affects the process. Also, the ability to run autonomously, with minimal maintenance and wide tolerance of biogas quality variation will be important for the adoption of the BSR process. Lastly, a smaller-scale steam reforming process is associated with higher cost due to high capital expenditures. Nonetheless, simplifications, intensification, size reductions and ultimately cost reductions might prove the viability for BSR (Albrecht et al., 2016).

Also, Effendi et al., 2005 showed that the addition of excess steam to a biogas stream with a molar CH_4/CO_2 ratio of 1.5 resulted in strong inhibition of carbon formation, while almost complete methane conversion was achieved. Moreover, Effendi et al., 2005 showed that increases in steam concentration resulted in a lean CO and high H_2 product stream and ultimately resulted in a hydrogen yield of around 68% at a CO conversion of $> 99\%$, in line with results of Albrecht et al., 2016. More specifically, Effendi et al., 2005 concluded that increased steam concentration boost CH_4 conversion and lower CO_2 conversion, with increased selectivity towards H_2 and reduction of CO concentration, increasing the H_2/CO ratio. Also, Hajjaji et al., 2016 showed that in line with the Le Chatelier principle increase in H_2O/CH_4 ratio improves the H_2 production, through a shift in the equilibrium. This effect showed until the ratio of H_2O/CH_4 exceeds 3, indicating an excessive of steam. Moreover, a steam to carbon ratio above 0.4 resulted in limited or no carbon formation, indicating the effectiveness of steam in suppressing the carbon formation. Moreover, Hajjaji et al., 2016 showed that at a H_2O/CH_4 ratio of 1 no coke formation was possible at temperatures over 700 °C. Additionally, Braga et al., 2012 also indicates the potential for the simultaneous dry- and steam reforming reactions to occur, where the biogas steam reform reaction can be indicated by the weighted partial reforming reactions. The same line of reasoning was given by Hajjaji et al., 2016, indicating the relevance of the stoichiometric relation between biomethane, steam and the presence of CO_2, where the ultimate syngas composition depends on the $CH_4/CO_2/H_2O$ ratio.

With respect to the ultimate performance of the BSR process, Braga et al., 2012 indicates that the efficiency of the BSR process is around 80% based on LHV of hydrogen as compared to 85% in the case of SMR, where the difference is due to the higher methane content in natural gas as compared to biogas. Hajjaji et al., 2016 similarly showed a thermal efficiency of around 77% based on the LHV of hydrogen, which are in within the range of values reported for the SMR systems. In addition, Avraam et al., 2010 performed both a modelling- and theoretical study, with extra attention to the performance of the heterogeneous aluminium-based catalyst, to show similar results between the experimental performance and theoretical prediction. In the study, the catalyst stability without carbon-containing species accumulation was assured, while optimal process conditions where identified as a feed input composition, consisting of a CH_4/CO_2 ratio of [1.0-1.5] and a H_2O/CH_4 ratio of [3.0-5.0] at a gas hourly space velocity (GHSV) of [10,000-20,000] per hour and a temperature of [700-800] °C. Ultimately, the study showed that methane conversion efficiencies of almost 100% could be achieved, with a hydrogen purity level on a dry basis reaching a plateau of maximum 58%, depending on the optimal balance between temperature, GHSV and input feed ratio. Lastly, Lin et al., 2012 also focused on the catalytic function in case of BSR, where the effects of nickel content was investigated. It was shown that higher methane conversion levels could be achieved at increasing nickel-content. Also, higher H_2/CO, lower H_2/CO_2 were obtained while the catalyst remained stable. This is in contrast to DR, where nickel-based catalysts show high deactivation due to coking- and sintering problems. Both high CH_4 and CO_2 conversion results were shown, with higher CH_4 conversion in case of BSR and higher CO_2 conversion in case of DR, at increasing levels of nickel. Also, hydrogen concentrations up to 75% were shown at long-term catalytic activity, which further indicates the adequacy of BSR for the production of bio-hydrogen (Lin et al., 2012).

Biogas dry oxidation reforming

Besides BSR, Alves et al., 2013 identify biogas dry oxidation reforming (BOX), the combination between DR and POX, as strategy to control carbon deposition on the catalyst surface. Moreover, BOX promises additional advantages such as reduction in total energy involved, improvement of the CH_4 conversion, increase product yield at lower temperatures, increased catalytic stability and potential H_2/CO ratio control. The latter, as well as the endothermic and exothermic nature can be controlled by manipulation of reaction conditions and relative concentration of O_2 feed. Moreover, the addition of O_2 helps the gasification of deposited carbon and increases the availability of catalytic sites, recovering the activity of the material. Previous studies shown a H_2/CO ratio of [1.0-1.9] with a methane conversion of [77-100]% for BOX, in contrast to [0.7-1.3] and [67-90]% in case of DR respectively (Alves et al., 2013).

Biogas autothermal reforming

Another reforming process is the biogas autothermal reforming (BATR) process that is able to provide a relatively high hydrogen yield, while allowing for simpler, more compact and more flexible operation (Albrecht et al., 2016). However, the addition of pure oxygen, might limit the associated benefits in case of smaller applications. On the contrary, the integration of oxygen obtained from water electrolysis with BATR could show relevant synergies (Albrecht et al., 2016). Also, Araki et al., 2010 focused on the BATR process over a nickel-based monolithic catalyst. Here, the highest hydrogen concentration and methane conversions were achieved at a ratio of the input oxidants of [0.45-0.55] for O_2/C and [1.5-2.5] for S/C to give a H_2/CO ratio in the range of [2-3] at a CH_4 conversion of at least 90%. It was stated however,

	Unit	SMR	Electrolysis	local ($0.6\ MW_{H2}$)	semi-central ($6\ MW_{H2}$)
TRL					
2015			8-9	8	8
2023				9	9
2030				9	9
Feedstock/Energy source		NG	Renewable Electricity	Maize	Maize, bio-waste, manure
Feedstock availability			High	limited	limited
Costs					
CAPEX	€/kW_{H2}		600-800	3,148	3,550
	€/(kWh_{H2}/yr)			0.42	0.47
	€/kWh_{H2}			0.046	0.052
OPEX	€/kWh_{H2}			0.072-0.112	0.067-0.089**
thereof feedstock	€/kWh_{H2}			0.015-0.055	0.016-0.038**
H_2 costs ex H_2 plant	€/kWh_{H2}			0.118-0.158	0.119-0.141**
	€/GJ_{H2}			32.8-43.8	33.0-39.1**
	€/kg_{H2}			3.9-5.3	4.0-4.7**
CGH_2 costs pathway	€/kWh_{H2}	0.099-0.156	0.123-0.171	0.177-0.217	0.200-0.222**
	€/GJ_{H2}	27.5-43.3	34.2-47.5	49.1-60.1	55.5-61.6**
	€/kg_{H2}	3.3-5.2	4.1-5.7	5.9-7.2	6.7-7.4**
Lifetime (H_2 plant)			30	15	15
Environment					
Area specific yield	kWh_{H2}/m^2*yr)	n. a.	42.2*	2.5***	n. a.
GHG emissions	g/kWh_{H2}	299-349	12-41	163-174	126
	g/MJ_{H2}	83-97	3-11	45-48	35
Other issues				Biodiversity, agrochemicals	

* Electricity from PV in Germany (solar irradiation: 1,200 kWh per m^2 an year); efficiency PV panel: 20%; PR = 0.80; ratio PV panel/land area = 0.33; electricity consumption electrolysis: 50 kWh/kg_{H2};
** lower value: including revenue for bio-waste treatment;
*** Maize whole plant yield: 44 t fresh substance per year; dry matter content: 35%; thereof organic matter: 96%; Storage losses: 12%; gross CH_4 yield: 312 Nm^3 per t of dry organic substance; Biogas for fermenter heating: approx. 10% of the gross biogas yield; Biogas requirement SMR plant: 1.45 kWh of biogas per kWh of H_2

Figure 6.9: Key performance indicators of the BSR process as compared to SMR and electrolysis (Albrecht et al., 2016)

that while higher methane conversion could be achieved, this mainly resulted in a decrease in hydrogen yield as a result of the combustion of hydrogen with steam in the presence of excess oxygen, indicating a relevant trade-off in the oxidant feeds. On the other hand, it was indicated that the H_2/CO ratio could be regulated by alteration in the respective ratio of oxidants in the process Albrecht et al., 2016. This in combination with high thermal efficiency, easy startup and rapid response indicates the usefulness of BATR for small-scale applications (Araki et al., 2010). Also, Nahar et al., 2017 mention that BATR could allow for the adjustment of the H_2/CO ratio in the presence of CO_2. Next to that, the presence of CO_2 could be beneficial in the reduction of hot-spots formed due to high temperature operations. Also, the utilisation of the CO_2 is favored due to the costlier removal methods at a smaller scale.

Next to the advantages of CO_2 in the BATR process, Nahar et al., 2017 showed that besides the insertion of steam and regulation of temperature, the type of catalyst used in the BATR process has a strong effect on the type of carbon and amount of carbon formed and subsequently the carbon formation. This subsequently impacts the H_2 yield and lifetime of the catalyst. While, the studies are limited, most focused on a nickel-based catalyst and reported methane conversion levels of around 90% and hydrogen yields at around 70%, for CH_4/CO_2 levels of 1.5 and O_2/C of mostly 0.25.

Also, Pino et al., 2014 focused on the development of nickel-supported catalyst to support the BATR, or called the tri-reforming of biogas, whereby the influence of the oxidants inputs was evaluated. Pino et al., 2014 indicated high conversion rates of both CH_4 and CO_2 with a H_2/CO ratio of 1.57 and without carbon deposition. More specifically, based on the feed input ratio methane conversion and carbon dioxide conversion levels of [87-99]% and [54-93]% were shown respectively for H_2/CO ratios of [1.53-1.68]. Here, it should be noted that both Pino et al., 2014 and Nahar et al., 2017 focused primarily on the creation of a syngas, which justifies the lower H_2/CO ratio and higher CO_2 conversion.

Nonetheless, the lack of various investigations indicate the newness of the approach and as result additional research is required, with focus on for example the effects on catalytic activity of H_2S, the effect on CO_2 conversion. Moreover, this could include renewed measures of the performance in terms of H_2 and CO yield and efficiencies, and study regarding the thermal neutrality (Nahar et al., 2017).

The BioRobur reactor as part of the FCH-JU BioRobur project aims to further improve the process features and process efficiency of the BATR process. In this case, an innovative catalytic system is used to promote the ATR reactions involved in the conversion of biogas to syngas. Moreover, the project incorporates another innovative feature which uses a catalytic trap for soot gasification, which forms in the combustion zone of the reformer. In the catalytic trap, the output stream of the ATR reactor is filtered from soot and subsequently converted into hydrogen (Battista et al., 2017). The concept operates under sub-stoichiometric conditions with an atomic O/C ratio of 1 and S/C ratio of 2, a maximum temperature of 700 °C, pressure of 1.5 bar, and a 65% efficiency of biogas to hydrogen conversion. However, alterations in process conditions could favor, for example, a higher hydrogen yield, but is in trade-off with a lower H_2/CO ratio. Moreover, the process results in a hourly output flow rate of 4.5 kgH_2/hr with a hydrogen purity level of 99.99%. An overview of the BioRobur process can be seen in figure 6.10. In this figure the pretreatment of feed stream section, the ATR section and the gas purification section can be distinguished as well as other components like valves and sensors (Battista et al., 2017). In a second version, the BioRoburPlus reactor increased internal heat recovery which enables minimization of air feed to the reformer, improved tailored pressure-temperature-swing adsorption (PTSA) which exploits both pressure and low-temperature recovery, and achieved further heat integration through innovative use of cellular ceramic-based recuperative burner. Moreover, the new design resulted in lower material costs, a faster start-up and shut-down mechanism, and easier process control. Ultimately, the BioRoburPlus operates at a lower temperature of 800 °C and higher process efficiency of >80% (HHV) at high hydrogen purity levels of 99.9% with an output of 107 kgH_2/day (Fino, 2017).

6.4 Intensification

Process intensification aims to improve the operational process, mainly though simplification of the reaction processes. This could be achieved by integration of unit operations or functions. Due to the multiple levels of unit operations needed in the process to convert biogas to bio-hydrogen, several initiatives aim to reduce the complexity.

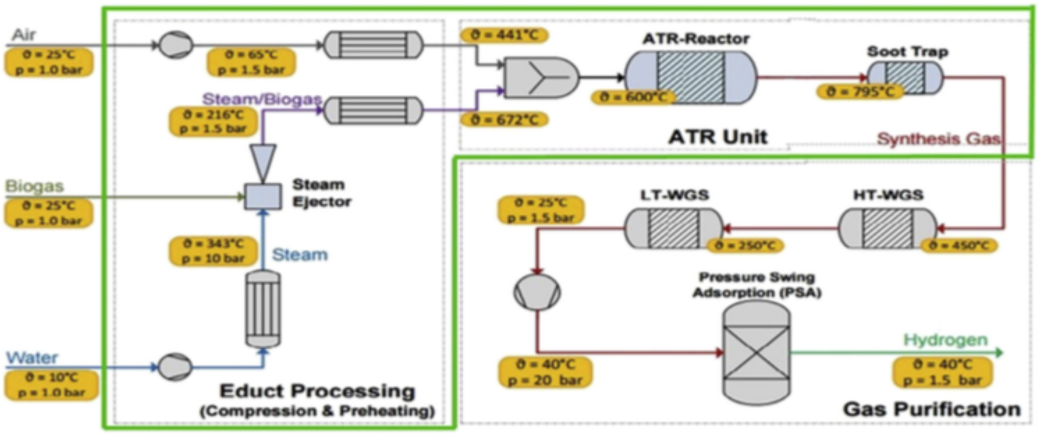


Figure 6.10: PFD of the BioRobur process with all major components (Battista et al., 2017)

Steam-iron reforming

In the steam-iron process (SIP) the reducing agents from the DR are responsible for reducing the iron-based oxides. Subsequently, the reduced iron-based oxides will be oxidized by steam to release hydrogen with less than 50 ppm of CO (Lachen et al., 2019). Thereby, the method is based on the redox properties of metal oxides, where the products from the DR serve as input. In the first stage, the metal oxide is reduced to a lower oxidation stage, while in the later stage the metal oxide can be oxidized with steam to release hydrogen. The released hydrogen can subsequently easily be separated from the unreacted steam by condensation, reducing the need for an additional purification step. The method relies on the following reaction mechanisms (Lachen et al., 2019):

$$Fe_2O_3 + 3H_2 \rightleftharpoons 2Fe + 3H_2O \tag{6.14}$$

$$Fe_2O_3 + 3CO \rightleftharpoons 2Fe + 3CO_2 \tag{6.15}$$

$$3Fe + 4H_2O \rightleftharpoons Fe_3O_4 + 4H_2 \tag{6.16}$$

The reaction operates above 700 °C in the reduction stage and below 500 °C in the oxidation stage in order to ensure coke minimization and avoid coke gasification respectively. Like SMR, the addition of steam as an oxidant, thereby technically incorporating the SMR, minimizes or even avoids the formation of carbonaceous depositions. However, this could slow down the efficiency of the reduction process. It was seen that the insertion of small amounts of steam ultimately allow for isothermal operations of both the reduction and oxidation at 700 °C. Ultimately, the process shows similar hydrogen yields and has the advantage of not requiring a subsequent purification step in contrast to biogas reforming process. However, SIP might suffer from complex engineering, unfavorable economics and reduction of the hydrogen yield over stages and or time, especially in comparison to BSR (Lachen et al., 2019).

The reformer steam iron cycle can also be integrated with a chemical looping system as a versatile process of biogas utilisation for high-purity hydrogen production. A schematic representation of this process can be seen in figure 6.11. Here, the co-feeding of steam with biogas results in syngas production through both the DR and

SMR reactions, with in parallel the WGSR occurring, resulting in an equilibrium mixture of CO, CO_2, H_2 and H_2O in the syngas. Downstream the reduction is carried out using the syngas to reduce the iron-based oxygen carrier, while the reduced iron is oxidized to release hydrogen in a subsequent process step. The advantages are related to the simplicity of process layout, where the steam reformer and steam-iron section are included within a single reactor to allow for both hydrogen production and purification (Bock et al., 2019). Results indicate a hydrogen production efficiency up to 73% at a 99.97% purity level. Here, the hydrogen yield was strongly related to the oxidation- to reduction (O/R) species relation, or $(H_2O + CO_2)/(CH_4)$ where increase in O/R of 1.2 to 1.6 resulted in a [15-20]% decrease in hydrogen production. The same could be stated regarding the higher share of dry reforming, which reduced the hydrogen output. With respect to the purity level, this was affected by the purging of the system prior to the steam oxidation and the prevention of solid carbon depositions during the reduction phase. The operating temperature affected both the production yield and purity level as the hydrogen production decreased [24-57]% in case of an operating temperature of 750 °C in comparison to 850 °C, while the absolute amount of impurities remained constant (Bock et al., 2019).

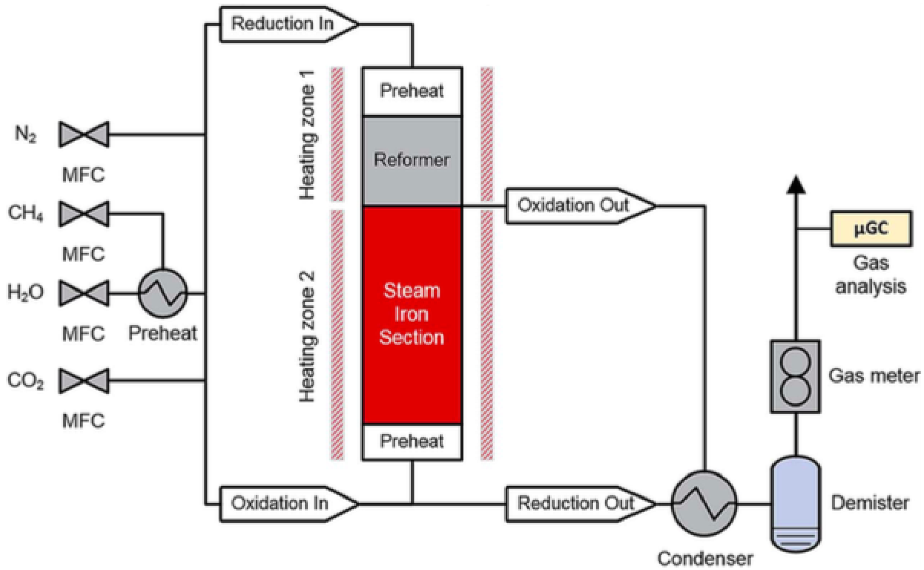


Figure 6.11: Schematic representation of the reformer steam iron cycle with chemical looping experimental setup (Bock et al., 2019)

Membrane reforming

The membrane reforming reaction is an innovative technology utilizing a membrane reactor design to intensify the process, enhance the system efficiency and lower the costs. In this case, the reactor design allows for the exclusion of the CAPEX intensive separation- or sequestration step, thereby also decreasing the volume and footprint of the reforming reactions (Marcoberardino, Foresti, et al., 2018). An overview of the conventional- and innovative membrane reforming process can be seen in figure 6.12. The system works on basis of the Le Chatelier principle, which states that the moment the concentration of one of the reactants in the equilibrium changes, the system aims to oppose the change. In this case, the reaction of CO and H_2O to produce more CO_2 and subsequently hydrogen is stimulated. Moreover, this allows the process to operate at milder conditions than traditional reforming reactions (Marcoberardino, Vitali, et al., 2018). In the work of Marcoberardino, Foresti, et al., 2018 the focus was on the ATR reaction within a two permeate-side fluidised bed catalytic membrane reactor design in order to simultaneously produce- and separate hydrogen. The membranes consists of a palladium-silver layer deposited on a ceramic multi-layer porous support structure and the performance was characterised by the hydrogen recovery rate, expressed as the permeated hydrogen versus maximum hydrogen output. The presumed reaction mechanisms follow the SR- and POX-, or ATR- and WGSR reactions and operated at 550 °C, 20 bar and a steam-to-carbon ratio of 3, yielding an almost complete methane conversion in case of the vacuum pump system. An overview of the BIONICO system, using a vacuum pump can be seen in figure 6.13. Ultimately, the system results in a higher hydrogen production efficiency of around 69% at an assumed delivery pressure of 10 bar and operates at a lower temperature and pressure as compared to reference SR- and ATR system designs. In this perspective, the SR system achieved a 52% efficiency at 12 bar and the ATR system a 28% efficiency at 18 bar, both based on LHV. Moreover, it was stated that the vacuum pump design resulted in a 15% higher system efficiency and 5 times smaller membrane area as compared to the sweep gas design due to the low hydrogen partial pressure in the feed side and the limited sweep flow rate. Moreover, better economic results for a hydrogen flow at 20 bar output of 100 kg/day were shown of [4.01-4.11] €/kg in comparison to [4.21-4.29] €/kg and [6.41-6.60] €/kg in case of SMR and ATR respectively (Marcoberardino et al., 2019). Here, in comparison to SMR the BIONICO system shows lower capital costs, but higher electricity costs. On the other hand, in contrast to ATR the system shows lower electricity costs (Marcoberardino, Foresti, et al., 2018). Moreover, Marcoberardino et al., 2019 indicated the better associated environmental performance of the system in comparison to the reference systems, based on 1 kg hydrogen delivery at 20 bar, 15 °C and 99.99% purity, specific for the reforming process. However, this is especially the case when biogas becomes a limiting factor due to the higher biogas conversion efficiency and as a result the volume substitution potential as compared to fossil fuels. However, in case of excess of biogas the system might perform similar or worst based on the higher electricity demand in comparison to SMR, as conversion efficiency becomes less relevant (Marcoberardino et al., 2019). Nonetheless, in case of sufficient renewable electricity integration, the latter conclusion might become less relevant.

Moreover, Lulianelli et al., 2014 also studied the reforming of biogas for the generation of bio-hydrogen through the use of a membrane reactor. However, in contrast to Marcoberardino, Foresti, et al., 2018, Lulianelli et al., 2014 specifically studied the BSR reaction. Besides the intensification of the reforming process, the potential further possibility of directly supplying hydrogen to fuel cells increase the relevancy of the membrane reactor design. Specifically, Lulianelli et al., 2014 focused on an inorganic membrane of a composite of palladium-aluminium oxide to separate the produced hydrogen through selective permeation. The BSR reaction occurred at a temperature of 450 °C, 3.5 bar and steam to methane ratio of 4 to 1 with a GHSV of 11,000 per hour. Ultimately, it resulted in a hydrogen permeate purity of lower than 70% at conversion level of around 34% and a hydrogen recovery of 70%. However, at a lower temperature a higher hydrogen purity of 96% could be achieved, while the conversion lowered to around 27% and hydrogen recovery to 20%. The main

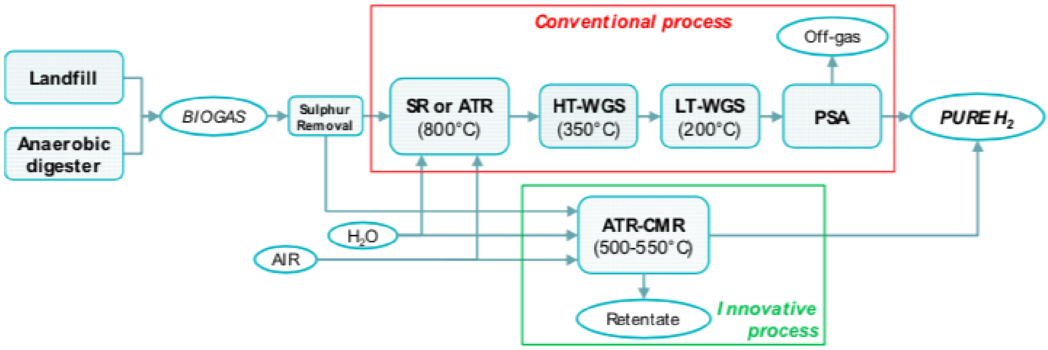


Figure 6.12: Hydrogen production from biogas in both conventional- and innovative process (Marcoberardino et al., 2019)

drawback related to the loss of H_2 selectivity was a result of thermal cycles required to regenerate the catalyst, and pinholes formation and sintering of the palladium layer (Lulianelli et al., 2014).

Castillo et al., 2015 in contrast operated the BSR within a palladium-silver membrane reactor at temperatures of [350-450] °C, [0.1-0.4] MPa on the reaction side, 0.002 MPa at the permeation side, and S/C of 3. Ultimately, a maximum hydrogen yield of 80% and hydrogen recovery of 50% was achieved at 450 °C and 0.4 MPa at 15 cubic centimeters (cc) per minute of pure hydrogen, yielding higher hydrogen production as compared to without permeation at the same conditions. Here, the permeation allows the conversion to proceed at a lower temperature due to the favorable shift of the reaction equilibrium. Also, the hydrogen recovery rate increased as function of temperature and pressure (Castillo et al., 2015).

In contrast, the work by Ugarte et al., 2017 focused on DR as a way to avoid the energy consumption associated with steam production. Moreover, Ugarte et al., 2017 deploy a two-zone fluidised bed reactor with a hydrogen selective membrane to combine the catalytic reaction, separation and catalyst regeneration in a single reactor. This reactor also should serve to counter the possible disadvantages of DR associated with coke formation and the lower H_2/CO ratio. Here, two zones are used to offset catalyst deactivation, where the DR occurs in the upper, reducing zone of the reactor forming carbon deposits. The oxidizing gas is then used to burn or gasify coke to regenerate the catalyst in the lower bed, oxidation zone. Through the fluidised bed design, a continuous mixing of solid is achieved, where the regenerated catalyst is transported to the upper part of the bed. Moreover, Ugarte et al., 2017 indicated the feasibility of using CO_2 for the in-situ catalyst, as a way to avoid the potential problems associated with the use of pure oxygen. Ultimately, this serves to show intensification through counteracting catalyst deactivation, increased conversion at given temperature or allowing operations at lower temperature, and the production of a stream of high-purity hydrogen. Small increases in methane conversion and H_2/CO ratio were obtained for a $CH_4 : CO_2$ molar ratio of 1:1 as compared to previous results in case of the two-bed zone reactor. Here, a methane conversion of [30-45]% was shown at H_2/CO of [1-1.5]. However, the incorporation of membrane configuration further improved the H_2/CO ratio and methane conversion to [40-45]%, achieving higher conversion than could be achieved according to the thermodynamic equilibrium in case of a conventional reactor. Moreover, part of the

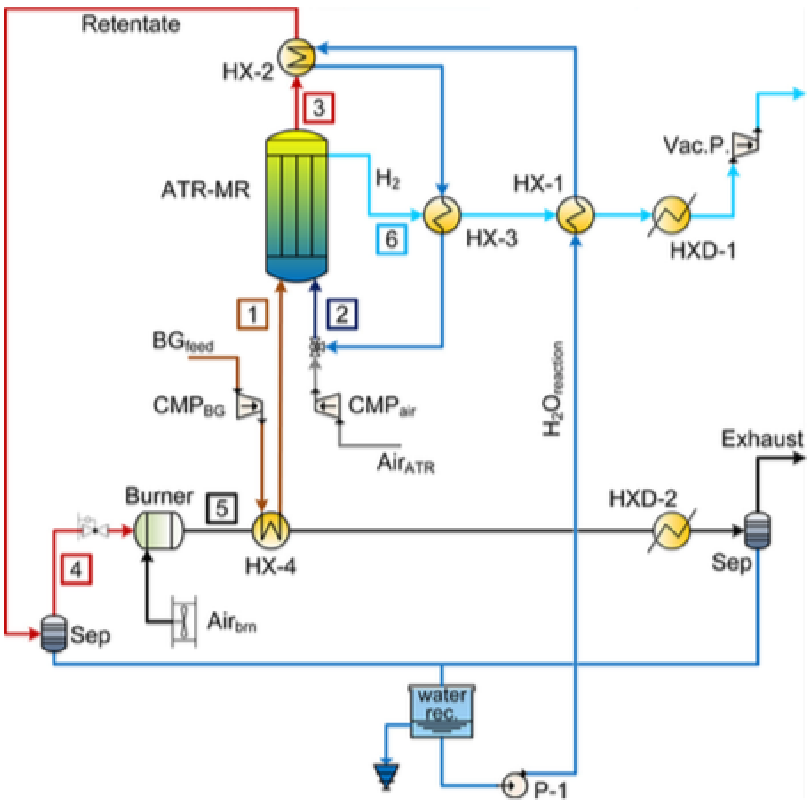


Figure 6.13: Layout of BIONICO system using a vacuum pump (Marcoberardino, Foresti, et al., 2018)

H_2 was obtained with a high degree of purity and without observation of a loss of conversion over time.

Sorption enhanced reforming

Sorption enhanced reforming (SER) is a process intensification method to produce hydrogen with in-situ CO_2 capture. More generally, SER incorporates the SMR, WGSR and H_2/CO_2 separation in the same vessel. The SER can be seen to increase the yield of the conventional SMR process by favourable shifting the equilibrium conditions by the in-situ removal of CO_2. Thereby, a higher hydrogen production and purity can be obtained at a lower temperature in the range of [450 - 490] °C and lower operating pressure of [180-890] kPa. Thereby, the process not only reduces CAPEX by reactor integration, it also increases productivity and output of the reformer itself. Moreover, the lower operational conditions and higher output, including purity, subsequently also have the potential to lower the OPEX (Soltani et al., 2021). The process mostly utilise nickel- or calcium oxide-based materials for catalysis and CO_2 capture, either on separate particles or in combined sorbent catalyst materials. The process mostly operates at around 650 °C, atmospheric pressure and a steam to carbon ratio of [3-4], obtaining a high purity hydrogen stream with over 95% volume percentage on dry dilution-free basis. This is in contrast to for example a 76% hydrogen volume in the case of industrial SMR operations (Giuliano and Gallucci, 2018). Moreover, in order for continuous process operations the calcium oxide (CaO) is regenerated through multi-cycle high temperature calcination in the temperature range of [800-950] °C. Through the regeneration process a concentrated- or pure CO_2 stream can be obtained (Giuliano and Gallucci, 2018). More specifically, the adsorption by solid sorbents for CO_2 capture is considered promising in terms of energy savings, capital costs and operating costs as compared to physical adsorption by solvents. Here, CaO is seen as a high-temperature CO_2 sorbent with easily availability in nature, a low costs mineralised form, high stoichiometric sorption capacity and fast kinetics in the high temperature range. The respective carbonation reaction can be described as follows, depending on partial pressures (Giuliano and Gallucci, 2018):

$$CaO_s + CO_2 \rightleftharpoons CaCO_3 \quad \Delta H = -175.7\frac{kJ}{mol} \tag{6.17}$$

In a second reactor vessel or alternating calcination condition, the CO_2 is subsequently regenerated through the calcination reaction and the sorbent is regenerated via increasing the temperature to around 850 °C. The overall SER reaction based on the CaO sorbent can be summarised as follows (Johnsen et al., 2006):

$$CaO_s + CH_4 + 2H_2O_{(g)} \rightarrow CaCO_3 + 4H_2 \tag{6.18}$$

Overall, the process can be observed in figure 6.14. Here, it can be seen that in the reformer, the formed CO_2 is captured by the sorbent, in this case CaO and removed from the reformer process to the regenerator vessel. In this concept, both the catalyst and sorbent are mixed in the reformer, where the SER is performed. As a result, the equilibrium reaction shifts towards the enhanced production of hydrogen and CO_2. The product gas consist subsequently mostly of hydrogen and steam, with minor quantities of CO and unconverted methane. In the regenerator, a high purity CO_2 is then extracted with the use of external heating to support the endothermic calcination reaction and the absorbent is then recirculated back to the reformer (Johnsen et al., 2006). Despite its potential, the current technology level readiness is around 4, where intended pilot-plant studies aim to lower the system LCOH through a reduction in CAPEX and OPEX of around 50% in comparison to a commercialised process with CCS, at a CO_2 capture rate of 96% and same hydrogen purity. However, currently the key challenges are associated with the development of efficient-, cheap- and stable catalysts to improve conversion efficiency, optimisation of the associated energy demand, the development- and implementation of heat- and energy recovery, and the optimisation of the process configuration to optimise total production costs (Soltani et al., 2021).

Methane cracking

Methane cracking or methane pyrolysis attracted attention for the production of hydrogen from methane with carbon as by-product. This carbon can subsequently be used for material production or can be sequestrated. Currently, the pyrolysis of natural gas is a well-known technology applied for the production of for example carbon black. In the case of hydrogen production the process might constitute to a carbon-neutral or carbon-negative hydrogen production method (Schneider et al., 2020). Methane pyrolysis can be described as the thermal decomposition of methane at temperatures of above at least 800 °C, based on the different processes. Here, plasma processes could operate at temperatures up to 2,000 °C. The primary reaction

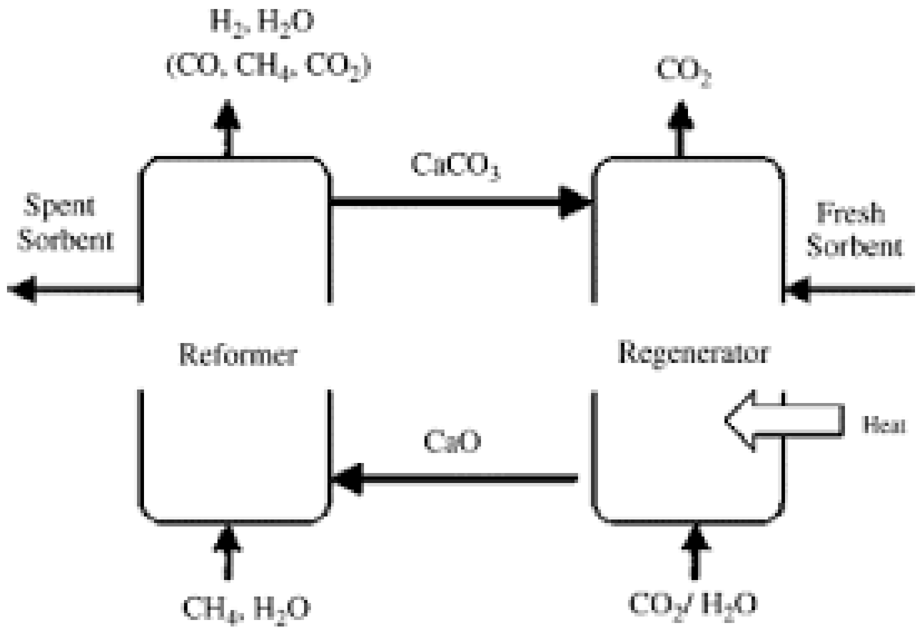


Figure 6.14: Simplified schematic of the SER process (Johnsen et al., 2006)

is endothermic and produces both gaseous hydrogen and solid carbon, according to the following reaction formula (Schneider et al., 2020):

$$CH_4 \rightarrow C_{(s)} + 2H_2 \quad \Delta H = 74.9\frac{kJ}{mol} \tag{6.19}$$

Compared to the SMR reaction, MC in general has a lower energy intensity due to the non-participation of the WGSR. Moreover, the MC operates in a single reactor, does not require an additional inflow stream, and operates near atmospheric pressure. However, side reactions produce saturated- and unsaturated hydrocarbons as well as cyclic aromatic compounds which can occur in all three states of aggregation. As a result, if technically pure hydrogen has to be produced, the methane cracking still requires further gas purification. In reality the presence of other compounds in the feed stream further complicate the process and have a significant effect on the selectivity, reaction products and conversion rate. This consequently impacts the gas quality, catalyst service life and solid deposits (Schneider et al., 2020). Despite this, another additional benefit of MC is that the process does not produce CO_2 but instead creates industrial grade graphite with a purity between [85-95] %, where the total carbon footprint accumulates. This graphite subsequently find a market as raw material for the production of, for example, electrodes or lithium-ion batteries. Depending on the projected revenues for the carbon by-product an estimated cost for hydrogen of [2,6-3,2] €/kg was determined, in contrast to around 2 €/kg for the SMR process (Schneider et al., 2020). However, so far the process faces technical challenges of high conversion rate requirements for economical operation, high associated process temperatures, low product gas purity, complex handling of solids generated from the gas phase and the potential resulting deposits or blocking (Schneider et al., 2020).

The methane pyrolysis process can more specifically be divided in three categories, namely thermal-, plasma-, and catalytic decomposition. Here, thermal decomposition occurs over temperatures of well over 1,000 °C, plasma decomposition sees high local energy densities and temperatures of up to 2,000 °C, while catalytic decomposition could operate well below 1,000 °C at satisfying reaction rates and conversion rates. There is no clear perspective yet on the ideal configuration and an overview of different developments can be seen in figure 6.15, showing the different projects, target products and TRL (Schneider et al., 2020).

In figure 6.15 it can for example be seen that the Hazer Group focuses on catalytic decomposition of methane with hydrogen as target product. In this case, the methane gas is brought into a distributor plate in the reactor where the gas is brought in contact with the iron catalyst that is fluidised and suspended in the gas, thereby mixing the methane gas with the solid sand-like particles (HazarGroup, 2021). The active iron ore is used to decompose the methane and produce hydrogen. The hydrogen yield, product quality of the carbon and the deactivation of the iron ore catalyst can be controlled through the pressure, temperature and mass flow in the reactor. The process is described to operate at 850 °C with a methane feed of 0.01 L/min and a methane conversion of 92%. However the pilot plant is expected to enhance the throughput of the process (Schneider et al., 2020). Moreover, currently the Hazer group funded a €23 million commercial demonstration plant which converts biogas into hydrogen and graphite (ARENA, 2019). In figure 6.16 a generic overview of the methane cracking process of the Hazer group can be seen (HazarGroup, 2021.

Principle	Developer, facility	Target product	Period	Reactor description	State of development	TRL
Thermal	BASF	H_2	2012–	Moving bed of carbon granules	Laboratory plant, R&D project for scale-up	4
Thermal	KIT / IASS	H_2	2013–	Liquid tin bubble column	Laboratory, R&D project for process development	3
Plasma	Kvaerner	Carbon black	1992–2003	Plasma torch	Pilot plant, with subsequent scale-up (Karbomont plant)	6
Plasma	Kvaerner, Karbomont plant	Carbon black	1997–2003	Plasma torch	Production plant (decommissioned and dismantled)	8
Plasma	Monolith materials, Seaport plant	Carbon black	2014–2018	Plasma torch (similar to Kvaerner)	Pilot plant (dismantled), with subsequent scale-up	6
Plasma	Monolith materials, Olive Creek Plant	Carbon black	2016–	Plasma torch (similar to Kvaerner)	Production plant, mechanical completion planned for 2020	8
Plasma	Atlantic hydrogen, carbonsaver	Mixture H_2 / natural gas	2005–2015	Plasma torch	Pilot plant (not put into operation), development stopped due to bankruptcy	5
Catalytic / Plasma	Tomsk Universities, TOMSK-GAZPROM	H_2	2008–	Microwave, Ni catalyst bed + plasma torch	Laboratory, no further information on scale-up	3
Catalytic	UOP, HYPRO process	H_2	1963	2-stage fluidized bed with Ni catalyst	Laboratory plant, development was stopped	4
Catalytic	Florida Solar Energy Center	H_2	2003–2005	2-stage fluidized bed with C catalyst	Laboratory, no information on further development	3
Catalytic	Hazer Group	H_2	2010–	3-stage fluidized bed with Fe catalyst	Laboratory, pilot plant to be constructed by 2021	3

Figure 6.15: Overview of methane cracking processes (Schneider et al., 2020)

BECCUS

According to R. J. Detz and van der Zwaan, 2019 the need to achieve negative CO_2 emissions before 2050 is presumable in order to comply with the ambition to not let the average atmospheric temperature increase exceed 1.5 °C. Here, a net negative balance implies that more CO_2 is taken out of the atmosphere than human activities emit into it. R. J. Detz and van der Zwaan, 2019 argue the likeliness of this

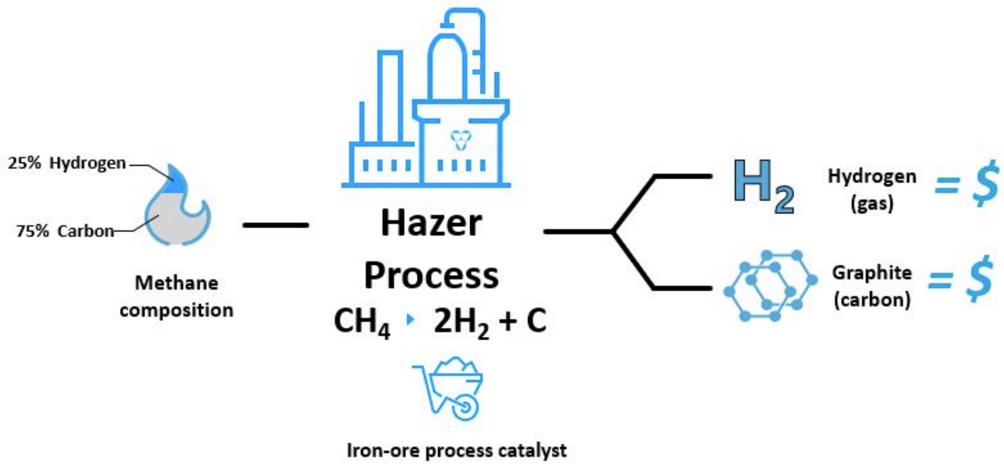


Figure 6.16: Depiction of the Hazer Group methane cracking process (HazarGroup, 2021)

scenario since the least developed countries may not be able to achieve a net zero CO_2 economy by 2050. Moreover, certain developed countries may fail to achieve the reduction targets, several sectors might be more difficult to achieve carbon neutrality. Additionally, net-zero CO_2 emissions also require strong reductions of other important GHG emissions that might be hard and more expensive to control. Lastly, currently achieving net-zero is already prone to a 70% probability, thereby reducing the likeliness of achieving net-zero by 2050.

The main options available so far for net-zero- or negative CO_2 emissions are agriculture, forestry and land use as well as biogenic energy in combination with CO_2 capture and storage (BECCS). However, R. J. Detz and van der Zwaan, 2019 argue that these predictions inaccurately fail to incorporate the potential usage of CO_2 in a process called CCU, or more general and in the case of biogenic carbon capture, utilisation and storage (BECCUS), where the CO_2 is processed as main building block in industrial usage and thereby can deliver to a circular carbon economy. The future demand for circular CO_2 is expected for the production of, in particular, chemicals and fertilizers, hydrocarbons like bitumen, fuels and lubricants, materials for construction and inorganic salts, and a large variety of plastics and fibers (R. J. Detz and van der Zwaan, 2019). In this way, only biomass, direct air capture (DAC), fossil fuels and industry, and recycling and waste can provide the demand for zero-emission carbon, where only BECCUS and DAC yield negative emissions. Here, the strongest carbon-based source is expected to come from biomass with over 50% of the total supply (R. J. Detz and van der Zwaan, 2019).

In this perspective, Primmer and Tredd, 2021 indicate that the storage of CO_2 and substitution of natural gas with biomethane provides a sustainable, carbon-negative bio-hydrogen production option. Hereby, the integration of CCUS technology can actively reverse emissions by removing atmospheric carbon from the biosphere. This is further complemented by ensuring renewable energy is used to power the entire process (Primmer and Tredd, 2021).

The study by Antonini et al., 2020 focused on the BECCS process through CO_2 capture from the syngas in the ATR- and SMR reforming reaction with the help of a

VPSA process which combines the hydrogen purification and CO_2 separation in one cycle. Here it was shown that the highest plant-wide CO_2 capture rate of almost 100% was achieved through the ATR configuration, which showed clear advantages as compared to SMR, in combination with a two-stage WGSR and VPSA. In the case of a SMR plant, two sources of carbon dioxide are present which are the oxidation of the carbon atoms in the feedstock during the reforming and shift reaction, and the combustion reaction occurring in the reformer furnace. As a result, pre-combustion capture only allows for the syngas CO_2 to be captured, while post-combustion CO_2 capture is required in the flue gas. In contrast, in ATR most direct CO_2 emissions could be avoided through pre-combustion capture from the syngas. In this case, only pre-combustion capture was investigated as this would be the most economical option and 90% an 98% capture rates where considered. While in the case of SMR the addition of a low-temperature WGSR hardly affected the process efficiencies and capture rates, it was determined crucial for ATR as the performance with only a high-temperature WGSR showed poor performance. However, it was recognized that the addition of CCS resulted in higher electricity requirements. Ultimately, while in case of natural gas, the global warming potential (GWP) can be reduced by [45-85]% depending on the SMR or ATR process, net negative GHG emissions can be achieved using biomethane, where the addition of CCS always let to net-negative emissions (Antonini et al., 2020).

6.5 Analysis

Within the context of the future renewable hydrogen system, biogas has been attributed great potential as bio-hydrogen and bio-carbon dioxide, or syngas, source. In this respect, the conversion of biogas to bio-hydrogen has to be feasible. Moreover, to potential of the possible conversion routes for biogas has to be assessed based on the relevant parameters within the research context. This is not limited to the actual reforming of biogas, but spans the wider value chain. At the moment, this includes the removal of contaminants present in raw biogas, the separation of biomethane and bio-carbon dioxide to achieve a natural gas-quality biomethane stream, the reforming of biomethane, and the separation of the second bio-carbon dioxide stream and bio-hydrogen to ultimately arrive at a high-purity bio-hydrogen stream. In this perspective, it has been shown that the conversion of biogas to bio-hydrogen and bio-carbon dioxide is feasible and includes several steps with different strengths and weaknesses in comparison to alternatives present.

Here, the exact utilisation of the contaminant removal technology or combination of technologies is prone to several relevant factors including the actual contaminants present, the level of contaminants, the gas flow rate, and the reliability-, adaptability- and flexibility of the process and is thereby site dependent. Broadly, adsorption on activated carbon and silica gel for H_2S and H_2O removal respectively have been named as important contaminants removal technologies. Also, [*Removed as confidential*]. Nonetheless, not one dominant contaminant removal technology can be identified. However, in the perspective of the concept of third-generation upgrading of biogas the contaminants removal technology is deemed necessary and as possible, with commercially deployment at the moment. As a result, despite potential cost reduction options and potential intensification opportunities, no bottleneck in the process of bio-hydrogen is expected from the contaminant removal technology.

After the contaminant removal technology it is observed that several different technologies are present for the upgrading of biogas, but the utilisation of membrane technology is dominant and increasing. [*Removed as confidential*].

The natural gas-quality biomethane is then processed as direct replacement of natural gas in the reforming process. In this respect, the SMR process is the most dominant technology at the moment, which in case of dedicated bio-hydrogen production shows a high hydrogen production potential. In this context, HyGear offers the potential for smaller-scale and on-site hydrogen production with a capacity varying of [10-1,000] Nm^3/h hydrogen output at a purity of [99.5-99.9999]% and pressure of [1.5-7.0] bar. However, here the containerised solution includes the final hydrogen purification step. Benefits of the process relates to the reliability-, stability- and long-life time of the process. Moreover, the process allows for modular scaling and modulation in the reformer- and hydrogen output (HyGear, 2021). However, ATR shows promising signs with additional benefits of an adjustable- and flexible reformer output, which could benefit the optimisation of the output products with respect to the required end application. Moreover, the ATR process design has been attributed better potential to operate cost-effectively at a smaller-scale as compared to the strong economies of scale observed in case of the SMR reformer design. Therefore, in light of the local- and of regional production of bio-hydrogen and bio-carbon dioxide or syngas from biogas, the ATR production process might become more relevant.

After the reforming step, mostly including a high-temperature and low-temperature WGSR, the resulting bio-hydrogen and bio-carbon dioxide have to be separated. In this respect, PSA is seen to be the most dominant technology, which benefits from the significantly different static capacity of hydrogen as compared to the other gaseous compounds present. Moreover, while other purification options exist limited scientific evidence indicates relevant commercial deployment. On top of that, continued research- and development with respect to the PSA technologies improves the applicability of the technology for bio-hydrogen purification. In this respect, VPSA shows positive results with respect to hydrogen recovery and yield. This technology is also deployed in the technology from HyGear which attributes the usage of to the energy- and cost-efficiency of the VPSA technology. Here, four parallel active vessels are deployed to enable a continuous cleaning process (HyGear, 2021). This also indicates the potential of the usage of PSA technology at smaller-scales, which is deemed relevant in the case of local- and or regional production of bio-hydrogen.

Thus, it can be seen that the biogas to bio-hydrogen conversion route can rely on mature technology and is technological feasible. Moreover, several options exist that could further lower the system cost or add additional flexibility with respect to the ultimate output mix. Overall, the actual process design is related to the specific feedstock input, input volume and end application requirements.

Nonetheless, the perspective on the conversion of biogas to bio-hydrogen and bio-carbon dioxide relies on the traditional production process and thereby ignores the future potential of biogas within the proposed renewable hydrogen system. In this respect, several relevant technological alternatives are present as well as process intensification options. To address the relevancy of the discussed technologies and processes, a HOQ assessment is used to analyse the relevant technological options along important parameters within the context of the future renewable hydrogen system.

House of quality analysis

The concept of third-generation upgrading of biogas is technological feasible. However, several alternative technological options that could further benefits the conversion of biogas in light of the proposed renewable hydrogen system are present. In this respect, these technological options are assessed along the lines of relevant technological parameters in light of the future renewable energy system. To do so, the house-of-quality analysis is utilised.

The house-of-quality framework is a methodological framework used for product- and process development where the goal is to compare both the qualitative- and quantitative parameters of the technology specifications and analyse these quantitatively. In order to do so, the technologies to compare and the relevant parameters including boundary conditions have to be chosen. Hereafter, the technologies are compared based on the respective parameters and scaled from 1 to 5, where 5 is the optimal score. These parameters are given an importance factor, also on a scale from 1 to 5, to yield a total weighted importance score. Here, the importance factors indicate the relative importance among the parameters used to assess the technology. Ultimately, the score, based on the relative importance of the parameters and the score of the technologies per parameter, can then be used to rank-, compare, and select or exclude the assessed technologies.

Therefore, initially the relevant technological parameters are identified. Hereafter, these technological parameters are assigned an importance factor based on the relative importance in light of the future renewable hydrogen system. The technological parameters used are:

- Technology fundamental limitations
  This parameter assesses potential fundamental technological limitations to the process design. Moreover, it aims to address the complexity of the technological challenges apparent in overcoming, the non-fundamental, limitations. Thereby, this parameters aims to establish an understanding of the technical feasibility of the process to contribute to the conversion of biogas within the future renewable hydrogen system.

- Technology readiness level
  The TRL parameter is used in tandem with the technology fundamental limitations parameter. In this respect, the TRL parameters aims to address the expected time frame to commercialisation of the proposed technological routes. In light of the future renewable hydrogen system, the TRL parameters thereby identifies the potential of the technology to contribute to a fast-, affordable- and fair transition.

- Technology scalability;
  The technology scalability parameters aims to address the potential of the technology to, cost-effectively, function at a local-, small-scale and regional, medium-scale. This includes the potential to operate as stand-alone process and or the dependency on external input. Moreover, this parameters includes the option for modular scaling of the technology in light of the expected increase

demand for biogas conversion methods.

- System cost;
  The system cost parameter addresses the expected cost perspective of the technology options. Hereby, the parameters incorporates the expected factors that influence the overall cost perspective, including CAPEX, OPEX and process lifetime. Here, the process outline as well as process requirements are included in the cost perspective.

- System cost reduction;
  In light of the future proposed hydrogen system, this parameters aims to include the expected technological developments that impact the system costs. Therefore, the system cost reduction parameters complements the system cost parameter to allow for dynamic interpretation of the system design.

- Process input flexibility;
  The process input flexibility parameter allows for the assessment of the effect of difference in feedstock composition on the process. In this case, it incorporates the effect of upstream input- and process variations that effect the actual composition of biogas streams. Hereby, the process input flexibility parameter assess the potential of the technology to operate for different biogas streams, mixed biogas streams and alternation of biogas streams.

- Process output flexibility;
  In light of the future renewable energy system, the relative valuation of the output products of biogas conversion are expected to alter over time and place. Therefore, modulation in output as well as flexibility in the output products could support the optimisation of the process.

- Process yield;
  In the future renewable hydrogen system, biogas is expected to increasingly be seen as a valuable biogenic input stream. As a result, the loss of valuable biogas has to be minimised in the process, including internal heat demand. Therefore the process yield parameters aims to assess the ratio of valuable output products versus the ratio of valuable input products on a molecular basis.

The resulting score of the respective technological options for the conversion of biogas, according to the house-of-quality analysis, can be seen in figure 6.17.

Here, it can be observed that most weight is attributed to the parameters of technology fundamental limitations and system costs. In light of the future renewable hydrogen system, the technological feasibility for the biogas conversion method is most important. Thereby, inherent problems associated with the conversion method could limit the adoption of the conversion method over time. Moreover, ultimately in the future renewable hydrogen system, the system requires optimisation from a system cost perspective. Even though this parameter includes factors as the system efficiency and energy utilisation, these are deemed less relevant in light of wide-scale renewable energy production technologies. On the contrary, the technology readiness level, process input flexibility and process yield are assigned the least importance. In case of the technology readiness level this allows for further research and development in light of the future renewable hydrogen system. Moreover, in case of process yield this relates to the conversion efficiency, however as mentioned the energy efficiency is deemed of lesser relevance in the future renewable energy system as indirect relation of the system costs. Moreover, similarity in conversion efficiencies, in light of potential trade-offs, limit the prescriptive value. Lastly, with respect to the process flexibility, limited variation is expected in the process input as a result of dedicated conversion production methods and the potential to operate in a fairly continuous operation. Moreover, little is known about the actual process specifications with respect to input flexibility. As a result, less weight is attributed to the process input flexibility parameter.

Hereafter, the respective technologies for the conversion of biogas are assessed. It can be seen that SMR has been attributed the highest score on technology fundamental limitations, as the technology is most developed and widespread used thereby the SMR process shows limited technological barriers. In contrast, biogas dry reforming suffers from thermodynamic limitations of the present CO_2 stream as well as carbon formations. These, form significant technological barriers to develop the technology. Also, methane cracking is characterised by unfavourable side-reactions that limit the adoption for high-purity hydrogen production, while the steam-iron process is hindered by the presence of H_2O and CO_2 in the inlet. On the contrary, membrane technology suffers from the trade-off between hydrogen selectivity and permeability of the membrane in combination with the membrane material degradation.

In case of the technology readiness level, both SMR and ATR are well-developed, while MC sees demonstration projects. However, in case of DR and BOX relatively limited research has been devoted to the conversion technology, while the research into the SIP technology is relatively new.

In case of technology scalability, the reactor, furnace-like, design of the SMR and MC technology limit the scalability of the process. Despite, examples of small-scale utilisation of SMR are present. These are assigned a significantly higher price points as compared to large-scale SMR processes. On the contrary, the compactness, process specification and modular character of ATR, BATR, SIP and membrane reforming support the adoption on smaller-scale.

The system cost for traditional reforming technologies suffers from the lowest level of intensification. More specifically, the traditional reforming technologies suffer from an additional upgrading step in contrast to biogas reforming technologies. The ultimate process intensification strategy through MC and membrane reforming support the lowest cost perspective, where the relative expensive hydrogen separation steps, mostly a combination of WGSR and PSA, are removed.

The process intensification possible for the SIP process through a one-reactor design in case of chemical looping stimulate further system cost reductions. These system cost benefits are expected to be lowest in case of the more mature reforming technologies.

The process input flexibility is assumed to be least in case of the technologies that are affected considerably by the presence of non-optimal feed conditions. This is the case in methane cracking and SIP, where in case of methane cracking the hydrogen purification is directly influenced while in case of SIP the reaction equilibrium is unfavourably altered. In contrast, the BOX process is presumed to allow for the highest level of flexibility, which includes the relatively high acceptable level of sulphur that can be presented. More generally, the biogas reforming technologies are assumed to allow higher levels of flexibility, due to processing of more complex biogas as compared to biomethane.

The process output flexibility is affected by the potential to alter the system output products, which is mostly achieved by alteration in the process input ratio. However, also alteration in the process conditions can stimulate process output flexibility. In this respect, the multitude of oxidants can support greater level of output flexibility, which can be observed in the autothermal reforming reactions. In contrast, the dedicated hydrogen production methods lack output flexibility as a result of the process specifications. This includes the separation of hydrogen via membrane technology, via molecules or via thermal decomposition.

The process yield is influenced by the ratio of useful output products on a mass balance as compared to the useful input products. Here, the thermal neutral nature of the ATR reaction limit the need for additional biogas and or biomethane input to provide the relevant process heat. On the contrary, the DR and BOX reactions suffer from the relatively low carbon conversion levels, which result in a relatively low output of useful products.

Ultimately, it can be observed that autothermal reforming reactions are ascribed most potential in the case of the conversion of biogas within the proposed renewable hydrogen system. This relates strongly to the high level of flexibility ascribed to the autothermal process, both in case of scalability and process output. Moreover, the level of technological feasibility and potential low system cost further support the autothermal reforming conversion route. In this respect, BATR is presumed most likely, while membrane reforming via autothermal reforming might become more relevant in case of dedicated hydrogen production. On the contrary, methane cracking and SMR are expected to become less relevant in the case of biogas reforming, despite the relevant potential in case of natural gas. This relates mostly to the expected scale of production and more dedicated hydrogen production. Despite the low levels of technology readiness the innovative SIP and SER processes might show promising signs, mostly related to the high level of process intensification and the expected benefits on a system cost perspective.

To conclude, the concept of third-generation upgrading would provide relevant benefits within the future renewable hydrogen system. In this respect, the concept values the inherent bio-carbon present in biogas. More, the concept of third-generation upgrading allows for the optimalisation of the output bio-hydrogen and bio-carbon dioxide over time and place. In this respect, it is important that the technological options to convert biogas to bio-hydrogen and bio-carbon dioxide are flexible with respect to the required output products. Moreover, the technology design should allow for scaling and modulation to support adoption on the regional- and or local scale. Moreover, in light of the increased value of renewable molecules the process should allow for optimal utilisation of scarce resources. Ultimately, the conversion method should support the system cost perspective. Here, it was shown that autothermal reforming technologies show relevant importance for the concept of third-generation upgrading. Not only does that ATR process allow for higher carbon capture rate as compared to SMR, it also shows significant advantages with respect to the process flexibility and scalability. Moreover, the ATR process shows positive signs with respect to system costs, which is deemed of most importance in the future renewable hydrogen system. Additional system integration is supported through increasing levels of process intensification as well as the coupling with renewable hydrogen production. As a result, the concept of third-generation upgrading shows strong technological potential within the future renewable hydrogen system.

Row number	Weight chart	Relative weight	Importance factor (1-5)	Technological process / Technology parameter	Steam methane reformig	Autothermal methane reforming	Methane cracking	Biogas dry reforming	Biogas steam reforming	Biogas dry oxidation reforming	Biogas autothermal reforming	Steam-iron process	Membrane reforming	Sorption enhanced reforming
1		16%	5	Technology fundamental limitations	5	4	3	2	4	4	4	3	3	4
2		10%	3	Technology readiness level	5	5	4	1	2	1	3	1	3	3
3		13%	4	Technology scalability	3	5	2	4	4	4	5	5	5	4
4		16%	5	System cost	3	3	5	4	4	4	4	4	5	4
5		13%	4	System cost reduction	1	2	3	3	2	2	3	5	4	4
6		10%	3	Process input flexibility	3	3	1	4	4	5	4	2	4	3
7		13%	4	Process output flexibility	2	5	1	3	4	4	5	2	2	1
8		10%	3	Process yield	4	5	4	3	4	3	5	5	5	4
				Target (1-5)	3,5	3,5	3,5	3,5	3,5	3,5	3,5	3,5	3,5	3,5
				Rating	3,23	3,94	2,94	3,03	3,55	3,45	4,13	3,45	3,87	3,42
				Relative weight	9%	11%	8%	9%	10%	10%	12%	10%	11%	10%
				Weight chart										
				Position	8	2	10	9	4	5	1	5	3	7

Figure 6.17: House-of-quality analysis of the respective technological biogas conversion options

Chapter 7

Process

Through the concept of third-generation upgrading, biogas has been assigned an higher valorisation potential as important source of bio-hydrogen and bio-carbon dioxide. In this respect, it was shown that the conversion of biogas to bio-hydrogen and bio-carbon dioxide shows strong technological potential within the wider proposed renewable hydrogen system. For example, it was shown that the ATR- or BATR process shows relevance for the concept of third-generation upgrading. Next to the technological layout, the process design has important implications for the respective streams of valuable output materials present in the value chain from biogas to bio-hydrogen. This subsequently impact the relevant parameters to identify the production potential of the concept of third-generation upgrading. These include the relevant carbon streams, which impact the sustainability of the conversion method. Moreover, this includes the output streams, which impact the economics of the conversion method. On top of that, this subsequently relates to the respective boundary conditions in relation to infrastructure- and regulation requirements.

As a result, this chapter aims to identify the potential process flow designs with respect to the conversion of biogas to bio-hydrogen and bio-carbon dioxide. Ultimately, the analysis concludes with a process flow diagram, which can subsequently be used as input to determine the key parameters- and the boundary condition requirements to assess the potential of the biogas to bio-hydrogen conversion method. This would especially be relevant in light of the place and time function of the concept of third-generation upgrading within the proposed future renewable hydrogen system.

7.1 Introduction

At industrial scale, the current hydrogen production capacity is on average 100,000 Nm^3/h with most current production capacities increasing to around 300,000 Nm^3/h hydrogen. Besides large-scale industrial hydrogen production, small-scale localised hydrogen production at typical sizes of around 150 Nm^3/h are also surfacing. These smaller-scale production capacities align with the average size of biogas installations of around 200 Nm^3/h or 2 MW_{th} (Holstein et al., 2018). However, larger-size containerised solutions in the order of [1,000-12,000] Nm^3/h are commercialised, which presently also allow for operations based on biogas (HyGear, 2021). As a result, today on-site production units can be produced in any required size and capacity. Here, harmonization of the technology, both in capacity and footprint, can unlock mass production and thereby reduce the cost of the installations (Schjolberg et al., 2012).

Overall, a distinction can be made with respect to the size of the production facility in terms of hydrogen output, which can be seen in table 7.1. Additionally, Schjolberg et al., 2012 make another distinction based on hydrogen refuelling need, on a home, a neighbourhood, up to a forecourt scale. Here, the distinction relies on different ranges, within the total range of production capacity, from [0.25->150] Nm^3/h hydrogen or [200-100,000] $kgH_2/year$, and is based on a hydrogen demand of 200 kg/year per car (Schjolberg et al., 2012).

Size of the facility	Pilot	Small	Medium	Large
Production capacity (kg/d)	100 - 1,000	1,001 - 5,000	5,001 - 50,000	> 50,000
Production capacity (Nm^3/h)	50 - 500	501 - 2,500	2,501- 25,000	> 25,000

Table 7.1: Production scale hydrogen production

A simplified overview of a typical on-site installation can be seen in figure 7.1 (HyGear, 2021). Here, the sulphur content is first removed from the natural gas or biomethane through a desulphurisation system. Hereafter, the methane, or even biogas, is mixed with steam, in the case of SMR, to produce a syngas mixture. The syngas is then send to a WGSR to lower the CO content and enhance the hydrogen yield. Then a PSA unit separates the hydrogen from mainly CO_2 to produce a high-purity hydrogen stream of up to 99.999% at a pressure between [7-25] bar. The off-gas from the PSA unit is subsequently fed into the burner to generate steam and other heat to fuel the process, which ultimately results in a typical efficiency of 72% based on HHV in the case of natural gas. The small-scale process is characterised by a startup time of 30 minutes in case of warm installation and 3 hours in case of a cold-start. Moreover, the capacity can be reduced down to 10% of the operational capacity. Lastly, next to natural gas, biomethane or biogas input the system requires water, compressed air and electricity (Holstein et al., 2018). In this process, the main components are compressors, pressure vessels, heat exchangers, pumps and the burner (Schjolberg et al., 2012).

To asses the potential of small-scale, local hydrogen production facilities, Matton et al., 2016 identifies energy performance, greenhouse gas footprint, economic performance and sustainability as key criteria to identify the adequate process setup. Here, most focus was devoted to the hydrogen- and carbon dioxide performance. In this respect, the small-scale hydrogen production incorporated a small-scale SMR unit to fulfill a [85-200] kg/day hydrogen demand, from a local hydrogen refuelling station (HRS). Matton et al., 2016 showed that the best small-scale, local hydrogen process set-up was through either grid-connected biomethane delivery or physical biogas delivery to the SMR unit, requiring [150,000-400,000] m^3 biomethane input. However, the study excluded the potential direct incorporation of biogas to SMR, while other options included were the physical delivery of biomethane, natural gas and different local water electrolysis options (Matton et al., 2016).

In contrast to small-scale installations, which align with the current production levels of biogas that happen at agricultural facilities, Bianchi, 2018 bring forward the potential scaling and professionalisation of the biogas and biomethane sector. Here, scaling

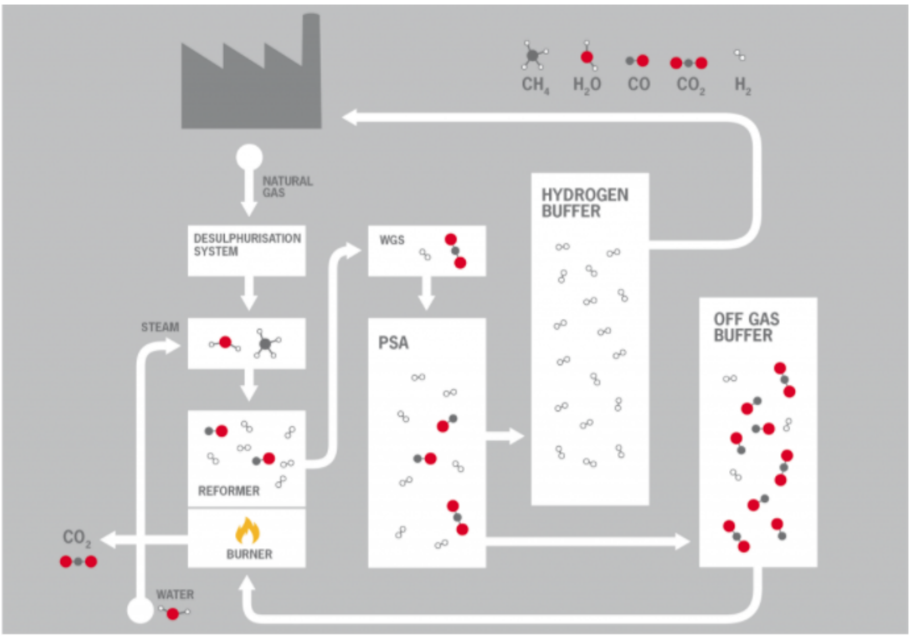
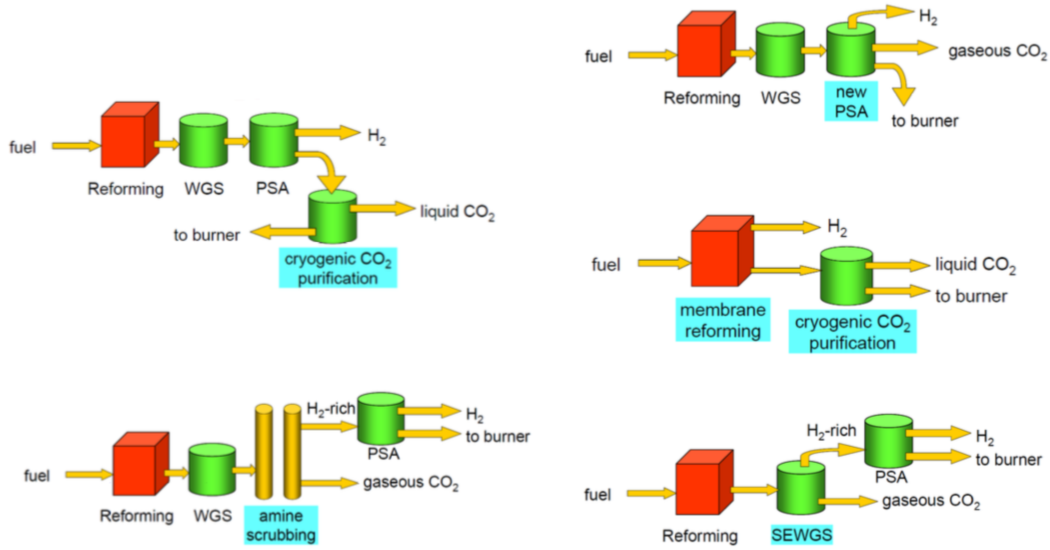


Figure 7.1: Simplified representation of a typical on-site SMR installation (HyGear, 2021)

could support the economic feasibility of the upgrading process, and the extraction and trading of co-products including CO_2 and digestate. Thereby, strategic hubs could support the production, upgrading and processing of agricultural waste. The strategic hubs in this way facilitate the incorporation of the complete process chain, including production, upgrading, valorisation, usage and transportation. This can ultimately support higher system efficiencies, lower costs, larger volumes, regional integration options and alternative business models (Bianchi, 2018). This could not only support the upgrading of biogas to biomethane, but also offers great potential for the generation of bio-hydrogen and bio-carbon dioxide. Here, the production of bio-hydrogen and bio-carbon dioxide could be supported by strong economies of scale and thereby the centralisation and scaling pave the way for further integration of bio-hydrogen production capacity.

However, Schjolberg et al., 2012 identify a set of six challenges for further research related to on-site small-scale reforming. These challenges include engineering challenges with respect to cost reductions of designing and building, in mass production, units and systems. Moreover, it includes the selection of materials that are able to be exposed to the operational conditions and feedstocks, the design of sulfur tolerant catalysts for the various reactions involved, the creation of sensors that allow for unattended- and continuous operations, the development of clean up technology that adhere to purity requirements, and the establishment of adequate process control to influence the behaviour of the process through manipulation of the process inputs for desired outputs. Next to the set of challenges, Schjolberg et al., 2012 pave the way for the emergence of new technologies that might further spur adoption of small-scale hydrogen production and the incorporation of CCS for small-scale reforming. Here, potential process integration is possible for CO_2 capture in the PSA off-gas or for the flue gas from the combustion of fuel gas for heat provision. However, the latter is characterised by lower CO_2 content and subsequently lower capture potential. The CO_2 could subsequently be transported in a supercritical fluid phase through pipelines or via liquid phase transport. For the latter, cryogenic distillation might suffice for both CO_2 purification and liquefaction. As a result, several process designs can be described and integrated, as can be seen in figure 7.2. This ultimately should lead to reduced production costs, improved system performance, larger volumes and mass production of on-site reformer units at beneficial ecological performance. In the case of the latter, the CO_2 reduction potential of the small-scale on-site hydrogen production, as compared to the traditional process design, is [30-75]%, [15-25]% and [30-60]% in case of the use of renewable feedstock, renewable electricity and CO_2 capture respectively (Schjolberg et al., 2012).



(a) Current technological options

(b) Future technological options

Figure 7.2: Small-scale hydrogen production with CCS integration possibilities (Schjolberg et al., 2012)

7.2 Green gas

For the upgrading of biogas to green gas, Angelidaki et al., 2018 reviewed the main principles, outcomes and the relations to biomethanation efficiency. An overview of the different upgrading technologies and relevant process parameters can be seen in figure 7.3. Here, it can be seen that the methane recovery of the physicochemical processes can reach over 96%, while the losses do not exceed 4%. Moreover, it can be seen that most upgrading technologies require an additional pretreatment step in the process design. With respect to the different upgrading technologies, one-, two- or multi-stage unit process steps are used to upgrade the biogas toward biomethane (Angelidaki et al., 2018).

Next to physicochemical methods, innovative biological technologies are surfacing, including chemoautotrophic methods including in-situ, ex-situ, and microbial communities. Also, photoautotrophic methods, other fermentation processes and microbial electrochemical methods exist. In case of in-situ chemoautotrophic conversion, high methane recovery in the range of [65-100]% is possible, with hydrogen conversion efficiency of [58-100]% and CO_2 removal of [43-100]%. For ex-situ biological upgrading processes higher methane recovery levels can be obtained between [79-98]%, with

CO_2 removal levels of [50-100]% and H_2 conversion efficiency of [72-100]%. Both processes operate in the temperature range of [37-60] °C and pH range of [7.0-8.5]. For photoautotrophic conversion, additional H_2S separation is achieved, cancelling the need for an extra recover step, with methane recovery- and CO_2 removal levels of [65-97]% and [54-98]% respectively. However, less is known about other process conditions and parameters. Moreover, the biological methods are still considered new and are not commercialised (Angelidaki et al., 2018).

In the same line, I. U. Khan et al., 2017 investigated the upgrading efficiency, methane loss, environmental effects and other process parameters with respect to biogas upgrading technologies. Key parameters of the respective physicochemical upgrading technologies can be seen in figure 7.4. Here, the inconsistency in values seen in figure 7.4b can be attributed to the material used, energy requirements and different process conditions utilised (I. U. Khan et al., 2017).

	Cryogenic	Sabatier process	PSA	Water scrubbing	Physical scrubbing	Chemical absorption	Membrane separation
Consumption for raw biogas (kWh/Nm^3)	0.76	nf	0.23–0.30	0.25–0.3	0.2–0.3	0.05–0.15	0.18–0.20
Consumption for clean biogas (kWh/Nm3)	nf	nf	0.29–1.00	0.3–0.9	0.4	0.05–0.25	0.14–0.26
Heat consumption (kWh/Nm^3)	nf	nf	None	None	< 0.2	0.5–0.75	None
Heat demand (°C)	− 196	270			55–80	100–180	
Cost	High	Medium	Medium	Medium	Medium	High	High
CH_4 losses (%)	2	nf	< 4	< 2	2–4	< 0.1	< 0.6
CH_4 recovery (%)	97–98	97–99	96–98	96–98	96–98	96–99	96–98
Pre-purification	Yes	Recommended	Yes	Recommended	Recommended	Yes	Recommended
H_2S co-removal	Yes	No	Possible	Yes	Possible	Contaminant	Possible
N_2 and O_2 co-removal	Yes	No	Possible	No	No	No	Partial
Operation pressure (bar)	80	8–10	3–10	4–10	4–8	Atmospheric	5–8
Pressure at outlet (bar)	8–10		4–5	7–10	1.3–7.5	4–5	4.-6

Figure 7.3: Overview and comparison of different biogas upgrading technologies (Angelidaki et al., 2018)

Technology	PSA	HPWS	OPS	AS	MS	CS
Electric energy (MJ/m^3),	0.72	0.97	–	–	1.80	–
(kWh/Nm^3)	0.24	0.20	–	–	0.19	–
MJ/ton of CO_2 removed	915	770	1069	433	1264	1275
Methane loss (%)	4	5.13	4	0.1	6	0.65
Upgrading yield (%)	65	68	–	–	65	–
Methane purity (%)	97.5	98	97	99	91	98

(a) Biogas upgrading technologies key parameters

Technology	Energy requirement (kWh/m^3 of upgraded biogas)					
	Collet et al. [128]	Patterson et al. [127]	Götz et al. [129]	Ncibi et al. [130]	Olsson et al. [131]	Meier et al. [126]
PSA	0.5–0.6	0.24	0.335	0.285	–	–
HPWS	0.3	0.2	0.43	0.391	–	–
OPS	0.4	–	0.49	0.511	–	–
CSP	0.15	0.12	0.646	0.126	–	–
MS	–	0.19	0.769	–	0.27	0.378
CS	–	–	–	–	0.42	–

(b) Biogas upgrading energy requirement

Figure 7.4: Parameters for the different physiochemical biogas upgrading technologies (I. U. Khan et al., 2017)

In case of further processing of biomethane towards bio-LNG, additional removal steps might be needed to achieve the required technical specifications. Moreover, the process requires a liquefaction technology, where the Rankine- and Reversed Brayton cycle is mostly used in commercial applications (Uslu et al., 2021). Here, 440 kg/hour bio-LNG could be obtained from a mono-manure digestion plant of >400 kW_{th} with a manure input of around 300 kt per year and based on a biogas yield of 25 $m^3/t\ manure$ (Uslu et al., 2021).

7.3 Bio-hydrogen

The process to convert biogas to hydrogen can be divided as either indirect usage of biogas via biomethane, the direct usage of biomethane or as alternative process.

7.3.1 Biomethane to hydrogen

The biogas-to-hydrogen (BTH) plant is a combination- and integration of a biogas plant and a hydrogen production facility. In this case, the BTH plant could provide an effective regional supply source of hydrogen energy. In this respect, Ohkubo et al., 2010 showed the feasibility of the BTH plant with an approximate capacity of hydrogen supply of 400 Nm^3/day. Here, the most environmental benign method was shown to operate on self-produced biogas as fuel. Moreover, the optimal reaction conditions, appropriate operation methods and a stable continuous operation of the individual processes and the overall system was shown. The BTH plant firstly operates through the generation of biogas, consisting of around 60% biomethane and 40% bio-carbon dioxide, from digested slurry from cow manure through methane fermentation technology, including acid fermentation and gas fermentation. The biogas plant converts 45.4 m^3/day of liquid cow waste input, from 1000 dairy cows in a methane fermenter of 1,500 m^3, at [35-37] °C for around 30 days. A process flow diagram of the biogas plant can be seen in figure 7.5. Here, it can be seen that the biogas produced is utilised as source for the energy requirement and as material for the reformation into hydrogen, while the digested slurry is used to make high-quality bio-fertiliser. Moreover, based on the organic matter difference between the cow waste and the digested slurry an approximate of 60% of the organic matter is actually contributing to the production of biogas (Ohkubo et al., 2010).

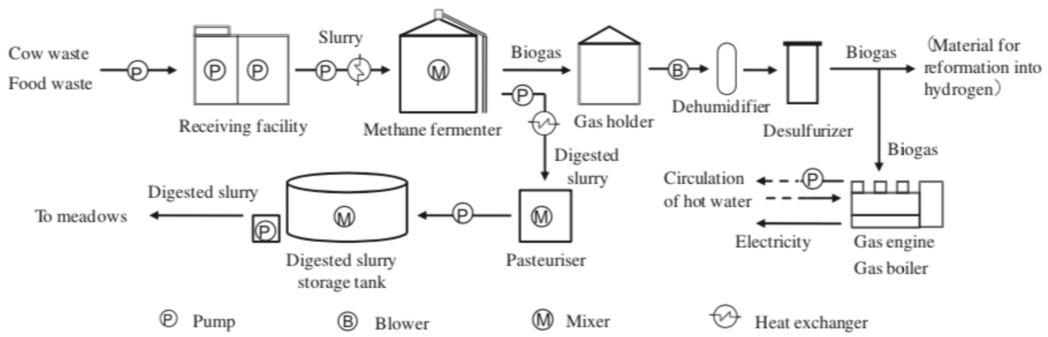


Figure 7.5: Process flow diagram of the biogas plant (Ohkubo et al., 2010)

With respect to the hydrogen production plant, firstly the biogas is upgraded to methane through separation of the carbon dioxide, after which it is used in the SMR process to produce hydrogen. An overview of the hydrogen production plant can be seen in figure 7.6. Here, the process operates at 750 °C and 0.47 MPa, to yield an approximate 90% methane conversion rate, a 73% hydrogen recovery rate in the PSA, and yield an 99.9% hydrogen pure stream. The hydrogen output volume was 280 Nm^3/day from 108 Nm^3/day of biomethane or 200 Nm^3/day biogas. The resulting off-gas was reused as combustion gas (Ohkubo et al., 2010).

A more detailed mass balance of the respective streams in the hydrogen plant can be seen in figure 7.7. Approximately 30 Nm^3/t biogas can be generated from the cow

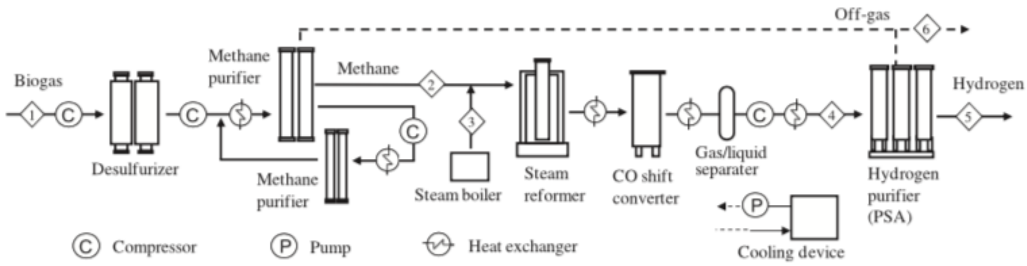


Figure 7.6: Process flow diagram of the hydrogen plant (Ohkubo et al., 2010)

waste, with an average cow waste of 65 kg/day, from which a biogas volume of 200 Nm^3/day was introduced and ultimately a hydrogen volume of 280 Nm^3/day. With respect to the energy requirements, the electricity demand of the biogas plant, for example for the pumps and agitator, was assumed to be proportional to the amount of biomass. The same assumption was included for the heat requirement, for example to preheat the biomass and maintain operating temperature, which was fulfilled by heat recovery from the biogas engines. For the hydrogen plant, the electricity demand, for example for gas compression and cooling, was assumed proportional to the biogas introduced, while the head demand, mainly from the SMR reactor, was assumed to be proportional to the surface area of the reactor. The storage facility electricity demand was obtained from a hydrogen station. Both low-temperature demand, for example for pre-heating of biomass, and high-temperature demand, for example SMR process heat, are assumed to be supplied through external sources. For the low-temperature demand this could originate from the power generation and heat recovery from the biogas engine. In case of high-temperature demand the direct usage of the biogas and off-gas combustion heat could be utilised. Lastly, different efficiencies of the biogas engine, fuel cell and gas boiler were assumed (Ohkubo et al., 2010).

Ultimately, the optimal specification values for the BTH plant operation can be seen in figure 7.8. Here, it can be seen that no GHG emission are emitted as the energy demand is met by self-produced carbon-neutral biogas. Moreover, the optimal hydrogen supply was around 400 Nm^3/d or 480 kWh/day based on an biogas production of 1950 Nm^3/day of which 290 Nm^3/d served for biogas input for reforming. Nonetheless, as can be seen in figure 7.8, a production output increase of 1.5 could be obtained when co-fermentation with food waste is used. Moreover, it should be noted that the design specifications relate to the most environmental benign operation method, while economic efficiency could alter the production since a higher yield of hydrogen could boost the economic performance (Ohkubo et al., 2010).

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Stream No.		1	2	3	4	5	6
Gas flow (Nm^3/day)		200	108	324	492	280	212
Composition (vol%)	CH_4	60	100		2.2		7.5
	CO_2	40			18.8		56.7
	CO				1.0		1.6
	H_2				78.0	100	34.2
	H_2O			100			

Figure 7.7: Process flow mass balance in the hydrogen plant (Ohkubo et al., 2010)

No.	Biomass	Cow waste	Cow waste + Food waste	Unit
	Item	Case 1	Case 2	
1	Biomass input (Cow waste/Food waste)	65.00 (65.00/0.00)	68.25 (65.00/3.25)	t (=10^3 kg)
2	Biogas production	1,950	2,440	Nm^3/day
3	Biogas consumption of gas boiler	210	265	Nm^3/day
4	Biogas input for reforming	290	455	Nm^3/day
5	Biogas consumption of biogas engine	1,450	1,720	Nm^3/day
6	Off-gas consumption of gas boiler	310	480	Nm^3/day
7	Generation of biogas engine	2,420	2,870	kWh/day
8	Heat recovery from biogas engine	13,800	14,540	MJ/day
9	Heat supply from gas boiler	7,400	10,230	MJ/day
10	Hydrogen output	410	640	Nm^3/day
11	Greenhouse gas emission from BTH-plant operation	0	0	kg-CO_2/day
12	Greenhouse gas mitigation through hydrogen energy use	327	513	kg-CO_2/day

Figure 7.8: Optimum specification values for the BTH plant (Ohkubo et al., 2010)

7.3.2 Biogas to hydrogen

In addition to hydrogen production from biomethane, Antonini et al., 2020 focused on the integration of bio-hydrogen production with carbon capture and storage technology. Here, Antonini et al., 2020 focuses on carbon capture through VPSA technology and compared this with conventional amine-based CCS technology. The carbon flows under varying modeling assumptions can be seen in figure 7.9. Here, the lower bound carbon balance relates to the usage of CCS technology, while the upper bound does not include CCS. Moreover, the use of digestate as fertiliser or for incineration is included, which also addresses the carbon uptake considerations (Antonini et al., 2020). Moreover, the carbon balance is related to the biogas composition and as such on the carbon content of the digested biowaste. Here, it is assumed that per kg of of biowaste treated from the 1 kg of carbon content, around 0.32 carbon on a dry mass basis ends up in the biogas, while another 0.41 ends up in solid digestate, 0.09 in liquid digestate and 0.05 in digestate manure. Nonetheless, the carbon balance faces uncertainty depending on the boundary conditions incorporated, including agricultural practices, land-use changes and long-term carbon sink potential. The respective mass- and energy balances then follow from the conventional hydrogen production process including- or excluding the carbon capture through VPSA- or amine-based technology. Here the former is a process intensification in which both hydrogen is purified as well as carbon captured, in contrast to amine-based technology that solely captures the CO_2 (Antonini et al., 2020). Ultimately, the highest plant-wide CO_2 capture rate, of almost 100%, was possible through the process of ATR with two-stage WGSR and VPSA CO_2 capture technology (Antonini et al., 2020). Hereby, additional energy requirements and infrastructure is needed for the liquefaction or compression of the CO_2, which scales with the amount of CO_2 captured. This includes the subsequent transport through pipelines or trucks and the potential storage before usage of CO_2 (Lamboo et al., 2021).

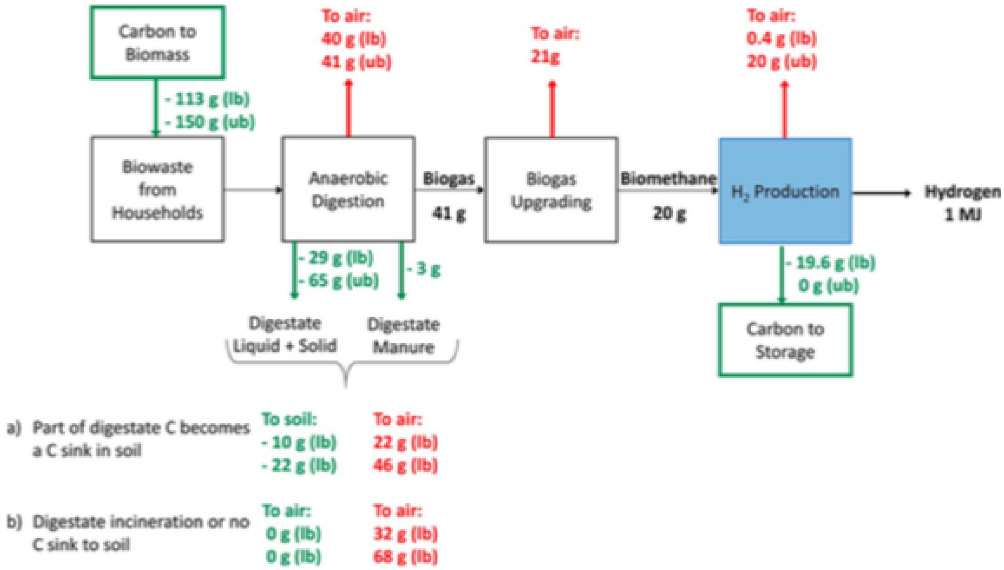


Figure 7.9: Carbon flow of biomethane hydrogen production for with (lb) and without (ub) CCS technology at the reformer and (lb) or (ub) on carbon uptake (Antonini et al., 2020)

The focus on the BTH system was also taken by Hajjaji et al., 2016. However, instead of connecting the biogas- to the hydrogen production system through biogas upgrading and feeding biomethane, Hajjaji et al., 2016 directly use the biogas through the BSR in order to produce hydrogen. In this case, the biogas production originates from AD from farm waste where the digester feedstock was a mixture of 7 t/day manure and 7 t/day agricultural waste to produce around 2027 Nm^3/day biogas with an average molar composition of 60% CH_4 and 35% CO_2. The liquid digestate was stored for usage as bio-fertiliser on the farm, while the solid digestate was used for fine-grade compost. In the end, around 25.5 kg of manure, 25.5 kg of residual of waste and 4055 kJ of electricity was used in the AD operation per kg of hydrogen to yield 7.18 Nm^3 biogas and around 43 kg digestate. For the hydrogen production 7.6 kg of water, 19.1 kg of air and 1950 kJ of electricity was required on top to produce 1 kg of hydrogen. An generic overview of the subsequent BSR process flow diagram can be seen in figure 7.10, while the stream properties are summarized in figure 7.11. Ultimately, the process yields a thermal efficiency based on LHV of 76.8%, indicating three quarters of the energy is in the end recovered in useful H_2 (Hajjaji et al., 2016).

In contrast to Hajjaji et al., 2016, Marcoberardino, Vitali, et al., 2018 studied next to the BSR, also the BATR reaction process. Here, a hydrogen production plant was designed to process 100 kg/day of hydrogen with a purity of at least 99.999% delivered at a pressure of 20 bar. Also, both biogas from both landfill sources and AD were studied. In the case of landfill biogas, the methane content is lower and the inert content higher resulting in a lower LHV in contrast to AD biogas. Both processes are assumed to start with a desulphurisation step to remove sulfur compounds through an activated carbon removal unit. Hereafter, the process layout of both BSR and

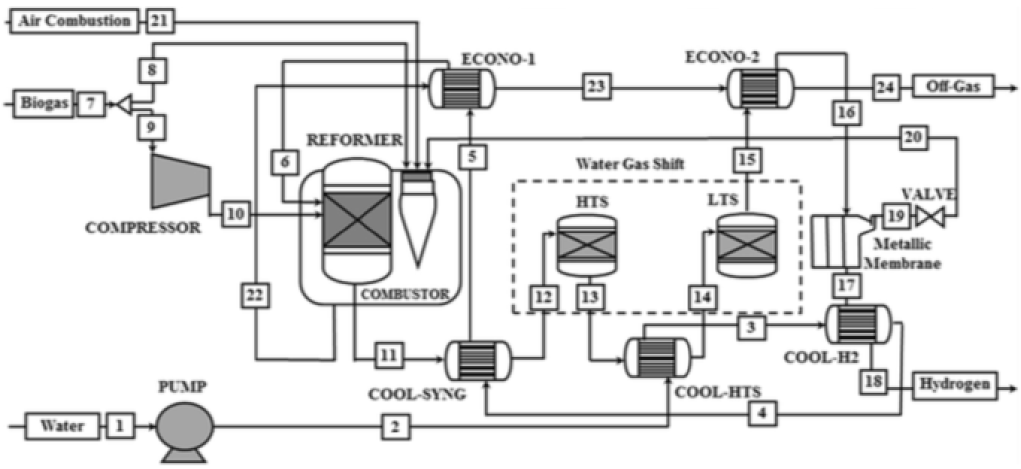


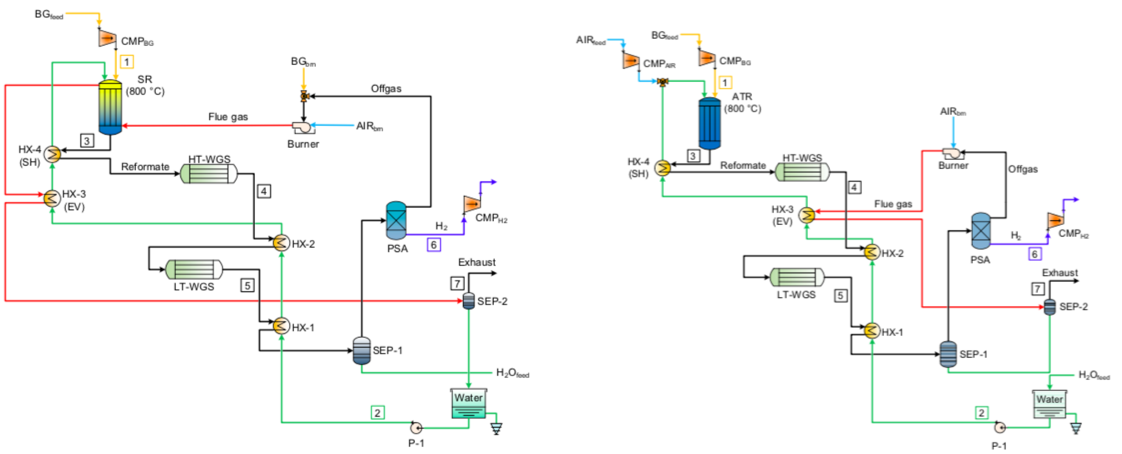
Figure 7.10: Flowsheet of BSR process (Hajjaji et al., 2016)

Stream	1 (Water)	7 (BG)	8 (BG comb.)	9 (BG ref.)	11 (SG)	18 (H_2)	21 (Air comb.)	24 (off-gas)
T (°C)	25	25	25	25	800	226.8	25	370.6
P (atm)	1	1	1	1	10	1	1	1
Mass flow (kg/h)	87.42	97.17	26.06	71.10	158.53	11.53	220.50	393.56
Composition (% mol.)								
CH_4	0	60.0	60.0	60.0	1.8	0.0	0.0	0.0
CO_2	0	35.0	35.0	35.0	10.3	0.0	0.0	26.4
H_2O	100	2.0	2.0	2.0	32.1	0.0	0.0	27.4
N_2	0	3.0	3.0	3.0	0.8	0.0	79.0	46.1
CO	0	0.0	0.0	0.0	12.6	0.0	0.0	0.0
H_2	0	0.0	0.0	0.0	42.5	100.0	0.0	0.0
O_2	0	0.0	0.0	0.0	0.0	0.0	21.0	0.1

Figure 7.11: Properties of the key stream of the BSR process (Hajjaji et al., 2016)

BATR can be seen in figure 7.12. In the case of BSR, the heat required for the SR reaction is supplied through the combustion of the off-gas from the PSA unit and additional amounts of biogas, while for the BATR the heat requirement is balanced through the partial oxidation of the feed fuel, in this case air supply, thus not requiring additional amount of biogas to the burner (Marcoberardino, Vitali, et al., 2018). An overview of the respective stream properties can be seen in figure 7.13 for the BSR and figure 7.14 for the BATR respectively, with input of landfill biogas assumed (Marcoberardino, Vitali, et al., 2018).

Ultimately, the BSR with AD biogas had the highest system LHV efficiency of around 52% as compared to landfill biogas of 46%, attributed to the higher methane content in biogas from AD. This relates to the quality of the biogas and as such to the amount of biogas required, where higher quantities of impurities result in a less effective conversion of biogas to bio-hydrogen. Additionally, a lower LHV value results in higher quantities of biogas that undergo oxidation, especially in BATR, which negatively impacts the efficiency. Moreover, the BSR outperformed the BATR configuration significantly, mainly due to the purification recovery, with BATR achieving an efficiency of around 28%. Based on a 100 kg/day hydrogen output at around [12-18] bar, the biogas input varied from 39.5 Nm^3/h in the case of AD BSR, 56.1 Nm^3/h in case of landfill BSR to 63.5 Nm^3/h for AD ATR (Marcoberardino, Vitali, et al., 2018). Additional parameters affecting the system efficiency are primarily the steam-to-carbon ratio, temperature in the reforming reaction and the WGSR conversion. However, while higher system efficiencies could be achieved by increasing the levels of the relevant parameters, the increase in hydrogen production cost indicate a trade-off. For example, an increase in steam-to-carbon ratio from, the reference of, 4 to 5 increased the LCOH from 5.190 €/kg to 5.213 €/kg, while an increase in temperature from 800 °C to 900 °C increased the LCOH from 5.190 €/kg to 5.321 €/kg, despite boosting the system efficiency with around 2.5% and 7% respectively (Marcoberardino, Vitali, et al., 2018).



(a) Process flow diagram BSR process (b) Process flow diagram BATR process

Figure 7.12: Process flow diagrams of biogas-to-hydrogen production routes (Marcoberardino, Vitali, et al., 2018)

Stream	Flow		T (°C)	P (bar)	Composition (% Molar Basis)						
	Molar (mol/s)	Mass (g/s)			CH_4	H_2	CO	CO_2	H_2O	O_2	N_2
1	0.648	18	150	14	44.2	<0.1	<0.1	34.0	3.2	2.5	16.0
2	1.145	21	15.1	14.1	-	-	-	-	100.0	-	-
3	2.344	39	800	23.95	0.9	35.0	9.6	11.5	38.5	-	4.5
4	2.344	39	391.1	13.9	0.9	43.7	1	20.1	29.8	-	4.5
5	2.344	39	209.9	13.85	0.9	44.5	<0.1	21.0	29.0	-	4.5
6	0.573	1	15	20	-	99.999	-	-	-	-	<0.1
7	2.557	76	60	1.1	-	-	-	21.2	18.3	2.5	59.4

Figure 7.13: Stream properties of the BSR process (Marcoberardino, Vitali, et al., 2018)

Besides the study into conventional BSR and BATR technology, Marcoberardino, Foresti, et al., 2018 also investigated the potential for process intensification through a membrane reactor design. Moreover, the design included both VPSA- and PSA technology for hydrogen purification as well as biogas from both landfill sources and AD. The stream properties, based on landfill biogas, can be seen in figure 7.15, while the process layout for the membrane reforming process, with vacuum pump, could be seen in figure 7.16 (Marcoberardino, Foresti, et al., 2018). Also, in case of the membrane reforming process the highest efficiencies can be obtained using AD biogas, with efficiencies up to [70-74]%. Moreover, the higher methane content associated with AD biogas allows for strong reduction in membrane surface requirement. Other influences are related to the trade-off between hydrogen conversion and retention and are related to the increase in temperature, permeate pressure improvements and increase in steam-to-carbon ratio. Ultimately, at the considered delivery pressure, purity and volume the membrane reforming system outperform the BSR and BATR

Stream	Flow		T (°C)	P (bar)	Composition (% Molar Basis)						
	Molar (mol/s)	Mass (g/s)			CH_4	H_2	CO	CO_2	H_2O	O_2	N_2
1	1.139	32	150	18	44.2	<0.1	<0.1	34.0	3.2	2.5	16.0
2	1.511	27	15.2	18.15	-	-	-	-	100.0	-	-
3	4.813	101	800	17.95	0.4	22.4	7.3	11.7	32.8	-	16.0
4	4.813	101	425.1	17.9	0.4	27.0	2.8	16.3	28.2	-	25.4
5	4.813	101	228.9	17.85	0.4	29.5	0.3	18.8	25.7	-	25.4
6	0.578	1	15	20	-	99.999	-	-	-	-	<0.1
7	5.270	155	60	1.1	-	-	-	17.4	15.7	2.5	64.4

Figure 7.14: Stream properties of the BATR process (Marcoberardino, Vitali, et al., 2018)

with 19- and 41 percent points respectively to yield an overall system LHV efficiency of 65%. The resulting biogas input is around 27 Nm^3/h for AD biogas and 35 Nm^3/h in the case of landfill biogas in case of the process design including VPSA technology. Next to improvements in efficiency, the reforming system was also able to operate at a lower temperature and pressure. Also, the LCOH could be reduced to [4-4.1] €/kg in comparison to 4.21 €/kg and 6.4 €/kg with respect to BSR and BATR respectively (Marcoberardino, Foresti, et al., 2018).

Stream	Flow		T (°C)	p (bar)	Composition (% molar basis)						
	Molar (mol/s)	Mass (g/s)			CH_4	H_2	CO	CO_2	H_2O	O_2	N_2
1	0.44	12.25	282.6	12	44.2	–	–	34.0	3.1	2.7	16
2	0.66	15.97	467	12	–	–	–	–	43.6	11.8	44.6
3	0.82	27.1	550	12	0.05	0.9	0.41	0.9	12.6	–	44.6
4	0.82	27.1	230	12	0.05	0.9	0.41	0.9	12.6	–	44.6
5	0.99	32.07	312.7	1.1	–	–	–	34.8	11.3	2.9	51.0
6	0.58	1.17	550	0.1	–	100	–	–	–	–	–

Figure 7.15: Stream properties of membrane reforming process (Marcoberardino, Foresti, et al., 2018)

7.3.3 Alternative process

Moreover, Stenberg et al., 2018 studied other process intensification options and focused on the combination of SMR with fluidised beds of oxygen carriers to achieve in-situ carbon capture. More specifically, Stenberg et al., 2018 investigated oxygen carrier aided combustion (OCAC) and chemical looping combustion (CLC). Here, the first concept is incorporated in a single bubbling fluidised bed reactor, while the second uses an external fluidised bed heat exchanger (FBHE). Both technologies provide an alternative approach to provide heat for the SMR reaction via oxygen carrier bed particles, rather than radiation of heat from tubes provided by gas-fired burners. The improved heat transfer characteristics should subsequently result in lower combustion temperatures, less thermal stress, shorter tube lengths, improved cold gas efficiency, less CO_2 emissions and less NO_x emissions (Stenberg et al., 2018). The CLC process is a combustion process with inherent capture of CO_2 and can be characterised as either conventional CLC, steam-iron chemical looping and SER. The OCAC process in contrast is related to CLC, where oxygen carriers are used to replace inert bed material so to introduce new mechanisms for conversion of fuel and the transport of oxygen in time and space. In this way, it supports the minimisation of carbon monoxide formation and unburned hydrocarbons as well as increase the conversion of methane in the dense zone of the fluidised bed. For both designs, the

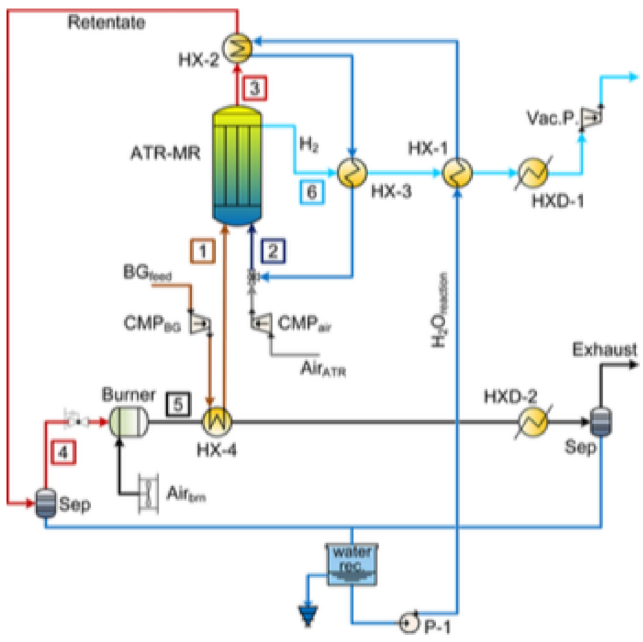


Figure 7.16: Process flow diagram of the membrane reforming process (Marcoberardino, Foresti, et al., 2018)

methane conversion can be altered through variation in temperature, pressure and carbon-to-steam ratio. In this case, a difference in pressure seems to have a limited effect, especially in light of undesired side-effects. With respect to the temperature and the steam-to-carbon ratio, both seem to show a steep increase in conversion initially, while flatting at higher levels. However, both show a clear trade-off with respect to system efficiency and system costs (Stenberg et al., 2018). An overview of both integrated fluidised bed processes can be seen in figure 7.17, while a schematic illustration of the process outline can be seen in figure 7.18, where the furnace represents the entire reactor system. The main flow rates are shown in figure 7.19, where A is the reference case of a conventional steam reforming process. In the latter, it can be seen that the gas compositions are mainly similar, where all are based on a feed of 1 mol CH_4/s, pure methane input, and hydrogen purity in the outlet of 100%, while the supplementary fuel added to the furnace explains the difference in flue gas composition. This results in similar a methane conversion and hydrogen yield of around 81% and 72% respectively. The difference in supplementary fuel resulted in a small decrease in cold gas efficiency based on LHV from 79.7% to 79.4% and 76.4% with respect to OCAC, CLC and the reference system respectively. Nonetheless, under the assumption of 100% capture rate for CLC, the direct CO_2 emissions related to the furnace decreased 100% for CLC and 4.1% for OCAC compared to the reference scenario. Ultimately, it showed the potential of a considerable decrease in fuel consumption, lower flue gas temperature, lower required air excess, lower CO_2 emissions and higher system efficiencies. Nonetheless, no estimation about economic gains of the process are present, despite potential benefits related to less fuel consumption and less thermal stress. However, additional cost are also expected for the oxygen carrier and additional reactor in case of CLC (Stenberg et al., 2018).

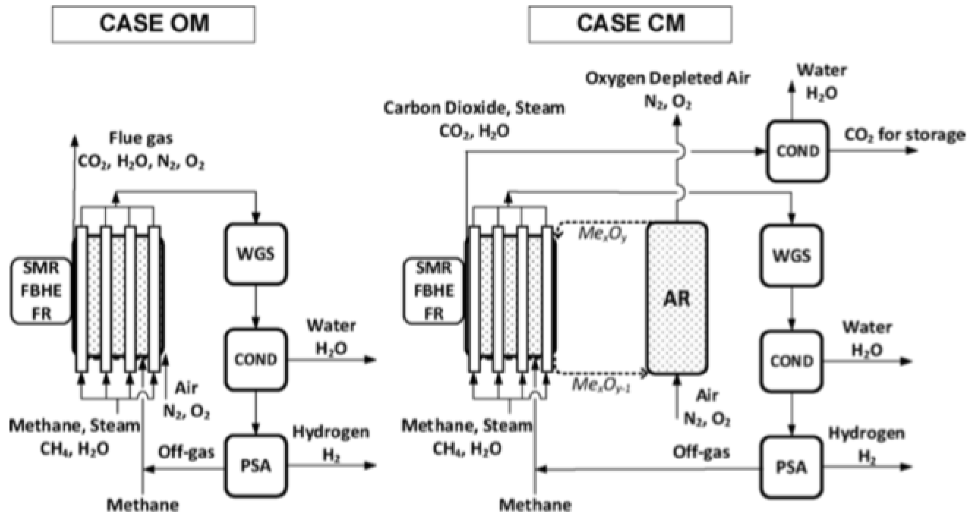


Figure 7.17: Process overview of OCAC (O) and CLC (C) processes (Stenberg et al., 2018)

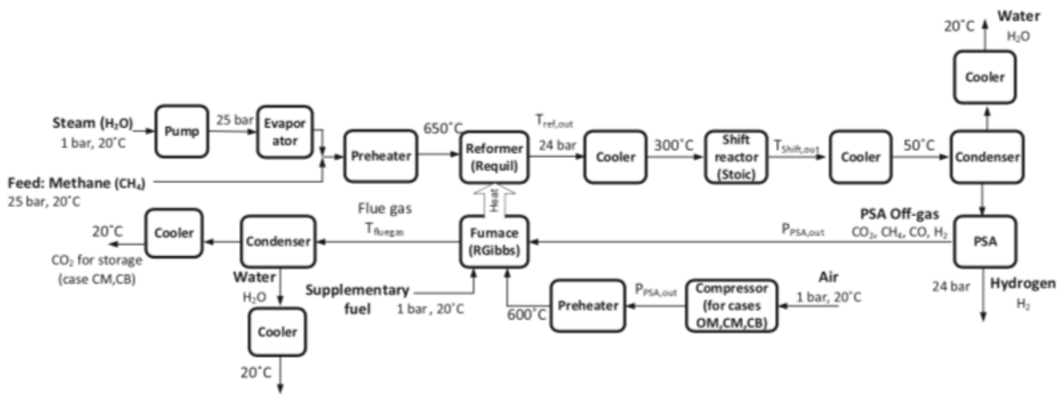


Figure 7.18: Process outline of OCAC/CLC processes (Stenberg et al., 2018)

7.4 Analysis

The conversion of biogas to bio-hydrogen and bio-carbon dioxide shows important potential within the future renewable hydrogen system. In this respect, the potential process flow designs with the respective technological parameters and stream numbers for the different bio-hydrogen production methods have been discussed. The respective process flow diagrams can subsequently serve as input to assess the relevant sustainability- and economic parameters of the concept of third-generation upgrading. Moreover, the exact process numbers can be utilised to draft the required infrastructural and regulatory conditions. On top of that, the process flow design can be used to develop a system perspective on the integration of biogas within the renewable hydrogen system over time and place.

In this respect, it has been discussed that the hydrogen production capacities show several different sizes. Here, it was shown that hydrogen production can also be applied at a local- and or regional scale to align with biogas production capacities. Moreover, it was shown that commercialisation and scaling of the biogas sector could stimulate the biogas to bio-hydrogen conversion route, through decrease in system costs, increase in output volumes, opening of sector coupling options, potential for

[All in moles/sec]		CH_4	H_2O	CO	CO_2	H_2
	Case A	0.191	1.878	0.495	0.313	2.739
Reformed gas composition	Case OM	0.191	1.878	0.495	0.313	2.739
	Case CM	0.191	1.878	0.495	0.313	2.739
	Case CB	0.0342	3.590	0.522	0.444	3.341
	Case A	0.191	1.432	0.0495	0.759	3.185
Shifted gas composition	Case OM	0.191	1.432	0.0495	0.759	3.185
	Case CM	0.191	1.432	0.0495	0.759	3.185
	Case CB	0.0342	3.121	0.0522	0.914	3.811
	Case A	0.191	0	0.0495	0.759	0.319
Off-gas composition	Case OM	0.191	0	0.0495	0.759	0.319
	Case CM	0.191	0	0.0495	0.759	0.319
	Case CB	0.0342	0	0.0522	0.914	0.381
	Case A	0	0.976	0	1.132	0
Flue gas composition	Case OM	0	0.872	0	1.086	0
	Case CM	0	0.880	0	1.089	0
	Case CB	0	1.103	0	1.683	0

Figure 7.19: Process outline of OCAC/CLC processes (Stenberg et al., 2018)

production integration, and the development of alternative business models.

Here, a potential option brought forward is the concept of the biogas-to-hydrogen plant, which integrates the biogas upgrading with hydrogen production technology. However, in this respect the SMR process was mentioned and therefore might require alteration in case of the proposed ATR design. Moreover, process intensification options which focus on the direct utilisation of biogas are proposed. Overall, the respective process flow diagrams highlight the mass flow potential of the concept of third-generation upgrading with respect to the bio-hydrogen and bio-carbon dioxide output streams.

Process flow diagram

In case of the biogas-to-hydrogen process layout, three different steps can be identified. These are, the production of biogas, the upgrading of biogas to biomethane, and the production of bio-hydrogen.

In the production of biogas step, it is assumed that diary cows produce on average 65 kg of waste, or 0.045 m^3 liquid waste, per day. This yields around 1,950 Nm^3/day biogas, based on the presumed biogas yield of 30 Nm^3/t waste and 1,000 cows. This yield can be increased to around 35 Nm^3/t waste, based on a mixture of 95% cow waste and 5% food waste. The biogas consists of around 60% bio-methane and 40% bio-carbon dioxide. Moreover, around 60% of the organic matter present in the waste is assumed to contribute to the production of biogas. With respect to the digestate usage, it is presumed that ultimately only around 30% of the carbon content ends up in the soil as sink, while the rest is emitted into the air.

In the biogas upgrading step, it is presumed that from the biogas stream containing around 60% of biomethane, around 54% ends up as a pure biomethane stream that can be used in the reformer process. Here, around 108 Nm^3/day of biomethane would be produced from 200 $Nm3/day$ biogas. However, even higher methane recovery percentage are shown up to around 99.5%. This indicates that higher percentages of biomethane that could ultimately end up in the reforming process. In this respect, the recycle stream ensures that no- or limited valuable carbon is lost in the process.

In the production of bio-hydrogen step, it is presumed that steam is added in a volumetric ratio based on Nm^3/day of 3:1 steam-to-carbon ratio. This translates in a stoichiometric molar ratio of 2:1 steam-to-biomethane. Then based on a methane conversion of around 90% and a hydrogen recovery after the PSA step of 73%, the volumetric outflow of hydrogen is presumed to be 2.6 times the methane volumetric inflow. Here, in case of a bio-methane inflow 108 Nm^3/day a pure hydrogen stream of 280 Nm^3/day is retrieved. Moreover, around 5 Nm^3/day CO and 92 Nm^3/day CO_2 is retrieved after the WGSR and the gas/liquid separator. This indicates an ultimate CO conversion of around 95%.

Overall, it was mentioned that, based on a yield of 30 $Nm^3\, biogas/t$ cow waste around 108 Nm^3/day biomethane can be produced from 200 Nm^3/day biogas. The biomethane can subsequently be reformed to around 280 Nm^3/day bio-hydrogen. Other results indicated that the usage of 120 Nm^3/h biogas could result in 69 Nm^3/h biomethane and 141 Nm^3/h bio-hydrogen. In case of the latter, the presumed higher biomethane flow originates from internal heat demand. However, this could also indicate the relevance of process optimalisation, including recovery rates and conversion levels.

Moreover, with respect to the biogas-to-hydrogen process, the process includes the receiving of biogenic waste and the methane fermenter to produce the required biogas. Moreover, a pasteuriser and storage tank could be required for the utilisation of the bio-fertiliser. Hereafter, one- or more biogas pretreatment steps are used before the biogas is upgraded via multi-stage membrane technology. In the membrane separation setup, a recycle stream is used to improve the bio-methane recovery and limit the bio-methane losses. Moreover, the treated biogas could be used in a gas engine or gas boiler to produce the required energy for the process. Hereafter, the bio-methane is mixed with steam to produce hydrogen in the steam reformer. A CO-shit converter, and gas/liquid separater, are then used, after which hydrogen purification occurs via PSA technology to obtain a high-purity hydrogen stream. Moreover, resulting off-gases from the methane purifier and hydrogen purifier could be utilised to generate energy for the process or are emitted. Lastly, carbon capture technology, via VPSA, could be used to recover most of the bio-carbon dioxide from the reforming process.

Overall, almost 85% of the produced biogas could be needed to fulfill the energy requirements of the system. On the other hand, an electricity-, water- and air consumption based on the hydrogen production of 141 Nm^3/h or 300 kg/d is stated to be around 29.5 kW, 300 L/h and 4.5 Nm^3/h respectively. However, this excludes the biogas production step. In case of the former, it is presumed that the energy demand is related to the respective flow rates of biomass in the biogas plant and biomethane flow rates in the hydrogen plant. However, in the hydrogen plant the heat demand is directly related to reactor volume and therefore does not scale linearly with the biogas flow rate. These assumptions could then be used for further scaling of the system. Moreover, the energy demand could be supported by further integration of renewable electricity potential which could, for example, fulfill the electricity demand of 0.19 kWh/Nm^3 biogas in the case of the upgrading step. Also, could the integration of renewable electricity support the electricity demand for the PSA unit and the carbon capture technology.

In case of process intensification, the biogas upgrading step is not required in the process. Moreover, in the analysis the biogas production step is excluded and starts with the input of pretreated biogas.

Initially, the biogas stream and oxidants are used as inputs to the reformer. In case of BSR, an approximate 1:1 ratio of steam-to-biogas on a mass basis is inserted. This translates into a H_2O/CH_4 ratio of around [2-4], depending on the biogas composition and process specifications. The output of the reforming reaction then yields a syngas consisting of a composition based on molar composition1 of around [0.9-1.8]% CH_4, [10.3-11.5]% CO_2, [32.1-38.5]% H_2O, [9.6-12.6]% CO and [35.0-42.5]% H_2, depending on the process conditions and input composition. This shows a methane conversion of around [92-95]%. After two-step WGSR the hydrogen molar content is increase to 44.5%, while the CO content is lowered to below 0.1% at the expense of an increase in CO_2 content to 21.0%, while H_2O reduces to 29.0%. Then, a potential gas/liquid separator could be utilised to reduce the H_2O content before the hydrogen purification unit. Ultimately, after purification of hydrogen a high-purity hydrogen stream can be obtained, while the off-gas stream can be used for the required process heat. Also, additional biogas and or air combustion could be used to fulfill the heat requirement of the process. In case of BSR, it can overall be seen that based on an input of biogas at a mass flow rate of 18 g/s or 0.648 mol/s and a CH_4 molar content of 44.2% and CO_2 molar content of 34%, a hydrogen output of 1 g/s, with 99.999% purity, or 0.573 mol/s can be retrieved. Therefore, per kg of biogas input, 0.05 kg hydrogen is obtained. On the other hand, based on a mass flow rate of biogas of 71.10 kg/h with a molar composition of 60% CH_4 and 35% CO_2 a high-purity hydrogen stream of 11.53 kg/h could be obtained, which translates in around 0.16 kg/h of hydrogen per kg/h biogas. Otherwise, stated a biogas flow rate of around 4.1 kmol/h converts into a hydrogen flow rate of 5.8 kmol/h. The difference in output indicates the importance of the process design and especially the biogas quality. Ultimately, in case of the production of bio-hydrogen via BSR of AD biogas, per kilogram of hydrogen output around 25.5 kg manure and 25.5 kg residual waste plus 4,055 kJ electricity was used to generated 7.18 Nm^3 biogas and 43 kg digestate. An additional 7.6 kg water, 19.1 kg air and 1,950 kJ of electricity was used to ultimately generate 1 kilogram of bio-hydrogen.

In case of BATR, the process operates in similar fashion where in contrast to steam, air is additionally introduced in the reforming reactor. Moreover, higher mass- and molar flow rates are required to obtain a 1 g/s pure hydrogen output at the same conditions. In this case, 1.139 mol/s or 32 g/s biogas with a CH_4 molar content of 44.2% and a CO_2 content of 34% is introduced. Moreover, the process required a higher pressure and showed a higher temperature in the WGSR. Ultimately, a higher methane conversion of around 96% is achieved. Nonetheless, only around 0.03 kg of pure-hydrogen is obtained per kg biogas. However, in case of the utilisation of AD biogas, the biogas requirement per kilogram of hydrogen could be lower. Here, an estimated 63.5 Nm^3/h biogas would have to be introduced to produce 100 kg/d hydrogen, while this increases to 92.4 Nm^3/h in case of landfill biogas.

In case of membrane reforming, the process has a high level of intensification. Here, only the reactor unit is required, while the WGSR and PSA unit are eliminated. However, a gas/liquid separator is included to remove the H_2O from the retentate, before the retentate is used to fuel the process. Also, the reforming occurs at a lower temperature and pressure. Ultimately, an almost complete methane conversion is achieved to produce around 0.1 kg of hydrogen per kg of biogas. Here, the expected biogas input for the production of 100 kg/day hydrogen is around 35 Nm^3/h in the case of landfill biogas, or 27 Nm^3/h in the case of AD biogas.

Next to the discussed elements, also heat exchangers, pressure valves, gas separators and gas burners are used to complete the process flow diagram.

Besides the full process flow for the conversion of biogas to bio-hydrogen, the direct utilisation of the produced syngas could also proof to be relevant in the future renewable hydrogen system. Here, in the case of the BSR AD biogas reforming, a biogas stream of 71.10 kg/h consisting of 65% of CH_2 and 30% of CO_2 and a 87.42 kg/h steam input resulted in an output stream of 158.53 kg/h with a molar content of 42.5 % H_2, 12/6% CO, 31.2% H_2O and 10.3% CO_2. After the potential removal of H_2O the resulting syngas flow consist of an approximate molar ratio of H_2/CO of 3.3 and a flow rate of 96 kg/h or 7.1 kmol/h. In similar terms, the reforming of landfill biogas with a mass flow rate of 18 g/s or 0.648 mol/s and steam input of 21 g/s or 1.145 mol/s yields a syngas flow, after potential removal of 100% H_2O, of 21.6 g/s with a H_2/CO molar ratio of around 3.6.

Thus, it could be seen that the different process layouts ultimately have an impact on the actual process streams of valuable bio-hydrogen and bio-carbon dioxide, or syngas. Moreover, it was shown that the process conditions and inputs affect the conversion yields of the respective streams in the process to upgrade biogas to bio-hydrogen and bio-carbon dioxide, or syngas. Overall, several rule of thumbs to identify the potential of the concept of third-generation upgrading where given. These include, the conversion of 1 Nm^3 biogas to [1.2-1.4] Nm^3 bio-hydrogen, or similarly 1 Nm^3 biomethane to [2.0-2.5] Nm^3 bio-hydrogen. Moreover, the direct utilisation of biogas for bio-hydrogen production indicated per kilogram of biogas the creation of [0.03-0.16] kg bio-hydrogen. Otherwise stated, per kilogram of bio-hydrogen an input of [6.5-22] Nm^3 biogas was presumed. On top of that, it was indicated that per 1 Nm^3 biomethane around 0.85 Nm^3 CO_2 was obtained after the WGSR. In light of the high CO conversion and high CO_2 capture potential, this indicates the presence of a considerable- and valuable bio-carbon dioxide stream. Next to the conversion to bio-hydrogen it was seen that the reforming of biogas or biomethane yields a valuable syngas stream with a H_2/CO ratio of over 3 and a mass flow rate of [1.2-1.35] kg/h per biogas inflow of 1 kg/h. Lastly, it was indicated that an approximate input of [7.6-23.6] kg water, [0.5-19.1] kg air and [6,005-8,360] kJ of electricity is required per kg of bio-hydrogen.

Overall, the main process flow stream numbers can be seen in table 7.2 and figure 7.20. Here, the process flow stream numbers are based on the traditional SMR process layout. Nonetheless, in case of the ATR layout similar numbers could be expected based on the respective conversion- and capture efficiencies. Nonetheless, the process numbers of the BATR process would exclude the intermediate upgrading step and as result the available bio-CO_2 stream as proposed in the concept of second generation upgrading. In this respect, depending on the actual conversion levels achievable in the reforming process and the respective bio-CO_2 capture rate, the main process stream numbers could alter moderately. The numbers in table 7.2 are based on an input of 1 tonne of manure, which translate into the waste of around 15 cows in case of daily process numbers. This in turn would translate to around 105 kg of original biogenic carbon, where around 14 kg of organic carbon could be captured in the soil. Moreover, the numbers results from a presumed input of 16% biogas to fuel the biogas production process and a biogas composition of 60% methane and 40% CO_2. Hereafter, a 99,5% methane recovery and 99,9% CO_2 recovery is presumed in the upgrading process. On top of that, it is assumed that around 70% of the bio-carbon dioxide is retrieved in the upgrading process as pure bio-CO_2 stream. Here, it presumed that 100% of the bio-CO_2 could be utilised. In turn, in the reforming process an additional 40% of biomethane input is assumed to fuel the process. Moreover, a 90% methane conversion and 95% CO conversion is considered. Ultimately, a hydrogen recovery rate of 85% is assumed, while the process CO_2 capture rate is 90%, which is applied to both fuel- and process CO_2. As a result, based on an input of 1 tonne of manure or 25 Nm^3 biogas, around 18.5 Nm^3 CO_2 could be obtained and 27.9 Nm^3 H_2. This translates in around 28.7 kg biogas, 34.1 kg CO_2 and 2.3 kg H_2, or 1.2 kg CO_2/kg biogas and 0.08 kg H_2/kg biogas.

Nonetheless, the main process flow stream numbers in table 7.2 are based on static assumptions. In this respect, alteration in the presumed process conditions would alter the main process flow stream numbers. In this respect, it could be observed that improvements in the process yield benefit the hydrogen yield. Here process- and or heat integration in the reforming reaction result in a linear percentage increase or decrease in the hydrogen yield, while in the case of the biogas production process a more positive, non-linear percentage increase or decrease can be observed. Overall, a complete reduction in the internal heat demand result in a 40% and 19% increase in hydrogen yield to 0.13 kg H_2/Nm^3 biogas and 0.11 kg H_2/Nm^3 biogas. In this respect, the ATR-related process could yield significant benefits as well as the utilisation of the flue gas. In contrast, the BATR process is presumed to show a lower hydrogen yield of 0.085 kg H_2/Nm^3 biogas as a result of the lower stoichiometric hydrogen output. On the other hand, an increase in bio-CO_2 yield could be observe to 1.54 kg CO_2/Nm^3 biogas. Moreover, in case of the bio-CO_2 yield it could be observed that the yield would reduce by around 21% in case no fuel CO_2 would be captured, while a decrease in process CO_2 capture rate to 60% would result in a decrease of around 16%. In contrast, an increase to full bio-CO_2 capture of the process CO_2 would result in an increase of around 5%. Nonetheless, the reduction of internal heat demand for biogas could increase the bio-CO_2 yield with approximately 19%. Overall, the process could be stated to yield around [0.09-0.13] kg H_2/Nm_3 biogas and [1.07-1.62] kg CO_2/Nm^3 biogas. An increase in biogas yield per tonne manure would subsequently linearly improve the yield per tonne manure.

Unit/stage	Input	Prod	Up CO_2	Up out	Ref fuel	Ref out
Nm^3 biogas	25	21	0	0	0	0
Nm^3 CH_4	15	12.6	0	12.5	0	0.9
Nm^3 CO_2	10	8.4	5.9	2.5	3.9	8.6
Nm^3 H_2	0	0	0	0	0	27.9

Table 7.2: Main process flow streams analysis

To conclude, in light of the future renewable hydrogen system the concept of third-generation upgrading shows important potential for the production of bio-hydrogen and bio-carbon dioxide. In this respect, per kg of biogas around 0.1 kg bio-hydrogen and 1.2 kg bio-carbon dioxide could be formed. However, technological innovation

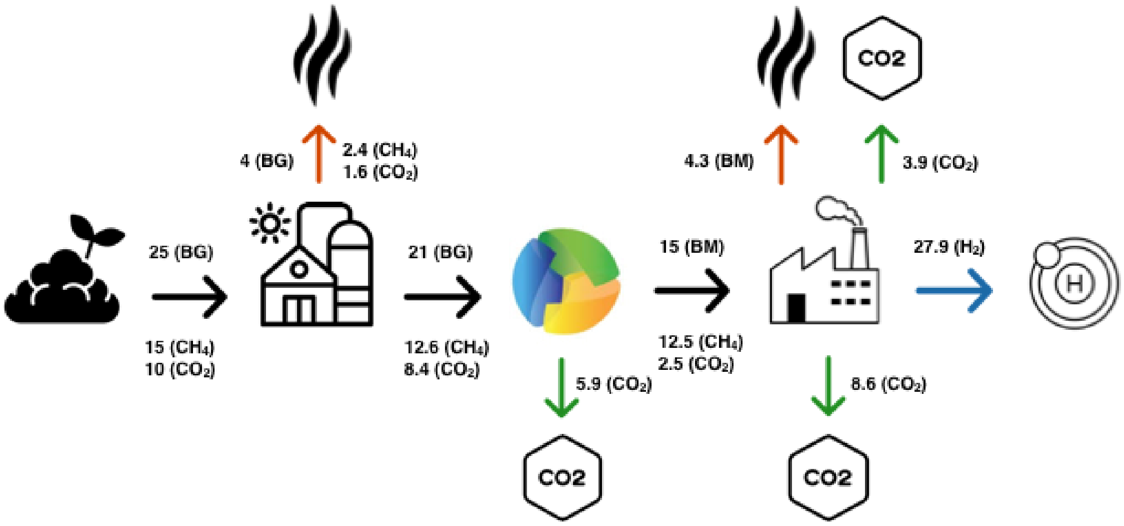


Figure 7.20: Main process flow streams analysis (Nm^3)

could further spark an increase in valuable output products per kilogram of biogas. In this respect, the exact composition of output products are discussed to be a function of the time and place dimensions within the proposed renewable hydrogen system. Next to the composition of valuable output products, the exact process layout will be dependent on the available input streams, reforming technology, production scale and output requirements. On top of that, it was shown that the conversion process shows important potential for the integration with renewable energy production and or e-hydrogen production in the form of electricity demand and or oxygen demand. The latter is especially important with respect to the proposed relevance of the ATR-related reforming technology.

However, it was also noted that the exact process conditions, parameters and inputs will have a strong effect on the exact process layout and outputs and therefore require careful optimalisation. Moreover, additional potential for carbon capture and storage could be identified as well as the adequate process layout be described including the required infrastructure. Lastly, also other potential process design could be drafted, which support process scaling and or intensification. This also includes more attention for the proposed relevance of the ATR or BATR production route in the future renewable hydrogen system.

Nonetheless, it was indicated that the concept of third-generation is technological feasible and shows relevant production potential for both bio-hydrogen and bio-carbon dioxide in light of the future renewable hydrogen system.

Chapter 8

Sustainability

The future renewable hydrogen system adheres to the perspective of climate-neutrality within the European Union by 2050. In this perspective, the concept of third-generation upgrading is discussed to provide significant relevance. This not only relates to the production potential of zero-pollution bio-hydrogen at a local- and or regional scale, but also supports the production of bio-carbon dioxide. The latter also supports the potential for negative carbon emissions which is deemed necessary to not overshoot the carbon balance. Here, the utilisation of bio-carbon dioxide is increasingly important over time, as carbon dioxide is no longer seen as a waste product of the energy system. In this respect, the continued shift away from fossil resources increases the inherent value of bio-carbon. In this respect, biogas could be seen as a platform molecules that could support both energetic hydrogen demand and molecular carbon demand. This strengthens the position of biogas within the future renewable hydrogen system and within both the renewable energy- and bio-economy domain. In this respect, the concept of third-generation upgrading should be interpreted as function over time with respect to the presumed valorisation potential of biogas. Moreover, biogas is discussed to provide additional benefits with relation to the rising problems associated with waste management. In the same line, biogas provides the option to directly lower the methane-related emissions over the waste life-cycle. On top of that, the renewed perspective on biogas as source of bio-hydrogen and bio-carbon could further lower the dependence on fossil fuel and as result the methane related losses and emissions from the production, distribution to utilisation. Lastly, no- or limited environmental penalties are observed that would hinder the production of bio-hydrogen and bio-carbon dioxide.

In this perspective, the concept of third-generation upgrading provides relevant environmental benefits in light of the future renewable hydrogen system. This chapter therefore focuses on the relevant benefits and quantification of these benefits. On top of that, this chapter aims to identify the relevant parameters that could be utilised in the perspective on the valorisation of biogas. Here, generic LCA results could be used to quantify the expected carbon benefits of the concept of third-generation upgrading. Nevertheless, due to associated interpretation issues with LCA results, this chapter specifically focuses on the actual carbon mass balance in the production of bio-hydrogen. Ultimately, the carbon mass balance analysis is used to assess the valorisation potential of the concept of third-generation upgrading.

8.1 Introduction

The use of biogenic source have been considered sustainable due to the short-cycled nature of the carbon present as opposed to long-cycled carbon from fossil sources. In this perspective, the emitted carbon dioxide is compensated by the renewed growth of plants and trees, which uptake emitted carbon dioxide from the atmosphere. As a result, the utilisation of biogenic short-cycled carbon source are seen to be carbon neutral. Moreover, more recently the capture and storage of biogenic carbon dioxide has sparked attention as a potential route to remove atmospheric CO_2 and thereby contribute to negative carbon emissions (Strengers and Elzenga, 2020).

However, the widespread usage of biogenic source has also faced concern which boil down to continued damage to nature, for example through land use change, biodiversity loss and environmental pollution. As a result, the question on sustainability of biogenic sources is complicated by a multitude of factors, including uncertain information, divergent views on environmental effects, monitoring need, various scientific perspectives, and different norms and values. This also include the payback time associated with the net CO_2 gains of biogenic carbon usage. Therefore, it seems that the potential and available usage are not solely based on scientific agreement but are also strongly dependent on the wider system perspective and as a result require not the sole collection of knowledge and facts but also decision-making on societal trade-offs and concerns (Strengers and Elzenga, 2020).

Nevertheless, in basis agreement is reached regarding certain aspects of sustainable usage of biogenic sources, including the need for careful land- and soil usage, the continued and important role as material and or feedstock, the unavoidable role for energetic usage but only in those cases of limit or no presence of alternatives, the trustworthiness of local sources, and the important climate benefits of long term storage rather than usage of biogenic carbon. Here, the cascading of biogenic sources, defined by the assigned social value, and the optimal- and efficient usage, is widely supported. For example, the renewed focus on the usage of biogenic sources lies on the long-term value of biogenic sources as chemical feedstock or material. This is in contrast to the current economic stimulus towards energetic usage. Nonetheless, the definition and principles of cascading are still discussed, including the potential trajectory and non-economic stimulus, for example top-down or bottom-up which determine the utilisation in volume of biogenic sources for different applications (Strengers and Elzenga, 2020).

With respect to alternative sustainability claims, a selection of ten themes can be distilled, indicating the possible arguments that could arise. Here, biodiversity is seen to be overlapping over all themes. Moreover, based on the different arguments, five distinct stakeholder perspectives can be identified that help to assess the relevant perspective on the potential and usage of biogenic sources. The themes span, climate, land usage and agriculture, energy transition, people plant profit, economy, air quality, certification, carbon counting, policy, and fair share. (Strengers and Elzenga, 2020).

In case of the utilisation of biogas, Sharma et al., 2020 indicate the anaerobic digestion is suggested to be the most environmental-, technical-, economical- and social waste-to-energy approach. This fits within the wider perspective on the waste-to-energy nexus based on the 5R principles of reduce, reuse, recycle, recover, and restore, which addresses the circular economy. For example, in the Netherlands the intended transition to a circular agriculture system focuses on the reuse of waste streams and optimum utilisation of biomass (Sharma et al., 2020). Here, anaerobic digestion offers a perspective on sustainable development of restoring waste and simultaneous energy production. Thereby it also offers a way to combat the negative environmental effects associated with inefficient waste management and imprudent waste disposal, like the release of contaminants into air, water and land including, among other, SO_x, NO_x, VOCs, heavy metals, carcinogenic dioxins, but also noise- and odor pollution. Ultimately, the waste-to-energy nexus offers the possibility to tackle pressing environmental problems simultaneously, including waste management, energy generation and environmental pollution (Sharma et al., 2020).

On top of that, Villadsen et al., 2019 go one step further and argue that the, self-pronounced, first-generation upgrading of biogas or usage of biogas for electricity-, heat- or fuel production is limited and disregards the potential of the co-produced bio-carbon dioxide. In this perspective, biogas should be seen as an important source of bio-carbon neutral CO_2 that could be used for the conversion to hydrocarbon-based high-energy-density fuels. This is called second-generation upgrading (Villadsen et al., 2019). This could in turn unlock new synergies with renewable energy generation, for example through green hydrogen production and conversion as well as for unlocking CO_2. Ultimately, this should align biogas as key enabler for closing the carbon cycle, especially for hard-to-abate sectors, with extra potential for negative carbon emissions in a cheaper- and more efficient fashion than DAC. Moreover, hereby biogas could be seen as a energy storage option over time and place. This view can be seen in figure 8.1 (Villadsen et al., 2019).

Moreover, R. J. Detz and van der Zwaan, 2019 specifically focus on the need of a net negative balance of CO_2 emissions. Here, more CO_2 is taken out of the atmosphere than human activities emit into it. This is seen as a necessity to achieve a carbon neutral energy system by 2050. In this respect, biogenic energy in combination with CO_2 capture and storage, or BECCS, is seen as the most dominant- and probable atmospheric CO_2 removal method that could result in negative CO_2 emissions. Hereby, the biogenic carbon dioxide can subsequently serve the demand for carbon-neutral CO_2 for uses as building block. In this perspective, BECCUS can deliver a circular carbon economy in processes driven by renewable energy. Ultimately, this should prepare society for achieving net negative CO_2 emission before 2050, where biogenic carbon dioxide utilisation provides a relevant contribution (R. J. Detz and van der Zwaan, 2019).

In the perspective of climate neutrality where no net emissions are allowed, a continued demand for, primarily carbon-containing, molecules will remain. Even though renewable hydrogen could be obtained from water- or hydro-carbon containing molecules, non-fossil hydrocarbon molecules can only be obtained from short-cycled biogenic sources. These are subsequently required to produce key molecules like methane, syngas, methanol, and more. In this line, green, renewable molecules can connect the different transitions, which incorporates both the energy system as well as the feedstock demand. In this case, biogenic resources can both be used as energetic and molecular-carbon source (van Soest and Warmenhoven, 2018).

However, it is argued that biogenic resources should be first and foremost be utilised as feedstock, due to the inherent continued demand for green molecules and the fact that products simply cannot be produced from electrons. Moreover, the continued utilisation of biogenic sources as energetic source will remain to produce

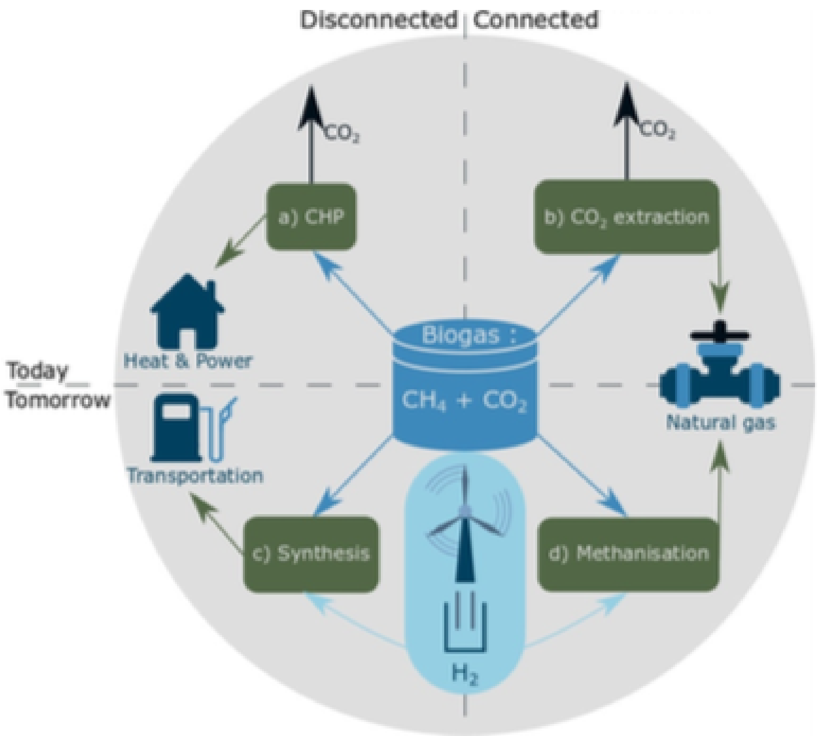


Figure 8.1: View on future utilisation of biogas as solution to energy storage and carbon neutral energy carrier (Villadsen et al., 2019)

CO_2 emissions during combustion, despite considered carbon-neutral. Also, in that way possible negative emissions through BECCUS cannot be realised, which are considered unavoidable to achieve the climate goals (van Soest and Warmenhoven, 2018). Ultimately, van Soest and Warmenhoven, 2018 argue for a renewed sustainable perspective on the use of biogenic sources for utilisation as feedstock and as material due to the impossibility of electrons to produce molecules. In contrast, most energetic sources could be fulfilled by electrons. However, in the short- to medium term a continued need for molecules might remain to allow for a more rapid and less costly transition. Hereby, the scarcity of resources and interconnection between both transitions remain to be relevant, where energetic usage should only follow in those instances no other usage for biogenic resources can be found. In this way, the significant demand for climate-neutral molecules can be fulfilled as feedstock, and where needed, for hard-to-abate energetic processes (van Soest and Warmenhoven, 2018).

Also, van Wijk et al., 2019 take a renewed perspective on biogenic sources where besides the production of biogenic hydrogen, biogenic sources co-produce biogenic carbon dioxide and solid organic sources. The biogenic carbon dioxide is subsequently attributed a value as feedstock or for direct usage, for example within the horticulture, while the solid organic sources could be used, for example as bio-fertiliser. As a result, the biogenic sources should not solely contribute to the energy system, but also sustainable contribute as feedstock and or material. Like, van Soest and Warmenhoven, 2018 it was argued that within a sustainable system, a continued demand for carbon-containing molecules will be present, where limited- to no alternative options exist. In the Northern Netherlands, this shows a direct use case in, for example, the production of green ammonia and methanol. This could be utilised in combination with green hydrogen production. Moreover, the solid by-products are them used in the agricultural sector or chemical industry (van Wijk, 2017). In this way, biogenic resources are one of the few, if not only, renewable sources that could be used for the production of both hydrogen and renewable carbon, from waste streams, unlocking the circular economy. Moreover, new synergies could be established with renewable hydrogen production through the incorporation of pure oxygen from renewable electrolysis within the biogenic conversion processes, supporting the wider system integration (van Wijk et al., 2019).

According to Chatzimarkakis et al., 2021 the CO_2 content of energy carriers and vectors will become the new currency of the energy system in order to establish a robust system of carbon reduction and to support economic recovery. Therefore, whether it is preventive emissions, negative emissions or direct utilization, the carbon content becomes of increased relevance within the renewable energy transition. To facilitate the renewed perspective on the currency value of CO_2, Chatzimarkakis et al., 2021 argue for the adoption of clear science-based definitions-, thresholds- and calculations of life-cycle GHG emissions of the potential renewable fuels. Moreover, it is argued to require transparent- and robust sustainability criteria that are in line with the principles of a circular economy. The carbon content can then link the economic perception to environmental performance and allow for a more accurate comparison of, and fairer competition between, energy products. Additionally, it can stimulate energy efficiency measures. To achieve this, the certification scheme should be based on the 5T's. Thus, the certification scheme should be traceable, trackable, tradable, transparent, and trustworthy in order to bring trust and credibility (Chatzimarkakis et al., 2021).

Both at the start of and during the transition the renewed perspective on the currency value of carbon dioxide could then be used to reflect the cost of carbon emissions. This thereby provides a price signal and could trigger incentives of the public, corporates and regulators to switch to clean solutions and technologies. These signals and triggers subsequently support the business case. In this way, the CO_2 abatement cost curve can be overcome. Moreover, a wider perspective on emission factors could be taken to further support the implementation of renewable technologies (HydrogenEurope, 2021e).

Moreover, to limit the CO_2 concentrations in the atmosphere and ensure the implied carbon budget will not be exceeded, the outflow of atmospheric carbon dioxide, or negative emissions is assumed to be required (Kuijper et al., 2021). In this perspective, the continued emission of CO_2 through eventual incineration of both fossil- and biogenic hydrocarbons pose a threat. As a result, the carbon stocks have to be both regulated and thereby contained. Moreover, the carbon stocks within the supply of energy and raw materials need to be decarbonised. Therefore, Kuijper et al., 2021 propose a carbon takeback obligation (CTBO) scheme to ensure an adequate balance of hydrocarbons on the market in a CO_2-neutral manner. This is in contrast to alternatives to limit CO_2 emissions like close down, which stop the burning of fossil carbons, or outcompete, which aims to reduce the costs of renewables and spark efficiency. Another alternative is carbon pricing and regulations that puts standards-, regulations- and financial incentives on carbon emissions (Kuijper et al., 2021).

More specifically, under the CTBO the CO_2 released during usage will need to be balanced through sequestration or storage of an equal amount of CO_2. In this way, the CO_2 released in the atmosphere is balance by the producers or importer, who is required to arrange for the possibility of storage and or sequestration. Therefore, this instrument places a producer responsibility on the usage of add-on carbon. Thereby the CTBO provides a carbon cycle scheme, which serves as a price mechanism. Moreover, the CTBO will complement the European Trading System by ensuring that CO_2 storage or sequestration is reserved for fossil carbon. Ultimately, this renews the perspective on the utilisation- or storage of biogenic carbon through a direct- and alternative price mechanism. Thereby, it anticipates on the future need for negative emissions, which are only applicable through DAC and BECCS, excluding enhanced weathering, as can be seen in figure 8.2 (Kuijper et al., 2021).

More precisely, the inherent value of carbon can be seen in the fuel initiative and the feasibility studies surrounding CCS technology. In the latter, the cost of CO_2 avoidance are shown in the range of [86-146] €/tonne CO_2. Moreover, this includes additional uncertainty regarding political direction, macro-economic developments, CO_2 commoditization and CO_2 price development (H-vision, 2019). In contrast, the former is supported by the renewed focus on environmental performance, specifically CO_2 emissions, of transport fuels. This includes an additional crediting mechanism, as a manner to achieve climate targets and support leadership in zero-emissions fuels (HydrogenEurope, 2021d).

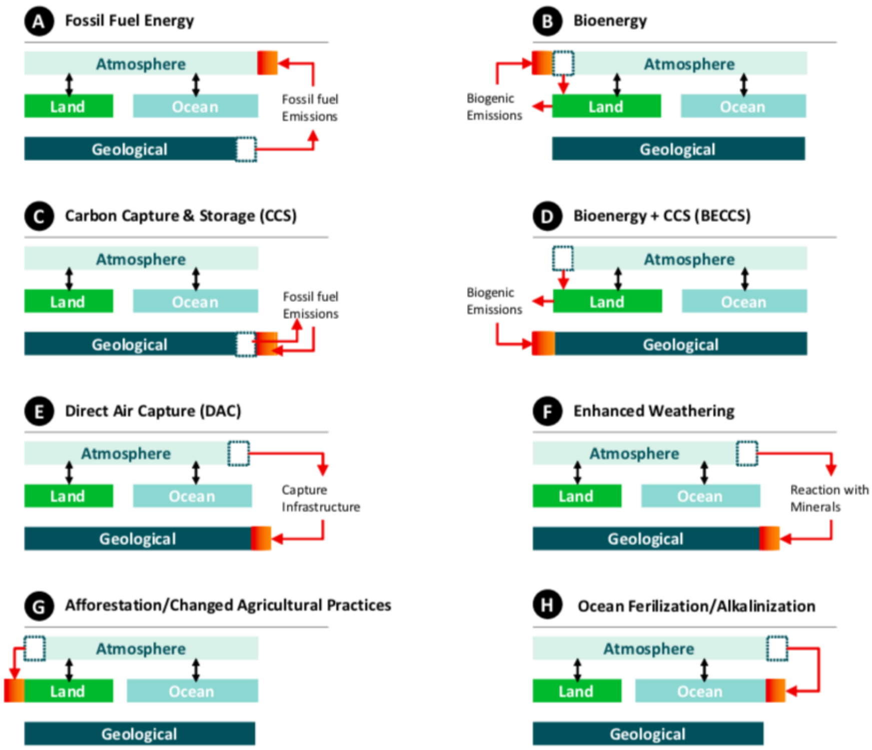


Figure 8.2: Human activities that impact the carbon stock in the geosphere, biosphere and atmosphere (Kuijper et al., 2021)

In case the captured CO_2 is used, for example in case of the horticulture, the captured CO_2 does not count as emission reduction as the CO_2 is merely transported to another location. Moreover, since in the case of horticulture only part of the CO_2

is taken up by the plants, which is considered small-cycled sequestration, the CO_2 usage is not recognized as long-term capture. In this perspective, the CO_2 storage time for different applications can be seen in figure 8.3.

Nonetheless, in case of horticulture, an emission reduction of around [0.91-0.95] ton CO_2/delivered CO_2 is achieved. This is due to the avoided gas usage for the production of CO_2 (Lamboo et al., 2021). However, extra electricity demand is required of approximately 50 kWh/t CO_2 for CO_2 capture, 125 kWh/t CO_2 for compression, and 162 kWh/t CO_2 in case of liquefaction. Moreover, an additional heat demand of approximately 300 kWh/t CO_2 in case of pre-combustion and 670 kWh/t CO_2 for post-combustion CO_2 capture would be required. However, this differs per type of process, CO_2 capture technology, CO_2 purity requirement and more. Overall, based on the electricity CO_2 emissions factor, fuel CO_2 emission factor of fossil resources, and conversion efficiencies the CO_2 savings per captured and delivered CO_2 decreases from around 0.93 ton CO_2/delivered CO_2 to around 0.80 ton CO_2/delivered CO_2 (Lamboo et al., 2021).

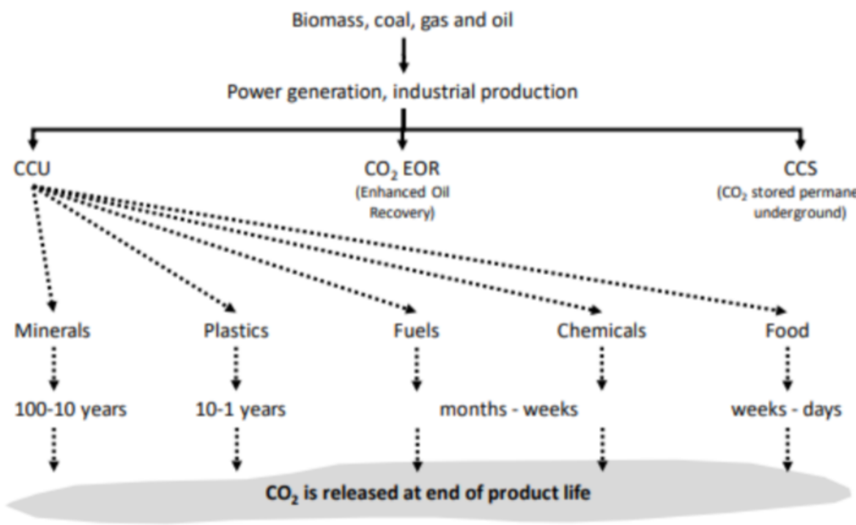


Figure 8.3: Overview of CO_2 storage period for different applications (Kampman et al., 2020)

Thus, it was discussed that the utilisation of biogas provides significant benefits within a future renewable hydrogen system. In this perspective, the concept of third-generation upgrading allow for the optimal utilisation of bio-carbon dioxide. This becomes especially relevant due to the lack of alternatives with respect the need for carbon-based feedstocks. Thereby, the utilisation of biogas provides both an energetic non-polluting bio-hydrogen value and a molecular bio-carbon dioxide value. This is expected to increasingly shift towards the utilisation of bio-carbon due to a renewed vision on the valorisation potential. This could therefor stimulate the direct utilisation of syngas. Moreover, the utilisation of biogas shows additional benefits with relation to the prevented methane emissions as well as with the potential utilisation of bio-fertiliser. The latter does not only constitute a direct economic value, but also shows important relevance as carbon sink. On top of that, the concept of third-generation upgrading shows important benefits through the renewed vision of the carbon emission factor. In this way, negative carbon emissions becomes the new economic currency of the energy system and provides direct benefits through concepts as the ETS, carbon abatement costs or potential addition of CTBO and fuel initiatives. Ultimately, in this way the concept of third-generation upgrading could provide the required potential to act as a carbon-sink to ensure climate-neutrality is obtainable and the carbon budget is not exhausted.

8.2 Green gas

The sustainability claims with respect to the production and utilisation of green gas can be divided over three steps, namely the biogas production, biogas upgrading and green gas utilisation.

8.2.1 Biogas production

The sustainability of green gas is directly related to the produced biogas and as a result the type of feedstock. Moreover, the different applications of biogas further impact the sustainability claims (Croezen et al., 2013). In this respect, it is shown that the usage of beef- and pig manure show the strongest positive climate impact, excluding the resulting application, in the range of negative [120-250] kg CO_2-eq/GJ raw biogas. In contrast, alternative residual waste streams do not exceed a climate benefit of negative 25 kg CO_2-eq/GJ raw biogas. Moreover, in line with the cascading principle, feedstock that found alternative use cases even showed a negative climate balance. This is for example the case for beet pulp show which was shown to emit CO_2 per GJ of raw biogas (Croezen et al., 2013). With respect to the subsequent applications of biogas, only limited difference in climate balance can be observed. This relates to the presumed replaced energy source and efficiency, mainly from the usage of natural gas. Overall, emission savings over the whole chain of 280-300 kg CO_2/GJ were observed. However, the upgrading towards green gas might show some decrease in environmental benefits as compared to the direct utilisation of biogas due to the additional production step (Croezen et al., 2013).

Moreover, with respect to additional pollution affects, like acidification, eutrophication and smog, these show strong correlation in the score with the score for the carbon emissions per feedstock. For example, the nutrient balance of biogas is positive, due to the higher availability of nutrients in the digestate as compared to the original biogenic source. The utilisation of manure is therefore attributed the highest environmental score, including factors like land use and toxicity. Nonetheless, the use of waste-water treatment plant (WWTP) sludge might show the best economics with respect to the cost per tonne of CO_2 reduced (Croezen et al., 2013).

8.2.2 Biogas upgrading

With respect to the upgrading technologies, a comparison of the different physicochemical methods of biogas upgrading based on sustainability related numbers can be seen in table 8.1 (Struk et al., 2020). Also, I. U. Khan et al., 2017 focused on the CH_4 production and loss, as well as the energy requirement and CO_2 removal of the different physicochemical methods. In this case, similar levels of methane loss and methane purity can be observed. Moreover, a similar upgrading yield in the case of PSA of 65%, water scrubbing of 68% and membrane of 65% was stated. However, with respect to the energy requirements per m^3 of upgraded biogas, a strong difference in consistency of the reported energy requirements can be observed. This was attributed to the different adsorbent used, the various thermal energy requirements and the difference in operating pressures. The mentioned energy requirements for the different upgrading technologies can be seen in figure 8.4 (I. U. Khan et al., 2017).

Removal method	CH_4 **purity**	CH_4 **losses**	**Energy consumption (kWh/**Nm^3**)**
Pressure swing adsorption	95-99	<4	0.3-0.9
Physical scrubbing	95-98	<4	0.4-0.6
Chemical absorption	95-99	<1	0.05-0.25
Water scrubbing	96-98	<2 (or 8-10)	0.3-0.9
Membrane separation	82-99	<5	0.14-0.26
Cryogenic separation	<97	<1	0.42-1.54

Table 8.1: Comparison physicochemical biogas upgrading technologies (Struk et al., 2020)

Technology	Energy requirement (kWh/m^3 of upgraded biogas)					
	Collet et al. [128]	Patterson et al. [127]	Götz et al. [129]	Ncibi et al. [130]	Olsson et al. [131]	Meier et al. [126]
PSA	0.5–0.6	0.24	0.335	0.285	–	–
HPWS	0.3	0.2	0.43	0.391	–	–
OPS	0.4	–	0.49	0.511	–	–
CSP	0.15	0.12	0.646	0.126	–	–
MS	–	0.19	0.769	–	0.27	0.378
CS	–	–	–	–	0.42	–

Figure 8.4: Energy requirements of various biogas upgrading technologies (I. U. Khan et al., 2017)

8.2.3 Green gas utilisation

Besides the respective upgrading technologies, also the further utilisation and conversion of biogas affect the sustainability score I. U. Khan et al., 2017. Here, special attention has been devoted to the use of bio-CNG as vehicular fuel. In this case, the results show similar CO_2 emissions but higher CO, NO_x and hydrocarbon emissions on a gram per km basis in contrast to fossil CNG. This is mainly attributed to the poor oxidation at lower temperatures for hydrocarbons in the CNG in contrast to the higher methane- and N_2 level in bio-CNG. Nonetheless, both fuels show similar fuel economy levels with around 24.2 km per kg of fuel. Moreover, the usage of CNG showed specifically better environmental performance in the use case of heavy vehicle fuels (I. U. Khan et al., 2017).

Moreover, Uslu et al., 2021 identified the avoided CO_2 emissions of bio-LNG as substitute for diesel. This also included the avoided emissions from manure, while the calculation was compensated for the usage of electricity during the upgrading of biogas and liquefaction of biomethane. However, this ignores the potential of the usage of renewable electricity in the future renewable energy system. Overall, this results in an avoided emission factor for bio-LNG of 0.389 kg CO_2/kWh based on emission factors for diesel of 0.261 CO_2/kWh and electricity of 0.216 kg CO_2/kWh. Moreover, the avoided emissions from manure were stated to be 22.5 kg CO_2/t. However, in case of all-digestion, the avoided emission factor for bio-LNG decreases to 0.233 kg CO_2/kWh as the avoided emissions from manure are unaccounted for (Uslu et al., 2021).

In practice, several ongoing commercial projects focus on the actual utilisation of the co-produced bio-CO_2 and the-organic carbon sources which are released in the production- and upgrading of biogas (de Laat, 2020). For example, this includes the production- and usage of liquid food grade bio-carbon dioxide. Here, the carbon dioxide is separated, filtered and liquefied to be used in the food- and beverage industry. In this case, a liquid CO_2 stream of 600 kg/hour with a 99.7% purity, from a green gas output of 10 million $Nm^3/year$ based on 120,000 tonne/year residual waste, was used (de Laat, 2020).

Another project showed a broad scope on the output potential of biogas production. The output products considered were sustainable heat, green gas, bio-LNG, bio-CO_2 and bio-fertiliser. In this case, 6,000 tonne/year of gaseous CO_2 and 3,600 tonne/year of bio-fertiliser is produced from a green gas output of 8 million $Nm^3/year$ based on an input of 40,000 tonne/year manure with equal amount of co-products. This is in contrast to a large scale facility based on [80,000-100,000] tonne/year of manure and an equal amount of co-products that produce 18 million $Nm^3/year$ of green gas for grid injection, 20,000 tonne/year of liquid CO_2 to be used in local horticulture, 35,000 tonne bio-compost, and another 115,000 tonne/year organic fertiliser (de Laat, 2020).

Others utilise the biogas production facility for a circular business model where the bio-CO_2 and digestate are used to feed the duckweed pond to produce protein-rich food (de Laat, 2020).

8.3 Bio-hydrogen

In the case of hydrogen, the main carbon emissions are produced in the production process. In contrast, no carbon emission are related to the end application of hydrogen, which mainly produces water vapor.

The breakdown of CO_2 emissions for hydrogen production through reforming technologies are contributed for 77% by the reformer, 15% by the electricity input and 8% by the feedstock production and distribution (Collodi et al., 2017). As a result, direct CO_2 reductions can be achieved true implementation of renewable electricity as well as the usage of biogas or biomethane. While the former has no associated LCA CO_2 emissions, the use of biogas was associated with LCA CO_2 emission of 16 g CO_2/MJ H_2. Nonetheless, this is in comparison to 63 g CO_2/MJ H_2 in case of natural gas usage. In this way, the sole utilisation of biogas could reduce the associated carbon emissions from 106 g CO_2/MJ H_2 in case of natural gas usage to 38 g CO_2/MJ H_2 in case of biogas. This could be further reduced to 23 g CO_2/MJ H_2 with the usage of renewable electricity. Further improvements could be achieved through efficiency gains. However, potential efficiency gains are assumed to be limited in case of the SMR process due to the high level of development and efficiencies, which reduced the CO_2 emissions down to nearly 10% of the theoretical minimum (Collodi et al., 2017). Another option to further reduce the associated

CO_2 emissions is through the incorporation of CCS technology. In this respect, the main sources of CO_2, in the case of small-scale SMR, are the PSA off-gas, with a typical CO_2 content of [45-55]%, and the flue gas from the combustion, with a typical CO_2 content of [10-20]%. However, due to the low CO_2 content and high volume flows in case of the flue gas, typical CCS technology is limited to the PSA off-gas. Also, Kampman et al., 2020 mention that pre-combustion CCS technology is mainly relevant for the hydrogen production via reforming technologies. This is especially the case for the ATR process, due to the high CO_2 concentration. In this case, the CCS technology could provide a CO_2 reduction potential of [30-60]% as compared to the traditional design. This can be compared to CO_2 reduction potential of [30-75]% in the case of renewable feedstock and [15-25]% in the case of renewable electricity usage. Nonetheless, the three options should be seen in combination to limit negative side-effects (Collodi et al., 2017).

Currently, the most used carbon capture technology involves the capture of CO_2 from the shifted syngas using a methyl di-ethyl amine (MDEA) solvent. Other capture option include the use of a H_2 rich burner in combination with capture of CO_2 from the shifted syngas by MDEA. Moreover, CO_2 from PSA tail gas could be captured using MDEA or through the use of cryogenic- or membrane separation. Additionally, the capture of CO_2 from the flue gas using monoethanolamine (MEA) also provides an option. However, also novel- and alternative adsorption technologies and advanced solvents exist to support carbon capture from the syngas, flue gas or tail gas. The potential carbon capture technology options could result in a CO_2 capture rate in the range of [56-90]%. Here, the highest capture rate occurs in case of flue gas CO_2 capture and require an additional natural gas consumption of [0.46-1.41] $MJ/Nm^3\, H_2$. As a result, an optimisation between capture rate and energy requirements could be established. Moreover, a trade-off could exist between the effect on production cost and CO_2 emissions of the respective carbon capture options. This results in differences in CO_2 avoidance cost (CAC), which are reported in the range of [47-70] €/tonne H-vision, 2019 (Collodi et al., 2017).

In case of the environmental performance of the hydrogen production methods, Valente et al., 2017 argue for the lack of adequacy in LCA results due to the differences in methodological choices. This mostly arises from differences in system boundaries or a lack of full information. As a result, a harmonisation protocol to facilitate the documentation of the GWP of the hydrogen production is developed. Here, relevant- and standardized default values are given including the GWP of electricity production, operational requirements and capital goods (Valente et al., 2017). Here, the harmonized GWP results of the different hydrogen production methods are compared to the harmonised carbon footprint of traditional SMR based on natural gas, which has a GWP of 12.95 kg CO_2-eq/kg H_2. The results of the harmonized GWP for bio-hydrogen production can be seen in table 8.2. Here, it can be observed that in general the GWP is increased which can be contributed to the inclusion of the compression stage following the purification step, which is assumed to use grid electricity for the energy requirement. The significant difference across the original and harmonized GWP also strengthens the caution when considering LCA values in practice (Valente et al., 2017).

More broadly, Kennedy et al., 2019 show the respective gate-to-gate environmental performance of different hydrogen production methods. These include both SMR and

Feedstock	Reforming	Original GWP	Harmonized GWP	Δ GWP
Cattle manure	ATR	4.80	5.79	0.99
Non-food biowaste	SMR	5.84	6.98	1.14
German substrate mix	SMR	6.08	7.22	1.14
Farm waste	BSMR	5.59	7.34	1.75
Cattle manure	SMR	4.80	5.80	1.00
Cattle manure	POX	4.90	5.88	0.98

Table 8.2: Original and harmonised GWP of biogas hydrogen production (Valente et al., 2017)

ATR equipped with CCS, and DR. However the hydrogen methods are all based on natural gas usage. Moreover, relevant environmental parameters for the conversion-, transportation- and storage of hydrogen are included. The relevant parameters include water consumption, water withdrawal, heat requirement, electricity requirement and GHG emissions. Here, the GHG emissions result from heat- or power demand in the plant or technology to produce the final product and the emissions related to the production process. The heat demand is generally from the production of steam and or process heat requirements. The water consumption includes the fraction of water use in the process that is not returned to its original source. This originates mainly from the embodiment in the product, the conversion and or the evaporation including cooling purposes. The water withdrawal in contrast defines the new water withdrawal from surface water or ground water sources (Kennedy et al., 2019). The relevant numbers for the different processes and steps can be seen in table 8.3. However, in case of pipeline H_2 no relevant environmental factor are known (Kennedy et al., 2019).

Process stage	Process step	Water consumption	Water withdrawal	Heat	Electricity	GHG emissions
Production	SMR-CCS	922 ($m^3/(yrMWH_2)$)	0.03 (m^3/kgH_2)	unk.	23.7 (MW/GW H_2)	20.5 (g CO_2/kWh H_2)
Production	ATR-CCS	461 ($m^3/(yrMWH_2)$)	0.03 (m^3/kgH_2)	unk.	48.4 (MW/GW H_2)	13.1 (g CO_2/kWh H_2)
Production	DR	unk.	0.017 (m^3/GJH_2)	N/A	unk.	45.5 (kg CO_2/GJ H_2)
Conversion	High-P H_2	0.42 (m^3/GJ)	0 (m^3/GJH_2)	0 (GJ/GJ H_2)	100 (kWh/GJ H_2)	6.21 (kg CO_2/GJ H_2)
Conversion	Liquefied H_2	0 (m^3/GJ)	0 (m^3/GJH_2)	0 (GJ/GJ H_2)	100 (kWh/GJ H_2)	44.7 (kg CO_2/GJ H_2)
Transport	Road cryogenic truck	N/A	N/A	unk.	unk.	0.06 (kg CO_2/(t km))
Transport	Road compressed H_2	N/A	N/A	unk.	1.45 (kWh/(t km)	1.13 (kg CO_2/(t km))
Storage	Salt caverns	N/A	N/A	min (GJ/GJ H_2)	min (kWh/GJ H_2)	0 (kg CO_2/GJ H_2)
Storage	Gas fields	N/A	N/A	unk.	unk.	0 (kg CO_2/GJ H_2)
Storage	Cryogenic tank	N/A	N/A	N/A	>20 (kWh/t H_2)	unk.

Table 8.3: Sustainability criteria over and for different process stages and steps in the hydrogen value chain (Kennedy et al., 2019)

Based on a detailed carbon balance, Antonini et al., 2020 focused on the life-cycle GHG performance of the production of hydrogen via biomethane. The study also incorporated CCS technology in the process design. The results indicated that the ATR with a two-stage WGSR and VPSA CO_2 capture configuration had the highest plant-wide CO_2 capture rate. This results from the the high CO_2 capture rate of 98% or more of VPSA, at comparable energy consumption, as compared to amine-based CO_2 capture. On a system perspective, the incorporation of VPSA limit the need for further hydrogen purification with PSA. This is in contrast to the usage of MDEA capture technology.

Moreover, in the case that bio-digestate is used as agricultural fertiliser, under the assumption that significant carbon remains in the soil, the biomethane route shows net-negative life-cycle GHG emissions, even without CCS. However, the addition of CCS technology to bio-hydrogen production leads to net-negative emissions in all cases (Antonini et al., 2020). The results for the incorporation of biomethane to produce hydrogen with- and without CCS technology for both SMR and ATR, and compared to natural gas, can be seen in figure 8.5. Without the application of CCS technology, the utilisation of the digestate is important to obtain net negative emissions, which can be reached in case of carbon sequestration in the soil as compared to incineration or altered field application. However, in case of the addition of CCS technology, the climate score may show negative CO_2 emissions of -125 g CO_2-eq/MJ H_2 as compared to traditional 25 g CO_2-eq/MJ H_2 in case of natural gas (Antonini et al., 2020).

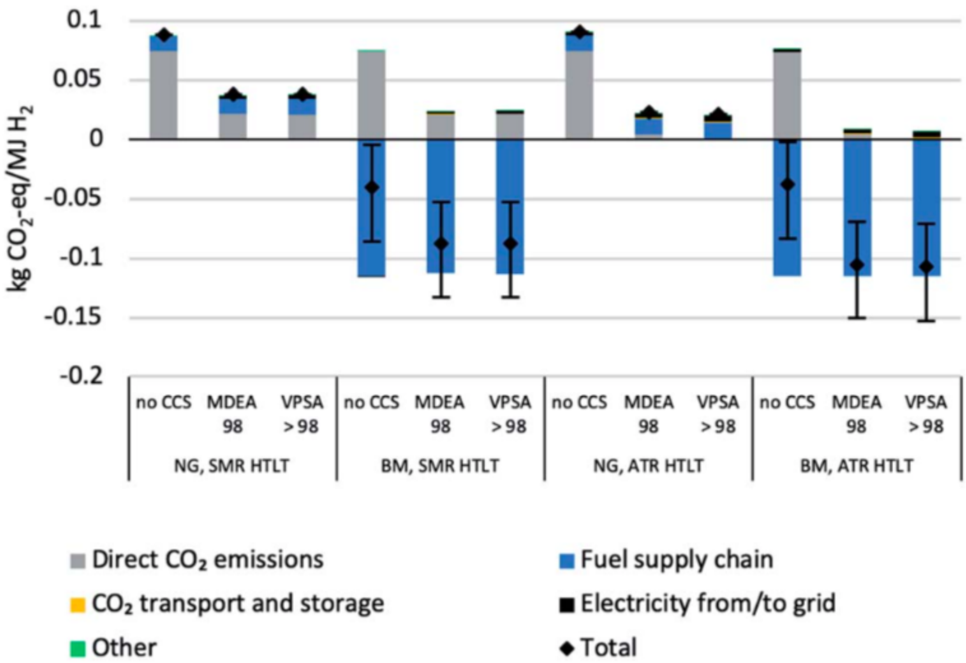


Figure 8.5: Life cycle impact of biomethane hydrogen production with and without CCS for both SMR and ATR (Antonini et al., 2020)

More specifically, Ohkubo et al., 2010 focused on the biogas-to-hydrogen production plant, where the production of biogas in combination with biogas upgrading was connected to the production of bio-hydrogen. Moreover, the study focused the optimisation of the plant performance based on the minimisation of greenhouse gases. In this perspective, it was shown that the optimal operation method involved the usage of self-produced biogas for the supply of the heat- and electricity requirement. Moreover, it was indicated that the introduction of 200 Nm^3/day biogas, with a volume composition of 60% CH_4 and 40% CO_2, resulted in an off-gas of 212 Nm^3/day containing around 57 volume % of CO_2 (Ohkubo et al., 2010). More specifically, to optimise the model, Ohkubo et al., 2010 incorporated a CO_2 emission intensity for commercial power systems of 0.517 kg CO_2/kWh and 0.6 kg CO_2/MJ for LPG combustion, with an intensity of CO_2 mitigation through biogas use of 0.809 kg CO_2/Nm^3. Moreover, standard generation- and heat recovery efficiencies based on LHV were employed. Overall, this showed that no greenhouse gas emissions are emitted in the plant operation and the overall GHG emissions are sufficiently reduced through the produced and subsequently used biogas saving 327 kg CO_2/day, based on a hydrogen output of 410 Nm^3/day. However, this also reduced the available biogas from 1,950 Nm^3/day to 290 Nm^3/day as input for reforming (Ohkubo et al., 2010).

In contrast, Braga et al., 2012 focused on the direct biogas steam reforming. Here, it was indicated that the BSR reaction supports a strong ecological efficiency of 94.95%. The ecological efficiency is used as an indicator to evaluate the system performance according to pollutants emissions by comparing the integrated pollutants emissions $(CO_2)_e$ with existing air quality standards. It is thereby based both on the equivalent carbon dioxide emissions and pollutant indicator, where 100% represents the ideal situation in case of ecological efficiency. In this respect, it was accounted for that process energy requirements where fulfilled by boiler fed by biogas. This ultimately resulted an equivalent carbon dioxide emission of 1.93 kg CO_2-eq/kg biogas for biogas combustion and 1.43 kg CO_2-eq/kg biogas for the steam reforming (Braga et al., 2012), which was used to derive the ecological efficiency.

Also, Hajjaji et al., 2016 focused on the direct biogas reforming for the production of bio-hydrogen. In this case, via both BSR and DR. In this perspective, the system boundaries included the life-cycle stages of the biogas production, biogas reforming as well as construction and decommissioning steps. Ultimately, total GHG system emission of 5.59 CO_2-eq/kg H_2 were indicated where half of the GHG emissions were associated with the traditional SMR process. Here, the amount of displaced artificial fertiliser is of significant importance as well as the impact credits associated with the recycling of the plant construction materials and equipment (Hajjaji et al., 2016). Moreover, Hajjaji et al., 2016 focuses next to the GWP on a larger number of parameters to account for the environmental- and energy performance of the bio-hydrogen production process. These include, but are not limited to, ozone depletion potential, acidification potential, terrestrial eutrophication and non-renewable energy requirement. The results can be seen in figure 8.6. Here, the total GHG emissions are seen to be mainly derived from the AD plant and the digestate. These result from the associated methane losses at the biogas plant account for 20% of, while the methane losses from the digestate during storage account for 80%. On the contrary, the CO_2 emissions at the hydrogen plant are assumed to be biogenic and therefore carbon neutral. Also, it could be observed that there is an overall reduction in abiotic reserve potential as a result of metals and minerals co-produced and recycled in the overall process. Additionally, due to the emissions of acidifying compounds like NO_x and SO_x the production shows acidification potential on soil, groundwater, materials and ecosystems. This is almost completely attributable to the AD plant, due to ammonia production during digestate spreading and the escape of ammonia during storage. Lastly, the cumulative energy demand as proxy for the overall environmental impact through the use of non-renewable energy and renewable sources over the life-cycle identifies the total energy consumption and most energy consuming step. Here it it shown that the total energy need is 4.97 MJ-eq per kg of H_2, where 4.15 MJ-eq is attributable to non-renewable energy demand. This is in turn dominated by the energy demand of the hydrogen production plant to fulfill the electricity requirement (Hajjaji et al., 2016).

Moreover, as part of the BioRobur project, Battista et al., 2017 conducted a detailed LCA study for a 4.5 kg/h, 99.99% purity hydrogen production process. This was

Impact category	Total	AD plant	H_2 plant	C & D
GWP (kg CO_2 eq)	5.59	5.38	5.99×10^{-2}	0.15
ODP (kg CFC-11 eq)	1.53×10^{-8}	-4.84×10^{-8}	5.11×10^{-8}	1.26×10^{-8}
HTPnce (CTUh)	2.76×10^{-7}	-1.53×10^{-8}	2.71×10^{-8}	2.64×10^{-7}
HTPce (CTUh)	8.64×10^{-9}	-1.72×10^{-7}	3.67×10^{-9}	1.77×10^{-7}
PMP (kg $PM_{2.5}$ eq)	5.25×10^{-3}	5.09×10^{-3}	3.47×10^{-5}	1.24×10^{-4}
IRP (kg U_{235} eq)	1.23	0.78	0.44	1.58×10^{-2}
POF (kg NMVOC eq)	-1.46×10^{-3}	-2.16×10^{-3}	1.61×10^{-4}	5.39×10^{-4}
AP (molc H^+ eq)	0.29	0.29	3.66×10^{-4}	9.31×10^{-4}
TEP (molc N eq)	1.33	1.33	5.43×10^{-4}	2.26×10^{-3}
FEP (kg P eq)	-6.02×10^{-5}	-1.88×10^{-4}	1.27×10^{-5}	1.15×10^{-4}
MEP (kg N eq)	6.60×10^{-3}	5.66×10^{-3}	6.12×10^{-4}	3.29×10^{-4}
FETP (CTUe)	4.85	−4.11	1.08	7.88
LUP (kg C deficit)	−2.37	−3.05	6.62×10^{-2}	0.61
WRD (m^3 water eq)	-1.67×10^{-3}	-3.25×10^{-3}	1.33×10^{-3}	2.48×10^{-4}
ADP (kg Sb eq)	-1.20×10^{-4}	-1.54×10^{-4}	3.16×10^{-6}	3.03×10^{-5}
CED (MJ eq)	4.98	−3.94	6.72	2.19
NRE (MJ eq)	4.15	−3.84	6.42	1.57

Figure 8.6: Life cycle impact assessment of biogas reforming process (Hajjaji et al., 2016)

then compared to the conventional process of hydrogen production through steam reforming for two different catalyst scenarios. The study assumed the production of 1 Nm^3 biogas from an input of 4 kg of agro-food waste. Additionally, a biogas to hydrogen conversion efficiency of 65% was mentioned. Moreover, around 3.1 million m^3 biogas, 2.7 million kg water and 5.7 million kg air was assumed in case of the BioRobur ATR process over the ten year, 330 days per year, and 24 hours per day operational life time. This was compared to 3.2 million m^3 biogas, 4.0 million kg water and 6.6 million kg air in the case of biogas steam reforming. Moreover, the energy balance shows a power consumption for the PSA compressor, air compressor and water pump of 18,465 W, 837 W and 29 W or 5.26 TJ, 0.24 TJ and 8.21 $E^{-}3$ TJ for the BioRobur process respectively. With incorporation of additional impact categories of ozone layer depletion, photochemical oxidation, acidification, eutrophication and global energy requirement (GER), the results for the hydrogen production processes is shown in figure 8.7 (Battista et al., 2017). In case of the BioRobur technology material LCA, the gas purification, ATR unit and other components sectors contribute almost similarly along all impact categories, except for the ozone layer depletion which is dominated by the ATR units higher contribution. Here, both the gas purification and other components sectors seem to dominate the impact with around 40% and 35% respectively. In contrast, the ATR unit has a contribution of around 20%. In the case of the complete LCA, which also incorporates the reagent feed steams and energy consumption, besides the materials used the pretreatment of feed stream section takes up almost the entire contribution of around 90%. The rest is dominated by the gas purification, which for the processing mainly relates to the biogas feed stream and related effects as the production of CO and CO_2 and non-negligible amounts of VOCs, NH_3, H_2S. Ultimately, the BioRobur technology showed an improvement in GWP of around 3.8% and 5.4% in the case of GER as opposed to steam reforming. In this case the BioRobur has an GWP- and GER environmental impact of around 0.6 kg CO_2-eq/Nm^3 H_2 and 4.5 MJ-eq/Nm^3 H_2 in case of complete LCA respectively (Battista et al., 2017).

For the BIONICO project, Marcoberardino et al., 2019 compare the environmental performance against the reference hydrogen production process via ATR and SMR for both landfill and AD biogas. Here, Marcoberardino et al., 2019 indicated that the membrane reforming process showed an increase of 20 percentage points with respect to the system efficiency. Moreover, in the case that biogas becomes a limiting factor the membrane reforming process outperforms the reference systems based on the LCA analysis. This results from the higher efficiency of the process and as such results in greater substitution potential for hydrogen produced by fossil fuels. Nonetheless, in the case the biogas is abundant, where a surplus of biogas is simply flared and thereby not competing with other potential uses, the system performs similar or worse. This relies on the presumed impact of the reliance on grid electricity energy demand and therefore the component use rather than the conversion efficiency (Marcoberardino et al., 2019). In the LCA analysis, Marcoberardino et al., 2019 excluded the biogas production process and hydrogen storage, delivery and use in order to be comparable along all systems. Ultimately, the membrane reforming process, in the biogas limiting scenario, yields a climate change impact of just below 8 kg CO_2/kg H_2 as opposed to 14 kg CO_2/kg H_2 in the case of conventional hydrogen production via natural gas SMR. In the scenario of abundant biogas, the climate impact lowers to around 2 CO_2/kg H_2 due to the exclusion of electrical- and thermal energy production losses. This stems from the usage of biogas in feeding a co-generation system. Moreover, in this scenario, the high electricity demand for the traditional ATR becomes prevalent, while the membrane reforming process shows slightly higher electricity demand than traditional SMR and as a result a higher climate impact. On top of that, with respect to other environmental factors, like human health, ecosystem quality and resources the membrane reforming and traditional SMR process seem to perform in similar terms, while the ATR process is assumed to score lower (Marcoberardino et al., 2019).

Impact category	Unit	BioRobur		SR scenario 1		SR scenario 2	
		Material	Complete	Material	Complete	Material	Complete
GWP	kg $CO_{2\ eq}$	29,517.64	2,581,422	34,555.45	2,678,970	28,395.54	2,672,810
Ozone layer depletion (ODP)	kg CFC-11_{eq}	0.003179	0.085249	0.003774	0.08996	0.003134	0.089321
Photochemical oxidation	kg $C_2H_{4\ eq}$	5,003,486	8,968,731	3,045,683	1182.83	4,947,432	9,277,357
Acidification	kg $SO_{2\ eq}$	9,482,512	7,091,832	7,297,567	13,796.05	9,419,706	7,440,457
Eutrophication	kg $PO_{4\ eq}^{3-}$	1,444,874	8,862,827	1,763,297	9,235,961	1,417,055	9,201,336
GER, non-renewable, fossil	MJ_{eq}	475,826	19,352,773	574,251.8	20,392,029	465,666.7	20,283,444

Figure 8.7: Results of the LCA comparison of the BioRobur technology and convention steam reforming process (Battista et al., 2017)

8.4 Analysis

In the future energy system, the carbon dioxide content becomes of increasing importance. This relates, for example, to the carbon emission factor, which is expected to become increasingly relevant, for example, through fuel initiatives, through the ETS or through the overall perspective on the carbon abatement costs. Moreover, the carbon emission factor could provide further benefits with respect to negative carbon emissions. Here, negative carbon emissions could become economically relevant due to the CTBO or via competition with alternative carbon sinks, like DAC. On top of this, the carbon content becomes more relevant due to renewed perspectives on the valorisation potential of biogenic resources, which is especially relevant in light of the proposed future hydrogen system. Next to the carbon content, additional environmental factors could become relevant- and prevalent over the multiple stages in the biogas value chain.

It was discussed that the utilisation- and production of biogas shows important benefits. This is not only related to the production of renewable energy, but also as solution for inefficient waste management and imprudent waste disposal. Hereby, the production of biogas shows the potential to lower the release of contaminants, including SO_x, NO_x and $VOCs$ into the air, water and land. In this respect, the actual acidification-, eutrophication- and smog potential could be related to the actual feedstock used in the production of biogas. This could, for example, be attributed to the emissions of ammonia in the biogas plant. Nonetheless, it was mentioned that the methane emissions in the biogas plant could still contribute significantly to the resulting CO_2-eq/output product. Nevertheless, despite this it was stated that overall the production of biogas reduced the harmful effects as compared to the reference scenario of doing nothing. This relates, for example, to the natural methanation process that occurs in the processed biogenic waste streams.

Moreover, the production- and utilisation of biogas was shown to attribute significant positive environmental benefits in relation to the CO_2-eq emissions. This is mainly attributed to the replacement of fossil fuels in competitive end applications. In this respect, the utilisation of manure biogas was mentioned to lower environmental effects with [150-250] kg CO_2-eq/GJ biogas or even [280-300] kg CO_2-eq/GJ biogas over the whole value chain. Another result indicated the avoided emissions from manure to be around 22.5 kg CO_2/t manure. In this respect, the exact end applications was seen to be of less importance due to the main replacement of natural gas. In this perspective, the usage of biogas was shows to contribute to around [1.43-1.93] kg $CO_2 - eq$/kg biogas used.

Nonetheless, it was mentioned that the upgrading towards biomethane might lower the expected benefits due to the additional energy requirement in the system. In the case of membrane technology, this would constitute to around [0.14-0.26] kWh/Nm^3 biogas of electricity demand. However, this perspective limits the potential integration option with renewable electricity and or other benefits associated with the upgrading to biomethane via enhanced flexibility and less curtailed capacity. On top of that, it lacks the perspective on the value of the bio-CO_2 potential with the concept of second-generation upgrading. In case of biogas upgrading, this mostly constitute around 29 vol% bio-CO_2. Moreover, it was mentioned that for the upgrading of biogas the loss of CH_4 of <[1-5]% could negatively impact the associated benefits. Nonetheless, through a multi-stage design the methane recovery percentage could be increased to around 99.5%.

However, in case of the utilisation of the biomethane it was discussed that the environmental pollution is similar- or worse as compared to traditional fossil counterparts. For example, in the case of bio-CNG in the transport sector the CO_2 emissions are similar at about 114 g CO_2/km, while the CO- and NO_x emissions might be higher as compared to fossil CNG. Nonetheless, over the whole chain environmental benefits for the usage of bio-LNG in the transport sector were discussed to be around 0.389 kg CO_2/kWh and arises from the replacement of diesel. Nonetheless, this number ignores the potential utilisation of renewable electricity as compared to fossil electricity, which shows significant CO_2-eq/kWh emissions.

In practice, it was indicated that the exact numbers for the biogas upgrading process based on the, type of, waste processing were around [45-110] t CO_2/year and [45-640] t bio-fertiliser/year for around 1 kt waste processed per year. This yields approximately [0.08-0.1] million Nm^3/year of biomethane. Otherwise stated, per million Nm^3/year of biomethane output, CO_2 streams of around [525-1,100] tonne/year were utilised. However, this neglects the potential carbon dioxide streams present in the production of bio-hydrogen and bio-carbon dioxide.

In case of hydrogen production it was discussed the CO_2 emissions of traditional hydrogen production primarily arises from the reforming, which constitutes around 77%. Another 15% came from the electricity input and 8% from the feedstock production and distribution. As a result, the utilisation of biogas or biomethane was indicated to show strong reduction potential of [30-75]% in the CO_2 emissions of the hydrogen plant. However, in case of the sole utilisation of biogas to provide the energy requirements, the process might show no carbon-related emissions. However, also the integration of renewable electricity shows important emission reduction potential of around [15-25]%. Ultimately, carbon capture technology is addressed the potential to reduce the carbon emissions by [30-60]%. However, it was mentioned that CCS technology could provide 90% or more capture potential of the hydrogen plant related emissions. Here, it was mentioned that the electricity requirement would be around [0.46-1.41] MJ/Nm^3 H_2, which further shows the relevance of the potential integration with renewable electricity. Overall it was mentioned that the impact of hydrogen production could be lowered from 106 g CO_2/MJ H_2 to 38 g CO_2/MJ H_2 due to the usage of biogas which has associated emissions of 16 g CO_2/MJ H_2 as compared to 63 g CO_2/MJ H_2 in the case of natural gas. Moreover, the utilisation of renewable electricity could further reduce this to 23 g CO_2/MJ H_2.

More generic results indicated life-cycle emissions of the bio-hydrogen process of [4.80-7.34] kg CO_2/kg H_2, based on, among others, the type of feedstock and reforming process. Other, individual results showed life-cycle emissions of 0.6 and 0.8 kg CO_2-eq/Nm^3 H_2 or [6.7-8.9] kg CO_2-eq/kg H_2. Moreover, another result indicated carbon emissions of [2-8] kg CO_2/kg H_2, which was dependent on the actual scenario of biogas availability. However, these results could further be broken down in the exact emissions related to the different process steps, including production, conversion, transportation and storage. In this case, electricity demand proves a significant factor in the process steps after the production of hydrogen. Here, the incorporation of renewable electricity could then show important environmental benefits. Nonetheless, other indicated negative life-cycle emissions, which was mentioned to be the case in all instances that CCS technology was utilised. In this respect, the life-cycle emissions show the potential of negative carbon emissions up to around 125 g CO_2-eq/MJ H_2.

Thus, it could be seen that biogas provides relevant environmental benefits which span waste management, renewable energy production and pollution reduction. Moreover, it was indicated that the utilisation of biogas yields significant positive carbon savings. In this perspective, the respective carbon savings relate to the actual carbon mass flows and as result portray the inherent carbon valorisation potential of biogas. Here, the utilisation of biogas or biomethane has been attributed a potential carbon emission factor saving of [280-300] kg CO_2/GJ CO_2 or in another perspective 0.389 kg CO_2/kWh. Nonetheless, this accounts only for the prevented emissions due to the substitution of fossil fuels, mostly natural gas. Moreover, this lack the perspective on the potential of second-generation upgrading and especially third-generation upgrading. In this respect, practical examples indicated that in case of biogas upgrading around [0.4-0.8] kg CO_2 could be utilised per Nm^3 biomethane produced. Theoretically, in case all carbon could be captured, this amount to around 29 volume % CO_2 per volume of biogas in relation to the concept of second-generation upgrading. Moreover, in the process flow design it was indicated that based on 1 Nm^3 biomethane output around 0.85 Nm^3 CO_2 was present before the hydrogen purification step. At a presumed capture rate of up to 90%, around 0.75 Nm^3 CO_2 could be obtained per 1 Nm^s biomethane input. Overall, it was indicated that the utilisation of biogas and CCS technology could show negative carbon emissions of around 125 g CO_2/MJ H_2.

Carbon mass balance analysis

The carbon mass balance analysis in the production of bio-hydrogen could be used to address the inherent environmental value of biogas. In this respect, the carbon mass balance analysis could be used to identify the relevant emission factor, potential negative emission savings and could be used with respect to the identification of the valorisation potential. Nevertheless, the carbon mass balance analysis ignores the other discussed benefits that are associated with the production of biogas. These include benefits related to the reduction of pollutants, to improved waste management and to the circular usage of bio-fertiliser. In case of the latter, it is presumed that around [40-60]% of the organic matter ultimately ends up in the biogas, while the rest ends up in the digestate. Hereafter, it presumed that around 30% of the respective carbon ultimately ends up in the soil as carbon sink. As comparison, around [25-50]% of the total carbon contained in the biogas is stored as carbon in the soil. Another [25-30]% of the original carbon in the biomass is presumed to be lost to the air prior to the anaerobic digestion plants and is not included in the organic matter calculation. On the contrary, the mass balance does not account for potential negative effects over the value chain. This could, for example, relate to the required transport of input materials or the need for grid electricity in the process. In case of the latter, it was mentioned that around 15% of the bio-hydrogen production emissions could be contributed to the electricity input. In this perspective, integration with renewable energy sources could lower the apparent negative environmental effects over the entire value chain. Nonetheless, the carbon mass balance analysis is able to, potentially indirectly, include the relevant carbon savings associated with the production of biogas.

At the start, it was indicated that the utilisation of manure for the production of biogas yields an approximate emission saving of around 22.5 kg CO_2/t manure. Moreover, it was mentioned that around 25 Nm^3 biogas could be obtained per tonne manure. In case of the latter, based on a presumed density of methane of 0.668 kg/Nm^3 and of carbon dioxide of 1.842 kg/Nm^3, and a biogas composition of 60% methane and 40% carbon dioxide, this would translate into around 28.5 kg biogas/t manure. Nonetheless, this is translated in a direct CO_2 capture of around 18.4 kg CO_2/t manure. In case of the biomethane presence, this would translate in around 10.3 kg CH_4/t manure. On top of that, practical examples showed that with respect to residual waste processing approximately [45-110] kg CO_2/t waste could be obtained, next to around 60 kg CH_4/ waste. As a result, for this carbon balance the conservative example of around 18.5 CO_2/t manure is presumed, which aligns with the perspective of the Dutch subsidy program. Then, in exclusion of the bio-fertiliser yield and based on a ratio of 2.7 kg CO_2/kg CH_4 or 1 Nm^3 CO_2/Nm^3 CH_4, the ultimately considered maximum negative carbon emissions potential of biogas production is around 46.7 kg CO_2/t manure.

Therefore, per tonne manure input 25 Nm^3 biogas could be obtained, with an approximate volumetric composition of 40% bio-carbon dioxide and 60% bio-methane. This would yield a negative carbon savings of around 47 kg CO_2/t manure. However, it presumed that around 16% of biogas would be lost due to the internal heat demand of the production process. Here, it is presumed that no carbon capture technology would be used to capture the carbon emissions related to combustion of biogas. As a result, the biogas yield would lower to around 21 Nm^3 biogas/t manure. In this respect, around 3 kg CO_2/t manure would be lost directly, while an additional 4.5 kg CO_2/t manure would be lost indirectly via the reduction in biomethane. Ultimately, this reduces the maximum potential CO_2 savings per tonne manure to around 39.3 kg CO_2/t manure.

Hereafter, in the upgrading of biogas to biomethane, it is presumed that the electricity requirement for the membrane separation process could be obtained via renewable electricity. In this way, the net-zero process carbon balance could be remained. Moreover, it is assumed that around 0.5% of biomethane would be lost and around 0.1% bio-carbon dioxide. In this respect, the output would consist of around 12.5 Nm^3 CH_4/t manure and 8.4 Nm^3 CO_2/t manure. As a result the presumed maximum negative carbon emission potential of biogas production is around 39.1 kg CO_2/t manure. However, it was assumed that around 30% of the bio-carbon dioxide would be captured in the bio-methane stream. In this respect, approximately 10.9 kg CO_2/t manure negative CO_2 emissions could be obtained in case of the utilisation- and or sequestration of the resulting bio-carbon dioxide stream. This would in turn result in a negative carbon mass balance for the concept of second-generation upgrading of 10.9 kg CO_2/t manure. In contrast, the other 28.2 kg CO_2/t manure is locked in the biomethane stream.

Lastly, in case of the reforming of biomethane it is presumed that around 40% more biomethane is required to fuel the process. As a result, around 72% of the biomethane stream can effectively be used in the reforming process. This amount to around 9.0 Nm^3 CH_4/t manure or 6.2 kg CH_4/t manure. Moreover, this includes 1.7 Nm^3 CO_2/t manure or 3.2 kg CO_2/t manure. Then based on a 90% methane- and 95% CO conversion this would yield approximately 2.3 kg CO_2/kg CH_4 or 0.9 Nm^3 CO_2/Nm^3 CH_4. Moreover, in case of the complete combustion of biomethane, the ratios would be 2.7 kg CO_2/kg CH_4 or 1 CO_2/Nm^3 CH_4. Then, at a presumed capture rate of 90% in case of both the process- and fuel CO_2, around 23.2 kg CO_2/t manure could be recovered, out of which around 69% arise from the process CO_2.

Therefore, per tonne of manure 34.1 kg negative CO_2 emission could be achieved. This could be translated in around negative CO_2 emission savings of around 1.4 kg CO_2/Nm^3 biogas. In this respect, around 30% of the negative CO_2 emissions can be recovered during the biogas upgrading and 70% during the biomethane reforming process. In this respect, the traditional reforming process based on SMR technology is presumed. However, in case of the ATR layout similar numbers could be expected based on the respective conversion- and capture efficiencies. Nonetheless, the process numbers of the BATR process would exclude the intermediate upgrading step and as result the available bio-CO_2 stream as proposed in the concept of second generation upgrading. In this respect, depending on the actual conversion levels achievable in the reforming process and the respective bio-CO_2 capture rate, the carbon mass balance numbers could alter moderately. Overall, the carbon mass balance analysis can be seen in table 8.4 and figure 8.8.

However, the numbers in table 8.4 are based on the above assumptions. In this respect, alteration in the above assumptions gives a wider range of possible carbon mass balance numbers. In this respect, the total CO_2 capture potential could be indicated as [26.9-40.6] kg CO_2/t manure. Here, the lowest range number arises from a 0% reforming fuel CO_2 capture, while the upper number relates to an increase in biogas yield per tonne of manure to 30 Nm^3/h. On the other hand, the former could be offset by an increase in process yield, for example through reduction of methane input to fuel the process. Here, the off-gas could be used for heat integration. Moreover, the thermal-neutrality of the ATR-related process could here also provide relevant benefits. Otherwise stated, the total CO_2 capture potential could be indicated as [1.07-1.62] kg CO_2/Nm^3 biogas. In this respect, the highest yield is obtained via an increase in process yield as a result of a complete reduction of the internal heat demand for biogas. This indicates the relevance of further process- and heat integration. Overall, the BATR process is presumed to yield a total CO_2 capture potential of 1.53 kg CO_2/Nm^3 biogas or 38.4 kg CO_2/t manure. In this respect, the approximate 13% increase in comparison to the reference case is attributable to the higher CO_2 production in the reforming process. Nonetheless, in accordance to the stoichiometric reaction, this would result in a decrease in stoichiometric hydrogen yield.

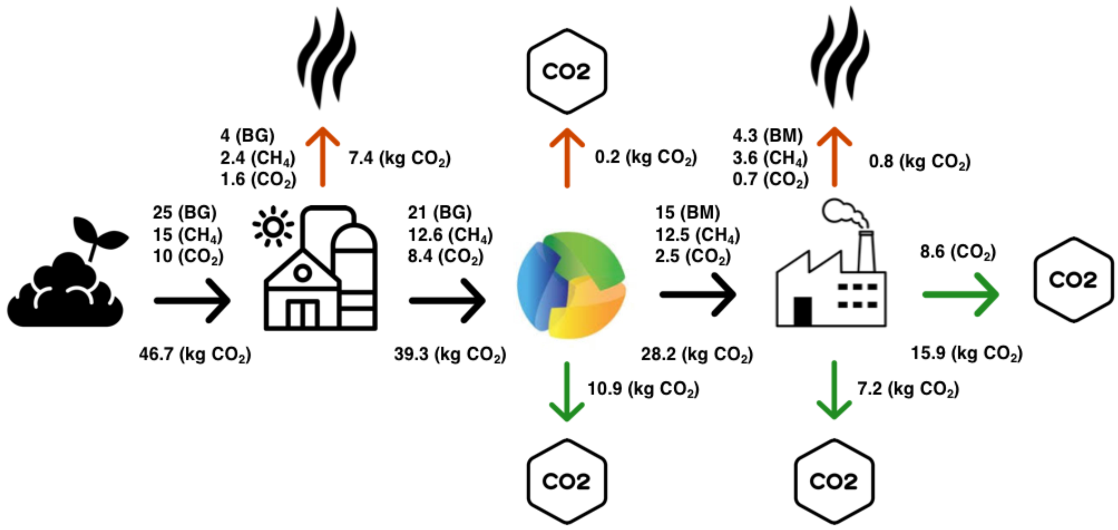


Figure 8.8: Carbon mass balance analysis (Nm^3)

To conclude, the concept of third-generation upgrading shows significant environmental benefits within the proposed renewable hydrogen system. This relates to the production of zero-pollution bio-hydrogen. More importantly, the concept of third-generation upgrading allows for the utilisation of the inherent negative bio-carbon present in biogas. As a result, the concept of third-generation upgrading allows for biogas to operate as platform molecule within both the renewable energy- and bio-economy domain. In this respect, the relevancy of both output products are presumed to vary over time and space. With respect to the latter, it was shown that the concept of third-generation upgrading shows the potential to yield around

Unit/stage	Input	Prod	Up CO_2	Up BM	Ref out	Ref fuel
Nm^3 biogas/t manure	25	21	0	0	0	0
Nm^3 CH_4/t manure	15	12.6	0	12.5	0.9	0
Nm^3 CO_2/t manure	10	8.4	5.9	2.5	8.6	3.9
Nm^3 CO_2 total/t manure	25.4	21.3	5.9	15.3	8.6	3.9
kg CH_4/t manure	10.3	8.7	0	8.6	0.6	0
kg CO_2/t manure	18.4	15.5	10.9	4.5	15.9	7.2
kg CO_2 total/t manure	46.7	39.3	10.9	28.2	15.9	7.2
cum. kg CO_2/Nm^3 biogas	0	0	0.4	0.4	1.1	1.4

Table 8.4: Carbon mass balance analysis

34.1 kg negative CO_2 emission per tonne of manure or 1.4 kg CO_2 per Nm^3 biogas. This is in contrast to a proposed yield of 10.9 kg negative CO_2 emission per tonne of manure or 0.4 kg CO_2 per Nm^3 biogas in the case of second-generation upgrading. This stream is subsequently assigned an inherent value through concepts of the EU ETS, CTBO or carbon abatement costs. However, the carbon balance is presumed to provide increasingly relevance as important climate-neutral carbon source for feedstock applications within the future renewable hydrogen system. However, this excludes other relevant environmental benefits that could be internalised within the concept of third-generation upgrading. This include adequate waste management, lower contaminants emissions, lower methane emissions, and the production of bio-fertiliser and related carbon soil storage. Overall, the concept of third-generation upgrading shows important environmental potential with respect to the conversion of problematic waste residues into valuable bio-hydrogen and bio-carbon dioxide.

Chapter 9

Economics

The concept of third-generation upgrading is described relevant benefits within the proposed future renewable hydrogen system. In this respect, biogas is seen as important bio-hydrogen and bio-carbon dioxide, or syngas, source. In this way, biogas is not only able to provide the necessary bio-carbon, it also allows for additional local- and or regional hydrogen production capacity. In this respect, the exact valorisation principle is presumed to be time and place dependent. Since the technologies to convert biogas to bio-hydrogen are mature, the biogas to hydrogen route is shown to be feasible and allows for a rapid transition towards hydrogen and away from methane. Thereby, this supports the overall devaluation of natural gas against hydrogen. This was supported by the relative environmental potential of the concept of third-generation upgrading as opposed to alternative use case of biogas. However, to ensure the transition is affordable and the concept of third-generation upgrading is adopted, relevant economic parameters can be defined. Here, the production cost of bio-hydrogen is seen to be dominant, both with respect to other source of hydrogen as well as alternative use cases for biogas. On top of that, the actual conversion, distribution and storage of hydrogen can add a significant part to the ultimate hydrogen delivery cost. Additionally, the total cost perspective argues that for wider adoption, also the cost perspective from the end user has to be taken into account to support adoption. This then contrasts the relevant value of bio-hydrogen and bio-carbon dioxide, over time and place, to identify the economic feasibility of the concept of third-generation upgrading within the wider perspective on the future renewable hydrogen system. However, this is complicated by alternative perspectives on the utilisation of biogas, including the concept of second-generation upgrading.

As a result, this chapter deals with the economics around the biogas to hydrogen conversion method. On top of that, this chapter aims to take a system cost perspective to adequately assess the potential of biogas within the future renewable hydrogen system. Moreover, this chapter also addresses the different cost perspectives of the alternative use cases of biogas as compared to the concept of third-generation upgrading. Ultimately, this chapter assesses the economic parameters within the proposed role of biogas within the future renewable hydrogen system through a business case analysis. This then support the overall perspective on the economic potential of the concept of third-generation and can serve as input to determine the adequate boundary condition requirements.

9.1 Introduction

In basis, the production of low-carbon hydrogen is considered more costly than the traditional production method based on fossil fuel. However, a decline in the production costs of renewables and the scaling up of the hydrogen production facility could stimulate cost reductions. Moreover, this could be further stimulated by the benefits from mass manufacturing. On top of that, developments in the hydrogen infrastructure could boost the adoption of low-carbon hydrogen and bring down the delivery cost of hydrogen (IEA, 2019). Additionally, (IEA, 2019) mention that addressing investment risks, positive experience with the development of clean energy technologies, and the support for R&D are further avenues that could reduce the costs of low-carbon hydrogen. This could also further improve the performance of hydrogen production technologies and support new applications of lower-carbon hydrogen.

In this respect, a high-level average potential production cost reduction for e-hydrogen and lower-carbon hydrogen in combination with a potential carbon price development can be seen in figure 9.1 (McKinsey, 2021). Here, in case of e-hydrogen production the production cost reduction arise from a decrease in electrolyser CAPEX. In this respect a, potentially conservative, 12% learning rate is assumed. Moreover, a decrease in levelised cost of energy (LCOE) and an increase in utilization levels also stimulate the price decrease. van Wijk, 2021 adds that the electrolyser technology can further benefit from cost reductions through mass production, technology integration and multiple gigawatt-scale projects. On top of that, the production of pure oxygen next to e-hydrogen could further boost the proposed hydrogen selling price or in similar terms reduce the required production costs (van Wijk, 2017). In case of lower-carbon hydrogen production, higher capture rates, CAPEX reductions for smaller capture installation and lower energy requirements reduce the presumed hydrogen production cost (McKinsey, 2021).

Overall, the hydrogen production costs as well as the future economics are driven by the actual feedstock-, fuel- and electricity costs. Other, indirect, drivers include, for example, the production scale and conversion level or efficiency. As a result, the actual hydrogen production costs vary over time and space (IEA, 2019).

However, next to a reduction in hydrogen production costs, a reduction in the transmission-, distribution- and storage costs are required to bring down the ultimate hydrogen delivery costs. Here, the relative costs of the steps in the value chain will be important in the competitiveness of hydrogen. For example, local production- and utilisation of hydrogen could potentially enjoy zero infrastructural costs. This is in contrast to long distance transmission- and distribution of hydrogen, which is stated to potentially increase the hydrogen delivery cost price by a factor three as comparison to the production costs (IEA, 2019).

In general, hydrogen requires a preparation step before transportation. This could be in the form of compression- or liquefaction of hydrogen. Moreover, this could entail the incorporation of another molecule or the conversion to another molecule. Thereby, the low volumetric energy density of hydrogen should be overcome. The exact preparation step in turn depends, among others, on the geographical location, transportation distance, production scale and the required end use. An overview of the transmission-, distribution- and storage elements of the hydrogen value chain can be seen in figure 9.2 (IEA, 2019). Next to the elements in the value chain, different

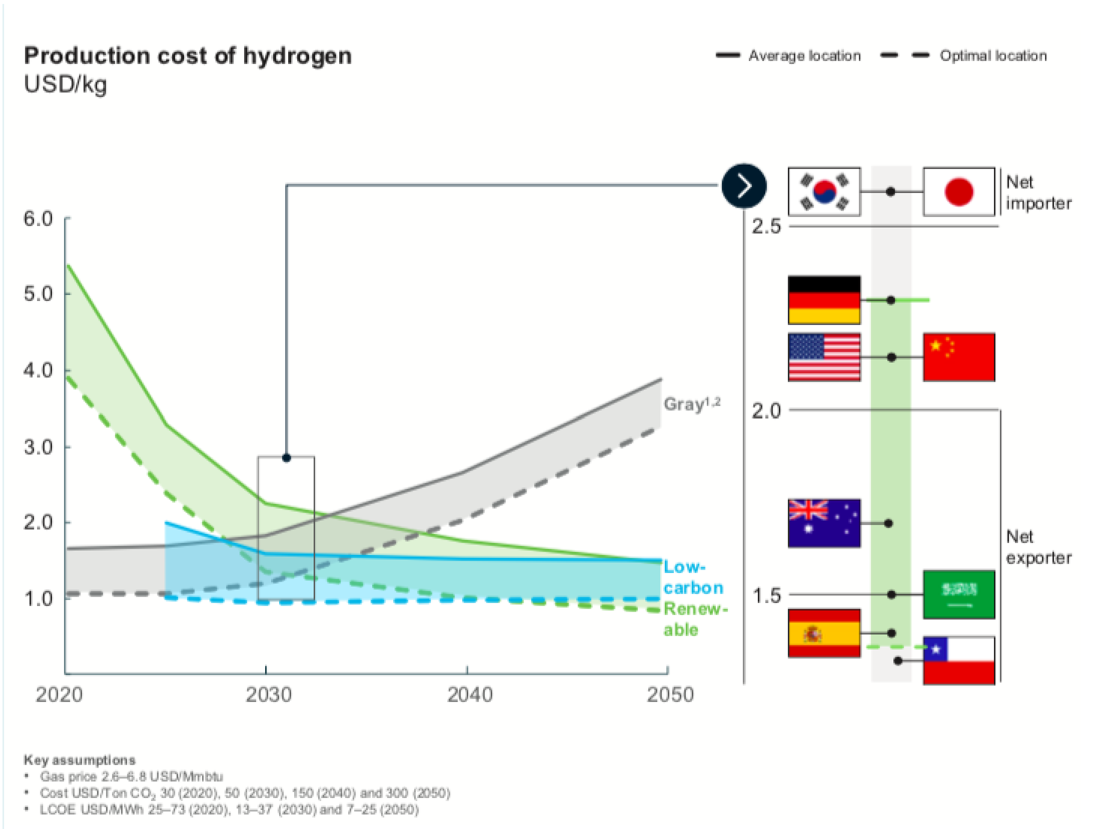


Figure 9.1: Hydrogen production cost pathways, including carbon costs (McKinsey, 2021)

types of value chains can be identified in the case of the production- and distribution of hydrogen. An overview of the proposed value chains can be seen in figure 9.3 (McKinsey, 2021).

9.1.1 Hydrogen storage

In case of hydrogen storage, geological storage and storage tanks are presumed to be the main storage methods. Here, geological storage is primarily used for large-scale and long-term storage. The geological storage options include salt caverns, depleted natural gas- or oil reserves, and aquifers. Salt caverns are characterised by a high efficiency of around 98%, low- to zero contamination and high discharge rates. The presumed costs for hydrogen storage in the case of salt caverns is around USD 0.6/kg H_2. In contrast, depleted oil- and gas reservoirs are typically more permeable and contain contaminants which could require an additional purification step before the utilisation of hydrogen. Moreover, water aquifers are the least mature technology and show mixed evidence with respect to the sustainability claims. In the case of storage tanks, these are primarily seen for applications an a smaller-scale. Here, both compressed- and liquefied hydrogen tanks are characterised by high discharge rates and high efficiencies of around 99% (IEA, 2019).

However, the low energy density of hydrogen makes the storage considerably harder than fossil fuels Bhavnagri et al., 2020. Moreover, low cost and large-scale options face geographic limitations. On top of that, the cost of alternative technologies might even exceed the production costs of hydrogen. An overview of the hydrogen storage

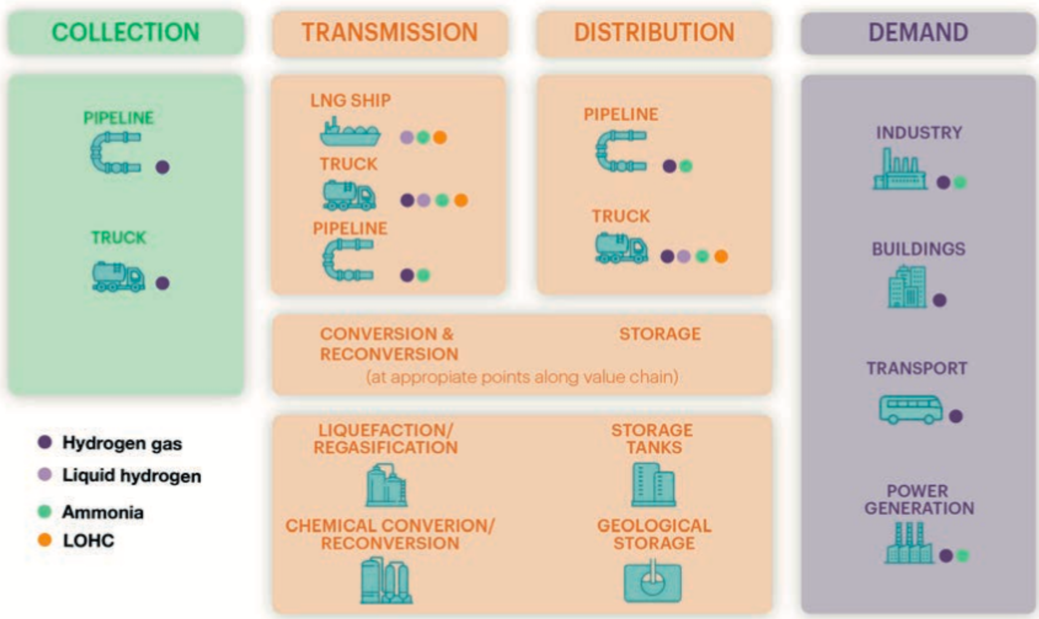


Figure 9.2: Transmission, distribution and storage steps of the hydrogen value chains (IEA, 2019)

options, the main use cases, and the current and expected future levelised cost of storage (LCOS) can be seen in figure 9.4 (Bhavnagri et al., 2020).

Here, it can be seen that salt caverns are the lowest cost option for storing hydrogen in large quantities and for long duration. The costs are expected to be around at cost of 0.23 USD/kg H_2 or 1.71 USD/MMBtu. However, the cost of storage in salt caverns might lower to 0.11 USD/kg or 0.82 USD/MMBtu, when cycled monthly. However it is mentioned that these costs are still around two to three times more than storing natural gas. Also, van Wijk and Wouters, 2019 mentioned the low cost storage option for hydrogen in salt caverns. In this respect, total installation costs of around €100 million, with a capacity of 6,000 ton hydrogen or around 240 GWh based on HHV, at 200 bar are mentioned. This contributes to CAPEX cost for hydrogen storage of around only 0.5 €/kWh. Additionally, van Wijk and Wouters, 2019 mention the storage of hydrogen in salt caverns will be at least hundreds times more cost-effect than the storage of electricity, for example through pumped hydro- or batteries storage. In case of the latter, the same storage requirement in batteries would cost around 100 €/kWh with, or an investment of €24 billion (van Wijk and Wouters, 2019).

On the other hand, pressurized containers are seen as the most viable option for storing hydrogen in small volumes and for short periods. In this case, the storage costs is estimated to be around 0.19 USD/kg H_2. Here, improvements could be made through for example the usage of lighter- and stronger materials to allow for higher pressures and therefore larger quantities. This could facilitate a decrease in the storage cost to around 0.17 USD/kg (Alvera et al., 2020).

In contrast, liquid state storage solutions are discussed to be geographically more versatile. However, liquid state storage suffers from a higher storage cost perspective due to the energy requirements for chilling or chemical conversion. Nevertheless, liquid state storage solution might not be used for stationary storage, but could

H_2 value chain	Example end user (Europe, 2030)	Example value chain steps: Production	Conversion/ transmission	Distribution	Cost, USD/kg
Onsite	Industrial, large scale offtaker	• Renewable/low-carbon production	• On-site storage for average of 1 day		
		1.6–2.3 USD/kg	0.5 USD/kg		~2–3
Regional	H_2 refueling stations (HRS)	• Renewable/low-carbon production	• Conversion to LH_2 and storage for average of 1 day *or* • Storage as GH_2 for average of 1 day and compression to 700 bar	• Trucking as LH_2 for 300km + operating of 1,000kg LH_2 HRS *or* • Piping as GH_2 for 300km and operating of 1,000kg GH_2 HRS[1]	
		1.6–2.3 USD/kg	0.7–1.0 USD/kg	1.0–2.0 USD/kg	~3–5
International	Industrial, large scale offtaker	• Renewable/ low-carbon production	• International pipeline for ~9,000km and storage at port for average of 2 weeks *or* • Carrier conversion/ reconversion, shipping for ~9,000km and storage at port for average of 2 weeks	• Trucking as LH_2/GH_2 for 300km and onsite storage for average of 1 day *or* • Piping as GH_2 for 300km and onsite storage for average of 1 day	
		1.0–1.4 USD/kg	0.6–3.5 USD/kg	0.1–2.0 USD/kg	~2–7

1 Refers to usage of existing pipeline to industrial hub

Figure 9.3: Emerging hydrogen distribution chains (McKinsey, 2021)

become relevant in combination with transportation in the value chain (Alvera et al., 2020).

	Gaseous state				Liquid state			Solid state
	Salt caverns	Depleted gas fields	Rock caverns	Pressurized containers	Liquid hydrogen	Ammonia	LOHCs	Metal hydrides
Main usage (volume and cycling)	Large volumes, months-weeks	Large volumes, seasonal	Medium volumes, months-weeks	Small volumes, daily	Small - medium volumes, days-weeks	Large volumes, months-weeks	Large volumes, months-weeks	Small volumes, days-weeks
Benchmark LCOS ($/kg)[1]	$0.23	$1.90	$0.71	$0.19	$4.57	$2.83	$4.50	Not evaluated
Possible future LCOS[1]	$0.11	$1.07	$0.23	$0.17	$0.95	$0.87	$1.86	Not evaluated
Geographical availability	Limited	Limited	Limited	Not limited	Not limited	Not limited	Not limited	Not limited

Source: BloombergNEF. Note: [1] Benchmark levelized cost of storage (LCOS) at the highest reasonable cycling rate (see detailed research for details). LOHC – liquid organic hydrogen carrier.

Figure 9.4: Comparison of different hydrogen storage options (Bhavnagri et al., 2020)

9.1.2 Hydrogen transportation

In case of hydrogen transportation, the low density of hydrogen makes transportation in general more expensive. This is especially the case for road- and ship transport of hydrogen. However, a higher flow rate could allow for cost-effective pipeline transportation of hydrogen. An overview of the respective hydrogen transport costs in USD/kg based on the respective distance and volume in 2019 can be seen in figure 9.5 (Bhavnagri et al., 2020).

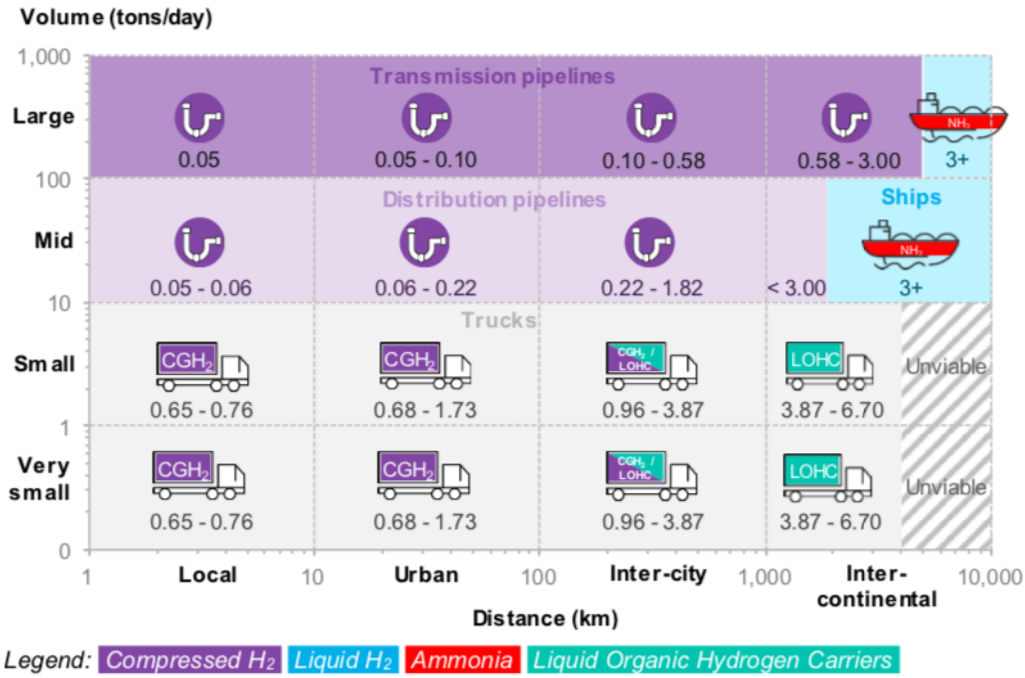


Figure 9.5: Hydrogen transport cost as function of distance and volume in USD/kg for 2019 (Bhavnagri et al., 2020)

Pipeline transport

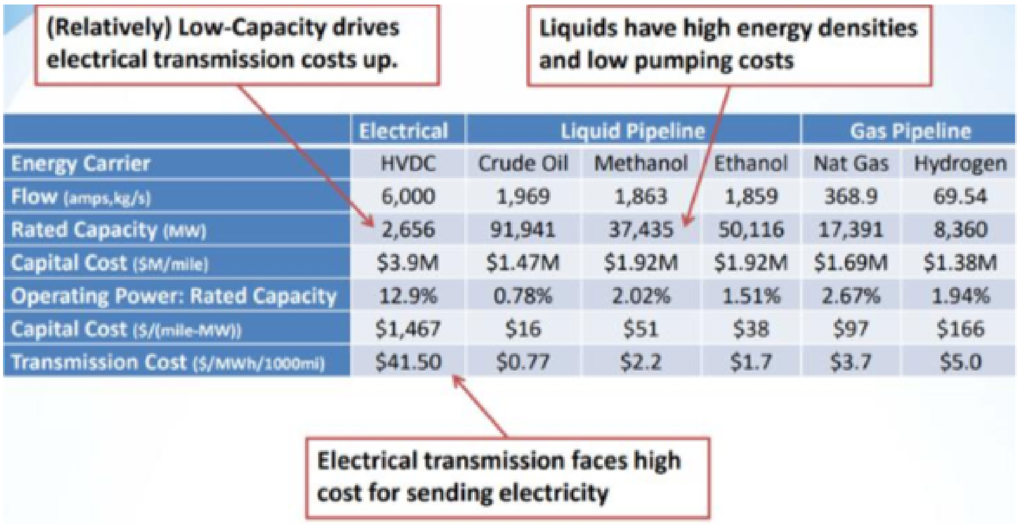
In figure 9.5 it is shown that a 100 km high-capacity hydrogen pipeline that would transport 100 tonnes of hydrogen per day would around 0.10 USD/kg H_2. However, this could be reduced due to better technology and wider adoption of hydrogen to around 0.06 USD/kg H_2. In the case of a longer distance and high-capacity hydrogen pipeline the cost would be around 0.09 USD/kg H_2 (Alvera et al., 2020). In contrast, the gaseous hydrogen pipeline transport from over around 1,500 km is stated to result in approximate storage of cost of around 1 USD/kg H_2 (IEA, 2019).

On the contrary, van Wijk, 2021 mention a cost of 0.16 EUR/kg H_2 per 1000km for hydrogen transport in the EU based on 75% converted- and 25% new hydrogen pipelines at 5,000 full load hours. This could further be reduced to below 0.1 EUR/kg H_2 per 1000km based on new large, and dedicated pipelines for base-load hydrogen transport at 80 bar (van Wijk, 2021).

Moreover, van Wijk, 2021 states potential hydrogen pipeline transport cost of 0.3 €/kg H_2. This is based on a capacity of 20 GW, 8,000 full load hours and a pipeline length of 3,000 km between Morocco and Germany. Here, the transport cost of hydrogen is mentioned to be lower than the difference in the domestic renewable hydrogen production costs between the two region (McKinsey, 2021).

Another example shows transport cost for hydrogen transport per pipeline from Egypt to Italy of over 2,500 km at 66 GW capacity with a load factor of 4,500 hours to be around 0.2 €/kg H_2 or 0.005 €/kWh (van Wijk and Wouters, 2019).

However, it should be noted that hydrogen pipelines are not equal and the actual transport costs are reflected by the type, length and condition of the pipeline. Moreover, the cost are reflected by the fact whether the pipelines are newly created or retrofitted. A distinction between the different pipeline categories based on different cost estimates can be made. In this respect, the categories include distribution pipelines, onshore transmissions pipelines and subsea transmission lines, where the cost per km are increasing from distribution- to subsea transmission lines (McKinsey, 2021). Moreover, van Wijk, 2021 indicates the comparison between between electric-, liquid pipeline- and gas pipeline transport over a distance of 1,000 km for different carriers. The comparison can be seen in figure 9.6. Here, the equivalent cost of liquid hydrogen pipeline transport of 0.1 EUR/kg H_2 per 1000km can be observed. Moreover, it could be observed that the hydrogen transport shows a factor [8-10] lower costs as compared to the electricity transport. Here, the relative difference is expected to remain prevalent over time as both modes of transmission show similar cost decrease perspectives (van Wijk, 2021).



	Electrical	Liquid Pipeline			Gas Pipeline	
Energy Carrier	HVDC	Crude Oil	Methanol	Ethanol	Nat Gas	Hydrogen
Flow (amps,kg/s)	6,000	1,969	1,863	1,859	368.9	69.54
Rated Capacity (MW)	2,656	91,941	37,435	50,116	17,391	8,360
Capital Cost ($M/mile)	$3.9M	$1.47M	$1.92M	$1.92M	$1.69M	$1.38M
Operating Power: Rated Capacity	12.9%	0.78%	2.02%	1.51%	2.67%	1.94%
Capital Cost ($/(mile-MW))	$1,467	$16	$51	$38	$97	$166
Transmission Cost ($/MWh/1000mi)	$41.50	$0.77	$2.2	$1.7	$3.7	$5.0

Figure 9.6: Transmission cost comparison between electricity transport cables, liquids and cases through pipelines (van Wijk, 2021)

Road transport

In the case of low-volume and short distance transport, compressed- or liquefied hydrogen transport is mentioned to be the most cost-efficient option. In this case, the transport costs are estimated to be around [0.81-1.19] USD/kg H_2 in case of short-trip compressed hydrogen transport and 3.30 USD/kg for medium distance liquefied transportation. However, due to technological development.the transport costs are expected to decrease to around 0.64 USD/kg H_2 and 1.10 USD/kg H_2 respectively.

Nevertheless, in case of local distribution, pipelines become increasingly cost-competitive with trucks for the distribution of hydrogen. This is especially relevant for larger transport volumes, where the usage of pipelines show a reduction in the hydrogen transport costs (IEA, 2019). In this perspective, the cost of hydrogen transport to a large centralised facility, including the cost of reconversion to gaseous hydrogen, can be seen in figure 9.7 (IEA, 2019).

Ship transport

In case of hydrogen transport per ship, the conversion-, shipping- and reconversion cost are included. As a result, transport by ship is considered more cost- and energy

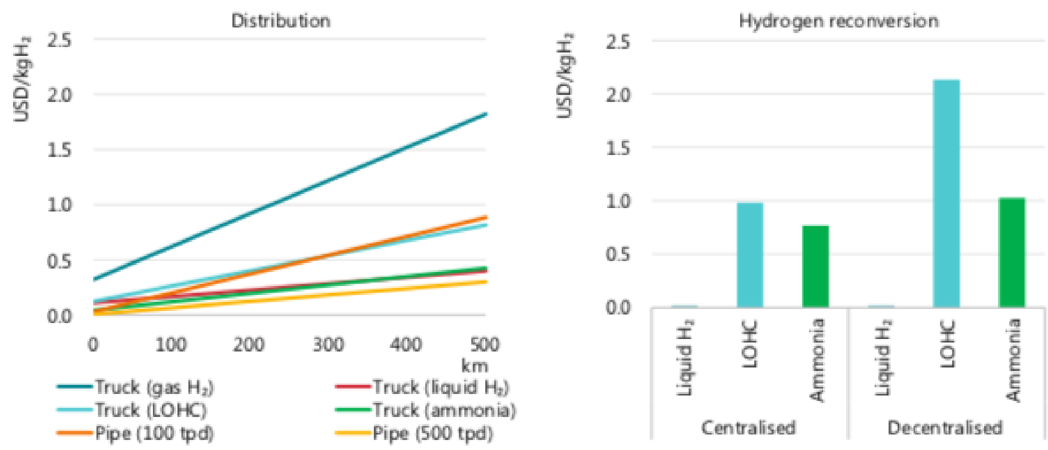


Figure 9.7: Cost of hydrogen distribution and reconversion to gaseous hydrogen (IEA, 2019)

intense. This results in a transport costs for over 5,000 km distance of around 3 USD/kg in the case of ammonia-, 7 USD/kg in the case of liquid hydrogen- and 5 USD/kg in the case of liquid organic hydrogen carrier (LOCH) transport. Here, the required liquefaction costs per kg H_2 lowers the cost-competitive of liquefied hydrogen transport by ship (McKinsey, 2021). However, the potential transport cost could decrease to around 2 USD/kg due to economies of scale and efficiency improvements (Alvera et al., 2020). In this perspective, the transport cost of hydrogen are mainly associated with the conversion and reconversion. For example, in case of the utilisation of ammonia instead the proposed shipment cost is limited to only [0.3-0.5] USD/kg ammonia. This is in contrast to the shipment cost of liquefied hydrogen, which are mentioned to be around [1.0-1.2] USD/kg H_2 (McKinsey, 2021).

Nonetheless, the optimal carbon-neutral hydrogen carrier for ship transport is not crystal clear. The decision is for example dependent on the end application, purity requirement and need for long term storage. In this perspective, the most considered carriers are liquid hydrogen, ammonia, and liquid organic carriers. These also are indicated to be the relevant considered hydrogen storage options. For example, an overview of the landed cost associated with renewable hydrogen shipment from Saudi Arabia to Europe can be seen in figure 9.8 (McKinsey, 2021).

Transport network

An overview of the distribution options, based on the different transportation modes and distances, and the respective cost ranges can be observed in figure 9.9 (McKinsey, 2021). Moreover, in the case of long-distance transmission of hydrogen, the cost of hydrogen storage, transmission, liquefaction and conversion can be seen in figure 9.10 (IEA, 2019).

9.1.3 Hydrogen demand

In case of the end application of hydrogen, use cases apply in the industrial-, transport-, build environment- and power sector. In this respect, the total cost of ownership (TCO) perspective is considered of significant importance for the adoption of hydrogen.

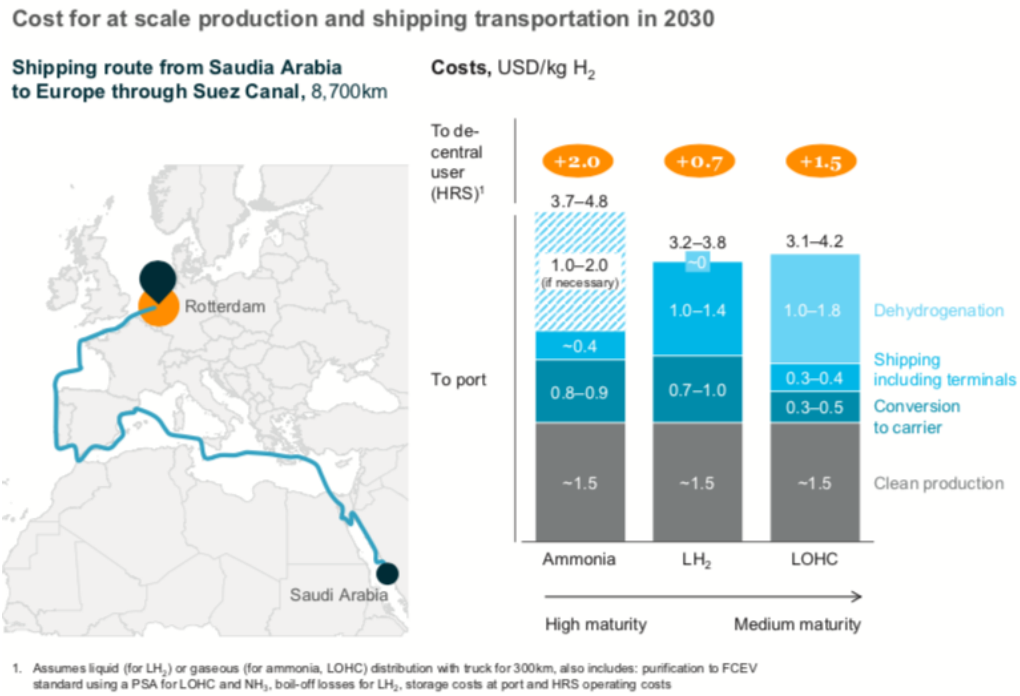


Figure 9.8: Landed costs at port of hydrogen transport from Saudi Arabia to Europe (McKinsey, 2021)

The TCO does not only include the hydrogen delivery- or retail cost, but also take into account additional CAPEX or other cost associated with the utilisation of hydrogen. This could subsequently help to identify end applications where low-carbon hydrogen can be most competitive solution. This is especially relevant in the short-term. However, next to the TCO perspective, also environmental regulations, expectations and associated green premiums are relevant for the adoption of hydrogen. Moreover, other relevant factors include the cost of capital for investment decisions and the relative fraction of the hydrogen delivery cost as part of the total end application costs (McKinsey, 2021).

Industry

Within the industrial sector, hydrogen is currently widely applied in oil refining and chemical production. The latter includes for example ammonia- and methanol production. However, future applications for hydrogen include iron- and steel production as well as high-temperature heat production.

In the case of oil refining, the industry is characterised by tight margins and a highly competitive playing field which limit the adoption of alternative processes. Here, most attention has been devoted to retro-fit CCUS technology, which could become cost-competitive at a carbon price of around 50 USD/t CO_2. Nonetheless, this assumed the availability-, accessibility and feasibility of CO_2 storage and or usage (IEA, 2019). Nevertheless, the utilisation of hydrogen within oil refining is expected to decrease over time, due to the phasing out of fossil fuel in the future energy system.

For the chemical production of ammonia and methanol, the production costs vary widely per region. This is based on the cost of chemical feedstock, electricity and

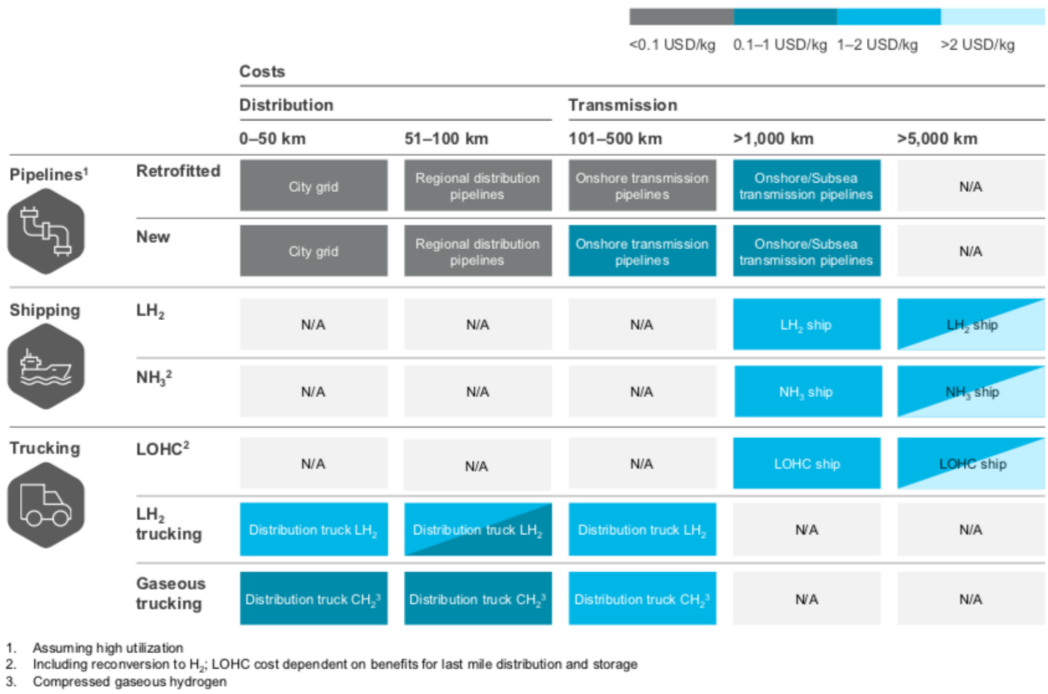


Figure 9.9: Overview of different distribution options (McKinsey, 2021)

or biomass. More specifically, the feedstock costs constitute around [65-80]% in the TCO ammonia production. As a result, at an indicated hydrogen delivery cost of around 2.1 USD/kg H_2 an average carbon price of 100 USD/t CO_2-eq would be required to break-even at a cost of ammonia of 580 USD/t (McKinsey, 2021).

For iron- and steel production, the energy- and other raw material input costs represent upwards of about 45% of the production costs in case of direct reduced iron (DRI) route. This indicates the considerable price effect with respect to the hydrogen production costs. Moreover, the iron- and steel industry is characterised by significant stranded assets in case of hydrogen adoption. On top of that, an additional barrier for the adoption of hydrogen as reducing agent in iron- and steel production is the proposed cost disadvantage in comparison to the current situation. As a result, the establishment of a differentiated market for low-carbon iron- and steel production is considered. This should support the increased costs faced by the producers of low-carbon iron- and steel (IEA, 2019). However, McKinsey, 2021 mention the possible cost-competitive production or iron- or steel at a hydrogen delivery cost of [1.7-2.1] USD/kg H_2 and a CO_2 cost of 80 USD/t CO_2. This carbon price required could even be lowered to 45 USD/t CO_2 in case of 40% reuse of scrap.

In the case of the production of high-temperature heat, hydrogen is discussed to remain an expensive alternative to fossil fuel usage. In this respect, hydrogen is not considered cost-competitive even in the context of CO_2 prices of over 100 USD/t CO_2. Moreover, hydrogen is expected to face additional price competition with bio-energy. In this perspective, the bio-energy delivery price is assumed to be [8-12] USD/GJ. As a result, the use of renewable hydrogen for high-temperature heat could therefore be primarily relevant in the instances of hard-to-reach segments of the industry. This could relate to geographically fragmented portions of demand (IEA, 2019.

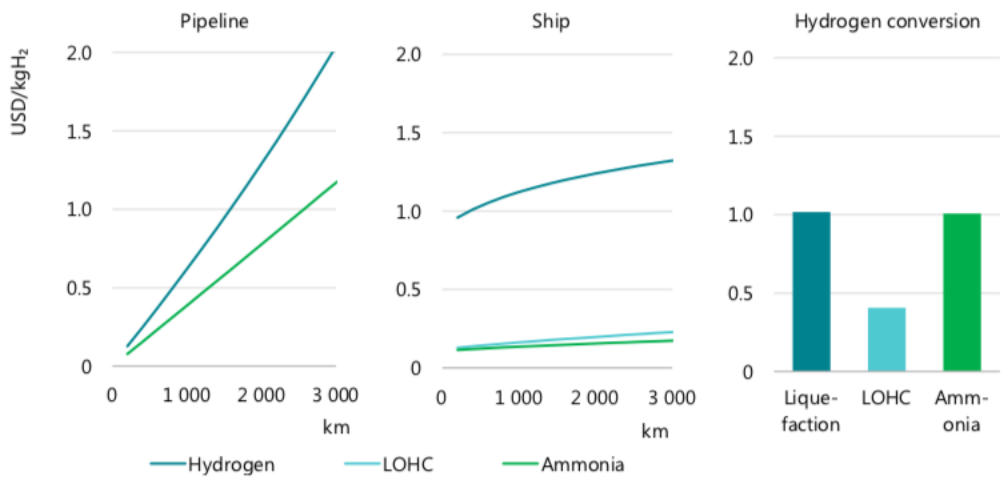


Figure 9.10: Cost of hydrogen storage, transmission and conversion for long-distance (IEA, 2019)

Transport

The use of hydrogen in transportation, includes the potential adoption in cars and vans- (light-duty vehicles), trucks and buses- (heavy-duty vehicles), maritime-, rail- and aviation applications (IEA, 2019).

In case of direct- and indirect uses of hydrogen in road transport, the competitiveness of fuel cell electric vehicles (FCEVs) as opposed to battery electric vehicles (BEVs) is important. Here, potential cost component reduction for FCEVs exist with respect to the fuel cell costs, the on-board storage costs and the cost of refuelling. As a result, this supports the relative cost perspective of FCEVs. Moreover, alternative criteria for the usage of FCEVs as opposed to BEVs include the performance-, comfort- and reliability of the FCEV. From a total cost of ownership perspective, the capital costs in the case of light-duty vehicles is in the range of [70-95]%. This is, among others, dependent on the size- and utilisation the FCEV. This further supports the importance to reduce the cost of the fuel cell- and storage system in FCEVs. As a result, the competitiveness of the FCEVs as compared to the BEVs is related to the expected fuel cell costs in USD/kW and battery price in USD/kWh for a respective, assumed similar, vehicle range in km. In this perspective, FECVs are stated to be more competitive over longer driving ranges (IEA, 2019). This becomes especially relevant for larger passenger cars, with longer-range requirements and heavier use cycles (McKinsey, 2021).

In contrast, the TCO in case of heavy-duty vehicles relies for approximate [40-70]% on the capital costs. As a result, the actual fuel costs become more important for heavy-duty vehicles. Moreover, the FECVs tend to be more immediately competitive as compared to BEVs in the case of heavy-duty vehicles. This is due to the long-range- and high power requirement (IEA, 2019). Moreover, especially in weight-sensitive use cases, for example transport of paper and pulp or iron and steel, FCEVs are the most important alternative. Here, FECVs are able to reduce the potential payload associated with weight of the batteries required. Also, in case of off-road and very heavy equipment FCEVs are assumed to be more competitive as opposed to BEVs. This is related to the high peak power requirement and harsh vibrations (McKinsey, 2021).

In case of the maritime industry, the infrastructure requirements, on-board equipment and fuel costs are determining factors. Moreover, the maritime industry is characterised by demanding fuel requirements, which is related to the energy intensity and large power needs. In this case, long-distance maritime trading routes could provide the best potential for the adoption of hydrogen- or hydrogen derived fuel. This relates to the fact that the CAPEX have a comparatively lower impact as compared to fuel costs. Moreover, this industry segment has potential lower problems associated with the additional space requirements. This is despite the possible redesign requirement. Overall, an carbon price of [40-230] USD/t CO_2 is expected to be required for ammonia fuel. This range depends, among others, on oil prices and electricity prices. In case of a first-owner and 15 year calculation hydrogen usage could become to be cost-competitive with fossil-based fuels at an additional carbon price of [35-45] USD/t CO_2. However it should be noted that, the respective price increase represents a small share of total price of the shipped goods. This is in contrast to the substantial costs perspective for the ship owners (IEA, 2019). For example, in case of container ships, McKinsey, 2021 identified green ammonia to be the cheapest zero-carbon fuel option. Here, the required carbon price is expected to be around of 85 USD/t CO_2 to be cost-competitive with heavy fuel oil. However, in this perspective, the higher cost price for the ship owner would translate in a, theoretical, price increase of less than 1% or 0.13 USD on a pair of jeans at retail value of 60 USD. In contrast, for cruise ships, the shorter trip lengths, frequent stops, safety regulations and risk consideration rule out ammonia as potential fuel. As a result, carbon-neutral methanol and liquid hydrogen are shown to be the lowest cost alternatives. However, in this instance a carbon break-even price of 300 USD/t CO_2 would be required. This in turn would impact the, theoretical end consumer, with a price increase of around 40% to ticket price of 1,400 USD (McKinsey, 2021).

For rail transport, the adoption of hydrogen is expected to be limited. However, non-electrified tracks with long-distance movement of large trains and low-frequency network utilisation might show a set of competitive conditions for hydrogen fuel cell technology. Moreover, a combination of hydrogen powered rail transport, other railyard machinery and logistic hub machinery could be established to decrease costs and improve flexibility. This thereby could unlock additional hydrogen demand (IEA, 2019).

In case of the aviation industry, the required aircraft design changes as well as new infrastructure demand might hinder the direct adoption of hydrogen. In contrast, hydrogen-based fuels could provide an alternative for the adoption of hydrogen. However, these hydrogen-derived fuels have an estimated price premium of four to six times. This is especially relevant in light of the high share of fuel cost as part of the total costs. Therefore, an assumed CO_2 price of [115-660] USD/t CO_2 is mentioned to be required for hydrogen to become a cost-competitive alternative. Moreover, price competition with biofuels might limit the adoption of hydrogen-based fuels (IEA, 2019). However, this will depend on the size of the aircraft as well as the distance covered. In this way, for short- to medium range utilisation liquid hydrogen, at unknown delivered costs, might be a more competitive abatement option as compared to hydrogen-derived fuel based on DAC. Here, a carbon cost of [90-150] USD/t CO_2-eq by 2040 would be required. On the other hand, beyond the 10,000 km range hydrogen-derived fuels could become more competitive at an abatement cost of 200 USD/t CO_2-eq (McKinsey, 2021).

Build environment

The demand for hydrogen for heat demand in the build environment could arise from different potential routes. These include hydrogen blending, methanation, dedicated hydrogen and or the use of fuel cells and co-generation. In the case of dedicated hydrogen demand, via fuel cell- or hydrogen boiler technology, the most attractive options are expected to arise from large commercial buildings, building complexes and district energy networks. This could potentially be utilised in combination with energy storage capacity. In case of residential housing, the hydrogen price and technology cost are critical factors. Depending on the region, building type and carbon price, a hydrogen delivery price of [1.5-4] USD/kg H_2 is expected to be required to be cost competitive with gas boilers or electric heat pumps. However, in this respect next to the operational costs, the capital investment costs will be highly relevant to convince adoption by the end consumer (IEA, 2019).

More specifically, van Wijk and Hellinga, 2021 make the case for the usage of hydrogen in the build environment, in the Netherlands. Here, based on integrated supply chain costs, the expected low-carbon hydrogen delivery costs are around 3.6 €/kg H_2. Moreover, a distinction is made between old neighbourhoods with costly adjustment needs and no feasibility of district heating, neighbourhoods with- or with the feasibility of district heating, and well-isolated newly build neighbourhoods including all-electric heat pumps. The distinction is made to show the decrease in respective hydrogen cost required for hydrogen to become cost-competitive. In this perspective, based on the cumulative expected demand, and an integrated hydrogen cost of around 3.6 €/kg H_2, hydrogen shows the potential for adoption for over two-third of the build environment by 2030. The adoption of hydrogen is further supported by the relative low transition costs, including cost for the boiler and pipeline transport (van Wijk and Hellinga, 2021).

On top of that, it is argued that the green gas show higher valorisation potential in the industrial- and chemical sector. Moreover,the expected delivery cost of green gas are stated to be approximately similar to the proposed integrated hydrogen costs. Therefor, the adoption of green gas in the build environment is hindered. Also, the CO_2 emissions over the entire value chain show significant reduction potential in the case of hydrogen usage as compared to green gas utilisation. Moreover, this is also the case as compared to other energy options including district heating, geothermal and heat pumps. Additionally, it is discussed that hydrogen is a more economical solution as compared to the costly energy saving methods, like insulation that might cost over [350-980] €/t CO_2. This significantly outweighing abatement costs in the industry (van Wijk and Hellinga, 2021).

Power

For power generation and electricity storage of hydrogen several options exists like co-firing ammonia in coal power plants, flexible power generation, back-up and off-grid power supply, and long-term- and large-scale energy storage. In case of flexible power generation, hydrogen-fired power plants are characterised by lower capital costs per unit of power as compared to alternatives like CCUS and biogas. This advantage becomes more pronounced at low load factors relevant for systems with high shares of variable renewable electricity. In basis, the competitiveness as opposed to natural gas-fired power generation for load balancing and peak load generation depends on the gas prices, potential carbon price, and hydrogen delivery price. In this respect, at a load factor of 15%, a CO_2 price of 100 USD/t CO_2 is needed in case of a hydrogen price of 1.5 USD/kg H_2. In contrast, a carbon price of 175 USD/t CO_2 is required in case of a hydrogen price of 2 USD/kg H_2 (IEA, 2019). However, Bhavnagri et al., 2020 argue that at hydrogen production costs of around [8-14] USD/MMBtu a mere carbon price of 32 USD/t CO_2 by 2050 could already make hydrogen price competitive for dispatchable power generation. In case of long-term and large-scale storage of electricity the hydrogen-based storage option suffer from low round-trip efficiencies of around 40% as opposed to storage cycle efficiency losses of lithium-ion batteries of 15%. However, batteries are less feasible in case of long-term and large-scale storage due to self discharge and the required amount of batteries. In contrast, pumped hydro storage, if available, might provide an alternative option. However, in case of longer discharge duration, hydrogen might become more relevant. Here, levelised costs of storage are expected to be around 200 USD/MWh (IEA, 2019).

On top of that, van Wijk, 2021 makes the case for the expected cost-competition that could arise between local- or regional produced renewable electricity, regional produced renewable hydrogen and imported e-hydrogen in all sectors and applications. Here, low-cost imported e-hydrogen, with an expected delivery cost in the range of [1-2] €/kg H_2 or [0.025-0.050] $€/kWh_{HHV}$, could outcompete local produced renewable energy (van Wijk, 2021).

Comparison

Overall, hydrogen utilisation is presumed to remain more expensive in contrast to traditional fossil fuel usage. This is partly related to the fact that hydrogen has to be produced, while fossil fuel only requires extraction. Moreover, the lower energy density makes hydrogen in basis more expensive to handle. As a result, carbon abatement costs are expected to remain required in most- or all sectoral applications. An overview of the marginal abatement cost curve, at a hydrogen price of 1 USD/kg, for the year 2050 can be seen in figure 9.11. Here, it can be observed that the strongest use case for hydrogen are the industrial processes, where hydrogen could be cost-competitive at relatively low carbon prices of below 100 USD/t CO_2. Moreover, in case of long-haul- and heavy-payload trucks the use of FCEVs could already outcompete diesel engines by 2031 (Bhavnagri et al., 2020).

In similar fashion, McKinsey, 2021 identified 22 end applications where hydrogen could become competitive based on the total cost perspective by 2030. This overview can be seen in figure 9.12. However, this perspective does not incorporate other factors that drive the purchase decision, including government targets and or premium placed on low carbon products (McKinsey, 2021). On top of that, the total cost perspective is complemented with an overview of the required hydrogen production costs that are required to break-even with conventional solutions at a carbon price of 100 USD/t CO_2-eq by 2030. This overview can be seen in figure 9.13. Here, it is indicated that road applications and industry feedstock applications show promising signs for the adoption of hydrogen (McKinsey, 2021).

Ultimately, low-carbon hydrogen will facilitate multiple and different demand sectors. In this regard, van Wijk, 2017 portray a vision for the use of low-carbon hydrogen in the Northern Netherlands. In this perspective, hydrogen will be used for the regional production of methanol and ammonia, to power local mobility options through passenger cars, busses, trains and other mobility, facilitate grid balance, and is exported to other chemical hubs in the Netherlands.

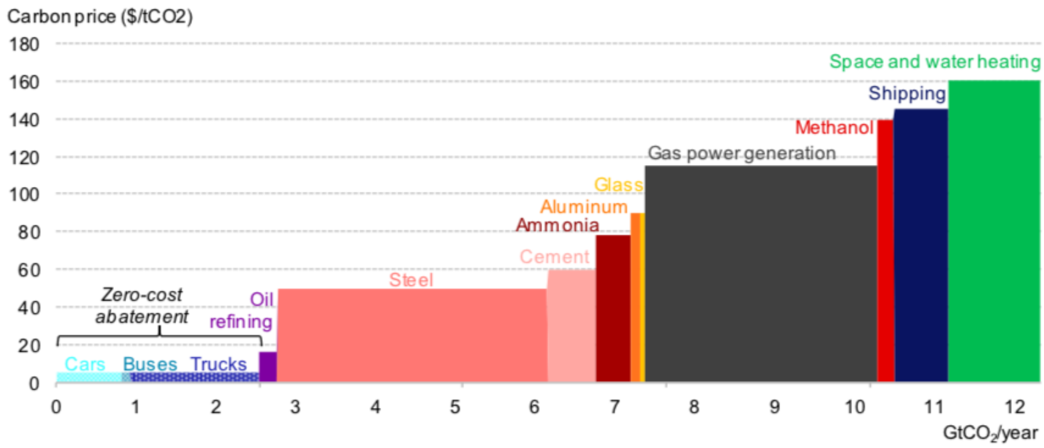


Figure 9.11: Marginal abatement cost curve for 1 USD/kg H_2 for emissions reductions, by sector in 2050 (Bhavnagri et al., 2020)

The Netherlands

The current hydrogen demand in The Netherlands, arises primarily from the dominant industrial clusters. An overview of the hydrogen demand per industrial cluster can seen in table 9.1. Nevertheless, future hydrogen demand is expected to differ considerably over different end applications (GL, 2020).

The industrial sector in the Netherlands is defined by 5 clusters. Here, the industrial cluster that combines Rotterdam and Zeeland as stated in table 9.1 is separated. The hydrogen demand in the Northern cluster, around Delfzijl, is expected to increase to [30-70] PJ by 2030 from 18 PJ in 2018. Here, the expected production potential of 70 PJ could be provided for 42 PJ by e-hydrogen and 28 PJ by lower-carbon hydrogen. Moreover, the a potential mismatch in the demand- and supply of hydrogen could be stored, injected in the hydrogen backbone or used around the region for domestic head or HRS. Next, in case of the North Sea Canal cluster around Amsterdam and IJmuiden, the hydrogen backbone facility will be a key factor for the establishment of hydrogen production and demand. Here, largely based on the infrastructure availability, the prognoses vary from [2.3-23] PJ in 2030 to [16-88] PJ in 2050. The demand is expected to be fulfilled by offshore e-hydrogen production for around [4-10] PJ. Moreover, the additional demand can be fulfilled by import, which can also serve to fulfill demand in the region or for the local- and national transport of hydrogen. In case of the Rotterdam region, the current hydrogen demand is around 35 PJ. This demand stems primarily from natural gas reforming or as by-product from refineries or chlorine production. The hydrogen production from lower-carbon- and e-hydrogen are expected to achieve 20 PJ in 2030 and 100 PJ by 2050. Like the Amsterdam region, the Rotterdam region would provide an excellent location for hydrogen import and further connection in-land. Also, the Zeeland region is at the moment characterised by a high demand for hydrogen amounting to 57 PJ. This primarily arises from the presence of ammonia plants. In this case, the hydrogen

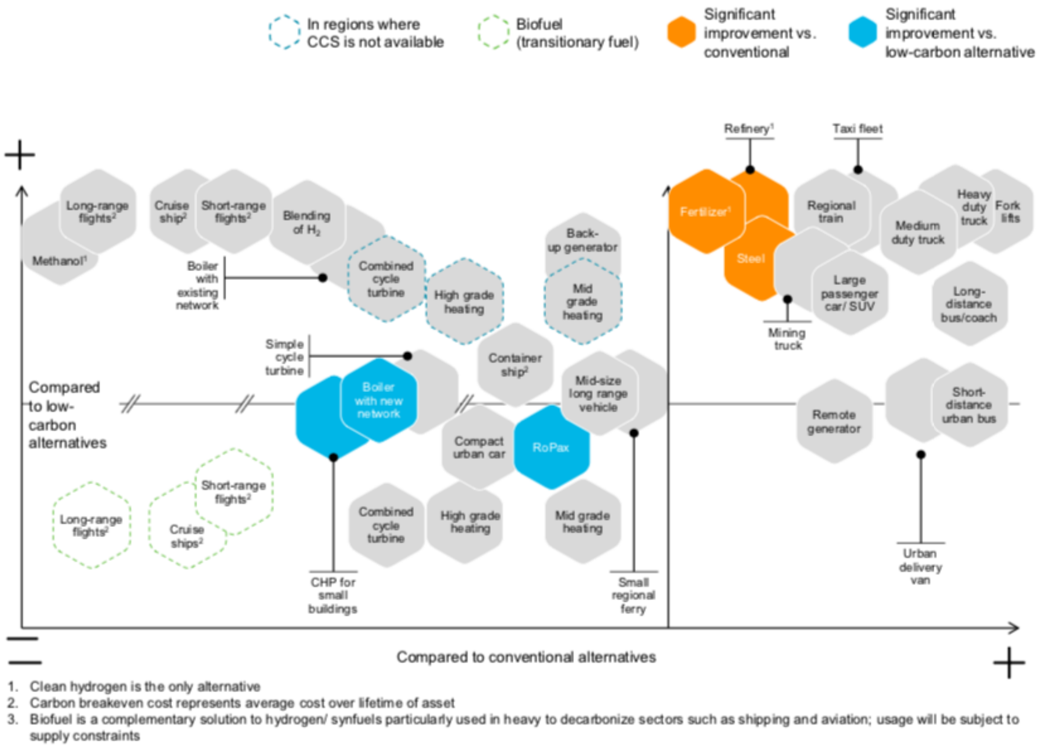


Figure 9.12: Hydrogen competitiveness per end application in 2030 (McKinsey, 2021)

in mainly produced from natural gas. By 2030, 28 PJ of the hydrogen demand is expected to be converted into e-hydrogen while the rest of the hydrogen demand could arise from maritime- or pipeline imports or from the national infrastructure. On top of that, the hydrogen demand in 2050 could become around 108 PJ. Finally, in the southern cluster, around Geleen, the hydrogen is at the moment mainly used to provide energy or is used as feedstock. The current hydrogen demand is around 28 PJ. The hydrogen demand is expected to arise from lower-carbon hydrogen by 2030 via storage connection with the Rotterdam region. However, an additional [0-7] PJ of e-hydrogen could be created by 2030. Nonetheless, by 2050 the hydrogen demand is expected to be fulfilled by e-hydrogen (GL, 2020).

In case of the hydrogen demand in the transportation sector, the future expectation follow the ambitions spelled out in the climate agreement in the Netherlands. Here, around 15,000 FCEVs and 3,000 heavy trucks are forecasted for 2025 up to 300,000 FCEVs by 2030. This would represent an hydrogen demand of 140 kt or 18 PJ. However, this expectation follows the high demand perspective, as can be seen in table 9.2. Here, the hydrogen demand in the transportation sector for a high demand- and low demand scenario until 2050 in the Netherlands is indicated (Leguijt et al., 2018. The high demand scenario is, for part, defined by the perspective on hydrogen as a zero-emission tank-to-wheel fuel. The perspectives aligns with the usage of battery technology but is in contrast with the usage of biofuels. However, due to the lower volumetric energy density of hydrogen and the high action radius required for heavy duty trucks, biofuels are expected to remain an important factor in the transportation strategy in the Netherlands. Nonetheless, technological developments are expected to improve the hydrogen uptake in heavy-duty transportation. In contrast, the use of hydrogen in the aviation- and maritime industry is presumed to

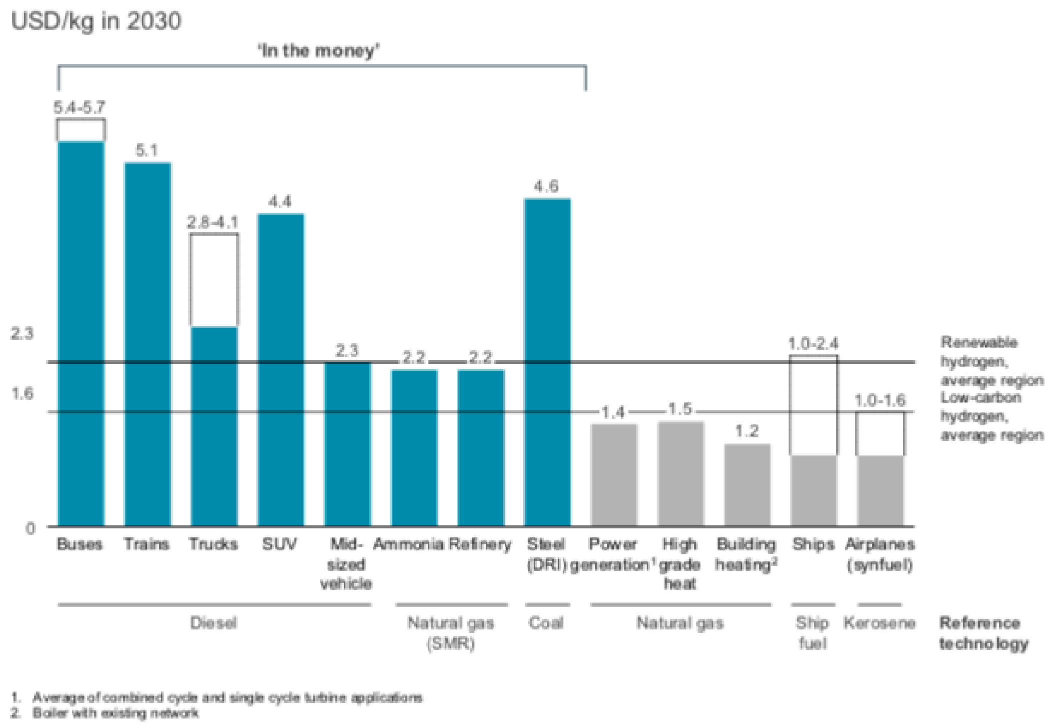


Figure 9.13: Breakeven hydrogen production costs at a carbon price of 100 USD/t CO_2-eq (McKinsey, 2021)

be limited in the Netherlands. However, this does not account for the production of synthetic fuels, relates to the direct application of hydrogen. Nonetheless, fossil-based fuels are expected to remain the most important fuel in the transportation sector by 2030, followed by biofuels, electricity and last hydrogen (Leguijt et al., 2018).

In case of the power sector demand for hydrogen, or the demand for electricity production and grid balancing, the electrification trend results in a strong increase in the renewable electricity capacity in the Netherlands. The renewable electricity production capacity is presumed to be primarily located in the Northern region and is assumed to boost the potential for renewable hydrogen production. In this perspective, depending on the active role of the government, a wind capacity of [26-43] GW is expected by 2050. In contrast, by 2030 the wind capacity is expected to account for 11.5 GW. In this respect, hydrogen production could be coupled to the overcapacity production to support the uptake of renewable electricity production and strengthen the business case. However, the additional capacity could also be linked directly to the hydrogen production capacity (GL, 2020).

In case of the hydrogen demand from the build environment, the focus lies on removing the natural gas dependencies. This primarily arises from the decoupling of the natural gas grid. Moreover, the shift is based on the presumed electrification of the heat demand and or the use of district heating. Also, geothermal energy is assumed to become important. However, during the transition and for hard-to-decouple regions, the option might not suffice. In this respect, alternative options are the use of green gas or the use of hydrogen. In this perspective, the ambition of 70 PJ of green gas to be used in the build environment by 2030 is spelled out. However, here also the addition of hydrogen into the gas grid within a blend percentage of [2-20]% could be used. Moreover, the natural gas infrastructure could be converted to a 100% dedicated hydrogen infrastructure (Leguijt et al., 2018). Moreover, it was argued that hydrogen could already by 2030 become a cost-competitive option for over two-third of the heat demand in the build environment (van Wijk and Hellinga, 2021). In contrast, the expectation for the usage of hydrogen in the build environment in limited to 1 PJ/year by 2030. However, the demand for hydrogen in the build environment show growth potential to 203 PJ/year by 2050 (Leguijt et al., 2018).

Region	**Volume (million m^3/year)**
Delfzijl	1.3
Geleen	1.8
IJmuiden	1.0
Rotterdam/Zeeland	6.1
Total	10.2

Table 9.1: Current hydrogen demand in the Netherlands over the dominant Industrial Clusters (GL, 2020)

	2020	2025	2030	2035	2040	2045	2050
Low demand scenario (PJ/year)	0	0	0	6	11	17	22
High demand scenario (PJ/year)	0	10	20	39	58	78	87

Table 9.2: Forecasted hydrogen demand in mobility in the Netherlands (Leguijt et al., 2018)

9.2 Green gas

The economic assessment of green gas could be divided along three stages in the value chain. These are green gas production, green gas transportation and green gas utilisation.

9.2.1 Green gas production

At the moment, the production of biomethane is presumed to operate primarily at a smaller-scale. This results from mainly small-scale and agricultural production of biogas. Moreover, due to low percentage of dry matter and quick emissions of landfill gas the transport of feedstock product, mainly manure, over longer distances is limited. Therefore, biogas production occurs in a range of [10-50] km from the waste stream. After production, biogas is upgraded, compressed and odorised. Then, based on assumptions with regards to the costs for production and upgrading the average unit costs of biomethane is determined to be around 100 €/MWh. This is based on a production capacity of 1.4 MW, a lifetime of 20 years, operating hours of around 8,000, CAPEX costs of 38.4 €/MWh, electricity input of 0.03 kWh/kWh biogas, other OPEX of 34.5 €/MWh in the case of biogas production, and investment costs of around €3 million in case of membrane separation with OPEX of around €660,000 per year. The latter results in upgrading costs of membrane separation of around 22 €/MWh and is depicted for a production capacity of around 5 MW

(Moraga et al., 2019).

However, this estimate is highly dependent on the actual feedstock costs. For example, the use of manure could result in negative input costs and thereby lower the production costs. Other factors that impact the biomethane production costs are shown to be associated with infrastructure, upgrading, electricity demand, other OPEX and the CAPEX. Overall, it is shown that the CAPEX account for around 40% of the cost per MWh of biomethane. On top of that, the other OPEX contribute around 35%, while operational costs include upgrading contribute around 18% (Moraga et al., 2019). However, economies of scale could reduce the cost associated biomethane production costs. This is especially relevant since the investment cost make up approximately one-third of the total costs (Moraga et al., 2019).

Ultimately, Moraga et al., 2019 indicate a break-even price for biomethane in the range of [5-200] €/MWh, where the higher end is primarily through the use of feedstock that is attributed higher valorisation potential. These include for example energy crops. In contrast, the lower end accounts for manure and is dependent on the market prices for manure collection. This results overlaps with generic results over Europe, showing a break-even price for biomethane of around [60-120] €/MWh (Moraga et al., 2019).

However, potential cost reductions with respect to the biomethane production costs are an emerging trend. At the moment, the production costs of AD biomethane are estimated to range from [50-90] €/MWh or [0.50-0.90] €/m^3. In this respect, the range depends, primarily, on the feedstock used and the digester size. Therefore, an increase in AD plant size and a renewed focus on waste stream- and residue feedstock could support the expected cost reductions. Moreover, a shift in upgrading technique towards membrane separation is expect to result in a gradual cost reduction for biomethane production (Wouters et al., 2020).

For example, the average increase in digester size was around 4% between 2017 and 2018. However, the average plant size in the Netherlands is still presumed to be small with an capacity of around 0.40 MW_{el} or around 400 Nm^3/hr output. This is in contrast to Belgium, with an average capacity of around 1.0 MW_{el}, or Spain with an average capacity of around 1.4 MW_{el}. Next, to the increase in digester size, it could be observed that waste- and residue streams are increasingly utilised as biogas feedstock as opposed to dedicated energy crops. In this respect, the contribution of waste- and residue streams as input stream increased from 40% in 2012 to 63% in 2019 (Wouters et al., 2020).

More specifically, an overview of the most important parameters in the AD biomethane production process can be seen in figure 9.14. Here, it can be observed that the average feedstock cost are around [19-36] €/t dry matter. However, in case of the utilisation of waste products these cost generally range from negative to zero. As example, large-scale manure digestion with an output of around 1,000 Nm^3/hr shows an average production cost of around 70 €/MWh. However, this could be reduced, for example through scaling, to around 50 €/MWh (Wouters et al., 2020).

Overall, the production costs of biomethane are expected to decline to around 47 €/MWh by 2050. Moreover, the sales of organic fertiliser might support additional positive cross-sectoral benefits (Wouters et al., 2020). Also, vectoring out the cost of biomethane that are associated with the enhancement of sustainable farming, soil enhancement, waste management and increased biodiversity could lower the associated production costs. This could for example be stimulated through additional price benefits besides the energy price (Schimmel et al., 2021). On top of that, Schimmel et al., 2021 argue for additional support schemes to support the market ramp-up and cost reduction of biomethane production. This could, for example, be achieved through setting a target for renewable gas uses. As a result, this could support investments, lead to larger production plants and trigger a learning curve to bring down the costs and ensure the increased availability of affordable biomethane (Schimmel et al., 2021).

	Size digester (Nm^3/hr)	CAPEX (€/MWh) biogas digester*	OPEX (€/MWh) biogas digester*	Biogas to biomethane upgrading* (€/MWh)	Feedstock cost (€/tDM)*	Maturity level
Small	100	25	22	5 - 12	0-120 Average in Europe:[6] 19-36	Mature
Medium	500	20	17			
Large	1,000	15	12			
Very large	>2,000-3,000	Not available[29]	Not available[29]			

* Costs converted from USD/MBtu and rounded, with $1 = €0.85.

Figure 9.14: Overview of cost drivers in the AD biomethane production process (Wouters et al., 2020)

However, the current production costs for biomethane are stated range from [2-5] times the price of natural gas in the wholesale market. This presumes production cost for biomethane of [40-100] €/MWh and is based on a natural gas price of 20 €/MWh. However, due to the negative externalities associated with natural gas, is is stated that there exist a clear economic rationale for the support of the production of green gas. In this respect, the actual financial support could be determined by the maximum of the externality and or could be combined with the value of other regulatory measures to internalise the externality. This is then compared to the additional cost of biomethane as compared to natural gas. In this case the support will allow for smooth- and rapid market presence of biomethane as well as has potential for other renewable gases (Moraga et al., 2019).

The need for economic support is also recognised through subsidies for biogas generation in the Netherlands. Here, the required economic support is based on financial-economic parameters related to the different production methods- and applications for biogas generation.

For example, in the case of large-scale biogas generation from waste streams in the food- and beverage industry input costs are based on the market price of biomass of around 28 €/t. In contrast, the utilisation of small- and large-scale mono-manure AD uses primarily self-produced manure with an associated input price of 0 €/t. The expected feedstock cost of manure also accounts for balancing the negative gate rate without AD with additional costs of administration-, disposal- and processing of digestate in case of AD. Moreover, an average biogas yield of 25 m^3/t manure or 0.53 GJ/t manure is assumed. This is in contrast to an average biogas yield of 3.4 GJ/t food- and beverage waste (Wolbers et al., 2021).

An overview of the respective financial-economic parameters for the production of biomethane from mono-manure digestion for the year 2022 can be seen in table 9.3 (Wolbers et al., 2021). Here, in case of small-scale AD the reference installation has a raw biogas production of around 47 m^3/hour or 30 m^3/hour of biomethane.

Moreover, the electricity is procured from the grid and heat demand can both be produced internally or externally, at a price of around 7.5 €/GJ. The total investment cost are around €0.9 million and the fixed O&M cost are €92,000 per year. In the case of large-scale mono-manure AD the reference installation decreased from 5.5 MW or 750 m^3/hour raw biogas in 2021 to 2.2 MW in 2022. This is a result of the increased insecurity in the manure market, which hindered centralisation and scaling of the biogas- and biomethane production. However, for large-scale installations the projects are seen to differ significantly in size and range from 0.4 MW all the way up to 19.5 MW. Nonetheless a lower realisation potential is observed in the higher range. The new reference installation therefore has a production capacity of around 381 m^3/hour raw biogas or 248 m^3/hour biomethane with a manure input of around 120 kton per year, consisting of a 80/20 ratio of slurry/thick fraction. The total investment cost are around €5.4 million and the fixed O&M are €0.64 million per year. Moreover, in case of external heat provision a price of 5 €/GJ is presumed (Wolbers et al., 2021). On top of that, in case of the life extension for small-scale mono-manure digestion the lower associated investment costs reduce the subsidy requirement. Here, investment cost of around €0.5 million are shown, which reduce the or subsidy base amount of 0.0722 €/kWh, which could be used for the renovation of the digester- and or upgrading system. In contrast, an investment of €0.65 million or subsidy base amount of 0.0764 €/MWh is needed in case of the conversion to green gas production instead of heat- and or electricity production from biogas (Wolbers et al., 2021).

Parameter	**Unit**	**Small-scale 2022**	**Large-scale 2022**	**Large-scale 2021**
Reference size	kW_{in}	270	2,200	5,500
Load hours	hour/year	8,000	8,000	8,000
Internal heat	% biogas	18	16	16
Investment cost (IC)	€/kW_{in}	3,300	N/A	N/A
IC digester	€/kW_{in}	N/A	2080	1980
IC upgrading	€/kW_{out}	N/A	370	350
Fixed O&M cost	€/kW_{in}	340	291	291
Energy-content input	GJ biogas/t	0.53	0.53	0.53
Feedstock costs	€/t	0	0	0
Subsidy base amount	€/kWh	0.0930	0.0741	0.0722
Duration subsidy	year	12	12	12

Table 9.3: Techno-financial-economic parameters for biomethane production, including subsidy requirement (Wolbers et al., 2021)

In contrast, I. U. Khan et al., 2017 focused specifically on the upgrading of biogas. In this respect, (I. U. Khan et al., 2017) investigate the commercialisation- and economic assessment of the different upgrading methods and applications. This includes the relevant investment-, and operating and maintenance costs. Here, based on a throughput of 1000 m^3/h of raw biogas, membrane separation shows the highest technical availability per year of 98% at a good cost perspective with maintenance cost of 25,000 €/year. In this respect, only high-pressure water scrubbing shows lower maintenance costs and effectively a lower contribution to OPEX and possibly CAPEX (I. U. Khan et al., 2017). In case of energy requirements, membrane separation shows an average low energy need of [0.19-0.378] kWh/m^3 of biogas. In contrast, the lowest energy demand is associated with chemical scrubbing, however the estimates show a wider range of values (I. U. Khan et al., 2017).

Ultimately, the capital- and operating costs depend on the process, quality of raw biogas, desired product quality and, possibly most important, capacity of the plant. The latter relates to the fact that even at low capacity, similar number of auxiliary components will be needed, despite smaller dimensions. In case of membrane separation, the average assumed CAPEX are 0.12 €$/Nm^3$ of biogas. However, the capital costs for 100, 600 and [700-1400] m^3/h biogas are 6,600, 2,500, and 2,200 USD$/m^3$ biogas per hour respectively (I. U. Khan et al., 2017).

Additionally, Angelidaki et al., 2018 investigated the incentives and feasibility of the biogas upgrading concepts. In this respect, Angelidaki et al., 2018 identified the economical payoff of biogas upgrading as opposed to electricity- and or heat production for raw biogas. This becomes increasingly important as a result of the high share of fluctuating power production and the cost-inefficient storage potential for biogas. In this respect, biomethane increases the storage option from a few hours to over a few months. As a result, biomethane provides can utilise the value of flexibility, which is especially apparent in those periods of high demand for power. On top of that, the heat- and or electricity production from biogas is presumed to required continuous operation. As a result, the biogas produced heat- and or electricity has a higher potential to replace the share of renewable electricity generation. This in turn lower the relative environmental benefits of biogas.

The cost of biogas upgrading, are in turn mainly dependent on the biogas flow and the economy of investment scale (Angelidaki et al., 2018). Here, the specific investment cost are based on €$/Nm^3/h$ and are seen to remain flat for capacity levels of around [1000-2000] Nm^3/h raw biogas at around €1000 for OPEX and €1200 for CAPEX. However, the ultimate specific upgrading costs in €/kWh biogas start to flatten at a biogas flow of around [40-80] Nm^3/h at a production costs, including both OPEX and CAPEX, of 0.02-0.04 €/kWh (Angelidaki et al., 2018). This is opposed to a sales prices for biomethane, including subsidies in Denmark, of 0.084 €/kWh. Another perspective indicate a total cost of upgraded biogas, including OPEX and all amortized CAPEX, to be [0.058-0.078] €/kWh (Angelidaki et al., 2018).

Moreover, Struk et al., 2020 investigated the costs comparison of the relevant physicochemical biogas upgrading technologies. Here, membrane separation show the smallest cost range of around [305-367] €/kWh for capital costs. However, this is as opposed to lower, but wider range values, for PSA and chemical scrubbing of [255-821] €/kWh and [264-438] €/kWh respectively. Nonetheless, the O&M costs show a significant range for membrane separation of [0.79-5.50] €/kWh. Here, only PSA and cryogenic separation show a higher range value. In this respect, water scrubbing and physical scrubbing show the lowest expected O&M costs of [0.47-0.97] €/kWh and [0.92-1.05] €/kWh respectively (Struk et al., 2020).

9.2.2 Green gas transportation

The grid injection volumes of biomethane increased fourfold over the past decade and is expected to boost its share in the average gas network another ten- to twenty times up to [5-8]%. This is simulated by early commercial deployment of centralised biomethane upgrading facilities and by the development of plants for reverse flow. Moreover, the development op biogas pooling further stimulates the centralisation trend (Wouters et al., 2020).

In this respect, biogas pooling lowers the costs associated with more costly- and smaller-scale individual gas grid connections. Moreover, biogas pooling supports economies of scale with respect to the upgrading facility. On the other hand, the reverse flow plants helps to limit local oversupply, especially in summer months by stimulating the flow upwards to higher pressure grids. Here, additional costs include the enhancement of pressure for the transport network and is affected by the operational hours. However, in basis only limited investments are required. Nevertheless, trade-off between the direct transport and a network connection could exist (Wouters et al., 2020).

Since most biogas upgrading facilities are located close to gas grids, the grid connection- and injection costs are assumed to be limited to around 5% of the total production costs, or an average of around 4.7 €/MWh per year. However, this does not include additional costs like the cost for a biogas pipeline and pipelines from the biomethane facility to the gas grid. In the respect, the total biomethane network costs are estimated to be around 9.7 €/MWh. Nevertheless, differences across regions exist with respect to the grid connection types, including distribution connection, transport connection and no grid connection. For example, in this regard France is developing a national biomethane planning framework. Here, France aims to map the high potential zones for biomethane production with the available grid connections (Wouters et al., 2020).

9.2.3 Green gas demand

The developments in supply of biomethane also helped to gain interest in biomethane as alternative to natural gas. For example, in applications of medium- and high temperature heat generation, and as feedstock including for hydrogen production. Moreover, biomethane is seen as energy carrier which could support the facilitation of process integration through grid injection (Wouters et al., 2020). In this way, biomethane allows for rapid- and high GHG savings. Moreover, biomethane could even boost negative emissions while improving waste management, at little associated technological risks (Schimmel et al., 2021). However, the current use cases of biomethane show strong differences across regions. For example, there is a high demand for electricity production in CHP units in Germany. In contrast, there is an equal and complete use of biomethane in the industry- and heating & cooling sector in Denmark. Moreover, biomethane if for 100% used in the transport sector in Italy (Wouters et al., 2020). In the case of biomethane usage in the transport sector, bio-CNG and bio-LNG see an increase in uptake. This is especially prevalent in heavy, road transport which is supported by a strong growth in LNG compatible buses and heavy freight trucks. In this respect, biomethane currently represents around 17% of all the gas used in road transport. This is also stimulated by an increase in LNG- and CNG fuelling stations. Moreover, an early trend in the deployment of bio-LNG for shipping can also be observed (Wouters et al., 2020).

For the utilisation of biomethane, specifically bio-LNG, Uslu et al., 2021 show the techno-financial-economic parameters and associated subsidy requirement. In this case, the bio-LNG is primarily for the use in the transport sector. Here, the boundaries are the input of biomass until the production of biofuel. Moreover, the process is based on mono-manure AD biogas production. The biogas upgrading occurs to [96-99]% biomethane purity and includes the removal of H_2S via active carbon, the removal of moisture, and the removal of other contaminants. Moreover, the removal of CO_2 occurs via membrane technology. Lastly, bio-LNG is obtained through liquefaction via the Brayton-cyclus. However, potential additional infrastructure needs are not considered.

The implemented bio-LNG installation capacities are around [500-1,500] Nm^3/hour biogas and are mostly suited for large-scale mono-manure digestion. This results in the production of around 440kg bio-LNG per hour and requires a manure input of around 300 kt per year (Uslu et al., 2021). The total investment costs, including downstream installed liquefaction, upgrading and digestion, are around €10.9 million for the digestion installation and €4.5 million for the upgrading- and liquefaction process. The O&M costs are assumed to be €1.9 million per year for the digestion and upgrading process, while for the liquefaction the fixed O&M costs are assumed to be 10% of the total investment costs of liquefaction. The variable costs also include the costs of electricity usage. Ultimately, this result, for an input capacity of 5.5 MW, 8,000 load hours and a thermal efficiency of 99%, based on MW bio-LNG per MW biogas, in investment costs of 1980 $€/kW_{in}$ for digestion and 820 $€/kW_{out}$ for upgrading and liquefaction. Moreover, the fixed O&M costs are around 290 $€/kW_{in}$ per year for digestion and upgrading and are 47 $€/kW_{out}$ for liquefaction. On top of that, the variable O&M costs are around 0.0055 $€/kWh_{out}$. This ultimately, results in a subsidy requirement of 0.088 €/kWh in the case of bio-LNG production via mono-digestion. Here, the subsidy requirement is slightly higher than the subsidy requirement in case of all-digestion from the food- and beverage industry, which is 0.0814 €/kWh. Lastly, this indicates CO_2 subsidy intensity of 166 €/t CO_2-eq for the use of bio-LNG from mono-manure and is based on a reduced emission factor of 0.389 kg CO_2-eq/kWh (Uslu et al., 2021).

9.3 Bio-hydrogen

The hydrogen production via traditional SMR consists for [45-75]% of the actual fuel costs. The variation is explained by the relative fuel costs prices per region. Moreover, an approximate additional [30-40]% of methane fuel is required, next to the usage as feedstock, to support the process heat requirement. Moreover, in the case of SMR, the CAPEX make up most of the other production costs and, as proxy, contributes twice as much as compared to OPEX. The relation between capital- and operational expenditure in apparent in both the design with- or without CCUS technology (IEA, 2019). Moreover, the hydrogen production scale significantly impacts the production costs. Here, in case of SMR the hydrogen production costs are estimated to decrease by [20-30]% when the capacity is increased from 100- to 500 tonnes of hydrogen per day (IEA, 2019). As a result, the increase in capacity if offset by the increase in production volume (Lepage et al., 2021). The effect of economies of scale is more apparent for the ATR process, since given the SMR process is described to encounter manufacturing limitations at higher production levels. For example, while SMR is presumed to scale up to 350,000 Nm^3/h syngas, the ATR technology could scale to 1 million Nm^3/h syngas (Wouters et al., 2020). On top of that, next to the CAPEX and feedstock cost, other parameters that impact the OPEX are relevant. These include for example process conditions related factors. For example, the energy- and electricity requirements for heat and pressures. Moreover, type-, volume- and cost of catalysts have an impact on the OPEX. On top of that, external factors like policies and taxation could influence the hydrogen production costs (Lepage et al., 2021).

However, the hydrogen production- and CO_2 capture technology costs could be lowered through enhancement of the efficiency. Other potential improvements relate to industrial symbiosis, project size and the actual capture technology (Wouters et al., 2020). In this respect, the ATR process shows favourable economics- and operations at large scales. The latter is especially relevant in combination with capture technology. Here, new capture technology, including process intensification options, help to increase the capture rate and reduce the system costs. Additionally, the integration of the pure oxygen by-product from e-hydrogen production could stimulate the ATR production process. Moreover, this could help to further reduce the indirect emissions (Wouters et al., 2020).

Overall, the costs for hydrogen production from natural gas with CCS is stated to be in the range of [37-41] €/MWh. This estimation is based on natural gas price of 15 €/MWh, which was based on historical low natural gas prices. Moreover, the price range depends on the actual technology and infrastructure requirements. In this perspective the lower cost range was attributed to ATR technology in comparison to SMR (Wouters et al., 2020). However, in case a carbon tax is added to the hydrogen production costs, this would translate in an increase of approximately 0.1 USD/kg for every 10 USD/t CO_2 price addition in carbon tax (van Wijk, 2021).

At the moment, high-pressure ATR is the preferred hydrogen production technology due the advantages of economy of scale and the operational flexibility H-vision, 2019. In this respect, a large-scale centralised setup is enables maximum utilisation of the economy of scale. Moreover, a centralised setup allows for potential steam- and utilities integration, which can further stimulate cost reductions and boost the business case. On top of that, the large-scale, centralised hydrogen production also supports the adoption of CCUS technology. This relates to the transport- and storage of CO_2. In this respect, the compression-, transport- and storage of CO_2 is presumed to add approximately [17-30] €/t H_2 to the commercial unit costs based on the tariff costs. However, the technical costs for the addition of CCUS technology on the large-scale hydrogen production facility might be limited to [8.6-11.9] €/t (H-vision, 2019).

Moreover, in case of large-scale deployment of hydrogen production, it is mentioned that nominal pipe size for hydrogen transport is ultimately related to the size of the transport capacity in GW_{th}. The nominal pipe size subsequently shows an increasing relation with respect to the costs per kilometer. On top of that, the length of transport and the end application determine the necessity of additional recompression steps (H-vision, 2019).

Additionally, for the large-scale storage of hydrogen, underground salt caverns is indicated to be the most cost-effective option. Here, also clear economies of scope exist where ground facilities can be shared to limit the additional investment costs of extra salt caverns. In this case, the fixed investment costs of a one system is estimated to cost around €7 million, while an additional cavern is expected to only add an additional [2-3]% to the storage costs. However, in case of a smaller plant layout and demand requirements, no storage facility might be necessary. In this respect, the required flexibility could be generated through ramping production up and down between [10-110]% of the ATR production capacity (H-vision, 2019).

Overall, in case of fossil hydrogen production via ATR equipped with CCUS technology the components of the economic model can be seen in figure 9.15. Here, it can be observed that OPEX hydrogen production are primarily determined by natural gas input. On top of that, the CO_2 transport and storage costs also have a significant impact on the net present value calculation. Moreover, with respect to the CAPEX the project indicates strong economies of scale with a 50% reduction in CAPEX as compared to a plant that would have 10 times lower capacity. In the other hand, the costs are presumed to be primarily regenerated through sales of hydrogen. Moreover, additional value is regenerated via the value of saved carbon emissions which can be priced in (H-vision, 2019).

Nevertheless, in case of hydrogen production the system costs have to be evaluated. In this respect, economic quantitative key performance indicators for the production-, conversion-, transportation-, storage- and reconversion of hydrogen can be defined (Kennedy et al., 2019).

These indicators include equipment costs, the CAPEX and the OPEX. In this instance, latter two are characterised based on different units of production. This subsequently allows for easier comparison among the different hydrogen production option. Additionally, in case of CAPEX, also the relevance of capacity is taken into account. Moreover, in case of transportation, the indicators show the costs per kilometer as unit. Next to the normalisation of the results, the equipment costs are used to identify the contribution of installation on the fixed capital investment. In contrast, the CAPEX are used to refer to the total fixed capital investments of both direct- and indirect costs. Ultimately, the key indicators are also annualised based on the capital expenditures over the economic lifetime. With respect to the OPEX, these account for the raw materials costs, utilities costs, maintenance costs, labor costs, fixed & general and overhead costs. Moreover, it should be noted that the respective parameter assume the utilisation of natural gas as opposed to green gas (Kennedy et al., 2019).

Ultimately, an overview of the economic key performance indicators over the hydrogen value chain can be seen in table 9.4 (Kennedy et al., 2019).

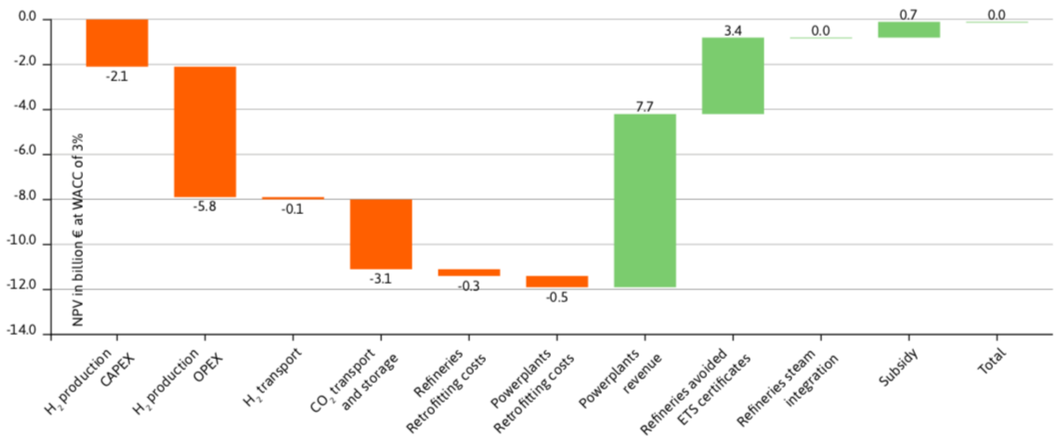


Figure 9.15: Components of the economic model, over costs and revenues, for the H-vision process (H-vision, 2019)

Research results

In case of hydrogen production for utilisation in a local HRS, Matton et al., 2016 focuses, among other, on the economic performance of the different hydrogen value

Process stage	Process step	Equipment/CAPEX (M€)	CAPEX (M€/y)	CAPEX ((€/y)/kg H_2)	OPEX (M€/y)	OPEX (€/kg H_2)
Production	SMR	234/1223	102.5	0.31	unk.	unk.
Production	ATR-CCS	224/1070 (ex CO_2)	89.7	0.27	3060	1.1
Production	DMR	unk./442	35.33	0.2	331	1.8
Conversion	High-P H_2	1.04/2.61	0.21	$4.4E^{-07}$ per GJ	0.225	$4.73E^{-07}$ per GJ
Conversion	Liquefied H_2	unk./39.6	4.7	$2.24E^{-05}$ per GJ	6.4	$3.07E^{-05}$ per GJ
Transport	Pipeline H_2 backbone	1700 (M€/1000km)			N/A	
Transport	Pipeline H_2 regional	N/A	5.13 (€/MWh/y)		N/A	
Transport	Pipeline H_2 existing	0.703 (M€/km)	0.018 (M€/y/km)		0.028 M€/km/y	
Transport	Road cryogenic truck	313 €/t H_2 per km			N/A	
Transport	Road compressed H_2	3.4 €/t CGH_2 per km			N/A	
Storage	Salt caverns	unk.	1.1	unk.	0.04	unk.
Storage	Gas fields	unk.	unk.	unk.	unk.	unk.
Storage	Cryogenic tank	unk.	500	unk.	0.025	unk.

Table 9.4: Economic criteria over and for different process stages and steps in the hydrogen value chain (Kennedy et al., 2019)

chains. Here, the economic performance was defined as €/kg H_2 and includes the CAPEX, OPEX, energy costs and external costs or subsidies.

In this respect, the physical delivery of biogas via pipeline scored better than hydrogen production via grid injected green gas and especially better than physical biomethane delivery via truck. However, the biogas route is strongly dependent on the biogas price and the investment costs for the new pipeline. For example, the use of green gas via the grid add an additional [0.29-0.70] €/kg H_2 to the cost price. This was primarily a result of the purchased guarantee of origin (GO). Moreover, in the case of physical green gas delivery no subsidy is obtained as compared to grid injection. This is on top of the higher cost associated with the transport via trucks as compared to pipeline transport (Matton et al., 2016).

In a similar fashion, Albrecht et al., 2016 identified the well-to-tank presumed hydrogen production costs for the year 2030. Here, BSR seems to outperform other pathways except for fossil-hydrogen and e-hydrogen. More specifically, BSR shows a cost for compressed gas (CG) hydrogen of around 5.80 €/kg. This includes the assumed revenue for biowaste treatment. In contrast, fossil hydrogen was attributed a production cost of 5.20 €/kg. In this case of BSR, the largest contribution of 2.39 €/kg came from the CAPEX. The other costs were attributed as 1.54 €/kg for OPEX, 1.59 €/kg for the HRS and 0.31 €/kg for H_2 compression. Moreover, the hydrogen storage was assumed to have an insignificant contribution (Albrecht et al., 2016).

In contrast, Holstein et al., 2018 make the case against smaller-scale hydrogen production, of around 10 kg H_2/hour. In this perspective, the small-scale hydrogen production is compared to a [5,000-10,000] kg H_2/hour larger-scale production facility. Here, the assumed relative investment costs are a factor 25 times higher for small-scale steam reforming at 725,000 €/(kg per hour). Subsequently, this negatively affects the hydrogen production costs which could show to be a factor 10 higher as compared to the reference large-scale hydrogen production. Next to the increase in relative CAPEX, also a decrease in system efficiency and an increase in fixed yearly operation costs could be observed (Holstein et al., 2018).

More specific, Braga et al., 2012 focused on the economic feasibility of the BSR process. Here, an estimated hydrogen production costs of around 0.27 USD/kWh H_2 was stated. Moreover, a payback period of 8 years was stated, which was based on the expected annual revenues of the obtained products. This was based on the presumed amortisation of the investment costs and was shown based on the hydrogen costs, which became independent of the operating hours. However, the process relates to an ultra small-scale hydrogen production of 1 Nm^3 or 0.008 kg H_2/h output with a biogas inflow of 0.34 kg/h. Here, the reformer investment costs are $15,000 and the biogas generation costs are 0.0518 USD/kWh. Moreover, the study lacked the perspective on the value of bio-carbon dioxide. Ultimately, due to alteration of key variables in the process, a significant hydrogen production cost margin can be observed. Therefore, the hydrogen production cost are assumed to range from [0.2-0.5] USD/kWh (Braga et al., 2012).

In contrast, Yao et al., 2017 focused on large-scale production hydrogen via BSR. Here, the investment costs are assumed to be around €9.9 million and the OPEX around €4.3 million. This in turn resulted in an after-tax H_2 break-even price of around 0.152 EUR/kWh. In this case, the investment costs in later years were adjusted using the chemical engineering plant cost index, while an order-of-magnitude estimate and capacity rationing was deployed to adjust plants and units of different sizes. Moreover, the plant startup expenses was determined to be 10% of the calculated capital costs. On top of that, in case of production costs both detailed- and factored estimates were used, where detailed estimates were used for raw materials, operating labor and utilities. In contrast, the factored estimates consisted of a percentage of operating labor or of investment costs. Here, also the straight-line depreciation method was used (Yao et al., 2017). In the end, the process used 3,433 kg/h wet maize silage and 437 kg/h water to produce 90 kg/h H_2. The investment costs consisted of around €4.5 million for the AD plant including desulphurisation unit. Moreover,the other €4.4 million investment costs was attributed to the reforming unit. With respect to the operational costs, around 40% consisted of the raw maize silage feedstock material. On top of that, operating labor accounted for around 8%, utilities for around 5% and depreciation for 12%, while the rest was attributed to other cost. This resulted, based on the expenses versus the hydrogen flow rate and annual operating hours, in a before tax break-even price of 0.18 €/kWh. However, it was mentioned that the after-tax break-even price could reduce to below 0.10 €/kWh based on feedstock cost of 0 EUR/kWh. This was in line with the observed relatively strong sensitivity of the break-even price to the feedstock price (Yao et al., 2017).

In case of the BioRobur process, Camacho et al., 2017 performed a techno-economic analysis for a 100 Nm^3/h green hydrogen production of high purity. The results indicated a hydrogen delivery cost of around 5 €/kg H_2. However, the hydrogen delivery cost could decrease to 2.5 €/kg H_2 for periods after the 10 years of amortization (Camacho et al., 2017).

In this respect, the used municipal solid waste feedstock was assigned a price of 0 €/t. Moreover, the biogas yield was assumed to contain a [55-60]% CH_4. This was in contrast to the usage of pig slurry, cow slurry and pig manure which were assigned costs of 2, 5 and 5 €/t respectively. However, all were assumed to yield an biogas with approximately [60-65]% CH_4. Moreover, the CAPEX included both direct- and indirect costs. Here, direct cost include the equipment, raw materials and instrumentation, while the indirect costs are derived from the supervision and construction activities. More specifically, these are classed as main equipment, structures, piping and valves, electrical works and materials, process instrumentation and controls, insulation, engineering and supervision, and construction. This ultimately yields a CAPEX of €872,000 of which €703,000 relates to direct costs. In this respect, the highest contribution came from the reactor including the catalyst of €250,000. Moreover, the PSA unit including filling contributed €115,000. On top of that, €169,000 was assigned to the indirect costs of engineering and supervision, and construction expenses (Camacho et al., 2017). With respect to the OPEX, these are divided into three main sections, namely streams, services and items. The OPEX were calculated to have a total cost of €93,091 per year. Here, the highest contribution arises from O&M with €26,160, at 3% of CAPEX. Moreover, the spare parts contributed €20,000, the PSA electrical consumption €19,473, and the desulphurisation accounts for €8,000 (Camacho et al., 2017).

Ultimately, the results show a hydrogen production cost of 5.36 €/kg H_2 based on 3 year amortization. The hydrogen production cost decrease to 2.52 €/kg H_2 for 10 year amortization. Moreover, the production cost flatten below €2 €/kg H_2 for amortization time over 15 years (Camacho et al., 2017). Moreover, in case of scaling of the production, the CAPEX are assumed to scale based on a factor of 0.6, with respect to the ratio in sizes for the CAPEX estimation. In contrast, the OPEX are assumed to scale linearly. Moreover, based on an amortization time of 4 years, the cost decrease from 4.34 €/kg H_2 for a size from 100 Nm^3/h of hydrogen to 2.7 €/kg H_2 for a size of 700 Nm^3/h of hydrogen. However, based the production scale, the production costs are also shown to be sensitive to, a combination of, production time, hydrogen production, and amortization time (Camacho et al., 2017).

In the BIONICO project, Marcoberardino, Vitali, et al., 2018 discussed the techno-economic assessment of hydrogen production via BSR, BATR and membrane reforming for both AD- and landfill biogas. Here, it was shown that the production cost of hydrogen via the BSR route amounts to around 5 €/kg H_2. This was based on a hydrogen production target of 100 kg/day at 99.999% purity and 20 bar delivery pressure operating 7,500 hours.

Here, the total plant cost consists of consumables, auxiliaries and fixed costs and is calculated via the bottom-up approach through the summation of basic components- or equipment costs, installation costs, indirect costs and contingencies costs. Moreover, scaling for the component costs was based on the CEPI index. With respect to the OPEX, the catalyst-, biogas feedstock-, electrical energy-, water-, maintenance-, insurance- and labour costs are incorporated. Overall, the breakdown of equipment costs for both the BSR and BATR process and based on AD biogas can be seen in figure 9.16 (Marcoberardino, Vitali, et al., 2018). Here it can be observed that the VPSA unit, H_2 compressor and heat exchanger are the most important equipment costs for both BATR and BSR. However, the VPSA is more dominant in the BATR layout due to the higher impact and higher flow rate of process gas. In contrast, the heat exchanger cost is smaller due to thermal integration in the ATR process (Marcoberardino, Vitali, et al., 2018). Moreover, in case of the BATR process, it can be observed that both electrical energy represent a higher contribution due, among other, the electrical energy for the air- and biogas compressor.

Ultimately, the total plant costs of the BSR process are around €176,000, where €75,000 originates from the total equipment cost. In contrast, the BATR process has total plant costs of €220,000 and total equipment costs of €93,000. This subsequently yields a levelised cost of hydrogen ranging from [4.208-5.005] €/kg H_2 in the case of BSR and [6.373-7.323] €/kg H_2 in the case of BATR. Here, the range is, among others, dependent on the inlet- and outlet pressure requirement (Marcoberardino, Vitali, et al., 2018).

However, with respect to the membrane reforming process, Marcoberardino, Foresti, et al., 2018 show that the hydrogen production costs could be reduced to 4.0 €/kg

H_2 as opposed to the 4.2 €/kg H_2 in the case of the BSR process, at a delivery pressure of 20 bar. Here, the total installation costs were taken to be 65% more than the total equipment costs. In contrast, the total installation costs was assumed to be 80% higher than the total equipment cost in the BSR layout. This is attributed to the compactness and simplicity of the respective processes. However, the catalyst has a higher specific costs as opposed to the conventional reforming catalyst. Overall, the total plant costs at a delivery pressure of 20 bar are €[144,000-174,000]. In contrast, for a delivery pressure of 700 bar the total plant costs increase to €[191,000-221,000]. Moreover, total variable O&M costs are [35,600-36,100] €/y in the case of a delivery pressure of 20 bar and [47,300-47,800] €/y in case of a delivery pressure of 700 bar. Here, the difference relates to the use of VPSA technology or sweep gas in the layout. Moreover, the membrane cost have the largest influence on the total plant costs. In this respect, the process prefers higher pressures and higher quality AD biogas. On the other hand, the difference in auxiliary cost is limited.

Ultimately, the membrane reforming layout based on AD biogas with VPSA show the lowest costs of hydrogen per kilogram. Here, the CAPEX constitute around 15%, fixed OPEX around 45% and variable OPEX around 25%. The rest is attributed to hydrogen compression is case of a 700 bar delivery pressure. The results indicate a hydrogen production cost of 4.8 €/kg H_2 at a delivery pressure of 700 bar and 4.0 €/kg H_2 at a delivery pressure of 20 bar. The difference is attributed to the the hydrogen compression costs (Marcoberardino, Foresti, et al., 2018).

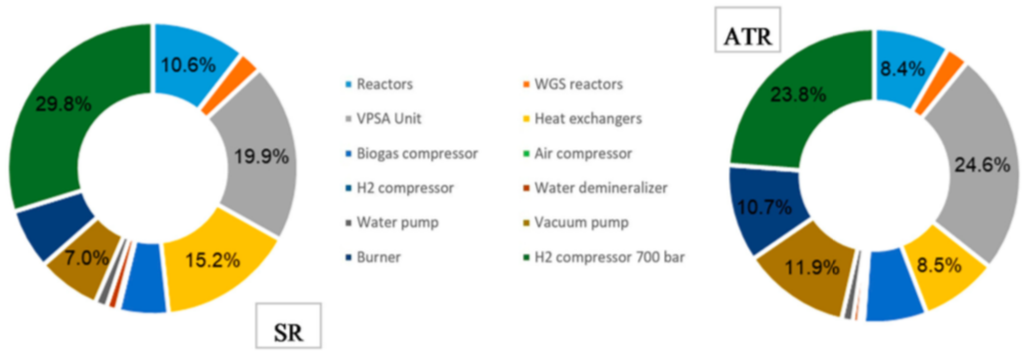


Figure 9.16: Total equipment costs of SMR and ATR for AD biogas (Marcoberardino, Vitali, et al., 2018)

Business case

[*Removed as confidential*]

9.4 Analysis

The concept of third-generation upgrading has been ascribed important relevance for local- and or regional bio-hydrogen production. This is especially relevant with respect to the potential to stimulate a rapid- and affordable energy transition. In this respect, the concept of third-generation upgrading allows for the devaluation of biomethane as compared to bio-hydrogen and bio-carbon dioxide, or syngas. Moreover, the concept of third-generation upgrading allows for the simultaneous production of valuable bio-carbon. Here, the exact valorisation potential is presumed to differ over time and location. As a result, the relevant economical parameters were analysed that relate to the production of bio-hydrogen and bio-methane. These include the hydrogen production costs via the levelised cost of hydrogen, the hydrogen delivery costs that incorporate, among other, the transport- and storage costs, and the total cost of ownership perspective. Moreover, it includes the perspective on negative carbon emissions and or bio-CO_2 utilisation. These economic parameters then serve to indicate the economic feasibility of the concept of third-generation upgrading.

It has been discussed that in basis the feedstock costs and capital expenditures are the main determinants to identify the economic feasibility of the respective hydrogen production routes. Moreover, related parameters can be used to assess the economic viability, including the production scale, production efficiency and operation conditions. On top of that, alternative economic parameters include the process requirements, carbon value, and external factors including by-products sales and the regulatory environment. However, besides the production costs, the system costs perspective might paint a more accurate picture with respect to the economic viability of the concept of third-generation upgrading within the proposed future renewable hydrogen system. This include, for example. the exact value chain design, consisting of the conversion-, transportation-, distribution- and storage options. In case of hydrogen storage, it was discussed that the levelised cost of storage are an important determinant for the storage option. Here, salt caverns have been attributed most potential in case of large-scale hydrogen storage, while for smaller-scale storage compressed- or liquid storage tanks show most relevance. In case of transport, the network design based on ship-, pipeline- and road transport has been mentioned. Here, for regional transport the network design mainly relates to the volume requirement and transport distance. In this respect, the larger the volumes and distance, the more pipeline transport outweigh road transport as the preferred mode of transportation. However, in case of local production- and utilisation of hydrogen the additional costs of the storage- and transport of hydrogen could be eliminated or reduced.

In case of the demand for hydrogen, this is expected to arise from the industrial-, transport-, build environment- and power sector. Here, the total cost of ownership perspective becomes increasingly relevant, with related parameters like the feedstock costs, CAPEX and OPEX. Ultimately, the hydrogen delivery costs, carbon abatement cost and presumed competition from both conventional- and lower-carbon alternatives determine the expected adoption.

With respect to the economic parameters related to biomethane, the perspective on the production, transportation and demand is taken. Here, the cost have been addressed based on the relative contribution of the main factors influencing the production costs. These include the feedstock costs, CAPEX and OPEX. Here, the production scale, production process and respective technology have an important effect. In case of transportation, new initiatives are surfacing that could impact the system perspective. These include biogas pooling and reverse flow. With respect to bio-hydrogen production, also the relevant economic parameters and cost perspectives have been shown. Here, several researches have tried to identify the ultimate hydrogen production costs with respect to the specific value chain design and reforming technology. Ultimately, the business case perspective was taken to identify the potential economic benefits of the biogas-to-hydrogen production method.

Next to the current cost perspective, several options for cost reductions have been identified. In general these relate to economies of scale and economies of scope in order to reduce the capital expenditures per unit of production. Moreover, the increased utilisation- and cost reduction of both renewables and residual feedstock aim to lower the ultimate cost per unit. This is further supported by continued research and development that, for example, could stimulate process efficiencies, produce alternative materials and or allow for the stimulation of alternative technologies. On top of that, from a system perspective the further infrastructural development, cross-sector integration and industrial symbiosis pose relevant areas for further cost reductions. Lastly, additional sales of by-products and other benefits could further stimulate the cost perspective.

Specifically, in the perspective of the future renewable hydrogen system, biogas has been attributed great potential as local- and or regional bio-hydrogen source. In this perspective, the commercialisation- and professionalisation of the biogas sector show relevance to improve the economic feasibility. For example, infrastructural development like biogas pooling support the scaling of the production volumes. This not only support cost reductions but also allow for the utilisation- and monetisation of additional output streams, like bio-carbon dioxide and bio-fertilisers.

Biomethane analysis

In relation to the production costs of biomethane, it can be seen that the current average biogas production capacity in the Netherlands is around 0.4 MW or around 400 Nm^s/h biogas. However, the average biogas production capacity in Belgium amount to 1 MW or even 1.4 MW in Spain. Moreover, while the reference size of large-scale biogas production capacities in the Netherlands was presumed to be 5.5 MW, this was corrected to 2.2 MW. Nonetheless, potential production capacities of 19.5 MW are discussed, despite lower realisation potential of large-scale production capacities. The scaling of the industry is especially relevant due to the cost benefits associated with economies of scale. Here, the CAPEX for biogas upgrading is discussed to lower from 6,600 to 2,500 and ultimately 2,200 USD/m^3 biogas in case of an increase in production volume from 100 to 600 and ultimately [700-1400] m^3/h biogas respectively.

In the same line, four different potential biomethane production capacities are discusses. These are small-, medium-, large-, and very large- installation sizes, where the digester size increase from 100 to 500, 1,000 and >2,000 Nm^s/h respectively. This would translate in an production capacity of around 1, 5, 10 and >20 MW respectively. The economies of scale are subsequently represented in both CAPEX and OPEX from 25 €/MWh and 22 €/MWh for small-size installations respectively to 20 €/MWh and 17 €/MWh for medium-size installation, and 15 €/MWh and 12 €/MWh for large-size installations. Hereafter, the additional biogas upgrading costs represent around [5-12] €/MWh. Lastly, the feedstock cost show a wide-perspective of values from [0-120] €/t dry matter, dependent on the actual feedstock usage. In this respect, the use of manure has been assigned a feedstock cost of [0-5] €/t dry matter.

Moreover, based on the actual subsidy requirement in the Netherlands, the relevant techno-economic parameters for a small-scale and large-scale reference installations that operate 8,000 hours per year are determined. Here, small-scale installations represent a size of 0.27 MW, while large-scale installations have a reference size of 2.2 MW. The subsequent investment costs are lowered from 3,300 €/kW_{in} for small-scale installations to a sum of 2,080 €/kW_{in} for the digester and 370 €/kW_{out} for the upgrading system. Additionally, the fixed O&M costs lower from 340 €/kW_{in} in the case of the small-scale installation to 291 €/kW_{in} for the large-scale installation. On top of that, the internal heat demand is lowered in case of the large-scale installation from 18% to 16% of the biogas demand. This could also be translated into an external energy need at an expected price of [5-7.5] €/GJ. Both installations are based on a manure input with an energy content of 0.53 GJ/t or 25 m^3/t with a cost price of 0 €/t. This translates into an expected manure input per year of 120,000 tonnes in case of the large-scale installation.

Overall, unit price points for the production of biomethane show widely diverging numbers. This mainly relates to the scale of production and cost of feedstock input. Here, the current unit cost price is show to be in the range of [60-120] €/MWh by one study or [50-90] €/MWh by another one. Nonetheless, the unit price is expected to decrease to [40-50] €/MWh as a result of professionalisation- and commercialisation of the industry. Another cost break down indicated a cost price of around 84 €/MWh with potential to lower to [58-78] €/MWh. In case of the former, the upgrading of biogas constituted around [20-40] €/MWh to the unit price. These unit prices were then placed in context by a reference historical low natural gas price of [10-20] €/MWh. Lastly, it was mentioned that in case of biomethane production the grid connection cost could amount up to [5-10]% of the production costs and in that case represented a cost of [4.7-9.7] €/MWh.

Thus, in the case of the Dutch subsidy scheme the unit price of methane production is presumed to lower from around 480 €/MWh to 360 €/MWh in the case the production scale is increased from a reference size of 270 kW_{in} to 2,200 kW_{in}. This could further be reduced to approximately 340 €/MWh in case of an installation size of 5,500 kW_{in}. However, in contrast internally a estimated biomethane production price of around [180-200] €/MWh is determined in the case of bio-hydrogen production. Moreover, other results indicate a unit price of [32-49] €/MWh based on the the respective digester size and upgrading costs, where the lower range assumed a capacity of around 10 MW and the upper range a capacity of 1 MW. The latter also shows more overlap with other individual study results. On top of that, it can be seen that in case of the Dutch subsidy scheme, the CAPEX of the digester constitute around 85% of the total CAPEX costs and over 70% of the total unit costs. However, this does not overlap with the results that show an almost equal division between the costs for biogas production and biogas upgrading. Lastly, according to the IEA the average cost of biogas production via anaerobic digester accounts for around [30-55] €/MWh, with an almost equal split in CAPEX and OPEX. Here, the difference is mainly attributed to the size of the digester (IEA, 2022).

As a result, in the context of the future renewable hydrogen system it is assumed to the biomethane production cost in the Netherlands could show a cost perspective of around [45-55] €/MWh This is based on a proposed production capacity of around [120-550] Nm^3/h green gas.

Bio-hydrogen analysis

In relation to the production of hydrogen is has been described that economies of scale play an important role with respect to the production costs. For example, it has been described that the hydrogen production cost could decrease by [20-30]% based on an increase in production capacity from 100 to 500 t/day hydrogen. Moreover, another result indicated that the CAPEX could decrease by as much as 50% due to an increase in plant size of a factor 10. More generally, with respect to the scaling of the production facility it was assumed that the CAPEX scaled with a factor of 0.6, as traditional industrial scaling factor. Lastly, a specific estimation showed a decrease in bio-hydrogen production cost from 4.34 €/kg H_2 to 2.7 €/kg H_2 in case of an increase in production from 100 Nm^3/h hydrogen to 700 Nm^3/h hydrogen.

A more precise cost breakdown in case of BSR for the local bio-hydrogen production in case of a HRS showed a hydrogen production cost of around 3.93 €/kg H_2, where 2.39 €/kg H_2 was attributed to the CAPEX and 1.54 €/kg H_2 to the OPEX. Moreover, this was in contrast to a fossil hydrogen production price of around 3.3 €/g H_2. Another study showed a before-tax production price of bio-hydrogen of 0.18 €/kWh for a production capacity of 90 kg/h hydrogen. This was based on a CAPEX of €9.9 million, which constituted €4.5 million for biogas production and €4.4 million for biogas reforming. Moreover, €4.3 million was assigned to OPEX, out of which 40% came from feedstock costs in the case of maize utilisation. However, in case the feedstock costs would be reduced to zero, the expected before-tax production price decreased to 0.1 €/kWh. On top of that, another study showed a production price of bio-hydrogen via BATR of 5 €/kg H_2 for a hydrogen production of 100 Nm^3/h. This was expected to be reduced to [2-2.5] €/kg H_2 after amortisation of the CAPEX for periods over 10 years. Here, the production costs included around €0.87 million for CAPEX and 93,000 €/year for OPEX. The last study indicated a hydrogen cost price of around 4.8 €/kg H_2 for the BSR process for a production of 100 kg/day hydrogen. This was expected to be reduced to 4 €/kg in the case of the membrane reforming process. Here, the actual production costs were strongly dependent on the delivery pressure requirements. For example, the compression costs in case of a delivery of 700 bar as opposed to 20 bar added 0.8 €/kg H_2 to the production costs. In case of the BSR, the production costs were made up of around €176,000 of CAPEX, where €75,000 was assigned to the equipment cost. An additional [65-80]% of the equipment costs were allocated to the installation costs. On top of that, around 36,000 €/year was contributed to OPEX. Overall, in case of the membrane reforming process, CAPEX contributed around 15% to the production costs, while fixed OPEX contributed around 45% and variable OPEX 25%.

Overall, a production price for bio-hydrogen production was given of 4.8 €/kg or 5.3 €/kg for the production of 150 Nm^3/h H_2 and 300 Nm^3/h H_2 respectively in the case of biomethane SMR. In another internal study the hydrogen production cost were mentioned to be around [0.82-1.0] €/Nm^3 H_2 and constituted for 0.25 €/Nm^3 of the biogas input, [0.3-0.35] €/Nm^3 of the biogas upgrading and [0.27-0.4] €/Nm^3 of the bio-hydrogen production.

On top of that, it was mentioned that alternative cost could arise from for example a carbon price. Here, a carbon price of 10 USD/t CO_2 would add 0.1 USD/kg H_2 to the production price. Moreover, in case of large-scale carbon capture technology, the market price would expected to increase the hydrogen delivery cost with an additional [17-30] €/t H_2 or technically only [9-12] €/t H_2. Also, the presumed end usage in a HRS could add another 1.59 €/kg H_2 to the hydrogen delivery costs, with an extra 0.31 €/kg H_2 assigned to hydrogen compression costs.

Thus, it was discussed that the hydrogen production costs could be reduced from around 4.34 €/kg for a production capacity of 100 $Nm3/h$ hydrogen to 2.70 €/kg for a production capacity of 700 Nm^3/h or from 5.3 €/kg to 4.8 €/kg when the production was increased from 150- to 300 Nm^3/h hydrogen. On top of that, it was indicated that the three steps in the production of bio-hydrogen from biomethane contribute approximately similar to the ultimate bio-hydrogen production costs. Also, in the case of BSR it was shown that the production costs of bio-hydrogen was almost equally divided over the biogas production and bio-hydrogen production plant. In contrast, earlier it was indicated that the biogas production could constitute almost [80-90]% of the ultimate biomethane price. As a result, in the context of the future renewable hydrogen system, both the direct reforming of biogas as well as the biomethane reforming process might show relevant economic conditions.

Overall, the current bio-hydrogen production costs are estimated to be around [90-160] €/MWh. This is in contrast to an estimated- and expected biomethane production cost of around [50-90] €/MWh and [45-55] €/MWh respectively.

Business case

To give an adequate representation of the economic feasibility of the concept of third-generation upgrading, the business case is used as methodological concept to give a more detailed overview of the relevant production costs, the potential development of the production costs and to include alternative factors besides the production costs. In this respect, the business case, for example, takes into consideration the sales of additional output products. Here, the sales potential of bio-CO_2 is of relevant importance. Additionally, the business case framework supports the incorporation of alternative use cases for, specifically, biomethane. On top of that, the business case methodology allows for a dynamic cost perspective through, for example, envisioned cost reductions that could result from economies of scale and or technological development. In the same line, several scenarios could be established that relate to the concept of third-generation upgrading perspective within the wider proposed renewable hydrogen system. For example, this includes an alteration of the process design and or process conditions to support the valorisation perspective over time and place.

To develop the business case, [*Removed as confidential*]. In this respect, three base scenarios could be established that rely on producer data with respect to the process requirement and costs. In case data was missing, the required data points were interpolated or scaled accordingly. Hereafter, based on producer flow stream information, the relevant mass balances with respect to the input-, throughput- and output flows were established.[*Removed as confidential*]. Here, assumptions with respect to process parameters, including conversion levels, capture rates and reaction mechanisms followed similar reasoning with respect to the process flow diagram. This includes a methane conversion and CO conversion of 90% and 95% respectively. Moreover, a hydrogen recovery rate of 85% was presumed, while the system carbon capture rate was 90%. Based on these numbers, the presumed additional biomethane input to fuel the process was around [30-50]%. Then, other relevant cost assumptions were incorporated based on producer data in order to establish an initial cost perspective. This includes an electricity price of 0.10 €/kWh, low maintenance requirements of 2.5% of the total investment costs, other CAPEX costs of around 6% and other OPEX cost of 170% based on 0.5 FTE costs. Lastly, the system has a presumed downtown of 5% per year and operates over a lifetime of 20 years. This originates from producer data and communication and overlap with the information from literature.

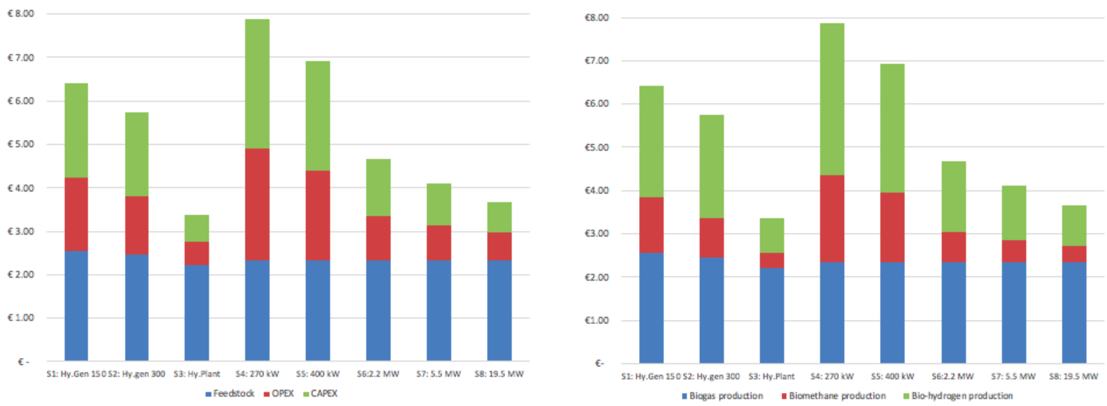
Next, several alterations to the production layout were made to draft a more complete overview of the potential process economics. In this respect, first the process was scaled to allow for the incorporation of production sizes in accordance to the proposed development of the biogas sector. This in turn allows for the presumed professionalisation- and commercialisation of the industry. Here, the respective production data points were scaled accordingly, while the process data remained similar. To do so, the plant investment costs were scaled based on respective scaling factors for the SMR technology and the membrane separation technology. Here, the SMR technology was scaled by a factor 0.6 based on the industrial scaling index that relate the cost development to the relation in capacity based on the ratio between volume and area. This relates to the strong focus on economies of scale in traditional hydrogen production facilities. In this case, the furnace like design of the SMR plant is used to justify the assumption. With respect to the membrane separation technology a lower scaling factor of 0.4 is used based on internal cost data for 120-, 500- and 1000 Nm^3/h biogas capacity installations. Hereafter, scaling factors for the production requirements are based on interpolation of the base scenario production data. Overall, this resulted in 8 scenarios of different production scale, ranging from [0.23 MW to 19.5 MW] biogas production installations. This excludes the HyGear plant size, which has a presumed production installation size of around 45 MW. In this respect, the HyGear plant production size is assumed not to align with the integration of biogas production. Therefore, the production size range from to the average small-scale biogas installation size- to the largest-scale production size in the Netherlands. However, extra emphasis was placed on the 5.5 MW installation as presumed reference size of large-scale installations in the Netherlands. This is due to the focus on commercialisation- and professionalisation of the biogas industry.

Then, based on the presumed reference installation size of 5.5 MW, alterations with respect to the plant scaling factor and plant requirements are made. More specifically, the SMR installation is presumed to scale at a higher scaling factor of 0.7 and 0.8 and the biogas upgrading installation is presumed to scale at a higher factor of 0.6 and 0.8 respectively. Moreover, the membrane technology is presumed to show a lower electricity demand, where a reduction of 50% and 75% are assumed to arise in accordance to literature data. Moreover, the internal heat demand for the SMR process is presumed to lower, thereby enhancing the bio-hydrogen production per Nm^3 biomethane. This relates, for example, to the usage of off-gas stream to fuel the process and improved heat integration of the process. Lastly, the price of biogas is presumed to lower by a factor 0.6 and 0.8. This can be explained by the presumed cost reduction in biogas production, which was assigned to the deployment of new digestion technology, the enhancement of production yield or efficiency, and or improved value chain design, among other. Moreover, the biogas cost reduction could also be justified by presumed improvements in the overall heat integration of the process to lower the internal heat demand. On top of that, it could indirectly reflect the additional sales potential of biogas via the sales of bio-fertiliser and or the internalisation of the additional environmental benefits assigned to the usage of bio-fertiliser. This could also relate to the outlined environmental benefits associated with overall biogas production.

Moreover, alterations in the process related parameters are presumed to identify potential effects on the production output and or costs. With respect to the process conditions, different CO_2 capture rates were presumed for both pre-combustion or process bio-CO_2 and post-combustion or fuel bio-CO_2. Here, in basis the feasibility of smaller-scale CCUS technology was presumed. The presumed capture rates were lowered from the presumed 90% system capture potential to 56% system capture potential as lowest range value in literature. Moreover, the capture rate of process bio-CO_2 was enhanced to 98% following improvements in VPSA capture technology, while the bio-CO_2 capture potential was lowered to 0% following difficulties with capturing post-combustion CO_2. Over all cases, the CCUS technology was presumed to add 0.5 €/kg H_2 to the hydrogen production costs where the CAPEX are assumed to constitute twice as much as the OPEX amount, in accordance to CCUS design layout. This aligns with the proposed energy demand of the CCUS technology per Nm^3 hydrogen flow. Moreover, CAPEX and OPEX were adjusted based on an increase in the presumed percentage of total investment costs. Additionally, the CAPEX was altered as a result of a decrease and increase in the presumed plant life from 20 years to 15 years and 30 years respectively. On top of that, the OPEX were altered based on differences in the price of process electricity in the range from [0.4-0.15] €/kWh. This relates to the current- and expected electricity prices in the Netherlands. Moreover, it accounts for a potential, unexpected, increase in the electricity price to indicate the relevance of electricity prices for the biogas-to-hydrogen production process.

Lastly, the CO_2 emission price as of 1 January 2022 was taken as, one-dimensional, proxy for the benefit of the inherent bio-carbon dioxide in the process. The presumed 80 €/t CO_2 was subsequently altered to include the scenario of a carbon price of 40, 120, 160 €/t CO_2 up to 240 €/t CO_2 to represent relevant carbon abatement costs numbers.

Ultimately, the results of the production costs calculation, for the different production scales, can be seen in figure 9.17. Here, it can be seen that the biogas production costs, or feedstock costs, significantly impact the ultimate bio-hydrogen production costs. This relates to the fact that the production yield is approximately 0.11 kg H_2/Nm^3 biogas or 9 Nm^3 biogas/kg H_2. As a result, the biogas production costs impact the ultimate bio-hydrogen production costs by around [2.20-2.50] €/kg H_2. However, this number excludes the potential cost reduction that is related to scaling of the biogas production facilities. Overall, it can be seen that scaling positively impacts the bio-hydrogen production costs perspective. Here, the production costs could be lowered to around 4.11 €/kg H_2 based on the reference scenario of 5.5 MW as compared to the base scenario production cost of 6.24 €/kg H_2 for a scale of around 0.65 MW. However, the hydrogen production cost for the reference scenario would lower to 1.76 €/kg H_2 in case of exclusion of the biogas production costs, which constitutes over 55% of the total production costs. An overview of the respective influence of the production scale on the ultimate bio-hydrogen production cost over the different process steps can be seen in table 9.5. Moreover, figure 9.17b shows that the biomethane production step accounts for around [10-25]% of the ultimate bio-hydrogen production costs. On the other hand, the bio-hydrogen production step accounts for approximately [25-45]% of the bio-hydrogen production costs. Here, the lower end of the range relates to higher production scales in which the biogas production cost relative contribution increase from around 30% to around 65%. In this respect, it could be observed that similar to traditional hydrogen production, the feedstock costs amount, in most cases, to over 50% of the ultimate production costs.



(a) Costs per main cost category (b) Costs per main production step

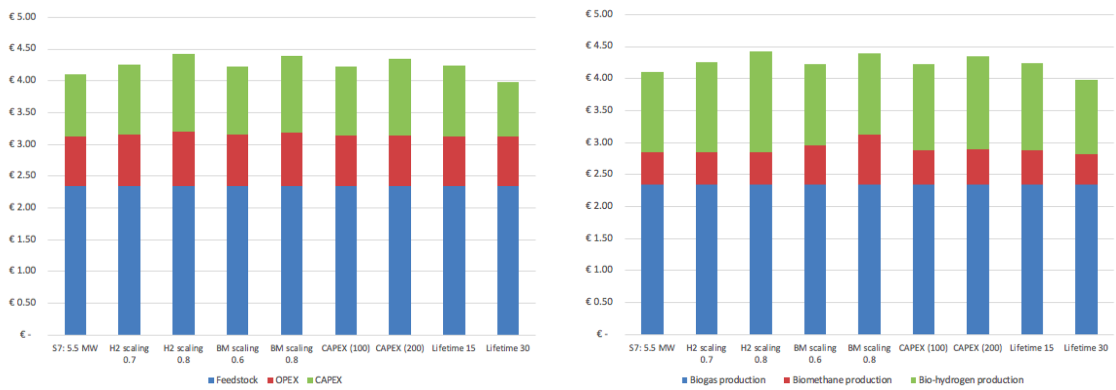
Figure 9.17: Business case cost perspective biogas-to-hydrogen production layout

Scale (MW)	Production cost (€/kg H_2)	Upgrading cost (€/kg H_2)	Feedstock costs (€/kg H_2)
0.27	3.51	2.02	2.34
0.4	2.98	1.60	
0.7	2.57	1.29	
1.4	2.38	0.91	
2.2	1.62	0.70	
5.5	1.25	0.51	
19.5	0.94	0.38	
45	0.82	0.33	

Table 9.5: Effect production scaling on bio-hydrogen production costs per step

Nonetheless, additional effects on the production costs could be observed through production- and or process alterations related to the CAPEX and OPEX. Here, looking at potential alterations in the reference scenario, the alternative outcomes that are related to the changes in CAPEX can be seen in figure 9.18. Moreover, the alternative outcomes to the bio-hydrogen production costs as a result of OPEX related changes can be seen in figure 9.19. Here, in figure 9.18 it can be seen that an increase of 200% in other CAPEX and an increase in the scaling factor of the hydrogen plant and biogas plant have the highest negative impact on the cost performance. On the other hand, an increase in the plant lifetime shows the best cost performance. Nonetheless, the production costs remain in the range of [97-108]% indicating a limited effect on the ultimate production costs. This can be explained by the continued relevance of the biogas production costs on the bio-hydrogen production price. In exclusion of the biogas production costs, the related changes would effect the production costs with +18% and -7% respectively. Moreover, in figure 9.19 it can be observed that the process economics can be significantly improved due to alteration in the process yield and or biogas production costs. Here, also the former directly impacts the biogas production costs per kilogram of hydrogen. In this respect, heat integration in the reforming process could yield cost savings of around 16% and results in a hydrogen production costs of around 3.45 €/kg H_2. In case of a decrease in biogas production costs of 40% this translates in a production cost saving of almost 25% and a production cost of approximately 3.17 €/kg H_2. This stems from the approximate 55% relative contribution of the biogas production cost to the ultimate bio-hydrogen production cost. On the other hand, an increase of 50% in the electricity price would increase the hydrogen production cost by around 4%, while an increase in the energy efficiency of the biomethane production process has limited cost benefits.

Overall, based on a single-variable alteration in the production costs it can be seen that the biogas-to-hydrogen yield a production cost price of [3.17-4.43] €/kg H_2 for a 5.5 MW installation capacity. In respect to the base scenarios it was observed that scaling of the production size favourably impacts the presumed bio-hydrogen production costs. Here, a decrease in the hydrogen production costs of around 35% was achieved in relation to the initial installation size of 0.65 MW. Hereafter, with respect to the 5.5 MW installation capacity it could be seen that the ultimate bio-hydrogen production cost is for around 55% determined by the biogas production cost. This relates to the proposed hydrogen yield of around 0.11 kg H_2/Nm^3 biogas. As a result, a decrease in the biogas production cost of 1.05 cents/Nm^3 biogas would result in a decrease in hydrogen production costs of around 0.1 €/kg H_2. Overall, alterations in the biogas production costs, or related factors, favourably impacts the bio-hydrogen production costs.

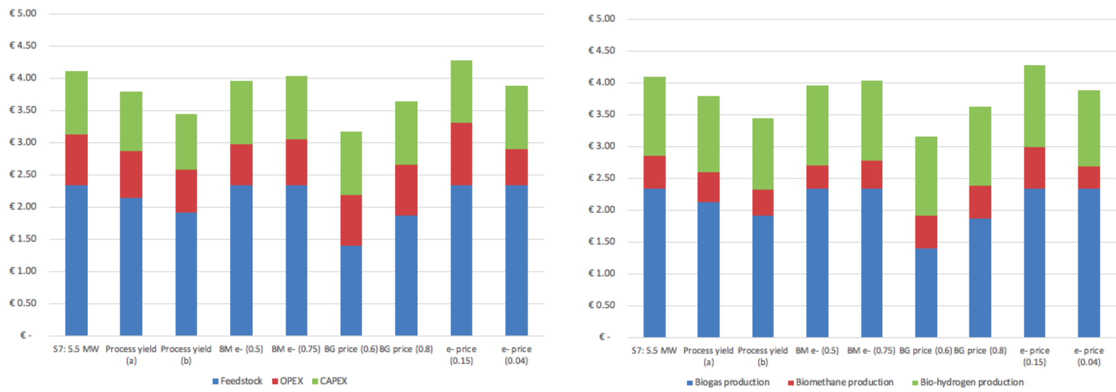


(a) Costs per main cost category

(b) Costs per main production step

Figure 9.18: Business case cost perspective biogas-to-hydrogen production layout after CAPEX alterations

Nonetheless, this perspective inaccurately excludes the inherent value of bio-CO_2 within the concept of third-generation upgrading. In this respect, the value of bio-carbon dioxide could be seen to lower the bio-hydrogen production cost. More precisely, it could be observed that the total bio-CO_2 yield amounts to around 15 kg CO_2/kg H_2 or 1.6 kg CO_2/Nm^3 biogas. In this respect, an increase in the bio-CO_2 price of 10 €/t CO_2 would translate into a bio-hydrogen production cost reduction of 0.15 €/kg H_2. In similar fashion, alterations of the process conditions, primarily the bio-CO_2 capture rates in the upgrading- or reforming step impacts the bio-hydrogen production costs. Figure 9.20a shows the impact of an initial carbon price of 80 €/t

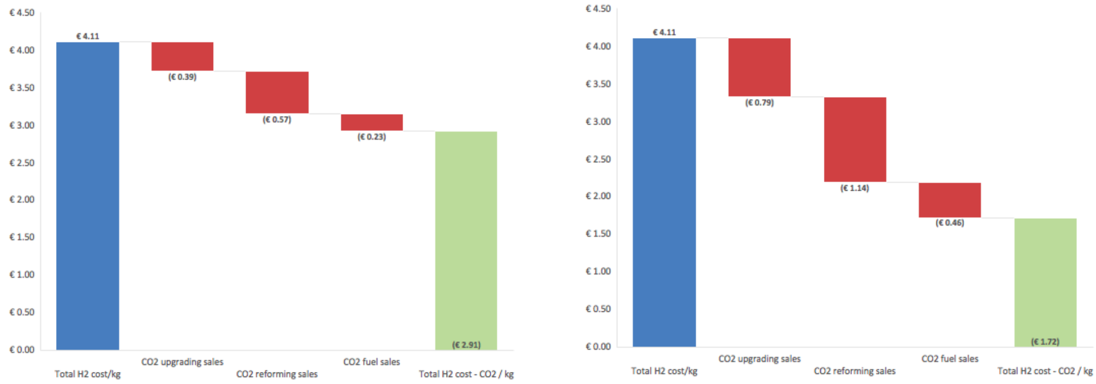


(a) Costs per main cost category (b) Costs per main production step

Figure 9.19: Business case cost perspective biogas-to-hydrogen production layout after OPEX alterations

CO_2, while figure 9.20b indicates the hydrogen production costs in case of a carbon price of 160 €/t CO_2. Here, it can be observed that a doubling CO_2 price, linearly impacts the carbon sales. Moreover, it indicates that an increase of 80 €/t CO_2 impacts the bio-hydrogen production with 1.20 €/kg H_2. However, this ignores the perspective on the additional cost of CCUS as this is incorporated as a fixed costs of 0.50 €/kg H_2 in the bio-hydrogen production costs. In this respect, it could be observed that, almost exact, 10 kg CO_2/kg H_2 could be obtained in the reforming process based on a 90% system carbon capture rate. As a result, a carbon price of at least 50 €/kg H_2 would be required, at the current conditions, to make the utilisation of bio-CO_2 economical feasible. Related to the carbon emission price, it could be observed that a decrease in the reforming bio-CO_2 capture rate would impact the bio-hydrogen production cost. In this respect, a system capture rate decrease to 56% would result an apparent increase in hydrogen production cost of 0.3 €/kg H_2, while a lack of fuel bio-CO_2 capture would result in an increase of 0.23 €/kg H_2. This relates to the respective CO_2 mass balances, which can be observed to be almost 2.5 times smaller for the fuel bio-CO_2 stream as compared to the process bio-CO_2 stream. For example, in case of the former, approximately 40% less bio-CO_2 could be captured at a price of 0.80 €/kg H_2. In contrast, an increase in the process bio-CO_2 capture rate would lower the apparent bio-hydrogen production costs by 0.05 €/kg H_2. Last, the bio-hydrogen obtained in the upgrading step accounts for around 0.5 kg CO_2/kg H_2.

Overall, the presumed business case scenario starts with the assumption of a bio-hydrogen sales value of 3.6 €/kg H_2. This relates to the presumed hydrogen delivery cost requirement in order to be a cost-efficient solution in the build environment in the Netherlands. In this respect, the business case for the 5.5 MW installation is altered based on differences with respect to the bio-hydrogen and bio-carbon dioxide assumed sales values. Moreover, the business case scenario is altered to include potential alterations in the bio-hydrogen cost structure. The latter occurs in similar fashion to the above discussed process alterations. In this respect, figure 9.21 indicates the relevant business case parameters based on the reference scenario and alternative price scenario. Here, it can be observed that the reference scenario shows moderately negative economic results and is based on a balance, income minus



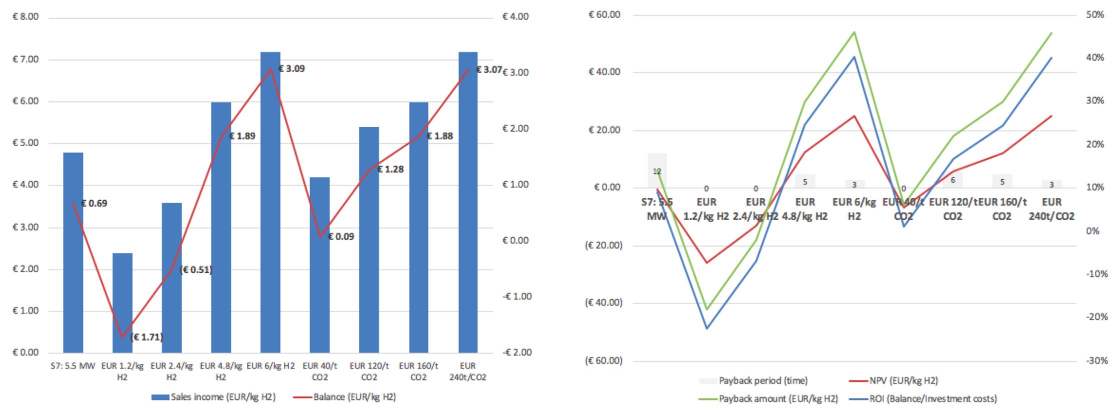
(a) Bio-CO_2 sales value of 80 €/kg CO_2 (b) Bio-CO_2 sales value of 160 €/kg CO_2

Figure 9.20: Bio-hydrogen production costs after bio-CO_2 sales value stream

costs, of 0.69 €/kg H_2. Even though, it is shown that this would be adequate to cover the cost over the plant life time, it would be insufficient to support a positive investment decision as measured by the NPV parameter. In this respect, a presumed discount factor of 7% is included due to the longer-term, higher-risk nature of the investment. This factor is further influenced by the potential risk-mitigation leverage percentage of around 50% with respect to the investment costs. This overlaps with the proposed biomass gasification financing structure which incorporates a leverage percentage of 60%. This is in turn balanced by a higher cost of debt percentage of 7% in the current model. Moreover, it can be observed that, as expected, an increase or decrease in the relatively price points effects the business case on a one-on-one basis with respect to the bio-hydrogen price and 0.15 €/kg H_2 on a 10 €/t CO_2 basis with respect to the carbon price. As a result, it could be stated that based on a hydrogen price of 3.6 €/kg H_2 a carbon price of [80-90] €/t CO_2 would be required to support a positive business case. On the other hand, a bio-hydrogen price of around 3.65 €/kg H_2 would be needed to support a positive business case at a carbon price of 80 €/t CO_2. In contrast, figure 9.22 shows the relevant business case parameters as result of alterations in cost-related parameters. Here, it can be observed that, especially, a decrease in biogas production costs would positively impact the business case scenario through a subsequent increase in the net income. In similar terms, an increase in the process yield could positively influence the business case via an increase in hydrogen yield and or decrease in valuable feedstock need. Nevertheless, due to the relative lower effect on the ultimate balance per kilogram bio-hydrogen less pronounced effects on the business case parameters can be observed.

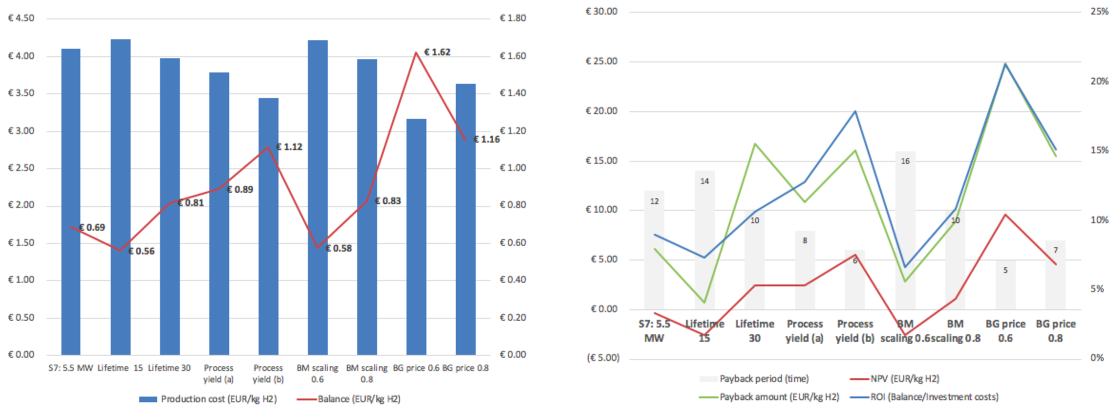
Overall, the respective influence on the reference case parameters can be derived from the ultimate sales and cost perspective. In this respect, bio-hydrogen sales constitute around 75% of the reference scenario sales income in contrast to 25% for bio-CO_2 sales. On the other hand, the feedstock costs constitute around 55% of the total production costs. In this line, a percentage increase in bio-hydrogen sales price shows relative higher results as compared to a decrease in biogas production costs and increase in the bio-CO_2 price respectively.

Nevertheless, within the perspective on the concept of third-generation upgrading, BATR has, especially, been assigned significant importance. In this perspective, the biomethane production step could be eliminated to lower the proposed cost structure



(a) Income price scenario (b) Key investment parameters scenario

Figure 9.21: Bio-hydrogen business case



(a) Income price scenario (b) Key investment parameters scenario

Figure 9.22: Bio-hydrogen business case

of bio-hydrogen production. In this respect, the presumed BATR reactions are:

$$CH_4 + CO_2 \rightarrow 2CO + 2H_2 \tag{9.1}$$

$$CH_4 + H_2O \rightarrow CO + 3H_2 \tag{9.2}$$

$$CH_4 + \frac{1}{2}O_2 \rightarrow CO + 2H_2 \tag{9.3}$$

As a result, a lower hydrogen-to-carbon ratio can be observed as compared to traditional SMR based on an equal contribution. This is despite similar conversion levels observed in BATR and SMR. This subsequently results in a higher requirement of biogas per kilogram of bio-hydrogen. Moreover, an additional oxygen stream is required to support the process, while a theoretical lower amount of steam is required to fuel the process. Besides alteration in the process specification, no expected changes arise with respect to the relative cost structure.

Overall, the bio-hydrogen production cost via the proposed BATR process can be seen in figure 9.23. Here, it can be observed that the bio-hydrogen production cost could be reduced by a factor [10-15]% in relation to the traditional bio-hydrogen production layout. This is despite an increase in the biogas production cost of almost 10%, and as result a contribution of around 65% in the 5.5 MW layout, as compared to the traditional layout. This can be attributed to the lower hydrogen yield of just below 0.1 kg H_2/Nm^3 biogas. Moreover, due to the lower capture potential in the reforming process as compared to the biomethane production process a moderately lower CO_2 yield can be observed of 1.48 kg CO_2/Nm^3 biogas as compared to 1.59 kg CO_2/kg biogas. Nevertheless, a minor increase in the CO_2 yield per kilogram hydrogen can be observed of 0.01 kg CO_2/kg H_2. Also, a small increase in the reformer cost of around 2% can be observed in case of the reference 5.5 MW installation due to the higher flow rate. Overall, a breakdown of the reference 5.5 MW installation for both the traditional- and BATR layout can be seen in figure 9.24. Here, it can be observed, that similar to literature results, the feedstock cost contribution amounts to [45-75]% of the bio-hydrogen production costs, while the CAPEX constitute almost [1.5-2] times as much as the OPEX costs. These relations increase both in case of the BATR process layout as compared to the traditional layout.

Moreover, similar to changes in the traditional layout, the effects in relation to alteration of the CAPEX of the process show limited effect on the ultimate bio-hydrogen price. This is related to the significant contribution of the biogas production costs in the ultimate bio-hydrogen production costs. As a result, alterations that impact the biogas input have a, even more, pronounced effect on the bio-hydrogen production costs. Figure 9.25 shows the respective bio-hydrogen production costs. It can be observed in figure 9.25a that the bio-hydrogen costs vary between [3.72-4.13] €/kg H_2. On the contrary, figure 9.25b indicates the potential to decrease the hydrogen production costs by around 25% to 2.79 €/kg H_2 as a result of a 40% decrease in biogas production costs. On top of that, a higher level of process integration, which corresponds to the thermal neutrality characteristics of the ATR reactor design, could lower the bio-hydrogen production costs to 3.21 €/kg H_2.

On top of that, the incorporation of the value of bio-CO_2 would in turn lower the apparent bio-hydrogen costs in similar fashion as the traditional process. This relates to the, almost, similar bio-CO_2 yield per kilogram of bio-hydrogen. However, an alteration in the bio-CO_2 capture rate would have a stronger impact on the bio-CO_2 output. This relates to the fact that approximately one-third of the bio-CO_2 was traditionally captured during the biogas upgrading process. In this respect, the bio-hydrogen costs would be negatively affected by 0.43 €/kg H_2 and 0.45 €/kg H_2 in case of the exclusion of the fuel bio-CO_2 capture and a lower system capture rate of 56% respectively. The bio-hydrogen production cost including the value of bio-CO_2 can be seen in figure 9.26.

In similar fashion, the ultimate results of the business case analysis can be shown for the BATR process and can be seen in figure 9.27. In contrast to the traditional bio-hydrogen production process it can be observed that at the same price levels for bio-hydrogen and bio-carbon dioxide the BATR process shows positive economics. In this respect, at a bio-hydrogen price of 3.6 €/kg H_2 a bio-CO_2 of around [40-50] €/kg CO_2 would be required for a positive investment decision. In contrast, at a carbon price of 80 €/kg CO_2 this would require a bio-hydrogen price of around [3.10-3.20] €/kg H_2. As a result, the BATR production route offers the potential to support a positive business case at an approximately 20% lower price point of bio-hydrogen.

Thus, it can be seen that depending on the exact process layout, scale and conditions

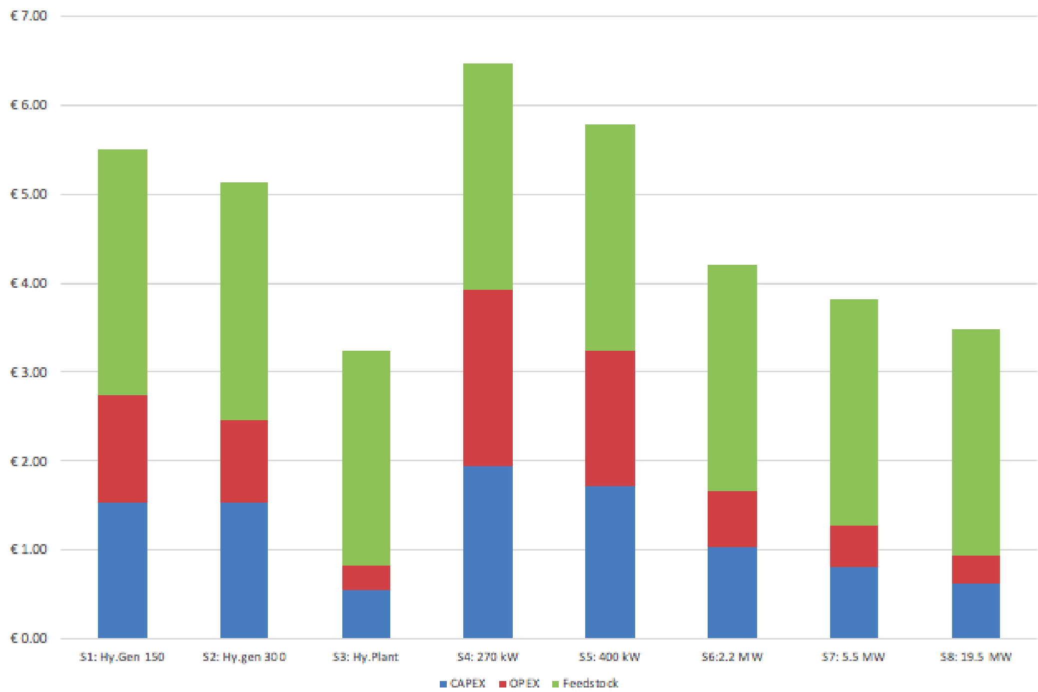
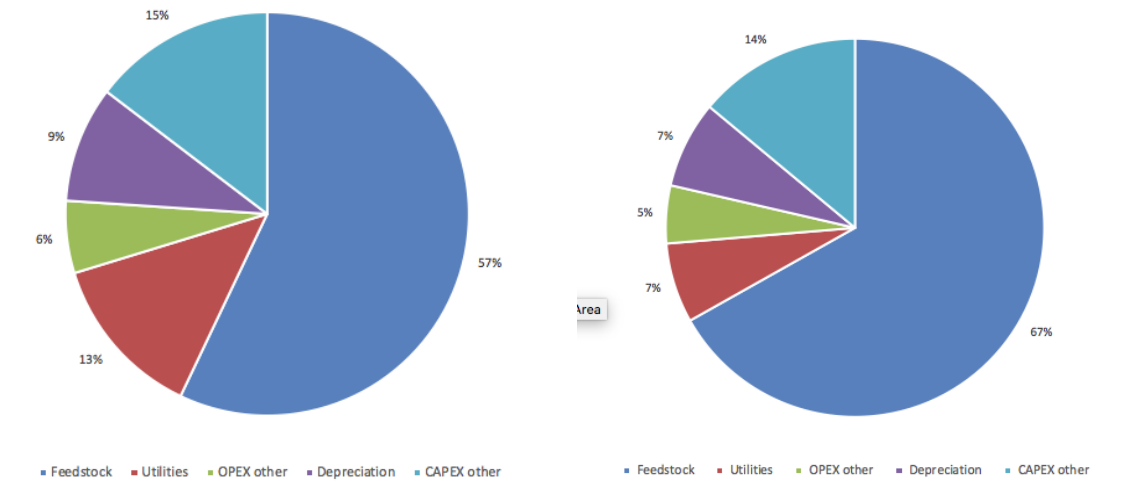


Figure 9.23: Business case cost perspective BATR production layout

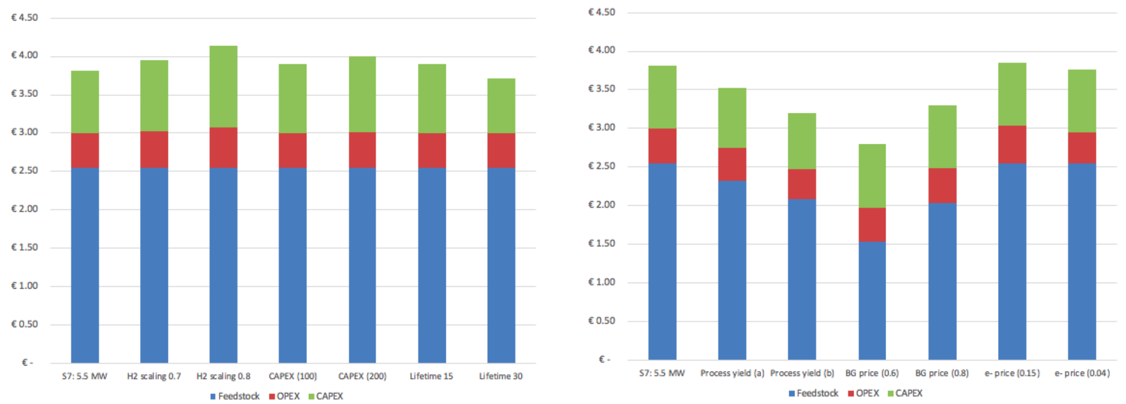
the bio-hydrogen production costs shows some divergence. This results in a bio-hydrogen price of [3.4-7.0] €/kg H_2 for the traditional layout and [3.2-6.5] €/kg H_2 in the case of the BATR process layout. Nonetheless, based on the reference size of 5.5 MW, under the presumed conditions, the bio-hydrogen costs are seen to vary in the case of the traditional layout from [3.2-4.4] €/kg H_2. However, the BATR process layout is shown to show the potential for an improved bio-hydrogen production costs perspective. In this respect, the BATR process shows a bio-hydrogen production costs of [2.8-4.1] €/kg H_2. Nonetheless, this incorporates an additional 0.5 €/kg H_2 based on the proposed CCUS technology. Therefore, the bio-hydrogen production costs could be seen to lower to [2.0-3.3] €/kg H_2 based on a presumed bio-CO_2 value of 80 €/t CO_2. Overall, the bio-hydrogen production cost seem to overlap well with the proposed bio-hydrogen costs of around [3-5.3] €/kg H_2 derived from literature results. In this respect, the discussed production results indicate the further cost reduction that could be obtained as a result of professionalisation- and commercialisation of the industry.

However, the sole perspective on the bio-hydrogen production costs insufficiently addresses the concept of third-generation upgrading. In this perspective, biogas constitute an inherent climate-neutral molecular carbon value. Here, it could be seen that per kilogram of hydrogen around 15 kilogram of bio-CO_2 could be obtained in production process. Through internalisation of the bio-carbon value, the cost of bio-hydrogen costs could be reduced in contrast to alternative hydrogen production methods. Moreover, this could be further stimulated through the incorporation of wider value chain climate benefits. This relates, for example, to the sale of bio-fertiliser in the biogas production process. In this respect, it has been shown that around 30% of the carbon in the bio-fertiliser could be stored in the soil and as such provide an inherent negative carbon value. Additionally, the production of



(a) Traditional layout (b) BATR layout

Figure 9.24: Overview of the relative contribution of the respective cost components



(a) CAPEX alterations (b) OPEX alterations

Figure 9.25: Business case cost perspective BATR production layout after CAPEX and OPEX alterations

biogas offers solutions for complex waste problems and could limit biogenic methane emissions. On top of that, non-carbon related environmental benefits could be internalised, for example, a reduction in contaminants emissions like VOCs or NO_x. The latter is especially relevant in comparison to traditional combustion technologies.

Nevertheless, the sole perspective on the bio-hydrogen production costs and apparent benefits limit the practical interpretation in relation to the ultimate hydrogen demand. In this respect, both the hydrogen delivery cost- and TCO perspective are relevant. In this perspective, within the perspective on the future renewable hydrogen system bio-hydrogen has been attributed primary potential for local- and or regional demand. As a result, additional costs with respect to conversion, transportation and reconversion could be circumvented. However, depending on the exact place and time dimension an additional need for storage, transportation, liquefaction and or compression would be required. Moreover, the same holds with the proposed utilisation of bio-carbon dioxide. In case of the former, the distribution via pipeline or truck and storage in above-ground tanks would be presumed. However, in the

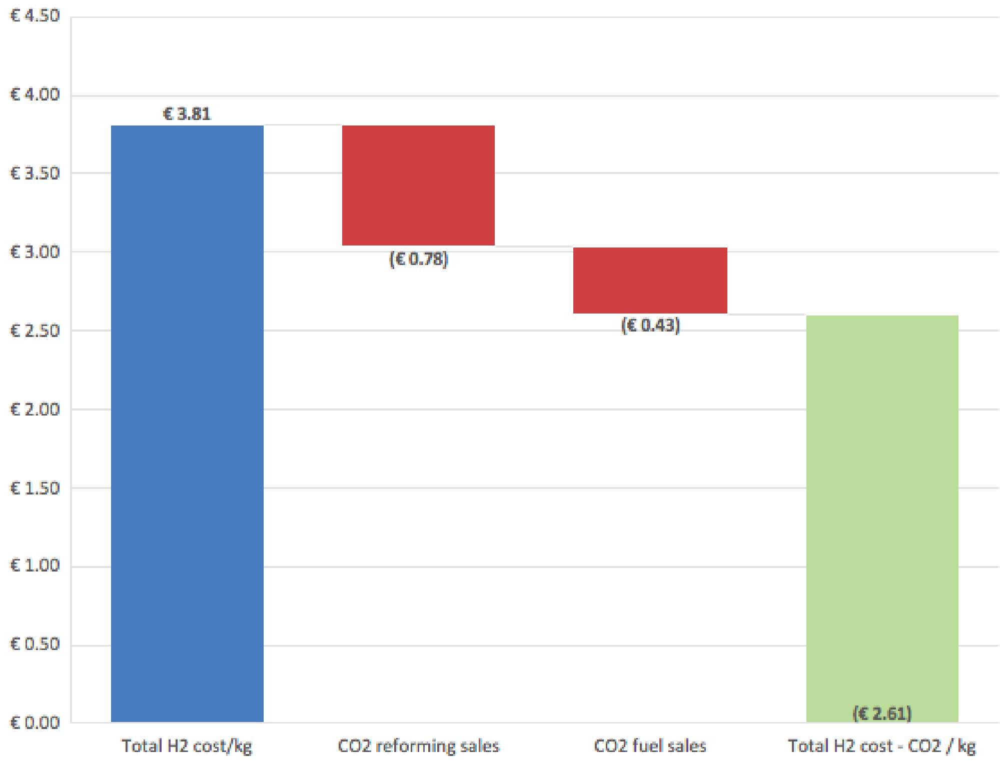
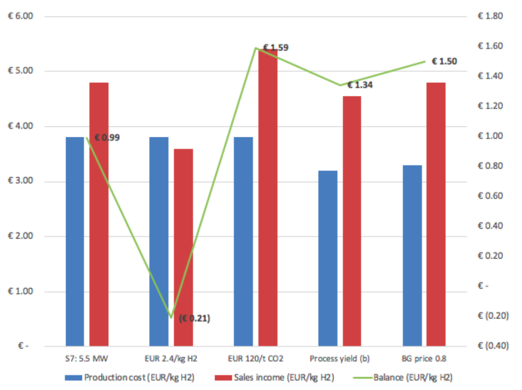


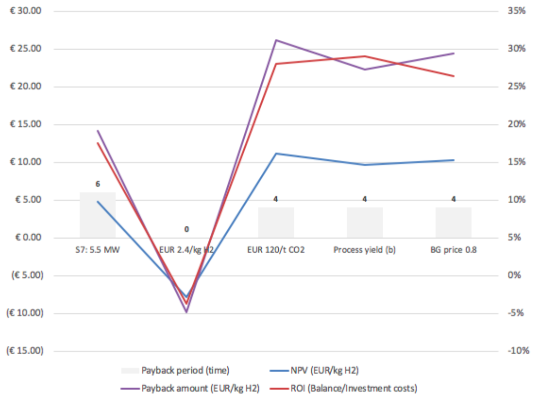
Figure 9.26: BATR bio-hydrogen production costs after bio-CO_2 sales value stream

case of reverse flow potential, the bio-hydrogen could also be stored as low cost option in geographical storage locations. Nonetheless, the latter is presumed to be in-effective from a system perspective due to the local demand for bio-hydrogen and bio-carbon dioxide. In this respect, it was mentioned that storage in pressurised containers would add approximately [0.15-0.20] €/kg H_2 to the production costs. In case of compression, this could add an additional 0.31 €/kg H_2 to derive at a presumed additional costs for on-site bio-hydrogen usage of around [0.4-0.5] €/kg H_2. Higher pressure applications might require higher compression costs, which were mentioned to be around 0.8 €/kg H_2. However, in case of more regional utilisation of bio-hydrogen, an additional costs for conversion and storage could add approximately [0.5-0.8] €/kg H_2 while truck- or pipeline transport over a, maximal, distance in the Netherlands of 300 km was stated to add an additional [1.0-1.5] €/kg H_2. Here, based on the approximate 2.5 t H_2/day output of the 5.5 MW installation, compressed hydrogen gas transport is presumed to account for around [0.5-1.5] €/kg H_2. At larger volumes, this could be lower to around [0.05-0.2] €/kg H_2. Thus overall, it is presumed that the bio-hydrogen delivery costs would be increased by around [0.5-1.5] €/kg H_2. In similar terms, the utilisation of bio-hydrogen for applications in HRS are presumed to add around 1.6 €/kg H_2. In case of the BATR process this would translate in an approximate bio-hydrogen delivery cost of around [3-4] €/kg H_2 in case of on-site utilisation and [4-5] €/kg H_2 for off-site utilisation. However, through incorporation of the bio-CO_2 value this could reduce to around [2-3] €/kg H_2 and [3-4] €/kg H_2. In similar terms, based on an additional 10% of the bio-hydrogen production costs for grid injection, the presumed grid-injected bio-hydrogen could show a delivery cost of around [3-4] €/kg H_2.

In contrast, a renewable hydrogen delivery cost of 3.6 €/kg H_2 is presumed to



(a) Income balance



(b) Key investment parameters

Figure 9.27: BATR bio-hydrogen business case

support the adoption of hydrogen within the build environment in the Netherlands by 2030. In this respect, an approximate additional 1.0 €/kg H_2 is required for the transport and storage of e-hydrogen produced from wind energy in the Netherlands. However, the hydrogen delivery costs might reduce to [1.5-2] €/kg H_2 in the longer-term as a result of the import of cheap e-hydrogen. This is in contrast to the presumed fossil hydrogen production costs of around [1.0-1.5] €/kg H_2 or [1.5-2.0] €/kg H_2 in the case of lower-carbon hydrogen. In this respect, the current fossil hydrogen production shows good potential for on-site production to lower the apparent delivery costs. However, in case of lower-carbon hydrogen production this might lower due to the lack of adequate infrastructure. This becomes increasingly prevalent in the proposed renewable hydrogen system due to the direct conversion of natural gas at the source and the lack of the traditional natural gas infrastructure.

In case of the utilisation of bio-CO_2 additional energy requirements are present due to the liquefaction or compression of the bio-CO_2 stream. In this respect, it was mentioned that an electricity of 125 kWh/t CO_2 would be required in case of compression and 162 kWh/t CO_2 in case of liquefaction. This would translate into an additional cost of around [10-15] €/t CO_2. Nonetheless, this could be supported by the increased integration with renewable electricity sources. Next to the electrical energy requirement, in case of pipeline transport, additional costs with respect to the grid connection would be incurred. Overall, in case of pipeline transport it was mentioned that this could add 0 €/t CO_2 in case of current under-capacity to approximately 50 €/t CO_2 in case of a new dedicated CO_2 pipeline. On the contrary, in case of liquefied road transport the apparent transport costs are approximately 20 €/t CO_2. In turn, an additional [30-65] €/t CO_2 could be added to the bio-CO_2 delivery costs.

Overall, this identifies the relevance of both the place and time dimension in the concept of third-generation upgrading. In this respect, bio-hydrogen would benefit from close-proximity demand to lower the ultimate hydrogen delivery cost perspective in contrast to cheap fossil- and or lower-carbon hydrogen, especially for local- and or regional demand. Hereafter, the place dimension remains important for the adoption of bio-hydrogen as a result of the declining costs for e-hydrogen. In this respect, the infrastructural requirements pose an interesting boundary condition to stimulate the adoption of bio-hydrogen. In similar terms, the proximity to demand centers for the utilisation of bio-CO_2 could stimulate the adoption due to the apparent costs with bio-CO_2 conversion and transport. Moreover, the relative cost perspectives identify the need for the respective time dimension. Here, initially bio-hydrogen competes with fossil- and lower-carbon hydrogen while this is presumed to alter in the longer-term due to the presence of more cost-effective e-hydrogen. Ultimately, this is expected to alter the perspective on the valorisation potential of the concept of third-generation upgrading in favour of bio-carbon. In this light, also the regulatory context pose relevant boundary conditions to stimulate the adoption of the concept of third generation upgrading. This relates to the inherent value of bio-CO_2 as climate-neutral carbon source as compared to traditional natural gas reforming and e-hydrogen production.

Nevertheless, the analysis focused primarily on the utilisation of bio-hydrogen as renewable hydrogen source. In this respect, the analysis did not incorporate the current perspective on the valorisation potential of biogas through the concept of second-generation upgrading. Here, the bio-CO_2 stream from the upgrading step is utilised next to the respective biomethane stream. The biomethane stream subsequently finds use through physical delivery and or pipeline transport in demand centers in the industrial-, transport- and or residential sectors. Here, the biomethane is utilised as direct replacement of natural gas primarily for heat energy requirements.

It could be observed that with respect to the traditional bio-hydrogen, including CCUS technology, production route, the biomethane production step adds between [10-20]% to the total bio-hydrogen production costs. Moreover, it was indicated that the ultimate bio-hydrogen production step adds approximately [25-35]% to the ultimate production costs. In this respect, the bio-hydrogen production costs adds approximately an additional [40-60]% to the biomethane production costs in order to produce bio-hydrogen and bio-CO_2. However, in case of the proposed BATR layout the ultimate bio-hydrogen production costs could be lowered by [10-15]%. Nonetheless, the additional costs to produce bio-hydrogen need to be recovered through additional sales in order for the concept of third-generation upgrading to become economical feasible as compared to the concept of second-generation upgrading. In this respect, it could be observed that in the traditional process around [1.8-2.2] Nm^3 H_2 could be obtained per Nm^3 biomethane or [0.15-0.19] kg H_2/Nm^3 biomethane. Otherwise stated, [1.3-1.6] Nm^3 H_2/Nm^3 biogas could be obtained in comparison to around 0.7 Nm^3 biomethane/Nm^3 biogas. Moreover, it was stated that approximately twice the amount of bio-CO_2 could be recovered in the bio-hydrogen production step as compared to the biomethane production step. This accounted for approximately [10-11] kg bio-CO_2/kg H_2 or [1.5-2.0] bio-CO_2/Nm^3 biogas. In case of the BATR layout this altered to around [1.2-1.5] Nm^3 H_2/Nm^3 biogas and [1.42-1.48] kg CO_2/ Nm^3 biogas or [12-15] kg CO_2/kg H_2. Thus, it could be observed that around twice the normal volume amount of bio-hydrogen could be obtained per normal volume amount of biomethane. Moreover, around three times the mass amount of bio-CO_2 could be recovered in case of bio-hydrogen production as compared to biomethane production. On the other hand, it was discussed that this adds around [40-60]% to the ultimate production costs.

As a result, for the concept of third-generation upgrading to be economical feasible, the double volumetric amount of bio-hydrogen and triple mass amount of bio-carbon dioxide has to recover the approximate [40-50]% increase in production costs, with respect to both production layouts. To compare this, it was mentioned that a bio-hydrogen price of around 3.6 €/kg H_2 would compare to around 0.952 €$/Nm^3$ natural gas equivalents. In similar terms, a hydrogen price of around 1 €/kg H_2 would translate into a price of approximately 0.24 €$/m^3$ natural gas equivalent. Therefore, based on a hydrogen content of 120 MJ/kg H_2 LHV and a natural gas energy content of 35.2 MJ$/Nm^3$ LHV, 1 €/kg H_2 would translate into a price of 0.3 €$/Nm^3$ biomethane. In similar terms, based on an energy content of around 10.8 MJ$/Nm^3$ H_2 LHV and a biomethane price of 1 €$/Nm^3$ this would translate into a bio-hydrogen price of around 0.3 €$/Nm^3$ H_2. Therefore, the energetic value would decrease with around [45-55]% in case of the upgrading of biomethane to bio-hydrogen. However, this perspective is limited to the energetic content of the respective fuel and does not constitute a system perspective. In this respect, due to the higher efficiency associated with the fuel cell technology as compared to combustion technology an energy gain of around [20-50]% could be obtained to effectively reduce the energy cost disparity to [25-45]% in favour of the utilisation of biomethane.

Therefore, to ensure the economic feasibility of the concept of third-generation upgrading as compared to second-generation upgrading the value of bio-CO_2 should be able to recoup the additional costs of [40-60]% and the additional energy losses of around [25-45]%. Here, based on the latter, per kg of H_2 an additional [0.5-0.8] €/kg H_2 would need to be recovered. In addition with the additional cost perspective, this would increase to around [1.0-1.6] €/kg H_2. In this respect, it was discussed that three times the amount of bio-CO_2 could be recovered in the concept of third-generation upgrading as compared to the concept of second-generation upgrading. This translated into around [13-16] kg CO_2/kg H_2 as compared to 0.75 kg CO_2/Nm^3 biomethane or around 5 kg CO_2/kg H_2 in the biomethane production step. Therefore, a theoretical bio-CO_2 price of [100-160] €/t CO_2 would be required to ensure the concept of third-generation upgrading is economical feasible as compared to the concept of second-generation upgrading.

Ultimately, based under the presumption of an increase in system efficiency from the utilisation of bio-hydrogen of 35%, a bio-hydrogen process efficiency gain of 10% and a bio-hydrogen cost reduction of 15% as result of the BATR process, the comparative business case parameters between the concept of third-generation upgrading and second-generation upgrading can be seen in figure 9.28. Here, it can be observed that at a bio-CO_2 price of 140 €/t CO_2 the concept of third-generation upgrading show better unit economics. However, due to the higher initial investment amount, a positive investment decision with regard to the concept of third-generation upgrading only materialises around 180 €/t CO_2. On the other hand, it can be seen that the payback period in case of the concept of third-generation upgrading is longer, despite the more positive payback amount with respect to the concept of third-generation upgrading starting at a carbon price of around 160 €/t CO_2.

However, this figure does not include other factors that could influence the widespread adoption of the concept of third-generation upgrading. In this respect, related to the TCO perspective, additional investment are required to stimulate the adoption of bio-hydrogen in comparison to biomethane. This relates to, for example, alterations in pipeline infrastructure or the stimulation of fuel cell technology. In this respect, the adoption of bio-hydrogen is presumed to lack the current demand for biomethane. Nevertheless, within the wider perspective of the renewable hydrogen system these system costs are required and therefore indifferent in the ultimate business case calculation. On top of that, the infrastructure boundary conditions are presumed to, over time, result in a binary devaluation of the respective energy carriers. In this respect, the value of hydrogen will be increased through the development of the adequate infrastructure, while the value of biomethane will be lowered due to the proposed re-purposing of the current natural gas infrastructure. On the other hand, figure 9.28 is based on the presumed utilisation of bio-hydrogen in fuel cell technology. However, in case of combustion of bio-hydrogen the respective efficiency gains are presumed to be limited or even negative. On the contrary, this perspective lacks the higher value utilisation of bio-hydrogen as relevant feedstock in the industry. Overall, it is presumed that the local- and or regional generation of bio-hydrogen primarily supports the adoption in higher system value applications. On top of that, the results of figure 9.28 are based on an energetic comparison and, one-dimensional, bio-CO_2 value. In this respect, regulatory boundary conditions could further stimulate the concept of second-generation upgrading through support of bio-hydrogen relative to biomethane, for example, via mandatory quota. Moreover, the inherent price of bio-CO_2 could be supported through, concepts like, double counting. Also, the relevant sales price of bio-CO_2 is expected to increase over time within the proposed future renewable hydrogen system. Overall, to adequately assess the economic feasibility of the concept of third-generation upgrading as compared to the concept of second-generation upgrading the relevant time and place dimensions with respect to the infrastructural- and regulatory boundary conditions respectively will be dominant.

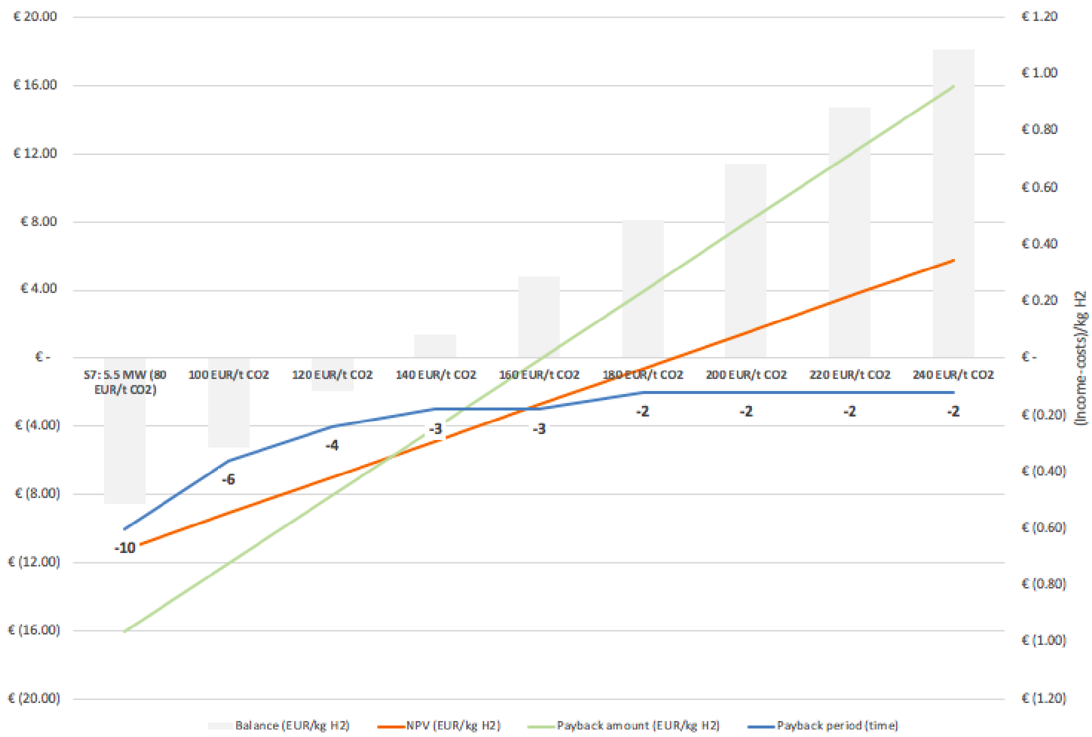


Figure 9.28: Business case comparison between the concept of third-generation upgrading and second-generation upgrading

Lastly, in case of the direct utilisation of syngas several cost reductions could be achieved as compared to the production of bio-hydrogen. In this respect, the cost of the purification of bio-hydrogen from bio-carbon dioxide will be eliminated. Therefore, the costs related to both the WGSR and VPSA would be removed. Also, no cost for the CCUS technology would be incurred. In contrast, as compared to the direct utilisation of biomethane, the proposed syngas requires an additional reforming step. This includes demand for steam and pure oxygen in case of the ATR-related processes. Nonetheless, as with the production of bio-hydrogen, the BATR layout could remove the need for the biomethane purification step. Moreover, the BATR layout could support wider flexibility with respect to the quality of the syngas output in terms of H_2/CO ratio. As a result, based on the process layout different relative comparisons could be made. Overall, the main output would constitute of the syngas where in case of the traditional reforming an extra bio-CO_2 stream could be obtained. This is in contrast to both a bio-hydrogen and bio-carbon dioxide output stream with respect to the bio-hydrogen production. Nevertheless, the valuable bio-carbon would be retained in the inherent value of the syngas. This is in contrast to the direct utilisation of biomethane. In this case, it was discussed that approximately two-third of the bio-carbon would be lost in case of the utilisation of biomethane. However, also the concept of second-generation upgrading is able, in part, to recover the inherent value of bio-CO_2 via the separation of bio-CO_2 in the process. This amounts to around 0.75 kg CO_2/Nm^3 biomethane in case of the second-generation upgrading and approximately 2.3 kg CO_2/Nm^3 biomethane in case of the concept of third-generation upgrading. Based on an output of 0.7 Nm^3 biomethane/Nm^3 biogas, this would translate into an output of 0.53 kg CO_2/Nm^3 biogas in case of the concept of second generation upgrading and 1.6 kg CO_2/Nm^3 biogas in case of the concept of third-generation upgrading.

In case of the direct utilisation of syngas, a syngas stream of around [2.5-3.5] Nm^3/Nm^3 biomethane could be obtained based on the required quality of the syngas, of [1.7-3] H_2/CO molar content, and subsequent relative, stoichiometric, oxygen- and steam input of around [0-0.45] kg O_2/Nm^3 biomethane and [0-0.6] kg H_2O/Nm^3 biomethane. This in turn translate to a syngas stream of approximately [2-2.5] Nm^3 syngas/Nm^3 biogas based on a volumetric ratio of CH_4 in biomethane of 82% and in biogas of 58%. In the case of the BATR process, this translates to around [1.8-2.4] Nm^3 syngas/Nm^3 biogas at a syngas quality of [1.2-3] H_2/CO molar content. In contrast, in case of biomethane production this would relate to 0.7 Nm^3 biomethane/Nm^3 biogas. In similar terms, a hydrogen stream of around 0.11 kg H_2/Nm^3 biogas or 0.15 kg H_2/Nm^3 biomethane could be obtained.

As a result, based on the concept of second-generation upgrading the additional reforming step results in an approximate factor 3 increase in the volumetric flow rate of syngas as compared to biomethane. This incorporates the inherent value of bio-carbon in the respective syngas stream, primarily in the form of carbon monoxide. However, this excludes the potential internal heat demand of the reforming process, which could lower the process yield. The internal heat demand includes an additional approximate [30-50]% biomethane in the case of the traditional SMR process. Nonetheless, the ATR-related process layout and the reduction of the H_2/CO_2 separation steps could limit the need for additional biomethane input. Therefore, in case of an overall increase in production costs of around [20-30]%, as proxy for half the total additional bio-hydrogen production step costs, the syngas value would need to be approximately [0.3-0.5] €$/Nm^3$ syngas per €$/Nm^3$ biomethane. This includes an inherent bio-carbon value of 1.52 kg CO_2/Nm^3 biomethane or around 0.12 €$/Nm^3$ biomethane at the presumed price of 80 €/t CO_2. Through this reasoning, an inherent carbon value of around [200-330] €/t CO_2 would inherently favor the production of syngas over the direct utilisation of biomethane. In contrast, in case of the direct utilisation of biogas, the proposed increase in production costs would be, approximately, offset by a decrease in production costs due to the exclusion of the biomethane production step. Nevertheless, in this respect the initial bio-CO_2 stream would be retained in the syngas stream, primarily, in the form of CO. As a result, the presumed syngas value would need to be [0.3-0.4] €$/Nm^3$ syngas per €$/Nm^3$ biomethane or [0.31-0.42] €$/Nm^3$ syngas/€$/Nm^3$ biomethane based on the presumed, external, carbon price of 80 €/t CO_2 and no internalisation of the bio-carbon in the syngas value.

With respect to the production of bio-hydrogen it could be observed that a bio-hydrogen yield of 1 kg H_2/Nm^3 biogas is similar to a syngas yield of approximately [16-22] Nm^3 syngas/Nm^3 biogas. In contrast, based on the BATR layout and a system capture rate of 90%, an approximate 1.5 kg CO_2/Nm^3 biogas or 15 kg CO_2/kg H_2 separate bio-CO_2 stream would be obtained in the case of bio-hydrogen production. However, depending on the required syngas quality and respective conversion levels, a similar amount of bio-carbon would be retained in the syngas, primarily, in the form of CO. Moreover, a lower production costs would be expected in case of syngas production due to the exclusion of the bio-hydrogen separation steps and the CCUS technology. As a result, based on a lower cost perspective of [50-75]% the syngas volumetric value would need to amount to around [0.03-0.05] €$/Nm^3$ syngas per €/kg H_2. This in turn would increase to [0.08-0.12] €$/Nm^3$ syngas per €/kg H_2 at the presumed carbon price of 80 €/t CO_2. This relates to an external bio-CO_2 price as compared to the internal value of bio-carbon.

Overall, it can be seen that the production of syngas could prove to be beneficial based on a mass balance assumption of the respective constituents. Here, it was seen that the value of the inherent bio-CO_2 shows a good proxy to determine the relevance for the higher valorisation potential to syngas as compared to the concept of second-generation upgrading. On the contrary, a more thorough calculation of the relevant value perspectives of syngas as compared to bio-hydrogen and bio-carbon dioxide would be required to determine the ultimate valorisation perspective as compared to the concept of third-generation upgrading. This could become increasingly relevant over time due to the presence of large volumes of low cost e-hydrogen. Ultimately, this is expected to be a function of time, place and end application depending on the relevant advantages and disadvantages of the output products.

To conclude, the concept of third-generation upgrading was assigned relevance within the proposed future renewable hydrogen system. In this respect, it was indicated that biogas has a higher valorisation potential as source of bio-hydrogen and bio-carbon dioxide. This is supported by the technological- and environmental feasibility of the conversion of biogas to bio-hydrogen and bio-CO_2. Moreover, this chapter indicated the economical feasibility of the concept of third-generation upgrading. In this respect, it was shown the the bio-hydrogen production costs would be around [2.0-3.3] €/kg H_2 based on a presumed bio-CO_2 value of 80 €/t CO_2 and a 5.5 MW biogas installation capacity. Here, the proposed BATR process layout showed a potential bio-hydrogen production cost decrease of [10-15]% as compared to the traditional bio-hydrogen production layout. On top of that, improvements in scale, process yield and reduction in biogas production costs were indicated to show relevant potential to lower the apparent bio-hydrogen production costs. Moreover, it was stated that the bio-hydrogen production supports a positive investment decision based on a BATR bio-hydrogen price of around [3.10-3.20] €/kg H_2 at a bio-CO_2 value of 80 €/t CO_2. On the contrary, it was indicated that at a BATR bio-hydrogen price of 3.6 €/kg H_2 a bio-CO_2 value of around [40-50] €/kg CO_2 would be required to support a positive investment decision.

Additionally, it was indicated that the concept of third-generation upgrading shows a higher valorisation potential compared to the concept of second generation upgrading due to the presence of the additional bio-CO_2 stream. In this respect, it was indicated that approximately three times the bio-CO_2 could be obtained in the concept of third-generation upgrading. As a result, based on an energetic basis, the concept of third-generation upgrading becomes economically feasible at a carbon price of around [140-180] €/t CO_2 in case of bio-hydrogen production. In case of the production of syngas, an inherent carbon price of around [200-330] €/t CO_2 is shown to, by its own, support the valorisation potential of the concept of third-generation upgrading.

Nonetheless, it was mentioned that the place and time dimension of the concept of third-generation will prove to be dominant in the actual adoption. This relates, for example, to the infrastructural demand and costs related to the conversion-, transport- and or storage of bio-hydrogen and or bio-CO_2. In this respect, it was indicated that a reduction of the apparent costs due to an optimal infrastructural design supports the adoption of bio-hydrogen as opposed to fossil hydrogen, lower-carbon hydrogen and e-hydrogen over time. In similar terms, this could support the adoption of syngas. Moreover, the time perspective becomes apparent in the ultimate perspective on the value of climate-neutral, or negative, bio-CO_2. In this way, the concept of third-generation upgrading is supported over the concept of second-generation upgrading. Moreover, it ensures favourable economics as compared to the alternative hydrogen production methods. This will become increasingly dominant in light of the value of bio-CO_2 within the proposed renewable hydrogen system.

Chapter 10

Infrastructure

Within the proposed future energy system, renewable hydrogen will become the dominant energy carrier. Here, renewable hydrogen is seen as the energy vector that can transport cheap renewable electricity over time and space. Moreover, renewable hydrogen will regionally- and or locally operate as a versatile energy carrier over different sectors and end applications. On top of that, renewable hydrogen will allow for regional integration and supports sector coupling. In this perspective, renewable hydrogen will operate in a similar manner as natural gas in the current energy system.

In this respect, infrastructure will be a vital enabler to support the transition to- and operation of the renewable hydrogen energy system. Here, the proposed infrastructure design will impact the feasibility of alternative- and or competitive energy carriers. In this perspective, the infrastructure overhaul could directly result in a devaluation of the methane utilisation as opposed to hydrogen applications. However, in order to support the adoption of hydrogen the infrastructural requirements and design should be feasible and adequate.

Here, the concept of third-generation upgrading has been assigned importance for the local- and or regional production of bio-hydrogen and bio-carbon dioxide as opposed to the direct utilisation of biogas or biomethane. In this respect, it was indicated that the concept of third-generation upgrading shows relevant technological-, environmental- and economical benefits. Nevertheless, the infrastructural boundary conditions are seen to be indispensable to support the adoption of bio-hydrogen. This indicates the place dimension of the concept of third-generation upgrading. This relates both to competitive hydrogen production methods and competitive use cases of biogas and or biomethane. In this perspective, the infrastructural design could impacts the relative system costs perspective, valuation and feasibility. This spans the entire value chain of bio-hydrogen production, from biogas production till the ultimate end application of bio-hydrogen and bio-carbon dioxide or syngas.

As a result, this chapter aims to identify the potential for hydrogen transport. Moreover, this chapter identifies the biomethane infrastructure and focuses on the interconnection of the alternative- and or competitive energy carriers in light of the infrastructure demand. Ultimately, the chapter aims to form, via a mapping exercise, a perspective on the infrastructure design in light of the feasibility of the concept of third-generation upgrading of biogas within the future renewable hydrogen system.

10.1 Introduction

The present gas system is considerably larger than the electricity system both in terms of volume and capacity. Here, gas is providing the required flexibility for the electricity system. The gas production in general has larger production volumes and is located further from the demand sites as opposed to power generation. In this respect, gas allows for transportation over longer distances, from continental to worldwide while electricity is restricted to transportation regionally and within the continent. Here, the transport of renewable electricity via hydrogen- or hydrogen-derived energy carriers benefits from higher energy densities, low- or no losses during transportation, beneficial economies of scale and point-to-point trading across networks as compared to electricity transport. Moreover, the gas system is balanced through large-scale storage, while electricity production and demand are balanced by ramping up- or ramping down the power plants. Some flexibility for the electricity system could also be obtained in the form of pumped hydro power (van Wijk, 2021).

Next to electricity production, the natural gas system also can provide flexibility for hydrogen production. This is the case since hydrogen at the moment does not have a public- and large-scale infrastructure. As a result, the flexibility for hydrogen production can be obtained via natural gas supply, primarily by pipeline transport, to hydrogen production plants that are located at- or near the hydrogen demand (van Wijk, 2021).

In similar fashion to the current natural gas system, the future renewable hydrogen system will be characterised by large-scale hydrogen production at those areas of good solar- and or wind resources. This could be supported, for an intermediate time period, by lower-carbon hydrogen. Both are presumed to, mostly, not be located at the hydrogen demand locations. In this way, hydrogen and hydrogen-derivatives will become the energy commodity (van Wijk, 2021). More regionally hydrogen is expected to be produced from biogenic waste resources that link energetic hydrogen production with molecular biogenic carbon dioxide production. Additionally, hydrogen production from local renewable electricity production could help to alleviate electricity grid capacity constraints (van Wijk, 2021). This system design ultimately helps to bring down the hydrogen delivery costs, enhance the baseload reliability, support flexibility, facilitate space requirement planning, stimulate renewable electricity integration, avoid a methane lock-in, and lower the methane leakages (van Wijk, 2021).

Next to production facilities, this system will require large-scale storage facilities to balance production fluctuations. Moreover, for an intermediate period, this will also require carbon storage facilities. On top of that, the system will need hydrogen processing plants to bring hydrogen on specifications. Hereafter, for the actual transport of hydrogen the system is based on intercontinental- and continental transport pipelines, a worldwide shipping- and port infrastructure, and regional- and continental pipeline transport and storage facilities. More locally, the system builds upon cite gate stations and local lower-pressure pipelines, and medium-pressure pipelines to facilitate- and integrate biogenic hydrogen production and local- and or regional e-hydrogen production (van Wijk, 2021).

Ultimately, this will allow for the transportation- and storage of renewable electricity, in the form of hydrogen, over time and place. This provides a more cost-effective- and technically feasible option for longer-term- and or larger-volume storage- and transport of renewable electricity. Alternatives would, for example, batteries and or pumped hydro storage. Moreover, with hydrogen- and oxygen from water, carbon from biomass, and nitrogen from air this will support the production of all chemical products in bulk. On top of that, renewable hydrogen in combination with renewable electricity will allow for the production of all metals (van Wijk et al., 2018).

An overview of the proposed future hydrogen system design can be seen in figure 10.1.

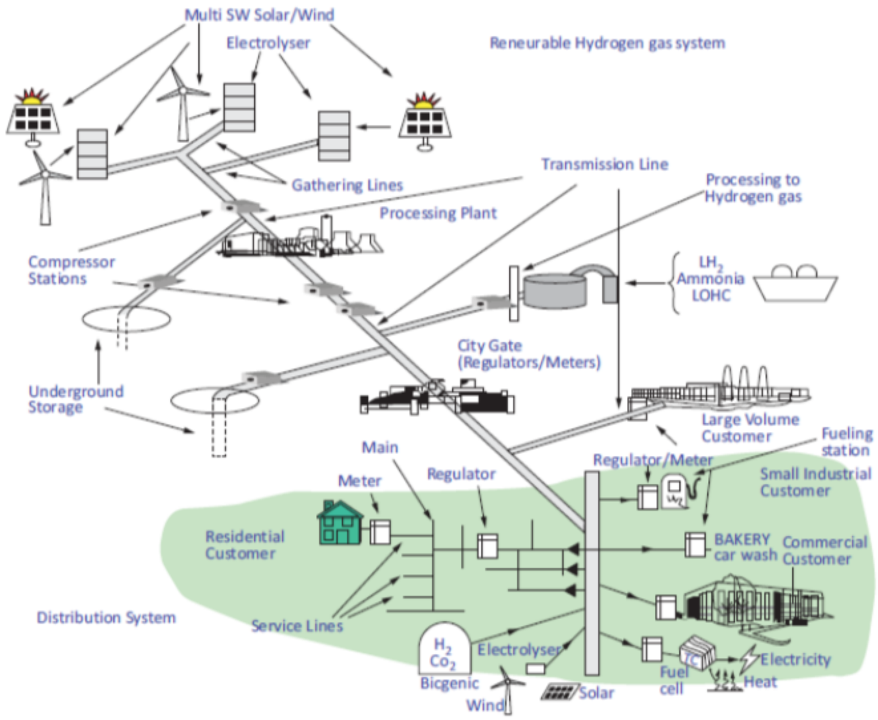


Figure 10.1: A schematic lay-out of a future renewable hydrogen system (van Wijk, 2021)

10.2 Green gas

The current natural gas system is depicted in picture 10.2 (GasTerra, 2021). Here, it can be observed that both low-caloric- and high-caloric main transmission pipelines exist. In this respect, the difference relates to the presence of nitrogen that lowers the caloric value of the natural gas stream. Next to this, also the green gas injection location, LNG import and natural gas distribution pipeline are depicted. Here, the respective pipeline specification has no impact on the potential injection of green gas. This is due to the fact that green gas could relatively simple be purified to the desired qualities. Moreover, green gas can either be injected in the gas distribution network at a low 8 bar pressure or in the gas transport network at a high [40-65] bar pressure (GasTerra, 2021). For the gas grid injection, the green gas requires support from green certificates to prove the origin from short-cycled organic sources as the biomethane is blend with- and indistinguishable from natural gas. This subsequently could also stimulate the adoption- and trade of biomethane. However, in a transition to the future renewable hydrogen system the potential to create a single certificate for all renewable gas, could further boost the market for certification trade. Moreover, it could support the continued sustainability efforts of gas production (GasTerra, 2021).

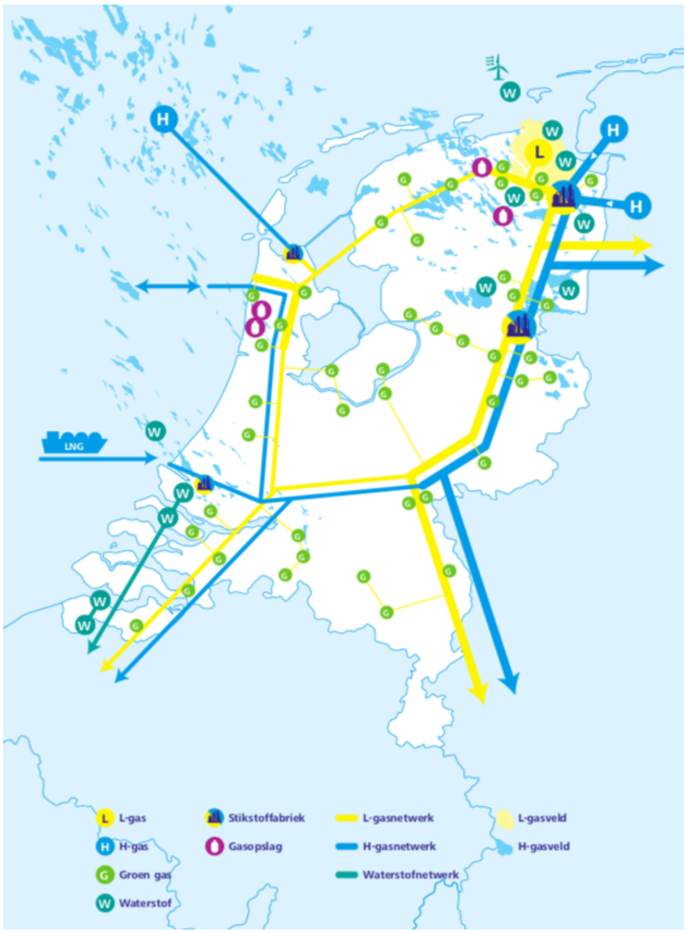


Figure 10.2: The Dutch gas system (GasTerra, 2021)

Therefore, for the widespread adoption of biomethane the infrastructure design is of considerable importance. In this respect, it is observed that there exist a trend in the increases of biomethane grid injection volume within the EU. This is in contrast to the direct utilisation of physical delivery of biomethane. Here, the grid injection occurs at both transmission- and distribution grid levels. This is stimulated by the direct connection of biomethane plants to the gas grid at either the distribution- or transmission level. However, the actual grid connection types for biomethane vary by country, but on average show that around 90% of the biomethane plants is connected at either level. Moreover, this is further facilitated through the development of a national biomethane planning framework to map high potential production zones of biomethane with grid injection locations (Wouters et al., 2020).

Next to utilisation of the traditional natural gas pipeline network, another trend that is observed with respect to the biomethane infrastructure is the early commercial deployment of biogas pooling. In this respect, biogas pooling supports large- and centralised biogas upgrading where biogas is collected from multiple dispersed biogas production locations. This subsequently allows for a potential increase in system efficiency and for possible lower cost of both the upgrading process and the grid connection. On top of that, biogas pooling supports flexibility as it allows for additional storage potential or conversion to biomethane as opposed to the direct usage of biogas for baseload heat- and electricity production. Next to biogas pooling, another trend observed is the development of reverse flow plants. The reverse flow plants allow for the mitigation of biomethane oversupply in periods of low gas demand as it allows biomethane to flow upwards towards medium- or high-pressure grids from lower level injection levels. The reverse flow plant operates via a decentralised gas compression mechanism unit. This supports the transportation of biomethane from the production location to different regions. Hereby, it boost the biomethane grid injection potential (Wouters et al., 2020).

Here, the biogas pipelines are expected to be mostly between [3-17] km of length and operate at pressures of [0.5-4] bar. However, for the pipeline transport of raw biogas from digestion five hazards are identified as compared to the transport of natural gas. Nonetheless, measures are proposed which are expected to mitigate the identified dangers and are usable for guidelines around licensing, owning and operating of biogas pooling (de Bruin et al., 2016). These identified hazards include, the negative effects of biogas components on the material integrity of the pipelines, the toxic effects of specific biogas components, the potential presence of harmful micro-organisms, the different odour of biogas, and the possible higher density of biogas. As a result, the proposed measures include the transport of only dry biogas with a dew point of -3 °C or lower at the maximum operating pressure, a maximum concentration of aromatic compounds of 800 pm and no condensed higher hydrocarbons, a maximum concentration of H_2S of 160 ppm, a pipeline located beyond a certain maximum distance, and local information provision. Here, the dry biogas and high pressure reduce the negative effects on materials and the negative effects from micro-organism. Moreover, the maximum concentration requirement reduce negative effects on material integrity and the toxic effects. Lastly, the placement and information is mentioned to ensure save operations with respect to the higher density and different odour of biogas (de Bruin et al., 2016). These measure will result in yearly costs in the range of €[20,000-40,000] depending on the respective measure and based on a biogas flow of 500 m^3/hr with a lifetime of 12 years. Here, the drying of biogas is assumed to be most expensive and has assigned costs that vary between °[9,000 - 30,000] over the whole chain. Nevertheless, the proposed measures are presumed to fulfill the demand requirement of the users and as a result could become an integral part of the ultimate purchase agreement (de Bruin et al., 2016).

10.2.1 Infrastructure design

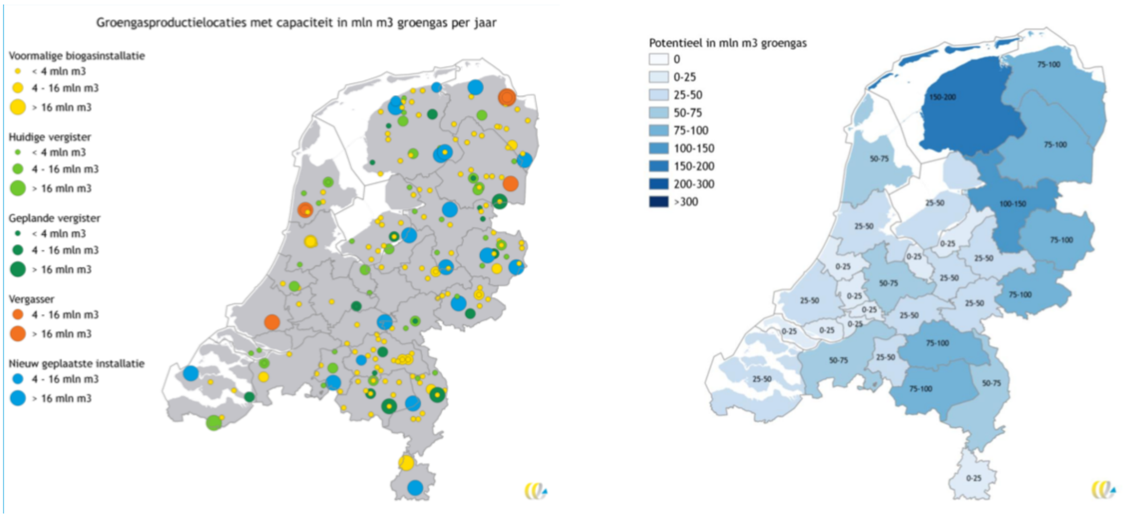
For the future development of the infrastructure, the interplay between national direction, regional design, municipal vision and neighbourhood implementation is importance Rendo, 2020. In this respect, the local- and decentral increase in green gas production could result in oversupply in the regional distribution network. As a result, to allow for continued transport of gas a connection pipeline to other regions might be required. Moreover, via the usage of a booster the oversupply of green gas in the distribution network of a region can then be connected to the national gas transport network. Nevertheless, this could in turn result in lower utilisation of the locally-produced biomethane, which has the potential to hinder regional support. Next to necessity of boosters to connect biomethane production locations with demand centers over a wider region, also sufficient injection points are required to distribute the potential green gas production capacity (Rendo, 2020).

Moreover, the potential for local storage- and or buffering of green gas is stated to become increasingly important. This relates to creation of a better match between seasonal demand for gas and the relatively constant green gas production. This in turn expected to become more prevalent due to the expected capacity constraints, primarily, in the local network. Moreover, it relates to the increase in variable renewable electricity production capacity and as such the inherent value of flexibility in the energy system. In this respect, the creation of connection distribution pipelines between local networks and gas receiving stations of different areas could resolve the main expected bottlenecks. This is relevant as currently the different areas, if connected, are mainly connected through lower-pressure pipelines. Moreover, in the longer term additional compressors are expected to be required in order to connect the distribution pipelines with the national gas infrastructure (Rendo, 2020).

The infrastructure requirement is related to the potential locations for green gas production and injection. Moreover, the required injection capacity per location correlate in turn with the production capacity of the respective digester. Additionally, the infrastructure requirement should account for the potential addition of new biomethane production capacity. This, could also include the potential usage of biogas collection infrastructure (van der Veen et al., 2020). Here, in case of sufficient- and proximate biogas production the coupling of biogas production locations with biomethane production locations could be envisioned. Here, it is presumed that these locations are not located more than 100 km apart. In this respect, the biogas infrastructure could then be used for the injection of biogas by multiple biogas producers at low pressure. The biogas is subsequently transported to a centralised biogas upgrading plant. Here, the produced biomethane can then be injected at a higher pressure in the grid. This design could show economic benefits, for example, with respect to lower investment requirements for gas treatment and compression in case of single biogas- and biomethane production. Moreover, the required infrastructure could be originate from re-purposed natural gas pipelines if this shows sufficient economic benefits for the gas system. This is in turn is related to the number of biogas producers present and as such location dependent (van der Veen et al., 2020).

Ultimately, based on the exact biogas production potential, an allocation, on a system-level, could be made to respective green gas production locations. This includes the required injection points and related green gas production capacity. In the case of the Netherlands, an estimate of potential locations for green gas installations by 2030 can be observed in figure 10.3a. The estimate is based the presumed economic green gas potential in the Netherlands. The respective economic green gas potential from AD biogas can be observed in 10.3b (van der Veen et al., 2020).

However, for the proposed- and expected scaling of the biomethane production the primary limiting factor relates to unlocking of the available biogenic resources Bianchi, 2018. At the moment it is mentioned that the collection- and distribution of biogenic resources lack logistic concepts. This is especially relevant since wet biomass streams are stated to be prohibitively expensive to transport. This relates to both the high moisture content and the respective degradation in biomass quality. Here, also the potential release of methane during storage and or transportation is of importance. As a result, manure requires rapid collection and conversion. This is turn limit the



(a) Green gas production locations (b) Economic green gas potential

Figure 10.3: Estimate of green gas production and potential in the Netherlands by 2050 (van der Veen et al., 2020)

logistical potential. Subsequently, it can be observed that the production of biogas occurs mainly at small-scale at decentral- and agricultural installations. However, this requires high capital expenditures per agriculturalist. Moreover, the production of biogas is not a core business practice of the agriculturalist. On top of that, most biogas production is discussed to not be sufficiently profitable and only limited incentives exist to support the production capacity. As a result, the production potential of biogas is hindered (Bianchi, 2018).

On the contrary, centralisation of the biogas production and or biogas upgrading could stimulate profitable business operations. In case of biogas upgrading, this betters the potential for green gas injection. Moreover, it eases the extraction- and trading of by-products, like bio-CO_2 and bio-digestate (Bianchi, 2018).

As a result, the creation of strategic, centralised hubs for the exploitation of the production-, upgrading- and processing of biogas towards biomethane, bio-CO_2 and digestate is proposed as infrastructure overhaul (Bianchi, 2018). The strategic hubs are then used to obtain the required economies of scale and as a result achieve system cost reduction. Moreover, it is proposed to eases business- and logistical operations. Ultimately, the strategic hubs could serve to unlock more biogenic resources, economically (Bianchi, 2018). Also, the strategic hubs could help in the creation of synergies with respect to additional compression requirements that are needed to link distribution networks with the national network. Additionally, strategic hubs have the potential to stimulate system integration, for example, through the connection with local temperature sources or renewable electricity- and renewable hydrogen production capacity (Bianchi, 2018). However, the benefits of the proposed strategic hubs are strongly dependent on the location. This relates to the proposed advantages with respect to scale, quality and costs. Therefore, several key characteristics should be present in the strategic hub design. These include, the presence of local, high-density biogenic sources and production locations, the presence of local demand centers for biomethane and or biogas, the availability of gas infrastructure for the distribution of biomethane and import of biogas, the availability of other infrastructural possibilities like rail and water as alternative transport modes, the close proximity to other sectors to allow for possible synergies, and finally a local, social support base (Bianchi, 2018).

10.3 Hydrogen

Since hydrogen is the lightest element in the universe, the energy density per unit of volume is relatively low. More precisely, gaseous hydrogen contains about 3 kWh or 10.8 MJ per cubic meter at atmospheric pressure. As a result, compressed hydrogen is one way to transport considerable amounts of energy in the form of hydrogen. Another option to transport more energy per volume unit is the liquefaction of hydrogen. This will allow for the transport of 800 times more hydrogen in liquid form per volume unit as opposed to the gaseous form at atmospheric pressure. In this respect, the compression- and liquefaction of hydrogen relate to the transport of natural gas in the form of CNG and LNG respectively. In the case of the liquefaction of hydrogen, the hydrogen has to be cooled down to -259 °C. This is opposed to -162 °C for natural gas. Moreover, the liquefaction process requires around 10 kWh per kilo of hydrogen, or almost one-third of the energy content per kilo of hydrogen. However, this could potentially be reduced in half at larger production facilities (van Wijk et al., 2018). An overview, of the respective energy requirements for different storage options, at different hydrogen densities can be seen in table 10.1 (DOE, 2021). In this respect, table 10.1 indicate the inherent efficiencies of the conversion options. Next to compression- and liquefaction of hydrogen, other options to transport more energy per volume unit is the conversion of hydrogen to another chemical or binding hydrogen with another chemical. These could also support transportation requirements. In this respect, ammonia represents an relevant opportunity as ammonia is considered to be the only chemical that can be made from abundant raw materials at remote locations. Moreover, ammonia production is a developed processes including mature technologies and installations, and is used on a large-scale in different applications (van Wijk et al., 2018).

Storage technology	Hydrogen density (kg/m^3)	Energy required
No pressure ([30-35 bar]) and 25 °C	2.77	H_2 production via PEM electrolysis
Low pressure ([50-150 bar]) and 25 °C	[3.95-10.9]	[0.2-0.8] kWh/kg H_2
High pressure (350 bar) and 25 °C	23	4.4 kWh/kg H_2
Liquid H_2 (-253 °C) and 1 bar	70.8	[10=13] kWh/kg H_2
Liquid NH_3 (-33 °C) and 1 bar	121	[2-3] kWh/kg H_2 based on 12 kWh/kg NH_3
Liquid NH_3 (25 °C) and 10 bar	107	Also, 8 kWh/kg H_2 for reconversion

Table 10.1: Hydrogen storage options, densities and energy requirement (DOE, 2021)

For the subsequent transport of hydrogen or hydrogen-derivatives over long distances, pipeline- and or ship transport is considered. In contrast, for lower-volume and shorter-distance transport hydrogen transport via tube trailers is considered.

In case of pipeline transport, hydrogen transport via pipeline has been common practice for over decades. For example, there are hydrogen pipelines present, which connects the Netherlands, Belgium and the north of France. Moreover, traditional natural gas pipelines, both large-transport steel pipelines and distribution synthetic pipelines, can be relatively simple- and cost-effective be converted to hydrogen transport pipelines. In this respect, a dedicated, European hydrogen backbone is proposed consisting of 75% converted gas pipelines and 25% newly constructed hydrogen pipelines of different inches or capacities (van Wijk, 2021). Moreover, next to hydrogen pipeline transport, also ammonia pipeline transport is an option. Like the transport of hydrogen via pipeline, the transport of ammonia via pipeline occurs at the moment. However, the drawbacks related to pipeline transport include the high capital costs entailed and the need to acquire rights of way. With respect to the former, these are presumed to be lower in the case of new pipelines for ammonia as opposed to hydrogen (IEA, 2019). Nevertheless, hydrogen pipelines are expected to have similar CAPEX costs as compared to natural gas pipelines (McKinsey, 2021). Next to a new hydrogen transmission and distribution infrastructure, for the initial period, hydrogen can also be blend in existing natural gas grids at relatively low increased cost. This is compared to costs associated with hydrogen production, for the potential injection stations and the presumed operational costs. However, in the case of hydrogen blending the actual the blending ratio is dependent on the presumed end application and equipment used. Moreover, regional- and or intercontinental interconnections and harmonisation is important for the determination of the acceptable blending percentage (IEA, 2019).

In case of hydrogen transport by ship, the hydrogen can be transported either as liquid hydrogen, can be converted to ammonia or could be bind to a liquid organic hydrogen carrier (van Wijk, 2021). In this respect, the different possibilities hold distinct characteristics and different advantages and or disadvantages. Here, liquid hydrogen transport is new and requires the development and building of new carrier transport options. On the other hand, ammonia transport is a mature technology with developed supply chains. In contrary, LOHCs benefits from the possibility to be transported by re-utilisation of the existing oil assets. Nevertheless, both ammonia and LOHC require conversion and reconversion in case of hydrogen demand in the end application (IEA, 2019). Moreover, liquid hydrogen has as drawback that it has a relatively low volumetric energy density, especially as compared to ammonia. This limits the amount of hydrogen per ship. Moreover, liquid hydrogen is characterised by a boil-off loss that occurs with every day of storage. On the other hand, ammonia faces drawbacks with respect to high costs of cracking it back into hydrogen, Moreover, the deployment of ammonia as hydrogen carrier is hindered by the achievable purity levels and the fact that ammonia is toxic. The latter results in restrictions in the handling- and storing of ammonia, especially in residential areas or for in-land distribution. In contrast, LOCHs are considered save to store hydrogen over long periods without loss and is presumed to use cheaper storage tanks. Nevertheless, LOCHs face disadvantages related to the novelty of the dehydrogenation process. For example, for the dehydrogenation process large amounts of heat are required. On top of that, LOHCs have a limited hydrogen carrying capacity as opposed to liquid hydrogen and ammonia (McKinsey, 2021). Next to the respective advantages and disadvantages, the respective transportation options are supported by port development related to, for example, the import- and export facilities and the wider system strategies (IEA, 2019). Ultimately, the costs, and as result the relevant transport options, depend on the distance and respective end application (van Wijk, 2021). Here, the costs include, among other, storage tanks, liquefaction- and gasification plants and or conversion- and reconversion plants (IEA, 2019).

Next to transport of hydrogen by pipeline and or ships, hydrogen transport by tube trailer is advancing rapidly. Moreover, the transport of hydrogen via tube trailers already exists (van Wijk et al., 2018). More specifically, hydrogen transport for less than 300 km today relies mostly on compressed gas trailer trucks. However, also liquid trailer trucks are relevant in case the liquefaction costs can be offset by lower unit costs of hydrogen transport (IEA, 2019). Moreover, the decision between compressed- or liquid hydrogen transport via tube trailer also relies on the respective end applications and as such the system cost (McKinsey, 2021). In the case of compressed gas transport, the hydrogen is transported in tubes under a pressure of [120-200] bar. However, technological development in carbon fibers could allow for higher pressures of up to 500 bar. Here, the transport of hydrogen at 500 bar allows for the transportation of 1,100 kilos of hydrogen at 39.4 kWh per kilogram of hydrogen in a tube trailer of around 40 feet and 30 tonnes (van Wijk et al., 2018). In case of liquid hydrogen transport, highly insulated cryogenic tanker trucks are used that carry up to 4,000 kg liquid hydrogen. These tanker truck can be used to transport hydrogen over long distances of a maximum up to 4,000 km (IEA, 2019). However, road transport could also be used to distribute ammonia or LOHCs in almost similar ways. In this case, around 5,000 kg of hydrogen or 1,700 kg of hydrogen in the form of ammonia or LOHC could be moved in a road tanker truck respectively. (IEA, 2019).

Also, hydrogen storage will be an integral part of the system design. In this respect, large-scale hydrogen storage in salt caverns is considered the most economic- and mature technology. The storage of hydrogen in salt caverns mimic the natural gas storage that has been applied for several decades. In the case of salt cavern storage, the hydrogen is stored at pressures up to 200 bar with a capacity of 6,000 ton hydrogen, or around 240 GWh based on HHV. Here, salt caverns are geographically available and or could be developed in different salt formations. In Europe, the on-shore potential is estimated to be around 7,300 TWh and the offshore capacity to be around 61,800 TWh. Therefore, the storage potential of hydrogen in salt caverns is stated to exceed the total final energy consumption in Europe. However, in contrast to hydrogen storage in salt caverns, the large-scale hydrogen storage in alternative options like empty gas field, rock caverns and aquifers require additional research to prove the potential (van Wijk, 2021). Next to large-scale geographical storage, hydrogen could also be stored in compressed form in, smaller-scale, tanks (van Wijk et al., 2018). Moreover, next to storage in compressed form hydrogen could also be stored in liquid states, in the form of ammonia, bind to metal hydrides or organic chemical hydrides, or adsorbed on a solid or liquid surface (van Wijk et al., 2018).

Overall, it is assumed that geological storage will be the best option for large-scale and long-term storage, while tanks provide a more suitable method for short-term, small-scale storage (IEA, 2019). In this respect, salt caverns enjoy high efficiencies, low operational costs, low land costs, high discharge rates, and reduced upfront costs due to series or separate operation of adjacent caverns. Depleted oil- and gas reserves on the other hand are typically larger than salt caverns, however face issues with permeability and contaminants, while water aquifers are the least mature option with mixed scientific evidence on sustainable operations (IEA, 2019). Storage tanks in contrast, also enjoy high discharge rates and high efficiencies, for both compressed- and liquefied hydrogen, which storage tanks well-suited for smaller-scale applications. However, the relatively lower volumetric energy density of compressed hydrogen as opposed to gasoline leads to considerable larger space requirements (IEA, 2019).

10.3.1 Infrastructure development

For the development of renewable hydrogen demand within Europe, the focus is on the re-use of the gas infrastructure interconnections with North-Africa. Moreover, this also applies for the transport- and store hydrogen across the different European gas producing countries. The overhaul then supports the potential for cost-effective transport and storage of large-volumes of reliable-, cheap- and abundant renewable electricity production in the form of hydrogen (van Wijk and Chatzimarkakis, 2020.

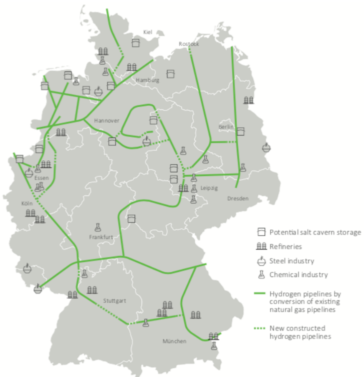
In this respect, the hydrogen gas infrastructure would be around [10-20] times cheaper than building the same energy transport capacity via new electricity infrastructure. On top of that, the existing gas infrastructure is presumed to be relatively quickly be converted to accommodate hydrogen transport (van Wijk, 2021). However, the reuse of the existing gas infrastructure is primarily relevant for modern low-pressure gas distribution pipelines that are made of polyethylene or fibre-reinforced polymer material (IEA, 2019). Moreover, the creation- and reuse of hydrogen pipelines depend on the type of hydrogen pipeline. Here, the costs of hydrogen transport is expect to decrease in cost from subsea transmission pipelines to onshore transmission pipelines to ultimately distribution pipelines. However, all show a factor three increase in CAPEX estimates per km for new hydrogen pipelines as compared to retrofit hydrogen pipelines. Ultimately, the actual cost for retrofitting pipelines depends on factors like diameter, pressure, quality of materials, overall condition, existence of cracks and other considerations (McKinsey, 2021). Nonetheless, the repurposing of natural gas pipeline is expected to primarily incur costs that are related to the replacement of compressor stations, valves and metering stations (Wouters et al., 2020). Besides the cost involved, the relevant technical points of attention arise from the addition of compressor stations in the case of growth in the hydrogen volume transport. Moreover, additional technical parameters include the suitability of delivery stations, the hardness requirement of the pipelines, the potential purity requirement variations throughout the value chain, the replacement of valves, the cleaning of pipelines, the replacement- or adjustment of measuring apparatus, and the change in process control and maintenance (GL, 2020) (Tezel and Hensgens, 2021).

More specifically, in the case of the Netherlands a hydrogen backbone is to be realised that connects hydrogen production facilities from offshore wind at the North Sea with hydrogen storage facilities in salt caverns and industrial demand sectors. The proposed hydrogen backbone in the Netherlands can been seen in figure 10.4a (van Wijk and Chatzimarkakis, 2020). Moreover, in the case of Germany a plan for a 5,900 km hydrogen transmission grid to connect production centers in the north with salt cavern storage and large customers in the west and south is developed. The proposed hydrogen transmission grid in Germany can be seen in figure 10.4b. On top of that, the transnational European hydrogen backbone is expected to facilitate the transport of large amounts of hydrogen from the solar- and wind resource locations to in-land Europe. These include solar-rich regions in North Africa and wind-rich regions in the Eastern pert of Europe. Moreover, the transnational European hydrogen backbone could, for the intermediate period, also support the transport of lower-carbon hydrogen from fossil-resource rich areas. The proposed transnational European hydrogen backbone can be observed in figure 10.5a (van Wijk and Chatzimarkakis, 2020). Lastly, the existing pipelines exporting natural gas from

North-Africa, like Algeria and Libya, to Europe can be converted to accommodate hydrogen. Moreover, new hydrogen pipelines are envisioned to be be constructed from, for example, Egypt or, possibly further, from Ethiopia and the Middle East, via Greece to Italy. This then could unlock the abundant- and cheap renewable electricity capacity of North-Africa and the Middle East for Europe. The proposed hydrogen pipelines can be seen in figure 10.5b (van Wijk and Chatzimarkakis, 2020).

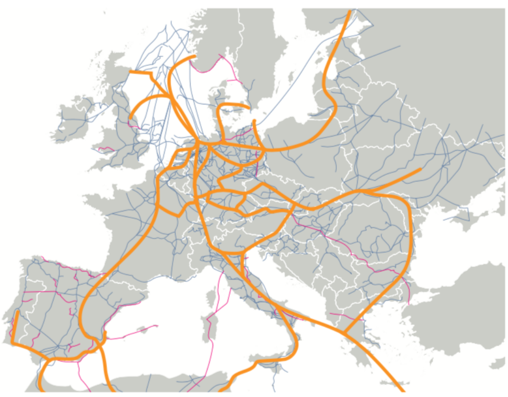
The proposal for repurposing existing natural gas pipelines or development of new natural gas pipeline from North-Africa to Europe is in contrast to a poorly developed electricity grid infrastructure present between North-Africa and Europe. Therefore, in order to transport renewable electricity from North-Africa to Europe, this would require reinforcements- and expansion of the electricity grid. However, the presumed costs for the development of the required electricity grid is expected to be significantly higher than the development of the proposed hydrogen infrastructure (van Wijk and Wouters, 2019).

(a) The Netherlands

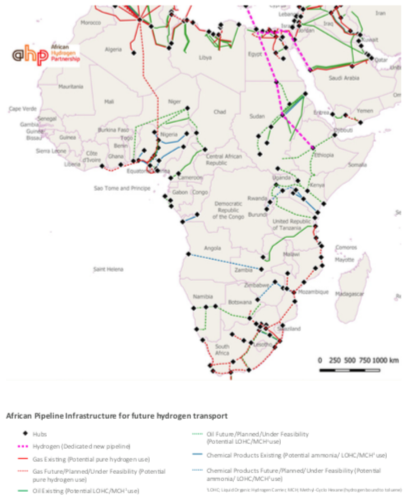


(b) Germany

Figure 10.4: National hydrogen backbone proposal (van Wijk and Chatzimarkakis, 2020)



(a) Transnational



(b) Intercontinental

Figure 10.5: Transnational and intercontinental hydrogen backbone proposal (van Wijk and Chatzimarkakis, 2020)

In the future renewable hydrogen system, the storage function is expected to become increasingly important. This is, for example, due to the expected mismatch between demand- and variable supply of renewable electricity. This is indicate to show an exponential increase in demand for hydrogen as increasing function of variable electricity sources (van Wijk and Wouters, 2019).

In case of large-scale storage, salt caverns are currently widely deployed for the storage of natural gas. In this respect, up to [15-20]% of the total gas consumption is stored in salt caverns. This is next to the storage of natural gas in empty gas fields and porous rock formation. Moreover, salt caverns are at the moment used to store oil, compressed air, other products, or hydrogen.

At the moment, Europe has a considerable amount of empty salt caverns. Moreover, Europe has the potential to reuse existing salt caverns or could develop dedicated salt caverns to ensure sufficient hydrogen storage. The overview of the salt cavern storage potential in Europe can been seen in figure 10.6 (van Wijk and Chatzimarkakis, 2020). Here, it can be seen that most salt caverns can be developed onshore in Germany, Poland and Portugal, while large offshore potential exists in the Netherlands and Norway (van Wijk and Chatzimarkakis, 2020).

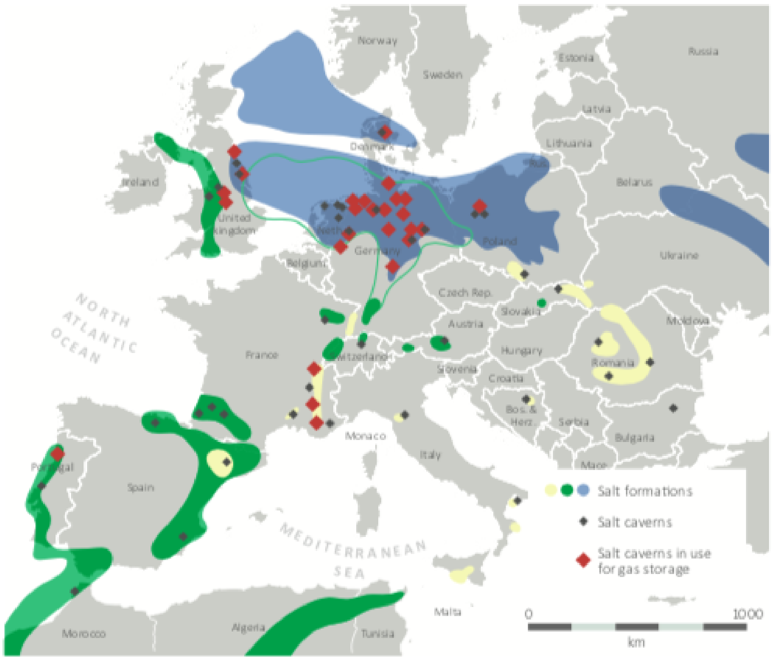


Figure 10.6: Salt formation with salt caverns throughout Europe (van Wijk and Chatzimarkakis, 2020)

Ultimately, the transition from a natural gas- to a hydrogen transport system, could be stimulated through the utilisation of lower-carbon hydrogen production, for some time, to boost the volume of hydrogen. Moreover, the blending of hydrogen with natural gas, which only require some- or minor adjustments could be used to stimulate the transition. Additionally, the insertion of a small hydrogen pipe within a natural gas pipeline could be used to support faster- and cheaper installation of required hydrogen capacity. On top of that, the development of liquefaction plants and special vessels could stimulate the large-volume- and large-distance transport of hydrogen. Alternatively, green ammonia plants could further ease export, while also other hydrogen- based solutions could stimulate the ship transport of hydrogen. Here, the preferred solution will depend on the regional characteristics (van Wijk and Chatzimarkakis, 2020).

On top of that, a smart combination of expansion of the electricity grid and the parallel re-using- and expansion of the gas grid for hydrogen transport is expected to result in a more cost- effective infrastructure system and transition. Moreover, the parallel development of infrastructure capacity could boost a faster renewable energy system realisation and cost-effectively replace fossil fuels.

Additionally, next to an assumed storage capacity of about [20-30]% of the final energy consumption, smart grids, demand-side management, strengthening interconnections and other balancing instruments could stimulate the reliability- and affordability of the renewable energy system (van Wijk and Wouters, 2019).

However, so far the development of the hydrogen infrastructure has been considered slow, which holds back the widespread adoption of hydrogen. This, for example, include the limited rollout of HRS to support FCEVs adoption, the lack of- and ability for public investments, and the observed complexity of co-ordination across borders (IEA, 2019). As a result, IEA, 2019 identified near-term opportunities to boost hydrogen adoption. These include making industrial ports the nerve centers for scaling up the use of clean hydrogen. This could then support scaling and drive down the overall costs perspective of hydrogen. Moreover, this will allow to fuel ships and trucks. Moreover, another opportunity include building on existing infrastructure especially natural gas pipelines to introduce clean hydrogen. This is seen as an route to boost demand for hydrogen and subsequently drive down the costs. Moreover, hydrogen could be expanded in transport fleets, freights and corridors to make FCEVs more competitive. Finally, hydrogen international trade shipping routes could be launched in similar fashion like the global LNG market. On top of that, McKinsey, 2021 mention co-location of hydrogen production on- or near-site large-scale clean hydrogen applications could be the most competitive setup in the short- to medium term. Here, the scaled production could then also be used to supply fuel to other hydrogen users in vicinity, like HRS and smaller industrial users.

10.3.2 Infrastructure design

At the moment, hydrogen production primarily occurs on-site and is used to fulfill bulk industrial demand. Here, multiple users in an industrial cluster are connected through dedicated pipelines for the transport of hydrogen. In the Netherlands, a 140 km private network exist to connect Rotterdam to local, clustered industries. Moreover, in the Netherlands part of a 1000 km private hydrogen pipeline is present that links the Port of Rotterdam via Belgium to the North of France. On top of that, a 12 km semi-public re-purposed natural gas pipeline is used in the Netherlands to connect two industrial sites for dedicated hydrogen transport. The former two networks can be seen in figure 10.7 (R. Detz et al., 2019). However, the hydrogen is, almost, exclusively produced from fossil fuel, mainly natural gas at the moment. This reliance on fossil fuels in turn explains the lack of infrastructure for hydrogen. This relates to the fact that due to a natural gas connection the hydrogen can be produced close to the end user (Tezel and Hensgens, 2021). In contrary, in case that hydrogen or hydrogen-rich residual gases are formed as byproducts the transport of hydrogen might be required. This is the case when the industrial offtakers are not co-located in the same industrial hub. Overall, The estimated transportation volume of the described hydrogen pipelines in the Netherlands is approximately 10 PJ/year.

On top of that, around 0.2 PJ/year is transported by truck (Tezel and Hensgens, 2021).

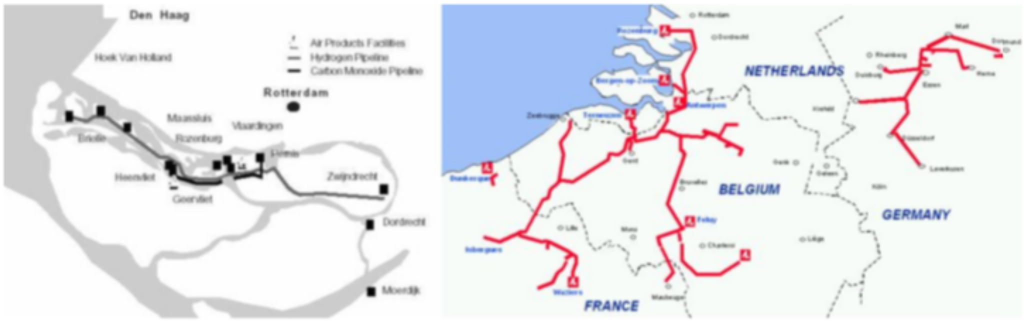


Figure 10.7: Current dedicated private hydrogen pipelines in the Netherlands (R. Detz et al., 2019)

However, the future hydrogen infrastructure design in the Netherlands will become more complex. In this respect, the infrastructure design will depend on the level-, structure- and time profile of the ultimate hydrogen demand and supply. Moreover, this includes the conversion- or modification of the current gas network. Also, the location-, capacity- and operation of power-to-hydrogen installations and the actual ownership- and regulation of the hydrogen infrastructure will be relevant for the infrastructure design (R. Detz et al., 2019). In this respect, GL, 2020 discuss that for the infrastructure design a stronger governmental directing task in tandem with industrial parties and infrastructure companies will be required. Here, projects should be considered from a cost perspective of the entire value chain. Moreover, it should consider emission reductions, system integration, international connections and potential innovations (GL, 2020). Moreover, it should follow the perspective on opening molecular transport as opposed to electron transport. This is especially relevant in those instances where net congestion exists. Here, the hydrogen modality is significantly more cost-effective as opposed to establishment of a high-voltage network with perspective on the entire value chain costs from production via conversion to utilisation (GL, 2020).

The infrastructure design should also relate to the CO_2 infrastructure. In this respect, the liability on carbon storage lies with the government and arrangements are to be made with respect to accessibility for third parties. This is in contrast to the current private infrastructure. Moreover, a further shift to CCUS technology would open redundant CO_2 infrastructure for the transport of alternative feedstock, like ammonia and ethanol (GL, 2020).

Ultimately, this fits with the perspective of the Dutch government to become a European hub for climate-neutral energy- and feedstock products. This in turn follows from the strategic positioning- and adequate infrastructure of the Netherlands (Tezel and Hensgens, 2021).

At start, to facilitate the rising demand- and supply of hydrogen, a dedicated national hydrogen transport and storage infrastructure will arise. These include cross-border connections with neighbouring countries. Here, the Netherlands can rely on the current extensive natural gas infrastructure (R. Detz et al., 2019). The initial development of the hydrogen infrastructure arises from two reasons. Firstly, it allows for the connection of sources of renewable electricity, via hydrogen, with demand centers at distance locations. Secondly, it allows for the large-scale utilisation of hydrogen storage facilities that are presumed necessary to support seasonal- and daily storage needs. In this respect, hydrogen transport via pipelines are stated to be the most cost-efficient, especially for large volumes and medium transport distances (Tezel and Hensgens, 2021).

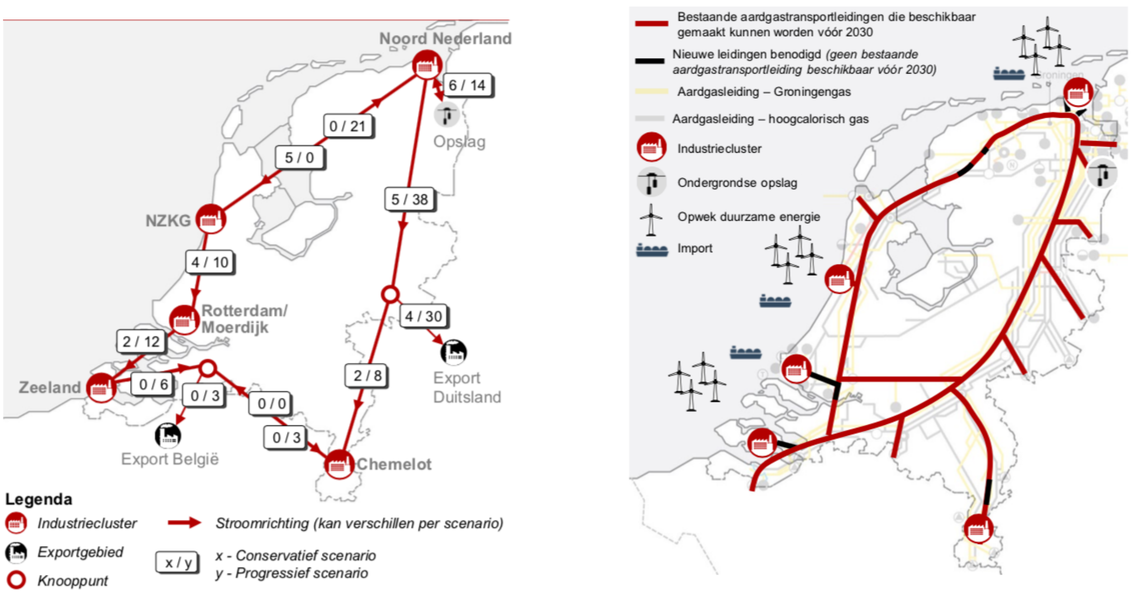
Here, an initial split into a hydrogen transmission- and methane distribution network is proposed to align with the required capacity. Hereafter, continued conversion of segments of the existing natural gas network is envisioned. This in turn can enable further development of hydrogen production capacity and stimulate the wider rollout throughout industrial clusters. Next, the rollout to other end-use sectors is expected (R. Detz et al., 2019). In this respect, the modular development of the hydrogen backbone allows for the initial hydrogen exchange between industrial clusters and support adequate infrastructure design planning with respect to further rollout (GL, 2020). This also includes alignment in design with neighbouring countries, which is relevant for, among others, the quality-, safety- and standards with respect to hydrogen transport. Hereby, the infrastructure design is able to anticipate on the future connections (GL, 2020). Moreover, the gradual development of the hydrogen infrastructure allows for a more dynamic- and liquid hydrogen commodity market (Tezel and Hensgens, 2021). Lastly, the gradual development is better able to anticipate on the development in hydrogen demand, supply and storage requirement. As a result, the exact configuration of the transport network is not fixed and as such can anticipate on where- and when the demand- and supply of hydrogen arise (Yeşilgöz-Zegerius, 2021).

In perspective, an overview of the expected hydrogen demand per industrial cluster, the hydrogen transport between clusters and the potential hydrogen export centers by 2030 can be seen in figure 10.8a (Tezel and Hensgens, 2021). Here, it is presumed that the hydrogen demand and transport is driven by a mismatch between the supply-, demand- and storage capacity requirement of hydrogen between the different centers. The required hydrogen transport is assumed to be technically feasible. Moreover, it is mentioned to occur via the conversion of the current natural gas pipelines into a dedicated hydrogen transport network. The dedicated hydrogen transport network is then also able to connect regional- and distribution networks. The proposed hydrogen network can be seen in figure 10.8b (Tezel and Hensgens, 2021). In this respect, the parallel nature of the current natural gas infrastructure in combination with an expected decrease in demand for natural gas thereby open up the possibility for repurposing of the natural gas infrastructure (GL, 2020). However, in those instances where significant volumes of natural gas are expected to remain transported, new dedicated hydrogen pipelines, or traces, are expected to be developed. Nonetheless, the need for new dedicated hydrogen pipelines is limited to a maximum of 15% of the required length (Yeşilgöz-Zegerius, 2021).

In this respect GL, 2020 takes a perspective on the industrial energy transition and focus on six industrial clusters in the Netherlands. In this case, the sixth industrial cluster represents decentralised industries like the food- and beverage-, paper and pulp-, and ceramics industry. An overview of the sixth cluster companies throughout the Netherlands, can be seen in figure 10.9. The sixth cluster is in turn depicted as the eastern cluster in 10.10 (GL, 2020). Here, the cluster six companies are currently connected via the main pipeline, regional pipelines or regional distribution pipelines. Therefore, based on the actual connection and proposed gradual development, the expected hydrogen connection of the cluster six companies is dependent on the regional characteristics (Tezel and Hensgens, 2021).

Next to the proposed network design, based on the presumed demand in the Netherlands, also strategic energy infrastructure connections with the Ruhr area and Flanders are portrayed. These connections thereby allow for the exchange in the hydrogen and CCUS facilities. In this perspective, the demand of hydrogen for utilisation as feedstock in the industry in Belgium and North Rhine-Westphalia is expected to exceed the demand in the Netherlands (Tezel and Hensgens, 2021). The proposed main hydrogen infrastructure design for 2030 is depicted in on the left in figure 10.10, while the expected CO_2 infrastructure can be observed on the right in figure 10.10 (GL, 2020).

On top of that, national ports are expected to serve as important points for the import of renewable hydrogen. This is especially relevant due to the presumed net-hydrogen import of the Netherlands (R. Detz et al., 2019). Moreover, this is further stimulated by the transit volumes required for neighbouring countries. This most dominantly will arise from North-Rhine Westphalia (Tezel and Hensgens, 2021).



(a) Hydrogen transport streams in PJ (b) Hydrogen transport pipeline network

Figure 10.8: Illustrative hydrogen transport network in the Netherlands in 2030 (Tezel and Hensgens, 2021)

The infrastructure design is next to the expected hydrogen demand and supply dependent on the hydrogen storage requirement and potential storage capacities. In this respect, storage in salt caverns are a proven technology and are primarily located in the North-East of the Netherlands. Besides storage, the salt caverns can be used to reduce oversizing of the infrastructure and as such have the potential to lower the system costs (GL, 2020. More specifically, Tezel and Hensgens, 2021 estimate that the number of onshore salt caverns is around 320. These onshore salt caverns have an estimated total capacity of round 14.5 bcm, or 43.3 TWh. This estimate is based on an average capacity of the onshore salt caverns of around [0.5-1] PJ. In this perspective, around [3-12] onshore salt caverns are required to fulfill the estimated storage need by 2030. An overview of the suitability for salt caverns in

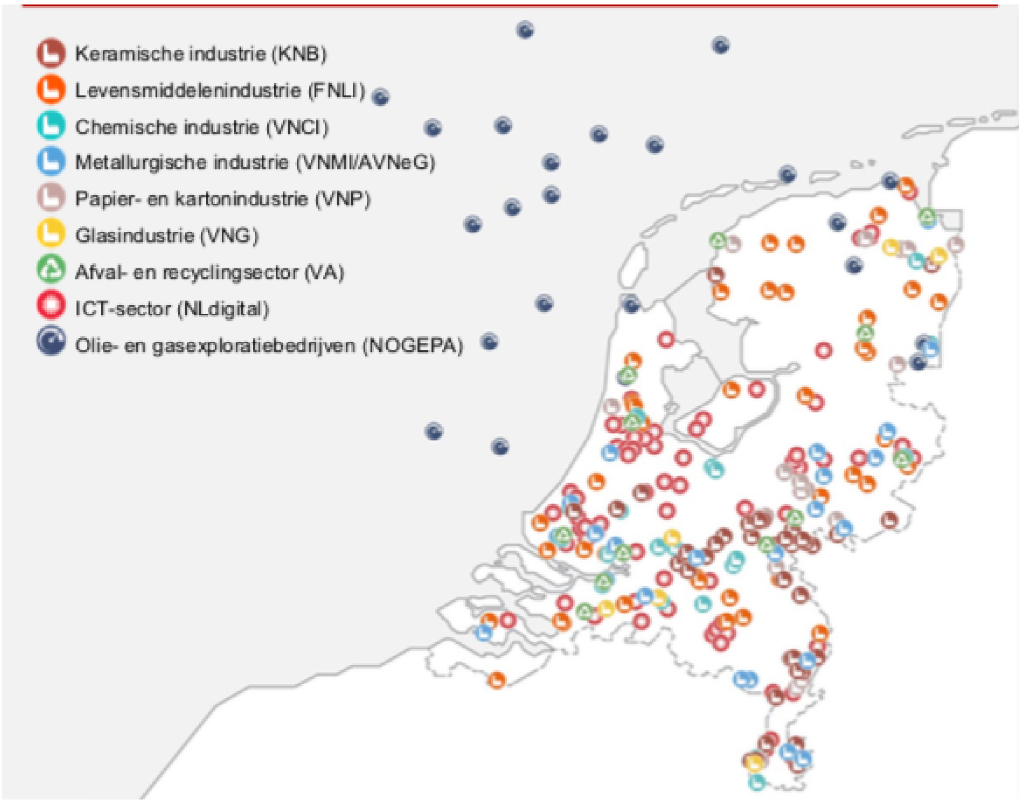


Figure 10.9: Overview of cluster-6 companies in the Netherlands (Tezel and Hensgens, 2021)

the Netherlands can be seen in figure 10.11 (Tezel and Hensgens, 2021).

In case of liquefied hydrogen, for example due to ship import, tank storage at import terminals could also become a relevant storage option. In turn, the storage terminals could also add the required flexibility. However, this depends on the relative reconversion cost perspective. Nonetheless, it is stated that the storage costs in pipelines or above-ground cylinders could increase the hydrogen storage costs [14-18] times on a €per kilogram hydrogen basis as opposed to salt cavern storage (Tezel and Hensgens, 2021).

On top of that, other potential storage options include offshore salt caverns in the North Sea, empty gas fields around Groningen and the North Sea or other salt formations in the Eastern part of the Netherlands. However, the use of offshore salt caverns, empty gas fields and aquifers remain unproven and therefore require additional research. This is opposed to the usage of onshore salt caverns (Tezel and Hensgens, 2021).

More specifically, van Wijk et al., 2019 highlight the need for a public infrastructure to stimulate green hydrogen adoption within the wider area of South-Holland. The design includes both dedicated hydrogen transport and the transport of CO_2. The latter is deemed indispensable for a sustainable industrial sector and horticulture. Additionally, it is expected that the CO_2 infrastructure would be required to transfer CO_2 to storage locations, primarily below the sea bottom. Moreover, the infrastructure design spans actions related to infrastructure in the harbor, hydrogen storage tanks and bunker infrastructure for inland shipping. It also includes, a perspective on infrastructure requirement for hydrogen busses, hydrogen refuelling stations and

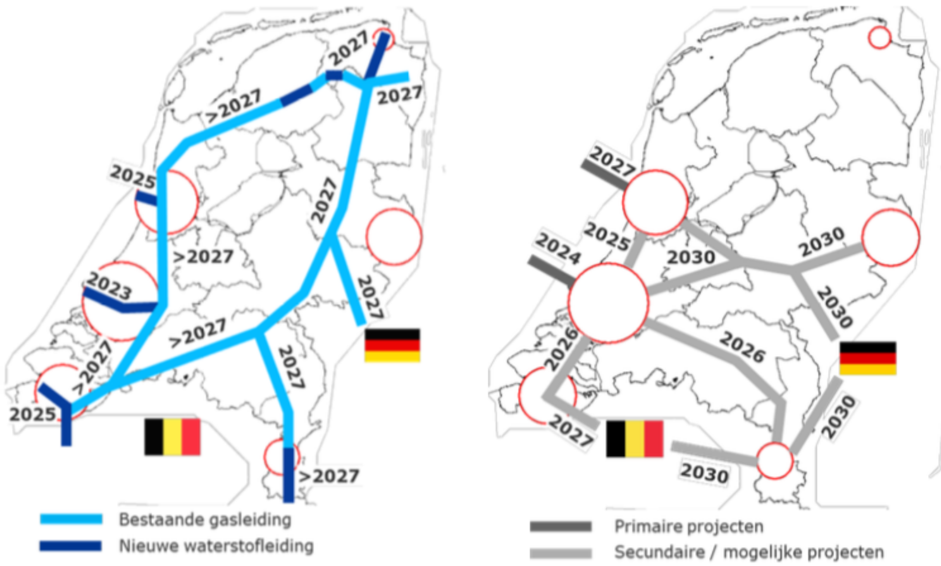


Figure 10.10: Main infrastructure requirement in the Netherlands for 2030 (GL, 2020)

industrial vehicles. On top of that, the design addresses repurposing of natural gas pipelines, the construction of new pipelines within the wider area, the development of alternative storage facilities, and finally the development of an import- and conversion site. In case of the latter, the unique pipeline infrastructure that is present in South-Holland poses a relevant competitive advantage for the South-Holland region to become a hub for renewable energy- and feedstock products (van Wijk et al., 2019).

Next to the hydrogen backbone, a hydrogen distribution infrastructure is mentioned to be required. In this way, the South-Holland region can be connected to the north of the Netherlands where most hydrogen storage facilities are located. This is especially relevant since the region does not have the geographical potential for hydrogen salt cavern storage. In turn, the hydrogen backbone would be connected to the the distribution network. The the hydrogen distribution in turn enables the connection of hydrogen supply sites with demand centers from the horticulture, industrial clusters, commercial buildings and residential housing. In this respect, repurposing of the current natural gas pipelines are expected to be adequate for the transport of hydrogen within the region (van Wijk et al., 2019).

Overall, the hydrogen backbone is presumed to be located around the region, spanning Rotterdam, Zeeland, Moerdijk and Antwerp. The hydrogen distribution pipeline, or ring lines, in turn can run based on a connection with the transport pipeline. Specifically, one hydrogen distribution pipeline is presumed to connect Goerree-Overflakkee, while the other one is located in the North in the direction of the horticulture. The hydrogen distribution pipelines could then both differ in hydrogen quality which depends on the respective use cases. The proposed structure can be observed in figure 10.12 (van Wijk et al., 2019).

Moreover, a CO_2 infrastructure will be required in the context of South-Holland to connect supply of CO_2 with demand centers in the horticulture and chemical industry. Moreover, the CO_2 infrastructure will also support the transportation of the captured CO_2 to storage locations. At the moment, an old-oil, re-purposed CO_2

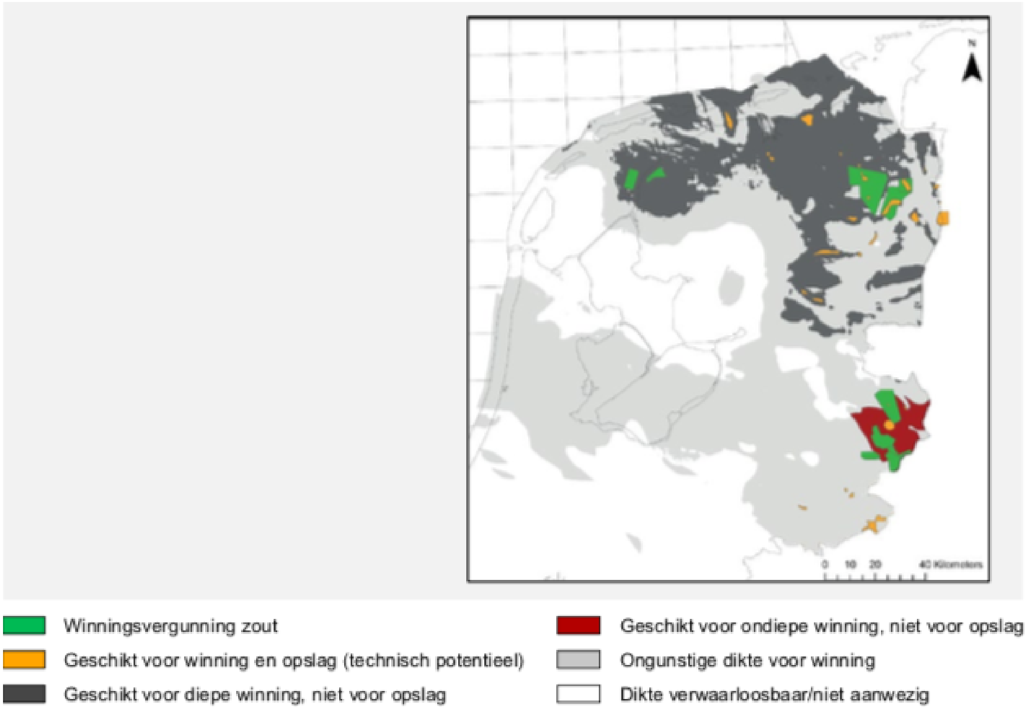


Figure 10.11: Overview of suitability of salt cavern for hydrogen storage in the Netherlands (Tezel and Hensgens, 2021)

pipeline connects the refining industry and chemical industry with the horticulture industry around the Westland. This pipeline currently covers around 600 kt CO_2 for around 600 horticulturist (van Wijk et al., 2019). However, not all CO_2 that is captured can be transported to demand centers in the horticulture. This is especially prevalent due to the seasonal demand of CO_2 in the horticulture. In that instance, the respective oversupply of CO_2 is emitted. Nonetheless, also storage- and delivery options for liquid CO_2 exist. In this case, the liquefied CO_2 can then be stored at the production site or at the horticulture site to support flexibility. The liquefied CO_2 is assumed to be transported by truck. This is primarily the case then there are no CO_2 transport- or distribution pipeline available or when the demand center is far away from the CO_2 capture unit (Lamboo et al., 2021). However, double- or triple the amount of CO_2 is expect to require transportation in the short-term. Therefore, a new pipeline infrastructure is expected to be required as well as industrial storage to support reliability in supply (van Wijk et al., 2019) (Lamboo et al., 2021). With respect to CO_2 storage, a collection pipeline is envisioned to connect several industrial producers of CO_2 with offshore storage locations. The pipeline is expected to transport around [2-5] Mt CO_2 (van Wijk et al., 2019). Overall, in case of carbon utilisation the CO_2 pipeline transport fee for a newly constructed CO_2 pipelines is expected to be around 49.3 €/t CO_2. This in contrast to expected transportation fees of 0 €/t CO_2 in case of overcapacity in the current CO_2 pipeline connection. In contrast, the cost for liquid CO_2 transport is expected to be 21 €/CO_2 are assumed (Lamboo et al., 2021).

Ultimately, based on the national hydrogen infrastructure design perspective up to 2030, the planned projects are expected to require investments of around €[0.7-2] billion for the hydrogen backbone, €[0.5-1.5] billion for the CO_2 infrastructure, and

Figure 10.12: Map of proposed hydrogen transport infrastructure in South-Holland (van Wijk et al., 2019)

€[0.6-1.0] billion for hydrogen storage. These investment requirement estimates are based on the respective maximum capacity per year, which are [2-4] Mt or 15 GW for hydrogen transport, [6.5-10] Mt for CO_2 transport and 6 PJ hydrogen storage (GL, 2020).

Here, it is assumed that the costs of repurposing the natural gas network is a factor [0.10-0.35] of the costs required to construct new dedicated hydrogen pipelines. In this perspective, around 45% of the investment costs for the repurposing of the natural gas pipelines arise from conversion costs. In this case, most costs are related to the cleaning- and preparation of the pipelines. This is expected to cost around 10% of the costs for newly constructed pipelines. The other conversion cost stem from costs related to the replacement of valves. The other 55% of the cost for repurposing natural gas pipelines are estimated to arise from fees for overtaking of the current assets. Overall, the costs are assumed to be 0.84 €million per km in the case of repurposing natural gas pipelines and 3.2 €million per km in the case of newly constructed hydrogen pipelines (Tezel and Hensgens, 2021).

However, the investments in the repurposing of the natural gas network are not expected to be directly profitable. This is due to underdevelopment of the hydrogen value chain. This subsequently relates to the fact that the utilisation of carbon-neutral hydrogen currently is more expensive as compared to traditional production methods and lower-carbon hydrogen. In turn, this reduces the need for the transportation of hydrogen. Moreover, the longer-term perspective that is required in the sizing of the infrastructure design does not correlate with the expected gradual increase in hydrogen demand and supply. Therefore, the infrastructure development inherently results in initial oversizing (Tezel and Hensgens, 2021). Also, in this case the development of one larger-capacity hydrogen pipeline is more cost-effective than the development of two smaller- size hydrogen pipelines with a combined similar capacity. Therefore, the anticipation on future hydrogen demand requires initial oversizing, which at a later stage result in the more cost-effective option. On top of that, oversizing is also a result of the fact that the current natural gas pipelines have a fixed diameter and as a result a fixed capacity, that might not align with the actual hydrogen transport demand. (Yeşilgöz-Zegerius, 2021). Therefore, public support would be required to ensure a positive business case, especially in the short-term (Tezel and Hensgens, 2021).

Infrastructure value chain

Three types of value chains from production to distribution, including conversion and or transmission, are expected to emerge (McKinsey, 2021). This includes any assets and processes from point of injection to end use. For example, blending stations, pipelines for both transmission and distribution, compressor stations, metering systems, city gate stations, and storage sites (Wouters et al., 2020). The expected value chains include on-site production for large-scale hydrogen offtakers in case of close proximity to favorable renewables or gas- and carbon storage sites. Another expected value chain consists of smaller offtakers that will require regional distribution, like HRS. Lastly, value chain for regions without optimal resources will arise that require the import of hydrogen for end use in both large- and small hydrogen offtakers (McKinsey, 2021).

In the same line, Alvera et al., 2020 discusses three different supply modes, based on production costs, storage costs, transport costs, security of supply and efficient markets. Initially, clean hydrogen is expected to be produced and procured in small quantities on-site to limit transport costs. However, the small-scale renewable hydrogen production costs are presumed to be higher and will be offset by the off-site supply from large-scale producers. This then requires the connection via pipeline transport of hydrogen. Here, the higher CAPEX on a unit basis for small-scale production will be offset by the costs savings related to a local direct connection. Moreover, the shift towards large-scale production is supported by commercial-scale demand, which would be hard to fulfill with decentralised capacity. This relates to both the production and- on-site above-ground storage of hydrogen. The large-scale supply of hydrogen would arise most dominantly from localized supply chains that could be established under a utility model, including large-scale geological storage facilities and, for term, carbon capture and storage facilities. However, in the longer-term it is expected that the separate clusters will form a comprehensive interconnected network of high-capacity pipelines to offer the lowest supply costs at sufficiently high hydrogen demand levels. This would be achieved via the connection of optimal hydrogen production locations and multiple storage facilities. Here, the cost benefits is expected to outweigh the upfront transmission pipeline costs. Moreover, the connection is presumed to also increase the security of supply, provide greater balancing flexibility and ensure efficient markets (Alvera et al., 2020).

Ultimately, the transport- and storage costs of hydrogen will play a determining role in the competitiveness of hydrogen. Here, on-site production could reduce the transport- and storage costs to close to zero, while for long-distance transport the distribution could add a factor three to the hydrogen production costs. Moreover, smooth operations and intercontinental values chains will require adequate system functionality including storage capacity, which in turn depends on volume, duration, price, speed of discharge and promotion of the development. Moreover, the costs of- and choice for the different hydrogen transport modalities will vary according to geography, distance, scale and the required end use. Finally, based on the regional characteristics some regions will depend on hydrogen import, while other regions might become net exporters of hydrogen as the cost of transport outweigh the difference in the production costs of renewable hydrogen. This is further strengthened by, for example constraints in land use availability, direct electrification need and existing infrastructure (IEA, 2019).

10.4 Analysis

The proposed future renewable hydrogen system shows similarity with the current natural gas energy system. In the future renewable hydrogen system, renewable hydrogen will be the energy carrier that allow for the transportation of cheap renewable electricity over place and time. Within the future renewable hydrogen system, biogenic sources are discussed to be important for the local- and or regional production of bio-hydrogen. Moreover, biogenic sources will be of high relevance as biogenic carbon source. As a result, the utilisation of biogas will play a key role within the future renewable hydrogen infrastructural design, primarily on a local- and or regional scale.

In this perspective, biogas could prove to be an important source of local- and or regional bio-hydrogen and bio-carbon dioxide in the transition towards the future renewable hydrogen system. Here, the utilisation of biogas fits well with the proposed development of, initially local-, then regional, and ultimately widespread production-, transportation- and utilisation of hydrogen. In this way, the conversion of biogas to bio-hydrogen could support the development of the wider hydrogen infrastructure, which was mentioned to lack at the moment. Thereby, it is important that both the repurposing of traditional natural gas pipelines is feasible and cost-effective. In this respect, it was indicated that repurposing of natural gas pipelines is feasible and show a cost factor of [0.10-0.35] as compared to the costs required to construct new dedicated hydrogen pipelines. Moreover, it was indicated that the ultimate capital expenditure perspective could become equal to the current utilisation of natural gas pipelines. On top of that, the utilisation of bio-hydrogen could reduce the need for an initial split in the hydrogen- and natural gas pipelines. This could further support a rapid- and more affordable transition. Lastly, the conversion of biogas to bio-hydrogen could support the proposed gradual development in the development of the hydrogen infrastructure. In this case, the additional local- and or regional capacity of bio-hydrogen could support the parallel re-purposing of natural gas pipelines of the distribution network next to the planned transformation of the transport network. Here, bio-hydrogen has the potential to more rapidly unlock the potential usage of hydrogen, especially within the discussed sixth industrial cluster. This cluster mainly consists of decentral production industries. In this perspective, the utilisation of bio-hydrogen for local- and or regional application is thereby presumed to fit well with the proposed regional energies strategies. In this way, the social support for re-purposing of the natural gas pipelines could be ensured.

Therefore, it could be stated that the concept of third-generation upgrading of biogas fits well within the proposed infrastructural design changes. This is further enhanced by the high percentage of grid-connected biomethane production facilities. In this way, biomethane production facilities could be modified to support bio-hydrogen production that subsequently could be transported via distribution pipelines. In the same line, the additional reverse flow- or booster facilities thereby support the transport of local produced bio-hydrogen for both local- and regional applications. This support the continued development of local- and or regional industrial hydrogen demand and or could, for example, facilitate the regional development of hydrogen refuelling stations.

Moreover, the professionalisation- and commercialisation of the biogas sector further supports the incorporation of bio-hydrogen production within the wider perspective on the future hydrogen system. In this respect, strategic hubs are created that are supported by adequate- and innovative infrastructure options. This subsequently has the potential to unlock more useful biogenic resources and enable more cost-effective and efficient processing. In this way, lower system costs could be obtained while the capacity of both bio-hydrogen and bio-carbon dioxide could be increased. In this perspective, it was indicated that the concept of biogas pooling shows good potential to allow for the more centralised processing of biogas. Here, it was indicated that traditional natural gas pipelines could be re-purposed to support biogas pooling. This could further stimulate a fast- and affordable transition. Additionally strategic hubs could support local- and or regional integration with bio-hydrogen demand centers including sixth cluster industries and horticulture. On top of that, strategic hubs have the potential to support the concept of third-generation upgrading via coupling with local- and or regional renewable electricity and e-hydrogen production.

Lastly, it was shown that the infrastructural demand for carbon dioxide is feasible and assumed to be expanded. As a result, no limitations are presumed for the increased utilisation of bio-carbon dioxide. In this way, the infrastructure development could support the adoption of bio-carbon dioxide as climate-negative feedstock.

Thus, the concept of third-generation upgrading would fit well within the proposed future renewable hydrogen system. Here, the infrastructural changes are seen to support the wider adoption of both bio-hydrogen and bio-carbon dioxide. This is expected to be especially relevant for local- and or regional demand. In this respect, the conversion of biogas to bio-hydrogen could facilitate a rapid-, affordable- and gradual development of the hydrogen infrastructure. Therefore, to form a perspective on the potential infrastructure design in light of the feasibility of the concept of third generation upgrading, a mapping exercise is used.

Mapping exercise

Within the future renewable hydrogen system, the concept of third-generation upgrading has been proposed to yield a valuable bio-hydrogen and bio-carbon dioxide or syngas output stream. In this perspective, bio-hydrogen could serve as input for local- and or regional hydrogen demand. Here, hydrogen demand could, for example, arise from the industrial sector as feedstock, the transport sector as fuel or the build environment as direct replacement of natural gas. Moreover, the bio-carbon dioxide output stream is seen as valuable carbon-negative feedstock. On the other hand, the direct utilisation of the formed syngas could combine the role as relevant climate-neutral feedstock in the industrial sector.

To support the concept of third-generation upgrading professionalisation- and commercialisation of the biogas sector is envisioned. This includes the centralisation of bio-hydrogen and bio-carbon dioxide and or biogas production. In this perspective, biogas pooling shows relevant potential to more cost-effectively transport the required input materials, especially in low manure density areas. This could be combined with a more local biogas production facility to reduce the system costs of resource-poor locations. The subsequent produced bio-hydrogen and bio-carbon dioxide streams are envisioned for direct local- and or regional utilisation. This could be supported by the repurposing of the current natural gas pipeline infrastructure. In this way, the utilisation of bio-hydrogen can benefit from the traditional biomethane grid connections and reverse flow operations. On top of that, the centralisation of the bio-hydrogen and or biogas production could stimulate further process integration and sector coupling. This could, for example, include the direct incorporation of pure oxygen from e-hydrogen production. This could also support the inclusion of renewable electricity to support both the production and compression or liquefaction of both bio-hydrogen and bio-carbon dioxide.

On top of that, the centralisation of the production process could support integration with demand locations. In this way, the bio-hydrogen production could benefit from on-site production potential. This relates to the elimination- or strong reduction of transportation- and or storage costs. Thereby, the ultimate hydrogen delivery costs could be reduced relative to competitive hydrogen production methods. In this respect, it was indicated that the bio-hydrogen production cost would be increased with [0.5-1.5] €/kg H_2 to arrive at the ultimate bio-hydrogen delivery costs. In similar terms, an additional [30-65] €/t CO_2 was mentioned to be added for the delivery costs of bio-CO_2. Therefore, in light of, current, low cost fossil hydrogen, potential, lower-carbon hydrogen and later low cost e-hydrogen, a reduction of transport related costs would benefit the adoption of bio-hydrogen.

Overall, the perspective on the infrastructural design for the concept of third generation upgrading depends on the production potential, the infrastructural requirement, the respective end application and potential competitive production capacity. Therefore, based on the available information with respect to biogas production potential, biomethane production capacity, end demand locations and grid availability, a map could be created to assess the presumed optimal configuration of the concept of third-generation upgrading. Here, the biomethane production capacities could overlap with the proposed strategic hubs and or could form bio-hydrogen production capacities via modification. This could subsequently support a more cost-effective transition towards the proposed renewable hydrogen system. The optimal configuration is thereby based on the system cost perspective and as a result dependent on the proposed transportation- and or storage costs. Moreover, the optimal configuration is based on the assessment of the relevant valorisation potential of the concept of third-generation upgrading. On top of that, it should include relevant boundary conditions related to the transportation feasibility over the value chain. In this respect, it was mentioned that biogas- and especially manure transportation is not eligible over longer distances. Also, due to, for example, methane leakage and resource degradation the transportation of biogenic resources should preferably occur as quickly as possible. Lastly, the mapping should relate to the proposed development of the hydrogen infrastructure. This becomes increasingly important due to the cost benefits associated with repurposing of the traditional natural gas pipelines for both biogas- and hydrogen transport.

Ultimately, the proposed mapping exercise would include the relevant underlying data related to figure 10.3, which can serve as input for the green gas production potential and proposed green gas production locations. This could further be supported by figure 10.9 which lays out the locations of potential demand for bio-hydrogen from decentralised industries. Lastly, this could be finalised with figure 10.13, which identifies the natural gas pipelines in the Netherlands. The collection of data points thereby allows for the identification of production potential, demand potential and infrastructure potential.

Here, the perspective on the infrastructural design should follow the commercialisation and professionalisation of the biogas industry through a focus on enhancement of the production scale. In this respect, a reference installation size of 5.5 MW was proposed to show adequate economic feasibility. In this case, approximately 300kt manure/year is required to support the process. This could be translated to a collective amount of around 12,500 dairy cows, based on a waste output of 65 kg/day. This would translate into a theoretical output potential of around 300 5.5 MW installations in the Netherlands based on total amount of around 3.8 million dairy cows. Similar, based on the theoretical biomethane output potential via AD biogas approximately [220-260] 5.5 MW installations would be available in the Netherlands. Nevertheless, the average amount of over 100 dairy cows/farm or 1,000 dairy cows/farm for the 10 largest farms in the Netherlands indicate the importance of an adequate infrastructural design. This also relates to the respective amount of dairy cows per hectare. Here, the potential for biogas pooling would be important to support the enhancement of the production scale, especially in low manure density areas. This in turn translates into a bio-hydrogen output of around [0.10-0.12] PJ per year that could, for example, be used in the industrial sector, local HRS and or grid injected. In perspective, this translates into around 2% of the current hydrogen demand in the Rotterdam industrial cluster. This indicates the potential of direct coupling of the bio-hydrogen production with decentralised industries in the sixth industrial cluster. On top of that, an additional approximate amount of 7,400 tonnes bio-CO_2 would be produced. In perspective, this translates into around [1.0-1.2]% of the total current CO_2 delivery to the horticulture or average demand of 6 horticulture companies, indicating the potential for coupling with the horticulture industry.

Ultimately, this indicates the importance but also the complexity of an adequate design for the required infrastructure to support the adoption of the concept of third-generation upgrading. As a result, more research should be devoted to the actual infrastructural design in light of the proposed future renewable hydrogen system. In this respect, the infrastructure design should support a system costs perspective, within defined infrastructural boundaries, stimulated by increase in production capacity, sector integration and demand center coupling. In this way, for the concept of third-generation upgrading the biogenic feedstock potential could be coupled with biogas production facilities, bio-hydrogen production capacity and ultimately demand centers to lower the inherent delivery cost of bio-hydrogen. This in turn should allow for the cost-effective delivery of bio-hydrogen as opposed to competitive production methods to support the adoption of the concept of third-generation upgrading.

To conclude, the concept of third-generation upgrading shows relevant technological-, environmental- and economical potential within the proposed future renewable hydrogen system. However, it was indicated that the infrastructural design would provide a pivotal boundary condition to support the adoption of bio-hydrogen and bio-carbon dioxide or syngas. In this way, it provides a perspective on the place dimension of the concept of third-generation upgrading. This would relate to both competitive hydrogen production capacity and competitive utilisation of the bio-hydrogen feedstock. As as result, a mapping exercise was discussed to portray a perspective on the infrastructural design to support the concept of third-generation upgrading. Here, increase in production capacity and increased integration with demand centers and utilities was discussed to be important to lower the ultimate bio-hydrogen delivery costs. In this respect, the concept of strategic hubs shows important benefits in combination with biogas pooling and re-purposed biomethane facilities, like reverse flow. In this way, based on available biogas resources the biogas production facilities and bio-hydrogen production capacities could be linked with local- and or regional demand centers, within proposed infrastructure constraints related to the biogas production. In turn, the bio-hydrogen production capacity could support the parallel overhaul of the local- and or regional infrastructure in favor of a hydrogen infrastructure. Thereby, the use of methane would be devalued against the utilisation of hydrogen. Ultimately, the concept of third-generation upgrading supports the rapid-, affordable- and reliable transition towards the proposed future renewable hydrogen system.

Figure 10.13: Complete overview of the natural gas transport in the Netherlands (NLOG, 2022)

Chapter 11

Regulations

For the development of the proposed future renewable hydrogen system, regulations will play a dominant role. Here, regulations are important to stimulate hydrogen production and adoption. Moreover, regulations are required to create the adequate boundary conditions to facilitate the transition towards renewable hydrogen. This is especially important since the production of renewable hydrogen is presumed to be less cost-effective as opposed to traditional production methods. Moreover, the renewable hydrogen system entails a complete overhaul of the current fossil-based energy system. This is turn does not only require financial support, but also coordination to ensure the transition is affordable, accessible, secure, reliable and fair. In this respect, regulations could support the transition through the development of a vision, through the creation of markets and via financial incentives.

In this perspective, the concept of third-generation upgrading is considered an innovative proposal to support the development of bio-hydrogen within the future renewable hydrogen system. Here, it was indicated that the concept of third-generation upgrading shows relevant technological-, environmental- and economical benefits. Nonetheless, it was indicated that the concept of third-generation upgrading is based on the adequate valuation of the inherent bio-carbon. This in turn results in a dynamic valorisation perspective on the use of biogas. In this respect, regulations provide an indispensable boundary conditions that relate to the time perspective of the concept of third-generation upgrading. This in turn relates to the relative valuation of bio-hydrogen and bio-carbon dioxide as opposed to biomethane, fossil- and lower carbon hydrogen and ultimately other renewable hydrogen capacity. However, at the moment limited attention for the usage of biogas for the production of bio-hydrogen and bio-carbon dioxide, or syngas is portrayed. As a result, the current regulations are insufficient to address the relevant boundary conditions to support the adoption of the concept of third-generation upgrading.

Therefore, this chapter aims to describe the relevant regulatory perspective that could be used to identify the appropriate regulatory context. This includes the perspective on the wider energy system as well as the focus on the utilisation- and interconnection of biomethane and renewable hydrogen. Moreover, this addresses the current- and probable future regulations associated with both biomethane and renewable hydrogen. Then, the regulatory context can be used to develop a regulatory vision of the concept of third-generation upgrading within the proposed future renewable hydrogen system. The regulatory vision and context could then be used to identify the potential for the creation of a market for bio-hydrogen and the incorporation of adequate financial incentives. This relates to the relative valuation of bio-hydrogen and bio-carbon dioxide as opposed to alternative hydrogen production capacity and or alternative uses of biogas and or biomethane. Overall, this serves to develop a regulatory impact analysis that could be used to design and analyse the potential of relevant regulatory boundary conditions to support the concept of third-generation upgrading. This relates to the time perspective of the concept of third-generation upgrading including the associated valorisation potential, associated environmental benefits, competitive and alternative energy carrier production, and the overall, social, cost perspective. Ultimately, the time perspective could be used to derive the overall feasibility of the concept of third-generation upgrading within the wider proposed renewable hydrogen system.

11.1 Introduction

The European Union is committed to reach carbon neutrality by 2050 as enshrined in the EU Climate Law. Moreover, the European Union is devoted to implement the global efforts that arise from the Paris Agreement. Lastly, the European Union pledged to work towards zero pollution (EC, 2020a). This in turn translated into the intermediate climate ambitions of reducing GHG emissions in Europe by 2030 with 55% as compared to the level in 1990 in a cost-effective way (EC, 2020a).

In this respect, hydrogen offers a solution to decarbonise industrial processes and economic sectors where the carbon reduction is urgent and hard to achieve. Moreover, hydrogen is seen as an energy vector that allow for the storage- and balancing of renewable electricity. Also, this allows for the connection of production locations of renewable electricity to more distant demand centers. Additionally, this could stimulate the repurposing and re-use of existing infrastructure which would help to avoid stranded assets (EC, 2020a). However, in order for hydrogen to contribute to the climate neutrality target, the production of hydrogen requires sufficient scale and needs to become fully decarbonised. This should ultimately support the integrated energy system alongside with renewable electrification, and more efficient- and circular usage of resources (EC, 2020a).

To support the adoption of hydrogen as important zero-pollution energy vector, the European Union climate ambitions are subsequently translated into plans for lower-carbon hydrogen in member states national energy- and climate plans. Here, examples entail a signed hydrogen initiative plan, the inclusion of hydrogen in the context of alternative fuels infrastructure and the adoption of national hydrogen strategies (EC, 2020a). Moreover, other relevant factors that stimulate he adoption of lower-carbon hydrogen in Europe are, among other things, a critical mass in investment, an enabling regulatory framework, research and innovation, and a large-scale infrastructure network (EC, 2020a).

Specifically, as part of the European Green Deal and building on the New Industrial Strategy for Europe, a European hydrogen strategy is developed. Here, in the first phase from 2020-2024 the objective is to install at least 6 GW of renewable hydrogen production capacity and to produce up to 1 million tonnes of renewable hydrogen in the European Union. Moreover, the hydrogen strategy also includes the possibility to decarbonise the existing hydrogen production plants through retrofitting the installations with carbon capture and storage technologies. Next to the hydrogen production capacity, the start of a hydrogen backbone infrastructure is envisioned. On top of that, adequate infrastructure for the transport, storage- and utilisation of CO_2 will start to be developed (EC, 2020a).

In the second phase, from 2025-2030, the hydrogen is subsequently considered to become an intrinsic part of an integrated energy system in the European Union. Here, the objective is to install at least 40 GW of renewable hydrogen production and to produce up to 10 million tonnes of hydrogen in the EU (EC, 2020a). In the second phase, the policy focus is on laying down the required regulatory framework for a hydrogen market and to incentivise both hydrogen supply and demand. This is, for example, supported via bridging the cost gap for hydrogen production, the implementation of appropriate state aid rules and the creation of adequate market conditions. Later, this is broadened by dedicated hydrogen demand side policies that are deemed necessary in order for hydrogen to gradually be deployed in new end applications. This should in turn result in an open- and competitive hydrogen market with unhindered cross-border trade. Moreover, this should stimulate the efficient allocation of hydrogen supply among sectors.

In the third phase, from 2030-2050, the renewable hydrogen technology should reach maturity. Here, renewable hydrogen is then envisioned to be deployed at a large-scale over all, primarily hard-to-abate, sectors, as low-cost alternative to the current fossil fuel utilisation (EC, 2020a).

However, the European hydrogen strategy is only seen as the first step. In this respect, the European Union subsequently needs to act in order to turn the ambitions into reality (Chatzimarkakis et al., 2021). As part of this, Chatzimarkakis et al., 2021 propose a single piece of legislation that is intended to be a vision for an umbrella framework which can be used to harmonise- and integrate all separate hydrogen related actions and legislation. This is required as momentarily the hydrogen policies are scattered over distinctive gas-, electricity-, fuel-, emissions- and industrial frameworks. Moreover, the proposal also includes different methods to incentivise market functioning and to further develop the required infrastructure. On top of that, it is envisioned that the establishment of a robust system of carbon reduction is important in this respect. Here, the CO_2 content of the respective energy carriers is proposed to become the new currency of the energy system and economic recovery. In turn, this could be the basis for relevant European Union funding programs and financial support. This should therefore be based on a traceable-, trackable-, tradable-, transparent- and trustworthy certification scheme, which also includes clear life-cycle GHG emission thresholds. Then, hydrogen can operate as a global commodity within a liquid market (Chatzimarkakis et al., 2021).

Ultimately, the proposed hydrogen act can be seen in figure 11.1. Here, it can be seen that the proposed hydrogen act consists of both a hydrogen infrastructure act and hydrogen market act (Chatzimarkakis et al., 2021). Overall, in the short- to medium-term the focus of the hydrogen act lies on kick-starting a hydrogen economy and ramping up the production of lower-carbon hydrogen. This also includes the ongoing replacement of unabated natural gas with lower-carbon hydrogen. In contrast, in the long-term the focus of the hydrogen act is on ensuring that an adequate legislative regime is in place to govern hydrogen production, market demand and infrastructure. This includes the review of all relevant legislative initiatives like the renewable energy directive (RED), Industrial Emissions Directive (IED), Alternative Fuels

Infrastructure Directive (AFID), Trans-European Energy Networks (TEN-E), and Trans-European Transport Network (TEN-T) (Chatzimarkakis et al., 2021).

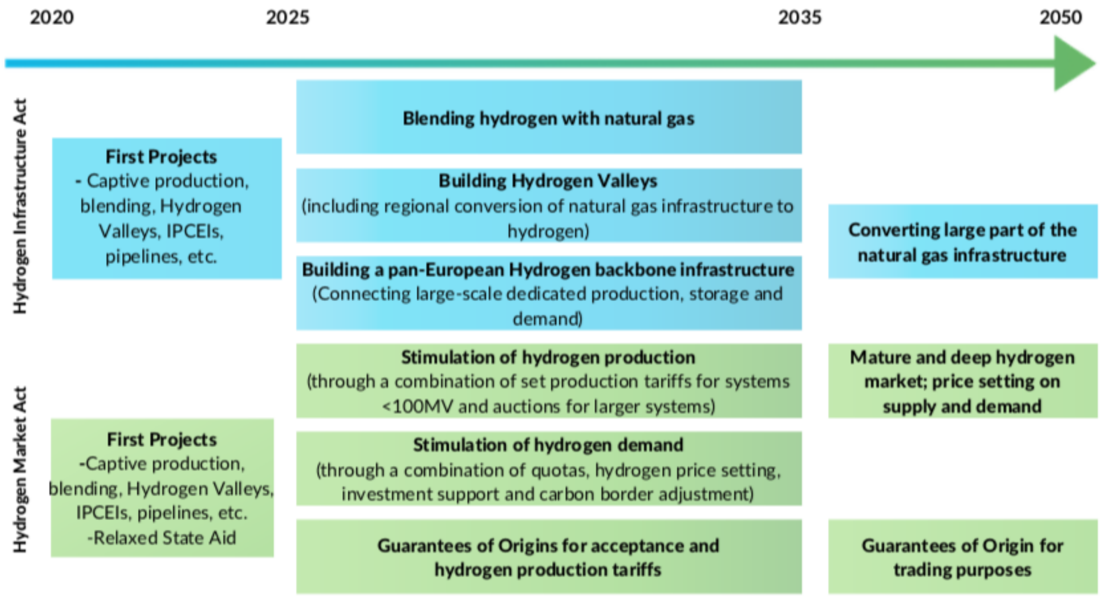


Figure 11.1: Overview of the proposed hydrogen act (Chatzimarkakis et al., 2021)

However, the European Union is not alone in the renewed perspective on the utilisation of hydrogen. In this respect, over thirty countries have released hydrogen roadmaps. Moreover, governments globally have committed more than $70 billion in public funding and have set capacity targets as well as sector level regulations. On top of that, 75 countries, which represent over half of the world's GDP, have net-zero carbon ambitions. Here, more than thirty have hydrogen-specific strategies, covering 73% of the world GDP. This is further complemented by CO_2 pricing mechanisms, which are present in several countries that combined represent 80% of the global GDP (McKinsey, 2021). Moreover, several companies have in total planned hydrogen-related investments of over €10 billion. Here, governmental co-funding is expected to be a key enabler for those projects to materialise (Alvera et al., 2020).

In this respect, the strong momentum for hydrogen could be assigned to the increased confidence in policy support and technological innovation to address the global clean energy transition. Moreover, the momentum is supported by the acknowledgement that hydrogen has the possibility to address a wider range of policy objectives. These include benefits related, for example, to energy security, local air pollution, economic development and energy access (IEA, 2019).

Here, the unprecedented levels of current government support for hydrogen are crucial for the further adoption of hydrogen. In this respect, industrial senior professionals mention government support as one of the key enablers for the adoption of hydrogen in practice. Other important factors mentioned in this respect were the expected boost in net profits and the moral conviction of the need to move towards net zero (DNV, 2021). In this case, the government support includes, for example, regulatory pressure to decarbonise, government subsidies or other incentives, and new uses for existing infrastructure. These were mentioned as the top drivers for the involvement in the hydrogen economy among senior professionals. However, 71% of respondents believed that the current hydrogen ambitions underestimate the practical limitations and barriers to the adoption of hydrogen. Here, infrastructure and costs are mentioned to be the biggest hurdle. In the case of infrastructure, the respondents mentioned the need for large-enough scale, low-enough costs and fast-enough speed to ensure adequate uptake of hydrogen. In this case, the re-purposing of existing infrastructure is believed to be key in developing the hydrogen economy. On top of that, the senior professionals indicated regulatory changes and the lack of required legislative frameworks as the greatest risk in progressing the hydrogen economy. Here, also a shift in support is discussed to possess a risk (DNV, 2021). Nonetheless, the right regulations are seen as the most powerful enabler followed by carbon pricing. Also, regulation is seen as the most important enabler of a successful hydrogen economy. This in turn requires strong-, stable- and supportive regulations. This can then be supported by a clear policy framework and transparent long-term goals that ultimately can be captured in regulations (DNV, 2021).

Therefore, the strong government commitment to hydrogen in combination with financial support, stimulating regulations, clear hydrogen strategies and renewed targets has triggered unprecedented momentum for the development of hydrogen (McKinsey, 2021). However, the momentum for hydrogen needs to be sustained. Here, a long-term regulatory framework has to be set and translated via concrete measures. This includes sector-level strategies with long-term targets and short-term milestones. Moreover, new partnerships between governments and businesses have to be formed to support the transition. This also requires development- and scaling of both hydrogen- and carbon transport. Here, a special case is the development of industrial clusters with large-scale hydrogen offtakers. These clusters could then support economies of scale throughout the value chain and can share investments and risks. Moreover, these clusters could establish positive reinforcing loops, allow piggy-back for smaller-scale offtakers, and ultimately reduce the cost of hydrogen production (McKinsey, 2021).

However, at the moment regulations are limiting the development of a renewable hydrogen industry (IEA, 2019). This relates to the uphold of barriers in existing regulations, the lack of standards to facilitate the trade-, transportation- and storage of hydrogen. Moreover, this is based on the lack of adequate tracing of the environmental impacts of different hydrogen production routes and to the slow development- and coordination effort with respect to the hydrogen infrastructure. Additionally, it is mentioned that regulations are not up-to-date to potential new applications of hydrogen. As such, the respective regulations would require to be updated or established and should be internationally agreed upon. On top of that, renewable hydrogen development is hindered due to the continuing uncertainty regarding the push for lower-carbon hydrogen production, for example, to speed up the transition. Overall, this relates to the lack of clear- and binding hydrogen commitments, unclear policy frameworks for financial support, and the absence of long-term strategies. Ultimately, this limits the attractiveness of financial commitments for public- and private investments and signifies technology uncertainty (IEA, 2019).

Therefore, international co-operation to accelerate the growth of hydrogen is of vital importance. Here, governments help to spur investments, enable knowledge sharing, work to scale hydrogen in a coordinated way, and set-up international standards. Here, hydrogen could benefit from a non-technology-neutral approach to facilitate the uptake of hydrogen (IEA, 2019). In this respect, IEA, 2019 state 7 key recommendations for governments to scale up hydrogen. These include the establishment of the role of hydrogen in long-term energy strategies and the stimulation of commercial demand for clean hydrogen. Moreover, the recommendations include addressing investment risks of first movers and financial support to bring down R&D costs. Also, the recommendations include the elimination of unnecessary regulatory barriers and the harmonisation of standards. Lastly, the recommendations discuss the need for engage internationally and track progress, and to focus on key opportunities to further increase the momentum around hydrogen. These recommendations are accompanied by the need for ambitious-, pragmatic- and near-term action to overcome barriers and reduce costs. In this respect, five policy actions are distilled. These include, among other, the establishment of long-term signals to foster investor confidence and the mitigation of salient risks like value chain complexity (IEA, 2019).

On top of that, Alvera et al., 2020 summarizes seven key actions that are discussed to be required for the development of the hydrogen economy. These actions discuss the need to price emissions and set long-term climate targets. Moreover, the need to harmonise standards and remove regulatory barriers is discussed. The actions also mention the need to introduce targets with long-term budgets and put in place investment mechanisms. Additionally, stringent emissions standards need to be set, markets for low-emission products have to be formed and strategies to coordinate infrastructure- and industrial rollout have to be in place. Lastly, hydrogen-ready equipment have to be made commonplace. These actions are derived as regulatory solutions to overcome barriers with respect to the deployment of hydrogen. Moreover, these actions should increase investment in hydrogen and drive down the costs (Alvera et al., 2020). In this respect, the barriers to invest in hydrogen projects and infrastructure are related to the lack of carbon prices and missing long-term emissions reduction targets. Moreover, regulatory barriers arise from legacy regulations. This relates to, for example, the restriction on the usage and transport of hydrogen and inadequate emission standards. Additionally, the barrier with respect to hydrogen deployment originate from a lack of long-term investment signals, immature markets for low emissions materials in, for example, the steel- and concrete industry, the absence of coordinated plans to decarbonise the industry, and continued investments in incompatible equipment. This includes investment in fossil fuel infrastructure (Alvera et al., 2020).

Lastly, in case of national hydrogen strategies, the national policies in the European Union show an increasing focus on an integrated energy system transition. This is in contrast to the previous isolated sectoral views (IEA and CIEP, 2021). Nevertheless, obstacles for the widespread development of hydrogen in the European Union still exists. The obstacles include limited cross-border collaboration, lack of regional market creation and a missing framework for trade. This also relates to the lack of standardisation and certification among the different member states. Similarly, the European Union state aid rules could hinder the deployment of hydrogen within specific member states. Here, also problems with the organisation and funding of joint projects across members states is still prevalent (IEA and CIEP, 2021). However, to address these obstacles, four priorities are mentioned. This includes building on the large unused potential to cooperate across member states including the opportunity to develop cross-border initiatives and the potential to develop an integrated regional hydrogen market. Another priority is the identification of requirements related to an integrated regional market requirements. This includes, for example, frameworks, standards and support mechanisms. Moreover, the development of support schemes to advance technology and to scale up the market in a coordinated way based on the relative strengths and identified bottlenecks should be prioritised. The last priority mentions the need to design a strategy to address emissions from existing hydrogen assets and to develop new renewable hydrogen production capacities (IEA and CIEP, 2021).

In the case of the Netherlands specifically, the climate act describes the overall emission reduction target in The Netherlands. Here, the Dutch government aims to reduce the GHG emissions relative to 1990 with 49% and 95% in 2030 and 2050 respectively. In this respect, the focus on the utilisation of hydrogen originates primarily in instances when other forms of decarbonisation are technically not possible or not cost-efficient. As such, the Dutch government foresees that the demand for hydrogen is mainly expected for industrial end applications. This includes both as energetic and molecular end applications. However, the perspective also incorporates the potential usage of hydrogen for, primarily, heavy-duty transportation. On top of that, hydrogen utilisation for heat generation in the build environment and for dispatchable power generation is mentioned. Lastly, the usage of hydrogen is also envisioned for renewables integration and renewable energy storage (IEA and CIEP, 2021).

Here, the foreseen hydrogen demand is stimulated through the development of a hydrogen backbone. Moreover, additional emphasis is placed on the development of significant off-shore wind potential. Also, the Dutch government discusses the potential future position as relevant hydrogen importer and hub for, especially, North-Western Europe (IEA and CIEP, 2021). In this perspective, several options exist to stimulate the adoption of hydrogen in the Netherlands. These include the demonstration and innovation subsidy (DEI+ scheme) and operating cost subsidy (SDE++ subsidy scheme). Moreover, additional project support can be obtained via the Growth Fund and Invest NL fund. On top of that, innovation is fostered through initiatives like the New Gas Top Sector, Electrochemical Conversion and Materials research program and the National Hydrogen Program (IEA and CIEP, 2021). Lastly, next to nation-specific initiatives, also a strong focus on international co-operation around hydrogen development exists. This includes legislation and regulation, safety and risk management, standardisation and certification, and infrastructure development (IEA and CIEP, 2021).

Moreover, for the development of hydrogen in the Netherlands specifically, a multi-year programmatic- and adaptive approach is proposed. This approach also focus on the respective innovation requirements (Gigler et al., 2020). Here, the approach focuses on four goals. These entail the development of a joint cross-sector approach to develop-, demonstrate-, implement- and scale hydrogen. Moreover, this include the acceleration of the hydrogen implementation and the utilisation of synergy benefits through a cross-sector approach. Lastly, the goal is to profile the Netherlands internationally. This should then ultimately result in targeted-, cost-effective- and large-scale reduction of CO_2 emissions to support sustainable development of the energy system (Gigler et al., 2020). Then, the approach is based on, among other, the coherence with the previously developed integrated knowledge and innovation agenda (IKIA). Here, the IKIA included 13 so-called mission-drive innovation programmes (MMIPs). Ultimately, the multi-year programmatic- and adaptive approach shows five interconnected components. This includes policy making to support clarity-, stability- and security with respect to hydrogen development. Moreover, it includes field project developments in order to identify research and development requirements as well as bottlenecks. Moreover, it addresses the creation of boundary conditions to enable the large-scale rollout of hydrogen. Also, it focuses on the research needs for the longer-term that aim to look at further improvements and optimalisation potential that could support widespread adoption. Lastly, it mentions supporting and accompanying activities to support the successful development and implementation of hydrogen. This includes certification, international attunement and regional cooperation (Gigler et al., 2020).

Regulatory barriers

A complete list of around 55 legal- and administrative barriers across eight categories of hydrogen applications and across eighteen countries have been identified (Floristean and Brahy, 2019). It was identified that most relevant acts impact the deployment of hydrogen technology indirectly due to the inclusion of hydrogen technology within the wider regulatory area. Here, the relevant acts are discussed to mostly relate to an obligation on the part of the developer and or manufacturer. However, the extent to which this forms an unreasonable barrier to the deployment of hydrogen technology is argued to be dependent on the national implementation of the respective obligation. On the other hand, more and more European law refer directly to hydrogen technology as a result of the importance of hydrogen as energy carrier and alternative fuel. In this respect, it was argued that these acts are rarely a source of unreasonable barrier to the deployment of hydrogen technology, despite the significant impact on the hydrogen technology deployment (Floristean and Brahy, 2019). Overall, it was discussed that hydrogen deployment in most applications is possible despite a potential experience of delay. This delay is in turn related to inexperience, lack of administrative maturity and missing legal clarity. Moreover, these result from regulatory gaps that are caused by a lack of harmonisation of rules and standards or by the involuntary mismatch between national- and European legislation (Floristean and Brahy, 2019).

On top of that, the identified legal- and administrative barriers were assessed based on the type of barrier and severity of the barrier. Here, the barriers could be identified as either structural barrier, operational barrier, economic barrier or regulatory gap. On top of that, the severity was listed from no, to low, medium and ultimately high and scored from 0 to 3 respectively. The result of the regulatory barrier assessment can be seen in figure 11.2 (Floristean et al., 2019). Here, it can be observed that the most severe barriers are related to grid issues, especially in case of the gas grid. This relates to structural barriers that arise mainly from permission, safety requirement and quality requirements. This for example hinder the injection of hydrogen in the natural gas grid and limits the commercial deployment of power-to-gas facilities. In contrast, the barrier related to the electricity grid primarily relates to the lack of recognition of the potential, balancing, services that hydrogen could fulfill. With respect to stationary power- and fuel cell applications the barriers are, almost exclusively, economic in nature. This relates, for example, to the lack of financial incentives. In case of hydrogen production, stationary storage and hydrogen as fuel, the barriers are mainly related to permission barriers. This in turn results in longer- and more costly permission processes. Lastly, in case of the use of hydrogen in road transport the barriers related to vehicle transport is mainly related to inconsistency in restrictions- and incentives regulations. On the contrary, hydrogen applications in the aviation- and maritime industry is hindered considerably due to regulatory barriers related to design- and type approval, and approval for landing- and bunkering installations.

Overall, it was observed that over all eighteen countries barriers with respect to hydrogen applications was present. Here, the Netherlands score relatively good with relatively low barriers to hydrogen deployment. In contrast, countries like Italy, Spain, France and the United Kingdom score relatively worse. On the contrary, Germany and Scandinavian countries score relatively better with respect to barriers for hydrogen technology deployment. Nonetheless, it was discussed that ultimately most hydrogen technology applications are possible.

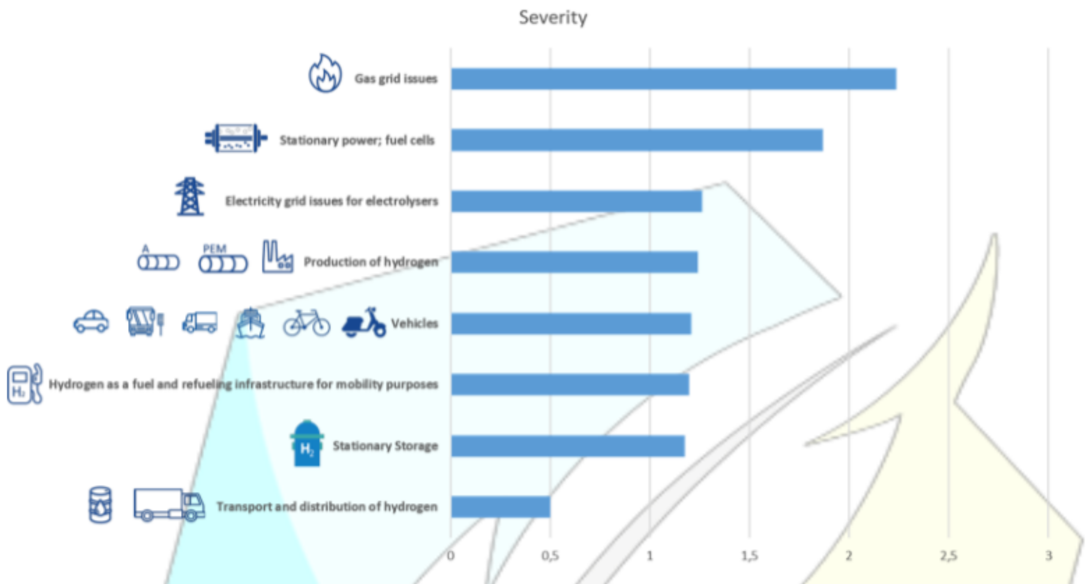


Figure 11.2: Average of severity of legal- and administrative barriers per application of hydrogen technology (Floristean et al., 2019)

Economic regulations

The presence of negative externalities within the current energy system provides a clear economic rationale for favourable support of renewable gases. These economic regulations serve to strengthen the position of renewable gases as compared to the unfavourable position in contrast to fossil alternatives as result of market failure. In the respect, an optimal set of regulations can be established to support the adoption of renewable molecules. This could include certificates schemes, support schemes, preferential access conditions and targets. Here, the actual economic support is mentioned to be a function of the value of the negative externality, the value of other regulatory measures to internalise the externality and the additional costs perspective (Moraga et al., 2019).

More broadly, Moraga et al., 2019 identify five categories of regulations that can be used to improve the cost perspective of renewable gases. These are the formulation of policy targets, the regulation of green certificate schemes, the regulation of access conditions, demand support schemes, and production support schemes. Here, based on fundamental economic criteria for optimal market interventions a matrix consisting of optimal economic regulations for renewable gases can be constructed. In this respect, a matrix with optimal economic regulations for renewable gases can be seen in figure 11.3 (Moraga et al., 2019).

First of all, with respect to the formulation of policy targets issues arise related to the allowed percentage of emissions. Moreover, issues could stem from the actual incentive mechanism to provide support at minimal costs. In this respect, based on economic theory, the maximum allowed level of emissions should be such that the marginal benefits equal the marginal costs. This then would result in an array of policy targets for the respective pollutant. Moreover, it is discussed that this should follow the perspective on technology neutrality. An example in this respect is the cap-and-trade scheme used for carbon emissions. However, a sole focus on markets and economic considerations might conflict with non-economic objectives of policy makers. As a result, a non-technology neutral target setting could be justified in this case. Moreover, a non-technology neutral target setting could further be supported due to inadequate estimates of actual marginal costs of abatement and or other market failures like entry costs and network effects. Therefore, the formulation of policy target could also be support by environmental policies and sectoral targets. However, policy target remain an important support scheme as targets indicate governmental commitment and vision. This in turn supports coordination and market trust (Moraga et al., 2019).

Next, with respect to certificates schemes, the physical similarity of renewable- and fossil gases results in information asymmetry. This subsequently leads to adverse selection with respect to higher-cost renewable gases. As a result, certification scheme are designed to help counter the information asymmetry and as as a result open the market for renewable gases. This is done through gaining additional remuneration in case of renewable gases. Here, in case of renewable gases the so-called mass-balancing approach is followed. This is in contrast to renewable electricity that is based on the book-and-claim approach. The book-and-claim approach disconnects the physical trade of the commodity with the certificate trade. As a result of the mass-balancing approach, international trade in certified fuels is only recognised when the physical transfer of gases is coupled to the trade in certificates. This therefore requiring a physical connection between demand- and supply centers of renewable gases. In the EU, the cooperation is facilitated by the European Renewable Gas Registry to facilitate cross-border trade of renewable gas certificates among registries. In practice, the Netherlands uses a three stage certification process for biogenic renewable gases. This includes the definition of standards for sustainable biomass via the Netherlands Technical Agreements (NTA) 8080 and NEN standards, the assessment of firms that produce-, process- or trade biomass via the DEKRA- or QS certification for the Better Biomass Certificate, and the handout of Vertogas certificates for renewable gas produced based on the Better Biomass Certificate. The latter refers to 1 MWh biomethane produced from sustainable sources with similar physical characteristics as natural gas. The certificate in turn can be sold to end users, form the basis of subsidy support via the SDE+, or could be used for green energy certificates via the renewable fuel units (HBE). This in turn allows for the gain of additional remuneration (Moraga et al., 2019).

Moreover, in the case of regulation of access condition, the natural gas transport is currently regulated in all European countries. Moreover, the natural gas transport is operated by network operators to hinder natural monopolies to arise. Otherwise, the natural monopolies could result in inefficient high prices for the usage of the natural gas system. Here, next to responsibilities regarding safety- and stability of the transport network, network operators are responsible for accessibility of the grid for all suppliers on the same conditions. This is done via the so-called third-party access (TPA). Here, financial compensation for using capacity from the network operator is regulated by the, either transmission or distribution, system operator via a tariff. The network code on tariffs result in harmonised calculation of transmission tariffs. However, entry- and exit capacity can be contracted separately. Moreover, the current regulation does not allow for discrimination in tariffs between renewable gases and traditional gases. In case of the Netherlands, the tariff structure is based on an annual tariff that can start every month based on entry- and exit-tariffs. In this case, entry points could be border, production or storage and exit points could be border, industrial, closed distribution, local distribution, production or storage. An additional cots for general balancing and maintenance is also included equally for all points. In case of the need of less than a year of capacity, a monthly factor is used to calculate the costs for capacity. Next to tariffs, also connection costs are present. This account for the physical connection to the transmission grid. However, no European Union regulation exist for connection costs. Here, in the Netherlands the connection costs are paid by the gas supplier independent of the source. However, new regulation makes that both the pipeline connection and cost for the connection point are paid by the network operator and subsequently billed via transport fees. Ultimately, based on economic theory, the prices and or tariffs should reflect the marginal costs. In this case, the network operator should also be able to recover the fixed costs. However, the costs should not exceed the break-even price. In this case, adequate information provision could reduce the potential for information asymmetry. Nevertheless, a discount on the fixed costs could be thought of as relevant economic regulation. This could for example be done in the form of production support in addition to priority access. The latter could especially be interesting in case of congestion a potential option to support the uptake of renewable gases (Moraga et al., 2019).

Lastly, in case of support schemes, these are deemed crucial to support market entry by overcoming barriers to entry. This could, for example, relate to the costs of development- and production of renewable energy. However, as the expected costs are ultimately paid by consumers the support scheme should be done to the minimum extent possible. On top of that, the support schemes should be flexible and adaptive to assure the minimum support perspective. Also, the support scheme should be clearly formulated according to fixed- and understandable rules. Lastly, the support schemes should take an European Union perspective. The latter relates to guidelines on state aid for individual member states. In line with the guidelines for support schemes, four types of support schemes are identified. These are feed-in tariffs (FITs), feed-in premiums (FIPs), investment grants, and tax exemptions and obligations. In practice, the Netherlands primarily utilises FIPs and tax exemptions for renewable gases. Specifically for the FIPs, the production- and consumption of renewable energy is stimulated via subsidisation programs like the SDE (stimulering duurzame energieproductie). The SDE has a single budget, is considered technology-neutral and is ultimately based on the difference between the cost of production and the market price. Moreover, the SDE is competitive and features a tender in the merit order of applications. Here, applications are favoured with a lower subsidy requirements. Moreover, the tender is capped with a maximum budget, which increases over phases in the year. With respect to the tax exemption, a tax relief on the investment in renewable energy is given via the corporate tax. This results in an approximate net benefit of around 10%. Ultimately, the right support scheme should on one hand sufficient to compensate for negative externalities and on the other hand should not higher than the actual extra costs of renewable gas production. This relates to the allocative efficiency- and preventing windfall profits theory respectively (Moraga et al., 2019).

Ultimately, the European Union should, for the development of renewable gases, set EU-wide targets for 2030 and 2050. Moreover, the European Union should stimulate an EU-wide certification scheme to support traceability and interoperability. Moreover, the European Union should give renewable gases a preferential treatment with respect to transport costs and grid access. Lastly, the European Union should introduce support schemes in order to overcome additional market failure (Moraga et al., 2019).

Economic criteria	**Categories of regulation**				
	Policy targets	**Certificates schemes**	**Access to the grid**	**Support schemes**	
				Production support	**Renewable energy obligations**
Allocative efficiency: price=MC			Tariffs per unit equal marginal costs	Support = value of externality – value of other regulatory measures to internalise (e.g. carbon tax)	Imposed cost = value of externality – value of other regulatory measures to internalise (e.g. carbon tax, production support)
Dynamic efficiency: sufficient return on investments	Long-term policy commitments	Long-term transparency on certificate scheme	Total revenues from regulated tariffs should cover fixed costs of grid	Long-term certainty on support schemes	Long-term policy view on obligations
No market power			Third-party access, unbundling	In case of competitive tendering: many producers required	Retailers should have a choice among producers to buy renewable gas from
No information asymmetry		Increase trust of consumers in certificates by e.g. standardisation, public certifier	Capacity and tariffs should be clear to (potential) network users	Between Regulator-Producer: organise competitive tenders in case of many producers; otherwise smart incentive mechanisms, like menus, price caps	Between retailer-producer: traceability of green gas. Between regulator-retailer: learning by doing (learn from market prices about level of efficient obligations)
No hold-up			Network operators should have certainty about compensation of costs of connecting renewable gas	Governments should not be held-up after the support decision has been made	
Fair distribution			Fees should be related to actual costs producers cause + fees should be related to the actual usage of the network + common costs should be fairly allocated among network users	Support <= actual costs – other revenues	Price certificates <= actual costs – other revenues
Cost-effective	Lowest-cost options should be chosen first, both in short and long run.	Clear information on certificate about production characteristics	No discrimination among production technologies; only based on costs	Lowest-cost options should be chosen first	Lowest-cost options should be chosen first

Figure 11.3: Principles of optimal economic regulation of renewable gases (Moraga et al., 2019)

11.2 Green gas

The focus on the utilisation of biomethane in the Netherlands was initially brought forward in the roadmap renewable gases in 2014 (van Soest et al., 2014). This perspective focused on biogas and biomethane, while little attention was devoted to renewable hydrogen. Here, actions and measures were spelled out to unlock the potential of renewable gases in the Netherlands. This was related to digestion- and gasification technologies with additional attention for proposed innovation (van Soest et al., 2014).

In case of digestion technologies, the stimulated actions entailed the creation of a public-private program to stimulate mono-manure digestion and the creation of a more flexible- and adjustable biogas SDE+ category for different use cases.

Moreover, the actions included a focus on the valorisation potential of biomass usage, especially in terms of public tenders. On top of that, the actions related to the organisation and professionalisation of the renewable gas market and sector. Additionally, the actions spelled out the systematical development of the societal valuation of biogas, the development of a level-playing field for the societal benefits of green gas and lastly the continued development of feedstocks and technologies to enhance the green gas potential. In contrast, due to the lower technology readiness of gasification technologies, the specific action for gasification technologies focused initially on the further development of the technology. Secondly, the actions focused on market development for gasification technologies. Finally, starting around 2025 the commercial development of gasification technologies was envisioned (van Soest et al., 2014).

In the long-term, the focus shifted towards the utilisation of renewable gaseous molecules for wider system functions. This included the production of hydrogen from renewable curtailed electricity production and the utilisation of green gas in the bio-based economy as feedstock. In case of the latter, the use of green gas was, only after cascading and exhausting of other option, envisioned for energetic purposes. However, it was mentioned that this would require further research-, development- and investment efforts to distill a perspective on the adequate utilisation of renewable gases (van Soest et al., 2014).

With respect to the long-term innovation potential, the positioning of renewable gases at the intersection of the renewable energy- and bio-based economy was considered important. In this respect, the creation of a robust innovation agenda was proposed. The proposed actions and measures focused on the business case of renewable gas production. These were in turn argued to be based on local situations, market dynamics and policy instruments. The relevant policy instruments were the SDE+, guarantees of origin (GOs), biotickets, the EU-ETS and general fiscal regulations. These in turn effect the green premium value. In this light, the conditions are deemed to become more flexible within the period of 2020-2030 (van Soest et al., 2014).

Recently, the focus is primarily on enhancing the production scale of green gas as green gas is envisioned as an important renewable gas for a sustainable energy system in the Netherlands. This aligns with the perspective on the sustainable usage of biogenic residual streams and the circularity principle (Wiebes, 2020b). In this respect, the Dutch government primarily focuses mainly on the reduction of the production costs of biomethane, the development of social support for biomethane and the efficient allocation of green gas among end applications. Ultimately, this should result in an increased green gas production potential. More specifically, this should result in 70 PJ green gas production by 2030, where 25 PJ green gas is envisioned to arise from digestion technology (Wiebes, 2020b). In order to achieve the objective, several policy intentions are discussed. These include alternative instruments to support the green gas production and flanking policies to realise adequate boundary conditions. These includes innovation, location availability, professionalisation, grid management and feedstock availability. Moreover, the alternative instruments includes more clarity regarding greening of the envisioned end applications (Wiebes, 2020b).

More general, the perspective on green gas fits within the wider perspective on the use of biomass as sustainable source for the transition to a low- or zero-carbon- and circular economy. In this perspective, biomass should be used at the highest valorisation potential. However, this entails some level of flexibility and adaptability regarding the exact definition. Nevertheless, the valorisation potential relates to applications where alternatives are technological- and or economical not feasible, or carbon-neutral molecules are indispensable. Moreover, this entails strict regulations with respect to the sustainable nature of biomass and includes a framework for biomass applications as is brought forward in the RED II (Wiebes, 2020b).

Nonetheless, to increase the green gas production, governmental involvement is deemed necessary. This also includes a sense of urgency at the moment in order to ensure adequate availability of biomethane by 2050. More specifically, to support the policy goals of upscaling, cost reduction, social support and efficient allocation, the unprofitable peak of biomethane production should be supported. On top of that, flanking policies should be enabled and end applications should required to be greened. In this respect, to overcome the unprofitable peak of biomethane production, this could be achieved through the usage of the SDE++ subsidy scheme next to the SDE+ subsidy currently in place. Here, the SDE++ broadens the subsidy scheme and opens special categories. However, to adequately support the envisioned growth of the biomethane production capacity, alternative support policy instruments are investigated. These include separate subsidy schemes, demand-side measures like blending quotas, or tax exemptions. Moreover, the flanking policies focuses on enabling future-proof scaling- and cost reduction of the biomethane production. In this respect, the proposed support for innovation focuses on increasing biomethane yields, lower production costs, increasing the feedstock possibilities and unlocking more product sales opportunities. On top of that, the focus on locations availability rely on unlocking more biomass streams, ensuring minimal effect on the local environment and on achieving an adequate scale. Moreover, the focus on professionalisation relies on centralisation- and integration of the biomethane sector. The grid management flanking policies relate solving grid capacity- and grid injection limitations. Lastly, the perspective on feedstock availability focuses on the development of new feedstock streams that are deemed sustainable, increase the conversion yield and lower the pre-treatment needs. Lastly, in case of greening end applications, the GOs system is used to support the uptake of biomethane in end-applications. Moreover, the GOs system reduces the potential for double counting of renewable credits and boosts the liquidity of the market. With respect to greening of the end applications also policy instrumentation like quotas and fiscal stimuli could be used to support green gas adoption. However, this depends on the actual production scale of- and demand for biomethane (Wiebes, 2020b).

Concretely, the Dutch government aims to stimulate renewable gases directly- and indirectly via emission targets, reduction targets, quotas and carbon pricing. Here, the coalition increases the focus on the utilisation of green gas. In this perspective, a blending quota for biomethane in the natural gas system, especially for the build environment, is envisioned. On top of that, additional blending quotas for sustainable biofuels in the transport sector are proposed. Also, the price for carbon is stimulated through a fixed bottom price and additional marginal ETS taxation on the usage of carbon in the industry. Moreover, the usage of carbon credits is also proposed in the agricultural sector to, for example, stimulate alternative business models (DutchParlement, 2021). Nonetheless, the coalition also aims to reduce the nitrogen emissions by 50% by 2030. This is in contrast to the earlier proposed reduction by 2035 as was spelled out in the law nitrogen reduction (DutchParlement, 2021).

According to Levitt, 2021 this could effectively reduce the livestock levels in The Netherlands by 30% (DutchParlement, 2021). As such, this could impact the green gas production potential via mono-manure AD.

In line, with the valorisation potential, the need for a wider perspective on the utilisation of renewable gases is proposed (van Soest and Warmenhoven, 2018). This also includes the perspective on renewable gases or renewable molecules as opposed to renewable electrons. Here, climate-neutral molecules, primarily carbon-containing molecules, should be reserved as feedstock for the industrial sector. This is based on the perspective that there are no alternatives for climate-neutral carbon molecules. Moreover, in this perspective, only in case of a surplus in climate-neutral carbon molecules these could be utilised in other transition pathways. These include, for example, the transport sector for the usage in, primarily, heavy-duty transport and the aviation- and maritime industry. Moreover, other options could relate to the power industry for, among other things, storage and buffering, and for the build environment in case of, mainly, peak supply. Here, also the rule that climate-neutral carbon molecules should be primarily reserved for those instances where alternatives are less pronounced is preserved (van Soest and Warmenhoven, 2018). To achieve this, van Soest and Warmenhoven, 2018 argue that a targeted-, dedicated- and phased development program is required to unlock the required supply of climate neutral gases. Here, the program should be able to account for technology acceleration, coordination of infrastructure, gradual market development, CO_2 pricing over time, and smart- and dynamic policy instruments. In this way, the program is able to incorporate the key pillars of the climate policy, which is related to a clean-, affordable- and reliable transition. Moreover, in this manner the program is able to incorporate the feedstock transition. This allows for the smart optimisation of renewable molecules, while interconnecting the different transition pathways (van Soest and Warmenhoven, 2018).

On top of that, another proposal, to stimulate the long-term vision of climate-neutrality by 2050, is the carbon takeback obligation (CTBO) Kuijper et al., 2021. The CTBO is an addition to the traditional focus on emissions rather than on sources. For example, emission-driven measures that are present are the EU-ETS, emission standards and the replacement of CO_2 emitting sources. The CTBO follows from the perspective that growth in demand for energy products and insufficient sources of renewable electricity result in the fact that, primarily fossil, hydrocarbon stock is placed on the market. The hydrocarbon stock in turn will eventually through incineration turn into CO_2 that is emitted in the air. On top of that comes the observation that the current volume of carbon concessions, carbon production, carbon processing and carbon in stock outweighs the accepted carbon budget of the atmosphere. As a result, a new perspective on carbon flows and stocks is proposed. This includes the regulation of stocks of both geological carbon and biotic carbon and the regulation of the decarbonisation of carbon flows (Kuijper et al., 2021).

More specifically, the CTBO entails that a carbon compound on the market has to be linked to the possibility of carbon storage or sequestration. In this perspective, the same amount of CO_2 that would be released during the end application requires to be balanced via contracting storage- and or contracting sequestration facilities. Other options in this respect include the purchase of carbon storage units (CSU) or the establishment of a storage company to generate CSUs. Here, the like-for-like principle is envisioned in order to connect geological carbon with geological storage- or mineralisation options. In this case, the carbon storage units are strictly linked to the volumes of CO_2 stored. Moreover, the production- or import of additional carbon compounds is then only allowed on the basis of an equivalent amount of CSUs. This thereby ensures that CO_2 is no longer added to the atmosphere (Kuijper et al., 2021).

In this respect, the CTBO is analogous to existing producer responsibilities like environment-friendly processing. This increases the cost price of produced- or imported gas and thereby constitute an incentive for the efficient use of products. Moreover, it generates a price differentiation in favor of lower carbon footprint energy units. On top of that, it directs the attention to cheap carbon storage- and or sequestration options. Lastly, the CTBO is expected to generate an incentive supplementary to the ETS. Here, the CTBO creates demand for CO_2 via the need to reserve CO_2 to be stored. This in turn supports CCUS technology or incentivises reduction in gas consumption. It also increases relevance to the need for negative emissions. This could entail DAC technology and BECCS (Kuijper et al., 2021).

11.2.1 Economic regulations

The current European Union policies, including the European Union energy- and climate policies, and the National Energy and Climate Plans (NECPs) are discussed not to support a large upscaling of renewable gases. However, the large upscaling is discussed to be necessary in order to meet the targets of 55% GHG emissions by 2030 as compared to 1990 and climate-neutrality by 2050 (Schimmel et al., 2021). In this perspective, long-term policy incentives, with the goal of climate-neutrality by 2050 in mind, and investment certainty are seen to be required to accelerate the development of renewable gases. Moreover, also higher carbon prices and stimulation of demand for renewable gases are expected to be required in order to create a positive business case (Schimmel et al., 2021).

In this respect, Schimmel et al., 2021 proposes the incorporation of a EU-wide binding target of 11% renewable gasses. Moreover, this included a sub-target of 3% renewable hydrogen and 8% biomethane. The targets are based on the potential for biomethane from sustainable biomass and renewable hydrogen from additional renewable electricity capacity. Here, the target ensure no major compatibility issues with respect to the increased production. In turn, the binding target could be incorporated in the RED II as an obligation for fuel suppliers. Hereby, the target can be used to provide a strong signal and long-term planning certainty. This should ultimately result in the delivery of at least 40 GW of renewable hydrogen production capacity and 360 TWh of biomethane capacity by 2030 (Schimmel et al., 2021).

Moreover, based on different starting points, the target is in turn translated into differentiated member state-level obligations. On top that, the target could be translated into nation-specific sectoral targets in order to guarantee a fair distribution of efforts and ensure political acceptance. Moreover, member states have the option to further specify the actual gas consumption targets spelled out in the RED II. This could in the end result in the creation of a liquid market at relatively low transition costs (Schimmel et al., 2021).

More broadly, overall measures and the public support framework for biomass utilisation for energy under the RED could be identified. Here, it is shown that differences exist in the support for biomass in the EU energy sector across the different member states (Banja et al., 2019). Nevertheless, feed-in tariffs and feed-in-premiums are seen to be the dominant support scheme for bio-electricity. Moreover, subsidies are important for the use of bio-heat. On top of that, mandatory blending quotas are mostly used for biofuels, especially in the transport sector. The overall measures arise from the important role assigned to the utilisation of biomass for energy within the EU. In this respect, targets are the most important driver. This is support by overarching guidelines with respect to environmental constraints and stable support in order to achieve effective deployment. Nonetheless, further harmonization across member states, more long-term support measures and a shared vision could continue to boost the deployment of biomass for energy within the European Union (Banja et al., 2019).

More specifically, there are several types of support schemes member states can use to promote renewable energy in the EU. An overview of the support schemes, and the respective advantages and disadvantages, can be seen in figure 11.4 (Banja et al., 2019).

Based on the respective support schemes possible, up to 2015 over 1,300 support measures, including economic-, financial-, regulatory-, administrative- and or support measures, were in place since 2005 in the European Union. Here, one-fourth was dedicated to biomass for electricity production, heat production or cooling and for the transport industry. These consisted for 60% of financial measures, while the rest were regulatory- and soft measures. The financial measures were used for all types of biomass, while biofuels specifically made up almost 70% of the regulatory measures (Banja et al., 2019). In this respect, financial measures included subsidies, tax reliefs, bio-energy schemes, support measures, eco-funds, investment grants, incentive programs, a guaranteed purchase price, zero-rated eco-loans, energy taxation, pollution taxes and more. In the case of regulatory measures, specifically in the transport sector, these included biofuel quotas, mandatory blending, sustainability criteria. These, varied over time and location (Banja et al., 2019).

More specific for the usage of support measures in the respective sectors, it could be observed that FITs and FIPs are the main support schemes deployed for biomass in the power sector. Other measures in the power sector included. for example, a quota system through tradable green certificates, a tendering system, contract for differences, and tax mechanisms with a difference in support levels in €/MWh. Here, the average incentive in the Netherlands for biogas and biomass in the power sector in 2018 was 75.7 €/MWh biogas-el under the FIP and 77.4 €/MWh solid biomass-el also under the FIP (Banja et al., 2019). In contrast, in the heating- and cooling sector, subsidies are the main type of support. Other schemes included tax mechanisms like tax relief, tax reduction and energy- and or CO_2 taxes. Moreover, the potential schemes includes FITs, FIPs, contracts for difference (CfD), quotas, and loan schemes. Here, the Netherlands applied a support scheme for fermentation in CHP via FIPs of 125 €$/MWh_{th}$, while other levels of support in the Netherlands was in the range of [43-84] €$/MWh_{th}$. In general, under the price mechanism scheme the average support level for biogas in the heating- and cooling sector is double that for other biomass (Banja et al., 2019). Lastly, in the transport sector, quotas are the most important support for biofuels. Other schemes included tax mechanisms, subsidy schemes and GHG reduction quota. In the transport sector, the mandatory blending quota for biofuels in the EU countries was shown to increase in percentage required over time (Banja et al., 2019).

Ultimately, it is mentioned that a stable support framework with regularly adaptations produced the largest effectiveness with relatively low financial support per MWh required (Banja et al., 2019).

Support scheme	Advantages	Disadvantages
Feed-in tariff	- Simple scheme that limits the risk for investors (fixed term support) - Provides an incentive to maximise production; - Drives technological development due to long terms support; - Create facilities for new players in the market - No burden to the public budget when founded by consumers - Can be adapted to impact on customer load patterns	- Difficult to find country-specific best FIT level and digression mechanism; - FIT can be very costly for a country; - Bad market integration since a fixed FIT does not respond to price signals; - Supports only grid connected generations - Badly design bring to high utility-costs for consumers - Less control over the installed capacity
Feed-in premium	- Incentive responds to the price signals of electricity market - Encourage investors to consider the engineering patters of a RES project (choice of site, type of wind turbines, orientation of PV panels etc.) - Efficient combination of electricity supply with demand - Reduce market price risks (minimum levels for FIP) - Provide security about minimum revenues (sliding FIP) - Possibility for higher revenues then FIT (when market price exceeds FIT level)	- Additional costs for the procurement of balancing services for wind and solar - A risk of over- and under compensation (the level of FIP is decided by an administrative decision) - Higher financing costs (related to evolution risks of market prices and corresponding revenues) - High complexity and costs for direct sale (prognosis systems, balancing services and electricity trading) especially for small-scale RES
Quota (TGC)	- Cost-efficient achievements because the TGC prices are determined by market price; - Penalty for not achieving the quota; - No risk for an uncontrolled growth of RES; - The scheme minimized the project costs - Possibility to introduce a "headroom" to prevent sudden drops in TGC prices	- Includes both electricity and TGC price risk increasing policy costs - Less suited for promoting a diversified energy mix while discouraging investments in expensive RES technologies; - Absence of incentive for beyond the upper limit create an oversupply of TGC which prices would sharply drop; - Tends to favour RES large-scale producers
Subsidy/Grants	- Allows for targeted development of renewable energy technologies especially when they are not sufficiently attractive to private markets; - Applicable for research and development into renewable energy innovations; - Facilitates renewable energy deployment especially in riskier environments	- Could be very difficult to remove when there is no longer needed - Long-term sustainability after grant is over may often be problematic - Payback and rate of return may be uncertain
Tenders	- Guaranteed purchase at fixed price; - Guaranteed access to the grid; - Long term guarantee leads to better financing options and potentially lower prices; - High competition results in cost efficiency and reveals the true market price of different technologies; - Limits can be set by the government for the capacity and the budget; - Due to the fixed schedule, electricity generation from RES becomes more predictable. - Bids can be selected according to specific criteria allowing for multiple country policies (ex: environment, employment)	- Can lead to discontinues (stop start) market development when regular action are not schedules - Difficult for small/medium biddings due to the high transaction costs (planning, feasibility study, risk assessments) and the risk of not getting a return on these investments in case they are not chosen. - High administrative costs. - High competition can lead to underbidding which results in low financial returns, contract failure or attempted post-auction price raises by successful bidders. - If there is not enough competition offers might be too high. - In open auctions there is a risk of collusive behaviour between bidders to drive up prices.

Figure 11.4: Advantages and disadvantages of main support schemes to support the deployment of renewables in the EU (Banja et al., 2019)

11.3 Hydrogen

The European Union adopted a set of legislative proposal to stimulate the production- and adoption of renewable gases. Here, an important focus is on the further stimulation of renewable hydrogen within the European Union. In order to do so, the hydrogen proposal are aligned with other relevant legislative proposals including the European Union ten-yer network development plan (TYNDP) and the European climate law. Moreover, the hydrogen proposal are developed to align with national network development plans and national energy- and climate plans. For example, the alignment with climate laws ensure to avoid potential lock-in effects and or stranded assets. Moreover, this ensures a gradual and timely phase out of fossil resources. On top of this, the hydrogen proposals overlap with the European Union energy system integration strategy and methane strategy (EC, 2021).

With respect to the hydrogen proposals, examples include the provision of information with respect to the decommissioning- or repurposing of the current infrastructure. Moreover, the hydrogen proposal address the removal of tariffs for cross-border interconnections and aim to lower the tariffs at injections points. Additionally, it focuses on the creation of a certification system, which is mentioned to be based on the life-cycle GHG emission footprint. Thereby, these proposals lower the barrier to entry for renewable gases. On top of that, the proposals aim to facilitate trade across borders in order to exploit the most promising production locations for renewable hydrogen (EC, 2021).

In this way, the European Commission sees hydrogen as central in order to achieve climate neutrality. Hereby, hydrogen is able to gradually replace fossil gases for usage as fuel, energy carrier and or feedstock. Moreover, domestically produced renewable hydrogen could further support resilience of the energy system and lower the dependency on imports of energy carriers and limit the effect of global market shocks (EC, 2021.

In this perspective, the Fit-for-55 package proposal promotes the uptake of renewable gases through the use of mandates, extension of the EU-ETS and via preferential tax treatment. Practically, the Fit-for-55 package could implemented through a revised renewable energy directive, by extension of the EU-wide certification scheme to include hydrogen, or through the use of concrete targets (EC, 2021).

Here, it is envisioned that the Fit-for-55 package builds upon the EU Hydrogen strategy and complements the RED II, the European Energy Directive (EED) and the EU-ETS. Moreover, the Fit-for-55 package focuses on the decarbonisation of the gas market and the establishment of a renewable hydrogen market. This includes a revision of the regulation on transmission networks and a directive on common rules for the internal market. Moreover it includes amendments to related legislative acts, the creation of conditions to increase the share of renewable gases and the establishment of a comprehensive certification scheme. In this way, the Fit-for-55 package aims to ensure security of supply and the liquidity- and competitiveness of the market. It should furthermore empower- and protects consumers. On top of that, the Fit-for-55 package aims to facilitate the integration of- and access to the grid. In this respect, it fosters integrated network planning, which includes a common vision related to the different energy vectors. Lastly, this entails the establishment of a European Network of Network Operators for Hydrogen (ENNOH) to ensure optimal development and management of the required hydrogen infrastructure (EC, 2021).

Moreover, the European hydrogen strategy is designed, in line with the Next Generation EU recovery package and the European Green Deal, in order to support an efficient-, interconnected-, prosperous- and green energy system (EC, 2020b). Here, the hydrogen strategy addresses the actualisation of the hydrogen potential through relevant investments, regulation, market creation, and research and innovation. More specifically, the hydrogen strategy aims to create sustainable industrial value chains, boost the demand for clean hydrogen, create a supportive framework, develop a well-functioning hydrogen markets and develop clear rules. Moreover, the strategy aims to promote research and innovation, cooperation between countries and regions, and aims to promote the creation of alliances (EC, 2020b).

Concretely, the hydrogen strategy is based on a phased approach and has the objective to developed at least 6 GW of e-hydrogen capacity in order to produce 1 million tonnes of hydrogen by 2025. Moreover, this should be increased to 40 GW e-hydrogen capacity with a production of up to 10 million tonnes of hydrogen by 2030. Ultimately, by 2050 renewable hydrogen should reach maturity and is expected to be widely deployed. In this respect, renewable hydrogen is able to boost economic growth, enhance system resilience, result in local job creation and could consolidation of the European Union global leadership in hydrogen technology (EC, 2020b).

More practical, the European Union has several policy options available to support the adoption of hydrogen. The options are related to demand-side- and supply side support, infrastructure development, the creation of market rules, stimulation of research and innovation, and wider international potential (EC, 2020a).

With respect to demand-side policy support, various options exist. These include minimum shares- or quotas in specific end-use sectors, direct market-based support schemes and competitive tenders. In the case of supply-side policy support different instruments are possible. These include a common lower-carbon threshold and or a common standard for the production of hydrogen. This should in turn be based on the life-cycle GHG performance of the respective hydrogen production methods and should be defined relative to existing ETS benchmarks. Moreover, other supply-side policy support options include the development of a comprehensive terminology- and criteria framework for the certification of lower-carbon hydrogen. On top of that, supply-side policy support options could be carbon contracts for difference in case tendering systems and State aid policies like funding could be utilised (EC, 2020a).

In case of infrastructure development, the Trans-European Network for Energy and the internal gas market legislation for competitive decarbonised gas markets should be reviewed. Here, the focus should be on the allowance of longer-range transportation, the development of common quality standards and the establishment of cross-border operational rules. In this way, the renewed legislation could ensure interoperability of the legislation. Moreover, the Alternative Fuels Infrastructure Directive and Trans-European Transport Network should be renewed in order to meet the transport demand. On top of that, the, low-caloric, natural gas pipeline infrastructure should be re-purposed and a new dedicated hydrogen infrastructure should be developed. This is turn should be based on the European Union ten-year network development plans (EC, 2020a).

With respect to the creation of market rules, the affordability- and security of supply are considered of high importance. Here, the market rules should allow for the creation of a liquid market. This could be done, for example, through the revision of the gas legislation to foster accessibility for all customers and producers on a non-discriminatory basis. Moreover, the development of market rules should be based on the energy carriers production costs, the carbon costs, and external costs and benefits. Hereby, market rules should dictate the efficiency allocation of hydrogen to end users who value it most. This should be based on the equal treatment of hydrogen with respect to alternative energy carriers. Lastly, the creation of market rules should be based on informed decision-making regarding the optimal trade-off between new market rules and alternative energy efficiency measures (EC, 2020a).

For the stimulation of research and innovation, a wider perspective should be taken. In this respect, research is needed to support policy making. This includes research at the supply-, infrastructure- and demand-side. Moreover, this includes research related to improved- and harmonised safety, standards and assessment of the environmental impact of hydrogen technologies. Also, it includes research into the supply of critical raw materials, material reduction potential and other large-scale high-impact projects across the entire hydrogen value chain. To address this, actions include the proposal of an institutionalised Clean Hydrogen Partnership alongside the Clean Hydrogen Alliance, the development of an ETS innovation Fund, the establishment of dedicated policy instruments in relevant national and regional programmes, and the cooperation of efforts in the Strategic Energy Technologies plan (EC, 2020a).

Lastly, with respect to the wider international potential, the advancement of supply diversification and the development of stable- and secure supply chains is envisioned. This could, for example, be achieved via international cooperation on research and development, financial contributions to clean energy transitions outside the European Union and through fostering sustainable growth and development. Moreover, other options include the support of investments and the mobilisation of available financing instruments. On top of that, EU regulations could be promoted and standards, definitions and methodologies could be shared. Additionally, new infrastructure could be developed. Lastly, market barriers could be removed and trade distortions could be solved, for example, through an ongoing EU Trade Policy review and bilateral dialogues (EC, 2020a).

Hydrogen Europe

Based on the European Union legislative proposal with respect to the deployment of renewable gases, and renewable hydrogen in particular, alternative proposals have been developed.

For example, in case of the hydrogen act proposes an umbrella legislative design to support the development of the hydrogen market and hydrogen infrastructure (Chatzimarkakis et al., 2021). Here, in the short-term or kick-start phase, the focus is discussed to be on projects that demonstrate the scalability of hydrogen and on projects that have sufficiently matured. Moreover, projects that increase the European competitiveness should be be prioritized. In this light, it is proposed that State Aid rules should be relaxed to allow for governmental support up to 100%. In the medium term, or ramp-up phase, the supporting framework then focuses on the facilitation of crucial elements that eventually stimulate the commercial competitiveness of hydrogen. This includes regulatory support mechanisms, like tariffs, auctions, tenders, quotas, investment support, tax relief, carbon border adjustment (CBAM), and guarantees of origin. These regulatory support mechanisms are based on the approved effectiveness in previous energy transitions and are should be defined by the actual funding gap under the presumption of market failure. In the long-term, or market-growth phase, much of the support frameworks will become obsolete. However, the deeper network integration of the market will require alternative regulation. This could include, for example, additional support to ensure interoperability and measures to avoid monopolistic behaviour (Chatzimarkakis et al., 2021).

Overall, for the required hydrogen infrastructure development, a legal framework is discussed to be required. The framework in turn could be supported through alteration of the current legislation in Europe. For example, in case of the re-purposing of the natural gas pipelines and the construction of new hydrogen pipelines the relevant legislation are the TEN-E, TEN-T and AFID legislation. Moreover, the development of a hydrogen network could be captured under the TYNDP. On top of that, the creation of hydrogen valleys would be relevant under the TEN-E. Moreover, the blending of hydrogen should be governed under the gas decarbonisation package. Lastly, in order to facilitate infrastructure development and the creation of alternative standards, new initiatives should be development. In contrast, for the market development, the relevant legislation includes the RED, the gas decarbonisation package, State Aid guidelines, the energy- and environmental aid guidelines, and the CBAM proposal (Chatzimarkakis et al., 2021).

Moreover, with respect to the proposed carbon reform in the European Union, alternative legislative proposals include an EU-ETS revision, the phasing out of ETS free allowances and the phasing in of the CBAM, the ETS reform for aviation, the separate EU-ETS creation for road transport and buildings, and the Energy Taxation Directive (ETC) reform (HydrogenEurope, 2021e).

In this respect, the EU-ETS could be revised, for example, by the extension of the ETS under hydrogen production technologies and sectors. Moreover, in case of the phasing out of ETS free allowances and the phasing in of the CBAM, proposals include, among others, the eligibility of renewable hydrogen for free allowances and the introduction of a CBAM to create a level-playing field between EU and non-EU countries and hinder carbon leakage. In case of the latter, also consistency between CBAM, the upcoming delegated act on renewable fuels from non-biological origin (RFNBO) and the GO system for renewable hydrogen should be ensured. This includes an assessment of the actual embedded emissions and to enable renewable hydrogen imports from non-EU countries. On top of that, in case of The ETS reform for aviation, the proposal relates to the stimulation to switch to sustainable aviation fuels especially hydrogen-based fuels. This is complemented by a potential mandate to support technologies and infrastructure for renewable-carbon fuels. Moreover, in case of the the creation of a separate EU-ETS for road transport and the build environment, a strong carbon price should support the uptake of renewable technologies and focus on the well-to-tank benefits of the respective fuel. Moreover, the separate ETS development should allow to factor in the different abatement costs of sectors and therefore the alternative pricing system. This in turn is expected to impact the the total cost of ownership perspective. Lastly, with respect to the Energy Taxation Direct, the proposal should, among others, grant fiscal rewards to clean energy technologies and should focus more on GHG emissions savings, energy efficiency measures and the deployment of alternative fuels. Here, hydrogen is envisioned to be included under the taxation. Moreover, in this perspective the principle of taxing energy products on the energy content and environmental performance is envisioned. In this case, a direct correlation between CO_2 emissions and applicable taxation should be developed (HydrogenEurope, 2021e).

Moreover, with respect to the Fit-for-55 package, the opportunity arises to put in place a concrete- and adequate framework for the development of a renewable hydrogen economy (HydrogenEurope, 2021c).

In this respect, several key recommendations were mentioned. These include the upward revision of renewable targets, the consideration of sub-targets for hard-to-abate sectors, the creation of a guarantees of origin system with hydrogen as a distinct energy carrier and the uphold of the principle of energy system efficiency along with the energy efficiency first principle. Moreover, the recommendations included, among other, the promotion of the allocation of emission premiums and the assurance that the AFID reflect the multi-faceted solutions that hydrogen technologies can bring (HydrogenEurope, 2021c).

Specifically, in the case of guarantees of origin, it is brought forward that different energy carriers require separate systems of GO HydrogenEurope, 2021b. In this case, a separate GO system should be created for hydrogen in contrast to the GO system for renewable electricity and gas. Moreover, the hydrogen GO system should be further encouraged in combination with purchase power agreements (PPA). In this way, the GO system could provide insight in the CO_2 intensity of renewable hydrogen production. This could in turn support the development of a global system with a track-and-trace and auditing function. Moreover, this could set ground rules to avoid false- or misleading claims. On top of that it could include the cancellation of hydrogen GOs in case of hydrogen blending in favor of traditional GOs. Overall, the current GO system should redesigned along the 5T principles of traceability, trackability, tradability, transparency and trustworthiness (HydrogenEurope, 2021b).

In the case of emission premiums, specifically for cars and vans, the revision of CO_2 emissions standards could be a key initiative to spark zero-emission vehicles. This is particular the case for FCEVs and could include a dedicated set of targets for each vehicle category. More specifically, the proposal includes, among other, setting ambitious- and appropriate CO_2 targets, accurate measurements of well-to-wheel emissions, the use of system efficiency- and technology neutrality as underlying principles, and the allocation of excess emissions premiums to support the transition of the transport industry (HydrogenEurope, 2021d).

The Netherlands

In the case of the Netherlands, policy ambitions and agreements with respect to the use of hydrogen are spelled out in the Climate agreement. Here, the focus lies on scaling of the hydrogen production capacity, lowering the hydrogen production costs, and supporting further innovation. Here, policy support is envisioned to ensure the adequate boundary conditions are in place. This includes, among other, the timely development of the required infrastructure and the provision of investment signals (Wiebes, 2020a).

However, it is recognised that hydrogen development in the Netherlands cannot happen in vacuum and therefore should be included in the, especially North-west, European and possibly global approach to hydrogen. This in turn supports wider cost reductions, technology innovation and an integrated energy market (Wiebes, 2020a).

As start, the government envisions an important role in the direction- and phasing of the development of hydrogen. This relates to the required simultaneous development of the hydrogen demand, supply, storage and infrastructure. Moreover, the development pathways are presumed to be strongly dependent on policy support, especially in the early startup and development phases. On top of that, these pathways will have distinctive policy requirements over time. Based on the presumed governmental role, the policy agenda is then based on four main categories. These are laws and regulations, cost reductions and scaling, sustainable end consumption, and supportive- and flanking policies (Wiebes, 2020a).

With respect to laws and regulations, the focus is on the reuse of the present natural gas system and the hydrogen market organisation. Moreover, the focus is on the tasks of network operators, the development of the guarantee of origin system, and wider system safety. On top of that, the laws- and regulations category addresses the development of a the main infrastructure in line with the national environmental vision. In case of cost reduction and scaling, the focus lies on instrumental support like the demonstration energy and climate innovation subsidy (DEI+), the SDE++

and the HBE. Moreover, additional support could be developed through potential new subsidy programs. This could include a temporary exploitation subsidy which could ensure the right level of support within the Important Projects of Common European Interest (IPCEI) framework. Moreover, blending quotas could be used to support cost reductions and scaling. For sustainable end consumption, a wide instrumentation of policy support mechanisms could be used to support initiatives on both a national- and local level. This could in turn help to create markets and facilitate implementation of hydrogen technology. In this respect, the RED is an important mechanism. Lastly, in case of supportive- and flanking policy, international strategies, regional policies, and research and development are addressed. In the case of international strategies, the focus lies on the development of standards, regulations and support. Moreover, this includes bilateral cooperation, the IPCEI, and other regional partnerships. In case of regional policies, support for the development- and facilitation of local infrastructure and projects is deemed important. This also includes the creation of regional energy strategies, regional interconnections and are ultimately linked to the overall national hydrogen program (Wiebes, 2020a).

In order to further specify a national hydrogen program, first the contours of a hydrogen roadmap are portrayed (Gigler and Weeda, 2018). Here, technology development, financing, laws and regulations, market creation, safety, human capital, and social acceptance are considered important for the development of hydrogen. In this light, a three-step approach for the development of hydrogen is proposed. This consists of an integral plan and vision building for hydrogen, putting hydrogen in practice, and finally the research-, development- and demonstration of hydrogen. The latter is based on the stimulation of cost reductions for both hydrogen production and usage. Moreover, it is aims to increase the efficiency of the production process. On top of that, it focuses on the development of new processes and to use of less scarce materials in order to development of a sustainable-, trustworthy- and affordable hydrogen system (Gigler and Weeda, 2018).

Here, a directing role for the government is of upmost importance to ensure consistency between the different activities. This includes between the sustainable energy and the feedstock system and over time and space. Moreover, in this respect the government is also considered important for the non-technical aspects surrounding the development of hydrogen. This entails policies, laws and regulations, subsidies, safety standards, social embedding, human capital agenda and trade (Gigler and Weeda, 2018).

In case of policies, laws and regulations these could be used as stimulation packages and or could remove potential bottlenecks- and barriers with respect to the deployment of hydrogen. For example, the deployment of FCEVs is limited due to the policy support for BEVs adoption. With respect to subsidies, several European- and national arrangements could be used to stimulate the production of hydrogen. Moreover, innovation could be supported via subsidies like the Topsector Energy, while early-stage research could be supported via the Netherlands Organisation of Scientific research (NWO). However, it should be ensured that structural- and sufficient funds are present. Moreover, in relation to safety standards, these are currently developed under the NEN safety program. In contrast, the human capital agenda requires more attention to ensure sufficient qualified personnel is available. Lastly, with respect to trade, an important question remains around the production specifications. This is especially important in light of the possibility to develop a transparent-, well-functioning- and open hydrogen market (Gigler and Weeda, 2018).

Specifically, in the case of the build environment in the Netherlands, the focus lies on a reduction of the CO_2 emission with a factor one-third by 2030. Here, two-third of the reduction is presumed to arise from a reduction in heat demand. This could be done via energy efficiency measures. In contrast, the other one-third is presumed to result from heat pumps and district heating networks. This could be further supported by renewable heat (van Wijk and Hellinga, 2021). However, in this perspective, no role for hydrogen is portrayed as potential decarbonisation option. Moreover, there is no clear perspective portrayed for the reduction of the other two-third of the CO_2 emissions. However, to would be required in order to reach a carbon-neutral energy system by 2050 (van Wijk and Hellinga, 2021). This becomes more relevant since, the utilisation of biomethane could find higher valorisation potential in other potential end applications (van Wijk and Hellinga, 2021).

As a result, van Wijk and Hellinga, 2021 portray a vision on the use of hydrogen in the build environment. Here, the hydrogen can support heat pumps and district heating networks. Moreover, the utilisation of hydrogen in the build environment has additional benefit related to investment security- and purchase guarantee of hydrogen. This in turn could boost wider hydrogen development and support a coordinated transition in line with the need for a carbon-neutral energy system by 2050. Moreover, this addresses the expected system role- and balancing mechanism of hydrogen. This is supported by the fact that direct governmental involvement in the residential sector is observed to be less complex as compared to involvement in the transportation- and, potentially, to industrial sector. Therefore, the adoption of hydrogen within the build environment is ultimately a matter of social support, political will and the choice about which transitional pathway to follow van Wijk and Hellinga, 2021).

11.4 Analysis

The regulatory context or vision has been described along the lines of carbon-neutrality and zero-pollution. In this respect, renewable energy is a key pillar next to large-scale electrification and the circular economy. Here, the European Union envisions to become climate-neutral by 2050. In order to achieve this, intermediate goals address strict reductions in the carbon emissions by 2030. In this case, the renewed Fit-for-55 proposal aims to achieve at least a reduction in carbon-equivalent emissions of 55% as compared to the levels in 1990. Also, in the European Union hydrogen strategy intermediate goals of, primarily, e-hydrogen production are mentioned to stimulate the development of renewable energy. In this respect, it was discussed that, mostly, three different stages in the future development of renewable energy in the European Union can be identified. In this perspective, the period starting 2025 is considered the medium-term, while the period from 2030-2050 is addressed as the long-term perspective. This inherently aligns with the presumed flexibility with respect to the prevailing regulations or more broadly the regulatory context.

Next to the end goals of climate-neutrality and zero-pollution, the regulatory context could be defined by the presumed objectives with respect to the required transition. Here, it is outlined that the transition away from the current fossil-based energy system should result in an alternative efficient-, prosperous-, green- and fair energy system. In this respect, the focus is on driving down the costs, increasing the scale and stimulating innovation around renewable energy technologies. Moreover, sustainable consumption was seen as an important criteria. Here, renewable hydrogen finds a central position as renewable-, versatile- and indispensable molecule in the future renewable energy system. Moreover, in this context the cascading principle finds considerable importance. Even though, the exact interpretation of cascading principles require a level of flexibility, in general it outlines the utilisation of renewable molecules in end applications that have limited practical- and or economical feasible alternatives. This in turn affects the proposed end applications of renewable hydrogen over time. Moreover, this is affected by different interpretations related to the proposed stages of future development. On top of that, the regulatory context surrounding the cascading principle finds relevant resemblances in the utilisation of biomethane. Here, it is mentioned that climate-neutral carbon molecules should ultimately be reserved as feedstock input for the industrial sector. This relates to the perspective that there are no practical available alternatives. This becomes increasingly relevant in the case that the future renewable energy system is not based on fossil resources where carbon dioxide is considered a waste product. In this perspective, the concept of third-generation upgrading shows great potential. Here, the climate-neutral carbon molecules and energetic bio-hydrogen molecule could be decoupled. Moreover, this allows for the flexible interpretation around the exact cascading principle where over time the inherent value over the output products of the concept of third-generation upgrading are presumed to alter. Therefore, within the regulatory context the concept of third-generation upgrading shows relevance as bio-hydrogen source within the short-term, as bio-hydrogen and bio-carbon dioxide source in the medium-term, and as bio-carbon source in the long-term.

Moreover, next to the creation of a regulatory vision and as such a regulatory context, the market development is important with respect to the exact regulations. In this respect, it was observed that the current adoption of renewable gases is hindered by the presence of, a multitude of, market failures. In the simplest form, this relates to the market failure that arise from the incorrect- or insufficient incorporation of negative externalities. In this context, the absence- or lack of carbon pricing hinders the adoption of renewable energy products. As a result, key in the development of a market for renewable energy products is regulatory support to overcome the present cost gap between renewable energy production and fossil energy production. This could further be supported by creation of the adequate market conditions. This, for example, includes the harmonisation of market rules and the support of efficient allocation of scarce resources. The latter could be supported through overcoming the information asymmetry. Here, examples include the development of a well-functioning guarantees of origin system and carefully crafting a (non)technology-neutral long-term perspective. In contrast, the harmonisation of market rules could be achieved through stable- and adaptive goal- or target setting. On top of this, additional support for research, development and demonstration, increased focus on sectoral integration, and continued focus on energy security could further stimulate the development of the renewable energy market within the proposed future renewable hydrogen system.

On top of that, in the perspective of market development the design- and development of the infrastructure is of upmost importance. In this respect, it was observed that the interconnection of the different energy carriers and sectors was considered. Moreover, the re-purposing of the existing infrastructure was seen as an important enabler to support the envisioned affordable- and fair transition. Therefore, with respect to the concept of third-generation upgrading the interconnection between biomethane and bio-hydrogen is important. Here, the concept of third-generation upgrading could support the re-purposing of the existing infrastructure in favor of a new hydrogen network. In this way, the production of bio-hydrogen can limit the potential natural gas infrastructure lock-in. Moreover, it could reduce the transition costs and more broadly the overall system costs. On top of that, the re-purposing of the natural gas infrastructure could further stimulate the concept of third-generation upgrading via the availability of the current infrastructure for the, potential, required transport of biogas. This in turn could align with both the perspective on lowering the production costs and increasing the production scale.

Last, within the regulatory context and with the focus on market development, regulatory support in the form of financial incentives could further stimulate the adoption of renewable energy products. In this respect, a broad spectrum of financial incentives are possible with distinct attributed advantages and disadvantages. Moreover, it was discussed that the actual utilisation of financial incentives for the stimulation of renewable energy differs over the stages in the value chain, over the different applications, over the different member states and over time. In this light, the mentioned financial incentives could be grouped as targets, certifications, access management and support schemes. More specifically, this entailed FITs, FIPs, subsidies, quotas, tax-related incentives, CfD, tariffs, certifications, tenders, grants and more.

For example, it was mentioned that traditionally the utilisation of biogas in the Netherlands was supported via feed-in premiums of 75.7 $€/MWh_el$ in case of the power sector and, maximum of, 125 $€/MWh_{th}$ in the combined heat- and power sector. In similar terms, under the current SDE++ subsidy the utilisation of biogas for the production of biomethane, CHP or heat is stimulated. Here, in case of the former, the subsidy amount, via tender, is around [70-95] €/MWh. This translates into a relative contribution of around [0.45-0.6] $€/Nm^3$ biogas or [0.65-0.8] $€/Nm^3$ biomethane. This operates in similar terms as the feed-in premium and is applicable for gas grid injection in combination with green certificates. On the contrary, the utilisation of biomethane, through physical transport or conversion of green certificates, is stimulated via the renewable fuel unit (HBE) based on a, recent, value of [18-21] €/GJ. This relates to 1 GJ of renewable energy delivered to the transport industry, in the Netherlands. In this respect, the HBE value is derived from the apparent CO_2-eq savings. In this case of biomethane, or biogas, utilisation this relates to a presumed saving of 64 kg CO_2-eq/GJ as compared to fossil fuel. As a result, this translates in an inherent CO_2 valuation of [280-330] €/t CO_2. Nevertheless, the HBE-value is ultimately determined by the market price as a result of the blending quota requirement and or target in the transport sector. This results in an increased demand for renewable fuel and as a result affects the price of the HBE-value. Here, the utilisation of residual waste as input for biomethane production is assigned a double HBE-value and as a result a price of around [130-150] €/MWh or around [1.3-1.5] $€/Nm^3$ biomethane. This stimulates the business case for biomethane production as renewable fuel. In this respect, the SDE amount is not applicable to ensure no double counting of additional carbon savings. Next to demand-side support mechanisms, preferential fuel taxation, vehicle taxation and subsidies to support the alternative fuel infrastructure are deployed in the Netherlands. In case of the former, an approximate, non-discriminatory, stimulation of 0.15 €$/Nm^3$ biomethane is applicable.

Overall, it was addressed that the concept of third-generation upgrading shows a dynamic valorisation potential. Here, renewable molecules are discussed to present the highest societal value in applications with limited practical- and or economical feasible alternatives. This is supported by the regulatory vision on climate-neutrality, zero-pollution and circularity. Here, the concept of third-generation could be seen as important source of bio-hydrogen, bio-hydrogen and bio-carbon dioxide, and bio-carbon over time. This could follow the relevant stages outlined in the current- and proposed regulatory context. In this way, the regulatory context serves as important boundary condition for the time perspective of the concept of third-generation upgrading. Here, increased level of flexibility could be assigned to stimulate the adoption of the concept of third-generation upgrading through a focus on innovation, cost reduction and production scale enhancement. Next, the support for market development and the creation of regulatory financial incentives are deemed important. In case of the former, the reduction of market failures assigned to, among other, negative externalities and information asymmetries need to be overcome. This relates, for example, to the internalisation of an adequate carbon price. Moreover, this relates to support- and coordination of the development of the required infrastructural design. Lastly, the regulatory financial incentives could be used to ultimately support the adoption of the concept of third-generation upgrading through a multitude of mechanisms. In this respect, the utilisation of bio-hydrogen and or bio-carbon dioxide could be valued over alternative hydrogen production and or alternative uses of biogas and biomethane. Ultimately, the, long-term, system costs perspective could guide the development of the adequate regulatory boundary conditions to support the concept of third-generation upgrading.

Therefore, a regulatory impact analysis is used to analyse and assess the current- and potential regulatory support to stimulate the concept of third-generation upgrading within the proposed future renewable hydrogen system.

Regulatory impact assessment

The regulatory impact assessment (RIA) aims to systematically- and critically assess the positive- and negative effects of proposed- and existing regulations and non-regulatory alternatives. In this way, RIA aims to ensure that regulations are efficient- and effective in a changing- and complex world. From this perspective, the purpose is to ensure that regulations will be welfare-enhancing from a societal-, environmental- and economic viewpoint. Here, the proposed benefits will exceed the costs. In this respect, the RIA will follow four steps. These include definition, identification, assessment and design (Nweke, 2011).

With respect to definition, both the regulatory context and objectives are important. In case of the proposed renewable hydrogen system, the regulatory context embodies the perspective on a climate-neutral and zero-pollution energy system in the European Union by 2050. Moreover, here the principles of the circular economy and the valorisation principles are highlighted. This is especially relevant in the case of the local- and or regional utilisation of biogenic resources. On top of that, within the proposed energy system, renewable hydrogen is seen as a versatile energy carrier that allows for sector coupling via, among other, the transport of cheap renewable hydrogen between apart production- to demand centers. In this respect, the regulatory context is shaped by the total system cost. Moreover, this is directed by the carbon content of molecules as inherent, environmental, currency. Hereafter, in light of the concept of third-generation upgrading, the regulatory objectives are to increase the production capacity of bio-hydrogen and bio-carbon dioxide, or syngas. Moreover, this entails to lower the presumed production costs. Also, it incorporates the development of the required infrastructure. Lastly, the objectives include the efficient allocation of the bio-hydrogen and bio-carbon dioxide, or syngas to end applications that represent the highest societal value according to the valorisation potential. This incorporates the highest, potential negative, emissions saving in the most cost-efficient way for applications with limited- or no alternatives.

With respect to identification, the respective regulatory options are important. In this perspective, it was observed that the deployment of hydrogen technologies is presumed possible over all applications. However, some delay could occur, which was primarily related to barriers that arise from obtaining permissions and meeting requirements. Underlying was the lack of harmonisation of standards and rules, the mismatch between national- and European legislation and the inadequate incorporation of the role of hydrogen within the future renewable energy system. This was further strengthened by the creation of economic barriers for hydrogen technology deployment. In turn, this, primarily, relates to the lack of financial incentives.

In this respect, it was mentioned that the principles of optimal economic regulation of renewable gases was based on a combination of economic criteria and categories of regulations. Here, the former includes allocative efficiency, dynamic efficiency, no market power, no information asymmetry, no hold-up, fair distribution and cost-effectiveness. The latter in turn includes policy targets, certification schemes, access to the grid, production support schemes and renewable energy obligation support schemes.

Moreover, in this respect it was mentioned that the main support schemes to support the deployment of renewable energy, specifically electricity, in the European Union consists of feed-in tariffs, feed-in premium, quotas or certifications, subsidies or grants, and tenders. Here, the support schemes could be identified by the respective advantages and disadvantages.

In case of assessment, the respective costs, benefits and other impacts of the potential policy options, which are drafted within the policy context and along the policy objectives, are analysed. Here, it is important to incorporate the actual- and marginal fixed costs and benefits. This also includes relevant externalities and other common costs. Moreover, this should incorporate other potential revenues. On top of that, it should be based on perfect competition, transparent information and limited risk. Ultimately, the assessment should be based on the system costs perspective and the carbon content as determining parameters within the wider perspective of the future renewable hydrogen system.

Here, for the concept of third-generation upgrading it is important that the inherent value of, potential negative, carbon savings is valued. This includes the value assigned to the biogenic nature of the feedstock and overall life-cycle benefits. Moreover, the carbon content should be valued within the perspective of a future fossil-free energy system. In this way, both perspectives could support the overall time-dependent valorisation potential of biogas. In the same line, the potential for zero-pollution hydrogen fuel applications has to be accurately supported. This includes the perspective on the sustainable end application of biogas within the wider system perspective. This, for example, relates to alternatives of biogas for heat- and power production. On top of that, increases in the professionalisation and scaling of the biogas sector has to be fostered to ultimately lower the system costs.

In this perspective, the umbrella European regulations entail the climate- and energy law, the renewable energy directive and related legislation like the EU ETS, the clean mobility act, the alternative fuel infrastructure directive and the fuel quality directive. Here, in case of former the Paris Agreement is central and the perspective on renewable molecules relate to energy security, flexibility and storage. The RED II subsequently translates the overall political context to, sector-specific, renewable energy targets. This is supported by a technology agnostic approach that focuses on CO_2 emission reduction. Here, guarantees of origin, access management, emission thresholds and sustainable consumption are brought forward. The related legislation subsequently focuses on the promotion of climate-friendly alternative energy products.

This is translated in the Dutch context via, for example, supportive taxation, subsidies, targets, quotas, tenders and certifications. In this respect, the most dominant support mechanisms for the commercialisation of renewable molecules are the SDE++ subsidy and the renewable fuel unit. Here, the former relates to the apparent CO_2-eq savings per cost unit and the latter is based on apparent emission savings, targets and quotas in the transport sector. Both are supported via a national certification scheme.

In this respect, the current SDE++ subsidy scheme in the Netherlands is insufficient for adequate support of the concept of third-generation upgrading. This aligns with the lack of long-term commitment in light of the proposed future renewable hydrogen system. Moreover, this relates to the limited perspective on the ultimate system costs and benefits perspective. As a result, short-term and or large-scale projects constitute the largest part of the subsidy scheme, while long-term and or small-scale projects are unable to receive adequate financial support. On top of that, the technology-neutral perspective on the highest CO_2-eq savings per euro is too narrowly defined. Here, it does not incorporate a long-term vision on the proposed energy system. As a result, innovative technologies are insufficiently supported due to the inherent higher cost in the early commercialisation phase. Lastly, the SDE++ scheme inaccurately does not incorporate the inherent value of negative carbon savings and or alternative applications. In this way, the upgrading of biogas is not assigned any additional societal, carbon, value. This inadequately devalues the concept of third-generation upgrading.

In contrast, the HBE scheme allows for the more adequate incorporation of the renewable molecular value of biogas upgrading. This in contrast to the more energetic perspective of biogas in the case of the SDE++ scheme. In this way, the upgrading of biogas towards biomethane is stimulated via a target-derived quota and subsequent price incentive related to the utilisation as fuel in the hard-to-abate transport sector. Moreover, a similar scheme is proposed in case of the build environment. However, this scheme insufficiently values the inherent value of bio-carbon dioxide in relation to the concept of second-generation upgrading of biogas. Here, it inaccurately devalues the potential for zero-pollution fuels or, potential negative, carbon savings. On top of that, the HBE scheme lacks the perspective on the proposed future renewable hydrogen system and as such inefficiently allocates the scarce biomethane towards road transport.

As a result, an alternative support scheme is proposed to support the concept of third-generation upgrading within the wider proposed renewable hydrogen system. Here, it is important that both the energetic bio-hydrogen and molecular bio-carbon dioxide constituents are valued dynamically. Moreover, it would be relevant to consider the potential of sectoral integration, for example, with respect to the industrial utilisation of bio-carbon. In this way, the relevant output streams of the concept of third-generation upgrading are valued as opposed to competitive- and or alternative production capacities. This includes fossil- or lower-carbon hydrogen and biomethane in the short-term and e-hydrogen in the longer-term. Moreover, this relates to the valuation of the atmospheric captured CO_2, the utilisation of bio-CO_2 and the promotion of non-polluting renewable hydrogen.

Therefore, from the demand-side support perspective, quotas in the industrial utilisation of bio-carbon could unlock demand and thereby increase in physical sales price of bio-CO_2. Moreover, this could ensure the adequate allocation of bio-CO_2 as climate-neutral feedstock. Next to that, the adoption of bio-carbon could be further supported by subsidy schemes and public tenders with respect to the bio-CO_2 end user. As a result, the bio-carbon producer is able gain a higher bio-CO_2 sales price next to the inherent valuation of bio-CO_2. Moreover, the user support schemes ensure that the higher feedstock costs could be recovered either via the support of unprofitable operations or through increased sales in relevant tenders. The latter could be used to stimulate sustainable consumption. In case of the former, the required subsidy scheme could be lowered through the internalisation of the inherent carbon price, which reflects negative carbon emissions. Thereby, this could ensure the utilisation, or storage, of atmospheric CO_2 as opposed to the release of short-cycled atmospheric CO_2. In this way, the carbon price could be used to devalue the direct utilisation of biogas or biomethane, for example, via a, tailpipe, emission quota, the carbon takeback obligation, the EU ETS or, physical, bio-CO_2 price. Moreover, the inherent, captured, carbon value and subsequent sales price could double stimulate bio-hydrogen as opposed to the alternative hydrogen production methods.

Next to a boost in the, primarily, physical value of bio-carbon, the concept of third-generation upgrading could be supported via supply-side support schemes that address the relevance of bio-hydrogen. In this respect, a form of feed-in premiums with a potential price cap, or feed-in tariffs, could be used to scale the production of bio-hydrogen. This could be further supported by redefinition of the subsidy scheme to allow for discriminatory support of renewable hydrogen production methods. Here, carbon saving could be accounted for as triple the amount as opposed to biomethane production and or four times as opposed to lower-carbon hydrogen. This ultimately depends on the interconnection with other proposed regulatory financial incentives. As a result, the respective price gap between alternative hydrogen production methods could be closed. Moreover, via an overall renewable molecule certification scheme the demand for renewable hydrogen could be supported. This could also be used to discriminate between the usage of biomethane as compared to bio-hydrogen. For example, quotas in relevant end applications could be used to stimulate demand and increase the value of bio-hydrogen. However, the respective comparison to biomethane could need to be offset by the respective value assigned to bio-carbon. On the other hand, the certification scheme could be used to discriminate between e-hydrogen and bio-hydrogen. This relates to the capture potential of atmospheric CO_2 in addition to the utilisation and capture of bio-CO_2. This could become a relevant dynamic policy mechanism, especially over the long-term where syngas might become increasingly relevant as input in the industrial sector. From the perspective of the end user, the uptake of hydrogen could be supported via relevant subsidy schemes and tax benefits to lower the overall costs associated with the adoption of bio-hydrogen.

The proposed complementary production support schemes have to be seen as additional revenue streams, which in turn could be used to dynamically support one of the two output streams over the other. In basis, the bio-carbon support schemes address the utilisation, as opposed to the emission, of short-cycled bio-CO_2. On the contrary, the bio-hydrogen support schemes address the capture potential of atmospheric carbon dioxide. Additionally, the utilisation of bio-hydrogen as zero-pollution fuel finds overlap in both support schemes and therefore require careful optimalisation. Here, from the perspective on allocative efficiency and maximising social welfare, the actual costs and or externality will have to be reflected. As a result, the combined support scheme benefits should not outweigh the social costs. On top of this, regulatory support surrounding the required infrastructural demand could further favor the adoption of the concept of third-generation upgrading. In this respect, the re-purposing of the current natural gas system could benefit both the production- and transport of end products.

An overview of the proposed regulatory support mechanisms in light of the concept of third-generation upgrading can be seen in table 11.1. These regulatory support mechanisms ultimately should resolve the respective market failures, over the required steps in the value chain, that hinder the adoption of the concept of third-generation upgrading within the perspective of the future renewable hydrogen system. In table 11.1 it could be observed that a multitude of, possible, regulatory support mechanisms are proposed. This spans the different steps in the value chain and focus on the different, valuable, streams within the concept of third-generation upgrading. In basis, the proposed support schemes follows the current regulatory design to support the adoption of renewable energy. Nonetheless, the proposed alterations rely on the assessed shortcomings in the current SDE++ subsidy scheme and HBE scheme. This relates to an adequate valuation of bio-CO_2, the potential negative emission savings, the potential for zero-pollution fuel and the efficient allocation of renewable molecules in line with the long-term- and dynamic valorisation potential. Ultimately, the concept of third-generation is supported via additional, social, valuation of the bio-CO_2 and the bio-H_2 stream in order to lower the production costs and enhance the scale.

To portray the envisioned impact of the regulatory support on the adoption of the concept of third-generation upgrading over time, figure 11.5 identifies the respective economic feasibility of the concept of third-generation upgrading. Moreover, figure 11.6 identifies the respective income streams and the relative contribution of the bio-CO_2.

Here, the business case over time is supported by the relevant expected alterations in sales price of the output products. In this respect, a hydrogen delivery price of 2.20 €/kg H_2 is presumed at the present moment in relation to fossil hydrogen production and delivery. However, the hydrogen delivery price is presumed to increase to 3.60 €/kg H_2 by 2030 to reflect the cost-effective utilisation of renewable hydrogen in the build environment in the Netherlands. Lastly, the hydrogen delivery price is expected to drop to 2 €/kg H_2 in light of the presumed delivery of cheap renewable hydrogen from good renewable resource locations. The price development in the intermediate period is presumed to follow a linear trend. This also relates to the presumed stages in the transition towards the renewable hydrogen energy system. Next to to hydrogen market sales price, the proposed subsidy scheme to stimulate the production of bio-hydrogen is presumed to be similar to the current subsidy scheme for biomethane production for grid injection. In this respect, the assumed hydrogen subsidy is 2.46 €/kg H_2 with an expected increase to 4.69 €/kg H_2 by 2050 to represent the upper range of the subsidy scheme. Here, the subsidy scheme also allows to recoup the transport costs due to the additional inclusion of the conversion-, transportation- and storage costs of both bio-CO_2 and bio-H_2 in the production price. However, the proposed transport costs could be lowered due to proposed infrastructural design in light of the place dimension of the concept of third-generation upgrading. Nevertheless, the presumed subsidy scheme is capped by the proposed cost gap and a nondiscriminatory perspective on renewable hydrogen production. As a result, until 2030 the price is set by the minimum of the presumed subsidy amount and the difference between the bio-hydrogen cost price and hydrogen market sales value. This ensures that the price gap with traditional fossil- or lower-carbon hydrogen is resolved. After 2030, the subsidy amount remains equal, at 1.71 €/kg H_2, to reflect the additional value of bio-H_2 as opposed to renewable hydrogen and in order to recover the production costs. In this way, the bio-hydrogen production regulatory support increases, only relatively and exclusively, by the presumed decrease in e-hydrogen delivery costs. Overall, the presumed income of bio-hydrogen in 2022 seems to overlap with market data that address a hydrogen income of [4-6] €/kg H_2. Moreover, the inherent value of bio-CO_2 is presumed to be reflected by the EU ETS or CTBO. Here, the initial value of 80 €/t CO_2 is increased to 100 €/t CO_2 by 2025, 135 €/t CO_2 by 2030, 165 €/t CO_2 by 2035 and 200 €/t CO_2 by 2050 to reflect the emission targets and efficient CO_2 price. On the other hand, the physical bio-CO_2 sales value is presumed to follow the price perspective of the current market conditions, including the horticulture. Here, a minimum sales value of 35 €/t CO_2 is presumed. This is increased to around 60 €/t CO_2 by 2030, 100 €/t CO_2 and 20 €/t CO_2 by 2050 to reflect the conversion towards the presumed EU ETS price in a linear fashion. Lastly, the biomethane sales value is assumed to be dictated by the, double counted, HBE value of 21 €/GJ, which translates into a sales value of 1.5 €/Nm^3 biomethane. This is presumed to lower to 15 €/GJ or 1.1 €/Nm^3 biomethane by 2030 to reflect the medium term perspective on the price development of biomethane in light of the decarbonisation of the transport sector fuel. However, after 2030 the HBE-value is assumed to decrease in linear fashion to ultimately reflect the renewable hydrogen price. In this respect, based on the 5.5 MW biogas installation, around 0.152 Nm^3 biomethane is required to produce 1 kg of bio-hydrogen. This results in an ultimate biomethane price of 0.304 €/Nm^3 biomethane or around 30 €/MWh by 2050.

Overall, figure 11.5 identifies the respective turning points in relation to the investment decision criteria. In this respect, it can be observed that around [2030-2031] the concept of third-generation upgrading shows a favourable investment decision as opposed to the concept of second-generation upgrading at an approximate net CO_2 price of 150 €/t CO_2. Nevertheless, due to the higher relative sales price of biomethane as opposed to bio-hydrogen the respective balance becomes positive around 2036. Moreover, in figure 11.6 it can be observed that the decrease in bio-hydrogen sales value is more than offset by the bio-CO_2 value. Here, a limited drop in overall sales value can be observed following the hydrogen price decrease post 2030. On top of that, starting 2042 it could be seen that the bio-CO_2 constitute the largest share of income with respect to the concept of third-generation upgrading. This shed light on the relative importance of the direct conversion to syngas as opposed to bio-hydrogen and bio-carbon dioxide production.

Nevertheless, in case of a more aggressive bio-CO_2 price development of 200 €/t CO_2 by 2030 and 350 €/t CO_2 by 2050 this would lower the investment decision based on NPV and reference balance to 2028 and 2034 respectively. Moreover, in this case the bio-CO_2 would contribute equally to the overall income by 2034 and ultimately would contribute over 2 times more than the bio-hydrogen. This indicates the relevance of an adequate- and interconnected CO_2 pricing. On the contrary, in case of a complete reduction of the bio-hydrogen subsidy after 2030, the investment decision would be delayed until 2037 with a positive balance arising at 2042. In case the subsidy amount is lowered to account for a similar relative decrease in the hydrogen sales value, the positive investment decision would be extended to around 2032 and 2037 respectively. On the other hand, in case of a complete, linear, reduction in the value of biomethane an immediate positive investment decision would be made, while in case of a reduction in biomethane sales price of 70% in 2050 as compared to 2030, to reflect the input value of biomethane at the market price of hydrogen, this would shift the investment decision to 2034 and 2040 respectively. Overall, it can be observed that the concept of third-generation upgrading shows important potential within the wider proposed renewable hydrogen system. In this respect, the proposed adequate inherent bio-CO_2 valuation, similar bio-hydrogen subsidy scheme and relative devaluation of biomethane proofs to provide important regulatory support mechanisms.

Then, based on the above results the net social costs of the proposed regulatory support mechanisms could be seen in figure 11.7a. Here, it can be seen that the net social costs initially increase, subsequently lower and starting 2030 steadily increase. Here, the net social costs are reflected in comparison to the current support for the concept of second-generation upgrading. In this respect, continued support of 65 €/MWh biomethane is presumed, while the subsidy amount for bio-H_2 initially increase and subsequently decrease as a result of the higher sales value of hydrogen. After, 2030 the bio-H_2 subsidy amount is presumed to remain constant, while the bio-CO_2 EU ETS value remains to increase. This increase is three times as pronounced for the concept of third-generation upgrading as compared to the concept of second-generation upgrading. Overall, it could be seen that the social costs relate to around 1.20 €/kg H_2 and is primarily related to the EU ETS price of 200 €/t CO_2 by 2050. However, in case the relevant price decrease in renewable hydrogen is taken into account, the social cost of the regulatory support mechanisms could be seen in figure 11.7b. In this perspective, an additional 1.60 €/kg H_2 is incorporated by 2050 as result of the expected decrease in e-hydrogen delivery costs from 3.60 €/kg H_2 to 2 €/kg H_2 at a presumed similar cost structure of bio-hydrogen. Nevertheless, this does not reflect the presumed decrease in the bio-hydrogen cost structure as a result of technological innovation, process improvement and lower feedstock costs.

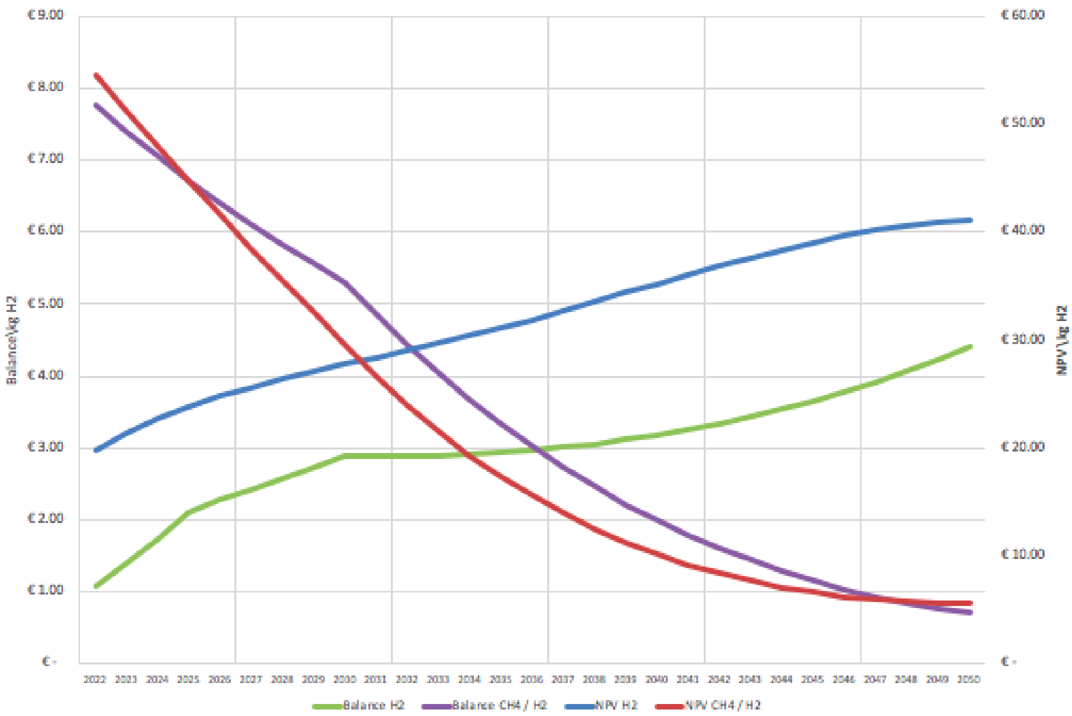


Figure 11.5: Regulatory support for the investment decision of the concept of third-generation upgrading over the concept of second-generation upgrading

Last, the design step includes interpretation with respect to enforcement-, compliance- and monitoring mechanisms. Here, transparent information provision and long-term targets are important to enhance certainty. In light of the concept of third-generation upgrading this relates to the proposed subsidy scheme and industrial targets. Moreover, this incorporates the relevant sectoral targets that, indirectly, influence the bio-CO_2 price. Here, continued monitoring and dynamic interpretation of the respective outputs is important to ensure the highest valorisation potential. Moreover, the certification system could be used to separate physical delivery and actual utilisation. This could then allow for a credit system for the required quotas. On top of that, subsidy requirements and tender assessments should become public and based on pre-defined open criteria. Here, reductions in the transaction- and administration costs would be beneficial. Any deviation from the proposed mechanism should result in strict penalties in line with the welfare theory. As a result, strong political will in combination with long-term target setting and welfare enhancing regulatory financial incentives could ultimately boost the adoption of third-generation upgrading. Moreover, this will allow for the dynamic interpretation of the valorisation potential of biogas. In this way, the concept of third-generation upgrading is able to provide the greatest net social benefits over time and place.

To conclude, the concept of third-generation upgrading has been assigned significant technological-, environmental- and economical benefits in light of the proposed future renewable hydrogen system. In this respect, regulations have been identified as dominant boundary conditions to support the adoption of the concept of third-generation upgrading in light of alternative utilisation of biogas and competitive hydrogen pro-

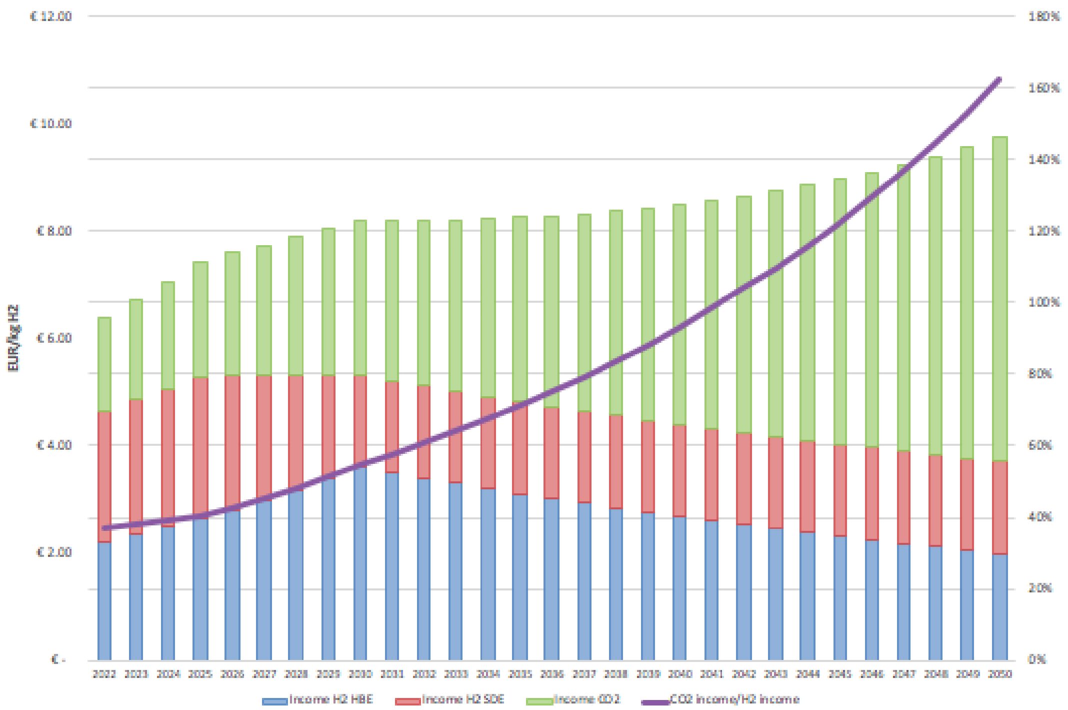
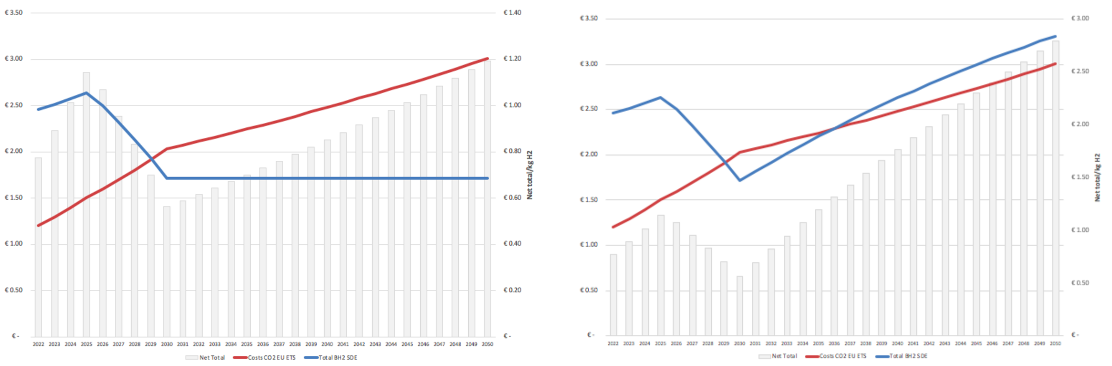


Figure 11.6: Regulatory support for the income of the concept of third-generation upgrading

duction. Here, it has been discussed that the regulatory context is derived from the overall vision on climate-neutrality, zero-pollution and circularity by 2050 in the European Union. Here, the focus lies on cost reduction, production increase, innovation and sustainable consumption. Moreover, through the cascading principle renewable molecules are assigned the highest societal value in end applications with limited practical- or economical feasible alternatives. In this perspective, the concept of third-generation upgrading is able to decouple renewable bio-hydrogen and bio-CO_2. In this case, the climate-neutral bio-carbon is envisioned to be ultimately reserved for usage as industrial feedstock. In this way, the concept of third-generation upgrading allows for the incorporation of a time perspective on the valorisation potential via initially bio-hydrogen production, subsequently the utilisation of both bio-hydrogen and bio-carbon dioxide and ultimately bio-carbon. However, it was mentioned that a lack of political vision limits the development of a bio-hydrogen market and result in a lack of adequate regulatory financial support. In this respect, market failures related to externalisation, information asymmetry, risk and infrastructure have to be resolved. In this respect, several, primarily, financial incentives were discussed and assessed. Here, after definition of the regulatory context and objectives, and the identification of relevant political- and economical barriers the current- and proposed regulatory support mechanism were assessed. In this perspective, the main implemented support schemes in the Netherlands, as derived from the overall European vision, to stimulate renewable energy are the SDE++ subsidy scheme and HBE scheme. Here, a lack of long-term vision on the value of bio-CO_2, the inefficient allocation of scarce renewable molecules and a limited perspective on, long-term, societal benefits limited the support for the concept of third-generation upgrading. Moreover, the need for the infrastructural overhaul was restated as key regulatory



(a) Traditional proposal (b) Including hydrogen price development

Figure 11.7: Net social cost perspective of the proposed regulatory support

support scheme.

In this light, renewed policy support mechanisms were proposed. These policy support mechanisms related to the current support schemes but aimed to overcome the identified limitations. Here, special attention was devoted to the adequate valuation of bio-CO_2 via the atmospheric CO_2 capture and utilisation potential. This was further strengthened by the renewed focus on the value of zero-pollution bio-hydrogen. In this respect, it was indicated that the concept of third-generation upgrading shows economic feasibility from 2030 onward, mainly related to the increase valuation of bio-CO_2. Moreover, it was identified that the relative valuation of bio-CO_2 over time could pave the way for the increased focus on bio-carbon, especially starting 2042. However, through alternative, social- and economical, valuation of bio-CO_2 this could be reduced to 2028, with a presumed switch to bio-carbon in 2034. This is supported by the efficient allocation of scarce climate-neutral bio-carbon and additional valuation of zero-pollution bio-hydrogen. Overall, it was indicated that the social cost amount to around 1.20 €/kg H_2 and was primarily related to the valuation of, negative, bio-CO_2 at 200 €/t CO_2. Nevertheless, more research would have to be devoted to the adequate development and design of the required regulatory boundary conditions. This relates to the relative valuation of bio-hydrogen as opposed to biomethane and renewable hydrogen. Moreover, this relates to the ultimate net social benefits and potential other impacts. On top of this, the regulatory support schemes could include the alternative environmental benefits associated with the production of bio-hydrogen.

Ultimately, through strong political will, clear target setting and adequate assessment of, social, welfare the concept of third-generation upgrading is able to play a pivotal role within the wider proposed renewable hydrogen system.

Policy	Related policy	Value stream	Advantage	Disadvantage
Bio-CO_2 industrial quota	Renewable energy directive	Bio-CO_2 usage	Increase sales price of bio-CO_2, allocation of bio-CO_2 as feedstock, support sector integration, stimulate business case	Limited production capacity, redundant, favor centralised industries
Bio-CO_2 public tender	Technical tender	Bio-CO_2 usage	Support sustainable consumption, unlock commercial demand, information transparency	Limited production capacity, quick obsolete, potential additional social cost
Bio-CO_2 user subsidy scheme	SDE++	Bio-CO_2 usage	Increase utilisation scale, support innovative technology, close cost gap	Tailor-made policy, potential no effect on consumer price, possible double social cost
CTBO	EU ETS	Bio-CO_2 storage	Values negative emissions, facilitate efficient allocation, market-based solution, follow targets	Relies on fossil perspective, potential passed on to end consumer
Emissions quota	Fuel quality direct (TTW)	Bio-CO_2 storage	Value non-pollution fuel, support infrastructure overhaul, simplifies carbon valuation	Limited applicability, reverse current policy trend, ignores life-cycle perspective
Feed-in premium or tariff	SDE++	Bio-H_2 production	Overlaps current regulations, values negative emissions, increase production, stable support	Overlaps with other support mechanisms
Bio-H_2 tax benefits	Fuel tax	Bio-H_2 production	Similar regulatory support, discriminate fossil alternatives, potential end consumer focus	Downstream support mechanism, could overlap with other regulatory mechanisms, possible sector focus, difficult to determine
Bio-H_2 quota	HBE	CO_2 capture	Support efficient allocation, target-based regulation, develop long-term perspective, market-price related, recognition bio-CO_2 value	Potential insufficient to support business case, Possible misinterpretation valorisation potential, interference other renewable production routes
Bio-H_2 certification scheme	Green certificates	CO_2 capture	Derivative of quota scheme, liquid market, potential interconnection other energy carriers, support trade, increase standardisation	No real regulatory support scheme, volatile price effects, complex definition of inherent value
Hydrogen infrastructure	AFID, Gas law	Bio-H_2 production	Support renewable hydrogen transition, support coordination efforts, lower system costs	Chicken-and-egg problem, initial overcapacity, potential complex integration

Table 11.1: Overview proposed regulatory support mechanism for concept of third-generation upgrading

Chapter 12

Discussion

The dramatic effects of human-induced climate change require a radical change in the energy system design. This includes a mentality shift towards embracing the need for radical transformations as opposed to incremental changes. Moreover, a rapid system overhaul is required to ensure a fair-, green-, and prosperous future. In this light, the energy system is envisioned to be, at least, climate-neutral in the European Union by 2050. Here, hydrogen has been ascribed a key pillar next to large-scale electrification and the circular usage of materials. In this respect, hydrogen can act as a renewable and cost-effective versatile energy carrier to decarbonise hard-to-abate sectors and green processes, products and materials. Moreover, renewable hydrogen is seen as important energy vector to the balancing, integration and storage of renewables. Most importantly, renewable hydrogen allows for the cost-effective transport of cheap renewable electricity from apart production and demand centers.

In this light, a future renewable hydrogen energy system is proposed that shows important similarities to the present natural gas system. Here, renewable hydrogen fulfils two essential systemic functions as complementary energy carrier for the transportation of cheap renewable electricity over time and space and as resource for the decarbonisation of hard-to-abate sectors. In the future renewable hydrogen system, hydrogen will act as a energy commodity in competition with local renewable electricity production and regional renewable hydrogen capacity.

In the proposed future renewable hydrogen system special attention has been devoted to the utilisation of biogenic resources for the local- and or regional production of bio-hydrogen and bio-carbon dioxide or syngas. Here, the bio-hydrogen is seen to support local- and or regional demand for renewable hydrogen, while the bio-carbon is assigned valorisation potential for the production of green products and materials in the industrial sector, or horticulture. The utilisation of bio-carbon is presumed to become increasingly relevant as a result of the radical change in the energy system away from, fossil, molecules towards, renewable, electrons. In this perspective, carbon dioxide is no longer a waste product of the energy system, but rather a valuable climate-neutral molecule.

However, it was mentioned that at the present moment both the low-carbon hydrogen capacity- and CO_2-eq reduction levels are insufficient to support the required radical transformation of the current energy system. Here, the regulatory framework and infrastructural design were mentioned to provide prevalent boundary conditions for the adoption of renewable hydrogen. Moreover, it was discussed that the current focus on lower-carbon hydrogen and e-hydrogen production has been inadequate. In this respect, lower-carbon hydrogen production is hindered due to the continued reliance on fossil resources, the potential natural gas lock-in, the immaturity of the capture- and storage technology and the questionable carbon savings. On the contrary, e-hydrogen production, so far, has been confronted with high production costs and competitive utilisation of renewable electricity capacity. This is despite the presumed considerable cost reductions that are attainable in the e-hydrogen production. On top of that, the biogenic hydrogen production via gasification technologies has been limited as a result of the low technology maturity, high cost price, alternative product applications, feedstock competition and process complexity and efficiency.

Therefore, in alignment with the proposed future renewable hydrogen system the production of bio-hydrogen from biogas has been proposed as technological feasible, environmental benign and, potential, cost-effective solution for the, especially, local- and or regional production of renewable hydrogen. Here, bio-hydrogen has been ascribed higher valorisation potential as compared to alternative applications of biogas and or biomethane through the increased versatility of hydrogen and due to alignment with the proposed future renewable hydrogen system. On top of that, it allows for the revision of biogas as platform molecule for the production of energetic renewable hydrogen and molecular bio-carbon dioxide. In this way, biogas is enabled to operate in a dual, time- and place dependent role within both the renewable energy- and bio-economy domain. This renewed systemic role of biogas within the proposed future renewable hydrogen system paved the way for the development of the concept of third-generation upgrading.

In the concept of third-generation upgrading problematic waste streams are, via biogas production, assigned the highest valorisation potential as bio-hydrogen and bio-carbon dioxide. Here, a flexible and dynamic interpretation over time and place is advocated to support the initial valuation of bio-hydrogen, the subsequent perspective on both bio-hydrogen and bio-carbon dioxide and ultimate the view on bio-carbon as indispensable source of climate-neutral carbon molecules. In this way, biogas is enabled to couple negative carbon emissions with zero-pollution renewable energy and circular utilisation of materials. Ultimately, this changes the way biogas is seen.

As a result, this research placed biogas central as important local- and or regional platform molecule that is able to couple the circular- and hydrogen economy. Here, biogas has been ascribed potential to offer zero-pollution energy and contribute as, climate-neutral or carbon negative, bio-based input material. In this way, the proposed concept of third-generation upgrading supports a rapid-, affordable- and reliable transition towards the future proposed renewable hydrogen system and contributes to political priorities and strategies to achieve climate-neutrality in the European Union by 2050.

In this respect, the research took a system design approach and assessed the technological-, environmental-, and economical potential of the concept of third-generation upgrading within the future proposed renewable hydrogen system. This was supported by the perspective on the relevant infrastructural- and regulatory boundary conditions to support the overall feasibility. This was used to discuss the dual, time- and place dependent perspective on the valorisation potential of biogas.

This resulted in the proposed hypotheses that stated that biogas has untapped potential to operate as a platform molecule for both energetic bio-hydrogen and molecular bio-carbon dioxide within the future renewable hydrogen energy system. Here, the technological conversion of biogas is possible, the utilisation of carbon dioxide results in negative carbon emissions, the utilisation of hydrogen supports zero-pollution emissions, and both output streams coherently and singularly show positive economic results. On top of that, it stated that the regulatory strategy and infrastructural development will devalue the usage of green gas as opposed to bio-hydrogen through dedicated infrastructure, price incentives and regulatory requirements. Moreover, bio-carbon will observe market creation, demand creation and price incentives related to a renewed vision on negative emissions, closing carbon cycles, and phasing out of fossil fuels.

To conclude, the research shed a new perspective on the role of biogas within the proposed future renewable hydrogen system. Here, it was stated that biogas has a higher valorisation potential as source of bio-hydrogen and bio-carbon dioxide over time and place. This was interpreted within the research context of the future renewable hydrogen system and compared against competitive hydrogen production methods and alternative uses of biogas. In this respect, the proposed concept of third-generation upgrading was assessed based on the technological-, environmental- and economical potential. Moreover, the concept of third-generation upgrading was placed within the place dependent infrastructural- and time dependent regulatory boundary conditions. This ultimately served to assess the way biogas should be seen.

Third-generation upgrading

Hydrogen was stated to become the key pillar within the future renewable energy system. Here, renewable hydrogen is presumed to overhaul the current natural gas system, displace non-power sector uses of fossil resources, and green products and processes. This is stimulated by the cost-effective transport and storage of cheap renewable electricity over time and place. As a result, hydrogen is seen as the energy vector that will integrate- and couple the future energy system. In this context, it was shown that bio-hydrogen would provide a relevant source of renewable hydrogen, especially in short- to medium term and for local- and or regional hydrogen demand. In this way, bio-hydrogen could provide cost-effective and environmental benign hydrogen capacity, already, in the short-term. In contrast, e-hydrogen is presumed not to become cost-effective until the medium-term due to limited- and competitive renewable electricity demand and as result of the limited economies of scope and scale at the moment. Nevertheless, e-hydrogen is presumed to become the dominant source of renewable hydrogen and contribute to the potential for renewable hydrogen as energy commodity. On the other hand, the environmental performance and overall alignment with the renewable hydrogen system was questioned, especially, for traditional fossil- and lower-carbon hydrogen production. Nonetheless, lower-carbon hydrogen is presumed to be relevant, especially, in the short-term. However, in this respect bio-hydrogen was indicated to provide additional value through the inherent bio-carbon dioxide which would boost the value, especially for local- and or regional demand centers. On top of that, alternative biogenic hydrogen production methods were not presumed a technological feasible production alternative until the medium-term due to the lack of commercial applications and presence of technological barriers.

As a result, bio-hydrogen shows important value for the local- and or regional production of bio-hydrogen, especially in the short- to medium term. This is derived from an environmental perspective, as compared to lower-carbon hydrogen, from an economical perspective, as compared to e-hydrogen, and from a technological perspective, as compared to alternative biogenic hydrogen. This is especially important due to the inherent interconnection between biomethane and bio-hydrogen as, for example, alternative energy carriers within a climate-neutral energy system. In this respect, renewable hydrogen is viewed to become the dominant energy carrier. As a result, the concept of third-generation upgrading envisioned the production of bio-hydrogen and bio-carbon dioxide as the higher valorisation potential as compared to the direct utilisation of biomethane. In this way, biogas not only constitute relevant renewable hydrogen production capacity but could also stimulate the transition towards the proposed renewable hydrogen system.

In this perspective, the concept of third-generation upgrading is an addition to the dynamic perspective on the valorisation potential of biogas over time and place. Here, biogas has initially been valued within the renewable energy domain as source of renewable electricity. This subsequently shifted towards the production of heat and later the combined heat- and electricity production. Hereafter, biogas has been primarily assigned value as source of biomethane, which was attributed value within the industrial-, transport- and build environment sector. More recently, the concept of second-generation upgrading was brought forward to value the inherent climate-neutral bio-CO_2 present in the initial upgrading of biogas to biomethane. Here, bio-CO_2 was envisioned as relevant biogenic feedstock for the production of hydrocarbon-based renewable fuels. In this line, the concept of third-generation upgrading identifies the production of zero-pollution hydrogen in combination with the production of, the complete or three times the amount of, bio-carbon the highest valorisation potential with flexible interpretation over time and place. In this way, the biogenic carbon could ultimately be reserved for application as industrial feedstock, which is assigned the highest valorisation potential due to the lack of feasible alternatives. In this way, bio-hydrogen could replace up to two-third of the current natural gas produced hydrogen in the Netherlands, while the bio-CO_2 could capture around 1% of the current fossil CO_2 emissions in the Netherlands and fulfill around 10% of the proposed demand for climate-neutral carbon feedstock in the industrial sector.

Thus, it was shown that bio-hydrogen production could fulfil an important role within the proposed future renewable hydrogen system. Moreover, it was stated that the production of bio-hydrogen and bio-carbon dioxide entails a renewed perspective on the utilisation of biogas. As a result, the concept of third-generation upgrading identifies the production of bio-hydrogen and bio-carbon dioxide as the highest valorisation potential of biogas over time and place within the wider proposed future renewable hydrogen system.

Technological potential

To support the renewed perspective on the utilisation of biogas the technological conversion of biogas to bio-hydrogen was shown. Here, it was indicated that after the production of biogas, the biogas is pretreated to remove contaminants, like H_2S and H_2O, via a combination of separation technologies. Hereafter, the biogas is upgraded via membrane technology to yield a, natural gas-like quality, biomethane stream and an initial bio-CO_2 stream. The biomethane is subsequently converted via a methane reforming technology to a syngas stream. Here, the quality of the syngas depends on the respective reforming technology and, potential, rate of oxidants. The syngas is in turn treated in a series of WGSR to increase the hydrogen yield and convert the CO to a bio-CO_2 stream. The bio-hydrogen and bio-CO_2 are, before potential compression or liquefaction, separated via a pressure swing adsorption method. In this respect, it was indicated that the conversion of biogas to bio-hydrogen and bio-carbon dioxide is technological feasible and relies on mature technologies.

In basis, this integrates the current biomethane production with the current fossil hydrogen production methods. Nonetheless, several innovative technologies were identified, that focused on the process efficiency and or process intensification. Here, the utilisation of ATR-related technologies, the direct deployment of biogas and the potential process intensification with respect to the bio-hydrogen and bio-carbon dioxide separation were identified to show important technological benefits. Ultimately, based on a HOQ assessment of 10 potential technological layouts within the perspective on the local- and or regional utilisation of biogas for bio-hydrogen and bio-carbon dioxide production, it was stated that ATR-related technologies, specifically BATR, showed most relevance with respect to the concept of third-generation upgrading. This was related to the technology maturity, flexible production scales, flexible process operations, high process yield and ultimately low system cost perspective. In this way, the concept of third-generation upgrading shows important technological potential within the proposed future renewable hydrogen system.

Hereafter, based on the discussed technological layouts, the potential process flow was assessed to identify the relevant process streams. This included a perspective on the potential production scale as commercialisation, professionalisation and integration of production is considered important to improve volume and lower costs. Overall, an approximate bio-hydrogen yield of 0.1 kg H_2/Nm^3 biogas and bio-carbon dioxide yield of 1.4 kg CO_2/Nm^3 biogas was presumed attainable. In case of the latter, around twice as much bio-CO_2 could be obtained in the reforming step as opposed to the biomethane production step, in case of the traditional layout. On top of that, it was mentioned that several improvements could be made to stimulate the respective process flows. This included, among other, renewables integration, process integration and process intensification.

Environmental potential

With respect to the environmental performance of the concept of third-generation upgrading, it was indicated that biogas production shows important benefits within the waste-to-energy nexus. Here, biogas production offers a solution to problematic waste management including related methane- and contaminants emissions. Moreover, biogas production allows for the production of bio-fertiliser that could replace fossil-based fertiliser. On top of that, it was indicated that the bio-fertiliser shows potential to store up to 30% of the atmospheric carbon content in the soil and thereby act as a negative carbon source.

Hereafter, the respective mass balance of the underlying process flow diagram was used to identify the environmental performance of the concept of third-generation upgrading in relation to the inherent bio-CO_2 value. In this respect, it was shown that the concept of third-generation upgrading has the potential to yield around 35 kg bio-CO_2 per tonne of manure or 1.4 kg bio-CO_2/Nm^3 biogas based on a biogas yield of 25 Nm^3/t manure. In contrast, the concept of second-generation upgrading lowers the potential bio-CO_2 yield to around 11 kg bio-CO_2/t manure as a result of the direct utilisation of biomethane. This was based on an environmental neutral perspective of the production process, for example, through the integration of renewables and high levels of process integration.

As a result, the concept of third-generation shows important environmental benefits in relation to production of valuable climate-negative bio-CO_2. Here, the environmental benefits are assigned value in light of climate-neutrality and the expected demand for biogenic industrial feedstock. This stimulates the perspective on the higher valorisation potential of the concept of third-generation upgrading. In this respect, the bio-CO_2 could be valued through, a combination of, the EU ETS, CTBO, carbon content and the inherent sales value. Therefore, the concept of third-generation upgrading provides next to a valuable zero-pollution bio-hydrogen stream a relevant bio-CO_2 output stream. Moreover, the concept of third-generation upgrading was shown to have additional environmental benefits over the production value chain. Ultimately, the relative value of the output streams is expected to align with the proposed time and place dimension within the wider proposed future renewable hydrogen system.

Economical potential

Based on the proposed technological layout, the associated process flow streams and the inherent environmental value of bio-CO_2 the economical potential of the concept of third-generation upgrading was identified. This included a system cost perspective, relevant economic parameters and the focus on the alternative- and competitive utilisation of biogas. In case of the former, different value chain layouts were discussed including the conversion-, reconversion-, transportation-, distribution- and storage of hydrogen. Here, the relative cost benefit associated with the local- and or regional production and utilisation of hydrogen was shown. It was mentioned that the total hydrogen delivery costs could add approximately [0.5-1.5] €/kg H_2 to the hydrogen production costs to account for possible compression or liquefaction, transportation and or storage of hydrogen.

Hereafter, the business case framework was used to indicate the relevant bio-hydrogen production costs as function of different production sizes, process designs, and CAPEX and OPEX related costs. In this respect, it was shown that the bio-hydrogen production costs are around [2.4-3.7] €/kg H_2 based on a presumed bio-CO_2 value of 80 €/t CO_2 and a 5.5 MW biogas production capacity. This relates to the bio-CO_2 yield of around 15 kg CO_2/kg H_2, which lowers the presumed bio-hydrogen price by net 0.70 €/kg H_2 at an assumed CCUS cost of 0.5 €/kg H_2. In case of the bio-hydrogen production costs, it was shown that the proposed professionalisation, commercialisation and integration of the bio-hydrogen production shows strong costs advantages. Moreover, it was shown that the proposed BATR technological layout shows improved costs performance of [10-15]% as a result of the increased level of process integration, despite the lower hydrogen yield.

Next to that, further improvements in process yield, for example through enhanced heat integration, and reduction in biogas production costs could would favour the cost perspective. This is an indirect and direct result of the high contribution of the biogas feedstock costs in the overall cost perspective. This relates to the approximate bio-hydrogen yield of 0.1 kg H_2/Nm^3 biogas. In this respect, it was shown that the feedstock costs contribute around [50-70]% to the ultimate production costs in case of the reference 5.5 MW installation. In similar lines, it was stated that the ultimate bio-hydrogen reforming costs add twice as much to the ultimate bio-hydrogen costs as opposed to the biomethane upgrading costs. In case of the cost components, is was indicated that the CAPEX costs contribute around [1.5-2] as much as the OPEX costs.

Overall, it was shown that in case of the BATR process layout at the reference installation size, a bio-hydrogen price of [3.10-3.20] €/kg H_2 at a bio-CO_2 value of 80 €/t CO_2 would contribute to a positive investment case. In contrast, at a presumed bio-H_2 price of 3.60 €/kg H_2 a bio-CO_2 price of [40-50] €/t CO_2 would suffice. Nonetheless, this excludes the proposed delivery costs that would directly impact the relative costs perspective as compared to alternative hydrogen production.

Hereafter, the economical feasibility of the concept of third-generation upgrading was assessed compared to the presumed concept of second-generation upgrading. This was based on the relative production costs perspective, the relative energetic valuation and the ultimate bio-CO_2 stream. Here, it was shown that an inherent bio-CO_2 value of [140-180] €/kg H_2 would suffice to support the higher valorisation potential of the concept of third-generation upgrading. This is based on the factor three times increase in bio-CO_2 output as compared to the concept of second-generation upgrading. Moreover, this was despite the higher production costs of around [40-50]% and the lower relative energetic value of [25-45]%. In similar lines, based on the inherent value of bio-CO_2 it was indicated that the proposed syngas output would be economical advantage at a carbon price of [200-330] €/t CO_2.

Boundary conditions

It was indicated that the concept of third-generation upgrading shows strong technological potential, good environmental performance and favourable economical potential. This was assessed within the wider proposed future renewable hydrogen system and compared to competitive hydrogen production methods and alternative biogas utilisation. Nonetheless, both the time- and place dimension of the concept of third-generation upgrading are essential to ensure overall feasibility. In this respect, both the infrastructural- and regulatory boundary conditions are presumed to be vital. This relates to the eventual relative- and absolute price points and system costs. Ultimately, this will support the concept of third-generation upgrading as highest valorisation potential of biogas within the wider proposed future renewable hydrogen system.

The infrastructural boundary conditions are deemed especially relevant from the place dimension. This relates to the relative delivery costs perspective of bio-hydrogen, and bio-carbon dioxide, as opposed to competitive production capacity. In this respect, the local- and or regional production and, potential, coupled demand could lower the associated costs of conversion, transportation and storage. Moreover, the infrastructural boundary conditions could impact the relative valuation of bio-hydrogen as opposed to biomethane. Stated differently, the support for bio-hydrogen would help to boost the infrastructural transformation and subsequently devalue the utilisation of biomethane.

In this respect, it was indicated that the infrastructural requirements for hydrogen, carbon dioxide and, potentially, biogas are feasible. Moreover, it was indicated that the repurposing of the traditional natural gas network could support an affordable transition towards the proposed renewable hydrogen gas system with presumed costs, of a factor [0.10-0.35] of the costs to construct new dedicated hydrogen pipelines, of 0.84 M€/km. On top of that, it was mentioned that hydrogen pipelines are expected to have similar CAPEX costs as compared to natural gas pipelines. In this respect, the concept of third-generation upgrading was mentioned to allow for the stimulation of parallel repurposing of the natural gas network. This is especially relevant on the local- or distribution scale next to the proposed alterations in the transportation network. In this respect, trends in biogas pooling, establishment of strategic hubs, and biomethane reverse flow could show relevant value for the local- and or regional production and utilisation of bio-hydrogen and bio-carbon dioxide.

Overall, it was mentioned that the total hydrogen delivery costs could add approximately [0.5-1.5] €/kg H_2 to the hydrogen production costs to account for possible compression or liquefaction, transportation and storage. In similar terms, an additional [30-65] €/t CO_2 was mentioned to be added for the delivery costs of bio-CO_2. As a result, an adequate infrastructure design would promote the adoption of the concept of third-generation upgrading both over competitive hydrogen production and alternative biogas utilisation potential.

As a result of the importance of the infrastructural boundary condition, a potential infrastructure design that would promote the adoption of the concept of third-generation upgrading was outlined via a mapping exercise. Here, the proposed output should result in an overall decrease in system costs, increase in system integration and enhancement of the production scale. In this respect, it was mentioned that the infrastructural design should include the biogas production potential, the current infrastructural network and, possible, decentral industrial demand to adequately integrate feedstock potential, production capacity and end demand in order to optimise the overall system costs. Overall, the infrastructural design should lower the relative delivery cost perspective of bio-hydrogen as opposed to competitive production methods, should allow for the utilisation of bio-CO_2 or syngas and should devalue the utilisation of biomethane as opposed to bio-hydrogen. Ultimately, the place dimension could unlock the practical feasibility of the concept of third-generation upgrading.

The regulatory boundary condition add the relevant time dimension to the concept of third-generation upgrading. Here, regulations are discussed to be indispensable as result of the low production costs associated with the traditional energy system and the need for a complete system overhaul. In this respect, regulations support the proposed future renewable hydrogen system via coordination and financial stimulation. Thereby, the development of a regulatory vision, the creation of markets and the ultimate use of financial incentives are of vital importance. In this perspective, regulations ultimately determine the actual valorisation potential of the concept of third-generation upgrading and as such the overall feasibility over time. Here, the regulations should adequately value the environmental benefits, relate to competitive- and alternative usage and take a system cost approach.

In this respect, it was discussed that the regulatory vision or context is formed by the perspective on climate-neutrality, circularity and zero-pollution in the European Union by 2050 with the overall objective of a green-, prosperous- and fair energy system. In this light, reduction of the overall costs, increases in the production scale and innovation are seen as key. Here, different stages in regulatory development were shown with different levels of flexibility, and progressive emissions- and uptake targets. Moreover, this allows for the time dependent interpretation of the valorisation potential of the concept of third-generation upgrading with increased attention for bio-carbon. Here, it was discussed that the valorisation potential should arise from end applications with limited or no practical- and or economical feasible alternatives.

However, it was mentioned that the lack of regulatory vision limits the development of a bio-hydrogen market. Thereby, from a market development perspective it was indicated that regulations are vital to overcome market failures related to negative externalities, information asymmetries and overall risk. This includes, for example, the adequate valuation of bio-CO_2, the development of a certification scheme based on the 5T principle and the harmonisation and standardisation of rules and regulations including clear target setting. Moreover, it was stated that in case of market creation the regulatory- and infrastructural boundary conditions interconnect due to the relevance of regulatory coordination and support in relation to the proposed infrastructural design.

Then, the appropriate design of regulatory financial incentives along the principles of optimal economic regulation theory should ensure the adoption of the concept of third-generation upgrading from a, social, welfare enhancing perspective. In this light, several different support mechanisms are described that finds different use cases over stages in the value chain, over time, over location and over end application. Overall, the interplay between the regulatory vision, market creation and financial incentives should focus on the valorisation potential over time and place of the concept of third-generation upgrading.

From this perspective, a regulatory impact assessment was utilised to identify, analyse and asses the current- and proposed regulatory boundary conditions in order to support the adoption of the concept of third-generation upgrading. Here, the main implemented support schemes in the Netherlands to stimulate renewable energy, as derived from the overall European vision, are the SDE++ subsidy scheme and HBE scheme. In this respect, a lack of long-term vision on the value of bio-CO_2, the inefficient allocation of scarce renewable molecules and a limited perspective on the, long-term, societal benefits limited the support for the concept of third-generation upgrading.

Therefore, renewed policy support mechanisms were proposed. In this case, special attention was devoted to the adequate valuation of bio-CO_2 via the atmospheric CO_2 capture and utilisation potential. This was further strengthened by the renewed focus on the value of zero-pollution bio-hydrogen. In this respect, it was indicated that the concept of third-generation upgrading shows economic feasibility from 2030 onward, mainly related to the increase valuation of bio-CO_2. Moreover, it was identified that the relative valuation of bio-CO_2 over time could pave the way for the increased focus on bio-carbon, especially starting 2042. This could be reduced to 2028, with a presumed switch to bio-carbon in 2034 through an alternative, social- and economical, valuation of bio-CO_2. Overall, it was indicated that the social cost amount to around 1.20 €/kg H_2 and was primarily related to the valuation of, negative, bio-CO_2 at 200 €/t CO_2.

To conclude, it has been shown that concept of third-generation upgrading offers technological-, environmental- and economical potential within the proposed future renewable hydrogen system. In this respect, the concept of third-generation upgrading redefines the role of biogas. Here, biogas has been assigned higher valorisation potential as bio-hydrogen and bio-carbon source over time and place. In this perspective, the concept of third-generation upgrading identifies biogas as a central platform molecule that is able to decouple the energetic renewable hydrogen and the molecular renewable carbon. As a result, it was stated that biogas is able to contribute to both the renewable energy- and bio-economy domain. Thereby, biogas is able to contribute to relevant local- and or regional bio-hydrogen capacity in the short-term, to both bio-hydrogen and bio-carbon dioxide in the medium term and ultimately provide valuable climate-neutral carbon in the long-term.

This was supported by adequate technological-, environmental-, and economical performance, both absolute and relative to competitive hydrogen production capacity and alternative utilisation of biogas. Here, it was indicated that the ATR- and BATR technological layout show most relevance in light of the proposed future renewable hydrogen system. This was supported by a hydrogen yield of approximately 0.1 kg H_2/Nm^3 biogas and a bio-carbon dioxide yield of 1.4 kg CO_2/Nm^3 biogas. Moreover, it was indicated that the concept of third-generation upgrading is able to yield around 35 kg bio-CO_2 per tonne of manure as compared to around 11 kg bio-CO_2/t manure in light of the concept of second-generation upgrading. Then, based on the relative production costs perspective and the relative energetic valuation, it was shown that an inherent bio-CO_2 value of [140-180] €/kg H_2 would suffice to support the higher valorisation potential of the concept of third-generation upgrading. Furthermore, it was indicated that the bio-hydrogen production costs are around [2.0-3.3] €/kg H_2 based on a presumed bio-CO_2 value of 80 €/t CO_2 and a 5.5 MW biogas production capacity. This excluded the approximate [0.5-1.5] €/kg H_2 addition to the hydrogen production costs to account for possible compression or liquefaction, transportation and storage of hydrogen as well as an additional [30-65] €/t CO_2 for the delivery costs of bio-CO_2. Overall, it was indicated that a bio-hydrogen price of [3.10-3.20] €/kg H_2 at a bio-CO_2 value of 80 €/t CO_2 would contribute to a positive investment case. On the other hand, at a presumed bio-H_2 price of 3.60 €/kg H_2 a bio-CO_2 price of [40-50] €/t CO_2 would suffice.

This could be stimulated by an adequate infrastructural design that supports the increase in production scale, decrease in delivery costs, and is optimised over the potential integration of feedstock availability, production capacity and demand centers. On top of that, regulatory support mechanisms that value the atmospheric CO_2 capture and utilisation is central. Overall, the boundary conditions ensure the adoption of the concept of third-generation upgrading over competitive hydrogen production and or the alternative utilisation of biogas or biomethane. This relates to the relative decrease in the cost perspective of bio-hydrogen and the overall devaluation of biomethane. Ultimately, the concept of third-generation upgrading is stated to become central for the local- and or regional production of bio-hydrogen and bio-carbon dioxide, or syngas, within the proposed future renewable hydrogen system.

Chapter 13

Evaluation

It was mentioned that the dramatic effects of human-induced climate change require a radical transformation of the current energy system. In this light, a future renewable hydrogen energy system is proposed. Here, renewable hydrogen is the energy carrier that allows for the cost-effective transport of cheap renewable electricity over time and space. Moreover, renewable hydrogen allows for the balancing of the power sector, is able to green processes, products and materials, and supports the decarbonisation of hard-to-abate sectors. In this perspective, the concept of third-generation upgrading is mentioned as the highest valorisation potential of biogas. In this way, biogas would be seen as a platform molecules for the production of both bio-hydrogen and bio-carbon dioxide.

It was indicated that the concept of third-generation upgrading is technological feasible, has superior environmental performance and shows important economical benefits. This was both in absolute terms and relative to competitive hydrogen production and alternative utilisation of biogas. Thereby, it was indicated that this could be further supported by an adequate infrastructural design and relevant policy support schemes. In this way, the concept of third-generation upgrading becomes central for the local- and or regional production of bio-hydrogen and bio-carbon dioxide, or syngas, within the wider proposed future renewable hydrogen system. This changes the way biogas is seen.

To support the theoretical analysis and reasoning, the output of the expert interviews serve to support the practical interpretation of the proposed concept of third-generation upgrading. Here, in light of the mentioned research context, the expert interviews offer a solution space for adequate alteration of the respective boundary conditions to facilitate the renewed perspective on the role of biogas within the proposed future renewable hydrogen system. As such, the output of the expert interviews will be assessed along the dimensions of the research context.

Hydrogen

The domination of renewable electricity generation in the current policy perspective and future energy system has been highlighted. Here, the large-scale electrification is stated to result in a massive shift in the specific energy need. This could result in an energy system were up to half of the direct energy demand is fulfilled by renewable electricity. As a result, the current policy measures are stated to primarily stimulate full-scale electrification.

However, it was mentioned that the need for renewable molecules is becoming more apparent. Here, renewable hydrogen has been assigned relevant potential to support the direct energy need, stimulate the integration of renewables and unlock the transport and storage of renewable electricity over time and space.

Nonetheless, it was stated that the role of renewable hydrogen in the energy system has not been well-defined. This arises from the uncertainty regarding the actual usability of renewable hydrogen in the main use cases over time and space. This was stated to relate to, for example, the fact that the industrial sector has been spoiled with cheap hydrogen, the transport sector has been, primarily, focused on electrons, the build environment has several alternatives and the power sector sees attention and research related to alternative solutions for the intermittency problem.

Moreover, the alternative utilisation of biogenic resources was mentioned to lower the proposed role of renewable hydrogen. This included the parallel utilisation of renewable hydrogen and biogenic resources to fulfill the prevalent sustainable energy demand. Here, biogenic resources were attributed benefits with respect to, among other, the current state of knowledge, the maturity of the technology and the subsequent scaling potential.

In this perspective, it was mentioned that the demand for low-carbon hydrogen is expected to be, primarily, driven by the current industrial market demand in the short to medium term. As a result, only, from the medium- to long term it is expected that new markets could be addressed. This was stated to relate to the economical- and political considerations with respect to available alternatives. Here, the new market demand is presumed to originate from several different sectors and end applications.

With respect to the transport sector, the presumed market demand for FCEVs is presumed to, mainly, arrive from heavy-duty transportation applications due to the apparent competition with BEVs. Moreover, the direct utilisation of hydrogen was presumed to be unlikely in the aviation- and maritime industry. Nonetheless, this ignored the potential of hydrogen-derived fuels. Overall, it was mentioned that the infrastructural developments are vital. Moreover, the interpretation of the RED was mentioned to determine the ultimate utilisation of hydrogen in the transport sector. Here, it was mentioned that the translation of the RED in the Netherlands, at least until 2030, does not provide a favourable treatment of e-hydrogen. Moreover, the utilisation of bio-hydrogen has been devalued as result of the presumed alternative applications of biomethane.

With respect to the industrial sector, new market demand is presumed to arise from the feedstock value of hydrogen for the greening of processes, products and materials from, for example, the iron and steel-, and bio-refinery industry. However, in this respect the production scale requirement and potential efficiency losses were respectively mentioned to hinder the presumed uptake of hydrogen.

Specifically, the demand for bio-hydrogen in the industrial sector is presumed to arise mainly from niche industry demand. This relates to the relative cost perspective, the available alternatives and the prevalent regulatory support mechanisms. For example, this relates to the bio-hydrogen delivery costs perspective, over time and space, in the ammonia industry, which is driven by the raw material costs in a commoditised market. Moreover, this relates to the demand for traceability and the biogenic nature of the feedstock, in the methanol industry, where bio-methanol finds an premium market in contrast to e-methanol. Also, this relates, for example, to the blending requirement in the transport industry or for the subsequent development of bio-products. This is further supported by the favourable syngas quality of biogas reforming and or the potential separate sales, based on the purity requirements, process continuity and delivery costs, of bio-hydrogen and bio-carbon dioxide in the methanol industry. On top of that, the potential to negotiate individual price contracts for bio-hydrogen was stated to, potentially, support the adoption of bio-hydrogen in the premium niche chemical industry.

On the contrary, the demand for bio-hydrogen in the main industrial sector is presumed to be limited due to the perspective on biomethane, or biogas, to green the process and products. Here, biomethane could directly replace the current natural gas demand in both the ammonia- and methanol industry. This is stated to be stimulated by the current regulatory support mechanisms, including, the EU ETS and the SDE+ subsidy.

With respect to the build environment, the adoption of renewable hydrogen was questioned as result of, potential, alternatives. This included the perspective on full-electric, hybrid heat networks and renewable electricity, and the utilisation of biomethane. As a result of the current focus on large-scale electrification, the utilisation of renewable hydrogen was stated to be limited to the, possible, replacement of biomethane. Nonetheless, this perspective was contrasted by the presumed European Union stimulation of all-hydrogen for local- and specific energy demand.

With respect to the power sector, the possible adoption of renewable hydrogen was presumed to be lowered due to the, previous, perspective on biogas as, alternative, renewable electricity source. This is next to the focus on the potential continental interconnection of the renewable electricity capacity or power sector.

In relation to the production of hydrogen, fossil hydrogen, lower-carbon hydrogen, e-hydrogen and biogenic hydrogen were mentioned as relevant production methods.

With respect to fossil hydrogen production, it was mentioned that the current production cost result in the continued reliance on fossil hydrogen production capacity in the current energy system. Subsequently, it was stated that the expected price development of fossil hydrogen remain important to assess the, potential, uptake of alternative hydrogen production capacity. Here, the carbon price development and political context are mentioned to prove of vital importance to support the proposed transition to the renewable hydrogen energy system.

With respect to lower-carbon hydrogen, the potential uptake in the short to medium term was highlighted. Here, the production capacity, technology maturity, process integration, carbon price development, political support, infrastructural possibility and presumed costs price were mentioned to support the uptake. On the contrary, possible, social resistance, storage capacity constraints and natural-gas lock in were mentioned to hinder the development of CCS technology.

With respect to e-hydrogen, the potential uptake in the short- to medium term was questioned as a result of the, possible, lack of e-hydrogen production capacity. Here, the mentioned focus on electrification was identified to hinder the adoption of e-hydrogen production. This was further complicated by the demand for low electricity costs, high utilisation rate and low system costs. This was supported by presumed limited efficiency- and economies of scale gains, in contrast to economies of scope benefits of the modular nature of electrolysis cells.

With respect to biogenic hydrogen production, the utilisation of gasification technology was presumed to be hindered as result of the alternative utilisation of the produced producer gas. This was related to the mass balance carbon efficiency as result of the higher carbon-to-hydrogen ratio as compared to methane reforming. This was further supported by the perspective on the valorisation potential of woody biomass and the associated social unrest, previously, related to renewable electricity- or heat generation. Also, the variations in production output, as result of variable process specifications and input, was mentioned to limit the adoption of gasification technology for biogenic hydrogen production. This in turn was related to the limits to centralised processing and adequate certification. On the other hand, the possible parallel utilisation of the green gas and biogenic hydrogen output products was mentioned as potential relevant benefit, for example, with respect to the distinct market values. On top of that, despite the uncertain development, SCWG technology was listed as possible relevant production route in relation to the production scale, scalability and input flexibility.

On the other hand, the bio-hydrogen production route was assigned several relevant benefits in contrast to the, presumed, primary hydrogen production methods. This includes the technology maturity, climate-neutral nature, possible negative CO_2 emissions, market potential of bio-CO_2, net bio-hydrogen delivery costs, established guarantees-of-origin market, de-risking of the current biomethane production, additional renewable hydrogen capacity, hydrogen infrastructure development, other value chain-related environmental benefits.

Overall, despite the renewed perspective on the relevance of renewable molecules and the presumed role of renewable hydrogen, the internalisation of the proposed future renewable hydrogen system was limited. This was a result of the, previous, sole focus on large-scale electrification of the energy system. Moreover, this was a result of the continued reliance on the old energy system including a low cost price perspective and inadequate valuation of CO_2. On top of that, it related to the limited long-term perspective and the subsequent incorrect valuation of potential alternatives to renewable hydrogen. In this respect, the interconnection between renewable hydrogen and biomethane as related energy vectors was mentioned. This in turn resulted in a short-sighted vision on the utilisation of renewable hydrogen in relevant end applications, including the transport-, the industrial-, build environment- and power sector. This was further supported by the limited perspective on the potential of lower-carbon- and, especially, renewable hydrogen production methods. This was mainly a result of the continued reliance on the traditional energy system and an insufficient political context.

In this respect, it could be argued that the current practical interpretation on the role of hydrogen is limited as result of a short-term perspective, the focus on gradual transformation and a lack of energy system, costs, perspective. This includes, for example, the limited interpretation of the role of renewable hydrogen as energy vector for the transport of cheap renewable electricity over time and space. Moreover, it lacks the perspective on the cost-effective transport of molecules as compared to electrons. Additionally, it ignores the relevance of renewable hydrogen within the build environment. On top of that, it misinterprets the importance of negative carbon emissions, zero-pollution fuel and biogenic climate-neutral feedstock. This includes the inadequate valuation of CO_2 and the respective political context. Thereby, it incorrectly devalues renewable hydrogen production methods. Nevertheless, it opens the potential of bio-hydrogen production capacity as a result of the assigned benefits.

Thus, the practical interpretation of the proposed research context is hindered by a more conservative perspective on the future energy system. In this respect, the solution space is skewed towards the importance of the boundary conditions. With respect to the regulatory boundary conditions, this includes, for example, long-term, radical, coherent and stable targets and goals, adequate valuation of CO_2-related emissions, sufficient infrastructural support and coordination, adopting a system costs perspective, and the overall assessment of valorisation potential or renewable molecules. With respect to the infrastructural boundary conditions, this includes the repurposing of the traditional natural gas network, the exclusion of traditional combustion engines and the support for cost-effective renewable hydrogen transport. Therefore, the solution space is supported by a prescriptive perspective on the future renewable hydrogen system, including the role of the concept of third-generation upgrading.

Biogas

The biogas production potential was questioned. This related to the availability and feasibility of manure digestion. Here, long-term contracts were mentioned to lower the accessibility of manure and or increase the relevant input price and subsequently the feasibility. Moreover, the proposed agricultural policy could stimulate a considerable reduction in the manure availability, in the Netherlands. This was further amplified by the negative, social, connotation of the environmental benefits of biomass utilisation, especially for energy production, which could hinder the deployment of biogas production capacity. On top of that, the phasing out of co-digestion was mentioned to, potentially, lower the biogas production capacity availability as a result of lower biogas yield. This was strengthened by a, possible, low profitability perspective on mono-digestion, especially at smaller-scales as, for example, advocated in cooperative hubs.

Next to the presumed lower production capacity, the direct utilisation of biogas, in the internal process, is stated to hinder the apparent biogas production capacity available for biomethane and or bio-hydrogen production. This is especially apparent in the industrial generation of biogas, primarily, in the food- and beverage industry. This is further strengthened by the, political, valuation of the physical delivery of biogas. Here, the industry places a premium on the physical delivery of biogas to, connected, industrial demand centers.

With respect to the utilisation of biogas it was mentioned that a general shift towards green gas production could be observed. This was, partly, assigned to the, political, valuation of green gas for end applications in the transport industry via associated HBE-credits. Moreover, this related to the vision on greening of the natural gas system and the perspective on the, social, benefits. On top of that, the increased biomethane production is associated with additional flexibility in the usage of green gas versus biogas. Especially, in combination with trends in the biomethane infrastructure, like reverse flow plants, this lowered curtailment issues in biomethane productions that are, primarily, prevalent in the summer months. This can also be seen to be supported by the use of green certificates. In this way, even in periods of higher production and lower demand the production of green gas is still stimulated.

Nevertheless, it was mentioned that the biomethane production capacity lacks the demand for green gas. As a result, the 2bcm alliance advocates for the increase in biomethane production capacity with a factor tenfold to 2 bcm in the Netherlands by 2030. This was based on the presumed low utilisation rate of available manure and the stated commercialisation and professionalisation of the biogas industry. Here, the focus is mentioned to be, primarily, to increase the biomethane gas grid injection, as high as possible. In this respect, and as result of presumed challenges, efforts and investments ahead to increase the green gas production capacity the development of bio-hydrogen capacity was presumed to be limited. On the other hand, the expected demand for biomethane was stated to come- or arrive from the transport-, industrial- and build environment sector.

With respect to transport sector, biomethane was mentioned to find, primarily, end application as bio-LNG in the heavy duty industry, including the maritime industry. This relates to the HBE-scheme support under the translation of the RED, which improved the relative cost perspective of bio-LNG as compared to, especially, HVO. However, the probable production capacity constraints and long-term commitment requirements was mentioned to limit the full-scale deployment of bio-LNG in, primarily, the maritime industry, despite the current lack of available alternatives.

With respect to the industrial sector, the demand for biomethane primarily arises as direct replacement of natural gas as feedstock or source of, high-temperature, heating. This demand was mentioned to mainly arise in relation to the presumed EU ETS costs perspective. However, also the utilisation of biomethane, or biogas, as feedstock was mentioned to become more important to produce, for example, syngas which subsequently can be used to create relevant chemical platform products. This was stated within the context of the sustainable utilisation of resources within the future energy system. In this perspective, it was stated that sustainable molecules would primarily have to be reserved, within the cascading principle, for closing the material cycles.

With respect to the build environment sector, the demand for green gas arise from the greening of the natural gas network. Here, it was mentioned that green gas grid injection was supported by the SDE++ subsidy. Nonetheless, the gas grid injection was stated to be limited due to the alternative utilisation of green gas in the transport sector under the HBE-scheme. Nevertheless, due to the direct replacement of natural gas, the continued utilisation of the natural gas network, the mentioned electrification options in the transport sector, the biomethane production capacity limitations and the alignment with local- and or regional energy strategies it was mentioned that the utilisation of green gas in the build environment could provide the highest societal value.

On the other hand, in tandem with the increased realisation of the need for renewable molecules, biogas has been mentioned to represent both an energetic hydrogen part and a molecular carbon part. In this respect, both parts are stated to represent a different but complementary value. Here, it is expected that the value is, primarily, derived from the material value of the renewable carbon. This can be assigned to the value of $CO_2 - eq$ emission savings within, for example, the EU ETS or via the direct utilization of CO_2 in, for example, the horticulture or as renewable carbon in the industry for the production of, for example, plastics, methanol or alternative fuels. This supports both the need for climate-neutral products and at the same time has the additional benefit of capturing and utilizing carbon dioxide.

However, from this perspective it was mentioned that the direct utilisation of syngas could be more beneficial. In this way, the bio-hydrogen value would be locked into the molecular syngas value. This was further supported by the idea that renewable hydrogen will become a commodity in the future energy system, thereby lowering the inherent value of bio-hydrogen. This would effectively devalue to the production of bio-hydrogen as opposed to e-hydrogen production capacity.

Moreover, the production of bio-hydrogen was presumed to be limited in the short-term. This results from proposed environmental-, economical- and political benefits from the utilisation of biomethane as direct replacement of natural gas. This argument was further supported by the market potential of both biogas and biomethane and the presumed scare, economical, potential of residual waste streams and biogas production capacity. Here, the relative biomethane production costs in relation to natural gas and the relative bio-hydrogen production costs as compared to biomethane or biogas are assumed to further hinder the bio-hydrogen production capacity. This is supported by the lack of inadequate policy support mechanisms for the adoption of bio-hydrogen, for example, via carbon pricing, targets, and or blending quotas.

On top of that, it was stated that the lack of infrastructural development in combination with a natural gas network lock-in further complicated the adoption of bio-hydrogen as opposed to biomethane. This was also related to the presumed transition costs, TCO perspective and process handling complexity. Also, the technology agnostic approach, lack of long-term vision, and, limited system costs- and coordination perspective hinder the adoption of bio-hydrogen. Here, also the social unrest in relation to the adoption of hydrogen as opposed to biomethane was mentioned to limit the overhaul of the current energy system design.

Additionally, the respective regulatory boundary conditions were presumed insufficient to support the adoption of bio-hydrogen production. In this respect, it was mentioned that the focus on short-term benefits and cost-effective $CO_2 - eq$ savings does not support the production of bio-hydrogen. This relates to the lack of long-term system costs benefits and the absence of negative CO_2 emission savings valuation. This is further supported by, present, regulatory financial incentives in relation to the alternative utilisation of biogas and biomethane as opposed to bio-hydrogen and or bio-CO_2. This is strengthened by perverse incentives in the overall economic policy structure that, could, hinder the upgrading of biogas to biomethane from a value chain perspective. On top of that, the lack of a stable- and long-term vision was mentioned to limit the potential for both private- and public investments in bio-hydrogen capacity, as well as other renewable gas capacity. Overall, this was supported by uncertainty regarding the relative $CO_2 - eq$ savings of bio-hydrogen to biomethane in contrast to the relative $CO_2 - eq$ savings of biomethane as opposed to natural gas in light of the need for rapid decarbonisation.

Last, it was mentioned that the perspective on bio-hydrogen production could be limited due to the perspective on the methanation of hydrogen and CO_2 in the reverse process.

Overall, it was stated that despite potential limitations in the economical availability of biogas the continued focus is on the increase of the green gas production capacity in the Netherlands. This related to the increased valuation of biomethane as opposed to biogas and as a result of the low uptake of economical potential of biogas. This is further strengthened by the increased focus on professionalisation and commercialisation of the biogas industry. However, in this respect it was mentioned that the primary focus on biomethane hinders the perspective on bio-hydrogen and bio-carbon dioxide production. In relation, the biomethane was envisioned to, primarily, find market demand in the transport sector under the translation of the RED or in the build environment as low cost alternative to traditional natural gas utilisation. This followed from the utilisation of biogas or biomethane in the industrial sector under the SDE subsidy and or EU ETS scheme. This was supported by the relative, presumed, benefits of biomethane over bio-hydrogen. This related to the, current, market potential, relative costs perspective, traditional natural gas infrastructure design, related transition costs, and the present regulatory framework. This was strengthened by the mentioned focus on the reverse methanation process. Nevertheless, some reference to the inherent valuation of bio-carbon as feedstock in the industrial industry was named as result of the cascading principle. Nonetheless, here the proposal related to the direct utilisation of syngas as opposed to the separate creation of bio-CO_2 and bio-H_2. As a result, this locks the renewable hydrogen value within the proposed syngas output. Ultimately, the relative cost and emission perspective between natural gas, biomethane and bio-hydrogen was termed to support the overall perception on the valorisation potential of the utilisation of biomethane.

In this perspective, the practical interpretation is current perspective on the valorisation potential in hindered by a short-term, traditional, and insufficient system cost perspective. In this respect, the current perspective inadequately incorporates the need for radical transformations in order to ensure a climate-neutral, or negative, zero-pollution energy system in the European Union by 2050. Here, the inherent value of bio-CO_2 is insufficiently valued. This was supported by the interpretation of the short-term market perspective, limited infrastructural boundary conditions and the inadequate regulatory framework. Nevertheless, the perspective on biogas supports the increased economical potential and could, in time, contribute to the higher valorisation potential of the utilisation of bio-carbon.

Thus, the solution space is hindered by the limited perspective on the valorisation potential of biogas. In this respect, inadequate valuation of bio-carbon resulted in the favourable treatment of biomethane utilisation. This was supported by current market structures, including the infrastructural design. As a result, the boundary conditions should be skewed towards the long-term systemic perspective on the need for a future renewable hydrogen system in light of climate-neutrality in the European Union by 2050. In this respect, the perception of increases in, economical, biogas potential could be coupled with the long-term cascading principle related to the value of climate-neutral carbon molecules in the industrial sector. This could be supported by the relative perspective on the costs and benefits of the concept of third-generation upgrading as compared to the concept of second-generation upgrading.

Potential

At first, it was mentioned that the conversion of biogas to bio-hydrogen and bio-carbon dioxide is possible. In this respect, the reforming of biomethane was mentioned to be the currently feasible route. Nonetheless, also the direct conversion of biogas and or alterations in process design were mentioned to list technological potential.

Next, it was stated the production of biogas was seen as an environmental friendly solution to the, primarily, manure waste management problem. Thereby, the bio-fertiliser was seen to contribute additional relevant environmental benefits. However, due to the short-cycled or climate-neutral perspective on bio-CO_2 limited environmental benefits were associated with the upgrading and potential reforming of biogas. In this respect, the additional energy demand was seen to hinder the environmental performance. This was supported by the direct decarbonisation need and potential of biogas and or biomethane. Nonetheless, the latter was assigned additional market value due to the utilisation in fuel applications and through the increased level of flexibility.

In case of the renewable hydrogen production costs it was stated that the feedstock costs are the primary determinant. As a result, the natural gas price, in case of fossil- and lower-carbon hydrogen, the renewable electricity price, in case of e-hydrogen, and the biomethane price, in case of bio-hydrogen, are important, including the relative-, time-dependent, and regional perspective. Moreover, the inherent bio-carbon value is mentioned to become the a relevant determinant over time. On top of that, location-dependent variables includes the ultimate delivery costs perspective, niche market possibilities and or integration options are stated to be important. Additionally, it was mentioned that relative economical perspective will be strictly dependent on the regulatory financial support schemes, which could complicate the interpretation over time and space.

Specifically, in the case of bio-hydrogen production it was mentioned that the ultimate physical $CO_2 - eq$ savings, over time, have to be determined and subsequently compared to alternative routes and use cases to determine the corresponding societal value. Moreover, it was stated to relate to the value of physical bio-CO_2 delivery, which is presumed to become increasingly relevant in light of a electron-dominated energy system. It was mentioned that this could provoke a 'biogenic carbon war'. This was further supported by the competitive utilisation of biogenic carbon, for example for nutrition, and the relative price competition in relation to DAC. In the short term, the demand for, physical, bio-CO_2 is stated to arise from demand in the industrial sector, for example, in case of bio-methanol production, and the horticulture. The latter was stated to arise due to the lack of biogenic CO_2, financial incentives to store fossil carbon, the increased sustainability character of heat generation in the horticulture and the increasing sustainability demands. Nonetheless, it was stated that this is subject to the feasibility of cost-effective separation of bio-CO_2 and the potential CO_2 purity requirements.

Overall, it was mentioned that the conversion of biogas to bio-hydrogen is technological feasible. Nevertheless, due to inadequate valuation of bio-CO_2 the concept of third-generation upgrading was not assigned relevant environmental benefits in relation to the production of biomethane, beyond the potential additional versatility of hydrogen and the physical sales price of bio-CO_2. Nevertheless, the importance of bio-CO_2 over time and space was brought forward in light of the economic valuation. This related to the physical demand for bio-CO_2, especially in light of a electron-dominated energy system. Also, in the short-term this could provide relevant economic value via direct sales to local- and or regional industrial sectors and or the horticulture. This could in the end, next to the feedstock costs and location-dependent costs and sales factors, become a main determinant of the bio-hydrogen delivery costs perspective.

In this perspective, the practical interpretation is limited to the, relative, valuation of physical bio-CO_2. This relates to the misinterpretation of the inherent value of bio-CO_2 with respect to negative CO_2 emissions and zero-pollution fuel. This is further strengthened by the inadequate design of the regulatory support mechanisms.

Thus, the solution space is hindered by the sole perspective on the value of physical bio-CO_2. This is due to the inadequate valuation of negative carbon emissions and zero-pollution fuel in the perspective of climate-neutrality, within the carbon budget, in the European Union by 2050. In this respect, the concept of third-generation upgrading assigns value both the inherent- and physical bio-CO_2 potential.

Boundary conditions

With respect to the production of hydrogen, it was mentioned that at the moment three options exists. This include the, centralised on-site production of hydrogen through the utilisation of the natural gas network. Moreover, another option includes the physical delivery of hydrogen via pipeline or truck transport. Lastly, decentralised on-site production via the physical delivery of methane is mentioned to be possible. Here, the cost benefits of the physical delivery of natural gas, via truck transport, and on-site reforming outweigh the costs of physical transport of hydrogen. It was mentioned that this is a function of distance, pipeline availability and the certification scheme. In this respect, it was mentioned that the establishment of new natural gas pipelines would support the centralised production of hydrogen over decentralised production. However, the lack of pipeline transport of natural gas was stated to result, primarily, from a lack of demand and as such is new pipeline transport presumed to be limited.

With respect to decentral production, the main limitation was mentioned to be associated with the production cost as a result of the apparent economies of scale in methane reforming. Moreover, due to the lack of production sites also the economies of scope were presumed to be limited. On top of that, the decentral production of hydrogen was mentioned to be hindered by area requirement, safety considerations, utilisation rate, process complexity, process inflexibility and uncertain carbon performance. On the other hand, it was stated that decentral hydrogen production could, potentially, benefit from cost savings due to lower- or absent transportation, distribution and or storage costs. Moreover, it was mentioned that on-site hydrogen production could, possibly, save an additional purification step that could be required with hydrogen transport through, re-purposed, pipelines.

In the case of central production or hydrogen pipeline transport, the beneficial production cost perspective were mentioned. Also, it was mentioned that the central production of hydrogen could benefit lower-carbon production due to the process integration option. On the other hand, the presumed fixed price point in central adoption of hydrogen could weaken the economic benefit of renewable hydrogen production. In light of central production, it was mentioned that in case of bio-hydrogen production this was expected to operate via green certificates and traditional natural gas pipeline transport. Here, the adoption of bio-hydrogen was presumed to be supported due to the market allocation of scarce biomethane resources. However, it was mentioned that potential limitations to widespread adoption of bio-hydrogen could arise from the requirement of physical green gas transport and or physical CO_2 savings. Moreover, the central adoption of bio-hydrogen could be hindered by complexity in green certificate trade. On top of that, the presumed natural gas lock-in could hinder the central adoption of bio-hydrogen.

Moreover, it was mentioned that due to the current hydrogen infrastructure limitations the adoption of renewable hydrogen is expected to become effective no earlier than the medium term. In light of global ship transport of hydrogen, this was also related to the potential competitive utilisation of the transport medium like, for example, ammonia. Moreover, in light of national pipeline transport the adoption of renewable hydrogen is presumed to be lowered to the alignment with the repurposing of the natural gas network, which is mentioned to related to the, potential, excess capacity that frees up as a result of lower natural gas transport. On top of that, the regional- and or local distribution networks are mentioned to, mainly, arise in phases as branches of the national transport network.

On top of that, it was stated that the policy support, so far, has been insufficient to support the rollout of a hydrogen network. In this respect, it was mentioned that especially the regulatory support of the infrastructural development is relevant to enhance the confidence of market parties and solve the so-called chicken-and-egg problem. This relates to the availability of additional capacity and the potential buffer solutions, which subsequently is presumed to signal positive market incentives and as a result stimulate public- and private investments. However, in this respect the required alterations in the national 'energiewet' and 'gaswet' in the Netherlands in line with European regulation were mentioned to be a barrier. An additional barrier mentioned is related to the potential blending of hydrogen in the current natural gas infrastructure. This followed the parallel discussion regarding a blend infrastructure, of up to [2-20]% hydrogen, or regarding a fully dedicated hydrogen transport pipelines. This also should align with the wider proposed European infrastructure. On top of that, the proposed hydrogen requirements further hindered the decision regarding the development of a hydrogen network. In this case, it was also mentioned that re-purposed pipelines could, potentially, for years dilute pure hydrogen streams leading to the, possible, need for an additional purification step.

Also, it was mentioned that infrastructural development for alternative energy carriers could hinder and or delay the development of the hydrogen infrastructure. This related, for example, to the development of biomethane injection points and reverse flow plants. This in turn were discussed to lengthen the use of the traditional national gas pipelines. On top of that, it was stated that internationally new natural gas pipelines were established to support the adoption of natural gas, as presumed more sustainable alternative compared to the utilisation of fossil coal.

With respect to the regulatory boundary conditions is was mentioned that these should be derived from the overall European policy development. In this respect, individual nations were stated to only have limited influence on the actual regulatory perspective and framework development.

In case of the regulatory vision it was mentioned that these mainly focus on large-scale electrification flanked by energy efficiency measures. Only recently, the policy vision shifted towards the importance of renewable molecules. Here, the perspective on hydrogen development primarily followed expansion of the lower-carbon and e-hydrogen production. In contrast, the vision on the utilisation of biogenic sources is mainly limited to the direct emission savings within the renewable energy domain. Nevertheless, it was mentioned that some attention is shifted to the vision on the valorisation potential of renewable molecules to support the production of circular- and climate-neutral products and materials. In this perspective, it was mentioned that the renewed perspective on the cascading principle of renewable molecules, from societal welfare point of view, could align the financial value in the marketplace with societal needs in the long run.

Overall, the regulatory vision has been followed from a technology agnostic approach. Nonetheless, it was added that this could have blurred the long-term regulatory vision, which could have negatively impacted both the technology-neutral approach and the deployment of renewable energy capacity. In this respect, the focus on the costs per $CO_2 - eq$ emission saving was stated to, potentially, hinder the overall long-term system optimalisation. In this respect, a focus on CO_2 prices combined with long-term and stable targets was proposed. In similar fashion, it was stated that the focus on the, apparent, costs per $CO_2 - eq$ emission savings could unfavourable support one technology over the other, effectively hinder the technology agnostic approach. Here, the stimulation of CCS technology in the Netherlands was mentioned to lower the potential for subsidy of alternative technological options. This was further complicated due to the lack of adequate distinction between the utilisation of renewable molecules and renewable electrons, especially in the perspective on the future energy system. In this respect, the present regulatory vision was mentioned to hinder the development of renewable molecules due to the inherent differences in input prices, especially, the bottom production price.

On top of that, it was mentioned that the regulatory execution to support the development of hydrogen production capacity in the Netherlands was insufficient. This was, for example, related to the conflicting interest of the presumed market demands for the different end applications of hydrogen. This in turn related to the required financial support, the accommodation of rules and regulations and or the development of new regulations surrounding the hydrogen ecosystem. This was contributed to the regulatory ambiguity of the relative advantages- and disadvantages of the hydrogen use cases. Moreover, this was stated to result from the limited perspective on the potential, short-cycled, CO_2 emissions savings of hydrogen deployment. Overall, it was mentioned to increase the perceived risk and result in public inertia. Nonetheless, in this respect it was mentioned that alteration in regulatory support could learn from previous market alterations like, for example, the gradual rollout of the LNG market.

It was also mentioned that it would be relevant to ensure social support of the proposed production route and as a result for the regulatory perspective. In this respect, it was mentioned that the biogas production industry faces barriers in relation to the overall negative perception on the utilisation of biogenic feedstock for renewable energy capacity. Moreover, it was listed that the biogas industry could be hampered by the negative social perspective that arises from the public perception of mega stables, the association with industrial activities, the potential impact of manure- and or biogas transport movements, highlighted fraud cases, and the negative connotation in relation to the general cattle industry.

Potentially contradictory, it was mentioned that the utilisation of green gas was associated with an overall positive social sentiment. This related to the direct support to lower the CO_2 emissions associated with natural gas utilisation. However, the utilisation of green gas was mentioned to face potential limitations due to possible pitfalls related to greenwashing. In this respect, it was stated that there could be a misalignment in the public perception between green gas production, physical delivery and guarantees of origin. In this perspective, biomethane production capacity could be initiated to green the local- and or regional build environment but ultimately end up in the transport sector. This was further stimulated to the lack of a clear vision on the ultimate end application of biomethane, which was shifted from the perspective on the industrial sector, the transport sector to the build environment.

Lastly, It was mentioned that due to the relevance for the interpretation of the boundary conditions over time and place, generalisation would be hindered. This relates, for example, to the international dimension of business operations and sales. Moreover, it was mentioned that this relates to the relative production capacities and potentials. On top of that, the regulatory ideology and, potential, gap between ambitions and current status is expected to be relevant. On top of that, the infrastructural boundary conditions are mentioned to differ over locations. This includes, for example, the technical hydrogen storage options and current transport network. In this perspective, it was mentioned that a limited natural gas network and market could result in rapid saturation of the green gas demand and subsequently open the perspective on bio-hydrogen production. Lastly, it was mentioned that this relates to the overall perspective on electrification of the energy system, and related, e-hydrogen production capacity.

Overall, it was stated that the practical interpretation is based on the production-, infrastructure- and regulatory options. This was supported by the different advantages and disadvantages of hydrogen production methods. More broadly, it was stated that a lack of infrastructural development could hamper the deployment of hydrogen. In this respect, the need for regulatory- and infrastructural support was connected. In general, it was mentioned that the regulatory support was derived from the European regulatory vision, including the nation-specific translation. Here, the technology agnostic approach was discussed to, potentially, hinder the required long-term vision on climate-neutrality in the European Union by 2050. Moreover, the lack of long-term vision hindered the perspective on the role of hydrogen within the future renewable energy system. On top of that, social support was mentioned as relevant determinant of both the practical interpretation and the potential infrastructural- and regulatory support. Lastly, as a result of the importance of the regulatory- and infrastructural boundary conditions it was stated to limit the generalisation over time and space.

In this perspective, the solution space should clearly define and argue the respective boundary conditions over time and space. This includes the relative applicability of the proposed concept of third-generation upgrading within the elements of the research scope. This includes, for example, the potential role of the concept of third-generation upgrading for the production of decentral bio-hydrogen and bio-carbon dioxide. This could thereby support the overhaul of the current national gas network and or not be limited by the natural gas lock-in. Moreover, this includes the redefinition of the role of biogas over time and space within the wider European regulatory context. Thereby, the regulatory interpretation could be altered to support the concept of third-generation upgrading within the perspective of the future renewable hydrogen system.

Thus, due to the importance of the respective boundary conditions the solution space for the adoption of the concept of third-generation upgrading should be clearly defined over time and space. This relates to the renewed perspective on biogas as source of local- and or regional bio-hydrogen and bio-carbon dioxide within the proposed future renewable hydrogen system. In this way, the solution space helps to change the way biogas is seen.

To conclude, as a result of the dramatic effects of human-induced climate change and the subsequent need for a climate-neutral energy system in the European Union by 2050, a future renewable hydrogen energy system is proposed. In this perspective, renewable hydrogen serves as an energy commodity for the cost-effective transport of renewable electricity over time and space. Moreover, renewable hydrogen will support the balancing of the power sector, green processes, products and materials, and decarbonise hard-to-abate sectors. Within this perspective, biogas has been attributed the highest valorisation potential as local- and or regional source of bio-hydrogen and bio-carbon dioxide, effectively decoupling the renewable hydrogen and renewable bio-carbon dioxide constituents over time and space. In this respect, it was indicated that the proposed concept of third-generation upgrading shows relevant technological-, environmental- and economical benefits both in absolute- and relative terms as compared to competitive hydrogen production methods and the alternative utilisation of biogas. In this respect, a renewed infrastructural design and regulatory context was proposed to change the way biogas is seen.

However, it was mentioned that the interpretation of the relevant boundary conditions is limited by the practical feasibility. In this respect, it was mentioned that, at the moment, the perspective on the future proposed renewable hydrogen system is insufficiently internalised. This resulted from the focus on electrification, the continued reliance on the traditional energy system, the lack of adequate carbon pricing and the inaccurate perspective on available alternatives. This was attributed to a short-sighted, gradual and partial perspective on the role of renewable molecules, specifically renewable hydrogen and biogenic carbon, in light of the need for a climate-neutral energy system in the European Union by 2050. As a result, the practical feasibility of the concept of third-generation upgrading is hindered by the lack of a long-term, coherent- and stable perspective on the role of renewable hydrogen and the valuation of biogenic carbon over time and space. This resulted in the absence of the required infrastructural- and regulatory boundary conditions to support the concept of third-generation upgrading.

As a result, a prescriptive roadmap for the development of the relevant boundary conditions for the concept of third-generation upgrading over time and space is proposed. This is in line with the overall cascading principle in light of the proposed future renewable hydrogen system and is based on the relative, social, costs and benefits of the concept of third-generation upgrading. This relates to the relative valuation of zero-pollution renewable hydrogen and climate-neutral carbon dioxide. In this way, the proposed solution alters the way biogas is practically seen.

Chapter 14

Roadmap

The European Union envisions to become climate-neutral by 2050. In this respect, the European Union translates the Paris Climate Agreement, which underwrites to limit the increase in the average global temperature to 1.5 °C as opposed to 1990. Here, renewable molecules are next to large-scale electrification and circular utilisation of materials a key pillar in the strategy. In this light, a future renewable hydrogen energy system is proposed. In the future energy system, renewable hydrogen will act as a cost-effective energy carrier to transport cheap renewable electricity over time and space. Moreover, renewable hydrogen allows for the balancing of the power sector, is able to decarbonise hard-to-abate sectors and could green processes, products and materials. In this perspective, the future renewable hydrogen system will resemble- and overhaul the current natural gas energy system.

In the future renewable hydrogen system, biogenic resources are assigned important relevance for the local- and or regional production of bio-hydrogen and bio-carbon dioxide. In this case, biogenic resources are not only able to provide additional volume of valuable renewable hydrogen but are also able to provide an indispensable source of climate-neutral carbon. In this respect, biogenic resources are able to operate as a negative carbon sink effectively lowering the atmospheric carbon budget and closing carbon cycles. More importantly, biogenic resources would be able to act as source of renewable carbon, which is presumed to become essential in an electron-dominated future energy system, for the production of climate-neutral products and materials.

In this perspective, the concept of third-generation upgrading is proposed as radical transformation of the way biogas is seen. Here, biogas is attributed the highest valorisation potential as local- and or regional source of bio-hydrogen and bio-carbon dioxide. This follows from the initial perspective on biogas as source of renewable electricity- and or heat generation, the later perspective on biogas as source of biomethane for direct replacement of natural gas in the industrial-, transport- and build environment sector, and most recently as source of both biomethane and bio-CO_2. In contrast to the later concept of second-generation upgrading the renewed perspective on biogas envisions biogas to operate as a platform molecule consisting of zero-pollution renewable hydrogen and climate-neutral carbon. In this way, biogas could effectively couple the hydrogen- and bio-economy domain. Here, the valorisation potential of biogas is ultimately ascribed as a function over time and space where biogas is initially seen as source of bio-hydrogen, secondly as source of both bio-hydrogen and bio-carbon dioxide and ultimately as source of bio-carbon.

Thereby, biogas is seen as enabler for a rapid-, affordable- and secure transition towards the future proposed renewable hydrogen system. Ultimately, this changes the way biogas is seen.

In this respect, it has been shown that biogas could constitute a relevant source of hydrogen production. Here, it was indicated that bio-hydrogen shows important environmental benefits as compared to fossil- and lower-carbon hydrogen. Moreover, it was shown that bio-hydrogen shows relevant technological benefits as compared to other sources of biogenic-hydrogen production. Additionally, bio-hydrogen shows important economical benefits as compared to e-hydrogen production, especially in the short- to medium-term. As a result, bio-hydrogen could prove to be- and or become a competitive source of hydrogen production, specifically for local- and or regional hydrogen production. On top of that, it was indicated that the concept of third-generation upgrading shows relevant benefits as compared to the traditional view on biogas in the perspective of the future renewable hydrogen system. This is supported by the renewed perspective on the, social, value of bio-CO_2 utilisation. This was further strengthened by the apparent devaluation of biomethane as compared to bio-hydrogen in light of the proposed future renewable hydrogen system.

Thereby, it was indicated that the conversion of biogas to bio-hydrogen and bio-carbon dioxide is technological possible. Here, the technological BATR layout was assigned additional relevance as compared to the traditional stream reforming of biomethane in light of production scale, flexibility and ultimately costs. Thereby, it was shown that the process yield indicates the relevance for bio-hydrogen and bio-carbon dioxide production with a yield of around 0.1 kg H_2/Nm^3 biogas and 1.4 kg CO_2/Nm^3 biogas. This was further supported by the factor three increase in bio-CO_2 yield as compared to the concept of second-generation upgrading. In this respect, the concept of third-generation upgrading allows for a yield of 35 kg CO_2/t manure. On top of that, additional benefits included the production of bio-fertiliser, with additional potential for carbon storage, the avoidance of contaminants emissions, the reduction of methane leakage and the support of problematic waste management. Hereafter, it was indicated that the concept of third-generation, support by scaling and professionalisation of the industry, could yield a bio-hydrogen production costs of around [2.0-3.3] €/kg H_2. This excluded potential additional costs of [0.5-1.5] €/kg H_2 and [30-65] €/t CO_2 for the, possible, conversion, transportation, reconversion and or storage. Overall, it was indicated that the concept of third-generation upgrading shows a positive business case at a bio-hydrogen price of [3.10-3.20] €/kg H_2 based on a carbon value of 80 €/t CO_2 or 3.60 €/kg H_2 at a carbon price of [40-50] €/t CO_2. This was further supported by the positive economic valuation of the concept of third-generation upgrading as opposed to the concept of second-generation upgrading at an inherent bio-CO_2 value of [140-180] €/t CO_2.

Therefore, to support the concept of third-generation upgrading in light of the future proposed renewable hydrogen system a renewed infrastructure design was proposed to stimulate the place dimension. In this light, the proposed future energy infrastructure should enable the coupling of biogas production potential, with bio-hydrogen production capacity and ultimately end demand centers, for bio-hydrogen, bio-CO_2 and or syngas. In this way, the concept of third-generation upgrading could become cost competitive with competitive hydrogen production capacity and would devalue alternative usage of biogas. In combination, to support the overall feasibility of the concept of third-generation upgrading over time, a renewed policy framework is proposed. In this respect, the capture- and utilisation of CO_2 is revalued as well as the perspective on bio-hydrogen as zero-pollution fuel. In this perspective, it was indicated that favourable policy support mechanism could support the economic valuation of the concept of third-generation upgrading by [2028-2030]. Moreover, this showed the relevance of the cascading principle of biogas as source of bio-carbon by [2034-2042].

Nonetheless, it was discussed that the theoretical application was limited by the practical interpretation. This was assigned to the inadequate internalisation of the proposed future renewable hydrogen system. This subsequently resulted in a short-sighted, gradual and partial perspective on the role of renewable molecules in light of a climate-neutral energy system in the European Union by 2050. In this light, the current infrastructural- and regulatory boundary conditions are insufficient to support the concept of third-generation upgrading.

As a result, a prescriptive roadmap is brought forward to unlock the time and space potential of the concept of third-generation upgrading within the proposed future renewable hydrogen system. This roadmap aligns with the proposed phases in regulatory development in the European Union and focuses on the key parameters highlighted, including the technological-, environmental- and economical potential as well as the infrastructural- and regulatory boundary conditions. In this way, the proposed roadmap alters the way biogas can practically be seen.

In figure 14.1 the proposed roadmap for the support of the concept of third-generation in light of the proposed future renewable hydrogen system can be seen. Moreover, table 14.1 list the highlighted areas of the roadmap.

In this respect, the roadmap follows the proposed regulatory flexibility as outlined in the renewable energy strategies within the European Union. Here, initially the focus is on the validation, development and execution of the concept of third-generation upgrading. This includes continued development of key technological areas and the development of the initial boundary conditions to support the development of the concept of third-generation in later phases.

Hereafter, initial development and implementation of the respective boundary conditions are mentioned to evolve. This overlaps with the proposed infrastructural overhaul of the traditional natural gas system. In this respect, the infrastructural overhaul is supported by supportive regulatory policy and positive investment decisions. Therefore, the medium-term allows for the improved valuation of the concept of third-generation upgrading in light of the proposed future renewable hydrogen system. This includes the devaluation of biomethane through re-purposing of the traditional natural gas network and redesign of the political framework. Moreover, both the value of captured CO_2 and utilised CO_2 will be adequately valued to further outline the benefits of the concept of third-generation upgrading.

Ultimately, this is followed by long-term and fixed targets in line with the perspective on climate-neutrality, the allowable carbon budget and the future proposed renewable hydrogen energy system to ensure the goals of the Paris Climate Agreement are met. Moreover, it ensures that the concept of third-generation upgrading is accurately valued as relevant source of bio-hydrogen and bio-carbon dioxide over time and place. Thereby, this aligns with the presumed economic valuation of the concept of third-generation upgrading over time, with the increased focus on the valuation and utilisation of bio-CO_2.

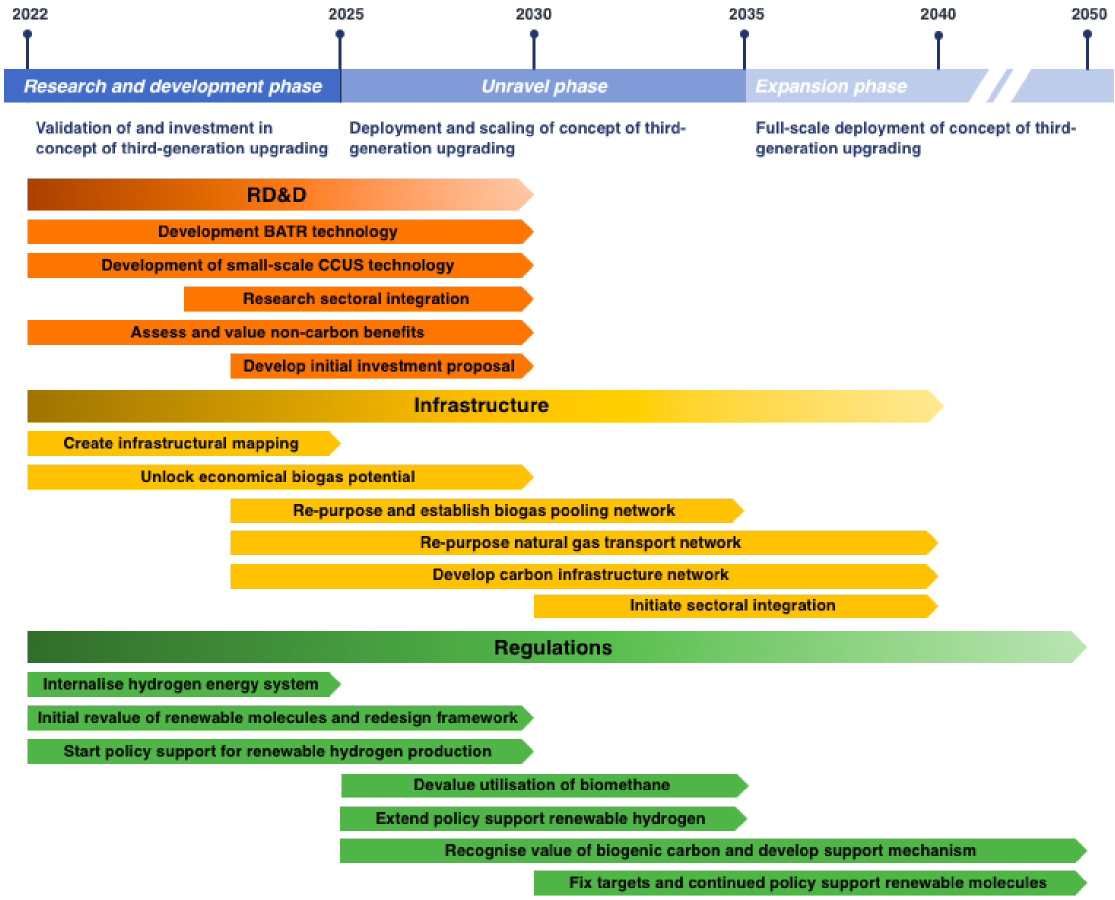


Figure 14.1: Roadmap to support the concept of third-generation upgrading

Theme	Area	Description
RD&D	Development of BATR technology	Continued research is required to adopt the proposed BATR layout, including variable feedstock input, catalyst development and process integration
	Development of small-scale CCUS technology	Continued research is required to support the adoption of CCUS technology, also, at smaller-scale including high system capture feasibility and potential
	Research sectoral integration	More research could be devoted to the actual integration of renewable energy sources, including renewable electricity capacity, e-hydrogen production and bio-hydrogen production
	Assess and value non-carbon benefits	The concept of third-generation upgrading provides relevant non-carbon environmental benefits that could be more accurately assessed and valued

	Develop initial investment proposal	Continue to develop and update business cases to support investments in local- and or regional bio-hydrogen- and bio-carbon dioxide production capacity
Infrastructure	Create infrastructural mapping	Develop infrastructural map in line with the proposed conditions, including the integration of biogas potential, bio-hydrogen production and end demand
	Unlock economical biogas potential	Continue to support the professionalisation and commercialisation of the industry as well as the continued focus on enlarging the economical biogas availability
	Re-purpose and establish biogas pooling network	Support the re-purposing of natural gas pipelines in line with the proposed infrastructural map to optimise system costs
	Re-purpose natural gas transport network	Support the overall system overhaul for the local- and or regional distribution pipelines in line with the proposed transport network redesign
	Develop carbon infrastructure network	Support the physical valuation and feasibility of bio-CO_2 utilisation through the establishment of the correct infrastructural conditions
	Initiate sectoral integration	Support sectoral integration of local- and or regional e-hydrogen production, renewable electricity production and bio-hydrogen production
Regulations	Internalise hydrogen energy system	Ensure support for the need of the proposed future renewable hydrogen system within the regulatory context
	Initial revalue of renewable molecules and redesign framework	In line with the proposed hydrogen system start to develop an initial perspective on regulatory support schemes in line with, social, welfare theory
	Start policy support for renewable hydrogen production	Offer, at least, similar support to the production of renewable hydrogen as other renewable energy production methods, including biomethane
	Devalue utilisation of biomethane	Alter governmental support schemes in line with the renewed perspective on the valorisation potential of biogas and the internalisation of the proposed renewable hydrogen system
	Extend policy support renewable hydrogen	Continue to support renewable hydrogen production to ensure a transformation to proposed renewable hydrogen system away from polluting energy sources

	Recognise value of biogenic carbon and develop support mechanism	Actively support the valuation of carbon through both pricing support of captured CO_2 and financial support for the physical sales of bio-CO_2 including targets for non-polluting fuel usage
	Fix targets and continued policy support renewable molecules	Ensure adequate conditions to limit risk, boost the required production capacity and ensure climate-neutrality by 2050.

Table 14.1: Themes, areas and description of the proposed roadmap

To conclude, the concept of third-generation upgrading has been ascribed technological, environmental and economical potential within the wider perspective on the future renewable hydrogen system. Here, biogas is seen as an important source of both bio-hydrogen and bio-carbon dioxide. Moreover, this includes the dynamic perspective on the valorisation potential of biogas with increasing focus on the utilisation of bio-carbon in light of a climate-neutral and or electron-dominated energy system. Nevertheless, it was mentioned that the practical application is hindered by the current traditional perspective on the energy system. This is dominated by a gradual, short-term and single-domain perspective on the required transformation in light of climate-neutrality in the European Union by 2050. As a result, the concept of third-generation is inadequately valued and supported, especially in relation to the infrastructural- and regulatory boundary conditions. Therefore, a prescriptive roadmap is proposed to support the development, deployment and scaling of the concept of third-generation upgrading within the wider proposed renewable hydrogen system.

In this respect, the proposed roadmap initially focuses on the validation and development of the concept of third-generation upgrading. This is flanked by preliminary proposals and alterations in the design of the infrastructural- and regulatory boundary conditions. This is subsequently strengthened to allow for further development of the concept of third-generation upgrading. This includes the devaluation of biomethane as opposed to bio-hydrogen and the adequate valuation of both captured- and utilised bio-CO_2. This also includes the re-purposing of the natural gas network to support the transport of bio-hydrogen, bio-CO_2 and biogas and aligns with the commercialisation and professionalisation of the industry. Ultimately, a complete overhaul of both the infrastructural- and regulatory boundary conditions are proposed in the medium- to long-term. This is supported by high-level of sectoral integration, continued recognition of the value of bio-CO_2 in the future energy system, the development of fixed targets in line with climate-neutrality by 2050 and ultimately continued- and adequate support for the deployment of renewable molecules.

In this way, the role of biogas is rewritten.

Chapter 15

Conclusion

In light of the dramatic effects of human-induced climate change and the need for a climate-neutral energy system in the European Union by 2050 a radical transformation of the energy system is required. In the proposed future renewable hydrogen energy system, renewable hydrogen will be the energy vector that allows for the cost-effective transport of cheap renewable electricity over time and space. Moreover, renewable hydrogen will allow for the balancing of the power sector, decarbonise hard-to-abate sectors and green processes, products and materials. Within the proposed future renewable hydrogen energy system, biogas has been ascribed relevant potential as local- and or regional source of bio-hydrogen and bio-carbon dioxide. As a result, the way biogas is seen should be radically changed.

In this perspective, the research aimed to renew the role of biogas as energy molecule towards a platform molecule that is possible of coupling the hydrogen- and bio-economy. Here, the concept of third-generation upgrading is proposed as higher valorisation potential for the utilisation of biogas. This includes a dual, time- and place- dependent perspective on to the role of biogas as source of bio-hydrogen and bio-carbon dioxide, or syngas, within the wider proposed renewable hydrogen system. In this way, the concept of third-generation upgrading is seen to provide additional local- and or regional zero-pollution hydrogen capacity and constitute an indispensable source of climate-neutral, or negative, bio-carbon, which is presumed to become increasingly valuable in light of a fossil-free, electron-dependent energy system.

As a result, the research aimed to answer the following research question:

What is the technological, environmental and economical potential of biogas as source of bio-hydrogen and bio-carbon dioxide within the transition to a renewable hydrogen energy system?

In line with the proposed hypothesis, it was indicated that biogas shows important technological, environmental and economical potential as source of bio-hydrogen and bio-carbon dioxide within the wider proposed renewable hydrogen energy system.

First of all, it was indicated that bio-hydrogen shows important environmental benefits, as compared to fossil- and lower-carbon hydrogen, economical benefits, as compared to e-hydrogen, and technological benefits, as compared to alternative biogenic hydrogen production. Moreover, it was indicated that the concept of third-generation upgrading shows important benefits over the traditional utilisation of biogas from a cascading principle. Overall, it was indicated that bio-hydrogen shows relevance as compared to competitive hydrogen production and alternative biogas utilisation.

Hereafter, it was shown that the conversion of biogas to bio-hydrogen and bio-carbon dioxide is technological feasible. Here, it was indicated that an ATR-related technological layout, especially BATR, shows important relevance from a process scale, process flexibility and system cost perspective. Moreover, it was indicated that this could yield a bio-hydrogen stream of over 0.1 kg H_2/Nm^3 biogas and a total bio-carbon dioxide stream of 1.4 kg CO_2/Nm^3 biogas. On top of that it was shown that the concept of third-generation upgrading could result in a threefold increase in the bio-CO_2 yield as compared to the concept of second-generation upgrading. In this perspective, a bio-CO_2 yield of 35 kg bio-CO_2/t manure could be obtained. Then based on the respective technological design and process layout a bio-hydrogen production cost of [2.0-3.3] €/kg H_2 was shown based on a carbon price of 80 €/t CO_2. Moreover, it was indicated that a positive business case could be obtained at a bio-hydrogen price of [3.10-3.20] €/kg H_2 based on a carbon value of 80 €/t CO_2 or 3.60 €/kg H_2 at a carbon price of [40-50] €/t CO_2. However, this excluded the, potential, additional costs of [0.5-1.5] €/kg H_2 and [30-65] €/t CO_2 for the, possible, conversion, transportation, reconversion and or storage. The concept of third-generation upgrading was further supported by the positive economic valuation as opposed to the concept of second-generation upgrading at an inherent bio-CO2 value of [140-180] €/t CO_2. On top of that, it was shown an inherent carbon price of around [200-330] €/t CO_2 was, by itself, sufficient to support the production of syngas over the concept of second-generation upgrading.

As a result, it could be concluded that biogas has untapped potential to operate as a platform molecule within the renewable hydrogen energy system for both energetic bio-hydrogen and molecular bio-carbon dioxide. Here, it was shown that the technological conversion is possible, the utilisation of carbon dioxide result in negative carbon emissions, the utilisation of hydrogen supports zero-pollution emissions, and the concept of third-generation upgrading shows positive economic results.

Nevertheless, it was indicated that practical interpretation of the theoretical potential of the concept of third-generation upgrading within the wider perspective on the future renewable hydrogen energy system is hindered. This relates to the current infrastructural- and regulatory boundary conditions. As a result, the research aimed to answer the following related research question:

Which boundary conditions will make the upgrading of biogas to bio-hydrogen and bio-carbon dioxide profitable, over time, within the European context?

Following the research hypothesis, it was proposed that the concept of third-generation upgrading follows a dual, time- and place-dependent perspective on the valorisation potential of biogas.

In this line, a renewed perspective on the infrastructural design was proposed that would effectively lower the apparent production- and delivery costs to improve the cost-effectiveness of bio-hydrogen as compared to competitive hydrogen production capacity. Moreover, the proposed infrastructural design focused on the devaluation of alternative usage of biogas through the re-purposing of the traditional natural gas network. Overall, this resulted in a proposal to optimise the infrastructural design from a system costs perspective through integration of the biogas production potential, bio-hydrogen production capacity and ultimate end demand for bio-hydrogen and bio-carbon dioxide, or syngas. Thereby, the infrastructural design could support the cost-effective application of bio-hydrogen and bio-carbon dioxide, or syngas in local- and or regional, industrial, applications. On top of that, the proposed infrastructural design is ascribed additional benefits in relation to a rapid, cost-effective, and secure transition towards the proposed renewable hydrogen system.

Moreover, a renewed policy support scheme was described to support the concept of third-generation upgrading in light of the proposed renewable hydrogen system. Here, the renewed policy scheme relied on the current dominant policy schemes and focused on the adequate valuation of both captured- and utilised bio-CO_2. Moreover, it supported the valuation of zero-pollution fuel. In this respect, it was shown that the concept of third-generation upgrading shows a positive economic investment decision by [2028-2030] as compared to the traditional view on biogas utilisation. On top of that, it was highlighted that the increased valuation of bio-carbon dioxide opens the time perspective on the valorisation potential of biogas. This becomes especially relevant by [2034-2042] as bio-CO_2 represent over half of the sales value of the concept of third-generation upgrading. Overall, it was stated that the net social costs would contribute to around 1.20 €/kg H_2 and is primarily related to the valuation of bio-carbon dioxide at a price of 200 €/t CO_2.

Lastly, to support the overall redesign of the required boundary conditions for the profitability of the concept of third-generation upgrading over time and place, a prescriptive roadmap was proposed. Here, in line with the proposed phases in regulatory development in the European Union it was stated that initially the concept of third-generation upgrading should be further supported through research, development and demonstration. In the subsequent phase, the concept of third-generation upgrading could be further developed and scaled as a result of supportive infrastructural development and adequate regulatory support schemes. Ultimately, this allows for the widespread local- and or regional deployment of the concept of third-generation upgrading.

As a result, the renewed perspective on the infrastructural design includes the coupling of biogas production potential, with bio-hydrogen production capacity and ultimate end demand to support the concept of third-generation over competitive hydrogen production and alternative biogas utilisation. This is supported by the focus on high-level on-site and or local integration options, or regional coupling to lower the overall system costs. Here, extra focus is placed on the re-purposing of the current natural gas network to support a rapid, cost-effective and secure energy transition. On top of that, the renewed perspective on the regulatory design relates to the relative valuation of the concept of third-generation upgrading to support the dynamic valorisation of biogas to bio-H_2 and bio-CO_2 and ultimately bio-carbon.

To conclude, the concept of third-generation upgrading shows important technological, environmental and economical potential within the proposed future renewable hydrogen energy system. This is supported by redefinition of the infrastructural- and regulatory boundary conditions to facilitate the profitability of the concept of third-generation upgrading over competitive hydrogen production and alternative usage of biogas. In this light, a roadmap is prescribed to support further development.

Ultimately, this should change the way biogas is seen.

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